ASME PTC 22-2005

[Revision of ASME PTC 22-1997 (R2003)]

Gas Turbines

Performance Test Codes

AN AMERICAN NATIONAL STANDARD

The American Society of
Mechanical Engineers

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Three Park Avenue • New York, NY 10016

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This Code will be revised when the Society approves the issuance of a new edition. There will be no addenda issued to ASME PTC 22-2005.

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The American Society of Mechanical Engineers
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NOTICE

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

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

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

FOREWORD

The original Performance Test Codes Committee No. 22 was established in 1945 to develop a test code on Gas Turbine Power Plants. This initial Code was published in 1953. Subsequent versions of the Code were published in 1966 and 1985, each time incorporating latest practice in accordance with the directives of PTC 1, General Instructions.

The 1997 version addressed for the first time the issue of measurement uncertainty, and also recognized the significant advances in gas turbine and instrumentation technologies.

The efforts on the current version began during the publication period of the 1997 Code. Objectives were to develop procedures for comparative (back-to-back, or before and after) testing and for determining exhaust flow and energy for heat recovery applications. This Code incorporates these procedures, as well as updated calculations in many areas to reduce the uncertainty of the results.

The PTC 22 Standards Committee wishes to acknowledge the contributions of past members George Howard and Carl Petroff (deceased).

The preparation of Appendix A was a joint effort of PTC 22 and PTC 4.4 Heat Recovery Steam Generators. Principal contributors from PTC 4.4 were Glen Bostick and Joseph Schroeder. Special recognition is given to non-member Axel vonRappard, who developed the method for calculating the exhaust energy heat balance without an iterative process.

This Code was approved by the Board on Performance Test Codes on May 16, 2005, and approved and adopted as an American National standard on July 8, 2005.

PERFORMANCE TEST CODE COMMITTEE 22
GAS TURBINES

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

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

Secretary, PTC 22 Standards Committee
The American Society of Mechanical Engineers
Three Park Avenue
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Proposing Revisions. Revisions are made periodically to the Code to incorporate changes that appear necessary or desirable, as demonstrated by the experience gained from the application of the Code. Approved revisions will be published periodically.

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

Interpretations. Upon request, the PTC 22 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 22 Standards Committee.

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 which 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.

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INTRODUCTION

ASME Performance Test Codes (PTCs) provide uniform rules and procedures for the planning, preparation, execution, and reporting of performance test results. These codes provide guidelines for test procedures, which 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. ASME PTCs were developed by balanced committees representing many concerned interests.

When tests are conducted in accordance with a code, the test results themselves, without adjustment for uncertainty, yield the best available indication of actual performance of the equipment tested. ASME PTCs 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 prior to signing the contract, on the method to be used for comparing the results to contractual guarantees. It is beyond the scope of any PTC to determine or interpret how such comparisons are made.

Test uncertainty is an estimate of the limit of error of a test result. It is the interval about a test result that contains the true value with a given probability, or level of confidence. It is based on calculations utilizing statistics, instrumentation information, calculation procedure, and the actual test data.

Code tests are suitable for use whenever performance must be determined with minimum uncertainty. They are meant specifically for equipment operating in an industrial setting.

PTCs are generally not used in troubleshooting equipment. However, they can be used to quantify the magnitude of performance anomalies of equipment that is suspected to be performing poorly, or to confirm the need for maintenance, if simpler means are not adequate. PTCs are excellent sources of references for simpler routine or special equipment test procedures. Conducting periodic performance tests on equipment can uncover the need for further investigation, which can lead to preventative maintenance or modification.

GAS TURBINES

Section 1
Object and Scope

1-1 OBJECT

1-1.1

This Test Code provides directions and rules for conduct and report of results of thermal performance tests for open cycle gas turbine power plants and gas turbine engines, hereafter referred to as *gas turbines.* The object is to determine the thermal performance of the gas turbine when operating at test conditions, and correcting these test results to Specified Reference Conditions. This Code provides explicit procedures for the determination of the following performance results:

(a) corrected power output
(b) corrected heat rate (efficiency)
(c) corrected exhaust flow, energy, and temperature

Tests may be designed to satisfy different goals, including:

(d) absolute performance
(e) comparative performance

1-1.2

It is the intent of the Code to provide results with the highest level of accuracy consistent with the best engineering knowledge and practice in the gas turbine industry. In planning the test, an uncertainty analysis must demonstrate that the proposed instrumentation and measurement techniques meet the requirements of the Code.

1-2 SCOPE

1-2.1

This Code provides for the testing of gas turbines supplied with gaseous or liquid fuels (or solid fuels converted to liquid or gas prior to entrance to the gas turbine). Tests of gas turbines with emission control and/or power augmentation devices, such as injection fluids and inlet air treatment, are included. It may be applied to gas turbines in combined cycle plants or with other heat recovery systems.

1-2.2

This Code provides for comparative (back to back) tests designed to verify performance differentials of the gas turbine, primarily for testing before and after modifications, uprates, or overhauls.

1-2.3

The Code does not apply to the following:

(a) gas turbines where useful output is other than power to drive a generator or other load device

(b) environmental compliance testing for gas turbines for stack emissions and sound levels. Procedures developed by regulatory agencies, ANSI, or other PTC Committees are available to govern the conduct of such testing.

(c) overall plant power output and thermal efficiency of gas turbine combined cycle and cogeneration facilities. Refer to PTC 46.

(d) performance of specific components of the gas turbine

(e) performance of auxiliary systems of the gas turbine power plant, such as inlet cooling devices, fuel gas booster compressors, etc.

1-3 TEST UNCERTAINTY

1-3.1

In accordance with para. 1.5.3(e) of PTC 1, this Code establishes a limit for the uncertainty of each required measurement, and also limits the variation of the critical parameters during the test. The test uncertainty is then calculated in accordance with the procedures defined herein and by ASME PTC 19.1. Both pre- and post-test uncertainty calculations are required.

1-3.2

For tests of absolute performance levels, users of this Code shall develop their own site- and equipment-specific uncertainty. The overall test uncertainty will be unique for each Code test because of the differences in the scope of supply, fuels used, turbine sensitivities, instruments selected, and driven equipment characteristics.

1-3.3

For comparative testing, unlike absolute level testing, the uncertainty is more complex since the desired result is the difference in performance rather than the absolute level. Difficulty in establishing the sensitivities (which depend on the age of the equipment and the extent of the restoration), must be considered, as well as the selection of instrumentation. The parties must also assess the viability of the test, based on the uncertainty as a percentage of the expected differential. As discussed in the Code and shown in the Appendix example, the comparative test uncertainty is strongly affected by the number of tests run, by whether or not the same instrumentation was used for both before and after tests, and by the sensitivities of the unit being tested. Thus the uncertainty values can have considerable variation.

1-3.4

For the optional test to determine exhaust energy and/or flow, these values are determined from an energy balance around the gas turbine. Uncertainty values can be minimized by achieving the Code limits for the key parameters in the energy balance.

1-4 OTHER REQUIREMENTS AND REFERENCES

1-4.1

The applicable provisions of PTC 1 are a mandatory part of this Code. It should be reviewed and followed when preparing the procedure for a gas turbine test.

1-4.2

PTC 2 defines many of the terms and numerical constants used in this Code. The PTC 19 series, Supplements on Instruments and Apparatus, should be consulted when selecting the instruments used to measure the required test parameters, and when calculating test uncertainties.

Section 2
Definitions and Description of Terms

Terms provided in this Section are confined to those for which clarification is considered to improve user's grasp of Code intent. The Code is not a tutorial. It is assumed persons using this Code are experienced in performance testing of gas turbine power plants and possess working knowledge of gas turbines, thermodynamic analysis, and measurement methods.

2-1 DEFINITIONS

absolute performance: performance (output, heat rate, exhaust temperature, exhaust flow/energy) of the gas turbine power plant at a specific point in time.

auxiliary power: electrical power used in the operation of the gas turbine power plant or elsewhere as defined by the test boundary.

comparative performance: change in performance of the gas turbine power plant expressed as a differential or ratio.

control temperature: temperature or schedule of temperatures determined by the manufacturer that defines one of the operating conditions for the test. This temperature may or may not coincide with temperature of the working fluid exiting the gas turbine. Regardless of measurement location, control temperature is internal to the test boundary.

corrected performance: performance parameter adjusted mathematically to specified reference conditions.

exhaust gas emissions: constituents of the working fluid exiting the gas turbine that may be used to define in part the operating conditions for the test.

exhaust gas energy: energy of the working fluid exiting the gas turbine at a point defined by the test boundary.

exhaust gas flow: flow of working fluid exiting the gas turbine at a point defined by the test boundary.

exhaust gas temperature: mass weighted average temperature of working fluid exiting the gas turbine at a location defined by the test boundary.

heat rate: the ratio of the fuel energy input to the power output produced by the gas turbine as measured at the test boundaries. The basis of the value should always be expressed as either lower heating value or higher heating value.

extraction air: a defined air stream that intentionally leaves the test boundary.

gas turbine: machine that converts thermal energy into mechanical work; it consists of one or several rotating compressors, a thermal device(s) which heats the working fluid, one or several turbines, a control system, and essential auxiliary equipment. Any heat exchangers (excluding exhaust heat recovery exchangers) in the main working fluid circuit are considered to be part of the gas turbine.

gas turbine power plant: gas turbine and all essential equipment necessary for the production of power in a useful form (e.g., electrical, mechanical, or thermal).

gaseous fuel: mixture of combustibles with or without inerts in which each component is present as a superheated or saturated vapor under conditions of use.

heat loss: energy quantity that leaves the test boundary outside defined exits.

injection fluid: non-fuel gaseous or liquid stream that enters the test boundary.

inlet air treatment: the devices used to cool or heat the inlet air prior to entry into the gas turbine compressor. The test boundary must clearly state whether the device is inside or outside of the scope of the test.

liquid fuel: mixture of combustibles with or without inerts, which is composed almost entirely of liquid components under conditions of use.

measurement uncertainty: estimated uncertainty associated with the measurement of a process parameter or variable.

open cycle: working fluid is primarily atmospheric air with heat addition through a direct combustion of fuel.

parameter: a direct measurement; a physical quantity at a location which is determined by a single instrument, or by the average of several measurements of the same physical quantity.

power output: electrical or mechanical output based upon direct measurement at the test boundary.

Specified Reference Conditions: the values of all the conditions to which the test results are corrected.

test: group of test runs for which operating conditions may vary.

test boundary: thermodynamic control volume defined by the scope of the test, and for which the mass and energy flows must be determined. Depending on the test, more than one boundary may be applicable. Definition of the test boundary or boundaries is an extremely important visual tool that aids in understanding the scope of test and the required measurements.

test reading: one recording of all required test instrumentation.

test run: group of readings taken over a specific time period over which operating conditions remain constant or nearly so.

test uncertainty: uncertainty associated with a corrected test result.

thermal efficiency: ratio of the power produced to the fuel energy supplied per unit time. Thermal efficiency may be expressed on either a lower heating value or higher heating value basis.

tolerance: a commercial allowance for deviation from contract performance levels.

uncertainty: the interval about the measurement or result that contains the true value for a 95% confidence level.

variable: a quantity that cannot be measured directly, but is calculated from other measured parameters.

2-2 SYMBOLS

The following symbols are to be used unless otherwise defined in the text.

Symbol	Description	Units	
		U.S. Customary	**SI**
I	Current	amps	amps
B	systematic error	. . .	. . .
CR	combustion ratio	. . .	. . .
ExcLoss	exciter power	kW	kW
FC	field current	amps	amps
FDA	fraction of dry air	. . .	. . .
FV	field voltage	volts	volts
g_c	gravitational constant	$\mathrm{lb_m\text{-}ft/lb_f\text{-}sec^2}$	$\mathrm{kg_m\text{-}m/N\text{-}sec^2}$
h	specific enthalpy	BTU/lb	kJ/kg
H°	exhaust gas enthalpy	BTU/lb	kJ/kg
HHV	fuel higher heating value	BTU/lb	kJ/kg
LHV	fuel lower heating value	BTU/lb	kJ/kg
M	mass flow rate	lb/hr, lb/s	kg/s
MF	mole fraction	. . .	. . .
Mo	molar flow	$\mathrm{lb_{mol}/hr}$	$\mathrm{kg_{mol}/hr}$
MW	molecular weight	$\mathrm{lb/lb_{mol}}$	$\mathrm{kg/kg_{mol}}$
HR	heat rate	BTU/kWhr	kJ/kWhr
p	pressure	psia	bar
P	power	kW, MW	kW, MW
PF	power factor	. . .	. . .
Q	energy flow	BTU/hr	kW, MW
RH	relative humidity	%	%
RMS	root mean square	. . .	. . .
S	standard deviation	. . .	. . .
T	temperature	°F, °R	°C, K
U	uncertainty	. . .	. . .
V	voltage	volts	volts
W	humidity ratio	lb water/lb dry air	kg water/kg dry air
WF	weight fraction	. . .	. . .
α	Multiplicative correction factor for power	. . .	. . .
β	Multiplicative correction factor for heat rate	. . .	. . .
Δ	Additive correction factor for power	. . .	. . .
$\Delta_f H^\circ$	Heat of formation	BTU/mol	J/mol
δ	Multiplicative correction factor for exhaust temperature	. . .	. . .
ε	Multiplicative correction factor for exhaust energy	. . .	. . .
γ	Multiplicative correction factor for exhaust flow	. . .	. . .
θ	Sensitivity factor for uncertainty calculation	. . .	. . .

2-3 SUBSCRIPTS

Subscripts	Description
atm	atmospheric
avg	average
calc	calculated
corr	corrected
exh	exhaust
ext	extraction
i	air constituent
inj	injection fluid
j	fuel constituent
k	non-water exhaust constituent
K	Kelvin
meas	measured
n	exhaust constituent
R	result
sat	saturated

Section 3
Guiding Principles

3-1 AGREEMENTS

3-1.1 General Agreements Before Test

The parties to the test shall agree in writing on the scope of the test. Agreements shall be reached and written on the following:

(a) objectives of test

(b) the division of responsibilities of each of the parties

(c) schedule and location for the test to be conducted

(d) test boundaries identifying inputs and outputs such as the location of compressor inlet and turbine exhaust interface points and identifying measurement locations

(e) confirmation of Specified Reference Conditions and guarantees, and the test plan

(f) acceptance criteria for the test results

(g) test plan including test procedures

(h) test final report format and contents

(i) selection of alternative instruments and/or calculation procedures not covered by this Code

These agreements shall be approved, prior to the testing, by authorized signatures of all parties to the test.

3-1.2 Design, Construction, and Start-up Considerations

The following recommendations should be considered concerning the requirements of instrumentation accuracy, calibration, recalibration documentation, and location of permanent plant and temporary test instrumentation, which will be used for performance testing.

(a) The design requirements for permanent plant instrumentation must consider the requirements of Section 4 for those instruments being used for primary test measurements. This includes obtaining appropriate laboratory calibration and submitting all laboratory calibration reports, certifications or calibration results for all permanent plant instrumentation used for the test, as applicable. The ability to do post-test recalibrations or verifications is required as described in this Code.

(b) The connections and spool sections required for temporary test instrumentation such as pressure connections, thermowells, spool sections for flow meters, and electrical metering tie-ins for temporary test instrumentation should be incorporated into the plant design. Flow conditioners are recommended for differential pressure type and turbine flow meters. Flow measurement devices should be installed in horizontal pipe runs. The flow element installation should occur after acid cleaning and/or flushes.

(c) If there are any changes in location of instrumentation, then this must be documented including recording the relocation of items in the process variable loop routing during the design and/or the construction phase of the plant. Any impact on test uncertainty should be identified and reviewed with consideration to Code limitations. An example is the relocation of a flow meter within a process line.

(d) The applicability of the instrumentation should be considered for measuring the desired test process value. Note whether the recorded value is an instantaneous or average value. Note also the historical logging capabilities necessary for the testing.

(e) Access and isolation capability is required for inspection, calibration, and any temporary instrument installation and removal.

(f) Review the quantity of devices and instrument ports available at each location to reduce uncertainty and provide contingency data acquisition. An example is using two (2) single or one dual element thermocouple to measure critical temperatures.

(g) Layout the instrument loops to minimize measurement error. Precautions are listed in Section 4 of this Code. If instrument transformers are used, adequate wire size should be used to reduce voltage drops and a neutral cable should be provided to enable accurate 3-phase watt metering.

(h) The design should include the ability to duplicate critical test measurements. This allows a validation of process values and includes a contingency plan for test measurements. A separate device should be identified to collaborate and backup a test measurement.

(i) A review should be performed of the water leg correction necessary for accurate process variable measurement.

3-1.3 Responsibilities of Parties

The parties to the test shall agree on individual responsibilities required to prepare, conduct, analyze, and report the test in accordance with this Code. This includes designation of a test coordinator who will be responsible for the execution of the test in accordance with the test requirements and will coordinate the setting of required operating conditions with the plant operations staff. Procurement and installation responsibilities for test equipment must also be defined. Representatives from each of the parties to the test should be designated to observe the test and confirm that it was conducted in accordance with the test requirements. They also shall have the authority to agree upon revisions to the test requirements during the test.

3-1.4 Schedule and Location of Test Activities

A test schedule should be prepared which should include the sequence of events and anticipated time of test, notification of the parties to the test, test plan preparations, test preparation and conduct, and preparation of the report of results. The location shall be designated such as at the actual plant site or at a test facility where control and ambient conditions are acceptable to the parties to the test.

3-1.5 Test Boundary and Required Measurements

The test boundary is an accounting concept used to define the streams that must be measured to determine performance. All energy streams, which cross the test boundary of the gas turbine, shall be identified.

3-1.5.1 Generic Test Boundaries

(a) The two typical test boundaries are:

(1) The hardware scope boundary for determination of corrected performance (power output and heat rate or efficiency) of the equipment within.

(2) The heat balance boundary for calculation of the exhaust gas mass flow and energy. This boundary is typically much tighter around the gas turbine unit.

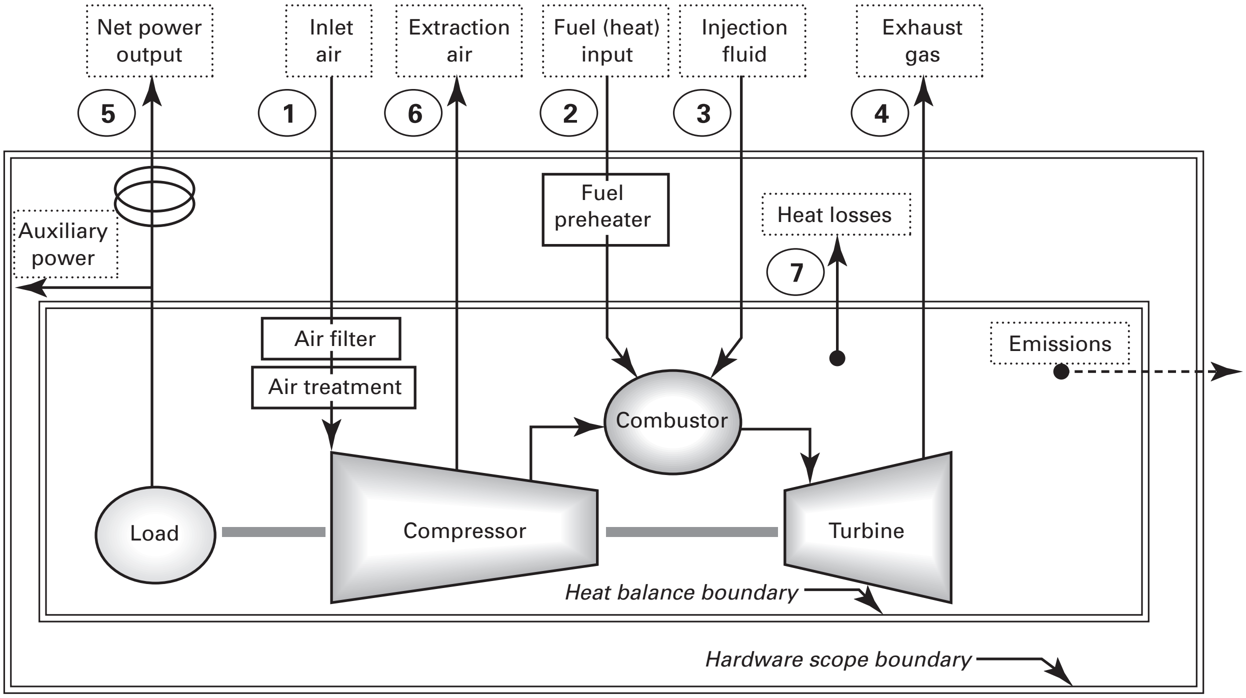
(b) For a particular test, the parties to the test must establish the test boundaries specific to their machine configuration and testing requirements. Typical boundary locations are shown in Fig. 3-1 where:

(1) air temperature measurement can be made at either the air inlet or the compressor inlet by mutual agreement of parties

(2) solid lines indicate some or all of mass flow rate, thermodynamic conditions, and chemical analysis of streams crossing the test boundary, which have to be determined to calculate the results of power and heat rate and/or to calculate the results of an exhaust flow or energy and temperature

(3) dotted lines indicate streams that do not have to be determined for calculation of the test results

3-1.5.2 Required Measurements. Flexibility is required in defining the test boundary since it is dependent on a particular gas turbine design. In general, measurements or determinations are required for the streams noted in Table 3-1.5.2.



GENERAL NOTES:

(a) Streams 1,2,3,4,5,6 required for power and heat rate calculations.

(b) Streams 1,2,3,4,5,6,7 required for exhaust flow, energy, and temperature calculations.

(c) Emissions stream not required for either calculation.

(d) Agreement required on location of inlet temperature measurement.

Fig. 3-1 Generic Test Boundaries

Table 3-1.5.2 Required Measurements

Energy Stream	Power and Heat Rate	Exhaust Flow, Energy, and Temperature
1 Inlet Air	Pressure, temperature, humidity	Pressure, temperature, humidity
2 Fuel	Temperature, flow, composition, pressure	Temperature, flow, composition, pressure
3 Injection fluid	Temperature, flow, pressure	Pressure, temperature, flow
4 Exhaust gas	Pressure, temperature	Temperature
5 Power	Net power output, power factor	Gross power output, power factor
6 Extraction air	Flow	Temperature, flow
7 Heat losses		Flow, temperature

GENERAL NOTES:

(a) Heat Losses: The measurements of heat losses from generators, lube oil coolers, turbine enclosures, rotor air coolers, etc. where it crosses the test boundary is only necessary for exhaust flow or energy calculations test. Estimated values may be used in lieu of actual measurements.

(b) Emissions: Determinations of emissions are outside the scope of this Code, and as such, no emission limitations or required measurements are specified. However, since emissions limits may have an effect on results, the test plan must specify emission levels or limits, as required operating conditions for the test.

3-1.6 Test Plan

A detailed test plan must be prepared prior to conducting a Code test. It will document agreements on all issues affecting the conduct of the test and provide detailed procedures for performing the test. It must reflect any contract requirements that pertain to the test objectives, guarantees, the schedule of test activities, responsibilities of the parties to the test, test procedures, report of results and provide any needed clarifications of contract issues. The test plan shall be approved, prior to the testing, by authorized signatures of all parties to the test. The following are included in the test plan:

(a) test acceptance criteria for test completion

(b) Specified Reference Conditions and guarantees

(c) defined test boundaries identifying inputs and outputs and measurement locations

(d) complete pretest uncertainty analysis, with systematic uncertainties established for each measurement

(e) specific type, location, and calibration requirements for all instrumentation and measurement systems

(f) method for establishing stabilization prior to test and maintaining constancy of load and other test conditions for the test

(g) fuel sample collection, handling, method of analysis, collection frequency, provision of duplicate samples for each party, and identification of testing laboratories to be used for fuel analyses

(h) allowable range of fuel conditions, including constituents and heating value

(i) required operating disposition or accounting for all internal thermal energy and auxiliary power consumers having a material effect on test results

(j) required levels of equipment cleanliness and inspection procedures

(k) control curves or control algorithms used to set the normal operating limits

(l) control parameters and allowable deviations of these parameters during the test

(m) procedure for recording test readings and observations

(n) number of test runs and durations of each run

(o) test loads and rotating speeds at which the test is to be conducted

(p) frequency of data acquisition, data acceptance, and rejection criteria

(q) the method for combining test runs to calculate the final test results

(r) numerical values, curves or algorithms for corrections and adjustments to be applied to test determinations when tests are conducted under conditions differing from the specified conditions

(s) procedures to account for performance degradation, if applicable

(t) sample calculations or detailed procedures specifying test run data reduction and calculation and correction of test results to Specified Reference Conditions

(u) the requirements for data storage, document retention, data and test report distribution

(v) method for agreeing to and documenting any modification to test plan

3-2 PREPARATIONS TO TEST

3-2.1 Preliminary to Test

All parties to the test shall be given timely notification, as defined by prior agreement, to allow them the necessary time to respond and to prepare personnel, equipment, or documentation. Updated information should be provided, as it becomes known.

3-2.2 Pretest Records

Dimensions and physical conditions of parts of the gas turbine required for calculations or other test purposes shall be determined and recorded prior to the test. Serial numbers and data from nameplates should be recorded to identify the gas turbine and auxiliary equipment tested. All instrumentation should be identified and model and serial numbers recorded. Documentation must be developed or be made available for calculated or adjusted data to provide independent verification of algorithms, constants, scaling, calibration corrections, offsets, base points, and conversions.

3-2.3 Protection of Instrument Uncertainty

Instrumentation used for data collection must be at least as accurate as instrumentation identified in the pretest uncertainty analysis. This instrumentation can either be permanent plant instrumentation or temporary test instrumentation.

Multiple instruments should be used as needed to reduce overall test uncertainty. The frequency of data collection is dependent on the particular measurement and the duration of the test. To the extent practical, multiple 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.

Calibration or adequate checks of all instruments prior to the test must be carried out, and those records and calibration reports must be made available. Following the test, recalibration or verification is required for those instruments that present an inconsistency observed by a party.

3-2.4 Equipment Inspection and Cleanliness

Prior to conducting a test, the cleanliness and condition of the equipment shall be determined by inspection of equipment or review of operational records, or both and witnessed by all parties. Cleaning, such as off line compressor water wash, should be completed prior to the test and equipment cleanliness agreed upon.

The gas turbine should be checked to ensure that equipment and subsystems are installed and operating in accordance with their design parameters.

It should be noted that all gas turbines are subject to performance degradation over time at differing rates depending on fuels, air and water quality, methods of dispatch and care in operation and maintenance of the gas turbines. It is recommended that there be an agreement by the parties to the test as to the definition of what constitutes a new and clean unit and the application method of any appropriate degradation curves.

3-2.5 Preliminary Operation and Adjustment

Before starting the test, the gas turbine shall be operated for sufficient time to demonstrate that there is acceptable mechanical operation and stable control and that the operating variables are within the deviation shown in Table 3-3.5. Verification shall be made at this time that the gas turbine is operating in accordance with the control curve or control algorithm provided by the manufacturer. During this period, instruments shall be checked.

3-2.6 Preliminary Testing

Preliminary testing should be conducted sufficiently in advance of the start of the overall performance test to allow time to calculate preliminary results, make final adjustments, and modify the test requirements and/or test equipment. Results from the preliminary testing should be calculated and reviewed to identify any problems with the quantity and quality of measured data.

3-2.7 Review of Results

It is recommended that a heat balance calculation be performed as part of the preliminary test to determine the exhaust flow. Suggested methods for checking confidence in exhaust flow results may include:

(a) compare to design exhaust flow

(b) refer to mass flow calculations in Nonmandatory Appendix A

(c) compare to HRSG balance

(d) compare O_2 calculated with O_2 measured at the stack

(e) compare CO_2 calculated with CO_2 measured at the stack

(f) compare to measured exhaust flow from traverses of exhaust duct

3-3 CONDUCT OF TEST

3-3.1 Specified Reference Conditions

These conditions are defined by the guarantees or object of the test and they form the baseline for the performance and heat rate corrections. Every effort should be made to run the test as close to Specified Reference Conditions as possible, in order to minimize the effect of corrections.

3-3.2 Starting and Stopping Tests and Test Runs

The test coordinator is 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.

3-3.2.1 Starting Criteria. Prior to starting the performance test, the following conditions must be satisfied:

(a) Operation, configuration, and disposition for testing has been reached in accordance with the agreed upon test requirements, including:

  (1) Equipment operation and method of control

  (2) Availability of consistent fuel within the allowable limits of the fuel analysis for the test (by analysis as soon as practicable preceding the test)

  (3) Gas turbine operation within the bounds of the performance correction curves, algorithms or programs

(4) Equipment operation within the manufacturer's allowable limits and emissions within permitted values

(5) The operating conditions will meet the requirements of para. 3-3.5.

(b) Stabilization. Before starting the test, the gas turbine shall be run until stable conditions have been established. Stability will be achieved when continuous monitoring indicates the readings have been within the maximum permissible variation established by the manufacturer.

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

3-3.2.2 Stopping Criteria. Tests are normally stopped when the test coordinator is satisfied that requirements for a complete test run have been satisfied. (See para. 3-3.4.) The test coordinator should verify that modes of operation during test, specified in para. 3-3.3, have been satisfied. The test coordinator may extend or terminate the test if the requirements are not met.

3-3.3 Operation Prior to and During Tests

All equipment necessary for normal and sustained operation at the specified conditions must be operated during the test or accounted for in the corrections. Intermittent operation of equipment within the test boundary should be accounted for in a manner agreeable to all parties.

3-3.3.1 Operating Mode. The gas turbine should be operated in a manner consistent with the basis of design or guarantee, and in a manner that will permit correction from test operating conditions to Specified Reference Conditions. The gas turbine operating mode shall be in accordance with the bounds of the correction curves provided prior to commencement of the test. It is mandatory that the control constants and inputs used to control the turbine be recorded during the test.

3-3.3.2 Auxiliary Equipment Operation. Equipment that is necessary for operation or that would normally be required for the gas turbine to operate at Specified Reference Conditions must be operating or accounted for in determining auxiliary power loads. Intermittent auxiliary loads must also be accounted for in an equitable manner and applied to the power consumption. Examples of intermittent loads are heaters and heat tracing.

3-3.3.3 Inlet Air Treatment (Evaporative Coolers, Chillers, Foggers, Heaters). Due to the increase in the uncertainty caused by the variability of the effectiveness of inlet air treatment devices, it is recommended that the gas turbine test be run without these devices in service. The performance results can then be adjusted using the appropriate design correction curves for the inlet air treatment equipment that is out of service. However, if inlet air treatment operation is specified as part of the scope of the performance test, the gas turbines may be tested with the inlet air treatment equipment in service, and the performance results adjusted using the appropriate correction curves. Since the sensible heat difference of the water added or removed (blowdown) is very small, no correction is necessary for testing with coolers. Refer to ASME PTC 46 in the case when a complete chilling system is included in the test boundary.

3-3.3.4 Adjustments Prior to and During Tests. Prior to start of the actual test run, adjustments are permitted provided that stabilization as defined in para. 3-3.2.1 is established. Once the test run has started, no adjustments are permitted except by agreement of all the parties to the test.

3-3.4 Duration of Test Run and Frequency of Readings

The duration of a test run and the frequency of the readings shall be selected to provide a reliable average of the readings. A 30 min test run is recommended to be in compliance with Table 3-3.5 and to meet the uncertainty requirements of this Code. A test can be a single 30 min run or the average of a series of runs, each being separately corrected, then averaged. While this Code does not require multiple runs, the advantages of multiple runs should be recognized as providing a means for valid rejection of bad test runs, reducing average uncertainty and to verify the repeatability of results.

3-3.5 Maximum Permissible Variations in Operating Conditions

The calculated standard deviation of the data sample shall not exceed the values given in Table 3-3.5. If operating conditions vary during any test run beyond the limits prescribed in Table 3-3.5 the results of the test run shall be discarded.

Table 3-3.5 Maximum Permissible Standard Deviations of Measurements in Operating Conditions

Variable	Relative Standard Deviation for Station [Note (1)]
Power output (electrical)	1.3%
Torque	1.3%
Barometric pressure	0.33%
Inlet air temperature	1.3°F
Pressure—gaseous fuel as supplied to gas turbine	0.65%
Fuel flow	1.3%
Absolute exhaust back pressure	0.33%
Rotating speed	0.65%

NOTE:
(1) It is the standard deviation of the population.

3-4 TEST RECORDS

3-4.1 Test Readings

To the extent possible, test readings shall be recorded on a data acquisition system. A complete set of unaltered data acquisition sheets and recorded charts, electronic media or facsimiles thereof, shall become the property of each party to the test at the end of the test. The observations shall include the date and time of day. They shall be the actual readings without application of any corrections. The log sheets and all recorded charts constitute a complete record.

3-4.2 Direct Readings

Direct manual readings of instruments are to be recorded at uniform frequent intervals during a test. It is preferable to observe simultaneously all instruments at the same intervals.

3-4.3 Certified Data

It is recommended that data considered to be especially important be confirmed by a second observer.

3-4.4 Test Log

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

3-4.5 Test Recording Errors

Manual data shall be recorded in ink. In case of error in a recorded observation, a line shall be drawn in ink through the incorrect entry, the correct reading is to be recorded in ink and initialed above the incorrect entry, and an explanation entered in the proper place in the test records. A comparison of these observations should be made as soon as possible and any discrepancies reconciled before the end of the test.

3-5 TEST VALIDITY

3-5.1 Validity of Results

If, during the conduct of a test or during the subsequent analysis or interpretation of the observed data, an inconsistency is found which affects the validity of the results, the parties should make every reasonable effort to adjust or eliminate the inconsistency by mutual agreement. Failure to reach such agreement will constitute rejection of the run or test.

3-5.2 Reporting of Results

In all cases, the test results shall be reported:

(a) as calculated from the test observations, with only instrument calibration adjustments having been applied; and

(b) as corrected for deviations of the test condition from the Specified Reference Conditions.

3-5.3 Causes for Rejection of Readings

Upon completion of test or during the test itself, the test data shall be reviewed to determine if any data should be rejected prior to the calculation of test results. Should serious inconsistencies which affect the results be detected, 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. Refer to ASME PTC 19.1 for data rejection criteria.

3-6 UNCERTAINTY

3-6.1 Objectives

The application of uncertainty analysis to a Code test has four objectives:

(a) demonstrates compliance of the test procedure with the uncertainty requirements of the Code;

(b) reduces the risk of making an erroneous decision when evaluating the results;

(c) identifies the contribution of each measurement to the overall uncertainty;

(d) provides a mechanism for improving the quality of the test.

3-6.2 Uncertainty Calculations

Reference should be made to ASME PTC 19.1 for definitions and theory behind uncertainty analyses, as well as for the mathematical derivations of the formulas used. Calculations shown in Section 7 are in accordance with ASME PTC 19.1. This Code provides a test procedure that produces results with the lowest practical uncertainties. However, no measurement is without error, and the uncertainty of each measurement should be evaluated by the parties. All uncertainty values that have been determined and agreed upon shall be included in the report (see Section 6).

3-6.3 Differences in Uncertainties

This Code specifies procedures for typical acceptance type tests for power output and efficiency, energy balance tests for exhaust flow, energy and/or temperature, and comparative tests for later uprates and modifications. The uncertainty calculation method for each type is different, and Section 7 provides an outline of the procedure, sample calculations, and guidance on the application of the analysis.

3-6.4 Pretest and Post-test Uncertainty Analyses

This Code recommends the following procedure for establishing test uncertainties that qualify as Code tests:

3-6.4.1 A pretest uncertainty analysis shall be performed so that the test can be designed to meet Code requirements. The parties can calculate a maximum uncertainty by using the Code limit for each measurement (from Table 4-1) along with the appropriate sensitivity factors for the turbine being tested. This will establish the Code limit test uncertainty.

3-6.4.2 The parties should then select the number and type of instrument(s) for each parameter that will result in an uncertainty equal to or less than the required Code uncertainty. This should provide some margin below the Code limit to allow for unexpected deviations during the test, as determined in the post-test analysis.

3-6.4.3 A post-test uncertainty analysis shall also be performed to reveal the actual quality of the test. If the post-test analysis shows that the uncertainty of any measurement exceeds the Code limit, but the exceeded measurement(s) do not result in an overall test uncertainty greater than the Code limit from para. 3-6.4.1 above, the test should be considered valid. A post-test result that exceeds the Code limit will require the parties to decide on acceptance or rejection of the test.

3-6.5 Uncertainty Limits for Each Type of Code Test

Procedures detailed in Section 7 show that the Code tests require different approaches for calculating test uncertainties.

3-6.5.1 Power Output, Heat Rate, Exhaust Flow/Energy, and Exhaust Temperature Tests. For these tests it is not possible to define a single value of uncertainty in order to be designated a Code test. The test uncertainty is a function of the number of components included in the gas turbine or power plant, the sensitivity of that turbine to the ambient and other corrections that must be applied to determine its performance at the Specified Reference Conditions, the type of fuel used, and the ability to measure the power output of the driven equipment. As stated above, the Code defines uncertainty limits for each of the measured parameters; the combination of the applicable limits will determine the Code limit for that particular configuration and test.

3-6.5.2 Comparative Tests. In this case the difference between two tests is of interest, and the uncertainty calculation method will not be the same as for para. 3-6.5.1. Based on the anticipated change in performance, the parties should agree on an acceptable uncertainty limit. To provide assurance that the test has accurately determined the change in performance, the test uncertainty must generally be no greater than 10% of the expected difference.

Section 4
Instruments and Methods of Measurement

4-1 GENERAL REQUIREMENTS

4-1.1 Introduction

This Section presents the mandatory requirements for instrumentation selection and application. The Instruments and Apparatus supplement (ASME PTC 19 Series) outlines the governing requirements for all ASME performance testing. This Code will refer to the pertinent ASME PTC 19 Code for each type of measuring device. New devices and methods may be employed in lieu of any instrumentation recommended in this Code as they become available, provided that they meet the maximum allowable uncertainty limits specified herein. U.S. Customary units are used primarily in this Section. However, any other consistent set of units may be used.

4-1.2 Maximum Uncertainties

This Code identifies specific uncertainty limits that shall be met for each test measurement. Table 4-1 summarizes these maximum allowable uncertainties. These mandatory uncertainty limits represent the total uncertainty of each particular measurement including all systematic (which include spatial) and random effects. These values are to be compared to the actual uncertainty for each measurement individually prior to multiplying by the relative sensitivity factors to calculate an overall test uncertainty for the tested parameter (output, heat rate, exhaust flow, exhaust energy, or exhaust temperature). If the uncertainties in this table are met, the test shall be deemed a valid Code test with respect to meeting measurement uncertainty requirements. These uncertainties may be achieved by the methods described in this Section 4 or by other means mutually acceptable by the parties to the test.

4-1.3 Instrument Calibration

4-1.3.1 Definition of Calibration. Calibration of an instrument is the act of applying process conditions to the candidate instrument and to a reference standard in parallel. Readings are taken from both the candidate instrument and the reference standard. The output of the instrument then may be adjusted to the standard reading. As an alternative, the difference between the instrument and the reference standard may be recorded and applied to the instrument reading. This alternative method is mandatory in the case of thermocouples, resistance temperature detector (RTD), voltage transformers (VT), and current transformers (CT) because their output cannot be easily altered.

4-1.3.2 Reference Standard. All test instrumentation requiring calibration must be calibrated against reference standards traceable to the National Institute of Standards and Technology (NIST), other recognized international standard organizations, or recognized physical constants. All reference standards should be calibrated as specified by the manufacturer or at other frequency as the user has data in support of the calibration period extension. Supporting data is historical calibration data that demonstrates a calibration drift less than the accuracy of the reference standard for the desired calibration period.

The reference standard should have an uncertainty at least four times less than the test instrument to be calibrated. A reference standard with a higher uncertainty may be employed if the uncertainty of the instrument be-

Table 4-1 Maximum Allowable Measurement Uncertainties

Parameter or Variable	Uncertainty
AC power (RSS of VTs, CTs and meters)	0.25%
Auxiliary power	5%
DC power	0.5%
Torque	1.5%
Speed	0.1%
Time	0.05%
Inlet temperature	1°F or 0.6°C
Barometric pressure	0.075%
Humidity: Wet bulb, or	2°F or 1.1°C
RH from meter	2%
Extraction/injection flows (Water, steam, N_2, rotor cool)	2%
Extraction/injection temperature	5°F or 2.8°C
Gas fuel heat input	
Orifice factors (orifice meter)	0.4%
Mass flow (turbine meter)	0.5%
% volume of constituents	0.33%
Oil fuel heat input	
Mass flow	0.5%
Heat value	0.4%
Gas fuel temperature (for sensible heat calculation)	5°F or 2.8°C
Oil fuel temperature (for sensible heat calculation)	5°F or 2.8°C
Inlet total pressure drop	10%
Exhaust static pressure drop	10%
Exhaust temperature (Appendix A)	10°F or 5.6°C

ing calibrated provides an overall measurement less than the mandatory uncertainty limits specified herein. Instruments with low relative sensitivity factors may be calibrated against another calibrated instrument provided the mandatory uncertainty limits specified herein are met.

4-1.3.3 Instrument Ranges and Calibration. The number of calibration points depends upon the magnitude of the measurement's sensitivity factor relative to the tested parameter. The calibration should bracket the expected measurement values as close as possible. All instruments should be calibrated such that the expected values are approached from a higher value as well as a lower value. This approach will minimize hysteresis effects. Test instruments should be calibrated at two (2) points more than the order of calibration curve fit. Instruments with variable ranges of operations must be calibrated at each range that might be used during the test.

Instruments used to measure variables not directly input into test calculations can be checked in place with two or more instruments measuring the variable with respect to the same location or can be calibrated against a previous calibrated instrument. The calibration of the instrument is sufficient at one point in the expected range of operation.

4-1.3.4 Timing of Calibration. Calibrations should take place as close to the test date as possible. The Code does not mandate a period of time between the initial calibration, the test period and the recalibration. Equipment manufacturers' requirements and indications should be used as a basis for determination of the optimum time interval needed to keep the calibration drift to a minimum.

The Code recommends conducting a post test instrument calibration if the recorded data indicates a possibility of instrument error. The post-test checking should include at least a loop calibration, as defined below, or a site verification using an additional instrument.

4-1.3.5 Calibration Drift. Calibration drift is defined in the calibration correction as a percent of reading. When a post-test calibration indicates the drift is less than the instrument bias uncertainty, the drift is considered acceptable and the pretest calibration is used as the bias 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 results from many sources including instrument malfunction, transportation, installation, or removal of the test instrument. Should unacceptable calibration drift occur, engineering judgment must be used to determine whether the initial calibration or the recalibration is correct. Below are some 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. Examples of this check include vented pressure transmitters, equalized ΔP transmitters, no load on power meters, and ice point temperature instrument checks.

(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.

(c) Consult the equipment manufacturer about potential problems if such potential is suspected.

4-1.3.6 Loop Calibration. All test instruments should be loop-calibrated when practicable. Loop calibration involves the calibration of the test instrument through the test signal conditioning equipment. This is normally accomplished by pairing the instrument and the signal conditioner prior to calibration, then calibrating both at the same time. When this is done, the instrument and signal conditioner must remain paired for the loop calibration to remain valid.

When a loop calibration is not possible, the instrument and signal conditioner may be calibrated separately. The instrument is calibrated using a known process and a high accuracy signal conditioner. The signal conditioner is calibrated by applying a known input signal generated by a precision signal generator. When this method is used, the total measurement uncertainty is the combination of the instrument and signal conditioner uncertainties. The combined uncertainty of both the instrument and signal conditioner must still meet the measurement system accuracy requirements described herein.

4-1.3.7 Quality Assurance Program. Each calibration laboratory must have in place a quality assurance program. This program is a method of documentation where the following information can be found:

(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. The program also ensures that properly trained technicians calibrate the equipment in the correct manner.

All parties to the test should be allowed access to the calibration facility as the instruments are calibrated. The quality assurance program should also be made available during the visit.

4-1.4 Data Collection and Handling

4-1.4.1 Data Collection and Calculation Systems. A data collection system should be designed to accept multiple instrument inputs and be able to sample data from all of the instruments within one to two minutes to obtain all necessary data for a given data point. In many cases, the data collection can be performed in less than 1 min. The system should be able to collect data and store data and results within 2 min.

The data calculation system should have the ability to average each input collected during the test and calculate test results based on the averaged results. The system should also calculate standard deviation and coefficient of variance for each instrument. The system should have the ability to locate and eliminate spurious data from 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 outliers.

4-1.4.2 Data Management. Signal inputs from the instruments should be stored to permit post test data correction for application of new calibration corrections. The engineering units for each instrument along with the calculated results should be stored for reporting and future reference. Prior to leaving the test site all test data should be stored in removable media (such as floppy disks, CDs, and/or hard copy printouts) in case collection system equipment is damaged during transport. It is always recommended to leave a copy of all data at the site or to transport it by alternate means (i.e., hand carry originals, mail copies).

Some test programs may require some data to be recorded manually. The data sheets should each identify the data point number and time, test site location, date, and name of the person recording.

The averaged data in engineering units and any manually collected data should be available to all parties to the test prior to leaving the test site.

4-1.4.3 Design of Data Collection Systems. With advances in computer technology, data collection system configurations have a great deal of flexibility. These can consist of a centralized processing unit or distributed processing to multiple plant locations. Each measurement loop must be designed with the ability to be loop calibrated separately, so that it can be individually checked for continuity and power supply; and if applicable, to trace problems during equipment setup and checkout. 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.

When considering the accuracy of a measurement, the accuracy of the entire measurement loop must be considered. This includes the instrument and the signal conditioning loop or process. Ideally, when an instrument is calibrated it should be connected to the position on the data collection system that will be employed during the test. Should this be impractical, each piece of equipment in the measurement loop should be individually calibrated. Separate pieces of equipment include current sources, volt meters, electronic ice baths, and resistors in the measurement loop. If the system is not loop calibrated prior to the test, the parties to the test should be allowed to spot check the measurement loop using a signal generator to satisfy that the combined inaccuracy of the measurement loop is within the expected value.

The Code does not prohibit the use of the plant measurement and control system for a test. However, the system must meet the requirements of this Section. Some cautions are mentioned below.

(a) Plant measurement and control systems typically do not calculate flows in a rigorous manner. Often the flow is merely based on a simple ratio relationship with some compensation factors. Flow calculations for a Code test should be in accordance with the applicable methods described in this Section.

(b) Often the plant systems do not have the ability to apply calibration correction electronically. The output of some instrumentation like thermocouples cannot be modified so electronic calibration is necessary.

(c) Some plant systems do not allow the raw instrument signal to be displayed or stored prior to conditioning. This raw signal must be available in order to check the signal conditioning for error.

(d) Distributed control systems typically only report changes in a variable when it exceeds a preset threshold (or deadband) value. The threshold value must be low enough so that all data signals sent to the distributed control system during a test are reported and stored to a sufficient precision level.

4-2 PRESSURE MEASUREMENT

4-2.1 General

All pressure measurements shall be carried out in accordance with ASME PTC 19.2. Calibrated transmitters, calibrated transducers, manometers, dead weight gages or calibrated elastic gages shall be used for reading pressures.

Pressure instruments should be installed with an isolation valve at the end of the sensing line upstream of the instrument. The line should be vented before the instrument installation. For steam service, a sufficient time should be allowed to form a water leg in the sensing line before any reading is taken.

4-2.2 Transmitters and Transducers

4-2.2.1 It is recommended that electronic transmitters and transducers be used for those measurements that require low uncertainty to minimize random error.

4-2.2.2 Two redundant transmitters are recommended for quality readings.

4-2.2.3 Prior to calibration, the pressure transducer range may need to be altered to better match the process. Some pressure transducers have the capability of changing the range once the transmitter is installed. All transmitters must be calibrated at each range to be used during the test period.

4-2.2.4 Pressure transmitters should be temperature compensated. If temperature compensation is not available, the ambient temperature at the measurement location during the test period must be compared to the temperature during calibration to allow compensation or to determine if the decrease in accuracy is acceptable.

4-2.2.5 Transmitters should be installed in the same orientation they are calibrated.

4-2.2.6 Digital signals are preferred between the transmitters and recorders to eliminate the digital-to-analog and analog-to-digital conversions and to preclude signal interference. All analog signal cables must have a grounded shield to drain any induced currents from nearby electrical equipment. All analog signal cables are to be installed as much away as possible from EMF producing devices such as motors, generators, electrical conduit, cable trays, and electrical service panels.

4-2.3 Manometers

Manometers should be of the vertical U-tube or single leg type. A bore of $^5/_{16}$ in. (7.94 mm) or more is required. In a single-leg manometer, means should be available for adjusting the zero of the scale while the instrument is in use. Manometers shall be selected such that the scale length and the fluid density permit reading to the uncertainty required by this Code, per Table 4-1.

4-2.4 Elastic Gages

Bourdon gages or other elastic gages may be used for measurement of pressure greater than 20 psig (1.38 bar) provided that they are calibrated with a deadweight gage before and after test. The temperature at the gage during calibration shall be within 20°F (11°C) of the average temperature during the test. Elastic gages shall be selected such that the scale diameter and graduations permit reading to the uncertainty required by this Code, per Table 4-1.

4-2.5 Barometric Pressure (Barometers)

Absolute pressure transmitters or electronic cells are recommended for sensing barometric pressure. Two redundant barometers are required. The barometer shall be located outdoors in a stable environment. The barometer shall be positioned upright (to be the same as when calibrated) at the same elevation as the gas turbine shaft centerline. The elevation of the barometer (or a photo recording its location) shall be included in the test report.

4-2.6 Inlet Total Pressure

Inlet pressure is defined as the absolute total pressure at the mutually agreed upon inlet interface. Unless agreed otherwise, inlet pressure is considered to be atmospheric barometric pressure. Total pressure readings at the gas turbine inlet may be taken at multiple centers of equal areas using Kiel probes; i.e., shrouded Pitot tubes. If it is not possible to acquire total pressure readings at the gas turbine inlet due to physical arrangement, the total pressure may be computed using calculated velocity and the average of four static pressure readings from locations equally spaced around the gas turbine inlet. The total pressure is:

$$P_{\text{total}} = (\text{Air Density})(\text{Velocity})^2/2g_c + \text{Static Pressure} \quad (4\text{-}2.1)$$

where g_c is the gravitational constant, the proportionality constant relating mass, and force.

When the bellmouth throat is outfitted with pressure indication, the pressure shall be recorded, for baseline flow information, unless agreed otherwise.

4-2.7 Static Pressure in Ducts

Static pressure in ducts shall be the average of the readings at four stations equally spaced around the duct in the same plane, and each read separately. Where duct walls are smooth and parallel, static pressure taps are preferred to pressure probes. The diameter of the static tap hole shall not exceed $^1/_{16}$ in. (1.59 mm). The length of the static hole shall have a minimum length of 2.5 times the tap hole diameter and a maximum length of six times the tap hole diameter. Where the duct walls are not suitable for pressure taps because of irregularities in shape, static pressure probes (e.g., pancake probes or guide plates) may be used instead. Care shall be taken to assure that static pressure probes are oriented along flow streamlines and are not located in regions of steep pressure gradients.

4-2.8 Compressor Discharge Pressure/Combustion Chamber Pressure

For units that use the subject pressure as part of the fuel control algorithm, the compressor discharge pressure being used for control shall be recorded, along with a test instrument for verification.

4-2.9 Outlet Pressure

Outlet pressure is defined as the static pressure at the turbine outlet duct plus barometric pressure. For method of measurement, refer to para. 4-2.7 on exhaust static pressure. If no outlet duct is used, outlet pressure shall be taken as barometric pressure.

The outlet pressure shall be measured at the exhaust connection or at a mutually agreed interface point. This point is usually at the limit of supply of the gas turbine manufacturer. Any equipment installed downstream of this point will result in backpressure which must be considered in the output and heat rate figures. Adjustment for any difference in this measured value and the Specified Reference Conditions must be made using the correction factors. Any velocity component of the outlet pressure at this interface point is to be considered as lost, the same as would occur if the gas turbine were exhausting to the atmosphere at this point.

4-2.10 Injection Fluid Pressure

Where steam or water injection is utilized, static pressure should be measured at the flow element on the upstream side of the flow element.

4-2.11 Gas Fuel Pressure

For gas fuel applications, static gas fuel pressure shall be measured at the flow element on the upstream side of the flow element.

4-2.12 Differential Pressure (As For Fuel Flow)

When fuel flow is measured with a differential pressure device (nozzle or orifice), two differential pressure instruments are required. The differential pressure shall be recorded (and not just the calculated flow) so the flow calculation can be verified.

Differential pressure transmitters are installed using a five-way manifold. This manifold is required rather than a three-way manifold because the five-way eliminates the possibility of leakage past the equalizing valve, a frequent source of error. Two (2) three-way manifolds are acceptable, providing the redundant measurements are in agreement.

Once the instrument is installed in the field, the differential pressure shall be equalized and a zero value read. This zero bias must be subtracted from the test-measured differential pressure.

During test preparations or during the test, the vent must be checked to ensure the equalizing valves are not leaking, and so noted in the test report.

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 that the square root is applied only once. The transmitter output may also be computed flow. The flow calculation contained in the transmitter must be verified as containing the full flow equation. When possible, the calculated flow should be treated as a backup reading, in favor of the raw differential pressure, temperature and static pressure readings.

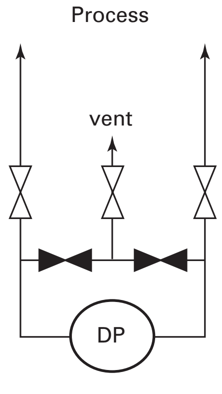


Fig. 4-2.1 Five-Way Manifold for Differential Pressure (DP) Instruments

4-2.13 Liquid in Sensing Lines (Water Legs)

For vacuum or gaseous service, sensing lines are installed with the sensing line sloping continuously upwards to the instrument so that any condensed liquid will flow out of the sensing lines. If this is not possible, the low points must be drained, before reading the instrument.

For steam and liquid processes at pressures larger than barometric pressure, the sensing lines are installed with the sensing line sloping continuously downwards to the instrument to eliminate any gas pockets. If this is not possible, the high points must be vented, before reading the instrument.

The "water leg" is the liquid in the sensing line. This liquid causes a static pressure head to develop in the sensing line. This static head must be subtracted from the pressure measurement. The static head is calculated by multiplying the sensing line vertical height by local gravity and the density of the water in the sensing line at the sensing line temperature. This static head adjustment may be applied at the transmitter, in the data acquisition system, or manually by the user after the raw data is collected. Care must be taken to ensure this adjustment is applied properly and that it is only applied once.

4-2.14 Differential Pressure Meters for Flow in Non-Horizontal Lines

When a differential pressure meter is installed on a flow element that is located in a non-horizontal line, the measurement must be corrected for the difference in sensing line height. For steam, the sensing lines should be uninsulated, and should protrude horizontally roughly 2 ft (0.6 m) from the pipe. This horizontal length will allow condensation to form completely so the downward portion will be completely full of water. The correction is as follows:

$$\Delta P_c = \Delta P_m + h \times (\rho_{\text{sen}} - \rho_{\text{fluid}})/g_c \times (g_L/\text{Conv}^3) \quad (4\text{-}2.2)$$

where

ΔP_c = corrected differential pressure, $\text{lb}_f/\text{in.}^2$ (or for SI, Newton/m^2 = Pascals)
ΔP_m = measured differential pressure, $\text{lb}_f/\text{in.}^2$ (or for SI, Newton/m^2 = Pascals)
h = Downstream Tap Elevation − Upstream Tap Elevation, in. (or cm)

(NOTE: h will be positive for flow up and negative for flow down.)

ρ_{sen} = density of sensing line fluid, lbm/ft^3 (for SI, kg/m^3)

ρ_{fluid} = density of process fluid, lbm/ft^3 (or for SI, kg/m^3)

g_L = local gravity, ft/sec^2 per an acknowledged source, or may be estimated as:

g_L = 32.1724 × [1 − 0.0026373 × cos(2 × [degrees − latitude × π/180]) + 0.0000059 × cos(2 × [degrees − latitude × π/180])^2] − 0.000003086 × ft. elevation (or for SI, g_L = m/sec^{2}2 = 9.80615 × [1 − 0.0026373 × cos(2 × [degrees − latitude × π/180]) + 0.0000059 × cos(2 × [degrees − latitude × π/180])^2] − 0.000003086 × meters elevation)

g_c = units conversion (a.k.a. standard gravity) = 32.1740486 lb$_m$-ft/lb$_f$-sec^2 (or for SI, 1)

(NOTE: the g_c conversion constant is not necessary if density is in slugs/ft^3)

(NOTE: the g_c conversion constant is not necessary with the SI units used here)

Conv = 12 inches per foot (or for SI, 100 centimeters per meter)

Note that for process liquids, the correction is small, being due only to the difference in temperature between the sensing line fluid and the process fluid.

4-2.15 Calibration of Pressure Instruments

4-2.15.1 Calibration of Absolute Pressure Instruments (e.g., Barometers). Absolute pressure instruments 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 calibrates by developing and holding a constant vacuum in a chamber using a suction and bleed control mechanism. The test instrument and the calibration standard are both connected to the chamber. The chamber must be maintained at constant vacuum during the calibration of the instrument. Other devices can be utilized to calibrate absolute pressure instruments provided that the same level of care is taken.

4-2.15.2 Calibration of Gage Pressure Instruments. Gage pressure instruments can be calibrated by an accurate deadweight gage. The pressure generated by the dead weight gage must be corrected for local gravity, air buoyancy, piston surface tension, piston area deflection, actual mass of weights, actual piston area, and working medium temperature. The actual piston area and mass of weights is determined each time the dead weight gage is calibrated. Other devices can be utilized to calibrate gage pressure instruments provided that the same level of care is taken.

4-2.15.3 Calibration of Differential Pressure Instruments. Differential pressure instruments used to measure low-uncertainty variables must be calibrated at line static pressure unless information is available about the effect of high line static pressure on the instrument accuracy. Calibrations at line static pressure are performed by applying the actual expected process pres-

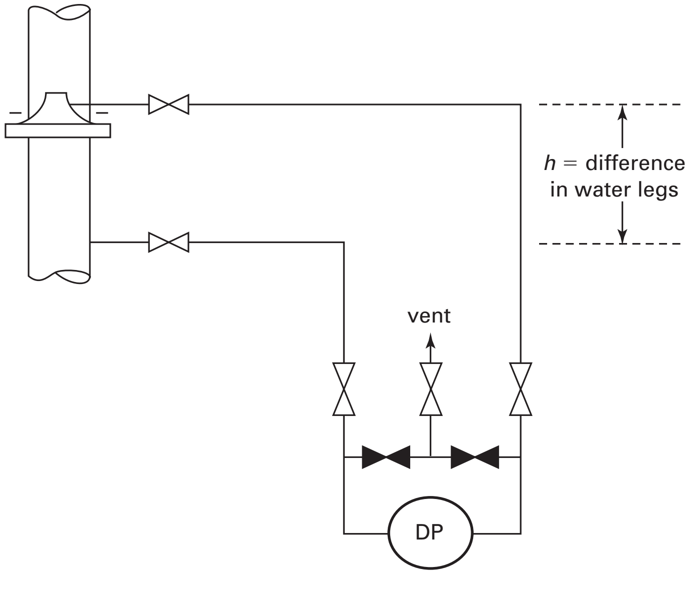


Fig. 4-2.2 Differential Pressure (DP) Correction for Flow in Non-Horizontal Lines

sure to the instrument as it is being calibrated. Calibrations at line static pressure can be accomplished by one of three methods:

(a) two highly accurate dead weight gages
(b) a dead weight gage and divider combination, or
(c) one dead weight gage and one differential pressure standard

Differential pressure instruments used to measure secondary variables do not require calibration at line static pressure and can be calibrated using one accurate dead weight gage connected to the "high" side of the instrument. If line static pressure is not used, the span must be corrected for high line static pressure shift unless the instrument is internally compensated for the effect.

Other devices can be utilized to calibrate differential pressure instruments provided that the same level of care is taken.

4-3 TEMPERATURE MEASUREMENT

4-3.1 General

Temperature measurement shall be carried out in accordance with accepted practice and procedures as discussed in ASME PTC 19.3. Temperature shall be measured with resistance thermometers or calibrated thermocouples used with precision-reading instruments. Calibrated mercury in-glass thermometers may be used for such secondary readings as temperatures at manometer and barometer. Stagnation type devices shall be used, or computed velocity corrections applied where such correction exceeds 1°F.

4-3.2 Air Inlet Temperature

Air inlet temperature shall be measured at the specified test boundary. It is recommended that this temperature be measured inside the air inlet duct of the gas turbine because of better mixing to attain true bulk inlet temperature. However, by mutual agreement between parties to the test, an alternate location, such as at the filter house inlet, may be used. At the specified location, the temperature of the air shall be measured such that the total uncertainty will not exceed the requirements of Table 4-1. If a nonuniform profile exists, the profile shall be determined by other measurable means. After determining the profile, the number and arrangement of sensors shall be selected such that the average of their readings shall be within 1°F of the temperature determined from the temperature profile measurement. As a rule of thumb, it is recommended that one temperature sensing device be used for every 100 ft^2 of duct cross-sectional area, but in no case less than four devices.

Air inlet temperature should be measured using RTDs or thermistors. Thermocouples should not be used because the voltage signal generated by a thermocouple is proportional to the temperature difference between the measurement junction and the reference junction. Since both temperatures are nearly identical for air inlet temperature measurement, the voltage signal is extremely small, thereby increasing the uncertainty of the measurement.

4-3.3 Exhaust Gas Temperature

The exhaust gas temperature must be measured near the test boundary which is often the interface plane between the gas turbine and HRSG or the gas turbine exhaust stack. The exhaust gas from a gas turbine usually has a nonuniform temperature and velocity profile. Therefore, the exhaust gas temperature shall be calculated on a mass weighted average basis. The parties to the test shall agree on how the mass weighted average is to be calculated. The preferred method is for the manufacturer to provide a calculation method based on either field test data from other similar units, or from analytical means such as CFD modeling. The alternate method is to conduct velocity, total temperature and total pressure traverses at several locations in the exhaust duct to determine the basis of the mass weighted average.

The required number of exhaust gas temperature measurement devices shall be determined to meet a maximum exhaust gas temperature uncertainty of 10°F. Large spatial variations in exhaust gas temperature readings will most likely require a significant number of measurement points.

If permanent exhaust gas temperature measurement devices are provided with the gas turbine, these may be used to determine mass weighted average exhaust gas temperature provided they meet the uncertainty requirement specified above. In the event that the uncertainty requirement cannot be met using permanent devices, temporary devices must be utilized.

4-3.4 Fuel Temperature

Fuel temperatures of fuel supply and, if applicable for liquid fuel, of fuel return lines, shall be measured at representative locations close to the corresponding flowmeters. Two different measurement locations may be required, one for fuel flow measurement, and one for the sensible heat at the test boundary.

Refer to ASME PTC 19.5 for guidance as to the proper location for these temperature measurements.

4-3.5 Extraction/Injection Fluid Temperature

Extraction/injection fluid temperature measurements (such as water, steam, nitrogen, air) shall be provided to determine the heat content of the fluid.

4-4 GAS FUEL HEAT INPUT

4-4.1 General

To determine the heat input while operating on gas fuel, the following parameters shall be determined:

(a) mass flow
(b) composition, including moisture content
(c) heat value
(d) sensible heat

4-4.2 Gas Fuel Test Boundary

Per para. 3-1.5, each energy stream is to be determined with reference to the point at which it crosses the test boundary. The choice of the test boundary can have a significant impact on the test results. It may be at a different location depending on what parameter is being determined (i.e., heat rate vs. exhaust energy via heat balance). Figure 4-4.1 provides some typical test boundaries that should be considered when determining the gas fuel heat input.

Leakage flows may exist during the test ($MF_1 \neq MF_2$) and care should be taken to minimize and account for such flows.

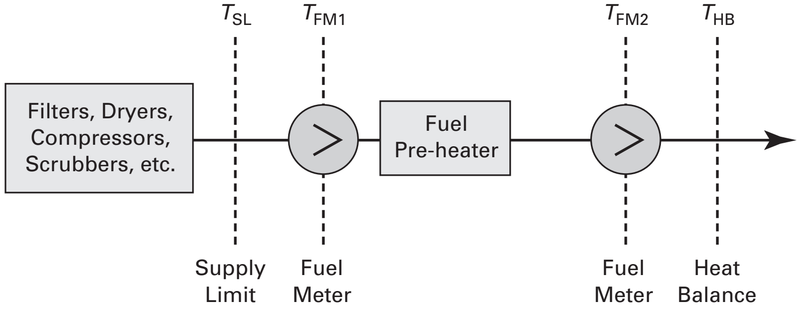
4-4.3 Mass Flow

4-4.3.1 Gas Fuel Flowmeters. Gas fuel flows shall be measured using a fuel flow device that has been calibrated in compliance with para. 4-1.3. The following paragraphs will describe the specific requirements of the flowmeters, based on pressure measurements and respectively positive displacement or turbine type. Other flow meters are permitted if the uncertainty of the mass flow measurement specified in Table 4-1 can be met.

Application, restriction of use, calibration and installation requirements of gas fuel flow measuring devices shall be in accordance with ASME PTC 19.5. Fuel flow measurement devices shall be put in service prior to the conduct of the test to avoid damage that can affect the device calibration. On-site inspection of the fuel flow devices prior to the conduct of the test is recommended only if the inspection does not invalidate the calibration results. Any activity that invalidates the calibration results, including on-site inspection of the fuel flow device, shall not be permitted.

Start-up procedures must ensure that spool pieces are provided during conditions that may violate the integrity of the flow measurement device to avoid altering the devices characteristics. Such conditions may include gas blows. While the flow measurement device is stored, it must be capped and protected from environmental damage such as moisture and dirt. During operation it is recommended that a strainer be installed upstream of the flow measurement device to protect the meter from objects and debris.

The calibration results from a properly calibrated flow device shall be used as the primary source in the determination of the mass flow of the gas fuel.



GENERAL NOTES:

(a) Temperature reference points:
T_{SL}: Fuel temperature at supply limit
T_{FM}: Fuel temperature at fuel meters
T_{HB}: Fuel temperature at heat balance boundary

(b) Fuel meter upstream of fuel preheater: $T_{SL} = T_{FM1} \neq T_{HB}$

(c) Fuel meter downstream of fuel preheater: $T_{SL} \neq T_{FM2} = T_{HB}$

(d) Whenever a fuel preheater is included as part of the scope of supply, the fuel temperature shall be measured both upstream and downstream of the preheater.

(e) Mass flow reference points:
MF_1: Mass flow upstream of fuel meter
MF_2: Mass flow downstream of fuel meter

Fig. 4-4.1 Generic Gas Fuel Test Boundary

4-4.3.1.1 Pressure Producing Flowmeters (e.g., Flange-tap Orifice Flowmeter). Calibration of the orifice flowmeters may be conducted with either water or natural gas. However, special consideration should be given to the applicability of each type. Calibrations conducted with water as the calibration fluid usually do not allow for calibration data to be taken at flow ranges experienced during normal base load operation of the gas turbine. For these situations, extrapolation of the calibration data shall be in accordance with ASME PTC 19.5.

Paragraphs 5-3.1.1 to 5-3.1.4 outline the applicable equations for the volumetric gas fuel flow measurements using a metering orifice flow meter.

4-4.3.1.2 Linear Scale Meters (e.g., Positive Displacement Flowmeter or Turbine Flowmeter). Turbine meter calibrations conducted with natural gas as the calibration fluid shall be conducted at design pressures and temperatures and calibration data points shall be taken at flow rates that surround the range of flow rates expected during the test.

Whenever volumetric flowmeters are used, the temperature of the gas fuel (at a location consistent with para. 4-4.2) and the fuel flow shall be measured simultaneously. The volumetric flow shall be determined from the totalized volume of gas fuel measured over a continuous period of not less than 4 min, and the time measured with an accurate stopwatch or electronic timer. Care must be taken that the measured totalized volume of gas fuel is not temperature compensated.

4-4.3.2 Density. The density for each fuel sample is calculated from the pressure, temperature, compressibility factor, and gas fuel composition, all recorded at a location consistent with para. 4-4.2. The applicable equation for calculating gas fuel density is outlined in para. 5-3.1.5. Compressibility factor (Z_g) shall be determined by the methods detailed in AGA Report No. 8 - Detailed Characterization Method. For gas mixtures not covered by this Report, an alternate method shall be used.

4-4.4 Fuel Composition

Methods of gas fuel composition determination shall be in accordance with the standards set forth in ASTM D 1945. Alternative methods may be used if they are equivalent in accuracy and are mutually agreed upon by all parties prior to the test.

Recognizing the importance of the gas composition as one of the main contributors to the determination of the heat rate, the Code makes the following recommendations, which may reduce the error level. The preferred solution for the determination of the gas composition is the analysis in a laboratory using methods and standards that are traceable to U.S. National Institute of Standards and Technology (NIST). Increasing the number of laboratories where fuel samples are analyzed will reduce the correlated component of the measurement uncertainty. Further reduction of the random part of the uncertainty may be achieved by increasing the frequency of the fuel sample collection. Prior to the onset of any activities all parties to the test shall agree upon the laboratory(s) that will be used to conduct the analysis of the test gas fuel samples. It should be noted that the recommended values of the ASTM D 1945 for repeatability and reproducibility should be considered the upper limit for determination of the errors. Conducting audits on quality of the laboratory(s), following the recommendations of the analyzing equipment manufacturer and using experienced technicians could significantly reduce these type of errors.

The use of calibrated on-line gas chromatographs is acceptable provided that a laboratory certifies the quality of the results. Special care should be given to the frequent calibration of the on-line gas chromatograph and use of high quality calibration gases.

4-4.4.1 Moisture Content. When the fuel is pipeline quality natural gas, the moisture content should be minute (less than 4 pounds per million standard cubic feet). It will therefore have a negligible effect on the gas heat value and the gas constant. In such cases, the moisture content can be taken from the supplier's records.

If required, the gas moisture content shall be determined in accordance with the standards set forth in ASTM D 1142. The fuel heat value shall be adjusted in accordance with procedures delineated in ASTM D 3588.

4-4.5 Heating Value

The heat value shall be determined from the constituents. The preferred method for determining the gas constituents is the use of a chromatograph in accordance with ASTM D 1945. Alternate methods may be used if they are equivalent in accuracy. The fuel heating value shall be calculated in accordance with procedures delineated in ASTM D 3588. The values from the constituents shall be taken from Table 4-4.5, which is based on GPA 2145. Alternative standards or the latest edition of GPA 2145 may be used as agreed upon.

4-4.6 Gas Fuel Sensible Heat

For an exhaust flow or energy test, the sensible heat must be determined to account for the difference between the measured fuel temperature at the test boundary and the user selected enthalpy reference temperature. For a heat rate test, if the heat rate is specified to include the latent heat and the sensible heat, then the sensible heat must be determined to account for the difference between the measured fuel temperature at the test boundary and the Specified Reference Temperature (not to be confused with the combustion reference temperature of 60°F as explained in Table 4-4.5). If the heat rate is specified to include only the latent heat, variations from the Specified Reference Temperature may be accounted for by apply-

Table 4-4.5 Gas Properties of Selected Ideal Gases at 60.0°F and 14.696 psia

Component	Formula	Molecular Weight lb/lbmol	Standard Density lb/1000 ft^3	Heating Value (Dry), Btu/lbm	
				High	Low
Methane	CH_4	16.0425	42.274	23,892.2	21,511.9
Ethane	C_2H_6	30.0690	79.237	22,334.1	20,429.2
Propane	C_3H_8	44.0956	116.199	21,654.1	19,922.2
Isobutane	C_4H_{10}	58.1222	153.161	21,232.3	19,589.8
n-Butane	C_4H_{10}	58.1222	153.161	21,300.2	19,657.8
Isopentane	C_5H_{12}	72.1488	190.123	21,043.7	19,455.9
n-Pentane	C_5H_{12}	72.1488	190.123	21,085.0	19,497.2
n-Hexane	C_6H_{14}	86.1754	227.085	20,943.8	19,392.9
n-Heptane	C_7H_{16}	100.2019	264.048	20,839.1	19,314.7
n-Octane	C_8H_{18}	114.2285	301.010	20,759.7	19,255.4
n-Nonane	C_9H_{20}	128.2551	337.972	20,701.0	19,212.3
n-Decane	$C_{10}H_{22}$	142.2817	374.934	20,651.6	19,175.5
Carbon Monoxide	CO	28.0101	73.811	4,342.2	4,342.2
Carbon Dioxide	CO_2	44.0095	115.972	0.0	0.0
Hydrogen Sulfide	H_2S	34.0809	89.808	7,094.1	6,533.8
Air	Air	28.9651	76.328	0.0	0.0
Hydrogen	H_2	2.0159	5.312	61,022.3	51,566.7
Oxygen	O_2	31.9988	84.322	0.0	0.0
Nitrogen	N_2	28.0134	73.820	0.0	0.0
Water	H_2O	18.0153	47.473	1,059.8	0.0
Helium	He	4.0026	10.547	0.0	0.0
Argon	Ar	39.9480	105.269	0.0	0.0

GENERAL NOTES:

(a) Heating values based on GPA 2145-03. Heating values are based on a combustion reference temperature of 60 F. This conversion of all reactants and products in the combustion equation was performed for GPA 2145 from the fundamental heat of combustion data (TRC/NIST Standard Reference Database 85) which are based on a combustion reference temperature of 77°F. The conversion is explained in GPA 2172-96.

(b) Heating values for CO and H_2 adapted from ASTM D 3588-98.

(c) Molecular weights adapted from Coursey, J.S., Schwab, D.J., and Dragoset, R.A. (2003), *Atomic Weights and Isotopic Compositions (version 2.4)*. [Online] Available: http://physics.nist.gov/Comp [January 2004]. National Institute of Standards and Technology, Gaithersburg, MD. Molecular weights are mostly consistent with GPA 2145-03 and NASA/TP-2002-211556.

(d) Also useful is *GPSA Engineering Data Book, 11th Edition,* Section 23, Gas Processors Suppliers Association, 1998 edition, Tulsa, OK.

(e) Density is based on Universal Gas Constant = 10.731619 psi-ft^3/lbmol-R.

(f) Air composition by mole fraction: N_2 = 78.084%, O_2 = 20.9476%, Ar = 0.9365%, CO_2 = 0.0319%, per ASHRAE 1997 Handbook of Fundamentals

(g) Btu/lb value for water is the ideal heat of vaporization

ing a correction factor to heat rate which can be determined from a calculation of sensible heat or application of a manufacturer supplied correction factor. The calculation of sensible heat is described in para. 5-3.1.11.

4-4.7 Sampling

Fuel samples shall be taken in accordance with GPA 2166. If it is suspected that the sampling procedure may result in a substantial gas fuel flow loss, the sampling point shall be located as close as possible to the test boundary, upstream of the metering station, such that the gas sample represents the bulk of the gas flowing through the flow meter device. Special care shall be taken to ensure that the fuel sampling location is as far downstream of all processes outside of the test boundary that may change the composition of the gas (e.g., filters, dryers, compressors, scrubbers, etc.), such that the samples are a true representations of the fuel actually crossing the test boundary.

A set of at least two gas fuel samples shall be taken at the beginning and end of each test run. Fuel samples may be taken more frequently, especially when unsteady fuel supply characteristics are suspected, provided that the fuel sampling process does not disturb the fuel flow measurements. One fuel sample from each set will be delivered to a qualified laboratory for analysis. The duplicate samples from each set will be retained until all fuel analyses are completed and results are concluded to be acceptable. The fuel characteristics used for a test run analysis shall be determined from the average of the characteristics from the individual fuel samples taken before and after each test run.

4-5 LIQUID FUEL HEAT INPUT

4-5.1 General

To determine the heat input while operating on liquid fuel, the following parameters shall be determined:

(a) mass flow
(b) heat value
(c) sensible heat

4-5.2 Liquid Fuel Test Boundary

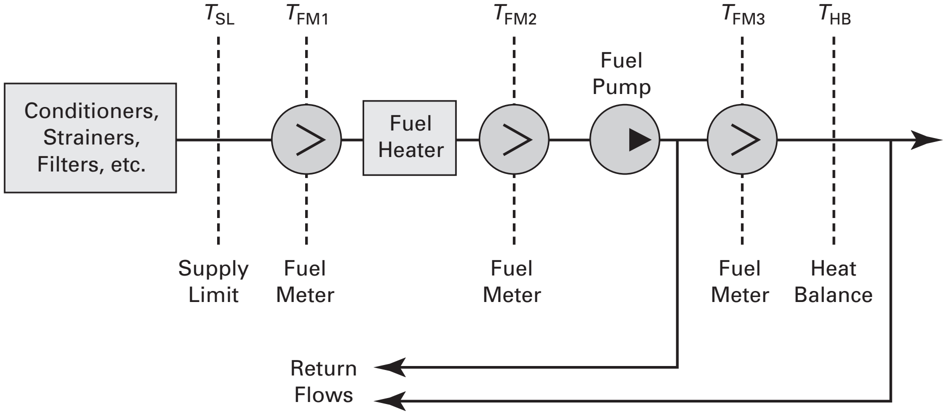
Per para. 3-1.5, each energy stream is to be determined with reference to the point at which they cross the test boundary. This is particularly significant with respect to liquid fuel heat input. The choice of the test boundary can have a significant impact on the measured flow, temperature, and test results. It may be at a different location depending on what parameter is being determined (i.e., heat rate vs. exhaust energy via heat balance). Figure 4-5.1 provides some typical test boundaries that should be considered when determining the liquid fuel heat input.

Leakage and unmetered return flows may exist during the test ($MF_1 \neq MF_2$) and care should be taken to minimize and account for such flows (e.g. separate metering in the return flow lines). Instances of leakage and unmetered return flows should be treated on a case-by-case basis and the method for accounting for such flows agreed upon.

4-5.3 Mass Flow

The uncertainty of the method to determine the mass flow of the liquid fuel shall not exceed the values listed in Table 4-1.

4-5.3.1 Flow Measurement. Liquid fuel flows shall be measured by using linear scale meters (e.g. positive displacement flowmeter or turbine flowmeter) for pipe diameters greater than 3 in. Other flowmeters are per-



GENERAL NOTES:

(a) Temperature reference points:
  T_{SL}: Fuel temperature at supply limit
  T_{FM}: Fuel temperature at fuel meters
  T_{HB}: Fuel temperature at heat balance boundary

(b) Fuel meter at supply limit:
  $T_{SL} = T_{FM1} \neq T_{HB}$ (Fuel temperature required to be measured in 2 locations)
(c) Fuel meter after fuel heater but before pump:
  $T_{SL} \neq T_{FM2} \neq T_{HB}$ (Fuel temperature required to be measured in 3 locations)
(d) Fuel meter after pump:
  $T_{SL} \neq T_{FM3} = T_{HB}$ (Fuel temperature required to be measured in 2 locations)

(e) Mass flow reference points:
  MF_1: Mass flow upstream of fuel meter
  MF_2: Mass flow downstream of fuel meter

Fig. 4-5.1 Generic Liquid Fuel Test Boundary

mitted if the uncertainty of the mass flow measurement specified in Table 4-1 can be met.

Liquid fuel flows shall be measured using a fuel flow device that has been calibrated in compliance with para. 4-1.3. Calibration data points shall be taken at flow rates that surround the range of flow rates expected during the test. The calibration results from a properly calibrated flow device shall be used as the primary source in the determination of the mass flow of the liquid fuel.

Whenever volumetric flowmeters are used, the temperature of the liquid fuel (at a location consistent with para. 4-5.2) and the fuel flow shall be measured at the same location. The volumetric flow shall be determined from the totalized volume of liquid fuel measured over a continuous period of not less than 10 min, and the time measured with an accurate stopwatch or electronic timer. Care must be taken that the measured totalized volume of liquid fuel is not temperature compensated.

Application, restriction of use, calibration and installation requirements of liquid fuel flow measuring devices shall be in accordance with ASME PTC 19.5. On-site inspection of the fuel flow devices prior to the conduct of the test is recommended only if the inspection does not invalidate the calibration results.

Paragraph 5-3 outlines the applicable equations for liquid fuel flow measurements using a metering orifice, a positive displacement flowmeter or a turbine flowmeter.

4-5.3.2 Density and Relative Density (Specific Gravity). The density or relative density for each fuel sample shall be determined from a fuel analysis conducted in accordance with ASTM D 1480 or equivalent standard. To obtain a correlation of density (or relative density) and temperature, each sample shall be analyzed for at least two different temperatures, with a temperature range encompassing all of the liquid fuel temperatures recorded during the test runs. The density (or relative density) at the test conditions for each individual fuel sample shall be determined from the interpolation of the analysis results and flowing temperature during the test run.

4-5.3.3 Kinematic Viscosity. The kinematic viscosity of the liquid fuel at the test temperature is usually different from the fluid used for the flowmeter calibration. The effect of kinematic viscosity on the flowmeter calibration K-factor is unique. Hence, the flowmeter manufacturer's curves shall be used to adjust the calibration K-factor to the actual kinematic viscosity of the liquid fuel at the test conditions. Measurement of kinematic viscosity shall be in accordance with ASTM D 445 or equivalent standard. To obtain a correlation of kinematic viscosity and temperature, each sample shall be analyzed at three different temperatures, with a temperature range encompassing all of the liquid fuel temperatures recorded during the test runs. The kinematic viscosity at the test conditions for each individual fuel sample shall be determined from the interpolation of the analysis results and flowing temperature during the test run.

4-5.4 Heating Value

The heating value shall be determined with an uncertainty no greater than the value listed in Table 4-1. The heating value of each fuel sample shall be determined in accordance with the procedures specified in ASTM D 4809 or equivalent standard.

4-5.4.1 Heating Value at Constant Volume. The higher heating value at constant volume (HHV_V) is determined by measuring the amount of heat liberated when a carefully weighed quantity of liquid fuel is burned in an oxygen-filled calorimeter bomb of constant volume. All heating values are referenced to a standard temperature base of 77°F (25°C). The lower heating value at constant volume (LHV_V) is the higher heating value at constant volume minus the latent heat of condensed water vapor at the same base temperature of 77°F (25°C).

4-5.4.2 Heating Value at Constant Pressure. In gas turbine combustors, the process is assumed to be a complete and adiabatic combustion, which occurs at constant pressure. Therefore, the higher and lower heating values shall be determined at constant pressure. Additionally, for gas turbine cycle calculation with the exhaust-gas exit boundary for the test configuration defined in para. 3-1.5, the lower heating value at constant pressure (LHV_P) is the characteristic parameter since the water content in the exhaust gas at the boundary is still in gaseous (non condensed) state. The higher and lower heating values at constant pressure shall be calculated from the higher heating value at constant volume using the equations outlined in para. 5-3.1.9.

4-5.4.3 Hydrogen Content. The hydrogen content of each fuel sample shall be determined in accordance with the procedures specified in ASTM D 1018 or equivalent standard.

4-5.5 Liquid Fuel Sensible Heat

For an exhaust flow or energy test, the sensible heat must be determined to account for the difference between the measured fuel temperature at the test boundary and the user selected enthalpy reference temperature. For a heat rate test, if the heat rate is specified to include the latent heat and the sensible heat, then the sensible heat must be determined to account for the difference between the measured fuel temperature at the test boundary and the Specified Reference Temperature [not to be confused with the combustion reference temperature of 77°F (25°C)]. If the heat rate is specified to include only the latent heat, variations from the Specified Reference Temperature may be accounted for by applying a correction factor to heat rate which can be determined from a calculation of sensible heat or application of a manufacturer supplied correction factor. The calculation of sensible heat is described in para. 5-3.1.10.

4-5.6 Sampling

Fuel samples shall be taken in accordance with ASTM D 4057. A fuel sampling location shall be jointly identified prior to the test. The sampling point shall be located as close as possible to the test boundary, upstream of the metering station, such that the liquid fuel sample represents the bulk of the liquid fuel flowing through the flow meter device. Special care shall be taken to ensure that the fuel sampling location is as far downstream of all processes outside of the test boundary that may change the composition of the liquid fuel (e.g., filters, strainers, conditioners, etc.), such that the samples are a true representations of the fuel actually crossing the test boundary.

A set of at least two liquid fuel samples shall be taken at the beginning and end of each test run. Fuel samples may be taken more frequently, especially when unsteady fuel supply characteristics are suspected, provided that the fuel sampling process does not disturb the fuel flow measurements. One fuel sample from each set will be delivered to a qualified laboratory for analysis. The duplicate samples from each set will be retained until all fuel analyses are completed and results are concluded to be acceptable. The fuel characteristics used for a test run analysis shall be determined from the average of the characteristics from the individual fuel samples taken before and after each test run.

4-6 ELECTRICAL GENERATION MEASUREMENT

4-6.1 Introduction

Electrical parameters required for the evaluation of gas turbine performance include gross electrical output, power factor, exciter power, and other auxiliary electrical loads. This Subsection of the Code provides guidance and requirements for the determination of these parameters. IEEE 120-1989 should be consulted for additional information and for measurement requirements not included in this Code.

4-6.2 Electrical Measurement System Connections

The connection of the primary elements for measurement of polyphase alternating current power systems is subject to required uncertainty and the degree of unbalance between phases which may be experienced. Many different and special connections can be used for measuring polyphase alternating current, however the connections covered in this Code will be for three-wire or four-wire type systems and are recommended for meeting the uncertainty requirements of this Code. The minimum metering methods required for use on each of these three-phase systems are as follows:

(a) three-wire generator connections — two single-phase meters or one two-phase meter

(b) four-wire generator connections — three single-phase meters or one three-phase meter

The following describes different types of three and four wire generator connections that may exist.

4-6.2.1 Three Wire Power Systems. Examples of three wire power generation systems are shown in Fig. 4-6A and 4-6B. Various three wire power systems exist due to the type of the connected generator. It is recom-

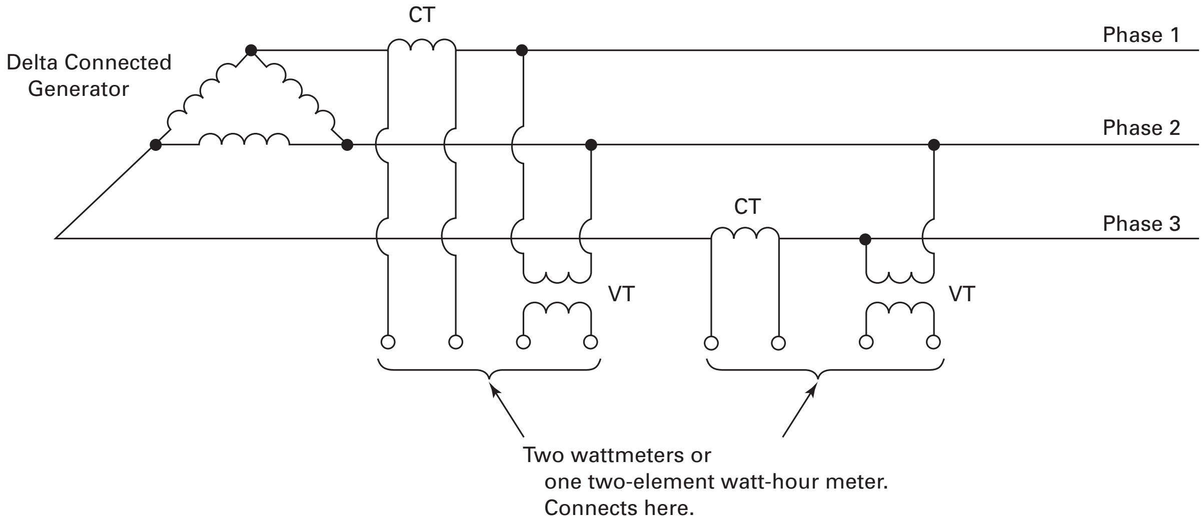


Fig. 4-6A Two-Meter Metering System for Use on Three-Wire Delta Connected Power Systems

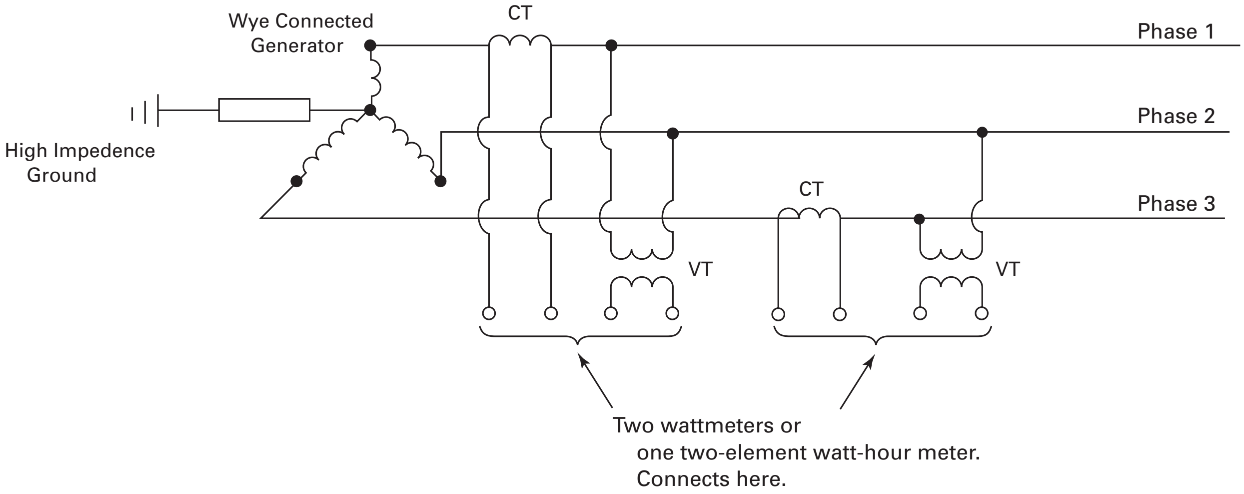


Fig. 4-6B Two-Meter Metering System for Use on Three-Wire Wye Connected Power Systems

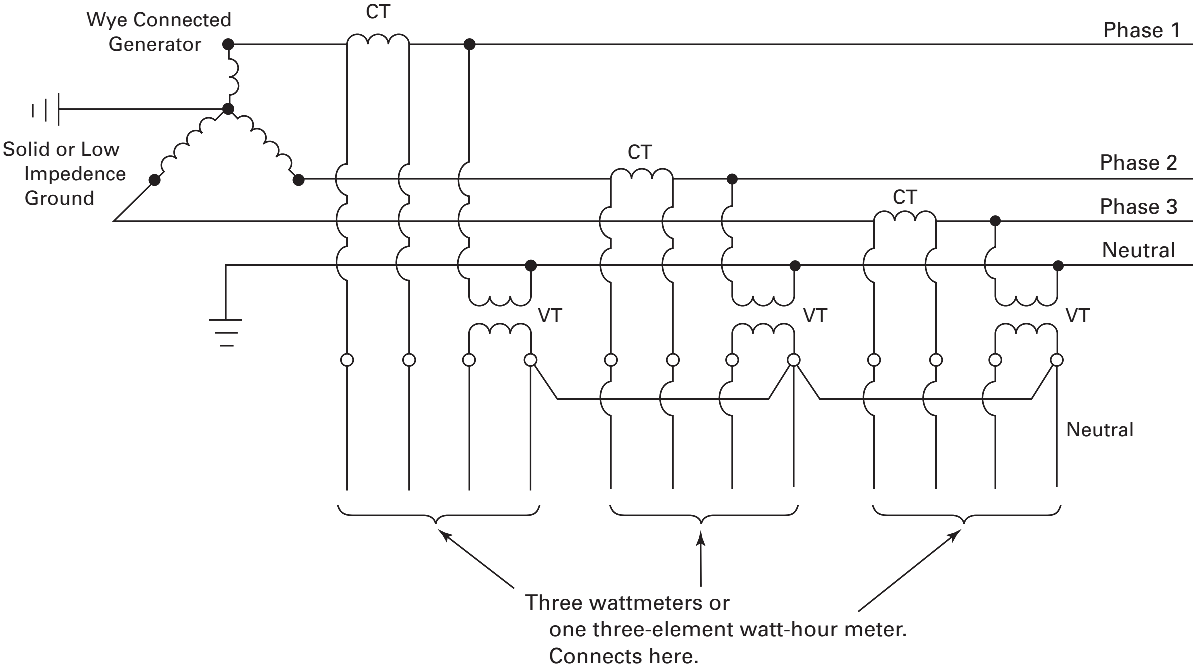


Fig. 4-6C Three-Meter Metering System for Use on Four-Wire Power Systems

mended to review the particular type and the site arrangement before deciding which one is suitable for a given measurement application.

Power and energy in three-wire power systems can be measured using two "Open Delta Connected" voltage transformers (VTs) and two current transformers (CTs). The two metering system is shown in Figures 4-6A and 4-6B for a Delta connected and a Wye connected generator, respectively.

Several types of metering devices can be used in connection with these instrument transformers: two watt meters, 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 calculation is provided in para. 5-1.2.1 including the case for balanced three-phase sinusoidal circuits.

4-6.2.2 Four-Wire Power Systems. A typical four-wire power system is shown in Fig. 4-6C. In addition, with the exception of the "Open Delta" generator connection, all of the three-wire systems described in para. 4-6.2.1 can also be measured using the four-wire measurement system described in this Section.

The measurement of power and energy in a four-wire power system is made using three VTs and three CTs as shown in Fig. 4-6C. Several metering devices can be used in connection with these instrument transformers: three watt/var meters, three watt-hour/varhour meters, or a three-element watt-hour/var-hour meter.

Power factor calculation is provided in para. 5-1.2 including the option where each phase voltage and current (volt-amps) are measured.

4-6.3 Instrument Transformers

Instrument transformers are used for the purpose of:

(a) reducing the voltages and current to values that can be conveniently measured, typically to ranges of 120 V and 5 A, respectively, and

(b) insulating the metering instruments from the high potential that may exist on the circuit under test. Instrument transformer practice is described in detail in IEEE C57.13-1993.

The impedances in the transformer circuits must be constant during the test. Protective relay devices or voltage regulators shall not be connected to the instrument transformers used for the test. Normal station instrumentation may be connected to the test transformers if the resulting total burden is known and is within the range of calibration data.

4-6.3.1 Voltage Transformers. Voltage transformers measure either phase to phase voltage or phase to neutral voltage. The voltage transformers serve to convert the line or primary 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 voltage transformer must be multiplied by a turns ratio to calculate the primary voltage which actually exists in the generator.

Correctly rated voltage transformers of at least 0.3% accuracy class (metering type) shall be used for the test. The transformers shall be calibrated for correction of ratio and phase angle error prior to the test over the ranges of voltage and current expected during the test. They shall be calibrated at zero burden, and at least one other, preferably the rated burden. The voltage transformer ratio corrections shall be applied at the actual burdens of the test, which may be determined by calculation from lead impedances, or by direct measurement. Corrections for voltage drop in the connecting lines shall be applied as shown in Appendix C-2.

4-6.3.2 Current Transformers. The current transformers convert the line or primary current to a lower secondary current safe for metering. For this reason, the secondary current measured by the current transformers must be multiplied by a turns ratio to calculate the primary current which actually exists in the generator output wiring.

For the measurement of generator output in a gas turbine test, at least 0.3% accuracy class current transformers shall be used. It is recommended that each current transformer should be calibrated at zero external burden (0 VA) and at least one burden that exceeds the maximum expected during the test from zero to rated current.

When testing at rated current, ratio and phase angle correction factors for current transformers may be neglected due to their minimal impact on measurement.

4-6.3.3 Instrument Transformer Connections. Test plans shall include a sketch showing the measurement and the test boundary locations.

The leads to the instruments shall be arranged so that inductance or any other similar cause will not influence the readings. Inductance may be minimized by utilizing twisted and shielded pairs for instrument leads. It is desirable to check the whole arrangement of instruments for stray fields.

In order to minimize the voltage drop in the voltage circuit, wire gauge shall be chosen considering the length of wiring, the load of the voltage transformer circuit, and the resistance of the safety fuses. The errors due to wiring resistance (including fuses) shall always be taken into account, either by direct voltage drop measurement or by calculation. An illustration of these measurements and corrections is shown in the sample calculation provided in Appendix C-2.

4-6.3.4 Precautions in the Use of Instrument Transformers. Current transformer cores may be permanently magnetized by inadvertent operation with the secondary circuit opened, resulting in a change in the ratio and phase-angle characteristics. If magnetization is suspected, it should be removed as described in IEEE 120, under "Precaution in the Use of Instrument Transformers."

4-6.3.5 Utilization of Existing Plant Instrument Transformers. Existing station voltage or current transformers may be used for the test if they meet the requirements of this Code.

4-6.4 Electrical Metering Equipment

There are five types of electrical metering equipment that may be used to measure electrical energy: (1) watt meters, (2) watt-hour meters, (3) var meters, (4) var-hour meters, and (5) power factor meters. Single or polyphase metering equipment may be used.

These meters are described below.

4-6.4.1 Watt Meters. Watt meters measure instantaneous active power. The instantaneous active power must 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 must be multiplied by the test duration in hours.

Watt meters measuring generator output must have a systematic uncertainty equal to or less than 0.1% of reading and a sampling rate of at least once per minute during the test.

4-6.4.2 Watt-hour Meters. Watt-hour meters measure cumulative active energy (kilowatt-hours) during a test period. The measurement of watt-hours must be divided by the test duration in hours to determine average active power (kilowatts) during the test period.

Watt-hour meters measuring generator output must have an uncertainty equal to or less than 0.1% of reading.

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 will have an analog or digital output with a higher resolution that may be used to increase the resolution. Some watt-hour meters will often 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 timed and counted during a test to increase resolution. Some electronic watt-hour meters also display blinking lights or LCD elements which correspond to disk revolutions that can be timed to determine the generator electrical output. In such cases, much higher resolution can be achieved usually by timing a discrete repeatable event (e.g. a certain number of blinks of an LCD or complete rotations of a disk) rather than counting the number of events in a fixed amount of time (e.g. number of rotations of a disk in 5 min).

4-6.4.3 Var Meters. Var meters measure instantaneous reactive power. The instantaneous reactive power must 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 must be multiplied by the test duration in hours.

Var meters measuring generator reactive power must have an uncertainty equal to or less than 0.5% of range and a sampling rate of at least once per minute.

4-6.4.4 Var-hour Meters. Var-hour meters measure reactive energy (kilovar-hours) during a test period. The measurement of var-hours must be divided by the test duration in hours to determine average reactive power (kilovars) during the test period.

Var-hour meters measuring generator output must have an uncertainty equal to or less than 0.5% of range.

The acceptable var-hour meters will have an analog or digital output with a higher resolution or a pulse type output that may be summed over time to determine an accurate total energy during the test period.

4-6.4.5 Power Factor Meters. Power factor may be measured directly using a 3-phase power factor transducer when balanced load and frequency conditions prevail. Power factor transducers must have an uncertainty equal to or less than 0.01 PF of the indicated power factor.

4-6.4.6 Existing Power Plant Instrumentation. Existing station instrumentation may be used for measurement of any of these parameters if it meets all of the requirements of this Code.

4-6.5 Electrical Generation Instrumentation Calibration

4-6.5.1 Watt and Watt-hour Meter Calibration. Watt and watt-hour meters, collectively referred to as power meters, are calibrated by applying power through the test power meter and a power meter standard simultaneously. Should polyphase metering equipment be used, the output of each phase must be available or the meter must be calibrated with all phases simultaneously in 3-phase operating condition.

Portable instruments shall be calibrated in a controlled laboratory environment if there is an indication of a problem with the measurement. The value of the voltage maintained on the potential circuit of the instruments during calibration shall cover the range of expected test values, based on the manufacturer's recommendations for required uncertainty. Polyphase meters, or metering systems which cannot be verified to be made up of separate single-phase meters, shall not be used unless they can be calibrated 3-phase.

4-6.5.2 Var and Var-hour Meter Calibration. In order to calibrate a var or var-hour meter, one must either have a var standard or a watt meter standard and an accurate phase angle measuring device. Also the device used to supply power through the standard and test instruments must 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 outlined above for watt meters should be used. Should a watt meter standard and phase angle meter be used, simultaneous measurements from the standard, phase angle meter, and test instrument should be taken. The var level will be calculated from the average watts and the average phase angle.

Var meters should be calibrated at the electrical line frequency of the equipment under test; i.e., do not calibrate meters at 60 Hz and use on 50 Hz equipment. Var meters are particularly sensitive to frequency and should be used within 0.5 Hz of the calibration frequency.

4-6.6 Excitation Power Measurement

If the exciter is powered by current supplied from the main generator bus at a point after the gross electrical output metering, the power supplied to the exciter must be determined. There are two methods:

(a) Derivation From Breaker Currents. Exciter power and any other auxiliary gas turbine loads included in the gas turbine vendor scope of supply can be calculated from the current and voltage input to the exciter power transformer or breaker. Since this is a measure of the actual power, which comes off of the main generator bus, this is the preferred method of determining exciter power required. The calculation is given in para. 5-1.3.1.1.

(b) Derivation From Field Voltage and Current. Power supplied to the exciter can also be estimated by calculating the power output by the exciter and by correcting for an assumed AC to DC conversion efficiency. The calculation is given in para. 5-1.3.1.2.

4-6.7 Measurement of Auxiliary Loads

If the test requires obtaining a net power output value for the gas turbine, auxiliary loads associated with the turbine must normally be measured. This is required when the gross electrical power metering is located upstream of the place where the auxiliary load power is supplied. Besides excitation power (see para. 4-6.6), the auxiliary loads generally consist of the electrical loads of the lubrication and hydraulic systems; water injection skids, external cooling air systems, etc. Another significant auxiliary load is the power required by the gas fuel compressor, necessary some times to boost the supply line gas pressure to the pressure required by the combustion system. The measurement of the auxiliary loads can be done with station permanent meters or locally using temporary instrumentation. In modern power stations, the permanent instrumentation used for this purpose can be found at the Motor Control Centers (MCC), where the electrical load is measured and displayed either as active power, or as voltage and current. A list should be created of all the auxiliary loads, measuring locations and clearly identify which system is fed through which corresponding MCC. The data could be collected manually or automated, but at least three readings shall be taken for each performance run. For loads measured locally by temporary instrumentation, the exact measuring point has to be clearly identified and qualified personnel should connect the meters to avoid accidents.

4-6.8 Measurement of Step-up and Step-down Transformers

In many cases, the transformer losses of step-up and step-down transformers must be determined for a test. Since the power loss for a step up/down transformer cannot be accurately measured in the field, it is necessary to use the results of the transformer's factory performance tests. Normally the factory tests determining the power loss are conducted at zero and one hundred percent rated load of the transformer and at various voltages.

In order to calculate the transformer power loss, measurements of the voltage and current at the high side of the transformer must be recorded. The calculation is then performed using the methodology described in IEEE C57.12.90 as shown in Appendix C-4.

4-7 MECHANICAL POWER MEASUREMENT

4-7.1 Torque and Speed Measurement

For gas turbines driving compressors, the determination of output shaft power is generally required. Reference should be made to ASME PTC 19.7 for guidance in these measurements.

A torque-measuring device shall be installed on the coupling between the gas turbine and its driven load (or load gear). This device shall be calibrated before the test, and if not left in place should be calibrated after the test. Speed of all gas turbine shafts shall be recorded.

4-7.2 Other Parameters and Variables

As required for generator drives, all other cycle and ambient data shall be recorded to permit correction of test data to specified reference conditions. Since the operation of the turbine may be restricted by the pipeline or process conditions, it is important to also record the control parameters such as exhaust (or control) temperature.

4-8 SPEED MEASUREMENT

Shaft speed is normally measured from either the shaft connected to the electrical generator in multishaft turbines or the shaft driving the load in mechanical drive turbines. Typically, for non-geared turbines the shaft speed shall be 3600 rpm for 60 Hz applications and 3000 rpm for 50 Hz applications.

The shaft speed may be measured by standard speed sensors used in the turbine control system. For gas turbines connected to AC electrical generators, the line frequency measured at the generator terminals may be used instead of shaft speed to correct gas turbine performance since the shaft speed is directly coupled to the line frequency. The chosen method must meet the uncertainty requirement in this Code.

4-9 HUMIDITY MEASUREMENT

The moisture content of air entering the compressor shall be measured directly with a hygrometer or indirectly by measuring the adiabatic wet bulb temperature. The measurement location shall be upstream of any air treatment device and shall be in close proximity to the dry-bulb temperature measurement. The measurement location shall be shielded from direct sunlight.

4-9.1 Direct Measurement

This method is required if freezing conditions are present during the test. The most common type of direct humidity measurement is a capacitive type hygrometer. Appropriate calibration standards for field calibration or recent factory calibration certification needs to be available in order to ensure compliance with the measurement uncertainty requirement. Be aware that uncertainty levels for a capacitive type device often increase at extreme low and extreme high humidity levels.

4-9.2 Indirect Measurement via Wet Bulb Temperature

This method does not require special calibration standards (other than what is needed for the temperature-sensing element). It can be used anytime conditions are above freezing. Wet bulb temperature is measured by snugly covering the temperature-sensing element with a wetted cotton sock. Distilled water shall be used as a wetting agent. Air velocity across the sensing element shall be kept between 800–1200 ft/min to ensure continuous evaporation of the distilled water. If the existing air velocity at the measurement location is insufficient (less than 800 ft/min), the air can be forced across the sensing element using a fan.

4-10 HEAT LOSSES

Gas turbine heat losses are all system losses that cross the test boundary. Gas turbine heat losses have a very small influence on the final calculated exhaust energy or flow, and therefore are often calculated from data provided by the manufacturer rather than measured directly. Manufacturers may identify and categorize heat losses differently, but they can generally be placed into four major categories: generator losses, gearbox losses, fixed losses, and variable losses.

Where the measurement of heat loss from lubricant coolers and other sources is required, the accuracy of temperature and flow measurement is such that determination of heat rejection may be accomplished with an uncertainty not greater than 10%. Where the actual measurement of heat loss is deemed unnecessary or impractical, the means of determining heat loss shall be determined by agreement among the parties to the test.

4-10.1 Generator Losses

Generator losses typically include exciter and collector losses, which are a function of generator output and power factor, and windage losses which are a function of the generator cooling medium temperature. It is not practical to measure these losses directly during a test, therefore they must be determined from curves provided by the generator manufacturer. Generator losses are typically on the order of 1% to 2% of the gross electrical output.

4-10.2 Gearbox Losses

Gearbox losses must be determined for applications that require load gears for speed reduction between the turbine rotor and the generator rotor. Gearbox losses are typically determined from data provided by the gearbox manufacturer. Gearbox losses can vary greatly, but are typically on the order of 1% to 2% of shaft output.

4-10.3 Fixed Losses

Fixed losses remain relatively constant across the range of base load operating conditions and may include mechanical losses of the turbine rotor bearings and any shaft driven accessories. The value for these losses should be provided by the manufacturer. Some fixed losses may be quantified by measuring the lube oil flow and the temperatures in and out of the lube oil cooler. However, caution should be used in cases where the cooler is partially bypassed to maintain a constant fluid temperature.

4-10.4 Variable Losses

Variable losses include heat rejected from the turbine rotor cooling system, overboard air or gas leakages, and heat radiated from the turbine casings. The algorithms for determining these losses should be provided by the manufacturer.

4-11 OTHER MEASUREMENTS

Various other measurements may be helpful for documenting the test. Some common ones are listed below.

4-11.1 Time

Precision timing may be required in conjunction with certain instruments that are time sensitive. Examples include watt-hour meters for power measurement and fluid displacement meters for flow measurement. In these cases, a precision timing device such as a digital stopwatch with a resolution to 0.1 sec is sufficient.

4-11.2 Flow

Flow measurements other than liquid or gas fuel should be in accordance with ASME PTC 19.5 and Table 4-1 of this Code.

4-11.3 Turbine Control Parameters

Gas turbines maintain a steady load by the use of turbine control parameters that adjust the fuel flow. These control parameters should be measured during a test because applicability of the manufacturer's correction curves depend on the appropriate operating conditions; however, these parameters do not have their own correction curves. The manufacturer determines which parameters are the controlling parameters and how each parameter is measured during a test. Typical turbine control parameters are variable guide vane position, turbine control temperature, compressor discharge or combustion chamber pressure, and fuel flow fractions.

4-11.3.1 Variable Guide Vane Position. Gas turbine installations may use variable geometry in the airflow path to control the volume of air passing through the gas turbine. In many gas turbine designs, variable geometry is achieved through the use of mechanically actuated guide vanes. Frequently, the definition of a load point, such as base load, at which a test is to be conducted, may depend on a specific guide vane angle. The position of each of the guide vanes should be measured prior to the test to ensure that the mean angle is consistent with both the manufacturer's specification and the indication in the turbine control system. Typically, the manufacturer's specification will include a recommended method of measurement and the allowable deviation for the mean guide vane angle.

4-11.3.2 Turbine Control Temperature. The turbine control temperature may be a critical parameter used by the control algorithm to set the gas turbine load level and turbine inlet temperature. Generally, turbine inlet temperature is virtually impossible to reliably measure, so the manufacturer chooses a lower temperature region for temperature measurement devices. The relationship between the turbine control temperature and the turbine inlet temperature is defined in a control algorithm determined by the manufacturer. The manufacturer, through experience, shall determine the number, type, and location of the control temperature measurements to account for expected temperature levels and inherent spatial variations.

4-11.3.3 Compressor Discharge or Combustion Chamber Pressure. Along with the turbine control temperature, compressor discharge or combustion chamber pressure is also often required as an input into the manufacturer's control algorithm. This pressure is often divided by the inlet pressure measurement to estimate a turbine expansion ratio. The manufacturer will determine the number, type, and location of the measurement(s). The pressure is measured using one or more static pressure transmitter(s) in accordance with para. 4-2.

Section 5
Computation of Results

The details required for computing results of an output and heat rate test are provided in this section. Additional computations are provided in Appendix A for the optional tests of exhaust flow, exhaust energy, and exhaust temperature.

5-1 ELECTRICAL POWER CALCULATIONS

5-1.1 Introduction

Electrical measurements required for the evaluation of gas turbine performance include gross electrical output, power factor, exciter power, and other auxiliary electrical loads. The measurement is discussed in para. 4-6. This subsection of the code provides guidance and requirements for the calculation of these measurements. The calculation method for average power or total energy should be performed in accordance with IEEE 120-1989 for the specific type of measuring system used. Power measurements must be corrected for actual voltage transformer ratio and for phase angle errors in accordance with the procedures of IEEE C57.13-1993.

A detailed sample calculation for electric power output is given in Appendix C-2.

5-1.2 Electrical Measurement System Connections

Based on the type of metering methods:

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

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

The following describes calculations for the two types of three and four-wire power systems that may exist.

5-1.2.1 Three-Wire Power Systems Power Factor Calculation. Power factor is then determined using the following formula:

$$PF = \frac{\text{Watts}_t}{\sqrt{\text{Watts}_t^2 + \text{Vars}_t^2}}$$

where

PF = power factor
Watts_t = total watts for three phases
Vars_t = total vars for three phases

Alternatively, for balanced three-phase sinusoidal circuits, power factor may be calculated from the two meter power measurement method using the following formula

$$PF = \frac{\text{Watts}_{1\text{-}2} + \text{Watts}_{3\text{-}2}}{2\sqrt{\text{Watts}_{1\text{-}2}^2 + \text{Watts}_{3\text{-}2}^2 - (\text{Watts}_{1\text{-}2} \times \text{Watts}_{3\text{-}2})}}$$

where

PF = power factor
$\text{Watts}_{1\text{-}2}$ = real power phase 1 to 2
$\text{Watts}_{3\text{-}2}$ = real power phase 3 to 2

5-1.2.2 Four-Wire Power Systems Power Factor Calculation. Power factor can be calculated from the watt and var meters using the following formula:

$$PF = \frac{\text{Watts}_t}{\sqrt{\text{Watts}_t^2 + \text{Vars}_t^2}}$$

where

PF = power factor
Watts_t = total watts for three phases
Vars_t = total vars for three phases

Alternatively, power factor may be determined by measuring each phase voltage and current (Volt-Amps), with the following equation:

$$PF = \frac{\text{Watts}_t}{\Sigma\, V_i I_i}$$

where

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

5-1.3 Excitation Power Calculation

5-1.3.1 Measured Excitation. If the exciter is powered by current supplied from the main generator bus at a point after the gross electrical output metering, the power supplied to the exciter must be determined, as described in para. 4-6.6. Two methods for determining the power supplied to the exciter are as follows:

5-1.3.1.1 Derivation From Breaker Currents. Exciter power and any other auxiliary gas turbine loads included in the gas turbine vendor scope of supply can be calculated from the current and voltage input to the exciter power transformer or breaker. Since this is a measure of the actual power, which comes off of the main generator bus, this is the preferred method of determining exciter power:

$$\text{ExcLoss} = \frac{\sqrt{3} \times V \times A \times PF}{1000}$$

where

ExcLoss = Exciter power (kw)

V = Average phase voltage (volts) − measured value

A = Average phase current (amps) − measured value

PF = Power Factor − measured or calculated value

1000 = Conversion factor from watts to kw

If the measurement point is downstream of a step down transformer, a correction should be applied for the transformer loss.

5-1.3.1.2 Derivation From Field Voltage and Current. Power supplied to the exciter can also be estimated by calculating the power output of the exciter and by correcting for an assumed AC to DC conversion efficiency using the following formula:

$$\text{ExcLoss} = \frac{FV \times FC}{1000 \times \text{ACDC}}$$

where

ExcLoss = exciter power (kw)

FV = field voltage (DC volts) − measured value

FC = field current (DC amps) − measured value

1000 = conversion factor from watts to kw

ACDC = AC to DC conversion efficiency factor (typically 0.975, assumed value)

5-1.3.2 Excitation Power Calculations From Supplier Information. Excitation power may be determined from supplier information based on load and power factor at the test conditions.

5-1.4 Instrument Transformers

The instrument transformers introduce errors when converting the high primary voltage/current to a low secondary voltage/current. These errors result in a variation of the true ratio from the marked ratio and also the variation of the phase angle from the ideal (zero). The magnitude of the errors depends on (1) the burden (number and kinds of instruments connected to the transformer), (2) the secondary current (in the case of current transformers), and (3) in the case of power measurement, the power factor of the device being measured. The correction methodology is presented in Appendix C.

5-1.4.1 Voltage Transformers. The secondary voltage measured by the voltage transformer must be multiplied by the voltage transformer marked ratio (VTR) and by the voltage transformer ratio correction factor ($VTRCF_C$), in order to calculate the primary voltage on the high side of the transformer. For the typical case where VTs are dedicated to voltage measurement and not to relays or voltage regulators, the secondary burden can be assumed to be close to zero. Therefore, the calibration data at zero burden plus 0.0005 may be assumed, leading to an estimated uncertainty of ± 0.05%.

5-1.4.2 Current Transformers. The current transformer ratio correction factor ($CTRCF_C$) is calculated in a similar manner as the voltage transformer correction factor ($VTRCF_C$). However, typical values at rated primary current vary little between 0.9999 and 1.0. Values outside this range should be accounted for. It should be emphasized that the $CTRCF_C$ for operation at conditions less than the rated primary current increases significantly and should not be neglected. The error at 10% current is permitted to be two times the value of the error at 100% rated primary current. CT calibration should therefore be provided at two different burdens and a function of load as detailed in para. 4-6.3.2.

5-1.4.3 Calculation of Corrected Primary Power. The power for each phase is corrected by applying calibration data from the transformers and the power meter as follows:

$$\text{Power}_{\text{highside}} = \text{Power}_{\text{lowside}}{*}\text{VTR}{*}\text{CTR}{*}\text{MCF}{*}\text{VTRCF}_C{*}\text{CTRCF}_C{*}\text{PACF}_C{*}\text{VTVDC}$$

where

$\text{Power}_{\text{highside (primary)}}$ = the corrected power on the high side of the transformer

$\text{Power}_{\text{lowside (secondary)}}$ = the power measured on the low side of the transformer

VTR = the voltage transformer marked ratio

CTR = the current transformer marked ratio

MCF = the meter correction factor from calibration

$VTRCF_C$ = the voltage transformer ratio correction factor from calibration data

$CTRCF_C$ = the current transformer ratio correction factor from calibration data

$PACF_C$ = the phase angle correction factor from calibration data

VTVDC = the voltage transformer voltage drop correction

The meter correction factor (MCF) is determined from calibration data. Each phase of the meter should be calibrated as a function of secondary current. The process should be done at a minimum of two different secondary voltages and at two different power factors. The actual MCF at test conditions could then be interpolated.

Phase angle correction factor for each phase ($PACF_C$) accounts for the phase shift that occurs in the voltage transformer (λ), current transformer (β), and the power meter (α). The Code will provide a more rigorous calculation; however, in most cases a linear interpolation as discussed below will provide a sufficiently accurate correction.

The phase shifts of each transformer could have an offsetting effect. For example, if the CT shifts the current waveform to the right and the VT shifts the voltage waveform in the same direction, the power meter output is not affected by a phase shift. Each of the phase shifts should be determined from calibration data.

$$\text{PACF}_C = \frac{\cos(\theta - \alpha + \beta - \gamma)}{\cos(\theta)} = \frac{\cos(\theta - \alpha + \beta - \gamma)}{(\text{Power Factor})}$$

where

α = shift in the power meter phase angle
β = shift in the current transformer phase angle
γ = shift in the voltage transformer phase angle
θ = arccos (Power Factor)

A good approximation in practice will be to assume that when power factor is 1, the PACF will also be equal to 1.

5-2 MECHANICAL POWER OUTPUT CALCULATION

5-2.1 Mechanical Drive Power

Power at the gas turbine shaft is the product of the torque and speed, with appropriate unit conversion constants. In U.S. Customary:

$$SHP = (\text{Torque} \times \text{Speed})/5252.1$$

where

SHP = shaft horsepower, with
Torque in lbf-ft
Speed in rpm

5-2.1.1 Correction to Specified Reference Conditions. If the gas turbine can be run at rated power, the corrections proceed as shown for generator drives. In the event that system conditions do not permit running the test at rated load, the parties will need to agree on the method of adjusting the output and heat rate to the specified conditions. Two methods are commonly employed.

(a) The manufacturer may supply correction curves or cycle data that will allow adjusting the data to rated speed(s) and control temperature, from which the corrections to specified reference conditions may be made.

(b) The gas turbine may be run at several points through a load and/or speed range to permit interpolation or extrapolation of the data to the rated load point. This generally involves normalizing the test results by applying dimensionless parameters, which are described in most thermodynamic textbooks.

It is expected that the first system will be more prevalent, given the availability and accuracy of gas turbine cycle performance programs.

5-2.2 Efficiency

Heat rate, conventionally used for generator drives, may not be the preferred parameter for mechanical drives. If thermal efficiency is required, it is

$$\eta\text{th} = SHP \times 2544.43/\text{Heat Input}$$

where heat input (Btu/hr in this case) is from para. 5-3.

Heat rate, in Btu/hp-hr, can be calculated from Heat Input/*SHP*.

5-3 HEAT RATE CALCULATIONS

5-3.1 Fuel Heat Input

Calculation procedures for gas and liquid fuel heat input are presented here. A sample calculation for gas fuel heat input can be found in Appendix C-1.

5-3.1.1 Differential Pressure Meter. The general equation for mass flow rate through a differential pressure class meter for both liquids and gases is as follows:

$$M_f = \frac{\pi}{4} * d^2 * C * \varepsilon * \sqrt{\frac{2 * \rho_{T,P} * \Delta P * g_c}{1 - \beta^4}} \quad (5\text{-}3.1)$$

where

M_f = fuel mass flow rate
d = diameter of orifice at flowing fluid temperature
C = orifice discharge coefficient (determined from calibration report)
ε = expansion factor
$\rho_{T,P}$ = fluid density at flowing temperature and pressure
ΔP = differential pressure across orifice
g_c = units conversion constant
β = ratio of orifice and pipe diameter (d/D), both diameters at the flowing fluid temperature
D = diameter of pipe at flowing fluid temperature

NOTE: Measurement units for the above parameters and variables are given in Table 5-3.1.

This equation can be further reduced to the following format.

$$M_f = N_1 \times d^2 \times C \times \varepsilon \times E_v \times \sqrt{\rho_{T,P} \times \Delta P} \quad (5\text{-}3.2)$$

where

N_1 = unit conversion factor
E_v = velocity of approach factor $= \dfrac{1}{\sqrt{1 - \beta^4}}$

5-3.1.2 Orifice Dimensions. If the flowing temperature of the fluid is different than the temperature at which the pipe and orifice dimensions were determined, the measured orifice and pipe dimensions must be corrected to compensate for the temperature variations.

$$d = [1 + \alpha_{PE} * (T_f - T_{\text{meas}})] * d_{\text{meas}} \quad (5\text{-}3.3)$$

$$D = [1 + \alpha_P * (T_f - T_{\text{meas}})] * D_{\text{meas}} \quad (5\text{-}3.4)$$

Table 5-3.1 Typical Values for Unit Conversion Factor N_1, Using Common Units of Measure

	U.S. Units	U.S. Units	U.S. Units	SI Units	SI Units	
			Calculation Constants			
π	3.14159	3.14159	3.14159	3.14159	3.14159	Universal constant
g_c	32.1740	32.1740	32.1740	NA	NA	lb_m-ft/(lb_f-sec^2)
g_c	NA	NA	NA	1.0000	1.0000	kg*m/N*sec^2)
			Units of Measure			
d	Inches	Inches	Inches	Millimeters	Millimeters	
ΔP	lb_f/in.^{2}	in.H_2O_{60}	In.H_2O_{68}	Millibar	KPa	
$\rho_{T,P}$	lb_m/ft^3	lb_m/ft^3	lb_m/ft^3	Kg/m^3	kg/m^3	
m_f	lb_m/sec	lb_m/sec	lb_m/sec	Kg/sec	kg/sec	
N_1	0.525021	0.0997424	0.0997019	0.000351241	0.0000351241	
	5.25021E-01	9.97424E-02	9.97019E-02	3.51241E-04	3.51241E-05	

where

d_{meas} = measured diameter of the orifice at T_{meas}

D_{meas} = measured diameter of the pipe at T_{meas}

α_{PE} = coefficient of thermal expansion for the orifice material

α_P = coefficient of thermal expansion for the pipe material

T_f = temperature of the flowing liquid

T_{meas} = temperature of the orifice or pipe material when the diameters were measured

5-3.1.3 Expansion Factor. The expansion factor (ε) compensates for the change in density due to an increase in pressure when the fluid flows through the orifice:

$$\varepsilon = 1 - (0.41 + 0.35 * \beta^4) \times \frac{\Delta P}{N_2 * \kappa * P_f} \qquad (5\text{-}3.5)$$

where

β = ratio of orifice and pipe diameter (d/D), both diameters at the flowing fluid temperature

ΔP = differential pressure

N_2 = unit conversion factor

κ = isentropic exponent

$= C_p/(C_P - 1.986/M_{\text{fluid}})$

where

C_p = specific heat at constant pressure

M_{fluid} = molecular weight of fluid

P_f = upstream static pressure of fluid

Typical values for unit conversion factor (N_2) are given in Table 5-3.2.

5-3.1.4 Compressibility. Fluid compressibility (Z_f) at flowing conditions shall be calculated based upon the methods outlined in AGA Report No. 8 utilizing the Detail Characterization Method (Input of individual gas constituents). Section 8.1 and Appendix A of AGA Report No. 8 present detailed information for the Detail Characterization.

5-3.1.5 Density—Gas Fuel. Gas fluid density at flowing fluid conditions is calculated from the following equation:

$$\rho_{T,P} = \frac{sg_i M_{\text{air}} P_f}{Z_f R T_f} \qquad (5\text{-}3.6)$$

where

$\rho_{T,P}$ = gas fluid density at flowing fluid temperature and pressure

sg_i = ideal gas specific gravity

$= M_{\text{gas}}/M_{\text{air}}$

M_{air} = molecular weight of air

M_{gas} = molecular weight of the gas mixture

$= \sum_{j=1}^{n} x_j * M_j$

x_j = mole fraction of gas component j

M_j = molecular weight of gas component j

n = total number of components

P_f = static pressure of fluid before orifice

Z_f = fluid compressibility at flowing pressure and temperature

R = universal gas constant

T_f = temperature of fluid (absolute, °F or °K)

5-3.1.6 Volumetric Meter. The general equation for mass flow rate through a volumetric meter for both liquids and gases is as follows:

$$M_f = q_v * \rho_{T,P} * \text{MCF} \qquad (5\text{-}3.7)$$

where

M_f = fuel mass flow rate

q_v = actual volume flow rate

$= V_g/\Delta t$

where

V_g = totalized volume of fluid measured during test

= final volume—starting volume

Δt = fluid volume timing period

Table 5-3.2 Typical Values for Unit Conversion Factor N_2, Using Common Units of Measure

	U.S. Units	U.S. Units	U.S. Units	Metric Units	Metric Units	Metric Units
ΔP	$lb_s/in.^2$	$in.H_2O_{60}$	$in.H_2O_{68}$	Kilopascals	Millibar	Millibar
P	$lb_s/in.^2$	$lb_s/in.^2$	$lb_s/in.^2$	Megapascals	Bar	Megapascals
N_2	1.00000	27.7070	27.7300	1000.00	1000.00	0.0100000
	1.00000E+00	2.77070E+01	2.77300E+01	1.0000E+03	1.0000E+03	1.0000E−02

$\rho_{T,P}$ = fluid density at flowing fluid temperature and pressure
MCF = meter calibration factor

5-3.1.7 Density—Liquid Fuel. Liquid fuel density is determined from the following equation:

$$\rho_T = \rho_{H_2O} * sg_T \qquad (5\text{-}3.8)$$

where
ρ_T = fluid density at flowing fluid temperature
ρ_{H_2O} = density of water which was used to define specific gravity of fuel
sg_T = specific gravity of the liquid fuel at the flowing temperature

5-3.1.8 Heating Values—Gas Fuel. The higher heating value (*HHV*) and lower heating value (*LHV*) of a gas fuel mixture are given by:

$$HHV = \sum_{j=1}^{n} x_j * M_j * HHV_j \Big/ \sum_{j=1}^{n} x_j * M_j \qquad (5\text{-}3.9)$$

$$LHV = \sum_{j=1}^{n} x_j * M_j * LHV_j \Big/ \sum_{j=1}^{n} x_j * M_j \qquad (5\text{-}3.10)$$

where
x_j = mole fraction of gas component j
M_j = molecular weight of gas component j
n = total number of components
HHV_j = higher heating value per unit mass for component j
LHV_j = lower heating value per unit mass for component j

5-3.1.9 Heating Values—Liquid Fuel. For liquid fuels, the higher heating value at constant volume is determined by fuel analysis per para. 4-5.4.1. The higher and lower heating values at constant pressure are determined from the following equations:

$$HHV_P = HHV_V + 2.64 * H \qquad (5\text{-}3.11)$$

$$LHV_P = HHV_V - 91.20 * H \qquad (5\text{-}3.12)$$

where
HHV_V = higher heating value at constant volume BTU/lbm
HHV_P = higher heating value at constant pressure BTU/lbm
LHV_P = lower heating value at constant pressure BTU/lbm
H = percent of Hydrogen (H_2) by weight contained in the liquid fuel

5-3.1.10 Sensible Heat—Liquid Fuel. The sensible heat for liquid fuels is calculated as:

$$SH_P = M_f\, x(h_T - h_{Ref}) \qquad (5\text{-}3.13)$$

where
SH_P = sensible heat at constant pressure
M_f = actual mass flow
h_T = specific enthalpy of the liquid fuel at the flowing temperature
h_{Ref} = specific enthalpy of the liquid fuel at the reference temperature.

NOTE: Reference temperature for heat rate determination is fuel temperature at specified reference conditions. Reference temperature for heat balance determination is user specified enthalpy reference temperature.

The specific enthalpy of liquid fuel is defined in D.W. Goulds' equation from the "Science of Petroleum," Vol. 2, page 1250, and reads as follows:

$$h = C_1 + C_2(°\text{API}) + C_3(T) + C_4(°\text{API})(T) + C_5 + C_6(°\text{API})(T^2)$$

where
h = specific enthalpy in Btu/lbm
°API = API gravity
T = temperature in °F
$C_1 = -30.016$
$C_2 = -0.11426$
$C_3 = 0.373$
$C_4 = 0.00143$
$C_5 = 2.18 \times 10^{-4}$
$C_6 = 7.0 \times 10^{-7}$

5-3.1.11 Sensible Heat—Gas Fuel. The sensible heat input for gaseous fuels is calculated as:

$$SH = M_f * (h_T - h_{Ref}) \qquad (5\text{-}3.14)$$

where
SH = sensible heat of gaseous fuel
M_f = actual mass flow
h_T = specific enthalpy of the gaseous fuel at the flowing temperature
h_{Ref} = specific enthalpy of the gaseous fuel at the reference temperature.

NOTE: Reference temperature for heat rate determination is fuel temperature at specified reference conditions. Reference temperature for heat balance determination is user specified enthalpy reference temperature.

The specific enthalpy of the actual gaseous fuel can be derived from gas properties published by NIST and others. As a simplifying assumption, the specific enthalpy of pure methane at 400 psia (referenced to 60°F) can be calculated with the following equation:

$$h = C_0 + C_1T + C_2T^2 + C_3T^3 \tag{5-3.15}$$

where

h = specific enthalpy in Btu/lbm
T = temperature in °F
$C_0 = -33.5813$
$C_1 = 5.5358 \times 10^{-1}$
$C_2 = 9.1067 \times 10^{-5}$
$C_3 = 1.7873 \times 10^{-3}$

The source data for this relationship is based upon *NIST Standard Reference Database 69, March 2003 Release*, and is available online at the NIST Chemistry Webbook.

The error introduced by using this simplified equation for a typical natural gas is less than 0.01% in total heat input compared to a value calculated directly from NIST gas properties for the actual composition and pressure. As a result, the parties may agree to use this simplified curve for typical methane rich fuels.

5-3.1.12 Heat Input. Calculation of heat input.

The total heat input is calculated as:

$$HI = M_f * HV + SH$$

where

HI = total heat input
M_f = fuel mass flow
HV = fuel heating value:
  For power output and heat rate test:
    HV = lower or higher heating value (LHV or HHV) of the fuel as defined in specified reference conditions.
  For exhaust flow or energy test:
    HV = lower heating value (LHV) of the fuel because the heat of vaporization for water is not recovered inside the heat balance boundary.
SH = sensible heat input (may be different for power/heat rate test and heat balance calculation, see paras. 5-3.1.10 and 5-3.1.11)

NOTE: Often the agreed calculation of heat input for a heat rate test is based solely on latent heat with no sensible heat component. In such cases, test correction curves may be used to account for variations in fuel supply temperature.

5-3.2 Heat Rate

The measured gas turbine heat rate is calculated as a ratio of the total heat input to power output. Heat rate is typically expressed in units of Btu/kWh, Btu/hp-hr or kJ/kWh.

The general equation to calculate heat rate from measured test data is:

$$HR_{\text{meas}} = HI_{\text{meas}}/P_{\text{meas}}$$

where

HI_{meas} = the measured total heat input value of the fuel (see para. 5-3.1.12)
P_{meas} = the measured value of power output (see para. 5-1 or 5-2)

Heat rate is directly related to thermal efficiency by the following conversion:

$$\eta_{\text{th}} = C/HR_{\text{meas}}$$

where

η_{th} = thermal efficiency, percent
C = 3412.14 when HR_{meas} is expressed in Btu/kWh
C = 2544.43 when HR_{meas} is expressed in Btu/hp-hr
C = 3600 when HR_{meas} is expressed in kJ/kWh

5-4 CORRECTION OF TEST RESULTS—FUNDAMENTAL PERFORMANCE EQUATIONS

The following fundamental performance equations for correcting calculated test values to the Specified Reference Conditions are applicable to any of the gas turbine types covered by this Code.

Corrected power is expressed as

$$P_{\text{corr}} = \frac{P_{\text{meas}} + \sum_{i=1}^{n} \Delta i}{\prod_{n=1}^{X} \alpha_n}$$

Corrected heat rate is expressed as:

$$HR_{\text{corr}} = \frac{HR_{\text{meas}}}{\prod_{n=1}^{X} \beta_n}$$

Corrected exhaust flow is expressed as

$$m_{\text{exh,corr}} = \frac{m_{\text{exh}}}{\prod_{n=1}^{X} \gamma_n}$$

Corrected exhaust energy is expressed as

$$Q_{\text{exh,corr}} = \frac{Q_{\text{exh}}}{\prod_{n=1}^{X} \varepsilon_n}$$

Corrected exhaust temperature is expressed as

$$t_{\text{exh,corr}} = t_{\text{exh}} + \sum_{n=1}^{X} \delta_n$$

Multiplicative correction factors α_n, β_n, γ_n, and ε_n and additive correction factors Δ_n and δ_n are used to correct measured results back to the Specified Reference Conditions. Attention should be paid to the basis of measured power and heat rate, as either net or gross, to make

Table 5-4.1 Summary of Additive Correction Factors for Power Fundamental Performance Equation

Power	Uncontrollable External Condition Requiring Correction	Comments
Δ_1	Generator power factor	Measured at the power measurement location
Δ_2	Generator excitation power	When excitation power is supplied after power measurement
Δ_3	Auxiliary loads	If required by test boundary
Δ_4	Transformer losses	If required by test boundary

Table 5-4.2 Summary of Correction Factors in All Fundamental Performance Equations

Power	Heat Rate	Exhaust Flow	Exhaust Energy	Exhaust Temperature	Uncontrollable External Condition Requiring Correction
α_1	β_1	γ_1	ε_1	δ_1	Inlet air temperature
α_2	β_2	γ_2	ε_2	δ_2	Barometric pressure
α_3	β_3	γ_3	ε_3	δ_3	Inlet humidity
α_4	β_4	γ_4	ε_4	δ_4	Fuel composition
α_5	β_5	γ_5	ε_5	δ_5	Injection fluid flow
α_6	β_6	γ_6	ε_6	δ_6	Injection fluid enthalpy
α_7	β_7	γ_7	ε_7	δ_7	Injection fluid composition
α_8	β_8	γ_8	ε_8	δ_8	Exhaust pressure loss
α_9	β_9	γ_9	ε_9	δ_9	Shaft speed
α_{10}	β_{10}	γ_{10}	ε_{10}	δ_{10}	Turbine extraction
α_{11}	β_{11}	γ_{11}	ε_{11}	δ_{11}	Fuel temperature
α_{12}	β_{12}	γ_{12}	ε_{12}	δ_{12}	Inlet pressure loss

sure that the correction curves use the same basis. Table 5-4.1 summarizes the additive corrections for the power fundamental performance equation. Table 5-4.2 summarizes the correction factors used in all the fundamental performance equations.

While these correction factors are intended to account for all variations from Specified Reference Conditions, it is possible that 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.

The correction factors that are not applicable to the specific type of gas turbine configuration being tested, or to the test objective, are simply set equal to unity or zero, depending on whether they are multiplicative correction factors or additive correction factors, respectively.

All correction factors must result in a zero correction if all test conditions are equal to the Specified Reference Conditions. Some correction factors may be significant only for unusually large deviations from Specified Reference Conditions, or not at all, in which case they can also be ignored. An example of this is the fuel composition correction. If the pre-test uncertainty analysis shows a correction to be insignificant, these corrections can be ignored. An insignificant correction is one that results in a correction of less than 0.05%.

The applicable corrections to use in the fundamental performance equations for a particular test depend on the type of gas turbine being tested and the goal of the test. Specific examples of the fundamental performance equations for different gas turbine configurations and boundary conditions are provided in Appendix C-3.

5-5 APPLICATION OF CORRECTION FACTORS

The format of the fundamental equations allows decoupling of the appropriate correction effects (ambient conditions, injection fluids, etc.) relative to the measured prime parameters of power, heat rate, exhaust flow or energy, and exhaust temperature so that measured performance can be corrected to the Specified Reference Conditions. Corrections are calculated for parameters at the test boundary different than Specified Reference Conditions, which affect measured performance results.

Since the variation in power, heat rate, exhaust flow or energy, and exhaust temperature due to various external conditions is unique to each gas turbine, the manufacturer may generate a set of site specific correction curves to be incorporated into the site specific test procedures prior to the test. Each correction factor is calculated by varying only one parameter over the possible range of deviations from the base reference condition. Some of the correction factors are summations of smaller corrections or require a family of curves. For example, the correction for fuel composition may be split into two or more components to better characterize the impact of fuel composition on gas turbine performance.

Manufacturers sometimes supply curves that are referenced to standard conditions other than the Specified Reference Conditions. In this case, relative corrections relating the measured test conditions and Specified Reference Conditions must be calculated as shown in the examples below:

$$\alpha_1 = \frac{\alpha_{1a}}{\alpha_{1b}}$$

$$\delta_1 = [\delta_{1a} - \delta_{1b}]$$

where the subscripts signify

a = correction from measured point to standard condition

b = correction from Specified Reference Condition to standard condition

In lieu of application of the equations and correction curves, a gas turbine simulation model provided by the manufacturer may be applied after the test using the appropriate test data and boundary conditions so that all of the corrections for the particular test run are calculated simultaneously. Studies of different gas turbine cycles using the performance curves and equations instead of the simulation model have demonstrated that interactivity between correction factors usually results in differences of less than 0.3%. An advantage of the post-test model simulation is a reduction or elimination of the efforts put forth to generate the correction curves and to apply the correction curves to actual test data.

The gas turbine power, heat rate, exhaust energy or flow, and exhaust temperature can be corrected to specified reference conditions based on ambient conditions and other external quantities using the multiplicative and additive correction factors as described below.

5-5.1 Inlet Temperature Correction ($\alpha_1\beta_1\gamma_1\varepsilon_1\delta_1$). Correction is made to gas turbine performance based on the inlet air temperature crossing the test boundary. The inlet air temperature shall be measured in accordance with para. 4-3.

5-5.2 Barometric Pressure Correction ($\alpha_2\beta_2\gamma_2\varepsilon_2\delta_2$). Correction is made to gas turbine performance based on the site barometric pressure (or other pressure mea-surement location if agreed upon by the parties). Barometric pressure is measured in accordance with para. 4-2.

5-5.3 Inlet Humidity Correction ($\alpha_3\beta_3\gamma_3\varepsilon_3\delta_3$). Correction is made to gas turbine performance based on humidity of the air crossing the test boundary. Typically the humidity of the air will be equal to the ambient humidity and will measured in accordance with para. 4-9.

5-5.4 Fuel Composition Correction ($\alpha_4\beta_4\gamma_4\varepsilon_4\delta_4$). Differences in fuel properties between the reference fuel analysis and the measured fuel analysis effect the performance of the gas turbine. The fuel analysis shall be measured near the test boundary in accordance with para. 4-4 for gaseous fuels and para. 4-5 for liquid fuels.

The fuel composition correction factors may be determined as a combination of multiple factors to better characterize the impact of the variance in composition on gas turbine performance. As another alternative, the fuel composition correction factors may be determined by the manufacturer's thermal performance simulation model after the test, if agreed upon by the parties. The manufacturer should provide a sample correction calculation in the detailed test procedures prior to the test.

5-5.5 Injection Fluid Flow Correction ($\alpha_5\beta_5\gamma_5\varepsilon_5\delta_5$). Correction is made to gas turbine performance based on the injection fluid flow crossing the test boundary. The injection fluid flow shall be measured in accordance with para. 4-11.

5-5.6 Injection Fluid Enthalpy Correction ($\alpha_6\beta_6\gamma_6\varepsilon_6\delta_6$). Correction is made to gas turbine performance based on the injection fluid enthalpy crossing the test boundary. The injection fluid enthalpy shall be calculated in accordance with the applicable version of the ASME Steam Tables or other appropriate standard for the given injection fluid. Injection fluid pressure shall be measured in accordance with para. 4-2. Injection fluid temperature shall be measured in accordance with para. 4-3.

5-5.7 Injection Fluid Composition Correction ($\alpha_7\beta_7\gamma_7\varepsilon_7\delta_7$). Differences in injection fluid composition between the reference injection fluid composition and the measured injection fluid composition affects the performance of the gas turbine. Typically, the injection fluid is either water or steam where the multiplicative correction factors are equal to 1.0 and the additive correction factor is equal to zero. If the injection fluid is a gaseous mixture such as a nitrogen/oxygen mixture in an IGCC plant, then the composition of the injection fluid will impact gas turbine performance and shall be determined in accordance with para. 4-4.

5-5.8 Exhaust Pressure Loss Correction ($\alpha_8\beta_8\gamma_8\varepsilon_8\delta_8$). Correction is made to gas turbine performance based on the turbine static exhaust pressure loss at the test boundary. If necessary, the exhaust gas static pressure loss is measured in accordance with para. 4-2.

5-5.9 Shaft Speed Correction ($\alpha_9\beta_9\gamma_9\varepsilon_9\delta_9$). Correction is made to gas turbine performance based on deviations of the shaft speed from the Specified Reference Conditions. See para. 4-8 for speed measurement methods.

5-5.10 Turbine Extraction Correction ($\alpha_{10}\beta_{10}\gamma_{10}\varepsilon_{10}\delta_{10}$). Correction is made to gas turbine performance based on the flow rate of any extractions from the gas turbine measured where they cross the test boundary. Typically, this correction might apply to an IGCC plant where large quantities of compressor exit air are extracted for use in the coal gasification process. Extraction flows shall be measured in accordance with para. 4-11, as appropriate.

5-5.11 Fuel Temperature Correction ($\alpha_{11}\beta_{11}\gamma_{11}\varepsilon_{11}\delta_{11}$). Correction is made to gas turbine performance based on the measured fuel temperature at the test boundary. The fuel temperature shall be measured near the test boundary in accordance with para. 4-4 for gaseous fuels and para. 4-5 for liquid fuels.

5-5.12 Inlet Pressure Loss Correction ($\alpha_{12}\beta_{12}\gamma_{12}\varepsilon_{12}\delta_{12}$). Correction is made to gas turbine performance based on the turbine inlet total pressure loss at the test boundary. The need for this correction may depend on the scope of equipment within the test boundary. If necessary, the inlet air total pressure loss is measured in accordance with para. 4-2.

5-6 DEGRADATION

The corrected results from para. 5-5 represent the thermal performance of the gas turbine at the specified reference conditions at the time of the performance test. If required by the contract or the parties, an additional correction for performance degradation may be applied.

Section 6
Test Report Requirements

6-1 GENERAL REQUIREMENTS

The test report shall provide definitive statements of the purpose of the test, the methodology for attainment of the objectives and descriptions of the results. It shall also clearly and concisely document all data generated by the test as well as all ensuing computations.

The test report for a performance test should incorporate the following general requirements:

(a) summary, described in para. 6-2
(b) test description, described in para. 6-3
(c) calculation and results, described in para. 6.4
(d) test equipment, described in para. 6-5
(e) appendices, described in para. 6-6

This outline is a recommended report format. Other formats are, however, acceptable. This report shall contain all the information described below.

6-2 SUMMARY

(a) General information about the plant and the test, such as the plant type and operating configuration, and the test objective
(b) Date and time of the test
(c) Summary of the results of the test
(d) Calculated post-test uncertainty
(e) Any agreements among the parties to the test to allow any major deviations from the test requirements

6-3 TEST DESCRIPTION

(a) Test description and objectives
(b) General information about the plant and the test, such as:
  (1) Brief history of the unit operation, from startup through the performance tests
  (2) Description of the equipment to be tested and all such ancillary equipment that may influence the test
  (3) Cycle diagram showing the test boundary
(c) Listing of the representatives of the parties to the test
(d) Organization of the test personnel
(e) All test agreements

6-4 TEST EQUIPMENT

(a) Tabulation of test equipment used, including quantity, make, model number, etc.
(b) Description of the location of the test equipment
(c) Means of data collection for each data point, e.g., temporary data acquisition system printout, plant control computer printout or manual data sheet, and any identifying tag number and/or address of each
(d) Description of data acquisition system(s) used
(e) Summary of test equipment calibration

6-5 CALCULATIONS AND RESULTS

(a) Tabulation of the operating conditions and results during all testing including any observations
(b) Format of the general performance equation that is used, based on the test goal and the applicable corrections
(c) Tabulation of the reduced data necessary to calculate the results, summary of additional operating conditions not part of such reduced data
(d) Calculation of test results from the reduced data (refer to the appendices for examples of step-by-step calculations for each plant type and test goal)
(e) Detailed calculation of fuel flow rates from applicable data, including intermediate results, if required
(f) Detailed calculations of fuel properties — density, heating value (higher or lower), constituent properties
(g) Rationale for any elimination of data
(h) Comparison of repeatability of test runs, if more than one test run was performed
(i) Clarify as to whether reported heat rate is based on higher heating value or lower heating value
(j) Discussion of results as applicable

6-6 APPENDICES

(a) Test procedure, including correction curves and sample calculations
(b) Copies of original data sheets and/or electronically acquired data in mutually agreeable format
(c) Copies of operator logs, messages or alarms, or other record of operating activity during each test
(d) Documentation indicating equipment operation in the required configuration (such as inlet air treatment, compressor guide vane angle, and/or fluids injection, etc)
(e) Documentation of control settings
(f) Results of laboratory fuel analysis
(g) Instrumentation calibration results from laboratories, certification from manufacturers
(h) Measurement uncertainty calculation
(i) Any pretest inspection sheets showing signatures of witnesses

Section 7
Test Uncertainty

7-1 INTRODUCTION

This Section contains sample calculations for gas turbine tests defined by this Code: unit output and thermal efficiency (para. 7-3), comparative tests (para. 7-4), and exhaust energy (para. 7-5). It also summarizes some of the key uncertainty considerations from PTC 19.1 Test Uncertainty (para. 7-2).

7-2 UNDERSTANDING TEST UNCERTAINTY

7-2.1 Systematic and Random Components of Measurement Uncertainties, U_{Ti}

The total uncertainty for each measurement, U_{Ti} has two components: (a) systematic B_i, and (b) random $2S_i$ as illustrated in Fig. 7-2.1. For Performance Test Codes, a 95% confidence interval is required for both uncertainties.

7-2.1.1 Systematic, or Bias, or Fixed, Uncertainty, B_i. This is an estimate, based on experience, and at the 95% confidence level, of the possible error of the average value not eliminated through calibration. It is a constant value despite repeated measurements. The systematic uncertainty can be reduced by such things as higher quality instruments and consideration of the factors in para. 7-2.1.1A.

7-2.1.1A Estimating Systematic Uncertainties, B_i. Systematic Uncertainties, B_i, are estimated using the experience of the parties, and the suggestions and analyses presented in PTC 19.1. Estimates should reflect the 95% confidence level used for PTC Codes. For assistance in establishing reasonable values for the systematic errors, consider the following:

(a) PTC 19.1 on test uncertainty

(b) PTC 19 series on instrumentation (pressure, temperature, flow, power)

(c) expected spatial variation, and the quantity of instruments used.

(d) cumulative test experience of the parties

(e) calibration lab's accuracy and their experience with different types of instruments

(f) laboratory standards for inter-laboratory agreement. For example, the allowed variation in fuel properties when the same fuel is submitted to different labs.

(g) comparison of measurements that depend on different principles

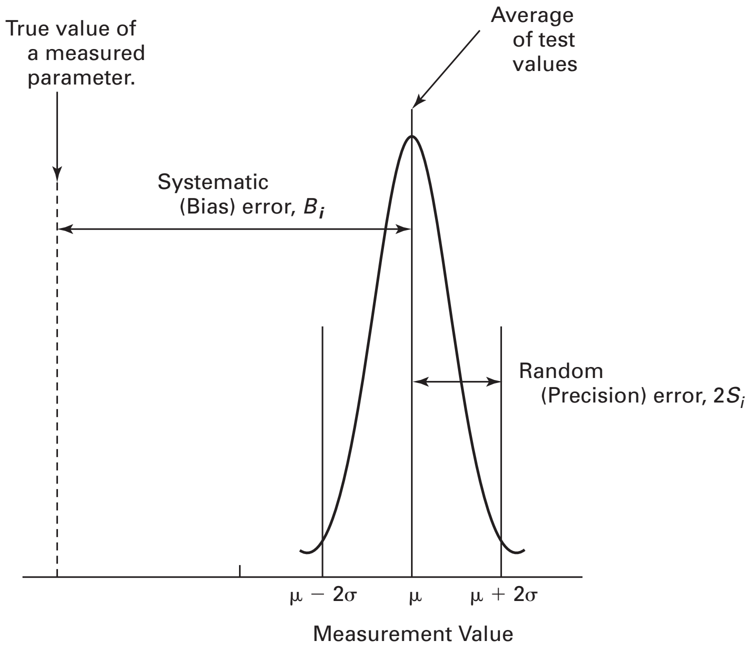


Fig. 7-2.1 Illustrating Systematic, B_i and Random Errors, $2S_i$

(h) experience with duplicate instruments measuring the same quantity, or with different instruments measuring the same quantity

(i) data acquisition system to be used (If manual readings, how accurately can the scale be read? If automatic, will the data acquisition system be calibrated, will deadbands be removed, etc.)

7-2.1.1B Correlated vs. Uncorrelated Systematic Uncertainties, B_i. The instrument accuracy component of the systematic uncertainty can be reduced by increasing the quantity of instruments only if the uncertainty is uncorrelated. For example, if multiple instruments are calibrated against the same standard, the systematic uncertainty reflects the error of the standard. However, if multiple instruments are independent of one another (i.e., calibrated against different standards), then the systematic uncertainty is reduced by dividing by the square root of the quantity of instruments. The parties should refer to PTC 19.1 for details on calculating correlation effects, and to the examples shown later in this Section.

7-2.1.1C Spatial Effects on Systematic Uncertainty, B_i. The systematic uncertainty is a combination of the instrument accuracy and the spatial variation. For example, if only one RTD calibrated to ±0.4°F is used to measure gas turbine inlet air temperature, the systematic uncertainty may be "judged" to be X°F due to the unknown spatial variation. With only one RTD, it is not known if it is placed in a hot or cold stream, where there might be as much as X-degrees difference from the average. But if nine RTDs were used, the uncertainty is reduced in two ways. First, the nine RTDs provide some insight into the spatial variation, and second, there are nine times as many instruments. Both the spatial and random uncertainties should be reduced with the added RTDs.

7-2.1.2 Random Uncertainty, $2S_i$. Random uncertainty is similar to standard deviation or repeatability, in that it represents the spread around the average. It is due to the nonrepeatability of the measurement system. It can be reduced by increasing the quantity of instruments used to measure a given parameter, and by increasing the quantity of readings taken. Random uncertainty is estimated in the pretest analysis and calculated in the post-test analysis. For pretest, use values from past experience.

7-2.1.2A Calculating Random Uncertainty, $2S_i$. The random uncertainty has been standardized by all the ASME codes as $2S_i$, which reflects the desire to have a 95% confidence level. Note that random uncertainty is always uncorrelated, and can always be reduced by increasing the quantity of instruments. Each method below for calculating random uncertainty includes dividing by the square root of the quantity of instruments.

7-2.1.2B Confidence Interval. Figure 7-2.1.2B illustrates the 95% confidence interval as ±2 standard deviations (for no systematic error).

7-2.1.2C Method for Calculating S_i. S_i equals the standard deviation of the mean, which is the standard deviation (STDEV), (available on most scientific calculators and spreadsheets), divided by the square root of N, and is calculated by the following formula:

$$S_i = (1/\sqrt{N}) * [\text{STDEV}] \tag{7-2.1}$$

where

$\text{STDEV} = \{[\Sigma(x_k - \overline{X})^2] \;/\; (N-1)\}^{0.5}$
N = the number of readings
$\overline{X}$ = the mean
x_k = individual measurement value

7-2.1.3 Combining B_i and S_i for the Total Uncertainty. The total uncertainty, U_{Ti}, for each parameter being measured is calculated from the root sum square (RSS) of the systematic and random components:

$$U_{Ti} = [\{B_i^2 + (2S_i)^2\}]^{0.5} \tag{7-2.2}$$

where

U_{Ti} = combined random and systematic uncertainty for measurement i
B_i = systematic uncertainty for measurement i
$2S_i$ = random uncertainty for measurement i

NOTE: "i" represents a measured value, not individual instruments. For example, there is only one B_i for ambient air temperature, regardless of how many instruments are used to determine ambient air temperature.

PTC 19.1 recommends that Eq. 7-2.2 be written in the form

$$U_{Ti} = 2[\{(B_i/2)^2 + (S_i)^2\}]^{0.5}$$

where the 2 multiplier is the Student's t value appropriate for the degrees of freedom for both the random and systematic uncertainties. For most applications, the degrees of freedom will be large enough (over 30) so that t can be taken as 2 for the 95% confidence interval. Refer to PTC 19.1 for further discussion.

7-2.1.4 Sensitivity or Influence Coefficients, Θ_i. Each performance parameter or variable has some influence on the desired result; this relationship is called the sensitivity or influence coefficient. Most sensitivities are unique to each gas turbine design, and are provided by the manufacturer. The sensitivity coefficients are generally equal to the slope of the correction curves at the conditions of the test run. In the pretest analysis, use the slope at the reference condition, or, if known, at the condition expected during the test. In the posttest analysis, use the slope at the test conditions. The sensitivity is the percent effect on the corrected result, in %/unit or %/%, respectively.

7-2.1.5 Combining the Measurement Uncertainties Into the Uncertainty of the Result. The uncertainty of the result, U_R is the RSS value of the uncertainty of each mea-

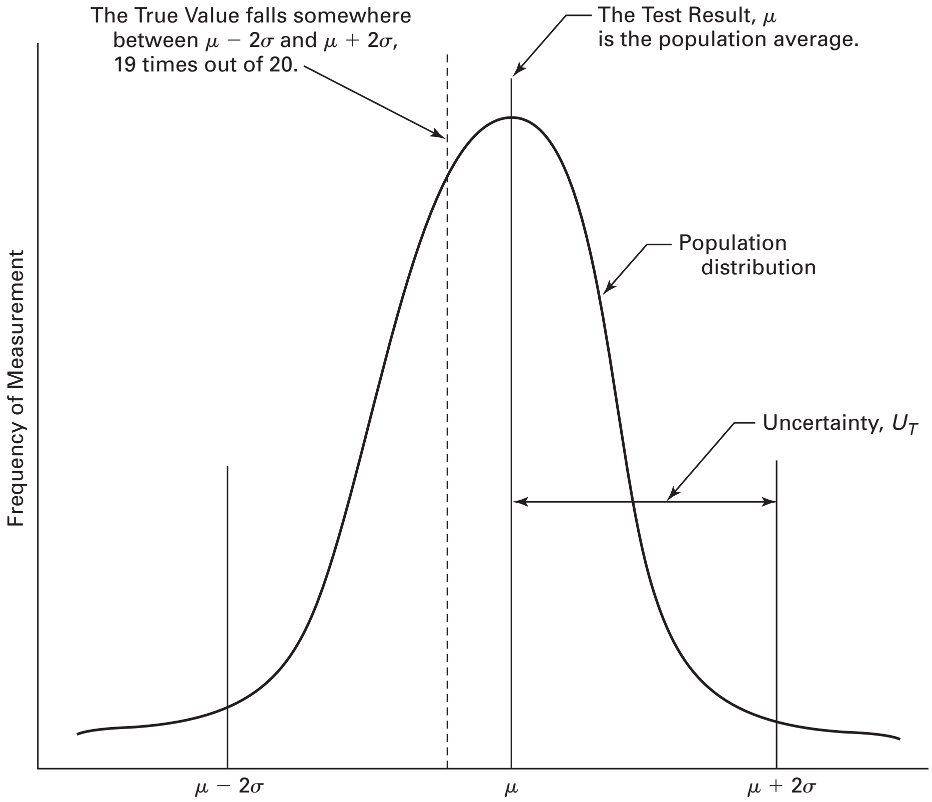


Fig. 7-2.1.2B Test Uncertainty Illustration

surement multiplied by the Sensitivity Coefficient, Θ_i, for each parameter. Alternate equivalent formulations are:

$$U_R = [\Sigma\Theta_i^2\{B_i^2 + (2S_i)^2\}]^{0.5} \quad (7\text{-}2.3)$$

$$U_R = [\Sigma(\Theta_i\, U_{Ti})^2]^{0.5} \quad (7\text{-}2.4)$$

where

U_R = the uncertainty of the result (such as the uncertainty of corrected output)

Θ_i = sensitivity coefficient for measurement i

B_i = systematic uncertainty

S_i = standard deviation of the mean

U_{Ti} = combined systematic and random uncertainty for measurement i

7-2.1.6 Uncertainty of Control Parameters Inside the Test Boundary. The calculations include only those measurements, and their associated sensitivity Θ_i values, necessary to adjust the test point results to the specified reference conditions. Internal control variables (such as compressor discharge pressure or exhaust temperature), are generally not part of the uncertainty analysis for output or heat rate.

7-2.1.7 Post-test Uncertainty Analysis. The data shall be plotted and examined for sudden shifts and outliers. A post-test uncertainty analysis shall be conducted to replace the assumptions made in the pretest analysis. In particular, the random uncertainties can now be calculated and incorporated. Also, the sensitivities can now be re-calculated at the test values (in other words, the slopes at the applicable portion of the correction curves may now be used).

7-3 UNIT OUTPUT AND THERMAL EFFICIENCY

7-3.1 Uncertainty Calculation Logic

The three-step process defined in para. 3-6 is recommended for establishing the pre- and post-test uncertainties. First, for pretest, an uncertainty limit is calculated based on the Code limits for each parameter or variable from Table 4-1. The information required for this first uncertainty is the power measurement (electrical or mechanical), fuel type, scope of supply (in this case water injection and air extraction are included), and the sensitivities at the reference conditions of the turbine being tested. Tabulate these in a format similar to Table 7-3.1A. This calculation will yield the maximum test uncertainty allowed for this particular Code test, which will be referred to as the ***Code Limit***.

The second step is to assess the instrumentation expected to be used for the test. The parties should attempt to improve on the uncertainties allowed by the Code, in order to assure that the post-test uncertainty will come in at or below the Code Limit. Accordingly, Table 7-3.1B is

Table 7-3.1A Step 1: Pretest Uncertainty Calculation, Code Limit

		Measured	Table 4.1	Pretest Uncert.		SENS Θ			Total	Pretest Code Limit
Result	Parameter	by	Limit	B_i	$2S_i$	[Note (1)]	$(U_{B_i}{*}\Theta)^2$	$(U_{2S_i}{*}\Theta)^2$	UNC $(U_T)^2$	Step 1
POWER	Watthours	3 meter method								
	Volts (ratio)	Calib. VTs								
	Amps (ratio)	Calib. CTs								
	Power factor	Station meter								
	Time (if req'd)	Digital watch								
	Gross power		0.25%			1			0.0625	0.250
	Aux power	Station meter	5.00%			0.015			0.005625	
	Net power							SUM	0.068125	0.261
ORIFICE FACTORS	Flow coeff, *C*	From calib.				1				
	Exp factor ϵ	$f(\Delta P, p, MW)$				1				
	ΔP	Diff. *p t/d*				0.5				
	Fuel press *P*	Press. *t/d*				0.5				
	Fuel temp. *T*	Thermocouples				−0.5				
	Total		0.40%			1			0.16	0.400
HEAT INPUT	Orif. factors		0.40%			1			0.16	
	Compress *Z*		0.10%			−0.5			0.0025	
	Volume %*Vi*		0.33%			1			0.1089	
	Heat Input							SUM	0.2714	0.521
HEAT RATE	RSS of net power and heat input							SUM	0.339525	0.583
CORRECTED POWER	Inlet temp.	Multiple RTDs	1°F			0.4			0.16	
	Bar. pressure	Abs. *p t/d*	0.075%			1			0.005625	
	Rel. humidity	Hygrometer	2%			0.004			0.000064	
	Water inj. flow	Orifice	2%			0.035			0.0049	
	Air extr. flow	Orifice	2%			0.021			0.001764	
	Net power					1			0.068125	
	Corr power							SUM	0.240478	0.490
CORRECTED HEAT RATE	Inlet temp		1°F			0.08			0.0064	
	Rel. humidity		2%			0.0076			0.000231	
	Water inj. flow		2%			0.013			0.000676	
	Water inj. *T*		5°			0.004			0.0004	
	Air extr. flow		2%			0.011			0.000484	
	Heat rate					1			0.339525	
	Corr heat rate							SUM	0.347716	0.590

NOTE:
(1) These sensitivities are assumed for this example. Every test will have its own set depending on the tested turbine's characteristics.

Table 7-3.1B Step 2: Pretest Planned Uncertainty Values

Result	Parameter	Measured by	Correlated	Target UNC	Pretest Uncert.		SENS Θ [Note (1)]	$(U_{B_i}{*}\Theta)^2$	$(U_{2S_i}{*}\Theta)^2$	Total UNC $(U_T)^2$	Pretest UNC Step 2	Pretest Code Limit Step 1
					B_i	$2S_i$						
POWER	Watthours	3 meter method	Yes	0.10%	0.1	0	1	0.01		0.01		
	Volts (ratio)	Calib. VTs	Yes	0.10%	0.1	0	1	0.01		0.01		
	Amps (ratio)	0.3% class CTs	Yes	0.15%	0.15	0	1	0.0225		0.0225		
	Power factor	Station meter		2.00%	1		0.02	0.0004		0.0004		
	Time (if req'd)	Digital watch		0.05%	NR							
	Gross power								SUM	0.0429	0.207	0.250
	Aux power	Station meter		5%	3	2	0.015	0.00203	0.0009	0.002925		
	Net power								SUM	0.045825	0.214	0.261
ORIFICE FACTORS	Flow coeff. *C*	From calib.		0.25%	0.25	0	1	0.0625	0	0.0625		
	Exp factor ϵ	$f(\Delta P, p, MW)$		0.01%	0.002	0.001	1	4E-06	0.000001	0.000005		
	ΔP	Diff. *p t/d*		0.25%	0.2	0.1	0.5	0.01	0.0025	0.0125		
	T	*t/c*		0.40%	0.25	0.1	−0.5	0.01563	0.0025	0.018125		
	P	*t/d*		0.25%	0.2	0.1	0.5	0.01	0.0025	0.0125		
	Total									0.10563	0.325	0.400
HEAT INPUT	Volume %*Vi*	Chromatograph		0.33%	0.3	0.1	1	0.09	0.01	0.1		
	Z	AGA 8		0.10%	0.05	0	−0.5	0.00063	0	0.000625		
	Orif. factors	From above					1			0.10563		
	Heat input									0.206255	0.454	0.521
HEAT RATE	Net power	From above								0.045825		
	Heat input	From above								0.206255		
	Heat rate									0.25208	0.502	0.583
CORRECTED POWER	Inlet temp.	Multiple RTDs		1°F	0.8	0.2	0.4	0.1024	0.0064	0.1088		
	Bar. pressure	Abs. *p t/d*		0.075%	0.075	0	1	0.00563	0	0.005625		
	Rel. humidity	Hygrometer		2%	2	0	0.004	6.4E-05	0	0.000064		
	Water inj. flow	Orifice		2%	1.75	0.75	0.035	0.00375	0.000689	0.004441		
	Air extr. flow	Orifice		2%	1.75	0.75	0.021	0.00135	0.000248	0.001599		
	Net power						1			0.045825		
	Corr. net power									0.166353	0.408	0.490
CORRECTED HEAT RATE	Inlet temp			1°F	0.8	0.2	0.08	0.0041	0.000256	0.004352		
	Rel. humidity			2%	2	0	0.0076	0.00023	0	0.000231		
	Water inj. flow			2%	1.75	0.75	0.013	0.00052	9.51E-05	0.000613		
	Water inj. *T*			5°	3	2	0.004	0.00014	0.000064	0.000208		
	Air extr. flow			2%	1.75	0.75	0.011	0.00037	6.81E-05	0.000439		
	Heat rate						1			0.25208		
	Corr. heat rate									0.257922	0.508	0.590

NOTE:
(1) These values assumed for this example [see Note (1) in Table 7-3.1a].

Table 7-3.1C Step 3: Post-Test Uncertainty Calculation

Result	Parameter	Test Uncertainty		SENS Θ [Note (1)]	$(U_{B_i}{*}\Theta)^2$	$(U_{2S_i}{*}\Theta)^2$	Total UNC $(U_T)^2$	Test UNC Step 3	Pretest UNC Step 2	Pretest Code Limit Step 1
		B_i	$2S_i$							
POWER	Watthours	0.1	0	1	0.01		0.01			
	Volts (ratio)	0.1	0	1	0.01		0.01			
	Amps (ratio)	0.15	0	1	0.0225		0.0225			
	Power factor	1		0.02	0.0004		0.0004			
	Time (if req'd)	NR								
	Gross power					SUM	0.0429	0.207	0.207	0.250
	Aux power	3	2.2	0.015	0.002025	0.001089	0.003114			
	Net power					SUM	0.046014	0.215	0.214	0.261
ORIFICE FACTORS	Flow coeff. *C*	0.25	0	1	0.0625	0	0.0625			
	Exp factor	0.0011	0.0005	1	1.21E-06	0.00000025	1.46E-06			
	ΔP	0.25	0.12	0.5	0.015625	0.0036	0.019225			
	T	0.25	0.15	−0.5	0.015625	0.005625	0.02125			
	p	0.25	0.13	0.5	0.015625	0.004225	0.01985			
	Orif factors						0.122826	0.350	0.325	0.400
HEAT INPUT	%*Vi* [Note (2)]	0.175	0.11	0.874	0.023394	0.0092429	0.032637			
	Z	0.05	0	−0.5	0.000625	0	0.000625			
	Orif. factors			1			0.122826			
	Heat input						0.156088	0.395	0.454	0.521
HEAT RATE	Net power						0.046014			
	Heat input						0.156088			
	Heat rate						0.202102	0.450	0.502	0.583
CORRECTED POWER	Inlet temp.	0.8	0.33	0.4	0.1024	0.017424	0.119824			
	Bar. pressure	0.075	0	1	0.005625	0	0.005625			
	Rel. humidity	2	0	0.004	0.000064	0	0.000064			
	Water inj. flow	1.75	1	0.035	0.003752	0.001225	0.004977			
	Air extr. flow	1.75	1	0.021	0.001351	0.000441	0.001792			
	Net power			1			0.046014			
	Corr. net power						0.178295	0.422	0.408	0.490
CORRECTED HEAT RATE	Inlet temp	0.8	0.33	0.08	0.004096	0.00069696	0.004793			
	Rel. humidity	2	0	0.0076	0.000231	0	0.000231			
	Water inj. flow	1.75	1	0.013	0.000518	0.000169	0.000687			
	Water inj. *T*	3	2	0.004	0.000144	0.000064	0.000			
	Air extr. flow	1.75	1	0.011	0.000371	0.000121	0.000			
	Heat rate			1			0.202			
	Corr. heat rate						0.209	0.457	0.508	0.590

NOTES:
(1) These values assumed for this example [see Note (1) on Table 7-3.1A].
(2) See Table 7-3.3.2.3 for actual calculation of the uncertainty for %*Vi*

prepared, using the best estimates for each parameter based on the selected instrumentation, their calibration levels, and the experience of the parties. Note that the electrical power and fuel mass flow measurements have been broken down into their individual measurements, such that the results are within the values from Table 4-1.

The third step, after the test, is to calculate the post-test uncertainty. This reflects the values for the actual instrumentation used, the random uncertainties calculated from the data, and the sensitivities at the test conditions. From an uncertainty standpoint, the test shall be considered successful if the post-test uncertainty does not exceed the Code Limit uncertainty. Table 7-3.1C is a sample calculation for the post-test case. This shows that all of the results are within the Code Limit.

7-3.2 Uncertainty Calculations

As defined in Eq. 7.1.4, the uncertainties in power output and thermal efficiency are equal to the RSS value of the uncertainty of each parameter multiplied by its sensitivity coefficient. The calculations include the measurements and Θ values necessary to adjust the test point results to the specified reference conditions.

The calculation procedure is as follows:

(a) The systematic B_i and random components $2S_i$ are established.

(b) The sensitivity Θ is calculated by differentiation of the equations, or from data supplied by the manufacturer for the test turbine.

(c) Each B_i and $2S_i$ is multiplied by Θ and squared, giving the factor U_i^2. All the U_i^2 factors are summed and the square root taken to determine the test uncertainty.

(d) For parameters that are correlated, these additional terms are calculated.

(e) Gas turbine tests normally cannot be run at the specified conditions of inlet temperature and pressure, and the test results must be corrected to the Specified Reference Conditions. The corrected power uncertainty is obtained in the same manner as the measured power uncertainty, considering the uncertainty and sensitivity for the added parameters of compressor inlet temperature, barometric pressure, specific humidity, and others as required. For Table 7-3.1A it was assumed that the water injection and air extraction flows had to be adjusted to the guaranteed level at the test conditions.

(f) Heat rate is equal to heat input divided by power. The corrected heat rate uncertainty is obtained similarly; by establishing the sensitivities of each of the parameters affecting heat rate and proceeding as above.

7-3.3 Sample Calculation

An example will illustrate the uncertainty calculation procedure. Table 7-3.1A tabulates the parameters necessary to obtain the test results for the particular turbine under test, and the instrumentation expected to be used. This is a gas fueled turbine with air extraction and water injection (and is based on the same performance as that in Section 5 and Appendix A). The measurement uncertainty limit from Table 4-1 is recorded for each. (Note that the performance and sensitivities throughout the sample calculation are the same; in reality, it is likely that the post-test numbers will differ.)

Then Table 7-3.1B is completed with expected or assumed values of random and systematic uncertainties based on the specific instrumentation to be used. In some cases the random uncertainty is taken as zero, where the parameter is a single value or calculation (e.g., orifice flow coefficient) or a fixed factor (e.g., VT and CT values).

The three most critical calculations are detailed in the following paragraphs.

7-3.3.1 Power. With the three watthour meter method total gross power is the sum of the three phase measurements.

$$P_g = P_1(\mathrm{CT}_1)(\mathrm{VT}_1) + P_2(\mathrm{CT}_2)(\mathrm{VT}_2) + P_3(\mathrm{CT}_3)(\mathrm{VT}_3)$$

Since P_1, P_2, and P_3 are nearly equal, the partial derivatives (normalized) will yield $\Theta = 1/3$. For calibrated watthour meters and VTs, and 0.3% class CTs, the systematic components of uncertainty should not exceed:

Instrument	Uncertainty	Symbol
Whr meter	0.1%	B_p
VT	0.1%	B_{vt}
CT	0.15%	B_{ct}

As was discussed in 7-2.1.1, it is likely that these parameters are correlated, as they were probably sourced from the same vendor and calibrated at their facility against the same standard. (See further discussion of correlation in PTC 19.1.) Therefore, the gross power systematic uncertainty is:

$$\begin{aligned}B_{gp} = {} & [(\Theta_1 B_{p_1})^2 + (\Theta_2 B_{p_2})^2 + (\Theta_3 B_{p_3})^2 + 2\Theta_1\Theta_2 B_{p_{12}} \\ & + 2\Theta_1\Theta_3 B_{p_{13}} + 2\Theta_2\Theta_3 B_{p_{23}}]^{0.5} + [(\Theta_1 B_{ct_1})^2 + (\Theta_2 B_{ct_2})^2 \\ & + (\Theta_3 B_{ct_3})^2 + 2\Theta_1\Theta_2 B_{ct_{12}} + 2\Theta_1\Theta_3 B_{ct_{13}} + 2\Theta_2\Theta_3 B_{ct_{23}}]^{0.5} \\ & + [(\Theta_1 B_{vt_1})^2 + (\Theta_2 B_{vt_2})^2 + (\Theta_3 B_{vt_3})^2 + 2\Theta_1\Theta_2 B_{vt_{12}} \\ & + 2\Theta_1\Theta_3 B_{vt_{13}} + 2\Theta_2\Theta_3 B_{vt_{23}}]^{0.5}\end{aligned}$$

where

$\Theta_1 B_{p_1}$ = sensitivity (1/3) × power meter systematic uncertainty
$2\Theta_1\Theta_2 B_{p_{12}}$ = correlation term for power meter
$\Theta_1 B_{ct_1}$ = sensitivity × current tfr. uncertainty etc.

The arithmetic here will show $B_{gp} = 0.206\%$. It can be shown that this is the same as the RSS value of the individual uncertainties: 0.1, 0.1, and 0.15. If the meters and/or the transformers were not correlated, B_{gp} would be less than 0.206%, since the appropriate $2\Theta\Theta B$ terms would be dropped.

For net power $P_{\mathrm{net}} = P_{\mathrm{meas}} - P_{\mathrm{aux}}$, if aux power is 1.5% of gross, $\Theta_{\mathrm{aux}} = 0.015$.

To evaluate the uncertainty in corrected power output, from Section 5:

$$P_{\mathrm{corr}} = (P_{\mathrm{net}} + \Delta\text{'s})/(\alpha_1\alpha_2 \ldots \alpha_{\mathrm{n}})$$

NOTE: The form of this equation depends on the manufacturer's method for correcting performance.

Since the Δ's are relatively small and should have low uncertainties, they will be neglected in this analysis.

The alpha terms themselves have no uncertainty, as they are taken directly from the manufacturer's correction curves or data. Each one, however, depends on a measured variable or parameter that does have uncertainty. The relationships of corrected power vs. inlet temperature, humidity, air extraction, and water injection are unique to each turbine model, and are usually provided in the form of % power per unit change in the variable, as shown in Table 7-3.1B. The normalized values become the sensitivities Θ to be used in the uncertainty calculation.

7-3.3.2 Heat Input. For gas fuel, the most influential contributor to uncertainty is the constituent analysis. This affects the molecular weight (*MW*), heat value (*HV*), and compressibility (*Z*). The first two are the summation of the mol or weight fraction times the value for each constituent, and *Z* is determined from AGA 8. For an analysis by chromatograph in accordance with ASTM D 1945, each constituent is measured and the percents summed. If the sum is not exactly 100%, the percentages are normalized to 100% (the original analysis must total within 1% of 100).

The uncertainty calculations are complicated by the fact that the results of the constituent analysis appear in several places. For flow measurement by orifice meter section and gas analysis by chromatograph, three groups of numbers will be calculated:

(a) items relying on the fuel constituent analysis
(b) items remaining from the orifice equation
(c) all others

It should be noted that there is no *correlation* here; correlation applies to the uncertainties, not to the parameters.

7-3.3.2.1 Fuel Constituents. The chromatograph will provide the volume percentages. If significant data from the fuel samples are not available, the uncertainties can be related to the repeatability/reproducibility figures given in ASTM D 1945.

Constituent %	Repeatability	Reproducibility	B_{vi}	$2S_x$
0 to 0.1	0.01	0.02	0.02	0.02
0.1 to 1.0	0.04	0.07	0.06	0.03
1.0 to 5.0	0.07	0.10	0.1	0.075
5.0 to 10	0.08	0.12	0.1	0.1
Over 10	0.10	0.15	0.15	0.1

The repeatability/reproducibility numbers are absolute, not percent of the volume percentage. The systematic uncertainties for this example have been arbitrarily taken as shown above. For a Code test this will be a judgment call based on the experience with the fuel gas and the labs, the number of labs used, and the number of samples tested. The random uncertainties were assumed based on previous experience.

The percentage of the constituents V_i in gas fuel affects the values for density (molecular wt. *MW* and compressibility *Z*), needed for mass flow, and heat value (LHV), and hence the Heat Input, *HI*. The basic equations are:

$$\text{Density } \rho = P{*}MW/Z{*}T{*}R$$

$$MW = \Sigma(V_i * MW_i), \text{ with } V_i = \% \text{ by volume of constituent}$$

Mass Flow *Mf* from orifice equation is proportional to $\sqrt{\rho}$

$$\text{LHV} = \Sigma MF_i{*}\text{LHV}_i, \text{ with } MF_i = \text{mol fraction}$$

$$= \Sigma V_i{*}MW_i{*}\text{LHV}_i/MW$$

$$HI = Mf{*}\text{LHV}$$

where *i* is the value of each constituent, summed from C1 to *Cn* (plus inerts, if any, for *MW*).

Using the Chain Rule:

$$\delta HI/\delta V_i = \delta HI/\delta Mf{*}\ \delta Mf/\delta V_i + \delta HI/\delta \text{LHV}{*}\ \delta \text{LHV}/\delta V_i$$

Table 7-3.3.2.2 Orifice Factors Uncertainty

Parameter	SENS Θ	*B*	$2S_x$	$(B\Theta)$^2	$(2S_x\Theta)$^2	SUM
p	0.5	0.25	0.13	0.015625	0.004225	0.01985
T	0.5	0.25	0.15	0.015625	0.005625	0.02125
C	1	0.25		0.0625	0	0.0625
Δ*P*	0.5	0.25	0.12	0.015625	0.0036	0.019225
ε (See below)	1	0.0011185	0.0005	1.25109E-06	2.5E-07	1.50109E-06
Calculation of *B*ε	**SENS Θ**	***B***	**$(B\Theta)$^2**			
Δ*P*	−0.00347	0.25	7.526E-07			
p	0.00347	0.2	4.816E-07			
MW	0.0013	0.1	1.69E-08			
		SUM	1.251E-06			
		*B*ε = sqrt	0.0011185			
			SUM	0.109376251	0.0134503	0.122826501
	ORIFICE FACTORS UNCERTAINTY U_{of}				SQRT	0.35046612

Table 7-3.3.2.3 Heat Input Uncertainty

STEP 1: Find Sensitivity $\delta HI/\delta V_i = V_i[MW_i/2MW - 1/2Z(\delta Z/\delta V_i) + MW_i{*}LHV_i/MW{*}LHV]$

	%V	MW	LHV	Mol Fract	$MW_i/2MW$	LHV$_i$/LHV	MW_iLHV$_i$/MWLHV	$1/2Z{*}\delta Z/\delta V_i$	Sensitivity $\delta HI/\delta V_i$
C1	82.78	16.043	21511	0.678714	0.339357	1.0208333	0.6928538	0.005	0.85032507
C2	10.92	30.07	20429	0.167815	0.0839077	0.9694856	0.162694613	0.005	0.026382973
C3	5	44.097	19922	0.112682	0.056341	0.9454252	0.106532466	0.005	0.007893675
iC4	0.5	58.123	19590	0.014852	0.0074262	0.9296697	0.013807736	0.005	8.11694E-05
nC4	0.5	58.123	19658	0.014852	0.0074262	0.9328967	0.013855664	0.005	8.14091E-05
iC5	0.1	72.15	19456	0.003687	0.0018437	0.9233106	0.003404551	0.005	2.48217E-07
nC5	0.2	72.15	19481	0.007375	0.0036873	0.924497	0.006817852	0.005	1.10104E-05
	100	19.567	21072	0.999978					

STEP 2: Calculate Uncertainties for V_i and Z

$\delta HI/\delta z = -1/2$

	%V	$\Theta_{vi} - \delta HI/\delta V_i$	B_{vi} Absolute	B_{vi} % of %V	$(B_{vi}{*}\Theta_{vi})$^2	$2S_x$	$(2S_x{*}\Theta_{vi})$^2
C1	82.78	0.85032507	0.15	0.181203	0.0237411	0.1	0.007230527
C2	10.92	0.026382973	0.15	1.373626	0.0013134	0.25	4.35038E-05
C3	5	0.007893675	0.1	2	0.0002492	1	6.23101E-05
iC4	0.5	8.11694E-05	0.06	12	9.487E-07	5	1.64712E-07
nC4	0.5	8.14091E-05	0.06	12	9.544E-07	5	1.65686E-07
iC5	0.1	2.48217E-07	0.06	60	2.218E-10	10	6.16115E-12
nC5	0.2	1.10104E-05	0.06	30	1.091E-07	10	1.21228E-08
	100			SUM	0.0253058		0.007336684

For Z:

	$(B_z{*}\Theta_z)$^2
B_z	0.05
$\Theta_z = \delta HI/\delta_z$	−0.5
$(B_z{*}\Theta_z)$^2	0.000625

STEP 3: HEAT INPUT UNCERTAINTY = SQRT(U_{of}^2 + U_{vi}^2 + U_z^2))

(U_{of})^2 from Table 7-3.3.2.2		0.122827
U_{vi}^2 = $\Sigma[(B_{vi}{*}\Theta_{vi})$^2 + $(2S_x{*}\Theta_{vi})$^2]		0.032642
U_z^2 = $(B_z{*}\Theta_z)$^2		0.000625
	SUM	0.156094
HEAT INPUT UNCERTAINTY	SQRT	0.395087

and,

$$\delta Mf/\delta V_i = \delta Mf/\delta MW{*}\ \delta MW/\delta V_i + \delta Mf/\delta Z{*}\ \delta Z/\delta V_i$$
$$MW = \Sigma V_i{*}MW_i$$
$$\delta MW/\delta V_i = MW_i$$
$$\mathrm{LHV} = [\Sigma(V_i{*}MW_i{*}\mathrm{LHV}_i)/\Sigma(V_i{*}MW_i)]$$
$$= \Sigma(V_i{*}MW_i{*}\mathrm{LHV}_i)/MW$$
$$\delta\mathrm{LHV}/\delta V_i = MW_i{*}\mathrm{LHV}_i/MW$$
$$\delta Mf/\delta MW = Mf/2MW$$
$$\delta Mf/\delta Z = -Mf/2Z$$

Then $\delta HI/\delta V_i = V_i[.5(MW_i/MW\text{-}\delta Z/\delta V_i/Z) + MW_i{*}\mathrm{LHV}_i/MW{*}\mathrm{LHV}]$, when the differentiation is normalized by multiplying by $V_i/(Mf{*}\mathrm{LHV})$.

The influence for each constituent on the HI can now be determined from this equation.

7-3.3.2.2 Orifice Equation. With a calibrated orifice, the equation is (from PTC 19.5 and Section 5):

$$Mf = (\pi d^2/4)(C\varepsilon)\{(2\rho\Delta P_g/(1-\beta^4)\}^{0.5}$$

For a calibrated metering section, there should be no uncertainty in diameter d, D, or the diameter ratio β. The density is $P{*}MW/(T{*}10.73{*}Z)$, and MW is covered above. This leaves ΔP, P, T, C, Z, and ε. The expansion factor $\varepsilon = 1 - (.41 + .35\ \beta^4)(\Delta P/N_{p\kappa})$; the specific heat ratio κ is $C_p/(C_p - 1.986/MW)$. The uncertainty of C_p will be neglected. For Z, although related to the fuel constituents, a single value of systematic uncertainty has been assumed since it is not practical to break down the AGA 8 value.

Sensitivities are determined by differentiating the equations, resulting in the following normalized values:

Parameter	Sens θ
C	1
ΔP	0.5
p	0.5
T	0.5
ε for p	$1 - \varepsilon$
for ΔP	$\varepsilon - 1$
for MW	$0.03156{*}MW{*}C_p{*}\ \Delta P/p{*}\ \varepsilon(MW{*}C_p - 1.986)^2$
Z	0.5

For this case the effects of ϵ could be neglected, but will be shown for illustrative purposes. The random uncertainty for ε can be calculated from $\sqrt{\Sigma(2Sx_i\Theta_i)^2}$. The orifice factor group's impact on the heat input uncertainty is shown in Table 7-3.3.2.2.

For this example, the only other parameter to consider is the sensible heat. This adjustment is very small, and its uncertainty has been neglected. For higher fuel temperatures, it should be included.

7-3.3.2.3 Heat Input. The uncertainty in Heat Input can be calculated as shown in Table 7.3.3.2.3. In accordance with ASTM 3588, the uncertainties in the tabular values for molecular weight, heat value, and compressibility are very small in comparison to that of the uncertainty of the composition, and can be neglected. For this example, the *MW* and LHV uncertainties have been neglected; for illustrative purposes, the uncertainty in *Z* has been included as follows:

The sensitivity for *Z* is:

$\delta HI/\delta Z = \delta HI/\delta Mf * \delta Mf/\delta Z$

$= \text{LHV}{*}\ (-Mf/2Z) = -0.5$ when normalized $= \Theta_z$

And $U_z = (B_z{*}\Theta_z)$, since there is no random uncertainty for Z

The uncertainty for Heat Input for this example is 0.40%. The result is particularly sensitive to the assumption for the uncertainty of the constituents, as well as the cumulative effect of the orifice parameters. Careful selection of instrumentation and confidence in the fuel analysis are critical to achieving a reasonable test uncertainty.

7-3.3.3 Inlet Temperature. The most critical parameter for obtaining corrected power is usually the compressor inlet temperature. PTC 22 requires that the total uncertainty be no greater than 1°F. An example will show how the parties can assure themselves that this limit will not be exceeded:

During a pretest the following data were collected from 4 RTDs located just inside the inlet filter house.

RTD	T-°F	S_x
1	88.6	0.9
2	86.5	0.75
3	87.9	0.82
4	87.0	0.63
Tavg	87.5	
STDEV		0.9345

S_x is the standard deviation of the 30 readings taken during the test, obtained from the DAS, and STDEV is the standard deviation of the four temperatures. Referring to PTC 19.1, first calculate the standard deviation of the average temperature:

$$S_{T\text{avg}} = [\Sigma(\Theta S_x)^2/\sqrt{30})]$$

where

Θ = sensitivity for each RTD = 0.25

$S_{T\text{avg}}$ = 0.071, and is the random component of the total uncertainty.

The spatial bias can be estimated as $S_s = 2\text{STDEV}/\sqrt{N}$, which is 0.9345. If the RTDs have an inherent reading bias of 0.25, then the total bias *B* is the RSS value of 0.25 and 0.9345, or 0.967. This assumes the RTDs are correlated.

The total uncertainty $U = 2[(B/2)^2 + S_{T\text{avg}}{}^2]^{0.5} = 0.978$ degrees.

Although this is within the 1 degree limit, the parties should note the fairly large spread among the four RTDs, and also the large S_x values. Good practice here would be to either relocate the four RTDs to the well mixed region downstream of the silencers, or add at least four more RTDs in the present measurement plane.

7-3.4 Test Uncertainty

Similarly, the rest of the uncertainties are calculated by RSS of the individual effects. The required post-test uncertainty, shown in Table 7-3.1C, reflects the actual systematic values from the instrumentation used in the test, and the random values calculated from the data. All results are less than the Code Limits.

7-3.5 Uniqueness of Tests

The uncertainties in this sample calculation are based on assumed systematic and random uncertainties and sensitivities. The uncertainties in Corrected Power and Efficiency (Heat Rate) in the Tables are indicative only of the levels achievable when performing a Code test on a turbine with the assumed sensitivities, using instruments with the assumed uncertainties. As stated in para. 3-6.5, each test will have its own value of uncertainty, depending on the sensitivities, the scope of supply, fuel used, instrumentation, type of load device, etc. It is important that this matrix of variables (Table 7-3.1A) be established prior to the test, so that a proper uncertainty level can be determined that will reflect the quality of a Code test.

7-3.6 Multiple Unit Tests

For a block of power, usually consisting of multiple gas turbines of the same model and rating, the uncertainty must be calculated carefully. For this case, block power is:

$$P_{\text{block}} = P_1 + P_2 + P_3 + \ \ldots P_n$$

where n = number of units

If the units are equal in power, and there is no correlation among the instruments used, then the sensitivity $\Theta = \delta P_{\text{block}}/\delta P = 1/n$, and the uncertainty $U_{\text{pblock}} = [\Sigma(\Theta U_i)^2]^{0.5} = U_i/\sqrt{n}$. It is likely, however, that the VTs, CTs, and power meters are from the same source, as may be the fuel properties, flowmeters and other instruments. These correlations will tend to make the systematic component of U_{pblock} approach the value in U_i, when all the $2\Theta\Theta B$ terms are added. An analysis similar to Table 7-3.1C can be done for the block, separating the correlated and uncorrelated measurements, and combining the results by root sum square to obtain the systematic uncertainty. The random component will be equal to $\sqrt{\Sigma(2S_{x_i}/n)^2}$.

7-3.7 Multiple Tests

If multiple tests are run, and averaged to arrive at the final performance, the uncertainty is reduced by dividing the random component by the square root of the number of tests run. The systematic component is unaffected. For the example in Table 7-3.1.2, the random components are quite small, and little would be gained from an uncertainty standpoint in running more tests. For Comparative Testing (see below) there may be an advantage for multiple tests.

7-4 COMPARATIVE TESTING UNCERTAINTY

7-4.1 General

When conducting gas turbine tests before and after a modification, and the parameter of interest is the difference between the results of the two tests, the *uncertainty of the difference* must be calculated. The basic equation is

$$U_d = 2\sqrt{B_d/2\hat{}2 + S_d\hat{}2} \tag{7-4.1}$$

where B is the systematic (bias) component, and S is the random component. Of particular interest in this case is B_d. From PTC 19.1 and Coleman et al. (1995), B_d for the difference is defined as

$$B_d = \sqrt{\Sigma(\Theta_a B_a)\hat{}2 + \Sigma(\Theta_b B_b)\hat{}2 + \Sigma(2\Theta_a\Theta_b B_{ab})} \tag{7-4.2}$$

where Θ = the partial derivative of the difference D with respect to the before (subscript b) and after (subscript a) parameters. The third term in Eq. (7-4.2) is the correlation term that must be evaluated for the instrumentation that is used for both tests.

For the difference in corrected power $D = P_{ca} - P_{cb}$, P_{ca} and P_{cb} are functions of the measured power and the correction factors needed to adjust the measured data to the Specified Conditions, as shown in Section 5. The partial derivatives Θ_a and Θ_b must be determined for each of the terms in the corrected power equation.

7-4.2 Reduction in Value of *B*

In general, the analysis will show that B_d will be less than B for a single test, but likely never zero due to different before and after sensitivities. The reduced value stems from the fact that the third term in Eq. (7-4.2) will be negative, since the partial derivatives of D with respect to P_{cb} are negative. If the instrumentation is changed or calibrated against a different standard between the tests, then it is no longer correlated and the third term disappears for those non-correlated parameters.

The reduction in the value of B also occurs if a power gain ratio (P_{ca}/P_{cb}) rather than the difference is desired, assuming again that the instrumentation is unchanged.

7-4.3 Multiple Test Advantage

For minimizing the value of S, it can be advantageous to run multiple tests both before and after. S then becomes the standard deviation of the mean.

7-4.4 Sample Calculation for Difference

Detailed sample calculations are provided here to determine the uncertainties for the difference between two tests. These calculations require care in determining the derivatives and a spreadsheet to calculate the various terms, since differences of small numbers will usually occur.

7-4.4.1 Power. This example is for a before and after test of a gas turbine modified to increase its output and upgrade the controls. The original turbine has an old, non-electronic control system with no data acquisition capability, so the before test requires manual readings. The parties want to minimize the pretest expense, but still wish to take advantage of the potential reduction in systematic uncertainty. The pretest uncertainty analysis will reveal what they need to do. Referring to Section 5, the corrected power is

$$P_c = P_m/(\alpha_1 \times \alpha_2 \ldots \alpha_n) \tag{7-4.3}$$

where P_m is the measured power and the α terms are the factors to correct it to specified operating conditions. From Part 7.2 of this Section, the corrected power uncertainty is the RSS value of each of the factors times its sensitivity. For this example only the measured power, inlet temperature, and barometric pressure will be assumed to apply. Hence for this example Eq. (7-4.3) will be reduced to

$$P_c = P_m/(\alpha_{T1})(\alpha_{\text{bar}}) \tag{7-4.4}$$

Assume that the parties plan to use the same power measurement and barometric pressure instrumentation, but different inlet temperature devices. For the before test, it will be measured with the original two thermocouples located in the inlet duct. As part of the control retrofit during the outage, four inlet temperature RTDs will be installed in the duct. The estimates for the uncertainty components are:

	Before	After
Inlet T Sys B_{T1}	3.0 degr	0.7
Random (S_x)	2.0 degr	0.5
Sensitivity	$-0.422\%/\text{degr}(\Theta_5)$	$-0.4(\Theta_2)$
Power (whrmeter)	0.15%	0.15%
VTs&CTs	0.3%	0.3%
S_x	0.1%	0.1%
Sensitivity	$-1(\Theta_4)$	$1(\Theta_1)$
Barometer B_{bar}	0.5%	0.5%
S_x (1 rdg.)	0	0
Sensitivity	$-1(\Theta_6)$	$1(\Theta_3)$

A correlation exists for both power and barometer measurement, so B_d (normalized) for the difference would be:

$$B_d/D = \sqrt{(B_{pma}\Theta_1)^2 + (B_{T1a}\Theta_2)^2 + (B_{\text{bar}a}\Theta_3)^2 + (B_{pmb}\Theta_4)^2 + (B_{T1b}\Theta_5)^2 + (B_{\text{bar}b}\Theta_6)^2 + 2\text{B}_{pmab}\Theta_1\Theta_4 + 2\text{B}_{\text{bar}ab}\Theta_3\Theta_6} \quad (7\text{-}4.5)$$

For the 0.15% wattmeter and two 0.3% class instrument transformers, B_{pm} will be

$$\sqrt{(0.15)\hat{\ }2 + (0.3)\hat{\ }2 + (0.3)\hat{\ }2} = 0.45\%$$

Continuing with the calculation of the total uncertainty, using Eq. 7-4.1:

$$U_d = 2\sqrt{(B_d/2D)\hat{\ }2 + (S_d)\hat{\ }2}$$

As shown in Table 7-4.4.1, the systematic uncertainty B_d/D for the difference is 1.30%, which is very small since only the inlet temperature terms contribute.

And S_d = RSS value of before and after S_i, which is 0.87% (1.73% for $2S_d$ for 95% confidence), so U_d = 2.18%. This is 25 KW, which is very small compared to the expected difference of 1150 KW. So despite the poor inlet temperature measurement on the before test, the net uncertainty for the difference is acceptable.

As prescribed for the unit test in this Code, a post test analysis will be necessary to establish the actual values of the sensitivities, the random components S_i, and to assure the quality of the test has been achieved.

Table 7-4.4.1 Comparative Test Uncertainty Example

	System		Random		Sensitivity	
	Before	After	Before	After	Before	After
Power	0.45	0.45	0.1	0.1	−1	1
Barometer	0.5	0.5	0	0	−1	1
Inlet T	3	0.7	2	0.5	−0.422	0.4
(SENS*B or	0.2025	0.2025	0.01	0.01		
R)^2	0.25	0.25	0	0		
	1.602756	0.0784	0.712336	0.04		
CORRELATED TERMS						
Power	−0.405					
Barometer	−0.5					
(B_d/D)^2	1.681156	(S_d)^2	0.772336			
B_d/D	1.296594	S_d	0.879			
Ud	2.18					

7-4.4.2 Heat Rate. Assume that the before fuel mass flow will be measured by pressure and temperature probes with an existing turbine meter. During the outage an uncalibrated orifice meter section is installed, with the same P and T probes. Fuel samples were sent to the same lab for heat value and composition determination. Thus there is correlation for the density and heat value as well as the measured power. Mass flow for the orifice meter is per the equation in para. 7-3, and for the turbine meter is $\rho F/k$, where F is frequency count and k is the calibration constant.

Of interest is the improvement in heat rate ΔHR = HRb-HRa, which is expected to be 2.5%. The calculation of the systematic uncertainty Bd follows.

The uncertainties and sensitivities are:

	Before		After	
	Θ	B	Θ	B
Pressure		0.5	0.5	
Temperature		0.2	0.2	
Composition		0.3		
Density	1	0.5385		
Turb meter K	−1	1		
Turb meter freq	1	0.2		
Orifice ΔP			−0.5	0.25
Pipe D ($\beta = 0.6$)			−0.298	0.2
Orif d			−2.298	0.1
Flow coef C			−1	0.6
Mol Wt			−0.5	0.3
LHV	1	0.3	−1	0.3
Meas power	1	0.45	−1	0.45

As before all the pertinent (ΘB) terms are squared and added. Note in this case the uncertainties for diameters d and D are included, as this is an uncalibrated orifice section. Smaller uncertainties for expansion factor and compressibility have been neglected. There are also correlation terms ($2\Theta_b\Theta_a B_{ba}$) for LHV and power:

	$2\Theta_b\Theta_a B_{ba}$
LHV	−0.18
P_{meas}	−0.405
Total	−0.585
Add the (ΘB) squared terms	2.419
Total	1.834

And $B_d = \sqrt{1.834} = 1.35\%$.

This is over half of the expected improvement in heat rate, even without considering the random error. Assuming there may be significant contractural consequences, the parties should agree to install the orifice meter section initially. Then everything is correlated and B_d will approach zero. (For this case the uncertainties in corrected heat rate have been ignored since the only applicable correction factor, the inlet temperature, has a very small effect.)

7-5 UNCERTAINTY OF FLOW CALCULATION FROM HEAT BALANCE

7-5.1 Heat Balance

When the airflow, exhaust flow, and/or exhaust energy is determined from the gas turbine heat balance, the uncertainty of the result can be calculated from the heat balance equation and the sensitivities obtained through partial differentiation of the equation. For example, if the exhaust flow is the desired result, the heat balance equation (from para. 5-2.2):

$$Q_{air} + Q_{fuel} + Q_{inj} = Q_{ext} + Q_{elect} + Q_{loss} + Q_{exh} \text{ where: } Q_n = m_n h_n \quad (7\text{-}5.1)$$

can be solved for the exhaust flow m_{exh}:

$$m_{exh} = [(m_{air})(h_{air}) + (m_{fuel}{*}\mathrm{LHV}) + (m_{inj})(h_{inj}) - Q_{pwr} - Q_{loss} - (m_{ext})(h_{ext})]/h_{exh} \quad (7\text{-}5.2)$$

From para. 7.2, for gas fuel, m_{fuel}*LHV = Heat Input, or Q_{fuel}.

7-5.2 Sensitivities

For each of the variables the partial derivatives are determined. The normalized, or relative, sensitivities are most useful, as errors are usually expressed as a percent of the parameter measured. For example:

Parameter	Partial	Normalized
m_{air}	h_{air}/h_{exh}	$(h_{air}/h_{exh})*m_{air}/m_{exh} = Q_{air}/Q_{exh}$

Similarly, the remaining normalized partials are:

h_{air}	Q_{air}/Q_{exh}
Q_{fuel}	Q_{fuel}/Q_{exh}
m_{inj}	Q_{inj}/Q_{exh}
h_{inj}	Q_{inj}/Q_{exh}
Q_{pwr}	$-Q_{pwr}/Q_{exh}$
Q_{loss}	$-Q_{loss}/Q_{exh}$
m_{ext}	$-Q_{ext}/Q_{exh}$
h_{ext}	$-Q_{ext}/Q_{exh}$
h_{exh}	-1

Note that these sensitivities are considerably different than those associated with a turbine test, as the heat balance equation puts a strong emphasis on the exhaust temperature and the heat input.

To evaluate the normalized partial derivatives, the performance or rating data for the gas turbine must be available. For this example, the data from the sample calculation will be used:

Power	MW	120.2
Heat input	million Btu/hr(LHV)	1149.4
Inlet air *T*	Deg F	80
Exhaust *T*	Deg F	1000
Inlet flow	million lb/hr	2.688
Water inj	lb/hr	50000
Air extr	lb/hr	10000

7-5.3 Heat Equivalents and Enthalpies

The heat equivalent of the power output is 120.2 × 3412.14 = 410.14 million Btu/hr.

The enthalpies of the fluid streams must either be referenced to the inlet temperature, which simplifies the calculations by essentially eliminating h_{air}, or to a "standard" reference temperature like 15°C (59°F). In this case an 80°F reference was used:

	T-°F	*h* at *T*
h_{exh}	1000	245.32 Btu/lb
h_{air}	80	.728
h_{inj}	200	−928
h_{extr}	600	128.40

The values for the sensitivities may now be calculated.

Partial for	Term	Value
Q_{fuel}	Θ_{fuel}	1.6838
h_{exh}	Θ_{hexh}	−1.0
Q_{pwr}	Θ_{pwr}	−0.6008
Q_{loss}	Θ_{loss}	−0.0131
h_{inj}	Θ_{hinj}	0.0679
m_{inj}	Θ_{minj}	0.0679
h_{extr}	Θ_{hextr}	−0.0188
m_{extr}	Θ_{mextr}	−0.0188

7-5.4 Uncertainties

The uncertainty in the exhaust flow determined by the heat balance can now be calculated from a simple spreadsheet. Measurement uncertainties have been taken from Table 7-3.1C, and calculated for the assumed temperatures.

MEASUREMENT	SYST UNC	RANDOM	SENS	Σ(UNC*SENS)^2
Heat Input	0.47	0.15	1.6838	.69008
Exh hx (10 F)	1.05	0.25	−1.0	1.1650
Power	0.214	0.05	−0.6008	.02346
Losses	5.0	0	−0.0131	.00429
Injection flow	2.0	0.75	0.0679	.02104
Inj. enthalpy (5 F)	0.54	0.1	0.0679	.00139
Extraction flow	2.0	0.75	−0.00188	.000016
Extr. enth. (5 F)	1.0	0.2	−0.00188	.000004
			Sum of sq.	1.905

The uncertainty in exhaust flow is $\sqrt{1.905} = 1.38\%$

7-5.5 Emphasis on Exhaust Temperature and Fuel Flow

This calculation shows the predominance of the exhaust temperature and heat input measurements. Every effort should be made to minimize the errors in these measurements if the heat balance method is to be used. The 10F uncertainty in exhaust temperature could possibly be reduced, considering the plane of the turbine exhaust temperature measurement, the extent of closure of the heat balance, adding more thermocouples or rakes, and previous experience with the turbine model.

7-5.6 Exhaust Energy

The uncertainty in the *exhaust energy* (Q_{exh}) will be less than that for airflow, since the uncertainty for exhaust enthalpy does not appear. In this case the value is 0.86%.

7-5.7 Corrected Values

The uncertainty in the *corrected* exhaust flow or energy will be slightly higher than the value shown above. For this case one would need to know the correction factors for water injection and extraction air, as well as the sensitivity to inlet temperature. The resultant uncertainty would then be calculated from the RSS value of the sensitivity times the measurement uncertainty as shown above.

7-5.8 HRSG Heat Balance

In many cases a heat balance will also be performed around the heat recovery device, to provide a check on the value determined by the gas turbine balance. The uncertainties of the two methods may be combined to give the most realistic assessment of the uncertainty of the exhaust flow or energy that has been determined. PTC 4.4 Gas Turbine Heat Recovery Steam Generators presents the methods for calculating the HRSG heat balance and combined uncertainties.

NONMANDATORY APPENDIX A
DETERMINATION OF GAS TURBINE EXHAUST ENERGY, FLOW, AND TEMPERATURE

A-1 INTRODUCTION

The first edition of ASME PTC 22 was published in 1953. At this time the majority of the gas turbine designs were principally used for driving compressors or utility peaking applications. Therefore, the Code addressed only gas turbine power output and efficiency testing. As time progressed and gas turbine designs improved both in efficiency and megawatt ratings, it became common to install gas turbines in base loaded combined cycle plants. These plants were typically designed and built by the gas turbine OEM, so the only testing dictated by the market was power output and efficiency which was reflected in later revisions of the Code. In today's market, it is typical for a customer to purchase the major components of a combined cycle plant from several different vendors. Therefore, in addition to power output and efficiency, gas turbine exhaust temperature and flow or energy are now critical measurements. The exhaust flow and temperature are necessary inputs to determine the performance of the HRSG's and bottoming cycle performance.

The PTC committee investigated several different means for determining exhaust flow and energy such as inlet flow measuring devices, exhaust flow measuring devices, HRSG heat balance, exhaust gas constituent analysis, and gas turbine heat balance. Based on reasonable economic considerations per the requirements of PTC 1, the gas turbine heat balance method has been selected as the method of choice.

A-2 TEST METHODOLOGY

The following summarizes the general test methodology for tests conducted for the evaluation of exhaust temperature, exhaust flow, and/or exhaust energy.

The gas turbine exhaust temperature is determined in accordance with Section 4.

The gas turbine exhaust flow and energy are determined by an energy and mass balance around the gas turbine as described in para. A-3.1. A test boundary is drawn around the gas turbine which identifies the energy streams which must be measured to calculate corrected results. The test boundary is an accounting concept used to define the streams that must be measured to determine performance. All input and output energy streams required for test calculations must be determined with reference to the point at which they cross the boundary. Energy streams within the boundary need not be determined unless they verify Specified Reference Conditions or unless they relate functionally to conditions outside the boundary.

The specific test boundary for a particular test must be established by the parties to the test. Typical energy streams crossing the test boundary for common gas turbine cycles are shown in Fig. 3-1 in Section 3 of this Code. Stream properties for the output and heat rate test are typically determined at the outer test boundary as indicated in Fig. 3-1. Stream properties for the exhaust energy or flow test are typically determined at the inner test boundary as indicated in Fig. 3-1.

For the determination of exhaust energy, a simple energy balance is performed around the test boundary. The exhaust energy may be determined directly if the reference temperature of all enthalpies is chosen as the measured inlet air temperature ($h_{\text{air}} = 0$, $Q_{\text{air}} = 0$).

For the determination of exhaust energy where the reference temperature is different from the inlet air temperature ($h_{\text{air}} \neq 0$, $Q_{\text{air}} \neq 0$), or for the determination of exhaust flow, a mass balance must also be performed around the test boundary and solved simultaneously with the energy balance.

A-3 CALCULATIONS AND RESULTS: GENERAL

The following sections describe the detailed procedures required for application of the gas turbine heat balance method. Due to length and complexity, these calculations are provided here for convenience rather than in Section 5 of the Code.

Determination of gas turbine exhaust energy or flow and temperature, corrected to Specified Reference Conditions, are the primary objects of this test. Test results are computed from the averaged values of observations made during a single test run, after applying instrument calibrations and other corrections as necessary, and as prescribed in this Appendix. A printout of a sample calculation spreadsheet is provided at the end of this Appendix.

A-3.1 Gas Turbine Energy Balance

The following sections provide the detailed calculations for the determination of exhaust energy and exhaust flow by gas turbine energy balance as outlined above. The measurement of exhaust gas temperature is as described in para. 4-3.3 of the Code.

A-3.1.1 Exhaust Energy. The exhaust energy is determined by an energy balance around the gas turbine. The energy into the system includes the air, fuel, and injection streams to the gas turbine. The energy from the system includes the exhaust leaving the gas turbine, compressor extractions, electrical or mechanical power, and heat losses. Therefore the energy equation is as follows.

$$\text{Energy In} = \text{Energy Out}$$
$$Q_{air} + Q_{fuel} + Q_{inj} = Q_{ext} + Q_{elect} + Q_{loss} + Q_{exh}$$

where

$Q_n = m_n h_n$

To determine the exhaust energy term, one must identify a reference temperature to which the calculated exhaust energy is indexed. Selection of the reference temperature varies in the industry and can be chosen as any temperature. All terms of the equation must be evaluated at the chosen reference temperature. The determination of exhaust energy is greatly simplified if the chosen reference temperature is the measured inlet air temperature into the compressor which eliminates the need to determine exhaust temperature, inlet air flow, inlet air moisture content, and inlet air enthalpy resulting in $Q_{air} = 0$. However, if corrections must be appied to the calculated exhaust energy for comparison to a standard value, the calculated exhaust energy must be based on the same reference temperature as the standard value. Therefore, rather than specifying a reference temperature, this Appendix allows the user to select the appropriate reference temperature on a test-specific basis.

For any selected reference temperature other than the measured compressor inlet temperature, the exhaust flow calculation process described below must be followed to determine the exhaust energy.

A-3.1.2 Exhaust Flow. The exhaust flow is determined by an energy and mass balance around the gas turbine. The energy into the system includes the air, fuel, and injection streams to the gas turbine. The energy from the system includes the exhaust leaving the gas turbine, compressor extractions, electrical or mechanical power, and heat losses. Therefore the energy and mass balance equations are as follows.

$$\text{Energy In} = \text{Energy Out}$$
$$Q_{air} + Q_{fuel} + Q_{inj} = Q_{ext} + Q_{elect} + Q_{loss} + Q_{exh}$$

where

$Q_n = m_n h_n$

$$\text{Mass In} = \text{Mass Out}$$
$$m_{air} + m_{fuel} + m_{inj} = m_{ext} + m_{exh}$$

Each term of the energy and mass balances in this format can be quantified by direct measurement or assumption except the exhaust flow and inlet air flow. However, this is not a simple case of two equations with two unknowns that can be solved simultaneously because the exhaust stream enthalpy is dependent upon the mass fraction of fuel flow to air flow.

Therefore, one of either of two methods may be used to calculate the exhaust flow. For the first method, the air flow and exhaust flow are determined iteratively. This is accomplished by assuming an air flow and proceeding through the calculations to determine both the heat entering and leaving the gas turbine. The correct air flow and exhaust flow are determined when both sides of the energy equation are equal.

The second method removes the need for iterations, but requires the inlet air and exhaust streams to be separated into combustion streams and non-combustion streams. The idea is to identify the air flow required for complete stoichiometric combustion and the excess air flow not required for combustion. With this approach, one can solve for all quantities directly with no iterations. This is the preferred method described herein.

The following additional definitions allow this non-iterative method to be implemented, along with the calculation of the mass flow required for stoichiometric combustion as described in para. A-3.2.4.

$$Q_{air} = Q_{air,excess(in)} + Q_{air,comb}$$
$$Q_{exh} = Q_{combprod} + Q_{air,excess(out)}$$
$$m_{combprod} = m_{air,comb} + m_{fuel} + m_{inj}$$
$$m_{exh} = m_{combprod} + m_{air,excess}$$

The reference temperature for these calculations can be selected by the user. The calculated exhaust flow result should be the same regardless of the chosen reference temperature, provided all terms of the energy balance equation are properly adjusted to the chosen reference temperature.

A-3.1.3 Required Data. The following data are required inputs to the calculations. The measurements and calculations required to determine these items are described in Section 4 of the Code.

(a) barometric pressure, psia

(b) compressor inlet air dry bulb temperature, °F

(c) compressor inlet air wet bulb temperature, °F or relative humidity, %

(d) fuel gas or oil mass flow, lb/h

(e) fuel gas molar analysis or liquid fuel ultimate (weight) analysis

(f) fuel lower heating value, Btu/lb

(g) fuel temperature, °F

(h) injection flow, lb/h

(i) injection enthalpy, Btu/lb

(j) extraction air flow, lb/h

(k) extraction air temperature, °F

(l) exhaust gas temperature, °F

(m) selected enthalpy reference temperature, °F

(*n*) gas turbine losses, Btu/h or kW
(*o*) power ouput, kW

A-3.1.4 Calculations. The calculations for determination of gas turbine exhaust energy or flow are presented in the following series of steps, many of which involve intermediate calculations detailed in para. A-3.2.

Step 1 Determine the gas turbine inlet air humidity ratio and wet air molar composition based on the ambient conditions as described in para. A-3.2.1.3.

Step 2 Determine the change in molar flow of the air to exhaust gas constituents due to the combustion of the gas turbine fuel as described in para. A-3.2.2 for fuel gas and para. A-3.2.3 for liquid fuel.

Step 3 Determine the mass flow of air required for stoichiometric combustion as described in para. A-3.2.4.

Step 4 Determine the gas turbine inlet air molar flows to the combustor based on the ambient conditions and the calculated combustor air mass flow as described in para. A-3.2.1.4.

Step 5 Determine the composition of combustion products using the combustor air molar flow as determined in *Step 4* and adding the change in molar flow due to the combustion of fuel in the gas turbine from *Step 2*. The turbine exhaust molar flow must also include the molar flow of steam or water injection into the gas turbine. The calculation of combustion product constituent mass fractions can then be calculated as described in para. A-3.2.5.

Step 6 Determine the combustion products enthalpy at turbine exhaust per para. A-3.2.6 with the combustion products constituent mass fractions as determined from *Step 5* and the measured gas turbine exhaust temperature.

Step 7 Determine the gas turbine inlet air enthalpy per para. A-3.2.6 with the inlet air composition from *Step 2* of A-3.2.1.4 and the measured dry bulb temperature. The compressor extraction air enthalpy is calculated with the same composition and the measured extraction air temperature. The excess air enthalpies are calculated using the same moist air composition, the inlet dry bulb temperature, and the turbine exhaust temperature.

Step 8 Determine the fuel heating value including the sensible heat of the fuel per para. A-3.2.7 for fuel gas and para. A-3.2.8 for liquid fuel.

Step 9 Determine the duty of a steam or water injection stream by multiplying the measured flow by the adjusted enthalpy. The adjusted enthalpy is determined by subtracting the saturated vapor enthalpy at the selected reference temperature from the ASME steam table enthalpy (ref. 32°F) at the measured pressure and temperature.

Step 10 Determine the electrical energy generated by multiplying the kilowatts produced by 3412.14 Btu/h/kW.

Step 11 Determine the gas turbine heat losses in accordance with para. 4-10.

Step 12 The excess air flow is now the only unknown parameter in the heat balance equation. Solve the equation for the excess air flow.

$$\begin{aligned} m_{\text{air,excess}}(h_{\text{air,inlet}} - h_{\text{air,exh}}) &= m_{\text{ext}}h_{\text{ext}} \\ &+ Q_{\text{elect}} + Q_{\text{loss}} + m_{\text{combprod}}h_{\text{combprod}} \\ &- m_{\text{air,comb}}h_{\text{air,inlet}} - m_{\text{fuel}}(\text{LHV}) - m_{\text{inj}}h_{\text{inj}} \\ m_{\text{combprod}} &= m_{\text{air,comb}} + m_{\text{fuel}} + m_{\text{inj}} \end{aligned}$$

Step 13 The turbine exhaust gas flow is finally calculated as the mass flow of combustion products plus the excess air flow.

$$m_{\text{exh}} = m_{\text{combprod}} + m_{\text{air,excess}}$$

A-3.2 Intermediate Calculations

A-3.2.1 Wet Air Composition and Molar Flows to Combustor. This section determines the mass fractions and molar flows of the wet air constituents entering the gas turbine combustor.

A-3.2.1.1 General. The following inlet dry air molar composition is assumed based on the American Society of Heating, Refrigerating, and Air Conditioning Engineers (ASHRAE) 1997 Handbook of Fundamentals.

Nitrogen	78.0840%
Oxygen	20.9476%
Argon	0.9365%
Carbon Dioxide	0.0319%
	100.000%

The dry air composition is corrected for humidity and atmospheric pressure effects via humidity calculations taken from the ASHRAE 1997 Handbook of Fundamentals as described in the following calculations.

A-3.2.1.2 Data Required

(*a*) barometric pressure, psia
(*b*) dry bulb temperature, °F
(*c*) wet bulb temperature, °F or relative humidity, %

A-3.2.1.3 Wet Air Composition and Humidity Ratio Calculations. The wet air molar analysis and humidity ratio are determined by the following steps. When required to calculate the water vapor saturation pressure, use the following relationship.

$$ln(p_{\text{vapor}}) = C_1/T + C_2 + C_3T + C_4T^2 + C_5T^3 + C_6T^4 + C_7ln(T)$$

where

$$T = °\text{R},\ t = °\text{F, and } T = t + 459.67$$

For the vapor pressure over ice in the temperature range of −148 to 32°F, the constants are:

$$C_1 = -1.0214165 \times 10^4$$
$$C_2 = -4.8932428$$
$$C_3 = -5.3765794 \times 10^{-3}$$
$$C_4 = 1.9202377 \times 10^{-7}$$
$$C_5 = 3.5575832 \times 10^{-10}$$

$$C_6 = -9.0344688 \times 10^{-14}$$
$$C_7 = 4.1635019$$

For the vapor pressure over water in the temperature range of 32 to 392°F, the constants are:

$$C_1 = -1.0440397 \times 10^{4}$$
$$C_2 = -1.1294650 \times 10^{1}$$
$$C_3 = -2.7022355 \times 10^{-2}$$
$$C_4 = 1.2890360 \times 10^{-5}$$
$$C_5 = -2.4780681 \times 10^{-9}$$
$$C_6 = 0.0$$
$$C_7 = 6.5459673$$

Step 1 If the relative humidity is known, go to Step 2 If the wet bulb temperature is known, go to Step 6

Step 2 Calculate the water vapor saturation pressure at the dry bulb temperature.

Step 3 Calculate the partial pressure of water by multiplying the vapor pressure times the relative humidity.

$$p_{H_2O} = p_{vapor} * RH / 100$$

Step 4 Calculate the fraction of dry air by subtracting the partial pressure of water from the atmospheric pressure and dividing this difference by the atmospheric pressure.

$$FDA = (p_{atm} - p_{H_2O})/p_{atm}$$

Step 5 Calculate the humidity ratio as a function of the fraction of dry air.

$$\varpi = (1/FDA - 1) * 18.01528/28.9651159$$

Go to Step 10

Step 6 Calculate the water vapor saturation pressure at the wet bulb temperature.

Step 7 Calculate the saturated humidity ratio from the atmospheric pressure and vapor pressure by the following equation:

$$\text{Saturated Humidity Ratio } (\varpi_{sat}) = \frac{0.62198 * (1.0039 * p_{vapor})}{(p_{atm} - 1.0039 * p_{vapor})}$$

Step 8 Calculate the actual humidity ratio from the saturated humidity ratio, wet bulb temperature, and dry bulb temperature by the following equation:

$$\text{Humidity Ratio } (\varpi) = \frac{(1093 - 0.556 * t_{wet\ bulb}) * \varpi_{sat} - 0.240 * (t_{dry\ bulb} - t_{wet\ bulb})}{1093 + 0.444 * t_{dry\ bulb} - t_{wet\ bulb}}$$

Step 9 Calculate the fraction of dry air from the actual humidity ratio by the following equation:

$$FDA = \frac{18.01528}{28.9651159\varpi + 18.01528}$$

Step 10 The wet air mole fractions can now be calculated. The fraction of dry air multiplied by the dry air mole fraction will give the actual air constituent mole fraction.

$$\text{Nitrogen mole fraction} = MF_{N_2} = FDA * 0.780840$$
$$\text{Oxygen mole fraction} = MF_{O_2} = FDA * 0.209476$$
$$\text{Argon mole fraction} = MF_{Ar} = FDA * 0.009365$$
$$\text{Carbon dioxide mole fraction} = MF_{CO_2} = FDA * 0.000319$$

The mole fraction of water is one minus the fraction of dry air.

$$\text{Water mole fraction} = MF_{H_2O} = 1.0 - FDA$$

The assumed mole fraction of sulfur dioxide in air is zero.

$$\text{Sulfur dioxide mole fraction} = MF_{SO_2} = 0.0$$

Step 11 Calculate the average molecular weight of the wet air by the following equation. Molecular weights are given in Table A-1 below.

$$MW_{air} = \Sigma[MF_i \times MW_i]$$

where

MW = molecular weight, lb/lbmol
MF = mole fraction
i = subscript denoting a given air constituent

A-3.2.1.4 Calculation of Molar Flows to Combustor. The wet air molar flows to the combustor are determined by the following steps. In addition to the parameters determined in the previous section, this calculation requires the mass flow of air to combustor (mair,comb) as calculated in para. A-3.2.4.

Step 1 Calculate the air molar flow to the combustor by dividing the air mass flow to the combustor by the average molecular weight. The air constituent molar flow to the combustor is the air molar flow times the constituent mole fraction.

$$M_i = m_{air,comb} \times MF_i \ / \ MW_{air}$$

where

M = molar flow, mol/h
$m_{air,comb}$ = air mass flow to the combustor, lb/h
MF = mole fraction

Table A-1 Elemental Molecular Weights

Element	Molecular Weight, lb/lbmol
Argon	39.948
Carbon	12.0107
Helium	4.002602
Hydrogen	1.00794
Nitrogen	14.0067
Oxygen	15.9994
Sulfur	32.065

Source: Molecular weights adapted from Coursey, J.S., Schwab, D.J., and Dragoset, R.A. (2003), *Atomic Weights and Isotopic Compositions (version 2.4).* [Online] Available: http://physics.nist.gov/Comp [January 2004]. National Institute of Standards and Technology, Gaithersburg, MD.

MW_{air} = molecular weight of the wet air mixture, lb/lbmol
i = subscript denoting a given air constituent

Step 2 Calculate the air constituent mass fraction by multiplying the constituent mole fraction by its molecular weight and dividing by the average molecular weight. The mass fractions are required only for determining enthalpy.

$$mF_i = MF_i \times MW_i \ / \ MW_{air}$$

where
mF = mass fraction
MF = mole fraction
MW = molecular weight
i = subscript denoting a given air constituent

A-3.2.2 Molar Flow Change Due to Fuel Gas Combustion

A-3.2.2.1 General. This section determines the molar flow change of the air to the exhaust stream constituents due to the complete stoichiometric combustion of each constituent of the fuel gas.

A-3.2.2.2 Data Required

(*a*) fuel gas flow, lb/h
(*b*) fuel gas molar analysis

A-3.2.2.3 Table of Combustion Ratios

Table A-2 provides the ratios of air constituent molar flow change per mole of fuel gas constituent resulting from complete stoichiometric combustion. The molar flow of any inert compound in the fuel gas, such as nitrogen or carbon dioxide, would pass directly into the combustion products on a mole per mole basis. The table values are determined from an oxidation chemical reaction for a unit mole of each fuel gas constituent in accordance with the following generic oxidation equation. The coefficients for oxygen are negative because oxygen is consumed in the reaction.

Table A-2 Fuel Gas Combustion Ratios

Fuel Gas Constituent	Air Constituent					
	N_2	O_2	CO_2	H_2O	Ar	SO_2
CH_4	0	−2	1	2	0	0
C_2H_6	0	−3.5	2	3	0	0
C_3H_8	0	−5	3	4	0	0
C_4H_{10}	0	−6.5	4	5	0	0
C_5H_{12}	0	−8	5	6	0	0
C_6H_{14}	0	−9.5	6	7	0	0
N_2	1	0	0	0	0	0
CO	0	−0.5	1	0	0	0
CO_2	0	0	1	0	0	0
H_2O	0	0	0	1	0	0
H_2	0	−0.5	0	1	0	0
H_2S	0	−1.5	0	1	0	1
He	0	0	0	0	1 [Note (1)]	0
O_2	0	1	0	0	0	0
Ar	0	0	0	0	1	0

NOTE:
(1) Helium, as an inert gas, is carried through the equations as Argon.

$$CxHySz + (x + y/4 + z)O_2 = (x)CO_2 + (y/2)H_2O + (z)SO_2$$

A-3.2.2.4 Calculations

Step 1 Calculate the fuel gas average molecular weight by summing, for all fuel gas constituents, the product of the constituent mole fraction and molecular weight. For molecular weights see Table A-1.

$$MW_{fuel} = \Sigma[MF_j \times MW_j]$$

Step 2 Calculate the fuel gas molar flow by dividing the fuel gas mass flow by the fuel gas average molecular weight.

$$M_{fuel}, \text{mol/h} = \frac{m_{fuel}, \text{lb/h}}{MW_{fuel}}$$

Step 3 Calculate the change in molar flow due to combustion of each air constituent by summing, for all fuel gas constituents, the product of the fuel gas molar flow, the fuel gas constituent mole fraction, and the corresponding combustion ratio for the given air constituent. Traces of helium in the fuel gas can usually be combined with argon.

$$\Delta M_i = \Sigma[M_{fuel} \times MF_j \times CR_{ij}]$$

where
ΔM = change in molar flow due to combustion, mol/h
M_{fuel} = fuel gas molar flow from Step 2, mol/h
MF = mole fraction
CR = combustion ratio from Table A-2
i = subscript denoting a given air constituent
j = subscript denoting a given fuel gas constituent

A-3.2.3 Molar Flow Change Due to Liquid Fuel Combustion

A-3.2.3.1 General. This section determines the molar flow change of the air to the exhaust stream constituents due to the complete stoichiometric combustion of each constituent of the liquid fuel.

A-3.2.3.2 Data Required

(*a*) liquid fuel flow, lb/h
(*b*) liquid fuel ultimate analysis (weight fractions)

A-3.2.3.3 Table of Combustion Ratios. Table A-3 provides the ratios of air constituent molar flow change per mole of liquid fuel constituent resulting from complete stoichiometric combustion.

A-3.2.3.4 Calculations

Step 1 Calculate the liquid fuel molar flow for each element in the liquid fuel analysis by multiplying the liquid fuel mass flow by the con-

Table A-3 Liquid Fuel Combustion Ratios

Liquid Fuel Constituent	Air Constituent					
	N_2	O_2	CO_2	H_2O	Ar	SO_2
C	0	−1	1	0	0	0
H	0	−0.25	0	0.5	0	0
O	0	0.5	0	0	0	0
N	0.5	0	0	0	0	0
S	0	−1	0	0	0	1

stituent mass fraction divided by the elemental molecular weight (see Table A-1).

$$M_j = m_{\text{fuel}} \times mF_j \; / \; MW_j$$

where

M = liquid fuel constituent molar flow, mol/h
m_{fuel} = liquid fuel mass flow, lb/h
mF = mass fraction of liquid fuel constituent
MW = molecular weight, lb/lbmol
j = subscript denoting a given liquid fuel elemental constituent

Step 2 Calculate the change in molar flow due to combustion of each air constituent by summing, for all liquid fuel constituents, the product of the liquid fuel molar flow and the corresponding combustion ratio for the given air constituent.

$$\Delta M_i = \Sigma[M_j \times CR_{ij}]$$

where

ΔM = change in molar flow due to combustion, mol/h
M = liquid fuel molar flow from Step 1, mol/h
CR = combustion ratio from Table A-3
i = subscript denoting a given air constituent
j = subscript denoting a given liquid fuel elemental constituent

A-3.2.4 Combustion Air Flow

A-3.2.4.1 General. This section describes the method for determining the mass flow of wet combustion air required for complete stoichiometric combustion. The determination allows for the direct calculation of the mass and energy balances with no iterations required.

A-3.2.4.2 Data Required

(a) humidity ratio (ϖ), lb H_2O/lb dry air (para. A-3.2.1.3)

(b) change in molar flow of O_2, mol/h (para. A-3.2.2 for fuel gas, para. A-3.2.3 for liquid fuel)

A-3.2.4.3 Calculations

Step 1 Calculate the mass flow of dry air to the combustor.

$$m_{\text{air,comb(dry)}} = \Delta M_{O_2} \, / \, MF_{O_2\text{(dry)}} \times MW_{\text{air(dry)}}$$

where

ΔM_{O_2} = change in molar flow of O_2 due to combustion, mol/h
$MF_{O_2\text{(dry)}}$ = mole fraction of O_2 in dry air = 0.209476
$MW_{\text{air(dry)}}$ = molecular weight of dry air = 28.9651159

Step 2 Calculate the mass flow of moist air to the combustor.

$$m_{\text{air,comb}} = m_{\text{air,comb(dry)}} \times (1 + \varpi)$$

A-3.2.5 Combustion Products Exhaust Composition

A-3.2.5.1 General. This section determines the gas turbine combustion products exhaust composition for the purpose of calculating the combustion products exhaust gas enthalpy. The exhaust consituents will include some or all of the following compounds: nitrogen, oxygen, carbon dioxide, water, argon, and sulfur dioxide.

A-3.2.5.2 Data Required

(a) combustor air flow, lb/h (para. A-3.2.4.3, Step 2)

(b) steam/water injection flow, lb/h

(c) fuel flow, lb/h

(d) combustor air molar flow, mol/h (para. A-3.2.1.4, Step 1)

(e) change in molar flow, mol/h (para. A-3.2.2.4, Step 3 for fuel gas; para. A-3.2.3.4, Step 2, for liquid fuel)

A-3.2.5.3 Calculations

Step 1 Calculate the molar flow of steam/water injection by dividing the injection mass flow by the molecular weight of water.

$$M_{\text{inj}} = m_{\text{inj}} \, / \, MW_{H_2O}$$

where

M_{inj} = injection water/steam molar flow, mol/h
m_{inj} = injection water/steam mass flow, lb/h
MW_{H_2O} = molecular weight of water, lb/mol

Step 2 Calculate the water molar flow in the exhaust stream as the sum of the water molar flow from the air, the change in molar flow of water from the combustion of the fuel, and the steam or water injection molar flow calculated in Step 1.

$$M_{\text{combprod},H_2O} = M_{\text{air},H_2O} + \Delta M_{H_2O} + M_{\text{inj}}$$

where

M_{combprod,H_2O} = molar flow of water in combustion products, lb/lbmol
M_{air,H_2O} = molar flow of water in combustion air, lb/lbmol
ΔM_{H_2O} = change in molar flow of water due to combustion
M_{inj} = injection water/steam molar flow, mol/h

Step 3 Calculate the molar flow for all other exhaust constituents as the sum of the molar flow from the air and the change in molar flow due to combustion of the fuel.

$$M_{\mathrm{combprod},k} = M_{\mathrm{air},k} + \Delta M_k$$

where

M_{combprod} = combustion products molar flow, lb/lbmol
M_{air} = combustion air molar flow, lb/lbmol
ΔM = change in molar flow due to combustion
k = subscript denoting a given combustion products constituent (non-water in this case)

Step 4 Calculate the mass fraction of each gas turbine combustion products exhaust constituent as the product of the molar flow and the molecular weight for that constituent divided by the total combustion products mass flow.

$$m_{\mathrm{combprod}} = m_{\mathrm{air,comb}} + m_{\mathrm{fuel}} + m_{\mathrm{inj}}$$
$$mF_{\mathrm{combprod},k} = M_{\mathrm{combprod},k} \times MW_k / m_{\mathrm{combprod}}$$

where

mF_{combprod} = combustion products mass fraction
M_{combprod} = combustion products molar flow, lb/lbmol
MW = constituent molecular weight, lb/lbmol
k = subscript denoting any combustion products constituent

A-3.2.6 Gas Enthalpy

A-3.2.6.1 General. This Section describes the method for determining the enthalpies in the exhaust gas and air streams. The gas or air stream enthalpy is a mass weighted value of the stream constituent enthalpies. The constituent enthalpy equations and coefficients are adapted from McBride, B.J., Zehe, M.J., and Gordon S. (September 2002), *NASA Glenn Coefficients for Calculating Thermodynamic Properties of Individual Species*, NASA/TP-2002-211556. National Aeronautics and Space Administration, Glenn Research Center, Cleveland, Ohio. This database is periodically updated as new research is completed, therefore the user should periodically confirm that the constants used in the enthalpy equations are consistent with the latest available research. Updates can be confirmed online at the NASA Glenn Chemical Equilibrium with Applications (CEA) computer program website: http://www.grc.nasa.gov/WWW/CEAWeb/ceaHome.htm using the available *Thermo-Build* function or the *CEAgui* program. The constants to be used should be agreed upon prior to conducting a test.

A-3.2.6.2 Data Required

- *(a)* gas temperature, °F
- *(b)* gas constituent mass fractions
- *(c)* selected enthalpy reference temperature, °F

A-3.2.6.3 Enthalpy Equation Constants. The enthalpy is calculated for each constituent in a gas stream as a function of the gas temperature. The NASA enthalpy correlations provided here for each constituent are applicable up to 1000 K (1340.33°F) which is sufficient for the objectives of this Appendix and for the current gas turbine technologies. Higher range correlations are available from the NASA database. The correlations require the temperature to be expressed in Kelvin.

$$T_{\mathrm{K}} = \text{temperature [K]} = (t\ [°\mathrm{F}] + 459.67) / 1.8$$

For a given exhaust constituent, the enthalpy, expressed as Btu/lb, and referenced to zero at 77°F (298.15 K) is determined by the following equation.

$$H^{\mathrm{o}} = [(-A_1 / T_{\mathrm{K}} + A_2 ln(T_{\mathrm{K}}) + A_3 T_{\mathrm{K}} + A_4 T_{\mathrm{K}}^2 / 2 + A_5 T_{\mathrm{K}}^3 / 3 + A_6 T_{\mathrm{K}}^4 / 4 + A_7 T_{\mathrm{K}}^5 / 5 + A_8)^* R - \Delta_f H^{\mathrm{o}}] / 2.326 / MW$$

where

$H^{\mathrm{o}} = H^{\mathrm{o}}(T_{\mathrm{K}}) - H^{\mathrm{o}}(298.15\ \mathrm{K})$ = Enthalpy (ref = 77°F), Btu/lb
T_{K} = temperature, K
R = 8.31451 J/mol-K
$\Delta_f H^{\mathrm{o}}$ = heat of formation, J/mol
MW = molecular weight
A_x = coefficents as given in Table A-4 below

For instances that require a reference temperature different than 77°F, the enthalpy relation must be evaluated twice.

$$H^{\mathrm{o}}(T_{\mathrm{K}})_{\mathrm{NewRef}} = H^{\mathrm{o}}(T_{\mathrm{K}})_{77°\mathrm{F}} - H^{\mathrm{o}}(\mathrm{NewRef})_{77°\mathrm{F}}$$

A-3.2.6.4 Calculations

Step 1 Calculate the enthalpy for each gas constituent for the given temperature at the selected reference temperature using the appropriate correlation coefficients.

Step 2 Calculate the gas enthalpy for the gas mixture as the sum of the products of the constituent enthalpy and constituent weight (mass) fraction for all constituents.

$$h_m = H^{\mathrm{o}}(T_{\mathrm{K}})_{\mathrm{mixture}} = \Sigma[mF_n \times H^{\mathrm{o}}(T_{\mathrm{K}})_n]$$

A-3.2.7 Fuel Gas Heating Value

A-3.2.7.1 General. The heat of combustion used in all calculations is the lower heating value. This is not to be confused with the higher heating value which includes the heat of vaporization for water. The heating value for fuel gas is a calculated number based upon the fuel gas composition as described in Section 5 of the Code. The heating value should always be calculated based on the latest available publication of GPA 2145, or other agreed upon source such as ASTM D3588 or the GPSA Engineering Data Book. The reference data presented in this Code is from GPA-2145-03 and is based on combustion reference conditions of 60°F and 14.696 psia. Other industry publications provide various combustion reference conditions such as 15°C, 20°C, and 25°C. Variations of heat of combustion due to changes

Table A-4 Enthalpy Equation Constants

Constituent	A1	A2	A3	A4	A5	A6	A7	A8	$\Delta_f H^\circ$
N_2	22103.7150	−381.846182	6.08273836	−0.008530914	1.38465E-05	−9.62579E-09	2.51971E-12	710.846086	0
O_2	−34255.6342	484.700097	1.11901096	0.004293889	−6.83630E-07	−2.02337E-09	1.03904E-12	−3391.4549	0
CO_2	49436.5054	−626.411601	5.30172524	0.002503814	−2.1273E-07	−7.68999E-10	2.84968E-13	−45281.9846	−393510
H_2O	−39479.6083	575.573102	0.931782653	0.007222713	−7.34256E-06	4.95504E-09	−1.33693E-12	−33039.7431	−241826
Ar	0	0	2.5	0	0	0	0	−745.375	0
SO_2	−53108.4214	909.031167	−2.35689124	0.0220445	−2.51078E-05	1.4463E-08	−3.36907E-12	−41137.5212	−296810
CH_4	−176685.0998	2786.18102	−12.0257785	0.039176193	−3.61905E-05	2.02685E-08	−4.97671E-12	−23313.1436	−74600
C_2H_6	−186204.4161	3406.19186	−19.51705092	0.075658356	−8.20417E-05	5.06114E-08	−1.31928E-11	−27029.3289	−83851.544
C_3H_8	−243314.4337	4656.27081	−29.39466091	0.118895275	−1.37631E-04	8.81482E-08	−2.34299E-11	−35403.3527	−104680
iso-C_4H_{10}	−383446.933	7000.03964	−44.400269	0.174618345	−2.07820E-04	1.33979E-07	−3.55168E-11	−50340.1889	−134990
n-C_4H_{10}	−317587.254	6176.33182	−38.9156212	0.158465428	−1.86005E-04	1.19968E-07	−3.20167E-11	−45403.6339	−125790
iso-C_5H_{12}	−423190.339	6497.1891	−36.8112697	0.153242473	−1.54879E-04	8.74990E-08	−2.07055E-11	−51554.1659	−153700
n-C_5H_{12}	−276889.4625	5834.28347	−36.1754148	0.153333971	−1.52840E-04	8.19109E-08	−1.79233E-11	−46653.7525	−146760
n-C_6H_{14}	−581592.67	10790.97724	−66.3394703	0.252371516	−2.90434E-04	1.80220E-07	−4.61722E-11	−72715.4457	−166920
CO	14890.45326	−292.2285939	5.72452717	−0.008176235	1.45690E-05	−1.08775E-08	3.02794E-12	−13031.31878	−110535.196
H_2S	9543.80881	−68.7517508	4.05492196	−0.000301456	3.76850E-06	−2.23936E-09	3.08686E-13	−3278.45728	−20600
H_2	40783.2321	−800.918604	8.21470201	−0.012697145	1.75361E-05	−1.20286E-08	3.36809E-12	2682.484665	0
He	0	0	2.5	0	0	0	0	−745.375	0

GENERAL NOTE: Adapted from McBride, B.J., Zehe, M.J., and Gordon S. (September 2002), NASA Glenn Coefficients for Calculating Thermodynamic Properties of Individual Species, NASA/TP-2002-211556. National Aeronautics and Space Administration, Glenn Research Center, Cleveland, Ohio.

in combustion reference temperature are relatively small and generally complex, so it is not necessary or practical to account for this provided the selected data set is agreed by all parties prior to the test. However, account must be made for the sensible heat difference between the selected enthalpy reference temperature for the heat balance calculation and the actual flowing temperature of the fuel.

There are several acceptable methods that may be used to calculate the sensible heat of the fuel gas. (See para. 5-3.1.11 of the Code.)

The most accurate way is to access specific heat or enthalpy data from NIST or GPSA databases at the actual temperature and partial pressure of each of the fuel gas constituents, then combining them to obtain an overall enthalpy or specific heat value for the compressed mixture.

One simplified method which ignores variations in composition and assumes a compressed condition is to use the simplified polynomial provided in para. 5-3.1.11 of this Code. That method is based on the assumption of pure methane and 400 psia, and is acceptable for methane rich fuels. Small variations in pressure are negligible. For various fuel compositions the error in calculated exhaust gas flow could be as much as 0.1% high.

A second simplified method considers the fuel composition variance but ignores the pressure effects by determining enthalpies at 1 atm which can lead to calculated exhaust flows which may be as much as 0.1% low. This is the same method used for the air and exhaust gas enthalpies at atmospheric pressure by applying the NASA formulations and coefficients adapted from NASA/TP-2002-211556. For consistency with the other enthalpy calculations in this overall heat balance, this method of determining sensible heat is demonstrated in the sample calculation at the end of this Appendix. The NASA coefficients are provided in Table A-4.

A-3.2.7.2 Data Required

(a) fuel gas constituent analysis
(b) fuel gas temperature, °F
(c) selected reference temperature, °F

A-3.2.7.3 Calculations

Step 1 Calculate the total fuel mass by summing the products of fuel gas compound mole fraction and compound molecular weight for all fuel gas compounds.

$$\text{Total Mass of Fuel} = \Sigma(MF_j \times MW_j)$$

Step 2 Calculate the heating value contribution of each fuel gas compound by computing the product of the fuel gas compound mole fraction, the fuel gas compound molecular weight, and the fuel gas compound heat of combustion (in Btu/lb) and dividing by the total fuel weight.

$$\text{LHV}_j = MF_j \times MW_j \times HC_j \ / \ \text{Total Mass of Fuel}$$

Step 3 Calculate the fuel gas ideal heating value by summing the heating value contributions of all fuel gas compounds.

$$\text{LHV}_{\text{chem}} = \Sigma \text{LHV}_j$$

Step 4 Calculate the sensible heat content (specific enthalpy) of the fuel in accordance with para. A-3.2.7.1 above. Calculate the fuel net heating value as the sum of the fuel gas ideal heating value and the fuel sensible heat, then adjust from the measured fuel temperature to the selected reference temperature.

$$\text{LHV} = \text{LHV}_{\text{chem}} + \text{LHV}_{\text{sens}}$$

A-3.2.8 Liquid Fuel Heating Value

A-3.2.8.1 General. The heat of combustion used in all calculations is the lower heating value. This is not to be confused with the higher heating value which includes the heat of vaporization for water. The heating value for liquid fuel is to be determined in accordance with the Code. Care should be taken to ensure the liquid fuel heating value is properly adjusted to the selected reference temperature. For most liquid fuels (No. 1 through No. 6 fuel oils) in the typical API gravity range, the empirical approximation provided in para. 5-2.10 of this Code is sufficient to determine the sensible heat above 77°F.

A-3.2.8.2 Data Required

(a) liquid fuel ideal lower heating value, Btu/lb
(b) liquid fuel temperature, °F
(c) selected reference temperature, °F

A-3.2.8.3 Calculations

Step 1 The Code is used to calculate the sensible heat content of the liquid fuel.

Step 2 The fuel net heating value is the sum of the liquid fuel ideal heating value and the fuel sensible heat.

$$\text{LHV} = \text{LHV}_{\text{chem}} + \text{LHV}_{\text{sens}}$$

A-4 SAMPLE EXHAUST FLOW BY GAS TURBINE HEAT BALANCE CALCULATION

This section presents an analysis program to simplify the calculation procedures in the test code (see Fig. A-1). It has been the intention to design a user-friendly example, which is the reason for using multiple sheets. The different sheets modularize the calculations. The "Main" worksheet is the main input/output sheet. This is the only sheet required for most cases. Intermediate calculations are on the other sheets. Some cases could require inputs on other sheets.

The reference temperature basis for gas calculations is 77°F. The reference temperature basis for steam/water enthalpy is 60°F. The example corrects all enthalpies to a user selected reference temperature.

Assumptions:

(a) Injection streams are always water or steam.

(b) Extraction streams are always a compressor air bleed.

(c) Pressure has negligible impact on compressor bleed enthalpy.

(d) Fuel gas pressure effects on sensible heat of the fuel are ignored.

(e) Gas enthalpy calculations are only valid up to 1000 K.

(f) Water and steam enthalpies are based on 1967 steam tables.

DESCRIPTION: PTC 22 SAMPLE CASE—INPUT SHEET

Barometric Pressure	14.696	psia
Inlet Dry Bulb Temperature	80.0	°F
Inlet Wet Bulb Temperature		°F
Inlet Relative Humidity	60.0	%

(Optional in lieu of Wet Bulb Temperature)

Gas Turbine Fuel Composition **Gas** Oil

Injection Stream Flow	50000	lb/h
(Zero for Standard) Temperature	200.0	°F
Pressure	150.0	psig
Phase 0-Water/1-Steam	0	
Compressor Extraction Air	10000	lb/h
Extraction Air Temperature	600.0	°F
Reference Temperature for Enthalpy	80.0	°F
Exhaust Outlet Temperature	1000.0	°F

GT Fuel Flow	54545	lb/h
Fuel Temperature	80.0	°F
Fuel LHV	21072	Btu/lb
GT Power Output	120.20	MW
Generator Losses	1424	kW
Gearbox Losses	0	kW
Fixed Heat Losses	1.00	MMBtu/h
Variable Heat Losses	3.10	MMBtu/h
GT EXHAUST FLOW =	**2,782,517**	**lb/h**
GT EXHAUST ENERGY =	**682.62**	**MMBtu/h**

DUTY SUMMARY TABLE

	Flow lb/h	**Enthalpy Btu/lb**	**Duty MMBtu/h**
Excess Air at Comp Inlet	1749726	0.00	0.00
Combustion Air + Ext	938246	0.00	0.00
Fuel	54545	21072.5	1149.40
Steam/Water Injection*	50000	−928.00	−46.40
Compressor Extraction	−10000	128.40	−1.28
Comb Prod at Turb Exit	1032791	267.32	−276.08
Power (MW*3.4121412)			−410.14
Total Heat Losses			−8.96
Change in Excess Air	1749726	232.34	406.53
Excess Air at Turb Exit	1749726	232.34	406.53
Turbine Exhaust	2782517	245.32	682.62

WET EXH MOLE FRACTION

N2 = 71.904%
O2 = 12.603%
CO2 = 3.549%
H2O = 11.081%
Ar = 0.862%
SO2 = 0.000%

DRY EXH MOLE FRACTION

N2 = 80.865%
O2 = 14.174%
CO2 = 3.991%
Ar = 0.970%
SO2 = 0.000%

Fig. A-1 Sample Exhaust Flow by Gas Turbine Heat Balance Calculation

DESCRIPTION: PTC 22 SAMPLE CASE — AIR CALCULATIONS

CALCULATION OF WET AIR COMPOSITION AND MOLAR FLOW

Barometric Pressure	14.696	psia
Dry Bulb Temperature	80.0	°F
Wet Bulb Temperature		°F
Relative Humidity	60.0	%
Moist Air Flow to Combustor	928,246	lb/h
Excess Air Flow	1,749,726	lb/h

$$\mathrm{Ln}(P_{vapor}) = C_1/T + C_2 + C_3{*}T + C_4{*}T^2 + C_5{*}T^3 + C_6{*}T^4 + C_7{*}\mathrm{Ln}(T)$$

For T <= 32°F	For T > 32°F
$C_1 = -1.0214165E+04$	$C_1 = -1.0440397E+04$
$C_2 = -4.8932428E+00$	$C_2 = -1.1294650E+01$
$C_3 = -5.3765794E-03$	$C_3 = -2.7022355E-02$
$C_4 = 1.9202377E-07$	$C_4 = 1.2890360E-05$
$C_5 = 3.5575832E-10$	$C_5 = -2.4780681E-09$
$C_6 = -9.0344688E-14$	$C_6 = 0$
$C_7 = 4.1635019E+00$	$C_7 = 6.5459673E+00$

Calculations for Case of Known Relative Humidity

$T = t_{dry\ bulb} + 459.67 = 539.67°R$ $\quad P_{vapor} = 0.5074$ psia

$p_{H2O} = \%RH{*}p_{vapor} = 0.3044$ psia

$FDA = (p_{atm} - p_{H2O})/p_{atm} = 0.979286$

Humidity Ratio $= (1/FDA - 1) \times MW_{H2O}/MW_{dryair}$ $= 0.013156$ lb H_2O/lb dry air

Calculations for Case of Known Wet Bulb Temperature

$T = t_{wet\ bulb} + 459.67 =$ *R $p_{vapor} =$ #VALUE! psia

Saturated Humidity Ratio $= HR_{sat} = 0.62198 * (1.0039{*}P_{vapor}/(P_{atm} - 1.0039{*}P_{vapor}))$

$HR_{sat} =$ lb H_2O/lb dry air

$$\text{Humidity Ratio} = \frac{(1093 - .556 * T_{wet\ bulb} * HR_{sat} - .240 * (T_{dry\ bulb} - T_{wet\ bulb})}{(1093 + .444 * T_{dry\ bulb} - T_{wet\ bulb})}$$

Humidity Ratio = lb H_2O/lb dry air

$$\text{Fraction Dry Air (FDA)} = \frac{18.01528}{(28.9651159) * (\text{Humidity Ratio}) + 18.01528}$$

Fraction Dry Air (FDA) =

MOIST AIR TO COMBUSTOR

A1	A2	A3	A4	A5	A6	A7
Compound	Calculation	Air Mole Fraction	Molecular Weight	[A3] × [A4]	Moist Air Molar Flow to Combustor lb/h × [A3]/Sum [A5] = mol/h	Air Weight Fraction [A5]/Sum [A5]
N_2	.780840 * FDA	0.7647	28.0134	21.4209	24699	0.7454
O_2	.209476 * FDA	0.2051	31.9988	6.5641	6626	0.2284
CO_2	.000319 * FDA	0.0003	44.0095	0.0137	10	0.0005
H_2O	1 − FDA	0.0207	18.01528	0.3732	669	0.0130
Ar	.009365 * FDA	0.0092	39.948	0.3664	296	0.0127
			Average Molecular Weight	28.7383		

DRY AIR TO COMBUSTOR

A1		A8	A9	A10
Compound		Air Mole Fraction	Molecular Weight	[A8] × [A9]
N_2		0.7808	28.0134	21.8740
O_2		0.2095	31.9988	6.7030
CO_2		0.0003	44.0095	0.0140
H_2O			18.01528	
Ar		0.0094	39.948	0.3741
			Average Molecular Weight	28.9651

SHEET A

Fig. A-1-A Sample Calculation of Wet Air Composition and Molar Flow

EXCESS AIR

A1	A11	A12	A13	A14	A15	A16
Compound	Calculation	Air Mole Fraction	Molecular Weight	[A12] × [A13]	Excess Moist Air Molar Flow lb/h × [A12]/Sum [A14] = mol/h	Air Weight Fraction [A14]/Sum [A14]
N_2	.780840 * FDA	0.7647	28.0134	21.4209	46557	0.7454
O_2	.209476 * FDA	0.2051	31.9988	6.5641	12490	0.2284
CO_2	.000319 * FDA	0.0003	44.0095	0.0137	19	0.0005
H_2O	1 − FDA	0.0207	18.01528	0.3732	1261	0.0130
Ar	.009365 * FDA	0.0092	39.948	0.3664	558	0.0127
			Average Molecular Weight	28.7383		

SHEET A (Cont'd)

Fig. A-1-A Sample Calculation of Wet Air Composition and Molar Flow (Cont'd)

DESCRIPTION: PTC 22 SAMPLE CASE — MASS FLOW

MASS FLOW CALCULATIONS

Molar Flow Change of O_2	6,625.9	mol/h
Molecular Weight of Dry Air	28.9651	lb/lbmol
O_2 Mole Fraction of Dry Air	0.20948	
Dry Air to Combustor	916,193	lb/h
Specific Humidity	0.01316	lbwater/lbdryair
Moist Air to Combustor	928,246	lb/h
Total Inlet Air	2,687,972	lb/h
Compressor Bleed Air	10,000	lb/h
Wet Excess Air	1,749,726	lb/h
Wet Combustion Air	928,246	lb/h
Fuel Flow	54,545	lb/h
Injection Flow	50,000	lb/h
Total Combustor Flow	1,032,791	lb/h
Turbine Exhaust Flow	2,782,517	lb/h

SHEET B

Fig. A-1-B Sample Mass Flow Calculations

DESCRIPTION: PTC 22 SAMPLE CASE — FUEL GAS COMBUSTION

FUEL GAS COMBUSTION CALCULATIONS

Fuel Gas Mass Flow =	54,545	lb/h	
Fuel Gas Molar Flow =	2,787.7	mol/h	(Mass Flow/MW_{avg})

C1	C2	C3	C4	C5	C6	C7	C8	C9	C10	C11	C12	C13	C14	C15	C16
Fuel Constituent	Normalized Mole Fractions	Molecular Weight	Molar Flow [C2] × [C3]	N_2 Ratio	N_2 Mole Change mol/h × [C2] × [C5]	O_2 Ratio	O_2 Mole Change mol/h × [C2] × [C7]	CO_2 Ratio	CO_2 Mole Change mol/h × [C2] × [C9]	H_2O Ratio	H_2O Mole Change mol/h × [C2] × [C11]	Ar Ratio	Ar Mole Change mol/h × [C2] × [C13]	SO_2 Ratio	SO_2 Mole Change mol/h × [C2] × [C15]
CH_4	0.8278	16.04246	13.279	0	0	−2	−4615	1	2308	2	4615	0	0	0	0
C_2H_6	0.1092	30.06904	3.284	0	0	−3.5	−1066	2	609	3	913	0	0	0	0
C_3H_8	0.0500	44.09562	2.205	0	0	−5	−697	3	418	4	558	0	0	0	0
iso-C_4H_{10}	0.0050	58.12220	0.291	0	0	−6.5	−91	4	56	5	70	0	0	0	0
n-C_4H_{10}	0.0050	58.12220	0.291	0	0	−6.5	−91	4	56	5	70	0	0	0	0
iso-C_5H_{12}	0.0010	72.14878	0.072	0	0	−8	−22	5	14	6	17	0	0	0	0
n-C_5H_{12}	0.0020	72.14878	0.144	0	0	−8	−45	5	28	6	33	0	0	0	0
C_6H_{14}	0.0000	86.17536		0		−9.5		6		7		0		0	
N_2	0.0000	28.01340		1		0		0		0		0		0	
CO	0.0000	28.01010		0		−0.5		1		0		0		0	
CO_2	0.0000	44.00950		0		0		1		0		0		0	
H_2O	0.0000	18.01528		0		0		0		1		0		0	
H_2S	0.0000	34.08088		0		−1.5		0		1		0		1	
H_2	0.0000	2.01588		0		−0.5		0		1		0		0	
He	0.0000	4.00260		0		0		0		0		1		0	
O_2	0.0000	31.9988		0		1		0		0		0		0	
Ar	0.0000	39.94800		0		0		0		0		1		0	
		Average Molecular Weight =	19.566												
		Molar Flow Change =			0		−6626		3488		6276		0		0

SHEET C

Fig. A-1-C Sample Fuel Gas Combustion Calculations

DESCRIPTION: PTC 22 SAMPLE CASE — FUEL OIL COMBUSTION

LIQUID FUEL COMBUSTION CALCULATIONS

Liquid Fuel Mass Flow = 54,545 lb/h

D1	D2	D3	D4	D5	D6	D7	D8	D9	D10	D11	D12	D13	D14
Element	Weight Fraction	Molecular Weight	Molar Flow lb/h × [D2]/[D3]	N_2 Ratio	N_2 Mole Change [D4] × [D5]	O_2 Ratio	O_2 Mole Change [D4] × [D7]	CO_2 Ratio	CO_2 Mole Change [D4] × [D9]	H_2O Ratio	H_2O Mole Change [D4] × [D11]	SO_2 Ratio	SO_2 Mole Change [D4] × [D13]
C	0.000	12.0107		0		−1		1		0		0	
H	0.000	1.00794		0		−0.25		0		0.5		0	
O	0.000	15.9994		0		0.5		0		0		0	
N	0.000	14.0067		0.5		0		0		0		0	
S	0.000	32.065		0		−1		0		0		1	
	0.000												
	0.000												
	0.000												
			Molar Flow Change =		0.00		0.00		0.00		0.00		0.00

SHEET D

Fig. A-1-D Sample Liquid Fuel Combustion Calculations

DESCRIPTION: PTC 22 SAMPLE CASE — EXHAUST COMPOSITION

CALCULATION OF EXHAUST COMPOSITIONS

Water or Steam Injection Flow = 50,000 lb/h
GT Fuel Flow = 54,545 lb/h
Moist Air to Combustor = 928,246 lb/h
Total Combustor Flow = 1,032,791 lb/h
Excess Air Flow = 1,749,726 lb/h
Turbine Exhaust Flow = 2,782,517 lb/h

COMBUSTION PRODUCTS

E1	E2	E3	E4	E5	E6	E7	E9
Compound	Air Molar Flow [A6]	Combustion Mole Change Previous Sheets	Wat or Stm Inj Molar Flow lb/h/[E7]	Comb Exh Molar Flow [E2] + [E3] + [E4]	Comb Exh Mole Fraction [E5]/sum[E5]	Molecular Weight	Comb Exhaust Mass Fraction [E5] × [E7]/CombFlow
N_2	24699	0	0	24699	0.64634	28.0134	0.66993
O_2	6626	−6626	0	0	0.00000	31.9988	0.00000
CO_2	10	3488	0	3498	0.09154	44.0095	0.14906
H_2O	669	6276	2775	9720	0.25437	18.01528	0.16955
Ar	296	0	0	296	0.00775	39.94800	0.01146
SO_2	0	0	0	0	0.00000	64.06380	0.00000
			Sum =	38,213			

TURBINE EXHAUST

E1	E10	E11	E12	E13	E14
Compound	Excess Air Molar Flow [A15]	Turbine Exhaust Molar Flow [E5] 1 [E10]	Wet Exhaust Mole Fraction [E11]/wetsum[E11]	Dry Exhaust Mole Fracion [E11]/drysum[E11]	Wet Turb Exh Mass Fraction [E11] 3 [E7]/TEF
N_2	46557	71255	0.71904	0.80865	0.71737
O_2	12490	12490	0.12603	0.14174	0.14363
CO_2	19	3517	0.03549	0.03991	0.05563
H_2O	1261	10981	0.11081		0.07110
Ar	558	855	0.00862	0.00970	0.01227
SO_2	0	0	0.00000	0.00000	0.00000
	Wet Sum =	99,098			
	Dry Sum =	88,117			

SHEET E

Fig. A-1-E Sample Calculation of Exhaust Compositions

DESCRIPTION:	PTC 22 SAMPLE CASE — ENTHALPY OF COMBUSTION PRODUCTS

CALCULATION OF ENTHALPY OF COMBUSTION PRODUCTS AT TURBINE EXIT

Exhaust Gas Temp = 1000 °F
810.9 K MAX = 1000 K

F1	F2	F3	F4
Compound	Stream Mass Fraction [A7]	Compound Enthalpy (eqns below)	[F2] × [F3]
N2	0.66993	236.190	158.230
O2	0.00000	217.754	0.000
CO2	0.14906	228.315	34.033
H2O	0.16955	439.747	74.560
Ar	0.01146	114.710	1.314
SO2	0.00000	162.700	0.000

Enthalpy at Process Temp (Ref = 77 F): Exh Enthalpy = 268.137 Btu/lb

Ref Temp = 80.0 °F
299.8 K

F11	F12	F13	F14
Compound	Stream Mass Fraction [A7]	Compound Enthalpy (eqns below)	[F12] × [F13]
N2	0.66993	0.745	0.499
O2	0.00000	0.658	0.000
CO2	0.14906	0.605	0.090
H2O	0.16955	1.336	0.227
Ar	0.01146	0.373	0.004
SO2	0.00000	0.446	0.000

Enthalpy at User Reference Temp: Exh Enthalpy = 0.820 Btu/lb

Enthalpy at Process Temp (Ref = User): 267.317 Btu/lb

Compound Enthalpies

$T_K = (T(°F) + 459.67)/1.8$

$H^o = [(-A_1/T_K + A_2\ln(T_K) + A_3T_K + A_4T_K^2/2 + A_5T_K^3/3 + A_6T_K^4/4 + A_7T_K^5/5 + A_8) * R - \Delta_fH^o]/MW/2.326$

Constituent	A_1	A_2	A_3	A_4	A_5	A_6	A_7	A_8	$\Delta_f H^o$	MW
N_2	22103.715	−381.846182	6.08273836	−0.008530914	1.38465E-05	−9.62579E-09	2.51971E-12	710.846086	0	28.01340
O_2	−34255.6342	484.700097	1.11901096	0.004293889	−6.83630E-07	−2.02337E-09	1.03904E-12	−3391.4549	0	31.99880
CO_2	49436.5054	−626.411601	5.30172524	0.002503814	−2.12730E-07	−7.68999E-10	2.84968E-13	−45281.9846	−393510	44.00950
H_2O	−39479.6083	575.573102	0.931782653	0.007222713	−7.34256E-06	4.95504E-09	−1.33693E-12	−33039.7431	−241826	18.01528
Ar	0	0	2.5	0	0	0	0	−745.375	0	39.94800
SO_2	−53108.4214	909.031167	−2.356891244	0.0220445	−2.51078E-05	1.44630E-8	−3.36907E-12	−41137.5212	−296810	64.06380

Enthalpy correlations adapted from McBride, B.J., Zehe, M.J., and Gordon S. (September 2002), NASA Glenn Coefficients for Calculating Thermodynamic Properties of Individual Species, NASA/TP-2002-211556. National Aeronautics and Space Administration, Glenn Research Center, Cleveland, Ohio.

SHEET F

Fig. A-1-F Sample Calculation of Enthalpy of Combustion Products at Turbine Exit

DESCRIPTION: PTC 22 SAMPLE CASE — MOIST AIR ENTHALPIES

CALCULATION OF MOIST AIR ENTHALPIES

Inlet Air Temp = 80 °F
299.8 K MAX = 1000 K

Extraction Air Temp = 600 °F
588.7 K

Exhaust Gas Temp = 1000 °F
810.9 K

1459.67

G1	G2	G3	G4
Compound	Stream Mass Fraction [A7]	Compound Enthalpy (eqns below)	[G2] × [G3]
N2	0.74538	0.745	0.555
O2	0.22841	0.658	0.150
CO2	0.00048	0.605	0.000
H2O	0.01299	1.336	0.017
Ar	0.01275	0.373	0.005
SO2	0.00000	0.446	0.000

G5	G6	G7
Stream Mass Fraction [A7]	Compound Enthalpy (eqns below)	[G5] × [G6]
0.74538	131.284	97.856
0.22841	119.351	27.261
0.00048	120.896	0.058
0.01299	240.835	3.127
0.01275	64.998	0.829
0.00000	87.035	0.000

G8	G9	G10
Stream Mass Fraction [E8]	Compound Enthalpy (eqns below)	[G8] × [G9]
0.74538	236.190	176.050
0.22841	217.754	49.737
0.00048	228.315	0.109
0.01299	439.747	5.710
0.01275	114.710	1.462
0.00000	162.700	0.000

Enthalpy at Process Temp (Ref = 77 F):

Inlet Air Enthalpy = 0.728 Btu/lb

Bleed Air Enthalpy = 129.131 Btu/lb

Exhaust Air Enthalpy = 233.070 Btu/lb

Ref Temp = 80.0 °F
299.8 K

Ref Temp = 80.0 °F
299.8 K

Ref Temp = 80.0 °F
299.8 K

539.67

G11	G12	G13	G14
Compound	Stream Mass Fraction [A7]	Compound Enthalpy (eqns below)	[G12] × [G13]
N2	0.74538	0.745	0.555
O2	0.22841	0.658	0.150
CO2	0.00048	0.605	0.000
H2O	0.01299	1.336	0.017
Ar	0.01275	0.373	0.005
SO2	0.00000	0.446	0.000

G15	G16	G17
Stream Mass Fraction [A7]	Compound Enthalpy (eqns below)	[G15] × [G16]
0.74538	0.745	0.555
0.22841	0.658	0.150
0.00048	0.605	0.000
0.01299	1.336	0.017
0.01275	0.373	0.005
0.00000	0.446	0.000

G18	G19	G20
Stream Mass Fraction [E8]	Compound Enthalpy (eqns below)	[G18] × [G19]
0.74538	0.745	0.555
0.22841	0.658	0.150
0.00048	0.605	0.000
0.01299	1.336	0.017
0.01275	0.373	0.005
0.00000	0.446	0.000

Enthalpy at User Reference Temp:

Inlet Air Enthapy = 0.728 Btu/lb

Extraction Air Enthalpy = 0.728 Btu/lb

Exhaust Air Enthalpy = 0.728 Btu/lb

Enthalpy at Process Temp (Ref = User): 0.000 Btu/lb 128.403 Btu/lb 232.342 Btu/lb

Change in Excess Air Enthalpy = 232.342 Btu/lb

Compound Enthalpies

$T_K = (T(°F) + 459.67)/1.8$

$H^o = [(-A_1/T_K + A_2 \ln(T_K) + A_3 T_K + A_4 T_k^2/2 + A_5 T_K^3/3 + A_6 T_K^4/4 + A_7 T_K^5/5 + A_8) * R - \Delta_f H^o]/MW/2.326$

Constituent	A_1	A_2	A_3	A_4	A_5	A_6	A_7	A_8	$\Delta_f H^o$	MW
N_2	22103.715	−381.846182	6.08273836	−0.008530914	1.38465E-05	−9.62579E-09	2.51971E-12	710.846086	0	28.01340
O_2	−34255.6342	484.700097	1.11901096	0.004293889	−6.83630E-07	−2.02337E-09	1.03904E-12	−3391.4549	0	31.99880
CO_2	49436.5054	−626.411601	5.30172524	0.002503814	−2.12730E-07	−7.68999E-10	2.84968E-13	−45281.9846	−393510	44.00950
H_2O	−39479.6083	575.573102	0.931782653	0.007222713	−7.34256E-06	4.95504E-09	−1.33693E-12	−33039.7431	−241826	18.01528
Ar	0	0	2.5	0	0	0	0	−745.375	0	39.94800
SO_2	−53108.4214	909.031167	−2.356891244	0.0220445	−2.51078E-05	1.44630E-8	−3.36907E-12	−41137.5212	−296810	64.06380

Enthalpy correlations adapted from McBride, B.J., Zehe, M.J., and Gordon S. (September 2002), NASA Glenn Coefficients for Calculating Thermodynamic Properties of Individual Species, NASA/TP-2002-211556. National Aeronautics and Space Administration, Glenn Research Center, Cleveland, Ohio.

SHEET G

Fig. A-1-G Sample Calculation of Moist Air Enthalpies

DESCRIPTION:	PTC 22 SAMPLE CASE — FUEL GAS SENSIBLE HEAT

CALCULATION OF FUEL GAS SENSIBLE HEAT

Fuel Gas Temp = 80 °F
299.8 K
539.67

Ref Temp = 80.0 °F
299.8 K
539.67

H1	H2	H3	H4
Compound	Stream Mass Fraction [A7]	Compound Enthalpy (eqns below)	[H2] × [H3]
CH_4	0.679	1.596	1.083
C_2H_6	0.168	1.253	0.210
C_3H_8	0.113	1.198	0.135
iso-C_4H_{10}	0.015	1.194	0.018
n-C_4H_{10}	0.015	1.219	0.018
iso-C_5H_{12}	0.004	1.183	0.004
n-C_5H_{12}	0.007	1.195	0.009
n-C_6H_{14}	0.000	1.188	0.000
N_2	0.000	0.745	0.000
CO	0.000	0.745	0.000
CO_2	0.000	0.605	0.000
H_2O	0.000	1.336	0.000
H_2S	0.000	0.720	0.000
H_2	0.000	10.252	0.000
He	0.000	3.721	0.000
O_2	0.000	0.658	0.000
Ar	0.000	0.373	0.000

Enthalpy at Process Temp (Ref = 77 F):

Fuel Gas Enthalpy = 1.477

H5	H6	H7	H8
Compound	Stream Mass Fraction [A7]	Compound Enthalpy (eqns below)	[H6] × [H7]
CH_4	0.679	1.596	1.083
C_2H_6	0.168	1.253	0.210
C_3H_8	0.113	1.198	0.135
iso-C_4H_{10}	0.015	1.194	0.018
n-C_4H_{10}	0.015	1.219	0.018
iso-C_5H_{12}	0.004	1.183	0.004
n-C_5H_{12}	0.007	1.195	0.009
n-C_6H_{14}	0.000	1.188	0.000
N_2	0.000	0.745	0.000
CO	0.000	0.745	0.000
CO_2	0.000	0.605	0.000
H_2O	0.000	1.336	0.000
H_2S	0.000	0.720	0.000
H_2	0.000	10.252	0.000
He	0.000	3.721	0.000
O_2	0.000	0.658	0.000
Ar	0.000	0.373	0.000

Enthalpy at User Reference Temp:

Fuel Gas Enthalpy = 1.477

Enthalpy at Process Temp (Ref = User): 0.000

Compound Enthalpies

$$T_K = (T(^\circ F) + 459.67)/1.8$$

$$H^o = [(-A_1/T_K + A_2\ln(T_K) + A_3T_K + A_4T_k^2/2 + A_5T_K^3/3 + A_6T_K^4/4 + A_7T_K^5/5 + A_8) * R - \Delta_f H^o]/MW/2.326$$

Constituent	A_1	A_2	A_3	A_4	A_5	A_6	A_7	A_8	$\Delta_f H^o$	MW
CH_4	−176685.0998	2786.18102	−12.0257785	0.039176193	−3.61905E-05	2.02685E-08	−4.97671E-12	−23313.1436	−74600	16.04246
C_2H_6	−186204.4161	3406.19186	−19.51705092	0.075658356	−8.20417E-05	5.06114E-08	−1.31928E-11	−27029.3289	−83851.544	30.06904
C_3H_8	−243314.4337	4656.27081	−29.39466091	0.118895275	−1.37631E-04	8.81482E-08	−2.34299E-11	−35403.3527	−104680	44.09562
iso-C_4H_{10}	−383446.933	7000.03964	−44.400269	0.174618345	−2.07820E-04	1.33979E-07	−3.55168E-11	−50340.1889	−134990	58.12220
n-C_4H_{10}	−317587.254	6176.33182	−38.9156212	0.158465428	−1.86005E-04	1.19968E-07	−3.20167E-11	−45403.6339	−125790	58.12220
iso-C_5H_{12}	−423190.339	6497.1891	−36.8112697	0.1532424473	−1.54879E-04	8.74990E-08	−2.07055E-11	−51554.1659	−153700	72.14878
n-C_5H_{12}	−276889.4625	5834.28347	−36.1754148	0.153333971	−1.52840E-04	8.19109E-08	−1.79233E-11	−46653.7525	−146760	72.14878
n-C_6H_{14}	−581592.67	10790.97724	−66.3394703	0.252371516	−2.90434E-04	1.80220E-07	−4.61722E-11	−72715.4457	−166920	86.17536
N_2	22103.715	−381.846182	6.08273836	−0.008530914	1.38465E-05	−9.62579E-09	2.51971E-12	710.846086	0	28.01340
CO	14890.45326	−292.2285939	5.72452717	−0.008176235	1.45690E-05	−1.08775E-08	3.02794E-12	−13031.31878	−110535.196	28.01010
CO_2	49436.5054	−626.411601	5.30172524	0.002503814	−2.12730E-07	−7.68999E-10	2.84986E-13	−45281.9846	−393510	44.00950
H_2O	−39479.6083	575.573102	0.931782653	0.007222713	−7.34256E-06	4.95504E-09	−1.33693E-12	−33039.7431	−241826	18.01528
H_2S	9543.80881	−68.7517508	4.05492196	−0.000301456	3.76850E-06	−2.23936E-09	3.08686E-13	−3278.45728	−20600	34.08088
H_2	40783.2321	−800.918604	8.21470201	−0.012697145	1.75361E-05	−1.20286E-08	3.36809E-12	2682.484665	0	2.01588
He	0	0	2.5	0	0	0	0	−745.375	0	4.002602
O_2	−34255.6342	484.700097	1.11901096	0.004293889	−6.83630E-07	−2.02337E-09	1.03904E-12	−3391.4549	0	31.99880
Ar	0	0	2.5	0	0	0	0	−745.375	0	39.94800

Enthalpy correlations adapted from McBride, B.J., Zehe, M.J., and Gordon S. (September 2002), NASA Glenn Coefficients for Calculating Thermodynamic Properties of Individual Species, NASA/TP-2002-211556. National Aeronautics and Space Administration, Glenn Research Center, Cleveland, Ohio.

SHEET H

Fig. A-1-H Sample Calculation of Fuel Gas Sensible Heat

DESCRIPTION:	PTC 22 SAMPLE CASE — FUEL TO COMBUSTOR

CALCULATION OF FUEL LHV

FUEL GAS

Fuel Temperature = 80 °F Reference Temp = 80 °F

J1	J2	J3	J4	J5	J6	J7
Compound	Fuel Mole Fraction	Mol. Wt.	[J2] × [J3]	Fuel Wt. Fraction = [J4]/Sum [J4]	Heat of Combustion Btu/lb	[J5] × [J6]
CH_4	0.8278	16.04246	13.279	0.679	21511.9	14599.9
C_2H_6	0.1092	30.06904	3.284	0.168	20429.2	3429.3
C_3H_8	0.0500	44.09562	2.205	0.113	19922.2	2244.9
iso-C_4H_{10}	0.0050	58.1222	0.291	0.015	19589.8	291.0
n-C_4H_{10}	0.0050	58.1222	0.291	0.015	19657.8	292.0
iso-C_5H_{12}	0.0010	72.14878	0.072	0.004	19455.9	71.7
n-C_5H_{12}	0.0020	72.14878	0.144	0.007	19497.2	143.8
n-C_6H_{14}	0.0000	86.17536	0.000	0.000	19392.9	0.0
N_2	0.0000	28.0134	0.000	0.000	0.0	0.0
CO	0.0000	28.0101	0.000	0.000	4342.2	0.0
CO_2	0.0000	44.0095	0.000	0.000	0.0	0.0
H_2O	0.0000	18.01528	0.000	0.000	0.0	0.0
H_2S	0.0000	34.08088	0.000	0.000	6533.8	0.0
H_2	0.0000	2.01588	0.000	0.000	51566.7	0.0
He	0.0000	4.002602	0.000	0.000	0.0	0.0
O_2	0.0000	31.9988	0.000	0.000	0.0	0.0
Ar	0.0000	39.948	0.000	0.000	0.0	0.0
		Sum =	19.566		Sum =	21072.5

Fuel Gas LHV (chemical energy only)	21,072.5	Btu/lb
Specific Enthalpy of Fuel at Process Temp	1.5	Btu/lb
Specific Enthalpy of Fuel at Ref Temp	1.5	Btu/lb
$HV_{gas} = LHV + SH_{Tfuel} - SH_{Tref}$	21,072.5	Btu/lb

LIQUID FUEL

LHV Input = 18500 Btu/lb

Liquid Fuel LHV (chemical energy only)	18,500.0	Btu/lb
Specific Enthalpy of Fuel at Process Temp = $T^2/4135 + 0.417*T - 25.9$	9.0	Btu/lb
Specific Enthalpy of Fuel at Ref Temp = $T^2/4135 + 0.417*T - 25.9$	9.0	Btu/lb
$HV_{oil} = LHV + SH_{Tfuel} - SH_{Tref}$	18,500.0	Btu/lb

FUEL LHV = 21,072.5

SHEET J

Fig. A-1-J Sample Calculation of Fuel LHV

DESCRIPTION: PTC 22 SAMPLE CASE — CORRECTED PERFORMANCE

SAMPLE TEST RESULT

All correction factors come from correction curves provided by the equipment manufacturer.

		Reference Case	Test Case
Measured Test Parameters			
Turbine Exhaust Flow, lb/h	m_{exh}	2,850,000	2,782,517
Turbine Exhaust Temperature, F	t_{exh}	985	1,000
Inlet Air Temperature, F	t_{air}	59	80
Barometric Pressure, psia	p_{air}	14.5	14.696
Inlet Humidity, %	RH	60	60
Injection Fluid Flow, lb/h	m_{inj}	55,000	50,000
Exhaust Flow Correction Factors			
Inlet Air Temperature	γ_1	1.0000	0.9500
Barometric Pressure	γ_2	1.0000	1.0135
Inlet Humidity	γ_3	1.0000	1.0000
Injection Fluid Flow	γ_5	1.0000	0.9985
Overall Correction Factor	$P\gamma_i$	*1.0000*	*0.9614*
Exhaust Temperature Correction Factors			
Inlet Air Temperature	d_1	0.0	18.0
Barometric Pressure	d_2	0.0	−4.0
Inlet Humidity	d_3	0.0	0.0
Injection Fluid Flow	d_5	0.0	−0.2
Overall Correction Factor	Sd_i	*0.0*	*13.8*
Corrected Test Results			
Turbine Exhaust Flow, lb/h	$m_{exh,corr}$	2,850,000	2,894,293
Exh Flow Margin, lb/h			44,293
Exh Flow Margin, %			1.55%
Turbine Exhaust Temperature, F	$t_{exh,corr}$	985.0	986.2
Exh Temp Margin, F			1.2

SHEET K

Fig. A-1-K Sample Corrected Performance Calculation

NONMANDATORY APPENDIX B
COMPARATIVE TESTING

B-1 INTRODUCTION

B-1.1 Application of Comparative Testing

PTC 22 has traditionally been applied for acceptance tests of new gas turbines. As the fleet of gas turbines has grown, there has been increased industry focus on obtaining the highest level of performance in existing gas turbines. Application of advanced gas path components developed by manufacturers for next generation gas turbines is a common method of achieving an uprate or additional performance from an existing gas turbine. Another common application of advanced technology is modifying the combustion process for improved emissions. Improvements to achieve additional performance are not confined to the gas path and may include changes to the inlet and exhaust systems of the gas turbine, such as the addition of inlet cooling devices or the addition of a heat recovery steam generator.

This Appendix provides guidance for conducting performance tests before and after completion of modifications to a gas turbine. This type of testing, known as comparative testing, has its own special consideration such as the partial cancellation of systematic errors when calculating differential performance. Comparative performance between pre- and post-tests will result in differential performance values with lower uncertainty than the individual absolute value performance uncertainties.

B-2 OBJECT AND SCOPE

B-2.1 Object

B-2.1.1 Guidelines are provided for the purpose of determining performance differentials for the gas turbine in situations where modifications have been made to the gas turbine and/or its surrounding package. This Nonmandatory Appendix allows the development of a simplified test method; however, it is still possible to use the main body of the code especially when uncertainties approach the expected performance gain. Testing per PTC 22 will result in absolute levels of performance with systematic and random errors completely identified. Comparative performance between pretest and post-test results obtained using the same test methods and instrumentation in accordance with the main body of PTC 22 will result in comparative test results with the minimum uncertainty. Guidelines in this appendix will result in measurement of relative performance with partial cancellation of systematic errors.

Results to be obtained are:

(a) Changes in power output and/or heat rate.

(b) Changes in exhaust flow, energy, and/or temperature (optional).

B-2.1.2 It is beyond the object of this code to distinguish the contribution of multiple actions, such as modifications, repairs, or cleanings. Therefore, the parties to the test will need to reach prior agreement as to how to account for performance changes that are the result of multiple actions taken during a common outage period.

B-2.2 Scope

B-2.2.1 Guidelines that are provided are those specially applicable to comparative testing of gas turbines. Provisions of the Code will be applicable in areas not covered by this Appendix.

B-2.2.2 Guidelines are confined to determining performance changes of the overall gas turbine. Methods of determining performance changes in individual gas path components are not provided.

B-3 DEFINITIONS AND DESCRIPTION OF TERMS

See Section 2 of this Code.

B-4 GUIDING PRINCIPLES

B-4.1 General Agreements Before Test

B-4.1.1 Uncertainty Level. The parties must decide beforehand whether a test can be designed with an uncertainty sufficiently small to meet all needs. The comparison test should have an uncertainty that is significantly lower that the performance benefit which is to be determined. Experience has shown that as-tested uncertainty can be a value as large or larger than the performance benefit to be verified resulting in an inconclusive test. In addition, the parties should realize that a cost/benefit analysis of the modification and its comparison test should determine the scope, cost and required accuracy of the test. It is left to the parties to the test to determine what uncertainty interval is appropriate.

B-4.1.2 Practical Considerations. The points listed below should be considered in the test preparation phase.

(a) Parties to the test should conduct a pretest uncertainty analysis that demonstrates that the expected performance benefit is higher than the calculated test uncertainty. To provide assurance that the test has accurately determined the change in performance, the test uncertainty must generally be no greater than 10% of the expected difference.

(b) Comparative performance between pre and post test results obtained using the same test instrumentation in accordance with the main body of PTC 22 will result in comparative test results with the minimum uncertainty. The systematic error for instruments used for both tests, without being disturbed or recalibrated, will approach zero for most cases.

(c) The scope of modification or restorative actions to the gas turbine or its envelope can permit comparative performance testing with a curtailed test scope without higher uncertainties than above.

(d) Since correcting the test data to specified reference conditions may be the largest contributor to the test uncertainty, corrections used should be limited to those needed to establish the objective. Rather than use a full set of envelope corrections around the test boundary as described in the main body of this test code, test parties can agree to a limited amount of correction factors based on the scope of modifications or restorative actions performed. For example, it may be advisable to correct the post-modification results to the same ambient, etc., conditions of the pre-mod test. This will eliminate one set of corrections, which additionally may be very advantageous since preparing accurate correction curves for a deteriorated turbine will likely be difficult.

(e) Repeat tests in both pre and post modifications states may be advisable to reduce the impact of random uncertainties in the performance comparison, particularly if the systematic errors have been minimized.

(f) With regard to the uncertainty associated with correcting pre-mod data, these curves may be verified by collecting test data from extended test periods that have enough variation in ambient conditions. Corrected results should not vary beyond the limits of random error.

B-4.2 Test Plan

B-4.2.1 A detailed test plan must be prepared prior to conducting a Code test. It will document agreements on all issues affecting the conduct of the test and provide detailed procedures for performing the test. It must reflect any contract requirements that pertain to the test objectives, guarantees, the schedule of test activities, responsibilities of the parties to the test, test procedures, or report of results, and provide any needed clarifications of contract issues. The test plan shall be approved, prior to the testing, by authorized signatures of all parties to the test. The test plan shall be in accordance with para. 3.1.6 of this Code.

B-4.3 Preparations for Test

B-4.3.1 Preliminary to Test. All parties to the test shall be given timely notification, as defined by prior agreement, to allow them the necessary time to respond and to prepare personnel, equipment, or documentation. Updated information should be provided to all parties, as it becomes available.

B-4.3.2 Pretest Records. Dimensions and physical conditions of parts of the gas turbine required for calculations or other test purposes shall be determined and recorded prior to the test. Serial numbers and data from nameplates should be recorded to identify the gas turbine and auxiliary equipment tested. All special instrumentation should be identified and model and serial numbers recorded. Documentation must be developed or be made available for calculated or adjusted data to provide independent verification of algorithms, constants, scaling, calibration corrections, offsets, base points, and conversions.

B-4.4 Pretest Considerations

B-4.4.1 The parties will have to agree on how the test results will be corrected. As discussed in para. B-4.1.2(d), it may be appropriate to correct post-modification performance to conditions of the pre-modification test since the manufacturer will usually provide a new description of sensitivity factors for the post-modification condition. Testing over an ambient temperature range in both the pre- and post-tests may provide additional basis for correcting results to a common reference condition although extreme care must be taken in the interpretation of this type of test result. In any case it would be advantageous to conduct both tests at nearly the same ambient conditions.

B-4.4.2 Most turbine modifications are designed to improve hot section performance. However it is common to do restorative action in other parts of the gas turbine package while it is in an outage period. Special cleaning of the compressor and replacement of inlet filters or damaged gas parts are examples of restorative action. The parties to a comparative test need to recognize the value of this additional restorative work and how it may be factored into the final results.

B-4.4.3 Testing should be conducted just prior to shut down for the outage and immediately following startup of the gas turbine at the conclusion of the outage. It is recommended that the pre-modification test be conducted following a compressor wash. The time frame for the test following such a wash is to be agreed to by all parties.

B-5 INSTRUMENTS AND METHODS OF MEASUREMENT

B-5.1 General Requirements

B-5.1.1 Agreement must be reached on the type of instrumentation (existing station instrumentation, test grade instrumentation, and/or calibrated to known standards or not) that will be used for the test. The use of plant grade instruments becomes possible in a comparative test due to the potential for reduced effect of systematic error in the uncertainty of performance differences. The reduced effect of systematic error is achieved by using the same instruments in both the pre-modification and post-modification tests, provided also that the systematic errors are known to remain constant in both pre- and post-tests.

B-5.2 Systematic Error Consideration

B-5.2.1 In some instruments systematic errors may not remain constant. Drift and sensitivity to conditions of ambient may be reasons for changing systematic error. To overcome this change in systematic error, it may be necessary to upgrade some instruments prior to pretest.

B-5.2.2 Re-calibration or other maintenance of instruments during the outage would be a cause for systematic error to change and should be avoided. Care must be taken with instruments that will be removed during the outage that they be replaced and used in the same manner in which they were used in the pretest.

B-5.2.3 Differences in the turbine control temperature determination may exist between the pre-modification and the post-modification test. This can change as a result of even changing one thermocouple during the outage. Change in the spatial distribution of this temperature due to modifications of the turbine or its operating condition (such as increased turbine inlet temperature or change in air management) is also likely. Since turbine power is so sensitive to any shift in control temperature, it may be advisable to install a new temperature measurement system prior to the pretest to retain minimum uncertainty.

B-5.2.4 Flow elements should not be cleaned or replaced during the outage. Again, any maintenance should be done *before* the pre-mod test.

B-6 COMPUTATION OF RESULTS

See Section 5 of this Code.

B-7 REPORT OF RESULTS

See Section 6 of this Code.

NONMANDATORY APPENDIX C
SAMPLE CALCULATIONS

This Appendix contains sample calculations for heat input (fuel flow, heating value, and sensible heat), electrical output, and corrected performance (output, heat rate, exhaust temperature, and exhaust flow).

C-1 CALCULATION OF HEAT INPUT

C-1.1 Gas Fuel Flow Test Data

Measurement	Symbol	Value
Flowing pressure	P_f	400 psia
Flowing temperature	T_f	80°F
Differential pressure	ΔP	111.24 “$H_2O_{68°F}$
Pipe diameter (measured)	D_{meas}	7.9991 in
Orifice diameter (measured)	d_{meas}	4.3495 in
Coefficient of discharge	C	0.6038
Pipe measurement temp	T_{meas}	68°F
Coefficient of thermal expansion for pipe	α_P	0.00000925 in/in-°F
Orifice measurement temperature	T_{meas}	68°F
Coefficient of thermal expansion for orifice	α_{PE}	0.00000925 in/in-°F

C-1.2 Gas Fuel Composition

Component	Formula	Molar Fraction	Component	Formula	Molar Fraction
Methane	CH_4	82.78%	n-Butane	C_4H_{10}	0.50%
Ethane	C_2H_6	10.92%	Isopentane	C_5H_{12}	0.10%
Propane	C_3H_8	5.00%	n-Pentane	C_5H_{12}	0.20%
Isobutane	C_4H_{10}	0.50%			

C-1.3 Temperature Compensated Pipe and Orifice Dimensions

$$\begin{aligned} d &= [1 + \alpha_{PE}(T_f - T_{meas})]d_{meas} \\ &= [1 + 0.00000925 \times (80 - 68)] \times 4.3495 = 4.3500 \text{ inches} \\ D &= [1 + \alpha_P(T_f - T_{meas})]D_{meas} \\ &= [1 + 0.00000925 \times (80 - 68)] \times 7.9991 = 8.0000 \text{ inches} \end{aligned}$$

C-1.4 Beta Ratio

$$\beta = d / D = 4.35 / 8.00 = 0.54375$$

C-1.5 Molecular Weight of Gas Mixture

$$MW_{gas} = \sum_{j=1}^{n} x_j * MW_j$$

Component	Molar Fraction (x_j)	Molecular Weight (MW_j)	(x_j*MW_j)
Methane	82.78%	16.043	13.280
Ethane	10.92%	30.069	3.284
Propane	5.00%	44.096	2.205
Isobutane	0.50%	58.122	0.291
n-Butane	0.50%	58.122	0.291
Isopentane	0.10%	72.149	0.072
n-Pentane	0.20%	72.149	0.144
Total			19.567

C-1.6 Isentropic Exponent

For typical natural gas compositions, the isentropic exponent ($\kappa = C_P/C_V$) can be assumed to be 1.3. A more detailed calculation can be performed as a function of the specific heat (C_P) as described in the following section.

$$\begin{aligned}\kappa &= C_P / (C_P - 1.986 / MW_{\text{gas}}) \\ &= 0.5188 / (0.5188 - 1.986 / 19.567) \\ &= 1.2432\end{aligned}$$

C-1.7 Specific Heat at Constant Pressure (C_p)

Specific heat at constant pressure is required to calculate the isentropic exponent for the flow equation. However, mass flow usually has a weak correlation with C_p. As a result, values for C_p generally can be obtained from GPSA or NIST publications at atmospheric pressure and fuel temperature. As a more accurate means for determining C_p, particularly in compositions where some of the higher species are liquid at actual fuel pressure, C_p should be calculated from mass averaging the Specific Heat values at the partial pressure of the constituents.

Component	Molar Fraction (x_j)	Partial Pressure (x_j*P)	Molecular Weight (MW_j)	(x_j*MW_j)	Specific Heat C_p (Note 1)	x_j*MW_j*C_P	$C_p = \Sigma x_j$*MW_j*C_P / Σx_j*MW_j
Methane	82.78%	331.12	16.043	13.280	0.56664	7.5252	
Ethane	10.92%	43.68	30.069	3.284	0.42789	1.4050	
Propane	5.00%	20.00	44.096	2.205	0.40779	0.8991	
Isobutane	0.50%	2.00	58.122	0.291	0.40019	0.1163	
n-Butane	0.50%	2.00	58.122	0.291	0.40787	0.1185	
Isopentane	0.10%	0.40	72.149	0.072	0.39968	0.0288	
n-Pentane	0.20%	0.80	72.149	0.144	0.40003	0.0577	
Total				19.567	3.0101	10.1508	0.5188

Note 1: Values for C_p are in units of Btu / lbm-R and were determined at 80°F and partial pressures from *NIST Standard Reference Database 69*, *March 2003 Release: NIST Chemistry Webbook*

C-1.8 Expansion Factor

$$\begin{aligned}\varepsilon &= 1 - (0.41 + 0.35\beta^4)\,\frac{\Delta P}{\kappa N_2 P_f} \\ &= 1 - (0.41 + 0.35 \times 0.54375^4)\,\frac{111.24}{1.2432 \times 27.73 \times 400} \\ &= 0.9964\end{aligned}$$

C-1.9 Velocity of Approach Factor

$$\begin{aligned}E_v &= \frac{1}{\sqrt{1 - \beta^4}} \\ &= \frac{1}{\sqrt{1 - 0.54375^4}} \\ &= 1.0468\end{aligned}$$

C-1.10 Gas Fluid Density

$$\rho_{T,P} = \frac{MW_{\text{gas}} P_f}{Z_f R T_f}$$

$$Z_f = 0.9246 \text{ (from AGA Report \#8)}$$

$$R = 10.7316 \text{ psi-ft}^3/(\text{lbmol-°R})$$

$$\begin{aligned}&= \frac{19.567 \times 400}{0.9246 \times 10.7316 \times 539.67} \\ &= 1.4616\end{aligned}$$

C-1.11 Reynolds Number and Coefficient of Discharge

The coefficient of discharge for a PTC 22 test comes from the meter calibration report. Extrapolation of calibration data, if required, is addressed in PTC 19.5.

The coefficient of discharge is a function of Reynolds number and therefore an iterative process. A mass flow rate is assumed, then Reynolds number calculated, then coefficient of discharge calculated, then the mass flow rate calculated. It typically only requires one or two iterations to converge on a coefficient from the calibration report

$$\begin{aligned} R_D &= M_f/(75\pi D\mu) \\ &= 54545.4\ /\ (235.61945 \times 8 \times 7.1674 \times 10^{-6}) \\ &= 4{,}037{,}340 \end{aligned}$$

where: μ is the dynamic viscosity in lbm/ft-sec, and can be typically be obtained by the same sources and methods given for C_P above.

C = 0.6038 based on the orifice calibration report.

C-1.12 Mass Flow Rate

$$\begin{aligned} M_f &= N_1 d^2 C\epsilon E_\nu \sqrt{\rho_{T,P}\Delta P} \\ &= 0.0997019 \times 4.35^2 \times 0.6038 \times 0.9964 \times 1.0468\sqrt{1.4616 \times 111.24} \\ &= 15.1515 \text{ lb/sec} \\ &= 54{,}545.4 \text{ lb/hr} \end{aligned}$$

C-1.13 Lower Heating Value

$$\text{LHV} = \sum_{j=1}^{n} x_j MW_j \text{LHV}_j \Big/ \sum_{j=1}^{n} x_j MW_j$$

LHV = 21,072 Btu / lbm

Component	Formula	Molar Fraction (x_j)	Molecular Weight (M_j)	(x_j*M_j)	Net Heating Value (h_j)	x_j*M_j*h_j	Σx_j*M_j*$h_j/\Sigma x_j$*M_j
Methane	CH_4	82.78%	16.043	13.280	21511.9	285687	
Ethane	C_2H_6	10.92%	30.069	3.284	20429.2	67080	
Propane	C_3H_8	5.00%	44.096	2.205	19922.2	43924	
Isobutane	C_4H_{10}	0.50%	58.122	0.291	19589.8	5693	
n-Butane	C_4H_{10}	0.50%	58.122	0.291	19657.8	5713	
Isopentane	C_5H_{12}	0.10%	72.149	0.072	19455.9	1404	
n-Pentane	C_5H_{12}	0.20%	72.149	0.144	19497.2	2813	
Total		100.00%		19.567		412314	21072

C-1.14 Higher Heating Value

$$\text{HHV} = \sum_{j=1}^{n} x_j MW_j \text{HHV}_j \Big/ \sum_{j=1}^{n} x_j MW_j$$

HHV = 23,269 Btu/lbm

Component	Formula	Molar Fraction (x_j)	Molecular Weight (MW_j)	(x_j*MW_j)	Gross Heating Value (H_j)	x_j*MW_j*H_j	Σx_j*MW_j*$H_j/\Sigma x_j$*MW_j
Methane	CH_4	82.78%	16.043	13.280	23892.2	317298	
Ethane	C_2H_6	10.92%	30.069	3.284	22334.1	73335	
Propane	C_3H_8	5.00%	44.096	2.205	21654.1	47743	
Isobutane	C_4H_{10}	0.50%	58.122	0.291	21232.3	6170	
n-Butane	C_4H_{10}	0.50%	58.122	0.291	21300.2	6190	
Isopentane	C_5H_{12}	0.10%	72.149	0.072	21043.7	1518	
n-Pentane	C_5H_{12}	0.20%	72.149	0.144	21085.0	3043	
Total		100.00%		19.567		455297	23269

C-1.15 Sensible Heat

The heat rate for this sample calculation includes the consideration of sensible heat with an actual fuel temperature of 80°F, and a specified reference fuel temperature of 60°F. The simplified equation in para. 5.3.1.11 may be used. From that equation, $h_T = 11.4$ Btu/lb, and $h_{\text{Ref}} = 0$ Btu/lb.

$$\begin{aligned} SH &= M_f\,(h_T - h_{\text{Ref}}) \\ &= 54{,}545.4 \times (11.4 - 0) = 621{,}818 \text{ Btu/h} \end{aligned}$$

C-1.16 Total Heat Input (LHV)

$$\begin{aligned} HI &= \text{LHV} \times M_f + SH \\ &= 21{,}072 \times 54{,}545.4 + 621{,}818 = 1150.0 \text{ MMBtu/h} \end{aligned}$$

C-2 CALCULATION OF ELECTRICAL OUTPUT

This section provides a sample calculation of the test electrical output for a 3-wattmeter method.

C-2.1 VT Test Data

	Label	Units	Phase 1	Phase 2	Phase 3
VT voltage (measured)	V	VAC	69.28	68.95	69.63
VT current (measured)	I	mA	360	350	410
VT VA(=VxI/1000)	Bc	VA	24.941	24.133	28.548
VT phase angle (measured)	PAc	deg.	8	0	12
VT Power factor (=cos(PA))	PF	ratio	0.990268	1	0.978148

C-2.2 VT Calibration Data

	Label	Units	Phase 1	Phase 2	Phase 3
Burden at Zero	Bo	VA	0	0	0
Burden at Calibration Test Point (Z)	Bt	VA	200	200	200
Power factor at Calibration Test Point (Z)	PFt	Ratio	0.85	0.85	0.85
Phase Angle at Calibration Test Point (Z)	PAt	deg.	31.78833	31.78833	31.78833
RCF at 0 VA	RCFo	Ratio	0.99765	0.99784	0.99760
RCF at 200 VA, 0.85 PF	RCFt	Ratio	1.00105	1.00240	1.00191
Phase Angle error at 0 VA	γo	min.	0.61	1.30	0.75
Phase Angle error at 200 VA, 0.85 PF	γt	min.	−0.46	−2.25	−2.48
RCF difference = RCFt-RCFo	RCFd	ratio	0.0034	0.00456	0.00431
Phase Angle difference = γt − γo	γd	min.	−1.07	−3.55	−3.23
Ratio Correction Factor	VTRCFc	ratio	0.998022	0.998242	0.998133
Simplified RCF (see explation below)	VTRCFs	ratio	0.998074	0.998390	0.998215
Complete formula:					
VTRCFc = RCFo + [Bc/Bt][RCFd × cos(PAt-PAc) + (1/3428) × sin(PAt − PAc) × γd)]					
simplified formula, ignoring PF and PA errors					
VTRCFs = RCFo+[Bc/Bt] × RCFd					
Added uncertainty due to simplification	UVTRCFs	%	0.027125	0.003838	0.021656

C-2.3 VT Voltage Drop

	Label	Units	Phase 1	Phase 2	Phase 3
Voltmeter 1 at VT	V1o	VAC	69.28		
Voltmeter 2 at VT	V2o	VAC	69.14		
VM difference (=V1o-V2o)	Vd	VAC	0.14	0.14	0.14
Voltmeter 1 at VT	V1t	VAC	69.28	68.95	69.63
Voltmeter 2 at Test watt meter	V2t	VAC	69.12	68.77	69.43
Corrected Reading at Test Watt Meter					
V2c = (V2t + Vd)	V2c	VAC	69.26	68.91	69.57
Voltage drop (=V1t − V2c)	VTVD	VAC	0.02	0.04	0.06
Voltage Drop Correction Factor					
VTVDC = 1 + VTVD/V1t	VTVDC	ratio	1.000289	1.00058	1.000862

C-2.4 CT Corrections

	Label	Units	Phase 1	Phase 2	Phase 3
CT measured	I	amps	4875.515	4875.515	4875.515
CT rated Current	Ir	amps	8000	8000	8000
CT percent of Rating	Ip	%	60.94394	60.94394	60.94394
Ratio Correction Factor (from calibration curve)	CTRCFc	ratio	1.00014	1.00014	1.00014

C-2.5 Gross Generation

	Label	Units	Phase 1	Phase 2	Phase 3
Secondary Watts at Meter (measured)	SW	Watts	209.0553	210.1042	207.5398
Voltage Drop Correction Factor	VTVDC	ratio	1.000289	1.00058	1.000862
Secondary Watts at VT:					
SWvt = SW × VTVDC	SWvt	Watts	209.1156	210.2261	207.7186
Simplified VTRCF	VTRCFs	ratio	0.998293	0.99828	0.99835
Phase Angle Correction Factor, PACF$_C$					
Apparent Primary Side Power Factor (includes the transformer	$\cos(\theta_2)$	ratio	0.9998	1.0000	0.9958
phase shift errors) arccosine (Apparent Power Factor)	θ_2	radians	0.0200	0.0000	0.0917
Power Meter Phase Shift, α	α	minutes	20.9	20.3	20.5
CT Phase Shift, β	β	minutes	7	2	5
VT Phase Shift, γ	γ	minutes	−3	−1	0
Total Secondary Side Phase Shift	$-\alpha + \beta - \gamma$	minutes	10.9	3.3	5.5
Total Phase Shift, in radians (multiply by PI /(180*60))	$-\alpha + \beta - \gamma$	radians	0.0032	0.0010	0.0016
PACF$_C$ = $\cos(\theta_2 - \alpha + \beta - \gamma)/\cos(\theta)$	PACF$_C$	ratio	0.999932	1.000000	0.999852

GENERAL NOTES:

(a) The Phase Angle Correction Factor, PACF$_C$, can be made negligible by testing near unity power factor, as shown in this example.

(b) Apparent Power Factor includes the transformer phase shift errors, that is, $\cos(\theta_2)$ is based on meters that have not been corrected for transformer errors. (True PF = $\cos(\theta)$, where $\theta = \theta_2 - \alpha + \beta - \gamma$)

(c) According to ASA standards:
Alpha (α) is positive when the current in the wattmeter potential circuit leads the voltage.
Beta (β) is positive when the reversed secondary current leads the primary current.
Gamma (γ) is positive when the reversed secondary voltage leads the primary voltage.

C-2.6 Corrected Secondary Watts

	Label	Units	Phase 1	Phase 2	Phase 3
SWc = SWvt × VTRCFs × PACF × CTRCFc	SWc	Watts	208.773 7	209.8939	207.374
VT Marked Ratio	VTR	ratio	120	120	120
CT Marked Ratio	CTR	ratio	1600	1600	1600
Corrected Primary watts					
PWc = SWc × VTR × CTR /1000	PWc	kW	40084.55	40299.63	39815.8
Measured Power					120,200.0

C-3 CALCULATION OF CORRECTED PERFORMANCE (OUTPUT, HEAT RATE, EXHAUST TEMPERATURE, AND EXHAUST FLOW)

Parameter	Test Condition	Specified Reference Condition	Output Correction Factor α	Heat Rate Correction Factor β	Exhaust Flow Correction Factor γ	Exhaust Temperature Correction Factor δ
Inlet temperature (°F)	80.0	68.0	0.9580	1.0123	0.9704	−9.0
Inlet pressure (psia)	14.696	14.500	1.0137	0.9991	1.0139	0.0
Inlet humidity (%)	60	70	1.0000	0.9991	1.0009	0.0
Fuel supply composition	see below	see below	0.9990	1.0003	1.0001	0.0
Fuel temperature (°F)	80	60	1.0000	0.9991	1.0000	0.0
Injection fluid (lb/hr)	50,000	45,000	1.0048	1.0019	1.0015	1.0
Injection fluid enthalpy (BTU/lb)	168.4	168.4	1.0000	1.0000	1.0000	0.0
Injection fluid composition	H_2O	H_2O	1.0000	1.0000	1.0000	0.0
Exhaust pressure (in. w.g.)	14.0	15.0	1.0016	0.9981	1.0000	1.0
Shaft speed (rpm)	3,600	3,600	1.0000	1.0000	1.0000	0.0
Turbine extraction flow (lb/hr)	10,000	10,000	1.0000	1.0000	1.0000	0.0
Equivalent operating hours	350	200	0.9984	1.0009	0.9996	−0.3
Overall correction factor			0.9749	1.0107	0.9860	−7.3

Fuel Analysis (vol %)	Test Condition	Specified Reference Condition
Methane	82.78	86.20
Ethane	10.92	8.60
Propane	5.00	4.10
Iso-butane	0.50	0.40
n-Butane	0.50	0.40
iso-Pentane	0.10	0.15
n-Pentane	0.20	0.15

GENERAL NOTE: The correction factor was determined from the manufacturer's model.

Parameter	Test Condition	Specified Reference Condition	Output Correction Factor
Generator power factor	0.99	0.90	235
Generator hydrogen pressure	n/a	n/a	n/a
Generator hydrogen purity	n/a	n/a	n/a
Overall correction factor			235

Corrected Power		*Corrected Heat Rate*	
P_{meas}	120,200	HR_{calc}	9,567
P_{corr}	123,050	HR_{corr}	9,466

Corrected Exhaust Flow		*Corrected Exhaust Temperature*	
EF_{calc}	2,874,980	ET_{meas}	1,000.0
EF_{corr}	2,915,902	ET_{corr}	992.7

C-4 CALCULATION OF TRANSFORMER LOSS

The losses through a transformer are determined by:

$$\text{Loss}_{\text{TOTAL}} = \text{Loss}_{\text{NO-LOAD}} + \text{Loss}_{\text{LOAD}}$$

where

$\text{Loss}_{\text{TOTAL}}$ = total transformer losses in kW

$\text{Loss}_{\text{NO-LOAD}}$ = transformer no-load losses in kW.

$\text{Loss}_{\text{LOAD}}$ = transformer load losses in kW.

$\text{Loss}_{\text{NO-LOAD}}$ 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

$L_{2\ \text{CORR}}$ = Stray load losses (kW), corrected to reference conditions

The load losses vary with winding temperature, oil temperature, ambient conditions, voltage, and load. Therefore, the values for the load losses taken from the shop test report need to be corrected. The following formula, derived from IEEE C57.12.90, corrects for these conditions:

$$L_{1\ \text{CORR}} = L_1 \times n \times K \times \left(\frac{T_K + T_M}{T_K + T_R}\right)\left(\frac{T_K + T_{MC}}{T_K + T_M}\right)$$

$$L_{2\ \text{CORR}} = L_2 \times n \times K \times \left(\frac{T_K + T_R}{T_K + T_M}\right)\left(\frac{T_K + T_M}{T_K + T_{MC}}\right)$$

where

L_1 = I^2R Losses (kW) from factory test report at rated load with rated winding temperature (T_R)

L_2 = Stray Load Losses (kW) from factory test report at rated load and rated winding temperature (T_R)

n = Load Correction Ratio, dimensionless

K = Voltage correction ratio, dimensionless

T_K = Transformer Material Correction factor
(Copper = 234.5°C)

T_M = Average winding temperature at prevailing ambient temperature, (°C), from calculation below
T_R = Rated Winding Temperature, (°C) from factory test report
T_{MC} = Average winding temperature, corrected to reference ambient temperature, (°C), from calculation below

To determine n and K:

$$n = \left(\frac{\text{Test Load}}{\text{Rated Load}}\right)^2$$

$$K = \left(\frac{\text{Rated Voltage}}{\text{Test Voltage}}\right)^2$$

The test load (kVA), in kVA, and test voltage (V), in kV, are determined from the power and voltage measurements, collected as test data. The rated load (kVA), in kVA, and voltage (V), in kV, are from the factory test reports. Rated voltage is a phase to phase value, so a Sqrt 3 factor is applied to the measured phase to ground voltage measurement.

$$\text{Test Load} = \left(\frac{P_{\text{MEAS}}}{PF_{\text{MEAS}}}\right) - \left(\frac{P_{\text{Line Loss}} + P_{\text{AUX MEAS}}}{PF_{\text{MEAS}}}\right)$$

where
P_{MEAS} = measured active power, in kW, at the generator terminals
PF_{MEAS} = generator power factor at test conditions, dimensionless
$P_{\text{AUX MEAS}}$ = measured auxiliary loads, if any, between power measurement and low side of the transformer, kW
$P_{\text{LINE LOSS}}$ = line losses between power measurement and low side of the transformer, in kW

$$\text{Test Voltage} = \text{V}_{\text{MEAS}} \times \text{PT RATIO} \times \sqrt{3}$$

where
V_{MEAS} = measured secondary voltage, in kV, at the low side of the transformer, adjusted for meter errors as necessary (phase to ground)
VT RATIO = from Instrument transformer design data.

To determine the average winding temperature, T_M, from IEEE C57.12.90:

$$T_M = T_C + T_{OM}$$

where
T_C = corrected difference between average winding temperature and the oil temperature (°C), measured in the filled oil thermometer pocket
T_{OM} = measured oil temperature (°C), measured in the filled oil thermometer pocket

T_C is determined by:

$$T_C = T_O \times \left(\frac{\text{Test Load}}{\text{Rated Load}}\right)^{2\text{m}}$$

where
T_O = measured difference between average winding temperature (from Factory test report) and the oil temperature (°C), measured in the filled oil thermometer pocket at rated load (from factory test report).
m = 1.0 for main step up transformer, 0.8 for auxiliary transformer

The average winding temperature is measured between the high voltage winding and the low voltage winding.

To determine the winding temperature, corrected for differences in ambient temperature (T_{MC}), the following equations are used:

$$T_{MC} = T_M + (T_A - T_{AM})$$

where
T_A = ambient temperature at rated conditions (°C), (conditions upon which transformer losses are based, from Factory test report)
T_{AM} = measured ambient temperature (°C)

NONMANDATORY APPENDIX D
REFERENCES

ASME PTC 1 General Instructions
ASME PTC 2 Definitions and Values
ASME PTC 19.1 Test Uncertainty
ASME PTC 19.2 Instruments and Apparatus: Part 2 Pressure Measurement
ASME PTC 19.3 Temperature Measurement
ASME PTC 19.5 Flow Measurement
ASME PTC 46 Overall Plant Performance
ASME Steam Tables

ASTM D 1945 Standard Test Method of Analysis of Natural Gas by Gas Chromatography
ASTM D 1142 Standard Test Method for Water Vapor Content of Gaseous Fuels by Measurement of Dew-Point Temperature
ASTM D 3588 Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density for Gaseous Fuels
ASTM D 445 Standard Test Method of Kinematic Viscosity of Transparent and Opaque Liquids (the Calculation of Dynamic Viscosity)
ASTM D 4809 Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (Precision Method)
ASTM D 1018 Hydrogen in Petroleum Fractions
ASTM D 4057 Standard Practice for Manual Sampling of Petroleum and Petroleum Products
Coleman, H.W., W.G. Steele, and R.P. Taylor, "Implications of Correlated Bias Uncertainties in Single and Comparative Tests," *Transactions of the ASME Journal of Fluids Engineering* 117 (December 1995): 552–556.

GPA 2145 Table of Physical Constants for Hydrocarbons and Other Compounds of Interest to the Natural Gas Industry
GPA 2166 Obtaining Natural Gas Samples
GPSA Engineering Data Book

IEEE 120 IEEE Master Test Guide for Electrical Measurements in Power Circuits
IEEE C57.12.90 Standard Test Code for Liquid-Immersed Distribution, Power, and Regulating Transformers
IEEE C57.13 IEEE Standard Requirements for Instrument Transformers

NONMANDATORY APPENDIX E
UNIT CONVERSION FACTORS

This table contains the factors for converting U.S. Customary units used in this Code, to units in the SI system (modified to reflect more frequently used times and kilo levels).

Quantity	Conversion	Multiplication Factor
Density ρ	lbm/cu.ft to kg/cu.m	16.01846
Gas constant R	ft.lbf/lbm°R to J/kg °K	5.380320
Heat Q	Btu to J	1055.056
Heat input	Btu/hr to Watts	0.2930711
Heat rate	Btu/kWhr to kJ/kWhr	1.055056
	Btu/hphr to kJ/kWhr	1.414853
Heat value	Btu/lb to J/kg	2326.000
	Btu/cu.ft to J/cu.m	37258.94
Length	in. to m.	0.025400
Mass	lbm. to kg	0.4535924
Power	hp to kW	0.7456999
Pressure	lbf/sq.in. to kPa	6.894757
Temperature	F to C	C = (F − 32)/1.8
	R to K	K = R/1.8
Torque	lbf.ft to Nm	1.355818
Volume	cu.ft to cu.m	0.02831685
	gallons to cu.m	0.003785412

PERFORMANCE TEST CODES (PTC)

General Instructions	PTC 1-2004
Definitions and Values	PTC 2-2001
Diesel and Burner Fuels	PTC 3.1-1958 (R1992)
Fired Steam Generators	PTC 4-1998
Steam-Generating Units (With 1968 and 1969 Addenda)	PTC 4.1-1964 (R1991)
Diagram for Testing of a Steam Generator, Figure 1 (Pad of 100)	
Heat Balance of a Steam Generator, Figure 2 (Pad of 100)	
ASME Test Form for Abbreviated Efficiency Test — Summary Sheet (Pad of 100)	PTC 4.1a-1964
ASME Test Form for Abbreviated Efficiency Test — Calculation Sheet (Pad of 100)	PTC 4.1b-1964 (R1965)
Coal Pulverizers	PTC 4.2-1969 (R2003)
Air Heaters	PTC 4.3-1968 (R1991)
Gas Turbine Heat Recovery Steam Generators	PTC 4.4-1981 (R2003)
Reciprocating Steam Engines	PTC 5-1949
Steam Turbines	PTC 6-2004
Interim Test Codes for an Alternative Procedure for Testing Steam Turbines	PTC 6.1-1984
Steam Turbines in Combined Cycles	PTC 6.2-2004
Appendix A to PTC 6, The Test Code for Steam Turbines	PTC 6A-2000
PTC 6 on Steam Turbines — Interpretations	PTC 6
Guidance for Evaluation of Measurement Uncertainty in Performance Tests of Steam Turbines	PTC 6 Report-1985 (R2003)
Procedures for Routine Performance Tests of Steam Turbines	PTC 6S-1988 (R2003)
Reciprocating Steam-Driven Displacement Pumps	PTC 7-1949 (R1969)
Displacement Pumps	PTC 7.1-1962 (R1969)
Centrifugal Pumps	PTC 8.2-1990
Performance Test Code on Compressors and Exhausters	PTC 10-1997 (R2003)
Fans	PTC 11-1984 (R2003)
Closed Feedwater Heaters	PTC 12.1-2000
Performance Test Code on Steam Surface Condensers	PTC 12.2-1998
Performance Test Code on Deaerators	PTC 12.3-1997 (R2004)
Moisture Separator Reheaters	PTC 12.4-1992 (R2004)
Single Phase Heat Exchangers	PTC 12.5-2000
Reciprocating Internal-Combustion Engines	PTC 17-1973 (R2003)
Hydraulic Turbines and Pump-Turbines	PTC 18-2002
Test Uncertainty	PTC 19.1-1998 (R2004)
Pressure Measurement	PTC 19.2-1987 (R2004)
Temperature Measurement	PTC 19.3-1974 (R2004)
Application, Part II of Fluid Meters: Interim Supplement on Instruments and Apparatus	PTC 19.5-2004
Weighing Scales	PTC 19.5.1-1964
Electrical Measurements	PTC 19.6-1955
Measurement of Shaft Power	PTC 19.7-1980 (R1988)
Measurement of Indicated Power	PTC 19.8-1970 (R1985)
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Measurement of Rotary Speed	PTC 19.13-1961
Linear Measurements	PTC 19.14-1958
Density Determinations of Solids and Liquids	PTC 19.16-1965
Determination of the Viscosity of Liquids	PTC 19.17-1965
Digital Systems Techniques	PTC 19.22-1986 (R2003)
Guidance Manual for Model Testing	PTC 19.23-1980 (R1985)
Speed and Load Governing Systems for Steam Turbine-Generator Units	PTC 20.1-1977 (R1988)
Overspeed Trip Systems for Steam Turbine-Generator Units	PTC 20.2-1965 (R1986)
Pressure Control Systems Used on Steam Turbine-Generator Units	PTC 20.3-1970 (R1991)
Particulate Matter Collection Equipment	PTC 21-1991
Gas Turbines	PTC 22 2005
Atmospheric Water Cooling Equipment	PTC 23-2003
Ejectors	PTC 24-1976 (R1982)
Pressure Relief Devices	PTC 25-2001
Safety and Relief Valves	PTC 25.3-1988
Speed-Governing Systems for Internal Combustion Engine-Generator Units	PTC 26-1962
Determining the Properties of Fine Particulate Matter	PTC 28-1965 (R1985)

(continued)

Speed-Governing Systems for Hydraulic Turbine-Generator Units	PTC 29-2005
Air Cooled Heat Exchangers	PTC 30-1991 (R1998)
Ion Exchange Equipment	PTC 31-1973 (R1985)
Nuclear Steam Supply Systems	PTC 32.1-1969 (R1992)
Methods of Measuring the Performance of Nuclear Reactor Fuel in Light Water Reactors	PTC 32.2 Report-1978 (R1992)
Large Incinerators	PTC 33-1978 (R1985)
Appendix to PTC 33-1978	PTC 33a-1980 (R1991)
ASME Form for Abbreviated Incinerator Efficiency Test	PTC 33a-1980 (R1991)
Measurement of Industrial Sound	PTC 36-2004
Determining the Concentration of Particulate Matter in a Gas Stream	PTC 38-1980 (R1985)
Steam Traps	PTC 39-2005
Flue Gas Desulfurization Units	PTC 40-1991
Wind Turbines	PTC 42-1988 (R2004)
Performance Test Code on Overall Plant Performance	PTC 46-1996
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Performance Monitoring Guidelines for Steam Power Plants	PTC PM-1993

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