ASME PTC 4-2013

(Revision of ASME PTC 4-2008)

Fired Steam Generators

Performance Test Codes

AN AMERICAN NATIONAL STANDARD

The American Society of Mechanical Engineers

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Two Park Avenue • New York, NY • 10016 USA

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This Code will be revised when the Society approves the issuance of a new edition.

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Errata to codes and standards may be posted on the ASME Web site under the Committee Pages to provide corrections to incorrectly published items, or to correct typographical or grammatical errors in codes and standards. Such errata shall be used on the date posted.

The PTC Committee Page can be found at go.asme.org/PTCcommittee. There is an option available to automatically receive an e-mail notification when errata are posted to a particular code or standard. This option can be found on the appropriate Committee Page after selecting “Errata” in the “Publication Information” section.

The American Society of Mechanical Engineers
Two Park Avenue, New York, NY 10016-5990

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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 the parties to a commercial test agree before starting the test and preferably before signing the contract 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.

FOREWORD

The Test Code for Stationary Steam Generating Units was one of the group of 10 forming the 1915 Edition of the ASME Power Test codes. A revision of these codes was begun in 1918, and the Test Code for Stationary Steam Generating Units was reissued in revised form in October 1926. Further revisions were issued in February 1930 and January 1936.

In October 1936 the standing Power Test Code Committee requested Committee No. 4 to consider a revision of the Code to provide for heat balance tests on large steam generating units. In rewriting the Code, advantage was taken of the experience of the several companies in the utility field that had developed test methods for large modern units including the necessary auxiliary equipment directly involved in the operation of the units. At the same time the needs of the small installations were not overlooked. At the November 3, 1945, meeting of the standing Power Test Codes Committee, this revision was approved. On May 23, 1946, the Code was approved and adopted by the Council.

In view of the continuously increasing size and complexity of steam generating units, it was obvious that changes were required in the 1946 Edition of the Test Code. In May 1958 the technical committee was reorganized to prepare this revision. The completely revised Code, the Test Code for Steam Generating Units, was approved by the Power Test Codes Committee on March 20, 1964. It was further approved and adopted by the Council as a standard practice of the Society by action of the Board on Codes and Standards on June 24, 1964.

The Board on Performance Test Codes (BPTC) in 1980 directed that the Code be reviewed to determine whether it should be revised to reflect current engineering practices. A committee was soon formed, and it had its first meeting in May 1981. The Committee soon recognized that the Code should be totally rewritten to reflect several changes in steam generator technology (primarily the increasing usage of fluidized bed combustors and other technologies for emission control) and in performance testing technology (primarily the widespread use of electronic instrumentation and the consideration of test uncertainty analysis as a tool for designing and measuring the quality of a performance test).

The Committee decided that the new code should discourage the use of an abbreviated test procedure (commonly known as "The Short Form" from PTC 4.1). The PTC 4 Code supersedes PTC 4.1, which is no longer an American National Standard or ASME Code. (Technical Inquiry #04-05 describes the differences between the PTC 4 and the invalid PTC 4.1.) The Committee reasoned that the best test is that which requires the parties to the test to deliberate on the scope of the performance test required to meet the objective(s) of the test. Measurement uncertainty analysis was selected as the tool whereby the parties could design a test to meet these objectives. (See para. 3-2.1.) As this Code will be applied to a wide configuration of steam generators, from small industrial and commercial units to large utility units, the soundness of this philosophy should be self-evident.

This expanded edition of the Code was retitled Fired Steam Generators to emphasize its limitation to steam generators fired by combustible fuels. The Code was subjected to a thorough review by Industry, including members of the BPTC. Many of their comments were incorporated and the Committee finally approved the Code on June 23, 1998. It was then approved and adopted by the Council as a Standard practice of the Society by action of the Board on Performance Test Codes on August 3, 1998. It was also approved as an American National Standard by the ANSI Board of Standards Review on November 2, 1998.

Calculations associated with the application of this Code can be facilitated by the use of computer software. Software programs that support calculations for this Code may become available at a future date on the ASME Web site. Any such software that may be furnished would not have been subject to the ASME consensus process and ASME would make no warranties, express or implied, including, without limitation, the accuracy or applicability of the program.

A revision to the Code was published in 2008. The main purpose of this revision was to include a general update of the Code to bring it into compliance with the definitions and terminology used in the revised PTC 19.1, Test Uncertainty. The major issue in this regard was to change all references to "bias" and "precision" to "systematic" and "random," respectively. Also, "precision index" was changed to "standard deviation." In conformance with PTC 19.1, a value of 2 was stipulated for the "Student's *t*" parameter, which simplifies the uncertainty calculations. This revision also included the addition of subsection 4-16 and para. 5-18.14. Subsection 4-16 provides procedures for the measurement of surface radiation and convection loss. Paragraph 5-18.14 contains procedures for calculating the uncertainty of corrected results. Also, the procedures for determining the average value of spatially nonuniform parameters were simplified. In addition to these changes, the 2008 revision included corrections of minor errors and omissions, an update of references, and text revisions for better clarity.

The 2008 revision was approved by the PTC Standards Committee on October 16, 2007, and approved and adopted as a Standard practice of the Society by action of the Board on Standardization and Testing on February 19, 2008. It was also approved as an American National Standard by the ANSI Board of Standards Review on October 14, 2008.

Work on the current edition began in 2009. The main purpose of this edition is to include revisions occasioned by Technical Inquiry 09-01, Code Case P-2, and the errata posted on February 8, 2012. As a result of

Technical Inquiry 09-01, changes to the text of para. 5-19.5, "Enthalpy of Steam/Water at 1 psia Btu/lbm," and Nonmandatory Appendix D, subsection D-4, "Efficiency on a Lower Heating Value, *LHV*, Basis," were made for improved clarity. Code Case P-2, concerning a mass balance/efficiency error on units utilizing sorbent, resulted in revisions to text, equations, and acronyms in Section 5 and changes to calculation forms in Nonmandatory Appendix A. The errata required changes in subsections A-3, A-4, and A-5 of Nonmandatory Appendix A and subsections D-3, D-4, and D-5 of Nonmandatory Appendix D. In addition to these changes, all the Code Sections were reviewed to correct minor errors and omissions, to update references, and to revise text for better clarity.

The following is a summary of major changes to each Section:

In Section 1, references to codes and standards were updated. Figures 1-4-2 through 1-4-5 were revised. These revisions and corrections included adding missing flow streams, revising text for improved clarity, and correcting spelling.

In Section 3, references to codes and standards were updated. Figure 3-1.1-1 (formerly designated as Fig. 3-1-1) was edited to correct the equation for NO_x formation loss.

In Section 4, Table 4-2-1 was split into two tables, one for energy losses [Table 4-2-1(a)] and one for energy credits [Table 4-2-1(b)]. Tables 4-3.6-1 and 4-3.6-4 (formerly designated as Tables 4-3-1 and 4-3-4, respectively) were edited to correct errors, and references to codes and standards were updated.

In Section 5, revisions occasioned by Technical Inquiry 09-01 and Code Case P-2 were made to text, equations, and acronyms. Changes required by the errata posted on February 8, 2012, were made. Other changes and corrections were made to formulas and acronyms. Also, text was revised to improve clarity, and references were corrected and updated.

In Nonmandatory Appendix A, many of the forms were revised in accordance with Code Case P-2 and the errata posted on February 8, 2012. Minor changes were made to the text and forms to improve clarity.

In Nonmandatory Appendix B, many of the forms were revised in accordance with Code Case P-2 and the errata posted on February 8, 2012. Paragraph B-5.1, including text and tables, was added to provide a sample steam generator efficiency calculation for a circulating fluidized bed (CFB) steam generator. Minor changes were made to the text and tables to improve clarity.

In Nonmandatory Appendix D, the text and equations in subsection D-4 concerning LHV were revised for clarity.

The PTC 4 Committee approved the Code on May 31, 2013. It was also approved by the PTC Standards Committee on May 31, 2013, and approved and adopted as a Standard practice of the Society by action of the Board on Standardization and Testing on October 21, 2013. Finally, it was also approved as an American National Standard by the ANSI Board of Standards Review on November 21, 2013.

ASME PTC COMMITTEE
Performance Test Codes

(The following is the roster of the Committee at the time of approval of this Code.)

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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, and attending Committee meetings. Correspondence should be addressed to:

Secretary, PTC Standards Committee
The American Society of Mechanical Engineers
Two Park Avenue
New York, NY 10016-5990

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 Code Case. Code Cases may be issued for the purpose of providing 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. Code Cases are effective immediately upon ASME approval and shall be posted on the ASME PTC Committee Web page.

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

The request for interpretation should be clear and unambiguous. It is further recommended that the inquirer submit his request in the following format:

Subject: Cite the applicable paragraph number(s) and a concise description.

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. 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 this format will be rewritten in this 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. ASME does not "approve," "certify," "rate," or "endorse" any item, construction, proprietary device, or activity.

Attending Committee Meetings. The PTC Standards Committee holds meetings or telephone conferences, which are open to the public. Persons wishing to attend any meeting 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.

FIRED STEAM GENERATORS

Section 1
Object and Scope

1-1 OBJECT

The object of this Code is to establish procedures for conducting performance tests of fuel-fired steam generators. This Code provides standard test procedures that can yield results giving the highest level of accuracy consistent with current engineering knowledge and practice.

The accuracy of a particular test may be affected by the fuel fired during the test or other factors within the discretion of the operator. A test is considered an ASME Code test only if the following conditions are met:

(a) Test procedures comply with procedures and allowed variations defined by this Code.

(b) Uncertainties of test results, determined in accordance with Section 7 of this Code, do not exceed target test uncertainties defined by prior written agreement in accordance with Section 3 of this Code.

1-1.1 Determination of Performance Characteristics

This Code can be used to determine the following performance characteristics:

(a) efficiency
(b) output
(c) capacity
(d) steam temperature/control range
(e) exit flue gas and entering air temperature
(f) excess air
(g) water/steam pressure drop
(h) air/flue gas pressure drop
(i) air infiltration
(j) sulfur capture/retention
(k) calcium-to-sulfur molar ratio
(l) fuel, air, and flue gas flow rates
(m) unburned carbon and unburned carbon loss

It is not necessary that all of these parameters be determined simultaneously for each and every test.

1-1.2 Purpose of Performance Characteristics

These performance characteristics are typically required for the following purposes:

(a) comparing actual performance to guaranteed performance

(b) comparing actual performance to a reference

(c) comparing different conditions or methods of operation

(d) determining the specific performance of individual parts or components

(e) comparing performance when firing an alternate fuel

(f) determining the effects of equipment modifications

This Code also provides methods for converting certain performance characteristics at test conditions to those that would exist under specified operating conditions.

1-2 SCOPE

1-2.1 General Scope

The rules and instructions presented in this Code apply to fired steam generators. These include coal-, oil-, and gas-fired steam generators as well as steam generators fired by other hydrocarbon fuels. The scope also includes steam generators with integral fuel-sulfur capture utilizing chemical sorbents.

Steam generators that are not fired by coal, oil, or gas may be tested using the concepts of this Code, but it should be noted that the uncertainty caused by variability of the fuel may be difficult to determine and is likely to be greater than the uncertainties in sampling and analysis of coal, oil, or gas.

Gas turbine heat recovery and other heat recovery steam generators designed to operate with supplemental firing should be tested in accordance with ASME Performance Test Code (PTC) 4.4, Gas Turbine Heat Recovery Steam Generators.

This Code does not apply to nuclear steam supply systems, which are specifically addressed in ASME PTC 32.1, Nuclear Steam Supply Systems. This Code does not apply to the performance testing of chemical heat recovery steam generators, municipal-waste-fired steam generators, pressurized steam generators with gas side pressure greater than 5 atm, or incinerators. Municipal-waste-fired steam generators can be tested in accordance with ASME PTC 34, Waste Combustors With Energy Recovery.

Testing of auxiliary equipment is not addressed in this Code, but shall be governed by the following Performance Test Codes that apply specifically to the equipment in question:

(a) ASME PTC 4.2, Coal Pulverizers

(b) ASME PTC 4.3, Air Heaters

(c) ASME PTC 11, Fans

Steam purity and quality shall be tested in accordance with ASME PTC 19.11, Steam and Water Sampling, Conditioning, and Analysis in the Power Cycle.

Methods used by this Code for determining emission-related parameters (e.g., sulfur retention and flue gas constituents) are not equivalent to methods required by the U.S. Environmental Protection Agency (EPA), New Stationary Source Performance Standards, 40CFR60 and are not intended to be used for evaluating compliance with those standards or any other environmental regulations.

This Code does not prescribe procedures for testing to determine chemical and physical properties of fuels. Applicable procedures may be found in the ASME PTC 3 series or other pertinent standards such as those published by ASTM.

This Code specifically addresses equipment used for the generation of steam; however, the basic principles presented are also applicable to other working fluids.

Certain types and sizes of equipment used for the recovery of heat released by combustion are not addressed in any specific Performance Test Code. This Code can be used as a general guide in developing performance tests for such equipment; however, such specially developed performance tests shall not be considered ASME Code tests.

1-2.2 Design Variations

This Code provides general procedures for conducting combustible-fuel-fired steam generator performance tests; however, it cannot possibly provide detailed procedures applicable to every steam generator design variation. Design variations considered in developing this Code include natural circulation, forced circulation, subcritical and supercritical once-through steam generators and oil, gas, stoker, cyclone, pulverized, and fluidized bed firing, including both balanced draft and pressurized designs (up to 5 atm). For each performance test, a competent engineer must study the actual steam generator and its relation to the remainder of the steam cycle, and develop test procedures that are consistent with this Code.

1-2.3 Reports

A test report shall be prepared. See Section 6.

1-2.4 References

Many references provide useful supplemental information in planning for a performance test in accordance with this Code. Those used most frequently are listed in subsection 3-3.

1-3 TYPICAL UNCERTAINTY FOR EFFICIENCY

Fossil-fuel-fired steam generators are custom designed for the most severe characteristics of the fuels expected to be burned. The specific arrangement for any given system may contain different low-level heat recovery systems as well as air quality equipment located within the steam generator envelope. Chemical additives (sorbent) may be added for control of emissions. These variations in steam generator design influence the energy balance method uncertainty result.

Table 1-3-1 shows typical values of uncertainty in steam generator efficiency as a function of fuel type, unit type, and test method selected. The steam generator sizes are shown to allow for defining a test with a cost consistent with the value of the project in accordance with ASME PTC 1, General Instructions. The utility/large industrial category refers in general to steam generators that supply steam to turbine/generators.

The lower values shown for the energy balance method for a utility/large industrial unit are based upon Code air temperature, gas temperature, and gas sampling grids with a typical electronic sampling rate. The small industrial unit values are based on a small grid and obtaining data manually.

The uncertainty of the Input–Output method is directly proportional to the uncertainty of measurement of feedwater/steam flow, fuel flow, and fuel heating value. To achieve the uncertainties shown in Table 1-3-1, the metering must be selected, manufactured, installed, and used in strict accordance with the applicable codes and standards. Most importantly, the required straight lengths of differential pressure metering runs and use of flow conditioners must be rigorously adhered to. For coal flow, gravimetric feeders must be calibrated by the direct measurement of coal weight, before and after the test.

With the above guidelines, the input–output uncertainties are based upon the following flow measurement-system uncertainties and fuel sampling criteria:

(a) feedwater, utility/large industrial: ASME PTC 6 flow nozzle, 0.38% system

(b) feedwater, small industrial: test orifice/empirical formulation, 0.80% system

(c) natural gas: test orifice/empirical formulation, 0.80% system

(d) oil flow: calibrated positive displacement meter, three viscosities (multiple tests for repeatability), 0.63% system

(e) rigorous calibration of coal feeders

(f) fuel analysis: multiple samples analyzed individually, ASTM reproducibility systematic error plus 0.5% sampling error for oil and gas and 2% sampling error for coal

Table 1-3-1 Typical Code Test Uncertainties for Efficiency

Type of Steam Generator	Energy Balance Method (Percentage Points)	Input–Output Method (Percentage Points)
Utility/large industrial		
Coal fired [Note (1)]	0.4–0.8	3.0–6.0
Oil fired	0.2–0.4	1.0
Gas fired	0.2–0.4	1.0
Fluidized bed [Note (1)]	0.9–1.3	3.0–6.0
Small industrial with heat trap [Note (2)]		
Oil	0.3–0.6	1.2
Gas	0.2–0.5	1.2
Small industrial without heat trap		
Oil	0.5–0.9	1.2
Gas	0.4–0.8	1.2

GENERAL NOTE: The uncertainty of the corrected efficiency is typically 0.1% to 0.3% points less than the uncertainty of the test efficiency.

NOTES:
(1) It is not recommended that coal-fired units be tested using the Input–Output method because of the large uncertainties of measuring coal flow.
(2) Economizer/air heater.

1-4 STEAM GENERATOR BOUNDARIES

Boundaries associated with different steam generator arrangements are shown in Figs. 1-4-1 through 1-4-7. The steam generator boundaries shown on these figures encompass the equipment to be included in the steam generator envelope for each case.

The following numbers are used to designate specific locations.

1-4.1 Fuel/Sorbent

1: coal leaving feeder or bunker
1A: sorbent leaving feeder or bunker
2: coal to burners (leaving pulverizer)
3: oil to burners
3A: oil to oil heaters
4: gas to burners

1-4.2 Air

5: pulverizer tempering air
6: FD fan inlet
6A: PA fan inlet
7: FD fan discharge
7A: PA fan discharge
7B: other air entering unit
8: combustion (secondary) air entering boundary
8A: primary air entering boundary
8B: combustion air leaving APH coils within boundary
8C: primary air leaving APH coils within boundary
9: combustion (secondary) air leaving air heater
9A: primary air leaving air heater
10: secondary air entering steam generator
11: pulverizer inlet air
11A: pulverizer outlet air and fuel mixture

1-4.3 Flue Gas

12: leaving steam generating bank (not shown)
13: entering economizer (not shown)
14: leaving economizer
14A: entering secondary air heater
14B: entering primary air heater
14C: leaving hot-side AQC equipment
15: leaving air heater(s)
15A: leaving secondary AH
15B: leaving primary AH
16: entering cold-side AQC equipment
17: leaving cold-side AQC equipment
18: entering ID fan
19: leaving ID fan
20: entering low-level heat exchanger (not shown)
21: leaving low-level heat exchanger (not shown)
22: entering gas recirculation fan
23: leaving gas recirculation fan (entering boiler)

1-4.4 Steam/Water

24: feedwater entering
25: superheater spray water
26: first reheater spray water
26A: second reheater spray water (not shown)
27: feedwater leaving economizer
28: feedwater entering drum
29: steam generator water entering circulating pump
30: steam generator water leaving circulating pump
31: saturated steam leaving drum
31A: entering first stage SH desuperheater
31B: leaving first stage SH desuperheater
31C: entering second stage SH desuperheater (not shown)
31D: leaving second stage SH desuperheater (not shown)

32: main steam
33: reheat steam entering boundary
33A: entering first reheat desuperheater
33B: leaving first reheat desuperheater
33C: entering second reheat desuperheater (not shown)
33D: leaving second reheat desuperheater (not shown)
34: leaving first reheater
34A: leaving second reheater (not shown)
35: blowdown
36: condensate leaving APH coils (internal to boundary)
36A: condensate leaving primary APH coils (internal to boundary)

1-4.5 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
43: steam entering fuel oil heater
44: steam leaving fuel oil heater
45: pulverizer rejects
46: soot blower steam
46A: auxiliary steam
47: boiler circulating pump water injection
48: boiler circulating pump water leakoff
49: hot air recirculation (not shown)
50: hot air bypass (not shown)
51: fuel/gas conditioners
52: economizer residue
53: hot AQC equipment residue
54: air heater residue
55: cold AQC equipment residue

Fig. 1-4-1 Typical Oil- and Gas-Fired Steam Generator

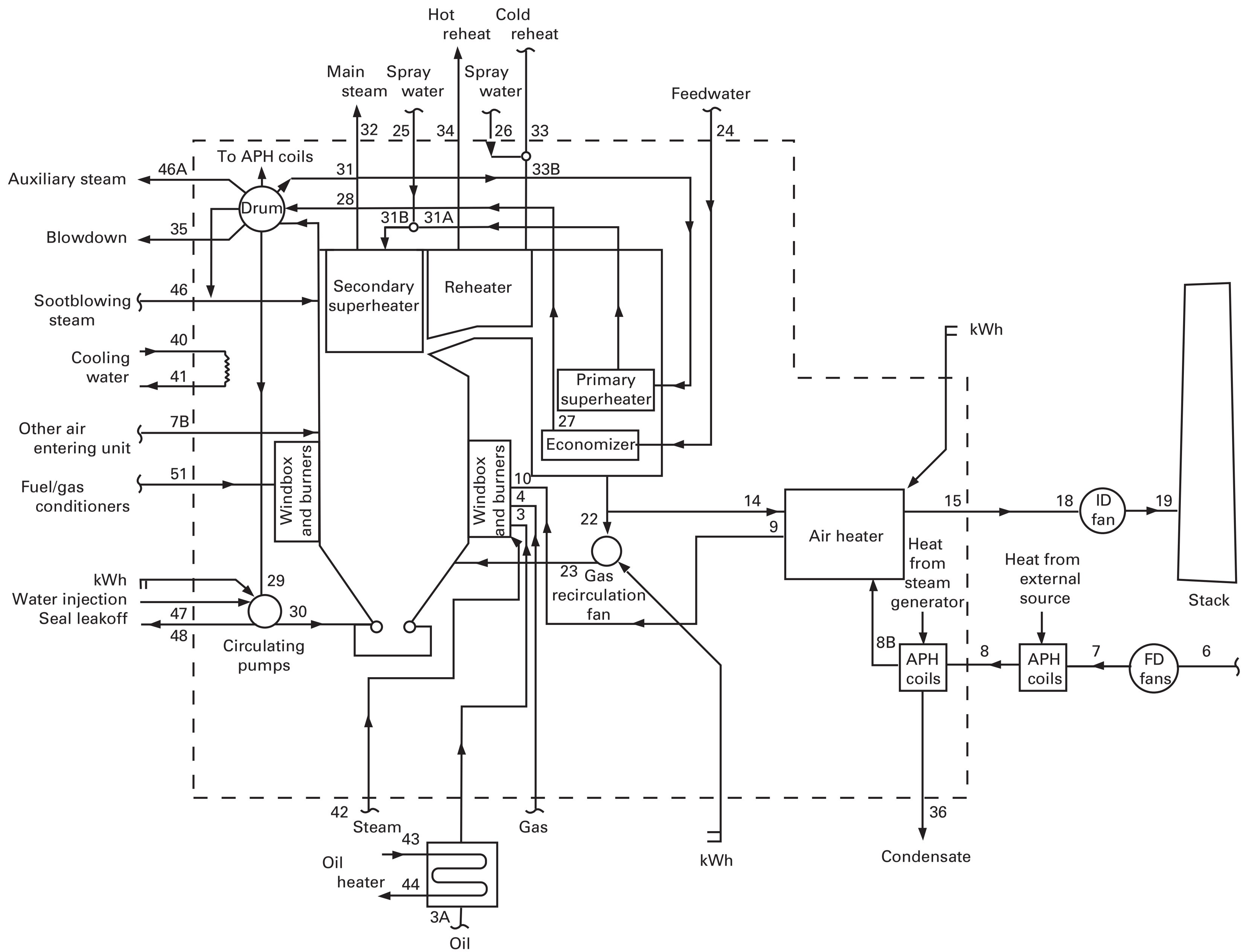


Fig. 1-4-2 Typical Pulverized-Coal-Fired Steam Generator, Alternative 1: Single Air Heater

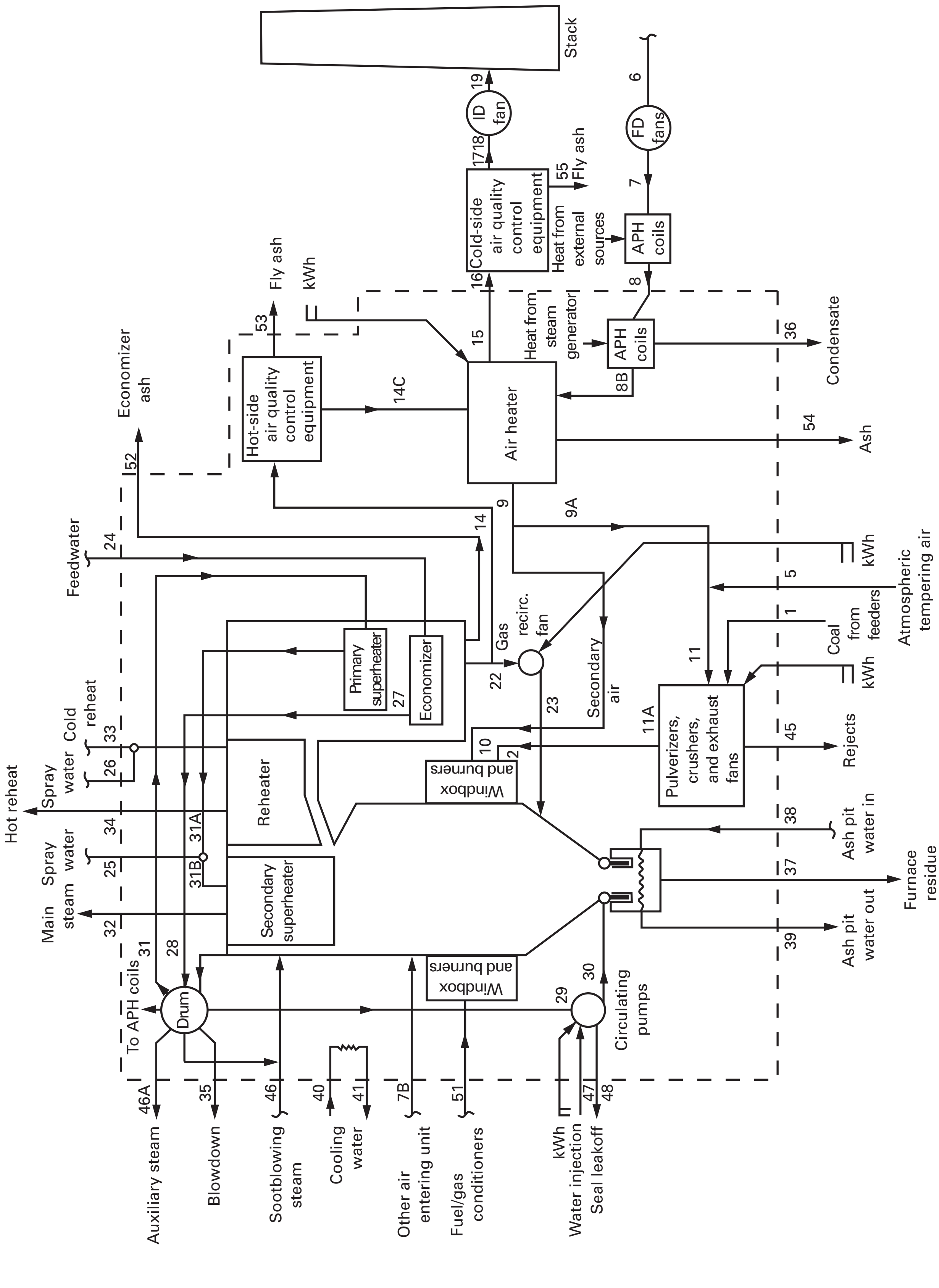


Fig. 1-4-3 Typical Pulverized-Coal-Fired Steam Generator, Alternative 2: Bisector Air Heater

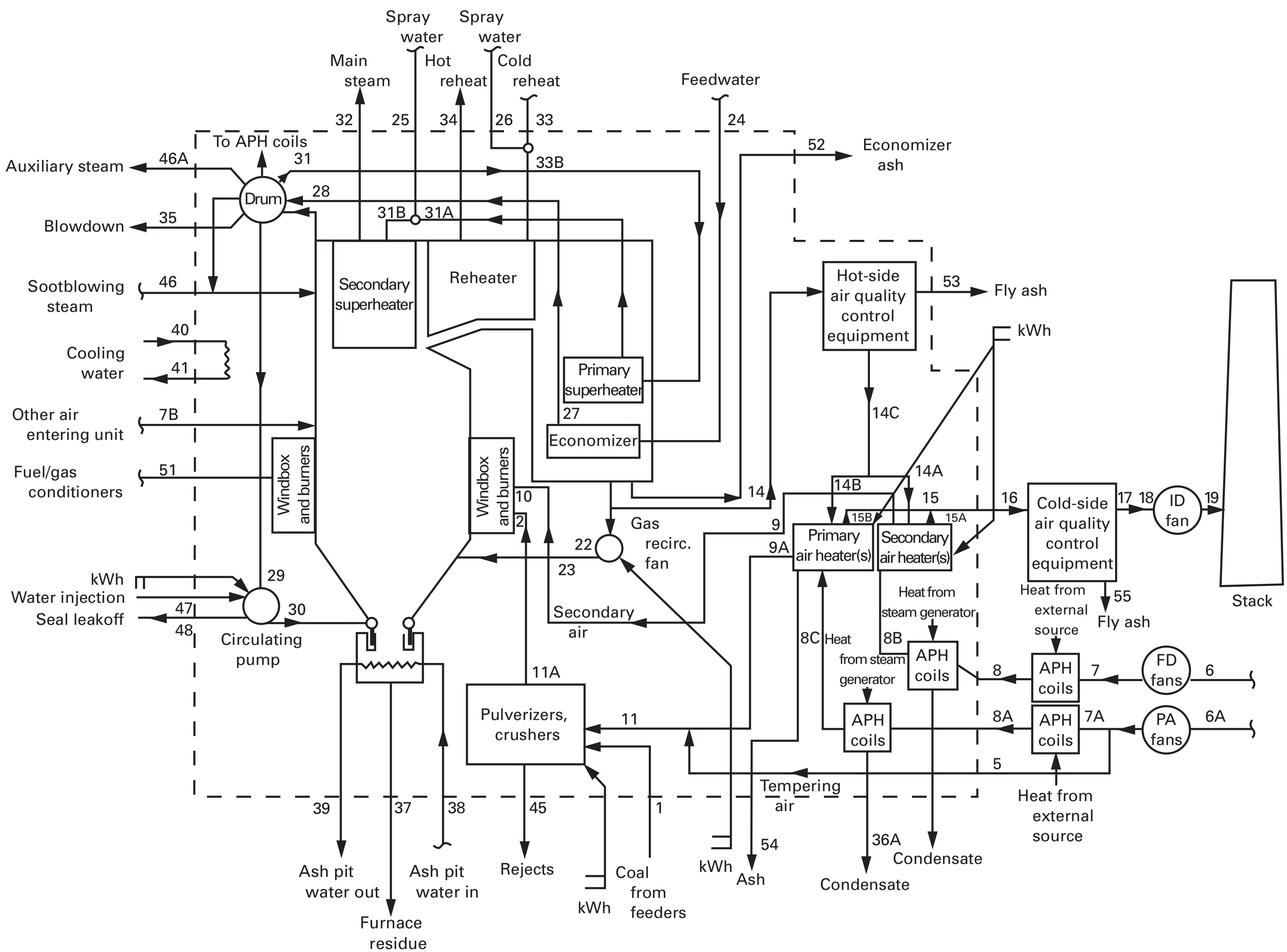


Fig. 1-4-4 Typical Pulverized-Coal-Fired Steam Generator, Alternative 3: Trisector Air Heater

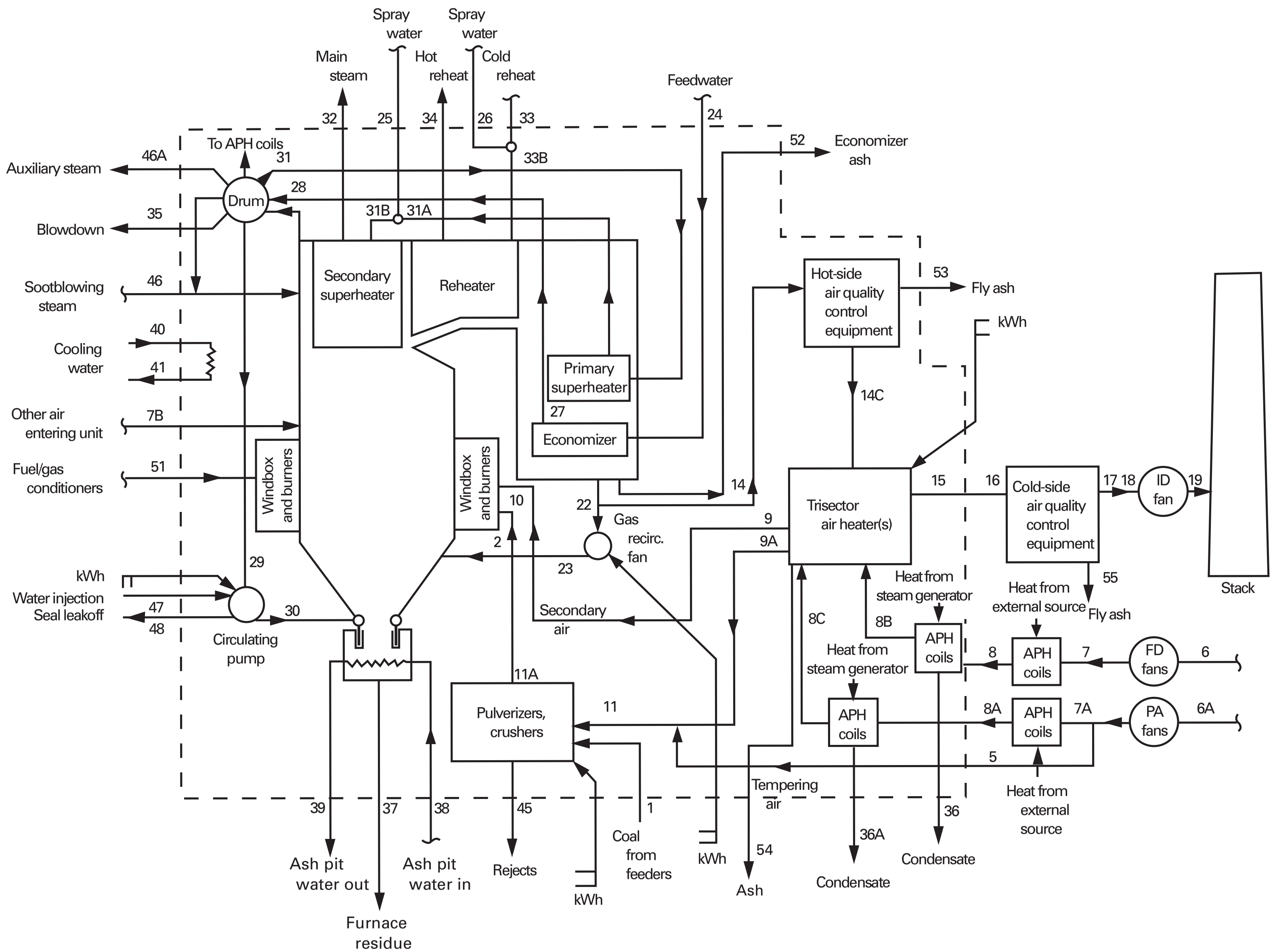


Fig. 1-4-5 Typical Circulation Bed Steam Generator

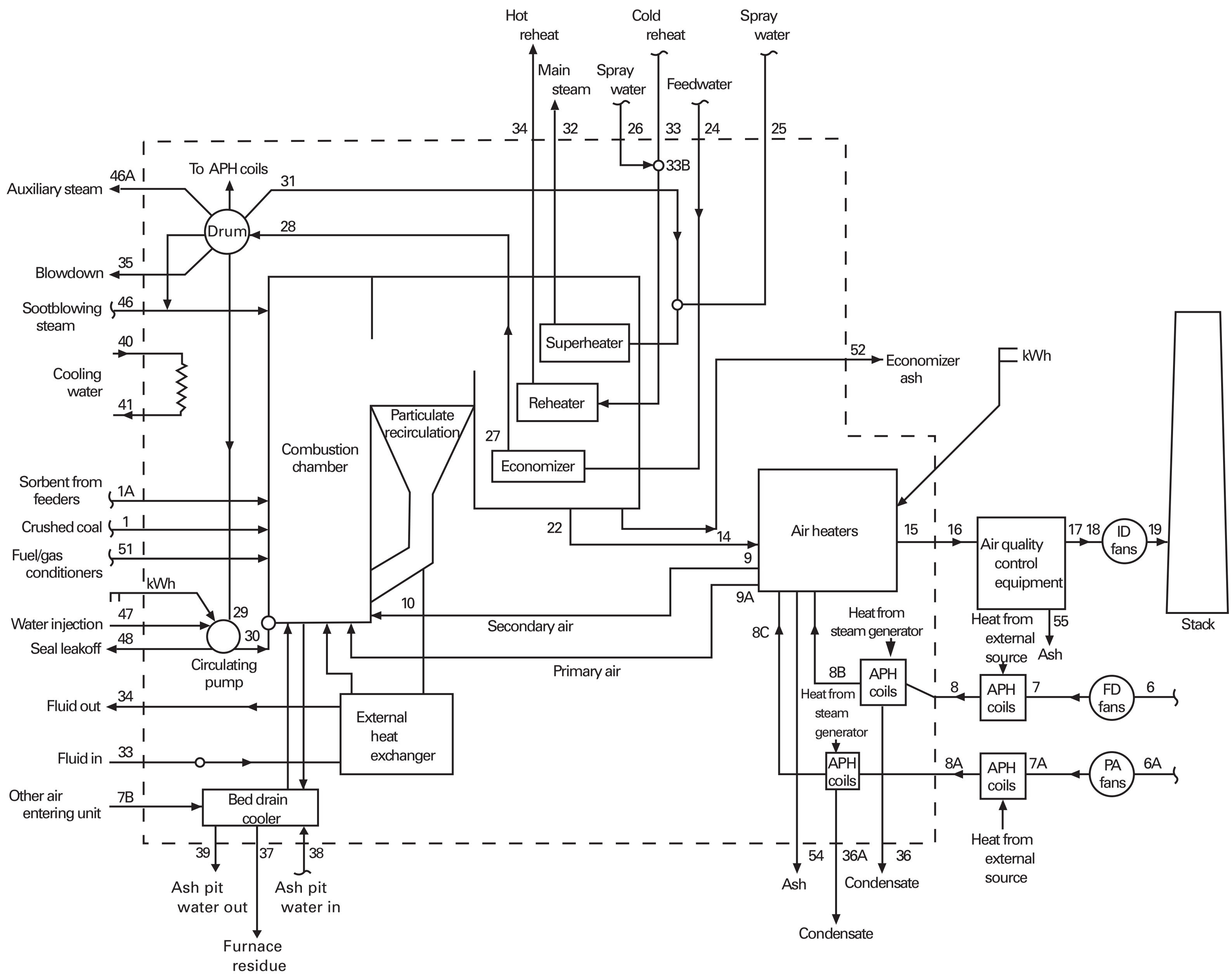


Fig. 1-4-6 Typical Stoker-Coal-Fired Steam Generator

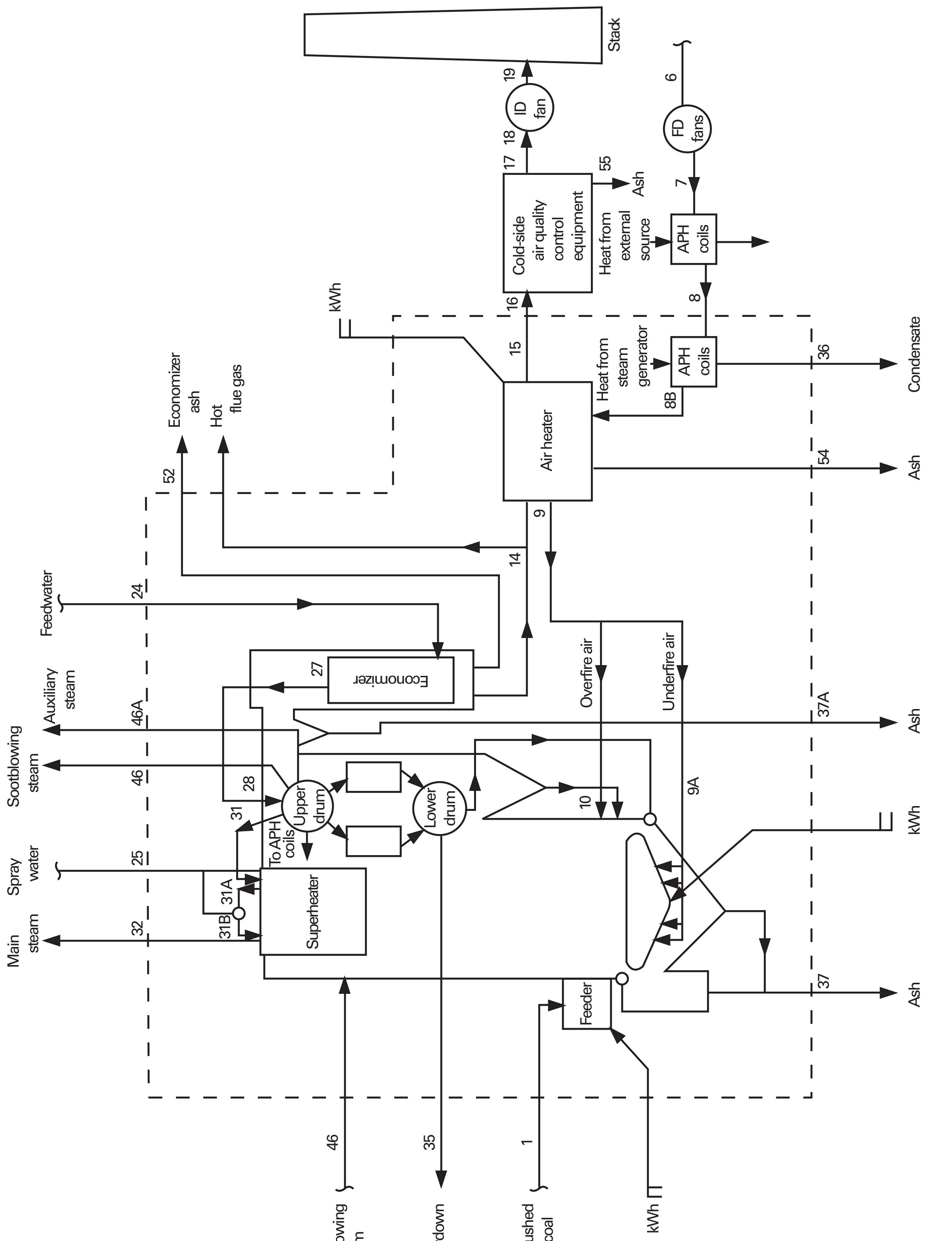
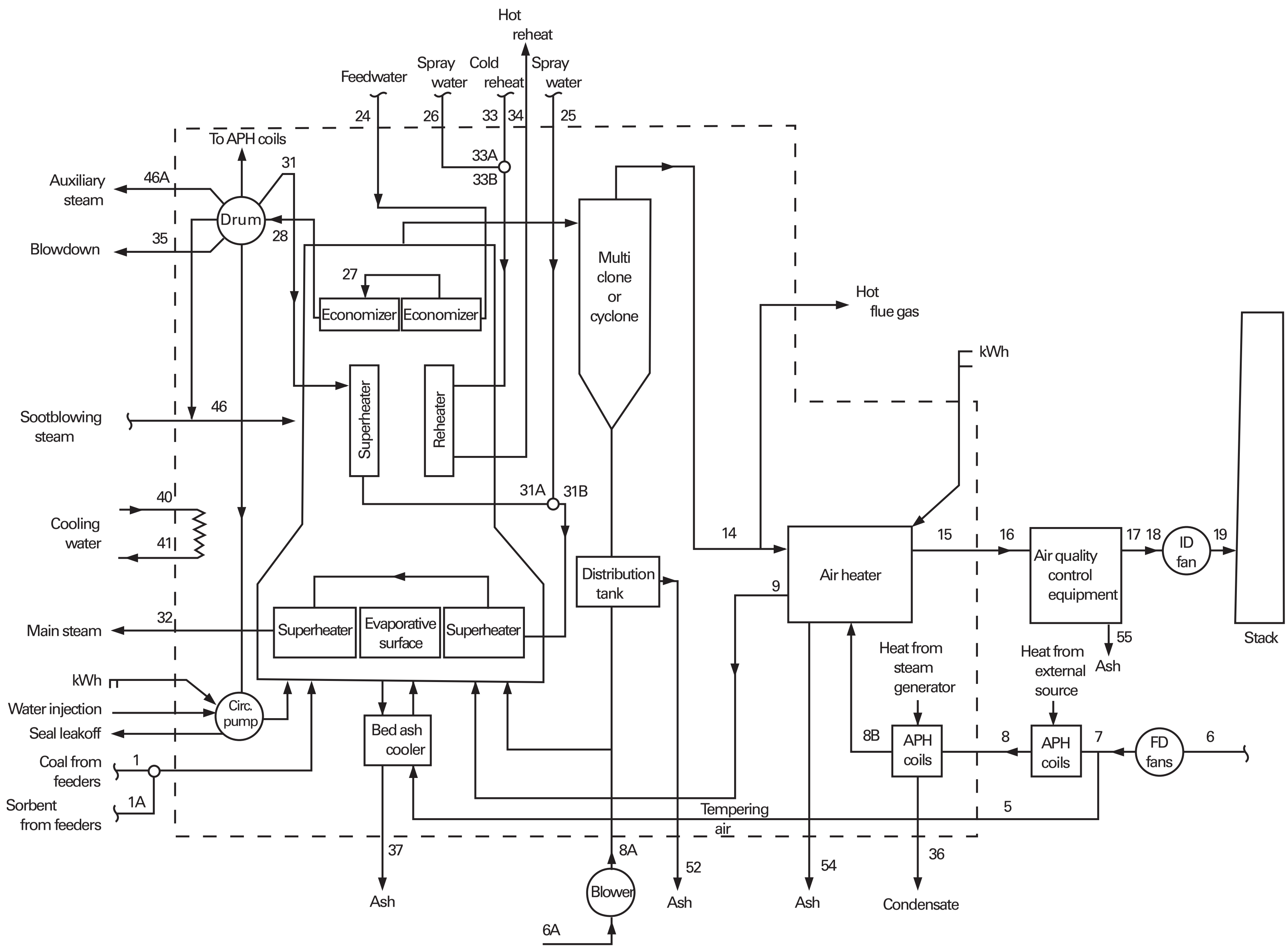


Fig. 1-4-7 Typical Bubbling Bed Steam Generator



Section 2
Definitions and Description of Terms

This Section contains abbreviations, unique terms, and variations on typically used engineering definitions required for the implementation of this Code.

2-1 DEFINITIONS

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

air, corrected theoretical: theoretical air adjusted for unburned carbon and additional oxygen required to complete the sulfation reaction.

air, excess: the air supplied to burn a fuel in addition to the corrected theoretical air. Excess air 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. Regenerative air heaters include bisector and trisector types, with fixed or rotating heating elements. Recuperative air heaters include tubular, plate, and heat pipe types.

air heater leakage: the total amount of air leakage from the air stream(s) to the flue gas stream within the air heater expressed as a percentage of the entering flue gas flow.

air, infiltration: air that leaks into the steam generator setting.

air, other: a number of other combustion air arrangements and splits (e.g., overfire air, tertiary air) are encountered in the combustion processes covered by this Code.

air preheater coils: a heat exchanger that typically uses steam, condensate, and/or glycol to heat air entering the steam generator and is often used to control corrosion in regenerative and recuperative air heaters.

air, primary: the transport and drying air for the coal from the pulverizers to the burners in pulverized-coal-fired applications. The primary air is often at a temperature different from that of the secondary air as it leaves the regenerative air heaters in large steam generators, and typically represents less than 25% of the total combustion air. Oil- and gas-fired steam generators usually do not have primary air. Primary air is the air used for fluidizing the bed material at the base of the combustion chamber in circulating fluidized beds.

air, secondary: secondary air is the balance of the combustion air not provided as primary air in pulverized and fluid bed applications. All of the combustion air leaving the air heater is usually referred to as "secondary air" in oil- and gas-fired steam generators. Secondary air may be split into overfire air or other streams as it enters the furnace; however, it remains secondary air up to and including the wind box.

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

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, in accordance with the appropriate ASTM standard, of a fuel sample providing the mass percentages of carbon, hydrogen, oxygen, nitrogen, sulfur, moisture, and ash.

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

ash: the noncombustible mineral matter constituent of fuel that remains after complete burning of a fuel sample in accordance with appropriate ASTM standards.

ash, bottom: all residue removed from the combustion chamber other than that entrained in the flue gas.

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

ash fusion temperatures: four temperatures (initial deformation, softening, hemispherical, and fluid) determined for a given fuel ash as determined by the appropriate ASTM standard. Frequently used in the singular to indicate only the softening temperature—the temperature at which the test cone has deformed to a shape whose height and width are equal.

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

ash pit: a pit or hopper located below a furnace where residue is collected and removed.

attemperator: see *desuperheater*.

calcination: the endothermic chemical reaction that takes place when carbon dioxide is released from calcium carbonate to form calcium oxide, or from magnesium carbonate to form magnesium oxide.

calcium-to-sulfur molar ratio (Ca/S): the total moles of calcium in the sorbent feed divided by the total moles of sulfur in the fuel feed.

calcium utilization: the percent of calcium in the sorbent that reacts with sulfur dioxide (SO_2) to form calcium sulfate ($CaSO_4$). It is sometimes called "sorbent utilization."

capacity: the maximum main steam mass flow rate the steam generator is capable of producing on a continuous basis with specified steam conditions and cycle configuration (including specified blowdown and auxiliary steam flow). This is frequently referred to as "maximum continuous rating."

capacity, peak: the maximum main steam mass flow rate the steam generator is capable of producing with specified steam conditions and cycle configuration (including specified blowdown and auxiliary steam flow) for intermittent operation (i.e., for a specified period of time without affecting future operation of the unit).

combustion chamber: an enclosed space provided for the combustion of fuel.

combustion efficiency: a measure of the completeness of oxidation of all fuel compounds. It is usually quantified as the ratio of actual heat released by combustion to the maximum heat of combustion available.

combustion split: the portion of energy released in the dense bed region of a fluidized bed expressed as a percentage of the total energy released.

control range: the capacity range over which main steam temperature and/or reheat steam temperature can be maintained at the rated conditions.

coverage: the percentage of observations (measurements) of a parameter that can be expected to differ from the true value of the parameter by no more than the uncertainty.

credits: energy entering the steam generator envelope other than the chemical energy in the as-fired fuel. These credits include sensible heat (a function of specific heat and temperature) in the fuel, entering air, and atomizing steam; energy from power conversion in the pulverizers, circulating pumps, primary air fans, and gas recirculation fans; and chemical reactions such as sulfation. Credits can be negative, such as when the air temperature is below the reference temperature.

dehydration: the endothermic chemical reaction that takes place when water is released from calcium hydroxide to form calcium oxide, or from magnesium hydroxide to form magnesium oxide.

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

dilute phase: the portion of the bed in a circulating fluidized bed combustion chamber above the secondary air inlet ducts (made up primarily of the circulating particulate material).

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

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

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. Section 3-1 provides detailed discussion of this method.

error, random: sometimes called "precision error," random error is a statistical quantity and is expected to be 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.

error, systematic: 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.

error, total: sum of systematic error and random error.

exit gas temperature: the average temperature of the flue gas leaving the steam generator boundary. This temperature may or may not be adjusted for air heater leakage.

fixed carbon: The carbonaceous residue less the ash remaining in the test container after the volatile matter has been driven off in making the proximate analysis of a solid fuel in accordance with the appropriate ASTM standard. (See also *volatile matter*.)

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

fluidized bed: a bed of suitably sized combustible and noncombustible particles through which a fluid (air in fluidized bed steam generators) is caused to flow upward at a sufficient velocity to suspend the particles and to impart to them a fluid-like motion.

fluidized bed, bubbling: a fluidized bed in which the fluidizing air velocity is less than the terminal velocity of most of the individual particles. Part of the gas passes through the bed as bubbles. This results in a distinct bed region because an insignificant amount of the bed is carried away by the fluidizing air.

fluidized bed, circulating: a fluidized bed in which the fluidizing air velocity exceeds the terminal velocity of most of the individual particles, so that they are carried from the combustion chamber and later reinjected.

freeboard: the volume from the upper surface of the expanded bed to the exit of the furnace. This definition applies to a fluidized bed of dense solids (bubbling bed) in which there is an identifiable bed surface. It does not apply to a circulating fluidized bed.

furnace: an enclosed space provided for the combustion of fuel.

heating value, higher: the total energy liberated per unit mass of fuel upon complete combustion as determined by appropriate ASTM standards. The higher heating value includes the latent heat of the water vapor. When the heating value is measured at constant volume, it must be converted to a constant pressure value for use in this Code.

heating value, lower: the total heat liberated per unit mass of fuel minus the latent heat of the water vapor in the products of combustion as determined by appropriate ASTM standards (not used in this Code).

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

Input–Output method: a method of determining steam generator efficiency by direct measurement of output and input. Referred to as I/O method.

loss on ignition: commonly referred to as LOI. The loss in mass of a dried dust sample, expressed in percent, occurring between two temperature levels. Typically used to approximate unburned carbon in residue.

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

maximum continuous rating: see *capacity*.

moisture: moisture in fuel is determined by appropriate ASTM standards. Water, in the liquid or vapor phase, present in another substance.

outliers: a data point judged to be spurious.

output: energy absorbed by the working fluid that is not recovered within the steam generator envelope.

purge: to introduce air into the furnace or the boiler flue passages in such volume and manner as to completely replace the air or gas-air mixture contained within.

recycle rate: the mass flow rate of material being reinjected into a furnace or combustion chamber.

recycle ratio: the recycle rate divided by the fuel mass flow rate.

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.

reinjection: the return or recycle of material back to the furnace.

residue: the solid material remaining after combustion. Residue consists of fuel ash, spent 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 virtually constant.

setting infiltration: see *air, infiltration*.

sorbent: chemical compound(s) that reacts with and captures a pollutant or, more generally, a constituent that reacts with and captures another constituent.

spent bed material: the bed drain residue removed from a fluidized bed.

spent sorbent: solids remaining after evaporation of the moisture in the sorbent, calcination/dehydration, and weight gain due to sulfation.

standard deviation: several types of standard deviation are defined in statistical analysis (e.g., population standard deviation, sample standard deviation, standard deviation of the mean). In this Code, the term "standard deviation" refers to standard deviation of the mean unless otherwise specified.

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

sulfur capture: see *sulfur retention*.

sulfur retention: the fraction of the sulfur that enters with the fuel that does not leave the steam generator as SO_2.

supplemental fuel: fuel burned to supply additional energy to the steam generator or to support combustion.

test: a single run or the combination of a series of runs for the purpose of determining performance characteristics. A test normally consists of two runs.

tolerance: the acceptable difference between the test result and its nominal or guaranteed value. Tolerances are contractual adjustments to test results or to guarantees and are not part of the Performance Test Codes.

unburned combustible: the combustible portion of the fuel that is not completely oxidized.

uncertainty: the estimated error limit of a measurement or result for a given coverage. Uncertainty defines a band within which the true value is expected to lie with a certain probability. Test uncertainty includes both random uncertainty and systematic uncertainty.

uncertainty, random: numerical estimate of the random errors. It is usually quantified by the standard deviation of the mean for a set of test data.

uncertainty, systematic: numerical estimate of the systematic error.

uncertainty, test: test uncertainty combines random and systematic uncertainties.

volatile matter: the portion of mass, except water vapor, which is driven off in a gaseous form when solid fuel is heated in accordance with the applicable ASTM standard. (See also *fixed carbon*.)

2-2 ABBREVIATIONS

The following abbreviations are used throughout the text of this Code.

A/D: analog to digital
AFBC: atmospheric fluidized bed combustion
AH: air heater
APC: air preheat coils
APH: air preheater
API: American Petroleum Institute
AQC: air quality control
Ar: argon
C: carbon
$Ca(OH)_2$: calcium hydroxide
CaO: calcium oxide
Ca/S: calcium-to-sulfur ratio
$CaSO_4$: calcium sulfate
CB: gasified carbon
CO: carbon monoxide
CO_2: carbon dioxide
CO_3: carbonate
CT: current transformer
DCS: distributed control system
EPA: Environmental Protection Agency
ESP: electrostatic precipitator
FC: fixed carbon
FD: forced draft
FEGT: furnace exit gas temperature
FG: flue gas
FID: flame ionization detector
FW: feedwater
H_2: hydrogen
H_2S: hydrogen sulfide
HHV: higher heating value
HHVF: higher heating value of fuel
HHVGF: higher heating value of gaseous fuels
HVT: high velocity thermocouple
ID: induced draft
I/O: input/output
K_2O: potassium oxide
kWh: kilowatt-hour
LOI: loss on ignition
MAF: moisture and ash free
MB: megabyte
$MgCO_3$: magnesium carbonate
$Mg(OH)_2$: magnesium hydroxide
MgO: magnesium oxide
N_2: nitrogen
N_2O: nitrous oxide
Na_2O: sodium oxide
NH_3: ammonia
NIST: National Institute of Standards and Technology
NO: nitric oxide
NO_2: nitrogen dioxide
NO_x: nitrogen oxides
O_2: oxygen
O_3: ozone
PA: primary air
PT: potential transformer
PTC: Performance Test Code
RAM: random access memory
RH: reheater or relative humidity
RTD: resistance temperature device
S: sulfur
SDI: Spatial Distribution Index
SH: superheater, superheated
SI: International System of Units
SiO_2: silicon dioxide, silica
SO_2: sulfur dioxide
SO_3: sulfur trioxide
SO_x: sulfur oxides
TC: thermocouple
TGA: thermogravimetric analysis
THC: total hydrocarbons
VM: volatile matter

2-3 UNITS AND CONVERSIONS

The following units and conversions are used throughout this Code. To obtain SI units, multiply U.S. Customary units by the conversion factor given in Table 2-3-1.

Table 2-3-1 Units and Conversions

Item	Units: U.S. Customary	Units: SI	Conversion [See Notes (1) and (2)]
Area	ft^2	m^2	9.2903 E−02
Convection and/or radiation heat transfer coefficient	Btu/ft^2·hr·°F	W/m^2·K	5.6779 E+00
Density	lbm/ft^3	kg/m^3	1.6018 E+01
Electrical energy	kWh	J	3.6000 E+06
Energy per unit area	Btu/ft^2	J/m^2	1.1341 E+04
Energy per unit mass	Btu/lbm	J/kg	2.3237 E+03
Energy, flux	Btu/ft^2·hr	W/m^2	3.1503 E+00
Energy, rate	Btu/hr	W	2.9307 E−01
Mass per unit energy	lbm/Btu	kg/J	4.3036 E−04
Mass flow rate	lbm/hr	kg/s	1.2599 E−04
Mean specific heat	Btu/lbm·°F	J/kg·K	4.1868 E+03
Moles per unit mass	moles/lbm	moles/kg	2.2046 E+00
Pressure	in. wg	Pa, gauge	2.491 E+02
Pressure, absolute	psia	Pa	6.8948 E+03
Pressure, gauge	psig	Pa, gauge	6.8948 E+03
Specific gas constant	ft·lbf/lbm·°R	J/kg·K	5.3812 E+00
Temperature	°F	°C	(°F − 32) / 1.8
Temperature, absolute	°R	K	(°F + 459.67) / 1.8
Universal molar gas constant	ft·lbf/mole·°R	J/mole·K	5.3812 E+00

NOTES:
(1) Care should be taken when converting formulas or equations that contain constant terms or factors. The value of these terms must be understood and may also require conversion.
(2) Conversion factors between SI and U.S. Customary units are given in SI-1, ASME Orientation and Guide for Use of SI (Metric) Units (ANSI Z210.1) [1]. Also, refer to Table 2 of SI-9, ASME Guide for Metrication of Codes and Standards SI (Metric) Units [2], for the number of significant digits to be retained when rounding SI.

Section 3
Guiding Principles

3-1 INTRODUCTION

In preparing to conduct a steam generator performance test, the parties to the test must make a number of decisions and establish certain agreements. This Section of the Code describes these decisions and agreements and provides guidance for performing a test in accordance with this Code.

All parties to the test are entitled and encouraged to witness the test to ensure that it is conducted in accordance with this Code and any written agreements made prior to the test.

3-1.1 Steam Generator Performance

The performance of a steam generator at a particular operating condition is usually quantified by three characteristics, defined as follows:

capacity: the maximum mass flow rate of steam produced at specified conditions.

efficiency: the ratio of output energy to input energy.

output: all energy absorbed by the working fluid except that recovered within the steam generator envelope.

Any method for determining steam generator performance must address the following two equally difficult questions:

(a) What are the proper definitions of the parameters to be measured and the performance characteristics to be determined (usually by calculation); e.g., exactly what should be included in the input and output?

(b) What are the most practicable and accurate methods for measuring parameters and calculating performance characteristics and how accurate must they be to achieve the required test quality [1]?

Capacity is easily defined; the main problems associated with its determination arise from measurement. Output, input, and thus efficiency are subject to several possible definitions. This Code uses specific definitions for these quantities. Fig. 3-1.1-1 illustrates the definitions used for input and output. This figure shows that output includes the energy in all working fluid streams that exit the steam generator envelope, thus accounting for all energy absorbed by the working fluid.

3-1.2 Types of Efficiency

Steam generator efficiency is defined by

$$efficiency = \frac{output}{input} \times 100 \quad (3\text{-}1\text{-}1)$$

This single definition yields many different values for efficiency depending upon the choice of items to be included as output, items to be included as input, and higher or lower heating value of the fuel. Entwistle et al. discuss this problem at length and demonstrate that at least 14 different values of efficiency can be computed from the same data [2, 3].

This Code recognizes the following two definitions of steam generator efficiency:

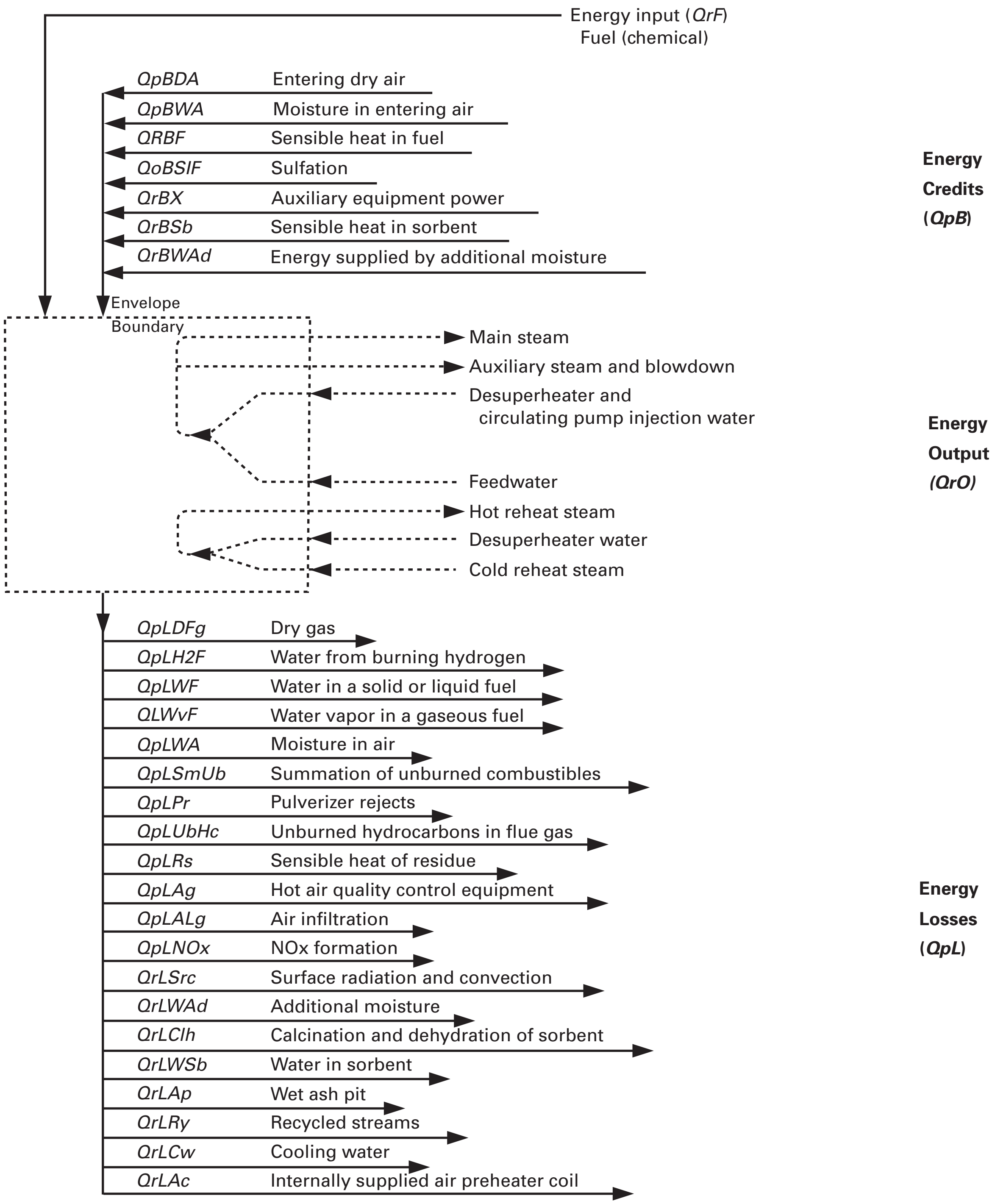
fuel efficiency: includes all energy absorbed by the working fluid as output but counts only chemical energy of the fuel as input. Fuel efficiency on a higher heating value basis is the preferred definition of efficiency for purposes of this Code and is the method supported by the calculations in Section 5.

gross efficiency: also includes all energy absorbed by the working fluid as output and counts all energy inputs entering the steam generator envelope as input. Thus, gross efficiency is usually less than or equal to fuel efficiency. Procedures for calculating gross efficiency are contained in Nonmandatory Appendix D.

Those energies that are considered outputs and inputs (including credits in the case of gross efficiency) are shown in Fig. 3-1.1-1.

This Code uses the higher heating value of the fuel to determine fuel energy input. Some other standards use the lower heating value (LHV), or net calorific value, of the fuel to compute boiler efficiency on an LHV basis. In this case, the products of combustion, including liquid water in the fuel, are assumed to remain in the gaseous state and the energy in the water latent heat of vaporization is not considered part of the chemical energy available in the fuel. For the same fuel mass flow rate (fuel input) and steam generator output, the computed efficiency based on LHV is always higher than the computed efficiency based on HHV. Conversely, the fuel input computed on an LHV basis is always lower than the fuel input computed on an HHV basis. Therefore, efficiency based on LHV may be misleading and could

Fig. 3-1.1-1 Steam Generator Energy Balance



Energy Balance:

OUTPUT* = *INPUT* − *LOSSES* + *CREDITS

$QrO = QrF - QrL + QrB$

$QpL = 100 \times (QrL \,/\, QrF)$, %

$QpB = 100 \times (QrB \,/\, QrF)$, %

Fuel efficiency (%) = *EF* (%) = 100 × *Output* − *Input* = 100 − *QpL* + *QpB*

confuse those making economic and environmental impact evaluations. Accordingly, the basis of the heating value must be consistent when making steam generator economic (fuel input) and environmental evaluations.

While the higher heating value of the fuel can be accurately determined by established testing procedures, LHV must be calculated from measured HHV. Thus the systematic uncertainty of the LHV is greater than the systematic uncertainty of the HHV.

Refer to Nonmandatory Appendix D for this Code's recommended methodology for calculating fuel LHV and its uncertainty, and for expressing the applicable heat losses and credits on an LHV basis. The equations shown consider solid and liquid fuels that contain water in liquid form.

3-1.3 Methods of Measurement and Computation to Determine Efficiency

Two generally accepted methods for determining the efficiency of a steam generator are the Input–Output method and the energy balance method.

The Input–Output method uses the following equation:

$$efficiency = \frac{output}{input} \times 100 \qquad (3\text{-}1\text{-}2)$$

Efficiency determination by the Input–Output method requires direct and accurate measurement of all output as well as all input. The primary measurements required are the following:

(a) feedwater flow rate entering the steam generator

(b) desuperheating water flow rates

(c) flow rates of all secondary output streams such as boiler blowdown, auxiliary steam, etc.

(d) pressure and temperature of all working fluid streams such as entering feedwater, superheater outlet, reheater inlet and outlets, auxiliary steam, etc.

(e) additional measurements in the turbine cycle as required to determine reheater flows by energy balance methods

(f) fuel flow rate

(g) higher heating value of the fuel

(h) waste energy input

The energy balance method combines the energy balance equation

$$input + credits = output + losses \qquad (3\text{-}1\text{-}3)$$

with the efficiency definition to arrive at

$$efficiency = \left[\frac{input - losses + credits}{input}\right] \times 100$$

$$= \left[1 - \frac{(losses - credits)}{input}\right] \times 100 \qquad (3\text{-}1\text{-}4)$$

Efficiency determination by the energy balance method requires the identification and measurement (or estimation) of all losses and credits. Fig. 3-1.1-1 illustrates all of the losses and credits identified by the ASME PTC 4 Committee at the time this Code was written. If additional types of losses or credits are identified for a specific unit (according to the requirements of para. 1-2.2), then the parties to the test must agree on a method for accounting for them.

Many other measurements are required to determine values for all of the losses; however, several of them usually have a minor effect on the results. In many cases, parties to the test may agree to estimate values for certain losses, rather than measuring them; however, the uncertainties of estimated values are usually greater than if the values were measured. Losses are sometimes determined on a "percent input" basis rather than an absolute basis.

Advantages and disadvantages of the Input–Output and energy balance methods are listed in Table 3-1.3-1. In many cases, the energy balance method yields lower overall test uncertainty because the quantities used to determine efficiency by the energy balance method (i.e., losses) are a much smaller portion of the total energy than is output, which is used to determine efficiency in the Input–Output method. Thus, a given uncertainty in measured or estimated values has less effect on the result in the energy balance method. The energy balance method also provides a means of examining the losses to determine potential improvements to the unit or its operation. The energy balance method allows for corrections of test results to standard or guarantee conditions. Accordingly, this Code recommends the energy balance method to determine efficiency when corrections to such conditions are required. In other cases, the choice between the methods should be based upon the available instrumentation and expected test uncertainty.

3-1.4 Unit Design and Construction Considerations to Facilitate Testing

Early planning and frequent follow-up during design and construction of a steam generating unit will help to minimize testing problems and ensure that tests can be performed in accordance with this Code after construction is complete. Ideally, provisions for conducting both acceptance tests and routine performance tests should be included in the design of a unit. Even if it is decided not to run an acceptance test, the provisions will be valuable for gathering information on the unit's operation and performance.

This Code should be used as a guide during preliminary engineering to determine the required test points and sampling provisions. This determination will normally require interaction between the intended parties to the test. The required test points and sampling provisions should be included in the specifications. Periodic reviews during design and construction should ensure that field installation does not jeopardize the test provisions.

Table 3-1.3-1 Comparison of Efficiency Determination

Advantages	Disadvantages
Input–Output Method	
Primary parameters from the efficiency definition (output, input) are directly measured.	Fuel flow and fuel heating value, steam flow rates, and steam properties need to be measured very accurately to minimize uncertainty.
Requires fewer measurements.	Does not aid in locating source of possible inefficiency.
Does not require estimation of unmeasurable losses.	Requires the use of energy balance calculation methodology for correction of test results to standard or guarantee conditions. Corrections to standard or guarantee conditions can only be made using the energy balance methodology.
Energy Balance Method	
The primary measurements (flue gas analyses and flue gas temperature) can be made very accurately.	Requires more measurements.
Permits corrections of test results to standard or guarantee conditions.	Does not automatically yield capacity and output data.
The as-tested efficiency often has lower uncertainty because the measured quantities (losses) represent only a small fraction of the total energy.	Some losses are practically unmeasurable and value must be estimated.
The effects of fairly substantial errors in secondary measurements and estimated values are minimal.	
Sources of large losses are identified.	

One of the problems most commonly encountered in the performance of measurements during testing is interference with other structures. Thermowells, pressure taps, and duct ports for air and gas measurements should be oriented so that test instruments can be installed as required. Bracing and support beam interference with duct sampling must be considered. On large ducts, overhead clearance for insertion of long sampling probes must also be considered.

Provisions should be made for obtaining the necessary samples of fly ash, bottom ash, pulverizer rejects, sorbent, and fuel. The equipment and procedures to be used in obtaining the samples should be considered in the design of sampling provisions.

Provisions should be made for measurement of auxiliary power used in determining energy credits.

Consideration should be given to the needs of personnel and instrumentation involved in conducting the test. Examples include safe access to test point locations, availability of suitable utilities, and safe work areas for personnel. Potential damage to instrumentation resulting from extreme ambient conditions such as high temperature and vibration should be considered.

3-2 PERFORMANCE TEST PROCEDURES

3-2.1 Determination of Level of Test

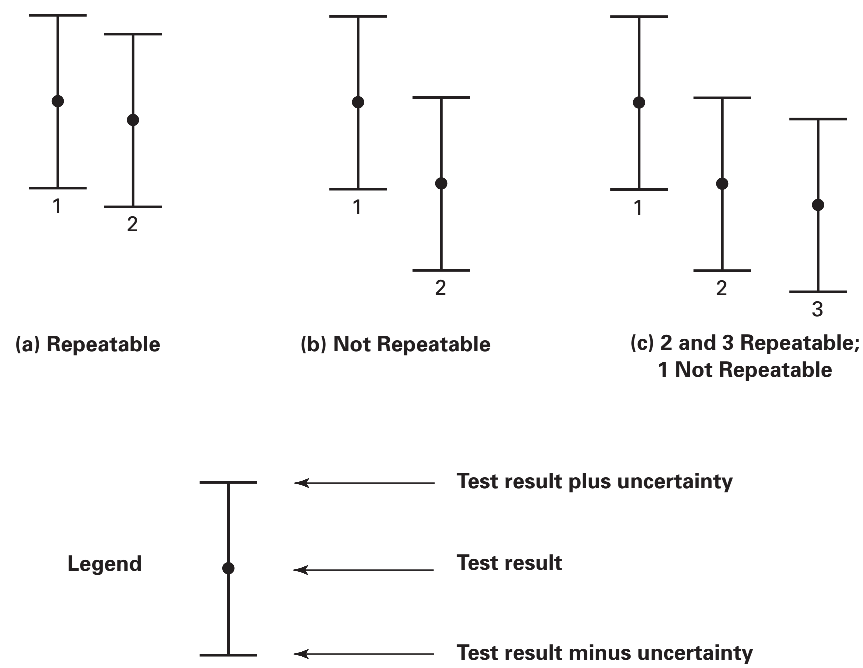
Accurate determination of the performance of a steam generator requires a significant expenditure of time and money. Many measurements are required to account for all losses, especially in the determination of efficiency by the energy balance method. At the same time, each individual loss or an error in its determination may have only a small effect on the results or their uncertainty.

It has long been recognized that no single set of procedures can yield the most cost-effective test for all cases. Previous editions of this Code provided for two different levels of test for tests that used the energy balance method. One level was a complete test in which all losses were determined from measurements. The other was an abbreviated test in which only major losses were determined from measurements while several minor losses were ignored or aggregated into an unmeasured loss term with an estimated numerical value.

This Code permits the parties to elect various levels of testing. While all necessary procedures are specified for the most accurate determination of steam generator performance, the parties to the test are permitted to design a lower level test if appropriate. Typically, a lower level test uses less accurate instruments or fewer instruments or will use assumed or estimated values for certain parameters rather than measuring them. This Code requires calculation of the uncertainties of the results to define the quality level of the test.

(a) By agreement prior to the test, the parties to the test shall define acceptable values for the uncertainties of the

Fig. 3-2.2.1-1 Repeatability of Runs



results (for example, they may decide that efficiency will be determined with an uncertainty of ±0.5 percentage points and that maximum capacity will be determined with an uncertainty of ±1.0% of the value). These values are called the target uncertainties of the results.

(b) A performance test must be designed to meet the target uncertainties. The choices of which parameters to measure, which parameters may be estimated, what estimated values to use, and the use of fewer or alternative instruments will strongly influence the ability to meet target uncertainties. Parties to the test should reach agreement on these choices prior to the test. A pretest uncertainty analysis, described in subsection 7-3, is strongly recommended to aid in this process.

(c) The parties to the test shall reach prior agreement on the uncertainties of values that will not be measured and on the systematic uncertainty of instruments and measurement methods. This agreement shall be documented in the written agreement required by para. 3-2.3.

(d) After each run has been conducted, the uncertainties of the results must be calculated in accordance with Section 7 and ASME PTC 19.1, as appropriate. If the uncertainties thus calculated are greater than the previously agreed upon target uncertainty values, the run is invalid.

It is strongly emphasized that the test uncertainties thus calculated are not tolerances on steam generator performance. The uncertainties are to be used to judge only the quality of the performance test and not the acceptability of the steam generator.

3-2.2 Number of Runs

A run is a complete set of observations made over a period of time with one or more of the independent variables maintained virtually constant. A test is a single run or the combination of a series of runs for the purpose of determining performance characteristics. A test normally consists of two or more runs.

Conducting more than one run will verify the repeatability of the test results. Results may not be repeatable due to variations in either the test methodology (test variations) or the actual performance of the equipment being tested (process variations). It is recommended that, at the end of each run that meets the criteria for an acceptable run, the data be consolidated and preliminary results calculated and examined to ensure the results are reasonable. If the parties to the test agree, the test may be concluded at the end of any run.

3-2.2.1 Repeatability. The criterion for repeatability between runs is that the normalized results of two or more runs all lie within the uncertainty intervals of each other. Refer to Fig. 3-2.2.1-1 for examples of runs that meet or do not meet this criterion. The results should be normalized to a base set of conditions. For example, efficiency for different runs should be calculated using a single representative fuel analysis and should be normalized for inlet air temperature, etc. Refer to subsection 5-18. The uncertainty interval calculated for each run is applied to the normalized result for that run for the purpose of evaluating repeatability between runs.

3-2.2.2 Invalidation of Runs. If serious inconsistencies affecting the results are detected during a run or during the calculation of the results, the run must be invalidated completely, or it may be invalidated only in part if the affected part is at the beginning or at the end of the run.

A run that has been invalidated must be repeated, if necessary, to attain the test objectives. The decision to reject a run is the responsibility of the designated representatives of the parties to the test.

3-2.2.3 Multiple Runs. The results of multiple runs that meet the criteria for repeatability and other Code requirements are averaged to determine the average test result. The uncertainties shall be reported for each individual run but shall not be reported for the average test result.

3-2.3 Prior Agreements

Prior to the test, the parties to the test shall prepare a definite written agreement. This agreement shall state the specific test objectives including the acceptable range of uncertainty for each result, as well as the method of operation during the test. For acceptance tests, the agreement shall identify any contract requirements pertinent to the test objectives (e.g., guarantee provisions), and it must include estimated values or other clarifications necessary to resolve any omissions or ambiguities in the contract.

This written agreement shall specifically include the following items and should also address other items considered pertinent by the parties to the test. For routine performance tests, some items may not be applicable and may be omitted.

(a) test objectives (e.g., efficiency, steam temperature).

(b) designation of a chief-of-test who will direct the test and exercise authority over all test personnel. It is preferred that this person be a registered professional engineer and have previous testing and power plant experience, good organizational skills, and a thorough understanding of instrumentation and uncertainty analysis.

(c) designation of representatives from each party to the test.

(d) organization, qualifications, and training of test personnel; arrangements for their direction; arrangements for calculating the test results.

(e) interpretation of any relevant contract requirements.

(f) target test uncertainties (Table 1-3-1 provides typical values for efficiency tests for various types of steam generators).

(g) whether to conduct a pretest uncertainty analysis and how to apply results of the analysis to improve the test (refer to para. 3-2.5.1).

(h) number of runs.

(i) pretest checkout procedures.

(j) establishment of acceptable operating conditions, allowable variance in operating conditions during the run (based on Table 3-2.3-1), number of load points, duration of runs, basis for rejection of runs, and procedures to be followed during the test.

(k) means for maintaining constant test conditions.

(l) maximum permissible deviation of average values of controlled parameters from target values during the test.

(m) unit cleanliness prior to the test and how cleanliness is to be maintained during the test (including any sootblowing to be conducted during the test).

(n) readings and observations to be taken; number and frequency.

(o) number, location, type, and calibration of instruments.

(p) systematic uncertainties of instruments and measurement methods, models for estimating systematic uncertainty, and any standard deviation that are to be set by agreement (refer to Section 7).

(q) parameters to be estimated rather than measured, estimated values to be used, and uncertainties of estimated values.

(r) efficiency determination:

(1) energy balance or Input–Output method

(2) parameters to be measured

(3) estimated values to be used for unmeasured parameters

(4) exiting streams to be included in output

(5) steam or water flow measurement

(6) duration

(s) capacity determination:

(1) exiting streams to be included in capacity

(2) steam or water flow measurement

(3) duration

(t) peak capacity determination:

(1) time limit for operation at peak capacity

(2) specific steam pressures (and temperatures for superheated steam generators) that define peak capacity operation

(3) feedwater pressure and temperature

(4) blowdown rate

(u) version of the ASME Steam Tables to be used; 1967 or 1997, which is based on IAPWS-IF97.

(v) fuel to be fired, method and frequency of obtaining fuel samples, laboratory that will make the fuel analyses, and fuel test method to be used.

(w) equivalence of fuel to standard or contract conditions or procedures for correcting to those conditions.

(x) procedures to be used for sampling and analysis of sorbent and the target sorbent-to-sulfur ratio (Ca/S molar ratio).

(y) distribution of residue quantities between various collection points and methods of residue sampling and analysis.

(z) procedures to be used for flue gas sampling and analysis.

Table 3-2.3-1 Operating Parameter Deviations

Controlled Parameter	Short-Term Fluctuation (Peak to Valley)	Deviation From Long-Term (Run) Average
Steam pressure		
> 500 psig set point	4% (25 psi max)	3% (20 psi max)
< 500 psig set point	20 psi	15 psi
Feedwater flow (drum unit)	10%	3%
Steam flow (once-through unit)	4%	3%
O_2 leaving boiler/economizer (by volume)		
Oil and gas units	0.4% (points of O_2)	0.2 (points of O_2)
Coal units	1.0 (points of O_2)	0.5 (points of O_2)
Steam temperature (if controlled)	20°F	10°F
Superheat/reheat spray flow	40% spray flow or 2% main steam flow	N/A
Fuel flow (if measured)	10%	N/A
Feedwater temperature	20°F	10°F
Fuel bed depth (stoker)	2 in.	1 in.
Sorbent/coal ratio (feeder speed ratio) [Note (1)]	4%	2%
Ash reinjection flow	20%	10%
Bed temperature (spatial average/per compartment) [Note (1)]	50°F	25°F
Bed/unit operating solids inventory [Note (1)]		
Bed pressure	4 in. wg	3 in. wg
Dilute phase pressure drop	4 in. wg	3 in. wg
Dependent parameters		
Steam flow	4%	3%
SO_2 (units with sulfur removal)	150 ppm	75 ppm
CO (if measured)	150 ppm	50 ppm
Freeboard temperature (if measured)	50°F	25°F

GENERAL NOTE: N/A = Not Applicable.
NOTE:
(1) Applicable to fluid bed units only.

(aa) whether to determine the need for and methods of flow weighting for flue gas temperature and oxygen content.

(bb) method for determining outliers.

(cc) corrections to be used for comparison to contract conditions, including any correction curves.

(dd) media, methods, and format to be used for recording data and providing copies for parties to the test (refer to para. 3-2.8).

3-2.4 Acceptance Test

An acceptance test should be conducted as soon as practical after initial operation of the unit or in accordance with the contract requirements.

Designated representatives of the parties to the test are encouraged to be present to verify that the test is conducted in accordance with this Code and the agreements made prior to the test.

3-2.5 Preparation for the Test

3-2.5.1 Pretest Uncertainty Analysis. A pretest uncertainty analysis should be performed to confirm that the test, as it has been designed and planned, is capable of achieving the target test uncertainties. This uncertainty analysis will help avoid the possibility of conducting a test that does not achieve the target test uncertainties and thus cannot be considered a Code test. In addition to indicating whether the target test uncertainties can be achieved, the pretest uncertainty analysis provides information that can be used to design a more cost-effective test that can still achieve the test uncertainty targets, or it enables setting achievable uncertainty targets.

A sensitivity analysis should be performed as part of the pretest uncertainty analysis to determine the relative sensitivity coefficients (i.e., the relationships of overall test uncertainties to the uncertainty of each parameter for which a value will be either measured or estimated; refer to Sections 5 and 7). Parameters with a relative sensitivity coefficient greater than 5% of the value of the maximum sensitivity coefficient are considered critical parameters. All critical parameters should be measured using accurate instruments. These instruments should be selected and calibrated in accordance with the criteria in Section 4. However, proper installation of the instruments and proper implementation of the chosen sampling schemes are at least as important as proper calibration in assuring that target test uncertainties are attainable. The sensitivity analysis may also provide opportunities for economies in conducting the test by identifying parameters that are less critical to attainment of target test uncertainties. These parameters might then be candidates for measurement by lower quality instruments and/or the existing plant instrumentation, or they might be considered for estimation of values rather than measurement.

Section 7 provides guidance for conducting uncertainty analysis including determination of sensitivity coefficients.

3-2.5.2 Pretest Checkout. Prior to initiating the test, the following actions must be taken to ensure the steam generator is ready for the test and to help avoid problems that might invalidate the test:

(a) Parties shall agree that the fuel, sorbent, and additives to be used during the test are satisfactory for the test (refer to Nonmandatory Appendix E).

(b) Any departures from standard or previously specified conditions in the physical state of equipment, cleanliness of heating surfaces, fuel characteristics, or stability of load must be noted and corrected if possible.

(c) A complete record shall be made, fully identifying the equipment to be tested and the selected testing method.

(d) All instruments must be checked for proper installation and for operability.

(e) Parties to the test shall agree that the steam generator is ready for testing (i.e., that its configuration and conditions conform to those specified in the pretest agreement).

In addition to these mandatory actions, the entire steam generator should be visually inspected for abnormal air infiltration. Air heater internal leakage should also be checked (refer to ASME PTC 4.3). Mechanical discrepancies that may contribute to excessive leakage should be corrected prior to the test.

3-2.5.3 Preliminary Run. A preliminary run should be made for the following purposes:

(a) determining whether the steam generator and the overall plant are in a suitable condition for conducting the test

(b) making minor adjustments that were not foreseen during preparation for the test, establishing proper combustion conditions for the particular fuel and firing rate to be employed, and confirming that specified operating conditions and stability (in accordance with para. 3-2.6.1) are attainable

(c) checking instruments

(d) verifying attainability of the target test uncertainty

(e) acquainting test personnel with the specific facility, test instruments, and procedures

After a preliminary run has been made, it may be declared a test run if agreed to by the parties to the test, provided all the requirements of a test run have been met.

3-2.6 Method of Operation During Test

3-2.6.1 Stability of Test Conditions. Prior to any test run, the equipment must be operated for a sufficient time to establish steady-state conditions. Steady-state sometimes implies that all input and output characteristics, as well as all internal characteristics, do not vary with time. This definition of steady-state is overly restrictive for the purposes of this Code. Steady-state is defined by this Code as an operating condition in which the system is at thermal and chemical equilibrium.

The criterion for thermal equilibrium is that, during the period of the test, there is no net change in energy stored inside the steam generator envelope. Energy can be stored in the water and steam, and in metal, refractories, and other solid materials within the steam generator. If the steam generator is at thermal equilibrium during the test, the average input and average output can be properly calculated and compared. For circulating fluidized bed units, thermal equilibrium includes the requirement that size equilibrium of the recirculating solids be established. The ultimate criterion for steady-state is that the average of the data during the test represents equilibrium between the fuel input and steam generator output.

Fluidized bed units that utilize limestone or other sorbent for reducing sulfur (or other) emissions have a large inventory of reactive material that must reach chemical equilibrium, including the recycled material from hoppers and hold-up bins. To achieve equilibrium between the calcium oxide (CaO) in the unit and sulfur in the fuel (sulfation), the sorbent-to-fuel ratio during the stabilization period shall be maintained within ±5% of the targeted ratio for the test.

The following are minimum pretest stabilization times typically required for various types of units:

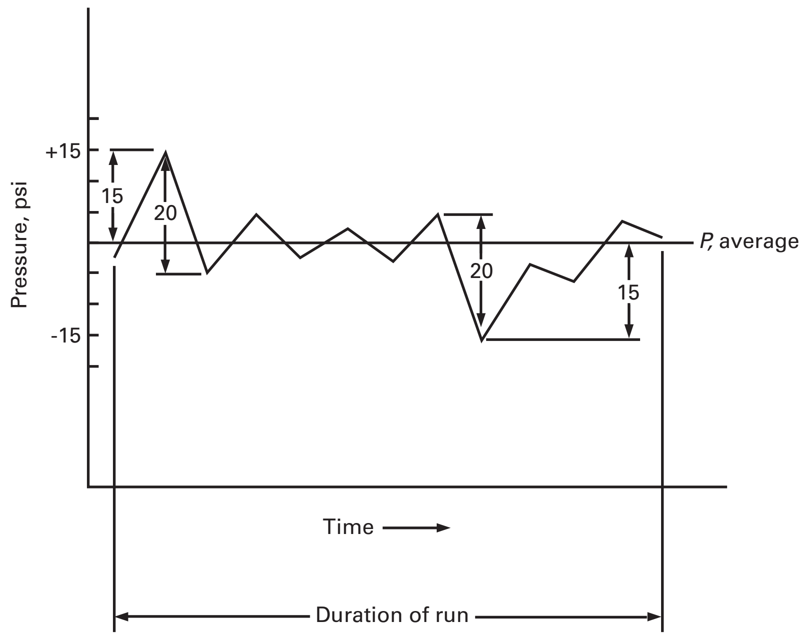
(a) pulverized-coal and gas/oil-fired units: 1 hr

(b) stoker units: 4 hr

(c) fluidized bed units: 24 hr to 48 hr

The purpose of the pretest stabilization period is to establish thermal, chemical, and recirculated material size equilibrium of the system at the test conditions. Minor adjustments to operating conditions are permitted

Fig. 3-2.6.1-1 Illustration of Short-Term (Peak to Valley) Fluctuation and Deviation From Long-Term (Run) Average



as long as they do not interfere with safe operation. However, the entire steam generator should be essentially at test conditions throughout the entire stabilization period. The actual stabilization time required will depend upon the specific unit operating characteristics and the quality of the control system. Table 3-2.3-1 provides criteria for stability of operating parameters that are indicative of units which have reached equilibrium. For fluidized bed units that use an inert bed material such as sand, the stoker unit criteria should be used. For fluidized bed units that have already been operating at the specified sorbent/fuel ratio for at least 24 hr, a 4-hr stabilization period is sufficient as long as the stability criteria of Table 3-2.3-1 are met.

Stability is attained when the agreed upon pretest stabilization period has been completed and monitoring indicates the controlled and dependent parameters are maintained within agreed upon maximum operating parameter deviations. The pretest agreement shall include a table of allowable maximum variations in operating parameters similar to Table 3-2.3-1. Values shown in Table 3-2.3-1 are typical and may be used directly or modified by agreement between parties to the test. For units utilizing limestone or other sorbent for reducing sulfur emissions, the SO_2 should be monitored continuously and used as an indication of chemical equilibrium between the bed and recycled material (i.e., the SO_2 trend should be reasonably flat). For circulating fluidized bed units, complying with the pretest stabilization period is the primary means of assuring chemical and mechanical equilibrium. Monitoring the dilute phase pressure drop provides a good indicator. Since relative changes are sought, plant instrumentation is acceptable for these trend measurements.

All parameters in Table 3-2.3-1, and any other conditions designated by the parties to the test in which variations might affect the results of the test, should be, as nearly as possible, the same at the end of the run as at the beginning. However, the primary criterion for steady-state is that the average of the data reflects equilibrium between input from fuel and steam generator output. Thus, gradual changes in the critical operating parameters over a significantly long test period are not necessarily grounds for rejecting a test.

During a complete test run, each observation of an operating condition shall not vary from the reported average for that operating condition by more than the allowable value under the "Deviation From Long-Term" column of Table 3-2.3-1, and the maximum variation between any peak and an adjacent valley in the data shall not exceed the limit shown in the "Short-Term Fluctuation" column. An illustration of the application of these limits is provided on Fig. 3-2.6.1-1. These limits may be modified by the parties to the test but, in any event, the established limits shall be tabulated in the pretest agreement. If operating conditions vary during any test run beyond the limits prescribed in that table, the test run is invalid unless the parties to the test agree to allow the deviation. Any such allowed deviations shall be explained in the test report.

Table 3-2.6.2-1 Minimum Test-Run Duration

Type of Steam Generating Unit	Energy Balance, hr	Input–Output, hr
Gas/oil	2	2
Stoker	4	10
Pulverized coal	2	8
Fluidized bed	4	8

3-2.6.2 Duration of Test Runs. The duration of a test run must be of sufficient length that the data reflects the average efficiency and/or performance of the unit. This includes consideration for deviations in the measurable parameters due to controls, fuel, and typical unit operating characteristics. The test duration shall not be less than that tabulated in Table 3-2.6.2-1.

The chief-of-test and the parties to the test may determine that a longer test period is required. The minimum times shown in Table 3-2.6.2-1 are generally based upon continuous data acquisition and utilization of composite gas sampling grids. Depending upon 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 achieve the required test uncertainty. When point-by-point traverses of large ducts are utilized, the test run should be long enough to complete at least two full traverses. Test runs using blended or waste fuels may also require longer durations if variations in the fuel are significant.

The duration of runs to determine the maximum short period output, when the efficiency is not to be determined, shall be set by agreement of the parties to the test.

The actual duration of all runs from which the final test data are derived shall be recorded.

3-2.6.3 Considerations for Conducting the Test. Each test run should be conducted with the steam generator operating as closely as possible to the specified conditions to avoid the application of corrections to the test results or to minimize the magnitude of the corrections. Critical considerations include type of fuel, flow rates, pressures, and temperatures. For stoker and fluidized bed units, it is particularly important to maintain constant coal quality and size distribution to ensure stability of operating conditions. For units utilizing sorbent, the sorbent-to-fuel ratio (Ca/S molar ratio) is also particularly important.

The pretest stabilization period, deviation of critical parameters during the test period, and criteria for rejection of tests are defined by the criteria in para. 3-2.6.1.

A test operations coordinator should be assigned to facilitate communication between the steam generator operator(s) and the parties to the test. The steam generator operator(s) should be apprised of his responsibilities with respect to the test. This includes the requirements of the pretest stabilization period as well as the specified maximum deviation of critical operating parameters. Communications between the test operations coordinator and the operator(s) should be such that, except under emergency operating situations, the test operations coordinator is consulted prior to changing operating parameters.

If sootblowing would normally be used during the period of a test run, it should be used during the conduct of each test run. The pretest agreement shall define the sootblowing plan for each run. Any sootblowing conducted during a test run shall be recorded and included in the analysis of the test results.

For stoker-fired units with a stationary grate, it is essential that major cleaning and conditioning of the fuel bed be accomplished some time before the run starts and again the same length of time before the run is completed. Normal cleaning of the fuel bed is permitted during the run. The ash pit must be emptied either just after the initial and final cleaning and conditioning of the fuel bed or just before the start and end of the run so that the quantity of residue corresponds to the quantity of fuel burned.

In the case of runs to determine the maximum output at which the unit can be operated for a short period, the run should be started as soon as the maximum output is reached and continue until the specified duration of the run is reached unless conditions necessitate terminating the run earlier. Refer to para. 3-2.6.2, Duration of Test Runs.

3-2.6.4 Frequency of Observations. The following measurement and sampling frequencies are recommended for use during a test. The frequencies may be increased or decreased based on a pretest uncertainty analysis. Refer to Sections 4, 5, and 7 for additional information.

(a) Readings should be taken at intervals of 15 min or less for all measurements except quantity measurements. Continuous monitoring is permissible.

(b) If the amount of fuel or feedwater is determined from integrating instruments, the readings should be taken at 1-hr intervals.

(c) If the quantities to be determined are weighed, the frequency of weighing is usually determined by the capacity of the scales, but the intervals should be such that a total can be obtained for each hour of the test.

(d) When differential pressure measurement devices are used with venturi tubes, flow nozzles, or orifice plates for subsequently determining quantity measurements, the flow-indicating element should be read at intervals of 5 min or less.

(e) Fuel and residue samples should be taken in accordance with guidance in Section 4.

3-2.6.5 Performance Curves. If runs are made at different outputs, curves may be drawn to relate the test parameters to output. Such curves are useful in appraising the performance of the unit, because the desired outputs are seldom exactly obtained during the test. If there are enough test points to establish characteristic curves, the performance corresponding to intermediate levels of output may be read from the curves.

3-2.7 Corrections to Test Results

Operating conditions at the time of the test may differ from the standard or specified conditions that were used to establish design or guarantee performance levels. Section 5 provides methods for applying corrections during the calculation of test results to account for many of these differences. Correction factors may be obtained from various sources such as tables, correction curves, or manufacturer's design data. Parties to the test shall record their agreement on the sources of any correction factors to be used and the methods for their application. Section 5 also provides a method for calculating the uncertainty of corrected results.

3-2.8 Records and Test Reports

Computer data logging is preferred to manual recording, provided all required points are recorded. Following completion of the test, a permanent record of the data shall be submitted in a mutually agreed upon format to each party of the test.

Any manually recorded data shall be entered on previously prepared forms that constitute original log sheets and shall be authenticated by the observers' signatures. Each party to the test shall be given a complete set of unaltered log sheets, recorded charts, or facsimiles. The observations shall include the date and time of day. They shall be the actual readings without application of any instrument calibration corrections. The log sheets and any recorded charts constitute a complete record of the test. It is recommended that sufficient space be left at the bottom of each log sheet to record average reading, correction for instrument calibration, and conversion to desired units for calculations.

Records made during tests must show the extent of fluctuations (i.e., minimum and maximum values of instrument readings) of the instruments so that data will be available for use in determining the influence of such fluctuations on the uncertainty of calculated results.

Every event connected with the progress of a test, however unimportant it may appear at the time, should be recorded on the test log sheets together with the time of occurrence and the name of the observer. Particular care should be taken to record any adjustments made to any equipment under test, whether made during a run or between runs. The reason for each adjustment shall be stated in the test record.

3-3 REFERENCES TO OTHER CODES AND STANDARDS

The necessary instruments and procedures for making measurements are prescribed in Section 4 and should be used in conjunction with the following ASME Performance Test Codes and Supplements on Instruments and Apparatus and other pertinent publications for detailed specifications on apparatus and procedures involved in the testing of steam generating units. These references are based upon the latest information available when this Code was published. In all cases, care should be exercised to refer to the latest revision of the document.

3-3.1 ASME Performance Test Codes

ASME PTC 1, General Instructions
ASME PTC 2, Definitions and Values
ASME PTC 4.2, Coal Pulverizers
ASME PTC 4.3, Air Heaters
ASME PTC 4.4, Gas Turbine Heat Recovery Steam Generators
ASME PTC 6, Steam Turbines
ASME PTC 6.2, Steam Turbines in Combined Cycles
ASME PTC 10, Compressors and Exhausters
ASME PTC 11, Fans
ASME PTC 19.1, Test Uncertainty
ASME PTC 19.2, Pressure Measurement
ASME PTC 19.3, Temperature Measurement
ASME PTC 19.5, Flow Measurement
ASME PTC 19.6, Electrical Measurements in Power Circuits
ASME PTC 19.10, Flue and Exhaust Gas Analyses
ASME PTC 19.11, Steam and Water Sampling, Conditioning, and Analysis in the Power Cycle
ASME PTC 21, Particulate Matter Collection Equipment
ASME PTC 22, Gas Turbine
ASME PTC 38, Determining the Concentration of Particulate Matter in a Gas Stream

Publisher: The American Society of Mechanical Engineers (ASME), Two Park Avenue, New York, NY 10016-5990; Order Department: 22 Law Drive, P.O. Box 2900, Fairfield, NJ 07007-2900 (www.asme.org)

3-3.2 ASTM Standard Methods

ASTM C25, Standard Test Methods for Chemical Analysis of Limestone, Quicklime, and Hydrated Lime
ASTM D95, Standard Test Method for Water in Petroleum Products and Bituminous Materials by Distillation
ASTM D240, Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter
ASTM D346/D346M, Standard Practice for Collection and Preparation of Coke Samples for Laboratory Analysis
ASTM D482, Standard Test Method for Ash From Petroleum Products

ASTM D1298, Standard Test Method for Density, Relative Density, or API Gravity of Crude Petroleum and Liquid Petroleum Products by Hydrometer Method
ASTM D1552, Standard Test Method for Sulfur in Petroleum Products (High-Temperature Method)
ASTM D1826, Standard Test Method for Calorific (Heating) Value of Gases in Natural Gas Range by Continuous Recording Calorimeter
ASTM D1945, Standard Test Method for Analysis of Natural Gas by Gas Chromatography
ASTM D2013, Standard Practice for Preparing Coal Samples for Analysis
ASTM D2234, Standard Practice for Collection of a Gross Sample of Coal
ASTM D2492-90, Standard Test Method for Forms of Sulfur in Coal
ASTM D3174, Standard Test Method for Ash in the Analysis Sample of Coal and Coke from Coal
ASTM D3176, Standard Practice for Ultimate Analysis of Coal and Coke
ASTM D3177, Standard Test Methods for Total Sulfur in the Analysis Sample of Coal and Coke
ASTM D3180-89, Standard Practice for Calculating Coal and Coke Analyses From As-Determined to Different Bases
ASTM D3302, Standard Test Method for Total Moisture in Coal
ASTM D3588, Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density of Gaseous Fuels
ASTM D4057, Standard Practice for Manual Sampling of Petroleum and Petroleum Products
ASTM D4239, Standard Test Method for Sulfur in the Analysis Sample of Coal and Coke Using High Temperature Tube Furnace Combustion
ASTM D4326, Standard Test Method for Major and Minor Elements in Coal and Coke Ash By X-Ray Fluorescence
ASTM D4809, Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (Precision Method)
ASTM D5142, Standard Test Methods for Proximate Analysis of the Analysis Sample of Coal and Coke by Instrumental Procedures
ASTM D5287, Standard Practice for Automatic Sampling of Gaseous Fuels
ASTM D5373, Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal
ASTM D5865, Standard Test Method for Gross Calorific Value of Coal and Coke
ASTM D6316, Standard Test Method for Determination of Total, Combustible, and Carbonate Carbon in Solid Residues From Coal and Coke
ASTM E178, Standard Practice for Dealing With Outlying Observations

Publisher: American Society for Testing and Materials (ASTM International), 100 Barr Harbor Drive, P.O. Box C700, West Conshohocken, PA 19428-2959 (www.astm.org)

3-3.3 IEEE Standard

120-1989, IEEE Master Test Guide for Electrical Measurements in Power Circuits

Publisher: Institute of Electrical and Electronics Engineers, Inc. (IEEE), 445 Hoes Lane, Piscataway, NJ 08854 (www.ieee.org)

3-3.4 ISO Standard

ISO 5167-1, Measurement of fluid flow by means of pressure differential devices inserted in circular cross-section conduits running full — Part 1: General principles and requirements

Publisher: International Organization for Standardization (ISO) Central Secretariat, 1, ch. de la Voie-Creuse, Case postale 56, CH-1211 Genève 20, Switzerland/Suisse (www.iso.org)

3-4 TOLERANCES AND TEST UNCERTAINTIES

Tolerances or margins on performance guarantees are not within the scope of this Code. The test results shall be reported as computed from test observations, with proper corrections for calibrations. The uncertainties of the test results shall be calculated in accordance with Sections 5 and 7. The calculated uncertainties shall be reported with the results of the test, and the uncertainty analysis shall be part of the record of the test. Test uncertainties are to be used only for evaluating the quality of the test.

Section 4
Instruments and Methods of Measurement

4-1 GUIDING PRINCIPLES

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, calculations, assumptions, and values for 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 the following three items:

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

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

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

It is the test engineer's responsibility to select the method for measuring each parameter that, when considered with all the other parameters, produces results within the uncertainty requirements of the test. In this Code, where there is a choice among several methods, a preferred method is identified. If a preferred procedure is not selected, the increased systematic uncertainty is quantified for the chosen method. Subsection 7-5 discusses methods for estimating such systematic uncertainties. Systematic uncertainties shall be agreed by all parties to the test.

4-2 DATA REQUIRED

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

(a) efficiency
(b) output
(c) capacity
(d) steam temperature/control range
(e) exit flue gas and air entering temperatures
(f) excess air
(g) water/steam pressure drops
(h) air/flue gas pressure drops
(i) air infiltration
(j) sulfur capture/retention
(k) calcium-to-sulfur molar ratio
(l) fuel, air, and flue gas flows

Tables 4-2-1(a) through 4-2-12 list the parameters required to determine each of these performance characteristics for typical units as defined by the Steam Generator System Boundaries on Figs. 1-4-1 through 1-4-7 in Section 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 for applying the principles of this Code for measuring the appropriate parameters to accomplish the objective of the test.

On the line with the major parameter, the "typical influence" and "typical source" entries relate to the major parameter. Typical sources are measured, calculated, or estimated. "Measured" is intended to indicate the parameter as determined from direct observation of a physical property such as voltage in a thermocouple or flow from a measured differential pressure. "Calculated" indicates the parameter is inferred from other measured parameters and calculated based on engineering principles. Some examples are flow calculated from an energy balance or a flow determined by difference. "Estimated" indicates that the value of the parameter is estimated or agreed to by the parties to the test. In general, "estimated" means that a reasonable order of magnitude estimate can be made based on experience from similar units, or, preferably, on previous tests on the unit. Examples are a contractually agreed ash split or radiation loss.

In these tables, the "Typical Influence" column designates those parameters that typically have a major (primary) effect on the result and those items that are required but have a lesser (secondary) effect on result. 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. For example, see "Unburned H_2 in Residue" in Table 4-2-1(a).

The "Typical Source" column identifies acceptable options for determining the parameter. These options are "measured," "calculated," and "estimated." "Typical" indicates what is usual or common industry

Table 4-2-1(a) Parameters Required for Efficiency Determination by Energy Balance Method: Energy Losses

Calculation Acronym	Parameter	Reference Section	Typical Influence [Note (1)]	Typical Source [Note (2)]	Remarks
QpLDFg	**Dry Gas**	**5-14.1**	**PRI**	**M**	**. . .**
	Fuel analysis	4-12.3	PRI	M	. . .
	% O_2 in flue gas	4-13.4	PRI	M	See Table 4-2-6
	Flue gas temperature	4-4.3	PRI	M	See Table 4-2-5
QpLH2F	**Water Formed From the Combustion of H_2 in the Fuel**	**5-14.2.1**	**PRI**	**M**	**. . .**
	Fuel analysis	4-12.3	PRI	M	. . .
	Flue gas temperature	4-4.3	PRI	M	See Table 4-2-5
QpLWF	**Water in a Solid or Liquid Fuel**	**. . .**	**. . .**	**. . .**	**. . .**
	Fuel analysis	5-14.2.2	PRI	M	. . .
	Flue gas temperature	4-12.3	PRI	M	. . .
		4-4.3	PRI	M	See Table 4-2-5
QpLWvF	**Water Vapor in a Gaseous Fuel**	**5-14.2.3**	**PRI**	**M**	**. . .**
	Fuel analysis	4-12.3	PRI	M	. . .
	Flue gas temperature	4-4.3	PRI	M	See Table 4-2-5
QpLWA	**Moisture in Air**	**5-14.3**	**SEC**	**M/E**	**. . .**
	Fuel analysis	4-12.3	PRI	M	. . .
	Flue gas O_2	4-13.4	PRI	M	See Table 4-2-6
	Dry-bulb temperature	4-15	PRI	M	. . .
	Wet-bulb temperature	4-15	PRI	M	. . .
	or relative humidity	4-15	PRI	M	. . .
	Barometric pressure	4-5.5	SEC	M	. . .
	Flue gas temperature	4-4.3	PRI	M	See Table 4-2-5
QpLUbC	**Unburned Carbon in Residue**	**5-14.4.1**	**PRI**	**M/E**	**. . .**
	Fuel analysis	4-12.3	PRI	M	. . .
	% carbon in residue	4-12.3.5	PRI	M	. . .
	Residue split	4-7.8	PRI	M/E	. . .
	Sorbent analysis	4-12.3	PRI	M	. . .
	Sorbent rate	4-8	PRI	M	See Table 4-2-12
	Fuel rate	4-7.5	PRI	C/M	. . .
	% CO_2 in residue	4-12.3	PRI	M	See Table 4-2-10
	SO_2/O_2 in flue gas	4-13.4	PRI	M	. . .
QpLH2Rs	**Unburned H_2 in Residue**	**5-14.4.2**	**SEC**	**E**	**Normally zero**
	Items for *QpLUbC*	. . .	PRI	M	See *QpLUbC*,
	% H_2 in residue	4-12.3	PRI	M	Table 4-2-1(a)
QpLCO	**CO in Flue Gas**	**5-14.4.3**	**SEC**	**M/E**	**. . .**
	Items for excess air	. . .	PRI	M	See Table 4-2-6
	CO in flue gas	4-13.3	PRI	M	. . .
QpLPr	**Pulverizer Rejects**	**5-14.4.4**	**SEC**	**E**	**. . .**
	Pulverizer rejects rate	4-7.5	PRI	M/E	. . .
	Pulverizer rejects analysis	4-12.3	PRI	M/E	. . .
	Pulverizer outlet temperature	4-4.3	PRI	M	. . .
	Fuel rate	4-7.7	PRI	C/M	See Table 4-2-12
	Fuel analysis	4-12.3	PRI	M	. . .
QpLUbHc	**Unburned Hydrocarbons in Flue Gas**	**5-14.4.5**	**SEC**	**E**	**. . .**
	Hydrocarbons in flue gas	4-13.4	PRI	M	. . .
	HHV of reference gas	. . .	PRI	M	. . .
QpLRs	**Sensible Heat of Residue**	**5-14.5**	**PRI**	**M/E**	**. . .**
	Residue split	4-7.8	PRI	M/C/E	. . .
	Temperature of residue	4-4.5.1	PRI	M	. . .

Table 4-2-1(a) Parameters Required for Efficiency Determination by Energy Balance Method: Energy Losses (Cont'd)

Calculation Acronym	Parameter	Reference Section	Typical Influence [Note (1)]	Typical Source [Note (2)]	Remarks
QpLAq	**Hot Air Quality Control Equipment**	**5-14.6**	**PRI**	**M**	**. . .**
	Flue gas temperature entering	4-4.3	PRI	M	. . .
	Flue gas temperature leaving	4-4.3	PRI	M	See Table 4-2-6
	% O_2 in flue gas entering	4-13.4	PRI	M	See Table 4-2-6
	% O_2 in flue gas leaving	4-13.4	PRI	M	See Table 4-2-12
	Wet gas weight entering	5-12.9	PRI	C	See Table 4-2-12
	Wet gas weight leaving	5-12.9	PRI	C	. . .
QpLALg	**Air Infiltration**	**5-14.7**	**SEC**	**M**	**Normally N/A**
	Infiltrating airflow	5-14.7	PRI	M	See Table 4-2-12
	Infiltrating air temperature	4-4.3	PRI	M	. . .
	Exit gas temperature	4-4.3	PRI	M	See Table 4-2-6
QpLNOx	**Formation of NO_x**	**5-14.8**	**SEC**	**M/E**	**. . .**
	NO_x in flue gas	4-13.4	PRI	M/E	. . .
	Wet gas weight	5-12.9	PRI	C	See Table 4-2-12
QrLSrc	**Surface Radiation and Convection**	**. . .**	**. . .**	**. . .**	**. . .**
	Steam generator surface area	5-14.9	PRI	M/E	Normally estimated
	Local ambient air temperature	. . .	PRI	C	based on surface
	Local surface temperature	4-4.3	PRI	M/E	area within
	Local surface air velocity	4-4.3	PRI	M/E	envelope.
		4-7	PRI	E	See para. 5-14.9
QrLWAd	**Additional Moisture**	**5-14.10**	**SEC**	**M/E**	**. . .**
	Mass flow of moisture	4-7.4	PRI	M/E	. . .
	Flue gas temperature	4-4.3	PRI	M	See Table 4-2-5
	Feedwater pressure	4-5.4	SEC	M	. . .
	Feedwater temperature	4-4.4	PRI	M	. . .
	Fuel flow	4-7.5/4-7.7	PRI	C/M	See Table 4-2-12
QrLClh	**Calcination/Dehydration of Sorbent**	**5-14.11**	**PRI**	**M**	**. . .**
	Sorbent analysis	4-12.3	PRI	M	. . .
	Fuel rate	4-7.5/4-7.7	PRI	C/M	See Table 4-2-12
	% carbon in residue	4-12.3	PRI	M	. . .
	% CO_2 in residue	4-12.3	PRI	M	. . .
	Residue split	4-7.8	PRI	M/E	. . .
	SO_2/O_2 in flue gas	4-13.4	PRI	M	See Table 4-2-10
QrLWSb	**Water in Sorbent**	**5-14.12**	**SEC**	**M**	**. . .**
	Sorbent analysis	4-12.3	PRI	M	. . .
	Flue gas temperature	4-4.3	PRI	M	See Table 4-2-5
QrLAp	**Estimated Radiation to the Wet Ash Pit**	**5-14.13.2**	**SEC**	**E**	**Normally estimated. See para. 5-14.13.1 for parameters required when measured.**
QrLRy	**Recycled Streams**	**5-14.14**	**SEC**	**M**	**. . .**
	Recycle flow	4-7	PRI	M/E	. . .
	Recycle temperature entering	4-4.3	PRI	M	See Table 4-2-5
	Recycle temperature leaving	4-4.3	PRI	M	. . .
QrLCw	**Cooling Water**	**5-14.15**	**SEC**	**M/E**	**. . .**
	Cooling water flow rate	4-7.4	PRI	M/E	. . .
	Temperature of water entering	4-4.4	PRI	M	. . .
	Temperature of water leaving	4-4.4	PRI	M	. . .
	Fuel rate	4-7.5/4-7.7	PRI	C/M	See Table 4-2-12

Table 4-2-1(a) Parameters Required for Efficiency Determination by Energy Balance Method: Energy Losses (Cont'd)

Calculation Acronym	Parameter	Reference Section	Typical Influence [Note (1)]	Typical Source [Note (2)]	Remarks
QrLAc	**Internally Supllied Air Preheat Coil**	**5-14.16**	**SEC**	**M**	. . .
	APC condensate flow rate	. . .	. . .	. . .	. . .
	APC condensate temperature	4-7.4	PRI	M/C	. . .
	APC condensate pressure	4-4.4	PRI	M	. . .
	Feedwater temperature	4-5.4	PRI	M	. . .
	Feedwater pressure	4-4.4	PRI	M	. . .
		4-5.4	SEC	M	. . .

NOTES:
(1) Typical influence: PRI = primary, SEC = secondary.
(2) Typical source: M = measured, C = calculated, E = estimated.

practice for this measurement. In many cases, the typical source choice may not be relevant for a particular unit; the test engineer's responsibility is then to choose a method that is consistent with the principles of this Code.

The determination of some parameters such as flue gas constituents can be extensive. Either a table or portion of a table is devoted to these types of parameters. When these items are required to determine other characteristics, the general parameter is noted, and the applicable table referenced. When sorbent is used, parameters related to sorbent are grouped separately starting with "Sorbent Analysis" and separated within the major parameter with a line.

4-3 GENERAL MEASUREMENT REQUIREMENTS

The methods for obtaining the required data determine 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.

The method of obtaining the data typically involves the use of a measurement system. This measurement system consists of the following four parts:

(a) primary element
(b) sensing device
(c) data collection/measurement device
(d) data storage device

The primary element provides access or causes an effect that the sensing device measures, typically by converting it to a proportional electrical signal. This electrical signal is then either converted to a digital value and stored electronically, or is sent to a chart recorder or analog meter.

4-3.1 Type of Equipment/Installation

In general, measuring equipment should be selected to minimize test uncertainty. In particular, critical parameters should be measured with instruments that have sufficient accuracy to ensure that target uncertainties will be achieved. Typical station recording instruments are designed for reliability and ease of use and maintenance, rather than for accuracy. Therefore, measurements made by station recording instruments may increase test uncertainty beyond agreed limits. All instruments must be checked to verify that they are the specified type, properly installed, working as designed, and functioning over the range of input expected.

4-3.2 Calibration

The parties to the test shall agree on which instruments will be calibrated for the test. This Code requires that, at a minimum, relevant components of all instrumentation loops have been 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 uncertainty estimate must be increased to the reference accuracy plus other systematic uncertainty influences described below. Reference accuracy is the systematic uncertainty a user may expect to achieve in the absence of a calibration after the instrument is

Table 4-2-1(b) Parameters Required for Efficiency Determination by Energy Balance Method: Energy Credits

Calculation Acronym	Parameter	Reference Section	Typical Influence [Note (1)]	Typical Source [Note (2)]	Remarks
QpBDA	**Entering Dry Air**	**5-15.1**	**PRI**	**M**	...
	Entering air temperature	4-4.3	PRI	M	See Table 4-2-5
	Excess air	5-11.4	PRI	M	See Table 4-2-6
	Fuel analysis	4-12.3	PRI	M	...
	Unburned carbon	5-10.4	SEC	M/E	See *QpLUbC*
	Sulfur capture	5-9.5	PRI	M	See Table 4-2-1(b) See Table 4-2-10
QpBWA	**Moisture in Entering Air**	**5-15.2**	**SEC**	**M/E**	...
	Items for *QpBDA*	...	PRI	M	...
	Moisture in air	4-15	PRI	M/E	...
	Dry-bulb temperature	4-15	PRI	M	...
	Wet-bulb temperature	4-15	PRI	M	...
	or relative humidity	4-15	PRI	M	...
	Barometric pressure	4-5.5	SEC	M	...
QpBF	**Sensible Heat in Fuel**	**5-15.3**	**SEC**	**M**	...
	Fuel analysis	4-12.3	PRI	M	...
	Fuel temperature entering	4-4	PRI	M/E	...
QpBSlf	**Sulfation**	**5-14.4**	**PRI**	**M**	...
	SO_2/O_2 in flue gas	4-13	PRI	M	See Table 4-2-10
	Fuel analysis	4-12.3	PRI	M	...
	Sorbent analysis	4-12.3	PRI	M	...
	Sorbent rate	4-7.7	PRI	M	...
	Fuel rate	4-7.5	PRI	C/M	See Table 4-2-12
	% carbon in residue	4-12.3	PRI	M	...
	% CO_2 in residue	4-12.3	PRI	M	...
QrBX	**Auxiliary Equipment Power**	**5-15.5**	**SEC**	**M/C/E**	...
	Steam driven equipment	...	...	...	...
	Mass flow of steam	4-7.4	PRI	M	...
	Entering steam pressure	4-5.4	PRI	M	...
	Entering steam temperature	4-4.4	PRI	M	...
	Exhaust pressure	4-5.4	PRI	M	...
	Drive efficiency	NA	PRI	E/M	...
	Electrical driven equipment	...	...	...	...
	For large motors:	...	...	...	...
	Watt hour reading	NA	PRI	M	...
	Drive efficiency	NA	PRI	E/M	...
	For small motors:	...	...	...	...
	Volts	NA	SEC	M	...
	Amps	NA	SEC	M	...
QrBSb	**Sensible Heat in Sorbent**	**5-15.6**	**SEC**	**M**	...
	Sorbent rate	4-7.5	PRI	M	...
	Sorbent temperature	4-4.5	PRI	M	...
QrBWAd	**Additional Moisture**	**5-15.7**	**SEC**	**M/E**	...
	Mass flow rate	...	...	...	...
	Entering temperature	4-7.4	PRI	M	...
	Entering pressure	4-4.4	PRI	M	...
		4-5.4	PRI	M	...

NOTES:
(1) Typical influence: PRI = primary, SEC = secondary.
(2) Typical source: M = measured, C = calculated, E = estimated.

Table 4-2-2 Parameters Required for Efficiency Determination by Input–Output Method

Calculation Acronym	Parameter	Reference Section	Typical Influence [Note (1)]	Typical Source [Note (2)]	Remarks
QrF	**Heat Input From Fuel**	**5-5**	**PRI**	**M**	. . .
	Fuel rate	4-7.5/4-7.7	PRI	M	. . .
	Heating value of fuel	4-12	PRI	M	. . .
	Fuel analysis	4-12.13	PRI	M	. . .
	Output	**5-4**	**PRI**	**C**	**See Table 4-2-3**

NOTES:
(1) Typical influence: PRI = primary, SEC = secondary.
(2) Typical source: M = measured, C = calculated, E = estimated.

initially adjusted in accordance with the manufacturer's specification. This systematic uncertainty is reduced when adjustments are made to an instrument to align it to a reference standard. The systematic uncertainty then becomes the accuracy of the reference standard used plus other systematic uncertainty influences. These influences may include environmental influences on the instrument as well as systematic uncertainty introduced due to nonuniformity of 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 uncertainty 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 value in the range expected to be measured during the test.

4-3.2.1 Temperature. Temperature-sensing devices can be calibrated when it is desired to reduce the uncertainty of the parameter. The level of the standard (interlaboratory, transfer, etc.) used in the calibration sets the reference accuracy. The temperature-sensing device should be calibrated against a standard that has a calibration traceable to the NIST or other internationally recognized standard. The sensing element should be compared to at least four different temperatures. The temperatures selected for calibration should span the range of the anticipated values expected during the test. Thermocouples must be heat soaked prior to calibration to ensure that shifts in output do not occur after calibration.

4-3.2.2 Pressure or Differential Pressure. The sensing device should be calibrated with an NIST traceable pressure standard at five different pressures. The pressures should be recorded at atmospheric (zero), 25% full scale, 50% full scale, 75% full scale, and full scale. The pressure should be recorded at each point while pressure is increased and again while pressure is decreased and the average should be used. The difference should be considered in the systematic uncertainty estimate.

4-3.2.3 Flue Gas Analysis. Analyzers used to measure oxygen, carbon monoxide, oxides of nitrogen, and total hydrocarbons shall be calibrated immediately prior to a test, and calibration shall be checked for drift immediately following a test. These calibrations are performed using certified calibration gases for zero, full span, and midpoint. Calibration gases must be EPA Protocol I quality gases or gases that have been compared to EPA Protocol I gases on a calibrated analyzer. Additionally, no calibration gas shall be used when the pressure in the cylinder is lower than 100 psi to ensure that atmospheric air does not contaminate it. The calibration gas used for full span standard must exceed the largest expected value by 10%. The span gas used for the post-test calibration check must exceed the largest measured value by 10%. If the analyzer is

Table 4-2-3 Parameters Required for Capacity Determination

Calculation Acronym	Parameter	Reference Section	Typical Influence [Note (1)]	Typical Source [Note (2)]	Remarks
QrO	**Output**	**5-4**	**PRI**	**C**	. . .
	Saturated steam generator	5-4.1.1	. . .	. . .	. . .
	Saturated steam flow	4-7.4	PRI	M	. . .
	Feedwater flow	4-7.4	PRI	M	. . .
	Blowdown flow	5-4.5	PRI	M/E	. . .
	Extraction flow	4-7.4	PRI	M	. . .
	Saturated steam pressure	4-4.4	PRI	M	. . .
	Feedwater temperature	4-4.4	PRI	M	. . .
	Feedwater pressure	4-5.4	SEC	M	. . .
	Superheated steam generator	5-4.1.2	. . .	. . .	. . .
	Main steam flow	4-7.4	PRI	M	. . .
	Feedwater flow	4-7.4	PRI	M	. . .
	Blowdown flow	4-7.4	SEC	M/E	. . .
	Extraction flow	4-7.4	PRI	M	. . .
	Desuperheating spray flow	4-7.4	PRI	C/M	. . .
	Main steam temperature	4-4.4	PRI	M	. . .
	Main steam pressure	4-5.4	PRI	M	. . .
	Feedwater temperature	4-4.4	PRI	M	. . .
	Feedwater pressure	4-5.4	SEC	M	. . .
	Desuperheating spray water temperature	4-4.4	PRI	M	. . .
	Desuperheating spray water pressure	4-5.4	SEC	M	. . .
	Reheat steam generator	5-4.2	. . .	. . .	. . .
	Reheat steam flow	5-4.2.1	PRI	C/M	See ASME PTC 6
	Reheat desuperheating spray water flow	4-7.4	PRI	M	. . .
	Feedwater heater extraction flow	5-4.2.1	PRI	C/M	. . .
	Feedwater heater extraction temperature	4-4.4	PRI	M	. . .
	Feedwater heater extraction pressure	4-5.4	PRI	M	. . .
	Feedwater heater entering water temperature	4-4.4	PRI	M	. . .
	Feedwater heater leaving water temperature	4-4.4	PRI	M	. . .
	Feedwater heater water pressure	4-5.4	SEC	M	. . .
	Feedwater water drain temperature	4-4.4	PRI	M	. . .
	Turbine leakage	NA	PRI	M	. . .
	Steam extraction flow (other)	4-7.4	PRI	M	. . .
	Reheat out steam temperature	4-4.4	PRI	M	. . .
	Reheat out steam pressure	4-5.4	SEC	M	. . .
	Reheat in steam temperature	4-4.4	. . .	. . .	. . .
	Reheat in steam pressure	4-5.4	PRI	M/E	. . .
	Reheat desuperheating spray water temperature	. . .	PRI	M	. . .
	Reheat desuperheating spray water pressure	4-4.4	PRI	M	. . .
	Auxiliary steam	4-5.4	PRI	M	. . .
	Auxiliary steam flow	5-4.3	SEC	M	. . .
	Auxiliary steam temperature	4-7.4	. . .	. . .	. . .
	Auxiliary steam pressure	4-4.4	. . .	. . .	. . .
	Feedwater temperature	4-5.4	. . .	. . .	. . .
	Feedwater pressure	4-4.4	. . .	. . .	. . .
		4-5.4	. . .	. . .	. . .

NOTES:
(1) Typical influence: PRI = primary, SEC = secondary.
(2) Typical source: M = measured, C = calculated, E = estimated.

Table 4-2-4 Parameters Required for Steam Temperature/Control Range Determination

Calculation Acronym	Parameter	Reference Section	Typical Influence [Note (1)]	Typical Source [Note (2)]	Remarks
...	**Superheated Steam Generators**	5-4.1.2	...	...	The primary measurements are listed here. All items needed for output are required.
	Main steam flow	4-7.4	PRI	M	
	Blowdown flow	4-7.4	PRI	M/E	
	Extraction flow	4-7.4	PRI	M	
	Main steam temperature	4-4.4	PRI	M	
	Main steam pressure	4-5.4	PRI	M	
	Drum pressure (if applicable)	4-5.4	PRI	M	
	Drum level	...	...	...	...
	Feedwater temperature	4-4.4	PRI	M	...
	Feedwater pressure	4-5.4	SEC	M	...
	Desuperheated spray water flow	4-7.4	PRI	M	...
	Desuperheated spray water temperature	4-4.4	PRI	M	...
	Desuperheated spray water pressure	4-5.4	SEC	M	...
	Other items required to determine output	5-4	SEC	M/C/E	...
...	**Reheat Steam Generators**	5-4.2	...	...	...
	Reheat steam flow	5-4.2.1	PRI	C/M	See Table 4-2-3
	Reheat out steam temperature	4-4.4	PRI	M	...
	Reheat out steam pressure	4-5.4	PRI	M	...
	Reheat in steam temperature	4-4.4	PRI	M	...
	Reheat out steam pressure	4-5.4	PRI	M	...
	Reheat desuperheating spray water flow	4-7.4	PRI	M	...
	Reheat desuperheating spray water	...	...	...	...
	Temperature	4-4.4	PRI	M	...
	Reheat desuperheating spray water	...	...	..	...
	Pressure	4-5.4	SEC	M	...
...	**Related Parameters**	...	...	...	...
	Excess air	5-11.4	...	M	...
	Gas proportioning damper	...	...	M	...
	Flue gas recirculation flow	...	...	M	...
	Blowdown	5-4.4	...	...	...

NOTES:
(1) Typical influence: PRI = primary, SEC = secondary.
(2) Typical source: M = measured, C = calculated, E = estimated.

calibrated on one range and the measurement during the test is performed on another, a post-test calibration check shall be performed on the second range. Potential systematic uncertainties introduced by the sampling system should be verified by the introduction of calibration gases into the sampling system at the probe after the instrumentation has been properly calibrated. Any deviation from what the instruments read when the gas is introduced directly versus when fed through the sampling system indicates a sampling system systematic uncertainty. If significant systematic uncertainty is observed, the sampling system design should be reviewed to reduce or eliminate this systematic uncertainty. Certain materials may absorb gases until saturated and then release them when concentrations are lower. This hideout phenomenon can be resolved by replacing the offending materials with more inert material.

4-3.3 Frequency of Measurements

Because of fuel variability, control system tuning, and other factors, variations in operational parameters are inevitable. To minimize the 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. Quantity measurements (e.g., fuel measured by volumetric or weigh tanks) are made at a frequency dictated by the collection device. Other data collection should be at a maximum interval of 15 min and a preferred interval of 2 min or less. If fluctuations are noted on any important parameters during the time data is being collected at

Table 4-2-5 Parameters Required for Exit Flue Gas and Air Entering Temperature Determinations

Calculation Acronym	Parameter	Reference Section	Typical Influence [Note (1)]	Typical Source [Note (2)]	Remarks
. . .	**No Air Heater**	. . .	. . .	. . .	. . .
	Flue gas temperature leaving steam generator	4-4.3	PRI	M	. . .
	Air temperature entering steam generator	4-4.3	PRI	M	. . .
. . .	**Single Bisector Type Air Heater**	. . .	. . .	. . .	. . .
	O_2 entering air heater	4-10	PRI	M	. . .
	O_2 leaving air heater	4-10	PRI	M	. . .
	Flue gas temperature entering air heater	4-4.3	PRI	M	. . .
	Flue gas temperature leaving air	4-4.3	PRI	M	. . .
	Air temperature entering air heater	4-4.3	PRI	M	Flue gas temperature entering is only required for correction to reference.
. . .	**Primary/Secondary Air Heaters**	. . .	. . .	. . .	. . .
	Items above for bisector air heater	. . .	PRI	. . .	. . .
	Plus:	. . .	. . .	. . .	. . .
	Air temperature leaving each air heater	4-4.3	PRI	M	. . .
	Primary airflow leaving air heater	4-7.3	PRI	C/M	. . .
	Tempering airflow	4-7.3	SEC	C	. . .
	Tempering air temperature	4-4.3	PRI	M	. . .
	Mixed airflow	4-7.3	PRI	C/M	. . .
	Mixed air temperature	4-4.3	PRI	M	. . .
	Items required for efficiency	. . .	PRI	. . .	See Tables 4-2-1(a) and 4-2-1(b)
	Items required for output	. . .	PRI	. . .	See Table 4-2-3
. . .	**Trisector Type Air Heaters**	. . .	. . .	. . .	. . .
	Items above for single air heater	. . .	PRI	. . .	. . .
	Secondary air temperature entering air heater	4-4.3	PRI	M	. . .
	Secondary air temperature leaving air heater	4-4.3	PRI	M	. . .
	Primary air temperature entering air heater	4-4.3	PRI	M	. . .
	Primary air temperature leaving air heater	. . .	. . .	. . .	. . .
	Primary airflow leaving air heater	4-4.3	PRI	M	. . .
	Tempering airflow	4-7.3	PRI	C/M	. . .
	Tempering air temperature	4-7.3	PRI	M	. . .
	Mixed airflow	4-4.3	PRI	M	. . .
	Mixed air temperature	4-7.3	PRI	M	. . .
	Items required for efficiency	4-4.3	PRI	M	See Tables 4-2-1(a) and 4-2-1(b)
	Items required for output	. . .	PRI	. . .	See Table 4-2-3
		. . .	PRI	. . .	. . .

NOTES:
(1) Typical influence: PRI = primary, SEC = secondary.
(2) Typical source: M = measured, C = calculated, E = estimated.

greater than 2-min intervals, the time interval between data collections should be decreased to no longer than 2 min. 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. In most modern data acquisition devices, A/D accuracy is no longer an issue; most have at least 14-bit accuracy. The major issue involves Distributed Control Systems (DCS) that use exception-based reporting. This method utilizes a deadband approach with which no change in the value is reported unless it exceeds a given percentage. This type of system is unacceptable unless the deadband can be set to approximately zero for test measurements.

4-3.4 Measurements Made by Traverse

Values for many parameters required to evaluate steam generator efficiency are determined by measuring

Table 4-2-6 Parameters Required for Excess Air Determination

Calculation Acronym	Parameter	Reference Section	Typical Influence [Note (1)]	Typical Source [Note (2)]	Remarks
XpA	**Excess Air**	5-11.4	. . .	M	. . .
	Fuel analysis	4-12.3	PRI	M	. . .
	% O_2 in flue gas	4-13.4	PRI	M/E	. . .
MpUbC	**Unburned Carbon**	5-10.4	PRI	M/E	. . .
	Percent carbon in residue	4-12.3.5	PRI	M	. . .
	Residue split	4-7.8	PRI	M/E	. . .
MFrWA	**Moisture in Air**	. . .	. . .	. . .	. . .
	Dry-bulb temperature	5-11.2	PRI	C/E	. . .
	Wet-bulb temperature	4-15	PRI	M	. . .
	or relative humidity	4-15	PRI	M	. . .
	Barometric pressure	4-15	PRI	M	. . .
	Additional moisture	4-5.5	SEC	M	. . .
		4-7.4	PRI	M	. . .
MoFrCaS	**Sorbent Analysis**	4-12.3	PRI	M	. . .
	Ca/S molar ratio	5-9.6	PRI	C/E	. . .
	Sorbent rate	4-7.7	PRI	M	. . .
	Fuel rate	4-7.5/4-7.7	PRI	C/M	See Table 4-2-12
MFrClhk	**Calcination**	5-10.8	PRI	C/E	. . .
	% CO_2 in residue	4-13.4	PRI	M	. . .
MFrSc	**Sulfur Capture**	5-9.5	PRI	C/E	. . .
	SO_2/O_2 in flue gas	4-13.4	PRI	M	See Table 4-2-10

NOTES:
(1) Typical influence: PRI = primary, SEC = secondary.
(2) Typical source: M = measured, C = calculated, E = estimated.

values at points in a traverse plane and then calculating averages. Examples include flue gas temperature and composition. Under some conditions, it is also required to measure air or gas velocity by traverse so that average properties can be flow/velocity weighted or so that flow rate can be determined. In all cases, the property averages are defined as integrated averages. The flow rate is itself defined in terms of the integral of the velocity distribution.

In the traverse method, the duct is subdivided into a number of elemental areas and, using a suitable probe, the property or velocity is measured at a point in each elemental area. The average property or 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 traverse method, many different techniques have been proposed for selecting the number of traverse points, 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 Chebyschev polynomial) distribution, the use of graphical or numerical techniques to integrate the property or 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 average or total, 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 can be increased by either increasing the number of points in the traverse plane or by using more sophisticated mathematical techniques (e.g., interpolation polynomials, boundary layer corrections). For measuring flow rate by traverse, ASME PTC 19.5, Flow Measurement recommends either a Gaussian or Chebyschev 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 and property distributions encountered in large flues and ducts, it is more in line with

Table 4-2-7 Parameters Required for Water/Steam Pressure Drop Determinations

Calculation Acronym	Parameter	Reference Section	Typical Influence [Note (1)]	Typical Source [Note (2)]	Remarks
. . .	**Superheater Pressure Drop**	**5-17**	. . .	**M/C**	. . .
	Superheater outlet pressure	4-5.4	PRI	M	. . .
	Superheater inlet (drum) pressure	4-5.4	PRI	M	. . .
	Main steam flow	4-7.4	PRI	M	. . .
	Feedwater flow	4-7.4	PRI	M	. . .
	Blowdown flow	4-7.4	SEC	M/E	. . .
	Extraction flow	4-7.4	PRI	M	. . .
	Superheater spray flow	4-7.4	PRI	C/M	. . .
	Superheater outlet steam temperature	4-4.4	SEC	M	. . .
	Superheater inlet steam temperature	4-4.4	SEC	M	Supercritical units
. . .	**Reheater Pressure Drop**	**5-17**	. . .	**M/C**	. . .
	Reheater inlet steam pressure	4-5.4	PRI	M	. . .
	Reheater outlet steam pressure	4-5.4	PRI	M	. . .
	Reheater steam flow	5-4.2.1	PRI	C/M	See Table 4-2-3
	Feedwater heater extraction flow	5-4.2.1	PRI	C/M	. . .
	Turbine leakage	NA	SEC	E	. . .
	Steam extraction flow	4-7.4	PRI	M	. . .
	Reheater spray water flow	4-7.4	PRI	M	. . .
	Reheater inlet steam temperature	4-4.4	SEC	M	. . .
	Reheater outlet steam temperature	4-4.4	SEC	M	. . .
. . .	**Economizer Pressure Drop**	**5-17**	. . .	**M/C**	. . .
	Economizer water inlet pressure	4-5.4	PRI	M	. . .
	Economizer water outlet (drum) pressure	4-5.4	PRI	M	. . .
	Feedwater flow	4-7.4	PRI	M	. . .
	Superheated spray water flow	4-7.4	PRI	M/C	. . .
	Economizer water inlet temperature	4-4.4	SEC	M	. . .
	Economizer water outlet temperature	4-4.4	SEC	M	. . .

NOTES:
(1) Typical influence: PRI = primary, SEC = secondary.
(2) Typical source: M = measured, C = calculated, E = estimated.

the requirements of field testing as well as more realistic in light of the varied distributions that may actually occur in the field, to obtain the desired accuracy by specifying measurements at a relatively large number of points at the center of equal areas rather than by relying on assumed velocity or property 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. A final advantage of equal-area traversing is that it can aid in visualizing and analyzing the actual property or velocity distribution in the duct. For these reasons, this Code adopts the equal-area method of traversing, with measurement at a relatively large number of points. Investigations of flow rate 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 Gaussian or Chebyschev measurement methodology, refer to ASME PTC 19.5.

4-3.5 Weighted Parameters

The flue gas temperature is needed to determine the sensible heat in a flue gas stream. Because the temperature varies across the duct cross section, the proper temperature to use is an integrated average (see para. 7-2.3). Because the sensible heat is the objective, the variation in mass flow or stratification should be taken into account. Ideally, this is done by simultaneously measuring the flue gas velocity, oxygen, pressure, and temperature at all points in the grid. Weighting factors based on the relative mass flow in the local area can be applied to the measured temperatures. Weighting factors based on velocity are also applied to flue gas oxygen concentration measurements.

Table 4-2-8 Parameters Required for Air/Flue Gas Pressure Drop Determinations

Calculation Acronym	Parameter [Note (1)]	Reference Section	Typical Influence [Note (2)]	Typical Source [Note (3)]	Remarks
. . .	**Air Side Resistance**	**5-17.3**	. . .	**M/C**	. . .
	Forced draft fan discharge pressure	4-5.3	PRI	M	. . .
	Air heater air inlet pressure	4-5.3	PRI	M	. . .
	Air heater air outlet pressure	4-5.3	PRI	M	. . .
	Windbox pressure	4-5.3	PRI	M	. . .
	Furnace pressure	4-5.3	PRI	M	. . .
	Airflow	5-11.6	PRI [Note (4)]	C	See Table 4-2-12
	Main steam flow	4-7.4	SEC	M	. . .
	Air temperature	4-4.3	SEC	M	. . .
. . .	**Gas Side Resistance**	**5-17.3**	. . .	**M/C**	. . .
	Furnace pressure	4-5.3	PRI	M	. . .
	Superheater inlet pressure	4-5.3	PRI	M	. . .
	Superheater outlet pressure	4-5.3	PRI	M	. . .
	Reheater inlet pressure	4-5.3	PRI	M	. . .
	Reheater outlet pressure	4-5.3	PRI	M	. . .
	Generating bank inlet pressure	4-5.3	PRI	M	. . .
	Generating bank outlet pressure	4-5.3	PRI	M	. . .
	Economizer inlet pressure	4-5.3	PRI	M	. . .
	Economizer outlet pressure	4-5.3	PRI	M	. . .
	Air quality control equipment inlet pressure	4-5.3	PRI	M	. . .
	Air quality control equipment outlet pressure	4-5.3	PRI	M	. . .
	Air heater gas inlet pressure	4-5.3	PRI	M	. . .
	Air heater gas outlet pressure	4-5.3	PRI	M	. . .
	Flue gas flow rate	5-12.9	PRI [Note (4)]	C	See Table 4-2-12
	Main steam flow	4-7.4	SEC	M	. . .
	Flue gas temperature	4-4.3	SEC	M	. . .

NOTES:
(1) Typical intermediate pressures are shown for evaluation of system resistance.
(2) Typical influence: PRI = primary, SEC = secondary.
(3) Typical source: M = measured, C = calculated, E = estimated.
(4) Air/gas side flow rates are required for corrections to reference conditions.

Although the theoretically correct weighting is by mass flow (weighting factors are the product of density and velocity) for temperature and by volume flow (weighting factor is velocity) for oxygen, this Code recommends that only velocity weighting be used in either case so that the procedure is as simple and as practical as possible.

In some cases, flow weighting can decrease the error in the results of a performance test; in other cases, flow weighting can increase the error. This latter case can occur when velocity is not determined simultaneously with temperature and oxygen data, when velocity data are inaccurate, or when the time required to obtain a point-by-point data results in fewer complete sets of data being obtained. Therefore, this Code only recommends flow weighting when the systematic uncertainty due to flow weighting is significantly large.

4-3.5.1 Applicability of Flow Weighting. The existence of stratification of the flue gas and its effect on uncertainty can be determined by a temperature or by a preliminary traverse.

The temperature traverse is useful when an existing temperature grid is available to eliminate concerns of stratification. Using the temperature data from the grid, an estimate for the flow-weighted temperature is made using the ratio of *absolute* temperatures to approximate the velocity weighting factors:

$$\frac{V_i}{\overline{V}} \cong \frac{T_i + 459.7}{\overline{T} + 459.7} \qquad (4\text{-}3\text{-}1)$$

If the difference between the weighted and unweighted temperatures (ΔT) calculated using this approximation exceeds 2°F (i.e., if the systematic

Table 4-2-9 Parameters Required for Air Infiltration Determination

Calculation Acronym	Parameter	Reference Section	Typical Influence [Note(1)]	Typical Source [Note (2)]	Remarks
. . .	**Infiltration Based on Measured O_2**	**5-17.6**	. . .	. . .	**See Table 4-2-6**
	Excess air entering component	5-11.4	PRI	C	. . .
	Flue gas O_2 entering component	4-13.4	PRI	M	. . .
	Excess air leaving component	5-11.4	PRI	C	See Table 4-2-6
	Flue gas O_2 leaving component	4-13.4	PRI	M	. . .
. . .	**Infiltration by Heat Balance**	**5-17.6**	. . .	**C**	. . .
	Flue gas rate entering air heater	5-12.9	PRI	C	See Table 4-2-12
	Flue gas O_2 entering air heater	4-13.4	PRI	M	. . .
	Fuel analysis	4-12.3	SEC	M	. . .
	Flue gas temperature entering air heater	4-4.3	PRI	M	. . .
	Flue gas temperature leaving air heater	4-4.3	PRI	M	. . .
	Air temperature entering air heater	4-4.3	PRI	M	. . .
	Air temperature leaving air heater	4-4.3	PRI	M	. . .
	Moisture in air	4-15	SEC	M/E	. . .

NOTES:
(1) Typical influence: PRI = primary, SEC = secondary.
(2) Typical source: M = measured, C = calculated, E = estimated.

uncertainty estimate exceeds 4°F, refer to para. 7-5.3.3), the parties to the test may wish to consider a preliminary velocity traverse to aid in deciding whether to employ flow weighting.

A preliminary velocity traverse can also be performed to determine if stratification will result in high systematic uncertainty and if flow weighting should be considered. First, the differences between flow-weighted averages and non-weighted averages are calculated:

$$\Delta T = ABS(\overline{T}_{FW} - \overline{T}_{UW}) \tag{4-3-2}$$

$$\Delta O_2 = ABS(\overline{O}_{2,FW} - \overline{O}_{2,UW}) \tag{4-3-3}$$

where ABS is the absolute value function. (These differences estimate the systematic uncertainty due to not flow weighting.) Then,

(a) if ΔT is less than 3°F and/or ΔO_2 is less than 0.2%, then flow weighting should not be used.

(b) if ΔT is greater than 3°F or ΔO_2 is greater than 0.2%, then three or more complete traverses are required to validate the velocity distribution, or else flow weighting may not be used. If the velocity factors have been verified, then the parties to the test shall decide if flow weighting is to be used.

4-3.5.2 Flow Weighting Method. If it is determined that flow weighting is applicable and the parties elect to flow weight, flow weighting shall be applied as follows.

Prior to any weighting, the "velocity" raw data (typically velocity pressure and pitch and yaw angles) should be reduced to determine velocity normal to the traverse plane. The (space and time) average velocity should be calculated so that the weighting factors are $V_i / \overline{V}$.

Two approaches may be considered for flow weighting using velocity factors. The first is to use the preliminary velocity weighting factors with the test measurements for temperature and (less frequently) oxygen, as discussed in the previous paragraph. The second is to traverse each grid point during the test to measure temperature, velocity, and oxygen. (Sometimes, only temperature and velocity are measured, with oxygen measured as a composite sample and therefore not flow weighted.) Each method has the potential for introducing error in the averages calculated from the data. In addition to the error in velocity determination, the first method introduces error by assuming that the test-time velocities are identical to those measured in the preliminary traverse(s). The error associated with the second method is more subtle. The time required to traverse each point is usually sufficiently large that only a few repeated measurements at each point (that is, only a few repeated traverses) are made, thus increasing the random error. An additional error may be introduced by the variation of the test conditions over time so that values measured at a point near the end of a traverse do not correspond to those measured at another point near the beginning of the traverse.

Table 4-2-10 Parameters Required for Sulfur Capture/Retention Determination

Calculation Acronym	Parameter	Reference Section	Typical Influence [Note (1)]	Typical Source [Note (2)]
MFrSc	**Sulfur Capture/Retention**	**5-9.5**	. . .	. . .
	SO_2 in flue gas	4-13.4	PRI	M
	O_2 in flue gas (same location as SO_2)	4-13.4	PRI	M
	Additional moisture	4-7.4	PRI	M/E
	Fuel analysis	4-12.3	PRI	M/E
MFrWA	**Moisture in Air**	**5-11.2**	**PRI**	**C/E**
	Dry-bulb temperature	4-15	PRI	M
	Wet-bulb temperature	4-15	PRI	M
	or relative humidity	4-15	PRI	M
MpUbC	**Unburned Carbon**	**5-10.4**	**PRI**	**M/E**
	% carbon in residue	4-12.3.5	PRI	M
	Residue split	4-7.8	PRI	M/E
	Sorbent analysis	4-12.3	PRI	M
MoFrCaS	**Ca/S Molar Ratio**	**5-9.6**	**PRI**	**C/E**
	Sorbent rate	4-7.7	PRI	M
	Fuel rate	4-7.5	PRI	C
MFrClhk	**Calcination**	**5-10.8**	**PRI**	**C/E**
	% CO_2 in residue	4-12.3	PRI	M

NOTES:
(1) Typical influence: PRI = primary, SEC = secondary.
(2) Typical source: M = measured, C = calculated, E = estimated.

Table 4-2-11 Parameters Required for Calcium-to-Sulfur Molar Ratio Determination

Calculation Acronym	Parameter	Reference Section	Typical Influence [Note (1)]	Typical Source [Note (2)]	Remarks
MoFrCaS	**Ca/S Molar Ratio**	**5-9.6**	. . .	**C**	. . .
	% CO_2 in residue	4-12.3	PRI	M	. . .
	% carbon in residue	4-12.3	PRI	M	. . .
	Residue split	4-7.8	PRI	E/M	. . .
	Fuel analysis	4-7.5/4-7.7	PRI	M	. . .
	Sorbent analysis	4-12.3	PRI	M	. . .
	Sorbent rate	4-7.7	PRI	M	. . .
	Fuel rate	4-7.5	PRI	C	. . .
. . .	**Sulfur Capture**	**5-9.5**	**SEC**	**C/E**	**See Table 4-2-10**
	SO_2/O_2 in flue gas	4-13.4	PRI	M	. . .

NOTES:
(1) Typical influence: PRI = primary, SEC = secondary.
(2) Typical source: M = measured, C = calculated, E = estimated.

Table 4-2-12 Parameters Required for Fuel, Air, and Flue Gas Flow Rate Determinations

Calculation Acronym	Parameter	Reference Section	Typical Influence [Note (1)]	Typical Source [Note (2)]	Remarks
QrI	**Input From Fuel**	**5-5**	. . .	. . .	. . .
	Fuel rate (measured)	4-7.7	PRI	M	. . .
	Fuel rate (calculated)	5-7.7	PRI	C	. . .
QrO	**Output**	**5-4**	**PRI**	**M**	**See Table 4-2-3**
EF	**Fuel Efficiency**	**5-7.1**	**PRI**	**C**	**See Tables 4-2-1(a) and 4-2-1(b)**
	Fuel analysis	4-12.3	PRI	M	. . .
MgA	**Wet Airflow Rate**	**5-11.6**	. . .	**C**	. . .
MrA	**Excess Air**	**5-11.4**	**PRI**	**C**	**See Table 4-2-6**
	Moisture in air	5-11.2	PRI	C	See Table 4-2-6
MqFg	**Wet Gas Flow Rate**	**5-12.9**	. . .	**C**	. . .
MrFg	**Fuel Analysis**	**4-12.3**	**PRI**	**M**	. . .
	Unburned carbon	5-10.3	PRI	M/E	. . .
	% carbon in residue	4-12.3.5	PRI	M	. . .
	Residue split	4-7.8	PRI	M/E	. . .
	Excess air	5-11.4	PRI	M/E	See Table 4-2-6
	Moisture in air	5-11.2	PRI	M/E	. . .
	Additional moisture	4-7.4	PRI	M/E	. . .
. . .	**Sorbent Analysis**	**4-12.3**	**PRI**	**M**	. . .
	Ca/S molar ratio	5-9.6	PRI	M/E	. . .
	Calcination	5-10.8	PRI	M/E	. . .
	Sulfur capture	5-9.5	PRI	M/E	. . .

NOTES:
(1) Typical influence: PRI = primary, SEC = secondary.
(2) Typical source: M = measured, C = calculated, E = estimated.

The following rules should be used when performing simultaneous velocity, temperature, and oxygen traverses during a test run:

(a) There should be no fewer than three complete traverses per test run.

(b) Flow weighting of O_2 should be considered only if ΔO_2 is greater than 0.2% and three or more complete traverses have been performed during the test run.

(c) The values of ΔT and ΔO_2 must be repeatable between the test runs. If the value for either ΔT or ΔO_2 for any traverse differs by more than 33% from the average value for all traverses, the most likely cause is bad velocity data and data from that traverse must be rejected.

During each test run, a velocity probe should be located at a fixed point where the velocity is approximately equal to the average value, the temperature is approximately equal to the average value, and the oxygen content is approximately equal to the average value. The velocity, temperature, and oxygen at this point should be recorded with the same frequency as the traverse points (that is, the data should be recorded each time the data at any traverse point is recorded). The resulting large number of data for the single point can be used to estimate the random error of the weighted average, as described in paras. 5-2.4.2 and 7-4.1.3.

4-3.6 Determination of Systematic Uncertainty Due to Measurements

Estimating the systematic uncertainty is a key step in designing the test and selecting instrumentation. The total systematic uncertainty associated with a particular measurement is the result of several systematic uncertainties in the measurement system. Subsection 7-5 describes the process of combining the systematic uncertainties. For each parameter in the test program, all possible sources of measurement system error associated with that parameter should be determined. All of the components of the system should be examined to estimate their systematic uncertainty.

Outside factors that influence the measurement should be considered. Factors such as an air leak into a flue gas analyzer should be considered and included as a one-sided systematic uncertainty, since a leak can only dilute the sample. Obviously, 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 uncertainties 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 uncertainties associated with these portions of the measurement system warrant discussion next. Following the discussion of the data collection system, each of the different types of process measurements are discussed along with the systematic uncertainties associated with their primary elements and sensing devices. Other sources that may be referenced for typical values of systematic uncertainty include other ASME publications, such as ASME MFC-3M, Measurement of Fluid Flow in Pipes Using Orifice, Nozzle, and Venturi; ASME PTC 19.2, Pressure Measurement; and ASME PTC 19.3, Temperature Measurement; ISO 5167; appropriate ASTM standards; and instrument manufacturer specifications.

Estimating the systematic uncertainty in a measurement involves the evaluation of all components of a measurement system, such as those listed in Tables 4-3.6-1 through 4-3.6-5. These systematic uncertainties, however, may not be representative of any specific measurement situation and tend to be conservative. It would be misleading for this Code to mandate specific values for systematic uncertainty and values must be agreed by parties to the test.

Many instrument specifications provide a reference accuracy. This accuracy is only a part of the potential systematic uncertainty of that instrument. Other factors such as drift, nonuniformity of flowing fluid, vibration, and differences between assumed and actual water leg density can influence the measurement. Often the reference accuracy of an instrument can be improved through calibration. After a calibration, the accuracy of the reference standard and the repeatability of the instrument can be combined to determine the new accuracy of the instrument.

The assignment of the appropriate systematic uncertainty requires the full knowledge of the test measurement system, the process being tested, and all other factors that may influence the systematic uncertainty 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 uncertainties.

When parameters are estimated rather than measured, the values for estimates and for systematic uncertainty shall be agreed upon by the parties to the test. The test engineer can usually arrive at reasonable values by considering that the probability is approximately 19:1 (95% confidence level) 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 4-3.6-1 Potential Instrumentation Systematic Uncertainty

Instrument	Systematic Uncertainty [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–600°F	±2°F
600°F–1,600°F	±0.4%
Premium Grade Type K	. . .
32°F–530°F	±2°F
530°F–2,300°F	±0.4%
Standard Grade Type E	. . .
32°F–600°F	±3°F
600°F–1,600°F	±0.5%
Standard Grade Type K	. . .
32°F–530°F	±4°F
530°F–2,300°F	±0.8%
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 (6)
Velocity	. . .
Standard pitot tube	. . .
Calibrated	±5% [Note (7)]
Uncalibrated	±8% [Note (7)]
S-type pitot tube	. . .
Calibrated	±5% [Note (7)]
Uncalibrated	±8% [Note (7)]
3-hole probe	. . .
Calibrated	±2% [Note (7)]
Uncalibrated	±4% [Note (7)]

Table 4-3.6-1 Potential Instrumentation Systematic Uncertainty (Cont'd)

Instrument	Systematic Uncertainty [Note (1)]
Hot wire anemometer	±10%
Turbometer	±2%
Flow (Air and Flue 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%
Flows (Steam and Water)	**Note (8)**
Flow nozzle	. . .
ASME PTC 6 (with flow straighteners)	. . .
Calibrated and inspected	±0.25%
Uncalibrated and inspected	±0.75%
Uncalibrated and uninspected	±2%
Pipe taps	. . .
Calibrated and inspected	±0.50% steam ±0.40% water
Uncalibrated and inspected	±2.2% steam ±2.1% water
Uncalibrated and uninspected	New plant: see above Existing plant: variable
Venturi	. . .
Throat taps	. . .
Calibrated and inspected	±0.50% steam ±0.40% water
Uncalibrated and inspected	±1.2% steam ±1.1% water
Uncalibrated and uninspected	New plant: see above Existing plant: variable
Orifice	**Note (9)**
Calibrated and inspected	±0.50% steam ±0.40% water
Uncalibrated and inspected	±0.75% steam ±0.70% water
Uncalibrated and uninspected	New plant: see above Existing plant: variable
Weir	±5%
Blowdown valve	±15%
Coriolis flowmeter (for liquid)	±0.1%
Liquid Fuel Flow (Calibrated)	. . .
Flowmeter	. . .
Positive displacement meter	±0.5%
Turbine meter	±0.5%
Orifice (for larger pipes, uncalibrated)	±1.0%
Coriolis flowmeter	±0.1%
Weigh tank	±1%
Volume tank	±4%
Gaseous Fuel Flow	**Note (9)**
Orifice	. . .

Table 4-3.6-1 Potential Instrumentation Systematic Uncertainty (Cont'd)

Instrument	Systematic Uncertainty [Note (1)]
Calibrated and inspected	±0.5%
Calibrated and uninspected	±2%
Uncalibrated and inspected	±0.75%
Turbometers	. . .
Non self-correcting	±1.0%
Self-correcting	±0.75%
Coriolis flowmeter	±0.35%
Solid Fuel and Sorbent Flow	. . .
Gravimetric feeders	. . .
Calibrated with weigh tank	±2%
Calibrated with standard weights	±5%
Uncalibrated	±10%
Volumetric feeders	. . .
Belt	. . .
Calibrated with weigh tank	±3%
Uncalibrated	±15%
Screw, rotary valve, etc.	. . .
Calibrated with weigh tank	±5%
Uncalibrated	±15%
Weigh bins	. . .
Weigh scale	±5%
Strain gauges	±8%
Level	±10%
Impact meters	±10%
Residue Flow	. . .
Isokinetic dust sampling	±10%
Weigh bins	. . .
Weigh scale	±5%
Strain gauges	±8%
Level	±20%
Screw feeders, rotary valves, etc.	. . .
Calibrated with weigh tank	±5%
Uncalibrated	±15%
Assumed split (bottom ash/fly ash)	10% of total ash
Solid Fuel and Sorbent Sampling	**See Tables 4-3.6-2 and 4-3.6-3**
Stopped belt	±0%
Full cut	⩾1%
"Thief" probe	⩾2%
Time-lagged	⩾5%
Liquid and Gaseous Fuel Sampling	**See Tables 4-3.6-4 and 4-3.6-5**
Flue Gas Sampling	. . .
Point-by-point traverse	See Section 7
Composite grid	See Section 7
Unburned Carbon (UBC) in Residue	**Note (10)**
Isokinetic dust sampling	±5%
"Thief" probe	±200%
Bottom ash	±50%
Bed drain	±20%
Fuel Handling and Storage	**−10% of moisture value**
Limestone handling and storage	+5% of moisture value
Residue	0

Table 4-3.6-1 Potential Instrumentation Systematic Uncertainty (Cont'd)

Instrument	Systematic Uncertainty [Note (1)]
Flue Gas Analysis	. . .
Oxygen analyzer	. . .
Continuous electronic analyzer	±1.0% of span
Orsat analyzer	±0.2 points
Portable analyzer	±5% of reading ±2% of span
Calibrated on air	. . .
Calibrated on cal gas	. . .
Carbon monoxide	. . .
Continuous electronic analyzer	±20 ppm
Orsat analyzer	±0.2 points
Sulfur dioxide	. . .
Continuous electronic analyzer	±10 ppm
CEM electronic analyzer	±50 ppm
Oxides of nitrogen	. . .
Chemiluminescent	±20 ppm
CEM electronic analyzer	±50 ppm
Hydrocarbons	. . .
Flame ionization detector	±5%
Electric Power	**Note (11)**
Voltage or current	. . .
Current transformer (CT), Class A/B	±0.3%
Voltage transformer (VT), Class A/B	±0.3%
Clamp-on measurements	±2%
Watts	. . .
Wattmeter, Class C	±0.5%
Humidity	. . .
Hygrometer	±2% RH
Sling psychrometer	±0.5 gradation
Weather station	Note (6)

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) Must be corrected for elevation and distance from weather station.
(7) These systematic uncertainties include user-induced errors such as probe location.
(8) Calibrations at test Reynolds number or use ASME PTC 6 nozzle for extrapolation. For uncalibrated devices, flow coefficients and uncertainties can be calculated in accordance with ASME PTC 19.5.
(9) Uncalibrated orifice uncertainty is generally not greater than beta ratio (d/D).
(10) The carbon content of all ash streams should be minimized.
(11) See ASME PTC 19.6, Electrical Measurements in Power Circuits, for applicability.

Table 4-3.6-2 Potential Systematic Uncertainty for Coal Properties

Coal Property	Analysis Procedure	Systematic Uncertainty	Comments
Sampling	ASTM D2234	±10% of ash content	<5% ash ± 0.5%
		±2% of other constituents	. . .
Sample preparation	ASTM D2013	None	. . .
Air dry moisture	ASTM D3302	±0.31% bituminous	. . .
		±0.33% subbituminous	. . .
Ash content	ASTM D3174	±0.15% bituminous with no carbonate	. . .
		±0.25% subbituminous with carbonate	. . .
		±0.5% > 12% ash with carbonate and pyrite	. . .
Proximate	ASTM D5142	Moisture = 0.12 + 0.017 x	Automated method
		Ash = 0.07 + 0.0115 x	. . .
		VM = 0.31 + 0.0235 x	. . .
Total moisture	ASTM D3173	±0.15% for fuels <5% moisture	. . .
		±0.25% for fuels >5% moisture	. . .
Carbon	ASTM D5373	±1.25% (1 − %H_2O/100) [Note (1)]	>100 mg sample
Hydrogen	ASTM D5373	± 0.15% (1 − %H_2O/100) [Note (1)]	>100 mg sample
Nitrogen	ASTM D5373	±0.09% (1 − %H_2O/100)	>100 mg sample Method B
	ASTM D3179	±0.205 × −0.13	. . .
Sulfur	ASTM D4239	±0.05% bituminous	. . .
		±0.07% subbituminous	. . .
	ASTM D3177	±0.5% for fuels <2% sulfur	. . .
		±0.1% for fuels >2% sulfur	. . .
HHV	ASTM D5865	±69 Btu/lb dry basis: anthracite/bituminous	. . .
		±59 Btu/lb dry basis: subbituminous/lignite	. . .
Converting analysis to different basis	ASTM D3180	None	. . .

GENERAL NOTE: All systematic uncertainties are absolute unless otherwise indicated.

NOTE:

(1) Estimated based on repeatability.

Table 4-3.6-3 Potential Systematic Uncertainty for Limestone Properties

Limestone Property	Analysis Procedure	Systematic Uncertainty	Comments
Limestone constituents	ASTM C25	Calcium oxide ±0.16%	Test Method 31
		Magnesium oxide ±0.11%	Test Method 31
		Free moisture ±10% value	. . .
		Inert by difference ±5.0% of value	. . .
Sampling	See para. 4-8.2	±2.0% thief sample	. . .
		±5.0% other	. . .

GENERAL NOTES:

(a) All systematic uncertainties are absolute unless otherwise indicated.

(b) Free moisture, inerts, and sampling systematic uncertainty are suggested values.

Table 4-3.6-4 Potential Systematic Uncertainty for Fuel Oil Properties

Fuel Oil	Analysis Procedure	Systematic Uncertainty	Comments
Sampling	ASTM D4057	±0.5% for multiple samples	. . .
		±1% for single sample	. . .
		±2% for supplier analysis	. . .
API gravity	ASTM D1298	±0.25 API for opaque (heavy oil)	. . .
		±0.15 API for transparent (distillate)	. . .
		±5 API if estimated	. . .
Water content	ASTM D95	±0.1% for fuels <1% water	. . .
		±5% of measured value for >1% water	. . .
Ash	ASTM D482	±0.003% for fuels <0.08% ash	. . .
		±0.012% for fuels 0.08%–0.18% ash	. . .
Sulfur	ASTM D1552	**%S IR Iodate**	. . .
		<0.5 0.07% 0.04%	
		0.5–1 0.11% 0.06%	
		1–2 0.14% 0.09%	
		2–3 0.19% 0.13%	
		3–4 0.22% 0.20%	
		4–5 0.25% 0.27%	
Carbon	ASTM D5291	± (x + 48.48) 0.009 [Note (1)]	. . .
	ASTM D5373		. . .
Hydrogen	ASTM D5291	± $(x^{0.5})$ 0.1157 [Note (1)]	. . .
Nitrogen	ASTM D5291	± 0.23	Reported to 0.00
	ASTM D3228	± 0.095 $N^{0.5}$	. . .
Heating value	ASTM D240	86 Btu/lbm	. . .
	ASTM D4809	±49 Btu/lbm, all fuels	. . .
		±51 Btu/lbm, nonvolatiles	. . .
		±44 Btu/lbm, volatiles	. . .

GENERAL NOTE: All systematic uncertainties are absolute unless otherwise indicated.

NOTE:

(1) Estimated based on repeatability.

Table 4-3.6-5 Potential Systematic Uncertainty for Natural Gas Properties

Natural Gas	Analysis Procedure	Systematic Uncertainty	Comments
Sampling	ASTM D5287	±0.5% for multiple sample	. . .
		±1.0% for single sample	. . .
		±2.0% for supplier analysis	. . .
		On-line analysis: use supplier specification for guidance	. . .
Gas constituents	ASTM D1945	Mole percent of constituent:	
		0.0–0.1 ±0.01%	. . .
		0.1–1.0 ±0.04%	. . .
		1.0–5.0 ±0.05%	. . .
		5.0–10.0 ±0.06%	. . .
		>10 ±0.08%	. . .
Higher heating value, calculated	ASTM D3588	None	Perturbed with fuel constituents
Higher heating value	ASTM D1826	0.3%–0.55%	. . .

GENERAL NOTE: All systematic uncertainties are absolute unless otherwise indicated.

4-4 TEMPERATURE MEASUREMENT

4-4.1 General

Temperature is typically measured with thermocouples (TCs), resistance temperature devices (RTDs), temperature gauges, or mercury-in-glass thermometers. These devices produce either a direct reading or a signal that can be read with a handheld meter or data logger.

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.

RTDs have a narrower operating range and a slower response time than thermocouples, but are potentially more accurate.

Mercury-in-glass thermometers are limited to measurement of temperatures lower than the boiling point of mercury and to visual reading only.

Each of these devices has advantages and constraints to its use. Users of this Code are referred to ASME PTC 19.3 for further information on temperature measurement techniques.

4-4.2 Systematic Uncertainty for Temperature Measurement

When estimating the systematic uncertainty of a temperature measurement, test personnel should consider the following potential sources. 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 4-3.6-1.

(a) TC type
(b) RTD type
(c) calibration
(d) lead wires
(e) thermowell location/geometry/condition
(f) pad weld (insulated/uninsulated)
(g) stratification of flowing fluid
(h) grid size
(i) grid location
(j) ambient conditions at junctions
(k) ambient conditions at meter
(l) intermediate junctions
(m) electrical noise
(n) heat conduction and radiation
(o) potentiometer/voltmeter
(p) reference junction accuracy
(q) drift
(r) thermometer nonlinearity
(s) parallax

4-4.3 Air and Gas Temperatures

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. Generally, temperature uncertainty can be reduced either by sampling more points or by using more sophisticated calculation methods. 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. 4-3.4 should be applied to reduce potential errors in the average temperature. Thermocouples shall be read individually and not be grouped together to produce a single output.

If flue gas temperature is measured at a point where the temperature of the gas is significantly different from the temperature of the surrounding surface, an error is introduced. This situation occurs when the gas temperature is high, and the surface is cooled well below the gas temperature. The thermocouple is cooled by radiation to the surrounding surface, and this reduction in measured temperature should be taken into account. A high velocity thermocouple (HVT) probe can be used to reduce this error.

4-4.3.1 Method of Measurement. The average values from multiple point samples are determined as discussed in para. 5-2.3.

This requires specific placement of sampling points. The minimum number of points is given; but uncertainty can be reduced by increasing the number of points. The following rules should apply to location of sampling points:

(a) Rectangular Ducts. Rectangular ducts shall be divided to form a grid with equal areas. Samples shall be taken at the centroid of each equal area. For ducts larger than 9 ft^2, there should be from 4 to 36 sampling points, based on the cross-sectional area of the duct. Each equal area should be no larger than 9 ft^2 unless there are more than 35 points. In such cases, the equal areas may be larger than 9 ft^2. The Code does not require more than 36 points.

There should be a minimum of two points spanning each dimension (height and width) of the duct cross section. In ducts with severe stratification, it is recommended that points be added in the direction of the steepest gradient.

According to the systematic uncertainty models suggested in para. 7-5.3.2, the systematic uncertainty due to numerical integration decreases as the square of the number of points; therefore, using more points has a significant effect on that component of the uncertainty.

The shape of the equal areas should be one of the following:

(1) a rectangle with the ratio of height to width the same as that of the cross section of the duct, so that it is of the same geometrical shape as the cross section,

as shown in Fig. 4-4.3.1-1, illustration (a). This is the preferred method.

(2) any rectangle, as shown in Fig. 4-4.3.1-1, illustration (b), that is more nearly square than the geometric shape on Fig. 4-4.3.1-1, illustration (a).

(3) a square, as shown in Fig. 4-4.3.1-1, illustration (c).

If the shape of the equal area is not square, the long dimension should align with the long dimension of the cross section. If a greater number of measurement points are being used than is recommended, the additional points may be added without concern for the aspect ratio.

(b) Circular Ducts. Circular ducts should be divided into equal areas of 9 ft^2 or less. There should be from 4 to 36 sampling points based on the cross-sectional area of the duct. Parties to the test may agree to divide the cross section into either 4, 6, or 8 sectors. The location of each sampling point must be at the centroid of each equal area. The location of these sampling points may be determined by the method shown in the example in Fig. 4-4.3.1-2, which shows the use of 20 points and 4 sectors. There must be at least 1 point per sector.

4-4.3.2 Estimating Systematic Uncertainty. An estimate of the systematic uncertainty from a temperature measurement grid is a combination of systematic uncertainties from temperature primary element and sensor type, data acquisition, grid size, temperature distribution, averaging method, and flow weighting. Potential sources of these systematic uncertainties are described in subsection 4-3 and para. 4-4.2. Models for the estimation of systematic uncertainties due to flow weighting, grid size, and averaging method are suggested in subsection 7-5.

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

4-4.4 Steam and Water Temperatures

Steam and water flowing in pipes typically have an approximately uniform temperature distribution. A potential exception is in the piping from a desuperheater in which spray impingement could cause nonuniformity.

4-4.4.1 Method of Measurement. Selection of the method of measurement and the temperature measuring instruments depends upon the conditions of the individual case. Steam and water temperatures are usually measured by insertion of 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 Systematic Uncertainty. An estimate of the systematic uncertainty from a temperature measurement is a combination of systematic uncertainties 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 Solid Streams

The temperatures of solid streams entering or leaving the unit are often difficult to measure. The parties to the test should decide whether the temperature of these streams will be assigned a value or measured. If temperatures are to be measured, the temperature probe should be inserted into a flowing stream. The average temperature of multiple solid streams should be mass flow weighted.

4-4.5.1 Method of Measurement. The following locations and methods of measurement shall be used:

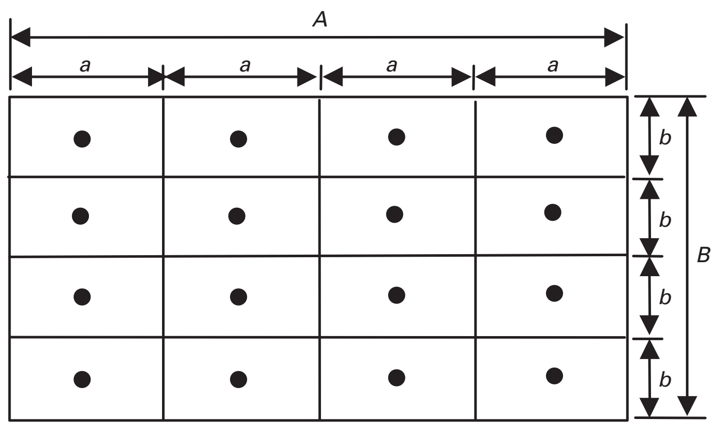
fuel: a rigidly supported temperature-measuring instrument should be inserted into the solid fuel stream as close as practical upstream of the point where the primary/transport air is mixed with the fuel.

sorbent: a rigidly supported temperature-measuring instrument should be inserted into the solid sorbent stream as close as practical upstream of the point where the transport air is mixed with the sorbent or the fuel/sorbent mixture.

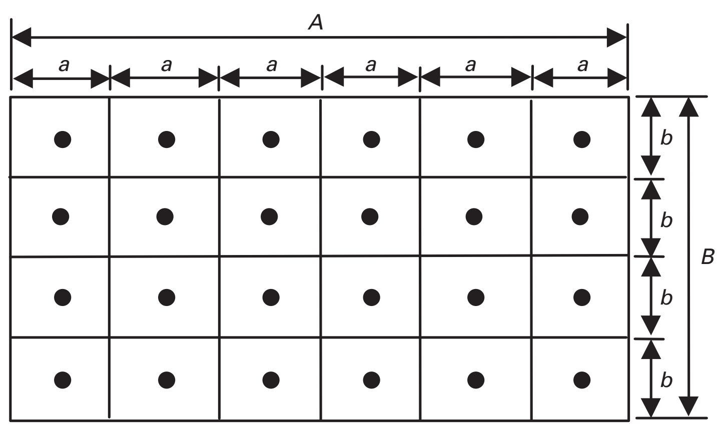
residue: residue that carries over in the flue gas stream (fly ash) can be considered to be the same temperature as the gas at the extraction point. An exception is ash leaving an air heater. The temperature of the gas leaving the air heater excluding leakage shall be used. For bed drains in fluidized bed combustors, the bed temperature may typically be used unless bed drain coolers return heat to the boundary. In that case, the temperature of the bed drain leaving the cooler should be measured. Refer to subsection 5-14 for estimating bottom ash temperature. If the residue temperature is measured (such as residue leaving a grate), a rigidly supported temperature-measuring instrument should be inserted into each flowing residue stream as close as practical to the point where the residue leaves the boundary.

4-4.5.2 Estimating Systematic Uncertainty. An estimate of the systematic uncertainty from a temperature measurement is a combination of systematic uncertainties from temperature primary element, sensor type, and data acquisition. Subsection 4-3 and para. 4-4.2 discuss potential sources of these systematic uncertainties. When systematic uncertainties are assigned to parameters that are assumed, typically a larger value for systematic uncertainty is chosen than if the parameter is directly measured. If the mass flows of multiple streams

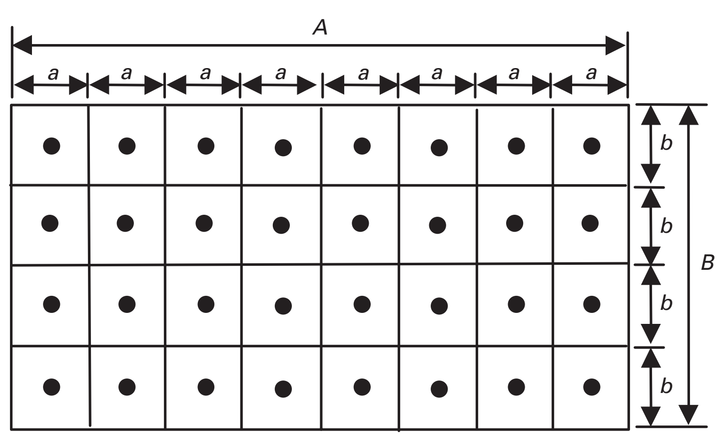
Fig. 4-4.3.1-1 Sampling Grids: Rectangular Ducts



(a) Same Geometric Shape as Cross Section $\left(\frac{A}{B} = \frac{a}{b}\right)$

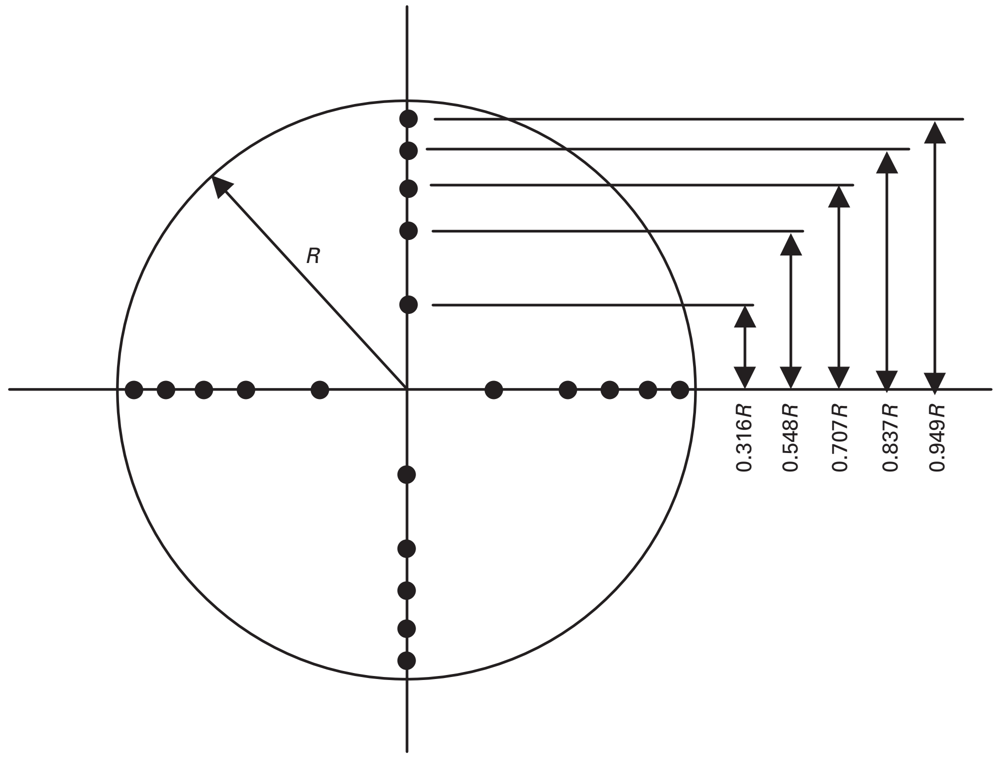


(b) More Nearly Square Than Illustration (a) $\left(\frac{A}{B} > \frac{a}{b} \text{ and } a > b\right)$



(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. To be 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

GENERAL NOTES:

(a) Indicates points of location of sampling tube.

(b) r_p will be in the same units as R.

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

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

are not approximately equal and the average temperature is not flow weighted, a higher systematic uncertainty should be assigned. If stratification is suspected in the solid stream, this should be incorporated into the systematic uncertainty estimate.

4-4.6 Liquid and Gaseous Fuels

Liquid or gaseous fuels flowing in pipes usually have approximately uniform temperature distribution.

4-4.6.1 Method of Measurement. A temperature measuring instrument should be inserted into the fuel stream at the entrance to the unit, preferably near the flow measurement device. If the fuel is heated by a source external to the unit being tested, the inlet temperature shall be measured after this heater. If the fuel is heated directly from the unit being tested, the temperatures shall be measured before the heater.

4-4.6.2 Estimating Systematic Uncertainty. An estimate of the systematic uncertainty from a temperature measurement is a combination of systematic uncertainties from temperature primary element, sensor type, and data acquisition. Subsection 4-3 and para. 4-4.2 discuss potential sources of these systematic uncertainties.

4-5 PRESSURE MEASUREMENT

4-5.1 General

Total pressure is the sum of static pressure and velocity pressure. Change in static head is calculated based on the average fluid conditions and local ambient conditions. Velocity pressure is usually calculated from average fluid velocity and density. If velocity is to be measured, refer to para. 4-6 for guidance in making these measurements. This section addresses the measurement of static pressure.

4-5.2 Systematic Uncertainty for Pressure Measurement

When estimating the systematic uncertainty of a pressure measurement, test personnel should consider the following list of potential sources. Not all sources are listed, and some of those sources listed may not be applicable to all measurements. These factors should be considered in conjunction with the factors listed in Table 4-3.6-1.

(a) gauge type
(b) manometer type
(c) transducer type
(d) calibration
(e) tap location/geometry/flow impact
(f) probe design
(g) stratification of flowing fluid
(h) number and location of measurement
(i) water leg
(j) specific gravity of manometer fluid
(k) ambient conditions at sensor
(l) ambient conditions at meter
(m) hysteresis
(n) electrical noise
(o) potentiometer/voltmeter
(p) drift
(q) transducer nonlinearity
(r) parallax

4-5.3 Air and Gas: Static and Differential Pressure

The static pressure in air and gas ducts may be required to determine pressure drop. Pressure drop determinations should be performed using differential measuring apparatus rather than two separate instruments.

4-5.3.1 Method of Measurement. Pressure is measured with gauges, manometers, or transducers. The output of these devices is either visual or a signal that can be read with a handheld meter or data logger. ASME PTC 19.2 provides further information on pressure measurement techniques.

Static pressure connections must be installed to minimize errors resulting from gas velocity impingement. This may be accomplished by proper location of taps around the perimeter of the duct or by use of specially designed probes. Measurements should be made at more than one location in or around the plane. Piping or tubing should be specifically installed for the test, and should be verified leak-proof. Provisions should be made for cleaning and draining. Connections from the instrument to the pressure tap should slope downward to allow condensate to flow back into the duct. When this is not possible, provisions must be made to account for condensate water legs. Purging may be used to keep pressure sensing lines clear. If purging is used, a constant low flow should be maintained.

4-5.3.2 Estimating Systematic Uncertainty. An estimate of the systematic uncertainty from a pressure measurement is a combination of systematic uncertainties from primary element, installation effects, and data acquisition. Potential sources of these systematic uncertainties are addressed in subsection 4-3 and para. 4-5.2.

4-5.4 Steam and Water: Static and Differential Pressure

The static pressure in steam and water piping may be required to determine fluid properties or pressure drop. To minimize uncertainty, pressure drop determinations should be performed using differential measuring apparatus rather than two separate instruments.

4-5.4.1 Method of Measurement. Pressure measurement devices should be located to minimize the effects of temperature and vibration. Adhere to the following in the installation of pressure measuring devices:

(a) Pressure measurement connections should be short and direct.

(b) All pressure measurement connections should be leakproof, 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 condensate allowed to fill the lines. Condensate water legs shall be included in the calculations.

4-5.4.2 Estimating Systematic Uncertainty. An estimate of the systematic uncertainty from a pressure measurement is a combination of systematic uncertainties from primary element, tap type, and data acquisition. Potential sources of these systematic uncertainties are discussed in subsection 4-3 and para. 4-5.2.

4-5.5 Barometric Pressure

Barometric pressure is required to determine ambient conditions.

4-5.5.1 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, not corrected to sea level, reported at the nearest weather station. The elevation of the weather station's reading and the test site should be noted and corrections made for any differences in elevation.

4-5.5.2 Estimating Systematic Uncertainty. The use of a barometer or other such measurement device at the site will be considered to have a negligible systematic uncertainty. Data from a weather station is considered the least accurate, and if used, an appropriate systematic uncertainty should be assigned.

4-6 VELOCITY TRAVERSE

4-6.1 General

A velocity traverse consists of measurements taken at numerous locations in a plane perpendicular to the flow. These measurements should include at least velocity pressure, static pressure, and temperature, and may also include velocity vector angles. The user should refer to subsections 4-4 and 4-5 related to temperature and pressure measurements for guidelines and specific instructions.

A probe is inserted into the duct, and measurements are made at a number of locations corresponding to the centers of equal areas. The probe is usually one of several types that sense the velocity pressure and pressure differentials indicating yaw and pitch. Users of this Code are referred to ASME PTC 19.5 and ASME PTC 11 for further information on velocity measurement techniques.

4-6.2 Systematic Uncertainty for Velocity Traverse

When estimating the systematic uncertainty of a velocity traverse, test personnel should consider the following potential sources. 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 4-3.6-1 and paras. 4-4.2 and 4-5.2.

(a) probe type
(b) calibration
(c) stratification of flowing fluid
(d) turbulent/laminar flow conditions
(e) yaw
(f) pitch
(g) grid size
(h) grid location
(i) ambient conditions at measurement location
(j) parallax
(k) pressure errors
(l) fluctuation of pressure in time
(m) temperature errors

4-6.3 Method of Measurement

Measurements are taken at the centers of equal areas. The traverse points must correspond to the temperature or oxygen measurement points. ASME PTC 19.5 and ASME PTC 11 may be consulted for information on velocity measurement. Numerous types of probes are used for velocity measurement, such as standard pitot, S-type, 3-hole and 5-hole, turbometer mass flow probe, and others. Determination that accounts for the direction of flow at the plane of measurement is preferred.

4-6.4 Estimating Systematic Uncertainty

An estimate of the systematic uncertainty 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 uncertainties. If the probe used for the velocity traverse does not account for the approach angle to the plane of measurement, the velocity may be overestimated, and an appropriate systematic uncertainty should be included.

4-7 FLOW MEASUREMENT

4-7.1 General

Numerous methods are employed in industry to determine the flow rate of solid, liquid, or gaseous streams. ASME PTC 19.5 is the primary reference for flow measurements. ASME PTC 6, Steam Turbines, and ISO 5167 provide further information on flow measurement techniques. These sources include design, construction, location, and installation of flowmeters, the connecting piping, and computations of flow rates. If an individual stream flow rate is to be determined by velocity traverse, refer to subsection 4-6.

For multiple streams where the total flow can be calculated more accurately than measured (e.g., air, flue gas, residue, etc.), all but one stream may be measured and the unmeasured stream flow rate calculated by difference. If all streams are measured, the mass flow 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 flow fraction of the individual streams and the total calculated mass flow rate.

4-7.2 Systematic Uncertainty for Flow Measurement

Flow is often measured indirectly (i.e., using measured differential pressure, pressure, and temperature); therefore, the measured inputs to the flow calculation must be examined for sources of systematic uncertainty and combined into the systematic uncertainty of the flow measurement. When estimating the systematic uncertainty of a flow measurement, test personnel should consider the following potential sources. 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 4-3.6-1.

(a) Potential Sources of Systematic Uncertainty of a Flow Measurement

(1) calibration of primary element (e.g., orifice, nozzle, venturi, airfoil, and differential sensing probes)
(2) stratification of flowing fluid
(3) temperature systematic uncertainties
(4) pressure systematic uncertainties
(5) installation
(6) condition of nozzle or orifice
(7) pressure correction (compensation)
(8) temperature correction (compensation)
(9) Reynolds number correction
(10) measurement location
(11) fan/pump curve
(12) valve position
(13) level accuracy/difference
(14) heat balance inputs/equations
(15) weir
(16) tap location

(b) Factors Influencing the Uncertainty of the Coriolis-Type Flowmeters. Direct measurement of fluid mass flow rate and density is possible with Coriolis type flowmeters. Factors that influence the uncertainty of the Coriolis type flowmeters include

(1) fluid properties
(2) void fraction
(3) bubbly flow
(4) pulsation at vibratory frequency
(5) pressure and temperature effects on zero stability

4-7.3 Air and Flue Gas

The total mass flow of air and flue gas crossing the steam generator boundary is calculated stoichiometrically. It may be necessary to measure the air or flue gas flow in addition to the temperature of the stream to account for an individual air or gas stream that crosses the steam generator boundary. The energy crossing the boundary in that air or gas stream then may be calculated.

4-7.3.1 Methods of Measurement. There are numerous methods for the measurement of air and gas flow (e.g., venturi, airfoil, velocity traverse, heat balance, etc.). If plant instrumentation is used, it should be calibrated. The flow may be calculated from velocity, as measured according to subsection 4-6, the density of the fluid, and the duct cross-sectional area. The use of sophisticated traversing strategies such as Gauss or Tchebycheff distribution of points as described in ASME PTC 19.5, generally leads to more accurate determination of flows.

4-7.3.2 Estimating Systematic Uncertainty. The most accurate way to determine the flow of air or gas in most applications is by calculation. The steam generator efficiency, total output, flue gas weight per pound of fuel, and heating value of the fuel can all be determined accurately. The measurement of air and flue gas flow is subject to significant error. Using a standard pitot tube or a Stauschibe (S-type or forward-reverse) tube can result in overestimating the flow if the flow is not perpendicular to the plane of measurement. The area of the duct may also be difficult to determine accurately because of obstructions within the duct or inaccurate dimensions. An estimate of the systematic uncertainty from an air or gas flow measurement is a combination of systematic uncertainties from measurement methods and data acquisition. Subsection 4-3 and para. 4-7.2 discuss potential sources of these systematic uncertainties. If the probe used for velocity traverse does not account for the approach angle to the plane of measurement, the velocity may be overestimated, and an appropriate systematic uncertainty should be included.

4-7.4 Steam and Water

Certain steam and water flow measurements may be required, depending on the objective of the test. When the determination of output is required, the preferred method is to use a calibrated and inspected flow element such as the ASME throat tap nozzle, as described in ASME PTC 6, Steam Turbines. On large units, the PTC 6 nozzle is preferred because of the potentially high Reynolds numbers of the measured flow. The requirement for the PTC 6 nozzle is eliminated if the flow element can be calibrated at the Reynolds numbers that will be encountered during the test. The PTC 6 flow nozzle should be used if flow coefficients need to be extrapolated to higher Reynolds numbers. While an energy balance calculation is acceptable for determining the superheat desuperheating spray flow, reheat desuperheating spray flow should be directly measured rather than calculated by energy balance. If the reheat desuperheating spray flow is low enough that the differential produced by the orifice or nozzle is at the lower range of the system, a measuring device and transmitter that is accurate at the spray flow rate or an energy balance calculation should be used.

4-7.4.1 Method of Measurement. 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 typically include reheat extraction flow to feedwater heaters, and possibly, superheater desuperheating spray flow. The method of calculation is outlined in subsection 5-4. Enthalpies shall be determined from the ASME Steam Tables, version per para. 3-2.3, using pressures and temperatures measured with test instrumentation.

(c) *Estimated Flows.* In some cases, it may not be feasible to quantify a flow using any of the methods listed above. In these cases, flow curves relating to either a known flow or a valve position may be used. Steam flow based on first-stage pressure, estimated turbine leakage based on main steam flow, or blowdown flow based on valve turns are examples of this type of flow. Design performance data also may be used. All parties involved in the performance test must agree to the method of calculation prior to the test, and an appropriate uncertainty must be assigned.

4-7.4.2 Estimating Systematic Uncertainty. An estimate of the systematic uncertainty from a flow measurement is a combination of systematic uncertainties from primary element type, sensor type, and data acquisition installation effect. Subsection 4-3 and para. 4-7.2 discuss potential sources of these systematic uncertainties.

4-7.5 Liquid Fuel

The Input–Output method for efficiency determination requires the mass flow rate of liquid fuel burned.

4-7.5.1 Method of Measurement. The quantity of fuel may be determined by flow measurement device, weigh tank, or volume tank. Refer to para. 4-7.4.1 for discussion of the use of flow nozzles and thin plate orifices. Coriolis flowmeters are capable of direct measurement of mass flow rate and density, high accuracy, and have negligible sensitivity to variations in fluid properties (density, viscosity, API gravity, etc.) and velocity. Density and viscosity are required to determine the mass flow rate from a volume measurement device or method. The Coriolis flowmeter is the preferred method of measurement for liquid fuels when the Input–Output efficiency method is used due to the elimination of the need to measure density and viscosity and the uncertainty associated with determining them, and the inherently low systematic error of the instrument.

If a level change in a volume tank is utilized to determine the flow measurement, accurate density determination is required. ASTM D1298 provides procedures to determine API Gravity and density.

Recirculation of fuel between the point of measurement and point of firing shall be measured and accounted for in the flow calculation. Branch connections on the fuel piping shall be either blanked off or provided with double valves.

4-7.5.2 Estimating Systematic Uncertainty. An estimate of the systematic uncertainty from a flow measurement is a combination of systematic uncertainties from primary element type, sensor type, and data acquisition. Subsection 4-3 and para. 4-7.2 discuss potential sources of these systematic uncertainties.

4-7.6 Gaseous Fuel

For the Input–Output method, the quantity of gaseous fuel burned must be determined.

4-7.6.1 Method of Measurement. Measurement of the relatively large volumes of gaseous fuel normally encountered while testing steam generators requires the use of an orifice, flow nozzle, mechanical meter, ultrasonic, or Coriolis meter. Ultrasonic and Coriolis meters provide high accuracy. Coriolis flowmeters are capable of direct measurement of mass flow rate and density and have negligible sensitivity to variations in gas density, viscosity, and velocity.

The pressure drop shall be measured using a differential pressure gauge or differential pressure transmitter. Outputs from these devices can be read manually, via handheld meters, or with data loggers. When gas flow is measured, the temperature and pressure used in the calculation of density are extremely important. Small variations can cause significant changes in the calculated gas density. In addition, the supercompressibility factor has a significant effect on the determination of gas density.

4-7.6.2 Estimating Systematic Uncertainty. An estimate of the systematic uncertainty from a flow measurement is a combination of systematic uncertainties from primary element type, sensor type, and data acquisition.

Subsection 4-3 and para. 4-7.2 discuss potential sources of these systematic uncertainties. The impact of pressure and temperature measurements on the gas density should be evaluated at the test operating conditions, because a 10 psi deviation or a 2°F variation can impact flow as much as 1%.

4-7.7 Solid Fuel and Sorbent Flow Measurement

The accurate measurement of solid flow is difficult because of solid material variability.

4-7.7.1 Method of Measurement. Numerous methods are available to measure the flow of solids, such as gravimetric feeders, volumetric feeders, isokinetic particulate sample, weigh bins/timed weights, impact meters, etc. To reduce uncertainty of any of these methods below 5% to 10% requires extensive calibration against a reference. The calibration can involve the collection of the solid material into a container that can be weighted rather than placing weights on the belt. For example, the output of a gravimetric feeder can be directed to a container suspended by load cells, and the rate of feed indicated by the feeder can then be compared to the timed catch in the container.

It is even more difficult to assess the accuracy of volumetric feeders. This assessment requires assumptions about the volume of material passed per revolution and the density of the material. The rotor may not be full, the density may vary as a result of size distribution or other factors, and all these parameters may vary over time.

Calibrations of solids flow measurement devices should be conducted just prior to the testing and at frequent intervals to ensure the minimum systematic uncertainty.

4-7.7.2 Estimate of Systematic Uncertainty. The systematic uncertainty from a solid flow measurement is one of the most difficult parameters to determine. Systematic uncertainties from instrument response variation resulting from size distribution, uneven loading on the weigh scale, or varying densities should be considered. Subsection 4-3 and para. 4-7.2 discuss other potential sources of systematic uncertainties.

4-7.8 Residue Splits

The amount of residue leaving the steam generator boundary is required to determine the sensible heat loss in the residue streams and the weighted average of unburned carbon (and CO_2 on units that utilize sorbent) in the residue. Typical locations where the residue is removed periodically or continuously are furnace bottom ash (bed drains), economizer or boiler hoppers, mechanical dust collector rejects, and fly ash leaving the unit.

4-7.8.1 Method of Measurement. The calculated total residue mass flow rate is used since it is normally more accurate than a direct measurement. Therefore, the percent of the total residue that leaves each location must be determined. The following methods can be used to determine the split between the various locations:

(a) The mass flow rate should be measured at each location.

(b) The residue at one or more locations should be measured (usually the locations with the highest loading), and the quantity at the other locations should be calculated by difference. Where there is more than one unmeasured location, the split between these locations should be estimated.

(c) The residue percentage leaving each location may be estimated based on the typical results for the type of fuel and method of firing.

The parties to the test shall reach agreement on what streams are to be measured and values for any estimated splits prior to the test.

The fly ash concentration leaving the unit, determined in accordance with subsection 4-11, is used to calculate residue mass flow rate leaving the unit. See Section 5 for calculating the mass flow rate from the grain loading.

The mass flow rate of residue discharged from hoppers or grates in a dry state may be determined from weigh bins/timed weights (e.g., the number of rotations of rotary feeders, screw speed, impact meters). See para. 4-7.7.1 for considerations regarding calibration and sources of uncertainty.

Determining the mass flow rate of residue discharged from sluice systems is even more difficult than determining the dry state. Generally, the total discharge flow must be captured in bins or trucks, freestanding water drained off, and the bin or truck weighed and compared against the tare weight. Since residue is considered to leave the unit in a dry state, moisture content of the sample must be determined, and the measured wet mass flow rate must be corrected for moisture.

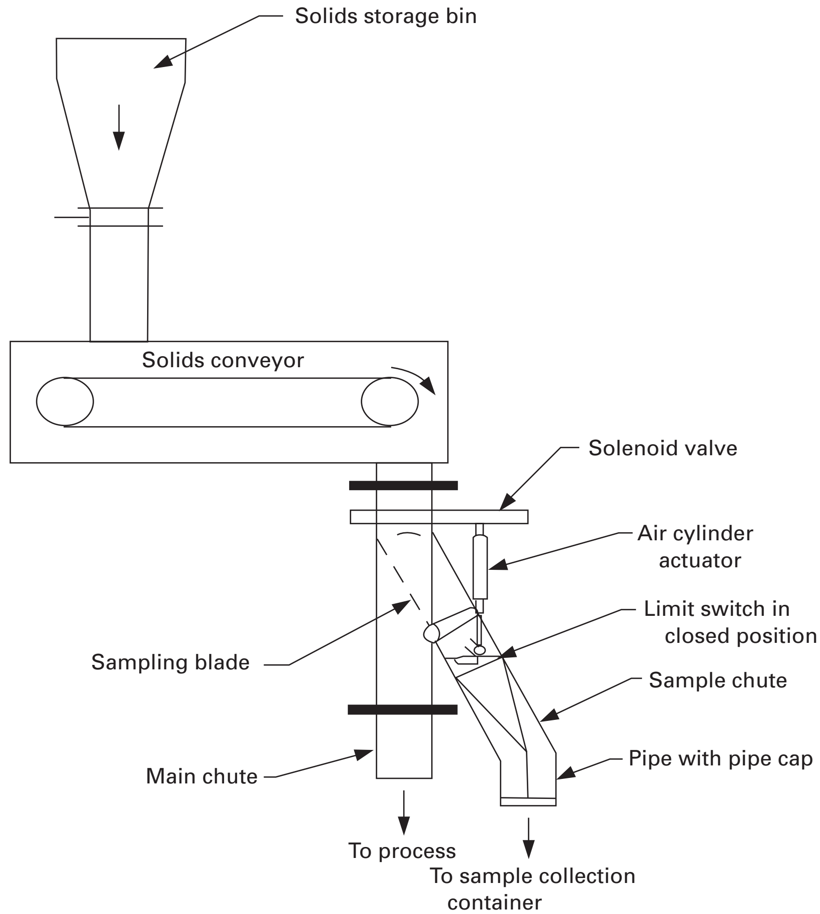
4-7.8.2 Estimating Systematic Uncertainty. When splits are estimated, a mean value should be selected such that the same positive and negative estimate of systematic uncertainty can be used. A systematic uncertainty that would produce a split of less than zero or more than 100% must not be used. Refer to subsection 4-11 regarding systematic uncertainty for dust loading (residue sampling). Where mass flow is determined from volumetric devices, considerations include repeatability of the fullness of the volume chamber and density and size distribution of the material. Also refer to para. 4-7.7.2.

4-8 SOLID FUEL AND SORBENT SAMPLING

4-8.1 General

The methods of sampling shall be agreed upon by all parties to the test and must be described in the test report. An appropriate uncertainty must be assigned for the method of sampling used for a test.

Fig. 4-8.2.1-1 Full Stream Cut Solid Sampling Process



Methods used to determine variances, standard deviations, and random uncertainties for the samples obtained during the test are discussed below. The estimation of systematic uncertainties is also addressed.

A pretest run is recommended to identify and alleviate potential problems in the sampling techniques.

4-8.2 Method of Solid Fuel and Sorbent Sampling

4-8.2.1 Sample Collection. ASTM D2234 provides guidance on sample collection. The stopped belt cut technique is the preferred or reference method. Zero sampling systematic uncertainty should be assigned if the stopped belt technique is used.

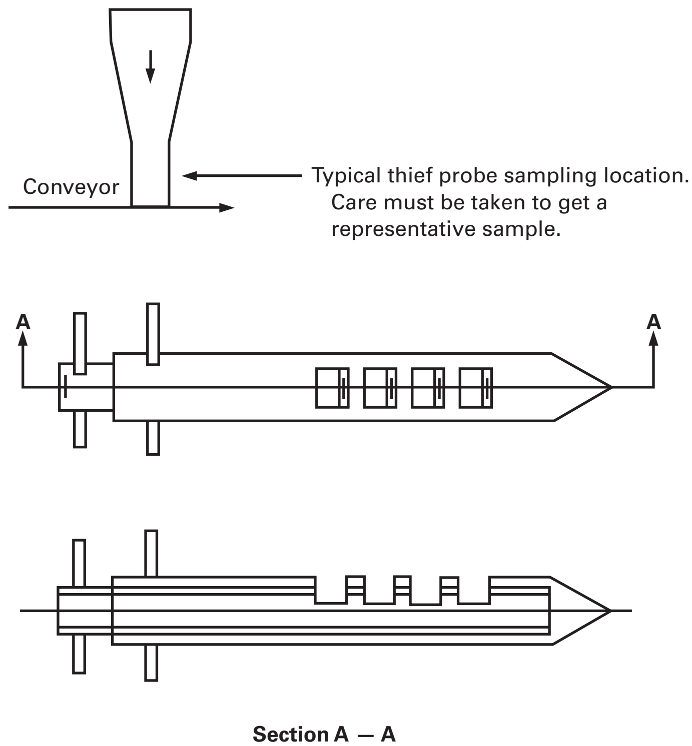
In many cases, however, stopped belt sampling is not practical; therefore, full stream cut sampling should be used. Full-cut sampling consists of taking full-diverted cut of a moving stream. Fig. 4-8.2.1-1 shows a typical full-cut sampling method.

A third method called "part-stream cut" is the most practical but may produce the greatest systematic uncertainty. A thief probe, as shown on Fig. 4-8.2.1-2, may be used for taking a part-stream cut from a flowing steam.

4-8.2.2 Sample Location. Fuel, sorbent (if applicable), and residue solids shall be sampled from a flowing stream as near to the steam generator as practical to ensure that samples are representative. If it is not possible or practical to sample near the steam generator, a time lag may be incurred between when the sample is taken and when it is actually injected or removed from the steam generator. This time lag must be determined based on estimated flow rates between the sample location and the steam generator. It is important that the time-lagged sample be representative of the actual material injected or removed from the steam generator.

Fuel or sorbent samples collected from upstream of silos, tanks, or hoppers typically have larger systematic uncertainty compared to samples collected downstream from the silos, tanks, and hoppers. Samplings from upstream of silos, tanks, and hoppers are classified as alternate procedures because of the possibility

Fig. 4-8.2.1-2 Typical "Thief" Probe for Solids Sampling in a Solids Stream



of samples not being representative of fuel fired during the test. Alternate procedures should not be used for acceptance tests. For other test purposes, if alternate procedures are used, the parties to the test shall assign appropriate systematic uncertainties.

4-8.2.3 Sample Interval. With one exception, the samples shall be collected at uniform, not random, intervals. The exception is when it is known that the collection sequence corresponds with "highs" or "lows" in the fine's content. In that instance, random time intervals should be used. Each sample should be of the same weight. The elapsed time to collect all coal samples must equal the duration of the test run.

4-8.2.4 Sample Number. As a minimum, it is recommended to obtain (collect) a sample at the beginning and the end of each test including once every hour during the test. Therefore, during a 4-hr test, five collections of samples will be exercised.

The number of individual samples collected will depend on the number of parallel streams. For example, if there are five parallel streams, a total of 20 individual samples will be collected.

The recommended minimum number of sample collections may be exceeded if the parties wish to increase accuracy of the fuel characteristics.

4-8.2.5 Sample Amount. For manual sampling of coal or sorbent, individual samples typically weighing from 2 lb to 8 lb are collected. For automatic sampling devices, much larger samples can be collected. Table 2 of ASTM D2234 provides information about sample size.

4-8.2.6 Parallel Streams. Parallel streams such as coal feed with belt feeders have the potential for variation from stream to stream because of different flow rates, particle sizes, and chemical composition. Therefore, unless the chemical constituents of the samples can be shown to be uniform, the samples must be taken from each of the parallel streams. If the flows for the parallel streams are unequal, the amount of samples of each parallel stream must be flow weighted. The flow for each of the parallel streams must be continuous throughout the test.

4-8.2.7 Sample Handling. Sampling must be carried out only under the supervision of qualified personnel. The procedure used must be developed and carefully implemented to ensure that representative samples are obtained and to prevent contamination in sampling devices and storage containers. Samples collected outdoors must be protected from external environmental influences during collection. Airtight, noncorrosive storage containers prevent degradation of the sample until it is analyzed. Each sample should be sealed immediately after being taken. Samples should not be mixed in open air prior to analysis for moisture because of the potential for moisture loss.

Samples must be properly labeled and described in terms of their significance to the test. The label should include, as a minimum, the date, time, location, and type of sample taken.

ASTM Standards D2013 and D3302 should be followed in the preparation of coal samples. Sorbent analysis procedures are addressed by ASTM D25.

4-8.3 Systematic Uncertainty

When the systematic uncertainty of a sampling procedure is estimated, the test engineer should consider the following potential sources. There may be other sources, and not all sources listed are applicable to all measurements.

(a) sampling location/geometry
(b) probe design
(c) stratification of flowing stream
(d) number and location of sample points
(e) ambient conditions at sample location
(f) fuel/sorbent variability
(g) fuel/sorbent size
(h) sample handling/storage
(i) duration of test
(j) quantity of sample obtained

An estimate of the systematic uncertainty from a sample is a combination of systematic uncertainties from sample acquisition, location, and stream consistency.

Sampling methods other than those recommended must be assigned higher systematic uncertainties.

Before conducting a performance test, it is mandatory that parties to the test make a pretest inspection of the sampling locations, identify the sampling methodology, and make the sampling probes available. Careful attention should be paid to areas where samples might not be representative. Sampling of coal and other solid materials from a moving stream can result in more of one size range of particles during collection. If systematic errors are present in the sampling system, the errors must be corrected, or the parties must assign conservative (higher) systematic uncertainties.

4-8.4 Methods to Determine Average and Standard Deviation of the Mean

Three methods to determine the average and standard deviation of the mean for the fuel characteristics (i.e., moisture, ash, carbon, etc.) are available. The three methods are

(a) individual
(b) partial composite
(c) full composite

4-8.4.1 Individual Method. An analysis sample is prepared from each individual sample, referred to as "increments" in the terminology of ASTM D2234, Standard Practice for Collection of a Gross Sample of Coal. Each analysis sample is individually analyzed for the applicable constituents, heating value, carbon content, moisture, etc. The average value and standard deviation of the mean for each constituent are calculated using eqs. (5-2-1) and (5-2-10). This procedure must be used when there are no historical data available to estimate the random uncertainty of the samples.

4-8.4.2 Partial Composite Method. Individual samples are collected as described in para. 4-8.4.1. The samples are collected in "sets" from which one set is individually analyzed for the variable constituents, such as ash and moisture (and sulfur if SO_2 reduction is to be considered). The average value and standard deviation of the mean for each variable constituent are calculated using eqs. (5-2-1) and (5-2-10).

The second set is thoroughly mixed (if they are from parallel streams) and analyzed for the composite constituents. The average value of each variable constituent is the measured value of the gross analysis sample. The standard deviation of the mean for the composite constituents are taken from valid historical data.

This is an alternative to analyzing individual samples, and is predicated on the availability of valid historical data. The objective is to reduce laboratory costs. The constituents are grouped into "composite" (e.g., carbon, hydrogen, and nitrogen) and "variable" (e.g., water, ash, and possibly sulfur) constituents.

The underlying premise for this alternative is that composite constituents for both the historical and test data are from the same statistical population. As the constituents are from the same population, a standard deviation of the mean derived from historical data may be used for the test uncertainty analysis. Paragraph 7-4.1.4 provides additional background for this alternative.

To simplify this discussion, coal constituents and terminology are used; sorbent constituents and terminology can be substituted as appropriate.

As coal is typically stored outdoors, the moisture content of as-fired coal may have greater variability than as-received coal. This increased variability may invalidate the premise that the historical as-received data and the test data are from the same statistical population; however, changes in moisture content do not affect constituents on a dry-and-ash-free basis. Where sulfur retention is an important consideration in the test, sulfur content should be included in the variable constituents. The variability of sulfur content is often relatively large.

This alternative is not suitable for residue samples. The composition of residue is affected by operating conditions within the steam generator. There is no simple way to ensure that historical and test data for residue would be from the same statistical population.

Historical data should satisfy the following criteria to be valid for estimating random uncertainty:

(a) the historical and test coal (sorbent) are from the same mine/quarry and seam

(b) historical data are the analyses of individual (not mixed) sample increments for the coal (sorbent)

(c) the historical and test samples are collected and prepared in accordance with ASTM standards D2234, Standard Practice for Collection of a Gross Sample of Coal, and D2013, Standard Practice for Preparing Coal Sample for Analysis

(d) the types of increments of the historical data and the test data are ASTM D2234 Type 1, Condition A

(e) (Stopped-Belt Cut) or Condition B (Full-Stream Cut), with systematic spacing

(f) the size of the historical samples is the same as the size of the samples collected during the test

If the historical samples were taken at a different location, it is likely that an additional systematic uncertainty would had been introduced.

The historical analyses are converted to the dry- and ash-free (daf) basis by multiplying the as-received percentages (other than the variable constituents, ash, and moisture) by

$$\frac{100}{100 - MpH_2OF_i - MpAsF_i} \tag{4-8-1}$$

where

$MpAsF_i$ = ash content, in percent, of historical sample increment, i

MpH_2OF_i = moisture content, in percent, of historical sample increment, I

For carbon content, the conversion equation is

$$MpCFdaf_i = MpCF_i\left(\frac{100}{100 - MpH_2OF_i - MpAsF_i}\right) \tag{4-8-2}$$

where

$MpAsF_i$ = ash content of the fuel in percent, as-fired basis (average of test analysis)

$MpCFdaf_i$ = carbon content of the fuel in percent, dry-and-ash-free basis

$MpCF_i$ = carbon content of the fuel in percent, as-fired basis

MpH_2OF_i = moisture content of the fuel in percent, as-fired basis (average of test analysis)

The conversion equations for heating value, hydrogen, nitrogen, sulfur, and oxygen are similar. ASTM D3180 addresses the conversion of analysis from one basis to another and should be used.

Using the dry-and-ash-free values of the individual historical samples, estimate the maximum probable standard deviation, s_{oj}, of each composite constituent. Use Appendix A2, Method of Estimating the Overall Variance for Increments, of ASTM D2234 to determine s_{oj}.

Table 4-8.4.2-1 *F* Distribution

$n-1$	F_{n-1}
1	. . .
2	2.9957
3	2.6049
4	2.3719
5	2.2141
6	2.0896
7	2.0096
8	1.9384
9	1.8799
10	1.8307
12	1.7522
15	1.6664
20	1.5705
40	1.3940
120	1.2214
Infinity	1.0000

The use of this appendix requires for each composite constituent 20 or more analyses of individual increments. If fewer than 20 are available, calculate the standard deviation, $STDDEV_j$, of each composite constituent using eq. (5-2-11).

The standard deviation of the mean for each composite constituent is as follows for 20 or more analyses:

$$STDDEVMN_j = \frac{s_{oj}}{\sqrt{N}} \tag{4-8-3}$$

For fewer than 20 analyses, use the following:

$$STNDEVMN_j = \left(\frac{F_{n-i,\infty} * STDDEV_j^2}{N}\right)^{1/2} \tag{4-8-4}$$

where

$F_{n-1,\infty}$ = the upper 5% point of the F distribution for $n-1$ and ∞ degrees of freedom. Table 4-8.4.2-1 provides selected values of the distribution.

n = the number of sample increments in the historical data

= the number of sample increments taken during the test

s_{oj} = the maximum probable standard deviation of each composite constituent on dry ash free basis

The degrees of freedom of this standard deviation of the mean are infinite.

4-8.4.3 Full-Composite Method. This is also an alternative to analyzing individual samples. For full-composite samples, none of the constituents are classified as variable constituents. This alternative may be applicable for sorbents and coal when historical data are available and changes in moisture or ash content are either very small or of minor concern.

A composite analysis sample is prepared from the (gross) samples taken during the test and analyzed for all constituents. The average value of each constituent is the measured value of the mixed analysis sample.

The criteria and calculations given above for partial composite samples are applicable to full-composite samples except that the conversion factor eqs. (4-8-1) and (4-8-2) are excluded.

4-9 LIQUID AND GASEOUS FUEL SAMPLING

4-9.1 General

A representative sample of the fuel fired during the performance test should be obtained using the methods described in ASTM D4057 or ASTM D5287. Fuel oil and natural gas typically have more consistent composition than coal or other solid fuels, and therefore require fewer samples. If fuel properties may vary because of outside factors, such as changing source of fuel, a more rigorous sampling program will be required to ensure representative samples.

4-9.2 Methods of Liquid or Gas Sampling

GPA Standard 2166, Method of Obtaining Natural Gas Samples for Analysis by Gas Chromatography, should be consulted for the proper procedures and equipment for sampling gas. The type of sample vessel and procedure is illustrated for various cases and types of liquid fuels in the appropriate ASTM standard.

4-9.3 Systematic Uncertainty for Liquid or Gas Sampling

The systematic uncertainty of liquid or gas sampling is similar to the systematic uncertainty of solid fuel and sorbent sampling. See para. 4-8.3 for potential sources of systematic uncertainty for liquid or gas sampling.

An estimate of the systematic uncertainty from a sample is a combination of systematic uncertainties from sample acquisition, location, and stream consistency.

4-10 SAMPLING OF FLUE GAS

4-10.1 General

Flue gas flowing through a duct has nonuniform composition distribution. In a plane across the flowing flue gas, this variation in composition or stratification also changes with time because of slight changes in fuel and airflow. The goal of flue gas sampling is to obtain the integrated average in both time and space across that plane of the flue gas composition. This is accomplished by repeatedly sampling a number of representative points in a cross section of the duct.

4-10.2 Systematic Uncertainty for Flue Gas Sampling

The systematic uncertainty of a flue gas sampling procedure is similar to the systematic uncertainty for solid fuel and sorbent sampling. Refer to para. 4-8.3 for potential sources of systematic uncertainty for flue gas sampling. An estimate of the systematic uncertainty from a sample is a combination of systematic uncertainties from sample acquisition, location, and stream consistency. Subsection 4-3 provides potential sources of these systematic uncertainties. If sampling procedures are performed using a composite sample, the systematic uncertainty error due to spatial nonuniformity may be estimated by making individual measurements at the grid sampling points and computing the spatial distribution index per para. 5-16.4. A sampling system that operates at subatmospheric pressure has a potential for in-leakage that will result in a one-sided systematic uncertainty. If the flue gas is severely stratified, the possibility of systematic uncertainty is increased.

4-10.3 Methods of Flue Gas Sampling

Multiple points in the sampling plane shall be sampled to compensate for stratification and to obtain a representative sample. The flue gas samples must be taken from the same measurement points used for temperature determination. The number of sampling points is chosen as described in para. 4-4.3. To minimize the uncertainty, the individual sample points should be combined to form a composite sample, which is then continuously analyzed during the test. The flow from each probe should be equal. Analysis at individual points can be utilized (along with using a greater systematic uncertainty) when the number of points is not so large as to reduce the number of complete traverses during the test.

4-10.3.1 Sample Collection and Transport. The flue gas should be collected from a sampling grid and combined into a single sample for each duct or location. The layout of points in the grid must be the same as temperature points described in para. 4-4.3.1. The sampling rate from each probe must remain equal, and the system must be checked for leaks prior to and throughout the test.

Large numbers of grid points are not required for SO_2 and total hydrocarbons (THC). These samples require heated sample lines and, therefore, a large number of points is impractical. The parties to the test shall agree on sampling procedures for these two gases. It should be noted that filtering the sample may cause a systematic uncertainty for SO_2 if CaO is present in the particulate filter. CaO reacts with the SO_2 and reduces it. In this case, the filters should be cleaned frequently.

4-11 RESIDUE SAMPLING

Those fuels that contain ash necessitate a sample of the various streams leaving the unit containing the ash. These streams typically include fly ash and bottom ash. Obtaining representative samples from each of these streams is a difficult task. Fly ash may be collected in several hoppers as the flue gas makes its way to the stack. The heaviest particles fall out first, with the smaller particles being removed by mechanical forces resulting from the turning of the gas stream. Unfortunately, the carbon is not uniformly distributed throughout the particle size range. The relative distribution of the ash into the various hoppers is also not accurately known. The best method for obtaining a representative fly ash sample is to isokinetically sample the ash in the flue gas upstream of as many ash collection hoppers as possible. This usually means at the economizer outlet. This obtains a sample that has a representative cross section of particle size and carbon content. It also ensures that the sample is representative of the testing period.

The bottom ash also presents challenges in the form of large chunks and poor distribution. A number of samples and several analyses of each sample may be required to obtain representative results. A single sample may contain a chunk of coal not typically found in other samples or may have no carbon content.

4-11.1 General

Fly ash may be sampled isokinetically as particulate by drawing a flue gas sample through a filter and weighing the amount of particulate gathered on the filter. The weight of the sample and the flue gas volume recorded during this process determine the particulate concentration in the flue gas stream. To avoid altering the concentration of the gas stream, the velocity of the stream entering the sample nozzle must equal the velocity of gas at that point in the duct. This process is known as isokinetic sampling. Multiple points are sampled in the testing plane to compensate for nonuniform velocity distributions and stratification of the particulate concentration.

4-11.2 Systematic Uncertainty for Residue Sampling

Isokinetic sampling is the reference method prescribed by this Code. The systematic uncertainty associated with this method is assumed to be zero. There is still an associated systematic uncertainty for the ash collected in the bottom ash as well as any hoppers located upstream of the fly ash collection point. If multiple samples are analyzed using multiple analysis for the bottom ash, an estimate of the associated systematic uncertainty can be made from this information. The procedure should also be reviewed to determine if other sources of systematic uncertainty may also be present.

4-11.3 Methods of Sampling Fly Ash

All apparatus and test procedures shall be in accordance with either ASME PTC 38, Determining the Concentration of Particulate Matter in a Gas Stream, or U.S. EPA Reference Method 17 as described as follows:

(a) ASME PTC 38. The particulate sampling train generally consists of a nozzle, probe, filter, condenser, dry gas meter, orifice meter, and vacuum pump or aspirator. ASME PTC 38 illustrates different configurations of sampling trains, and should be consulted for the type of train to be used on specific installations.

(b) U.S. EPA Method 17. The U.S. Environmental Protection Agency has established two methods for particulate sampling. These reference Methods 5 and 17 are similar, except that Method 17 uses an in-stack filter, whereas Method 5 uses an external filter. Method 17 is preferred since all of the particulate catch remains in the filter holder. Method 5 requires an acetone wash of the probe assembly, which may not be suitable for analysis for carbon. Detailed procedures for these methods are contained in 40CFR60 Appendix A.

Isokinetic sampling of the flue gas is both the reference and the preferred method for sampling fly ash. The number of grid points on the traverse sampling plane must be in accordance with ASME PTC 38.

4-11.4 Methods of Sampling Bottom Ash

For a bottom ash sluice stream, the preferred method of sample collection is to take the sample with a multiholed probe extending the width of the sluice stream. Pages 2-3, 2-4, and 2-5 of EPRI Report EA-3610 illustrate a multihole probe. Alternatively, a portion of the sluice stream may be diverted to a collection device where the ash is allowed to settle and a sample is then taken.

4-11.5 Other Residue Streams

In some cases, the parties to the test may decide not to sample from a residue stream that does not contribute significantly to the energy loss. Possible examples of such streams are air heater disposal drains or vent lines, where the flow rate is negligible, or bottom ash drains, which may have insignificant sensible heat and unburned combustible losses. Alternatively, samples of bottom ash sluiced to a settling pond can yield a result that is no more certain than using an assumed value. If a solid stream is not sampled, the appropriate systematic uncertainty shall be assigned, and the historical evidence shall be documented in the final report.

4-12 FUEL, SORBENT, AND RESIDUE ANALYSIS

4-12.1 General

It is the intent of this Code that the samples be analyzed in accordance with the latest methods and procedures. When choosing a laboratory, the parties to the test should choose a laboratory agreed to by parties to the test.

4-12.2 Systematic Uncertainty for Fuel, Sorbent, and Residue Analysis

ASTM provides guidelines for typical lab-to-lab reproducibility. These values are listed in Tables 4-3.6-2 through 4-3.6-5 for use in estimating the systematic uncertainty of a sample analysis. In general, the systematic uncertainty is taken as one-half the reproducibility.

4-12.3 Methods of Fuel, Sorbent, and Residue Analysis

4-12.3.1 Solid Fuels. For solid-fuel–fired steam generators, the minimum fuel information required to determine efficiency is the ultimate analysis, proximate analysis, and the higher heating value. Tables 4-3.6-2 through 4-3.6-5 identify the ASTM procedures to be used for analysis. ASTM D3180 defines the procedures for converting the analysis from one basis to another. The latest versions of these procedures shall be utilized. If ASTM adds a new or revised procedure that is agreeable to both parties to the test, that procedure may be used.

The determination of other solid fuel qualities such as fusion temperature, free swelling index, grindability, ash chemistry, and fuel sizing are important to judge the equivalence of the test fuel and the specified fuel, and they may be required for other test objectives. Nonmandatory Appendix E offers additional information.

4-12.3.2 Sorbent and Other Additives. The minimum information needed to determine the sulfur capture and efficiency is the sorbent ultimate analysis (calcium, magnesium, moisture, and inert). The determination of other solid sorbent qualities such as sorbent sizing may be required, depending on the objectives of the particular test.

4-12.3.3 Liquid Fuel. For liquid-fuel–fired steam generators, the minimum fuel information needed to determine efficiency is the ultimate analysis and higher heating value of the fuel. The determination of other liquid fuel qualities such as API gravity and density may be required depending on the objectives of the test. The procedures for these determinations are found in ASTM D1298.

4-12.3.4 Gaseous Fuel. For gaseous-fuel-fired steam generators, the minimum fuel information needed to determine efficiency is the constituent volumetric analysis of the fuel. ASTM D1945 is used for this determination. This analysis is converted to an elemental mass analysis as detailed in para. 5-8.2. Higher heating value may be determined by a continuous online calorimeter as defined in ASTM D1826. The parties to the test shall agree on which method will be used.

4-12.3.5 Residue. Particulate residue samples shall be analyzed for total, combustible, and carbonate carbon content according to ASTM D6316. This test method comprises the use of any of several methods for determination of total carbon content. If the instrument method, ASTM D5373, is used to determine total carbon content, then the instrument shall be capable of analyzing prepared residue samples of not less than 100 mg. Use of a loss on ignition (LOI) analysis is not permitted for the determination of unburned combustible loss, because several reactions may occur in the combustion process that reduce or increase the weight of the sample and that have no heating value.

The test for total carbon in the residue includes the determination of hydrogen, and the hydrogen result may be reported in addition to the carbon. This portion of the test is not mandatory for testing carbon in residue, and experience indicates that H_2 in fuel volatilizes readily and no significant quantity of H_2 exists in residue in the normal combustion process. This test may result in a measured hydrogen content on the order of 0.1% or less. Hydrogen quantities of this order of magnitude should be considered as zero in the combustion and efficiency calculations. A potential source for error in the determination of free hydrogen is that, as with carbon, this test method yields the total percentage of hydrogen in the residue as analyzed and the results present the hydrogen present in the free moisture accompanying the sample as well as hydrogen present as water of hydration of silicates or calcium oxide [$Ca(OH)_2$].

4-13 FLUE GAS ANALYSIS

4-13.1 General

It is the intent of this Code that the samples be analyzed in accordance with the latest methods and procedures.

4-13.2 Systematic Uncertainty for Flue Gas Analysis

A number of factors need to be considered in determining the systematic uncertainty of a flue gas analysis system. The following are some potential sources of systematic uncertainty for the flue gas system:

(a) analyzer accuracy
(b) sampling system interference
(c) analyzer drift
(d) spatial variation
(e) time variation

(f) cal 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

4-13.3 Methods of Flue Gas Analysis

The following paragraphs describe methods and equipment operation for measurement of flue gas oxygen (O_2), carbon monoxide (CO), sulfur dioxide (SO_2), oxides of nitrogen (NO_x), and total hydrocarbons (THC).

The equipment needed to conduct a flue gas analysis by extractive sampling is composed of two parts: the sample collection and transport system and the 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. The flue gas analyzers each measure 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, in which the moles of the constituent of interest are divided by the total moles present. The difference between the wet and dry basis is that the wet basis includes both the dry moles and water vapor moles in the denominator.

4-13.4 Flue Gas Analysis

The types of analyzers currently in use are continuous electronic analyzers and manual instruments such as the Orsat analyzer. Although manual instruments are permitted, operator skill, chemical freshness, and other factors related to manual instruments contribute to potentially high systematic uncertainties. In addition, it is recommended that flue gas composition be monitored on a continuous basis throughout the test. Fuel variations, control system tuning, and other factors cause variations in flue gas constituents. Therefore, a continuously analyzed composite sample taken from a representative grid best represents the true average gas composition.

4-13.4.1 Oxygen. 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. When an electrochemical cell is being used, care must be taken to ensure that other gases such as CO_2 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.

4-13.4.2 Carbon Monoxide. The most common method for carbon monoxide analysis is nondispersive infrared. The main disadvantage of this methodology is that CO, CO_2, and H_2O all have similar infrared wavelength absorption. For accurate CO readings, the sample must be dry and the analyzer must compensate for CO_2 interference. Better quality instruments determine CO_2, then compensate CO for that value; preset CO_2 interference factor may also be used. For determining heat loss due to CO, the inaccuracy resulting from neglecting CO_2 (approximately 20 ppm) is minimal. However, an overestimate of 20 ppm may be significant in relation to environmental protection regulations.

4-13.4.3 Sulfur Dioxide. The analysis of sulfur dioxide (SO_2) is typically performed using one of two accepted methods: pulsed fluorescent or ultraviolet. SO_2 is very reactive, and only glass, stainless steel, or Teflon can be used in the sampling and analysis system.

4-13.4.4 Oxides of Nitrogen. Chemiluminescent analyzers are the preferred method of analysis. These analyzers first convert NO_2 to NO in a thermal converter, then mix the NO with ozone (O_3) and produce NO_2 in the reaction chamber. This reaction process emits light, which is measured to determine the concentration of NO_2. Even though NO_2 represents a very small percentage of the NO_x emissions (typically less than 5%), NO_x is reported as NO_2. This has negligible effect on steam generator efficiency.

4-13.4.5 Total Hydrocarbons. Total hydrocarbons (THC) measurement by flame ionization detector (FID) based instrument is the preferred method. Either methane or propane should be used for calibration and the resulting THC value reported as THC ppm methane or THC ppm propane.

4-14 ELECTRIC POWER

4-14.1 General

The accurate measurement of three-phase power is a complex issue. Fortunately, highly accurate electrical measurement is of minor importance for determining steam generator efficiency. If power measurements are used to determine auxiliary power consumption, a more exhaustive procedure should be used. The best approach is to measure the current and voltage in each phase of the circuit and sum the power in each phase to determine the total. In practice, this is difficult and costly.

4-14.2 Systematic Uncertainty for Electrical Power Measurement

When estimating the systematic uncertainty of an electric power 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) current transformer (CT) accuracy
(b) potential transformer (PT) accuracy
(c) power factor on each phase
(d) wattmeter accuracy
(e) load imbalance
(f) frequency of sampling

4-14.3 Method of Measurement

For the measurement of electrical power for steam generator efficiency, measurement of a single phase current and voltage along with the assumption of balanced load for the auxiliaries is sufficiently accurate. Should a highly accurate determination of auxiliary power be required for other purposes, the determination shall be made in accordance with the 2 wattmeter or 3 wattmeter methods. IEEE 120 should be consulted for methods to use in making electrical power measurements.

4-14.4 Estimating Systematic Uncertainty

An estimate of the systematic uncertainty from an electrical measurement is a combination of systematic uncertainty limits from primary sensor type, wattmeter, and data acquisition. Subsection 4-3 and para. 4-14.2 provide potential sources of these systematic uncertainties. The uncertainty of protection CTs is typically ±10% to 20%. Measurement CTs vary but usually have uncertainty in the range of 1% to 5%. These CTs are used to send a signal to the operator. Usually only one phase uses a measurement CT, and the assumption is made that the power used on the other two phases is the same (balanced load). This assumption is not necessarily accurate due in part to varying power factors.

4-15 HUMIDITY

4-15.1 General

The moisture carried by the entering air must be taken into consideration in calculations of steam generator efficiency.

4-15.2 Systematic Uncertainty for Humidity Measurement

When estimating the systematic uncertainty of a humidity measurement, test personnel should consider the following 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

4-15.3 Method of Measurement

The dry-bulb and wet-bulb temperatures should be determined at the atmospheric air inlet to the unit. Since the specific humidity does not change with heat addition unless there is a moisture addition, the specific humidity of the combustion air leaving the air heater is the same as the specific humidity entering. To determine specific humidity, either dry-bulb and wet-bulb, or dry-bulb and relative humidity, are needed. Paragraph 5-11.2 addresses absolute or specific humidity (pounds of moisture per pound of dry air). The moisture may be determined with the aid of a sling-type psychrometer, hygrometer with temperature or similar device, and an observed barometric pressure reading.

4-16 MEASUREMENTS FOR SURFACE RADIATION AND CONVECTION LOSS

4-16.1 General

This Code provides the following two methods for determining this loss:

(a) by measuring the average surface temperature of the steam generator and ambient conditions near it

(b) by using actual component areas with standard values for surface and ambient conditions (see para. 5-14.9)

To determine this loss by measurement, measurements of surface temperature, ambient temperature, and ambient air velocity should be determined at a sufficient number of locations to calculate representative average values. Any measurements of ambient air temperature and velocity should be taken between 2 ft and 5 ft from the surface.

4-16.2 Method of Measurement

Measurement of surface temperature can be accomplished with a thermocouple, contact pyrometer, infrared pyrometer, or thermal imaging camera. If a thermocouple is used, a 1 in. to 2 in. thick piece of insulating material should be used to cover the hot junction. The insulation should be approximately 2 in.^{2} to prevent erroneous readings.

The large number of temperature readings required and accessibility difficulties may support the use of infrared instruments. Use of the infrared thermometer or the thermal imaging camera requires a calibration of the surface emissivity for the instrument. This is best accomplished in the field using a thermocouple and potentiometer. Measure a surface temperature with the thermocouple using the insulation procedure described above. After this temperature is determined, measure the temperature in the same location with the infrared thermometer or the thermal imaging camera. Adjust the emissivity on the instrument until the readings match the temperature taken with the thermocouple. This is the surface emissivity to be used for further temperature measurements. This procedure should be repeated periodically since surface emissivity can be different on other walls. This can be due to dust particles, oxidation, or other differences in surface material or preparation. The emissivity value determined for calibration of the instrument is not to be used for heat loss calculations. The calculation procedure described in para. 5-14.9 shall be used.

Infrared thermometers are very sensitive to angle of incidence of the reading. When using this instrument, be sure that the infrared beam is perpendicular to the surface being read. Thermal imaging cameras are not as sensitive to the angle of incidence, but it is good practice to keep the instrument as normal to the surface as possible. Infrared instruments typically have a circular field of view and read the average temperature in this field. Local hot spots caused by lagging support hardware will distort the reading if in the field of view.

Ambient air temperature is typically measured with a handheld temperature gauge or a thermometer. Users of this Code are referred to ASME PTC 19.3 for further information on temperature measurement techniques. Ambient air velocity is typically measured with a handheld anemometer, either hot wire or vane type. Many handheld anemometers also have a built-in ambient temperature measurement.

4-16.3 Estimating Systematic Uncertainty

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

Section 5
Computation of Results

5-1 INTRODUCTION

This Section describes the data required and the computation procedures for determining the performance of steam generators covered by this Code. Data acquisition principles, instruments, and methods of measurement are given in Sections 3 and 4. Derivations of certain equations are detailed in Nonmandatory Appendix C.

The computation equations use acronyms for variables that consist of alphanumeric characters that may be used directly in computer programs without loss of interpretation. The format for these acronyms, definition of letters or letter combinations, and a summary of developed acronyms are described in subsection 5-20. The alphanumerical designation that identifies the locations of gaseous, liquid, and solid streams in relation to the steam generator components are listed on the Steam Generator Boundaries data identification lists in subsection 1-4 and shown schematically on Figs. 1-4-1 through 1-4-7.

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 are 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 for uncertainty analysis calculations. Subsections 5-3 through 5-15 present the equations to determine steam generator performance. Subsection 5-16 presents the equations to determine the systematic component of the 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 design conditions, and enthalpy calculations.

5-2 MEASUREMENT DATA REDUCTION

5-2.1 Calibration Corrections

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

In this same category is any 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 random and systematic error of the instruments required to determine flow should be incorporated in the total random and systematic uncertainty of the measured flow parameter (refer to para. 5-16.1, Sensitivity Coefficients).

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 believed to be not valid and should not be included as part of the calculations and uncertainty analyses. Causes of outliers are human errors in reading and writing values and instrument errors resulting from electrical interference, etc. Several documents provide guidance and statistical methods for determining outliers; among them are ASME PTC 19.1, Test Uncertainty, and ASTM E178. This Code does not recommend a 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. The rejection of outliers based on engineering judgment and/or pretest agreements by the parties involved in the test is recommended. 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 the rejection of 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 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.

However, some parameters measured during a test run 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 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 value of the parameters, along with their standard deviations of the mean and degrees of freedom, 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.

For parameters modeled as constant in/over space (e.g., feedwater temperature or pressure), or values of a parameter at a fixed point in space (e.g., exit flue gas temperature at one point in the thermocouple grid), the equation used to calculate average values is

$$X_{AVG} = \frac{1}{n}(x_1 + x_2 + x_3 + \ldots + x_n) = \frac{1}{n}\sum_{i=1}^{n} x_i \qquad (5\text{-}2\text{-}1)$$

where

n = number of times parameter x is measured

X_{AVG} = 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. Each set has n readings. The average value, $X_{AVG\,k}$, for set k is given by eq. (5-2-1) with the addition of a subscript to denote the set. The overall average value of such parameters is

$$X_{AVG} = \frac{1}{m}\sum_{k=1}^{m} X_{AVG\,k} \qquad (5\text{-}2\text{-}2)$$

When individual measured parameter data and standard deviation information are available for each set of measurements, the total standard deviation may be calculated in accordance with eq. (5-2-8). If this information is not available, the subsets should 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 by first calculating the average value of all the data for each defined point in a measurement grid. The average value of all points in the grid is then determined.

5-2.4 Random Uncertainty

General guidelines for calculating the standard deviation of the mean for individual measurement parameters are given below. A more detailed description of uncertainty analysis calculations along with derivations is included in Section 7. Section 7 should be reviewed before beginning any uncertainty calculations. The random component of uncertainty must be calculated using several steps. Each measured parameter has a standard deviation, standard deviation of the mean, and a certain number of degrees of freedom. There is also an overall standard deviation of the mean and number of degrees of freedom for all measurement parameters combined. These cannot be calculated until after the steam generator performance computations shown in subsections 5-3 through 5-15 are completed. The calculation of the overall test standard deviation of the mean and the random component of uncertainty are presented in subsection 5-16.

The first step in determining the standard deviation of the mean and degrees of freedom for a measured parameter is to calculate the average value and standard deviation using the data recorded during a test. The average value, standard deviation, and degrees of freedom for a measured parameter are calculated differently for parameters that vary in both time and space and those parameters that vary only in time.

5-2.4.1 Random Uncertainty for Spatially Uniform Parameters. For multiple measurements of a parameter that is not expected to exhibit spatial variations, the standard deviation and standard deviation of the mean for the parameter are calculated from

[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. (5-2-1) to calculate the average value of such parameters and increasing the number of readings to reduce the standard deviation of the mean. 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 utilized, 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 standard deviation of the mean

$$STDDEVMN = \left(\frac{STDDEV^2}{n} \right)^{1/2} = \left[\frac{1}{n(n-1)} \sum_{i=1}^{n} (x_i - X_{AVG})^2 \right]^{1/2} \quad (5\text{-}2\text{-}3)$$

$$STDDEV = \left[\frac{1}{(n-1)} \sum_{i=1}^{n} (x_i - X_{AVG})^2 \right]^{1/2} \quad (5\text{-}2\text{-}4)$$

or

$$STDDEV = \left[(PSTDDEV)^2 \frac{n}{(n-1)} \right]^{1/2} \quad (5\text{-}2\text{-}5)$$

where

n = number of times parameter is measured
$PSTDDEV$ = population standard deviation for a measured parameter
$STDDEV$ = standard deviation estimate from the sample measurements
$STDDEVMN$ = standard deviation of the mean for a measured parameter
X_{AVG} = arithmetic average value of a measured parameter
x_i = value of measured parameter i at any point in time

The equations are presented in the above format because some electronic calculators and spreadsheet programs calculate the population standard deviation while others calculate the sample standard deviation. Some also calculate the standard deviation of the mean. It is important that the individual calculating the standard deviation of the mean used to determine random uncertainty understands the difference between population standard deviation, sample standard deviation, and standard deviation of the mean. With the use of a computer or scientific calculator, if the function for "sample standard deviation" is used with the measured values of the parameter, the result would be *STDDEV*. If the function for "population standard deviation" is used on these values, the result would be *PSTDDEV*. If the function for standard deviation for the mean or "standard error of the mean" is used, the result would be *STDDEVMN*. An understanding of the differences will help in the use of the correct functions and formulae.

The degrees of freedom for the standard deviation of the mean of a spatially uniform parameter is determined from the following equation:

$$DEGFREE = n - 1 \quad (5\text{-}2\text{-}6)$$

where

$DEGFREE$ = number of degrees of freedom

For summary data (refer to para. 5-2.3.2), the associated standard deviation of set k is

$$STDDEV_k = \left[\frac{1}{(n-1)} \sum_{i=1}^{n} (x_i - X_{AVG\,k})^2 \right]^{1/2} \quad (5\text{-}2\text{-}7)$$

where

n = the number of measurements within each set

The standard deviation of the mean for multiple summary data sets is

$$STDDEVMN = \left(\frac{1}{m\,n\,(m\,n-1)} \sum_{k=1}^{m} \left[(n-1)\,STDDEV_k^2 + n\,X_{AVG\,k}^{\;2} \right] - m\,n\,X_{AVG}^{\;2} \right)^{1/2} \quad (5\text{-}2\text{-}8)$$

where

m = the number of sets of data

The degrees of freedom for the standard deviation of the mean for the summary data sets are

$$DEGFREE = m\,n - 1 \quad (5\text{-}2\text{-}9)$$

The overall averages and the standard deviations of the mean of both the summary data and the total $m \cdot n$ measurements have to be the same. The model is a constant value parameter for both.

5-2.4.2 Random Uncertainty for Spatially Nonuniform Parameters. The standard deviation of the mean (random uncertainty) and degrees of freedom for a parameter with spatial variations must be determined in a manner consistent with the integration methods discussed in subsection 7-4 for use of weighted or unweighted averages.

First, calculate for each grid point location, i: average, *STDDEV*, *STDDEVMN*, and *DEGFREE*. Then calculate the average of all points in the grid.

The standard deviation of the mean for an integrated average parameter is

$$STDDEVMN = \frac{1}{m} \left[\sum_{i=1}^{m} STDDEVMN_i^2 \right]^{1/2} \quad (5\text{-}2\text{-}10)$$

The associated degrees of freedom are

$$DEGFREE = \frac{STDDEVMN^4}{\displaystyle\sum_{i=1}^{m} \frac{STDDEVMN_i^4}{m^4\,DEGFREE_i}} \quad (5\text{-}2\text{-}11)$$

where

$DEGFREE$ = degrees of freedom for average parameter
$DEGFREE_i$ = degrees of freedom of the parameter at point i
m = number of grid points
$STDDEVMN$ = standard deviation of the mean for average parameter
$STDDEVMN_i$ = standard deviation of the mean of the parameter at point i

The degrees of freedom must fall between a minimum and maximum value based on the number of readings taken at each grid point and the number of grid points.

The minimum possible degrees of freedom is the smaller of the following:

(a) number of points in the grid, m

(b) number of readings taken at each grid point minus 1, $n - 1$

The maximum possible degrees of freedom is the product of the two items listed above.

Equations (5-2-10) and (5-2-11) are for unweighted averages and also for weighted averages when the weighting factors are measured simultaneously with the parameters so that the standard deviation of the mean of the grid points are calculated by using weighted parameters ($X_{FW} = F_i X_i$). This calculation should be used for weighted averages only when there are a large enough number of readings at each grid point to assure statistical significance.

If weighted averages are to be employed in performance calculations, with only a small number of simultaneous traverses (fewer than six), giving only a small number of readings at each point, then the standard deviation of the mean of the weighted average is estimated using a single probe as described in subsection 7-4. This probe is arranged to simultaneously measure velocity and the parameter of interest (temperature or oxygen) at a fixed point. There are n readings at the single point. The readings are multiplied as follows:

$$X_{FW,i} = \left[\frac{V_i}{V_{AVG}}\right] X_i \qquad (5\text{-}2\text{-}12)$$

The sample standard deviation of X_{FW}, $STDDEV$, is calculated from eq. (5-2-4) or (5-2-5). The standard deviation of the mean for the weighted average parameter is

$$STDDEVMN_W = \frac{F_{n-1,\infty}\, STDDEV}{N^{1/2}} \qquad (5\text{-}2\text{-}13)$$

where

$F_{n-1,\infty}$ = F distribution
N = number of traverses
n = number of readings at the single point
W = weighted average

The standard deviation of the mean for each grid point is determined from the standard deviation of the single fixed reference point. The degrees of freedom for the single point are taken as infinite; therefore, the F-distribution table is used.

If weighted averages are to be employed in performance calculations with weighting factors (velocities) determined separately from the weighted parameter, then the standard deviation of the mean of the weighted average parameter is calculated from

$$STDDEVMN = \left[STDDEVMN_{UW} + \left(PARAVG_{UW} - PARAVG_{FW}\right)^2 \times \left(\frac{STDDEVMN_V}{V_{AVG}}\right)^2\right]^{1/2} \qquad (5\text{-}2\text{-}14)$$

where

$PARAVG_{FW}$ = the weighted average value of the parameter
$PARAVG_{UW}$ = the unweighted average value of the parameter
$STDDEVMN_{UW}$ = standard deviation of the mean of the unweighted average
$STDDEVMN_V$ = the standard deviation of the mean of the velocity
V_{AVG} = the average velocity

If the velocity distribution is determined by a limited number of traverses, $STDDEVMN_V$ can be estimated from a large number of velocity readings taken over time at a single point, as described immediately above, with V_i used in place of $X_{FW,i}$.

5-3 CAPACITY

5-3.1 Capacity

Capacity is the maximum main steam mass flow rate the steam generator is capable of producing on a continuous basis with specified steam conditions and cycle configuration (including specified blowdown and auxiliary steam). This is also frequently referred to as maximum continuous rating (MCR).

5-3.2 Capacity, Peak

Peak capacity is the maximum main steam mass flow rate the steam generator is capable of producing with specified steam conditions and cycle configuration (including specified blowdown and auxiliary steam) for intermittent operation (i.e., for a specified period of time without affecting future operation of the unit).

5-4 OUTPUT (*QrO*), Btu/hr (W)

Output is the energy absorbed by the working fluid that is not recovered within the steam generator envelope, such as energy to heat the entering air. It includes the energy added to the feedwater and desuperheating water to produce saturated/superheated steam, reheat steam, auxiliary steam (refer to para. 5-4.3), 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

$$QrO = \sum MrStz2\,(HLvz2 - HEnz1),\ \text{Btu/hr (W)} \qquad (5\text{-}4\text{-}1)$$

where

$HEnz1$ = enthalpy of fluid entering location $z1$, Btu/lbm (J/kg)
$HLvz2$ = enthalpy of fluid leaving location $z2$, Btu/lbm (J/kg)
$MrStz2$ = mass flow rate of fluid leaving location $z2$, lbm/hr (kg/s)

5-4.1 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). Refer also to auxiliary steam and blowdown, which are outputs generated from the entering high-pressure feedwater.

5-4.1.1 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.

$$QrO = MrSt31\,(HSt31 - HW24),\ \text{Btu/hr (W)} \qquad (5\text{-}4\text{-}2)$$

5-4.1.2 Superheated Steam Generators. Output in main steam is equal to the difference between the main steam 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.

$$QrO = (MrSt32 - MrW25)\,(HSt32 - HW24) + MrW25\,(HSt32 - HW25),\ \text{Btu/hr (W)} \qquad (5\text{-}4\text{-}3)$$

5-4.2 Reheat Steam Generators

For reheat steam, a term for each stage of reheat must be added to the output equation. (Refer to para. 5-4.2.1 for the logic for determining reheat flow.) The additional output from the first-stage reheat is the reheat mass flow rate times the difference between the reheat enthalpies entering and leaving and added to the reheat spray mass flow rate times the difference between the reheat steam and reheat spray water enthalpies.

$$QRh = MrSt33\,(HSt34 - HSt33) + MrW26\,(HSt34 - HW26),\ \text{Btu/hr (W)} \qquad (5\text{-}4\text{-}4)$$

5-4.2.1 Reheat Flow. For purposes of this Code, first-stage reheat flow is calculated by subtracting from the main steam flow the sum of the extraction flow(s) to feedwater heater(s), turbine shaft and seal leakages, and any other flows extracted after the main steam flow leaves the steam generator boundary and prior to returning to the reheater, and by adding reheat spray flow. The preferred method for determining extraction flow to feedwater heaters is to calculate the flow by energy balance. Turbine shaft and seal leakages may be estimated from the manufacturer's turbine heat balances or recent turbine test data. Extraction flows that cannot be calculated by energy balance must be measured, or, if minor, estimated with appropriate uncertainty factors applied.

The logic for calculating second-stage reheat flow is similar to first-stage reheat flow except the calculated first-stage reheat flow leaving the unit is used in lieu of main steam flow.

Consult ASME PTC 6, Steam Turbines, for guidance in determining reheat flow.

5-4.3 Auxiliary Steam

Auxiliary steam includes steam that exits the steam generator envelope as well as miscellaneous steam, such as atomizing steam and sootblowing steam, and is included in the boiler output. It does not include steam utilized to heat the entering air. For each extraction point, add the following term to the output equation:

$$QrAxSt = MrSt46A\,(HSt46A - HW24),\ \text{Btu/hr (W)} \qquad (5\text{-}4\text{-}5)$$

where

MrSt46A and *HSt46A* = the mass flow rate and enthalpy at the extraction point

5-4.4 Blowdown

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

$$QrBd = MrW35\,(HW35 - HW24),\ \text{Btu/hr (W)} \qquad (5\text{-}4\text{-}6)$$

5-5 INPUT

Input is the potential combustion energy. It is the maximum amount of energy available when the fuel is completely burned.

$$QrI = QrF = MrF\ HHVF,\ \text{Btu/hr (W)} \qquad (5\text{-}5\text{-}1)$$

where

HHVF = higher heating value of fuel, Btu/lbm (J/kg). Refer to subsection 5-8.
MrF = mass flow rate of fuel, lbm/hr (kg/s)
QrF = input from fuel, Btu/hr (W)
QrI = input, Btu/hr (W)

5-6 ENERGY BALANCE

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

Energy entering the system − Energy leaving the system = Accumulation Energy in the system

Since a steam generator should be tested under steady-state conditions, such that accumulation is zero, the equation is

Energy entering the system = Energy leaving the system

or

$$QEn = QLv,\ \text{Btu/hr (W)} \qquad (5\text{-}6\text{-}1)$$

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 heat transfer to the environment from the steam generator surfaces.

Expressing the energy balance in terms that can be readily measured and calculated, eq. (5-6-1) becomes

$$QrF = QrO + Qb, \text{ Btu/hr (W)} \quad (5\text{-}6\text{-}2)$$

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 radiative and convective heat transfer to the environment.

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

$$Qb = QrL - QrB, \text{ Btu/hr (W)} \quad (5\text{-}6\text{-}3)$$

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 the above in eq. (5-6-2), the overall energy balance becomes

$$QrF + QrB = QrO + QrL, \text{ Btu/hr (W)} \quad (5\text{-}6\text{-}4)$$

where

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

5-7 EFFICIENCY

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

$$EF = 100\frac{Output}{Input} = 100\frac{QrO}{QrI} = 100\frac{QrO}{QrF}, \% \quad (5\text{-}7\text{-}1)$$

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). Nonmandatory Appendix D addresses calculation of gross efficiency.

5-7.1 Efficiency by Energy Balance Method

In the energy balance method, the energy closure losses and credits are used to calculate efficiency. Equation (5-6-4) can be rewritten as follows:

$$QrF = QrO + QrL - QrB, \text{ Btu/hr (W)} \quad (5\text{-}7\text{-}2)$$

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

$$EF = 100\frac{QrO}{QrF} = 100\frac{QrO}{QrO + QrL - QrB} = 100\frac{QrF - QrL + QrB}{QrF}, \% \quad (5\text{-}7\text{-}3)$$

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

$$QpL = 100\frac{QrL}{QrF} \text{ and } QpB = 100\frac{QrB}{QrF}, \% \quad (5\text{-}7\text{-}4)$$

Thus, combining eqs. (5-7-3) and (5-7-4), fuel efficiency can also be expressed as

$$EF = 100\left(\frac{QrF}{QrF} - \frac{QrL}{QrF} + \frac{QrB}{QrF}\right) = 100 - QpL + QpB, \% \quad (5\text{-}7\text{-}5)$$

While most losses and credits can be calculated conveniently on a percent input from fuel basis as they are a function of the input from fuel, some losses and credits are calculated more readily on a Btu/hr (W) basis. The expression for fuel efficiency using mixed units for losses and credits is

$$EF = (100 - SmQpL + SmQpB)\left(\frac{QrO}{QrO + SmQrL - SmQrB}\right), \% \quad (5\text{-}7\text{-}6)$$

where

$SmQpL$ and $SmQpB$ = the sum of the losses and credits calculated on percent input from fuel basis

$SmQrL$ and $SmQrB$ = the sum of the losses and credits calculated on a Btu/hr (W) basis

Refer to Nonmandatory Appendix C, subsection C-6 for derivation.

The mass flow rate of fuel (MrF) may be calculated from output and fuel efficiency determined by the energy balance method, as follows:

$$MrF = 100\left(\frac{QrO}{EF\ HHVF}\right), \text{lbm/hr (kg/s)} \qquad (5\text{-}7\text{-}7)$$

The calculated mass flow rate of solid fuel is generally more accurate than the measured flow.

The energy balance method is the preferred method for determining efficiency. It is usually more accurate than the Input–Output method (refer to para. 5-7.2) because measurement errors impact the losses and credits rather than the total energy. For example, if the total losses and credits are 10% of the total input, a 1% measurement error would result in only a 0.1% error in efficiency, where a 1% error in measuring fuel flow results in a 1% error in efficiency. Another major advantage to the energy balance method is that reasons for variations in efficiency from one test to the next can be identified. Also, it is readily possible to correct the efficiency to standard or contract conditions for deviations from test conditions such as the fuel analysis.

5-7.2 Efficiency by Input–Output Method

Efficiency calculated by the Input–Output method is based upon measuring the fuel flow and steam generator fluid side conditions necessary to calculate output. The uncertainty of efficiency calculated by the Input–Output method is directly proportional to the uncertainty of determining the fuel flow, a representative fuel analysis, and steam generator output. Therefore, to obtain reliable results, extreme care must be taken to determine these items accurately.

$$EF = 100\,\frac{Output}{Input} = 100\,\frac{QrO}{MrF\ HHVF}, \% \qquad (5\text{-}7\text{-}8)$$

where

MrF = the measured mass flow rate of fuel

5-7.3 Efficiency Calculation Convergence

The calculation procedure is iterative for most types of units. That is, an efficiency or fuel rate (input) is estimated to initiate the efficiency calculations. The calculations are repeated until the efficiency (fuel rate/input) is within an acceptable limit. 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 for the first or second decimal place, a convergence limit of 0.1% efficiency is sufficient (1.0% for hand calculations).

For calculations to develop sensitivity coefficients (refer to 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 limit on the order of 10^{-5}% efficiency is recommended.

5-8 FUEL PROPERTIES

5-8.1 Heating Value of Fuel

Higher heating value, *HHVF*, refers to the as-fired higher heating value on a constant pressure basis. For solid and liquid fuels, *HHVF* is determined in a bomb calorimeter, which is a constant volume device. Since fuel is burned in a steam generator under essentially constant pressure conditions, the bomb calorimeter values must be corrected to a constant pressure basis.

$$HHVF = HHVFcv + 2.644\ MpH2F, \text{Btu/lbm (J/kg)} \qquad (5\text{-}8\text{-}1)$$

where

HHVFcv = the higher heating value of the fuel on a constant volume basis as determined from a bomb calorimeter

MpH2F = the mass percent of H_2 in the fuel

The user should ensure that the laboratory performing the fuel analysis has not made this correction. For gaseous fuels, the higher heating value is determined under constant pressure conditions; therefore, the calorimeter values do not need correction.

The calculations throughout this Code utilize higher heating value expressed in units on a mass basis, Btu/lbm (J/kg). For gaseous fuels, the higher heating value is normally expressed on a volume basis, Btu/scf (J/N·m^3), *HHVGF*. For compatibility with the units used in the calculation procedure, the higher heating value must be converted to an energy per unit mass basis, Btu/lbm (J/kg).

$$HHVF = \frac{HHVGF}{DnGF}, \text{Btu/lbm (J/kg)} \qquad (5\text{-}8\text{-}2)$$

where

DnGF = density of gas at the standard temperature and pressure conditions used for *HHVGF*, lbm/scf (kg/N·m^3)

For fossil fuels, the reasonableness of the higher heating value can be checked based on the theoretical air calculated from the ultimate analysis (refer to para. 5-11.3). Higher heating value based on typical theoretical air values can be estimated using the following equation:

$$HHVF = 10^6\,\frac{MFrThA}{MqThAF}, \text{Btu/lbm (J/kg)} \qquad (5\text{-}8\text{-}3)$$

where

MFrThA = theoretical air, lbm/lbm (kg/kg) fuel as-fired

MqThAF = normal value of theoretical air for fuel being checked, lbm/MBtu. (Refer to para. 5-11.3 for typical ranges.)

5-8.2 Chemical Analysis of Fuel

An ultimate analysis of solid and liquid fuels is required to determine the mass of the individual elements involved in the combustion process, and the mass of inert ash. The total as-fired moisture content must also be determined. When the ultimate analysis is on an air-dried or moisture-free basis, it must be converted to an as-fired basis. A gaseous fuel analysis is usually reported on a dry or saturated basis. The amount of moisture as-fired should be determined, and the chemical analysis and *HHVGF* should be adjusted to the as-fired condition.

The ultimate analysis of the fuel is used to calculate the quantity of air and products of combustion. When the ultimate analysis is expressed on a percent mass basis, the constituents considered in the calculations are carbon (CF), hydrogen (H_2F), nitrogen (N_2F), sulfur (SF), oxygen (O_2F), water (H_2OF), and ash (AsF). Note that in the calculations, the symbol used for the solid and liquid fuel constituent H_2OF is *WF* (for gaseous fuels, the symbol for H_2OvF is *WvF*). Trace gaseous elements, such as chlorine, which is not considered in the calculations, should be added to the nitrogen in the fuel for calculation purposes. Note that hydrogen is considered on a dry or moisture-free basis (i.e., it does not include the hydrogen in the water in the fuel).

For some combustion processes, those involving solid fuels in particular, all of the carbon may not be burned. When there is unburned carbon, the combustion calculations utilize the carbon burned, Cb, rather than the actual carbon in the fuel (refer to para. 5-10.5). Similarly, if it is ascertained that there is a significant quantity of unburned hydrogen (greater than 1% of the actual hydrogen in the fuel), the hydrogen burned, H_2b, should be used in the calculations rather than the actual hydrogen available in the fuel. (Refer to para. 5-10.3.)

A proximate analysis for solid fuels (typically coal) includes the determination of volatile matter, fixed carbon and ash, as well as the as-fired moisture. The sulfur content may also be reported. A complete proximate analysis is not necessarily required for determination of efficiency. Typical applications for a proximate analysis include

(a) a cost-effective means for obtaining the variations in ash, moisture, and sulfur during a test, to better quantify the uncertainty of these constituents. A large number of proximate analyses can be used to determine ash, moisture, and possibly sulfur in lieu of a large number of ultimate analyses.

(b) for coal, the volatile matter and fixed carbon are required to determine enthalpy of the entering coal. If not determined, dry ash free values may be agreed upon prior to the test and adjusted for the measured ash and moisture content of the as-fired fuel.

(c) volatile matter and fixed carbon (frequently expressed as the ratio of fixed carbon to volatile matter) are an indication of how difficult a coal is to burn. In general, the lower the volatile matter with respect to the fixed carbon, the more difficult the fuel is to burn. For guarantee tests, this ratio may be considered when evaluating whether the test fuel is suitably equivalent to the contract fuel.

A gaseous fuel analysis expresses the individual hydrocarbon compounds and the other constituents on a volumetric percentage basis. For the combustion calculations in this Code, the gaseous fuel analysis is converted to a mass basis. The Gaseous Fuel Calculation Form included in Nonmandatory Appendix A may be used for this conversion. The calculations follow the general logic below.

$$MpFk = 100\ \frac{MvFk}{MwGF},\ \%\ \text{mass} \quad (5\text{-}8\text{-}4)$$

$$MwGF = \sum MvFk,\ \text{lbm/mole (kg/mole)} \quad (5\text{-}8\text{-}5)$$

$$MvFk = Mwk \sum \frac{VpGj\ \ Mokj}{100},\ \text{lbm/mole fuel (kg/mole)} \quad (5\text{-}8\text{-}6)$$

where

j = fuel components expressed on a by volume or mole basis, such as CH_4, C_2H_6, etc.

k = fuel constituents expressed on a mass basis. For this Code, these are C, H_2, N_2, S, O_2, and H_2O. For a gaseous fuel, it is assumed that water is in a vaporous state and the acronym H_2Ov is used throughout the calculations.

Mokj = moles of constituent k in component j. For example,
for component $j = C_2H_6$, and k = C, $Mokj = 2$
for component $j = C_2H_6$, and $k = H_2$, $Mokj = 3$

MpFk = mass percentage of constituent k

MvFk = mass of constituent k per unit volume of fuel, lbm/mole or lbm/ft^3 (kg/mole or kg/m^3)

MwGF = molecular weight of the gaseous fuel, lbm/mole (kg/mole). This is the sum of each *MvFk* value on a mass per unit mole (or volume) basis, lbm/mole (kg/mole).

Mwk = molecular weight of constituent k, lbm/mole (kg/mole)

VpGj = as-fired fuel components (such as CH_4, C_2H_6), percent by volume

5-8.3 Multiple Fuels

When more than one fuel is fired, the ultimate analysis and higher heating value is the weighted average based upon the mass flow rate of each fuel. For the initial calculation, the total fuel input is estimated from measured fuel flow or calculated from output and estimated efficiency. The input from the primary fuel (fuel with the major input) is calculated by difference from the total input and the input calculated for the fuel(s) for which the measured mass flow rate is used. The mass flow rate of the unmeasured fuel is then calculated from the *HHV* and input from that fuel. The efficiency calculations must be reiterated until the estimated input and the input calculated from measured output and efficiency are within the convergence tolerance discussed in para. 5-7.3.

5-9 SORBENT AND OTHER ADDITIVE PROPERTIES

This Section addresses solid and/or gaseous material other than fuel that is added to the gas side of the steam generator envelope. Additives can impact the efficiency and combustion process in several ways.

(a) Additives may increase the quantity of residue and "sensible heat of residue" losses.

(b) Additives may introduce moisture that increases "moisture in flue gas" losses and alters the flue gas specific heat.

(c) Additives may undergo a chemical change and alter the flue gas composition or may alter the air requirement.

(d) Chemical reactions that are endothermic require heat, which is an additional loss.

(e) Chemical reactions that are exothermic add heat, which is an additional credit.

Since limestone is widely used for sulfur removal, this Code specifically addresses the impact of the addition of limestone on the efficiency and combustion calculations. The term "sorbent" is used throughout the Code to refer to any material added to the flue gas (within the steam generator envelope) that is not fuel. The calculations for limestone demonstrate the principles of calculation required for the effect of most additives on efficiency and combustion products. If the effects of other additives on flue gas constituents or particulates are independently demonstrated and measurable or calculable, the parties to the test may include the associated credits and/or losses. In addition to limestone, the calculations address hydrated lime, which consists of calcium hydroxide, $Ca(OH)_2$, and magnesium hydroxide $Mg(OH)_2$, as a potential sorbent for reducing SO_2. When inert materials such as sand are added, the calculations below should be made as if limestone containing only inert material and moisture were used.

5-9.1 *MFrSb*, Mass Fraction of Sorbent, lbm/lbm Fuel (kg/kg)

Combustion and efficiency calculations are sensitive to the measured sorbent mass flow rate. Therefore, the mass flow rate of sorbent must be determined accurately.

To simplify the combustion and efficiency calculations, the sorbent mass flow rate is converted to a mass of sorbent/mass of fuel basis. The mass flow rate of fuel is measured or estimated initially. The efficiency calculations are repeated until the estimated and calculated fuel mass flow rates are within the convergence tolerance of para. 5-7.3.

$$MFrSb = \frac{MrSb}{MrF}, \text{ lbm/lbm fuel (kg/kg fuel)} \quad (5\text{-}9\text{-}1)$$

where

MrF = mass flow rate of fuel, lbm/hr (kg/s). Repeat efficiency calculation until the calculated *MrF* converges within the guidelines of para. 5-7.3.

MrSb = measured mass flow rate of sorbent, lbm/hr (kg/s)

5-9.2 *MFrSbk*, Mass of Constituents in Sorbent, lbm/lbm Fuel (kg/kg)

The important constituents in the sorbent are the reactive products, the moisture, and the inerts. The mass of each constituent is converted to a mass/mass from fuel basis.

$$MFrSbk = MFrSb\,\frac{MpSbk}{100}, \text{ lbm/lbm fuel (kg/kg)} \quad (5\text{-}9\text{-}2)$$

where

k = constituent in the sorbent. The reactive constituents specifically addressed are as follows:

$CaCO_3$ = calcium carbonate (Cc)

$Ca(OH)_2$ = calcium hydroxide (Ch)

$MgCO_3$ = magnesium carbonate (Mc)

$Mg(OH)_2$ = magnesium hydroxide (Mh)

MpSbk = percent of constituent *k* in the sorbent

5-9.3 $MqCO_2Sb$, Gas From Calcination of Sorbent, lbm/Btu (kg/J)

When heat is added to calcium carbonate and magnesium carbonate, CO_2 is released. This increases the dry gas weight.

$$MoCO2Sb = \sum MoFrClhk\,\frac{MFrSbk}{Mwk}, \text{ moles/lbm fuel (moles/kg)} \quad (5\text{-}9\text{-}3)$$

$$MFrCO2Sb = 44.0098\; MoCO2Sb, \text{ lbm/lbm fuel(kg/kg)} \quad (5\text{-}9\text{-}4)$$

$$MqCO2Sb = \frac{MFrCO2Sb}{HHVF}, \text{ lbm/Btu (kg/J)} \quad (5\text{-}9\text{-}5)$$

where

k = constituents that contain carbonates, typically calcium carbonate (Cc) and magnesium carbonate (Mc)

MFrCO2Sb = mass fraction of gas (CO_2) from sorbent, lbm/lbm fuel (kg/kg), and where 44.0098 is the molecular weight of carbon dioxide

MoCO2Sb = moles of gas (CO_2) from sorbent, moles/lbm fuel (moles/kg)

MoFrClhk = calcination fraction for constituent *k*, moles CO_2 released/mole of constituent. Two constituents are addressed directly by this Code. Magnesium carbonate (Mc) calcines readily at partial pressures of CO_2 typical of combustion with air and normal operating temperatures of atmospheric fluidized bed steam generators and thus the calcination fraction is normally considered to be 1.0; however, not all of the $CaCO_3$ (Cc) is converted to CaO and CO_2. Refer to para. 5-10.8 for determination.

MqCO2Sb = mass of gas (CO_2) from sorbent on an input from fuel basis, lbm/Btu (kg/J)

Mwk = molecular weight of constituent *k*, lbm/mole (kg/mole)

5-9.4 *MqWSb*, Water From Sorbent, lbm/Btu (kg/J)

The total moisture added due to sorbent is the sum of the moisture in the sorbent and the moisture released due to the dehydration of calcium hydroxide and magnesium hydroxide.

$$MoWSb = \frac{MFrH2OSb}{18.0153} + \sum MoFrClhk \frac{MFrSbk}{Mwk}, \text{ moles/lbm fuel} \quad (5\text{-}9\text{-}6)$$

$$MFrWSb = 18.0153\ MoWSb, \text{ lbm/lbm fuel (kg/kg)} \quad (5\text{-}9\text{-}7)$$

$$MqWSb = \frac{MFrWSb}{HHVF}, \text{ lbm/Btu (kg/J)} \quad (5\text{-}9\text{-}8)$$

$$MrWSb = MFrWSb\ MrF, \text{ lbm/hr (kg/s)} \quad (5\text{-}9\text{-}9)$$

where

k = constituents that contain water or hydroxides that are dehydrated, typically calcium hydroxide (Ch) and magnesium hydroxide (Mh)

MFrH2OSb = mass fraction of the water in sorbent, lbm/lbm fuel (kg/kg)

MFrWSb = mass fraction of total water from sorbent, lbm/lbm fuel (kg/kg)

MoFrClhk = mole fraction of dehydration (normally considered 1.0) of constituent *k*, moles H_2O released/mole of constituent

MoWSb = total moles of water from sorbent, moles/lbm fuel (moles/kg)

MqWSb = mass of total water from sorbent on an input from fuel basis, lbm/Btu (kg/J)

MrWSb = mass flow rate of total water from sorbent, lbm/hr (kg/s)

5-9.5 *MFrSc*, Sulfur Capture/Retention Ratio, lbm/lbm (kg/kg)

The sulfur capture/retention ratio is the mass of sulfur removed divided by the total mass of sulfur available. The sulfur capture/retention ratio is determined from the measured O_2 and SO_2 in flue gas. If sorbent or other means of sulfur capture/retention is not utilized within the steam generator envelope, the mass fraction of sulfur capture, *MFrSc*, shall be considered to be zero.

5-9.5.1 *MFrSc* When SO_2 and O_2 Are Measured on a Dry Basis

$$MFrSc = \frac{1 - \left(\dfrac{DVpSO2\ (MoDPcu + 0.7905\ MoThAPcu)}{100\ (1 - DVpO2/20.95)\ MoSO2} \right)}{\left[1 + 0.887 \left(\dfrac{DVpSO2/100}{1 - DVpO2/20.95} \right) \right]}, \text{ lbm/lbm (kg/kg)} \quad (5\text{-}9\text{-}10)$$

$$MoThAPcu = \frac{1}{0.2095} \left(\frac{MpCb}{1{,}201.1} + \frac{MpH2F}{403.2} + \frac{MpSF}{3{,}206.5} - \frac{MpO2F}{3{,}199.9} \right), \text{ moles/mass fuel} \quad (5\text{-}9\text{-}11)$$

$$MoDPcu = \frac{MpCb}{1{,}201.1} + \frac{MpSF}{3{,}206.5} + \frac{MpN2F}{2{,}801.3} + MoCO2Sb, \text{ moles/mass fuel} \quad (5\text{-}9\text{-}12)$$

$$MoSO2 = \frac{MpSF}{3{,}206.5}, \text{ moles/lbm fuel (moles/kg)} \quad (5\text{-}9\text{-}13)$$

where

DVpO2, *DVpSO2* = measured O_2 and SO_2 in the flue gas, percent volume. They must be measured at the same location and expressed on a dry basis. SO_2 is usually measured in parts per million. To convert to a percent basis, divide parts per million by 10,000.

MoDPcu = moles of dry products from the combustion of fuel (CO_2, SO_2, N_2 from fuel) with 100% conversion of the sulfur to SO_2 plus the dry gas from sorbent (CO_2), moles/mass fuel

MoSO2 = moles of SO_2 per lbm fuel that would be produced with 100% conversion of the sulfur in the fuel to SO_2, moles/lbm fuel (moles/kg)

MoThAPcu = moles of theoretical air required for the gasified products in the fuel with total conversion of the sulfur in fuel to SO_2, moles/mass of fuel. The constituents in the fuel, CB (carbon burned), H_2, S, and O_2 are on a percent mass basis.

5-9.5.2 *MFrSc* When SO_2 and O_2 Are Measured on a Wet Basis

$$MFrSc = \frac{1 - \left(\frac{VpSO2\ [MoWPcu + MoThAPcu\,(0.7905 + MoWA)]}{100\,[1 - (1 + MoWA)\,VpO2/20.95]\,MoSO2} \right)}{1 + K\left(\frac{VpSO2/100}{1 - (1 + MoWA)\,VpO2/20.95} \right)},$$

$$\text{lbm/lbm (kg/kg)} \qquad (5\text{-}9\text{-}14)$$

$$MoWPcu = MoDPcu + \frac{MpH2F}{201.59} + \frac{MpWF}{1{,}801.53} + \frac{MFrWAdz}{18.0153} + MoWSb, \text{ moles/mass fuel} \qquad (5\text{-}9\text{-}15)$$

$$K = 2.387\,(0.7905 + MoWA) - 2.3 \qquad (5\text{-}9\text{-}16)$$

$$MoWA = 1.608\ MFrWA, \text{ moles/mole dry air} \qquad (5\text{-}9\text{-}17)$$

where

MFrWA = mass of moisture in air per mass of dry air, lbm/lbm (kg/kg)
MFrWAdz = additional moisture at location *z*, such as atomizing steam and sootblowing steam, lbm/lbm fuel as-fired. Also refer to para. 5-12.7.
MoWA = moles moisture per mole of dry air, moles/mole. See para. 5-11.4.3.
MoWPcu = *MoDPcu* plus moles of water from fuel, plus moles of water from sorbent, plus moles of additional water, moles/mass fuel
VpO2, *VpSO2* = measured O_2 and SO_2 in the flue gas, percent volume. They must be measured at the same location and expressed on a wet basis. SO_2 is usually measured in parts per million. To convert to a percent basis, divide parts per million by 10,000.

5-9.6 *MoFrCaS*, Calcium-to-Sulfur Molar Ratio, moles/mole

$$MoFrCaS = MFrSb\ \frac{MwS}{MpSF} \sum \frac{MpCak}{MwCak}, \text{ moles/mole} \qquad (5\text{-}9\text{-}18)$$

where

CaCO3 = calcium carbonate (Cc) *MW* = 100.087
Ca(OH)2 = calcium hydroxide (Ch) *MW* = 74.0927
MpCak = percent of calcium in sorbent in form of constituent *k*, percent mass
MwCak = molecular weight of calcium compound *k*, lbm/mole (kg/mole)
MwS = molecular weight of sulfur, 32.065 lbm/mole

5-9.7 *MFrSsb* and *MFrO3ACr* — Mass Fraction Spent Sorbent and Mass Fraction of O_3 From Air Correction, lbm/lbm Fuel (kg/kg)

Spent sorbent is the solid residue remaining from the sorbent after evaporation of the moisture in the sorbent, calcination/dehydration, and mass gain due to sulfation (formation of $CaSO_4$ from CaO and $MgSO_4$ from MgO). The O_3 from air required to form SO_3 from the fuel becomes part of the spent sorbent, a solid. Therefore, a correction to the flue gas flow rate is required due to the reduction of O_3 from the air.

$$MFrSsb = MFrSb - MFrCO2Sb - MFrWSb + MFrSO3, \text{ lbm/lbm fuel (kg/kg)} \qquad (5\text{-}9\text{-}19)$$

$$MFrSO3 = 0.025\ MFrSc\ MPSF, \text{ lbm/lbm fuel (kg/kg)} \qquad (5\text{-}9\text{-}20)$$

$$MoO3ACr = MFrO3ACr/MwO3, \text{ moles/lbm fuel (moles/kg)} \qquad (5\text{-}9\text{-}21)$$

$$MqO3ACr = MFrO3ACr/HHVF, \text{ lbm/Btu (kg/J)} \qquad (5\text{-}9\text{-}22)$$

$$MFrO3ACr = 0.6\ MFrSO3, \text{ lbm/lbm fuel (kg/kg)} \qquad (5\text{-}9\text{-}23)$$

where

MFrO3ACr = mass fraction of O_3 from air required to form SO_3 in the sulfation process, lbm/lbm (kg/kg). The constant 0.6 is the molecular weight of O_3 divided by the molecular weight of SO_3.
MFrSO3 = mass fraction of SO_3 formed in the sulfation (sulfur capture) process, lbm/lbm fuel (kg/kg). The constant 0.025 is the molecular weight of SO_3 divided by the molecular weight of sulfur and divided by 100 to convert percent to a mass-to-mass fraction.
MoO3ACr = dry gas flow correction for the O_3 in air required to form SO_3, moles/lbm fuel (moles/kg)
MqO3ACr = dry gas flow correction for the O_3 in air required to form SO_3, lbm/Btu (kg/J)
MwO3 = molecular weight of O_3, 47.9982, lbm/mole (kg/mole)

5-10 RESIDUE PROPERTIES

Residue is the ash and unburned fuel removed from the steam generating unit. When a sorbent such as limestone or an inert material such as sand is introduced, the residue includes the spent sorbent (solid sorbent products remaining after evaporation of the moisture in the sorbent, calcination/dehydration, and weight gain due to sulfation). Residue is analogous to refuse when used to refer to the solid waste material removed from a fossil-fuel-fired steam generator.

5-10.1 *MFrRs*, Mass of Residue, lbm/lbm Fuel (kg/kg)

The ash in fuel and spent sorbent are converted to a mass of residue per mass of fuel basis.

$$MFrRs = \frac{MpAsF + 100\ MFrSsb}{(100 - MpCRs)}, \text{lbm/lbm fuel (kg/kg)} \quad (5\text{-}10\text{-}1)$$

where

$MFrSsb$ = mass fraction of spent sorbent per mass of fuel, lbm/lbm fuel (kg/kg)
$MpAsF$ = ash in fuel, % mass
$MpCRs$ = unburned carbon in the residue, % mass

5-10.2 *MqRsz*, Mass of Residue at Location *z*, lbm/Btu (kg/J)

The mass of residue exiting the steam generator envelope must be determined for the energy balance calculations and for the intermediate residue calculations below.

$$MqRsz = \frac{MpRsz\ MFrRs}{100\ HHVF}, \text{lbm/Btu (kg/J)} \quad (5\text{-}10\text{-}2)$$

where

$MpRsz$ = percent of total residue exiting the steam generator envelope at location z, %

It may be impractical to measure the residue collected at all extraction points. In such cases, the unmeasured residue may be calculated by difference from the total calculated residue and the measured residue. The estimated split between the unmeasured locations must be agreed upon by all parties to the test.

$$MpRsz = 100 \frac{MrRsz}{MFrRs\ MrF}, \text{\% mass} \quad (5\text{-}10\text{-}3)$$

where

MrF = mass flow rate of fuel, lbm/hr (kg/s). The mass flow rate of fuel should be measured or estimated initially and the calculations repeated until the calculated mass flow rate of fuel based on efficiency is within the guidelines of para. 5-7.3.
$MpRsz$ = residue collected at location z, %
$MrRsz$ = measured mass flow rate of residue at location z, lbm/hr (kg/s)

The usual measurement location for the mass of residue is the dust loading or fly ash leaving the unit; refer to subsection 4-11. The results of this test procedure are normally reported on a mass per volume of flue gas basis. While the dust loading result from this test is considered accurate, the flue gas mass flow calculation from this test is not considered as accurate as the gas mass flow calculated stoichiometrically by this Code. Accordingly, the mass flow rate of residue based on dust loading results is calculated as follows:

$$MrRsz = \frac{MvRs\ MrFg}{C1\ DnFg}, \text{lbm/hr (kg/s)} \quad (5\text{-}10\text{-}4)$$

where

$C1$ = 6,957 grains/lbm (U.S. Customary), 1 000 g/kg (SI)
$DnFg$ = density of wet flue gas at conditions $MvRs$ above reported, lbm/ft^3 (kg/m^3)
$MrFg$ = mass flow rate of wet flue gas; refer to para. 5-12.9, lbm/hr (kg/s)
$MvRs$ = dust loading results tested in accordance with subsection 4-11, grains/ft^3 (g/m^3)

5-10.3 *MpCRs*, Unburned Carbon in the Residue, Percent

The unburned carbon in the residue, *MpCRs*, refers to the free carbon and is used to determine unburned carbon from fuel. The residue contains carbon in the form of carbonates and free carbon when limestone is utilized, as well as from fuels with a high carbonate content in the ash. The standard tests for carbon in the residue determine total carbon (*MpToCRs*). It is also necessary to determine the carbon dioxide content in the residue (*MpCO2Rs*), and correct the total carbon results to a free carbon basis (*MpCRs*). Refer to subsection 4-12 regarding the analysis methods to be specified. If the laboratory analysis is not clear whether total carbon (*MpToCRs*) or free carbon (*MpCRs*) is reported, it should be clarified. When sorbent with calcium carbonate is utilized, the CO_2 in residue is required to calculate the quantity of $CaCO_3$ in the residue and the calcination fraction of calcium carbonate in the sorbent.

$$MpCRs = MpToCRs - \frac{12.011}{44.0098} MpCO2Rs, \text{lbm/100 lbm residue} \quad (5\text{-}10\text{-}5)$$

When residue is collected at more than one location, the weighted average of carbon and carbon dioxide in residue is calculated from

$$MpCRs = \sum \frac{MpRsz\ MpCRsz}{100}, \text{\% mass} \quad (5\text{-}10\text{-}6)$$

$$MpCO2Rs = \sum \frac{MpRsz\ MpCO2Rsz}{100}, \text{\% mass} \quad (5\text{-}10\text{-}7)$$

NOTE: If measured, unburned hydrogen is to be reported on a dry basis. On units utilizing limestone sorbent, it is quite likely that hydrogen in the residue is from the water of hydration of calcium oxide, which would not be detected by the normal method of testing for free moisture. If it is ascertained that unburned hydrogen in the residue is real and significant and it cannot be corrected by operating techniques, the hydrogen in the fuel should be corrected for unburned hydrogen for the combustion and efficiency calculations in the same manner as unburned carbon. Refer also to para. 5-10.5.

5-10.4 *MpUbC*, Unburned Carbon in Fuel, Percent Mass

The unburned carbon in the residue is used to calculate the percent of the carbon in the fuel that is unburned.

$$MpUbC = MpCRs\ MFrRs, \%\ \text{mass} \tag{5-10-8}$$

5-10.5 *MpCb*, Carbon Burned, Percent Mass

The actual percent carbon in the fuel that is burned is the difference between the carbon in the fuel from the ultimate analysis and the unburned carbon. The actual carbon burned (*MpCb*) is used in the stoichiometric combustion calculations in lieu of carbon in fuel.

$$MpCb = MpCF - MpUbC, \%\ \text{mass} \tag{5-10-9}$$

NOTE: If it is determined that there is unburned hydrogen, *MpUbH2*, the actual hydrogen burned, *MpH2b*, must be used in the combustion and efficiency calculations in lieu of *MpH2F*.

$$MpH2b = MpH2F - MpUbH2, \%\ \text{mass} \tag{5-10-10}$$

Refer to para. 5-10.3.

5-10.6 *MpCbo*, Carbon Burnout, Percent

Carbon burnout is the carbon burned divided by the carbon available and expressed as a percentage.

$$MpCbo = 100\frac{MpCb}{MpCF}, \% \tag{5-10-11}$$

5-10.7 *Ecm*, Combustion Efficiency, Percent

The combustion efficiency is 100 minus the unburned combustible losses on subsection 5-14 (excluding the loss due to pulverizer rejects).

$$ECm = 100 - QpLUbC - QpLCO - QpLH2Rs - QpLUbHc, \% \tag{5-10-12}$$

5-10.8 *MoFrClhCc*, Calcination Fraction of Calcium Carbonate, Moles CO_2/Mole $CaCO_3$

Calcination is the endothermic chemical reaction when carbon dioxide is released from compounds containing carbonate (CO_3) such as calcium carbonate to form calcium oxide and magnesium carbonate to form magnesium oxide. Magnesium carbonate, $MgCO_3$ (Mc), calcines readily under the normal operating conditions of atmospheric fluidized bed boilers. However, not all of the calcium carbonate, $CaCO_3$ (Cc), is converted to CaO and CO_2. The calcination fraction is determined from the measured CO_2 in the residue. Assuming that the principal carbonates in the sorbent are magnesium carbonate and calcium carbonate, these calculations assume that the CO_2 in the residue is in the form of calcium carbonate. If a sorbent is used that contains significant amounts of a carbonate that is more difficult to calcine than calcium carbonate, the principles of this Code should be followed, but the amount of CO_2 in the residue should be proportioned among the carbonate compounds in view of the difficulty of calcination.

$$MoFrClhCc = 1 - \frac{MFrRs\ MpCO2\ Rs\ MwCc}{MFrSb\ \ MpSbCc\ \ MwCO2} \tag{5-10-13}$$

where

MFrSb = mass fraction of sorbent, lbm/lbm fuel (kg/kg)
MpCO2Rs = mass of CO_2 in residue, percent mass
MpSbCc = mass of $CaCO_3$ (Cc) in sorbent, percent
MwCc = molecular weight of $CaCO_3$ (Cc), 100.087 lbm/mole (kg/mole)
MwCO2 = molecular weight of CO_2, 44.0098 lbm/mole (kg/mole)

5-11 COMBUSTION AIR PROPERTIES

5-11.1 Physical Properties

The calculations and derivation of constants used in this Code are based upon a composition of air as follows [1]: 0.20946 O_2, 0.78102 N_2, 0.00916 Ar, 0.00033 CO_2 moles per mole of air (and other trace elements), yielding an average molecular weight of 28.9625. For simplification of the calculations, nitrogen (N_2) includes the argon and other trace elements, and is referred to as "atmospheric nitrogen" (N_{2a}), having an equivalent molecular weight of 28.158.

The nominal properties of air used in this Code are

(*a*) volumetric composition: 20.95% oxygen, 79.05% nitrogen

(*b*) gravimetric composition: 23.14% oxygen, 76.86% nitrogen

5-11.2 *MFrWDA*, Moisture in Air, lbm/lbm Dry Air (kg/kg)

The moisture in air is determined from measured inlet air wet-bulb and dry-bulb temperature or dry-bulb temperature and relative humidity in conjunction with psychrometric charts, or calculated from vapor pressure as determined from Carrier's eq. (5-11-2) when wet-bulb temperature is measured, or eq. (5-11-3) when relative humidity is measured.

$$MFrWDA = 0.622\frac{PpWvA}{(Pa - PpWvA)}, \text{lbm } H_2O/\text{lbm dry air (kg/kg)} \tag{5-11-1}$$

$$PpWvA = PsWTwb - \frac{(Pa - PsWvTwb)(Tdbz - Twbz)}{2830 - 1.44\,Twbz}, \text{psia} \tag{5-11-2}$$

$$PpWvA = 0.01\,RHMz\,PsWvTdb, \text{psia} \tag{5-11-3}$$

$$PsWvTz = C1 + C2T + C3T^2 + C4T^3 + C5T^4 + C6T^5, \text{psia} \tag{5-11-4}$$

where

$C1$ = 0.019257
$C2$ = 1.289016E–3
$C3$ = 1.211220E–5
$C4$ = 4.534007E–7
$C5$ = 6.841880E–11
$C6$ = 2.197092E–11
Pa = barometric pressure, psia. To convert in. Hg to psia, divide by 2.0359.
$PpWvA$ = partial pressure of water vapor in air, psia. This may be calculated from relative humidity or wet- and dry-bulb temperature
$PsWvTz$ = saturation pressure of water vapor at wet-bulb temperature, *PsWvTwb,* or dry-bulb temperature, *PsWvTdb*, psia. The curve fit is valid for temperatures from 32°F to 140°F.
$Rhmz$ = relative humidity at location *z*
$Tdbz$ = temperature of air (dry-bulb) at location *z*, °F
$Twbz$ = temperature of air (wet-bulb) at location *z*, °F

5-11.3 *MqThACr*, Theoretical Air (Corrected), 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 less frequently measured. The impact of these minor species is negligible on the combustion calculations addressed by this Code. Refer to Nonmandatory Appendix C for a rigorous treatment of CO and NO_x that may be used if CO and/or NO_x is significant (i.e., greater than 1,000 ppm).

$$MqThA = \frac{MFrThA}{HHVF}\text{, lbm/Btu (kg/J)} \qquad (5\text{-}11\text{-}5)$$

$$MFrThA = 0.1151\,MpCF + 0.3429\,MpH2F + 0.0431\,MpSF - 0.0432\,MpO2F\text{, lbm/lbm fuel (kg/kg)} \qquad (5\text{-}11\text{-}6)$$

where fuel constituents *MpCF*, *MpH2F*, *MpSF*, and *MpO2F* are on a percent mass basis.

For typical fossil fuels, the value of calculated theoretical air is a good check on the reasonableness of the fuel analysis. Expressed on a lbm/million Btu (MBtu) basis ($MQTHA \times 10^6$), a valid fuel analysis should fall within the ranges of theoretical air shown below:

(a) Coal (VMmaf > 30%): 735 lbm/MBtu through 775 lbm/MBtu

(b) Oil: 735 lbm/MBtu through 755 lbm/MBtu

(c) Natural Gas: 715 lbm/MBtu through 735 lbm/MBtu

The theoretical air for carbon and hydrogen, 816 lbm/MBtu and 516 lbm/MBtu, respectively, are the practical maximum and minimum values for hydrocarbon fuels.

For monitoring operation and analysis of combustion, the theoretical air required to produce the gaseous products of combustion is more meaningful than the ideal value defined above. In commercial applications, particularly for solid fuels, it is not feasible to burn the fuel completely. The gaseous products of combustion are the result of the fuel that is burned or gasified. When additives are used, secondary chemical reactions may also occur. For example, when CaO reacts with SO_2 in the flue gas to form $CaSO_4$ (a method of sulfur reduction), additional O_2 supplied from air is required. Therefore, for purposes of the calculations in this Code, corrected theoretical air that accounts for the actual combustion process is used.

Corrected theoretical air is defined as the amount of air required to complete the combustion of the gasified fuel and support secondary chemical reactions with zero excess O_2. By definition, the theoretical products of combustion would have no CO or gaseous hydrocarbons.

$$MqThACr = \frac{MFrThACr}{HHVF}\text{, lbm/Btu (kg/J)} \qquad (5\text{-}11\text{-}7)$$

$$MFrThACr = 0.1151\,MpCb + 0.3429\,MpH2F + 0.0431\,(1 + 0.5\,MFrSc)\,MpSF - 0.0432\,MpO2F\text{, lbm/lbm fuel (kg/kg)} \qquad (5\text{-}11\text{-}8)$$

$$MoThACr = \frac{MFrThACr}{28.9625}\text{, moles/mass fuel "as-fired"} \qquad (5\text{-}11\text{-}9)$$

where

$MFrSc$ = sulfur capture ratio, lbm/lbm. This item is normally assumed to be zero when the sulfur removal occurs external to the steam generator envelope. Refer to para. 5-9.5 for calculation instructions.
$MoThACr$ = theoretical air (corrected), moles/mass fuel as-fired
$MpCb$ = $MpCF - MpUbC$ = carbon burned on a mass percentage basis
$MqThACr$ = theoretical air (corrected), lbm/Btu. Note that when a sulfur removal process is employed, the excess air and combustion calculations are dependent upon where the sulfur removal occurs in relation to the flue gas composition measurements.

5-11.4 *XpA*, Excess Air, Percent

Excess air is the actual quantity of air used, minus the theoretical air required, divided by the theoretical air, and expressed as a percentage.

$$XpA = 100\frac{(MFrDA - MFrThACr)}{MFrThACr} \quad (5\text{-}11\text{-}10)$$
$$= 100\frac{(MqDA - MqThACr)}{MqThACr}, \%$$

In this Code, corrected theoretical air [eq. (5-11-7)] is used as the basis for calculating excess air. Defined as such, 0% O_2 in the flue gas corresponds to 0% excess air. Excess air may also be defined based on ideal theoretical air and calculated by substituting ideal theoretical air [eq. (5-11-5) or (5-11-6)] in eq. (5-11-10) above.

For efficiency calculations, excess air must be determined at the steam generator exit (14), as well as air heater exits (15), (15A), and (15B), if applicable; and air heater gas inlets (14A) and (14B), if different from the steam generator exit. Refer to Figs. 1-4-1 through 1-4-7, and subsection 1-4 for boundary data identification numbers. Excess air is determined from the volumetric composition of the flue gas. It may be calculated stoichiometrically based on O_2 or CO_2, and analytically based on CO_2 and *MpCb/S* ratio in the fuel. Measurement of O_2 is the most common and preferred continuous analysis method. O_2 is used as the basis for calculation of excess air in this Code. An additional advantage of using measured O_2 is that for a given type of fuel (coal, oil, gas, etc.), excess air depends only on O_2 and not on the specific analysis. Conversely, the relationship between CO_2 and excess air is strongly dependent on the fuel analysis due to the amount of CO_2 produced being dependent on the carbon/hydrogen ratio of the fuel. When O_2 is measured on a wet basis, an additional variable is introduced (H_2O in the flue gas). However, even on a wet basis, O_2 versus excess air is essentially constant for typical variations in moisture in flue gas produced from a given fuel source.

5-11.4.1 O_2 Analysis on Dry Basis Where the Moisture in the Flue Gas Is Condensed, Such as When an Extractive Sampling System Is Used

$$XpA = 100\frac{DVpO2\,(MoDPc + 0.7905\,MoThACr)}{MoThACr\,(20.95 - DVpO2)}, \% \quad (5\text{-}11\text{-}11)$$

$$MoDPc = \frac{MpCb}{1,201.1} + (1 - MFrSc)\frac{MpSF}{3,206.5} + \frac{MpN2F}{2,801.34} + MoCO2Sb, \text{moles/mass fuel} \quad (5\text{-}11\text{-}12)$$

where

DVpO2 = oxygen concentration in the flue gas, percent by volume, dry basis
MFrSc = mass fraction of sulfur capture, lbm/lbm fuel (kg/kg)
MoCO2Sb = moles of gas from sorbent, moles/lbm fuel (moles/kg). Refer to subsection 5-9 for calculation.
MoDPc = moles of dry products from the combustion of fuel [CO_2 from carbon burned, actual SO_2 produced (excluding sulfur retained due to SO_2 capture techniques), N_2 from fuel and the dry gas from sorbent, CO_2, moles/mass fuel]

5-11.4.2 Calculation of *DVpO2*, *DVpCO2*, *DVpSO2*, *DVpN2f*, and *DVpN2a* on a Dry Basis When Excess Air Is Known

$$DVpO2 = \frac{XpA\;MoThACr\;0.2095}{MoDFg}, \% \quad (5\text{-}11\text{-}13)$$

$$DVpCO2 = \left(\frac{\frac{MpCb}{12.011} + 100\,MoCO2Sb}{MoDFg}\right), \% \quad (5\text{-}11\text{-}14)$$

$$DVpSO2 = \frac{\frac{MpSF}{32.065}(1 - MFrSc)}{MoDFg}, \% \quad (5\text{-}11\text{-}15)$$

$$DVpN2F = \frac{\left(\frac{MpN2F}{28.0134}\right)}{MoDFg}, \% \quad (5\text{-}11\text{-}16)$$

$$DVpN2a = 100 - DVpO2 - DVpCO2 - DVpSO2 - DVpN2F, \% \quad (5\text{-}11\text{-}17)$$

$$MoDFg = MoDPc + MoThACr\,(0.7905 + \frac{XpA}{100}) - MoO3ACr \quad (5\text{-}11\text{-}18)$$

where

DVpCO2 = carbon dioxide in the flue gas, %. Note that for comparison to an Orsat analysis, *DVpSO2* must be added.
DVpN2a = atmospheric nitrogen (refer to para. 5-11.1) in the flue gas, % volume
DVpN2F = nitrogen from fuel in the flue gas, % volume. This term is shown separately from the atmospheric nitrogen from the air to note the technical distinction between the two. Since the quantity of nitrogen from the fuel is generally insignificant compared to the nitrogen in the air, calculation of this term is sometimes omitted.
DVpSO2 = sulfur dioxide in the flue gas, % volume
MoDFg = moles of dry gas per lbm of fuel as-fired
MoO3ACr = dry gas flow correction for the O_3 in air required to form SO_3, moles/mass fuel (refer to para. 5-9.7)

5-11.4.3 O_2 Analysis on Wet Basis Where the Flue Gas Sample Includes Moisture, Such as In Situ Monitors and Heated Extractive Systems

$$XpA = 100\left[\frac{VpO2\,(MoWPc + MoThACr\,[0.7905 + MoWA])}{MoThACr\,(20.95 - VpO2\,[1 + MoWA])}\right], \% \qquad (5\text{-}11\text{-}19)$$

$$MoWA = 1.608\ MFrWA, \text{ moles/mole dry air} \qquad (5\text{-}11\text{-}20)$$

$$MoWPc = MoDPc + \frac{MpH2F}{201.59} + \frac{MpWF}{1{,}801.53} + \frac{MFrWAdz}{18.0153} + MoWSb, \text{ moles/lbm fuel} \qquad (5\text{-}11\text{-}21)$$

where
- 1.608 = molecular weight of dry air (28.9625) divided by the molecular weight of water (18.0153)
- *MFrWAdz* = additional moisture at location *z*, such as atomizing steam and sootblowing steam, lbm/lbm fuel as-fired. Refer to para. 5-12.7. Measured values of steam and fuel flow are usually sufficiently accurate for this calculation. If the mass flow rate of fuel is reiterated based on calculated efficiency, this item should be included.
- *MFrWDA* = moisture in air, lbm H_2O/lbm dry air
- *MoWA* = moles of moisture in air, moles H_2O/mole dry air
- *MoWPc* = *MoDPc* plus moles of wet products from the combustion from fuel, plus the wet products from sorbent, plus any additional moisture, moles/mass fuel
- *MoWSb* = total water from sorbent, moles/lbm fuel. Refer to subsection 5-9.
- *MpWF* = H_2O in fuel, percent mass basis
- *VpO2* = oxygen concentration in the flue gas, percent by volume, wet basis

5-11.4.4 Calculation of *VpO2*, *VpCO2*, *VpSO2*, *VpH2O*, *VpN2F*, and *VpN2a* on a Wet Basis When Excess Air Is Known

$$VpO2 = \frac{XpA\ MoThACr\ 0.2095}{MoFg}, \% \qquad (5\text{-}11\text{-}22)$$

$$VpCO2 = \left(\frac{\frac{MpCb}{12.011} + 100\ MoCO2Sb}{MoFg}\right), \% \qquad (5\text{-}11\text{-}23)$$

$$VpSO2 = \frac{\frac{MpSF}{32.065}(1 - MFrSc)}{MoFg}, \% \qquad (5\text{-}11\text{-}24)$$

$$VpH2O = \frac{\left[\frac{MpH2F}{2.0159} + \frac{MpWF}{18.0153} + \frac{MFrWAdz}{0.180153} + 100\ MoWSb\right.}{MoFg} \frac{\left. + (100 + XpA)\ MoThACr\ MoWA\right]}{MoFg}, \% \qquad (5\text{-}11\text{-}25)$$

$$VpN2F = \frac{\left(\frac{MpN2F}{28.0134}\right)}{MoFg}, \% \qquad (5\text{-}11\text{-}26)$$

$$VpN2a = 100 - VpO2 - VpCO2 - VpSO2 - VpH2O - VpN2F, \% \qquad (5\text{-}11\text{-}27)$$

$$MoFg = MoWPc + MoThACr\left[0.7905 + MoWA + \frac{XpA}{100}(1 + MoWA)\right] - MoO3ACr \qquad (5\text{-}11\text{-}28)$$

where
- *MoFg* = moles of wet gas per lbm fuel as-fired

5-11.5 *MqDAz*, Dry Air, lbm/Btu (kg/J)

The quantity of dry air entering the steam generator ahead of location *z* is calculated from the excess air determined to be present at location *z* as follows:

$$MqDAz = MqThACr\left(1 + \frac{XpAz}{100}\right), \text{lbm/Btu (kg/J)} \qquad (5\text{-}11\text{-}29)$$

$$MFrDAz = MFrThACr\left(1 + \frac{XpAz}{100}\right), \text{lbm/lbm fuel (kg/kg)} \qquad (5\text{-}11\text{-}30)$$

5-11.6 *MrAz*, Wet Air, lbm/hr (kg/s)

The quantity of wet air at any location *z* is the sum of the dry air plus moisture in air.

$$MqAz = (1 + MFrWA)\ MqDAz, \text{lbm/Btu (kg/J)} \qquad (5\text{-}11\text{-}31)$$

$$MrAz = MqAz\ QrF, \text{lbm/hr (kg/s)} \qquad (5\text{-}11\text{-}32)$$

where
- *QrF* = input from fuel, Btu/hr (W)

Note that to determine the air mass flow rate leaving the air heaters (to the burners), the excess air leaving the boiler or economizer must be reduced by the estimated amount of setting infiltration.

5-11.7 *Dn*, Density of Air, lbm/ft³ (kg/m³)

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

$$DnA = \frac{C1\,(C2\,Pa + PAz)}{Rk\,(C3 + TAz)},\ \text{lbm/ft}^3\ \ (\text{kg/m}^3) \qquad (5\text{-}11\text{-}33)$$

$$Rk = \frac{R}{Mwk},\ \frac{\text{ft}\cdot\text{lbm}}{\text{lbm}\cdot\text{R}}\left(\frac{\text{J}}{\text{kg}\cdot\text{K}}\right) \qquad (5\text{-}11\text{-}34)$$

$$MwA = \frac{1 + MFrWA}{\dfrac{1}{28.9625} + \dfrac{MFrWA}{18.0153}},\ \text{lbm/mole}\ \ (\text{kg/mole}) \qquad (5\text{-}11\text{-}35)$$

where

- *C1* = 5.2023 lbf/ft (U.S. Customary), 1.0 J/m³ (SI)
- *C2* = 27.68 in. wg/psi (U.S. Customary), 1.0 Pa/Pa (SI)
- *C3* = 459.7°F (U.S. Customary), 273.2°C (SI)
- *MwA* = molecular weight of wet air, lbm/mole (kg/mole)
- *Pa* = barometric pressure, psia (Pa). To convert in. Hg to psia, divide by 2.0359.
- *PAz* = static pressure of air at point *z*, in. wg (Pa)
- *R* = universal molar gas constant, 1,545 ft lbf/lbm mole °R (8 314.5 J/kg mole K)
- *Rk* = specific gas constant for gas *k*,
  $$\frac{\text{ft}\cdot\text{lbf}}{\text{lbm}\cdot{}^\circ\text{R}}\quad\left(\frac{\text{J}}{\text{kg}\cdot\text{K}}\right)$$
- *TAz* = temperature of air at point z, °F (°C)

5-12 FLUE GAS PRODUCTS

Flue gas quantity is calculated stoichiometrically from the fuel analysis and excess air. Computations are not valid if significant quantities (in comparison to flue gas weight) of unburned hydrogen or other hydrocarbons are present in the flue gas.

The total gaseous products are referred to as "wet flue gas." Solid products, such as ash from the fuel, unburned carbon, and spent sorbent, are considered separately and are not a part of the wet flue gas mass. Wet flue gas is required for calculations such as air heater leakage, hot air quality control equipment energy losses, and draft loss corrections. The total gaseous products excluding moisture are referred to as "dry flue gas" and are used in the energy balance efficiency calculations. The general logic of this Section is that wet flue gas is the sum of the wet gas from fuel (fuel less ash, unburned carbon, and sulfur captured), combustion air, moisture in the combustion air, and any additional moisture, such as atomizing steam and moisture and gas added from the addition of sorbent. Dry flue gas is determined by subtracting all moisture from the wet flue gas.

5-12.1 *MqFgF*, Wet Gas From Fuel, lbm/Btu (kg/J)

$$MqFgF = \frac{(100 - MpAsF - MpUbC - MFrSc\ MpSF)}{100\ HHVF},\ \text{lbm/Btu}\ \ (\text{kg/J}) \qquad (5\text{-}12\text{-}1)$$

where

- *MFrSc* = mass fraction of sulfur capture, lbm/lbm (kg/kg)
- *MpAsF* = ash in fuel, % mass
- *MpSF* = sulfur in fuel, % mass
- *MpUbC* = unburned carbon, % mass

5-12.2 *MqWF*, *MqWvF*, Moisture From H_2O (Water) in Fuel, lbm/Btu (kg/J)

$$MqWF = \frac{MpH2OF}{100\ HHVF},\ \text{lbm/Btu}\ \ (\text{kg/J}) \qquad (5\text{-}12\text{-}2)$$

where

- *MpWF* = the water in the fuel, % mass

For gaseous fuels, moisture is assumed to be in a vaporous state. Water vapor from fuel (*MpWvF*) must be accounted for separately from liquid water for the energy balance calculations.

5-12.3 *MqWH2F*, Moisture From the Combustion of Hydrogen in Fuel, lbm/Btu (kg/J)

$$MqWH2F = \frac{8.937\ MpH2F}{100\ HHVF},\ \text{lbm/Btu}\ (\text{kg/J}) \qquad (5\text{-}12\text{-}3)$$

5-12.4 *MqCO2Sb*, Gas From Sorbent, lbm/Btu (kg/J)

$$MqCO2Sb = \frac{MFrCO2Sb}{HHVF},\ \text{lbm/Btu}\ (\text{kg/J}) \qquad (5\text{-}12\text{-}4)$$

5-12.5 *MqWSb*, Water From Sorbent, lbm/Btu (kg/J)

$$MqWSb = \frac{MFrWSb}{HHVF},\ \text{lbm/Btu}\ \ (\text{kg/J}) \qquad (5\text{-}12\text{-}5)$$

5-12.6 *MqWAz*, Moisture in Air, lbm/Btu (kg/J)

Moisture in air is proportional to excess air and must be calculated for each location *z* where excess air is determined.

$$MqWAz = MFrWDA\ MqDAz,\ \text{lbm/Btu}\ \ (\text{kg/J}) \qquad (5\text{-}12\text{-}6)$$

5-12.7 *MqWAdz*, Additional Moisture in Flue Gas, lbm/Btu (kg/J)

This item accounts for any moisture added to the flue gas not accounted for above. Typical sources are atomizing steam and sootblowing steam. Additional moisture measured on a mass flow basis is converted to a mass per unit mass of fuel basis for the stoichiometric calculations. For the initial calculations, either the measured or an estimated fuel rate is used. Where the quantity of additional moisture is small compared to the total moisture, this is usually sufficiently accurate. If the efficiency calculations are reiterated for other purposes, the mass fraction of additional moisture with respect to mass rate of fuel should also be corrected.

$$MqWAdz = \frac{MFrWAdz}{HHVF}, \text{ lbm/Btu (kg/J)} \quad (5\text{-}12\text{-}7)$$

$$MFrWAdz = \frac{MrStz}{MrF}, \text{ lbm/lbm fuel (kg/kg)} \quad (5\text{-}12\text{-}8)$$

where

MrStz = the summation of the measured additional moisture sources entering the steam generator upstream of location *z*, lbm/hr

Moisture due to evaporation of water in the ash pit is considered negligible with regard to the mass flow rate of flue gas, and is ignored in this calculation. However, if measured, it should be included here.

5-12.8 *MqWFgz*, Total Moisture in Flue Gas, lbm/Btu (kg/J)

The total moisture in flue gas at any location *z* is the sum of the individual sources, as follows:

$$MqWFgz = MqWF + MqWvF + MqWH2F + MqWSb + MqWAz + MqWAdz, \text{ lbm/Btu (kg/J)} \quad (5\text{-}12\text{-}9)$$

5-12.9 *MqFgz*, Total Wet Flue Gas Weight, lbm/Btu (kg/J)

The total wet gas at any location *z* is the sum of the dry air (less the dry airflow correction for the O_3 in air required to form SO_3), moisture in air, wet gas from the fuel, gas from sorbent, water from sorbent, and any additional moisture.

$$MqFgz = (MqDAz - MqO3ACr) + MqWAz + MqFgF + MqCO2Sb + MqWSb + MqWAdz, \text{ Btu/lbm (J/kg)} \quad (5\text{-}12\text{-}10)$$

The mass flow rate of wet flue gas at any location *z* may be calculated from the following:

$$MrFgz = MqFgz\, QrF = MqFgz\, MrF\, HHVF, \text{ lbm/hr (kg/s)} \quad (5\text{-}12\text{-}11)$$

5-12.10 *MqDFgz*, Dry Flue Gas Weight, lbm/Btu (kg/J)

The dry flue gas weight is the difference between the wet flue gas and the total moisture in flue gas at location *z*.

$$MqDFgz = MqFgz - MqWFgz, \text{ lbm/Btu (kg/J)} \quad (5\text{-}12\text{-}12)$$

5-12.11 *MpWFgz*, Moisture in Flue Gas, Percent Mass

The percent moisture in wet flue gas is required for determining the flue gas enthalpy.

$$MpWFgz = 100\,\frac{MqWFgz}{MqFgz}, \text{ \% mass} \quad (5\text{-}12\text{-}13)$$

5-12.12 *MpRsFg*, Residue (Solids) in Flue Gas, Percent Mass

The solids in flue gas add to the enthalpy of flue gas. When the mass of residue exceeds 15 lbm/MBtu input from fuel or when sorbent is utilized, the mass of solids in gas should be accounted for.

$$MpRsFgz = \frac{MpRsz\, MFrRs}{MqFgz\, HHVF}, \text{ \% mass} \quad (5\text{-}12\text{-}14)$$

where

MpRsz = the percent of total residue (solids) in the flue gas at location *z*, % wet gas

5-12.13 *DnFg*, Density of Wet Flue Gas, lbm/ft^3 (kg/m^3)

The density of wet flue gas is calculated using the ideal gas relationship. Refer to subsection 5-11 for calculation of the flue gas constituents on a volumetric basis and calculation of the density of air.

$$DnFgz = \frac{C1\,(C2\,Pa + PFg)}{Rk\,(C3 + TFg)}, \text{ lbm/ft}^3 \text{ (kg/m}^3\text{)} \quad (5\text{-}12\text{-}15)$$

$$Rk = \frac{R}{MwFg}, \frac{\text{ft}\cdot\text{lbf}}{\text{lbm}\cdot{}^\circ\text{R}}\left(\frac{\text{J}}{\text{kg}\cdot\text{K}}\right) \quad (5\text{-}12\text{-}16)$$

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

$$MwFg = 0.31999\,VpO2 + 0.4401\,VpCO2 + 0.64063\,VpSO2 + 0.28013\,VpN2F + 0.28158\,VpN2a + 0.18015\,VpH2O, \text{ mass/mole} \quad (5\text{-}12\text{-}17)$$

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

$$MwFg = (MwDFg + 0.18015\,DVpH2O)\,\frac{MoDFg}{MoFg}, \text{ lbm/mole (kg/mole)} \quad (5\text{-}12\text{-}18)$$

$$MwDFg = 0.31999\,DVpO2 + 0.4401\,DVpCO2 + 0.64063\,DVpSO2 + 0.28013\,DVpN2F + 0.28158\,DVpN2a, \text{ mass/mole} \quad (5\text{-}12\text{-}19)$$

$$DVpH2O = 100 \frac{MoFg - MoDFg}{MoDFg}, \ \% \ H_2O \text{ dry} \tag{5-12-20}$$

where

C1 = 5.2023 lbf/ft (U.S. Customary), 1.0 J/m^3 Pa (SI)
C2 = 27.68 in. wg/psi (U.S. Customary), 1.0 Pa/Pa (SI)
C3 = 459.7°F (U.S. Customary), 273.2°C (SI)
DVpH2O = percent H_2O in flue gas, dry basis, % volume
MoDFg = moles dry gas. Refer to eq. (5-11-18) for calculation.
MoFg = moles wet gas. Refer to eq. (5-11-28) for calculation.
MwDFg = molecular weight of dry flue gas, lbm/mole (kg/mole)
MwFg = molecular weight of wet flue gas, lbm/mole (kg/mole)
Pa = barometric pressure, psia (Pa). To convert in. Hg to psia, divide by 2.0359.
PFgz = static pressure of flue gas at point *z*, in. wg (Pa)
R = universal molar gas constant, 1,545 ft lbf/lbm mole °R (8 314.5 J/kg mole K)
Rk = specific gas constant for gas *k*, $\frac{\text{ft} \cdot \text{lbf}}{\text{lbm} \cdot {}^\circ\text{R}} \left(\frac{\text{J}}{\text{kg} \cdot \text{K}}\right)$
TFgz = temperature of flue gas at point *z*, °F (°C)

5-13 AIR AND FLUE GAS TEMPERATURE

5-13.1 *TRe*, Reference Temperature, °F (°C)

The reference temperature is the datum temperature to which streams (e.g., air, fuel, sorbent, and flue gas) entering and leaving the steam generator envelope are compared for calculation of sensible heat credits and losses. The reference temperature for this Code is 77°F (25°C) and is not related to any specific stream temperature. The energy credit will be negative for any stream entering the steam generator envelope at a temperature lower than the reference temperature.

5-13.2 *TMnAEn*, 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, *TRe*. The air temperature entering the fan(s) is usually taken as the design ambient condition but may be some other specified condition such as when the fan inlets are supplied by air from within the building. The fan compression energy (approximately ½°F/1 in. wg fan pressure rise[2]) may be considered to establish the fan discharge temperature in the design stage.

When air preheating coils are utilized and the energy is supplied from outside the envelope, the entering air temperature is the temperature leaving the air preheating coils. When the energy to an air preheating coil is supplied from within the envelope (steam from the steam generator), the entering air temperature is the temperature entering the air preheating coils. Refer to location 8 in Figs. 1-4-1 through 1-4-7.

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 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 (calculated stoichiometrically). It should be noted that some amount of air (usually not more than 2% or 3% at full load) 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 uncertainty. Typical examples of units with multiple air sources are pulverized-coal-fired units with cold primary air fans (*TA8A*) or pulverizer tempering air supplied from the environment (*TA5*). The weighted average air temperature entering the unit, *TMnAEn*, shall be calculated.

$$TMnAEn = MFrAz1\, TAz1 + MFrAz2\, TAz2 \ldots + MFrAzi\, TAzi, \ {}^\circ\text{F} \ ({}^\circ\text{C}) \tag{5-13-1}$$

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.

$$HMnAEn = MFrAz1\, HAz1 + MFrAz2\, HAz2 \ldots + MFrAzi\, HAzi, \ \text{Btu/lbm (J/kg)} \tag{5-13-2}$$

where

HAz = enthalpy of wet air at temperature *TAz*, Btu/lbm (J/kg)
HMnAEn = average enthalpy of wet air entering the boundary, Btu/lbm (J/kg). The average

[2] The temperature rise above is based upon a fan efficiency of approximately 75% and an air density of 0.075 lbm/ft^3.

air temperature is determined from the average enthalpy.

MFrAz = mass flow rate fraction of wet air entering at location *z* to total wet airflow leaving the steam generator based on excess air at location (14), lbm/lbm (kg/kg)

TAz = temperature of wet air at location *z*, °F (°C)

For pulverized-coal units with cold primary air fans, the mass flow fraction of the primary air, *MFrA11*, may be calculated as follows:

$$MFrA11 = \frac{MrA11}{MqA14\ MrF\ HHVF}, \text{lbm/lbm (kg/kg)} \qquad (5\text{-}13\text{-}3)$$

where

MqA14 = total wet air entering steam generator envelope upstream of location (14), lbm/Btu (kg/J)

MrA11 = measured primary airflow to pulverizers, lbm/hr (kg/s)

MrF = fuel mass flow rate, lbm/hr (kg/s). Estimate or use the measured mass flow rate initially. The efficiency calculations are repeated until the estimated and calculated fuel mass flow rates are within the convergence tolerance of para. 5-7.3.

and where secondary air is the only other significant source of air, the mass flow fraction of the remaining air equals (1 − *MFrA11*). For the equation above, it is assumed that the tempering air to the pulverizers is the same temperature as the air entering the primary air heater. Refer to the tempering air calculation below if it is not.

For units with hot primary air fans or exhauster fans, and where pulverizer tempering air is supplied from the environment (*TA5*), the mass flow rate of the tempering air may be calculated as follows:

$$MFrA5 = \frac{MrA5}{MqA14\ MrF\ HHVF}, \text{lbm/lbm (kg/kg)} \qquad (5\text{-}13\text{-}4)$$

$$MrA5 = \frac{MrA11\,(HA9A - HA11)}{HA9A - HA5}, \text{lbm/hr (kg/s)} \qquad (5\text{-}13\text{-}5)$$

where

MrA5 = pulverizer tempering air mass flow rate, lbm/hr (kg/s)

5-13.3 *TFgLvCr*, Corrected Gas Outlet Temperature (Excluding Leakage), °F (°C)

On units with air heaters, air leakage within the air heater depresses the exit gas temperature without performing any useful work. 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 utilizes the nomenclature and products of combustion calculated in the preceding Section. Refer to Nonmandatory Appendix C for the derivation of the eq. (5-13-6). For alternate calculation methods, refer to 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. 5-13.4.

$$TFgLvCr = TFgLv + \frac{MnCpA}{MnCpFg}\left(\frac{MqFgLv}{MqFgEn} - 1\right) \times (TFgLv - TAEn), \text{°F (°C)} \qquad (5\text{-}13\text{-}6)$$

$$MnCpA = \frac{HATFgLv - HAEn}{TFgLv - TAEn}, \text{Btu/lbm °F (J/kg K)} \qquad (5\text{-}13\text{-}7)$$

where

MnCpA = mean specific heat of wet air between *TAEn* 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.

MnCpFg = mean specific heat of *wet* flue gas between *TFgLv* 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.

MqFgEn = wet gas weight entering the air heater from para. 5-12.9 using the excess air entering the air heater, lbm/Btu

MqFgLv = wet gas weight leaving the air heater from para. 5-12.9 using the excess air leaving the air heater, lbm/Btu

TAEn = air temperature entering the air heater, °F (°C). Location (7), (7A), (8), or (8A), Figs. 1-4-1 through 1-4-7. For air heaters that have two air inlets and one gas outlet (a trisector air heater, for example), 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). Location (15) or (15A), Figs. 1-4-1 through 1-4-7.

The determination of *MnCpFg* above is iterative. *TFgLvCr* may be determined from *HFgLvCr*, which may be solved for directly from the following equation:

$$HFgLvCr = HAEn + \frac{MqFgLv}{MqFgEn}(HFgLv - HAEn) \quad (5\text{-}13\text{-}8)$$

5-13.4 *TMnFgLvCr*, Average Exit Gas Temperature (Excluding Leakage), °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, etc.). 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 (calculated stoichiometrically). 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 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. For units with multiple air heaters not of the same type where the gas mass flow *and* gas temperature leaving the air heaters is not the same (for example, separate primary and secondary air heaters for pulverized-coal-fired units with cold primary air fans), the gas flow distribution between the air heaters must be determined to calculate a weighted average exit gas temperature (excluding leakage). On some units, gas may be extracted upstream of the air heater(s) or other stream generator heat trap(s) and must be included in the determination of the average exit gas temperature.

The following addresses pulverized-coal-fired units with separate primary air heater(s) (used to heat the air to the pulverizers) and secondary air heater(s) and is a typical example of how the calculations for two different types of air heaters might be handled. The methodology is based upon measuring the primary airflow to the pulverizers and calculating the gas flow through the primary air heaters by energy balance.

$$TMnFgLvCr = MFrFg14B\ TFg15BCr + (1 - MFrFg14B)\,TFg15ACr,\ °F\ (°C) \quad (5\text{-}13\text{-}9)$$

When there is a significant difference in the gas temperature at the various exiting locations, the average gas temperature, *TMnFgLvCr*, should be determined from the average enthalpy of the exiting wet gas.

$$HMnFgLvCr = MFrFg14B\ HFg15BCr + (1 - MFrFg14B)\,HFg15ACr,\ \text{Btu/lbm (J/kg)} \quad (5\text{-}13\text{-}10)$$

$$MFrFg14B = \frac{MrFg14B}{MqFg14\ MrF\ HHVF},\ \text{lbm/lbm (kg/kg)} \quad (5\text{-}13\text{-}11)$$

where

HMnFgLvCr = average enthalpy of wet gas leaving the boundary (excluding leakage), Btu/lbm (J/kg). The average temperature is determined from the average enthalpy.

MFrFg14B = mass fraction of wet gas entering the primary air heater to total wet gas entering the air heaters, lbm/lbm (kg/kg)

MqFg14 = total wet gas entering air heaters, para. 5-12.8, lbm/Btu (kg/J)

MrF = fuel mass flow rate, lbm/hr (kg/s). Estimate or use the measured mass flow rate initially. Refer to para. 5-7.3 regarding convergence tolerance.

MrFg14B = mass flow rate of wet gas entering the primary air heater, lbm/hr (kg/s). This item may be calculated by energy balance.

$$MrFg14B = MrA11\frac{(HA11 - HA8A)}{(HFg14B - HFg15BCr)},\ \text{lbm/hr (kg/s)} \quad (5\text{-}13\text{-}12)$$

where

HA11 = average enthalpy of wet air entering pulverizers. If the pulverizers are not operating at the same primary airflow, this should be a flow-weighted average rather than an arithmetic average.

HFg15BCr = enthalpy of wet gas for the gas temperature leaving the primary air heater excluding leakage (corrected), using the moisture in wet gas entering the air heater

MrA11 = measured primary air mass flow rate, lbm/hr (kg/s)

5-14 LOSSES

The calculation of losses falls into two categories in accordance with the method in which they are measured and conveniently calculated. In the first category are losses that are a function of input from fuel and can be readily expressed in terms of loss per unit of input from fuel, i.e., expressed as a percentage of fuel input. Losses due to products of combustion (dry gas, water from fuel, etc.) are expressed in these units. In the second category are losses not related to fuel input, which are more readily calculated on an energy per unit of time basis, such as the loss due to surface radiation and convection. The losses in each category are grouped generally in order of significance and universal applicability with applicability taking preference.

The logic for calculating losses that are a function of fuel input is described below.

$$QpLk = 100\ Mqk \times (HLvk - HRek) = 100\ Mqk \times MnCpk \times (TLvk - TRe),\ \% \quad (5\text{-}14\text{-}1)$$

$$QpLk = 100 \times \frac{lbm\ constituent}{Btu\ fuel\ input} \times \frac{Btu}{lbm\ °F} \times °F$$

$$= \frac{Btu\ loss}{100\ Btu\ In}, \% \qquad (5\text{-}14\text{-}2)$$

where

HLvk = enthalpy of constituent *k* at temperature *TLvk*, Btu/lbm (J/kg)

HRek = enthalpy of constituent *k* at temperature *TRe*, 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 *TRe* is 45 Btu/lbm (105 kJ/kg). For all other constituents, the enthalpy is based upon 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.

MnCpk = mean specific heat of constituent *k* between temperatures *TRe* and *TLvk*, Btu/lbm °F (J/kg K). Whenever practical, enthalpy is used in lieu of the mean specific heat and the difference in temperature.

Mqk = mass of constituent *k* per Btu input in fuel. This is the unit system used throughout this Code for items that are related to the fuel such as air and gas quantities.

QpLk = loss from constituent *k*, percent of input from fuel, Btu/100 Btu input from fuel (J/100 J)

TLvk = temperature of constituent *k* leaving the steam generator envelope, °F (°C)

TRe = reference temperature, °F (°C). The reference temperature is 77°F (25°C).

5-14.1 *QpLDFg*, Dry Gas Loss, Percent

$$QpLDFg = 100\ MqDFg\ HDFgLvCr, \% \qquad (5\text{-}14\text{-}3)$$

where

HDFgLvCr = enthalpy of dry gas at the temperature leaving the boundary corrected for leakage (excluding leakage). Refer to para. 5-19.2 for curve fit.

MqDFg = dry gas mass flow leaving the steam generator based on the excess air at location (13) or (14), lbm/Btu (kg/J). 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.

5-14.2 *QpLH2F*, *QpLWF*, *QpLWvF*, Water From Fuel Losses, Percent

5-14.2.1 Water Formed From the Combustion of H_2 in the Fuel Loss

$$QpLH2F = 100\ MqWH2F\ (HStLvCr - HWRe), \% \qquad (5\text{-}14\text{-}4)$$

5-14.2.2 Water (H_2O) in a Solid or Liquid Fuel Loss. This may also be applicable to manufactured gaseous fuels.

$$QpLWF = 100\ MqWF\ (HStLvCr - HWRe), \% \qquad (5\text{-}14\text{-}5)$$

5-14.2.3 Water Vapor in a Gaseous Fuel Loss

$$QpLWvF = 100\ MqWvF\ \ HWvLvCr, \% \qquad (5\text{-}14\text{-}6)$$

where

HStLvCr = enthalpy of steam (water vapor) at 1 psia at temperature *TFgLvCr* or *TMnFgLvCr*. The enthalpy of steam (water vapor) 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. Refer to para. 5-19.5 for curve fit.

HWRe = enthalpy of water at the reference temperature *TRe*, Btu/lbm (J/kg) = *TRe* − 32 = 45, Btu/lbm

HWvLvCr = enthalpy of water vapor at *TFgLvCr* or *TMnFgLvCr*, Btu/lbm (J/kg). The distinction of enthalpy of steam (*HSt*) versus the enthalpy of water vapor (*HWv*), is that *HSt* is the enthalpy of *vapor* with respect to *liquid* water at 32°F (0°C) as the reference in accordance with ASME Steam Tables, and includes the latent heat of vaporization of water, where *HWv* 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). Refer to para. 5-19.4 for curve fit.

5-14.3 *QpLWA*, Moisture in Air Loss, Percent

$$QpLWA = 100\ MFrWA\ \ MqDA\ \ HWvLvCr, \% \qquad (5\text{-}14\text{-}7)$$

where

MqDA = mass of dry air corresponding to the excess air used for dry gas loss, lbm/Btu (kg/J)

5-14.4 *QpLSmUb*, Summation of Unburned Combustible Losses, Percent

The loss due to unburned combustibles is the sum of the applicable losses for the individual unburned constituents.

5-14.4.1 Unburned Carbon in Residue Loss, Percent

$$QpLUbC = MpUbC \frac{HHVCRs}{HHVF}, \% \quad (5\text{-}14\text{-}8)$$

where

HHVCRs = the heating value of carbon as it occurs in residue

When unburned hydrogen in the residue is considered insignificant (normal case, refer to unburned hydrogen below), a value of 14,500 Btu/lbm (33 700 kJ/kg) should be used for *HHVCRs*. Any unburned carbon is expected to be in an amorphous form. The *NBS Technical Notes* [2] do not list the heat of formation of carbon in the amorphous form; only the heats of formation of carbon in the graphite and diamond forms are listed. The higher heating value for carbon in the residue adopted by ASME PTC 4.1-1964 has been retained in this Code. When it is determined that unburned hydrogen is present in the residue and is accounted for separately, a value of 14,100 Btu/lbm (32 800 kJ/kg) shall be used based on the heat of formation of CO_2.

5-14.4.2 Unburned Hydrogen in Residue Loss, Percent. Refer to para. 5-10.3. Where it is established that unburned hydrogen is present and cannot be eliminated by operating adjustments,

$$QpLH2Rs = \frac{MrRs\ MpH2Rs\ HHVH2}{MrF\ HHVF}, \% \quad (5\text{-}14\text{-}9)$$

where

HHVH2 = 61,100 Btu/lbm (142 120 kJ/kg)

MpH2Rs = the mass weighted average of unburned hydrogen in residue, %

5-14.4.3 Carbon Monoxide in Flue Gas Loss, Percent

$$QpLCO = DVpCO\ MoDFg\ MwCO \frac{HHVCO}{HHVF}, \%$$

or

$$QpLCO = VpCO\ MoFg\ MwCO \frac{HHVCO}{HHVF}, \%$$

(5-14-10)

where

DVpCO = quantity of CO measured on a dry basis, percent volume

HHVCO = higher heating value of CO, 4,347 Btu/lbm (10 111 kJ/kg)

MoDFg = moles of dry gas with excess air measured at the same location as the CO, moles/lbm fuel (moles/kg). Refer to subsection 5-11 for calculation.

MoFg = moles of wet gas with excess air measured at the same location as the CO, moles/lbm fuel (moles/kg). Refer to subsection 5-11 for calculation.

MwCO = molecular weight CO, 28.01 lbm/mole (kg/mole)

VpCO = quantity of CO measured on a wet basis, percent volume

5-14.4.4 Pulverizer Rejects Loss, Percent. This loss includes the chemical and sensible heat loss in pulverizer rejects.

$$QpLPr = 100\ MqPr\ (HHVPr + HPr), \% \quad (5\text{-}14\text{-}11)$$

$$MqPr = \frac{MrPr}{MrF\ HHVF}, \text{lbm/Btu (kg/J)} \quad (5\text{-}14\text{-}12)$$

where

HHVPr = higher heating value of pulverizer rejects from laboratory analysis of representative sample, Btu/lbm (J/kg)

HPr = sensible heat or enthalpy of pulverizer rejects leaving the pulverizer, Btu/lbm (J/kg). Use the enthalpy of ash at the mill outlet temperature.

MrPr = measured mass flow rate of pulverizer rejects, lbm/hr (kg/s)

5-14.4.5 Unburned Hydrocarbons in Flue Gas Loss, Percent. Where it is established that unburned hydrocarbons are present and cannot be eliminated by operating adjustments,

$$QpLUbHc = DVpHc\ MoDFg\ MwHc \frac{HHVHc}{HHVF}, \%$$

or

$$QpLUbHc = VpHc\ MoFg\ MwHc \frac{HHVHc}{HHVF}, \%$$

(5-14-13)

where

DVpHc = quantity of hydrocarbons in flue gas measured on a dry basis, percent volume

HHVHc = higher heating value of the reference gas used to determine the volume percentage of total hydrocarbons, Btu/lbm (J/kg)

VpHc = quantity of hydrocarbons in flue gas measured on a wet basis, percent volume

5-14.5 *QpLRs*, Sensible Heat of Residue Loss, Percent

For units with a wet furnace ash hopper, refer to para. 5-14.13.

$$QpLRs = 100 \sum MqRsz\ HRsz, \% \quad (5\text{-}14\text{-}14)$$

where

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

MqRsz = mass flow rate of residue at location *z*, lbm/Btu (kg/J) from subsection 5-10. For units with a wet furnace ash hopper, when the total ash pit losses are tested, the wet ash pit loss, *QrLAp*, 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, *QrLRsAp*, the loss due to sensible heat in residue leaving the ash pit is calculated in accordance with this paragraph.

5-14.6 *QpLAq*, Hot Air Quality Control Equipment Loss, Percent

This item refers to flue gas cleanup equipment located between the boiler exit and air heater gas inlet, such as a mechanical dust collector, hot precipitator, or SCR equipment.

This separate loss need not be calculated when such equipment is considered part of the steam generator system. For instance, selective catalytic reduction (SCR) systems are commonly supplied as part of the steam generator scope, and the effect of typical levels of ammonia addition and dilution air are considered minor. When this separate equipment loss is not calculated, the equipment surface area should be included in the total surface area utilized to calculate the radiation and convection loss for the steam generator. O_2 (excess air) shall be measured at the air heater flue gas inlet for determining efficiency and air heater leakage and for evaluating air heater performance. It is recommended that O_2 also be measured at the economizer flue gas outlet (HAQC equipment inlet) to ensure there is no significant infiltration, as this is the location that excess air to the burners is monitored.

If the air infiltration across the equipment is significant, then it should be recognized that the infiltration amount is not passing through the air side of the air heater and air heater performance will be impacted. In such cases, since efficiency is based on the excess air entering the air heater, it is not necessary to calculate a separate air infiltration loss (refer to para. 5-14.7).

If determination of a separate HAQC equipment loss is desired, the following points should be considered:

(a) The steam generator surface radiation and convection loss should not include the area of the HAQC equipment.

(b) O_2 (excess air) shall be measured at the economizer outlet/HAQC equipment inlet for determining efficiency and related air and gas weights.

(c) O_2 (excess air) shall be measured at the air heater gas inlet for determination of HAQC infiltration (if present) and associated efficiency loss as well as the determination of air heater leakage, the undiluted air heater exit gas temperature, and evaluating air heater performance.

The calculation below incorporates the effects of the dry gas loss due to air infiltration, moisture in infiltration air loss, and surface radiation and convection loss of the separate equipment. Refer to Nonmandatory Appendix C for derivation.

$$QpLAq = 100\,[\,MqFgEn\,(HFgEn - HFgLv) - (MqFgLv - MqFgEn) \times (HAAqLv - HALvCr)],\ \% \tag{5-14-15}$$

where

MqFgEn = mass of wet gas entering with excess air entering, lbm/Btu (kg/J)
MqFgLv = mass of wet gas leaving with excess air leaving, lbm/Btu (kg/J)
HAAqLv = enthalpy of wet air at a temperature corresponding to the gas temperature leaving the hot AQC device, Btu/lbm (J/kg)
HALvCr = enthalpy of wet air at the average gas temperature (excluding air heater leakage) leaving the steam generator envelope, Btu/lbm (J/kg)
HFgEn = enthalpy of wet gas entering based on the entering moisture content and the leaving residue content, Btu/lbm (J/kg)
HFgLv = enthalpy of wet gas leaving based on the entering moisture content and the leaving residue content, Btu/lbm (J/kg)

(Residue content is considered in gas enthalpy determination only if considered for other gas losses.)

5-14.7 *QpLALg*, Air Infiltration Loss, Percent

This item refers to air infiltration between the point where dry gas weight is determined (normally the boiler exit) and the air heater flue gas inlet, excluding air infiltration in hot AQC equipment that is accounted for separately.

$$QpLALg = 100\,MqALg\,(HALvCr - HALgEn),\ \% \tag{5-14-16}$$

where

HALgEn = enthalpy of infiltrating wet air, normally air inlet temperature, Btu/lbm (J/kg)
HALvCr = enthalpy of wet air at the average gas temperature (excluding air heater leakage) leaving the steam generator envelope, Btu/lbm (J/kg)
MqALg = mass rate of wet infiltration air, lbm/Btu (kg/J). Refer to para. 5-11.6.

5-14.8 *QpLNOx*, NO_x Formation Loss, Percent

This item refers to the loss associated with the net formation of NO_x within the steam generator system. If an SCR system is installed, this loss should be based on the final, outlet NO_x level. (The loss associated with initial NO_x production is partly regained by exothermic reduction in the SCR.) Even without an SCR, this loss is usually small, on the order of 0.025% for 0.3 lb NO_2/MBtu (220 ppm at 3% O_2), and may be estimated if not measured. This calculation procedure is based on the principle that the NO_x formed in the steam generator is predominantly NO (usually less than 5% NO_2). It is assumed that the NO_x analyzer converts the NO_2 in the gas sample to NO and gives a total reading of NOx in parts per million as NO in accordance with EPA Method 7E. When NOx is reported on an energy basis, the NO_x is in the form of NO_2 (NO oxidizes to NO_2 in the atmosphere) in accordance with EPA reporting methods. Note, however, that the energy loss is based on the heat of formation of NO. On some types of steam generators (CFB units, for example), N_2O is also produced. For most units, N_2O is negligible. The equations below assume that N_2O is negligible and are based on the heat of formation of NO. If both NO and N_2O are measured, the loss for N_2O may be calculated by substituting the heat of formation of N_2O in eq. (5-14-17). The total loss attributed to NO_x is the sum of the losses for NO and N_2O.

When testing, NO_x is measured on a volumetric basis, and eq. (5-14-17) is applicable for computing the loss.

In the design stage, the NO_x design limit is normally specified on an energy basis, lbm/Btu (kg/J), in accordance with EPA reporting methods. Equation (5-14-18) may be used to calculate the loss when NO_x is specified on an energy basis.

$$QpLNOx = DVpNOx\ MoDFg\ \frac{HrNOx}{HHVF},\ \%$$

or

$$QpLNOx = VpNOx\ MoFg\ \frac{HrNOx}{HHVF},\ \% \qquad (5\text{-}14\text{-}17)$$

$$QpLNOx = 100\ \frac{MqNO2}{MwNO2}\ HrNO,\ \% \qquad (5\text{-}14\text{-}18)$$

where

$DVpNOx$ = quantity of NO_x as NO on a dry basis, percent volume. NO_x is normally measured on a ppm basis. Divide by 10,000 to convert to percent.

$HrNOx$ = the heat of formation of NO is 38,630 Btu/lb mole (89 850 kJ/gm mole) or the heat of formation of N_2O is 35,630 Btu/lb mole (82 880 kJ/gm mole). Use whichever is applicable.

$MoDFg$ = moles of dry gas with excess air measured at the same location as the NO_x, moles/lbm fuel (moles/kg fuel)

$MoFg$ = moles of wet gas with excess air measured at the same location as the NO_x, moles/lbm fuel (moles/kg fuel)

$MqNO2$ = quantity of NO_2 expressed on an energy basis, lbm/Btu (kg/J). When expressed on an energy basis, the units used are usually MBtu (MJ). Divide by 1E6 to convert to Btu (J).

$MwNO$ = molecular weight of NO, 30.006 lb/lb mole (g/g mole)

$MwNO2$ = molecular weight of NO_2, 46.0055 lb/lb mole (g/g mole)

$VpNOx$ = quantity of NO_x as NO on a wet basis, percent volume

5-14.9 *QrLSrc*, Surface Radiation and Convection Loss, Btu/hr (W)

This loss is determined indirectly by measuring[3] the average surface temperature of the steam generator and the ambient conditions near it. Surface temperature, ambient temperature, and ambient air velocity should be determined at a sufficient number of locations to determine representative average values. Alternatively, the parties to the test may decide to determine this loss based on the actual area of the unit and the standard surface and ambient conditions described below. The parties to the test shall decide whether to measure the surface and ambient conditions,[4] including the number and location of measurements, or to use the standard conditions described below. Use of surface and ambient conditions as specified for design of unit insulation shall not be permitted for loss evaluation. Test conditions or the standard values specified herein are the only allowable options.

The loss shall be calculated by

$$QrLSrc = C1 \sum (Hcaz + Hraz)\ Afz\ (TMnAfz - TMnAz),\ \text{Btu/hr (W)} \qquad (5\text{-}14\text{-}19)$$

where

$$Hcaz = \text{the larger of } 0.2\ (TMnAfz - TMnAz)^{0.33} \text{ or } 0.35\ VAz^{0.8} \qquad (5\text{-}14\text{-}20)$$

$$Hraz = 0.847 + 2.367\text{E}{-3}\ TDi + 2.94\text{E}{-6}\ TDi^2 + 1.37\text{E}{-9}\ TDi^3 \qquad (5\text{-}14\text{-}21)$$

where

Afz = flat projected surface area of the casing/lagging over the insulation (circumferential area for circular surfaces) for location z, ft^2. For protuberances such as buckstays, only the flat projected area of the face adjacent to the hot surface is to be included in the flat projected surface area. The areas to be considered are the steam generator, flues and ducts within

[3] "Measure" is used in the general sense in this paragraph and does not preclude estimation of parameters by qualified personnel.

[4] It is not mandatory that this test be performed in conjunction with the efficiency test. It may be performed separately to establish the actual setting heat loss and the results corrected to standard or design conditions in accordance with subsection 5-18 for use with an efficiency test performed at a different time. When so used, the corrected *QrLRc* results shall meet the criteria for repeatability in Section 3.

the envelope, major piping (i.e., size with respect to the steam generator), and major equipment such as pulverizers. Hot air quality control equipment (such as hot precipitators) should not be included if this loss is accounted for separately.

C1 = 1.0 Btu/hr (U.S. Customary units); C1 = 0.293 W (SI units).

Hcaz = convection heat transfer coefficient for area *z*, Btu/ft^2·h·F. The constants used in this correlation are based upon using U.S. Customary units. The characteristic length is approximately 10 ft. If the parameters required to determine *Hcaz* are measured, a systematic uncertainty for the correlation of ±20% is suggested. If not measured, the suggested systematic uncertainty for the radiation loss is included in the systematic uncertainty for the total radiation and convection loss below.

Hraz = radiation heat transfer coefficient for area *z*, Btu/ft^2·h·F. The constants used in this equation are based upon using U.S. Customary units (°F). This correlation is based on an ambient temperature of 77°F (25°C) and an emissivity of 0.80. The high emissivity (compared to 0.1 to 0.2 commonly published for clean aluminum) is based upon a dirty, oxidized surface and shall be used for calculating the radiation loss. It is recommended that published values for clean surfaces be used for sizing insulation thickness, although this recommendation is not a part of this Code. If the temperatures, required to determine *Hraz*, are measured, a systematic uncertainty for the correlation of ±20% is suggested. If not measured, the suggested systematic uncertainty for the radiation loss is included in the systematic uncertainty for the total radiation and convection loss below.

TDi = (*TAfz* − *TAz*) = temperature difference

TMnAfz = average surface temperature, *TAf*, of area *z*

TMnAz = average ambient air temperature, *TAz*, at location *z*, °F. The local ambient air temperature is the temperature within 2 ft to 5 ft of the surface.

VAz = average velocity of air near surface, typically within 2 ft to 5 ft of the surface, ft/sec (m/s)

If values for *TAf*, *TA*, and *VA* are not measured, this loss shall be calculated using the actual component areas and the following standard values:

(a) *VA* = 1.67 ft/sec (100 ft/min).

(b) *TDi*, the differential temperature, shall be 50°F or, if the situation warrants it for components where personnel safety is not a problem, a larger value used. For example, where it is not practical to design for a temperature differential of 50°F or less (PC piping and hot cyclones, for example), the expected differential should be used.

This calculation method applies to estimation of the efficiency loss and is not intended for use in designing casing insulation.

If the loss is not measured, a systematic uncertainty of ±50% is suggested for *QrLSrc*. The estimated systematic error includes consideration of the random error when the loss is not measured.

5-14.10 *QrLWAd*, Additional Moisture Loss, Btu/hr (W)

Additional moisture is water or steam injected in the gas side of the steam generator and not accounted for separately. Typical examples of additional moisture are atomizing and sootblowing steam. It is noted that when air is utilized as the atomizing or sootblowing medium, the loss is included in the dry gas and moisture in air loss, since it is included in the measured O_2 in the flue gas.

$$QrLWAd = \sum MrStEnz\,(HStLvCr - HWRe),\ \text{Btu/hr (W)} \tag{5-14-22}$$

where

HStLvCr = enthalpy of steam in gas leaving the boundary (excluding leakage), Btu/lbm (J/kg). Refer to para. 5-14.2.

HWRe = enthalpy water at the reference temperature, Btu/lbm (J/kg)

MrStEnz = mass flow rate of additional moisture at location *z*, lbm/hr (kg/s)

5-14.11 *QrLClh*, Calcination and Dehydration of Sorbent Loss, Btu/hr (W)

$$QrLClh = \sum MrSbk\ MFrClhk\ Hrk,\ \text{Btu/hr (W)} \tag{5-14-23}$$

where

Hrk = heat of reaction for calcination of calcium or magnesium carbonate or dehydration of calcium or magnesium hydroxide

$CaCO_3$ (Cc) = 766 Btu/lbm (1 782 kJ/kg)

$MgCO_3$ (Mc) = 652 Btu/lbm (1 517 kJ/kg)

$Ca(OH)_2$ (Ch) = 636 Btu/lbm (1 480 kJ/kg)

$Mg(OH)_2$ (Mh) = 625 Btu/lbm (1 455 kJ/kg)

MFrClhk = mass fraction of calcination or dehydration of constituent *k*. Refer to para. 5-10.8 for $CaCO_3$. Use 1.0 for other constituents.

MrSbk = mass flow rate of reactive constituents *k*, lbm/hr (kg/s)

Heats of reaction were calculated from the heats of formation and the molecular weights given in the *NBS Technical Notes* [2]. $MgCO_3$ is assumed to be in its most common form, dolomite, $CaCO_3 \cdot MgCO_3$.

5-14.12 *QrLWSb*, Water in Sorbent Loss, Btu/hr (W)

$$QrLWSb = MrWSb\,(HStLvCr - HWRe),\ \text{Btu/hr (W)} \tag{5-14-24}$$

5-14.13 *QrLAp*, Wet Ash Pit Loss, Btu/hr (W)

On units with a wet ash pit, there is a loss due to heat absorbed by the water from radiation through the furnace hopper throat, in addition to the sensible heat in residue loss. The test procedure for this loss requires the measurement of the mass flow rate and temperature of the water entering and leaving the ash pit, the mass flow rate of the residue/water mixture leaving the ash pit, and a laboratory determination of the water in the residue leaving the ash pit.

Due to the difficulty of determining the mass flow rate of the residue leaving the ash pit and the uncertainty of determining the water in the residue, the parties to the test may agree to estimate this loss. The procedure for estimating this loss is described in para. 5-14.13.2.

5-14.13.1 *QrLAp*, Wet Ash Pit Loss When Tested. By energy balance, the ash pit loss is the sum of the energy gain by the water leaving the ash pit, energy loss due to evaporation of pit water, and sensible heat in the residue/water mixture as it leaves the pit. Note that if measured, the sensible heat loss of residue to the ash pit in para. 5-14.5 should be omitted.

$$QrLAp = QrApW + QrApEv + QrRsWLv,\ \text{Btu/hr (W)} \tag{5-14-25}$$

(a) Energy Increase in Ash Pit Water

$$QrApW = MrW39\,(HW39 - HW38),\ \text{Btu/hr (W)} \tag{5-14-26}$$

(b) Ash Pit Water Evaporation Loss

$$QrApEv = \left[MrW38 - MrW39 + MrRsW37\left(\frac{MFrWRs}{1 + MFrWRs}\right)\right] \times (HStLvCr - HW38),\ \text{Btu/hr (W)} \tag{5-14-27}$$

(c) Sensible Heat in Residue/Water Mixture Leaving the Ash Pit

$$QRsWLv = \left(\frac{MrRsW37}{1 + MFrWRs}\right)\left[HRs37 + MFrWRs\left(HW37 - HW38\right)\right],\ \text{Btu/hr (W)} \tag{5-14-28}$$

where

HRs37 = enthalpy of dry residue at the temperature of the residue/water mixture leaving the ash pit, Btu/lbm (J/kg)
HWz = enthalpy of water at location *z*, Btu/lbm (J/kg)
MFrWRs = mass fraction of water in residue in the residue/water mixture leaving location (37), lbm H_2O/lbm dry residue (kg/kg)
MrRsW37 = mass flow rate of the residue/water mixture leaving the ash pit, lbm/hr (kg/hr)

5-14.13.2 *QrLAp*, Estimated Ash Pit Radiation Loss. If agreed to by the parties to the test, the loss due to radiation to the ash pit may be estimated. When the loss due to radiation to the ash pit is estimated, the sensible heat in residue loss, *QpLRs*, must also be calculated (estimated) in accordance with para. 5-14.5.

$$QrLAp = QrAp\ ApAf,\ \text{Btu/hr (W)} \tag{5-14-29}$$

where

ApAf = flat projected area of hopper opening, ft^2 (m^2)
QrAp = equivalent heat flux through furnace hopper opening absorbed by ash pit water. Based on limited data of apparent water usage, an estimated equivalent heat flux of 10,000 Btu/ft^2 h (31 500 W/m^2) is recommended. A systematic uncertainty of ±50% is suggested.

5-14.14 *QrLRy*, Recycled Streams Loss, Btu/hr (W)

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

$$QrLRy = QrLRyRs + QrLRyFg,\ \text{Btu/hr (W)} \tag{5-14-30}$$

5-14.14.1 Recycled Solids. Residue may be recycled to utilize unburned carbon in the residue and/or reduce the amount of sorbent added. If the recycle piping and holdup bins are included in the area used to calculate the surface radiation and convection loss (*QrLSrc*), para. 5-14.9, then this calculation is omitted.

$$QrLRyRs = MrRyRs\,(HRsLv - HRsEn),\ \text{Btu/hr (W)} \tag{5-14-31}$$

where

HRsEn = enthalpy of the residue when it is readmitted to the steam generator, Btu/lbm (J/kg)
HRsLv = enthalpy of the residue where it is collected or exits the system boundary, Btu/lbm (J/kg)
MrRyRs = mass flow rate of recycled residue, lbm/hr (kg/s)

5-14.14.2 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. Refer to Nonmandatory Appendix C if the excess air in the recycled gaseous stream is different from the excess air upon which the dry gas weight is based.

$$QrLRyFg = MrRyFg\,(HFgLvCr - HFgEn)\text{, Btu/hr (W)} \quad (5\text{-}14\text{-}32)$$

where

$HFgEn$ = enthalpy of the recycled flue gas entering the steam generator, Btu/lbm (J/kg)

$HFgLvCr$ = enthalpy of wet flue gas at the average gas temperature leaving the unit (excluding leakage), Btu/lbm (J/kg)

$MrRyFg$ = mass flow rate of the recycled gas, lbm/hr (kg/s)

5-14.15 *QrLCw*, Cooling Water Loss, Btu/hr (W)

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 upon the temperature of residue entering the ash cooler, there would be no loss associated with the ash cooler; however, if the temperature of the residue is measured after the ash cooler, the energy absorbed by the ash cooler must be added to the steam generator losses.

$$QrLCw = \sum MrCwn\,(HWLv - HWEn)\text{, Btu/hr (W)} \quad (5\text{-}14\text{-}33)$$

where

$MrCw$ = mass flow rate of cooling water at location z, lbm/hr (kg/s)

5-14.16 *QrLAc*, Internally Supplied Air Preheater Coil Loss, Btu/hr (W)

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

$$QrLAc = MrSt36\,(HW36 - HW24)\text{, Btu/hr (W)} \quad (5\text{-}14\text{-}34)$$

5-14.17 Conversion of Loss on Rate Basis to Percent Input 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.

$$QpLk = 100\,\frac{QrLk}{QrF}\text{, \%} \quad (5\text{-}14\text{-}35)$$

5-15 CREDITS

As in the loss section, the calculation of credits falls into two categories in accordance with the method in which they are measured and conveniently calculated. In the first category are those credits that can be readily expressed as a percent of input from fuel, such as energy in entering air; and second, those that are more readily calculated on an energy per unit of time basis, such as energy supplied by auxiliary equipment power. The credits are arranged in approximate order of significance and universal applicability, with the latter taking precedence.

5-15.1 *QpBDA*, Entering Dry Air Credit, Percent

$$QpBDA = 100\,MqDA\,HDAEn\text{, \%} \quad (5\text{-}15\text{-}1)$$

where

$HDAEn$ = enthalpy of dry air at the average air temperature entering the steam generator envelope (*TMnAEn*), Btu/lbm (J/kg). This is the weighted average of the various sources of the airflow contributing to *MqDA* as defined above. Note that when an air preheating coil is supplied from the steam generator, the air temperature entering the air preheater coil is used for that portion of the air entering the steam generator.

$MqDA$ = total dry air entering the steam generator corresponding to the excess air leaving the boiler used to calculate dry gas weight, lbm/Btu (kg/J)

5-15.2 *QpBWA*, Moisture in Entering Air Credit, Percent

$$QpBWA = 100\,MFrWA\,MqDA\,HWvEn\text{, \%} \quad (5\text{-}15\text{-}2)$$

where

$HWvEn$ = the enthalpy of water vapor at the average air temperature entering the steam generator envelope (*TMnAEn*), Btu/lbm (J/kg)

5-15.3 *QpBF*, Sensible Heat in Fuel Credit, Percent

$$QpBF = \frac{100}{HHVF}\,HFEn\text{, \%} \quad (5\text{-}15\text{-}3)$$

where

$HFEn$ = enthalpy of the fuel at the temperature of fuel entering the steam generator envelope at locations (1), (3), or (4), Btu/lbm (J/kg)

5-15.4 *QpBSlf*, Sulfation Credit, Percent

Sulfation is the reaction of sulfur dioxide (SO_2) with calcium oxide (CaO) and oxygen to form calcium sulfate ($CaSO_4$). The reaction is exothermic.

$$QpBSlf = MFrSc \frac{MpSF}{HHVF} HrSlf, \% \tag{5-15-4}$$

where

HrSlf = heat generated in the reaction of sulfur dioxide, oxygen, and calcium oxide to form calcium sulfate per pound of sulfur capture, 6,733 Btu/lbm (15 660 kJ/kg)

MFrSc = mass fraction of sulfur capture, lbm/lbm (kg/kg)

5-15.5 *QrBX*, Auxiliary Equipment Power Credits, Btu/hr (W)

Typical auxiliary equipment includes pulverizers, gas recirculating fans, hot primary air fans, and boiler circulating pumps. Note that credits shall not be calculated for forced draft fans, cold primary air 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 in accordance with para. 5-15.1, 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.

5-15.5.1 For Steam Driven Equipment

$$QrBX = \frac{MrStX\,(HStEn - HStLv)\,EX}{100}, \text{Btu/hr (W)} \tag{5-15-5}$$

where

EX = overall drive efficiency, percent; includes turbine and gear efficiency

HStEn = enthalpy of the steam supplied to drive the auxiliaries, Btu/lbm (J/kg)

HStLv = enthalpy at the exhaust pressure and the initial entropy of steam supplied to drive the auxiliaries, Btu/lbm (J/kg)

5-15.5.2 For Electrically Driven Equipment

$$QrBX = QX\,C1 \frac{EX}{100}, \text{Btu/hr (W)} \tag{5-15-6}$$

where

C1 = 3,412 Btu/kWh (1 W)

EX = overall drive efficiency, percent; includes such items as motor efficiency, electric and hydraulic coupling efficiency, and gear efficiency

QX = energy input to the drives, kWh (J)

5-15.6 *QrBSb*, Sensible Heat in Sorbent Credit, Btu/hr (W)

$$QrBSb = MrSb\ HSbEn, \text{Btu/hr (W)} \tag{5-15-7}$$

where

HSbEn = enthalpy of the sorbent entering the steam generator envelope, Btu/lbm (J/kg)

MrSb = mass flow rate of sorbent, lbm/hr (kg/s)

5-15.7 *QrBWAd*, Energy Supplied by Additional Moisture Credit, Btu/hr (W)

Typical examples of additional moisture are sootblowing and atomizing steam.

$$QrBWAd = \sum MrStEnz\,(HStEnz - HWRe), \text{Btu/hr (W)} \tag{5-15-8}$$

where

HStEnz = enthalpy of additional moisture entering the envelope, Btu/lbm (J/kg)

HWRe = enthalpy of water at the reference temperature, Btu/lbm (J/kg)

MrStEnz = mass flow rate of additional moisture, lbm/hr (kg/s) at location *z*

5-15.8 Conversion of Credits on Rate Basis to Percent Input 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.

$$QpB = 100 \frac{QrBk}{QrF}, \% \tag{5-15-9}$$

5-16 UNCERTAINTY

Subsection 5-2, Measurement Data Reduction, discussed calculation of the standard deviation of the mean and degrees of freedom for individual parameters. This Section presents calculations for overall standard deviation of the mean and degrees of freedom for the random uncertainty. This Section also presents calculation methods for sensitivity coefficients and the combination of random and systematic components into overall test 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 Section. The uncertainty calculations presented in this Section, as well as those presented in para 5-2.4, 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.

Refer to Section 7 for additional guidance on pretest uncertainty analysis. The majority of systematic uncertainty estimates can be made prior to starting a performance test. 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 Code does not require a pretest uncertainty analysis; however, a pretest uncertainty analysis is strongly recommended. Waiting until after a performance test is complete to calculate uncertainty can result in actual test uncertainties in excess of expected or agreed upon values.

This Section 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 or other result. 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 the following:

$$CHGPAR = \frac{(PCHGPAR\ X_{AVG})}{100} \text{ or } \frac{(PCHGPAR\ U)}{100} \tag{5-16-1}$$

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. For development of sensitivity coefficients, care must be taken to use units that will not be zero such as absolute temperature and pressure.

X_{AVG} = arithmetic average value of a measured parameter. Refer to definition of U above for note regarding units.

Alternatively, such as when X_{AVG} is very small or zero, $CHGPAR$ can be any convenient small increment of X_{AVG}.

Absolute sensitivity coefficients are calculated for each measured parameter from equations like the following, which considers fuel efficiency as the result of interest:

$$ASENSCO = \frac{RECALEF - EF}{CHGPAR} \tag{5-16-2}$$

where

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

EF = steam generator fuel efficiency (or other desired uncertainty parameter such as output, etc.), calculated for the actual (measured) parameter

$RECALEF$ = recalculated steam generator fuel efficiency (or other desired uncertainty parameter such as output, etc.) using ($X+CHGPAR$) or ($U+CHGPAR$) 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. If smaller, it should be considered zero. Refer to para. 5-7.3 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:

$$RSENSCO = \frac{(ASENSCO\ X_{AVG})}{EF} \text{ or } \frac{(ASENSCO\ U)}{EF} \tag{5-16-3}$$

where

EF = steam generator fuel efficiency (or other desired uncertainty parameter such as output etc.), calculated for the actual (measured) parameter

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

5-16.2 Random Uncertainty and Its Degrees of Freedom

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

$$STDDEVMN_R = \sum_{i=1}^{N} \left[(ASENSCO_i \, STDDEVMN_i)^2 \right]^{1/2} \quad (5\text{-}16\text{-}4)$$

where

$ASENSCO_i$ = absolute self-measured parameters
N = number or random uncertainty (standard deviation of the mean) of result
$STDDEVMN_i$ = standard deviation of the mean for measured parameter, i
$STDDEVMN_R$ = overall sensitivity coefficient for measured parameter, i

The number of degrees of freedom for the random uncertainty is calculated from the following equation:

$$DEGFREE_R = \frac{STDDEVMN_R^4}{\sum_{i=1}^{N} \frac{(ASENSCO_i \; STDDEVMN_i)^4}{DEGFREE_i}} \quad (5\text{-}16\text{-}5)$$

where

$DEGFREE_i$ = degrees of freedom for measured parameter, i
$DEGFREE_R$ = degrees of freedom for random uncertainty

5-16.3 Random Component of Uncertainty

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

$$URC = STDTVAL \; STDDEVMN_R \quad (5\text{-}16\text{-}6)$$

where

$STDTVAL$ = two-tailed Student's t value evaluated for the degrees of freedom of the result ($DEGFREE_{UNC}$)
URC = random component of uncertainty

5-16.4 Systematic Uncertainty

Systematic 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. Elementary systematic uncertainties for each measured parameter are combined according to the root-sum-square rule.

$$SYS_i = \left(\sum_{j=1}^{M} SYS_j^2 \right)^{1/2} \quad (5\text{-}16\text{-}7)$$

where

M = number of components in the measurement system of parameter, i
SYS_i = systematic uncertainty limit of measured parameter, i. The units of systematic uncertainty are the same as the units of the measured parameter.
SYS_j = systematic uncertainty of individual components used to determine the value of parameter, j. Refer to note on units above.

The degrees of freedom for systematic uncertainties shall be taken as 50, corresponding to a probable range of 10% in estimates of systematic uncertainty (see para. 7-5.5)

$$DEGFREE_S = 50 \quad (5\text{-}16\text{-}8)$$

5-16.4.1 Systematic Uncertainties Associated With Spatially Nonuniform 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). The SDI is calculated from the following equation:

$$SDI = \left[\frac{1}{N} \sum_{i=1}^{N} (z_i - Z)^2 \right]^{1/2} \quad (5\text{-}16\text{-}9)$$

The following equation is suggested for numerical integration:

$$SYSNI = \frac{SDI}{(N-1)^{1/2}} \quad (5\text{-}16\text{-}10)$$

where

N = number of points in the measurement grid
SDI = spatial distribution index
$SYSNI$ = systematic uncertainty from numerical integration
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.

$$SYS_R = \left[\sum_{i=1}^{N} (ABSENCO_i \, SYS_i)^2 \right]^{1/2} \quad (5\text{-}16\text{-}11)$$

where

SYS_R = 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* ($ABSENCO_i \times SYS_i$) determines whether the term is summed with the positive or negative systematic uncertainties.

5-16.5 Test Uncertainty

The test uncertainty is calculated from the overall random and systematic uncertainty components.

$$UNC = STDTVAL\left[URC^2 + \left(\frac{SYS_R}{2}\right)\right] \quad (5\text{-}16\text{-}12)$$

where

UNC = test 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 5-16.5-1 shows the Student's t value as a function of degrees of freedom. A value of 2 is shown for 30 or more degrees of freedom in accordance with Section 7 and ASME PTC 19.1, which suggest a value of 2 for a relatively large degree of freedom. Interpolation in the table is done using reciprocal degrees of freedom.

A curve fit for t is

$$t = 1.959 + \frac{2.372}{DEGFREE} + \frac{3.121}{DEGFREE^2} + \frac{0.799}{DEGFREE^3} + \frac{4.446}{DEGFREE^4} \quad (5\text{-}16\text{-}13)$$

The number of degrees of freedom for the overall test result is calculated from the following equation:

$$DEGFREE_{UNC} = \frac{\left[\left(\frac{SYS_R}{2}\right)^2 + (URC)^2\right]^2}{\frac{URC^4}{DEGFREE_R} + \frac{\left(\frac{SYS_R}{2}\right)^4}{50}} \quad (5\text{-}16\text{-}14)$$

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

Table 5-16.5-1 Two-Tailed Student's *t* Table for the 95% Confidence Level

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

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

5-17 OTHER OPERATING PARAMETERS

It is sometimes desirable to test a steam generator for performance parameters other than rated capacity and efficiency. This Section 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 and equipment condition, and control system adjustments do not adversely affect the tests, particular attention should be given to the recommendations in paras. 3-2.5.2, 3-2.5.3, and 3-2.6.

5-17.1 Peak Capacity

Peak capacity is defined as the maximum steam mass flow rate, at a specific pressure and temperature, that the steam generator is capable of producing, including specified blowdown and auxiliary steam, for a limited time period without damaging the steam generator components.

Peak capacity can be either measured directly (*MrSt31* for saturated steam generators, *MrSt32* for superheated steam generators) or calculated from feedwater, desuperheater water, and blowdown mass flow rates.

When desuperheater water flow is not measured, it may be determined by an energy balance. When blowdown flow is not measured, it may be determined from the setting of a calibrated valve or by energy balance around a blowdown heat recovery system.

Data required for peak capacity determination are summarized in Table 4-2-3. Prior to the test, the following shall be defined and agreed upon:

(a) duration of the "limited time period." This determines the minimum run time.

(b) steam pressure and temperature for superheated steam generators.

(c) steam pressure for saturated steam generators.

(d) feedwater pressure and temperature.

(e) blowdown rate.

5-17.2 Steam Temperature

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

5-17.3 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.

5-17.4 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.

5-17.5 Exit Gas Temperature

Data required for exit gas temperature tests are given in Table 4-2-5. 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 para. 5-13.3.

5-17.6 Air Infiltration

Determination of the amount of air infiltration through the steam generator casing where the flue gas constituents can be measured is accomplished by comparing the excess air or air mass flow rate difference across the section of interest. Total setting infiltration may also be determined by energy balance across an air-to-gas heat exchanger (see below). Data required for excess air determination are given in Table 4-2-9. Excess air and mass flow rate computational procedures are given in subsection 5-11.

The amount of air infiltration, or leakage, is expressed in terms of the increase in percent excess air.

$$MpAl = 100\,(XpAz2 - XpAz1),\ \% \qquad (5\text{-}17\text{-}1)$$

where

MpAl = mass percent air infiltration
XpAz1 = mass percent of excess air at the upstream sampling location
XpAz2 = mass percent of excess air at the downstream sampling location

The previous paragraph addressed calculating air infiltration between two points where the O_2 in the flue gas can be measured entering and leaving the section in question (e.g., a hot precipitator). On units with recuperative air heaters (air-to-gas heat exchangers), the setting infiltration between the air heater air exit and the point of measuring O_2 in the flue gas can be calculated by energy balance. The combustion airflow to the burners (and pulverizers, if applicable) can be calculated by energy balance around the air heater based on the flue gas flow entering the air heater(s) and measured air and gas temperature entering and leaving the air heater(s). Setting infiltration between the air heater air outlet and the point of measuring O_2 (excess air) in the flue gas (usually boiler or economizer gas outlet) can be calculated from the difference between the wet airflow determined at the point of O_2 measurement and the wet airflow leaving the air heater. All airflows and gas flows are calculated stoichiometrically in accordance with subsections 5-11 and 5-12. When there is more than one air heater of the same type, it is usually sufficiently accurate to assume equal flows between the air heaters. If gas flow or airflow is measured to determine the imbalance, the ratio of the results should be used to correct the gas flow/airflow calculated stoichiometrically. For pulverized-coal-fired units with cold primary air systems, refer to subsection 5-13 for calculation of air and gas weights.

5-17.6.1 *MpAhLg*, Air Heater Leakage, Percent.

Air heater leakage is defined as the total amount of air leakage from all air streams to the flue gas stream within the air heater, on a wet basis, and is expressed as a percentage of the incoming (undiluted) flue gas mass flow. Note that this calculated value will include any ingress air that may be present between the air heater flue gas inlet and flue gas outlet test planes.

$$MpAhLg = 100\,\frac{(MqFgLv - MqFgEn)}{MqFgEn},\ \% \qquad (5\text{-}17\text{-}2)$$

where

MqFgEn = wet flue gas weight entering the air heater using the excess air (calculated from measured O_2) entering the air heater, lbm/Btu. Refer to para. 5-12.9.
MqFgLv = wet flue gas weight leaving the air heater using the excess air (calculated from measured O_2) leaving the air heater, lbm/Btu. Refer to para. 5-12.9.

5-18 CORRECTIONS TO STANDARD OR DESIGN CONDITIONS

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

The corrections to efficiency described in this Section specifically address efficiency calculated by the energy balance method. Paragraph 5-18.10 discusses correcting input–output efficiency test results to contract conditions.

Corrections to efficiency described in this Section consist of using the standard or corrected air inlet temperature, correcting air heater gas outlet temperature for deviations between the test and standard conditions, and repeating the efficiency calculations utilizing the standard or design fuel and other operating variables described below. The corrections described herein are for the most common variables. In accordance with para. 3-2.3, the parties to the test shall agree upon other corrections for a specific unit, including correction curves.

The corrections address off-design test conditions, not changes in load. Variations between the targeted test output and actual test output should not be more than 5%. It is expected that the difference between the test efficiency and corrected efficiency will usually be no more than two to three percentage points.

5-18.1 *TAEnCr*, Corrected Entering Air Temperature

If the air temperature entering the system boundary (i.e., entering the air heater or unit, *TA8*) is specified, the corrected entering air temperature is the design entering air temperature, *TA8Ds.*

$$TAEnCr = TA8Ds, \text{°F (°C)} \qquad (5\text{-}18\text{-}1)$$

If the design entering air temperature is based upon design ambient and/or a specified air temperature entering the fan(s), the corrected entering air temperature depends upon whether the air preheater coil is in service during the test.

(a) Air Preheater Coil Not in Service. The corrected entering air temperature is the test entering air temperature plus the difference between the design air temperature entering the fan(s) and the test air temperature entering the fan(s).

$$TAEnCr = TA8 + (TA6Ds - TA6), \text{°F (°C)} \qquad (5\text{-}18\text{-}2)$$

(b) Air Preheater Coil in Service (Design Without APC in Service). The corrected entering air temperature is the test air temperature leaving the fan(s) plus the difference between the design air temperature entering the fan(s) and the test air temperature entering the fan(s).

$$TAEnCr = TA7 + (TA6Ds - TA6), \text{°F (°C)} \qquad (5\text{-}18\text{-}3)$$

where

TA6, TA6Ds = test and design air temperature entering the fans, °F (°C)
TA7 = test air temperature leaving the fans, °F (°C)
TA8 = test air temperature entering the air heater, °F (°C)
TA8Ds = design air temperature entering the air heater, °F (°C)

Corrections to the credits for changes in test entering air temperature to the corrected entering air temperature are made by substituting the corrected entering air temperature for the test temperature in the applicable credit equations. For units with air heaters, the corrected entering air temperature is also one of the air heater exit gas temperature corrections.

5-18.2 Exit Gas Temperature

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

5-18.2.1 Units Without Air-to-Gas Heat Exchanger Type Air Heater(s). The exit gas temperature may be corrected based upon the manufacturer's correction curves for deviations from design conditions if agreed upon between the parties to the test. Examples of deviation from design conditions when in excess of those for which the thermal performance is unaffected (refer to para. 5-18.3) might include deviations from design fuel, significant difference in entering air temperature, and feedwater inlet temperature.

5-18.2.2 Units With Air-to-Gas Heat Exchanger Type Air Heater(s). The exit gas temperature shall be corrected for the standard or design conditions based upon the test air heater performance for deviations from standard or design conditions. The parties to the test may agree to use ASME PTC 4.3, Air Heaters, as described below, or a different model if the corrections described can be accomplished.

$$TFgLvCrDs = TFgLvCr + TDiTAEn + TDiTFgEn + TDiMrFgEn + TDiXr, \text{°F (°C)} \qquad (5\text{-}18\text{-}4)$$

where

TDiMrFgEn = temperature correction for entering gas mass flow, °F (°C)
TDiTAEn = temperature correction for entering air temperature, °F (°C)
TDiTFgEn = temperature correction for entering gas temperature, °F (°C)
TDiXr = temperature correction for off-design *X*ratio, °F (°C)
TFgLvCr = flue gas temperature leaving air heater corrected for zero air heater leakage and used for calculation of efficiency (as tested), °F (°C)
TFgLvCrDs = flue gas temperature leaving air heater corrected to design conditions, °F (°C)

ASME PTC 4.3-1968, Air Heaters, does not cover corrections to trisector air heaters (partitioned sections to separate primary and secondary air). Until ASME PTC 4.3-1968, Air Heaters, is revised, this Code will handle the corrections as a standard bisector air heater. The airflow is the sum of the primary and secondary air leaving the air heater. The entering air temperature is the mass weighted average air temperature entering the primary and secondary air heater sections, weighted on the basis of the airflow mass flow rates leaving the primary and secondary air heater sections. The corrected air temperature leaving the air heater is required for some calculations such as pulverizer tempering airflow for the corrected conditions. It is sufficiently accurate for these correction calculations to assume the primary and secondary air temperatures leaving the air heater change by the same amount as the predicted change in average air temperature entering the air heater.

The terms for eq. (5-18-4) and other considerations for determining the corrected exit gas temperature are shown in (a) through (f) below.

(a) Entering Air Temperature

$$TDiTAEn = \frac{TAEnCr\,(TFgEn - TFgLvCr)}{(TFgEn - TAEn)} + \frac{TFgEn\,(TFgLvCr - TAEn)}{(TFgEn - TAEn)} - TFgLvCr,\ ^\circ\text{F}\ (^\circ\text{C}) \quad (5\text{-}18\text{-}5)$$

where

TAEn = air temperature entering air heater(s), °F (°C).

TAEnCr = corrected entering air temperature, °F (°C). Refer to para. 5-18.1.

TFgEn = flue gas temperature entering air heater(s), °F (°C).

(b) Entering Gas Temperature. Correction for entering gas temperature shall be agreed upon by the parties to the test. Examples for which corrections due to the entering gas temperature may be applicable include

(1) equipment within the steam generator envelope not supplied by the steam generator vendor, such as hot air quality control equipment. 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.

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

(3) 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:

$$TDiTFgEn = \frac{TFgEnCrDs\,(TFgLvCr - TAEn)}{(TFgEn - TAEn)} + \frac{TAEn\,(TFgEn - TFgLvCr)}{(TFgEn - TAEn)} - TFgLvCr,\ ^\circ\text{F}\ (^\circ\text{C}) \quad (5\text{-}18\text{-}6)$$

where

TFgEnCrDs = entering gas temperature corrected to design conditions, °F (°C)

(c) 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 for the contract conditions.

An example of when this correction may be necessary is when equipment between the steam generator air inlet and gas outlet is not supplied by the steam generator vendor and the equipment does not perform as specified. An example is hot air quality control equipment in which the tested air infiltration across the equipment may be different than specified. The air heater gas outlet temperature shall be corrected for the gas mass flow entering the air heater that would occur using the specified infiltration and the gas mass flow that would occur with efficiency and operating conditions corrected to design conditions.

For units with separate primary air heaters and secondary air heaters (for the remainder of the combustion air), it is recommended for simplification of the calculations that the test gas mass flow be used for the primary air heater for the corrected conditions (assuming normal operation); thus, no correction is required for the primary air heater. The balance of the difference in the gas mass flow is used to correct the secondary air heater exit gas temperature.

Because of the possibility of abnormal coal or other operating considerations during the test, the parties to the test should agree upon how to determine the split between the air heaters for the corrected conditions.

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

(d) 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. The most typical reason for the heat capacity ratio to be different from design is air bypassing the air heater(s). Examples of cases in which this may occur are excessive setting infiltration (normally older units) and excessive pulverizer tempering airflow. For units with separate primary and secondary air heaters (as described above), if the test is conducted with the target primary air heater exit gas temperature and corrections to pulverizer tempering airflow are not required due to negligible differences in the moisture between the test and contract coal, it is recommended for simplification of the calculations that the test *X*-ratio be used for the primary air heater. This eliminates the need for calculating a primary air heater correction. Subparagraph (f) below addresses calculation of corrected pulverizer tempering airflow and corrected mass flow rate of flue gas entering the primary air heater.

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

(e) Corrections for Pulverizer Tempering Airflow, Units Without Primary Air Heater. The air temperature leaving the air heater may be significantly different from the test conditions that could impact the amount of pulverizer tempering air required. When tempering air is normally utilized, the corrected air temperature leaving the air heater shall be calculated by energy balance based on the corrected conditions. A corrected tempering airflow

and corresponding corrected secondary airflow should be determined for the corrected air temperature leaving the air heater and test or design pulverizer inlet air temperature (para. 5-18.3). The revised *X*-ratio correction and revised corrected air heater exit gas temperature should be determined. This process is iterative and should be repeated until the corrected exit gas temperature is within 0.5°F (0.3°C).

(f) Corrections for Pulverizer Tempering Airflow, Units With Primary Air Heater. When required, this correction should be performed before the entering gas flow and *X*-ratio corrections. Refer to paras. 5-18.2.2(e) and 5-18.3 regarding when corrections for pulverizer tempering airflow may be required. Corrections for tempering airflow can generally be solved directly (as opposed to iteratively) for units with separate primary air heaters that are controlled to a fixed exit gas temperature. The parties to the test shall agree upon the controlled primary exit gas temperature (normally the test temperature) and design pulverizer entering air temperature. Since the primary airflow to the pulverizers is constant and the primary air heater inlet and outlet flue gas temperatures are known, the required primary air heater gas flow can be solved for directly as follows:

$$MrFg14BCr = MrA11\left(\frac{HA11Ds - HA8BDs}{HFg14BDs - HFg15BDs}\right), \text{lbm/hr (kg/s)} \tag{5-18-7}$$

where

HA8BDs = enthalpy of the design air temperature entering the primary air heater, Btu/lbm (J/kg)
HA11Ds = enthalpy of the design air temperature entering the pulverizer, Btu/lbm (J/kg)
HFg14BDs = enthalpy of the design gas temperature entering the primary air heater, Btu/lbm (J/kg)
HFg15BDs = enthalpy of the design gas temperature leaving the primary air heater (excluding leakage), Btu/lbm (J/kg)
MrA11 = primary airflow entering pulverizers, lbm/hr (kg/s)
MrFg14BCr = corrected mass flow rate of flue gas entering primary air heater, lbm/hr (kg/s)

This energy balance procedure is only valid if the air heater surface and performance characteristics are capable of producing the design air temperature leaving. This can be verified by calculating the corrected air heater exit gas temperature utilizing the design boundary conditions. If the corrected exit gas temperature is higher than the desired control exit gas temperature, the actual air temperature leaving will be lower than the required pulverizer inlet temperature. This indicates that the air heater is not capable of performing in accordance with the energy balance, and the actual expected performance will have to be calculated iteratively using the correction procedure parameters as the air heater model.

5-18.3 Fuel Analysis

Corrections to credits, losses (efficiency), and air and flue gas mass flow rates for differences in fuel constituents between the test and contract fuel are made by utilizing the standard or contract fuel analysis in the applicable computations. Corrections to air heater performance for pulverized-coal-fired units (units with controlled air temperature for drying the fuel) and air and gas resistance resulting from differences in air and flue gas mass flow rates are described below. Additional corrections should not be required if the test and contract fuels are equivalent (i.e., have similar ultimate and proximate analyses and similar slagging, fouling, and combustion characteristics). Refer to Nonmandatory Appendix E for guidance regarding equivalent fuels.

Equivalent fuels do not affect the thermal performance of the steam generator. Thermal performance with regard to efficiency refers to the gas temperature exiting the steam generator pressure parts, but also applies to furnace, superheat, and reheat absorption and may include other parameters such as steam temperature and desuperheater spray.

The differences in the slagging and fouling characteristics have the most significant impact on thermal performance. Differences in fuel moisture content (on the order of ±5 points) and ash content (±10 points) have minimal impact on the gas temperature leaving the pressure parts, but may affect component absorptions.

For manufactured or process gases and/or synthetic fuels, differences in constituents may impact flue gas mass flow rate and yet have a minimal impact on the gas temperature leaving the pressure parts. However, if the corrected flue gas mass flow rate is different by more than 2% or 3%, absorptions may be affected.

This Code requires that the parties to the test agree that the test fuel is equivalent to the contract fuel, or that they reach a pretest agreement as to a method for correcting the thermal performance of the steam generator for differences between the test fuel and the standard or contract fuel.

On pulverized-coal-fired units, the air temperature entering the pulverizer is controlled to maintain a design pulverizer air-coal outlet temperature. The required pulverizer inlet air temperature is a function of the moisture in the coal. If the test coal is appreciably off design (more than two or three percentage points of water in coal) the pulverizer tempering airflow and air heater performance should be corrected for the mill inlet temperature required for the design coal. High moisture coals generally do not require pulverizer tempering air, and corrections for coal moisture are not required unless tempering air is utilized during the test. The parties to the test shall agree upon whether this correction is required, and if it is required, either agree upon a design mill inlet air temperature or a method of correcting the test mill inlet temperature for off design moisture in coal.

5-18.4 Sorbent Analysis and Sorbent Reactions

The actual sulfur content of the coal during a test is not known until after the test. Therefore, the calcium-to-sulfur molar ratio during the test is likely to be different from the agreed upon target value for the test. Deviation from the target calcium-to-sulfur molar ratio impacts the sulfur capture/retention result. Also, differences between the test and the standard or contract sulfur content of the fuel and sorbent analysis impact the sorbent mass flow rate required (Ca/S ratio) as well as the sulfur capture/retention. These differences also impact efficiency and air and flue gas mass flow rates.

5-18.4.1 Corrections for Sorbent Analysis and Sorbent Reactions. In accordance with para. 5-18.4.2, agreed upon values for the calcium-to-sulfur (Ca/S) molar ratio and sulfur capture are used to make the corrected combustion and efficiency calculations. The calcium-to-sulfur molar ratio is used in conjunction with the standard or contract fuel analysis to calculate the corrected sorbent rate, lbm/lbm fuel (kg/kg fuel). The corrected sorbent rate, agreed upon sulfur capture/retention, standard or contract sorbent analysis, and calcination fraction determined from the test are all substituted for the test values to calculate the required input data for the corrected efficiency calculations.

5-18.4.2 Guidelines for Establishing a Standard or Design Ca/S Molar Ratio and Sulfur Capture. It is desirable that the sorbent rate versus sulfur capture/retention characteristics of the unit be determined prior to an efficiency test. This allows the parties to the test to establish a target calcium-to-sulfur molar ratio for operating the unit during the test. This agreed upon value would normally be used as the value for corrections to standard or contract conditions in conjunction with the tested sulfur capture/retention result. There may be occasions when the target value for the test does not reflect steam generator capability such as off-design fuel sulfur content, sorbent characteristics versus the design sorbent, overfeeding of sorbent to meet a lower than contract sulfur emissions level, etc. In such cases, it may be necessary for the parties to the test to agree upon calcium-to-sulfur molar ratio and sulfur capture/retention values to use for the corrected efficiency results. The test calcium-to-sulfur molar ratio (Ca/S) may be corrected for the changes between the test and the standard or contract sulfur capture and sulfur content of the fuel by use of correction curves or equations agreed to by the parties to the test. Note that the purpose of this Section is to calculate a normalized efficiency that reflects the unit's capability.

5-18.5 Residue

The considerations for residue are losses related to unburned combustible in the residue, sensible heat of residue losses, residue split between the various boiler collection points, the quantity of ash in the fuel, and the quantity of spent sorbent, which are discussed in the following sections.

5-18.5.1 Unburned Carbon Loss. Unless otherwise agreed to, the test unburned carbon loss, QpLUbC, is to be used for the corrected conditions. The unburned carbon mass per mass of fuel for the standard or design fuel, *MpUbCCr*, is calculated by multiplying the unburned carbon calculated for the test, *MpUbC*, by the ratio of the higher heating value of the standard or design fuel divided by the higher heating value of the test fuel.

The quantity of ash in solid fuels is variable, and therefore it is sometimes desirable to correct the measured percent unburned carbon in residue to a standard or design fuel ash content in order to evaluate combustion system performance. For given boiler operating conditions, the heat loss due to unburned carbon (*QpLUbC*) is assumed to remain constant for typical variations in fuel ash (or spent sorbent). The unburned carbon as it would appear in a residue produced by the standard or design fuel (and sorbent) may be calculated using the following equation:

$$MpCRsDs = \frac{100}{\left[\dfrac{14,500 \times (AsDs + 100 \times MFrSsbDs)}{QpLUbC \times HHVDs} + 1\right]} \tag{5-18-8}$$

where

$AsDs$ = mass percent ash from standard or design fuel, %

$HHVDs$ = higher heating value of standard or design fuel, btu/lbm

$MFrSsbDs$ = mass fraction of spent sorbent (corrected conditions), lbm/lbm fuel

$MpCRsDs$ = unburned carbon in residue corrected to standard or design fuel ash (and spent sorbent), %

$QpLUbC$ = heat loss due to unburned carbon, test conditions, %

Equation (5-18-8) assumes that the *QpLUbC* is constant between the test and design conditions.

5-18.5.2 Residue Quantity. The residue quantity is calculated from the ash in the fuel, spent sorbent, and unburned carbon in the residue (*MpUbCCr*), as outlined in para. 5-10.1, except that the standard or design-basis value is substituted for each parameter.

5-18.5.3 Residue Split. The residue split between the various collection locations should be assumed to be the same as tested unless otherwise agreed upon. For fluidized bed units, the quantity of ash in the fuel and sorbent used can impact the ash split. In cases where this may be significant, a correction curve or procedure should be agreed upon.

5-18.5.4 Sensible Heat in Residue Loss. The sensible heat in residue loss at each location is calculated based upon the total mass of residue calculated for the standard or design conditions, using the residue split in accordance with para. 5-18.5.3 and temperatures (corrected to standard or design conditions, if applicable).

5-18.6 Excess Air

Minor deviations in excess air between the test and standard or contract value that are due to variability of establishing test conditions may be corrected to the standard, contract, or other agreed upon value. Corrections to losses or credits due to excess air are made by substituting the target value in the applicable equations. If the unit must operate at an excess air level other than the standard or contract value to meet other performance parameters such as unburned carbon, emissions, steam temperature, etc., then no correction to the "as tested" excess air value should be applied.

5-18.7 Other Entering Streams

5-18.7.1 Moisture in Air. Substitute the standard or design value for the test value in the applicable calculations.

5-18.7.2 Fuel Temperature. Substitute the standard or design value for the test value.

5-18.7.3 Sorbent Temperature. Substitute the standard or design value for the test value.

5-18.8 Surface Radiation and Convection Loss

When this item is measured, the results shall be corrected to the standard or design ambient conditions (air temperature and velocity). This is a three-step process. For each incremental area measured

(a) solve for the insulation and lagging heat transfer coefficient, *Hwz*, based on the measured parameters

(b) based on the assumption that *Hwz* is constant, solve for the corrected surface temperature, *TMnAfCrz*, for the standard or design ambient conditions

(c) with the corrected surface temperature and standard or design ambient conditions, solve for the corrected surface convection and radiation loss, *QrLSrcCrz*

5-18.8.1 Insulation and Lagging Heat Transfer Coefficient, *Hwz*

$$Hwz = \frac{\left(\dfrac{QrLSrcz}{Afz}\right)}{Thfz - TMnAfz}, \text{ Btu / ft}^2\text{hr°F (W / m}^2\text{s °C)} \quad (5\text{-}18\text{-}9)$$

where

Thfz = the hot face temperature of the insulation and lagging (steam generator wall, flue, duct, etc.)

5-18.8.2 Corrected Surface Temperature, *TMnAfCrz*. The corrected surface temperature requires the solution of the following equation:

$$Hwz\,(Thfz - TMnAfCrz) = Hrcaz\,(TMnAfCrz - TMnAd) \quad (5\text{-}18\text{-}10)$$

where

Hrcaz = the sum of the radiation and convection heat transfer coefficients for *TMnAfCrz* and the design ambient air temperature, *TMnAd*, and design surface velocity

An iterative solution is required to solve eq. (5-18-10) using the standard method for calculating *Hrcaz*. The solution can be simplified by using a linear curve fit for Hrcaz in the range of the corrected surface temperatures and design ambient air temperature and design velocity. The following curve fit predicts a surface temperature within 0.5% for a range of surface temperatures from 130°F to 280°F for design ambient conditions:

$$Hrcaz = 1.4254 + 0.00593\,(TMnAfCrz - TMnAd) \quad (5\text{-}18\text{-}11)$$

The user should develop a similar curve fit if different standard conditions are used. This simplification allows for solving for the corrected surface temperature directly from the following equation:

$$TMnAfCrz = \frac{-B + \sqrt{B^2 - 4\,A\,C}}{2\,A}, \text{ °F (°C)} \quad (5\text{-}18\text{-}12)$$

where

$A = 0.00593$

$B = 1.4254 - 2.0 \times 0.00593\,TMnADs + Hwz \quad (5\text{-}18\text{-}13)$

$C = 1.4254\,TMnADs - Hwz\,Thfz + 0.00593\,(TMnADs)^2 \quad (5\text{-}18\text{-}14)$

where

TMnADs = the design surrounding air temperature

5-18.8.3 Corrected Surface Radiation and Convection Loss, *QrLSrcCrz*. Solve for the corrected surface radiation and convection loss in accordance with para. 5-14.9 using the corrected surface temperature and the standard or design ambient conditions.

5-18.9 Miscellaneous Efficiency Corrections

Other minor losses and/or credits that are measured should be reviewed by the parties to the test and agreement reached as to whether corrections to the efficiency are applicable.

5-18.10 Corrected Input–Output Efficiency

When efficiency is determined by the Input–Output method, the test result is corrected to the standard or design conditions by adding the difference between the corrected efficiency and test efficiency (both as calculated by the energy balance method) to the Input–Output test results. Design boundary conditions (such as entering air and exit gas temperatures) shall be used if they are not measured. The most significant corrections are typically fuel analysis, entering air temperature and exit gas temperature corrected for entering air temperature (for unit with air-to-gas heat exchangers). Correcting for the test fuel versus the design fuel requires that the ultimate analysis be determined for the test fuel as well as the heating value. For units with air-to-gas heat exchangers, if the entering air temperature is measured, the exit gas temperature (expected temperature if not measured) should be corrected in accordance with para. 5-18.2. Any other corrections discussed above can be applied if measurements of necessary parameters are made.

5-18.11 Air and Gas Resistance

The measured resistance shall be corrected to standard or design conditions for the difference in mass flow of the flowing fluid and the density of the fluid between the test condition and the conditions corrected to design. The general equations for correcting air resistance or draft loss are

$$PDiAFgCr = C1\left[\left(PDiAFg - Se\right)\left(\frac{MrAFgCr}{MrAFg}\right)^2\left(\frac{DnAFg}{DnAFgCr}\right) + Se\right],\ \text{in. wg (Pa)} \tag{5-18-15}$$

$$Se = C2\,\frac{2.31}{12}\,Ht\left(DnAFg - DnA\right),\ \text{in. wg (Pa)} \tag{5-18-16}$$

where

$C1$ = unit conversion factor, 1.0 for in. wg (2.4884E+02 for Pa)

$C2$ = unit conversion factor, 1.0 for in. wg (2.4884E+02 for Pa)

DnA = density of ambient air in vicinity of pressure measurement, lbm/ft^3 (kg/m^3)

$DnAFg$ = density of air or flue gas, lbm/ft^3 (kg/m^3). For the furnace shaft, use a value of 0.0125 lbm/ft^3 (0.20 kg/m^3).

$DnAFgCr$ = density of air or flue gas corrected to design conditions, lbm/ft^3 (kg/m^3). The corrected density will normally be very close to the test density, $DnAFg$, and this correction can usually be disregarded. The density correction is included if the density at the test conditions is significantly different from the density corrected to design conditions.

Ht = height between the pressure locations [i.e., the difference in elevation between the downstream and upstream pressure locations, ft (m)]. Ht will be positive if the fluid is flowing upward.

$MrAFg$ = mass flow rate of air or flue gas for test conditions, lbm/hr (kg/s)

$MrAFgCr$ = corrected mass flow rate of air or flue gas, lbm/hr (kg/s)

$PDiAFg$ = measured air resistance or draft loss, in. wg (Pa)

$PDiAFgCr$ = corrected air resistance or draft loss, in. wg (Pa)

Se = stack effect or difference in static pressure between the air/gas side of boiler and surrounding ambient air. Se will be negative if the fluid is flowing upward.

The pressure drop characteristics of each system must be examined in detail, and a detailed pressure drop correction procedure for the specific system must be developed. The above general pressure drop equation may not be applicable for all equipment (pulverizers, for example) and systems (for example, where pressure drop is controlled, such as cyclone furnaces).

5-18.12 Steam or Water Pressure Loss

The general equations for correcting steam/water pressure drop between the test and design or contract conditions are as follows:

$$PDiStCr = \left(PDiSt - C1 \times Ht \times DnSt\right)\left(\frac{DnSt}{DnStDs}\right)\left(\frac{MrStDs}{MrSt}\right) + C1 \times Ht \times DnStDs - VhCr,\ \text{psi (Pa)} \tag{5-18-17}$$

where

$C1$ = unit conversion factor, 0.00694 for psi (4.788026E+01 for Pa)

$DnSt$ = density of the steam/water at the test conditions, lbm/ft^3 (kg/m^3)

$DnStDs$ = density of the steam/water at the design conditions, lbm/ft^3 (kg/m^3)

Ht = height between the pressure locations [i.e., the difference in elevation between the downstream and upstream pressure locations, ft (m)]. Ht will be positive if the fluid is flowing upward.

$MrSt$ = mass flow rates of the steam/water at the test condition, lbm/hr (kg/s)

MrStDs = mass flow rates of the steam/water at the design condition (for feedwater flow and intermediate superheater flows, calculated based on the corrected spray water flow), lbm/hr (kg/s)
PDiSt = the measured pressure drop, psi (Pa)
PDiStCr = the corrected pressure drop, psi (Pa)
VhCr = velocity head correction (if applicable) calculated as follows:

$$VhCr = C2\frac{1}{DnSt}\left[\left(\frac{MrStDs}{Aid}\right)\left(\frac{MrStDs}{AidDs}\right) + VhCf\left(\frac{MrStDs}{AidDs}\right)\right], \text{psi (Pa)} \quad (5\text{-}18\text{-}18)$$

where
Aid = area of the pipe where pressure tap is installed, ft^2 (m^2)
AidDs = area of the pipe at the contractual terminal point, ft^2 (m^2)
C2 = unit conversion factor, 8.327E–12 for psi (5.741E–8 for Pa)
VhCf = loss coefficient for the change in cross section geometry involved based on the diameter of the pipe at the terminal point. Parties to test to agree upon value based on geometry involved utilizing fluid flow reference text.

The measured pressure differential across a steam generating unit or a portion of the unit shall be corrected to standard or design conditions due to the difference in mass flow of the flowing fluid and the specific volume between the test condition and the design conditions. A correction for velocity pressure may also be required if the static pressure measurement tap is located at a point with a cross-sectional area different from the terminal point for the guarantee.

5-18.13 Steam Temperature and Desuperheating Spray

Steam temperature and desuperheating spray guarantees shall be evaluated based on actual and design superheater (and reheater if applicable) absorptions rather than actual temperature due to potential deviations from the target steam temperature during the test and/or deviations from the design cycle conditions. The actual main steam and reheat mass flow rates utilized to calculate actual absorptions are corrected for off-design test conditions. In general

(a) the steam temperature shall be evaluated by comparing the actual superheater/reheater absorption to the design required superheater/reheater absorption.

(b) desuperheating spray shall be evaluated based on the calculated spray required for the actual versus design required superheater/reheater absorption.

(c) the test main steam and reheat mass flow rates utilized to calculate actual absorptions are corrected for offdesign load by multiplying by the ratio of the design main steam flow divided by the test main steam flow, *MFrStCr*.

(d) main steam temperature and desuperheater spray for once-through steam generators are not functions of surface arrangement, and corrections are not necessary. Main steam temperature is a matter of steam generator controls and should be acknowledged as achievable unless there are other limiting design considerations.

(e) certain designs, such as divided gas flow units, may require test and/or correction procedures not addressed by this Code (a simplified approach for divided gas flow units is presented below).

Actual and design required superheat and reheater absorptions are defined below. The main steam and reheat steam mass flow rates used to calculate actual absorptions are corrected for off-design main steam flow by multiplying the test main steam/reheat steam flow by the ratio of the design main steam flow divided by the test main steam flow (*MFrStCr*). The resulting absorption term generally referred to as "actual absorption" above is referred to as corrected absorption in the following Sections. While a second stage of reheat is not addressed directly, the same principles apply as for the first stage of reheat.

5-18.13.1 Superheater Absorption Corrected, *QrShCr*. The superheater absorption corrected for design main steam flow is calculated from

$$QrShCr = MrSt32Ds\,(HSt32 - HSt31) + MrW25\,(HSt31 - HW25) + MrSt46A\,(HSt46A - HSt31), \text{Btu/hr (W)} \quad (5\text{-}18\text{-}19)$$

where
MrSt32Ds = design main steam flow, lb/hr (kg/s)
MrSt46A = superheater extraction flow for the test conditions, lb/hr (kg/s)
MrW25 = desuperheating water flow for the test conditions, lb/hr (kg/s)

5-18.13.2 Required Superheater Absorption, *RqQrSh*. The required superheater absorption for the design main steam flow is calculated from

$$RqQrSh = MrSt32d\,(HSt32d - HSt31Cr) + MrSt46Ad\,(HSt46A - HSt31Cr), \text{Btu/hr (W)} \quad (5\text{-}18\text{-}20)$$

where
HSt31Cr = enthalpy of saturated steam calculated from the design superheater outlet pressure and corrected superheater pressure drop
HSt46A = enthalpy of auxiliary or extraction steam at the test conditions, Btu/lbm (J/kg)

Other terms are based on design conditions.

5-18.13.3 Reheater Absorption Corrected, *QrRhCr*. The reheater absorption corrected for design main steam flow is calculated from

$$QrRhCr = MFrStCr\ MrSt33\ (HSt34 - HSt33) + MrW26\ (HSt34 - HW26), \text{Btu/hr (W)} \quad (5\text{-}18\text{-}21)$$

where

MFrStCr = the ratio of the design main steam flow divided by the test main steam flow

5-18.13.4 Required Reheater Absorption, *RqQrRh*. The required reheater absorption for the design main steam flow is calculated from

$$RqQrRh = MrSt33Ds\ (HSt34Ds - HSt33Ds), \text{Btu/hr (W)} \quad (5\text{-}18\text{-}22)$$

where all terms are the contract or design conditions for the design main steam flow.

5-18.13.5 Corrected Superheat and Reheat Steam Temperature and Desuperheating Spray. When the corrected component absorption is equal to or exceeds the required component absorption, the corrected steam temperature is considered to be the design temperature. The required superheat and reheat spray is based on excess absorption of the specific component and is calculated in accordance with the following equations:

$$MrW25Cr = \left(\frac{QrShCr - RqQrSh}{HSt31Cr - HW25Ds}\right), \text{lbm/hr (kg/s)} \quad (5\text{-}18\text{-}23)$$

$$MrW26Cr = \left(\frac{QrRhCr - RqQrRh}{HSt34Ds - HW26Ds}\right), \text{lbm/hr (kg/s)} \quad (5\text{-}18\text{-}24)$$

Paragraph 5-18.13.6 discusses divided gas flow units where steam temperature is controlled by exchanging energy between the reheater and superheater.

If the corrected component absorption is less than the required absorption, the corrected spray flow is zero. The corrected outlet temperature is determined from the outlet enthalpy calculated from the corrected component absorption, design steam and extraction flows, and the design (or corrected) inlet conditions as follows:

$$HSt32Cr = HSt31Cr + \frac{QrShCr - QrAxStCr}{MrSt32Ds}, \text{Btu/lbm (J/kg)} \quad (5\text{-}18\text{-}25)$$

$$QrAxStCr = MrSt46ADs\,(HSt46A - HSt31Cr), \text{Btu/hr (W)} \quad (5\text{-}18\text{-}26)$$

$$HSt34Cr = HSt33Ds + \frac{QrRhCr}{MrSt34Ds}, \text{Btu/lbm (J/kg)} \quad (5\text{-}18\text{-}27)$$

where

QrAxStCr = energy in the superheated auxiliary or extraction steam, Btu/hr (W)

5-18.13.6 Corrected Superheat and Reheat Steam Temperature and Desuperheating Spray, Divided Gas Flow Units. On divided gas flow units, reheat steam temperature is controlled by exchanging energy between the reheater and superheater by biasing gas flow between the reheat and superheat pass. Tests are normally conducted by controlling to the design reheat temperature. Superheat absorption can be impacted if the reheat boundary conditions are different from the design conditions. Therefore, superheat and reheat absorption must be evaluated collectively.

For differences in corrected versus required reheat absorption on the order of 5%, a direct exchange in energy between the superheat and reheat can be assumed. The following corrected results are based on this assumption.

An alternate test method is to control to a target reheat outlet steam temperature and/or reheater desuperheater spray flow equivalent to the design required reheat absorption, *RqQrRh*. This method may be required if the differences between the corrected and required reheat absorption are larger than 5%. Due to normal deviations between the desired set point and actual performance, a minor correction in accordance with this Section is still expected. The disadvantage of this test method is that the required versus corrected reheat absorption may not be known at the time of the test.

Main steam and reheat steam temperature are deemed to be met if the sum of the corrected superheat and corrected reheat absorption is greater than the sum of the required superheat and required reheat absorption and the reheat absorption is controllable.

The reheat absorption is deemed to be controllable if the gas biasing dampers are within an operating range capable of achieving the required change in reheat absorption. The required change in reheat absorption is the difference between the corrected reheat absorption and the required reheat absorption, $QrRhCr - RqQrRh$.

Based upon these assumptions, the corrected superheater spray is calculated from the following equation:

$$MrW25Cr = \left(\frac{(QrShCr - RqQrSh) + (QrRhCr - RqQrRh)}{HSt31Cr - HW25Ds}\right), \text{lbm/hr (kg/s)} \quad (5\text{-}8\text{-}28)$$

For corrected steam temperature for under absorption conditions, the main steam temperature is normally deemed to be met and the reheat outlet steam temperature determined from the enthalpy calculated based upon the design reheat inlet conditions and the difference in the sum of the corrected reheat and superheat absorption less the required superheat absorption.

$$HSt34Cr = HSt33Ds + \frac{QrRhCr + (QrShCr - RqQrSh)}{MrSt33} \quad \text{Btu/lbm (J/kg)} \qquad (5\text{-}18\text{-}29)$$

5-18.14 Uncertainty of Corrected Results

From a designer's standpoint, the actual performance of the unit with specified inputs is not precisely known. The purpose of a test is to establish how the unit actually performs with the test inputs. The purpose of correcting the results is adjusting the test performance to the design conditions. In general, there is no uncertainty in the corrected results associated with the design values of most of the streams entering the steam generator envelope (e.g., fuel analysis, fuel heating value and fuel temperature, sorbent analysis and sorbent temperature, entering air temperature, excess air, and moisture in air). That being said, the uncertainty of the test values of some of these parameters may cause an uncertainty of calculated parameters used as input in the corrected results. This requires that their uncertainty be determined separately. The two calculated parameters for the corrected results that require development of their uncertainty are as follows:

(a) There is no uncertainty related to the design values of fuel and sorbent analyses. However, the uncertainty of the unburned carbon loss, *QpLUbC*, is a function of the uncertainty of the test fuel and sorbent analyses and other test parameters. Therefore, it is recommended that the test uncertainty of the unburned carbon loss be determined for all test parameters and used as the uncertainty of *QpLUbC* for the corrected conditions.

(b) The key test parameter required for the corrected efficiency is the tested exit gas temperature (air heater exit gas temperature excluding leakage, *TFgLvCr*, for units with air heaters). For units with air heaters, there is an uncertainty of *TFgLvCr* not only due to the measurement of the exit gas temperature, but also due to the measurement of the entering air temperature and O_2 in the flue gas entering and leaving the air heater. Other test parameters such as the fuel and sorbent analysis also impact the uncertainty of *TFgLvCr*. Therefore, it is recommended that the test uncertainty of *TFgLvCr* be determined for all test parameters and used as the uncertainty of the flue gas leaving the unit for the corrected conditions.

For units with air heaters, the test flue gas temperature leaving the air heater is corrected for off design entering air temperature, heat capacity ratio (*X*-ratio) and possibly for entering gas temperature and mass flow rate. Since this correction is based upon sound engineering principles and the purpose of the uncertainty calculation is to assess the quality of the test, no uncertainty for this correction calculation is considered.

A discussion regarding the uncertainty of individual design parameters follows. The emphasis is on design parameters that are considered to have no uncertainty. For input parameters not discussed, use the test uncertainty.

5-18.14.1 Fuel Analysis, Fuel Heating Value, and Fuel Temperature. There is no uncertainty of the calculation of the corrected results associated with the design value. The test uncertainty associated with determining the actual fuel fired impacts the unburned carbon loss and calculated gas temperature leaving the air excluding leakage (if applicable), and the test uncertainty of these parameters should be used in the corrected results. When firing very low heating value fuels [typically less than 5,000 Btu/lbm (11 600 kJ/kg)] where the test fuel analysis is significantly different than design, a correction of the gas temperature leaving the pressure parts may be agreed to, in which case the uncertainty of the corrected temperature (taking into consideration the uncertainty of the measured temperature) should be agreed upon.

5-18.14.2 Sorbent Analysis and Sorbent Temperature. There is no uncertainty of the corrected results associated with the design values. See comments above regarding unburned carbon loss and the air heater exit gas temperature.

5-18.14.3 Unburned Carbon Loss. Determine the uncertainty of the unburned carbon loss utilizing the uncertainty of all the test parameters as discussed above.

5-18.14.4 Unit Output (Design or Corrected). There is no uncertainty in the corrected results associated with the value of output. The uncertainty of corrected output is considered to be negligible.

5-18.14.5 Moisture in Air. There is no uncertainty of the corrected results associated with the design value.

5-18.14.6 Exit Gas Temperature, Units Without Air Heaters. Use the uncertainty of the measured exit gas temperature. If the exit gas temperature is corrected for off design conditions, any additional uncertainty shall be agreed upon.

5-18.14.7 Exit Gas Temperature, Units With Air Heaters. Calculate an uncertainty of *TFgLvCr* utilizing the uncertainty of all the test parameters as discussed above. Use the resulting uncertainties for the exit gas temperature corrected for entering air temperature and heat capacity ratio (also entering gas temperature and gas weight if applicable).

5-18.14.8 Air Temperature Entering the Air Heater

(a) For contracts where the design entering air temperature is the air temperature entering the air heater,

there is no uncertainty of the corrected results associated with the design value(s).

(b) For contracts where the design entering air temperature is linked to the specified ambient conditions or a specified air temperature entering the fans, utilize the test uncertainty of the entering air temperature, since the corrected entering air temperature is a calculated value dependent upon the measured air temperature entering the air heater.

5-18.14.9 Air Temperature Entering the Fans. For contracts where the entering air temperature is dependent upon the air temperature entering the fans, utilize the uncertainty of the test air temperature entering the fans.

5-18.14.10 Air Temperature Leaving the Fans. For contracts where the entering air temperature is dependent upon the air temperature entering the fans and an air preheater coil is in service during the test (design conditions exclude using an air preheater coil), utilize the uncertainty of the test air temperature leaving the fans.

5-18.14.11 Average Excess Air Entering the Air Heater(s) (Leaving Unit If No Air Heater). There is no uncertainty of the calculation of the corrected results associated with the assigned value of excess air. For units with air heaters, the uncertainty of the excess air (O_2) entering the air heaters has been considered in developing the uncertainty of *TFgLvCr*.

5-18.14.12 Ca/S Molar Ratio

(a) Design Value Used. There is no uncertainty associated with the design value.

(b) Test Value Used. Estimate the uncertainty of the Ca/S Molar Ratio based on the uncertainty of the measured sorbent flow rate. The impact of the other test parameters on the uncertainty of the Ca/S Molar Ratio are considered insignificant compared to that of the measured sorbent flow rate.

5-18.14.13 Calcination Fraction

(a) Calculated Value From Test Results Used (Normal Practice). Estimate the uncertainty of the calcination fraction based on the systematic uncertainty of the CO_2 in residue and the residue split.

(b) Agreed Upon Value Used. Use an agreed upon uncertainty of the value.

5-18.14.14 Sulfur Capture/Retention. Use the test value or an agreed upon corrected value. Estimate the uncertainty of sulfur capture based on the SO_2 measurement error. This uncertainty is applicable whether the test or corrected value is used.

5-18.14.15 Hot AQC Equipment Infiltration

(a) Air Infiltration Specified. There is no uncertainty associated with the specified design value.

(b) Air Infiltration Not Specified. Use the test uncertainty of the measured O_2 entering and leaving the hot AQC equipment.

5-18.14.16 Residue Split. Use the test value or an agreed upon corrected value of the residue split. Use the same uncertainty for the measured and corrected results.

5-18.14.17 Carbon in Residue. This parameter is calculated from the assigned unburned carbon loss. The uncertainty of the carbon in residue measurement is included in the uncertainty of the unburned carbon loss.

5-18.14.18 CO_2 in Residue. This parameter is considered in determining the uncertainty of the calcination fraction used for the corrected results. See calcination fraction above.

5-18.14.19 SO_2, ppm. The SO_2 in flue gas is calculated from the test or agreed upon Sulfur Capture/Retention used for the corrected results. There is no uncertainty in the calculated SO_2.

5-18.14.20 Gas Temperature Entering Hot AQC Equipment

(a) Gas Temperature Differential Specified. The specified temperature differential is utilized for the Loss calculations. The uncertainty of the gas temperature entering the hot AQC equipment becomes the uncertainty of the gas temperature leaving the unit (entering the air heater). This parameter should be used to determine *TFgLvCr*.

(b) Gas Temperature Differential Not Specified. Use the uncertainty of the test gas temperature.

5-18.14.21 Gas Temperature Leaving Hot AQC Equipment

(a) Gas Temperature Differential Specified. Calculate the gas temperature leaving by difference from the entering gas temperature. Since the gas temperature differential is a specified design parameter, the uncertainty of the gas temperature leaving is considered to be zero with respect to the calculation of the hot AQC Loss.

(b) Gas Temperature Differential Not Specified. Use the uncertainty of the test gas temperature.

5-18.14.22 Average Air Temperature Entering the Pulverizers/Mills. Use the uncertainty of the measured temperature. This is applicable whether the measured or a corrected mill entering air temperature is used.

5-18.14.23 Average Pulverizer Tempering Air Temperature

(a) For contracts where the design entering air temperature is the air temperature entering the air heater,

there is no uncertainty of the corrected results associated with the design value(s).

(b) For hot primary air systems or exhauster mills where the tempering air temperature is the specified ambient air temperature local to the mills, there is no uncertainty of the corrected results associated with the design value.

(c) For contracts where the design entering air temperature is linked to the specified ambient conditions or a specified air temperature entering the fans, utilize the test uncertainty of the entering air temperature since the corrected tempering air temperature is a calculated value dependent upon the measured tempering air temperature.

5-18.14.24 Pulverizer/Mill Primary Air-to-Coal Ratio. Use the design airflow to coal flow ratio. There is no uncertainty in the air/coal flow ratio.

5-18.14.25 Gas Temperature Leaving Primary Air Heater. There are several flue gas control philosophies for separate primary air heaters including controlling

(a) the hot primary air temperature to minimize tempering

(b) to a minimum exit gas temperature

(c) to the same exit gas temperature as the secondary air heater.

Use the uncertainty of the measured temperature for all cases.

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

The specific energy (energy per unit mass) of many different flow streams is required to evaluate energy losses and credits for efficiency calculation. A few of the streams are steam, water, air, flue gas, sorbent, coal, and residue (ash and spent sorbent). Specific energy of a flow stream is evaluated by the enthalpy of the flowing material.

The measured quantities that allow determination of enthalpy of substances are the temperature and pressure. Enthalpy is related to temperature and pressure by relationships that are simple for some ranges of temperature and pressure and complicated for other ranges. Accurate determination of enthalpy at all values of temperature and pressure requires the use of tables, charts, or computer software. Engineers who deal with steam almost invariably obtain the enthalpy of steam using tables or software

Frequently, changes of specific energy of streams other than steam are evaluated using the specific heat and temperature difference.

$$Hn - Hp = MnCpk\,(Tn - Tp)$$

where

MnCpk = the mean specific heat between the two temperatures

The mean specific heat is usually taken as the value at the mean temperature.

$$TMn = \frac{(Tn + Tp)}{2}$$

In reality, specific heat and enthalpy are both nonlinear functions of temperature and are related by the following:

$$Hn - Hp = \int_{Tp}^{Tn} MnCpk \; dT$$

As specific heat is usually nonlinear, *MnCpk* is not equal to the specific heat at temperature *TMn*. The differences are slight for small temperature differences; however, a steam generator test may require evaluation of enthalpy differences between temperatures typical of inlet air (50°F) and of flue gas leaving an economizer (700°F).

To gain accuracy, as well as be more theoretically correct, this Code requires that enthalpy of substances other than steam be evaluated directly from temperature via enthalpy–temperature curve fits. Pressure effects are neglected because all streams other than water/steam are at low and nearly constant pressure:

When the mean specific heat is required, it is obtained from

$$MnCpk = \frac{[H(Tn) - H(Tp)]}{Tn - Tp}$$

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

Unless otherwise noted, the reference source is the JANAF Thermo-chemical Tables [3], and curve fit coefficients developed in accordance with NASA Publication SP-273 [4]. Abbreviated JANAF/NASA correlations are presented below.

For convenience in hand calculations, curves are provided at the end of this Section for calculating enthalpy of air, flue gas, water vapor, and residue. Refer to para. 5-19.12 for a description of how these curves are used.

Unless otherwise noted, the curve fits for enthalpy in this Section are in U.S. Customary units of Btu/lbm. To convert to J/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.

$$HA = (1 - MFrWA)\,HDA + MFrWA\,HWv, \text{ Btu/lbm (J/kg)} \quad (5\text{-}19\text{-}1)$$

$$MFrWA = MFrWDA\,/\,(1 + MFrWDA), \text{ lbm/lbm (kg/kg)} \quad (5\text{-}19\text{-}2)$$

where

HA = enthalpy of wet air, Btu/lbm (J/kg)

HDA = enthalpy of dry air, Btu/lbm (J/kg). Refer to para. 5-19.10 below.
HWv = enthalpy of water vapor, Btu/lbm (J/kg). Refer to paras. 5-19.4 and 5-19.10.
MFrWDA = mass fraction of water vapor in dry air, lbm H_2O/lbm dry air (kg/kg). This is the standard method for expressing moisture in air.
MFrWA = mass fraction of water vapor in wet air, lbm H_2O/lbm wet air (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.

$$HFg = (1 - MFrWFg)\,HDFg + MFrWFg\,HWv + MFrRsFg\,HRs, \text{ Btu/lbm J/kg)} \quad (5\text{-}19\text{-}3)$$

where
HDFg = enthalpy of dry flue gas, Btu/lbm (J/kg). Refer to para. 5-19.10 below.
HFg = enthalpy of wet flue gas, Btu/lbm (J/kg)
HRs = enthalpy of residue, Btu/lbm (J/kg). Refer to paras. 5-19.3 and 5-19.10 below.
MFrRsFg = mass fraction of residue in wet gas, lbm/lbm wet gas (kg/kg). Refer to para. 5-12.12 for calculation. The sensible heat of residue may be omitted if sorbent is not utilized and the ash in the fuel is less than 15 lbm/MBtu input (i.e., where 10,000 × *MpAsF*/*HHVF* is less than 15).
MFrWFg = mass fraction of water in wet gas, lbm H_2O/lbm wet gas (kg/kg). Refer to para. 5-12.11 for calculation.

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 utilized. 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. 5-19.10 for all dry residue streams. The following abbreviated equation developed from the fifth order curve fit may be used for hand calculations:

$$HRs = 0.16\,T + 1.09\text{E–}4\,T^2 - 2.843\text{E–}8\,T^3 - 12.95, \text{ Btu/lbm} \quad (5\text{-}19\text{-}4)$$

where
T = temperature, °F

5-19.4 Enthalpy of Water Vapor, Btu/lbm

The coefficients for the JANAF/NASA fifth order curve fit are given in para. 5-19.10. 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).

$$HWv = 0.4408\,T + 2.381\text{E–}5\,T^2 + 9.638\text{E–}9\,T^3 - 34.1, \text{ Btu/lbm} \quad (5\text{-}19\text{-}5)$$

where
T = temperature, °F

NOTE: The reference temperature is 77°F (25°C).

5-19.5 Enthalpy of Steam/Water at 1 psia, Btu/lbm

The enthalpy of steam at 1 psia is required to determine the loss from water that 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):

$$HSt = 0.4329T + 3.958\text{E–}5\,T^2 + 1{,}062.2, \text{ Btu/lbm} \quad (5\text{-}19\text{-}6)$$

$$HW = T - 32, \text{ Btu/lbm} \quad (5\text{-}19\text{-}7)$$

where
T = temperature, °F

NOTE: The reference temperature is 32°F (0°C).

5-19.6 Enthalpy of Coal, Btu/lbm

The correlation for enthalpy of coal is based upon the constituents in coal as determined from a Proximate Analysis. It is developed from N.Y. Kirov's correlation as reported in *Chemistry of Coal Utilization* [5]. The original specific heat equations were integrated to obtain enthalpy at a reference temperature of 77°F (25°C). The polynomial for fixed carbon was reduced by one order for simplicity. The enthalpy of ash was developed from SiO_2 for consistency with enthalpy of residue.

The correlation is not applicable for frozen coal or for temperatures above which devolatization occurs.

$$HCoal = MFrFc\ HFc + MFrVm1\ HVm1 + MFrVm2\ HVm2 + MFrWF\ HW + MFrAsF\ HRs, \text{ Btu/lbm} \quad (5\text{-}19\text{-}8)$$

$$HFc = 0.152T + 1.95E\text{–}4\ T^2 - 12.860, \text{ Btu/lbm} \quad (5\text{-}19\text{-}9)$$

$$HVm1 = 0.38T + 2.25E\text{–}4\ T^2 - 30.594, \text{ Btu/lbm} \quad (5\text{-}19\text{-}10)$$

$$HVm2 = 0.70T + 1.70E\text{–}4\ T^2 - 54.908, \text{ Btu/lbm} \quad (5\text{-}19\text{-}11)$$

$$HRs = 0.17T + 0.80E\text{–}4\ T^2 - 13.564, \text{ Btu/lbm} \quad (5\text{-}19\text{-}12)$$

$$HW = T - 77, \text{ Btu/lbm} \quad (5\text{-}19\text{-}13)$$

$$MFrVm = MFrVm1 + MFrVm2, \text{ lbm/lbm fuel as-fired} \quad (5\text{-}19\text{-}14)$$

$$MFrVmCr = MFrVm/(1 - MFrAsF - MFrWF), \text{ lbm/lbm fuel dry-ash free} \quad (5\text{-}19\text{-}15)$$

If $MFrVmCr \leq 0.10$, then

$$MFrVm2 = MFrVm \quad (5\text{-}19\text{-}16)$$

$$MFrVm1 = 0.0 \quad (5\text{-}19\text{-}17)$$

If $MFrVmCr > 0.10$, then

$$MFrVm2 = 0.10\ (1 - MFrAsF - MFrWF) \quad (5\text{-}19\text{-}18)$$

$$MFrVm1 = MFrVm - MFrVm2 \quad (5\text{-}19\text{-}19)$$

where

- Hk = enthalpy of coal component k, Btu/lbm
- $MFrAsF$ = mass fraction of ash, lbm/lbm coal as-fired
- $MFrFc$ = mass fraction of fixed carbon, lbm/lbm coal as-fired
- $MFrVm$ = mass fraction of volatile matter, lbm/lbm coal as-fired
- $MFrVm1$ = mass fraction of primary volatile matter, lbm/lbm coal as-fired
- $MFrVm2$ = mass fraction of secondary volatile matter, lbm/lbm coal, as-fired
- $MFrVmCr$ = mass fraction of volatile matter on a dry and ash-free basis, lbm/lbm coal, dry-ash free
- $MFrWF$ = mass fraction of water, lbm/lbm coal as-fired
- T = temperature, °F

5-19.7 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 °API [6].

$$HFo = C1 + C2\ API + C3\ T + C4\ API\ T + (C5 + C6\ API)\ T^2, \text{ Btu/lbm} \quad (5\text{-}19\text{-}20)$$

$$API = (141.5 - 131.5\ Sg)/Sg \quad (5\text{-}19\text{-}21)$$

$$Sg = Dn/62.4 \quad (5\text{-}19\text{-}22)$$

where

- API = density at 60°F (16°C), °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/ft^3
- HFo = enthalpy of fuel oil, Btu/lbm
- Sg = specific gravity at 60°F (16°C), lbm/lbm
- T = temperature, °F

5-19.8 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 (CH_4), 5% ethane (C_2H_6), and 5% nitrogen. It is valid from 0°F to 500°F. Natural gas is normally near the reference temperature of 77°F (25°C), and thus utilizing 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 upon the actual constituents in the gas.

$$HGF = 0.4693\ T + 0.17523E{-}3\ T^2 + 0.4326E{-}7\ T^3 - 37.2, \text{ Btu/lbm} \quad (5\text{-}19\text{-}23)$$

where

- T = temperature, °F

5-19.9 Enthalpy of Limestone Sorbent, Btu/lbm

The following correlation is based upon JANAF/NASA data for $CaCO_3$ with a correction for water. It is valid from 0°F to 200°F.

$$HSb = (1 - MFrH2OSb)\ HCc + MFrH2OSb\ (T - 77), \text{ Btu/lbm} \quad (5\text{-}19\text{-}24)$$

$$HCc = 0.179\ T + 0.1128E{-}3\ T^2 - 14.45, \text{ Btu/lbm} \quad (5\text{-}19\text{-}25)$$

where

- $MFrH2OSb$ = mass fraction of water in sorbent, lbm/lbm sorbent
- T = temperature, °F

5-19.10 Enthalpy Coefficients for Abbreviated JANAF/NASA Correlation

The enthalpy/temperature curves in this Section are based upon the following abbreviated enthalpy correlation and the coefficients tabulated below. The reference temperature is 77°F (25°C).

$$Hk = C0 + C1\ TK + C2\ TK^2 + C3\ TK^3 + C4\ TK^4 + C5\ TK^5, \text{ Btu/lbm} \quad (5\text{-}19\text{-}26)$$

$$TK = (T + 459.7)\ /\ 1.8,\ K \qquad (5\text{-}19\text{-}27)$$

where

Hk = enthalpy of the constituents, Btu/lbm
T = temperature, °F
TK = temperature, K

Coefficients for dry air are based upon the composition of air as defined in this Code.

Coefficients for dry air for temperatures from 255 K to 1 000 K:

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 temperature above 1 000 K:

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 255 K to 1 000 K:

C0 = −0.2394034E+03
C1 = +0.8274589E+00
C2 = −0.1797539E−03
C3 = +0.3934614E−06
C4 = −0.2415873E−09
C5 = +0.6069264E−13

Coefficients for water vapor temperatures above 1 000 K:

C0 = −0.1573460E+03
C1 = +0.5229877E+00
C2 = +0.3089591E−03
C3 = −0.5974861E−07
C4 = +0.6290515E−11
C5 = −0.2746500E−15

Coefficients for dry flue gas are based on a flue gas composition of 15.3% CO_2, 3.5% O_2, 0.1% SO_2, and 81.1% atmospheric nitrogen by volume. The enthalpy of *dry* flue gas does not vary significantly for fossil fuels because atmospheric nitrogen is the predominant component. It varies between 80% for coal and approximately 88% for natural gas. The difference is predominately CO_2 and O_2, which have similar heat capacity characteristics that are not significantly different from those of atmospheric nitrogen. For typical hydrocarbon fuels combusted with less than 300% excess air, the following coefficients are sufficiently accurate for most heat transfer calculations. For unusual fuels such as manufactured gases, hydrogen, and/or combustion processes utilizing an oxidizing medium other than air, refer to para. 5-19.11 below.

Coefficients for dry flue gas for temperatures from 255 K to 1 000 K:

C0 = −0.1231899E+03
C1 = +0.4065568E+00
C2 = +0.5795050E−05
C3 = +0.6331121E−07
C4 = −0.2924434E−10
C5 = +0.2491009E−14

Coefficients for dry flue gas for temperatures above 1 000 K:

C0 = −0.1180095E+03
C1 = +0.3635095E+00
C2 = +0.1039228E−03
C3 = −0.2721820E−07
C4 = +0.3718257E−11
C5 = −0.2030596E−15

Coefficients for residue of unknown composition and sand for temperatures from 255 K to 1 000 K. The following coefficients are based upon a smoothed curve fit for SiO_2 around the discontinuous point at approximately 1 000 K:

C0 = −0.3230338E+02
C1 = −0.2431404E+00
C2 = +0.1787701E−02
C3 = −0.2598230E−05
C4 = +0.2054892E−08
C5 = −0.6366886E−12

Coefficients for residue of unknown composition and sand for temperatures above 1 000 K:

C0 = +0.1822637E+02
C1 = +0.3606155E−01
C2 = +0.4325735E−03
C3 = −0.1984149E−06
C4 = +0.4839543E−10
C5 = −0.4614088E−14

5-19.11 Enthalpy Coefficients for Gaseous Mixtures General

For normal flue gas mixtures, refer to coefficients for dry flue gas above. The enthalpy coefficients for gaseous mixtures not covered above may be calculated from the mass fraction of the constituents, *MFrk*, in the gaseous mixture in accordance with

$$Cfi\ mix = \sum MFrk\ Cfik \qquad (5\text{-}19\text{-}28)$$

where

Cfik = coefficient *i* for the constituent *k* as listed in this text or derived from an appropriate source

If the long procedure is used to derive coefficients for a specific flue gas mixture from a specific fuel (or oxidant), it is recommended that the mixture be on a dry gas basis based on a typical excess air. The moisture content (and residue, if applicable) at the location in question can then be used in conjunction with the dry flue gas to calculate the enthalpy of wet flue gas in accordance with para. 5-19.2. The enthalpy coefficients for dry flue gas are applicable over a wide range of excess air; therefore, it is usually only necessary to calculate the dry flue gas coefficients once for an average fuel.

Coefficients for O_2 temperatures from 255 K to 1 000 K:

$C0$ = −0.1189196E+03
$C1$ = +0.4229519E+00
$C2$ = −0.1689791E−03
$C3$ = +0.3707174E−06
$C4$ = −0.2743949E−09
$C5$ = +0.7384742E−13

Coefficients for O_2 temperatures above 1 000 K:

$C0$ = −0.1338989E+03
$C1$ = +0.4037813E+00
$C2$ = +0.4183627E−04
$C3$ = −0.7385320E−08
$C4$ = +0.9431348E−12
$C5$ = −0.5344839E−16

Coefficients for N_2 (elemental) temperatures from 255 K to 1 000 K:

$C0$ = −0.1358927E+03
$C1$ = +0.4729994E+00
$C2$ = −0.9077623E−04
$C3$ = +0.1220262E−06
$C4$ = −0.3839777E−10
$C5$ = −0.3563612E−15

Coefficients for N_2 (elemental) temperatures above 1 000 K:

$C0$ = −0.1136756E+03
$C1$ = +0.3643229E+00
$C2$ = +0.1022894E−03
$C3$ = −0.2678704E−07
$C4$ = +0.3652123E−11
$C5$ = −0.1993357E−15

Coefficients for N_2a (atmospheric) temperatures from 255 K to 1 000 K:

$C0$ = −0.1347230E+03
$C1$ = +0.4687224E+00
$C2$ = −0.8899319E−04
$C3$ = +0.1198239E−06
$C4$ = −0.3771498E−10
$C5$ = −0.3502640E−15

Coefficients for N_2a (atmospheric) temperatures above 1 000 K:

$C0$ = −0.1129166E+03
$C1$ = +0.3620126E+00
$C2$ = +0.1006234E−03
$C3$ = −0.2635113E−07
$C4$ = +0.3592720E−11
$C5$ = −0.1960935E−15

Coefficients for CO_2 temperatures from 255 K to 1 000 K:

$C0$ = −0.8531619E+02
$C1$ = +0.1951278E+00
$C2$ = +0.3549806E−03
$C3$ = −0.1790011E−06
$C4$ = +0.4068285E−10
$C5$ = +0.1028543E−16

Coefficients for CO_2 temperatures above 1 000 K:

$C0$ = −0.1327750E+03
$C1$ = +0.3625601E+00
$C2$ = +0.1259048E−03
$C3$ = −0.3357431E−07
$C4$ = +0.4620859E−11
$C5$ = −0.2523802E−15

Coefficients for Ar temperatures from 255 K to 1 000 K:

$C0$ = −0.6674373E+02
$C1$ = +0.2238471E+00
$C2$ = +0.0000000E+00
$C3$ = +0.0000000E+00
$C4$ = +0.0000000E+00
$C5$ = +0.0000000E+00

Coefficients for Ar temperatures above 1 000 K:

$C0$ = −0.6674374E+02
$C1$ = +0.2238471E+00
$C2$ = +0.0000000E+00
$C3$ = +0.0000000E+00
$C4$ = +0.0000000E+00
$C5$ = +0.0000000E+00

Coefficients for SO_2 temperatures from 255 K to 1 000 K:

$C0$ = −0.6741655E+02
$C1$ = +0.1823844E+00
$C2$ = +0.1486249E−03
$C3$ = +0.1273719E−07
$C4$ = −0.7371521E−10
$C5$ = +0.2857647E−13

Coefficients for SO_2 temperatures above 1 000 K:

$C0$ = −0.1037132E+03
$C1$ = +0.2928581E+00
$C2$ = +0.5500845E−04
$C3$ = −0.1495906E−07
$C4$ = +0.2114717E−11
$C5$ = −0.1178996E−15

Coefficients for CO temperatures 255 K to 1 000 K:

$C0$ = −0.1357404E+03
$C1$ = +0.4737722E+00
$C2$ = −0.1033779E−03
$C3$ = +0.1571692E−06
$C4$ = −0.6486965E−10
$C5$ = +0.6117598E−14

Coefficients for CO temperatures above 1 000 K:

$C0$ = −0.1215554E+03
$C1$ = +0.3810603E + 00
$C2$ = +0.9508019E−04
$C3$ = −0.2464562E−07
$C4$ = +0.3308845E−11
$C5$ = −0.1771265E−15

Coefficients for H_2 temperatures from 255 K to 1 000 K:

$C0 = -0.1734027E+04$
$C1 = +0.5222199E+01$
$C2 = +0.3088671E-02$
$C3 = -0.4596273E-05$
$C4 = +0.3326715E-08$
$C5 = -0.8943708E-12$

Coefficients for H_2 temperatures above 1 000 K:
$C0 = -0.1529504E+04$
$C1 = +0.5421950E+01$
$C2 = +0.5299891E-03$
$C3 = -0.9905053E-09$
$C4 = -0.9424918E-11$
$C5 = +0.8940907E-15$

Coefficients for H_2S temperatures from 255 K to 1 000 K:
$C0 = -0.1243482E+03$
$C1 = +0.4127238E+00$
$C2 = -0.2637594E-04$
$C3 = +0.1606824E-06$
$C4 = -0.8345901E-10$
$C5 = +0.1395865E-13$

Coefficients for H_2S temperatures above 1 000 K:
$C0 = -0.1001462E+03$
$C1 = +0.2881275E+00$
$C2 = +0.2121929E-03$
$C3 = -0.5382326E-07$
$C4 = +0.7221044E-11$
$C5 = -0.3902708E-15$

5-19.12 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 on Figs. 5-19.12-1 through 5-19.12-4. 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 (77°F reference), multiply the mean specific heat times the temperature, *T*, minus 77°F.

$$Hk = MnCpk\,(T - 77),\ \text{Btu/lbm} \qquad (5\text{-}19\text{-}29)$$

The resolution of the curves is such that the calculated result will be within 0.1 Btu/lbm of the actual correlations. Explanations are given 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.

$$Tc = 2T - 77,\ ^\circ\text{F} \qquad (5\text{-}19\text{-}30)$$

For example, to obtain the instantaneous specific heat at 300°F, enter the mean specific heat curve with a temperature of 523°F.

Fig. 5-19.12-1 Mean Specific Heat of Dry Air Versus Temperature

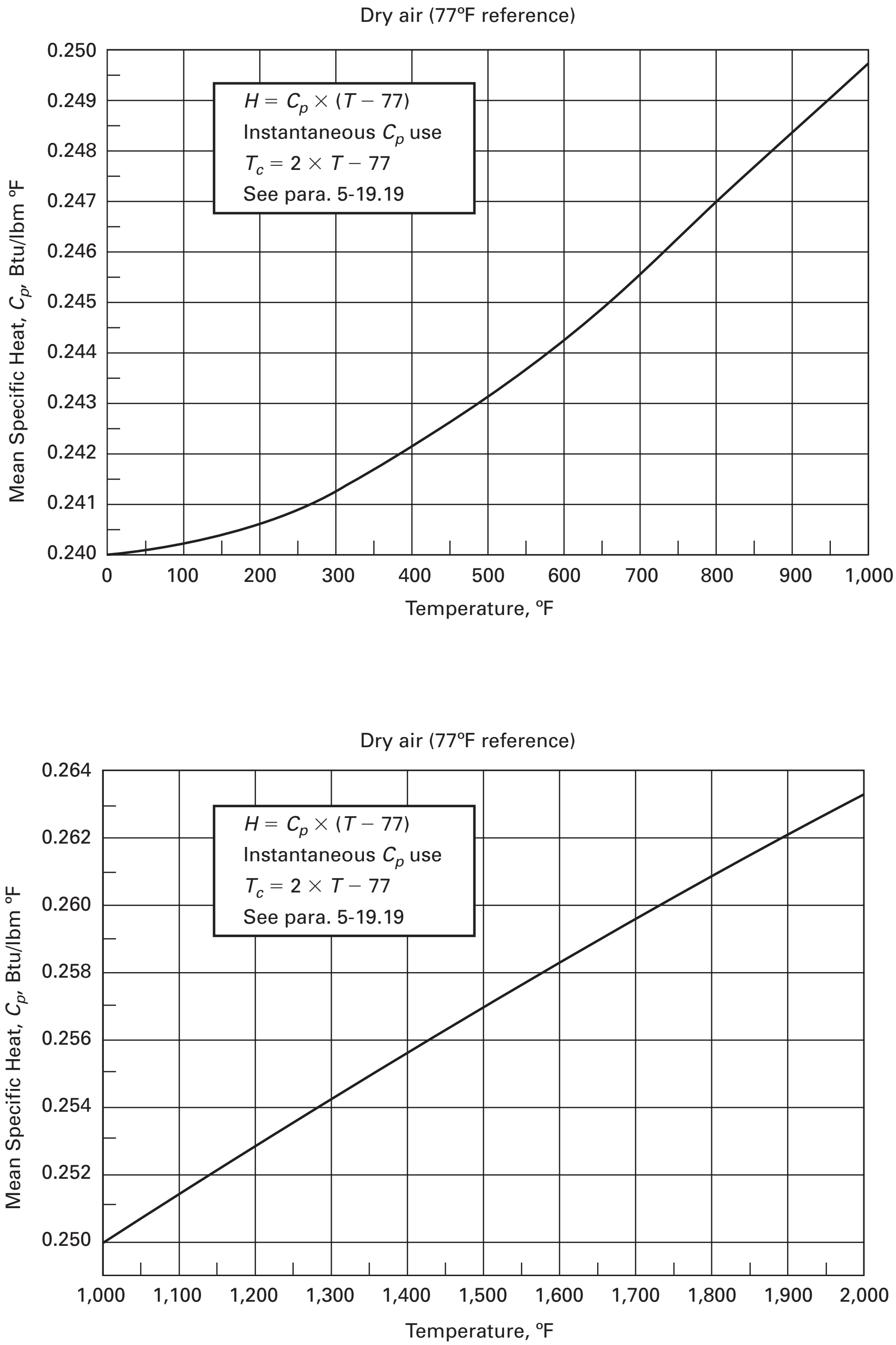
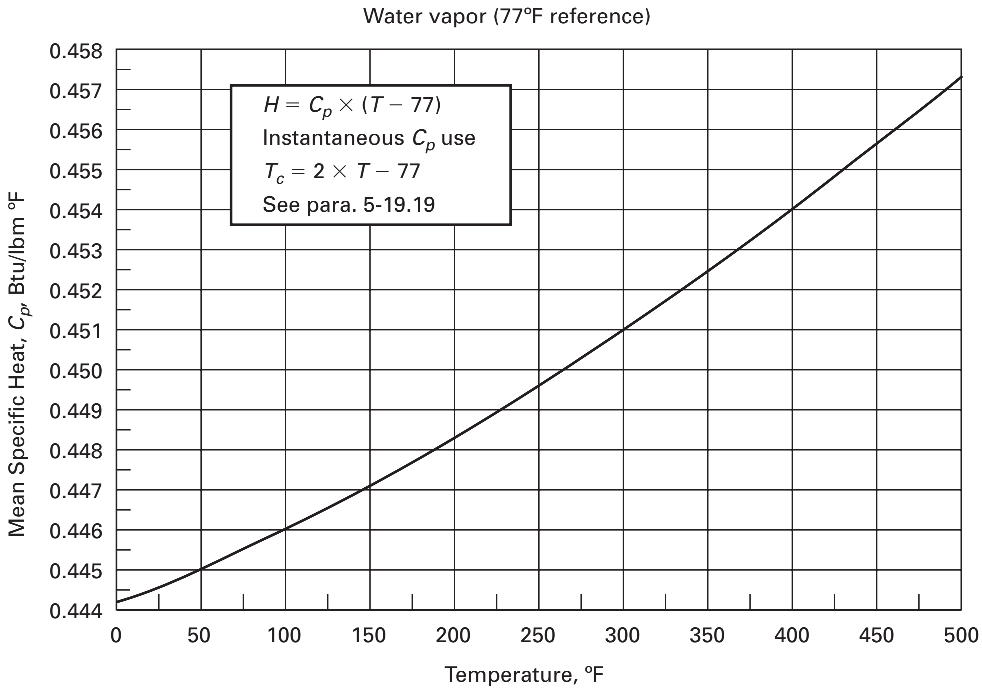


Fig. 5-19.12-2 Mean Specific Heat of Water Vapor Versus Temperature



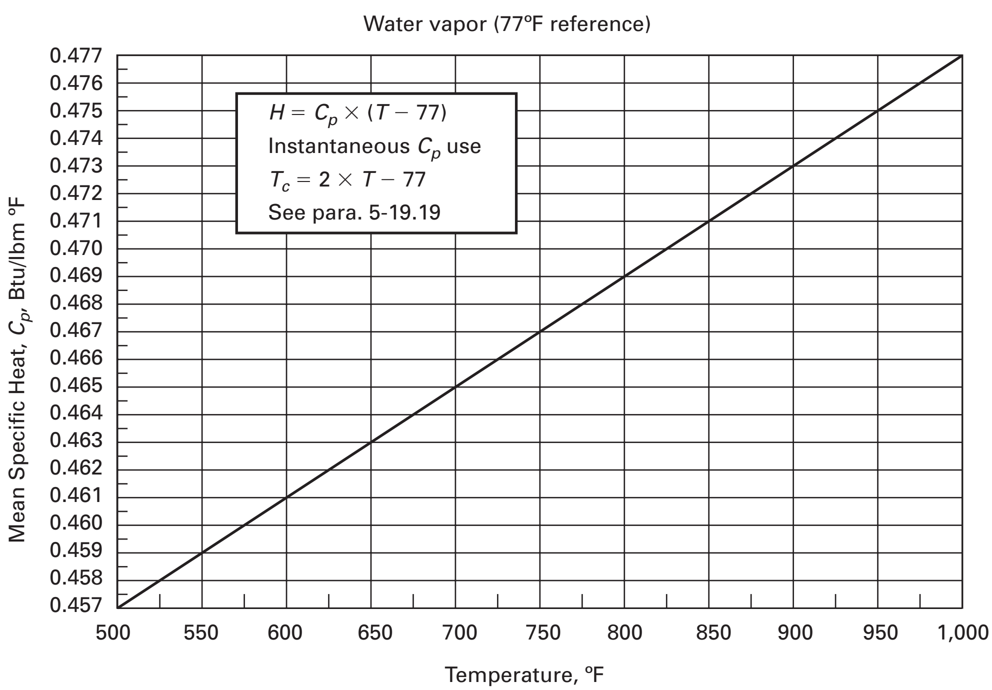
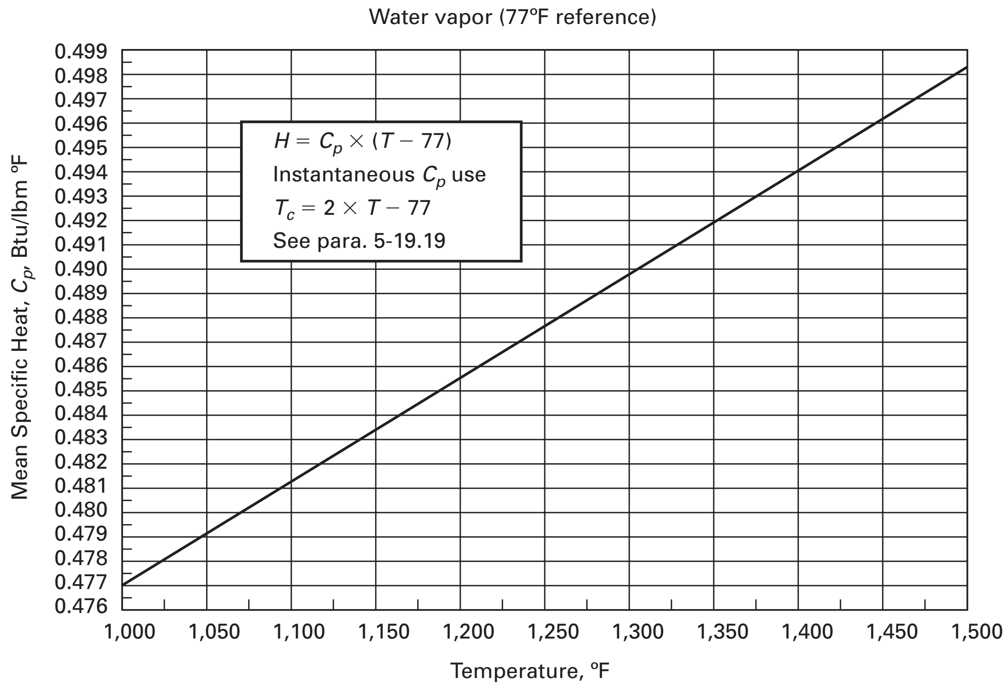


Fig. 5-19.12-2 Mean Specific Heat of Water Vapor Versus Temperature (Cont'd)



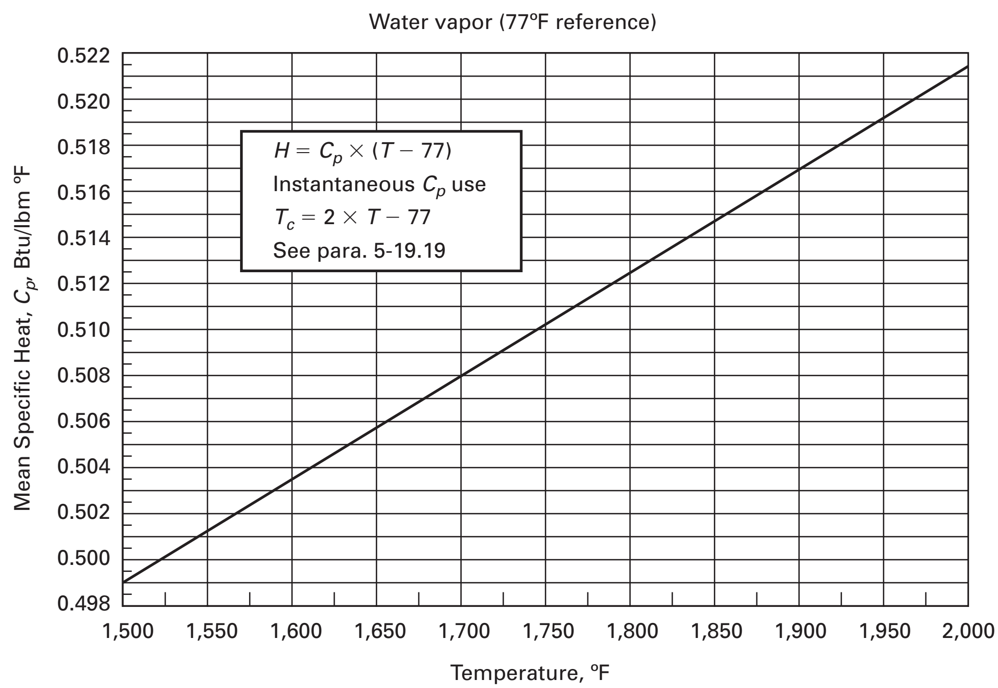
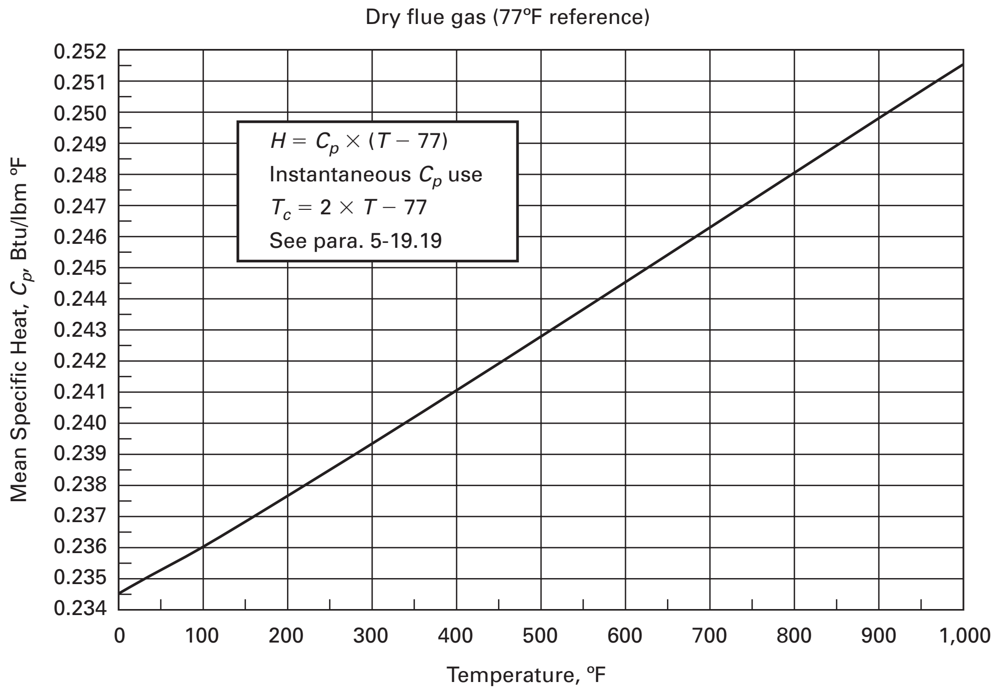


Fig. 5-19.12-3 Mean Specific Heat of Dry Flue Gas Versus Temperature



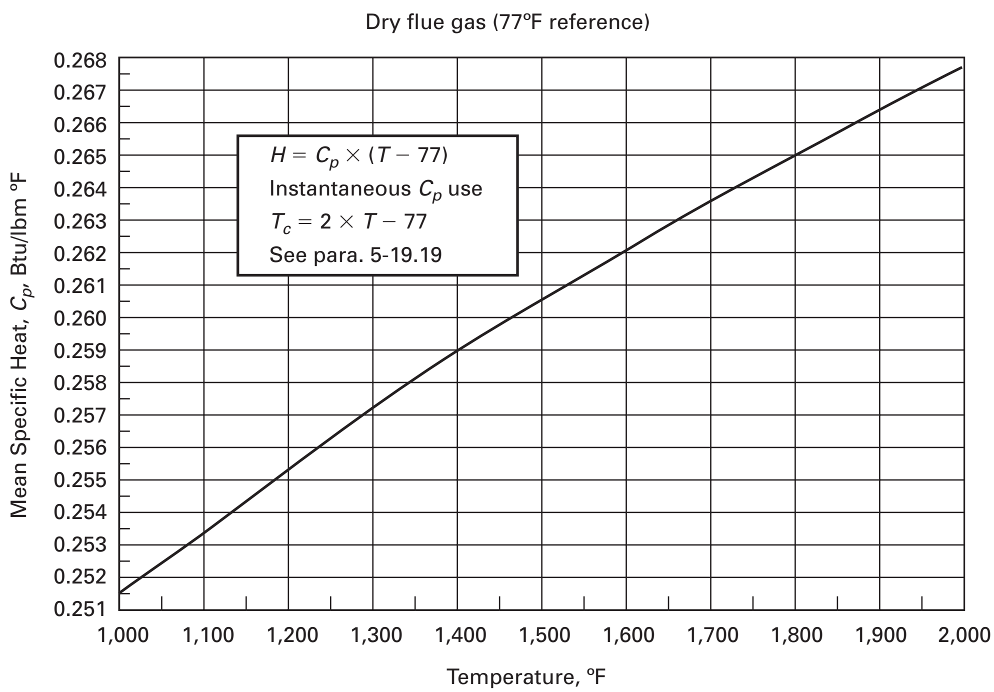
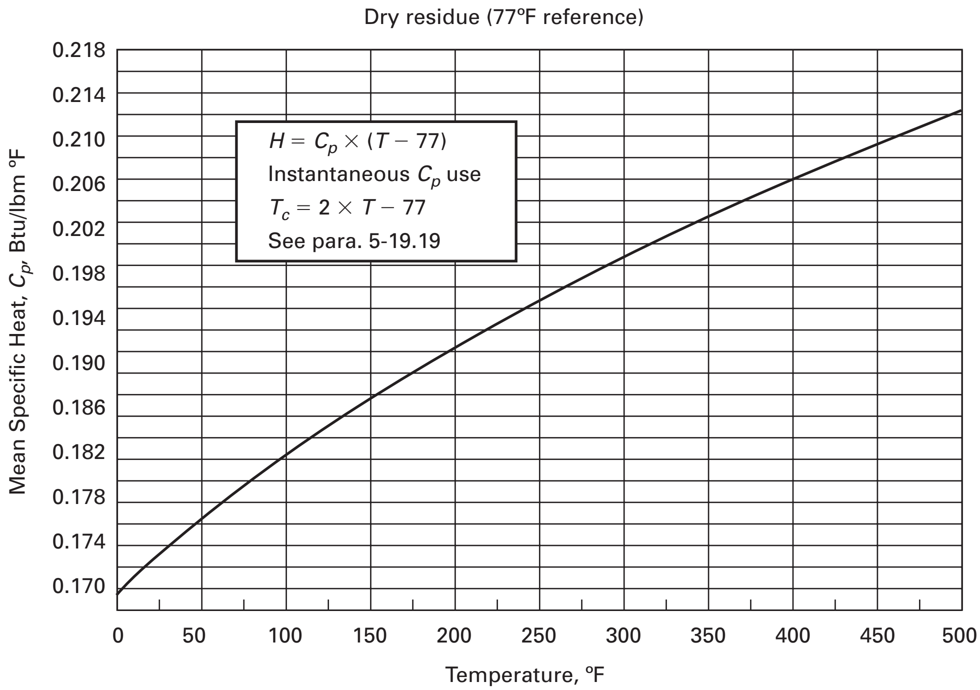


Fig. 5-19.12-4 Mean Specific Heat of Dry Residue Versus Temperature



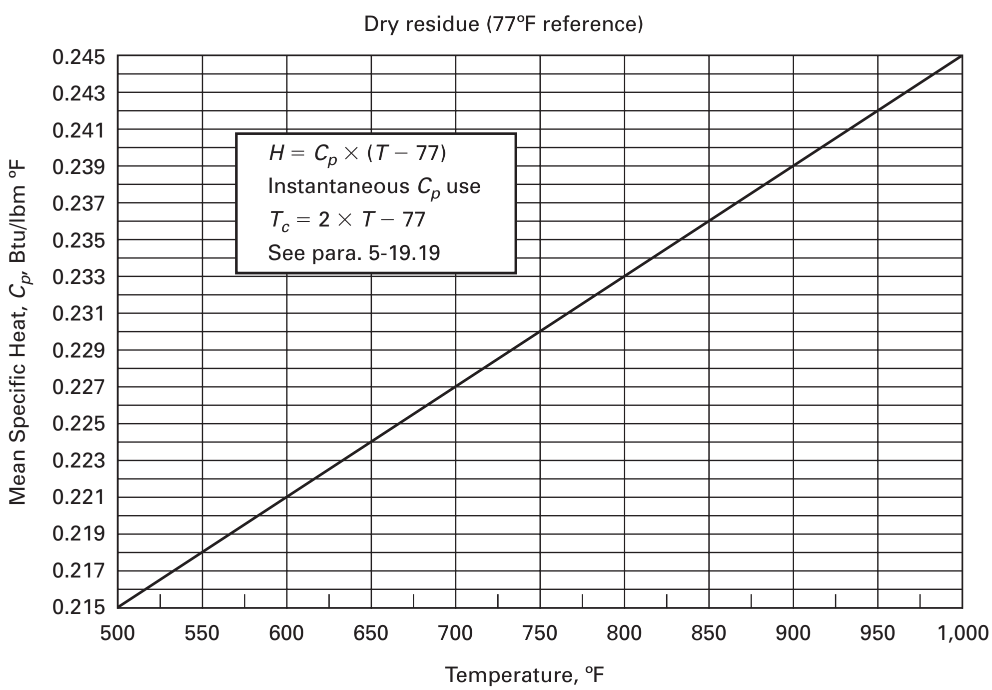
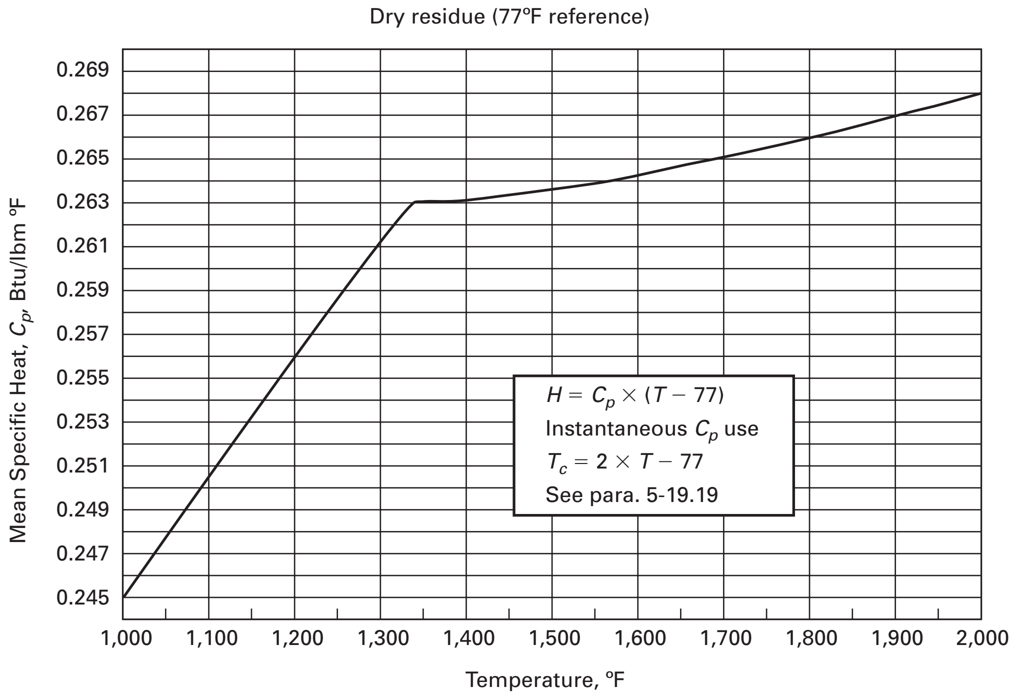


Fig. 5-19.12-4 Mean Specific Heat of Dry Residue Versus Temperature (Cont'd)



5-20 CALCULATION ACRONYMS

5-20.1 Basis for Section 5 Acronyms

The acronyms used throughout this Section (except for uncertainty) are built from symbols from the following groups and arranged in the following sequence:

PROPERTY → FUNCTION → (EQUIPMENT, STREAM, EFFICIENCY) → (LOCATION, COMPONENT, CONSTITUENT) → CORRECTION

5-20.1.1 Property Symbols

Af = flat projected surface area
Aid = area, inside dimension
Cp = mean specific heat at constant pressure
D = dry
Dn = density
H = enthalpy
Hca = convection heat transfer coefficient
HHV = higher heating value, mass basis
HHVcv = higher heating value, constant volume basis
HHVv = higher heating value, volume basis
Hra = radiation heat transfer coefficient
Hrca = combined radiation and convection heat transfer coefficient
Ht = height
Hw = insulation heat transfer coefficient
M = mass
Mo = mole
Mp = percent mass
Mq = mass per unit of energy
Mr = mass rate
Mv = mass volume
Mw = molecular weight
P = pressure
Pa = atmospheric pressure
Pp = partial pressure
Ps = saturation pressure
Q = energy
Qp = percent fuel input energy
Qr = heat transfer rate
R = universal gas constant
Ra = radiation
Rhm = relative humidity
Rq = required
Se = stack effect
Sg = specific gravity
T = temperature
Tdb = dry-bulb temperature
Thf = hot face temperature
Twb = wet-bulb temperature
V = velocity
Vh = velocity head
Vp = percent volume

5-20.1.2 Function Symbols

Ad = additional
Clc = calculated
Di = difference (delta)
Fr = fractional

Mn = mean
Ms = measured
Sm = sum

5-20.1.3 Equipment, Stream, and Efficiency Symbols

A = air
Ac = air preheater coil
Ah = air heater
Al = air leakage
Ap = ash pit
Aq = air quality control equipment
As = ash
B = credit
Bd = blowdown
C = carbon
Ca = calcium
Cb = carbon burned
Cbo = carbon burnout
Cc = calcium carbonate
Cf = coefficient
Ch = calcium hydroxide
Clh = calcination and/or dehydration
Cm = combustion
CO = carbon monoxide
CO2 = carbon dioxide
Coal = coal
Cw = cooling water
E = efficiency, percent
Ec = economizer
El = electrical
Ev = evaporation
F = fuel
Fc = fixed carbon
Fg = flue gas
Fo = fuel oil
G = gaseous fuel
Gr = gross
Hc = hydrocarbons, dry basis
I = input
In = inerts
L = loss
Lg = leakage
Mc = magnesium carbonate
Mh = magnesium hydroxide
N2 = nitrogen
N2a = atmospheric nitrogen
NOx = nitrous oxides
O = output
O2 = oxygen
Pc = products of combustion
Pcu = products of combustion uncorrected for sulfur capture
Pr = pulverizer rejects
Rh = reheat
Rs = residue
Ry = recycle
S = sulfur
Sb = sorbent
Sc = sulfur capture
Sh = superheat
Slf = sulfation
SO2 = sulfur dioxide
Src = surface radiation and convection
Ssb = spent sorbent
St = steam
Th = theoretical
To = total
Ub = unburned
W = water
Wv = water vapor
X = auxiliary
Xp = percent excess
Xr = X-ratio

5-20.1.4 Location, Area, Component, Constituent Symbols

Ds = design
En = inlet or entering
f = fuel, specific or related
j = fuel, sorbent component
k = fuel, sorbent constituent
Lv = outlet, exit, or leaving
Re = reference
z = location (Refer to Figs. 1-4-1 through 1-4-7 for specific locations.)

5-20.1.5 Correction Symbol

Cr = reading or computational correction

5-20.2 List of Acronyms Used

See Tables 5-20.2-1 and 5-20.2-2.

Table 5-20.2-1 Acronyms

Acronyms	Description	Units
Afz	Flat projected surface area for location *z*	ft^2 (m^2)
ApAf	Flat projected area of ash pit hopper opening	ft^2 (m^2)
API	Density of oil	Degrees API
DnA	Density of wet air	lbm/ft^3 (kg/m^3)
DnAFg	Density of wet air or flue gas	lbm/ft^3 (kg/m^3)
DnFg	Density of wet flue gas	lbm/ft^3 (kg/m^3)
DnGF	Density of gaseous fuel	lbm/ft^3 (kg/m^3)
DnSt	Density of steam/water	lbm/ft^3 (kg/m^3)
DVpCO	Percent CO in flue gas, dry basis	% volume
DVpCO2	Percent CO_2 in flue gas, dry basis	% volume
DVpHc	Percent hydrocarbons in flue gas, dry basis	% volume
DVpH2O	Percent H_2O in flue gas, dry basis	% volume
DVpN2a	Percent nitrogen (atmospheric) in flue gas, dry basis	% volume
DVpN2f	Percent nitrogen from fuel in flue gas, dry basis	% volume
DVpNOx	Percent NO_x in flue gas, dry basis	% volume
DVpO2	Percent O_2 in flue gas, dry basis	% volume
DVpSO2	Percent SO_2 in flue gas, dry basis	% volume
ECm	Combustion efficiency	%
EF	Fuel efficiency	%
EGr	Gross efficiency	%
EX	Combined efficiency of auxiliary drive, coupling, and gears	%
HA	Enthalpy of wet air	Btu/lbm (J/kg)
HAAqLv	Enthalpy of wet air at gas temperature leaving AQC device	Btu/lbm (J/kg)
HAEn	Enthalpy of wet air entering, general	Btu/lbm (J/kg)
HALgEn	Enthalpy of infiltrating wet air entering	Btu/lbm (J/kg)
HALvCr	Enthalpy of wet air at average gas temperature leaving envelope	Btu/lbm (J/kg)
HATFgLv	Enthalpy of air at the gas outlet temperature	Btu/lbm (J/kg)
Hcaz	Convection heat transfer coefficient for location *z*	Btu/ft^2·h·°F (J/m^2·s·°C)
Hcc	Enthalpy of calcium carbonate (limestone)	Btu/lbm (J/kg)
HCoal	Enthalpy of coal	Btu/lbm (J/kg)
HDA	Enthalpy of dry air	Btu/lbm (J/kg)
HDAEn	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)
HFc	Enthalpy of fixed carbon	Btu/lbm (J/kg)
HFEn	Enthalpy of the fuel at the temperature of fuel	Btu/lbm (J/kg)
HFg	Enthalpy of wet flue gas	Btu/lbm (J/kg)
HFgEn	Enthalpy of wet flue gas entering	Btu/lbm (J/kg)
HFgLv	Enthalpy of wet flue gas leaving	Btu/lbm (J/kg)
HFo	Enthalpy of fuel oil	Btu/lbm (J/kg)
HGF	Enthalpy of natural gas	Btu/lbm (J/kg)
HHVC	Higher heating value of carbon	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)
HHVGF	Higher heating value of gaseous fuel, volume basis	Btu/ft^3 (J/m^3)
HHVH2	Higher heating value of unburned hydrogen	Btu/lbm (J/kg)
HHVHc	Higher heating value of unburned hydrocarbons	Btu/lbm (J/kg)
HHVPr	Higher heating value of pulverizer rejects	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)
HMnA	Average enthalpy of wet air	Btu/lbm (J/kg)
HMnFg	Average enthalpy of wet gas	Btu/lbm (J/kg)

Table 5-20.2-1 Acronyms (Cont'd)

Acronyms	Description	Units
HMnFgLvCr	Average enthalpy of wet gas at *TMnLvCr*	Btu/lbm (J/kg)
HPr	Enthalpy of pulverizer rejects leaving pulverizer	Btu/lbm (J/kg)
Hraz	Radiation heat transfer coefficient for location *z*	Btu/ft^2·h·°F (J/m^2·s·°C)
HRe	Enthalpy at reference temperature	Btu/lbm (J/kg)
Hrk	Heat of reaction for constituent *k*	Btu/lbm (J/kg)
HrNOx	Heat of formation of NO (or N_2O)	Btu/lb mole (J/kg)
HRs	Enthalpy of residue	Btu/lbm (J/kg)
HRsEn	Enthalpy of residue entering	Btu/lbm (J/kg)
HrSlf	Heat generated due to sulfation	Btu/lbm (J/kg)
HRsLv	Enthalpy of residue leaving	Btu/lbm (J/kg)
HSb	Enthalpy of sorbent	Btu/lbm (J/kg)
HSbEn	Enthalpy of sorbent entering steam generator envelope	Btu/lbm (J/kg)
HStEnz	Enthalpy of additional moisture (steam) entering flue gas	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)
HStzDs	Enthalpy of steam at location *z*, design conditions	Btu/lbm (J/kg)
Ht	Height, elevation difference between pressure measurements	ft (m)
HVmi	Enthalpy of volatile matter, *i*, where *i* is 1 or 2	Btu/lbm (J/kg)
HW	Enthalpy of water (based on ASME Steam Tables)	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)
HWvEn	Enthalpy of water vapor at average entering air temperature	Btu/lbm (J/kg)
Hwz	Heat transfer coefficient for insulation and lagging	Btu/ft^2·h·°F (J/m^2·s·°C)
HWzDs	Enthalpy of water at location *z*, design conditions	Btu/lbm (J/kg)
MFrAsF	Mass fraction of ash in fuel	mass/mass fuel
MFrAz	Mass fraction of air at location *z* to total air	mass/mass
MFrClhk	Mass fraction of calcination or dehydration constituent *k*	mass CO_2/ mass const
MFrCO2Sb	Mass of gas (CO_2) from sorbent per mass fuel	mass/mass fuel
MFrFc	Mass fraction of fixed carbon	mass/mass fuel
MFrFgz	Mass fraction of wet gas at location *z*	mass/mass fuel
MFrH2OSb	Mass fraction of the water in sorbent	mass/mass sorbent
MFrInSb	Mass of inerts in sorbent per mass fuel	mass/mass fuel
MFrO3ACr	Mass fraction of O_3 from air required to form SO_3 in the sulfation process	mass/mass fuel
MFrRs	Total mass of residue per mass fuel	mass/mass fuel
MFrSb	Mass of sorbent per mass of fuel	mass/mass fuel
MFrSbk	Mass of reactive constituent *k* in sorbent	mass/mass sorbent
MFrSc	Sulfur capture ratio	lbm/lbm (kg/kg)
MFrSO3	Mass fraction of SO_3 formed in the sulfation	mass/mass fuel
MFrSsb	Mass of spent sorbent per mass fuel	mass/mass fuel
MFrStCr	Ratio of the design main steam flow divided by the test main steam flow	mass/mass
MFrThA	Theoretical air, ideal	mass/mass fuel
MFrThACr	Mass of theoretical air corrected per mass of fuel	mass/mass fuel
MFrVm	Mass fraction of volatile matter	mass/mass fuel
MFrVm1	Mass fraction of primary volatile matter	mass/mass fuel
MFrVm2	Mass fraction of secondary volatile matter	mass/mass fuel
MFrVmCr	Mass fraction of volatile matter, dry-ash free	mass/mass fuel
MFrWAdz	Additional water at location *z* per mass fuel	mass/mass fuel
MFrWDA	Mass fraction of moisture in dry air, mass H_2O/mass dry air	lbm/lbm (kg/kg)
MFrWF	Mass fraction of water in fuel	mass/mass fuel
MFrWRs	Mass fraction of water in dry residue	mass/mass residue
MFrWSb	Water from sorbent per mass fuel	mass/mass fuel
MnCpA	Mean specific heat of wet air	Btu/lbm °F (J/kg K)
MnCpDFg	Mean specific heat of dry flue gas	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)

Table 5-20.2-1 Acronyms (Cont'd)

Acronyms	Description	Units
MoCO2Sb	Moles of dry gas (CO_2) from sorbent per mass fuel	moles/mass fuel
MoDFg	Moles dry gas per mass fuel	mass/mass fuel
MoDPc	Moles dry products from fuel (CO_2, N_2F and actual SO_2 produced)	moles/mass fuel
MoDPcu	Moles dry products from fuel (CO_2, N_2F and total conversion of SO_2 in fuel)	moles/mass fuel
MoFg	Moles wet gas per mass fuel	moles/mass fuel
MoFrCaS	Calcium to sulfur molar ratio	moles/mole
MoFrClhCc	Calcination fraction of calcium carbonate	moles CO_2/mole $CaCO_3$
MoFrClhk	Calcination or dehydration fraction of constituent *k*	moles /mole const
Mokj	Moles of fuel constituent *k* in gaseous component *j*	moles/mass fuel
MoO3ACr	Dry gas flow correction for the O_3 in air required to form SO_3	moles/mass fuel
MoSO2	Maximum theoretical SO_2 per mass fuel	moles/mass fuel
MoThACr	Moles of theoretical air required (corrected)	moles/mass fuel
MoThAPcu	Theoretical air required for gasified fuel products	moles/mass fuel
MoWA	Moles of moisture in air	moles/mass air
MoWPc	*MoDPc* plus moles H_2O from fuel, sorbent and any additional moisture	moles/mass fuel
MoWPcu	*MoDPcu* plus moles H_2O from fuel, sorbent and any additional moisture	moles/mass fuel
MoWSb	Moles moisture in sorbent	moles/mass fuel
MpAhLg	Air heater leakage, percent of entering flue gas weight	% mass
MpAl	Air infiltration, percent theoretical air	% mass
MpAsF	Percent ash in fuel	% mass
MpCak	Percent of sorbent calcium in the form of constituent *k* (CO_3 or OH)	% mass
MpCb	Carbon burned	% mass
MpCbo	Percent carbon burnout	% mass
MpCF	Percent carbon in fuel	% mass
MpCO2Rs	Percent carbon dioxide in residue	% mass
MpCRs	Percent free carbon in residue	% mass
MpCRsDs	Percent free carbon in residue corrected to design conditions	% mass
MpFk	Percent fuel constituent *k*	% mass
MpH2b	Percent hydrogen burned	% mass
MpH2F	Percent hydrogen in fuel	% mass
MpInSb	Percent of sorbent inert material	% mass
MpN2F	Nitrogen in fuel	% mass
MpO2F	Oxygen in fuel	% mass
MpRsFgz	Solids in flue gas at location *z*, percent of wet gas	% mass
MpRsz	Mass of residue collected at location *z*	% mass
MpSbk	Percent of constituent *k* in sorbent	% mass
MpSF	Sulfur in fuel	% mass
MpToCRs	Total carbon content in residue sample, includes CO_2	% mass
MpUbC	Percent unburned carbon	% mass
MpUbH2	Percent unburned hydrogen	% mass
MpWF	Percent water in fuel	% mass
MpWFgz	Moisture in flue gas at location *z*, percent of wet flue gas	% mass
MqAl	Mass rate of wet infiltration air	lbm/Btu (kg/J)
MqAz	Mass wet air at location *z* on input from fuel basis	lbm/Btu (kg/J)
MqCO2Sb	Mass of dry gas (CO_2) from sorbent, input from fuel basis	lbm/Btu (kg/J)
MqDAz	Mass dry air at location *z* on input from fuel basis	lbm/Btu (kg/J)
MqDFgz	Mass dry gas at location *z* on input from fuel basis	lbm/Btu (kg/J)
MqFgEn	Mass wet flue gas entering on input from fuel basis	lbm/Btu (kg/J)
MqFgF	Wet gas from fuel	lbm/Btu (kg/J)
MqFgLv	Mass wet flue gas entering on input from fuel basis	lbm/Btu (kg/J)
MqFgz	Mass of wet gas at location *z*, input from fuel basis	lbm/Btu (kg/J)
Mqk	Mass of constituent *k* on input from fuel basis	lbm/Btu (kg/J)
MqNOx	Mass of NO_x in flue gas expressed on input from fuel basis	lbm/Btu (kg/J)
MqO3AC	Dry gas flow correction for the O_3 in air required to form SO_3	lbm/Btu (kg/J)

Table 5-20.2-1 Acronyms (Cont'd)

Acronyms	Description	Units
MqPr	Mass of pulverizer rejects on input from fuel basis	lbm/Btu (kg/J)
MqRsz	Mass of residue collected at location *z*	lbm/Btu (kg/J)
MqSb	Mass of sorbent on input from fuel basis	lbm/Btu (kg/J)
MqSbk	Mass of sorbent constituent *k*, input from fuel basis	lbm/Btu (kg/J)
MqThA	Theoretical air, ideal, on input from fuel basis	lbm/Btu (kg/J)
MqThACr	Theoretical air corrected on input from fuel basis	lbm/Btu (kg/J)
MqThAf	Typical value of theoretical air for fuel *f* (ideal)	lbm/Btu (kg/J)
MqWA	Water from moisture in air	lbm/Btu (kg/J)
MqWAdz	Additional water at location *z*, input from fuel basis	lbm/Btu (kg/J)
MqWF	Water from H_2O in fuel	lbm/Btu (kg/J)
MqWFgz	Total moisture in flue gas at location *z*	lbm/Btu (kg/J)
MqWH2F	Water from combustion of hydrogen in fuel	lbm/Btu (kg/J)
MqWSb	Water from sorbent on input from fuel basis	lbm/Btu (kg/J)
MqWvF	Water from H_2O vapor in fuel	lbm/Btu (kg/J)
MrAFg	Mass flow rate of air or flue gas, general	lbm/hr (kg/s)
MrAFgCr	Mass flow rate of air or flue gas, corrected for fuel and efficiency	lbm/hr (kg/s)
MrAz	Mass flow rate of wet air at location *z*	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)
MrF	Mass flow rate of fuel	lbm/hr (kg/s)
MrFgz	Mass flow rate of wet gas at location *z*	lbm/hr (kg/s)
MrPr	Mass flow rate of pulverizer rejects	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)
MrSb	Mass flow rate of sorbent	lbm/hr (kg/s)
MrStDs	Mass flow rate of steam, design value	lbm/hr (kg/s)
MrStEnz	Mass flow rate of additional moisture (steam) entering flue gas	lbm/hr (kg/s)
MrStX	Mass flow rate of auxiliary equipment steam	lbm/hr (kg/s)
MrStz	Mass flow rate of steam at location *z*	lbm/hr (kg/s)
MrStzDs	Mass flow rate of steam at location *z*, design value	lbm/hr (kg/s)
MrWSb	Mass flow rate water in sorbent	lbm/hr (kg/s)
MrWz	Mass flow rate water at location *z*	lbm/hr (kg/s)
MrWzCr	Mass flow rate of feedwater corrected	lbm/hr (kg/s)
MvFk	Mass fuel constituent *k* per mole gaseous fuel	mass/mole
MvRs	Mass per unit volume, used in dust loading	grains/ft^3 (g/m^3)
MwA	Molecular weight of wet air	mass/mole
MwCak	Molecular weight of sorbent calcium compound *k*	mass/mole
MwCc	Molecular weight of calcium carbonate	mass/mole
MwCo	Molecular weight of carbon monoxide, CO	mass/mole
MwCO2	Molecular weight of carbon dioxide, CO_2	mass/mole
MwDFg	Molecular weight of dry flue gas	mass/mole
MwFg	Molecular weight of wet flue gas	mass/mole
MwGF	Molecular weight of gaseous fuel	mass/mole
MwHc	Molecular weight of hydrocarbons	mass/mole
Mwk	Molecular weight of constituent *k*	mass/mole
MwNOx	Molecular weight of NO	mass/mole
MwO3	Molecular weight of O_3, 47.9982	mass/mole
MwS	Molecular weight of sulfur	mass/mole
Pa	Barometric pressure	psia (Pa)
Paz	Static pressure of air at point *z*	in. wg (Pa)
PDiAFg	Pressure differential, air (air resistance) or flue gas (draft loss)	in. wg (Pa)
PDiAFgCr	Pressure differential, air or flue gas corrected to contract	in. wg (Pa)
PFgk	Static pressure of flue gas at point *k*	in. wg (Pa)

Table 5-20.2-1 Acronyms (Cont'd)

Acronyms	Description	Units
PpWvA	Partial pressure of water vapor in air	psia (Pa)
PsWTdb	Saturation pressure of water vapor at dry-bulb temperature	psia (Pa)
PsWTwb	Saturation pressure of water vapor at wet-bulb temperature	psia (Pa)
PsWvTz	Saturation pressure of water vapor at temperature *T*	psia (Pa)
Qb	Energy balance closure	Btu/hr (W)
QEn	Energy entering the system	Btu/hr (W)
QLv	Energy leaving the system	Btu/hr (W)
QpB	Credits calculated on a % input from fuel basis, general	% fuel input
QpBDA	Credit due to energy in entering dry air	% fuel input
QpBF	Credit due to sensible heat in fuel	% fuel input
QpBk	Credit due to constituent *k*	% fuel input
QpBSlf	Credit due to sulfation	% fuel input
QpBWA	Credit due to moisture in entering air	% fuel input
QpL	Losses calculated on a % input from fuel basis, general	% fuel input
QpLALg	Loss due to air infiltration	% fuel input
QpLAq	Loss from hot air quality control equipment	% fuel input
QpLCO	Loss due to carbon monoxide (CO) in flue gas	% fuel input
QpLDFg	Loss due to dry gas	% fuel input
QpLH2F	Loss due to water formed from combustion of H_2 in fuel	% fuel input
QpLH2Rs	Loss due to unburned hydrogen in residue	% fuel input
QpLk	Loss due to constituent *k*	% fuel input
QpLNOx	Loss due to the formation of NO_x	% fuel input
QpLPr	Loss due to pulverizer rejects	% fuel input
QpLRs	Loss due to sensible heat of residue	% fuel input
QpLSmUb	Summation of losses due to unburned combustibles	% fuel input
QpLUbC	Loss due to unburned carbon in residue	% fuel input
QpLUbHc	Loss due to unburned hydrocarbons in flue gas	% fuel input
QpLWA	Loss due to moisture in air	% fuel input
QpLWF	Loss due to water in fuel	% fuel input
QpLWvF	Loss due to water vapor in gaseous fuel	% fuel input
QrAp	Equivalent heat flux through furnace hopper	Btu/hr (W)
QrApEv	Loss due to evaporation of ash pit water	Btu/hr (W)
QrApW	Energy increase in ash pit water	Btu/hr (W)
QrAxSt	Energy in auxiliary steam	Btu/hr (W)
QrB	Credits calculated on an energy basis, general	Btu/hr (W)
QrBd	Energy increase in output for blowdown water	Btu/hr (W)
QrBk	Credit due to constituent *k*	Btu/hr (W)
QrBSb	Credit due to sensible heat in sorbent	Btu/hr (W)
QrBWAd	Credit due to energy supplied by additional moisture	Btu/hr (W)
QrBX	Credit due to auxiliary equipment power	Btu/hr (W)
QrF	Potential energy of combustion available from fuel	Btu/hr (W)
QRh	Reheat absorption	Btu/hr (W)
QrI	Energy input (*QrF* for input from fuel)	Btu/hr (W)
QrIGr	Energy input gross, energy input from fuel plus credits	Btu/hr (W)
QrL	Losses calculated on an energy basis, general	Btu/hr (W)
QrLAc	Loss due to air preheater coil supplied from the steam generator	Btu/hr (W)
QrLAp	Total wet ash pit losses when tested	Btu/hr (W)
QrLClh	Loss due to calcination and dehydration of sorbent	Btu/hr (W)
QrLCw	Loss from cooling water	Btu/hr (W)
QrLk	Loss due to constituent *k*	Btu/hr (W)
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)
QrLWAd	Loss due to additional moisture	Btu/hr (W)

Table 5-20.2-1 Acronyms (Cont'd)

Acronyms	Description	Units
QrLWSb	Loss due to water in sorbent	Btu/hr (W)
QrO	Total heat output	Btu/hr (W)
QrRhCr	Corrected reheat absorption for contract conditions	Btu/hr (W)
QrRsWLv	Sensible heat in residue/water leaving the ash pit	Btu/hr (W)
QrShCr	Superheater absorption corrected for design conditions	Btu/hr (W)
QSh	Superheat absorption	Btu/hr (W)
QX	Energy input to auxiliary equipment drives	kWh (J)
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)
RqQrRhDs	Required reheater absorption, design	Btu/hr (W)
RqQrShDs	Required superheater absorption, design	Btu/hr (W)
Se	Stack effect	in. wg (Pa)
Sg	Specific gravity	mass/mass
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)
TAEn	Entering air temperature	°F (°C)
TAEnCr	Corrected entering air temperature	°F (°C)
TAfz	Average surface temperature of area *z*	°F (°C)
TAz	Temperature of wet air at location *z*	°F (°C)
Tc	Temperature on x-axis of enthalpy figures	°F (°C)
TDAz	Temperature of dry air at location *z*	°F (°C)
Tdb	Dry-bulb temperature	°F (°C)
TDi	Temperature difference	°F (°C)
TDiMrFgEn	Air heater temperature correction for entering gas mass flow	°F (°C)
TDiTAEn	Air heater temperature correction for entering air temperature	°F (°C)
TDiTFgEn	Air heater temperature correction for entering gas temperature	°F (°C)
TDiXr	Air heater temperature correction for off design X-ratio	°F (°C)
TFg	Temperature of flue gas	°F (°C)
TFgEn	Temperature of flue gas entering component	°F (°C)
TFgEnCrDs	Gas temperature entering air heater corrected to design conditions	°F (°C)
TFgLv	Temperature of flue gas leaving	°F (°C)
TFgLvCr	Corrected gas outlet temperature (excluding leakage)	°F (°C)
TFgLvCrDs	Exit gas temperature corrected to design conditions	°F (°C)
Thfz	Hot face (wall) temperature at location *z*	°F (°C)
TK	Temperature in K	K
Tkz	Temperature of constituent *k* at location *z*	°F (°C)
TLvk	Temperature of constituent *k* leaving the steam	°F (°C)
TMnADs	Design surrounding air temperature	°F (°C)
TMnAEn	Average entering air temperature	°F (°C)
TMnAfCrz	Average surface temperature corrected to design at location *z*	°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)
TStz	Temperature of steam at location *z*	°F (°C)
Twb	Wet-bulb temperature	°F (°C)
VAz	Average velocity of air	ft/sec (m/s)
VpCO2	Percent of CO_2 in flue gas, wet basis	% volume
VpCOz	Percent CO in flue gas at location *z*, wet basis	% volume
VpGj	Gaseous fuel component *j*	Btu/ft^2 (J/m^2)
VpH2O	Percent water in flue gas, wet basis	% volume

Table 5-20.2-1 Acronyms (Cont'd)

Acronyms	Description	Units
VpHc	Percent hydrocarbons in flue gas, wet basis	% volume
VpN2a	Percent N_2 (atmospheric) in flue gas, wet basis	% volume
VpN2f	Percent N_2 from fuel in flue gas, wet basis	% volume
VpNOx	Percent NO_x in flue gas, wet basis	% volume
VpO2	Percent of O_2 in flue gas, wet basis	% volume
VpSO2	Percent of SO_2 in flue gas, wet basis	% volume
XpAz	Percent excess air at location *z*	% mass

Table 5-20.2-2 Measurement and Uncertainty Acronyms

Acronyms	Description
ASENSCO	Absolute sensitivity coefficient
CHGPAR	Incremental change in value of measured parameter
DEGFREE	Number of degrees of freedom
F	Weighting factor
i	Measured parameter
m	Number of sets of data or grid points
n	Number of times parameter is measured
PARAVG	Average value of a parameter
PCHGPAR	Percent change in value of measured parameter
PSTDDEV	Population standard deviation
Pv	Velocity pressure measurement
RECALEF	Recalculated fuel efficiency
RSENSCO	Relative sensitivity coefficient
SDI	Spatial distribution index
STDDEV	Standard deviation of the sample
STDDEVMN	Standard deviation of the mean
STDTVAL	Two-tailed Student's *t* value
SYS	Systematic uncertainty
SYS_R	Overall systematic uncertainty
SYSNI	Systematic uncertainty for numerical integration
U	Integrated average value of measured parameter
$U_{p,q}$	Arithmetic (or velocity weighted if applicable) average value of each row, *p*, and column, *q*, measurement point
UNC	Total uncertainty
URC	Random component of uncertainty
V	Velocity
X_{AVG}	Arithmetic average value
Xi	Value of a measured parameter at time *i*
Z	Summation, integrated average value of *z*
z	Time averaged value of the measured parameter
ϕ	Pitch angle
ψ	Yaw angle

Section 6
Report of Test 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 to describe the test procedures and pertinent results. This Section presents guidance on both content and format of information typically included in this report.

6-2 REPORT CONTENTS

Although the materials prepared for the performance test reports may vary somewhat, the contents will typically be organized and include the information as described in paras. 6-2.1 through 6-2.11.

6-2.1 Title Page

The title page contains the title of the test, the name of the plant on which the test is being conducted and its location, the unit designation, the names of those who conducted the test and approved it, and the date the report was prepared.

6-2.2 Table of Contents

The table of contents lists major subdivisions of the reports to the third level, as well as titles of tables, figures, and appendices.

6-2.3 General Information

This portion of the report gives the reader information needed to understand the basis of the test and must include the following:

(a) title of test
(b) owner
(c) steam generator manufacturer
(d) steam generator size
(e) date of first commercial operation
(f) elevation of steam generator above mean sea level
(g) description of steam generator
(h) description of other auxiliary apparatus, the operation of which may influence the test results
(i) manufacturer's predicted performance data sheets
(j) contractual obligations and guaranteed performance data
(k) name of chief-of-test
(l) test personnel, their affiliations, and test responsibilities
(m) dates of test

6-2.4 Executive Summary

This Section briefly describes the objectives, results, and conclusions of the test and includes the signatures of the test director(s), reviewer(s) and approver(s).

6-2.5 Introduction

The introduction states the purpose of the test and relevant background information such as age, unusual operating characteristics, problems, etc., on the unit to be tested.

6-2.6 Objectives and Agreements

This Section addresses the objectives of the test, required test uncertainty, guarantees, operating conditions, and any other stipulations.

6-2.7 Test Descriptions and Procedures

This Section includes the following:

(a) a schematic of the steam generator system boundary showing the locations of all measured parameters
(b) a list of equipment and auxiliaries being tested, including nameplate data
(c) methods of measurement and a list and description of the test instruments identified in the system diagram
(d) a summary of key measurements and observations
(e) the magnitude of primary uncertainties in measurement and sampling
(f) correction factors to be applied because of deviations, if any, of test conditions from those specified
(g) the methods of calculation from observed data and calculation of probable uncertainty
(h) sample calculations are also presented

6-2.8 Results

Test results are presented computed on the basis of test operating conditions, instrument calibrations only having been applied, and as corrected to specified conditions if test operating conditions have deviated from those specified. Test uncertainty is also stated in the results. Tabular and graphical presentation of the test results is included.

6-2.9 Uncertainty Analysis

This Section provides sufficient detail to document the target uncertainty and demonstrate that the test has met this target.

6-2.10 Conclusions and Recommendations

This Section discusses the test, the test results, and conclusions. Conclusions directly relevant to the test objectives as well as other conclusions or recommendations drawn from the test are included.

6-2.11 Appendices

Test logs, test charts, data sheets, instrument calibration sheets and corrections curves, records of major fluctuations and observations, laboratory analyses, computations, computer printouts, and uncertainty analyses are among the kinds of materials that are included in the appendices.

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, which 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, Test Uncertainty.

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
S_X = sample standard deviation (S_X^2 is the sample variance)
$S_{\bar{X}}$ = standard deviation of the mean
SDI = spatial distribution index
T = temperature
t = Student's t statistic
U = uncertainty
u = any parameter
V = velocity
v = any parameter
w = any parameter
x = any parameter
y = any parameter
z = any parameter
$\delta()$ = small change of ()
${}_R\Theta_x$ = sensitivity coefficient for parameter x on result R (${}_R\Theta_x = \partial R/\partial x$)
ν = degrees of freedom
σ = population standard deviation (σ^2 is the population variance)
$\sum_b^a ()_i$ = sum of $()i$ from $i = b$ to $i = a$
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
x = pertaining to parameter x
w = weighted (average)

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 [1].

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 section 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:

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]

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.

The calculated average value of a parameter plus or minus the uncertainty thus 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 test[2] that uses a specific instrument system and data reduction and calculation procedures.

When the magnitude and sign of a systematic error is known, it must be handled as a correction to the measured value with the corrected value used to calculate test result. Systematic uncertainty estimates considered in uncertainty analysis attempt to cover those systematic errors whose magnitudes are unknown. Examples of systematic errors that are intended to be included in uncertainty analysis are drift in calibration of a flue gas analyzer, the systematic error resulting from using an uncalibrated flowmeter, the systematic error arising from the deteriorated condition of a previously calibrated flowmeter, errors resulting from calculation procedure approximations, and the potential errors made in estimating values for unmeasured parameters.

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 [2] or systematic uncertainty [3] 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).

[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

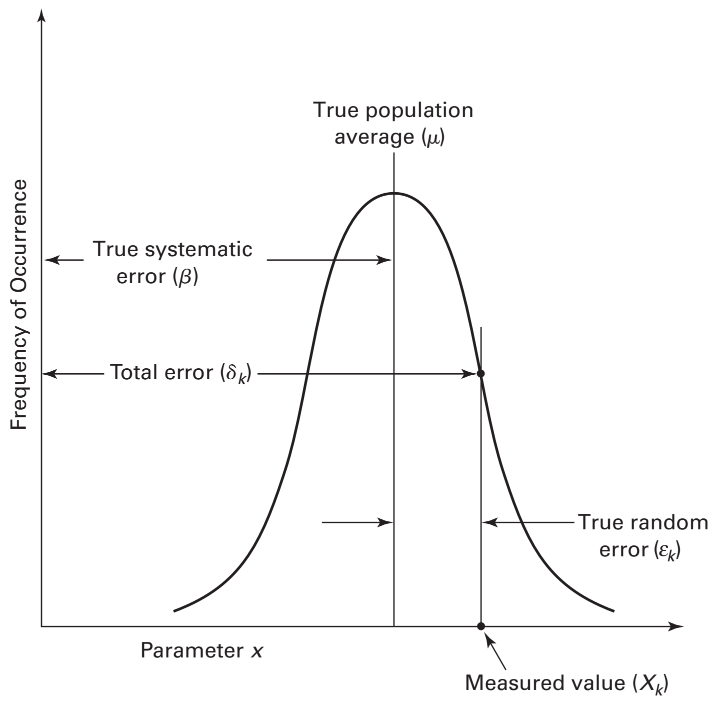
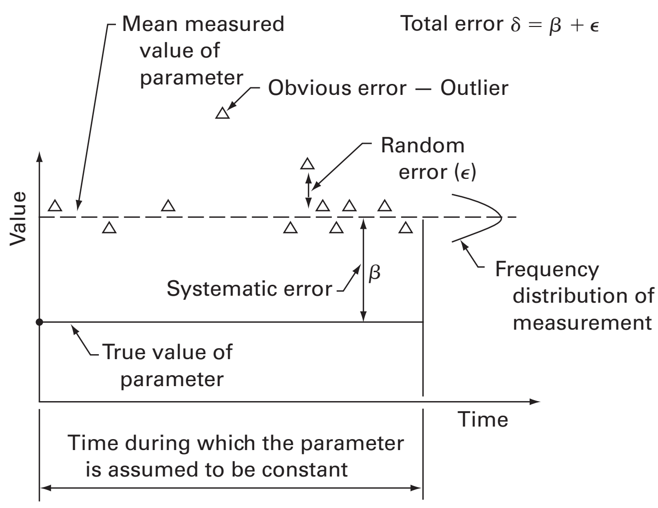


Fig. 7-2.2-2 Time Dependence of Errors



7-2.3 Averaging and Models for Variability

Instruments used in performance testing measure parameters such as temperature and concentration of 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, space, or both, and a continuous variable model, in which it is assumed that the parameter has some continuous variation in time, space, or both (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. Figure 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

$$\bar{x} = \frac{1}{N}\sum_{i=1}^{N} x_i \qquad (7\text{-}2\text{-}1)$$

and the population standard deviation of the mean or its estimate, the sample standard deviation of the mean

$$S_{\bar{X}} = \frac{\left[\frac{1}{N-1}\sum_{1}^{n}\left(x_i - \bar{x}\right)^2\right]^{1/2}}{N^{1/2}} \qquad (7\text{-}2\text{-}2)$$

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, instants of time, or both, 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. (7-2-1); however, the standard deviation is not calculated by eq. (7-2-2) 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. (7-2-1) 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
(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

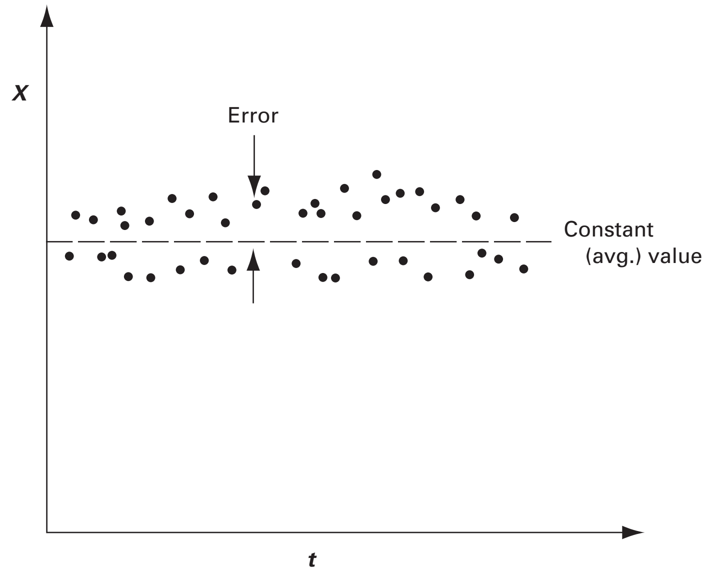
The working equations and procedures for calculating uncertainties for steam generator test results are given in subsections 7-4 through 7-6. This section gives an overview of the procedures and emphasizes certain critical concepts. An especially critical concept, the distinction between constant value 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].

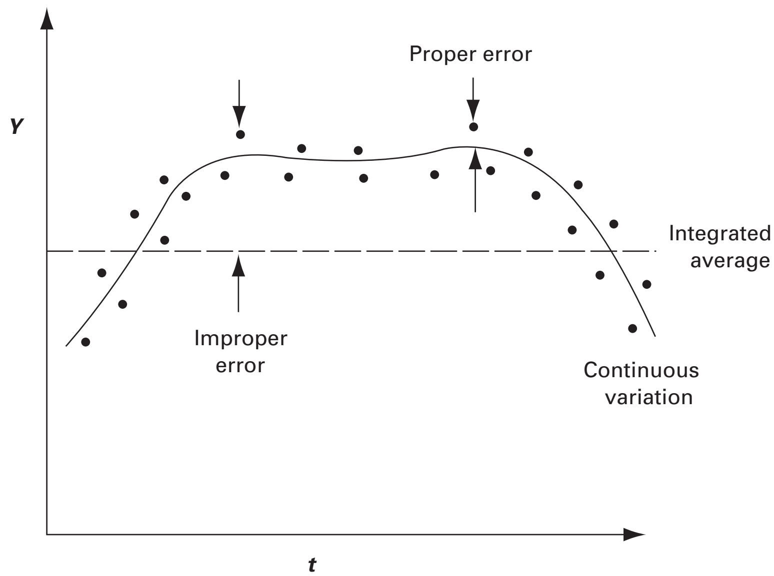
Analysis of random errors is based on the assumption that they follow a Gaussian (normal) probability distribution. One important result of this assumption is the root-sum-square method for combining errors due to individual sources.

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 [2].

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,

$$s_T = \left[\frac{1}{N-1} \sum_{i=1}^{N} (T - \bar{T})^2 \right]^{1/2} \qquad (7\text{-}2\text{-}3)$$

requires use of the calculated mean, $\bar{T}$, so the standard deviation has only 9 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

$$S_{\bar{T}} = \frac{S_T}{\sqrt{N}} = \left[\frac{1}{N(N-1)} \sum_{i=1}^{N} (T - \bar{T})^2 \right]^{1/2} \qquad (7\text{-}2\text{-}4)$$

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 statistical 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 estimators 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 to use "data" in a performance test that is based on estimates rather than on measurements. Likewise, it is sometimes more cost-effective to assign reasonable values to certain parameters rather than 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

$$R = f(x_1, x_2, ..., x_M)$$

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

$$e_R = \left[\left(\frac{\partial f}{\partial x_1} e_{x1} \right)^2 + \left(\frac{\partial f}{\partial x_2} e_{x2} \right)^2 + ... + \left(\frac{\partial f}{\partial x_m} e_{X_M} \right)^2 \right]^{1/2} \qquad (7\text{-}2\text{-}5)$$

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 [2,5].

The propagation equation can be written in the following dimensionless form:

$$\frac{e_R}{R} = \left[\sum_{i=1}^{M} \left[\left(\frac{x_i}{R} \frac{\partial f}{\partial x_i} \right) \left(\frac{e_{x_i}}{x_i} \right) \right]^2 \right]^{1/2} \qquad (7\text{-}2\text{-}6)$$

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 is often complicated, it is often impossible to analytically evaluate the required partial derivatives. These derivatives are usually estimated by a numerical perturbation technique.

$$\frac{\partial f}{\partial x_i} \approx \frac{f(x_1, \dots x_i + \delta x_i, \dots, x_M) - f(x_1, \dots, x_i, \dots, x_M)}{\delta x_i} \qquad (7\text{-}2\text{-}7)$$

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, a degrees of freedom for the result, R, is determined from the degrees of freedom for the systemic 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

$$u = 2\left[\left(\frac{B_R}{2} \right)^2 + \left(S_{\bar{R}} \right)^2 \right]^{1/2} \qquad (7\text{-}2\text{-}8)$$

where the "2" multiplier is the Student's t statistic and $\frac{B_R}{2}$ 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. (7-2-5).

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 upon 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 provides an excellent discussion of pretest uncertainty analysis and test planning [6].

7-4 EQUATIONS AND PROCEDURES FOR DETERMINING THE STANDARD DEVIATION FOR THE ESTIMATE OF RANDOM ERROR

This Section 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

$$\sigma_x^2 = \sigma_{xr}^2 + \sigma_I^2 \tag{7-4-1}$$

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 [7]. The instrumentation variance is often estimated from published data because testing of 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

$$S_x = \sqrt{\frac{s_x^2}{N}} \tag{7-4-2}$$

where

$$s_x^2 = \left(\frac{1}{N-1}\right)\sum_{i=1}^{N}(x_i - \bar{x})^2 \tag{7-4-3}$$

The number of degrees of freedom is

$$\nu_x = N - 1 \tag{7-4-4}$$

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

$$x_i = \frac{1}{N}\sum_{j=1}^{N}(x_j)_j \tag{7-4-5}$$

where
i = the point in the grid
N = the 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. (7-4-2) through (7-4-4).

The standard deviation of the integrated average parameter is

$$S_{\overline{X}} = \frac{1}{m}\left[\sum_{i=1}^{m}(S_{\overline{X}_i})^2\right]^{1/2} \tag{7-4-6}$$

The associated degrees of freedom is

$$\nu = \frac{S_{\overline{X}}^{\ 4}}{\displaystyle\sum_{i=1}^{m}\left[\frac{S_{\overline{X}_i}^{\ 4}}{(m^4\nu_i)}\right]} \tag{7-4-7}$$

where
m = the number of grid points
$S_{\overline{X}_i}$ = the standard deviation of the mean for the parameter at point i [from eq. (7-4-2)]
ν_i = the degrees of freedom of $S_{\overline{X}_i}$ which is the number of readings at point i minus 1

If less than six measurements from each grid point are collected during a test run such as when individual grid point measurements of O_2 and/or temperature are made using manual point-by-point traverses, the standard deviation of the integrated average parameter shall be determined by multiple measurements at a single representative point in the test plane. Plant station instrumentation may be used to determine the standard deviation of the integrated average parameter, provided that the instrumentation is in a representative location. Any dead bands or "exception reporting" that the plant's data collection/archiving system may use should be removed and/or reduced to the satisfaction of all parties to the test.

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 assure statistical significance. Generally, six or more readings are required. In this case, the standard deviation and degrees of freedom are calculated using eqs. (7-4-2) through (7-4-7), as appropriate, with the parameter $x_{j,i}$ being the weighted value. For temperature, for example,

$$x_{j,i} = \left(\frac{V_{j,i}}{\overline{V}}\right)T_{j,i} \tag{7-4-8}$$

where
$\overline{V}$ = 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.

$$x_j = \left(\frac{V_j}{\overline{V}}\right)T_j \tag{7-4-9}$$

The sample standard deviation for x is calculated from eq. (7-4-3).

(c) Velocity Measured Separately From the Parameter. The standard deviation of the mean for the weighted average parameter is

$$S_{\overline{P},FW} = \left[S^2_{\overline{P},UW} + (\overline{P}_{UW} - \overline{P}_W)^2\frac{S^2_{\overline{V}}}{\overline{V}^2}\right]^{1/2} \tag{7-4-10}$$

where
FW = the weighted average
P = the parameter (temperature or oxygen)
UW = the unweighted average

$S_{\overline{P},}$ is calculated as described in para. 7-4.1.2.

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. (7-4-2) and (7-4-4).

(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

$$S_{\overline{X}} = \frac{S_{X,H}}{\sqrt{N}} \tag{7-4-11}$$

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, seldom are the individual point samples 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 due to numerical integration by this Code.

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. (7-4-2) and (7-4-4) and the results for the mixed samples

[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.

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 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" formula, eq. (7-2-4), 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. The following describes 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 $z = a_0 + a_1\bar{x} + a_2\bar{x}^2 + \ldots + a_n\bar{x}^n$. Equation (7-2-4) is applicable to functions of one variable; in this case the variable is $\bar{x}$. The sensitivity coefficient for $\bar{x}$ is

$$_z\Theta_x = \frac{\partial z}{\partial x} = a_1 + 2a_2\bar{x} + \ldots + na_n\bar{x}^{n-1} \qquad (7\text{-}4\text{-}12)$$

The standard deviation of the mean is

$$S_{\bar{Z}} = (_z\Theta_x)(S_{\bar{X}}^2) \qquad (7\text{-}4\text{-}13)$$

The degrees of freedom for z is the same as for 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), average the values of the intermediate result, and calculate their 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" formula.

The sensitivity coefficients are

$$(_z\Theta_u) = C\bar{v} \quad and \quad (_z\Theta_v) = C\bar{u} \qquad (7\text{-}4\text{-}14)$$

The standard deviation is

$$S_{\bar{Z}} = [(C\bar{v}S_{\bar{u}})^2 + (C\bar{u}S_{\bar{v}})^2]^{1/2} \qquad (7\text{-}4\text{-}15)$$

The degrees of freedom is

$$\nu = \frac{\left(\dfrac{S_{\bar{Z}}}{C}\right)^4}{\bar{v}^4\dfrac{S_{\bar{u}}^4}{\nu_u} + \bar{u}^4\dfrac{S_{\bar{v}}^4}{\nu_v}} \qquad (7\text{-}4\text{-}16)$$

7-4.2.4 Flow Rates Using Weigh Bins or Tanks. Weigh bins or tanks are used as integrating devices to 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 weight and time readings are taken at the beginning and the end of the test period, the average flow rate, w, is

$$w = \frac{u_2 - u_1}{\tau_2 - \tau_1} \qquad (7\text{-}4\text{-}17)$$

where

u_1, u_2 = the initial and final weight readings, respectively
τ_1, τ_2 = the 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

$$S_{\bar{W}} = \left\{ 2\left[\left(\frac{w}{u_2 - u_1}\right)^2 \sigma_{ul}^2 + \left(\frac{w}{\tau_2 - \tau_1}\right)^2 \sigma_{\tau l}^2 \right] \right\}^{1/2} \qquad (7\text{-}4\text{-}18)$$

[4] While it may be argued that the standard deviation and degrees of freedom are better than those calculated by eqs. (7-4-2) and (7-4-4) because of several points sampled, it is impossible to determine these better values after samples are mixed.

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.

$$S_{\overline{R}} = \left[\sum_{i=1}^{k} ({}_R\Theta_{x_i}\ S_{\overline{X}_i})^2 \right]^{1/2} \tag{7-4-19}$$

where

${}_R\Theta_{x_i}$ = $(\partial R / \partial x_i)$ = the sensitivity coefficient of parameter x_i on result R and k is 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

$$\nu_{S_R} = \frac{S_{\overline{R}}^4}{\sum_{i=1}^{k} \frac{\left({}_R\Theta_{x_i} S_{\overline{x}_i}\right)^4}{\nu_{x_i}}} \tag{7-4-20}$$

7-4.3.3 Sensitivity Coefficients. The sensitivity coefficients are the partial derivatives of the result with respect to the parameter

$$(\Theta_{x_i}) = \left(\frac{\partial R}{\partial x_i} \right)_{xi = \overline{x}} \tag{7-4-21}$$

in accordance with eq. (7-2-4).

Sometimes, it may be more convenient to work with a relative sensitivity coefficient, which is calculated by

$$({}_R\Theta_{x_i'}) = \left(\frac{\overline{x}_i}{R} \right) (\Theta_{x_i}) \tag{7-4-22}$$

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 $x_1, ..., x_k$, 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

$$({}_R\Theta_{x_i}) = \left(\frac{\partial R}{\partial x_i} \right) \approx \frac{\delta R}{\delta x_i} \tag{7-4-23}$$

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 a 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 Section gives certain mandatory rules for making estimates of the systematic error and for mathematical manipulation of them. These estimates are called "systematic uncertainty." This Section 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 Section, provided that the parties to the test agree to do so and that they agree on an appropriate substitute.

7-5.1 General Rules

Systematic uncertainties used in this Code have the following characteristics:

(a) Systematic uncertainties shall be agreed upon by the parties to the test.

(b) Systematic uncertainties should be estimated at a 95% confidence level; the maximum conceivable values of systematic uncertainty should not be used.

(c) Systematic uncertainty estimates may be one-sided or nonsymmetrical if the physical process so suggests

and the parties to the test agree that such estimates are the best available. 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. This shall be permitted if both parties to the test agree.

7-5.2 Systematic Uncertainties in Measured Parameters Due to Instrumentation

Many sources of instrumentation systematic uncertainty that can occur in any measurement include primary element, primary sensor, transducer, amplifier, analog/digital converter, recording device, and environmental effects. ISA Standard ANSI/ISA S51.1 may be consulted for general information about instrumentation systematic uncertainty [7].

Section 4 gives guidance for estimating systematic uncertainties due to specific instrumentation systems. This Section 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 many ways: 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

$$B = (B_1^2 + B_2^2 + \ldots + B_m^2)^{1/2} \qquad (7\text{-}5\text{-}1)$$

where subscripts $1, 2 \ldots m$ 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.

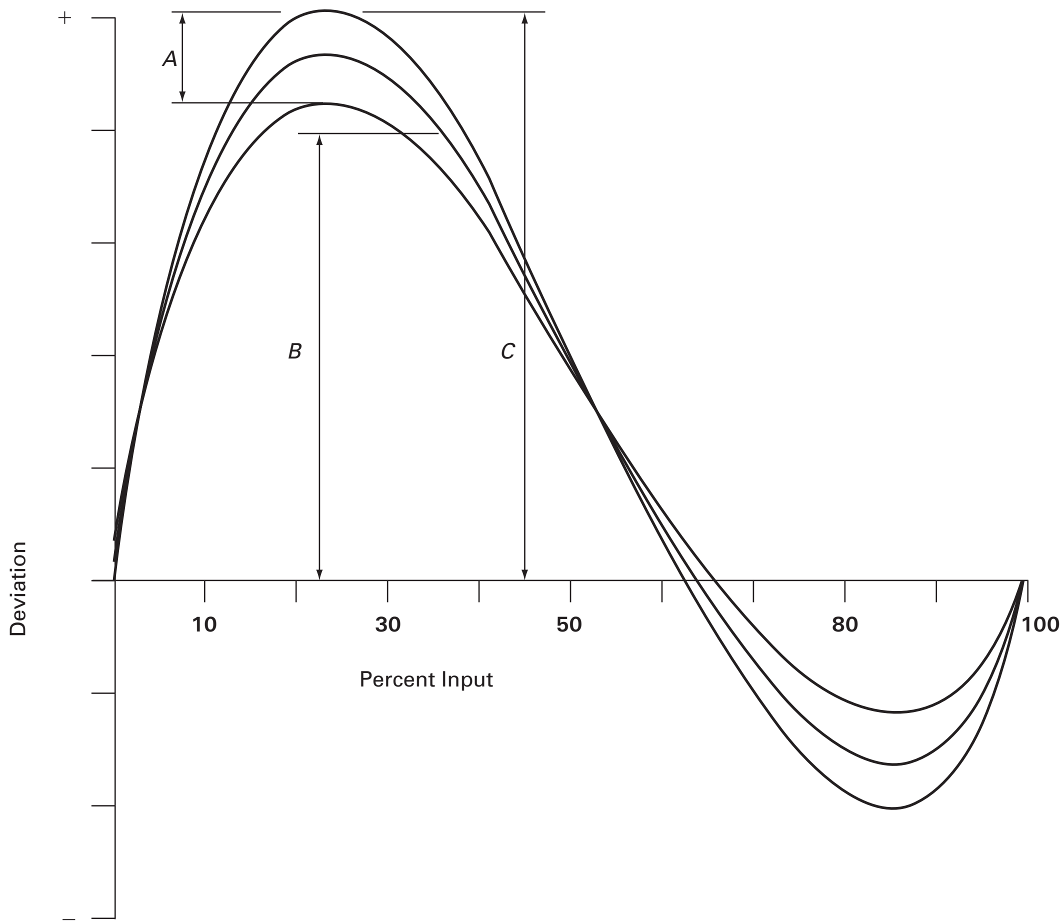
7-5.2.3 Multiple Measurements With a Single Instrument. For multiple measurements at a single location with a single instrument (such as measuring the temperature at several points in a flue gas duct cross section with the same thermocouple system), the instrumentation systematic uncertainty of the average value of the parameter is equal to the instrumentation systematic uncertainty of a single measurement.

$$B_{\bar{x}} = B_{x_i} \qquad (7\text{-}5\text{-}2)$$

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.

Fig. 7-5.2.1-1 Generic Calibration Curve



$$B_{\bar{x}} = B_{x_i} \text{ (any } i\text{)} \tag{7-5-3A}$$

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.

$$B_{\bar{x}} = \frac{1}{N}\sum_{i=1}^{N} B_{x_i} \tag{7-5-3B}$$

where

B_{xi} = the systematic uncertainty of a single instrument loop i

N = the 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 [8] (refer to paras. 4-3.4 and 7-2.3).

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 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 by agreement between parties to the test. 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*:

$$SDI = \left[\frac{1}{A} \int (z - \bar{z})^2 \, dA \right]^{1/2}$$

where

z = *time* averaged value of the continuously distributed parameter (temperature, oxygen content, etc.)

$\bar{z}$ = *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.

$$SDI = \left[\frac{1}{m} \sum_{i=1}^{m} (z_i - \bar{z})^2 \right]^{1/2} \qquad (7\text{-}5\text{-}4)$$

where

m = 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. (7-5-4) 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, the parties to the test may agree 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

$$B_n = \left[\frac{1.0}{(m-1)^{0.5}} \right] SDI \qquad (7\text{-}5\text{-}5)$$

where

m = the number of points in the measurement grid

The coefficient in eq. (7-5-5) 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 *first option*, where the velocity is measured simultaneously with the parameter being averaged, the flow weighting systematic uncertainty estimate is

$$B_{FW} = (\bar{P}_{UW} - \bar{P}_{FW}) \frac{B_v}{\bar{V}} \qquad (7\text{-}5\text{-}6)$$

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 *second option*, where the velocity is determined by preliminary traverse(s), the following is recommended:

$$B_{FW} = 2(\overline{P}_{UW} - \overline{P}_{FW})\frac{B_v}{\overline{V}} \qquad (7\text{-}5\text{-}7)$$

The terms in this equation have the same meaning as above.

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. Again, there are two options:

(a) there is no reliable velocity data, or

(b) preliminary velocity traverse data exist, but the parameters are nevertheless not flow weighted

For the *first option* where there is no reliable velocity data available, the systematic uncertainty for temperature is estimated as follows. First, a weighted average is estimated by

$$\overline{T}_{FW} = \frac{1}{m}\sum_{i=1}^{m}\frac{\theta_i}{\overline{\theta}}T_i \qquad (7\text{-}5\text{-}8)$$

where

m = number of points in the traverse plane

θ = absolute temperature ($\theta = T$°F + 459.7)

The systematic uncertainty estimate is

$$B_{T,FW} = 2(\overline{T}_{UW} - \overline{T}_{FW}) \qquad (7\text{-}5\text{-}9)$$

The systematic uncertainty for oxygen concentration is taken as the same percentage of the average value as the temperature systematic uncertainty

$$\frac{B_{O_2,FW}}{\overline{O}_2} = \frac{B_{T,FW}}{\overline{T}} \qquad (7\text{-}5\text{-}10)$$

For the *second option*, where preliminary velocity data is available, but not used to calculate a weighted average, the recommended systematic uncertainty model is

$$B_{FW} = P_{UW} - P_{FW} \qquad (7\text{-}5\text{-}11)$$

where the velocity data is 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

$$B_{IA} = (B_I^2 + B_n^2 + B_{FW}^2)^{1/2} \qquad (7\text{-}5\text{-}12)$$

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, of course, by judgment and agreed to by the parties to the test.

In some cases, unsymmetrical systematic uncertainties may be used if physical considerations imply it. For example, an ash split cannot be 10% ± 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 that 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 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:

$$\nu_B \approx \frac{1}{2}\left(\frac{\Delta B}{B}\right)^{-2} \qquad (7\text{-}5\text{-}13)$$

For example, if we think that there is as much as a ±10% uncertainty, ΔB, in our estimate of B, then the degrees of freedom for B would be 50. 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. (7-5-13), 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

$$B_R = \left[\sum_{i=1}^{k} ({}_R\Theta_{x_i} B_{x_i})^2 \right]^{1/2} \tag{7-5-14}$$

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. (7-5-15). Also, if unsymmetrical systematic uncertainties are present, the techniques in ASME PTC 19.1 should be used.

The degrees of freedom for B_R is determined as

$$\nu_{B_R} = \frac{(B_R)^4}{\sum_{i=1}^{k} \frac{({}_R\Theta_{xi} B_{xi})^4}{\nu_{B_{xi}}}} \tag{7-5-15}$$

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

$$U_R = t_{\nu,0.025} \left[\left(\frac{B_R}{2} \right)^2 + S_{\bar{R}}^2 \right]^{1/2} \tag{7-6-1}$$

where

$t_{\nu,\,0.025}$ = the percentile point of Student's t distribution for $\nu = \nu_R$ degrees of freedom. A 95% confidence limit and is taken from Table 5-16.5-1 or eq. (5-16-7).

The degrees of freedom of the result, ν_R, is obtained from the expression

$$\nu_R = \frac{\left[\left(\frac{B_R}{2} \right)^2 + S_{\bar{R}}^2 \right]^2}{\frac{S_{\bar{R}}^4}{\nu_{S_R}} + \frac{\left(\frac{B_R}{2} \right)^4}{\nu_{B_R}}} \tag{7-6-2}$$

For most engineering applications, the value of ν_R will be relatively large (≥9) based on all of the error sources that influence it; therefore, for most applications the value of Student's t for the result can be taken as 2 for 95% confidence estimates, and the uncertainty in the result is determined as

$$U_R = 2 \left[\left(\frac{B_R}{2} \right)^2 + S_{\bar{R}}^2 \right]^{1/2} \tag{7-6-3}$$

or

$$U_R = \left[B_R^2 + (2S_{\bar{R}})^2 \right]^{1/2} \tag{7-6-4}$$

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 ν_R was taken as a large value so that Student's t is approximately 2.

NONMANDATORY APPENDIX A
CALCULATION FORMS

A-1 INTRODUCTION

Calculation forms are provided at the end of this Appendix to aid the user in performing calculations in a logical sequence. The forms also are an instructional aid. Even when a computer program is used, it is suggested that the first-time user perform a set of calculations by hand. Brief instructions have been prepared for each calculation form; these should be supplemented by Sections 4, 5, and 7 in the main text.

Due to the wide variety of the types of units and fuels addressed by this Code, calculation forms have been developed for several specific requirements for typical unit configurations. The purpose of each form is described briefly below.

(a) EFF — Efficiency Calculations. Used to calculate efficiency by the energy balance method. It is necessary that the combustion calculation forms be completed first.

(b) CMBSTN — Combustion Calculations. Used for the general combustion calculations such as excess air, dry gas weight, etc.

(c) GAS — Gaseous Fuels. Used to convert the ultimate analysis of gaseous fuels from a percent volume basis to a percent mass basis. All calculations requiring a fuel analysis are on a percent mass basis.

(d) RES — Unburned Carbon and Residue Calculations. Used to calculate the weighted average of carbon in the residue, unburned carbon, and sensible heat of residue loss. When sorbent is used, this form is used to calculate the weighted average of carbon and carbon dioxide in the residue. These results are used in conjunction with the sorbent calculation forms to calculate unburned carbon and calcination fraction of calcium carbonate.

(e) SRB — Sorbent Calculation Sheet, Measured C and CO_2 in Residue. Used in conjunction with the unburned carbon and residue calculation form to calculate unburned carbon in the residue and calcination. Percent sulfur capture, calcium-to-sulfur molar ratio, and losses and credits associated with sorbent and sulfur capture are also calculated.

(f) OUTPUT — Output Calculation Form. Used to calculate unit output. Provision is made for calculating superheater spray water flow by energy balance. For units with reheat, calculation of feedwater heater steam extraction flow, cold reheat flow, and reheat absorption are provided for.

(g) MEAS — Measured Data Reduction Worksheet. Used to calculate the average value and standard deviation for spatially uniform parameters with respect to time. Conversion from instrument output units (mv, ma, etc.) to English units and calibration correction factors are also performed on this form. Refer to the INTAVG Uncertainty Worksheet for spatially nonuniform parameters.

(h) SYSUNC — Systematic Uncertainty Data Reduction Worksheet. Used to account for and calculate the systematic uncertainty for each measurement device, including all the components of the measurement.

(i) UNCERTa — Uncertainty Worksheet No. 1. Contains the input information for data reduction and information required for determination of the random component of uncertainty. For spatially uniform parameters (i.e., parameters that vary with respect to time only), the Average Value, Standard Deviation, and number of readings are obtained from the MEAS Data Worksheets. The Total Positive and Negative Systematic Uncertainty on both a percent Basis and Unit of Measure Basis are obtained from the SYSUNC Worksheets. For spatially nonuniform parameters, the Average Value, Standard Deviation, Total Positive and Negative Systematic Uncertainty, and the number of readings are obtained from the INTAVG Worksheets.

(j) UNCERTb — Uncertainty Worksheet No. 2. Contains the information required to calculate total uncertainty. As indicated by items 10 and 20, the attached worksheet is set up for calculating the uncertainty of efficiency; however, this sheet can be used for any calculated item such as output, fuel flow, unburned carbon loss, calcium/sulfur ratio, etc.

(k) INTAVG — Uncertainty Worksheet Integrated Average Value Parameters. This worksheet contains the input information required for data reduction and determination of the random and systematic components of uncertainty for spatially nonuniform parameters (i.e., any parameter that varies with both space and time, such as flue gas temperature in a large duct cross section). The worksheet includes the calculation of the systematic uncertainty attributable to the integrated average of nonuniform parameters and flow weighting (estimated). For simplification of entering the results on the UNCERTa form, the sample standard deviation is calculated from the standard deviation of the mean and the degrees of freedom is converted to the number of readings.

A-2 SYSTEM OF UNITS

Fuel efficiency is a function of the percent input from fuel. Therefore, calculations that are related to the fuel, such as airflow, use units of lbm/lbm of fuel or lbm/Btu input from fuel. The latter is a convenient system of units because, in effect, it is a normalized result. For example, 10% ash in the fuel has a meaning only when fuels with similar higher heating values (HHV) are compared. If the HHV of a fuel is 10,000 Btu/lbm fuel, 10% ash would be 10 lbm/million Btu. For a 5,000 Btu/lbm fuel, 10% ash would be 20 lbm/million Btu, or twice as much actual ash as the higher Btu fuel.

In the interest of space on the forms and convenient numbers to work with, the units used on the forms are abbreviated and are some multiple of the basic mass/mass or mass/unit of heat input. Some of the more frequently used abbreviations are described below.

(a) lbm/lbm. Pound mass of one constituent per pound mass of another constituent or total. For example, lbm ash/lbm fuel is the mass fraction of ash in the fuel.

(b) lb/100 lb. Pound mass of one constituent per 100 lb mass of another constituent or total. For example, lbm ash/100 lbm fuel is the same as percent ash in fuel.

(c) lb/10 KBtu. Pound mass per 10,000 Btu input from fuel. These are convenient units to use for the combustion calculations.

(d) lb/10 KB. Abbreviation for lb/10 KBtu.

(e) Klb/hr. 1,000 pound mass per hour.

(f) MKBtu/hr. Million Btu/hr.

(g) MKB. Abbreviation for million Btu/hr.

A-3 ORDER OF CALCULATIONS

The calculation sequence is described below for three levels of complexity, depending upon fuel type. Prior to these calculations, the user will have to complete the following preliminary calculations:

(a) Average the data with respect to time, Form MEAS.

(b) Output. Calculate the boiler output for the test conditions, Form OUTPUT.

(c) Temperature Grids. Calculate the average gas and air temperatures for each of the air and gas temperature grids as described in subsection 5-17, Form INTAVG.

(d) Average Entering Air Temperature. If air enters the steam generator envelope at different temperatures, for example, primary and secondary air, calculate the weighted average entering the air temperature. Refer to subsection 5-13.

(e) Average Exit Gas Temperature (Excluding Leakage). If the gas temperature leaves the steam generator envelope at different temperatures, for example, units with primary and secondary air heaters, the weighted average exit gas temperature is required. Refer to subsection 5-13 and the input instructions for Form EFF. This item requires that the combustion calculations be completed first and is mentioned here only because it might require reiteration.

(f) Gaseous Fuels. Calculate the ultimate analysis and HHV on a percent mass basis.

(g) Estimate the Total Input From Fuel. The following calculations require an estimated fuel input. Refer to the input instructions for Form CMBSTN regarding estimating input. The estimated total input must be compared to the calculated result when the efficiency results are completed and the calculations reiterated if the difference is greater than 0.1%. Refer to para. 5-7.3.

(h) Multiple Fuels. Calculate a composite fuel analysis and weighted average HHV based on the percent mass flow rate of each fuel. Use the measured fuel flow for the fuel(s) with the lesser input and calculate the fuel flow for the fuel with the major input by the difference between the total input and the input from the measured fuel flow.

A-3.1 Order of Calculations for Low Ash Fuels (Oil and Gas)

Step 1: Complete the combustion calculation forms, CMBSTN.

Step 2: Complete the efficiency calculation forms, EFF.

Step 3: If the unit configuration or fuel required estimating total input as described in subsection A-3 above, repeat the calculations until convergence is obtained.

A-3.2 Order of Calculations for Fuels With Ash (Coal): No Sorbent

Step 1: Complete the residue calculation form, RES.

Step 2: Complete the combustion calculation forms, CMBSTN.

Step 3: Complete the efficiency calculation forms, EFF.

Step 4: If the unit configuration or fuel required estimating total input as described in subsection A-3 above, or the residue split was measured at some but not all locations as described for RES, repeat the calculations until convergence is obtained.

A-3.3 Order of Calculations When Sorbent Is Used

These instructions assume that the residue mass flow rate leaving the steam generator envelope is measured at some locations and calculated by difference for the unmeasured location. (Refer to instructions for RES.)

Step 1: Complete items 1 through 10, Form RES.

Step 2: Complete the calculations on Forms SRBa and SRBb. The calculations are iterative until convergence on unburned carbon and calcination is obtained.

Step 3: Repeat Steps 1 and 2 until convergence is obtained for the mass rate of residue.

Step 4: Complete the remaining items on Form RES.

Step 5: Complete the calculations on the combustion calculation forms, CMBSTN.

Step 6: Complete the efficiency calculations on forms EFF and SRBc.

Step 7: Compare the estimated fuel flow (input) to that calculated on EFFb, and repeat calculations in subsection A-3 (if applicable) and Steps 1 through 6 until convergence is obtained.

A-4 EFFICIENCY CALCULATIONS: INSTRUCTIONS FOR EFF FORMS

The efficiency calculation forms are used to calculate efficiency as tested as well as efficiency corrected to standard or contract conditions. The combustion calculation forms, CMBSTN, must be completed prior to performing the efficiency calculations. These instructions are intended as an aid to completing the calculation form. The user should refer to Section 5 for details regarding the definition and calculation of individual losses and credits.

A-4.1 Form EFFa

This Form contains the input data required for the efficiency calculations. Some efficiency calculations are performed on other calculation forms, if applicable, and so noted under the specific efficiency loss or credit items.

Items 1–6 *Temperatures, °F.* These items require that the user enter the temperature and determine an enthalpy for certain constituents. Calculation of enthalpy for wet air and wet flue gas requires data from the combustion calculation form, items 10 through 25 below. Refer to subsection 5-19 for calculation of enthalpies.

Item 1 *Reference Temperature.* The standard reference temperature for efficiency calculations in accordance with this Code is 77°F (25°C).

Item 2 *Average Entering Air Temperature.* Enter the average air temperature entering the steam generator envelope. Where more than one source of air, such as primary and secondary air, enter at different temperatures, the average entering air temperature is the weighted average of the different sources. Refer to items 35 through 44 below.

Item 3 *Average Exit Gas Temperature (Excluding Leakage).* Enter the average gas temperature leaving the steam generator envelope. When an air to gas heat exchanger is used and there is air leakage from the air to gas side of the air heater, this is the gas temperature corrected for leakage (gas temperature excluding leakage). When gas leaves the steam generator envelope at different temperatures, such as on a unit with primary and secondary air heaters, this is the weighted average of the gas temperature leaving each location (excluding leakage if leaving air heater). Refer to items 45 through 51 below.

Item 4 *Fuel Temperature.* Enter the temperature of the fuel entering the steam generator envelope. This item is required to calculate the enthalpy of fuel. For multiple fuel firing, calculate an average enthalpy based on the percent input of each fuel.

Items 5, 6 *Hot Air Quality Control Equipment.* These items refer to equipment such as hot precipitators where there is a combined efficiency loss due to surface radiation and convection, and air infiltration. If applicable, enter the gas temperature entering and leaving the equipment.

Items 10–25 *Results From Combustion Calculation Form CMBSTN.* These items are calculated on the combustion calculation forms and the item number from those forms is indicated in brackets.

Item 10 *Dry Gas Weight [77].* Enter the dry gas weight leaving the boiler, economizer, or entering the air heater (no hot AQC equipment). This is normally the boiler operating control point for excess air. This item is used to calculate the dry gas loss. The loss due to air infiltration beyond this point will be accounted for by either the air heater gas outlet temperature corrected for leakage, hot AQC equipment loss, or separately as an additional air infiltration loss. This should be a mass weighted value for units with separate air heaters.

Item 11 *Dry Air Weight ([69] + [45]).* Enter the gas from dry air weight, item 69 from Form CMBSTNc, plus the O3 (SO3) Corr, item 45 from Form CMBSTNb. These values should correspond to the same location as item 10 above. This should be a mass weighted value for units with separate air heaters.

Items 12–14 *Water From Fuel.* Enter results from the combustion calculation form as indicated.

Item 15 *Moisture in Air, lb/lb DA [7].* This item is required to calculate the enthalpy of wet air.

Item 16 *Moisture in Air, lb/10 KB [72].* Enter the moisture in air on an input from fuel basis corresponding to the same location as item 10 above.

Item 17 *Fuel Rate Est. Klb/hr [3].* Enter the estimated mass flow rate of fuel. Refer to item 4a on Form CMBSTNa.

Items 18, 19 Enter values as described.

Items 20–23 *Hot AQC Equipment.* Refer to items 5 and 6 for applicability. The letter "E" following the item number refers to entering the equipment, and "L" refers to leaving the equipment.

Item 25 *Excess Air Leaving Steam Generator, Percent.* Enter the calculated excess air leaving the steam generator and entering the air heater(s). This should be a mass weighted value for units with separate air heaters.

Item 30 *Unit Output, MKBtu/hr.* Enter the unit output in units of million Btu per hour.

Item 31 *Auxiliary Equipment Power, MKBtu/hr.* Enter the input to the steam generator envelope from auxiliary equipment in units of million Btu per hour. This item is the credit for energy supplied by auxiliary equipment power. If applicable, this item must be calculated and the result entered here. Refer to Section 5. Note that energy added to the envelope is credited; the power to the driving equipment must be reduced by the overall drive efficiency that includes the motor, coupling, and gear drive efficiency.

Items 32, 33 *Loss Due to Surface Radiation and Convection, Percent.* Items 33A through 33D. If not measured, use standard or design values.

The calculation of items 35 through 44 are required only when two or more air streams enter the unit at different temperatures. Units with separate primary and secondary air streams and pulverized-coal-fired units with atmospheric tempering air are examples of units that require these calculations.

Item 35A *Primary Air Temperature Entering, °F.* This is the temperature of the primary air as it enters the boundary and normally the same as item 16B on Form CMBSTNa.

Item 35B Calculate the enthalpy of wet air based on the moisture in air content indicated for Item 7, CMBSTNa.

Item 36A *Primary Air Temperature Leaving Air Heater, °F.* This item is required only when pulverizer tempering air calculations are required for pulverized-coal-fired units. Refer to item 38A.

Item 36B Calculate the enthalpy of wet air. Refer to item 35B.

Item 37A *Average Air Temperature Entering Pulverizers, °F.* This item is required only when pulverizer tempering air calculations are required for pulverized-coal-fired units. Refer to item 38A.

Item 37B Calculate the enthalpy of wet air. Refer to item 35B.

Item 38A *Average Pulverizer Tempering Air Temperature, °F.* This item is required to calculate pulverizer tempering airflow for pulverized-coal-fired units. When the pulverizer tempering air temperature is different from the entering primary air temperature, item 35A, it is necessary to calculate the pulverizer tempering airflow to obtain the average entering air temperature. The temperature of pulverizer tempering airflow may also be helpful in evaluating air heater performance.

Item 38B Calculate the enthalpy of wet air. Refer to item 35B.

Item 39 *Secondary Air Temperature Entering, °F.* Enter value from Form CMBSTNa item 16A.

Item 40 *Primary Airflow (Entering Pulverizer), klb/hr.* Enter the measured primary airflow. For pulverized-coal-fired units, this is the total airflow to the pulverizers, including tempering airflow.

Item 41 *Pulverizer Tempering Airflow, Klb/hr.* Calculate the pulverizer tempering airflow by energy balance as indicated. Note that the calculations assume that the measured primary airflow includes the tempering airflow.

Item 42 *Total Airflow, Klb/hr.* Enter the calculated value from Form CMBSTNc, item 96, based on the excess air leaving the pressure part boundary.

Item 43 *Secondary Airflow, Klb/hr.* Calculate the secondary airflow by difference.

Item 44 *Average Entering Air Temperature, °F.* Calculate the weighted average entering air temperature.

The calculation of items 45 through 51 are required only for units with separate primary and secondary air heaters.

Item 45A *Flue Gas Temperature Entering Primary Air Heater, °F.* Enter measured flue gas temperature from CMBSTNb item 50.

Item 45B Calculate the enthalpy of wet flue gas based on the flue gas moisture and solids content determined on Form CMBSTNc, items 78 and 81.

Item 46A *Flue Gas Temperature Leaving Primary Air Heater.* Enter calculated value excluding air heater leakage from Form CMBSTNc, item 88.

Item 46B Calculate the enthalpy of wet flue gas. Refer to item 45B.

Item 47 *Flue Gas Temperature Leaving Secondary Air Heater.* Enter calculated value excluding air heater leakage from Form CMBSTNc, item 88.

Item 48 *Total Gas Entering Air Heaters, klb/hr.* Enter calculated value from Form CMBSTNc, item 93.

Item 49 *Flue Gas Flow Entering Primary Air Heater, Klb/hr.* Calculate by energy balance as indicated.

Item 50 *Gas Flow Entering Secondary Air Heater.* Calculate by difference as indicated.

Item 51 *Average Exit Gas Temperature, °F.* Calculate the weighted average exit gas temperature.

The above calculations or item 51 must be iterated to determine the primary/secondary air split. An air split must initially be assumed and then recalculated until convergence occurs.

A-4.2 Form EFFb

Calculation of the major and most universally applicable losses and credits are provided for on this form. The losses and credits are separated into those that can be conveniently calculated on a percent input from fuel basis and those that can be calculated on a Btu/hr basis (units of million Btu per hr are used). The efficiency is then calculated directly in accordance with the equation for item 100. For losses or credits calculated on a percent input from fuel basis, enter the result in column B, percent. For losses or credits calculated on input basis, enter the results in column A, MKB (million Btu/hr). Upon completion of the input from fuel calculation, item 101, those items calculated on an input basis can be converted to a percent fuel efficiency basis by dividing the result by the input from fuel and multiplying by 100. Each section of losses and credits contains an item titled "Other," which refers to the results from Form EFFc.

The calculation of losses and credits is generally self-explanatory with the aid of the instructions for the input form, EFFa. Refer to Section 5 for definitions and explanations.

Item 75 *Surface Radiation and Convection Loss.* This is the one item on this form for which a complete calculation form has not been provided. Refer to items 33A through 33D from EFFa for required measured parameters. If a test has been performed, enter the test result. Refer to Section 5 for estimating a value to use for contract or reference conditions.

Item 100 *Fuel Efficiency, Percent.* Calculate fuel efficiency in accordance with the equation. This equation allows the direct computation of efficiency using losses and credits calculated in mixed units.

Item 101 *Input From Fuel, MKB.* Calculate the input from fuel in million Btu per hour in accordance with the equation.

Item 102 *Fuel Rate, Klbm/hr.* Calculate the mass flow rate of fuel based on the measured efficiency and measured output. For some units, an estimated mass flow rate of fuel (input) is required for the calculations. This item should be compared to item 17, and if the result is not within 0.1% (refer to subsection A-3 or para. 5-7.3 for convergence tolerance based on application), the CMBSTN (and applicable accompanying calculations) should be repeated until convergence is obtained. Examples of where fuel rate is required include, but are not necessarily limited to, the following:

(a) more than one source of entering air temperature, not all sources measured (use calculated total airflow to calculate weighted average)
(b) more than one source of exiting gas temperature, not all sources measured (use calculated total gas flow to calculate weighted average)
(c) residue mass flow rate measured at some locations and calculated result used to determine total
(d) sorbent used
(e) multiple fuel firing

A-4.3 Form EFFc

This Form provides for entering the results of losses and credits that are not universally applicable to all fossil-fired steam generators and are usually minor. Refer to Section 5 for the definition of the losses. For any unit to be tested, if the losses/credits are applicable, it should be indicated whether they were tested or estimated. The calculated or estimated result should be entered where appropriate. It is noted that it is not possible to identify all potential losses/credits in a changing technology. This Form should also be used to record the results of losses and credits that are not currently identified.

A-5 COMBUSTION CALCULATIONS: INSTRUCTIONS FOR CMBSTN FORMS

The combustion calculation forms are used to perform all combustion calculations. They are useful for normal power plant performance monitoring calculations and for efficiency calculations. Users will find this calculation form readily adaptable to a spreadsheet program as well as a subroutine(s) for a larger program.

The calculations on this form include the following:

(a) excess air for O_2, wet or dry basis.

(b) O_2, CO_2, and SO_2 on a wet or dry basis for excess air (commonly used for a stoichiometric check on orsat and/or analyzer results).

(c) conversion of O_2, CO_2, and SO_2 from a wet to dry or dry to wet basis.

(d) dry gas weight, used for efficiency calculations.

(e) wet gas weight, used for energy balance calculations.

(f) dry and/or wet air weight.

(g) determination of air infiltration.

(h) calculation of corrected air heater exit gas temperature (temperature excluding air heater leakage).

(i) percent moisture in flue gas, used for determining enthalpy of flue gas.

(j) percent residue in flue gas, used for determining of enthalpy of flue gas (high ash fuels or when sorbent is used).

(k) fuel, residue, flue gas, and air mass flow rate when input is known.

(l) fuel analysis check based on theoretical air. This is a check on whether the fuel analysis is reasonable. Refer to Section 5.

A-5.1 Form CMBSTNa

This Form contains most of the input required to complete the three combustion calculation forms. Some of the general input and impacting combustion/efficiency calculations required for other calculation forms is also contained here. Below are supplementary comments to assist the user. Refer to Section 5 of the Code if more in-depth explanation is required.

Item 1 — *HHV: Higher Heating Value of Fuel, Btu/lbm "As-Fired."* This item must be consistent with the fuel analysis in Item 30. When multiple fuels are fired simultaneously, this is the weighted average HHV based on percent mass flow rate from each fuel. (Refer to Section 5.)

Item 2 — *UBC: Unburned Carbon, lbm/100 lbm fuel From the RES or SRBb Form.* Also enter in item 30B.

For gaseous and liquid fuels, this item is normally zero. For solid fuels with ash and/or when sorbent is used, completion of the residue calculation form, RES, is required if UBC is tested.

For general combustion and excess air calculations, use a typical value for the type unit.

Item 3 — *Fuel Flow, Klbm/hr [4a] or [4b].* For some intermediate calculations (in particular when residue mass flow rates are measured and/or when sorbent is used), the calculations require a fuel flow. For the first interaction, the fuel flow is estimated. The calculations are reiterated using the calculated fuel flow until convergence is obtained.

For the first estimate, the user may use measured fuel flow [4a] or calculated fuel flow [4b] from measured output and estimated efficiency. If the operating characteristics of a unit are known, the calculated fuel flow based on an estimated fuel efficiency is usually better than the measured fuel flow.

Item 4a — *Measured Fuel Flow, Klbm/hr.* Refer to item 3.

Item 4b — *Calculated Fuel Flow, Klbm/hr.* Refer to item 3. Calculated result, Option 4b, and used for subsequent efficiency calculation iterations when fuel flow is required.

Item 5 — *Output, MKBtu/hr.* Required to calculate fuel flow, Option 4b, and used for subsequent efficiency calculation iterations when fuel flow is required.

Item 6 — *Fuel Efficiency, Percent (Estimate Initially).* Required to calculate fuel flow, Option 4b, and used for subsequent efficiency calculation iterations when fuel flow is required.

Item 7 — *Moisture in Air, lbm/lbm Dry Air.* This item is required for the general gas and air mass flow calculations and is required for excess air/O_2 calculations on a wet basis. Refer to items 8 through 11. If moisture in air is not measured, a standard value may be used. The standard U.S. industry value is 0.013 lbm H_2O/lbm dry air (80°F ambient and 60% relative humidity).

Items 8–11 — These items are required to calculate moisture in air. Moisture in air may be determined from relative humidity and dry-bulb temperature and/or wet- and dry-bulb temperature. Refer to Section 5 for calculation procedure.

Item 12 — *Summation Additional Moisture Measured, Klbm/hr.* Enter any moisture introduced into the air/flue gas in the spaces above. When steam soot blowers are used, enter the average value for the test period.

Item 13 — *Additional Moisture, lbm/100 lbm Fuel.* Convert the additional moisture to an lbm moisture per 100 lbm fuel basis. When atomizing steam is the only source of additional moisture, this value is frequently measured and/or agreed to prior to a test on a lbm H_2O/100 lbm fuel basis, in which case this agreed upon value would be entered here.

Item 14 — *Additional Moisture, lbm/10 KBtu.* Convert additional moisture above to lbm/10 KBtu basis.

Item 15 — *Gas Temperature Leaving Air Heater, °F, Primary/Secondary or Main.* This item is used for the calculation of gas temperature leaving the air heater(s) corrected for no leakage (excluding leakage). If there is no air heater, this item may be ignored. If applicable, enter the measured gas temperature (including leakage). Space is provided for two types of air heaters. Values for multiple air heaters of the same type are usually averaged for efficiency calculations but may be calculated individually for more detailed analysis of individual air heater performance and leakage and the results averaged later. Refer to items 45 through 51 on EFFa for separate air heaters with different flow rates.

Item 16 — *Air Temperature Entering Air Heater, °F, Primary/Secondary or Main.* See above for multiple air heaters. Enter air temperature entering each air heater compatible with format above.

Item 17 — *O_2 Entering Air Heater, Primary/Secondary or Main.* Enter the measured oxygen content entering each air heater.

Item 18 — *O_2 Leaving Air Heater, Primary/Secondary or Main.* Enter the measured oxygen content leaving each air heater.

Item 18D — If Trisector AH, enter the primary air-to-gas leakage as a percent of total air-to-gas leakage. This would normally be based on the manufacturer's data.

Fuel Analysis, Percent Mass As-Fired: Enter in Column [30]. This analysis must correspond to the HHV in item 1. For multiple fuel firing, this is the composite analysis. Refer to item 1.

Item 19 — *Mass Ash, lbm/10 KBtu.* The mass fraction of total residue is required at specific locations to determine the enthalpy of flue gas. For low ash fuels when sorbent is not used, the sensible heat of ash in flue gas can be ignored when the enthalpy of flue gas is determined.

If sorbent is not used and the result of the calculation for item 19 is less than 0.15 lbm/10 KBtu, enter zero for item 79 for each column where O_2 is entered.

If the result of item 19 is greater than 0.15 lbm/10 KBtu or sorbent is used, enter the mass fraction of residue in the flue gas with respect to the total residue leaving the steam generator envelope under item 79 for each column where O_2 is entered. This normally can be calculated from item 8 on the residue form (RES) depending upon whether sorbent is used. For example, if there is 75% residue leaving the air heater, enter 0.75 under item 79 for entering and leaving the air heater.

Items 20–25 — These items are applicable only if sorbent is used. Enter zero if not applicable. It is noted that any addition of solids other than fuel qualifies as sorbent for calculation purposes. If applicable, the residue (RES) and sorbent (SRB) calculation sheets must be completed and the results entered for these items.

A-5.2 Form CMBSTNb

Items 30–34 — Complete calculations as indicated. The term "K" refers to the constant in the column under the Item No. Refer to Section 5 for the significance of the individual columns. If the sorbent calculation forms (SRB) were used, items 31, 32, and 33 are the same as SRBa items 16, 17, and 18, and the previously calculated results may be copied.

Item 35 — *Total Theoretical Air Fuel Check, lb/10 KB.* All fossil fuels have a statistical theoretical air range that should be checked to ensure that the fuel analysis is reasonable. Refer to Section 5.

A-5.2.1 Corrections for Sorbent Reactions and Sulfur Capture

Items 40–45 — The calculations are descriptive and generally self-explanatory. Enter zero for items 40 through 42 and item 45 if sorbent is not used.

Items 45 — O3 (SO3) Corr, lb/10KBtu, correction for the O_2 required to form SO_3 in the sulfation process ($CaO + O_3 = CaSO_4$, which is a solid).

Items 46–48 — Theoretical air expressed in different units. Calculations are in a logical progression, and different units are required for convenience of other calculations.

Item 49 — *Wet Gas From Fuel, lbm/10 KB.* This is the mass of gaseous combustion products from fuel on an input from fuel basis.

A-5.2.2 Calculation of Excess Air Based on Measured O_2. Items 50 through 60 on CMBSTNb are used to calculate excess air when O_2 is measured. The CMBSTN calculation forms may also be used to calculate O_2, CO_2, SO_2, air, and gas weights when excess air is known, such as when calculating dry gas weight for efficiency corrected to contract conditions. If excess air is known, proceed to item 60 on CMBSTNc.

LOCATION — Enter description such as "AH IN," "AH OUT," "SAH IN," etc., in accordance with input from Item 16.

Item 50 Enter the measured flue gas temperature entering the air heater(s).

Item 51 Enter the measured combustion air temperature leaving the air heater(s).

Item 52 Enter the flue gas O_2 entering and leaving the air heater(s). This should be the same as values entered on CMBSTNa, items 17A, 17B, 18A, and 18B.

Item 53 *Moisture in Air.* If O_2 at location is on a dry basis, enter zero. If O_2 at location is on a wet basis, enter the result of the calculation.

Item 54 Enter the appropriate value depending upon whether the O_2 for the location is on a wet or dry basis.

Item 55 If O_2 at location is on a dry basis, enter 0. If it is on a wet basis and there is additional moisture (refer to item 13), perform the calculation.

Items 56–58 These calculations are reduced to several steps to simplify the calculation of excess air by using a calculator.

Item 60 The calculation process yields excess air, percent.

A-5.3 Form CMBSTNc

Item 60 Enter excess air calculated on CMBSTNb or, if combustion calculations are desired for a specific excess air, such as corrections to contract conditions, enter the known excess air.

Items 61–68 These items are used to calculate CO_2 and SO_2 stoichiometrically, such as to check orsat or analyzer readings and to calculate O_2 when excess air is known. These items are not required for the remaining combustion calculations and may be skipped.

If the stoichiometric O_2, CO_2, and SO_2 results are desired, complete items 62 and 64 to obtain O_2, CO_2, and SO_2 on a dry basis and items 63 and 65 to obtain O_2, CO_2, and SO_2 on a wet basis. When orsat CO_2 results are checked, the orsat CO_2 reading is actually $CO_2 + SO_2$, since the orsat CO_2 sorbent also absorbs SO_2.

A-5.3.1 Flue Gas Products, lbm/10 KBtu

Items 69–74 The mass of the products that make up wet flue gas on an lbm/10 KBtu input from fuel basis.

Items 69 The gas from the dry airflow entering the unit corrected to the dry airflow remaining in the flue gas after the conversion of the sulfur captured to SO_3. Refer to para. 5-11.3.

Item 75 The mass of wet flue gas is the sum of the products in the wet flue gas on an lbm/10 KBtu basis.

Item 76 The sum of water in the flue gas on an lbm/10 KBtu basis.

Item 77 The mass of dry flue gas is the difference between the mass of wet flue gas less the total mass of water in wet flue gas.

Item 78 The moisture in wet flue gas expressed on a percent mass basis. This item is used to determine the enthalpy or specific heat of wet flue gas.

Items 79–81 Required to determine the enthalpy of wet flue gas. For gas, oil, and other low ash fuels, these calculations may be omitted. Refer to item 19.

Item 79 The mass fraction of residue in flue gas at location with respect to the total residue leaving the steam generator envelope. Refer to item 19.

Item 80 The mass of residue leaving the steam generator envelope on an lbm/10 KBtu basis. It is the sum of the ash in fuel, unburned carbon, and spent sorbent products. If residue is recycled from a point downstream of the location, the mass of recycled residue must be added.

Item 81 The mass fraction of residue in wet flue gas, lbm/lbm wet gas.

Item 82 *Leakage, Percent Gas Entering.* This item is used to calculate the air infiltration between two locations [e.g., when the O_2 entering and leaving the air heater(s) has been entered]. Item 75E is the wet gas weight entering, and item 75L is the wet gas weight leaving as calculated above.

Items 83–88 Used to calculate the gas temperature leaving an air heater corrected for no leakage, or gas temperature excluding leakage. These items may be skipped if there is no air heater or temperature is not measured.

Item 83 Enter (from item 15) the measured temperature of the gas leaving the air heater.

Item 84 Enter (from item 16) the temperature of the air entering the air heater.

Item 85 Enter the enthalpy of wet air based on the temperature of the gas leaving the air heater (in item 83) and the moisture in air (in item 7).

Item 87 Enter the specific heat of wet flue gas based on the temperature of the gas leaving the air heater (in item 83), moisture in flue gas entering the air heater (in item 78E), and residue in wet flue gas entering the air heater (in item 81E). If the corrected temperature of the gas leaving the air heater is significantly higher than the measured gas temperature, use the average between the measured and corrected gas temperature to determine the mean specific heat of flue gas.

Item 88 Calculate the corrected air heater gas outlet temperature or gas temperature excluding leakage. This is the temperature of the gas leaving the steam generator envelope that is used for the energy balance efficiency calculations.

A-5.3.2 Air, Gas, Fuel Mass Flow Rates, Klbm/hr. These items are calculated after the efficiency calculations have been completed but are included on this form since the calculations fall under the general category of combustion calculations.

Item 90 Enter the input from fuel from the efficiency calculation form in million Btu/hr.

Items 91–93 Calculate the fuel rate, residue rate, and wet flue gas rate in Klb/hr.

Item 95 Enter the percent excess air if calculating the total air weight to the boiler is desired. This item is commonly required to calculate the weighted average air inlet temperature for determining efficiency when air is supplied from two sources such as primary and secondary air fan. It may also be required to correct air resistance to contract conditions. O_2 (excess air) is usually measured at the boiler exit; most units have some setting infiltration and/or seal air, and thus the calculated value using the excess air leaving the boiler will be higher than the actual flow through the forced draft fan(s). For air resistance and/or fan power corrections, an allowance for setting infiltration may be desired.

Item 96 Calculate the total wet airflow based on the excess air in item 95.

A-6 GASEOUS FUELS: INSTRUCTIONS FOR GAS FORM

The gaseous fuel calculation form is used to convert a gaseous fuel analysis from a percent volume basis to a percent mass basis. The ultimate analysis of a gaseous fuel is reported in terms of the as-fired fuel components (such as CH_4, C_2H_6) on a percent volume basis. The higher heating value of a gaseous fuel is reported on a volume or Btu/ft^3 basis. The calculations in this Code require an elemental fuel analysis on a percent mass basis and a higher heating value on a mass or Btu/lbm basis. The components of the elemental analysis are C, H_2, O_2, N_2, S, and H_2OV.

Item 1 *Fuel Type.* This item is provided to allow the user to identify the fuel source.

Item 2 *Ultimate Analysis, Percent by Volume.* Enter the percent by volume of each gaseous component in column 5. Space is provided for additional components.

Item 3 *Density of Const., lbm/ft^3.* The reference conditions for density are 60°F (15.6°C) and 30 in. Hg (762 mm) in accordance with the standard reference temperature for reporting the higher heating value of gaseous fuels.

Item 4 *Density of Gas.* Multiply columns 2 and 3 to obtain the gas density of each constituent.

Item 5 The higher heating value of each constituent is provided. Refer to item 3.

Item 6 *Higher Heating Value of Gas.* Multiply columns 2 and 5 to obtain the HHV of each constituent.

Items 7–12 *Elemental Constituents, Moles/100 mol Gas.* Calculate the molar percentage of the elemental constituents and enter the sum for each constituent on line 14. The constant "K" refers to the constant in each column and is the number of moles of each elemental constituent in the fuel component. Note that water, H_2OV, is considered to be in the vapor state.

Line 14 *MW, lbm/mole.* The molecular weight of each elemental constituent is given on this line.

Line 15 *Mass, lbm/100 mol.* Calculate the mass of each elemental constituent and enter the result for each column of line 16.

Item 16 *Summation of Line 16.* Enter the summation line 16.

Item 17 *Analysis, Percent Mass.* Calculate the ultimate analysis of each elemental constituent and enter the result on this line. The calculated result of the largest constituent should be rounded so that the summation of the constituents equals 100.00%.

Item 18 *Density at 60°F and 30 in. Hg, lbm/ft^3.* Calculation of the density is based on the sum of column 4.

Item 19 *Higher Heating Value, Btu/ft^3.* Calculate the higher heating value on a volume basis. This is the total of column 6 divided by 100.

Item 20 *Higher Heating Value, Btu/lbm.* The higher heating value is calculated as indicated.

A-7 UNBURNED CARBON AND RESIDUE CALCULATIONS: INSTRUCTIONS FOR RES FORM

This Form is used to calculate the weighted average of carbon in the residue, unburned carbon, and sensible heat of residue loss. When sorbent is used, this Form is used to calculate the weighted average of carbon and carbon dioxide in the residue. These results are used in conjunction with the sorbent calculation forms to calculate unburned carbon and calcination fraction of calcium carbonate.

Determine where ash is removed from the unit, and enter the description under "Location." Typical locations are furnace bottom ash (bed drains), economizer or boiler hoppers, and multiclone rejects and fly ash leaving the unit.

It is necessary to know the quantities of ash leaving the unit at each location to determine the weighted average of carbon (and carbon dioxide for units with sorbent) in the residue and sensible heat loss for each location. There are several methods for determining the quantities of residue leaving each location.

(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 residue at one or more locations may be measured and the quantity at the other locations calculated by difference. For example, the quantity of residue leaving the boiler may be measured by dust loading and the split of the remaining residue estimated for the other locations.

(c) The percent residue leaving each location may be estimated on the basis of typical results for the type of fuel being used and the method of firing. For example, for a stoker-fired unit, 90% furnace bottom ash and 10% flyash leaving the boiler may be assumed. In this case, the assumed residue split would be entered in column 8. The larger the total residue mass rate and/or the difference in carbon in the residue at each location, the greater the uncertainty of both unburned carbon and sensible heat loss, and thus the test.

Item 1 *Ash in Fuel, Percent.* Enter percent ash in fuel.

Item 2 *HHV Fuel, Btu/lb "As-Fired."* Enter the higher heating value of the fuel "as-fired."

Item 3 *Fuel Mass Flow Rate, Klbm/hr.* Not required if residue split is measured or measured at all locations. When residue is measured at some locations, the total residue rate is dependent upon fuel rate. Use measured or estimated fuel rate initially. Refer to Form CMBSTNa. It will be necessary to recalculate the residue (RES) and sorbent (SRB) forms after completion of the efficiency calculations until the efficiency result converges. For efficiency calculations this is generally within 1% of the fuel rate used for the calculations. Refer to para. 5-7.3.

Item 5 *Residue Mass Flow, Klbm/hr.* If residue split is estimated or measured at all locations, enter the split in item 8. When residue is measured at some locations, enter the measured residue mass flow rate for the applicable locations. Enter the total residue (from item 21) under item 5F. Estimate the total residue, item 5F, initially from the sum of the sorbent flow rate plus item 1 × (item 3)/100. For locations where residue mass flow rate was not measured, enter the estimated mass flow rate. This is calculated from the difference between the total residue mass flow rate, item 5F, and the sum of the measured mass flow rates times the estimated split for the remaining residue locations. The column for calculated residue mass flow rate is used if the residue splits are entered in item 8.

Item 6 *Percent C in Residue.* Enter the free carbon (carbon corrected for CO_2) in the residue for each location.

Item 7 *Percent CO_2 in Residue.* Required only for units using sorbent. Enter the carbon dioxide for each location.

Item 8 *Residue Split, Percent.* If the residue quantity is measured at all locations, calculate the percent residue split for each location. If the residue split is estimated, enter the assigned value in this column. Refer to item 5.

Item 9 *C Weighted Average, Percent.* Calculate the unburned carbon in residue for each location and enter the sum under item 9F.

Item 10 *CO_2 Weighted Average, Percent.* Calculate the carbon dioxide in refuse for each location and enter the sum under item 10F.

A-7.1 Units Without Sorbent

Item 11 *Unburned Carbon, lbm/100 lbm Fuel.* Calculate the average unburned carbon. This item is used on the combustion calculation and efficiency forms.

Item 20 *Total Residue, lbm/100 lbm Fuel.* The total residue is the sum of the ash in fuel and unburned carbon.

A-7.2 Units With Sorbent

Enter the average carbon, C, and carbon dioxide, CO_2 in residue, items 9F and 10F, on Form SRBa (items 4 and 5) and complete the sorbent calculation forms.

Item 11 *Unburned Carbon, lbm/100 lbm Fuel.* Enter the calculated value from Form SRBb, item 49.

Item 20 *Total Residue, lbm/100 lbm Fuel.* Enter the total residue calculated on Form SRBb, item 50.

A-7.3 Total Residue

Item 21 *Total Residue, Klbm/hr.* Calculate the total residue in Klbm/hr. Compare item 21 to item 5F. Repeat items 5 through 21 (including sorbent forms if applicable) until item 5F and item 21 are within 2%.

Item 22 *Total Residue, lbm/10 KBtu.* Convert residue to lbm/10 KBtu input from fuel basis.

A-7.4 Sensible Heat Residue Loss, Percent

Item 24 — 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.

Item 25 — *Sensible Heat Residue Loss, Percent.* Enter the summation of the loss for each location.

A-8 SORBENT CALCULATION SHEET: MEASURED C AND CO_2 IN RESIDUE

The Sorbent Calculation Forms SRBa and SRBb are used to calculate sulfur capture, calcination of calcium carbonate ($CaCO_3$), unburned carbon (C), mass flow rate of spent sorbent and residue, and the calcium-to-sulfur molar ratio. These two forms are used in conjunction with the unburned carbon and residue calculation form for units with sorbent, RES. Sorbent Form SRBc is used to calculate the efficiency losses and credits related to sorbent, including losses and credits due to sorbent chemical reactions and sulfur capture. The sensible heat loss from residue, which includes spent sorbent, is calculated on Form RES.

The calculations are based upon measuring C in the residue to determine unburned carbon, and carbon dioxide (CO_2) in the residue to determine percent calcination of the $CaCO_3$ in the sorbent. As a result, the calculations on Forms SRBa and SRBb are iterative. It is necessary to estimate unburned carbon, item 15B, and percent calcination, item 23A, initially and reiterate until the estimated values agree within 2% of the calculated values. It will be found that these items converge readily.

Items marked with an asterisk (*) are the items that are estimated initially and results are reiterated using the last calculated values.

Items marked with a plus sign (+) are the calculation results that must be recalculated after each iteration.

The results of this form are also required for general combustion/efficiency calculations, such as for corrections to contract conditions or performance monitoring. For general combustion/efficiency calculations when the C and CO_2 in residue are not measured, enter typical values for unburned carbon, item 15B, and calcination, item 23A. Typical values for sulfur capture may be used, or calculations of sulfur capture may be based on measured SO_2 and O_2 and a typical fuel analysis. For corrections to contract conditions, refer to Section 5.

A-8.1 Form SRBa

A-8.1.1 Data Required

*Item 1 — *Fuel Rate, Klb/hr.* Initially enter the measured or estimated fuel mass flow rate. Refer to Form CMBSTNa. It will be necessary to recalculate the residue and sorbent using the RES and SRB forms after completion of the efficiency calculations until the estimated fuel flow used for these calculations agrees within 1% of the fuel flow calculated from the efficiency results. Refer to paras. A-3 or 5-7.3 for convergence tolerance for different applications.

Item 2 — *Sorbent Rate, Klb/hr.* Enter the measured sorbent mass flow rate.

+Item 3 — *Sorbent/Fuel Ratio.* The sorbent-to-fuel ratio (lbm sorbent/lbm fuel) is used to convert the sorbent mass flow rate to a fuel rate or input from fuel basis, which is used for all calculations related to input from fuel. It is calculated by dividing item 2 by item 1.

Item 4 — *Carbon in Residue, Percent.* This is the weighted average of carbon in all the residue streams leaving the steam generator envelope. Enter the result calculated for item 9F on Form RES. For general performance calculations when the C and CO_2 in the residue are not measured, enter zero to indicate not measured.

Item 5 — *CO_2 in Residue, Percent.* This is the weighted average of carbon dioxide in all the residue streams leaving the steam generator envelope. Enter the result calculated for item 10F on Form RES. For general performance calculations when the C and CO_2 in the residue are not measured, enter zero to indicate not measured.

Item 6 — *Moisture in Air, lbm/lbm Dry Air.* Enter the moisture in air from CMBSTNa, item 7. This item is not required if the O_2 and SO_2 analyses are measured on a dry basis.

Items 7, 8 — Sulfur capture is calculated from O_2 and SO_2 measured at the same location. The method of measurement should be on the same basis (i.e., wet or dry). Although this is not described, if they are not on the same basis, the conversion ratio from wet to dry may be assumed to convert the constituent measured on a wet basis to a dry basis and the calculations reiterated until the assumed wet-to-dry conversion ratio agrees with the calculated ratio.

Item 7 — *SO_2 Flue Gas.* Enter the measured value of SO_2 in ppm in item 7A and convert to percent and enter in item 7B.

Item 8 — *O_2 Flue Gas at Loc SO_2, Percent.* Enter the measured value of O_2 measured at the same location as the SO_2 above.

Item 9 — *SO_2 and O_2 Basis Wet or Dry.* Enter "wet" or "dry," depending upon the method of measurement for items 7 and 8.

Item 10 *Additional Moisture, lb/100 lb Fuel.* Enter the total additional moisture from CMBSTNa, item 13. This item is not required if items 7 and 8 are measured on a dry basis.

A-8.1.2 Combustion Products

Item 15 *Ultimate Analysis, Percent Mass.* Enter the ultimate fuel analysis. Enter the estimated value for unburned carbon, item 15B. Item 15C is the carbon burned, 15A minus 15B. When carbon in the residue is measured, it will be necessary to repeat the calculations until the assumed unburned carbon is within 2% of the estimated value.

Items 16–18 Complete calculations as indicated. The term "K" refers to the constant in the column under the item number. These items are the same as items 31 through 33 number Form CMBSTNb. Refer to instructions for CMBSTNb for more details.

A-8.1.3 Sorbent Products

Item 20 *Percent Mass.* Enter the sorbent analysis on a percent mass basis.

Item 21 *MW.* Molecular weight of the sorbent products; used for calculation of item 22.

Item 22 *Ca Mol/100 lb.* Calculate the moles of calcium per 100 lbm sorbent (unshaded items) and enter the sum under item 22I. This item is used to calculate the calcium-to-sulfur molar ratio, item 52.

*Item 23 *CAL FRAC (Calcination Fraction).* Enter the estimated calcination fraction for $CaCO_3$, item 23A. When CO_2 in residue is measured, it is necessary to repeat the calculations until the assumed calcination fraction is within 2% of the calculated value.

+Item 25 *CO_2, lb/100 lb Sorbent.* This item is the CO_2 added to the flue gas from the sorbent. Complete the calculation for the unshaded items and enter the sum under item 25I.

Item 26 *H_2O, lb/100 lb Sorbent.* This item is the H_2O added to the flue gas from the sorbent. Complete the calculation for the unshaded items and enter the sum under item 26I.

A-8.2 Form SRBb

A-8.2.1 Sulfur Capture Based on Gas Analysis

Items 30–45 Calculate sulfur capture based on SO_2 and O_2 in the flue gas. These calculations have been divided into several steps to simplify the calculation of sulfur capture when a calculator is used. For general combustion calculations, if sulfur capture is estimated or assigned a value for corrections to contract conditions, enter the assigned value under item 45 and skip items 30 through 40.

Items 30–33 If O_2 and SO_2 are measured on a dry basis, enter the values indicated in the "Dry" column. If measured on a wet basis, perform the calculations in the "Wet" column.

Items 34–40 These items are descriptive and generally self-explanatory and arranged for convenience of hand calculations.

Item 45 The mass-fraction of sulfur capture/retention ratio based on the measurement of O_2 and SO_2 in the flue gas at a single location.

A-8.2.2 Unburned Carbon, Calcination, and Other Sorbent/Residue Calculations

+Item 47 *SO_3, lb/100 lb Fuel.* Calculate the SO_3 formed in the calcium oxide ($CaO + SO_3$) reaction to form $CaSO_4$ on a 100 lbm fuel basis.

+Item 48 *Spent Sorbent, lb/100 lb Fuel.* Calculate the mass of spent sorbent added less the CO_2 and H_2O released plus the SO_3 in the $CaO + SO_3$ sulfur capture reaction to form $CaSO_4$.

+Item 49 *Unburned Carbon, lb/100 lb Fuel.* Calculate the unburned carbon in fuel. If carbon in residue is not measured, enter the estimated value from item 15B.

+Item 50 *Residue Rate, lb/100 lb Fuel.* Calculate the total mass of residue on a 100 lbm fuel basis. Residue is the sum of the ash in the fuel, unburned carbon, and spent sorbent.

+Item 51 *Calcination, lb/lb $CaCO_3$.* Calculate the mass fraction of $CaCO_3$ converted to CaO. If CO_2 in residue is not measured, enter the estimated value from item 23A.

Item 52 *Ca/S Molar Ratio, Mols Ca/Mol S.* Calculate the calcium-to-sulfur molar ratio. This is an important operating parameter when sorbent is used for sulfur capture.

Compare the calculated unburned carbon and calcination fraction to the values estimated. Repeat the calculations of items 15 through 51 marked with a "+" until estimate is within 2% of the calculated result.

Refer to the instructions for Form RES. Enter the results of item 50 above under item 20 on Form RES and complete the calculations on Form RES. If the residue mass flow rate was measured for some locations and calculated by difference for the remaining locations, item 21 on RES must be within 2% of item 5F. If not, repeat the residue calculations, RES items 5 through 10, revise items 4 and 5 on SRBa, and repeat the sorbent form calculations for the items marked with a "+" until convergence is obtained.

A-8.3 Sorbent Calculation Form SRBc: Efficiency Calculations

Calculation of efficiency losses and credits related to sorbent, including losses and credits due to sorbent chemical reactions and sulfur capture, are provided for on this form. The sensible heat loss from residue, which includes spent sorbent, is calculated on Form RES. The calculation of average exit gas temperature requires that the combustion calculation forms, CMBSTNa through CMBSTNc, be completed first. It is suggested that this form be completed after completing the input for the efficiency calculation forms.

Item 61 — *Sorbent Temperature, °F.* Enter the temperature of the sorbent. Calculate the enthalpy of sorbent (77°F reference temperature) based on the constituents in the sorbent in accordance with Section 5. For limestone, refer to calculations at bottom of SRBc.

Item 62 — *Average Exit Gas Temperature (Excluding Leakage).* Refer to item 3 on Efficiency calculation Form EFFa. Enter enthalpy of steam at 1 psia (32°F Ref) under item 62A, which is the same as item 3b on Form EFFa.

Item 63 — *HHV Fuel, Btu/lbm "As-Fired."* Enter the higher heating value of fuel "as-fired."

Item 65 — *Water From Sorbent Loss, MKBtu/hr.* Calculate water from sorbent loss and enter result on Form EFFb, item 59, in column A (MKB).

Items 71–77 — *Losses From Calcination/Dehydration, MKBtu/hr.* Calculate the losses for the individual constituents in the sorbent and enter the sum under item 77 and on Form EFFb, item 58, in column A (MKB).

Item 80 — *Credit Due to Sulfation, Percent Fuel Input.* Calculate credit due to sulfation and enter result on Form EFFb, item 66, in column B (percent).

Item 85 — *Credit Due to Sensible Heat from Sorbent, MKBtu/hr.* Calculate credit due to sensible heat from sorbent and enter result on Form EFFb, item 73, in column A (MKB).

A-9 OUTPUT: INSTRUCTIONS FOR FORM OUTPUT

This Form is used to calculate unit output. The Form consists of two parts. The first portion deals with the calculation of output from the main steam or high-pressure side of the boiler. Provision is made for calculation of superheater spray flow by energy balance if the flow is not measured. For units with reheat, the second portion of the form deals with the calculation of reheat steam flow and reheat output. For units with two stages of reheat, the calculations for the second stage are similar to the first reheat stage except reheat-2 flow is calculated by subtracting the reheat-2 extraction and turbine seal flow and shaft leakage from the sum of the cold reheat-1 flow plus reheat-1 spray water flow.

Enter the applicable location (item number)/calculation codes in the lightly shaded cells, including the Steam Table version number at the top of the page. The darkly shaded cells indicate that additional input data and/or calculations are not required for that item. Enter all applicable measured flows, temperatures, and pressures in the blank cells. Determine the enthalpy for each applicable parameter and enter in column H. For the applicable high-pressure parameters, calculate the absorption, Q, with respect to the entering feedwater.

A-9.1 High-Pressure Steam Output

Item 1 — *Feedwater.* The steam mass flow throughput is determined from either measured feedwater flow or measured steam flow with feedwater flow usually having the lowest uncertainty. When SH spray water is supplied from the feedwater, for purposes of accounting in these instructions, the feedwater flow in item 1 should not include SH spray water flow.

Item 2 — *SH Spray Water.* In the Flow column, enter the code that indicates whether the super spray water flow is measured or calculated by energy/heat balance. Refer to items 3 through 8. Note that when the spray water temperature is lower than the feedwater temperature, the additional energy, Q, required to be added to the spray water should be calculated by the difference between the enthalpy of the FW and the spray water (H1, H2) rather than as indicated on the Form. This item is not applicable to units where the spray water is from a sweet water condenser internal to the steam generator envelope.

Items 3–8 — These items are used to calculate SH spray water by energy balance. If SH spray is not measured, enter the applicable data and perform the calculations.

Items 9–14 — *Internal Extraction Flows.* These are steam/water extraction flows internal to the steam generator and are considered as part of the boiler output in addition to the output from main steam calculated in item 18. The lightly shaded cells are used to indicate the location/source of these flows.

Items 15–17 — *Auxiliary Extraction Flows.* These are steam extraction flows that are considered as part of the boiler output and are in addition to the output from main steam calculated in item 18. The lightly shaded cells indicate the source.

Item 18 — *Main Steam.* When feedwater flow is measured, main steam flow is the sum of the feedwater flow and SH spray water flow less the blowdown flow, internal extraction flows, and miscellaneous auxiliary extraction flows.

Item 19 *High-Pressure Steam Output.* The high-pressure steam output is the sum of the energy in the main steam, internal extraction flows, miscellaneous auxiliary extractions, and energy added to the superheater spray water.

A-9.2 Units With Reheat

Item 20 *Reheat Outlet.* Enter the reheat outlet temperature and pressure and calculate the enthalpy.

Item 21 *Cold Reheat Entering Attemperator.* Enter the temperature and pressure upstream of the reheat attemperator/desuperheater and calculate the enthalpy.

Item 22 *RH Spray Water.* Enter the spray water flow, temperature, and pressure, and calculate the enthalpy. It is recommended the flow be measured rather than calculated by energy balance due to the difficulty of obtaining a representative temperature downstream of the desuperheater.

Item 23 *Cold Reheat Extraction Flow.* Enter any extraction flows between the point where main steam flow, W18, was determined and the reheat desuperheater inlet in addition to feedwater heater extraction flow(s) and turbine seal flow and shaft leakages. This flow would normally be an additional measured flow.

Item 24 *Turbine Seal Flow and Shaft Leakage.* This item is normally estimated from the turbine manufacturer's heat balances or turbine test data.

Items 25–29 *FW Heater No. 1.* The highest pressure feedwater heater is considered to be the No. 1 FW heater. Enter the feedwater flow, temperatures, and pressures indicated, and calculate enthalpy. Enter a "1" in the lightly shaded cell if the FW flow includes superheater spray water flow. The steam extraction flow is calculated by energy balance in item 29.

Items 30–34 *FW Heater No. 2.* Applicable for units where the second point heater extraction is from the cold reheat (usually first point heater supplied from intermediate high-pressure turbine extraction point). Enter the feedwater flow and temperatures and pressures indicated, and calculate enthalpy. The steam extraction flow is calculated by energy balance in item 34.

Item 35 *Cold Reheat Flow.* The cold reheat flow is calculated from the main steam flow less the feedwater heater extraction flow(s), turbine seal flow and shaft leakages, and any other miscellaneous extraction flows.

Item 36 *Reheat Output.* The reheat output is the sum of the energy added to the cold reheat flow and the energy added to the reheater spray water flow.

Item 37 *Total Output.* Total output is the sum of the high-pressure steam output plus the reheat steam output. Note that if there is a second stage of reheat, the output for the second stage must be calculated by following the same principles as for the first stage reheater and added to the total output above.

A-10 DATA REDUCTION WORKSHEETS: INSTRUCTIONS FOR DATA FORMS

A-10.1 Form MEAS, Measured Data Reduction Worksheet

This Form is used to average spatially uniform parameters with respect to time and calculate the standard deviation for use in determining the random component of uncertainty. Refer to the INTAVG Form for spatially nonuniform parameters.

Items A–Z Enter each data reading for a single data point in the first column. This may be an analog value or a digital value, such as millivolts. If the value in column 1 is a digital value, convert it to an analog value in column 2. If the instrument has a calibration factor, enter this in column 3 and calculate the calibrated value and enter in column 4.

Item 1 Total Number of Readings for the test period.

Item 2 Calculate the average value for the test period.

Item 3 Calculate the standard deviation for this data point as indicated. Refer to para. 5-2.4.1 for information on standard deviation.

A-10.2 Form SYSUNC, Systematic Uncertainty Data Reduction Worksheet

This data sheet is used to account for and calculate the systematic uncertainty for each measurement device, which includes all the instrument components required for the measurement. Therefore, if pressures are read by two different qualities of pressure transducers or some thermocouples are read with an automated voltmeter and others read with a handheld potentiometer, more than one data sheet would be required for both pressure and temperature. Refer to Section 4 for suggestions on what should be considered and typical values.

Item 1 List all of the potential sources of systematic error.

Items 2, 3 — Enter agreed upon values for both positive and negative systematic uncertainty. Two columns are provided for each positive and negative systematic uncertainty. The systematic uncertainty may be entered as a percent of the reading or in the same units as the measured parameter. Note that the units must be the same as the units for the average value of the measured parameter.

Items 2A, 2B, 3A, 3B — Calculate the total positive and negative systematic uncertainty and enter the result.

A-11 UNCERTAINTY CALCULATIONS: INSTRUCTIONS FOR UNCERTAINTY WORKSHEET FORMS

The Uncertainty Worksheet Forms are used to calculate overall test uncertainty. These forms can be used to estimate pretest uncertainty or to calculate the as-tested uncertainty. All other calculation forms should be completed before the uncertainty calculations are performed. The user should refer to Section 5 of the Code for details on the uncertainty calculation procedures. The user should refer to Sections 4 and 7 of the Code for details on uncertainty analysis as well as guidance on determining random and systematic errors for measured parameters.

A-11.1 Form UNCERTa, Uncertainty Worksheet No. 1

The worksheet provided has been set up for efficiency. The worksheet form contains the input information for data reduction and information required for determination of the random component of uncertainty. The inputs for spatially uniform parameters (i.e., parameters that vary with time only, are obtained from the MEAS Data worksheets). The inputs for spatially nonuniform parameters are obtained from the INTAVG Form.

Items a–z — *Measured Parameters.* These items should include all parameters that are measured and/or estimated for use in calculating efficiency (or any other calculated result such as output, fuel flow, etc.).

Item 1 — *Average Value.* Enter the average value of each measured parameter from Form MEAS, item 2, or Form INTAVG, item 52.

Item 2 — *Standard Deviation.* Enter the standard deviation of each measured parameter from Form MEAS, item 3, or Form INTAVG, item 53.

SYSUNC Sheet Number — *Enter the SYSUNC Sheet Number.* The *same* SYSTEMATIC data can often be used for measured parameters using similar instrumentation.

Item 3 — *Total Positive Systematic Uncertainty.* Enter the applicable positive systematic information from the SYSUNC worksheet, items 2A and 2B or Form INTAVG, item 48 or 49.

Item 4 — *Total Negative Systematic Uncertainty.* Enter the applicable negative systematic information from the SYSUNC worksheet, items 3A and 3B or Form INTAVG, item 48 or 49.

Item 5 — *Number of Readings.* Enter the number of times each parameter was measured during the test period from Form MEAS, item 1 or Form INTAVG, item 54.

Item 6 — Calculate the standard deviation of the mean for each measured parameter in accordance with the equation.

Item 7 — *Degrees of Freedom.* The degrees of freedom for each measured parameter is one less than the number of readings.

Item 8 — *Percent Change.* Enter the percent change in the average value of each measured parameter. The recommended percent change is 1.0% (1.01).

Item 9 — *Incremental Change.* Calculate the incremental change for each measured parameter in accordance with the equation. If the average value of the measured parameter is zero, enter any small incremental change. It is important that the incremental change be in the same units as the average value.

A-11.2 Form UNCERTb, Uncertainty Worksheet No. 2

The worksheet provided has been set up for efficiency. The worksheet form contains the information required to calculate total uncertainty. The nomenclature used on these worksheets refers to efficiency; however, the sheet can be used for any calculated item such as output, fuel flow, calcium/sulfur ratio, etc.

Items a–z — *Measured Parameters.* These items should include all parameters that are measured and/or estimated for use in calculating efficiency (or any other calculated result such as output). These parameters should correspond to the items on Form UNCERTa.

Item 10 — *Recalculated Efficiency.* Enter the recalculated efficiency (or other calculated item such as output) based on the incremental change in the measured parameter from item 9. The average value of all other measured parameters should not change during the recalculation for each measured parameter.

Item 11 — *Absolute Sensitivity Coefficient.* Calculate the absolute sensitivity coefficient in accordance with the equation.

Item 12 — *Relative Sensitivity Coefficient.* Calculate the relative sensitivity coefficient in accordance with the equation.

Item 13 — *Random Uncertainty of Result Calculation.* Enter the product of items 11 and 6.

Item 14 — *Degrees of Freedom for Random Uncertainty Contribution.* Calculate the numerator of eq. (5-16-5) in accordance with the equation.

Item 15 — *Positive Systematic Uncertainty of Result.* Calculate the positive systematic uncertainty of result using the equation shown. This converts the percentage systematic uncertainty numbers to the measured units for each measured parameter.

Item 16 — *Negative Systematic Uncertainty of Result.* Calculate the negative systematic uncertainty of result using the equation shown. This converts the percentage systematic uncertainty numbers to the measured units for each measured parameter.

Item 20 — *Base Efficiency.* Enter item 100 from Form EFFb, calculated with the average value of all measured parameters or the desired uncertainty of calculated item such as output.

Item 21 — *Random Component of Uncertainty.* Calculate the random component of uncertainty in accordance with the equation.

Item 22 — *Degrees of Freedom for Random Uncertainty.* Calculate the degrees of freedom for random uncertainty in accordance with the equation.

Items 23, 24 — *Positive and Negative Systematic Uncertainty of Result.* Calculate in accordance with the equation for each item.

Item 25 — *Degrees of Freedom for Overall Test Result.* Calculate the positive degrees of freedom for the overall test result in accordance with the equation. Substitute item 24 for item 23 to calculate the negative degrees of freedom for the overall test result.

Item 26 — *Student's t Value for Overall Degrees of Freedom for Test.* Enter the Student's t value determined from Table 5-16.5-1 in the Code for both the positive and negative degrees of freedom for the overall test result.

Items 27, 28 — *Total Positive and Negative Test Uncertainty.* Calculate the final positive and negative uncertainty result in accordance with the equation for each item.

A-11.3 Form INTAVG, Uncertainty Worksheet, Spatially Nonuniform Value Parameters

This worksheet form contains the input information required for the data reduction of each grid point as well as the information required for determination of the random component of uncertainty and the total systematic uncertainty of spatially nonuniform parameters. This includes any parameter that varies with both space and time such as the temperature in a large duct. The Form provides for multiple flues/ducts that are common on large units.

Item 30 — *Number of Points Wide.* Enter the number of grid points in the horizontal (X) direction.

Item 31 — *Number of Points High.* Enter the number of grid points in the vertical (Y) direction.

Item 32 — *Number of Points Total.* Enter the total number of grid points.

Item 33 — *Number of Readings per Point.* Enter the number of measurement readings recorded at each grid point MEAS.

Item 34 — *Degrees of Freedom per Point.* The degrees of freedom per point is one less than the number of readings.

Grid Point — Identify each grid point location.

Item 35 — *Average Value.* Enter the average value with respect to time for each grid point.

Item 36 — *Standard Deviation of the Mean.* Calculate the standard deviation of the mean for each grid point in accordance with the equation.

Item 37 — *Degrees of Freedom Calculation.* Calculate a component of the degrees of freedom equation for each grid point in accordance with the equation.

Item 38 — *Spatial Distribution Index Calculation.* Calculate a component of the spatial distribution index in accordance with the equation.

Item 39 — *Flow Wt. Est.* Calculate the estimated flow-weighted value of each grid point in accordance with the equation.

Item 40 — *Number of Working Points.* Enter the actual number of working points for each grid.

Item 41 — *Average Value of Grid.* Calculate the average value of each grid measurement in accordance with the equation.

Item 42 — *Standard Deviation of the Mean for Each Grid.* Calculate the standard deviation of the mean for each grid in accordance with the equation.

Item 43 — *Sum of Degrees of Freedom Calculation for Each Grid.* Calculate the sum of the degrees of freedom calculation for each grid in accordance with the equation.

Item 44 — *Spatial Distribution Index for Grid, SDI.* Calculate the spatial distribution index for the grid in accordance with the equation.

Item 45 — *Flow-Weighted Average Value of Grid, Estimated.* Calculate the estimated flow-weighted value of each grid in accordance with the equation.

Item 46 — *Sys Unc, Integrated Average, Unit of Measure.* Calculate the systematic uncertainty due to the integrated average on a unit of measure basis for each grid in accordance with the equation.

Item 47 *Sys Unc, Flow Weighting (Est), Unit of Measure.* Calculate the estimated systematic uncertainty due to the flow weighting on a unit of measure basis for each grid in accordance with the equation.

Item 48 *Total Instrument Systematic Uncertainty.* Enter the total positive and negative instrument systematic uncertainty from the SYSUNC Form on both a percentage and unit of measure basis. The systematic uncertainty on a percentage basis is the value used in the appropriate column for items 3 and 4 on the UNCERTa Form.

Item 49 *Total Combined Systematic Uncertainty for Integrated Average on a Unit of Measure Basis.* Calculate in accordance with the equation. The systematic uncertainty on a unit of measure basis is the value used in the appropriate column for items 3 and 4 on the UNCERTa Form.

Item 50 *Standard Deviation of the Mean for the Location.* This is the average value for all the individual flues/ducts. For convenience of interfacing with the UNCERTa Form in conjunction with the MEAS Data Form, the sample standard deviation is calculated below.

Item 51 *Degrees of Freedom for the Location.* This is the average value for all the individual flues/ducts. For convenience of interfacing with the UNCERTa Form in conjunction with the MEAS Data Form, the number of readings is calculated below.

Item 52 *Average Value for the Location for UNCERTa Form.* This is the average value for all the individual flues/ducts.

Item 53 *Standard Deviation for the Location for UNCERTa Form.* Conversion of the standard deviation of the mean for the location to the sample standard deviation for uniform interfacing with Form UNCERTa in conjunction with the MEAS Data Form.

Item 54 *Number of Readings for the UNCERTa Form.* Conversion of the degrees of freedom for the location to the number of readings for uniform interfacing with Form UNCERTa in conjunction with the MEAS Data Form.

Form EFFa Efficiency Calculations Data Required

	TEMPERATURES, °F				
1	Reference Temperature	77	1A	Enthalpy Water (32°F Ref)	
2	Average Entering Air Temp from CMBSTNa [16] or EFFa [44]		2A	Enthalpy Dry Air	
			2B	Enthalpy Water Vapor	
3	Average Exit Gas T (Excl Lkg) from CMBSTNc [88] or EFFa [51]		3A	Enthalpy Dry Gas	
			3B	Enthalpy Steam @ 1 psia	
			3C	Enthalpy Water Vapor	
4	Fuel Temperature		4A	Enthalpy Fuel	
	HOT AIR QUALITY CONTROL EQUIPMENT				
5	Entering Gas Temperature		5A	Enthalpy Wet Gas	
6	Leaving Gas Temperature		6A	Enthalpy of Wet Gas	
			6B	Enthalpy of Wet Air	
			6C	Enthalpy of Wet Air @ T=[3]	
	RESULTS FROM COMBUSTION CALCULATION FORM CMBSTN				
10	Dry Gas Weight [77]		18	Unburned Carbon, % [2]	
11	Dry Air Weight [69] + [45]		19	HHV, Btu/lbm "as-fired" [1]	
12	Water from H2 Fuel [34E]			**HOT AQC EQUIPMENT**	
13	Water from H2O Fuel [34F]		20	Wet Gas Entering [75E]	
14	Water from H2Ov Fuel [34G]		21	H2O in Wet Gas, % [78E]	
15	Moisture in Air, lb/lb DA [7]		22	Wet Gas Leaving [75L]	
16	Moisture in Air, lb/10KB [72]		23	Residue in Wet Gas, % [81E]	
17	Fuel Rate Est, Klb/hr [3]				
			25	Excess Air, % [95]	
	MISCELLANEOUS				
30	Unit Output, MKBtu/hr		31	Aux Equip Power, MKBtu/hr	
32	Loss Due to Surface Radiation and Convection, %				
33A	Flat Projected Surface Area, ft^2		33C	Average Surface Temperature, °F	
33B	Average Velocity of Air Near Surface, ft/sec		33D	Average Ambient Temperature Near Surface, °F	
	ENT AIR TEMP (Units With Primary and Secondary Airflow)			**Item Nos. CMBSTN**	
35A	Pri Air Temp Entering, °F CMBSTNa [16B]		35B	Enthalpy Wet Air, Btu/lb	
36A	Pri Air Temp Leaving Air Htr, °F CMBSTNb [51]		36B	Enthalpy Wet Air, Btu/lb	
37A	Average Air Temp Entering Pulverizers, °F		37B	Enthalpy Wet Air, Btu/lbm	
38A	Average Pulverizers Tempering Air Temp., °F		38B	Enthalpy Wet Air, Btu/lbm	
39	Sec Air Temp Entering, °F CMBSTNa [16A]		40	Primary Airflow (Ent Pulv), Klb/hr	
41	Pulverizer Tempering Airflow, Klb/hr	[40] × ([36B] − [37B]) / ([36B] − [38B])			
42	Total Airflow, Klb/hr from Form CMBSTNc [96]		43	Secondary Airflow, Klb/hr [42] − [40]	
44	Average Entering Air Temperature, °F	([35A] × ([40] − [41]) + [39] × [43] + [38A] × [41]) / [42]			
	GAS FLOW ENT PRI AH AND AVG EXIT GAS TEMP (Units With Primary and Secondary AHs)				
45A	Flue Gas Temp Ent Pri AH, °F CMBSTNb [50]		45B	Enthalpy Wet Flue Gas, Btu/lbm	
46A	Flue Gas Temp Lvg Pri AH, °F CMBSTNc [88]		46B	Enthalpy Wet Flue Gas, Btu/lbm	
47	Flue Gas Temp Lvg Sec AH, °F CMBSTNc [88]		48	Total Gas Ent Air Htrs, Klb/hr CMBSTNc [93]	
49	Flue Gas Flow Ent Pri Air Htr, Klb/hr	([40] − [41]) × ([36B] − [35B]) / ([45B] − [46B])			
50	Flue Gas Flow Ent Sec Air Htr, Klb/hr	[48] − [49]			
51	Average Exit Gas Temperature, °F	([46A] × [48] + [47] × [50]) / [48]			
	Iteration of flue gas split % primary AH gas flow	Initial Estimate		Calculated	

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Form EFFb Efficiency Calculations

	LOSSES, % Enter Calculated Result in % Column [B]	A MKB	B %
60	Dry Gas [10] × [3A] / 100 × / 100		
61	Water from H2 Fuel [12] × ([3B] − [1A]) / 100 × (− 45) / 100		
62	Water from H2O Fuel [13] × ([3B] − [1A]) / 100 × (− 45) / 100		
63	Water from H2Ov Fuel [14] × ([3C]) / 100 × / 100		
64	Moisture in Air [16] × [3C] / 100 × / 100		
65	Unburned Carbon in Ref [18] × 14,500 / [19] = × 14,500 /		
66	Sensible Heat of Refuse from Form RES		
67	Hot AQC Equip ([20] × ([5A] − [6A]) − ([22] − [20]) × ([6C] − [6B])) / 100 (× (−) − (−) × (−)) / 100		
68	Other Losses, % Basis from Form EFFc Item [110]		
69	Summation of Losses, % Basis		
	LOSSES, MKBtu/hr Enter in MKB Column [A]		
75	Surface Radiation and Convection from Form EFFa Item [32]		
76	Sorbent Calcination/Dehydration from Form SRBc Item [77]		
77	Water from Sorbent from Form SRBc Item [65]		
78			
79			
80	Other Losses, MKBtu/hr Basis from Form EFFc Item [111]		
81	Summation of Losses, MKBtu/hr Basis		
	CREDITS, % Enter Calculation Result in % Column [B]		
85	Entering Dry Air [11] × [2A] /100 × /100		
86	Moisture in Air [16] × [2B] /100 × /100		
87	Sensible Heat in Fuel 100 × [4A] / [19] 100 × /		
88	Sulfation from Form SRBc Item [80]		
89	Other Credits, % Basis from Form EFFc Item [112]		
90	Summation of Credits, % Basis		
	CREDITS, MKBtu/hr Enter Calculated Result in MKB Column [A]		
95	Auxiliary Equipment Power [31]		
96	Sensible Heat from Sorbent from Form SRBc Item [85]		
97	Other Credits, MKBtu/hr Basis from Form EFFc Item [113]		
98	Summation of Credits, MKBtu/hr Basis		
100	Fuel Eff, % (100 − [69] + [90]) × [30] / ([30] + [81] − [98]) (100 − +) × / (+ −)		
101	Input from Fuel, MKB 100 × [30] / [100] = 100 × /		
102	Fuel Rate, Klbm/hr 1,000 × [101] / [19] = 1,000 × /		

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Form EFFc Efficiency Calculations
Other Losses and Credits

The losses and credits listed on this sheet are not universally applicable to all fossil-fired steam generators and are usually minor. Losses/credits that have not been specifically identified by this Code but are applicable in accordance with the intent of the Code should also be recorded on this sheet.
Parties to the test may agree to estimate the losses or credits in lieu of testing. Enter a “T” for tested or “E” for estimated in the second column, and result in appropriate column.
Enter the sum of each group on Form EFFb.
Refer to the text of ASME PTC 4 for the calculation method.

Itm	T or E	LOSSES, % Enter Calculated Result in % Column [B]	A MKB	B %
110A		CO in Flue Gas		
110B		Formation of NOx		
110C		Pulverizer Rejects		
110D		Air Infiltration		
110E		Unburned Hydrocarbons in Flue Gas		
110F		Other		
110G				
110		Summation of Other Losses, % Basis		
		LOSSES, MKBtu/hr Enter in MKB Column [A]		
111A		Wet Ash Pit		
111B		Sensible Heat in Recycle Streams, Solid		
111C		Sensible Heat in Recycle Streams, Gas		
111D		Additional Moisture		
111E		Cooling Water		
111F		Air Preheater Coil (supplied by unit)		
111G		Other		
111		Summation of other Losses, MKBtu/hr Basis		
		CREDITS, % Enter Calculation Result in % Column [B]		
112A		Other		
112		Summation of Credits, % Basis		
		CREDITS, MKBtu/hr Enter Result in MKB Column [A]		
113A		Heat in Additional Moisture (external to envelope)		
113B		Other		
113		Summation of Credits, MKBtu/hr Basis		

PLANT NAME:	ASME PTC 4 MASTER FORM	UNIT NO.:
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Form CMBSTNa Combustion Calculations

	DATA REQUIRED			
1	HHV, Higher Heating Value of Fuel, Btu/lbm as-fired			
2	UBC, Unburned Carbon, lbm/100 lbm fuel from RES or SRBb FORM			
3	Fuel Flow, Klbm/hr [4b]			
4	a. Measured Fuel Flow			
4	b. Calculated Fuel Flow 100,000 × [5] / [6] / [1]			
5	Output, MKBtu/hr	from OUTPUT Item [37]		
6	Fuel Efficiency, % (estimate initially)			
7	Moisture in air, lbm/lbm Dry Air			
8	Barometric Pressure, in. Hg	pwva = ← Calc	Input →	
9	Dry Bulb Temperature,°F	pswvd = ← Calc	Input →	
10	Wet Bulb Temperature,°F	pswvw = ← Calc	Input →	
11	Relative Humidity, %	pwva = ← Calc	Input →	
	Additional Moisture (Measured)		Klbm/hr	
	Atomizing Steam	from OUTPUT Item [14]		
	Sootblowing Steam	from OUTPUT Item [11]		
	Other			
12	Summation Additional Moisture			
13	Additional Moisture, lbm/100 lbm Fuel	100 × [12] / [3]		
14	Additional Moisture, lbm/10KBtu	[13] / ([1] / 100)		
	If Air Heater (Excl Stm/Wtr Coil) Enter following			
15	Gas Temp Lvg AH,°F	Primary / Secondary or Main	15B	15A
16	Air Temp Ent AH,°F	Primary / Secondary or Main	16B	16A
17	O2 in FG Ent Air Heater	Primary / Secondary or Main	17B	17A
18	O2 in FG Lvg Air Heater	Primary / Secondary or Main	18B	18A
18C	O2 Measurement Basis Dry (0) or Wet (1)			18C
18D	Primary AH Leakage for Trisector Type AH, Percent of Total			18D
	Fuel Analysis, % Mass as-fired	Enter in Col [30]		
19	Mass Ash, lbm/10KBtu	100 × [30J] / [1]		
	If mass of ash (Item [19]) exceeds 0.15 lbm/10KBtu or Sorbent			
	utilized, enter Mass Fraction of Refuse in Item [79] for each location.			
	SORBENT DATA (Enter 0 if Sorbent not Used)			
20	Sorbent Rate, Klbm/hr			
21	CO2 from Sorbent, lbm/100 lbm Sorb	from SRBa Item [25I]		
22	H2O from Sorbent, lbm/100 lbm Sorb	from SRBa Item [26I]		
23	Sulfur Capture, lbm/lbm Sulfur	from SRBb Item [45]		
24	Spent Sorbent, lbm/100 lbm fuel	from SRBb Item [48]		
25	Sorb/Fuel Ratio, lbm Sorb/lbm Fuel	[20] / [3]		
	HOT AIR QUALITY CONTROL EQUIPMENT DATA			
26	O2 in FG Ent HAQC Equipment, %			
	See Form EFFa for HAQC Flue Gas Temperatures			

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Form CMBSTNa, Combustion Calculations, is available at go.asme.org/PTC4FORM_CMBSTNa.

Form CMBSTNb Combustion Calculations

COMBUSTION PRODUCTS

		30 Ultimate Analysis % Mass		31 Theo Air °F lbm/100 lbm Fuel [30] × K		32 Dry Prod °F Mol/100 lbm Fuel [30] / K		33 Wet Prod °F Mol/100 lbm Fuel [30] / K		34 H2O Fuel lbm/10KB [30] × K / ([1] / 100)	
A	C										
B	UBC										
C	Cb			11.51		12.0110					
D	S			4.31		32.065					
E	H2			34.29				2.0159		8.937	
F	H2O							18.0153		1.0	
G	H2Ov							18.0153		1.0	
H	N2					28.0134					
I	O2			−4.32							
J	ASH										
K	VM										
L	FC										
M	TOTAL			31		32		33		34	

35	Total Theo Air Fuel Check, lb/10KB	([31M] + [30B] × 11.51) / ([1] / 100)	
	CORRECTIONS FOR SORBENT REACTIONS AND SULFUR CAPTURE		
40	CO2 from Sorb, lb/100 lb fuel	[21] × [25]	
41	H2O from Sorb, lb/100 lb fuel	[22] × [25]	
42	SO2 Reduction, Mol/100 lb fuel	[32D] × [23]	
43	Dry Prod Comb, Mol/100 lb fuel	[32M] + [40] / 44.01− [42]	
44	Wet Prod Comb, Mol/100 lb fuel	[33M] + [41] / 18.0153 + [43]	
45	O3 (SO3) Corr, lb/10KBtu	[23] × [30D] × 1.5 / ([1] / 100)	
46	Theo Air Corr, lb/100 lb fuel	[31M] + 2.16 × [30D] × [23]	
47	Theo Air Corr, Mol/100 lb fuel	[46] / 28.9625	
48	Theo Air Corr, lb/10KBtu	[46] / ([1] / 100)	
49	Wet Gas from Fuel, lb/10KBtu	(100 − [30J] − [30B] − [30D] × [23]) / ([1] / 100)	

				HAQC In	Sec AH In	Sec AH Out	Pri AH In	Pri AH Out
	LOCATION			HAQC In	Sec AH In	Sec AH Out	Pri AH In	Pri AH Out
50	Flue Gas Temperature Entering Air Heater, °F							
51	Air Temperature Leaving Air Heater, °F							
52	Flue Gas Oxygen Content, %							
	FLUE GAS ANALYSIS, Mol/100 lb Fuel	Dry	Wet					
53	Moisture in Air	0	[7] × 1.608					
54	Dry/Wet Products Comb	[43]	[44]					
55	Additional Moisture	0	[13]/18.0153					
56	[47] × (0.7905 + [53])							
57	Summation	[54] + [55] + [56] − [45] × [1] / 4,799.8						
58	20.95 − [52] × (1 + [53])							
60	Excess Air, %	100 × [52] × [57] / [47] / [58]						

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Form CMBSTNb, Combustion Calculations, is available at go.asme.org/PTC4FORM_CMBSTNb.

Form CMBSTNc Combustion Calculations

	LOCATION		Dry	Wet	HAQC In	Sec AH In	Sec AH Out	Pri AH In	Pri AH Out
60	Excess Air, %								
	O2, CO2, SO2 WHEN EXCESS AIR KNOWN								
61									
62	Dry	[47] × (0.7905 + [60] / 100)							
63	Wet	[47] × (0.7905 + [53] + (1 + [53]) × [60] / 100)							
64	Dry Gas, Mol/100 lb Fuel	[43] + [62] − [45] × [1] / 4,799.8							
65	Wet Gas, Mol/100 lb Fuel	[44] + [63] + [55] − [45] × 1 / 4,799.8							
			Dry	Wet					
66	O2, %	[60] × [47] × 0.2095/	[64]	[65]					
67	CO2, %	([30C] / 0.1201 + [40] / 0.4401)/	[64]	[65]					
68	SO2, ppm	10,000 × (1 − [23]) × [30D] / 0.32065 /	[64]	[65]					
	FLUE GAS PRODUCT, lbm/10KBtu								
69	Gas from Dry Air	(1 × [60] / 100) × [48] − [45]							
70	Wet Gas from Fuel	[49]							
71	CO2 from Sorbent	[40] / ([1] / 100)							
72	Moisture in Air	[7] × (1 + [60] / 100) × [48]							
73	Water from Sorbent	[41] × ([1] / 100)							
74	Additional Moisture	[14]							
75	Total Wet Gas	[69] + [70] + [71] + [72] + [73] + [74]							
76	H2O in Wet Gas	[34M] + [72] + [73] + [74]							
77	Dry Gas	[75] − [76]							
78	H2O in Wet Gas, % Mass	100 × [76] / [75]							
79	Residue, lb/lb Total Refuse at each location								
80	Residue, lb/10KBtu	([30J] + [2] + [24]) / ([1]/100)							
81	Residue in West Gas, lb/lb Wet Gas	[79] × [80] / [75]							
82	Leakage, % Gas Entering	100 × ([75L] − [75E]) / [75E]							
	GAS TEMPERATURE CORRECTION FOR AH LEAKAGE								
83	Gas Temp Lvg (INCL LKG),°F	[15]							
84	Average AH Air Leakage Temp,°F	(1 − [18D]) × [16A] + [18D] × [16B]							
85	H Air Lvg., Btu/lbm	T = [83], H2O = [7]							
86	H Air Ent., Btu/lbm	T = [84], H2O = [7]							
87	Cpg, Btu/lbm, °F	T = [83], H2O = [78E], RES = [81E]							
88	AH Gas Outlet Temperature Excluding Leakage,°F								
	[83] + ([82] / 100 × ([85] − [86]) / [87])								
	AIR, GAS, FUEL, AND RESIDUE MASS FLOW RATES, Klbm/hr								
90	Input from Fuel, MBtu/hr	[5] × [6] / 100							
91	Fuel Rate, Klb/hr	1,000 × [90] / [1]							
92	Residue Rate, Klb/hr	[80] × [90] / 10							
93	Wet Flue Gas, Klb/hr	[75] × [90] / 10							
94	Wet Flue Gas, Klb/hr				Entering Air Heaters		Leaving Air Heaters		
95	Excess Air Lvg Blr, %				Entering HAQC Equip		Entering Air Heaters		
96	Total Air to Blr, Klbm/hr	(1 + [95] / 100) × (1 + [7]) × [48] × [90] / 10							

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Form CMBSTNc, Combustion Calculations, is available at go.asme.org/PTC4FORM_CMBSTNc.

Form GAS Gaseous Fuels

1	Fuel Type										
	2 Ultimate Analysis % by Volume	3 Density of Const. lb/ft³	4 Density of Gas [2] × [3] lb/100, ft³	5 HHV of Const. Btu/ft³	6 HHV of Gas [2] × [5] Btu/ft³	7 C K × [2] mol/100	8 H2 K × [2] mol/100 mol Gas	9 O2 K × [2] mol/100 mol Gas	10 N2 K × [2] mol/100 mol Gas	11 S K × [2] mol/100 mol Gas	12 H2Ov K × [2] mol/100 mol Gas
CH4		0.0423		1,010.0		1	2				
C2H2		0.0686		1,474.3		2	1				
C2H4		0.0739		1,599.8		2	2				
C2H6		0.0792		1,769.6		2	3				
C3H6		0.1109		2,333.0		3	3				
C3H8		0.1162		2,516.1		3	4				
C4H8		0.1479		3,079.9		4	4				
C4H10		0.1532		3,257.1		4	5				
C5H12		0.1901		4,003.0		5	6				
C6H6		0.2058		3,741.8		6	3				
C6H14		0.2271		4,747.0		6	7				
C7H8		0.2428		4,475.0		7	4				
C8H10		0.2798		5,212.0		8	5				
C10H8		0.3749		7,742.9		10	4				
N2		0.0738		0.0					1		
NH3		0.0449		434.3			1.5		0.5		
CO		0.0738		320.5		1		0.5			
CO2		0.1160		0.0		1		1			
SO2		0.1688		0.0				1		1	
H2		0.0053		324.2			1				
H2S		0.0898		637.1			1			1	
H2OV		0.0475		0.0							1
O2		0.0843		0.0				1			
13 TOTAL											
14	MW, lbm/mole					12.0110	2.0159	31.9988	28.0134	32.0650	18.0153
15	Mass, lbm/100 moles		[13] × [14]								
16	Summation Line [16]										
17	Analysis, % Mass		100 × [15] / [16]								
18	Density at 60°F and 30 in. Hg, lbm/ft³					[4] / 100					
19	Higher heating Value, Btu/ft³					[6] / 100					
20	Higher heating Value, Btu/lbm					[19] / [18]					

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Form RES Unburned Carbon and Residue Calculations

	DATA REQUIRED FOR RESIDUE SPLIT				
1	Ash in Fuel, % from Form CMBSTNb [30J]		2	HHV Fuel, Btu/lb "as-fired" from Form CMBSTNa [1]	
3	Fuel Mass Flow Rate, Klbm/hr from Form CMBSTNa [4b]				

(a) Item [3] — Use measured or estimated value initially. (See CMBSTNa.) Recalculate after boiler efficiency has been calculated until estimated value is within 1% of calculated value.

(b) Residue splits estimated: Enter value in Col [8] and calculate Col [5]. Residue rate measured: Enter measured mass flow rates in Col [5]. When residue not measured at all locations, estimate split and flow for measured locations. Reiterate until estimated total residue is within 2% of calculated.

(c) Enter the % free carbon in Col [6] (total carbon correcter for CO2). Units with sorbent: Enter the % CO2 in Col [7].

	Location	5 Residue Mass Flow Input Klbm/hr	Calculated Klbm/hr	6 C in Residue %	7 CO2 in Residue %	8 Residue Split % Input	Calculated 100×[5]/[5F]	9 C Wtd Ave % [6] × [8] / 100	10 CO2 Wtd Ave % [7] × [8] / 100
A	Bottom Ash								
B	Economizer								
C	Fly Ash								
D									
E									
F	TOTAL	5				8		9	10

	UNITS WITHOUT SORBENT		
11	Unburned Carbon, lbm/100 lbm Fuel	[1] × [9F] / (100 − [9F])	
20	Total Residue, lbm/100 lbm Fuel	[1] + [11]	
	UNITS WITH SORBENT		
(d)	Enter average C and CO2 in residue, [9F] and [10F] above or SRBa (Items [4] and [5]), and complete Sorbent Calculation Forms.		
11	Unburned Carbon, lbm/100 lbm Fuel	from Form SRBb Item [49]	
20	Total Residue, lbm/100 lbm Fuel	from Form SRBb Item [50]	
	TOTAL RESIDUE		
21	Total Residue, Klbm/hr	[20] × [3] / 100	
(e)	When all residue collection locations are measured, the measured residue split is used for calculations. If a portion of the residue mass is estimated, repeat calculation above until Col [5F] and Item [21] agree within 2%.		
22	Total Residue, lbm/10KBtu	100 × [20] / [2]	
23	**SENSIBLE HEAT RESIDUE LOSS, %**		

	Location	24 Temp Residue	[8] %	×	[22] Residue lbm/10 KBtu	×	Btu/lbm	/ 1,000	Loss %
A	Bottom Ash		0.00	×	0.000	×	0.00	/ 10,000	
B	Economizer		0.00	×	0.000	×	0.00	/ 10,000	
C	Fly Ash		0.00	×	0.000	×	0.00	/ 10,000	
D			0.00	×	0.000	×	0.00	/ 10,000	
E			0.00	×	0.000	×	0.00	/ 10,000	
								Total 25	

$$H\ residue = 0.16 \times T + 1.09E{-4} \times T^2 - 2.843E{-8} \times T^3 - 12.95$$

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Form RES, Unburned Carbon and Residue Calculations, is available at go.asme.org/PTC4FORM_RES.

Form SRBa Sorbent Calculation Sheet
Measured C and CO_2 in Residue

DATA REQUIRED

1	Fuel Rate, Klbm/hr	from CMBSTNa [4b]	*	4	Carbon in Residue, %	from Form RES [9F]	
2	Sorbent Rate, Klbm/hr	from CMBSTNa [20]		5	CO2 in Residue,	from Form RES [10F]	
3	Sorb/Fuel Ratio	[2] / [1]	+	6	Moisture in Air, lb/lb Dry Air	from CMBSTNa [7]	
7	SO2 Flue Gas, ppm	7A			[7A] / 10,000	% 7B	
8	O2 Flue Gas @ Loc SO2, %			9	SO2 & O2 Basis Wet(1) or Dry(0)		
10	Additional Moisture, lb/100 lb Fuel				(CMBSTNa, Item [13])		

Item [1] — Use measured or estimated value initially. Recalculate after boiler efficiency has been calculated until estimated value is within 1% of calc.

Enter fuel analysis in Col [15].

Enter sorbent analysis in Col [20].

* Estimate Unburned Carbon [15B], and Calcination [23A] initially.

Reiterate until estimated value is within 2% of calculated value.

\+ Items that must be recalculated for each iteration.

COMBUSTION PRODUCTS

		15 Ultimate Analysis % Mass from CMBSTNb [30]		16 Theo Air °F lbm/100 lbm Fuel [15] × K		17 Dry Prod °F Mol/100 lbm Fuel [15] / K		18 Wet Prod °F Mol/100 lbm Fuel [15] / K	
A	C								
B	UBC		*						
C	Cb		+	11.51	+	12.0110	+		
D	S			4.31		32.0650			
E	H2			34.29				2.0159	
F	H2O							18.0153	
G	H2Ov							18.0153	
H	N2					28.0134			
I	O2			−4.32					
J	ASH								
K									
L									
M	TOTAL			16	+	17	+	18	

SORBENT PRODUCTS

		20 % Mass	21 MW	22 Ca Mol/100 lb [20] / [21]	23 Calcination Fraction	24 MW	25 CO2 lb/100 lb Sorb [22] × [23] × [24]	26 H2O lb/100 lb Sorb [22] × [23] × [24]
A	CaCO3		100.0872		*	44.0098	+	
B	Ca(OH)2		74.0927		1.0	18.0153		
C	MgCO3		84.3142		1.0	44.0098		
D	Mg(OH)2		58.3197		1.0	18.0153		
E	H2O		18.0153		1.0	18.0153		
F	INERT							
G								
H								
I	TOTAL Ca, Mol/100 lb Sorb					TOTAL	+	

PLANT NAME:	ASME PTC 4 MASTER FORM	UNIT NO.:
TEST NO.:	DATE:	LOAD:
TIME START:	TIME END:	CALC BY:
REMARKS:		DATE:
		SHEET OF

Form SRBb Sorbent Calculation Sheet
Sulfur Capture and Other Sorbent/Residue Calculations

	SULFUR CAPTURE BASED ON GAS ANALYSIS			
	Select Column per Item [9]	Dry	Wet	
30	Moisture in Air Mols/Mol DA		[6] × 1.608	
31	Additional Moisture		[10] / 18.015	
32	Products Combustion Fuel	[17M]	[17M] + [18M]	+
33	H2O Sorb [3] × [26I] / 18.016		Calc	
34	CO2 Sorb [3] × [25I] / 44.01			+
35	(0.7905 + [30]) × [16M] / 28.9625			+
36	Summation [31] through [35]			+
37	1.0 − (1.0 + [30]) × [8] / 20.95			
38	(0.7905 + [30]) × 2.387 − 2.3			
39	[7B] × [36] / [17D] / [37]			+
40	[38] × [7B] / [37]			
45	Sulfur Capture, lb/lb Sulfur (100 − [39]) / (100 + [40])			+
	UNBURNED CARBON, CALCINATION, AND OTHER SORBENT/RESIDUE CALCULATIONS			
47	SO3 Formed, lb/100 lb Fuel [45] × [15D] × 2.5			+
48	Spent Sorbent, lb/100 lb Fuel [47] + ((100 − [25I]) − [26I]) × [3]			+
49	Unburned Carbon, lb/100 lb Fuel ([48] + [15J]) × [4] / (100 − [4])			+
50	Residue Rate, lb/100 lb Fuel [49] + [48] + [15J]			+
51	Calcination, Mols CO2/Mol CaCO3 1 − [50] × [5] × 0.0227 / [20A] / [3]			+
52	Ca/S Molar Ratio, Mols Ca/Mol S [3] × [22I] × 32.065 / [15D]			

Compare the following, reiterate if initial estimate not within 2% calculated.

	Initial Est	Calculated
Unburned Carbon, lb/100 lb Fuel	[15B]	[49]
Calcination, Mols CO2/Mol CaCO3	[23A] 0.000	[51]

Enter result of Item [50] on Form RES, Item [20].
If residue mass flow rate not measured at all locations, recalculate
RES and SRBa and SRBb until convergence on refuse rate of 2%.

PLANT NAME:	ASME PTC 4 MASTER FORM	UNIT NO.:
TEST NO.:	DATE:	LOAD:
TIME START:	TIME END:	CALC BY:
REMARKS:		DATE:
		SHEET OF

Form SRBc Sorbent Calculation Sheet Efficiency

	DATA REQUIRED				
60	Reference Temperature, °F		60A	Enthalpy Water (32°F Ref)	
61	Sorbent Temperature, °F		61A	Enthalpy Sorbent (77°F Ref)	
62	Ave Exit Gas Temp (Excl Lkg)		62A	Enthalpy Steam @ 1 psia	
63	HHV Fuel, Btu/lbm "as-fired"				
	LOSSES, MKBtu/hr				
65	Water from Sorbent	[2] × [26I] × ([62A] − [60A]) / 100,000 × × (−) / 100,000			
	Calcination/Dehydration				
71	CaCO3	[20A] × [23A] × [2] × 0.00766 = 0.00 × 0.00 × 0.00 × 0.00766			
72	Ca(OH)2	[20B] × 1 × [2] × 0.00636 = 0.00 × 1 × 0.00 × 0.00636			
73	MgCO3	[20C] × 1 × [2] × 0.00652 = 0.00 × 1 × 0.00 × 0.00652			
74	Mg(OH)2	[20D] × 1 × [2] × 0.00625 = 0.00 × 1 × 0.00 × 0.00625			
75					
76					
77	Summation of Losses Due to Calcination/Dehydration	SUM [71] − [76]			
	CREDITS, %				
80	Sulfation	6,733 × [45] × [15D] / [63] 6,733 × × /			
	CREDITS, MKBtu/hr				
85	Sensible Heat from Sorbent	[2] × [61A] / 1,000 × / 1,000			
	Enthalpy of Limestone — See text for other sorbents.				
	HCACO3 = [61] × (0.179 + 0.1128E – 3 × [61]) − 14.45 × (0.179 + 0.1128E – 3 ×) − 14.45				
	[61A] = (1− [20E] / 100) × HCACO3 + [20E] × ([61] − 77) / 100 = (1− / 100) × + × (− 77) / 100				

PLANT NAME:	ASME PTC 4 MASTER FORM	UNIT NO.:
TEST NO.:	DATE:	LOAD:
TIME START:	TIME END:	CALC BY:
REMARKS:		DATE:
		SHEET OF

Form Output

	PARAMETER	*W,* Flow Klbm/hr	*T,* Temperature °F	*P,* Pressure psig	*H,* Enthalpy Btu/lbm	*Q,* Absorption MKBtu/hr W×(H−H1)/1,000
	Steam Table Version (0 = 1967; 1 = 1997)					1
1	Feedwater (Excluding SH Spray)					
2	SH Spray Water: 0 = Ms; 1 = Clc by HB	1				
3	Ent SH-1 Attemp					
4	Lvg SH-1 Attemp					
5	SH-1 Spray Water Flow		W3 × (H3 − H4) / (H4 − H2) or W4 × (H3 − H4) / (H3 − H2)			
6	Ent SH-2 Attemp					
7	Lvg SH-2 Attemp					
8	SH-2 Spray Water Flow		W6 × (H6 − H7) / (H7 − H2) or W7 × (H6 − H7) / (H6 − H2)			
	INTERNAL EXTRACTION FLOWS					
9	Blowdown / Drum					
10	Sat Steam Extraction					
11	Sootblowing Steam					
12	SH Steam Extraction 1					
13	SH Steam Extraction 2					
14	Atomizing Steam					
	AUXILIARY EXTRACTION FLOWS					
15	Aux Steam 1					
16	Aux Steam 2					
17						
18	Main Steam					
19	High Press Steam Output	Q18 + Q2 + Q9 through Q17				
	REHEAT UNITS					
20	Reheat Outlet					
21	Cold Reheat Ent Attemperator					
22	RH Spray Water					
23	Cold Reheat Extraction Flow					
24	Turb Seal Flow & Shaft Lkg					
	FW HEATER NO. 1					
25	FW Entering: 1 = FW + Spray					
26	FW Leaving					
27	Extraction Steam					
28	Drain					
29	FW Heater No. 1 Extr Flow		W25 × (H26 − H25) / (H27 − H28)			
	FW HEATER NO. 2					
30	FW Entering					
31	FW Leaving					
32	Extraction Steam					
33	Drain					
34	FW Heater No. 2 Extr Flow		W30 × [(H31 − H30) − W29 × (H28 − H33)] / (H32 − H33)			
35	Cold Reheat Flow		W18 − W23 − W24 − W29 − W34			
36	Reheat Output	W35 × (H20 − H21) + W22 × (H20−H22)				
37	Total Output	Q19 + Q36				
	PLANT NAME:	ASME PTC 4 MASTER FORM			UNIT NO.:	
	TEST NO.:	DATE:			LOAD	
	TIME START:	TIME END:			CALC BY	
	REMARKS:				DATE	
					SHEET	OF

Form MEAS Measured Data Reduction Worksheet

Measured Parameter:

	Measured Data	Conversion to English Units	Correction Factor	Calibrated Data
a				
b				
c				
d				
e				
f				
g				
h				
i				
j				
k				
l				
m				
n				
o				
p				
q				
r				
s				
t				
u				
v				
w				
x				
y				
z				
1	Total number of readings			
2	Average value ([1a] + [1b] + [1c] + ... [1z]) / [1]			
3	Standard deviation $\{(1/([1] - 1)) \times (([1a] - [2])^2 + ([1b] - [2])^2 + \ldots + ([1z] - [2])^2)\}^{1/2}$			

PLANT NAME:	ASME PTC 4 MASTER FORM	UNIT NO.:
TEST NO.:	DATE:	LOAD:
TIME START:	TIME END:	CALC BY:
REMARKS:		DATE:
		SHEET OF

Form SYSUNC Systematic Uncertainty Worksheet

Measured Parameter:				Worksheet No:		
Estimate of Systematic Uncertainty						
1	Measured Parameter Individual Sys Unc	Source Sys Unc	2 Positive		3 Negative	
			Percent*	Unit of Meas	Percent*	Unit of Meas
a						
b						
c						
d						
e						
f						
g						
h						
i						
j						
k						
l						
m						
n						
o						
Total Systematic Uncertainty $(a^2 + b^2 + c^2 + \ldots)^{1/2}$			2A	2B	3A	3B

*This is a percent of reading.

PLANT NAME:	ASME PTC 4 MASTER FORM	UNIT NO.:
TEST NO.:	DATE:	LOAD:
TIME START:	TIME END:	CALC BY:
REMARKS:		DATE:
		SHEET OF

Form UNCERTa Efficiency Uncertainty Worksheet No. 1

	Measured Parameter (from DATA)	1 Average Value (Item [2] on MEAS Form)	2 Standard Deviation (Item [3] on MEAS Form)	Sys Uncert Sheet No.	3 Total Positive Systematic Uncert (Item [2] on SYSUNC Form)		4 Total Negative Systematic Uncert (Item [2] on SYSUNC Form)		5 No. of Readings (Item [1] on MEAS Form)	6 Standard Dev of Mean $\{[2]^2 / [5]\}^{1/2}$	7 Degrees of Freedom [5] − 1	8 Percent Change	9 Incremental Change* [8] × [1] / 100
					%	Unit	%	Unit					
a													
b													
c													
d													
e													
f													
g													
h													
i													
j													
k													
l													
m													
n													
o													
p													
q													
r													
s													
t													
u													
v													
w													
x													
y													
z													
aa													
ab													
ac													

Input source for Items [1] through [5]
For Spatially Uniform Parameters, enter results from the MEAS Data SYSUNC forms.
For Spatially Nonuniform Parameters, enter results from the INTAVG form.

* The value used for incremental change can be any Increment of the average value.
The recommended increment is 1.0% (0.01 times the average value).
If the average value of the measured parameter is zero, use any small incremental change.
It is important to note that the Incremental change must be in the same units as the average value.

PLANT NAME:	ASME PTC 4 MASTER FORM	UNIT NO.:
TEST NO.:	DATE:	LOAD:
TIME START:	TIME END:	CALC BY:
REMARKS:		DATE:
		SHEET OF

Form UNCERTb Efficiency Uncertainty Worksheet No. 2

	Measured Parameter	10 Recalc Efficiency*	11 Absolute Sensitivity Coefficient {[10] − [20]} / [9]	12 Relative Sensitivity Coefficient [11] × [1] / [20]	13 Random Unc of Result Calculation [11] × [6]	14 Deg of Freedom for Random Uncert Contribution {[11] × [6]}⁴ / [7]	15 Positive Sys Unc of Result [11] × {([1] × [3A] / 100)² + [3B]²}½	16 Negative Sys Unc of Result [11] × {([1] × [4A] / 100)² + [4B]²}½
a								
b								
c								
d								
e								
f								
g								
h								
i								
j								
k								
l								
m								
n								
o								
p								
q								
r								
s								
t								
u								
v								
w								
x								
y								
z								
aa								
ab								
ac								

* This uncertainty worksheet is set up for calculating the uncertainty effect on efficiency; however, this sheet can be used for any calculated item, such as output , fuel flow, calcium/sulfur ratio, etc.

20	*Base Efficiency	from item [100] on EFFb form				
21	Random Component of Uncertainty	$([13a]^2 + [13b]^2 + \ldots)^{1/2}$				
22	Degrees of Freedom for Random Uncertainty	$[21]^4 / ([14a] + [14b] + \ldots)$				
23	Positive Systematic Uncertainty of Result	$([15a]^2 + [15b]^2 + \ldots)^{1/2}$				
24	Negative Systematic Uncertainty of Result	$([16a] + [16b]^2 + \ldots)^{1/2}$	Pos		Neg	
25	Degrees of Freedom for Overall Test Result	$\{([23]/2)^2 + ([21])^2\}^2 / \{([21])^4 / [22] + ([23] / 2)^4 / 50\}$	Pos		Neg	
26	Student's *t* Value for Overall Degrees of Freedom for Test	from Table 5-16.5-1 In Code				
27	Positive Total Test Uncertainty	$[Pos\ 26]\ \{([21])^2 + ([23] / 2)^2\}^{1/2}$				
28	Negative Total Test Uncerainty	$[Neg\ 26]\ \{([21])^2 + ([23] / 2)^2\}^{1/2}$				

PLANT NAME:	ASME PTC 4 MASTER FORM	UNIT NO.:
TEST NO.:	DATE:	LOAD:
TIME START:	TIME END:	CALC BY:
REMARKS:		DATE:
		SHEET OF

Form INTAVG Uncertainty Worksheet
Spatially Nonuniform Value Parameters

Grid Location:				
30	No. of Points Wide			Formulas for Items [36] through [39] are tabulated below.
31	No. of Points High			[36] = (STDDEV$_j$)^2 / [33])$^{1/2}$
32	No. of Points Total	[30] × [31]		[37] = ([36]^4 / [32]^4 × [34])
33	No. of Readings Per Point			[38] = [35] − [41]
34	Degrees of Freedom Per Point	[33] − 1		[39] = [35] × ([35] + 459.7) / ([41] + 459.7)

FlueDuct		A					B					C					D				
		35A	36A	37A	38A	39A	35B	36B	37B	38B	39B	35C	36C	37C	38C	39C	35D	36D	37D	38D	39D
		Ave	Std Dev	Deg Free	SDI	Flow	Ave	Std Dev	Deg Free	SDI	Flow	Ave	Std Dev	Deg Free	SDI	Flow	Ave	Std Dev	Deg Free	SDI	Flow
Grid Point		Value	Mean	Calc	Calc	Wt Est	Value	Mean	Calc	Calc	Wt Est	Value	Mean	Calc	Calc	Wt Est	Value	Mean	Calc	Calc	Wt Est
	X,Y																				
a																					
b																					
c																					
d																					
e																					
f																					
g																					
h																					
i																					
j																					
k																					
l																					
m																					
n																					
o																					
p																					
q																					
r																					
s																					
t																					
u																					
v																					
w																					
x																					
y																					
z																					
aa																					
ab																					
ac																					
ad																					
ae																					
af																					
ag																					
ah																					
ai																					
aj																					

	FlueDuct		A	B	C	D	
40	Number of Working Points						
41	Average Value of Grid	([35a] + [35b] +...) / [40]					
42	Standard Deviation of the Mean for the Grid	([36a]^2 + [36b]^2 +...)$^{1/2}$/[40]					
43	Sum of Degrees of Freedom Calculation	SUM OF [37]					
44	Spatial Distribution Index, SDI	(([38a]^2 + [38b]^2 +...)/[40])$^{1/2}$					
45	Flow-Weighted Ave Value of Grid, Estimated	([39a] + [39b] +...)/[40]					
46	Sys. Unc. Integrated Average, Unit of Meas	{[44] / ([40] − 1)}$^{1/2}$					
47	Sys. Unc. Flow Weighting [Est], Unit of Meas	2 × ([40] − [45])					
				Total Positive Systematic Uncertainty		Total Negative Systematic Uncertainty	
				Percent Reading	Unit of Measure	Percent Reading	Unit of Measure
48	Total Instrument Systematic Uncertainty	From Systematic Uncertainty Worksheet					
49	Total Combined Sys Unc for Integrated Ave. Unit of Meas	(([46A]^2 + [46B]^2...) + ([47A]^2 + [47B]^2...) + [48]^2)$^{1/2}$					
50	Standard Deviation of the Mean for the Location	(([42A]^2 + [42B]^2...) / [No Grids])$^{1/2}$					
51	Degrees of Freedom for Location	[50]^4 / ([43A] + [43B] +...)					
52	Average Value for the Loaction for UNCERTa Form	([41A] + [41B] +...) / (No Grids)					
53	Standard Deviation for the Location for UNCERTa Form	[45] × ([48])$^{1/2}$			54 Number of readings for UNCERTa Form [51] + 1		

PLANT NAME:	ASME PTC 4 MASTER FORM	Unit No.:		Test No.:	
REMARKS:		Load:		Date Test:	
		Time 1:		Time 2:	
		Calc By:		Data Calc:	

NONMANDATORY APPENDIX B
SAMPLE CALCULATIONS

This Appendix presents examples that demonstrate the calculation methods outlined or recommended in this Code. The calculations in this Appendix focus primarily on uncertainty calculations. The efficiency and output calculations are discussed in Section 5 and Nonmandatory Appendix A. This Appendix includes the following example problems:

(a) B-1, Temperature Measurement
(b) B-2, Pressure Measurement
(c) B-3, Flow Measurement
(d) B-4, Output Calculation
(e) B-5, Coal-Fired Steam Generator
(f) B-5.1, CFB Coal-Fired Steam Generator
(g) B-6, Oil-Fired Steam Generator

The sample calculations presented in subsections B-1 through B-4 are building blocks for the coal-fired steam generator example in subsection B-5. The first three sections illustrate temperature, pressure, and flow measurements for feedwater to the steam generator.

To emphasize that systematic uncertainty must be assigned by knowledgeable parties to a test, systematic uncertainties used in the following examples do not always agree with the potential values listed in Section 4.

B-1 TEMPERATURE MEASUREMENT

This example illustrates how feedwater temperature can be measured and the uncertainty determined. Figure B-1-1 shows the temperature measuring system.

The following temperatures were recorded during the test: 440°F, 440°F, 439°F, 439°F, 440°F, and 439°F. The average value and standard deviation for these six measurements were 439.5°F and 0.55°F, respectively. The Measured Data Reduction Worksheet provided with this Code can be used to perform this calculation, or the procedures presented in Section 5 can be followed. A completed Measured Data Reduction Worksheet for feedwater temperature is shown in Table B-1-1. The standard deviation is required as part of the overall random uncertainty calculation shown in subsection B-4.

The systematic uncertainty for this measurement is determined by evaluating the measurement system shown in Fig. B-1-1. Paragraph 4-4.2 of the Code was reviewed to determine possible systematic uncertainties. The following individual systematic uncertainties were evaluated for this example:

(a) thermocouple type
(b) calibration
(c) lead wires
(d) ice bath
(e) thermowell location
(f) stratification of fluid flow
(g) ambient conditions at junctions
(h) intermediate junctions
(i) electrical noise
(j) conductivity
(k) drift

Section 4 of this Code provides additional systematic uncertainties that could be applicable for a temperature measurement. Several of the above systematic uncertainties may not be applicable for a particular temperature measurement. As this example illustrates, most of the above systematic uncertainties are very small and can be ignored.

The Systematic Uncertainty Worksheet provided with this Code can be used to summarize the systematic uncertainties and calculate the overall systematic uncertainty for this measurement. A completed Systematic Uncertainty Worksheet for water temperature is shown in Table B-1-2.

The feedwater temperature was measured with a standard grade Type E thermocouple. This thermocouple has a systematic uncertainty of ±3°F. This value is determined from published manufacturers' accuracy data. The systematic uncertainty for the lead wire is assumed to be ±1.0°F based on engineering judgment and experience from similar measurement systems. Depending on the location and fluid stratification where the temperature is measured, there can be a bias error. The ambient conditions at the thermocouple and junction boxes were assumed to have no effect on the measurement. In addition, electrical noise and conductivity were assumed to have a negligible effect. The thermocouple was not recalibrated after the test, so a drift of 0.1°F was assumed.

Based on the above bias errors, the overall systematic uncertainty of the feedwater temperature was calculated to be ±3.16°F.

It should be noted that there are many ways to reduce the systematic uncertainty of this example, including post-test calibration or using a premium grade thermocouple.

B-2 PRESSURE MEASUREMENT

This example illustrates how feedwater pressure can be measured and the uncertainty determined. Figure B-2-1 shows the pressure measuring system.

Fig. B-1-1 Temperature Measurement

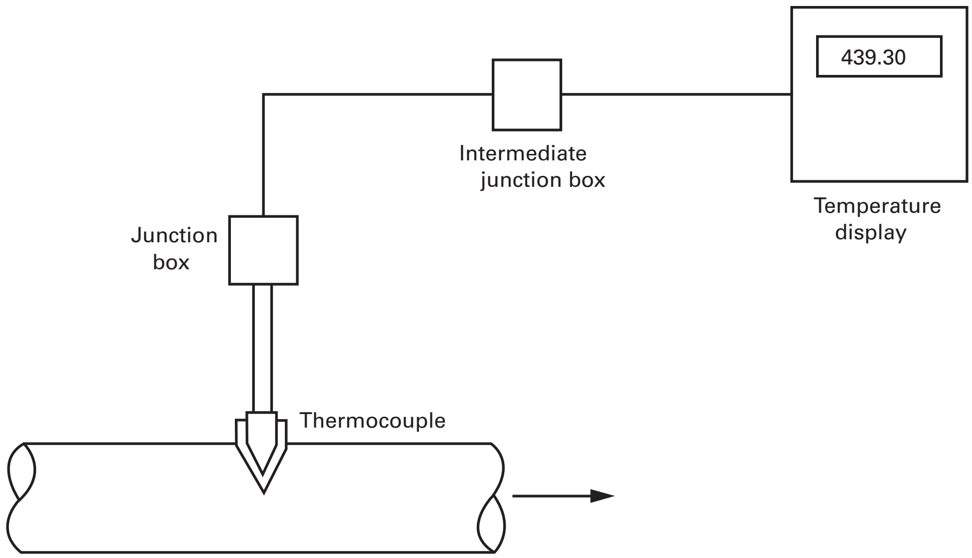
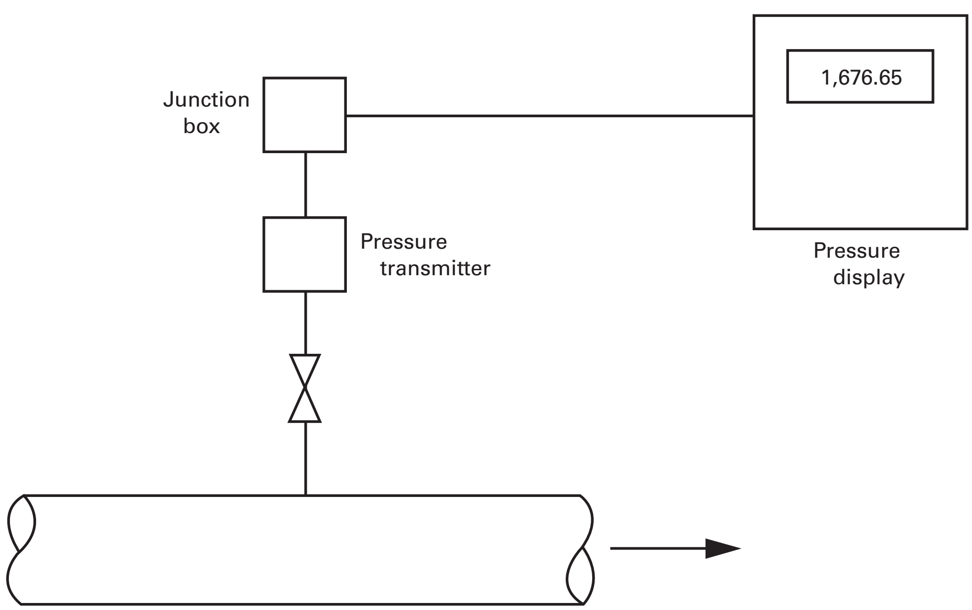


Fig. B-2-1 Pressure Measurement



The following pressures were recorded in pound-force per square inch gauge (psig) during the test: 1,672; 1,674; 1,668; 1,678; and 1,691. The average value and standard deviation for these five measurements were 1,676.6 psig and 8.82 psig, respectively. The Systematic Uncertainty Worksheet provided with this Code can be used to perform this calculation or the procedures presented in Section 5 can be followed. A completed Measured Data Reduction Worksheet for feedwater pressure is shown in Table B-2-1. The standard deviation is required as part of the overall random uncertainty calculation shown in subsection B-4.

The systematic uncertainty for this measurement is determined by evaluating the measurement system shown on Fig. B-2-1. Paragraph 4-5.2 of the Code was reviewed to determine possible systematic uncertainties. The following individual systematic uncertainties were evaluated for this example:

(a) transmitter
(b) calibration
(c) location
(d) ambient conditions at transmitter
(e) ambient conditions at junctions
(f) electrical noise
(g) drift
(h) static and atmospheric pressure

Section 4 of this Code provides additional systematic uncertainties that could be applicable for a pressure measurement. Several of the above systematic uncertainties may not be applicable for a particular pressure measurement. As this example illustrates, several of the above systematic uncertainties are very small and could be ignored.

The Systematic Uncertainty Worksheet, provided with this Code, can be used to summarize the systematic uncertainties and calculate the overall systematic uncertainty for this measurement. A completed Systematic Uncertainty Worksheet for feedwater pressure is shown in Table B-2-2.

The feedwater pressure was measured with a standard transmitter. This transmitter has a span of 800 psig to 2,400 psig and a systematic uncertainty of ±1% for reference accuracy. This value is determined from published manufacturers' accuracy data. The calibration of the transmitter prior to the test included corrections for static pressure and ambient pressure. Depending on the location where the pressure is measured, there could be an additional systematic uncertainty; however, this problem assumed the location effect was negligible.

Published manufacturers' data were also used to determine the drift and ambient temperature effects. This systematic uncertainty of 9.6 psi was based on ±1% of maximum scale per 100°F. In addition, electrical noise was assumed to have a negligible effect. The transmitter was not recalibrated after the test, so a drift of 2 psi, based on 0.25% of maximum scale per 6 mo, was used.

Based on the above systematic uncertainties, the overall systematic uncertainty of the feedwater pressure was calculated to be ±1% and 9.81 psi.

It should be noted that there are a number of ways to reduce the systematic uncertainty of this example, including using a more accurate measurement device.

B-3 FLOW MEASUREMENT

This example illustrates how feedwater flow can be measured and the uncertainty determined. Figure B-3-1 shows the flow measuring system. The following flows were recorded in thousand pounds per hour (klb/hr) during the test: 437.0, 437.1, 433.96, 428.7, 461.9, 428.3, 434.8, 438.28, 431.2, 427.5, 426.93, 430.3, 424.6, 435.2, 431.48, 425.9, 438.7, 427.5, 434.43, and 441.7.

The average value and standard deviation for these 20 measurements were 433.77 klb/hr and 8.1914 klb/hr, respectively. The Measured Data Reduction Worksheet provided with this Code can be used to perform this calculation or the procedures presented in Section 5 can be followed. A completed Measured Data Reduction Worksheet for feedwater flow is shown in Table B-3-1. The standard deviation is required as part of the overall random uncertainty calculation shown in subsection B-4.

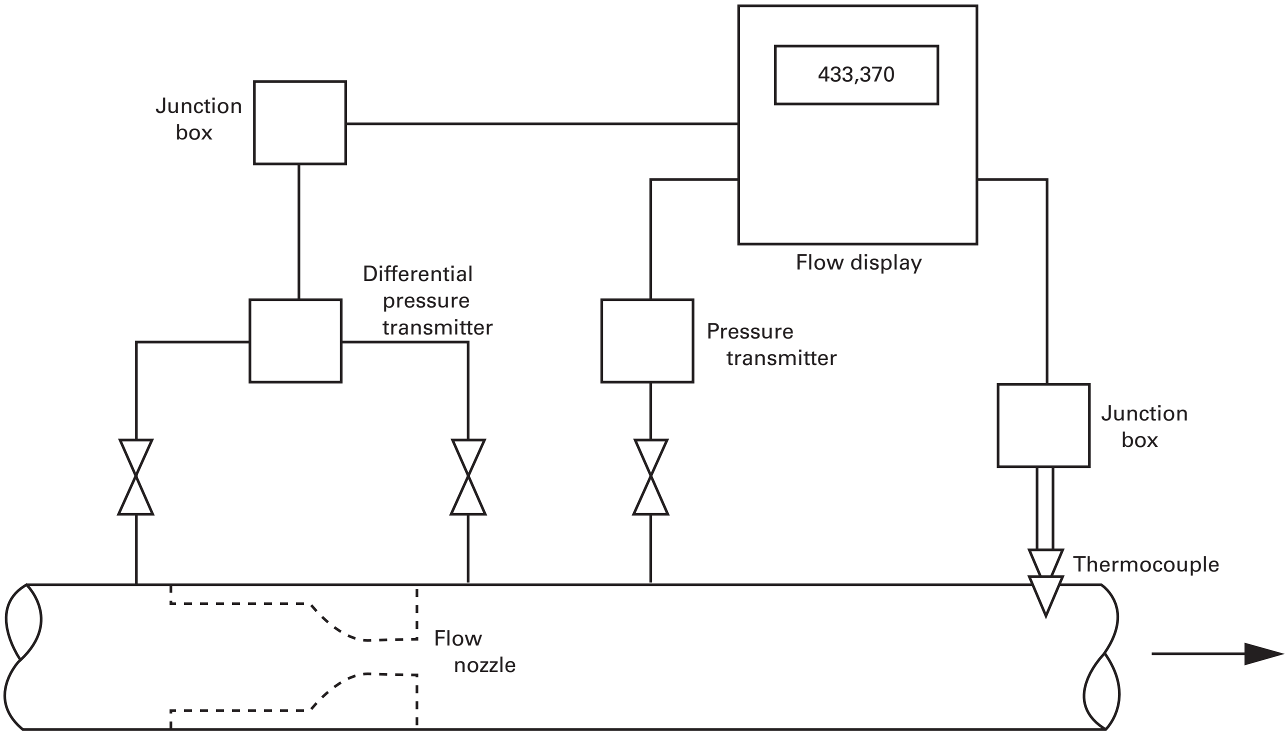
The systematic uncertainty for this measurement is determined by evaluating the measurement system shown on Fig. B-3-1. Paragraph 4-7.2 of the Code was reviewed to determine possible bias errors. The following individual systematic uncertainties were evaluated for this example:

(a) calibration of primary element
(b) stratification
(c) temperature systematic uncertainty
(d) pressure systematic uncertainty
(e) installation
(f) condition of nozzle
(g) nozzle thermal expansion
(h) pressure correction (density effect)
(i) temperature correction (density effect)
(j) Reynolds number correction
(k) measurement location

Section 4 of this Code provides additional systematic uncertainties that could be applicable for a flow measurement. Several of the above systematic uncertainties may not be applicable for a particular flow measurement. As this example illustrates, several of the above systematic uncertainties are very small and can be ignored.

The Systematic Uncertainty Worksheet, provided with this Code, can be used to summarize the systematic uncertainties and calculate the overall systematic uncertainty for this measurement. A completed Systematic Uncertainty Worksheet for feedwater flow is shown in Table B-3-2.

Fig. B-3-1 Flow Measurement



The feedwater flow was measured with a calibrated flow nozzle with pipe taps. The nozzle was inspected prior to the test. This type of nozzle has a systematic uncertainty of ±0.4%. The test was run at a flow with a Reynolds number similar to the laboratory calibration results; therefore, the bias is considered negligible. The nozzle is provided with flow straighteners, so the stratification and installation effects are considered negligible. The nozzle was not inspected after the test, so a systematic uncertainty of ±0.5% was assigned. The differential pressure transmitter systematic uncertainty is ±0.12% based on an accuracy of ±0.25%. The feedwater pressure systematic uncertainty was determined to be 9.81 psi, but has a negligible impact on feedwater density. The feedwater temperature systematic uncertainty was determined to have a systematic uncertainty of ±3.16°F, which has an impact of ±0.27% on feedwater density for an uncertainty ±0.14% measured feedwater flow. There is a systematic uncertainty of ±0.10% due to thermal expansion and a measurement system systematic uncertainty of ±0.10% was assigned.

Based on the above systematic uncertainties, the overall systematic uncertainty of the feedwater flow was calculated to be ±0.68%.

It should be noted that there are many ways to reduce the systematic uncertainty of this example, including a more accurate measurement device.

B-4 OUTPUT CALCULATION

B-4.1 Purpose

The purpose of this example is to illustrate how steam generator output is calculated and the uncertainty of the result determined. This Code recommends that the uncertainty of steam generator output be calculated independent of efficiency for the following reasons:

(a) The output is typically a calculated parameter that is guaranteed or determined independently of efficiency.

(b) The individual measured parameters associated with output typically have a very small effect on efficiency. However, the overall uncertainty of output can have a larger effect, especially in the case of steam generators that use sorbent.

(c) Determining output uncertainty simplifies the calculations required for efficiency uncertainty.

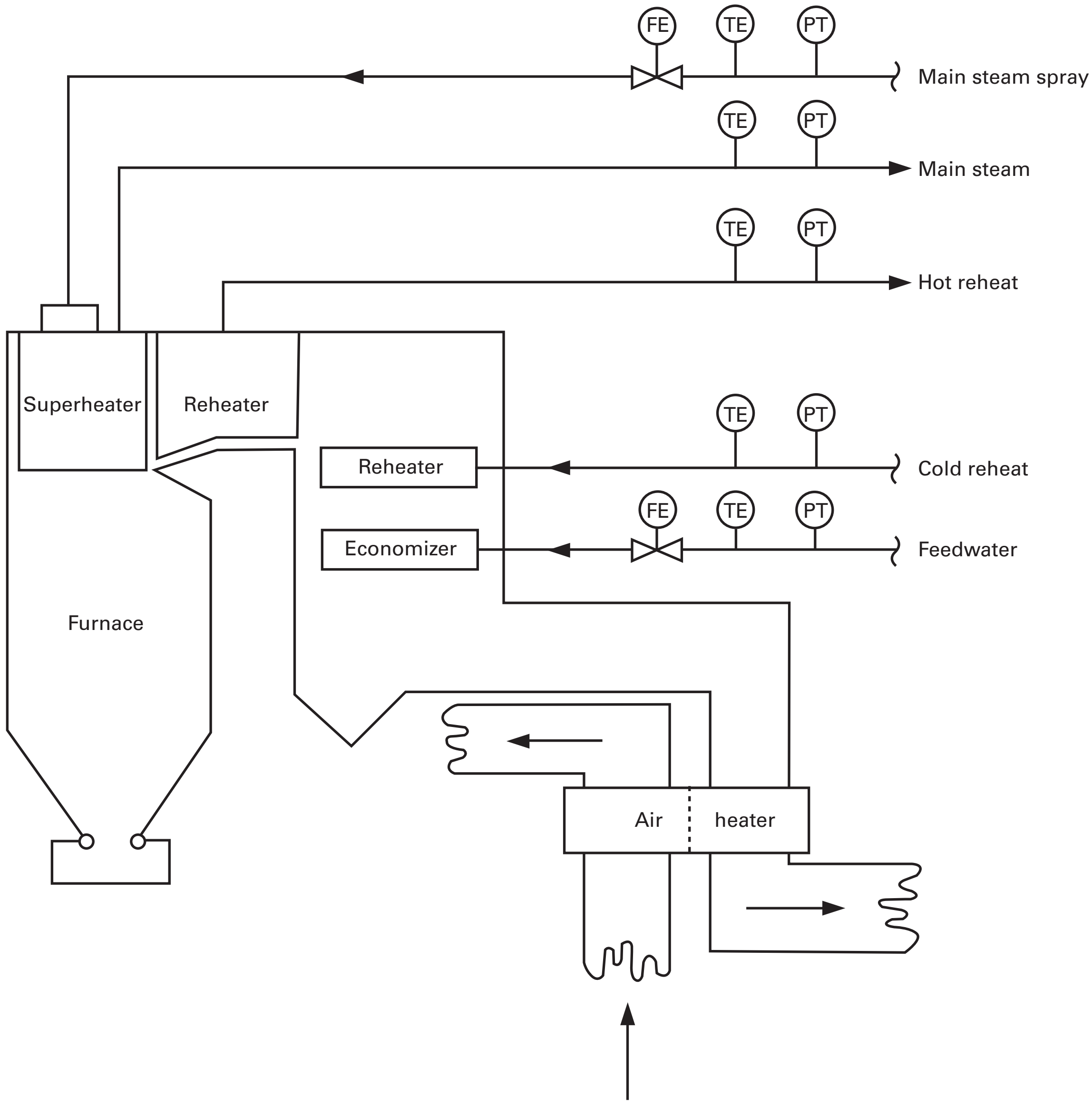
B-4.2 Schematic

Figure B-4.2-1 shows a schematic of the steam generator and the measurements recorded to determine output.

The following measurements were recorded:

(a) barometric pressure
(b) feedwater flow
(c) feedwater temperature
(d) feedwater pressure
(e) main steam spray flow

Fig. B-4.2-1 Output Schematic



(f) main steam spray temperature
(g) main steam spray pressure
(h) main steam temperature
(i) main steam pressure
(j) hot reheat outlet temperature
(k) hot reheat outlet pressure
(l) cold reheat temperature
(m) cold reheat pressure
(n) cold reheat extraction flow

The steam generator output was calculated to be 565.276E+6 Btu/hr using the output calculation form shown in Table B-4.2-1. The use of this calculation form is discussed in Nonmandatory Appendix A. Subsections B-1 through B-3 show how the feedwater measurements and uncertainty were determined. The uncertainty for the other parameters was determined in a similar manner.

The Output Uncertainty Worksheets provided with this Code can be used to calculate the uncertainty for the output measurements. The completed Output Uncertainty Worksheets are included in Tables B-4.2-2, B-4.2-3, and B-4.2-4. The average value, standard deviation, number of readings, and positive and negative bias limit for each of the measurements is required to complete the calculations.

The output total uncertainty was calculated to be +6.55E+6 Btu/hr and −6.55E+6 Btu/hr. This includes a random uncertainty component of 2.29E+6 and a systematic uncertainty of +4.68E+6 and −4.68E+6 Btu/hr.

Table B-1-1 Measured Data Reduction Worksheet

Measured Parameter:	Feedwater Temperature, °F			
1	**Measured Data**	**Conversion to English Units**	**Correction Factor**	**Calibrated Data**
a	440.00			
b	440.00			
c	439.00			
d	439.00			
e	440.00			
f	439.00			
g				
h				
i				
j				
k				
l				
m				
n				
o				
p				
q				
r				
s				
t				
u				
v				
w				
x				
y				
z				
1	Total number of readings			6
2	Average value	([1a] + [1b] + [1c] + ... [1z]) / [1]		439.50
3	Standard deviation {(1/ ([1] − 1)) × (([1a] − [2])^2 + ([1b] − [2])^2 + ... + ([1z] − [2])^2)}$^{1/2}$			0.5477

PLANT NAME:	ASME PTC 4 EXAMPLE PROBLEMS B-1 and B-5	UNIT NO.:
TEST NO.:	DATE:	LOAD:
TIME START:	TIME END:	CALC BY:
REMARKS:		DATE:
		SHEET OF

Table B-1-2 Systematic Uncertainty Worksheet

Measured Parameter:		Water Temperature, °F	**Worksheet No.:** 1D			
Estimate of Systematic Uncertainty						
1	**Measured Parameter Individual Sys Unc**	**Source of Sys Unc**	**2 Positive**		**3 Negative**	
			Percent*	**Unit of Meas**	**Percent***	**Unit of Meas**
a	TC or RTD type	Manufacturer's data		3.00		3.00
b	Calibration	Included in Item a		0.00		0.00
c	Lead Wires	Engineering judgment		1.00		1.00
d	Ice bath	Negligible		0.00		0.00
e	Thermowell location/geometry	Negligible		0.00		0.00
f	Pad weld (insulated/uninsulated)	Not Applicable		0.00		0.00
g	Stratification of flowing liquid	Negligible		0.00		0.00
h	Ambient conditions at junction	Negligible		0.00		0.00
i	Ambient conditions of thermocouple	Negligible		0.00		0.00
j	Intermediate junctions	Negligible		0.00		0.00
k	Electrical noise	Negligible		0.00		0.00
l	Conductivity	Negligible		0.00		0.00
m	Drift	Engineering judgment		0.10		0.10
n	Instrument system	Engineering judgment	0.1	0	0.1	0
o						
Total Systematic Uncertainty $(a^2 + b^2 + c^2 + \ldots)^{1/2}$			**2A** 0.10	**2B** 3.16	**3A** 0.10	**3B** 3.16
* This is a percent of reading.						

PLANT NAME:	ASME PTC 4 EXAMPLE PROBLEMS B-1 and B-5	UNIT NO.:
TEST NO.:	DATE:	LOAD:
TIME START:	TIME END:	CALC BY:
REMARKS:		DATE:
		SHEET OF

Table B-2-1 Measured Data Reduction Worksheet

Measured Parameter:	Feedwater Temperature, psig			
1	**Measured Data**	**Conversion to English Units**	**Correction Factor**	**Calibrated Data**
a	1,672.0			
b	1,674.0			
c	1,668.0			
d	1,678.0			
e	1,691.0			
f				
g				
h				
i				
j				
k				
l				
m				
n				
o				
p				
q				
r				
s				
t				
u				
v				
w				
x				
y				
z				
1	Total number of readings			5
2	Average value	([1a] + [1b] + [1c] + ... [1z]) / [1]		1,676.60
3	Standard deviation $\{(1/ ([1] - 1)) \times (([1a] - [2])^2 + ([1b] - [2])^2 + \ldots + ([1z] - [2])^2)\}^{1/2}$			8.8204

PLANT NAME:	ASME PTC 4 EXAMPLE PROBLEMS B-2 and B-5	UNIT NO.:
TEST NO.:	DATE:	LOAD:
TIME START:	TIME END:	CALC BY:
REMARKS:		DATE:
		SHEET OF

Table B-2-2 Systematic Uncertainty Worksheet

Measured Parameter: Steam and Feedwater Pressure, psig **Worksheet No.:** 2A

Estimate of Systematic Uncertainty

1	Measured Parameter Individual Sys Unc	Source of Sys Unc	2 Positive Percent*	2 Positive Unit of Meas	3 Negative Percent*	3 Negative Unit of Meas
a	Gauge, manomtr, or transmitter type	Manufacturer's data	1.00		1.00	
b	Calibration	Included in 1a				
c	Tap location/geometry/flow impact	Negligible				
d	Amb conditions at transmitter	Manufacturer's data		9.60		9.60
e	Amb conditions at junction	Negligible				
f	Electrical noise	Negligible				
g	Drift	Manufacturer's data		2.00		2.00
h	Static and atmospheric pressure	Included in calibration				
i						
j						
k						
l						
m						
n						
o						
	Total Systematic Uncertainty $(a^2 + b^2 + c^2 + \ldots)^{1/2}$		2A 1.00	2B 9.81	3A 1.00	3B 9.81

*This is a percent of reading.

PLANT NAME:	ASME PTC 4 EXAMPLE PROBLEM B-2	UNIT NO.:
TEST NO.:	DATE:	LOAD:
TIME START:	TIME END:	CALC BY:
REMARKS:		DATE:
		SHEET OF

Table B-3-1 Measured Data Reduction Worksheet

Measured Parameter:	Feedwater Flow, Klbm/hr			
1	**Measured Data**	**Conversion to English Units**	**Correction Factor**	**Calibrated Data**
a	437.0			
b	437.1			
c	434.0			
d	428.7			
e	461.9			
f	428.3			
g	434.8			
h	438.3			
i	431.2			
j	427.5			
k	426.9			
l	430.3			
m	424.6			
n	435.2			
o	431.5			
p	425.9			
q	438.7			
r	427.5			
s	434.4			
t	441.7			
u				
v				
w				
x				
y				
z				
1	Total number of readings			20
2	Average value	([1a] + [1b] + [1c] + ... [1z]) / [1]		433.77
3	Standard deviation $\{(1/([1]-1)) \times (([1a]-[2])^2 + ([1b]-[2])^2 + \ldots + ([1z]-[2])^2)\}^{1/2}$			8.1914

PLANT NAME:	ASME PTC 4 EXAMPLE PROBLEMS B-3 and B-5	UNIT NO.:
TEST NO.:	DATE:	LOAD:
TIME START:	TIME END:	CALC BY:
REMARKS:		DATE:
		SHEET OF

Table B-3-2 Systematic Uncertainty Worksheet

Measured Parameter:		Feedwater Flow, klb/hr		**Worksheet No.:** 3C		
Estimate of Systematic Uncertainty						
1	**Measured Parameter Individual Sys Unc**	**Source of Sys Unc**	**2** Positive		**3** Negative	
			Percent*	**Unit of Meas**	**Percent***	**Unit of Meas**
a	Calibration of primary element	Calibration facility	0.40		0.40	
b	Stratification	Negligible	0.00		0.00	
c	Pressure bias	Calculation	0.12		0.12	
d	Installation	Negligible	0.00		0.00	
e	Condition of nozzle or orifice	Engineering judgment	0.50		0.50	
f	Pressure correction	Calculation	0.00		0.00	
g	Temperature correction	Calculation	0.14		0.14	
h	Reynolds number correction	Negligible	0.00		0.00	
i	Measurement location	Negligible	0.00		0.00	
j	Thermal expansion	Engineering judgment	0.10		0.10	
k	Systems error	Engineering judgment	0.10		0.10	
l						
m						
n						
o						
Total Systematic Uncertainty $(a^2 + b^2 + c^2 + \ldots)^{1/2}$			**2A** 0.68	**2B** 0.00	**3A** 0.68	**3B** 0.00
*This is a percent of reading.						

PLANT NAME:	ASME PTC 4 EXAMPLE PROBLEMS B-3 and B-5	UNIT NO.:
TEST NO.:	DATE:	LOAD:
TIME START:	TIME END:	CALC BY:
REMARKS:		DATE:
		SHEET OF

Table B-4.2-1 Output

	Steam Table Version (0 = 1967; 1 = 1997)						1
	PARAMETER		*W,* Flow Klbm/hr	*T,* Temperature °F	*P,* Pressure psig	*H,* Enthalpy Btu/lbm	*Q,* Absorption MKBtu/hr W×(H−H1)/1,000
1	Feedwater (Excluding SH Spray)		433.774	439.5	1,676.6	419.44	
2	SH Spray Water: 0 = Ms; 1 = Clc by HB		0	312.5	2,006.4	286.13	3.524
3	Ent SH-1 Attemp		433.774	0.0	0.0	0.00	
4	Lvg SH-1 Attemp		460.205	0.0	0.0	0.00	
5	SH-1 Spray Water Flow		26.431	W3 × (H3 − H4) / (H4 − H2) or W4 × (H3 − H4) / (H3 − H2)			
6	Ent SH-2 Attemp		460.205	0.0	0.0	0.00	
7	Lvg SH-2 Attemp		460.205	0.0	0.0	0.00	
8	SH-2 Spray Water Flow		0.000	W6 × (H6 − H7) / (H7 − H2) or W7 × (H6 − H7) / (H6 − H2)			
	INTERNAL EXTRACTION FLOWS						
9	Blowdown / Drum		0.000		0.0	0.00	0.000
10	Sat Steam Extraction		0.000		0.0	0.00	0.000
11	Sootblowing Steam	0	0.000	0.0	0.0	0.00	0.000
12	SH Steam Extraction 1	0	0.000	0.0	0.0	0.00	0.000
13	SH Steam Extraction 2	0	0.000	0.0	0.0	0.00	0.000
14	Atomizing Steam	0	0.000	0.0	0.0	0.00	0.000
	AUXILIARY EXTRACTION FLOWS						
15	Aux Steam 1	0	0.000	0.0	0.0	0.00	0.000
16	Aux Steam 2	0	0.000	0.0	0.0	0.00	0.000
17							
18	Main Steam		460.205	1,005.400	1,517.200	1,492.32	493.745
19	High Press Steam Output		Q18 + Q2 + Q9 through Q17				497.269
	REHEAT UNITS						
20	Reheat Outlet			1,001.7	365.0	1,524.74	
21	Cold Reheat Ent Attemperator			651.5	369.0	1,337.80	
22	RH Spray Water		0.000	0.0	0.0	0.00	
23	Cold Reheat Extraction Flow		47.960				
24	Turb Seal Flow & Shaft Lkg		15.739				
	FW HEATER NO. 1						
25	FW Entering: 1 = FW + Spray	0	433.774	344.5	1,676.6	318.50	
26	FW Leaving			439.5	1,676.6	419.44	
27	Extraction Steam			651.5	369.0	1,337.80	
28	Drain			354.2	369.0	326.55	
29	FW Heater No. 1 Extr Flow		43.298	W25 × (H26 − H25) / (H27 − H28)			
	FW HEATER NO. 2						
30	FW Entering		0.000	0.0	0.0	0.00	
31	FW Leaving			0.0	0.0	0.00	
32	Extraction Steam			0.0	0.0	0.00	
33	Drain			0.0	0.0	0.00	
34	FW Heater No. 2 Extr Flow		0.000	W30 × [(H31 − H30) − W29 × (H28 − H33)] / (H32 − H33)			
35	Cold Reheat Flow		353.208	W18 − W23 − W24 − W29 − W34			
36	Reheat Output		W35 × (H20 − H21) + W22 × (H20−H22)				68.007
37	Total Output		Q19 + Q36				565.276

PLANT NAME:	ASME PTC 4 EXAMPLE PROBLEMS B-4 AND B-5	UNIT NO.:
TEST NO.:	DATE:	LOAD
TIME START:	TIME END:	CALC BY
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Table B-4.2-2 Output Uncertainty Worksheets: A Worksheet No. 1A

	Measured Parameter (from DATA)	1 Average Value (Item [2] on MEAS Form)	2 Standard Deviation (Item [3] on MEAS Form)	Sys Uncert Sheet No.	3 Total Positive Systematic Uncert (Item [2] on SYSUNC Form) %	Unit	4 Total Negative Systematic Uncert (Item [2] on SYSUNC Form) %	Unit	5 No. of Readings (Item [1] on MEAS Form	6 Standard Dev of Mean ($[2]^2$ / [5])$^{1/2}$	7 Degrees of Freedom [5] − 1	8 Percent Change	9 Incremental Change* [8] × [1] / 100
a	Barometric Pressure	29.50	0.04	4B	0.00	0.32	0.00	0.32	3	0.02	2	1.00	0.30
b	Feedwater Flow	433.77	8.19	3C	0.68	0.00	0.68	0.00	20	1.83	19	1.00	4.34
c	Feedwater Temp	439.50	0.55	1D	0.10	3.16	0.10	3.16	6	0.22	5	1.00	4.40
d	Feedwater Press	1,676.60	8.82	2A	1.00	9.81	1.00	9.81	5	3.94	4	1.00	16.77
e	Main Steam Spray Flow	26.43	0.72	3D	2.00	1.41	2.00	1.41	20	0.16	19	1.00	0.26
f	Main Steam Spray Temp	312.50	0.52	1C	0.10	3.16	0.10	3.16	12	0.15	11	1.00	3.13
g	Main Steam Spray Press	2,006.40	9.81	2A	1.00	9.81	1.00	9.81	5	4.39	4	1.00	20.06
h	SH-2 Attemp Flow	0.00	0.00	3E	2.00	1.41	2.00	1.41	0	0.00	0	1.00	0.00
i	MS Ent SH-1 Attemp Temp	0.00	0.00	1C	0.00	3.16	0.00	3.16	0	0.00	0	1.00	0.00
j	MS Ent SH-1 Attemp Press	0.00	0.00	2A	1.00	9.81	1.00	9.81	0	0.00	0	1.00	0.00
k													
l	MS Lvg SH-1 Attemp Temp	0.00	0.00	1C	0.00	3.16	0.00	3.16	0	0.00	0	1.00	0.00
m													
n													
o	MS Ent SH-2 Attemp Temp	0.00	0.00	1C	0.00	3.16	0.00	3.16	0	0.00	0	1.00	0.00
p	MS Ent SH-2 Attemp Press	0.00	0.00	2A	1.00	9.81	1.00	9.81	0	0.00	0	1.00	0.00
q													
r	MS Lvg SH-2 Attemp Temp	0.00	0.00	1C	0.00	3.16	0.00	3.16	0	0.00	0	1.00	0.00
s													
t	Blowdown Flow	0.00	0.00	3D	2.00	1.41	2.00	1.41	0	0.00	0	1.00	0.00
u	Blowdown Pressure	0.00	0.00	2A	1.00	9.81	1.00	9.81	0	0.00	0	1.00	0.00
v	Saturated Steam Extractn Flow	0.00	0.00	3E	2.12	0.00	2.12	0.00	0	0.00	0	1.00	0.00
w													
x	Sootblowing Steam Flow	0.00	0.00	3E	2.12	0.00	2.12	0.00	0	0.00	0	1.00	0.00
y	Sootblowing Steam Temp	0.00	0.00	1C	0.00	3.16	0.00	3.16	0	0.00	0	1.00	0.00
z	Sootblowing Steam Press	0.00	0.00	2A	1.00	9.81	1.00	9.81	0	0.00	0	1.00	0.00
aa													
ab													
ac													

Input source for Items [1] through [5]
For Spatially Uniform Parameters, enter results from the MEAS Data SYSUNC Forms.
For Spatially Nonuniform Parameters, enter results from the INTAVG Form.

* The value used for incremental change can be any increment of the average value.
The recommended increment is 1.0% (0.01 times the average value).
If the average value of the measured parameter is zero, use any small incremental change.
It is important to note that the incremental change must be in the same units as the average value.

PLANT NAME:	ASME PTC 4 EXAMPLE PROBLEMS B-4 and B-5	UNIT NO.:
TEST NO.:	DATE:	LOAD:
TIME START:	TIME END:	CALC BY:
REMARKS:		DATE:
		SHEET OF

Table B-4.2-2 Output Uncertainty Worksheets: A (Cont'd)
Worksheet No. 2A

	Measured Parameter	[10] Recalc Efficiency *	[11] Absolute Sensitivity Coefficient ([10] − [20])/[9]	[12] Relative Sensitivity Coefficient ([11] × [1])/[20]	[13] Random Unc of Result Calculation [11] × [6]	[14] Deg of Freedom for Random Uncert Contribution ([11] × [6])^4/[7]	[15] Positive Sys Unc of Result [11] × {([1] × [3A]/100)^2 + [3B]^2}$^{1/2}$	[16] Negative Sys Unc of Result [11] × {([1] × [4A]/100)^2 + [4B]^2}$^{1/2}$
a	Barometric Pressure	565.276	0.0000	0.0000	0.0000	0.0000E+00	0.00	0.00
b	Feedwater Flow	570.652	1.2393	0.9510	2.2700	1.3975E+00	3.66	3.66
c	Feedwater Temp	563.185	−0.4758	−0.3699	−0.1064	2.5617E−05	−1.52	−1.52
d	Feedwater Press	565.270	−0.0004	−0.0011	−0.0014	9.8268E−13	−0.01	−0.01
e	Main Steam Spray Flow	565.642	1.3868	0.0648	0.2229	1.2993E−04	2.09	2.09
f	Main Steam Spray Temp	565.191	−0.0271	−0.0150	−0.0041	2.5159E−11	−0.09	−0.09
g	Main Steam Spray Press	565.275	0.0000	−0.0002	−0.0002	5.0743E−16	0.00	0.00
h	SH-2 Attemp Flow	565.276	0.0000	0.0000	0.0000	0.0000E+00	0.00	0.00
i	MS Ent SH-1 Attemp Temp	565.276	0.0000	0.0000	0.0000	0.0000E+00	0.00	0.00
j	MS Ent SH-1 Attemp Press	565.276	0.0000	0.0000	0.0000	0.0000E+00	0.00	0.00
k								
l	MS Lvg SH-1 Attemp Temp	565.276	0.0000	0.0000	0.0000	0.0000E+00	0.00	0.00
m								
n								
o	MS Ent SH-2 Attemp Temp	565.276	0.0000	0.0000	0.0000	0.0000E+00	0.00	0.00
p	MS Ent SH-2 Attemp Press	565.276	0.0000	0.0000	0.0000	0.0000E+00	0.00	0.00
q								
r	MS Lvg SH-2 Attemp Temp	565.276	0.0000	0.0000	0.0000	0.0000E+00	0.00	0.00
s								
t	Blowdown Flow	565.276	0.0000	0.0000	0.0000	0.0000E+00	0.00	0.00
u	Blowdown Pressure	565.276	0.0000	0.0000	0.0000	0.0000E+00	0.00	0.00
v	Saturated Steam Extractn Flow	565.276	0.0000	0.0000	0.0000	0.0000E+00	0.00	0.00
w								
x	Sootblowing Steam Flow	565.276	0.0000	0.0000	0.0000	0.0000E+00	0.00	0.00
y	Sootblowing Steam Temp	565.276	0.0000	0.0000	0.0000	0.0000E+00	0.00	0.00
z	Sootblowing Steam Press	565.276	0.0000	0.0000	0.0000	0.0000E+00	0.00	0.00
aa								
ab								
ac								

*This uncertainty worksheet is set up for calculating the uncertainty effect on output; however, this sheet can be used for any calculated item, such as efficiency, fuel flow, calcium/sulfur ratio, etc.

20	* Base Output	From Item [37] on OUTPUT form				See UncOutb 2C
21	Random Component of Uncertainty	([13a]^2 + [13b]^2 +...)$^{1/2}$				5.2140
22	Degrees of Freedom for Random Uncertainty	[21]^4 / ([14a] + [14b] +...)				1.3977E+00
23	Positive Systematic Uncertainty of Result	([15a]^2 + [15b]^2 + ...)$^{1/2}$				20.1101
24	Negative Systematic Uncertainty of Result	([16a]^2 + [16b]^2 + ...)$^{1/2}$				20.1101
25	Degrees of Freedom for Overall Test Result	[([23]/2)^2 + ([21])^2]^2/[([21])^4 /[22] + ([23]/2)^4/50]	Pos	See UncOutb 2C	Neg	See UncOutb 2C
26	Student's *t* Value for Overall Degrees of Freedom for Test	From Table 5-16.5-1 in Code	Pos	See UncOutb 2C	Neg	See UncOutb 2C
27	Positive Total Test Uncertainty	[Pos 26] (([21])^2 + ([23]/2)^2)$^{1/2}$				See UncOutb 2C
28	Negative Total Test Uncertainty	[Neg 26] (([21])^2 + ([23]/2)^2)$^{1/2}$				See UncOutb 2C

PLANT NAME:	ASME PTC 4 EXAMPLE PROBLEMS B-4 and B-5	UNIT NO.:
TEST NO.:	DATE:	LOAD:
TIME START:	TIME END:	CALC BY:
REMARKS:		DATE:
		SHEET OF

Table B-4.2-3 Output Uncertainty Worksheets: B Worksheet No. 1B

	Measured Parameter (from DATA)	1 Average Value (Item [2] on MEAS Form)	2 Standard Deviation (Item [3] on MEAS Form)	Sys Uncert Sheet No.	3 Total Positive Systematic Uncert (Item [2] on SYSUNC Form)		4 Total Negative Systematic Uncert (Item [2] on SYSUNC Form)		5 No. of Readings (Item [1] on MEAS Form)	6 Standard Dev of Mean ([2]^2 / [5])$^{1/2}$	7 Degrees of Freedom [5] − 1	8 Percent Change	9 Incremental Change* [8] × [1] / 100
					%	Unit	%	Unit					
a	SH Steam Extraction 1 Flow	0.00	0.00	3E	2.12	0.00	2.12	0.00	0	0.00	0	1.00	0.00
b	SH Steam Extraction 1 Temp	0.00	0.0000	1C	0.00	3.16	0.00	3.16	0	0.0000	0	1.00	0.00
c													
d	SH Steam Extraction 2 Flow	0.00	0.00	3E	2.12	0.00	2.12	0.00	0	0.00	0	1.00	0.00
e	SH Steam Extraction 2 Temp	0.00	0.0000	1C	0.00	3.16	0.00	3.16	0	0.0000	0	1.00	0.00
f	Atomizing Steam Flow	0.00	0.00	3E	2.12	0.00	2.12	0.00	0	0.00	0	1.00	0.00
g	Atomizing Steam Temp	0.00	0.00	1C	0.00	3.16	0.00	3.16	0	0.00	0	1.00	0.00
h	Atomizing Steam Press	0.00	0.00	2A	1.00	9.81	1.00	9.81	0	0.00	0	1.00	0.00
i	Auxiliary Steam 1 Flow	0.00	0.00	3E	2.12	0.00	2.12	0.00	0	0.00	0	1.00	0.00
j	Auxiliary Steam 1 Temp	0.00	0.00	1C	0.00	3.16	0.00	3.16	0	0.00	0	1.00	0.00
k	Auxiliary Steam 1 Press	0.00	0.00	2A	1.00	9.81	1.00	9.81	0	0.00	0	1.00	0.00
l	Auxiliary Steam 2 Flow	0.00	0.00	3E	2.12	0.00	2.12	0.00	0	0.00	0	1.00	0.00
m	Auxiliary Steam 2 Temp	0.00	0.00	1C	0.00	3.16	0.00	3.16	0	0.00	0	1.00	0.00
n	Auxiliary Steam 2 Press	0.00	0.00	2A	1.00	9.81	1.00	9.81	0	0.00	0	1.00	0.00
o	Main Steam Flow	0.00	0.00	3E	2.12	0.00	2.12	0.00	0	0.00	0	1.00	0.00
p	Main Steam Temp	1,005.40	0.55	1C	0.00	3.16	0.00	3.16	5	0.24	4	1.00	10.05
q	Main Steam Press	1,517.20	2.05	2A	1.00	9.81	1.00	9.81	5	0.92	4	1.00	15.17
r	Hot Reheat Outlet Temp	1,001.67	0.82	1C	0.00	3.16	0.00	3.16	6	0.33	5	1.00	10.02
s	Hot Reheat Outlet Press	365.00	0.71	2A	1.00	9.81	1.00	9.81	5	0.32	4	1.00	3.65
t	Cold Reheat Temp Ent Attemp	651.5	1.00	1C	0.00	3.16	0.00	3.16	12	0.29	11	1.00	6.52
u	Cold Reheat Press Ent Attemp	369.00	1.00	2A	1.00	9.81	1.00	9.81	5	0.45	4	1.00	3.69
v	Reheat Spray Water Flow	0.0	0.00	3D	2.00	1.41	2.00	1.41	0	0.00	0	1.00	0.00
w	Reheat Spray Water Temp	0.00	0.00	1D	0.10	3.16	0.10	3.16	0	0.00	0	1.00	0.00
x	Reheat Spray Water Press	0.00	0.00	2A	1.00	9.81	1.00	9.81	0	0.00	0	1.00	0.00
y	Cold Reheat Extraction Flow	47.96	1.64	3E	2.12	0.00	2.12	0.00	20	0.37	19	1.00	0.48
z	Turb Seal & Shaft Lkg Pct MS	3.42	0.00	3E	2.12	0.00	2.12	0.00	24	0.00	23	1.00	0.03
aa													
ab													
ac													

Input source for Items [1] through [5]
For Spatially Uniform Parameters, enter results from the MEAS Data SYSUNC Forms.
For Spatially Nonuniform Parameters, enter results from the INTAVG Form.

* The value used for incremental change can be any increment of the average value.
The recommended increment is 1.0% (0.01 times the average value).
If the average value of the measured parameter is zero, use any small incremental change.
It is important to note that the incremental change must be in the same units as the average value.

PLANT NAME:	ASME PTC 4 EXAMPLE PROBLEMS B-4 and B-5	UNIT NO.:
TEST NO.:	DATE:	LOAD:
TIME START:	TIME END:	CALC BY:
REMARKS:		DATE:
		SHEET OF

Table B-4.2-3 Output Uncertainty Worksheets: B (Cont'd)
Worksheet No. 2B

	Measured Parameter	10 Recalc Efficiency *	11 Absolute Sensitivity Coefficient ([10] − [20])/[9]	12 Relative Sensitivity Coefficient ([11] × [1])/[20]	13 Random Unc of Result Calculation [11] × [6]	14 Deg of Freedom for Random Uncert Contribution ([11] × [6])⁴/[7]	15 Positive Sys Unc of Result [11] × {([1] × [3A] /100)² + [3B]²}^½	16 Negative Sys Unc of Result [11] × {([1] × [4A] /100)² + [4B]²}^½
a	SH Steam Extraction 1 Flow	565.276	0.0000	0.0000	0.0000	0.0000E+00	0.00	0.00
b	SH Steam Extraction 1 Temp	565.276	0.0000	0.0000	0.0000	0.0000E+00	0.00	0.00
c								
d	SH Steam Extraction 2 Flow	565.276	0.0000	0.0000	0.0000	0.0000E+00	0.00	0.00
e	SH Steam Extraction 2 Temp	565.276	0.0000	0.0000	0.0000	0.0000E+00	0.00	0.00
f	Atomizing Steam Flow	565.276	0.0000	0.0000	0.0000	0.0000E+00	0.00	0.00
g	Atomizing Steam Temp	565.276	0.0000	0.0000	0.0000	0.0000E+00	0.00	0.00
h	Atomizing Steam Press	565.276	0.0000	0.0000	0.0000	0.0000E+00	0.00	0.00
i	Auxiliary Steam 1 Flow	565.276	0.0000	0.0000	0.0000	0.0000E+00	0.00	0.00
j	Auxiliary Steam 1 Temp	565.276	0.0000	0.0000	0.0000	0.0000E+00	0.00	0.00
k	Auxiliary Steam 1 Press	565.276	0.0000	0.0000	0.0000	0.0000E+00	0.00	0.00
l	Auxiliary Steam 2 Flow	565.276	0.0000	0.0000	0.0000	0.0000E+00	0.00	0.00
m	Auxiliary Steam 2 Temp	565.276	0.0000	0.0000	0.0000	0.0000E+00	0.00	0.00
n	Auxiliary Steam 2 Press	565.276	0.0000	0.0000	0.0000	0.0000E+00	0.00	0.00
o	Main Steam Flow	565.276	0.0000	0.0000	0.0000	0.0000E+00	0.00	0.00
p	Main Steam Temp	568.040	0.2750	0.4891	0.0674	5.1455E−06	0.87	0.87
q	Main Steam Press	565.059	−0.0143	−0.0383	−0.0131	7.3269E−09	−0.26	−0.26
r	Hot Reheat Outlet Temp	567.219	0.1940	0.3437	0.0647	3.4961E−06	0.61	0.61
s	Hot Reheat Outlet Press	565.237	−0.0106	−0.0068	−0.0034	3.1664E−11	−0.11	−0.11
t	Cold Reheat Temp Ent Attemp	563.966	−0.2010	−0.2317	−0.0580	1.0309E−06	−0.64	−0.64
u	Cold Reheat Press Ent Attemp	565.364	0.0238	0.0155	0.0107	3.2191E−09	0.25	0.25
v	Reheat Spray Water Flow	565.276	0.0000	0.0000	0.0000	0.0000E+00	0.00	0.00
w	Reheat Spray Water Temp	565.276	0.0000	0.0000	0.0000	0.0000E+00	0.00	0.00
x	Reheat Spray Water Press	565.276	0.0000	0.0000	0.0000	0.0000E+00	0.00	0.00
y	Cold Reheat Extraction Flow	565.186	−0.1869	−0.0159	-0.0687	1.1738E−06	−0.19	−0.19
z	Turb Seal & Shaft Lkg Pct MS	565.246	− 0.8603	−0.0052	0.0000	1.4186E−64	−0.06	−0.06
aa								
ab								
ac								

*This uncertainty worksheet is set up for calculating the uncertainty effect on output; however, this sheet can be used for any calculated item, such as efficiency, fuel flow, calcium/sulfur ratio, etc.

20	* Base Output	from Item [37] on OUTPUT form				See UncOutb 2C
21	Random Component of Uncertainty	$([13a]^2 + [13b]^2 + ...)^{1/2}$				0.0171
22	Degrees of Freedom for Random Uncertainty	$[21]^4 / ([14a] + [14b] + ...)$				1.0857E−05
23	Positive Systematic Uncertainty of Result	$([15a]^2 + [15b]^2 + ...)^{1/2}$				1.7177
24	Negative Systematic Uncertainty of Result	$([16a]^2 + [16b]^2 + ...)^{1/2}$				1.7177
25	Degrees of Freedom for Overall Test Result	$[([23]/2)^2 + ([21])^2]^2/[([21])^4/[22] + ([23]/2)^4/50]$	Pos	See UncOutb 2C	Neg	See UncOutb 2C
26	Student's *t* Value for Overall Degrees of Freedom for Test	from Table 5-16.5-1 in Code	Pos	See UncOutb 2C	Neg	See UncOutb 2C
27	Positive Total Test Uncertainty	$[Pos\ 26]\ (([21])^2 + ([23]/2)^2)^{1/2}$				See UncOutb 2C
28	Negative Total Test Uncertainty	$[Neg\ 26]\ (([21])^2 + ([23]/2)^2)^{1/2}$				See UncOutb 2C

PLANT NAME:	ASME PTC 4 EXAMPLE PROBLEMS B-4 and B-5	UNIT NO.:
TEST NO.:	DATE:	LOAD:
TIME START:	TIME END:	CALC BY:
REMARKS:		DATE:
		SHEET OF

Table B-4.2-4 Output Uncertainty Worksheets: C
Worksheet No. 1C

	Measured Parameter (from DATA)	1 Average Value (Item [2] on MEAS Form)	2 Standard Deviation (Item [3] on MEAS Form)	Sys Uncert Sheet No.	3 Total Positive Systematic Uncert (Item [2] on SYSUNC Form) %	3 Unit	4 Total Negative Systematic Uncert (Item [2] on SYSUNC Form) %	4 Unit	5 No. of Readings (Item [1] on MEAS Form)	6 Standard Dev of Mean $([2]^2 / [5])^{1/2}$	7 Degrees of Freedom $[5] - 1$	8 Percent Change	9 Incremental Change* $[8] \times [1] / 100$
a													
b	Heater 1 Ent Feedwater Temp	344.50	0.55	1D	0.10	3.16	0.10	3.16	6	0.22	5	1.00	3.45
c	Heater 1 Ent Feedwater Press	1,676.60	8.82	2A	1.00	9.81	1.00	9.81	5	3.94	4	1.00	16.77
d	Heater 1 Lvg Feedwater Temp	439.50	0.55	1D	0.10	3.16	0.10	3.16	6	0.22	5	1.00	4.40
e													
f	Heater 1 Ext Steam Temp	0.00	1.00	1C	0.00	3.16	0.00	3.16	12	0.29	11	1.00	6.52
g	Heater 1 Ext Steam Press	0.00	1.00	2A	1.00	9.81	1.00	9.81	5	0.45	4	1.00	3.69
h	Heater 1 Drain Temp	0.00	0.00	1D	0.10	3.16	0.10	3.16	0	0.00	0	1.00	0.00
i													
j													
k	Heater 2 Ent Feedwater Temp	0.00	0.00	1D	0.10	3.16	0.10	3.16	0	0.00	0	1.00	0.00
l													
m	Heater 2 Lvg Feedwater Temp	0.00	0.00	1D	0.10	3.16	0.10	3.16	0	0.00	0	1.00	0.00
n													
o	Heater 2 Ext Steam Temp	0.00	0.00	1C	0.00	3.16	0.00	3.16	0	0.00	0	1.00	0.00
p	Heater 2 Ext Steam Press	0.00	0.00	2A	1.00	9.81	1.00	9.81	0	0.00	0	1.00	0.00
q	Heater 2 Drain Temp	0.00	0.00	1D	0.10	3.16	0.10	3.16	0	0.00	0	1.00	0.00
r													
s													
t													
u													
v													
w													
x													
y													
z													
aa													
ab													
ac													

Input source for Items [1] through [5]
For Spatially Uniform Parameters, enter results from the MEAS Data SYSUNC Forms.
For Spatially Nonuniform Parameters, enter results from the INTAVG Form.

* The value used for incremental change can be any increment of the average value.
The recommended increment is 1.0% (0.01 times the average value).
If the average value of the measured parameter is zero, use any small incremental change.
It is important to note that the incremental change must be in the same units as the average value.

PLANT NAME:	ASME PTC 4 EXAMPLE PROBLEMS B-4 and B-5	UNIT NO.:
TEST NO.:	DATE:	LOAD:
TIME START:	TIME END:	CALC BY:
REMARKS:		DATE:
		SHEET OF

Table B-4.2-4 Output Uncertainty Worksheets: C (Cont'd)
Worksheet No. 2C

	Measured Parameter	10 Recalc Efficiency *	11 Absolute Sensitivity Coefficient ([10] − [20])/[9]	12 Relative Sensitivity Coefficient ([11] × [1])/[20]	13 Random Unc of Result Calculation [11] × [6]	14 Deg of Freedom for Random Uncert Contribution ([11] × [6])⁴/[7]	15 Positive Sys Unc of Result [11] × {([1] × [3A]/100)² + [3B]²}½	16 Negative Sys Unc of Result [11] × {([1] × [4A]/100)² + [4B]²}½
a								
b	Heater 1 Ent Feedwater Temp	565.493	0.0629	0.0383	0.0141	7.8268E−09	0.20	0.20
c	Heater 1 Ent Feedwater Press	565.277	0.0000	0.0001	0.0002	3.7203E−16	0.00	0.00
d	Heater 1 Lvg Feedwater Temp	564.984	−0.0665	−0.0517	−0.0149	9.7685E−09	−0.21	−0.21
e								
f	Heater 1 Ext Steam Temp	565.292	0.0000	0.0000	0.0000	0.0000E+00	0.00	0.00
g	Heater 1 Ext Steam Press	565.275	0.0000	0.0000	0.0000	0.0000E+00	0.00	0.00
h	Heater 1 Drain Temp	565.276	0.0000	0.0000	0.0000	0.0000E+00	0.00	0.00
i								
j								
k	Heater 2 Ent Feedwater Temp	565.276	0.0000	0.0000	0.0000	0.0000E+00	0.00	0.00
l								
m	Heater 2 Lvg Feedwater Temp	565.276	0.0000	0.0000	0.0000	0.0000E+00	0.00	0.00
n								
o	Heater 2 Ext Steam Temp	565.276	0.0000	0.0000	0.0000	0.0000E+00	0.00	0.00
p	Heater 2 Ext Steam Press	565.276	0.0000	0.0000	0.0000	0.0000E+00	0.00	0.00
q	Heater 2 Drain Temp	565.276	0.0000	0.0000	0.0000	0.0000E+00	0.00	0.00
r								
s								
t								
u								
v								
w								
x								
y								
z								
aa								
ab								
ac								

*This uncertainty worksheet is set up for calculating the uncertainty effect on output; however, this sheet can be used for any calculated item, such as efficiency, fuel flow, calcium/sulfur ratio, etc.

20	* Base Output	from Item [37] on OUTPUT form				565.276
21	Random Component of Uncertainty	$([13a]^2 + [13b]^2 + ...)^{1/2}$				2.2873
22	Degrees of Freedom for Random Uncertainty	$[21]^4 / ([14a] + [14b] + ...)$				19.5813
23	Positive Systematic Uncertainty of Result	$([15a]^2 + [15b]^2 + ...)^{1/2}$				4.6811
24	Negative Systematic Uncertainty of Result	$([16a]^2 + [16b]^2 + ...)^{1/2}$				4.6811
25	Degrees of Freedom for Overall Test Result	$[([23]/2)^2 + ([21])^2]^2/[([21])^4/[22] + ([23]/2)^4/50]$	Pos	53.34	Neg	57.41
26	Student's *t* Value for Overall Degrees of Freedom for Test	from Table 5-16.5-1 in Code	Pos	2.00	Neg	2.00
27	Positive Total Test Uncertainty	$[\text{Pos } 26]\ (([21])^2 + ([23]/2)^2)^{1/2}$				6.5452
28	Negative Total Test Uncertainty	$[\text{Neg } 26]\ (([21])^2 + ([23]/2)^2)^{1/2}$				6.5452

PLANT NAME:	ASME PTC 4 EXAMPLE PROBLEMS B-4 and B-5	UNIT NO.:
TEST NO.:	DATE:	LOAD:
TIME START:	TIME END:	CALC BY:
REMARKS:		DATE:
		SHEET OF

B-5 COAL-FIRED STEAM GENERATOR

In this subsection, the calculations for two types of coal-fired steam generators are discussed: a pulverized-coal-fired unit is discussed first, and a circulating fluidized bed (CFB) unit is discussed in para. B-5.1. The purpose of these examples is to illustrate how steam generator efficiency is calculated and the uncertainty of the result determined.

Figure B-5-l shows a schematic of the steam generator and the measurements recorded to determine efficiency.

The following measurements were assumed or measured:

(a) fuel higher heating value
(b) fuel flow
(c) barometric pressure
(d) ambient dry-bulb temperature
(e) relative humidity
(f) flue gas temperature leaving air heater
(g) combustion air temperature entering air heater
(h) flue gas leaving air heater oxygen content
(i) flue gas entering air heater oxygen content
(j) combustion air temperature leaving air heater
(k) fuel carbon content
(l) fuel sulfur content
(m) fuel hydrogen content
(n) fuel moisture content
(o) fuel nitrogen content
(p) fuel oxygen content
(q) fuel ash content
(r) flue gas temperature entering air heater
(s) combustion air temperature leaving air heater
(t) primary airflow
(u) furnace ash flow
(v) economizer ash flow
(w) precipitator ash flow
(x) furnace ash carbon content
(y) economizer ash carbon content
(z) precipitator as carbon content
(aa) bottom ash residue temperature
(bb) economizer ash residue temperature
(cc) precipitator ash residue temperature
(dd) fuel temperature

The pulverized-coal-fired steam generator efficiency was calculated to be 88.62% using the calculation forms included at the end of this Nonmandatory Appendix (Tables B-5-1 through B-5-7). The use of these calculation forms is discussed in Nonmandatory Appendix A. In addition to the above parameters, the steam generator output was calculated as described in subsection B-4. See para. B-5.1 for a discussion on the efficiency uncertainty.

Also included in this Nonmandatory Appendix are Input Data Sheets, Tables B-5-8 through B-5-10. These sheets are used to document all measured or estimated parameters for the test. These input sheets are primarily for use in a computer spreadsheet program that was developed to complete the calculations.

B-5.1 CFB Coal-Fired Steam Generator

The following additional measurements are required for a CFB unit:

(a) sorbent rate
(b) sorbent analysis
(c) flue gas sulfur dioxide (SO_2) content
(d) flue gas oxygen content at the location where SO_2 is measured

For the pulverized-coal unit example, the ash splits were estimated and appropriate systematic uncertainties assigned. For the CFB unit example, the bottom ash mass flow rate was measured and the fly ash mass flow rate was calculated; see Tables B-5.1-7 through B-5.1-10. Also, the unburned carbon and primary airflow were increased to be more representative of a CFB unit. For comparison of the pulverized-coal unit to the CFB unit, all other input parameters were kept the same. The efficiency for the CFB unit was calculated to be 87.21%. The most significant differences in efficiency losses compared to the pulverized-coal unit were

(a) +1.5% unburned carbon (which was assumed)
(b) +0.24% in the sensible heat of residue because of the increased amount of solids from the sorbent and chemical reactions
(c) –0.3% for the net heat of formation between the sorbent and fuel gaseous products of combustion. Refer to Tables B-5.1-1 through B-5.1-10 for the efficiency calculations. The uncertainty for the above parameters as well as output were determined in a manner similar to the methods described in subsections B-1 through B-4.

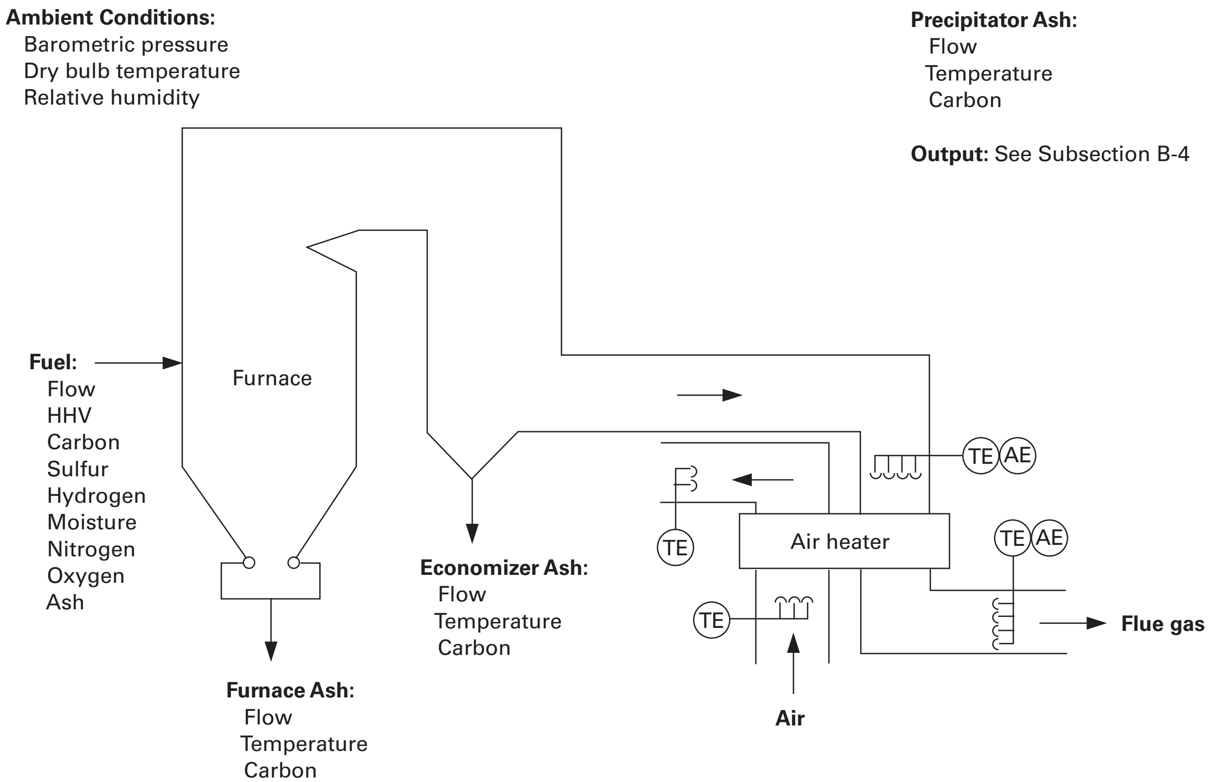
The Efficiency Uncertainty Worksheets provided with this Code were used to calculate the uncertainty for the efficiency measurements. Refer to Tables B-5.1-11 through B-5.1-14 for the efficiency uncertainty calculations for the CFB example. The average value, standard deviation, number of readings, and positive and negative systematic uncertainties for each of the measurements were required to complete the calculations.

The total uncertainty of efficiency for the CFB unit was calculated to be +0.36% and −0.38%. This includes a random uncertainty component of 0.06% and a systematic uncertainty of +0.34% and −0.37%. The uncertainty results for the pulverized-coal unit were essentially the same (±0.02%) since the same data was used for both examples.

B-6 OIL-FIRED STEAM GENERATOR

In this example, the efficiency of an oil-fired unit is determined by both the Input–Output method and the energy balance method. The uncertainty of the efficiency is also calculated for each method to evaluate the quality of each test method. The same steam generator and boundary conditions used for the coal-fired steam generator in subsection B-5 are used except for the following differences that are related to the fuel:

Fig. B-5-1 Efficiency Schematic



(a) fuel properties

(b) fuel residue flow and associated properties are deemed to be negligible

(c) unburned combustibles are deemed to be negligible

B-6.1 Efficiency by the Input–Output Method

The required data for this method consists of those measurements necessary to determine output (subsection B-4) and input. Input is calculated from measured fuel flow and the fuel higher heating value.

Higher heating value (HHV) fuel was sampled during the test in accordance with Section 4, the samples were mixed, and one sample was analyzed. The average higher heating value for the test was determined to be 17,880 Btu/lbm. The systematic uncertainties for the higher heating value were considered to consist of the ASTM reproducibility interval (89 Btu/lbm per ASTM D4809) and a 0.5% of the measured value for systematic uncertainty attributed to sampling (89 Btu/lbm) for a combined systematic uncertainty of 0.70%.

A unit output of 565.28 kBtu/hr was determined in accordance with the description in subsection B-4. In that presentation, it was determined that the most critical item was the feedwater flow nozzle. While output has a negligible impact on the uncertainty of efficiency determined by the energy balance method (refer to the Efficiency Uncertainty Worksheet 2A, Table B-6.2-7, items 15 and 16), it is directly proportional to the uncertainty of efficiency determined by the Input–Output method. To minimize the uncertainty of the output, a calibrated and inspected ASME PTC 6 flow nozzle with a flow straightener was purchased. A nozzle coefficient uncertainty of 0.35% was used. A calibrated differential pressure transmitter with an uncertainty of 0.1% of range was used, and an uncertainty of 0.1% was assumed for system uncertainty. The total systematic uncertainty for feedwater flow was reduced to 0.38%. It was also noted that the feedwater random uncertainty was high. The controls were tuned and more readings were taken, reducing the random uncertainty of the result to 0.1%. This reduced the total uncertainty of the output result to 0.626%.

The plant oil flow measurement system utilized a square edge orifice with D and $D/2$ taps. The orifice has a Beta value of 0.734 and installed in a 2 in., schedule 40 pipe. The systematic uncertainty associated with the orifice was considered to be 0.5%.

The systematic uncertainty of the transducer and calibration uncertainty were considered to be 0.6% and

1.90% of the full range of the transmitter respectively. The full range of the transmitter was 60 in. wg, thus the combined systematic uncertainty is 0.6708 in. wg.

The oil analysis included the specific gravity, which was determined to have a systematic uncertainty of 0.33% based on the ASTM reproducibility limit.

The following differential pressure readings across the orifice were recorded in inches of water gauge (in. wg) during a pretest uncertainty analysis: 45.85, 46.85, 47.35, 45.35, 48.85, 47.55, 45.05, 45.08, 48.75, 48.25, and 46.15, for an average of 46.80 in. wg with a resulting standard deviation of 1.368144.

The Uncertainty Worksheets were used to calculate the random and combined systematic uncertainties of the flow measuring system (refer to the Oil Flow Uncertainty Worksheets).

On Table B-6.1-1, Worksheet 1, the basic flow equation is provided and all parameters are defined. The parameters to be evaluated in the calculation of the oil flow are

(a) differential pressure, in. wg
(b) specific gravity
(c) orifice diameter
(d) discharge coefficient

The systematic uncertainty for the discharge coefficient is the only systematic uncertainty not considered above. Note the low Reynolds number of the orifice on Worksheet 1. A systematic uncertainty of 0.6 + β% = 1.334% is assigned to the coefficient due to the low Reynolds number and an uncalibrated orifice.

Items 27 and 28 on Worksheet 2 report the overall uncertainty of the measured oil flow. The result is 2.05%, which was deemed to be unacceptable for an input–output test.

To reduce the uncertainty of the measured oil flow, a positive displacement flowmeter was purchased for the test and calibrated at several viscosities spanning the expected viscosity of the oil. The total systematic uncertainty of the result using the calibrated positive displacement meter was determined to be 0.6% of the measured flow based on a meter uncertainty of 0.5%, an uncertainty of 0.33% due to SG, 0.1% due to viscosity, and 0.1% assumed system systematic uncertainty. The random uncertainty was reduced to 0.2% by tuning the controls and taking more readings. Thus, by improving the fuel measurement system and test techniques, the total uncertainty for the measured oil flow was reduced to 0.62%. The measured oil flow for the test was determined to be 35,140 lbm/hr.

The efficiency by the Input–Output method is calculated per the following equation:

$$\text{Efficiency} = 100 \times \frac{\text{Output}}{\text{Fuel Flow} \times \text{HHV}}$$

$$= 100 \times \frac{565,325,000}{35,439 \times 17880} = 89.217\%$$

The Efficiency by Input–Output Uncertainty Worksheets, Table B-6.1-2, were used to calculate the uncertainty of the efficiency determined by the Input–Output method.

For this test, the overall uncertainty of the efficiency result determined by the Input–Output method was +1.062% and −1.068%.

B-6.2 Efficiency by the Energy Balance Method

The combustion calculations, efficiency calculations and efficiency uncertainty calculation forms for efficiency calculated by the energy loss method are shown on Tables B-6.2-1 through B-6.2-10.

The steam/water side measurements required to determine unit output for an efficiency test by the energy balance method are the same as for the Input–Output method. However, as can be observed by the uncertainty results below, the influence of the output is insignificant on the efficiency determined by the energy balance method result. Thus, the accuracy of the instrumentation required to determine output is less critical.

Measured fuel flow is not required. Any calculations utilizing fuel flow are based upon the measured output and fuel flow determined from the calculated efficiency.

Fuel sampling requirements are comparable. The fuel must be analyzed for ultimate analysis (elemental constituents) in addition to the higher heating value and density.

Air and flue gas measurements are the principle measurements required in addition to those required for the Input–Output method. The most common measurements are defined in subsection B-5.

The Efficiency Uncertainty Worksheets for the OIL FIRING Example Problem list the measurements required to determine efficiency by the energy balance method for this oil-fired boiler example.

The quality of the test using the Input–Output method versus the energy balance method is evaluated by comparing the uncertainty of the result for the two methods. Note that even with the precautions of using calibrated feedwater and oil flow nozzles for the input–output test, the uncertainty was 1.06% versus an uncertainty of 0.26% for the energy balance method test with reasonable quality instrumentation.

Table B-5-1 Efficiency Calculations Data Required Worksheet EFFa

	TEMPERATURES, °F					
1	Reference Temperature		77	1A	Enthalpy Water (32°F Ref)	45
2	Average Entering Air Temp		85.6	2A	Enthalpy Dry Air	2.06
	from CMBSTNa [16] or EFFa [44]			2B	Enthalpy Water Vapor	3.83
3	Average Exit Gas T (Excl Lkg)		298.6	3A	Enthalpy Dry Gas	52.96
	from CMBSTNc [88] or EFFa [51]			3B	Enthalpy Steam @ 1 psia	1,195.34
				3C	Enthalpy Water Vapor	100.25
4	Fuel Temperature		84.0	4A	Enthalpy Fuel	2.68
	HOT AIR QUALITY CONTROL EQUIPMENT					
5	Entering Gas Temperature		0.0	5A	Enthalpy Wet Gas	0.00
6	Leaving Gas Temperature		0.0	6A	Enthalpy of Wet Gas	0.00
				6B	Enthalpy of Wet Air	0.00
				6C	Enthalpy of Wet Air @ T= [3]	0.00
	RESULTS FROM COMBUSTION CALCULATION FORM CMBSTN					
10	Dry Gas Weight	[77]	9.499	18	Unburned Carbon, % [2]	0.384
11	Dry Air Weight	[69] + [45]	9.145	19	HHV, Btu/lbm "as-fired" [1]	11,447.6
12	Water from H2 Fuel	[34E]	0.337		**HOT AQC EQUIPMENT**	
13	Water from H2O Fuel	[34F]	0.088	20	Wet Gas Entering [75E]	0.00
14	Water from H2Ov Fuel	[34G]	0.000	21	H2O in Wet Gas, % [78E]	0.00
15	Moisture in Air, lb/lb DA	[7]	0.012	22	Wet Gas Leaving [75L]	0.00
16	Moisture in Air, lb/10KB	[72]	0.111	23	Residue in Wet Gas, % [81E]	0.00
17	Fuel Rate Est., Klb/hr	[3]	55.72			
				25	Excess Air, % [95]	22.08
	MISCELLANEOUS					
30	Unit Output, MKBtu/hr		565.28	31	Aux Equip Power, MKBtu/hr	0.0
32	Loss Due to Surface Radiation and Convection, %					0.00
33A	Flat Projected Surface Area, ft^2		0 / 0 / 50	33C	Average Surface Temperature, °F	0 / 0 / 127
33B	Average Velocity of Air Near Surface, ft/sec		0 / 0 / 1.67	33D	Average Ambient Temperature Near Surface, °F	0 / 0 / 77
	ENT AIR TEMP (Units With Primary and Secondary Airflow)					
35A	Pri Air Temp Entering, °F CMBSTNa [16B]		84.9	35B	Enthalpy Wet Air, Btu/lb	1.9
36A	Pri Air Temp Leaving Air Htr, °F CMBSTNb [51]		511.7	36B	Enthalpy Wet Air, Btu/lb	102.5
37A	Average Air Temp Entering Pulverizers, °F		350.6	37B	Enthalpy Wet Air, Btu/lbm	66.8
38A	Average Pulverizer Tempering Air Temp, °F		84.9	38B	Enthalpy Wet Air, Btu/lbm	1.9
39	Sec Air Temp Entering, °F CMBSTNa [16A]		85.7	40	Primary Airflow (Ent Pulv), Klb/hr	103.0
41	Pulverizer Tempering Airflow, Klb/hr		[40] × ([36B] − [37B]) / ([36B] − [38B])			36.5
42	Total Airflow, Klb/hr from Form CMBSTNc [96]		590.4	43	Secondary Airflow, Klb/hr [42] − [40]	487.4
44	Average Entering Air Temperature, °F		([35A] × ([40] − [41]) + [39] × [43] + [38A] × [41]) / [42]			85.6
	GAS FLOW ENT PRI AH AND AVG EXIT GAS TEMP (Units With Primary and Secondary AHs)					
45A	Flue Gas Temp Ent Pri AH, °F CMBSTNb [50]		0.0	45B	Enthalpy Wet Flue Gas, Btu/lbm	0.0
46A	Flue Gas Temp Lvg Pri AH, °F CMBSTNc [88]		0.0	46B	Enthalpy Wet Flue Gas, Btu/lbm	0.0
47	Flue Gas Temp Lvg Sec AH, °F CMBSTNc [88]		299.4	48	Total Gas Ent Air Htrs, Klb/hr CMBSTNc [93]	640.1
49	Flue Gas Flow Ent Pri Air Htr, Klb/hr		([40] − [41]) × ([36B] − [35B]) / ([45B] − [46B])			69.9
50	Flue Gas Flow Ent Sec Air Htr, Klb/hr		[48] − [49]			640.1
51	Average Exit Gas Temperature, °F		([46A] × [49] + [47]×[50]) / [48]			299.4
	Iteration of flue gas split, % primary AH gas flow		Initial Estimate 0.0		Calculated 0.0	

PLANT NAME:	ASME PTC 4 EXAMPLE PROBLEM B-5	UNIT NO.:
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REMARKS: PC, Trisect AH, Res splits estimated.		DATE:
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Table B-5-2 Efficiency Calculations
Worksheet EFFb

		A MKB	B %
	LOSSES, % Enter Calculated Result in % Column [B]		
60	Dry Gas [10] × [3A] /100 × /100		5.048
61	Water from H2 Fuel [12] × ([3B] − [1A]) /100 ×(− 45) /100		3.875
62	Water from H2O Fuel [13] × ([3B] − [1A]) /100 × (− 45) /100		1.010
63	Water from H2Ov Fuel [14] × ([3C]) /100 × /100		0.000
64	Moisture in Air [16] × [3C] /100 × /100		0.111
65	Unburned Carbon in Ref [18] × 14,500 / [19] = × 14,500 /		0.486
66	Sensible Heat of Refuse from Form RES		0.118
67	Hot AQC Equip ([20] × ([5A] − [6A]) − ([22] − [20]) × ([6C] − [6B])) /100 (× (−) − (−) × (−)) /100		0.000
68	Other Losses, % Basis from Form EFFc Item [110]		0.280
69	Summation of Losses, % Basis		10.928
	LOSSES, MKBtu/hr Enter in MKB Column [A]		
75	Surface Radiation and Convection from Form EFFa Item [32]	4.272	0.670
76	Sorbent Calcination/Dehydration from Form SRBc Item [77]	0.000	0.000
77	Water from Sorbent from Form SRBc Item [65]	0.000	0.000
78			
79			
80	Other Losses, MKBtu/hr Basis from Form EFFc Item [111]	0.000	0.000
81	Summation of Losses, MKBtu/hr Basis	4.272	0.670
	CREDITS, % Enter Calculation Result in % Column [B]		
85	Entering Dry Air [11] × [2A] /100 × /100		0.189
86	Moisture in Air [16] × [2B] /100 × /100		0.004
87	Sensible Heat in Fuel 100 × [4A] / [19] 100 × /		0.023
88	Sulfation from Form SRBc Item [80]		0.000
89	Other Credits, % Basis from Form EFFc Item [112]		0.000
90	Summation of Credits, % Basis		0.216
	CREDITS, MKBtu/hr Enter Calculated Result in MKB Column [A]		
95	Auxiliary Equipment Power [31]	0.000	0.000
96	Sensible Heat from Sorbent from Form SRBc Item [85]	0.000	0.000
97	Other Credits, MKBtu/hr Basis from Form EFFc Item [113]	0.000	0.000
98	Summation of Credits, MKBtu/hr	0.000	0.000
100	Fuel Eff, % (100 − [69] + [90]) × [30] /([30] + [81] − [98]) (100 − +) × /(+ −)		88.619
101	Input from Fuel, MKB 100 × [30] /[100] = 100 × /	637.873	
102	Fuel Rate, Klbm/hr 1,000 × [101] /[19] = 1,000 × /		55.721

PLANT NAME:	ASME PTC 4 EXAMPLE PROBLEM B-5	UNIT NO.:
TEST NO.:	DATE:	LOAD:
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REMARKS: PC, Trisect AH, Res splits estimated.		DATE:
		SHEET OF

Table B-5-3 Efficiency Calculations Other Losses and Credits Worksheet EFFc

The losses and credits listed on this sheet are not universally applicable to all fossil-fired steam generators and are usually minor. Losses/credits that have not been specifically identified by this Code but are applicable in accordance with the intent of the Code should also be recorded on this sheet. Parties to the test may agree to estimate the losses or credits in lieu of testing. Enter a "T" for tested or "E" for estimated in the second column, and result in appropriate column. Enter the sum of each group on Form EFFb. Refer to the text of ASME PTC 4 for the calculation method.

Itm	T or E	LOSSES, % Enter Calculated Result in % Column [B]	A MKB	B %
110A		CO in Flue Gas		0.050
110B		Formation of NOx		0.000
110C		Pulverizer Rejects		0.090
110D		Air Infiltration		0.000
110E		Unburned Hydrocarbons in Flue Gas		0.000
110F		Other		0.140
110G				0.000
110		Summation of Other Losses, % Basis		0.280
		LOSSES, MKBtu/hr Enter in MKB Column [A]		
111A		Wet Ash Pit	0.000	
111B		Sensible Heat in Recycle Streams, Solid	0.000	
111C		Sensible Heat in Recycle Streams, Gas	0.000	
111D		Additional Moisture	0.000	
111E		Cooling Water	0.000	
111F		Air Preheater Coil (supplied by unit)	0.000	
111G		Other	0.000	
111		Summation of Other Losses, MKBtu/hr Basis	0.000	
		CREDITS, % Enter Calculation Result in % Column [B]		
112A		Other		0.000
112		Summation of Credits, % Basis		0.000
		CREDITS, MKBtu/hr Enter Result in MKB Column [A]		
113A		Heat in Additional Moisture (external to envelope)	0.000	
113B		Other	0.000	
113		Summation of Credits, MKBtu/hr Basis	0.000	

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REMARKS: PC, Trisect AH, Res splits estimated.		DATE:
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Table B-5-4 Combustion Calculations
Worksheet CMBSTNa

	DATA REQUIRED					
1	HHV, Higher Heating Value of Fuel, Btu/lbm as-fired					11,447.6
2	UBC, Unburned Carbon, lbm/100 lbm fuel from RES or SRBb FORM					0.384
3	Fuel Flow, Klbm/hr [4b]					55.72
4	a. Measured Fuel Flow			61.90		
4	b. Calculated Fuel Flow	100,000 × [5] / [6] / [1]		55.72		
5	Output, MKBtu/hr	from OUTPUT Item [37]		565.28		
6	Fuel Efficiency, % (estimate initially)			88.62		
7	Moisture in air, lbm/lbm Dry Air					0.0121
8	Barometric Pressure, in. Hg	pwva = 0.0000		29.50		
9	Dry Bulb Temperature, °F	pswvd = 0.5135		80.4		
10	Wet Bulb Temperature, °F	pswvw = 0.0000		0.0		
11	Relative Humidity, %	pwva = 0.2763		53.8		
	Additional Moisture (Measured)			Klbm/hr		
	Atomizing Steam	from OUTPUT Item [14]		0.0		
	Sootblowing Steam	from OUTPUT Item [11]		0.0		
	Other			0.0		
12	Summation Additional Moisture			0.0		
13	Additional Moisture, lbm/100 lbm Fuel	100 × [12] / [3]				0.0000
14	Additional Moisture, lbm/10KBtu	[13] / ([1] / 100)				0.0000
	If Air Heater (Excl Stm/Wtr Coil) Enter following					
15	Gas Temp Lvg AH, °F	Primary / Secondary or Main	15B	0.0	15A	280.7
16	Air Temp Ent AH, °F	Primary / Secondary or Main	16B	84.9	16A	85.7
17	O2 in FG Ent Air Heater	Primary / Secondary or Main	17B	0.00	17A	3.88
18	O2 in FG Lvg Air Heater	Primary / Secondary or Main	18B	0.00	18A	5.57
18C	O2 Measurement Basis Dry (0) or Wet (1)				18C	0
18D	Primary AH Leakage for Trisector Type AH, Percent of Total				18D	75.00
	Fuel Analysis, % Mass as-fired	Enter in Col [30]				
19	Mass Ash, lbm/10KBtu	100 × [30J] / [1]				0.092
	If mass of ash (Item [19]) exceeds 0.15 lbm/10KBtu or Sorbent					
	utilized, enter Mass Fraction of Refuse in Item [79] for each location.					
	SORBENT DATA (Enter 0 if Sorbent not Used)					
20	Sorbent Rate, Klbm/hr					0.00
21	CO2 from Sorbent, lbm/100 lbm Sorb	from SRBa Item [25I]				0.00
22	H2O from Sorbent, lbm/100 lbm Sorb	from SRBa Item [26I]				0.00
23	Sulfur Capture,lbm/ lbm Sulfur	from SRBb Item [45]				0.000
24	Spent Sorbent,lbm/ 100 lbm fuel	from SRBb Item [48]				0.00
25	Sorb/Fuel Ratio, lbm Sorb/lbm Fuel	[20] / [3]				0.000
	HOT AIR QUALITY CONTROL EQUIPMENT DATA					
26	O2 in FG Ent HAQC Equipment, %					0.00
	See Form EFFa for HAQC Flue Gas Temperatures					

PLANT NAME:	ASME PTC 4 EXAMPLE PROBLEM B-5	UNIT NO.:
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Table B-5-5 Combustion Calculations Worksheet CMBSTNb

COMBUSTION PRODUCTS

		30 Ultimate Analysis % Mass		31 Theo Air °F lbm/100 lbm Fuel [30] × K		32 Dry Prod °F Mol/100 lbm Fuel [30] / K		33 Wet Prod °F Mol/100 lbm Fuel [30] / K		34 H2O Fuel lbm/10KB [30] × K / ([1] / 100)	
A	C	63.68									
B	UBC		0.384								
C	Cb		63.30	11.51	728.54	12.0110	5.270				
D	S	2.93		4.31	12.61	32.065	0.091				
E	H2	4.32		34.29	147.96			2.0159	2.140	8.937	0.337
F	H2O	10.05						18.0153	0.558	1.0	0.088
G	H2Ov	0.00						18.0153	0.000	1.0	0.000
H	N2	1.24				28.0134	0.044				
I	O2	7.32		−4.32	−31.60						
J	ASH	10.48									
K	VM	45.00									
L	FC	45.00									
M	TOTAL	100.00		31	857.51	32	5.405	33	2.698	34	0.425

35	Total Theo Air Fuel Check, lb/10KB	([31M] + [30B] × 11.51) / ([1] / 100)	7.529

CORRECTIONS FOR SORBENT REACTIONS AND SULFUR CAPTURE

40	CO2 from Sorb, lb/100 lb fuel	[21] × [25]	0.0000
41	H2O from Sorb, lb/100 lb fuel	[22] × [25]	0.0000
42	SO2 Reduction, Mol/100 lb fuel	[32D] × [23]	0.0000
43	Dry Prod Comb, Mol/100 lb fuel	[32M] + [40] / 44.01 − [42]	5.4052
44	Wet Prod Comb, Mol/100 lb fuel	[33M] + [41] / 18.0153 + [43]	8.1035
45	O3 (SO3) Corr, lb/10KBtu	[23] × [30D] × 1.5 / ([1] / 100)	0.0000
46	Theo Air Corr, lb/100 lb fuel	[31M] + 2.16 × [30D] × [23]	857.5059
47	Theo Air Corr, Mol/100 lb fuel	[46] / 28.9625	29.6075
48	Theo Air Corr, lb/10KBtu	[46] / ([1] / 100)	7.4907
49	Wet Gas from Fuel, lb/10KBtu	(100 − [30J] − [30B] − [30D] × [23]) / ([1] / 100)	0.7787

	LOCATION			HAQC In	Sec AH In	Sec AH Out	Pri AH In	Pri AH Out
50	Flue Gas Temperature Entering Air Heater, °F				660.2083		0.0000	
51	Air Temperature Leaving Air Heater, °F					494.1000		511.7000
52	Flue Gas Oxygen Content, %			0.0000	3.8750	5.5690	0.0000	0.0000
	FLUE GAS ANALYSIS, Mol/100 lb Fuel	Dry	Wet					
53	Moisture in Air	0	[7] × 1.608					0.0000
54	Dry/Wet Products Comb	[43]	[44]					5.4052
55	Additional Moisture	0	[13]/18.0153					0.0000
56	[47] × (0.7905 + [53])							23.4047
57	Summation	[54] + [55] + [56] − [45] × [1] / 4,799.8						28.8098
58	20.95 − [52] × (1 + [53])			0.0000	17.0750	15.3810	0.0000	0.0000
60	Excess Air, %	100 × [52] × [57] / [47] / [58]		0.0000	22.0826	35.2316	0.0000	0.0000

PLANT NAME:	ASME PTC 4 EXAMPLE PROBLEM B-5	UNIT NO.:
TEST NO.:	DATE:	LOAD:
TIME START:	TIME END:	CALC BY:
REMARKS: PC, Trisect AH, Res splits estimated.		DATE:
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Table B-5-6 Combustion Calculations
Worksheet CMBSTNc

	LOCATION		Dry	Wet	HAQC In	Sec AH In	Sec AH Out	Pri AH In	Pri AH Out
60	Excess Air, %				0.0000	22.0826	35.2316	0.0000	0.0000
	O2, CO2, SO2 WHEN EXCESS AIR KNOWN								
61									
62	Dry	[47] × (0.7905 + [60] / 100)			0.0000	29.9428	33.8359	0.0000	0.0000
63	Wet	[47] × (0.7905 + [53] + (1 + [53]) × [60] / 100)			0.0000	0.0000	0.0000	0.0000	0.0000
64	Dry Gas, Mol/100 lb Fuel	[43] + [62] − [45] × [1] / 4,799.8			0.0000	35.3480	39.2410	0.0000	0.0000
65	Wet Gas, Mol/100 lb Fuel	[44] + [63] + [55] − [45] × 1 / 4,799.8			0.0000	0.0000	0.0000	0.0000	0.0000
			Dry	Wet					
66	O2, %	[60] × [47] × 0.2095/	[64]	[65]	0.0000	3.8750	5.5690	0.0000	0.0000
67	CO2, %	([30C] / 0.1201 + [40] / 0.4401)/	[64]	[65]	0.0000	14.9085	13.4294	0.0000	0.0000
68	SO2, ppm	10,000 × (1 − [23]) × [30D] / 0.32065 /	[64]	[65]	0	2,581	2,325	0	0
	FLUE GAS PRODUCT, lbm/10KBtu								
69	Gas from Dry Air	(1 × [60] / 100) × [48] − [45]			0.0000	9.145	10.130	0.000	0.000
70	Wet Gas from Fuel	[49]							0.779
71	CO2 from Sorbent	[40] / ([1] / 100)							0.000
72	Moisture in Air	[7] × (1 + [60] / 100) × [48]			0.0000	0.111	0.122	0.000	0.000
73	Water from Sorbent	[41] × ([1] / 100)							0.000
74	Additional Moisture	[14]							0.000
75	Total Wet Gas	[69] + [70] + [71] + [72] + [73] + [74]			0.000	10.034	11.031	0.000	0.000
76	H2O in Wet Gas	[34M] + [72] + [73] + [74]			0.000	0.535	0.547	0.000	0.000
77	Dry Gas	[75] − [76]			0.000	9.499	10.484	0.000	
78	H2O in Wet Gas, % Mass	100 × [76] / [75]			0.000	5.334	4.960	0.000	0.000
79	Residue, lb/lb Total Refuse at each location				0.000	0.000	0.000	0.000	0.000
80	Residue, lb/10KBtu	([30J] + [2] + [24]) / ([1]/100)							0.159
81	Residue in West Gas, lb/lb Wet Gas	[79] × [80] / [75]			0.000	0.000	0.000	0.000	0.000
82	Leakage, % Gas Entering	100 × ([75L] − [75E]) / [75E]			0.000		9.935		0.000
	GAS TEMPERATURE CORRECTION FOR AH LEAKAGE								
83	Gas Temp Lvg (INCL LKG), °F	[15]					280.70		0.00
84	Average AH Air Leakage Temp, °F	(1 − [18D]) × [16A] + [18D] × [16B]				85.1		0.0	
85	H Air Lvg., Btu/lbm	T = [83], H2O = [7]					49.63		0.00
86	H Air Ent., Btu/lbm	T = [84], H2O = [7]					1.96		0.00
87	Cpg, Btu/lbm, °F	T = [83], H2O = [78E], RES = [81E]					0.2538		0.0000
88	AH Gas Outlet Temperature Excluding Leakage, °F								
	[83] + ([82] / 100 × ([85] − [86]) / [87])						299.36		0.00
	AIR, GAS, FUEL, AND RESIDUE MASS FLOW RATES, Klbm/hr								
90	Input from Fuel, MBtu/hr	[5] × [6] / 100							637.87
91	Fuel Rate, Klb/hr	1,000 × [90] / [1]							55.72
92	Residue Rate, Klb/hr	[80] × [90] / 10							6.05
93	Wet Flue Gas, Klb/hr	[75] × [90] / 10			0.00	640.05	703.64	0.00	0.00
94	Wet Flue Gas, Klb/hr				Entering Air Heaters	640.05	Leaving Air Heaters		703.64
95	Excess Air Lvg Blr, %				Entering HAQC Equip	0.00	Entering Air Heaters		22.08
96	Total Air to Blr, Klbm/hr	(1 + [95] / 100) × (1 + [7]) × [48] × [90] / 10				0.00			590.38

PLANT NAME:	ASME PTC 4 EXAMPLE PROBLEM B-5	UNIT NO.:
TEST NO.:	DATE:	LOAD:
TIME START:	TIME END:	CALC BY:
REMARKS: PC, Trisect AH, Res splits estimated.		DATE:
		SHEET OF

Table B-5-7 Unburned Carbon and Residue Calculations Worksheet RES

DATA REQUIRED FOR RESIDUE SPLIT

1	Ash in Fuel, %	from Form CMBSTNb [30J]	10.48	2	HHV Fuel, Btu/lb "as-fired" from Form CMBSTNa [1]	11,447.6
3	Fuel Mass Flow Rate, Klbm/hr	from Form CMBSTNa [4b]	55.72			

(a) Item [3] — Use measured or estimated value initially. (See CMBSTNa.)
Recalculate after boiler efficiency has been calculated until estimated value is within 1% of calculated value.

(b) Residue splits estimated: Enter value in Col [8] and calculate Col [5].
Residue rate measured: Enter measured mass flow rates in Col [5]. When residue not measured at all locations, estimate split and flow for measured locations. Reiterate until estimated total residue is within 2% of calculated.

(c) Enter the % free carbon in Col [6] (total carbon correcter for CO2). Units with sorbent: Enter the % CO2 in Col [7].

	Location	[5] Residue Mass Flow Input Klbm/hr	Residue Mass Flow Calculated Klbm/hr	[6] C in Residue %	[7] CO2 in Residue %	[8] Residue Split % Input	Residue Split % Calculated 100×[5]/[5F]	[9] C Wtd Ave % [6] × [8] / 100	[10] CO2 Wtd Ave % [7] × [8] / 100
A	Bottom Ash	0.00	0.91	0.10	0.0	15.0	15.00	0.015	0.000
B	Economizer	0.00	0.61	3.70	0.0	10.0	10.00	0.370	0.000
C	Fly Ash	0.00	4.54	4.20	0.0	75.0	75.00	3.150	0.000
D		0.00	0.00	0.00	0.0	0.0	0.00	0.000	0.000
E		0.00	0.00	0.00	0.0	0.0	0.00	0.000	0.000
F	TOTAL	5 0.00	6.05			8 100.0	100.00	9 3.535	10 0.000

UNITS WITHOUT SORBENT

11	Unburned Carbon, lbm/100 lbm Fuel	[1] × [9F] / (100 − [9F])	0.384
20	Total Residue, lbm/100 lbm Fuel	[1] + [11]	10.86

UNITS WITH SORBENT

(d) Enter average C and CO2 in residue, [9F] and [10F] above or SRBa (Items [4] and [5]), and complete Sorbent Calculation Forms.

11	Unburned Carbon, lbm/100 lbm Fuel	from Form SRBb Item [49]	0.000
20	Total Residue, lbm/100 lbm Fuel	from Form SRBb Item [50]	0.000

TOTAL RESIDUE

21	Total Residue, Klbm/hr	[20] × [3] / 100	6.05

(e) When all residue collection locations are measured, the measured residue split is used for calculations. If a portion of the residue mass is estimated, repeat calculation above until Col [5F] and Item [21] agree within 2%.

22	Total Residue, lbm/10KBtu	100 × [20] / [2]	0.159

23 SENSIBLE HEAT RESIDUE LOSS, %

	Location	[24] Temp Residue	[8] %	×	[22] Residue lbm/10 KBtu	Btu/lbm	/ 1,000	Loss %
A	Bottom Ash	2,000.0	15.00	×	0.159 ×	515.73	/ 10,000	0.073
B	Economizer	660.2	10.00	×	0.159 ×	131.23	/ 10,000	0.012
C	Fly Ash	299.4	75.00	×	0.159 ×	44.72	/ 10,000	0.032
D		0.0	0.00	×	0.159 ×	0.00	/ 10,000	0.000
E		0.0	0.00	×	0.159 ×	0.00	/ 10,000	0.000
							Total 25	0.118

H residue $= 0.16 \times T + 1.09E{-}4 \times T^2 - 2.843E{-}8 \times T^3 - 12.95$

PLANT NAME:	ASME PTC 4 EXAMPLE PROBLEM B-5	UNIT NO.:
TEST NO.:	DATE:	LOAD:
TIME START:	TIME END:	CALC BY:
REMARKS: PC, Trisect AH, Res splits estimated.		DATE:
		SHEET OF

Table B-5-8 Input Data Sheet 1

		COMBUSTION CALCULATIONS, FORM CMBSTNa				
1		HHV, Higher Heating Value of Fuel, Btu/lbm as-fired				11,447.6
4		Fuel Flow: b. Calculated	55.721	a. Measured		61.9
6		Fuel Efficiency, % (estimate initially)				**88.619**
8		Barometric Pressure, in. Hg				29.50
9		Dry Bulb Temperature, °F				80.4
10		Wet Bulb Temperature, °F				0.0
11		Relative Humidity, %				53.8
15		Gas Temp Lvg AH, °F Primary / Secondary or Main	15B	276.08	15A	280.70
16		Air Temp Ent AH, °F Primary / Secondary or Main	16B	84.9	16A	85.73
17		O2 in Flue Gas Ent AH, % Primary / Secondary or Main	17B	3.90	17A	3.875
18		O2 in Flue Gas Lvg AH, % Primary / Secondary or Main	18B	5.50	18A	5.569
18C		O2 Measurement Basis Dry (0) or Wet (1)				0
18D		Primary AH Lkg to Gas for Trisector Air Heater, % of Total				75.00
20		Sorbent Rate, Klbm/hr				0.0
		HOT AIR QUALITY CONTROL EQUIPMENT DATA				
26		O2 in FG Ent HAQC Equipment %				0.0
		O2 in FG Lvg HAQC Equipment same as entering AHs, %				
		See Form EFFa for HAQC Flue Gas Temperatures				
		COMBUSTION CALCULATIONS, FORM CMBSTNb				
30		Fuel Ultimate Analysis, % Mass				
	A	Carbon				63.680
	B	Unburned Carbon in Ash (Calculated by program)				
	D	Sulfur				2.925
	E	Hydrogen				4.315
	F	Moisture				10.050
	G	Moisture (Vapor for gaseous fuel)				0.000
	H	Nitrogen				1.235
	I	Oxygen				7.315
	J	Ash				10.475
	K	Volatile Matter, AF, Required for Enthalpy Coal				45.00
	L	Fixed Carbon, AF, Required for Enthalpy Coal				45.00
	M	API for Oil Fuels, Required for Enthalpy Fuel Oil				0.00
50		Flue Gas Temperature Entering Primary Air Heater				0.00
		Flue Gas Temperature Entering Secondary Air Heater				660.21
51		Combustion Air Temperature Leaving Primary Air Heater				511.70
		Combustion Air Temperature Leaving Secondary Air Heater				494.10
		CORRECTED AH PERFORMANCE, INPUT SHEET				
1		Air Temp Ent Fans, °F Primary / Secondary	1B	0.0	1A	0.0
2		Air Temp Lvg Fans, °F Primary / Secondary	2B	0.0	2A	0.0

PLANT NAME:	ASME PTC 4 EXAMPLE PROBLEM B-5	UNIT NO.:
TEST NO.:	DATE:	LOAD:
TIME START:	TIME END:	CALC BY:
REMARKS:		DATE:
		SHEET OF

Table B-5-9 Input Data Sheet 2

		COMBUSTION CALCULATIONS, FORM CMBSTNc				
		None				
		UNBURNED CARBON & RESIDUE CALCULATIONS, FORM RES				
5		Residue Mass Flow		Klbm/hr		Split, %
	A	Bottom Ash	Change Location	0.00		15.00
	B	Economizer	Names as Applicable	0.00		10.00
	C	Fly Ash		0.00		75.00
	D			0.00		0.00
	E			0.00		0.00
6		Carbon in Residue, %				
	A	Bottom Ash				0.10
	B	Economizer				3.70
	C	Fly Ash				4.20
	D					
	E					
7		Carbon Dioxide in Residue, %				
	A	Bottom Ash				0.00
	B	Economizer				0.00
	C	Fly Ash				0.00
	D					
	E					
24		Temperature of Residue, °F				
	A	Bottom Ash				2,000.0
	B	Economizer				660.2
	C	Fly Ash				280.7
	D					
	E					
		SORBENT CALCULATION SHEET **MEASURED C AND CO_2 IN RESIDUE, FORM SRBa**				
7A		SO2 in Flue Gas, ppm				0
8		O2 in Flue Gas at location where SO2 is measured, %				3.00
9		SO2 & O2 Basis, Wet [1] or Dry [0]				0
20		Sorbent Products, % Mass				
	A	CaCO3				0.00
	B	Ca(OH)2				0.00
	C	MgCO3				0.00
	D	Mg(OH)2				0.00
	E	H2O				0.00
	F	Inert				0.00

PLANT NAME:	ASME PTC 4 EXAMPLE PROBLEM B-5	UNIT NO.:
TEST NO.:	DATE:	LOAD:
TIME START:	TIME END:	CALC BY:
REMARKS:		DATE:
		SHEET OF

Table B-5-10 Input Data Sheet 3

	SORBENT CALCULATION SHEET MEASURED C AND CO2 IN RESIDUE, FORM SRBb			
	None			
	SORBENT CALCULATION SHEET EFFICIENCY, FORM SRBc			
61	Sorbent Temperature, °F			0.0
	EFFICIENCY CALCULATIONS DATA REQUIRED, FORM EFFa			
4	Fuel Temperature			84.0
5	Gas Temperature Entering Hot Air Quality Control Equipment, F			0.0
6	Gas Temperature Leaving Hot Air Quality Control Equipment, F (Use Entering AH)			
31	Auxiliary Equipment Power, MKBtu/hr			0.0
32	Loss Due to Surface Radiation and Convection, % (use only if not area calculated)			0.000
	Surface Radiation & Convection Loss Location	B	A	C
33A	Flat Projected Surface Area, 10^3 ft^2	0.0	0.0	50.0
33B	Average Velocity of Air Near Surface, ft/sec	0.0	0.0	1.7
33C	Average Surface Temperature, °F	0.0	0.0	127.0
33D	Average Ambient Temperature Near Surface, °F	0.0	0.0	77.0
37A	Average Air Temperature Entering Pulverizers, °F (Enter "0" for no Pulv and/or Temp Air)			350.6
38A	Average Pulverizer Tempering Air Temperature, °F			84.9
40	Primary Airflow (Entering Pulverizer), Klb/hr			103.0
	Estimated flue gas split, % primary—Not required for computer-generated results			0.0
	EFFICIENCY CALCULATIONS, FORM EFFb			
	None			
	EFFICIENCY CALCULATIONS OTHER LOSSES AND CREDITS, FORM EFFc			
Losses, %				
85A	CO in Flue Gas			0.05
85B	Formation of NOx			0.00
85C	Pulverizer Rejects			0.09
85D	Air Infiltration			0.00
85E	Unburned Hydrocarbons in Flue Gas			0.00
85G	Other			0.14
Losses, MKBtu/hr				
86A	Wet Ash Pit			0.000
86B	Sensible Heat in Recycle Streams, Solid			0.000
86C	Sensible Heat in Recycle Streams, Gas			0.000
86D	Additional Moisture			0.000
86E	Cooling Water			0.000
86F	Air Preheat Coil (Supplied by Unit)			0.000
86G	Other			0.000
Credits, %				
87A	Other			0.00
Credits, MKBtu/hr				
88A	Heat in Additonal Moisture (External to Envelope)			0.000
88B	Other			0.000

PLANT NAME:	ASME PTC 4 EXAMPLE PROBLEM B-5	UNIT NO.:
TEST NO.:	DATE:	LOAD:
TIME START:	TIME END:	CALC BY:
REMARKS:		DATE:
		SHEET OF

Table B-5.1-1 Efficiency Calculations Data Required

Worksheet EFFa

	TEMPERATURES, °F				
1	Reference Temperature	77	1A	Enthalpy Water (32°F Ref)	45
2	Average Entering Air Temp from CMBSTNc [88] or EFFa [44]	85.4	2A	Enthalpy Dry Air	2.02
			2B	Enthalpy Water Vapor	3.74
3	Average Exit Gas T (Excl Lkg) from CMBSTNc [88] or EFFa [51]	299.0	3A	Enthalpy Dry Gas	53.05
			3B	Enthalpy Steam @ 1 psia	1,195.17
			3C	Enthalpy Water Vapor	100.07
4	Fuel Temperature	84.0	4A	Enthalpy Fuel	2.68
	HOT AIR QUALITY CONTROL EQUIPMENT				
5	Entering Gas Temperature	0.0	5A	Enthalpy Wet Gas	0.00
6	Leaving Gas Temperature	0.0	6A	Enthalpy of Wet Gas	0.00
			6B	Enthalpy of Wet Air	0.00
			6C	Enthalpy of Wet Air @ T=[3]	0.00
	RESULTS FROM COMBUSTION CALCULATION FORM CMBSTN				
10	Dry Gas Weight [77]	9.412	18	Unburned Carbon, % [2]	1.613
11	Dry Air Weight [69] + [45]	9.054	19	HHV, Btu/lbm "as-fired" [1]	11,447.6
12	Water from H2 Fuel [34E]	0.337		**HOT AQC EQUIPMENT**	
13	Water from H2O Fuel [34F]	0.088	20	Wet Gas Entering [75E]	0.00
14	Water from H2Ov Fuel [34G]	0.000	21	H2O in Wet Gas, % [78E]	0.00
15	Moisture in Air, lb/lb DA [7]	0.012	22	Wet Gas Leaving [75L]	0.00
16	Moisture in Air, lb/10KB [72]	0.019	23	Residue in Wet Gas, % [81E]	0.00
17	Fuel Rate Est, Klb/hr [3]	56.62			
			25	Excess Air, % [95]	22.06
	MISCELLANEOUS				
30	Unit Output, MKBtu/hr	565.28	31	Aux Equip Power, MKBtu/hr	0.0
32	Loss Due to Surface Radiation and Convection, %				0.00
33A	Flat Projected Surface Area, ft^2	0/0/50	33C	Average Surface Temperature, °F	0/0/127
33B	Average Velocity of Air Near Surface, ft/sec	0/0/1.67	33D	Average Ambient Temperature Near Surface, °F	0/0/77
	ENT AIR TEMP (Units With Primary and Secondary Airflow)				
35A	Pri Air Temp Entering, °F CMBSTNa [16B]	84.9	35B	Enthalpy Wet Air, Btu/lb	1.9
36A	Pri Air Temp Leaving Air Htr, °F CMBSTNb [51]	511.7	36B	Enthalpy Wet Air, Btu/lb	102.5
37A	Average Air Temp Entering Pulverizers, °F	0.0	37B	Enthalpy Wet Air, Btu/lbm	0.0
38A	Average Pulverizers Tempering Air Temp, °F	0.0	38B	Enthalpy Wet Air, Btu/lbm	0.0
39	Sec Air Temp Entering, °F CMBSTNa [16A]	85.7	40	Primary Airflow (Ent Pulv), Klb/hr	236.2
41	Pulverizer Tempering Airflow, Klb/hr	[40] × ([36B] − [37B]) / ([36B] − [38B])			0.0
42	Total Airflow, Klb/hr from Form CMBSTNc [96]	594.0	43	Secondary Airflow, Klb/hr [42] − [40]	357.8
44	Average Entering Air Temperature, °F	([35A] × ([40] − [41]) + [39] × [43] + [38A] × [41]) / [42]			85.4
	GAS FLOW ENT PRI AH AND AVG EXIT GAS TEMP (Units With Primary and Secondary AHs)				
45A	Flue Gas Temp Ent Pri AH, °F CMBSTNb [50]	0.0	45B	Enthalpy Wet Flue Gas, Btu/lbm	0.0
46A	Flue Gas Temp Lvg Pri AH, °F CMBSTNc [88]	0.0	46B	Enthalpy Wet Flue Gas, Btu/lbm	0.0
47	Flue Gas Temp Lvg Sec AH, °F CMBSTNc [88]	299.0	48	Total Gas Ent Air Htrs, Klb/hr CMBSTNc [93]	644.7
49	Flue Gas Flow Ent Pri Air Htr, Klb/hr	([40] − [41]) × ([36B] − [35B]) / ([45B] − [46B])			0.0
50	Flue Gas Flow Ent Sec Air Htr, Klb/hr	[48] − [49]			644.7
51	Average Exit Gas Temperature, °F	([46A] × [48] + [47] × [50]) / [48]			299.0
	Iteration of flue gas split % primary AH gas flow	Initial Estimate	0.0	Calculated	0.0

PLANT NAME:	ASME PTC 4 EXAMPLE PROBLEM B-5.1	UNIT NO.:
TEST NO.:	DATE:	LOAD:
TIME START:	TIME END:	CALC BY:
REMARKS: CFB, Trisect AH, Meas Bot Ash Flow		DATE:
		SHEET OF

Table B-5.1-2 Efficiency Calculations
Worksheet EFFb

		A MKB	B %
	LOSSES, % Enter Calculated Result in % Column [B]		
60	Dry Gas [10] × [3A] / 100 × / 100		4.993
61	Water from H2 Fuel [12] × ([3B] − [1A]) / 100 × (− 45) / 100		3.875
62	Water from H2O Fuel [13] × ([3B] − [1A]) / 100 × (− 45) / 100		1.010
63	Water from H2Ov Fuel [14] × ([3C]) / 100 × / 100		0.000
64	Moisture in Air [16] × [3C] / 100 × / 100		0.110
65	Unburned Carbon in Ref [18] × 14,500 / [19] = × 14,500 /		2.043
66	Sensible Heat of Refuse from Form RES		0.357
67	Hot AQC Equip ([20] × ([5A] − [6A]) − ([22] − [20]) × ([6C] − [6B])) / 100 (× (−) − (−) × (−)) / 100		0.000
68	Other Losses, % Basis from Form EFFc Item [110]		0.280
69	Summation of Losses, % Basis		12.666
	LOSSES, MKBtu/hr Enter in MKB Column [A]		
75	Surface Radiation and Convection from Form EFFa Item [32]	4.272	0.659
76	Sorbent Calcination/Dehydration from Form SRBc Item [77]	8.174	1.261
77	Water from Sorbent from Form SRBc Item [65]	0.009	0.001
78			
79			
80	Other Losses, MKBtu/hr Basis from Form EFFc Item [111]	0.000	0.000
81	Summation of Losses, MKBtu/hr Basis	12.455	1.922
	CREDITS, % Enter Calculation Result in % Column [B]		
85	Entering Dry Air [11] × [2A] /100 × /100		0.183
86	Moisture in Air [16] × [2B] /100 × /100		0.004
87	Sensible Heat in Fuel 100 × [4A] / [19] 100 × /		0.023
88	Sulfation from Form SRBc Item [80]		1.581
89	Other Credits, % Basis from Form EFFc Item [112]		0.000
90	Summation of Credits, % Basis		1.791
	CREDITS, MKBtu/hr Enter Calculated Result in MKB Column [A]		
95	Auxiliary Equipment Power [31]	0.000	0.000
96	Sensible Heat from Sorbent from Form SRBc Item [85]	0.017	0.003
97	Other Credits, MKBtu/hr Basis from Form EFFc Item [113]	0.000	0.000
98	Summation of Credits, MKBtu/hr Basis	0.017	0.003
100	Fuel Eff, % (100 − [69] + [90]) × [30] / ([30] + [81] − [98]) (100 − +) × / (+ −)		87.206
101	Input from Fuel, MKB 100 × [30] / [100] = 100 × /	648.207	
102	Fuel Rate, Klbm/hr 1,000 × [101] / [19] = 1,000 × /		56.624

PLANT NAME:	ASME PTC 4 EXAMPLE PROBLEM B-5.1	UNIT NO.:
TEST NO.:	DATE:	LOAD:
TIME START:	TIME END:	CALC BY:
REMARKS: CFB, Trisect AH, Meas Bot Ash Flow		DATE:
		SHEET OF

Table B-5.1-3 Efficiency Calculations Other Losses and Credits Worksheet EFFc

The losses and credits listed on this sheet are not universally applicable to all fossil-fired steam generators and are usually minor. Losses/credits that have not been specifically identified by this Code but are applicable in accordance with the intent of the Code should also be recorded on this sheet.

Parties to the test may agree to estimate the losses or credits in lieu of testing. Enter a "T" for tested or "E" for estimated in the second column, and result in appropriate column.

Enter the sum of each group on Form EFFb.

Refer to the text of ASME PTC 4 for the calculation method.

Itm	T or E	LOSSES, % Enter Calculated Result in % Column [B]	A MKB	B %
110A		CO in Flue Gas		0.050
110B		Formation of NOx		0.000
110C		Pulverizer Rejects		0.000
110D		Air Infiltration		0.000
110E		Unburned Hydrocarbons in Flue Gas		0.000
110F		Other		0.230
110G				0.000
110		Summation of Other Losses, % Basis		0.280
		LOSSES, MKBtu/hr Enter in MKB Column [A]		
111A		Wet Ash Pit	0.000	
111B		Sensible Heat in Recycle Streams, Solid	0.000	
111C		Sensible Heat in Recycle Streams, Gas	0.000	
111D		Additional Moisture	0.000	
111E		Cooling Water	0.000	
111F		Air Preheater Coil (supplied by unit)	0.000	
111G		Other	0.000	
111		Summation of other Losses, MKBtu/hr Basis	0.000	
		CREDITS, % Enter Calculation Result in % Column [B]		
112A		Other		0.000
112		Summation of Credits, % Basis		0.000
		CREDITS, MKBtu/hr Enter Result in MKB Column [A]		
113A		Heat in Additional Moisture (external to envelope)	0.000	
113B		Other	0.000	
113		Summation of Credits, MKBtu/hr Basis	0.000	

PLANT NAME:	ASME PTC 4 EXAMPLE PROBLEM B-5.1	UNIT NO.:
TEST NO.:	DATE:	LOAD:
TIME START:	TIME END:	CALC BY:
REMARKS: CFB, Trisect AH, Meas Bot Ash Flow		DATE:
		SHEET OF

Table B-5.1-4 Combustion Calculations Worksheet CMBSTNa

	DATA REQUIRED					
1	HHV, Higher Heating Value of Fuel, Btu/lbm as-fired					11,447.6
2	UBC, Unburned Carbon, lbm/100 lbm fuel from RES or SRBb FORM					1.613
3	Fuel Flow, Klbm/hr [4b]					56.62
4	a. Measured Fuel Flow			61.90		
4	b. Calculated Fuel Flow 100,000 × [5] / [6] / [1]			56.62		
5	Output, MKBtu/hr	from OUTPUT Item [37]		565.28		
6	Fuel Efficiency, % (estimate initially)			87.21		
7	Moisture in air, lbm/lbm Dry Air					0.0121
8	Barometric Pressure, in. Hg	pwva = 0.0000		29.50		
9	Dry Bulb Temperature, °F	pswvd = 0.5135		80.4		
10	Wet Bulb Temperature, °F	pswvw = 0.0000		0.0		
11	Relative Humidity, %	pwva = 0.2763		53.8		
	Additional Moisture (Measured)			Klbm/hr		
	Atomizing Steam	from OUTPUT Item [14]		0.0		
	Sootblowing Steam	from OUTPUT Item [11]		0.0		
	Other			0.0		
12	Summation Additional Moisture			0.0		
13	Additional Moisture, lbm/100 lbm Fuel	100 × [12] / [3]				0.0000
14	Additional Moisture, lbm/10KBtu	[13] / ([1] / 100)				0.0000
	If Air Heater (Excl Stm/Wtr Coil) Enter following					
15	Gas Temp Lvg AH, °F	Primary / Secondary or Main	15B	0.0	15A	280.7
16	Air Temp Ent AH, °F	Primary / Secondary or Main	16B	84.9	16A	85.7
17	O2 in FG Ent Air Heater	Primary / Secondary or Main	17B	0.00	17A	3.88
18	O2 in FG Lvg Air Heater	Primary / Secondary or Main	18B	0.00	18A	5.57
18C	O2 Measurement Basis Dry (0) or Wet (1)				18C	0
18D	Primary AH Leakage for Trisector Type AH, Percent of Total				18D	75.00
	Fuel Analysis, % Mass as-fired	Enter in Col [30]				
19	Mass Ash, lbm/10KBtu	100 × [30J] / [1]				0.092
	If mass of ash (Item [19]) exceeds 0.15 lbm/10KBtu or Sorbent					
	utilized, enter Mass Fraction of Refuse in Item [79] for each location.					
	SORBENT DATA (Enter 0 if Sorbent not Used)					
20	Sorbent Rate, Klbm/hr					12.49
21	CO2 from Sorbent, lbm/100 lbm Sorb	from SRBa Item [25I]				37.76
22	H2O from Sorbent, lbm/100 lbm Sorb	from SRBa Item [26I]				0.06
23	Sulfur Capture, lbm/lbm Sulfur	from SRBb Item [45]				0.919
24	Spent Sorbent, lbm/100 lbm fuel	from SRBb Item [48]				20.44
25	Sorb/Fuel Ratio, lbm Sorb/lbm Fuel	[20] / [3]				0.221
	HOT AIR QUALITY CONTROL EQUIPMENT DATA					
26	O2 in FG Ent HAQC Equipment, %					0.00
	See Form EFFa for HAQC Flue Gas Temperatures					

PLANT NAME:	ASME PTC 4 EXAMPLE PROBLEM B-5.1	UNIT NO.:
TEST NO.:	DATE:	LOAD:
TIME START:	TIME END:	CALC BY:
REMARKS: CFB, Trisect AH, Meas Bot Ash Flow		DATE:
		SHEET OF

Table B-5.1-5 Combustion Calculations
Worksheet CMBSTNb

COMBUSTION PRODUCTS

		30 Ultimate Analysis % Mass		31 Theo Air °F lbm/100 lbm Fuel [30] × K		32 Dry Prod °F Mol/100 lbm Fuel [30] / K		33 Wet Prod °F Mol/100 lbm Fuel [30] / K		34 H2O Fuel lbm/10KB [30] × K / ([1] / 100)	
A	C	63.68									
B	UBC		1.613								
C	Cb		62.07	11.51	714.39	12.0110	5.168				
D	S	2.93		4.31	12.61	32.065	0.091				
E	H2	4.32		34.29	147.96			2.0159	2.140	8.937	0.337
F	H2O	10.05						18.0153	0.558	1.0	0.088
G	H2Ov	0.00						18.0153	0.000	1.0	0.000
H	N2	1.24				28.0134	0.044				
I	O2	7.32		−4.32	−31.60						
J	ASH	10.48									
K	VM	45.00									
L	FC	45.00									
M	TOTAL	100.00		31	843.36	32	5.303	33	2.698	34	0.425

35	Total Theo Air Fuel Check, lb/10KB	([31M] + [30B] × 11.51) / ([1] / 100)	7.529

CORRECTIONS FOR SORBENT REACTIONS AND SULFUR CAPTURE

40	CO2 from Sorb, lb/100 lb fuel	[21] × [25]	8.3279
41	H2O from Sorb, lb/100 lb fuel	[22] × [25]	0.0141
42	SO2 Reduction, Mol/100 lb fuel	[32D] × [23]	0.0838
43	Dry Prod Comb, Mol/100 lb fuel	[32M] + [40] / 44.01 − [42]	5.4082
44	Wet Prod Comb, Mol/100 lb fuel	[33M] + [41] / 18.0153 + [43]	8.1073
45	O3 (SO3) Corr, lb/10KBtu	[23] × [30D] × 1.5 / ([1] / 100)	0.0352
46	Theo Air Corr, lb/100 lb fuel	[31M] + 2.16 × [30D] × [23]	849.1649
47	Theo Air Corr, Mol/100 lb fuel	[46] / 28.9625	29.3195
48	Theo Air Corr, lb/10KBtu	[46] / ([1] / 100)	7.4179
49	Wet Gas from Fuel, lb/10KBtu	(100 − [30J] − [30B] − [30D] × [23]) / ([1] / 100)	0.7445

	LOCATION			HAQC In	Sec AH In	Sec AH Out	Pri AH In	Pri AH Out
50	Flue Gas Temperature Entering Air Heater, °F				660.2083		0.0000	
51	Air Temperature Leaving Air Heater, °F					494.1000		511.7000
52	Flue Gas Oxygen Content, %			0.0000	3.8750	5.5690	0.0000	0.0000
	FLUE GAS ANALYSIS, Mol/100 lb Fuel	Dry	Wet					
53	Moisture in Air	0	[7] × 1.608					0.0000
54	Dry/Wet Products Comb	[43]	[44]					5.4082
55	Additional Moisture	0	[13]/18.0153					0.0000
56	[47] × (0.7905 + [53])							23.1770
57	Summation	[54] + [55] + [56] − [45] × [1] / 4,799.8						28.5012
58	20.95 − [52] × (1 + [53])			0.0000	17.0750	15.3810	0.0000	0.0000
60	Excess Air, %	100 × [52] × [57] / [47] / [58]		0.0000	22.0606	35.1965	0.0000	0.0000

PLANT NAME:	ASME PTC 4 EXAMPLE PROBLEM B-5.1	UNIT NO.:
TEST NO.:	DATE:	LOAD:
TIME START:	TIME END:	CALC BY:
REMARKS: CFB, Trisect AH, Meas Bot Ash Flow		DATE:
		SHEET OF

Table B-5.1-6 Combustion Calculations Worksheet CMBSTNc

	LOCATION				HAQC In	Sec AH In	Sec AH Out	Pri AH In	Pri AH Out
60	Excess Air, %				0.0000	22.0606	35.1965	0.0000	0.0000
	O2, CO2, SO2 WHEN EXCESS AIR KNOWN								
61									
62	Dry	[47] × (0.7905 + [60] / 100)			0.0000	29.6451	33.4965	0.0000	0.0000
63	Wet	[47] × (0.7905 + [53] + (1 + [53]) × [60] / 100)			0.0000	0.0000	0.0000	0.0000	0.0000
64	Dry Gas, Mol/100 lb Fuel	[43] + [62] − [45] × [1] / 4,799.8			0.0000	34.9693	38.8206	0.0000	0.0000
65	Wet Gas, Mol/100 lb Fuel	[44] + [63] + [55] − [45] × 1 / 4,799.8			0.0000	0.0000	0.0000	0.0000	0.0000
			Dry	Wet					
66	O2, %	[60] × [47] × 0.2095/	[64]	[65]	0.0000	3.8750	5.5690	0.0000	0.0000
67	CO2, %	([30C] / 0.1201 + [40] / 0.4401)/	[64]	[65]	0.0000	15.3184	13.7987	0.0000	0.0000
68	SO2, ppm	10,000 × (1 − [23]) × [30D] / 0.32065 /	[64]	[65]	0	211	190	0	0
	FLUE GAS PRODUCT, lbm/10KBtu								
69	Gas from Dry Air	(1 × [60] / 100) × [48] − [45]			0.0000	9.019	9.993	0.000	0.000
70	Wet Gas from Fuel	[49]							0.744
71	CO2 from Sorbent	[40] / ([1] / 100)							0.073
72	Moisture in Air	[7] × (1 + [60] / 100) × [48]			0.0000	0.109	0.121	0.000	0.000
73	Water from Sorbent	[41] × ([1] / 100)							0.000
74	Additional Moisture	[14]							0.000
75	Total Wet Gas	[69] + [70] + [71] + [72] + [73] + [74]			0.000	9.946	10.932	0.000	0.000
76	H2O in Wet Gas	[34M] + [72] + [73] + [74]			0.000	0.534	0.546	0.000	0.000
77	Dry Gas	[75] − [76]			0.000	9.412	10.386	0.000	0.000
78	H2O in Wet Gas, % Mass	100 × [76] / [75]			0.000	5.372	4.995	0.000	0.000
79	Residue, lb/lb Total Refuse at each location				0.000	0.755	0.755	0.755	0.755
80	Residue, lb/10KBtu	([30J] + [2] + [24]) / ([1]/100)							0.284
81	Residue in West Gas, lb/lb Wet Gas	[79] × [80] / [75]			0.000	0.022	0.020	0.000	0.000
82	Leakage, % Gas Entering	100 × ([75L] − [75E]) / [75E]			0.000		9.916		0.000
	GAS TEMPERATURE CORRECTION FOR AH LEAKAGE								
83	Gas Temp Lvg (INCL LKG), °F	[15]					280.70		0.00
84	Average AH Air Leakage Temp, °F	(1 − [18D]) × [16A] + [18D] × [16B]				85.1		0.0	
85	H Air Lvg., Btu/lbm	T = [83], H2O = [7]					49.63		0.00
86	H Air Ent., Btu/lbm	T = [84], H2O = [7]					1.96		0.00
87	Cpg, Btu/lbm, °F	T = [83], H2O = [78E], RES = [81E]					0.2586		0.0000
88	AH Gas Outlet Temperature Excluding Leakage, °F [83] + ([82] / 100 × ([85] − [86]) / [87])						298.98		0.00
	AIR, GAS, FUEL, AND RESIDUE MASS FLOW RATES, Klbm/hr								
90	Input from Fuel, MBtu/hr	[5] × [6] / 100							648.21
91	Fuel Rate, Klb/hr	1,000 × [90] / [1]							56.62
92	Residue Rate, Klb/hr	[80] × [90] / 10							18.42
93	Wet Flue Gas, Klb/hr	[75] × [90] / 10			0.00	644.70	708.62	0.00	0.00
94	Wet Flue Gas, Klb/hr				Entering Air Heaters	644.70	Leaving Air Heaters		708.62
95	Excess Air Lvg Blr, %				Entering HAQC Equip	0.00	Entering Air Heaters		22.06
96	Total Air to Blr, Klbm/hr	(1 + [95] / 100) × (1 + [7]) × [48] × [90] / 10				0.00			594.00

PLANT NAME:	ASME PTC 4 EXAMPLE PROBLEM B-5.1	UNIT NO.:
TEST NO.:	DATE:	LOAD:
TIME START:	TIME END:	CALC BY:
REMARKS: CFB, Trisect AH, Meas Bot Ash Flow		DATE:
		SHEET OF

Table B-5.1-7 Sorbent Calculation Sheet
Worksheet SRBa Measured C and CO_2 in Residue

DATA REQUIRED

1	Fuel Rate, Klbm/hr	from CMBSTNa [4b]	* 56.62	4	Carbon in Residue, %	from Form RES [9F]	4.959
2	Sorbent Rate, Klbm/hr	from CMBSTNa [20]	12.49	5	CO2 in Residue,	from Form RES [10F]	2.887
3	Sorb/Fuel Ratio	[2] / [1]	+ 0.221	6	Moisture in Air, lb/lb Dry Air	from CMBSTNa [7]	0.012
7	SO2 Flue Gas, ppm	7A	211.0		[7A] / 10,000	% 7B	0.021
8	O2 Flue Gas @ Loc SO2, %		3.875	9	SO2 & O2 Basis Wet(1) or Dry(0)		0
10	Additional Moisture, lb/100 lb Fuel				(CMBSTNa, Item [13])		0.00

Item [1] — Use measured or estimated value initially. Recalculate after boiler efficiency has been calculated until estimated value is within 1% of calc.

Enter fuel analysis in Col [15].

Enter sorbent analysis in Col [20].

* Estimate Unburned Carbon [15B], and Calcination [23A] initially.

Reiterate until estimated value is within 2% of calculated value.

\+ Items that must be recalculated for each iteration.

COMBUSTION PRODUCTS

		[15] Ultimate Analysis % Mass from CMBSTNb [30]		[16] Theo Air °F lbm/100 lbm Fuel [15] × K		[17] Dry Prod °F Mol/100 lbm Fuel [15] / K		[18] Wet Prod °F Mol/100 lbm Fuel [15] / K	
A	C	63.68							
B	UBC		* 1.613						
C	Cb		+ 62.07	11.51	+ 714.4	12.0110	+ 5.17		
D	S	2.93		4.31	12.6	32.0650	0.09		
E	H2	4.32		34.29	148.0			2.0159	2.140
F	H2O	10.05						18.0153	0.558
G	H2Ov	0.00						18.0153	0.000
H	N2	1.24				28.0134	0.04		
I	O2	7.32		−4.32	−31.6				
J	ASH	10.48							
K									
L									
M	TOTAL	99.995	0.00	16	+ 843.4	17	+ 5.303	18	2.698

SORBENT PRODUCTS

		[20] % Mass	[21] MW	[22] Ca Mol/100 lb [20] / [21]	[23] Calcination Fraction	[24] MW	[25] CO2 lb/100 lb Sorb [22] × [23] × [24]	[26] H2O lb/100 lb Sorb [22] × [23] × [24]
A	CaCO3	94.034	100.0872	0.940	* 0.897	44.0098	+ 37.100	
B	Ca(OH)2	0.000	74.0927	0.000	1.0	18.0153		0.000
C	MgCO3	1.256	84.3142		1.0	44.0098	0.656	
D	Mg(OH)2	0.000	58.3197		1.0	18.0153		0.000
E	H2O	0.064	18.0153		1.0	18.0153		0.064
F	INERT	4.646						
G								
H								
I	TOTAL Ca, Mol/100 lb Sorb			0.940		TOTAL	+ 37.755	0.064

PLANT NAME:	ASME PTC 4 EXAMPLE PROBLEM B-5.1	UNIT NO.:
TEST NO.:	DATE:	LOAD:
TIME START:	TIME END:	CALC BY:
REMARKS: CFB, Trisect AH, Meas Bot Ash Flow		DATE:
		SHEET OF

Table B-5.1-8 Sorbent Calculation Sheet
Worksheet SRBb Sulfur Capture and Other Sorbent/Residue Calculations

	SULFUR CAPTURE BASED ON GAS ANALYSIS				
	Select Column per Item [9]	Dry	Wet		0
30	Moisture in Air Mols/Mol DA	0.0	[6] × 1.608		0.000
31	Additional Moisture	0.0	[10] / 18.015		0.000
32	Products Combustion Fuel	[17M]	[17M] + [18M]	+	5.303
33	H2O Sorb [3] × [26I] / 18.016	0.0	Calc		0.000
34	CO2 Sorb [3] × [25I] / 44.01			+	0.189
35	(0.7905 + [30]) × [16M] / 28.9625			+	23.019
36	Summation [31] through [35]			+	28.511
37	1.0 − (1.0 + [30]) × [8] / 20.95				0.815
38	(0.7905 + [30]) × 2.387 − 2.3				−0.413
39	[7B] × [36] / [17D] / [37]			+	8.091
40	[38] × [7B] / [37]				−0.011
45	Sulfur Capture, lb/lb Sulfur (100 − [39]) / (100 + [40])			+	0.919
	UNBURNED CARBON, CALCINATION, AND OTHER SORBENT/RESIDUE CALCULATIONS				
47	SO3 Formed, lb/100 lb Fuel [45] × [15D] × 2.5			+	6.722
48	Spent Sorbent, lb/100 lb Fuel [47] + ((100 − [25I]) − [26I]) × [3]			+	20.437
49	Unburned Carbon, lb/100 lb Fuel ([48] + [15J]) × [4] / (100 − [4])			+	1.613
50	Residue Rate, lb/100 lb Fuel [49] + [48] + [15J]			+	32.525
51	Calcination, Mols CO2/Mol CaCO3 1 − [50] × [5] × 0.0227 / [20A] / [3]			+	0.897
52	Ca/S Molar Ratio, Mols Ca/Mol S [3] × [22I] × 32.065 / [15D]				2.272
	Compare the following, reiterate if initial estimate not within 2% calculated.				
			Initial Est	Calculated	
	Unburned Carbon, lb/100 lb Fuel		[15B] 1.613	[49]	1.613
	Calcination, Mols CO2/Mol CaCO3		[23A] 0.897	[51]	0.897
	Enter result of Item [50] on Form RES, Item [20].				
	If residue mass flow rate not measured at all locations, recalculate				
	RES and SRBa and SRBb until convergence on refuse rate of 2%.				

PLANT NAME:	ASME PTC 4 EXAMPLE PROBLEM B-5.1	UNIT NO.:
TEST NO.:	DATE:	LOAD:
TIME START:	TIME END:	CALC BY:
REMARKS: CFB, Trisect AH, Meas Bot Ash Flow		DATE:
		SHEET OF

Table B-5.1-9 Sorbent Calculation Sheet
Worksheet SRBc Efficiency

	DATA REQUIRED				
60	Reference Temperature, °F	77	60A	Enthalpy Water (32°F Ref)	45
61	Sorbent Temperature, °F	84.0	61A	Enthalpy Sorbent (77°F Ref)	1.39
62	Ave Exit Gas Temp (Excl Lkg)	299.0	62A	Enthalpy Steam @ 1 psia	1,195.17
63	HHV Fuel, Btu/lbm "as-fired"				11,447.6

	LOSSES, MKBtu/hr		
65	Water from Sorbent	[2] × [26I] × ([62A] − [60A]) / 100,000 × × (−) / 100,000	0.009

	Calcination/Dehydration			
71	CaCO3	[20A] × [23A] × [2] × 0.00766 =	94.03 × 0.90 × 12.49 × 0.00766	8.072
72	Ca(OH)2	[20B] × 1 × [2] × 0.00636 =	0.00 × 1 × 12.49 × 0.00636	0.000
73	MgCO3	[20C] × 1 × [2] × 0.00652 =	1.26 × 1 × 12.49 × 0.00652	0.102
74	Mg(OH)2	[20D] × 1 × [2] × 0.00625 =	0.00 × 1 × 12.49 × 0.00625	0.000
75				
76				
77	Summation of Losses Due to Calcination/Dehydration		SUM [71] − [76]	8.174

	CREDITS, %		
80	Sulfation	6,733 × [45] × [15D] / [63] 6,733 × × /	1.581

	CREDITS, MKBtu/hr		
85	Sensible Heat from Sorbent	[2] × [61A] / 1,000 × / 1,000	0.017

Enthalpy of Limestone — See text for other sorbents.	
HCACO3 = [61] × (0.179 + 0.1128E − 3 × [61]) − 14.45 × (0.179 + 0.1128E − 3 ×) − 14.45	1.382
[61A] = (1 − [20E] / 100) × HCACO3 + [20E] × ([61] − 77) / 100 = (1 − / 100) × + × (− 77) / 100	1.386

PLANT NAME:	ASME PTC 4 EXAMPLE PROBLEM B-5.1	UNIT NO.:
TEST NO.:	DATE:	LOAD:
TIME START:	TIME END:	CALC BY:
REMARKS: CFB, Trisect AH, Meas Bot Ash Flow		DATE:
		SHEET OF

Table B-5.1-10 Unburned Carbon and Residue Calculations Worksheet RES

DATA REQUIRED FOR RESIDUE SPLIT

1	Ash in Fuel, %	from Form CMBSTNb [30J]	10.48	2	HHV Fuel, Btu/lb "as-fired" from Form CMBSTNa [1]	11,447.6
3	Fuel Mass Flow Rate, Klbm/hr	from Form CMBSTNa [4b]	56.62			

(a) Item [3] — Use measured or estimated value initially. (See CMBSTNa.)
Recalculate after boiler efficiency has been calculated until estimated value is within 1% of calculated value.

(b) Residue splits estimated: Enter value in Col [8] and calculate Col [5].
Residue rate measured: Enter measured mass flow rates in Col [5]. When residue not measured at all locations, estimate split and flow for measured locations. Reiterate until estimated total residue is within 2% of calculated.

(c) Enter the % free carbon in Col [6] (total carbon correcter for CO2). Units with sorbent: Enter the % CO2 in Col [7].

	Location	[5] Residue Mass Flow Input Klbm/hr	[5] Residue Mass Flow Calculated Klbm/hr	[6] C in Residue %	[7] CO2 in Residue %	[8] Residue Split % Input	[8] Residue Split % Calculated 100×[5]/[5F]	[9] C Wtd Ave % [6] × [8] / 100	[10] CO2 Wtd Ave % [7] × [8] / 100
A	Bottom Ash	4.51	4.51	1.35	0.81	0.0	24.49	0.331	0.198
B	Economizer	0.00	0.00	0.00	0.00	0.0	0.00	0.000	0.000
C	Fly Ash	0.00	13.91	6.13	3.56	0.0	75.51	4.629	2.688
D		0.00	0.00	0.00	0.00	0.0	0.00	0.000	0.000
E		0.00	0.00	0.00	0.00	0.0	0.00	0.000	0.000
F	TOTAL	5 4.51	18.42			8 0.0	100.00	9 4.959	10 2.887

UNITS WITHOUT SORBENT

11	Unburned Carbon, lbm/100 lbm Fuel	[1] × [9F] / (100 − [9F])	0.000
20	Total Residue, lbm/100 lbm Fuel	[1] + [11]	0.00

UNITS WITH SORBENT

(d) Enter average C and CO2 in residue, [9F] and [10F] above or SRBa (Items [4] and [5]), and complete Sorbent Calculation Forms.

11	Unburned Carbon, lbm/100 lbm Fuel	from Form SRBb Item [49]	1.613
20	Total Residue, lbm/100 lbm Fuel	from Form SRBb Item [50]	32.525

TOTAL RESIDUE

21	Total Residue, Klbm/hr	[20] × [3] / 100	18.42

(e) When all residue collection locations are measured, the measured residue split is used for calculations. If a portion of the residue mass is estimated, repeat calculation above until Col [5F] and Item [21] agree within 2%.

22	Total Residue, lbm/10KBtu	100 × [20] / [2]	0.284

23 SENSIBLE HEAT RESIDUE LOSS, %

	Location	[24] Temp Residue	[8] %	×	[22] Residue lbm/10 KBtu	Btu/lbm	/ 1,000	Loss %
A	Bottom Ash	1,499.2	24.49	×	0.284 ×	374.90	/ 10,000	0.261
B	Economizer	660.2	0.00	×	0.284 ×	131.23	/ 10,000	0.000
C	Fly Ash	299.0	75.51	×	0.284 ×	44.64	/ 10,000	0.096
D		0.0	0.00	×	0.284 ×	0.00	/ 10,000	0.000
E		0.0	0.00	×	0.284 ×	0.00	/ 10,000	0.000
							Total [25]	0.357

H residue = $0.16 \times T + 1.09E{-}4 \times T^2 - 2.843E{-}8 \times T^3 - 12.95$

PLANT NAME:	ASME PTC 4 EXAMPLE PROBLEM B-5.1	UNIT NO.:
TEST NO.:	DATE:	LOAD:
TIME START:	TIME END:	CALC BY:
REMARKS: CFB, Trisect AH, Meas Bot Ash Flow		DATE:
		SHEET OF

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Table B-5.1-11 Efficiency Uncertainty Worksheets (CFB): A Worksheet No. 1A

	Measured Parameter (From DATA)	1 Average Value (Item [2] on MEAS Form)	2 Standard Deviation (Item [3] on MEAS Form)	Sys Uncert Sheet No.	3 Total Positive Systematic Uncert (Item [2] on SYSUNC Form)		4 Total Negative Systematic Uncert (Item [2] on SYSUNC Form)		5 No. of Readings (Item [1] on MEAS Form)	6 Standard Dev of Mean $([2]^2 / [5])^{1/2}$	7 Degrees of Freedom [5] − 1	8 Percent Change	9 Incremental Change *[8] × [1] / 100
					%	Unit	%	Unit					
a	Output	565.28		Unc Frm		4.68		2.00		2.29	20	1.00	5.65
b	Fuel HHV	11,447.55	0.0707	6A	2.00	54.00	2.24	54.00	2	0.0500	1	1.00	114.48
c	Fuel Flow	61.90	0.6558	3A	5.10	0.00	5.10	0.00	20	0.1457	19	1.00	0.62
d	Barometric Pressure	29.50	0.0361	4B	0.00	0.32	0.00	0.32	3	0.02	2	1.00	0.30
e	Amb Dry-Bulb Temp	80.40	1.1690	A1	0.00	1.03	0.00	1.03	6	0.4773	5	1.00	0.80
f	Amb Wet-Bulb Temp	0.00	0.0000	A1	0.00	1.03	0.00	1.03	0	0.0000	0	1.00	0.00
g	Relative Humidity	53.80	0.8944	4A	0.00	0.71	0.00	0.71	6	0.37	5	1.00	0.54
h	Flue Gas Temp Lvg Pri AH	0.00	0.3239	1B	0.00	3.32	0.00	3.32	7	0.13	6	1.00	0.00
i	Flue Gas Temp Lvg Sec AH	280.70	0.5904	1B	0.00	3.33	0.00	3.33	8	0.21	7	1.00	2.81
j	Comb Air Temp Ent Pri Air Htr	84.89	0.3066	1A	0.00	1.03	0.00	1.03	10	0.10	9	1.00	0.85
k	Comb Air Temp Ent Sec Air Htr	85.73	0.3652	1A	0.00	1.04	0.00	1.04	9	0.12	8	1.00	0.86
l	O2 in FG Ent Pri Air Htr	0.00	0.1342	5A	0.00	0.31	0.00	0.31	10	0.04	9	1.00	0.00
m	O2 in FG Ent Sec Air Htr	3.88	0.1421	5A	0.00	0.31	0.00	0.31	10	0.04	9	1.00	0.04
n	O2 in FG Lvg Pri Air Htr	0.00	0.4346	5B	0.00	0.59	0.00	0.59	10	0.14	9	1.00	0.00
o	O2 in FG Lvg Sec Air Htr	5.57	0.4560	5B	0.00	0.59	0.00	0.59	10	0.14	9	1.00	0.06
p	Pri AH Lkg for Trisector	0.00		INPUT	0.00	10.00	0.00	20.00	2	0.00	1	1.00	0.75
q	Sorbent Flow	0.00	0.6170	3B	7.00	0.00	7.00	0.00	24	0.13	23	1.00	0.12
r	Fuel Carbon	63.68	0.0707	6B	0.32	0.00	0.32	0.00	2	0.05	1	1.00	0.64
s	Fuel Sulfur	2.93	0.0071	6C	0.11	0.00	0.11	0.00	2	0.01	1	1.00	0.03
t	Fuel Hydrogen	4.32	0.0071	6D	0.12	0.00	0.12	0.00	2	0.01	1	1.00	0.04
u	Fuel Moisture	10.05	0.0707	6E	2.02	0.00	10.20	0.00	2	0.05	1	1.00	0.10
v	Fuel Moisture (vaporous gas)									0.00	0	1.00	0.00
w	Fuel Nitrogen	1.24	0.0071	6G	0.14	0.00	0.14	0.00	2	0.01	1	1.00	0.01
x	Fuel Oxygen	7.32	0.0071	6D	0.12	0.00	0.12	0.00	2	0.01	1	1.00	0.07
y	Fuel Ash	10.48	0.0071	6F	2.01	0.00	2.01	0.00	2	0.00	1	1.00	0.10
z	FG Temp Ent Pri Air Htr	0.00	1.3687	1B	0.00	3.39	0.00	3.39	5	0.59	4	1.00	0.00
aa	FG Temp Ent Sec Air Htr	660.21	1.0847	1B	0.00	3.32	0.00	3.32	4	0.53	3	1.00	6.60
ab	Comb Air Temp Lvg Pri Air Htr	511.70	0.6409	1A	0.00	1.08	0.00	1.08	9	0.22	8	1.00	5.12
ac	Comb Air Temp Lvg Sec Air Htr	494.10	2.5007	1A	0.00	1.30	0	1.30	10	0.79	9	1.00	4.94

Input source for Items [1] through [5]
For Spatially Uniform Parameters, enter results from the MEAS Data SYSUNC Forms.
For Spatially Nonuniform Parameters, enter results from the INTAVG Form.

* The value used for incremental change can be any increment of the average value.
The recommended increment is 1.0% (0.01 times the average value).
If the average value of the measured parameter is zero, use any small incremental change.
It is important to note that the incremental change must be in the same units as the average value.

PLANT NAME:	ASME PTC 4 EXAMPLE PROBLEM B-5.1	UNIT NO.:
TEST NO.:	DATE:	LOAD:
TIME START:	TIME END:	CALC BY:
REMARKS: CFB, Trisect AH, Meas Bot Ash Flow		DATE:
		SHEET OF

Table B-5.1-11 Efficiency Uncertainty Worksheets (CFB): A (Cont'd)
Worksheet No. 2A

	Measured Parameter	10 Recalc Efficiency *	11 Absolute Sensitivity Coefficient ([10] − [20])/[9]	12 Relative Sensitivity Coefficient ([11] × [1])/[20]	13 Random Unc of Result Calculation [11] × [6]	14 Deg of Freedom for Random Uncert Contribution ([11] × [6])^4/[7]	15 Positive SYSUNC of Result [11] × {([1] × [3A] /100)^2 + [3B]^2}$^{1/2}$	16 Negative SYSUNC of Result [11] × {([1] × [4A] /100)^2 + [4B]^2}$^{1/2}$
a	Output	87.2338	0.0049	0.0318	0.0112	8.0733E−10	0.0229	0.0229
b	Fuel HHV	87.2983	0.0008	0.1058	0.0000	2.6323E−18	0.1895	0.2108
c	Fuel Flow	87.2061	0.0000	0.0000	0.0000	7.2756E−31	0.0000	0.0000
d	Barometric Pressure	87.2061	0.0000	0.0000	0.0000	1.6150E−36	0.0000	0.0000
e	Amb Dry-Bulb Temp	87.2061	0.0000	0.0000	0.0000	8.9396E−29	0.0000	0.0000
f	Amb Wet-Bulb Temp	87.2061	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
g	Relative Humidity	87.2061	0.0000	0.0000	0.0000	1.6369E−28	0.0000	0.0000
h	Flue Gas Temp Lvg Pri AH	87.2061	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
i	Flue Gas Temp Lvg Sec AH	87.1297	−0.0272	−0.0875	−0.0057	1.5942E−10	−0.0906	−0.0906
j	Comb Air Temp Ent Pri Air Htr	87.2148	0.0103	0.0100	0.0010	1.1069E−13	0.0106	0.0106
k	Comb Air Temp Ent Sec Air Htr	87.2177	0.0135	0.0133	0.0016	7.8148E−13	0.0141	0.0141
l	O2 in FG Ent Pri Air Htr	87.2061	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
m	O2 in FG Ent Sec Air Htr	87.2062	0.0033	0.0001	0.0001	5.0694E−17	0.0010	0.0010
n	O2 in FG Lvg Pri Air Htr	87.2061	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
o	O2 in FG Lvg Sec Air Htr	87.1894	−0.2992	−0.0191	−0.0431	3.8517E−07	−0.1751	−0.1751
p	Pri AH Lkg for Trisector	87.2061	0.0000	0.0000	0.0000	0.0000E+00	−0.0002	−0.0004
q	Sorbent Flow	87.1823	−0.1906	−0.0273	−0.0240	1.4431E−08	−0.1666	−0.1666
r	Fuel Carbon	87.1651	−0.0644	−0.0470	−0.0032	1.0761E−10	−0.0130	−0.0130
s	Fuel Sulfur	87.2165	0.3560	0.0119	0.0018	1.0040E−11	0.0012	0.0012
t	Fuel Hydrogen	87.1626	−1.0067	−0.0498	−0.0050	6.4187E−10	−0.0053	−0.0053
u	Fuel Moisture	87.1968	−0.0920	−0.0106	−0.0046	4.4829E−10	−0.0186	−0.0943
v	Fuel Moisture (vaporous gas)	87.2061	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
w	Fuel Nitrogen	87.2061	−0.0017	0.0000	0.0000	4.6781E−21	0.0000	0.0000
x	Fuel Oxygen	87.2077	0.0227	0.0019	0.0001	1.6741E−16	0.0002	0.0002
y	Fuel Ash	87.1985	−0.0723	−0.0087	−0.0004	1.7121E−14	−0.0152	−0.0152
z	FG Temp Ent Pri Air Htr	87.2061	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
aa	FG Temp Ent Sec Air Htr	87.2061	0.0000	0.0000	0.0000	5.1608E−32	0.0000	0.0000
ab	Comb Air Temp Lvg Pri Air Htr	87.2061	0.0000	0.0000	0.0000	1.6983E−33	0.0000	0.0000
ac	Comb Air Temp Lvg Sec Air Htr	87.2061	0.0000	0.0000	0.0000	3.0203E−31	0.0000	0.0000

* This uncertainty worksheet is set up for calculating the uncertainty effect on efficiency; however, this sheet can be used for any calculated item, such as output, fuel flow, calcium/sulfur ratio, etc.

20	* Base Efficiency	From Item [100] on EFFb form				See UncEffb 2D
21	Random Component of Uncertainty	([13a]^2 + [13b]^2 +...)$^{1/2}$				0.0027
22	Degrees of Freedom for Random Uncertainty	[21]^4 / ([14a] + [14b] +...)				4.0178E–07
23	Positive Systematic Uncertainty of Result	([15a]^2 + [15b]^2 + ...)$^{1/2}$				0.1042
24	Negative Systematic Uncertainty of Result	([16a]^2 + [16b]^2 + ...)$^{1/2}$				0.1212
25	Degrees of Freedom for Overall Test Result	[([23]/2)^2 + ([21])^2]^2/[([21])^4 /[22] + ([23]/2)^4/50]	Pos	See UncEffb 2D	Neg	See UncEffb 2D
26	Student's *t* Value for Overall Degrees of Freedom for Test	From Table 5-16.5-1 in Code	Pos	See UncEffb 2D	Neg	See UncEffb 2D
27	Positive Total Test Uncertainty	[Pos 26] (([21])^2 + ([23]/2)^2)$^{1/2}$				See UncEffb 2D
28	Negative Total Test Uncertainty	[Neg 26] (([21])^2 + ([23]/2)^2)$^{1/2}$				See UncEffb 2D

PLANT NAME:	ASME PTC 4 EXAMPLE PROBLEM B-5.1	UNIT NO.:
TEST NO.:	DATE:	LOAD:
TIME START:	TIME END:	CALC BY:
REMARKS: CFB, Trisect AH, Meas Bot Ash Flow		DATE:
		SHEET OF

Table B-5.1-12 Efficiency Uncertainty Worksheets (CFB): B Worksheet No. 1B

	Measured Parameter (From DATA)	1 Average Value (Item [2] on MEAS Form)	2 Standard Deviation (Item [3] on MEAS Form)	Sys Uncert Sheet No.	3 Total Positive Systematic Uncert (Item [2] on SYSUNC Form) %	3 Unit	4 Total Negative Systematic Uncert (Item [2] on SYSUNC Form) %	4 Unit	5 No. of Readings (Item [1] on MEAS Form)	6 Standard Dev of Mean ([2]^2 / [5])$^{1/2}$	7 Degrees of Freedom [5] − 1	8 Percent Change	9 Incremental Change* [8] × [1] / 100
a	Furnace Residue Flow, %	0.00	0.00	3F	0.00	10.00	0.00	5.00	2	0.00	1	1.00	0.00
b	Economizer Residue Flow, %	0.00	0.00	4F	7.00	0.00	7.00	0.00	2	0.00	1	1.00	0.00
c	Precipitator Residue Flow, %	0.00	0.00	3G	0.00	20.00	0.00	20.00	2	0.00	1	1.00	0.00
d	Furnace Residue Flow, lb/hr	4.51	2.57	3F	7.00	0.00	7.00	5.00	24	0.52	23	1.00	0.05
e	Economizer Residue Flow, lb/hr	0.00	0.00	4F	7.00	0.00	7.00	0.00	0	0.00	0	1.00	0.00
f	Precipitator Residue Flow, lb/hr	0.00	0.00	3G	0.00	20.00	0.00	20.00	0	0.00	0	1.00	0.00
g	Furn Residue Carbon Content	1.35	0.00	7A	5.01	0.00	5.01	0.00	2	0.00	1	1.00	0.01
h	Econ Residue Carbon Content	0.00	0.45	7A	5.01	0.00	5.01	0.00	6	0.19	5	1.00	0.00
i	Precip Residue Carbon Content	6.13	0.51	7A	5.01	0.00	5.01	0.00	6	0.21	5	1.00	0.06
j	Furnace Residue CO2 Content	0.81	0.00	7B	5.01	0.00	5.01	0.00	0	0.00	0	1.00	0.01
k	Econ Residue CO2 Content	0.00	0.00	7B	5.01	0.00	5.01	0.00	0	0.00	0	1.00	0.00
l	Precip Residue CO2 Content	3.56	0.00	7B	5.01	0.00	5.01	0.00	0	0.00	0	1.00	0.04
m	Furnace Residue Temp	2,000.00	0.00	1B	0.00	3.32	0.00	3.32	2	0.00	1	1.00	20.00
n	Economizer Residue Temp	660.21	1.08	1B	0.00	3.32	0.00	3.32	24	0.22	23	1.00	6.60
o	Precipitator Residue Temp	280.70	0.59	1B	0.00	3.33	0.00	3.33	24	0.12	23	1.00	2.81
p	SO2 in Flue Gas	211.00	6.3	8A	0.00	22.91	0.00	22.91	24	1.29	23	1.00	2.11
q	O2 in Flue Gas	3.88	0.1	8B	0.00	0.73	0.00	0.73	24	0.00	23	1.00	0.04
r	CaCO3 in Sorbent	94.03	0.0	9A	2.00	0.16	2.00	0.16	0	0.00	0	1.00	0.94
s	Ca(OH)2 in Sorbent	0.00	0.0	9A	2.00	0.16	2.00	0.16	0	0.00	0	1.00	0.00
t	MgCO3 in Sorbent	1.26	0.0	9B	2.00	0.11	2.00	0.11	0	0.00	0	1.00	0.01
u	Mg(OH)2 in Sorbent	0.00	0.0	9B	2.00	0.11	2.00	0.11	0	0.00	0	1.00	0.00
v	Moisture in Sorbent	0.06	0.0	9C	5.39	0.00	5.39	0.00	0	0.00	0	1.00	0.00
w	Inert Material in Sorbent	4.65	0.0	9D	14.28	0.00	10.20	0.00	0	0.00	0	1.00	0.05
x	Sorbent Temp	84.00	0.0	1F	0.00	7.07	0.00	7.07	0	0.00	0	1.00	0.84
y	Fuel Temp	84.00	1.0	1F	0.00	3.16	0.00	3.16	3	0.58	2	1.00	0.84
z	FG Temp Ent Hot AQCS Equip	0.00	0.0	1B	0.00	0.00	0.00	0.00	0	0.00	0	1.00	0.00
aa	O2 Ent Hot AQCS Equip	0.00	0.0	5A	0.00	0.00	0.00	0.00	0	0.00	0	1.00	0.00
ab													
ac													

Input source for Items [1] through [5]
For Spatially Uniform Parameters, enter results from the MEAS Data SYSUNC Forms.
For Spatially Nonuniform Parameters, enter results from the INTAVG Form.

* The value used for incremental change can be any increment of the average value.
The recommended increment is 1.0% (0.01 times the average value).
If the average value of the measured parameter is zero, use any small incremental change.
It is important to note that the incremental change must be in the same units as the average value.

PLANT NAME:	ASME PTC 4 EXAMPLE PROBLEM B-5.1	UNIT NO.:
TEST NO.:	DATE:	LOAD:
TIME START:	TIME END:	CALC BY:
REMARKS: CFB, Trisect AH, Meas Bot Ash Flow		DATE:
		SHEET OF

Table B-5.1-12 Efficiency Uncertainty Worksheets (CFB): B (Cont'd)
Worksheet No. 2B

	Measured Parameter	10 Recalc Efficiency *	11 Absolute Sensitivity Coefficient ([10] − [20])/[9]	12 Relative Sensitivity Coefficient ([11] × [1])/[20]	13 Random Unc of Result Calculation [11] × [6]	14 Deg of Freedom for Random Uncert Contribution ([11] × [6])^4/[7]	15 Positive Sys Unc of Result [11] × {([1] × [3A]/100)^2 + [3B]^2}$^{1/2}$	16 Negative Sys Unc of Result [11] × {([1] × [4A]/100)^2 + [4B]^2}$^{1/2}$
a	Furnace Residue Flow, %	87.2061	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
b	Economizer Residue Flow, %	87.2061	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
c	Precipitator Residue Flow, %	87.2061	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
d	Furnace Residue Flow, lb/hr	87.2084	0.0506	0.0026	0.0265	2.1340E–08	0.0160	0.0160
e	Economizer Residue Flow, lb/hr	87.2061	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
f	Precipitator Residue Flow, lb/hr	87.2061	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
g	Furn Residue Carbon Content	87.2061	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
h	Econ Residue Carbon Content	87.2061	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
i	Precip Residue Carbon Content	87.2061	0.0000	0.0000	0.0000	5.0794E–25	0.0000	0.0000
j	Furnace Residue CO2 Content	87.2061	0.0058	0.0001	0.0000	0.0000E+00	0.0002	0.0002
k	Econ Residue CO2 Content	87.2061	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
l	Precip Residue CO2 Content	87.2061	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
m	Furnace Residue Temp	87.2033	–0.0001	–0.0032	0.0000	0.0000E+00	–0.0005	–0.0005
n	Economizer Residue Temp	87.2061	0.0000	0.0000	0.0000	3.8566E–34	0.0000	0.0000
o	Precipitator Residue Temp	87.2061	0.0000	0.0000	0.0000	3.2938E–37	0.0000	0.0000
p	SO2 in Flue Gas	87.2052	–0.0004	–0.0010	–0.0005	3.9114E–15	–0.0098	–0.0098
q	O2 in Flue Gas	87.2059	–0.0053	–0.0002	–0.0002	2.7299E–17	–0.0039	–0.0039
r	CaCO3 in Sorbent	87.1991	–0.0074	–0.0080	0.0000	0.0000E+00	–0.0139	–0.0139
s	Ca(OH)2 in Sorbent	87.2061	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
t	MgCO3 in Sorbent	87.2060	–0.0040	–0.0001	0.0000	0.0000E+00	–0.0005	–0.0005
u	Mg(OH)2 in Sorbent	87.2061	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
v	Moisture in Sorbent	87.2061	–0.0048	0.0000	0.0000	0.0000E+00	0.0000	0.0000
w	Inert Material in Sorbent	87.2061	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
x	Sorbent Temp	87.2064	0.0004	0.0004	0.0000	0.0000E+00	0.0026	0.0026
y	Fuel Temp	87.2088	0.0032	0.0031	0.0019	6.1711E–12	0.0103	0.0103
z	FG Temp Ent Hot AQCS Equip	87.2061	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
aa	O2 Ent Hot AQCS Equip	87.2061	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
ab								
ac								

* This uncertainty worksheet is set up for calculating the uncertainty effect on efficiency; however, this sheet can be used for any calculated item, such as output, fuel flow, calcium/sulfur ratio, etc.

20	* Base Efficiency	From Item [100] on EFFb form					See UncEffb 2D
21	Random Component of Uncertainty	$([13a]^2 + [13b]^2 + ...)^{1/2}$					0.0007
22	Degrees of Freedom for Random Uncertainty	$[21]^4 / ([14a] + [14b] + ...)$					2.1346E–08
23	Positive Systematic Uncertainty of Result	$([15a]^2 + [15b]^2 + ...)^{1/2}$					0.0007
24	Negative Systematic Uncertainty of Result	$([16a]^2 + [16b]^2 + ...)^{1/2}$					0.0007
25	Degrees of Freedom for Overall Test Result	$[([23]/2)^2 + ([21])^2]^2/[([21])^4/[22] + ([23]/2)^4/50]$	Pos	See UncEffb 2D	Neg		See UncEffb 2D
26	Student's t Value for Overall Degrees of Freedom for Test	From Table 5-16.5-1 in Code	Pos	See UncEffb 2D	Neg		See UncEffb 2D
27	Positive Total Test Uncertainty	$[Pos\ 26]\ (([21])^2 + ([23]/2)^2)^{1/2}$					See UncEffb 2D
28	Negative Total Test Uncertainty	$[Neg\ 26]\ (([21])^2 + ([23]/2)^2)^{1/2}$					See UncEffb 2D

PLANT NAME:	ASME PTC 4 EXAMPLE PROBLEM B-5.1	UNIT NO.:
TEST NO.:	DATE:	LOAD:
TIME START:	TIME END:	CALC BY:
REMARKS: CFB, Trisect AH, Meas Bot Ash Flow		DATE:
		SHEET OF

Table B-5.1-13 Efficiency Uncertainty Worksheets (CFB): C Worksheet No. 1C

	Measured Parameter (From DATA)	1 Average Value (Item [2] on MEAS Form)		2 Standard Deviation (Item [3] on MEAS Form)	Sys Uncert Sheet No.	3 Total Positive Systematic Uncert (Item [2] on SYSUNC Form) %	Unit	4 Total Negative Systematic Uncert (Item [2] on SYSUNC Form) %	Unit	5 No. of Readings (Item [1] on MEAS Form)	6 Standard Dev of Mean ([2]^2 / [5])$^{1/2}$	7 Degrees of Freedom [5] − 1	8 Percent Change	9 Incremental Change* [8] × [1] / 100
a	Avg Air Temp Ent Pulverizer		0.0	2.81	1A	0.00	1.03	0.00	1.03	20	0.6291	19	1.00	0.00
b	Avg Pulv Tempering Air Temp		0.0	0.45	1A	0.00	1.03	0.00	1.03	10	0.1424	9	1.00	0.00
c	Pri Airflow (Ent Pulverizer)		236.2	1.09	3H	5.12	0.00	5.12	0.00	20	0.2439	19	1.00	2.36
d	Aux Equip Power		0.0	0.0	4C	2.04	0.00	2.04	0.00	0	0.0000	0	1.00	0.00
e														
f	Surf Rad & Conv Loss Assigned		0.0	0.0	INPUT	0.00	0.00	0.00	0.00	0	0.00	0	1.00	0.00
g	Flat Projected Surface Area	C	50.00	0.00	INPUT	5.00	0.00	5.00	0.00	0	0.0000	0	1.00	0.75
h	Avg Vel of Air Near Surface	C	1.7	0.00	INPUT	5.00	0.00	5.00	0.00	2	0.0000	1	1.00	0.02
i	Avg Surface Temp	C	127.0	0.00	INPUT	0.00	5.00	0.00	5.00	2	0.0000	1	1.00	1.27
j	Avg Amb Temp Near Surface	C	77.0	0.00	INPUT	0.00	5.00	0.00	5.00	2	0.0000	1	1.00	0.77
k														
l	Flat Projected Surface Area	A	0.00	0.00	INPUT	5.00	0.00	5.00	0.00	0	0.0000	0	1.00	0.76
m	Avg Vel of Air Near Surface	A	0.0	0.00	INPUT	5.00	0.00	5.00	0.00	0	0.0000	0	1.00	0.02
n	Avg Surface Temp	A	0.0	0.00	INPUT	0.00	5.00	0.00	5.00	0	0.0000	0	1.00	1.27
o	Avg Amb Temp Near Surface	A	0.0	0.00	INPUT	0.00	5.00	0.00	5.00	0	0.0000	0	1.00	0.77
p														
q	Flat Projected Surface Area	B	0.00	0.00	INPUT	5.00	0.00	5.00	0.00	0	0.0000	0	1.00	0.76
r	Avg Vel of Air Near Surface	B	0.0	0.00	INPUT	5.00	0.00	5.00	0.00	0	0.0000	0	1.00	0.02
s	Avg Surface Temp	B	0.0	0.00	INPUT	0.00	5.00	0.00	5.00	0	0.0000	0	1.00	1.27
t	Avg Amb Temp Near Surface	B	0.0	0.00	INPUT	0.00	5.00	0.00	5.00	0	0.0000	0	1.00	77.00
u														
v	Fuel Vol Matter		45.00	0.10	5C	0.00	0.00	0.00	0.00	3	0.0577	2	1.00	0.45
w	Fuel Fixed Carbon Content		45.00	1.00	5D	0.00	0.00	0.00	0.00	3	0.5774	2	1.00	0.45
x	Oil API Gravity		0.00	0.00	5E	5.39	0.00	5.39	0.00	0	0.0000	0	1.00	0.00
y														
z														
aa														
ab														
ac														

Input source for Items [1] through [5]
For Spatially Uniform Parameters, enter results from the MEAS Data SYSUNC Forms.
For Spatially Nonuniform Parameters, enter results from the INTAVG Form.

* The value used for incremental change can be any increment of the average value.
The recommended increment is 1.0% (0.01 times the average value).
If the average value of the measured parameter is zero, use any small incremental change.
It is important to note that the incremental change must be in the same units as the average value.

PLANT NAME:	ASME PTC 4 EXAMPLE PROBLEM B-5.1	UNIT NO.:
TEST NO.:	DATE:	LOAD:
TIME START:	TIME END:	CALC BY:
REMARKS: CFB, Trisect AH, Meas Bot Ash Flow		DATE:
		SHEET OF

Table B-5.1-13 Efficiency Uncertainty Worksheets (CFB): C (Cont'd)
Worksheet No. 2C

	Measured Parameter		10 Recalc Efficiency *	11 Absolute Sensitivity Coefficient ([10] − [20]) / [9]	12 Relative Sensitivity Coefficient [11] × [1] / [20]	13 Random Unc of Result Calculation [11] × [6]	14 Deg of Freedom for Random Uncert Contribution ([11] × [6]^4)/ [7]	15 Positive Sys Unc of Result [11] × {([1] × [3A] / 100)^2 + [3B]^2}$^{1/2}$	16 Negative Sys Unc of Result [11] × {([1] × [4A] / 100)^2 + [4B]^2}$^{1/2}$
a	Avg Air Temp Ent Pulverizer		87.2061	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
b	Avg Pulv Tempering Air Temp		87.2061	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
c	Pri Airflow (Ent Pulverizer)		87.2060	0.0000	−0.0001	0.0000	1.6441E−22	−0.0004	−0.0004
d	Aux Equip Power		87.2061	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
e									
f	Surf Rad & Conv Loss Assigned		87.2061	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
g	Flat Projected Surface Area	C	87.1997	−0.0085	−0.0049	0.0000	0.0000E+00	−0.0213	−0.0213
h	Avg Vel of Air Near Surface	C	87.2061	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
i	Avg Surface Temp	C	87.1862	−0.0156	−0.0228	0.0000	0.0000E+00	−0.0782	−0.0782
j	Avg Amb Temp Near Surface	C	87.2181	0.0156	0.0137	0.0000	0.0000E+00	0.0778	0.0778
k									
l	Flat Projected Surface Area	A	87.2061	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
m	Avg Vel of Air Near Surface	A	87.2061	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
n	Avg Surface Temp	A	87.2061	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
o	Avg Amb Temp Near Surface	A	87.2061	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
p									
q	Flat Projected Surface Area	B	87.2061	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
r	Avg Vel of Air Near Surface	B	87.2061	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
s	Avg Surface Temp	B	87.2061	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
t	Avg Amb Temp Near Surface	B	87.2061	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
u									
v	Fuel Vol Matter		87.2061	0.0001	0.0000	0.0000	1.1386E−18	0.0000	0.0000
w	Fuel Fixed Carbon Content		87.2061	−0.0001	0.0000	0.0000	1.2444E−18	0.0000	0.0000
x	Oil API Gravity		87.2061	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
y									
z									
aa									

* This uncertainty worksheet is set up for calculating the uncertainty effect on efficiency; however, this sheet can be used for any calculated item such as output, fuel flow, calcium/sulfur ratio, etc.

20	* Base Efficiency	From Item [100] on EFFb form				See UncEffb 2D
21	Random Component of Uncertainty	([13a]^2 + [13b]^2 +...)$^{1/2}$				0.0000
22	Degrees of Freedom for Random Uncertainty	[21]^4 / ([14a] + [14b] +...)				2.3832E−18
23	Positive Systematic Uncertainty of Result	([15a]^2 + [15b]^2 + ...)$^{1/2}$				0.0126
24	Negative Systematic Uncertainty of Result	([16a]^2 + [16b]^2 + ...)$^{1/2}$				0.0126
25	Degrees of Freedom for Overall Test Result	[([23]/2)^2+([21])^2]^2/[([21])^4/[22]+([23]/2)^4/50]	Pos	See UncEffb 2D	Neg	See UncEffb 2D
26	Student's *t* Value for Overall Degrees of Freedom for Test	From Table 5-16.5-1 in Code	Pos	See UncEffb 2D	Neg	See UncEffb 2D
27	Positive Total Test Uncertainty	[Pos 26] (([21])^2 + ([23]/2)^2)$^{1/2}$				See UncEffb 2D
28	Negative Total Test Uncertainty	[Neg 26] (([21])^2 + ([23]/2)^2)$^{1/2}$				See UncEffb 2D

PLANT NAME:	ASME PTC 4 EXAMPLE PROBLEM B-5.1	UNIT NO.:
TEST NO.:	DATE:	LOAD:
TIME START:	TIME END:	CALC BY:
REMARKS: CFB, Trisect AH, Meas Bot Ash Flow		DATE:
		SHEET OF

Table B-5.1-14 Efficiency Uncertainty Worksheets (CFB): D
Worksheet No. 1D

	Measured Parameter (From DATA)	1 Average Value (Item [2] on MEAS Form)	2 Standard Deviation (Item [3] on MEAS Form)	Sys Uncert Sheet No.	3 Total Positive Systematic Uncert (Item [2] on SYSUNC Form)		4 Total Negative Systematic Uncert (Item [2] on SYSUNC Form)		5 No. of Readings (Item [1] on MEAS Form)	6 Standard Dev of Mean $([2]^2 / [5])^{1/2}$	7 Degrees of Freedom [5] − 1	8 Percent Change	9 Incremental Change* [8] × [1] / 100
					%	Unit	%	Unit					
a	Losses, %												
b	CO in Flue Gas	0.050	0.001	10A	0.05	0.00	0.05	0.00	3	0.0003	2	1.00	0.0005
c	Formation of NOx	0.000	0.000	10B	0.05	0.00	0.05	0.00	0	0.0000	0	1.00	0.0000
d	Pulverizer Rejects	0.000	0.000	11A	111.80	0.00	53.85	0.00	2	0.0000	1	1.00	0.0009
e	Air Infiltration	0.000	0.000	INPUT	0.00	0.00	0.00	0.00	0	0.0000	0	1.00	0.0000
f	Unburned HC in Flue Gas	0.000	0.000	INPUT	0.00	0.00	0.00	0.00	0	0.0000	0	1.00	0.0000
g	Other	0.230	0.000	INPUT	0.00	0.00	0.00	0.00	0	0.0000	0	1.00	0.0023
h	Losses, MKBtu/hr												
i	Wet Ash Pit	0.000	0.000	10C	25.74	0.00	11.72	0.00	0	0.0000	0	1.00	0.0000
j	Sen Ht in Solid Recirc Strms	0.000	0.000	INPUT	0.00	0.00	0.00	0.00	0	0.0000	0	1.00	0.0000
k	Sen Ht in Gas Recirc Strms	0.000	0.000	INPUT	0.00	0.00	0.00	0.00	0	0.0000	0	1.00	0.0000
l	Additional Moisture	0.000	0.000	INPUT	0.00	0.00	0.00	0.00	0	0.0000	0	1.00	0.0000
m	Cooling Water	0.000	0.000	INPUT	0.00	0.00	0.00	0.00	0	0.0000	0	1.00	0.0000
n	Air Preheat Coils	0.000	0.000	INPUT	0.00	0.00	0.00	0.00	0	0.0000	0	1.00	0.0000
o	Other	0.000	0.000	INPUT	0.00	0.00	0.00	0.00	0	0.0000	0	1.00	
p	Credits, %												
q	Other	0.000	0.000	INPUT	0.00	0.00	0.00	0.00	0	0.0000	0	1.00	0.0000
r	Credits, MKBtu/hr												
s	Heat in Add Moisture	0.000	0.000	INPUT	0.00	0.00	0.00	0.00	0	0.0000	0	1.00	0.0000
t	Other	0.000	0.000	INPUT	0.00	0.00	0.00	0.00	0	0.0000	0	1.00	0.0000
u													
v													
w													
x													
y													
z													
aa													
ab													
ac													

Input source for Items [1] through [5]
For Spatially Uniform Parameters, enter results from the MEAS Data SYSUNC Forms.
For Spatially Nonuniform Parameters, enter results from the INTAVG Form.

*The value used for incremental change can be any increment of the average value.
The recommended increment is 1.0% (0.01 times the average value).
If the average value of the measured parameter is zero, use any small incremental change.
It is important to note that the incremental change must be in the same units as the average value.

PLANT NAME:	ASME PTC 4 EXAMPLE PROBLEM B-5.1	UNIT NO.:
TEST NO.:	DATE:	LOAD:
TIME START:	TIME END:	CALC BY:
REMARKS: CFB, Trisect AH, Meas Bot Ash Flow		DATE:
		SHEET OF

Table B-5.1-14 Efficiency Uncertainty Worksheets (CFB): D (Cont'd)
Worksheet No. 2D

	Measured Parameter	10 Recalc Efficiency *	11 Absolute Sensitivity Coefficient ([10] − [20])/[9]	12 Relative Sensitivity Coefficient ([11] × [1])/[20]	13 Random Unc of Result Calculation [11] × [6]	14 Deg of Freedom for Random Uncert Contribution ([11] × [6])^4/[7]	15 Positive Sys Unc of Result [11] × {([1] × [3A]/100)^2 + [3B]^2}$^{1/2}$	16 Negative Sys Unc of Result [11] × {([1] × [4A]/100)^2 + [4B]^2}$^{1/2}$
a	Losses, %							
b	CO in Flue Gas	87.2056	−0.9660	−0.0006	−0.0003	3.0235E−15	0.0000	0.0000
c	Formation of NOx	87.2061	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
d	Pulverizer Rejects	87.2061	−0.9926	−0.0010	0.0000	0.0000E+00	0.0000	0.0000
e	Air Infiltration	87.2061	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
f	Unburned HC in Flue Gas	87.2061	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
g	Other	87.2039	−0.9680	−0.0026	0.0000	0.0000E+00	0.0000	0.0000
h	Losses, MKBtu/hr							
i	Wet Ash Pit	87.2061	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
j	Sen Ht in Solid Recirc Strms	87.2061	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
k	Sen Ht in Gas Recirc Strms	87.2061	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
l	Additional Moisture	87.2061	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
m	Cooling Water	87.2061	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
n	Air Preheat Coils	87.2061	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
o	Other	87.2061	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
p	Credits, %							
q	Other	87.2061	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
r	Credits, MKBtu/hr							
s	Heat in Add Moisture	87.2061	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
t	Other	87.2061	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
u								
v								
w								
x								
y								
z								
aa								
ab								
ac								

*This uncertainty worksheet is set up for calculating the uncertainty effect on efficiency; however, this sheet can be used for any calculated item, such as output, fuel flow, calcium/sulfur ratio, etc.

20	* Base Efficiency	From Item [100] on EFFb form				87.2061
21	Random Component of Uncertainty	([13a]^2 + [13b]^2 +...)$^{1/2}$				0.0580
22	Degrees of Freedom for Random Uncertainty	[21]^4 / ([14a] + [14b] +...)				26.7608
23	Positive Systematic Uncertainty of Result	([15a]^2 + [15b]^2 + ...)$^{1/2}$				0.3427
24	Negative Systematic Uncertainty of Result	([16a]^2 + [16b]^2 + ...)$^{1/2}$				0.3668
25	Degrees of Freedom for Overall Test Result	[([23]/2)^2 + ([21])^2]^2/[([21])^4 /[22] + ([23]/2)^4/50]	Pos	60.63	Neg	59.40
26	Student's *t* Value for Overall Degrees of Freedom for Test	From Table 5-16.5-1 in Code	Pos	2.00	Neg	2.00
27	Positive Total Test Uncertainty	[Pos 26] (([21])^2 + ([23]/2)^2)$^{1/2}$				0.3618
28	Negative Total Test Uncertainty	[Neg 26] (([21])^2 + ([23]/2)^2)$^{1/2}$				0.3847

PLANT NAME:	ASME PTC 4 EXAMPLE PROBLEM B-5.1	UNIT NO.:
TEST NO.:	DATE:	LOAD:
TIME START:	TIME END:	CALC BY:
REMARKS: CFB, Trisect AH, Meas Bot Ash Flow		DATE:
		SHEET OF

Table B-6.1-1 Oil Flow Uncertainty Worksheets
Worksheet No. 1

	Measured Parameter (from DATA)	1 Average Value (Item [2] on MEAS Form)	2 Standard Deviation (Item [3] on MEAS Form)	Sys Uncert Sheet No.	3 Total Positive Systematic Uncert (Item [2] on SYSUNC Form) %	3 Unit	4 TotalNegative Systematic Uncert (Item [2] on SYSUNC Form) %	4 Unit	5 No. of Readings (Item [1] on MEAS Form)	6 Standard Dev of Mean ([2]^2 / [5])$^{1/2}$	7 Degrees of Freedom [5] − 1	8 Percent Change	9 Incremental Change* [8] × [1] / 100
a	Differential Press, in. Wg	46.8000	1.3681		0.0000	0.6708	0.0000	0.6708	12	0.3949	11	1.00	0.4680
b	Specific Gravity	0.9300	0.0000		0.0000	0.0031	0.0000	0.0031	0	0.0000	0	1.00	0.0093
c	Discharge Coefficient, C	0.6881	0.0000		0.0000	0.0092	0.0000	0.0092	0	0.0000	0	1.00	0.0069
d	Orifice Diameter, d	1.5172	0.0000		0.0000	0.0076	0.0000	0.0076	0	0.0000	0	1.00	0.0152
e													
f													
g													
h													
i													
j													
k													
l													

m	From ASME MFC-3M–1989		
n	qm = 0.0997 * C * E * Y * Fa * d^2 * (Rho * h)$^{0.5}$ (lbm/sec)	= 9.761	
o	C = Discharge Coefficient, C = 0.5959 + 0.0312 B$^{2.1}$ − 0.1840 B^8 + 0.0390 B^4 / (1 – B^4) − 0.01584 B^3 + 91.71 B$^{2.5}$ ReD$^{-0.75}$		C = 0.68807
p	E = Approach Factor = 1 / (1 − Beta^4)^5	= 1.1870	
q	Y = Compressibility Factor = 1.0 for liquids	= 1.00	
r	Fa = Thermal Expansion Factor = 1.0 at given temperature	= 1.00	
s	d = Orifice diameter = Beta * Pipe Inside Diameter (inches)	= 1.5172	
t	Beta	Beta = 0.734	
u	Pipe (D) = 2 in Schedule 40	D = 2.067	
v	Rho = Density of fluid = 62.32 * S.G. (lbm/ft^3)	Rho = 57.95	
w	h = Head across orifice (inches of water)	h = 46.80	
x	Re = 4 * m / (Pi * Vis * D)	Re = 4,162.05	
y	Vis = Viscosity (lbm/sec/in.)	Vis = 0.00148	
z	SG = Specific Gravity	SG = 0.930	
aa			
ab			
ac			

Input source for Items [1] through [5]
For Spatially Uniform Parameters, enter results from the MEAS Data SYSUNC Forms.
For Spatially Nonuniform Parameters, enter results from the INTAVG Form.

* The value used for incremental change can be any increment of the average value.
The recommended increment is 1.0% (0.01 times the average value).
If the average value of the measured parameter is zero, use any small incremental change.
It is important to note that the incremental change must be in the same units as the average value.

PLANT NAME:	ASME PTC 4 EXAMPLE PROBLEM B-6.1	UNIT NO.:
TEST NO.:	DATE:	LOAD:
TIME START:	TIME END:	CALC BY:
REMARKS:		DATE:
		SHEET OF

Table B-6.1-1 Oil Flow Uncertainty Worksheets (Cont'd)
Worksheet No. 2

	Measured Parameter	10 Recalc Oil Flow *	11 Absolute Sensitivity Coefficient ([10] − [20])/[9]	12 Relative Sensitivity Coefficient ([11] × [1])/[20]	13 Random Unc of Result Calculation [11] × [6]	14 Deg of Freedom for Random Uncert Contribution ([11] × [6])^4/[7]	15 Positive Sys Unc of Result [11] × {([1] × [3A]/100)^2 + [3B]^2}^{½}	16 Negative Sys Unc of Result [11] × {([1] × [4A]/100)^2 + [4B]^2}^{½}
a	Differential Press, in. Wg	9.8102	0.1040	0.4988	0.0411	2.5906E−07	0.0698	0.0698
b	Specific Gravity	9.8102	5.2350	0.4988	0.0000	0.0000E+00	0.0161	0.0161
c	Discharge Coefficient, C	9.8591	14.1867	1.0000	0.0000	0.0000E+00	0.1302	0.1302
d	Orifice Diameter, d	9.9577	12.9323	2.0100	0.0000	0.0000E+00	0.0981	0.0981
e								
f								
g								
h								
i								
j								
k								
l								
m								
n								
o								
p								
q								
r								
s								
t								
u								
v								
w								
x								
y								
z								
aa								
ab								
ac								

* This uncertainty worksheet is set up for calculating the uncertainty effect on oil flow; however, this sheet can be used for any calculated item, such as output, fuel flow, calcium/sulfur ratio, etc.

20	* Base Oil Flow	per equation on Sheet 1, lbm/sec					9.7615
21	Random Component of Uncertainty	([13a]^2 + [13b]^2 +...)^{½}					0.0411
22	Degrees of Freedom for Random Uncertainty	[21]^4 / ([14a] + [14b] +...)					11.0000
23	Positive Systematic Uncertainty of Result	([15a]^2 + [15b]^2 + ...)^{½}					0.1781
24	Negative Systematic Uncertainty of Result	([16a]^2 + [16b]^2 + ...)^{½}					0.1781
25	Degrees of Freedom for Overall Test Result	[([23]/2)^2+([21])^2]^2/[([21])^4/[22]+([23]/2)^4/50]	Pos	60.99	Neg		60.99
26	Student's *t* Value for Overall Degrees of Freedom for Test	From Table 5-16.5-1 in Code	Pos	2.00	Neg		2.00
27	Positive Total Test Uncertainty	[Pos 26] (([21])^2 + ([23]/2)^2)^{½}					0.1961
28	Negative Total Test Uncertainty	[Neg 26] (([21])^2 + ([23]/2)^2)^{½}					0.1961

PLANT NAME:	ASME EXAMPLE PROBLEM B-6.1	UNIT NO.:
TEST NO.:	DATE:	LOAD:
TIME START:	TIME END:	CALC BY:
REMARKS:		DATE:
		SHEET OF

Table B-6.1-2 Efficiency by Input–Output Uncertainty Worksheets Worksheet No. 1

	Measured Parameter (from DATA)	1 Average Value (Item [2] on MEAS Form)	2 Standard Deviation (Item [3] on MEAS Form)	Sys Uncert Sheet No.	3 Total Positive Systematic Uncert (Item [2] on SYSUNC Form)		4 Total Negative Systematic Uncert (Item [2] on SYSUNC Form)		5 No. of Readings (Item [1] on MEAS Form)	6 Standard Dev of Mean $([2]^2 / [5])^{1/2}$	7 Degrees of Freedom [5] − 1	8 Percent Change	9 Incremental Change* [8] × [1] / 100
					%	Unit	%	Unit					
a	Output, 1E+6, Btu/hr	565.325				3.55		3.55		0.3248	54	1.00	5.65
b	Fuel Flow, klbm/hr	35.439	0.4027	3A	0.62	0.00	0.62	0.00	31	0.0723	30	1.00	0.35
c	Fuel Higher Heating Value	17,880.00			0.50	86.00	0.50	89.00			0	1.00	178.80
d													
e													
f													
g													
h													
i													
j													
k													
l													
m													
n													
o													
p													
q													
r													
s													
t													
u													
v													
w													
x													
y													
z													
aa													
ab													
ac													

Input source for Items [1] through [5]
For Spatially Uniform Parameters, enter results from the MEAS Data SYSUNC Forms.
For Spatially Nonuniform Parameters, enter results from the INTAVG Form.

* The value used for incremental change can be any increment of the average value.
The recommended increment is 1.0% (0.01 times the average value).
If the average value of the measured parameter is zero, use any small incremental change.
It is important to note that the incremental change must be in the same units as the average value.

PLANT NAME:	ASME PTC 4 EXAMPLE PROBLEM B-6.1	UNIT NO.:
TEST NO.:	DATE:	LOAD:
TIME START:	TIME END:	CALC BY:
REMARKS:		DATE:
		SHEET OF

Table B-6.1-2 Efficiency by Input–Output Uncertainty Worksheets (Cont'd)
Worksheet No. 2

	Measured Parameter	10 Recalc Efficiency *	11 Absolute Sensitivity Coefficient ([10] − [20])/[9]	12 Relative Sensitivity Coefficient ([11] × [1])/[20]	13 Random Unc of Result Calculation [11] × [6]	14 Deg of Freedom for Random Uncert Contribution ([11] × [6])^4/[7]	15 Positive Sys Unc of Result [11] × {([1] × [3A]/100)^2 + [3B]^2}$^{1/2}$	16 Negative Sys Unc of Result [11] × {([1] × [4A]/100)^2 + [4B]^2}$^{1/2}$
a	Output, 1E+6, Btu/hr	90.1088	0.1578	0.1578	0.0513	1.2711E−07	0.56	0.56
b	Fuel Flow, klbm/hr	88.3333	−2.4925	−0.1563	−0.1803	3.5209E−05	−0.54	−0.54
c	Fuel Higher Heating Value	88.3333	−0.0049	−0.1563	0.0000	0.0000E+00	−0.61	−0.62
d								
e								
f								
g								
h								
i								
j								
k								
l								
m								
n								
o								
p								
q								
r								
s								
t								
u								
v								
w								
x								
y								
z								
aa								
ab								
ac								

*This uncertainty worksheet is set up for calculating the uncertainty effect on efficiency; however, this sheet can be used for any calculated item, such as output, fuel flow, calcium/sulfur ratio, etc.

20	* Base Efficiency	from Item [37] on OUTPUT form				89.2167
21	Random Component of Uncertainty	([13a]^2 + [13b]^2 +...)$^{1/2}$				0.1874
22	Degrees of Freedom for Random Uncertainty	[21]^4 / ([14a] + [14b] +...)				34.9196
23	Positive Systematic Uncertainty of Result	([15a]^2 + [15b]^2 + ...)$^{1/2}$				0.9929
24	Negative Systematic Uncertainty of Result	([16a]^2 + [16b]^2 + ...)$^{1/2}$				0.9994
25	Degrees of Freedom for Overall Test Result	[([23]/2)^2 + ([21])^2]^2/[([21])^4 /[22] + ([23]/2)^4/50]	Pos	63.42	Neg	63.4230
26	Student's *t* Value for Overall Degrees of Freedom for Test	from Table 5-16.5-1 in Code	Pos	2.00	Neg	2.0000
27	Positive Total Test Uncertainty	[Pos 26] (([21])^2 + ([23]/2)^2)$^{1/2}$				1.0613
28	Negative Total Test Uncertainty	[Neg 26] (([21])^2 + ([23]/2)^2)$^{1/2}$				1.0673

PLANT NAME:	ASME PTC 4 EXAMPLE PROBLEM B-6.1	UNIT NO.:
TEST NO.:	DATE:	LOAD:
TIME START:	TIME END:	CALC BY:
REMARKS:		DATE:
		SHEET OF

Table B-6.2-1 Combustion Calculations
Worksheet CMBSTNa

	DATA REQUIRED					
1	HHV, Higher Heating Value of Fuel, Btu/lbm as-fired					17,880.0
2	UBC, Unburned Carbon, lbm/100 lbm fuel from RES or SRBb FORM					0.000
3	Fuel Flow, Klbm/hr [4b]					35.36
4	a. Measured Fuel Flow			35.44		
4	b. Calculated Fuel Flow 100,000 × [5] / [6] / [1]			35.36		
5	Output, MKBtu/hr	from OUTPUT Item [37]		565.33		
6	Fuel Efficiency, % (estimate initially)			89.42		
7	Moisture in air, lbm/lbm Dry Air					0.0093
8	Barometric Pressure, in. Hg	pwva = 0.0000		29.50		
9	Dry Bulb Temperature, °F	pswvd = 0.5617		83.2		
10	Wet Bulb Temperature, °F	pswvw = 0.0000		0.0		
11	Relative Humidity, %	pwva = 0.2135		38.0		
	Additional Moisture (Measured)			Klbm/hr		
	Atomizing Steam	from OUTPUT Item [14]		0.0		
	Sootblowing Steam	from OUTPUT Item [11]		0.0		
	Other			0.0		
12	Summation Additional Moisture			0.0		
13	Additional Moisture, lbm/100 lbm Fuel 100 × [12] / [3]					0.0000
14	Additional Moisture, lbm/10 KBtu [13] / ([1]/100)					0.0000
	If Air Heater (Excl Stm/Wtr Coil) Enter following					
15	Gas Temp Lvg AH, °F	Primary / Secondary or Main	15B	276.1	15A	280.7
16	Air Temp Ent AH, °F	Primary / Secondary or Main	16B	84.9	16A	85.7
17	O2 in FG Ent Air Heater	Primary / Secondary or Main	17B	3.90	17A	3.88
18	O2 in FG Lvg Air Heater	Primary / Secondary or Main	18B	5.50	18A	5.57
18C	O2 Measurement Basis	Dry (0) or Wet (1)			18C	0
18D	Primary AH Leakage for Trisector Type AH, Percent of Total				18D	0.00
	Fuel Analysis, % Mass as-fired — Enter in Col [30]					
19	Mass Ash, lbm/10 KBtu 100 × [30J] / [1]					0.000
	If mass of ash (Item [19]) exceeds 0.15 lbm/10 KBtu or Sorbent					
	utilized, enter Mass Fraction of Refuse in Item [79] for each location.					
	SORBENT DATA (Enter 0 if Sorbent not Used)					
20	Sorbent Rate, Klbm/hr					0.00
21	CO2 from Sorbent, lbm/100 lbm Sorb	from SRBa Item [25I]				0.00
22	H2O from Sorbent, lbm/100 lbm Sorb	from SRBa Item [26I]				0.00
23	Sulfur Capture, lbm/lbm Sulfur	from SRBb Item [45]				0.000
24	Spent Sorbent, lbm/100 lbm fuel	from SRBb Item [48]				0.00
25	Sorb/Fuel Ratio, lbm Sorb/lbm Fuel	[20] / [3]				0.000
	HOT AIR QUALITY CONTROL EQUIPMENT DATA					
26	O2 in FG Ent HAQC Equipment, %					0.00
	See Form EFFa for HAQC Flue Gas Temperatures					

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Table B-6.2-2 Combustion Calculations
Worksheet CMBSTNb

COMBUSTION PRODUCTS

30	Ultimate Analysis % Mass			31 Theo Air F lbm/100 lbm Fuel [30] × K		32 Dry Prod F Mol/100 lbm Fuel [30] / K		33 Wet Prod F Mol/100 lbm Fuel [30] / K		34 H2O Fuel lbm/10KB [30] × K/([1]/100)	
A	C	88.90									
B	UBC		0.000								
C	Cb		88.90	11.51	1,023.24	12.0110	7.402				
D	S	1.00		4.31	4.31	32.065	0.031				
E	H2	9.20		34.29	315.47			2.0159	4.564	8.937	0.460
F	H2O	0.00						18.0153	0.000	1.0	0.000
G	H2Ov	0.00						18.0153	0.000	1.0	0.000
H	N2	0.35				28.0134	0.012				
I	O2	0.55		−4.32	−2.38						
J	ASH	0.00									
K	VM	0.00									
L	FC	0.00									
M	TOTAL	100.00		31	1,340.64	32	7.445	33	4.564	34	0.460

35	Total Theo Air Fuel Check, lb/10KB	([31M] + [30B] x 11.51) / ([1]/100)	7.498

CORRECTIONS FOR SORBENT REACTIONS AND SULFUR CAPTURE

40	CO2 from Sorb, lb/100lb fuel	[21] × [25]	0.00
41	H2O from Sorb, lb/100 lb fuel	[22] × [25]	0.000
42	SO2 Reduction, Mol/100 lb fuel	[32D] × [23]	0.000
43	Dry Prod Comb, Mol/100 lb fuel	[32M] + [40] / 44.01 − [42]	7.445
44	Wet Prod Comb, Mol/100 lb fuel	[33M] + [41] / 18.0153 + [43]	12.009
45	O3 (SO3) Corr, lb/10KBtu	[23] × [30D] × 1.5 / ([1] / 100)	0.000
46	Theo Air Corr, lb/100 lb fuel	[31M] + 2.16 × [30D] × [23]	1,340.64
47	Theo Air Corr, Mol/100 lb fuel	[46] / 28.9625	46.29
48	Theo Air Corr, lb/10KBtu	[46] / ([1]/100)	7.498
49	Wet Gas from Fuel, lb/10KBtu	(100 − [30J] − [30B] − [30D] × [23]) / ([1]/100)	0.559

	LOCATION			HAQC In	Sec AH In	Sec AH Out	Pri AH In	Pri AH Out
50	Flue Gas Temperature Entering Air Heater, °F				660.21		659.17	
51	Air Temperature Leaving Air Heater, °F					494.10		511.700
52	Flue Gas Oxygen Content, %			0.00	3.88	5.57	0.00	5.50
	FLUE GAS ANALYSIS, Mol/100 lb Fuel	Dry	Wet					
53	Moisture in Air	0	[7]×1.608					0.0000
54	Dry/Wet Products Comb	[43]	[44]					7.445
55	Additional Moisture	0	[13]/18.0153					0.000
56	[47] × (0.7905 + [53])							36.591
57	Summation [54] + [55] + [56]							44.036
58	20.95 − [52] × (1 + [53])			0.000	17.075	15.381	17.049	15.454
60	Excess Air, %	100 × [52] × [57] / [47] / [58]		0.00	21.590	34.445	21.77	33.83

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Table B-6.2-3 General Combustion Calculations Worksheet CMBSTNc

	LOCATION				HAQC In	Sec AH In	Sec AH Out	Pri AH In	Pri AH Out
60	Excess Air, %				0.00	21.59	34.45	21.77	33.83
	O2, CO2, SO2 WHEN EXCESS AIR KNOWN								
61									
62	Dry	[47] × (0.7905 + [60] / 100)			0.00	46.58	52.53	46.67	52.25
63	Wet	[47] × (0.7905 + [53] + (1 + [53]) × [60]/100)			0.00	0.00	0.00	0.00	0.00
64	Dry Gas, Mol/100 lb Fuel	[43] + [62] – [45] × [1] / 4,799.8			0.00	54.03	59.98	54.11	59.70
65	Wet Gas, Mol/100 lb Fuel	[44] + [63] + [55] – [45] × [1] / 4,799.8			0.00	0.00	0.00	0.00	0.00
			Dry	Wet					
66	O2, %	[60] × [47] × 0.2095 /	[64]	[65]	0.00	3.88	5.57	3.90	5.50
67	CO2, %	([30C]/0.1201 + [40]/0.4401) /	[64]	[65]	0.00	13.70	12.34	13.68	12.40
68	SO2, ppm	10,000 × (1 − [23]) × [30D] / 0.32065 /	[64]	[65]	0	577	520	576	522
	FLUE GAS PRODUCTS, lbm/10KBtu								
69	Gas from Dry Air	(1 + [60]/100) × [48] – [45]			0.00	9.12	10.08	9.13	10.03
70	Wet Gas from Fuel	[49]							0.559
71	CO2 from Sorbent	[40] / ([1]/100)							0.000
72	Moisture in Air	[7] × (1 + [60]/100) × [48]			0.000	0.085	0.094	0.085	0.093
73	Water from Sorbent	[41] / ([1]/100)							0.000
74	Additional Moisture	[14]							0.000
75	Total Wet Gas	[69]+[70]+[71]+[72]+[73]+[74]			0.00	9.76	10.73	9.77	10.69
76	H2O in Wet Gas	[34M]+[72]+[73]+[74]			0.000	0.545	0.554	0.545	0.553
77	Dry Gas	[75] − [76]			0.00	9.22	10.18	9.23	10.13
78	H2O in Wet Gas, % Mass	100 × [76]/[75]			0.00	5.58	5.16	5.57	5.18
79	Residue, lb/lb Total Refuse at each location				0.000	0.000	0.000	0.000	0.000
80	Residue, lb/10KBtu	([30J]+[2]+[24]) / ([1]/100)							0.000
81	Residue in Wet Gas, lb/lb Wet Gas	[79] × [80] / [75]			0.000	0.000	0.000	0.000	0.000
82	Leakage, % Gas Entering	100 × ([75L] – [75E]) / [75E]			0.000		9.967		9.342
	GAS TEMPERATURE CORRECTION FOR AH LEAKAGE								
83	Gas Temp Lvg (INCL LKG), °F	[15]					280.70		276.08
84	Average AH Air Leakage Temp, °F	(1– [18D]) × [16A] + [18D] × [16B]				85.73		84.9	
85	H Air Lvg, Btu/lbm	T = [83], H_2O = [7]					49.51		48.38
86	H Air Ent, Btu/lbm	T = [84], H_2O = [7]					2.11		1.91
87	Cpg, Btu/lbm °F	T = [83], H_2O = [78E], RES = [81E]					0.2543		0.2541
88	AH Gas Outlet Temperature Excluding Leakage, °F								
	[83] + ([82]/100 × ([85]−[86]) / [87])						299.28		293.17
	AIR, GAS, FUEL & RESIDUE MASS FLOW RATES, Klbm/hr								
90	Input from Fuel MBtu/hr	[5] × [6] / 100							632.2
91	Fuel Rate, Klb/hr	1,000 × [90] / [1]							35.4
92	Residue Rate, Klb/hr	[80] × [90] / 10							0.0
93	Wet Flue Gas, Klb/hr	[75] × [90] / 10			0.0	617.1	678.6	0.0	0.0

94	Wet Flue Gas, Klb/hr		Entering Air Heaters	617.1	Leaving Air Heaters	678.6
95	Excess Air Lvg Blr, %		Entering HAQC Equip	0.00	Entering Air Heaters	21.59
96	Total Air to Blr, Klbm/hr	(1 + [95]/100) × (1+ [7]) × [48] × [90] / 10		0.0		581.8

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Table B-6.2-4 Efficiency Calculations Data Required Worksheet EFFa

	TEMPERATURES, °F				
1	Reference Temperature	77	1A	Enthalpy Water (32°F Ref)	45
2	Average Entering Air Temp from CMBSTNa [16]	85.7	2A	Enthalpy Dry Air	2.10
	or EFFa [44]		2B	Enthalpy Water Vapor	3.89
3	Average Exit Gas T (Excl Lkg) from CMBSTNc [88]	299.3	3A	Enthalpy Dry Gas	53.12
	or EFFa [51]		3B	Enthalpy Steam @ 1 psia	1,195.30
			3C	Enthalpy Water Vapor	100.21
4	Fuel Temperature	200.0	4A	Enthalpy Fuel	64.01
	HOT AIR QUALITY CONTROL EQUIPMENT				
5	Entering Gas Temperature	**0.0**	5A	Enthalpy Wet Gas	0.00
6	Leaving Gas Temperature	**0.0**	6A	Enthalpy of Wet Gas	0.00
			6B	Enthalpy of Wet Air	0.00
			6C	Enthalpy of Wet Air @ T = [3]	0.00
	RESULT FROM COMBUSTION CALCULATION FORM CMBSTN				
10	Dry Gas Weight [77]	9.216	18	Unburned Carbon, % [2]	0.000
11	Dry Air Weight [69]	9.117	19	HHV, btu/lbm "as-fired" [1]	17,880.0
12	Water from H2 Fuel [34E]	0.460		**HOT AQC EQUIPMENT**	
13	Water from H2O Fuel [34F]	0.000	20	Wet Gas Entering [75E]	0.00
14	Water from H2Ov fuel [34G]	0.000	21	H2O in Wet Gas, % [78E]	0.00
15	Moisture in Air, lb/lb DA [7]	0.009	22	Wet Gas Leaving [75L]	0.00
16	Moisture in Air, lb/10KB [72]	0.085	23	Residue in Wet Gas, % [81E]	0.00
17	Fuel Rate Est., Klb/hr [3]	35.36			
			25	Excess Air, % [95]	21.59
	MISCELLANEOUS				
30	Unit Output, MKBtu/hr	565.33	31	Aux Equip power, MKBtu/hr	0.0
32	Loss Due to Surface Radiation and Convection, %				0.00
33A	Flat Projected Surface Area, ft^2	0/0/50	33C	Average Surface Temperature, °F	0/0/127
33B	Average Velocity of Air Near Surface, ft/sec	0/0/1.67	33D	Average Ambient Temperature Near Surface, °F	0/0/77
	ENT AIR TEMP (Units With Primary Airflow)				
35A	Pri Air Temp Entering, °F CMBSTNa [16B]	84.9	35B	Enthalpy Wet Air, Btu/lb	0.0
36A	Pri Air Temp Leaving Air Htr, °F CMBSTNb [51]	511.7	36B	Enthalpy Wet Air, Btu/lb	0.0
37A	Average Air Temp Entering Pulverizers, °F	0.0	37B	Enthalpy Wet Air, Btu/lb	0.0
38A	Average Pulverizer Tempering Air Temp, °F	0.00	38B	Enthalpy Wet Air, Btu/lb	0.0
39	Sec Air Temp Entering, °F CMBSTNa [16A]	85.7	40	Primary Airflow (Ent Pulv), Klb/hr	0.0
41	Pulverizer Tempering Airflow, Klb/hr	[40] × ([36B] − [37B])/([36B] − [38B])			0.0
42	Total Airflow, Klb/hr from FORM CMBSTNc [96]	581.8	43	Secondary Airflow, Klb/hr [42] − [40]	581.8
44	Average Entering Air Temperature, °F	([35A] × ([40] − [41] + [39] × [43] + [38A] × [41])/[42]			85.7
	GAS FLOW ENT PRI AH AND AVG EXIT GAS TEMP (Units With Primary and Secondary)				
45A	Flue Gas Temp Ent pri AH, °F CMBSTNb [50]	659.2	45B	Enthalpy Wet Flue Gas, Btu/lbm	149.9
46A	Flue Gas Temp Lvg Pri AH, °F CMBSTNc [88]	293.2	46B	Enthalpy Wet Flue Gas, Btu/lbm	54.2
47	Flue Gas Temp Lvg Sec AH, °F CMBSTNc [88]	299.3	48	Total Gas Ent Air Htrs, Klb/hr CMBSTNc [93]	617.1
49	Flue Gas Flow Ent Pri Air Htr, Klb/hr	([40] − [41]) × ([36B] − [35B])/([45B] − [46B])			0.0
50	Flue Gas Flow Ent Sec Air Htr, Klb/hr	[48] − [49]			617.1
51	Average Exit Gas Temperature, °F	([46A] × [49] + [47] × [50])/[48]			299.3
	Iteration of flue gas split, % primary AH gas flow	Initial Estimate	**0.0**	Calculated 0.0	

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Table B-6.2-5 Efficiency Calculations
Worksheet EFFb

		A	MKB	B	%
	LOSSES, % Enter Calculated Result in % Column [B]				
60	Dry Gas [10] × [3A] /100 × /100				4.896
61	Water from H2 Fuel [12] × ([3B] − [1A]) /100 ×(− 45) /100				5.290
62	Water from H2O Fuel [13] × ([3B] − [1A]) /100 × (− 45) /100				0.000
63	Water from H2Ov Fuel [14] × ([3C])/100 × /100				0.000
64	Moisture in Air [16] × [3C] /100 × /100				0.085
65	Unburned Carbon in Ref [18] × 14,500 / [19] = × 14,500 /				0.000
66	Sensible Heat of Refuse from Form RES				0.000
67	Hot AQC Equip ([20] × ([5A] − [6A]) − ([22] − [20]) × ([6C] − [6B])) /100 (× (−) − (−) × (−)) /100				0.000
68	Other Losses, % Basis from Form EFFc Item [110]				0.190
69	Summation of Losses, % Basis				10.460
	LOSSES, MKBtu/hr Enter in MKB Column [A]				
75	Surface Radiation and Convection from Form EFFa Item [32]		4.272		0.676
76	Sorbent Calcination/Dehydration from Form SRBc Item [77]		0.000		0.000
77	Water from Sorbent from Form SRBc Item [65]		0.000		0.000
78					
79					
80	Other Losses, MKBtu/hr Basis from Form EFFc Item [111]		0.000		0.000
81	Summation of Losses, MKBtu/hr Basis		4.272		0.676
	CREDITS, % Enter Calculation Result in % Column [B]				
85	Entering Dry Air [11] × [2A] /100 × /100				0.191
86	Moisture in Air [16] × [2B] /100 × /100				0.003
87	Sensible Heat in Fuel 100 × [4A] / [19] 100 × /				0.358
88	Sulfation from Form SRBc Item [80]				0.000
89	Other Credits, % Basis from Form EFFc Item [112]				0.000
90	Summation of Credits, % Basis				0.552
	CREDITS, MKBtu/hr Enter Calculated Result in MKB Column [A]				
95	Auxiliary Equipment Power [31]		0.000		0.000
96	Sensible Heat from Sorbent from Form SRBc Item [85]		0.000		0.000
97	Other Credits, MKBtu/hr Basis from Form EFFc Item [113]		0.000		0.000
98	Summation of Credits, MKBtu/hr Basis		0.000		0.000
100	Fuel Eff, % (100 − [69] + [90]) × [30] /([30] + [81] − [98]) (100 − +) × /(+ −)				89.416
101	Input from Fuel, MKB 100 × [30] /[100] = 100 × /		632.239		
102	Fuel Rate, Klbm/hr 1,000 × [101] /[19] = 1,000 × /				35.360

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Table B-6.2-6 Efficiency Calculations Other Losses and Credits Worksheet EFFc

The losses and credits listed on this sheet are not universally applicable to all fossil-fired steam generators and are usually minor. Losses/credits that have not been specifically identified by this Code but are applicable in accordance with the intent of the Code should also be recorded on this sheet. Parties to the test may agree to estimate the losses or credits in lieu of testing. Enter a "T" for tested or "E" for estimated in the second column, and result in appropriate column. Enter the sum of each group on Form EFFb. Refer to the text of ASME PTC 4 for the calculation method.

Itm	T or E	LOSSES, % Enter Calculated Result in % Column [B]	A MKB	B %
110A		CO in Flue Gas		0.050
110B		Formation of NOx		0.000
110C		Pulverizer Rejects		0.000
110D		Air Infiltration		0.000
110E		Unburned Hydrocarbons in Flue Gas		0.000
110F		Other		0.140
110G				0.000
110		Summation of Other Losses, % Basis		0.190
		LOSSES, MKBtu/hr Enter in MKB Column [A]		
111A		Wet Ash Pit	0.000	
111B		Sensible Heat in Recycle Streams, Solid	0.000	
111C		Sensible Heat in Recycle Streams, Gas	0.000	
111D		Additional Moisture	0.000	
111E		Cooling Water	0.000	
111F		Air Preheater Coil (supplied by unit)	0.000	
111G		Other	0.000	
111		Summation of Other Losses, MKBtu/hr Basis	0.000	
		CREDITS, % Enter Calculation Result in % Column [B]		
112A		Other		0.000
112		Summation of Credits, % Basis		0.000
		CREDITS, MKBtu/hr Enter Result in MKB Column [A]		
113A		Heat in Additional Moisture (external to envelope)	0.000	
113B		Other	0.000	
113		Summation of Credits, MKBtu/hr Basis	0.000	

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Table B-6.2-7 Efficiency Uncertainty Worksheets: A Worksheet No. 1A

	Measured Parameter (from DATA)	1 Average Value (Item [2] on MEAS Form)	2 Standard Deviation (Item [3] on MEAS Form)	Sys Uncert Sheet No.	3 Total Positive Systematic Uncert (Item [2] on SYSUNC Form) %	3 Unit	4 Total Negative Systematic Uncert (Item [2] on SYSUNC Form) %	4 Unit	5 No. of Readings (Item [1] on MEAS Form)	6 Standard Dev of Mean ([2]^2 / [5])$^{1/2}$	7 Degrees of Freedom [5] − 1	8 Percent Change	9 Incremental Change* [8] × [1] / 100
a	Output	565.33		Unc Frm		53.34		2.00		0.3248	54	1.00	5.65
b	Fuel HHV	17,880.00	0.0000	6A	0.50	86.00	0.50	89.00	2	0.0000	1	1.00	178.80
c	Fuel Flow	35.44	0.4027	3A	0.62	0.00	0.62	0.00	31	0.0723	30	1.00	0.35
d	Barometric Pressure	29.50	0.0361	4B	0.00	0.32	0.00	0.32	3	0.0208	2	1.00	0.30
e	Amb Dry Bulb Temp	83.17	1.1690	A1	0.00	1.03	0.00	1.03	6	0.4773	5	1.00	0.83
f	Amb Wet Bulb Temp	0.00	0.0000	A1	0.00	1.03	0.00	1.03	0	0.0000	0	1.00	0.00
g	Relative Humidity	38.00	0.8944	4A	0.00	0.71	0.00	0.71	6	0.3651	5	1.00	0.38
h	Flue Gas Temp Lvg Pri AH	276.08	0.3239	1B	0.00	3.32	0.00	3.32	7	0.1261	6	1.00	2.76
i	Flue Gas Temp Lvg Sec AH	280.70	0.5904	1B	0.00	3.33	0.00	3.33	8	0.2111	7	1.00	2.81
j	Comb Air Temp Ent Pri Air Htr	84.89	0.3066	1A	0.00	1.03	0.00	1.03	10	0.0970	9	1.00	0.85
k	Comb Air Temp Ent Sec Air Htr	85.73	0.3652	1A	0.00	1.04	0.00	1.04	9	0.1185	8	1.00	0.86
l	O2 in FG Ent Pri Air Htr	3.90	0.1342	5A	0.00	0.31	0.00	0.31	10	0.0424	9	1.00	0.04
m	O2 in FG Ent Sec Air Htr	3.88	0.1421	5A	0.00	0.31	0.00	0.31	10	0.0449	9	1.00	0.04
n	O2 in FG Lvg Pri Air Htr	5.50	0.4346	5B	0.00	0.59	0.00	0.59	10	0.1374	9	1.00	0.05
o	O2 in FG Lvg Sec Air Htr	5.57	0.4560	5B	0.00	0.59	0.00	0.59	10	0.1442	9	1.00	0.06
p	Pri AH Lkg for Trisector	0.00		INPUT	0.00	10.00	0.00	20.00	2	0.0000	1	1.00	0.00
q	Sorbent Flow	0.00	0.0000	3B	7.00	0.00	7.00	0.00	0	0.0000	0	1.00	0.00
r	Fuel Carbon	88.90	0.0000	6B	0.32	0.00	0.32	0.00	2	0.0000	1	1.00	0.89
s	Fuel Sulfur	1.00	0.0000	6C	0.11	0.00	0.11	0.00	2	0.0000	1	1.00	0.01
t	Fuel Hydrogen	9.20	0.0000	6D	0.12	0.00	0.12	0.00	2	0.0000	1	1.00	0.09
u	Fuel Moisture	0.00	0.0000	6E	2.02	0.00	10.20	0.00	0	0.0000	0	1.00	0.00
v	Fuel Moisture (vaporous gas)									0.0000	0	1.00	0.00
w	Fuel Nitrogen	0.35	0.0000	6G	0.14	0.00	0.14	0.00	2	0.0000	1	1.00	0.00
x	Fuel Oxygen	0.55	0.0000	6D	0.12	0.00	0.12	0.00	2	0.0000	1	1.00	0.01
y	Fuel Ash	0.00	0.0000	6F	2.01	0.00	2.01	0.00	0	0.0000	0	1.00	0.00
z	FG Temp Ent Pri Air Htr	659.17	1.3687	1B	0.00	3.39	0.00	3.39	5	0.5870	4	1.00	6.59
aa	FG Temp Ent Sec Air Htr	660.21	1.0847	1B	0.00	3.32	0.00	3.32	4	0.5312	3	1.00	6.60
ab	Comb Air Temp Lvg Pri Air Htr	511.70	0.6409	1A	0.00	1.08	0.00	1.08	9	0.2163	8	1.00	5.12
ac	Comb Air Temp Lvg Sec Air Htr	494.10	2.5007	1A	0.00	1.30	0	1.30	10	0.7920	9	1.00	4.94

Input source for Items [1] through [5]
For Spatially Uniform Parameters, enter results from the MEAS Data SYSUNC Forms.
For Spatially Nonuniform Parameters, enter results from the INTAVG Form.

* The value used for incremental change can be any increment of the average value.
The recommended increment is 1.0% (0.01 times the average value).
If the average value of the measured parameter is zero, use any small incremental change.
It is important to note that the incremental change must be in the same units as the average value.

PLANT NAME:	ASME PTC 4 EXAMPLE PROBLEM B-6.2	UNIT NO.:
TEST NO.:	DATE:	LOAD:
TIME START:	TIME END:	CALC BY:
REMARKS:		DATE:
		SHEET OF

Table B-6.2-7 Efficiency Uncertainty Worksheets: A (Cont'd)
Worksheet No. 2A

	Measured Parameter	10 Recalc Efficiency *	11 Absolute Sensitivity Coefficient ([10] − [20])/[9]	12 Relative Sensitivity Coefficient ([11] × [1])/[20]	13 Random Unc of Result Calculation [11] × [6]	14 Deg of Freedom for Random Uncert Contribution ([11] × [6])⁴/[7]	15 Positive Sys Unc of Result [11] × {([1] × [3A] /100)² + [3B]²}½	16 Negative Sys Unc of Result [11] × {([1] × [4A] /100)² + [4B]²}½
a	Output	89.4231	0.0012	0.0074	0.0004	3.9000E–16	0.0627	0.0023
b	Fuel HHV	89.5119	0.0005	0.1068	0.0000	0.0000E+00	0.0663	0.0674
c	Fuel Flow	89.4164	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
d	Barometric Pressure	89.4164	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
e	Amb Dry Bulb Temp	89.4164	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
f	Amb Wet Bulb Temp	89.4164	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
g	Relative Humidity	89.4164	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
h	Flue Gas Temp Lvg Pri AH	89.4164	0.0000	0.0000	0.0000	0.0000E+00	–0.0099	0.0000
i	Flue Gas Temp Lvg Sec AH	89.3407	–0.0270	–0.0847	–0.0057	1.5409E–10	–0.0898	–0.0898
j	Comb Air Temp Ent Pri Air Htr	89.4164	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
k	Comb Air Temp Ent Sec Air Htr	89.4374	0.0244	0.0234	0.0029	8.3000E–12	0.0255	0.0255
l	O2 in FG Ent Pri Air Htr	89.4164	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
m	O2 in FG Ent Sec Air Htr	89.4165	0.0025	0.0001	0.0001	1.8384E–7	0.0008	0.0008
n	O2 in FG Lvg Pri Air Htr	89.4164	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
o	O2 in FG Lvg Sec Air Htr	89.3997	–0.3010	–0.0187	–0.0434	3.9440E–07	–0.1762	–0.1762
p	Pri AH Lkg for Trisector	89.4164	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
q	Sorbent Flow	89.4164	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
r	Fuel Carbon	89.3798	–0.0412	–0.0410	0.0000	0.0000E+00	–0.0116	–0.0116
s	Fuel Sulfur	89.4163	–0.0154	–0.0002	0.0000	0.0000E+00	0.0000	0.0000
t	Fuel Hydrogen	89.3559	–0.6583	–0.0677	0.0000	0.0000E+00	–0.0074	–0.0074
u	Fuel Moisture	89.4164	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
v	Fuel Moisture (vaporous gas)	89.4164	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
w	Fuel Nitrogen	89.4164	–0.0010	0.0000	0.0000	0.0000E+00	0.0000	0.0000
x	Fuel Oxygen	89.4165	0.0146	0.0001	0.0000	0.0000E+00	0.0000	0.0000
y	Fuel Ash	89.4164	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
z	FG Temp EntPri Air Htr	89.4164	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
aa	FG Temp Ent Sec Air Htr	89.4164	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
ab	Comb Air Temp LvgPri Air Htr	89.4164	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
ac	Comb Air Temp Lvg Sec Air Htr	89.4164	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000

*This uncertainty worksheet is set up for calculating the uncertainty effect on efficiency; however, this sheet can be used for any calculated item, such as output, fuel flow, calcium/sulfur ratio, etc.

20	* Base Efficiency	from Item [100] on EFFb form				See UncEffb 2D
21	Random Component of Uncertainty	([13a]² + [13b]² + ...)½				0.0019
22	Degrees of Freedom for Random Uncertainty	[21]⁴/([14a] + [14b] + ...)				3.9456E–07
23	Positive Systematic Uncertainty of Result	([15]² + [15b]² + ...)½				0.0483
24	Negative Systematic Uncertainty of Result	([16]² + [16b]² + ...)½				0.0445
25	Degrees of Freedom for Overall Test Result	[([23]/2)² + ([21])²]²/ [([21])⁴ / [22] + [23]/2)⁴ /50]	Pos	See UncEffb 2D	Neg	See UncEffb 2D
26	Student's *t* Value for Overall Degrees of Freedom for Test	From Table 5-16.5–1 in Code	Pos	See UncEffb 2D	Neg	See UncEffb 2D
27	Positive Total Test Uncertainty	[Pos 26] (([21])² + ([23]/2)²)½				See UncEffb 2D
28	Negative Total Test Uncertainty	[Neg 26] (([21])² + ([23]/2)²)½				See UncEffb 2D

PLANT NAME:	ASME PTC 4 EXAMPLE PROBLEM B-6.2	UNIT NO.:
TEST NO.:	DATE:	LOAD:
TIME START:	TIME END:	CALC BY:
REMARKS:		DATE:
		SHEET OF

Table B-6.2-8 Efficiency Uncertainty Worksheets: B Worksheet No. 1B

	Measured Parameter (from DATA)	1 Average Value (Item [2] on MEAS Form)	2 Standard Deviation (Item [3] on MEAS Form)	Sys Uncert Sheet No.	3 Total Positive Systematic Uncert (Item [2] on SYSUNC Form)		4 Total Negative Systematic Uncert (Item [2] on SYSUNC Form)		5 No. of Readings (Item [1] on MEAS Form)	6 Standard Dev of Mean $([2]^2 / [5])^{1/2}$	7 Degrees of Freedom [5] − 1	8 Percent Change	9 Incremental Change* [8] × [1] / 100
					%	Unit	%	Unit					
a	Furnace Residue Flow, %	15	0.00	3F	0.00	10.00	0.00	5.00	2	0.0000	1	1.00	0.15
b	Economizer Residue Flow, %	10.00	0.00	4F	7.00	0.00	7.00	0.00	2	0.0000	1	1.00	0.10
c	Precipitator Residue Flow, %	75	0.00	3G	0.00	20.00	0.00	20.00	2	0.0000	1	1.00	0.75
d	Furnace Residue Flow, lb/hr	0.0	0.00	3F	0.00	10.00	0.00	5.00	0	0.0000	0	1.00	0.00
e	Economizer Residue Flow, lb/hr	0.0	0.00	4F	7.00	0.00	7.00	0.00	0	0.0000	0	1.00	0.00
f	Precipitator Residue Flow, lb/hr	0.0	0.00	3G	0.00	20.00	0.00	20.00	0	0.0000	0	1.00	0.00
g	Furn Residue Carbon Content	0.0	0.00	7A	5.01	0.00	5.01	0.00	2	0.0000	1	1.00	0.00
h	Econ Residue Carbon Content	0.0	0.00	7A	5.01	0.00	5.01	0.00	2	0.0000	1	1.00	0.00
i	Precip Residue Carbon Content	0.0	0.00	7A	5.01	0.00	5.01	0.00	2	0.0000	1	1.00	0.00
j	Furnace Residue CO2 Content	0.0	0.00	7B	5.01	0.00	5.01	0.00	0	0.0000	0	1.00	0.00
k	Econ Residue CO2 Content	0.0	0.00	7B	5.01	0.00	5.01	0.00	0	0.0000	0	1.00	0.00
l	Precip Residue CO2 Content	0.0	0.00	7B	5.01	0.00	5.01	0.00	0	0.0000	0	1.00	0.00
m	Furnace Residue Temp	2,000.0	0.00	1B	0.00	3.32	0.00	3.32	2	0.0000	1	1.00	20.00
n	Economizer Residue Temp	660.2	1.08	1B	0.00	3.32	0.00	3.32	24	0.2214	23	1.00	6.60
o	Precipitator Residue Temp	280.7	0.59	1B	0.00	3.33	0.00	3.33	24	0.1205	23	1.00	2.81
p	SO2 in Flue Gas	0.0	0.0	8A	0.00	22.91	0.00	22.91	0	0.0000	0	1.00	0.00
q	O2 in Flue Gas	3.0	0.0	8B	0.00	0.73	0.00	0.73	2	0.0000	1	1.00	0.03
r	CaCO3 in Sorbent	0.0	0.0	9A	2.00	0.16	2.00	0.16	0	0.0000	0	1.00	0.00
s	Ca(OH)2 in Sorbent	0.0	0.0	9A	2.00	0.16	2.00	0.16	0	0.0000	0	1.00	0.00
t	MgCO3 in Sorbent	0.0	0.0	9B	2.00	0.11	2.00	0.11	0	0.0000	0	1.00	0.00
u	Mg(OH)2 in Sorbent	0.0	0.0	9B	2.00	0.11	2.00	0.11	0	0.0000	0	1.00	0.00
v	Moisture in Sorbent	0.0	0.0	9C	5.39	0.00	5.39	0.00	0	0.0000	0	1.00	0.00
w	Inert Material in Sorbent	0.0	0.0	9D	14.28	0.00	10.20	0.00	0	0.0000	0	1.00	0.00
x	Sorbent Temp	0.0	0.0	1F	0.00	7.07	0.00	7.07	0	0.0000	0	1.00	0.00
y	Fuel Temp	200.0	1.4	1F	0.00	3.16	0.00	3.16	10	0.4444	9	1.00	2.00
z	FG Temp Ent Hot AQCS Equip	0.0	0.0	1B	0.00	0.00	0.00	0.00	0	0.0000	0	1.00	0.00
aa	O2 Ent Hot AQCS Equip	0.0	0.0	5A	0.00	0.00	0.00	0.00	0	0.0000	0	1.00	0.00
ab													
ac													

Input source for Items [1] through [5]
For Spatially Uniform Parameters, enter results from the MEAS Data SYSUNC Forms.
For Spatially Nonuniform Parameters, enter results from the INTAVG Form.

* The value used for incremental change can be any increment of the average value.
The recommended increment is 1.0% (0.01 times the average value).
If the average value of the measured parameter is zero, use any small incremental change.
It is important to note that the incremental change must be in the same units as the average value.

PLANT NAME:	ASME PTC 4 EXAMPLE PROBLEM B-6.2	UNIT NO.:
TEST NO.:	DATE:	LOAD:
TIME START:	TIME END:	CALC BY:
REMARKS:		DATE:
		SHEET OF

Table B-6.2-8 Efficiency Uncertainty Worksheets: B (Cont'd)
Worksheet No. 2B

	Measured Parameter	10 Recalc Efficiency *	11 Absolute Sensitivity Coefficient ([10] − [20])/[9]	12 Relative Sensitivity Coefficient ([11] × [1])/[20]	13 Random Unc of Result Calculation [11] × [6]	14 Deg of Freedom for Random Uncert Contribution ([11] × [6])^4/[7]	15 Positive Sys Unc of Result [11] × {([1] × [3A] /100)^2 + [3B]^2}$^{1/2}$	16 Negative Sys Unc of Result [11] × {([1] × [4A] /100)^2 + [4B]^2}$^{1/2}$
a	Furnace Residue Flow,%	89.4164	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
b	Economizer Residue Flow,%	89.4164	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
c	Precipitator Residue Flow,%	89.4164	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
d	Furnace Residue Flow, lb/hr	89.4164	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
e	Economizer Residue Flow, lb/hr	89.4164	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
f	Precipitator Residue Flow, lb/hr	89.4164	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
g	Furn Residue Carbon Content	89.4164	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
h	Econ Residue Carbon Content	89.4164	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
i	Precip Residue Carbon Content	89.4164	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
j	Furnace Residue CO2 Content	89.4164	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
k	Econ Residue CO2 Content	89.4164	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
l	Precip Residue CO2 Content	89.4164	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
m	Furnace Residue Temp	89.4164	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
n	Economizer Residue Temp	89.4164	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
o	Precipitator Residue Temp	89.4164	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
p	SO2 in Flue Gas	89.4164	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
q	O2 in Flue Gas	89.4164	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
r	CaCO3 in Sorbent	89.4164	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
s	Ca(OH)2 in Sorbent	89.4164	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
t	MgCO3 in Sorbent	89.4164	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
u	Mg(OH)2 in Sorbent	89.4164	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
v	Moisture in Sorbent	89.4164	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
w	Inert Material in Sorbent	89.4164	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
x	Sorbent Temp	89.4164	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
y	Fuel Temp	89.4225	0.0030	0.0068	0.0013	3.6303E+13	0.0096	0.0096
z	FG Temp Ent Hot AQCS Equip	89.4164	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
aa	O2 Ent Hot AQCS Equip	89.4164	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
ab								
ac								

*This uncertainty worksheet is set up for calculating the uncertainty effect on efficiency; however, this sheet can be used for any calculated item, such as output, fuel flow, calcium/sulfur ratio, etc.

20	* Base Efficiency	From Item [100] on EFFb form					See UncEffb 2D
21	Random Component of Uncertainty	([13a]^2 + [13b]^2 +...)$^{1/2}$					0.0000
22	Degrees of Freedom for Random Uncertainty	[21]^4 / ([14a] + [14b] +...)					3.6303E−13
23	Positive Systematic Uncertainty of Result	([15a]^2 + [15b]^2 + ...)$^{1/2}$					0.0001
24	Negative Systematic Uncertainty of Result	([16a]^2 + [16b]^2 + ...)$^{1/2}$					0.0001
25	Degrees of Freedom for Overall Test Result	[([23]/2)^2 + ([21])^2]^2/[([21])^4 /[22] + ([23]/2)^4/50]	Pos	See UncEffb 2D	Neg	See UncEffb 2D	
26	Student's *t* Value for Overall Degrees of Freedom for Test	From Table 5-16.5-1 in Code	Pos	See UncEffb 2D	Neg	See UncEffb 2D	
27	Positive Total Test Uncertainty	[Pos 26] (([21])^2 + ([23]/2)^2)$^{1/2}$					See UncEffb 2D
28	Negative Total Test Uncertainty	[Neg 26] (([21])^2 + ([23]/2)^2)$^{1/2}$					See UncEffb 2D

PLANT NAME:	ASME PTC 4 EXAMPLE PROBLEM B-6.2	UNIT NO.:
TEST NO.:	DATE:	LOAD:
TIME START:	TIME END:	CALC BY:
REMARKS:		DATE:
		SHEET OF

Table B-6.2-9 Efficiency Uncertainty Worksheets: C Worksheet No. 1C

	Measured Parameter (from DATA)	1	Average Value (Item [2] on MEAS Form)	2 Standard Deviation (Item [3] on MEAS Form)	Sys Uncert Sheet No.	3 Total Positive Systematic Uncert (Item [2] on SYSUNC Form)		4 Total Negative Systematic Uncert (Item [2] on SYSUNC Form)		5 No. of Readings (Item [1] on MEAS Form)	6 Standard Dev of Mean ($[2]^2$ / [5])$^{1/2}$	7 Degrees of Freedom [5] − 1	8 Percent Change	9 Incremental Change* [8] × [1] /100
						%	Unit	%	Unit					
a	Avg Air Temp Ent Pulverizer		0.0	0.00	1A	0.00	1.03	0.00	1.03	0	0.0000	0	1.00	0.00
b	Avg Pulv Tempering Air Temp		0.0	0.00	1A	0.00	1.03	0.00	1.03	0	0.0000	0	1.00	0.00
c	Pri Airflow (Ent Pulverizer)		0.0	0.00	3H	5.12	0.00	5.12	0.00	0	0.0000	0	1.00	0.00
d	Aux Equip Power		0.0	0.0	4C	2.04	0.00	2.04	0.00	0	0.0000	0	1.00	0.00
e														
f	Surf Rad & Conv Loss Assigned		0.0	0.0	INPUT	0.00	0.00	0.00	0.00	0	0.0000	0	1.00	0.00
g	Flat Projected Surface Area	C	50.00	0.00	INPUT	5.00	0.00	5.00	0.00	0	0.0000	0	1.00	0.75
h	Avg Vel of Air Near Surface	C	1.7	0.00	INPUT	5.00	0.00	5.00	0.00	2	0.0000	1	1.00	0.02
i	Avg Surface Temp	C	127.0	0.00	INPUT	0.00	5.00	0.00	5.00	2	0.0000	1	1.00	1.27
j	Avg Amb Temp Near Surface	C	77.0	0.00	INPUT	0.00	5.00	0.00	5.00	2	0.0000	1	1.00	0.77
k														
l	Flat Projected Surface Area	A	0.00	0.00	INPUT	5.00	0.00	5.00	0.00	0	0.0000	0	1.00	0.76
m	Avg Vel of Air Near Surface	A	0.0	0.00	INPUT	5.00	0.00	5.00	0.00	0	0.0000	0	1.00	0.02
n	Avg Surface Temp	A	0.0	0.00	INPUT	0.00	5.00	0.00	5.00	0	0.0000	0	1.00	1.27
o	Avg Amb Temp Near Surface	A	0.0	0.00	INPUT	0.00	5.00	0.00	5.00	0	0.0000	0	1.00	0.77
p														
q	Flat Projected Surface Area	B	0.00	0.00	INPUT	5.00	0.00	5.00	0.00	0	0.0000	0	1.00	0.76
r	Avg Vel of Air Near Surface	B	0.0	0.00	INPUT	5.00	0.00	5.00	0.00	0	0.0000	0	1.00	0.02
s	Avg Surface Temp	B	0.0	0.00	INPUT	0.00	5.00	0.00	5.00	0	0.0000	0	1.00	1.27
t	Avg Amb Temp Near Surface	B	0.0	0.00	INPUT	0.00	5.00	0.00	5.00	0	0.0000	0	1.00	77.00
u														
v	Fuel Vol Matter		0.00	0.00	5C	0.00	0.00	0.00	0.00	2	0.0000	1	1.00	0.00
w	Fuel Fixed Carbon Content		0.00	0.00	5D	0.00	0.00	0.00	0.00	0	0.0000	0	1.00	0.00
x	Oil API Gravity		0.00	0.00	5E	5.39	0.00	5.39	0.00	0	0.0000	0	1.00	0.00
y														
z														
aa														
ab														
ac														

Input source for Items [1] through [5]
For Spatially Uniform Parameters, enter results from the MEAS Data SYSUNC Forms.
For Spatially Nonuniform Parameters, enter results from the INTAVG Form.

* The value used for incremental change can be any increment of the average value.
The recommended increment is 1.0% (0.01 times the average value).
If the average value of the measured parameter is zero, use any small incremental change.
It is important to note that the incremental change must be in the same units as the average value.

PLANT NAME:	ASME PTC 4 EXAMPLE PROBLEM B-6.2	UNIT NO.:
TEST NO.:	DATE:	LOAD:
TIME START:	TIME END:	CALC BY:
REMARKS:		DATE:
		SHEET OF

Table B-6.2-9 Efficiency Uncertainty Worksheets: C (Cont'd)
Worksheet No. 2C

	Measured Parameter		10 Recalc Efficiency *	11 Absolute Sensitivity Coefficient ([10] − [20]) / [9]	12 Relative Sensitivity Coefficient [11] × [1] / [20]	13 Random Unc of Result Calculation [11] × [6]	14 Deg of Freedom for Random Uncert Contribution ([11] × [6]^4)/[7]	15 Positive Sys Unc of Result [11] × {([1] × [3A] / 100)^2 + [3B]^2}$^{1/2}$	16 Negative Sys Unc of Result [11] × {([1] × [4A] / 100)^2 + [4B]^2}$^{1/2}$
a	Avg Air Temp Ent Pulverizer		89.4164	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
b	Avg Pulv Tempering Air Temp		89.4164	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
c	Pri Airflow (Ent Pulverizer)		89.4164	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
d	Aux Equip Power		89.4164	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
e									
f	Surf Rad & Conv Loss Assigned		89.4164	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
g	Flat Projected Surface Area	C	89.4097	−0.0089	−0.0050	0.0000	0.0000E+00	−0.0224	−0.0224
h	Avg Vel of Air Near Surface	C	89.4164	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
i	Avg Surface Temp	C	89.3956	−0.0164	−0.0234	0.0000	0.0000E+00	−0.0822	−0.0822
j	Avg Amb Temp Near Surface	C	89.4290	0.0163	0.0141	0.0000	0.0000E+00	0.0817	0.0817
k									
l	Flat Projected Surface Area	A	89.4164	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
m	Avg Vel of Air Near Surface	A	89.4164	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
n	Avg Surface Temp	A	89.4164	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
o	Avg Amb Temp Near Surface	A	89.4164	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
p									
q	Flat Projected Surface Area	B	89.4164	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
r	Avg Vel of Air Near Surface	B	89.4164	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
s	Avg Surface Temp	B	89.4164	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
t	Avg Amb Temp Near Surface	B	89.4164	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
u									
v	Fuel Vol Matter		89.4164	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
w	Fuel Fixed Carbon Content		89.4164	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
x	Oil API Gravity		89.4164	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
y									
z									
aa									
ab									
ac									

*This uncertainty worksheet is set up for calculating the uncertainty effect on efficiency; however, this sheet can be used for any calculated item, such as output, fuel flow, calcium/sulfur ratio, etc.

20	* Base Efficiency	From Item [37] on OUTPUT form				See UncEffb 2D
21	Random Component of Uncertainty	([13a]^2 + [13b]^2 +...)$^{1/2}$				0.0000
22	Degrees of Freedom for Random Uncertainty	[21]^4 / ([14a] + [14b] +...)				0.0000E+00
23	Positive Systematic Uncertainty of Result	([15a]^2 + [15b]^2 + ...)$^{1/2}$				0.0139
24	Negative Systematic Uncertainty of Result	([16a]^2 + [16b]^2 + ...)$^{1/2}$				0.0139
25	Degrees of Freedom for Overall Test Result	[([23]/2)^2 + ([21])^2]^2/[([21])^4 /[22] + ([23]/2)^4/50]	Pos	See UncEffb 2D	Neg	See UncEffb 2D
26	Student's *t* Value for Overall Degrees of Freedom for Test	From Table 5-16.5-1 in Code	Pos	See UncEffb 2D	Neg	See UncEffb 2D
27	Positive Total Test Uncertainty	[Pos 26] (([21])^2 + ([23]/2)^2)$^{1/2}$				See UncEffb 2D
28	Negative Total Test Uncertainty	[Neg 26] (([21])^2 + ([23]/2)^2)$^{1/2}$				See UncEffb 2D

PLANT NAME:	ASME PTC 4 EXAMPLE PROBLEM B-6.2	UNIT NO.:
TEST NO.:	DATE:	LOAD:
TIME START:	TIME END:	CALC BY:
REMARKS:		DATE:
		SHEET OF

Table B-6.2-10 Efficiency Uncertainty Worksheets: D Worksheet No. 1D

	Measured Parameter (from DATA)	1 Average Value (Item [2] on MEAS Form)	2 Standard Deviation (Item [3] on MEAS Form)	Sys Uncert Sheet No.	3 Total Positive Systematic Uncert (Item [2] on SYSUNC Form)		4 Total Negative Systematic Uncert (Item [2] on SYSUNC Form)		5 No. of Readings (Item [1] on MEAS Form)	6 Standard Dev of Mean ($[2]^2$ / [5])$^{1/2}$	7 Degrees of Freedom [5] − 1	8 Percent Change	9 Incremental Change* [8] × [1] /100
					%	Unit	%	Unit					
a	Losses, %												
b	CO in Flue Gas	0.050	0.001	10A	0.05	0.00	0.05	0.00	3	0.0003	2	1.00	0.0005
c	Formation of NOx	0.000	0.000	10B	0.05	0.00	0.05	0.00	0	0.0000	0	1.00	0.0000
d	Pulverizer Rejects	0.000	0.000	11A	111.80	0.00	53.85	0.00	0	0.0000	0	1.00	0.0000
e	Air Infiltration	0.000	0.000	INPUT	0.00	0.00	0.00	0.00	0	0.0000	0	1.00	0.0000
f	Unburned HC in Flue Gas	0.000	0.000	INPUT	0.00	0.00	0.00	0.00	0	0.0000	0	1.00	0.0000
g	Other	0.140	0.000	INPUT	0.00	0.00	0.00	0.00	0	0.0000	0	1.00	0.0014
h	Losses, MKBtu/hr												
i	Wet Ash Pit	0.000	0.000	10C	25.74	0.00	11.72	0.00	0	0.0000	0	1.00	0.0000
j	Sen Ht in Solid Recirc Strms	0.000	0.000	INPUT	0.00	0.00	0.00	0.00	0	0.0000	0	1.00	0.0000
k	Sen Ht in Gas Recirc Strms	0.000	0.000	INPUT	0.00	0.00	0.00	0.00	0	0.0000	0	1.00	0.0000
l	Additional Moisture	0.000	0.000	INPUT	0.00	0.00	0.00	0.00	0	0.0000	0	1.00	0.0000
m	Cooling Water	0.000	0.000	INPUT	0.00	0.00	0.00	0.00	0	0.0000	0	1.00	0.0000
n	Air Preheat Coils	0.000	0.000	INPUT	0.00	0.00	0.00	0.00	0	0.0000	0	1.00	0.0000
o	Other	0.000	0.000	INPUT	0.00	0.00	0.00	0.00	0	0.0000	0	1.00	0.0000
p	Credits, %												
q	Other	0.000	0.000	INPUT	0.00	0.00	0.00	0.00	0	0.0000	0	1.00	0.0000
r	Credits, MKBtu/hr												
s	Heat in Add Moisture	0.000	0.000	INPUT	0.00	0.00	0.00	0.00	0	0.0000	0	1.00	0.0000
t	Other	0.000	0.000	INPUT	0.00	0.00	0.00	0.00	0	0.0000	0	1.00	0.0000
u													
v													
w													
x													
y													
z													
aa													
ab													
ac													

Input source for Items [1] through [5]
For Spatially Uniform Parameters, enter results from the MEAS Data SYSUNC Forms.
For Spatially Nonuniform Parameters, enter results from the INTAVG Form.

* The value used for incremental change can be any increment of the average value.
The recommended increment is 1.0% (0.01 times the average value).
If the average value of the measured parameter is zero, use any small incremental change.
It is important to note that the incremental change must be in the same units as the average value.

PLANT NAME:	ASME PTC 4 EXAMPLE PROBLEM B-6.2	UNIT NO.:
TEST NO.:	DATE:	LOAD:
TIME START:	TIME END:	CALC BY:
REMARKS:		DATE:
		SHEET OF

Table B-6.2-10 Efficiency Uncertainty Worksheets: D (Cont'd) Worksheet No. 2D

	Measured Parameter	10 Recalc Efficiency *	11 Absolute Sensitivity Coefficient ([10] − [20])/[9]	12 Relative Sensitivity Coefficient ([11] ×[1])/[20]	13 Random Unc of Result Calculation [11] × [6]	14 Deg of Freedom for Random Uncert Contribution ([11] × [6])^4/[7]	15 Positive Sys Unc of Result [11] × {([1] × [3A] /100)^2 + [3B]^2}$^{1/2}$	16 Negative Sys Unc of Result [11] × {([1] × [4A] /100)^2 + [4B]^2}$^{1/2}$
a	Losses, %							
b	CO in Flue Gas	89.4159	−0.9925	−0.0006	−0.0003	3.3692E−15	0.0000	0.0000
c	Formation of NOx	89.4164	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
d	Pulverizer Rejects	89.4164	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
e	Air Infiltration	89.4164	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
f	Unburned HC in Flue Gas	89.4164	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
g	Other	89.4150	−0.9925	−0.0016	0.0000	0.0000E+00	0.0000	0.0000
h	Losses, MKBtu/hr							
i	Wet Ash Pit	89.4164	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
j	Sen Ht in Solid Recirc Strms	89.4164	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
k	Sen Ht in Gas Recirc Strms	89.4164	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
l	Additional Moisture	89.4164	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
m	Cooling Water	89.4164	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
n	Air Preheat Coils	89.4164	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
o	Other	89.4164	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
p	Credits, %							
q	Other	89.4164	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
r	Credits, MKBtu/hr							
s	Heat in Add Moisture	89.4164	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
t	Other	89.4164	0.0000	0.0000	0.0000	0.0000E+00	0.0000	0.0000
u								
v								
w								
x								
y								
z								
aa								
ab								
ac								

*This uncertainty worksheet is set up for calculating the uncertainty effect on efficiency; however, this sheet can be used for any calculated item, such as output, fuel flow, calcium/sulfur ratio, etc.

20	* Base Efficiency	From Item [100] on EFFb form				88.4164
21	Random Component of Uncertainty	([13a]^2 + [13b]^2 +...)$^{1/2}$				0.0439
22	Degrees of Freedom for Random Uncertainty	[21]^4 / ([14a] + [14b] +...)				9.4103
23	Positive Systematic Uncertainty of Result	([15a]^2 + [15b]^2 + ...)$^{1/2}$				0.2496
24	Negative Systematic Uncertainty of Result	([16a]^2 + [16b]^2 + ...)$^{1/2}$				0.2419
25	Degrees of Freedom for Overall Test Result	[([23]/2)^2 + ([21])^2]^2/[([21])^4 /[22] + ([23]/2)^4/50]	Pos	58.39	Neg	58.63
26	Student's t Value for Overall Degrees of Freedom for Test	From Table 5-16.5-1 in Code	Pos	2.00	Neg	2.00
27	Positive Total Test Uncertainty	[Pos 26] (([21])^2 + ([23]/2)^2)$^{1/2}$				0.2646
28	Negative Total Test Uncertainty	[Neg 26] (([21])^2 + ([23]/2)^2)$^{1/2}$				0.2573

PLANT NAME:	ASME PTC 4 EXAMPLE PROBLEM B-6.2	UNIT NO.:
TEST NO.:	DATE:	LOAD:
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REMARKS:		DATE:
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NONMANDATORY APPENDIX C
DERIVATIONS

C-1 INTRODUCTION

The derivation equations utilize the same acronym format as used in Section 5. Subsection 5-20 shows the format, definition of letters or letter combinations, and a summary of acronyms used.

C-2 DERIVATIONS OF SULFUR CAPTURE/RETENTION FROM MEASURED O_2 AND SO_2

The derivation below is shown for O_2 and SO_2 measured on a wet basis. For a dry basis, substitute *MODPP* for *MOWPP* and delete moles of moisture in air, *MOWA*. For the derivation below, CO and NO_x in the flue gas are assumed to be minimal such that they do not have a significant impact on the result. Refer also to subsection C-5 for derivation with CO and NO_x.

$$VFO2 = \frac{VPO2}{100} = \frac{MOO2}{MOWG} \text{ moles } O_2/\text{mole wet gas (measured)} \tag{C-2-1}$$

$$VSFO2 = \frac{(1 - MFSC)\,MOSO2}{MOWG} \text{ moles } SO_2/\text{mole wet gas (measured } SO_2) \tag{C-2-2}$$

where *MFSC* is the fraction of sulfur in fuel captured or retained.

$$MOSO2 = \frac{MPSF}{3{,}206.4}, \text{ maximum moles } SO_2/\text{mass fuel} \tag{C-2-3}$$

$$MODPP = \frac{MPCB}{1{,}201} + \frac{MPSF}{3{,}206.4} + \frac{MPN2F}{2{,}801.3} + MODGSB$$
maximum moles of dry products from fuel and sorbent/mass fuel (C-2-4)

$$MOWPP = MODPP + \frac{MPH2F}{201.6} + \frac{MPWF}{1{,}801.5} + \frac{MFWADn}{18.015} + MOWSB$$
maximum moles of wet products from fuel and sorbent/mass fuel (C-2-5)

$$MOTHAP = \frac{1}{0.2095}\left[\frac{MPCB}{1{,}201} + \frac{MPH2F}{403.2} + \frac{MPSF}{3{,}206.4} - \frac{MPO2F}{3{,}200}\right]$$
moles of theoretical air with 100% conversion sulfur in fuel/mass fuel (C-2-6)

$$MOTHAC = MOTHAP + \frac{MFSC}{2}\,\frac{MOSO2}{0.2095}, \text{ moles}$$
theoretical O_2 corrected for sulfur retention/mass fuel (C-2-7)

The corrected theoretical air requires one-half mole of O_2 for every mole of sulfur captured to form SO_3 in the reaction $CaO + SO_3 \rightarrow CaSO_4$.

The moles of wet gas (*MOWG*) is the sum of the maximum moles of wet products from fuel and sorbent less the moles of SO_2 captured plus the moles of nitrogen in the theoretical air plus the moles of water in the theoretical air plus the moles of wet excess air.

$$MOWG = MOWPP - MFSC\ MOSO2 + 0.7905\ MOTHAC + MOTHAC\ MOWA + \frac{MOO2}{0.2095}(1 + MOWA),$$
moles wet gas/mass fuel (C-2-8)

$$MOWG = MOWPP - MFSC\ MOSO2 + MOTHAP\ (0.7905 + MOWA) + \frac{MFSC}{2}\,\frac{MOSO2}{0.2095}\,(0.7905 + MOWA) + MOWG\,\frac{VFO2}{0.2095}(1 + MOWA) \tag{C-2-9}$$

$$\text{Let } K = (0.7905 + MOWA)\,\frac{1}{2}\,\frac{1}{0.2095} - 1 = 2.387\ (0.7905 + MOWA) - 1 \tag{C-2-10}$$

$$MOWG\left[1 - (1 + MOWA)\frac{VFO2}{0.2095}\right] = MOWPP + MOTHAP\ (0.7905 + MOWA) + K\ MFSC\ MOSO2 \tag{C-2-11}$$

$$MOWG = \frac{MOWPP + MOTHAP\,(0.7905 + MOWA) + K\ MFSC\ MOSO2}{\left[1 - (1 + MOWA)\frac{VFO2}{0.2095}\right]} \tag{C-2-12}$$

$$VFSO2 = \frac{(MOSO2 - MFSC\ MOSO2)\left[1 - (1 + MOWA)\frac{VFO2}{0.2095}\right]}{MOWPP + MOTHAP\,(0.7905 + MOWA) + K\ MFSC\ MOSO2} \tag{C-2-13}$$

$$\text{Let } B = \frac{VFSO2}{\left[1 - (1 + MOWA)\frac{VFO2}{0.2095}\right]} \tag{C-2-14}$$

$$B\,[MOWPP + MOTHAP\,(0.7905 + MOWA)] + B\,K\ MFSC\ MOSO2 + MFSC\ MOSO2 = MOSO2 \tag{C-2-15}$$

$$MFSC\ MOSO2\,(1 + B\,K) = MOSO2 - B\,[MOWPP + MOTHAP\,(0.7905 + MOWA)] \tag{C-2-16}$$

$$MFSC = \frac{1 - \left[\frac{VFSO2\,[MOWPP + MOTHAP\,(0.7905 + MOWA)]}{[1 - (1 + MOWA)\,VFO2\,/\,0.2095]\,MOSO2}\right]}{1 + K\left[\frac{VFSO2}{1 - (1 + MOWA)\,VFO2\,/\,0.2095}\right]}$$
mass/mass (C-2-17)

C-3 DERIVATION OF EXCESS AIR BASED ON MEASURED O_2

The derivation shown below is for O_2 measured on a wet basis. For a dry basis, substitute *MODP* for *MOWP* and delete moles of moisture in air, *MOWA*. The resulting equation below is the same as presented in Section 5 and does not consider the impact of CO and NO_x on excess air as they are offsetting and usually insignificant. Refer to subsection C-4 for excess air corrected for CO and NO_x.

$$VFO2 = \frac{VPO2}{100} - \frac{MOO2}{MOWG}$$
moles O_2/mole wet gas (measured) (C-3-1)

$$MODP = \frac{MPCB}{1{,}201} + (1 - MFSC)\frac{MPSF}{3{,}206.4} + \frac{MPN2F}{2{,}801.3} + MODGSB$$
moles of dry products from fuel and sorbent/mass fuel (C-3-2)

$$MOWP = MODP + \frac{MPH2F}{201.6} + \frac{MPWF}{1{,}801.5} + \frac{MFWADn}{18.015} + MOWSB$$
moles of wet products from fuel and sorbent/mass fuel (C-3-3)

$$MOTHAC = \frac{1}{0.2095}\left[\frac{MPCB}{1{,}201} + \frac{MPH2F}{403.2} + (1 + 0.5\,MFSC)\frac{MPSF}{3{,}206.4} - \frac{MPO2F}{3{,}200}\right]$$
moles of theoretical air corrected for sulfur capture/mass fuel (C-3-4)

Moles of wet gas (*MOWG*) is the sum of the moles of wet products from fuel and sorbent plus the moles of nitrogen in the theoretical air plus the moles of water in the theoretical air plus the moles of wet excess air.

$$MOWG = MOWP + 0.7905\,MOTHAC + MOWA\,MOTHAC + FXA\,MOTHAC\,(1 + MOWA)$$
moles of wet gas/mass fuel (C-3-5)

$$MOWG = MFWA\,\frac{28.966}{18.015} = 1.608\,MFWA$$
moles water/mole dry air (C-3-6)

$$MOO2 = FXA\,0.2095\,MOTHAC$$
moles excess O_2/mass fuel (C-3-7)

$$VFO2 = \frac{MOO2}{MOWG}$$

$$= \frac{FXA\,0.2095\,MOTHAC}{MOWP + MOTHAC\,(0.7905 + MOWA) + FXA\,MOTHAC\,(1 + MOWA)}$$
(C-3-8)

$$FXA\,0.2095\,MOTHAC - VFO2\,FXA\,MOTHAC\,(1 + MOWA) = VFO2\,[MOWP + MOTHAC\,(0.7905 + MOWA)]$$
(C-3-9)

$$FXA = \frac{VFO2[MOWP + MOTHAC\,(0.7905 + MOWA)]}{MOTHAC\,[0.2095 - VFO2\,(1 + MOWA)]}$$
mass fraction of excess air (C-3-10)

$$PXA = 100\,\frac{VPO2\,[MOWP + MOTHAC\,(0.7905 + MOWA)]}{MOTHAC\,[20.95 - VPO2\,(1 + MOWA)]}$$
% excess air (C-3-11)

C-4 DERIVATION OF O_2 CORRECTED FOR CO AND NO_X FOR DETERMINING EXCESS AIR

The excess air equations shown in Section 5 and subsection C-3 consider all of the carbon gasified, CB, to be converted to CO_2 and that CO for most combustion processes will be small and have an insignificant impact on calculated excess air. The formation of NO_x reduces the oxygen content of the flue gas and is also considered to have an insignificant impact on calculated excess air.

In this paragraph, an oxygen content corrected for CO and NO_x (VPO_2C) is derived that can be substituted for VPO_2 in the excess air equations presented previously.

Consider the following reactions:

$$2\,O_2 + 2\,C \rightarrow 2 \text{ Complete Combustion} \quad \text{(C-4-1)}$$

$$2\,O_2 + 2\,C \rightarrow CO + CO_2 + \frac{1}{2}\,N_2 + \frac{1}{2} \text{ Incomplete Combustion} \quad \text{(C-4-2)}$$

$$N_2 + O_2 \rightarrow NO + \frac{1}{2}N_2 + \frac{1}{2}O_2 \quad \text{(C-4-3)}$$

When CO is present, there is one-half mole more O_2 present per mole of CO than there would be if all the gasified carbon, CB, were oxidized to CO_2. For simplicity, NO_x will be considered in its most abundant form, NO. When NO is formed, there is one-half mole less O_2 than if there were no NO; however, the total number of moles of gas does not change.

Referring to subsection C-3, the equation for MOO_2 [eq. (C-3-7)] becomes

$$MOO2 = FXA\,0.2095\,MOTHAC + \frac{MOCO}{2} - \frac{MONO_x}{2}$$
moles excess O_2/lbm fuel (C-4-4)

$$\frac{VPO2}{100} = \frac{MOO2}{MOG}$$

$$= \frac{FXA\ 0.2095\ MOTHAC}{MOG} + \frac{1}{2}\frac{MOCO}{MOG} - \frac{1}{2}\frac{MONO_x}{MOG} \quad \text{(C-4-5)}$$

$$\frac{VPCO}{100} = \frac{MOCO}{MOG} \text{ or } \frac{1}{2}\frac{MOCO}{MOG} = \frac{VPCO}{200} \quad \text{(C-4-6)}$$

$$\frac{VPNO_x}{100} + \frac{MONO_x}{MOG} \text{ or } \frac{1}{2}\frac{MONO_x}{MOG} + \frac{VPNO_x}{200} \quad \text{(C-4-7)}$$

$$\text{Let } \frac{VPO2Cl}{100} = \frac{VPO2}{100} - \frac{VPCO}{200} + \frac{VPNO_x}{200}$$

$$= \frac{FXA\ 0.2095\ MOTHAC}{MOG} \quad \text{(C-4-8)}$$

where *MOG* is the moles of gas on a wet or dry basis.

Let *MOTHG* equal *MOWG* defined in subsection C-3 (or *MODG* if measurement on a dry basis). Then the moles of gas considering CO and NO_x become

$$MOG = MOTHG + \frac{MOCO}{2} = MOTHG + \frac{VPCO}{200}\ MOG \quad \text{(C-4-9)}$$

$$\text{Let } MOGCF = \frac{1}{\left[1 - \frac{VPCO}{200}\right]} \quad \text{(C-4-10)}$$

then

$$MOG = \frac{MOTHG}{\left[1 - \frac{VPCO}{200}\right]} = MOTHG\ MOGCF \quad \text{(C-4-11)}$$

Dividing eq. (C-4-8) by the moles of gas correction factor (*MOGCF*) yields

$$VPO2C = \frac{VPO2Cl}{100\ MOGCF} = \frac{FXA\ 0.2095\ MOTHAC}{MOTHG} \quad \text{(C-4-12)}$$

which is the same as eq. (C-3-8). Thus, to correct excess air for CO and NO_x, substitute VPO_2C for VPO_2 in the excess air equations in Section 5 and subsection C-3. VPO_2C becomes

$$VPO2C = \left[VPO2 - \frac{VPCO}{2} + \frac{VPNO_x}{2}\right]\left[1 - \frac{VPCO}{200}\right], O_2 \text{ corrected for CO and } NO_x \quad \text{(C-4-13)}$$

C-5 DERIVATION OF LOSS FROM HOT AIR QUALITY CONTROL EQUIPMENT

The heat losses attributable to hot air quality control equipment are categorized as noted in paras. C-5.1 through C-5.3. Figure C-5-1 presents a schematic of hot air qua-lity control equipment.

C-5.1 Surface Heat Loss

The surface area of the hot air quality control equipment and connecting flues exposed to ambient air can be on the order of twice the area of the boiler with a conventional flue and duct arrangement.

C-5.2 Air Infiltration on Suction Units

Due to the large surface area, size of the connecting flues, and precipitator penetrations, the air infiltration may be significant. It is noted that there may be a measurable amount of infiltration on pressure fired units due to seal air.

C-5.3 Heat in Ash Loss at the Collection Temperature Rather Than the Air Heater Gas Outlet Temperature

This loss is accounted for separately as part of the loss due to sensible heat of residue, *QpLRs53*, and is therefore not considered part of the additional losses from hot air quality control equipment.

C-6 FUEL EFFICIENCY: MIXED UNITS FOR LOSSES AND CREDITS

Most losses and credits can be calculated conveniently on an input from fuel basis. However, some losses/credits can only be calculated on an energy per unit of time basis such as radiation and convection loss. One approach is to estimate the input from fuel and convert the loss/credit on an energy per unit of time basis to an input from fuel basis. This requires reiterating until the estimated input from fuel agrees with the calculated input based on the calculated efficiency. The following equation allows solving for efficiency using losses and credits in mixed units:

$$QRF + QRB = QRO = QRL \quad \text{(C-6-1)}$$

Multiplying by $\frac{100}{QRF}$

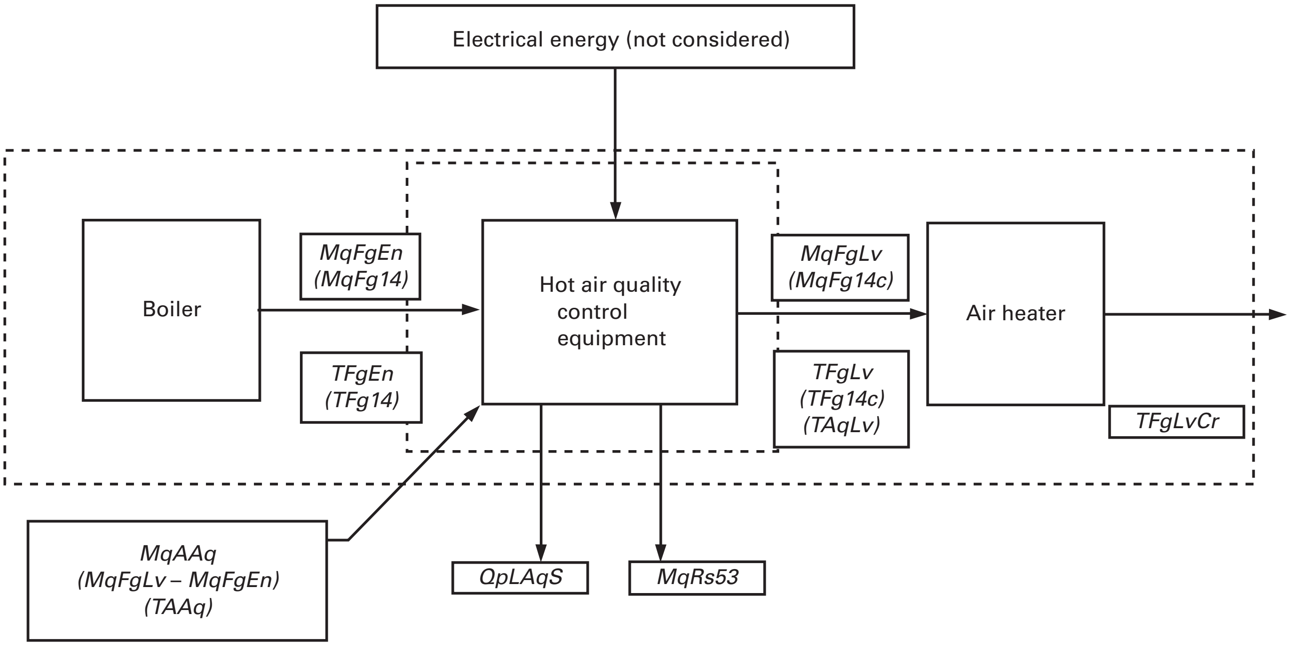
$$100 + 100\frac{QRB}{QRF} = 100\frac{QRO}{QRF} + \frac{QRL}{QRF} \quad \text{(C-6-2)}$$

By definition,

$$PFE = 100\frac{QRO}{QRF}, \% \quad \text{(C-6-3)}$$

$$QPL = 100\frac{QRL}{QRF}, \% \quad \text{(C-6-4)}$$

Fig. C-5-1 Schematic of Hot Air Quality Control Equipment



GENERAL NOTES:

(a) Hot air quality control equipment:

(1) Surface heat loss, %
$QpLAqS = 100 \times MqFgEn \times (HFgEn - HFgLv) - (MqFgLv - MqFgEn) \times (HAAqLv - HAAq)$

(2) Loss due to wet air infiltration, %
$QpLAqMqA = 100 \times MqAAq \times (HAAqLv - HAAq)$

(b) Combine equations in (1) and (2) above:

$QpLAq$ = loss from hot air quality control equipment, %
$= QpLAqS + QpLAqMqA$
$= 100 \times [MqFgEn \times (HFgEn - HFgLv) - (MqFgLv - MqFgEn) \times (HAAqLv - HALvCr)]$,%

$$QPB = 100\,\frac{QRB}{QRF},\ \% \qquad \text{(C-6-5)}$$

$$\therefore PFE = 100 - QPL + QPB,\ \% \qquad \text{(C-6-6)}$$

Losses calculated on an energy input basis can be converted to a percent basis:

$$100\,\frac{QRL}{QRF} = QPL = \frac{QRL}{QRO}\,PFE,\ \% \qquad \text{(C-6-7)}$$

As in eq. (C-6-6), adding credits and losses:

$$PFE = 100 - QPL + QPB - PFE\,\frac{QRL}{QRO} + PFE\,\frac{QRB}{QRO},\ \% \qquad \text{(C-6-8)}$$

which reduces to

$$PFE = (100 - QPL + QPB)\left[\frac{QRO}{QRO + QRL - QRB}\right],\ \% \qquad \text{(C-6-9)}$$

NONMANDATORY APPENDIX D
GROSS EFFICIENCY: ENERGY BALANCE AND INPUT–OUTPUT METHOD; LHV EFFICIENCY: ENERGY BALANCE METHOD

D-1 INTRODUCTION

Efficiency is the ratio of energy output to energy input, expressed as a percentage. This Code recognizes two definitions of steam generator efficiency: fuel efficiency and gross efficiency. The output term (*QrO*) is the same for both definitions of efficiency and is defined in Sections 2 and 5 as the energy absorbed by the working fluid that is not recovered within the steam generator envelope, such as energy to heat the entering air. For fuel efficiency (*EF*), the energy input to the system is defined as the total heat of combustion available from fuel or the fuel input (*QrF*). For gross efficiency (*EGr*), the energy input to the system is defined as the total energy added to the system or gross input (*QrIGr*). The gross input is the sum of the input from fuel (*QrF*) plus credits (*QrB*) or the energy added to the system from other sources with respect to the reference temperature, 77°F (25°C). Refer to Section 5 for a more complete definition of credits.

$$EGr = 100\frac{OUTPUT}{GROSS\ INPUT} + 100\frac{QrO}{QrIGr}, \% \quad \text{(D-1-1)}$$

$$QrIGr = QrF + QrB, \text{ Btu/hr (W)} \quad \text{(D-1-2)}$$

The advantage of gross efficiency versus fuel efficiency is that it is a measure of the total energy required to produce a given output, and thus may have some meaning if the costs of the other energy sources are not evaluated separately. The major disadvantage of gross efficiency is that it is not universally understood by those evaluating a total system and may be used incorrectly. The major sources of energy added to the system and credits are electrical and steam energy. The cost of these energy sources is not the same on a Btu basis as the energy cost of the fuel, and should be (usually is) evaluated separately. If the cost of credits is evaluated separately, gross efficiency is not appropriate for the evaluation of energy cost to produce a given output. Therefore, fuel efficiency is the preferred method in this Code for expressing efficiency.

D-2 ENERGY BALANCE METHOD

To calculate gross efficiency (*EGr*) by the energy balance method, the fuel efficiency (*EF*) should be calculated first by the energy balance method in accordance with Section 5. Gross efficiency may then be calculated from one of the following equations:

$$EGr = 100\frac{QrO}{QrF + QrB} = 100\left[1 - \frac{QpL}{100 + QpB}\right] = 100\left[1 - \frac{QrL}{QrF + QrB}\right], \% \quad \text{(D-2-1)}$$

$$QrF = 100\frac{QrO}{EF}, \text{ Btu/hr (W)} \quad \text{(D-2-2)}$$

where
- *QpB* = summation of credits, percent (%) basis
- *QpL* = summation of losses, percent (%) basis
- *QrB* = summation of credits, Btu/hr (W) basis. Items that result in a negative credit shall still be considered as a "credit" in the calculation of gross efficiency. It may be questioned why exothermic reactions, sulfation in particular, are considered a credit. This is a matter of definition adopted by the Code committee, but it is interesting to note that they have no impact on gross efficiency because the input from fuel will be reduced by the exact amount of the heat gained from sulfation.
- *QrL* = summation of losses, Btu/hr (W) basis

D-3 INPUT–OUTPUT METHOD

Efficiency calculated by the Input–Output method is based upon measuring the fuel flow and boiler fluid side conditions necessary to calculate output. Credits are measured and/or calculated to determine total input as defined above. The uncertainty of efficiency calculated by the Input–Output method is directly proportional to the accuracy of determining the fuel flow, a representative fuel analysis, and steam generator output; therefore, to obtain reliable results, extreme care must be taken to determine these items accurately.

$$EGr = 100\frac{QrO}{QrF + QrB}, \% \quad \text{(D-3-1)}$$

$$QrF = MrF \times HHVF, \text{ Btu/hr (W)} \qquad \text{(D-3-2)}$$

where

HHVF = higher heating value of fuel, Btu/lbm (J/kg). Refer to subsection 5-8.

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

QrF = heat input from fuel, Btu/hr (W)

QrB = summation of credits, Btu/hr (W) basis. Refer to Section 5 for the general method of calculation. For the credits calculated on a percent input from fuel basis, multiply by (*QrF*/100) to convert to Btu/hr (W). Below are supplementary comments on the calculation of credits that are not measured directly.

The credits due to heat in entering dry air (*QrBDA*) and moisture in entering dry air (*QrBWA*) require the mass flow rate of dry air. The mass flow rate of dry air is calculated stoichiometrically from the ultimate fuel analysis and unburned carbon in the refuse (refer to Section 5 and the Combustion Calculation Form, Nonmandatory Appendix B). For units that do not utilize sorbent for reduction of sulfur emissions, it may be necessary to calculate unburned carbon in the refuse (refer to the Unburned Carbon in Refuse Calculation Form, Nonmandatory Appendix A). For units that do use sorbent, it will be necessary to calculate the mass fraction of sulfur capture as well as the unburned carbon in the refuse (refer to the Sorbent Calculation Form, Nonmandatory Appendix A). The credit due to sulfation (*QrBSlf*) is calculated from the mass fraction of sulfur capture that is calculated above. The use of sorbent also impacts the mass flow rate of dry air.

D-4 EFFICIENCY ON A LOWER HEATING VALUE, *LHV*, BASIS

This Code uses the higher heating value of the fuel as the preferred method to determine fuel energy input. This Section explains how to compute efficiency on a lower heating value (*LHV*), or net calorific value, basis. Refer to para. 3-1.2 regarding the disadvantages of expressing efficiency on a lower heating value basis.

It is necessary to calculate *LHV* from the measured *HHV*. There is no universally accepted standard for calculation of *LHV*; the constant used for heat of combustion and the temperature used to determine the latent heat of vaporization (h_{FG}) vary between references. Some published methods are incorrect for SOLID OR LIQUID fuels that contain water. It is important that the temperature used for the calculation of h_{FG} be consistent with the basis for the boiler efficiency calculations, otherwise the calculated fuel mass flow rate for a given boiler output will be incorrect.

This Code specifies a reference temperature of 77°F (25°C). Based on the ASME International Steam Tables for Industrial Use, IAWPS-IF97, the recommended value for solid and liquid fuels for h_{FG} at 77°F (25°C) is 1,050 Btu/lbm (2 422 kJ/kg). Calculation of *LHV* from *HHV* is then

$$LHV = HHV - C1\left(\frac{H2F \times 8.937 + H2OF}{100}\right), \text{ Btu/lbm (kJ/kg)} \qquad \text{(D-4-1)}$$

where

C1 = 1,050 Btu/lbm (2 422 kJ/kg)

H2F = the quantity of H_2 in the fuel, % mass

H2OF = the quantity of H_2O in the fuel, % mass

For gaseous fuels, the *LHV* should be calculated based on the *LHV* values specified for the individual gas fuel constituents in ASTM D3588.

It is recognized that calculation of *LHV* (and fuel efficiency) is dependent upon the temperature at which the test is conducted. However, the difference in the calculated *LHV* due to the difference between 77°F (25°C) and the temperatures of the laboratory test is minor and within the uncertainty of the measured *HHV*.

LHV will be on the same basis, constant pressure or constant volume, as *HHV*.

The systematic uncertainty of the *LHV* must consider the uncertainty of determining the quantity of hydrogen and moisture in the fuel as well as systematic uncertainty; however, the additional uncertainty is usually minimal.

Efficiency on a lower heating value basis is calculated by substituting the lower heating value for the higher heating value in all computations. Since the *LHV* is calculated by reducing the fuel *HHV* by the latent heat of vaporization of the water formed from the combustion of the H_2 in fuel and the water content of solid or liquid fuels, the method of calculating the *LHV* losses due to water from fuel are different depending upon whether calculated on a *HHV* or *LHV* basis. The energy loss on an *HHV* basis is based on the difference in the enthalpy of steam at the exit gas temperature, *HStLvCr*, and the enthalpy of water, *HWRe*, at the reference temperature. The energy loss on an *LHV* basis is based on the difference in the enthalpy of water vapor, at the exit gas temperature, *HWvLvCr*, and the enthalpy of water vapor, at the reference temperature, *HWvRe*. Thus, the loss due to water formed from the combustion of H_2 on an *LHV* basis, $QpLH2F_{LHV}$, is calculated per the following equation:

$$QpLH2F_{LHV} = 100\, MqWH2F\,(HWvLvCr - HWv\,\mathrm{Re})\,HHV/LHV, \% \qquad \text{(D-4-2)}$$

where

MqWH2F = water produced from the combustion of H_2 in the fuel on a mass per energy input on an *HHV* basis

It is recommended that parameters associated with the fuel or input from fuel continue to be calculated on an *HHV* basis to maintain recognition of these normalized values such as theoretical air. Accordingly, the following assumes all losses and credits calculated on a percent of fuel input basis will be calculated on an *HHV* basis in accordance with Section 5 and multiplied by the ratio of the higher heating value divided by the lower heating value, *RHV*:

$$RHV = \frac{HHV}{LHV} \qquad \text{(D-4-3)}$$

For this Code, the enthalpy of all parameters with the exception of steam, are based upon the Code reference temperature of 77°F (25°C). Therefore, the enthalpy of water vapor at the reference temperature is zero (0.0). Refer to para. 5-19.4 for curve fit.

Considering the above, the equations for losses due to water formed from the combustion of H_2 in the fuel and water (H_2O) in a solid or liquid fuel are as follows:

$$QpLH2F_{LHV} = 100\, MqWH2F \times HWvLvCr \times RHV, \% \qquad \text{(D-4-4)}$$

$$QpLWF_{LHV} = 100\, MqWF \times HWvLvCr \times RHV, \% \qquad \text{(D-4-5)}$$

For all other losses and credits calculated on a percent input from fuel basis, multiply by the *HHV* value by *RHV*.

Combining losses and credits calculated on a percent input from fuel on an *LHV* basis with the losses and credits calculated on a Btu/hr (W) basis, the expression for fuel efficiency using mixed units for losses and credits is

$$EF_{LHV} = (100 - SmQpL_{LHV} + SmQpB_{LHV})\left(\frac{QrO}{QrO + SQrL - SmQrB}\right), \% \qquad \text{(D-4-6)}$$

where

$SmQpL_{LHV}$ and $SmQpB_{LHV}$ = sum of the losses and credits calculated on percent input from fuel *LHV* basis

SmQrL and *SmQrB* = sum of the losses and credits calculated on a Btu/hr (W) basis

The input from fuel on an *LHV* basis (QrF_{LHV}), and mass flow rate of fuel (*MrF*) may be calculated from output and fuel efficiency determined by the energy balance method on an *LHV* basis in accordance with the following:

$$QrF_{LHV} = 100 \times \left(\frac{QrO}{EF_{LHV}}\right), \text{ Btu/hr (W)} \qquad \text{(D-4-7)}$$

$$MrF = 100\left(\frac{QrO}{EF_{LHV} \times LHVF}\right) = \frac{QrF_{LHV}}{LHVF}, \text{ lbm/hr (kg/s)} \qquad \text{(D-4-8)}$$

NONMANDATORY APPENDIX E THE PROBABLE EFFECTS OF COAL AND SORBENT PROPERTIES

E-1 INTRODUCTION

This Appendix addresses the following:

(a) probable effects of coal properties on pulverized-coal steam generator design and performance

(b) probable effects of coal and sorbent properties on fluidized bed steam generator design and performance

E-2 PULVERIZED-COAL-FIRED STEAM GENERATORS

This Section gives general guidance for identifying the relationship of steam generator design and effects on its performance when a fuel is other than the design generator acceptance test. This Section is not intended to be inclusive but rather to identify significant coal properties and their impact on steam generator design and performance trends.

E-2.1 Coal Rank/Equipment Size

Steam, Its Generation, and Use [7] provides a complete discussion of coal rank. Coal characteristics, and coal rank in particular, have a dramatic impact on furnace sizing. Tuppeny [8] compares the size of a furnace burning eastern bituminous, midwestern bituminous/subbituminous, Texas lignite, and Northern Plains lignite coals. Table E-2.1-1 summarizes the relative furnace sizes, coal quantities, and pulverizer sizes based upon the assumptions made in the reference.

E-2.2 Slagging and Fouling

Slagging and fouling, other than expected and accounted for by the boiler design, can significantly alter steam generator performance and efficiency. It is thus very important that the coal selected for a performance test have substantially the same slagging, fouling, and combustion characteristics as the design coal.

Slagging, fouling, and combustion indices must be developed for the design coal and compared to the test coal before any performance test is begun. The test coal must have the same characteristics as the design coal. The analysis should be based on the application of several indices developed by the industry and found in sources such as Reference [4].

The Test Engineer is cautioned to use several slagging, fouling, and combustion indices in making this judgment, since no single index gives totally accurate and indisputable results.

E-2.3 Coal Properties Determination

Standard tests for coal are identified below. Examination of the results of these standard coal tests is used to infer the effects on steam generator design and performance. The Test Engineer should use these standard tests to assess the coals to be burned before undertaking steam generator performance testing. Major coal property tests include the following:

(a) proximate analysis

(b) ultimate analysis

(c) ash fusibility

(d) hardgrove grindability index

(e) ash mineral analysis

(f) combustion characteristics

These and many other tests and indices are listed and discussed in Reference [4].

E-2.4 Probable Effects of Coal Properties on Steam Generator Design and Performance

The complex effects of the coal properties, as assessed by the above standard tests, on steam generator design, thermal performance, and overall boiler operation are listed in Table E-2.4-1. This table primarily lists effects that cannot be corrected to contract conditions.

E-3 FLUIDIZED BED COMBUSTION COAL-FIRED STEAM GENERATORS

There are three main parameters for atmospheric fluidized bed combustors (AFBC).

(a) Thermal Efficiency. This is the combined effect of combustion efficiency, heat transfer performance of the heat surfaces throughout the steam generator, and auxiliary power required to run the steam generation operation.

(b) Sulfur Dioxide Capture Efficiency

Table E-2.1-1 Effects of Coal Ranks on Steam Generators

Coal	Relative Coal Quantities	Relative Furnace Dimensions			Relative Pulverizer Sizes
		Depth	Width	Height	
Eastern bituminous	1	1	1	1	1
Subbituminous	1.43	1.06	1.08	1.05	1.7
Texas lignite	1.64	1.08 to 1.24	1.16 to 1.26	1.07 to 1.30	1.84
Northern Plains lignite	1.76	1.76	1.26	1.45	2.0

GENERAL NOTE: From this table it becomes obvious that a steam generator designed for one coal rank will not operate well or may be totally unsuitable for other types of coals. This emphasizes the need to evaluate test coals relative to the specified coals to establish their suitability for the unit being tested.

Table E-2.4-1 Effects of Coal Properties on Steam Generator Design and Performance

Coal Property Variable	Affected Component(s)	Probable Effect On
1. Coal heating value	Silo storage Feeders Pulverizers Burners Emission control Equipment Coal handling system	Coal flow rate Equipment capacity Number of components in service Turndown ratio
2. Coal moisture content	Silo storage Feeders Pulverizers Primary air system ID fans Coal handling system	Coal flow rate Equipment capacity Coal flow ability Pulverizer outlet Temperature Primary air/tempering air Flow quantities Turndown ratio
3. Volatile content	Burners Furnace Pulverizers Ignitors	Required fineness Burner design Flame stability ignition Unburned carbon loss Furnace geometry Firing methods Pulverizer inerting needs Turndown ratio
4. Grindability index	Pulverizers	Capacity Fineness Power requirements
5. Coal abrasiveness index	Coal handling system Pulverizer Components Coal piping Burner nozzles Convection passes Air heater (A/H) heating elements and seals	Equipment outages Maintenance Design velocity requirements Material selection Tube wear and life Reliability Air heater performance
6. Nitrogen content	Burners Furnace Air distribution	Burner design Furnace geometry Air and flue gas system NO_x emissions Required burner zone Stoichiometry

Table E-2.4-1 Effects of Coal Properties on Steam Generator Design and Performance (Cont'd)

Coal Property Variable	Affected Component(s)	Probable Effect On
7. Sulfur content	Scrubber Precipitators Air preheaters Steam coils	Corrosion rate Equipment sizing requirements Stack gas temperature requirements Emission control equipment
8. Reactivity index	Burners Pulverizers Inerting system Ignitors	Combustion Explosion potential Unburned carbon loss Turndown ratio
9. Ash content	Ash handling Pulverizers Soot blowers Precipitators Convection passes	Capacity Performance Design velocity requirement Tube wear and life Reliability Sootblowing requirements
10. Ash fusibility	Furnace Soot blower Water lancing	Slagging/FEGT/steam temperature Fouling/steam temperature NO_x emissions Sootblowing and water lancing operation
11. Coal ash analyses	Steam generator Emission control equipment Soot blowers Ash handling systems	Slagging/FEGT/steam temperature Fouling/steam temperature Precipitator efficiency Design tube spacing requirement Excess air requirement NO_x emissions Ash split

GENERAL NOTE: For general information on steam generator design and operation, refer to References [1] through [7]. References [2] and [7] are texts used extensively in the industry.

(c) NO_x Generation Rate. To determine these performance parameters in the field, the Test Engineer must be aware of and understand all factors which may influence these parameters. These factors can be inherent in the design parameters, operating conditions, coal and sorbent material properties, or any combination of these factors. Due to the complexity of such interrelations between these factors and the AFBC performance parameter, this Section addresses only the major factors as reported by the industry.

This portion of Nonmandatory Appendix E gives general guidance for predicting the effect on steam generator design and performance when the fuel and/or sorbent is changed from the design coal and/or sorbent. As with the previous section, this section is not intended to be inclusive but rather to identify many of the design and performance trends. In this Section, standard tests for coal and sorbent are identified. Examination of the results of these standard tests is used to infer the effects on steam generator design and performance.

E-3.1 Coal Properties Determination

E-3.1.1 Standard Analyses. Some of the coal property tests previously described for conventional coal units are applicable to AFBC units.

The following standard analyses should be conducted on the fuel in question:

(a) proximate
(b) ultimate
(c) coal mineral ash
(d) higher heating value
(e) ash fusion temperature

E-3.1.2 Tests for AFBC Application. However, some of the key fuel characteristics pertinent to combustion in AFBC boilers are different from the characteristics pertinent to combustion in pulverized-coal and stoker-fired boilers (References [9], [10], [11]). The differences are a result of the distinct environment in AFBC boilers (lower temperature, longer residence times, larger coal particles, and mechanical effects of bed material). Therefore, to obtain these AFBC fuel characteristics, tests specially designed for AFBC applications are suggested in addition to standard tests and analyses (References [9] and [10]). These tests are described below.

(a) Feed System Attrition Test (Underbed Feed). This test indicates the extent of breakage of attrition of the new fuel with respect to the design fuel due to transport through the coal feed system and feed point. High attrition increases the fines content, which can reduce combustion efficiency and increase emissions.

(b) Combustion-Enhanced Mechanical Attrition Test. This test is important mainly for low reactivity fuels and indicates the extent of attrition which occurs in the AFBC unit during combustion. Again, high attrition increases the fines content, which can reduce combustion efficiency.

(c) Devolatilization/Bulk Reactivity Test. This set of tests provides the data to determine the volatile yield (which may be different from the proximate volatile yield resulting from the different combustion environment), devolatilization rate, volatiles and char burnout times, and activation energy and pre-exponential coefficient for reactivity determination.

(d) Coal Swelling Test. For coals that swell (caking coals), this test establishes the size of a coal particle after devolatilization, which affects burnout time. The test also provides an indication of agglomeration potential; if a coal swells, agglomeration may be a potential problem.

(e) Fragmentation Test. This test establishes the extreme of fragmentation for the planned coal feed size distribution. Coal particles greater than a critical size which is specified to each coal fragment during combustion. The number and size of fragments affect the coal burnout time. This test is most important for overbed feed application.

Ideally, the range of fuels planned for a unit would be characterized prior to design to incorporate the flexibility required to accommodate the fuels into the unit and auxiliary equipment. For a fuel not previously considered, neglecting to run the AFBC characterization tests risks performance and operational problems. Because the standard analyses are not entirely relevant to AFBC, comparing the standard analyses of the design fuel with the new fuel will not reveal the characteristics that may cause changes in performance and operation.

E-3.2 The Effect of Coal Properties on Steam Generator Design and Performance

One example of the unseen differences among coals was shown in a coal selection study identified in Reference [12]. Four medium-volatility coals appeared similar by comparison of ultimate and proximate analyses, but AFBC fuels characterization tests revealed significant differences in combustion efficiency resulting from differences in the devolitilization rates and char reactivities. A fifth medium-volatility coal, Bradford, had still different characteristics from the other four, although the ultimate and proximate analyses were similar. These characteristics were not disclosed by the standard analyses.

Tables E-3.2-1 through E-3.2-4 show the performance and design variations that could be expected from a change in coal. The first column shows the specific coal property tests. In the second column, the steam generator component or process parameter is identified that is affected by a change in the listed coal property. In the third column, the effect is described for a change in property from the coal test. In the fourth column, consequences are identified for the effect if action is not taken to rectify the problem created by the variation in the coal property. In the fifth and sixth columns, general corrective actions are identified that could alleviate or minimize the consequence identified in the fourth column. The fifth column is a process corrective action, and the sixth column is an equipment corrective action.

E-3.3 Sorbent Properties Determination

Determining sorbent characterizations from property tests is not always conclusive. In some cases, there is more than one recognized test for the same property. The purpose of this Appendix is to suggest sorbent tests for guidance in characterizing sorbent for use in steam generator design and performance.

Tables E-3.3-1 through E-3.3-3 show the performance and design variations that would be expected from a change in sorbent. These tables have the same format as the previously described tables for coal.

The first step suggested for predicting the change of sorbent is to conduct the following standard chemical analyses for the sorbent: calcium, magnesium, moisture, and silica.

In addition, it is advisable to perform an abrasion test for the sorbent and a particle size distribution.

If the geological classification for the new sorbent is different from the design sorbent, the following tests are also recommended:

(a) thermogravimetric analysis (TGA)
(b) grain size
(c) pore size
(d) attrition
(e) surface area (raw and calcined)
(f) pore volume (raw and calcined)

E-3.4 The Effect of Sorbent Properties on Steam Generator Design and Performance

See Tables E-3.3-1 through E-3.3-3. Review References [13] and [14] for more information.

Table E-3.2-1 Proximate Analysis for Coal

Approximate Analysis	Component/ Process Parameter	Effect	Consequences	Corrective Action	
				Process	Equipment
Moisture	Underbed feed lines	Excessive surface moisture (>6%) could cause pluggage	Extra maintenance to alleviate line pluggage	Feed lower moisture coal	Install coal dryer with flexibility to dry wetter coal
	Bed temperature	Excessive moisture could cause a drop below optimum temperature range for process performance	Higher SO_x emissions Lower combustion efficiency	Increase firing rate; drop bed level (bubbling bed)	Fans. In-bed tube bundle design
	Coal feed equipment	Higher coal feed rates required	Load reduction		Upgrade feed equipment size
Volatile matter and fixed carbon	In-bed/freeboard combustion split	Change in either fixed carbon or volatile matter could cause substantially different bed temperature	Change in combustion efficiency, SO_x, NO_x, and CO emissions, and heat transfer	Adjust firing rate; adjust bed level. Additional tests	Adjust in-bed heat transfer surface. Install larger transport fans
				Adjust recycle (bubbling bed)	. . .
				Adjust solids loading (circulating bed)	. . .
	Furnace temperature profile	. . .	. . .	Vary particle size distribution	Install crusher with wider range
Ash	Ash removal systems	Higher ash content could exceed capabilities of removal systems	Load reduction	. . .	Upgrade ash removal system
	Recycle	At a given recycle ratio, higher ash content implies lower combustible and sorbent recirculation	Lower combustion efficiency and higher SO_2 emissions	Adjust recycle	Install ash classifier
	Multiclone/ cyclone	Inert ash could dilute recycle material	Combustion efficiency reduction. Baghouse or ESP overload	. . .	Install with higher capacity: ESP, baghouse, recycle, and/or multiclone
	Ash coolers	Higher ash content could exceed ash cooler capabilities	Load reduction	. . .	Upgrade ash coolers

Table E-3.2-2 Ultimate Analysis of Coal

Ultimate Analysis	Component/ Process Parameter	Effect	Consequences	Corrective Action	
				Process	Equipment
Sulfur	Sulfur retention	An increase in sulfur would increase sulfur emissions	Higher sulfur emissions	Increase sorbent feed rate. Increase recycle (bubbling bed)	Upgrade sorbent feed system. Upgrade lime-stone feed system
Coal Ash Analysis					
MgO CaO	Sulfur retention	A decrease in either MgO content and/or CaO content would increase sulfur emissions	Higher sulfur emissions	Increase sorbent feed	Upgrade sorbent feed system
Na_2O	Ash fusion temperature	A higher Na_2O content could be indicator of lower ash fusion temperature. If freeboard temperature exceeds ash fusion temperature, then slagging could occur on freeboard waterwall	Lower heat transfer to freeboard waterwall and lower boiler efficiency. Decreased load	Require repeated outages to remove slag	. . .
		An increase in sodium content could cause ash agglomeration in bed	Lower in-bed heat absorption. Inability to fluidize bed compartment	Requires repeated outages to remove ash agglomeration	. . .
Na_2O K_2O	Fly ash resistivity	An increase in Na_2O and K_2O could increase fly ash resistivity and decrease ESP efficiency	Higher solids emissions	Decrease back-end temperature if possible	Upgrade ESP design. Install ammonia injection, water injection system for ESP

Table E-3.2-3 Special Tests and Size Analysis for Coal

Special/ Standard Tests	Component/ Process Parameter	Effect	Consequences	Corrective Action	
				Process	Equipment
Higher heating value (*HHV*)	Fuel feed rate	Lower HHV requires greater feed rate and capabilities of fuel feed or ash removal system could be exceeded	Load reduction	Increase firing rate	Upgrade coal reed system capacity. Upgrade ash removal system
Ash fusion temperature	Ash fusion temperature	If freeboard temperature exceeded ash fusion temperature, slagging could occur on freeboard waterwall	Lower freeboard waterwall heat absorption. Lower boiler efficiency	Reduce firing rate or recycle rate	Upgrade freeboard heat transfer surface
Size Analysis					
Sieve	Fines (coal particles less than 30 mesh)	Excessive fines (15%–20%) could result in higher free-board temperatures	Slagging. Boiler not surfaced correctly. Higher SO emissions	Double screen or wash coal	Select crusher with flexibility to produce coarser product
		Excessive carbon elutriated from combustor when feeding overbed	Lower combustion efficiency	. . .	Adjust crusher (remove plates) Ash reinjection
	Large coal sizes	The underbed feed lines or splitters could plug	Operating bed below performance temperature. Reduction in load	. . .	. . .
		Rocks could accumulate in bed when feeding overbed	Reduction in load	. . .	Upgrade in-bed rock removal system. Coal preparation system design to selectively remove large particles

Table E-3.2-4 Special AFBC Tests for Coal

Special AFBC Tests	Component/ Process Parameter	Effect	Consequences	Corrective Action	
				Process	Equipment
Feed line attrition coefficients	Feed lines Combustion split Combustion efficiency	Feed line attrition causes increase in fines	More carbon elutriated from combustor. Lower combustion efficiency	Adjust transport velocity	Adjust crusher. Install with more flexibility. Upgrade fuel feed system design
Bulk reactivity	Reactivity Combustion split Combustion efficiency	Change of in-bed/ freeboard heat split could cause excessively high or low freeboard and/or bed temperatures	Imbalance in superheat and evaporative heat duties. Attemperation. Lower efficiency possible for less reactive fuel	Adjust bed depth (bubbling bed). Adjust solids loading (circulating bed). Adjust recycle rate	Upgrade fuel feed system
Combustion enhanced mechanical attrition (CEMA)	Attrition Combustion split Combustion efficiency	Carbon particles can have excessive attrition in bed	More freeboard combustion; higher freeboard temperatures; possibly more carbon elutriated from combustor. Lower combustion efficiency. More in-bed combustion and lower freeboard temperatures	Adjust fuel feed size. Adjust velocity to increase residence time	Adjust crusher
Swelling index	Expansion of coals Particles	Bituminous coals swell and then break	Without this information, less confidence in results from certain combustion models	An increase in swelling index tends to decrease overall combustion efficiency	Decrease air velocity or increase recycle rate
Fragmentation index	Fragmentation Combustion split Combustion efficiency	Lignite and subbituminous coals usually fragment less	Without this information, less confidence in results from certain combustion models	Is more important for overbed feed than for underbed feed, unless the fuel is an agglomerate to start with	. . .

Table E-3.3-1 Chemical Analysis of Sorbent

Chemical Analysis	Component/ Process Parameter	Effect	Consequences	Corrective Action	
				Process	Equipment
Calcium	Sorbent flow rate	Decrease in calcium content in limestone	Increase in sulfur emissions or calcium-to-sulfur molar ratio	Adjust sorbent flow rate	Increase sorbent feed system capacity
Magnesium	Sorbent flow rate	Decrease in magnesium content in limestone	Increase in sulfur emissions or calcium-to-sulfur molar ratio	Adjust sorbent flow rate	Increase sorbent feed system capacity
Moisture	Underbed feed lines	The occurrence of pluggages of feed lines and splitters could increase	Segments of beds operating below optimum temperature for process performance. Reduced load could occur	Maintain stricter quality control on limestone	. . .
	Boiler efficiency	Additional heat will be required to evaporate moisture	Lower boiler efficiency	. . .	. . .
Silica	Feed lines	More silica content might result in more erosion in limestone feed lines	Possible replacement of limestone feed lines	. . .	Choose fix. Refer to entry for “Abrasion index” below
Abrasion					
Abrasion index	Feed lines	Higher abrasion index would indicate more erosion	Repair and replacement of feed lines	. . .	Use erosive-prevention devices when possible such as blind tees. Use of ceramic lining. Addition of wear pads in areas where high erosion would be expected. Use of special coatings
	Heat exchanger tubes	. . .	Repair and replacement of tubes	. . .	Install tube bundles. Install protective devices on bottom of tubes such as balls or studs

Table E-3.3-2 Size and TGA Analysis and Geological Classification of Sorbent

Particle Size Distribution	Component/ Process Parameter	Effect	Consequences	Corrective Action	
				Process	Equipment
Sieve	Underbed feed lines	Large particles can cause pluggage	More feed line pluggage. If same feed lines as coal feed, then local temperature below optimum for process performance	Upgrade limestone preparation system	Upgrade sorbent feed system design. Increase baghouse capacity. Increase ESP capacity
	Sulfur capture	Smaller particles could blow out of bed and have lower sulfur capture. Large particles have less surface area, thus lower sulfur capture	Less sulfur capture and less calcium utilization	. . .	. . .
	Multiclone	Sufficiently small particles cannot be captured by multiclones	Increase fly ash burden on air preheater and baghouse	. . .	. . .
			Limit recycle rate	. . .	. . .
Thermogravimetric (TGA)					
Reactivity	Sulfur capture	Less reactive limestone could have lower sulfur capture	Possibly more sulfur emissions	Possibly increase sorbent feed rate. Conduct other types of tests to increase confidence in reactivity estimate	Increase sorbent feed system capacity
Geological Classification					
Geological age	Calcium utilization	Younger limestone would probably not be as efficient	More sulfur emissions	Increase sorbent feed rate	Increase sorbent system capacity

Table E-3.3-3 Attrition, Grain, and Pore Size Analysis of Sorbent

Attrition	Component/ Process Parameter	Effect	Consequences	Corrective Action: Process	Corrective Action: Equipment
Attrition constant	In-bed attrition Sulfur capture	Limestone with high attrition constant will attrite into many pieces and be blown out of bed	Lower sulfur capture and calcium utilization	Adjust velocity	Install transport fans with flexible capacity Upgrade fly ash removal
		If attrition is severe, then the fly ash to disposal would increase	Increase in fly ash to be disposed	Increase cleaning frequency of baghouse	Install baghouse with higher capacity
Tem Micrographs					
Grain size	Grain size	Generally, sorbents with smaller grain sizes have more sulfur capture potential. Two exceptions are very finely grained dense limestones and crenoidal limestones	Lower sulfur capture or higher calcium-to-sulfur molar ratio	Increase sorbent feed	Increase sorbent system capacity Increase ash removal system capacity
Mercury Penetration Porosimeters					
Pore size	Pore size	Generally, sorbents with larger pore sizes have more sulfur capture potential	Lower sulfur capture or higher calcium-to-sulfur molar ratio	Increase sorbent feed	. . .

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None.

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Section 6

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Appendix A

None.

Appendix B

None.

Appendix C

None.

Appendix D

None.

Appendix E

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