

ASME PTC 34-2017
(Revision of ASME PTC 34-2007)

Waste Combustors With Energy Recovery

Performance Test Codes

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AN AMERICAN NATIONAL STANDARD



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Mechanical Engineers**

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**The American Society of
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Two Park Avenue • New York, NY • 10016 USA

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NOTICE

All Performance Test Codes must adhere to the requirements of ASME PTC 1, General Instructions. The following information is based on that document and is included here for emphasis and for the convenience of the user of the Code. It is expected that the Code user is fully cognizant of Sections 1 and 3 of ASME PTC 1 and has read them prior to applying this Code.

ASME Performance Test Codes provide test procedures that yield results of the highest level of accuracy consistent with the best engineering knowledge and practice currently available. They were developed by balanced committees representing all concerned interests and specify procedures, instrumentation, equipment-operating requirements, calculation methods, and uncertainty analysis.

When tests are run in accordance with a Code, the test results themselves, without adjustment for uncertainty, yield the best available indication of the actual performance of the tested equipment. ASME Performance Test Codes do not specify means to compare those results to contractual guarantees. Therefore, it is recommended that before starting the test, and preferably before signing the contract, the parties to a commercial test agree on the method to be used for comparing the test results to the contractual guarantees. It is beyond the scope of any Code to determine or interpret how such comparisons shall be made.

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FOREWORD

In 1966, the ASME Performance Test Code Committee recognized the need for a Performance Test Code for Large Incinerators. A Committee was formed in 1967 and charged with the task of developing a comprehensive Test Code for Large Incinerators, a task to be followed by a Short Form Test Procedure. This Committee was officially designated as PTC Committee 33 Large Incinerators. At the time of its issue, PTC 33 represented the highest state of the art in incinerator testing. It was submitted to industry for trial use and comment in 1977. PTC 33 was approved by the Performance Test Codes Supervisory Committee on June 30, 1978, and was approved as an American National Standard by the American National Standards Institute (ANSI) Board of Standards Review on December 6, 1978.

PTC 34 was formed in 1988 as a follow-up to PTC 33. PTC 33 was essentially a procedure for determining combustion efficiency and waste capacity and did not address units with energy recovery. At that time, it was recognized that the procedures for sampling tons of a heterogeneous material were unrealistic and impractical as a key element of a waste combustion performance test. At the urging of the ASME Research Committee on Industrial and Municipal Waste, the U.S. Bureau of Standards [now the National Institute of Standards and Technology (NIST)] developed, over a period of about 10 years, a larger calorimeter but concluded that the larger one was not much better than the smaller one because of the sampling dilemma. This provided the incentive to pursue the boiler-as-a-calorimeter method covered by this test Code.

The 2007 edition of the Code was approved by the PTC 34 Committee on January 9, 2007, and by the Performance Test Codes Standards Committee on January 9, 2007. It was then approved and adopted by the Council as a Standard practice of the Society by action of the Board on Standardization and Testing on February 20, 2007. It was approved by ANSI as an American National Standard on April 12, 2007.

This update of PTC 34 does not include any significant philosophical or computational changes. It is more a clarification (i.e., we fixed typographical errors) of previously established procedures, and we added clarity and detail to aid the user in the determination of test uncertainty. It was approved by ANSI as an American National Standard on January 6, 2017.

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General. ASME Codes are developed and maintained with the intent to represent the consensus of concerned interests. As such, users of this Code may interact with the Committee by requesting interpretations, proposing revisions or a case, and attending Committee meetings. Correspondence should be addressed to:

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Proposing Revisions. Revisions are made periodically to the Code to incorporate changes that appear necessary or desirable, as demonstrated by the experience gained from the application of the Code. Approved revisions will be published periodically.

The Committee welcomes proposals for revisions to this Code. Such proposals should be as specific as possible, citing the paragraph number(s), the proposed wording, and a detailed description of the reasons for the proposal, including any pertinent documentation.

Proposing a Case. Cases may be issued to provide alternative rules when justified, to permit early implementation of an approved revision when the need is urgent, or to provide rules not covered by existing provisions. Cases are effective immediately upon ASME approval and shall be posted on the ASME Committee Web page.

Requests for Cases shall provide a Statement of Need and Background Information. The request should identify the Code and the paragraph, figure, or table number(s), and be written as a Question and Reply in the same format as existing Cases. Requests for Cases should also indicate the applicable edition(s) of the Code to which the proposed Case applies.

Interpretations. Upon request, the PTC Standards Committee will render an interpretation of any requirement of the Code. Interpretations can only be rendered in response to a written request sent to the Secretary of the PTC Standards Committee.

Requests for interpretation should preferably be submitted through the online Interpretation Submittal Form. The form is accessible at <http://go.asme.org/InterpretationRequest>. Upon submittal of the form, the Inquirer will receive an automatic e-mail confirming receipt.

If the Inquirer is unable to use the online form, he/she may mail the request to the Secretary of the PTC Standards Committee at the above address. The request for an interpretation should be clear and unambiguous. It is further recommended that the Inquirer submit his/her request in the following format:

Subject:	Cite the applicable paragraph number(s) and the topic of the inquiry in one or two words.
Edition:	Cite the applicable edition of the Code for which the interpretation is being requested.
Question:	Phrase the question as a request for an interpretation of a specific requirement suitable for general understanding and use, not as a request for an approval of a proprietary design or situation. Please provide a condensed and precise question, composed in such a way that a "yes" or "no" reply is acceptable.
Proposed Reply(ies):	Provide a proposed reply(ies) in the form of "Yes" or "No," with explanation as needed. If entering replies to more than one question, please number the questions and replies.
Background Information:	Provide the Committee with any background information that will assist the Committee in understanding the inquiry. The Inquirer may also include any plans or drawings that are necessary to explain the question; however, they should not contain proprietary names or information.

Requests that are not in the format described above may be rewritten in the appropriate format by the Committee prior to being answered, which may inadvertently change the intent of the original request.

ASME procedures provide for reconsideration of any interpretation when or if additional information that might affect an interpretation is available. Further, persons aggrieved by an interpretation may appeal to the cognizant ASME Committee or Subcommittee. ASME does not “approve,” “certify,” “rate,” or “endorse” any item, construction, proprietary device, or activity.

Attending Committee Meetings. The PTC Standards Committee regularly holds meetings and/or telephone conferences that are open to the public. Persons wishing to attend any meeting and/or telephone conference should contact the Secretary of the PTC Standards Committee. Future Committee meeting dates and locations can be found on the Committee Page at go.asme.org/PTCcommittee.

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INTRODUCTION

This Code contains instructions for testing waste fuel combustion systems with energy recovery. These facilities are defined as combinations of apparatus for consuming the organic content of waste by releasing its chemical energy. For the purpose of this Code, performance will be a measurement of the available heat energy released during the process. The recovery of useful energy in the form of steam is considered to be the measure of performance in this Code. It is not the intent of these testing procedures to obtain data on specific components of the system or to establish design criteria for these components or the process. Testing of individual components such as fans shall be conducted in accordance with their respective test Codes. See ASME PTC 11.

It is intended that in using this Code a detailed examination will be made of the Code of General Instructions, ASME PTC 1, and all other Codes herein referenced before starting preparations for the tests. Such study is for the purpose of ensuring an orderly and thorough testing procedure since it provides the user with an overall understanding of the ASME Performance Test Code requirements and enables the tester to understand readily the interrelationship of the various Codes. Care should be exercised to obtain and use the latest revision of the Codes.

Subsection 5-20 of this Code is concerned with symbols and their description, relating specifically to testing of waste combustion systems. This Code has departed from the use of symbols used in earlier Codes in an attempt to make the symbols compatible with current word processors, personal computer spreadsheets, and computer code. Hence a symbol set was adopted that does not use superscripts, subscripts, hyphens, or Greek letters.

The ASME Supplements on Instruments and Apparatus PTC 19 series referenced herein should be

studied thoroughly, because the value of the test results depends on the selection and application of the instruments, their calibration, and the accuracy of the readings.

Other items of vital importance to the value of the test are the proper determination of the characteristics of the effluent gas and water streams. The appropriate procedures for test and analysis as listed herein should be followed carefully.

This Code is intended as a test guide for all waste combustor systems with energy recovery, but it could not possibly detail a test applicable to every variation in the design of waste combustion systems. In every case, a competent engineer must study the particular facility and develop test procedures that are in agreement with the intent, guiding principles, and required accuracy of this Code. Examples of the system variations at the time of preparation of this Code include rotary kilns, refractory and waterwall furnaces, rotary combustors, mechanical grates, semi-suspension and suspension burning, multiple-chamber solid hearth units, and two-stage combustion systems. Such systems were considered as the Code was being prepared.

Portions of this Code may be used for waste combustors without energy recovery in the area of unburned combustibles in residue.

For systems fired either by waste or by waste in combination with other fuels in which heat recovery is a major portion of the heat output, ASME PTC 4 may be used, along with appropriate sections of this Code. The user is cautioned to note the difference between capacity and efficiency as defined in ASME PTC 4 and ASME PTC 34.

Advanced instrument systems such as those using electronic devices or mass flow techniques may, by mutual agreement, be used as alternatives to the specified Code instruments, provided that applications of such instruments have been demonstrated to be no less accurate than required by the Code.

WASTE COMBUSTORS WITH ENERGY RECOVERY

Section 1 Object and Scope

1-1 OBJECT

1-1.1 Introduction

The object of this Code is to provide a test procedure for evaluating the performance of waste fuel combustors with energy recovery using the boiler as a calorimeter. These procedures apply when the variability and waste fuel composition result in a lack of confidence in obtaining representative samples for laboratory analysis.

This Code is used to determine

- (a) the thermal efficiency of systems combusting waste fuels
- (b) the thermal capacity (heat input per unit time) of systems combusting waste fuels
- (c) the higher heating value (HHV) of waste fuels

1-1.2 Other Applications

A determination of the items specified in subsection 1-1.1 may be used for other purposes such as

- (a) comparing the actual performance with guaranteed performance
- (b) determining performance of system components
- (c) evaluating performance when firing any fuel
- (d) determining the optimal method of operation

1-2 SCOPE

The rules and instructions given in this Code apply to all waste combustor systems with energy recovery, but the Code cannot detail a test applicable to every variation in the design of waste combustor systems. In every case, a qualified engineer must study the particular facility and develop a test procedure that is in agreement with the intent, guiding principles, and required accuracy of this Code. Examples of systems considered at the time of preparation of this Code include rotary kilns, refractory and waterwall furnaces, rotary combustors, mechanical grates, semi-suspension and suspension burning, multiple-chamber solid hearth, and two-stage combustion systems. Portions of this Code may be used for waste combustors without energy

recovery in the area of unburned combustibles in residue.

Testing of accessory equipment shall be performed using the applicable Performance Test Code. Refer to Fig. 2-4-1 for a typical system boundary. Test methods of this Code apply to solid, liquid, or gaseous waste fuels.

Instructions are given to determine the thermal capacity and thermal efficiency of waste combustor systems by applying the concept of using the boiler as a calorimeter. In addition, the HHV of the waste fuel can be determined by weighing the waste fuel that has been consumed during the test.

1-3 UNCERTAINTY

The uncertainty values are used to determine the quality of the test and have no relationship to the expected performance of the equipment. The uncertainty values reflect the accuracy of the test instrumentation and stability of the test conditions.

This Code provides standard test procedures that can yield results giving the highest level of accuracy consistent with current engineering knowledge and practice. A test may be considered an ASME Code test only if the following conditions are met:

- (a) Test procedures (and allowed variations) comply with this Code.
- (b) The uncertainty of test results is determined in accordance with Section 7 of this Code and ASME PTC 19.1.
- (c) Pretest uncertainty analysis and post-test confirmation of uncertainty values are conducted. The parties to the test shall agree to a target test uncertainty prior to the start of the test.

Typical values of the test uncertainties for

- (1) thermal efficiency are 1.2% to 2.0%
- (2) thermal capacity are 1.2% to 2.0%
- (3) waste fuel HHV are 2.3% to 5.0%

These numbers reflect the Committee's experience considering the variation in unit design. The large uncertainty for the waste fuel HHV is the result of the inability to measure the mass flow rate of the waste fuel accurately.

Section 2

Definitions and Description of Terms

2-1 DEFINITIONS

This Section contains only terms and variations of normally used engineering definitions that are required for the implementation of this Code.

accuracy: the closeness of agreement between a measured value and the true value (see also *uncertainty*); the arithmetic average of a repeated measured value compared to the true value.

additive: a substance added to a gas, liquid, or solid stream to cause a desired chemical or mechanical effect.

air: the natural atmospheric mixture of nitrogen, oxygen, water vapor, carbon dioxide, argon, neon, and small quantities of other rare gases. See para. 5-9.1.

air, corrected theoretical: theoretical air adjusted for unburned carbon.

air, excess: the air supplied to burn a fuel in addition to the theoretical air necessary for complete combustion of the fuel; it is expressed as a percentage of the corrected theoretical air in this Code.

air heater: a heat exchanger that transfers heat from a high-temperature medium such as hot gas to an incoming air stream, usually recovering heat from hot gas exiting from the boiler bank or economizer.

air, infiltration: the leakage of air into the steam generator system envelope, also referred to as *tramp air*.

air, other: any air supplied to the system that is not primary or secondary air. A number of other combustion air arrangements and splits are encountered in the combustion processes covered by this Code. The user must be thoroughly familiar with the combustion air arrangement of the steam generator being tested when applying this Code.

air preheater coils: a heat exchanger that typically uses steam, condensate, and/or glycol to heat combustion air entering the steam generator system.

air, primary: air supplied through or with a waste/fuel to initiate and sustain combustion. This air is usually supplied through the fuel bed and may be at ambient temperature or heated to induce drying fuel; it is also referred to as *undergrate air* or *underfire air*.

air, secondary: air supplied above the zone where burning is initiated. This air, at ambient temperature or heated, may be used to stimulate mixing of the burning combustible gases and suspended solids to ensure complete

combustion, to reduce furnace temperature, and/or to introduce additives; it is also referred to as *overfire air*.

air, theoretical: the quantity of air required to supply the exact quantity of oxygen necessary for complete combustion of a given quantity of fuel. (Theoretical air and stoichiometric air are the same.)

analysis, proximate: laboratory analysis, in accordance with the appropriate ASTM standard, of a fuel sample providing the mass percentages of fixed carbon, volatile matter, moisture, and noncombustibles (ash).

analysis, ultimate: laboratory analysis of a fuel sample providing the mass percentages of noncombustibles (ash), carbon, hydrogen, nitrogen, sulfur, oxygen, chlorine, and moisture.

as-fired fuel: fuel in the condition as it enters the steam generator system boundary.

ash: the inherent noncombustible materials contained in the fuel; see also *residue*.

ash, bottom: all residue removed from the combustion chamber other than that which is entrained in the flue gas; includes siftings.

ash, fly: the particles of residue entrained in the flue gas leaving the waste combustor–steam generator system boundary.

ash, hopper: residue extracted from the steam generator at locations beyond the furnace such as boiler bank hoppers, air heater hoppers, and economizer hoppers.

ash pit: a storage pit, hopper, or bunker located below a furnace where residue is collected and removed; may also be called *discharger* or *quench tank*.

attenuator: see *desuperheater*.

auxiliary fuel: see *supplementary fuel*.

bias: see *systematic error*.

bone dry: drying a sample at 221°F (105°C) in a ventilated oven under controlled conditions until no further weight loss occurs.

bulk density: see *density*.

calcination: the endothermic chemical reaction that takes place when calcium carbonate (limestone) is heated to form calcium oxide and carbon dioxide is released.

calorific value: see *heating value, higher (gross calorific value)* and *heating value, lower (net calorific value)*.

capacity (system)

maximum continuous rating (MCR): the maximum steam flow the steam generator is designed to produce on a continuous basis at a specified steam pressure and temperature.

peak: the maximum steam flow the steam generator is designed to produce for a specified period of time on a continuous basis at a specified steam pressure and temperature.

processing: the quantity (volumetric or gravimetric) of waste material that a system is designed to process in a specified time period under specified conditions.

rated: see *maximum continuous rating (MCR)*.

capacity, thermal: the heat input from fuel per unit time.

clinker: hard, sintered, or fused pieces of residue formed in a furnace by the agglomeration of ash; may contain char, metals, glass, and/or ceramics.

confidence level: the probability that the true value falls within the specified limits (expressed as a percent).

credits (heat): energy entering the steam generator envelope other than the chemical energy in the as-fired fuels. These credits include "sensible heat" (a function of specific heat and temperature) in the entering air, sensible heat in the fuels, as well as energy from power conversion in the pumps, and fans. Credits can be negative such as when the air temperature is below the reference temperature.

density

absolute: the mass of a unit volume of a material without voids at a stated temperature.

bulk: the mass of a unit loose or unpacked volume of a material, including voids, at a stated temperature.

desuperheater: apparatus for reducing and controlling the temperature of a superheated vapor.

economizer: a heat recovery device designed to transfer heat from the products of combustion to boiler feedwater.

efficiency, fuel: the ratio of the output to the input of the chemical energy in the fuel.

efficiency, gross: the ratio of the output to the total energy entering the steam generator envelope.

efficiency, thermal: see *efficiency, fuel*, and *efficiency, gross*.

energy balance method: sometimes called the *heat balance method*. A method of determining steam generator efficiency by a detailed accounting of all energy entering and leaving the steam generator envelope.

error, bias: see *systematic error*.

error, precision: see *random error*.

exit gas temperature: the average temperature of the flue gases leaving the steam generator boundary.

flue gas: the gaseous products of combustion, including excess air.

fly ash: see *ash, fly*.

fouling: accumulation of entrained materials in gas passages or on heat-absorbing surfaces. See also *slag*.

fuel: a material that is burned to release its thermochemical energy.

furnace: an enclosed chamber for the combustion of fuel.

heat balance: the utilization of the first law of thermodynamics (i.e., conservation of energy, wherein energy can be neither created nor destroyed, only converted from one form to another) to reconcile incoming and outgoing streams of energy.

heating value, higher (gross calorific value): the total energy liberated per unit mass of fuel upon complete combustion. The higher heating value includes the latent heat of the water vapor.

heating value, lower (net calorific value): the total heat liberated per unit mass of fuel minus the latent heat of the water vapor in the products of combustion.

input: the total thermochemical energy available from the fuel. Input is based on the higher heating value.

losses: the energy that exits the steam generator envelope other than the energy in the output stream(s).

material balance: an accounting of the mass of material entering and leaving a process usually made on a time-related basis.

maximum continuous rating (MCR): see *capacity (system)*.

moisture: water, in the liquid or vapor phase, present in another substance.

municipal solid waste (MSW): composed of unprocessed residential waste, yard waste, and street waste; may include similar forms of waste from commercial and industrial establishments and institutions.

output: the energy absorbed by the working fluid that is not recovered within the steam generator envelope, such as energy to heat the entering air.

precision: see *random error*.

random error: sometimes called *precision error*, random error is a statistical quantity that is normally distributed. Random error results from the fact that repeated measurements of the same quantity by the same measuring system operated by the same personnel do not yield identical values.

reference conditions: the specified numerical values of all external parameters (i.e., parameters outside the test boundary that affect either the corrected heat rate or corrected net power). In addition, the specified secondary heat inputs and outputs are reference conditions such as those listed in para. 3-5.2.

reference temperature: the datum temperature to which streams entering and leaving the steam generator envelope are compared for calculation of sensible heat credits and losses.

refuse-derived fuel (RDF): fuel produced by shredding municipal solid waste and perhaps processing the shredded material to expedite removal of extraneous noncombustible components such as glass, stone, and metals.

repeatability: the random error of a method expressed as the agreement attainable between independent determinations performed by a single analyst.

reproducibility: the random error of determinations by different analysts in different laboratories.

residue: the solid material remaining after combustion. Residue consists of fuel ash, spent and unreacted sorbent, inert additives, and unburned matter.

run: a complete set of observations made over a period of time with one or more of the independent variables maintained constant.

slag: a semiliquid or solid mineral substance formed by chemical action and fusion at furnace operating temperatures accumulated on surfaces within the steam generator envelope. See also *fouling*.

soot blower: device using high-velocity steam or air jets for cleaning solids from heat transfer surfaces.

sorbent: an additive that reacts with and captures specific constituents of flue gas.

spent sorbent: solids remaining after sorbent, calcination/dehydration, and weight gain due to sulfation.

stoichiometric air: see *air, theoretical*.

sulfation: the exothermic chemical reaction that takes place when calcium oxide unites with oxygen and sulfur dioxide to form calcium sulfate.

supplementary fuel: fuel burned to supply additional energy to the steam generator.

systematic error: sometimes called *bias error*; the difference between the average of the total population and the true value; the true systematic or fixed error that characterizes every member of any set of measurements from the population.

theoretical air: see *air, theoretical*.

unburned combustibles: the combustible portion of the fuel not completely oxidized.

uncertainty: a band within which the true value is expected to lie with a certain probability.

waste fuel: discarded combustible substances destined for disposal.

2-2 DESCRIPTION OF TERMS

The symbols, subscripts, and acronyms used in this Code are listed in Sections 4, 5, and 7. Sections 4 and 7 use algebraic-type format. Section 5 uses unique acronyms that can be used easily for computer-based calculations. Units of measurement are included with the acronyms in Section 5.

2-3 UNITS AND CONVERSIONS

For units and conversions, see Table 2-3-1.

2-4 STEAM GENERATOR ENVELOPE

The steam generator boundaries shown in Fig. 2-4-1 encompass the equipment to be included in the steam generator envelope for the test. The following numbers are used to designate specific locations of process streams. Numbers have been assigned to be as compatible as possible with the numbering used in ASME PTC 4.

2-4.1 Fuel

- 1 Primary Fuel
- 3 Auxiliary Fuel

2-4.2 Air

- 6 Primary Air Fan Inlet
- 6A Secondary Air Fan Inlet
- 7 Primary Air Fan Discharge
- 7A Secondary Air Fan Discharge
- 8 Primary Air Entering Boundary
- 8A Secondary Air Entering Boundary
- 8B Primary Air Leaving Air Preheater (APH) Coils Within Boundary
- 9 Primary Air Leaving Air Heater (AH)

2-4.3 Flue Gas

- 13 Entering Economizer
- 14 Leaving Economizer
- 14A Entering Primary Air Heater
- 15 Leaving Primary AH
- 16 Entering Cold-Side Air Quality Control (AQC) Equipment
- 17 Leaving Cold-Side AQC Equipment
- 19 Leaving Induced-Draft (ID) Fan
- 22 Entering Gas Recirculation Fan
- 23 Leaving Gas Recirculation Fan (entering boiler)

2-4.4 Steam/Waters

- 24 Feedwater Entering
- 25 Superheater Spray Water
- 26 Furnace Spray Water
- 27 Feedwater Leaving Economizer
- 28 Feedwater Entering Drum
- 31 Saturated Steam Leaving Drum
- 31B Leaving First-Stage Superheater (SH) Desuperheater
- 32 Main Steam
- 35 Blowdown
- 36 Condensate Leaving APH Coils (internal to boundary)

2-4.5 Miscellaneous

37	Furnace Residue
38	Ash Pit Water In
39	Ash Pit Water Out
40	Cooling Water In
41	Cooling Water Out
42	Atomizing Steam
46	Soot Blower Steam
46A	Auxiliary Steam
52	Economizer Fly Ash
53	Hot AQC Equipment Fly Ash
55	Cold AQC Equipment Fly Ash

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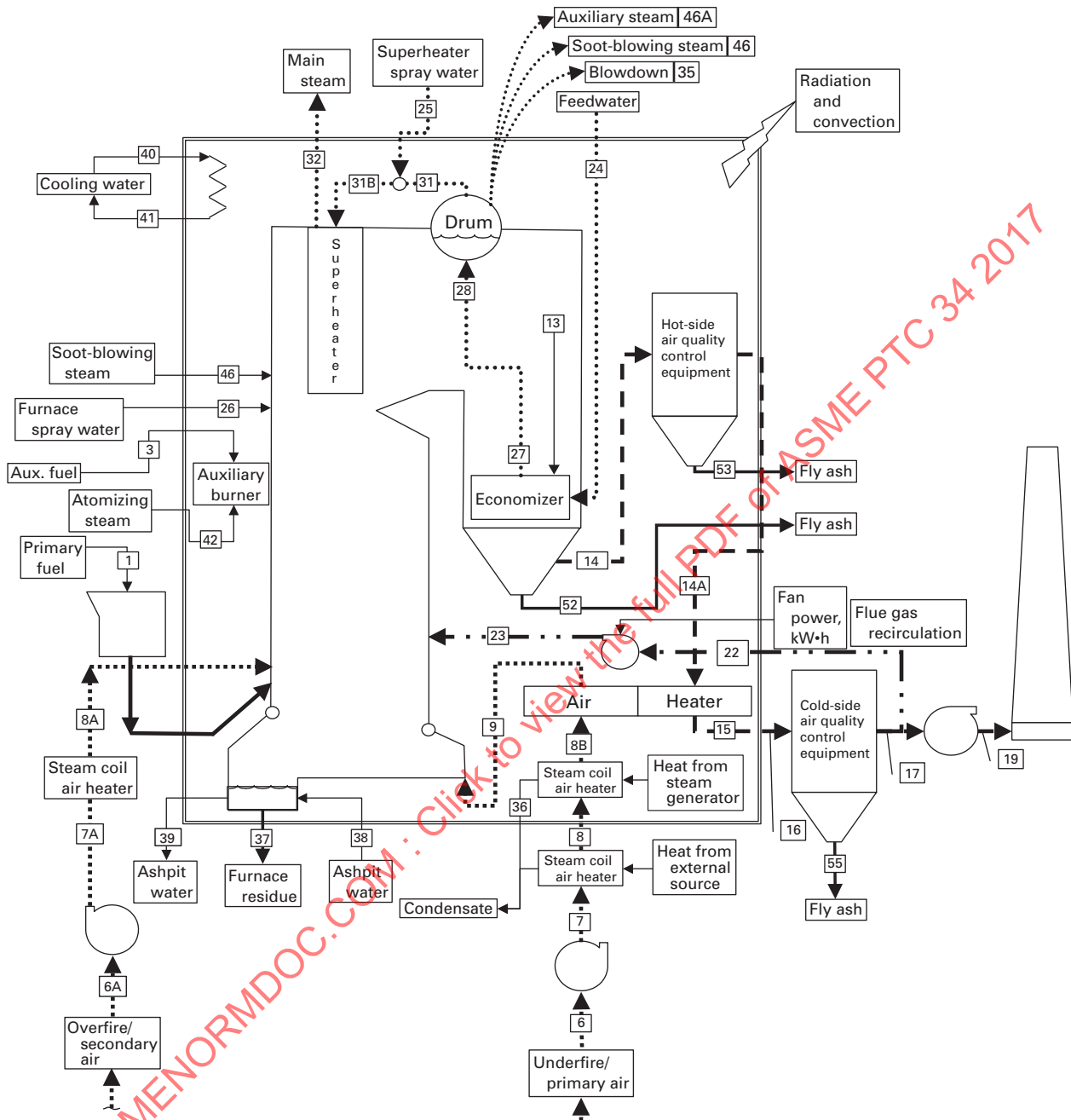
Table 2-3-1 Units and Conversions

U.S. Customary	Multiply	SI
Length		
inch (in.)	25.4	millimeter (mm)
foot (ft)	0.3048	meter (m)
mile	1.609	kilometer (km)
Area		
square inch (in. ²)	6.4516	square centimeter (cm ²)
square foot (ft ²)	0.0929	square meter (m ²)
Volume		
cubic inch (in. ³)	16.39	cubic centimeter (cm ³)
gallon (gal)	3.785	liter (L)
cubic foot (ft ³)	0.02832	cubic meter (m ³)
Mass		
grain (gr)	64.80	milligram (mg)
ounce (oz)	28.34	gram (g)
pound (lb)	0.4536	kilogram (kg)
ton (2,000 lb)	0.90703	megagram (Mg) or tonne (t)
Mass Flow		
pound per hour (lb/hr)	0.4536	kilogram per hour (kg/h)
ton per hour (ton/hr)	0.90703	megagram per hour (Mg/h) or tonne per hour (t/h)
Volumetric Flow		
cubic feet per minute (cfm)	0.02832	cubic meter per minute (m ³ /min)
gallons per minute (gpm)	3.785	liter per minute (L/min)
Energy		
Mechanical		
foot-pound (ft-lb)	1.356	newton-meter (N·m)
Heat or Chemical		
British thermal unit (Btu)	1.055	kilojoule (kJ)
	0.2520	kilocalorie (kcal)
Mechanical Power		
horsepower (hp)	0.746	kilowatt (kW)

Table 2-3-1 Units and Conversions (Cont'd)

U.S. Customary	Multiply	SI
Pressure		
Standard Atmospheric		
29.92 inches of mercury (in. Hg) at 32°F	...	760 millimeters of mercury (mm Hg) at 0°C
14.696 pounds per square inch absolute (psia)	...	1.0332 kilograms per square centimeter (kg/cm ²) 101.325 kilopascals (kPa) 1.01325 bar 1.01325 atmospheres (atm)
Absolute		
pounds per square inch absolute	6.895 0.0703 0.06895 0.06804	kilopascal kilogram per square centimeter (kg/cm ²) bar atmosphere
inches of mercury	25.4	millimeters of mercury
Gauge		
pound per square inch gauge (psig)	6.895	kilopascal (gauge)
inches of water (in. H ₂ O) at 39°F	25.4	millimeters of water (mm H ₂ O) at 4°C
Temperature		
Fahrenheit (°F) + 460 = Rankine (R)	0.5556	kelvin (K) = Celsius (°C) + 273
Fahrenheit (°F) – 32	0.5556	Celsius (°C)
Density		
pound per cubic foot (lb/ft ³)	16.018	kilogram per cubic meter (kg/m ³)
pound per gallon (lb/gal)	0.1198	kilogram per liter (kg/L)
Heating Value		
Btu per pound (Btu/lb)	2.326 0.5556	kilojoule per kilogram (kJ/kg) kilocalories per kilogram (kcal/kg)
Btu per cubic foot (Btu/ft ³)	37.25	kilojoule per cubic meter (kJ/m ³)
Heat Flow Rate		
Btu per hour (Btu/hr)	1.055	kilojoule per hour (kJ/h)
Plant Heat Rate		
Btu per kilowatt-hour (Btu/kW·h)	1.055	kilojoule per kilowatt-hour (kJ/kW·h)
kilowatt-hour per ton (kW·h/ton)	1.1024	kilowatt-hour per tonne (kW·h/tonne)

Fig. 2-4-1 Typical System Boundary



Section 3 Guiding Principles

3-1 INTRODUCTION

The purpose of this Section is to provide guidance to plan, conduct, and evaluate a Code test of a waste combustor with energy recovery. Prior to conducting the performance test, a number of decisions and agreements must be reached between the parties. This Section provides a framework for these decisions and provides guidance where applicable. The following subsections discuss

- (a) planning for the test (subsection 3-2)
- (b) test personnel and responsibilities (subsection 3-3)
- (c) test preparations and test apparatus/plant equipment (subsection 3-4)
- (d) conduct of test (subsection 3-5)
- (e) data evaluation and reporting (subsection 3-6)
- (f) summary of prior agreements (subsection 3-7)

3-2 PLANNING FOR THE TEST

3-2.1 General Preparations

It is recommended that a comprehensive test plan and schedule be developed. This should be initiated at an early phase of the project to provide sufficient time for the parties to complete test preparations and to make any modifications to the existing plant equipment or instrumentation deemed necessary. The plan should clearly identify tasks and responsibilities for such activities as pretest uncertainty analysis, instrumentation evaluation and selection, test apparatus delivery and setup, site inspections and preparations, testing activities, post-test data analysis including uncertainty analysis, and test reporting. The scheduling process should identify milestones for completion of tasks and any critical path activities.

This Code provides procedures for determining the thermal capacity, efficiency, and waste fuel higher heating value (HHV). The intent of the test Code is to provide performance test procedures for waste fuels; therefore it is important to minimize the use of supplementary fuel. The Code recognizes that some facilities may be designed to co-fire supplementary fuel on a continuous basis.

3-2.2 Pretest Uncertainty Analysis

Section 7 of this Code stipulates that a pretest uncertainty analysis is necessary to evaluate the anticipated quality of the test and to provide a technical basis for

decisions regarding type of instruments required, frequency of data sampling, location of data measurements, and applicability of plant instruments. This Code uses the calculated uncertainty of the results to determine the quality level of the test.

This Code permits accommodating various levels of testing within the range of allowable uncertainties noted in subsection 1-3. While all necessary procedures are specified for the most accurate determination of performance, the parties to the test are permitted to design a lower-level test (within the above allowable range) if that is appropriate to their needs. Typically, a lower-level test may use less accurate or fewer instruments, or will use assumed or estimated values for certain parameters rather than measuring them.

A performance test shall be designed to meet the target uncertainties. The choice of which parameters to measure, which parameters may use estimated values, what values to assign, and the use of fewer or alternate instruments will strongly influence the ability to meet target uncertainties. This Code provides guidance regarding systematic and random uncertainties for various test measurement systems.

The pretest uncertainty analysis will confirm that the test is capable of achieving the target test uncertainty. In addition, the pretest uncertainty analysis can provide information that can be used to design a more cost-effective test. Many measurements are required to account for all losses and credits; however, each individual loss or credit (or error in its determination) may have only a small effect on the results or the total test uncertainty. This process will provide an opportunity to identify parameters that are less critical and therefore may be measured using plant instruments or through the use of an assigned value. Instrument selection, installation, and application of effective sampling methods are as important as accurate calibration in assuring that the target uncertainties are attainable. It is recommended that particular attention be given to the selection of methodology for measuring flue gas flow, flue gas composition, and feedwater flow.

3-3 TEST PERSONNEL AND RESPONSIBILITIES

A Test Coordinator shall be appointed who is experienced in the technical and operational aspects of the test. The Test Coordinator shall have the responsibility for the implementation of the test in accordance with the test objectives and the requirements of this Code.

Personnel shall be identified to support the execution of the test. Support personnel shall be familiar with the operation and layout of the plant and the test procedures to ensure that safe, steady operation of the plant is maintained as required for an accurate test.

3-4 TEST PREPARATION, TEST APPARATUS, AND PLANT EQUIPMENT

3-4.1 General Preparations

This subsection outlines activities required in preparing instrumentation and plant equipment for the performance test and preliminary test runs. Consideration should be given to safe and clear access to test point locations, availability of suitable utilities, and safe work areas for personnel. The physical location of instruments should be reviewed for potential damage or calibration shifting because of extreme ambient conditions such as temperature or vibration.

Instrumentation used for data collection shall reflect accuracy requirements identified in the pretest uncertainty analysis. This instrumentation may be either permanent plant instrumentation or temporary test instrumentation. Where practical, multiple instruments should be used to reduce overall test uncertainty. The frequency of data collection shall be commensurate with the duration of the test and with the temporal variations in the parameter being measured. The use of high-speed, high-accuracy data acquisition systems is recommended.

Instrument calibration shall be completed prior to and after the test, and those records and calibration reports shall be made part of the test documentation. Paragraph 4-3.1 provides guidance regarding instrument calibration.

The test objective and facility's operating configuration should be reviewed to confirm control objectives and valve/damper operations. All critical operating parameters should be reviewed in detail to familiarize both operators and test personnel.

Consideration and arrangements for the sampling of residue shall be completed. Section 4 provides recommended procedures. Equipment such as sealable containers, shovels, and plastic sheeting as required shall be procured.

All parties shall have reasonable opportunity to examine the plant and to render it suitable to undergo test. The plant shall be checked to ensure that equipment and subsystems are installed and operating in accordance with their design parameters. Prior to conducting a test, the cleanliness, condition, and age of the equipment should be determined by inspection of equipment and operational records. The equipment shall be in a normal state of cleanliness. Inlet air filters and heat exchangers should not be abnormally clean or dirty. Boilers and heat recovery equipment should be normally

clean, which usually means that the soot-cleaning system may have been operated and that abnormal ash slag will not be present in or on the grate area, furnace walls, or convection passes. Any off-line cleaning shall be completed prior to the test. It is recommended that testing be initiated no sooner than 350 hr following off-line cleaning.

3-4.2 Preliminary Testing

Preliminary testing should be conducted sufficiently in advance of the start of the performance test to allow time to calculate preliminary results, make final adjustments, and modify the test procedures and/or test equipment. Results from the preliminary testing should be calculated and reviewed to identify any problems with the quality of the measured data. Any test modifications shall be identified through this activity. Reasons for a preliminary run could include the following:

- (a) to determine whether the plant equipment is in suitable condition for the conduct of the test
- (b) to make adjustments, the needs of which were not evident during the preparation of the test
- (c) to check the operation of all instruments, controls, and data acquisition systems
- (d) to verify that the target uncertainty can be obtained by checking the complete system
- (e) to ensure that the facility's operation can be maintained in a stable steady status of performance
- (f) to ensure that the waste fuel heating value is within permissible limits and that sufficient quantity will be available to avoid interruption of the test
- (g) to ensure that process boundary inputs and outputs can be achieved
- (h) to familiarize test personnel with their assignments
- (i) to retrieve enough data to evaluate the control system

After a preliminary test has been made it may be declared an acceptance test, provided that all the requirements of an acceptance test have been met and that parties to the test are in agreement.

3-5 CONDUCT OF TEST

This section provides guidelines regarding the operation of the equipment during the performance test. This subsection addresses the following areas:

- (a) starting and stopping of test run
- (b) methods of operation during test run
- (c) adjustments during tests
- (d) duration and number of test runs and number of readings
- (e) constancy of test conditions

3-5.1 Starting and Stopping Test Runs

The Test Coordinator is responsible for ensuring that all data collection begins at the agreed-on start of the

test, and that all parties to the test are informed of the starting time. Prior to starting each performance test, the following conditions must be satisfied:

- (a) equipment operation and method of control in accordance with test plan
- (b) unit configuration including operation at required process flow rates
- (c) valve line-up
- (d) availability of sufficient test waste fuel and supplementary fuel
- (e) plant operation within the bounds of the performance correction curves, algorithms, or programs
- (f) for a series of test runs, completion of internal adjustments required for repeatability
- (g) steam flow within $\pm 10\%$ of set point
- (h) stable operation for at least 2 hr at test load
- (i) data acquisition system(s) functioning
- (j) test personnel in place and ready to collect samples/record data

Tests are stopped when the requirements for a complete test run have been satisfied. The Test Coordinator should verify that methods of operation during the test have been satisfied. The Test Coordinator may extend the test or terminate it if the requirements are not met.

3-5.2 Methods of Operation During Tests

All equipment necessary for normal and sustained operation at the test conditions must be operating during the test or accounted for in the corrections. Intermittent operation of equipment within the test boundary should be accounted for in a manner agreeable to all parties. Nothing within the plant shall be run or shut down abnormally without the consent of the parties to the test. The corrections used in the general performance equations and the development of correction curves will be affected by the operating mode of the plant. Plant equipment shall be operated in a manner consistent with the basis of design or guarantee and in a manner that will permit correction from test operating conditions to reference conditions. If a specified corrected or measured load or plant disposition is desired, the plant control system should be configured to maintain these conditions during the test. Items to be considered include, but are not limited to, air preheat, blowdown, steam export, cycle conditions, and feedwater heater disposition.

Process energy (electrical power, process steam, and condensate) shall be controlled in the most stable manner possible. This may require operation in manual mode or venting to the atmosphere if the host is unable to satisfy stability or quantity criteria.

Throughout the tests, the plant should be operated in compliance with applicable permits. This test Code does not require an emissions test to be conducted as part of the performance test.

3-5.3 Adjustments During Tests

Permissible adjustments during tests are those required to correct malfunctioning controls, to maintain equipment in safe operation, or to maintain plant stability. Any adjustments requested by the Test Coordinator should be noted in the test log. Switching from automatic to manual control and adjusting operating limits or set points of instruments or equipment should be avoided during a test.

Any adjustments that would result in equipment being operated beyond the recommended manufacturer's design or safety limits and/or specified operating limits are not permissible at any time prior to or during testing. Adjustments or recalibrations, which would adversely affect the stability of a primary measurement during a test, are not permitted.

3-5.4 Duration and Number of Test Runs

The recommended test duration is 8 hr. During the test, the Test Coordinator and the parties to the test may determine that a longer test period is required; however, it is not the intent of this Code to cover extended-term system availability tests. Depending on the personnel available and the method of data acquisition, it may be necessary to increase the length of a test to obtain a sufficient number of samples of the measured parameters to attain the required test uncertainty.

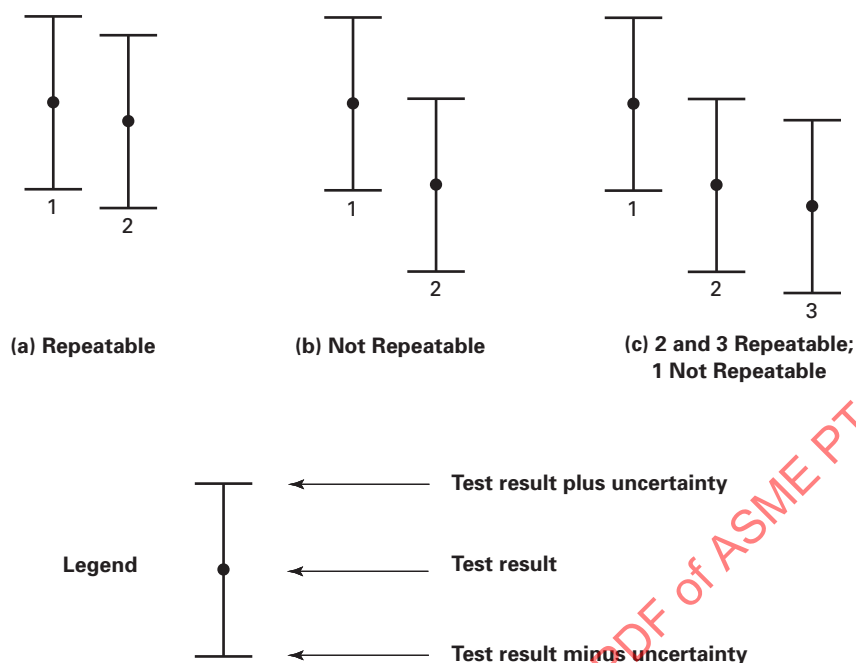
A "run" is a complete set of observations made over a period of time with the unit at stable operating conditions. A "test" is a single run or the combination (average) of a series of runs for the purpose of determining performance characteristics. A test normally consists of two or more runs. However, a Code test may consist of only one run.

While multiple runs are not required, the advantages of multiple runs should be recognized. Conducting more than one run will

- (a) provide a valid method of rejecting bad test runs.
- (b) allow the parties to the test to examine the validity of the results.
- (c) verify the repeatability of the results. Results may not be repeatable due to variations in either test methodology (test variations) or the actual performance of the equipment being tested (process variations).

After completing the first test run that meets the criteria for an acceptable test run (which may be the preliminary test run), the data should be consolidated and preliminary results calculated and examined to ensure that the results are reasonable. If the parties to the test agree, the test may be concluded at the end of any test run.

The criterion for repeatability between test runs is that the results (corrected efficiency and/or corrected thermal capacity) of two or more runs lie within the uncertainty interval of the other(s). See Fig. 3-5.4-1 for examples of runs that meet or do not meet this criterion.

Fig. 3-5.4-1 Repeatability of Runs

Should a set of runs fail to meet the repeatability criteria, the results from all of the runs should be reviewed in an attempt to explain the reason. Should no reason become obvious, the parties to the test can either increase the uncertainty band to encompass the runs and, therefore, make them repeatable, or conduct more runs, which will allow them to calculate the random error component of uncertainty directly from the test results. The results of multiple runs that meet the criteria for repeatability and other Code requirements shall be averaged to determine the mean result. The uncertainty shall be reported for individual runs, but shall not be reported for the average test result.

3-5.5 Constancy of Test Conditions

During a complete test run, operating conditions should not vary from the target value for that operating condition by more than the value in Table 3-5.5-1.

The criteria in Table 3-5.5-1 can also be used for defining stable conditions before starting a test run. The length of operating time necessary to achieve the required steady state will depend on specifics of the plant design; however, 2 hr is typical.

3-6 DATA EVALUATION AND REPORTING

3-6.1 Causes for Rejection of Specific Data or Test Runs

Upon completion of the test or during the test itself, the test data shall be reviewed in accordance with Table 3-5.5-1. Section 7 of this Code and ASME PTC 19.1

Table 3-5.5-1 Operating Parameter Deviations

Parameter	Deviation of $\frac{1}{2}$ hr Average From Set Point/Target	Deviation Over Test Run Duration
Steam flow	$\pm 10\%$	$\pm 4\%$
O ₂ leaving boiler/ economizer (by volume)	$\pm 4\%$ O ₂	$\pm 2\%$ O ₂
Steam temperature (if controlled)	20°F	10°F
Steam pressure		
>500 psi	4% (25 psi max.)	3% (40 psi max.)
<500 psi	20 psi	15 psi

provide further criteria for evaluation of data quality. A test log should be kept, and any plant upsets, which cause test data to violate the requirements of Table 3-5.5-1, shall be documented.

Should serious inconsistencies that affect the results be detected during a test run or during the calculation of the results, the run shall be invalidated. If the inconsistencies occur at the beginning or at the end of the run, the parties to the test may choose to reject only that portion of the data. A run that has been invalidated shall be repeated as necessary to attain the test objectives. The decision to reject a run shall be the responsibility of the designated representatives of the parties to the test.

3-6.2 Uncertainty

Each Code test shall include pretest and post-test uncertainty analyses, and the results of these analyses shall fall within Code requirements as stated in subsection 1-3.

Procedures relating to test uncertainty are based on concepts and methods described in ASME PTC 19.1, Test Uncertainty. ASME PTC 19.1 specifies procedures for evaluating measurement uncertainties from both random and fixed errors, as well as the effects of these errors on the uncertainty of a test result.

Following each performance test run the uncertainty of the results shall be calculated in accordance with Section 7 and ASME PTC 19.1.

3-6.3 Data Storage and Retrieval

It is strongly recommended that test data be captured and stored in an electronic format to facilitate post-test uncertainty and data analysis.

3-6.4 Test Report

A comprehensive test document shall be prepared in accordance with Section 6 of this Code. Every event connected with the progress of the test shall be recorded on the test log sheets, together with the time of occurrence and name of the observer. Particular care should be taken to record any adjustments made to any equipment under test. At the conclusion of the test, authorized parties shall sign respective data logs recorded or witnessed. They shall also sign a document to indicate the test was conducted in accordance with the approved test procedure. Parties to the test have the right to copies of all raw data at the conclusion of the test.

The results of the test should be presented as a formal document that is certified by all parties to the test.

3-7 PRIOR AGREEMENTS

Prior to conducting a plant performance test, there shall be a written agreement between the parties to the test on the specific subjects affecting the planning, scheduling, execution, and reporting aspects of the test. This subsection provides an itemized list of the activities and the items for agreement. It is intended that the parties will use this information to review and develop the overall test document, and to assign and schedule test activities. Subsections 3-2 through 3-6 provide additional guidance for the items specified in paras. 3-7.1 through 3-7.5.

3-7.1 Test Planning

- (a) Define test objective.
- (b) Prepare test plan manual, including schedule of test preparation activities, test execution, data analysis, and reporting.

(c) Define test boundaries, measured variables, unmeasured variables, and test assumptions.

(d) Define target test uncertainty.

(e) Perform pretest uncertainty analysis using agreed-on systematic uncertainty.

(f) Define test instrumentation requirements, data sampling frequency and storage methods, instrument locations, etc., to suit uncertainty objectives. Recommendations for methods of measurement are provided in Section 4 of this Code.

(g) Define uncertainties of unmeasured (estimated) values.

(h) Define gas flow and composition measurement procedures.

(i) Define residue sampling methodology, including reduction techniques and frequencies.

(j) Define acceptance and rejection criteria for data (see subsection 5-2).

(k) Provide criteria for corrections to off-design conditions.

(l) Define report format.

3-7.2 Test Personnel

(a) Determine number of personnel required.

(b) Determine organization, qualifications and training of test personnel, arrangements for personnel direction, and arrangements for calculating results.

(c) Designate the Test Coordinator.

(d) Assign responsibility for various activities in test preparation, execution, validity of test data, and data reduction.

3-7.3 Test Preparation and Test Apparatus/Plant Equipment

(a) Review and inspect plant instruments to suit uncertainty objectives.

(b) Assess unit cleanliness and define means of maintaining cleanliness.

(c) Procure special test instruments necessary to suit uncertainty objectives.

(d) Identify plant instrumentation modifications required to meet uncertainty objectives.

(e) Identify instrument calibration requirements, including methodology, record keeping, and schedule.

(f) Define sampling frequencies for all measured parameters and data storage methods/devices.

(g) Define facility operating configuration (valve line-up, etc.) for testing.

(h) Identify operating and test equipment requiring pretest inspections to verify proper operation.

(i) Identify any preliminary test run requirements.

(j) Perform pretest equipment inspection.

(k) Perform preliminary test run.

3-7.4 Conduct of Test

The following items pertaining to the operation of the facility prior to and during the test shall be defined:

- (a) method of operation
- (b) start and stop procedures
- (c) consequences of upsets and unscheduled interruptions including retest criteria
- (d) duration of each run and number of test runs
- (e) criteria for stable operation and degree of constancy required in test runs

(f) permissible and nonpermissible adjustments during test runs

- (g) criteria for allowable supplementary fuel firing

3-7.5 Data Analysis, Calculations, and Reporting

- (a) Determine and arrange for laboratory analysis of residue and supplementary fuels.
- (b) Perform post-test uncertainty analysis.
- (c) Assess need for further tests.
- (d) Complete formal test report.

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Section 4

Instruments and Methods of Measurement

4-1 INTRODUCTION

This Section provides guidance in test measurement. When planning a test, the engineer has many choices regarding the parameters to be measured, the method of measurement, and values of any assumed variables. Because the technology of test measurement is constantly improving, this Code permits flexibility in the design and selection of test instrumentation, yet maintains a prescribed quality level. A test can be designed within the guidelines provided here to suit the particular needs and objectives of all parties to the test.

This Section addresses three items.

(a) For each Code objective, the parameters to be measured and needed to compute the final result are identified.

(b) The relative importance of each parameter is indicated and several methods for measuring the parameter are identified.

(c) Appropriate systematic uncertainties are suggested for each method used to measure the required parameters.

4-2 DATA REQUIRED

This Code addresses the methodology to determine performance characteristics including the following:

- (a) thermal capacity
- (b) thermal efficiency
- (c) waste fuel HHV

Tables 4-2-1, 4-2-2, and 4-2-3 list the parameters required to determine each of these performance characteristics for typical units as defined by Fig. 2-4-1. Each table lists the parameters required, their relative importance, and the paragraph in this Section covering the applicable measurement procedure for the specific measurement/test objective. The user of this Code is responsible for identifying any features of the unit to be tested that are not included in the typical examples and applying the principles of this Code for measuring the appropriate parameters to accomplish the objective of the test.

In these tables, the calculation parameter acronym and name are given. The "Typical Influence" column designates those parameters that typically have a major (primary) effect on the results of the measured parameter and those items that are required but have a lesser (secondary) effect on the results. In some cases, the general parameter may have a secondary impact on the results,

but the items required to determine the parameter have a primary impact on the parameter itself.

The "Typical Source" column identifies one or more of three acceptable options for determining the parameter. These three options are measured, calculated, and estimated. In general, for those items that are typically estimated, it is assumed that a reasonable estimate can be made based on experience from similar units, or preferably based on previous tests on the unit being tested. The "Remarks" column is intended to clarify the other items of information.

4-3 GENERAL MEASUREMENT REQUIREMENTS

The methods for obtaining the required data impact the quality of the test. There are usually several ways to measure any given parameter. Each of these ways has inherent measurement errors attributable to both the process involved and the measurement system used. The test engineer must take all of this into account when designing the test program.

Consideration should be given to the target uncertainty when selecting test equipment. The best available instrumentation will result in the lowest test uncertainty. Typical station recording instruments are designed for reliability, ease of use, and ease of maintenance rather than for accuracy. Therefore, measurements made by station recording instruments usually increase test uncertainty.

All instruments shall be checked to verify that they are the specified types, properly installed, working as designed, and functioning over the range of input expected.

4-3.1 Calibration

This Code requires, as a minimum, that relevant components of all instrumentation loops be initially aligned (the zero offsets or spans have been adjusted to their respective specifications). Calibrations prior to and following the tests shall be against standards whose calibrations are traceable to the National Institute of Standards and Technology (NIST) or other recognized international standard. All measurements should be corrected for any calibrations before use in the performance calculations; otherwise, the systematic error estimate must be increased to the reference accuracy plus other systematic error influences described below. Reference accuracy is the systematic error a user may expect to

Table 4-2-1 Parameters Required for Input, Efficiency, and HHV Determinations

Calculation Acronym	Parameter	Reference Paragraph	Typical Influence	Typical Source	Remarks
QrO	Main Steam Output	5-3.1	Primary
MrW24	Feedwater flow	...	Primary	Measured	...
HSt32	Main steam enthalpy	Note (1)
TSt32	Main steam temperature	...	Primary	Measured	...
PSt32	Main steam pressure	...	Primary	Measured	...
HW24	Feedwater enthalpy	Note (1)
TW24	Feedwater temperature	...	Primary	Measured	...
PW24	Feedwater pressure	...	Secondary	Meas./calc.	...
QrAxSt	Auxiliary Steam Output	5-3.2	Secondary
MrSt46A	Auxiliary steam flow	...	Secondary	Meas./calc.	...
HSt46A	Auxiliary steam enthalpy	Note (1)
TSt46A	Auxiliary steam temperature	...	Secondary	Measured	...
PSt46A	Auxiliary steam pressure	...	Secondary	Measured	...
HW24	Feedwater enthalpy	Note (1)
QrBd	Blowdown Output	5-3.3	Secondary	...	Typically isolated
MrW35	Blowdown flow	...	Secondary	Meas./est.	Meas./calc./est.
HW35	Blowdown enthalpy
PW35	Drum pressure	...	Secondary	Measured	...
HW24	Feedwater enthalpy	Note (1)
QrLDFg	Dry Gas Loss	5-11.1	Primary
MrDFg	Dry flue gas flow	...	Primary	Calculated	...
MrFg	Wet flue gas flow	...	Primary	Meas./calc.	See Table 4-2-2
MFrH2O	Flue gas moisture	...	Primary	Measured	...
HDFgCr	Enthalpy of dry flue gas	Note (2)
TFgCr	Flue gas temperature corrected for air heater leakage	...	Primary	Calculated	See Table 4-2-3
QrLWF	Water From Fuel Loss	5-11.2	Primary
MrWFg	Water in flue gas	...	Primary	Calculated	...
MrFg	Wet flue gas flow	...	Primary	Calculated	See Table 4-2-2
MpWFg	Percent flue gas moisture	...	Primary	Measured	...
HWvLvCr	Enthalpy of water vapor at 1 psia and TFgLvCr	Note (1)
TFgCr	Flue gas temperature	...	Primary	Calculated	See Table 4-2-3
HWRe	Enthalpy of water at TRE	Note (2)
Tre	Reference temperature	...	Primary	...	77°F (25°C)
QrLApEv	Wet Ash Pit Loss	5-11.3.4	Secondary
QrApEv	Ash Pit Water Evaporation Loss	5-11.3.1	Secondary
MrApW	Water evaporated from ash pit	...	Secondary	Calculated	...
HStLvCr	Enthalpy steam at 1 psia and TFgLvCr	Note (1)
TFgLvCr	Flue gas temperature	...	Secondary	Calculated	...
HW38	Enthalpy of ash pit make-up water	Note (2)
HW39	Enthalpy of ash pit water overflow
QrLRsApW	Sensible Heat in Ash Pit Overflow Water Loss	5-11.3.2	Secondary
MrW39	Ash pit water overflow	...	Secondary	Measured	...
HW39	Enthalpy of overflow water leaving ash pit
TW39	Temperature of overflow water leaving ash pit	...	Secondary	Measured	...
HW38	Enthalpy of ash pit make-up water
QrLRsWLv	Sensible Heat in Wet Residue Loss	5-11.3.3	Secondary
MrRsW37	Wet residue flow leaving ash pit	...	Primary	Calculated	...
MFrWRs	Residue moisture	...	Primary	Measured	...

Table 4-2-1 Parameters Required for Input, Efficiency, and HHV Determinations (Cont'd)

Calculation Acronym	Parameter	Reference Paragraph	Typical Influence	Typical Source	Remarks
HRs37	Enthalpy of dry residue leaving ash pit
TRs37	Temperature of wet residue leaving ash pit	...	Primary	Measured	...
HW37	Enthalpy of water in residue leaving ash pit
TW37	Temperature of wet residue leaving ash pit	...	Primary	Measured	...
HW38	Enthalpy of ash pit make-up water
QrLWA	Moisture in Air Loss	5-11.4	Secondary
MFrWDA	Air specific humidity	...	Secondary	Calc./est.	...
Tdb	Dry bulb temperature	...	Secondary	Measured	...
Twb	Wet bulb temperature or relative humidity	...	Secondary	Measured	...
MrDA	Dry airflow	...	Secondary	Calculated	...
MrDFg	Dry flue gas flow	...	Secondary	Calculated	...
DVpO ₂ ,CO ₂	Flue gas O ₂ , CO ₂	...	Secondary	Measured	...
DVpN ₂	Flue gas N ₂	...	Secondary	Calculated	...
HWvLvCr	Enthalpy of water vapor	Note (2)
TFgLvCr	Flue gas temperature	...	Secondary	Calculated	See Table 4-2-3
QrLUBC	Unburned Combustible Loss	5-11.5	Primary
MrRsD39	Dry residue stream(s) flow	...	Primary	Measured	...
MrUBC	Unburned carbon in residue	...	Primary	Measured	Note (3)
HHVRs	Higher heating value of dry residue	...	Primary	Measured	...
QrLCO	Carbon Monoxide Loss	5-11.6	Secondary
DvpCO	Dry volume % CO in flue gas	Measured	...
MrDFg	Dry flue gas flow	Calculated	...
QrLRs	Residue Sensible Heat Loss	5-11.7	Secondary	Calculated	...
MrRsZ	Mass flow rate of residue at location z	...	Primary	Measured	...
HRsz	Enthalpy of residue at location z	Estimated	...
QRLSrc	Surface Radiation Loss	5-11.8	Primary	Estimated	Radiation loss curve
QrLWAd	Additional Moisture Loss	5-11.9	Secondary
MrStz	Mass flow rate of additional water
HSvLvCr	Enthalpy of steam in flue gas leaving envelope
HwRe	Enthalpy of water at reference temperature
QrLRy	Recycled Streams Loss	5-11.10	Secondary
Gaseous					
MrRyFg	Recycled gas flow
HfGvLvCr	Corrected flue gas enthalpy leaving the envelope
HfGEn	Flue gas enthalpy entering the envelope
Solids					
MrRyRs	Recycled residue flow
HRsLv	Recycled residue enthalpy leaving
HrsEn	Recycled residue enthalpy entering
QrL36	Internal Air Preheater Coil	5-11.11	Secondary
MrW36	Air preheater condensate flow
HW36	Enthalpy of condensate leaving air preheater
HW24	Enthalpy of feedwater
QrLCw	Cooling Water Loss	5-11.12	Secondary
MrCwz	Mass flow rate of cooling water
HW41	Enthalpy of water leaving
TW41	Temperature of water leaving
HW40	Enthalpy of water entering
TW40	Temperature of water entering

Table 4-2-1 Parameters Required for Input, Efficiency, and HHV Determinations (Cont'd)

Calculation Acronym	Parameter	Reference Paragraph	Typical Influence	Typical Source	Remarks
QrBDA	Entering Dry Air Credit	5-12.1	Primary
MrDA	APH (heated) dry airflow	...	Primary	Calculated	...
MrA	APH (heated) wet airflow	...	Primary	Measured	...
MFrWDA	Air specific humidity	...	Primary	Measured	...
HDAMnEn	Enthalpy of dry air entering
TAhALv	Temperature of heated air leaving APH	...	Primary	Measured	...
QrBWA	Moisture in Entering Air Credit	5-12.2	Secondary
MrDA	APH (heated) dry airflow	...	Primary	Calculated	...
MFrWDA	Air specific humidity	...	Primary	Measured	...
HWv	Water vapor enthalpy leaving APH
TA8	Temperature of heated air leaving APH	...	Primary	Measured	...
QrBF	Sensible Heat in Fuel Credit	5-12.3	Secondary
MrF	Fuel (waste fuel) flow	...	Secondary	Calc./est.	...
MFrWF	Water in fuel	...	Secondary	Estimated	...
TF	Temperature of fuel (waste fuel)	Measured	...
Tre	Reference temperature	77°F (25°C)
QrBAx	Auxiliary Equipment Power Credit	5-12.4	Secondary
	Steam-driven equipment
	Mass flow of steam
	Entering steam pressure
	Entering steam temperature
	Exhaust pressure
	Drive efficiency
	Electrically driven equipment
	For large motors:				
	Watt-hour reading
	Drive efficiency
	For small motors:				
	Volts
	Amps
QrBWAd	Energy in Additional Moisture Credit	5-12.5	Secondary
MrStz	Mass flow rate
HStFgEnz	Enthalpy of additional steam entering
HWRe	Enthalpy of water at reference temperature
QrFs	Supplementary Fuel Input	5-13	Primary
MrFs	Mass flow rate of supplementary fuel	...	Primary	Measured	...
HHVFs	Higher heating value of supplementary fuel	Meas./est.	...
QrF and EF	Heat Input and Efficiency	5-4, 5-6
QrO	Output
QrL	Losses
QrB	Credits
HHVF	Fuel (Waste) Higher Heating Value	5-14	Primary
MrF	Fuel flow (waste fuel)	...	Primary	Measured	...
QrO	Output
QrL	Losses
QrB	Credits

NOTES:

- (1) ASME Steam Tables.
- (2) See JANAF.
- (3) Use either HHVRs or MpUbC.

Table 4-2-2 Parameters Required for Wet Flue Gas Flow Using Economizer Heat Balance

Calculation Acronym	Parameter	Reference Paragraph/Equation	Typical Influence	Typical Source
MrFg	Economizer wet flue gas flow	5-8.1	Primary	Calculated
Mrfw	Economizer feedwater flow	4-6.3	Primary	Measured
TFge	Economizer inlet flue gas temperature	4-4.3	Primary	Measured
TFg1	Economizer outlet flue gas temperature	4-4.3	Primary	Measured
Tfwe	Economizer inlet water temperature	4-4.4	Primary	Measured
Tfw1	Economizer outlet water temperature	4-4.4	Primary	Measured
MfH2O	Economizer outlet flue gas moisture	4-7.1, 4-7.2, 4-7.3	Primary	Measured
DVpO2	Economizer outlet flue gas dry O ₂	4-7.1, 4-7.2, 4-7.4	Secondary	Measured
DVpCO2	Economizer outlet flue gas dry CO ₂	4-7.1, 4-7.2, 4-7.5	Secondary	Measured
ST	Heating surface of economizer and steam/water-cooled enclosure	5-8.1	Secondary	Calculated/estimated
SB	Total heating surface of economizer	5-8.1	Secondary	Calculated/estimated

Table 4-2-3 Parameters Required to Determine Corrected Flue Gas Exit Temperature

Calculation Acronym	Parameter	Reference Paragraph/Figure	Typical Influence	Typical Source	Remarks
TFgLvCr	Corrected air heater outlet flue gas temperature	5-10.3	Primary	Calculated	...
TFgLv	Temperature of flue gas leaving air heater	4-4.3	Primary	Measured	...
TAEn	Temperature of flue gas entering air heater	4-4.3	Primary	Measured	...
MnCpA	Mean specific heat of air	Fig. 5-19.9-1
MnCpFg	Mean specific heat of flue gas	Fig. 5-19.9-3
MrFgLv	Flue gas flow leaving air heater	...	Primary	Calculated	...
MrFgEn	Flue gas flow entering air heater	5-8.1	Primary	Calculated	See Table 4-2-2

achieve in the absence of a calibration after the instrument is initially adjusted in accordance with the manufacturer's specification. This systematic error is reduced when adjustments are made to an instrument to align it to a reference standard. The systematic error then becomes the accuracy of the reference standard used plus other systematic error influences. These influences may include environmental influences on the instrument as well as systematic error introduced due to nonuniformity of the measured medium.

Certain instrumentation should be calibrated immediately prior to and immediately following the testing period to determine the amount of drift. If the pretest and post-test calibrations differ, the amount of drift shall be determined and one half added to the systematic error estimate for the instrument. Drift is assumed to be linear with time. Therefore, the average of the pretest and post-test calibrations shall be used for the calibration value.

In general, the best methodology for calibrating the test instrumentation is to calibrate the entire system. This is accomplished by introducing a known input to a sensing device and comparing the result on the recording device to the known value. An example of this is the introduction of a known pressure to a transmitter mounted at its measurement location and connected to the data acquisition, measurement, and recording system. Using this approach, effects of the installation such as a high-temperature environment or wiring connections are thus included in the calibration experiment. Any calibration should be performed at a minimum of three different points bracketing the highest and lowest values in the range expected to be measured during the test.

4-3.1.1 Temperature. The temperature-sensing device should be calibrated against a NIST-traceable temperature standard at four different temperatures.

The temperatures selected for calibration should span the range of the anticipated values expected during the test.

4-3.1.2 Pressure or Differential Pressure. The pressure-sensing device should be calibrated against a NIST-traceable pressure standard at five different pressures. The pressures selected for calibration should span the range of the anticipated values expected during the test. The pressure should be recorded at each point while increasing pressure and again while decreasing pressure.

4-3.1.3 Flue Gas Composition. The analyzers used to measure oxygen, carbon dioxide, and carbon monoxide should be calibrated immediately prior to a test and calibration checked for drift immediately following a test. These calibrations should be performed using certified calibration gases for zero, full span, and midpoint. Calibration gases shall be EPA Protocol 1 gases, on a calibrated analyzer. Additionally, no calibration gas should be used when the pressure in the cylinder is lower than 100 psi. If the analyzer is calibrated on one range and the measurement during the test is performed on another, a post-test calibration check should be performed on the second range.

4-3.2 Flue Gas Analysis

4-3.2.1 Dry Flue Gases. The O_2 and CO_2 measurements should be performed using an extractive sampling system from a stationary grid. If it is known that the waste combustor generates large quantities of carbon monoxide, an analyzer should be provided and calibrated for carbon monoxide. Since most waste combustors operate with carbon monoxide emissions less than 100 ppm dry volume corrected to 7% oxygen, the impact of the efficiency loss due to carbon monoxide in the flue gas will be less than 0.05% (about 2 Btu/lb for 5,000 Btu/lb waste). Therefore, in these cases, the carbon monoxide loss may be estimated or ignored. Nitrogen is determined by difference.

4-3.2.2 Water Vapor. Water vapor in flue gas measurements should be performed according to EPA Method 4, which uses a single-point probe. The probe shall traverse a grid layout similar to the dry flue gas grid. Although a stationary grid would reduce the systematic error of the test, use of a stationary grid is not considered practical for this application.

4-3.3 Flow Weighting

The average temperature of flue gas flowing in a duct is needed to determine the loss due to energy in the gas. The average temperature is obtained from measurements of the gas temperature at multiple points distributed across the duct cross section. This Code does not require that flow-weighted average temperatures, oxygen, carbon dioxide, or carbon monoxide content be

used. If mass flow weighting is used, refer to ASME PTC 4 for calculations.

4-3.4 Frequency of Measurements

Because of fuel variability, control system tuning, and other factors, variations in operational parameters are inevitable. To minimize uncertainty, more measurements are taken during the test to reduce random errors in the data collected.

The frequency of data collection has a direct correlation to the test uncertainty and should therefore be guided by the pretest uncertainty analysis. If fluctuations are noted on any primary parameters during the data collection, the time interval between collections should be decreased. The resulting increase in the quantity of data provides a greater statistical base from which to determine performance and reduces the random component of uncertainty.

The use of automated data collection devices is preferred. Analog to digital (A/D) accuracy is no longer an issue with most modern data acquisition devices. The major issue involves distributed control systems (DCS), which use exception-based reporting. This method uses a deadband approach where no change in a value is reported unless that value varies by a predetermined percentage. This type of system is unacceptable unless the deadband can be set to approximately zero for the test measurements.

4-3.5 Estimating Measurement Systematic Error

Estimating the systematic error is a key element in designing the test and selecting instrumentation. The total systematic error associated with a particular measurement is the result of several systematic errors in the measurement system. Section 7 describes the process of combining the systematic errors. For each parameter in the test program, all possible sources of measurement system error associated with that parameter must be determined. All of the components of the system must be examined to estimate their systematic errors.

Outside factors that influence the measurement should be considered. Factors such as air leakage into a flue gas analyzer should be considered and included as a one-sided systematic error, since a leak can only dilute the sample. All leaks should be found and repaired prior to the beginning of the test, although it is recognized that a small leak could occur during the test, or a very small leak may not be found prior to testing. All of these systematic errors must then be combined into a single value for the parameter.

Since data collection and storage are often the same for many parameters, the systematic errors associated with these portions of the measurement system warrant evaluation next. Following the evaluation of the data collection system, each of the different types of process measurements will be evaluated, along with the systematic errors associated with their primary elements and

sensing devices. Other sources that may be referenced for typical values of systematic errors include ASME PTC 19.5 (Flow Measurement), ASME PTC 19.2 (Pressure Measurement), ASME PTC 19.3 (Temperature Measurement), appropriate ASTM standards, and instrument manufacturer specifications.

Estimating the systematic error in a measurement involves the evaluation of all components of a measurement system, such as those listed in Table 4-3.5-1. These systematic errors, however, may not be representative of any specific measurement situation, and it would be misleading for this Code to mandate specific values for systematic error. The assignment of the appropriate systematic error requires the full knowledge of the test measurement system, the process being tested, and all other factors that may influence the systematic error of the measurement. The test engineer is in the best position to evaluate these factors and can use this table as a tool to assist in assigning values for measurement systematic errors.

When parameters are estimated rather than measured, the values for estimates and for systematic uncertainties need to be determined. The test engineer can usually obtain reasonable values by considering that the probability is approximately 19:1 (95% confidence level) and that the upper and lower limits will not be exceeded, and by noting that most processes are governed by well-known physical principles (e.g., radiant heat transfer occurs from a hotter object to a colder object; air can only leak into a sample train held under vacuum).

Table 4-3.5-1 Potential Instrumentation Systematic Uncertainties

Instrument	Systematic Uncertainties [Note (1)]
Data acquisition	Note (2)
Digital data logger	Negligible
Plant control computer	±0.1%
Handheld temperature indicator	±0.25%
Handheld potentiometer (including reference junction)	±0.25%
Temperature	Note (3)
Thermocouple	
NIST-traceable calibration	Note (4)
Premium Grade Type E	
32°F to 600°F	±2°F
600°F to 1,600°F	±0.4%
Premium Grade Type K	
32°F to 530°F	±2°F
530°F to 2,300°F	±0.4%
Standard Grade Type E	
32°F to 600°F	±3°F
600°F to 1,600°F	±0.5%
Standard Grade Type K	
32°F to 530°F	±4°F
530°F to 2,300°F	±0.8%

Table 4-3.5-1 Potential Instrumentation Systematic Uncertainties (Cont'd)

Instrument	Systematic Uncertainties [Note (1)]
Resistance temperature device (RTD)	
NIST-traceable calibration standard	Note (4)
32°F	±0.03%
200°F	±0.08%
400°F	±0.13%
570°F	±0.18%
750°F	±0.23%
930°F	±0.28%
1,100°F	±0.33%
1,300°F	±0.38%
Temperature gauge	±2% of span
Mercury-in-glass thermometer	±0.5 gradation
Pressure	Note (5)
Gauge	
Test	±0.25% of span
Standard	±1% of span
Manometer	±0.5 gradation
Transducer and transmitter	
High accuracy	±0.1% of span
Standard	±0.25% of span
Aneroid barometer	±0.05 in. Hg
Weather station	Note (3)
Velocity	
Standard pitot tube	
Calibrated	±5% [Note (6)]
Uncalibrated	±8% [Note (6)]
S-type pitot tube	
Calibrated	±5% [Note (6)]
Uncalibrated	±8% [Note (6)]
Three-hole probe	
Calibrated	±2% [Note (6)]
Uncalibrated	±4% [Note (6)]
Hot wire anemometer	±10%
Turbometer	±2%
Flow (air and gas)	
Multipoint pitot tube (within range)	
Calibrated and inspected (directional velocity probe)	±5%
Calibrated with S-type or standard	±10%
Uncalibrated and inspected	±8%
Uncalibrated and uninspected	±20%
Airfoil	
Calibrated	±5%
Uncalibrated	±20%
Flow — Steam [Note (7)]	
Orifice, uncalibrated	0.60%–0.75%
Orifice, calibrated	0.3%–0.5%
Venturi, uncalibrated	1.1%–1.2%
Venturi, calibrated	0.3%–0.5%
Nozzle, pipe taps, uncalibrated	1.1%–1.2%
Nozzle, pipe taps, calibrated	0.3%–0.5%
Nozzle, throat taps, uncalibrated	1.1%–1.2%
Nozzle, throat taps, calibrated	0.3%–0.5%

Table 4-3.5-1 Potential Instrumentation Systematic Uncertainties (Cont'd)

Instrument	Systematic Uncertainties [Note (1)]
Flow — Water [Note (7)]	
Orifice, uncalibrated	0.60%–0.70%
Orifice, calibrated	0.3%–0.4%
Venturi, uncalibrated	1.0%–1.1%
Venturi, calibrated	0.3%–0.4%
Nozzle, pipe taps, uncalibrated	1.0%–1.1%
Nozzle, pipe taps, calibrated	0.3%–0.4%
Nozzle, throat taps, uncalibrated	1.0%–1.1%
Nozzle, throat taps, calibrated	0.3%–0.4%
Weir	±5%
Blowdown valve	±15%
Liquid Fuel Flow (Calibrated)	
Flowmeter	
Positive-displacement meter	±0.5%
Turbine meter	±0.5%
Orifice (uncalibrated)	±1.0%
Weigh tank	±1%
Volume tank	±4%
Gaseous Fuel Flow	Note (1)
Orifice	
Calibrated and inspected	±0.5%
Calibrated and uninspected	±2%
Uncalibrated and inspected	±0.75%
Turbometers	
Non-self-correcting	±1.0%
Self-correcting	±0.75%
Waste Fuel Flow	
Weighed piles	0.50%
Overhead crane load cell	
Calibrated	±0.5%
Uncalibrated	±5%
Residue Flow	
Isokinetic dust sampling	±10%
Weigh bins	
Weigh scale	±5%
Strain gauges	±8%
Level	±20%
Assumed split (bottom ash/fly ash)	10% of total ash
Flue Gas Sampling	
Point-by-point traverse	See Section 7
Composite grid	See Section 7
Residue Sampling (for unburned combustibles)	
Isokinetic dust sampling	±5%
"Thief" probe	±200%
Bottom ash	±50%
Flue Gas Analysis	
Oxygen analyzer	
Continuous electronic analyzer	±1.0% of span
Portable analyzer	±2% of span
Carbon dioxide analyzer	
Continuous electronic analyzer	±1% of reading or 0.1% of scale, whichever is greater

Table 4-3.5-1 Potential Instrumentation Systematic Uncertainties (Cont'd)

Instrument	Systematic Uncertainties [Note (1)]
Moisture in flue gas	
EPA Method 4 traverse	±10% of reading [Note (8)]
Continuous analyzer	Type ±1.0% of span
Carbon monoxide	
Continuous electronic analyzer	±20 ppm
Electric Power Use	
Voltage or current	
Current transformer	±10%
Potential transformer	±10%
Handheld digital ammeter	±5%
Watts	
Wattmeter	±2%
Humidity	
Hygrometer	±2% RH
Sling psychrometer	±0.5 gradation
Weather station	Note (9)

NOTES:

- (1) All systematic uncertainties are percent of reading unless noted otherwise.
- (2) For thermocouples, error may be introduced depending on the method of correcting for a reference junction. Also, the algorithm for conversion of thermocouple millivolts to temperature may introduce errors.
- (3) See ASME PTC 19.3, Temperature Measurement, for applicability.
- (4) NIST-traceable instruments have a systematic uncertainty equal to the accuracy of the calibration device. These systematic uncertainties do not include drift.
- (5) See ASME PTC 19.2, Pressure Measurement, for applicability.
- (6) These systematic uncertainties include user-induced errors such as probe location.
- (7) Calibrate at test Reynolds number or use ASME PTC 6 nozzle for extrapolation. For uncalibrated devices, flow coefficients and uncertainties can be taken from ASME PTC 19.5 or ISO 5167.
- (8) The 10% number could be reduced if multiple traverses are done.
- (9) Must be corrected for elevation and distance from weather station.

4-4 TEMPERATURE MEASUREMENT**4-4.1 General**

Temperature is typically measured with thermocouples, resistance temperature devices, temperature gauges, or mercury-in-glass thermometers. These devices produce either a direct reading or an electronic signal.

Data measurement devices must be allowed to reach thermal equilibrium in the environment where the measurements will be taken. Thermocouple lead wires shall be placed in a nonparallel position relative to electrical

sources to avoid possible electrical interference.

Refer to ASME PTC 19.3 for further information on temperature measurement techniques and constraints on use of various devices.

4-4.2 Measurement Systematic Errors for Temperature

When estimating the systematic error of a temperature measurement, test personnel should consider the following list of potential systematic error sources in addition to the factors listed in Table 4-3.5-1:

- (a) calibration and drift
- (b) thermowell location and geometry
- (c) stratification of air and flue gas
- (d) grid size and location
- (e) heat conduction and radiation

4-4.3 Air and Gas Temperature

Air and flue gas flowing through a duct have nonuniform velocity, temperature, and composition. This is especially true near a flow disturbance, such as a bend or transition. To compensate for stratification and to obtain a representative average, multiple points must be sampled in a plane perpendicular to the flow. The measurement plane should be located away from bends, constrictions, or expansions of the duct. If the stratification is severe, mass flow weighting as described in para. 4-3.3 may be considered to reduce potential errors in the average temperature. Thermocouples shall be read and recorded individually.

4-4.3.1 Method of Measurement. There shall be one point for every 9 ft² of duct cross-section area with a minimum of four points and a maximum of 36 points. See Figs. 4-4.3.1-1 and 4-4.3.1-2 for rectangular and circular duct sampling grids, respectively.

4-4.3.2 Estimating Measurement Systematic Errors.

An estimate of the systematic error from a temperature measurement grid is a combination of systematic uncertainties from the temperature primary element and sensor type, data acquisition, grid size, temperature distribution, averaging method, and flow weighting. Potential sources of these systematic errors are described in subsection 4-3 and para. 4-4.2. See Section 7 for a model for the estimation of systematic errors due to flow weighting, grid size, and averaging method.

When the average entering air temperature is a mass-weighted average of two or more streams at different temperatures, the impact of the systematic error associated with the determination of the mass flow rate shall be included in the overall systematic error for the average air temperature.

4-4.4 Steam and Water Temperatures

Steam and water flows are considered to have a uniform temperature distribution.

4-4.4.1 Method of Measurement. Steam and water temperatures should be measured by inserting the sensing device into a thermowell located in the piping. Alternatively, “pad” or “button” thermocouples can be located around the pipe and insulated, but use of this method substantially increases the uncertainty of the measurement.

4-4.4.2 Estimating Measurement Systematic Errors.

An estimate of the systematic error from a temperature measurement is a combination of systematic error limits from the temperature primary element, sensor type, and data acquisition. Potential sources of these systematic uncertainties are discussed in subsection 4-3 and para. 4-4.2.

4-4.5 Waste Fuel Temperature

The temperatures of solid streams entering or leaving the unit are required and are often difficult to measure. The Code recommends using the ambient temperature in the area where the as-fired waste fuel is stored. The measurement systematic error should be assigned a value of zero.

4-4.6 Residue Temperature

Residue temperature shall be measured as close as practicable to the point where it leaves the boundary. Quenched bottom ash is considered to be the same temperature as the quench bath. The temperature of the bottom ash or bath may be measured. Residue, which is not discharged with the bottom ash and leaves the boundary elsewhere, shall be assigned the temperature of the flue gas at its extraction point.

An estimate of the systematic error from a temperature measurement is a combination of the systematic uncertainties from the temperature primary element, sensor type, and data acquisition. Subsection 4-3 and para. 4-4.2 discuss potential sources of these systematic errors. When systematic errors are assigned to parameters that are assumed, typically a larger value for the systematic error is chosen than if the parameter is directly measured.

4-5 PRESSURE MEASUREMENT

4-5.1 General

Pressure is typically measured with pressure gauges, water or mercury manometers, or transmitter/transducers. These devices produce either a direct reading or an electronic signal.

The effect of static sensing lines should be accounted for in the calibration of the instrument or corrections applied to the readings.

Refer to ASME PTC 19.3 for further information on pressure measurement techniques and constraints on the use of various devices.

Fig. 4-4.3.1-1 Sampling Grids — Rectangular Ducts

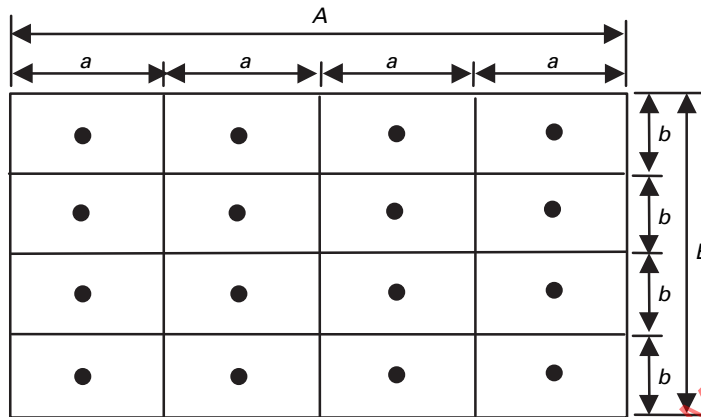
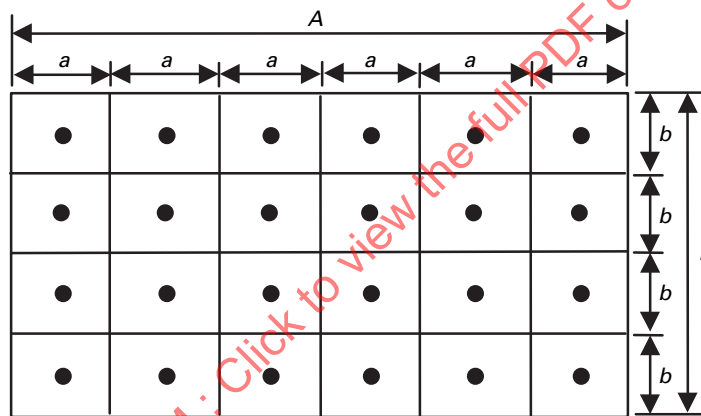
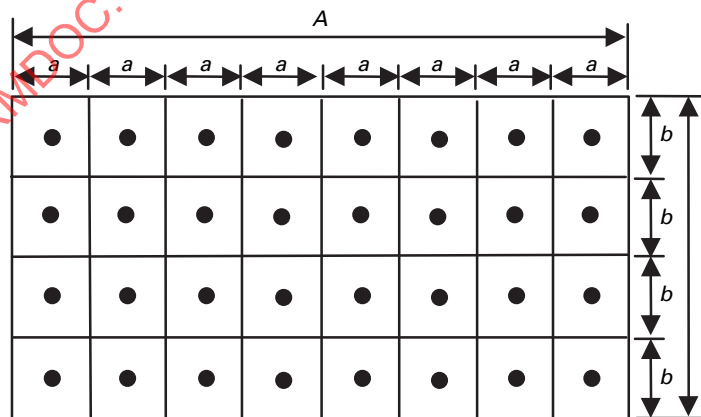
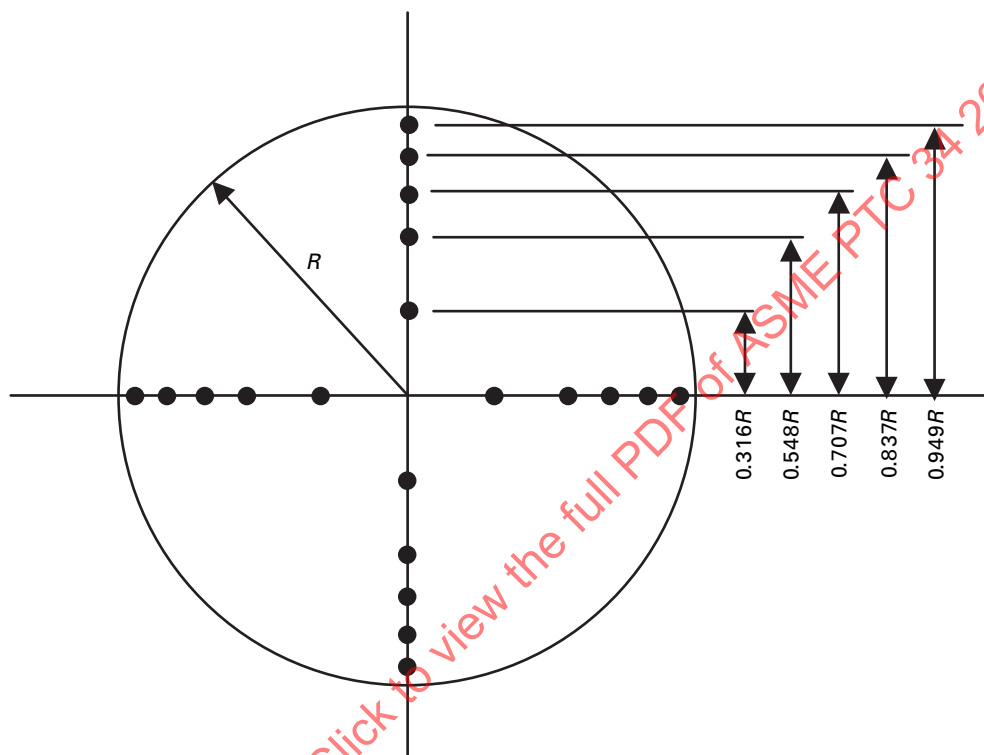
(a) Same Geometric Shape as Cross Section ($\frac{A}{B} = \frac{a}{b}$)(b) More Nearly Square Than Illustration (a) ($\frac{A}{B} > \frac{a}{b}$ and $a > b$)(c) Square ($a = b$)

Fig. 4-4.3.1-2 Sampling Grids — Circular Ducts



Formula for determining location points in circular duct:

$$r_p = \sqrt{\frac{2R^2(2p-1)}{n}}$$

where

n = total number of points

p = sampling point number, numbered from center of duct outward.

All four points on the same circumference have the same number.

R = radius of duct

r_p = distance from center of duct to point p

NOTE: r_p will be in the same units as R .

Example: Duct radius = R ; 20 points total; distance to point 3 = r_3 .

$$r_3 = \sqrt{\frac{2R^2(2 \cdot 3 - 1)}{n}} = \sqrt{\frac{2R^2(5)}{20}} = \sqrt{0.5R^2} = 0.707R$$

GENERAL NOTE: ● Indicates points of location of sampling tube.

4-5.2 Measurement Systematic Errors for Pressure

When estimating the systematic error of a pressure measurement, test personnel should consider the following list of potential sources in addition to the factors listed in Table 4-3.5-1:

- (a) calibration and drift
- (b) tap location and geometry flow impact
- (c) number and location of measurements
- (d) water leg
- (e) ambient conditions at sensor and meter

4-5.3 Steam and Water Static Pressure

The static pressure in steam and water piping is required to determine fluid properties in the unit.

4-5.3.1 Method of Measurement. Pressure measurement devices should be located so as to minimize the effects of temperature and vibration. The following should be adhered to in the installation of pressure-measuring devices:

- (a) Pressure measurement connections should be short and direct.
- (b) All pressure measurement connections should be free of leaks, with provisions for cleaning and drainage.
- (c) Pressure connections should be located and installed with care to exclude velocity effects.
- (d) Connections from the instrument to the pressure tap should be purged and the condensate allowed to fill the lines. Condensate water legs shall be accounted for in the calculations.

4-5.3.2 Estimating Measurement Systematic Errors.

An estimate of the systematic error from a pressure measurement is a combination of systematic uncertainties from the primary element, tap type, and data acquisition. Potential sources of these systematic errors are discussed in subsection 4-3 and paras. 4-4.2 and 4-5.2.

4-5.4 Barometric Pressure

Barometric pressure is required to determine air and flue gas flows.

4-5.4.1 Method of Measurement. The preferred method for determining barometric pressure is from a barometer at the test site. An alternate method is the use of the barometric pressure reported at the nearest weather station. The elevations of the weather station's reading and of the test site should be noted and corrections made for any differences in elevation.

4-5.4.2 Estimating Measurement Systematic Errors. The use of a barometer or other such measurement device at the site will be considered to have a negligible systematic error. Data from a weather station is considered less accurate, and, if used, an appropriate systematic error should be assigned.

4-6 FLOW MEASUREMENT

4-6.1 General

See ASME PTC 19.5 for information on flow measurement techniques.

It should be recognized that a flow stream, e.g., air, flue gas, and continuous blowdown, could result in lower uncertainty by calculation instead of measurement. It is recommended that such measurements be reviewed to see if they can be calculated. It is recommended that the total flue gas mass flow rate be calculated by economizer heat balance and the total air mass flow rate be calculated by nitrogen balance.

Where several individual flow streams sum to a total flow stream and the total stream can be calculated more accurately than measured (e.g., air), all but one of the individual streams may be measured and the unmeasured streams calculated by difference.

If individual airflow streams are broken up into heated and unheated streams, then the heated stream should be measured and the unheated stream calculated by difference. Otherwise, the smallest flow stream should be measured and the larger streams calculated.

For streams where the total flow can be calculated more accurately than measured (e.g., air), all but one stream may be measured and the unmeasured streams calculated by difference. When all streams are measured, the mass fraction of each stream shall be calculated from the measured mass flow rate. The mass flow rate of the individual streams is then determined from the product of the mass fraction of the individual streams and the total calculated mass flow rate.

4-6.2 Systematic Errors for Flow

When estimating the systematic error of a flow measurement, the following list of potential sources should be considered. Not all sources are listed, and some of those listed may not be applicable to all measurements. These factors should be considered in conjunction with the factors listed in Table 4-3.5-1.

- (a) calibration and drift
- (b) stratification of flow
- (c) temperature
- (d) pressure
- (e) installation
- (f) location or geometry
- (g) grid size and location
- (h) pressure correction (compensation)
- (i) temperature correction (compensation)
- (j) Reynolds number correction

The measured inputs to a flow calculation must be examined for sources of systematic errors, and these systematic errors must be combined into the systematic error of the flow measurement.

4-6.3 Steam and Water Flow

Certain steam and water flow measurements are required to determine output.

4-6.3.1 Method of Measurement. Guidance for measurement of steam and water flows is given in ASME PTC 19.5. The following methods of measurement are typically used to determine steam and water flows:

(a) *Flow Measurement Through a Nozzle, Venturi, or Orifice.* One method of measuring flow is to measure pressure drop across a flow nozzle, venturi, or orifice plate. This method is usually the most accurate and should be used for all critical flow measurements.

(b) *Energy and Mass Balance Calculation.* Certain flows may be quantified by energy balance calculations. These flows include blowdown flow and desuperheating spray flow.

(c) *Estimated Flows.* In some cases, it may not be possible to quantify a flow directly. In these cases, flow curves derived from either a known flow or a valve position may be used; e.g., blowdown flow may be estimated based on valve turns.

Other devices may be used if it can be demonstrated that they meet the uncertainty requirements of the test.

4-6.3.2 Estimating Measurement Systematic Errors.

An estimate of the systematic error from a flow measurement is a combination of systematic uncertainties from the primary element type, sensor type, and data acquisition. Subsection 4-3 and para. 4-4.2 discuss potential sources of these systematic errors.

4-6.4 Wet Flue Gas Flow

There are two acceptable methods for determining wet flue gas flow. These are the economizer heat balance and the velocity traverse. The economizer heat balance is the preferred method. However, this method cannot be used when the economizer is operated in a steaming mode. Dry flue gas flow is calculated from the wet flue gas flow and flue gas moisture.

4-6.4.1 Economizer Heat Balance Method of Flow Measurement. Gas temperatures shall be measured using a grid of thermocouples at the inlet and outlet of the economizer. The number of points and areas of the grid for the inlet and outlet will be determined using the procedure in subsection 4-4. The temperature measurements will be taken at the centers of the equal areas.

The feedwater flow through the economizer will be measured. Care shall be used to account for any feedwater used for desuperheating or if the economizer has a bypass. The feedwater temperature into and out of the economizer shall also be measured. The gas flow is calculated by determining the mass of gas necessary to balance the heat released from the gas and captured by the feedwater in the economizer.

Flue gas temperature should be measured at a point where the temperature of the gas is not significantly

different from the temperature of the surrounding surface. An error is introduced when the gas temperature is high, usually greater than 1,000°F, and the thermocouple is cooled by radiation to the surrounding surface. This error in measured temperature should be taken into account. A high-velocity thermocouple probe can be used to reduce this error.

4-6.4.2 Estimating Systematic Errors for Economizer Heat Balance. Since the flue gas flow is calculated from an economizer heat balance, there is no measurement systematic error for the flue gas flow. Estimation of the systematic error for the individual temperature, pressure, and feedwater flow measurements is described in subsections 4-4, 4-5, and 4-6.

4-6.4.3 Velocity Traverse Method of Measurement.

When it is not possible to determine the flue gas mass flow rate by an economizer energy balance, the velocity traverse method may be the only practical alternative. In the velocity traverse method, the duct is subdivided into a number of elemental areas and, using a suitable probe, the velocity is measured at a point in each elemental area. The total flow is then obtained by summing the contributions of each elemental area (perhaps, depending on the measurement and calculation technique, using different weighting factors for different areas). Within the framework of the velocity traverse method, many different techniques have been proposed for selecting the number of points at which velocity is measured, for establishing the size and geometry of the elemental areas, and for summing (theoretically integrating) the contributions of each elemental area. Options that have been proposed include the placing of points based on an assumed (log-linear, Legendre polynomial, or Chebyshev polynomial) velocity distribution, the use of graphical or numerical techniques to integrate the velocity distribution over the duct cross section, the use of equal elemental areas with simple arithmetic summing of the contribution of each area to the total flow, and the use of boundary layer corrections to account for the thin layer of slow-moving fluid near a wall. As a general rule, accuracy of flow measurement can be increased either by increasing the number of points in the traverse plane or by using more sophisticated mathematical techniques (e.g., interpolation polynomials, boundary layer corrections). ASME PTC 19.5 recommends either a Gaussian or Chebyshev integration scheme. Investigations performed by the ASME PTC 11 — Fans Committee using different velocity distributions similar to those that actually occur in the field have shown that no particular technique is always more accurate.

For velocity distributions encountered in large flues and ducts, it is more in line with the requirements of field testing, as well as more realistic in light of the varied distributions of velocity that may actually occur

in the field, to obtain the desired accuracy of flow measurement by specifying measurements at a relatively large number of points at the center of equal areas rather than by relying on assumed velocity distributions or unsubstantiated assumptions regarding such things as boundary layer effects. Additionally, it is usually desirable to have a large number of points (elemental areas) to improve the accuracy of the flow measurement. For these reasons, this Code adopts the equal-area method with measurement at a relatively large number of points. Investigations of flow measurement under conditions similar to those expected in application of this Code have demonstrated the validity of this approach. For specific details on the use of Gaussian or Chebyshev measurement methodology, refer to ASME PTC 19.5.

Due to the highly disturbed flow at typical flue gas flow measurement locations and the errors associated with making measurements with probes unable to distinguish flow direction, probes capable of indicating gas direction and speed, hereinafter referred to as "directional probes," are generally required. Only the component of velocity normal to the elemental area is pertinent to the calculation of flow. Measurement of this component cannot be accomplished by simply aligning a non-directional probe parallel to the duct axis, since such probes only indicate the correct velocity pressure when aligned with the velocity vector. Errors are generally due to undeterminable effects on the static (and to a lesser degree, total) pressure-sensing holes. Therefore, adequate flow measurements in a highly disturbed region can only be made by measuring speed and direction at each point and then calculating the component of velocity parallel to the duct axis.

4-6.4.4 Estimating Measurement Systematic Errors.

An estimate of the systematic error from a velocity traverse is a combination of systematic uncertainties from probe type, measurement methods, and data acquisition. Subsection 4-3 and para. 4-6.2 include potential sources of these systematic errors.

4-6.5 Waste Fuel Flow

The amount of waste fuel entering the waste combustor is required to determine waste fuel higher heating value (HHV) in Btu/lb. Waste fuel may be charged into a furnace in several ways. It may be loaded from a refuse pit into a feed hopper by means of a crane grapple with a weigh scale system. It may also be fed from a pile on a tipping or storage floor into a feed chute/hopper or onto a conveyor feeding a feed chute/hopper. Two important concepts apply to obtain an accurate measurement. First, all waste must be accounted for, and second, the crane/truck weigh scale system must be calibrated. To minimize uncertainty by making sure all test waste is accounted for, the following items must be addressed:

(a) The feed/storage hopper levels should be the same at the start and end of the test. If not, the difference

in level must be determined and the associated amount of waste added or subtracted from the test waste fuel flow.

(b) For cranes with grapples charging hoppers, it is imperative during feeding the hopper that no waste is spilled out of the hopper and back into the refuse pit.

(c) For the pile method, when waste remains at the end of the test, that waste must be weighed and subtracted from the gross pile weight.

4-6.5.1 Method of Measurement

(a) *Crane Scales.* The weight of each grapple load fed to the feed hopper should be recorded, along with the date, time, unit number fed, and crane number. Crane grapples can be operated by wire rope or a hydraulic system and have different design scale systems requiring different attention.

In the case of the wire rope system, the weigh scale system typically consists of load cells under the trolley raise/lower and open/close rope spools. Therefore, the position of the grapple and the tension on the closing cable can affect the weigh scale reading. The grapple must always be in the same position as during its calibration and have the same amount of closing pressure. Use of automatic limit switches may help, but close attention and consistent operation are necessary. It is recommended to have the same crane operator for the duration of the test if possible.

Hydraulic grapple systems typically have load bars built into the attachment of the grapple to the raise/lower rope. These systems are inherently more accurate and reliable. The grapple need not be in the same location, and closing tension does not affect the scale reading.

(b) *Calibration of Crane Scales.* The calibration of the crane scales consists of making and lifting a known test weight(s) several times and comparing the scale reading to this value. If there is a demonstrated effect, to minimize uncertainty, the scale reading may have to be taken while the grapple and weight are in the same location and open/close position as when waste fuel would normally be fed.

(c) *Test Weight(s).* Several test weights can be made to check the scale across the expected load range. As a minimum, the scale should be checked at mid and full scale. A concrete block can be fabricated as the test weight(s). Lifting lugs should be installed in the concrete block and on the grapple to expedite the calibration process.

The test weight can itself be calibrated on facility truck scales. The weight of the test weight should be clearly marked on the block. The weigh scale shall be calibrated prior to and after the test in accordance with ASME PTC 19.5. Commercial scales, such as truck scales, shall be certified accurate within 1 month prior to the test, in accordance with laws and regulations regarding scales used in commerce.

(d) *Pile Feeds.* Waste fuel amount can also be determined by feeding a known amount of waste fuel (pile) during a specified period. The duration of the test can be until the pile is completely gone; or if the test is ended with test waste remaining, the remaining waste must be weighed. The weight of the pile may be directly obtained by using facility truck scales as is typically associated with a mass-burn plant. The pile weight may also be indirectly determined by difference due to materials removed as is typical with an RDF plant. All materials removed must be collected and weighed using calibrated and certified facility truck scales. Estimates of moisture evaporation have been used and are acceptable.

4-6.5.2 Estimating Random Errors

(a) *Grapples.* The random error for waste fuel flow metered with a crane scale system may be estimated by repeated lifting of a test weight through a minimum of 10 simulated, complete load cycles. Load readings should be taken for each cycle. The random error is the value that corresponds to a calculated 95% confidence level. Random errors are highly dependent on the design and maintenance/calibration of the grapple/weigh system. Random errors for hydraulic grapples with universal-joint-type load cells can be as low as 1% of the net waste fuel weight, while random errors for wire-rope-type grapples with load cells under the take-up reel bearings can be as high as 10% of the net weight. Rope-type grapple scale systems are dependent on closing pressure, which may not be possible to simulate with a test weight.

(b) *Weighed Piles.* The random error for a waste fuel pile metered with a truck scale may be estimated by loading a vehicle with certified test weights. The vehicle should be driven on and off of the truck scale a minimum of 10 cycles. Load readings should be taken for each cycle over the scale. Truck scale calibrations are usually performed by their vendor representatives.

(c) *Belt Scales.* The random error for refuse flow metered with a belt scale may be estimated by referring to scale manufacturer specifications. An alternative method to determine random error is to compare the readings of the belt scale with a known mass of refuse (as determined using truck scales) equivalent to at least one operating hour at full capacity.

4-6.6 Residue Flow

The amount of residue leaving the waste combustor boundary is required to determine the heat losses associated with the residue streams. Residue streams that leave the facility (cross the boundary) may include bottom ash, boiler ash, or fly ash.

4-6.6.1 Method of Measurement. The total quantity of residue for the test period shall be segregated, collected, and weighed if it is practical to do so. If the

residue is quenched in water, the residue shall be weighed wet and the weight of moisture subtracted from the total weight to determine the dry weight.

If it is not practical to segregate the test ash residue, then a method to estimate the quantity shall be developed and an appropriate systematic error assigned. The weigh scale shall be calibrated prior to and after the test in accordance with ASME PTC 19.5. Commercial scales, such as truck scales, shall be certified accurate within 1 month prior to the test, in accordance with laws and regulations regarding scales used in commerce.

4-6.6.2 Estimating Measurement Systematic Errors.

When residue splits are estimated, parties to the test should agree on a mean value of systematic uncertainty such that the same positive and negative estimates can be used. A systematic uncertainty that would result in a split of less than 0 or greater than 100 must not be used. When the residue flows are measured, the procedures used and the guidance in Table 4-3.5-1 should be reviewed for potential sources of systematic uncertainty.

4-6.7 Supplementary Fuel Flow

The quantity and heating value of liquid and gaseous supplementary fuels burned must be determined to establish the heat value from this source. Other supplementary fuels such as coal or wood chips would normally be considered as part of the waste fuel stream. However, if an accurate quantity measurement is possible and its heating value can be accurately determined, these solid fuels may be considered supplementary and their heat input determined.

4-6.7.1 Method of Measurement. Gaseous fuel flows are usually measured by orifice metering runs. Liquid fuel flows are usually measured by orifice or other differential pressure meter, positive-displacement meter, or turbine meter. Nonstandard flow elements, e.g., vortex shedding, mass flowmeters, etc., may be used if demonstrated to be as accurate as or more accurate than standard meters. Supplementary solid fuel flows that cannot be measured by standard flowmeters need special measurement techniques similar to MSW flow measurement. Supplementary continuous or batch-fed fuels such as coal or wood chips can be measured by a crane scale system, gravimetric belt feeder, storage bin or hopper level changes, or from feeding a known weight of a pile determined using truck scales.

4-6.7.2 Estimating Measurement Systematic Errors.

The systematic errors for standard flow elements are discussed in Table 4-3.5-1. Using other devices is acceptable if the uncertainty can be shown to meet the requirements of the test. Depending on the percentage of supplementary solid fuel fed, an estimate of the systematic error from the measurement can be agreed on by the parties to the test or determined by a separate test. A separate test might consist of feeding the fuel into

containers or trucks and weighing them on truck scales while performing the flow measurement technique. One or several comparisons of the test and reference methods would be used to establish a measurement systematic error.

4-6.8 Airflow

Airflow entering the boiler, particularly heated air, is required to determine the average entering air temperature. Typically, these air streams are measured using permanent plant instrumentation, e.g., orifice, venturi, averaging pitot meter, or airfoil. If these flow elements do not exist, flow traverses should be performed. If the temperature difference between the various streams is small, the flow splits shall be estimated.

Unheated air streams may be calculated by mass balance using the calculated total airflow and the measured heated air stream. See para. 5-10.2.

4-6.8.1 Method of Measurement. A standard or impact pitot tube can be used in a clean, cool air stream and is preferred to minimize pitot coefficient uncertainty. (See para. 4-6.4.3 for procedures.)

4-6.8.2 Estimating Measurement Systematic Errors. An estimate of the systematic error from a velocity traverse is a combination of systematic errors from probe type, measurement methods, and data acquisition. Subsection 4-3 and para. 4-6.2 include potential sources of these systematic errors. Pitot traverses should be performed to calibrate existing flow elements to minimize the measurement uncertainty.

4-6.9 Minor Water Flow

Water flow streams crossing the system boundary used in the calculation of minor losses, e.g., cooling water, can be measured using noncritical flowmeters.

4-6.9.1 Method of Measurement. Typical types of these noncritical flowmeters include paddle wheel, turbine, or ultrasonic.

4-6.9.2 Estimating Measurement Systematic Errors. Measurement systematic error can be estimated by temporarily diverting the relatively small water stream into a suitably sized container or tank, measuring the level change to calculate the volume of water displaced, and comparing to the meter output.

4-7 SAMPLING AND ANALYSIS

4-7.1 General

Analysis by methods that deviate from this Code can lead to serious errors. Only individuals or companies experienced in the analyses as required by this Code shall do the analyses to ensure that a Code test is conducted.

4-7.2 Flue Gas Sampling

The composition of the flue gas exiting the system boundary must be determined to calculate the molecular weight from the hot gases crossing the system boundary.

Combustion gas flowing through a flue, i.e., flue gas, has nonuniform composition distribution. In a plane across the flowing flue gas this variation in composition or stratification also changes with time as with slight changes in fuel and airflow. The goal of flue gas sampling then is to obtain the integrated average in both time and space across that plane of the flue gas composition.

The flue gas shall be analyzed for the following gases at the system boundary: H_2O , CO_2 , and O_2 . Carbon dioxide and oxygen shall be measured on a dry basis from the same sampling system.

Carbon monoxide and sulfur dioxide concentrations need not be measured for the system heat loss determination. Emission levels commonly observed from municipal waste combustion systems are less than 100 ppm CO , and 50 ppm to 200 ppm SO_2 . The flue gas oxygen and carbon dioxide composition shall be measured at the system boundary, which should be located where sampling should be most accurate. The individual sampling lines from each sampling point would come together in a header (e.g., bubbling jar) to form a composite sample. A common gas sampling line will take the composite flue gas sample from a bubbling jar to the CO_2 and O_2 sampling system(s). Flue gas moisture will be sampled by traverse from a single, separate heated sample line. The traverse will be performed immediately downstream of the gas sampling grid if possible.

Gas samples will be drawn continuously into gas analyzers (preferred) or integrated gas sampling bags. All sampling apparatus shall be in accordance with the recommendations of ASME PTC 19.10. Sampling tubes shall be made of material that shall not contaminate the sample at the temperatures encountered by the system. For sampling high-temperature flue gas, suitable water-cooled samplers must be employed.

Sampling lines shall be as short and straight as possible, shall be accessible for cleaning and blowing out, shall slope in the direction of the flow, shall be suitably drained, and shall be maintained tight.

Analysis of O_2 and CO_2 shall be done from a calibrated flue gas analyzer. Nitrogen will be calculated by difference. The O_2 and CO_2 analyzers shall have a range of 0% to 25% by volume. Calibrations will be conducted at a low range and a high range using EPA Protocol 1 gases. The low-range O_2 gas will be between 5% and 10% O_2 . The high-range CO_2 gas will be between 10% and 15% CO_2 . The high-range O_2 gas and the low-range CO_2 gas can be dried ambient air.

Flue gas moisture will be measured by traverse per EPA Method 4. The time sampled at each traverse point should be equal and calculated such that a complete

traverse of the grid is performed every hour. Two, three, or four traverses should be performed before changing sampling trains. Spare sampling trains should be readied such that no sampling time is lost. When traversing, care should be taken to change ports quickly, so the time when the sampling probe is removed from the flue is minimal and air is not taken into the sample stream.

4-7.2.1 Methods of Flue Gas Sampling. To compensate for stratification and to obtain a representative specimen, multiple points in the sampling plane must be sampled. The flue gas samples shall be taken from the same measurement points used for temperature determination. The number of sampling points shall be chosen as described in para. 4-4.3.1. To minimize the uncertainty, the individual sample points shall be combined to form a composite sample. The flue gas shall be collected from the sampling grid as described in subsection 4-3 and combined into a single sample for each flue or location. The sampling rate from each probe should remain equal and the system should be checked for leaks before the test and inspected for leaks throughout the test.

4-7.2.2 Measurement Systematic Error for Flue Gas Sampling. An estimate of the systematic error from a sample is a combination of systematic uncertainties from sample acquisition, location, and stream consistency. Subsection 4-3 and para. 4-7.3.2 provide potential sources of these systematic errors. If sampling procedures are performed using a composite sample, the systematic error due to spatial nonuniformity may be estimated by making individual measurements at the grid sampling points and computing the spatial distribution index according to para. 5-16.4.1. On a sampling system that operates under a vacuum, there is the potential that in-leakage will result in a one-sided systematic error. If the flue gas is severely stratified, the possibility of systematic error is increased.

The challenge associated with sampling flue gas moisture is that the spatial distribution index (SDI) is calculated relatively easily for temperature and O_2/CO_2 measurements, but presents substantial difficulties when used for moisture measurements. Each temperature grid point can be rapidly sampled many times (essentially simultaneously) using a multichannel data logger and the SDI calculated. With moisture you are limited by the time (~1 hr) needed to collect enough moisture to accurately weigh and/or the number of trains that can be simultaneously and practically used. Flue gas O_2 and CO_2 sampling falls somewhere in between, but is closer to temperature since it only takes about 1 min to obtain a sample and multiple analyzers are more feasible than multiple moisture trains.

Paragraph 4-7.2 describes the method for sampling flue gas moisture. It is sampled by making a traverse using an EPA Method 4 moisture train. As indicated

above, moisture spatial systematic error can be estimated by performance pretest moisture measurements at individual points in the gas stream. These individual measurements require using separate moisture trains. One individual point measurement should be located in the center of the flue and the others spaced as far away as possible, i.e., near the sides of the flue. Several 1-hr runs should be sufficient to establish a representative spatial systematic error.

Random error for the sampling of flue gas moisture is based on the total number of "measurements" taken at the individual grid points during the moisture traverse. If desired, random error can be reduced by decreasing the time at each grid point and/or by using multiple traverse points. Both options will increase the number of measurements. Data analyzed in a relatively small flue (<30 ft²) showed that spatial systematic error i.e., stratification, for moisture, was very small (<0.1%). If there is little or no spatial systematic error, then random error is essentially zero due to the continuous nature of the sampling train. All systematic errors are then associated only with the instrument, i.e., the sampling train itself. An uncertainty analysis of EPA Method 4 showed that the instrument systematic error is ~5% of the reading.

4-7.3 Flue Gas Analysis

4-7.3.1 Methods of Flue Gas Analysis. Sampling of H_2O shall be done with a dry gas meter and condensing bottles, per the EPA Method 4 sample train. The Method 4 sampling train consists of a heated sample probe, impingers, drying sorbent, a condenser ice bath, needle valve, leak-free pump, rotameter, and dry gas volume meter. Barometric pressure may be determined using a barometer or the nearest National Weather Service (NWS) station and correcting for elevation differences between the sampling point and the NWS station. A moisture analyzer may be used if it is demonstrated to be as accurate as EPA Method 4.

The following paragraphs describe methods and operation of equipment for measurement of flue gas oxygen (O_2), carbon dioxide (CO_2), and carbon monoxide (CO).

The equipment needed to conduct a flue gas analysis by extractive sampling is composed of two parts: the sample collection and transport system, and flue gas analyzers. The sample collection and transport system is composed of a grid of probes, sample lines, flue gas mixing device, filter, condenser or gas dryer, and pump. Each flue gas analyzer measures a particular flue gas constituent. Since an extractive sample removes water vapor from the sample prior to analysis, this type of analysis is on a dry basis. A nonextractive or "in situ" analysis produces results on a wet basis. Flue gas constituents are analyzed on a volumetric or molar basis, and the moles of the constituents of interest are divided by the total moles present. The difference between the wet

and dry bases is that the wet basis includes both the dry moles and water vapor moles in the denominator.

The only types of analyzers currently allowed for use are continuous electronic analyzers. It is highly recommended that users monitor and record flue gas composition on a continuous basis throughout the test. Fuel variations, control system tuning, and other factors cause minor variations in flue gas constituents. Therefore, a continuously analyzed composite sample taken from a representative grid best represents the true average gas composition.

(a) *Oxygen Analysis.* Several methods are employed to measure oxygen; among them are paramagnetic, electrochemical cell, fuel cell, and zirconium oxide. The test engineer must ensure that the method selected is appropriate for the application employed. As an example, zirconium oxide cells should not be used if the gas contains combustible constituents such as CO or THC. The high temperature in a zirconium oxide cell causes these combustible components to react with the oxygen present, thereby reducing it. When an electrochemical cell is being used, care must be taken to ensure that other gases such as CO₂ do not interfere with the oxygen measurement. An interfering gas in the calibration gas of the approximate concentration found in the flue gas can be used to minimize the error.

(b) *Carbon Dioxide Analysis.* Several spectroscopic methods are employed to measure CO₂; among them are nondispersive infrared (NDIR), nondispersive ultraviolet photometers (NDUV), Fourier transform infrared (FTIR), and gas filter correlation (GFC). The most common method for analysis is NDIR. The test engineer must be aware of interferences that can cause errors in CO₂ readings. Among these are water and carbon monoxide, which absorb infrared light in the same spectral regions as does CO₂.

When the flue gas moisture is removed from gas samples before analysis, as is typically the case with sampling systems used for boiler performance tests, interference from moisture does not exist. To minimize interference from carbon monoxide, it is recommended that the calibration gases that are used include approximately the same volume fraction of CO expected to be present in the flue gas.

(c) *Carbon Monoxide Analysis.* The most common method for carbon monoxide analysis is NDIR. The main disadvantage of this methodology is that CO, CO₂, and H₂O all have similar infrared (IR) wavelength absorption. For accurate CO readings, the sample must be dry and the analyzer must compensate for CO₂ interference. Better-quality instruments determine CO₂, then compensate CO for that value; others use a preset CO₂ interference factor. For determining heat loss due to CO, the inaccuracy resulting from neglecting CO₂ (approximately 20 ppm) is minimal. However, an overestimate of 20 ppm may be significant in relation to environmental protection laws.

4-7.3.2 Measurement Systematic Error for Flue Gas Analysis. A number of factors need to be considered in determining the systematic error of a flue gas analysis system. Some of the potential sources of systematic errors for the flue gas system are the following:

- (a) analyzer accuracy
- (b) sampling system interference
- (c) analyzer drift
- (d) spatial variation
- (e) time variation
- (f) calibration gas accuracy
- (g) sample temperature and pressure influence on analyzer
- (h) undetected leaks
- (i) interference gases
- (j) ambient temperature influence on analyzer
- (k) sample moisture influence on analyzer
- (l) accuracy of dilution ratio, if used

4-7.4 Ash Residue Sampling

An ash residue sample, which is representative of the various facility streams, should be collected, mixed, reduced, and composited for laboratory analysis.

Location of sampling point(s) shall be selected with regard to accessibility, safety of sampling personnel, uniformity of mixed streams, and presence of processing influences. Each stream that leaves the boundary separately should be sampled separately.

Beginning 1 hr to 2 hr after the start of the test, hourly residue samples shall be collected. The delay in ash residue sampling is to account for the time lapse from the start of the test until the ash residue arising from the test waste fuel leaves the system. Each hourly sample should weigh about 40 lb. Samples shall be collected from the ash residue stream by shoveling or scooping and placed into a watertight 5-gal bucket. The bucket shall be covered quickly to minimize evaporation. Large combustible items (e.g., a log) and large noncombustible items (e.g., an automobile radiator) should be avoided while sampling. Bulky residues, which are considered nontypical or representative of the residue stream, should not be included in the samples of residue extracted for subsequent analysis.

A good sample would be represented by a uniform cut by a shovel or scoop across the entire width of a stopped ash residue conveyor or a free-falling stream of residue from which oversize materials have been removed.

4-7.4.1 Mixing and Reduction. When the first four hourly samples have been collected, they shall be mixed and passed through a screen with nominal 2-in. openings to remove large pieces in the ash residue (pieces of paper or cloth on the screen should be pushed through the screen by hand). A section of chain link fence held in a frame makes a suitable screen. The material passing the screen shall be quartered down to a representative

40-lb sample to represent the first 4 hr of the test. This process should be repeated for hours five through eight.

4-7.4.2 Compositing. At the end of the ash residue sampling portion of the test, the two 40-lb samples representing the two 4-hr segments of the test shall be mixed and quartered down to three 5-lb samples. One of the 5-lb samples shall be used for ash residue analysis, and the remaining two samples should be held as “control samples.”

4-7.4.3 Measurement Systematic Error for Residue Sampling. When estimating the systematic error of an ash residue measurement, test personnel should create a list of potential sources.

4-7.5 Ash Residue Analysis

Two procedures are suggested for determining moisture content, percent combustibles, and heat loss in the ash residue. One method must be selected and followed for the entire test procedure. The determination should be performed by an experienced technician. Paragraphs 4-7.5.1 through 4-7.5.3 provide a general description of Method 1. Refer to Nonmandatory Appendix B for a detailed test method that is suitable for a laboratory to follow.

4-7.5.1 Moisture in the Ash Residue

(a) *Method 1.* The 5-lb laboratory sample container should be opened, thoroughly mixed, and approximately 2 lb of ash residue placed into an aluminum pan roughly 12 in. long, 8 in. wide, and at least 1 in. deep. (The remaining portion of the laboratory sample should be resealed for use in duplicate tests, if desired.) The sample in the pan is then weighed and placed in a ventilated furnace, sized to accommodate the pan, at 221°F (105°C) and weighed at ½-hr intervals until a constant weight is reached. (The sample can be stirred to speed up the drying process.) The sample should be weighed on a balance with a capacity of 6.62 lbm (3 000 g) and an accuracy of 0.004 oz (0.1 g). The weight loss divided by the initial weight of the analysis sample times 100 is the percent of surface moisture in the ash residue.

(b) *Method 2.* The moisture analysis is conducted in accordance with ASTM D3302. This method is based on air drying the entire residue sample.

4-7.5.2 Dry Weight of the Analysis Sample

(a) *Method 1.* The furnace temperature is increased to 356°F (180°C), and the sample is weighed at ½-hr intervals until a constant weight is reached. This step is to drive off bound water in the unreacted slake-lime sorbent from the flue gas scrubber. (The sample can be stirred to speed up the drying process.) The constant weight is recorded as the dry weight of the analysis sample.

(b) *Method 2.* The laboratory will prepare the dried sample for the remainder of the analyses by standard

methods of particle size reduction. The laboratory analysis shall include the weight fraction of large particles of metal and glass removed from the sample.

4-7.5.3 Unburned Combustibles in the Ash Residue

(a) *Method 1.* The furnace temperature is increased to 932°F (500°C) and held for 2 hr. The sample is weighed, stirred, and returned to the furnace. At ½-hr intervals the sample is weighed and stirred until a constant weight is reached. At this point, the sample should be free of black specks of carbon. If it is not black-speck-free, stir and place in the oven for another ½ hr. The weight loss is the weight of the unburned combustibles in the analysis sample. The weight loss divided by dry weight of the analysis sample times 100 is the percent of combustibles in the ash residue.

The decimal percent of combustibles in the ash residue times 12,000 is the heat loss in Btu per dry pound of ash residue due to combustibles in the ash residue. The multiplier of 12,000 Btu/lb is an approximation of the heating value of the combustibles on a moisture-and-ash-free basis. The combustibles in the ash residue are a combination of carbon at about 14,500 Btu/lb and carbohydrates (such as cellulose) at less than 8,000 Btu/lb.

(b) *Method 2.* The unburned carbon determination will be performed in accordance with ASTM D2015, using the adiabatic bomb calorimeter to determine the higher heating value. The results from the laboratory will be adjusted to account for the materials removed during sample preparation and testing to calculate the moisture and HHV of the residue leaving the furnace.

The mass fraction of unburned carbon in the residue may be obtained by dividing the reported HHV of the residue by 12,000 Btu/lb.

4-7.6 Supplementary Fuels

4-7.6.1 Liquid Fuel. For liquid fuel fired as a supplementary fuel, the minimum fuel information needed is its higher heating value. The heating value may be obtained from the fuel supplier or, if not available, by measurement of the higher heating value from a bomb calorimeter test.

4-7.6.2 Gaseous Fuel. For gaseous fuel fired as a supplementary fuel, the minimum fuel information needed is its volumetric analysis or higher heating value. The HHV of gaseous fuels may be determined by a continuous online calorimeter as defined in ASTM D1826, or calculated using the volumetric analysis.

4-7.7 Humidity

4-7.7.1 Method of Measurement. The dry bulb and wet bulb temperatures shall be determined hourly near

the combustion air inlet to the unit. The absolute quantity of moisture crossing the envelope in the air is the same as that measured at the ambient air inlet. To determine specific humidity, either dry bulb and wet bulb or dry bulb and relative humidity are needed. The moisture may be determined with aid of a sling psychrometer, mechanically aspirated psychrometer, hygrometer with temperature, or a similar device.

4-7.7.2 Measurement Systematic Error for Humidity. When estimating the systematic error of a humidity

measurement, test personnel should consider the following list of potential sources. Not all sources are listed, and some of those listed may not be applicable to all measurements.

- (a) hygrometer
- (b) wet/dry bulb thermometer type
- (c) calibration
- (d) drift
- (e) thermometer nonlinearity
- (f) parallax

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Section 5

Computation of Results

5-1 INTRODUCTION

This Section describes the data required and the computation procedures for determining the performance of waste combustors with energy recovery. Data acquisition principles, instruments, and methods of measurement are given in Sections 3 and 4. The computation equations use acronyms that consist of alphanumeric characters, which may be used directly in computer programs without loss of interpretation. The format of these acronyms, definitions of letters or letter combinations, and a summary of developed acronyms are described in subsection 5-20. The alphanumeric designation that identifies the locations of gaseous, liquid, and solid streams in relation to the steam generator components are shown schematically in Fig. 2-4-1.

This Section is generally arranged in the sequence required to compute steam generator performance after completion of a test. The test measurements recorded during a performance test must be reduced to average values before performance and uncertainty calculations can be completed. Subsection 5-2 provides guidance for reducing test measurements to average values. Subsection 5-2 also presents the equations to determine the standard deviation of the mean of the uncertainty analysis calculations. Subsections 5-3 through 5-15 present the equations to determine steam generator performance, efficiency, and fuel HHV. Subsection 5-16 presents the equations to determine the systematic error component of uncertainty and the remaining equations required to complete the test uncertainty analysis. Subsections 5-17 through 5-19 present guidance for determining other operating parameters, corrections to standard or guarantee conditions, and enthalpy calculations.

5-2 MEASUREMENT DATA REDUCTION

5-2.1 Calibration Corrections

When an instrument has been calibrated, the calibration correction shall be applied prior to data reduction. An example is a pressure transducer where an actual pressure versus output reading (e.g., millivolt output) has been determined statistically via laboratory measurements. Similarly, an error correlation versus millivolts (mV) may have been determined for a thermocouple in a laboratory and shall be applied to the measured result prior to averaging.

In this same category is the dependent variable that is a result of multiple measurements. Measurement of fluid flow is a common example. The flow result is a square root function of differential pressure and approximately linear function of temperature and pressure. The calculated result should be used in the data average. The systematic and random errors of the instruments that are required to determine flow should be incorporated in the total random and systematic uncertainty of the measured flow parameter.

5-2.2 Outliers

The first step in determining the average value for a measurement is to reject bad data points, or outliers. "Outliers" are spurious data that are not believed to be valid and should not be included as part of the calculations and uncertainty analysis. Examples of outliers are human errors in reading and writing values and instrument errors due to electrical interference, etc. Several documents provide guidance for determining outliers; among them are ASME PTC 19.1 and ASTM E178. These documents present statistical methods to determine outliers. This Code does not recommend any particular statistical method for determining outliers. It is important to note that the use of statistical methods to determine outliers can produce unrealistic results depending on the method and criteria used. Most outliers are obvious when all data recorded for a given parameter are compared. It is also recommended that the test engineer and all parties involved determine the likely cause of any outliers.

5-2.3 Averaging Test Measurement Data

The average value of a parameter measured during a performance test is determined before or after rejecting outliers. The average value can provide important information that can be used to determine outliers. If the average value is calculated before determining outliers, it must be recalculated after all outliers are rejected.

Parameters measured during a performance test can vary with respect to time and spatial location. The majority can be averaged on the basis that the parameter has perturbations about a constant value. This includes any parameter that is measured at a single point to determine the value, such as steam temperature or pressure. During a steady-state performance test (as defined in Section 3),

some single-point parameters may exhibit time dependency. However, for purposes of this Code, such parameters are assumed to have a constant value equal to the arithmetic average.

There are, however, some parameters measured during a test run that must be considered with respect to space as well as time (i.e., parameters that are not uniform within a plane perpendicular to the direction of flow). This would include any measured parameter that is determined from more than one point at a given location. Air heater flue gas outlet temperature measurements, using a grid of thermocouples, is a typical example. Parameters that vary with space as well as time are averaged differently from parameters that vary only with time.

The average values of the parameters, along with their standard deviations of the mean, are used to calculate the overall random uncertainty.

5-2.3.1 Average Value for Spatially Uniform Parameters.¹ The average value of a parameter that is not expected to exhibit spatial variations is calculated by averaging readings taken over time. Equation (5-1) is used to calculate average values for the following cases:

(a) parameters that are modeled as constant in/over space (e.g., feedwater temperature or pressure)

(b) values of a parameter at a fixed point in space (e.g., exit flue gas temperature at one point in the thermocouple grid) is

$$XAVE = \frac{1}{n} (x_1 + x_2 + x_3 + \dots + x_n) = \frac{1}{n} \sum_{i=1}^n x_i \quad (5-1)$$

where

n = number of times parameter x is measured

$XAVE$ = arithmetic average value of a measured parameter

x_i = value of measured parameter i at any point in time

5-2.3.2 Summary Data. It is common for data acquisition systems to print out (and store on electronic media) average values and standard deviations for measured parameters several times during a test period. These are called "summary data." The total set of measurements for a test consists of m sets of measurements.

¹ Some parameters measured at a single point in space may exhibit a time dependency, e.g., combustion air temperature due to ambient air temperature changes. This Code recommends the use of eq. (5-1) to calculate the average value of such parameters and increasing the number of readings to reduce the precision index. However, at the option of the parties to the test, a polynomial may be fitted to the data for a fixed point in space. If a curve fit is used, the user must

(a) statistically validate the model

(b) mathematically integrate the fitted curve to determine the average value of the parameter

(c) develop the method for calculating the variance of the average value for determining the precision index

Each set has n readings. The average value, $XAVE_k$, for set k is given by eq. (5-1) with the addition of a subscript to denote the set.

The overall average value of such parameters is

$$XAVE = \frac{1}{m} \sum_{k=1}^m XAVE_k \quad (5-2)$$

Summary data can only be used if individual measured parameter data and standard deviation information are available for each set of measurements. If this information is not available, the subsets shall be treated as individual samples.

5-2.3.3 Average Value for Spatially Nonuniform Parameters. The average value of parameters having spatial variations can be determined using numerical integration methods. Several methods for numerical integration exist, but this Code recommends the multiple midpoint rule. First, the average value at each grid point is determined using either eq. (5-1) or eq. (5-2). Next, if weighted averages are used, the individual point averages are multiplied by a weighting factor

$$X_{iw} = F_i X_i \quad (5-3)$$

where

F_i = weighting factor for point i

X_i = arithmetic average value of parameter at measurement point i

X_{iw} = weighted average value of parameter at measurement point i

This Code does not require that integrated-average parameters be mass-flow or velocity weighted. If the parameter average is not weighted, an appropriate systematic error must be assigned in the uncertainty analysis. Section 7 provides guidance for estimating the systematic error.

This Code uses only one type of weighting factor: velocity.

The individual weighting factor is

$$F_i = V_i / V_{avg} \quad (5-4)$$

where

V_{avg} = average velocity at traverse plane

V_i = velocity normal to the traverse plane at point i

Finally, after averaging the parameter at each grid point and applying the weighting factors (if applicable), spatial averaging is computed by numerical integration.

5-3 OUTPUT (QrO), Btu/hr (W)

Output is the energy absorbed by the working fluid that is not recovered and used within the steam generator envelope, such as energy to heat the entering air

with the following clarifications. It includes the energy added to the feedwater and desuperheating water to produce saturated/superheated steam, auxiliary steam (see para. 5-3.2), and blowdown. It does not include the energy supplied to preheat the entering air such as air preheater coil steam supplied by the steam generator.

The general form of the output equation is

$$QrO = \sum MrStz (HLvz - HEnz), \text{ Btu/hr (W)} \quad (5-5)$$

where

$HEnz$ = enthalpy of fluid entering location z ,
Btu/lbm (J/kg)

$HLvz$ = enthalpy of fluid leaving location z ,
Btu/lbm (J/kg)

$MrStz$ = mass flow rate of fluid leaving location z ,
lbm/hr (kg/s)

5-3.1 Output in Main Steam

The output energy in main steam is the energy added to the entering high-pressure feedwater (and superheater spray water for superheat units). See also paras. 5-3.2 and 5-3.3 on auxiliary steam and blowdown, which are outputs generated from the entering high-pressure feedwater.

5-3.1.1 Saturated Steam Generators. Output in main steam is equal to the steam mass flow rate leaving the unit times the difference between the enthalpy of the steam leaving the unit and the feedwater entering the unit

$$QrO = MrSt31 (HSt31 - HW24), \text{ Btu/hr (W)} \quad (5-6)$$

5-3.1.2 Superheated Steam Generators. Output in main steam is equal to the difference between the feedwater and spray mass flow rates multiplied by the difference between the main steam and feedwater enthalpies and added to the spray mass flow rate multiplied by the difference between the main steam and spray water enthalpies

$$QrO = (MrW24 - MrW25)(HSt32 - HW24) + MrW25(HSt32 - HW25), \text{ Btu/hr (W)} \quad (5-7)$$

5-3.2 Auxiliary Steam

Auxiliary steam includes steam that exits the steam generator envelope as well as miscellaneous steam, such as atomizing steam and soot-blowing steam, and is included in the boiler output. Auxiliary steam does not include steam used to heat the entering air. The term added to the output equation for each extraction point is

$$QrAxSt = MrSt46A(HSt46A - HW24), \text{ Btu/hr (W)} \quad (5-8)$$

where

$HSt46A$ = enthalpy at the extraction point

$MrSt46A$ = mass flow rate at the extraction point

5-3.3 Blowdown

The term added to the output equation when blowdown is used is

$$QrBd = MrW35 (HW35 - HW24), \text{ Btu/hr (W)} \quad (5-9)$$

5-4 INPUT

"Input" is the potential combustion energy. It is the maximum amount of energy available when the waste and supplementary fuels are completely burned

$$QrI = QrF = MrF HHVF + MrFs HHVFs, \text{ Btu/hr (W)} \quad (5-10)$$

5-5 ENERGY BALANCE

Expressing the energy balance in terms that can be readily measured and calculated, eq. (5-10) becomes

$$QrF = QrO + Qb, \text{ Btu/hr (W)} \quad (5-11)$$

where

Qb = the energy balance closure

"Energy balance closure" is the net sum of the energy associated with entering and leaving mass flow streams (excluding input and output), energy due to chemical reactions that occur within the steam generator envelope, motive power energy, and radiation and convection heat transfer to the environment.

In keeping with conventional practice, energy balance closure may be divided into credits and losses

$$Qb = QrL - QrB, \text{ Btu/hr (W)} \quad (5-12)$$

where

QrB = credits, Btu/hr (W). Credits are the net sum of energy transferred to the system by mass flow streams entering the envelope (excluding fuel combustion energy) plus exothermic chemical reactions and motive power energy of auxiliary equipment within the steam generator envelope.

QrL = losses, Btu/hr (W). Losses are the net sum of energy transferred from the system (excluding external steam output) by mass flow streams leaving the envelope plus endothermic chemical reactions that occur within the steam generator envelope and radiative and convective heat transferred to the environment from envelope surfaces.

Substituting eq. (5-12) into eq. (5-11), the overall energy balance becomes

$$QrF + QrB = QrO + QrL, \text{ Btu/hr (W)} \quad (5-13)$$

where

$QrF + QrB$ = total energy added to the system

5-6 EFFICIENCY

In accordance with the first law of thermodynamics, the energy balance around the steam generator envelope can be stated as

$$\text{energy entering} - \text{energy leaving} = \text{accumulated energy}$$

Since a steam generator should be tested while at steady-state conditions, the accumulated energy is zero such that

$$\text{energy entering the system} = \text{energy leaving the system}$$

Energy entering the system is the energy associated with the entering mass flow streams and auxiliary equipment motive power. Energy leaving the system is the energy associated with the leaving mass flow streams and the heat transferred to the environment from the steam generator surfaces.

Efficiency is the ratio of energy output to energy input, expressed as a percentage

$$EF = 100 \frac{\text{output}}{\text{input}} = 100 \frac{QrO}{QrI} = 100 \frac{QrO}{QrF}, \% \quad (5-14)$$

When input (QrI) is defined as the total energy of combustion available from the fuel (QrF), the resulting efficiency is commonly referred to as fuel efficiency (EF).

Fuel efficiency is the preferred method in this Code for expressing efficiency. Another method for expressing efficiency is to consider the total energy input to the steam generator envelope ($QrF + QrB$). This is commonly referred to as gross efficiency (EGr). Calculation of gross efficiency is not addressed in this Code; however, the methodology can be obtained by referring to ASME PTC 4.

5-6.1 Efficiency – Energy Balance Using the Boiler as a Calorimeter

In the energy balance method, the energy closure losses and credits are used to calculate efficiency. Equation (5-13) can be rewritten as follows:

$$QrF = QrO + QrL - QrB, \text{ Btu/hr (W)} \quad (5-15)$$

Thus, fuel efficiency expressed in terms of the losses and credits becomes

$$\begin{aligned} EF &= 100 \frac{QrO}{QrF} = 100 \frac{QrO}{QrO + QrL - QrB} \\ &= 100 \frac{QrF - QrL + QrB}{QrF}, \% \end{aligned} \quad (5-16)$$

Most losses and credits can be calculated on a percent input from fuel basis in accordance with the following equations:

$$QpL = 100 \frac{QrL}{QrF} \text{ and } QpB = 100 \frac{QrB}{QrF}, \% \quad (5-17)$$

Combining eqs. (5-16) and (5-17), fuel efficiency can also be expressed as

$$\begin{aligned} EF &= 100 \left(\frac{QrF}{QrF} - \frac{QrL}{QrF} + \frac{QrB}{QrF} \right) \\ &= 100 - QpL + QpB, \% \end{aligned} \quad (5-18)$$

Using the boiler-as-a-calorimeter test procedure, all losses and credits are measured/calculated on an energy per unit of time (Btu/hr) basis. If some losses have been estimated on a percent input from fuel basis, the expression for fuel efficiency using mixed units (both rate and percent) is

$$EF = (100 - \Sigma QpL + \Sigma QpB) \times \left(\frac{QrO}{QrO + \Sigma QrL - \Sigma QrB} \right), \% \quad (5-19)$$

where ΣQpL and ΣQpB are the sum of the losses and credits calculated on a percent input from fuel basis and ΣQrL and ΣQrB are the sum of the losses and credits calculated on a Btu/hr (W) basis.

5-6.2 Efficiency Calculation Convergence Tolerance

The calculation procedure is iterative for some types of units. That is, an efficiency or input is estimated to initiate the efficiency calculations. The calculations are repeated until the efficiency (fuel rate/input) is within an acceptable tolerance. The calculation process is relatively insensitive to the initial estimate and converges easily.

For calculations to determine efficiency only, where the efficiency result is only required to the first or second decimal place, a convergence tolerance of 0.1% efficiency is sufficient.

For calculations to develop sensitivity coefficients (see subsection 5-16), the sensitivity coefficient is determined from the difference between the base efficiency and the efficiency calculated with the perturbed data. Since the perturbation may be small, the change in efficiency may be small. For developing sensitivity coefficients, an efficiency convergence tolerance on the order of $10^{-5}\%$ efficiency is recommended.

5-7 RESIDUE PROPERTIES

5-7.1 Mass Flow Rate(s) of Residue

Residue is the solid material removed from the steam generator envelope including fuel ash, unburned fuel, spent sorbent, etc. Measurement of residue mass flow rate(s) will be specific to the design and layout of the steam generator residue removal system.

If separate residue streams exit the steam generator envelope at different locations, then the mass flow rate, temperature, and moisture content of the residue must be determined at each location.

5-7.2 Wet Bottom Ash Removal Systems

It may normally be assumed that any moisture evaporated from a wet bottom ash removal system is measured as part of the total flue gas moisture exiting the steam generator envelope. If this is the case, the following apply:

(a) If the temperature of the water entering the wet bottom ash removal system is the same as the fuel temperature, no separate loss due to the evaporation of ash pit moisture should be considered.

(b) If the temperature of the water entering the wet bottom ash removal system differs from the fuel temperature, the amount of water evaporated can be measured (as the difference between the mass flow rate of water entering and leaving the wet bottom ash removal system) and accounted for separately when calculating heat losses and credits.

Sensible heat added to the wet bottom ash removal system can be considered by measuring the temperature of the pit water entering and leaving the system envelope and the mass flow rate of pit water leaving the envelope.

5-8 FLUE GAS PRODUCTS

5-8.1 Wet Gas From Fuel

Using the boiler-as-a-calorimeter test procedure, the flue gas mass flow rate is determined either by direct measurement (see para. 4-6.4.3) or by energy balance across the economizer (see para. 4-6.4.1). The economizer energy balance is the method preferred by this Code to determine flue gas flow, but is only possible if

- (a) the steam generator has an economizer
- (b) there is space and access to install multipoint temperature grids both upstream and downstream of the economizer
- (c) the economizer water outlet is subcooled (below the saturation temperature)
- (d) the average economizer water outlet temperature can be measured

$$\text{MrFg} = \text{MrW24} \times \frac{(\text{HW27} - \text{HW24})}{(\text{HFg13} - \text{HFg14})} \times \frac{\text{ST}}{\text{SB}}, \text{ lbm/hr (kg/s)} \quad (5-20)$$

where

SB = total effective heating surface of the economizer, ft²

ST = total effective heating surface of the economizer and steam/water-cooled enclosure (if applicable). It is assumed that the absorption of the steam/water-cooled enclosure is proportional to the bank absorption, ft².

Users of this Code should be aware of the potential for thermocouple temperature measurement error due

to radiation from the thermocouple hot junction to cooler surfaces. The potential error is dependent on gas temperature and the proximity of the bare thermocouple to the cooler tube/enclosure surface(s).

5-8.2 Dry Gas From Fuel

The dry flue gas mass flow rate is determined by subtracting flue gas moisture, measured per para. 4-7.2, from the wet flue gas mass flow rate

$$\text{MrDFg} = \text{MrFg} \times (100 - \text{MFrH}_2\text{O}), \text{ lbm/hr (kg/s)} \quad (5-21)$$

5-8.3 Simplifications — N₂ and SO_x From Fuel

This Code does not consider the difference between N₂ and N_{2a} in the calculations, which eliminates the need to estimate the elemental nitrogen from fuel and simplifies the calculation procedure. All calculations can be done assuming all nitrogen in the flue gas is nitrogen from air (N_{2a}), which has an equivalent molecular weight of 28.158 lbm/mole. Uncertainty analysis has demonstrated that this simplification has a negligible effect on calculated boiler efficiency and heat input.

This Code does not require that SO_x be measured as part of the steam generator test. If SO_x is not measured, it may be assumed to be zero for the calculation of boiler efficiency and input. This assumption eliminates the need to estimate sulfur in the fuel, and uncertainty analysis has demonstrated that it has a negligible effect on calculated boiler efficiency and heat input.

5-8.4 Molecular Weight of Dry Flue Gas

When the flue gas constituents have been calculated on a wet basis, the molecular weight of wet flue gas is calculated as follows:

$$\text{MwFg} = \text{MwDFg} \frac{\text{MoFg}}{\text{MoDFg}}, \text{ lbm/mole (kg/mole)} \quad (5-22)$$

When the flue gas constituents have been calculated on a dry basis, the molecular weight of dry flue gas can be calculated as follows:

$$\text{MwDFg} = 0.32 \text{ DVpO}_2 + 0.4401 \text{ DVpCO}_2 + 0.64064 \text{ DVpSO}_2 + 0.28158 \text{ DVpN}_2 \quad (5-23)$$

5-8.5 Dry Air Weight

The mass flow rate of dry air at the location of measurement of flue gas constituents is calculated as follows:

$$\text{MrDA} = \frac{28.158}{0.7685} \times \frac{\text{DVpN}_2 \times \text{MrDFg}}{100 \times \text{MoDFg}}, \text{ lbm/hr (kg/s)} \quad (5-24)$$

where

DVpN₂ = percent nitrogen in the flue gas, all treated as nitrogen from air (see para. 5-8.3), % dry volume
 = DVpO₂ – DVpCO₂ – DVpCO – DVpSO₂

- 28.158 = molecular weight of atmospheric nitrogen
(see para. 5-8.3), mass/mole
0.7685 = mass of N₂ per mass dry air, lbm N₂/lbm
dry air (kg N₂/kg dry air)

5-8.6 Water From Air

The portion of the total mass flow rate of water in the flue gas that is present as a result of moisture in air is

$$\text{MrWA} = \text{MrDA} \times \text{MFrWDA}, \text{ lbm/hr (kg/s)} \quad (5-25)$$

5-8.7 Additional Moisture

This item accounts for any measured moisture flows added to the flue gas stream. Typical sources would be soot-blowing steam, wastewater disposal, and wet ash pit evaporation (when the entering water temperature differs from the fuel temperature).

5-8.8 Water From Fuel

The moisture in the flue gas, resulting from evaporation of water and combustion of H₂ in the fuel, is the total measured moisture, less moisture from air, and additional moisture, less moisture evaporated from the ash pit

$$\begin{aligned} \text{MrWF} &= \text{MrWFg} - \text{MrWA} - \text{MrWAd} \\ &\quad - \text{MrWAp}, \text{ lbm/hr (kg/s)} \end{aligned} \quad (5-26)$$

5-8.9 Determination of Performance Parameters at Alternate Locations

It may be desirable or necessary to determine flue gas composition, air weight, or gas weight at locations within the steam generator boundary other than the location where the flue gas flow rate was measured. An example would be a unit with an air heater. The only required measurement at the alternate location is O₂. O₂ at the alternate location shall be determined with a sampling grid that meets the requirements of para. 4-4.3.1.

The excess air at location *z* can be calculated from O₂ at location *z* as follows:

$$X_{pAz} = X_{pA} \times \frac{\text{DVpO}_{2z}}{\text{DVpO}_2} \times \frac{(20.95 - \text{DVpO}_2)}{(20.95 - \text{DVpO}_{2z})} \quad (5-27)$$

$$\text{MrWDAz} = \text{MrDAz} \times \text{MFrWDA}, \text{ lbm/hr (kg/s)}$$

$$\text{MrDFgz} = \text{MrDFg} + (\text{MrDAz} - \text{MrDA}), \text{ lbm/hr (kg/s)}$$

$$\text{MrDAz} = \left(1 + \frac{X_{pAz}}{100}\right) \times \text{MrThA}, \text{ lbm/hr (kg/s)}$$

$$\begin{aligned} \text{MrFgz} &= \text{MrDFgz} + \text{MrWFg} + (\text{MrWDAz} \\ &\quad - \text{MrWDA}), \text{ lbm/hr (kg/s)} \end{aligned}$$

$$\text{MpWFgz} = 100 \times \left(\frac{\text{MrWFgz} - \text{MrFgz}}{\text{MrWFgz}} \right), \% \text{ mass}$$

5-8.10 Density of Flue Gas

The density of wet flue gas is calculated using the ideal gas relationship

$$\text{DnFgz} = \frac{C1(C2 \text{ Pa} + \text{PFg})}{\text{Rk}(C3 + \text{TFg})}, \text{ lbm/ft}^3 \text{ (kg/m}^3\text{)}$$

$$\text{Rk} = \frac{\text{R}}{\text{MwFg}}, \text{ ft/R (J/kg/K)}$$

where

$$C1 = 5.2023 \text{ lbf/ft (1.0 J/m}^3\text{)}$$

$$C2 = 27.68 \text{ in. wg/psi (1.0 Pa/Pa)}$$

$$C3 = 459.7^\circ\text{F (273.2}^\circ\text{C)}$$

$$\text{Pa} = \text{barometric pressure, psia (Pa). To convert inches Hg to psia, divide by 2.0359.}$$

$$\text{R} = \text{universal molar gas constant, 1,545 ft-lbf/lbm-mole-R (8 314.5 J/kg-mole-K)}$$

$$\text{Rk} = \text{specific gas constant for gas } k, \text{ ft/R (J/kg K)}$$

When the flue gas constituents have been calculated on a wet basis, the molecular weight of wet flue gas is calculated as follows:

$$\begin{aligned} \text{MwFg} &= 0.32 \text{ VpO}_2 + 0.4401 \text{ VpCO}_2 + 0.64064 \text{ VpSO}_2 \\ &\quad + 0.28158 \text{ VpN}_2 + 0.18015 \text{ VpH}_2\text{O}, \text{ mass/mole} \end{aligned}$$

When the flue gas constituents have been measured on a dry basis, the molecular weight of wet flue gas can be calculated as follows:

$$\begin{aligned} \text{MwDFg} &= 0.32 \text{ DVpO}_2 + 0.4401 \text{ DVpCO}_2 \\ &\quad + 0.64064 \text{ DVpSO}_2 + 0.28158 \text{ DVpN}_2, \\ &\quad \text{mass/mole} \end{aligned}$$

$$\text{MwFg} = \text{MeDFg} \frac{\text{MoFg}}{\text{MoDFg}}, \text{ lbm/mole (kg/mole)}$$

5-9 COMBUSTION AIR PROPERTIES

5-9.1 Physical Properties

The calculations and derivation of constants used in this Code are based on a composition of air as follows:² 0.20946 O₂, 0.78102 N₂, 0.00916 Ar, 0.00033 CO₂ moles per mole of air (and other trace elements), yielding an average molecular weight of 28.9625. For simplification of the calculations, N₂ includes the argon and other trace elements and is referred to as "atmospheric nitrogen," N_{2a}, having an equivalent molecular weight of 28.158. This Code does not consider the difference between N₂ and N_{2a} in the calculations. This eliminates the need to estimate the elemental nitrogen from fuel and simplifies the calculation procedure. Uncertainty analysis has demonstrated that this simplification has a negligible effect on calculated boiler efficiency and heat input.

² Jones, F. E., "The Air Density Equation and the Transfer of the Mass Unit," *Journal of Research* of the National Bureau of Standards, Vol. 83, No. 5, September–October 1978.

Below is a summary of the nominal properties of air that are used in this Code.

(a) Volumetric composition is 20.95% oxygen, 79.05% nitrogen.

(b) Gravimetric composition is 23.14% oxygen, 76.86% nitrogen.

5-9.2 Moisture in Air, lbm/lbm (kg/kg) Dry Air

The moisture in air is determined from measured inlet air wet bulb and dry bulb temperatures or dry bulb temperature and relative humidity in conjunction with psychrometric charts or calculated from vapor pressure as determined from Carrier's eq. (5-29) when wet bulb temperature is measured or eq. (5-30) when relative humidity is measured

$$\text{MFrWDA} = 0.622 \frac{\text{PpWvA}}{(\text{Pa} - \text{PpWvA})}, \text{ lbm H}_2\text{O/lbm dry air (kg/kg)} \quad (5-28)$$

$$\text{PpWvA} = \text{PsWTwb} - \frac{(\text{Pa} - \text{PsWvTwb})(\text{Tdbz} - \text{Twbz})}{2,830 - 1.44 \text{ Twbz}}, \text{ psia} \quad (5-29)$$

$$\text{PpWvA} = 0.01 \text{ Rhmz PsWvTdb, psia} \quad (5-30)$$

$$\text{PsWvT} = \text{C1} + \text{C2T} + \text{C3T}^2 + \text{C4T}^3 + \text{C5T}^4 + \text{C6T}^5, \text{ psia} \quad (5-31)$$

where

$$\text{C1} = 0.019257$$

$$\text{C2} = 1.289016\text{E-}3$$

$$\text{C3} = 1.211220\text{E-}5$$

$$\text{C4} = 4.534007\text{E-}7$$

$$\text{C5} = 6.841880\text{E-}11$$

$$\text{C6} = 2.197092\text{E-}11$$

PpWvA = partial pressure of water vapor in air, psia. This may be calculated from relative humidity or wet and dry bulb temperatures.

PsWvTz = saturation pressure of water vapor at wet bulb temperature or dry bulb temperature, psia. The curve fit is valid for temperatures from 32°F to 140°F.

5-9.3 Excess Air

Excess air is the actual quantity of air used, in excess of the theoretical minimum amount of air required for combustion

$$\text{XrA} = 100 \times \frac{32}{0.2314} \times \frac{\text{DVpO}_2 \times \text{MrDFg}}{\text{MoDFg}}, \text{ lbm/hr (kg/s)}$$

where

$$32 = \text{molecular weight of O}_2, \text{ mass/mole}$$

$$0.2314 = \text{lbm dry air per 100 moles of O}_2$$

5-9.4 Theoretical Air, lbm/Btu (kg/J)

Theoretical air is defined as the ideal minimum air required for the complete combustion of the fuel, i.e., carbon to CO_2 , hydrogen to H_2O , and sulfur to SO_2 . In the actual combustion process, small amounts of CO and nitrous oxides (NO_x) are formed and commonly measured. Also, small amounts of SO_3 and gaseous hydrocarbons are formed, but they are less frequently measured. The effects of SO_3 , hydrocarbons, and NO_x are negligible on the combustion calculations and are not considered by this Code

$$\text{MrThA} = \text{MrDA} - \text{MrXA}, \text{ lbm/hr (kg/s)}$$

Excess air is more commonly expressed as a percentage of theoretical dry air

$$\text{XpA} = 100 \times \frac{\text{MrXA}}{\text{MrThA}}, \%$$

It is noted that the theoretical and excess air values as calculated above do not exactly fit the definitions of each, because in practice there is always some amount of unburned combustibles (see equation for MqThACr).

Theoretical air can be used as a general quality check of the test measurement system. Experience has shown that the theoretical dry air required to combust typical waste fuels, expressed on a mass per unit input basis ($\text{lbm}/10^4 \text{ Btu}$), does not vary significantly between fuel sources. If the calculated theoretical air falls outside of the range typical of the fuel being fired, it may be an indication of erroneous measurements, i.e., that there is not reasonable agreement between boiler input, measured flue gas mass flow rate, and flue gas composition. Measured O_2 and flue gas mass flow rate have a relatively large influence on calculated theoretical air. If flue gas flow rate is measured directly via velocity traverse (as opposed to using an economizer energy balance), boiler output will also have a large influence on the calculated theoretical air.

Experience with laboratory analyses of many waste fuel samples indicates that a typical range of theoretical air for waste fuels (MSW and RDF) is $6.8 \text{ lbm}/10^4 \text{ Btu}$ to $7.6 \text{ lbm}/10^4 \text{ Btu}$. Users should review available fuel composition data to determine if there is a more specific theoretical air range for the test fuel. For comparison of measured theoretical air to the typical range, it is expressed on a mass per unit input basis and corrected to 0% unburned combustibles

$$\text{MqThACr} = \left[\frac{\text{MrDA} - \text{MrXA}}{\text{QrI}} \right] + \left(9.6 \times \frac{\text{QpLubC}}{100} \right), \text{ lbm/Btu (kg/J)}$$

Evaluation of preliminary test results (see para. 3-4.2) should include a comparison of measured theoretical air to the expected range, and the test measurement

system(s) should be checked if there is a significant deviation. If, when evaluating test results, the calculated theoretical air falls outside of the typical range, it will not invalidate the test run.

5-9.5 Density of Air, lbm/ft³ (kg/m³)

The density of wet air is calculated using the ideal gas relationship

$$DnA = \frac{C1 C2(Pa + PAz)}{Rk (C3 + TAz)}, \text{ lbm/ft}^3 \text{ (kg/m}^3\text{)}$$

$$Rk = \frac{R}{Mwk'}, \text{ ft/R (J/kg K)}$$

$$MwA = \frac{1 + MFrWDA}{\frac{1}{28.963} + \frac{MFrWDA}{18.015}}, \text{ lbm/mole (kg/mole)}$$

where

$$C1 = 5.023 \text{ lbf/ft (1.0 J/m}^3\text{)}$$

$$C2 = 27.68 \text{ in. wg/psi (1.0 Pa/Pa)}$$

$$C3 = 459.7^\circ\text{F (273.2}^\circ\text{C)}$$

$$R = \text{universal molar gas constant, 1,545 ft-lbf/lbm-mole R (8 314.5 J/kg-mole K)}$$

$$Rk = \text{specific gas constant for gas } k, \text{ ft/R (J/kg K)}$$

5-10 AIR AND FLUE GAS TEMPERATURE

5-10.1 Reference Temperature, °F (°C)

The reference temperature is the base temperature to which streams (air, fuel, and additional moisture) entering the steam generator envelope are compared for calculation of sensible heat losses and credits. The reference temperature for this Code is 77°F (25°C).

5-10.2 Average Entering Air Temperature, °F (°C)

The air temperature entering the steam generator envelope is required to calculate the credit due to the difference between the entering air temperature and the reference temperature. When air-preheating coils are used and the energy is supplied from outside the envelope, the entering air temperature is the temperature leaving the air-preheating coils, TA8. When the energy to air-preheating coils is supplied from within the envelope (steam from the steam generator), the entering air temperature is the temperature entering the air-preheating coils, TA7. When there is more than one fan of the same type, such as two forced-draft fans, it is normally sufficiently accurate to assume balanced airflows between the fans and to use the arithmetic average of the air temperatures in each stream. When there is evidence of unbalance, weighted averages should be used. When there is more than one source of air entering at different temperatures, the average entering air temperature must be determined. The general philosophy for determining the mass fraction of individual streams is that all air

streams may be measured or some streams may be measured (and/or calculated by energy balance) and the balance calculated by difference from the total airflow. It should be noted that some amount of air enters the unit as leakage through the setting and the actual temperature is indeterminate. Unless otherwise specified or agreed to by the parties to the test, the infiltration air is considered to enter the unit at the same temperature as the measurable air streams and the uncertainty accounted for in the measurement systematic error.

A typical example of units with multiple air sources are units with heated primary/undergrate air, and separately supplied secondary and tertiary air. The weighted average air temperature entering the unit, TMnAEn, must be calculated

$$TMnAEn = MFrAz1 TAz1 + MFrAz2 TAz2 + \dots + MFrAzi TAzi, ^\circ\text{F (}^\circ\text{C)}$$

When the entering air temperature at the various locations differs significantly, it is more correct to determine the average entering air temperature from the average entering enthalpy of the entering air

$$HMnA = MFrAz1 HAz1 + MFrAz2 HAz2 + \dots + MFrAzi HAzi, \text{ Btu/lbm (J/kg)}$$

5-10.3 Corrected Gas Outlet Temperature (Excluding AH Leakage), °F (°C)

On units with air heaters, air leakage within the air heater depresses the exit gas temperature without performing any useful work. This is of particular concern for units with regenerative air heaters. For the efficiency calculations, the measured gas temperature leaving the air heater must be corrected to the temperature that would exist if there were no air heater leakage, TFgLvCr.

The correction calculation method below uses the nomenclature and products of combustion calculated in the preceding paragraphs. For alternate calculation methods, see ASME PTC 4.3, Air Heaters.

When there are two or more air heaters with approximately the same gas flow through each, the air and gas temperatures may be averaged, and one corrected gas temperature calculated. However, when there are two or more air heaters with different gas flows, such as a primary and secondary air heater, the corrected gas temperature must be calculated separately for each and a weighted average used for efficiency. See para. 5-10.4 below

$$TFgLvCr = TFgLv + \frac{MnCpA}{MnCpFg} \left(\frac{MrFgLv}{MrFgEn} - 1 \right) \times (TFgLv - TAEEn), ^\circ\text{F (}^\circ\text{C)}$$

$$MnCpA = \frac{HATFgLv - HAEEn}{TFgLv - TAEEn}, \text{ Btu/lbm } ^\circ\text{F (J/kg K)}$$

where

MnC_pA = mean specific heat of *wet* air between TA_{En} and $TFgLv$, Btu/lbm °F (J/kg K). This is equal to the enthalpy of wet air at the measured gas outlet temperature minus the enthalpy of wet air at the air inlet temperature divided by the temperature difference.

MnC_pFg = mean specific heat of *wet* flue gas between $TGLv$ and $TFgLvCr$, Btu/lbm °F (J/kg K). If using the curves of subsection 5-19 (as opposed to the computer code that calculates specific heat), use the *instantaneous* specific heat for the mean temperature.

TA_{En} = air temperature entering the air heater, °F (°C); see location (7), (7A), (8), or (8A) in Fig. 2-4-1. For air heaters that have two air inlets and one gas outlet (e.g., trisector air heaters), this item is the weighted average of the air temperature leaking to the gas side of the air heater. Use the manufacturer's estimated leakage split to calculate the average air temperature of the leakage air.

$TFgLv$ = gas temperature leaving the air heater, °F (°C); see location (15) in Fig. 2-4-1.

5-10.4 Average Exit Gas Temperature, °F (°C)

The average exit gas temperature (excluding leakage) is used to calculate the losses associated with constituents leaving the unit in the flue gas (e.g., dry gas loss, water from fuel loss). On units where the flue gas exits at more than one location, the weighted average gas temperature must be determined. The general philosophy for determining the mass fraction of individual flue gas streams is that all gas streams may be measured or some streams may be measured (and/or calculated by energy balance) and the balance calculated by difference from the total (measured or calculated by economizer heat balance). On units with two or more air heaters of the same type and size, it is normally sufficiently accurate to assume equal gas flows and to use the arithmetic average of the gas temperature leaving each air heater (excluding leakage), $TFgLvCr$. When there is evidence of unbalance, weighted averages should be used. On some units, gas may be extracted upstream of the air heater(s) or other steam generator heat trap(s) and must be included in the determination of the average exit gas temperature. When no AH exists, $TFgLv$ is the temperature leaving the system boundary.

5-11 LOSSES

Using the boiler-as-a-calorimeter test procedure, losses are calculated on an energy per unit of time basis.

After efficiency and input from fuel have been determined, the losses can be expressed as a percentage of fuel input.

The loss from constituent k is

$$\begin{aligned} Q_{rLk} &= 100 M_{rk} \times (H_{kz} - H_{Rek}) = 100 M_{rk} \times M_{nCpk} \\ &\quad \times (T_{kz} - T_{Re}), \text{ Btu/hr (W)} \\ &= \frac{\text{lbm constituent}}{\text{hr}} \times \frac{\text{Btu}}{\text{lbm } ^\circ\text{F}} \times ^\circ\text{F} \\ &= \frac{\text{Btu loss}}{\text{hr}}, \text{ Btu/hr (W)} \end{aligned}$$

The loss from constituent k , in percent of input from fuel, is

$$Q_{pLk} = 100 \times \frac{Q_{rLk}}{Q_{rF}}, \%$$

where

H_{Rek} = enthalpy of constituent k at temperature T_{Re} , Btu/lbm (J/kg). For water that enters the steam generator envelope as liquid and leaves the envelope as steam (water vapor), the ASME Steam Tables are used for enthalpy and are based on a 32°F reference temperature for enthalpy. The enthalpy of water at T_{Re} is 45 Btu/lbm (105 kJ/kg). For all other constituents, the enthalpy is based on the Code reference temperature of 77°F (25°C). Thus, the reference enthalpy is zero and does not appear in the loss/credit energy balance equation as shown above.

M_{nCpk} = mean specific heat of constituent k between temperatures T_{Re} and $T_{Lv k}$, Btu/lbm °F (J/kg K). Whenever practical, enthalpy is used in lieu of the mean specific heat and the difference in temperature.

5-11.1 Dry Gas Loss, Btu/hr

$$Q_{rLDFg} = M_{rDFgLv} \times H_{DFgLvCr}, \text{ Btu/hr (W)}$$

Note that when hot air quality control equipment (e.g., precipitator) is located between the steam generator exit and the air heater gas inlet, there may be a dry gas loss due to air infiltration. This loss is included in the loss calculated for the hot AQC equipment.

Refer to para. 5-19.9 for curve fits.

5-11.2 Water From Fuel Loss

The water from fuel loss is calculated from measured moisture in the flue gas and is intended by this Code to include water in the fuel and water from the combustion of H_2 in the fuel. The measured moisture in the flue gas could include water from sources other than the fuel, such as water evaporated from a wet bottom ash

removal system, fuel pit spray water, wastewater disposal, furnace gas tempering systems, etc. It may not be necessary to separately account for additional water that enters the steam generator envelope as long as it is in liquid form and the temperature is the same as the fuel temperature. To determine the heat loss due to additional moisture sources see para. 5-11.9

$$\begin{aligned} Q_{rLWF} &= M_{rWFg} (H_{StLvCr} - H_{WRe}) \\ &= M_{rFg} \times M_{pWFg} \\ &\quad (H_{StLvCr} - H_{WRe}), \text{ Btu/hr (W)} \end{aligned}$$

The enthalpy of steam does not vary significantly at the low partial pressures of water vapor in air or flue gas, and thus, specifically calculating the actual partial pressure of water vapor is not warranted. See para. 5-19.5 for curve fit.

The distinction of enthalpy of steam (H_{St}) versus the enthalpy of water vapor (H_{Wv}) is that H_{St} is the enthalpy of vapor with respect to liquid water at 32°F (0°C) as the reference per ASME Steam Tables and includes the latent heat of vaporization of water, where H_{Wv} is the enthalpy of water vapor with respect to the enthalpy of water vapor at 77°F (25°C) as the reference (which is zero). See para. 5-19.4 for curve fit.

5-11.3 QrLAp — Wet Ash Pit Loss

On units with a wet bottom ash removal system, there is some evaporation of water from quenching of the hot bottom ash. Most of the evaporated ash pit water is normally entrained in the flue gas and the loss is measured as part of the total flue gas moisture leaving the steam generator envelope. It is only necessary to consider accounting for this loss separately from the water from fuel loss if the water temperature entering the ash pit differs from the fuel temperature. The other losses are the sum of the energy gain in the water and the sensible heat in the residue discharged from the ash pit.

5-11.3.1 Loss Due to Evaporation of Pit Water. The loss due to evaporation of pit water may be considered separately from the water from fuel loss by measuring the evaporation rate as the difference between the mass flow rates of water leaving and entering the ash pit. If this loss is considered separately from the water from fuel loss, the mass flow rate of ash pit water evaporated must be subtracted from the total water measured in the flue gas leaving the steam generator envelope

$$Q_{rLApEv} = M_{rApW} (H_{W39} - H_{StLvCr}), \text{ Btu/hr (W)}$$

5-11.3.2 Loss Due to Energy Increase in Ash Pit Water

$$Q_{rLRsApW} = M_{rW39} (H_{W39} - H_{W38}), \text{ Btu/hr (W)}$$

5-11.3.3 Loss Due to Sensible Heat in Residue/Water Mixture Leaving the Ash Pit

$$Q_{rLRsWLv} = \frac{M_{rRsW37}}{1 + M_{FrWRs}} [H_{Rs37} + M_{FrWRs} (H_{W37} - H_{W38})], \text{ Btu/hr (W)}$$

5-11.3.4 QrLAp — Wet Ash Pit Loss Calculation

$$\begin{aligned} Q_{rLAp} &= Q_{rLApEv} + Q_{rLRsApW} \\ &\quad + Q_{rLRsWLv}, \text{ Btu/hr (W)} \end{aligned}$$

5-11.4 Loss Due to Moisture in Air

$$Q_{rLWDA} = (M_{FrWA})(M_{rDA})(H_{WvLvCr}), \text{ Btu/hr (W)}$$

where

M_{rDA} = mass of dry air corresponding to the excess air used for dry gas loss, lbm/hr (kg/s)

5-11.5 Loss Due to Unburned Combustibles in Residue

For the purposes of this Code, a value of 12,000 Btu/lb shall be used for HHVCRs. This reflects the heating value of the fixed carbon and cellulose typically found in waste fuel residue

$$Q_{rLUBC} = M_{rUBC} HHVCRs, \text{ Btu/hr (W)}$$

5-11.6 Loss Due to Carbon Monoxide in Flue Gas, Btu/hr

$$\begin{aligned} Q_{rLCO} &= (M_{VpCO})(M_{rDFg})(M_{wCO}) \frac{HHVCO}{MoDFg} \\ &\quad \text{or } (V_{pCO})(M_{rFg})(M_{wCO}) \frac{HHVCO}{MoFg}, \text{ Btu/hr (W)} \end{aligned}$$

5-11.7 Loss Due to Sensible Heat of Residue

For units with a wet furnace ash hopper, when the total ash pit losses are tested, the wet ash pit loss is

$$Q_{rLRs} = 100 \sum (M_{rRsZ})(H_{rRsZ}), \text{ Btu/hr (W)}$$

Q_{rLAp} includes the sensible heat of residue, and the sensible heat of residue to the ash hopper should be omitted here. When the loss due to radiation to the wet ash pit is estimated, Q_{rLRsAp} , the loss due to sensible heat in residue leaving the ash pit, is calculated in accordance with this paragraph.

For locations other than the bottom, the residue can be assumed to be at gas temperature. For dry bottom ash, use 2,000°F (1 100°C) if not measured. For wet bottom ash, a typical enthalpy of 900 Btu/lbm (2 095 kJ/kg) is recommended. See para. 5-19.3 for curve fit.

5-11.8 Loss Due to Surface Radiation and Convection

Refer to Mandatory Appendix I, Standard Radiation and Convection Loss Chart.

5-11.9 Loss Due to Additional Moisture

Additional moisture is water or steam injected in the gas side of the steam generator that is to be treated separately from total moisture. When the heat loss due to an additional moisture stream is considered separately from the total water from fuel loss (para. 5-11.2), the

mass flow rate of the additional moisture must be subtracted from the total water measured in the flue gas leaving the steam generator envelope

$$Q_{rLWAd} = \sum MrStz(H_{StLvCr} - H_{WRe}), \text{ Btu/hr (W)}$$

5-11.10 Loss From Recycled Streams

The loss due to recycled streams is the sum of the loss due to recycled solids and recycled gas

$$Q_{rLRy} = Q_{rLRyRs} + Q_{rLRyFg}, \text{ Btu/hr (W)}$$

5-11.10.1 Recycled Gaseous Streams. An example of a recycled gaseous stream is flue gas recirculation after the air heater (typically ID fan gas recirculation). However, this loss is applicable to any gaseous stream added to the steam generator from an external source

$$Q_{rLRyFg} = MrRyFg(H_{FgCr} - H_{FgEn}), \text{ Btu/hr (W)}$$

5-11.10.2 Recycled Solids Streams. Residue may be recycled back into the steam generator envelope

$$Q_{rLRyRs} = MrRyRs(H_{RsLV} - H_{RsEn}), \text{ Btu/hr (W)}$$

5-11.11 Loss Due to Steam Coil Air Heater When Steam Source Is From Boiler

When an air preheater coil is supplied by steam from the steam generator, the coil shall be considered within the steam generator envelope. The loss is the product of the condensate flow from the air preheater coil and the difference in enthalpy of the condensate and entering feedwater. The condensate flow should not be included in the boiler output

$$Q_{rL36} = (MrW36)(H_{W36} - H_{W24})$$

5-11.12 Loss From Cooling Water

This loss occurs when cooling water (external to the steam generator steam/water circuits) removes energy from the steam generator envelope. Typical equipment that uses cooling water are water-cooled doors, ash coolers, and boiler circulating pumps. Care should be taken not to consider a loss twice. For example, if the sensible heat in residue is based on the temperature of residue entering the ash cooler, then there would be no loss associated with the ash cooler; however, if the temperature of the residue is measured after the ash cooler, then the energy absorbed by the ash cooler must be added to the steam generator losses

$$Q_{rLCw} = \sum MrCwz (H_{W41} - H_{W40}), \text{ Btu/hr (W)}$$

5-11.13 Conversion of Losses to Percent Input From Fuel Basis

The loss calculated on a rate or unit of time basis may be used to calculate efficiency. If the loss on a percent input from fuel basis is desired, it may be calculated

after completion of the efficiency calculations using the calculated fuel input

$$Q_{pLk} = 100 \frac{Q_{rLk}}{Q_{rF}}, \%$$

5-12 CREDITS

As in the loss section, when using the boiler-as-a-calorimeter test procedure, credits are calculated on an energy per unit of time basis. After efficiency and input from fuel have been determined, the credits can be expressed as a percentage of fuel input. The credits are arranged in approximate order of significance and universal applicability, with the latter taking precedence.

5-12.1 Credit Due to Entering Dry Air

$$Q_{rBDA} = (MrDA)(H_{DAMnEn}), \text{ Btu/hr (W)}$$

where

H_{DAMnEn} = enthalpy of dry air at the average air temperature entering the steam generator envelope (T_{MnAEn}), Btu/lbm (J/kg). This is the weighted average of the various sources of the airflow contributing to M_{qDA} as defined above. Note, when an air-preheating coil is supplied from the steam generator, the air temperature entering the air preheater coil shall be used for that portion of the air entering the steam generator.

$MrDA$ = mass flow rate of dry air entering the steam generator corresponding to the excess air leaving the boiler used to calculate dry gas weight, lbm/hr (kg/s)

5-12.2 Credit Due to Moisture in Entering Dry Air

$$Q_{rBWA} = (M_{FrWA})(MrDA)(H_{WvEn}), \text{ Btu/hr (W)}$$

where

H_{WvEn} = the enthalpy of water vapor at the average air temperature entering the steam generator envelope (T_{MnAEn}), Btu/lbm (J/kg)

5-12.3 Credit Due to Sensible Heat in As-Fired Fuel

The enthalpy of the as-fired fuel is dependent on the moisture content of the fuel. This Code does not require that waste fuel samples be collected for moisture determination. For the purposes of this Code, the specific heat of dry waste fuel shall be 0.3 Btu/lbm °F. The following equation is based on an assumed approximate fuel moisture content:

$$Q_{rBF} = MrF [0.3(1 - M_{FrFw})(T_F - T_{Re}) + M_{FrFW} (H_{FW} - H_{WRe})], \text{ Btu/hr (W)}$$

5-12.4 Credit Due to Auxiliary Equipment Power

Typical auxiliary equipment includes gas recirculating fans, hot (after the air heater) overfire air fans, and boiler circulating pumps. Note that credits shall not be calculated for forced-draft fans, cold air (before the air heater) fans, and other equipment when credits are calculated based on the measured fluid temperature exiting the equipment. For example, when a credit is calculated for entering air per para. 5-12.1, the energy added by the forced-draft and primary air fans is included; thus, adding the credit for fan power would be accounting for the energy added twice.

For steam-driven equipment

$$QrBAx = \frac{MrStAx(HStAxEn - HStAxLv)EAX}{100}, \text{ Btu/hr (W)}$$

For electrically driven equipment

$$QrBAx = QAx C1 \frac{EAX}{100}, \text{ Btu/hr (W)}$$

where

$$C1 = 3,412 \text{ Btu/kWh (1 J/J)}$$

5-12.5 Credit Due to Energy in Additional Moisture

Typical examples of additional moisture are soot-blowing and atomizing steam

$$QrBWAd = \sum MrStz(HStFgEnz - HWRe), \text{ Btu/hr (W)}$$

5-12.6 Conversion of Credits to Percent Input From Fuel Basis

The credit calculated on a rate or unit of time basis may be used to calculate efficiency directly. If the credit on a percent input from fuel basis is desired, it may be calculated after completion of the efficiency calculations using the calculated fuel input

$$QpB = 100 \frac{QrBk}{QrF}, \%$$

5-13 SUPPLEMENTARY FUEL INPUT

When a supplementary fuel such as oil or natural gas is fired, the energy input from the supplementary fuel can be determined from the measured mass flow rate times the higher heating value

$$QrFs = MrFs \times HHVFs, \text{ Btu/hr (W)}$$

Measured supplementary fuel input is not required to determine fuel efficiency as defined in this Code or boiler heat input. However, if the higher heating value of the waste fuel is a desired result of the test, input from supplementary fuel must be known.

5-14 HHV OF WASTE FUEL

The higher heating value of the waste fuel can be calculated by dividing the total combustion energy available less combustion energy available from supplementary fuel by the measured mass flow rate of the waste fuel

$$HHVF = \left(\frac{QrO + QrL - QrB - QrFs}{MrF} \right), \text{ Btu/lbm (J/kg)}$$

where

MrF = the measured mass flow rate of the waste fuel, lbm/hr (kg/s)

5-15 SORBENT AND OTHER ADDITIVES

Sorbent additives for reducing acid gases are not readily handled using the boiler-as-a-calorimeter test procedures and are beyond the scope of this Code. Refer to ASME PTC 4 to address the effects of the addition of limestone and other sorbents on combustion and efficiency calculations. Additives can affect efficiency and the combustion process in several ways, including the following:

- (a) Additives may increase the quantity of residue and the loss due to sensible heat in the residue.
- (b) Additives may introduce moisture that increases moisture in flue gas losses and alters flue gas specific heat.
- (c) Additives may undergo a chemical change and alter flue gas composition and/or the combustion air requirement.
- (d) Chemical reactions that are endothermic require heat, which is an additional loss.
- (e) Chemical reactions that are exothermic add heat and must be accounted for.

If only inert materials such as sand are added, the procedures specified in this Code should be used for waste fuels.

5-16 UNCERTAINTY

Subsection 5-2 discussed calculation of the precision index degrees of freedom for individual parameters. This subsection presents calculations for overall precision index degrees of freedom for the test. This subsection also presents calculation methods for sensitivity coefficients and the random and systematic error components of uncertainty. For post-test uncertainty calculation, all steam generator performance calculations must be complete prior to the beginning of the uncertainty calculations presented in this subsection. The uncertainty calculations presented in this subsection, as well as those presented in para. 5-2.3, can be used for pretest as well as post-test uncertainty analysis.

The pretest uncertainty analysis can provide important information and reduce the effort required to calculate uncertainty after completion of a performance test. See Section 7 for additional guidance on pretest uncertainty analysis. The majority of systematic uncertainty estimates can be made prior to starting a performance test. The standard deviation of the mean can be estimated based on preliminary observation of equipment operating conditions. Pretest estimates of the parameter standard deviation and degrees of freedom can be used to determine the frequency and number of measurements required for a given variable during the test. This subsection provides general guidelines for calculating the uncertainty associated with a steam generator performance test. A more detailed description of uncertainty analysis calculations, along with derivations, is included in Section 7, which should be reviewed prior to beginning any uncertainty calculations.

5-16.1 Sensitivity Coefficients

Sensitivity coefficients represent the absolute or relative effect of a measured parameter on the calculated steam generator efficiency. Sensitivity coefficients can also be used for determining the effect of a parameter on an intermediate calculation such as steam generator output. Sensitivity coefficients are important for pretest uncertainty analysis to determine what parameters have the largest impact on the desired result (e.g., efficiency, output, gas temperature).

Sensitivity coefficients are calculated by arbitrarily perturbing the value of a parameter. The change in the value of a measured parameter can be calculated from

$$\text{CHGPAR} = \frac{(\text{PCHGPAR XAVE})}{100} \text{ or } \frac{(\text{PCHGPAR } U)}{100}$$

where

CHGPAR = incremental change in the value of a measured parameter

PCHGPAR = percent change in the value of a measured parameter. The recommended value of PCHGPAR is 1.0%. If the average value of the measured parameter is zero, enter any small incremental change.

U = integrated average value of a measured parameter. See definition of XAVE for information regarding units.

XAVE = arithmetic average value of a measured parameter. For development of sensitivity coefficients, care must be taken to use units that will not be zero, such as absolute temperature and pressure.

Alternatively, such as when XAVE is very small or zero, CHGPAR can be any convenient small increment of XAVE.

Absolute sensitivity coefficients are calculated for each measured parameter from the following equation:

$$\text{ASENSCO} = \frac{\text{RECALEF} - \text{EF}}{\text{CHGPAR}}$$

where

ASENSCO = absolute sensitivity coefficient for a measured parameter, percent efficiency per measured parameter units

EF = steam generator fuel efficiency, calculated for the actual (measured) parameter

RECALEF = recalculated steam generator fuel efficiency using $(X + \text{CHGPAR})$ or $(U + \text{CHGPAR})$ in place of X (or U) while all other measured parameters are held fixed

In no case shall an absolute sensitivity coefficient smaller than the efficiency convergence tolerance be considered (i.e., if smaller, it should be considered zero). See para. 5-6.2 regarding the efficiency convergence tolerance.

The above equation gives the sensitivity coefficient associated with steam generator efficiency. However, this form of equation can be used for any calculated result such as output, fuel flow, calcium/sulfur ratio, etc., by substituting the result for EF and RECALEF.

Relative sensitivity coefficients are calculated for each measured parameter from the following equation:

$$\text{RSENSCO} = \frac{(\text{ASENSCO XAVE})}{\text{PFE}} \text{ or } \frac{(\text{ASENSCO } U)}{\text{PFE}}$$

where

RSENSCO = relative sensitivity coefficient for a measured parameter, percent change in result per percent change in measured parameter

The above equation is shown for efficiency but can be used for other calculated results.

5-16.2 Standard Deviation of the Mean

The standard deviation of the mean of the calculated steam generator efficiency is obtained by combining the standard deviation of the means of all measured parameters according to the root-sum-square rule

$$\text{PIR} = \left[\sum_{i=1}^N (\text{ASENSCO}_i \text{PI}_i)^2 \right]^{1/2}$$

where

ASENSCO_{*i*} = absolute sensitivity coefficient for measured parameter *i*

N = number of measured parameters

Table 5-16.3-1 Two-Tailed Student's t Table for the 95% Confidence Level

Degrees of Freedom	t
1	12.706
2	4.303
3	3.182
4	2.776
5	2.571
6	2.447
7	2.365
8	2.306
9	2.262
10	2.228
11	2.201
12	2.179
13	2.160
14	2.145
15	2.131
16	2.120
17	2.110
18	2.101
19	2.093
20	2.086
21	2.080
22	2.074
23	2.069
24	2.064
25	2.060
26	2.056
27	2.052
28	2.048
29	2.045
30 or more	1.960

PI_i = precision index for measured parameter i

PIR = overall precision index of test

5-16.3 Random Error Component of Uncertainty

The random error component of uncertainty is calculated from the standard deviation of the mean and degrees of freedom of the result using the following equation:

$$UPC = STDVAL \text{ PIR}$$

where

STDVAL = two-tailed Student's t value

UPC = random error component of uncertainty

The two-tailed Student's t value is based on the 95th percentile point distribution and the degrees of freedom of the result. Table 5-16.3-1 shows the Student's t value as a function of degrees of freedom. Interpolation in the table is done using reciprocal degrees of freedom.

A curve fit for t is

$$t = 1.9588 + \frac{2.3717}{\text{DEGFREE}} + \frac{3.1213}{\text{DEGFREE}^2} + \frac{0.7993}{\text{DEGFREE}^3} + \frac{4.4550}{\text{DEGFREE}^4}$$

5-16.4 Systematic Uncertainty

Systematic uncertainties for uncertainty calculations are estimated based on the method used to determine the values of a measured parameter. Recommended procedures for estimating systematic uncertainty are presented in Sections 4 and 7. The elementary systematic uncertainties for each measured parameter are combined according to the root-sum-square rule

$$\text{BIAS}_i = \left(\sum_{j=1}^M \text{BIAS}_j^2 \right)^{1/2}$$

where

BIAS_i = systematic uncertainty of measured parameter i . The units of systematic uncertainty are the same as the units of the measured parameter.

BIAS_j = systematic uncertainty of individual components used to determine the value of parameter i . See note on units above.

M = number of components in the measurement system of parameter i

NOTE: "Measure" and "measurement system" are used in a general sense and do not exclude estimation of parameters.

5-16.4.1 Systematic Uncertainties Associated With Integrated-Average Parameters. The systematic uncertainties associated with spatially nonuniform parameters that vary in both space and time are discussed in detail in Sections 4 and 7. Section 7 presents models that can be used to estimate the systematic uncertainty associated with these types of parameters. These models use a variable called spatial distribution index (SDI). SDI is calculated from the following equation:

$$\text{SDI} = \left[\frac{1}{N} \sum_{i=1}^N (z_i - Z)^2 \right]^{1/2}$$

The following equation is used to determine the multiple midpoint average:

$$\text{multiple midpoint BIAS}_i = \frac{\text{SDI}}{(N-1)^2}$$

where

N = number of points in the measurement grid

SDI = spatial distribution index

Z = integrated-average value of z

z = time-averaged value of the measured parameter

It should be noted that although SDI is calculated identically to standard deviation, there is a significant statistical difference between the two variables.

5-16.4.2 Systematic Uncertainty of Result. The systematic uncertainty of a result is also calculated according to the root-sum-square rule

$$\text{BIASR} = \left[\sum_{i=1}^N (\text{ABSENCO}_i \text{BIAS}_i)^2 \right]^{1/2}$$

where

BIASR = overall systematic uncertainty of the test result

The systematic uncertainty of the result can be positive and/or negative. If the positive and negative systematic uncertainties are not symmetrical, the positive and negative values must be calculated separately. The sign of the product ($\text{ABSENCO}_i \times \text{BIAS}_i$) determines whether the term is summed with the positive or negative systematic uncertainty.

5-16.5 Total Overall Uncertainty

The total uncertainty of a test is calculated by adding the random and systematic uncertainties

$$\text{UNC} = (\text{UPC}^2 + \text{BIASR}^2)^{1/2}$$

where

UNC = total uncertainty

The total uncertainty must be calculated separately for both positive and negative ranges if the systematic uncertainties are not symmetrical.

5-17 OTHER OPERATING PARAMETERS

It is sometimes desirable to test a steam generator for performance parameters other than rated capacity and efficiency. This subsection covers such tests.

Instruments to be used, methods of measurement, and acceptable values for uncertainty of results shall be the subject of pretest agreements. Instruments and methods of measurement are described in Section 4.

To ensure that operating, equipment condition, and control system adjustments will not adversely affect the tests, particular attention should be given to the recommendations in paras. 3-2.2 (pretest checkout), 3-4.2 (preliminary run), and 3-5 (method of operation during test).

5-17.1 Steam Temperature

Data required for the determination of superheater steam temperature characteristics and control ranges are given in Table 4-2-4 of ASME PTC 4.

5-17.2 Pressure Loss

Instruments and methods of measurement for steam and water differential pressure tests, i.e., pressure loss

across the steam generator or a particular section of the steam generator, are given in para. 4-5.4.

Instruments and methods of measurement for air or flue gas differential pressure tests, i.e., draft loss across the steam generator or a particular section of the generator are given in para. 4-5.3.

5-17.3 Static Pressures

Instruments and methods of measurement for steam water static pressure tests are given in para. 4-5.4.

Instruments and methods of measurement for air and gas static pressure tests are given in para. 4-5.3.

5-17.4 Exit Gas Temperature

Data required for exit gas temperature tests are given in Table 4-2-5 of ASME PTC 4. Instruments and methods of gas temperature measurement are given in para. 4-4.3.

Computational procedures for obtaining the corrected gas outlet temperature (TFgLvCr) are given in para. 5-18.2. Computational procedures for obtaining the average exit gas temperature (TMnFgLvCr) are given in paras. 5-10.3 and 5-10.4.

5-17.5 Air Leakage or Infiltration

Reference ASME PTC 4 and ASME PTC 4.3 for methods to measure air in-leakage.

5-18 CORRECTIONS TO STANDARD OR GUARANTEE CONDITIONS

It is usually not possible to test a unit with the standard or guarantee fuel and at the exact standard or guarantee operating conditions. By correcting the test results to standard or guarantee conditions, it is possible to make a more meaningful comparison and evaluation of efficiency, input, output, and performance.

The corrections to efficiency described in this subsection specifically address efficiency calculated using the boiler-as-a calorimeter method; i.e., by the heat balance method using measured flue gas flow rate and measured moisture in the flue gas.

Corrections to efficiency described in this subsection consist of using the standard or guarantee air inlet temperature, correcting air heater gas outlet temperature for deviations between the test and reference conditions, and repeating the efficiency calculations using the standard or guarantee fuel and other operating variables described below. The air and gas flow rates and moisture from fuel at standard or guarantee conditions will be determined stoichiometrically from the design ultimate fuel analysis and higher heating value and design fuel input or heat output.

Users may have a concern regarding the accuracy of corrected efficiency. The corrections address off-design test conditions, not changes in load. The corrected efficiency will usually be different from the test efficiency and corresponds to a different input/output or load. It

is expected that the difference between the test efficiency and corrected efficiency will usually be no more than two to three percentage points. Thus, the order of magnitude of the corrections with respect to load are the same order of magnitude as the ability to establish test conditions versus design conditions.

5-18.1 Entering Air Temperature

Corrections to the heat credits for changes in test entering air temperature to a standard or guarantee condition are made by substituting the standard or guarantee temperature for the test temperature in the applicable heat credit equations.

5-18.2 Exit Gas Temperature

When correction of the exit gas temperature is applicable, corrections to the heat losses are made by substituting the corrected exit gas temperature for the test conditions in the applicable heat loss equations.

5-18.3 Units Without Recuperative Air Heater(s)

The exit gas temperature may be corrected based on the manufacturer's correction curves for deviations from design conditions. Examples of deviation from design conditions might include deviations from design fuel, significant difference in entering air temperature, feedwater inlet temperature, off-design main steam temperature due to desuperheater spray flow, etc.

5-18.4 Units With Recuperative Air Heater(s)

The exit gas temperature shall be corrected for the standard or guarantee conditions based on the test air heater performance in accordance with ASME PTC 4.3, Air Heaters, for deviations from standard or reference conditions as described below

$$TFgLvCrDs = TFgLvCr + TDiTAEn + TDiTFgEn + TDiMrFgEn + TDiXr, ^\circ F (^{\circ}C)$$

where

$TDiMrFgEn$ = temperature correction for entering gas mass flow, $^{\circ}F (^{\circ}C)$

$TDiTAEn$ = temperature correction for entering air temperature, $^{\circ}F (^{\circ}C)$

$TDiTFgEn$ = temperature correction for entering gas temperature, $^{\circ}F (^{\circ}C)$

$TDiXr$ = temperature correction for off-design X-ratio, $^{\circ}F (^{\circ}C)$

$TFgLvCr$ = exit gas temperature corrected for air heater leakage and used for calculation of efficiency (as tested), $^{\circ}F (^{\circ}C)$

$TFgLvCrDs$ = exit gas temperature corrected to design conditions, $^{\circ}F (^{\circ}C)$

5-18.4.1 Entering Air Temperature

$$TDiTAEn = \frac{TAEnd(TFgEn - TFgLvCr)}{(TFgEn - TAEn)} + \frac{TFgEn(TFgLvCr - TAEn)}{(TFgEn - TAEn)} - TFgLvCr, ^\circ F (^{\circ}C)$$

where

$TAEn$ = air temperature entering air heater(s), $^{\circ}F (^{\circ}C)$

$TAEnd$ = design entering air temperature, $^{\circ}F (^{\circ}C)$

$TFgEn$ = gas temperature entering air heater(s), $^{\circ}F (^{\circ}C)$

5-18.4.2 Entering Gas Temperature. Examples where corrections due to the entering gas temperature may be applicable may include but are not limited to

(a) equipment within the steam generator envelope not supplied by the steam generator vendor. The specified temperature drop across the terminal points shall be used to determine the corrected air heater entering gas temperature based on the measured gas temperature entering such equipment.

(b) feedwater inlet temperature. The entering feedwater temperature is significantly different from the standard or guarantee conditions.

(c) deviations from contract fuel. The test fuel is significantly different from the contract fuel.

The exit gas temperature correction due to off-design entering gas temperature may be calculated from the following equation:

$$TDiTFgEn = \frac{TFgEnCrd(TFgLvCrd - TAEn)}{(TFgEn - TAEn)} + \frac{TAEn(TFgEn - TFgLvCrd)}{(TFgEn - TAEn)} - TFgLvCr, ^\circ F (^{\circ}C)$$

where

$TFgEnCrd$ = entering gas temperature corrected to design conditions, $^{\circ}F (^{\circ}C)$

5-18.4.3 Entering Gas Mass Flow. For determining corrected efficiency, the air heater exit gas temperature may be corrected for the difference in the gas mass flow entering the air heater for the test conditions and the gas mass flow entering the air heaters calculated for the corrected efficiency and contract steam generator output/input.

DTMGI is obtained from a correction curve, usually provided by the air heater vendor.

5-18.4.4 Heat Capacity or X-Ratio. For determining corrected efficiency, the air heater exit gas temperature may be corrected for the difference in the heat capacity ratio for the test conditions and the heat capacity ratio calculated for the corrected efficiency and the contract steam generator output/input. The most typical reason for the heat capacity ratio to be different from design is air bypassing the air heater(s). An example of when this may occur would be excessive setting infiltration (normally older units).

DTXR is obtained from a correction curve, usually provided by the air heater vendor.

5-18.5 Fuel Analysis

Corrections to credits and losses are made by using the standard or contract fuel analysis to determine quantities of air, flue gas, and moisture from fuel. The corrected mass flow rates of air and flue gas shall be calculated stoichiometrically from excess air (see para. 5-18.9) and the design or standard fuel ultimate analysis following the methodology prescribed in ASME PTC 4.

It is assumed for purposes of this Code that the differences between the test and reference fuel do not impact the thermal performance of the steam generator or suitability of test fuel. This is not to preclude an agreement between parties as to a method for compensating for differences in thermal performance of the steam generator between the test and standard or guarantee fuels.

5-18.6 Throughput

To correct as-measured fuel throughput performance (i.e., mass of fuel consumed per unit time) to standard or guarantee conditions, design or test steam generator heat output is first divided by corrected fuel efficiency to determine corrected fuel heat input. Corrected fuel heat input is then divided by the design higher heating value of the fuel to determine corrected fuel throughput. Note that the design fuel higher heating value is sometimes referred to as "reference waste" HHV

$$QrFCr = \frac{QrOd, t}{EFCr}$$

$$MrFCr = \frac{QrFCr}{HHVd}$$

where

EFCr = fuel efficiency corrected to design conditions, %

HHVd = design fuel higher heating value, Btu/lb

MrFCr = mass flow rate of fuel fired, corrected to design fuel and boundary conditions, lbm/hr

QrFCr = steam generator fuel input, corrected to design conditions, Btu/hr

QrOd, t = design or test steam generator heat output, Btu/hr

5-18.7 Output

To correct as-measured steam generator capacity performance (i.e., output or steam flow) to standard or guarantee conditions, design or test boiler heat input is multiplied by corrected fuel efficiency to determine corrected boiler heat output. Depending on the equipment arrangement and design, and what type of capacity guarantee is being evaluated, parties to the test shall agree on a procedure to use corrected boiler output to determine parameters such as corrected steam flow

$$QrOCr = QrFd, t \times EFCr$$

where

EFCr = corrected fuel efficiency, %

QrFd, t = design steam generator fuel heat input, Btu/hr

QrOCr = steam generator output corrected to design conditions, Btu/hr

5-18.8 Residue

The considerations for residue are losses related to unburned combustible in the residue, residue split between the various boiler collection points, and the ash quantity in the fuel.

5-18.8.1 Unburned Combustible Loss. It is beyond the scope of this Code to adjust the unburned combustible loss with respect to fuel-burning characteristics, or operating parameters. Therefore, unless otherwise agreed to, the test unburned combustible loss shall be considered equivalent to the unburned combustible loss for the corrected conditions.

5-18.8.2 Residue Quantity. The residue quantity is the sum of the ash in the fuel and unburned combustible and is calculated for the standard or guarantee conditions using the reference fuel analysis and other corrected conditions, unlike the test residue quantity, which is normally measured.

5-18.8.3 Residue Split. If measured, the residue split between the various collection locations shall be assumed to be the same as tested unless otherwise agreed on.

5-18.8.4 Sensible Heat in Residue Loss. The sensible heat in residue loss at each location shall be calculated based on the total mass of residue calculated for the standard or guarantee conditions, using the test residue splits (per para. 4-6.6) and temperatures (corrected to standard or guarantee conditions, if applicable).

5-18.9 Excess Air

Minor deviations in excess air between the test and standard or guaranteed value that are due to variability of establishing test conditions may be corrected to the standard, guaranteed, or other agreed-on value. Corrections to losses or credits due to excess air are made by substituting the standard or guarantee conditions in the applicable equations.

5-18.10 Other Entering Streams

5-18.10.1 Moisture in Air. Substitute the standard or guarantee value for the test value in the applicable calculations.

5-18.10.2 Fuel Temperature. Substitute the standard or guarantee value for the test value.

5-18.11 Miscellaneous Efficiency Corrections

The most common efficiency correction parameters are discussed below.

5-18.11.1 Surface Radiation and Convection Loss.

When this item is measured or corrected for ambient conditions, the standard or guarantee conditions shall be used for the efficiency corrected to reference conditions.

5-18.11.2 Soot-Blowing Steam. The standard or specified quantity used as the basis for guarantee conditions shall be used.

5-18.12 Air and Gas Resistance

The measured resistance shall be corrected to standard or guarantee conditions for the difference in mass flow of the flowing fluid and the specific volume of the fluid between the test condition and the reference conditions. The corrected resistance is the product of the tested resistance, the ratio of the corrected specific volume divided by the test specific volume, and the square of the ratio of the corrected mass flow divided by the test mass flow.

5-18.13 Steam or Water Pressure Loss

The measured pressure differential across a steam generating unit or a portion of the unit shall be corrected to standard or guarantee conditions due to the difference in mass flow of the flowing fluid and the specific volume between the test condition and the reference conditions. The corrected pressure loss is the product of the tested resistance, the corrected specific volume divided by the test specific volume, and the square of the ratio of the corrected mass flow divided by the test mass flow.

5-18.14 Uncertainty of Corrected Results

Uncertainty values are used to judge the quality of the performance test. If the calculated test uncertainty is less than or equal to the target values, the test is acceptable and the test results (efficiency, output, etc.) can be used to judge the performance of the steam generator.

Corrections of steam generator performance parameters to standard or guarantee conditions are based on the test results and do not involve the test uncertainty. Although it is possible to define and calculate uncertainties for corrected results, these uncertainties are not relevant to performance testing because they do not indicate the quality of the test. Accordingly, this Code does not address the uncertainty of corrected results.

5-19 ENTHALPY OF AIR, FLUE GAS, AND OTHER SUBSTANCES COMMONLY REQUIRED FOR ENERGY BALANCE CALCULATIONS

The enthalpy correlations presented in this subsection are recommended for users interested in general heat transfer calculations involving air and flue gas.

Unless otherwise noted, the reference source is the JANAF Thermochemical Tables, 2nd edition, NSRDS-NBS 37, and curve-fit coefficients developed in accordance with NASA publication SP-273. Abbreviated JANAF/NASA correlations are presented below.

For convenience in hand calculations, curves are provided at the end of this subsection for calculating enthalpy of air, flue gas, water vapor, and residue. Refer to para. 5-19.9 for a description of how these curves are used.

Unless otherwise noted, the curve fits for enthalpy in this subsection are in U.S. Customary units of Btu/lbm. To convert to kJ/kg, multiply the result by 2.326.

5-19.1 Enthalpy of Air, Btu/lbm (J/kg)

Enthalpy of air is a function of the mass of the mixture of dry air and water vapor in air. To determine the enthalpy of dry air, use a water vapor content of zero

$$H_A = (1 - M_{FrWA}) H_{DA} + M_{FrWA} H_{Wv}, \text{ Btu/lbm (J/kg)}$$

$$M_{FrWA} = M_{FrWDA} / (1 + M_{FrWDA}), \text{ lbm/lbm (kg/kg)}$$

5-19.2 Enthalpy of Flue Gas, Btu/lbm (J/kg)

"Wet flue gas," as defined by the calculations in this Code, is composed of dry gaseous products of combustion and water vapor. Solid residue may also be entrained in the gas stream. The enthalpy of wet flue gas accounts for the enthalpies of all of these components. If the enthalpy of dry flue gas is desired, the water and solid residue components are zero

$$H_{Fg} = (1 - M_{FrWFg}) H_{DFg} + M_{FrWFg} H_{Wv}, \text{ Btu/lbm (J/kg)}$$

The sensible heat of residue may be omitted if the ash in the fuel is less than 15 lbm/million Btu input (i.e., where $10,000 \times M_{pAsF} / HHVF$ is less than 15).

5-19.3 Enthalpy of Dry Residue, Btu/lbm

Residue is composed of numerous complex compounds and may include spent sorbent products when sorbent is used. One approach for determining enthalpy of residue would be to determine or estimate (calculate) the major constituents in the residue and use a mass-weighted average of the enthalpy for each component to determine the average enthalpy. In the interest of simplicity and considering the insignificant impact of inaccuracies in calculating the enthalpy of residue on the energy balance calculations within the scope of this Code compared to the error in measuring the mass flow rate of residue streams, this Code adopts the curve fit below for all dry residue streams. It was developed from data for SiO_2 , 77°F (25°C) reference temperature, and is applicable from 0°F to 2,000°F (−20°C to 1 100°C). This Code adopts the fifth-order correlations described in para. 5-19.9 for all dry residue streams. The following

abbreviated equation developed from the fifth-order curve fit may be used for hand calculations:

$$HRs = 0.16T + 1.09E - 4T^2 - 2.843E - 8T^3 - 12.95, \text{ Btu/lbm}$$

where T is in degrees Fahrenheit.

5-19.4 Enthalpy of Water Vapor at 77°F (25°C) Reference, Btu/lbm

The coefficients for the JANAF/NASA fifth-order curve fit, at a reference temperature of 77°F (25°C), are given in para. 5-19.8. The following simplified curve fit for calculating credits and losses due to moisture may also be used. The results are within 0.3% of the JANAF values for temperatures between 0°F and 1,000°F (-20°C and 540°C)

$$HW_v = 0.4408T + 2.381E - 5T^2 + 9.638E - 9T^3 - 34.1, \text{ Btu/lbm}$$

where T is the temperature in degrees Fahrenheit and the reference temperature is 77°F (25°C).

5-19.5 Enthalpy of Steam/Water at 1 psia, 32°F (0°C) Reference, Btu/lbm

The enthalpy of steam (water vapor) at 1 psia is required to determine the loss/credit of water that enters the boundary in the liquid state and leaves the boundary in the flue gas in a vaporous state. An example is the calculation of the water from fuel losses. The following equation may be used in lieu of the ASME Steam Tables for temperatures from 200°F to 1,000°F (95°C to 540°C):

$$HW_v = 0.4329T + 3.958E - 5T^2 + 1062.2, \text{ Btu/lbm}$$

$$HW = T - 32, \text{ Btu/lbm}$$

where T is in degrees Fahrenheit.

5-19.6 Enthalpy of Fuel Oil, Btu/lbm

The enthalpy of fuel oil has been correlated as a function of specific gravity at 60°F (16°C) in degrees API. Reference *The Science of Petroleum*, D. W. Gould, 1938

$$HFO = C1 + C2 \text{ API} + C3 T + C4 \text{ API} T + (C5 + C6 \text{ API}) T^2, \text{ Btu/lbm}$$

$$\text{API} = (141.5 - 131.5Sg)/Sg$$

$$Sg = Dn/62.4$$

where

API = density at 60°F (16°C), degrees API

$$C1 = -30.016$$

$$C2 = -0.11426$$

$$C3 = +0.373$$

$$C4 = +0.143E-2$$

$$C5 = +0.2184E-3$$

$$C6 = +7.0E-7$$

Dn = density at 60°F (16°C), lbm/ft³

HFO = enthalpy of fuel oil, Btu/lbm

Sg = specific gravity at 60°F (16°C), lbm/lbm

T = temperature, °F

5-19.7 Enthalpy of Natural Gas, Btu/lbm

The following curve fit was developed from the JANAF/NASA data for a typical natural gas fuel analysis of 90% methane (CH₄), 5% ethane (C₂H₆), and 5% nitrogen. It is valid from 0°F to 500°F. Natural gas will normally be near the reference temperature of 77°F (25°C), and thus using a typical analysis for natural gas is sufficiently accurate for efficiency calculations. For manufactured gases that enter the steam generator at an elevated temperature, the enthalpy should be determined based on the actual constituents in the gas

$$HGF = 0.4693 + 0.17523E-3T^2 + 0.4326E-7T^2 - 37.2, \text{ Btu/lbm}$$

where T is in degrees Fahrenheit.

5-19.8 Enthalpy Coefficients for Abbreviated JANAF/NASA Correlation

The enthalpy/temperature curves in this subsection are based on the following abbreviated enthalpy correlation and the coefficients tabulated below. The reference temperature is 77°F (25°C)

$$Hk = C0 + C1Tk + C2Tk^2 + C3Tk^3 + C4Tk^4 + C5Tk^5, \text{ Btu/lbm}$$

$$TK = (T + 459.7)/1.8, \text{ K}$$

where

Hk = enthalpy of the constituents, Btu/lbm

T = temperature, °F

TK = temperature, K

Coefficients for dry air are based on the composition of air as defined in this Code.

Coefficients for dry air for temperatures from 0°F to 1,340°F

$$C0 = -0.1310658E+03$$

$$C1 = +0.4581304E+00$$

$$C2 = -0.1075033E-03$$

$$C3 = +0.1778848E-06$$

$$C4 = -0.9248664E-10$$

$$C5 = +0.16820314E-13$$

Coefficients for dry air for temperature above 1,340°F

$$C0 = -0.1177723E+03$$

$$C1 = +0.3716786E+00$$

$$C2 = +0.8701906E-04$$

$$C3 = -0.2196213E-07$$

$$C4 = +0.2979562E-11$$

$$C5 = -0.1630831E-15$$

Coefficients for water vapor temperatures from 0°F to 1,340°F

$$\begin{aligned}C0 &= -0.2394034E+03 \\C1 &= +0.8274589E+00 \\C2 &= -0.1797539E-03 \\C3 &= +0.3934614E-06 \\C4 &= -0.2415873E-09 \\C5 &= +0.6069264E-13\end{aligned}$$

Coefficients for water vapor temperatures above 1,340°F

$$\begin{aligned}C0 &= -0.1573460E+03 \\C1 &= +0.5229877E+00 \\C2 &= +0.3089591E-03 \\C3 &= -0.5974861E-07 \\C4 &= +0.6290515E-11 \\C5 &= -0.2746500E-15\end{aligned}$$

For typical hydrocarbon fuels, including waste fuels, combusted with less than 300% excess air, the enthalpy of dry flue gas does not vary significantly. The following coefficients are sufficiently accurate for the heat transfer calculations in this Code. For unusual fuels such as manufactured gases, hydrogen, and/or combustion processes using an oxidizing medium other than air, see ASME PTC 4.

Coefficients for dry flue gas for temperatures from 0°F to 1,340°F

$$\begin{aligned}C0 &= -0.1231899E+03 \\C1 &= +0.4065568E+00 \\C2 &= +0.5795050E-05 \\C3 &= +0.6331121E-07 \\C4 &= -0.2924434E-10 \\C5 &= +0.2491009E-14\end{aligned}$$

Coefficients for dry flue gas for temperatures above 1,340°F

$$\begin{aligned}C0 &= -0.1180095E+03 \\C1 &= +0.3635095E+00 \\C2 &= +0.1039228E-03 \\C3 &= -0.2721820E-07 \\C4 &= +0.3718257E-11 \\C5 &= -0.2030596E-15\end{aligned}$$

Coefficients for residue of unknown composition and sand for temperatures from 0°F to 1,340°F. The following coefficients are based on a smoothed curve fit for SiO₂ around the discontinuous point at approximately 1,340°F:

$$\begin{aligned}C0 &= -0.3230338E+02 \\C1 &= -0.2431404E+00 \\C2 &= +0.1787701E-02 \\C3 &= -0.2598230E-05 \\C4 &= +0.2054892E-08 \\C5 &= -0.6366886E-12\end{aligned}$$

Coefficients for residue of unknown composition and sand for temperatures above 1,340°F

$$\begin{aligned}C0 &= +0.1822637E+02 \\C1 &= +0.3606155E-01 \\C2 &= +0.4325735E-03 \\C3 &= -0.1984149E-06 \\C4 &= +0.4839543E-10 \\C5 &= -0.4614088E-14\end{aligned}$$

5-19.9 Curves for Calculating Enthalpy

The abbreviated JANAF/NASA correlations for air and flue gas are fifth-order polynomials. For convenience in hand calculations, specific heat curves for dry air, water vapor, dry flue gas, and residue are provided as Figs. 5-19.9-1 through 5-19.9-4. These curves show the *mean* specific heat of the constituent between the temperatures desired and 77°F (25°C). To obtain enthalpy (*H*) for any of the constituents (i.e., dry flue gas, water vapor, dry air, or residue) at a 77°F reference temperature, multiply the mean specific heat times the temperature (*T*) minus 77°F

$$H = MCP (T - 77), \text{ Btu/lbm}$$

The resolution of the curves is such that the calculated result will be within 0.1 Btu/lbm of the actual correlations. Refer to the explanations above for calculation of enthalpy of mixtures such as wet air and wet flue gas.

For some calculations, the instantaneous specific heat (as an approximation of mean specific heat over a small temperature band) at a specific temperature is required, such as for the calculation of corrected air heater exit gas temperature. Instantaneous specific heat can be obtained from the mean specific heat curves by entering the curve with a temperature (*Tc*) equal to 2 times the temperature (*T*) desired minus 77°F

$$Tc = 2T - 77, ^\circ\text{F}$$

For example, to obtain the instantaneous specific heat at 300°F, enter the mean specific heat curve with a temperature of 523°F [(2 × 300) – 77].

5-20 ACRONYMS

5-20.1 Basis for Acronyms

The acronyms (except for uncertainty) are built from symbols from the following groups and generally arranged in the following sequence:

PROPERTY → FUNCTION → (EQUIPMENT, STREAM, EFFICIENCY) → (LOCATION, COMPONENT, CONSTITUENT) → CORRECTION

5-20.1.1 Property Symbols

A_f = flat projected surface area
C_p = mean specific heat at constant pressure
D = dry
D_n = density

H = enthalpy
 H_{ca} = convection heat transfer coefficient
 HHV = higher heating value, mass basis
 H_{ra} = radiation heat transfer coefficient
 M = mass
 M_o = mole
 M_p = percent mass
 M_q = mass per unit of energy
 M_r = mass rate
 M_w = molecular weight
 P = pressure
 P_a = atmospheric pressure
 P_p = partial pressure
 P_s = saturation pressure
 Q = energy
 Q_p = percent fuel input energy
 Q_r = heat transfer rate
 R_{hm} = relative humidity
 T = temperature
 T_{db} = dry bulb temperature
 T_{wb} = wet bulb temperature
 V = velocity
 V_p = percent volume

5-20.1.2 Function Symbols

A_d = additional
 b = energy balance (see subsection 5-5)
 C_1, C_2, \dots = constants as defined in the text
 C_r = corrected
 Δ = difference (delta)
 F_r = fractional
 M_n = mean
 p = percentage
 Σ = sum

5-20.1.3 Equipment, Stream, and Efficiency Symbols

A = air
 A_p = ash pit
 A_x = auxiliary
 B = credit
 B_d = blowdown
 C = carbon
 CO = carbon monoxide
 CO_2 = carbon dioxide
 C_w = cooling water
 E = efficiency, %
 E_v = evaporation
 F = fuel
 F_g = flue gas
 F_s = supplementary fuel
 G_r = gross
 H_2O = flue gas moisture
 I = input
 L = loss
 N = nitrogen
 N_{2a} = atmospheric nitrogen
 O = output

O_2 = oxygen
 R_s = residue
 R_y = recycle
 SO_2 = sulfur dioxide
 S_{rc} = surface radiation and convection
 St = steam
 Th = theoretical
 U_b = unburned
 W = water
 W_v = water vapor
 X = auxiliary
 X_p = percent excess
 X_r = X-ratio

5-20.1.4 Location, Component, and Constituent

Symbols

d = design
 E_n = inlet or entering
 k = constituent
 L_v = outlet, exit, or leaving
 R_e = reference
 z = location number from system boundary
 7 = primary air fan discharge
 $7A$ = secondary air fan discharge
 8 = primary air entering boundary
 $8A$ = secondary air entering boundary
 $8B$ = primary air leaving APH coils within boundary
 9 = primary air leaving air heater
 13 = entering economizer
 14 = leaving economizer
 $14A$ = entering primary air heater
 15 = leaving primary AH
 17 = leaving cold-side AQC equipment
 19 = leaving ID fan
 22 = entering gas recirculation fan
 23 = leaving gas recirculation fan (entering boiler)
 24 = feedwater entering
 25 = superheater spray water
 26 = furnace spray water
 27 = feedwater leaving economizer
 28 = feedwater entering drum
 31 = saturated steam leaving drum
 $31B$ = leaving first-stage SH desuperheater
 32 = main steam
 35 = blowdown
 36 = condensate leaving APH coils (internal to boundary)
 37 = furnace residue
 38 = ash pit water in
 39 = ash pit water out
 40 = cooling water in

- 41 = cooling water out
- 42 = atomizing steam
- 46 = soot blower steam
- 46A = auxiliary steam
- 52 = economizer fly ash
- 53 = hot AQC equipment fly ash
- 55 = cold AQC equipment fly ash

5-20.2 List of Acronyms Used

See Tables 5-20.2-1 and 5-20.2-2.

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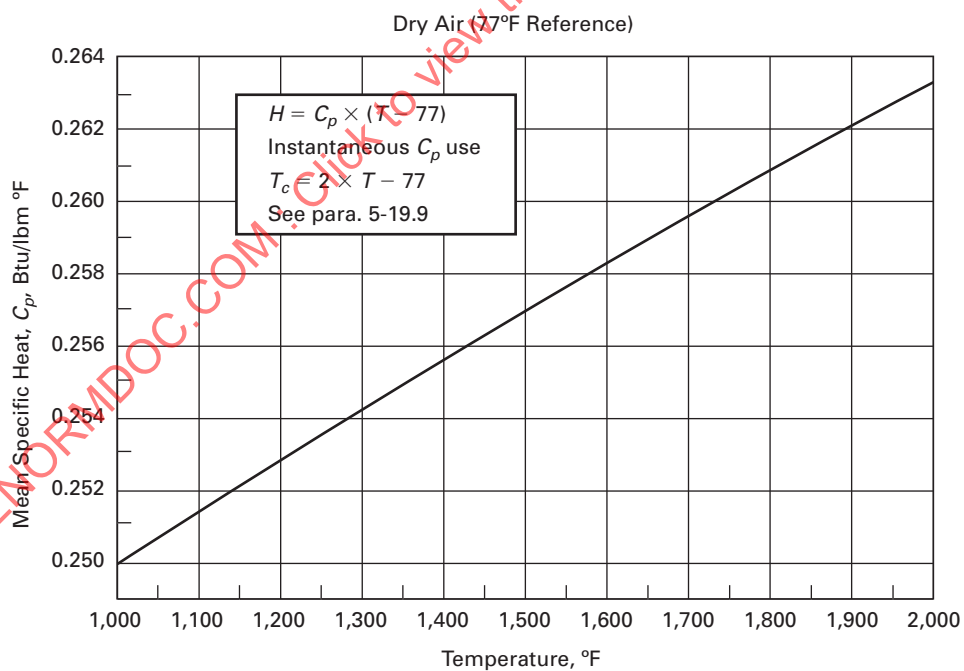
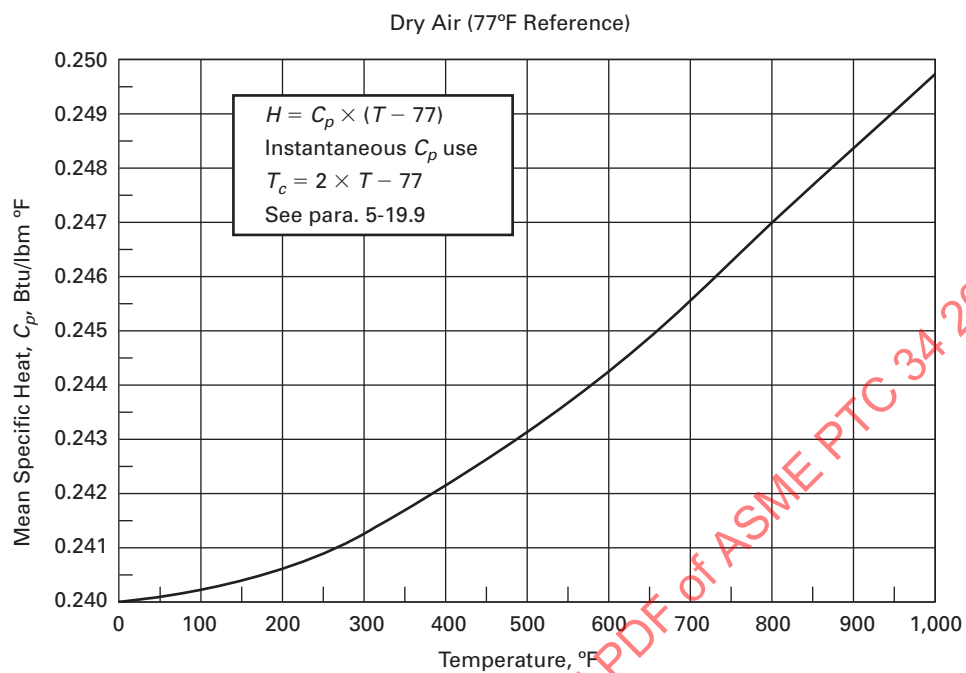
Fig. 5-19.9-1 Mean Specific Heat of Dry Air vs. Temperature

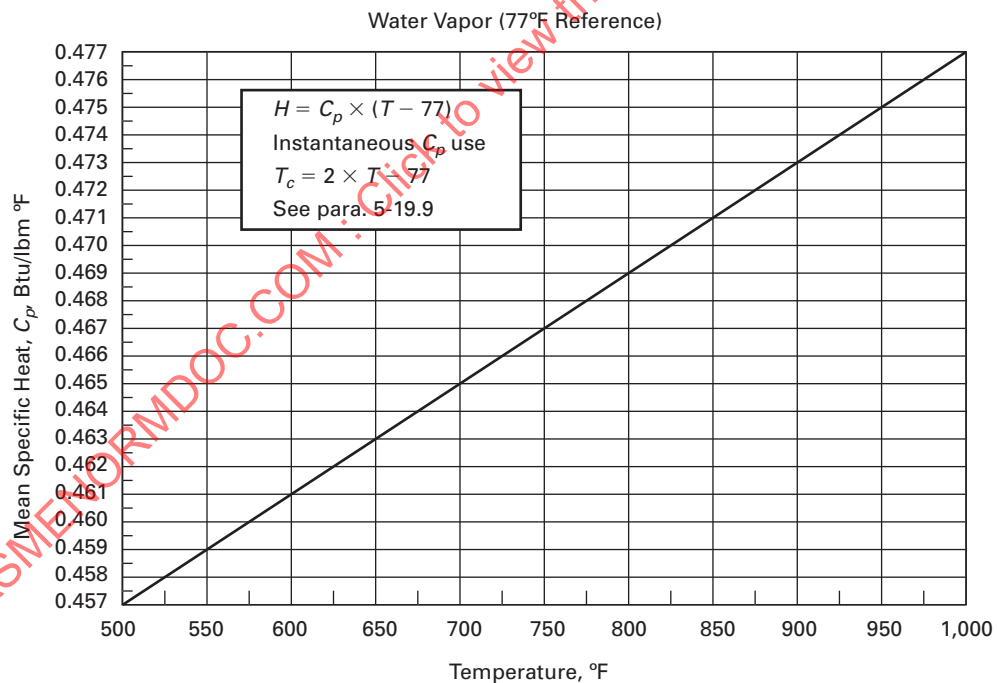
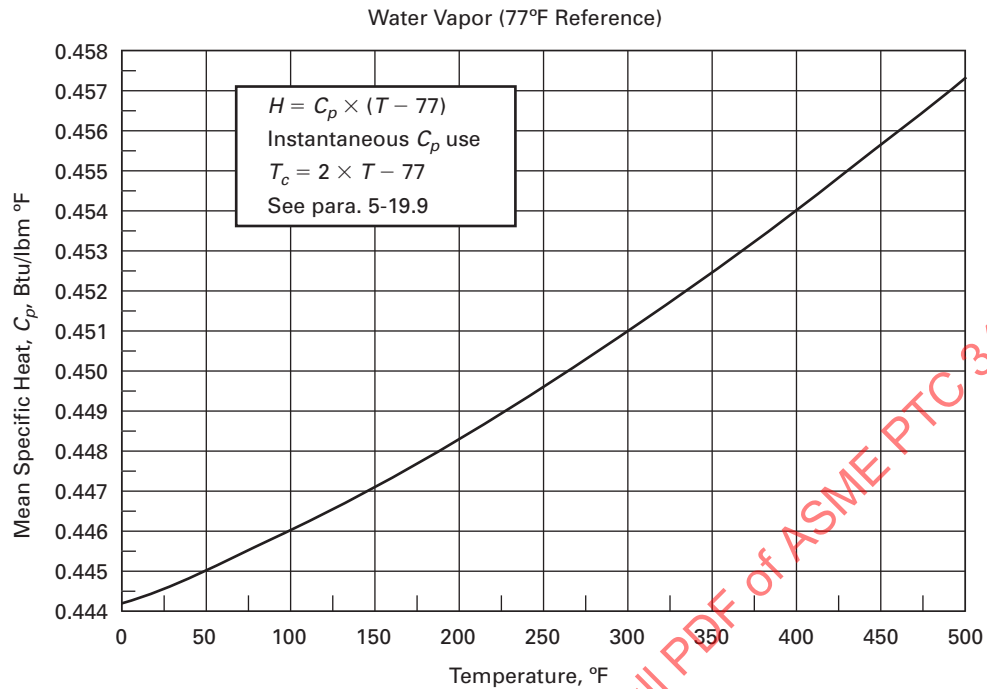
Fig. 5-19.9-2 Mean Specific Heat of Water Vapor vs. Temperature

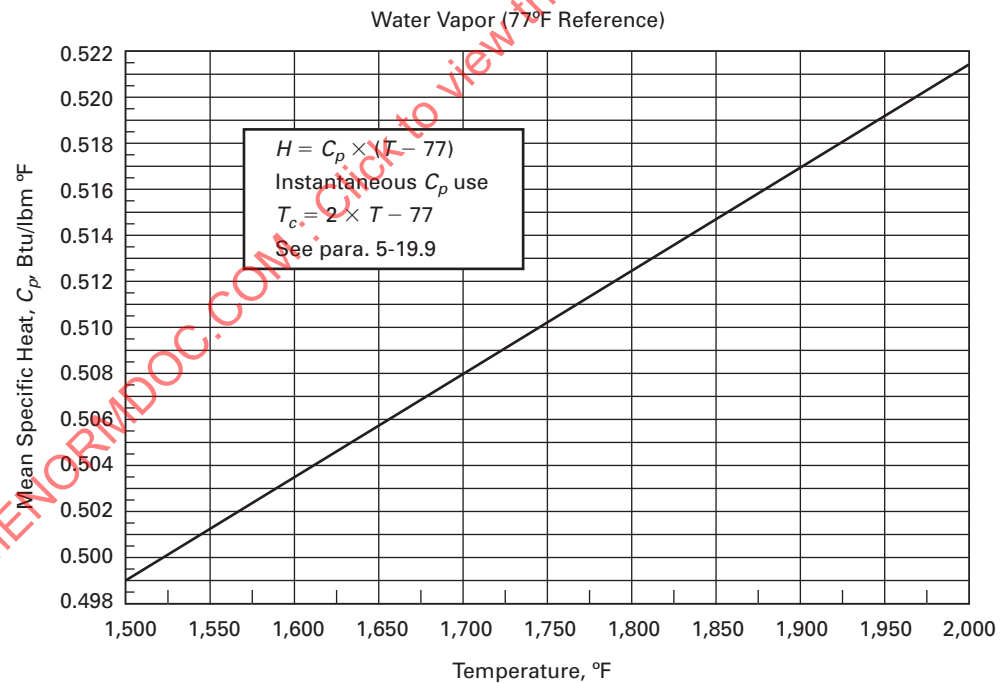
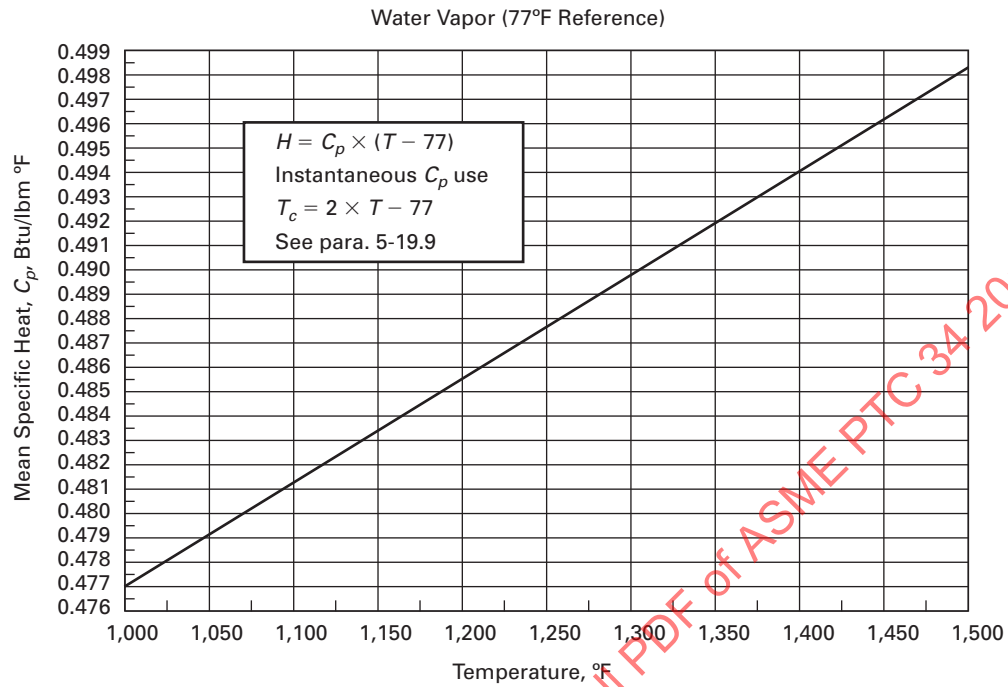
Fig. 5-19.9-2 Mean Specific Heat of Water Vapor vs. Temperature (Cont'd)

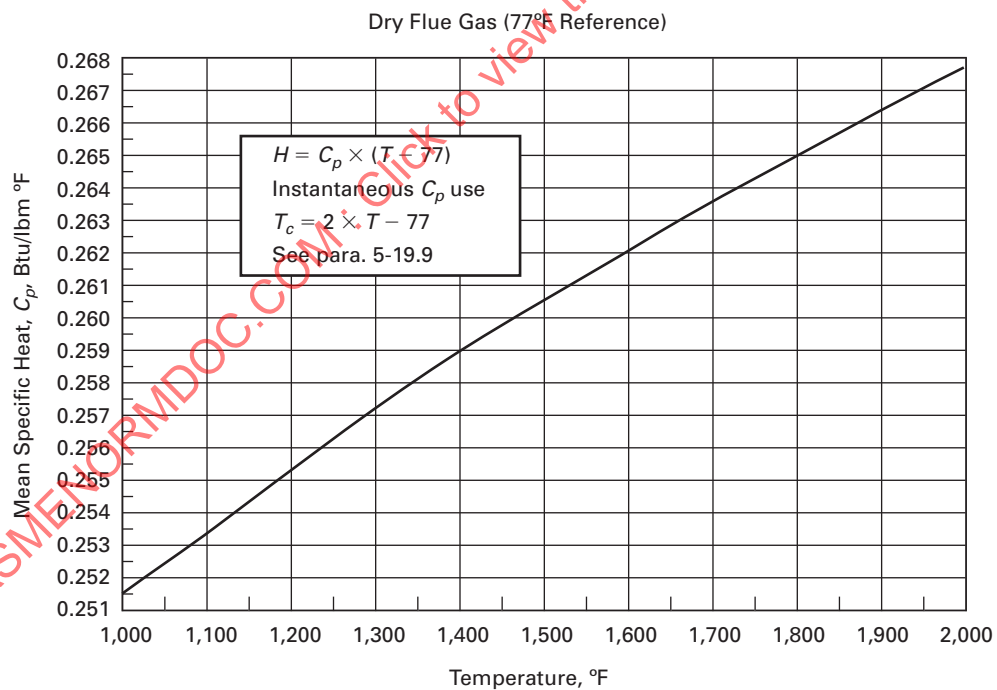
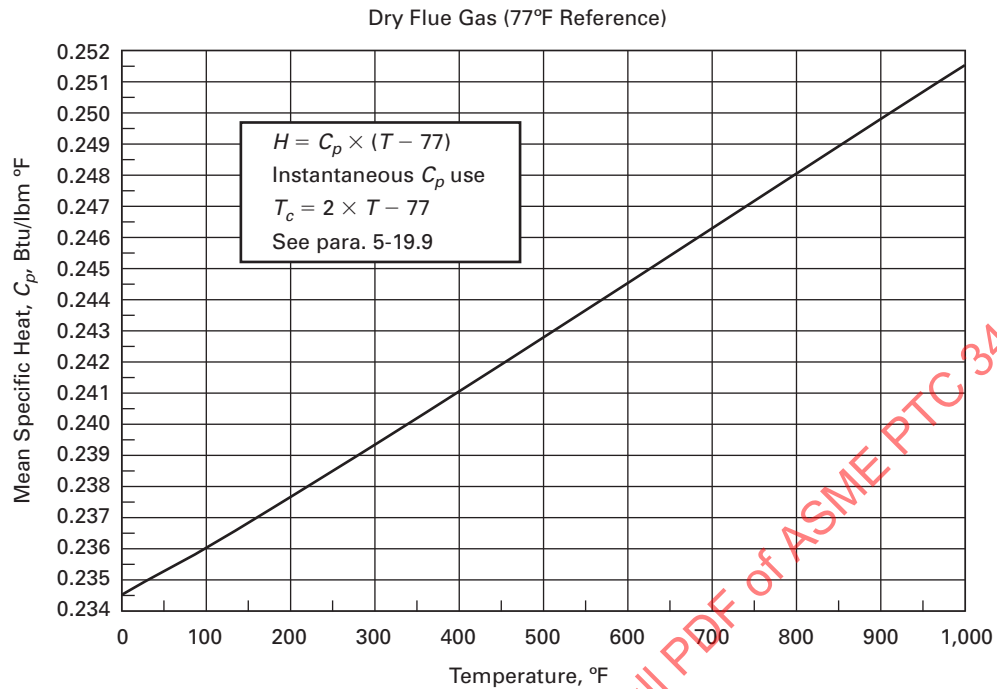
Fig. 5-19.9-3 Mean Specific Heat of Dry Flue Gas vs. Temperature

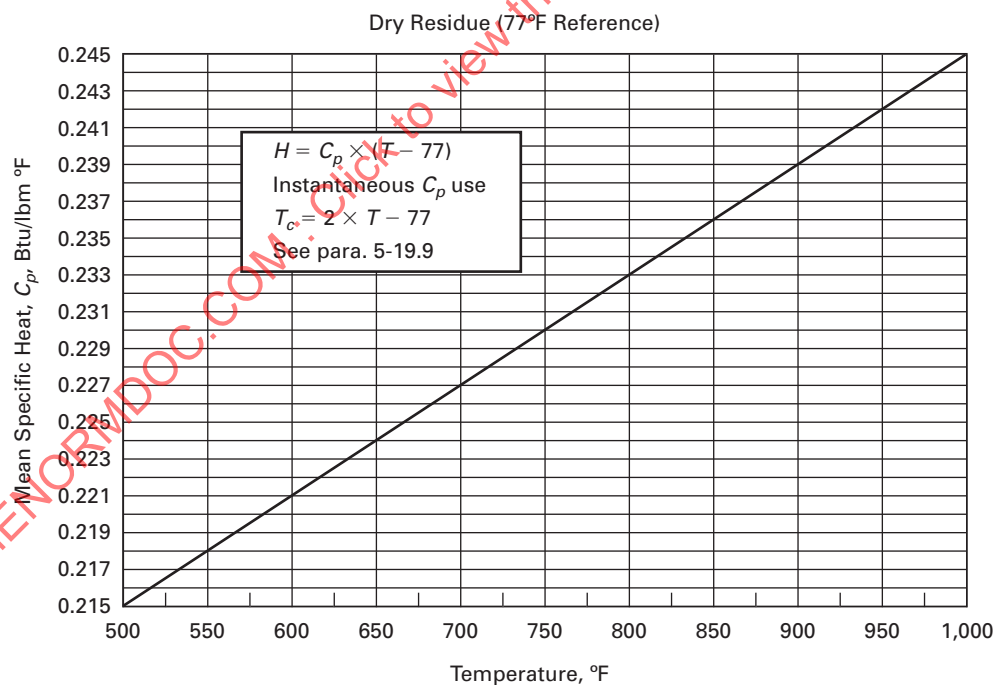
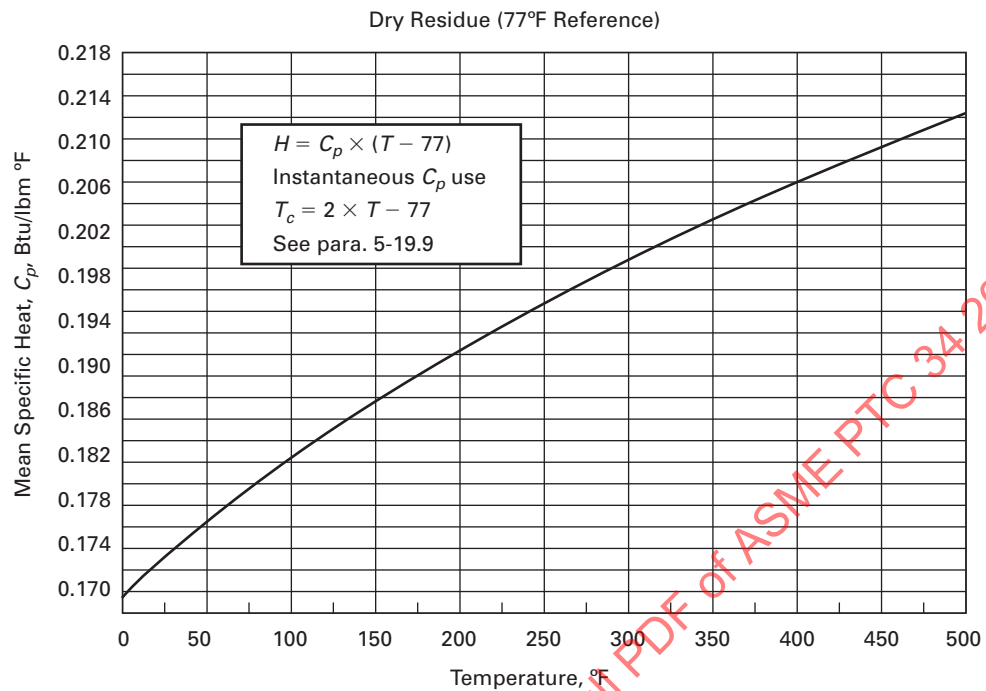
Fig. 5-19.9-4 Mean Specific Heat of Dry Residue vs. Temperature

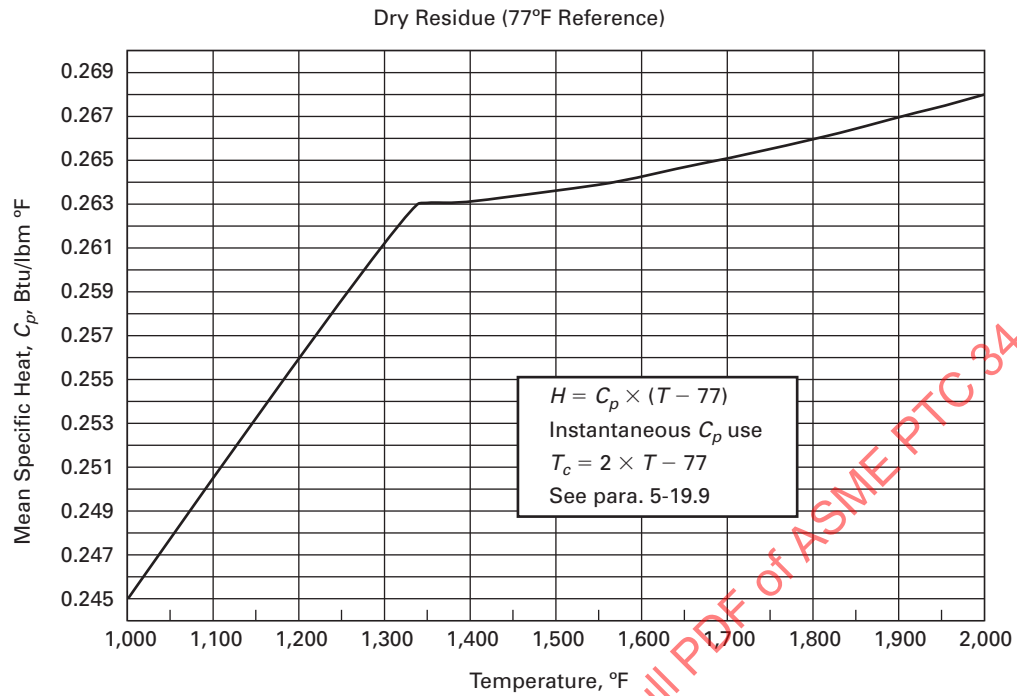
Fig. 5-19.9-4 Mean Specific Heat of Dry Residue vs. Temperature (Cont'd)

Table 5-20.2-1 List of Acronyms Used

Acronyms	Description	Units
Afz	Flat projected surface area for location z	ft ² (m ²)
DnA	Density of wet air	lbm/ft ³ (kg/m ³)
DnFg	Density of wet flue gas	lbm/ft ³ (kg/m ³)
DnFgz	Density of wet flue gas at location z	lbm/ft ³ (kg/m ³)
DVpCO	Percent CO in flue gas, dry basis	% volume
DVpCO ₂	Percent CO ₂ in flue gas, dry basis	% volume
DVpH ₂ O	Percent H ₂ O in flue gas	% volume
DVpN ₂	Percent nitrogen in flue gas, dry basis	% volume
DVpO ₂	Percent O ₂ in flue gas, dry basis	% volume
DVpO ₂ z	Percent O ₂ in flue gas at location z, dry basis	% volume
DVpSO ₂	Percent SO ₂ in flue gas, dry basis	% volume
EAx	Combined efficiency of auxilliary drive, coupling, and gears	%
EF	Fuel efficiency	%
EGr	Gross efficiency	%
HA	Enthalpy of wet air	Btu/lbm (J/kg)
HAEn	Enthalpy of wet air entering, general	Btu/lbm (J/kg)
HATFgLv	Enthalpy of air at the gas outlet temperature	Btu/lbm (J/kg)
HAz	Enthalpy of wet air at location z	Btu/lbm (J/kg)
Hcaz	Convection heat transfer coefficient for location z	Btu/ft ² hr °F (J/m ² s °C)
HDA	Enthalpy of dry air	Btu/lbm (J/kg)
HDAMnEn	Enthalpy of dry air at the average entering air temperature	Btu/lbm (J/kg)
HDFg	Enthalpy of dry flue gas	Btu/lbm (J/kg)
HDFgLvCr	Enthalpy of dry flue gas leaving, excluding leakage	Btu/lbm (J/kg)
HEn	Enthalpy entering, general	Btu/lbm (J/kg)
HEnz	Enthalpy entering at location z	Btu/lbm (J/kg)
HFg	Enthalpy of wet flue gas	Btu/lbm (J/kg)
HFgCr	Enthalpy of wet flue gas, corrected	Btu/lbm (J/kg)
HFgEn	Enthalpy of wet flue gas entering	Btu/lbm (J/kg)
HFw	Enthalpy of water at temperature of waste fuel	Btu/lbm (J/kg)
HHVCO	Higher heating value of carbon monoxide	Btu/lbm (J/kg)
HHVCRs	Higher heating value of carbon in residue	Btu/lbm (J/kg)
HHVF	Higher heating value of fuel at constant pressure	Btu/lbm (J/kg)
HHVFcV	Higher heating value of fuel at constant volume	Btu/lbm (J/kg)
HHVFs	Higher heating value of supplementary fuel at constant pressure	Btu/lbm (J/kg)
Hk	Enthalpy of constituent k	Btu/lbm (J/kg)
Hkz	Enthalpy of constituent k at location z	Btu/lbm (J/kg)
HLv	Enthalpy leaving, general	Btu/lbm (J/kg)
HLvz	Enthalpy leaving at location z	Btu/lbm (J/kg)
HMnA	Average enthalpy of wet air	Btu/lbm (J/kg)
Hraz	Radiation heat transfer coefficient for location z	Btu/ft ² hr °F (J/m ² s °C)
HRe	Enthalpy at reference temperature	Btu/lbm (J/kg)
HRek	Enthalpy of constituent k at reference temperature	Btu/lbm (J/kg)
HRs	Enthalpy of residue	Btu/lbm (J/kg)
HRsEn	Enthalpy of residue entering	Btu/lbm (J/kg)
HRsLv	Enthalpy of residue leaving	Btu/lbm (J/kg)
HRsz	Enthalpy of residue at location z	Btu/lbm (J/kg)
HSt	Enthalpy of steam (based on ASME Steam Tables)	Btu/lbm (J/kg)
HStAxEn	Enthalpy of steam entering auxiliary equipment drive	Btu/lbm (J/kg)
HStAxLv	Enthalpy of steam leaving auxiliary equipment drive	Btu/lbm (J/kg)
HStFgEnz	Enthalpy of additional moisture (steam) in flue gas entering	Btu/lbm (J/kg)
HStLvCr	Enthalpy of steam (based on ASME Steam Tables), at corrected exit gas temperature	Btu/lbm (J/kg)
HStz	Enthalpy of steam at location z	Btu/lbm (J/kg)
HW	Enthalpy of water (based on ASME Steam Tables)	Btu/lbm (J/kg)
HWLvCr	Enthalpy of water at corrected exit temperature	Btu/lbm (J/kg)
HWRe	Enthalpy of water at reference temperature	Btu/lbm (J/kg)
HWv	Enthalpy of water vapor (JANAF/NASA reference)	Btu/lbm (J/kg)

Table 5-20.2-1 List of Acronyms Used (Cont'd)

Acronyms	Description	Units
HWvEn	Enthalpy of water vapor at average entering air temperature	Btu/lbm (J/kg)
HWvLvCr	Enthalpy of water vapor at corrected exit temperature	Btu/lbm (J/kg)
HWvz	Enthalpy of water vapor at location z	Btu/lbm (J/kg)
HWz	Enthalpy of water at location z	Btu/lbm (J/kg)
MFrAz	Mass fraction of air at location z to total air	mass/mass
MFrFW	Mass fraction of moisture in fuel	mass/mass fuel
MFrH ₂ O	Mass fraction of the moisture in flue gas	mass/mass flue gas
MFrWA	Mass fraction of moisture in air	mass/mass fuel
MFrWDA	Mass fraction of moisture in dry air, mass H ₂ O/mass dry air	lbm/lbm (kg/kg)
MFrWFg	Mass fraction of water in wet flue gas	mass/mass fuel
MFrWRs	Mass fraction of water in dry residue	mass/mass residue
MnCpA	Mean specific heat of wet air	Btu/lbm °F (J/kg K)
MnCpFg	Mean specific heat of wet flue gas	Btu/lbm °F (J/kg K)
MnCpk	Mean specific heat of constituent k	Btu/lbm °F (J/kg K)
MoDFg	Moles dry gas per mass fuel	moles/mass fuel
MoFg	Moles wet gas per mass fuel	moles/mass fuel
MpCRsz	Mass percent combustibles in residue at location z	% mass
MpWFg	Moisture in flue, percent of wet flue gas	% mass
MqDA	Mass dry air on input from fuel basis	lbm/Btu (kg/l)
MqDAz	Mass dry air at location z on input from fuel basis	lbm/Btu (kg/l)
MqThACr	Fuel theoretical air corrected to 0% unburned combustibles on an input from fuel basis	lbm/Btu
MrApW	Mass flow rate of ash pit water	lbm/hr (kg/s)
MrCwz	Mass flow rate of cooling water at location z	lbm/hr (kg/s)
MrDA	Mass flow rate of dry air	lbm/hr (kg/s)
MrDAz	Mass flow rate of dry air at location z	lbm/hr (kg/s)
MrDFg	Mass flow rate of dry flue gas	lbm/hr (kg/s)
MrDFgz	Mass flow rate of dry flue gas at location z	lbm/hr (kg/s)
MrF	Mass flow rate of fuel	lbm/hr (kg/s)
MrFg	Mass flow rate of wet flue gas	lbm/hr (kg/s)
MrFgEn	Mass flow rate of wet flue gas entering	lbm/hr (kg/s)
MrFgLv	Mass flow rate of wet flue gas leaving	lbm/hr (kg/s)
MrFs	Mass flow rate of supplementary fuel	lbm/hr (kg/s)
Mrk	Mass flow rate of constituent k	lbm/hr (kg/s)
MrRsW	Mass flow rate of residue/water mixture	lbm/hr (kg/s)
MrRsz	Mass flow rate of residue at location z	lbm/hr (kg/s)
MrRyFg	Mass flow rate of recycled flue gas	lbm/hr (kg/s)
MrRyRs	Mass flow rate of recycled residue	lbm/hr (kg/s)
MrStAx	Mass flow rate of auxiliary equipment steam	lbm/hr (kg/s)
MrStz	Mass flow rate of steam at location z	lbm/hr (kg/s)
MrThA	Mass flow rate of theoretical air	lbm/hr (kg/s)
MrUbC	Mass flow rate of unburned combustibles	lbm/hr (kg/s)
MrW	Mass flow rate of water	lbm/hr (kg/s)
MrWA	Mass flow rate of moisture in air	lbm/hr (kg/s)
MrWAd	Mass flow rate of additional moisture	lbm/hr (kg/s)
MrWAp	Mass flow rate of moisture in ash pit	lbm/hr (kg/s)
MrWDA	Mass flow rate of moisture in dry air	lbm/hr (kg/s)
MrWDAz	Mass flow rate of moisture in dry air at location z	lbm/hr (kg/s)
MrWF	Mass flow rate of moisture in fuel	lbm/hr (kg/s)
MrWFg	Mass flow rate of moisture in flue gas	lbm/hr (kg/s)
MrWFgz	Mass flow rate of moisture in flue gas at location z	lbm/hr (kg/s)
MrWz	Mass flow rate of water at location z	lbm/hr (kg/s)
MwA	Molecular weight of wet air	mass/mole
MwCO	Molecular weight of carbon monoxide, CO	mass/mole
MwDFg	Molecular weight of dry flue gas	mass/mole
MwFg	Molecular weight of wet flue gas	mass/mole
Mwk	Molecular weight of constituent k	mass/mole
Pa	Barometric pressure	psia (Pa)

Table 5-20.2-1 List of Acronyms Used (Cont'd)

Acronyms	Description	Units
PAz	Static pressure of air at location z	in. wg (Pa)
PFg	Static pressure of flue gas	in. wg (Pa)
PFgz	Static pressure of flue gas at location z	in. wg (Pa)
PpWvA	Partial pressure of water vapor in air	psia (Pa)
PsWvT	Saturation pressure of water vapor at temperature T	psia (Pa)
PsWvTdb	Saturation pressure of water vapor at dry bulb temperature	psia (Pa)
PsWvTwb	Saturation pressure of water vapor at wet bulb temperature	psia (Pa)
QAx	Energy input to auxiliary equipment drives	kWh (J)
Qb	Energy balance closure	Btu/hr (W)
QpB	Credits calculated on a percent input from fuel basis, general	% fuel input
QpL	Losses calculated on a percent input from fuel basis, general	% fuel input
QpLk	Loss due to constituent k	% fuel input
QrAxSt	Energy in auxiliary steam	Btu/hr (W)
QrB	Credits calculated on an energy basis, general	Btu/hr (W)
QrBAX	Credit due to auxiliary equipment power	Btu/hr (W)
QrBd	Energy in output for blowdown water	Btu/hr (W)
QrBDA	Credit due to entering dry air	Btu/hr (W)
QrBF	Credit due to sensible heat in as-fired fuel	Btu/hr (W)
QrBk	Credit due to constituent k	Btu/hr (W)
QrBWA	Credit due to moisture in entering dry air	Btu/hr (W)
QrBWAd	Credit due to energy supplied by additional moisture	Btu/hr (W)
QrF	Potential energy of combustion available from fuel	Btu/hr (W)
QrFs	Potential energy of combustion available from supplementary fuel	Btu/hr (W)
QrFW	Energy input from the waste fuel	Btu/hr (W)
QrI	Energy input (QrF for input from fuel)	Btu/hr (W)
QrL	Losses calculated on an energy basis, general	Btu/hr (W)
QrLAp	Total wet ash pit losses	Btu/hr (W)
QrLApEv	Loss due to evaporation of ash pit water	Btu/hr (W)
QrLCw	Loss from cooling water	Btu/hr (W)
QrLCO	Loss from carbon monoxide	Btu/hr (W)
QrLDFg	Loss from dry flue gas	Btu/hr (W)
QrLk	Loss due to constituent k	Btu/hr (W)
QrLRs	Loss due to sensible heat of residue	Btu/hr (W)
QrLRsAp	Loss due to residue in the ash pit	Btu/hr (W)
QrLRsApW	Loss due to increase in ash pit water temperature	Btu/hr (W)
QrLRsWlv	Loss due to sensible heat in residue/water leaving the ash pit	Btu/ft ² hr (W/m ²)
QrLRy	Loss from recycled streams	Btu/hr (W)
QrLRyFg	Loss from recycled flue gas	Btu/hr (W)
QrLRyRs	Loss from recycled residue	Btu/hr (W)
QrLsrc	Loss due to surface radiation and convection	Btu/hr (W)
QrLubC	Loss due to unburned combustibles in residue	Btu/hr (W)
QrLWA	Loss due to moisture in air	Btu/hr (W)
QrLWAd	Loss due to additional moisture	Btu/hr (W)
QrLWF	Loss due to water in fuel	Btu/hr (W)
QrO	Total heat output	Btu/hr (W)
R	Universal molar gas constant	ft lbf/mole °R
Rhmz	Relative humidity at location z	mass/mass
Rk	Specific gas constant for gas k	ft/R (J kg/K)
SB	Total effective heating surface of the economizer	ft ²
SmQpB	Total credits calculated on a percent input from fuel basis	% fuel input
SmQpL	Total losses calculated on a percent input from fuel basis	% fuel input
SmQrB	Total heat credits calculated on an energy basis	Btu/hr (W)
SmQrL	Total losses calculated on an energy basis	Btu/hr (W)
ST	Total effective heating surface of the economizer and steam/water-cooled enclosure (if applicable). It is assumed that the absorption of the steam/water-cooled enclosure is proportional to the bank absorption	ft ²
TAEn	Entering air temperature	°F (°C)

Table 5-20.2-1 List of Acronyms Used (Cont'd)

Acronyms	Description	Units
TAz	Temperature of wet air at location z	°F (°C)
Tdb	Dry bulb temperature	°F (°C)
Tdbz	Dry bulb temperature at location z	°F (°C)
TF	Temperature of waste fuel	°F (°C)
TFg	Temperature of flue gas	°F (°C)
TFgLv	Temperature of flue gas leaving	°F (°C)
TFgLvCr	Corrected gas outlet temperature (excluding leakage)	°F (°C)
Tk	Temperature of constituent k	°F (°C)
TMnAEn	Average entering air temperature	°F (°C)
TMnAfz	Average surface temperature at location z	°F (°C)
TMnAz	Average surrounding air temperature	°F (°C)
TMnFgLvCr	Average corrected gas outlet temperature	°F (°C)
TRe	Reference temperature	°F (°C)
Twb	Wet bulb temperature	°F (°C)
Twbz	Wet bulb temperature at location z	°F (°C)
VAz	Average velocity of air at location z	ft/sec (m/s)
VpCO	Percent CO in flue gas, wet basis	% volume
VpCO2	Percent CO ₂ in flue gas, wet basis	% volume
VpH2O	Percent water in flue gas, wet basis	% volume
VpN2	Percent N ₂ in flue gas, wet basis	% volume
VpO2	Percent O ₂ in flue gas, wet basis	% volume
VpSO2	Percent SO ₂ in flue gas, wet basis	% volume
XpA	Percent excess air	% mass
XrA	Fraction excess air	...

Table 5-20.2-2 Measurement and Uncertainty Acronyms

Acronym	Description
ASENSCO	Absolute sensitivity coefficient
BIAS	Bias error
BIASR	Overall bias error
CHGPAR	Incremental change in value of measured parameter
DEGFR	Number of degrees of freedom
DEGFR	Overall degrees of freedom for test
EF	Steam generator fuel efficiency
<i>i</i>	Measured parameter
<i>M</i>	Number of sets of data or grid points
<i>N</i>	Number of times parameter is measured
PCHGPAR	Percent change in value of measured parameter
PI	Precision index
PIR	Overall precision index
RECALEF	Recalculated fuel efficiency
RSENSCO	Relative sensitivity coefficient
SDI	Spatial distribution index
STDVAL	Two-tailed Student's <i>t</i> value
<i>U</i>	Integrated average value of measured parameter
UNC	Total uncertainty
UPC	Precision component of uncertainty
XAVE	Arithmetic average value
<i>Z</i>	Summation, integrated average value of z
<i>z</i>	Time-averaged value of the measured parameter

Section 6

Report of Results

6-1 INTRODUCTION

The Performance Test Report documents the data, calculations, and processes employed in conducting the performance test. The report presents specific information to demonstrate that all objectives of the test have been met and describes the test procedures and pertinent results. This Section presents guidance on both the content and format of information typically included in this report.

6-2 CONTENTS OF REPORT

Although the materials prepared for Performance Test Reports will vary somewhat, the contents will typically be organized and include the information described in paras. 6-2.1 through 6-2.11.

6-2.1 Title Page

This contains the title of the test, the name of the facility or unit designation on which the test was conducted, the facility's location, the date(s) that the test was conducted, the names of those who conducted the test and those who approved the test results, and the date that the test report was approved.

6-2.2 Table of Contents

This lists subdivisions of the report to the third level, as well as titles of tables, figures, and appendices.

6-2.3 General Information

This list gives the reader information needed to understand the basis of the test and should contain the following:

- (a) facility owner
- (b) system supplier
- (c) facility operator
- (d) rated capacity
- (e) facility location including site elevation

- (f) predicted performance data including characteristics of waste used to calculate performance
- (g) allowable range of waste characteristics
- (h) guaranteed performance data
- (i) names of chief-of-test and other test personnel with their affiliations and test duties

6-2.4 Summary

This briefly describes the objectives, results, and conclusions of the test.

6-2.5 Introduction

This states the purpose of the test and relevant background information such as age, unusual operating characteristics, problems encountered and overcome, etc.

6-2.6 Objectives and Agreements

This addresses the objectives of the test, required test uncertainty, guarantees, operating conditions, and stipulated agreements.

6-2.7 Test Descriptions and Procedures

This should include the following:

- (a) a schematic of the system boundary showing the locations where parameters are measured
- (b) a list of equipment tested including nameplate data
- (c) a list and description of test instrumentation
- (d) a list of any deviations from agreed-on test procedures
- (e) a description of the method used to reach agreement among the parties to the test that
 - (1) the waste available for the test was within the allowable range of waste characteristics.
 - (2) the mass of waste combusted during the test was properly measured.
- (f) the magnitude of uncertainties in measurement and sampling, and methods of calculation and correction factors (sample calculations may be provided)
- (g) a description of the methods for a reduction of data to its final form

6-2.8 Results

Test results are presented as measured and, as agreed, on a corrected basis.

6-2.9 Uncertainty Analysis

This provides sufficient detail to document the target uncertainty and demonstrate if the test met this target.

6-2.10 Conclusions and Recommendations

This includes all conclusions directly relevant to the test objectives as well as other conclusions or recommendations drawn from the test.

6-2.11 Appendices

Typical kinds of information included in appendices are test logs, test charts, data sheets, instrumentation calibration sheets and correction curves, record of major fluctuations and observations, laboratory analyses, computations and computer printouts, and uncertainty analyses.

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Section 7

Uncertainty Analysis

7-1 INTRODUCTION

Uncertainty analysis is a procedure by which the accuracy of test results can be quantified. Because it is required that the parties to the test agree to the quality of the test (measured by test uncertainty), pretest and post-test uncertainty analyses are an indispensable part of a meaningful performance test.

ASME PTC 19.1, Test Uncertainty, is the primary reference for uncertainty calculations, and any uncertainty analysis method that conforms to ASME PTC 19.1 is acceptable. This Section provides specific methods that are tailored for use in conducting uncertainty analysis specific to this Code. This Section addresses the following:

- (a) determining random uncertainties
 - (b) estimating systematic uncertainties
 - (c) propagating the random and systematic uncertainties
 - (d) obtaining the test uncertainty
- Additional information on uncertainty is available in ASME PTC 19.1.

7-1.1 General List of Symbols for Section 7

The following symbols are generally used throughout Section 7. Some symbols are used only in a specific paragraph and are defined or redefined locally.

- A = (cross-sectional) area
- a_0, a_1 = polynomial coefficients
- B = systematic uncertainty
- C = a constant
- $f()$ = (mathematical) function
- m = number of grid points or number of different measurement locations
- N = number of measurements or number of points
- n = number of data points used in calculating standard deviation
- O_2 = oxygen concentration
- R = a result (such as efficiency, output)
- r = number of readings or observations
- SDI = spatial distribution index
- S_X = sample standard deviation (S_X^2 is the sample variance)
- \bar{S}_X = standard deviation of the mean
- T = temperature
- t = Student's t statistic
- U = uncertainty

- u = any parameter
- V = velocity
- ν = any parameter
- w = any parameter
- x = any parameter
- y = any parameter
- z = any parameter
- $\delta()$ = small change of $()$
- θ_x = sensitivity coefficient for parameter x on result R
= $(\partial R / \partial x)$
- ν = degrees of freedom
- σ = population standard deviation (σ^2 is the population variance)
- $\sum_i^a ()$ = sum of $()$ from $i = a$ to $i = b$
- τ = time

7-1.2 Subscripts

- B = systematic uncertainty
- I = instrument, instrumentation
- i = index of summation, a specific point
- j = index of summation, a specific point
- k = index of summation, a specific point
- n = pertaining to numerical integration
- P = random uncertainty
- R = pertaining to result R
- r = real
- w = weighted (average)
- x = pertaining to parameter x

7-1.3 Superscript

- = average

7-2 FUNDAMENTAL CONCEPTS

7-2.1 Benefits of Uncertainty Analysis

The benefits of performing an uncertainty analysis are based on the following facts about uncertainty:

(a) Uncertainty analysis is the best procedure to estimate the error limit in a set of measurements or test results.

(b) There is a high probability (usually 95%) that a band defined by the measured value plus or minus the uncertainty includes the true value.

(c) The uncertainty of a test result is a measure of the quality of the test.

(d) Uncertainty analysis performed after a test is run allows the test engineer to determine those parameters

and measurements that were the greatest contributors to testing error.

(e) Uncertainty analysis performed while a test is being planned (using nominal or estimated values for primary measurement uncertainties) identifies potential measurement problems and permits designing a cost-effective test.

(f) A Performance Test Code based on a specified uncertainty level is much easier to adapt to new measurement technology than a Code tied to certain types of instruments. (See ref. [1] in Nonmandatory Appendix D.)

This Code allows the parties to a steam generator test to choose among many options for test instruments and procedures and even to choose between two different methods (energy balance or input/output) for evaluating steam generator efficiency. Uncertainty analysis helps the parties to the test make these choices.

7-2.2 Uncertainty Analysis Principles

This subsection reviews fundamental concepts of uncertainty analysis.

It is an accepted principle that all measurements have errors. Any results calculated from measured data, such as the efficiency of a steam generator, also contain errors, resulting not only from the errors in the data but also from approximations or errors in the calculation procedure. The methods of uncertainty analysis require the engineer to first determine estimates of the error (uncertainty) of the basic measurements and data reduction procedures and then to propagate those uncertainties into the uncertainty of the result.

Note the following definitions:

coverage: percentage of observations (measurements) that can be expected to differ from the true value by no more than the uncertainty. Stated another way, a typical value, say 95% coverage, means that the true value will be bounded by the measured value plus or minus the uncertainty with 95% confidence. The concept of coverage is necessary in uncertainty analysis since the uncertainty is only an estimated error limit.

error: difference between the true value of a parameter and the measured or calculated value of the parameter. Error is unknown because the true value is unknown. Obviously, if the error were known, the test results could be based on the true value, not the measured or calculated value.

uncertainty: estimated error limit of a measurement or result.¹

The calculated average value of a parameter plus or minus the uncertainty defines a band in which the true

value of the parameter is expected to lie with a certain coverage.

Error and uncertainty are similar in many respects. There are many types and sources of error, but when a number is assigned to error, it becomes an uncertainty. The term “accuracy” is often used interchangeably with uncertainty; however, the two are not synonymous since high accuracy implies low uncertainty.

Measurements contain two types of error, which are illustrated in Fig. 7-2.2-1. The total error of any specific measurement is the sum of a systematic error and a random error. Other names for systematic error and random error are bias error and precision error, respectively. The characteristics of these two types of error are quite different.

Random error is manifested by the fact that repeated measurements of the same quantity by the same measuring system operated by the same personnel do not yield identical values. Random error is described by a normal (Gaussian) probability distribution.

Systematic uncertainty is a characteristic of the measurement system. Systematic uncertainty is not random; it is an essentially fixed (although unknown) quantity in any experiment or test² that uses a specific instrument system and data reduction and calculation procedures.

When the magnitude and sign of a systematic error are known, the systematic error must be handled as a correction to the measured value, with the corrected value used to calculate test results. Systematic uncertainty estimates considered in uncertainty analysis attempt to cover those systematic errors whose magnitudes are unknown.

It is not always easy to classify a specific uncertainty as systematic or random. Usually random uncertainties are associated with variability in time, whereas systematic uncertainties are considered fixed in time as shown in Fig. 7-2.2-2. Variability in space (such as temperature stratification or nonuniform gas velocity in a flue gas duct) has been treated as random (see ref. [2] in Nonmandatory Appendix D) or systematic uncertainty (see ref. [3] in Nonmandatory Appendix D) in different works. This Code treats spatial variability as a potential source of systematic uncertainty.

A complete uncertainty analysis requires determining values for both random and systematic uncertainty in the basic measurements, their propagation into the calculated results, and their combination into the overall uncertainty of the results. Uncertainty analysis can be performed before a test is run (pretest analysis) and/or after a test is run (post-test analysis).

7-2.3 Averaging and Models for Variability

Instruments used in performance testing measure parameters such as temperature and concentration of

¹ Note that measurement uncertainty is not a tolerance on equipment performance.

² Systematic errors may change slowly over the course of a test, such as calculation drift of an instrument.

Fig. 7-2.2-1 Types of Errors in Measurements

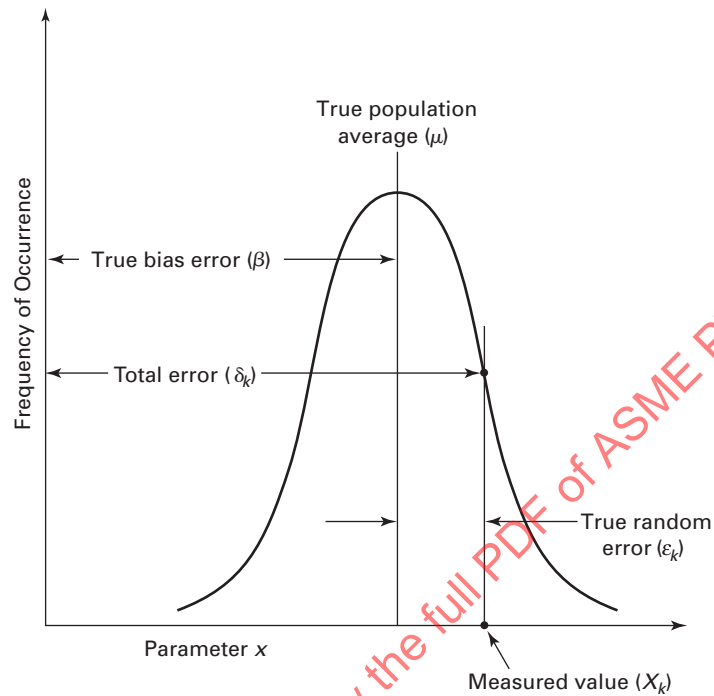
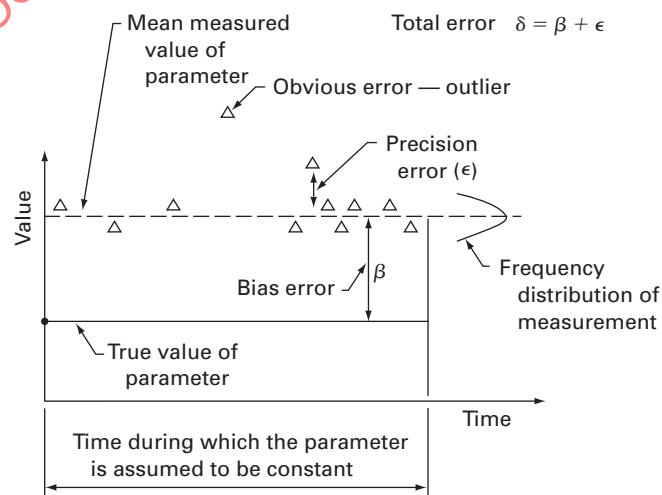


Fig. 7-2.2-2 Time Dependence of Errors



certain constituents in a gas stream. Most instruments are capable of sensing the value of a parameter only at a single point or within a limited region of space and at discrete instants or over limited “windows” of time. It is well known that parameters such as gas temperature and composition vary in space (stratification) and time (unsteadiness). It should be realized that this variation is primarily due to physical processes rather than experimental error. For example, the laws of physics dictate that the velocity of a flowing fluid must be zero at the walls of a duct while the velocity nearer the center of the duct is usually not zero.

In a performance test, engineers sample several points in space and time and then use averages of the data to calculate test results. The averages are the best available estimates, and the differences between the average value of a parameter and its instantaneous and/or local values are used to estimate the error in the measurements and in any results calculated from them. The method of calculating the average and the method of calculating the uncertainty in the average depend on the model selected for the variability of the parameter. The choice is between a “constant-value” model, in which the parameter is assumed to be constant in time and/or space, and a “continuous-variable” model, in which it is assumed that the parameter has some continuous variation in time and/or space (refer to para. 5-2.3.1).

Consider the velocity of gas in a duct. The proper model for the variation over time of gas velocity at a fixed point in the center of the duct may be a constant value; however, it is improper to adopt a constant-value model for the variability of gas velocity over the duct cross section because the laws of physics dictate that it must be otherwise. Fig. 7-2.3-1 illustrates these concepts. All of the variability in the actual data for a constant-value model parameter is taken as error; however, only the scatter about the continuous variation should be considered error for a continuous-variable model.

The proper average value for a constant-value model is the familiar arithmetic average

$$\bar{x} = \frac{1}{N} \sum_{i=1}^n x_i \quad (7-1)$$

and the population standard deviation of the mean or its estimate, the sample standard deviation of the mean

$$S_{\bar{x}} = \frac{\left[\frac{1}{N-1} \sum_{i=1}^n (x_i - \bar{x})^2 \right]^{1/2}}{N^{1/2}} \quad (7-2)$$

is the proper index of the random error.

The proper average for a continuous-variable model parameter is an integrated average. For time variation, the proper average is

$$\bar{y} = \frac{1}{\tau} \int_0^{\tau} y \, d\tau$$

and for area variation it is

$$\bar{y} = \frac{1}{A} \int_0^A y \, dA$$

Because data are obtained only at discrete points in space and/or instants of time, numerical integration schemes are typically used to approximate the integrated average. If the data are sampled at the midpoints of equal time or area increments, the integrated average may be calculated with eq. (7-1); however, the standard deviation is not calculated by eq. (7-2) because a constant-value model is inappropriate. It must also be emphasized that alternative, more accurate, numerical integration schemes can be developed that do not use eq. (7-1) to calculate the average.

The experimental error in an integrated average is due to the following two sources:

- (a) error in the point values of the data, and
- (b) error due to the numerical integration

The first type is the “ordinary” experimental error due to process variations, instrument errors, etc. The second type results from the imperfect representation of the continuous variable by a set of discrete points and the approximations in the integration scheme. In this Code, the numerical integration error is taken as systematic error.

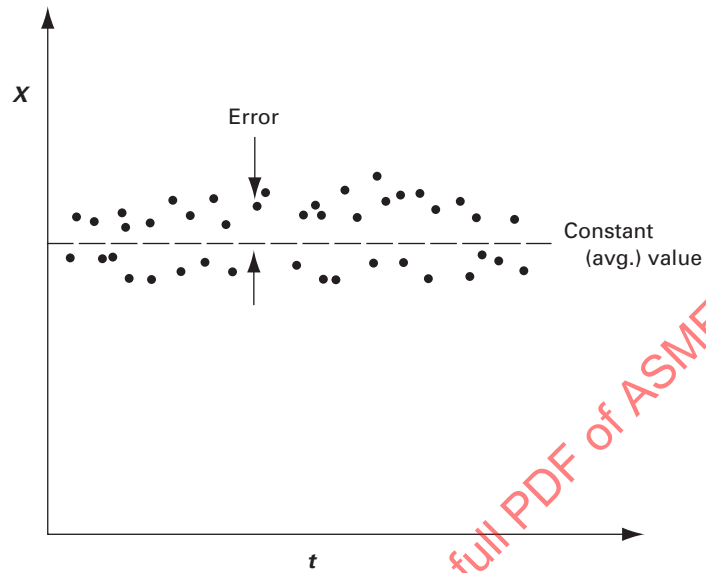
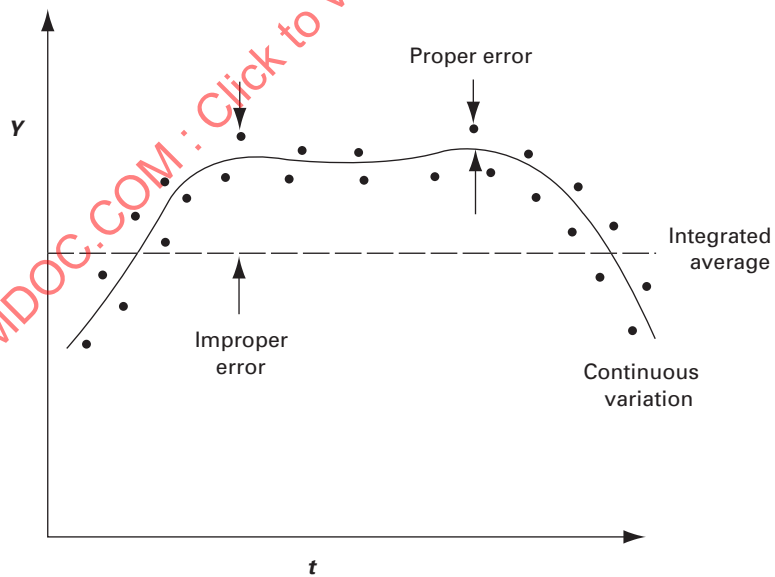
7-2.4 Overview of Procedures for Determining Random and Systematic Uncertainty and Their Propagation

The working equations and procedures for calculating uncertainties for steam generator test results are given in subsections 7-4 through 7-6. This subsection gives an overview of the procedures and emphasizes certain critical concepts. An especially critical concept, the distinction between constant-value and continuous-variable parameters, was discussed in para. 7-2.3.

Random errors are the result of random variations during the test. Random errors can be estimated by taking numerous readings and applying the methods of statistics to the results. The following discussion of these methods is based on the assumption that the reader has an understanding of elementary statistics. Statistical concepts for Performance Test Code work are discussed in ASME PTC 19.1 and Benedict and Wyler [4].

Analysis of random errors is based on the assumption that they follow a Gaussian (normal) probability distribution. One important result of this assumption is the root-sum-square method for combining errors due to individual sources.

Two important concepts concerning random error are *independence* and *degrees of freedom*.

Fig. 7-2.3-1 Constant-Value and Continuous-Variable Models**(a) Constant-Value Model****(b) Continuous-Variable Model**

Parameters are independent if a change in one does not imply a change in another. If this is not true, the parameters are dependent. As an example, the dry gas loss depends on both the gas temperature and the oxygen content of the gas. Any error in temperature is unconnected with oxygen content; the two are independent. On the other hand, the results of a fuel analysis are given as percentages of various constituents. Since all of the percentages must add to 100, the constituent percentages are dependent. Physically, if the percentage of one component (e.g., carbon), is lower than the percentage of another component (e.g., ash), the percentage of another component(s) must be higher.

Measurement errors can also be independent or dependent. The independence or dependence of errors can be different from the independence or dependence of the measured parameters. If all constituents of a fuel sample are determined independently from different procedures applied to different subsamples, then the errors are independent, even though the constituents themselves are dependent. If, however, one constituent is determined by difference rather than by direct analysis, then the error of that constituent is obviously dependent on the errors of the remaining constituents.

Special care must be taken in dealing with dependent parameters or dependent errors. When parameters are dependent, this dependence must be accounted for in the sensitivity coefficients. When errors are dependent, the cross-correlation between them must be considered. (See ref. [2] in Nonmandatory Appendix D.)

Problems with parameter and error dependence can be minimized by reducing measurements and result calculations to sets involving only independent parameters and measurements. For example, the closure relationship between fuel constituent percentages should be used to eliminate one measurement and its error. This Code generally follows this approach; therefore, it is usually not necessary to include consideration of dependent parameters and dependent errors.

The degrees of freedom of a set of data is a measure of the amount of independent information in the data. A set of 10 temperature readings begins with 10 degrees of freedom. The number of degrees of freedom of a particular statistic calculated from the data is reduced by the number of other statistics used to calculate the particular statistic. The mean temperature calculated from 10 readings has 10 degrees of freedom. To calculate the sample standard deviation of the temperature

$$S_T = \left[\frac{1}{N-1} \sum_{i=1}^N (T_i - \bar{T})^2 \right]^{1/2} \quad (7-3)$$

requires use of the calculated mean, \bar{T} , so the standard deviation has only nine degrees of freedom. (This is why the division is $N-1$ rather than N .)

A somewhat cumbersome formula is needed to determine the resulting degrees of freedom when a result depends on several parameters, each with a different number of degrees of freedom. Fortunately, if all parameters have a large number of degrees of freedom, the effects of degrees of freedom disappear from the calculations. In theory, a "large sample" has more than about 25 degrees of freedom, but in practice, about 10 degrees of freedom is often sufficient.

The random uncertainty of a result is the product of the sample standard deviation of the mean of the result and the appropriate Student's t statistic.

The sample standard deviation of the mean is calculated by

$$S_{\bar{T}} = \frac{S_T}{\sqrt{N}} = \left[\frac{1}{N(N-1)} \sum_{i=1}^N (T_i - \bar{T})^2 \right]^{1/2} \quad (7-4)$$

In this Code, the phrase "standard deviation" is used to refer to the sample standard deviation of the mean unless otherwise noted. The standard deviation of a single set of data is the standard deviation of the mean of the single set of data. The standard deviation of a result is obtained by combining the values of the standard deviations of all the parameters that affect the result according to the equations given in subsection 7-4.

There are times when it is necessary to estimate standard deviations. Obviously, a pretest uncertainty analysis must use estimated values of the standard deviations, since the test data from which to calculate them do not yet exist. In some cases, it is not feasible to obtain multiple observations of the data during a test. If only one observation of each measurement is available, the standard deviation of the data must be estimated.

The Student's t statistic is based on the degrees of freedom of the standard deviation of the result and the probability level selected (95% in this Code). As discussed in ASME PTC 19.1, a value of 2 (the value assumed by Student's t for large degrees of freedom) can be used for the Student's t statistic for most situations arising in performance testing.

Systematic error is "frozen" in the measurement system and/or the data reduction and result calculation process and cannot be revealed by analysis of the data. For a given set of measurements using a given measurement system, the systematic error is fixed and is not a random variable. Systematic errors are those fixed errors that remain even after instrument calibration (systematic error can be no smaller than the random error of the calibration experiment). It is sometimes possible to conduct experimental tests for systematic uncertainty. Most often, however, it is necessary to estimate values for systematic uncertainty. The problem of estimating uncertainty was discussed by Kline and McClintock [5]. Note that, although the actual systematic uncertainties

are not random variables, estimates of systematic uncertainty are random variables because different estimates are likely to choose different values for the estimate.

Systematic uncertainty estimates must be based on experience and good judgment. ASME PTC 19.1 provides a few general guidelines for estimating systematic uncertainty. Obviously, the person in the best position to estimate systematic uncertainty is the person who conducted the test. The recommended practice in estimating systematic uncertainty is to estimate the value that is expected to provide 95% coverage. This estimated value is essentially a two-standard-deviation estimate.

It is sometimes necessary in a performance test to use "data" that are based on estimates rather than on measurements. Likewise, it is sometimes more cost-effective to assign reasonable values to certain parameters rather than to measure them. Examples include the distribution fractions ("splits") of combustion residue between various hoppers or the amount of heat radiated to an ash pit. It is also necessary to assign uncertainties to such data. It is perhaps an academic question whether such assigned values of uncertainty are labeled as systematic uncertainty or random uncertainty. In this Code, uncertainties in estimated parameters are generally treated as systematic uncertainty.

After values for both random and systematic uncertainties have been determined, it is necessary to determine the uncertainty in any results calculated from the data. This process is called "propagation of uncertainties." Because random and systematic uncertainties are different types of quantities, it is customary to propagate them separately and combine them as the final step in an uncertainty calculation. The calculation procedure is straightforward, if somewhat tedious. Assume that a result, R , is calculated by

$$R = f(x_1, x_2, \dots, x_M)$$

where

x_1 through x_M = independent measured quantities

Each x has both random and systematic uncertainty. For either type of uncertainty, the basic propagation equation is

$$e_R = \left[\left(\frac{\partial f}{\partial x_1} e_{x1} \right)^2 + \left(\frac{\partial f}{\partial x_2} e_{x2} \right)^2 + \dots + \left(\frac{\partial f}{\partial x_M} e_{xM} \right)^2 \right]^{1/2} \quad (7-5)$$

where

e = the standard deviation or the systematic uncertainty

M = the number of independent measured quantities

The root-sum-square addition of errors is theoretically correct for random uncertainty and is assumed to be

proper for systematic uncertainty as well. (See refs. [2] and [5] in Nonmandatory Appendix D.)

The propagation equation can be written in the following dimensionless form:

$$\frac{e_R}{R} = \left\{ \sum_{i=1}^M \left[\left(\frac{x_i}{R} \frac{\partial f}{\partial x_i} \right) \left(\frac{e_{xi}}{x_i} \right) \right]^2 \right\}^{1/2} \quad (7-6)$$

where

e_{xi} = the uncertainty (random or systematic uncertainty) in x_i

The coefficients

$$\left[\frac{x_i}{R} \frac{\partial f}{\partial x_i} \right]$$

are called "relative sensitivity coefficients."

Since the calculation procedure may be complicated, it is often impossible to analytically evaluate the required partial derivatives. These derivatives are usually estimated by a numerical perturbation technique

$$\frac{\partial f}{\partial x_i} \approx \frac{f(x_1, \dots, x_i + \delta x_i, \dots, x_M) - f(x_1, \dots, x_i, \dots, x_M)}{\delta x_i} \quad (7-7)$$

One at a time, each parameter (x_i) is changed by a small amount (δx_i , typically 0.1% to 1%) and the result is recalculated with the perturbed parameter replacing the nominal value. All other parameters are held constant for the recalculation. The difference between the result with the perturbed value and the nominal result, divided by the perturbation, estimates the partial derivative. Since this procedure requires recalculation of the result many times (one recalculation for each independent parameter), an automated calculation procedure is highly desirable.

The uncertainty of the result is the root-sum-square of the random and systematic components of uncertainty times an appropriate value of the Student's t statistic. Because the systematic uncertainty estimates are made assuming the systematic errors are random variables (as noted earlier), the systematic uncertainties also have degrees of freedom. A large number of degrees of freedom indicates that the systematic uncertainty estimate covers the range of possible fixed errors with a high degree of certainty. Conversely, a small number of degrees of freedom implies that there is some uncertainty in the uncertainty estimates. This concept is discussed in the *ISO Guide to the Expression of Uncertainty in Measurement* and in ASME PTC 19.1.

As shown in ASME PTC 19.1, the number of degrees of freedom for the result, R , is determined from the degrees of freedom for the systematic and random uncertainties of all the independent measured quantities. The effective degrees of freedom of the result is usually large enough that the Student's t statistic for a

95% confidence interval for the uncertainty can be taken as 2.

The uncertainty of the result is then determined as

$$u = 2 \left[\left(\frac{B_R}{2} \right)^2 + (S_{\bar{R}})^2 \right]^{1/2}$$

where the “2” multiplier is the Student’s t statistic and is an estimate of the standard deviation for the systematic uncertainty of the result. The values of B_R and $S_{\bar{R}}$ are obtained from eq. (7-5).

7-3 PRETEST UNCERTAINTY ANALYSIS AND TEST PLANNING

A pretest uncertainty analysis is an excellent aid in test planning. The parties to a test can use a pretest uncertainty analysis to assist in reaching many of the agreements required in Section 3. Decisions regarding number and types of instruments, number of readings, number of sampling points in a grid, and number of fuel and/or sorbent samples can be made based on their predicted influence on the uncertainty of the test results.

A careful pretest uncertainty analysis can help control the costs of testing by keeping the number of readings or samples at the minimum necessary to achieve the target uncertainty and by revealing when it is not necessary or cost-effective to make certain measurements. For example, it may be possible to achieve the agreed-on target test uncertainty by using a 9-point flue gas sampling grid rather than a 16-point grid or by using historical data rather than multiple laboratory analyses for fuel and sorbent properties.

The methodology of a pretest uncertainty analysis is formally identical to that for a post-test analysis with one exception. Since the actual test data are not yet available, elementary standard deviations must be estimated rather than calculated from test statistics. This makes it possible to “decompose” the random error into its various components (process variations, primary sensor, data acquisition, etc.). Random uncertainty estimates, like estimates of systematic uncertainty in both pretest and post-test analyses, should be the best estimates of experienced persons. Values obtained from similar tests are often a good starting point.

A complete pretest uncertainty analysis may require several repetitions of the calculations as basic instrument uncertainties, numbers of readings, and numbers of samples are all varied in an effort to obtain the target uncertainty in the most cost-effective manner. Computer support is essential to do this effectively.

Sotelo [6] provides an excellent discussion of pretest uncertainty analysis and test planning.

7-4 EQUATIONS AND PROCEDURES FOR DETERMINING THE STANDARD DEVIATION FOR THE ESTIMATE OF RANDOM ERROR

This subsection contains equations and procedures for calculating the standard deviation. The required post-test uncertainty analysis uses actual data from the performance test. The recommended pretest uncertainty analysis uses expected values for the parameter averages and estimates for the standard deviations. The equations and procedures of this section are aimed at a post-test uncertainty analysis, for which actual test data are available.

Process parameters (such as exit gas temperature or steam pressure) naturally exhibit perturbations about their true (or average) values. These perturbations are the real variations of the parameters. For a set of measurements of the process parameters, the instrumentation system superimposes further perturbations on the average values of the parameters. These instrumentation-based perturbations are assumed to be independent random variables with a normal distribution. The variance of the measured value of a parameter is

$$\sigma_x^2 = \sigma_{xr}^2 + \sigma_I^2 \quad (7-8)$$

where

- σ_I^2 = the (population) variance of the instrumentation system
- σ_x^2 = the (population) variance of the measured value of parameter x
- σ_{xr}^2 = the real (population) variance of parameter x

The random uncertainty of an instrument is sometimes called the “reproducibility” of the instrument. Reproducibility includes hysteresis, deadband, and repeatability (see ref. [7] in Nonmandatory Appendix D). The instrumentation variance is often estimated from published data because testing a specific instrument for its random uncertainty can rarely be justified.

For a post-test uncertainty analysis, the instrumentation variances are not specifically required, because they are already embedded in the data. Knowledge of instrumentation variances may be needed when instrumentation alternatives are compared in a pretest uncertainty analysis. In most instances, an instrument’s variance is small enough relative to the real variance of the parameter that the instrumentation variance may be ignored. If the instrumentation variance is less than one-fifth of the real variance of a measured parameter, the instrumentation random error can be ignored.

7-4.1 Standard Deviation of Individual Parameters

The standard deviation of an individual parameter depends on the type of parameter, integrated-average or constant-value, and the method used to measure the parameter. Some of the methods are as follows:

(a) multiple measurements made over time at a single location (e.g., main steam pressure and power input to a motor driver)

(b) multiple measurements made at several locations in a given plane (e.g., flue gas temperature, flue gas constituents, and air temperature at air heater inlet)

(c) the sum of averaged measurements (e.g., total coal flow rate when multiple weigh feeders are used)

(d) measurements on samples taken in multiple increments (e.g., fuel and sorbent characteristics)

(e) multiple sets of measurements at weigh bins or tanks to determine the average flow rates (e.g., solid residue flow rates)

(f) a single measurement

(g) the sum of single measurements

7-4.1.1 Multiple Measurements at a Single Point.

For multiple measurements of a constant-value parameter made over time at a single location, the standard deviation is

$$S_x = \sqrt{\frac{S_x^2}{N}} \quad (7-9)$$

where

$$S_x^2 = \left(\frac{1}{N-1} \right) \sum_{i=1}^N (x_i - \bar{x})^2 \quad (7-10)$$

The number of degrees of freedom is

$$v_x = N - 1 \quad (7-11)$$

7-4.1.2 Integrated-Average Parameters (Unweighted Averages). Examples of integrated-average parameters are flue gas temperature and oxygen content. Multiple measurements are made over time at each of several points in a grid. The measurements over time at each point are averaged to determine the value of the parameter at the point

$$\bar{x}_i = \frac{1}{N} \sum_{j=1}^N (x_j)_i \quad (7-12)$$

where

i = identifies the point in the grid

N = number of readings over time

For unweighted averages, x is the measured parameter, such as temperature or oxygen.

The sample standard deviations, sample standard deviations of the mean, and degrees of freedom are calculated at each grid point as if the parameter exhibited a constant value; that is, by eqs. (7-9), (7-10), and (7-11).

The standard deviation of the integrated-average parameter is

$$S_{\bar{x}} = \frac{1}{m} \left[\sum_{i=1}^m (S_{x_i})^2 \right]^{1/2} \quad (7-13)$$

The associated degrees of freedom is

$$v = \frac{S_{\bar{x}}^4}{\sum_{i=1}^m \left[\frac{S_{x_i}^4}{(m^4 v_i)} \right]} \quad (7-14)$$

where

m = the number of grid points

S_{x_i} = the standard deviation of the mean for the parameter at point i [from eq. (7-9)]

v_i = the degrees of freedom of S_{x_i} , which is the number of readings at point i minus 1

7-4.1.3 Integrated-Average Parameters (Weighted Averages).

Parameters such as flue gas temperature or oxygen are sometimes calculated as weighted averages. The weighting factor is the fluid velocity fraction evaluated at the same point as the parameter measurement. Calculation (or estimation) of the standard deviation for a flow-weighted integrated average depends on the available data for the velocity distribution.

(a) *Velocity Measured Simultaneously With the Parameter, With Several Complete Traverses.* The number of readings at each point in the grid must be large enough to ensure statistical significance. Generally six or more readings are required. In this case, the standard deviation and degrees of freedom are calculated using eqs. (7-9) through (7-14), as appropriate, with the parameter $x_{j,i}$ being the weighted value. For temperature, for example,

$$x_{j,i} = \left[\frac{V_{ji}}{\bar{V}} \right] T_{ji} \quad (7-15)$$

where \bar{V} is the space- and time-averaged velocity.

(b) *Velocity Measured Simultaneously With the Parameter With a Small Number of Complete Traverses.* In this case, the standard deviation is estimated from a large number of readings taken at a single point. Instruments must be provided to simultaneously measure the velocity and the parameter at a single fixed point. The point should be selected so that the expected values of velocity and the parameter are approximately the average values. Data should be recorded with a frequency comparable to that for other data.

The instantaneous values from the point are multiplied to give a variable x_j

$$x_j = \left[\frac{V_j}{\bar{V}} \right] T_j \quad (7-16)$$

The sample standard deviation for x is calculated from eq. (7-10).

(c) *Velocity Measured Separately From the Parameter.* The standard deviation of the mean for the weighted average parameter is

$$S_{\bar{P},FW} = \left[S_{\bar{P},UW}^2 + \left(\bar{P}_{UW} - \bar{P}_W \right)^2 \frac{S_v^2}{\bar{V}^2} \right]^{1/2} \quad (7-17)$$

where

FW = weighted average

P = parameter (temperature or oxygen)

$S_{\bar{P}}$ = calculated as described in para. 7-4.1.2

UW = unweighted average

Ideally, the standard deviation of velocity is evaluated from multiple readings over time at each point in the velocity-measuring grid. If such readings are not available, the standard deviation of velocity is estimated from historical data.

7-4.1.4 Measurements on Samples Taken in Multiple Increments. Samples of material streams are obtained and analyzed to determine the chemical composition of the streams. These streams may be gaseous (such as flue gas) or solid (such as coal, sorbent, and residue). Usually, these samples are obtained in increments; that is, a finite sample is taken at periodic intervals. The sample locations may be separated in space, as in sampling multiple coal feeders or multiple points in a flue gas duct cross section, as well as in time. It should be noted that in this Code, solids composition is treated as a constant-value parameter and flue gas composition is treated as a spatially nonuniform parameter. A second major difference between solid streams and gaseous streams is that the gaseous samples are usually analyzed “online” during the test while solid samples are usually analyzed in a laboratory at a later time.

There are two alternative means for determining the average properties of material samples taken in increments; therefore, there are two means for determining the standard deviation. The first method for determining the average properties uses a separate analysis of each individual sample. The average value for all samples (the value to be used in the performance calculations) is then determined as the mean of all of the individual sample results. In the second method, the individual samples are mixed together into a composite sample and an analysis is made of the composite sample. While there may be replicated analyses of the composite sample, there is still only one sample for analysis.

Often, a combination of both methods is the most cost-effective approach. Some constituents can be determined from a single analysis of a gross sample while other constituents are determined from analysis of individual samples. For example, when the steam generator fires coal from a single seam, the moisture and ash can be highly variable while the other constituents,

expressed on a moisture-and-ash-free basis, are relatively constant. In this case, as-fired moisture and ash, and their standard deviations, should be determined from analysis of several individual samples, while the average values for the other constituents (on a moisture-and-ash-free basis) can be determined from a single analysis of a mixed gross sample. The following paragraphs describe determination of random uncertainty in these two cases.

(a) *Increments Individually Analyzed.* If each incremental sample is properly mixed, reduced, and divided separately, the average value of a constituent is the mean of the analysis measurements. The standard deviation and degrees of freedom are determined from eqs. (7-9) and (7-11).

(b) *Increments Mixed Prior to Analysis.* If the sample increments are mixed prior to analysis, the various increments are mechanically averaged (an example is the “ganging” of several flue gas sampling lines into a mixing chamber or bubbler prior to analysis). If proper procedures have been followed in mixing and reducing the gross sample, the results of the analysis of the mixed sample may be considered a proper average. As there is only one set of results, the standard deviation cannot be calculated from statistics and must therefore be estimated.³ It is often possible to obtain accurate estimates using historical data or, sometimes, limited measurements, for determining random uncertainty.

(c) *Estimates From Historical Data.* Cases where this method can be used include those where past test data are available or when fuel or sorbent used during the test has been obtained from a source whose characteristics have been previously established. One criterion for a proper estimate is that the historical data and the test data are taken from the same measurement population. If this is the case, the data have the same population mean μ and the same population standard deviation σ . Moisture-and-ash-free constituents for coal mined from a single seam should satisfy this condition so that historical data from the same seam can be used to estimate the random uncertainty for the test data.

Suppose that historical data on a particular parameter (e.g., carbon content) are available. The historical data are based on n_H observations and have sample standard deviation $S_{X,H}$.

The standard deviation can be conservatively estimated by

$$S_{\bar{X}} = \frac{S_{X,H}}{\sqrt{N}} \quad (7-18)$$

³ It should be noted that multiple analyses of the same gross sample can give the standard deviation of the analytical instruments and procedures but give no information about the real variation in the material properties or the sampling variation. In most cases, these latter two sources of variability dominate the standard deviation of material properties.

where N is the number of individual samples that were mixed. The degrees of freedom for this estimate is $n_H - 1$.

(d) *Estimates From Limited Measurements.* To illustrate this approach, consider the random uncertainty of flue gas oxygen concentration, O_2 . While samples are typically taken from several grid points in a duct cross section, the individual point samples are seldom analyzed; instead, samples are mixed and passed to a single analyzer. As flue gas oxygen concentration is a spatially nonuniform parameter, the mixing simulates the integrated-averaging process. If equal extraction rates are taken from each grid point, the process most closely matches multiple midpoint averaging. The point-to-point variation in O_2 , although not revealed by the composite sample, is considered a systematic uncertainty by this Code, due to numerical integration.

Even though the point-to-point variation is not considered as random error, the variation over time at each point does contribute to random error. Information on this variation is revealed only in the composite sample. It is assumed that several composite samples are taken and analyzed over time. The standard deviation and degrees of freedom should be calculated from eqs. (7-9) and (7-11) and the results for the mixed samples as if the parameter (e.g., spatially averaged oxygen concentration) were a constant-value parameter.⁴

7-4.1.5 A Single Measurement or the Sum of Single Measurements. For parameters determined by a single measurement or the sum of single measurements, the standard deviation is the square root of the estimate of the instrumentation variance. The magnitude of the standard deviation is likely to be small enough so that it can be neglected. The spatial and time variations of such parameters should be considered as systematic uncertainties, with appropriate estimates made for their magnitude. The problem of uncertainty of single measurements was considered extensively by Kline and McClintock [5].

7-4.2 Standard Deviation and Degrees of Freedom for Intermediate Results

Frequently, a parameter used as if it were measured data is actually calculated from more primary measurements. Two examples are fluid flow rate, which is often determined from differential pressure and measurements, and enthalpy, which is determined from temperature (and, sometimes, pressure) measurements. There are two possibilities for calculating the standard deviation of these intermediate results. One is to use the "propagation-of-error" equation [eq. (7-4)], together with the equation(s) relating the intermediate result to the primary measurements. This is not as difficult as it

appears because the equations connecting the intermediate results to the data are usually simple. The second option is to transform the data into the intermediate result prior to averaging and then calculate the standard deviation of the result. Paragraphs 7-4.2.1 through 7-4.2.4 describe specific cases.

7-4.2.1 Parameters of the Form $z = C\sqrt{x}$. The measurements, x_i , should first be converted to z_i . Then the average and the sample variance of z can be calculated from the z_i . Differential pressure flowmeters exhibit this type of parameter relationship.

7-4.2.2 Parameters of the Form $z = a_0 + a_1\bar{x} + a_2\bar{x}^2 + \dots + a_n\bar{x}^n$. Equation (7-4) is applicable to functions of one variable; in this case the variable is \bar{x} . The sensitivity coefficient for \bar{x} is

$$z_{\theta_x} = \frac{\partial z}{\partial \bar{x}} = a_1 + 2a_2\bar{x} + \dots + na_n\bar{x}^{n-1} \quad (7-19)$$

The standard deviation of the mean is

$$S_z = (z_{\theta_x}) (S_{\bar{x}}) \quad (7-20)$$

The number of degrees of freedom for z is the same as for \bar{x} .

The most common occurrence of this form of equation in steam generator performance testing is an enthalpy-temperature relationship.

7-4.2.3 Parameters of the Form $z = C\bar{u}\bar{v}$. For this type of parameter, two choices are available. The first is to transform the primary data values (u_i , v_i) into the intermediate result (z_i) and then average the values of the intermediate result and calculate the standard deviation and degrees of freedom.

The second alternative calculates z from the averages of u and v

$$z = C\bar{u}\bar{v}$$

and uses the propagation-of-error equation.

The sensitivity coefficients are

$$(z_{\theta_u}) = C\bar{v} \text{ and } (z_{\theta_v}) = C\bar{u} \quad (7-21)$$

The standard deviation is

$$S_z = [(C\bar{v}S_{\bar{u}})^2 + (C\bar{u}S_{\bar{v}})^2]^{1/2} \quad (7-22)$$

The number of degrees of freedom is

$$\nu = \frac{\left(\frac{S_z}{C}\right)^4}{\bar{v}^4 \frac{S_{\bar{u}}^4}{\nu_u} + \bar{u}^4 \frac{S_{\bar{v}}^4}{\nu_v}} \quad (7-23)$$

7-4.2.4 Flow Rates Using Weigh Bins or Tanks. Weigh bins or tanks are used as integrating devices to

⁴ While it may be argued that the standard deviation and degrees of freedom are better than those calculated by eqs. (7-9) and (7-11) because of several points sampled, it is impossible to determine these "better" values after samples are mixed.

smooth out variances in the flow rate. The desired flow rate generally is one occurring upstream of a component with storage capacity. For example, the catch of a baghouse can be determined by a weigh bin on the disposal line from the baghouse hoppers. If mass and time readings are taken at the beginning and the end of the test period, the average flow rate, w , is

$$w = \frac{u_2 - u_1}{\tau_2 - \tau_1} \quad (7-24)$$

where

u_1, u_2 = initial and final mass readings, respectively
 τ_1, τ_2 = initial and final time readings, respectively

As multiple measurements are not typically made of the weights and times, the random uncertainty of w depends on the instrumentation. The standard deviation is

$$S_w = \left\{ 2 \left[\left(\frac{w}{u_2 - u_1} \right)^2 \sigma_{u1}^2 + \left(\frac{w}{\tau_2 - \tau_1} \right)^2 \sigma_{\tau1}^2 \right] \right\}^{1/2} \quad (7-25)$$

Generally, the magnitude of the instrumentation variances is small and the standard deviation can be neglected. The instrumentation systematic uncertainties are likely to be significant.

7-4.3 Standard Deviation and Degrees of Freedom of Test Results

If the test result is a measured parameter, such as the temperature of the flue gas exiting the steam generator, then the standard deviation and degrees of freedom of the result are just the values for the parameter itself. If the test result must be computed from the measured data, such as steam generator efficiency, then the standard deviation and degrees of freedom of the result must be calculated from their values for the individual parameters.

7-4.3.1 Combining Standard Deviations. The standard deviation of a calculated result is obtained by combining the standard deviations of all of the parameters that affect the result according to the root-sum-square rule

$$S_R = \left[\sum_{i=1}^k \left({}_R\Theta_{xi} S_{\bar{x}_i} \right)^2 \right]^{1/2} \quad (7-26)$$

where

${}_R\Theta_{xi}$ = the sensitivity coefficient of parameter x_i on result R
 $= (\partial R / \partial x_i)$
 k = the total number of parameters that are used to calculate R

7-4.3.2 Combining Degrees of Freedom. The degrees of freedom of the standard deviation of R is computed by

$$v_{S_R} = \frac{S_R^4}{\sum_{i=1}^k \frac{\left({}_R\Theta_{xi} S_{\bar{x}_i} \right)^4}{v_{x_i}}} \quad (7-27)$$

7-4.3.3 Sensitivity Coefficients. The sensitivity coefficients are the partial derivatives of the result with respect to the parameter

$$({}_R\Theta_{xi}) = \left(\frac{\partial R}{\partial x_i} \right)_{xi} = \bar{x} \quad (7-28)$$

in accordance with eq. (7-4).

Sometimes, it may be more convenient to work with a relative sensitivity coefficient, which is calculated by

$$({}_R\Theta_{xi}) = \left(\frac{\bar{x}_i}{R} \right) ({}_R\Theta_{xi}) \quad (7-29)$$

The relative sensitivity coefficient is useful in a pretest analysis when judging the relative influence of the error in a particular parameter on the uncertainty of the test result.

7-4.3.4 Calculation of Sensitivity Coefficients. For test results such as steam generator efficiency, calculating the sensitivity coefficients analytically is cumbersome. An alternative is to calculate them by numerical methods using a computer. If a computer program is available to calculate the test resultant, R , from the parameters x_1, \dots, x_k , then the sensitivity coefficients can be approximated by perturbing each parameter, one at a time, by a small amount (δx_i), keeping the value of the other parameters constant and evaluating the change in the calculated value of the test resultant, δR . The sensitivity coefficient is then

$$({}_R\Theta_{xi}) = \left(\frac{\partial R}{\partial x_i} \right) \approx \frac{\delta R}{\delta x_i} \quad (7-30)$$

δx_i is a small value such as $x_i/100$ or $x_i/1,000$.

For a pretest uncertainty analysis, predicted performance data are used for the average values. The actual average values of the measured parameters are used for the post-test analysis.

7-5 EQUATIONS AND GUIDANCE FOR DETERMINING SYSTEMATIC UNCERTAINTY

Systematic uncertainty is a "built-in" component of the error. The systematic error is what remains after all reasonable attempts to eliminate it (such as calibrating instruments) have been made. An essential characteristic of systematic uncertainty is that it cannot be determined directly from the test data. It is always necessary to

estimate systematic uncertainty. Sometimes, models based on the test data or observations of conditions during the test can be used in making estimates, but they remain estimates nevertheless. A second essential fact concerning systematic uncertainty is that its value(s) is unique to the measurement system employed in a specific test and to the process and ambient conditions during the test.

This subsection gives certain mandatory rules for making estimates of the systematic error and for mathematical manipulation of them. These estimates are called "systematic uncertainty." This subsection also provides guidance and some models for estimating values of systematic uncertainties. Users of this Code are free to adopt, modify, or reject any models for systematic uncertainty set forth in this subsection.

7-5.1 General Rules

Systematic uncertainties used in this Code have the following characteristics:

(a) Systematic uncertainties should be estimated at a 95% confidence level; the maximum conceivable values of systematic uncertainty should not be used.

(b) Systematic uncertainty estimates may be one-sided or nonsymmetrical if the physical process so suggests. If nonsymmetrical or one-sided systematic uncertainties are used, then the technique given in ASME PTC 19.1 should be used to propagate the parameter uncertainties into the test result.

Although the actual systematic uncertainty in any measurement or result is a fixed value, we do not know the value. The plus and minus range that would contain about 95% of the possible estimates of the systematic error is what is used as the systematic uncertainty estimate. This Code specifies that systematic uncertainty estimates shall be combined by using the root-sum-square principle.

Generally, the same systematic uncertainties will be used for both pretest and post-test uncertainty analyses. Observations of conditions during the test may indicate that it is allowable to decrease one or more systematic uncertainties or that it is advisable to increase one or more systematic uncertainties.

7-5.2 Systematic Uncertainties in Measured Parameters Due to Instrumentation

There are a number of sources of instrumentation systematic uncertainty in any measurement; these include primary element, primary sensor, transducer, amplifier, analog/digital converter, recording device, and environmental effects. ANSI/ISA S51.1 [7] may be consulted for general information about instrumentation systematic uncertainty.

Section 4 gives guidance for estimating systematic uncertainties due to specific instrumentation systems. This subsection provides general guidelines and rules

for combining these elemental systematic uncertainties.

7-5.2.1 Systematic Uncertainty Due to a Single Component.

If a typical calibration curve for an instrumentation component is available, the magnitude of the component's systematic uncertainty can be estimated. Figure 7-5.2.1-1 is a generic calibration curve. The deviation is the difference between the input, as measured by a standard, and the output of the device under steady-state conditions.

The deviation is expressed in a number of ways, including units of the measured variable, percent of span, percent of output reading, etc. Figure 7-5.2.1-1 shows an envelope within which repeated readings at the same input have been made. The width of the envelope, A , is a measure of the random uncertainty of the device and is sometimes called the "reproducibility" of the device. Reproducibility includes hysteresis error, deadband, repeatability, and, occasionally, limited time drift.

The maximum positive or negative deviation from the zero deviation line, C , is sometimes called the "reference accuracy." The reference accuracy of a typical device can be used as an estimate of the corresponding systematic uncertainties of similar devices. Systematic uncertainties estimated from reference accuracy do not include the effects of drift, installation, etc.

If the curve is for a specific device, then the values to the midpoints, B , of the envelope at various inputs are to be used as calibration corrections in the data reduction. In this case, the systematic uncertainty is estimated as $(A/2)$. Note that such estimates may not include systematic uncertainties arising from drift, ambient effects, etc.

If an instrument or an entire instrumentation loop has been calibrated for a test, the systematic uncertainty is estimated as the root-sum-square of the standard deviation of the calibration curve (the standard error of estimate of the fitted curve) and the systematic uncertainty of the reference instrument. Refer to ASME PTC 19.1, Test Uncertainty, for further information.

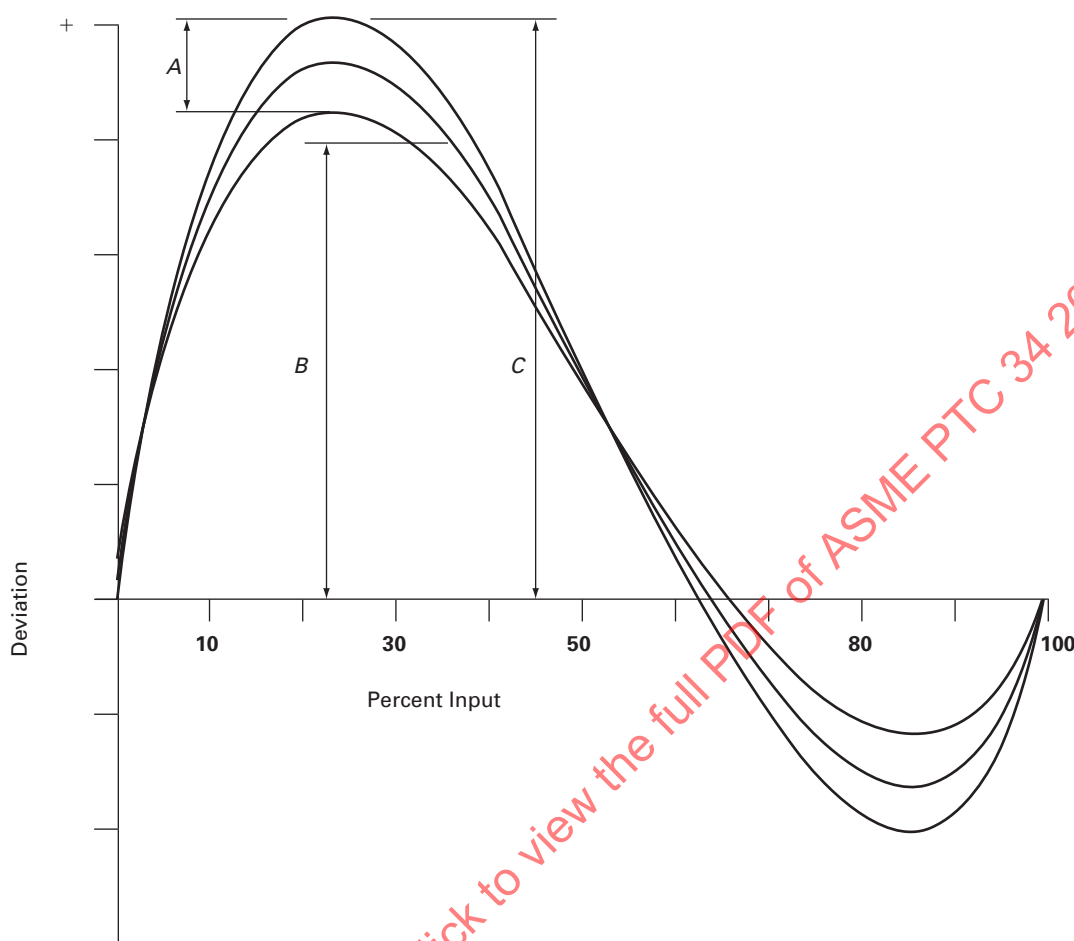
7-5.2.2 Combining Systematic Uncertainties From Several Components.

If an instrument system has several components and each has a separate systematic uncertainty, the combined systematic uncertainty of the measurement is

$$B = (B_1^2 + B_2^2 + \dots + B_m^2)^{1/2} \quad (7-31)$$

where subscripts 1, 2, ..., m represent the various components of the system. Because this root-sum-square rule is used, systematic uncertainties whose estimated magnitude is less than one-fifth of the largest in a specific loop may be ignored in calculating the systematic uncertainty of the parameter.

Fig. 7-5.2.1-1 Generic Calibration Curve



7-5.2.3 Multiple Measurements With a Single Instrument. For multiple measurements at a single location with a single instrument (such as measuring the temperature at several points in a flue gas duct cross section with the same thermocouple system) the instrumentation systematic uncertainty of the average value of the parameter is equal to the instrumentation systematic uncertainty of a single measurement

$$B_{\bar{x}} = B_{xi} \quad (7-32)$$

7-5.2.4 Multiple Measurements With Multiple Instruments at Several Locations. The most common example is the use of a fixed grid of thermocouples to measure (average) flue gas temperature. Two different situations may be present.

The first situation is when all instrument loops (each thermocouple plus lead wire, data logger, etc., constitutes one loop) are judged to have the same systematic uncertainty. This would occur when all of the instrument loops are calibrated in place against the same standard. In this case, the instrument systematic uncertainty in the average parameter (temperature) is equal to the

instrument systematic uncertainty for any one of the loops

$$B_{\bar{x}} = B_{xi} \text{ (any } i \text{)} \quad (7-33A)$$

The second situation is when different loops are judged to have different systematic uncertainties. This would occur if different independent calibrations are used, or for a variety of other reasons. In this case, the instrument systematic uncertainty for the average parameter is the average of the systematic uncertainties for each loop

$$B_{\bar{x}} = \frac{1}{N} \sum_{i=1}^N B_{xi} \quad (7-33B)$$

where

B_{xi} = systematic uncertainty of a single instrument loop i

N = number of different instrument loops

7-5.3 Systematic Uncertainty in Spatially Nonuniform Parameters

Certain parameters in a steam generator performance test, namely flue gas and air temperatures at the steam

generator envelope boundaries and flue gas composition, should be evaluated as flow-weighted integrated-average values (refer to paras. 4-3.4 and 7-2.3; also see ref. [8] in Nonmandatory Appendix D).

In practice, integrated averages are approximated by sampling at a finite number of points and using a numerical approximation to the necessary integral. In addition to this approximation, the parties to the test may agree to forego measurement of the velocity and omit the flow weighting. In certain cases, e.g., flue gas composition, the samples may be mixed and mechanically averaged prior to analysis. Each of these approximations may introduce an error, which this Code treats as systematic uncertainty. These systematic uncertainties are in addition to the instrumentation systematic uncertainties discussed in para. 7-5.2.

If measurements are made at only a few points (sometimes as few as one or two), then the methods suggested below for estimating these systematic uncertainties cannot be used. Likewise, these methods cannot be used for multipoint samples that are mixed prior to analysis. In both cases, the systematic uncertainty in integrated averages must be estimated and assigned. Experience and data from previous tests on similar units can serve as the basis for a model. Systematic uncertainty estimates must be large enough to account for the indeterminate errors present in small samples.

7-5.3.1 Spatial Distribution Index. It is possible to make mathematically elegant estimates of numerical integration error; however, these estimates require knowledge of the exact distribution. Since this information is usually not available, a heuristic model is proposed for numerical integration systematic uncertainty. The model assumes that numerical integration errors are proportional to the following spatial distribution index:

$$SDI = \left[\frac{1}{A} \int \left(z - \bar{z} \right)^2 dA \right]^{1/2}$$

where z is the time-averaged value of the continuously distributed parameter (temperature, oxygen content, etc.) and \bar{z} is the integrated-average value of z . Since SDI is itself an integral, it must be calculated by a numerical integration method. While it is probably advantageous to use the same integration rule that is used to calculate z for the performance calculations, the value calculated by the multiple midpoint rule is satisfactory

$$SDI = \left[\frac{1}{m} \sum_{i=1}^m \left(z_i - \bar{z} \right)^2 \right]^{1/2} \quad (7-34)$$

where m is the number of points in the measurement grid. In the case of a single stream (e.g., flue gas) divided between two or more separate ducts, SDI is calculated

for each duct. It should be noted that although SDI as calculated by eq. (7-34) appears to be identical to the "standard deviation," it does not have the same statistical significance.

If reliable historical data or data from a preliminary traverse are available, such data may be used to estimate the SDI for one or more parameters from this data.

7-5.3.2 Systematic Uncertainty Due to Numerical Integration. The recommended systematic uncertainty is

$$B_n = \left[\frac{1.0}{(m-1)^{0.5}} \right] SDI \quad (7-35)$$

where m is the number of points in the measurement grid. The coefficient in eq. (7-35) was selected by the Code Committee to reflect the relative magnitude of the systematic uncertainties and the dependence of the systematic uncertainty on the number of grid points but has no other theoretical basis. In the case of a single stream (e.g., flue gas) divided between two or more separate ducts, the model is applied to each duct. If historical or preliminary traverse data are used to estimate SDI, these systematic uncertainty estimates should be increased as appropriate to the applicability of the preliminary data to the actual test.

7-5.3.3 Systematic Uncertainty Associated With Flow Weighting. Although the theoretically proper averages for some parameters such as flue gas temperature and oxygen content are flow-weighted, it is often not advisable to use flow weighting in a performance test because the errors associated with velocity determination may be greater than the error made by not flow weighting. There are, therefore, two different types of systematic error associated with flow weighting.

(a) If flow weighting is used in the performance calculations, then there is a systematic error due to the systematic uncertainty in the velocity data used for weighting.

(b) If flow weighting is not used in the performance calculations, then there is a (systematic uncertainty) error of method. This error is equal to the difference between the (true) weighted average and the unweighted average actually used in the calculations.

It is clear that only one of these two types of errors can be present in any one data set (either the average is weighted or it is not). This Code treats either type as flow-weighting systematic uncertainty.

7-5.3.3.1 Flow-Weighting Systematic Uncertainty When Flow Weighting Is Used. There are two options in this case.

(a) The velocity used for flow weighting is measured simultaneously with the parameter being weighted (temperature or oxygen content).

(b) The velocity used for flow weighting is measured in one or more preliminary traverses.

In either of these cases, it is assumed that the velocity data are deemed sufficiently accurate and statistically valid (see para. 4-3.4 for rules regarding use of velocity data for flow weighting).

For the option in para. (a), where the velocity is measured simultaneously with the parameter being averaged, the flow-weighting systematic uncertainty estimate is

$$B_{FW} = (\bar{P}_{UW} - \bar{P}_{FW}) \frac{B_v}{\bar{V}} \quad (7-36)$$

where

- B_v = systematic uncertainty for velocity
- FW = weighted averages
- \bar{P} = the (integrated) average parameter (either temperature or oxygen concentration)
- UW = unweighted averages
- \bar{V} = average velocity

For the option in para. (b), where the velocity is determined by preliminary traverse(s), the following is recommended:

$$B_{FW} = 2(\bar{P}_{UW} - \bar{P}_{FW}) \frac{B_v}{\bar{V}} \quad (7-37)$$

The terms in this equation have the same meaning as for eq. (7-36).

7-5.3.3.2 Flow-Weighting Systematic Uncertainty When Flow Weighting Is Not Used. In this case, the systematic uncertainty estimate is an estimate of the difference between the weighted and unweighted averages. One of the following two options will hold:

- (a) There is no reliable velocity data.
- (b) Preliminary velocity traverse data exist, but the parameters are nevertheless not flow weighted.

For the option in para. (a), where there is no reliable velocity data available, the systematic uncertainty for temperature is estimated as follows. First, a weighted average is estimated by

$$\bar{T}_{FW} = \frac{1}{m} \sum_{i=1}^m \frac{\theta_i}{\theta} T_i \quad (7-38)$$

where

- m = number of points in the traverse plane
- θ = absolute temperature ($\theta = T^{\circ}\text{F} + 459.7$)

The systematic uncertainty estimate is

$$B_{T,FW} = 2(\bar{T}_{UW} - \bar{T}_{FW}) \quad (7-39)$$

The systematic uncertainty for oxygen concentration is taken as the same percentage of the average value as the temperature systematic uncertainty

$$\frac{B_{O_2,FW}}{\bar{O}_2} = \frac{B_{T,FW}}{T} \quad (7-40)$$

For the option in para. (b), where preliminary velocity data are available but are not used to calculate a weighted average, the recommended systematic uncertainty model is

$$B_{FW} = P_{UW} - P_{FW} \quad (7-41)$$

where the velocity data are used to calculate an estimate of the weighted average, P_{FW} .

7-5.3.4 Combined Systematic Uncertainty for Integrated Averages. The combined systematic uncertainty for integrated-average values is

$$B_{IA} = (B_I^2 + B_n^2 + B_{FW}^2)^{1/2} \quad (7-42)$$

where B_I is the instrumentation systematic uncertainty discussed in para. 7-5.2.

7-5.4 Systematic Uncertainty Due to Assumed Values for Unmeasured Parameters

The midpoint between reasonable “limiting” values of an assumed parameter normally should be used as the value of the parameter in performance calculations. Half the difference between the “limiting” values is normally used as a systematic uncertainty in uncertainty analyses. If, for example, the bottom ash flow rate was taken as a percentage of the total ash produced in a pulverized-coal-fired boiler, the percentage would be an assumed parameter. It would be the midpoint between the “limiting” values set.

In some cases, unsymmetrical systematic uncertainties may be used if physical considerations imply it. For example, an ash split cannot be $10\% \pm 15\%$, as a negative 5% is unrealistic. Likewise, systematic uncertainty due to air infiltration into an oxygen sampling system cannot be positive (the true value can be lower than the measurement but not higher).

7-5.5 Degrees of Freedom for Systematic Uncertainty Estimates

As discussed previously, the systematic uncertainty is an estimate of the limits of the possible values of the unknown fixed error that remain after calibration. In a given experiment, these errors remain fixed, but we do not know their values. All we know is our 95% confidence estimate of the range that we think covers the possible error values. There will always be some uncertainty in the estimate of the range. ISO *Guide to the Expression of Uncertainty in Measurement* and ASME PTC 19.1 give a methodology for handling this uncertainty.

If the uncertainty in the systematic uncertainty estimate, B , is expressed as ΔB , then the ISO guide recommends the following approximation for the degrees of freedom for B :

$$v_B \approx \frac{1}{2} \left(\frac{\Delta B}{B} \right)^{-2} \quad (7-43)$$

For example, if we think that there is as much as a $\pm 25\%$ uncertainty, ΔB , in our estimate of B , then the degrees of freedom for B would be 8. The more certain we are in our systematic uncertainty estimate, the larger the degrees of freedom will be. Conversely, more uncertain estimates for B will yield smaller degrees of freedom.

The degrees of freedom expression for the systematic uncertainty, eq. (7-43), applies to all of the systematic uncertainty estimates discussed in subsection 7-5. In the most general case for doing an uncertainty analysis, the degrees of freedom for each systematic uncertainty would have to be estimated.

7-5.6 Systematic Uncertainty for Test Results

The total systematic uncertainty for a result calculated from the measured and assumed parameters is

$$B_R = \left[\sum_{i=1}^k ({}_R\Theta_{xi} B_{xi})^2 \right]^{1/2} \quad (7-44)$$

This expression assumes that none of the parameters have systematic uncertainties that arise from common sources. If separate pressures, temperatures, etc., have the same systematic errors, such as those arising from a calibration standard, then these correlated systematic uncertainties must be taken into account in the evaluation of B_R . See ASME PTC 19.1 for the more general form of eq. (7-44). Also, if unsymmetrical systematic uncertainties are present, the techniques in ASME PTC 19.1 should be used.

The number of degrees of freedom for B_R is determined as

$$v_{B_R} = \frac{(B_R)^4}{\sum_{i=1}^k \frac{({}_R\Theta_{xi} B_{xi})^4}{v_{B_{xi}}}}$$

7-6 UNCERTAINTY OF TEST RESULTS

The standard deviation and the systematic uncertainty of a test result are combined into the test uncertainty according to the following equation:

$$U_R = t_{v,0.025} \left[\left(\frac{B_R}{2} \right)^2 + S_R^2 \right]^{1/2} \quad (7-45)$$

where

$t_{v,0.025}$ = the percentile point of Student's t distribution for $v = v_R$ degrees of freedom and a 95% confidence limit and is taken from Table 5-16.3-1 or the equation for curve fit in para. 5-16.3

The number of degrees of freedom of the result, v_R , is obtained from the expression

$$v_R = \frac{\left[\left(\frac{B_R}{2} \right)^2 + S_R^2 \right]^2}{\frac{S_R^4}{v_{S_R}} + \frac{\left(\frac{B_R}{2} \right)^4}{v_{B_R}}}$$

For most engineering applications, the value of v_R will be relatively large (≥ 9) based on all of the error sources that influence it; therefore, for most applications the number of degrees of freedom for the result can be taken as 2 for 95% confidence estimates, and the uncertainty in the result is determined as

$$U_R = 2 \left[\left(\frac{B_R}{2} \right)^2 + S_R^2 \right]^{1/2}$$

or

$$U_R = \left[B_R^2 + (2S_R)^2 \right]^{1/2}$$

In the test report, the uncertainty, U_R , shall be stated, along with the values of S_R and B_R . If the large sample approximation is used, the report shall state the v_R was taken as a large value so that Student's t is approximately 2.

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MANDATORY APPENDIX I

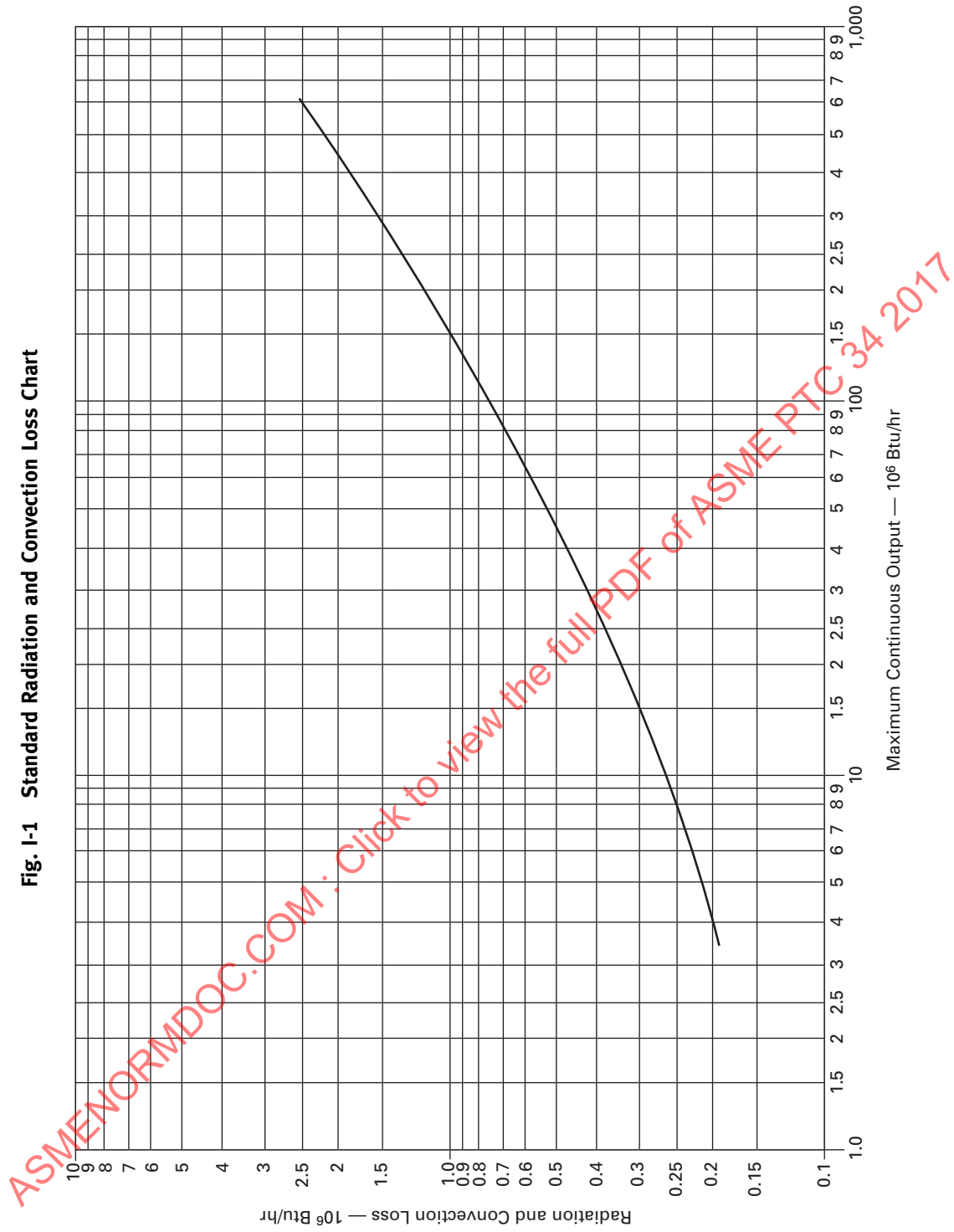
STANDARD RADIATION AND CONVECTION LOSS CHART

The curve on the Standard Radiation and Convection Loss Chart (Fig. I-1) is based on the American Boiler Manufacturers Association (ABMA) Standard Radiation Loss Chart, a waterwall furnace, 65% boiler efficiency, and an insulation system designed for 50°F differential between ambient air temperature and surface temperature with natural convection (100 fpm).

USAGE NOTES:

- (1) The curve on the Standard Radiation and Convection Loss Chart is used to establish radiation and convection heat loss in Btu/hr as a function of the maximum continuous output of a steam generator.
- (2) Once determined for maximum continuous output, the radiation and convection heat loss in Btu/hr are constant for all other outputs.
- (3) For insulation systems designed for other temperature differentials, multiply the heat loss from the curve by the ratio of ΔT (design): 50.
- (4) For furnaces with refractory walls, multiply the heat loss from the curve by 1.33.
- (5) Insulation systems designed for natural convection, if subjected to higher air velocity (e.g., outdoor installation), will experience reduced temperature differentials; however, the heat loss will not increase appreciably. Therefore, an adjustment is not provided for air velocity.

Fig. I-1 Standard Radiation and Convection Loss Chart



NONMANDATORY APPENDIX A

SAMPLE CALCULATION PROCEDURES FOR WASTE COMBUSTORS WITH ENERGY RECOVERY

A-1 BOILER EFFICIENCY BY THE HEAT BALANCE METHOD HHV OF FUEL USING THE BOILER-AS-A-CALORIMETER METHOD

This procedure describes the methodology used to calculate boiler efficiency by the “heat balance method” using measured flue gas mass and water in flue gas. Used in conjunction with measured fuel flow, the HHV of the fuel can be calculated. This methodology is commonly referred to as the “boiler-as-a-calorimeter” method. Assumptions and/or methodology for establishing parameters that cannot be reasonably measured over an extended test period are also addressed.

This method of determining boiler efficiency is recommended for units that fire a nonhomogeneous fuel, i.e., a fuel that the uncertainty of the analysis of a reasonable number of samples and/or the uncertainty of the analysis of a sample produced using standard procedures to reduce a large sample to the size required for analysis cannot be determined. An example of this type of fuel is municipal solid waste.

The major boiler efficiency losses are due to dry gas and water from fuel losses. This procedure uses the measurement of flue gas flow, water in flue gas, and flue gas analysis to determine these losses. Other losses are determined conventionally, i.e., in accordance with ASME PTC 4 procedures.

The calculations described in this procedure use the Heat Loss or Heat Balance principle for determining losses and credits. The heat balance method provides an order of magnitude of improvement in uncertainty over the input-output method in that the losses are only a fraction of the total input and thus an error in determining a loss has less of an impact on the final result. For example, if the dry gas loss is 10%, an error of 1% in measurement will only result in a 0.1% error in efficiency, whereas a 1% error in determining fuel input (fuel flow and HHV in the 1/0 calculation procedure) will result in a 1% error in efficiency (fuel input).

The procedure described below is based on the principles of the heat balance method described in ASME PTC 34 and is intended to be consistent with ASME PTC 4. Calculation forms are provided to describe the calculation methodology. The purpose of each form is described briefly below:

(a) *Form RESREF — Unburned Combustible and Residue Calculations.* This form is used to calculate the average

unburned combustible in the boiler residue and sensible heat in residue loss.

(b) *Form CMBREF — Combustion Calculations.* This form is used for the general combustion calculations such as excess air, dry gas mass, water from fuel, etc., which are required for the efficiency/input from fuel calculations.

(c) *Form EFFREF — Efficiency/Input/HHV Calculations.* This form provides for the calculation of steam generator efficiency, input from fuel, and higher heating value of waste fuel.

A-2 UNBURNED COMBUSTIBLE AND RESIDUE CALCULATIONS (FORM RESREF)

Form RESREF provides for the calculation of unburned combustible in the residue from the steam generator and the efficiency loss due to the sensible heat in the residue leaving the unit. Determine the locations where residue is removed from the unit and enter their descriptions under “Location.” Typical locations are the bottom and where flue dust leaves the unit. It is necessary to know the quantities of residue leaving the unit at each location in order to determine the weighted average of unburned combustible and sensible heat loss for each location. There are several methods for determining the quantities of residue leaving the unit.

(a) The mass of residue leaving each location may be measured, in which case, the measured values for each location would be entered in column 5.

(b) The total residue may be measured and the split assumed.

(c) To facilitate long-term performance monitoring or extended-duration testing where it is not practical to continuously monitor, sample, and weigh the various residue streams, the ash in a measured/estimated fuel analysis may be used to calculate total residue, and the percent residue leaving each location may be estimated as described above. Using this method, total residue flow will be calculated from the measured/estimated fuel sample analyses, calculated input by the heat balance method, and combustible loss based on earlier testing.

The example calculation forms in this Appendix are configured to facilitate calculation of unburned combustible and sensible heat in residue losses using any of

the three methods described above. Input to calculation Form RESREF is described as follows:

- Item 1 *Ash in Fuel, %*. Enter percent ash in fuel. Not required if total residue is measured.
- Item 2 *HHV Fuel, Btu/lb "As Fired."* Enter the higher heating value of the fuel as fired. Not required if total residue is measured.
- Item 3 *Input From Fuel, Million Btu/hr.* Estimated from Form CMBREF, item 13.
- Item 4 *Reference Temperature, °F*. Enter the reference temperature used for the efficiency calculations.
- Item 5 *Residue Mass Flow, klb/hr.* Mass flow rate of residue at the various locations leaving the steam generator boundary, such as flue dust residue and bottom ash.
- Item 7 *Combustibles in Residue, %*. Unburned combustible material in each residue stream will be determined by analysis of the residue samples.
- Item 8 *Residue Split, %*. This item is the percentage of total residue at each of the locations.
- Item 9 *Combustible, Weighted Average, %*. This item is the mass flow-weighted unburned combustible content of the residue and is used to calculate the unburned combustible loss.

A-2.1 If Residue Mass Flow Rate(s) Not Measured

- Item 11 *Unburned Combustible, lbm/100 lbm Fuel*. Calculate the average unburned combustible. This item is used on Form EFFREF.
- Item 12 *Unburned Combustible, klb/hr.* This item is calculated based on the input in fuel calculated by the heat balance method.
- Item 20 *Total Residue, lbm/100 lb Fuel*. The total residue is the sum of the ash in the fuel and the unburned combustible.
- Item 22 *Total Residue, klb/hr.* Convert total residue to a klb/hr basis.

A-2.2 If Residue Mass Flow Rate(s) Measured

- Item 12 *Unburned Combustible, klb/hr.* Calculate the unburned combustible from the measured total residue mass flow rate and the average unburned combustible in the residue.
- Item 22 *Total Residue, klb/hr.* This item is the same as measured and calculated for item 5F.

A-2.3 Sensible Heat Loss From Residue

- Item 24 *Residue Temperature, °F*. Enter the temperature of the residue leaving the unit for each location and calculate the enthalpy of residue for each temperature. Using the residue splits in column 8, calculate the sensible heat of residue loss for each location. The equation for enthalpy of residue is valid from 0°F to 2,000°F and is recommended for use for ash/residue of unknown composition.
- Item 25 *Sensible Heat Loss From Residue, Million Btu/hr.* Enter the summation of the loss for each location.

A-3 COMBUSTION CALCULATIONS — WASTE COMBUSTORS USING MEASURED GAS WEIGHT (FORM CMBREF)

A-3.1 Introduction

Form CMBREF is used for general combustion calculations when efficiency and input from fuel are calculated based on measured gas weight. It provides for the calculation of theoretical air, excess air, dry gas weight, and water from fuel. For purposes of the combustion calculations, N_2 includes argon and other trace elements and is referred to as "atmospheric nitrogen," N_{2a} , having an equivalent molecular weight of 28.158. This Code does not consider the difference between elemental nitrogen from fuel, N_2 , and atmospheric nitrogen, N_{2a} . Uncertainty analysis has demonstrated that this simplifying assumption has a negligible effect on calculated boiler efficiency and heat input.

A description of Form CMBREF is as follows:

- Item 1 *Mass Flow Wet Gas, klb/hr.* Enter the measured flue gas mass flow rate.
- Item 2 *Moisture in Wet Gas, lbm/lbm Wet Gas.* Enter the measured moisture in wet flue gas.
- Items 3–6 *Measurement of SO_2 ; Item 6 Is Optional.* These items must be measured at the same location as the gas mass is measured. The calculation procedure provides for calculating gas and air weights at other locations based on measuring O_2 at either location. This is particularly important if there is an air heater in the system and it is necessary to calculate air heater leakage and corrected air heater exit gas temperature. The calculations presented on this form are based on all flue gas analyses being on a dry basis. In the example calculations, the gas mass was measured after the regenerative air heater.

- Items 1–5 These items are normally measured via a gas sampling grid using gas analyzers connected to an electronic data acquisition system.
- Item 3 *O₂, % Dry Volume*. Enter the O₂ in flue gas at the location where the gas mass is measured.
- Item 4 Enter the CO₂ at the location where the gas mass is measured. If SO₂ is measured and CO₂ is determined by orsat, subtract the SO₂ from the orsat result (the orsat CO₂ reading includes SO₂).
- Item 5 *CO, % Dry Volume*. Enter the CO on a percent basis (CO is normally expressed in ppm and must be divided by 10,000 to convert ppm to %). If CO is not measured at the same location as the measured gas mass, refer to item 51 for conversion.
- Item 6 *SO₂, % Dry Volume*. If measured, enter the SO₂ on a percent basis (ppm/10,000). The sulfur content of municipal solid waste is usually very low, and estimating the SO₂ content does not significantly affect the calculated boiler efficiency or heat input. See item 15 below.
- Items 7–9 These items are self-explanatory and are required to calculate the moisture in air.
- Item 10 *Moisture in Air, lbm/lbm Dry Air*. Determine from items 7 through 9 using a psychometric chart or suitable calculation procedure.
- Item 11 *Unit Output, Million Btu/hr*. Enter the unit output.
- Item 12 *Unit Efficiency, % (Estimate Initially)*. Enter the estimated unit efficiency. This is used to estimate the input from fuel for the initial calculations.
- Item 13 *Additional Moisture in Flue Gas, klb/hr*. Enter any moisture introduced into the air/flue gas such as atomizing steam flow.
- Item 14 *Gas Temperature Leaving Air Heater (Including Leakage), °F*. This is the actual measured gas temperature leaving the air heater. Enter a value if applicable. The corrected gas temperature leaving the air heater (excluding leakage) that is used for the efficiency calculations is calculated below.
- Item 15 *Air Temperature Entering Air Heater, °F*. Enter the air temperature entering the recuperative air heater if applicable.
- Item 24 *MW Dry Gas, lbm/mole Dry Gas*. This is the molecular weight of dry flue gas.
- Item 26 *Dry Air Weight, klbm/hr*. The mass flow rate of dry air is calculated from the mass flow rate of atmospheric nitrogen in the flue gas, i.e., 0.7685 lbm N_{2a} per lbm dry air.
- Item 29 *O₂ Corrected for CO, %*. This item is used to calculate excess air. Excess air is defined as the amount of air in excess of that required to combust all the carbon used (carbon burned) to CO₂, thus a correction for CO is required. The first part of the equation, (O₂ – CO₂), is published in all the test Codes. The second part is consistent with ASME PTC 4.
- Item 31 *Theoretical Air, klb/hr*. Theoretical air, for the purposes of combustion calculations, is defined by PTC 4 as the amount of air required to combust the fuel constituents comprised of carbon used (carbon burned) to CO₂, hydrogen to H₂O, and sulfur to SO₂.
- Items 50–59 These calculations provide for the determination of air and gas weights at locations other than where gas weight and the complete flue gas analysis are measured; these properties are based on measured O₂ at the alternate location.
- Item 54 *Excess Air, %*. The excess air at any location is calculated based on calculated excess air at the base location and O₂ at the base and new location(s).
- Items 65–70 These items are not applicable for units without a recuperative air heater (air to gas heat exchanger). These items provide for the calculation of the air heater gas outlet temperature for no leakage (excluding leakage) in accordance with ASME PTC 4.3. The gas temperature leaving the air heater corrected for no leakage is used in the efficiency calculation.

A-3.2 Calculations

The calculations are generally self-explanatory and easy to follow. Comments are provided where the intent or source of the equation may be unclear.

A-4 EFFICIENCY/INPUT/HHV CALCULATIONS — WASTE COMBUSTORS USING MEASURED GAS WEIGHT (FORM EFFREF)

A-4.1 Introduction

Form EFFREF provides for the calculation of boiler efficiency and heat input by the heat balance method, and fuel higher heating value by using the boiler as a calorimeter. It is applicable when flue gas flow, moisture, and major gaseous constituents are measured. Boiler efficiency is calculated by the “heat loss method” using measured and calculated input from Forms EFFREF and

RESREF. Heat losses and credits are calculated on a Btu/hr basis since the primary measurement of the variables impacting the major losses and credits are measured on a lbm/hr basis. The calculations are independent of measured fuel flow for determination of input from fuel and efficiency (with the exception of assumptions and/or measurements required to account for minor losses or credits). The principles for calculating losses/credits, efficiency, and input are as follows:

$$\text{INPUT from FUEL} = \text{OUTPUT} + \text{LOSSES} - \text{CREDITS, Btu/hr}$$

$$\text{FUEL EFFICIENCY} = 100 \times \text{OUTPUT} / \text{INPUT from FUEL, \%}$$

$$\text{HHV of FUEL} = \text{INPUT from FUEL} / \text{FUEL FLOW, Btu/lbm fuel}$$

For an item measured on a lbm/hr basis, the basic concept for calculating a loss or credit on a Btu/hr basis is

$$\begin{aligned} &\text{Loss or Credit} - (\text{mass flow rate}) \times C_p \\ &\times (\text{Temperature entering/leaving boiler} - T_{\text{ref}}), \text{ Btu/hr} \end{aligned}$$

The calculation procedure is somewhat iterative. Upon completion of the calculation of the losses and credits on a Btu/hr basis, they are converted to a percent loss/credit basis by dividing by the calculated input from fuel. The calculations are generally self-explanatory; only those items requiring clarification are specifically addressed here.

A-4.2 Data Required

Item 1	<i>Reference Temperature, °F.</i> Enter the reference temperature to be used for the calculation of efficiency. Enter the enthalpy of water for this temperature in 1A ($T - 32$). The reference temperature of 77°F (25°C) is consistent with ASME PTC 4 and shall be used for calculation of heat losses and credits. This value has no impact on the calculation of fuel input other than the uncertainty of the sensible heat of fuel credit due to the uncertainty of the mass flow rate and average specific heat of a waste fuel.	Item 3	<i>Average Gas Temperature Leaving Unit (Excluding Leakage), °F.</i> For units with recuperative air heaters, this is the temperature calculated on Form CMBREF. For units without air heaters, this is the gas temperature leaving the steam generator envelope. Enter the enthalpy of steam at 1 psia in item 3A.
Item 2	<i>Average Air Temperature Entering Unit, °F.</i> This item is used to calculate the heat credit due to the entering air temperature and is after the discharge of the fans and air preheater coils if applicable. The air temperature entering the unit is the mass flow-weighted average of all air streams entering the unit.	Item 4	<i>Fuel Temperature, °F.</i> Enter the temperature of the fuel entering the unit. For most cases, the fuel temperature will be assumed to be the same temperature as the air temperature entering the forced-draft (FD) fan.
		Item 5	<i>Temperature of Additional Moisture, °F.</i> See item 12 on Form CMBREF. Enter the enthalpy of the steam or water as it enters the steam generator envelope (this is the enthalpy of feedwater for steam supplied from the steam generator).
		Items 10–12	Losses and credits are calculated based on the gas/air weight leaving the boiler (upstream of the air heater); thus, depending on the location of the gas flow measurement and primary flue gas analysis, the source of input can be from two locations on Form CMBREF.
		Items 17–19	Items 17 through 19 are used to calculate the loss due to CO in the flue gas and are dependent on the calculated molecular weight of dry flue gas at the point where the gas flow is measured to be consistent with Form CMBREF. Therefore, these items are obtained from the location where flue gas flow is measured.
		Item 25	<i>Refuse Fuel Flow, klbm/hr.</i> This item is only required if it is desired to calculate the HHV of the waste fuel by the boiler-as-a-calorimeter method. It is not required to calculate boiler efficiency and input from fuel (except that a value may have to be assumed for the calculation of the heat credit in as-fired fuel).
		Items 26, 27	<i>Auxiliary Fuel Flow and HHV.</i> If applicable, enter the measured values for these items. These items are used to differentiate between input from waste fuel and input from auxiliary fuel.
		Item 28	<i>Radiation and Convection Loss, Million Btu/hr.</i> This loss is determined from the modified ABMA Radiation and Convection Loss curve included in Mandatory Appendix I of this Code.
		Item 29	<i>Unburned Combustible, klbm/hr.</i> Enter the result from Form RESREF.

- Item 31 *Unmeasured or Estimated Losses, %.*
Enter the estimated value or the value agreed on between the parties to the test.
- Items 32, 33 *Auxiliary Equipment Drives.* These items are used to calculate the heat credit for auxiliary equipment motor drives that are inside the steam generator envelope, such as pressure-boosting undergrate or overfire air fans. The motor drive efficiency may be estimated from the motor manufacturer's design data or shop tests.

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