ASME PTC 47.4-2015

Power Block of an Integrated Gasification Combined Cycle Power Plant

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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The next edition of this Code is scheduled for publication in 2020.

ASME issues written replies to inquiries concerning interpretations of technical aspects of this Code. Interpretations are published on the Committee Web page and under go.asme.org/InterpsDatabase. Periodically certain actions of the ASME PTC Committee may be published as Cases. Cases are published on the ASME Web site under the PTC Committee Page at go.asme.org/PTCcommittee as they are issued.

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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

ASME Performance Test Codes (PTCs) have been developed and have long existed for determining the performance of most major components used in electric power production facilities. A PTC has heretofore not existed to determine the overall performance of an integrated gasification combined cycle (IGCC) power generation plant. The ability to fire a wide range of fuels has been a key advantage of gas turbines over competing technologies. Until recently, the traditional fuels for gas turbines have been natural gas and liquid fuels. Today, environmental concerns and economic considerations are causing power generation suppliers to develop gasification systems that can use solid and liquid fuels (e.g., coal, biomass, waste, and heavy oils). Preparation of an alternative fuel suitable for a gas turbine includes removal of ash, contaminants, erodents, and corrodents. In response to these needs, the ASME Board on Performance Test Codes approved the formation of the PTC 47 Committee in 1993 with the charter of developing a code for determining overall power plant performance of gasification power generation plants. The organizational meeting of this Committee was held in November 1993. The resulting Committee included experienced and qualified users, manufacturers, and general interest personnel.

The Committee has striven to develop an objective code that addresses the multiple needs for explicit testing methods and procedures, while attempting to provide maximum flexibility in recognition of the wide range of plant designs.

This Code was approved by the PTC 47 Committee and the PTC Standards Committee on February 3, 2015. It was then approved as an American National Standard by the America National Standards Institute (ANSI) Board of Standards Review on May 22, 2015.

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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CORRESPONDENCE WITH THE PTC COMMITTEE

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

Secretary, PTC Standards Committee
The American Society of Mechanical Engineers
Two Park Avenue
New York, NY 10016-5990
http://go.asme.org/Inquiry

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

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

Proposing a Case. Cases may be issued 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. Cases are effective immediately upon ASME approval and shall be posted on the ASME Committee Web page.

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

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

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

Subject:	Cite the applicable paragraph number(s) and the topic of the inquiry.
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 or Subcommittee. ASME does not “approve,” “certify,” “rate,” or “endorse” any item, construction, proprietary device, or activity.

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

INTRODUCTION

This Code describes testing procedures for the IGCC power block and is part of the following set of related Codes:

(a) ASME PTC 47, Integrated Gasification Combined Cycle Power Generation Plants, for testing the overall plant performance on an IGCC plant.

(b) ASME PTC 47.1, Cryogenic Air Separation Unit, for testing the performance of the air separation unit (ASU). If the physical IGCC plant includes an ASU, the inclusion of the ASU within the overall test envelope is recommended but not required.

(c) ASME PTC 47.2, Gasification System, for testing the thermal performance of the combined gasifier and fuel gas cleaning equipment.

(d) ASME PTC 47.3, Fuel Gas Cleaning, for testing the contaminant content of gas delivered to the power block.

(e) ASME PTC 47.4, Power Block of an Integrated Gasification Combined Cycle Power Plant, for testing the thermal performance of the gas turbine combined cycle power block.

NOTE: ASME PTC 47.1, ASME PTC 47.2, and ASME PTC 47.3 are in the course of preparation.

It is recommended that overall plant and subsystems be tested separately, not simultaneously, to accommodate any boundary constraints and valve isolations and lineups that may be needed for subsystem testing. In highly integrated IGCC plants, the entire plant may need to be operating during a subsystem test, even though the only performance parameters being measured are those of the subsystem.

Test results can be used as defined by a contract to determine the fulfillment of contract guarantees. Test results can also be used by a plant owner to compare plant performance to a design number, or to trend plant performance changes in time. However, the results of a test conducted in accordance with this Code will not provide a basis for comparing the thermoeconomic effectiveness of different plant designs.

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POWER BLOCK OF AN INTEGRATED GASIFICATION COMBINED CYCLE POWER PLANT

Section 1
Object and Scope

1-1 OBJECT

The object of this Code is to provide uniform test methods and procedures for the determination of the thermal performance and electrical output of an integrated gasification combined cycle (IGCC) power block.

(a) This Code provides explicit procedures for the determination of the following performance results:

(1) corrected net power
(2) corrected net heat rate
(3) corrected heat input

(b) Tests may be designed to satisfy different goals, including

(1) specified disposition
(2) specified net corrected power
(3) specified net power

1-2 SCOPE

This Code applies to combined cycle power plants (power blocks) that operate in conjunction with a gasification plant, an IGCC power plant, or an IGCC cogeneration plant. This Code does not apply to power blocks other than those associated with IGCC plants.

This Code is applicable to the combined cycle power block of IGCC power plants, whereas ASME PTC 46 is applicable to conventional combined cycles. The thermal streams and corrections in ASME PTC 46 for conventional combined cycles are normally limited to gas or liquid hydrocarbon fuel input and steam or water input. In ASME PTC 47.4, test measurements and associated corrections are needed to address multiple thermal streams such as heated hydrocarbon syngas fuel input, water and steam inputs from gasification process units, nitrogen input from the air separation plant, and air extraction to the air separation plant.

Emissions tests, operational demonstration tests, and reliability tests are outside the scope of this Code.

1-3 UNCERTAINTY

The explicit measurement methods and procedures to be used for the power block of an IGCC have been developed to provide guidelines for test procedures that yield results of the highest level of accuracy based on current engineering knowledge, taking into account test costs and the value of information obtained from testing. The calculation of test uncertainty shall be performed in accordance with ASME PTC 19.1 and as outlined in this Code.

Because of the diverse range of integration of the power block with the gasification block and the air separation unit block, the test results will have different levels of uncertainty.

A pretest uncertainty analysis shall be performed to establish the expected level of uncertainties for the test. Most tests conducted in accordance with this Code will result in uncertainties that are lower than those shown in Table 1-3-1. A post-test uncertainty analysis is also required to validate the test.

The largest expected overall test uncertainties are given in Table 1-3-1. These values are not targets. A primary philosophy underlying this Code is that the lowest achievable uncertainty is in the best interest of all parties to the test. Deviations from the methods recommended in this Code are acceptable only if it can be demonstrated they provide equal or lower uncertainty.

Table 1-3-1 Largest Expected Test Uncertainty

Test Result	Test Uncertainty
Corrected net power	1.0%
Corrected heat rate	1.5%
Corrected heat input	1.5%

1-4 REFERENCES

The following is a list of publications referenced in this Code.

ANSI/IEEE Standard 120, 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)

ASME MFC-3M, Measurement of Fluid Flow in Pipes Using Orifice, Nozzle, and Venturi
ASME PTC 6, Steam Turbines
ASME PTC 12.4, Moisture Separator Reheaters
ASME PTC 19.1, Test Uncertainty
ASME PTC 19.2, Pressure Measurement
ASME PTC 19.3, Temperature Measurement
ASME PTC 19.3 TW, Thermowells
ASME PTC 19.5, Flow Measurement
ASME PTC 19.22, Data Acquisition Systems
ASME PTC 22, Gas Turbines
ASME PTC 46, Performance Test Code on Overall Plant Performance
ASME PTC 47, Integrated Gasification Combined Cycle Power Generation Plants
Publisher: The American Society of Mechanical Engineers, Two Park Avenue, New York, NY 10016-5990 (www.asme.org)

ASTM D1945, Standard Test Method for Analysis of Natural Gas by Gas Chromatography
ASTM D4809, Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (Precision Method)
ASTM D7833, Standard Test Method for Determination of Hydrocarbons and Non-Hydrocarbon Gases in Gaseous Mixtures by Gas Chromatography
ASTM E1137, Standard Specification for Industrial Platinum Resistance Thermometers
ASTM MNL 12, Manual on the Use of Thermocouples in Temperature Measurement
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)

Dahl, A. I. "Stability of Base-Metal Thermocouples in Air From 800ºF to 2,200ºF," National Bureau of Standards, Washington, D.C., in *Temperature*, Vol. 1, Reinhold: New York, 1941, p. 1238

ISO 5167-2, Measurement of fluid flow by means of pressure differential devices inserted in circular cross-section conduits running full — Part 2, Orifice plates
Publisher: International Organization for Standardization (ISO), Central Secretariat, Chemin de Blandonnet 8, Case Postale 401, 1214 Vernier, Geneva, Switzerland (www.iso.org)

NFPA 70, National Electric Code
Publisher: National Fire Protection Association (NFPA), 1 Batterymarch Park, Quincy, MA 02169 (www.nfpa.org)

NIST Reference Fluid Thermodynamic and Transport Properties Database (REFPROP)
NIST Technical Note 1265, Guidelines for Realizing the International Temperature Scale of 1990 (ITS-90)
Thermodynamic Quantities: Thermocouples, Thermocouple Materials, Thermometer Indicators (http://www.nist.gov/calibrations/thermocouples.cfm)
Publisher: National Institute of Standards and Technology (NIST), 100 Bureau Drive, Stop 1070, Gaithersburg, MD 20899 (www.nist.gov)

Tampa Electric Polk Power Station Integrated Gasification Combined Cycle Project Final Technical Report (August 2002)
Publisher: Tampa Electric, P.O. Box 111, Tampa, FL 33601-0111 (www.tecoenergy.com)

Section 2
Definitions and Descriptions of Terms

2-1 GENERAL

The definitions in subsection 2-2 are specific to ASME PTC 47.4. The terms and values of physical constants and conversion factors common to equipment testing and analysis are defined in ASME PTC 2.

2-2 DEFINITIONS

acceptance test: the evaluating action(s) to determine if a new or modified piece of equipment satisfactorily meets its performance criteria, permitting the purchaser to "accept" it from the supplier.

accuracy: the closeness of agreement between a measured value and the true value.

air, inlet: air crossing the test boundary and entering power plant equipment. Because of local effects, the properties of inlet air may not be the same as the properties of ambient air.

ambient temperature: static dry bulb temperature considered to be site specific and monitored at mutually agreed-upon location(s) inside the boundary.

auxiliary power: electrical power consumed by equipment in an IGCC power block plant during normal operation of the power plant. This power consumption is subtracted from the gross power output, measured at the gas and steam turbine generators' terminals, to obtain net power block output. Depending on the contractual agreement, auxiliary power can include common supply and/or the intermittent power, such as that for water treatment, HVAC, and lighting.

bias error: see *error, systematic.*

calibration: the process of comparing the response of an instrument to a standard instrument over some measurement range and adjusting the instrument, if appropriate, to match the standard.

combined cycle: two sequential thermodynamic power conversion systems operating at different temperatures. This Code applies only to combined cycles consisting of Brayton and Rankine cycles.

error: the difference between the true value and the measured value. It includes both bias (systematic) and precision (random) errors.

error, random: sometimes called precision error, random error is a statistical quantity that 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, systematic error is the difference between the average of the total population and the true value. It is the true systematic or fixed error that characterizes every member of any set of measurements from the population, the constant component of the total error.

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

heat input: the mass flow rate of fuel(s) multiplied by the high or low heating value of the fuel(s).

heat rate (mechanical or electrical): the fuel heat input per unit of power output, based on either the low or high heat value of the fuel, which shall be specified.

high heat value (HHV): the heat produced by combustion of a unit quantity of gaseous, liquid, or solid fuels under specified conditions, expressed in J/kg (Btu/lbm). All water vapor formed by the combustion reaction is condensed to the liquid state.

influence coefficient: the ratio of the change in a result to a unit change in a parameter.

instrument: a tool or device used to measure physical dimensions of length, thickness, width, weight, or any other value of a variable. These variables can include size, weight, pressure, temperature, fluid flow, voltage, electric current, density, viscosity, and power. Sensors are included that may not, by themselves, incorporate a display but instead transmit signals to remote computer-type devices for display, processing, or process control. Also included are items of ancillary equipment directly affecting the display of the primary instrument, e.g., an ammeter shunt, and tools or fixtures used as the basis for determining part acceptability.

losses: the energy that exits an equipment or envelope of equipment other than the energy in the output stream(s). Examples are heat lost to the atmosphere and to mechanical inefficiencies or cooling water.

low heat value (LHV): the heat produced by combustion of a unit quantity of gaseous, liquid, or solid fuel under specified conditions, expressed in J/kg (Btu/lbm). All of the water in the product remains in the vapor phase. This value is calculated from higher heating value at constant volume for liquid fuel(s) and from the higher heating value at constant pressure for gaseous and solid fuel(s).

measured power output (electrical): power output measured at the test boundary.

measurement error: the true, unknown difference between the measured value and the true value.

moisture: water, in the liquid or vapor phase, present in another substance. Moisture in fuel is determined by appropriate ASTM standards or other internationally recognized tables.

net power output (electrical): power output determined from the measured power output by application of charges and credits as described in Section 5.

output: the power produced by the gas turbine or steam turbine; the electrical power produced by the generators or the electrical power output of the IGCC power block facility.

parties to a test: those persons and companies interested in the results of a test.

precision: the closeness of agreement between repeated measurements, usually measured by the precision index of the measurements.

precision error: see *error, random.*

primary variables: variables used in calculations of test results. Primary variables are further classified as follows:

(a) Class 1: primary variables that have a relative influence coefficient of 0.2 or greater

(b) Class 2: primary variables that have a relative influence coefficient of less than 0.2

Refer to ASME PTC 19.1 for the determination of relative influence coefficients.

rated power output (continuous rating): power output stated or guaranteed under specified operating conditions and on the basis of continuous operation.

reference conditions: also called base reference conditions or test reference conditions, these are the pressures, temperatures, and other properties of streams at the design point, guarantee point, or other selected operating points of the equipment to be tested. Code tests should be conducted as close as possible to reference conditions. See also *standard reference condition* and *test conditions*.

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

secondary variables: variables that are measured but do not enter into the calculation of corrected performance.

sensitivity: see *influence coefficient*.

serialize: to assign to an instrument a unique number that is then permanently inscribed on or to the instrument so that it can be identified and tracked.

specified corrected net power test: a test run at a specified corrected net power that is near to the design value of interest. A performance test is at the guaranteed point; tests at other points are demonstration tests.

specified reference conditions: the values of all external parameters, i.e., parameters outside the test boundary, to which the test results are corrected. Also, the specified secondary heat inputs and outputs are specified reference conditions.

standard reference condition: the pressure, temperature, and physical state of a material at which the enthalpy of that material is defined as zero. Standard reference conditions form the basis for comparisons between different sets of data. The choice of standard reference conditions is arbitrary, although water and steam properties are typically compiled at the triple point of water, 273.16 K [0.01°C (32.018°F)]. See also *reference conditions* and *test conditions*.

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

synthesis gas (syngas): the gas produced by partial oxidation of the hydrocarbon feed. Raw syngas is gas that has not undergone contaminant removal; clean syngas has had the bulk of impurities removed. The primary use of this gas is to fuel a gas turbine.

systematic error: see *error, systematic*.

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.

test boundary: thermodynamic control volume for which the mass and energy streams must be determined to calculate corrected results.

test conditions: the pressures, temperatures, and other properties of streams measured during a Code test. Test conditions should be as close as possible to reference conditions. See also *reference conditions* and *standard reference condition*.

test reading: one time-coincident recording of all required test instrumentation for the purpose of determining performance characteristics.

test run: a group of test readings.

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.

traceable: term used to describe an instrument for which records are available demonstrating that the instrument can be traced through a series of calibrations to an appropriate ultimate reference such as the National Institute for Standards and Technology (NIST).

uncertainty: the interval about the measurement or result that contains the true value for a given confidence level.

uncertainty, random: an estimate of the plus/minus limits of random error with a defined level of confidence (usually 95%).

uncertainty, systematic: an estimate of the plus/minus limits of systematic error with a defined level of confidence (usually 95%).

Section 3
Guiding Principles

3-1 INTRODUCTION

This Section provides guidance on the conduct of the power block unit of the integrated gasification combined cycle (IGCC power block) plant testing, and outlines the steps required to plan, conduct, and evaluate a Code test of plant performance. Subsections 3-2 through 3-6 discuss the following:

(a) defining the test boundary
(b) developing a test plan
(c) preparing for the test
(d) conducting the test
(e) performing calculation and reporting of results

Regardless of the test goals or operating mode, the results of a Code test will be corrected net power, corrected heat rate, or corrected heat input. The test shall be designed with the appropriate goal in mind to ensure that proper procedures are developed, the appropriate operating mode during the test is followed, and the correct performance equations are applied. Section 5 provides information on the general performance equations and variations of the equations to support specific test goals.

3-2 TEST BOUNDARY AND REQUIRED MEASUREMENTS

The general methodology of the Code involves three steps: defining the test boundary, identifying energy streams related to the calculation of the test results, and conducting a pretest uncertainty analysis.

3-2.1 Define the Test Boundary

The test boundary is an imaginary line that surrounds the system or the specific equipment to be tested. The test boundary is used to identify the energy streams that shall be measured to calculate corrected results. For a particular test, the specific test boundary shall be established by the parties to the test, based on the goals of the test.

3-2.2 Identify Energy Streams Related to the Calculation of the Test Results

All energy streams entering or exiting the test boundary shall be identified. Energy streams can consist of fluid or solid material flows having chemical, thermal, and potential energy. They can also consist of pure energy flows such as thermal radiation, thermal conduction, and electrical current.

Physical properties of all input and output energy streams that are required for calculating the corrected performance test results shall be determined with reference to the point at which they cross the test boundary. Energy streams within the test boundary need not be determined unless they verify base operating conditions or they relate functionally to conditions outside the boundary. All heating values and enthalpies shall be based on the same standard reference conditions that were used to generate the heat balance data and correction curves for the equipment to be tested, and sensible heat shall be counted as a separate element in calculations.

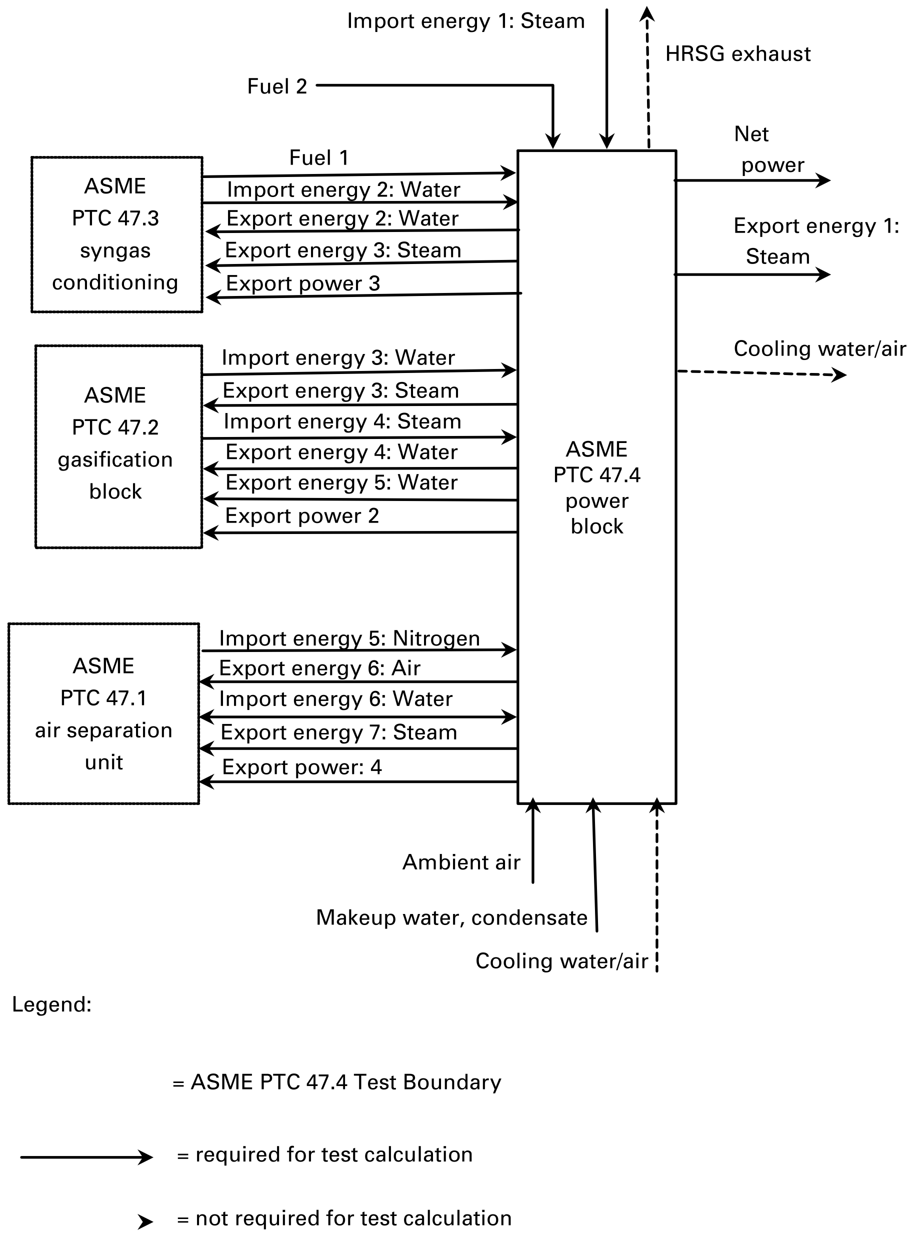
Typical streams required for an IGCC power block plant are shown in Fig. 3-2.2-1. The solid lines indicate the streams crossing the test boundary for which the mass flow rate, thermodynamic conditions, chemical makeup, or power must be determined to calculate the results of an overall plant performance test.

The properties of streams indicated by dashed lines may need to be determined for an energy and mass balance or for individual steps of the gasification process. If the cooling system, such as a cooling tower, is inside the power block, the cooling medium inlet line ("Cooling water/air") in Fig. 3-2.2-1 should be a solid line.

When the net electrical power metering is located downstream of the auxiliary load supplied to processes other than the power block, the net power block electrical output is calculated by subtracting the measured power block auxiliary loads from the gross electrical output. Besides excitation power, the power block auxiliary loads generally consist of the electrical loads of the lubrication and hydraulic systems, water systems, external cooling air systems, feed and circulating water pumps, cooling tower fans, etc.

IGCC plant design may include extraction air from the gas turbine to supplement air supply to the air separation unit (ASU). Extraction air temperature is high, and if it is not cooled, will remove energy from the power block and increase the power consumption of the cryogenic cooling system of the ASU. The compressed air heat can be used to generate steam or heat water, or to heat nitrogen in a gas-to-gas heat exchanger, which also reduces the cryogenic cooling system power consumption. For the heat exchanger, extraction air enters the hot side of the gas-to-gas heat exchanger and diluent nitrogen is on the cold side. Typically a horizontal counterflow shell-and-tube heat exchanger is used for this

Fig. 3-2.2-1 ASME PTC 47.4 Power Block Test Boundary

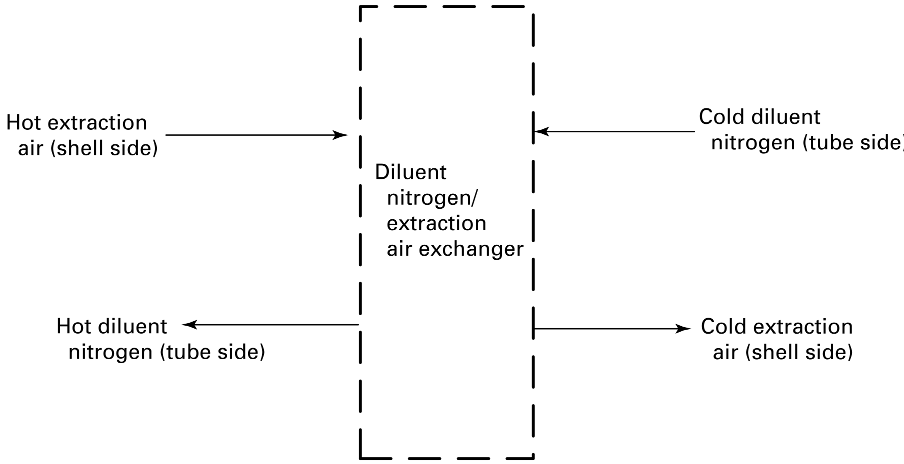


GENERAL NOTES:
(a) HRSG = heat recovery steam generator.
(b) ASME PTC 47.1, ASME PTC 47.2, and ASME PTC 47.3 are in the course of preparation.

application. Extraction air enters the shell side (hot side), and diluent nitrogen enters the tube side (cold side). The heat exchanger does not require any utilities (i.e., steam, feedwater, electricity, etc.). A flow-measuring device is used to measure the flow of both extraction air and diluent nitrogen. Figure 3-2.2-2 illustrates the boundary of the gas-to-gas heat exchanger.

Diluent nitrogen/extraction air heat exchangers are normally considered to be part of the power block and located within the ASME PTC 47.4 test boundary. Nitrogen compressors that are not part of the ASU block are also considered to be part of the power block and located within the ASME PTC 47.4 test boundary. In these cases, the measured streams crossing the power block test

Fig. 3-2.2-2 Diluent Nitrogen/Extraction Air Heat Exchanger Boundary



boundary are the diluent nitrogen leaving the ASU block and the air leaving the nitrogen-to-air heat exchanger.

Oxygen compressors, however, are normally considered to be part of the ASU and not part of the power block.

3-2.3 Pretest Uncertainty Analysis

Once all energy streams have been identified, a pretest uncertainty analysis, as described in Section 7, shall be performed to identify the primary energy flows whose physical properties shall be measured and inputted into the test results calculation. The pretest uncertainty analysis is also used to determine the level of measurement accuracy required for each measurement to maintain the agreed-upon overall test uncertainty.

Measurement locations are selected to provide the lowest level of measurement uncertainty. The preferred location is at the test boundary, but only if the measurement location is the best location for determining required parameters.

Other measurements may be required, such as those used in the application of correction factors for off-design ambient conditions to confirm test point stability, or those needed to ensure that the plant does not exceed emissions or safety limits.

Equations utilized in the calculations of results should be reviewed to verify that all references to heating value are consistent (either all lower or all higher) and that all correction curves and heat balance programs are based on the same definition of heating value. The use of higher heating value is customary, but lower heating value may also be used. The equations in Section 5 are applicable for either higher or lower heating value.

3-3 TEST PLAN AND OBJECT OF THE TEST

A detailed test plan should be prepared prior to conducting a Code test. The test plan shall document agreements on all issues affecting the conduct of the test and provide detailed procedures for performing the test. The test plan shall be approved, prior to the testing, by authorized signatures of all parties to the test. It shall reflect any contract requirements that pertain to the test objectives and performances guarantees.

The object of the test shall be agreed to by the parties to the test and shall be defined in writing before the test commences.

In addition to documenting all prior agreements, the test plan should include the schedule of test activities, responsibilities of the parties to the test, test procedures, and report formats.

3-4 TEST PREPARATIONS

(a) General Precautions. Reasonable precautions should be taken when preparing to conduct a Code test. Indisputable records shall be made to identify and distinguish the equipment to be tested and the exact method of testing selected. Descriptions, drawings, or photographs may be used to ensure a permanent, explicit record. Instrument location shall be predetermined, agreed to by the parties to the test, and described in detail in test records. Redundant, calibrated instruments should be provided for those instruments susceptible to in-service failure or breakage.

(b) Agreements. Prior to any tests, the parties to the test shall agree on the exact method of testing and the methods of measurement. The following should be considered:

(1) object of test
(2) location and timing of test
(3) test boundaries
(4) selection of instruments: number, location, and type
(5) method of calibration of instruments
(6) number of copies of original data required
(7) data to be recorded and method of recording and archiving data
(8) values of measurement uncertainty and method of determining overall test uncertainty
(9) method of operating equipment under test, including that of any auxiliary equipment the performance of which may influence the test result
(10) methods of maintaining constant operating conditions as near as possible to those specified
(11) method of determining duration of operation under test conditions before test readings are started
(12) system alignment or isolation
(13) organization of personnel, including designation of engineer in responsible charge of test
(14) duration and number of test runs
(15) measurement frequency
(16) base reference conditions
(17) methods of correction and values used for corrections for deviations of test conditions from those specified
(18) methods of computing results
(19) method of comparing test results with specified performance
(20) conditions for rejection of outlier data or runs
(21) intent of contract or specification if ambiguities or omissions appear evident
(22) pretest inspections

This subsection describes preparations relating to test apparatus, equipment inspection, and preliminary testing.

3-4.1 Test Apparatus

Test instruments are classified as described in Section 4. Instrumentation used for data collection shall be at least as accurate as instrumentation identified in the pretest uncertainty analysis. This instrumentation can be either permanent plant instrumentation or temporary test instrumentation.

3-4.1.1 Frequency and Timing of Observations. The timing of instrument observations shall be determined by an analysis of the time lag of both the instrument and the process so that a correct and meaningful mean value and departure from allowable operating conditions may be determined. Sufficient observations shall be recorded to prove that steady-state conditions existed during the test where this is a requirement. A sufficient number of observations shall be taken to reduce the random component of uncertainty to an acceptable level.

The frequency of data collection is dependent on the particular measurement, variability of plant operation, and the duration of the test. To the extent practical, at least 30 readings should be collected to minimize the random error impact on the post-test uncertainty analysis. The use of automated data acquisition systems is recommended to facilitate acquiring sufficient data.

3-4.1.2 Location and Identification of Instruments. Transducers shall be located to minimize the effect of ambient conditions, e.g., temperature or temperature variations, on uncertainty. Care shall be taken in routing lead wires to the data collection equipment to prevent electrical noise in the signal. Manual instruments shall be located so that they can be read with precision and convenience by the observer. All instruments shall be marked uniquely and unmistakably for identification. Calibration tables, charts, or mathematical relationships shall be readily available to all parties to the test. Observers recording data shall be instructed on the desired degree of precision of readings.

All instruments shall be calibrated or adequately checked prior to the test, and those records and calibration reports shall be made available to the parties to the test. Following the test, recalibration or adequate reconfirmation or verification of proper calibration is recommended. When using an automated data acquisition system, the calibration procedure shall include signal conditioners and data-logging devices, such that the desired measurement accuracy is maintained from the primary sensor to the final readout or storage device.

3-4.2 Equipment Inspection

Prior to conducting a test, the condition of the equipment to be tested should be determined by inspection of equipment or review of operational records, or both. Cleaning should be completed prior to the test and equipment cleanliness agreed upon.

Prior to preparation for acceptance and other official tests, all parties to the test shall have reasonable opportunities to examine the equipment, correct defects, and render the equipment suitable to test. Parties to the test, however, are not thereby empowered to alter or adjust equipment or conditions in such a way that regulations, contract, safety, or other stipulations are altered or voided. Parties to the test shall not make adjustments to the equipment for test purposes that may prevent immediate, continuous, and reliable operation at all capacities or outputs under all specified operating conditions. Any actions taken shall be documented and immediately reported to all parties of the test.

3-4.3 Preliminary Testing

Preliminary testing should be conducted sufficiently in advance of the start of the official performance test to allow time to calculate preliminary results and perform an uncertainty analysis using the standard deviations observed during the test. Based on the results of the preliminary testing, final test equipment adjustments and modifications may be made. Results from the preliminary testing should be calculated and reviewed to identify any problems with the quantity and quality of measured data.

3-4.3.1 Preliminary Test Runs. Preliminary test runs, with records, serve to determine if equipment is in suitable condition to test, to check instruments and methods of measurement, to check adequacy of organization and procedures, and to train personnel. All parties to the test may conduct reasonable preliminary test runs as necessary. Observations during preliminary test runs should be carried through to the calculation of results as an overall check of procedure, layout, and organization. If such preliminary test run complies with all the necessary requirements of the appropriate test code, it may be used as an official test run within the meaning of the applicable code.

3-4.3.2 Conduct of Test. The parties to the test shall designate a person, hereafter called the test coordinator, to direct the test. Intercommunication arrangements should be established between all test personnel, all parties to the test, and the test coordinator. Complete written records of the test, even including details that at the time may seem irrelevant, should be reported. Controls by ordinary operating (indicating, reporting, or integrating) instruments, preparation of graphical logs, and close supervision should be established to give assurance that the equipment under test is operating in substantial accord with the intended conditions. If a commercial test, accredited representatives of the purchaser and the manufacturer or supplier should be present at all times to assure themselves that the tests are being conducted according to the test code and prior agreement.

3-5 CONDUCT OF TEST

(a) Operating Philosophy. The tests should be conducted as closely as possible to specified operating conditions, thereby reducing the magnitude and number of corrections for deviations from specified conditions.

(b) Starting and Stopping. Acceptance and other official tests shall be conducted as promptly as possible following initial equipment operation and preliminary test runs. The equipment should be operated for sufficient time to demonstrate that intended test conditions have been established, e.g., steady state. Agreement on procedures and time should be reached before commencing the test.

This subsection provides guidelines on the actual conduct of the performance test and addresses the following areas:

– valve lineup and cycle isolation
– proximity to design conditions
– stabilization
– starting and stopping criteria
– duration and number of test runs

3-5.1 Valve Lineup/Cycle Isolation

A cycle isolation checklist should be developed to the satisfaction of all parties to the test. The checklist should be a complete list of all the valves that should be set in a manner consistent with the basis of design or guarantee. These are the valves that affect the accuracy or results of the test if they are not secured. These valve positions should be checked by physically looking at the valves before and after the test. All automatic valve positions should be checked prior to the preliminary test and monitored during subsequent testing.

Valves that need to be opened between tests shall be closed before the start of the next test.

3-5.2 Variation During Test

It is desirable to operate the plant during the test at conditions as close as possible to the reference conditions, and within the allowable design range of the plant and its equipment so as to limit the magnitude of corrections. Excessive corrections to plant performance parameters can adversely affect overall test uncertainty.

It is recommended that each test run be conducted within the criteria given in Table 3-5.2-1 or other mutually agreed-upon operating criteria that limit overall test uncertainty to those in Table 1-3-1. Oscillation amplitudes during the test period as much as twice the allowable value are acceptable as long as the average value of the readings reflects steady-state operation without upward or downward trend.

3-5.3 Stabilization

The power block shall be in stable operation for at least 1 hr before starting the test.

3-5.4 Starting Criteria

The test coordinator shall be responsible for ensuring that all data collection begins at the agreed-upon start of the test, and that all parties to the test are informed of the starting time. Prior to starting each performance test, the following conditions shall be satisfied:

(a) Operation and Configuration. The unit is in the proper configuration and being operated in accordance with the agreed-upon test requirements.

(b) Stabilization. The plant shall be operated for a sufficient period of time at test load to demonstrate and verify stability in accordance with para. 3-5.3. All operating parameters shall be within the acceptable test range.

Table 3-5.2-1 Variation During Test

Parameter	Variation From Average During Test [Note (1)]
External Connections	
Inlet air	
Pressure	7 mbar (0.1 psia)
Temperature	3°C (5°F)
Relative humidity	10 percentage points
Makeup water, condensate return temperature at test boundary	3°C (5°F)
Power block secondary fuel	
Heating value	1%
Combustible constituents	2.5%
Temperature	6°C (10°F)
Flow rate	2.5%
Input steam no. 2 (multiple)	
Pressure	2.5%
Temperature	3°C (5°F)
Enthalpy	2.5%
Flow rate	2.5%
Net power	
Frequency	0.25%
Power factor	0.05
Export/output steam (multiple)	
Pressure	2.5%
Temperature	3°C (5°F)
Enthalpy	2.5%
Cooling air (if used) temperature at test boundary	3°C (5°F)
Cooling (circulating) water (if used)	
Temperature	3°C (5°F)
Flow rate	5%
or	
Condenser pressure (if used) at test boundary	9 mbar (0.25 in. Hg)
Connections to ASU	
Nitrogen	
Pressure	2.5%
Temperature	3°C (5°F)
Flow rate	2.5%
(Compressed extraction) air	
Pressure	2.5%
Temperature	3°C (5°F)
Flow rate	2.5%
Cooling water temperature	3°C (5°F)
Connections to Gasification Block	
Input water no. 1	
Temperature	3°C (5°F)
Flow rate	2.5%
Output steam no. 1 (multiple)	
Pressure	2.5%
Temperature	3°C (5°F)
Enthalpy	2.5%
Flow rate	5%
Input steam no. 1 (multiple)	
Pressure	2.5%
Temperature	3°C (5°F)
Enthalpy	2.5%
Flow rate	2.5%
Output water no. 1	
Temperature	3°C (5°F)
Flow rate	5%
Output water no. 2	
Temperature	3°C (5°F)
Flow rate	5%
Connections to Syngas Conditioning Block	
Power block primary fuel gas	
Heating value	2.5%
Combustible constituents	2.5%
Temperature	3°C (5°F)
Flow rate	2.5%
Input water no. 2	
Temperature	3°C (5°F)
Flow rate	2.5%
Output water no. 2	
Enthalpy	2.5%
Flow rate	2.5%
Input steam no. 3	
Enthalpy	2.5%
Flow rate	2.5%

NOTE:
(1) All values are +/−.

(c) Data Collection. Data acquisition system(s) shall be functioning, and test personnel shall be in place and ready to collect samples or record data.

(1) Data shall be collected by automatic data-collecting equipment or by a sufficient number of competent observers. Automatic data-logging and advanced instrument systems shall be calibrated to the required accuracy. No observer shall be required to take so many readings that lack of time may result in insufficient care and precision. Consideration shall be given to specifying duplicate instrumentation and taking simultaneous readings for certain test points to attain the specified accuracy of the test.

A list should be created of all the auxiliary loads and measuring locations, and should clearly identify which system is fed through which corresponding motor control center (MCC). The data may be collected manually or the process may be automated. For loads measured using temporary instrumentation, the exact measuring point shall be clearly identified, and qualified personnel should connect temporary meters to avoid accidents.

(2) Once testing has started, readjustments to the equipment that can influence the results of the test should require repetition of any test runs conducted prior to the readjustments. No adjustments should be permissible for the purpose of a test that are inappropriate for reliable and continuous operation following a test under any and all of the specified outputs and operating conditions.

3-5.5 Stopping Criteria

Tests are normally stopped when the test coordinator is satisfied that requirements for a complete test run have been satisfied (see paras. 3-5.6 and 3-5.7). The test coordinator should verify that methods of operation during the test, specified in paras. 3-5.1 through 3-5.3, have been satisfied. The test coordinator may extend or terminate the test if the requirements are not met.

3-5.6 Duration of Runs

The duration of a test run shall be of sufficient length that the data reflect the average efficiency and/or performance of the plant. This includes consideration for deviations in the measurable parameters due to controls, fuel, and typical plant operating characteristics. There should be a minimum of two 1-hr test runs.

When point-by-point traverses are required, the test run should be long enough to complete two full traverses. Test runs using blended or waste fuels may also require longer durations if variations in the fuel are significant. Test-run duration should also consider transit times of samples.

3-5.7 Number of Test Runs

A test shall be comprised of two or more test runs. A test run is a complete set of observations with the unit at stable operating conditions. If the results vary significantly between the first two runs, then a third run shall be required.

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

3-5.8 Number of Readings

Sufficient readings shall be taken within the test duration to yield total uncertainty consistent with those listed in Table 1-3-1. The pretest uncertainty analysis shall be used to determine the necessary number of readings for each measurement. Ideally at least 30 sets of data should be recorded for all nonintegrated measurements of primary variables. There are no specific requirements for the number of integrated readings or for measurements of secondary variables for each test run.

3-5.9 Constancy of Test Conditions

The primary criterion for steady-state test conditions is that the average of the data reflects equilibrium between energy input from fuel and energy output to thermal and/or electrical generation. The primary uncontrollable parameters affecting the steady-state conditions of a test are typically the ambient conditions. Testing durations and schedules shall be such that changes in ambient conditions are minimized. See Table 3-5.2-1.

During the conduct of a test, or during the subsequent analysis or interpretation of the observed data, an obvious inconsistency may be found. If so, reasonable effort should be made to adjust or eliminate the inconsistency. Failing this, test runs should be repeated.

3-6 CALCULATION AND REPORTING OF RESULTS

For all acceptance and other official tests, a complete set of data and a complete copy of the test log shall become the property of each of the parties to the test. The original log, data sheets, files, disks, recorder charts, tapes, etc., being the only evidence of actual test conditions, shall permit clear and legible reproduction. Copying by hand is not permitted. The completed data records shall include the date and time of day the observation was recorded. Corrected measurement data should be distributed to each of the parties to the test. Upon request, raw data (prior to conversion to engineering units and/or application of instrument corrections) shall also be made available.

The test log should constitute a complete record of events, including details that at the time may seem trivial or irrelevant. Erasures on or destruction or deletion of any data record, page of the test log, or recorded observation is not permitted. If the test log is corrected, the alteration shall be entered so that the original entry remains legible and an explanation is included. For manual data collection, the test observations shall be entered on carefully prepared forms that constitute original data sheets authenticated by the observers' signatures. For automatic data collection, printed output or electronic files shall be authenticated by the test coordinator and other representatives of the parties to the test. When no paper copy is generated, the parties to the test shall agree in advance to the method used for authenticating, reproducing, and distributing the data. Copies of the electronic data files shall be copied onto tape or disks and distributed to each of the parties to the test. The data files shall be in a format that is easily accessible to all. Data residing on a machine should not remain there unless a backup, permanent copy is made.

The data taken during the test should be reviewed and rejected in part or in whole if not in compliance with the requirements for the constancy of test conditions (see para. 3-5.9). Each Code test shall include pretest and post-test uncertainty analyses, and the results of these analyses shall fall within Code requirements for the type of plant being tested. If the post-test uncertainty analysis is higher than the agreed-upon maximum expected uncertainty, then the parties to the test may either agree to a higher uncertainty or redesign the test.

3-6.1 Causes for Rejection of Test Runs

Should serious inconsistencies that affect the results be detected during a test run or during the calculation of the results, the run shall be invalidated 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 shall be repeated, if necessary, to attain the test objectives. The decision to reject a run shall be the responsibility of the designated representatives of the parties to the test.

An outlier analysis of spurious data should also be performed in accordance with ASME PTC 19.1 on all critical measurements after the test has ended.

If any measurement influencing the result of a test is inconsistent with some other like measurement, although either or both of them may have been made strictly in accordance with the rules of the individual test code, the cause of the inconsistency shall be identified and eliminated.

3-6.2 Uncertainty

A post-test uncertainty analysis shall be performed as part of test calculations. The post-test uncertainty analysis will reveal the actual quality of the test to determine whether the required uncertainty limits stated in Section 1 have been met.

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

3-6.3 Application of Correction Factors

The calculation of results described by this Code requires adjusting the test-determined values of thermal input, Q, and power, P, by the application of additive and multiplicative correction factors. The general forms of these equations are as follows:

$$P_{corr} = (P_{meas} + \text{additive } P \text{ corrections}) \times (\text{multiplicative } P \text{ corrections})$$

$$Q_{corr} = (Q_{meas} + \text{additive } Q \text{ corrections}) \times (\text{multiplicative } Q \text{ corrections})$$

Corrected heat rate is defined as follows:

$$HR_{corr} = \frac{Q_{meas} + \text{additive } Q \text{ corrections}}{P_{meas} + \text{additive } P \text{ corrections}} \times (\text{multiplicative } P \text{ corrections})$$

While these correction factors are intended to account for all variations from base reference conditions, it is possible that plant performance could be affected by processes or conditions that were not foreseen at the time this Code was written. In this case, additional correction factors, either additive or multiplicative, would be required.

These correction factors correct for allowable variations in controllable operating parameters and uncontrollable external effects, such as ambient temperature. All correction factors shall result in a zero correction if all test conditions are equal to the base reference conditions.

Section 4
Instruments and Methods of Measurement

4-1 GENERAL

This Section describes measurement equipment and methods used to calculate the performance of the power block in terms of the results in Table 1-3-1. This Section is organized as follows:

(a) Pressure Measurement, subsection 4-2
(b) Temperature Measurement, subsection 4-3
(c) Humidity Measurement, subsection 4-4
(d) Flow Measurement, subsection 4-5
(e) Primary Heat Input Measurement, subsection 4-6
(f) Electrical Generation Measurement, subsection 4-7
(g) Data Collection and Handling, subsection 4-8

4-1.1 Introduction

This Section presents the mandatory provisions for instrumentation utilized in the implementation of a ASME PTC 47.4 test. Per the philosophy of ASME PTC 1 and subsection 1-1 herein, it does so in consideration of the minimum reasonably achievable uncertainty.

The Instruments and Apparatus Supplements to ASME Performance Test Codes (ASME PTC 19 series) outline the details concerning instrumentation and the governing requirements of instrumentation for all ASME performance testing. The user of this Code shall be familiar with ASME PTC 19.1, ASME PTC 19.2, ASME PTC 19.3, ASME PTC 19.5, and ASME PTC 19.22 as applicable to the instrumentation specified and explained in this Section.

For the convenience of the user, this Section reviews the critical highlights of portions of those supplements that directly apply to the requirements of this Code. This Section also contains details of the instrumentation requirements of this Code that are not specifically addressed in the referenced supplements. Such details include classification of data for the purpose of instrumentation selection and maintenance, field verification recommendations for instrumentation removed from a laboratory, calibration requirements, electrical metering, and other information specific to an ASME PTC 47.4 test.

If the instrumentation requirements in the ASME PTC 19 series supplements become more rigorous as they are updated, due to advances in the state of the art, their requirements shall supersede those set forth in this Code.

Both SI units and U.S. Customary units are shown for the equations in this Section. In text, tables, and figures, the SI value is followed by the U.S. Customary value in parentheses. However, any other consistent set of units may be used.

4-1.2 Measurements

4-1.2.1 Measurement Designation. Measurements may be designated as either a parameter or a variable. The terms *parameter* and *variable* are sometimes used interchangeably in the industry, and in some other ASME Codes. This Code distinguishes between the two.

A parameter is considered a direct measurement and is a physical quantity at a location that is determined by a single instrument, or by the average of the measurements from several similar instruments. In the latter case, several instruments may be used to determine a parameter that has potential to display spatial gradient qualities, such as inlet air temperature. Similarly, multiple instruments may be used to determine a parameter simply for redundancy to reduce test uncertainty, such as utilization of two temperature measurements of the fluid in a pipe in the same plane, where the temperature gradient is expected to be insignificant. Typical parameters measured in an ASME PTC 47.4 test are temperature, static and differential pressure, flow, stream constituents, voltage, and current.

A variable is considered an indirect measurement and is an unknown quantity in an algebraic equation that is determined by parameters. The performance equations in Section 5 contain the variables used to calculate the performance results, including corrected net power, corrected heat input, and corrected heat rate. Typical variables in these equations are flow, enthalpy, correction factors, and electrical power. Each variable can be thought of as an intermediate result needed to determine the performance result.

Parameters are therefore the quantities measured directly to determine the value of the variables needed to calculate the performance results per the equations in Section 5. Examples of such parameters are temperature and pressure to determine the variable enthalpy; temperature, pressure, or differential pressure for the calculation of the variable flow; and fuel gas composition for calculation of fuel heating value.

4-1.2.2 Measurement Classification. A parameter or variable is classified as primary or secondary depending on its usage in the execution of this Code. Parameters and variables used in the calculation of test results are considered primary parameters and primary variables. Alternatively, secondary parameters and secondary variables do not enter into the calculation of the results but are used to ensure that the required test condition was not violated.

Primary parameters and primary variables are further classified as Class 1 or Class 2 depending on their relative sensitivity coefficient to the results of the test. Class 1 primary parameters and Class 1 primary variables are those that have a relative sensitivity coefficient of 0.2% or greater. The primary parameters and primary variables that have a relative sensitivity coefficient of less than 0.2% are classified as Class 2 primary parameters and Class 2 primary variables.

4-1.3 Instrumentation

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

4-1.3.1 Instrumentation Categorization. The instrumentation employed to measure a parameter will have different required type, accuracy, redundancy, and handling depending on how the measured parameter is used and how it affects the performance result. This Code does not require high-accuracy instrumentation for determining secondary parameters. The instruments that measure secondary parameters may be permanently installed plant instrumentation. This Code does require verification of instrumentation output prior to the test period. This verification can be by calibration or by comparison against two or more independent measurements of the parameters referenced to the same location. The instruments should also have redundant or other independent instruments that can verify the integrity during the test period. Instrumentation is categorized as Class 1 or Class 2, depending on the instrumentation requirements defined by that parameter. Care shall be taken to ensure the instrumentation meets the requirements set forth in this Code with regard to classification.

4-1.3.1.1 Class 1 Instrumentation. Class 1 instrumentation shall be used to determine Class 1 primary parameters. Class 1 instrumentation is high accuracy instrumentation with precision laboratory calibration that meets specific manufacturing and installation requirements, as specified in the ASME PTC 19 series supplements.

4-1.3.1.2 Class 2 Instrumentation. Class 2 instrumentation shall be used to determine Class 2 primary parameters. Class 2 instrumentation does not require laboratory calibrations other than that performed in the factory for certification, but it does require field verification by techniques described herein.

4-1.3.2 Plant Instrumentation. It is acceptable to use plant instrumentation for primary parameters only if the plant instrumentation (including signal-conditioning equipment) can be demonstrated to meet the overall uncertainty requirements. Many times this is not the case. In the case of flow measurement, all instrument measurements (process pressure, temperature, differential pressure, or pulses from metering device) shall be made available as plant conversions to flow are often not rigorous enough for the required uncertainty.

4-1.3.3 Redundant Instrumentation. Redundant instruments are two or more devices measuring the same parameter with respect to the same location. Where experience in the use of a particular model or type of instrument dictates that calibration drift can be unacceptable, and no other device is available, redundancy is recommended. Redundant instruments should be used to measure all primary (Class 1 or Class 2) parameters except flow and electrical input. Redundant flow elements and redundant electrical-metering devices are not required because of the large increase in costs associated with such redundancy, but should be considered when developing a test plan.

Other independent instruments in separate locations can also monitor instrument integrity. A sample case would be a constant enthalpy process where pressure and temperature at one point in a steam line verify the pressure and temperature of another location in the line by comparing enthalpies.

4-1.4 Instrument Calibration

4-1.4.1 Definition of Calibration. Calibration is the set of operations that establish, under specified conditions, the relationship between values indicated by a measuring instrument or measuring system and the corresponding reference standard or known values derived from the reference standard. The result of a calibration permits the estimation of errors of indication of the measuring instrument or measuring system, or the assignment of values to marks on arbitrary scales. The result of a calibration is sometimes expressed as a calibration factor or as a series of calibration factors in the form of a calibration curve. Calibrations performed in accordance with this Code are categorized as either laboratory or field calibrations.

4-1.4.1.1 Laboratory-Grade Calibration. Laboratory-grade calibration, as defined by this Code, is the process by which calibrations are performed under controlled conditions with highly specialized measuring and test equipment that has been calibrated by approved sources and remain traceable to the National Institute of Standards and Technology (NIST), another recognized international standard organization, or a natural physical (intrinsic) constant through an unbroken comparison having defined uncertainties. These calibrations shall be performed in strict compliance with established policy, requirements, and objectives of a laboratory quality assurance program. Laboratory calibration applications shall be employed on Class 1 instrumentation with the exception of fluid-metering devices that strictly adhere to specific manufacturing and installation requirements, as specified in the ASME PTC 19 series supplements.

4-1.4.1.2 Field Calibration. Field calibration, as defined by this Code, is the process by which calibrations are performed under conditions that are less controlled, either with or without less rigorous measurement and test equipment, than provided under a laboratory-grade calibration. Field calibration measurement and test equipment requires calibration by approved sources that remain traceable to NIST, another recognized international standard organization, or a natural physical (intrinsic) constant through an unbroken comparison having defined uncertainties. Field calibration applications are commonly employed on instrumentation measuring secondary parameters and Class 2 instrumentation that are identified as out-of-calibration during field verification as described in para. 4-1.5.

4-1.4.2 Reference Standards. Reference standards are generally of the highest metrological quality available at a given location from which the measurements made at that location are derived. Reference standards include all measuring and test equipment and reference materials that have a direct bearing on the traceability and accuracy of calibrations. Reference standards shall be routinely calibrated in a manner that provides traceability to NIST or defined natural physical constants and shall be maintained for proper calibration, handling, and usage in strict compliance with an accredited calibration laboratory quality program. The integrity of reference standards shall be verified by proficiency testing or interlaboratory comparisons. All reference standards should be calibrated at the frequency specified by the manufacturer unless the user has data to support extension of the calibration period. Supporting data is historical calibration data that demonstrates a calibration drift less than the accuracy of the reference standard for the desired calibration period.

Reference standards should be selected such that the collective uncertainty of the standards used in the calibration contributes less than 25% to the overall calibration uncertainty. The overall calibration uncertainty of the calibrated instrument should be determined at a 95% confidence level. A reference standard with a lower uncertainty may be employed if the uncertainty of the reference standard combined with the random uncertainty of the instrument being calibrated is less than the accuracy requirement of the instrument.

Except for flow-metering instrumentation, all Class 1 and Class 2 instrumentation used to measure primary (Class 1 and Class 2) parameters shall be calibrated against reference standards traceable to NIST, another recognized international standard organization, or recognized natural physical constants with values assigned or accepted by NIST. Instrumentation used to measure secondary variables need not be calibrated against a reference standard. These instruments may be calibrated against a calibrated instrument.

4-1.4.3 Environmental Conditions. Calibration of instruments used to measure primary parameters (Class 1 or Class 2) should be performed in a manner that replicates the condition under which the instrument will be used to take the test measurements. As it is often not practical or possible to perform calibrations under replicated environmental conditions, additional elemental error sources shall be identified and estimated. Error source considerations shall be given to all process and ambient conditions that may affect the measurement system, including temperature, pressure, humidity, electromagnetic interference, and radiation.

4-1.4.4 Instrument Ranges and Calibration Points. The number of calibration points depends on the classification of the parameter the instrument will measure. The classifications are discussed in para. 4-1.2.2. The calibration should have points that bracket the expected measurement range. In some cases of flow measurement, it may be necessary to extrapolate a calibration. Field verifications as described in para. 4-1.5 shall be employed on all installed instrumentation prior to the test on all measured primary and secondary parameters.

4-1.4.4.1 Class 1 Instrumentation. The instruments measuring Class 1 primary parameters should be laboratory-grade calibrated at 2 points more than the order of the calibration curve fit, whether it is necessary to apply the calibration data to the measured data, or the instrument is of the quality that the deviation between the laboratory calibration and the instrument reading is negligible in terms of affecting the test result. Flow metering that requires calibration should have a 20-point calibration. Instrument transformers do not require calibration at 2 points more than the order of the calibration curve fit and shall be calibrated in accordance with para. 4-7.4.

Each instrument should also be calibrated such that the measuring point is approached in an increasing and decreasing manner. This exercise minimizes the possibility of any hysteresis effects. Some instruments are built with a mechanism to alter the range once the instrument is installed. In this case, the instrument shall be calibrated at each range to be used during the test period.

Some devices cannot practically be calibrated over the entire operating range. For example, flow-measuring devices are often calibrated at flows lower than the operating range and the calibration data is extrapolated. This extrapolation is described in subsection 4-5.

4-1.4.4.2 Class 2 Instrumentation. If calibration for instruments measuring Class 2 primary parameters is to be curve fitted, the calibration should contain, as a minimum, one point more than the order of the calibration curve fit. If the instrument can be shown to typically have a hysteresis of less than the required accuracy, the measuring point need only be approached from one direction (either increasing or decreasing to the point).

4-1.4.5 Secondary Parameters. The instruments measuring secondary parameters shall undergo field verifications as described in para. 4-1.5 and if calibrated need only be calibrated at one point in the expected operating range.

4-1.4.6 Timing of Calibration. Because of the variance in different types of instrumentation and their care, no mandate is made regarding the time interval between the initial laboratory calibration and the test period. Treatment of the device is much more important than the elapsed time since calibration. An instrument may be calibrated one day and mishandled the next. Conversely, an instrument may be calibrated and placed on a shelf in a controlled environment and the calibration will remain valid for an extended time period. Similarly, the instrument may be installed in the field but valved-out of service, and/or it may, in many cases, be exposed to significant cycling. In these cases, the instrumentation is subject to vibration or other damage, and shall undergo field verification.

All test instrumentation used to measure Class 1 primary parameters shall be laboratory-grade calibrated prior to the test and/or shall meet specific manufacturing and installation requirements, as specified in the ASME PTC 19 series supplements. No mandate is made regarding quantity of time between the laboratory calibration and the test period. The quantity of time between the laboratory calibration and the test period should, however, be kept to a minimum to obtain an acceptable calibration drift as determined by the manufacturer's specifications and demonstrated by field verification. Similarly, the quantity of time between the field verification and the test period should be kept to a minimum to minimize instrument drift. Test instrumentation used to measure Class 2 parameters and secondary parameters do not require laboratory calibration other than that performed in the factory for certification, but it does require field verification prior to the test.

Following a test, field verifications shall be conducted on instruments measuring parameters where there is no redundancy or for which data is questionable. For the purposes of redundancy, plant instrumentation may be used in the field verification. If results indicate unacceptable drift or damage, then further investigation is required. Flow element devices used to measure Class 1 primary parameters that do not have redundancy shall require field verification, including nondestructive inspection, following the test. Flow element devices used to measure Class 2 primary parameters need not undergo inspection following the test if the devices have not experienced conditions that would violate their integrity. Such conditions may include steam blows and chemical cleaning.

Flow-measuring devices and current and potential transformers by nature are not conducive to post-test calibration. In the case of flow-measuring devices used to measure Class 1 primary variables, the device may be inspected following the test rather than recalibrated. Flow element devices used to measure Class 2 primary variables need not be inspected following the test if the devices have not experienced steam blow or chemical cleaning.

4-1.4.7 Calibration Drift. Calibration drift is defined as a shift in the calibration characteristics. When the field verification indicates the drift is less than the instrument accuracy, the drift is considered acceptable and the pretest calibration is used as the basis for determining the test results. Occasionally the instrument calibration drift is unacceptable. Should the calibration drift, combined with the reference standard accuracy as the square root of the sum of the squares, exceed the required accuracy of the instrument, it is unacceptable.

Calibration drift can result from instrument malfunction, transportation, installation, or removal of the test instrumentation. When a field verification of calibration indicates unacceptable drift to meet the uncertainty requirements of the test, further investigation is required.

A post-test laboratory calibration may be ordered, and engineering judgment shall be used to determine whether the initial calibration or the recalibration is correct by evaluating the field verifications. Below are some recommended field verification practices that lead to the application of good engineering judgment.

(a) When instrumentation is transported to the test site between the calibration and the test period, a

single-point check prior to and following the test period can isolate when the drift may have occurred. For example, verify the zero-pressure point on the vented pressure transmitters, the zero-load point on the wattmeters, or the ice point on the temperature instrument.

(b) In locations where redundant instrumentation is employed, calibration drift should be analyzed to determine which calibration data (the initial or recalibration) produces better agreement between redundant instruments.

4-1.4.8 Loop Calibration. All analog instruments used to measure primary parameters (Class 1 or Class 2) should be loop calibrated. Loop calibration involves the calibration of the instrument through the signal-conditioning equipment. This may be accomplished by calibrating instrumentation using the test signal-conditioning equipment either in a laboratory or on-site during test setup before the instrument is connected to process. Alternatively, the signal-conditioning device may be calibrated separately from the instrument by applying a known signal to each channel using a precision signal generator. Where loop calibration is not practical, an uncertainty analysis shall be performed to ensure that the combined uncertainty of the measurement system meets the uncertainty requirements described in Table 1-3-1.

Instrumentation with digital output need only be calibrated through to the digital signal output. There is no further downstream signal-conditioning equipment as the conversion of the units of measure of the measured parameter has already been performed.

4-1.4.9 Quality Assurance Program. Each calibration laboratory shall have in place a quality assurance program that documents the following information:

(a) calibration procedures
(b) calibration technician training
(c) standard calibration records
(d) standard calibration schedule
(e) instrument calibration histories

The quality assurance program should be designed to ensure that the laboratory standards are calibrated as required and that properly trained technicians calibrate the equipment in the correct manner.

The parties to the test should be allowed access to the calibration facility for auditing. The quality assurance program should also be made available during such a visit.

4-1.5 Instrument Verification

Verification is a set of operations that establishes evidence by calibration or inspection that specified requirements have been meet. It provides a means for checking that the deviations between values indicated by a measuring instrument and corresponding known values are consistently smaller than the limits of the permissible error defined in a standard, regulation, or specification particular to the management of the measuring device.

Field verifications shall be employed on all installed instrumentation prior to the test on all secondary measured parameters. The verifications shall demonstrate the instrumentation and systems are within acceptable limits of error as defined in this Section. Verification techniques may include field calibrations, nondestructive inspections, and comparison of redundant instruments.

Elemental error sources arising from the methods of measurement shall be evaluated during the field verifications to identify the uncertainty sources beyond those contained in the calibration or manufacturer's specification, data acquisition, and data reduction, that may significantly affect the assessment of the verification. Some common examples include vibration effects, mounting position effects, electromagnetic effects, external temperature and humidity effects, and, in some cases, static temperature effects. The errors may be of either a systematic or random nature depending on their effect on the measurement.

4-2 PRESSURE MEASUREMENT

4-2.1 Introduction

This subsection presents requirements and guidance regarding the measurement of pressure. Given the state of the art and general practice, it is recommended that electronic pressure measurement equipment be used for primary measurements to minimize systematic and random error. Electronic pressure measurement equipment provides inherent compensation procedures for sensitivity, zero balance, thermal effect on sensitivity, and thermal effect on zero. Deadweight gages, manometers, and other measurement devices that meet the uncertainty requirements of this Section may be used. Factors affecting the uncertainty of the pressure measurement include, but are not limited to, ambient temperature, resolution, repeatability, linearity, hysteresis, vibration, power supply, stability, mounting position, radio frequency interference (RFI), static pressure, water leg, warm-up time, data acquisition, spatial variation, and primary element quality.

The piping between the process and secondary elements shall accurately transfer the pressure to obtain accurate measurements. Possible sources of error include pressure transfer, leaks, friction loss, trapped fluid (i.e., gas in a liquid line or liquid in a gas line), and density variations between legs.

All signal cables should have a grounded shield or twisted pairs to drain any induced currents from nearby electrical equipment. All signal cables should be installed away from electromotive force (EMF) producing devices such as motors, generators, electrical conduit, cable trays, and electrical service panels.

Prior to calibration, the pressure transducer range may be altered to match the process better. However, the sensitivity to ambient temperature fluctuation may increase as the range is altered.

Additional points will increase the accuracy but are not required. During calibration, the measuring point should be approached from an increasing and decreasing manner to minimize the hysteresis effects.

Some pressure transducers allow the user to change the range once the transmitter is installed. The transmitters shall be calibrated at each range to be used during the test period.

Where appropriate for steam and water processes, the readings from all static pressure transmitters and any differential pressure transmitters with taps at different elevations (such as on vertical flow elements) shall be adjusted to account for elevation head in water legs. This adjustment shall be applied at the transmitter, automatically by the control system or data acquisition system, or manually by the user after the raw data is collected. Care shall be taken to ensure this adjustment is applied properly, particularly at low static pressures, and that it is applied only once.

4-2.2 Required Uncertainty

The required uncertainty depends on the type of parameters and variables being measured. Refer to paras. 4-1.2.2 and 4-1.3.1 for discussion on measurement classification and instrumentation categorization.

Class 1 primary parameters and variables shall be measured with 0.1% accuracy class pressure transmitters or equivalents that have a total uncertainty of ±0.3% or better of calibrated span. Pressure transmitters should be temperature compensated. If temperature compensation is not available, the ambient temperature at the measurement location during the test period shall be compared to the temperature during calibration to determine if the decrease in accuracy is acceptable.

Class 2 primary parameters and variables shall be measured with 0.25% accuracy class pressure transmitters or equivalents that have a total uncertainty of ±0.50% or better of calibrated span. These pressure transmitters do not need to be temperature compensated.

Secondary variables can be measured with any type of pressure transmitter or equivalent device.

4-2.3 Recommended Pressure Measurement Devices

Pressure transmitters are the recommended pressure measurement devices. There are three types of pressure transmitters, as follows, with varying application considerations:

(a) absolute pressure transmitters
(b) gage pressure transmitters
(c) differential pressure transmitters

4-2.3.1 Absolute Pressure Transmitters

4-2.3.1.1 Application. Absolute pressure transmitters measure pressure referenced to absolute zero pressure. Absolute pressure transmitters should be used on all measurement locations with a pressure equal to or less than atmospheric. Absolute pressure transmitters may also be used to measure pressures above atmospheric pressure.

4-2.3.1.2 Calibration. Absolute pressure transmitters can be calibrated using one of two methods. The first method involves connecting the test instrument to a device that develops an accurate vacuum at desired levels. Such a device can be a deadweight gage in a bell jar referenced to zero pressure or a divider piston mechanism with the low side referenced to zero pressure.

The second method uses a suction-and-bleed control mechanism to develop and hold a constant vacuum in a chamber to which the test instrument and the calibration standard are both connected. The chamber shall be maintained at constant vacuum during the calibration of the instrument. Other devices may be utilized to calibrate absolute pressure transmitters provided that the same level of care is taken.

4-2.3.2 Gage Pressure Transmitters

4-2.3.2.1 Application. Gage pressure transmitters measure pressure referenced to atmospheric pressure. To obtain absolute pressure, the test site atmospheric pressure shall be added to the gage pressure. This test site atmospheric pressure should be measured by an absolute pressure transmitter. Gage pressure transmitters may be used only on measurement locations with pressures higher than atmospheric. Gage pressure transmitters are preferred over absolute pressure transmitters in measurement locations above atmospheric pressure because they are easier to calibrate.

4-2.3.2.2 Calibration. Gage pressure transmitters can be calibrated by an accurate deadweight gage. The pressure generated by the deadweight gage shall be corrected for local gravity, air buoyancy, piston surface tension, piston area deflection, actual mass of weights, actual piston area, and working medium temperature. If the above corrections are not used, the pressure generated by the deadweight gage may be inaccurate. The actual piston area and mass of weights are determined each time the deadweight gage is calibrated. Other devices may be utilized to calibrate gage pressure transmitters provided that the same level of care is taken.

4-2.3.3 Differential Pressure Transmitters

4-2.3.3.1 Application. Differential pressure transmitters are used where flow is determined by a differential pressure meter, or where pressure drops in a duct or pipe must be determined.

4-2.3.3.2 Calibration. Differential pressure transmitters used to measure Class 1 primary parameters and variables shall be calibrated at line static pressure unless information is available detailing the effect of line static pressure on the instrument accuracy that demonstrates compliance with the uncertainty requirements of para. 4-2.2. Calibrations at line static pressure are performed by applying the actual expected process pressure to the instrument as it is being calibrated. Calibrations at line static pressure can be accomplished by one of the following three methods:

(a) two highly accurate deadweight gages

(b) a deadweight gage and divider combination

(c) one deadweight gage and one differential pressure standard

Differential pressure transmitters used to measure Class 2 primary parameters and variables or secondary parameters and variables do not require calibration at line static pressure and can be calibrated using one accurate deadweight gage connected to the "high" side of the instrument.

If line static pressure is not used, the span shall be corrected for high line static pressure shift unless the instrument is internally compensated for the effect. Once the instrument is installed in the field, the differential pressure from the source should be equalized and a zero value read. This zero bias shall be subtracted from the test-measured differential pressure. Other devices can be utilized to calibrate differential pressure transmitters provided that the same level of care is taken.

4-2.4 Absolute Pressure Measurements

4-2.4.1 Introduction. Absolute pressure measurements are pressure measurements that are below or above atmospheric pressure. Absolute pressure transmitters should be used for these measurements. Typical absolute pressure measurements include ambient pressure and condenser pressure.

For vacuum pressure measurements, differential pressure transmitters may be used with the "low" side of the transmitter connected to the source to effectively result in a negative gage that is subtracted from atmospheric pressure to obtain an absolute value. This latter method may be used but is not recommended for Class 1 primary parameters and variables since these measurements are typically small and the difference of two larger numbers may result in error.

4-2.4.2 Installation. Absolute pressure transmitters used for absolute pressure measurements shall be installed in a stable location to minimize the effects associated with ambient temperature, vibration, mechanical shock, corrosive materials, and RFI. Transmitters should be installed in the same orientation as when they were calibrated. If the transmitter is mounted in a position other than that in which it was calibrated, the zero point may shift by an amount equal to the liquid head caused by the varied mounting position. Impulse tubing and mounting requirements should be installed in accordance with manufacturer's specifications. In general, the following guidelines should be used to determine transmitter location and placement of impulse tubing:

(a) Keep the impulse tubing as short as possible.

(b) Slope the impulse tubing at least 8 cm/m (1 in./ft) upward from the transmitter toward the process connection for liquid service.

(c) Slope the impulse tubing at least 8 cm/m (1 in./ft) downward from the transmitter toward the process connection for gas service.

(d) Avoid high points in liquid lines and low points in gas lines.

(e) Use impulse tubing large enough to avoid friction effects and prevent blockage.

(f) Keep corrosive or high-temperature process fluid out of direct contact with the sensor module and flanges.

In steam service, the sensing line should extend at least 0.6 m (2 ft) horizontally from the source before the downward slope begins. This horizontal length will allow condensation to form completely so the downward slope will be completely full of liquid.

The water leg is the condensed liquid or water in the sensing line. This liquid causes a static pressure head to develop in the sensing line. This static head shall be subtracted from the pressure measurement. The static head is calculated by multiplying the sensing line vertical height by gravity and the density of the liquid in the sensing line.

All vacuum measurement sensing lines shall slope continuously upward from the source to the instrument. The Code recommends using a purge system that isolates the purge gas while measuring the process. A continuous purge system may be used; however, it shall be regulated to have no influence on the reading. Prior to the test period, readings from all purged instrumentation should be taken successively with the purge on and with the purge off to prove that the purge air has no influence.

Each pressure transmitter should be installed with an isolation valve at the end of the sensing line upstream of the instrument. The instrument sensing line should be vented to clear water or steam (in steam service) before the instrument is installed. This will clear the sensing line of sediment or debris. After the instrument is installed, allow sufficient time for liquid to form in the sensing line so the reading will be correct.

Once transmitters are connected to the process, a leak check shall be conducted. For vacuum measurements, the leak check is performed by isolating first the purge system and then the source. If the sensing line has no leaks, the instrument reading will not change. For nonvacuum measurements, the leak check is performed using a leak detection fluid on the impulse tubing fittings.

Ambient pressure transmitters should be installed in the same general area and at the same general elevation as the gage pressure transmitters and should be protected from air currents that could influence the measurements.

4-2.5 Gage Pressure Measurements

4-2.5.1 Introduction. Gage pressure measurements are pressure measurements that are at or above atmospheric pressure. These measurements may be made with gage or absolute pressure transmitters. Gage pressure transmitters are recommended since they are easier to calibrate and to check in situ. Typical gage pressure measurements include gas fuel pressure and process return pressure.

Caution shall be used with low-pressure measurements because they may enter the vacuum region at part-load operation.

4-2.5.2 Installation. Gage pressure transmitters used for gage pressure measurements shall be installed in a stable location to minimize the effects associated with ambient temperature, vibration, mechanical shock, corrosive materials, and RFI. Transmitters should be installed in the same orientation as when they were calibrated. If the transmitter is mounted in a position other than that in which it was calibrated, the zero point may shift by an amount equal to the liquid head caused by the varied mounting position. Impulse tubing and mounting requirements should be installed in accordance with manufacturer's specifications. In general, the following guidelines should be used to determine transmitter location and placement of impulse tubing:

(a) Keep the impulse tubing as short as possible.

(b) Slope the impulse tubing at least 8 cm/m (1 in./ft) upward from the transmitter toward the process connection for liquid service.

(c) Slope the impulse tubing at least 8 cm/m (1 in./ft) downward from the transmitter toward the process connection for gas service.

(d) Avoid high points in liquid lines and low points in gas lines.

(e) Use impulse tubing large enough to avoid friction effects and prevent blockage.

(f) Keep corrosive or high-temperature process fluid out of direct contact with the sensor module and flanges.

In steam service, the sensing line should extend at least 0.6 m (2 ft) horizontally from the source before the downward slope begins. This horizontal length will allow condensation to form completely so the downward slope will be completely full of liquid.

The water leg is the condensed liquid or water in the sensing line. This liquid causes a static pressure head to develop in the sensing line. This static head shall be subtracted from the pressure measurement. The static head is calculated by multiplying the sensing line vertical height by gravity and the density of the liquid in the sensing line.

Each pressure transmitter should be installed with an isolation valve at the end of the sensing line upstream of the instrument. The instrument sensing line should be vented to clear water or steam (in steam service) before the instrument is installed. This will clear the sensing line of sediment or debris. After the instrument is installed, allow sufficient time for liquid to form in the sensing line so the reading will be correct.

Once transmitters are connected to the process, a leak check shall be conducted. The leak check is performed using a leak detection fluid on the impulse tubing fittings.

4-2.6 Differential Pressure Measurements

4-2.6.1 Introduction. Differential pressure measurements are used to determine the difference in static pressure between pressure taps in a primary device. Differential pressure transmitters should be used for these measurements. Typical differential pressure measurements include the differential pressure of gas fuel or process return through a flow element or pressure loss in a pipe or duct. The differential pressure transmitter measures the pressure difference or pressure drop that is used to calculate the fluid flow.

4-2.6.2 Installation. Differential pressure transmitters used for differential pressure measurements shall be installed in a stable location to minimize the effects associated with ambient temperature, vibration, mechanical shock, corrosive materials, and RFI. Transmitters should be installed in the same orientation as when they were calibrated. If the transmitter is mounted in a position other than that at which it was calibrated, the zero point may shift by an amount equal to the liquid head caused by the varied mounting position. Impulse tubing and mounting requirements should be installed in accordance with manufacturer's specifications. In general, the following guidelines should be used to determine transmitter location and placement of impulse tubing:

(a) Keep the impulse tubing as short as possible.

(b) Slope the impulse tubing at least 8 cm/m (1 in./ft) upward from the transmitter toward the process connection for liquid service.

(c) Slope the impulse tubing at least 8 cm/m (1 in./ft) downward from the transmitter toward the process connection for gas service.

(d) Avoid high points in liquid lines and low points in gas lines.

(e) Ensure both impulse legs are at the same temperature.

(f) When using a sealing fluid, fill both impulse legs to the same level.

(g) Use impulse tubing large enough to avoid friction effects and prevent blockage.

Fig. 4-2.6.2-1 Five-Way Manifold

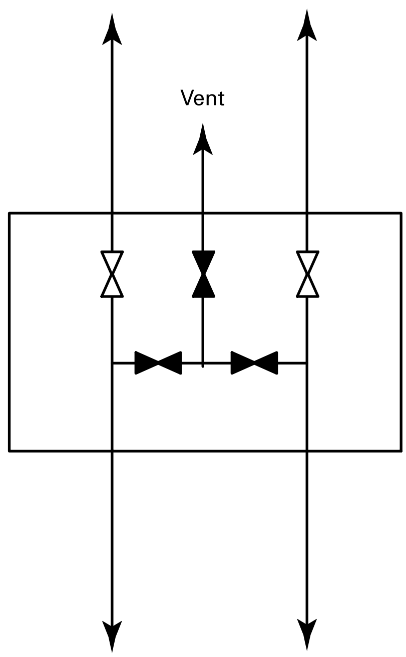
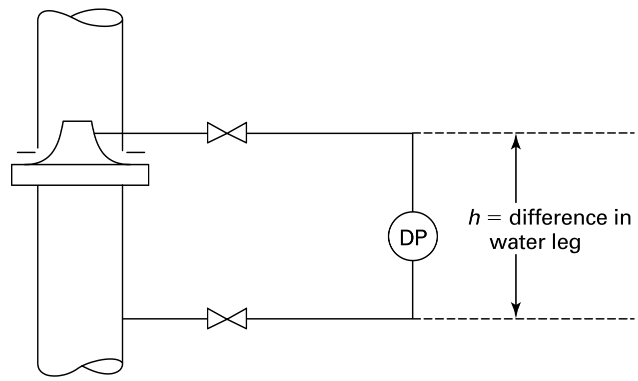


Fig. 4-2.6.2-2 Water Leg Correction for Flow Measurement



GENERAL NOTE:

For upward flow, $\Delta p_{true} = \Delta p_{meas} + (\rho_{amb} - \rho_{pipe})(g/g_c)h$

For downward flow, $\Delta p_{true} = \Delta p_{meas} - (\rho_{amb} - \rho_{pipe})(g/g_c)h$

where

g = local gravitational force per unit mass
$\approx$ 9.81 m/s^2 (32.17 ft/sec^2)
g_c = gravitational dimensional constant
= 1.00 (kg-m)/(N-s^2) [32.17 (lbm-ft)/(lbf-sec^2)]
h = difference in water leg, m (ft)
Δp_{meas} = measured pressure difference, Pa (lbf/ft^2)
Δp_{true} = true pressure difference, Pa (lbf/ft^2)
ρ_{amb} = fluid density at ambient conditions, kg/m^3 (lbm/ft^3)
ρ_{pipe} = fluid density at conditions within pipe, kg/m^3 (lbm/ft^3)

(h) Keep corrosive or high-temperature process fluid out of direct contact with the sensor module and flanges.

In steam service, the sensing line should extend at least 0.6 m (2 ft) horizontally from the source before the downward slope begins. This horizontal length will allow condensation to form completely so the downward slope will be completely full of liquid.

Each pressure transmitter should be installed with an isolation valve at the end of the sensing lines upstream of the instrument. The instrument sensing lines should be vented to clear water or steam (in steam service) before the instrument is installed. This will clear the sensing lines of sediment or debris. After the instrument is installed, allow sufficient time for liquid to form in the sensing line so the reading will be correct.

Differential pressure transmitters should be installed utilizing a five-way manifold, as shown in Fig. 4-2.6.2-1. This manifold is recommended rather than a three-way manifold because the five-way eliminates the possibility of leakage past the equalizing valve. The vent valve acts as a telltale for leakage detection past the equalizing valves.

Once transmitters are connected to process, a leak check shall be conducted. The leak check is performed using a leak detection fluid on the impulse tubing fittings.

When a differential pressure meter is installed on a flow element that is located in a vertical steam or water line, the measurement shall be corrected for the difference in sensing line height and fluid head change unless the upper sensing line is installed against a steam or water line inside the insulation down to where the lower sensing line protrudes from the insulation. The correction for the noninsulated case is shown in Fig. 4-2.6.2-2.

For differential pressure transmitters on flow devices, the transmitter output is often an extracted square root value unless the square root is applied in the plant control system. Care should be taken to ensure the square root is applied only once.

4-3 TEMPERATURE MEASUREMENT

4-3.1 Introduction

This Subsection presents requirements and guidance regarding the measurement of temperature. Recommended temperature measurement devices and the calibration and application of temperature measurement devices are discussed. Given the state of the art and general practice, it is recommended that electronic temperature measurement equipment be used for primary measurements to minimize systematic and random error. Factors affecting the uncertainty of the temperature measurement include, but are not limited to, stability, environment, self-heating, parasitic resistance, parasitic voltages, resolution, repeatability, hysteresis, vibration, warm-up time, immersion or conduction, radiation, dynamic, spatial variation, and data acquisition.

Since temperature measurement technology changes over time, this Code does not limit the use of other temperature measurement devices not currently available or not currently reliable. If such a device becomes available and is shown to be of the required uncertainty and reliability, it may be used.

All signal cables should have a grounded shield or twisted pairs to drain any induced currents from nearby electrical equipment. All signal cables should be installed away from EMF-producing devices such as motors, generators, electrical conduit, cable trays, and electrical service panels.

4-3.2 Required Uncertainty

The required uncertainty depends on the type of parameters and variables being measured. Refer to paras. 4-1.2.2 and 4-1.3.1 for discussion on measurement classification and instrumentation categorization.

Class 1 primary parameters and variables shall be measured with temperature measurement devices that have an instrument systematic uncertainty of no more than ±0.28°C (±0.50°F) for temperatures less than 93°C (200°F) and no more than ±0.56°C (±1.0°F) for temperatures more than 93°C (200°F).

Class 2 primary parameters and variables shall be measured with temperature measurement devices that have an instrument systematic uncertainty of no more than ±1.7°C (±3.0°F).

Secondary variables should be measured with temperature measurement devices that have an instrument systematic uncertainty of no more than ±2.8°C (±5.0°F).

4-3.3 Recommended Temperature Measurement Devices

Thermocouples, resistance temperature detectors, and thermistors are the recommended temperature measurement devices. Economic, application, and uncertainty factors should be considered in the selection of the most appropriate temperature measurement device.

4-3.3.1 Thermocouples. Thermocouples may be used to measure temperature of any fluid above 93°C (200°F). The maximum temperature is dependent on the type of thermocouple and sheath material used.

Thermocouples may be used for measurements below 93°C (200°F) if caution is used. The thermocouple is a differential-type device. The thermocouple measures the difference between the temperature at the measurement location in question and a reference temperature. The greater this difference, the higher the EMF from the thermocouple. Therefore, below 93°C (200°F) the EMF becomes low and subject to induced noise, causing increased systematic uncertainty and inaccuracy.

Measurement errors associated with thermocouples typically derive from the following primary sources:

(a) junction connection
(b) decalibration of thermocouple wire
(c) shunt impedance
(d) galvanic action
(e) thermal shunting
(f) noise and leakage currents
(g) thermocouple specifications

ASME PTC 19.3 describes the operation of the thermocouple as follows:

> The emf developed by a thermocouple made from homogeneous wires will be a function of the temperature difference between the measuring and the reference junction. If, however, the wires are not homogeneous, and the inhomogeneity is present in a region where a temperature gradient exists, extraneous emf's will be developed, and the output of the thermocouple will depend upon factors in addition to the temperature difference between the two junctions. The homogeneity of the thermocouple wire, therefore, is an important factor in accurate measurements.[1]

Dahl (1941) gives the following guidance on the application of the thermocouple:

> All base-metal-metal thermocouples become inhomogeneous with use at high temperatures, however, if all the inhomogeneous portions of the thermocouple wires are in a region of uniform temperature, the inhomogeneous portions have no effect upon the indications of the thermocouple. Therefore, an increase in the depth of immersion of a used couple has the effect of bringing previously unheated portion of the wires into the region of temperature gradient, and thus the indications of the thermocouple will correspond to the original EMF–temperature relation, provided the increase in immersion is sufficient to bring all the previously heated part of the wires into the zone of uniform temperature. If the immersion is decreased, more inhomogeneous portions of the wire will be brought into the region of temperature gradient, thus giving rise to a change in the indicated EMF. Furthermore a change in the temperature distribution along inhomogeneous portions of the wire nearly always occurs when a couple is removed from one installation and placed in another, even though the measured immersion and the temperature of the measuring junction are the same in both cases. Thus the indicated EMF is changed.[2]

The elements of a thermocouple shall be electrically isolated from each other, from ground, and from conductors on which they may be mounted, except at the measuring junction. When a thermocouple is mounted along a conductor, such as a pipe or metal

[1] ASME PTC 19.3-1974 (R2004), chapter 9, p. 106, para. 70

[2] A. I. Dahl, "Stability of Base-Metal Thermocouples in Air From 800 to 2200ºF," National Bureau of Standards, Washington, D.C., in *Temperature*, Vol. 1, Reinhold: New York, 1941, p. 1238

structure, special care should be exercised to ensure good electrical insulation between the thermocouple wires and the conductor to prevent stray currents in the conductor from entering the themocouple circuit and vitiating the readings. Stray currents may further be reduced with the use of guarded intergrating analog-to-digital (A/D) techniques. Further, to reduce the possibility of magnetically induced noise, the thermocouple wires should be constructed in a twisted uniform manner.

Thermocouples are susceptible to drift after cycling. Cycling is the act of exposing the thermocouple to process temperature and removing to ambient conditions. The number of times a thermocouple is cycled should be kept to a minimum.

Thermocouples can effectively be used in high-vibration areas such as main or high-pressure inlet steam to the steam turbine. High-vibration measurement locations may not be conducive to other measurement devices. This Code recommends that the highest EMF per degree be used in all applications. NIST has recommended temperature ranges for each specific type of thermocouple (see subsection 1-4).

4-3.3.1.1 Class 1 Primary Parameters. Thermocouples used to measure Class 1 primary parameters shall have continuous leads from the measuring junction to the connection on the reference junction. These high-accuracy thermocouples shall have a reference junction at 0ºC (32ºF) or an ambient reference junction that is well insulated and calibrated.

4-3.3.1.2 Class 2 Primary Parameters. Thermocouples used to measure Class 2 primary parameters can have junctions in the sensing wire. The junction of the two sensing wires shall be maintained at the same temperature. The reference junction may be at ambient temperature provided the ambient is measured and the measurement is compensated for changes in the reference junction temperature.

4-3.3.1.3 Reference Junctions. The temperature of the reference junction shall be measured accurately using either software or hardware compensation techniques. The accuracy with which the temperature of the measuring junction is measured can be no greater than the accuracy with which the temperature of the reference junction is known. The reference junction temperature shall be held at the ice point or at the stable temperature of an isothermal reference. When thermocouple reference junctions are immersed in an ice bath, consisting of a mixture of melting, shaved ice and water,[3] the bulb of a precision thermometer shall be immersed at the same level as the reference junctions and in contact with them. Any deviation from the ice point shall be promptly corrected. Each reference junction shall be electrically insulated. When the isothermal–cold junction reference method is used, it shall employ an accurate temperature measurement of the reference sink acceptable to the parties to the test. When electronically controlled reference junctions are used, they shall have the ability to control the reference temperature to within ±0.03°C (±0.05°F). Particular attention shall be paid to the terminals of any reference junction since errors can be introduced by temperature variation, material properties, or by wire mismatching. By calibration, the overall reference system shall be verified to have an uncertainty of less than ±0.1°C (±0.2°F). Isothermal thermocouple reference blocks furnished as part of digital systems may be used in accordance with this Code provided the accuracy is equivalent to the electronic reference junction. Commercial data acquisition systems employ a measured reference junction, and the accuracy of this measurement is incorporated into the manufacturer's specification for the device. The uncertainty of the reference junction shall be included in the uncertainty calculation of the measurement to determine if the measurement meets the standards of this Code.

4-3.3.1.4 Thermocouple Signal Measurement. Many instruments are available to measure the output voltage. The use of these instruments in a system to determine temperature requires they meet the uncertainty requirements for the parameter. It is recommended that International Temperature Scale of 1990 (ITS-90) software compensaton techniques be used for the thermocouple signal conversion.

4-3.3.2 Resistance Temperature Detectors (RTDs). Resistance temperature detectors (RTDs) may be used in testing from any low temperature to the highest temperature depending on the RTDs' mechanical configuration and the method by which they were manufactured. RTDs can measure temperatures from −270°C to 850°C (−454°F to 1,562°F). ASTM E1137 provides standard specifications for industrial platinum resistance thermometers that include requirements for manufacture, pressure, vibration, and mechanical shock to improve the performance and longevity of these devices.

Measurement errors associated with RTDs typically derive from the following primary sources:

(a) self-heating
(b) environmental factors
(c) thermal shunting
(d) thermal EMF
(e) instability
(f) immersion

Although RTDs are considered a more linear device than thermocouples, due to manufacturing technology, RTDs are more susceptible to vibrational applications. As such, care should be taken in the specification and application of RTDs, with consideration for the effect

[3] ASTM MNL 12, chapter 7, "Reference Junctions"

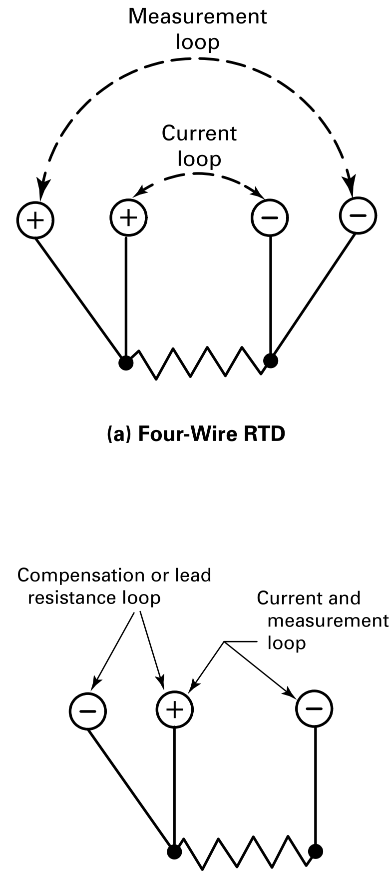
on the devices' stability. Field verification techniques should be used to demonstrate the stability is within the uncertainty requirements of para. 4-3.2.

4-3.3.2.1 Class 1 Primary Parameters. Class 1 primary parameters shall be measured with Grade A four-wire platinum RTDs, as shown in Figure 4-3.3.2.1-1, illustration (a), if they can be shown to meet the uncertainty as required in para. 4-3.2.

4-3.3.2.2 Class 2 Primary Parameters. Class 2 primary parameters shall be measured with Grade A three-wire platinum RTDs, as shown in Fig. 4-3.3.2.1-1, illustration (b), if they can be shown to meet the uncertainty as required in para. 4-3.2. The four-wire technique is preferred to minimize effects associated with lead wire resistance due to dissimilar lead wires.

4-3.3.2.3 RTD Signal Measurement. Many instruments are available to measure the output resistance. The use of these instruments in a system to determine temperature requires they meet the uncertainty requirements for the parameter. It is recommended that the RTD signal conversion use the Callandar–Van Dusen equation for curve fitting. The values for the coefficients α, β, and δ should be taken from the calibration coefficients. RTDs should be calibrated in accordance with the methods detailed in NIST Technical Note 1265, subsection 4-6.

Fig. 4-3.3.2.1-1 Three-and Four-Wire RTDs



(a) Four-Wire RTD

(b) Three-Wire RTD

4-3.3.3 Thermistors. Thermistors are constructed with ceramic-like semiconducting material that acts as a thermally sensitive variable resistor. This device may be used on any measurement below 149°C (300°F). Above this temperature, the signal is low and susceptible to error from current-induced noise. Although positive temperature coefficient units are available, most thermistors have a negative temperature coefficient (TC); that is, unlike an RTD, their resistance decreases with increasing temperature. The negative TC can be as large as several percent per degree Celsius, allowing the thermistor circuit to detect minute changes in temperature that could not be observed with an RTD or thermocouple circuit. As such, the thermistor is best characterized for its sensitivity while the thermocouple is the most versatile and the RTD the most stable.

Measurement errors associated with thermistors typically derive from the following primary sources:

(a) self-heating
(b) environmental factors
(c) thermal shunting
(d) decalibration
(e) instability
(f) immersion

The four-wire resistance measurement is not required for thermistors as it is for RTDs due to their high resistivity. Thus the measurement lead resistance produces an error magnitudes less than the equivalent RTD error. Thermistors are generally more fragile than RTDs and thermocouples and shall be carefully mounted and handled in accordance with manufacturer's specifications to avoid crushing or bond separation.

4-3.3.3.1 Thermistor Signal Measurement. Many instruments are available to measure the output resistance. The use of these instruments in a system to determine temperature requires they meet the uncertainty requirements for the parameter. It is recommended that the thermistor signal conversion use the Steinhart–Hart equation for curve fitting. The values for the coefficients A, B, and C should be taken from the calibration coefficients. Thermistor should be calibrated in accordance with the methods detailed in NIST Technical Note 1265, subsection 4-6.

4-3.4 Calibration of Primary Parameter Temperature Measurement Devices

This Code recommends that primary (Class 1 or Class 2) parameter instrumentation used in the measurement of temperature have a suitable calibration history (three or four sets of calibration data). The calibration history should include the temperature level the device experienced between calibrations. A device that is stable after being used at low temperatures may not be stable at higher temperature. Hence, the calibration history of the device should be evaluated to demonstrate the required stability of the parameter.

During the calibration of any thermocouple, the reference junction shall be held constant, preferably at the ice point, with an electronic or isothermal reference junction or in an ice bath. The calibration shall be made by an acceptable method, with the standard being traceable to a recognized national standards laboratory such as NIST. The calibration shall be conducted over the temperature range in which the instrument is used.

The calibration of temperature measurement devices is accomplished by inserting the candidate temperature measurement device into a calibration medium along with a traceable reference standard. The calibration medium type is selected based on the required calibration range and commonly consists of either a block calibrator, fluidized sand bath, or circulating bath. The temperature of the calibration medium is then set to the calibration temperature set point. The temperature of the calibration medium is allowed to stabilize until the temperature of the standard is fluctuating less than the accuracy of the standard. The signal or reading from the standard and the candidate temperature measurement device are sampled to determine the bias of the candidate temperature device. See ASME PTC 19.3 for a more detailed discussion of calibration methods.

4-3.5 Temperature Scale

The International Temperature Scale of 1990 (ITS-90) is realized and maintained by NIST to provide a standard scale of temperature for use by science and industry in the United States. This scale was adopted by the International Committee for Weights and Measures at its meeting in September 1989, and it became the official International Temperature Scale on January 1, 1990. The ITS-90 supersedes the International Practical Temperature Scale of 1968 (IPTS-68), the amended edition of 1975 [IPTS-68(75)], and the 1976 Provisional 0.5 K to 30 K Temperature Scale (EPT-76).

Temperatures on the ITS-90 can be expressed in terms of International Kelvin Temperatures, represented by the symbol T_{90}, or in terms of International Celsius Temperatures, represented by the symbol t_{90}. T_{90} values are expressed in units of kelvin (K), and t_{90} values in degrees Celsius (°C). The relation between T_{90} (in K) and t_{90} (in °C) is

$$t_{90} = T_{90} - 273.15$$

Values of Fahrenheit temperature, t_f [in degrees Fahrenheit (°F)], are obtained from the conversion formula

$$t_f = \left(\frac{9}{5}\right)t_{90} + 32$$

The ITS-90 was designed in such away that the temperature values on it very closely approximate Kelvin thermodynamic temperature values. Temperatures on the ITS-90 are defined in terms of equilibrium states of pure substances (defining points), interpolating instruments, and equations that relate the measured property to T_{90}. The defining equilibrium states and the values of temperature assigned to them are listed in NIST Technical Note 1265 and ASTM MNL 12 .

4-3.6 Typical Applications

4-3.6.1 Temperature Measurement of Fluid in a Pipe or Vessel. Temperature measurement of a fluid in a pipe or vessel is accomplished by installing a thermowell. A thermowell is a pressure-tight device that protrudes from the pipe or vessel wall into the fluid to protect the temperature measurement device from harsh environments, high pressure, and flows. The thermowell can be installed into a system by a threaded, socket-weld, or flanged connection and has a bore extending to near the tip to facilitate the immersion of a temperature measurement device. Thermowells should be designed and installed to meet the requirements of ASME PTC 19.3 TW.

The bore should be sized to allow adequate clearance between the temperature measurement device and the well. Often the temperature measurement device becomes bent, causing difficulty in the insertion of the device.

The bottom of the bore of the thermowell should be the same shape as the tip of the temperature measurement device. Tubes and wells should be as thin as possible, consistent with safe stress and other ASME PTC 19.3 TW requirements, and the inner diameters of the wells should be clean, dry, and free from corrosion or oxide. The bore should be cleaned with high-pressure air prior to insertion of the device.

The thermowell should be installed so that the tip protrudes through the boundary layer of the fluid to be measured. Unless limited by design considerations, the temperature sensor shall be immersed in the fluid at least 75 mm (3 in.) but not less than one-quarter of the pipe diameter. If the pipe is less than 100 mm (4 in.) in diameter, the temperature sensor shall be arranged axially in the pipe, by inserting it in an elbow or tee. If such fittings are not available, the piping should be modified to render this possible. The thermowell should be located in an area where the fluid is well mixed and has no potential gradients. If the location is near the discharge of a boiler, turbine, condenser, or other power plant component, the thermowell should be downstream of an elbow in the pipe.

If more than one thermowell is installed in a given pipe location, the second thermowell should be installed on the opposite side of the pipe and not directly downstream of the first thermowell.

When the temperature measurement device is installed, it should be "spring-loaded" to ensure positive thermal contact between the temperature measurement device and the thermowell.

For Class 1 primary parameter measurements, the portion of the thermowell or lag section protruding outside the pipe or vessel should be insulated, along with the device itself, to minimize conduction losses. The locations at which Class 1 primary temperature measurements are taken for use in determining enthalpy shall be as close as possible to the points at which the corresponding pressures are to be measured.

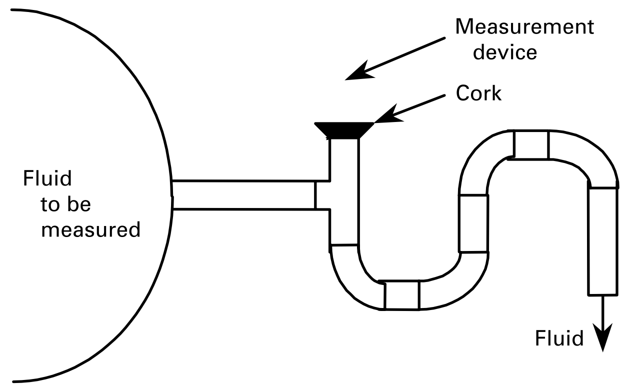
For measuring the temperature of desuperheated steam, the thermowell location relative to the desuperheating spray injection shall be carefully chosen. The thermowell shall be located where the desuperheating fluid has thoroughly mixed with the steam. This can be accomplished by placing the thermowell downstream of two elbows in the steam line, past the desuperheating spray injection point.

4-3.6.2 Temperature Measurement of Low-Pressure Fluid in a Pipe or Vessel. As an alternative to installing a thermowell in a pipe, if the fluid is at low pressure, the temperature measurement device can be installed directly into the pipe or vessel, or "flow-through wells" may be used.

The temperature measurement device can be installed directly into the fluid using a bored-through-type compression fitting. The fitting should be of proper size to clamp onto the device. A plastic or Teflon-type ferrule is recommended so that the device can be removed easily and used elsewhere. The device shall protrude through the boundary layer of the fluid. The device should not protrude so far into the fluid that the flowing fluid causes it to vibrate. If the fluid is a hazardous gas such as natural gas or propane, the fitting should be checked for leaks.

A flow-through well is shown in Fig. 4-3.6.2-1. This arrangement is applicable only for water in a cooling system where the fluid is not hazardous and the fluid can be disposed of without great cost. The principle is to allow the fluid to flow out of the pipe or vessel, over the tip of the temperature measurement device.

Fig. 4-3.6.2-1 Flow-Through Well



4-3.6.3 Temperature Measurement of Products of Combustion in a Duct. Measurement of the fluid temperature in a duct requires several measurement points to minimize the uncertainty effects of temperature gradients. Typically, the duct pressures are low or negative so that thermowells or protection tubes are not needed. A long sheathed thermocouple or an unsheathed thermocouple attached to a rod will suffice.

The number of measurement points necessary is determined experimentally or by experience from the magnitude of the temperature variations at the desired measurement cross section and the required maximum uncertainty of the value of the average temperature. The total uncertainty of the average temperature is affected by the uncertainty of the individual measurements, the number of points used in the averaging process, the velocity profile, the temperature gradients, and the time variation of the readings. The parties to the test should locate the measurement plane at a point of uniform temperatures and velocities to the extent practical. Points should be located every 0.84 m^2 (9 ft^2) or less, with a minimum of 4 points and a maximum of 36 points.

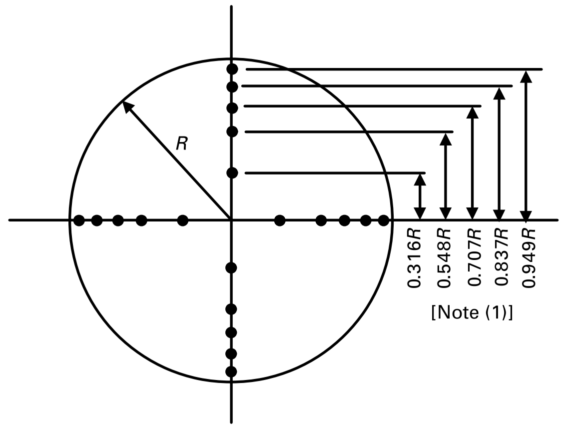
ASME PTC 19.1 describes the method of calculating the uncertainty of the average of multiple measurements that vary with time.

For circular ducts, the points should be installed in two diameters 90 deg from each other, as shown in Fig. 4-3.6.3-1, which also shows the method of calculating the measurement-point spacing. The point spacing is based on locating the measurement points at the centroids of equal areas.

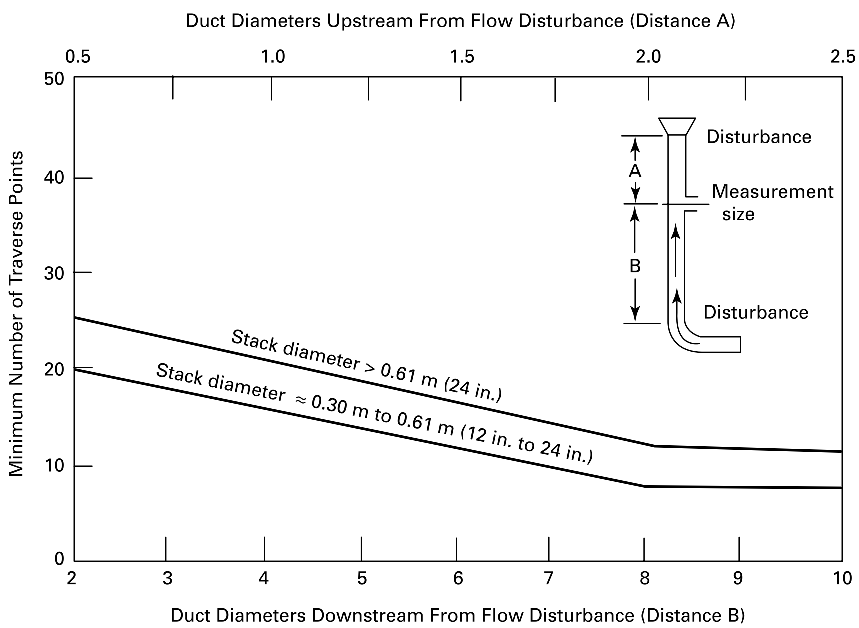
For square or rectangular ducts, the same concept of locating the measurement points at centroids of equal areas should be used. The measurement points should be laid out in a rectangular pattern that takes into account the horizontal and vertical temperature gradients at the measurement cross section. The direction with the highest temperature gradient should have the closer point spacing.

4-3.6.4 Temperature Measurement of Inlet Air. The temperature of air crossing the test boundary at the gas turbine compressor inlet(s) varies in space, and hence, temperature measurement is subject to spatial variations. As such, the number and location of temperature measurement devices should be determined such that the overall measurement uncertainty of the average inlet air temperature measurement devices is less than 0.5°C (1°F). Due to the shape of the inlet system, air at the compressor inlet bellmouth has a better chance of mixing, and therefore, temperature measurements taken close to the compressor inlet bellmouth provide a more

Fig. 4-3.6.3-1 Duct Measurement Points



Cross Section of Circular Gas Passage



NOTE:
(1) Dots indicate location of sample points. To calculate the distance from sampling point to center of pipe, use the following equation:

$$r_p = R\sqrt{\left[\frac{2(2p-1)}{n}\right]}$$

where

n = total number of points
  = $\Pi \times R^2/A_{cmax}$, rounded to the next multiple of 4, but no fewer than 4 and no more than 36, where
    A_{cmax} = maximum area per centroid
      = 0.8 m^2 (ft^2)

p = sampling point number, to be numbered from the center outward; all four points on the same circumference have the same number

R = radius of duct (in the same units as r_p), m (ft)

r_p = distance from center of duct to point p, m (ft) representative distribution of the temperature profile. Spatial variation effects are considered errors of method and contributors to the systematic uncertainty in the measurement system. ASME PTC 19.1 should be consulted for the determination of the uncertainty associated with spatial variation.

4-4 HUMIDITY MEASUREMENT

4-4.1 Introduction

This subsection presents requirements and guidance regarding the measurement of humidity. Recommended humidity measurement devices and the calibration and application of such devices are also discussed. Given the state of the art and general practice, it is recommended that electronic humidity measurement equipment be used for primary measurements to minimize systematic and random error. Factors affecting the uncertainty of humidity measurement include, but are not limited to, resolution, stability, environment, temperature measurement errors, pressure measurement errors, warm-up time, spatial variation, nonlinearity, repeatability, analog output, and data acquisition.

Since humidity measurement technology changes over time, this Code does not limit the use of other humidity measurement devices not currently available or not currently reliable. If such a device becomes available or is shown to be of the required uncertainty and reliability, it may be used.

Measurements to determine moisture content shall be made in proximity to measurements of ambient dry bulb temperature to provide the basis for determination of air properties.

All signal cables should have a grounded shield or twisted pairs to drain any induced currents from nearby electrical equipment. All signal cables should be installed away from EMF-producing devices such as motors, generators, electrical conduit, cable trays, and electrical service panels.

4-4.2 Required Uncertainty

The required uncertainty depends on the type of parameters and variables being measured. Refer to paras. 4-1.2.2 and 4-1.3.1 for discussion on measurement classification and instrumentation categorization.

Class 1 primary parameters and variables shall be measured with humidity measurement devices that determine relative humidity to an uncertainty of no more than 2 percentage points or 0.39°C (0.7°F) wet bulb.

Class 2 primary parameters and variables shall be measured with humidity measurement devices that determine relative humidity to an uncertainty of not more than 4 percentage points or 0.76°C (1.37°F) wet bulb.

Secondary variables can be measured with any type of humidity measurement device.

4-4.3 Recommended Humidity Measurement Devices

Relative humidity transmitters, wet and dry bulb psychrometers, and chilled-mirror dew point meters are the recommended humidity measurement devices. Economic, application, and uncertainty factors should be considered in the selection of the most appropriate humidity measurement device.

4-4.3.1 Relative Humidity Transmitters

4-4.3.1.1 Application. Relative humidity transmitters employ specifically selected hydrophilic materials. As the humidity changes at the ambient temperature, the material exchanges enough moisture to regain equilibrium, and corresponding measurable changes occur in the electrical resistance or capacitance of the device. Commercially available relative humidity transmitters use sensors with a wide variety of hygroscopic substances, including electrolytes and substantially insoluble materials. Relative humidity transmitters are commonly employed for the direct measurement of parameters such as relative humidity and dry bulb temperature and use a thin polymer film as the sensor to absorb water molecules. These instruments are often microprocessor based and from the parameters of relative humidity and dry bulb temperature, variables such as dew point temperature, absolute humidity, mixing ratio, wet bulb temperature, and enthalpy may be calculated. In cases where the instruments output moisture-indicating parameters or variables that are used in the calculation of the test results (primary parameter or primary variable), the instrument's internal calculation formulas and basis shall be verified to demonstrate compliance with the uncertainty requirements detailed in para. 4-4.2. Relative humidity transmitters typically provide accuracy specifications that include nonlinearity and repeatability over relative humidity (RH) conditions (i.e., ±2% RH from 0% to 90% RH and ±3% RH from 90% to 100% RH).

The application of relative humidity transmitters is highly sensitive to temperature equilibrium as a small difference between the measured object and sensor causes an error. This error is greatest when the sensor is colder or warmer than the surroundings and the humidity is high.

The sensor location should be selected so as to minimize sensor contamination. Air should circulate freely around the sensor. A rapid airflow is recommended as it ensures that the sensor and the surroundings are at temperature equilibrium. The installation orientation should be in accordance with the device manufacturer's specifications.

Measurement errors associated with hygrometers typically derive from the following primary sources:

(a) sensor contamination
(b) analog output
(c) installation location

(d) temperature fluctuation
(e) inaccurate calibration
(f) insufficient display resolution

4-4.3.1.2 Calibration. Relative humidity transmitters shall be calibrated using one of two methods. The first method involves calibrating against high-quality, certified humidity standards to achieve the maximum achievable accuracy. The second method calibrates with certified salt solutions that may include lithium chloride (LiCl), magnesium chloride ($MgCl_2$), sodium chloride (NaCl), and potassium sulfate (K_2SO_4). During calibration, the temperature of the sensor and that of the measured object shall be in equilibrium to minimize the error associated with the temperature equilibrium. Further, when using the second method, the equilibrium humidity of the salt solutions shall be corrected for the temperature of the solution using Greenspan's calibration corrections or equivalent.

Relative humidity transmitters shall be calibrated to meet the uncertainty requirements in specific humidity as described in para. 4-4.2. This shall be demonstrated with the application of an uncertainty analysis with consideration for the uncertainty associated with other measured parameters, including barometric pressure and ambient dry bulb or wet bulb temperature.

4-4.3.2 Wet and Dry Bulb Psychrometers

4-4.3.2.1 Application. The wet and dry bulb psychrometer consists of two temperature sensors and uses the temperature effects caused by latent heat exchange. One sensor measures the ambient dry bulb temperature; the other is covered with a clean wick or other absorbent material, which is wetted and the resulting evaporation cools it to the wet bulb temperature. Traditionally, the temperature sensors are resistance temperature detectors or thermistors, as discussed in paras. 4-3.3.2 and 4-3.3.3, respectively. The temperature sensors shall be shielded from solar and other sources of radiation and shall have a constant airflow across the sensing element.

Sling psychrometers are susceptible to the effects of radiation from the surroundings and other errors, such as those resulting from faulty capillary action. If using a sling psychrometer, it is important that the instrument is whirled for a sufficient number of times until the wet bulb temperature reaches a steady minimum value. Once this occurs, it is imperative that the temperature be read quickly with consideration for inertial effects on the temperature element in the case of a liquid-in-glass thermometer to minimize observation errors. The use of an average temperature from at least three observations is advisable.

Although not required, a mechanically aspirated psychrometer, as described in (a) through (e) below, is recommended. If a psychrometer is used, a wick should not be placed over the dry bulb temperature sensor (as is required for measurement of wet bulb temperature). If the air velocity across the sensing element is greater than 7.6 m/s (1,500 ft/min), shielding of the sensing element is required to minimize stagnation effects.

The thermodynamic wet bulb temperature is the air temperature that results when air is adiabatically cooled to saturation. Wet bulb temperature can be inferred by a properly designed mechanically aspirated psychrometer. The process by which a psychrometer operates is not adiabatic saturation, but one of simultaneous heat and mass transfer from the wet bulb sensing element. The resulting temperature achieved by a psychrometer is sufficiently close to the thermodynamic wet bulb temperature over most range of conditions. However, a psychrometer should not be used for temperatures below 5°C (40°F) or when the relative humidity is less than 15%. Within the allowable range of use, a properly designed psychrometer can provide a determination of wet bulb temperature with an uncertainty of approximately ±0.14°C (±0.25°F) (based on a temperature sensor uncertainty of ±0.08°C (±0.15°F).

The mechanically aspirated psychrometer should incorporate the following features:

(a) The sensing element is shielded from direct sunlight and any other surface that is at a temperature other than the dry bulb temperature. If the measurement is to be made in direct sunlight, the sensor shall be enclosed by a double-wall shield that permits the air to be drawn across the sensor and between the walls.

(b) The sensing element is suspended in the airstream and is not in contact with the shield walls.

(c) The sensing element is snugly covered by a clean, cotton wick that is kept wetted from a reservoir of distilled water. The length of the wick shall be sufficient to minimize the sensing element stem conduction effects and ensure it is properly wetted.

(d) The air velocity across the sensing element is maintained constant in the range of 240 m/min to 360 m/min (800 ft/min to 1,200 ft/min).

(e) Air is drawn across the sensing element in such a manner that it is not heated by the fan motor or other sources of heat. The psychrometer should be located at least 1.5 m (5 ft) above ground level and should not be located within 1.5 m (5 ft) of vegetation or surface water.

Measurement errors associated with wet and dry bulb psychrometers typically derive from the following primary sources:

– temperature sensor
– installation location
– radiation
– conduction

4-4.3.2.2 Calibration. The temperature sensors of wet and dry bulb psychrometers shall be calibrated in accordance with para. 4-3.4 and shall meet the uncertainty requirements in specific humidity as described in para. 4-4.2. This shall be demonstrated with the application of an uncertainty analysis with consideration for the uncertainty associated with other measured parameters, including barometric pressure.

4-4.3.3 Chilled-Mirror Dew Point Meters

4-4.3.3.1 Application. The dew point temperature is the temperature of moist air when it becomes saturated at the same ambient pressure. The dew point temperature may be measured with chilled-mirror dew point meters. The operation of these instruments is based on the establishment of the temperature corresponding to the onset of condensation. The meter determines the partial pressure of water vapor in a gas by directly measuring the dew point temperature of the gas. The temperature of the sensor surface or mirror is manually or automatically adjusted until condensation forms as dew or frost. The condensation is controlled at equilibrium, and the surface temperature is measured with a high-accuracy temperature device. Commercially available chilled-mirror dew point meters use a piezoelectric quartz element as the sensing surface. A surface acoustic wave is generated at one side of the quartz sensor and measured at the other. Chilled-mirror dew point meters require a sampling system to draw air from the sampling location across the chilled mirror at a controlled rate. Commercially available chilled-mirror dew point meters measure the dew point temperature with accuracy ranges of ±0.1°C to ±1°C (±0.2°F to ±2°F) over a dew point temperate range of −75°C to 60°C (−103°F to 140°F).

Measurement errors associated with chilled-mirror dew point meters typically derive from the following primary sources:

(a) sensor contamination
(b) analog output
(c) installation location
(d) inaccurate calibration
(e) insufficient display resolution

4-4.3.3.2 Calibration. Chilled-mirror dew point meters shall be calibrated to meet the uncertainty requirements in specific humidity as described in para. 4-4.2. This shall be demonstrated with the application of an uncertainty analysis, with consideration for the uncertainty associated with other measured parameters, including barometric pressure and ambient dry bulb temperature or wet bulb temperature.

4-5 FLOW MEASUREMENT

For information about flow-measuring devices, refer to the ASME MFC series for differential measuring devices (orifice plates, venturis, and nozzles) and ASME PTC 19.5 for all other flow measurements.

4-5.1 Water and Steam

4-5.1.1 Water Measurement Preferred. Water flows can be measured more accurately than steam flows. Whenever possible, it is best to configure the tests so that water flows are measured and used to calculate steam flows. The usual method of determining flow is with a mass (Coriolis) flowmeter or a differential pressure meter, using two independent differential pressure instruments.

4-5.1.2 Class 1 Measuring Devices. The flow section with a throat tap nozzle as described in ASME PTC 6 is recommended for the Class 1 primary flow measurements when the test Reynolds numbers are greater than the maximum calibrated Reynolds number.

4-5.1.3 Other Flow-Measuring Devices. Information relative to the construction, calibration, and installation of other flow-measuring devices appears in ASME PTC 19.5. These devices can be used for Class 2 flow measurements and for secondary flow measurements. They can also be used for Class 1 primary flow measurement when Reynolds number extrapolation is not required.

(a) Class 1 primary flow measurement requires calibration.

(b) For Class 2 primary and secondary flows, the appropriate reference coefficient for the actual device given in ASME PTC 19.5 may be used.

4-5.1.4 Water Flow Characteristics. Flow measurements shall not be undertaken unless the flow is steady or fluctuates only slightly with time. Fluctuations in the flow shall be suppressed before the beginning of a test by careful adjustment of flow and level controls or by introducing a combination of conductance, such as pump recirculation, and resistance, such as throttling the pump discharge, in the line between the pulsation sources and the flow-measuring device. Hydraulic damping devices on instruments do not eliminate errors due to pulsations and, therefore, should not be used.

In passing through the flow-measuring device, the water should not flash into steam. The minimum throat static pressure shall be higher than the saturation pressure corresponding to the temperature of the flowing water by at least 20% of the throat velocity head, to avoid cavitation.

4-5.1.5 Steam Flow Characteristics

(a) In passing through the flow-measuring device, the steam shall remain superheated. For steam lines with desuperheaters, the flow section should be installed ahead of desuperheaters and the total flow should be determined from the sum of steam flow and the desuperheater water flow.

(b) The calculation of steam flow through a nozzle, an orifice, or a venturi should be based on upstream conditions of pressure, temperature, and viscosity. To avoid the disturbing influence of a thermowell located upstream of a primary element, downstream measurements of pressure and temperature can be used to determine the enthalpy of the steam, which is assumed to be constant throughout a well-insulated flow measurement section. Based on this enthalpy and the upstream pressure, the desired upstream properties can be computed from the steam tables.

4-5.1.6 Enthalpy Drop Method for Steam Flow Determination. The enthalpy drop method may be used to determine steam flow but is applicable only to noncondensing or back-pressure turbines having a superheated exhaust. Separate generator tests shall be available from which electrical losses can be computed, or their design value shall be agreed upon. The parties to the test shall assign and agree upon values for the mechanical losses of the turbine. The steam flow is calculated from an energy balance based on measurements of pressure and temperature of all steam entering and leaving the turbine, including consideration of leak-offs, generator output, and the agreed-upon mechanical and electrical losses.

4-5.1.7 Additional Flow Measurements. There are instances when it is desirable to measure the flow rate of a two-phase mixture. ASME PTC 12.4 describes methods for measurement of two-phase flow.

4-5.2 Liquid Fuel

Liquid fuel flows shall be measured using flowmeters that are calibrated throughout their Reynolds number range expected during the test using the actual flow. For volume flowmeters, the temperature of the fuel also shall be accurately measured to correctly calculate the flow. Other flowmeters are permitted if a measurement error of 0.7% or less can be achieved.

Use of oil flowmeters is recommended without temperature compensation. The effects of temperature on fluid density can be accounted for by calculating the mass flow based on the specific gravity at the flowing temperature.

$$q_{mh} = \rho\,(60)\,q_v\,(sg)$$

where

60 = minutes per hour, min/hr
q_{mh} = mass flow, kg/h (lbm/hr)
q_v = volume flow, m^3/min (gpm)
sg = specific gravity at flowing temperature, dimensionless
ρ = density of water at 15.6°C (60°F)
= 998.99 kg/m^3 (8.34 lbm/gal)

Fuel analyses should be completed on samples taken during testing. The lower and higher heating value of the fuel and the specific gravity of the fuel should be determined from these fuel analyses. The specific gravity should be evaluated at three temperatures covering the range of temperatures measured during testing. The specific gravity at flowing temperatures should then be determined by interpolating between the measured values to the correct temperature.

4-5.3 Gas Fuel

Gas fuel flows may be measured using a number of devices that will not exceed a total uncertainty of 0.8%. The list includes orifices, turbines, and ultrasonic and mass (Coriolis-type) flowmeters. While some volumetric flow-measuring devices require a fuel analysis to determine density, a direct mass flowmeter will be able to respond faster to changes in gas fuel composition.

ASME PTC 19.5 details the calculation of the uncertainty of an orifice-metering run manufactured and installed correctly. The manufacturer requirement is to demonstrate that the meter was manufactured in accordance with the appropriate references, shown in para. 4-5.3.1.

Uncertainty of turbine meters is usually by statement of the manufacturer as calibrated in atmospheric air or water, with formulations for calculating the increased uncertainty when used in gas flow at higher temperatures and pressures. Sometimes, a turbine meter is calibrated in pressurized air. The turbine meter calibration report shall be examined to confirm the uncertainty as calibrated in the calibration medium.

4-5.3.1 Calculation of Gas Fuel Flow Using an Orifice. The requirements described in this paragraph are for calculation of gas fuel flow using measurements from a flange-tapped orifice meter. The orifice-metering run shall meet the straight-length requirements of ISO 5167-2, and the manufacturing and other installation requirements of ASME MFC-3M. These include circularity and diameter determination of orifice and pipe, pipe surface smoothness, orifice edge sharpness, plate and edge thickness, and other requirements detailed in ASME MFC-3M. The calculations shall be done in strict accordance with ASME MFC-3M.

4-5.3.2 Turbine Meters for Gas Fuel Flow Measurement. Use of turbine meters is one alternative to orifice gas flow measurement. The turbine meter measures actual volume flow. The turbine meter rotates a shaft connected to a display. Through a series of gears, the rotational shaft speed is adjusted so that the counter displays in actual volume units per unit time, e.g., cubic meters (cubic feet) per minute. This value shall be adjusted to mass flow units, e.g., kilograms (pounds) per hour.

$$q_{ms} = 60 q_v \rho_f$$

where

60 = minutes per hour, min/hr

q_{ms} = mass flow, kg/h (lb/hr)

q_v = actual volume flow, m^3/min (ft^3/min)

ρ_f = density at flowing conditions, kg/m^3 (lb/ft^3)

$$= \frac{p_f \, Mr_{\text{air}} \, sg_i}{Z_f \, R \, T_f}$$

where

Mr_{air} = molecular weight of standard air, 28.96 kg/kg mol (lb/lb mol)

p_f = pressure of gas, Pa (psia)

R = universal gas constant
= 8 314.46 (Pa-m^3)/(kg mol-K) [10.73 (psia-ft^3)/(lb mol-°R)]

sg_i = gas ideal specific gravity, dimensionless

T_f = absolute temperature of gas, K (°R)

Z_f = gas compressibility factor, dimensionless [developed from NIST Reference Fluid Thermodynamic and Transport Properties Database (REFPROP)]

4-6 PRIMARY HEAT INPUT MEASUREMENT

4-6.1 Consistent Solid Fuels

The composition of the syngas used in this Code depends on the consistency of the solid fuel entering the gasifier. Consistent solid fuels are defined as those with a heating value that varies less than 2.0% over the course of a performance test. It is therefore recommended during the performance test of the power island to maintain a consistent input of the design solid fuel.

4-6.2 Consistent Liquid or Gaseous Fuels

Consistent liquid or gaseous fuels are those with heating values that vary less than 1.0% over the course of a performance test. Since liquid and gas flows and heating values can be determined with high accuracy, the heat input from these type fuels is usually determined by direct measurement of fuel flow and the laboratory- or online-chromatograph-determined heating value. The heat input of consistent liquid or gaseous fuels can also be determined by calculation, as for solid fuels.

Homogenous gas and liquid fuel flows are usually measured directly for gas-turbine-based power plants.

Subsection 4-4 includes a discussion of the measurement of liquid and gaseous fuel flow. Should the direct method be used, the flow is multiplied by the heating value of the stream to obtain the facility heat input to the cycle. The heating value can be measured by an online chromatograph or by sampling the stream periodically (at least three samples per test) and analyzing each sample individually for heating value. The analysis of gas, either by online chromatography or from laboratory samples, in accordance with ASTM D1945 results in the amount and kind of gas constituents, from which heating value is calculated. Liquid fuel heating value may be determined by calorimeter in accordance with ASTM D4809.

4-6.3 Gaseous Fuel Sampling

The sampling point shall be located as close as possible to the test boundary, upstream of the metering section such that the gas sample represents the gas flowing through the flowmeter device. Also, the fuel sampling location shall be as far downstream as possible of all processes outside of the test boundary that may change the composition of the gas, such that the samples are a true representation of the fuel entering the flow section and/or crossing the test boundary.

The proper sampling of the gas fuel is important, since gas composition determines its density and heating values, the two most significant contributors in the calculation of the heat rate. It is therefore necessary to develop a test procedure describing a consistent method of sampling gas in the gas piping system. The specification should cover the collection, conditioning, and handling of representative samples of the fuel gas stream. ASME PTC 22 provides a sample of such procedure that addresses only spot sampling of dry natural gas, which does not contain heavy hydrocarbon components that may become liquid at room temperature. The procedure described herein is the purging — fill-and-empty — method due to its simplicity and minimal equipment requirement.

An alternative method is the use of online gas analyzers, which use gas chromatography for determining the gas composition on a discrete basis. The equipment usually includes several analyzers capable of identifying hydrocarbons up to C12 plus conventional analyzers for nitrogen (N_2), carbon dioxide (CO_2), sulfur, and moisture content. The rate of sampling may vary from 2 min to 15 min. The accuracy of the composition can achieve 1 ppm. Some more sophisticated systems offer processing units loaded with software packages capable of providing already calculated values for density, dew point, etc. The so-called process gas analyzers should be capable of operating in a rugged environment, providing continuous reliable operation, with relatively simple maintenance.

The methods described in ASTM D1945 should be used to analyze natural gas, and the methods described in ASTM D7833 should be used to analyze syngas.

A large number of samples taken by the online analyzers during a test may reduce the temporal measurement uncertainty associated with spot sampling. In addition, online analyzers eliminate the errors associated with human sampling techniques and the potential for mishaps during handling and shipping to laboratories.

The use of online analyzers for performance testing is suggested if proper calibration of the analyzer is conducted prior to the test. It is also recommended that an audit be conducted comparing the results of the online system with a laboratory analysis of samples taken at the same time as the performance test.

4-7 ELECTRICAL GENERATION MEASUREMENT

4-7.1 Introduction

This subsection presents requirements and guidance regarding the measurement of electrical generation. Power output should be measured by sufficient instrumentation to ensure that no additional uncertainty is introduced due to the metering method under all conditions of the test.

The scope of this subsection includes

(a) the measurement of polyphase (three-phase) alternating current (AC) real and reactive power output. Typically, the polyphase measurement will be net or overall plant generation, the direct measurement of generator output (gross generation), or power consumption of large plant auxiliary equipment (such as boiler feed pump drives).

(b) the measurement of direct current (DC) power output. Typically, the DC measurement will be on the generator side of any connections to the power circuit by which power can enter or leave the circuit and as close to the generator terminals as physically possible.

ANSI/IEEE Standard 120 is referenced for measurement requirements not included in this subsection or for any additionally required instruction.

4-7.2 Polyphase AC Electrical Measurement System Connections

The connection of the primary elements for measurement of polyphase AC power systems is subject to required uncertainty and the anticipated degree of unbalance between phases. Many different connections can be used for measuring polyphase AC; however, the connections covered in this Code are for three-wire- or four-wire-type systems and are recommended for meeting the uncertainty requirements of this Code.

The fundamental principle on which polyphase AC power measurement is based is Blondel's theorem. This theorem states that for a system of N conductors, the total power can be measured by $N - 1$ wattmeter elements. This is true for any condition of load unbalance. It is evident, then, that the electrical connections of the generator to the system govern the selection of the metering system. Hence, the minimum metering methods required for use on three-phase systems are as follows:

(a) for three-wire power systems: two single-phase meters or one two-phase meter

(b) for four-wire power systems: three single-phase meters or one three-phase meter

NOTE: These categories are for minimum metering requirements; three-wire power systems can also employ three single-phase meters or one three-phase meter.

Three- and four-wire power systems are defined by connections between the generator and transformers: wye–delta, delta–wye, wye–wye, or delta–delta. The type of connection and the site arrangement should be reviewed before deciding which power-metering system is suitable to a given measurement application. Paragraphs 4-7.2.1 and 4-7.2.2 describe each of these systems and how the measurements are made.

4-7.2.1 Three-Wire Power Systems. Various three-wire power systems are described below. See Fig. 4-7.2.1-1.

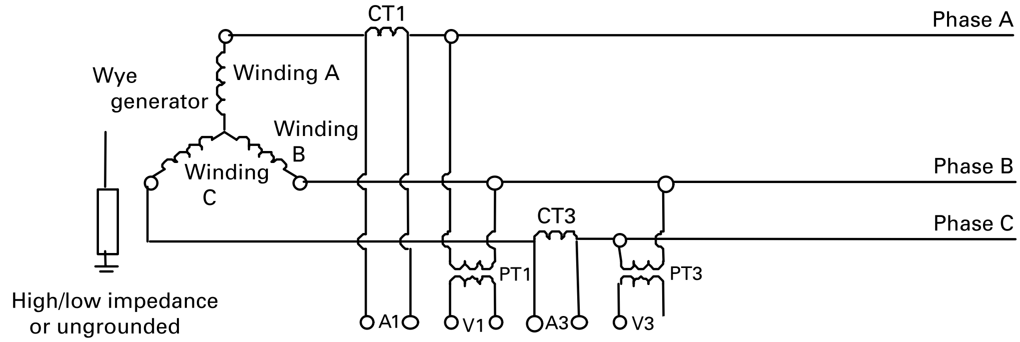
(a) Open Delta. The open delta–connected generator has no neutral or fourth wire available to facilitate a neutral conductor; hence, it can be connected only in a three-wire connection. The open delta-connected generator is common since it is associated with a higher level of reliability (if one winding fails open, the other two can still maintain full line voltages to the load).

(b) High-Impedance Grounded Wye. A common three-wire system is a wye-connected generator with a high-impedance neutral grounding device. The generator is connected directly to a transformer with a delta primary winding, and load distribution is made on the secondary, grounded-wye side of the transformer. Any load unbalance on the load distribution side of the generator transformer is seen as neutral current in the grounded-wye connection. On the generator side of the transformer, the neutral current is effectively filtered out due to the delta winding, and a neutral conductor is not required.

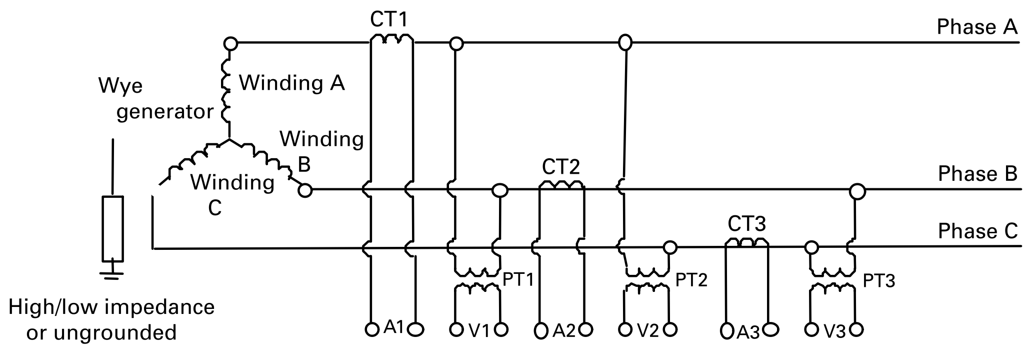
(c) Low-Impedance Grounded Wye. Another type of three-wire system utilizes a wye-connected generator with a low-impedance neutral grounding resistor. In this case, the generator is connected to a three-wire load distribution bus and the loads are connected either phase to phase, single phase, or three-phase delta. The grounding resistor is sized to carry 400 A to 2 000 A of fault current.

(d) Ungrounded Wye. A less common example of a three-wire system is an ungrounded wye generator used with a delta–wye grounded transformer. The ungrounded wye connector, in most cases, is not allowed under the National Electric Code (NFPA 70), since it is susceptible to impulses, ringing transients, and faults that cause high voltages to ground.

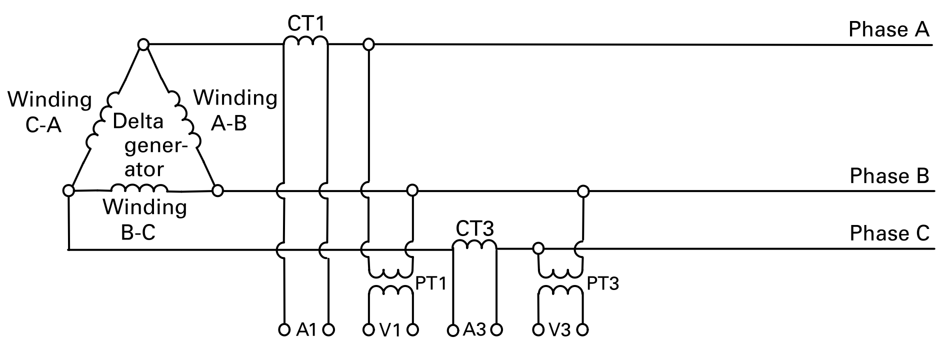
Fig. 4-7.2.1-1 Three-Wire Metering Systems



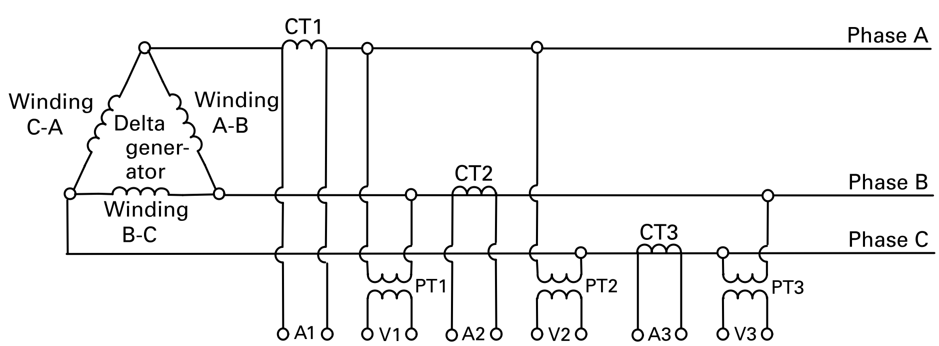
(a) Connections for Two Wattmeters or One Two-Element Watt-Hour Meter



(b) Connections for Three Wattmeters or One Three-Element Watt-Hour Meter

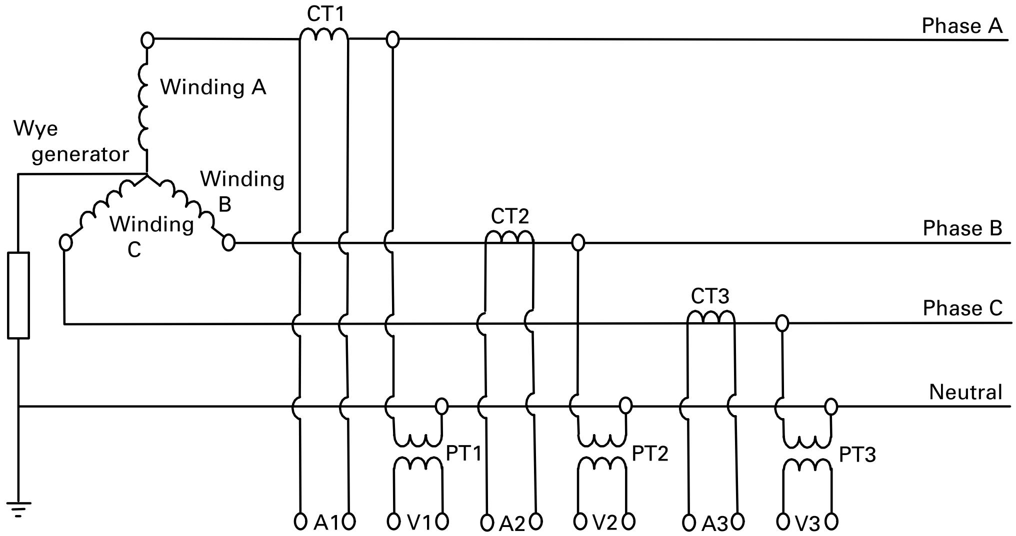


(c) Connections for Two Wattmeters or One Two-Element Watt-Hour Meter



(d) Connections for Three Wattmeters or One Three-Element Watt-Hour Meter

Fig. 4-7.2.2-1 Four-Wire Metering System



Connections for three wattmeters or one three-element watt-hour meter

Power of three-wire power systems can be measured using two open delta–connected potential transformers (PTs) and two current transformers (CTs). The open delta metering system is shown in Fig. 4-7.2.1-1. These instrument transformers are connected to two wattmeters, two watt-hour meters, or a two-element watt-hour meter. A var-type meter is the recommended method to measure reactive power to establish the power factor. Power factor, *PF*, is then determined as follows:

$$PF = \frac{\text{watts}_t}{\left[\text{watts}_t^{\,2} + \text{vars}_t^{\,2}\right]^{0.5}}$$

where

vars_t = total vars
watts_t = total watts

Alternatively, for balanced three-phase sinusoidal circuits, power factor, *PF*, may be calculated from the phase-to-phase power measurement, as follows:

$$PF = \frac{1}{\sqrt{\left(1 + 3\left[\frac{(\text{watts}_{1-2} - \text{watts}_{3-2})}{(\text{watts}_{1-2} + \text{watts}_{3-2})}\right]^2\right)}}$$

where

watts_{1-2} = real power phase 1 to 2
watts_{3-2} = real power phase 3 to 2

4-7.2.2 Four-Wire Power Systems. A typical four-wire power-metering system is shown in Fig. 4-7.2.2-1. There are two types of four-wire power systems, as follows:

(a) In the first type, generator output is desired from a wye-connected generator with a solid or impedance ground through which current can flow.

(b) In the second type, net plant generation is measured somewhere other than at the generator, such as at the high side of the step-up transformer. In this case, the neutral is simulated by a ground.

In addition, with the exception of the open delta generator connection, all of the three-wire systems described in para. 4-7.2.1 can also be measured using the four-wire measurement system described in this paragraph.

In a four-wire power system, power is measured using three PTs and three CTs, as shown in Fig. 4-7.2.2-1. These instrument transformers are connected to three wattmeters or var meters, three watt-hour or var-hour meters, or a three-element watt-hour or var-hour meter. The var meters are necessary to establish the power factor, *PF*, as follows:

$$PF = \frac{\text{watts}_t}{\sqrt{\text{watts}_t^{\,2} + \text{vars}_t^{\,2}}}$$

where

vars_t = total vars for three phases
watts_t = total watts for three phases

Alternatively, power factor, *PF*, may be determined by measuring each phase current and voltage, with the following equation:

$$PF = \frac{\text{watts}_t}{\sum V_i I_i}$$

where

I_i = phase current for each of the three phases
V_i = phase voltage for each of the three phases

4-7.3 Electrical-Metering Equipment

There are four types of electrical-metering equipment that may be used to measure electrical energy:

wattmeters, watt-hour meters, var meters, and var-hour meters. Single or polyphase metering equipment may be used. However, if polyphase equipment is used, the output from each phase shall be available or the meter shall be calibrated three phase.

4-7.3.1 Wattmeters. Wattmeters measure instantaneous active power. The instantaneous active power shall be measured frequently during a test run and averaged over the test run period to determine average power (kilowatts) during the test. Should the total active electrical energy (kilowatt-hours) be desired, the average power shall be multiplied by the test duration in hours.

Wattmeters measuring a Class 1 primary variable such as net or gross active generation shall have an accuracy equal to or less than 0.2% of reading. Metering with an uncertainty equal to or less than 0.5% of reading may be used for the measurement of Class 2 primary variables. There is no metering accuracy requirement for measurement of secondary variables. The output from the wattmeters shall be sampled with a frequency high enough to attain an acceptable precision. This is a function of the variation of the power measured. A general guideline is a frequency of not less than once per minute.

4-7.3.2 Watt-Hour Meters. Watt-hour meters measure active energy (kilowatt-hours) during a test period. The measurement of watt-hours shall be divided by the test duration in hours to determine average active power (kilowatts) during the test period.

Watt-hour meters measuring a Class 1 primary variable such as net or gross active generation shall have an uncertainty equal to or less than 0.2% of reading. Metering with an uncertainty equal to or less than 0.5% of reading may be used for measurement of Class 2 primary variables. There are no metering accuracy requirements for measurement of secondary variables.

The resolution of watt-hour meter output is often so low that high inaccuracies can occur over a typical test period. Often watt-hour meters have an analog or digital output with a higher resolution that may be used to increase the resolution. Some watt-hour meters also have a pulse-type output that may be summed over time to determine an accurate total energy during the test period. For disk-type watt-hour meters with no external output, the disk revolutions can be counted during a test to increase resolution.

4-7.3.3 Var Meters. Var meters measure instantaneous reactive power. The var measurements are typically used on four-wire systems to calculate power factor, as discussed in para. 4-7.2.2. The instantaneous reactive power shall be measured frequently during a test run and averaged over the test run period to determine average reactive power (kilovars) during the test. Should the total reactive electrical energy (kilovar-hours) be desired, the average power shall be multiplied by the test duration in hours.

Var meters measuring a Class 1 or Class 2 primary variable shall have an uncertainty equal to or less than 0.5% of reading. There is no metering accuracy requirement for measurement of secondary variables. The output from the var meters shall be sampled with a frequency high enough to attain an acceptable precision. This is a function of the variation of the power measured. A general guideline is a frequency of not less than once per minute.

4-7.3.4 Var-Hour Meters. Var-hour meters measure reactive energy (kilovar-hours) during a test period. The measurement of var-hours shall be divided by the test duration in hours to determine average active power (kilovars) during the test period.

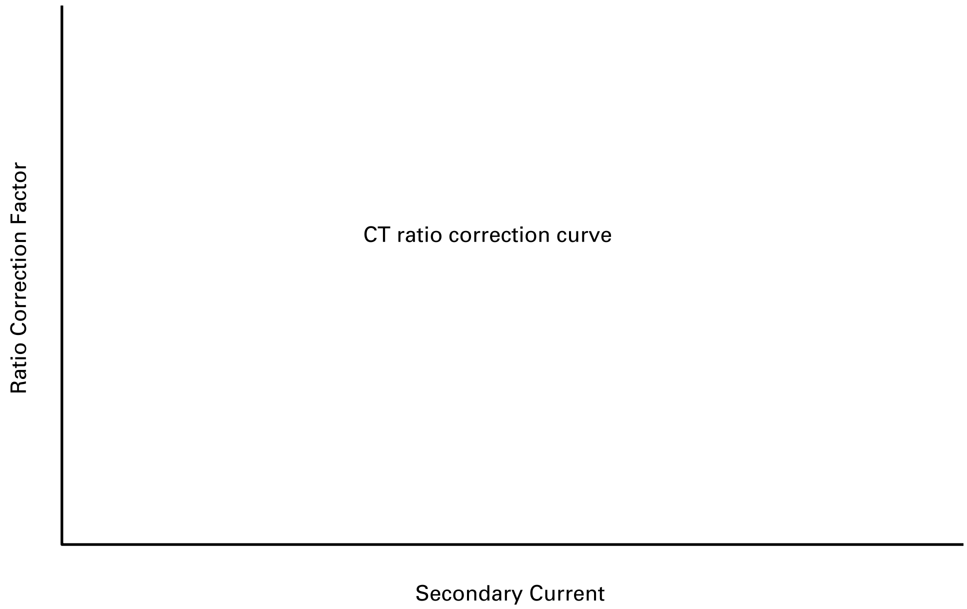
Var-hour meters measuring a Class 1 or Class 2 primary variable shall have an uncertainty equal to or less than 0.5% of reading. There is no metering accuracy requirement for measurement of secondary variables.

The resolution of var-hour meter output is often so low that high inaccuracies can occur over a typical test period. Often var-hour meters have an analog or digital output with a higher resolution that may be used to increase the resolution. Some var-hour meters also have a pulse-type output that may be summed over time to determine an accurate total energy during the test period. For disk-type var-hour meters with no external output, the disk revolutions can be counted during a test to increase resolution.

4-7.3.5 Wattmeter and Watt-Hour Meter Calibration. Wattmeters and watt-hour meters, collectively referred to as power meters, are calibrated by applying power through the test power meter and a wattmeter or watt-hour meter standard simultaneously. This comparison should be conducted at several power levels (at least five) across the expected power range. The difference between the test and standard instruments for each power level should be calculated and applied to the power measurement data from the test. For test points between the calibration power levels, a curve fit or linear interpolation should be used. The selected power levels should be approached in an increasing and decreasing manner. The calibration data at each power level should be averaged to minimize any hysteresis effect. Should polyphase metering equipment be used, the output of each phase shall be available or the meter shall be calibrated with all three phases simultaneously.

When calibrating watt-hour meters, the output from the wattmeter standard should be measured with frequency high enough to reduce the precision error during calibration so the total uncertainty of the calibration process meets the required level. The average output can

Fig. 4-7.4.1-1 Typical Correction Curve



be multiplied by the calibration time interval to compare against the watt-hour meter output.

Wattmeters should be calibrated at the electrical line frequency of the equipment under test, i.e., do not calibrate meters at 60 Hz and use them on 50-Hz equipment.

Wattmeter standards should be allowed to have power flow through them prior to calibration to ensure the device is adequately "warm." The standard should be checked for zero reading each day prior to calibration.

4-7.3.6 Var Meter and Var-Hour Meter Calibration. To calibrate a var meter or var-hour meter, one shall have either a var standard or a wattmeter standard and an accurate phase-angle measuring device. Also, the device used to supply power through the standard and test instruments shall have the capability of shifting phase to create several different stable power factors. These different power factors create reactive power over the calibration range of the instrument.

Should a var meter standard be employed, the procedure for calibration of wattmeters outlined in para. 4-7.3.5 should be used. Should a wattmeter standard and phase-angle meter be used, simultaneous measurements from the standard, phase-angle meter, and test instrument should be taken. The var level shall be calculated from the average watts and the average phase angle.

Wattmeters should be calibrated at the electrical line frequency of the equipment under test, i.e., do not calibrate meters at 60 Hz and use them on 50-Hz equipment.

When calibrating var-hour meters, the output from the var meter standard or wattmeter/phase-angle meter combination should be measured with frequency high enough to reduce the precision error during calibration so the total uncertainty of the calibration process meets the required level. The average output can be multiplied by the calibration time interval to compare against the watt-hour meter output.

Should polyphase metering equipment be used, the output of each phase shall be available or the meter shall be calibrated with all three phases simultaneously.

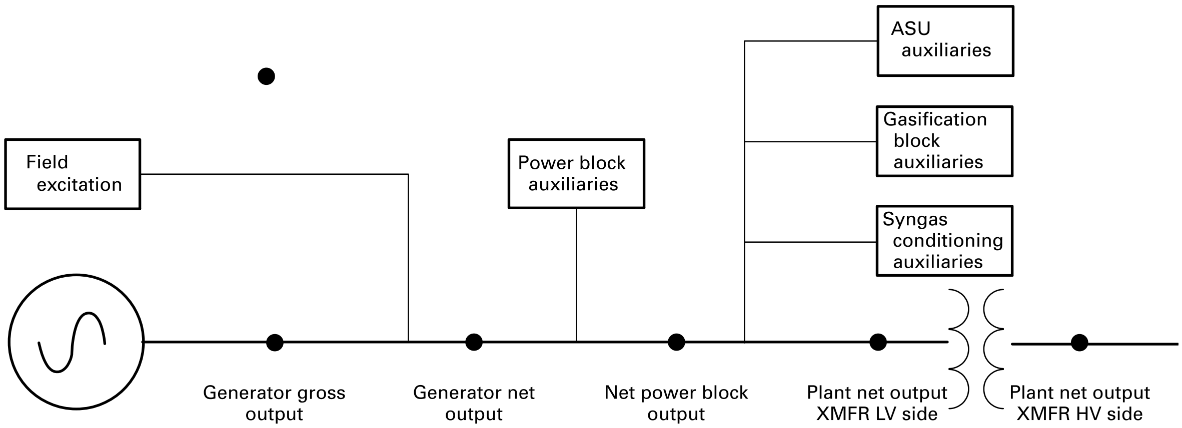
4-7.4 Instrument Transformers

Instrument transformers include potential transformers and current transformers. The potential transformers measure voltage from a conductor to a reference, and the current transformers measure current in a conductor.

4-7.4.1 Potential Transformers. Potential transformers measure either phase-to-phase voltage or phase-to-neutral voltage. The potential transformers serve to convert the line or primary voltage (typically high in voltage) to a lower or secondary voltage safe for metering (typically 120 V for phase-to-phase systems and 69 V for phase-to neutral-systems). For this reason, the secondary voltage measured by the potential transformer shall be multiplied by a turns ratio to calculate the primary voltage. See Fig. 4-7.4.1-1.

Potential transformers are available in several metering accuracy classes. For the measurement of Class 1 or Class 2 primary variables or secondary variables, potential transformers in the 0.3% accuracy class shall be used. In the case of Class 1 primary variable measurement, potential transformers shall be calibrated for turns ratio and phase angle and operated within their rated burden range.

Fig. 4-7.6-1 Typical Auxiliary Loads



GENERAL NOTE: XMFR LV = transformer, low voltage; XMFR HV = transformer, high voltage.

4-7.4.2 Current Transformers. Current transformers measure current in a given phase. Current transformers serve to convert line or primary current (typically high) to lower or secondary metering current. For this reason, the secondary current measured by the current transformer shall be multiplied by a turns ratio to calculate the primary current.

Current transformers are available in several metering accuracy classes. For the measurement of Class 1 or Class 2 primary variables or secondary variables, potential transformers in the 0.3% accuracy class shall be used. In the case of Class 1 primary variable measurement, current transformers shall be calibrated for turns ratio and phase angle and operated within their rated burden range.

4-7.5 Calculation of Corrected Average Power or Corrected Total Energy

The calculation method for average power or total energy should be performed in accordance with ANSI/IEEE Standard 120 for the specific type of measuring system used. For Class 1 primary variables, power measurements shall be corrected for actual instrument transformer ratio and for phase-angle errors in accordance with the procedures of ANSI/IEEE Standard 120.

4-7.6 Measurement of Auxiliary Electrical Load

A separate transformer and associated load metering may be available to measure the power block auxiliary loads, such as those depicted in Fig. 4-7.6-1.

The methods described in ASME PTC 47, subsection 4-9 are also applicable for determining the auxiliary power calculation.

Station permanent instrumentation can be used for measuring the electrical load to the gasification block, where the electrical load is measured and displayed either as active power or as voltage and current. If real power (kilowatts) is not measured, the auxiliary power is calculated as described in Section 5.

4-7.7 Measurement of Step-Up and Step-Down Transformers

The transformer losses of step-up and step-down transformers may be required for a test or a test correction. Since the power loss for a step-up or step-down transformer is difficult to measure in the field, it may be necessary to use the results of the transformer's factory performance tests. Normally the factory tests for determining the power loss are conducted at 0% and 100% rated load of the transformer and at various voltages. To calculate the transformer power loss, the measurements of the voltage and current at the high side of the transformer shall be recorded. The calculations are described in Section 5.

4-8 DATA COLLECTION AND HANDLING

4-8.1 Introduction

This subsection presents requirements and guidance regarding the acquisition and handling of test data. Also presented are the fundamental elements that are essential to the makeup of an overall data acquisition and handling system.

This Code recognizes that technologies and methods in data acquisition and handling will continue to change and improve over time. If new technologies and methods becomes available and are shown to meet the required standards stated within this Code, they may be used.

4-8.1.1 Data Acquisition System. The purpose of a data acquisition system is to collect data and store it in a form suitable for processing or presentation. Systems may be as simple as a person manually recording data to as complex as a digital computer-based system. Regardless of the complexity of the system, a data acquisition system shall be capable of recording, sampling, and storing the data within the requirements of the test and target uncertainty set by this Code.

4-8.1.2 Manual System. In some cases, it may be necessary or advantageous to record data manually. It should be recognized that this type of system introduces additional uncertainty in the form of human error, and such uncertainty should be accounted for accordingly. Further, due to their limited sampling rate, manual systems may require longer periods of time or additional personnel for a sufficient number of samples to be taken. Test period duration should be selected with this in mind, allowing for enough time to gather the number of samples required by the test. Data collection sheets should be prepared prior to the test. The data collection sheets should identify the test site location, date, time, and type of data collected, and should delineate the sampling time required for the measurements. Sampling times should be clocked using a digital stopwatch or other sufficient timing device. If it becomes necessary to edit data sheets during the testing, all edits shall be made using black ink, and all errors shall be marked through with a single line and initialed and dated by the editor.

4-8.2 Data Management

4-8.2.1 Data Collected With an Automated System. All data collected using an automated data acquisition system should be recorded in its uncorrected, uncalculated state on both permanent and removable media to permit post-test application of any necessary calibration corrections. Immediately after test and prior to leaving the test site, the data should be copied to a removable medium and distributed among the parties to the test to prevent such data being accidentally lost, damaged, or modified. Similar steps should be taken with any corrected or calculated results from the test.

4-8.2.2 Manually Collected Data. All manually collected data recorded on data collection sheets shall be reviewed for completeness and correctness. Immediately after test and prior to leaving the test site, photocopies of the data collection sheets should be made and distributed among the parties to the test to prevent such data being accidentally lost, damaged, or modified. If photocopying is not available, manual replication of the data collection sheets should be made and the replicated data collection sheets should be clearly marked as a replication and signed off by the parties to the test.

4-8.2.3 Data Calculation System. The data calculation system should have the capability to average each input collected during the test and to calculate the test results based on the average values. The system should also calculate standard deviation and coefficient of variance of each instrument. The system should have the ability to locate spurious data and exclude it from the calculation of the average. The system should also have the ability to plot the test data and each instrument reading over time to look for trends and outlying data.

4-8.3 Data Acquisition System Selection

4-8.3.1 Data Acquisition System Requirements. Prior to selection of a data acquisition system, it is necessary to have the test procedure in place that dictates the requirements of the system. The test procedure should clearly dictate the type of measurements to be made, number of data points needed, the length of the test, the number of samples required, and the frequency of data collection to meet the target test uncertainty set by this Code. This information shall serve as a guide in the selection of equipment and system design.

Each measurement loop shall be designed with the ability to be loop calibrated and to be checked for continuity and power supply problems. To prevent signal degradation due to noise, each instrument cable should be designed with a shield around the conductor, and the shield should be grounded on one end to drain any stray induced currents.

4-8.3.2 Temporary Automated Data Acquisition System. This Code encourages the use of temporary automated data acquisition systems for testing purposes. These systems can be carefully calibrated and their proper operation confirmed in the laboratory and then transported to the testing area, thus providing traceability and control of the complete system. Temporary systems limit the instruments' exposure to the elements and avoid the problems associated with construction and ordinary plant maintenance.

Site layout and ambient conditions shall be considered when determining the type and application of temporary systems. Instruments and cabling shall be selected to withstand or minimize the impact of any stresses, interference, or ambient conditions to which they may be exposed.

4-8.3.3 Existing Plant Measurement and Control System. This Code does not prohibit the use of the plant measurement and control system for Code testing. However, the system shall meet the requirements set forth in this Code. Further, users should recognize the limitations and restrictions of these systems for performance testing, including the following:

(a) Most distributed plant control systems apply threshold or deadband restraints on data signals. This results in data that is only the report of the change in a parameter that exceeds a set threshold value. All threshold values shall be set low enough so that all data signals sent to the distributed control system during a test are reported and stored.

(b) Most plant systems do not calculate flow rates in accordance with this Code, but rather by simplified relationships. This includes, for example, constant discharge coefficient or even expansion factor. A plant system indication of flow rate is not to be used in the execution of this Code, unless the fundamental input parameters are also logged and the calculated flow is confirmed to be in accordance with this Code and ASME PTC 19.5.

Section 5
Calculations and Results

5-1 INTRODUCTION

Most energy streams within a power block of an IGCC system contain thermal energy, or sensible heat, and chemical energy, or heating value. To properly specify thermal–chemical properties of an energy stream in the power plant, enthalpy used in this Code is defined as the sum of thermodynamic enthalpy (product of constant-pressure specific heat and absolute temperature) and heat of formation. This definition avoids inconsistency of energy calculation for different type of flows, and unifies mass-energy balance calculations between the subsections and systems.

The major objective of a performance test for a power plant is to determine the effectiveness of energy conversion and utilization. Heat rate, defined as the ratio of fuel heat input to net power output, has been traditionally used in a power generation system in which fuel heat is the only energy input and electricity is the only energy output.

The test boundaries for the power block are shown in Fig. 3-2.2-1. The input and output streams across the test boundaries are listed in Table 5-1-1.

Selected properties of these streams shall be measured separately as described in this Section to evaluate the performance of an IGCC power block. The power block primary and secondary fuel input streams are energy inputs into the IGCC power block test boundary, net power is the energy output, and the remaining stream measurements are used to determine correction factors.

Table 5-1-1 IGCC Power Block Input and Output Streams

Input Streams	Output Streams
Power block primary fuel	Net power
Power block secondary fuel	Export steam
Input steam (multiple)	Output steam (multiple)
Input water (multiple)	Output water (multiple)
Input nitrogen	Extraction air
Ambient air	Auxiliary power
Makeup water	
Cooling water/air	

5-2 DATA REDUCTION

Following each test, when all test logs and records have been completed and assembled, they should be examined critically to determine whether or not the limits of permissible deviations from specified operating conditions have exceeded those prescribed by the individual test code. Adjustments of any kind should be agreed upon and explained in the test report. If adjustments cannot be agreed upon, the test run(s) may have to be repeated. Inconsistencies in the test record or test result may require tests to be repeated in whole or in part to attain test objectives. Corrections resulting from deviations of any of the test operating conditions from those specified are applied when computing test results.

5-3 FUNDAMENTAL EQUATIONS

5-3.1 Corrected Net Power, P_{corr}

$$P_{\text{corr}} = (P_{\text{meas}} + \Sigma\, AP_i)\, \Pi\, MP_j,\ i = 1, n;\ j = 1, m \qquad \text{(5-3-1)}$$

where

AP_i = additive correction factors for power generation

MP_j = multiplicative correction factors for power generation

P_{meas} = measured total net power flows from individual generators out of the IGCC power block test boundary during the test, as determined in eq. (5-5-1)

5-3.2 Corrected Power Block Primary Fuel Input, $Q_{pf,corr}$

$$Q_{pf,\text{corr}} = (Q_{pf} + \Sigma\, AQ_{fi})\, \Pi\, MQ_{fj},\ i = 1, n;\ j = 1, m \qquad \text{(5-3-2)}$$

where

AQ_{fi} = additive correction factors for the primary fuel input

MQ_{fj} = multiplicative correction factors for the primary fuel input

Q_{pf} = measured total energy containing in the primary fuel flows entering into the power block during the test, as determined in eq. (5-5-3)

5-3.3 Power Block Heat Rate, HR_{corr}

As defined in ASME PTC 46, heat rate has been traditionally used to characterize effectiveness of energy conversion in a power generation system. Power block heat rate is defined as corrected primary fuel input divided by corrected net power.

$$HR_{corr} = Q_{pf,corr} / P_{corr} \tag{5-3-3}$$

or

$$= [(Q_{pf} + \Sigma\, AQf_i) / (P_{meas} + \Sigma\, AP_i)]\, \Pi\, MHR_j,\ i = 1, n;\ j = 1, m \tag{5-3-4}$$

where

MHR_j = multiplicative correction factors for heat rate

5-4 CORRECTION FACTORS

If the test is a specified unit disposition test, the goal of the test is to operate the facility based on a particular condition, such as gas turbines operating at base load. This Code does not preclude using duct burner operation. If duct burners are used, the duct burners are fired to a specific heat input. The correction factors are applied to determine the corrected net plant output and the corrected net plant heat rate at basis conditions. Both output and heat rate are corrected to the reference conditions and compared with the test criteria.

If the test is a specified net power test, the goal of the test is to operate the plant at a specified net (or measured) plant output. The correction factors are applied to determine the corrected plant heat rate. Because it is difficult to exactly match the net plant output under test conditions, a correction, X, shall be applied to adjust for the small difference between actual adjusted net power and desired net power. The corrected heat rate is compared with the plant criteria.

$$P_{corr} = P_{ref} = P_{meas} + X_{PWR} \tag{5-4-1}$$

$$HR_{corr} = (Q_{pf} + X_{HR}) / P_{corr} \tag{5-4-2}$$

The correction, X, may be determined from a plant computational model or by performing several test runs at different load points to determine the relationship between the corrected net power and the corrected net heat rate.

Streams crossing the test boundary should be measured, and their deviations from design values should be used as the basis for corrections to calculate the test results. Two types of correction factors are applicable to the measured parameters in eqs. (5-3-1) through (5-3-4): additive correction factors and multiplicative correction factors. Their symbols are expressed in Table 5-4-1.

Additive correction factors are applied to bring the performance of the decoupled subsystems of the plant to the common base reference conditions, and then the multiplicative correction factors are applied to correct for the conditions that impact the entire plant: inlet temperature, barometric pressure, relative humidity, fuel conditions and properties, and grid frequency.

Table 5-4-1 Test Correction Factors for IGCC Power Block

Parameters	Additive Correction Factors	Multiplicative Correction Factors
Net power	AP	MP
Fuel input	AQ_f	MQ_f
Heat rate	...	MHR

5-4.1 Additive Correction Factors

There are 14 additive correction factors used in the fundamental performance equations, as summarized in Table 5-4.1-1.

The additive correction factors that are not applicable to the measured results for the specific type of plant being tested, or to the test objectives, are simply set equal to zero.

5-4.2 Multiplicative Correction Factors

There 13 multiplicative correction factors used in the fundamental performance equations, as summarized in Table 5-4.2-1. The composition of the nitrogen stream has a minimal effect on thermal performance, but residual oxygen in the nitrogen stream should not exceed the maximum level specified by the equipment supplier.

The multiplicative correction factors that are not applicable to the measured results for the specific type of plant being tested, or to the test objectives, are simply set equal to unity. The fundamental performance equations can be simplified to be specific to the particular plant and test program objectives.

The format of the fundamental equations allows decoupling of the appropriate correction effects relative to the measured parameters, so that measured performance can be corrected to the reference conditions. Corrections are calculated for parameters at the test boundary that differ from base reference conditions and that affect measured performance results.

Correction curves applied to measured performance are calculated by a heat balance model of the thermal systems contained within the test boundary of the IGCC power block. Each correction factor is calculated by running the heat balance model with a variance in only the parameter to be corrected for over the possible range of deviation from the reference conditions. Correction curves thus developed are incorporated into the specific test procedure document.

This Code permits the parties to the test to utilize a heat balance computer program with the appropriate test data input following a test run, so that the corrected performance can be calculated from data with only one heat balance run necessary.

Table 5-4.1-1 Additive Correction Factors

Number	Net Power	Fuel Input	Parameter
1	AP_1	[Note (1)]	Secondary fuel (duct burner) thermal input (flow × LHV)
2	AP_2	[Note (1)]	Generator(s) power factors
3	AP_3	AQ_{f3}	Steam generator blowdown different than design
4	AP_4	AQ_{f4}	Import steam flow rate and enthalpy
5	AP_5	AQ_{f5}	Import water flow rate and enthalpy
6	AP_6	AQ_{f6}	Heat energy from input water/makeup water streams
7	AP_7	AQ_{f7}	Export water flow rate and enthalpy
8	AP_8	AQ_{f8}	Export steam flow rate and enthalpy
9a	AP_{9a}	AQ_{f9a}	Ambient conditions (temperature and humidity) at cooling tower or air-cooled condenser different than ambient conditions at the gas turbine inlet
9b1	AP_{9b1}	AQ_{f9b1}	Circulating water flow different than design for once-through condenser cooling system (when cooling tower or air-cooled condenser is outside the test boundary)
9b2	AP_{9b2}	AQ_{f9b2}	Circulating water temperature different than design for once-through condenser cooling system (when cooling tower or air-cooled condenser is outside the test boundary)
9c	AP_{9c}	AQ_{f9c}	Condenser pressure (when the entire heat rejection system is outside the test boundary)
10	AP_{10}	AQ_{f10}	Condensate water temperature
11	AP_{11}	AQ_{f11}	Measured power different than predetermined or required power

NOTE:
(1) These correction factors are not applicable and have been set equal to zero.

5-4.3 Functional Requirements of the Power Block Model

The main functional requirements of the power block model are completeness, flexibility, and accuracy.

5-4.3.1 Completeness. The model shall be able to predict changes in the power block performance in response to changes in the test boundary conditions. These include ambient conditions such as temperature, pressure, and humidity; fuel composition; process steam and water flow conditions; and secondary thermal and electrical inputs and outputs.

Table 5-4.2-1 Multiplicative Correction Factors

Number	Net Power	Fuel Input	Heat Rate	Parameter
1	MP_1	MQ_{f1}	MHR_1	Ambient temperature
2	MP_2	MQ_{f2}	MHR_2	Ambient pressure
3	MP_3	MQ_{f3}	MHR_3	Ambient humidity
4	MP_4	MQ_{f4}	MHR_4	Primary fuel supply temperature
5	MP_5	MQ_{f5}	MHR_5	Primary fuel composition
6	MP_6	MQ_{f6}	MHR_6	Secondary fuel (to gas turbine) flow rate
7	MP_7	MQ_{f7}	MHR_7	Secondary fuel (to gas turbine) supply temperature
8	MP_8	MQ_{f8}	MHR_8	Secondary fuel (to gas turbine) composition
9	MP_9	MQ_{f9}	MHR_9	Export air extraction flow rate
10	MP_{10}	MQ_{f10}	MHR_{10}	Export air extraction temperature
11	MP_{11}	MQ_{f11}	MHR_{11}	Import nitrogen flow rate
12	MP_{12}	MQ_{f12}	MHR_{12}	Import nitrogen temperature
13	MP_{13}	MQ_{f13}	MHR_{13}	Grid frequency

5-4.3.2 Flexibility. The normal range of the model is expected to be at base load with the expected variation ambient conditions and the expected variation of streams that cross the test boundary. Inputs to and outputs from the model should include the measured terms listed in Table 5-1-1.

5-4.3.3 Accuracy. The methods and calculations used to develop the power block plant model, including property methods, convergence techniques, and engineering models, shall be of sufficient accuracy to satisfy the needs of the acceptance test. For the primary purpose of correcting plant performance to reference conditions, consistency and relative accuracy of the calculations are more important than absolute accuracy, meaning that the ability to accurately predict changes in performance due to a change, Δ, in a test boundary condition is more important than matching the actual plant output or heat consumption at a given set of conditions. The final results should be accurate enough to meet the uncertainty levels defined in Table 1-3-1.

5-4.3.4 Model Validation. Model validation is desirable, but the proprietary nature of comprehensive plant models may preclude complete validation. Normally the uncertainties of correction factors, curves, and models cannot be ascertained because of the proprietary nature of such information. This aspect of uncertainty has not been included in Table 1-3-1.

The basic power block model is based on equipment supplier data and expected performance over a range of conditions. The individual component performance used in the comprehensive plant model shall be verified to match the equipment supplier's expected performance for the component. If the equipment supplier supplies performance curves or data, the model should be adjusted to allow comparison of the plant model predicted performance against the equipment supplier curve or data. The comparison should be made at the rating point and the extremes of the equipment supplier predicted performance.

The limit of the model's use and accuracy is restricted to the limit of the components used as an input to the plant model.

5-4.3.4.1 Comparison With Measured Data. As much as practicable prior to the test, the model results should be compared with measured data from the plant. This comparison allows model refinement and tuning to match the actual operation of the plant as closely as possible.

Where possible, selected plant boundary parameters should be adjusted so that change in the model's calculated dependent variables match the change in the measured plant values. The parties to the test should agree to such adjustments. The agreement should be included in the test plan. Adjustable model parameters should be limited to equipment characteristics, such as turbine efficiency, heat exchanger heat-transfer coefficients, and correlation coefficients that affect the model outputs over a range of conditions in the same way as at test conditions. Directly measured variables should not be adjusted.

5-4.3.4.2 Extremes and End Points. Ideally, the test will be conducted at the reference conditions to minimize the amount and size of corrections to the measured performance. If the model is used for test corrections, the model will in effect be interpolating within the valid range of the model rather than extrapolating beyond it.

5-4.3.4.3 Limits. It is important during the development, testing, and tuning of the power block model to identify the limits of the model, that is, those operating regions where the accuracy of the model is reduced or is unacceptable for the purposes of testing. The model cannot be used for testing plant operation beyond the validated limits.

5-5 MEASURED PARAMETERS IN THE FUNDAMENTAL EQUATIONS

5-5.1 Measured Net Power for IGCC Power Block, P_{meas}

Measured net power, P_{meas}, in eq. (5-3-1) for an IGCC power block plant with multiple prime generators is expressed as

$$P_{meas} = [\Sigma P_{meas,\, n\, =\, 1,\, k}]_{generator} - P_{aux} - P_{tranf.\ loss} - P_{line\ loss} \tag{5-5-1}$$

where

k = total number of generators
n = an individual generator
P_{aux} = total auxiliary power consumption
$P_{line\ loss}$ = line power loss
$P_{tranf.\ loss}$ = transformer power loss
$[P_{meas}]_{generator}$ = power generation

5-5.2 Measured Steam Export, Q_{st}

Net thermal heat output contained in steam streams from the power block is expressed as

$$Q_{st} = \Sigma[(M_{st,n})(h_{st,n})]_{ex} \tag{5-5-2}$$

where

h_{st} = steam enthalpy calculated based on measured steam pressure and temperature
M_{st} = steam flow rate directly measured
n = an individual steam stream

5-5.3 Measured Power Block Primary Fuel Input, Q_{pf}

Thermal heat input from primary fuel(s) to the power block is expressed as

$$Q_{pf} = \Sigma[(HV_{pf,n})(M_{pf,n})] \tag{5-5-3}$$

where

HV_{pf} = heating value of primary fuel
M_{pf} = mass flow rate of primary fuel
n = an individual fuel input to the power block

5-5.4 Measured Input Steam, Q_{est}

Thermal heat input from external steam to the power block is expressed as

$$Q_{est} = \Sigma[(M_{st,n})(h_{st,n})]_{in} \tag{5-5-4}$$

where

n = an individual steam input to the power block

5-5.5 Power Block Secondary Fuel Input, Q_{sf}

Thermal heat input from secondary fuel(s) that can be directly measured in the power plant is expressed as

$$Q_{sf} = \Sigma[(HV_{sf,n})(M_{sf,n})] \quad (5\text{-}5\text{-}5)$$

where

HV_{sf} = heating value of secondary fuel
M_{sf} = mass flow rate of secondary fuel
n = an individual fuel input to the power block

5-5.6 Auxiliary Electrical Load

If real power (kilowatt) auxiliary load is not measured, the auxiliary power, Aux (in kilowatts), is calculated by the following equation and inputs:

$$\text{Aux} = \frac{\sqrt{3} \times V \times I \times PF}{1\,000} \quad (5\text{-}5\text{-}6)$$

where

$\sqrt{3}$ = accounts for phase-to-phase voltage, assuming three-phase power
I = average RMS phase current, A
PF = power factor (as a decimal)
V = average phase-to-phase voltage, V

When power metering is not available, individual input power to an electric load can be estimated by making RMS voltage and current measurements. The measurements can be made with handheld instruments such as clamp-on ammeters and multimeters, and a power factor meter, if available.

NOTE: Do not attempt to make direct voltage measurements above 600 V RMS. If the motor supply voltage is higher, a voltage transformer will be required.

The three-phase input power, P_t (in kilowatts), to the motor can be calculated from the same equation as for auxiliary power, eq. (5-5-6).

Measurement of all three phases should be made and the average value used for the calculation. This applies to the voltage, current, and power factor measurements, all of which can usually be made at the motor starter box.

Refer to ASME PTC 19.6, subsections 3-6 and 3-7 for additional information on measuring auxiliary power.

5-5.7 Measurement of Step-Up and Step-Down Transformers

To calculate the transformer power loss, the measurements of the voltage and current at the high side of the transformer shall be recorded. The calculations below are then performed.

$$\text{loss}_{\text{total}} = \text{loss}_{\text{no-load}} + \text{loss}_{\text{load}} \quad (5\text{-}5\text{-}7)$$

$\text{Loss}_{\text{no-load}}$ is determined from the factory shop test report. It is a constant value. The load losses of a transformer are determined as

$$\text{loss}_{\text{load}} = L_{1,\text{corr}} + L_{2,\text{corr}}$$

where

$L_{1,\text{corr}}$ = I^2R losses, kW, corrected to reference conditions, where
  I = average RMS phase current, A
  R = resistance, Ω
$L_{2,\text{corr}}$ = stray load losses, kW, corrected to reference conditions

The load losses vary with voltage and load. Therefore, the values for the load losses taken from the test report need to be corrected. The following equations correct for these conditions:

$$L_{1,\text{corr}} = L_1 \times n \times K \quad (5\text{-}5\text{-}8)$$

$$L_{2,\text{corr}} = L_2 \times n \times K \quad (5\text{-}5\text{-}9)$$

where

L_1 = I^2R losses, kW, from factory test report at rated load
L_2 = stray load losses, kW, from factory test report at rated load
n = (test load / rated load)^2
K = (rated voltage / test voltage)^2, where
  test voltage = $V_{\text{meas}} \times$ PT ratio $\times \sqrt{3}$
  PT ratio = potential transformer ratio from instrument transformer design data
  V_{meas} = measured secondary voltage, kV, at the low side of the transformer, adjusted for meter errors as necessary

The test load (in kilovolt-amps) and test voltage (in kilovolts) are determined from the power and voltage measurements collected from the test. The rated load (in kilovolt-amps) and voltage (in kilovolts) are from the factory test reports.

$$\text{test load} = (P_{\text{meas}} / PF_{\text{meas}}) \quad (5\text{-}5\text{-}10)$$

where

P_{meas} = measured active power, kW
PF_{meas} = power factor at test, dimensionless

Section 6
Report of Results

6-1 GENERAL REQUIREMENTS

At a minimum, the report should include the following sections:

(a) executive summary
(b) introduction
(c) calculation and results
(d) instrumentation
(e) appendices

This outline is a recommended report format. Other formats are acceptable; however, a report of an overall plant performance test should contain, in a suitable location, all the information described in subsections 6-2 through 6-7.

6-2 EXECUTIVE SUMMARY

The executive summary is a brief synopsis of the full report and contains only the most essential information in a concise format. The following items should be contained in the executive summary:

(a) general information about the plant and the test, such as the plant type and operating configuration, and the test objectives
(b) date and time of test
(c) summary of the results of the test, including uncertainty, and conclusions reached
(d) comparison with the contract guarantee
(e) any agreements among the parties to the test that allow any major deviations from the test requirements, e.g., if the test requirements call for three test runs, and all parties agree that two are sufficient
(f) signatures of test director(s) and reviewer(s)
(g) approval signature(s)

6-3 INTRODUCTION

The introduction of the test report gives general background information necessary for the reader to understand the circumstances leading up to, and the reasons for, the test. This section includes the following topics:

(a) any additional general information about the plant and the test not included in the executive summary
(b) an historical perspective, if appropriate
(c) a cycle diagram showing the test boundary (see Fig. 3-2.2-1)
(d) a listing of the representatives of the parties to the test and their involvement in the testing process
(e) any pretest agreements that were not tabulated in the executive summary
(f) the organization of the test personnel, including number and type of personnel supplied by each organization and the tasks for which each organization was responsible during the test
(g) test goals per Sections 3 and 5
(h) description of the equipment tested and any other auxiliary apparatus the operation of which may influence the test result
(i) method of test, giving arrangement of testing equipment, instruments used and their location, operating conditions, and complete description of methods of measurement not prescribed by the individual code

6-4 CALCULATIONS AND RESULTS

(a) The goal of the calculation and results section is to lay out all calculation procedures used in the analysis phase of the test. It should contain the following:

(1) summary of measurements and observations
(2) methods of calculation from observed data and calculation of probable uncertainty
(3) correction factors to be applied because of deviations, if any, of test conditions from those specified
(4) primary measurement uncertainties, including method of application
(5) the test performances stated under the following headings:

(-a) test results computed on the basis of the test operating conditions, instrument calibrations only having been applied
(-b) test results corrected to specified conditions if test operating conditions have deviated from those specified

(6) tabular and graphical presentation of the test results

(b) Using the detailed description and sample calculations, the reader should be able to understand and reproduce any results contained in the report. In addition to the details listed in (a) above, the following should be included in the calculations and results section:

(1) the format of the general performance equation used, based on the test goals and applicable corrections

(2) tabulation of the reduced data necessary to calculate the results, and summary of additional operating conditions not part of such reduced data

(3) step-by-step calculation of test results from the reduced data (Refer to Nonmandatory Appendix A for examples of step-by-step calculations.)

(4) detailed calculation of primary flow rates from applicable data, including intermediate results, if required (Primary flow rates are fuel flow rates, and, if cogeneration, process flow rates.)

(5) detailed calculations of fuel properties, such as density and heating value (Values of constituent properties, used in the detailed calculations, shall be shown.)

(6) any calculations showing elimination of data for outlier reason, or for any other reasons

(7) comparison of the repeatability of test runs

6-5 INSTRUMENTATION

The instrumentation section contains a detailed description of all instrumentation used during the test, its accuracy, and how each measurement made conforms to the Code requirements. This section should include the following:

(a) tabulation of instrumentation used for the primary and secondary measurements, including make and model number, etc.

(b) description of the instrumentation location

(c) means of data collection for each data set, such as temporary data acquisition system printout, plant control computer printout, or manual data sheet, and an identifying tag number and/or address of each data set

(d) identification of the instruments used as backup

(e) description of data acquisition system(s) used

(f) summary of pretest and post-test calibration

(g) calibration reports added as an appendix to the report

6-6 CONCLUSIONS

The conclusions section should include the following:

(a) discussion of the test, its results, and the conclusions drawn

(b) discussion and details of the uncertainties of the test results

(c) any recommended changes to future test procedures due to "lessons learned"

6-7 APPENDICES

Appendices to the test report should include

(a) the test requirements

(b) copies of original data sheets and/or data acquisition system(s) printouts

(c) copies of operator logs or other recording of operating activity during each test

(d) copies of signed isolation checklists and valve lineup sheets, and other documents and disposition

(e) results of laboratory fuel analysis

(f) instrumentation calibration results from laboratories, and certification from manufacturers

Section 7
Uncertainty Analysis

7-1 INTRODUCTION

This Section describes the methodology to be used in developing the uncertainty analysis of the performance test. Uncertainty calculations provide pretest and post-test estimates of the accuracy expected from the test methods proposed in this Code, and also help identify those measurements that significantly affect the test results and the correction factors that should be determined. Uncertainty calculations are required for every test carried out in accordance with the Code. Pretest uncertainty calculations should be included in the test procedure. Post-test uncertainty calculations shall be included in the test report.

Test uncertainty is an estimate of the limit of error of a test result. It is the interval about the test result that contains the true value within a level of confidence. This Code uses a 95% confidence interval for uncertainty calculations. The primary technical reference for uncertainty calculations is ASME PTC 19.1, which provides general procedures for determining the uncertainties in individual test measurements for both random errors and systematic errors, and for tracking the propagation of these errors into the uncertainty of a test result.

Pretest and post-test uncertainty analysis is an indispensable part of a performance test.

7-1.1 Pretest Uncertainty Analysis

A pretest uncertainty analysis allows corrective action to be taken prior to the test, either to decrease the uncertainty to a level consistent with the overall objective of the test, or to reduce the cost of the test while still attaining the objective. This is most important when deviations from Code-specified instruments or methods are expected. An uncertainty analysis is useful for determining the number of observations required to meet the test code criteria for tests.

7-1.2 Post-Test Uncertainty Analysis

A post-test uncertainty analysis determines the uncertainty for the actual test. This analysis should confirm the pretest systematic and random uncertainty estimates. It serves to validate the quality of the test results, or to expose problems.

A sample calculation for uncertainty is shown in Nonmandatory Appendix B.

Test results should be reported using the following form: $R \pm U_R$.

7-2 OBJECTIVE OF UNCERTAINTY ANALYSIS

The objective of a test uncertainty analysis is to estimate the limit of error of the test results.

This Code does not cover nor discuss test tolerances; test tolerances are defined as contractual agreements regarding an acceptable range of test results.

7-3 DETERMINATION OF OVERALL UNCERTAINTY

There are two types of uncertainty that comprise the total uncertainty, as follows:

(a) systematic error: the portion of the total error that remains constant in repeated measurement of the true value in a test process. Systematic error is caused by measurement characteristics that are inherent to a particular method of measurement, not to a particular plant or test. The estimated value of each systematic error is obtained by nonstatistical methods, and it has many potential sources. This is usually an accumulation of individual errors not eliminated through calibration.

(b) random error: error due to limitations or repeatability of measurements. Random error is the portion of total error that varies in repeated measurements of the true value throughout the test process. Estimates of random error are derived by statistical analysis of repeated independent measurements. The random error may be reduced by increasing the number of instruments or the number of readings taken.

In general, the overall uncertainty of a measurement is calculated as the square root of the sum of the squares (RSS) of the systematic and random uncertainties. Sensitivity coefficients are used to correct the individual parameter's uncertainty for the impact on the total uncertainty.

7-4 SOURCES OF ERROR

Identification of sources of error that affect the test result should be undertaken to determine if they are random or systematic. Error sources may be grouped into the following categories:

(a) calibration error — residual error not removed by the calibration process

(b) installation error — results from nonideal instrumentation installation

(c) data acquisition error — typically results from analog-to-digital conversion

(d) data reduction error — introduced through truncation, round-off, nonlinear curve fitting, or data storage algorithms

(e) sampling error — introduced by sampling techniques

(f) correction methodology error — introduced by using correction formula

(g) interpolation error — results from curve fitting or from the shape of a curve between discrete formulation points

(h) model error — occurs when equipment and system models do not properly account for changes in input parameters or actual unit response

7-5 CALCULATION OF UNCERTAINTY

The elements of uncertainty calculations for a complete test can be presented in tabular form, as shown in Table 7-5-1. Typical stream measurements for an IGCC power block are listed in the table, but they are not all used in all configurations.

The test uncertainty associated with each measured parameter includes the effects of its sensitivity, systematic uncertainty, and random uncertainty. Each systematic and random uncertainty entry in the Table 7-5-1 is specified at a 95% confidence interval, as is the overall combined expanded uncertainty of the results.

The same tabular format and calculation procedures can be used to calculate corrected heat rate uncertainty and corrected net power uncertainty.

The column headings in Table 7-5-1 are as follows:

(a) Measured Parameter — the fluid or energy stream parameter that crosses the test boundary, required for test calculation

(b) Sensitivity Coefficient, θ_i — the percent change in corrected result caused by a unit change in the measured parameter

(c) Systematic Uncertainty, $b_{\overline{X}i}$ — inherent systematic error for the type of measurement

(d) Systematic Uncertainty Contribution, $(\theta_i b_{\overline{X}i})^2$ — the square of the product of sensitivity and systematic uncertainty

(e) Random Uncertainty, $s_{\overline{X}i}$ — the standard deviation of the mean statistically determined from multiple measurements of the same variable

(f) Random Uncertainty Contribution, $(\theta_i s_{\overline{X}i})^2$ — the square of the product of sensitivity and the standard deviation

The overall uncertainty of a measurement, $U_{\overline{X}}$, is the root-sum-square total of overall systematic and random uncertainties.

$$U_{\overline{X}} = \sqrt{\left(b_{\overline{X}}^{\,2} + s_{\overline{X}}^{\,2}\right)} \tag{7-5-1}$$

where

$b_{\overline{X}}$ = systematic uncertainty of the measurement
$s_{\overline{X}}$ = random uncertainty of the measurement

The uncertainty of the result is calculated from the overall test random and systematic uncertainty terms. Each systematic and random uncertainty entry in Table 7-5-1 is specified at a 95% confidence interval, so the overall combined expanded uncertainty of the result, U_R, at 95% confidence is calculated from the sum of systematic and random uncertainty contributions.

$$U_R = \sqrt{\left(b_R^{\,2} + s_R^{\,2}\right)} \tag{7-5-2}$$

where

b_R = systematic uncertainty of the result, the sum of systematic uncertainty contributions
s_R = random uncertainty of the result, the sum of random uncertainty contributions

The expanded uncertainty at 95% confidence is given by

$$U_{R,95} = 2U_R \tag{7-5-3}$$

7-6 SENSITIVITY COEFFICIENTS

Sensitivity coefficients indicate the absolute or relative effect of a measured parameter on the test result. Relative sensitivity coefficients, which are calculated during the pretest uncertainty analysis, identify the parameters with the largest impacts on the test objectives. A relative sensitivity coefficient should be calculated for each measured parameter to determine its influence on test results. Correction calculations are required for all measured parameters with relative sensitivity coefficient values greater than 0.002. The relative sensitivity coefficient, θ, is calculated by either of the following equations:

(a) Partial Differential Form

$$\theta = \frac{\left(\dfrac{\partial R}{R}\right)}{\left(\dfrac{\partial X}{X_{\text{avg}}}\right)} = \frac{X_{\text{avg}}}{R} \times \left(\frac{\partial R}{\partial X}\right) \tag{7-6-1}$$

where

R = corrected test result
X_{avg} = average value of the measured parameter
∂R = change (partial differential) in corrected test result
∂X = change (partial differential) in measured parameter

Table 7-5-1 Uncertainty of Corrected Net Power or Corrected Heat Rate

Measured Parameter	Sensitivity Coefficient, θ_i	Systematic Uncertainty (95% CI), $\pm\left(b_{\bar{X}_i}\right)$	Systematic Uncertainty Contribution, $\left(\theta_i b_{\bar{X}_i}\right)^2$	Random Uncertainty (95% CI), $\pm\left(s_{\bar{X}_i}\right)$	Random Uncertainty Contribution, $\left(\theta_i s_{\bar{X}_i}\right)^2$
EXTERNAL CONNECTIONS					
Inlet air					
Barometric pressure	% / %	%		%	
Temperature	% / °F	°F		°F	
Relative humidity	% / %pt	%pt		%pt	
Makeup water condensate temperature	% / °F	°F		°F	
Secondary fuel					
Heating value	% / %	%		%	
Gas constituent	% / %	%		%	
Temperature	% / °F	°F		°F	
Fuel flow rate	% / %	%		%	
Input steam no. 2					
Enthalpy	% / %	%		%	
Flow rate	% / %	%		%	
GT power, kW	% / %	%		%	
ST power, kW	% / %	%		%	
Auxiliary load	% / %	%		%	
Net power					
Frequency	% / %	%		%	
Power factor	% / %	%		%	
Export steam					
Enthalpy	% / %	%		%	
Flow rate	% / %	%		%	
Steam generator blowdown differential	% / %	%		%	
Cooling water					
Temperature	% / °F	°F		°F	
Flow rate	% / %	%		%	
Cooling air temperature (if used)	% / °F	°F		°F	
Condenser pressure (if used)	% / %	%		%	

Table 7-5-1 Uncertainty of Corrected Net Power or Corrected Heat Rate (Cont'd)

Measured Parameter	Sensitivity Coefficient, θ_i	Systematic Uncertainty (95% CI), $\pm\left(b_{\bar{X}_i}\right)$	Systematic Uncertainty Contribution, $\left(\theta_i b_{\bar{X}_i}\right)^2$	Random Uncertainty (95% CI), $\pm\left(s_{\bar{X}_i}\right)$	Random Uncertainty Contribution, $\left(\theta_i s_{\bar{X}_i}\right)^2$
CONNECTIONS TO ASU					
Nitrogen					
Pressure	% / %	%		%	
Temperature	% / °F	°F		°F	
Flow rate	% / %	%		%	
Extraction air					
Pressure	% / %	%		%	
Temperature	% / °F	°F		°F	
Flow rate	% / %	%		%	
Cooling water temperature	% / °F	°F		°F	
Process water temperature	% / °F	°F		°F	
CONNECTIONS TO GASIFICATION BLOCK					
Input water no. 1					
Temperature	% / °F	°F		°F	
Flow rate	% / %	%		%	
Output steam no. 1					
Enthalpy	% / %	%		%	
Flow rate	% / %	%		%	
Input steam no. 1					
Enthalpy	% / Btu	%		%	
Flow rate	% / %	%		%	
Output water no. 1					
Temperature	% / °F	°F		°F	
Flow rate	% / %	%		%	
Output water no. 2					
Temperature	% / °F	°F		°F	0
Flow rate	% / %	%		%	0
CONNECTIONS TO SYNGAS CONDITIONING BLOCK					
Primary fuel					
Heating value	% / %	%		%	
Gas constituent	% / %	%		%	
Gas temperature	% / °F	°F		°F	
Flow rate	% / %	%		%	

Table 7-5-1 Uncertainty of Corrected Net Power or Corrected Heat Rate (Cont'd)

Measured Parameter	Sensitivity Coefficient, θ_i	Systematic Uncertainty (95% CI), $\pm\left(b_{\bar{X}_i}\right)$	Systematic Uncertainty Contribution, $\left(\theta_i b_{\bar{X}_i}\right)^2$	Random Uncertainty (95% CI), $\pm\left(s_{\bar{X}_i}\right)$	Random Uncertainty Contribution, $\left(\theta_i s_{\bar{X}_i}\right)^2$
CONNECTIONS TO SYNGAS CONDITIONING BLOCK (CONT'D)					
Input water no. 2					
Temperature	% / °F	°F		°F	
Flow rate	% / %	%		%	
Output steam no. 2					
Enthalpy	% / %	%		%	
Flow rate	% / %	%		%	
Input steam no. 3					
Enthalpy	% / %	%		%	
Flow rate	% / %	%		%	
CORRELATED UNCERTAINTIES					
Sum of squares				...	
Square root (sum of squares)				...	
Combined Expanded Uncertainty of the Results, $U_{R,95}$					%

(b) *Finite Difference Form*

$$\theta = \frac{\left(\frac{\Delta R}{R}\right)}{\left(\frac{\Delta X}{X_{avg}}\right)} = \frac{X_{avg}}{R} \times \left(\frac{\Delta R}{\Delta X}\right) \tag{7-6-2}$$

where R and X_{avg} are the same as in (a) and

ΔR = change (finite difference) in corrected test result

ΔX = change (finite difference) in measured parameter, typically $0.01X_{avg}$

7-7 SYSTEMATIC UNCERTAINTY

Identification of the systematic error is an important step of the uncertainty analysis. Failure to identify a significant systematic error will lead to underestimating the accuracy of the test. The process requires a thorough understanding of the test objectives and methods of the test. Published data, calibration information, and engineering judgment should be used to eliminate or understand the systematic errors in measurements.

Systematic uncertainty of a measurement is identified as $b_{\bar{X}}$. The individual systematic uncertainties can be combined into the systematic uncertainty of the result, b_R. The systematic uncertainty of the result can be calculated according to the square root of the sum of squares rule.

$$b_R = \sqrt{\sum_{i=1}^{n}\left(b_{\bar{X}i}\theta_i\right)^2} \tag{7-7-1}$$

where

b_R = systematic uncertainty of the result

$b_{\bar{X}i}$ = systematic uncertainty of the result of a measured parameter, i

n = the number of measured parameters

θ_i = relative sensitivity coefficient for measured parameter, i

The systematic uncertainty is assumed to have a normal distribution. If the positive and negative systematic uncertainty limits are not symmetrical, positive and negative values of the random uncertainty shall be calculated separately. If different values of the systematic uncertainty have been calculated for positive and negative systematic uncertainty limits, the larger value should be used to compute the total uncertainty.

7-8 RANDOM STANDARD UNCERTAINTY FOR SPATIALLY UNIFORM PARAMETERS

The standard deviation, s_X, is a measurement of the dispersion of the sample measurements, the standard deviation of the mean, $s_{\bar{X}}$, and a characteristic degree of freedom ($\upsilon = N - 1$). Test measurements need to be reduced to average values and the standard deviation calculated before the performance and uncertainty calculations can be executed. The random standard uncertainty is calculated using the sample standard deviation. For a result, R, calculated from many measured parameters, there is a combined standard uncertainty for the result, s_R, for the combined measurement parameters.

(a) Sample Mean. The mean, $\overline{X}$, for the sample is calculated from

$$\overline{X} = \frac{1}{N}\sum_{i=1}^{N} X_i \qquad (7\text{-}8\text{-}1)$$

where

N = the number of readings for each set

X_i = average value for measurement set i

(b) Pooled Averages. For parameters measured several times during a test period that have M sets of measurements with N readings for each set, the pooled average value for measurement set k is as follows:

$$\overline{X} = \frac{1}{M}\sum_{k=1}^{M} \overline{X}_k \qquad (7\text{-}8\text{-}2)$$

where

$\overline{X}$ = sample set pooled average

M = number of sets of measurements

$\overline{X}_k$ = average value for measurement set k

(c) Sample Standard Deviation. For measurements that do not exhibit spatial variations, the standard deviation, s_X, of an averaged measurement, $\overline{X}$, based on statistical analysis is calculated from the N multiple measurements of X according to the equation

$$s_X = \left[\sum_{i=1}^{N} \frac{\left(X_i - \overline{X}\right)^2}{N-1}\right]^{1/2} \qquad (7\text{-}8\text{-}3)$$

where

N = number of times the parameter is measured

(d) Random Standard Uncertainty of the Mean. The random standard uncertainty of the mean of an averaged measurement, $\overline{X}$, based on statistical analysis is calculated from the N multiple measurements of X according to the equation

$$s_{\overline{X}} = \frac{s_X}{\sqrt{N}} \qquad (7\text{-}8\text{-}4)$$

where s_X = standard deviation of the mean.

(e) Random Standard Uncertainty of the Result. The random uncertainty of the result is determined from the propagation equation (see ASME PTC 19.1). There are two forms.

The absolute random standard uncertainty is determined using

$$s_R = \left[\sum_{i=1}^{l}\left(\theta_i s_{\overline{X}i}\right)^2\right]^{1/2} \qquad (7\text{-}8\text{-}5)$$

where

l = counter for correlated sources of systematic error

θ = absolute sensitivity coefficient

The relative random standard uncertainty of a result is determined using

$$\frac{s_R}{R} = \left[\sum_{i=1}^{l}\left(\theta' i \frac{s_{\overline{X}i}}{\overline{X}_i}^2\right)\right]^{1/2} \qquad (7\text{-}8\text{-}6)$$

where

l = counter for correlated sources of systematic error

θ' = relative sensitivity coefficient

7-9 RANDOM STANDARD UNCERTAINTY FOR SPATIALLY NONUNIFORM PARAMETERS

The spatial contribution to the systematic standard uncertainty for a given parameter is calculated as follows:

$$b_{\text{spatial}} = \frac{s_{\text{spatial}}}{\sqrt{J}} \qquad (7\text{-}9\text{-}1)$$

where

J = number of sensors (i.e., spatial measurement locations)

s_{spatial} = standard deviation of the multiple-sensor time-averaged values

$$= \sqrt{\frac{\sum_{i=1}^{J}(\overline{X}_i - \overline{\overline{X}})}{J-1}}$$

where

$\overline{\overline{X}}$ = grand average for all averaged measurands

$\overline{X}_i$ = average for the sampled measurand i

7-10 CORRELATED SYSTEMATIC STANDARD UNCERTAINTY

For multiple measurements where systematic errors of measurements are not independent, systematic errors are correlated. Examples include measurements of different parameters taken with the same instrument, or multiple instruments calibrated with the same standard. For these cases, ASME PTC 19.1 should be consulted to address the proper approach for uncertainty calculations. The general equation for calculating the correlated systematic uncertainty is

$$b_R = \sum_{i=1}^{l}\left(\theta_i b_i\right)^2 + 2\sum_{i=1}^{l-1}\sum_{k=i+1}^{l}\theta_i\theta_k b_{ik} \qquad (7\text{-}10\text{-}1)$$

NONMANDATORY APPENDIX A
SAMPLE CALCULATION: IGCC POWER BLOCK

A-1 GENERAL

This Appendix provides a sample calculation for how ASME PTC 47.4 is applied for the power block of an IGCC power plant at test conditions that are different than the design reference conditions. The example identifies how key measurements (net power and heat rate) are corrected to design (reference) conditions by using correction factors. Table 5-1-1 lists all the correction parameters that were required for this sample calculation.

A-2 CYCLE DESCRIPTION

The power block of the IGCC power plant used in this sample calculation is shown in Fig. A-2-1. The plant configuration is based on the original design of the Tampa Electric Polk Power Station IGCC.

There is a single train throughout the plant including one air separation unit (ASU), one gasification train, one gas turbine (GT), and one steam turbine (ST). The gasifier is a single-stage slurry-feed (coal or other solids), pressurized, oxygen-blown, entrained flow reactor. The ASU is based on traditional cryogenic air separation to produce an oxygen stream for the gasifier and nitrogen for use as a gas turbine diluent and for other services such as purging and blanketing. A radiant syngas cooler and pair of convective coolers extract high-level heat from the syngas exiting the gasifier.

The gas turbine exhausts into a three-pressure-level heat recovery steam generator (HRSG). The HRSG is unfired. The high-pressure (HP) steam from the process island is combined with the steam from the HRSG and fed into a condensing steam turbine. A large reservoir provides an ample supply of cooling water at a fixed temperature. There is no air extraction from the gas turbine; the air separation main air compressor supplies all of the air to the ASU cold-box to satisfy the oxygen and nitrogen needs of the entire plant.

For the test associated with this sample calculation, the gas turbine is base loaded and the power output is governed by the ambient conditions and the composition of the syngas. All of the synthesis gas from the process island is used in the gas turbine to produce power. Except for the steam used internally within the plant, all of the steam generated is used for producing power; there is no export of steam, syngas, or other product besides power. For this reason, the gasifier production rate is set by the gas turbine load. The sample calculations given below are only for the power block of the IGCC plant. The ASU, gasifier, syngas cooling, and syngas cleaning are outside the scope of this example.

Fundamental parameters of this example are described in paras. A-2.1 through A-2.7.

A-2.1 Gas Turbine

(a) 192 MW at inlet conditions of 59°F, 14.63 psia, 60% relative humidity (RH)
(b) inlet pressure (IP) drop: 3.5 in. of water
(c) exhaust pressure drop: 14 in. of water
(d) nitrogen diluent injection, no air extraction

A-2.2 Heat Recovery Steam Generator

(a) three steam pressure levels with reheat and separate deaerator
(b) HP steam outlet conditions: 1,401 psia at 1,000°F
(c) HP steam from the process island: 1,483 psia
(d) IP steam outlet conditions: 338.8 psia at 1,000°F
(e) flue gas exhaust temperature: 332°F

A-2.3 Steam Turbine

(a) condensing type, 136 MW nominal rating
(b) exhaust pressure: 2 in. Hg
(c) extractions: low-pressure (LP) steam at 56 psia

A-2.4 Condenser

(a) shell-and-tube design
(b) design cooling water (CW) inlet temperature: 55°F
(c) design temperature rise: 15°F
(d) design CW flow

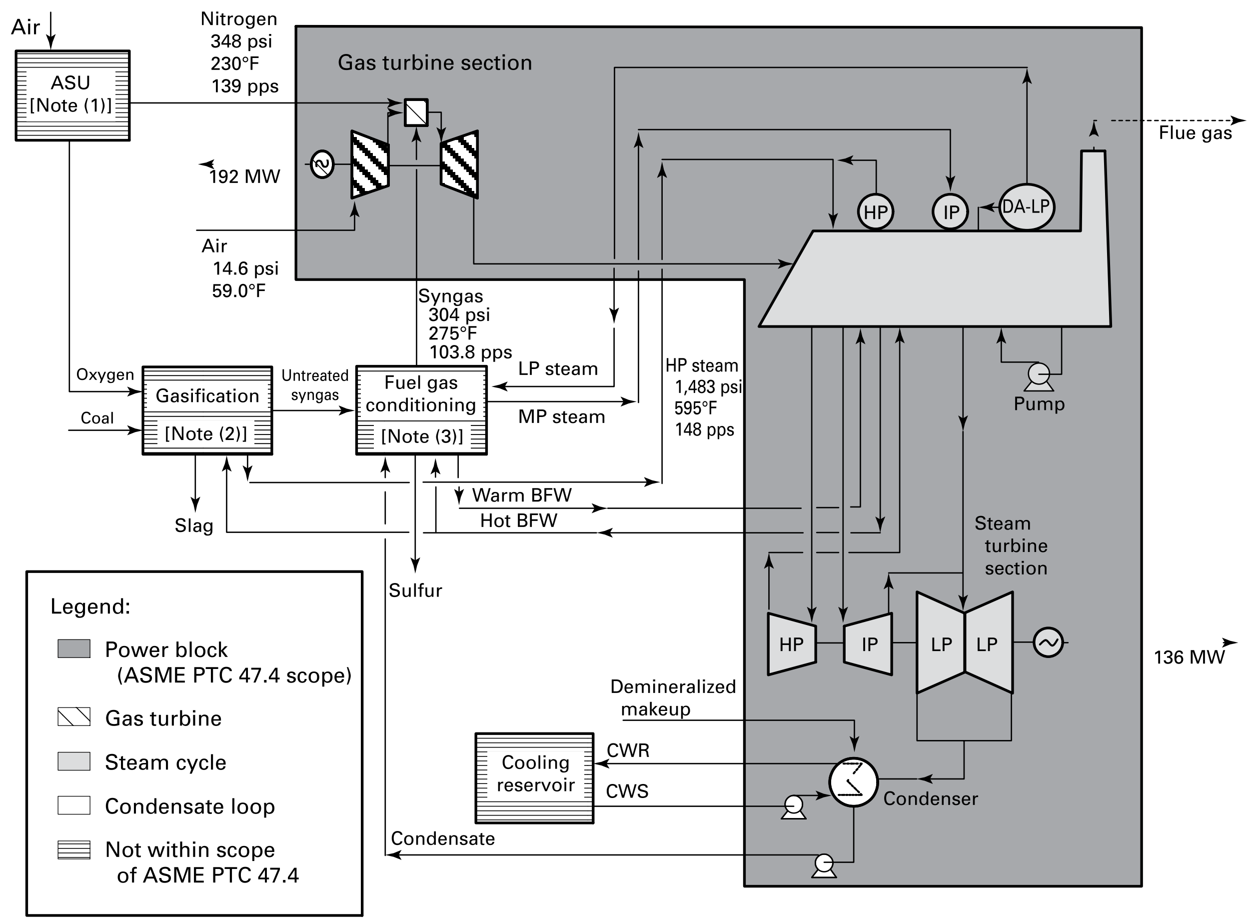
A-2.5 Gasifier

(a) oxygen-blown, entrained-flow, slurry-fed, slagging gasifier
(b) syngas LHV: 4,349 Btu/lb at 77°F

A-2.6 Air Separation Unit

(a) no extraction air from GT
(b) nitrogen is sent to GT for control of nitrogen oxides (NO_x)
(c) nitrogen supply conditions: 348 psia at 230°F
(d) power consumption: 51.4 MW

Fig. A-2-1 A Simplified Sketch Separating the Power Block From an Integrated Gasification and Combined Cycle Plant



GENERAL NOTE:
BFW = boiler feedwater
CWR = cooling water return
CWS = cooling water supply
DA = deaerator
HP = high pressure
IP = inlet pressure
LP = low pressure
MP = medium pressure

NOTES:
(1) The ASU is within the scope of ASME PTC 47.1, which is in the course of preparation.
(2) Gasification is within the scope of ASME PTC 47.2, which is in the course of preparation.
(3) Fuel gas conditioning is within the scope of ASME PTC 47.3, which is in the course of preparation.

A-2.7 Syngas Cooling and Cleaning

(a) radiant and convective syngas cooling, wet scrubbing, and amine-based acid gas removal
(b) HP boiler feedwater supply: 1,483 psig at 572°F
(c) HP steam returned: 1,483 psig saturated

NOTE: *IGCC power plant* refers to the entire facility including gasification, ASU, and the power block. The *IGCC power block* for this example corrects for all the streams crossing the dark gray area shown in Fig. A-2-1.

A-3 BASIS FOR EXAMPLE CASE

It is difficult to obtain detailed performance-related data for any of the IGCC power plants due to their proprietary and confidential nature, and as a result, the ASME PTC 47 Committee has modeled the plant in this example case using data available in the public domain. A commercially available power plant simulation program was used to model the Tampa Electric Polk Power Station. The model of the Tampa Electric IGCC power plant was created using the limited design and operating data available to the ASME PTC 47 Committee and the "Tampa Electric Polk Power Station Integrated Gasification Combined Cycle Project Final Technical Report" (August 2002) based on the conditions shown in Table A-3-1.

Table A-3-1 Operating and Design Data for Tampa Electric Polk Power Station

Parameter	Value
Ambient temperature	59°F
Relative humidity	60%
Elevation	125 ft
Ambient pressure	14.63 psia
GT inlet pressure drop	3.5 in. of water
GT exhaust losses	14 in. of water
GT fuel temperature	275°F
GT fuel composition	(Mole %)
Carbon monoxide (CO)	42.01
Hydrogen (H_2)	38.93
Carbon dioxide (CO_2)	17.03
Nitrogen (N_2)	2.00
Water (H_2O)	0.02
Methane (CH_4)	0.01

A commercially available thermodynamic modeling tool was used to calculate plant performance. This modeling tool has a full set of standard gas turbine models on conventional fuels now operating worldwide. However, the GE 7FA gas turbine model for IGCC syngas fuel operation used in this example was modified using General Electric–provided technical performance data. Steam cycle component design data was tuned based on 136-MW power from the steam turbine. All the interface steam and water streams for the gasification were modeled as sources and sinks based on data provided by Tampa Electric as shown in Table A-3-1. For the purpose of this example, minor flows such as the gland steam flows and leakages were ignored in the model. The thermodynamic model of the Tampa Electric Polk Power Plant is shown in Fig. A-2-1.

A-4 TEST BOUNDARY

The power block test boundary is shown in the dark-gray-highlighted area in Fig. A-2-1. All energy streams entering or exiting this highlighted area can be easily identified. Physical properties of all input and output energy streams must be determined with reference to the point at which they cross the test boundary.

As shown in Fig. A-2-1, air crosses the boundary at the inlets of the gas turbine. Net plant electrical output is determined from measurements of the output of each generator less the auxiliary power block loads. Fuel flow rate, temperature, and heating values are measured at the GT fuel supply line. Diluent nitrogen flow and temperature are also measured at the GT inlet. Additionally, import steam, export water, and the circulating water flows and temperatures are measured where these streams cross the test boundary.

A-5 REFERENCE AND MEASURED CONDITIONS FOR EXAMPLE CALCULATIONS

Table A-5-1 lists the reference conditions for the power block as well as the test parameters. For this example, the export water and import steam enthalpies were calculated from the pressure and temperatures crossing the test boundary.

Table A-5-1 Reference and Test Conditions

Parameter	Reference Conditions	Test Conditions
Ambient air		
Pressure	14.63 psia (100.87 kPa)	14.70 psia (101.35 kPa)
Temperature	59°F (15°C)	65°F (18.33°C)
Relative humidity	60%	60%
HP process steam admission		
Enthalpy	1,170.5 Btu/lb (2 722.6 kJ/kg)	1,170 Btu/lb (2 721.4 kJ/kg)
Flow rate	148 lb/sec (67.13 kg/s)	150 lb/sec (68.04 kg/s)
HP economizer water extraction		
Enthalpy	577.9 Btu/lb (1 334.2 kJ/kg)	581 Btu/lb (1 351.4 kJ/kg)
Flow rate	148 lb/sec (67.13 kg/s)	150 lb/sec (68.04 kg/s)
Primary syngas fuel		
Temperature	275°F (135.0°C)	300°F (148.9°C)
LHV	4,349.3 Btu/lb (10 116.38 kJ/kg)	4,349.3 Btu/lb (10 116.38 kJ/kg)
Circulating water		
Temperature	55°F (12.78°C)	68°F (20.00°C)
Flow rate	12,022 lb/sec (5 453.09 kg/s)	11,500 lb/sec (5 216.31 kg/s)
GT nitrogen injection		
Temperature	230°F (110.0°C)	230°F (110.0°C)
Flow rate	139 lb/sec (63.05 kg/s)	136 lb/sec (61.69 kg/s)
Measured Results		
Primary syngas fuel flow rate	103.9 lb/sec (47.11 kg/s)	103.4 lb/sec (46.90 kg/s)
GT generator output	192,054 kW	192,160 kW
ST generator output	136,174 kW	132,190 kW
Gross plant output	328,228 kW	324,350 kW
Auxiliary power to power block	6,550 kW	6,491 kW
Net power block		
Output	321,678 kW	317,859 kW
Heat rate, LHV	5,054.8 Btu/kW·h (5 333.1 kJ/kW·h)	5,093.4 Btu/kW·h (5 373.8 kJ/kW·h)

A-6 TEST CORRECTION FACTORS

Regardless of the test goals or operating mode, the results of a performance test will be corrected net power and corrected heat rate or corrected thermal efficiency, or both. The calculation of results described by this Code requires adjusting the test-determined values of power, P, and thermal input, Q, or heat rate, HR, by the application of additive and multiplicative correction factors. These correction factors correct for allowable variations in controllable operating parameters and uncontrollable external effects, such as ambient temperature.

Correction curves applied to measured performance are calculated by a heat balance model of the thermal systems contained within the test boundary of the IGCC power block. Each correction factor is calculated by running the heat balance model with a variance in only the parameter to be corrected over the possible range of deviations from the reference conditions. Correction curves thus developed are incorporated into the specific test procedure document.

The fundamental performance equations can be simplified to be specific to the particular plant and test program objectives. The format of the fundamental equations allows decoupling of the appropriate correction effects relative to the measured parameters, so that measured performance can be corrected to the reference conditions.

Additive and multiplicative correction factors applied to the measured parameters are listed in Tables A-6-1 and A-6-2, respectively.

A-6.1 Additive Correction Factors

There are 11 additive correction factors used in the fundamental performance equations, as summarized in Table A-6-1. The additive correction factors that are not applicable to the measured results for the specific type of plant being tested, or to the test objectives, are set equal to zero. Parameters 1, 2, 3, 9a, 9c, 10, and 11 in Table A-6-1 are set to zero for this sample calculation.

Table A-6-1 Additive Correction Factors

Number	Additive Correction Factors for Net Power	Parameter	Reason Correction Is Not Required for This Example
1	AP_1	Secondary fuel (duct burner) thermal input (flow × LHV)	There were no secondary duct burner heat inputs
2	AP_2	Generator(s) power factors	Power factors at test were the same as design
3	AP_3	Steam generator blowdown different than design	HRSG blowdown was closed for test and the guarantee was based on no blowdown
4	AP_4	Import steam flow rate and enthalpy	...
5	AP_5	Import water flow rate and enthalpy	...
6	AP_6	Heat energy from input water/makeup water streams	...
7	AP_7	Export water flow rate and enthalpy	...
8	AP_8	Export steam flow rate and enthalpy	...
9a	AP_{9a}	Ambient conditions (temperature and humidity) at cooling tower or air-cooled condenser different than ambient conditions at the gas turbine inlet	Does not apply to this condensing boundary
9b1	AP_{9b1}	Circulating water flow different than design for once-through condenser cooling system (when cooling tower or air-cooled condenser is outside the test boundary)	...
9b2	AP_{9b2}	Circulating water temperature different than design for once-through condenser cooling system (when cooling tower or air-cooled condenser is outside the test boundary)	...
9c	AP_{9c}	Condenser pressure (when the entire heat rejection system is outside the test boundary)	Does not apply to this condensing boundary
10	AP_{10}	Condensate water temperature	Not applicable
11	AP_{11}	Measured power different than predetermined or required power	This was a base-load test and therefore this correction does not apply

A-6.2 Multiplicative Correction Factors

There are 13 multiplicative correction factors used in the fundamental performance equations, as summarized in Table A-6-2.

The multiplicative correction factors that are not applicable to the measured results for the specific type of plant being tested, or to the test objectives, are set equal to unity. For example, if there is no air export, parameters 9 and 10 in Table A-6-2 are set to 1. Corrections are calculated for parameters at the test boundary that are different from the base reference conditions and that affect the measured performance results. Parameters 3, 5, 6, 7, 8, 9, 10, 12, and 13 in Table A-6-2 are set to 1 for this sample calculation.

See subsection A-8 for the correction curves. These curves and fitted equations are based on this specific plant model and should not be used generically for any ASME PTC 47.4 test.

A-7 CALCULATIONS TO DETERMINE CORRECTED PERFORMANCE

This IGCC power block comprises a generating process for the production of only electric power. The fundamental performance equation for output is net power. The corrected net power is calculated based on its measured value with two types of corrections: additive correction factors and multiplicative correction factors.

The curves in Figs. A-8-1 through A-8-11 are typical manufacturers' curves that show changes to net plant performance at various off-design conditions. Corrections, however, compensate for off-design conditions, so their numerical values are the opposites of the values in the performance curves. Therefore, additive corrections are the negatives of net power changes, CP_x, and multiplicative corrections are the reciprocals of normalized output factors, FP_x, or normalized heat rate factors, FHR_x, in their respective curves.

A-7.1 Corrected Net Power, P_{corr}

(a) Equation for Corrected Net Power, P_{corr}

$$P_{corr} = [(P_{meas} + \Sigma\, AP_i)\, \Pi\, MP_j],\ i = 1, n;\ j = 1, m \tag{A-7-1}$$

where

AP_i = additive correction factor for power generation
m = number of multiplicative correction factors
MP_j = multiplicative correction factor for power generation
n = number of additive correction factors

Table A-6-2 Multiplicative Correction Factors

Number	Multiplicative Correction Factors: Net Power	Net Heat Rate	Parameter	Reason Correction Is Not Required for This Example
1	MP_1	MHR_1	Ambient temperature	...
2	MP_2	MHR_2	Ambient pressure	...
3	MP_3	MHR_3	Ambient humidity	Humidity at test was the same as design
4	MP_4	MHR_4	Primary fuel supply temperature	...
5	MP_5	MHR_5	Primary fuel composition	Fuel analysis matched the design fuel
6	MP_6	MHR_6	Secondary fuel (to GT) flow rate	There were no secondary fuel heat inputs
7	MP_7	MHR_7	Secondary fuel (to GT) supply temperature	There were no secondary fuel heat inputs
8	MP_8	MHR_8	Secondary fuel (to GT) composition	There were no secondary fuel heat inputs
9	MP_9	MHR_9	Export air extraction flow rate	Not applicable to this cycle configuration
10	MP_{10}	MHR_{10}	Export air extraction temperature	Not applicable to this cycle configuration
11	MP_{11}	MHR_{11}	Import nitrogen flow rate	...
12	MP_{12}	MHR_{12}	Import nitrogen temperature	Nitrogen temperature at test was the same as design
13	MP_{13}	MHR_{13}	Grid frequency	Grid frequency at test was the same as design

P_{meas} = measured total net electric power flow from individual generators as determined in eq. (A-7-2)

Measured net power for an IGCC power block with multiple prime generators is expressed as

$$P_{meas} = [P_{meas,n}]_{generator} - P_{aux} \tag{A-7-2}$$

where
n = individual generator
P_{aux} = auxiliary power used by the power block

Using the values shown in Table A-5-1, for this example the net plant output was calculated as follows for the test:

$$\begin{aligned} P_{meas} &= \text{GT output} + \text{ST output} - P_{aux} \\ &= 192{,}160 + 132{,}190 - 6{,}491 \\ &= 317{,}859 \text{ kW} \end{aligned}$$

The next step is to correct P_{meas} by applying the additive and multiplicative correction factors.

(b) Additive Correction Factors for Net Power

(1) Import Steam Flow Rate and Enthalpy. The correction to account for import steam energy that is different than design requires interpolating between the correction curves in Fig. A-8-9.

When the difference, dH, between HP process admission steam enthalpy and HP economizer outlet enthalpy equals 572.6 Btu/lb, use the following equation:

$$\begin{aligned} CP_4 &= 3.13604\text{E}{+}02\, x - 4.79192\text{E}{+}04 \\ &= -878.6 \text{ kW} \end{aligned}$$

where
x = test steam admission flow = 150 lb/sec

When dH = 592.6 Btu/lb, use the following equation:

$$\begin{aligned} CP_4 &= 3.22849\text{E}{+}02\, x - 4.77919\text{E}{+}04 \\ &= 635.4 \text{ kW} \end{aligned}$$

Since the test dH (i.e., enthalpy of steam admission − enthalpy of water extraction; see Table A-5-1 for values) equals 589.0, interpolation of the above two results yields

$$CP_4 = 362.9 \text{ kW}$$

The correction, AP_4, is the negative of this value.

$$AP_4 = -CP_4 = -362.9 \text{ kW}$$

(2) Circulating Water Flow Rate. The correction to account for circulating water flow rate that is different than design is determined as follows:

$$\begin{aligned} CP_{9b1} &= 6.57365\text{E}{-}09\, x^3 - 3.51646\text{E}{-}04\, x^2 \\ &\quad + 5.98273\text{E}{+}00\, x - 3.25363\text{E}{+}04 \\ &= -242.4 \text{ kW} \end{aligned}$$

where
x = test-measured circulating water flow = 11,500 lb/sec

The correction is the negative of this value.

$$AP_{9b1} = -CP_{9b1} = 242.4 \text{ kW}$$

(3) Circulating Water Temperature. The correction to account for circulating water temperature that is different than design is determined as follows:

$$\begin{aligned} CP_{9b2} &= 7.20242\text{E}{-}02\, x^3 - 2.08110\text{E}{+}01\, x^2 \\ &\quad + 1.40058\text{E}{+}03\, x - 2.60344\text{E}{+}04 \\ &= -4{,}378.3 \text{ kW} \end{aligned}$$

where
x = test-measured circulating water temperature = 68°F

The correction is the negative of this value.

$$AP_{9b2} = -CP_{9b2} = 4{,}378.3 \text{ kW}$$

(c) Multiplicative Correction Factors for Net Power

(1) Ambient Air Temperature. The correction to account for ambient air temperature that is different than design is determined as follows:

$$FP_1 = 1.11676\text{E}{-04}\,x + 9.93695\text{E}{-01}$$
$$= 1.0010$$

where

x = test-measured air temperature = 65°F

The correction is the reciprocal of this value.

$$MP_1 = 1/FP_1 = 0.9990$$

(2) Ambient Air Pressure. The correction to account for ambient air pressure that is different than design is determined as follows:

$$FP_2 = 4.38307\text{E}{-03}\,x + 9.35874\text{E}{-01} \text{ (when ambient temperature, } T_{amb}, < 80°\text{F)}$$
$$= 1.0003$$

where

x = test-measured air pressure = 14.70 psia

The correction is the reciprocal of this value.

$$MP_2 = 1/FP_2 = 0.9997$$

(3) Primary Syngas Fuel Temperature. The correction to account for primary syngas fuel temperature that is different than design is determined as follows:

$$FP_4 = -4.05334\text{E}{-06}\,x + 1.00111\text{E}{+00}$$
$$= 0.9999$$

where

x = test-measured syngas fuel temperature = 300°F

The correction is the reciprocal of this value.

$$MP_4 = 1/FP_4 = 1.0001$$

(4) Nitrogen Injection Flow Rate. The correction to account for nitrogen injection flow rate that is different than design is determined as follows:

$$FP_{11} = 0.00059x + 0.91812$$
$$= 0.9984$$

where

x = test-measured nitrogen flow = 136 lb/sec

The correction is the reciprocal of this value.

$$MP_{11} = 1/FP_{11} = 1.0016$$

(d) Corrected Net Power Calculation. Combining the values from (a) through (c)(4), the corrected power is

$$P_{corr} = [P_{meas} + (AP_4 + AP_{9b1} + AP_{9b2})]\,(MP_1 \times MP_2 \times MP_4 \times MP_{11})$$
$$= [317{,}859 + (-362.9 + 242.4 + 4{,}378.3)]\,(0.9990 \times 0.9997 \times 1.0001 \times 1.0016)$$
$$= 322{,}274 \text{ kW}$$

A-7.2 Corrected Net Heat Rate, HR_{corr}

(a) Equation for Corrected Net Heat Rate, HR_{corr}

$$HR_{corr} = [(Q_{pf} + \Sigma\, AQf_i) \,/\, (P_{meas} + \Sigma\, AP_i)]\; \Pi\, MHR_j,$$
$$i = 1, n;\ j = 1, m \qquad \text{(A-7-3)}$$

where

AQf_i = additive correction factor for the primary fuel input
m = number of multiplicative correction factors
MHR_j = multiplicative correction factor for heat rate
n = number of additive correction factors
Q_{pf} = measured total energy contained in the primary fuel flows entering into the power block during the test

As stated in Section 5, for additive corrections 1 through 11, for a given correction i, usually either AP or AQ_f will be used, but not both. For this example, AQ_f = 0, since output corrections have been applied.

Thermal heat input from primary fuel, Q_{pf}, to the power block is expressed as

$$Q_{pf} = \Sigma[(HV_{pf,n})(W_{pf,n})] \qquad \text{(A-7-4)}$$

where

HV_{pf} = heating value, calculated based on the combustion energy of measured primary fuel composition
n = an individual fuel input to the plant
W_{pf} = primary fuel flow rate, directly measured

Using the values shown in Table A-5-1, for this example, the measured primary syngas heat consumption was calculated as follows for the test:

$$Q_{pf} = HV_{pf} \times W_{pf}$$
$$= 4{,}349.3 \text{ Btu/lb} \times 103.4 \text{ lb/sec} \times 3{,}600 \text{ sec/hr}$$
$$= 1{,}618{,}969{,}000 \text{ Btu/hr}$$

The next step is to determine the multiplicative heat rate correction factors, MHR.

(b) Multiplicative Correction Factors for Net Heat Rate

(1) Ambient Air Temperature. The correction to account for ambient air temperature that is different than design is determined as follows:

$$FHR_1 = 2.13828\text{E}{-06}\,x^2 - 3.85894\text{E}{-04}\,x + 1.01557\text{E}{+00}$$
$$= 0.9995$$

where

x = test-measured air temperature = 65°F

The correction is the reciprocal of this value.

$$MHR_1 = 1/FHR_1 = 1.0005$$

(2) Ambient Air Pressure. The correction to account for ambient air pressure that is different than design is determined as follows:

$$FHR_2 = 9.88190\text{E}{-}03\,x + 8.55349\text{E}{-}01 \quad (\text{when } T_{amb} < 80°\text{F}) = 1.0006$$

where

x = test-measured air pressure = 14.70 psia

The correction is the reciprocal of this value.

$$MHR_2 = 1/FHR_2 = 0.9994$$

(3) Primary Syngas Fuel Temperature. The correction to account for primary syngas fuel temperature that is different than design is determined as follows:

$$FHR_4 = -8.29831\text{E}{-}05\,x + 1.02280\text{E}{+}00 = 0.9979$$

where

x = test-measured syngas fuel temperature = 300°F

The correction is the reciprocal of this value.

$$MHR_4 = 1/FHR_4 = 1.0021$$

(4) Nitrogen Injection Flow Rate. The correction to account for nitrogen injection flow rate that is different than design is determined as follows:

$$FHR_{11} = 2.85830\text{E}{-}07\,x^2 - 1.26040\text{E}{-}04\,x + 1.01205\text{E}{+}00 = 1.0002$$

where

x = test-measured nitrogen flow = 136 lb/sec

The correction is the reciprocal of this value.

$$MHR_{11} = 1/FHR_{11} = 0.9998$$

(c) Corrected Heat Rate Calculation. Combining values from A-7.1(a), A-7.1(b), and (a) and (b)(1) through (b)(4) above, the corrected heat rate is

$$\begin{aligned} HR_{corr} &= [Q_{pf} / (P_{meas} + AP_4 + AP_{9b1} + AP_{9b2})]\,(MHR_1 \times MHR_2 \times MHR_4 \times MHR_{11}) \\ &= [1{,}618{,}969{,}000 / (317{,}859 - 362.9 + 242.4 + 4{,}378.3)]\,(1.0005 \times 0.9994 \times 1.0021 \times 0.9998) \\ &= 5{,}034.9 \text{ Btu/kW·h} \end{aligned}$$

A-8 CONCLUSION

The example calculation illustrates several important points.

(a) Using the values from the sample test data, the resulting additive and multiplicative correction values are calculated. These correction values are then inserted into the appropriate equations to correct the power and heat rate to design boundary conditions.

(b) Corrections are required for all energy streams that cross the test boundary that affect power block performance. All additive and multiplicative corrections that are not required for the specific cycle being tested are set to 0 or 1, respectively.

(c) Corrections for heat rate have been used instead of those for fuel energy. Either method could have been applied, but the method chosen must be consistent with the basis of the correction curves.

(d) The fact that certain corrections were not applied in this example does not mean that they should always be neglected. Not all of the variables need to be incorporated in the calculation or corrections; inclusion of specific variables is dependent on the cycle being tested.

(e) The curves need to be prepared so that they cover the range of expected test parameters.

(f) The corrected results are compared with the required performance at reference conditions.

For this example, the corrected power, P_{corr}, is 322,274 kW, which exceeds the target output at reference conditions of 321,678 kW. The corrected heat rate, HR_{corr}, is 5,034.9 Btu/kW·h, which is lower than the target heat rate of 5,054.8 Btu/kW·h. In both cases, the performance test results are better than the guarantees.

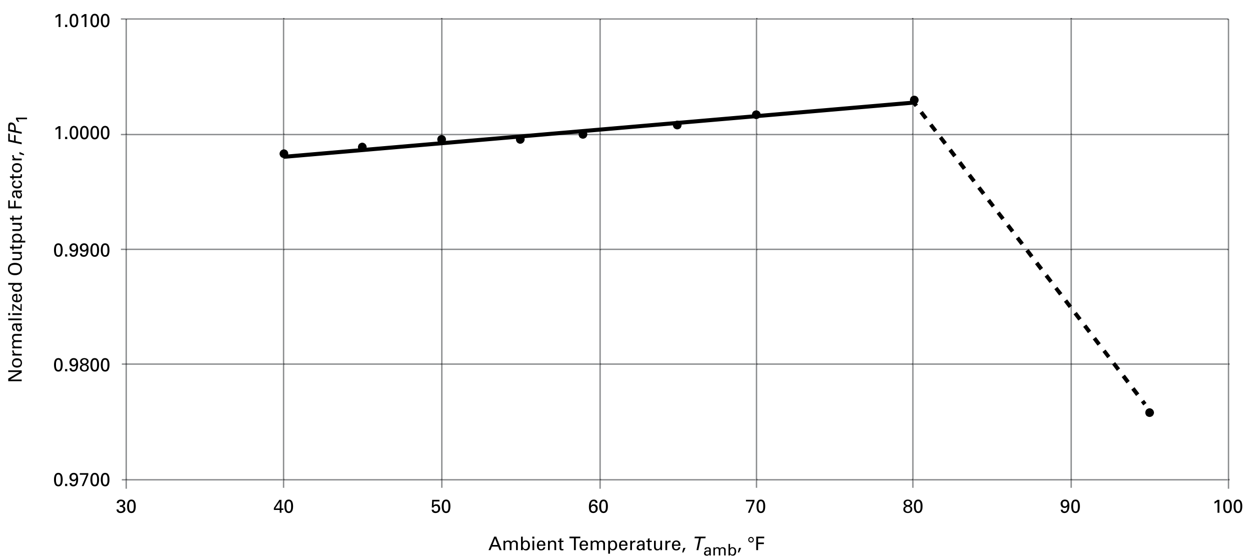
Table A-8-1 lists the correction curves used in this example. The 11 curves with the fitted equations are provided in Figs. A-8-1 through A-8-11.

Table A-8-1 List of Correction Curves

Figure	Description	Correction Factor Type	Reference Value	Lower Limit	Upper Limit
A-8-1	Ambient temperature vs. output	M	59°F	40°F	98°F
A-8-2	Ambient temperature vs. heat rate	M	59°F	40°F	98°F
A-8-3	Ambient pressure vs. output	M	14.63 psia	14.4 psia	14.9 psia
A-8-4	Ambient pressure vs. heat rate	M	14.63 psia	14.4 psia	14.9 psia
A-8-5	Syngas fuel temperature vs. output	M	275°F	225°F	315°F
A-8-6	Syngas fuel temperature vs. heat rate	M	275°F	225°F	315°F
A-8-7	GT nitrogen injection mass flow vs. output	M	139 lb/sec	125 lb/sec	150 lb/sec
A-8-8	GT nitrogen injection mass flow vs. heat rate	M	139 lb/sec	125 lb/sec	150 lb/sec
A-8-9	HP steam admission energy vs. output	A	148 lb/sec	138 lb/sec	158 lb/sec
A-8-10	Condenser CW mass flow vs. output	A	12,022 lb/sec	10,000 lb/sec	14,000 lb/sec
A-8-11	Condenser CW temperature vs. output	A	55°F	45°F	95°F

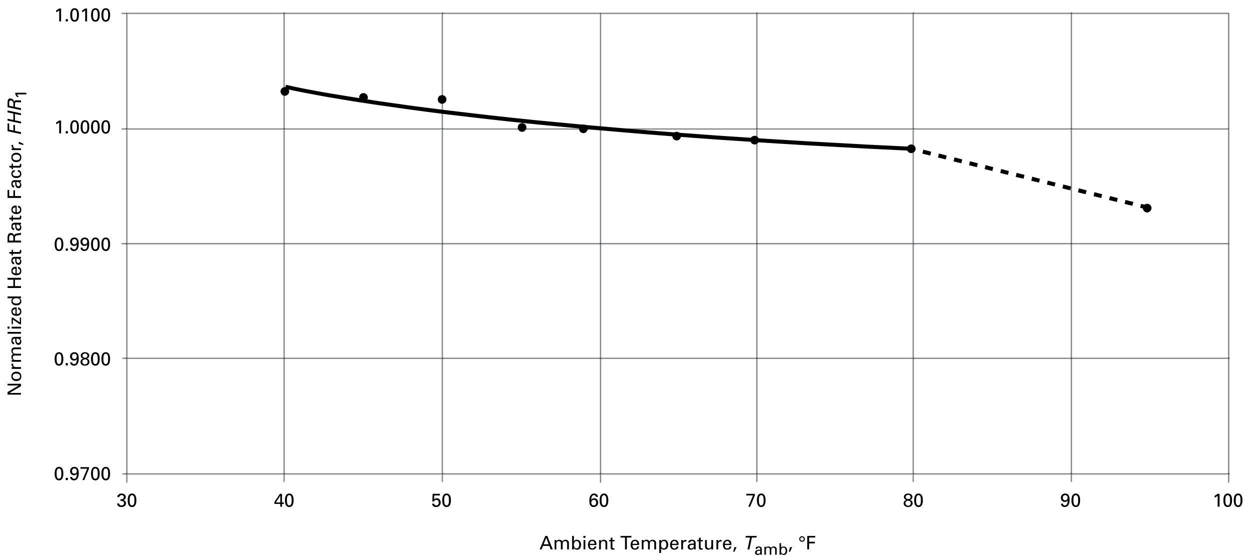
GENERAL NOTE: A = additive; M = multiplicative.

Fig. A-8-1 Output Correction for Ambient Temperature



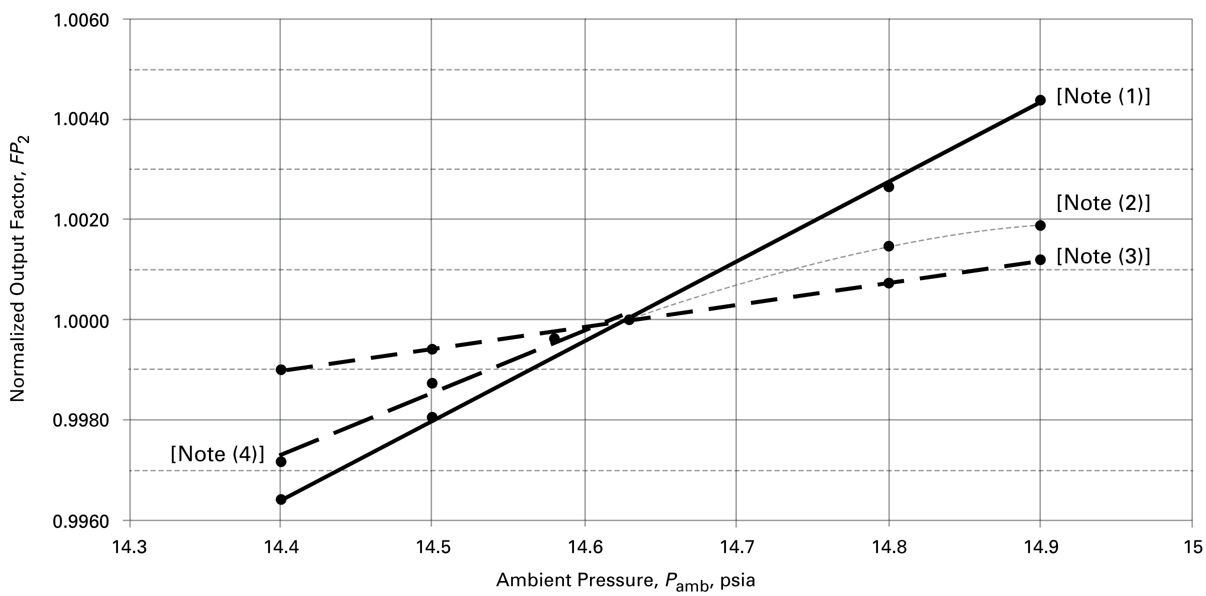
GENERAL NOTES:
(a) For $T_{amb} < 80$°F, $FP_1 = 1.11676\text{E–}04\ T_{amb} + 9.92695\text{E–}04$.
(b) For $T_{amb} > 80$°F, $FP_1 = 1.80221\text{E–}03\ T_{amb} + 1.14798\text{E+}00$.
(c) Correction factor $MP_1 = 1/FP_1$.

Fig. A-8-2 Net Plant Heat Rate Correction for Ambient Temperature



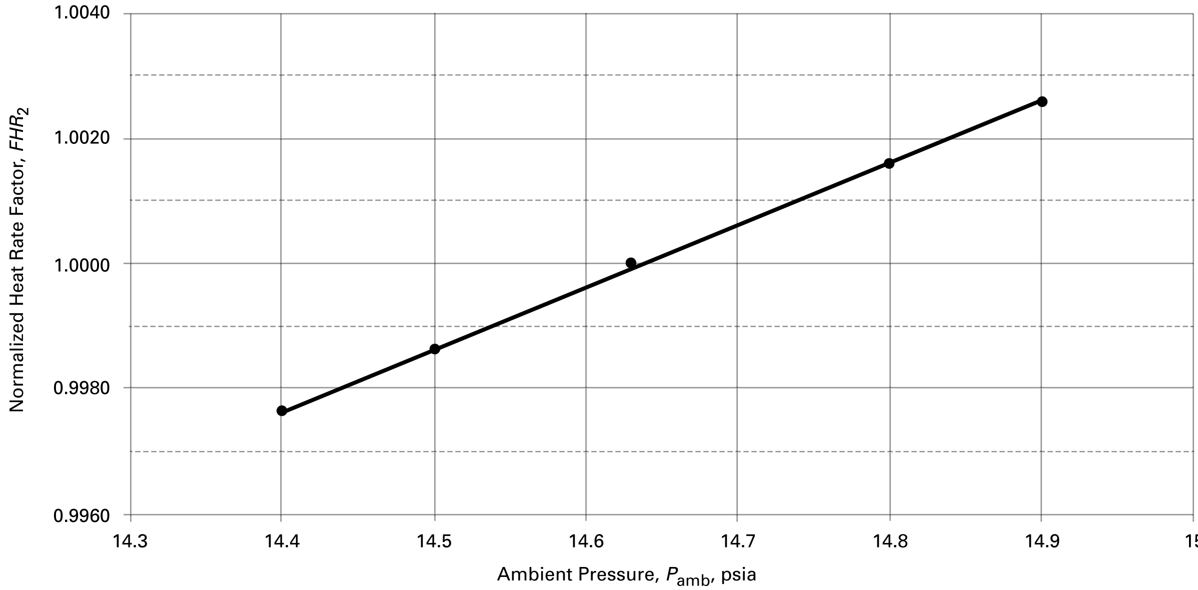
GENERAL NOTES:
(a) For $T_{amb} < 80°F$, $FHR_1 = 2.13828E–06\ T_{amb}^2 – 3.85894E–04\ T_{amb} + 1.01557E+00$.
(b) For $T_{amb} > 80°F$, $FHR_1 = 3.41953E–04\ T_{amb} + 1.02579E+00$.
(c) Correction factor $MHR_1 = 1/FHR_1$.

Fig. A-8-3 Net Plant Output Correction for Ambient Pressure



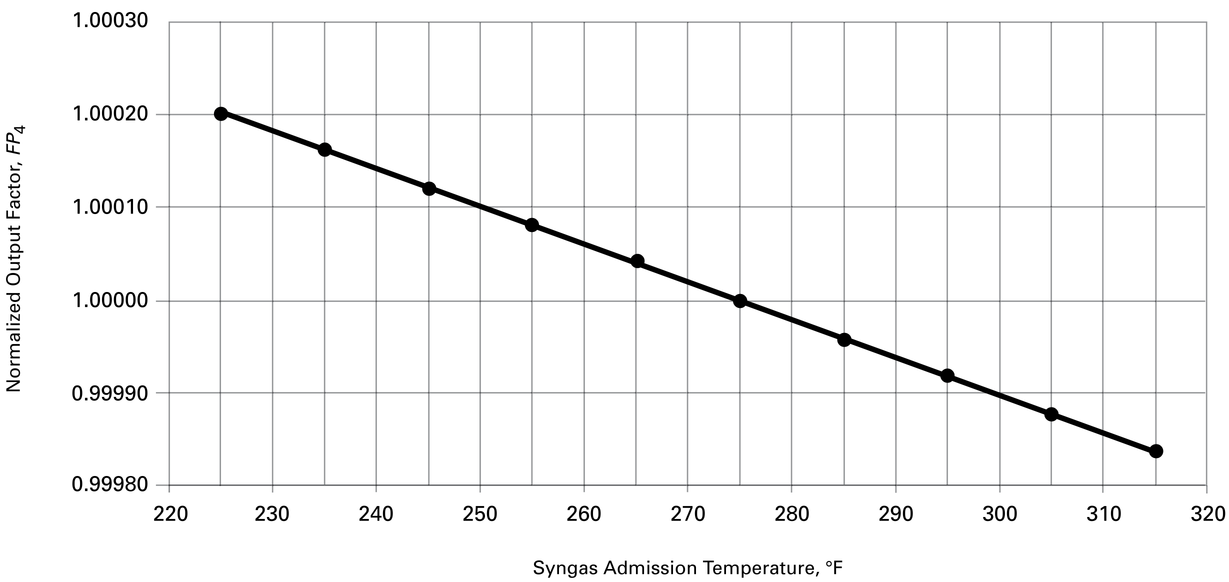
GENERAL NOTE: Correction factor $MP_2 = 1/FP_2$.
NOTES:
(1) For $T_{amb} > 82°F$, $FP_2 = –1.57929E–02\ T_{amb} + 7.69000E–01$.
(2) For $T_{amb} = 81°F$, and $P_{amb} > 14.63$ psia, $FP_2 = –1.59886E–02\ T_{amb}^2 + 4.79172E–01\ T_{amb} – 2.58813E+00$.
(3) For $T_{amb} < 80°F$, $FP_2 = –4.38307E–03\ T_{amb} + 9.35874E–01$.
(4) For $T_{amb} = 80°F$, and $P_{amb} < 14.63$ psia, $FP_2 = –1.24795E–02\ T_{amb} + 8.17578E–01$.

Fig. A-8-4 Net Plant Heat Rate Correction for Ambient Pressure



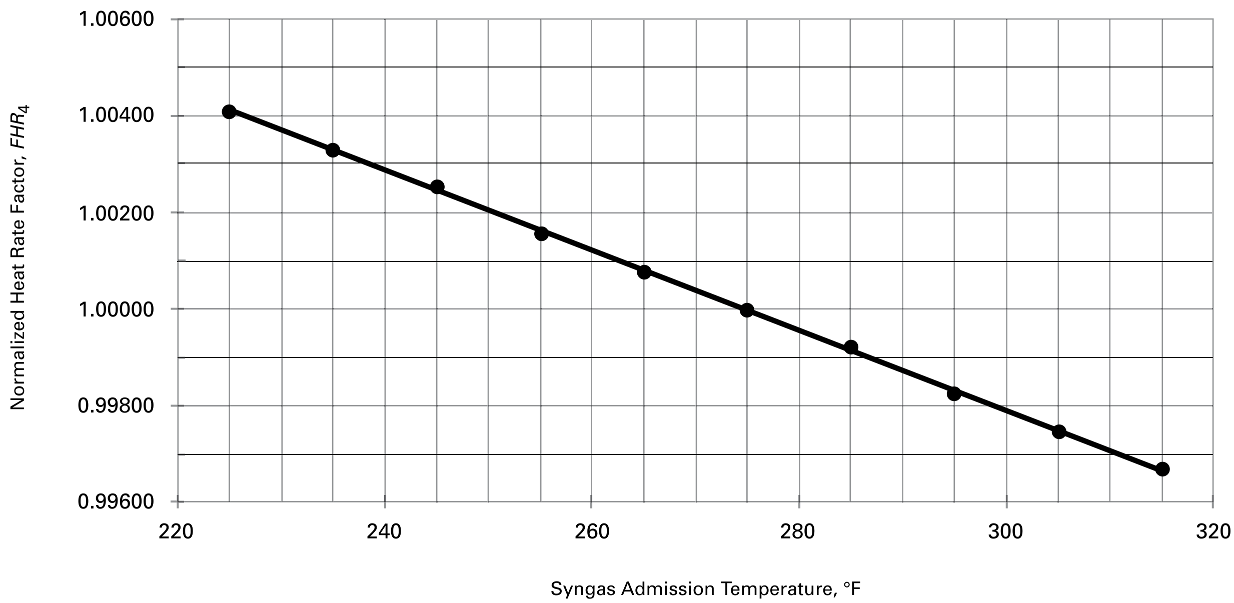
GENERAL NOTES:
(a) $FHR_2 = 9.88190E{-}03\ P_{amb} + 8.55349E{-}01$.
(b) Correction factor $MHR_2 = 1/FHR_2$.

Fig. A-8-5 Net Plant Output Correction for Syngas Admission Temperature



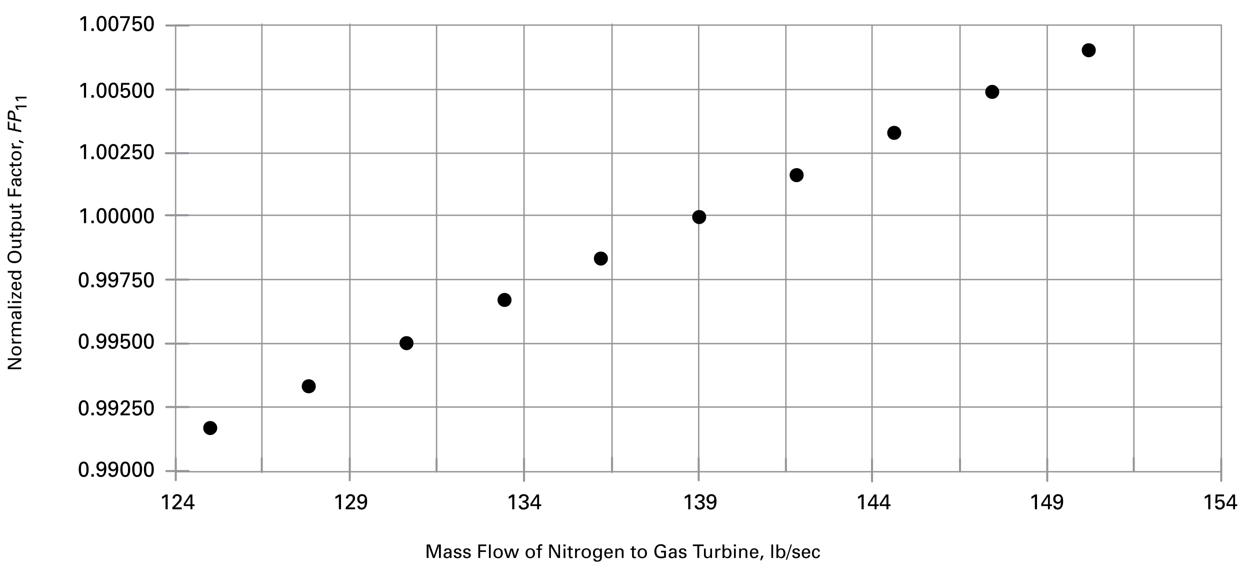
GENERAL NOTES:
(a) $FP_4 = -4.05334E{-}06\ x + 1.00111E{+}00$, where x = syngas admission temperature, °F.
(b) Correction factor $MP_4 = 1/FP_4$.

Fig. A-8-6 Net Plant Heat Rate Correction for Syngas Admission Temperature



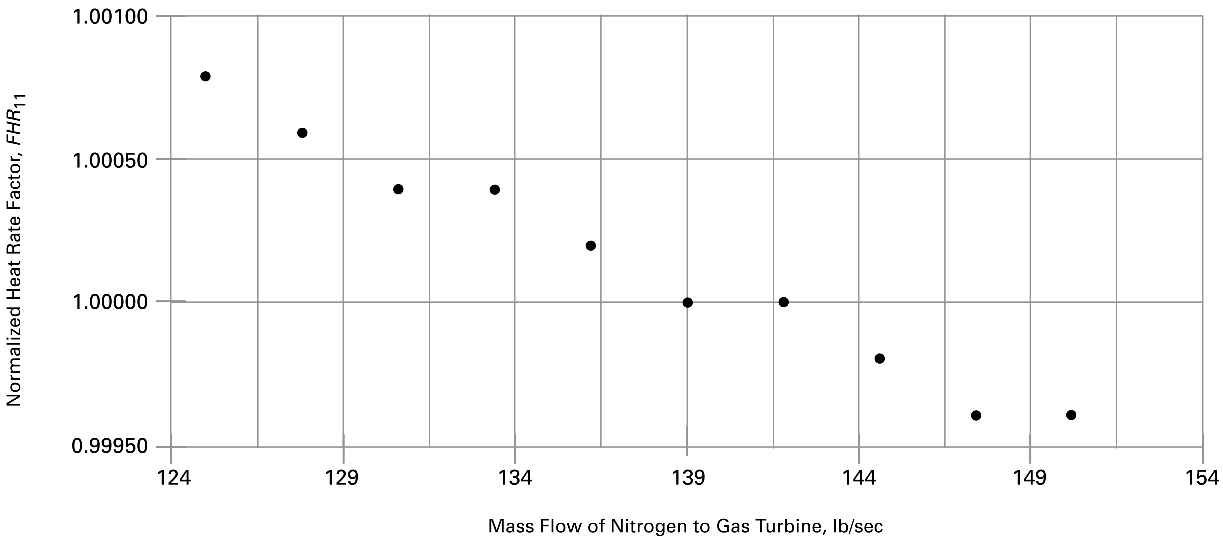
GENERAL NOTES:
(a) $FHR_4 = -8.29831E{-}05\,x + 1.02280E{+}00$, where x = syngas admission temperature, °F.
(b) Correction factor $MHR_4 = 1/FHR_4$.

Fig. A-8-7 Net Plant Output Correction for Nitrogen Admission Flow Rate



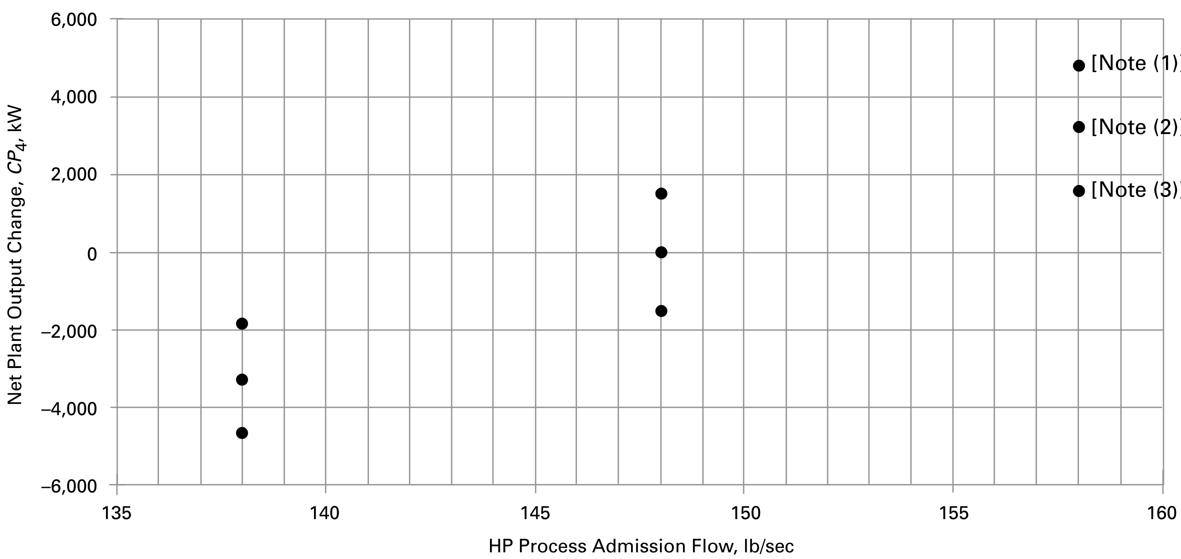
GENERAL NOTES:
(a) $FP_{11} = 0.00059\,x + 0.91812$, where x = mass flow of nitrogen to gas turbine, lb/sec.
(b) Correction factor $MP_{11} = 1/FP_{11}$.

Fig. A-8-8 Net Plant Heat Rate Correction for Nitrogen Admission Flow Rate



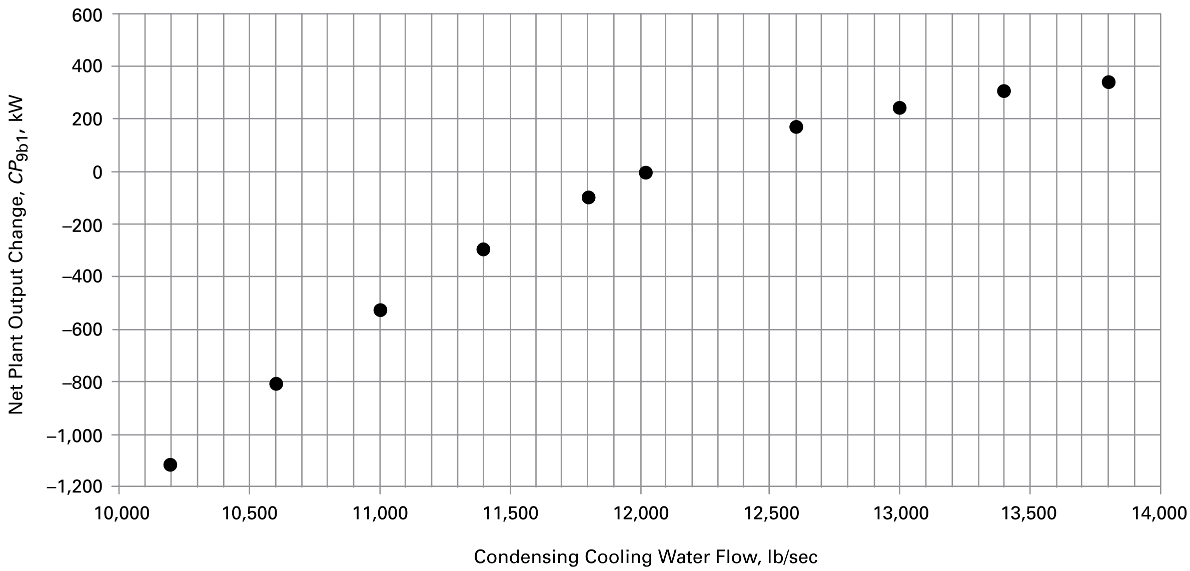
GENERAL NOTES:
(a) FHR_{11} = 2.85830E−07 x^2 − 1.26040E−04 x + 1.01205E+00, where x = mass flow of nitrogen to gas turbine, lb/sec.
(b) Correction factor $MHR_{11} = 1/FHR_{11}$.

Fig. A-8-9 Net Plant Output Correction for Import Steam Flow Rate and Enthalpy



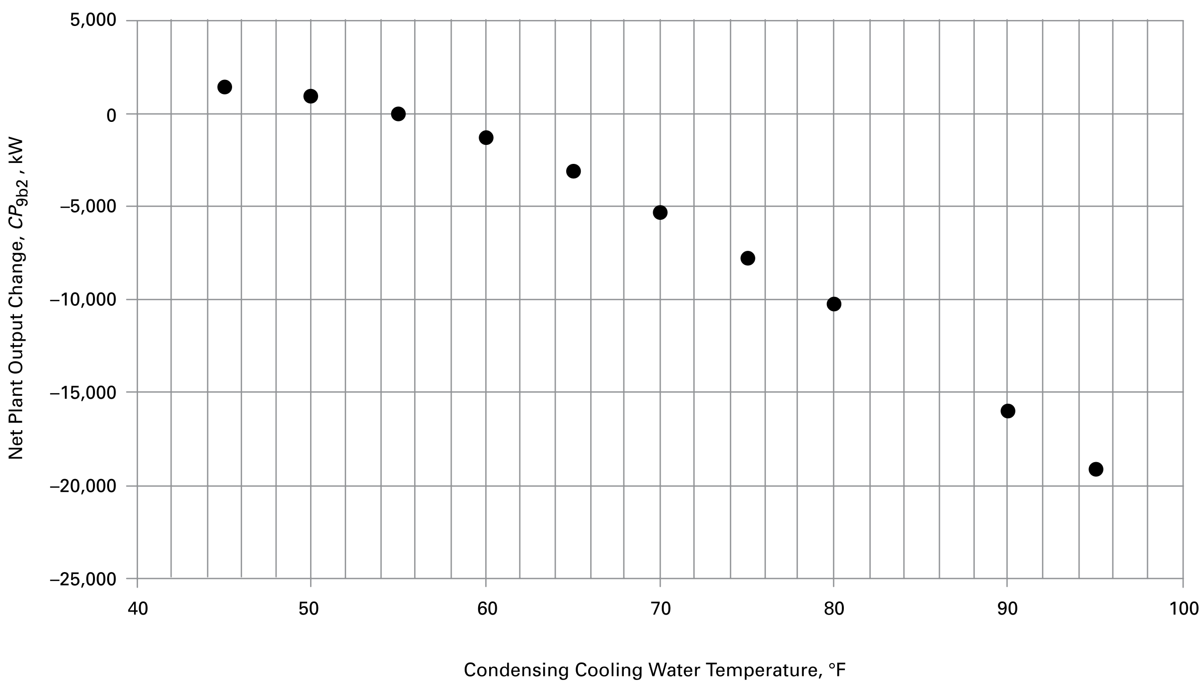
GENERAL NOTES:
(a) Correction factor $AP_4 = -CP_4$.
(b) HP = high pressure.
NOTES:
(1) For dH = 612.6 Btu/lb, CP_4 = 3.31450E+02 x − 4.75576E+04, where
dH = difference between HP process admission enthalpy and HP economizer outlet enthalpy
x = HP process admission flow, lb/sec
(2) For dH = 592.6 Btu/lb, CP_4 = 3.22849E+02 x − 4.77919E+04.
(3) For dH = 572.6 Btu/lb, CP_4 = 3.13604E+02 x − 4.79192E+04.

Fig. A-8-10 Net Plant Output Correction for Circulating Water Flow Rate



GENERAL NOTES:
(a) $CP_{9b1} = 6.57365\text{E}{-}09\,x^3 - 3.51646\text{E}{-}04\,x^2 + 5.98273\text{E}{+}00\,x - 3.25363\text{E}{+}04$, where x = condenser cooling water flow, lb/sec.
(b) Correction factor $AP_{9b1} = -CP_{9b1}$.

Fig. A-8-11 Net Plant Output Correction for Circulating Water Temperature



GENERAL NOTES:
(a) $CP_{9b2} = 7.20242\text{E}{-}02\,x^3 - 2.08110\text{E}{+}01\,x^2 + 1.40058\text{E}{+}03\,x - 2.60344\text{E}{+}04$, where x = condenser cooling water temperature, °F.
(b) Correction factor $AP_{9b2} = -CP_{9b2}$.

NONMANDATORY APPENDIX B
SAMPLE UNCERTAINTY ANALYSIS

Performance test results are influenced by errors in measuring devices and corrections to reference conditions. The potential gap between the test results and the "actual true" value can be statistically evaluated by a rigorous measurement uncertainty analysis, such as the sample analysis in this Appendix. This Appendix provides the overall test uncertainty calculations for the sample power block in Nonmandatory Appendix A, using the calculation methods described in Section 7.

Tables B-1 and B-2 are used to calculate the combined expanded uncertainty of net power and heat rate results, respectively, by approximating the following for each parameter influencing the test results:

(a) sensitivity coefficient, θ_i

(b) systematic uncertainty, $b_{\bar{X}_i}$

(c) systematic uncertainty contribution, $\left(\theta_i b_{\bar{X}_i}\right)^2$

(d) random uncertainty, $s_{\bar{X}_i}$

(e) random uncertainty contribution, $\left(\theta_i s_{\bar{X}_i}\right)^2$

Note that each systematic and random uncertainty entry in Tables B-1 and B-2 is specified at a 95% confidence interval (CI), as is the overall combined expanded uncertainty of the results, $U_{R,95}$. Blank rows represent parameters that are present in some configurations but are not present in this example.

Table B-1 Uncertainty of Corrected Power Block Output

Measured Parameter	Sensitivity Coefficient, θ_i	Systematic Uncertainty (95% CI), $\pm\left(b_{\overline{X}_i}\right)$	Systematic Uncertainty Contribution, $\left(\theta_i b_{\overline{X}_i}\right)^2$	Random Uncertainty (95% CI), $\pm\left(s_{\overline{X}_i}\right)$	Random Uncertainty Contribution, $\left(\theta_i s_{\overline{X}_i}\right)^2$
		EXTERNAL CONNECTIONS			
Inlet air					
Barometric pressure	0.0641% / %	0.100%	4.1119E−09	0.022%	1.9902E−10
Temperature	0.0112% / °F	0.250°F	7.7897E−10	0.141°F	2.4779E−10
Relative humidity	−0.0050% /%pt	2.000%pt	0.00000001	0.576%pt	8.2944E−10
Makeup water condensate temperature	% / °F	°F		°F	
Secondary fuel					
Heating value	% / %	%		%	
Gas constituent	% / %	%		%	
Temperature	% / °F	°F		°F	
Fuel flow rate	% / %	%		%	
Input steam no. 2					
Enthalpy	% / %	%		%	
Flow rate	% / %	%		%	
GT power, kW	0.6045% / %	0.450%	7.4009E−06	0.101%	3.7282E−07
ST power, kW	0.4159% / %	0.450%	3.5023E−06	0.100%	1.7295E−07
Auxiliary load	0.0204% / %	2.000%	1.6681E−07	0.100%	4.1702E−10
Net power					
Frequency	0.4850% / %	0.200%	9.409E−07	0.100%	2.3523E−07
Power factor	−0.014% / %	0.200%	7.84E−10	0.020%	7.84E−12
Export steam					
Enthalpy	% / %	%		%	
Flow rate	% / %	%		%	
Steam generator blowdown differential	% / %	%		%	
Cooling water					
Temperature	−0.1054% / °F	1.000°F	1.1109E−06	0.100°F	1.1109E−08
Flow rate	0.0164% / %	1.000%	2.6994E−08	0.201%	1.0906E−09
Cooling air temperature (if used)	% / °F	°F		°F	
Condenser pressure (if used)	% / %	%		%	

Table B-1 Uncertainty of Corrected Power Block Output (Cont'd)

Measured Parameter	Sensitivity Coefficient, θ_i	Systematic Uncertainty (95% CI), $\pm\left(b_{\bar{X}_i}\right)$	Systematic Uncertainty Contribution, $\left(\theta_i b_{\bar{X}_i}\right)^2$	Random Uncertainty (95% CI), $\pm\left(s_{\bar{X}_i}\right)$	Random Uncertainty Contribution, $\left(\theta_i s_{\bar{X}_i}\right)^2$
CONNECTIONS TO ASU					
Nitrogen					
Pressure	% / %	%		%	
Temperature	0.00006% / °F	1.000°F	3.6E−13	0.100°F	3.60E−15
Flow rate	0.0820% / %	0.500%	1.681E−07	0.011%	8.7384E−11
Extraction air					
Pressure	% / %	%		%	
Temperature	% / °F	°F		°F	
Flow rate	% / %	%		%	
Cooling water temperature	% / °F	°F		°F	
Process water temperature	% / °F	°F		°F	
CONNECTIONS TO GASIFICATION BLOCK					
Input water no. 1					
Temperature	% / °F	°F		°F	
Flow rate	% / %	%		%	
Output steam no. 1					
Enthalpy	% / %	%		%	
Flow rate	% / %	%		%	
Input steam no. 1					
Enthalpy	0.0238% / Btu	2.150%	2.6184E−07	0.210%	2.498E−09
Flow rate	0.1485% / %	1.000%	2.2065E−06	0.009%	1.8757E−10
Output water no. 1					
Temperature	% / °F	°F		°F	
Flow rate	% / %	%		%	
Output water no. 2					
Temperature	% / °F	°F		°F	0
Flow rate	% / %	%		%	0
CONNECTIONS TO SYNGAS CONDITIONING BLOCK					
Primary fuel					
Heating value	% / %	%		%	
Gas constituent	% / %	%		%	
Gas temperature	−4.10E−04% /°F	1.000°F	1.681E−11	0.151°F	3.8328E−13
Flow rate	% / %	%		%	

Table B-1 Uncertainty of Corrected Power Block Output (Cont'd)

Measured Parameter	Sensitivity Coefficient, θ_i	Systematic Uncertainty (95% CI), $\pm\left(b_{\overline{X}_i}\right)$	Systematic Uncertainty Contribution, $\left(\theta_i b_{\overline{X}_i}\right)^2$	Random Uncertainty (95% CI), $\pm\left(s_{\overline{X}_i}\right)$	Random Uncertainty Contribution, $\left(\theta_i s_{\overline{X}_i}\right)^2$
CONNECTIONS TO SYNGAS CONDITIONING BLOCK (CONT'D)					
Input water no. 2					
Temperature	% / °F	°F		°F	
Flow rate	% / %	%		%	
Output steam no. 2					
Enthalpy	% / %	%		%	
Flow rate	% / %	%		%	
Input steam no. 3					
Enthalpy	% / %	%		%	
Flow rate	% / %	%		%	
CORRELATED UNCERTAINTIES					
Sum of squares			1.5801E−05	...	7.9767E−07
Square root (sum of squares)			0.398%	...	0.089%
Combined Expanded Uncertainty of the Results, $U_{R,95}$					**0.407%**

GENERAL NOTES:
(a) Each entry for systematic and random standard uncertainty in this Table is specified at a 95% confidence interval (CI).
(b) Rows with no values represent parameters that are present in some configurations but are not present in this example.

Table B-2 Uncertainty of Corrected Power Block Heat Rate

Measured Parameter	Sensitivity Coefficient, θ_i	Systematic Uncertainty (95% CI), $\pm\left(b_{\bar{X}_i}\right)$	Systematic Uncertainty Contribution, $\left(\theta_i b_{\bar{X}_i}\right)^2$	Random Uncertainty (95% CI), $\pm\left(s_{\bar{X}_i}\right)$	Random Uncertainty Contribution, $\left(\theta_i s_{\bar{X}_i}\right)^2$
EXTERNAL CONNECTIONS					
Inlet air					
Barometric pressure	0.1446% / %	0.100%	2.0909E−08	0.022%	1.012E−09
Temperature	−0.0121% / °F	0.250°F	9.1506E−10	0.141°F	2.9108E−10
Relative humidity	0.0030% / %pt	2.000%pt	3.6E−09	0.576%pt	2.986E−10
Makeup water condensate temperature	% / °F	°F		°F	
Secondary fuel					
Heating value	% / %	%		%	
Gas constituent	% / %	%		%	
Temperature	% / °F	°F		°F	
Fuel flow rate	% / %	%		%	
Input steam no. 2					
Enthalpy	% / %	%		%	
Flow rate	% / %	%		%	
GT power, kW	0.6045% / %	0.450%	7.4009E−06	0.101%	3.7282E−07
ST power, kW	0.4159% / %	0.450%	3.5023E−06	0.100%	1.7295E−07
Auxiliary load	0.0204% / %	2.000%	1.6681E−07	0.100%	4.1702E−10
Net power					
Frequency	−0.0230% / %	0.200%	2.116E−09	0.100%	5.29E−10
Power factor	−0.0140% / %	0.200%	7.84E−10	0.020%	7.84E−12
Export steam					
Enthalpy	% / %	%		%	
Flow rate	% / %	%		%	
Steam generator blowdown differential	% / %	%		%	
Cooling water					
Temperature	−0.1054% / °F	1.000°F	1.1109E−06	0.100°F	1.1109E−08
Flow rate	0.0164% / %	1.000%	2.6994E−08	0.201%	1.0906E−09
Cooling air temperature (if used)	% / °F	°F		°F	
Condenser pressure (if used)	% / %	%		%	

Table B-2 Uncertainty of Corrected Power Block Heat Rate (Cont'd)

Measured Parameter	Sensitivity Coefficient, θ_i	Systematic Uncertainty (95% CI), $\pm\left(b_{\bar{X}_i}\right)$	Systematic Uncertainty Contribution, $\left(\theta_i b_{\bar{X}_i}\right)^2$	Random Uncertainty (95% CI), $\pm\left(s_{\bar{X}_i}\right)$	Random Uncertainty Contribution, $\left(\theta_i s_{\bar{X}_i}\right)^2$
CONNECTIONS TO ASU					
Nitrogen					
Pressure	% / %	%		%	
Temperature	0.0001% / °F	1.000°F	1.0E−12	0.100°F	1.0E−14
Flow rate	−0.0066% / %	0.500%	1.089E−09	0.0114%	5.6611E−13
Extraction air					
Pressure	% / %	%		%	
Temperature	% / °F	°F		°F	
Flow rate	% / %	%		%	
Cooling water temperature	% / °F	°F		°F	
Process water temperature	% / °F	°F		°F	
CONNECTIONS TO GASIFICATION BLOCK					
Input water no. 1					
Temperature	% / °F	°F		°F	
Flow rate	% / %	%		%	
Output steam no. 1					
Enthalpy	% / %	%		%	
Flow rate	% / %	%		%	
Input steam no. 1					
Enthalpy	0.0238% / Btu	2.150%	2.6184E−07	0.210%	2.498E−09
Flow rate	0.1485% / %	1.000%	2.2065E−06	0.009%	1.8757E−10
Output water no. 1					
Temperature	% / °F	°F		°F	
Flow rate	% / %	%		%	
Output water no. 2					
Temperature	% / °F	°F		°F	0
Flow rate	% / %	%		%	0
CONNECTIONS TO SYNGAS CONDITIONING BLOCK					
Primary fuel					
Heating value	1.000% / %	0.350%	0.00001	0.170%	0.00000289
Gas constituent	−0.027% / %	0.044%	1.4113E−10	0.030%	6.561E−11
Gas temperature	−0.008% / °F	1.000°F	6.889E−09	0.120°F	9.9202E−11
Flow rate	1.000% / %	0.600%	0.000036	0.200%	0.000004

Table B-2 Uncertainty of Corrected Power Block Heat Rate (Cont'd)

Measured Parameter	Sensitivity Coefficient, θ_i	Systematic Uncertainty (95% CI), $\pm\left(b_{\bar{X}_i}\right)$	Systematic Uncertainty Contribution, $\left(\theta_i b_{\bar{X}_i}\right)^2$	Random Uncertainty (95% CI), $\pm\left(s_{\bar{X}_i}\right)$	Random Uncertainty Contribution, $\left(\theta_i s_{\bar{X}_i}\right)^2$
CONNECTIONS TO SYNGAS CONDITIONING BLOCK (CONT'D)					
Input water no. 2					
Temperature	% / °F	°F		°F	
Flow rate	% / %	%		%	
Output steam no. 2					
Enthalpy	% / %	%		%	
Flow rate	% / %	%		%	
Input steam no. 3					
Enthalpy	% / %	%		%	
Flow rate	% / %	%		%	
CORRELATED UNCERTAINTIES					
Sum of squares			6.2963E−05	…	7.4534E−06
Square root (sum of squares)			0.793%	…	0.273%
Combined Expanded Uncertainty of the Results, $U_{R,95}$					0.839%

GENERAL NOTES:
(a) Each entry for systematic and random standard uncertainty in this Table is specified at a 95% confidence interval (CI).
(b) Rows with no values represent parameters that are present in some configurations but are not present in this example.

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