ASME PTC 46-2015

(Revision of ASME PTC 46-1996)

Overall Plant Performance

Performance Test Codes

AN AMERICAN NATIONAL STANDARD

The American Society of Mechanical Engineers

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Two Park Avenue • New York, NY • 10016 USA

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

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

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NOTICE

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

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

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

FOREWORD

ASME Performance Test Codes (PTCs) have been developed and have long existed for determining the performance of most major components used in electric power production facilities. These major component focused performance test codes served the industry well until changes in the electric power generation industry exposed the need for a code addressing overall power plant performance testing. In response to these needs, the ASME Board on Performance Test Codes approved the formation of a committee (ASME PTC 46) in June 1991 with the charter of developing a code for the determination of overall power plant performance. The organizational meeting of this Committee was held in September 1991. The resulting Committee included experienced and qualified users, manufacturers, and general interest category personnel from both the regulated and non-regulated electric power generating industry.

In developing the first issue of this Code, the Committee reviewed common industry practices with regard to overall power plant and cogeneration facility testing. The Committee was not able to identify any general consensus testing methods, and discovered many conflicting philosophies. The Committee has strived to develop an objective code which addresses the multiple needs for explicit testing methods and procedures, while attempting to provide maximum flexibility in recognition of the wide range of plant designs and the multiple needs for this Code.

The first edition of ASME PTC 46 was found to be very beneficial to the industry, as predicted. It was applied around the world by reference in contracts, as well as applied as the basis of ongoing plant performance engineering activities.

The committee members met about seven years after the initial publication to discuss lessons-learned from experience with code applications that required strengthening or otherwise modifying the Code. New members with extensive experience using the Code were at that time brought on to the committee.

All sections were revamped, based on the lessons-learned study and industry assessment, to clarify unforeseen misinterpretations and to add more necessary information.

Section 3 was revised to sharpen the descriptions of the fundamental principles used for an overall plant performance test, and to present information in a more organized fashion.

Section 4 was rewritten. The instrumentation technology was brought up-to-date, and more in-depth information was provided for each type of instrument, including harmonization with ASME PTC 19.5. ASME PTC 46 was the first ASME Performance Test Code to clearly differentiate between calculated variables and measured parameters, and classify them as primary or secondary. Instrumentation requirements were thus determined as being Class 1 or Class 2. As such, selection of instrumentation was made more structured, economical, and efficient. This information was clarified further in the Section 4 revision. Details concerning calibration methodology both in the instrumentation laboratory as well as for field calibrations were also added to Section 4.

Details regarding application of the generalized performance equations to specific power technologies and test goals have been clarified and expanded in Section 5, providing additional guidance for various types of plants and cycles. In the decade and a half since the publication of the original version of this Code, the industry has had sufficient time to study the uncertainty implications of testing plants with the inlet air conditioning equipment in service and also to accrue a significant body of practical experience in the application of the Code. These developments have led the authors to conclude that testing with inlet air conditioning equipment in service can be accomplished within required considerations of practicality and test uncertainty. Based on this, Section 5 was revised to recommend testing with the inlet air conditioning systems configured to match the reference conditions provided the ambient conditions allow. The combined cycle plant phase testing methodology was updated to account for additional parameters when going from simple cycle to combined cycle operation and incorporates the use of "non-phased" CC plant correction curves in combination with GT correction curves, which leads to a more accurate test result while providing more usability for the set of correction curves. Section 5 also provides more background on development of correction curves from integrated heat balance computer models as opposed to non-integrated heat balance computer models of Rankine cycle power plants. By integrated model, it is meant that the steam generator is integrated into the heat balance computer model. Additionally, Nonmandatory Appendix H was added to define a methodology to determine part load test corrected heat rate at a specified reference condition. More direction is given for testing Rankine cycle power plants in Nonmandatory Appendix E, with two new detailed sample calculations (one using an integrated model and one using a non-integrated model) given in the appendices for a coal-fired steam power plant.

A far more detailed uncertainty analysis was published than in the previous edition, and is in harmony with ASME PTC 19.1. Detailed explanations are provided for each step of the calculation in Nonmandatory Appendix F.

Lastly, ASME PTC 46 was perceived by some in the industry who had only passing acquaintance with it as being applicable to combined cycle power plants only. The strengthening of Section 5 applications to Rankine cycles and the more thorough coal-fired plant sample calculations should go far to change that perception. Performance test engineers who are experienced users of the Code also recognize the applicability of the generalized performance equations and test methods of ASME PTC 46 to tests of nuclear steam cycles or, to the thermal cycle of solar power plants, and other power generation technologies. The committee has added language to the Code to confirm its applicability to such technologies, and looks forward to adding sample calculations for nuclear, thermal solar, geothermal, and perhaps other power generation technologies in the next revision.

This Code was approved by the PTC 46 Committee and the PTC Standards Committee on March 12, 2015. It was then approved as an American National Standard by the American National Standards Institute (ANSI) Board of Standards Review on September 25, 2015.

ASME PTC COMMITTEE
Performance Test Codes

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

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The Committee Personnel wish to express their sincere thanks to Mr. Jeffrey Russell Friedman for the defining role he has played in the development of this Code.

Before his passing on August 24, 2012, Jeff acted with great passion and leadership in his role of Committee Chair.

CORRESPONDENCE WITH THE PTC COMMITTEE

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

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

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

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

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

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

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

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

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

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

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

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

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

INTRODUCTION

APPLICATIONS AND LIMITATIONS

This Test Code provides explicit procedures for the determination of power plant thermal performance and electrical output. Test results provide a measure of the performance of a power plant or thermal island at a specified cycle configuration, operating disposition and/or fixed power level, and at a unique set of base reference conditions.

Test results can then be used as defined by a contract for the basis of determination of fulfillment of contract guarantees. Test results can also be used for comparison to a design number, to trend performance changes over time, to help evaluate possible modifications or to validate them, or for any application in which the overall plant performance is needed.

The results of a test conducted in accordance with this Code will not provide the sole basis for comparing the thermo-economic effectiveness of different plant designs, or to compare different generation technologies.

Power plants, which produce secondary energy outputs, i.e., cogeneration facilities, are included within the scope of this Code. For cogeneration facilities, there is no requirement for a minimum percentage of the facility output to be in the form of electricity; however, the guiding principles, measurement methods, and calculation procedures are predicated on electricity being the primary output. As a result, a test of a facility with a low proportion of electric output may not be capable of meeting the maximum allowable test uncertainties of this Code.

Power plants are comprised of many equipment components. Test data required by this Code may also provide limited performance information for some of this equipment; however, this Code was not designed to facilitate simultaneous code level testing of individual components of a power plant. ASME PTCs that address testing of major power plant equipment provide a determination of the individual equipment isolated from the rest of the system. ASME PTC 46 has been designed to determine the performance of the entire heat cycle as an integrated system. Where the performance of individual equipment operating within the constraints of their design specified conditions are of interest, ASME PTCs developed for the testing of specific components should be used. Likewise, determining overall plant performance by combining the results of ASME Code tests conducted on each plant component is not an acceptable alternative to an ASME PTC 46 test, and an incorrect application of the other Codes.

GUIDANCE IN USING THIS CODE

As with all PTC's, ASME PTC 46 was initially developed primarily to address the needs of contract acceptance or compliance testing. This is not intended, however, to limit or prevent the use of this Code for other types of testing where the accurate determination of overall power plant performance is required. ASME PTC 46 is appropriate for all applications of Performance Test Codes tabulated in ASME PTC 1, see subsection 1-4.

This Code is not a tutorial. It is intended for use by persons experienced in power plant performance testing per ASME Performance Test Codes. A detailed knowledge of power plant operations, thermodynamic analysis and heat balance development, test measurement methods, and the use, control, and calibration of measuring and test equipment are presumed prerequisites. Additional Performance Test Codes that the user should be highly experienced in using include the following:

(a) ASME PTC 1, General Instructions

(b) ASME PTC 4, Fired Steam Generators, (if testing, for example, a Rankine cycle plant with a coal-fueled fired steam generator in the test boundary)

(c) ASME PTC 19.1, Test Uncertainty

Other ASME PTC 19 Instrument and Apparatus Supplement series codes and other referenced Codes & Standards will need to be consulted during the planning and preparation phases of a test, as applicable. Use of ASME PTC 46 is recommended whenever the performance of a heat cycle power plant must be determined with minimum uncertainty.

OVERALL PLANT PERFORMANCE

Section 1
Object and Scope

1-1 OBJECT

The object of this Code is to provide uniform test methods and procedures for the determination of the thermal performance and electrical output of heat-cycle electric power plants and cogeneration facilities.

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

(a) corrected power
(b) corrected heat rate or efficiency
(c) corrected heat input

Tests may be designed to satisfy different goals, including specified unit disposition, specified corrected power, and specified measured power.

1-2 SCOPE

1-2.1 General Scope

This Code applies to any plant size. It can be used to measure the performance of a plant in its normal operating condition, with all equipment in a clean and fully functional condition. This Code provides explicit methods and procedures for combined cycle power plants and for most gas, liquid, and solid fueled Rankine cycle plants. There is no intent to restrict the use of this Code for other types of heat cycle power plants, providing the explicit procedures can be met. For example, the performance equations and test methods herein are applicable to the steam cycle portion of a solar plant, or of a nuclear plant steam cycle. Refer to ASME PTC 47 for power block thermal performance test procedures associated with an IGCC plant (Integrated Gasification Combined Cycle).

This Code does not apply to component testing, for example, gas turbines (ASME PTC 22) or steam turbines (ASME PTC 6 or ASME PTC 6.2) or other individual components. To test a particular power plant or cogeneration facility in accordance with this Code, the following must be met:

(a) a means must be available to determine, through either direct or indirect measurements, all of the heat inputs entering the test boundary and all of the electrical power and secondary outputs leaving the test boundary;

(b) a means must be available to determine, through either direct or indirect measurements, all of the parameters to correct the results from the test to the base reference condition;

(c) the test result uncertainties should be less than or equal to the uncertainties given in subsection 1-3 for the applicable plant type; and

(d) the working fluid for vapor cycles must be steam. This restriction is imposed only to the extent that other fluids may require measurements or measurement methods different from those provided by this Code for steam cycles.

1-2.2 Tests Outside the Scope of ASME PTC 46

Tests addressing other power plant performance-related issues are outside the scope of this Code. These include the following:

(a) emissions tests: testing to verify compliance with regulatory emissions levels (e.g., airborne gaseous and particulate, solid and wastewater, noise, etc.), or required for calibration and certification of emission-monitoring systems.

(b) operational demonstration tests: the various standard power plant tests typically conducted during start-up, or periodically thereafter, to demonstrate specified operating capabilities (e.g., minimum load operation, automatic load control and load ramp rate, fuel switching capability, etc.).

(c) reliability tests: tests conducted over an extended period of days or weeks to demonstrate the capability of the power plant to produce a specified minimum output level or availability. The measurement methods, calculations, and corrections to design conditions included herein may be of use in designing tests of this type; however, this Code does not address this type of testing in terms of providing explicit testing procedures or acceptance criteria.

1-3 TEST UNCERTAINTY

The explicit measurement methods and procedures have been developed to provide a test of the highest level of accuracy consistent with practical limitations.

Table 1-3-1 Largest Allowable Test Uncertainties

Type of Plant	Description	Corrected Heat Input/Heat Rate Efficiency, %	Corrected Power, %
Simple cycle with steam generation	Gas turbine with exhaust heat used for steam generation	1.25	0.80
Combined cycles	Combined gas turbine and steam turbine cycles with or without supplemental firing of a steam generator	1.25	0.80
Steam cycle	Direct steam input (i.e., geothermal)	1.5	1.0
Steam cycle	Consistent liquid or gas fuel	1.5	1.0
Steam cycle	Consistent solid fuel	3.0	1.0

GENERAL NOTES:

(a) For gas turbine based plants, the above largest allowable uncertainties have the gas turbine operating at conditions as defined by the gas turbine manufacturers, and for steam turbine plants the above largest allowable uncertainties have the steam turbine plants operating at or near full load.

(b) If a plant design does not clearly fall under one of the categories included in this table, the test uncertainty may be higher. In all cases, it is particularly important to examine the pretest uncertainty analysis to ensure that the lowest achievable uncertainty has been planned by following the methods described in Section 4.

(c) Corrected power and heat rate are presented in this Table on a net basis.

Any departure from Code requirements could introduce additional uncertainty beyond that considered acceptable to meet the objectives of the Code.

The largest allowable test uncertainties (as a percent of test results) for selected power plant types are given in Table 1-3-1.

It is recognized there is a diverse range of power plant designs that cannot be generally categorized for purposes of establishing testing methods and uncertainty limits. The uncertainty levels achievable from testing in accordance with this Code are dependent on the plant type, specific design complexity, and consistency of operation during a test. For example, because of the wide range of process mass and energy flows, and the locations for their extraction, uncertainty limits for cogenerators cannot be so generalized. Testing with cogeneration efflux may increase the test uncertainty, the amount of which depends on the location in the cycle and the relative amount of the cogeneration energy.

The special cases in paras. 5-5.2 and 5-5.3 are also not considered in Table 1-3-1.

The values in Table 1-3-1 are not targets. A primary philosophy underlying this Code is to design a test for the highest practical level of accuracy based on current engineering knowledge. If the test is for commercial acceptance, this philosophy is in the best interest of all parties to the test. Deviations from the methods recommended in this Code are acceptable only if it can be demonstrated they provide equal or lower uncertainty.

1-4 REFERENCES

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

AGA Report No. 8, Compressibility Factors of Natural Gas and Other Related Hydrocarbon Gases

Publisher: American Gas Association, 400 North Capitol Street NW #450, Washington, DC 20001 (www.aga.org)

ANSI/IEEE Standard 120, Master Test Guide for Electrical Measurements in Power Circuits

ANSI/IEEE Standard C57.13, Requirements for Instrument Transformers

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

ASME MFC 11, Measure of Fluid Flow by Means of Coriolis Mass Flowmeter

ASME PTC 1, General Instructions

ASME PTC 2, Definitions and Values

ASME PTC 4, Fired Steam Generators

ASME PTC 4.4, Gas Turbine Heat Recovery Steam Generators

ASME PTC 6, Steam Turbines

ASME PTC 6.2, Steam Turbines in Combined Cycles

ASME PTC 12.4, Moisture Separator Reheaters

ASME PTC 19.1, Test Uncertainty

ASME PTC 19.2, Pressure Measurement

ASME PTC 19.3, Temperature Measurement

ASME PTC 19.3TW, Thermowells

ASME PTC 19.5, Flow Measurement

ASME PTC 22 Gas Turbines

ASME PTC 23, Atmospheric Water Cooling Equipment

ASME PTC 30.1, Air-Cooled Steam Condensers

ASME PTC 47, Integrated Gasification Combined Cycle Power Generation Plants

ASME PTC 51, Gas Turbine Inlet Air-Conditioning Equipment

ASME STP-TS-012-1, Thermophysical Properties of Working Gases Used in Working Gas Turbine Applications

Publisher: The American Society of Mechanical Engineers (ASME), Two Park Avenue, New York, NY 10016-5990 (www.asme.org)

ASTM D1945, Standard Test Method for Analysis of Natural Gas by Gas Chromatography
ASTM D3588, Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density of Gaseous Fuel
ASTM D4809, Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (Precision Method)
ASTM E177, Standard Practice for Use of the Terms Precision and Bias in ASTM Test Methods
ASTM MNL 12, Manual on the Use of Thermocouples in Temperature Measurement
Publisher: ASTM International, 100 Barr Harbor Drive, P.O. Box C700, West Conshohocken, PA 19428-2959 (www.astm.org)

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

GPA 2145, Table of Physical Constants for Hydrocarbons and Other Compounds of Interest for the Natural Gas Industry
Publisher: Gas Processors Suppliers Association (GPSA), 6526 E. 60th Street, Tulsa, OK 74145 (https://gpsa.gpaglobal.org)

ISO 6974-1, Natural gas — Determination of composition and associated uncertainty by gas chromatography — Part 1: General guidelines and calculation of composition
ISO/IEC 17025, General requirements for the competence of testing and calibration laboratories
ISO/TS 21748, Guidance for the use of repeatability, reproducibility and trueness estimates on measurement uncertainty estimation
Publisher: International Organization for Standardization (ISO), Central Secretariat, Chemin de Blandonnet 8, Case postale 401, 1214 Vernier, Geneva, Switzerland (www.iso.org)

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

NIST Technical Note 1265, Guidance for Realizing the International Scale of 1990 (ITS-90)
Publisher: National Institute of Standards and Technology (NIST), 100 Bureau Drive, Stop 1070, Gaithersburg, MD 20899 (www.nist.gov)

Section 2
Definitions and Descriptions of Terms

2-1 DEFINITIONS OF CORRECTION FACTORS

ω_1, Δ_1: additive correction factors to thermal heat input and power, respectively, to correct to base reference thermal efflux.

ω_2, Δ_2: additive correction factors to thermal heat input and power, respectively, to correct to base reference generator power factor.

ω_3, Δ_3: additive correction factors to thermal heat input and power, respectively, to correct to base reference steam generator blowdown.

ω_4, Δ_4: additive correction factors to thermal heat input and power, respectively, to correct to base reference secondary heat inputs.

ω_{5A}, Δ_{5A}: additive correction factors to thermal heat input and power, respectively, to correct to base reference inlet air conditions at the cooling tower or air-cooled condenser air inlet.

ω_{5B}, Δ_{5B}: additive correction factors to thermal heat input and power, respectively, to correct to base reference circulation water temperature.

ω_{5C}, Δ_{5C}: additive correction factors to thermal heat input and power, respectively, to correct to base reference condenser pressure.

ω_6, Δ_6: additive correction factors to thermal heat input and power, respectively, to correct to base reference auxiliary loads.

ω_7, Δ_7: additive correction factors to thermal heat input and power, respectively, to correct for measured power different from specified if test goal is to operate at a predetermined power. Can also be used if required unit operating disposition is not as required.

β_1, α_1, f_1: multiplicative correction factors to thermal heat input, power, and heat rate, respectively, to correct to base reference inlet temperature.

β_2, α_2, f_2: multiplicative correction factors to thermal heat input, power, and heat rate, respectively, to correct to base reference inlet pressure.

β_3, α_3, f_3: multiplicative correction factors to thermal heat input, power, and heat rate, respectively, to correct to base reference inlet humidity.

β_4, α_4, f_4: multiplicative correction factors to thermal heat input, power, and heat rate, respectively, to correct to base reference fuel supply temperature.

β_5, α_5, f_5: multiplicative correction factors to thermal heat input, power, and heat rate, respectively, to correct to base reference fuel analysis.

β_6, α_6, f_6: multiplicative correction factors to thermal heat input, power, and heat rate, respectively, to correct to base reference grid frequency.

2-1.1 Symbols and Subscripts

Symbols used in this Code are listed in Table 2-1.1-1. Subscripts used in this Code are listed in Table 2-1.1-2.

2-2 TERMS

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

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

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

bias error: see *systematic error.*

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

calibration drift: a shift in the calibration characteristics.

cogeneration plant: a cycle that produces both electric power and at least one secondary output for use in a process external to the test boundary.

consistent liquid or gas fuels: fuels with a heating value that varies less than ±1% peak to valley during testing.

corrected heat input: the primary heat input entering the test boundary corrected to base reference conditions.

corrected heat rate: the test calculated heat rate corrected to base reference conditions.

corrected power: the power leaving the test boundary at the test-specified operating conditions and corrected to the base reference conditions.

Table 2-1.1-1 Symbols

Symbol	Description	Units U.S. Customary	Units SI
C_x	Correction factor for gas turbine deterioration in a phased performance test [Note (1)]	. . .	. . .
f_n	Multiplicative correction factor for heat rate or efficiency [Note (2)]	. . .	. . .
H	Enthalpy	Btu/lbm	kJ/kg
HHV	Higher heating value of fuel	Btu/lbm	kJ/kg
HR	Heat rate	Btu/kW-hr	kJ/kW-h
HV	Heating value	Btu/lbm	kJ/kg
I	Amps	A	A
LHV	Lower heating value of fuel	Btu/lbm	kJ/kg
M	Mass flow	lbm/hr	kg/s
P	Power	kW or MW	kW or MW
p	Pressure	psia	bara
PF	Power factor	. . .	. . .
Q	Thermal heat input from fuel	Btu/hr	kJ/s
T	Temperature	°F	°C
T	Absolute temperature	°R	K
V	Volts	V	V
Vars	Reactive power	MVA	MVA
Watts	Real power	kW or MW	kW or MW
α_n	Multiplicative correction factor for power [Note (2)]	. . .	. . .
β_n	Multiplicative correction for thermal heat input [Note (2)]	. . .	. . .
Δ_n	Additive correction factor for power [Note (3)]	kW or MW	kW or MW
δ_n	Additive correction factor for exhaust temperature flow in phased performance test [Note (3)]	°F	°C
γ_n	Multiplicative correction factor for air flow in phased performance [Note (2)]	. . .	. . .
η_n	Efficiency	%	%
λ_n	Multiplicative correction factor for auxiliary load [Note (2)]	. . .	. . .
μ_n	Additive correction factor for piping pressure drop [Note (3)]	kW or MW	kW or MW
ω_n	Additive correction factor for heat input [Note (3)]	Btu/hr	kJ/s

NOTES:
(1) See para. 5-5.3 for subscript definitions.
(2) See Table 5-1-2 for subscript definitions.
(3) See Table 5-1-1 for subscript definitions.

Table 2-1.1-2 Subscripts

Symbol	Description
corr	Corrected measured or calculated result to base reference conditions
meas	Measured or determined result prior to correcting to base reference conditions
GT	Gas turbine
ST	Steam turbine
db	Dry bulb
wb	Wet bulb

disposition: the arrangement of plant hardware and software to align the operation of the plant to support the goal of the performance test.

efficiency: the electrical power output divided by the thermal heat input. When there are secondary heat inputs or outputs, such as steam for the process generated by a cogeneration power plant, the efficiency is expressed at specified reference values of those secondary heat flows.

emissions: emissions are any discharges from the plant. These may include gaseous, particulate, thermal, or noise discharges to the ambient air, waterways, or ground. They may be monitored for regulatory or other requirements.

error (measurement, elemental, random, systematic): refer to ASME PTC 19.1 for definition.

field calibration: the process by which calibrations are performed under conditions that are less controlled and using less rigorous measurement and test equipment than provided under a laboratory calibration.

heat input: the energy entering the test boundary.

heat rate: the reciprocal of thermodynamic efficiency, expressed as the quotient of thermal heat input to electrical power output. When there are secondary heat inputs or outputs, such as steam for the process generated by a cogeneration power plant, the heat rate is expressed at specified reference values of those secondary heat flows.

heat sink: the reservoir to which the heat rejected to the steam turbine condenser is transferred. For a cooling pond, river, lake, or ocean cooling system, the reservoir is a body of water. For an evaporative or dry air-cooled heat exchanger system, the reservoir is the ambient air.

heating value: the amount of thermal energy released by complete combustion of a fuel unit at constant pressure.

influence coefficient: see *sensitivity*; the ratio of the change in a result to a unit change in a parameter.

inlet air: air that enters the test boundary at the planes of applicable plant equipment.

inlet scroll: also known as bellmouth, the fixed area entrance to the gas turbine.

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

interlaboratory comparisons: the organization, performance, and evaluation of calibrations on the same or similar items by two or more laboratories in accordance with predetermined conditions.

laboratory calibration: the process by which calibrations are performed under very controlled conditions with highly specialized measuring and test equipment that has been calibrated by approved sources and remain traceable to National Institute of Standards and Technology (NIST), a recognized international standard organization, or a recognized natural physical (intrinsic) constant through an unbroken comparisons having defined uncertainties.

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

out-of-tolerance: a condition in which a given measuring instrument or measuring system does not meet the designed prescribed limits of permissible error as permitted by calibrations, specifications, regulations, etc.

parameter: a direct measurement that is a physical quantity at a location that is determined by a single instrument, or by the average of several similar instruments.

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

power: the plant electrical power leaving the test boundary.

power island: for a Rankine-cycle steam power plant, the portion exclusive of the fired steam generator and its auxiliaries and of the heat sink system. For a combined cycle power plant, the portion of the cycle that is exclusive of the heat sink system.

precision error: see *random error.*

primary heat input: energy supplied to the cycle from fuel or other source (such as steam) available for conversion to power plus secondary outputs.

primary parameters/variables: the parameters/variables used in the calculation of test results. They are further classified as

(a) *Class 1:* primary parameter/variables are those that have a relative sensitivity coefficient of 0.2% or greater.

(b) *Class 2:* primary parameter/variables are those that have a relative sensitivity coefficient of less than 0.2%.

proficiency testing: a determination of the laboratory calibration performance by interlaboratory comparisons or other means.

random error, ϵ*:* sometimes called "precision error"; the true random error that characterizes a member of a set of measurements, ϵ varies in a random, Gaussian-Normal manner, from measurement to measurement.

random uncertainty (2S): an estimate of the plus or minus (±) limits of random error with a defined level of confidence (usually 95% which requires sufficient degrees of freedom to have a Student's t equal to 2).

redundant instrumentation: two or more devices measuring the same parameter with respect to the same location.

reference material: a material or substance of which one or more properties are sufficiently well established to be used for the calibration of an apparatus, the assessment of a measurement method, or for assigning values to materials.

reference standard: a standard, generally of the highest metrological quality available at a given location that includes all measuring and test equipment and reference materials that have a direct bearing on the traceability and accuracy of calibrations, from which the measurements made at that location are derived.

repeatability: the measure of how closely the results of two test runs correspond.

secondary heat inputs: the additional heat inputs to the test boundary that must be accounted for, such as cycle makeup and process condensate return.

secondary outputs: any useful non-electrical energy output stream that is used by an external process.

secondary parameters/variables: the parameters/variables that are measured but do not enter into the calculation of the test results.

sensitivity: see *influence coefficient*; the ratio of the change in a result to a unit change in a parameter.

sensitivity coefficient, absolute or relative: refer to ASME PTC 19.1 for definition.

specified corrected power test: a test run at a specified corrected power that is near to the design value of interest; for example, an acceptance test of a steam cycle plant where heat rate is guaranteed at a specific load, and partial-load tests for development of heat rate curve conditions.

specified disposition test: a test run at a specified plant disposition with both load and heat rate determined by the test. Examples of this test goal are valve-point testing on a steam cycle plant (including maximum capability testing) and base-load testing on a combined cycle plant with or without duct firing.

systematic error, β: sometimes called "bias error"; the true systematic or fixed error that characterizes every member of any set of measurements from the population; the constant component of the total measurement error, δ.

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

test boundary: identifies the energy streams required to calculate corrected results.

test reading: one recording of all required test instrumentation.

test run: a group of test readings.

thermal island: for a Rankine-cycle steam power plant, the portion of the cycle consisting of the fired steam generator and its auxiliaries. For a combined cycle power plant, "it is synonymous with power island" or "the thermal island is equivalent to the power island."

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

traceability: the property of the result of a measurement whereby it can be related to appropriate standards, generally national or international standards through an unbroken chain of comparisons.

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

uncertainty, U: $\pm U$ is the interval about the measurement or result that contains the true value for a given confidence interval.

variable: an indirect measurement that is an unknown physical quantity in an algebraic equation that is determined by parameters.

verification: the set of operations that establishes evidence by calibration or inspection that specified requirements have been met.

Section 3
Guiding Principles

3-1 INTRODUCTION

This Section provides guidance on the conduct of overall plant testing, and outlines the steps required to plan, conduct, and evaluate a Code test of overall plant performance. The subsections discuss the following:

(a) test plan (subsection 3-2)

(b) test preparations (subsection 3-3)

(c) conduct of test (subsection 3-4)

(d) calculation and reporting of results (subsection 3-5)

This Code includes procedures for testing the plant to determine various types of test goals. It also provides specific instructions for multiple party tests conducted to satisfy or verify guaranteed performance specified in commercial agreements.

3-1.1 Test Goals

The following paragraphs define the three different test setups (or goals) considered by the Code and include some examples.

(a) Specified Disposition. The test can be run at a specified disposition. An example of this test goal would be valve-point testing on a steam cycle plant (including maximum capability testing) or base-load testing on a combined cycle plant with or without duct firing. Corrected power and corrected heat rate may be determined by the test or a part-load testing on a combined cycle plant at a specified percent of base load output.

(b) Specified Corrected Power. The test can be run at a specified corrected power. Examples of this test would be:

(1) a test of a steam cycle plant where heat rate is guaranteed at a specific load, or partial-load tests for development of heat rate curves

(2) a combined cycle plant with variable duct firing to satisfy the corrected power goal. In any case, the power is set to achieve a corrected power equal to the design value of interest and the corrected heat rate is determined by the test

(c) Specified Uncorrected Power. The test can be run at a specified (uncorrected) power regardless of operating conditions or external conditions at the test boundary. An example of this test goal is an acceptance test on a duct-fired combined cycle plant with an output guarantee over a range of inlet temperatures. Corrected or uncorrected power and corrected heat rate may be determined by the test.

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

3-1.2 General Precaution

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

3-1.3 Agreements and Compliance to Code Requirements

This Code is suitable for use whenever performance must be determined with minimum uncertainty. Strict adherence to the requirements specified in this Code is critical to achieving that objective.

3-1.4 Acceptance Tests

This Code may be incorporated by reference into contracts to serve as a means to verify commercial guarantees for plant heat rate and power output. If this Code is used for guarantee acceptance testing or for any other tests where there are multiple parties represented, those parties shall mutually agree on the exact method of testing and the methods of measurement, as well as any deviations from the Code requirements.

3-1.4.1 Prior Agreements. The parties to the test shall agree on all material issues not explicitly prescribed by the Code as identified throughout the Code and summarized as follows:

(a) Approval of the test plan by all parties to the test.

(b) Representatives from each of the parties to the test shall be designated who will be part of the test team and observe the test and confirm that it was conducted in accordance with the test requirements. They should also have the authority, if necessary, to approve any

agreed-upon revisions to the test requirements during the test.

(c) Contract or specification requirements regarding operating conditions, base reference conditions, performance guarantees, test boundary, and environmental compliance.

(d) Requirements in support of a Code test, including test fuel supply and thermal and electrical hosts' ability to accept loads.

(e) Notification requirements prior to test preparation to ensure all parties have sufficient time to be present for the test.

(f) Reasonable opportunity to examine the plant and agree that it is ready to test.

(g) Modifications to the test plan based on preliminary testing.

(h) Cycle isolation and valve line-up checklist.

(i) Operations of equipment outside of suppliers' instructions.

(j) Actions to take if site conditions are outside the limits listed in Table 3-1.4.1-1.

(k) Plant stability criteria prior to starting a test.

(l) Permissible adjustments to plant operations during stabilization and between test runs.

(m) Duration of test runs.

(n) Resolution of non-repeatable test runs results.

(o) Rejection of test readings.

3-1.4.2 Data Records and the Test Log. A complete set of data and a complete copy of the test log shall be provided to all parties to the test. All data and records of the test must be prepared to allow for clear and legible reproduction. The completed data records shall include the date and time of day the observation was recorded. The observations shall be the actual readings without application of any additional instrument corrections beyond the calibration so that the relationship between the actual reading and the value recorded for the test are traceable. The test log should constitute a complete record of events. Erasures on or destruction or deletion of any data record, page of the test log, or of any recorded observation is not permitted. If corrected, the alteration shall be entered so that the original entry remains legible and an explanation is included. For manual data collection, the test observations shall be entered on prepared forms that constitute original data sheets authenticated by the observer's signatures. For automatic data collection, printed output or electronic files shall be authenticated by the Test Coordinator and other representatives of the parties to the test. When no paper copy is generated, the parties to the test must agree in advance to the method used for authenticating, reproducing, and distributing the data. Copies of the electronic data files must be copied onto tape or disks and distributed to each of the parties to the test. The data files shall be in a format that is easily accessible to all.

3-1.5 Test Boundary

The test boundary 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 base operating conditions or unless they relate functionally to conditions outside the boundary.

The methods and procedures of this Code have been developed to provide flexibility in defining the test boundary for a test. The test boundary is to be defined for the specific test objective. For example, an acceptance test may be required for a bottoming cycle that is added in the re-powering portion of an upgrade.

For this Code to apply, the test boundary must encompass a discrete electric-power-producing heat cycle. This means that all energy streams must be accounted for that cross the boundary.

For a particular test, the specific test boundary must be established by the parties to the test. Some or all of the typical streams required for common plant cycles are shown in Fig. 3-1.5-1.

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 an overall plant performance test.

The properties of streams indicated by dashed lines may be required for an energy and mass balance, but may not have to be determined to calculate test results. Determinations of emissions are outside the scope of this Code.

Typical test boundaries for the two most common applications of steam power plants and combined cycle power plants are shown in Figs. 3-1.5-2 and 3-1.5-3, respectively. If these plants were cogeneration plants, secondary process input and output streams would also be shown crossing the test boundary. More definitive test boundaries for specific representative cycles are shown in Figs. 5-4.1.5-1, 5-4.1.5-2, 5-4.1.5-3, and 5-7.4-1, and in the appendices describing sample calculations.

3-1.6 Required Measurements

Some flexibility is required by this Code in defining the test boundary, since it is somewhat dependent on a particular plant design. Although not excluded from use within this Code, extra care is to be taken if plant instrumentation and distributed control system (DCS) is to be used for recording primary measurements. In general, in the case of the instrumentation, the factory calibration is not to the standard required by this Code for performance testing. Additionally, the DCS is not

Table 3-1.4.1-1 Guidance for Establishing Permissible Deviations From Design (All ± Values)

Condition	Combined Cycle Plant	Gas Turbine with HRSG for Steam Generation	Steam Turbine Cycle Plant Primary Heat Input Measured Directly	Steam Turbine Cycle Plant Primary Heat Input Measured by Heat Loss Method
Inlet air conditions to equipment	Gas turbine maximum allowable deviation in required mode, such as base loaded. Varies by gas turbine.	Gas turbine maximum allowable deviation in required mode, such as base loaded. Varies by gas turbine.	25°F (14°C) wet bulb or 30°F (17°C) dry bulb if the air-cooled heat sink (cooling tower or air-cooled condenser) is included in test boundary.	More stringent of the allowable deviation for a steam cycle plant with primary heat input measured directly, or of the boiler limits on inlet air temperature.
Heat sink conditions: air cooling in the test boundary	See "Inlet Air" in this table	See "Inlet Air" in this table	See "Inlet Air" in this table	See "Inlet Air" in this table
Heat sink conditions: (a) circulating water cooling or (b) condenser pressure at the test boundary	Equivalent to limits of calculable steam turbine output variation with condenser pressure. Varies by steam turbine.	N/A	Equivalent to limits of calculable steam turbine output variation with condenser pressure. Varies by steam turbine.	Equivalent to limits of calculable steam turbine output variation with condenser pressure. Varies by steam turbine.
Thermal efflux: minimum process efflux F(min), as a function of base reference process efflux[Notes (1) and (2)]	If Rb is 0.30 or less: $F(\mathrm{min}) = 0.30 \times Fb \times (P_{ps}/P_{ms})$ If Rb exceeds 0.30: $F(\mathrm{min}) = Rb \times Fb \times (P_{ps}/P_{ms})$ [Note (1)]	If Rb is 0.30 or less: $F(\mathrm{min}) = 0.30 \times Fb \times (P_{ps}/P_{ms})$ If Rb exceeds 0.30: $F(\mathrm{min}) = Rb \times Fb \times (P_{ps}/P_{ms})$ [Notes (1) and (2)]	If Rb is 0.30 or less: $F(\mathrm{min}) = 0.75 \times Fb \times (P_{ps}/P_{ms})$ If Rb exceeds 0.30: $F(\mathrm{min}) = [0.75 + (Rb - 0.30)/0.70 \times 0.25] \times Fb \times (P_{ps}/P_{ms})$ [Notes (1) and (2)]	If Rb is 0.30 or less: $F(\mathrm{min}) = 0.75 \times Fb \times (P_{ps}/P_{ms})$ If Rb exceeds 0.30: $F(\mathrm{min}) = [0.75 + (Rb - 0.30)/0.70 \times 0.25] \times Fb \times (P_{ps}/P_{ms})$ [Notes (1) and (2)]
Thermal efflux: process steam enthalpy, referenced to ISO or absolute temperature	Equivalent to 10% of enthalpy downstream of attemperation, if applicable	Equivalent to 10% of enthalpy downstream of attemperation, if applicable	Equivalent to 10% of enthalpy downstream of attemperation, if applicable	Equivalent to 10% of enthalpy downstream of attemperation, if applicable
Gas, liquid fuel: fuel analysis (heating value, constituents)	Allowable deviation permitted for the gas turbine. Varies with turbine.	Allowable deviation permitted for the gas turbine. Varies with turbine.	Allowable deviation permitted for the boiler. Varies with boiler.	Allowable deviation permitted for the boiler. Varies with boiler.
Solid fuel: fuel analysis (heating value, constituents)	Contract fuel specification limits	Contract fuel specification limits	Contract fuel specification limits	Contract fuel specification limits
Electrical parameters: power factor, kW, frequency	Allowable deviation from reference by generation equipment manufacturers. Varies with specific generators or turbines.	Allowable deviation from reference by generation equipment manufacturers. Varies with specific generators or turbines.	Allowable deviation from reference by generation equipment manufacturers. Varies with specific generators or turbines.	Allowable deviation from reference by generation equipment manufacturers. Varies with specific generators or turbines.

NOTES:

(1)

Fb = base reference process efflux, lbm/h, kg/h, Btu/h, or kW(t)
$F(\mathrm{min})$ = minimum process efflux flow during test, units consistent with Fb
NP = plant net power output from base heat balance, kW(e)
PE = mechanical equivalent of the process efflux from base heat balance, kW(t)
P_{ms} = main steam pressure, psia or kPa
P_{ps} = process steam pressure, psia or kPa
Rb = ratio of $PE/(NP + PE)$, dimensionless

(2) Smaller values may be used for the minimum required process efflux only if steam cycle characteristics (such as steam turbine flow factors) needed for heat balance calculations can be confirmed with data.

Fig. 3-1.5-1 Generic Test Boundary

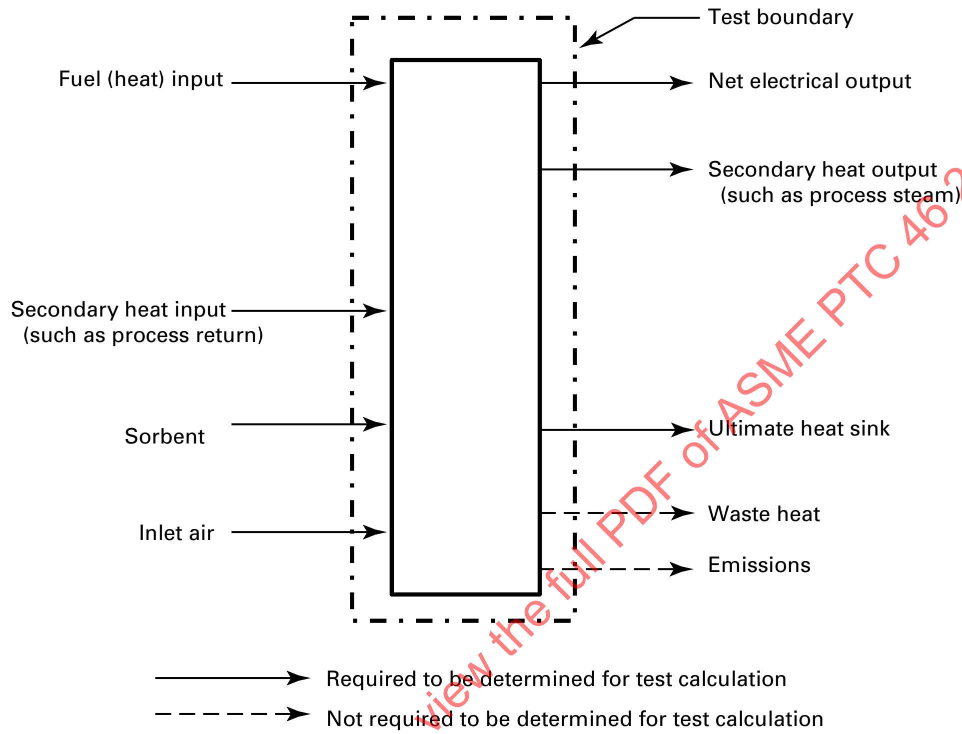


Fig. 3-1.5-2 Typical Steam Plant Test Boundary

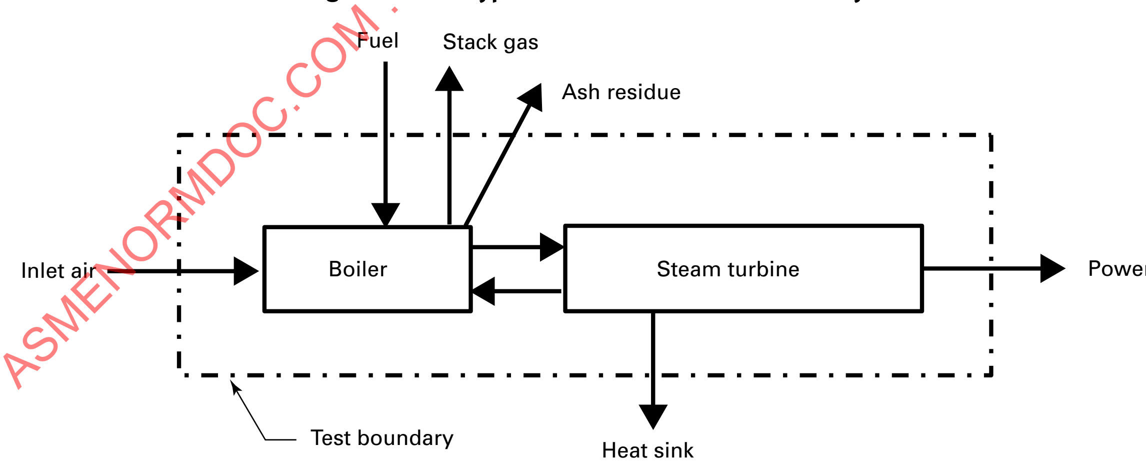
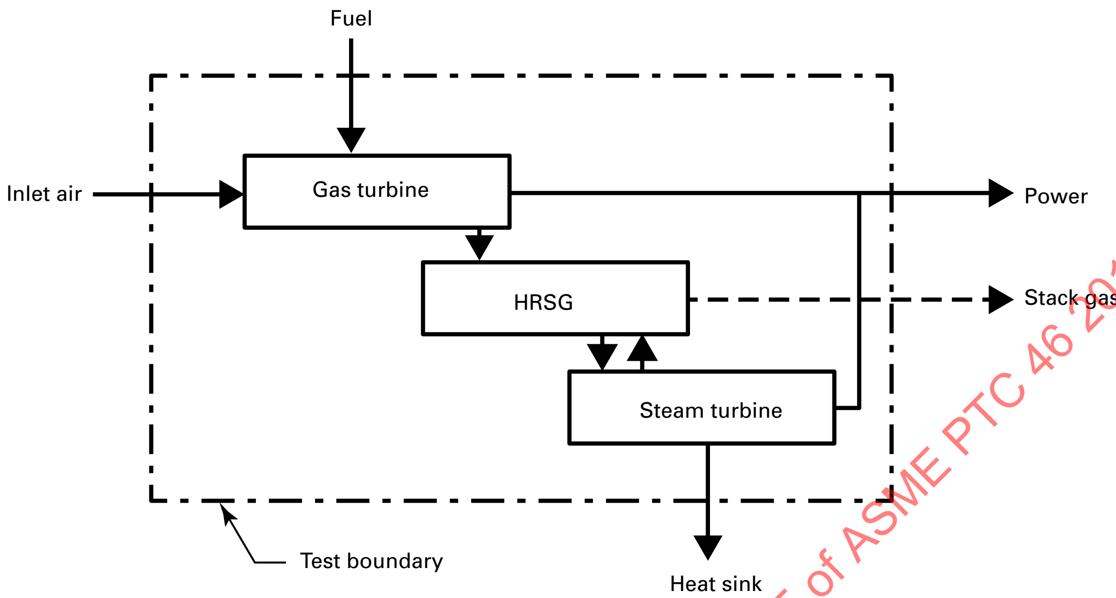


Fig. 3-1.5-3 Typical Combined Cycle Plant Test Boundary



designed to be used as a Code-level data acquisition system. If the DCS is to be used, the test lead must understand the compression (number of significant figures recorded) and dead band settings within the DCS or data historian, the uncertainty of analog to digital conversions, and any algorithms that impact the reading and its impact on uncertainty within the DCS. In general, measurements or determinations are required for the following streams.

3-1.6.1 Primary Heat Input. Measure or calculate fuel mass flow and heating value, including sensible heat, at the point at which they cross the test boundary. The test boundary would typically be where the fuel enters the plant equipment; however, the actual measurement may be upstream or downstream of that point if a better measuring location is available and if the flow and fuel constituents at the metering point are equivalent to or can be accurately corrected to the conditions at the test boundary.

For gas and liquid fuels, the method of primary heat input determination depends on the particular fuel and plant type. In most cases it is determined by the product of the measured fuel flow and the average fuel heating value and sensible heat. If the plant is a steam plant fired by solid fuels of consistent quality, or sometimes for gas or liquid fuels, the heat input is determined by the product of heat input to the steam and the inverse of the steam generator fuel efficiency determined by the energy balance method (also called the heat loss method). If the plant is a steam turbine plant fired by gas or liquid fuels, primary heat input can be determined by the product of the measured fuel flow and the average heating value and sensible heat.

For solid fuels of consistent constituency, the energy balance method, as defined in ASME PTC 4, is required.

The heating value of a fuel may be expressed as higher heating value, HHV, or lower heating value, LHV. Water vapor is formed as a product of combustion of all hydrocarbon-based fuels. When expressed as LHV, all water vapor formed is inferred to remain in the gaseous state. When expressed as HHV, the water vapor formed is inferred to condense to liquid at the reference temperature of the combustion reactants. The presentation of HHV therefore includes the heat of vaporization of water in the reported value. This Code does not mandate the use of either HHV or LHV. When using the energy balance method, the treatment of heat of vaporization must be consistent with the use of either HHV or LHV.

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

3-1.6.2 Secondary Heat Inputs. Secondary heat inputs to the cycle may include process energy return, makeup, and low energy external heat recovery. Measurements to determine the mass flow and energy level are required for correction to the base reference conditions.

3-1.6.3 Inlet Air Conditions. The pressure, temperature, and humidity must be determined for the air used in combustion and heat rejection system components, as applicable. The measurements of these properties shall be made at the plane representative of the air properties where the air enters each of the combustion and heat rejection system components. The measurement of ambient air properties at a single location or multiple locations upstream of the plant is not an acceptable alternative. A discussion of the rationale for this requirement is provided in Nonmandatory Appendix G. The major components which have inlet air conditions measurement requirements, depending on the type of plant and the equipment in the test boundary, are

(a) gas turbine
(b) cooling tower
(c) air-cooled condenser
(d) fired steam generator

3-1.6.4 Sorbents. The quality, analysis, and quantity of sulfur sorbent or other chemical additives that affect the corrected heat rate or corrected power must be determined for correction to the design conditions. Corrections for sorbent injection rate are limited to variations attributable to differences between test and design fuel or sorbent characteristics, or due to variations attributable to ambient conditions.

3-1.6.5 Electric Power. The electric power output from the plant is the plant output at the test boundary. When the test boundary is on the high side of the step-up transformer, the specific point of measurement may be at that location, at a remote location, or may be made by measuring the generator outputs and the auxiliary loads with corrections for step-up transformer losses based on transformer efficiency tests plus any significant line losses between the measurement point and the test boundary. The criteria for selection of the specific measurement points is based on a determination of the lowest achievable uncertainty.

3-1.6.6 Secondary Outputs. Nonelectrical energy outputs shall be determined to calculate the results.

3-1.6.7 Heat Sink Conditions. Corrections to the plant output are required for differences between the base reference conditions and test heat sink conditions. The parameters of interest depend on the type of heat sink used. For open cycle cooling, it is the temperature and flow of the circulating water where it crosses the test boundary. For evaporative and dry cooling systems, it is the properties of the air at the inlet to the cooling system (i.e., barometric pressure, dry-bulb temperature, and wet-bulb temperature, as applicable). When the test boundary excludes the heat rejection system, the correction is based on the steam turbine exhaust pressure.

3-1.7 Criteria for Selection of Measurement Locations

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

3-1.8 Specific Required Measurements

The specific measurements required for a test depend on the particular plant design and the test boundary required to meet the specific test intent.

3-1.9 Application of Corrections

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

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

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

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

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

An alternate definition of corrected heat rate and efficiency is

$$HR_{corr} = \frac{Q_{corr}}{P_{corr}}$$

$$\eta_{corr} = \frac{P_{corr}}{Q_{corr}}$$

The format of the general equations identifies and represents the various corrections to measured performance and to mathematically decouple them so that they can be applied separately. The correction factors are also identified as being necessary due to operational effects for which corrections are allowable, such as those caused by changes in cogeneration plant process flows, and as those necessary due to uncontrollable external effects, such as inlet air temperature to the equipment.

Also, Section 5 permits the Code user to utilize a heat balance computer program with the appropriate test data input following a test run, so that the corrected performance can be calculated from data with only one heat balance run necessary.

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

All correction factors must result in a "no correction" if all test conditions are equal to the base reference conditions. Test correction curves should reflect the final control settings.

3-1.10 Design, Construction, and Start-up Considerations

During the design phase of the plant, consideration should be given to accurately conducting acceptance testing for overall performance for the specific type of plant.

Consideration should also be given to the requirements of instrumentation accuracy, calibration, recalibration documentation requirements, and location of permanent plant instrumentation to be used for testing. Adequate provisions for installation of temporary instrumentation where plant instrumentation is not adequate to meet the requirements of this Code must also be considered during the design stages. For example, all voltage transformers (VTs) must be calibrated and all current transformers (CTs) should be calibrated for power measurement.

If the electrical or steam hosts are unable to accept electricity or process steam, then other provisions shall be made to maintain the test values within the appropriate permissible deviations from design values in Table 3-1.4.1-1.

Table 3-1.10-1 lists the items to consider during the specific plant design, construction, and startup.

3-2 TEST PLAN

A detailed test plan shall be prepared prior to conducting a Code test to document all issues affecting the conduct of the test and provide detailed procedures for performing the test. The test plan should include the schedule of test activities, designation, and description of responsibilities of the test team, test procedures, and report of results.

3-2.1 Schedule of Test Activities

A test schedule should be prepared that includes the sequence of events, 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.

3-2.2 Test Team

The test plan shall identify the test team organization that will be responsible for the planning and preparation, conduct, analysis, and reporting of the test in accordance with this Code. The test team should include test personnel needed for data acquisition, sampling, and analysis, as well as operations and other groups needed to support the test preparations and implementation, such as supplier representatives, customer(s), witnessing party(s), and outside laboratory and other services.

A Test Coordinator shall be designated with the responsibility for the execution of the test in accordance with the test requirements. The Test Coordinator is responsible for establishing a communication plan for all test personnel and all test parties. The Test Coordinator shall also ensure that complete written records of all test activities are prepared and maintained. The Test Coordinator coordinates the setting of required operating conditions with the plant operations staff.

3-2.3 Test Procedures

The test plan should include test procedures, such as the following, that provide details for the conduct of the test.

(a) object of test
(b) method of operation
(c) test acceptance criteria for test completion
(d) base reference conditions
(e) defined test boundary identifying inputs and outputs and measurements locations
(f) complete pretest uncertainty analysis, with systematic uncertainties established for each measurement and an estimate of random uncertainties
(g) specific type, location, and calibration requirements for all instrumentation and measurement systems and frequency of data acquisition
(h) sample, collection, handling, and analysis method and frequency for fuel, sorbent, ash, etc.
(i) method of plant operation
(j) identification of testing laboratories to be used for fuel, sorbent, and ash analyses
(k) required operating disposition or accounting for all internal thermal energy and auxiliary power consumers having a material effect on test results
(l) required levels of equipment cleanliness and inspection procedures
(m) procedures to account for performance degradation, if applicable
(n) valve line-up requirements
(o) preliminary testing requirements
(p) pretest stabilization criteria
(q) required steadiness criteria and methods of maintaining operating conditions within these limits
(r) allowable variations from base reference conditions and methods of setting and maintaining operating conditions within these limits
(s) number of test runs and durations of each run
(t) test start and stop requirements
(u) data acceptance and rejection criteria
(v) allowable range of fuel conditions, including constituents and heating value
(w) correction curves with curve-fitting algorithms, tabular data, or a thermal model

Table 3-1.10-1 Design, Construction, and Start-up Considerations

Item	Elect	Flow	Pressure	Temperature	Note
Permanent plant instrumentation used for test measurements	X	X	X	X	(1)
Connections and spool sections	X	X	X	X	(2)
Changes in location	. . .	X	X	X	(3)
Changes in loop routing	. . .	X	X	X	(4)
Applicability	X	X	X	X	(5)
Access	X	X	X	X	(6)
Environment effects	X	X	X	X	(7)
Quantity	. . .	. . .	X	X	(8)
Layout	X	X	X	. . .	(9)
Ability to duplicate measurement	X	X	X	X	(10)
Installation timing	. . .	X	. . .	. . .	(11)
Upstream and downstream straight lengths	. . .	X	. . .	. . .	(12)
Water leg correction	. . .	X	X	. . .	(13)
Water leg inspection	. . .	X	X	. . .	(14)
Condensate pots	. . .	X	X	. . .	(15)
Heat tracing	. . .	X	X	. . .	(16)

NOTES:

(1) It must be considered in the plant design if it is desired to use some permanent plant instrumentation for primary measurements. Such permanent plant instrumentation must meet the Class 1 requirements of Section 4 if it must be considered Code quality Class 1 instrumentation, or the Class 2 requirements of Section 4 if lesser accuracy is acceptable. This includes obtaining appropriate laboratory calibrations 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. Many times, after considering such requirements, it may be decided to use temporary instrumentation in some areas where permanent instrumentation was initially desired to be used. Similarly, it might also be determined to use alternate permanent instrumentation. These decisions are best taken care of in the design stages.

(2) Connections and spool sections required for temporary test instrumentation which will be used for primary measurements. Pressure connections, thermowells, spool sections for flow meters, and electrical metering tie-ins for temporary test instrumentation needed to meet the Class 1 requirements of Section 4 should be incorporated into the plant design.

(3) Documentation that records 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 contractual and code limitations. An example is the relocation of a flow meter within a process line.

(4) An example is the rerouting of condensate legs.

(5) The proximity to the desired test process value measured. Note whether the recorded value is an instantaneous or average value. Note also the historical logging capabilities necessary for the testing.

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

(7) Minimize EMF effects, vibration and pulsation to instruments, and instrument loops. Ensure proper grounding for instrument circuits and digital systems.

(8) Quantity of devices and instrument ports available at one location to reduce uncertainty and provide contingency data acquisition. An example is using two (2) or dual element thermocouples to measure critical temperatures.

(9) Layout of 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.

(10) This allows a validation of process value and includes a contingency plan for test measurements. A separate device should be identified to collaborate and backup a test measurement.

(11) Timing of flow elements installation with respect to acid cleaning and/or steam blows. For instance, a calibrated flow measuring device should not be installed prior to acid cleaning or steam blows.

(12) Upstream and downstream straight lengths for flow elements to minimize uncertainty. The upstream and downstream lengths impact the flow measurement uncertainty, and therefore should be maximized.

(13) Water leg correction necessary for accurate process variable measurement. A difference in flow measurement tap elevation will alter the differential pressure measured at a zero flow condition. Flow measurement devices should be installed in horizontal pipe runs.

(14) Ability to inspect water legs to validate water leg height.

(15) Accessible condensate pots to check or refill condensate lines to transmitter.

(16) Validate the installation of heat tracing. A check should be made to validate that heat tracing done on water legs is in accordance with manufacturer's instructions to prevent boiling of condensate.

(x) sample calculations or detailed procedures specifying test run data reduction and calculation and correction of test results to base reference condition

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

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

(aa) test report format, contents, inclusions, and index

3-3 TEST PREPARATIONS

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.

A test log shall be maintained during the test to record any occurrences affecting the test, the time of the occurrence, and the observed resultant effect. This log becomes part of the permanent record of the test.

The safety of personnel and care of instrumentation involved in the test should be considered. For example, provision of safe access to test point locations, availability of suitable utilities and safe work areas for personnel as well as potential damage to instrumentation or calibration shifting because of extreme ambient conditions such as temperature or vibration.

Documentation shall 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.

The remainder of this subsection describes preparations relating to various aspects of testing.

3-3.1 Test Apparatus

Test instruments are classified as described in para. 4-1.2.3. Instrumentation used for data collection must be at least as accurate as instrumentation identified in the pretest uncertainty analysis. This instrumentation can be either permanent plant instrumentation or temporary test instrumentation.

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, at least 30 readings should be collected to minimize the random error impact on the post-test uncertainty analysis. The use of automated data acquisition systems is recommended to facilitate acquiring sufficient data.

Calibration or adequate checks of all instruments must be carried out, and those records and calibration reports must be made available.

3-3.2 Data Collection

Data shall be taken by automatic data-collecting equipment or by a sufficient number of competent observers. Automatic data-logging and advanced instrument systems shall be calibrated to the required accuracy. No observer shall be required to take so many readings that lack of time may result in insufficient care and precision. Consideration shall be given to specifying duplicate instrumentation and taking simultaneous readings for certain test points to attain the specified accuracy of the test. The data collection and handling requirements are discussed in detail in subsection 4-9.

3-3.3 Location and Identification of Instruments

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

3-3.4 Test Personnel

Test personnel are required in sufficient number and expertise to support the execution of the test (see para. 3-2.2, Test Team). Operations personnel must be familiar with the test operating requirements in order to operate the equipment accordingly.

3-3.5 Equipment Inspection and Cleanliness

Since an ASME PTC 46 test is not intended to provide detailed information on individual components, this Code does not provide corrections for the effect of any equipment that is not in a clean and functional state. Prior to conducting a test, the cleanliness, condition, and age of the equipment should be determined by inspection of equipment or review of operational records, or both. Cleaning should be completed prior to the test and equipment cleanliness agreed upon.

The plant should be checked to ensure that equipment and subsystems are installed and operating in accordance with their design parameters and the plant is ready to test.

When the manufacturer or supplier is a party to the test, they should have reasonable opportunity to examine the equipment, correct defects, and render the equipment suitable to test. The manufacturer, however, is not thereby empowered to alter or adjust equipment or conditions in such a way that regulations, contract, safety, or other stipulations are altered or voided. The manufacturer may not make adjustments to the equipment for test purposes that may prevent immediate, continuous, and reliable operation at all capacities or outputs under all specified operating conditions. Any actions taken must be documented and immediately reported to all parties to the test.

3-3.6 Preliminary Testing

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

(a) to determine whether the plant equipment is in suitable condition for the conduct of the test

(b) to make adjustments, the needs of which were not evident during the preparation of the test

(c) to check the operation of all instruments, controls, and data acquisition systems

(d) to ensure that the estimated uncertainty as determined by the pretest analysis is reasonable by checking the complete system

(e) to ensure that the facilities operation can be maintained in a steady state performance

(f) to ensure that the fuel characteristics, analysis, and heating value are within permissible limits, and that sufficient quantity is on hand to avoid interrupting the test

(g) to ensure that process boundary inputs and outputs are not constrained other than those identified in the test requirements

(h) to familiarize test personnel with their assignments

(i) to retrieve enough data to fine tune the control system, if necessary

3-4 CONDUCT OF THE TEST

This subsection provides guidelines on the actual conduct of the performance test and addresses the following areas: starting and stopping tests and test runs (para. 3-4.1), methods of operation prior to and during tests (para. 3-4.2), adjustments prior to and during tests (para. 3-4.3), duration and number of test runs and number of readings (para. 3-4.4), and constancy of test conditions (para. 3-4.5).

In addition, this subsection contains the following tables:

(a) Table 3-1.4.1-1, Guidance for Establishing Permissible Deviations from Design

(b) Table 3-1.10-1, Design, Construction, and Start Up Considerations

Table 3-4-1 Typical Pretest Stabilization Periods

Type of Plant	Stabilization
Gas fired boiler	1 hr
Oil fired boiler	1 hr
Pulverized coal-fired boiler	1 hr
Fluidized bed combustor	24 hr [Note (1)]
Simple cycle with heat recovery	1 hr
Combined cycle	1 hr
Reciprocating engines	1 hr
Stoker and cyclone stabilization	4 hr

GENERAL NOTE: This Table represents recommended time after plant has been operating near or at the test target so as to have proper heat soak and transient behaviors mitigated. These periods do not include time from cold start.

NOTE:

(1) If chemical stability has been satisfied, then testing may commence one (1) hr following achievement.

Table 3-4-2 Recommended Minimum Test Run Durations

Type of Plant	Test Run
Gas fired boiler	2 hr
Oil fired boiler	2 hr
Pulverized coal-fired boiler	2 hr
Fluidized bed combustor	4 hr
Simple cycle with heat recovery	1 hr
Combined cycle	1 hr
Stoker and cyclone stabilization	4 hr

(c) Table 3-4-1, Typical Pretest Stabilization Periods

(d) Table 3-4-2, Recommended Minimum Test Run Durations

3-4.1 Starting and Stopping Test 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.

3-4.1.1 Starting Criteria. Prior to starting each performance test, the following conditions must be satisfied:

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

(1) equipment operation and method of control

(2) unit configuration, including required process efflux flow

(3) valve line-up/cycle isolation

(4) availability of consistent fuel and fuel supplements within the allowable limits of the fuel analysis for the test (by analysis as soon as practicable preceding the test)

(5) plant operation within the bounds of the performance correction curves, algorithms, or programs

(6) equipment operation within allowable limits

(7) for a series of test runs, completion of internal adjustments required for repeatability

(b) Stabilization. Prior to starting the test, the plant must be operated for a sufficient period of time at test load to demonstrate and verify stability in accordance with para. 3-4.2.5.

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

3-4.1.2 Stopping Criteria. Tests are normally stopped when the Test Coordinator is satisfied that requirements for a complete test run have been satisfied (see paras. 3-4.4 and 3-4.5). The Test Coordinator should verify that methods of operation during test, specified in para. 3-4.2, have been satisfied. The Test Coordinator may extend or terminate the test if the requirements are not met.

Data logging should be checked to ensure completeness and quality. After all test runs are completed, secure equipment operating for purposes of test only (such as vent steam). Return operation control to normal dispatch functions, if appropriate.

3-4.2 Methods of Operation Prior to and During Tests

All equipment necessary for normal and sustained operation at the test 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.

Typical but nonexhaustive examples of operating equipment for consideration include fuel handling equipment, soot blowers, ash handling systems, gas turbine compressor inlet chillers or evaporative coolers, gas compressors, water treatment equipment, environmental control equipment, and blowdown.

3-4.2.1 Operating Mode. The operating mode of the plant during the test shall be consistent with the goal of the test and which forms the basis of the correction methodology. The corrections utilized in the general performance equation and the development of correction curves will be affected by the operating mode of the plant. If a specified corrected or measured load is desired, the plant control system should be configured to maintain the load during the test. If a specified disposition is required, the control system should maintain the disposition and not make changes to the parameters, which should be fixed, such as valve position.

The plant equipment should be operated in a manner consistent with the basis of design or guarantee, or in a manner that will reduce the overall test uncertainty and in a manner that will permit correction from test operating conditions to base reference conditions.

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

3-4.2.2 Valve Line-up/Cycle Isolation. A cycle isolation checklist shall be developed to meet the goals of the test. The checklist should be divided into three categories: manual valve isolation checklist, automatic valve isolation checklist, and test valve isolation checklist.

3-4.2.2.1 Manual Valve Isolation Checklist. This checklist should be an exhaustive list of all manual valves that should be closed during normal operation, and that affect the accuracy or results of the test if they are not secured. The plant equipment should be operated in a manner consistent with the basis of design or guarantee or in a manner that will reduce the overall test uncertainty, and in a manner that will permit correction from test operating conditions to base reference conditions. These valve positions should be checked before and after the test.

3-4.2.2.2 Automatic Valve Isolation Checklist. This checklist is a list of valves that should be closed during normal operation but may from time to time cycle open (such as feedwater heater emergency dump valves). As in para. 3-4.2.2.1, these are the valves that affect the accuracy or results of the test if they are not secured. These valve positions should be checked prior to the preliminary test and monitored during subsequent testing. (To the extent available from the plant control system, these valve positions should be continually monitored during the test.)

3-4.2.2.3 Test Valve Isolation Checklist. This checklist is a list of those valves that should be closed during the performance test. These valves should be limited to valves that must be closed to accurately measure the plant performance during the test. For example, the boiler blowdown may need to be closed during all or part of the test to accurately measure boiler steam production. The blowdown valve position should be addressed in the test plan.

No valves normally open should be closed for the sole purpose of changing the maximum performance of the plant.

The valves on the test valve isolation checklist should be closed prior to the preliminary test. The valves may need to be opened between test runs.

Effort should be made to eliminate leaks through valves that are required to be closed during the test, and to determine the magnitude of any valve through-leakage if elimination is not possible. The following methods are suggested for isolating or verifying isolation of miscellaneous equipment and extraneous flows from the steam-feedwater cycle:

(a) double valves

(b) blank flanges
(c) blank between two flanges
(d) removal of spool piece for visual inspection
(e) visual inspection for steam blowing to atmosphere from such sources as safety valves, start-up vent valves, and blowdown tank vents
(f) close valve which is known to be leak-proof (test witnessed by both parties) and is not operated prior to or during test
(g) temperature indication (acceptable only under certain conditions with mutual agreement necessary)

If through-leakage cannot be eliminated, methods are available if agreed upon to quantify leakages. Some non-intrusive methods are frequency spectrum analysis, Doppler effect analysis, and transient analysis that can be used for flow detection through valves.

Levels of the various storage tanks in the water-steam cycle (e.g., hotwell, drums, etc.) should be measured in order to estimate unaccounted for cycle losses.

3-4.2.3 Equipment Operation. Plant equipment required for normal plant operation shall be operated as defined by the respective equipment suppliers' instructions (to support the overall objectives of the plant test). Equipment that is necessary for plant operation or that would normally be required for the plant to operate at base reference conditions must be operating or accounted for in determining auxiliary power loads.

An equipment checklist shall be developed. The checklist should be divided into the following two categories:
(a) electrical auxiliaries
(b) non-electric internal energy consumers' checklist

The checklist shall include a tabulation of the required operating disposition of all electric and non-electric internal energy consumers that have the potential to affect corrected plant output by more than 0.05%, as well as the actual status during testing.

Any changes in equipment operation that affect test results by more than 0.25% will invalidate a test run, or may be quantified and included in test result calculations. A switch over to redundant equipment, such as a standby pump, is permissible. Intermittent non-electrical internal energy consumption and electrical auxiliary loads, such as prorating, or proportioning, must be accounted for in an equitable manner and applied to the power consumption of a complete equipment operating cycle over the test period. Examples of intermittent loads include water treatment regeneration, well pump, material handling, soot blowing, blowdown, heat tracing, and air preheating.

3-4.2.4 Proximity to Design Conditions. It is desirable to operate the plant during the test as closely as possible to the base reference performance conditions, and within the allowable design range of the plant and its equipment so as to limit the magnitude of corrections to electrical output and heat rate. Table 3-1.4.1-1 was developed based on achieving the overall test uncertainties described in Table 1-3-1. Excessive corrections to plant performance parameters can adversely affect overall test uncertainty. To maintain compliance with test Code requirements, the actual test should be conducted within the criteria given in Tables 3-1.4.1-1, 3-4-1, and 3-4-2 or other operating criteria that result in overall test uncertainty compatible with Table 1-3-1.

3-4.2.5 Stabilization. The length of operating time necessary to achieve the required steady state will depend on previous operations, using Table 3-4-1 as a guide.

3-4.2.6 Plant Output. A test may be conducted at any load condition, as required to satisfy the goals of the test. For those tests that require a specified corrected or measured load, the test run electrical output should be set so that the estimated test result of electrical power is within 1% of the applicable design value. For those tests that require a specified disposition of the plant, the test electrical output will be dependent on the performance of the plant itself and will not be controlled. At no time should the actual test conditions exceed any equipment ratings provided by the manufacturer.

3-4.2.7 Plant Thermal Energy. Cogeneration plant thermal energy export shall be set at levels specified. If automatic control of export energy does not provide sufficient stability and proximity to design conditions, manual control or venting of export energy may be required.

3-4.2.8 Fuel and Fuel Supplements. Consumption and properties of fuel and fuel supplements (such as limestone) should be maintained as constant as practicable for the duration of the preliminary test and actual test. Permissible deviations in fuel properties for various fuels and components are specified in Table 3-1.4.1-1.

3-4.2.9 Emissions. While there may be specific instances dictated by contractual requirements in which environmental compliance or other compliance requirements and thermal performance must be demonstrated simultaneously, this is not a technical requirement of this Code.

3-4.2.10 On-line Cleaning. On-line cleaning of boiler heat transfer surfaces and gas turbine compressors should be addressed.

3-4.3 Adjustments Prior to and During Tests

This subsection describes the following three types of adjustments related to the test:
(a) permissible adjustments during stabilization periods or between test runs
(b) permissible adjustments during test runs
(c) nonpermissible adjustments

3-4.3.1 Permissible Adjustments During Stabilization Periods or Between Test Runs. Any adjustments may be made to the equipment and/or operating conditions, but the requirements for determination of stable operation (see para. 3-4.2.5) still apply. For example, if the fuel distribution on a stoker is altered, sufficient stable operating time must be allowed for a complete change of the ash on the grates. Similarly, a change in fluidized bed combustor ash reinjection must permit restabilization of the bed. Changes in nonprimary measurements, such as steam temperature, may be made so long as the requirement for stability of primary measurements still holds.

Typical adjustments prior to tests are those required to correct malfunctioning controls or instrumentation or to optimize plant performance for current operating conditions. Recalibration of suspected instrumentation or measurement loops are permissible. Tuning and/or optimization of component or plant performance is permissible. Adjustments to avoid corrections or to minimize the magnitude of performance corrections are permissible.

3-4.3.2 Permissible Adjustments During Test Runs. Permissible adjustments during tests are those required to correct malfunctioning controls, maintain equipment in safe operation, or to maintain plant stability. Switching from automatic to manual control, and adjusting operating limits or set points of instruments or equipment, should be avoided during a test.

3-4.3.3 Nonpermissible Adjustments. Any adjustments that would result in equipment being operated beyond manufacturer's operating, design, or safety limits and/or specified operating limits are not permitted. Adjustments or recalibrations which would adversely affect the stability of a primary measurement during a test are also not permitted.

3-4.4 Duration of Runs, Number of Test Runs, and Number of Readings

3-4.4.1 Duration of Runs. The duration of a test run shall be of sufficient length that the data reflects the average efficiency and/or performance of the plant. This includes consideration for deviations in the measurable parameters due to controls, fuel, and typical plant operating characteristics. The recommended test durations are tabulated in Table 3-4-2.

The Test Coordinator may determine that a longer test period is required. The recommended times shown in Table 3-4-2 are generally based upon continuous data acquisition. Depending upon the personnel available and the method of data acquisition, it may be necessary to increase the length of a test in order to obtain a sufficient number of samples of the measured parameters to attain the required test uncertainty. When point-by-point traverses are required, such as velocity and temperature traverse for exhaust flow or high velocity thermocouple probe in a boiler to determine oxygen and temperature distribution, the test run should be long enough to complete two full traverses. Test runs using blended or waste fuels may also require longer durations if variations in the fuel are significant. Test run duration should consider transit times of samples.

3-4.4.2 Number of Test Runs. A run is a complete set of observations with the unit at stable operating conditions. A test is a single run or the average of a series of runs.

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

(a) provide a valid method of rejecting bad test runs.

(b) examine the validity of the results.

(c) verify the repeatability of the results. Results may not be repeatable due to variations in either test methodology (test variations) or the actual performance of the equipment being tested (process variations).

After completing the first test run that meets the criteria for an acceptable test run (which may be the preliminary test run), the data should be consolidated and preliminary results calculated and examined to ensure that the results are reasonable.

3-4.4.3 Evaluation of Test Runs. When comparing results from two test runs (X_1 and X_2) and their uncertainty intervals, the three cases illustrated in Fig. 3-4.4.3-1 should be considered.

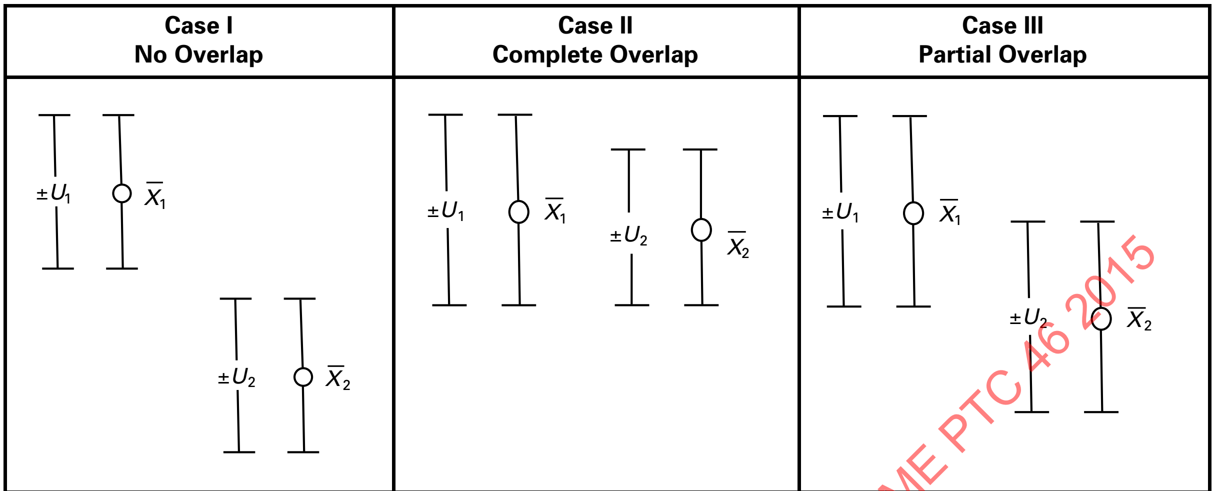
(a) *Case 1.* A problem clearly exists when there is no overlap between uncertainty intervals. Either uncertainty intervals have been grossly underestimated, an error exists in the measurements, or the true value is not constant. Investigation to identify bad readings, overlooked or underestimated systematic uncertainty, etc., is necessary to resolve this discrepancy.

(b) *Case 2.* When the uncertainty intervals completely overlap, as in this case, one can be confident that there has been a proper accounting of all major uncertainty components. The smaller uncertainty interval, $X_2 \pm U_2$, is wholly contained in the interval, $X_1 \pm U_1$.

(c) *Case 3.* This case, where a partial overlap of the uncertainty exists, is the most difficult to analyze. For both test run results and both uncertainty intervals to correct, the true value lies in the region where the uncertainty intervals overlap. Consequently, the larger the overlap, the more confidence there is in the validity of the measurements and the estimate of the uncertainty intervals. As the difference between the two measurements increases, the overlap region shrinks.

Should a run or set of runs fall under case 1 or case 3, the results from all of the runs should be reviewed in an attempt to explain the reason for excessive variation. If the reason for the variation cannot be determined, then either increase the uncertainty band to encompass

Fig. 3-4.4.3-1 Three Post-test Cases



the runs to make them repeatable, or conduct more runs so that the precision component of uncertainty may be calculated directly from the test results.

The results of multiple runs shall be averaged to determine the mean result. The uncertainty of result is calculated in accordance with ASME PTC 19.1.

3-4.4.4 Number of Readings. Sufficient readings shall be taken within the test duration to yield total uncertainty consistent with those listed in Table 1-3-1. Ideally at least 30 sets of data should be recorded for all non-integrated measurements of primary parameters and variables. There are no specific requirements for the number of integrated readings or for measurements of secondary parameters and variables for each test run.

3-4.5 Constancy of Test Conditions

The primary criteria for steady-state test conditions is that the average of the data reflects equilibrium between energy input from fuel and energy output to thermal and/or electrical generation. The primary uncontrollable parameters affecting the steady-state conditions of a test are typically the ambient conditions. Testing durations and schedules must be such that changes in ambient conditions are minimized. See para. 3-4.2.5.

3-5 CALCULATION AND REPORTING OF RESULTS

The data taken during the test should be reviewed and rejected in part or in whole if not in compliance with the requirements for the constancy of test conditions. See para. 3-4.5.

Each Code test shall include pretest and post-test uncertainty analyses and the results of these analyses shall fall within Code requirements for the type of plant being tested.

3-5.1 Causes for Rejection of Readings

Upon completion of the test or during the test itself, the test data shall be reviewed to determine if data from certain time periods should be rejected prior to the calculation of test results. Refer to ASME PTC 19.1 for data-rejection criteria. A test log shall be kept. Any plant upsets that causes test data to violate the requirements of Table 3-1.4.1-1 shall be rejected. A minimum of 10 min following the recovery of these criteria shall also be rejected to allow for re-stabilization.

Should serious inconsistencies that affect the results be detected during a test run or during the calculation of the results, the run shall be invalidated completely, or it may be invalidated only in part if the affected part is at the beginning or at the end of the run. A run that has been invalidated shall be repeated, if necessary, to attain the test objectives. During the test, should any control system set points be modified that affects stability of operation beyond Code allowable limits as defined in Table 3-1.4.1-1, test data shall be considered for rejection from the calculations of test results. The period rejected shall start immediately prior to the change and end no less than 10 min following the recovery of the criteria found in Table 3-1.4.1-1.

An outlier analysis of spurious data should also be performed in accordance with ASME PTC 19.1 on all primary measurements after the test has ended. This analysis will highlight any other time periods that should be rejected prior to calculating the test results.

3-5.2 Uncertainty

Test uncertainty and test tolerance are not interchangeable terms. This Code does not address test tolerance, which is a contractual term.

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

This Code addresses test uncertainty in the following four Sections.

(a) Section 1 defines maximum allowable test uncertainties.

(b) Section 3 defines the requirements for pretest and post-test uncertainty analyses, and how they are used in the test. These uncertainty analyses and limits of error are defined and discussed in para. 3-5.2.1.

(c) Section 4 describes the systematic uncertainty required for each test measurement.

(d) Section 7 and Nonmandatory Appendix F provide applicable guidance for determining pretest and post-test uncertainty analysis results.

3-5.2.1 Pretest and Post-test Uncertainty Analyses

(a) Pretest. A pretest uncertainty analysis shall be performed so that the test can be designed to meet Code requirements. Estimates, systematic, and random errors for each of the proposed test measurements should be used to help determine the number and quality of test instruments required for compliance with Code or contract specifications.

The pretest uncertainty analysis shall include an analysis of random uncertainties to establish permissible fluctuations of key parameters in order to attain allowable uncertainties. In addition, a pretest uncertainty analysis can be used to determine the correction factors that are significant to the corrected test. For simplicity, this Code allows elimination of those corrections that do not change the test results by 0.05%. Also, pretest uncertainty analysis should be used to determine the level of accuracy required for each measurement to maintain overall Code standards for the test.

(b) Post-test. A post-test uncertainty analysis shall also be performed as part of a Code test. The post-test uncertainty analysis will reveal the actual quality of the test to determine whether the allowable test uncertainty described in Section 1 has been realized.

3-5.3 Data Distribution and Test Report

Copies of all data will be distributed by the Test Coordinator to those requiring it at the conclusion of the test. A test report shall be written in accordance with Section 6 of this Code and distributed by the Test Coordinator. A preliminary report incorporating calculations and results may be required before the final test report is submitted.

Section 4
Instruments and Methods of Measurement

4-1 GENERAL REQUIREMENTS

4-1.1 Introduction

This Section presents the mandatory provisions for instrumentation utilized in the implementation of an ASME PTC 46 test. Using the philosophy of ASME Performance Test Codes (ASME PTC 1) and subsection 1-1 herein, it does so in consideration of the minimum reasonably achievable uncertainty.

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

For the convenience of the user, this Section reviews the critical highlights of portions of those Supplements that directly apply to the requirements of this Code. This Section also contains details of the instrumentation requirements of this Code that are not specifically addressed in the referenced Supplements. Such details include classification of measurements for the purpose of instrumentation selection and maintenance, calibration and verification requirements, electrical metering, and other information specific to an ASME PTC 46 test.

If the instrumentation requirements in the Instrument and Apparatus Supplement become more rigorous as they are updated, due to advances in the state of the art, their requirements shall supersede those set forth in this Code. 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 allowable uncertainty specified herein.

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

4-1.2 Criteria for Selection of Instrumentation

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

A parameter is considered a direct measurement and is a physical quantity at a location that is determined by a single instrument, or by the average of the measurements from several similar instruments. In the latter case, several instruments may be used to determine a parameter that has potential to display spatial gradient qualities, such as inlet air temperature. Similarly, multiple instruments may be used to determine a parameter simply for redundancy to reduce test random uncertainty, such as using two temperature measurements of the fluid in a pipe in the same plane, where the temperature gradient is expected to be insignificant. Typical parameters measured in an ASME PTC 46 test are temperature and pressure.

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

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

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

Primary parameters and primary variables are further classified as Class 1 or Class 2 depending on their relative sensitivity coefficient to the results of the test. Class 1 primary parameters and Class 1 primary variables are those that have a relative sensitivity coefficient of 0.2% or greater. The primary parameters and primary variables that have a relative sensitivity coefficient of less than 0.2% are classified as Class 2 primary parameters and Class 2 primary variables. Due to an arbitrary zero point, in the case of temperature measurements for primary parameters and primary variables, the relative sensitivity coefficient of 0.2% shall be substituted as 0.2% per °C (0.11% per °F).

4-1.2.3 Instrumentation Categorization. The instrumentation employed to measure a parameter will have different required type, accuracy, redundancy, and handling depending on how the measured parameter is used and how it affects the performance result. This Code does not require high-accuracy instrumentation used to determine secondary parameters. The instruments that measure secondary parameters may be permanently installed plant instrumentation.

This Code does require verification of instrumentation output prior to the test period. This verification can be by calibration or by comparison against two or more independent measurements of the parameters referenced to the same location. The instruments should also have redundant or other independent instruments that can verify the integrity during the test period. Instrumentation is categorized as Class 1 or Class 2, depending on the instrumentation requirements defined by that parameter. Care must be taken to ensure the instrumentation meets the requirements set forth in this Code with regards to classification.

4-1.2.3.1 Class 1 Instrumentation. Class 1 instrumentation must be used to determine Class 1 primary parameters. Class 1 instrumentation requires high accuracy and must meet specific manufacturing and installation requirements, as specified in the ASME PTC 19 series supplements. Class 1 instrumentation requires precision laboratory calibration.

4-1.2.3.2 Class 2 Instrumentation. Class 2 instrumentation, or better, shall be used to determine Class 2 primary parameters. Some Class 2 instrumentation may meet uncertainty requirements set forth in this Code with the factory calibration performed for certification, but it does require verification by techniques described in para. 4-1.3.2.

4-1.3 Instrument Calibration and Verification

4-1.3.1 Introduction. The result of a calibration permits the estimation of errors of indication of the measuring instrument, measuring system, or the assignment of values to marks on arbitrary scales. The result of a calibration is sometimes expressed as a calibration factor, or as a series of calibration factors in the form of a calibration curve. Calibrations shall be performed in a controlled environment to the extent necessary to ensure valid results. Due consideration shall be given to temperature, humidity, lighting, vibration, dust control, cleanliness, electromagnetic interference, and other factors affecting the calibration. Where pertinent, these factors shall be monitored and recorded, and as applicable, compensating corrections shall be applied to calibration results obtained in an environment that departs from acceptable conditions. Calibrations performed in accordance with this Code are categorized as either laboratory or field calibrations. Laboratory calibration applications shall be employed on all Class 1 instrumentation.

4-1.3.1.1 Laboratory-Grade Calibration. Laboratory-grade calibrations shall be performed in strict compliance with established policy, requirements, and objectives of a laboratory's quality assurance program. Consideration must be taken to ensure proper space, lighting, and environmental conditions such as temperature, humidity, ventilation, and low noise and vibration levels.

4-1.3.1.2 Field Calibration. Adequate measures shall be taken to ensure that the necessary calibration status is maintained during transportation and while on-site. The response of the reference standards to environmental changes or other relevant parameters shall be known and documented. Field calibration measurement and test equipment requires calibration by approved sources that remain traceable to NIST, a recognized international standard organization, or a recognized natural physical (intrinsic) constant through unbroken comparisons having defined uncertainties. Field calibrations' achievable uncertainties can normally be expected to be larger than laboratory calibrations due to allowances for aspects such as the environment at the place of calibration and other possible adverse affects such as those caused by transportation of the calibration equipment. Field calibration applications are commonly employed on instrumentation measuring secondary parameters and Class 2 instrumentation that are identified as out-of-tolerance during field verification as described in para. 4-1.3.2. Field calibrations should include loop calibrations as defined in para. 4-1.3.8. Field calibrations should be used as a check of Class 1 instrumentation that is suspected to have drifted, or that does not have redundancy.

4-1.3.2 Verification. Verification provides a means for checking that the deviations between values indicated by a measuring instrument and corresponding known values are consistently smaller than the limits of the permissible error defined in a standard, regulation, or specification particular to the management of the measuring device. The result of the verification leads to a decision either to restore to service, or to perform adjustments, repair, downgrade, or declare obsolete.

Verification techniques include field calibrations, nondestructive inspections, intercomparison of redundant instruments, check of transmitter zeros, and energy stream accounting practices. Nondestructive inspections include, but are not limited to, atmospheric pressure observations on absolute pressure transmitters, field checks including visual inspection, and no-load readings on power meters. Intercomparisons include, but are not limited to, water or electronic bath checks on temperature measurement devices and reconciliations on redundant instruments. Energy stream accounting practices include, but are not limited to, mass, heat, and energy balance computations. The applicable field verification requirements shall be judged based on the unique requirements of each setup. As appropriate, manufacturer's recommendations and the Instruments and Apparatus Supplements to ASME Performance Test Codes should be referenced for further field verification techniques.

4-1.3.3 Reference Standards. Reference standards shall be routinely calibrated in a manner that provides traceability to NIST, other recognized international standard organization, or defined natural physical (intrinsic) constants and have accuracy, stability, range, and resolution for the intended use. They shall be maintained for proper calibration, handling, and usage in strict compliance with a calibration laboratory quality program. When it is necessary to utilize reference standards for field calibrations, adequate measures shall be taken to ensure that the necessary calibration status is maintained during transportation and while on-site. The integrity of reference standards shall be verified by proficiency testing or interlaboratory comparisons. All reference standards should be calibrated at the frequency specified by the manufacturer unless the user has data to support extension of the calibration period. Supporting data is historical calibration data that demonstrates a calibration drift less than the accuracy of the reference standard for the desired calibration period.

The collective uncertainty of reference standards shall be known and the reference standards should be selected such that the collective uncertainty of the standards used in the calibration contributes less than 25% to the overall calibration uncertainty. The overall calibration uncertainty of the calibrated instrument shall be determined at a 95% confidence level. A reference standard with a lower uncertainty may be employed if the uncertainty of the reference standard combined with the random uncertainty of the instrument being calibrated is less than the accuracy requirement of the instrument. For example, for some kinds of flow metering the 25% rule cannot be met. However, curve fitting from calibration is achievable from a 20-point calibration in a lab with an uncertainty of better than 0.2%.

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

4-1.3.4 Environmental Conditions. Calibration of instruments used to measure primary parameters (Class 1 or Class 2) should be performed in a manner that replicates the condition under which the instrument will be used to take the test measurements. As it is often not practical or possible to perform calibrations under replicated environmental conditions, additional elemental error sources must be identified and estimated. Error source considerations must be given to all process and ambient conditions that may affect the measurement system including temperature, pressure, humidity, electromagnetic interference, and radiation.

4-1.3.5 Instrument Ranges and Calibration Points. The number of calibration points depends on the classification of the parameter the instrument will measure. The classifications are discussed in para. 4-1.2.2. The calibration should have points that bracket the expected measurement range. In some cases of flow measurement, it may be necessary to extrapolate a calibration (see ASME PTC 19.5).

4-1.3.5.1 Primary Parameters

(a) Class 1 Instrumentation. The instruments measuring Class 1 primary parameters should be laboratory-calibrated at a minimum of 2 points more than the order of the calibration curve fit, whether it is necessary to apply the calibration data to the measured data, or if the instrument is of the quality that the deviation between the laboratory calibration and the instrument reading is negligible in terms of affecting the test result. Flow metering that requires calibration should have a 20-point calibration. Instrument transformers do not require calibration at 2 points more than the order of the calibration curve fit and shall be calibrated in accordance with para. 4-7.6.

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

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

(b) Class 2 Instrumentation. The instruments measuring Class 2 primary parameters should be calibrated at a minimum of the number of points equal to the order of the calibration curve fit. If the instrument can be shown to typically have a hysteresis of less than the required accuracy, the measuring point need only be

approached from one direction (either increasing or decreasing to the point).

Some Class 2 instrumentation may meet uncertainty requirements set forth in this Code with the factory calibration performed for certification, but it does require field verification by techniques described herein.

4-1.3.5.2 Secondary Parameters. The instruments measuring secondary parameters should undergo field verifications as described in para. 4-1.3.2 and, if calibrated, need only be calibrated at one point in the expected operating range.

4-1.3.6 Timing of Calibration. Because of the variance in different types of instrumentation and their care, no mandate is made regarding the time interval between the initial laboratory calibration and the test period. Treatment of the device is much more important than the elapsed time since calibration. An instrument may be calibrated one day and mishandled the next. Conversely, an instrument may be calibrated and placed on a shelf in a controlled environment and the calibration will remain valid for an extended time period. Similarly, the instrument may be installed in the field but valved out of service, and/or it may, in many cases, be exposed to significant cycling. In these cases, the instrumentation is subject to vibration or other damage, and must undergo field verification.

All test instrumentation used to measure Class 1 primary parameters shall be laboratory-grade calibrated prior to the test and must meet specific manufacturing, installation, and operating requirements, as specified in the ASME PTC 19 series supplements. No mandate is made regarding quantity of time between the laboratory-grade calibration and the test period. Some test instrumentation used to measure Class 2 parameters may meet uncertainty requirements set forth in this Code with the factory calibration performed for certification, but it does require field verification by techniques described herein. Test instrumentation used to measure secondary parameters do not require laboratory calibration other than that performed in the factory for certification, but it does require field verification prior to the test.

Following a test, field verifications shall be conducted on instruments measuring parameters for which data is questionable. If results indicate unacceptable drift or damage, then further investigation is required. Flow-element devices meeting the requirements set forth by this Code to measure Class 1 and Class 2 primary parameters and variables need not undergo inspection following the test if the devices have not experienced conditions that would violate their integrity. Such conditions include steam blows and chemical cleaning.

4-1.3.7 Calibration Drift. When field verification indicates the drift is less than the instrument accuracy, the drift is considered acceptable and the pretest calibration is used as the basis for determining the test results. Occasionally the instrument calibration drift is unacceptable. Should the calibration drift, combined with the reference standard accuracy as the square root of the sum of the squares, exceed the required accuracy of the instrument, it is unacceptable.

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

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

(a) When instrumentation is transported to the test site between the calibration and the test period, a single-point check prior to and following the test period can isolate when the drift may have occurred. For example, verify the zero-pressure point on the vented pressure tansmitters, the zero-load point on the wattmeters, or the ice point on the temperature instrument.

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

4-1.3.8 Loop Calibration. All instruments used to measure primary parameters (Class 1 or Class 2) should be loop calibrated. Loop calibration involves the calibration of the instrument through the signal-conditioning equipment. This may be accomplished by calibrating instrumentation using the test signal-conditioning equipment either in a laboratory or on-site during test setup before the instrument is connected to process. Alternatively, the signal-conditioning device may be calibrated separately from the instrument by applying a known signal to each channel using a precision signal generator.

If loop calibration is not performed, an uncertainty analysis in accordance with ASME PTC 19.1 and ASME PTC 19.22 must be performed to ensure that the combined uncertainty of the measurement system meets the uncertainty requirements of this Code.

4-1.3.9 Quality Assurance Program. Any facility that performs a calibration for Class 1 instrumentation shall have in place a quality assurance program that documents the following information:

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

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

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

4-1.4 Plant Instrumentation

Plant instrumentation can be used for primary measurements, if the plant instrumentation (including signal-conditioning equipment) can be demonstrated to meet the overall uncertainty requirements.

In the case of flow measurement, all instrument measurements (process pressure, temperature, differential pressure, or pulses from metering devices) must be recorded.

4-1.5 Redundant Instrumentation

Where experience in the use of a particular model or type of instrument dictates that calibration drift can be unacceptable, and no other device is available, redundancy is recommended. Redundant instruments should be used to measure all primary (Class 1 or Class 2) parameters, when practical. Exceptions are redundant flow elements and redundant electrical metering devices, because of the large increase in costs.

A benefit of redundant instruments is realized in a reduction in the random component of uncertainty. Further, one gains the ability to monitor instrument integrity through comparison techniques to detect instrument-related problems.

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

4-2 PRESSURE MEASUREMENT

4-2.1 Introduction

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

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

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

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

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

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

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

4-2.2 Required Uncertainty

The required uncertainty depends on the type of parameters and variables being measured. Refer to paras. 4-1.2.2 and 4-1.2.3 for discussion on measurement classification and instrumentation categorization, respectively.

Class 1 primary parameters and variables shall be determined with 0.1% accuracy class pressure transmitters or equivalent that has an instrument systematic uncertainty of ±0.3% or better of calibrated span. Barometric pressure shall be measured with a pressure transmitter that has an instrument systematic uncertainty of ±0.1% or better of calibrated span.

Class 2 primary parameters and variables shall be determined with 0.25% accuracy class pressure transmitters or equivalent, that have an instrument systematic uncertainty of ±0.50% or better of calibrated span.

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

4-2.3 Recommended Pressure Measurement Devices

Pressure transmitters are the recommended pressure measurement devices. Three types of pressure transmitters due to application considerations are absolute pressure transmitters, gage pressure transmitters, and differential pressure transmitters.

4-2.3.1 Absolute Pressure Transmitters

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

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

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

4-2.3.2 Gage Pressure Transmitters

(a) Application. Gage pressure transmitters measure pressure referenced to atmospheric pressure. The test site atmospheric pressure must be subtracted from the absolute pressure to obtain gage pressure.

$$p_g = p_{\mathrm{abs}} - p_{\mathrm{baro}} \tag{4-2-1}$$

This test site atmospheric pressure should be measured by an absolute pressure transmitter. Gage pressure transmitters may be used only on measurement locations with pressures higher than atmospheric. Gage pressure transmitters are preferred over absolute pressure transmitters in measurement locations above atmospheric pressure because they are easier to calibrate.

(b) Calibration. Gage pressure transmitters can be calibrated by an accurate deadweight gage. The pressure generated by the deadweight 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. If the above corrections are not used, the pressure generated by the deadweight gage may be inaccurate. The actual piston area and mass of weights is determined each time the deadweight gage is calibrated. Other devices can be utilized to calibrate gage pressure transmitters provided that the same level of care is taken.

4-2.3.3 Differential Pressure Transmitters

(a) Application. Differential pressure transmitters are used where flow is determined by a differential pressure meter, or where pressure drops in a duct or pipe must be determined and it is practical to route the pressure tubing.

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

(1) two highly accurate deadweight gages

(2) a deadweight gage and divider combination

(3) one deadweight gage and one differential pressure standard

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

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

4-2.4 Absolute Pressure Measurements

4-2.4.1 Introduction. Absolute pressure measurements are pressure measurements that are below or above atmospheric pressure. Absolute pressure transmitters should be used for these measurements. Typical absolute pressure measurements in an ASME PTC 46 test may include barometric pressure and condenser pressure.

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

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

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

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

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

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

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

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

In steam service, the sensing line should extend at least 0.61 m (2 ft) horizontally from the source before the downward slope begins. This horizontal length will allow condensation to form completely so the downward slope will be completely full of liquid.

The water leg is the condensed liquid 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 gravity and the density of the liquid in the sensing line.

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

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

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

Barometric pressure devices should be installed in the same general area and at the same general elevation that is most representative of the test boundary and minimizes test uncertainty.

4-2.5 Gage Pressure Measurements

4-2.5.1 Introduction. Gage pressure measurements are pressure measurements that are at or above atmospheric pressure. These measurements may be made with gage or absolute pressure transmitters. Gage pressure transmitters are recommended since they are easier to calibrate and to check in situ. Typical gage pressure measurements in an ASME PTC 46 test may include gas fuel pressure and process return pressure. Caution must be used with low-pressure measurements because they may enter the vacuum region at part load operation.

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

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

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

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

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

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

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

In steam service, the sensing line should extend at least 0.61 m (2 ft) horizontally from the source before the downward slope begins. This horizontal length will allow condensation to form completely so the downward slope will be completely full of liquid.

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

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

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

4-2.6 Differential Pressure Measurements

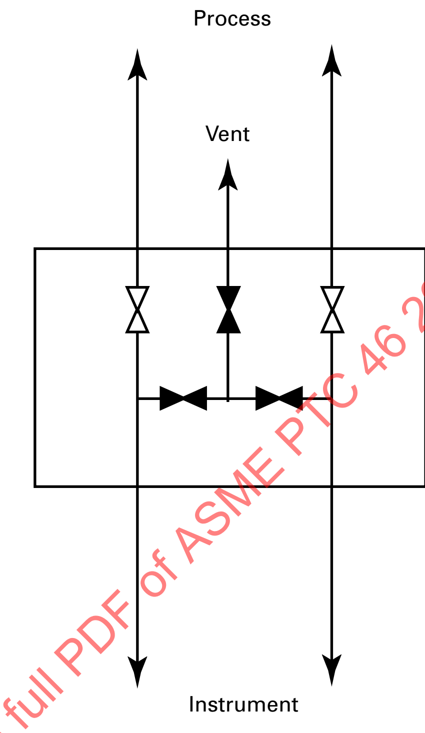
4-2.6.1 Introduction. Differential pressure measurements are used to determine the difference in static pressure between pressure taps in a primary element. Differential pressure transmitters should be used for these measurements. Typical differential pressure measurements in an ASME PTC 46 test may include the differential pressure of gas fuel or process return through a flow element or pressure loss in a pipe or duct. The differential pressure transmitter measures the pressure difference or pressure drop that is used to calculate the fluid flow.

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

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

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

Fig. 4-2.6.2-1 Five-Way Manifold



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

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

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

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

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

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

In steam service, the sensing line should extend at least 0.61 m (2 ft) horizontally from the source before the downward slope begins. This horizontal length will allow condensation to form completely so the downward slope will be completely full of liquid.

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

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

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

When a differential pressure meter is installed on a flow element that is located in a vertical steam or water line, the measurement must be corrected for the difference in sensing line height and fluid head change unless the upper sensing line is installed against a steam or water line inside the insulation down to where the lower sensing line protrudes from the insulation. The correction for the noninsulated case is shown in Fig. 4-2.6.2-2. See also Table 4-2.6.2-1 for units and conversion factor.

For upward flow

$$\Delta p_{\text{true}} = \Delta p_{\text{meas}} + n^*(\rho_{\text{amb}} - \rho_{\text{pipe}})(g/g_c)^*\Delta z \qquad (4\text{-}2\text{-}2)$$

For downward flow

$$\Delta p_{\text{true}} = \Delta p_{\text{meas}} - n^*(\rho_{\text{amb}} - \rho_{\text{pipe}})^*(g/g_c)^*\Delta z \qquad (4\text{-}2\text{-}3)$$

4-3 TEMPERATURE MEASUREMENT

4-3.1 Introduction

This subsection presents requirements and guidance for the measurement of temperature. Recommended temperature measurement devices, and the calibration and application of temperature measurement devices are discussed. Electronic temperature measurement equipment should be used for primary measurements to minimize systematic and random error. Factors affecting the uncertainty of the temperature include, but are not limited to, stability, environment, self-heating, parasitic resistance, parasitic voltages, resolution, repeatability, hysteresis, vibration, warm-up time, immersion or conduction, radiation, dynamic, spatial variation, and data acquisition.

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

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

4-3.2 Required Uncertainty

The required uncertainty depends on the type of parameters and variables being measured. Refer to paras. 4-1.2.2 and 4-1.2.3 for discussion on measurement classification and instrumentation categorization, respectively.

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

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

Secondary parameters and variables should be determined with temperature measurement devices that have an instrument systematic uncertainty of no more than ±3.9°C (7.0°F).

The uncertainty limits above are exclusive of any effects of temperature spatial gradient uncertainty effects, which are considered to be systematic.

4-3.3 Recommended Temperature Measurement Devices

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

4-3.3.1 Thermocouples. Thermocouples may be used to measure temperature of any fluid above 93°C (200°F). The maximum temperature is dependent on the type of thermocouple and sheath material used. Thermocouples should not be used for measurements below 93°C (200°F). The thermocouple is a differential-type device. The thermocouple measures the difference between the measurement location in question and a reference temperature. The greater this difference, the higher the EMF from the thermocouple. Therefore, below 93°C (200°F) the EMF becomes low and subject to induced noise, causing increased systematic uncertainty and inaccuracy.

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

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

"The emf developed by a thermocouple made from homogeneous wires will be a function of the temperature difference between the measuring and the reference junction. If, however, the wires are not homogeneous, and the inhomogeneity is present in a region where a temperature gradient exists, extraneous emf's will be

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

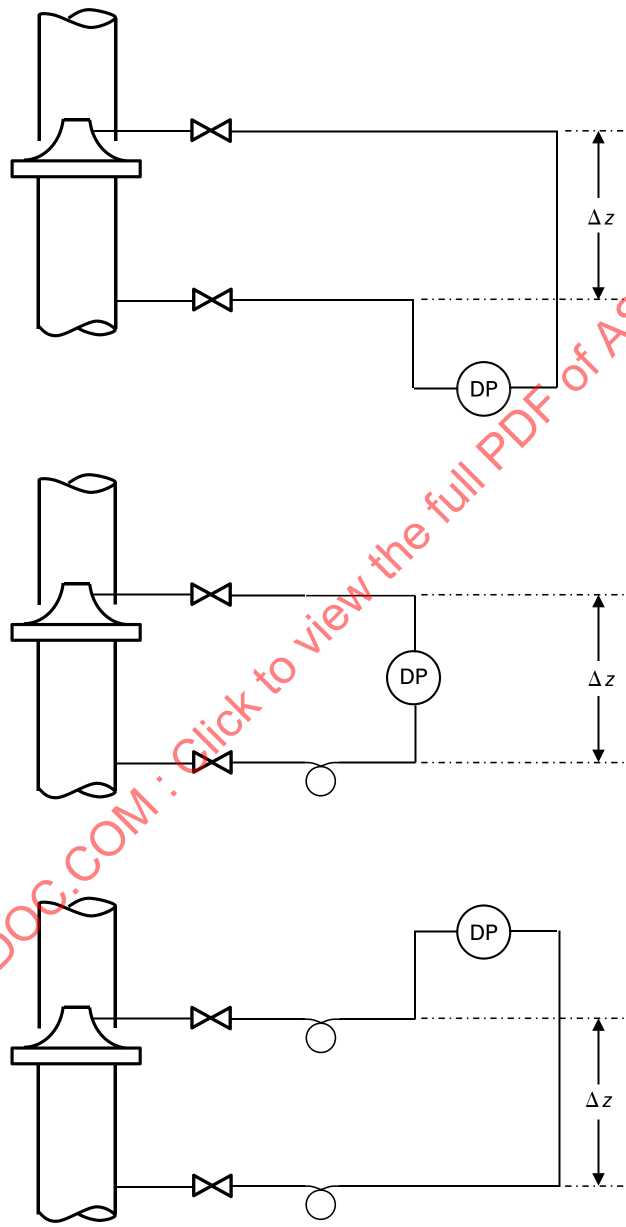


Table 4-2.6.2-1 Units and Conversion Factor for Water Leg Correction for Flow Measurement

Units In Elevation Correction Equation	Elevation, Fluid Density, and Differential Pressure Units				Values of Constants	
Symbol	Δ_p	ρ	g	Δz	Proportionality Constant, g_c	Units Conversion Constant, n
SI Units	Pa	$\frac{kg}{m^3}$	$\frac{m}{s^2}$	m	$g_c \equiv 1.0$ dimensionless	$n \equiv 1.0$ dimensionless [Note (1)]
U.S. Customary Units	$\frac{lbf}{in.^2}$	$\frac{lbm}{ft^3}$	$\frac{ft}{sec^2}$	in.	$g_c \equiv 32.174056$ $\frac{lbm\text{-}ft}{lbf\text{-}sec^2}$	$n \equiv \frac{1}{144}$ $\frac{ft^2}{in.^2}$

GENERAL NOTE: g is the local acceleration due to gravity, ft/sec^2 per an acknowledged source, or may be estimated as: g = 32.17245 × {1 − 0.0026373 × cos(2 × degrees latitude × π/180) + 0.0000059 × [cos^2 (2 × degrees latitude × π/180)]} − 0.000003086 × feet elevation or for SI, g = m/s^2 = 9.80616 × {1 − 0.0026373 × cos(2 × degrees latitude × π/180) + 0.0000059 × [cos^2 (2 × degrees latitude × π/180)]} − 0.000003086 × meters elevation.

NOTE:
(1) N ≡ kg-m/s^2, and Pa ≡ N/m^2. Therefore, Pa ≡ kg/m-s.^{2}

developed, and the output of the thermocouple will depend upon factors in addition to the temperature difference between the two junctions. The homogeneity of the thermocouple wire, therefore, is an important factor in accurate measurements."[1]

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

The elements of a thermocouple must be electrically isolated from each other, from ground and from conductors on which they may be mounted, except at the measuring junction. When a thermocouple is mounted along a conductor, such as a pipe or metal structure, special care should be exercised to ensure good electrical insulation between the thermocouple wires and the conductor to prevent stray currents in the conductor from entering the thermocouple circuit and vitiating the readings. Stray currents may further be reduced with the use of guarded integrating analog-to-digital (A/D) techniques. Further, to reduce the possibility of magnetically induced noise, the thermocouple wires should be constructed in a twisted uniform manner.

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

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

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

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

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

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

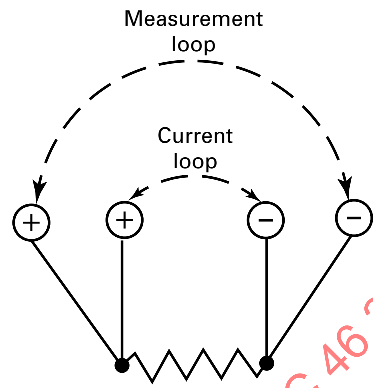
4-3.3.1.3 Reference Junctions. The temperature of the reference junction shall be measured accurately using either software or hardware compensation techniques. The accuracy with which the temperature of the measuring junction is measured can be no greater than the accuracy with which the temperature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

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

4-3.3.2 Resistance Temperature Detectors (RTDs). Resistance temperature detectors (RTDs) may only be used to measure from −270°C to 850°C (−454°F to 1,562°F). ASTM E1137 provides standard specifications for industrial platinum resistance thermometers and includes requirements for manufacture, pressure, vibration, and mechanical shock to improve the performance and longevity of these devices.

[3] ASTM MNL 12, Manual on the Use of Thermocouples in Temperature Measurement, chapter 7, Reference Junctions.

Fig. 4-3.3.2.1-1 Four-Wire RTDs



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

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

Although RTDs are considered a more linear device than thermocouples, due to manufacturing technology, RTDs are more susceptible to vibrational applications. As such, care should be taken in the specification and application of RTDs with consideration for the effect on the devices stability. Field verification techniques should be used to demonstrate the stability is within the uncertainty requirements of para. 4-3.2.

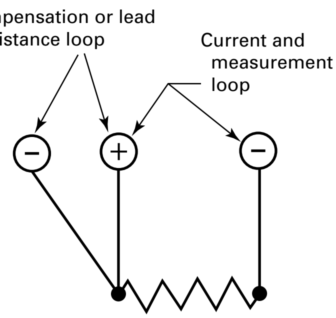
4-3.3.2.1 Class 1 Primary Parameters. Class 1 primary parameters shall be measured with Grade A four-wire platinum RTDs as shown in Fig. 4-3.3.2.1-1. Three-wire RTDs are acceptable only if they can be shown to meet the uncertainty requirements of this Code.

4-3.3.2.2 Class 2 Primary Parameters. Class 2 primary parameters shall be measured with Grade A three-wire platinum RTDs as shown in Fig. 4-3.3.2.2-1. The four-wire technique is preferred to minimize effects associated with lead-wire resistance due to dissimilar lead wires.

4-3.3.2.3 RTD Signal Measurement. Many devices are available to measure the output resistance. The use of each of these instruments in a system to determine temperature requires they meet the uncertainty requirements for the parameter.

4-3.3.3 Thermistors. Thermistors are constructed with ceramic-like semiconducting material that acts as a thermally sensitive variable resistor. This device may be used on any measurement below 149°C (300°F). Above this temperature, the signal is low and susceptible

Fig. 4-3.3.2.2-1 Three-Wire RTDs



to error from current induced noise. Although positive temperature coefficient units are available, most thermistors have a negative temperature coefficient (TC); that is, unlike an RTD, their resistance decreases with increasing temperature. The negative TC can be as large as several percent per degree Celsius, allowing the thermistor circuit to detect minute changes in temperature that could not be observed with an RTD or thermocouple circuit. As such, the thermistor is best characterized for its sensitivity while the thermocouple is the most versatile and the RTD the most stable.

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

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

Typically, the four-wire resistance measurement is not required for thermistors as it is for RTDs measuring Class 1 primary parameters due to its high resistivity. Thus the measurement lead resistance produces an error magnitudes less than the equivalent RTD error. However, in the case where long lead length wires, or wires with high resistance are used which was not part of the calibration, the lead-wire resistance must be compensated for in the measurement. Thermistors are generally more fragile than RTDs and thermocouples and must be carefully mounted and handled in accordance with manufacturer's specifications to avoid crushing or bond separation.

4-3.3.3.1 Thermistor Signal Measurement. Many instruments are available to measure the output resistance. The use of each of these instruments in a system to determine temperature requires they meet the uncertainty requirements for the parameter.

4-3.4 Calibration of Primary Parameter Temperature Measurement Devices

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

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

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

4-3.5 Temperature Scale

The International Temperature Scale of 1990 (ITS-90) is realized and maintained by NIST to provide a standard scale of temperature for use by science and industry in the United States.

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

$$t_{90} = T_{90} - 273.15 \qquad (4\text{-}3\text{-}1)$$

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

$$t_f = (9/5)t_{90} + 32 \qquad (4\text{-}3\text{-}2)$$

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

4-3.6 Typical Applications

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

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

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

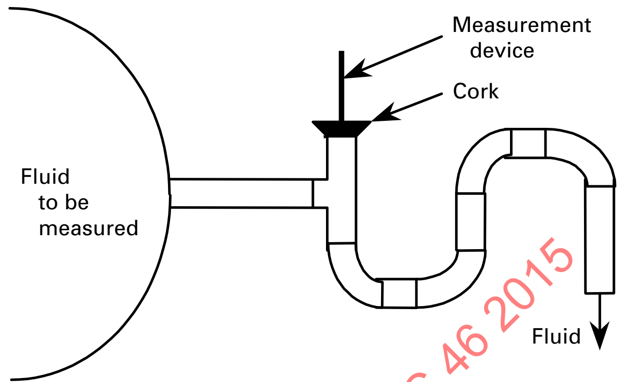
The thermowell should be installed so that the tip protrudes through the boundary layer of the fluid to be measured. Unless limited by design considerations, the temperature sensor shall be immersed in the fluid at least 75 mm (3 in.) but not less than one-quarter of the pipe diameter. If the pipe is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

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

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

For Class 1 primary parameter measurements, the portion of the thermowell or lag section protruding outside the pipe or vessel should be insulated, along with the device itself, to minimize conduction losses.

Fig. 4-3.6.2-1 Flow-Through Well



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

Please refer to ASME PTC 19.3 and ASME PTC 19.3TW for further guidance.

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

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

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

4-3.6.3 Temperature Measurement of Air and Combustion Products. Air (i.e., cooling, combustion, blending, etc.) and combustion products (i.e., exhaust gas, flue gas, etc.) flowing into and through a duct are subject to spatial variations such as nonuniform velocity, varying flow angle, temperature, and composition. This is especially true at the inlet of a duct or near a flow disturbance, such as a bend, tee, fan, vane, damper, or transition. Spatial variation effects, if not addressed by the measurement approach, are considered errors of method and contributors to the systematic uncertainty in the measurement system. Generally, temperature uncertainty can be reduced either by sampling more points in a plane perpendicular to the flow or by using more sophisticated calculation methods such as flow/velocity weighting and flow angle compensation.

The measurement plane should be located away from bends, constrictions, or expansions of the duct. If the stratification is severe, mass/velocity flow weighting should be applied to reduce potential errors in the determination of average temperature. Temperature measurements shall be read individually and not be grouped together to produce a single output. As such, the number and location of temperature measurement devices and flow velocity measurement points should be determined such that the overall systematic uncertainty of the average inlet air temperature measurement devices is minimized as much as practically possible. Velocity weighting is not necessary in cases where pretest uncertainty analysis, based on CFD or past experience of similar flow streams, demonstrates the uncertainty of the average temperature of the stream meets the required uncertainty limits without application of flow/velocity weighting.

The total temperature of the stream is required and, if the average velocity in the area of temperature measurement exceeds 30.48 m/s (100 ft/sec), then it is suggested that the individual temperature reading be adjusted for velocity effect.

$$T_t = T + V^2/(2JC_p) = T + T_v$$

where

C_p = the specific heat, kJ/kg °C
J = the mechanical equivalent of heat, 1 000 kg·m²/kJ·s²
T = the measured temperature, °C
T_t = the total temperature, °C
T_v = the dynamic temperature, °C
V = the gas velocity, m/s

$$T_t = T + V^2/(2Jg_cC_p) = T + T_v$$

where

C_p = the specific heat, Btu/lbm °F
g_c = the gravity constant, 32.1741 lbm·ft/(lbf·s²)
J = the mechanical equivalent of heat, 778.1692623 ft·lbf/Btu
T = the measured temperature, °F
T_t = the total temperature, °F
T_v = the dynamic temperature, °F
V = the gas velocity, ft/sec

NOTE: It is very important for the user of the Code, when adjusting for the velocity effect, to ensure that it is appropriate to apply this adjustment as station instrument systems and parameter/variable corrections based on these measurements may already include this adjustment.

It is recommended that air and combustion products of temperature be measured at the specified test boundary; however, there may be cases where the measurement upstream or downstream may be more practical and result in a measurement of lower uncertainty such as selecting to measure temperature inside the air inlet duct instead of at the inlet of the duct because of better mixing to attain a more representative bulk temperature measurement. If measurements are made at locations other than the specified test boundary, the location selected shall be such that no heat addition or loss occurs between the specified boundary and the selected measurement location.

The following sections provide guidance on the more prevalent encountered boundaries that require temperature measurement by this Code for air and combustion products. Further guidance on proper measurement techniques for plant boundaries can be found within the equipment-specific test codes (i.e., ASME PTC 22, ASME PTC 4.4, ASME PTC 4, ASME PTC 30.1, ASME PTC 23, ASME PTC 51, etc.) and should be consulted when designing an ASME PTC 46 test. ASME PTC 19.1 methods shall be used for the determination of the uncertainty associated with spatial variations.

4-3.6.3.1 Temperature Measurement of Inlet Combustion Air. Measurement of temperature and velocity of inlet combustion air requires several measurement points to minimize the uncertainty effects of stratification. The number of measurement points necessary shall be determined to ensure that the measurement uncertainty for average inlet temperature is below 0.55°C (1°F).

(a) Fixed Temperature Measurements. Measurements of temperature at the inlet air stream should be taken at centroids of equal areas or as appropriate for the given geometry. A minimum of one temperature device per 9.29 m² (100 ft²) shall be used to determine the inlet air temperature or four devices, whichever is greater.

(b) Velocity Measurements. In this case the velocity profile is determined using pitot traverses, hot wire anenometers, or similar devices. Measurements of velocity at the inlet air stream shall be taken at the same point at which the temperature measurement is made. Velocity weighting is not necessary in cases where pretest uncertainty analysis, based on CFD or past experience of similar flow streams indicated, demonstrates the uncertainty in the average inlet temperature is below 0.55°C (1°F).

Measurement frequency and locations shall be sufficient to account for stratification of the air temperature after applications with inlet cooling or heating system. In applications with inlet fogging, evaporative cooling, or chilling, the sensors shall be capable of measuring dry-bulb temperature at the boundary without the effects of condensation or water droplet impingement. The number of locations and frequency of measurements shall be determined by the pretest uncertainty analysis.

4-3.6.3.2 Temperature Measurement of Products of Combustion in a Duct. Measurement of temperature and velocity of products of combustion requires several measurement points to minimize the uncertainty effects of stratification. The number of measurement points necessary shall be determined to ensure that the measurement uncertainty for average products of combustion temperature is below 5.56°C (10°F).

(a) Fixed Temperature Measurements. Measurements of temperature at the products of combustion stream should be taken at centroids of equal areas or as appropriate for the given geometry. A minimum of 4 to a maximum of 36 measurement points are required. Measurements shall be taken at equal areas of 0.84 m^2 (9 ft^2) or less to attain a minimum of 4 measurement points. In cases where the equal areas requirement of 0.84 m^2 (9 ft^2) results in more points than 36, the equal areas may be larger than 0.84 m^2 (9 ft^2). Alternate grid designs and number of measurement points can deviate from the Code requirements if it can be demonstrated that the measurement uncertainty for average products of combustion temperature is below 5.56°C (10°F).

(b) Velocity Measurements. In this case the velocity profile is determined using pitot traverses, laser anenometers, or similar devices. Measurements of velocity at the products of combustion stream shall be taken at the same point at which the temperature measurement is made. Velocity weighting is not necessary in cases where pretest uncertainty analysis, based on CFD or past experience of similar flow streams indicated, demonstrates the uncertainty in the average inlet temperature is below 5.56°C (10°F).

Typically, as in a steam generator or gas turbine exhaust, the duct pressures are low or negative so that thermowells or protection tubes are not needed. A long sheathed thermocouple or an unsheathed thermocouple attached to a rod or velocity probe will suffice. If the products of combustion temperature are measured at a point where the temperature of the gas is significantly different from the temperature of the surrounding surface, an error is introduced. This situation occurs when the gas temperature is high, and the surface is cooled well below the gas temperature. The thermocouple is cooled by radiation to the surrounding surface, and this reduction in measured temperature should be taken into account. Alternatively, when the measurement point is at a location exposed to actual combustion processes or in direct site, the thermocouple is heated by radiation from the combustion process. A high-velocity thermocouple (HVT) probe can be used to reduce this error.

4-3.6.3.3 Measured Cooling Tower Inlet Dry-Bulb and Wet-Bulb Temperature. The measurement of inlet air wet-bulb temperature is required for the testing of plant configurations with cooling towers inside the boundary covered by this Code. The measurement of inlet dry-bulb temperature is required for natural draft, fan assisted, and wet/dry cooling towers. The measurement of inlet dry-bulb temperature is also required for mechanical draft cooling towers of forced draft design in order to determine the fan inlet air density for fan power correction. The devices selected for measurement of dry-bulb and wet-bulb temperature shall meet all the requirements for humidity measurement of para. 4-4.3.2 with the exception of the wick and water supply for dry-bulb measurements. The equipment selected and the number of measurement points necessary should be determined to ensure that the overall measurement uncertainty for average inlet temperature is below 1.11°C (2°F).

For the measurement of inlet dry-bulb and wet-bulb temperature, the instruments shall be located no more than 1.5 m (5 ft) outside the air intake(s). Care should be taken to ensure that splashing at the air inlet does not affect the instruments. A sufficient number of measurement stations shall be applied to ensure that the test average is an accurate representation of the true average inlet wet-bulb temperature.

It is recommended that as a conservative starting point, one temperature measuring point per air inlet be considered for the purposes of determining the average dry-bulb and/or wet-bulb temperature at the cooling tower.

This instrumentation requirement around the cooling tower can typically be reduced without significantly impacting the test uncertainty for situations in which the following apply:

(a) The equipment scope is combined cycle, for which the ST performance is typically between one-quarter and one-half of the plant output.

(b) The operating regime of the ST last stage blades and cooling tower are close to the middle of the design operating envelope, which tends to reduce the sensitivity coefficient of inlet air temperature differences on plant results. Examples of this could include cold day operation of an air-cooled condenser, wet-bulb temperatures 10R or more below the design maximum for a wet cooling tower, or a test disposition without duct firing for a unit that is designed with duct firing.

(c) Test scopes that have no anticipated sources of either cooling tower inlet air stratification or temperature difference between the cooling tower and other test boundary streams. Typical sources of stratification include windy areas such as coastal sites as well as sites with inlet air flow restrictions due to either structures or natural terrain. Typical sources of temperature difference can come from plant waste heat streams (i.e., HRSG stack and generator cooling systems) and neighboring facilities with atmospheric heat-rejection equipment.

Practical minima for instrument counts for cooling towers are given as 4 for duties or for duties below 100 MWth, and 8 for duties greater than this. Further reductions in instrument count require detailed sensitivity factor analysis as well as project-specific knowledge of tower stratification.

4-3.6.3.4 Measured Air Cooled Condenser Inlet Dry Temperature. The inlet air temperature measurement shall consist of a specified number of dry-bulb temperature sensors. The number of measurement points necessary shall be determined to ensure that the measurement uncertainty for average inlet temperature is below 0.55°C (1°F). At least one inlet dry-bulb temperature measuring point per fan shall be selected, with a minimum of 12 total inlet dry-bulb temperature-measuring points per unit. The measurement points shall be located downstream from the fan discharge plane, within the air stream, as near to the fan deck elevation as practical. The walkway or fan bridge is a suggested location. Measurement points shall be generally in the outer half of the fan radius, on the side nearest to the closest ACC perimeter wall and 1 m from the outer fan diameter.

An alternative arrangement is to locate the temperature instruments around the perimeter of the ACC. These instruments shall be separated in equal amounts and positioned equidistantly around the ACC perimeter with one in the center of the ACC plot. These instruments shall be hung 1 m (39.37 in.) below the top of the air inlet opening. If these locations are not accessible due to the design of the ACC, then other locations shall be selected and agreed upon.

4-4 HUMIDITY MEASUREMENT

4-4.1 Introduction

This subsection presents requirements and guidance for the measurement of humidity. Recommended humidity measurement devices and calibration and application of humidity measurement devices are also discussed. Electronic humidity measurement equipment should be used for primary measurements to minimize systematic and random error.

The uncertainty of humidity measurement equipment shall consider effects including, but not limited to, resolution, stability, environmental, temperature measurement errors, pressure measurement errors, warm-up time, spatial variation, nonlinearity, repeatability, analog output, and data acquisition.

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

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

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

4-4.2 Required Uncertainty

The required uncertainty depends on the type of parameters and variables being measured. Refer to paras. 4-1.2.2 and 4-1.2.3 for discussion on measurement classification and instrumentation categorization, respectively.

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

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

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

4-4.3 Recommended Humidity Measurement Devices

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

4-4.3.1 Relative Humidity Transmitters

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

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

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

4-4.3.1.1.1 Primary Sources of Measurement Errors. The primary sources of measurement errors associated with relative humidity transmitters are typically

(a) sensor contamination
(b) analog output
(c) installation location
(d) temperature equilibrium
(e) accuracy
(f) resolution

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

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

4-4.3.2 Wet- and Dry-Bulb Psychrometers

4-4.3.2.1 Application. The wet- and dry-bulb psychrometer consists of two temperature sensors and use the temperature effects caused by latent heat exchange. One sensor measures the ambient dry bulb temperature; the other is covered with a clean wick or other absorbent material, which is wetted and the resulting evaporation cools it to the wet-bulb temperature. Traditionally, the temperature sensors are resistance temperature detectors or thermistors as discussed in paras. 4-3.3.2 and 4-3.3.3, respectively. The temperature sensors must be shielded from solar and other sources of radiation and must have a constant air flow across the sensing element. Psychrometer measurements require skilled operators to ensure careful control of a number of variables that can affect the measurement results.

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

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

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

The mechanically aspirated psychrometer should incorporate the following features:

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

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

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

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

(e) Air is drawn across the sensing element in such a manner that it is not heated by the fan motor or other sources of heat.

(f) The psychrometer should be located at least 1.5 m (5 ft) above ground level and should not be located within 1.5 m (5 ft) of vegetation or surface water.

4-4.3.2.1.1 Primary Sources of Measurement Errors. The primary sources of measurement errors associated with wet- and dry-bulb psychrometers are typically

(a) temperature sensor
(b) installation location
(c) radiation
(d) conduction (water in reservoir too warm)
(e) faulty capillary action (very large wet bulb depression)
(f) too high or too low air flow across the wick

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

4-4.3.3 Chilled-Mirror Dew Point Meters

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

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

(a) sensor contamination
(b) analog output
(c) installation location
(d) accuracy
(e) resolution

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

4-5 FLOW MEASUREMENT

4-5.1 Introduction

This subsection presents requirements and guidance for the measurement of flow for this Code. It also discusses recommended flow measurement devices, calibration of flow measurement devices, and application of flow measurement devices.

Differential pressure meters (orifice, nozzle, and venturi), mass flowmeter (Coriolis flowmeters), ultrasonic, and mechanical meters (turbine and positive displacement) are the classes of meters recommended in this Code. Table 4-5.1-1 defines the recommended (R), acceptable (A), and not recommended (N) meters for different applications.

See para. 4-5.3 for additional details on application of flow measurement devices and 8 cm (3 in.). However, since flow measurement technology will change over time, this Code does not limit the use of other flow measurement devices not currently available or not currently reliable. If such a device becomes available and is shown to be of the required uncertainty and reliability, it may be used.

Table 4-5.1-1 Recommendations for Differential Pressure Meters for Different Applications

Fluid	Orifice	Nozzle or Venturi	Coriolis	Ultrasonic	Turbine	Positive Displacement
Water [Note (1)]	R	R	R	A	A	A
Steam	R	R	N	N	N	N
Natural gas	R	N	R	A	A	N
Oil	A	N	A	N	A	R
Organic heat transfer fluid	A	N	A	N	A	R

GENERAL NOTE: R = recommended, A = acceptable, and N = not recommended.

NOTE:
(1) Positive displacement or turbine meters are recommended for water flows in pipes smaller than 3 in.

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 steam blows or chemical cleanings. While the flow measurement device is stored, it must be capped and protected from environmental damage such as moisture and dirt.

In accordance with ASME PTC 19.5, the flow must be steady, or changing very slowly as a function of time. Pulsations of flow must be small compared with the total flow rate. The frequency of data collection must adequately cover several periods of unsteady flow. Fluctuations in the flow shall be suppressed before the beginning of a test by very careful adjustment of flow and level controls or by introducing a combination of conductance, such as pump recirculation, and resistance, such as throttling the pump discharge, in the line between the pulsation sources and the flow-measuring device. Hydraulic damping devices such as restrictors on instruments do not eliminate errors due to pulsations and, therefore, shall not be permitted.

If the fluid does not remain in a single phase while passing through the flow measurement device, or if it has two phases when entering the meter, then it is beyond the scope of ASME PTC 19.5. In passing water through the flow measurement device, the water should not flash into steam. In passing steam through the flow measurement device, the steam must remain superheated. ASME PTC 12.4 describes methods for measurement of two-phase flow in instances when it is desirable to measure the flow rate of a two-phase mixture.

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

Mass flow rate as shown by computer printout or flow computer is not acceptable without showing intermediate results and the data used for the calculations. In the case of a differential pressure class meter, intermediate results would include the discharge coefficient, corrected diameter for thermal expansion, expansion factor, etc. Raw data includes static and differential pressures, and temperature.

For the case of a mechanical meter, intermediate results include the meter constant(s) used in the calculation, and how it is determined from the calibration curve of the meter. Data includes frequency, temperature, and pressure.

For any flow measurement devices, fuel analysis and the intermediate results used in the calculation of the fluid density is required.

4-5.2 Required Uncertainty

The required uncertainty will depend upon the type of parameters and variables being measured. Refer to paras. 4-1.2.2 and 4-1.2.3 for discussion on measurement classification and instrumentation categorization, respectively.

If not otherwise specified by this Code, Class 1 primary parameters and variables shall be determined with flow measurement devices that have a systematic uncertainty of no more than ±0.5% of mass flow rate. Class 1 primary parameters and variables shall have a laboratory calibration performed.

Class 2 primary parameters and variables shall be measured with flow measurement devices/methods that will result in a relative uncertainty contribution of the parameters and variables to the result of no more than ±0.2%.

$$\text{Expansion: (relative sensitivity coefficient} \times \text{relative combined uncertainty)} < \text{or} = 0.2\%$$

Class 2 primary parameters and variables may use the empirical formulations for the discharge coefficient for differential pressure class meters if the uncertainty requirements are met and the meter is manufactured, installed, and operated in strict accordance with ASME PTC 19.5. Mechanical meters used in the measurement of Class 2 primary parameters and variables shall be laboratory calibrated.

4-5.3 Flow Measurement Devices

Differential pressure meters (orifice, nozzle, and venturi), Coriolis flowmeters, ultrasonic flowmeters, and mechanical meters (turbine and positive displacement) are the recommended flow measurement devices for the specific applications noted herein. Economic, application, and uncertainty considerations should be used in the selection of the most appropriate flow measurement device.

In the case when a flow measurement device is laboratory calibrated, the entire primary device must be calibrated. This shall include the primary element, upstream and downstream metering runs, and flow conditioners. A positive, mechanical alignment method shall be in place to replicate the precise position of the meter run or primary element when it was calibrated. The flow section must remain dirt- and moisture-free for shipping and storage. Whenever possible it is preferred to ship the flow section as one piece, and not disassembled for shipping or installation.

4-5.3.1 Differential Pressure Meters. In this subsection, the application and calibration requirements for the use of orifice, flow nozzle, and venturi meters are presented.

All differential pressure meters used in the measurement of Class 1 primary parameters and variables shall be laboratory calibrated. If flow straighteners or other flow-conditioning devices are used in the test, they shall be included in the meter piping run when the calibration is performed. Qualified hydraulic laboratories commonly calibrate within an uncertainty of 0.2%. Thus, with inherent curve-fitting inaccuracies, uncertainties of less than 0.3% in the discharge coefficients of laboratory-calibrated meters can be achieved. The procedures for fitting a curve through laboratory calibration data is provided in detail in ASME PTC 19.5 for each differential pressure meter. The procedures for extrapolation of a calibration to a higher Reynolds number than available in the laboratory, if necessary, is also given for each meter in ASME PTC 19.5. Differential pressure meters used in the measurement of Class 2 primary parameters and variables may use the empirical formulations for the discharge coefficient for differential pressure class meters if the uncertainty requirements are met and the meter is designed, manufactured, installed, and operated in strict accordance with ASME PTC 19.5.

For a differential pressure meter to be used as a Class 1 meter, it shall be manufactured, calibrated, installed, and operated in accordance with ASME PTC 19.5. The calculation of the flow must be done in accordance with that Code. The documentation of factory measurements, manufacturing requirements, dimensional specifications of the installation including upstream and downstream disturbances, and of the start-up procedures, must be examined to validate compliance with the requirements of ASME PTC 19.5. Details shall be documented as suggested in (a) through (m) below.

(a) piping straight length requirements upstream and downstream of the primary element and between the flow conditioner (if used) and the primary element

(b) piping and flow element diameters and roundness, and locations of roundness measurements

(c) piping smoothness

(d) internal smoothness of flow nozzle or venturi element

(e) smoothness and flatness of upstream face of orifice plate

(f) dimensions and machining tolerances for all dimensions of primary element given in ASME PTC 19.5

(g) sharpness of orifice plate edge

(h) thickness of orifice plate required

(i) inspection for assurances of no burrs, nicks, wire edges, etc.

(j) location, size, and manufacturing requirements of pressure taps, including machining and dimensional tolerances

(k) location of temperature measurement

(l) eccentricity of primary element and piping

(m) type and manufacturing requirements of flow conditioner, if used

Class 1 primary parameters and variables shall be measured with a minimum of two sets of differential pressure taps each with independent differential pressure measurement devices. It is recommended that the two sets of pressure taps be separated by 90 deg or 180 deg. Additionally, it is recommended for the throat tap nozzle that the meter be manufactured with four sets of differential pressure taps and two sets of taps be individually measured. Further, the flow calculation should be done separately for each pressure tap pair, and averaged. Investigation is needed if the results differ from each tap set calculation by more than the flow measurement uncertainty. In cases where the metering run is installed downstream of a bend or tee, it is recommended that the pairs of single taps be installed so that their axes are perpendicular to the plane of the bend or tee. Differential pressure meters should be assembled, calibrated (if applicable), and left intact for the duration of the test since manufacture. Once manufactured and calibrated (if applicable), the flowmeter assembly should not be disassembled at the primary element flanges. If it is necessary to disassemble the section for inspection or other means prior to the test, provisions for the accurate realignment and reassembly, such as pins, must be built into the section to replicate the precise position of the flow element when it was manufactured and calibrated (if applicable). If proper reassembly is not assured by the recommended methods, then the flow element shall be treated as uncalibrated in the uncertainty analysis. In addition, gaskets or seal rings (if used) shall be inserted in such a way that they do not protrude at any point inside the pipe or across the pressure tap or slot when corner tap orifice meters are used.

Table 4-5.3.1-1 Units and Conversion Factor for Mass Flow Through a Differential Pressure Class Meter

Units In General Flow Equation	Mass Flow Rate Units	Meter Geometry, Fluid Density, and Differential Pressure Units			Values of Constants	
Symbol	m	*d* or *D*	ρ	$\Delta\rho$	Proportionality Constant, g_c	Units Conversion Constant, *n*
SI Units	$\frac{\text{kg}}{\text{s}}$	m	$\frac{\text{kg}}{\text{m}^3}$	Pa	$g_c \equiv 1.0$ dimensionless	$n \equiv 1.0$ dimensionless [Note (1)]
U.S. Customary Units	$\frac{\text{lbm}}{\text{hr}}$	in.	$\frac{\text{lbm}}{\text{ft}^3}$	$\frac{\text{lbf}}{\text{in.}^2}$	$g_c = 32.174056$ $\frac{\text{lbm-ft}}{\text{lbm-ft sec}^2}$	$n \equiv 300.0$ $\frac{\text{ft}^2}{\text{sec}^2}\left(\frac{\text{in.}^2}{\text{ft}^2} \times \frac{\text{sec}^2}{\text{hr}^2}\right)^{0.5}$

NOTE:
(1) $\text{N} \equiv \text{kg-m/s}^2$, and $\text{Pa} \equiv \text{N/m}^2$. Therefore, $\text{Pa} \equiv \text{kg/m-s}^2$.

The general equation of mass flow through a differential pressure class meter for liquids and gases flowing at subsonic velocity from ASME PTC 19.5 is

$$m = n\frac{\pi}{4}d^2 C_\epsilon \sqrt{\frac{2\rho(\Delta p)g_c}{1-\beta^4}} \tag{4-5-1}$$

where
- C = discharge coefficient
- d = diameter of flow element (bore) at flowing fluid temperature
- g_c = proportionality constant
- m = mass flow
- n = units conversion factor for all units to be consistent
- β = ratio of flow element (bore) and pipe diameters (d/D), both diameters at the flowing fluid temperature
- ξ = expansion factor
- ρ = fluid density
- Δp = differential pressure

Table 4-5.3.1-1 provides the appropriate units and the conversion factor for eq. (4-5-1) in U.S. Customary and SI units.

The procedures for determining the discharge coefficient and expansion factor for the various devices are given in ASME PTC 19.5. Note that because the discharge coefficient is dependent on Reynolds number, which in turn is dependent on flow, both the sizing of and calculation of flow through these meters involve iteration. For a properly constructed differential pressure meter, the discharge coefficient is a function of the Reynolds number of flow, and the diameters of the flow element and the pipe for the range of flows found in power plants. Discharge coefficients for nozzle and venturi meters are in the order of 1.0, as compared to typical discharge coefficients of orifice meters in the order of 0.6.

Laboratory calibration data for differential pressure meters of like type and size, and relationships of discharge coefficient (C) vs. Reynolds number, are available for each type of differential pressure meter. Empirical formulations for discharge coefficient are based on studies of the results of large numbers of calibrations. Application of the empirical formulations for discharge coefficient may be used for Class 2 primary variables if uncertainty requirements are met. In some cases it is preferable to perform a hydraulic laboratory calibration of a specific differential pressure meter to determine the specific discharge coefficient. To meet the uncertainty requirements of this Code for Class 1 primary parameters and variables, it is required to calibrate the meter. The expansion factor is a function of the diameters of the flow element and the pipe, the ratio of the differential pressure to the static pressure, and the isentropic exponent of the gas or vapor. It is used for compressible flows; in this case commonly gas. It corrects the discharge coefficient for the effects of compressibility. This means that a hydraulic calibration of a differential pressure flowmeter is equally as valid for compressible flow application as in incompressible flow application with trivial loss of accuracy. This is a strong advantage of differential pressure meters in general because laboratory determination of compressible flow is generally less accurate than of incompressible flow. The value of ξ for water flow measurement is unity, since it is incompressible.

The systematic uncertainty of the empirical formulation of the discharge coefficient and the expansion factor in the general equation for each of the recommended differential pressure meters is presented in ASME PTC 19.5 and repeated in Table 4-5.3.1-2 for convenience. It should be noted that the tabulated uncertainty values have analytical constraints on Reynolds numbers, bore diameters, and beta ratios and it is to be emphasized that these values assume that the flow measurement device is manufactured, installed, and operated as specified in ASME PTC 19.5 and herein. In using the empirical formulations, the uncertainty of the discharge coefficient is by far the most significant component of the flow measurement uncertainty, and is the dominant factor in the uncertainty analysis, assuming that the process and

Table 4-5.3.1-2 Summary Uncertainty of Discharge Coefficient and Expansion Factor

Location	Uncertainty of Empirical Discharge Coefficient, C, for an Uncalibrated Flow Element	Uncertainty of Expansion Factor, ϵ [Note (1)]
Orifice	0.6% for $0.2 \leq \beta \leq 0.6$ β% for $0.6 \leq \beta \leq 0.75$	$\frac{4(\Delta p)}{p_1}$
Venturi	0.7% for $0.3 \leq \beta \leq 0.75$	$\frac{(4 + 100\beta^8)(\Delta p)}{p_1}$
Nozzle, wall taps	1.0% for $0.2 \leq \beta \leq 0.5$	$\frac{2(\Delta p)}{p_1}$
Nozzle, throat taps	0.5% $0.25 \leq \beta \leq 0.5$	$\frac{2(\Delta p)}{p_1}$

GENERAL NOTES:
(a) Pressure and differential pressure are the same units.
(b) Please see ASME PTC 19.5 for additional uncertainty sources (i.e., pulsation, alignment, etc.).

NOTE:
(1) The systematic uncertainty of the empirical formulation of the discharge coefficient and the expansion factor in the general equation for each of the recommended differential pressure meters is sourced from ASME PTC 19.5 and provided in this Table for convenience.

differential pressure instrumentation used in conjunction with the meter is satisfactory.

The total measurement uncertainty of the flow contains components consisting of the uncertainty in the determination of fluid density, flow element (bore) and pipe diameter, and of pressure, temperature, and differential pressure measurement uncertainty in addition to the components caused by the uncertainty in C and ϵ. Refer to ASME PTC 19.5 for the methodology in the determination of the systematic uncertainty.

4.5.3.1.1 Orifice Meters

4-5.3.1.1.1 Application. Orifice meters may be used for fuel gas and liquids in pipes greater than 5 cm (2 in.) and low pressure steam.

In accordance with ASME PTC 19.5, three types of tap geometries are available and include flange taps, D and $D/2$ taps, and corner taps. This Code recommends that only flange taps or corner taps be used for primary variable measurements with orifice meters.

The lip-like upstream side of the orifice plate that extends out of the pipe, called the tag, shall be permanently marked with the following information:

(a) identification as the upstream side
(b) measured bore diameter to five significant figures
(c) measured upstream pipe diameter to five significant figures if same supplier as orifice plate
(d) instrument, or orifice, identifying number

4-5.3.1.1.2 Calibration. Water calibration of an orifice meter does not increase the measurement uncertainty when the meter is used in gas measurements. The uncertainty of the expansion factor in the fundamental flow [eq. (4-5-1)] is the same whether the orifice is water or air/gas calibrated. The uncertainty of the expansion factor is shown in Table 4-5.3.1-2. The procedure for curve fitting, including extrapolation, if necessary, and evaluating the curve for the coefficient of discharge shall be conducted in compliance with ASME PTC 19.5.

4-5.3.1.2 Nozzle Meters

4-5.3.1.2.1 Application. Nozzle meters in an ASME PTC 46 test may be used for steam flows, and for water flow in pipes at least 10 cm (4 in.). For water flows, calibrated ASME flow sections with a throat tap nozzle can achieve a measurement uncertainty of 0.3%.

In accordance with ASME PTC 19.5, three types of ASME primary elements are recommended including low beta ratio nozzles, high beta ratio nozzles, and throat tap nozzles. Other nozzles may be used if equivalent level of care is taken in their fabrication and installation and if they are calibrated in a laboratory with the same care and precision as required in ASME PTC 19.5 and herein.

As detailed in ASME PTC 19.5, the flow section is comprised of the primary element, the diffusing section if used, the flow conditioner, and the upstream and downstream piping lengths.

4-5.3.1.2.2 Calibration. At least 20 calibration points should be run over the widest range of Reynolds numbers possible that applies to the performance test. The procedure for determining whether the calibration curve parallels the theoretical curve shall be conducted in accordance with ASME PTC 19.5. The procedure for fitting including extrapolation, if necessary, and evaluating the curve for the coefficient of discharge shall be conducted in compliance with ASME PTC 19.5.

4-5.3.1.3 Venturi Meters

4-5.3.1.3.1 Application. Venturi meters in an ASME PTC 46 test may be used for steam flows, and for water flow in pipes at least 10 cm (4 in.).

In accordance with ASME PTC 19.5, the ASME (classical Herschel) venturi is the recommended type of primary element. Other venturis may be used if equivalent level of care is taken in their fabrication and installation and if they are calibrated in a laboratory with the same care and precision as required in ASME PTC 19.5 and herein.

4-5.3.1.3.2 Calibration. In accordance with ASME PTC 19.5, due to similar design considerations, ASME venturi meters commonly maintain the same physics of the flow as the throat tap nozzles. As such, similar to nozzle meters, at least 20 calibration points should be run over the widest range of Reynolds numbers possible which applies to the performance test. The procedure for fitting including extrapolation, if necessary, for the coefficient of discharge shall be conducted in compliance with ASME PTC 19.5.

4-5.3.2 Coriolis Flowmeter

4-5.3.2.1 Application. Coriolis flowmeters in an ASME PTC 46 test may be used for gas fuel flows and liquid flows within the line pressure and temperature specification and characterization of the flowmeter. Coriolis flowmeters measure mass flow directly. Due to the meters insensitivity to velocity profile distortion and swirl, no straight-run or flow-conditioning requirements are typically required. To minimize measurement uncertainty, the zero reading of the Coriolis meter must be verified at the test line temperature prior to the start of the performance test. ASME MFC 11 provides additional details on Coriolis flowmeters.

4-5.3.2.2 Calibration. The calibration of the Coriolis flowmeter is generally conducted with water. Other fluids may be used because the constants are valid for other fluids. The calibration points shall be taken at flow rates that surround the range of flow rates expected during the test. The effect of operating pressure and temperature on the flowmeter during the test must be applied to correct for the influence of operating conditions different than calibration conditions. The Coriolis flowmeter must be characterized for the line pressure and line temperature. Care must be taken such that the constants within the meter's processing that exist during lab calibrations are identical to those present in the meter when it is put into operation and during performance testing. Such constants compensate for physical, electrical, and sensor characteristics. In addition, it should be confirmed that the calibration factors determined during lab calibration are also applied correctly in the meter's processor.

4-5.3.3 Ultrasonic Meters

4-5.3.3.1 Application. Ultrasonic flowmeters can be used for gas fuel flow measurements and water flow measurements. These meters measure velocity of the flowing fluid by which volumetric flow can be calculated by known physical dimensions of the metering section. ASME PTC 19.5, Section 10 describes ultrasonic flowmeters in more detail. Due to the sensitivity on velocity profile on its measurement, a flow conditioner shall be used as well as adequate upstream and downstream straight-run lengths. To ensure proper application, manufacturers often provide ultrasonic flowmeters complete with flow conditioner and spool pieces of necessary straight-run length.

4-5.3.3.2 Calibration. The laboratory calibration of ultrasonic flowmeters shall be conducted in a complete assembled spool piece configuration. When used for natural gas flow measurement, the laboratory calibration is typically conducted with natural gas at flow rates that surround the range of flow experienced during base load operation of the gas turbine. Care must be taken such that the constants and algorithms within the meter's processing that exist during laboratory calibrations are identical to those present in the meter when it is put into operation and during performance testing. Such constants and algorithms compensate for physical, electrical, and sensor characteristics. In addition, it should be confirmed that the calibration factors determined during laboratory calibration are also applied correctly in the meter's processor.

4-5.3.4 Mechanical Meters. In this subsection, the application and calibration requirements for the use of turbine and positive displacement meters are presented. Turbine meters are commonly classified as inference meters as they measure certain properties of the fluid stream and "infer" a volumetric flow while positive displacement meters are commonly classified as direct meters as they measure volumetric flow directly by continuously separating (isolating) a flow stream into discrete volumetric segments and counting them.

A fundamental difference between differential pressure meters and mechanical meters is the flow equation derivation. Differential pressure meters flow calculation may be based on fluid flow fundamentals utilizing a First Law of Thermodynamics derivation where deviations from theoretical expectation may be assumed under the discharge coefficient. Thus, one can manufacture, install, and operate a differential pressure meter of known uncertainty. Conversely, mechanical meter operation is not rooted deeply in fundamentals of thermodynamics and have performance characteristics established by design and calibration. Periodic maintenance, testing, and recalibration are required because the calibration will shift over time due to wear, damage, or contamination.

All mechanical meters used in the measurement of Class 1 or Class 2 primary parameters and variables shall be laboratory calibrated. These calibrations shall be performed on each meter using the fluid, operating conditions, and piping arrangements as nearly identical to the test conditions as practical. If flow straighteners or other flow-conditioning devices are used in the test, they shall be included in the meter piping run when the calibration is performed.

4-5.3.4.1 Turbine Meters

4-5.3.4.1.1 Application. Recommended applications of turbine meters by this Code are liquid flow rates in pipes less than 8 cm (3 in.).

The turbine meter is an indirect volumetric meter. Its main component is an axial turbine wheel turning freely in the flowing fluid. The turbine wheel is set in rotation by the fluid at a speed that is directly proportional to the average velocity of the fluid in the free cross section of the turbine meter. The speed of the turbine wheel is therefore directly proportional to the volumetric flow rate of the flow, with the number of revolutions proportional to the volume that has passed through the meter. There are two basic turbine meter designs: electromagnetic and mechanical.

The electromagnetic-style meter has two moving parts including the rotor and bearings. The rotor velocity is monitored by counting pulses generated as the rotor passes through a magnetic flux field created by a pickup coil located in the measurement module. A meter factor, or "K" factor, is determined for the meter in a flow calibration laboratory by counting the pulses for a known volume of flow and is normally expressed as pulses per acf (actual cubic feet). This "K" factor is unique to the meter and defines its accuracy.

The mechanical-style meter uses a mechanical gear train to determine the rotor's relationship to volume. The gear train is commonly comprised of a series of worm gears, drive gears, and intermediate gear assemblies that translates the rotor movement to a mechanical counter. In the mechanical-style meter, a proof curve is established in a flow calibration laboratory and a combination of change gears is installed to shift the proof curve to 100%.

Turbine meter performance is commonly defined by rangeability, linearity, and repeatability.

(a) Rangeability. Rangeability is a measure of the stability of the output under a given set of flow conditions and is defined as the ratio of the maximum meter capacity to the minimum capacity for a set of operating conditions and during which the meter maintains its specified accuracy.

(b) Linearity. Linearity is defined as the total deviation in the meter's indication over a stated flow range and is commonly expressed by meter manufacturers to be within ±0.5% over limited flow ranges. High-accuracy meters have typical linearities of ±0.15% for liquids and ±0.25% for gases, usually specified over a 10:1 dynamic range below maximum rated flow.

(c) Repeatability. Repeatability is defined as the ability of the meter to indicate the same reading each time the same condition exist and is normally expressed as ±0.1% of reading for liquids and ±0.25% for gases. Accuracy must be expressed as a composite statement of repeatability and linearity over a stated range of flow rates.

Turbine meters are susceptible to over-registration due to contaminants, positive swirl, nonuniform velocity profile, and pulsations. In gas flow, contaminants can build on internal meter parts and reduce the flow area which results in higher-velocity fluid, a faster-moving rotor, and a skewed rotor exit angle. The increased velocity and the altered exit angle of the fluid cause the rotor to over-register. For all fluids, positive upstream swirl may be caused by a variety of conditions that may include out-of-plane elbows, insufficient flow conditioning, partially blocked upstream filters, or damaged internal straightening vanes. The positive swirl causes the fluid flow to strike the rotor at an accentuated angle, causing the rotor to over-register. In cases where there is a distortion of the velocity profile at the rotor inlet introduced by upstream piping configuration, valves, pumps, flange misalignments, and other obstruction, the rotor speed at a given flow will be affected. For a given average flow rate, generally a nonuniform velocity profile results in a higher rotor speed than a uniform velocity profile. In pulsating flow, the fluid velocity increases and decreases, resulting in a cyclical acceleration and deceleration of the rotor causing a net measurement over-registration. Dual-rotor turbine meters with self-checking and self-diagnostic capabilities are recommended to aid measurement accuracy to detect and adjust for mechanical wear, fluid friction, and upstream swirl. Additionally, dual-rotor meters electronics and flow algorithms detect and make partial adjustments for severe jetting and pulsation. ASME PTC 19.5 should be consulted for guidance for flow disturbances that may affect meter performance and standardized tests to assess the effects of such disturbances.

4-5.3.4.1.2 Calibration. In accordance with ASME PTC 19.5, an individual calibration shall be performed on each turbine meter at conditions as close as possible to the test conditions under which the meter is to operate. This shall include using the fluid, operating conditions (temperature and pressure), and piping arrangements as nearly identical to the test conditions as is practical with calibration data points that are taken at flow rates that surround the range of expected test flows. The orientation of the turbine meter will influence the nature of the load on the rotor bearings, and thus, the performance of the meter at low flow rates. For optimum accuracy, the turbine meter should be installed in the same orientation in which it was calibrated. The turbine meter calibration report must be examined to confirm the uncertainty as calibrated in the calibration medium.

As the effect of viscosity on the turbine meter calibration "K" factor is unique, turbine meters measuring liquid fuel flow rate shall be calibrated at two kinematic viscosity points surrounding the test fluid viscosity. Each kinematic viscosity point shall have three different calibration temperatures that encompass the liquid fuel temperature expected during the test. It is recommended that a universal viscosity curve (UVC) be developed to establish the sensitivity of the meter's "K" factor to a function of the ratio of the output frequency to the kinematic viscosity. The universal viscosity curve reflects the combined effects of velocity, density, and absolute viscosity acting on the meter. The latter two effects are combined into a single parameter by using kinematic viscosity.

The result of the calibration shall include

(a) the error at the minimum flow and all the flowing flow rates that are above the minimum flow: 0.1/0.25/0.4/0.7 of the maximum flow;

(b) the name and location of the calibration laboratory;

(c) the method of calibration (bell prover, sonic nozzles, critical flow orifice, master meters, etc.);

(d) the estimated uncertainty of the method, using ASME PTC 19.1;

(e) the nature and conditions (pressure, temperature, viscosity, specific gravity) of the test fluid; and

(f) the position of the meter (horizontal, vertical — flow up, vertical — flow down).

In presenting the calibration data, either the relative error or its opposite (the correction), or the volumetric efficiency or its reciprocal (the meter factor), shall be plotted versus the meter bore Reynolds number. (The meter's bore shall be measured accurately as part of the calibration process.)

4-5.3.4.2 Positive Displacement Meters

4-5.3.4.2.1 Application. This Code recommends positive displacement meters for liquid fuel flows for all size pipes, but in particular for pipes less than 8 cm (3 in.). There are many designs of positive displacement meters including wobble plate, rotating piston, rotating vanes, and gear or impellor types. All of these designs measure volumetric flow directly by continuously separating (isolating) a flow stream into discrete volumetric segments and counting them. As such, they are often called volumeters. Because each count represents a discrete volume of fluid, positive displacement meters are ideally suited for automatic batching and accounting. Unlike differential pressure class meters and turbine meters, positive displacement meters are relatively insensitive to piping installations and otherwise poor flow conditions; they in fact are more of a flow disturbance than practically anything else upstream or downstream in plant piping.

Positive displacement meters provide high accuracy (±0.1% of actual flow rate in some cases) and good repeatability (±0.05% of reading in some cases) and accuracy is not significantly affected by pulsating flow unless it entrains air or gas in the fluid. Turndowns as high as 100:1 are available, although ranges of 15:1 or lower are more common.

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

$$q_{mh} = q_v \times s_g \tag{4-5-2}$$

$$q_{mh} = 8.337 \times 60 \times q_v \times s_g \tag{4-5-3}$$

where

q_{mh} = mass flow, kg/s (lbm/hr)
q_v = volume flow, L/s (gal/min)
s_g = specific gravity at flowing temperature, dimensionless
8.337 = density of water at 60°F, lbm/gal
60 = minutes per hour, m/h

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

4-5.3.4.2.2 Calibration. The recommended practice is to calibrate these meters in the same fluid at the same temperature and flow rate as is expected in their intended performance test environment or service. If the calibration laboratory does not have the identical fluid, the next best procedure is to calibrate the meter in a similar fluid over the same range of viscosity-pressure drop factor expected in service. This recommendation implies duplicating the absolute viscosity of the two fluids.

4-6 PRIMARY HEAT INPUT MEASUREMENT

4-6.1 Consistent Solid Fuels

Consistent solid fuels are defined as those with a heating value that varies less than 2.0% over the course of a performance test. The heat input to the plant by consistent solid fuel flow must be measured and calculated by indirect methods since solid fuel flow cannot be accurately measured using direct methods. The approach requires dividing the heat added to the working fluid by the boiler fuel efficiency as follows:

$$\text{facility heat input} = \frac{\text{boiler energy output}}{\text{b.e.}} \tag{4-6-1}$$

$$1 - \frac{\Sigma \text{ losses} + \Sigma \text{ credits}}{\text{heating value}}$$

where

b.e. = boiler fuel efficiency

boiler energy output = heat added to the working fluid (including blowdown) by the boiler, kJ/kg (Btu/lbm)

facility heat input = the energy added to the facility by the consistent fuel, kJ/kg

The boiler fuel efficiency (b.e.) shall be calculated using the energy balance method per ASME PTC 4.

The boiler energy output is the energy added to the boiler feedwater as it becomes superheated steam and as steam is reheated if applicable. The boiler energy output is calculated by drawing a mass and energy control volume around the boiler. Then the product of the flow and enthalpy of each water and steam stream crossing the volume are summed. Flows entering the volume are negative and the flows leaving are positive. All steam or water flows into or out of the boiler will be included. These flows include feedwater, superheat spray, blowdown, sootblower steam, and steam flows.

The following is some guidance as to when flow should be included and how to make measurements. Superheat spray/attemperator flow generally originates at the boiler feed pump discharge. However, occasionally it originates from the feedwater line downstream of any feedwater heaters and downstream of the feedwater measurement. Should the latter be the case, do not include the superheat spray flow in the calculation.

Boiler blowdown most often leaves the cycle and should be counted as one of the leaving streams. The enthalpy of this stream is saturated liquid at the boiler drum pressure. This Code recommends that the boiler blowdown be isolated since it is difficult to measure a saturated liquid flow.

Sootblowing steam should be counted as a leaving flow stream if it originates within the boiler. Often this steam originates upstream of one of the superheat sections. If sootblowing steam cannot be measured it should be isolated during the test. If the sootblowing steam originates downstream of the main steam it should not be included in the calculation.

The main steam flow is typically calculated by subtracting blowdown and other possible extraneous flow like sootblowing steam from the feedwater flow.

The reheat steam flow to the boiler is determined by subtracting from the main steam flow any leakages and extractions that leave the main steam before it returns to the boiler as reheat steam. Leakages shall be either measured directly, calculated using vendor pressure for flow relationships, or determined by methods acceptable to all parties. Extraction flows shall either be measured directly or calculated by heat balance around the heater if the extraction is serving a heater. ASME PTC 6 provides details on the measurements required to calculate the extraction flows to feedwater heaters and the heat input to the steam turbine cycle.

Reheat spray flow must also be included as one of the flow streams into the boiler. The reheat return flow is the summation of the reheat steam flow to the boiler and the cold reheat spray.

4-6.2 Consistent Liquid or Gaseous Fuels

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

Homogenous gas and liquid fuel flows are usually measured directly for gas-turbine-based power plants. For steam turbine plants, the lowest uncertainty method should be employed depending on the specific site.

Subsection 4-5 includes a discussion of the measurement of liquid and gaseous fuel flow. Should the direct method be employed, the flow is multiplied by the heating value of the stream to obtain the facility heat input to the cycle. The heating value can be measured by an online chromatograph or by sampling the stream periodically (at least three samples per test) and analyzing each sample individually for heating value. The analysis of gas, either by online chromatography or from laboratory samples, in accordance with ASTM D1945, results in the amount and kind of gas constituents, from which heating value is calculated. See also ASME STP-TS-012-1 for Thermophysical Properties of Working Gases Used In Gas Turbine Applications. Liquid fuel heating value may be determined by calorimeter in accordance with ASTM D4809.

4-6.3 Solid Fuel and Ash Sampling

Refer to ASME PTC 4 for sampling requirements and procedures.

4-7 ELECTRICAL GENERATION MEASUREMENT

4-7.1 Introduction

This subsection presents requirements and guidance regarding the measurement of electrical generation.

The scope of this subsection includes

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

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

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

4-7.2 Required Uncertainty

The required uncertainty will depend on the type of parameters and variables being measured. Refer to paras. 4-1.2.2 and 4-1.2.3 for discussion on measurement classification and instrumentation categorization, respectively.

4-7.2.1 Primary Parameters and Variables

(a) Class 1. Class 1 primary parameters and variables shall be measured with 0.1% or better accuracy class power metering, 0.3% or better accuracy class (metering type) current transformers, and 0.3% or better accuracy class (metering type) voltage transformers.

(b) Class 2. Class 2 primary parameters and variables should be measured with 0.5% or better accuracy class power metering, 0.3% or better accuracy class (metering type) current transformers, and 0.3% or better accuracy class (metering type) voltage transformers. In the event that a Class 2 primary parameters or variable has a relative sensitivity of less than 0.02 percent per percent, then it is acceptable to determine the power with an overall uncertainty of ±0.5%.

4-7.2.2 Secondary Parameters and Variables. Secondary parameters and variables can be measured with any type of power measurement device. The use of calibrated transformers will lower overall test uncertainty, if the calibration data is used in the calculation of the test results; however, use of calibrated transformers is not a Code requirement.

4-7.3 Polyphase Alternating Current 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 fundamental principle on which polyphase alternating current power measurement is based is that of Blondel's Theorem. This theorem states that for a system of N conductors, N-1 metering elements are required to measure the true power or energy of the system. This is true for any condition of load unbalance. It is evident, then, that the electrical connections of the generator to the system govern the selection of the metering system. Hence, the minimum metering methods required for use on each of these three-phase systems can be divided into the following categories:

(a) Three-Wire Power Systems. Three-wire power systems consist of two single-phase meters or one two-phase meter.

(b) Four-Wire Power Systems. Four-wire power systems consist of three single-phase meters or one three-phase meter.

Table 4-7.3-1 Metering Method Restrictions Summary

Configuration			Restrictions	
Code	Application	Connection	Voltage	Load
1.5E	1½ element	3 phase, 3-wire	Balanced	Balanced
2E	2 element	3 phase, 3-wire	None	None
3E	3 element	3 phase, 3-wire	None	None
2.5E	2½ element	3 phase, 4-wire	Balanced	Balanced
3E	3 element	3 phase, 4-wire	None	None

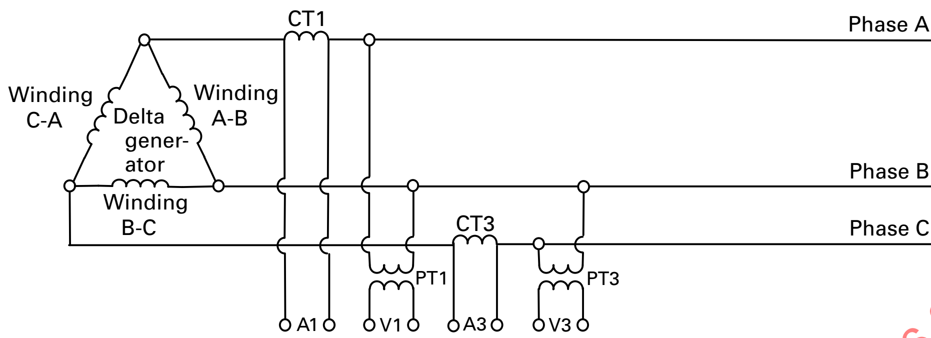
Table 4-7.3-1 provides guidance on the restrictions of various connection metering methods to ensure the appropriate metering method is selected to meet the uncertainty requirements as described in para. 4-7.3. It should be noted, in the two-element configuration of the three-phase, three-wire connection that if the load (phase currents) is unbalanced, this method could result in an error in calculating the total power factor since only two VA measurements are used in the calculation. As such, the three-element configuration of the three-phase, three-wire connection is the recommended configuration in the determination of power factor due to insensitivity in the load balance of a three-wire power system.

Three-wire and four-wire power systems are defined by connections between the generator and transformers: wye-delta, delta-wye, wye-wye, delta-delta. The type of connection and the site arrangement should be reviewed before deciding which power-metering system is suitable to a given measurement application. Paragraphs 4-7.3.1 and 4-7.3.2 describe each of these systems and the measurement techniques.

4-7.3.1 Three-Wire Power Systems. Three-wire power systems are used for several types of power systems as shown in Fig. 4-7.3.1-1. Brief descriptions of various three-wire power systems are as follows:

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

Fig. 4-7.3.1-1 Three-Wire Metering System



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

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

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

Three-wire power systems can be measured using two Open Delta-connected voltage transformers (VTs) and two current transformers (CTs). The open delta metering system is shown in Fig. 4-7.3.1-1. These instrument transformers are connected to either two watt/var meters, a two-element watt/var meter, two watt hour/var-hour meters, or a two-element watt hour/var hour meter. The var meters are necessary to establish the power factor, PF, as follows:

$$PF = \frac{Watts_t}{\sqrt{Watts_t^2 + Vars_t^2}} \tag{4-7-1}$$

where

PF = power factor

$Vars_t$ = total vars for three phases

$Watts_t$ = total watts for three phases

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

$$PF = \frac{1}{\sqrt{\left(1 + 3\left[\frac{(Watts_{A-B} - Watts_{C-B})}{(Watts_{A-B} + Watts_{C-B})}\right]^2\right)}} \tag{4-7-2}$$

where

PF = power factor

$Watts_{A\text{-}B}$ = real power phase A to B

$Watts_{C\text{-}B}$ = real power phase C to B

4-7.3.2 Four-Wire Power Systems. A typical four-wire power-metering system is shown in Fig. 4-7.3.2-1. There are two types of four-wire power systems, as follows:

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

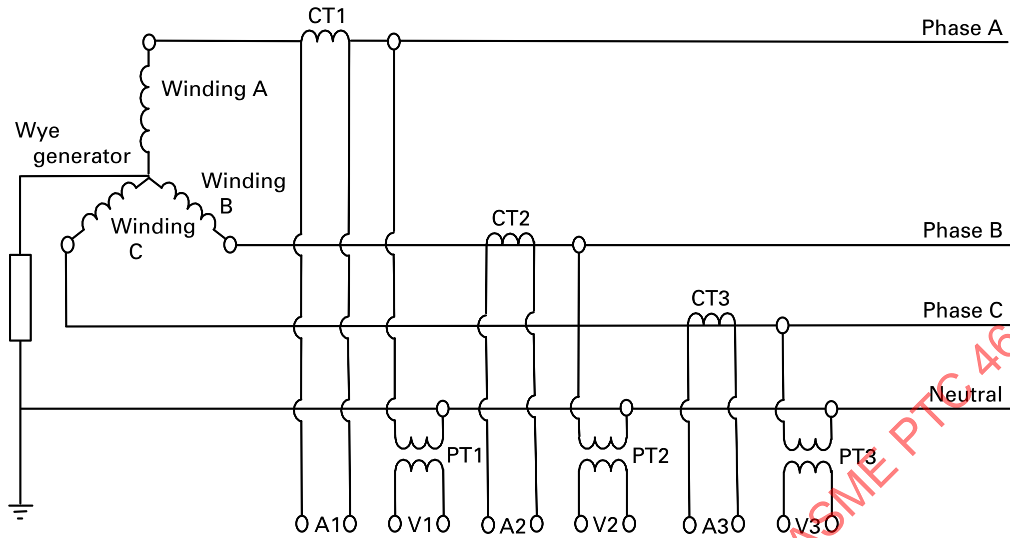
(b) In the second type, where plant generation is measured somewhere other than at the generator, such as at the high side of the step-up transformer. In this case, the neutral is simulated by a ground.

In addition, with the exception of the open delta generator connection, all of the three-wire systems described in para. 4-7.3.1 can also be measured using the four-wire measurement system described in this paragraph.

In a four-wire power system, power is measured using three VTs and three CTs, as shown in Fig. 4-7.3.2-1. These instrument transformers are connected to three watt/var meters, a three-element watt/var meter, three watt-hour/var-hour meters, or a three-element watt-hour/var-hour meter. The var meters are necessary to establish the power factor, PF, as follows:

$$PF = \frac{Watts_t}{\sqrt{Watts_t^2 + Vars_t^2}} \tag{4-7-3}$$

Fig. 4-7.3.2-1 Four-Wire Metering System



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

where

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

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

$$\text{PF} = \frac{\text{Watts}_t}{\Sigma V_i I_i} \tag{4-7-4}$$

where

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

4-7.4 Electrical-Metering Equipment

There are five types of electrical-metering equipment that may be used to measure electrical energy.

(a) watt meters
(b) watt-hour meters
(c) var meters
(d) var-hour meters
(e) power factor meters

Single- or polyphase metering equipment may be used. However, if polyphase metering equipment is used, the output from each phase must be available or the meter must be calibrated for three-phase measurements. These meters are described below.

The warm-up time of electrical-metering equipment shall be in accordance with the manufacturer's recommendations to ensure instrument specifications are met. Electrical-metering equipment with various measurement range settings should be selected to minimize the reading error while encompassing the test conditions. The systematic uncertainty associated with digital power analyzers that use some form of digitizing technique to convert an analog signal to digital form accuracy specifications shall consider influence quantities including, but not limited to, environmental effects such as ambient temperature, magnetic fields, electric fields, and humidity, power factor, crest factor, *D/A* output accuracy, timer accuracy (integration time), and long-term stability.

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. Additionally, the lead wires shall have insulation resistance appropriate for their ratings.

In order to minimize the voltage drop in the voltage circuit, wire gage shall be chosen considering the length of the wiring, the load on 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 voltage-drop measurement or by calculation.

Extreme care must be exercised in the transportation of calibrated portable instruments. The instruments should be located in an area free of stray electrostatic and magnetic fields as possible. Where integrating meters are used, a suitable timing device shall be provided to accurately determine the real power during the test time period.

To reduce the effect of instrumental loss on measurement accuracy, power-metering equipment should be selected that use a separate source of power and that have high-impedance voltage inputs (i.e., 2.4 MΩ) and low-impedance current inputs (i.e., 6 mΩ).

4-7.4.1 Wattmeters. Wattmeters 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.

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

4-7.4.2 Watt-Hour Meters. Watt-hour meters measure 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 a Class 1 primary variable such as net or gross active power generation shall have an uncertainty equal to or less than 0.2% of reading. Metering with an uncertainty equal to or less than 0.5% of reading shall be used for measurement of Class 2 primary variables. There are no metering accuracy requirements for measurement of secondary variables.

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

Some electronic watt-hour meters also display blinking lights or LCD elements that 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).

4-7.4.3 Var Meters. Var meters measure instantaneous reactive power. The var measurements are typically used on four-wire systems to calculate power factor, as discussed in para. 4-7.3.2. 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 a Class 1 or Class 2 primary variable shall have a systematic uncertainty equal to or less than 0.5% of range. There are no metering accuracy requirements for measurement of secondary variables. The output from the var meters must be sampled with a frequency high enough to attain an acceptable random uncertainty. This is a function of the variation of the power measured. A general guideline is a frequency of not less than once each minute.

4-7.4.4 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 a Class 1 or Class 2 primary variable shall have an uncertainty equal to or less than 0.5% of range. There are no metering accuracy requirements for measurement of secondary variables.

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

4-7.4.5 Power Factor Meters. Power factor meters may be measured directly using three-phase power factor transducers when balanced load and frequency conditions prevail. Power factor transducers shall have a systematic uncertainty equal to or less than 0.01 PF of the indicated power factor.

4-7.5 Electrical-Metering Equipment Calibration

4-7.5.1 Wattmeter and Watt-Hour Meter Calibration. Wattmeters and watt-hour meters, collectively referred to as power meters, are calibrated by applying power through the test power meter and a wattmeter or watt-hour meter standard simultaneously. This comparison should be conducted at a minimum of five power levels across the expected power range. The difference between the test and standard instruments for each power level should be calculated and applied to the power measurement data from the test. For test points between the calibration power levels, a curve fit or linear interpolation should be used. The selected power levels should be approached in an increasing and decreasing manner. The calibration data at each power level should be averaged to minimize any hysteresis effect. Should polyphase metering equipment be used, the output of each phase must be available or the meter must be calibrated with all three phases simultaneously.

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

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

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

4-7.5.2 Var Meter and Var-Hour Meter Calibration. To calibrate a var meter or var-hour meter, one must have either a var standard or a wattmeter standard and an accurate phase-angle measuring device. Also, the device used to supply power through the standard and test instruments 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 of wattmeters outlined in para. 4-7.5.1 should be used. Should a wattmeter standard and phase-angle meter be used, simultaneous measurements from the standard, phase-angle meter, and test instrument should be taken. The var level shall be calculated from the average watts and the average phase angle.

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 and vice versa. Var meters are particularly sensitive to frequency and should be used within 0.5 Hz of the calibration frequency.

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

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

4-7.6 Instrument Transformers

Instrument transformers are used for the purpose of reducing the voltages and currents to values that can be conveniently measured, typically to ranges of 120 V and 5 A, respectively, and 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 Standard C57.13.

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.

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

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 the burden (number and kinds of instruments connected to the transformer), the secondary current (in the case of current transformers), and in the case of power measurement, the power factor of the device being measured.

Testing near a power factor of unity minimizes the sensitivity of the measured power to the phase-angle errors arising from the power meter, α, current transformers, β, and voltage transformers, γ.

4-7.6.1 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 (typically very high in voltage) to a lower or secondary voltage safe for metering (typically 120 V for phase-to-phase systems and 69 V for phase-to-neutral systems). For this reason the secondary voltage measured by the voltage transformer must be multiplied by a marked ratio to calculate the primary voltage.

Voltage transformers are available in several metering accuracy classes. For the measurement of Class 1 or Class 2 primary variables, 0.3% or better accuracy class (metering type) voltage transformers shall be used. In the case of Class 1 primary variable measurements, voltage transformers must be calibrated for turns ratio and phase angle and operated within their rated burden range. The method of calibration should permit the determination of the turns ratio and phase angle to an uncertainty of ±0.1% and ±0.9 mrad (3 min), respectively. The calibration shall consist of ratio and phase-angle tests from 90% to 110% of rated primary voltage at rated frequency with zero burden, and with the maximum standard burden for which the transformer is rated at its best accuracy class. The magnitude of such corrections depend upon the burden (number and kinds of instruments connected to the transformer) and in the case of power measurement, the power factor of the device being measured. The ratio is usually from 0.1% to 0.3% below the nominal value for a small burden while the phase angle is commonly negligible being slightly leading. Voltage transformer ratio correction factors shall be applied for the actual burdens that exist during the test. Actual volt-ampere burdens shall be determined either by calculation from lead impedances or by direct measurement. IEEE C57.13 should be consulted for determining the associated equations in providing an analytical determination of the transformer ratio correction factor (RCF_c). Corrections for voltage drop of the connecting lines should be determined and applied.

In using voltage transformers, care should be taken to avoid short-circuiting the secondary. The circuit may be opened whenever desired.

4-7.6.2 Current Transformers. Current transformers measure current in a given phase. Current transformers serve to convert line or primary current (typically very high) to a lower or secondary metering current. For this reason, the secondary current measured by the current transformer shall be multiplied by a marked ratio to calculate the primary current.

Current transformers are available in several metering accuracy classes. For the measurement of Class 1 or Class 2 primary variables, 0.3% or better accuracy class (metering type) current transformers shall be used. It is recommended for primary variable measurements, current transformers be calibrated for turns ratio and phase angle at zero external burden (0 VA) and at least one burden that exceeds the maximum expected during the test at 10% and 100% of rated primary current. Accuracy test results may be used from factory type (design) tests in the determination of turns ratio and phase-angle correction factors. Type tests are commonly performed on at least one transformer of each design group that may have a different characteristic in a specific test. Current transformers shall be operated within their rated burden range during the test and should be operated near 100% of rated current to minimize instrument error.

Near the rated current outputs, ratio and phase-angle correction factors for current transformers may be neglected due to their minimal impact on measurement uncertainty; however, if the ratio or phase-angle correction factor is expected to exceed 0.02% at actual test conditions, actual correction factors should be applied.

In using current transformers, care should be taken never to open the secondary circuit while the current is in the primary winding because of the dangerously high voltage that may be developed and the excessive temperature rise that may ultimately take place due to high losses in the transformer. Also, 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 ANSI/IEEE Standard 120, under "Nature of Deviations from Nominal Ratio in Current Transformers." When it is necessary to open the secondary circuit while the current is in the primary winding, in order to change the instrument for example, the secondary winding should be short-circuited, preferably at the transformer terminals.

4-7.7 Calculation of Corrected Average Power or Corrected Total Energy

The calculation method for average power or total energy should be performed in accordance with ANSI/IEEE Standard 120 for the specific type of measuring system used. For Class 1 primary variables, power measurements shall be corrected for actual voltage transformer ratio and for phase-angle errors in accordance with the procedures of IEEE Standard C57.13. The error for each phase is corrected by applying calibration data from the transformers and the power meter as follows:

$$PW_C = SW \times VTR \times CTR \times MCF \times VTRCF_C \times PACF_C \times VTVDC \tag{4-7-5}$$

where

CTR = current transformer marked ratio
$CTRCF_c$ = current transformer ratio correction factor from calibration data (if applicable)
MCF = meter correction factor from calibration data (if applicable)
$PACF_c$ = phase-angle correction factor from calibration data
PW_c = corrected primary power
SW = measured secondary power
VTR = voltage transformer marked ratio
$VTRCF_c$ = voltage transformer ratio correction factor from calibration data
$VTVDC$ = 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 may be then interpolated.

Phase-angle correction factor for each phase ($PACF_C$) accounts for the phase shift that occurs in the voltage transformer, γ, current transformer, β, and the power meter, α. 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.

$$\mathrm{PACF_C} = \frac{\cos(\theta - \alpha + \beta - \gamma)}{\cos(\theta)} = \frac{\cos(\theta - \alpha + \beta - \gamma)}{\mathrm{PF}} \tag{4-7-6}$$

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)

4-7.8 Excitation Power Electrical Measurement

If the measurement of the excitation power is required, the power supplied to the exciter may be determined by the following two methods:

(a) Derivation from Breaker Currents. Excitation power can be calculated from the current and voltage input to the exciter power transformer or breaker. Note that the active power to the exciter has a low power factor (~0.3) so this measurement contains harmonic distortion that can impact the measurement uncertainty. The calculation is done as follows:

$$\mathrm{ExcLoss} = \frac{\sqrt{3} \times V \times A \times \mathrm{PF}}{1000} \tag{4-7-7}$$

where

A = average phase field current (A) — measured value
ExcLoss = exciter power (kW)
PF = Power Factor — measured or calculated value
V = average field voltage (V) — measured value
1000 = conversion factor from watts to kW

(b) Derivation from Field Voltage and Current. Power supplied to the exciter can be determined by calculating the power output by the exciter and by correcting for an assumed AC to DC conversion efficiency. The calculation is done as follows:

$$\mathrm{ExcLoss} = \frac{\mathrm{FV} \times \mathrm{FC}}{1000 \times \mathrm{ACDC}} \tag{4-7-8}$$

where

ACDC = AC to DC conversion efficiency factor (typically 0.975) — assumed value
ExcLoss = exciter power (kW)
FC = field current (DC A) — measured value
FV = field voltage (DC V) — measured value

4-8 GRID FREQUENCY

Grid frequency can be determined by measuring shaft speed. Typically, for non-geared turbines the shaft speed shall be 3,600 rpm for 60-Hz applications and 3,000 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 DATA COLLECTION AND HANDLING

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

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

4-9.1 Data Acquisition System

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

4-9.2 Manual System

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

4-9.3 Automated System

Automated systems are beneficial in that they allow for the collection of data from multiple sources at high frequencies while recording the time interval with an internal digital clock. Rapid sampling rates serve to reduce test uncertainty and test duration. These systems can consist of a centralized processing unit or distributed processing to multiple locations in the plant.

The setup, programming, channel lists, signal conditioning, operational accuracies, and lists of the equipment making up the automated system used to determine primary Class 1 parameters shall be prepared and supplied in the test report.

4-9.4 Data Management

4-9.4.1 Automated Collected Data. All automated collected data should be recorded in its uncorrected, uncalculated state to permit post-test data correction for application of any necessary calibration corrections. Immediately after test and prior to leaving the test site, copies of the automated collected data should be distributed between the parties to the test to secure against the chance of such data being accidentally lost, damaged, or modified. Similar steps should be taken with any corrected or calculated results from the test.

4-9.4.2 Manually Collected Data. All manually collected data recorded on data collection sheets must be reviewed for completeness and correctness. Immediately after test and prior to leaving the test site, photocopies of the data collection sheets should be made and distributed between the parties to the test to eliminate the chance of such data being accidentally lost, damaged, or modified.

4-9.4.3 Data Calculation Systems. The data calculation system should have the capability to average each input collected during the test. The system should also calculate standard deviation and coefficient of variance of each instrument. The system should have the ability to locate and eliminate spurious data from being used in the calculation of the average. The system should also have the ability to plot the test data and each instrument reading over time to look for trends and outlying data.

4-9.5 Data Acquisition System Selection

4-9.5.1 Data Acquisition System Requirements. The test procedure should clearly dictate the type of measurements to be made, allowable uncertainty of each measurement, number of data points needed, the length of the test, the number of samples required, and the frequency of data collection to meet the allowable test uncertainty set by this Code. This information will serve as a guide in the selection of data acquisition equipment and system design.

The data acquisition system must meet the loop calibration requirements of para. 4-1.3.8.

4-9.5.2 Temporary Automated Data Acquisition System. This Code recommends the usage of temporary automated data acquisition systems for testing purposes. These systems can be carefully calibrated and their proper operation confirmed in the laboratory and then transported to the testing area, thus providing traceability and control of the complete system. Instruments are limited in their exposure to the elements and avoid the problems associated with construction and ordinary plant maintenance.

Site layout and ambient conditions must be considered when determining the type and application of temporary systems.

4-9.5.3 Existing Plant Measurement and Control System. This Code does not prohibit the use of the plant measurement and control system. However, the system must meet the requirements set forth in this Code. The limitations and restrictions of these systems should be considered when deciding whether to use them for performance testing.

Most distributed plant control systems apply threshold or deadband restraints on data signals. This results in data that is only the report of the change in a parameter that exceeds a set threshold value. All threshold values must be set low enough so that all data signals sent to the data acquisition system during a test are reported and stored. In addition to deadbands, most DCSs include analog-to-digital conversion and apply compression to the signal, which increases uncertainty. Similar to instrumentation, all systematic uncertainty impacts of using the DCS as a data logger must be fully understood and accounted for in the pretest and post-test uncertainty analysis using the guidelines of ASME PTC 19.1 and ASME PTC 19.22.

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

Section 5
Calculations and Results

5-1 FUNDAMENTAL EQUATIONS

The fundamental performance equations (5-1-1), (5-1-2), (5-1-3), and (5-1-4) are applcable to any of the types of power plants covered by this Code.

Corrected Power is expressed as

$$P_{corr} = \left(P_{meas} + \sum_{i=1}^{7} \Delta_i\right) \prod_{j=1}^{6} \alpha_j \tag{5-1-1}$$

Corrected Heat Input is expressed as

$$Q_{corr} = \left(Q_{meas} + \sum_{i=1}^{7} \omega_i\right) \prod_{j=1}^{6} \beta_j \tag{5-1-2}$$

Corrected Heat Rate is expressed as

$$HR_{corr} = \frac{\left(Q_{meas} + \sum_{i=1}^{7} \omega_i\right) \prod_{j=1}^{6} \beta_j}{\left(P_{meas} + \sum_{i=1}^{7} \Delta_i\right) \prod_{j=1}^{6} \alpha_j} \tag{5-1-3}$$

or

$$HR_{corr} = \frac{\left(Q_{meas} + \sum_{i=1}^{7} \omega_i\right)}{\left(P_{meas} + \sum_{i=1}^{7} \Delta_i\right)} \prod_{j=1}^{6} f_j \tag{5-1-4}$$

Additive correction factors ω_i and Δ_i, and multiplicative correction factors α_j, β_j, and f_j, are used to correct measured results back to base reference conditions. From the formats of eqs. (5-1-1) through (5-1-4), it is seen that additive correction factors are applied to bring the performance of the decoupled subsystems of the plant to the common base reference conditions, and then the multiplicative correction factors are applied to correct for the test boundary conditions that impact the entire plant: inlet conditions, fuel conditions and properties, and grid frequency. Tables 5-1-1 and 5-1-2 summarize the correction factors used in the fundamental performance equations.

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

Some correction factors may be significant only for unusually large deviations from base reference conditions, or not at all, in which case they can be ignored. An example of this is some secondary heat inputs, such as process return temperature in a cogenerator or condenser cooling water flow in a combined cycle plant. If the pretest uncertainty analysis shows a correction for a specific parameter impacts corrected test results by less than 0.05% at expected test conditions, it can either be ignored or included.

The fundamental performance equations, which are generalized, can then be simplified to be specific to the particular plant type and test program objectives.

5-2 MEASURED PLANT POWER AND HEAT INPUT TERMS IN THE FUNDAMENTAL EQUATIONS

Measured Plant Power may be measured directly at the test boundary, or expressed as

$$P_{meas} = \left[\sum_{n=1}^{k} P_{\substack{\text{measured,}\\ \text{generator}_n}}\right] - P_{\substack{\text{plant}\\ \text{aux.}}} - P_{\substack{\text{transformer}\\ \text{losses}}} - P_{\substack{\text{line}\\ \text{losses}}} \tag{5-2-1}$$

Table 5-1-1 Summary of Additive Correction Factors in Fundamental Performance Equations

Additive Correction to Thermal Heat Input	Additive Correction to Power	Operating Condition or Uncontrollable External Condition Requiring Correction	Comments
ω_1	Δ_1	Thermal efflux (operating)	Calculated from efflux flow rate and energy level, such as process steam flow and enthalpy
ω_2	Δ_2	Power factor(s) (operating)	Impact of off-design power factors
ω_3	Δ_3	Steam generator(s) blow-down different than design (operating)	BD is sometimes isolated so that performance may then be exactly corrected to design BD flow rate.
ω_4	Δ_4	Secondary heat inputs (external)	Process return or makeup temperature is typical
ω_{5A}	Δ_{5A}	Inlet air conditions, cooling tower or air-cooled heat exchanger air inlet (external)	For some combined cycles, may be based on the conditions at the combustion turbine inlets.
ω_{5B}	Δ_{5B}	Circulating water temperature different than design (external)	To be used if there is no cooling tower or air-cooled condenser in the test boundary.
ω_{5C}	Δ_{5C}	Condenser pressure (external)	If the entire heat rejection system is outside the test boundary.
ω_{5D}	Δ_{5D}	Circulating water flow different than design (external)	To be used if there is no cooling tower or air-cooled condenser in the test boundary If the impact on corrected test results is lower than 0.05%, the parties could agree on avoiding its application.
ω_6	Δ_6	Auxiliary loads, thermal and electrical (operating)	(1) To account for auxiliary loads when the multiplicative corrections are based on gross generation (2) To compensate for irregular, cyclical, intermittent, or off-design auxiliary loads
ω_7	Δ_7	Measured power different than specified if test goal is to operate at a predetermined power, or operating disposition slightly different than required if a specified disposition test (operating)	To account for (1) the small difference in measured versus desired power for a test run to be conducted at a specified measured or corrected power level, or (2) small differences between required and actual unit operating disposition such as valve point operation of a steam turbine plant

GENERAL NOTES:

(a) For additive corrections 1 through 6, for a given correction i, usually either ω_i or Δ_i will be used for combined cycle plants, but not both. Use of both usually means that a correction is being made twice for a given condition. For steam turbine plants, it is sometimes necessary to use ω_i and Δ_i corrections with the same subscript, as shown in the sample calculations.

(b) Additive correction factors with subscript 7 must always be used together. The correction $\omega 7$ is the correction to heat input that corresponds to Δ_7.

Table 5-1-2 Summary of Multiplicative Correction Factors in Fundamental Performance Equations

Mulitplicative Correction to Thermal Heat Input	Multiplicative Correction to Power	Multiplicative Correction to Heat Rate, $f_j = \frac{\beta_j}{\alpha_j}$	Operating Condition or Uncontrollable External Condition Requiring Correction	Comments
β_1	α_1	f_1	Inlet temperature correction (external)	Determined at the test boundary at the inlet to the equipment
β_2	α_2	f_2	Inlet air pressure correction (external)	As per β_1, α_1, f_1
β_3	α_3	f_3	Inlet air humidity (external)	As per β_1, α_1, f_1
β_4	α_4	f_4	Fuel supply temperature correction (external)	Care must be taken to not double account if equation method is used to correct for sensible heat in place of the correction curves.
β_5	α_5	f_5	Correction due to fuel analysis different than design (external)	This correction is multivariate and varies by fuel.
β_6	α_6	f_6	Grid frequency (external)	. . .

GENERAL NOTE: Inlet air conditions and fuel/sorbent chemical analysis deviations from base reference conditions are part of the corrections for the energy balance method for coal or solid fuel plant when that method is used to determine thermal heat input. In those circumstances, they are not part of the overall plant performance test corrections per para. 5-3.2(b).

Any of the loss terms can be excluded from eq. (5-2-1) if the test boundary so dictates.

Line losses can be calculated based on calculations of linear resistance, line lengths, and measured electrical current. Transformer losses may be determined using transformer factory test reports.

Heat input which can be calculated from measured fuel flow and heating value is expressed as

$$Q_{\text{meas}} = [(\text{HV})(q_m)]_{\text{fuel}} + [q_m * (h_T - h_{\text{Ref}})]_{\text{fuel}} = [(\text{HV})(q_m)]_{\text{fuel}} + \text{SH}_{\text{fuel}} \tag{5-2-2}$$

where

HV = lower or higher heating value (LHV or HHV) of the fuel as defined in specified reference conditions and goal of the test

h_T = specific enthalpy of the fuel at the flowing temperature

h_{Ref} = specific enthalpy of the fuel at the reference temperature

q_m = actual mass flow

SH = sensible heat input of fuel (may be different for power/heat rate test and heat balance calculation; see Note)

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. 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 (see para. 5-4.2.2). In particular, when fuel conditioning systems (such as fuel gas performance heaters, gas compressors, etc.) are within the test boundary, it is recommended to utilize correction curves to account for the difference between test and reference fuel supply temperature instead of using the sensible heat component in eq. (5-2-2).

If the fuel flow cannot be directly measured, Q_{meas}, it may be determined from results of heat input computations based on other energy balance methods.

For solid fuel power plants, heat input may be calculated based on measured boiler absorption (defined as the heat added to the working fluid by the fuel) and measured steam generator fuel energy efficiency. Steam generator measured fuel energy efficiency would be determined by the energy balance method per ASME PTC 4. Boiler absorption is determined by steam generator water-/steam-side measurements. Corrected heat input would then be determined by the methods described in para. 5-3.2(b).

5-3 PARTICULARIZING FUNDAMENTAL PERFORMANCE EQUATIONS TO SPECIFIC CYCLES AND TEST OBJECTIVES

5-3.1 General

The applicable corrections to use in the fundamental performance equations for a particular test depend on the type of plant or cycle being tested, and the goal of the test. The equations in this subsection might be further reduced depending on plant or test specifics (i.e., an additive correction shown might be zero, or a multiplicative correction shown might be unity for a specific test).

5-3.2 Specified Disposition Test Goal

If the goal of the test is to determine plant power and heat rate under a specified unit operating disposition without setting output to a predetermined numerical power, then eqs. (5-1-1) and (5-1-3) are simplified differently depending on the type of power plant.

(a) Combined Cycle Plants: Specified Unit Disposition. For combined cycle plants without duct firing, or duct firing out of service, and the specified operating disposition being the base loading of the gas turbines, the Δ correction factors are the only additive corrections that are used. Use of both types of additive corrections would be double-accounting. Note that all the Δ corrections through subscript 5 are steam turbine cycle power related except for the gas turbine generator power factor correction. For a combined cycle plant, eqs. (5-1-1) and (5-1-4) reduce to

$$P_{corr} = (P_{meas} + \Delta_1 + \Delta_2 + \ldots \Delta_7)\ \alpha_1 \alpha_2 \alpha_3 \alpha_4 \alpha_5 \alpha_6 \tag{5-3-1}$$

$$HR_{corr} = \frac{Q_{meas}}{(P_{meas} + \Delta_1 + \Delta_2 + \ldots \Delta_7)}\ (f_1 f_2 f_3 f_4 f_5 f_6) \tag{5-3-2}$$

Examples of applications of eqs. (5-3-1) and (5-3-2) are shown in Nonmandatory Appendix A and Nonmandatory Appendix C.

(b) Rankine Cycle (Steam Turbine) Plants: Specified Unit Disposition. For steam turbine plants, if the test goal is tied to a specified disposition, it is usually based on either a valve point operating mode, or on the throttle flow rate. For a steam turbine plant, the steam generator calculations are done separately from the overall plant calculations in order to calculate ASME PTC 46 measured fuel energy input. However, in the case where the specified disposition test is performed while utilizing an integrated model of the steam turbine plant, eqs. (5-3-1) and (5-3-2) would apply with the inclusion of Δ_7 and ω_7 under certain specified dispositions.

For a nonintegrated thermal heat balance model (see subsection 5-4 and para. 5-7.4), the multiplicative correction factors for inlet air conditions (exclusive of the heat sink) and fuel analysis and conditions are embedded in the steam generator data analysis. Q_{meas} for the overall plant test is the corrected thermal input as determined from an ASME PTC 4 test (see para. 5-7.4).

Hence, the multiplicative correction factors are all unity (except for grid frequency) in the overall plant performance equations, and some of the additive correction factors with the same subscript are used.

The fundamental performance equations for nonintegrated model for power, eq. (5-1-1), becomes

$$P_{corr} = (P_{meas} + \Delta_1 + \Delta_2 + \ldots \Delta_7) \tag{5-3-3}$$

For measured boiler fuel heat input

$$Q_{boiler\ meas} = \frac{\text{Measured Boiler Absorption}}{\text{Measured Boiler Fuel Efficiency per ASME PTC 4}} \tag{5-3-4}$$

For nonintegral models, corrected boiler fuel heat input becomes

$$Q_{boiler\ corr} = \frac{\text{Measured Boiler Absorption}}{\text{Corrected Boiler Fuel Efficiency per ASME PTC 4}} \tag{5-3-5}$$

For heat rate, eq. (5-1-3), for nonintegral models then becomes

$$HR_{corr} = \frac{Q_{boiler\ corr} + \omega_1 + \omega_3 + \omega_7}{P_{meas} + \Delta_1 + \Delta_2 + \ldots \Delta_7} \tag{5-3-6}$$

The Δ_7 and ω_7 corrections only apply if the specified disposition is throttle flow.

In eq. (5-3-6), $Q_{\text{boiler corr}}$ is thus equal to the steam generator tested output (boiler absorption) as defined in ASME PTC 4, including blowdown energy if applicable, divided by the steam generator corrected fuel energy efficiency calculated per ASME PTC 4 (see subsection 5-2).

The ω factors are used to correct the calculated measured thermal input to the plant base reference conditions process efflux, and required operating disposition.

For steam cycle plants that use an integrated thermal model, eqs. (5-3-1) and (5-3-2) apply.

For a nonintegrated model (see subsection 5-4 and para. 5-4.6), the ω correction curves are calculated by heat balance using base reference steam generator test corrected fuel energy efficiency. If the tested corrected efficiency deviates significantly from reference, then recalculation of the ω corrections simply by multiplying each one by the ratio of base reference fuel energy efficiency to the test corrected fuel energy efficiency can be done if the difference affects the results significantly.

Examples of application of the performance equations to steam plants are shown in Nonmandatory Appendix E.

Note that eq. (5-3-4) is in the format

$$HR_{corr} = \frac{Q_{corr}}{P_{corr}} \tag{5-3-7}$$

5-3.3 Specified Corrected Power

Specified corrected power tests can be conducted for steam turbine plants or, in some cases, for combined cycle plants

(a) with duct burning or some form of power augmentation, or

(b) for part load testing.

When a test is run with the goal that heat rate is determined at a specific corrected power, the unit operating power, *after* being corrected to the base reference conditions, is adjusted for the test, to be as close as possible to the design value of interest. Δ_7 and ω_7 are applied to adjust for the small difference between the actual adjusted power and the desired adjusted power.

The applicable equations are identical to those in para. 5-3.2 when the goal is to test at a fixed operating disposition, with the exception that Δ_7 and ω_7 are applied to adjust for the small difference between the actual adjusted power and the desired adjusted power. For a combined cycle plant, for which a test is run at baseload with duct burning or some form of power augmentation, the equations in para. 5-3.2(a) apply, while for Rankine cycle plants, equations in para. 5-3.2(b) apply. For combined cycle part load testing, refer to the formulation outlined in Nonmandatory Appendix H.

5-3.4 Specified Measured Power

The other test whose required unit operating disposition dictates adjustment of power to a predetermined value for testing is a Specified Measured Power test where the goal is heat rate. This test is conducted for a combined cycle power plant with duct firing or other form of power augmentation, such as steam or water injection when used for that purpose.

For this test, the power is set as closely as possible to a specified amount regardless of test boundary conditions.

The ω additive corrections are applicable (but not the Δ corrections except Δ_7).

Δ_7 and ω_7 are applied to adjust for the small difference between the actual adjusted power and the desired adjusted power.

In this case, the fundamental performance equation for corrected power simplifies to

$$P_{corr} = P_{\text{base reference}} = (P_{meas} + \Delta_7) \tag{5-3-8}$$

The fundamental equation for corrected heat rate simplifies to

$$HR_{corr} = \frac{(Q_{meas} + \omega_1 + \omega_2 + \omega_3 + \omega_4 + \omega_5 + \omega_6 + \omega_7)}{(P_{meas} + \Delta_7)} (f_1 f_2 f_3 f_4 f_5 f_6) \tag{5-3-9}$$

Note that eq. (5-3-9) is also in the format of eq. (5-3-7). Because $\alpha_j = 1$, then $\beta_j = f_j$.

Table 5-3.4-1 summarizes the format of the general performance equations to use for various types of power plants or thermal islands, and test objectives discussed in this subsection. There may be other applications for which different combinations of the correction factors are used, but the general performance equations should always apply.

Table 5-3.4-1 Examples of Typical Cycles and Test Objectives — Corresponding Specific Performance Equations

Type of Plant or Thermal Island	Test Objective	Applicable Performance Test Equations	Test Objective Type
Combined cycle (steam turbine/ gas turbine). No heat recovery steam generator duct firing.	Unit disposition is to be operating base loaded for the test	Power: eq. (5-3-1) Heat Rate: eq. (5-3-2)	Specified disposition
Combined cycle (steam turbine/ gas turbine). Heat recovery steam generator duct firing.	Operate base loaded and fire external duct firing to the same required plant power level regardless of test boundary conditions	Power: eq. (5-3-6) Heat Rate: eq. (5-3-7)	Specified measured power
Combined cycle (steam turbine/ gas turbine) with or without heat recovery steam generator duct firing or other power augmentation	Operate part load at a given percentage of plant base load output or at a specific corrected output	Refer to Nonmandatory Appendix H	Specified corrected power
Steam turbine plant (Rankine cycle)	Fire until the design power level for the base reference conditions at the time of the test is reached	Power: eq. (5-3-3) Heat Rate: eq. (5-3-4)	Specified corrected power
Steam turbine plant (Rankine cycle)	Operate at required valve point disposition	Power: eq. (5-3-3) Heat Rate: eq. (5-3-4)	Specified disposition
Steam turbine plant (Rankine cycle)	Operate at required throttle flow rate	Power: eq. (5-3-3) Heat Rate: eq. (5-3-4)	Specified disposition

5-3.5 Alternate to Δ_7 and ω_7 Correction Factors

During a test run for which the test objective requires setting the power level, power will not be precisely at the required level because

(a) adjustments are made utilizing readings of most operating conditions from the control room

(b) there are normal fluctuations during the test run after the unit is set for testing

(c) desired power level might be dependent on final fuel analysis, which has to be assumed for the test.

Similarly, during a specified disposition test of a steam turbine plant, the unit may be found to have been operating in a slightly different disposition than required for the same reasons.

There are two ways to handle these situations. The preferred method is to incorporate the Δ_7 and ω_7 correction factors.

The second and alternate technique is to interpolate through the results of several test runs to determine where the results are at the desired power level or desired disposition. If the alternate method is used, then Δ_7 and ω_7 are not applicable and can be eliminated from the performance equations. However, the measured power levels or disposition of the test runs should have enough of a spread given the test uncertainty for reasonable results to be achieved this way.

This is shown in the example in Nonmandatory Appendix E for a fixed corrected power test. In lieu of the additive corrections Δ_7 and ω_7, three tests were conducted and the result was interpolated.

Usually, power levels can be set close enough to desired levels such that the alternate method is not necessary. For steam turbine plants in particular, heat rate vs. power at full loads is a relatively flat curve.

5-3.6 Different Test Goals for the Same Cycle

Tests with different objectives can be conducted at the same power plant, in which case care must be taken to ensure that appropriate sets of correction factors are calculated based on the test goal.

5-4 DISCUSSION OF APPLICATION OF CORRECTION FACTORS

The format of the fundamental equations allows decoupling of the appropriate correction effects (process efflux, inlet air conditions, etc.) relative to the measured prime variables of heat rate and power, so that measured performance can be corrected to the base reference conditions. Corrections are calculated for parameters at the test boundary different than base reference conditions which affect measured performance results. Tables 5-1-1 and 5-1-2 indicate whether each correction is considered due to uncontrollable external conditions, or to operating conditions.

Correction curves applied to measured performance are calculated by a heat balance model of the thermally integrated systems contained within the test boundary with the exception of off-design fuel composition for Rankine cycle plant. Off-design fuel composition for Rankine cycle plant shall be addressed using the correction procedures prescribed in ASME PTC 4. The heat balance model represents the mathematical definition of the expected performance of the energy conversion facility. Each correction factor is calculated by running the heat balance model with a variance in only the variable to be corrected for over the possible range of deviation from the reference condition. Correction curves are thus developed to be incorporated into the specific plant Test Procedure document. The model is finalized following purchase of all major equipment and receipt of performance information from all vendors. Inasmuch as practical, the test correction curves should reflect the final control settings.

Some of the correction factors require a family of curves. For example, the correction for relative humidity usually contains curves across the humidity range at multiple inlet air temperatures.

It is noted that for convenience, identical subscripts for all additive correction factors, and similarly for all multiplicative correction factors, represent the same variable to be corrected for, but the symbols are different depending on the result being corrected.

In lieu of application of the equations in subsection 5-3, a heat balance computer model may be applied after the test using the appropriate test data and boundary conditions so that all the corrections for the particular test run are calculated simultaneously. Heat balance studies of different cycles using the performance equations in the above format have demonstrated that interactivity between correction factors usually results in differences of less than 0.2% compared to calculation of the complete heat balance post-test with the test data. An advantage of this post-test heat balance calculation is a reduction in or elimination of heat balance calculations required to generate all the heat balance correction curves.

Either an integrated method or a nonintegrated method can be used to correct the performance of a steam turbine Rankine cycle plant. A nonintegrated method separates the steam generator from the remainder of the Rankine cycle. The steam generator performance is corrected in accordance with the method of ASME PTC 4, taking precaution not to take inappropriate corrections to the steam generator efficiency that are internal to the overall plant performance test (refer to para. 5-7.4 for the method to correct the steam generator performance). These corrections for an ASME PTC 4 test are inappropriate to apply because they correct steam generator performance for some steam-generator-based reference conditions that are inapplicable to the overall plant performance test due to the differences in the test boundary.

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

5-4.1 Additive Correction Factors: Δ and ω

The additive corrections are discussed below in paras. 5-4.1.1 through 5-4.1.7.

5-4.1.1 Correction Due to Thermal Efflux Different Than Design: Δ_1 or ω_1. For a cogeneration power plant, the design power and heat rate is specified at a design thermal efflux, or secondary output. These are the corrections for deviations from design reference thermal efflux during the performance test run, when applicable.

If thermal efflux is in the form of process steam, which is the most common, then the design thermal efflux for each process may be defined as

$$Q_{\text{thermal efflux, design}} = \left[(mh)_{\text{process steam}} - (mh)_{\text{process return}} - \left(m_{\text{process steam}} - m_{\text{process return}}\right) h_{\text{makeup}}\right]_{\text{design}} \tag{5-4-1}$$

If the design process return flow is equal to design process steam flow, then eq. (5-4-1) simplifies to

$$Q_{\text{thermal efflux, design}} = \left[\left(m_{\text{process steam}}\right)\left(h_{\text{process steam}} - h_{\text{process return}}\right)\right]_{\text{design}} \tag{5-4-2}$$

Test results are corrected for deviations from base reference conditions of each term in eq. (5-4-2). The sum of the corrections equals Δ_1 (or ω_1).

It is also permissible to include the process return energy correction as part of the correction Δ_4 (or ω_4, which is for secondary heat inputs) into the cycle (see para. 5-4.1.4), if more convenient.

If that option is selected, then process return is not considered as part of the Δ_1 (or ω_1) correction.

5-4.1.2 Power Factor Correction: Δ_2 or ω_2. The output of each generator is corrected to its design power factor rating. Care must be taken to ensure that corrections include the off-design characteristics of all equipment in the test boundary, including isolated phase bus ducting, excitation systems, and step-up transformers as applicable. The sum of all the corrections to each generator comprise Δ_2 (or ω_2).

In the event that the plant corrections are calculated based on the low side of the step-up transformers and do not include consideration of the impact of off-design power factor on step-up transformer loss, and the test boundary includes the transformers, then eq. (5-2-1) is expressed as follows:

$$P_{\text{meas}} = \left(\sum_{n=1}^{k} P_{\text{measured generator}_n} \right) - P_{\text{plant aux}} - P_{\text{line losses}} \tag{5-4-3}$$

$$P_{\text{corr w/o step-up transformer}} = (P_{\text{meas}} + \Delta_1 + \Delta_{2_{\text{generator+exciter}}} + \ldots\Delta_7)\ \alpha_1\alpha_2\alpha_3\alpha_4\alpha_5\alpha_6 \tag{5-4-4}$$

and

$$P_{\text{corr w/step-up transformer}} = P_{\text{corr w/o step-up transformer}} - P_{\text{step-up transformer losses, } P_{\text{corr}} \,\&\, PF_{\text{design}}} \tag{5-4-5}$$

$$P_{\text{step-up transformer losses, } P_{\text{corr}} \,\&\, PF_{\text{design}}} = \sum P_{\text{step-up transformer NO-LOAD losses}} + \sum\left\{ \left(P_{\text{step-up transformer LOAD losses, } PF_{\text{design}}} \right) \times \left(\frac{P_{\text{corr w/o step-up transformer}}}{P_{\text{rated}}} \right)^2 \right\} \tag{5-4-6}$$

where

P_{rated} = the rated active power (based on the rated MVA) of the step-up transformer at design power factor (PF_{design}); $\Sigma\Delta$ are the additive corrections applicable to either the GT or ST component

PF_{design} = the design (test boundary) power factor

LOAD losses are the MVA-dependent losses associated with the step-up transformer.

NO-LOAD losses are the fixed step-up transformer losses independent of load.

If $P_{\text{step-up transformer losses, measured PF}}$ and $\Delta_{2\text{ step-up transformer}}$ come from the same design or test data, then eq. (5-4-5) simplifies to

$$P_{\text{corr w/step-up transformer}} = P_{\text{corr w/o step-up transformer}} - P_{\text{step-up transformer losses, design } PF} \tag{5-4-7}$$

where $P_{\text{step-up transformer, design PF}}$ is the transformer loss at the design power factor and corrected power output upstream of the step-up transformer, kW.

5-4.1.3 Steam Generator Blowdown Correction: Δ_3 or ω_3. To compare test results to design reference heat balance values, it is recommended to isolate blowdown if possible and to correct to the design blowdown flow rate. This simplifies the test because of the difficulty in determining actual blowdown flow rates.

5-4.1.4 Secondary Heat Input: Δ_4 or ω_4. Secondary heat inputs are all heat inputs to the test boundary other than primary fuel. Examples are makeup water and low level external heat recovery. The process steam return portion for a cogeneration unit can be considered in this correction term or as part of Δ_4 (or ω_4.)

Effects of differences in makeup temperature or flow from design should be considered for those cases where it has impact. The same holds true for process steam returned as water.

If any of the return is stored in a tank and then added to the cycle, as opposed to direct return to the cycle, the conditions prior to entering the cycle are corrected to reference conditions.

5-4.1.5 Heat Sink: Δ_5 or ω_5 Factors. Only one of the correction factors Δ_{5A}, Δ_{5B}, or Δ_{5C} (or ω_{5A}, ω_{5B}, or ω_{5C}) is applied, depending on the cycle test boundary, or cycle configuration of the plant or the thermal island. Figures 5-4.1.5-1, 5-4.1.5-2, and 5-4.1.5-3 show configurations where these corrections are respectively applicable for a combined cycle power plant.

(a) Inlet Air Conditions at the Cooling Tower or Air-Cooled Condenser Air Inlet: Δ_{5A}, or ω_{5A}. If cooling tower(s) or air-cooled condenser(s) exist within the test boundary, then a correction is made for cooling tower/air-cooled condenser atmospheric inlet conditions. For a wet cooling tower, applicable inlet conditions are wet bulb temperature and barometric pressure. Humidity and dry bulb temperature may be used in lieu of wet bulb temperature. Typically, for a dry cooling tower, or air-cooled condenser, dry bulb temperature and barometric pressure are the required applicable inlet air conditions. The barometric pressure component of this correction can be incorporated into the

Fig. 5-4.1.5-1 Typical Test Boundary for a Power Plant Requiring Application of Heat Sink Correction Factor, Δ_{5A} or ω_{5A}

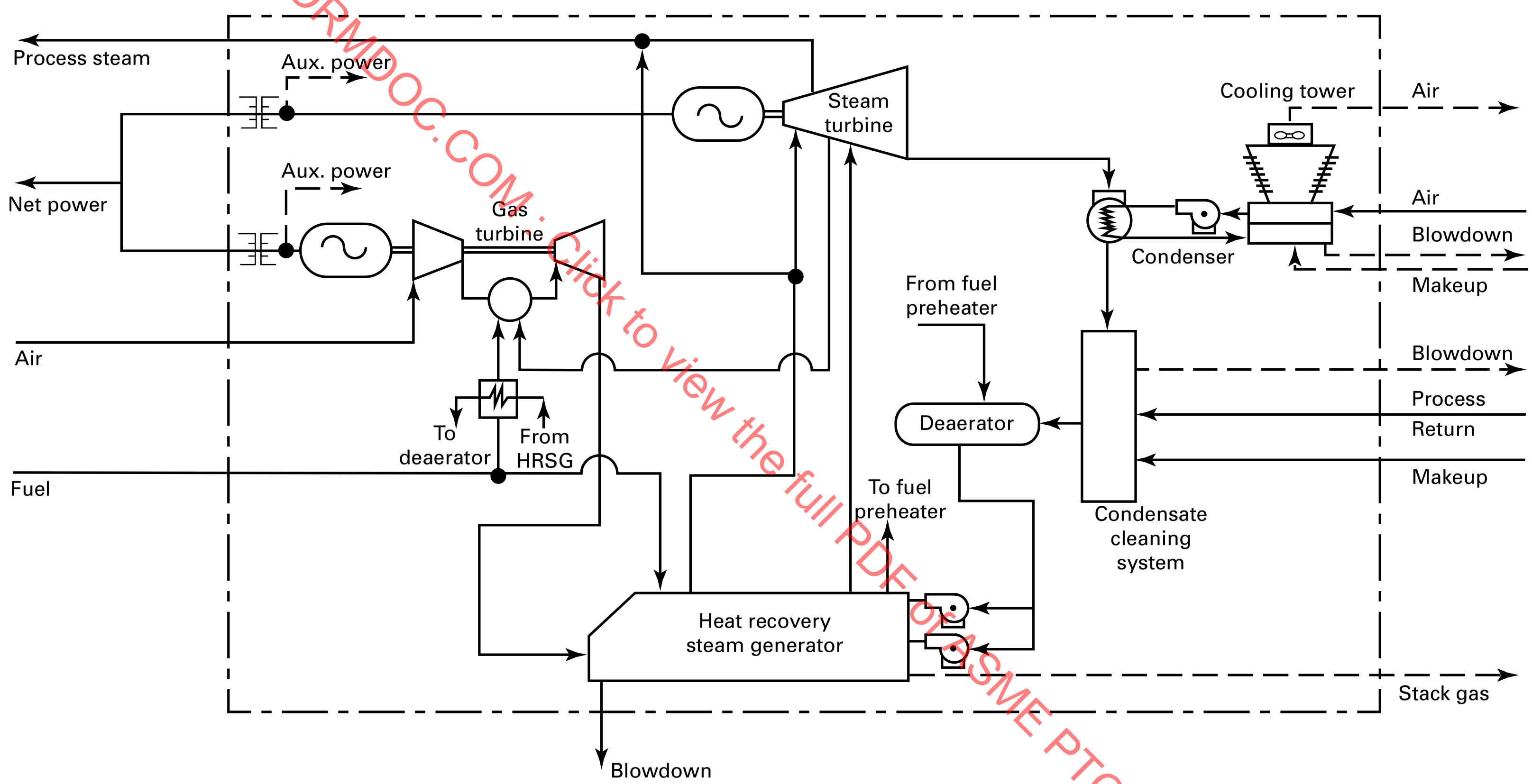


Fig. 5-4.1.5-2 Typical Test Boundary for a Power Plant Requiring Application of Heat Sink Correction Factor, Δ_{5B} or ω_{5B}

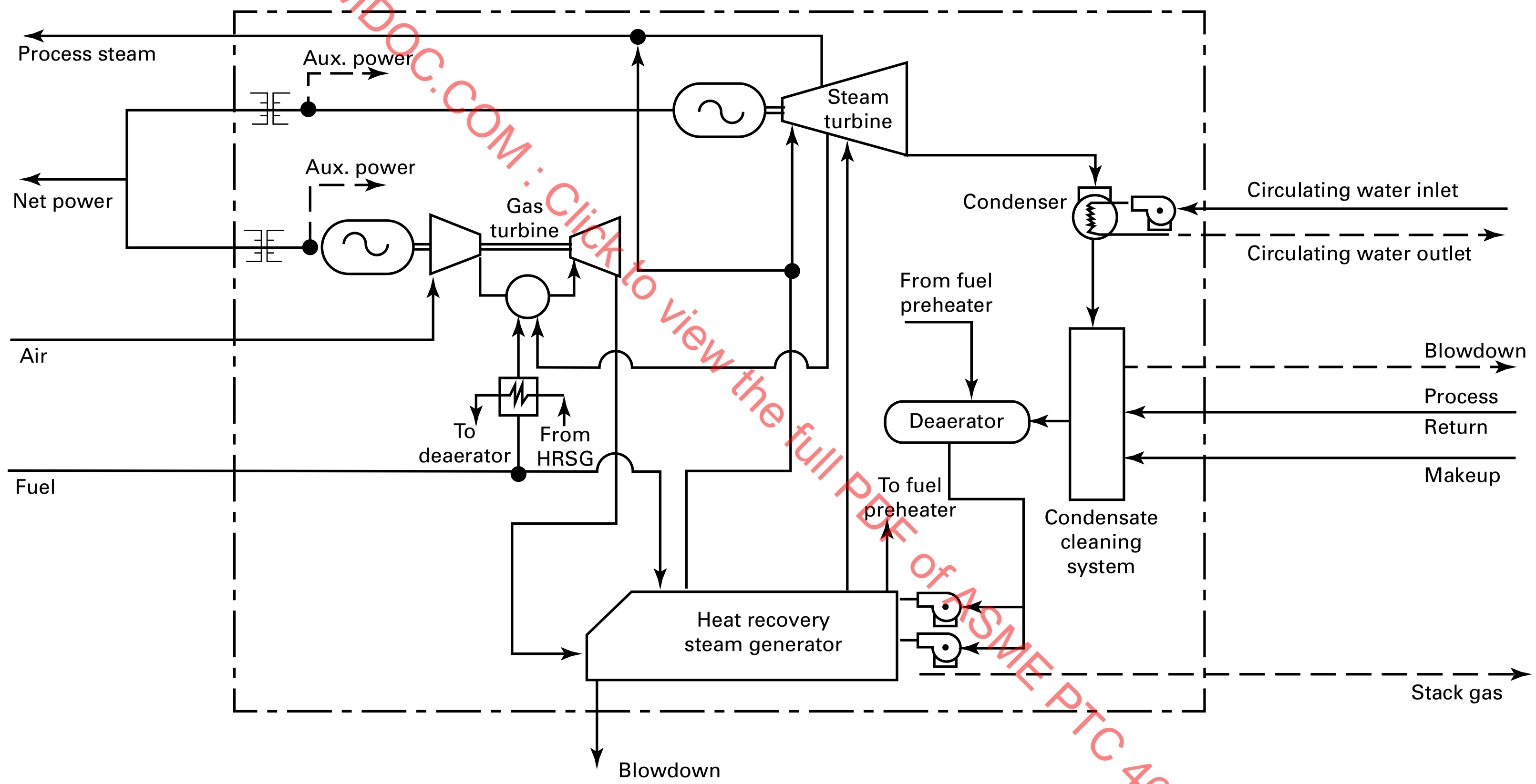
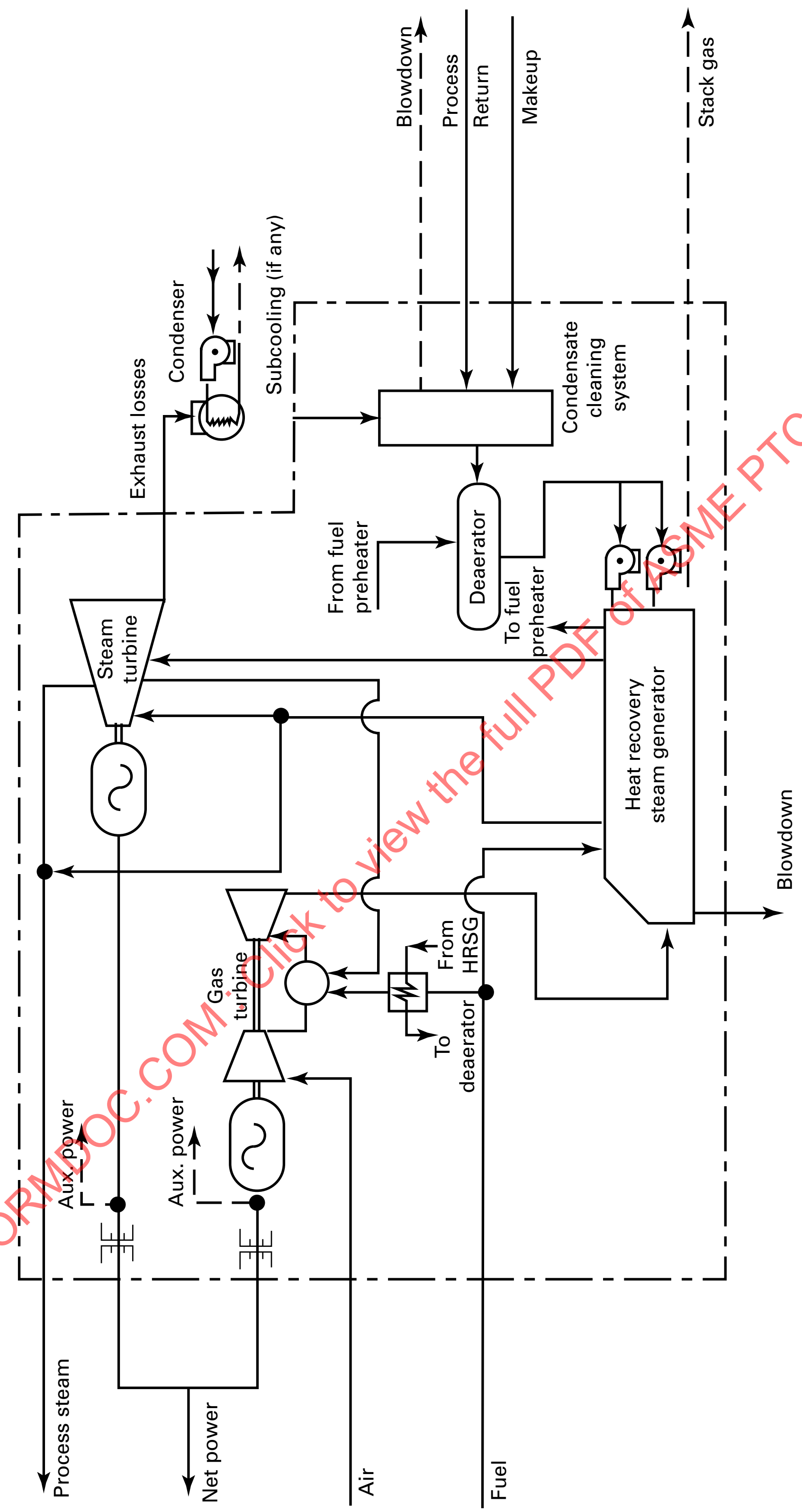


Fig. 5-4.1.5-3 Typical Test Boundary for a Power Plant Requiring Application of Heat Sink Correction Factor, Δ_{5C} or ω_{5C}



subscripted "2" multiplicative correction factors. For certain air-cooled condenser installations, it may be necessary to consider the impact of wind velocity on the performance.

(b) Circulating Water Temperature: Δ_{5B} *or* ω_{5B}. If there are no cooling tower(s) or air-cooled condenser(s) within the test boundary, then the heat sink correction is made based on measured circulating water temperature.

(c) Circulating Water Flow: Δ_{5D} *or* ω_{5D}. If there are no cooling tower(s) or air-cooled condenser(s) and also no circulating water pumps within the test boundary, then a correction can be made based on measured circulating water flow.

(d) Condenser Pressure: Δ_{5C} *or* ω_{5C}. If the condenser is not part of the test boundary, a correction is made to the steam turbine cycle based on the measured condenser pressure.

5-4.1.6 Thermal and Electrical Auxiliary Loads: Δ_6 or ω_6. These corrections are for off-design auxiliary load lineup at the tested conditions. Care must be taken to assure that no overlap exists between corrections taken here as well as for inlet temperature and other external condition corrections in which normal auxiliary load variations with varying external conditions have already been considered. For off-design loads that are constant over the range of inlet air and other conditions, the Δ_6 or ω_6 corrections are additive and may be applied outside of the brackets, meaning that this factor is applied to the test result after correction for the remaining additive and then the multiplicative factors.

5-4.1.7 Small Difference in Measured Power From Target Power, or Actual Unit Disposition From Operating Disposition: Δ_7 or ω_7. For Specified Measured Power and Specified Corrected Power Tests, in which the power during the test is set, these corrections are used to correct for the fact that measured or corrected power will never equal precisely the desired power for the practical reasons tabulated in para. 5-3.5. These corrections must always both be used together. Once power is corrected to the precise value it should have been exactly set to, then the concomitant change in thermal heat input must be considered.

For the same reasons, these corrections are used when the required unit operating disposition is slightly different than required for a steam turbine plant.

Note that the difference in power is to be small and this correction is for the minor adjustment of the power to the design value. This correction is not intended to correct the power up when there is a deficiency in power output.

5-4.2 Multiplicative Correction Factors: α, f, and β

For combined cycles, once the appropriate electrical additive corrections and the water/steam portion of the cycle has been corrected to base reference conditions by the additive corrections, then the plant performance can be corrected based on inlet air conditions and other external quantities using the multiplicative correction factors as described below.

α multiplicative corrective factors are used to correct measured power, and either f or β is used to correct heat rate or measured thermal heat input, respectively.

The multiplicative correction factors are discussed below in paras. 5-4.2.1 through 5-4.2.4.

5-4.2.1 Inlet Temperature, Pressure, and Humidity Corrections α_1, α_2, α_3 and f_1, f_2, and f_3, or β_1, β_2, and β_3. Correction is made to plant performance based on the inlet temperature (α_1 and f_1, or β_1), inlet pressure (α_2 and f_2, or β_2), and inlet humidity (α_3 and f_3, or β_3). For combined cycle plants, the inlet air temperature and humidity are typically measured at the inlet filter house of the gas turbine, while the pressure is measured at the gas turbine centerline. For an integrated steam plant test, inlet air conditions are typically measured at the combustion air fan inlet of the boiler.

5-4.2.2 Fuel Supply Temperature Correction: α_4 and f_4 or β_4. Fuel supply temperature upstream of any conditioning device such as preheating which is different than base reference affect performance. Provision is made for correction in the performance equations for this.

Another method of incorporating off-design fuel supply temperature is by calculation, wherein the heating value used for results calculation is the sum of the fuel heating value at reference conditions and the fuel sensible heat at the measured temperature. Care should be made by the user of the Code not to accidentally double account for the impacts of fuel sensible heat by using the equation method with application of the α_4 and ϕ_4, or β_4 at the same time.

Variations in fuel pressure impact the fuel sensible heat; however, the impact on plant performance is usually minimal except for extreme changes in pressure.

5-4.2.3 Fuel Analysis Correction: α_5 and f_5, or β_5. Differences in fuel properties between the design fuel and the performance test fuel can lead to variance from design performance. This corrects for difference in fuel properties.

5-4.2.4 Grid Frequency Correction: α_6 and f_6, or β_6. When operated at off-design frequency, turbomachinery performance is impacted. This correction compensates for this condition.

Due to the highly nonlinear nature of grid frequency corrections, it may be necessary to calculate corrections by averaging the corrections calculated from individual measurements, if grid frequency is highly variable over the test duration.

5-5 SPECIAL CONSIDERATIONS OF PERFORMANCE EQUATIONS AS APPLIED TO COMBINED CYCLES

5-5.1 Multiple Locations of Air Inlet

Corrected performance by utilizing the fundamental performance equations in the formats for combined cycles shown in subsection 5-3 assumes that the air at each gas turbine inlet is equivalent. The equations are written to also satisfy the requirement for separate measurement of air inlet conditions at the cooling tower(s) or air-cooled condenser(s) (heat sink).

For facilities with more than one gas turbine, it is almost always acceptable to average the inlet measurements at all gas turbine inlets and use the average for the determination of the gas turbine inlet correction (α_1, β_1, and f_1), provided the gas turbines are identical models, which is usually the case. Slight differences between conditions at each inlet will not impact the calculated results if the machines are all the same model and fulfill the base loading requirement of unit disposition.

A separate correction for inlet conditions at the heat sink different than at the inlets shall be developed and used (Δ_{5A} or ω_{5A}).

Barometric pressure can be assumed uniform for the entire site if measured in the vicinity of the gas turbine inlets.

If necessary, expansion of eq. (5-3-1) for a cycle mandating a test goal of constant unit disposition is written as

$$\begin{aligned} P_{\text{corr}} = & \sum_{m=\text{GT}_1}^{\substack{\text{Total \# of gas}\\ \text{turbines}}} \left[\left(P_{\text{meas,grossGT}_m} + \Delta_{2_{\text{GT}_m}} \right) \prod_{n=1}^{6} \alpha_{n_{\text{GT}_m}} \right] \\ & + \sum_{j=1}^{\substack{\text{Total \# of}\\ \text{steam turbines}}} \left[\left(P_{\text{meas,grossST}_j} + \sum_{k=1}^{5} \Delta_{k_{\text{ST}_j}} \right) \prod_{n=1}^{6} \alpha_{n_{\text{ST}_j}} \right] \\ & - P_{\text{aux}} \prod_{n=1}^{6} \lambda_n - P_{\text{transformer loss}} - P_{\text{line loss}} \end{aligned} \tag{5-5-1}$$

if it is more prudent not to average conditions at each gas turbine inlet due to unusual site conditions.

The subscripts for the new multiplicative correction factors, λ_η, refer to the same parameters to be corrected for as in the other multiplicative corrections. Care is taken in calculating heat balances to determine correction factors for the format of eq. (5-5-1) to base the λ_η correction factors on gross power. Heat balance calculations to determine corrections to inlet air conditions utilizing the format of eq. (5-3-1) include auxiliary load effects in that equation's respective αs.

Note that the α corrections for the steam turbines in eq. (5-5-1) will not be unity even if the cooling tower is outside the test boundary, due to the inlet air effect at the gas turbine inlet on steam production.

Similarly, for the test goal of a specified unit disposition without setting output to a predetermined level (para. 5-3.2), the corrected heat rate equation may be expanded into the following format if eq. (5-5-1) is used in lieu of eq. (5-3-1):

$$\text{HR}_{\text{corr}} = \frac{\displaystyle\sum_{m=1}^{\substack{\text{total \# of}\\ \text{fuel inputs}}} \left[\left(Q_{\text{meas}_m} \right) \prod_{n=1}^{6} \beta_{n_m} \right]}{P_{\text{corr}} \text{ per eq. (5-5-1)}} \tag{5-5-2}$$

Similar formulations can be developed for specified measured power tests for combined cycles in which there is duct firing, if necessary.

5-5.2 Special Case of Inlet Air Conditioning Equipment(s)

The Code recommends testing with the inlet air conditioning systems configured to match the reference conditions, provided the ambient conditions allow. Some specific cases are addressed hereunder.

(a) For an evaporative cooler, it is advised to execute the test in normal operating conditions of the evaporative cooler and apply the corrections via a model or a family of curves as a function of dry bulb temperature and humidity within the limits of operating range of the evaporative cooler (i.e., typically at ambient temperatures higher than 15°C to 20°C). If the evaporative cooler is not operational during the test due to operational limitations

specified by manufacturer, the plant performance test can still be executed and the parties to the test are encouraged to reach mutual agreement with regards to the evaporative cooler performance. Parties are also encouraged to agree on the ambient conditions envelope during which the performance test will be conducted so as to minimize the error introduced due to inherent measurement uncertainties (e.g., humidity).

(b) Fogging and high fogging systems are usually installed in order to saturate incoming air with water vapor or go oversaturation at a predetermined level (high fogging). In either case, if the plant reference conditions include operation of these systems, the test may be conducted with these systems in service. As with plants equipped with evaporative coolers, attention should be paid to the operating limits of the fogging system. The operational window during which the performance test is conducted may be chosen to be a subset of the manufacturer defined operational window in order to minimize errors introduced due to measurement uncertainties (e.g., ambient temperature and humidity). Also, care should be taken when choosing the type and the quantity of instrumentation used to measure the ambient conditions to ensure that the accuracy requirements defined in this Code are met or exceeded.

(c) For inlet chiller systems, it is noted that the auxiliary loads necessary for operation may be significant and difficult to model in nonbase reference conditions.

(d) For electrical resistance-based anti-icing systems, the auxiliary loads necessary for operation may be significant and difficult to model in nonbase reference conditions.

(e) For compressor air recirculation type anti-icing systems, the difficulties associated with both determination of actual air inlet temperature and modeling off-design compressor behavior are likely to lead to high uncertainty and, therefore, usually it is advised not to run guarantee verification tests in such condition.

Nonmandatory Appendix I can be referenced if these considerations lead to the decision to conduct testing with the inlet air conditioning equipment out of service.

ASME PTC 51-2011 provides detailed methods for testing inlet air conditioning equipment.

5-5.3 Staged Testing of Combined Cycle Plants for Phased Construction Situations

This subsection details a methodology to test for new and clean power and heat rate of a combined cycle plant when it is constructed in phases. The gas turbines of the plant usually operate for several months in simple cycle mode while the steam portion of the combined cycle plant is being constructed.

In order to determine the combined cycle new and clean performance, it is therefore necessary to test the gas turbines when they are new and clean (Phase 1 test series), and combine those results with new and clean steam turbine cycle performance data (Phase 2 test series). In the event that the expected or measured change in gas turbine performance parameters (air flow, output, heat consumption, and exhaust temperature) is smaller than their respective relative test uncertainty, then an alternate technique, such as a degradation curve, should be considered by the parties to the test.

This protocol requires corrections in addition to the standard corrections tabulated in Tables 5-1-1 and 5-1-2. These are

(a) air flow rate deterioration of the gas turbines.

(b) output deterioration of the gas turbines.

(c) heat consumption deterioration of the gas turbines.

(d) exhaust temperature deterioration of the gas turbines. Note that degradation can cause an increase in exhaust temperature.

Determination of these items requires gas turbine test data taken with the steam cycle bypassed during the Phase 2 test series. If the plant does not include a bypass, the simple cycle Phase 2 test should be conducted just prior to shut down for the HRSG tie-in.

The simple cycle tests during Phase 2 are called Phase 2A tests, while the final combined cycle operation tests are considered as Phase 2B tests.

Nomenclature for the unique correction factors to this protocol are as follows:

C_f = correction to steam cycle gross power output at design reference conditions to new and clean air flow rate of the gas turbines

C_h = correction to Phase 2B combined cycle thermal heat input at design reference conditions to account for gas turbine heat consumption deterioration

C_o = correction to Phase 2B gas turbine gross power output at design reference conditions to account for output deterioration between test phases

C_t = correction to steam cycle gross power output at design reference conditions to new and clean exhaust temperature of the gas turbines

Table 5-5.3-1 Required Test Series for Phased Construction Combined Cycle Plants

Test Phase	Reasons for Tests	Operating Mode
Phase 1	New and clean gas turbine performance	Simple cycle operation after initial simple cycle start-up
Phase 2A	Gas turbine performance to determine degradation effect on output, heat consumption, exhaust gas flow rate, and exhaust temperature changes	Simple cycle operation (see para. 5-5.3)
Phase 2B	For determination of combined cycle plant performance in new and clean condition. This is accomplished by combining the Phase 2B combined cycle performance data, with appropriate degradation corrections based on Phase 1 and Phase 2A tests.	Full combined cycle operation

Table 5-5.3-1 summarizes the reasons for each test series. Note that there is usually an air flow reduction, an output reduction, a heat rate increase, and an exhaust temperature increase in the simple cycle mode after extended operation, which is why the second phase of testing should be done in two parts. Phase 2A is used in conjunction with Phase 1 to determine these degradation factors. In order to ensure an accurate determination of the degradation factors it is critical to ensure that the gas turbines are properly inspected and cleaned prior to the gas turbine tests per para. 3-3.5.

5-5.3.1 Phase 1 Testing

(a) Test Series Objective — Phase 1. The objective of the Phase 1 test series is to establish the new and clean gas turbine performance for each machine as follows:

(1) gas turbine new and clean corrected power in simple cycle operation

(2) gas turbine new and clean corrected heat input in simple cycle operation with unheated fuel

(3) air flow at new and clean conditions

(4) inlet air conditioning, if any, effectiveness

(5) exhaust temperature in new and clean conditions

(b) Test Series Configuration — Phase 1. The Phase 1 tests will occur in the simple cycle mode of operation. In cases where fuel heating is provided from the steam/water cycle, the Phase 1 test may be conducted with unheated fuel gas on each gas turbine.

The total gas turbine corrected new and clean power in simple cycle operation is the measured power corrected for deviations from base reference conditions as follows:

$$\sum_{i=1}^{\text{number of gas turbines}} P_{\text{corrGT}_i - \text{Phase 1}} = \left(\sum_{j=1}^{\text{number of gas turbines}} P_{\text{measGT}_j - \text{Phase 1}} + \Delta_2 \right) \alpha_1 \alpha_2 \alpha_3 \alpha_4 \alpha_5 \alpha_6 \tag{5-5-3}$$

The corrections in eq. (5-5-3) are calculated for simple cycle operation only.

Total gas turbine measured new and clean heat input is expressed as the product of the fuel gas lower heating value and the measured fuel gas flow.

$$\sum_{i=1}^{\substack{\text{number of}\\\text{gas turbines}}} Q_{\text{measGT}_i\text{ – Phase 1}} = (\text{LHV})\left(\sum_{j=1}^{\substack{\text{number of}\\\text{gas turbines}}} qm_j\right) \tag{5-5-4}$$

The GT new and clean heat rate corrected to base reference conditions is defined as follows:

$$\overline{\overline{\text{HR}}}_{\text{corrGT – Phase 1}} = \left\{\sum_{i=1}^{\substack{\text{number of}\\\text{gas turbines}}} Q_{\text{measGT}_i\text{ – Phase 1}} \Bigg/ \left(\sum_{j=1}^{\substack{\text{number of}\\\text{gas turbines}}} P_{\text{measGT}_j\text{ – Phase 1}} + \Delta_2\right)\right\} f_1 f_2 f_3 f_4 f_5 f_6 \tag{5-5-5}$$

Total gas turbine corrected new and clean heat input is therefore

$$\sum_{i=1}^{\substack{\text{number of}\\\text{gas turbines}}} Q_{\text{corrGT}_i\text{ – Phase 1}} = \overline{\text{HR}}_{\text{corrGT – Phase 1}} \times \sum_{j=1}^{\substack{\text{number of}\\\text{gas turbines}}} P_{\text{corrGT}_j\text{ – Phase 1}} \tag{5-5-6}$$

In situations where each gas turbine in the combined cycle plant is tested separately, eqs. (5-5-3) through (5-5-6) may be simplified to accommodate a single gas turbine at a time and these results may be aggregated for determining the total gas turbine simple cycle performance.

(c) Air Flow at Baseload in New and Clean Conditions. Phase 1 test will provide air flow, adjusted to guarantee reference conditions, for each gas turbine at baseload in simple cycle operation under new and clean condition. Air flow can be determined either by using inlet scroll methods or by heat balance.

$$\text{mair}_{\text{corr,GT}i\text{,Phase 1}} = \text{mair}_{\text{meas,GT}i\text{,Phase 1}} \times \gamma_1\gamma_2\gamma_3\gamma_4\gamma_5\gamma_6 \tag{5-5-7}$$

NOTE: The definition of subscripts used is based on Table 5-1-2.

(d) Exhaust Temperature at Base Load in New and Clean Conditions. The Phase 1 test series will also provide the GT exhaust temperature for each gas turbine at base load in simple cycle operation new and clean. This variable will be identified as $\text{GT}T\text{exh}_{\text{meas,GT}i\text{,Phase 1}}$.

Measured exhaust temperature is corrected for the inlet conditions during the test by the application of corrections and is then known as

$$\text{GT}T\text{exh}_{\text{corr,GT}i\text{,Phase 1}} = \text{GT}T\text{exh}_{\text{meas,GT}i\text{,Phase 1}} + \delta_1 + \delta_2 + \delta_3 + \delta_4 + \delta_5 + \delta_6 \tag{5-5-8}$$

NOTE: The definition of subscripts used is based on Table 5-1-2, but treated as additive correction.

(e) Inlet Air Conditioning Equipment. Inlet air conditioning equipment during phased testing is treated per para. 5-5.2.

5-5.3.2 Phase 2A Testing

(a) Test Series Objective — Phase 2A. The objective of the Phase 2A test series is to establish the magnitude of degradation to gas turbine air flow, output, heat input, and exhaust temperature in simple cycle operation immediately prior to the changeover to combined cycle operation. Special care is needed to verify that gas turbine control parameters for variable guide vanes and firing temperature are consistent with the Phase 1 test. The Code recommends that Phase 2A testing be structured to recreate the instrumentation type, quantity, and installation method from Phase 1 in order to reduce the effect of systematic errors in measurements between the phases.

(b) Test Series Configuration — Phase 2A. Phase 2A tests will be carried out for each of the gas turbines. The exhaust pressure will be recorded with the machines at base load in simple cycle operation. The air flow degradation test is repeated from the Phase 1 tests.

(c) Test Series Calculations — Phase 2A. Similar to Phase 1 calculations, the simple cycle corrected gas turbine output, heat rate, air flow, and exhaust temperature will be calculated following the Phase 2A test. The equations for the individual parameters defined in para. 5-5.3.1 apply, with the "Phase 1" subscript replaced with "Phase 2A."

5-5.3.3 Phase 2B Testing

(a) Test Series Objective — Phase 2B. The objective of the Phase 2B test series is to determine the magnitude of the final test values for plant power and plant heat rate corrected to the project base reference conditions and in the new and clean condition. This calculation shall be done in four parts as follows:

(1) determine combined cycle power at test conditions

(2) calculate plant power corrected to new and clean conditions using CC correction curves and degradation factors from Phase 1 and 2A tests

(3) determine plant heat input at test conditions while accounting for fuel heating

(4) calculate plant heat rate corrected at new and clean conditions using CC correction curves and degradation factors from Phase 1 and Phase 2A tests

(b) Test Series Configuration — Phase 2B. Phase 2B tests shall be conducted with the gas turbines in parallel base load operation exhausting through the HRSGs and with the Steam Turbine base loaded. In this test series the gas turbines will operate with heated fuel if that is their normal combined cycle mode. In this phase the plant is operating with the blowdown streams isolated.

(c) Test Series Calculation — Phase 2B. Similar to Phase 1 calculations, the corrected gas turbine output, heat rate, and air flow will be calculated following the Phase 2B test. These terms are required in order to calculate the individual correction factors used to capture degradation. The equations for the individual parameters defined in para. 5-5.3.1 apply, with the "Phase 1" subscript replaced with "Phase 2B."

The individual correction factors to capture the degradation from Phase 1 to Phase 2A for each of these parameters can be determined as follows:

(1) C_f: The magnitude of the gas turbine air flow degradation correction is determined using the corrected air flow from Phases 1, 2A, and 2B as follows:

$$C_f = 1 - \left[\mathrm{mair}_{\mathrm{IF}} * \left(\Sigma \mathrm{mair}_{\mathrm{corr,GT}i\mathrm{,Phase2A}} - \Sigma \mathrm{mair}_{\mathrm{corr,GT}i\mathrm{,Phase1}}\right) \Big/ \Sigma \mathrm{mair}_{\mathrm{corr,GT}i\mathrm{,Phase2B}}\right] \tag{5-5-9}$$

where $\mathrm{mair}_{\mathrm{IF}}$ is GT airflow impact factor (percent change in steam cycle output per 1% change in GT airflow). This value can be determined by means of a thermodynamic model of the plant.

This formulation also accounts for any modifications to the hardware/control systems regulating the Gas Turbine air flow (e.g., Variable Inlet Guide Vanes) between the simple cycle and combined cycle modes of operation.

Alternatively, C_f may also be determined using gas turbine exhaust flow, obtained by gas turbine heat balance, for the two test phases.

(2) $C_{o\mathrm{GT}i}$: The magnitude of the gas turbine output degradation correction is determined using the corrected gas turbine output from Phases 1, 2A, and 2B as follows:

$$C_{o\mathrm{GT}i} = 1 - \left[\left(P_{\mathrm{corr,GT}i\mathrm{,Phase2A}} - P_{\mathrm{corr,GT}i\mathrm{,Phase1}}\right) \Big/ P_{\mathrm{corr,GT}i\mathrm{,Phase2B}}\right] \tag{5-5-10}$$

(3) $C_{h\mathrm{GT}i}$: The magnitude of the gas turbine heat input degradation correction is determined using the corrected gas turbine heat consumption from Phases 1, 2A, and 2B as follows:

$$C_{h\mathrm{GT}i} = 1 - \left[\left(Q_{\mathrm{corr,GT}i\mathrm{,Phase2A}} - Q_{\mathrm{corr,GT}i\mathrm{,Phase1}}\right) \Big/ Q_{\mathrm{corr,GT}i\mathrm{,Phase2B}}\right] \tag{5-5-11}$$

(4) C_t: The magnitude of $C_{t\mathrm{GT}i}$ for each gas turbine is determined using the corrected gas turbine exhaust temperature from Phases 1 and 2A as follows:

$$C_t = 1 - \left[Texh_{\mathrm{IF}} * \Sigma \left(\mathrm{GT}Texh_{\mathrm{corr,GT}i\mathrm{,Phase2A}} - \mathrm{GT}Texh_{\mathrm{corr,GT}i\mathrm{,Phase1}}\right) \Big/ (100 * \text{number of gas turbines})\right] \tag{5-5-12}$$

where $Texh_{\mathrm{IF}}$ is GT exhaust temperature impact factor (percent change in steam cycle output per 1°F change in GT temperature). This value can be determined by means of a thermodynamic model of the plant.

The corrected total gross output of the steam turbine used for the combined cycle plant performance evaluations is

$$P_{\mathrm{corr}} = \left\{\left(\sum_{i=1}^{\#\text{ of gas turbines}} \left[P_{\mathrm{meas,GT}i} * C_{o\mathrm{GT}i}\right] + \sum_{j=1}^{\#\text{ of steam turbines}} \left[P_{\mathrm{meas,ST}j} * C_f * C_t\right]\right) + \sum_{k=1}^{7} \Delta_k\right\} \prod_{n=1}^{6} \alpha_n \tag{5-5-13}$$

Equation (5-5-13) corrects the measured combined cycle power output to design reference conditions, and also to gas turbine new and clean condition by application of C_o, C_t, and C_f. The Δ and α correction factors are per Tables 5-1-1 and 5-1-2.

The corrected thermal heat input from the fuel used for the combined cycle plant performance evaluation is

$$Q_{\mathrm{corr}} = \left\{\left(\sum_{i=1}^{\#\text{ of gas turbines}} \left[Q_{\mathrm{meas,GT}i} * C_{h\mathrm{GT}i}\right]\right) + \sum_{k=1}^{7} \omega_k\right\} \prod_{n=1}^{6} \beta_n \tag{5-5-14}$$

Equation (5-5-14) expresses the total thermal heat input from the fuel as corrected to reference conditions, and in new and clean condition, by means of application of the factor C_h. It also, inherently, accounts for any fuel preheating introduced in the combined cycle mode of operation. The ω and β correction factors are per Tables 5-1-1 and 5-1-2.

The total plant heat rate in new and clean conditions, combined cycle mode, and at new and clean base reference conditions, is therefore expressed as

$$\mathrm{HR}_{\mathrm{corr}} = \frac{Q_{\mathrm{corr}}}{P_{\mathrm{corr}}} \tag{5-5-15}$$

5-6 SPECIAL CASE WHEN PIPING IS OUTSIDE THE TEST BOUNDARY

In the event that the power plant test boundary does not include the connective steam piping, it may be necessary to correct the plant performance if these piping pressure drops deviate significantly from design. In such an instance, the corrected plant performance would be calculated as

$$P_{\mathrm{corr}} = \left(P_{\mathrm{meas}} + \sum_{i=1}^{7} \Delta_i + \sum_{k=1}^{n} U_k\right) \prod_{j=1}^{6} \alpha_j \tag{5-6-1}$$

where U_k represents additive correction factors for each piping pressure drop for which a correction is made. Performance is usually much more strongly impacted by pressure drop in the steam piping than in the water piping, so corrections for the latter are not expected.

5-7 SPECIAL CONSIDERATIONS AS APPLIED TO STEAM TURBINE PLANTS

5-7.1

The specified disposition for a steam-turbine-based power plant may be defined in multiple ways. These definitions include a specified amount of main steam flow, a particular valve point condition, or the thermal input from the fuel. A Specified Corrected Power or a Specified Measured Power test may also be conducted. The thermal input from the fuel is also used as a definition of full load.

5-7.2

The method of adjusting the firing rate under a specified throttle pressure control mode and a test goal shall be established prior to developing the heat balance model, correction curves, and calculation procedure.

5-7.3

For a test goal with a specified disposition at a valve point under a pressure control operating mode, performance correction to a reference condition requires knowledge or estimation of how the corrected plant electrical output varies with corrected fuel energy input. Figure 5-7.3-1 illustrates how gross output of a steam-turbine-based plant varies with steam turbine throttle flow. If the specified disposition is a throttle flow rate, refer to para. 5-3.5. The plant may be tested over a range of steam turbine throttle flows sufficient to encompass the corrected performance point of interest. The applicable performance equations in this scenario are thus for a fixed unit disposition, with the corrected power floating. A corrected output vs. corrected input curve is developed from the test data. The curve is entered at the corrected output to determine the corrected fuel energy input. Another procedure for this specified disposition would be to apply the Δ_7 and ω_7 corrections.

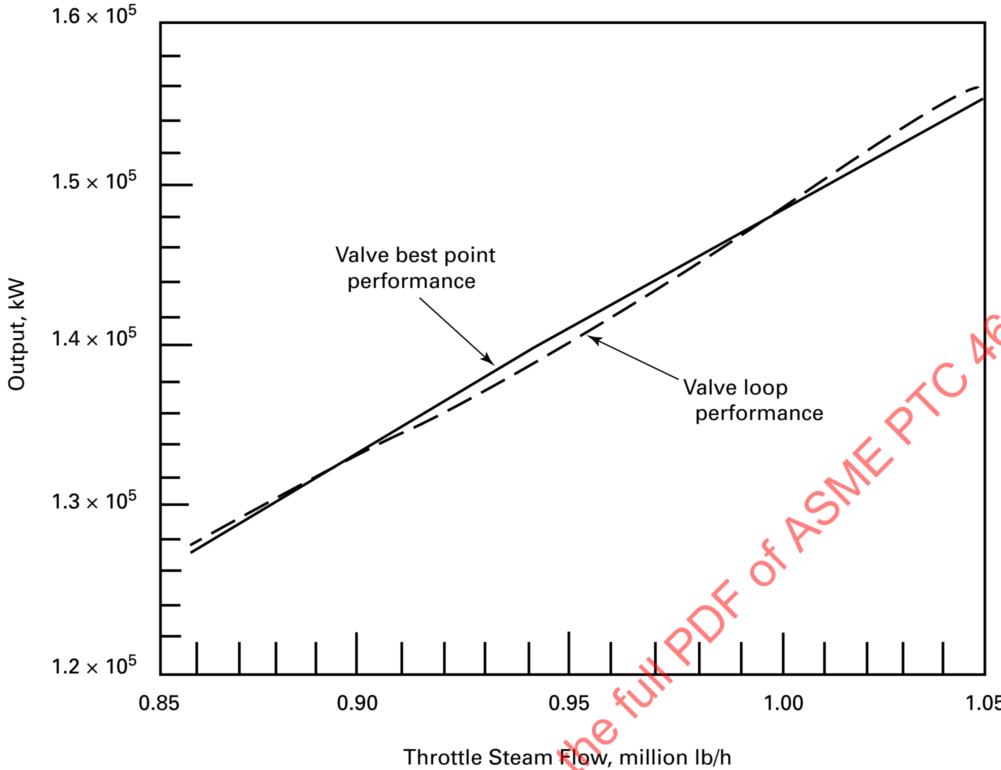
The nonlinearity in the valve loop performance curve is primarily due to the control action of the steam turbine throttle valves. The straight line curve labeled "valve best point performance" shows how the plant output would vary if calculated on a valve point basis. This performance is not realizable but is synthesized by passing a straight line through the steam turbine valve points. In practice, the actual performance varies from the valve point performance by about 0% to 0.15% for a six-valve reheat machine and by 0% to 0.25% or more for a non-reheat machine.

A steam turbine plant for which required operating disposition is based on operation at valve point must be tested at that valve point.

5-7.4

The ASME PTC 4 energy balance method is used to determine the heat input to the plant from the fuel. Thus, all the data required for an ASME PTC 4 test is taken during the ASME PTC 46 test. Care has to be taken to assure,

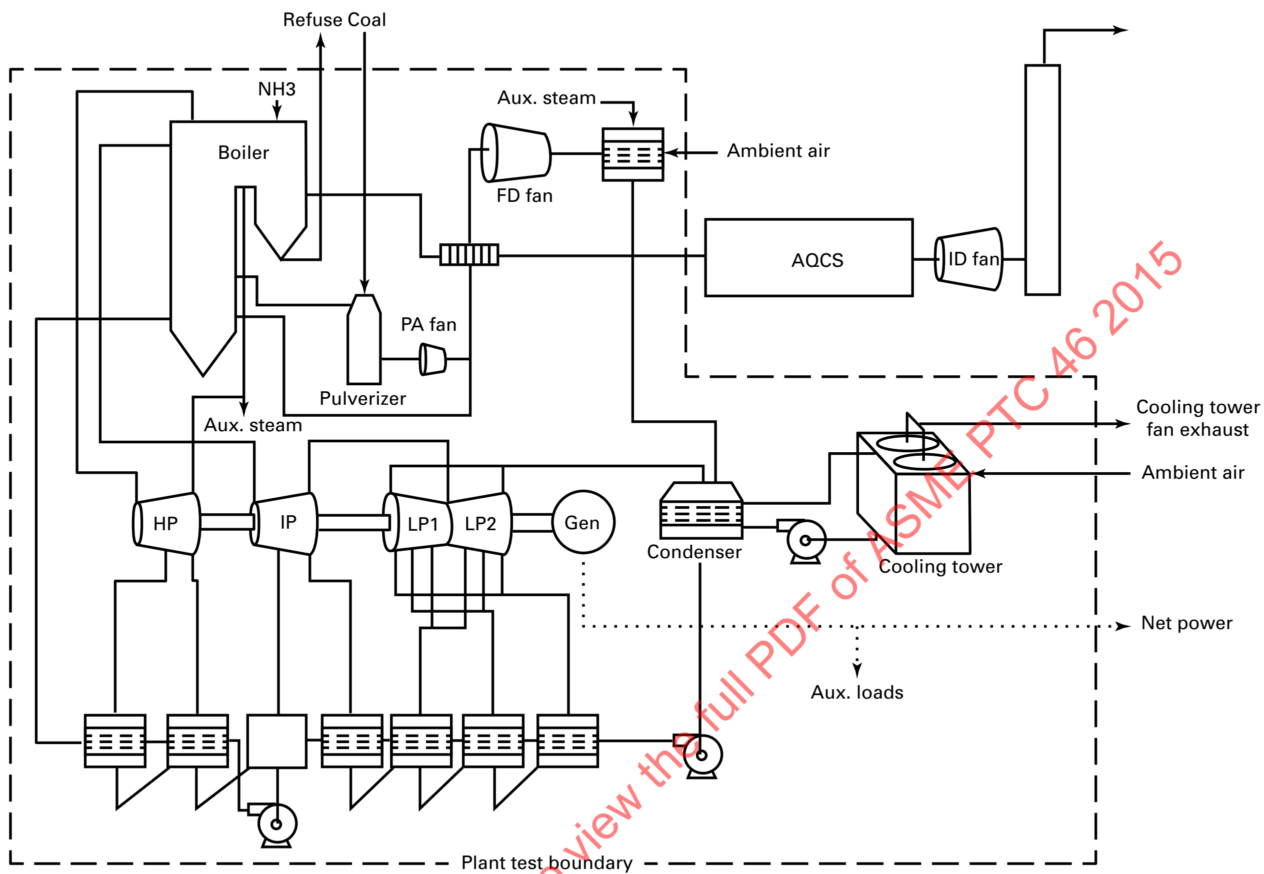
Fig. 5-7.3-1 Output Versus Throttle Steam Flow



however, that the ASME PTC 4 corrections for parameters and operating dispositions internal to the ASME PTC 46 test boundary that are normally ASME PTC 4 corrections are *not* used for the ASME PTC 46 test in determining fuel energy input. The major corrections falling into that category would be final feedwater temperature, cold reheat steam temperature, and air quality control equipment integral to the boiler prior to the flue gas exiting the air heater. Similarly, items that are sometimes not considered as part of a boiler test boundary that are to be internal to the ASME PTC 46 test boundary, such as FD, PA fans, and steam coil air preheaters, must be considered. For the ASME PTC 46 test, the base reference inlet temperature to the steam generator is at the inlet to the fans, if they are within the overall plant performance test boundary. In all cases, corrections for off-design fuel (and sorbent, if applicable) composition shall be made using the fuel component substitution correction procedures prescribed in ASME PTC 4, subsection 5-18.

Figure 5-7.4-1 shows a typical test boundary for a reheat Rankine steam cycle that may be used in straight power generation.

Fig. 5-7.4-1 Typical Test Boundary for a Reheat Rankine Steam Cycle Power Plant



Section 6
Report of Results

6-1 GENERAL REQUIREMENTS

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

(a) Executive Summary, described in subsection 6-2

(b) Introduction, described in subsection 6-3

(c) Calculation and Results, described in subsection 6-4

(d) Instrumentation, described in subsection 6-5

(e) Conclusions, described in subsection 6-6

(f) Appendices, described in subsection 6-7

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

6-2 EXECUTIVE SUMMARY

The Executive Summary is brief and should contain the following:

(a) general information about the plant and the test, such as the plant type and operating configuration, and the test objective including the test objective values

(b) date and time of the test

(c) signature of Test Coordinator(s)

(d) signature of reviewer(s)

(e) approval signature(s)

(f) summary of the results of the test including uncertainty and conclusions reached

(g) comparison with the contract guarantee

(h) any agreements among the parties to the test to allow any major deviations from the test requirements including a description of why the deviation occurred, the mitigation plan, and the impact to the uncertainty of the test due to the deviation

6-3 INTRODUCTION

The Introduction of the test report includes the following information:

(a) authorization for the tests, their object, contractual obligations and guarantees, stipulated agreements, by whom the test is directed, and the representative parties to the test

(b) any additional general information about the plant and the test not included in the executive summary, such as

(1) a historical perspective, if appropriate

(2) a cycle diagram showing the test boundary (refer to the figures in the Appendices for examples of test boundary diagrams for specific plant type or test goal)

(3) description of the equipment tested and any other auxiliary apparatus, the operation of which may influence the test result

(c) a listing of the representatives of the parties to the test;

(d) any pretest agreements that were not tabulated in the executive summary, including a detailed description of deviations to the test procedure during the test, resolution, and impact to the test results

(e) the organization of the test personnel

(f) test goal per Sections 3 and 5

6-4 CALCULATIONS AND RESULTS

This section of the test report should include, in detail, the following information:

(a) method of the test and operating conditions

(b) the format of the general performance equation that is used, based on the test goal and the applicable corrections (this is repeated from the test requirements for convenience)

(c) tabular summary of measurements and observations including the reduced data necessary to calculate the results and a summary of additional operating conditions not part of such reduced data

(d) step-by-step calculation of test results from the reduced data including the probable uncertainty (refer to the appendices for examples of step-by-step calculations for each plant type and test goal)

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

(f) detailed calculations of heat input from fuel from a coal-fired power plant utilizing PTC 4 and water-/steam-side measurements

(g) detailed calculations of fuel properties — density, compressibility factor, and heating value (values of constituent properties, used in the detailed calculations shall be shown)

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

(i) comparison of repeatability of test runs

(j) clarity as to whether reported heat rate is based on HHV or LHV

(k) correction factors to be applied because of deviations, if any, of test conditions from those specified

(l) primary measurement uncertainties, including method of application

(m) the test performances stated under the following headings:

(1) test results computed on the basis of the test operating conditions, instrument calibrations only having been applied, and

(2) test results corrected to specified conditions if test operating conditions have deviated from those specified

(n) tabular and graphical presentation of the test results

(o) discussion and details of the test results uncertainties

(p) discussion of the test, its results, and conclusions

6-5 INSTRUMENTATION

The Instrumentation section of the test report includes the following information:

(a) tabulation of instrumentation used for the primary and secondary measurements, including make, model number, tag name and number, calibration date, and bias value

(b) description of the instrumentation location

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

(d) identification of the instrument that was used as back-up

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

(f) complete description of methods of measurement not prescribed by the individual code

(g) summary of pretest and post-test calibration

6-6 CONCLUSIONS

This section of the test report includes the following information:

(a) if a more detailed discussion of the test results is required

(b) any recommended changes to future test procedures due "lesson learned"

6-7 APPENDICES

Appendices to the test report should include the following information:

(a) the test requirements

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

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

(d) copies of signed valve line-up sheets, and other documents indicating operation in the required configuration and disposition

(e) results of laboratory fuel analysis

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

Section 7
Test Uncertainty

7-1 INTRODUCTION

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 probability theory, instrumentation information, calculation procedure, and actual test data. ASME PTC 46 requires that uncertainty be reported with a 95% level of confidence.

This Code addresses test uncertainty in the following four Sections.

(a) Section 1 defines maximum allowable test uncertainties above which the test is not acceptable for each type, or configuration, of power plant. The maximum uncertainty presented in Section 1 is a limit and is not a target in designing a test.

(b) Section 3 defines the requirements for pretest and post-test uncertainty analyses, and how they are used in the test. These uncertainty analyses and limits of error are defined and discussed in para. 3-5.2.1.

(c) Section 4 describes the systematic uncertainty required for each test measurement.

(d) Section 7 and Nonmandatory Appendix F provide applicable guidance for calculating pretest and post-test uncertainty.

ASME PTC 19.1 is the Performance Test Code Supplement that covers general procedures for calculation of test uncertainty. A sample calculation is shown in Nonmandatory Appendix G of this Code.

7-2 PRETEST UNCERTAINTY ANALYSIS

A pretest uncertainty analysis is required as stated in para. 3-5.2.1 of this Code to allow corrective action to be taken prior to the test, either to decrease the uncertainty to a level consistent with the overall objective of the test, or to reduce the cost of the test while still attaining the objective. An uncertainty analysis is also useful for determining the number of observations that will be required.

7-3 POST-TEST UNCERTAINTY ANALYSIS

A post-test uncertainty analysis is required to determine the uncertainty intervals for the actual test. A post-test uncertainty analysis shall be conducted to verify the assumptions made in the pretest uncertainty analysis. In particular, the data should be examined for sudden shifts and outliers. The assumptions for random errors should be checked by determining the degrees of freedom and the standard deviation of each measurement. This analysis serves to validate the quality of the test results, or to expose problems.

7-4 INPUTS FOR AN UNCERTAINTY ANALYSIS

To perform an uncertainty analysis for an overall plant, test inputs are required to estimate the uncertainty of each of the required measurements, and the sensitivity of each of the required measurements on corrected results. Guidance on estimating the uncertainty and calculating the required sensitivity coefficients can be found in ASME PTC 19.1.

The following is a sample list of some of the items that should be considered when developing a pre- and post-test uncertainty analysis:

(a) calibration methodology

(b) linearity or nonlinearity of instruments

(c) spatial uncertainty

(d) uncertainty of the correction for evaporative cooler or fogger performance, if tested separate from the overall plant

(e) method of calibration and corresponding regression

(f) actual operating conditions for instrument versus designed use of instrument

(g) signal degradation, manipulation, compression, or dead band application prior to reading

NONMANDATORY APPENDIX A
SAMPLE CALCULATIONS, COMBINED CYCLE COGENERATION PLANT WITHOUT DUCT FIRING

Heat Sink: Completely Internal to the Test Boundary
Test Goal: Corrected Net Power and Corrected Net Heat Rate With the Gas Turbines Operating at Specified Measurement Gross Power

A-1 GENERAL

This Nonmandatory Appendix demonstrates the calculating procedure for a combined cycle cogeneration plant without duct firing as specified in Section 5. The numerical values of these corrections and the number of independent variables used to calculate apply to this example only. Unique corrections shall be developed for each specific plant.

A-2 CYCLE DESCRIPTION

The plant to be tested is a non-reheat combined cycle cogeneration plant that is powered by two nominal 85 MW gas turbines with inlet evaporative coolers and steam injection for NOx control and power augmentation.

The gas turbine exhausts produce steam in two triple-pressure heat recovery steam generators (HRSG). The high-pressure, 89.27 bara/482°C (1,280 psig/900°F) steam feeds the throttle of an 88 MW condensing steam turbine that has an intermediate pressure extraction port at 25.1 bara/(350 psig) to supply thermal efflux steam and makeup for shortages of gas turbine injection steam. The exhaust steam from the steam turbine is fed to an air-cooled condenser. The low pressure, 3.1 bara/30 psig saturated steam is used only for boiler feedwater deaeration. There is no supplemental firing capability in the HRSGs. The electrical grid frequency is stable at the reference condition.

Thermal efflux is in the form of export steam, primarily extracted from the steam turbine with steam conditions controlled to 21.7 bara/288°C (300 psig/550°F).

The operating disposition of this plant is to have the gas turbines at a specified, measured power. The heat sink is completely internal to the test boundary. The performance test goal is corrected net power and corrected net heat rate.

A-3 TEST BOUNDARY DESCRIPTION

Basically, the entire plant is included within the test boundary, as is indicated on the process flow diagram. Air crosses the boundary at the inlets of the gas turbines and the inlet to the air-cooled condenser.

Net plant electrical output is determined from measurements of the output of each generator with an allowance made for the losses of each step-up transformer. Plant auxiliary loads are supplied from the utility high voltage supply during the test.

Fuel flow rate and heating value are measured in the plant fuel supply line near where the fuel crosses the test boundary.

Export steam is measured in the steam export line where it crosses the test boundary.

A-4 REFERENCE AND MEASURED CONDITIONS

Refer to Table A-4-1.

A-5 MEASURED RESULTS

Refer to Table A-5-1.

Table A-4-1 Reference and Measured Conditions

Parameter	Reference Conditon	Measured Condition	Unit
Steam export	31.5 (250)	27.5 (218)	kg/s (KPPH)
Power factor	0.85	0.975	. . .
Gas turbine inlet temperature	21 (70)	15 (59)	°C (°F)
Air-cooled condenser inlet air temperature	21 (70)	16 (61)	°C (°F)
Ambient pressure	0.9951 (14.433)	1.00635 (14.595)	bara (psia)
Relative humidity	60	77	%
Grid frequency	60	60	Hz

Table A-5-1 Measured Results

Parameter	Measured Results
Fuel input	579.4 MJ/s (1,977 MBtu/hr) HHV
Gas turbine 1 power	87.0 MW
Gas turbine 2 power	87.5 MW
Steam turbine power	49.5 MW
Auxiliary load	4.5 MW

A-5.1 Fundamental Equations [Refer to Eqs. (5-3-1) and (5-3-2)]

$$P_{\text{corr}} = \left(P_{\text{meas}} + \sum_{i=1}^{7} \Delta_i\right) \prod_{j=1}^{6} \alpha_j$$

$$\text{HR}_{\text{corr}} = \frac{Q_{\text{corr}}}{P_{\text{corr}}}$$

$$Q_{\text{corr}} = \left(Q_{\text{meas}} + \sum_{i=1}^{7} \omega_i\right) \prod_{j=1}^{6} \beta_j$$

A-6 REQUIRED CORRECTIONS AND CORRECTION FACTORS

Refer to Table A-6-1.

A-7 CORRECTIONS NOT REQUIRED

The corrections and correction factors listed in Table A-7-1 have been determined to not be required for this specific test. These factors are also listed with the reasons for not including such corrections and correction factors in the calculations of the test results.

The corrections shown in Table A-7-1 may be required for calculations of an actual test of a similar plant. The fact that such corrections were neglected in this particular example does not mean that they should always be neglected.

A-8 CORRECTION CURVES AND FITTED EQUATIONS

These curves and equations are linear and nonlinear regressions of calculated performance deviations based on a model of a specific plant, and should not be used generically for any ASME PTC 46 test. Apply U.S. Customary units to these equations.

$$\Delta_1 = -22{,}180 + 88.8 \times F \tag{A-8-1}$$

where

F = kg/s × 7 936.641 (KPPH)

$$\Delta_{2A} = \text{MW} \times 1\,000 \times 0.987 \times [0.01597 \times (\text{pf} - 0.85) - 0.012104 \times (\text{pf}^2 - 0.85^2) - 0.021571 \times (\text{pf} - 0.85) \times \text{MW}/135)] \tag{A-8-2}$$

Table A-6-1 Required Corrections and Correction Factors

Correction/Factor	Power	Fuel Energy
Additive Corrections		
Thermal efflux	Δ_1	. . .
Gas turbine (1) power factor	Δ_{2A}	. . .
Steam turbine power factor	Δ_{2B}	. . .
Gas turbine (2) power factor	Δ_{2C}	. . .
Air-cooled condenser inlet air temperature	Δ_{5A}	. . .
Multiplicative Correction Factors		
Gas turbine inlet air temperature	α_1	β_1
Ambient pressure	α_2	β_2
Relative humidity	α_3	β_3

Table A-7-1 Correction Factors Not Required

Correction Factor	Reason Not Required
Δ_3	HRSG blowdown was closed for the test and the guarantee was based on no blowdown
Δ_4	There were no secondary heat inputs
Δ_{5B}	Does not apply to this condensing system
Δ_{5C}	Does not apply to this condensing system
Δ_6	There were no irregular or off-design auxiliary loads during the test
Δ_7	The test was a constant disposition test and therefore this correction is zero
α_4 and β_4	Fuel supply conditions were the same as for design
α_5 and β_5	Fuel analysis matched the design fuel
α_6	Grid frequency

where

MW = gas turbine power, MW

pf = power factor

$$\Delta_{2B} = \text{MW} \times 1\,000 \times 0.9825 \times [0.01597 \times (\text{pf} - 0.85) - 0.012104 \times (\text{pf}^2 - 0.85^2) - 0.021571 \times (\text{pf} - 0.85) \times \text{MW}/88] \quad \text{(A-8-3)}$$

where

MW = gas turbine power, MW

pf = power factor

$$\Delta_{2C} = \text{MW} \times 1\,000 \times 0.987 \times [0.01597 \times (\text{pf} - 0.85) - 0.012104 \times (\text{pf}^2 - 0.85^2) - 0.021571 \times (\text{pf} - 0.85) \times \text{MW}/135)] \quad \text{(A-8-4)}$$

where

MW = gas turbine power, MW

pf = power factor

$$\Delta_{5A\ (150\ \text{k lb/hr steam flow})} = -0.0130234 \times \delta^2 + 125.416 \times \delta - 1.30740\text{E-12} \quad \text{(A-8-5)}$$

where

δ = air-cooled condenser inlet air temperature minus the gas turbine inlet air temperature, °C × 9/5 (°F)

$$\Delta_{5A\ (250\ \text{k lb/hr steam flow})} = -5.95856\text{E-02} \times \delta + 95.3636 \times \delta + 2.55795\text{E-13} \quad \text{(A-8-6)}$$

where
δ = air-cooled condenser inlet air temperature minus the gas turbine inlet air temperature, °C × 9/5 (°F)

$$\Delta_{5A\ (350\ \mathrm{k\ lb/hr\ steam\ flow})} = 1.37108 \times \delta^2 + 49.2821 \times \delta + 7.10543\text{E-13} \tag{A-8-7}$$

where
δ = air-cooled condenser inlet air temperature minus the gas turbine inlet air temperature, °C × 9/5 (°F)

$$\alpha_1 = 0.844902 + 0.00146818 \times (T) + 0.000010612 \times (T)^2 \tag{A-8-8}$$

where
T = gas turbine inlet air temperature, °C × 9/5 + 32 (°F)

$$\alpha_2 = 2.134403 - 0.07858 \times (p) \tag{A-8-9}$$

where
p = ambient pressure, bara/0.0689476 (psia)

$$\alpha_3 = 0.957444 + 0.078668 \times (\mathrm{RH}/100) - 0.01301 \times (\mathrm{RH}/100)^2 \tag{A-8-10}$$

where
RH = relative humidity, %

$$\beta_1 = 0.852007 + 0.001696891 \times (T) + 5.9245\text{E-06} \times (T)^2 \tag{A-8-11}$$

where
T = gas turbine inlet air temperature, °C × 9/5 + 32 (°F)

$$\beta_2 = 2.045731 - 0.07245 \times (p) \tag{A-8-12}$$

where
p = ambient pressure, bara × 0.0689476 (psia)

$$\beta_3 = 0.958413 + 0.078079 \times (\mathrm{RH}/100) - 0.01474 \times (\mathrm{RH}/100)^2 \tag{A-8-13}$$

where
RH = relative humidity, %

A-9 DISCUSSION

Corrections are for factors affecting plant performance that are outside the control of the party running the test.

Steam export flow rate has been corrected to guarantee temperature and pressure conditions in the measurement process.

Corrections for fuel energy input have been used instead of those for heat rate based on a personal preference for this particular method of correction.

The gas turbine inlet air temperature used for this correction is the average dry bulb air temperature at the inlets of the two gas turbines. The relative humidity is the average of the measurements taken at the inlets of the two gas turbines.

The correction for differences between the gas turbine inlet air temperature and the air-cooled condenser inlet air temperature (Δ_{5A}) for this plant was determined based on the results of modeling to be a function of export steam flow only; however, the effects of other ambient conditions on the Δ_{5A} correction (for example, ambient pressure and ambient relative humidity) should be verified to be negligent by means of modeling before being ignored for a given testing situation.

To simplify the calculations, the power factors of the three generators are assumed to be equal during the measurement period. This is not always true.

Refer to Table A-9-1.

Table A-9-1 Correction Factors

Type	Description	U.S. Customary Value	Units	SI Value	Units
basis	Steam export	250	k lb/hr	31.5	kg/s
basis	Power factor	0.85		0.85	
basis	Gas turbine inlet air temperature	70	°F	21	°C
basis	Air-cooled condenser inlet air temperature	70	°F	21	°C
basis	Ambient pressure	14.433	psia	0.99512	bar(a)
basis	Relative humidity	60	%	60	%
test	Gas turbine 1 power	87,000	kW	87 000	kW
test	Gas turbine 2 power	87,500	kW	87 500	kW
test	Steam turbine power	49,500	kW	49 500	kW
test	Auxiliary load	4,500	kW	4 500	kW
test	Fuel input-HHV	1,977.0	MBtu/hr	579.4	MJ/s
test	Steam export	218	k lb/hr	27.5	kg/s
test	Power factor	0.975		0.975	
test	Gas turbine inlet air temperature	59	°F	15	°C
test	Air-cooled condenser inlet air temperature	61	°F	16	°C
test	Ambient pressure	14.595	psia	1.0063	bar(a)
test	Relative humidity	77	%	77	%
test	Transformer losses	0.5	%	0.5	%
test	Gross power	224,000	kW	224 000	kW
test	Auxiliary load	4,500	kW	4 500	kW
test	Transformer losses	1,120	kW	1 120	kW
test	Net power	219,500	kW	219 500	kW
	Thermal Efflux — delta 1				
test	Steam export	218	k lb/hr	27.5	kg/s
curve	Correction delta 1	(2,822)	kW	(2 822)	kW
	Gas Turbine Power Factor — delta 2A and 2C				
test	Power factor	0.975	kW	0.975	kW
test	Gas turbine 1 power	87,000	kW	87 000	kW
curve	GT 1 corr delta 2A	(215)	kW	(215)	kW
test	Gas turbine 2 power	87,500	kW	87 500	kW
curve	GT 2 corr delta 2C	(217)	kW	(217)	kW
add	Total corr delta 2A & 2C	(432)	kW	(432)	kW
	Steam Turbine Power Factor — delta 2B				
test	Power factor	0.975		0.975	
test	Steam turbine power	49,500	kW	49 500	kW
curve	Corr delta 2B	(111)	kW	(111)	kW
	Air-Cooled Condenser Inlet Air Temperature — delta 5A				
test	Air-cooled condenser inlet air temperature	61	°F	16	°C
Test	Gas turbine inlet air temperature	59	°F	15	°C
test	Steam export	218	k lb/hr	27.5	kg/s
curve	Correction delta 5A (150 k lb/hr steam flow)	251	kW	251	kW
curve	Correction delta 5A (250 k lb/hr steam flow)	190	kW	190	kW
interpolated	Correction delta 5A	210	kW	210	kW
	Gas Turbine Inlet Air Temperature — Power — alpha 1				
test	Gas turbine inlet air temperature	59	°F	15	°C
curve	Corr alpha 1	0.96846		0.96846	
	Ambient Pressure — alpha 2				
test	Ambient pressure	14.595	psia	1.0063	bar(a)
curve	Corr alpha 2	0.98756		0.98756	
	Relative Humidity — Power — alpha 3				
test	Relative humidity	77	%	77	%
curve	Corr alpha 3	1.01030		1.01030	

Table A-9-1 Correction Factors (Cont'd)

Type	Description	U.S. Customary Value	Units	SI Value	Units
	Gas Turbine Inlet Air Temperature — Fuel Flow — beta 1				
test	Gas turbine inlet air temperature	59	°F	15	°C
curve	Corr beta 1	0.97275		0.97275	
	Ambient Pressure — Fuel Flow — beta 2				
test	Ambient pressure	14.595	psia	1.0063	bar(a)
curve	Corr beta 2	0.98831		0.98831	
	Relative Humidity — Fuel — beta 3				
test	Relative humidity	77	%	77	%
curve	Corr beta 3	1.00980		1.00980	
	Corrected Power				
test	Net power	219,500	kW	219 500	kW
curve	Delta 1	(2,822)	kW	(2 822)	kW
curve	Total delta 2A	(432)	kW	(432)	kW
curve	Delta 2B	(111)	kW	(111)	kW
curve	Delta 5A	210	kW	210	kW
curve	Alpha 1	0.96846		0.96846	
curve	Alpha 2	0.98756		0.98756	
curve	Alpha 3	1.01030		1.01030	
calc	Corrected net power	209,046	kW	209 046	kW
	Corrected Fuel				
test	Fuel input — HHV	1,977.0	MBtu/hr	579	MJ/s
curve	Beta 1	0.97275		0.97275	
curve	Beta 2	0.98831		0.98831	
curve	Beta 3	1.00980		1.00980	
calc	Corrected fuel input — HHV	1,919.3	MBtu/hr	562.1	MJ/s
	Corrected Heat Rate				
calc	Corrected fuel input — HHV	1,919.3	MBtu/hr	562.1	MJ/s
calc	Corrected net power	209,046	kW	209 046	kW
calc	Corrected net heat rate — HHV	9,181	Btu/kWh	9 680	kJ/kWh

NONMANDATORY APPENDIX B
SAMPLE CALCULATIONS, COMBINED CYCLE COGENERATION PLANT WITH DUCT FIRING

Heat Sink: External to the Test Boundary
Test Goal: Measurement of Corrected Heat Rate at the Specified, Corrected Net Power — Operate to the Desired Power Level By Duct Firing the HRSG

B-1 GENERAL

This Nonmandatory Appendix demonstrates the calculating procedure for combined cycle cogeneration plant with duct firing as specified in Section 5. The numerical values of these corrections and the number of independent variables used to calculate apply to this example only. Unique corrections shall be developed for each specific plant.

B-2 CYCLE DESCRIPTION AND UNIT DESCRIPTION

This cycle consists of a gas turbine that exhausts to a two pressure level heat recovery steam generator with duct firing, plus a single case steam turbine that exhausts to a water-cooled condenser. (Refer to the cycle diagram in Fig. B-2-1.) HP steam from the HRSG goes to the steam turbine throttle valve. An extraction port on the steam turbine provides steam for gas turbine NOx control. The steam turbine also has an LP induction/extraction port. When little or no process steam is required, LP steam from the HRSG is inducted into the turbine. When design quantities of process steam are required, LP steam is extracted from the turbine and combined with LP steam from the HRSG. The cycle also includes a fuel preheater, a deaerator, and a chemical cleaning system.

The operating disposition of this plant is such that it allows adjustment to plant power by adjusting the rate of fuel to the duct burner. The heat sink is external to the test boundary. The gas turbine is base loaded and its power output is a function of ambient conditions. The electrical grid frequency is stable at the design value. The steam turbine must provide the difference between the design power level and the gas turbine power output. By varying duct burner fuel flow, the necessary amount of steam in the HRSG is produced to meet the required steam turbine power output and process steam flow requirements.

Thus, the performance test goal is to duct fire until design power is reached. The unit was designed to meet this power level on a 365-day per year basis in a temperate climate zone.

B-3 TEST BOUNDARY DESCRIPTION

The test boundary is also shown on Fig. B-2-1. Note that the condenser is outside the test boundary.

The streams with energy entering the system that need to be determined are

(a) air for the gas turbine
(b) fuel to both gas turbine and the duct burner
(c) makeup flow
(d) saturated condensate from the condenser to the condensate system

The streams with energy leaving the system that need to be determined are

(e) electrical power
(f) process steam
(g) steam turbine exhaust to condenser
(h) blowdown from the HRSG

B-4 TABLE OF REFERENCE CONDITIONS

The parameters requiring correction, and their design values, are given in Table B-4-1.

Fig. B-2-1 Cycle Diagram and Test Boundary

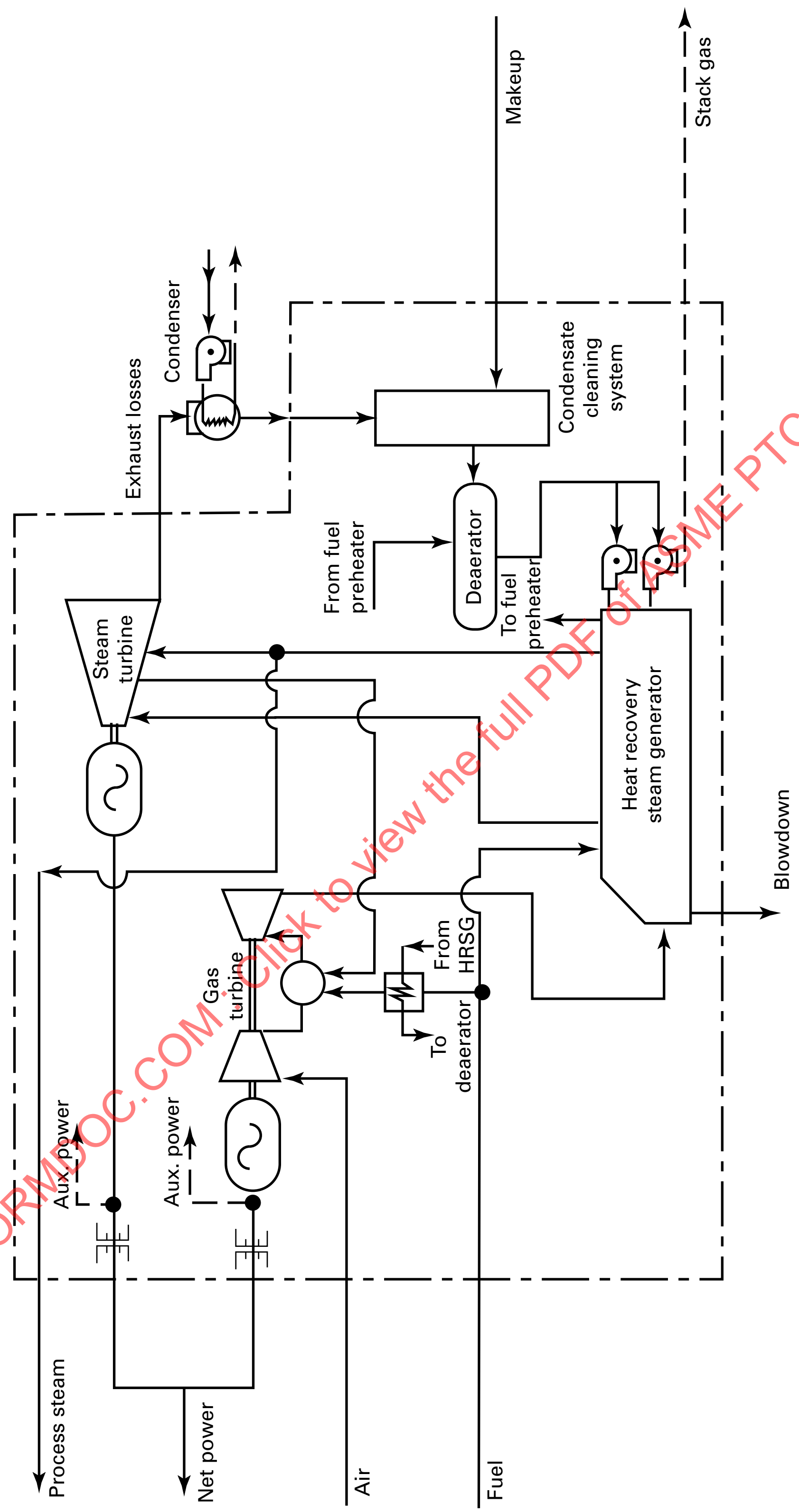


Table B-4-1 Reference Conditions

Reference Condition Description	Reference Value
Gross plant power output	81,380 kW
Ambient temperature	-1.1°C (30°F)
Ambient pressure	101.2 kPa (14.68 psia)
Ambient relative humidity	60%
Gas turbine fuel temperature	177°C (350°F)
Fuel heating value, HHV	50 723.6 kJ/kg (21,826 Btu/lbm)
Fuel carbon to hydrogen ratio	3.06
Gas turbine generator power factor	0.85
Steam turbine generator power factor	0.85
HRSG HP drum blowdown	1% steam flow
HRSG LP drum blowdown	1% steam flow
Makeup water temperature	16°C (60°F)
Excess makeup water flow [Note (1)]	0 kg/s (0 lb/hr)
Condenser pressure	5.08 kPa (1.50 in. HgA)
Process steam flow	6.2999 kg/s (50,000 lb/hr)
Process steam enthalpy	2 882.9 kJ/kg (1,240.5 Btu/lbm)
Grid frequency	60.00 Hz

NOTE:
(1) This is the flow in excess of that required for makeup due to NO_x steam, process steam, etc., that enters the cycle.

B-5 REQUIRED CORRECTION FACTORS

For the test, the plant is operated by adjusting the amount of duct firing until the design power level is reached. Since it is desired to minimize corrections to power, additive corrections are made to heat input using the ω corrections [refer to eq. (5-3-6)]. Multiplicative corrections are made to heat rate using the *f* correction factors [refer to eq. (5-3-7)]. There is one additive correction to power Δ_7, which is used in combination with ω_7 to correct from measured power to design power.

Therefore, from the overall general heat rate equation

$$\mathrm{HR}_{corr} = \frac{(Q_{meas} + \Sigma\omega_i)\Pi\beta_j}{(P_{meas} + \Sigma\Delta_i)\Pi\alpha_j}$$

and the relationship

$$f_j = \frac{\beta_j}{\alpha_j}$$

the test equation for this specific plant and test becomes

$$\mathrm{HR}_{corr} = \frac{(Q_{meas} + \omega_1 + \omega_2 + \omega_3 + \omega_4 + \omega_5 + \omega_7)}{(P_{meas} + \Delta_7)} f_1 f_2 f_3 f_4 f_5$$

The individual corrections in this equation are described in Tables B-5-1 and B-5-2.

B-6 CORRECTION CURVES AND FITTED EQUATIONS

A series of heat balances were run in order to determine the performance test corrections.

The corrections are first presented in equation form followed by a series of curves (see Figs. B-6-1 through B-6-11).

Table B-5-1 Required Correction Factors

Symbol	Description
ω_1	Correction to heat input to account for process efflux (i.e., process steam) different than design
ω_2	Correction to heat input to account for generator power factor different than design. This is broken down to ω_{2A} for the GT generator and ω_{2B} for the ST generator.
ω_3	Correction to heat input to account for blowdown different than design
ω_4	Correction to heat input to account for secondary heat inputs (i.e., makeup) different than design
ω_{5C}	Correction to heat input to account for condenser pressure different than design. (The correction would be ω_{5A} for cooling tower air inlet temperature different than design. The correction would be ω_{5B} for circulating water temperature different than design.)
ω_7	Correction to heat input to account for difference between measured power and design power
Δ_7	Difference between design power and measured power
f_1	Correction factor to plant heat rate to account for ambient temperature different than design
f_2	Correction factor to plant heat rate to account for ambient pressure different than design
f_3	Correction factor to plant heat rate to account for relative humidity different than design
f_4	Correction factor to plant heat rate to account for fuel temperature different than design
f_5	Correction factor to plant heat rate to account for fuel composition different than design

Table B-5-2 Measured Data

Description	Measured Value
Gross gas turbine power output	54 921 kW
Gross steam turbine output	27 244 kW
GT generator power factor	0.95
ST generator power factor	0.95
Inlet air temperature	8.5°C (47.3°F)
Ambient pressure	101.8 kPa (14.76 psia)
Ambient inlet relative humidity	30%
Gas turbine fuel temperature	180°C (356°F)
Fuel heating value, HHV	53 103 kJ/kg (22,850 Btu/lbm)
Fuel carbon to hydrogen ratio	3.05
HRSG HP drum blowdown	Isolated
HRSG LP drum blowdown	Isolated
Makeup water temperature	17.9°C (64.2°F)
Condenser pressure	4.06 kPa (1.20 in. HgA)
Process steam pressure	1 299 kPa (188.4 psia)
Process steam temperature	239.6°C (463.3°F)
The data below is calculated from other measurements:	
Gas turbine fuel flow	3.2641 kg/s (25,906 lbm/hr)
Duct burner fuel flow	0.6864 kg/s (5,448 lbm/hr)
Process steam flow	5.8748 kg/s (46,626 lbm/hr)
NOx steam flow	5.7395 kg/s (45,552 lbm/hr)
Makeup flow	11.630 kg/s (92,303 lbm/hr)
Process steam enthalpy	2 904.5 kJ/kg (1,249.8 Btu/lbm)

Correction to heat input to account for process efflux (i.e., process steam) different than design, expressed in U.S. Customary units:

$$\omega_1 = 55{,}082{,}885 - 78.4074405F + 6.7583{*}10^{-7}F^2 - 25{,}310.41H + 9.68613371H^2 - 0.41827648FH - 1.0758{*}10^{-9}F^2H - 0.00011342FH^2 + 4.2804{*}10^{-13}F^2H^2$$

where

F = process steam flow, kg/s × 7,936.641 (lb/hr)
H = process steam enthalpy, kJ/kg/2.326 (Btu/lb)
ω_1 = correction to heat input, Btu/hr

Correction to heat input to account for gas turbine generator power factor different than design, expressed in U.S. Customary units:

$$\omega_{2A} = 76{,}855{,}305.67 - 154{,}591{,}165(\mathrm{PF}) + 75{,}497{,}833.33(\mathrm{PF})^2 - 3{,}387.76765P + 0.034160678P^2 + 6{,}736.6085(\mathrm{PF})P - 3{,}236.47(\mathrm{PF})^2P - 0.06782565(\mathrm{PF})P^2 + 0.032513667(\mathrm{PF})^2P^2$$

where

(PF) = gas turbine generator power factor
P = gross electric power output measured at gas turbine generator terminals, kW
ω_{2A} = correction to heat input, Btu/hr

Correction to heat input to account for steam turbine generator power factor different than design, expressed in U.S. Customary units:

$$\omega_{2B} = 6{,}286{,}157 - 12{,}273{,}205(\mathrm{PF}) + 5{,}738{,}500(\mathrm{PF})^2 - 443.8303P + 0.004955327P^2 + 914.5335714(\mathrm{PF})P - 461.6238095(\mathrm{PF})^2P - 0.012295(\mathrm{PF})P^2 + 0.007606122(\mathrm{PF})^2P^2$$

where

(PF) = gas turbine generator power factor
P = gross electric power output measured at gas turbine generator terminals, kW
ω_{2B} = correction to heat input, Btu/hr

Correction to heat input to account for blowdown different than design.
Correction from isolated to 1% HP blowdown, expressed in U.S. Customary units:

$$\omega_3 = 592{,}390.1 - 672.4T + 1{,}000.0485T^2$$

where

T = inlet temperature, °C × 9/5 + 32 (°F)
ω_3 = correction to heat input, Btu/hr

LP blowdown is insignificant.
Correction to heat input to account for secondary heat inputs (i.e., makeup) different than design, expressed in U.S. Customary units:

$$\omega_4 = -571{,}800 - 1{,}300.38F + 5.9631{*}10^{-19}F^2 + 9{,}440T + 1.5T^2 + 0.17475FT + 6.7793{*}10^{-21}F^2T + 0.0002125FT^2 - 5.294{*}10^{-23}F^2T^2$$

where

F = excess makeup flow, kg/s × 7,936.641 (lb/hr)
T = makeup temperature, °C × 9/5 + 32 (°F)
ω_4 = correction to heat input, Btu/hr

Correction to heat input to account for condenser pressure different than design, expressed in U.S. Customary units as follows:

$$\omega_{5C} = 11{,}686{,}296.56 - 8{,}308{,}140.313P + 344{,}850.625P^2 + 68{,}357.175T - 393.718125T^2 - 52{,}424.275PT + 4{,}568.55P^2T + 282.085625PT^2 - 13.07125P^2T^2$$

Fig. B-6-1 Correction to Heat Input for Thermal Efflux

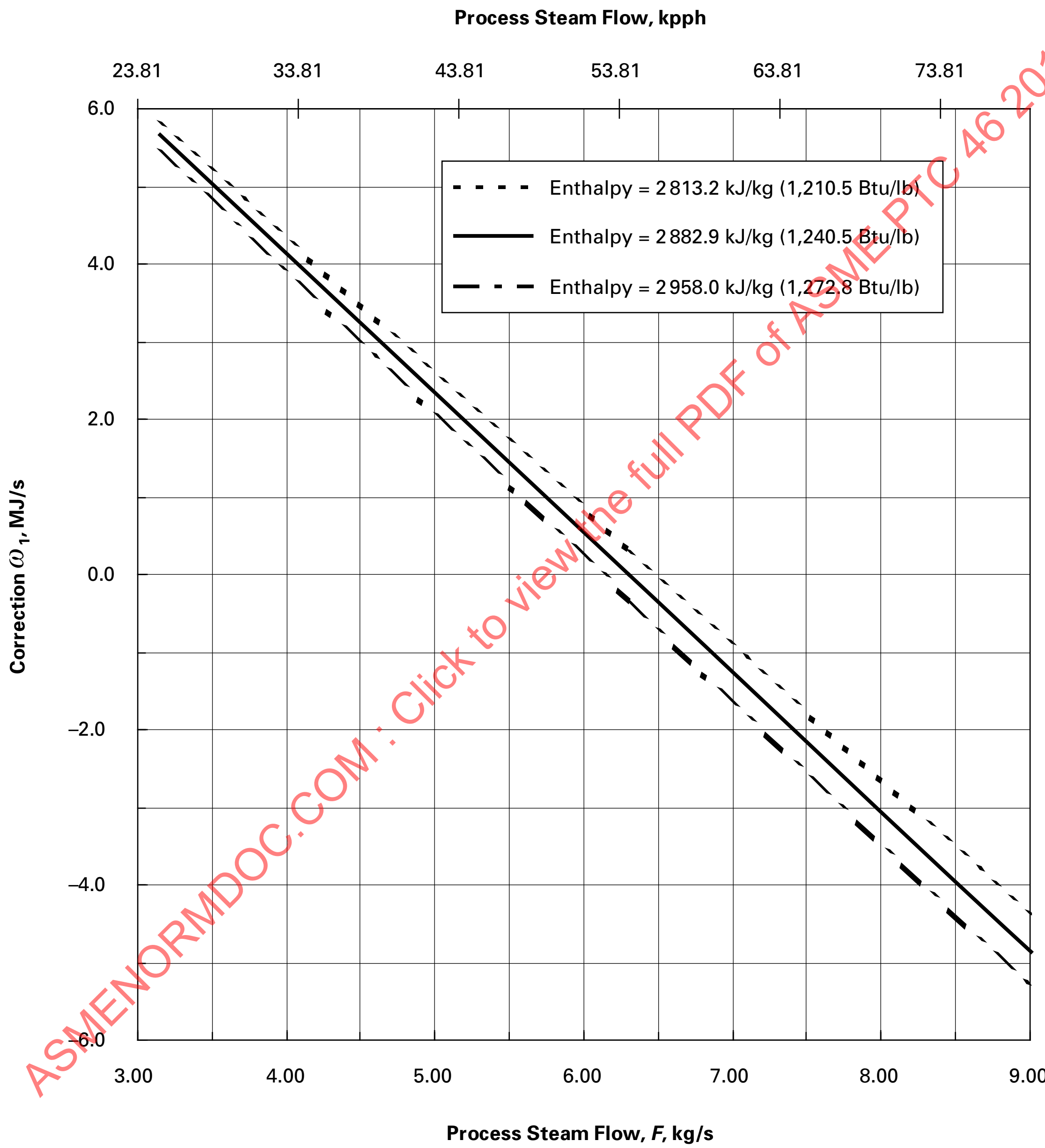


Fig. B-6-2 Correction to Heat Input for Gas Turbine Power Factor

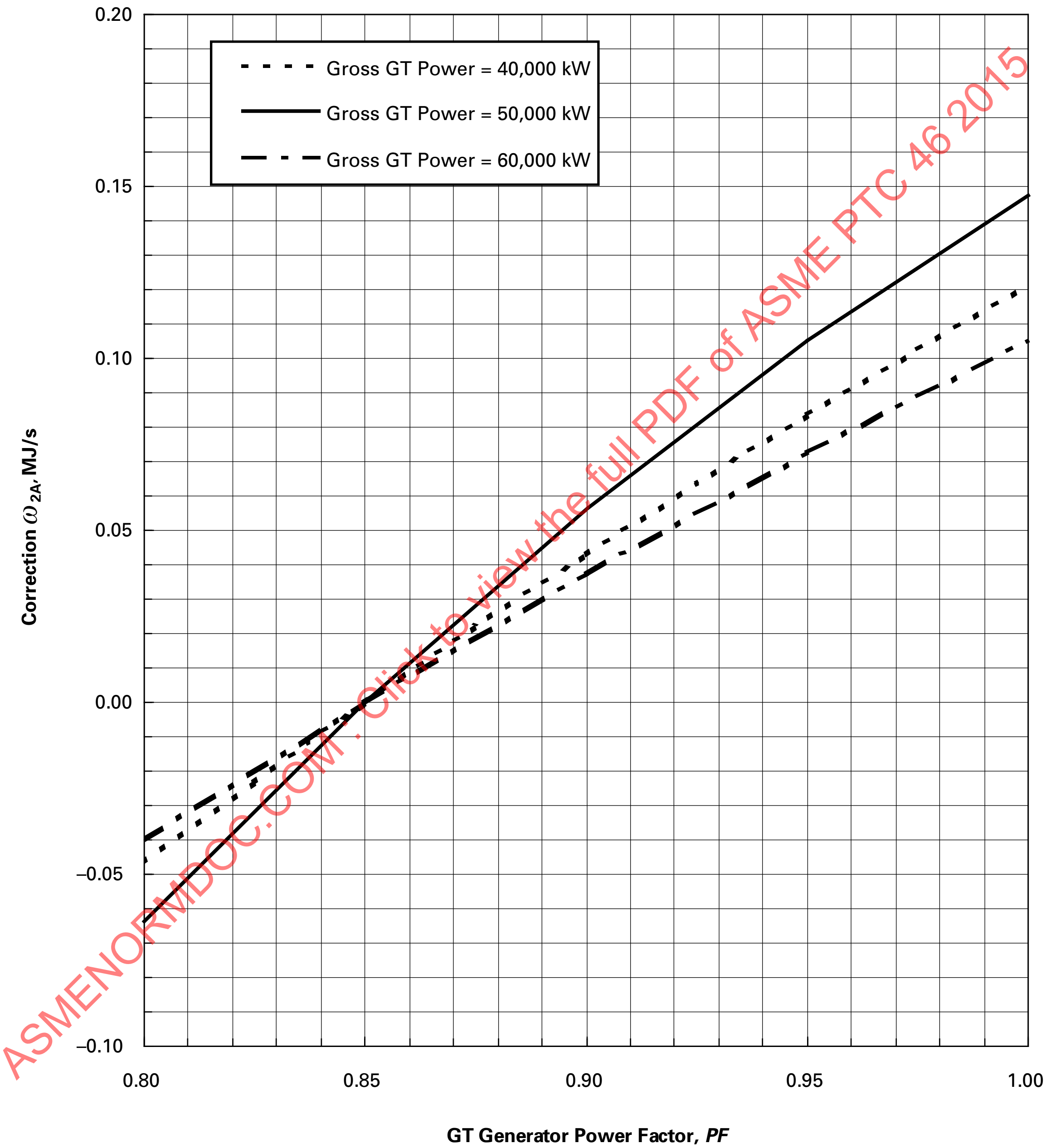


Fig. B-6-3 Correction to Heat Input for Steam Turbine Power Factor

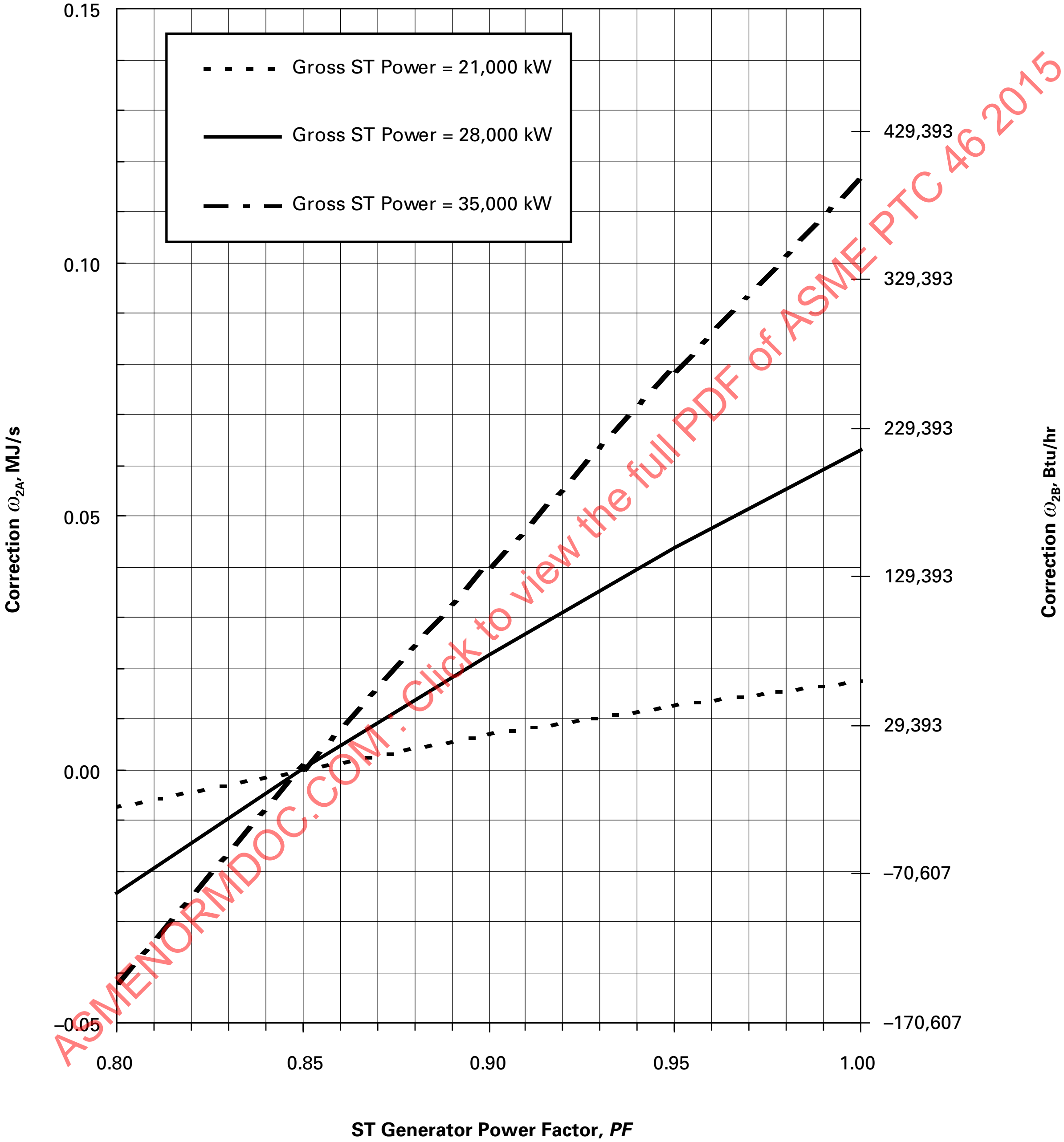
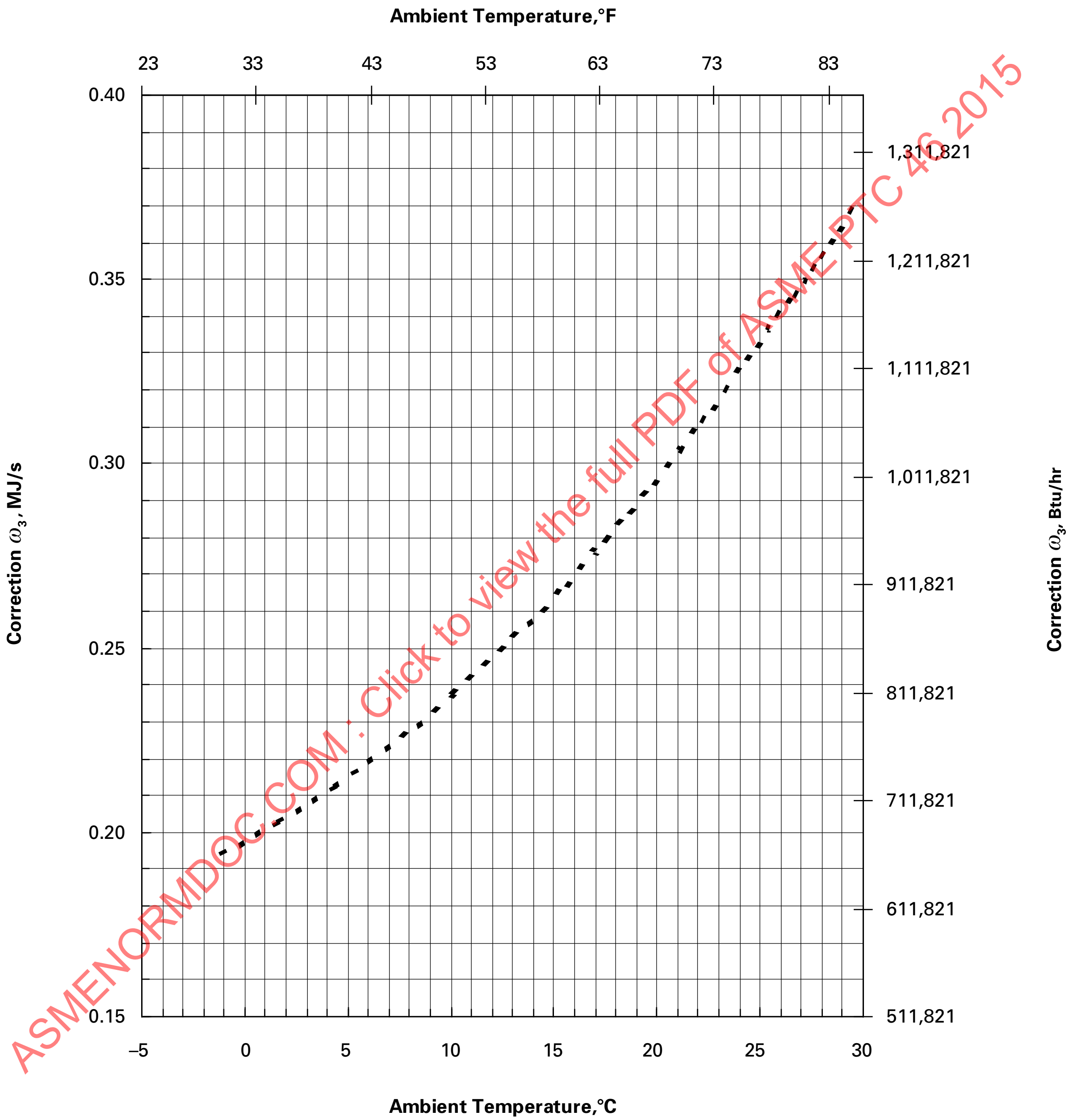


Fig. B-6-4 Correction to Heat Input for HP Blowdown



GENERAL NOTE: Correction from isolated to 1%.

Fig. B-6-5 Correction to Heat Input for Excess Cycle Makeup

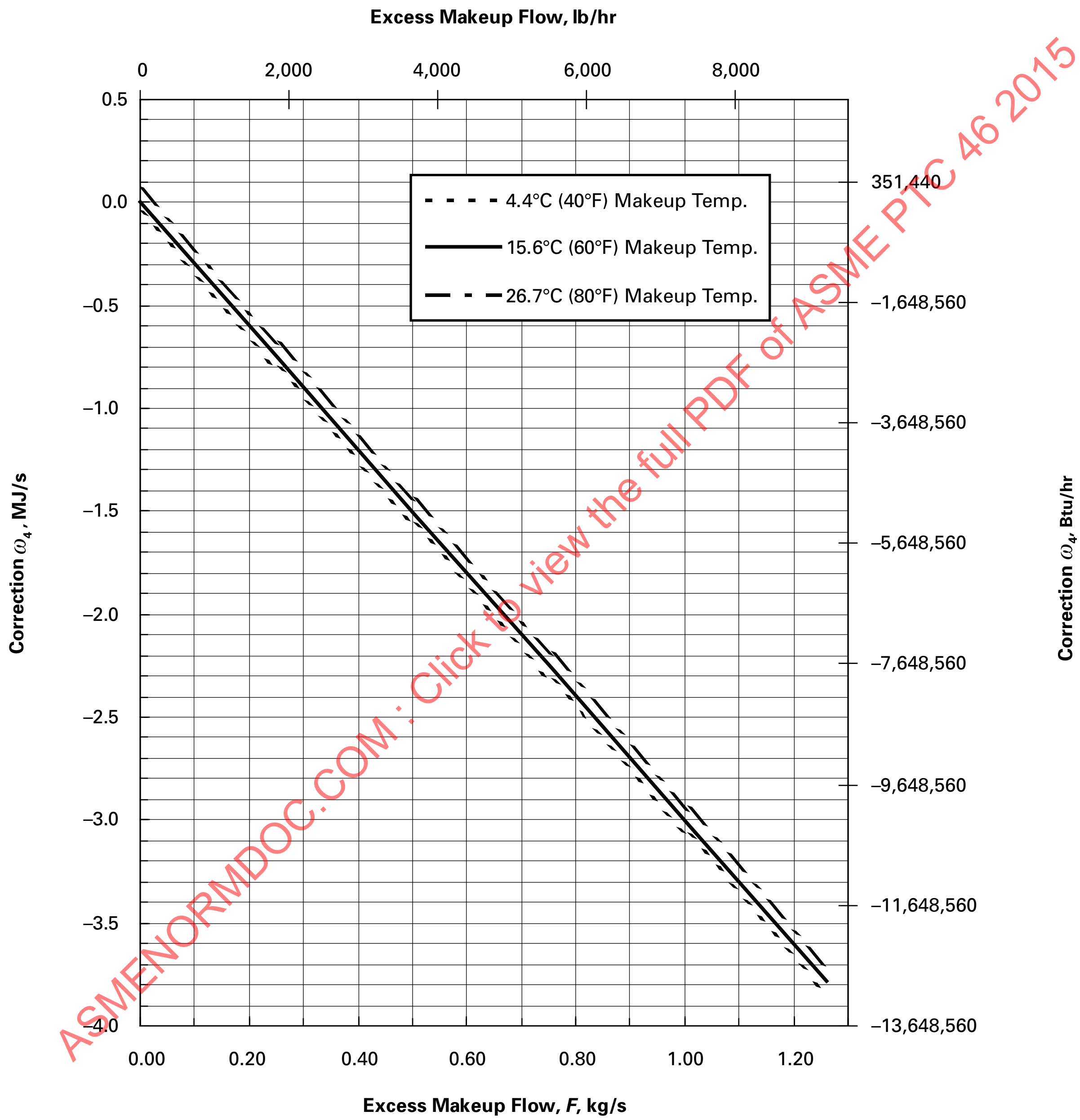


Fig. B-6-6 Correction to Heat Input for Steam Turbine Condenser Pressure

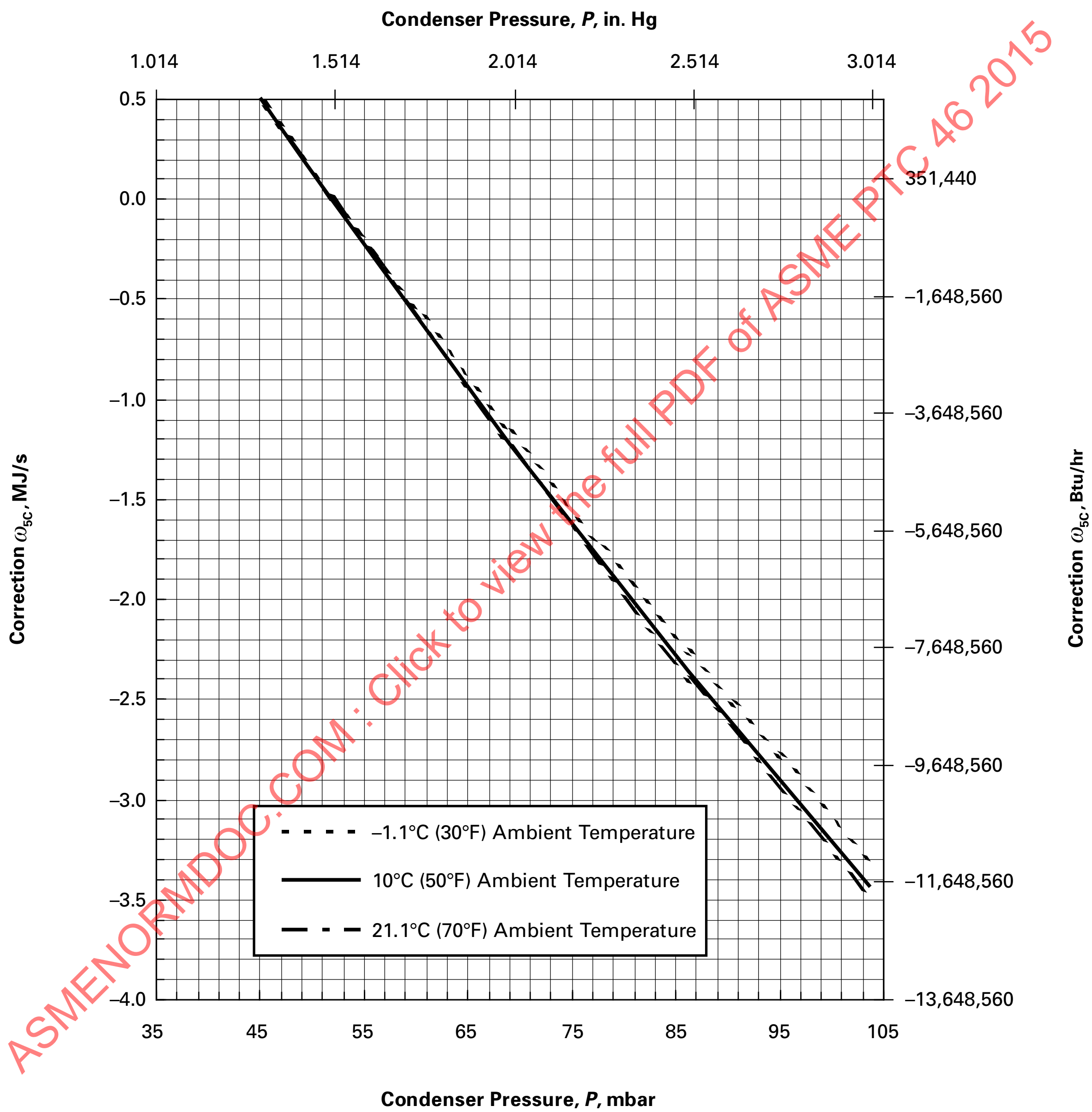


Fig. B-6-7 Correction to Heat Input for Measured Power Different Than Design

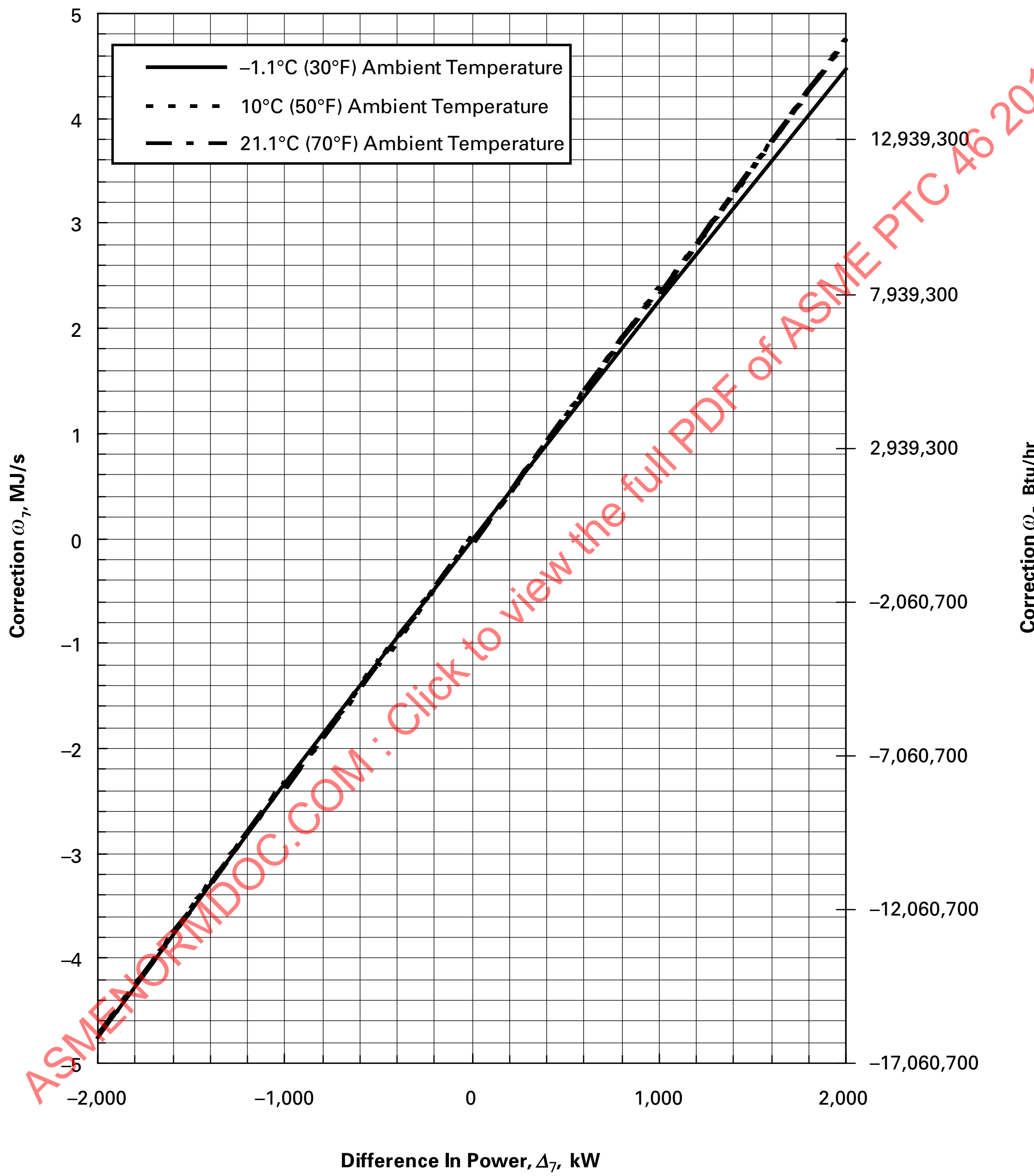


Fig. B-6-8 Correction to Heat Rate for Inlet Air Temperature

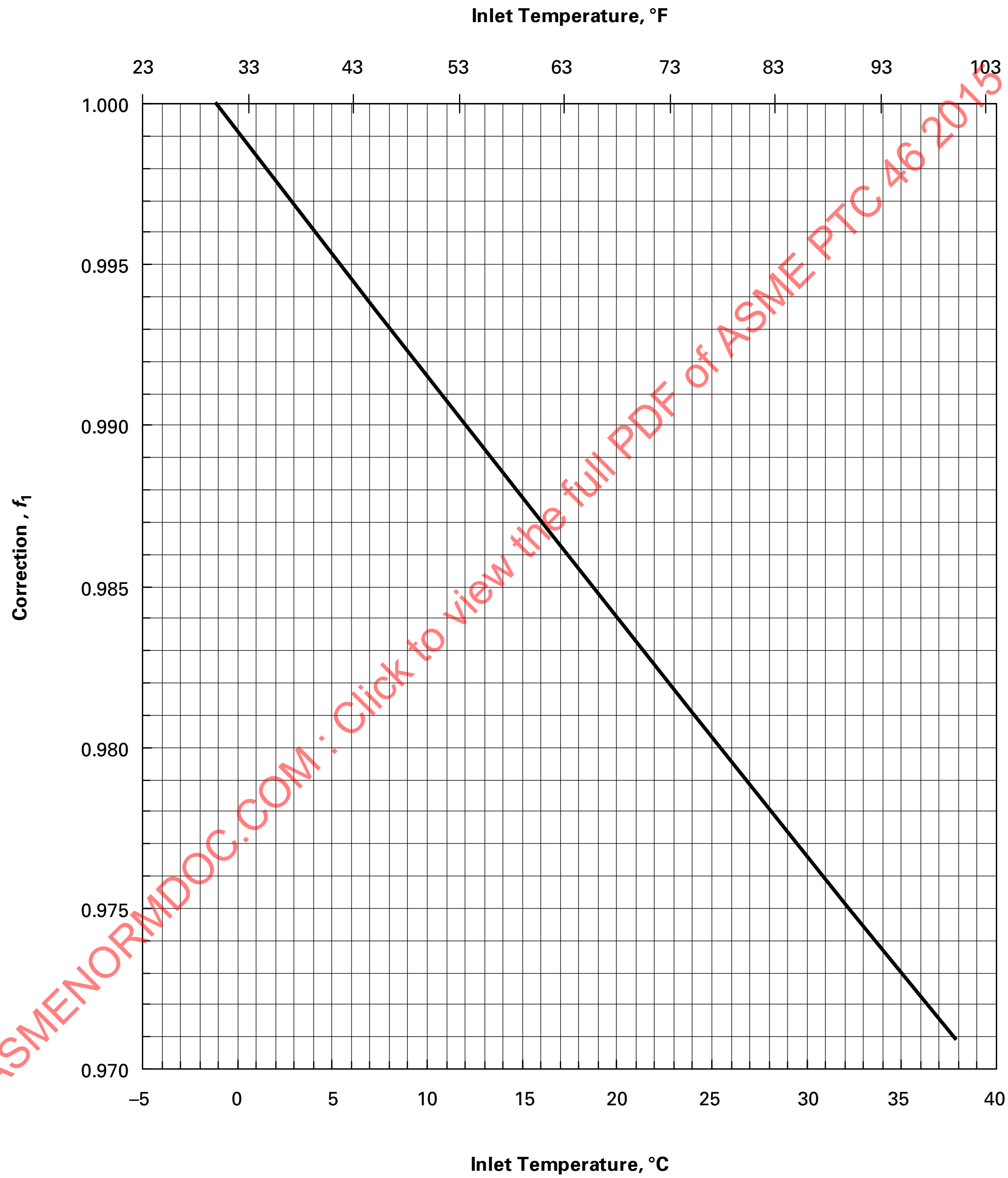


Fig. B-6-9 Correction to Heat Rate for Ambient Pressure

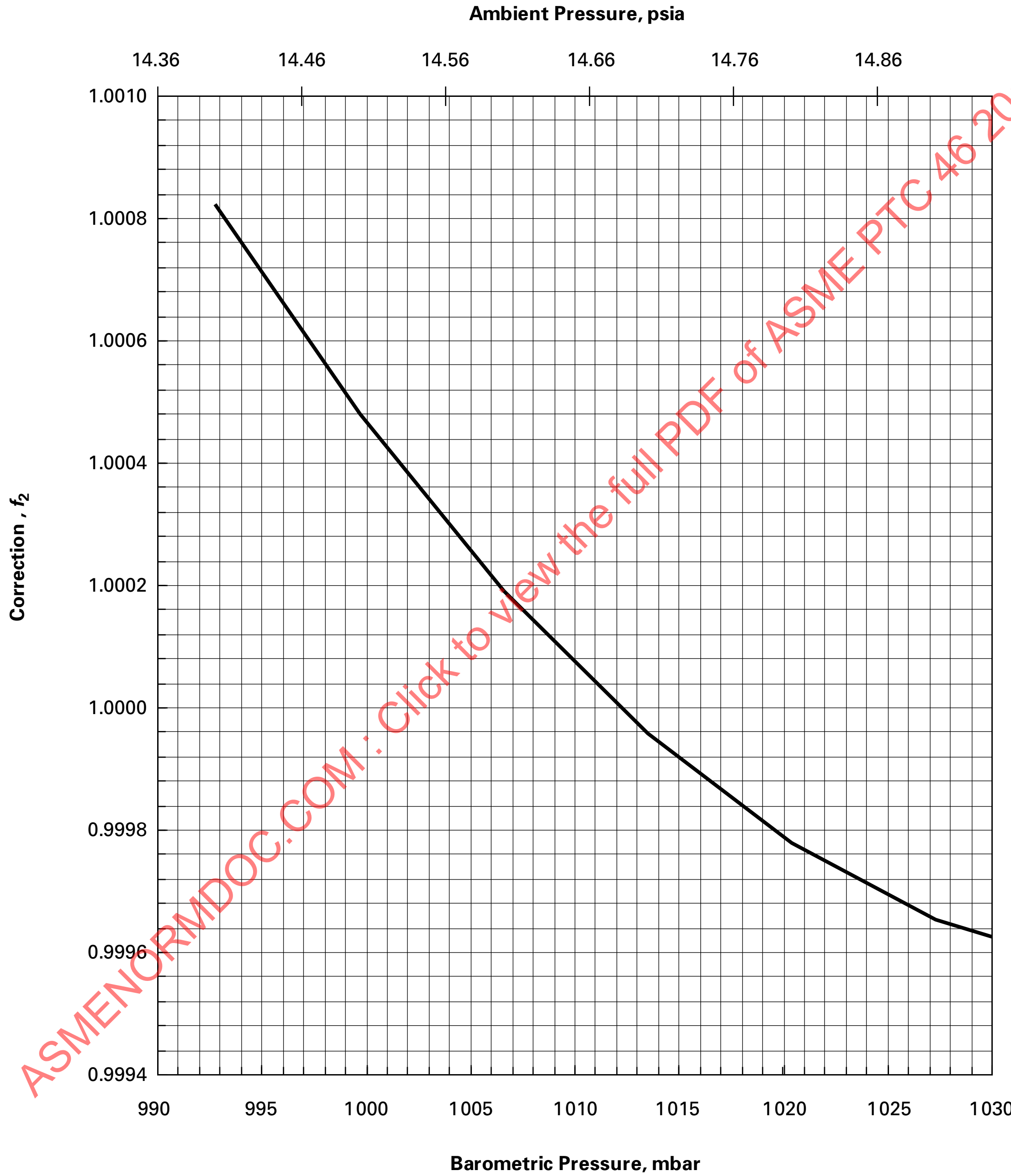


Fig. B-6-10 Correction to Heat Rate for Fuel Temperature

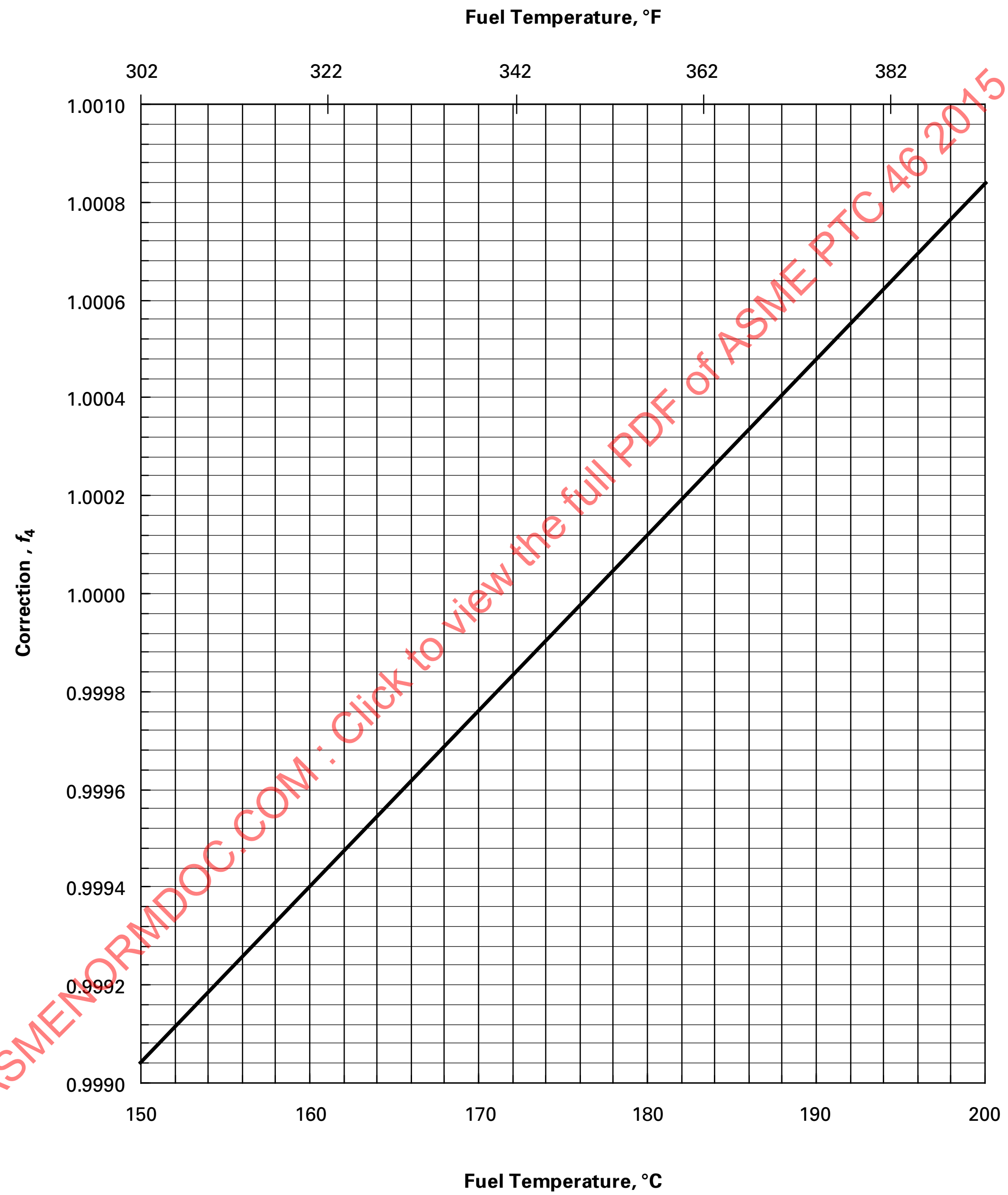
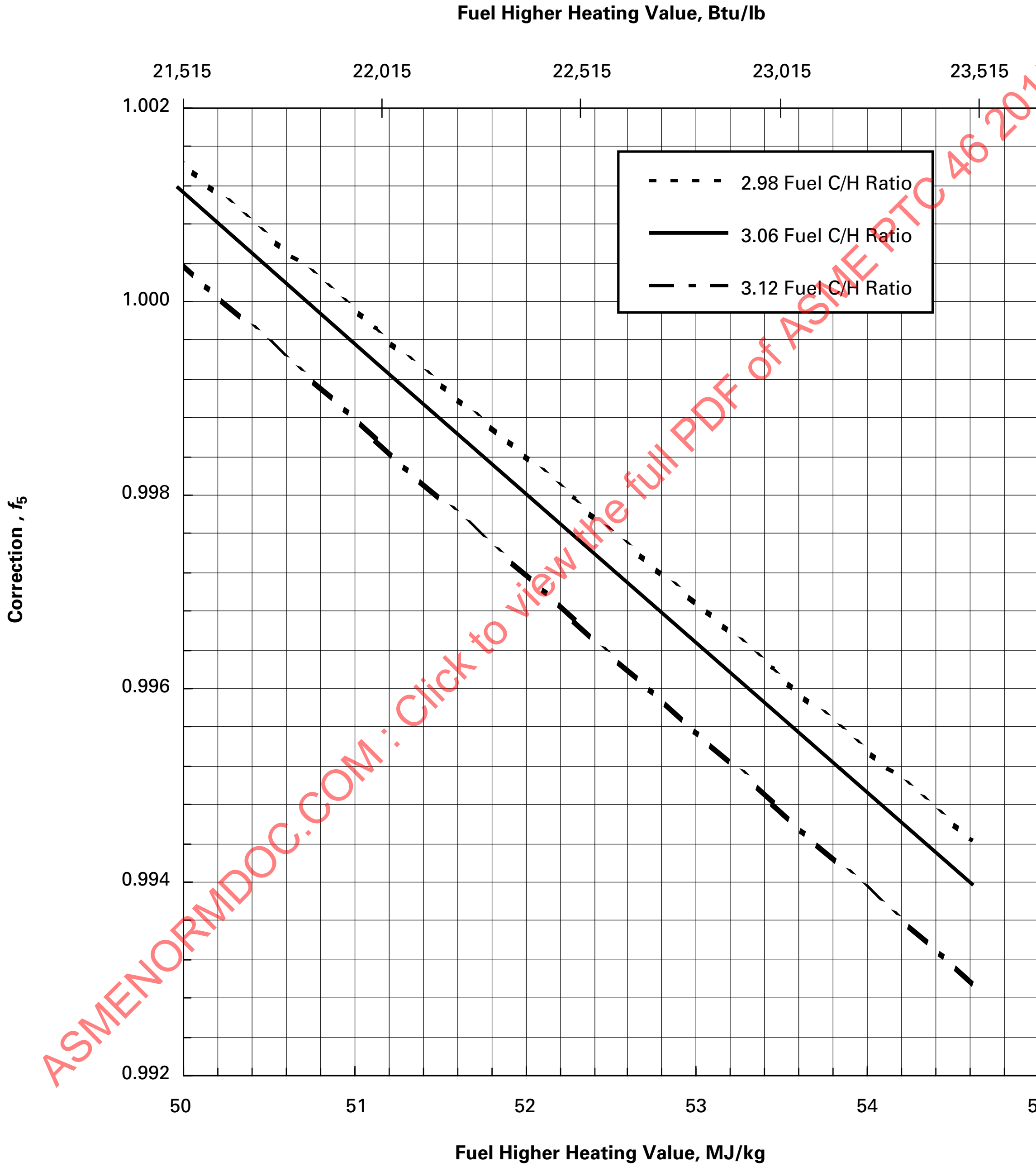


Fig. B-6-11 Correction to Heat Rate for Fuel Analysis



where

P = condenser pressure, kPa × 0.0345 (in. Hg, absolute)

T = inlet temperature, °C × 9/5 + 32 (°F)

ω_{5C} = correction to heat input, Btu/hr

Correction to thermal heat input to account for difference between measured power and design power, expressed in U.S. Customary units:

$$\omega_7 = -2.61186*10^{-12} + 7{,}260.752844\Delta_7 - 0.537355297\Delta_7^2 + 4.27425*10^{-14}T - 2.24607*10^{-15}T^2 + 26.6786625\Delta_7 T + 0.018662119\Delta_7^2 T - 0.222322188\Delta_7 T^2 - 0.000155518\Delta_7^2 T^2$$

where

Δ_7 = difference between design power and measured power, $P_{design} - P_{meas}$ (kW)

T = inlet temperature, °C × 9/5 + 32 (°F)

Difference between design power and measured power, where Δ_7 = 81,380 − P_{meas} and Δ_7 = correction to heat input, Btu/hr.

Correction factor to heat input to account for inlet temperature different than design, applying U.S. Customary units as follows:

$$f_1 = 1.012975085 - 0.0004378037T + 1.766957*10^{-7}T^2$$

where

T = inlet temperature, °C × 9/5 + 32 (°F)

Correction factor to heat input to account for ambient pressure different than design, applying U.S. Customary units as follows:

$$f_2 = 1.617199959 - 0.08191305P + 0.002715903P^2$$

where

P = ambient pressure kPa × 0.145059, psia

Correction factor to heat input to account for relative humidity different than design.

$$f_3 = 1.0 \text{ (correction is insignificant)}$$

Correction factor to heat input to account for gas turbine fuel temperature different than design, applying U.S. Customary units as follows:

$$f_4 = 0.99301814 + 0.00001994817T$$

where

T = fuel temperature, °C × 9/5 + 32 (°F)

Correction factor to heat input to account for fuel heating value different than design, applying U.S. Customary units as follows:

$$f_5 = 2.66107573 - 0.00010133V + 3.3266*10^{-13}V^2 - 1.06344696R + 0.17852287R^2 + 6.5632*10^{-5}VR - 2.1534*10^{-13}V\mathrm{R} - 1.1011*10^{-5}VR + 3.4844*10^{-14}V^2R^2$$

where

R = fuel carbon to hydrogen ratio, no units

V = fuel higher heating value, kJ/kg × 0.42992 (Btu/lb)

B-7 SAMPLE CALCULATIONS AND RESULTS

The "Corrected Value" entries of Table B-7-1 are calculated as described below. The plant-specific test equation is repeated for convenience.

$$HR_{corr} = \frac{(Q_{meas} + \omega_1 + \omega_2 + \omega_3 + \omega_4 + \omega_5 + \omega_7)}{(P_{meas} + \Delta_7)} f_1 f_2 f_3 f_4 f_5$$

The additive correction to power is

$$82{,}165 \text{ kW} - 785 \text{ kW} = 81{,}380 \text{ kW}$$

The additive corrections to heat input are

$$755{,}874{,}400 \text{ kJ/hr} + 2{,}415{,}228 \text{ kJ/hr} + 346{,}164 \text{ kJ/hr} + 144{,}560 \text{ kJ/hr} + 827{,}610 \text{ kJ/hr} - 127{,}245 \text{ kJ/hr} + 2{,}760{,}379 \text{ kJ/hr} - 6{,}648{,}343 \text{ kJ/hr} = 755{,}592{,}753 \text{ kJ/hr}$$

$$(716{,}438{,}900 \text{ Btu/hr} + 2{,}289{,}194 \text{ Btu/hr} + 328{,}100 \text{ Btu/hr} + 137{,}016 \text{ Btu/hr} + 784{,}423 \text{ Btu/hr} - 120{,}605 \text{ Btu/hr} + 2{,}616{,}334 \text{ Btu/hr} - 6{,}301{,}412 \text{ Btu/hr} = 716{,}171{,}950 \text{ Btu/hr})$$

The multiplicative corrections are

$$(0.9926623)(0.9998435)(1.000000)(1.0001197)(0.9964189) = 0.989071059$$

The complete equation is then

$$\text{HR}_{corr} = [(755{,}592{,}753 \text{ kJ/hr})(0.989071)]/81{,}380 \text{ kW}$$

$$\text{HR}_{corr} = 9{,}183 \text{ kJ/kW-hr}$$

$$(\text{HR}_{corr} = [(716{,}171{,}950 \text{ Btu/hr})(0.989071)]/81{,}380 \text{ kW})$$

$$(\text{HR}_{corr} = 8{,}704 \text{ Btu/kW-hr})$$

Table B-7-1 Peformance Corrections

Description	Measured Value	Correction	Corrected Value
	Gross Plant Design Power		
GT generator gross power	54 921 kW	...	...
ST generator gross power	27 244 kW	...	...
Gross plant power	82 165 kW	...	...
Difference from design power	...	Δ_7 = −785 kW	...
Corrected gross plant power	...	...	81 380 kW
Gas turbine gas flow	3.2641 kg/s 25,906 lbm/hr	...	...
Duct burner gas flow	0.6864 kg/s 5,448 lbm/hr	...	...
Total gas flow	3.9505 kg/s 31,354 lbm/hr	...	...
Fuel heating value, HHV	53 149k kJ/kg 22,850 Btu/lbm	...	...
Measured heat input	755 886,026 kJ/h 716,438,900 Btu/hr	...	...
Process steam flow	5.8748 kg/s 46,626 lbm/hr	...	...
Process steam enthalpy	2 907.0 kJ/kg 1,249.8 Btu/lbm	...	...
Process efflux correction	...	ω_1 = 2 415 237 kJ/h ω_1 = 2,289,194 Btu/hr	...
GT generator power factor	0.95		
GT generator power factor correction	...	ω_{2A} = 346 165 kJ/h ω_{2A} = 328,100 Btu/hr	...
ST generator power factor	0.95	...	...
ST generator power factor correction	...	ω_{2B} = 144 561 kJ/h ω_{2B} = 137,016 Btu/hr	...
HP and LP blowdown	Isolated	...	...
Blowdown correction	...	ω_3 = 827 610 kJ/h ω_3 = 784,423 Btu/hr	...
Excess makeup flow	0.0157 kg/s 125 lbm/hr	...	...
Makeup temperature	17.9°C 64.2°F	...	...
Makeup correction	...	ω_4 = −127 245 kJ/h ω_4 = −120,605 Btu/hr	...
Condenser pressure	4.06 kPa 1.20 in. HgA	...	...
Condenser pressure correction	...	ω_{5C} = 2 760 389 kJ/h ω_{5C} = 2,616,334 Btu/hr	...
Power difference (Δ_7)	...	−785 kW	...
Power difference correction	...	ω_7 = −6 648 368 kJ/h ω_7 = −6,301,412 Btu/hr	...
Ambient temperature	8.50°C 47.3°F	...	...
Ambient temperature correction	...	f_1 = 0.9926623	...
Ambient pressure	101.8 kPa 14.76 psia	...	...
Ambient pressure correction	...	f_2 = 0.9998435	...
Ambient relative humidity	30%	...	...
Ambient relative humidity correction	...	f_3 = 1.0000000	...
GT fuel temperature	180°C 356°F	...	...
GT fuel temperature correction	...	f_4 = 1.0001197	...
Fuel heating value, HHV	53,149 kJ/kg	...	...
Fuel carbon to hydrogen ratio	22,850 Btu/lbm 3.05	...	...

NONMANDATORY APPENDIX C
SAMPLE CALCULATIONS, COMBINED CYCLE COGENERATION PLANT WITHOUT DUCT FIRING

Heat Sink: Cooling Water Source External to the Test Boundary
Test Goal: Specified Disposition is Gas Turbine Base Loaded (Power Floats)

C-1 INTRODUCTION

The combined cycle/cogeneration plant for this sample calculation is shown in Fig. C-1-1. The major equipment items are as follows:

(a) gas turbine: 115 MW at ISO conditions {[15°C (59°F), 60% RH, sea level (1,013 mbara (14.696 psia)]}, 12 mbar (4.8 in. H_2O) inlet and 36 mbar (14.5 in. H_2O) exhaust pressure drop, steam injection for NO_X control to 25 ppm, and pipeline natural gas.

(b) heat recovery steam generator: three steam pressure levels, one of which is used with an integral deaerator. The design conditions at the outlet of the HRSG are 88 barg (1 276 psig) and 482°C (900°F) for the HP steam, 23 barg (334 psig) and 260°C (500°F) for the IP steam, and saturated 1.0 barg (15 psig) steam for the integral deaerator.

(c) steam turbine: condensing type, 40 MW nominal rating, with an exhaust pressure of 67.5 mbara (2.0 in. Hg) with two extraction ports at 21.7 barg (315 psig) and 11.4 barg (165 psig).

(d) condenser: shell and tube with a cooling water inlet temperature of 26.5°C (80°F) and an 11 K (19.8°R) rise.

(e) deaerator: integral with LP drum with pegging steam from IP steam line if needed.

C-2 TEST BOUNDARY

The test boundary is shown in Fig. C-1-1. The measurement points for this calculation are as follows:

(a) combined net power output from the gas and steam turbine generator

(b) fuel input to the gas turbine (specified as LHV for reference)

(c) cogeneration steam flow to the user

(d) condensate return flow from the user

(e) inlet air conditions at the entrance to the gas turbine filter house

(f) condenser cooling water inlet temperature

(g) blowdown from the HRSG

(h) makeup water temperature

C-3 TEST REFERENCE CONDITION

For the sample calculation that follows, the design reference conditions are

Reference Condition	Calculation
Inlet air temperature	15.6°C (60.1°F)
Inlet air relative humidity	60%
Inlet air pressure	1.01325 bar (14.696 psia)
Process steam flow	18.9 kg/s (150,000 lb/hr)
Process steam pressure	10.3 barg (149 psig)
Process steam temperature	189°C (372°F)
Condensate return flow	75% at 82°C (180°F)
Makeup water temperature	16.1°C (61.0°F)
Blowdown flow	1.81 kg/s (14,365 lb/hr)
Cooling water inlet temperature	18°C (64.4°F)
Net plant power output	145,540 kW
Net plant heat rate LHV	8 405 kJ/kWh (7,966 Btu/kWh)

C-4 CORRECTION FACTORS

The general equation for corrected power from Section 5 is

$$P_{corr} = \left(P_{meas} + \sum_{i=1}^{7} \Delta_i\right) \prod_{j=1}^{6} \alpha_j$$

The overall general heat rate equation from Section 5 is

$$HR_{corr} = \frac{\left(Q_{meas} + \sum_{i=1}^{7} \omega_i\right)}{\left(P_{meas} + \sum_{i=1}^{7} \Delta_i\right)} \prod_{j=1}^{6} f_j$$

The test requirements are based on fixed unit disposition which for this example is defined as the gas turbine at base load with no duct burning. For this test configuration, correction factors ω_1 through ω_7 and Δ_7 all become zero.

Other specific simplifying assumptions for this example are with regard to the variables found in the above equation and in Tables 5-1-1 and 5-1-2.

(a) The generator power factor is specified as a constant value of 0.9 lead and will not vary, thus Δ_2 becomes zero.

(b) The influence of the amount of condensate returned and makeup water temperature is accounted for in the calculation of net process steam energy exported; therefore, Δ_4 is zero.

(c) Since net power is the measurement basis, Δ_6 becomes zero.

(d) Fuel temperature during the test is constant at the design value, so α_4 and f_4 are unity.

(e) The fuel composition is relatively close to the design value, so α_5 and f_5 are unity.

(f) Grid frequency during the test is constant at the design value, so α_6 and f_6 are unity.

The compete list of additive and multiplicative corrections from Tables 5-1-1 and 5-1-2 that are applicable for the boundary conditions described above are shown in Table C-4-1.

The test equations for this specific plant and test become

$$P_{\text{corr}} = (P_{\text{meas}} + \Delta_1 + \Delta_3 + \Delta_{5B})\,\alpha_1\alpha_2\alpha_3$$

and

$$\text{HR}_{\text{corr}} = \frac{(Q_{\text{meas}})}{(P_{\text{meas}} + \Delta_1 + \Delta_3 + \Delta_{5B})} f_1 f_2 f_3$$

C-5 CORRECTED CURVES AND FITTED EQUATIONS

The correction factors listed in subsection C-4 are best determined using a computer model of the complete plant. This subsection contains tables (Tables C-5-1 through C-5-6) that show the resulting correction factors from the plant model calculations for different ranges of the parameters. For each parameter the power correction variable and/or the heat rate correction variables were curve fit using a third-order polynomial fit. Following the table containing the correction factors for each boundary condition, a graph showing the data points and the curve fits is presented (Figs. C-5-1 through C-5-6).

C-6 SAMPLE CALCULATION AND RESULTS

The measured test data for the sample calculation are shown in Table C-6-1.

Using the sample test data in Table C-6-1, the resulting additive and multiplicative correction factors are calculated based on the curve fit equations presented in subsection C-5. The calculated values of the correction factors are then inserted into the appropriate equations to correct the as-tested power and the heat rate to the reference conditions. The boundary value inputs, the resulting correction values, the corrected power, the corrected heat rate, and the variance of the corrected power and heat rate from the design point are all presented in Tables C-6-2, C-6-3, and C-6-4.

Test equations are

$$P_{\text{corr}} = (P_{\text{meas}} + \Delta_1 + \Delta_3 + \Delta_{5B})\,\alpha_1\alpha_2\alpha_3$$

and

$$\text{HR}_{\text{corr}} = \frac{(Q_{\text{meas}})}{(P_{\text{meas}} + \Delta_1 + \Delta_3 + \Delta_{5B})} f_1 f_2 f_3$$

C-7 DISCUSSION OF RESULTS

The corrected power is better than design. The corrected heat rate is worse than design.

Fig. C-1-1 Test Boundary for Combined Cycle/Cogeneration Plant With External Cooling Source

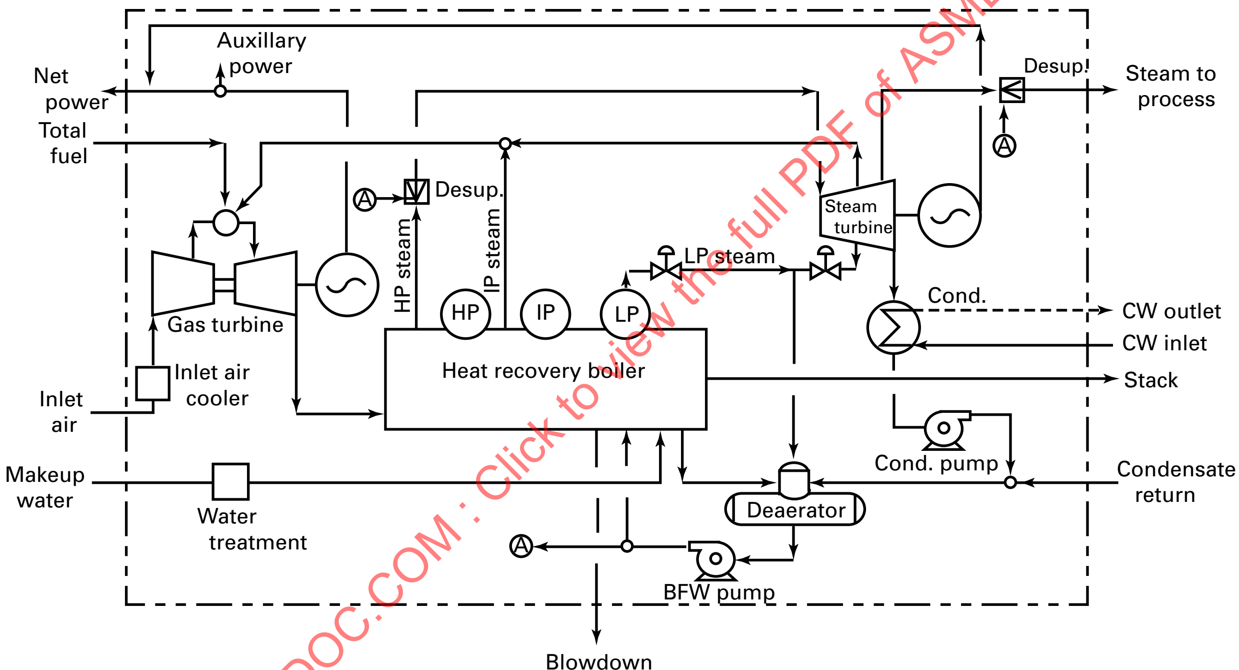


Fig. C-5-1 Inlet Temperature Correction Factors

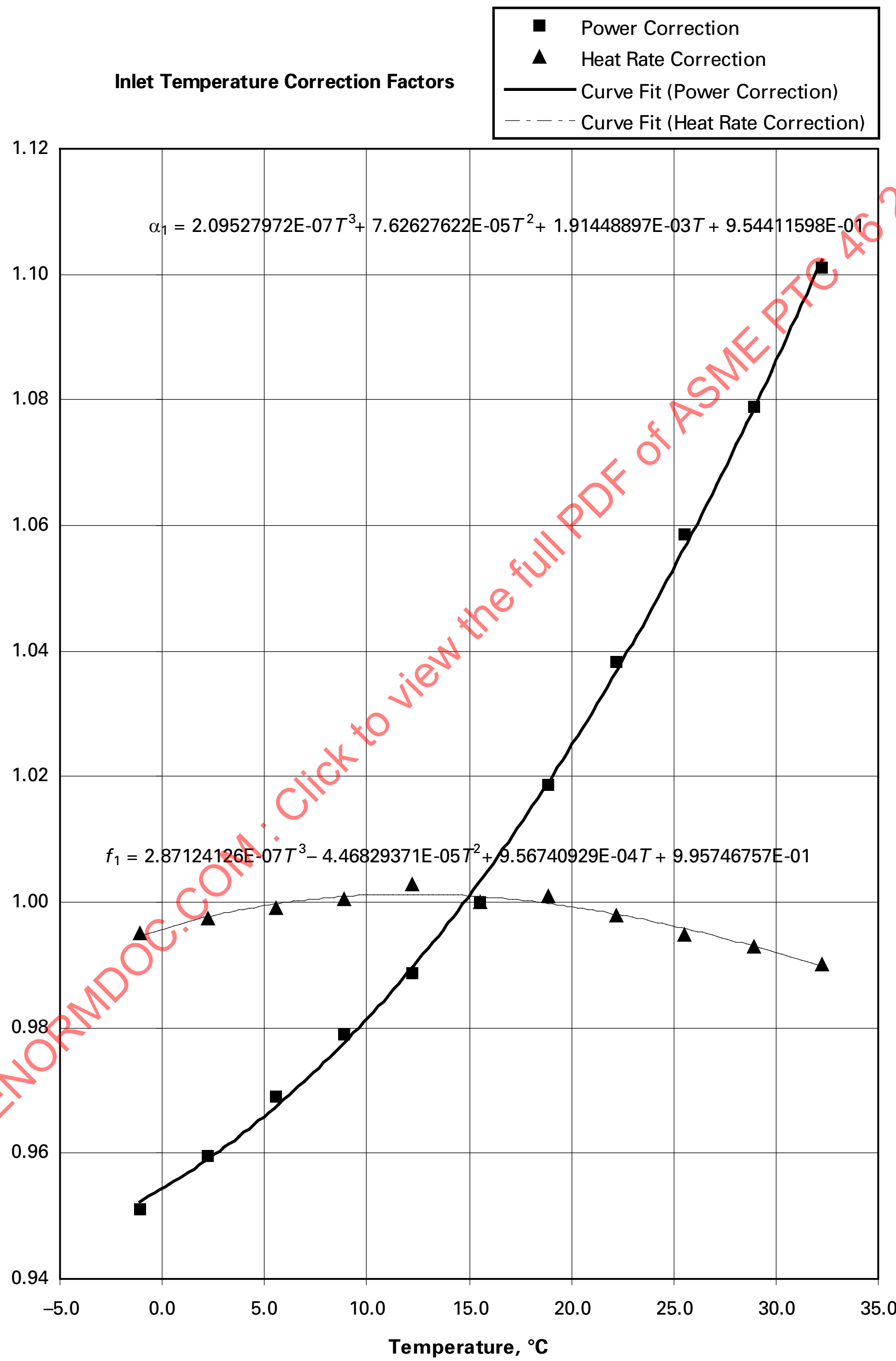


Fig. C-5-2 Inlet Pressure Correction Factors

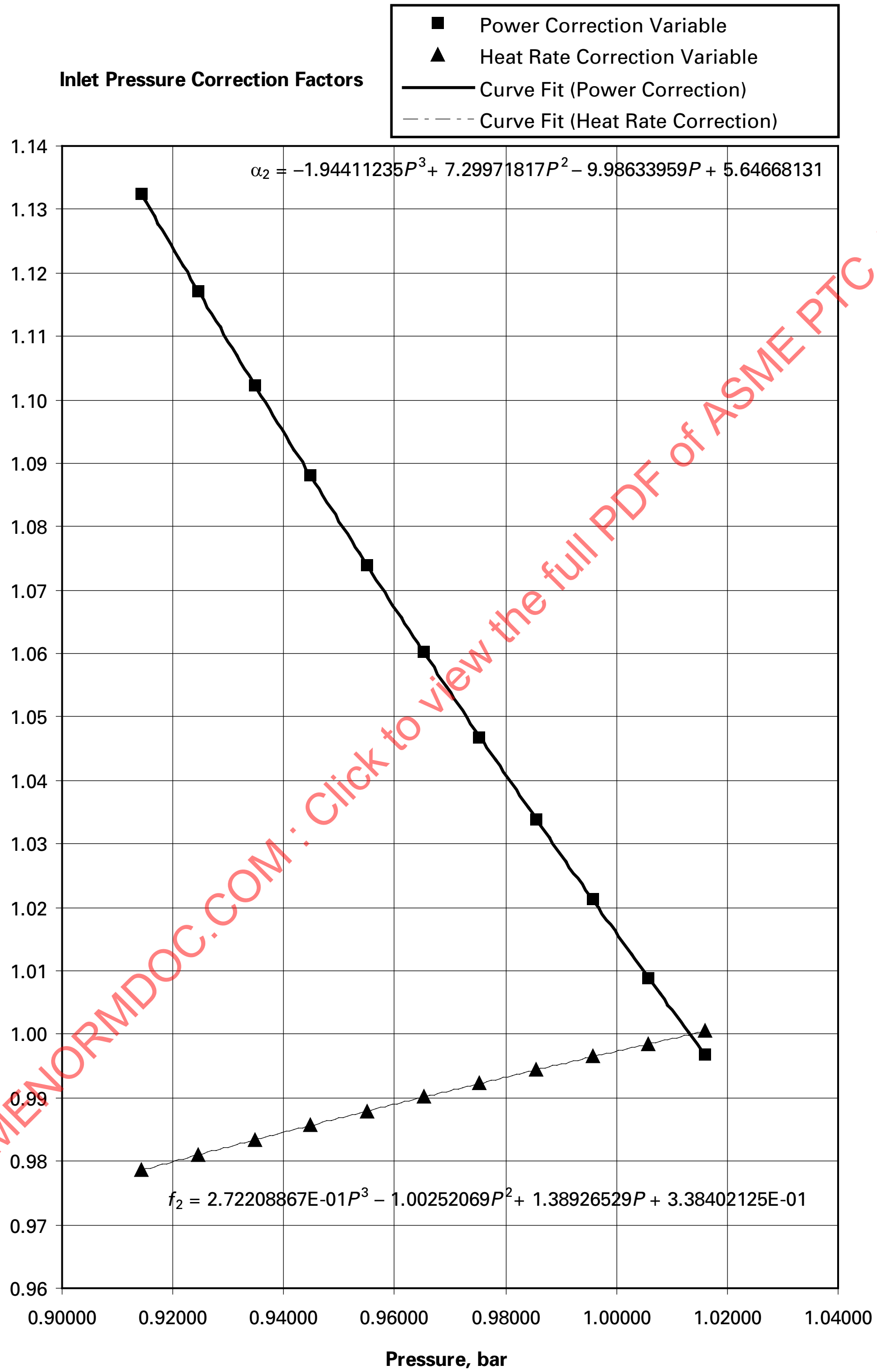


Fig. C-5-3 Inlet Relative Humidity Correction Factors

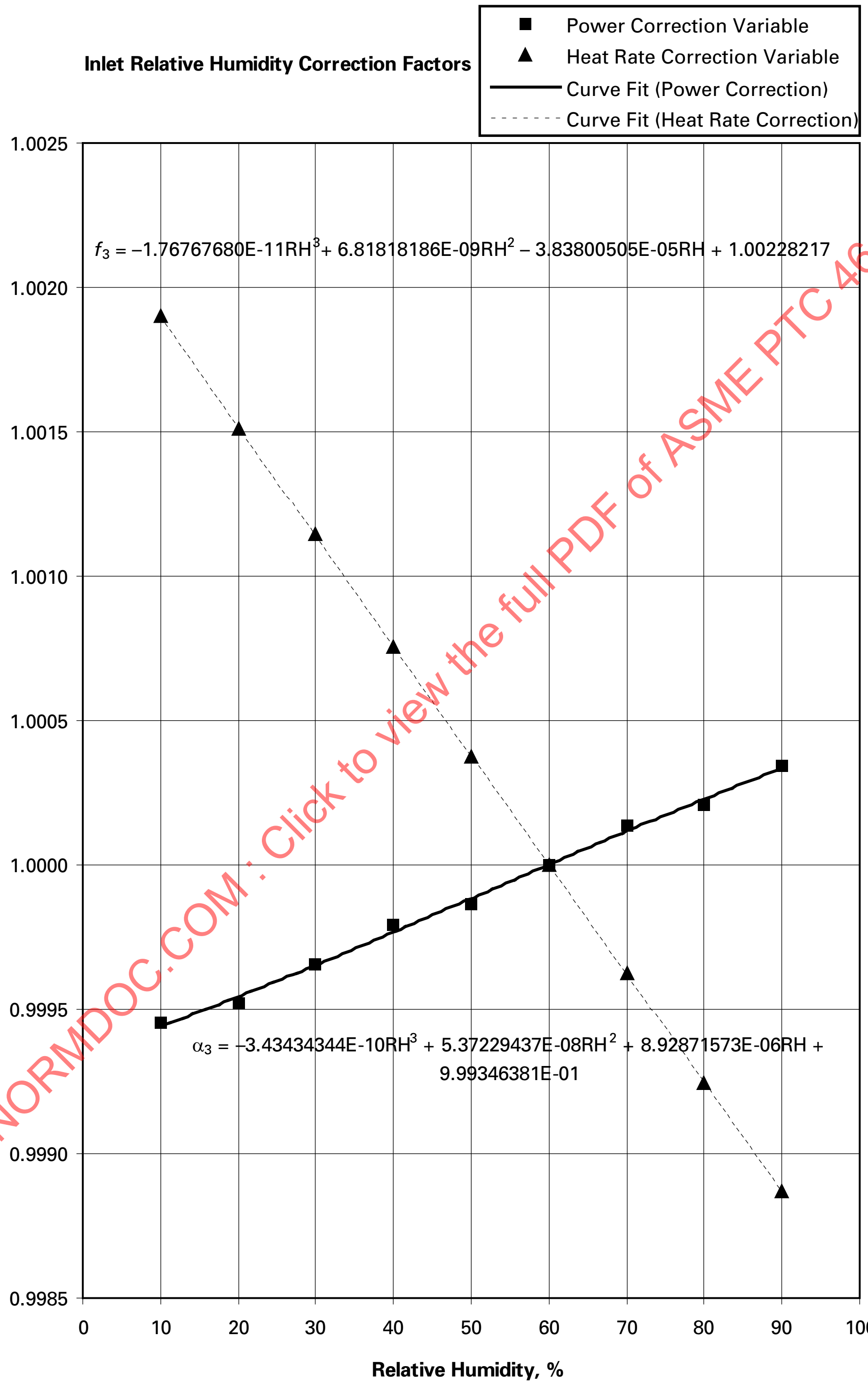


Fig. C-5-4 Net Process Steam Energy Correction Factors

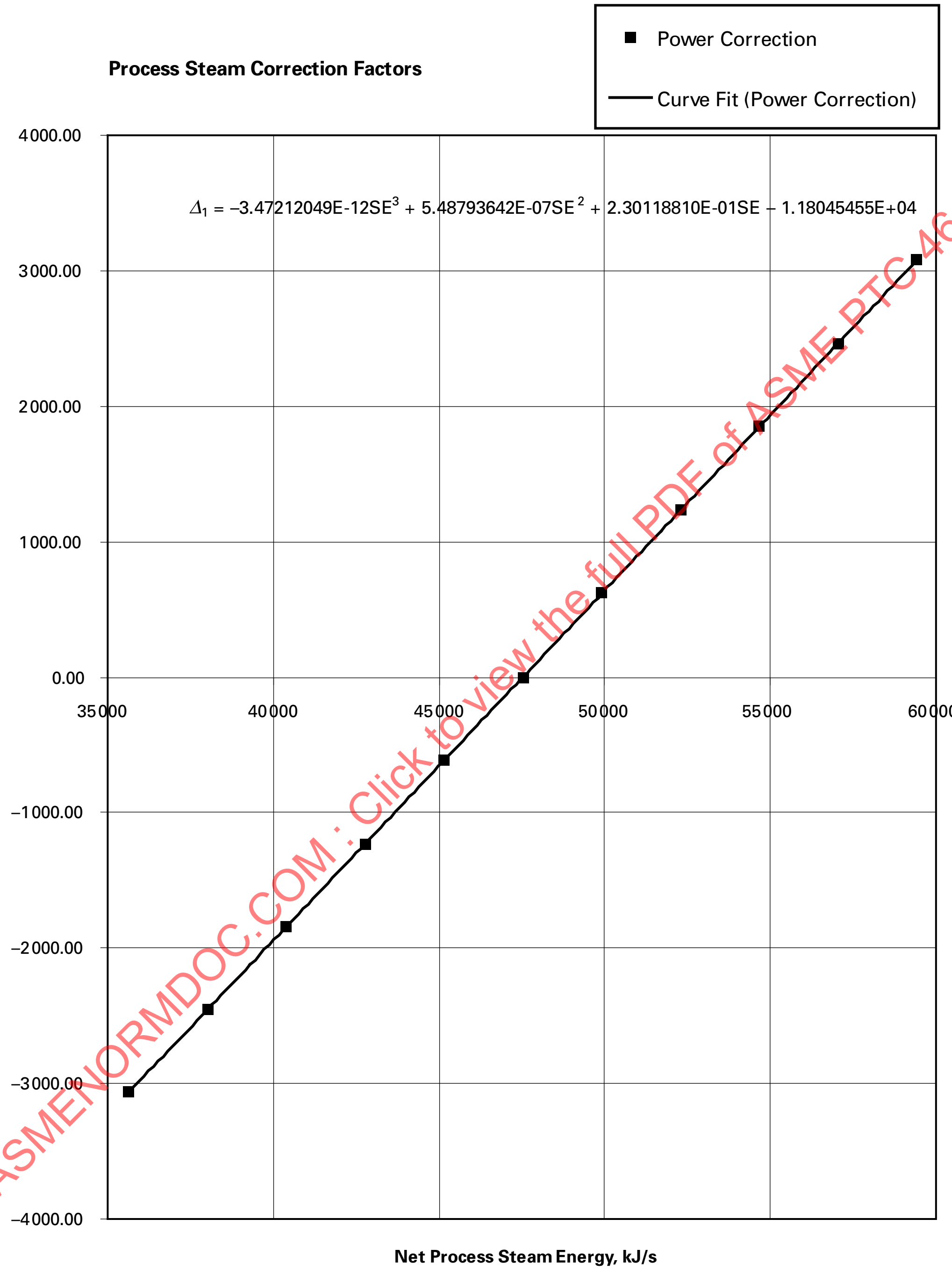


Fig. C-5-5 Blowdown Flow Correction Factors

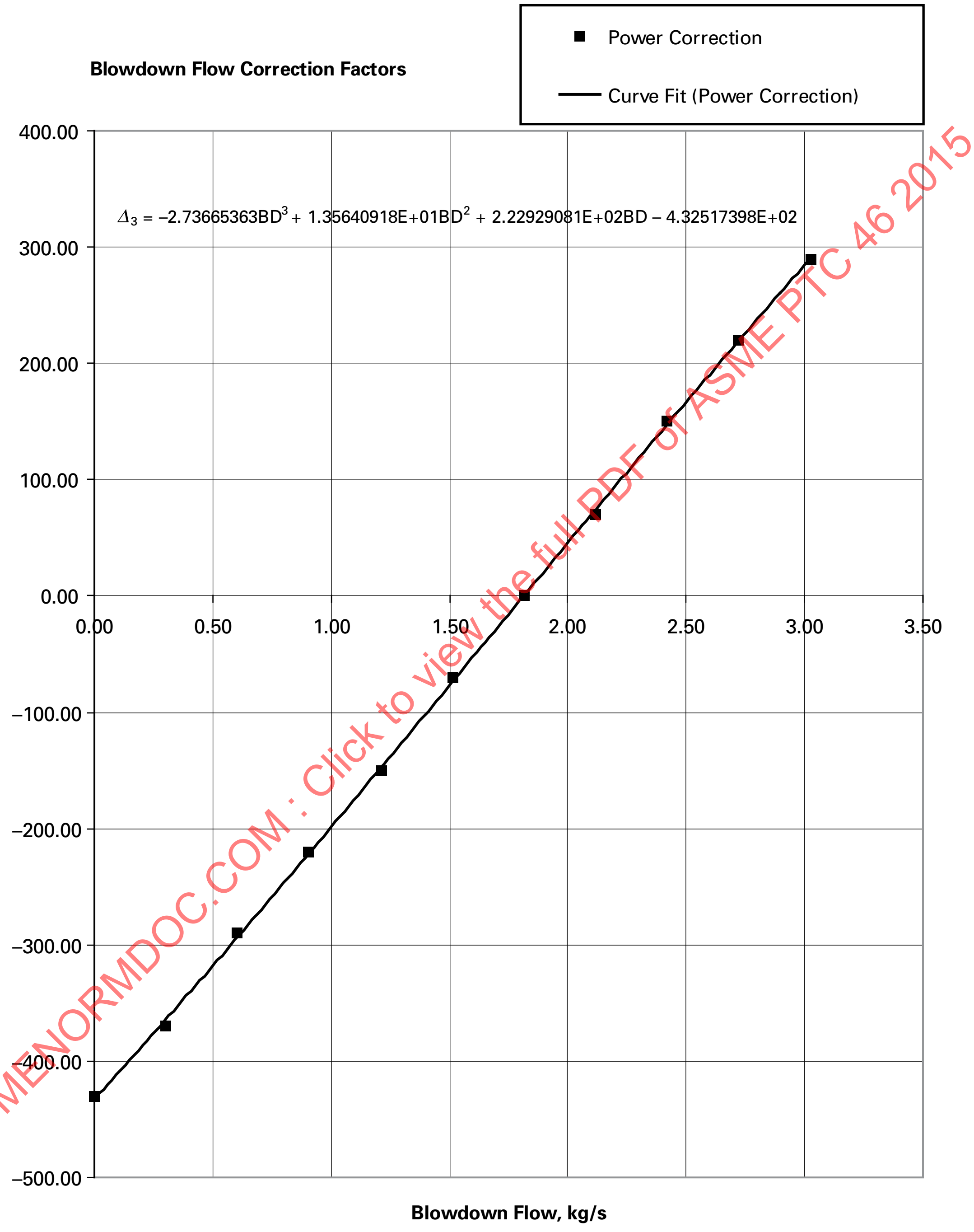


Fig. C-5-6 Condenser Cooling Temperature Correction Factors

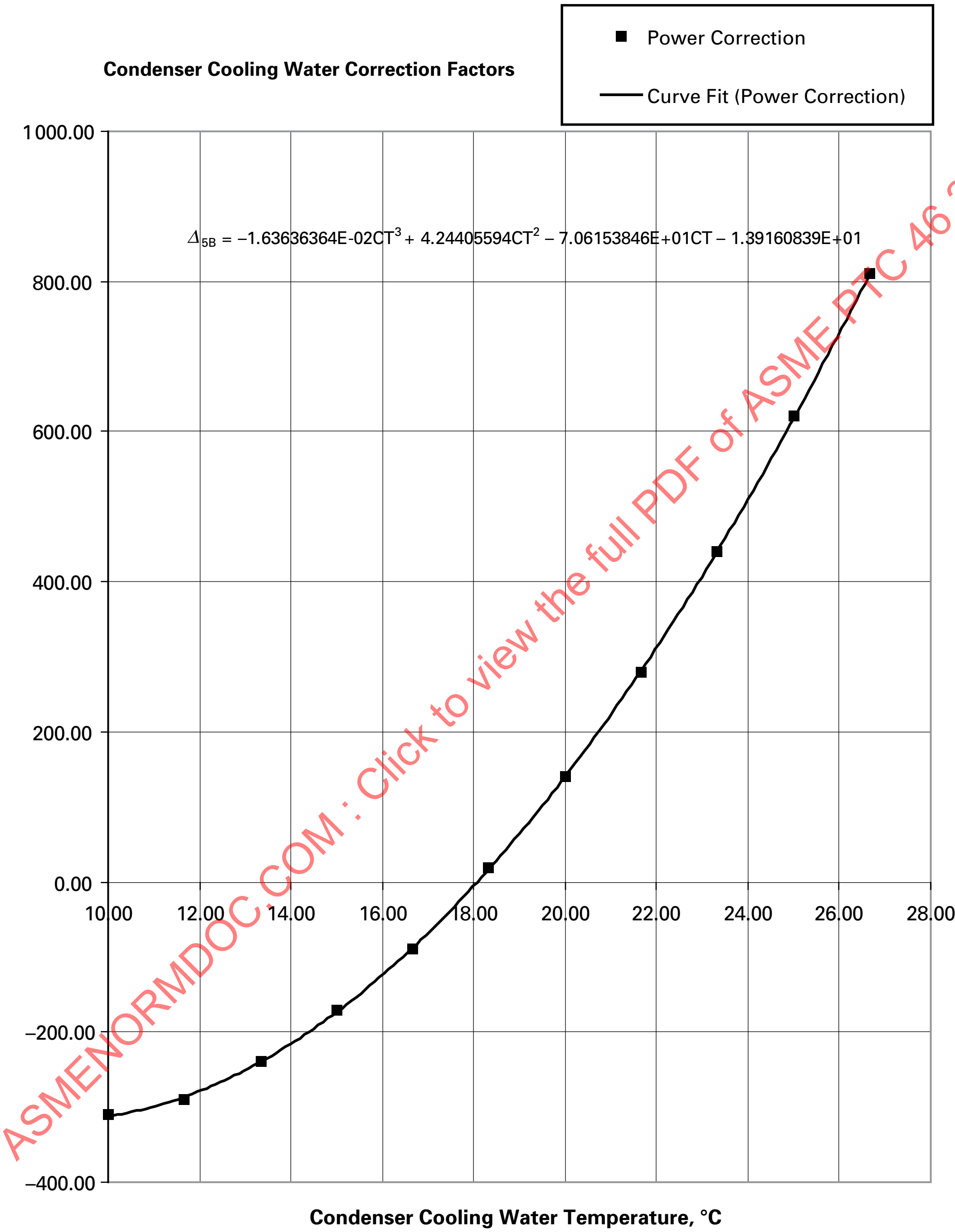


Table C-4-1 Applicable Correction Factors

Operating Condition	Correction Factor
Inlet air temperature	α_1, f_1
Inlet air pressure	α_2, f_2
Inlet air humidity	α_3, f_3
Net process steam energy	Δ_1
HRSG blowdown flow	Δ_3
Condenser cooling water temperature	Δ_{5B}

Table C-5-1 Inlet Temperature Correction Factors

Inlet Temperature, T, °C	Net Plant Power, PWR, kW	Net Plant Heat Rate, HR, kJ/kWh	Power Correction, α_1	Heat Rate Correction, f_1
−1.1	153,010	8 478.3	0.951180	0.995035
2.2	151,660	8 457.7	0.959647	0.997455
5.6	150,170	8 445.0	0.969168	0.998963
8.9	148,650	8 432.1	0.979078	1.000488
12.2	147,220	8 412.4	0.988589	1.002834
15.6	145,540	8 404.6	1.000000	1.000000
18.9	142,880	8 428.2	1.018617	1.000951
22.2	140,190	8 454.0	1.038162	0.997903
25.6	137,500	8 479.4	1.058473	0.994911
28.9	134,900	8 495.9	1.078873	0.992971
32.2	132,170	8 520.3	1.101158	0.990131

GENERAL NOTE:
Curve fit results:

$$\alpha_1 = 2.09527972\text{E-}07T^3 + 7.62627622\text{E-}05T^2 + 1.91448897\text{E-}03T + 9.54411598\text{E-}01$$
$$f_1 = 2.87124126\text{E-}07T^3 - 4.46829371\text{E-}05T^2 + 9.56740929\text{E-}04T + 9.95746757\text{E-}01$$

Table C-5-2 Barometric Pressure Correction Factors

Inlet Pressure, P, bar	Net Plant Power, PWR, kW	Net Plant Heat Rate, HR, kJ/kWh	Power Correction Variable, α_2	Heat Rate Correction Variable, f_2
0.91438	128,530	8 588.2	1.132343	0.978624
0.92451	130,280	8 567.2	1.117132	0.981022
0.93472	132,030	8 546.7	1.102325	0.983372
0.94485	133,770	8 526.8	1.087987	0.985672
0.95506	135,520	8 507.3	1.073937	0.987921
0.96519	137,270	8 488.3	1.060246	0.990131
0.97533	139,020	8 469.9	1.046900	0.992289
0.98553	140,770	8 451.8	1.033885	0.994408
0.99567	142,510	8 434.2	1.021262	0.996485
1.00587	144,260	8 417.0	1.008873	0.998521
1.01601	146,010	8 400.1	0.996781	1.000528

GENERAL NOTE:
Curve fit results:

$$\alpha_2 = -1.94411235P^3 + 7.29971817P^2 - 9.98633959P + 5.64668131$$
$$F_2 = 2.72208867\text{E-}01P^3 - 1.00252069P^2 + 1.38926529P + 3.38402125\text{E-}01$$

Table C-5-3 Inlet Relative Humidity Correction Factors

Inlet Relative Humidity, RH, %	Net Plant Power, PWR, kW	Net Plant Heat Rate, HR, kJ/kWh	Power Correction Variable, α_3	Heat Rate Correction Variable, f_3
10	145,620	8 388.6	0.999451	1.001901
20	145,610	8 391.9	0.999520	1.001510
30	145,590	8 395.0	0.999657	1.001145
40	145,570	8 398.2	0.999794	1.000754
50	145,560	8 401.4	0.999863	1.000377
60	145,540	8 404.6	1.000000	1.000000
70	145,520	8 407.7	1.000137	0.999623
80	145,510	8 410.9	1.000206	0.999247
90	145,490	8 414.1	1.000343	0.998870

GENERAL NOTE:
Curve fit results:

$$\alpha_3 = -3.43434344\text{E-}10\text{RH}^3 + 5.37229437\text{E-}08\text{RH}^2 + 8.92871573\text{E-}06\text{RH} + 9.99346381\text{E-}01$$

$$f_3 = -1.76767680\text{E-}11\text{RH}^3 + 6.81818186\text{E-}09\text{RH}^2 - 3.83800505\text{E-}05\text{RH} + 1.00228217$$

Table C-5-4 Net Process Steam Energy Correction Factors

Net Process Steam Energy, SE, kJ/s	Net Plant Power, PWR, kW	Power Correction, Δ, kW
35 652	148,600	−3,060
38 029	147,990	−2,450
40 406	147,380	−840
42 782	146,770	−1,230
45 159	146,150	−610
47 536	145,540	0
49 913	144,920	620
52 290	144,310	1,230
54 666	143,690	1,850
57 043	143,080	2,460
59 420	142,460	3,080

GENERAL NOTE: Curve fit results: $\Delta_1 = -3.47212049\text{E-}12\text{SE}^3 + 5.48793642\text{E-}07\text{SE}^2 + 2.30118810\text{E-}01\text{SE} - 1.18045455\text{E+}04$

Table C-5-5 Blowdown Flow Correction Factors

Blowdown Flow, BD, kg/s	Net Plant Power, PWR, kW	Power Correction, Δ_3, kW
0	145,970	−430
0.30250	145,910	−370
0.60500	145,830	−290
0.90750	145,760	−220
1.21000	145,690	−150
1.51250	145,610	−70
1.81500	145,540	0
2.11750	145,470	70
2.42000	145,390	150
2.72250	145,320	220
3.02499	145,250	290

GENERAL NOTE: Curve fit results: $\Delta_3 = -2.73665363\text{BD}^3 + 1.35640918\text{E+01BD}^2 + 2.22929081\text{E+02BD} - 4.32517398\text{E+02}$

Table C-5-6 Condenser Cooling Temperature Correction Factors

Condenser Cooling Temperature, CT, °C	Net Plant Power, PWR, kW	Power Correction, Δ_{5B}, kW
10.0	145,850	−310
11.7	145,830	−290
13.3	145,780	−240
15.0	145,710	−170
16.7	145,630	−90
18.3	145,520	20
20.0	145,400	140
21.7	145,260	280
23.3	145,100	440
25.0	144,920	620
26.7	144,730	810

GENERAL NOTE: Curve fit results: $\Delta_{5B} = -1.63636364\text{E-02CT}^3 + 4.24405594\text{CT}^2 - 7.06153846\text{E+01CT} - 1.39160839\text{E+01}$

Table C-6-1 Measured Data

Variable	Value	Units
Inlet air temperature	26.7	°C
Inlet relative humidity	70	%
Inlet pressure	0.951	bar
Net power output	125 910	kW
Fuel flow	6.045	kg/s
Fuel heating value (LHV)	50 021	kJ/kg
Steam flow to process	20.79	kg/s
Steam to process pressure	10.34	barg
Steam to process temperature	189.0	°C
Condensate return flow	15.59	kg/s
Feedwater makeup temperature	21.0	°C
Cooling water inlet temperature	21.0	°C
HRSG blowdown	0	kg/s

Table C-6-2 Calculated Values

Variable	Value	Units
Heat input	302 377	kJ/s
Heat input	1.0886E+09	kJ/h
Process steam pressure	11.291	bar
Process steam enthalpy	2 790.6	kJ/kg
Process steam export energy	58 016	kJ/s
Condensate return enthalpy [Note (1)]	344.2	kJ/kg
Condensate return energy	5 366	kJ/s
Makeup water flow	5.20	kg/s
Makeup water enthalpy	89.1	kJ/kg
Makeup water energy	463.3	kJ/s
Net process steam energy [Note (2)]	52 187	kJ/s

NOTES:
(1) Condensate return temperature is constant at the design value of 82°C.
(2) Net process steam energy is calculated as the difference between the process steam export energy and the energy of the returned condensate and makeup water.

Table C-6-3 Correction Factor Values

Correction Factor	Calculated Value
α_1	1.063884
α_2	1.079442
α_3	1.000117
f_1	0.994903
f_2	0.987036
f_3	0.999623
Δ_1	1,205.7
Δ_3	−432.5
Δ_{5B}	223.2

Table C-6-4 Calculated Values

Variable	Value	Units
Corrected net plant power	145,757	kW
Corrected net plant heat rate	8 420.1	kJ/kWh
Guaranteed net plant power	145,540	kW
Guaranteed net plant heat rate	8 405.0	kJ/kWh
Net plant power variance	217	kW
Net plant heat rate variance	15.1	kJ/kWh

NONMANDATORY APPENDIX D
REPRESENTATION OF CORRECTION FOR DIFFERENT HEAT SINK TEMPERATURE THAN GAS TURBINE AIR INLET TEMPERATURE (Δ_5 OR ω_5), IF NECESSARY, FOR A TYPICAL COMBINED CYCLE PLANT

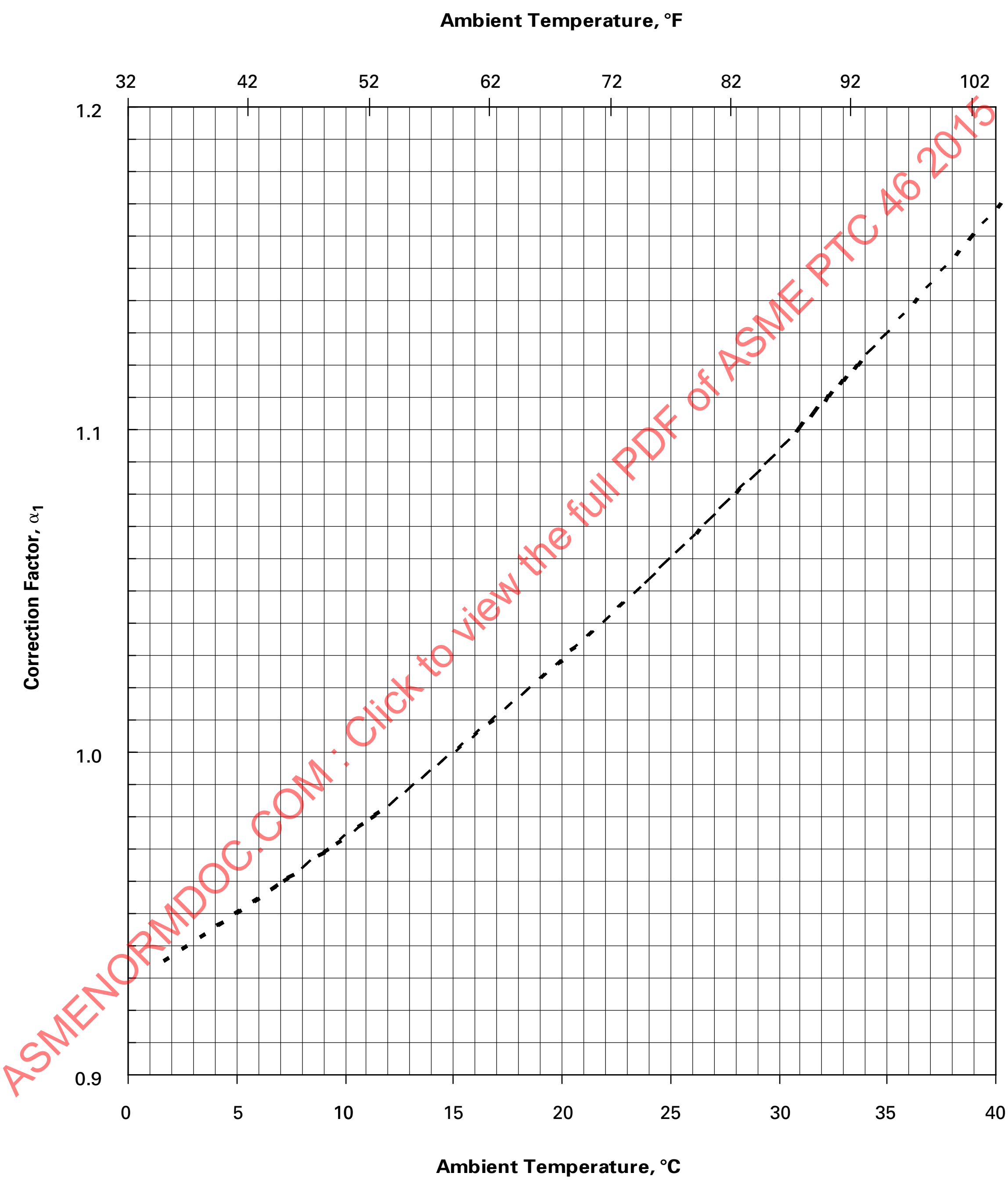
D-1 GENERAL

The calculation of Nonmandatory Appendix A assumed that the inlet air conditions at the gas turbine(s) inlet(s) were identical to those at the cooling tower(s) air inlet(s), which is allowable per Section 5. See para. 5-5.1. For a combined cycle power plant, for which differences in dry bulb temperatures at each location should be considered, Figs. D-1-1 and D-1-2 show typical correction curves α_1 and Δ_{5A}, respectively. The intent is to show how Δ_{5A} can be represented.

Figure D-1-1 is based on the temperature measured at the inlet to the gas turbine. Figure D-1-2 is the Δ_{5A} correction for the difference in temperature between the cooling tower inlet and the gas turbine inlet.

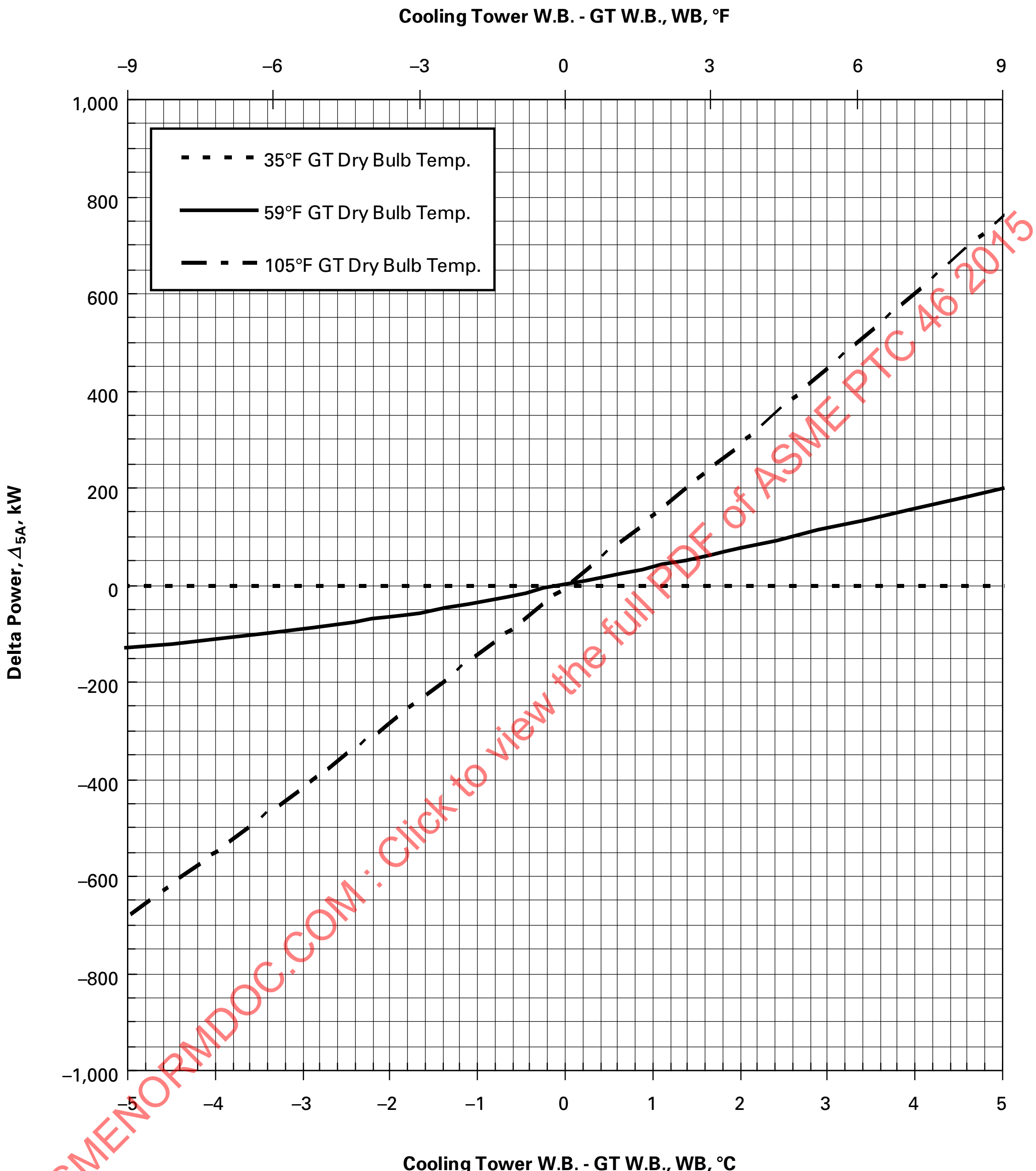
The plant is a typical 150 MW combined cycle. Note that, at 15°C (59°F) gas turbine inlet temperature, the correction to plant power is approximately 35 kW per degrees kelvin (19 kW/°R) difference between the gas turbine compressor inlet and the cooling tower inlet — a rather small amount considering the built-in errors in measurement of cooling tower air inlet.

Fig. D-1-1 Gas Turbine Inlet Temperature Correction Curve



GENERAL NOTE: Applicable for gas turbine base-loaded natural gas fuel.

Fig. D-1-2 Inlet Air Condition Difference Between Cooling Tower and Gas Turbine



GENERAL NOTE: Applicable for gas turbine base-loaded natural gas fuel.

NONMANDATORY APPENDIX E
SAMPLE CALCULATION OF A COAL-FIRED SUPERCRITICAL CONDENSING STEAM TURBINE BASED PLANT

E-1 CYCLE DESCRIPTION

The ASME PTC 46 Example Steam Plant is a coal-fired supercritical condensing steam turbine based plant, with eight feedwater heaters and an uncontrolled extraction from the main steam line for process steam. Process steam condensate is returned at low temperature to the plant water treatment system. The steam generator is pulverized coal, burning Western subbituminous coal. The condenser is cooled with circulating water drawn from a river.

There are two plant cases available for this example. The first case (Case 1) is an example of a plant operating in fixed pressure mode at a specified measured net power. Case 1 also demonstrates a correction methodology using an integrated plant model. The second case (Case 2) is an example of a plant operating in sliding pressure mode and operating at a specified throttle steam flow. Case 2 also demonstrates a correction methodology using a nonintegrated plant model.

Although similar in size and configuration, the boiler and turbines are not identical for both cases.

For Case 1 (fixed throttle pressure with a fixed net power operating mode), the STG is sized to be at steam turbine valves-wide-open (VWO) with a throttle pressure of 3,689 psia at a steam flow of 5,065,000 lb/hr and main steam/reheat steam temperatures of 1,050°F/1,050°F. The boiler is designed to produce 5,115,000 lb/hr, with a boiler output of 5,540.1 MBtu/hr HHV. At these STG inlet conditions, the main steam pressure and temperature at the boiler are 3,789 psia and 1,055°F. The plant's gross electrical output is 748,010 kW, with net electrical output of 676,949 kW. The planned operating mode for Case 1 would be to vary the firing rate to maintain the target net output of 663,419 kW (98% electrical load) while maintaining a fixed pressure at the STG throttle.

For Case 2 (sliding throttle pressure with a fixed throttle flow operating mode), the STG is sized for a throttle flow of 5,090,000 lb/hr at a pressure of 3,792 psia and main steam/reheat steam temperatures of 1,050°F. The boiler outlet steam flow is 5,139,000 lb/hr at a SH outlet pressure of 3,892 psia and a temperature of 1,050°F/1,050°F. The throttle valves are always at VWO. The design plant gross electrical output is 780,620 kW, with a net electrical output of 706,461 kW. The design boiler output is 5,569.2 MBtu/hr HHV. The planned mode of operation for this test would be to reduce the firing rate of the boiler to maintain the nominal throttle flow of 4,940,000 lb/hr (97% of design steam flow).

E-2 TEST BOUNDARY DESCRIPTION

The entire plant is located within the test boundary. Air enters the steam generators at the forced draft and primary air fan inlets. Cooling water from the river crosses the test boundary. Net electrical power is delivered from the high side of the step-up transformer. Net power measurement is taken on the low side of the step-up transformer with allowance for transformer losses. Gross steam turbine power is measured at the generator terminals. Plant auxiliary power is calculated from the difference between the measured gross and net power. Process steam is measured at the plant boundary with a calibrated flow measuring section.

E-3 GENERAL DESCRIPTION OF TEST CASES, MODELS, AND CORRECTIONS

There are two sets of sample calculations that are demonstrated with this example Appendix.

Case 1 is run with fixed steam pressure, specified measured net electrical output, and will address the use of an integrated boiler model for calculations and corrections. The integrated method utilizes an overall plant model for predicting the thermal performance characteristics of the boiler, turbine generator, heat sink, and feedwater heating cycle. An important characteristic of an integrated thermal model is its ability to predict boiler efficiency at off-design conditions, eliminating the need for correcting boiler performance to base reference conditions using the ASME PTC 4 methodology (with the exception of corrections for fuel properties).

Case 2 is run with sliding steam pressure, specified throttle steam flow, and will address the use of a nonintegrated boiler model for calculations and corrections. The nonintegrated method calculates the net plant heat rate by combining the corrected boiler efficiency with the corrected steam cycle performance.

Each test case sample calculation is a based on three independent test runs. Each test run is independently corrected. The final test result is calculated as the average of the three corrected test runs.

A caution concerning boiler and turbine corrections that may be used should be noted here. Because this is an Overall Plant Performance Test (based on corrections to external plant base reference conditions), certain boiler, turbine, and perhaps other equipment corrections will not be part of the proper correction methodology for this Code. For example, corrections based on internal plant parameters that would normally be part of ASME PTC 4 (for boiler efficiency) or ASME PTC 6 (for corrections to turbine output and heat rate) tests, should not be used. A few non-exhaustive examples are boiler auxiliaries, feedwater heater performance, generator hydrogen pressure, etc. This also includes certain corrections in the ASME PTC 4 calculation methodology [e.g., feedwater temperature, air heater performance (nonfuel related), excess air levels, etc.]. An exception to this caveat is that if the goal of the test is to determine the plant performance at a specified operating condition, then that parameter may also be a correction to plant performance (e.g., steam turbine throttle flow).

It is also important to recognize how the choice of operating mode affects the plant performance calculation methodology. For a properly designed test, the thermal performance model should develop the plant (or steam cycle) correction curves, based on the established test goal and the planned mode of operation during the test. The plant must then be operated in accordance with the operating philosophy upon which the correction curves are based when executing the performance test.

Lastly, the plant test boundary should include the forced draft and primary air fans in the test boundary. When a nonintegrated model is used, this requires that the air heater inlet temperature be corrected to base reference conditions by entering the design ambient air temperature plus the measured fan rises forced draft/primary air (FD/PA) into the ASME PTC 4 calculations. Corrections to the gas temperatures leaving the air heater due to changes in ambient air temperature may also be implemented, based on the measured air heater effectiveness.

E-3.1 Case 1 Sample Calculation: Specified Measured Output

The test goal is to demonstrate plant performance at the specified measured output of 663,419 kW. The plant was operated in fixed steam pressure mode, with throttle valves maintaining 3,689 psia. Boiler firing rate was adjusted to maintain constant specified measured output. Calculations were performed with an "integrated boiler model." (Throttle losses were estimated by the thermal model using a "mean of valve loops" calculation.) A specified disposition correction adjusts the net output to a constant value, with a corresponding adjustment to plant heat input. A positive auxiliary load correction corrects for additional nonessential equipment that was in operation during the test.

The base reference conditions and test data for Example Case 1 are as listed in Tables E-3.1-1 and E-3.1-2.

E-3.1.1 Corrected Output. Corrected output for each test run is calculated using eq. (5-3-3), repeated below. Terms in the equation are described in Section 5.

$$P_{corr} = P_{meas} + \Delta_7$$

The only output correction applicable to this test protocol for Case 1 is Δ_7. This is because the test goal was to hold output constant and let heat input vary with changes in test boundary conditions. Therefore, the correction curves do not reflect any change in output to be consistent with this test goal. Delta 7 (Δ_7) is the only correction applied to account for small differences between the actual output and the test target output.

A summary of the output and heat rate corrections for the test runs is given in Table E-3.1.1-1.

E-3.1.2 Corrected Fuel Energy Input and Corrected Heat Rate. The corrected fuel energy (Q_{corr}) is calculated according to the numerator of eq. (5-3-4), where

$$Q_{corr} = (Q_{corrfuel} + \omega_{1A} + \omega_{1C} + \omega_2 + \omega_4 + \omega_{5A1} + \omega_{5A2} + \omega_{5B} + \omega_6 + \omega_7)$$

Note that certain ω corrections were deemed to be negligible (e.g., changes in process steam pressure), while other corrections were expanded into several parts (e.g., fuel properties). The ω terms are described in Table 5-1-1 in Section 5.

Q_{meas} is similar to, but not identical to the steam generator tested output, Q_rO, as defined in ASME PTC 4, including blowdown energy (not applicable to the supercritical boiler example) or other losses, divided by corrected fuel energy efficiency calculated per ASME PTC 4. Q_{meas} in this sense represents the test fuel energy consumption

Table E-3.1-1 Example of Test Boundary Conditions for Supercritical Unit — Case 1

Measurement Parameter	Unit of Measure	Design	Test Run 1A	Test Run 1B	Test Run 1C
U.S. Customary Units					
Site dry bulb temperature	°F	92.0	75.0	77.0	78.0
Site relative humidity	%	52.36	87.07	86.13	84.35
Site barometric pressure	psia	14.100	14.300	14.280	14.200
Process steam flow	lb/hr	50,000	63,000	66,000	60,000
Process steam pressure	psia	1,200	1,230	1,250	1,240
Process steam temperature	°F	900	910	920	918
Process condensate (makeup) return temperature	°F	60.0	60.0	60.0	60.0
Makeup enthalpy	Btu/lb	28.13	28.13	28.13	28.13
River water temperature	°F	55.0	62.0	60.0	59.0
SI Units					
Site dry bulb temperature	°C	33.3	23.9	25.0	25.6
Site relative humidity	%	52.4	87.1	86.1	84.3
Site barometric pressure	bara	0.972	0.986	0.985	0.979
Process steam flow	kg/s	6.30	7.94	8.32	7.56
Process steam pressure	bara	82.732	84.801	86.180	85.490
Process steam temperature	°C	12.8	16.7	15.6	15.0
Process condensate (makeup) return temperature	°C	15.6	15.6	15.6	15.6
Makeup enthalpy	kJ/kg	65.43	65.43	65.43	65.43
River water temperature	°C	12.8	16.7	15.6	15.0
Power Factor generator terminals coal properties (as fired);	. . .	0.840	0.960	0.970	0.960
Powder River Basin, PRB					
Carbon	% wt	49.000	51.000	50.000	49.500
Hydrogen	% wt	3.400	4.000	4.200	3.800
Nitrogen	% wt	0.800	0.800	0.800	0.800
Oxygen	% wt	11.930	8.190	5.490	5.090
Sulfur	% wt	0.510	0.510	0.510	0.510
Moisture	% wt	27.590	32.000	35.000	37.000
Ash	% wt	6.770	3.500	4.000	3.300
HHV	Btu/lb	8,535	9,284	9,472	9,182
HHV	kJ/kg	19 852	21 595	22 032	21 358
Auxiliary load corrections (plus sign is addition to output)	kW	0.0	450.0	300.0	100.0

GENERAL NOTE: Load = 100%; Operating mode = fixed pressure; Goal = Specified measured net output; Model = Integrated.

Table E-3.1-2 Case 1 Measured Data

Measurement Parameter	Unit of Measure	Design	Test Run 1A	Test Run 1B	Test Run 1C
		(U.S. Customary Units)			
Boiler Operating Parameters, as measured					
Boiler SH outlet flow	lb/hr	5,039,600	4,983,500	4,983,500	4,970,600
Boiler SH outlet enthalpy	Btu/lb	1,455.5	1,455.5	1,455.5	1,455.5
Boiler losses	lb/hr	0.000	0.000	0.000	0.000
Boiler loss enthalpy	Btu/lb	570.5	566.1	566.0	565.8
SH spray flow	lb/hr	0.000	0.000	0.000	0.000
SH spray enthalpy	Btu/lb	269.0	269.5	269.5	269.4
RH spray flow	lb/hr	0.000	0.000	0.000	0.000
Cold reheat flow	lb/hr	3,861,588	3,839,140	3,836,131	3,832,547
Cold reheat enthalpy boiler	Btu/lb	1,286.4	1,282.8	1,282.7	1,282.7
Hot reheat flow	lb/hr	3,861,588	3,839,141	3,836,133	3,832,550
Hot reheat enthalpy at boiler	Btu/lb	1,546.3	1,547.1	1,547.1	1,547.1
Feedwater flow	lb/hr	5,110,700	4,983,400	4,983,500	4,970,600
Feedwater enthalpy	Btu/lb	570.5	566.1	566.0	565.8
SCAH flow (from boiler)	lb/hr	0.0	0.0	0.0	0.0
Boiler output, as measured	MMBtu/hr	5,422.9	5,446.8	5,446.8	5,435.6
Boiler reference temperature (constant)	°F	77.0	77.0	77.0	77.0
Measured primary AH gas outlet temperature	°F	360.00	357.00	356.00	358.00
Measured secondary AH gas outlet temperature	°F	355.00	352.00	351.00	353.00
Measured air heater gas inlet temperature	°F	630.00	636.00	635.00	635.00
Boiler auxiliary load, uncorrected	kW	13,928.1	13,339.3	13,391.0	13,373.8
Boiler fuel efficiency, as measured	%	86.23	86.30	86.31	86.28
Key Operating Parameters					
Throttle flow	lb/hr	4,990,232	4,920,952	4,917,682	4,910,793
Throttle pressure	psia	3,689	3,689	3,689	3,689
Throttle temperature	°F	1,050.0	1,050.0	1,050.0	1,050.0
Hot reheat temperature turbine	°F	1,050.0	1,050.0	1,050.0	1,050.0
Process steam energy	MMBtu/hr	72.04	91.08	95.77	87.01
Gross electrical output	kW	733,060	732,930	733,350	733,210
Auxiliary loads (% of uncorrected gross), uncorrected	%	9.50	9.10	9.13	9.12
Condenser cooling water flow	lb/hr	155,011,632	151,996,608	151,996,608	151,996,608
Makeup flow	lb/hr	120,987	63,012	66,003	60,002
Test Results, uncorrected					
Boiler heat output, HHV, uncorrected	MMBtu/hr	5,422.9	5,446.8	5,446.8	5,435.6
Boiler efficiency, HHV, uncorrected	%	86.23	86.30	86.31	86.28
Boiler heat input, uncorrected	MMBtu/hr	6,288.9	6,311.5	6,310.7	6,299.9
Net electrical output, uncorrected	kW	663,419	666,233	666,395	666,341
Net heat rate, HHV, uncorrected	Btu/kWh	9,479.5	9,473.4	9,470.0	9,454.5

Table E-3.1-2 Case 1 Measured Data (Cont'd)

Measurement Parameter	Unit of Measure	Design	Test Run 1A	Test Run 1B	Test Run 1C
	(SI Units)				
Boiler Operating Parameters, as measured					
Boiler SH outlet flow	kg/s	634.99	627.92	627.92	626.29
Boiler SH outlet enthalpy	kJ/kg	3 385.40	3 385.40	3 385.40	3 385.40
Boiler losses	kg/s	0.00	0.00	0.00	0.00
Boiler loss enthalpy	kJ/kg	1 327.08	1 316.81	1 316.54	1 316.10
SH spray flow	kg/s	0.00	0.00	0.00	0.00
SH spray enthalpy	kJ/kg	625.66	626.85	626.74	626.69
RH spray flow	kg/s	0.00	0.00	0.00	0.00
Cold reheat flow	kg/s	486.56	483.73	483.35	482.90
Cold reheat enthalpy boiler	kJ/kg	2 992.04	2 983.76	2 983.64	2 983.51
Hot reheat flow	kg/s	486.56	483.73	483.35	482.90
Hot reheat enthalpy at boiler	kJ/kg	3 596.64	3 598.53	3 598.56	3 598.60
Feedwater flow	kg/s	643.94	627.90	627.92	626.29
Feedwater enthalpy	kJ/kg	1 327.08	1 316.81	1 316.54	1 316.10
SCAH flow (from boiler)	kg/s	0.00	0.00	0.00	0.00
Boiler output, as measured	GJ/h	5 721.4	5 746.7	5 746.7	5 734.8
Boiler reference temperature (constant)	°C	25.0	25.0	25.0	25.0
Measured primary AH gas outlet temperature	°C	182.2	180.6	180.0	181.1
Measured secondary AH gas outlet temperature	°C	179.4	177.8	177.2	178.3
Measured air heater gas inlet temperature	°C	332.2	335.6	335.0	335.0
Boiler auxiliary load, uncorrected	kW	13 928.14	13 339.326	13 390.971	13 373.7504
Boiler fuel efficiency, as measured	%	86.23	86.3	86.31	86.28
Key Operating Parameters					
Throttle flow	kg/s	628.77	620.04	619.62	618.76
Throttle pressure	bara	254.340	254.340	254.340	254.340
Throttle temperature	°C	565.6	565.6	565.6	565.6
Hot reheat temperature turbine	°C	565.6	565.6	565.6	565.6
Process steam energy	GJ/h	76.0	96.1	101.0	91.8
Gross electrical output	kW	733 060	732 930	733 350	733 210
Auxiliary loads (% of uncorrected gross), uncorrected	%	9.50	9.10	9.13	9.12
Condenser cooling water flow	kg/s	19 531.34	19 151.45	19 151.45	19 151.45
Makeup flow	kg/s	15.24	7.94	8.32	7.56
Test Results, uncorrected					
Boiler heat output, HHV, uncorrected	GJ/h	5 721.4	5 746.7	5 746.7	5 734.8
Boiler efficiency, HHV, uncorrected	%	86.23	86.30	86.31	86.28
Boiler heat input, uncorrected	GJ/h	6 635.1	6 659.0	6 658.2	6 646.8
Net electrical output, uncorrected	kW	663 419	666 233	666 395	666 341
Net heat rate, HHV, uncorrected	kJ/kWh	10 001.4	9 995.0	9 991.3	9 975.0

Table E-3.1.1-1 Case 1 Corrected Test Results

Correction Factors (Net Output and Heat Input)	Unit of Measure	Design	Test Run 1A	Test Run 1B	Test Run 1C
		(U.S. Customary Units)			
Specified disposition, Δ_7 (electrical output)	kW	...	−2,814	−2,976	−2,922
Thermal efflux, ω_1					
Process flow, Δ_{1A}	MMBtu/hr	...	−11.7	−14.4	−9.0
Process pressure, ω_{1B}	MMBtu/hr	...	Negligible	Negligible	Negligible
Process temperature, ω_{1C}	MMBtu/hr	...	−0.3	−0.6	−0.6
Generator power factor, ω_2	MMBtu/hr	...	5.0	5.5	5.0
Secondary heat inputs (MU temperature), ω_4	MMBtu/hr	...	Negligible	Negligible	Negligible
Ambient conditions, ω_{5A}					
Ambient temperature, ω_{5A1}	MMBtu/hr	...	14.6	12.9	12.0
Ambient relative humidity, ω_{5A2}	MMBtu/hr	...	−21.4	−20.8	−19.7
River water temperature, ω_{5B}	MMBtu/hr	...	−28.5	−17.3	−12.3
Auxiliary loads, ω_6	MMBtu/hr	...	−4.6	−3.1	−1.0
Specified disposition, ω_7	MMBtu/hr	...	−28.7	−30.3	−29.8
Test Results					
Boiler heat input, HHV, corrected	MMBtu/hr	6,288.9	6,235.7	6,242.3	6,244.5
Net electrical output, corrected	kW	663,419	663,419	663,419	663,419
Net heat rate, HHV, corrected	Btu/kWh	9,479.5	9,399.3	9,409.3	9,412.7
		(SI Units)			
Specified disposition, Δ_7 (electrical output)	kW	...	−2 814	−2 976	−2 922
Thermal efflux, ω_1					
Process flow, ω_{1A}	GJ/h	...	−12.3	−15.1	−9.5
Process pressure, ω_{1B}	GJ/h	...	Negligible	Negligible	Negligible
Process temperature, ω_{1C}	GJ/h	...	−0.3	−0.7	−0.6
Generator power factor, ω_2	GJ/h	...	5.3	5.8	5.3
Secondary heat inputs (MU temperature), ω_4	GJ/h	...	Negligible	Negligible	Negligible
Ambient conditions, ω_{5A}					
Ambient temperature, ω_{5A1}	GJ/h	...	15.4	13.6	12.7
Ambient relative humidity, ω_{5A2}	GJ/h	...	−22.6	−22.0	−20.8
River water temperature, ω_{5B}	GJ/h	...	−30.1	−18.3	−12.9
Auxiliary loads, ω_6	GJ/h	...	−4.8	−3.2	−1.1
Specified disposition, ω_7	GJ/h	...	−30.3	−32.0	−31.4
Test Results					
Boiler heat input, HHV, corrected	GJ/h	6 635.1	6 579.0	6 586.0	6 588.3
Net electrical output, corrected	kW	663 419	663 419	663 419	663 419
Net heat rate, HHV, corrected	kJ/kWh	10 001.4	9 916.8	9 927.4	9 930.8

corrected to reference fuel and reference ambient temperature for the steam generator. The Q_rO term used in ASME PTC 46 differs from ASME PTC 4 in that it does not make corrections to boiler efficiency that include plant internal parameters that do not cross the test boundary, such as feedwater temperature. This sample uses an "integrated boiler efficiency model," which means that the overall plant correction curves already have the boiler efficiency effects incorporated.

The ground rules for determining corrected steam generator fuel efficiency must be considered prior to the test. The base reference fuel analysis is detailed in Table E-3.1.2-1.

$$Q_{meas} = Q_rO / \eta_{\text{fuel uncorrected}}$$

where

Q_rO = steam generator tested output, including blowdown energy (if applicable)

$\eta_{\text{fuel uncorrected}}$ = steam generator corrected fuel energy efficiency expressed as a decimal

Fuel energy efficiency corrections are performed by utilizing the anlayzed fuel composition at the time of the test.

Once the actual heat input is known, the heat input is first corrected for fuel properties. This is done by substituting the design fuel properties into the ASME PTC 4 spreadsheet to determine boiler fuel efficiency, to determine a partially corrected heat input, referred to as $Q_{\text{corr fuel}}$

$$Q_{\text{corr fuel}} = Q_{r0} / \eta_{\text{fuel uncorrected}} \times \eta_{\text{fuel uncorrected}} / \eta_{\text{fuel corr for fuel}}$$

where

$\eta_{\text{fuel corr for fuel}}$ = steam generator corrected fuel energy efficiency expressed as a decimal

Fuel energy efficiency corrections are performed by utilizing the design fuel composition in the calculated efficiency instead of the anlayzed fuel composition at the time of the test.

Corrected heat rate for each test run is calculated from eq. (5-3-4).

$$HR_{corr} = \frac{(Q_{\text{corr fuel}} + \omega_{1A} + \omega_{1C} + \omega_2 + \omega_4 + \omega_{5A1} + \omega_{5A2} + \omega_{5B} + \omega_6 + \omega_7)}{(P_{meas} + \Delta_7)} = \frac{Q_{corr}}{P_{corr}}$$

Given here are the corrected output results and corrected heat rate results of each test run for Sample Case 1.

E-3.2 Case 2 Sample Calculation: Specified Steam Flow

The test goal is to demonstrate plant performance at a specified throttle steam flow of 4,940,000 lb/hr (622.44 kg/s) operating in sliding pressure mode.

The base reference conditions for Example Case 2 are as listed in Table E-3.2-1. These are identical to Case 1, with the exception of relative humidity.

Table E-3.2-2 documents the measured test data and some key operating parameters of the plant during the test. As in the Case 1 example, the measured boiler efficiency is calculated using the ASME PTC 4 Code calculations. However, because Case 2 demonstrates an ASME PTC 46 coal-fired power plant test using a "nonintegrated" thermal model (boiler not included), a corrected boiler efficiency using corrections per ASME PTC 4 must be determined with the same cautions to this calculation as detailed in the Case 1 Sample calculation.

As in Case 1, corrections for boiler feedwater temperature and other ASME PTC 4 corrections for parameters inside the plant test boundary on boiler fuel efficiency are not taken. It is assumed that changing fuel properties have no significant effect on steam temperatures for this example. Output and heat rate correction curves assume that the boiler firing rate is adjusted to maintain 4,940 lb/hr (622.44 kg/s) at the STG throttle; the turbine valves are always at valves-wide-open (VWO).

In Table E-3.2-2, a corrected entering air temperature based on design FD/PA fan inlet temperatures and measured fan rises is used in the calculation of corrected boiler efficiency.

Table E-3.2-1 Example of Test Boundary Conditions for Supercritical Unit — Case 2

Measurement Parameter	Unit of Measure	Design	Test Run 2A	Test Run 2B	Test Run 2C
(U.S. Customary Units)					
Site dry bulb temperature	°F	92.0	75.0	76.0	78.0
Site wet bulb temperature	°F	75.0	75.0	75.0	75.0
Site barometric pressure	psia	14.100	14.100	14.100	14.100
Process steam flow	lb/hr	50,000	52,000	45,000	49,000
Process steam pressure	psia	1,200	1,210	1,150	1,180
Process steam temperature	°F	900	910	902	890
Process condensate (makeup) return temperature	°F	60.0	52.0	56.0	57.0
Makeup enthalpy	Btu/lb	28.13	20.11	24.12	25.12
River water temperature	°F	55.0	51.0	51.0	52.0
(SI Units)					
Site dry bulb temperature	°C	33.3	23.9	24.4	25.6
Site wet bulb temperature	°C	23.9	23.9	23.9	23.9
Site barometric pressure	bara	0.972	0.972	0.972	0.972
Process steam flow	kg/s	6.30	6.55	5.67	6.17
Process steam pressure	bara	82.732	83.422	79.285	81.354
Process steam temperature	°C	482.2	487.8	483.3	476.7
Process condensate (makeup) return temperature	°C	15.6	11.1	13.3	13.9
Makeup enthalpy	kJ/kg	65.43	46.78	56.10	58.42
River water temperature	°C	12.8	10.6	10.6	11.1
Power factor generator terminals	. . .	0.840	0.960	0.970	0.960
Coal properties (as fired); Powder River Basin, PRB					
Carbon	% wt	49.000	48.860	48.860	48.860
Hydrogen	% wt	3.400	3.420	3.400	3.410
Nitrogen	% wt	0.800	0.723	0.710	0.696
Oxygen	% wt	11.930	10.479	11.170	11.165
Sulfur	% wt	0.510	0.518	0.520	0.499
Moisture	% wt	27.590	31.300	30.500	30.600
Ash	% wt	6.770	4.700	4.840	4.770
HHV	Btu/lb	8,500	8,523	8,513	8,520
HHV	kJ/kg	19 852	19 824	19 801	19 818

GENERAL NOTE: Load = 100%; Operating mode = Fixed pressure; Goal = Specified steam flow; Model = Nonintegrated.

Table E-3.2-2 Case 2 Measured Test Data

Measurement Parameter	Unit of Measure	Design	Test Run 2A	Test Run 2B	Test Run 2C
(U.S. Customary Units)					
Boiler Operating Parameters, as measured					
Boiler reference temperature (constant)	°F	77.0	77.0	77.0	77.0
Boiler SH outlet flow	lb/hr	4,989,410	4,970,000	5,010,000	4,990,000
Boiler SH outlet enthalpy	Btu/lb	1,455.5	1,457.6	1,456.5	1,457.0
Boiler losses	lb/hr	0.000	0.000	0.000	0.000
Boiler loss enthalpy	Btu/lb	571.5	570.1	571.4	570.7
SH spray flow	lb/hr	0.000	0.000	0.000	0.000
SH spray enthalpy	Btu/lb	269.6	268.5	269.0	268.7
RH spray flow	lb/hr	0.000	0.000	0.000	0.000
Cold reheat flow	lb/hr	3,831,472	3,820,243	3,854,227	3,837,178
Cold reheat enthalpy boiler	Btu/lb	1,278.1	1,280.8	1,280.0	1,280.4
Hot reheat flow	lb/hr	3,831,472	3,820,243	3,854,227	3,837,178
Hot reheat enthalpy at boiler	Btu/lb	1,546.294	1,546.363	1,546.214	1,546.288
Feedwater flow	lb/hr	4,990,000	4,970,000	5,011,000	4,991,000
Feedwater enthalpy	Btu/lb	571.5	570.1	571.4	570.7
SCAH flow (from boiler)	lb/hr	0.0	0.0	0.0	0.0
Boiler output, as measured	MMBtu/hr	5,438.4	5,425.3	5,460.8	5,443.0
Boiler fuel efficiency, as measured	%	86.30	86.28	86.25	86.10
Boiler Operating Parameters					
Base reference ambient air temperature					
Percent PA flow (percentage of total)	°F	92.00	92.00	92.00	92.00
(assumed)	%	17.00	17.00	17.00	17.00
Measured PA fan temperature rise		20.00	21.00	21.00	21.00
Measured FD fan temperature rise	°F	18.00	16.00	17.00	16.00
Primary air temperature entering air heater, corrected	°F °F	112.00	113.00	112.50	112.80
Secondary air entering air heater, corrected	°F	110.00	108.00	109.00	108.00
Weighted entering air temperature, corrected	°F	110.34	108.85	109.60	108.00
Measured primary AH gas outlet temperature	°F	360.00	364.00	363.00	365.00
Measured air heater gas inet temperature	°F	632.00	634.00	638.00	632.00
Measured primary air heater effectiveness	%	48.00	47.00	46.50	47.40
Primary air temperature entering air heater, corrected	°F	112.00	113.00	112.50	112.80
Primary AH gas outlet temperature, corrected	°F	382.40	389.13	393.64	385.90
Measured secondary AH gas outlet temperature	°F	355.00	359.00	358.00	355.00
Measured air heater gas inlet temperature	°F	632.00	634.00	638.00	632.00
Measured secondary air heater effectiveness	%	52.00	51.00	53.00	52.50
Secondary air temperature entering air heater, corrected	°F	112.00	113.00	112.50	112.80
Secondary AH gas outlet temperature, corrected	°F	361.60	368.29	359.49	359.42
Weighted air heater gas outlet temperature, corrected	°F	365.14	371.83	365.29	363.92

Table E-3.2-2 Case 2 Measured Test Data (Cont'd)

Measurement Parameter	Unit of Measure	Design	Test Run 2A	Test Run 2B	Test Run 2C
(U.S. Customary Units) (Cont'd)					
Boiler auxiliary load, uncorrected	kW	14,470.0	13,724.6	13,887.3	13,809.7
Boiler fuel efficiency, uncorrected		86.30	86.28	86.25	86.10
Boiler fuel efficiency, corrected per ASME PTC 4	%	86.30	86.31	86.29	86.24
Boiler efficiency versus load correction	. . .	1.00	1.00	1.00	1.00
Boiler fuel efficiency, corrected	%	86.30	86.31	86.29	86.24
Key Operating Parameters					
Throttle flow (basis of correction curves)	lb/hr	4,940,000	4,918,457	4,965,453	4,941,859
Throttle pressure	psia	3,689	3,624	3,656	3,640
Throttle temperature	°F	1,050.0	1,050.0	1,050.0	1,050.0
Hot reheat temperature turbine	°F	1,050.0	1,050.0	1,050.0	1,050.0
Process steam energy	MMBtu/hr	72.04	75.22	64.98	70.35
Gross electrical output	kW	761,580	754,100	760,530	757,110
Auxiliary loads (% of uncorrected gross), uncorrected	%	9.50	9.10	9.13	9.12
Condenser cooling water flow	lb/hr	150,339,968	152,546,768	152,546,768	152,546,768
Makeup flow	lb/hr	49,998	52,000	45,008	49,008
Test Results, uncorrected					
Boiler heat output, HHV, uncorrected	MMBtu/hr	5,438.4	5,425.3	5,460.8	5,443.0
Net electrical output, uncorrected	kW	689,230	685,477	691,094	688,062
Net heat rate, HHV, uncorrected	Btu/kWh	9,143.1	9,170.0	9,157.1	9,172.9
(SI Units)					
Boiler Operating Parameters, as measured					
Boiler reference temperature	°C	25.0	25.0	25.0	25.0
Boiler SH outlet flow	kg/s	628.66	626.22	631.26	628.74
Boiler SH outlet enthalpy	kJ/kg	3 385.4	3 390.2	3 387.9	3 389.1
Boiler losses	kg/s	0.00	0.00	0.00	0.00
Boiler loss enthalpy	kJ/kg	1 329.3	1 326.0	1 329.0	1 327.5
SH spray flow	kg/s	0.00	0.00	0.00	0.00
SH spray enthalpy	kJ/kg	627.1	624.4	625.8	625.1
RH spray flow	kg/s	0.00	0.00	0.00	0.00
Cold reheat flow	kg/s	482.76	481.35	485.63	483.48
Cold reheat enthalpy boiler	kJ/kg	2 972.7	2 979.1	2 977.3	2 978.2
Hot reheat flow	kg/s	482.76	481.35	485.63	483.48
Hot reheat enthalpy at boiler	kJ/kg	3 596.6	3 596.8	3 596.5	3 596.6
Feedwater flow	kg/s	628.74	626.22	631.38	628.86
Feedwater enthalpy	kJ/kg	1 329.3	1 326.0	1 329.0	1 327.5
SCAH flow (from boiler)	kg/s	0.00	0.00	0.00	0.00
Boiler output, as measured	GJ/h	5 737.8	5 724.0	5 761.4	5 742.7
Boiler fuel efficiency, as measured	%	86.30	86.28	86.25	86.10
Boiler Operating Parameters					
Base reference ambient air temperature	°C	33.3	33.3	33.3	33.3
Percent PA flow (percentage of total) (assumed)	%	17.0	17.0	17.0	17.0
Measured PA fan temperature rise	°C	11.1	11.7	11.7	11.7
Measured FD fan temperature rise	°C	10.0	8.9	9.4	8.9
Primary air temperature entering air heater, corrected	°C	44.4	45.0	44.7	44.9
Secondary air entering air heater, corrected	°C	43.3	42.2	42.8	42.2
Weighted entering air temperature, corrected	°C	43.5	42.7	43.1	42.7

Table E-3.2-2 Case 2 Measured Test Data (Cont'd)

Measurement Parameter	Unit of Measure	Design	Test Run 2A	Test Run 2B	Test Run 2C
(SI Units) (Cont'd)					
Measured primary AH gas outlet temperature	°C	182.2	184.4	183.9	185.0
Measured air heater gas inlet temperature	°C	333.3	334.4	336.7	333.3
Measured primary air heater effectiveness	%	48.0	47.0	46.5	47.4
Primary air temperature entering air heater, corrected	°C	44.4	45.0	44.7	44.9
Primary AH gas outlet temperature, corrected	°C	194.7	198.4	200.9	196.6
Measured secondary AH gas outlet temperature	°C	179.4	181.7	181.1	179.4
Measured air heater gas inlet temperature	%	333.3	334.4	336.7	333.3
Measured secondary air heater effectiveness	°C	52.0	51.0	53.0	52.5
Secondary air temperature entering air heater, corrected	°C	44.4	45.0	44.7	44.9
Secondary AH gas outlet temperature, corrected	°C	183.1	186.8	181.9	181.9
Weighted air heater gas outlet temperature, corrected	°C	185.1	188.8	185.2	184.4
Boiler auxiliary load, uncorrected	kW	14 470	13 725	13 887	13 810
Boiler fuel efficiency, uncorrected		86.30	86.28	86.25	86.10
Boiler fuel efficiency, corrected	%	86.30	86.31	86.29	86.24
Boiler efficiency versus load correction per ASME PTC 4	. . .	1.00	1.00	1.00	1.00
Boiler fuel efficiency, corrected	%	86.30	86.31	86.29	86.24
Key Operating Parameters					
Throttle flow (basis of correction curves)	kg/s	622.44	619.72	625.64	622.67
Throttle pressure	bara	254.338	249.837	252.033	250.931
Throttle temperature	°C	565.6	565.6	565.6	565.6
Hot reheat temperature turbine	°C	565.6	565.6	565.6	565.6
Process steam energy	GJ/h	76.0	79.4	68.6	74.2
Gross electrical output	kW	761 580	754 100	760 530	757 110
Auxiliary loads (% of uncorrected gross), uncorrected	%	9.50	9.10	9.13	9.12
Condenser cooling water flow	kg/s	18 942.71	19 220.77	19 220.77	19 220.77
Makeup flow	kg/s	6.30	6.55	5.67	6.17
Test Results, uncorrected					
Boiler heat output, HHV, uncorrected	GJ/h	5 737.8	5 724.0	5 761.4	5 742.7
Net electrical output, uncorrected	kW	689 230	685 477	691 094	688 062
Net heat rate, HHV, uncorrected	kJ/kWh	9 646.5	9 674.9	9 661.2	9 677.9

Also, the boiler fuel efficiency calculation uses a corrected air heater gas inlet temperature based on corrected entering air temperature and air heater effectiveness. The flue gas exit temperature [air heater gas inlet temperature (AHGIT)] from the primary and secondary air heaters at reference condition is as follows:

$$\mathrm{AHGIT_{corr}} = \mathrm{AHGIT_{meas}} - \frac{\eta_p}{100}(\mathrm{AHGIT} - \mathrm{AHAIT})$$

where

AHAIT = corrected air heater air inlet temperature, °F
AHGIT = measured air heater gas inlet temperature, °F
$\mathrm{AHGIT_{corr}}$ = air heater gas inlet temperature, corrected, °F
$\mathrm{AHGIT_{meas}}$ = air heater gas inlet temperature, measured, °F
η_p = measured air heater effectiveness, %

and air heater effectiveness (η_p) is calculated as

$$\eta_p = \frac{\mathrm{AHGIT} - \mathrm{AHGOT}}{\mathrm{AHGIT} - \mathrm{AHAIT}} \times 100$$

where

AHAIT = measured air heater air inlet temperature, °F
AHGIT = measured air heater air inlet temperature, °F
AHGOT = measured air heater gas outlet temperature, °F

The primary and secondary air heater corrected gas inlet temperatures are determined and weighted based on gas flow splits between the primary and secondary air heaters. This weighted corrected air heater gas inlet temperature is used in the corrected boiler efficiency calculation.

A list of key operating parameters is also provided for the test. Key parameters such as these should be determined for a specific plant configuration and test, and monitored during the test to verify plant stability and appropriate operating range.

E-3.2.1 Corrected Output. Corrected output for each test run is calculated using eq. (5-3-3), modified to reflect the specific Case 2 example repeated below. Terms in the equation are described in Section 5.

$$P_{\mathrm{corr}} = P_{\mathrm{meas}} + \Delta_{1\mathrm{A,B,C}} + \Delta_2 + \Delta_4 + \Delta_{5\mathrm{B}} + \Delta_{6\mathrm{A,B,C}} + \Delta_7$$

Section 5 supplemental definitions are as follows:

Δ_{1A} thermal efflux correction, process flow
Δ_{1B} thermal efflux correction, process pressure
Δ_{1C} thermal efflux correction, process temperature
Δ_{6A} auxiliary load correction, fan power
Δ_{6B} auxiliary load correction, fuel effects on mills and fans
Δ_{6C} auxiliary load correction, intermittent loads

A summary of the output and heat rate corrections for the test runs are given in Table E-3.2.1-1.

Because this is a supercritical unit, there is no blowdown correction.

E-3.2.2 Corrected Fuel Boiler Output and Corrected Heat Rate. The corrected steam generator output (Q_rO_{corr}) is calculated according to the numerator of eq. (5-3-4), modified to reflect the specific example described in Case 2

$$Q_rO_{\mathrm{corr}} = Q_rO + \omega_{1\mathrm{A,B,C}} + \omega_7$$

where

Q_rO = steam generator tested output, including blowdown energy (if applicable)

Table E-3.2.1-1 Case 2 Corrected Test Results

Correction Factors (Net Output and Boiler Output)	Unit of Measure	Design	Test Run 2A	Test Run 2B	Test Run 2C
(U.S. Customary Units)					
Thermal efflux, Δ_1					
Process flow, Δ_{1A}	kW	0	63	−210	−54
Process pressure, Δ_{1B}	kW	0	3	−10	−5
Process temperature, Δ_{1C}	kW	0	-27	−3	35
Generator power factor, Δ_2	kW	0	−892	−1,021	−908
Blowdown, Δ_3	kW	NA	NA	NA	
Secondary heat inputs (MU temperature), Δ_4	kW	0	−3	−2	−1
River water temperature, Δ_{5B}	kW	0	−1,614	−1,614	−1,400
Auxiliary loads, Δ_6					
Correction for air temperature on fan power, Δ_{6A}	kW	0	31	30	27
Correction for fuel effects on mills and fans, Δ_{6B}	kW	0	−22	−17	−18
Correction for nonessential/ intermittent loads, Δ_{6C}	kW	0	345	360	420
Specified disposition, Δ_7 (constant throttle flow)	kW	0	2,868	−2,701	95
Thermal efflux, ω_1					
Process steam flow, ω_{1A}	MMBtu/hr	0.0	−1.8	4.2	0.8
Process steam pressure, ω_{1B}	MMBtu/hr	0.0	0.0	0.0	0.0
Process steam temperature, ω_{1C}	MMBtu/hr	0.0	0.0	0.0	0.0
Generator power factor, ω_2	MMBtu/hr	NA	NA	NA	NA
Blowdown, ω_3	MMBtu/hr	NA	NA	NA	NA
Secondary heat inputs (MU temperature), ω_4	MMBtu/hr	NA	NA	NA	NA
River water temperature (multivariate w/flow), ω_{5B}	MMBtu/hr	NA	NA	NA	NA
Auxiliary loads, ω_6	MMBtu/hr	NA	NA	NA	NA
Specified disposition, ω_7	MMBtu/hr	0.8	19.7	−21.6	−0.9
Test Results					
Boiler heat output, HHV, corrected	MMBtu/hr	5,439.1	5,443.2	5,443.3	5,442.9
Net electrical output, corrected	kW	689,230	686,229	685,905	686,254
Boiler efficiency, corrected per ASME PTC 4, HHV	%	86.30	86.31	86.29	86.24
Net heat rate, HHV, corrected	Btu/kWh	9,144.4	9,190.2	9,196.9	9,196.9
(SI Units)					
Thermal efflux, Δ_1					
Process flow, Δ_{1A}	kW	0	63	−210	−54
Process pressure, Δ_{1B}	kW	0	3	−10	−5
Process temperature, Δ_{1C}	kW	0	−27	−3	35
Generator power factor, Δ_2	kW	0	−892	−1,021	−908
Blowdown, Δ_3	kW	NA	NA	NA	NA
Secondary heat inputs (MU temperature), Δ_4	kW	0	−3	−2	−1
River water temperature (multivariate w/flow), Δ_{5B}	kW	0	−1,614	−1,614	−1,400

Table E-3.2.1-1 Case 2 Corrected Test Results (Cont'd)

Correction Factors (Net Output and Boiler Output)	Unit of Measure	Design	Test Run 2A	Test Run 2B	Test Run 2C
(SI Units) (Cont'd)					
Auxiliary loads, Δ_6					
Correction for air temperature on fan power, Δ_{6A}	kW	0	31	30	27
Correction for fuel effects on mills and fans, Δ_{6B}	kW	0	−22	−17	−18
Correction for nonessential/ intermittent loads, Δ_{6C}	kW	0	345	360	420
Specified disposition, Δ_7 (constant throttle flow)	kW	0	2,868	−2,701	95
Thermal efflux, ω_1					
Process steam flow, ω_{1A}	GJ/hr	0.00	−1.94	4.44	0.79
Process steam pressure, ω_{1B}	GJ/h	0.00	0.00	0.00	0.00
Process steam temperature, ω_{1C}	GJ/h	0.00	0.00	0.00	0.00
Generator power factor, ω_2	GJ/h	NA	NA	NA	NA
Blowdown, ω_3	GJ/h	NA	NA	NA	NA
Secondary heat inputs (MU temperature), ω_4	GJ/h	NA	NA	NA	NA
River water temperature, ω_{5B}	GJ/h	NA	NA	NA	NA
Auxiliary loads, ω_6	GJ/h	NA	NA	NA	NA
Specified disposition, ω_7	GJ/h	0.77	19.74	−21.64	−0.86
Test Results					
Boiler heat output, HHV, corrected	GJ/h	5 738.6	5 742.9	5 743.0	5 742.6
Net electrical output, corrected	kW	689 230	686 229	685 905	686 254
Boiler efficiency, corrected per ASME PTC 4, HHV	%	86.30	86.31	86.29	86.24
Net heat rate, HHV, corrected	kJ/kWh	9 647.9	9 696.2	9 703.2	9 703.2

Certain correction factors listed in eq. (5-3-4) in the above equation were determined to be negligible or not applicable for the stated choice of a test goal.

$$Q_{corr} = Q_rO_{\ corr}/\eta_{\text{fuel corrected}}$$

where

Q_{corr} = corrected plant heat input
$\eta_{\text{fuel corrected}}$ = steam generator corrected fuel energy efficiency expressed as a decimal

In the above equation, Q_rO is similar to, but not identical to the steam generator tested output (Q_rO) as defined in ASME PTC 4, including blowdown energy or other losses, divided by corrected fuel energy efficiency calculated per ASME PTC 4. Q_rO in this sense represents the test fuel energy consumption corrected to reference fuel and reference ambient temperature for the steam generator. The Q_rO term used in ASME PTC 46 differs from ASME PTC 4 in that it does not make corrections to boiler efficiency that include plant internal parameters that do not cross the test boundary, such as feedwater heater performance. This sample uses a "nonintegrated boiler efficiency model," which means that the correction methodology of ASME PTC 4 must be implemented.

The ground rules for determining corrected steam generator fuel efficiency must be considered prior to the test. The base reference fuel analysis is detailed in Table E-3.2-1. The corrections to the measured test results (except boiler efficiency) are shown in Table E-3.2.1-1.

The ω terms are described in Table 5-1-1 in Section 5. For a nonintegrated example, the omega corrections are to boiler output, not heat input. Using relationships and terms discussed above, corrected output is determined as

$$P_{corr} = P_{meas} + \Delta_{1A,B,C} + \Delta_2 + \Delta_4 + \Delta_{5B} + \Delta_{6A,B,C} + \Delta_7$$

Corrected heat rate for each test run is calculated from eq. (5-3-4).

$$HR_{corr} = \frac{(Q_r O + \omega_{1A,B,C} + \omega_7)}{(P_{meas} + \Delta_{1A,B,C} + \Delta_2 + \Delta_4 + \Delta_{5B} + \Delta_{6A,B,C} + \Delta_7)\eta_{\text{fuel corrected}}} = \frac{Q_{corr}}{P_{corr}}$$

Given here are the corrected output and corrected heat rate results of each test run.

E-3.3 Case 1 Correction Curves

Figures E-3.3-1 through E-3.3-8 show Case 1 correction curves and changes in heat input.

E-3.4 Case 2 Correction Curves

Figures E-3.4-1 through E-3.4-9 show Case 2 correction curves and changes in net output and boiler output.

E-3.5 Design Cases and Test Runs

Figures E-3.5-1 and E-3.5-1M through E-3.5-8 through E-3.5-8M show examples of Design Cases 1 and 2, and test runs for each.

Fig. E-3.3-1 Change in Heat Input vs. Process Steam Flow

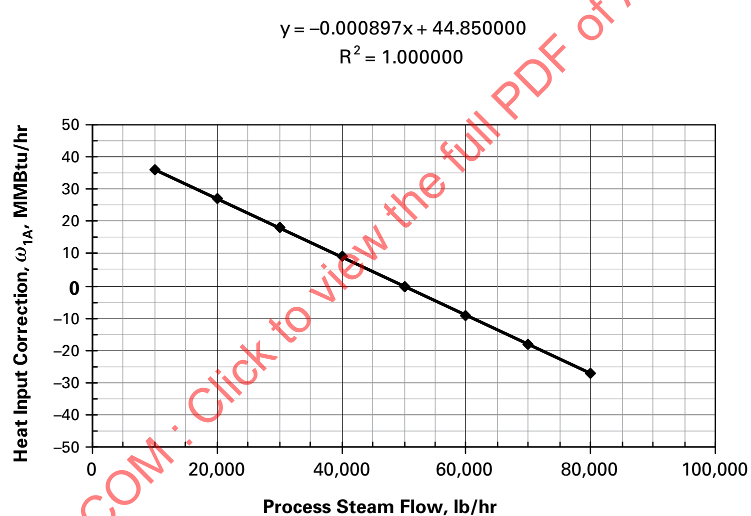


Fig. E-3.3-2 Change in Heat Input vs. Process Steam Temperature

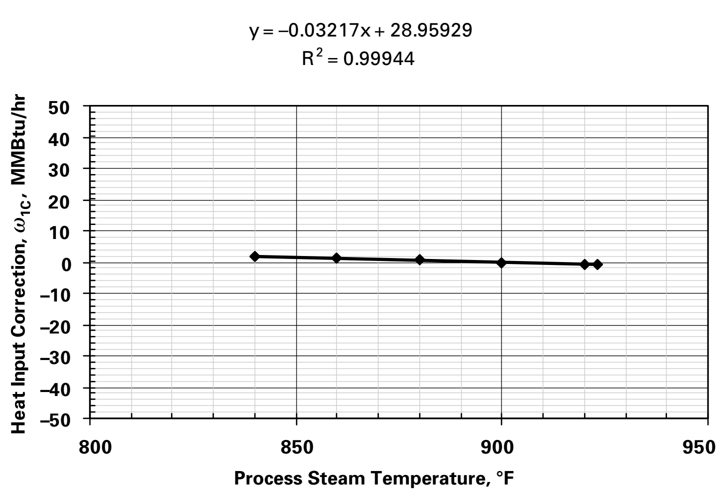


Fig. E-3.3-3 Change in Heat Input vs. Steam Turbine Generator Power Factor

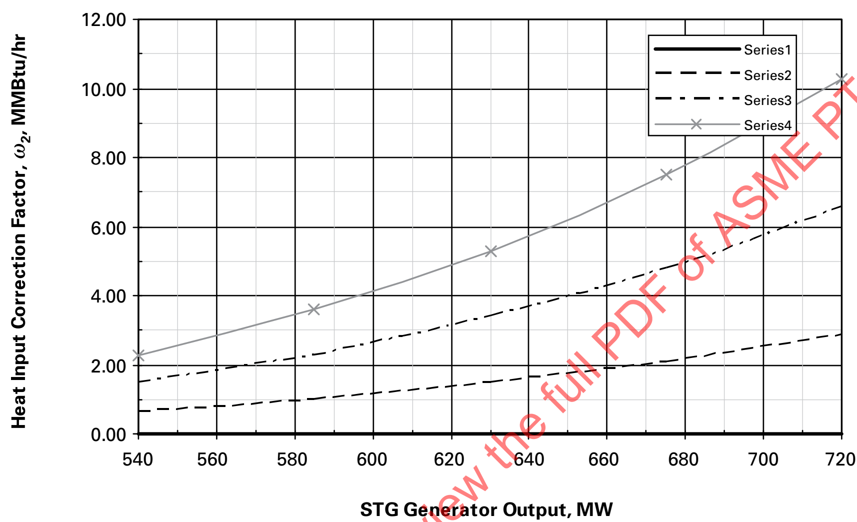


Fig. E-3.3-4 Change in Heat Input vs. Ambient Temperature

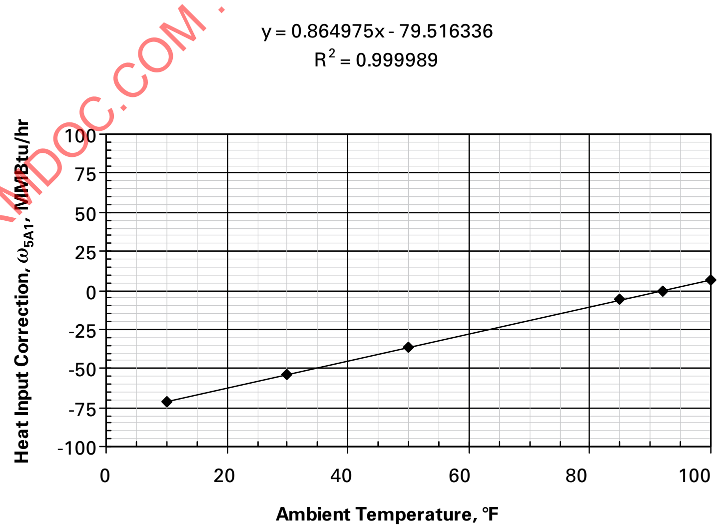


Fig. E-3.3-5 Change in Heat Input vs. Relative Humidity

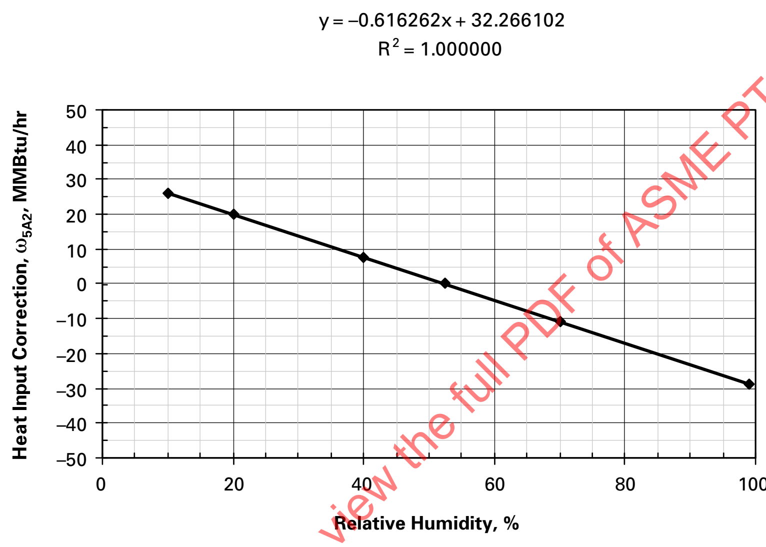


Fig. E-3.3-6 Change in Heat Input vs. River Water Temperature

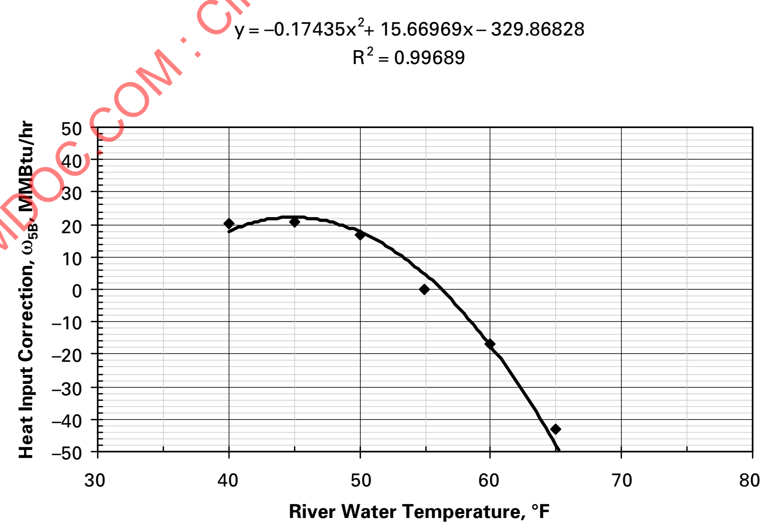


Fig. E-3.3-7 Change in Heat Input vs. Auxiliary Loads

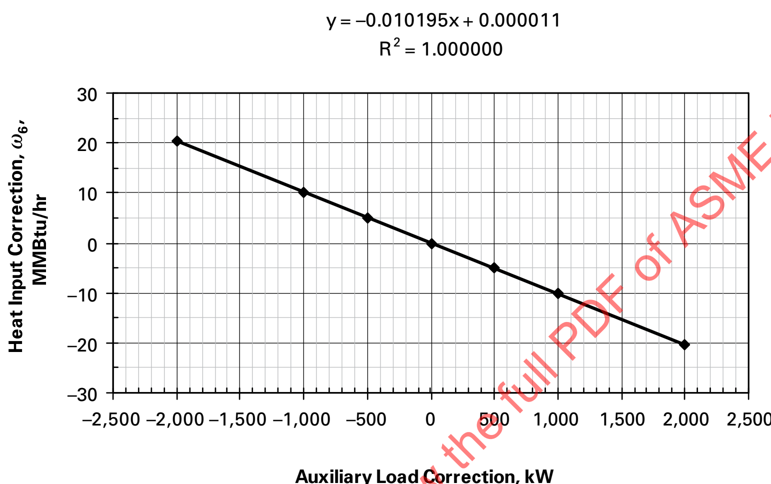


Fig. E-3.3-8 Change in Heat Input vs. Change in Net Output

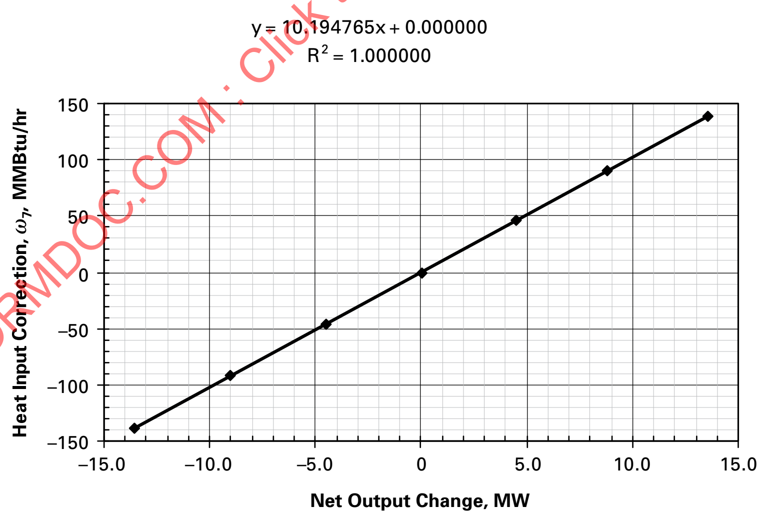


Fig. E-3.4-1 Change in Net Output vs. Process Steam Flow

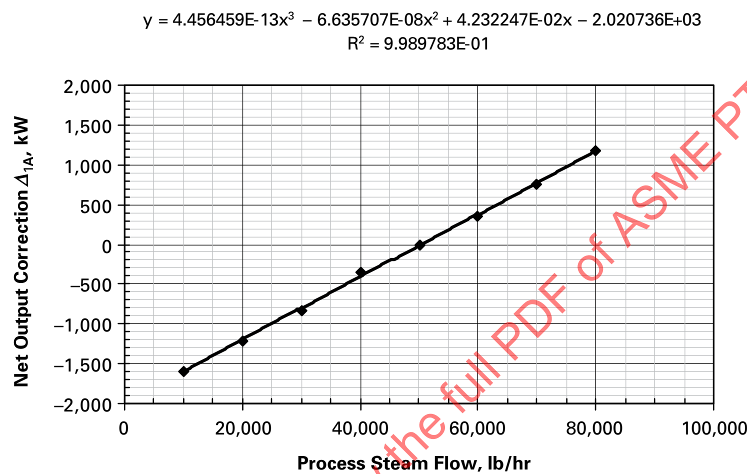


Fig. E-3.4-2 Change in Net Output vs. Process Steam Pressure

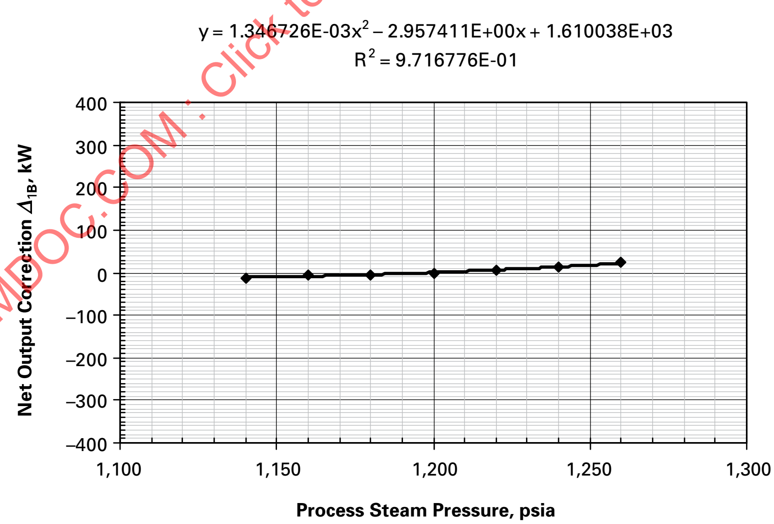


Fig. E-3.4-3 Change in Net Output vs. Process Steam Temperature

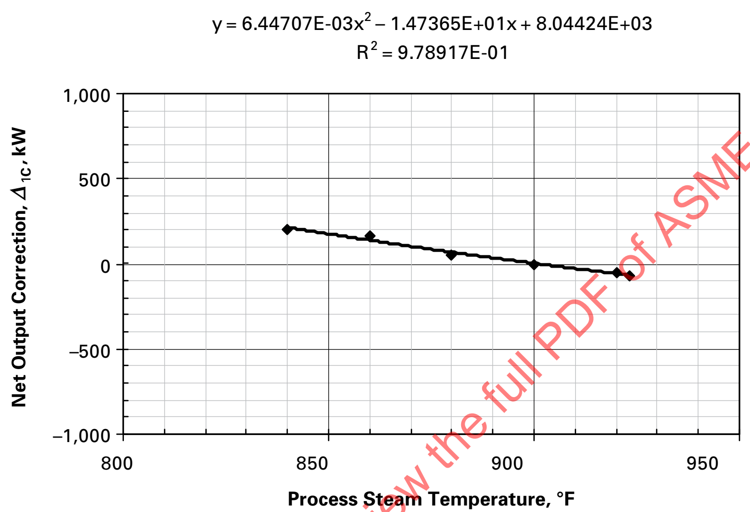


Fig. E-3.4-4 Change in Net Output vs. Steam Turbine Generator Power Factor

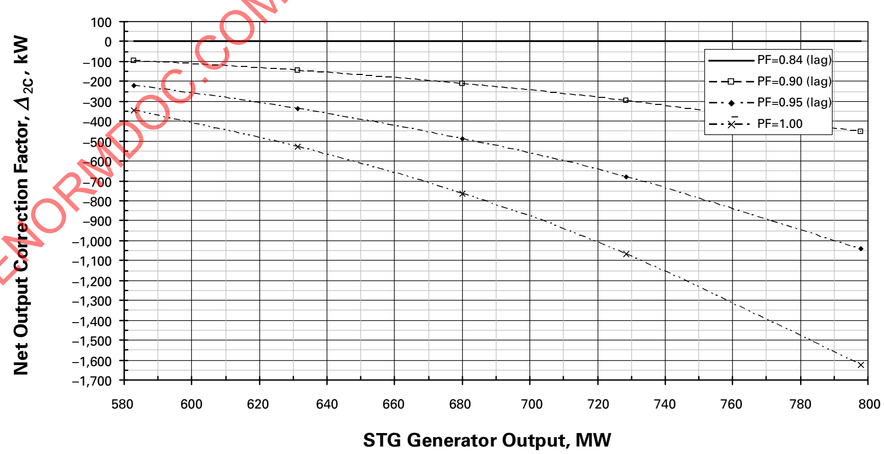


Fig. E-3.4-5 Change in Net Output vs. Makeup Temperature

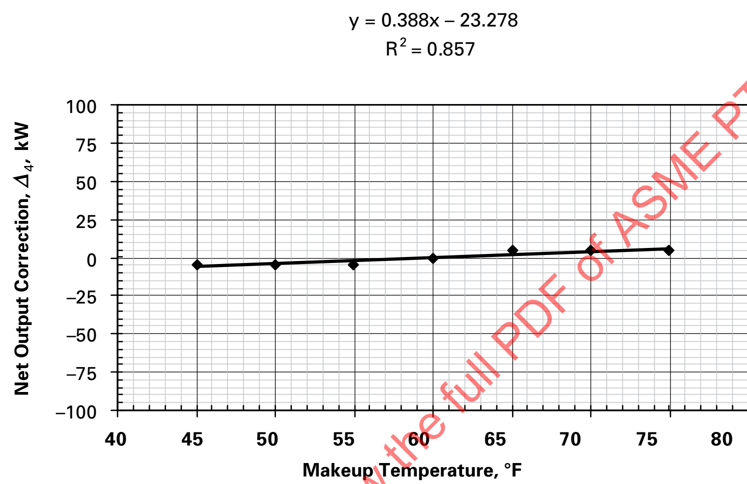


Fig. E-3.4-6 Change in Net Output vs. River Water Temperature

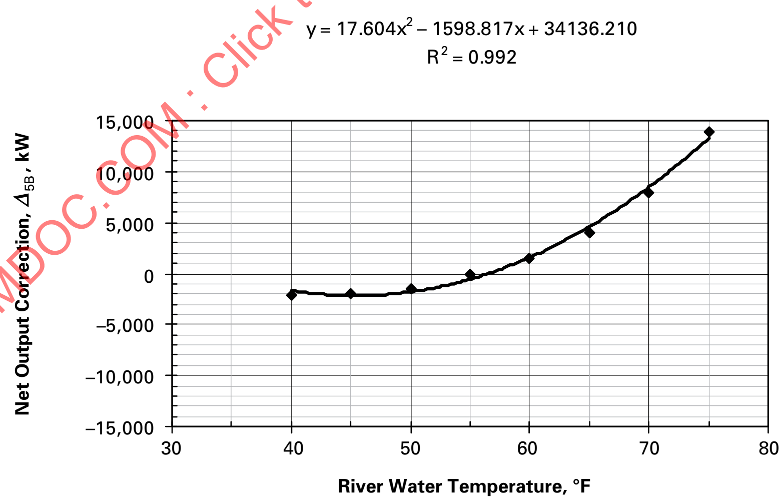


Fig. E-3.4-7 Change in Net Output vs. Change in Throttle Flow

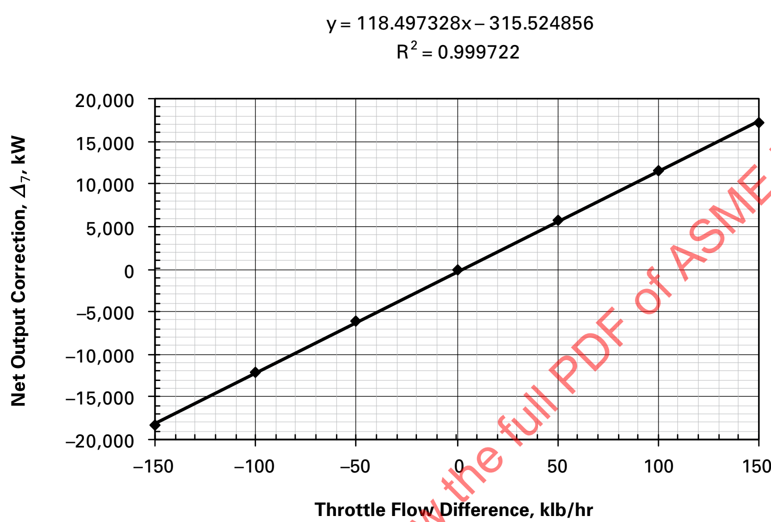


Fig. E-3.4-8 Change in Boiler Output vs. Process Steam Flow

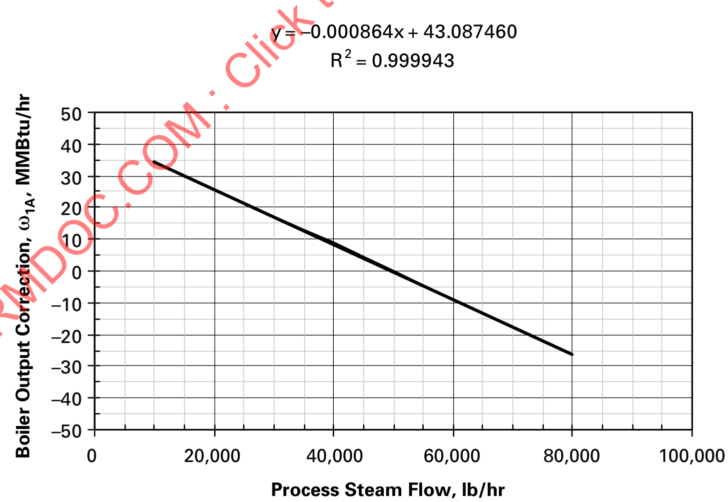


Fig. E-3.4-9 Change in Boiler Output vs. Change in Throttle Flow

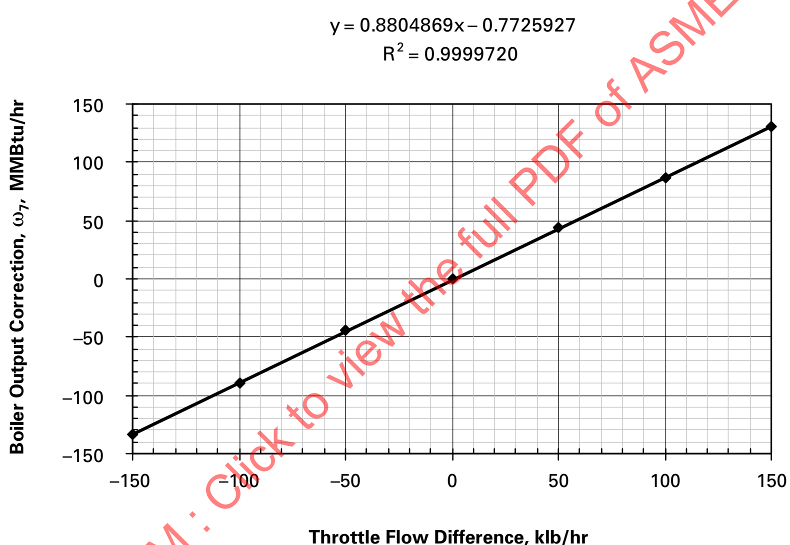


Fig. E-3.5-1 Design Case 1 (U.S. Customary Units)

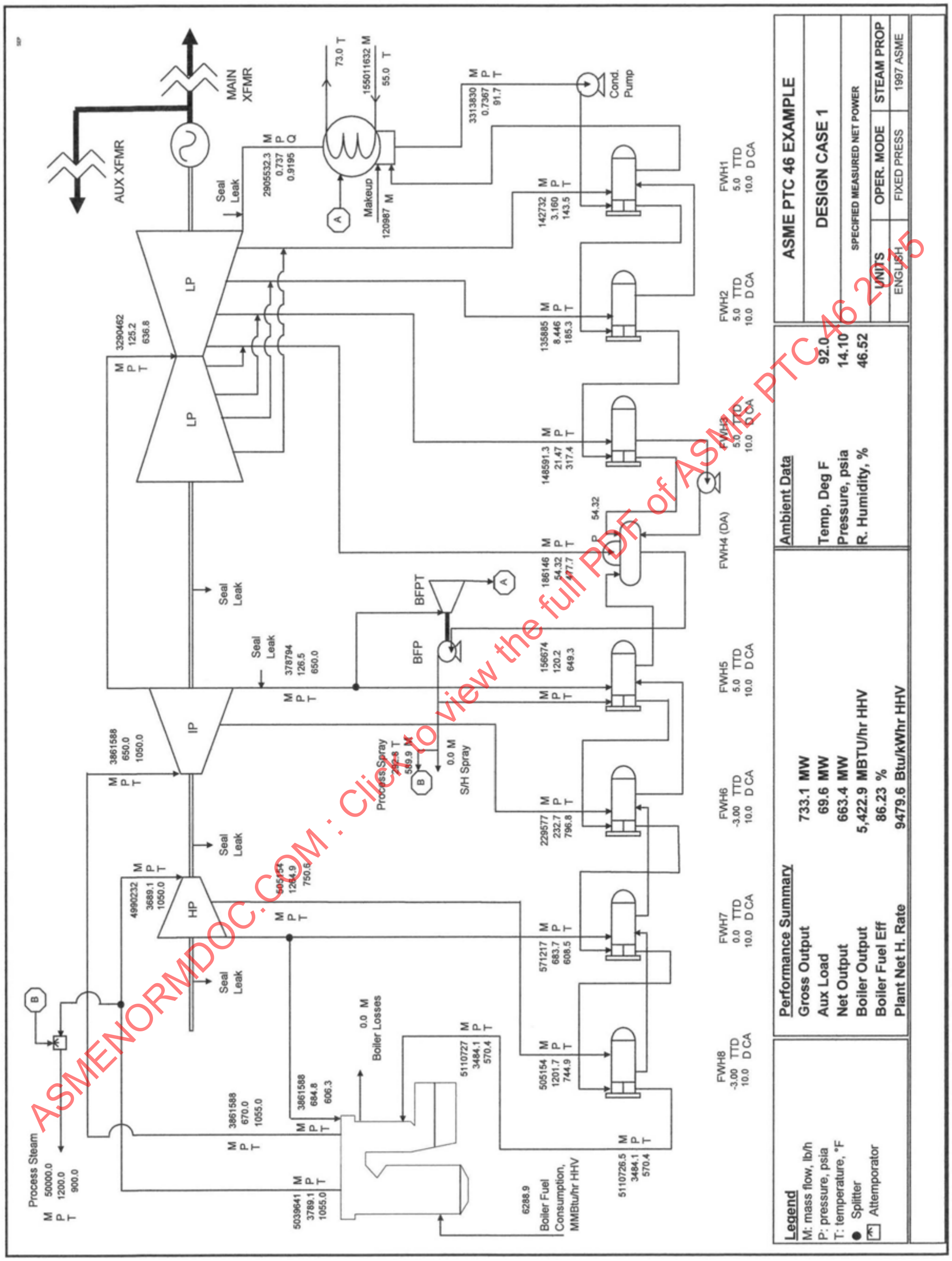


Fig. E-3.5-1M Design Case 1 (SI Units)

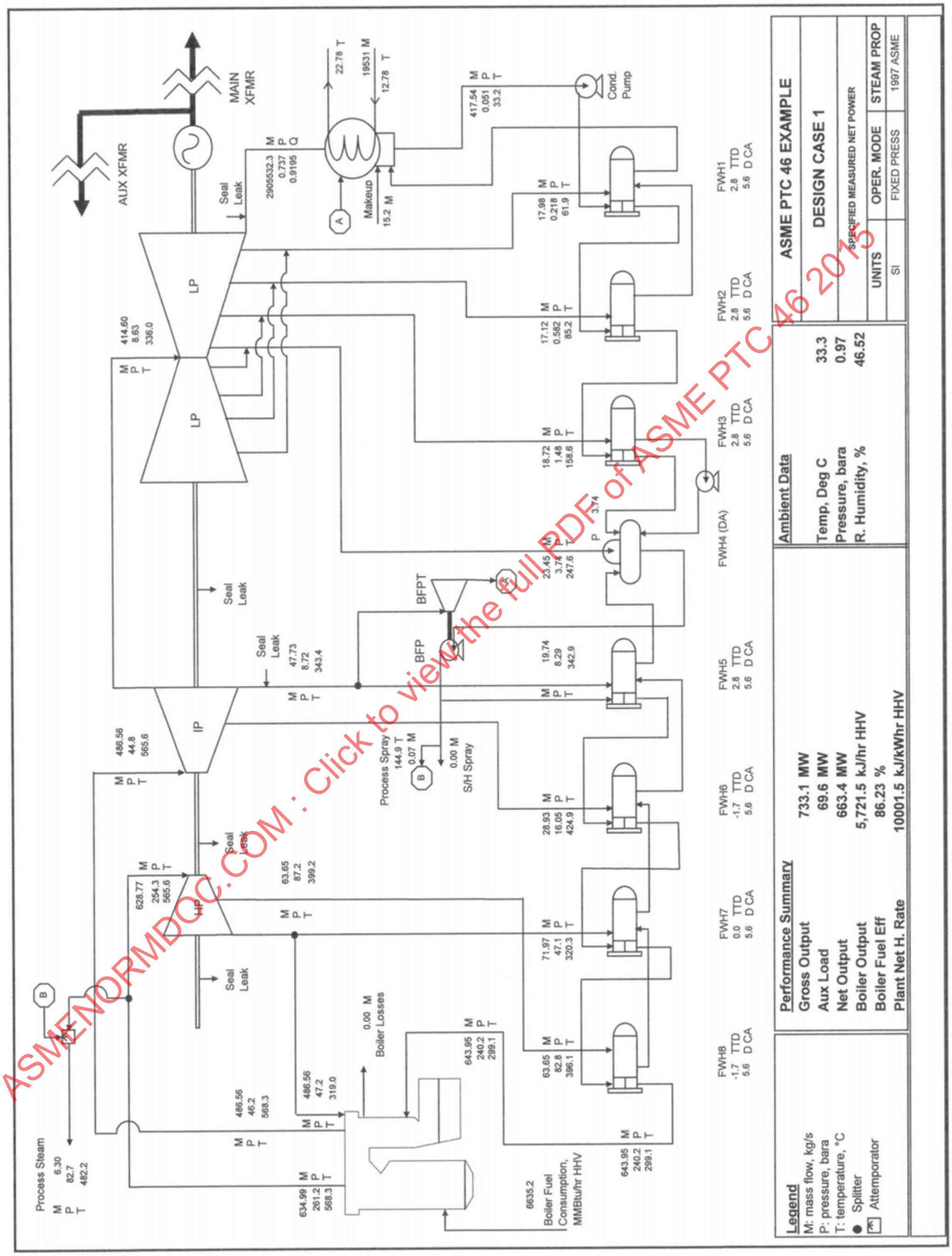


Fig. E-3.5-2 Test Run 1A (U.S. Customary Units)

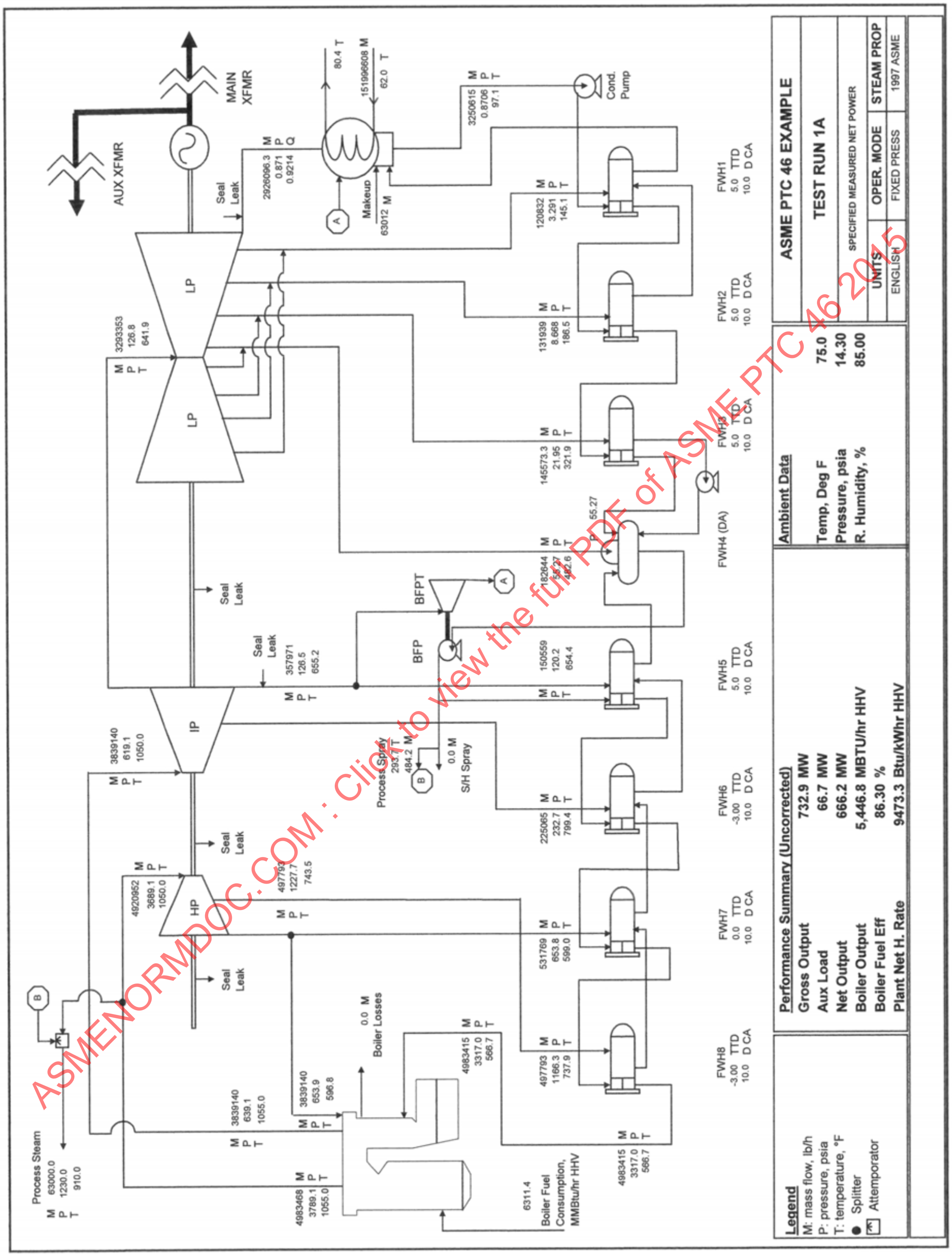


Fig. E-3.5-2M Test Run 1A (SI Units)

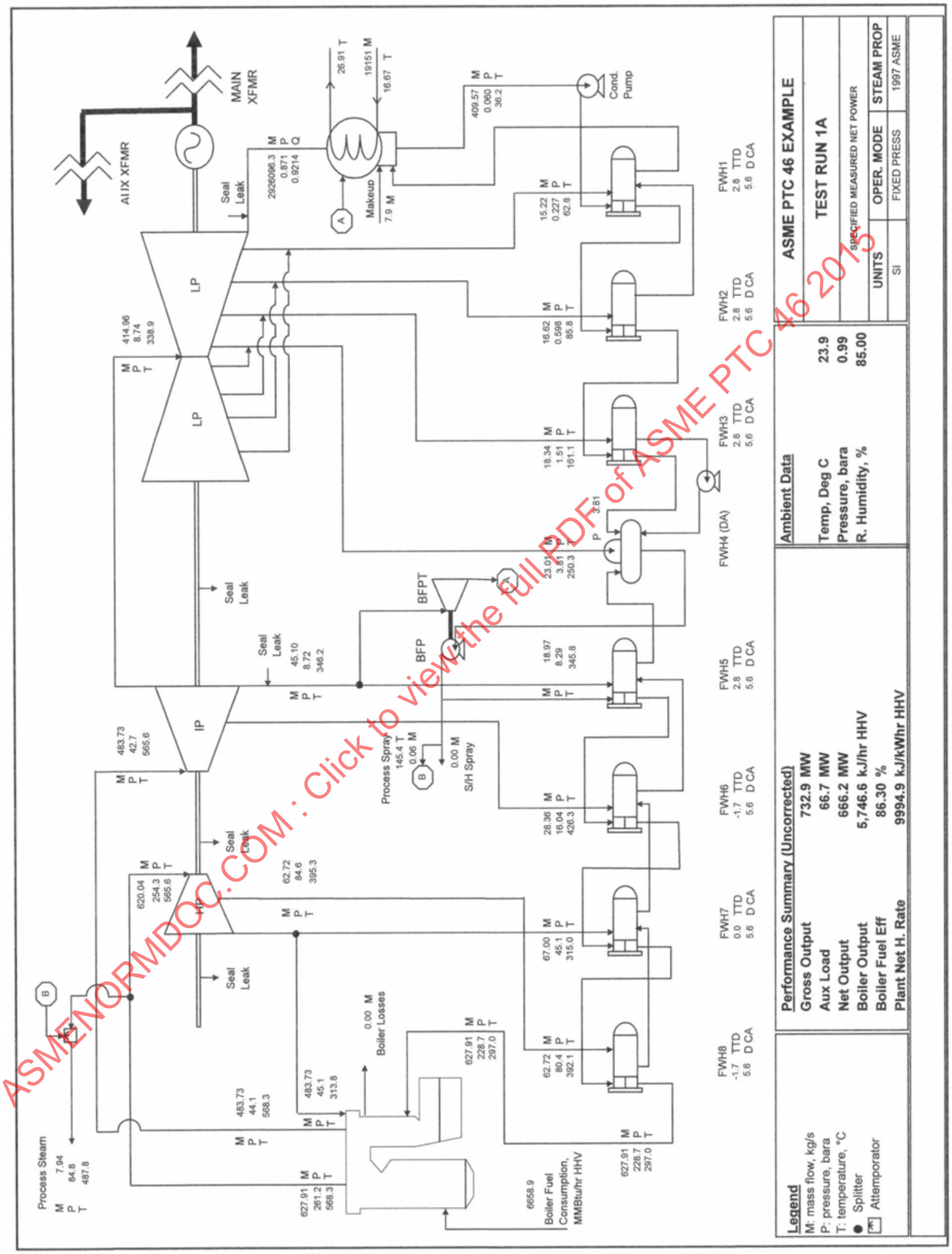


Fig. E-3.5-3 Test Run 1B (U.S. Customary Units)

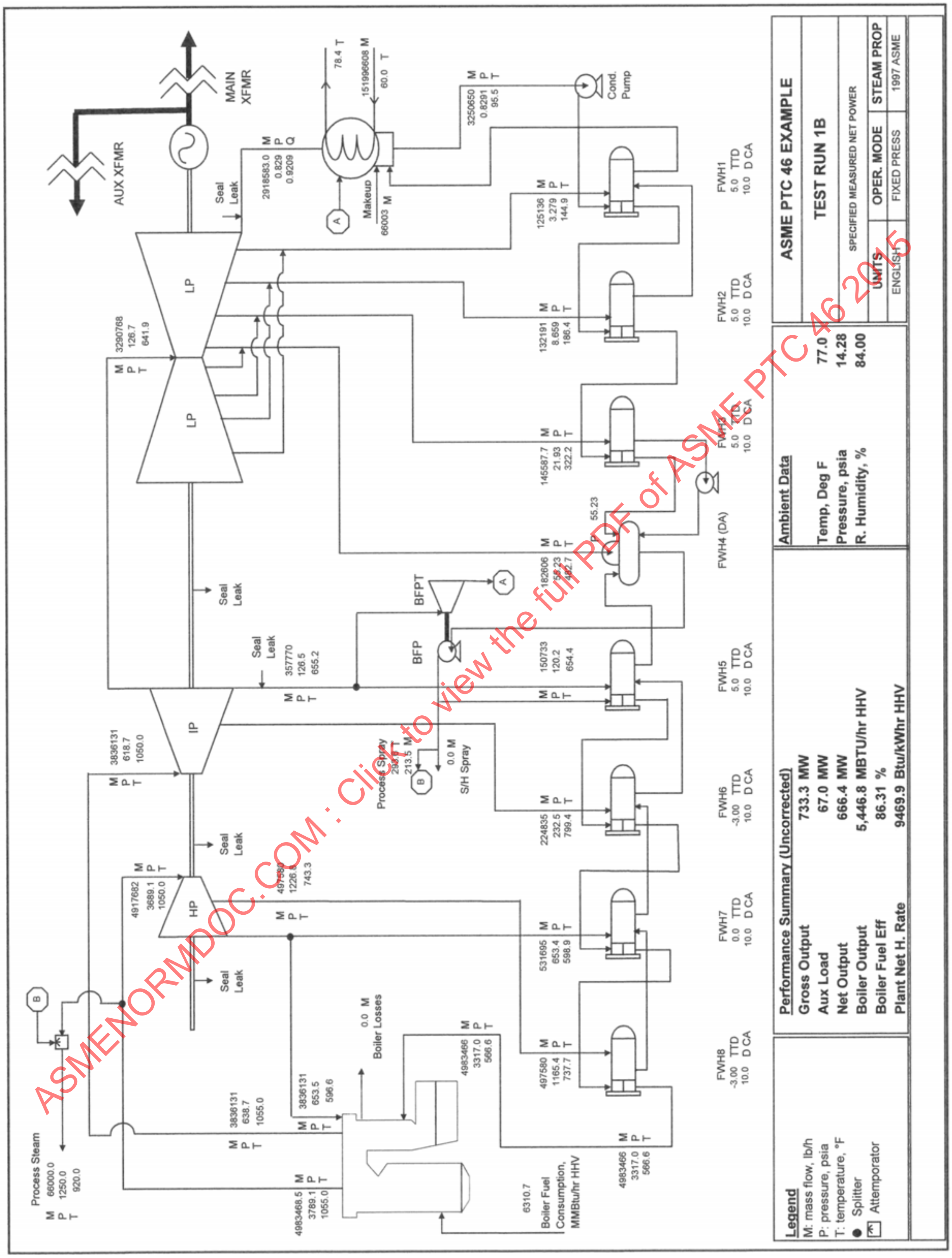
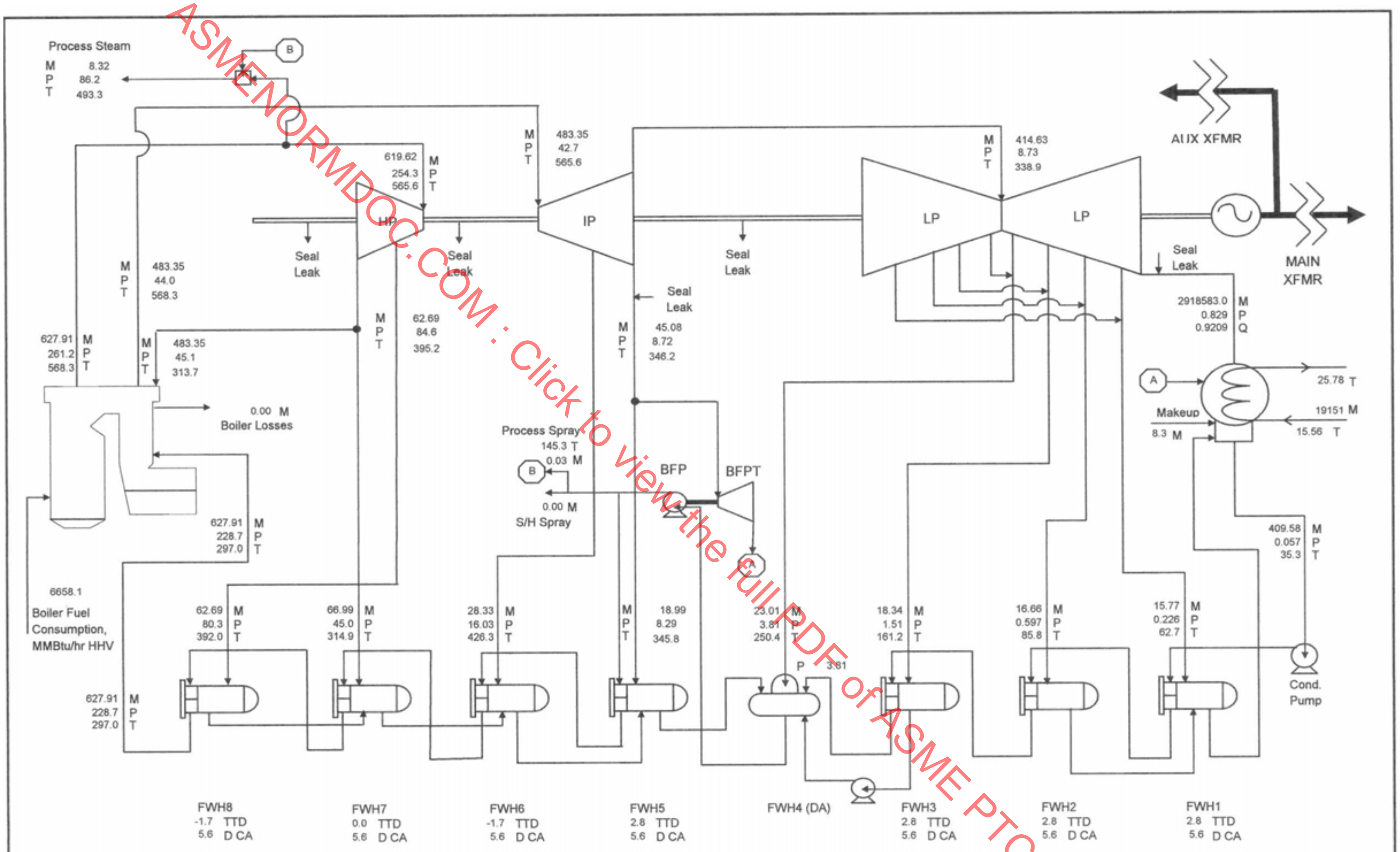


Fig. E-3.5-3M Test Run 1B (SI Units)



Legend
M: mass flow, kg/s
P: pressure, bara
T: temperature, °C
● Splitter
Attemporator

Performance Summary (Uncorrected)

Gross Output	733.3	MW
Aux Load	67.0	MW
Net Output	666.4	MW
Boiler Output	5,746.6	kJ/hr HHV
Boiler Fuel Eff	86.31	%
Plant Net H. Rate	9991.3	kJ/kWhr HHV

Ambient Data

Temp, Deg C	25.0
Pressure, bara	0.98
R. Humidity, %	84.00

ASME PTC 46 EXAMPLE

TEST RUN 1B

SPECIFIED MEASURED NET POWER

UNITS	OPER. MODE	STEAM PROP
SI	FIXED PRESS	1997 ASME

Fig. E-3.5-4 Test Run 1C (U.S. Customary Units)

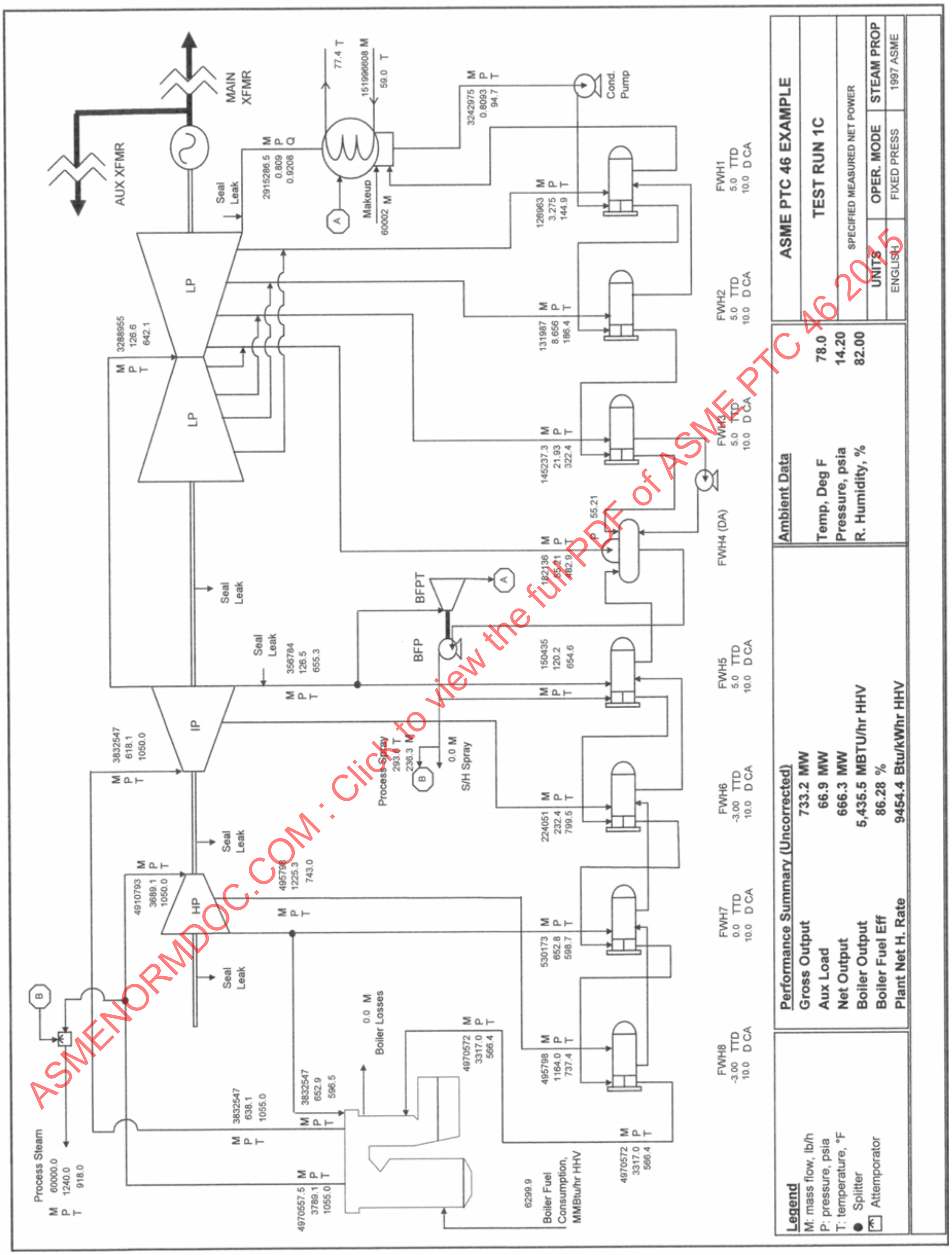


Fig. E-3.5-4M Test Run 1C (SI Units)

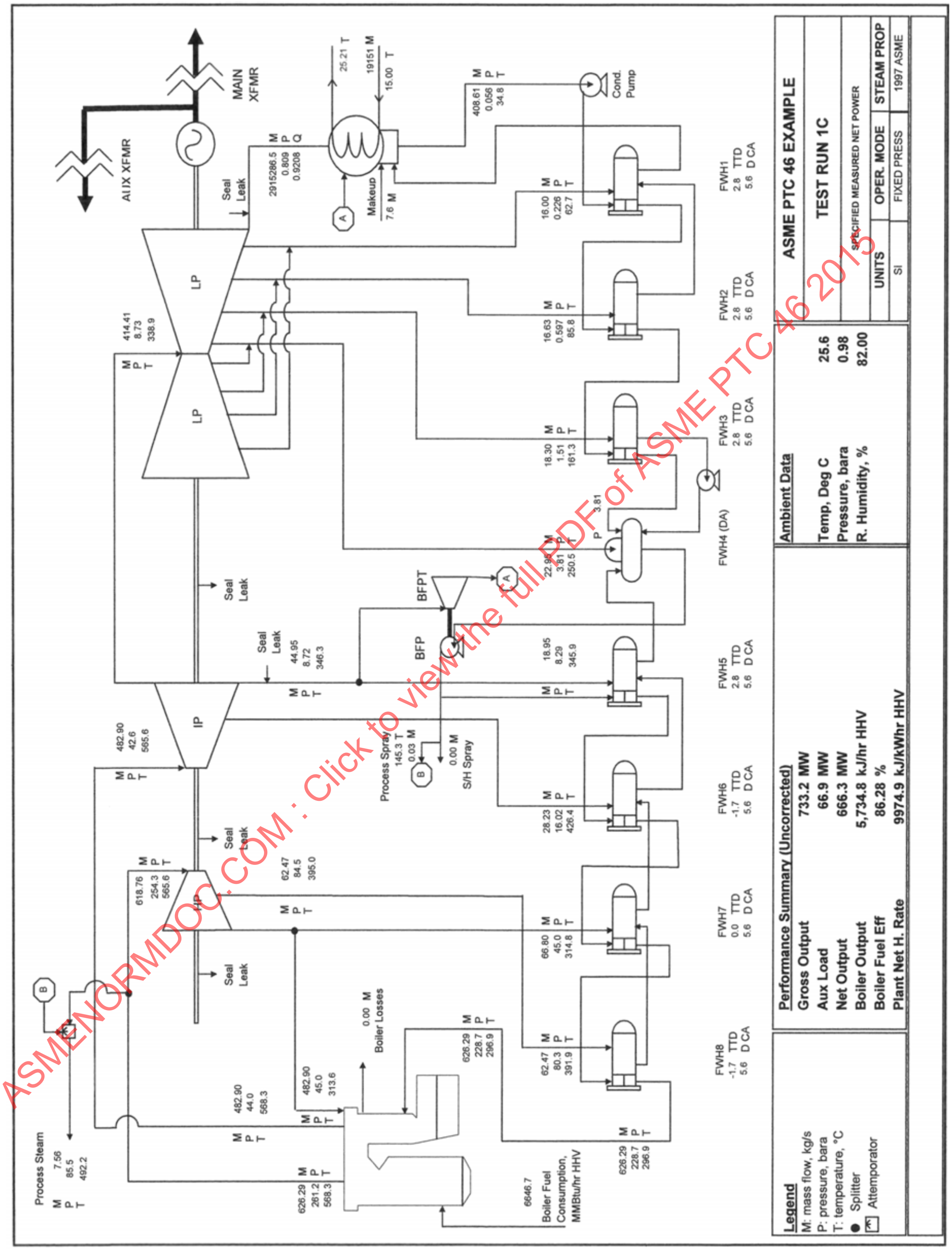


Fig. E-3.5-5 Design Case 2 (U.S. Customary Units)

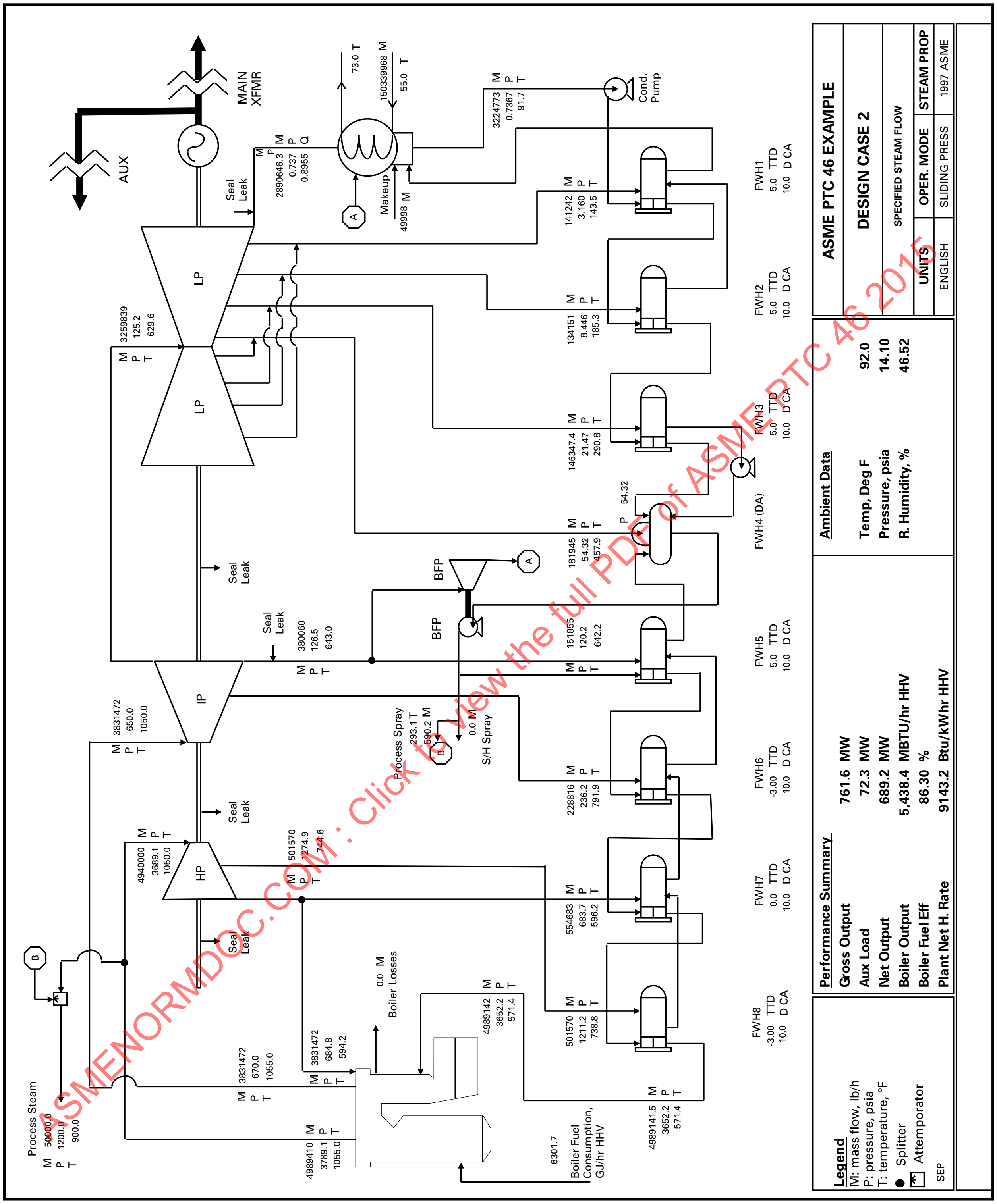


Fig. E-3.5-5M Design Case 2 (SI Units)

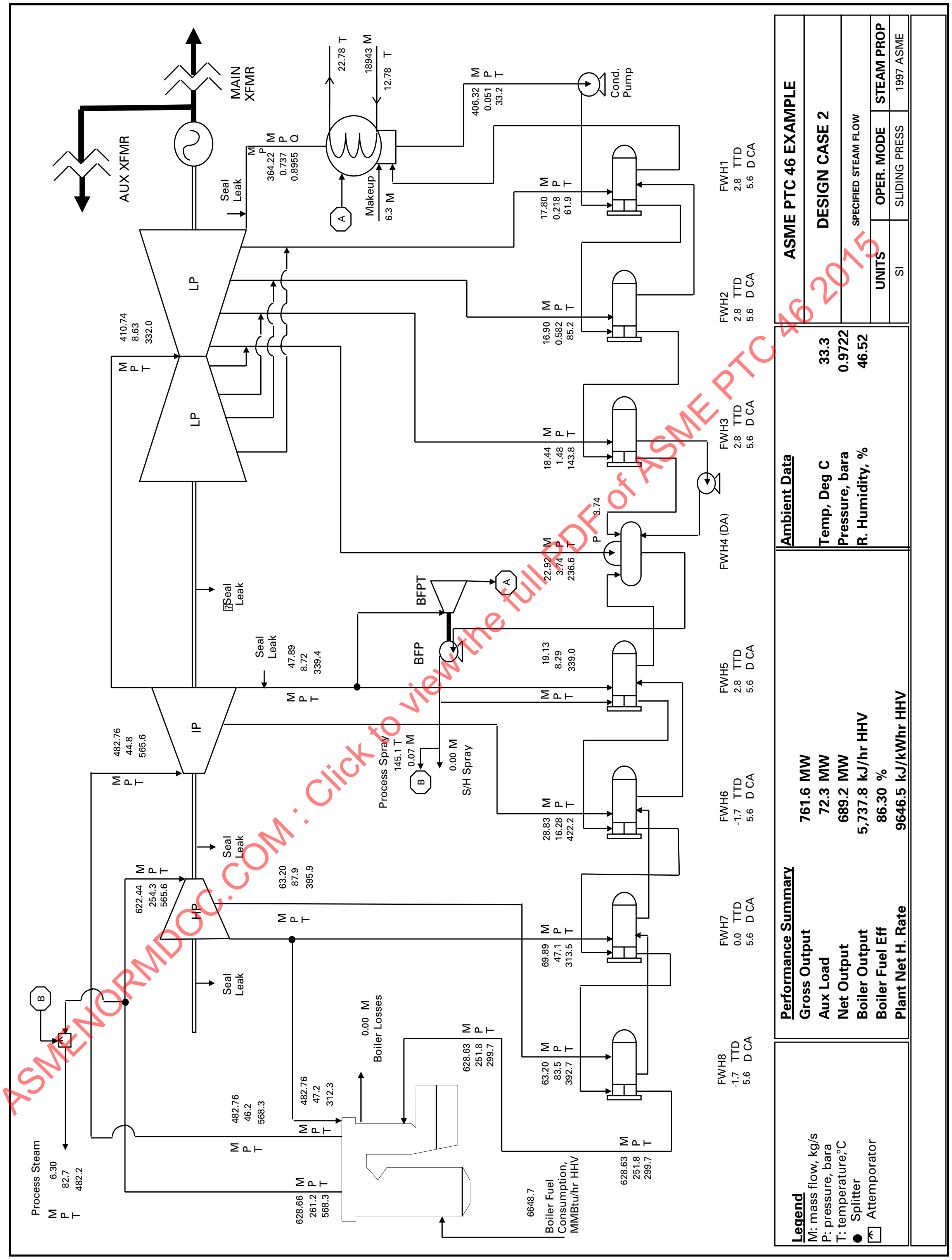


Fig. E-3.5-6 Test Run 2A (U.S. Customary Units)

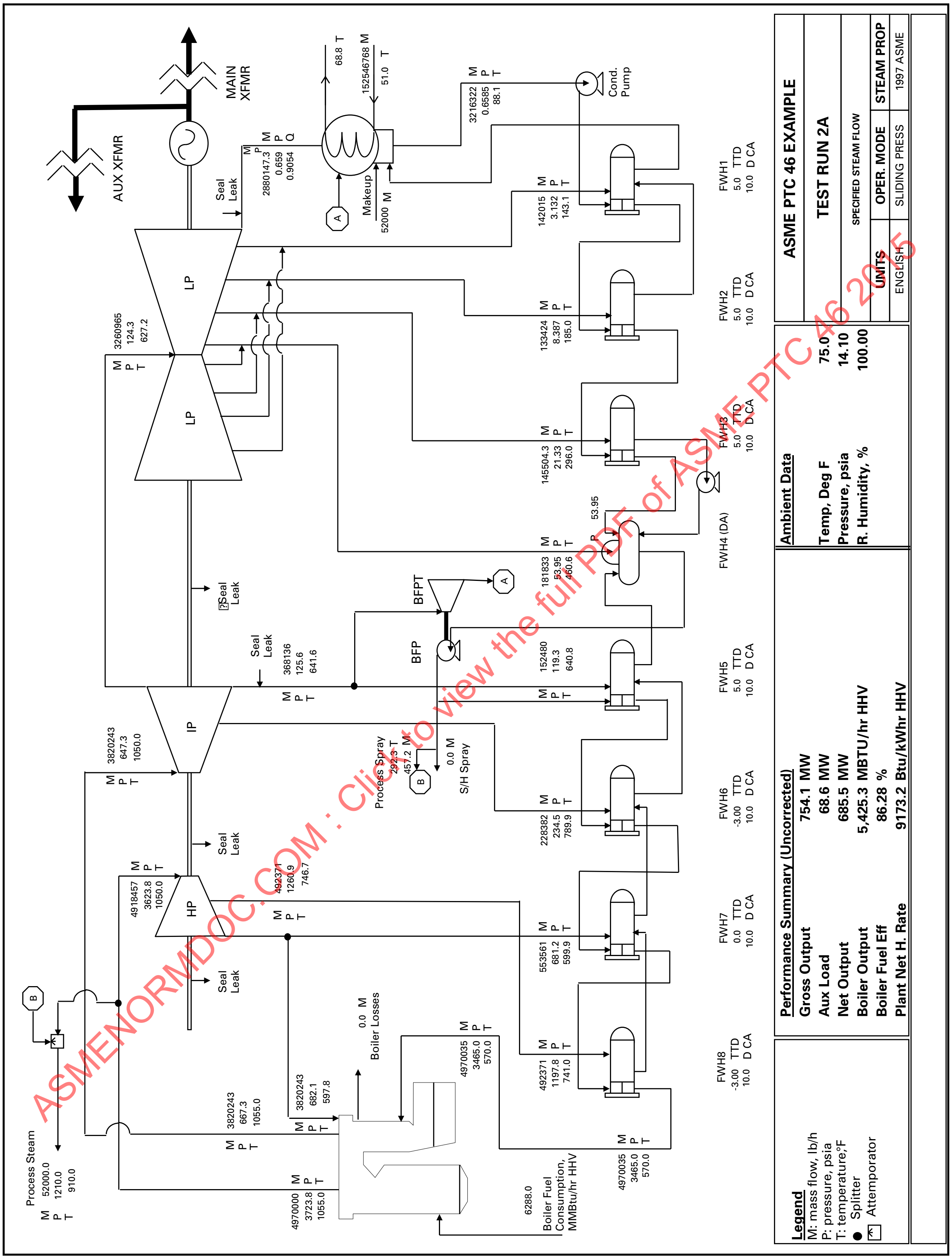


Fig. E-3.5-6M Test Run 2A (SI Units)

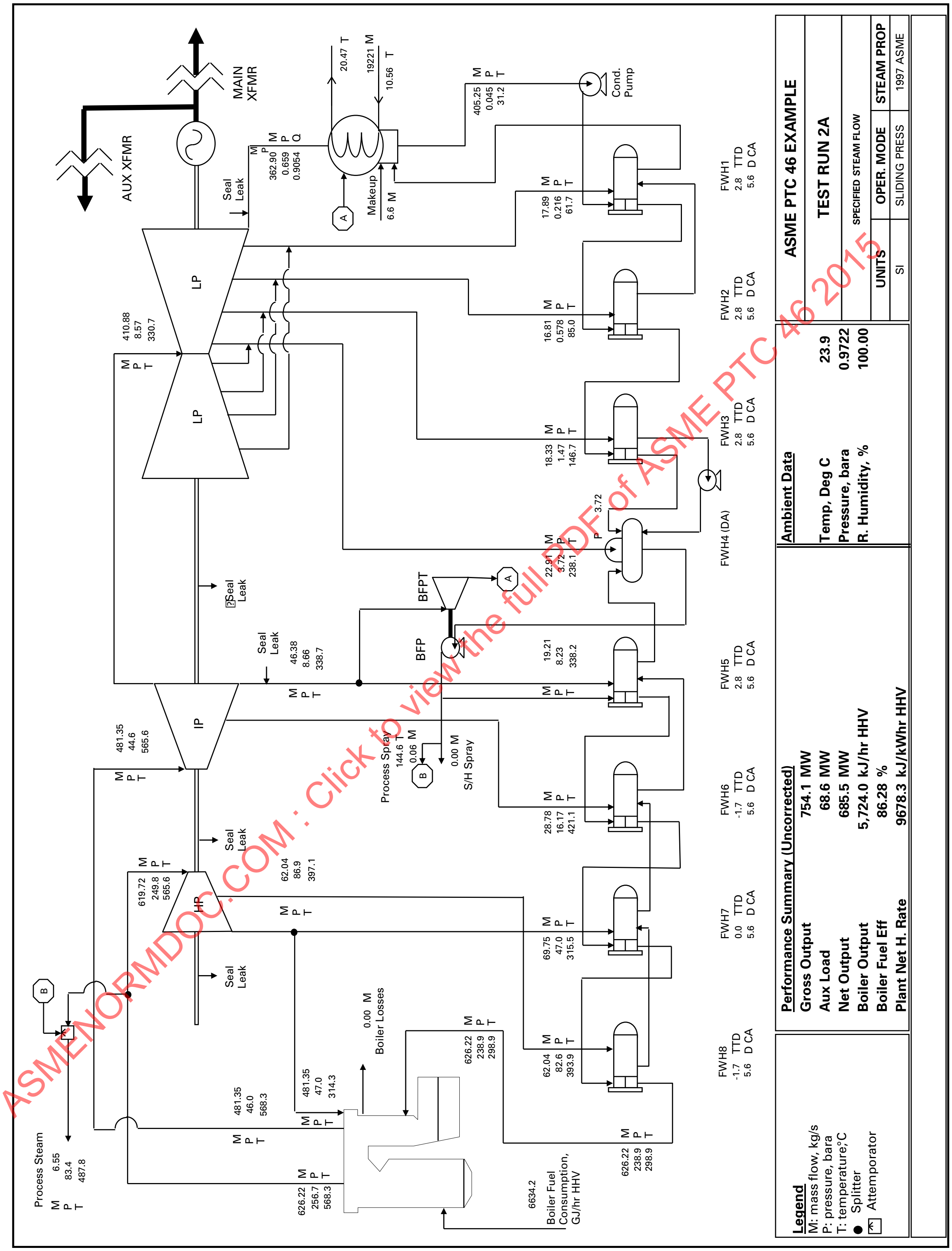


Fig. E-3.5-7 Test Run 2B (U.S. Customary Units)

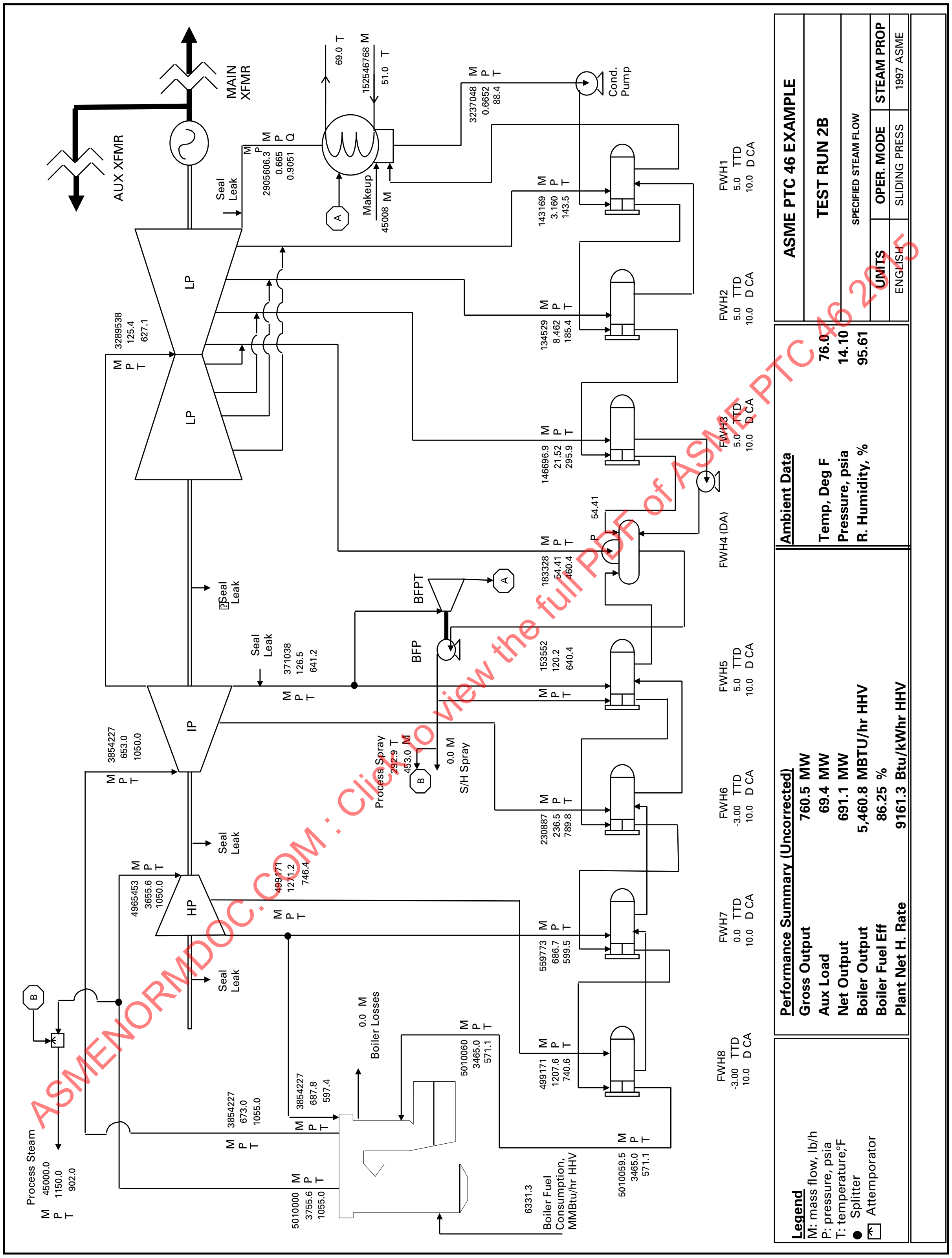


Fig. E-3.5-7M Test Run 2B (SI Units)

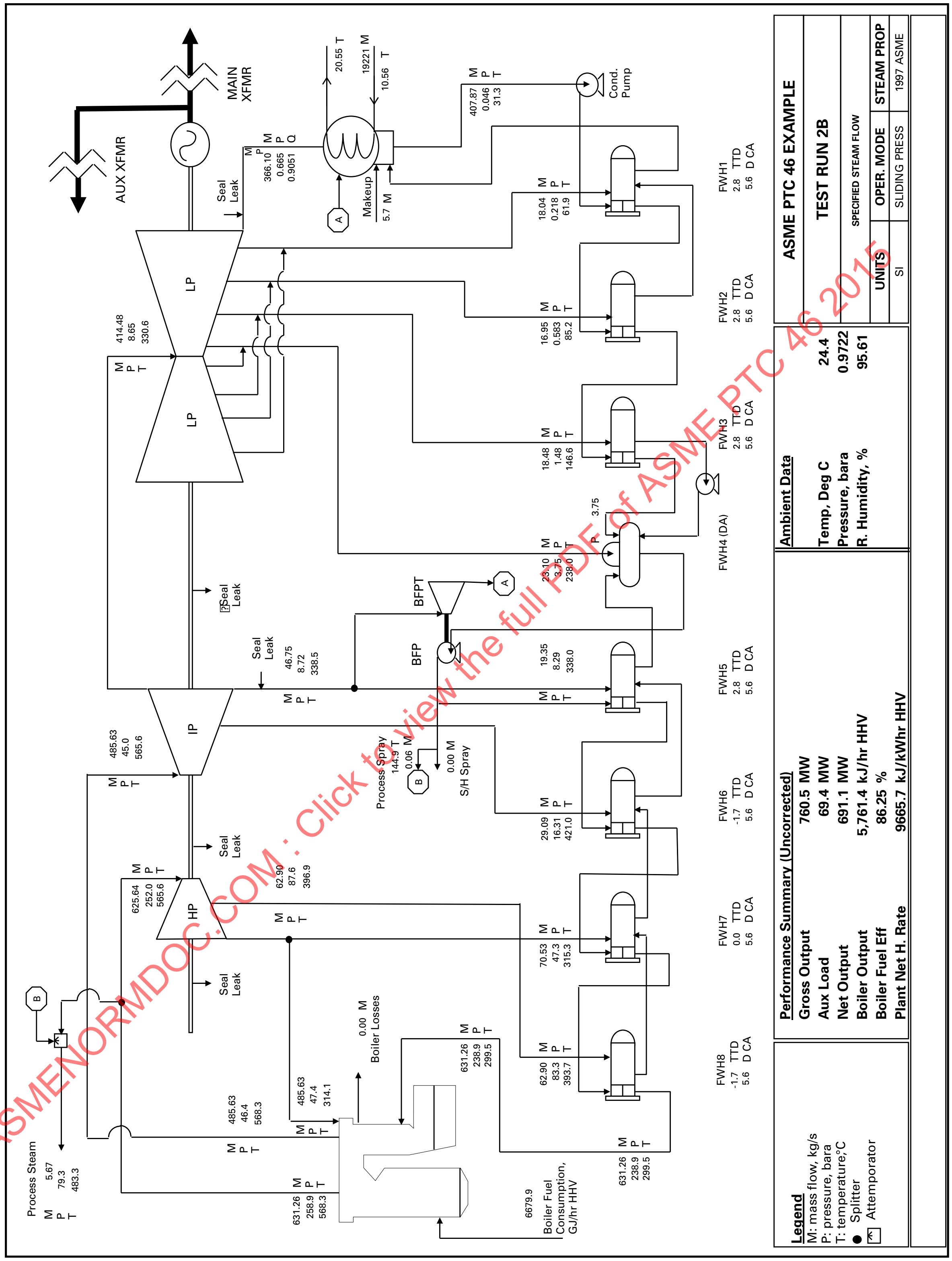


Fig. E-3.5-8 Test Run 2C (U.S. Customary Units)

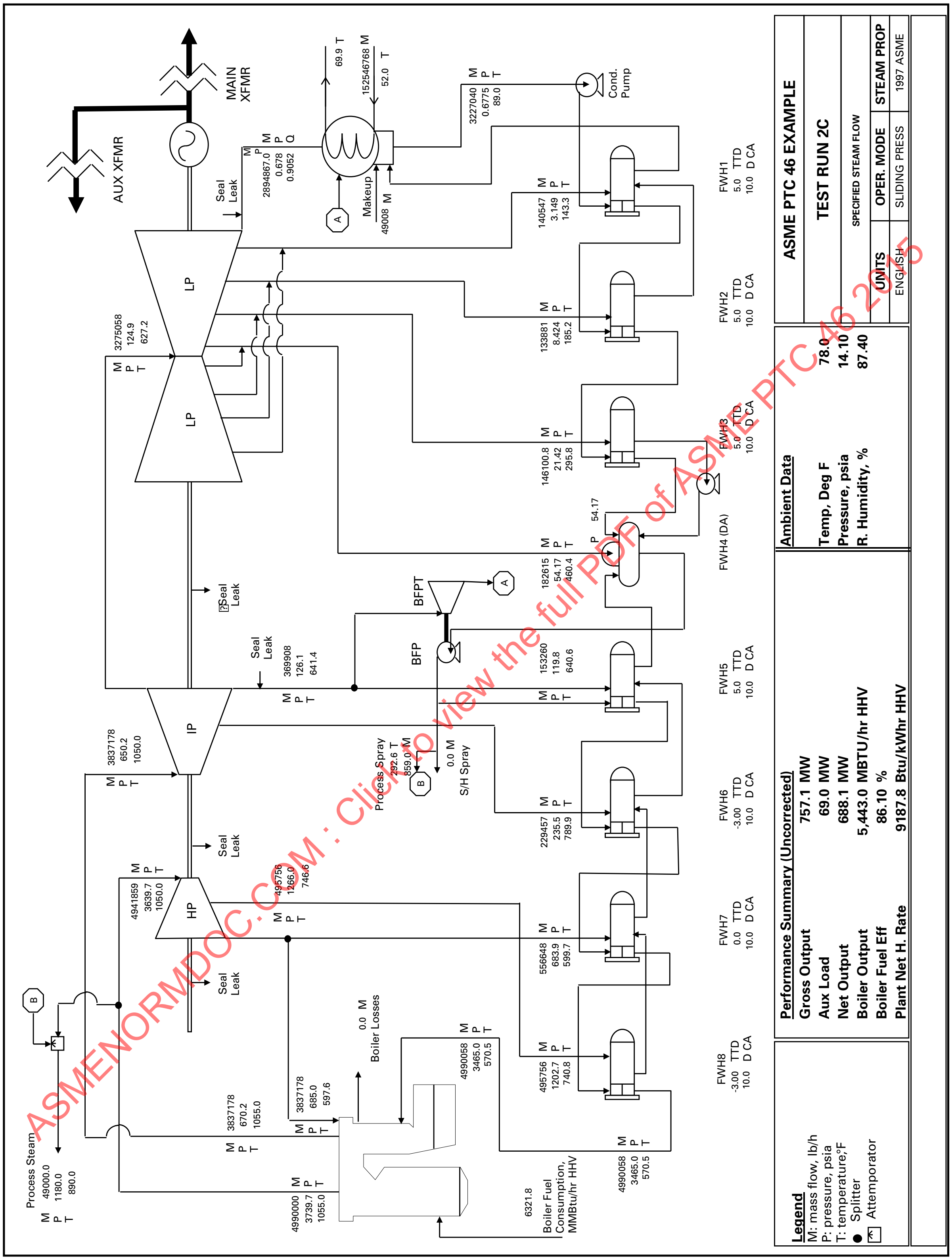
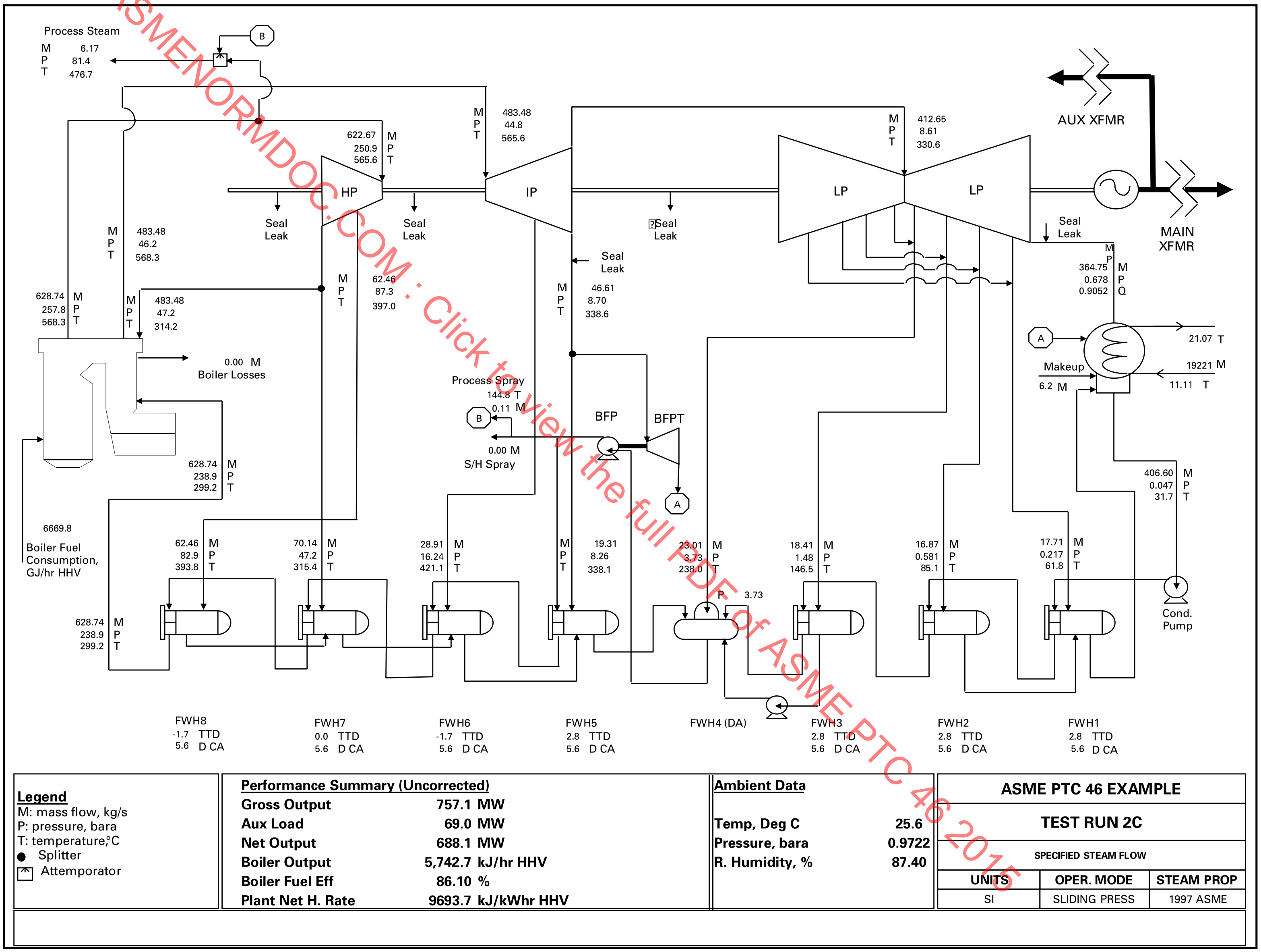


Fig. E-3.5-8M Test Run 2C (SI Units)



NONMANDATORY APPENDIX F
SAMPLE UNCERTAINTY CALCULATION: COMBINED CYCLE PLANT WITHOUT DUCT FIRING

Heat Sink: Air-Cooled Condenser Internal to the Test Boundary
Test Goal: Determine Corrected Net Electrical Output and Corrected Net Heat Rate From Plant Base Load Specified Disposition (Power Floats)

F-1 INTRODUCTION

This Appendix illustrates the calculation of post-test uncertainty for corrected net electrical output and corrected net heat rate for a thermal performance test conducted on a nominal 600 MW 2X2X1 combined cycle plant. The uncertainty calculations are conducted in accordance with ASME PTC 19.1, Measurement Uncertainty. Sample calculations of uncertainty for corrected net electrical output and corrected net heat rate are given. The sample calculations provided herein are based on a specific plant layout, test procedure, test equipment, and test data. Do not apply the sample uncertainties to any other performance test. The user of this Code shall evaluate the uncertainty taking into account the test objective, the calculation method, and the specific measurement methods used for their particular test. The sample calculations are given only to show the methodology by which the uncertainty is calculated for this example. This example, in that it is a post-test uncertainty analysis, will utilize the actual standard deviations (random uncertainty components) and sensitivity coefficients based on the as-tested data. In a pretest uncertainty analysis, these quantities must be estimated based on engineering experience or judgment.

F-2 CYCLE DESCRIPTION AND UNIT DISPOSITION

The plant tested was a 2X2X1 combined cycle plant powered by two nominal 174 MW gas turbines outfitted with dry low NO_x burners and with evaporative cooler inlet conditioning. The gas turbines exhaust into two, triple-pressure, heat recovery steam generators with intermediate pressure feedwater extraction for thermal supply to one natural gas fuel heater. The steam flows generated in the triple-pressure, reheat, heat recovery steam generators (HRSGs) are fed into one, nominal 255 MW, condensing steam turbine. The exhaust steam from the steam turbine is fed to an air-cooled condenser (ACC). There is no supplemental firing capability in the HRSGs.

The test reference conditions were based on fixed unit disposition designated by base loaded gas turbines with evaporative cooler inlet conditioning in service. The test was conducted with the evaporative cooler systems out of service. The evaporative coolers were tested separately in accordance with ASME PTC 51 and the results of the plant test were corrected for actual evaporative cooler as per Nonmandatory Appendix I. This Appendix has been written to demonstrate the special case where evaporative coolers are removed from service and is not intended to contradict para. 5-5.2 which recommends testing with evaporative coolers in service. The steam turbine was set at valves wide open/sliding pressure control. There was no bypass on the HRSG or the steam turbine generator (STG), and the air-cooled condenser fans were set to full speed. Blowdown and makeup were isolated.

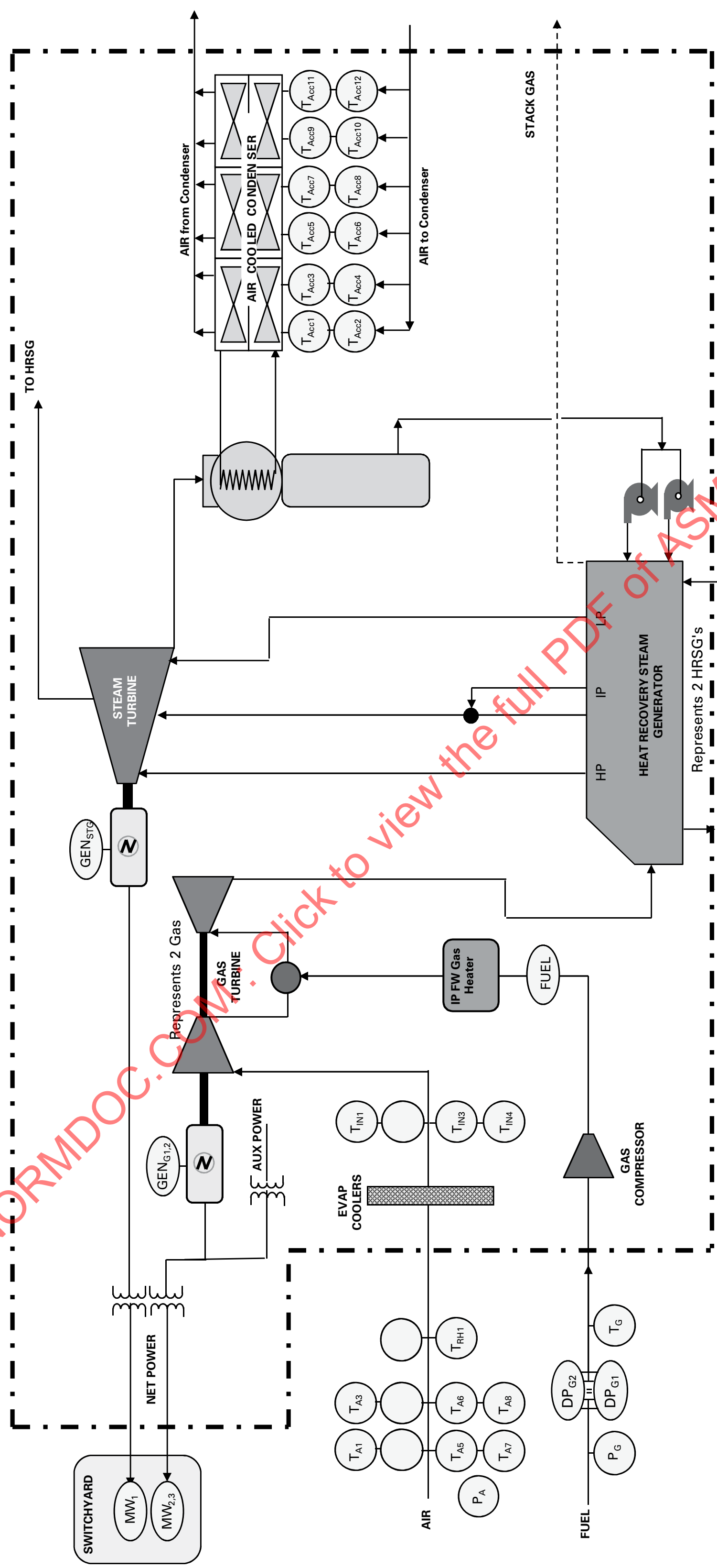
F-3 TEST BOUNDARY DESCRIPTION

The test boundary includes the entire plant, as indicated on the process flow diagram shown in Fig. F-3-1. Air crosses the boundary at the inlets of the gas turbines and the inlet to the condenser. Net plant electrical output of each generator is exported on separate lines. Fuel flow rate is measured at the orifice flowmeter located in the plant fuel flow line near the point at which the fuel crosses the test boundary. The fuel composition and resulting heating value are based on grab samples taken in the plant fuel flow line, also near the point at which the fuel crosses the test boundary, yet downstream of the plant fuel moisture/filter separator unit.

(a) The streams through which energy enters the system include

(1) air for the gas turbines

Fig. F-3-1 Combined Cycle Plant Air-Cooled Condenser-Process Flow Diagram



Primary Measurements:

$MW_{1,2,3}$ - Plant Net Power Outputs
$DP_{G1,G2}$ - Fuel Gas to Plant DP
P_G - Fuel Gas to Plant Press
T_G - Fuel Gas to Plant Temp
$T_{A1\text{-}A8}$ - CTG Ambient Temp
$T_{RH1,2}$ - Ambient Relative Humidity
P_A - CTG Inlet / Ambient Pressure
$T_{Acc1\text{-}Acc12}$ - Air Cooled Condenser Air Inlet Temp
$GEN_{G1,2}$ - CTG Generator MW and MVar
GEN_{ST} - STG Generator MW and MVar
$T_{IN1\text{-}IN4}$ - CTG Inlet Temp (after Evaps)
FUEL - Fuel Samples for Analysis

(2) air for air-cooled condenser
(3) fuel to both gas turbines
(4) makeup water flow

(b) The streams through which energy exits the system include
(1) gas turbine 1 net electrical output
(2) gas turbine 2 net electrical output
(3) steam turbine net electrical output
(4) blowdown
(5) HRSG stack exhaust gas
(6) air from air-cooled condenser

In addition to the streams crossing the boundary, influences outside the boundary that affect the streams that cross the boundary must be addressed. An example of this is Power Factor. Since Power Factor is typically driven by the grid and outside the control of the plant, this influence must be taken into account in the analysis through correction.

F-4 MEASUREMENTS

The testing conducted was implemented utilizing a combination of station and temporary test instrumentation. Table F-4-1 provides a listing of the measurements taken and the number of instruments used to determine the measurements.

F-5 REFERENCE CONDITIONS

The parameters requiring correction and their base reference values are given in Table F-5-1.

F-6 MEASURED CONDITIONS

The plant performance testing consisted of four 30-min test runs. Summaries of the averages for test runs 1, 2, 3, and 4 are given in Tables F-6-1, F-6-2, F-6-3, and F-6-4, respectively.

The evaporative cooler testing consisted of one 60-min test run. The summary of the averages for the evaporative cooler testing are given in Table F-6-5.

F-7 FUNDAMENTAL EQUATIONS AND APPLICABLE CORRECTIONS

For this example, the general equations for corrected net electrical output and for corrected net heat rate are given by

$$P_{corr} = \left(P_{meas} + \sum_{i=1}^{7} \Delta_i\right) \prod_{j=1}^{7} \alpha_j$$

and

$$HR_{corr} = \frac{\left(Q_{meas} + \sum_{i=1}^{7} \omega_i\right)}{\left(P_{meas} + \sum_{i=1}^{7} \Delta_i\right)} \prod_{j=1}^{7} f_j = \frac{(Q_{meas})}{\left(P_{meas} + \sum_{i=1}^{7} \Delta_i\right)} \prod_{j=1}^{7} f_j$$

Since this plant is a combined cycle without duct firing, Section 5 specifies that the additive corrections of either ω_i or Δ_i can be used, but both factors can not be applied. For this example, the additive correction to power was chosen in lieu of the correction to heat input although it is equally valid to perform the latter. Thus, for this example, additive corrections for heat input are not utilized. Tables F-7-1 and F-7-2 provide summaries of additive correction factors and multiplicative correction factors, respectively, applied for this example.

Table F-4-1 Performance Test Measurements and Instruments

Measurement	Instrument Used
Time Data	
CTG 1 fired hours	Gas turbine clock
CTG 2 fired hours	Gas turbine clock
Electrical Data	
CTG 1 net export (high side of transformer)	Revenue meter
CTG 1 power factor (high side of transformer)	Revenue meter
CTG 2 net export (high side of transformer)	Revenue meter
CTG 2 power factor (high side of transformer)	Revenue meter
STG net export (high side of transformer)	Revenue meter
STG power factor (high side of transformer)	Revenue meter
Combustion turbine 1 generator output	Station meter
Combustion turbine 2 generator output	Station meter
Steam turbine generator output	Station meter
Combustion turbine 1 generator reactive power	Station meter
Combustion turbine 2 generator reactive power	Station meter
Steam turbine generator reactive power	Station meter
Ambient/Inlet Data	
CTG 1 compressor inlet temperature	4 thermistors
CTG 2 compressor inlet temperature	4 thermistors
CTG 1 ambient dry bulb temperature	8 thermistors @ filter house
CTG 2 ambient dry bulb temperature	8 thermistors @ filter house
CTG 1 ambient relative humidity	2 RH sensors
CTG 2 ambient relative humidity	2 RH sensors
Barometric pressure	1 test pressure transmitter
ACC inlet dry bulb temperature	12 thermistors with psychrometers
Fuel Flow Data	
Plant fuel supply pressure (gas compressor inlet)	1 test pressure transmitter
Plant fuel flow differential pressure	2 test pressure transmitters
Plant fuel flowing pressure	1 test pressure transmitter
Plant fuel flowing temperature	1 thermistor
Plant fuel flow element pipe I.D.	Laboratory measurement
Plant fuel flow element throat diameter	Laboratory measurement
Fuel Analysis Data	
Methane (xCH_4)	Gas Chromatograph Lab Analysis (300cc Grab Sample)
Ethane (xCH_2)	Gas Chromatograph Lab Analysis (300cc Grab Sample)
Propane (xCH_3)	Gas Chromatograph Lab Analysis (300cc Grab Sample)
Iso-Butane ($xICH_4$)	Gas Chromatograph Lab Analysis (300cc Grab Sample)
N-Butane ($xNCH_4$)	Gas Chromatograph Lab Analysis (300cc Grab Sample)
Iso-Pentane ($xICH_5$)	Gas Chromatograph Lab Analysis (300cc Grab Sample)
N-Pentane ($xNCH_5$)	Gas Chromatograph Lab Analysis (300cc Grab Sample)
N-Hexane (xCH_6)	Gas Chromatograph Lab Analysis (300cc Grab Sample)
N-Heptane (xCH_7)	Gas Chromatograph Lab Analysis (300cc Grab Sample)
N-Octane (xCH_8)	Gas Chromatograph Lab Analysis (300cc Grab Sample)
Nonane (xCH_9)	Gas Chromatograph Lab Analysis (300cc Grab Sample)
Decane (xCH_{10})	Gas Chromatograph Lab Analysis (300cc Grab Sample)
Carbon dioxide (xCO_2)	Gas Chromatograph Lab Analysis (300cc Grab Sample)
Nitrogen (xN_2)	Gas Chromatograph Lab Analysis (300cc Grab Sample)
Oxygen (xO_2)	Gas Chromatograph Lab Analysis (300cc Grab Sample)
Helium (xHe)	Gas Chromatograph Lab Analysis (300cc Grab Sample)
Hydrogen (xH_2)	Gas Chromatograph Lab Analysis (300cc Grab Sample)
Carbon monoxide (xCO)	Gas Chromatograph Lab Analysis (300cc Grab Sample)
Hydrogen sulfide (xH_2S)	Gas Chromatograph Lab Analysis (300cc Grab Sample)
Water (xH_2O)	Gas Chromatograph Lab Analysis (300cc Grab Sample)

Table F-5-1 Performance Reference Conditions

Operating Points	SI Units		U.S. Customary Units	
	Test Value	Units	Test Value	Units
Net plant electrical output	515 000	kW	515,000	kW
Net plant heat rate (LHV)	6638.5	kJ/kWh	6,292.1	Btu/kWh
Ambient dry bulb temperature	14.4	°C	58.0	°F
Ambient relative humidity	53.0	%	53.0	%
Inlet evaporative cooler	On	. . .	On	. . .
Compressor inlet temperature	10.3	°C	50.5	°F
Elevation	3.658	m	12.00	ft
Barometric pressure	1.012	bara	14.68	psia
CTG fired hours	< 200	hr	< 200	hr
CTG Power Factor	0.85 lagging	. . .	0.85 lagging	. . .
STG Power Factor	0.85 lagging	. . .	0.85 lagging	. . .
Fuel supply pressure	13.79	barg	200.0	psig
Fuel supply temperature	25.0	°C	77.0	°F
Nitrogen	0.500	Mole %	0.500	Mole %
Carbon dioxide	0.800	Mole %	0.800	Mole %
Methane	95.032	Mole %	95.032	Mole %
Ethane	2.500	Mole %	2.500	Mole %
Propane	0.800	Mole %	0.800	Mole %
n-Butane	0.102	Mole %	0.102	Mole %
Iso-butane	0.105	Mole %	0.105	Mole %
n-Pentane	0.030	Mole %	0.030	Mole %
Iso-pentane	0.045	Mole %	0.045	Mole %
n-Hexane	0.086	Mole %	0.086	Mole %
Specific volume	1.38	M^3/kg	22.10	SCF/lb
Fuel gas lower heating value (LHV)	48,339	kJ/kg	20,782	Btu/lb
Fuel gas higher heating value (HHV)	53,609	kJ/kg	23,048	Btu/lb
Fuel gas H/C atom ratio	3.895	. . .	3.895	. . .

GENERAL NOTES:
(a) Combustion turbine at base load as defined by the manufacturer's exhaust temperature control curve.
(b) Combustion turbine at new and clean condition as defined by the manufacturer (< 200 fired hr).

Table F-6-1 Performance Test 1 Measured Conditions

Operating Parameters	SI Units: Test Value	SI Units: Units	U.S. Customary Units: Test Value	U.S. Customary Units: Units
Average CTG fired hours	353.9	h	353.9	hr
CTG 1 net export power	158 750	kW	158,750	kW
CTG 2 net export power	163 458	kW	163,458	kW
STG net export power	173 850	kW	173,850	kW
CTG 1 generator output	167.68	MW	167.68	MW
CTG 2 generator output	168.40	MW	168.40	MW
STG generator output	174.04	MW	174.04	MW
CTG 1 generator reactive power	28.09	MVar	28.09	MVar
CTG 2 generator reactive power	27.25	MVar	27.25	MVar
STG generator reactive power	18.47	MVar	18.47	MVar
Inlet evaporative cooler status	Off	. . .	Off	. . .
Ambient dry bulb temperature	16.7	°C	62.0	°F
Ambient relative humidity	77.0	%	77.0	%
Barometric pressure	0.9975	bara	14.468	psia
ACC inlet dry bulb temperature	17.0	°C	62.7	°F
Plant fuel supply pressure (gas compressor inlet)	16.53	barg	239.8	psig
Plant supply fuel flow DP	542.1	cm H_2O	213.4	in. H_2O
Plant supply fuel flow pressure	17.64	bara	255.8	psia
Plant supply fuel flow temperature	16.76	°C	62.16	°F
Nitrogen	0.737	Mole %	0.737	Mole %
Carbon dioxide	0.687	Mole %	0.687	Mole %
Oxygen	0.010	Mole %	0.010	Mole %
Helium	0.020	Mole %	0.020	Mole %
Hydrogen	0.000	Mole %	0.000	Mole %
Methane	96.093	Mole %	96.093	Mole %
Ethane	1.967	Mole %	1.967	Mole %
Propane	0.303	Mole %	0.303	Mole %
n-Butane	0.057	Mole %	0.057	Mole %
Iso-butane	0.077	Mole %	0.077	Mole %
n-Pentane	0.017	Mole %	0.017	Mole %
Iso-pentane	0.030	Mole %	0.030	Mole %
n-Hexane	0.003	Mole %	0.003	Mole %

Table F-6-2 Performance Test 2 Measured Conditions

	SI Units		U.S. Customary Units	
Operating Parameters	Test Value	Units	Test Value	Units
Average CTG fired hours	354.4	h	354.4	hr
CTG 1 net export power	159 563	kW	159,563	kW
CTG 2 net export power	164 210	kW	164,210	kW
STG net export power	174 300	kW	174,300	kW
CTG 1 generator output	167.92	MW	167.92	MW
CTG 2 generator output	168.60	MW	168.60	MW
STG generator output	174.54	MW	174.54	MW
CTG 1 generator reactive power	31.15	MVar	31.15	MVar
CTG 2 generator reactive power	30.25	MVar	30.25	MVar
STG generator reactive power	14.01	MVar	14.01	MVar
Inlet evaporative cooler status	Off	. . .	Off	. . .
Ambient dry bulb temperature	16.8	°C	62.2	°F
Ambient relative humidity	77.0	%	77.0	%
Barometric pressure	0.9984	bara	14.48	psia
ACC inlet dry bulb temperature	17.1	°C	62.8	°F
Plant fuel supply pressure (gas compressor inlet)	16.51	barg	239.4	psig
Plant supply fuel flow dp	545.4	cm H_2O	214.7	in. H_2O
Plant supply fuel flow pressure	17.608	bara	255.38	psia
Plant supply fuel flow temperature	16.6	°C	62.0	°F
Nitrogen	0.753	Mole %	0.753	Mole %
Carbon dioxide	0.693	Mole %	0.693	Mole %
Oxygen	0.010	Mole %	0.010	Mole %
Helium	0.020	Mole %	0.020	Mole %
Hydrogen	0.000	Mole %	0.000	Mole %
Methane	96.067	Mole %	96.067	Mole %
Ethane	1.970	Mole %	1.970	Mole %
Propane	0.327	Mole %	0.327	Mole %
n-Butane	0.067	Mole %	0.067	Mole %
Iso-butane	0.057	Mole %	0.057	Mole %
n-Pentane	0.010	Mole %	0.010	Mole %
Iso-pentane	0.017	Mole %	0.017	Mole %
n-Hexane	0.010	Mole %	0.010	Mole %

Table F-6-3 Performance Test 3 Measured Conditions

Operating Parameters	SI Units Test Value	SI Units Units	U.S. Customary Units Test Value	U.S. Customary Units Units
Average CTG fired hours	354.9	h	354.9	hr
CTG 1 net export power	158 940	kW	158,940	kW
CTG 2 net export power	163 300	kW	163,300	kW
STG net export power	174 190	kW	174,190	kW
CTG 1 generator output	167.28	MW	167.28	MW
CTG 2 generator output	168.14	MW	168.14	MW
STG generator output	173.92	MW	173.92	MW
CTG 1 generator reactive power	32.53	MVar	32.53	MVar
CTG 2 generator reactive power	31.72	MVar	31.72	MVar
STG generator reactive power	16.10	MVar	16.10	MVar
Inlet evaporative cooler status	Off	. . .	Off	. . .
Ambient dry bulb temperature	17.4	°C	63.4	°F
Ambient relative humidity	77.1	%	77.1	%
Barometric pressure	0.9985	bara	14.48	psia
ACC inlet dry bulb temperature	18.1	°C	64.6	°F
Plant fuel supply pressure (gas compressor inlet)	16.50	barg	239.3	psig
Plant supply fuel flow dp	542.3	cm H_2O	213.5	in. H_2O
Plant supply fuel flow pressure	17.60	bara	255.2	psia
Plant supply fuel flow temperature	16.5	°C	61.7	°F
Nitrogen	0.747	Mole %	0.747	Mole %
Carbon dioxide	0.690	Mole %	0.690	Mole %
Oxygen	0.010	Mole %	0.010	Mole %
Helium	0.020	Mole %	0.020	Mole %
Hydrogen	0.003	Mole %	0.003	Mole %
Methane	96.050	Mole %	96.050	Mole %
Ethane	1.980	Mole %	1.980	Mole %
Propane	0.330	Mole %	0.330	Mole %
n-Butane	0.073	Mole %	0.073	Mole %
Iso-butane	0.060	Mole %	0.060	Mole %
n-Pentane	0.010	Mole %	0.010	Mole %
Iso-pentane	0.017	Mole %	0.017	Mole %
n-Hexane	0.010	Mole %	0.010	Mole %

Table F-6-4 Performance Test 4 Measured Conditions

Operating Parameters	SI Units Test Value	SI Units Units	U.S. Customary Units Test Value	U.S. Customary Units Units
Average CTG fired hours	355.4	h	355.4	hr
CTG 1 net export power	158 500	kW	158,500	kW
CTG 2 net export power	163 298	kW	163,298	kW
STG net export power	174 100	kW	174,100	kW
CTG 1 generator output	167.08	MW	167.08	MW
CTG 2 generator output	167.78	MW	167.78	MW
STG generator output	174.18	MW	174.18	MW
CTG 1 generator reactive power	36.21	MVar	36.21	MVar
CTG 2 generator reactive power	35.49	MVar	35.49	MVar
STG generator reactive power	23.57	MVar	23.57	MVar
Inlet evaporative cooler status	Off	. . .	Off	. . .
Ambient dry bulb temperature	17.7	°C	63.8	°F
Ambient relative humidity	77.1	%	77.1	%
Barometric pressure	0.9990	bara	14.489	psia
ACC inlet dry bulb temperature	18.5	°C	65.3	°F
Plant fuel supply pressure (gas compressor inlet)	16.479	barg	239.01	psig
Plant supply fuel flow DP	541.6	cm H_2O	213.2	in. H_2O
Plant supply fuel flow pressure	17.581	bara	254.99	psia
Plant supply fuel flow temperature	16.5	°C	61.6	°F
Nitrogen	0.747	Mole %	0.747	Mole %
Carbon dioxide	0.683	Mole %	0.683	Mole %
Oxygen	0.007	Mole %	0.007	Mole %
Helium	0.020	Mole %	0.020	Mole %
Hydrogen	0.007	Mole %	0.007	Mole %
Methane	96.053	Mole %	96.053	Mole %
Ethane	1.980	Mole %	1.980	Mole %
Propane	0.323	Mole %	0.323	Mole %
n-Butane	0.070	Mole %	0.070	Mole %
Iso-butane	0.067	Mole %	0.067	Mole %
n-Pentane	0.013	Mole %	0.013	Mole %
Iso-pentane	0.020	Mole %	0.020	Mole %
n-Hexane	0.010	Mole %	0.010	Mole %

Table F-6-5 Evaporative Cooler Test Averages

Operating Points	SI Units Test Value	SI Units Units	U.S. Customary Units Test Value	U.S. Customary Units Units
CTG 1 Evaporative Cooler (Design Effectiveness = 85.0%)				
CTG 1 ambient dry bulb temperature	21.4	°C	70.5	°F
CTG 1 ambient relative humidity	55.0	%	55.0	%
CTG 1 ambient wet bulb temperature	15.6	°C	60.1	°F
CTG 1 compressor inlet temperature	16.0	°C	60.8	°F
CTG 1 inlet evaporative cooler operation	On	. . .	On	. . .
CTG 1 barometric pressure	1.0105	bara	14.656	psia
Effectiveness	93.2	%	93.2	%
CTG 2 Evaporative Cooler (Design Effectiveness = 85.0%)				
CTG 2 ambient dry bulb temperature	21.1	°C	70.0	°F
CTG 2 ambient relative humidity	55.0	%	55.0	%
CTG 2 ambient wet bulb temperature	15.3	°C	59.6	°F
CTG 2 compressor inlet temperature	15.7	°C	60.3	°F
CTG 2 inlet evaporative cooler operation	On	. . .	On	. . .
CTG 2 barometric pressure	1.0105	bara	14.656	psia
Effectiveness	93.7	%	93.7	%

Table F-7-1 Summary of Additive Correction Factors

Additive Correction to Power	Required (Yes/No)	Correction	Comments
Δ_1	No	Thermal efflux	There was no thermal efflux stream for this test. Thus, $\Delta_1 = 0$
Δ_2	Yes	Power Factor	Δ_2 = Additive Correction for Power Factor at each generator terminal = $\Delta_{2a} + \Delta_{2b} + \Delta_{2c}$ where Δ_{2a} = Power Factor correction for combustion turbine generator # 1 Δ_{2b} = Power Factor correction for combustion turbine generator # 2 Δ_{2c} = Power Factor correction for the steam turbine generator
Δ_3	No	Steam generator(s) blowdown different than design	BD was isolated so that the actual flow rate exactly matched the design BD flow rate. Thus, $\Delta_3 = 0$.
Δ_4	No	Secondary heat inputs	This plant was not equipped with any process returns and makeup was isolated. Thus, $\Delta_4 = 0$.
Δ_{5A}	Yes	Inlet air conditions, cooling tower, or air-cooled heat exchanger air inlet	Inlet air conditions at the gas turbines and air-cooled condenser were monitored during the test.
Δ_{5B}	No	Circulating water temperature different than design	Plant was equipped with an air-cooled condenser, so the plant is without a circulating water system. Thus, $\Delta_{5B} = 0$.
Δ_{5C}	No	Condenser pressure	The entire heat rejection system is inside the test boundary. Thus, $\Delta_{5C} = 0$.
Δ_6	Yes	Auxiliary loads, thermal and electrical	Two primary components to the Δ_6 correction will be as follows: (1) ACC fan operation different from design (2) gas compressor load different from design.
Δ_7	No	Measured power different than specified if test goal is to operate at a predetermined power, or operating disposition slightly different than required if a specified disposition test	The goal of the test was not specified disposition. Thus, $\Delta_7 = 0$.

Table F-7-2 Summary of Multiplicative Correction Factors

Multiplicative Correction to Power	Multiplicative Correction to Heat Rate	Required (Yes/No)	Correction	Comments
α_1	f_1	Yes	Inlet temperature correction	Measured at the filter house inlets of the gas turbines and around the inlet to the air-cooled condenser.
α_2	f_2	Yes	Inlet air pressure correction	Measured at the centerline of the gas turbines.
α_3	f_3	Yes	Inlet air humidity	Measured at the filter house inlets of the gas turbines.
α_4	f_4	Yes	Fuel supply temperature correction	Fuel supply temperature was near design and treated as negligible. Thus, $\alpha_4 = f_4 = 1.000$ (Unity)
α_5	f_5	Yes	Correction due to fuel analysis different than design	Measured at the boundary of the plant.
α_6	f_6	No	Grid frequency (external)	This was not considered under this example. $F_6 = 1.000$ (Unity)
α_{7a}	f_{7a}	Yes	Evaporative cooler operation	This correction was added to correct to the design basis of evaporative cooler in operation with 85% effectiveness since the test was conducted with the evaporative cooler out of operation.
α_{7b}	f_{7b}	Yes	Evaporative cooler operation	This correction was added to correct for actual evaporative cooler performance.

F-8 CORRECTION CURVES AND POLYNOMIAL EQUATIONS

For this example, a series of heat balances were run with a heat balance program in order to determine the performance test corrections. These corrections are presented in plotted curve form in Figs. F-8-1 and F-8-1M through F-8-12 and F-8-12M. Tables F-8-1 and F-8-2 provide summaries of the third order polynomial coefficients for each correction.

The correction curves for α_1 through α_6 and f_1 through f_6 were generated with the evaporative cooler out of service. Additional correction factors (α_{7a} and f_{7a}) were applied to account for the operational status of the 85.0% effective evaporative coolers.

The following multiplicative corrections were applied to account for the evaporative coolers being out of service during the test:

(a) *Multiplicative Correction Factor to Output*

$$\alpha_{7a} = 1.01506$$

(b) *Multiplicative Correction Factor to Heat Rate*

$$f_{7a} = 1.00027$$

Additional corrections for electrical output (α_{7b}) and heat rate (f_{7b}) were applied in this example to correct for the actual performance of the evaporative cooler determined by a separate evaporative cooler test.

F-9 SAMPLE CALCULATIONS AND CORRECTED TEST RESULT

Tables F-9-1 and F-9-2 provide summaries of the averaged test measured parameters, summaries of the corrections applied, and the resulting corrected net power and corrected net heat rate for all four tests.

F-10 UNCERTAINTY ANALYSIS APPROACH

The uncertainty analysis presented herein categorizes the uncertainty in a measurement as either uncertainty due to random error or uncertainty due to systematic error. Uncertainty due to systematic error is further divided into instrument systematic uncertainty and spatial systematic uncertainty. Correlation between instruments or elemental uncertainty sources of instruments must be accounted for in the instrument systematic uncertainty. Spatial systematic uncertainty of a measurement must be accounted for when the parameter being measured varies in space.

Subsections F-12 through F-17 identify and categorize sources of instrument systematic uncertainty for each measurement instrument that recorded data used in the calculation of the test result. Subsection F-21 illustrates the calculation of the spatial systematic uncertainty. Subsection F-24 describes the determination of the random uncertainty. Correlated systematic uncertainty is discussed in subsection F-26.

These measurement uncertainties are then propagated through the data reduction and analysis process to determine the uncertainties associated with corrected net electrical output and corrected net heat rate. All uncertainty quantities presented herein are on a 95% confidence level. ASME PTC 19.1 has introduced the concept of standard uncertainty and expanded uncertainty, where standard uncertainty is uncertainty stated on a single standard deviation of the average basis, and expanded uncertainty is on the 95% confidence basis. This example skips the step of combining element uncertainties on a standard basis and then converting to the 95% basis by presenting all elemental uncertainties on a 95% confidence basis.

F-11 UNCERTAINTY ANALYSIS GENERAL EQUATIONS AND TERMS

The following general equations and terms are utilized within this example.

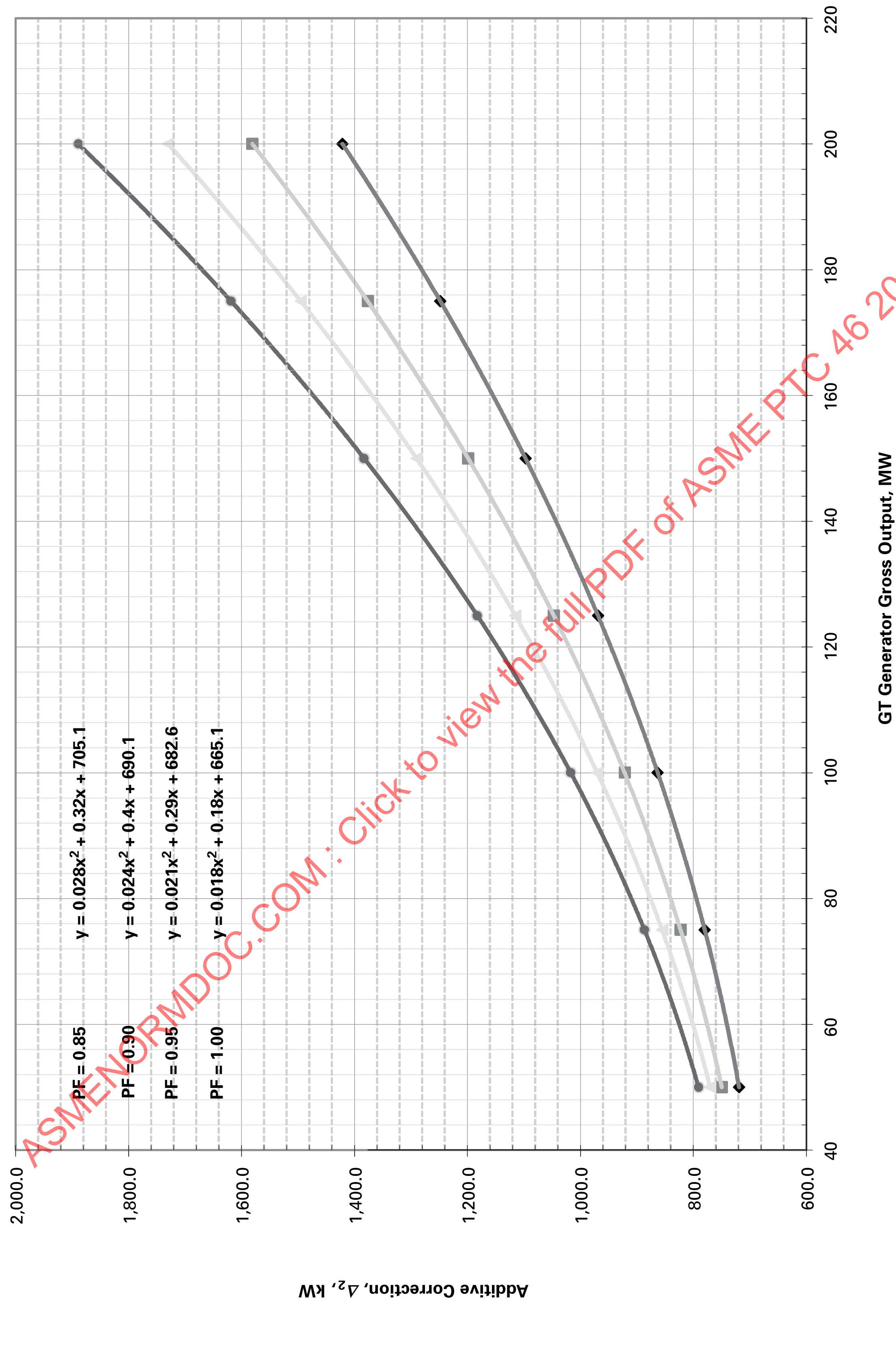
B_{inst} = instrument systematic uncertainty. The value of this term is equal to the root-sum-square of the elemental systematic uncertainty sources for the instrument.

$B_{spatial}$ = spatial systematic uncertainty. The value of this term is calculated from actual test data for those measurements that typically exhibit spatial variation.

$U_{95,SYS}$ = overall systematic uncertainty of the measurement at 95% confidence. The value of this term is equal to the root-sum-square of B_{inst} and $B_{spatial}$.

$$U_{95,SYS} = \sqrt{B_{inst}^2 + B_{spatial}^2}$$

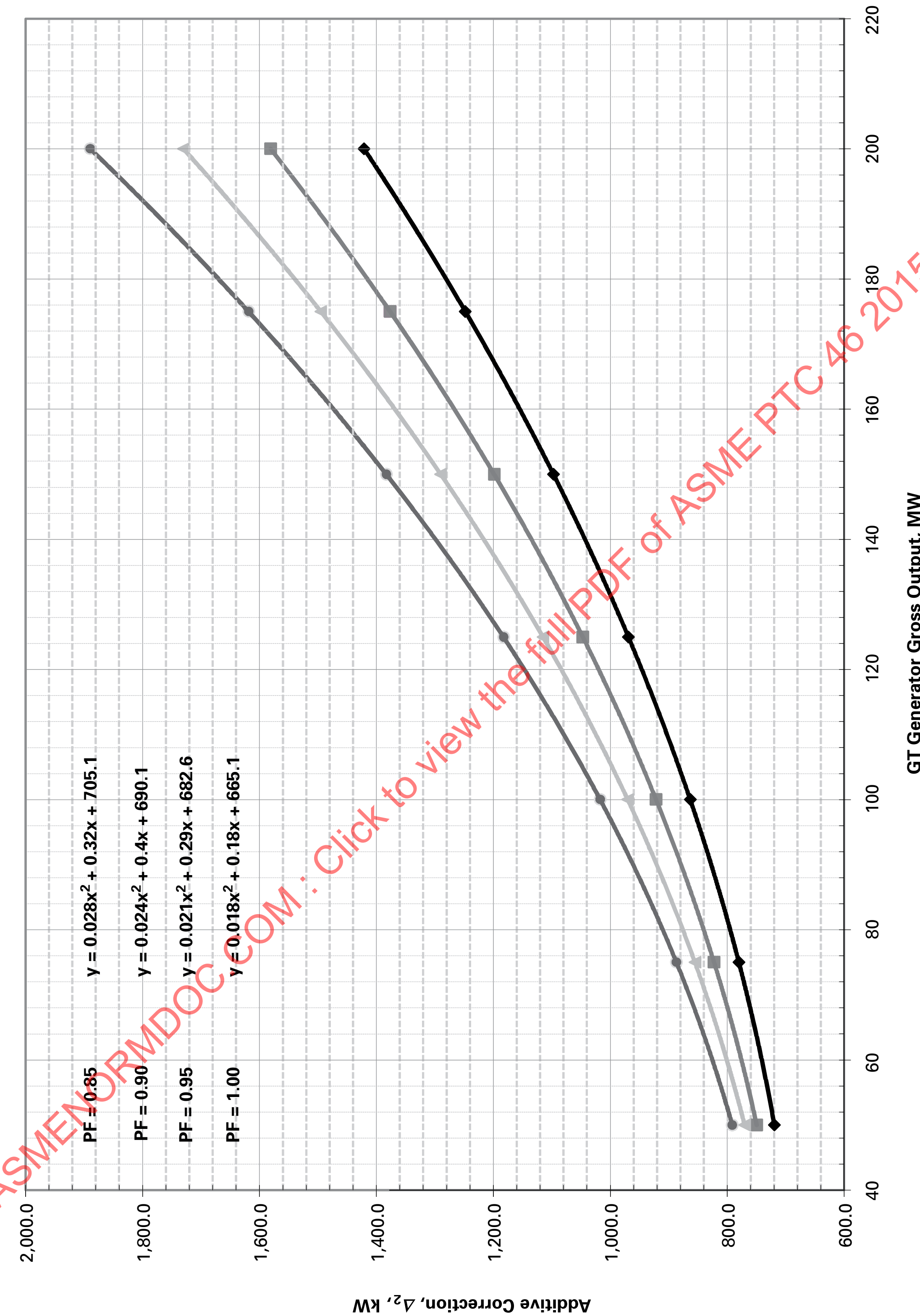
Fig. F-8-1 Correction to Power for Gas Turbine Generator Power Factor (U.S. Customary Units)



LEGEND: ◆ PF = 1.00 ■ PF = 0.95 ▲ PF = 0.90 ● PF = 0.85

GENERAL NOTE: Design dry bulb = 58°F, RH = 53%, Design CIT = 50.5°F, Evaporative cooler off, Design barometric = 14.68 psia.

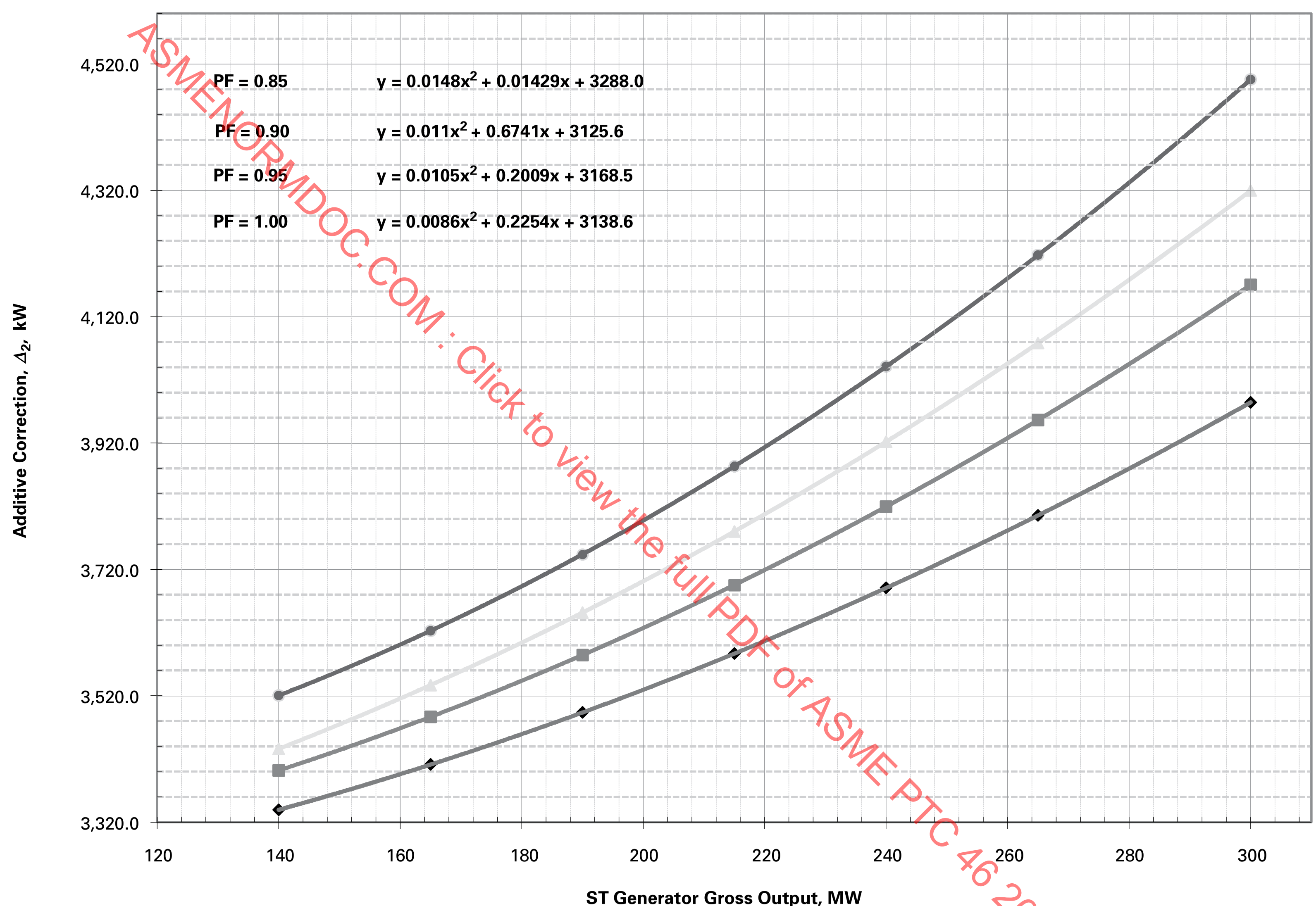
Fig. F-8-1M Correction to Power for Gas Turbine Generator Power Factor (SI Units)



LEGEND: ◆ PF = 1.00 ■ PF = 0.95 ▲ PF = 0.90 ● PF = 0.85

GENERAL NOTE: Design dry bulb = 14.44°C, RH = 53%, Design CIT = 10.28°C, Evaporative cooler off, Design barometric = 1.012 bar.

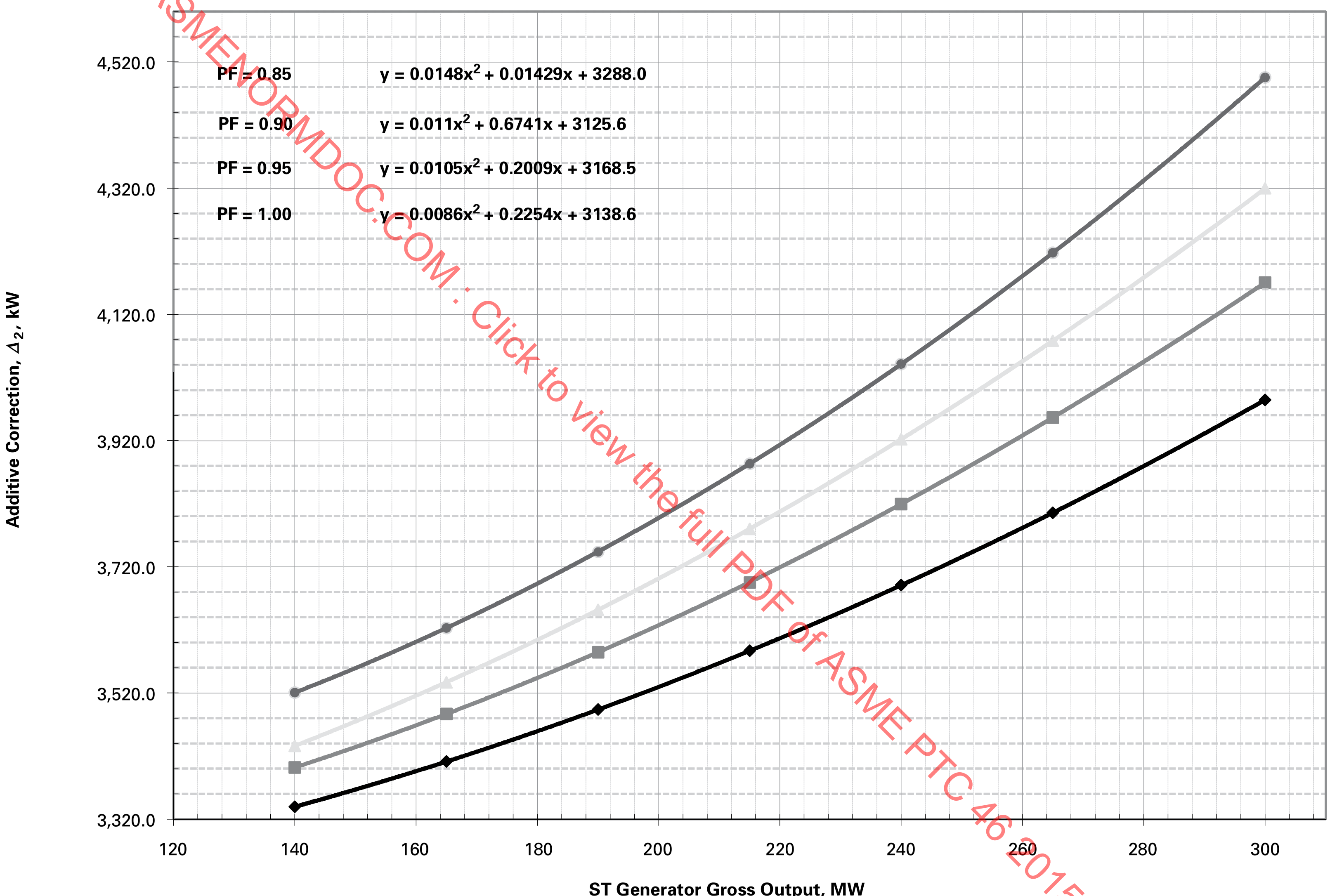
Fig. F-8-2 Correction to Power for Steam Turbine Generator Power Factor (U.S. Customary Units)



LEGEND: ◆ PF = 1.00 ■ PF = 0.95 ▲ PF = 0.90 ● PF = 0.85

GENERAL NOTE: Design dry bulb = 58°F, RH = 53%, Design CIT = 50.5°F, Evaporative cooler off, Design barometric = 14.68 psia.

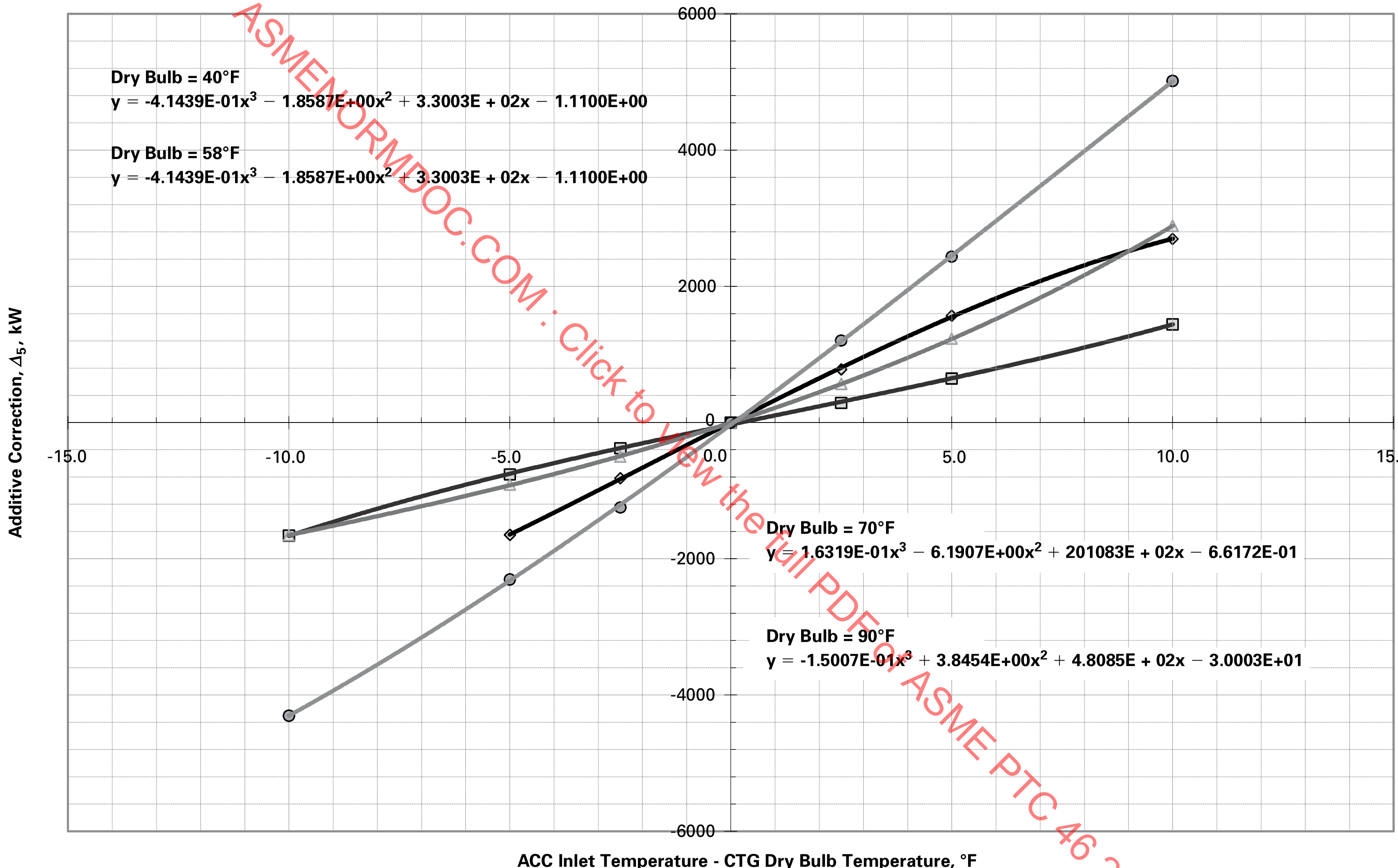
Fig. F-8-2M Correction to Power for Steam Turbine Generator Power Factor (SI Units)



LEGEND: ◆ PF = 1.00 ■ PF = 0.95 ▲ PF = 0.90 ● PF = 0.85

GENERAL NOTE: Design dry bulb = 14.44°C, RH = 53%, Design CIT = 10.28°C, Evaporative cooler off, Design barometric = 1.012 bar.

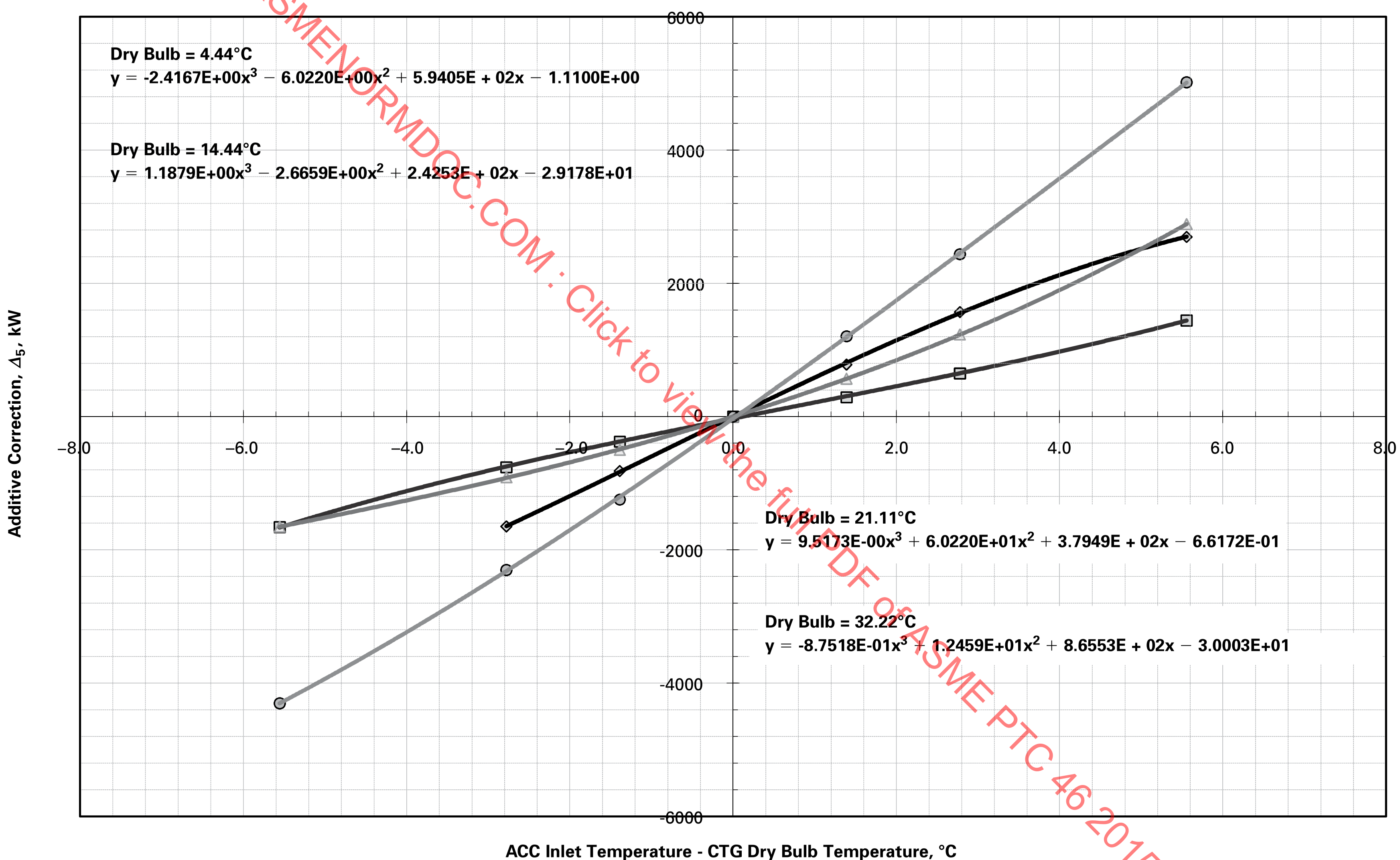
Fig. F-8-3 Correction to Power for ACC Inlet Dry Bulb Temperature (U.S. Customary Units)



LEGEND: ◆ Dry bulb = 40°F ■ Dry bulb = 58°F ▲ Dry bulb = 70°F ● Dry bulb = 90°F

GENERAL NOTE: Design dry bulb = 58°F, RH = 53%, Design CIT = 50.5°F, Evaporative cooler off, Design barometric = 14.68 psia.

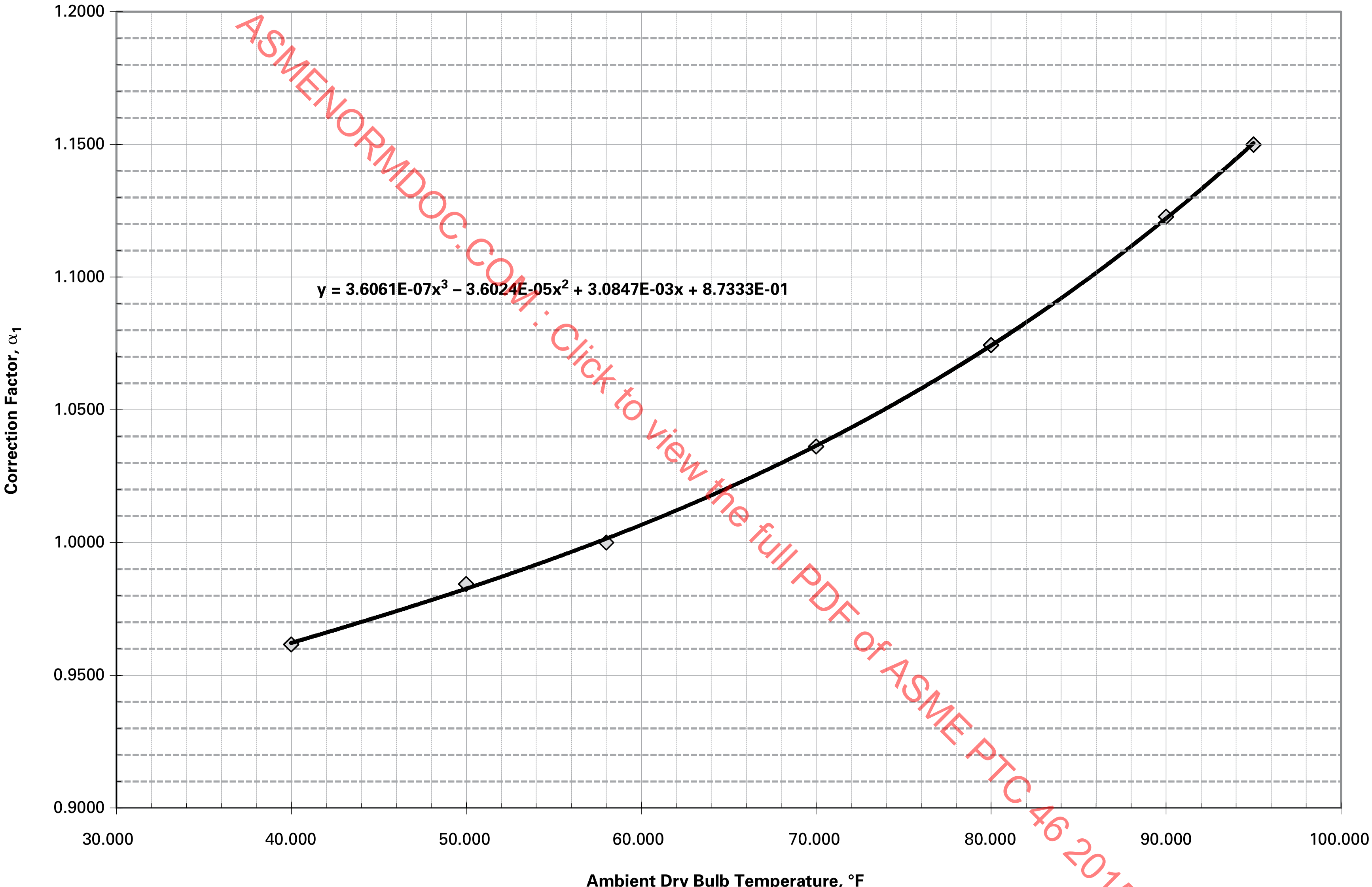
Fig. F-8-3M Correction to Power for ACC Inlet Dry Bulb Temperature (SI Units)



LEGEND: ◆ Dry bulb = 4.44°C ■ Dry bulb = 14.44°C ▲ Dry bulb = 21.11°C ● Dry bulb = 32.22°C

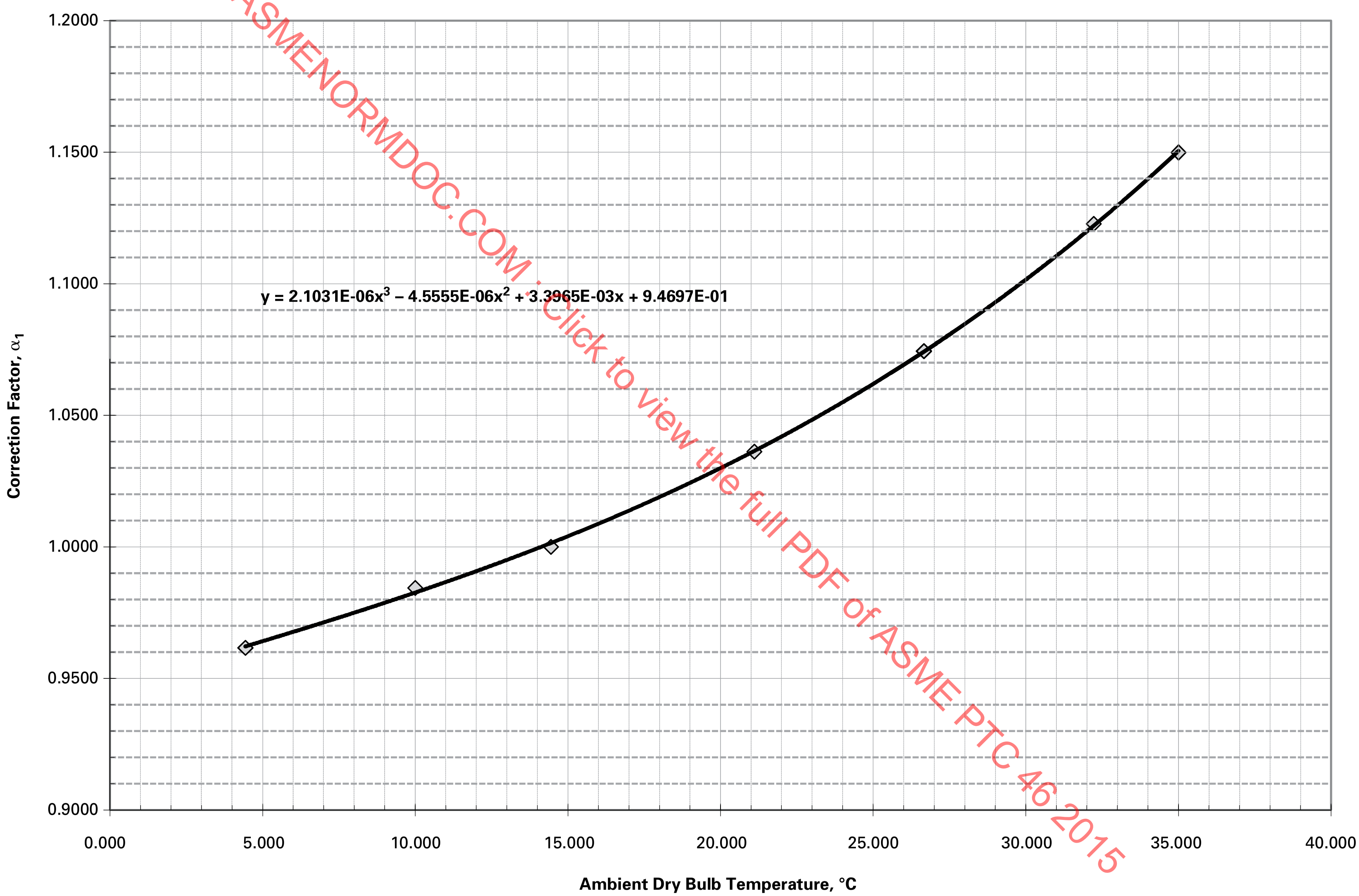
GENERAL NOTE: Design dry bulb = 14.44°C, RH = 53%, Design CIT = 10.28°C, Evaporative cooler off, Design barometric = 1.012 bar.

Fig. F-8-4 Correction to Power for Ambient Dry Bulb Temperature (U.S. Customary Units)



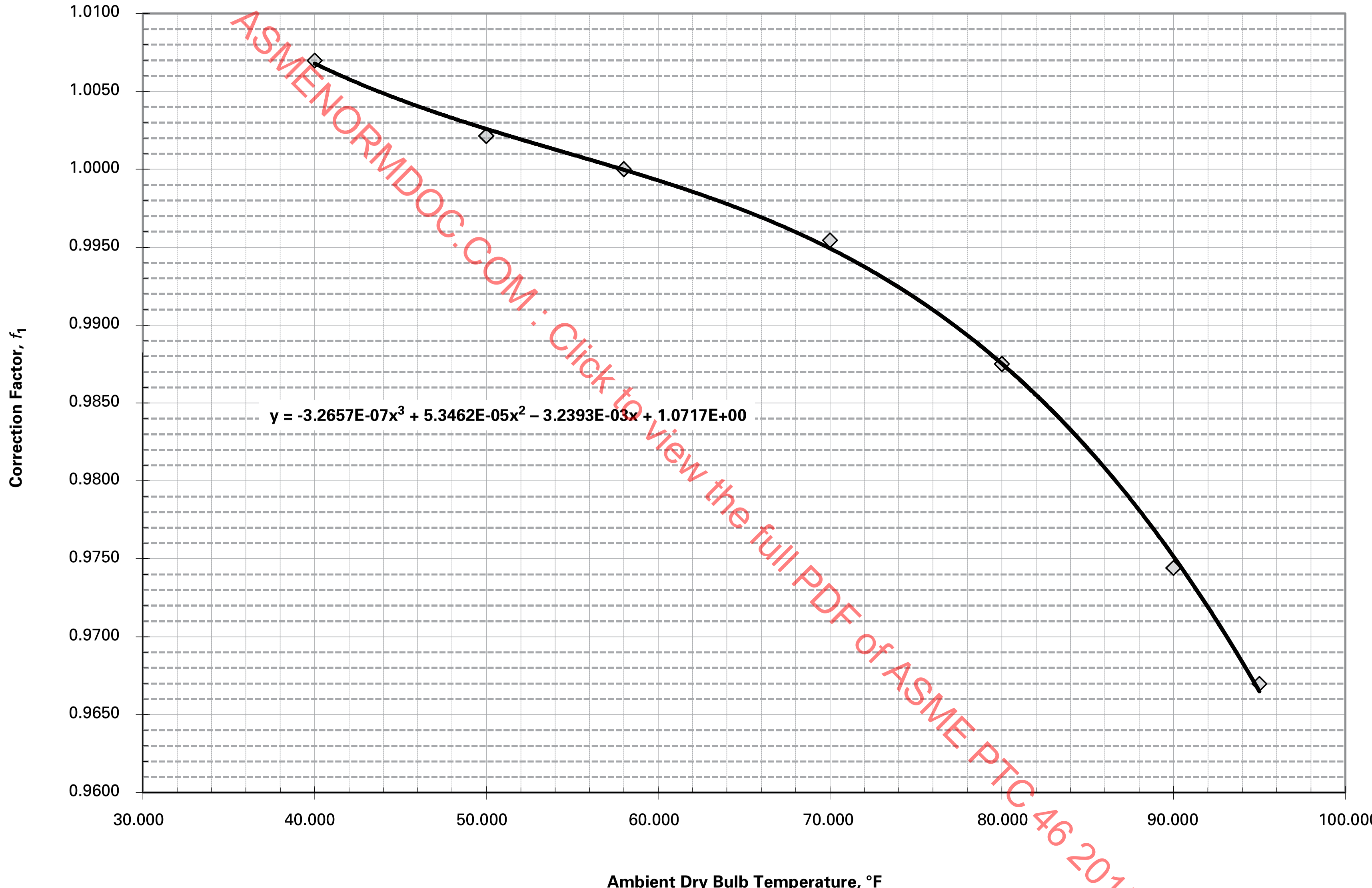
GENERAL NOTE: Design dry bulb = 58°F, RH = 53%, Design CIT = 50.5°F, Evaporative cooler off, Design barometric = 14.68 psia.

Fig. F-8-4M Correction to Power for Ambient Dry Bulb Temperature (SI Units)



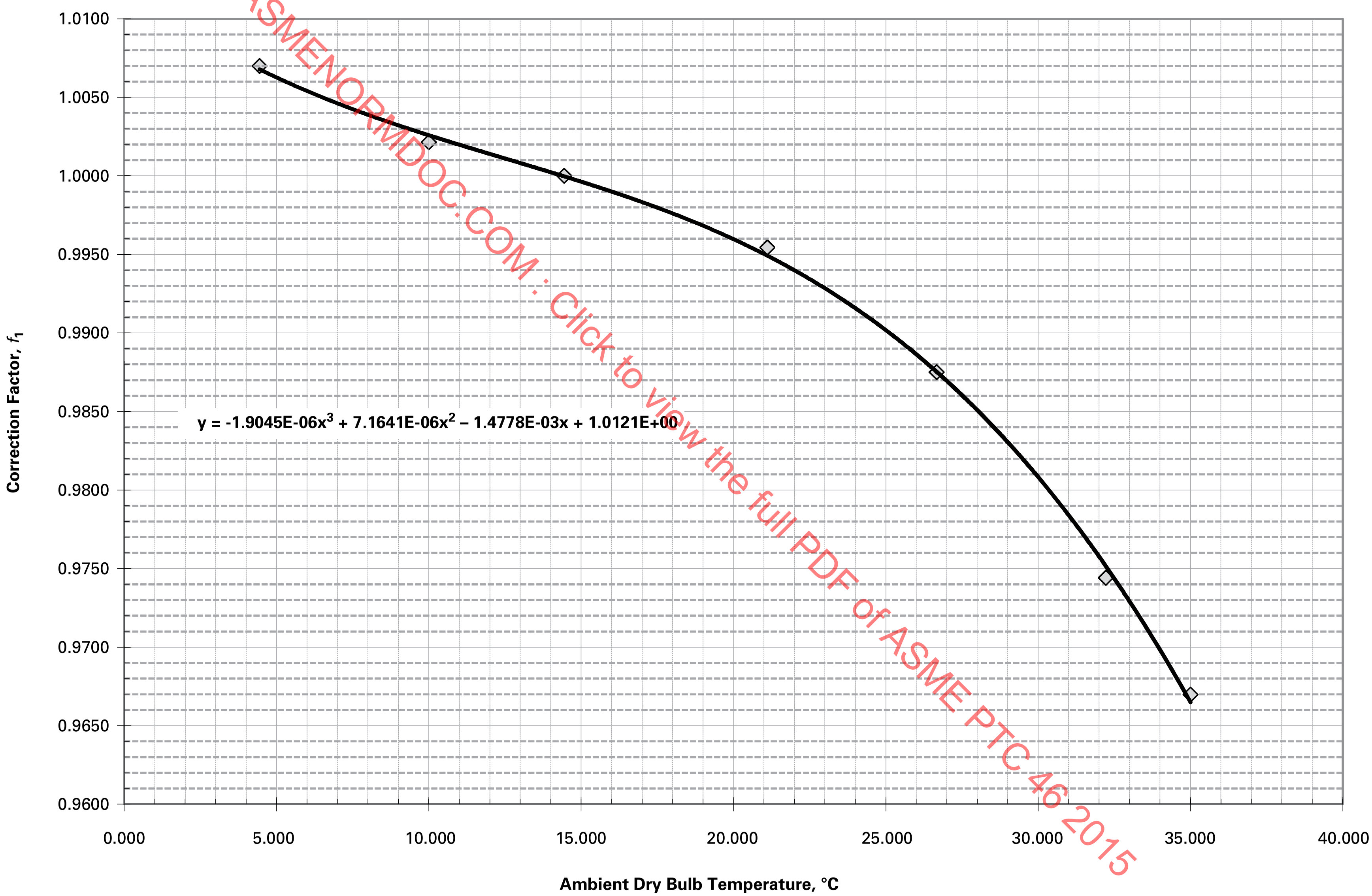
GENERAL NOTE: Design dry bulb = 14.44°C, RH = 53%, Design CIT = 10.28°C, Evaporative cooler off, Design barometric = 1.012 bar.

Fig. F-8-5 Correction to Heat Rate for Ambient Dry Bulb Temperature (U.S. Customary Units)



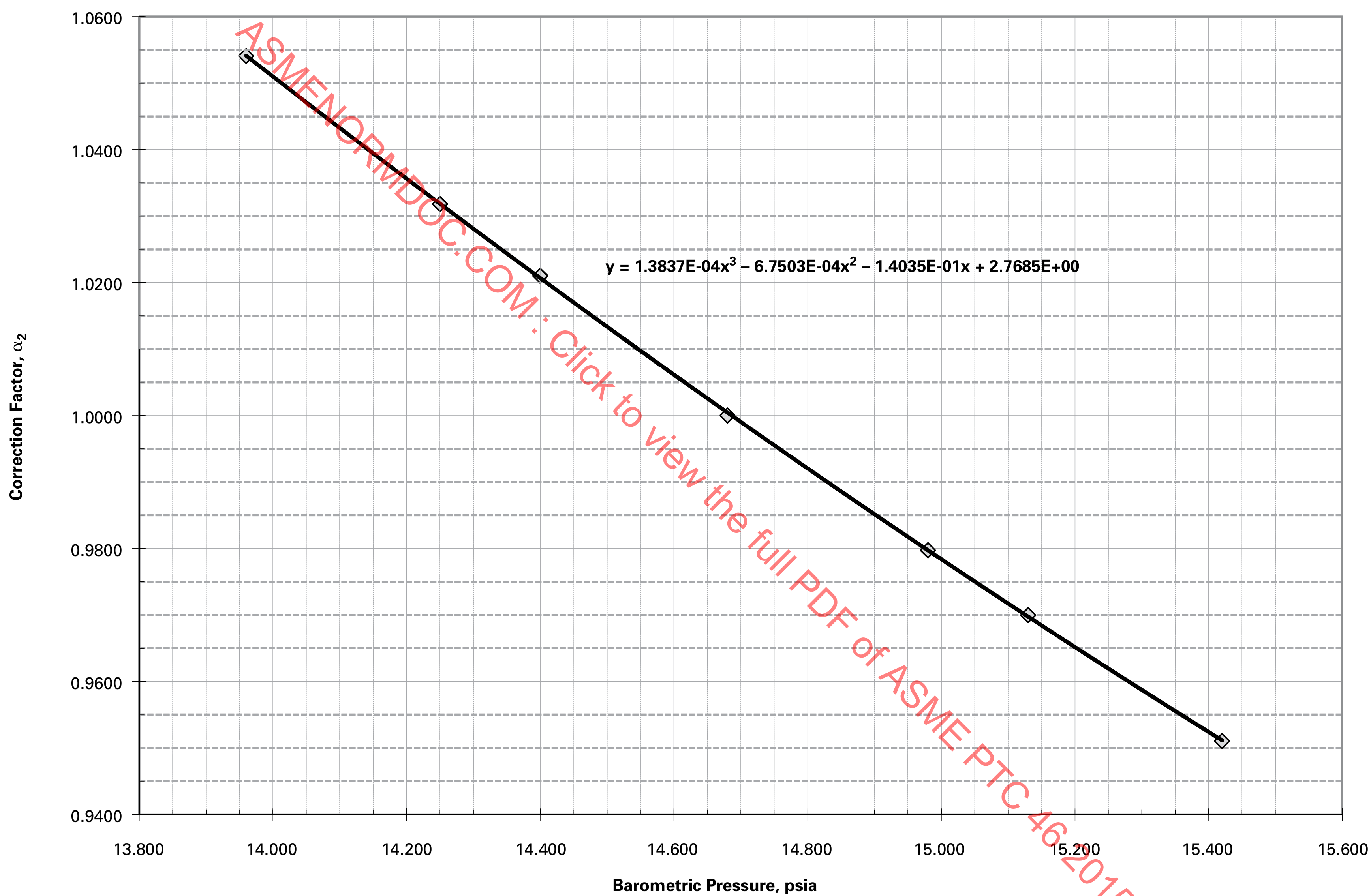
GENERAL NOTE: Design dry bulb = 58°F, RH = 53%, Design CIT = 50.5°F, Evaporative cooler off, Design barometric = 14.68 psia.

Fig. F-8-5M Correction to Heat Rate for Ambient Dry Bulb Temperature (SI Units)



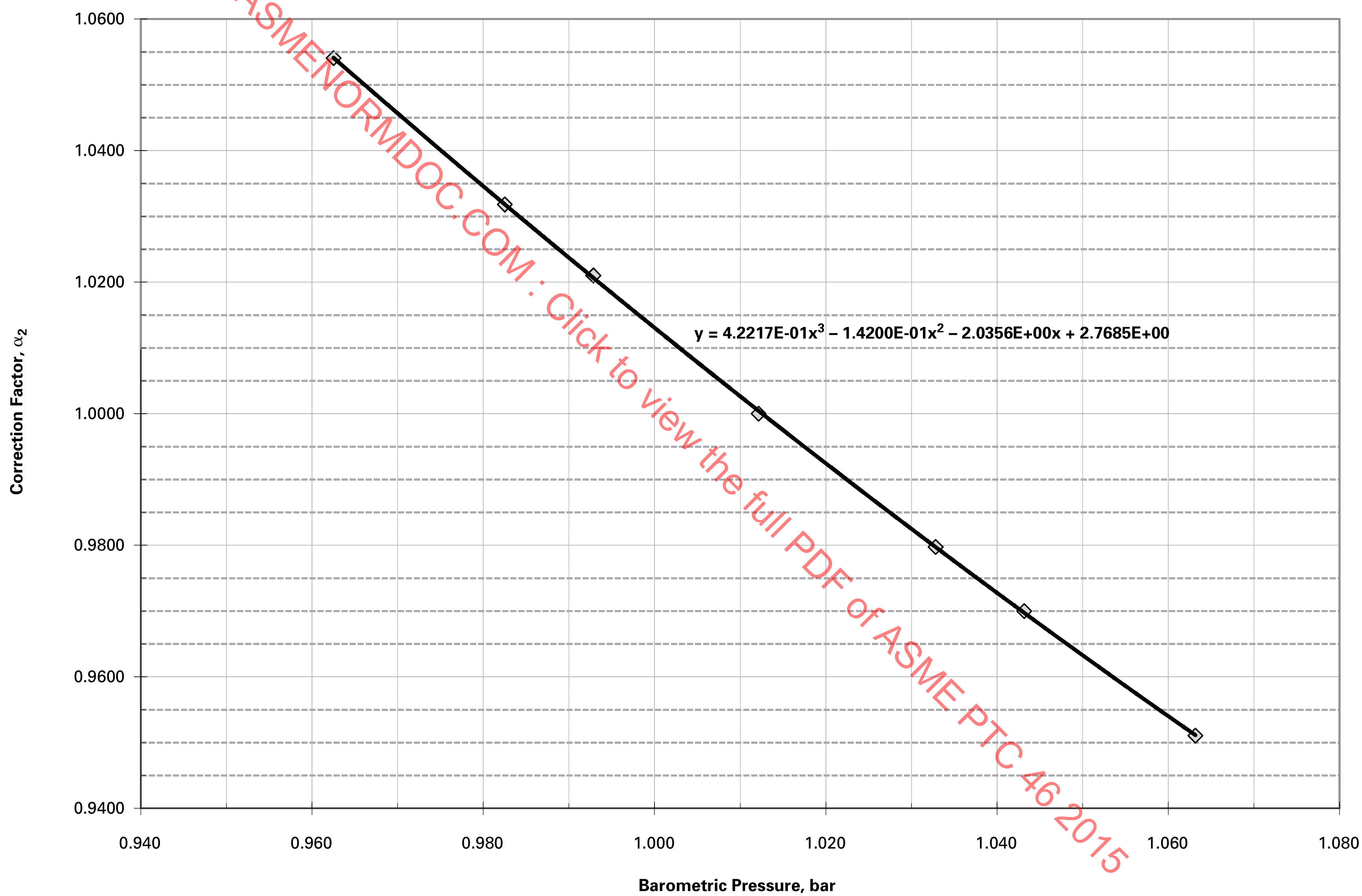
GENERAL NOTE: Design dry bulb = 14.44°C, RH = 53%, Design CIT = 10.28°C, Evaporative cooler off, Design barometric = 1.012 bar.

Fig. F-8-6 Correction to Power for Barometric Pressure (U.S. Customary Units)



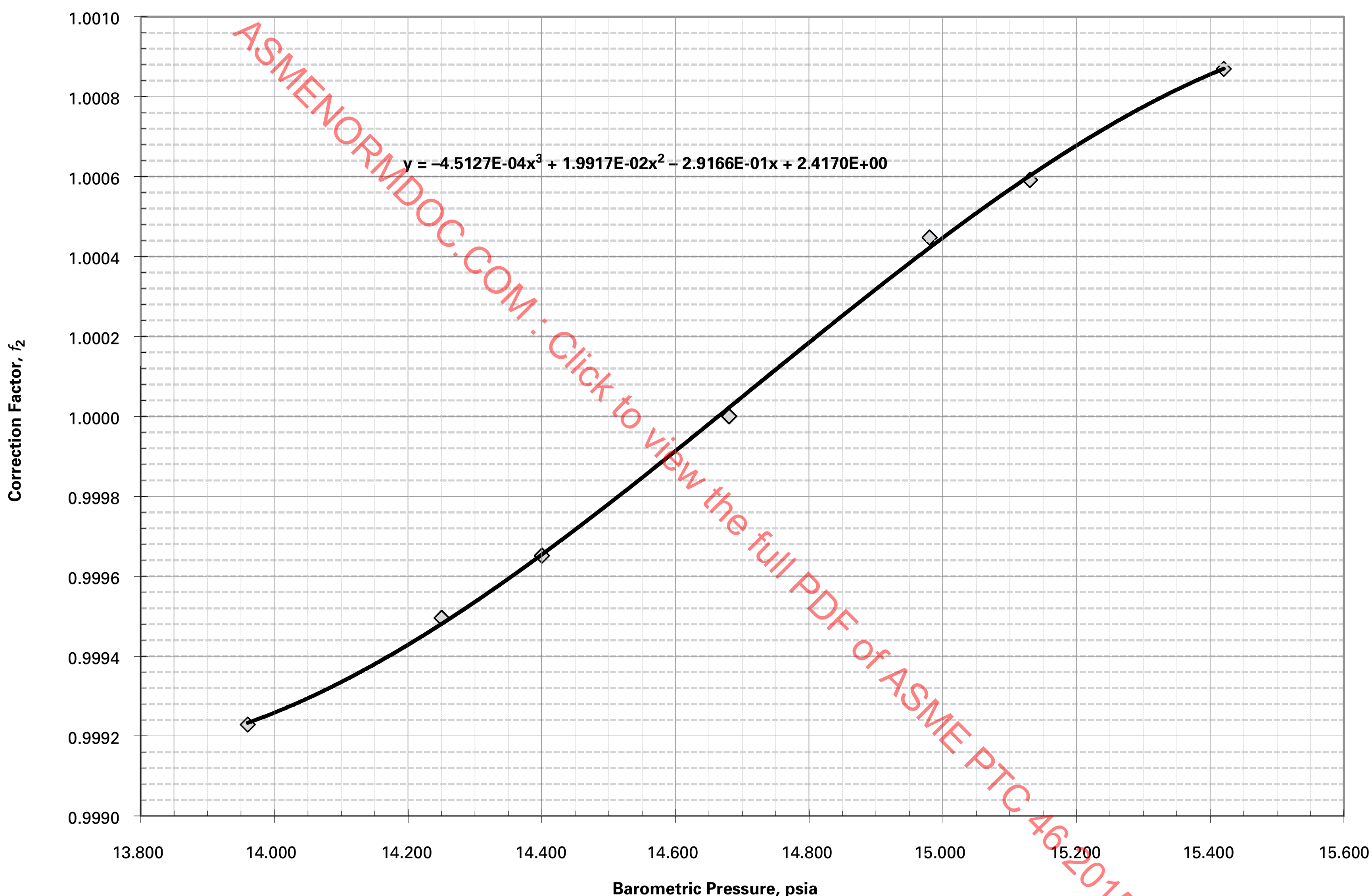
GENERAL NOTE: Design dry bulb = 58°F, RH = 53%, Design CIT = 50.5°F, Evaporative cooler off, Design barometric = 14.68 psia.

Fig. F-8-6M Correction to Power for Barometric Pressure (SI Units)



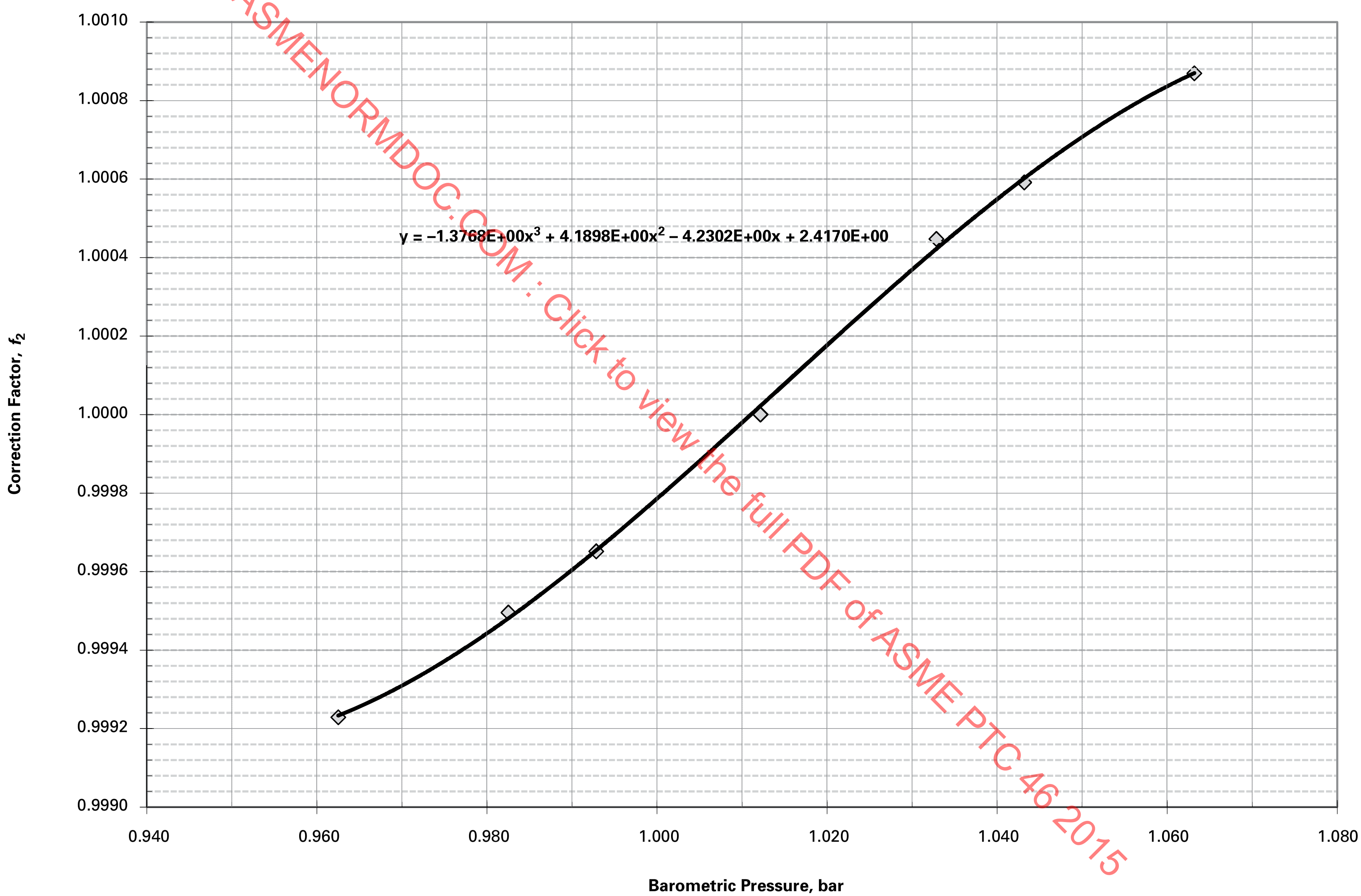
GENERAL NOTE: Design dry bulb = 14.44°C, RH = 53%, Design CIT = 10.28°C, Evaporative cooler off, Design barometric = 1.012 bar.

Fig. F-8-7 Correction to Heat Rate for Barometric Pressure (U.S. Customary Units)



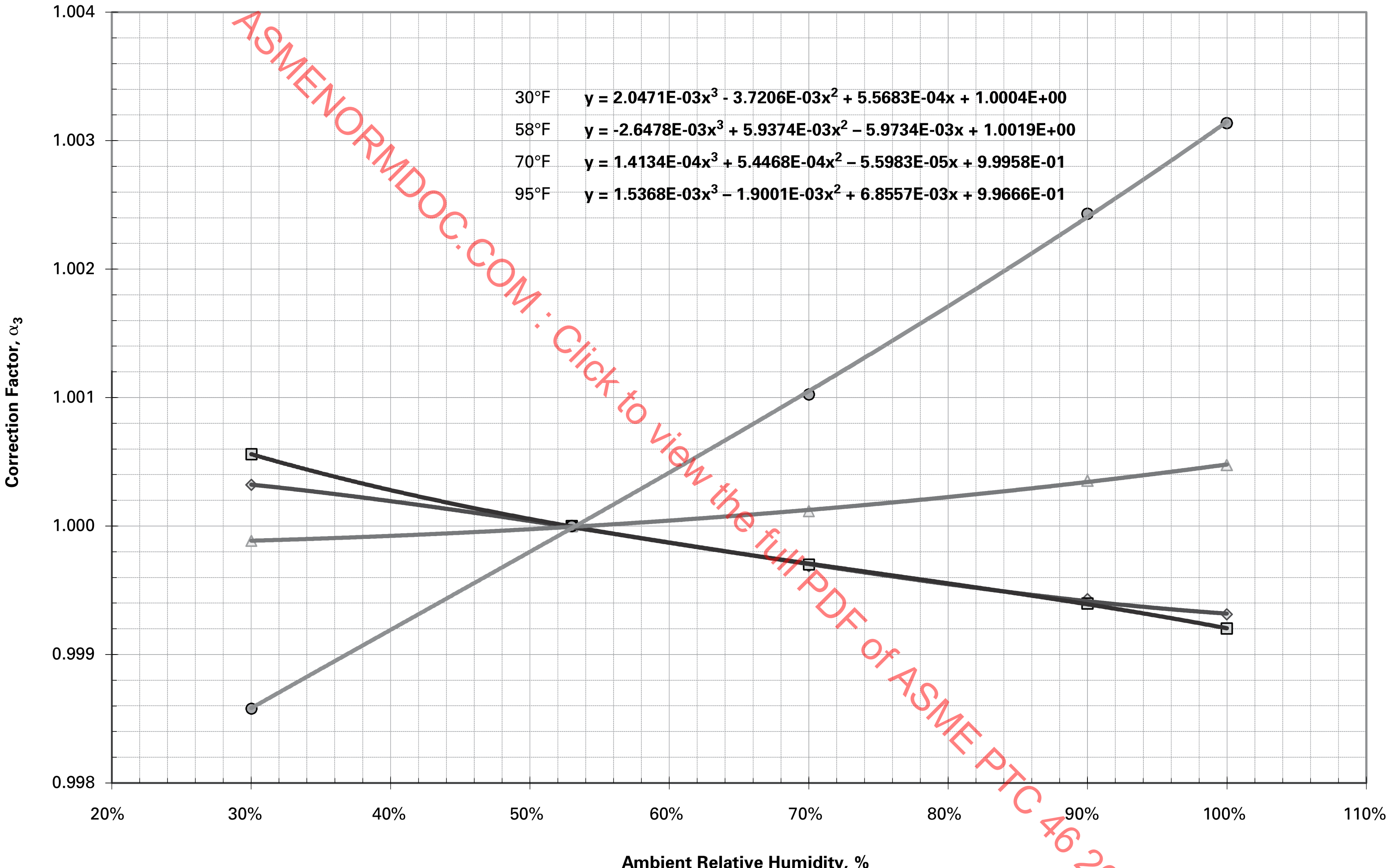
GENERAL NOTE: Design dry bulb = 58°F, RH = 53%, Design CIT = 50.5°F, Evaporative cooler off, Design barometric = 14.68 psia.

Fig. F-8-7M Correction to Heat Rate for Barometric Pressure (SI Units)



GENERAL NOTE: Design dry bulb = 14.44°C, RH = 53%, Design CIT = 10.28°C, Evaporative cooler off, Design barometric = 1.012 bar.

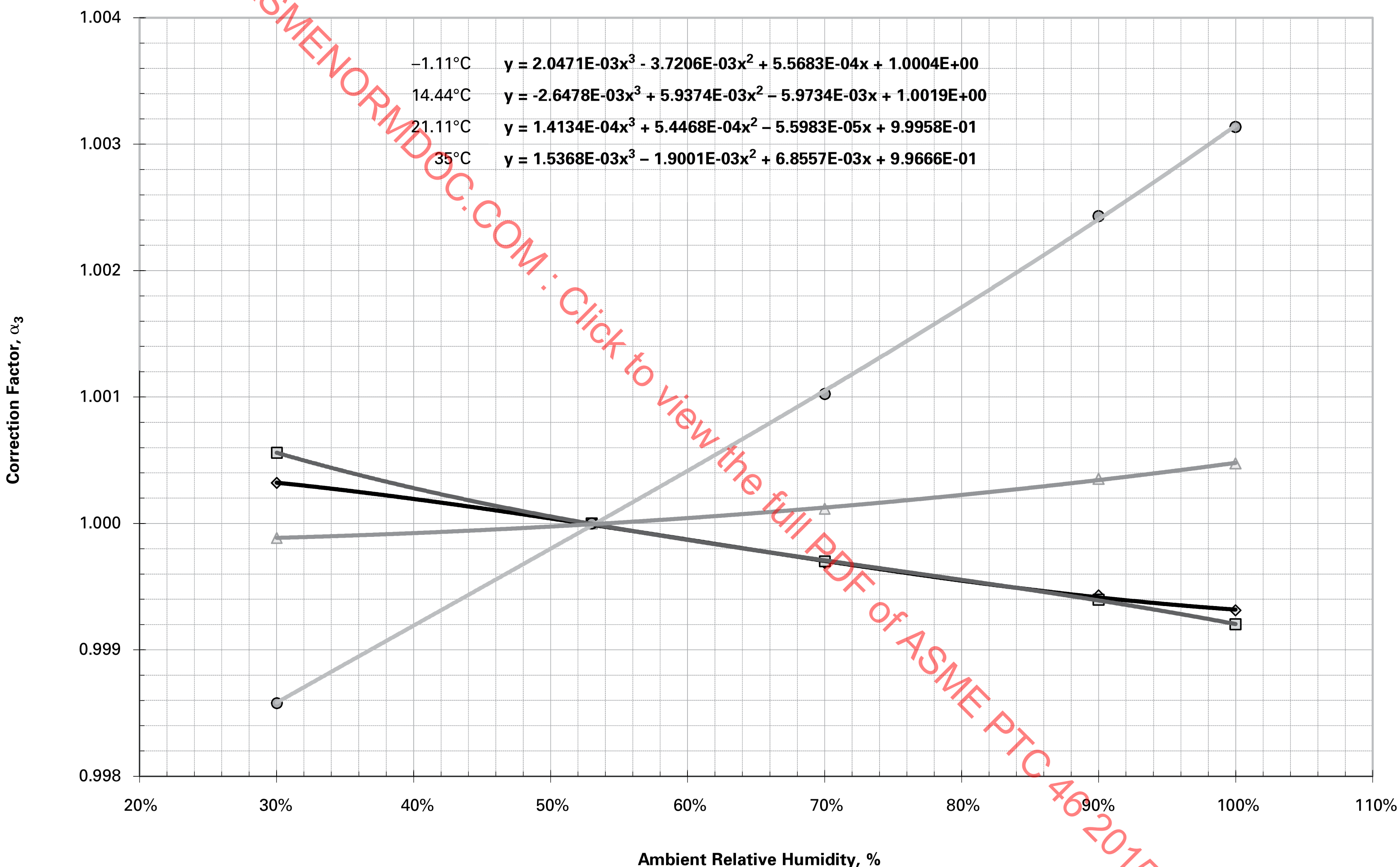
Fig. F-8-8 Correction to Power for Ambient Relative Humidity (U.S. Customary Units)



LEGEND: ◆ Dry bulb = 30°F ■ Dry bulb = 58°F ▲ Dry bulb = 70°F ● Dry bulb = 95°F

GENERAL NOTE: Design dry bulb = 58°F, RH = 53%, Design CIT = 50.5°F, Evaporative cooler off, Design barometric = 14.68 psia.

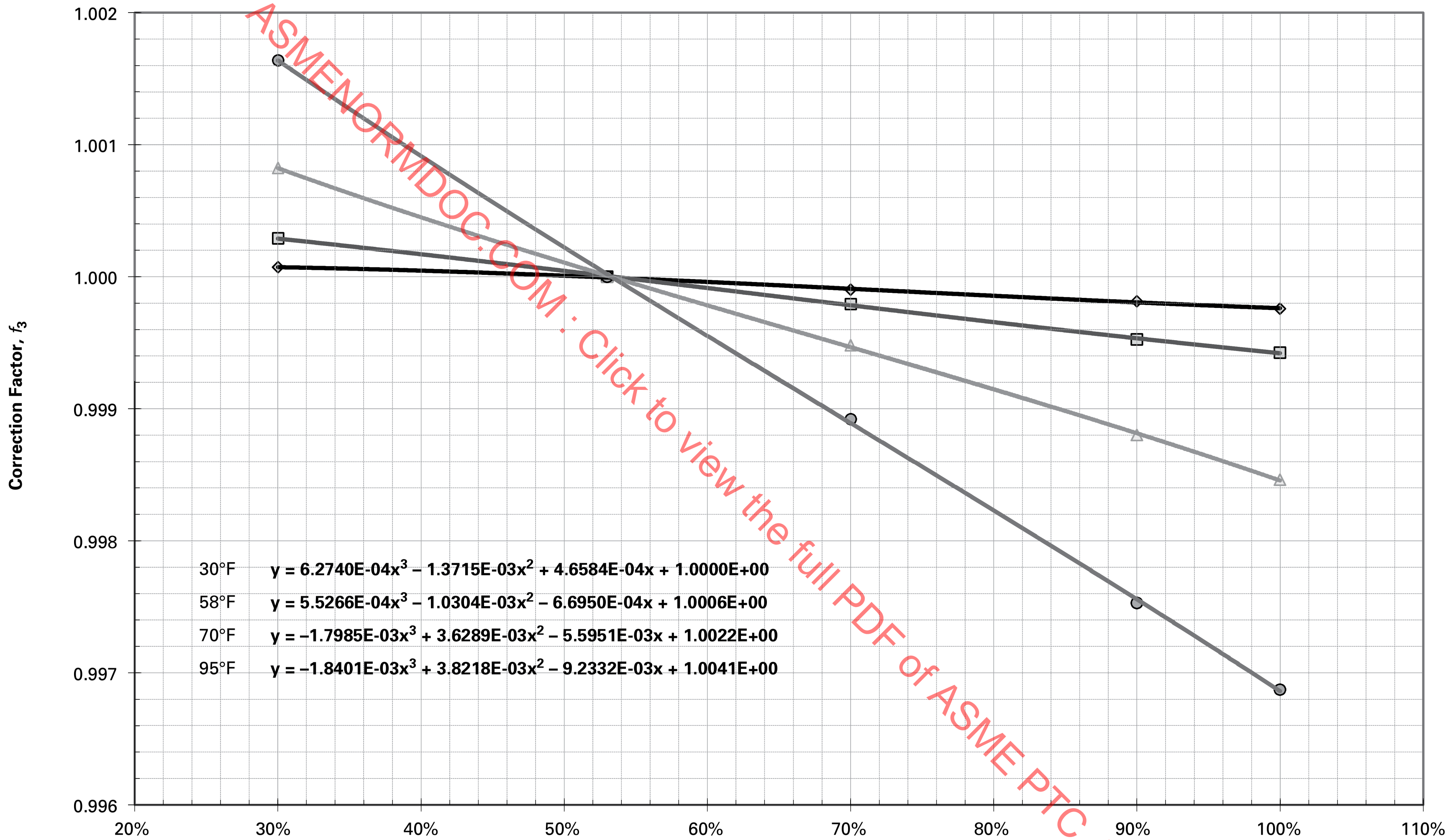
Fig. F-8-8M Correction to Power for Ambient Relative Humidity (SI Units)



LEGEND: ◆ Dry bulb = −1.11°C ■ Dry bulb = 14.44°C ▲ Dry bulb = 21.11°C ● Dry bulb = 35°C

GENERAL NOTE: Design dry bulb = 14.44°C, RH = 53%, Design CIT = 10.28°C, Evaporative cooler off, Design barometric = 1.012 bar.

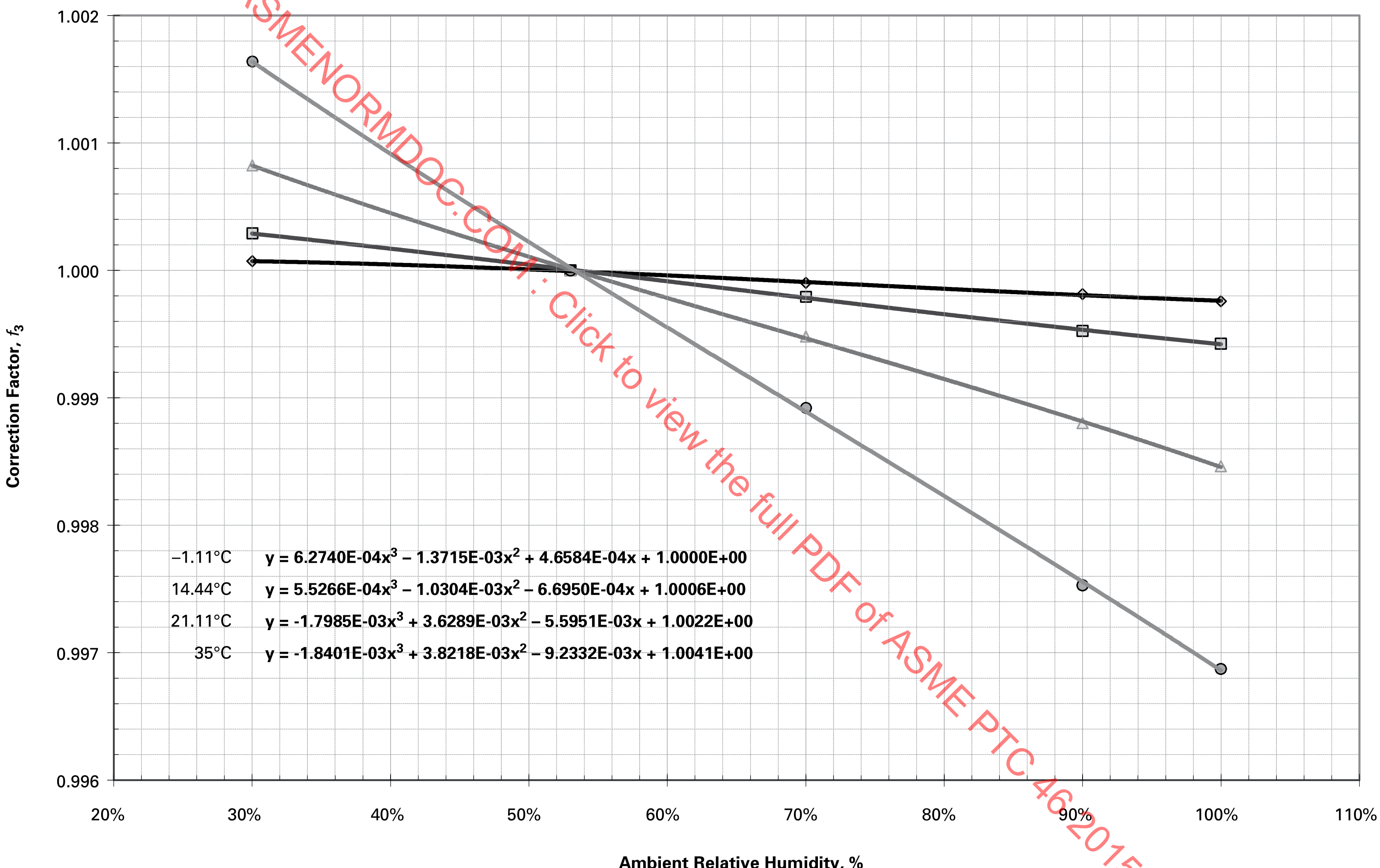
Fig. F-8-9 Correction to Heat Rate for Ambient Relative Humidity (U.S. Customary Units)



LEGEND: ◆ Dry bulb = 30°F ■ Dry bulb = 58°F ▲ Dry bulb = 70°F ● Dry bulb = 95°F

GENERAL NOTE: Design dry bulb = 58°F, RH = 53%, Design CIT = 50.5°F, Evaporative cooler off, Design barometric = 14.68 psia.

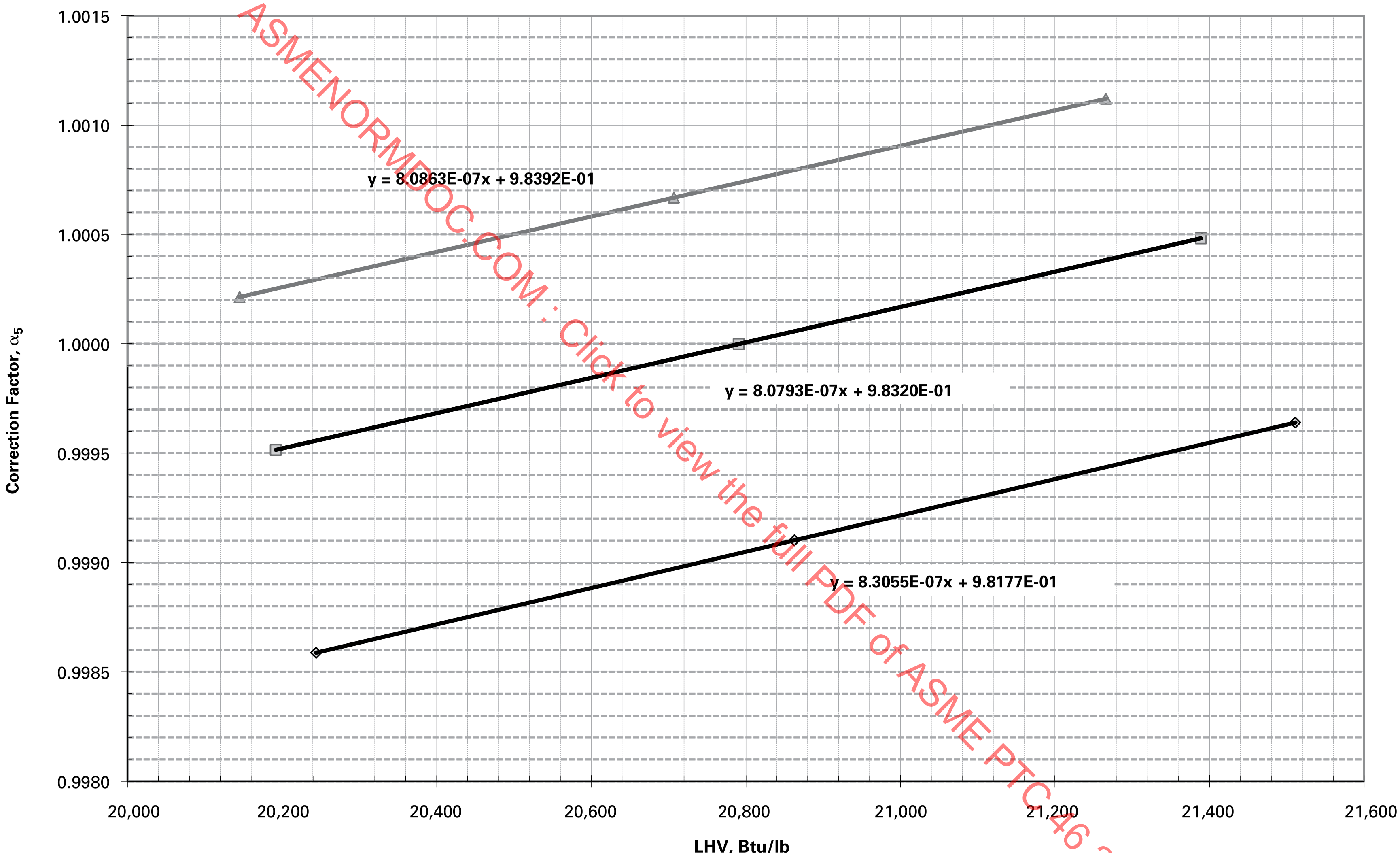
Fig. F-8-9M Correction to Heat Rate for Ambient Relative Humidity (SI Units)



LEGEND: ◆ Dry bulb = −1.11°C ■ Dry bulb = 14.44°C ▲ Dry bulb = 21.11°C ● Dry bulb = 35°C

GENERAL NOTE: Design dry bulb = 14.44°C, RH = 53%, Design CIT = 10.28°C, Evaporative cooler off, Design barometric = 1.012 bar.

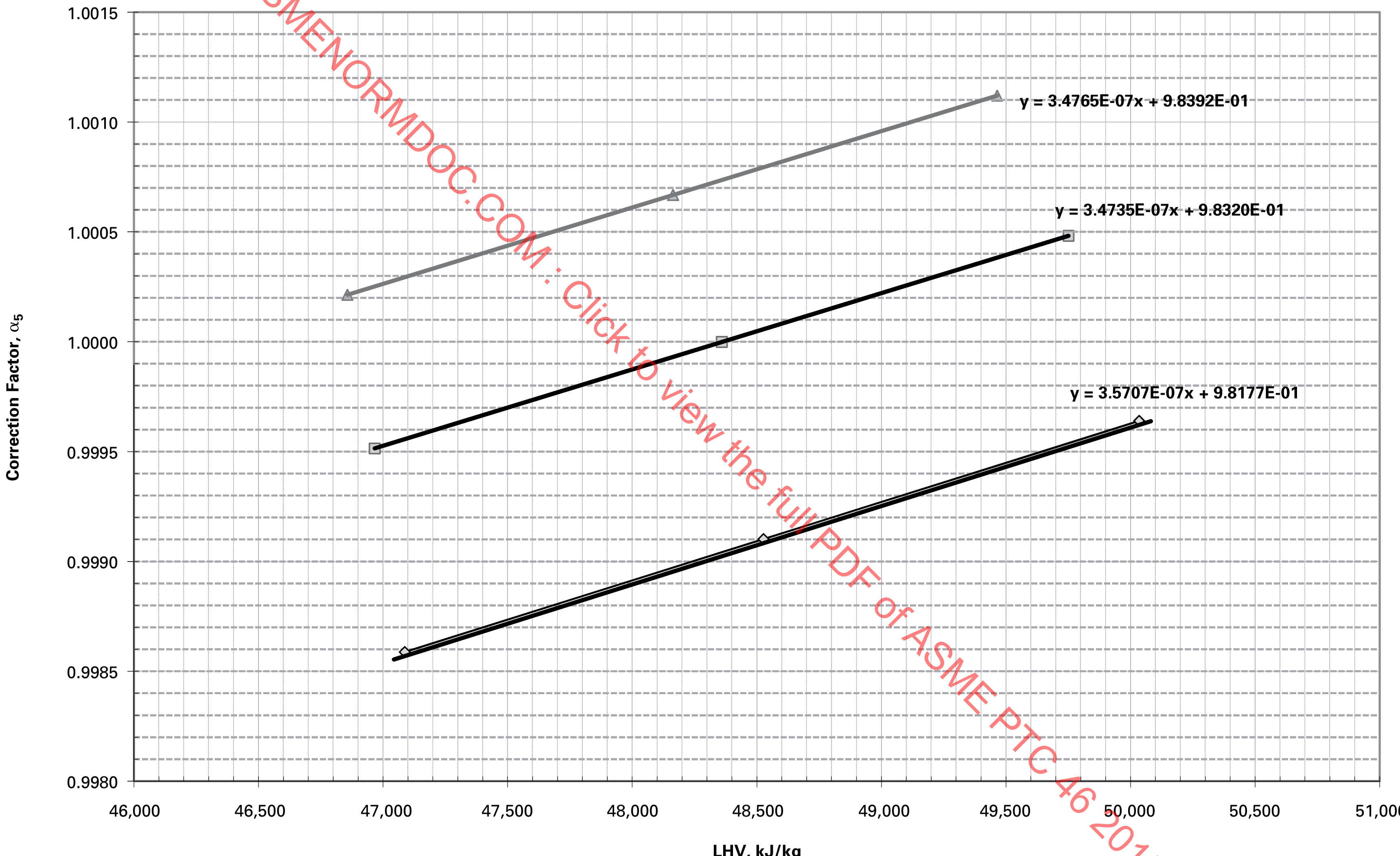
Fig. F-8-10 Correction to Power for Fuel Composition (U.S. Customary Units)



LEGEND: ◆ H/C = 4.00 ■ H/C = 3.89 ▲ H/C = 3.80

GENERAL NOTE: Design dry bulb = 58°F, RH = 53%, Design CIT = 50.5°F, Evaporative cooler off, Design barometric = 14.68 psia.

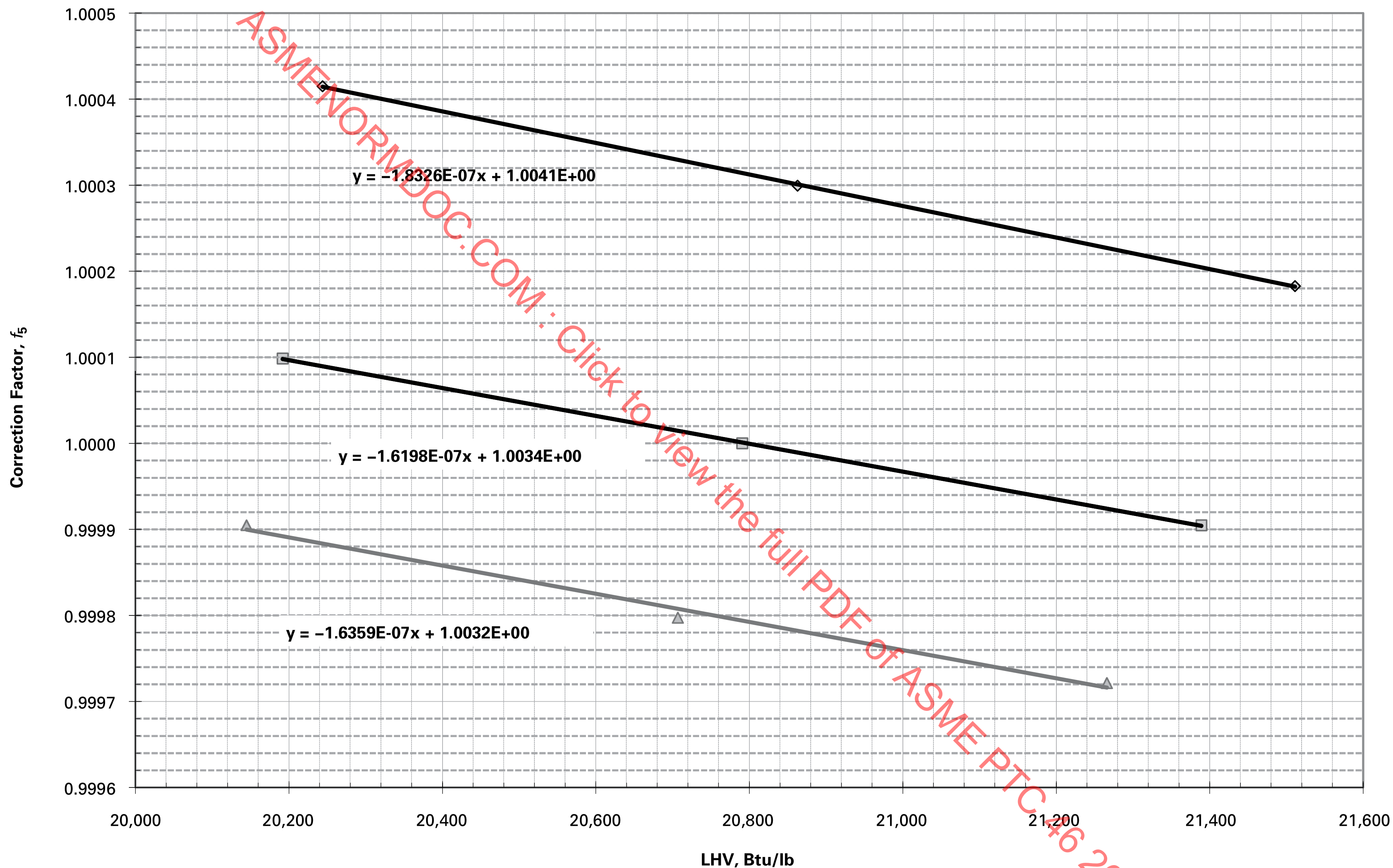
Fig. F-8-10M Correction to Power for Fuel Composition (SI Units)



LEGEND: ◆ H/C = 4.00 ■ PF = 3.89 ▲ H/C = 3.80

GENERAL NOTE: Design dry bulb = 14.44°C, RH = 53%, Design CIT = 10.28°C, Evaporative cooler off, Design barometric = 1.012 bar.

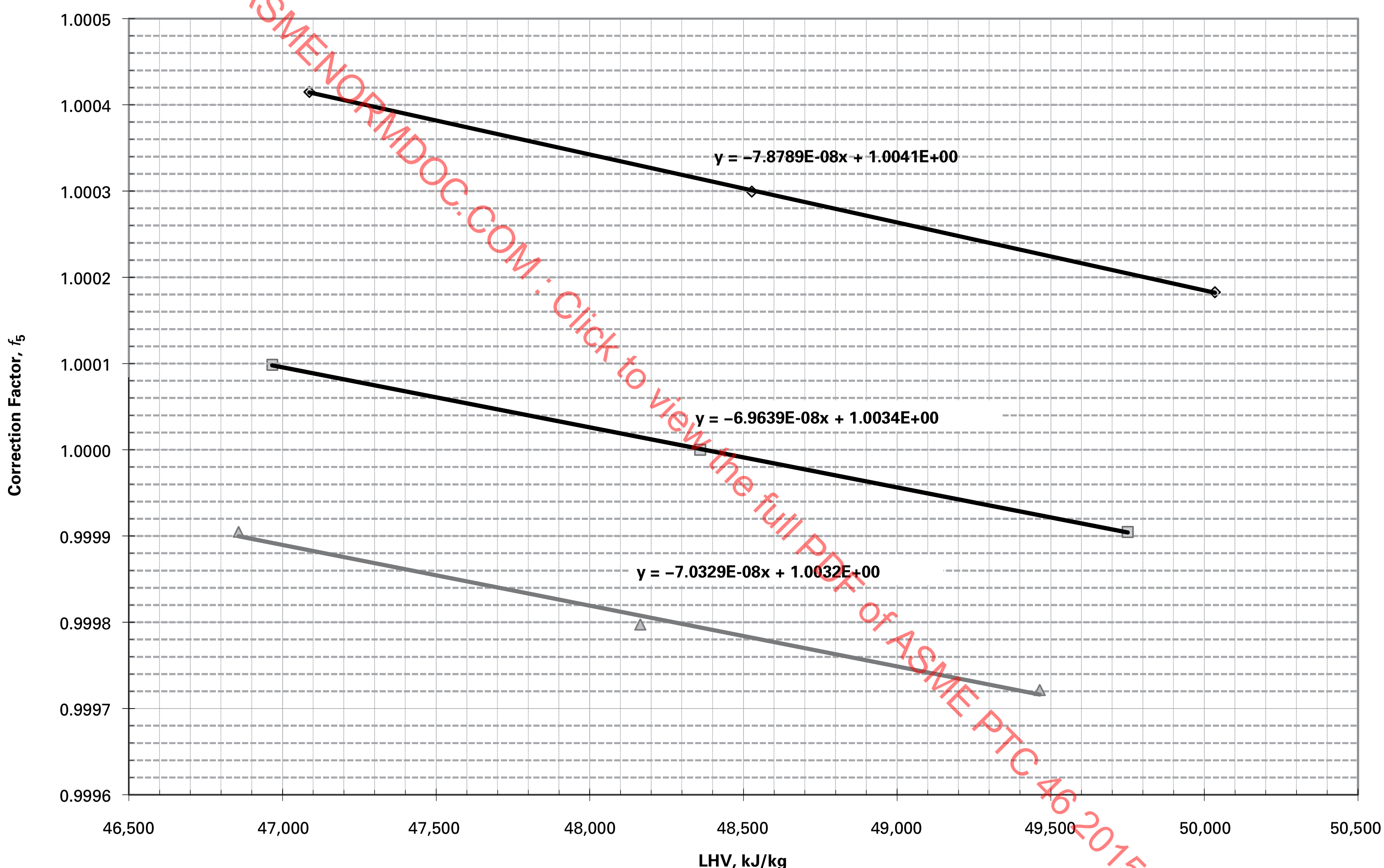
Fig. F-8-11 Correction to Heat Rate for Fuel Composition (U.S. Customary Units)



LEGEND: ◆ H/C = 4.0 ■ H/C = 3.89 ▲ H/C = 3.80

GENERAL NOTE: Design dry bulb = 58°F, RH = 53%, Design CIT = 50.5°F, Evaporative cooler off, Design barometric = 14.68 psia.

Fig. F-8-11M Correction to Heat Rate for Fuel Composition (SI Units)



LEGEND: ◆ H/C = 4.0 ■ H/C = 3.89 ▲ H/C = 3.80

GENERAL NOTE: Design dry bulb = 14.44°C, RH = 53%, Design CIT = 10.28°C, Evaporative cooler off, Design barometric = 1.012 bar.

Fig. F-8-12 Correction to Power and Heat Rate for Evaporative Cooler Performance (U.S. Customary Units)

The evaporative coolers were out of service during the performance test. However, design performance is with the evaporative coolers on. Therefore, the following additional multiplicative corrections are applied to account for evaporative cooler operation.

The following corrections were used to correct to the design basis ofevaporative cooler in operation with 85% effectiveness since the test was conducted with the evaporative cooler out of operation.

Multiplicative Correction Factor to Output:

$\alpha_{7a} = 1.01506$

Multiplicative Correction Factor to Heat Rate

$f_{7a} = 1.00027$

The following corrections were used to correct for actual evaporative cooler performance. These corrections were determined from a separate evaporative cooler test.

Multiplicative Correction Factor to Output:

$\alpha_{7b} = 1.0167$

Multiplicative Correction Factor to Heat Rate

$f_{7b} = 0.99975$

Fig. F-8-12M Correction to Power and Heat Rate for Evaporative Cooler Performance (SI Units)

The evaporative coolers were out of service during the performance test. However, design performance is with the evaporative coolers on. Therefore, the following additional multiplicative corrections are applied to account for evaporative cooler operation.

The following corrections were used to correct to the design basis of evaporative cooler in operation with 85% effectiveness since the test was conducted with the evaporative cooler out of operation.

Multiplicative Correction Factor to Output:

α_{7a} = 1.01506

Multiplicative Correction Factor to Heat Rate

f_{7a} = 1.00027

The following corrections were used to correct for actual evaporative cooler performance. These corrections were determined from a separate evaporative cooler test.

Multiplicative Correction Factor to Output:

α_{7b} = 1.0167

Multiplicative Correction Factor to Heat Rate

f_{7b} = 0.99975

Table F-8-1 Summary of Correction Curve Coefficients (SI Units)

Correction Curves	a_0	a_1	a_2	a_3
Additive Correction Factors				
Δ_2, CTG generator losses (PF = 1.00)	6.651E+02	1.800E−01	1.800E−02	0.000E+00
Δ_2, CTG generator losses (PF = 0.95)	6.826E+02	2.900E−01	2.100E−02	0.000E+00
Δ_2, CTG generator losses (PF = 0.90)	6.901E+02	4.000E−01	2.400E−02	0.000E+00
Δ_2, CTG generator losses (PF = 0.85)	7.051E+02	3.200E−01	2.800E−02	0.000E+00
Δ_2, STG generator losses (PF = 1.00)	3.139E+03	2.254E−01	8.650E−03	0.000E+00
Δ_2, STG generator losses (PF = 0.95)	3.169E+03	2.009E−01	1.046E−02	0.000E+00
Δ_2, STG generator losses (PF = 0.90)	3.126E+03	6.741E−01	1.102E−02	0.000E+00
Δ_2, STG generator losses (PF = 0.85)	3.289E+03	−4.129E−01	1.479E−02	0.000E+00
Δ_{5a}, difference between ACC and CTG inlet temps (T_{db} = 4.44°C)	−1.110E+00	5.945E+02	6.022E+00	2.417E+00
Δ_{5a}, difference between ACC and CTG inlet temps (T_{db} = 14.44°C)	−2.918E+01	2.425E+02	2.666E+00	1.188E+00
Δ_{5a}, difference between ACC and CTG inlet temps (T_{db} = 21.11°C)	−6.617E−02	3.795E+02	2.006E+01	9.517E−01
Δ_{5a}, difference between ACC and CTG inlet temps (T_{db} = 32.22°C)	−3.000E+01	8.655E+02	1.246E+01	−8.752E−01
Multiplicative Correction Factors for Power				
α_1, ambient dry bulb temperature	9.470E−01	3.397E−03	−4.556E−06	2.103E−06
α_2, ambient pressure	2.769E+00	2.036E+00	−1.420E−01	4.222E−01
α_3, ambient relative humidity (T_{db} = −1.11°C)	1.000E+00	5.568E−04	−3.721E−03	2.047E−03
α_3, ambient relative humidity (T_{db} = 14.44°C)	1.002E+00	−5.973E−03	5.937E−03	−2.648E−03
α_3, ambient relative humidity (T_{db} = 21.11°C)	9.998E−01	−5.598E−05	5.447E−04	1.413E−04
α_3, ambient relative humidity (T_{db} = 35°C)	9.967E−01	6.856E−03	−1.900E−03	1.537E−03
α_5, fuel analysis different than design (H/C = 3.80)	9.839E−01	3.477E−07	0.000E+00	0.000E+00
α_5, fuel analysis different than design (H/C = 3.89)	9.832E−01	3.474E−07	0.000E+00	0.000E+00
α_5, fuel analysis different than design (H/C = 4.00)	9.818E−01	3.571E−07	0.000E+00	0.000E+00
α_6, grid frequency (external)	1.000E+00	0.000E+00	0.000E+00	0.000E+00
α_{7a}, evaporative cooler operation	1.015E+00	0.000E+00	0.000E+00	0.000E+00
α_{7b}, evaporative cooler performance	1.0017E+00	0.000E+00	0.000E+00	0.000E+00
Multiplicative Correction Factors for Heat Rate	2.417E+00	4.230E+00	4.190E+00	1.377E+00
f_1, ambient dry bulb temperature	1.000E+00	4.658E−04	−1.371E−03	6.274E−04
f_2, ambient pressure	1.001E+00	−6.695E−04	−1.030E−03	5.527E−04
f_3, ambient relative humidity (T_{db} = −1.11°C)	1.002E+00	−5.595E−03	3.629E−03	−1.799E−03
f_3, ambient relative humidity (T_{db} = 14.44°C)	1.004E+00	−9.233E−03	3.822E−03	−1.840E−03
f_3, ambient relative humidity (T_{db} = 21.11°C)	1.003E+00	−7.033E−08	0.000E+00	0.000E+00
f_3, ambient relative humidity (T_{db} = 35°C)	1.003E+00	−6.964E−08	0.000E+00	0.000E+00
f_5, fuel analysis different than design (H/C = 3.80)	1.004E+00	−7.879E−08	0.000E+00	0.000E+00
f_5, fuel analysis different than design (H/C = 3.89)	1.000E+00	0.000E+00	0.000E+00	0.000E+00
f_5, fuel analysis different than design (H/C = 4.00)	1.0003E+00	0.000E+00	0.000E+00	0.000E+00
f_6, grid frequency (external)	9.9975E−01	0.000E+00	0.000E+00	0.000E+00
f_{7a}, evaporative cooler operation	1.001E+00	−2.510E−06	2.132E−10	0.000E+00
f_{7b}, evaporative cooler performance	6.651E+02	1.800E−01	1.800E−02	0.000E+00

Table F-8-2 Summary of Correction Curve Coefficients (U.S. Customary Units)

Correction Curves	a_0	a_1	a_2	a_3
Additive Correction Factors				
Δ_2, CTG generator losses (PF = 1.00)	6.651E+02	1.800E−01	1.800E−02	0.000E+00
Δ_2, CTG generator losses (PF = 0.95)	6.826E+02	2.900E−01	2.100E−02	0.000E+00
Δ_2, CTG generator losses (PF = 0.90)	6.901E+02	4.000E−01	2.400E−02	0.000E+00
Δ_2, CTG generator losses (PF = 0.85)	7.051E+02	3.200E−01	2.800E−02	0.000E+00
Δ_2, STG generator losses (PF = 1.00)	3.139E+03	2.254E−01	8.650E−03	0.000E+00
Δ_2, STG generator losses (PF = 0.95)	3.169E+03	2.009E−01	1.046E−02	0.000E+00
Δ_2, STG generator losses (PF = 0.90)	3.126E+03	6.741E−01	1.102E−02	0.000E+00
Δ_2, STG generator losses (PF = 0.85)	3.289E+03	−4.129E−01	1.479E−02	0.000E+00
Δ_{5a}, delta between ACC and CTG inlet temps (T_{db} = 40°F)	−1.110E+00	3.300E+02	1.859E+00	−4.144E−01
Δ_{5a}, delta between ACC and CTG inlet temps (T_{db} = 58°F)	−2.918E+01	1.347E+02	−8.228E−01	2.037E−01
Δ_{5a}, delta between ACC and CTG inlet temps (T_{db} = 70°F)	−6.617E−01	2.108E+02	6.191E+00	1.632E−01
Δ_{5a}, delta between ACC and CTG inlet temps (T_{db} = 90°F)	−3.000E+01	4.808E+02	3.845E+00	−1.501E−01
Multiplicative Correction Factors for Power				
α_1, ambient dry bulb temperature	8.733E−01	3.085E−03	−3.602E−05	3.606E−07
α_2, ambient pressure	2.769E+00	−1.404E−01	−6.749E−04	1.384E−04
α_3, ambient relative humidity (T_{db} = 30°F)	1.000E+00	5.568E−04	−3.721E−03	2.047E−03
α_3, ambient relative humidity (T_{db} = 58°F)	1.002E+00	−5.973E−03	5.937E−03	−2.648E−03
α_3, ambient relative humidity (T_{db} = 70°F)	9.998E−01	−5.598E−05	5.447E−04	1.413E−04
α_3, ambient relative humidity (T_{db} = 95°F)	9.967E−01	6.856E−03	−1.900E−03	1.537E−03
α_5, fuel analysis different than design (H/C = 3.80)	9.839E−01	8.086E−07	0.000E+00	0.000E+00
α_5, fuel analysis different than design (H/C = 3.89)	9.832E−01	8.079E−07	0.000E+00	0.000E+00
α_5, fuel analysis different than design (H/C = 4.00)	9.818E−01	8.305E−07	0.000E+00	0.000E+00
α_6, grid frequency (external)	1.000E+00	0.000E+00	0.000E+00	0.000E+00
α_{7a}, evaporative cooler operation	1.015E+00	0.000E+00	0.000E+00	0.000E+00
α_{7b}, evaporative cooler performance	1.0017E+00	0.000E+00	0.000E+00	0.000E+00
Multiplicative Correction Factors for Heat Rate				
f_1, ambient dry bulb temperature	1.072E+00	−3.239E−03	5.346E−05	−3.266E−07
f_2, Ambient Pressure	2.417E+00	−2.917E−01	1.992E−02	−4.513E−04
f_3, ambient relative humidity (dry bulb = 30°F)	1.000E+00	4.658E−04	−1.371E−03	6.274E−04
f_3, ambient relative humidity (dry bulb = 58°F)	1.001E+00	−6.695E−04	−1.030E−03	5.527E−04
f_3, ambient relative humidity (dry bulb = 70°F)	1.002E+00	−5.595E−03	3.629E−03	−1.799E−03
f_3, ambient relative humidity (dry bulb = 95°F)	1.004E+00	−9.233E−03	3.822E−03	−1.840E−03
f_5, fuel analysis different than design (H/C = 3.80)	1.003E+00	−1.636E−07	0.000E+00	0.000E+00
f_5, fuel analysis different than design (H/C = 3.89)	1.003E+00	−1.620E−07	0.000E+00	0.000E+00
f_5, fuel analysis different than design (H/C = 4.00)	1.004E+00	−1.833E−07	0.000E+00	0.000E+00
f_6, grid frequency (external)	1.000E+00	0.000E+00	0.000E+00	0.000E+00
f_{7a}, evaporative cooler operation	1.0003E+00	0.000E+00	0.000E+00	0.000E+00
f_{7b}, evaporative cooler performance	9.9975E−01	0.000E+00	0.000E+00	0.000E+00

Table F-9-1 Summary of Measured Parameters, Corrections, and Results (SI Units)

Description	Units	Test Run 1	Test Run 2	Test Run 3	Test Run 4
Inputs					
Evaporative coolers in service (Y/N)	Y/N	N	N	N	N
CTG 1 fired hours	h	350.6	351.1	351.6	352.1
CTG 2 fired hours	h	357.2	357.7	358.2	358.7
Average unit fired hours	h	353.9	354.4	354.9	355.4
CTG1 net export	kW	158,750	159,563	158,940	158,500
CTG2 net export	kW	163,458	164,210	163,300	163,298
STG net export	kW	173,850	174,300	174,190	174,100
Plant fuel supply pressure	barg	16.532	16.505	16.500	16.479
Plant supply fuel flow	kg/h	67,865	68,018	67,831	67,767
Fuel heating value, LHV	kJ/kg LHV	48,356	48,335	48,343	48,354
Fuel H/C atom ratio for combustibles	. . .	3.938	3.938	3.937	3.937
Ambient dry bulb temperature at CTG	°C	16.7	16.8	17.4	17.7
Barometric pressure	bara	0.9975	0.9984	0.9985	0.9990
Ambient relative humidity	%	77.0	77.0	77.1	77.1
ACC inlet dry bulb temperature	°C	17.0	17.1	18.1	18.5
Combustion turbine #1 generator output	MW	167.678	167.923	167.285	167.080
Combustion turbine #1 generator reactive power	. . .	28.085	31.146	32.526	36.211
Combustion turbine #2 generator output	MW	168.397	168.604	168.143	167.780
Combustion turbine #2 generator reactive power	. . .	27.251	30.252	31.721	35.491
Steam turbine generator output	MW	174.037	174.539	173.920	174.180
Steam turbine generator reactive power	. . .	18.465	14.012	16.102	23.566
Auxiliary load deviation from design	kW	−192.1	−200.1	−205.3	−212.5
Calculated Values					
P_{meas}, measured net plant electrical output	kW	496,058	498,073	496,430	495,898
CTG 1 generator power factor	. . .	0.986	0.983	0.982	0.977
CTG 2 generator power factor	. . .	0.987	0.984	0.983	0.978
ST generator power factor	. . .	0.994	0.997	0.996	0.991
ACC inlet dry bulb temperature — CTG dry bulb temperature	°C	0.39	0.34	0.69	0.82
Measured total plant fuel flow	kg/h	67,865	68,018	67,831	67,767
Q_{meas}, measured heat input to the plant	GJ/h LHV	3,281.7	3,287.6	3,279.2	3,276.8
Measured net plant heat rate	kJ/kWh	6,615.5	6,600.7	6,605.5	6,607.8
Additive Correction Factors					
Δ_1 thermal efflux	kW	0.0	0.0	0.0	0.0
Δ_{2a}, CTG 1 power factor correction	kW	−311.6	−305.1	−299.3	−288.3
Δ_{2b}, CTG 2 power factor correction	kW	−316.1	−309.8	−304.4	−292.9
Δ_{2c}, STG power factor correction	kW	−216.1	−220.6	−218.0	−210.7
$\Delta_{3,HP}$, HRSG HP blowdown	kW	0.0	0.0	0.0	0.0
$\Delta_{3,IP}$, HRSG IP blowdown	kW	0.0	0.0	0.0	0.0
Δ_4, secondary heat inputs	kW	0.0	0.0	0.0	0.0
Δ_{5a}, difference between ACC and CTG inlet temps	kW	278.5	264.4	388.2	438.1
Δ_6, auxiliary loads different from design conditions	kW	−192.1	−200.1	−205.3	−212.5
Δ_7, measured power different than specified	kW	0.0	0.0	0.0	0.0
Sum of Δ's	**kW**	**−757.3**	**−771.2**	**−638.9**	**−566.4**

Table F-9-1 Summary of Measured Parameters, Corrections, and Results (SI Units) (Cont'd)

Description	Units	Test Run 1	Test Run 2	Test Run 3	Test Run 4
Inputs					
Multiplicative Correction Factors for Power					
α_1, ambient dry bulb temperature	...	1.0105	1.0111	1.0144	1.0158
α_2, ambient barometric pressure	...	1.0153	1.0143	1.0142	1.0137
α_3, ambient relative humidity	...	0.9998	0.9998	0.9999	0.9999
α_4, fuel supply temperature	...	1.0000	1.0000	1.0000	1.0000
α_5, fuel analysis different than design	...	0.9996	0.9996	0.9996	0.9996
α_6, grid frequency (external)	...	1.0000	1.0000	1.0000	1.0000
α_{7a}, evaporative cooler operation	...	1.01506	1.01506	1.01506	1.01506
α_{7b}, evaporative cooler performance different than design	...	1.00167	1.00167	1.00167	1.00167
Product of α's	...	**1.0426**	**1.0422**	**1.0445**	**1.0465**
Multiplicative Correction Factors for Heat Rate					
f_1, ambient dry bulb temperature	...	0.9986	0.9985	0.9981	0.9979
f_2, ambient barometric pressure	...	0.9997	0.9997	0.9997	0.9997
f_3, ambient relative humidity	...	0.9995	0.9995	0.9995	0.9994
f_4, fuel supply temperature	...	1.0000	1.0000	1.0000	1.0000
f_5, fuel analysis different than design	...	1.0001	1.0001	1.0001	1.0001
f_6, grid frequency (external)	...	1.0000	1.0000	1.0000	1.0000
f_{7a}, evaporative cooler operation	...	1.00027	1.00027	1.00027	1.00027
f_{7b}, evaporative cooler performance different than design	...	0.99975	0.99975	0.99975	0.99975
Product of f's	...	**0.9980**	**0.9979**	**0.9974**	**0.9972**
Net Power Calculations					
P_{corr}, corrected net power output	kW	516,382	518,278	518,365	518,350
Net Heat Rate Calculations					
HR_{corr}, corrected net heat rate	kJ/kWh LHV	6,267.1	6,252.8	6,252.7	6,252.7

Table F-9-2 Summary of Measured Parameters, Corrections, and Results (U.S. Customary Units)

Description	Units	Test Run 1	Test Run 2	Test Run 3	Test Run 4
Inputs					
Evaporative coolers in service (Y/N)	Y/N	N	N	N	N
CTG 1 fired hours	hr	350.6	351.1	351.6	352.1
CTG 2 fired hours	hr	357.2	357.7	358.2	358.7
Average unit fired hours	hr	353.9	354.4	354.9	355.4
CTG 1 net export	kW	158,750	159,563	158,940	158,500
CTG 2 net export	kW	163,458	164,210	163,300	163,298
STG net export	kW	173,850	174,300	174,190	174,100
Plant fuel supply pressure	psig	239.8	239.4	239.3	239.0
Plant supply fuel flow	kpph	149.62	149.95	149.54	149.40
Fuel heating value, LHV	Btu/lb LHV	20,789	20,780	20,784	20,789
Fuel H/C atom ratio for combustibles	. . .	3.937	3.938	3.937	3.937
Ambient dry bulb temperature at CTG	°F	61.97	62.16	63.35	63.82
Barometric pressure	psia	14.468	14.480	14.482	14.489
Ambient relative humidity	%	77.04	77.03	77.12	77.07
ACC inlet dry bulb temperature	°F	62.67	62.77	64.60	65.30
Combustion turbine #1 generator output	MW	167.678	167.923	167.285	167.080
Combustion turbine #1 generator reactive power	. . .	28.085	31.146	32.526	36.211
Combustion turbine #2 generator output	MW	168.397	168.604	168.143	167.780
Combustion turbine #2 generator reactive power	. . .	27.251	30.252	31.721	35.491
Steam turbine generator output	MW	174.037	174.539	173.920	174.180
Steam turbine generator reactive power	. . .	18.465	14.012	16.102	23.566
Auxiliary load deviation from design	kW	−192.1	−200.1	−205.3	−212.5
Calculated Values					
P_{meas}, measured net plant electrical output	kW	496,058	498,073	496,430	495,898
CTG 1 generator power factor	. . .	0.986	0.983	0.982	0.977
CTG 2 generator power factor	. . .	0.987	0.984	0.983	0.978
ST generator power factor	. . .	0.994	0.997	0.996	0.991
ACC inlet dry bulb temperature — CTG dry bulb temperature	°F	0.70	0.61	1.25	1.48
Measured total plant fuel flow	KPPH	149.62	149.95	149.54	149.40
Q_{meas}, measured heat input to the plant	mm Btu/hr LHV	3,110.4	3,116.1	3,108.1	3,105.8
Measured net plant heat rate	Btu/kWh LHV	6,270.3	6,256.2	6,260.8	6,263.0
Additive Correction Factors					
Δ_1 thermal efflux	kW	0.0	0.0	0.0	0.0
Δ_{2a}, CTG 1 power factor correction	kW	−311.6	−305.1	−299.3	−288.3
Δ_{2b}, CTG 2 power factor correction	kW	−316.1	−309.8	−304.4	−292.9
Δ_{2c}, STG power factor correction	kW	−216.1	−220.6	−218.0	−210.7
$\Delta_{3,HP}$, HRSG HP blowdown	kW	0.0	0.0	0.0	0.0
$\Delta_{3,IP}$, HRSG IP blowdown	kW	0.0	0.0	0.0	0.0
Δ_4, secondary heat inputs	kW	0.0	0.0	0.0	0.0
Δ_{5a}, difference between ACC and CTG inlet temps	kW	278.5	264.4	388.2	438.1
Δ_6, auxiliary loads different from design conditions	kW	−192.1	−200.1	−205.3	−212.5
Δ_7, measured power different than specified	kW	0.0	0.0	0.0	0.0
Sum of Δ's	**kW**	**−757.3**	**−771.2**	**−638.9**	**−566.4**
Multiplicative Correction Factors for Power					
α_1, ambient dry bulb temperature	. . .	1.0105	1.0111	1.0144	1.0158
α_2, ambient barometric pressure	. . .	1.0153	1.0143	1.0142	1.0137
α_3, ambient relative humidity	. . .	0.9998	0.9998	0.9999	0.9999
α_4, fuel supply temperature	. . .	1.0000	1.0000	1.0000	1.0000
α_5, fuel analysis different than design	. . .	0.9996	0.9996	0.9996	0.9996
α_6, grid frequency (external)	. . .	1.0000	1.0000	1.0000	1.0000
α_{7a}, evaporative cooler operation	. . .	1.01506	1.01506	1.01506	1.01506
α_{7b}, evaporative cooler performance different than design	. . .	1.00167	1.00167	1.00167	1.00167
Product of α's	**. . .**	**1.0426**	**1.0422**	**1.0445**	**1.0465**

Table F-9-2 Summary of Measured Parameters, Corrections, and Results (U.S. Customary Units) (Cont'd)

Description	Units	Test Run 1	Test Run 2	Test Run 3	Test Run 4
Multiplicative Correction Factors for Heat Rate					
f_1, ambient dry bulb temperature	. . .	0.9986	0.9985	0.9981	0.9979
f_2, ambient barometric pressure	. . .	0.9997	0.9997	0.9997	0.9997
f_3, ambient relative humidity	. . .	0.9995	0.9995	0.9995	0.9994
f_4, fuel supply temperature	. . .	1.0000	1.0000	1.0000	1.0000
f_5, fuel analysis different than design	. . .	1.0001	1.0001	1.0001	1.0001
f_6, grid frequency (external)	. . .	1.0000	1.0000	1.0000	1.0000
f_{7a}, evaporative cooler operation	. . .	1.00027	1.00027	1.00027	1.00027
f_{7b}, evaporative cooler performance different than design	. . .	0.99975	0.99975	0.99975	0.99975
Product of f's	. . .	**0.9980**	**0.9979**	**0.9974**	**0.9972**
Net Power Calculations					
P_{corr}, corrected net power output	kW	516,382	518,278	518,365	518,350
Net Heat Rate Calculations					
HR_{corr}, corrected net heat rate	Btu/kWh LHV	6,612.2	6,597.1	6,596.9	6596.9

$s_{\bar{x}}$ = standard deviation of the mean. The value of this term is calculated from test data in accordance with eq. (6-1.4) of ASME PTC 19.1.

$t_{95,v}$ = Student's t. The value of the Student's t is determined for each measurement based on the degrees of freedom for the measurement and a 95% confidence level.

$U_{95,\,RND}$ = random uncertainty of the measurement at 95% confidence. The value of this term is equal to the product of $s_{\bar{x}}$ and $t_{95,v}$.

$$U_{95,RND} = S_{\bar{x}} t_{95,v}$$

$U_{95,TOT}$ = Total Measurement Uncertainty at 95% confidence. The value of this term is equal to the root-sum-square of $U_{95,SYS}$ and $U_{95,RND}$. $U_{95,TOT} = \sqrt{U_{95,SYS}^2 + U_{95,RND}^2}$

θ = absolute sensitivity coefficient.

θ' = relative sensitivity coefficient.

where

$U_{kW,SYS}$, $U_{HR,SYS}$, $U_{HI,SYS}$ = systematic uncertainty of corrected output, corrected heat rate, and measured heat input, respectively. The value of each term is equal to the product of $U_{95,SYS}$ and the applicable sensitivity coefficient.

$U_{kW,RAND}$, $U_{HR,RAND}$, $U_{HI,RAND}$ = random uncertainty of corrected output, corrected heat rate, and measured heat input, respectively. The value of each term is equal to the product of $U_{95,RAND}$ and the applicable sensitivity coefficient.

$U_{kW,TOT}$, $U_{HR,TOT}$, $U_{HI,TOT}$ = total uncertainty of corrected output, corrected heat rate, and measured heat input, respectively. The value of each term is equal to the root-sum-square of U_{SYS} and U_{RAND}.

Sensitivity coefficients are calculated numerically in accordance with eqs. (7-2.3) and (7-2.4) of ASME PTC 19.1.

For absolute sensitivity coefficients

$$\theta_i = \frac{\Delta R}{\Delta \overline{X}_i}$$

For relative sensitivity coefficients

$$\theta'_i = \frac{\overline{X}_i}{R}\left(\frac{\Delta R}{\Delta \overline{X}_i}\right)$$

Table F-12-1 Pressure Transmitter Operating and Vendor Information

Measurement Location	Qty.	URL [Note (1)]	Span [Note (2)]	TR [Note (3)]
		SI Units		
Barometric pressure	1	2.0684 bara	0.8274–1.0342 bara = 0.2068	10:1
Plant fuel supply pressure (gas compressor inlet)	1	55.1581 bara	0–55.1581 bara = 55.1581	1:1
Plant supply fuel flow differential pressure	2	635.00 cm–H_2O	0–635.00 cm–H_2O = 635.00	1:1
Plant supply fuel flowing pressure	1	55.1581 bara	0–27.5790 bara = 27.5790	2:1
		U.S. Customary Units		
Barometric pressure	1	30 psia	12–15 psia = 3	10:1
Plant fuel supply pressure (gas compressor inlet)	1	800 psia	0–800 psia = 800	1:1
Plant supply fuel flow differential pressure	2	250 in.–H_2O	0–250 in.–H_2O = 250	1:1
Plant supply fuel flowing pressure	1	800 psia	0–400 psia = 400	2:1

NOTES:
(1) URL = upper range limit
(2) Span = calibration span
(3) TR = turndown ratio = URL/span

where

ΔR = the resulting finite numerical result perturbation by the finite numerical perturbation of the input parameter of a data reduction calculation procedure

$\Delta \overline{X}_i$ = the finite numerical perturbation of the input parameter of a data reduction calculation procedure

F-12 PRESSURE TRANSMITTER SYSTEMATIC UNCERTAINTY ANALYSIS

Digital pressure transmitters powered by a 24-V power supply loop were employed for this test. The data was recorded on 30-sec intervals utilizing a personal computer, digital communication software, and digital loop communication modem. The connecting cable was individually shielded twisted pair wire with shielding ground. Table F-12-1 presents a listing of the measurement locations and vendor operating information for pressure transmitters utilized at the measurement locations during the test.

For the purpose of this analysis, the sources of uncertainty identified for the pressure transmitters employed in the execution of this test are as follows:

(a) Stated Accuracy
(b) Calibration Uncertainty
(c) Stated Uncertainty [Reference Uncertainty/Calibration Uncertainty (RU/CU)]
(d) Ambient Temperature Effect (TE)
(e) Line Pressure Effect Zero Error (LPZE)
(f) Line Pressure Effect Span Error (LPSE)
(g) Mounting Position Effect (MPE)
(h) Vibration Effect (VE)
(i) Power Supply Effect (PSE)
(j) Radio Frequency Interference (RFI) Effect (RFIE)
(k) Data Acquisition Effect (DAE)

Each source of uncertainty was studied individually before combining into a total performance specification for the transmitter as shown in paras. F-12.1 through F-12.11.

F-12.1 Stated Accuracy

The manufacturer of the pressure transmitters claims a reference accuracy depending on the turndown ratio (TD) set during the calibration process. The manufacturer states that the reference accuracy is inclusive of the following:

(a) repeatability
(b) reproducibility
(c) linearity
(d) hysteresis

Table F-12.3-1 Pressure Transmitter Reference Uncertainty/Calibration Uncertainty

Measurement Location	Stated Accuracy, % of Span	Calibration Uncertainty, % of Span	Stated Uncertainty, % of Span
Barometric pressure	0.05	0.10	0.10
Plant fuel supply pressure (gas compressor inlet)	0.027	0.04	0.04
Plant supply fuel flow differential pressure	0.05	0.075	0.075
Plant supply fuel flow pressure	0.027	0.04	0.04

F-12.2 Calibration Uncertainty

The results from a pretest calibration analysis.

F-12.3 Stated Uncertainty [Reference Uncertainty/Calibration Uncertainty] (RU/CU)

The greater of the stated accuracy and the calibration uncertainty.

In the present example, the goal of the calibration process was to demonstrate that the transmitter was within the original performance specifications stated by the vendor. However, in the case of the barometric pressure, the laboratory calibration certificate stated a calibration uncertainty of 0.10% of span which is higher than the vendor reference accuracy. Thus the calibration uncertainty is utilized as the stated uncertainty for the device. Table F-12.3-1 presents a summary of the reference accuracy/calibration uncertainties and the stated accuracy for the pressure devices employed during the testing.

F-12.4 Ambient Temperature Effect (TE)

The pressure transmitters used for the testing exhibit sensitivity to changes in ambient temperature. Per the calibration certificates, the calibrations were conducted at 20°C (68°F). The nominal ambient temperature measured at the measurement locations was never lower than 62°F, and thus 62°F was considered the limiting ambient temperature as was utilized in the estimation of the temperature effect. The manufacturer quantifies the ambient temperature effect by presenting equations based on URL, percent of span, ambient temperature, calibration temperature, and T_{Diff} = 28°C (50°F). Testing of the pressure devices in an ambient chamber has revealed that this effect is linear with temperature. These equations, provided by the instrument manufacturer, and the resulting temperature effect are presented in Table F-12.4-1.

F-12.5 Line Pressure Effect Zero Error (LPZE)

The uncertainty contribution for line pressure effect is assumed negligible since the differential transmitters were zero trimmed at line pressure. The process of zero trimming does not affect the validity of the calibration. The Line Pressure Effect Zero Error does not apply to the barometric pressure or static pressure transmitters.

F-12.6 Line Pressure Effect Span Error (LPSE)

The uncertainty contribution for line pressure effect is given by the manufacturer as 0.01% of reading per 68.9476 bar (1,000 psi). For simplicity, the maximum line pressure and the maximum differential pressure reading sensed during the testing is utilized in the analysis along with the actual span of the instrument, thus representing the worst case scenario. With these assumptions applied, the maximum uncertainty contribution is presented in Table F-12.6-1. The Line Pressure Effect Span Error does not apply to the barometric pressure or static pressure transmitters.

F-12.7 Mounting Position Effect (MPE)

The uncertainty contribution for mounting effect is assumed negligible since the transmitters were installed in the same orientation of calibration. The installation was checked with a level to confirm proper orientation.

F-12.8 Vibration Effect (VE)

Measurement effect due to vibrations is negligible except at resonance frequencies. Resonance frequencies were not observed and mounting locations were checked for presence of vibration prior to mounting.

F-12.9 Power Supply Effect (PSE)

Power supply effects are negligible since the power supply is regulated at 24 V and the transmitters were read digitally.

Table F-12.4-1 Ambient Temperature Effect

Measurement Location	Ambient Temperature Effect Calculation	TE, % of Span
Barometric pressure	$\pm \frac{2}{3} \times (0.025\%\text{URL} + 0.125\%\ \text{span}) \times \left(\frac{T_{Amb}-T_{Cal}}{T_{Diff}}\right)/\text{span}$	0.030
Plant fuel supply pressure (gas compressor inlet)	$\pm \frac{2}{3} \times (0.0125\%\text{URL} + 0.0625\%\ \text{span}) \times \left(\frac{T_{Amb}-T_{Cal}}{T_{Diff}}\right)/\text{span}$	0.006
Plant supply fuel flow differential pressure	$\pm \frac{2}{3} \times (0.009\%\text{URL} + 0.04\%\ \text{span}) \times \left(\frac{T_{Amb}-T_{Cal}}{T_{Diff}}\right)/\text{span}$	0.00387
Plant supply fuel flow pressure	$\pm \frac{2}{3} \times (0.0125\%\text{URL} + 0.0625\%\ \text{span}) \times \left(\frac{T_{Amb}-T_{Cal}}{T_{Diff}}\right)/\text{span}$	0.007

Table F-12.6-1 Line Pressure Effect Span Error

Measurement Location	Max. Line Pressure	Max. Reading	Line Pressure Effect Span Uncertainty, % of Span
SI Units			
Plant supply fuel flow differential pressure	16.7437 barg	546.6 cm–H_2O	$\pm \frac{2}{3} \times 0.01\% \times (\text{Reading}) \times \frac{\text{LinePress}}{68.9476}/\text{Span}$ $\pm \frac{2}{3} \times 0.01\% \times (546.66) \times \frac{16.7437}{68.9476}/635.00 = 0.0014\%$
U.S. Customary Units			
Plant supply fuel flow differential pressure	242.85 psig	215.22 in.–H_2O	$\pm \frac{2}{3} \times 0.01\% \times (\text{Reading}) \times \frac{\text{LinePress}}{1000}/\text{Span}$ $\pm \frac{2}{3} \times 0.01\% \times (215.22) \times \frac{242.85}{1000}/250 = 0.0014\%$

F-12.10 RFI Effect (RFIE)

RFI effects are negligible since the system was properly insulated, and the transmitters were read digitally.

F-12.11 Data Acquisition Effect (DAE)

Data acquisition effects are negligible since the data acquisition system is an integrated component of the transmitter and the data was transmitted digitally from the transmitters and recorded by a laptop computer. Further, since the data acquisition is integrated, it is calibrated along with the instrument.

With each source of error identified, categorized, and estimated, the total performance specification can be determined by root-sum squaring the individual contributors since they are uncorrelated. The general equation is as follows:

Total Pressure Transmitter Performance Specification Uncertainty =

$$\pm \sqrt{\begin{matrix}(RU/CU)^2 + (TE)^2 + (LPZE)^2 + (LPSE)^2 \ldots \\ \ldots + (MPE)^2 + (VE)^2 + (PSE)^2 + (RFIE)^2 + (DAE)^2\end{matrix}}$$

The total device measurement uncertainties are presented in Table F-12.11-1.

F-13 THERMISTOR TEMPERATURE MEASUREMENT SYSTEMATIC UNCERTAINTY ANALYSIS

All temporary test instrument temperature measurements were made with analogue 2.2 kΩ thermistors connected to a data acquisition switch unit measuring resistance. Resistance measurements were then converted to engineering temperature units (°C and °F) using a software package that applied the Steinhart-Hart Equation determined through calibration by the laboratory. The thermistors and data acquisition switch unit were loop calibrated. The connecting cable was individually shielded, twisted pair wire with shielding ground. The data was recorded on 30-sec intervals utilizing a personal computer and data acquisition switch communication software. Individual

Table F-12.11-1 Total Pressure Transmitter Performance Specification Uncertainty

Measurement Location	Total Performance Specification Uncertainty, % of Span
Barometric pressure	$\pm\sqrt{(0.1)^2 + (0.3)^2 + (0)^2 + (0)^2 + (0)^2 + (0)^2 + (0)^2 + (0)^2} = \pm 0.10\%$
Plant fuel supply pressure (gas compressor inlet)	$\pm\sqrt{(0.04)^2 + (0.006)^2 + (0)^2 + (0)^2 + (0)^2 + (0)^2 + (0)^2 + (0)^2} = \pm 0.040\%$
Plant supply fuel flow differential pressure	$\pm\sqrt{(0.075)^2 + (0.00392)^2 + (0)^2 + (0.0014)^2 + (0)^2 + (0)^2 + (0)^2 + (0)^2} = \pm 0.075\%$
Plant supply fuel flowing pressure	$\pm\sqrt{(0.04)^2 + (0.007)^2 + (0)^2 + (0)^2 + (0)^2 + (0)^2 + (0)^2 + (0)^2} = \pm 0.041\%$

GENERAL NOTE: The above uncertainty statements are in percent of span. To utilize these in the uncertainty analysis, they will be converted to % of reading.

Table F-13-1 Thermistor Operating and Vendor Information

Interchangeability Tolerance 0°C—70°C (32°F—158°F)	Zero Power Resistance Ω at 25°C (77°F)	Beta 0°C—50°C (32°F—122°F)	Ratio Ω at 25°C/125°C (77°F/257°F)
±0.1°C (±0.18°F)	2 252	3 891	29.26

GENERAL NOTE: Maximum Working Temperature is 150°C (302°F).

lead line resistances were measured and compensated for in the data acquisition software. Thermistors used for measurement of the ambient dry bulb temperature were deployed in the filter house within 0.127 m (5 in.) of the filter face in an equal area grid pattern. The probes were placed such that they were not exposed to solar radiation (shaded). Thermistors placed within the compressor inlet ducting to measure compressor inlet temperature were inserted into the duct through fixed ports in the duct wall in an equal area grid pattern. These probes were firmly affixed to support structures to avoid vibration induced by the inlet flow. Thermistors used for measurement of the air-cooled condenser inlet dry bulb temperature were deployed with aspirating psychrometer fixtures to protect the element from solar radiation impacts. The wicking and water bottles were removed from the aspirating psychrometers so to measure dry bulb.

Table F-13-1 presents a listing of the vendor operating information for thermistors utilized in the test.

Since the thermistor temperature measurements were performed in conjunction with a data acquisition switch, both the thermistors and the data acquisition were analyzed for their uncertainty contributions individually. The uncertainties for the thermistor and data acquisition were then combined to attain a total systematic uncertainty.

For the purpose of this analysis, the sources of uncertainty identified for the thermistors utilized in the execution of this test are as follows:

(a) Thermistor Stated Accuracy [Reference Uncertainty/Calibration Uncertainty (TRU/CU)]
(b) Thermistor Environmental Effect (TEE)
(c) Thermistor Stability Effects (TSE)
(d) Thermistor Self Heating Effects (TSHE)
(e) Thermistor Heat Transfer Effects (THTE)

The sources of uncertainty identified for the data acquisition system (DAS) utilized in the execution of this test are as follows:

(f) DAS Stated Accuracy [Reference Uncertainty/Calibration Uncertainty (DRU/CU)]
(g) DAS Environmental Effect (DEE)
(h) DAS Stability Effects (DSE)
(i) DAS Parasitic Resistance Effect (DPRE)
(j) DAS Parasitic Voltage Effect (DPVE)

Each source of uncertainty was studied individually before combining into a total performance specification for the thermistor and data acquisition switch used together as shown in paras. F-13.1 through F-13.10.

F-13.1 Thermistor Stated Accuracy [Reference Uncertainty/Calibration Uncertainty (TRU/CU)]

The manufacturer of the thermistor claims an interchangeability of ±0.1°C (±0.18°F). This term is sometimes confused with uncertainty. Interchangeability refers to how accurately thermistors track a nominal resistance curve. The uncertainty for thermistors at a measured temperature is significantly better than their interchangeability statement if calibrated. In the present example, the role of the calibration process was to demonstrate the uncertainty and to provide the Steinhart-Hart regression for the calibration. The calibration certificates for the thermistors state a ±0.056°C (±0.1°F) uncertainty when the calibration regression determined Steinhart-Hart equation is used to convert resistance readings to temperature units for a temperature calibration range from 0°C (32°F) to 121.11°C (250°F).

F-13.2 Thermistor Environmental Effect (TEE)

The heat transfer characteristics between the thermistor probe and its surroundings change from calibration conditions to test conditions, introducing additional error into the temperature measurement. Thermistors deployed in the filter house and compressor inlets were installed away from incident heat sources and out of the influence region of solar radiation. Thermistors deployed at the ACC inlet were equipped with aspirating psychrometers designed to minimize solar radiation influence. Thermistors used to measure fuel temperatures were placed in thermowells and were well insulated. Every precaution was taken to ensure that the thermistor probes were protected from incident heating, heat transfer, and solar radiation sources. It has been assumed that sufficient installation, insulation, and shielding practices have been strictly adhered to in order to remove and/or minimize these errors, and as a result the environmental effects uncertainty contribution is assumed negligible.

F-13.3 Thermistor Stability Effects (TSE)

Post-test calibrations were used to verify the stability within the accuracy limit of ±0.056°C (±0.10°F). Therefore, the stability effects uncertainty contribution is negligible.

F-13.4 Thermistor Self Heating Effects (TSHE)

As current flows through the resistor element of a thermistor, heat is generated due to the continuous power dissipated in the sensor. The heat generated results in a potential measurement offset depending on heat transfer characteristics between the sensor and its surroundings. In the present example, this effect is included in the calibration process since the probes are loop calibrated with the data acquisition system that provides the current to the sensor. Therefore, no separate uncertainty contribution is applied under the self heating effect category.

F-13.5 Thermistor Heat Transfer Effects (THTE)

The thermistor used for the fuel measurement was installed in a stainless steel thermowell, and the pipe in which the thermowell was installed was insulated. When a temperature difference between the flowing gas and the pipe wall exists, heat transfer will occur. This heat transfer is present between the thermistor and the pipe wall due to conduction through the thermowell. Convection is also present between the flowing gas and the thermowell. Though lower than convection and conduction, radiation heat transfer also exists. The convection drives the thermistor reading closer to the gas flowing temperature while the conduction drives the thermistor reading closer to the pipe wall temperature. To account for the uncertainty contribution due to the heat transfer effects, a thermal model of the thermowell which took into account the gas density, gas velocity, gas temperature, pipe wall temperature, thermowell geometry, and pipe material was utilized to approximate the temperature error. The thermowell specifications were 1.27 cm (0.5 in.) O.D., 0.635 cm (0.25 in.) I.D., and 24.21 cm (9.53 in.) for the gas flow stream. The average gas temperature was 15.59°C (61.86°F) and the average gas velocity was 29.46 m/s (96.66 ft/sec). The average pipe wall temperature was measured to be 174.0°C (345.2°F). The thermal model resulted in a prediction of temperature error of 0.000048°C (0.000085°F).

With each source of error identified, categorized, and estimated for the thermistor, the total thermistor performance specification can be determined by root-sum squaring the individual contributors since they are uncorrelated. The general equation is as follows:

Total Thermistor Performance Specification Uncertainty =

$$\pm\sqrt{(TRU/CU)^2 + (TEE)^2 + (TSE)^2 + (TSHE)^2 + (THTE)^2}$$

The total thermistor element uncertainties are presented in Table F-13.5-1. Separate calculations are shown for those thermistors installed inside a thermowell and those that are not.

F-13.6 DAS Stated Accuracy [Reference Uncertainty/Calibration Uncertainty (DRU/CU)]

The DAS manufacturer states a 90-day uncertainty specification for resistance measurements is ±(0.008% of reading + 0.001% of range) for the 10 kΩ range. The manufacturer states that the uncertainty specification is inclusive of the following:

(a) measurement error

Table F-13.5-1 Total Thermistor Performance Specification Uncertainty

Application	Total Performance Specification Uncertainty, °C
SI Units	
Nonthermowell	$\pm\sqrt{(0.056)^2 + (0)^2 + (0)^2 + (0)^2 + (0)^2} = \pm 0.056°C$
Thermowell	$\pm\sqrt{(0.056)^2 + (0)^2 + (0)^2 + (0)^2 + (0.000048)^2} = \pm 0.056°C$
U.S. Customary Units	
Nonthermowell	$\pm\sqrt{(0.1)^2 + (0)^2 + (0)^2 + (0)^2 + (0)^2} = \pm 0.1°F$
Thermowell	$\pm\sqrt{(0.1)^2 + (0)^2 + (0)^2 + (0)^2 + (0.0009)^2} = \pm 0.1°F$

(b) switching error
(c) transducer conversion error

In the present example, the primary role of the calibration process was to demonstrate that the DAS was within the original performance specifications stated by the vendor.

The highest reading of 7 355 Ω at 0°C (32°F) corresponds to the highest uncertainty expected in the 0°C (32°F) to 121.11°C (250°F) calibration range. Therefore, the worst case systematic error associated with the HP DAS calibration accuracy becomes

$$B_R = \pm(0.008\% * 7\,355\ \Omega + 0.001\% * 10\,000\ \Omega) = \pm 0.6884\ \Omega$$

A resistance error sensitivity coefficient is used to convert the DAS calibration accuracy bias error from resistance to temperature. ASME PTC 19.1 defines sensitivity as the error propagated to the resulting measurement due to a unit error in the measurement parameter. Sensitivity coefficients may be determined through analytical or numerical analysis as

$$\theta_{r,P_i} = \partial r/\partial P_i \text{ or } \theta_{r,P_i} \approx \Delta r/\Delta P_i$$

where

P_i = measurement parameter
r = resulting measurement
$\theta_{r,Pi}$ = sensitivity coefficient for the resulting measurement with respect to a measurement parameter

The sensitivity can then be applied as

$$B_T = B_R * \theta_{T,R}$$

where

B_R = resistance bias, Ω
B_T = resistance bias, °C (°F)
$\theta_{T,R}$ = resistance error sensitivity coefficient, °C/Ω (°F/Ω)

The general form of the Steinhart-Hart equation that relates measured resistance to temperature given by

$$T = \frac{1}{a + b[\ln R_T] + c[\ln R_T]^3}$$

where

a = coefficient = 0.001470268
b = coefficient = 0.000237817
c = coefficient = 1.04014 E−07
R_T = resistance at temperature T, Ω
T = temperature, K (°R)

NOTE: Coefficients are for standard 2.2k Ω thermistor.

The following equation results by taking the partial derivative of T with respect to R_T:

$$\theta_{T,R} = \frac{\partial T}{\partial R_T} = \frac{-1}{\left(a + b \cdot \ln(R_T) + c \cdot \ln(R_T)^3\right)^2} \cdot \left(\frac{b}{R_T} + 3 \cdot c \cdot \frac{\ln(R_T)^2}{R_T}\right)$$

The sensitivity coefficient may be calculated for 7 355 Ω and 0°C (32°F) as follows:

$$\theta_{T,R} = \frac{\partial T}{\partial R_T} = \frac{-1}{\left(0.001470268 + 0.000237817 \cdot \ln(7\,355) + 1.04014\mathrm{E} - 7 \cdot \ln(7\,355)^3\right)^2} \cdots$$

$$\cdots \left(\frac{0.000237817}{7\,355} + 3 \cdot 1.04014\mathrm{E} - 7 \cdot \frac{\ln(7\,355)^2}{7\,355}\right) = -0.002663388\ \mathrm{K}/\Omega$$

The sensitivity coefficient sign demonstrating the slope at 7 355 Ω and 0°C (32°F) point is negative. However, only the magnitude for $\theta_{T,R}$ is needed. Now the resistance error sensitivity coefficient can be applied to convert the DAS calibration accuracy bias error from resistance to temperature as follows:

$$B_T = B_R \cdot \theta_{T,R} = (\pm 0.6884\ \Omega) \cdot (0.002663388\ \mathrm{K}/\Omega) = \pm 0.0018\ \mathrm{K} = \pm 0.0018°\mathrm{C}\ (\pm 0.0032°\mathrm{F})$$

F-13.7 DAS Environmental Test Effect (DEE)

Operation of the DAS in environmental conditions that differ from those in which it was calibrated can potentially introduce additional uncertainty. Manufacturer's specifications often provide temperature coefficients which may be used to derate the performance of the instrument based on the expected operating temperature range.

The DAS environmental bias error may be calculated from the following equation:

$$B_{DAS} = TC * \Delta T$$

where

TC = temperature coefficient used to derate the accuracy specifications, given by the manufacturer for the proper resistance range

Δ_T = difference between the ambient temperature range during calibration and the ambient temperature range during operation, evaluated for the worst-case difference

For the 10 kΩ measurement range, the manufacturer gives a temperature coefficient of

$$TC = [\pm(0.0006\% \text{ of reading} + 0.0001\% \text{ of range})/°\mathrm{C}]$$

or

$$TC = [\pm(0.00033\% \text{ of reading} + 0.000055\% \text{ of range})/°\mathrm{F}]$$

This temperature coefficient is valid for operating temperature ranges from 0°C (32°F) to 18°C (64.4°F) and 28°C (82.4°F) to 55°C (131°F). There is no temperature coefficient for operating temperatures between 18°C (64.4°F) and 28°C (82.4°F). The temperature differential, ΔT, is calculated as the difference in the operating temperature and the calibration range bounding temperature. During the testing, the DAS was placed in an air-conditioned room and the temperature differential was measured as

$$\Delta T = 9°\mathrm{C}\ (16.2°\mathrm{F})$$

Substituting the values of the temperature coefficient and temperature differential into the equation for the DAS environmental bias yields

$$B_{\mathrm{DAS,env}} = [\pm(0.0006\% \text{ of reading} + 0.0001\% \text{ of range})/°\mathrm{C}]*[9°\mathrm{C}]$$

$$B_{\mathrm{DAS,env}} = [\pm(0.00033\% \text{ of reading} + 0.000055\% \text{ of range})/°\mathrm{F}]*[16.2°\mathrm{F}]$$

$$B_{\mathrm{DAS,env}} = [\pm(0.0054\% \text{ of reading} + 0.0009\% \text{ of range})]$$

From this expression it can be seen that the maximum environmental error exists when the thermistor resistance is maximized. This occurs at the lower limit of the calibration range, at a temperature of 0°C (32°F) corresponding to an RTD resistance of 7 355 Ω. The maximum DAS environmental bias for the system is then calculated to be

$$B_{\mathrm{DAS,env}} = \left[\pm(0.0054\% \text{ of } * 7\,355\ \Omega + 0.0009\% * 10\,000\ \Omega)\right]$$

$$B_{\mathrm{DAS,env}} = \pm 0.487\ \Omega$$

Applying the resistance error sensitivity coefficient to the DAS environmental bias yields the additional error due to DAS environmental bias as

$$B_{\mathrm{DAS,env}} = (°\mathrm{F}) = B_{\mathrm{DAS,env}}(\Omega) * \theta_{T,R}$$

$$B_{\mathrm{DAS,env}} = (\pm\ 0.487\ \Omega) * (0.002663388\ \mathrm{K}/\Omega) = \pm\ 0.0013\ \mathrm{K} = \pm 0.0013°\mathrm{C}\ (\pm\ 0.0023°\mathrm{F})$$

F-13.8 DAS Stability Effects (DSE)

Post-test calibrations are used to verify the system stability within the accuracy limit of ±(0.008% of reading + 0.001% of range). Therefore, the additional bias due to DAS stability is negligible.

F-13.9 DAS Parasitic Resistance Effect (DPRE)

Parasitic resistances are introduced into the measurement circuit by lead wires, lead wire imbalances, circuit connections, and multiplexing relays. Effects of parasitic resistance may be minimized by using proper installation, calibration, and measurement techniques. It has been assumed for this analysis that these techniques have been strictly adhered to in order to minimize these effects. The individual effects of these error sources will now be analyzed.

(a) Lead Wire Effects. The thermistors were wired to the DAS using the 4-wire measurement technique. Lead wire resistance effects are removed via the 4-wire measurement technique. Therefore, the bias error due to the parasitic resistance of the lead wires is zero.

(b) Lead Wire Imbalance Effects. Lead wire imbalances do not contribute error to the measurement due to the use of the 4-wire measurement technique, which eliminates parasitic resistances introduced by lead wire imbalances. Therefore, the additional bias error due to lead wire imbalance effects does not contribute.

(c) Connection Effects. Connectors present in the measurement circuit have the potential for introducing parasitic resistances. The 4-wire measurement technique eliminates the effects of parasitic resistance introduced by circuit connections. Therefore, the additional bias error introduced by circuit connection effects is assumed negligible.

(d) Multiplexing Relay Effects. Parasitic resistances are introduced into the measurement circuit by the "contact resistance" inherent in all multiplexing relays. Contact resistance values for two wire armature relays for the multiplexer are less than 1 Ω. However, the 4-wire measurement technique employed by the DAS eliminates contact resistance effects in the measurement circuit. Therefore, the additional bias introduced by multiplexing relay effects is assumed negligible.

F-13.10 DAS Parasitic Voltage Effect (DPVE)

Parasitic voltages are introduced into the measurement circuit by noise and thermal EMFs. The effects of parasitic voltages may be minimized and/or removed by using proper installation and measurement techniques. These practices have been strictly adhered to in order to minimize parasitic voltage effects.

(a) Noise. The effects of electrostatic and electromagnetic noise are minimized by the use of shielded, twisted pair instrument cable and proper grounding techniques. Also, the DAS uses a guarded, integrating analog to digital converter that further reduces external noise effects on measurements. Integration of the input signal is performed at a constant frequency, typically the line frequency, in order to remove all 60 Hz noise from the signal.

Through the use of the 4-wire measurement method and the use of the offset compensated ohms techniques, the additional bias error due to noise is negligible.

(b) Thermal EMFs. Thermal EMFs are minimized by use of clean copper to copper connections and by minimizing temperature gradients in the measurement circuit. The two most common sources of thermal EMFs in the measurement circuit are across circuit connections and multiplexer relays.

The DAS manufacturer lists the thermoelectric potential for common types of connections as shown in Table F-13.10-1.

Table F-13.10-1 Thermal Electric Potentials for Common Types of Connections

Materials	Potential
Cu–Cu	≤ 0.2 μV/°C
Cu–Pb/Sn	1–3 μV/°C

Assuming no more than a 1°C (1.8°F) temperature differential across any connection and assuming all connections are either clean Cu-Cu or Cu-Pb/Sn, the potential thermal EMF across any junction is

$$B_{\mathrm{DAS,connection}} = 3\mu\mathrm{V}$$

The DAS uses two wire armature relays in its multiplexers, and the DAS manufacturer lists the thermal electric potential of a two wire armature relay as <3μV. Therefore, the potential EMF across any multiplexer relay is

$$B_{\mathrm{DAS,relay}} = 3\mu\mathrm{V}$$

Since the magnitude and sign of the thermal EMFs across each connection and relay is dependent upon the quality of the junction and the temperature differential across the junction, the bias at each junction will be considered independent. The total bias due to parasitic voltages can be estimated as the square root of the sum of the squares of the bias at each junction. For the measurement circuit consisting of two multiplexer relays and eight Cu-Pb/Sn connections, the total bias due to thermal EMFs is

$$B_{\mathrm{DAS,EMF}} = \sqrt{2\left(B_{\mathrm{DAS,relay}}\right)^2 + 8\left(B_{\mathrm{DAS,connection}}\right)^2}$$

This would yield an uncertainty bias due to thermal EMF of

$$B_{\mathrm{DAS,EMF}} = \sqrt{2(3\mu\mathrm{V})^2 + 8(3\mu\mathrm{V})^2} = 9.5\mu\mathrm{V}$$

Next, a voltage error sensitivity coefficient should be developed to convert these bias errors from voltage to temperature. Once again using the ASME PTC 19.1 definition of sensitivity as the error propagated to the resulting measurement due to a unit error in the measurement parameter, the voltage error sensitivity coefficient can be found using Ohms Law.

$$R_{\mathrm{unknown}} = \mathrm{V}_{\mathrm{measured}}/\mathrm{I}_{\mathrm{source}}$$

The sensitivity of resistance to voltage errors is

$$\theta_{R,V} = \frac{\partial R}{\partial \mathrm{V}} = \frac{1}{\mathrm{I}_{\mathrm{source}}}$$

According to the DAS manufacturer, the source current for the 10 kΩ range is 0.1 mA, therefore

$$\theta_{R,V} = \frac{1}{0.1mA} = 10\,\frac{\Omega}{V}$$

The sensitivity of the resulting temperature measurement to a voltage error can then be determined as

$$\theta_{T,V} = \theta_{T,R}\left(\frac{K}{\Omega}\right) * \theta_{R,V}\left(\frac{\Omega}{V}\right)$$

Using the resistance error sensitivity coefficient calculated previously, this equation yields a voltage error sensitivity coefficient of

$$\theta_{T,V} = 0.002663388\,\frac{K}{\Omega} * 10\,\frac{\Omega}{V} = 0.02663388\,\frac{K}{V}$$

This error can be converted to temperature units by multiplying the parasitic voltage error by the voltage error sensitivity coefficient as follows:

$$B_{\mathrm{DAS,EMF}} = (°\mathrm{F}) = B_{\mathrm{DAS,EMF}}\,(\mathrm{V}) * \theta_{T,V}$$

Table F-13.10-2 Total DAS Performance Specification Uncertainty

SI Units
$\pm\sqrt{(0.0018)^2 + (0.0013)^2 + (0)^2 + (0)^2 + (2.53 \times 10^{-7})^2} = \pm 0.0022°C$
U.S. Customary Units
$\pm\sqrt{(0.0032)^2 + (0.0023)^2 + (0)^2 + (0)^2 + (4.55 \times 10^{-7})^2} = \pm 0.0039°F$

Table F-13.10-3 Total Thermistor Temperature Measurement Systematic Uncertainty

Application	SI Units
Nonthermowell	$\pm\sqrt{(0.056)^2 + (0.0022)^2} = \pm 0.056°C$
Thermowell	$\pm\sqrt{(0.056)^2 + (0.0022)^2} = \pm 0.056°C$
	U.S. Customary Units
Nonthermowell	$\pm\sqrt{(0.1)^2 + (0.0039)^2} = \pm 0.1°F$
Thermowell	$\pm\sqrt{(0.1)^2 + (0.0039)^2} = \pm 0.1°F$

Applying this sensitivity to the DAS environmental bias yields the additional error due to thermal EMFs as

$$B_{\text{DAS,EMF}} = (\pm 9.5\ \mu\text{V}) * (0.02663388\ \text{K/V})$$

$$B_{\text{DAS,EMF}} = \pm\ 2.53\times10^{-7}\ \text{K} = \pm\ 2.53\times10^{-7}\ °\text{C} = \pm\ 4.55\times10^{-7}\ °\text{F}$$

As can be observed, this influence can be assumed negligible.

With each source of error identified, categorized, and estimated for the DAS, the total DAS performance specification can be determined by root-sum squaring the individual contributors since they are uncorrelated. The general equation is as follows:

Total DAS Performance Specification Uncertainty =

$$\pm\sqrt{(\text{DRU/CU})^2 + (\text{DEE})^2 + (\text{DSE})^2 + (\text{DPRE})^2 + (\text{DPVE})^2}$$

The total DAS elemental uncertainties, combined to yield the total DAS performance specification uncertainties, are presented in Table F-13.10-2.

The total thermistor temperature measurement systematic uncertainty can now be determined by combining the total thermistor performance specification uncertainty with the total DAS performance specification uncertainty. The calculation is performed as shown in Table F-13.10-3.

F-14 RELATIVE HUMIDITY TRANSMITTER SYSTEMATIC UNCERTAINTY ANALYSIS

Humidity transmitters powered by a 24-V power supply loop were employed for the relative humidity measurements during this test. The data was recorded on 30-sec intervals utilizing a personal computer, digital communication software, and digital loop communication modem. The connecting cable was individually shielded, twisted pair wire with shielding ground.

Table F-14.6-1 Total Humidity Transmitter Performance Specification Uncertainty

Measurement Description	Total Performance Specification Uncertainty (Absolute Units)
Ambient relative humidity	$\pm\sqrt{(2)^2 + (0)^2 + (0)^2 + (0)^2 + (0)^2 + (0)^2} = \pm 2\%$

For the purpose of this analysis, the sources of uncertainty identified for the humidity transmitters employed in the execution of this test are as follows:

(a) Stated Accuracy [Reference Uncertainty/Calibration Uncertainty (RU/CU)]
(b) Ambient Temperature Effect (TE)
(c) Vibration Effect (VE)
(d) Power Supply Effect (PSE)
(e) RFI Effect (RFIE)
(f) Data Acquisition Effect (DAE)

Each source of uncertainty was studied individually before combining into a total performance specification for the humidity transmitter as shown in paras. F-14-1 through F-14-6.

F-14.1 Stated Accuracy [Reference Uncertainty/Calibration Uncertainty (RU/CU)]

The manufacturer of the humidity transmitters claims a reference accuracy at 20°C (68°F) depending on the relative humidity. For relative humidity less than 90%, the stated accuracy is ±2% RH. The pretest calibration showed a lower calibration uncertainty than the stated accuracy. Therefore, the stated uncertainty (RU/CU) is equal to the stated accuracy of ±2%.

F-14.2 Ambient Temperature Effect (TE)

The manufacturer of the humidity transmitters states that the humidity reading is dependent on ambient temperature. When the ambient temperature is between 10°C and 40°C (50°F and 104°F), the temperature dependence is zero. Since the ambient temperature during the test was just above 60°F, there is no additional uncertainty contribution due to the ambient temperature effect.

F-14.3 Vibration Effect (VE)

Measurement effect due to vibrations is negligible except at resonance frequencies. Resonance frequencies were not observed.

F-14.4 Power Supply Effect (PSE)

Power supply effects are negligible since the power supply is regulated at 24 V and the humidity transmitters were read digitally.

F-14.5 RFI Effect (RFIE)

RFI effects are negligible since the system was properly insulated, and the humidity transmitters were read digitally.

F-14.6 Data Acquisition Effect (DAE)

Data acquisition effects are negligible since the data acquisition system is an integrated component of the humidity transmitter and the data was transmitted digitally from the humidity transmitters and recorded by a laptop computer. Furthermore, since the data acquisition is integrated, it is calibrated along with the instrument.

With each source of error identified, categorized, and estimated, the total performance specification can be determined by root-sum squaring the individual contributors since they are uncorrelated. The general equation is as follows:

Total Humidity Transmitter Performance Specification Uncertainty =

$$\pm\sqrt{(RU/CU)^2 + (TE)^2 + (VE)^2 + (PSE)^2 + (RFIE)^2 + (DAE)^2}$$

The total device measurement uncertainties are presented in Table F-14.6-1.

Table F-15.1-1 Power Meter Stated Accuracy Systematic Uncertainty

Measurement Location	Min. Reading	Range	Stated Accuracy Uncertainty Contribution (% of Reading)
CTG 1 export line net power output	156,500 kW	250,000 kW	$\frac{\pm 0.04\% \times (\text{Reading}) + 0.04\% \times (\text{Range})}{(\text{Reading})}$ $\pm \frac{0.04\% \times (156{,}500) + 0.04\% \times (250{,}000)}{(156{,}500)} = 0.104\%$
CTG 2 export line net power output	161,900 kW	250,000 kW	$\frac{\pm 0.04\% \times (\text{Reading}) + 0.04\% \times (\text{Range})}{(\text{Reading})}$ $\pm \frac{0.04\% \times (161{,}900) + 0.04\% \times (250{,}000)}{(161{,}900)} = 0.102\%$
STG export line net power output	173,300 kW	300,000 kW	$\frac{\pm 0.04\% \times (\text{Reading}) + 0.04\% \times (\text{Range})}{(\text{Reading})}$ $\pm \frac{0.04\% \times (173{,}300) + 0.04\% \times (300{,}000)}{(173{,}300)} = 0.109\%$

F-15 POWER METER SYSTEMATIC UNCERTAINTY ANALYSIS

The net power output measurements were made at the revenue metering location on the high side of each of the generator step-up transformers. Station instrumentation was used for the net power metering system, which included a high-accuracy (0.1% accuracy class), digital power meter, three potential transformers, and three current transformers for each export line. A three-phase, three-wire wiring configuration was used for each export line. Instantaneous kilowatt data was recorded on 30-sec intervals utilizing a personal computer and communication software. The power meters were located in an air-conditioned enclosure where the temperature was controlled 70°F ±2°F. The potential transformers and current transformers were of 0.3% accuracy class and were not calibrated. The three power meters are the same model from the same manufacturer. The nine potential transformers and current transformers were purchased at the same time from the same manufacturer. Therefore, these measurements are considered correlated.

For the purpose of this analysis, the sources of uncertainty identified for the power meter used in the execution of this test are as follows:

(a) Power Meter Stated Accuracy [Reference Uncertainty/Calibration Uncertainty (RU/CU)]
(b) Ambient Temperature Effect (TE)
(c) Power Factor Effect (PFE)
(d) Input Range Effect (IRE)
(e) Line Filter Effect (LFE)
(f) Aging Effect (AE)

Each source of uncertainty was studied individually before combining into a total performance specification for the power meter, as shown in paras. F-15-1 through F-15-6.

F-15.1 Power Meter Stated Accuracy (TRU/CU)

The manufacturer of the power meter publishes an accuracy of 0.04% of reading + 0.04% of range at temperatures between 20°C and 26°C (68°F and 78.8°F). For each power meter, the minimum reading during the test was used to calculate the uncertainty contribution, as shown in Table F-15.1-1.

F-15.2 Ambient Temperature Effect (TE)

The manufacturer's stated accuracy is given for a range of temperatures. In this case, the stated accuracy is valid between 20°C and 26°C (68°F and 78.8°F). Since the power meters were used in an enclosure that was air conditioned to 70°F ±2°F, there is no additional temperature effect.

F-15.3 Power Factor Effect (PFE)

The manufacturer's stated power factor effect is zero for power factors between unity and 0.85. Therefore, no additional uncertainty is contributed by this effect.

Table F-15.6-1 Total Power Meter Performance Specification Uncertainty

Measurement Location	Total Performance Specification Uncertainty (% of Reading)
CTG 1 export line net power output	$\pm\sqrt{(0.104)^2 + (0)^2 + (0)^2 + (0)^2 + (0)^2 + (0)^2} = \pm 0.104\%$
CTG 2 export line net power output	$\pm\sqrt{(0.102)^2 + (0)^2 + (0)^2 + (0)^2 + (0)^2 + (0)^2} = \pm 0.102\%$
STG export line net power output	$\pm\sqrt{(0.109)^2 + (0)^2 + (0)^2 + (0)^2 + (0)^2 + (0)^2} = \pm 0.109\%$

F-15.4 Input Range Effect (IRE)

The manufacturer's stated accuracy given above is valid when the input voltage and current values are between 10% and 110% of their respective rated values. During this test, the voltage and current values were within that specified range for all three power meters. No additional uncertainty contribution is applied for the input range effect.

F-15.5 Line Filter Effect (LFE)

The manufacturer's stated accuracy given above is when the line filter is off. When the line filter is on, there is an additional uncertainty contribution. During this testing, all power meters were used with the line filter off, so there is no addition uncertainty contribution to include.

F-15.6 Aging Effect (AE)

The manufacturer's stated accuracy given above is qualified as the six-month accuracy. Between six months and 1 yr (the manufacturer's stated calibration period), there is an additional uncertainty contribution to the range portion of the meter accuracy. All three power meters were calibrated three months prior to this test. No additional aging uncertainty contribution is applied.

With each source of error identified, categorized, and estimated, the total performance specification can be determined by root-sum squaring the individual contributors since they are uncorrelated. The general equation is as follows:

Total Power Meter Performance Specification Uncertainty =

$$\pm\sqrt{(RU/CU)^2 + (TE)^2 + (PFE)^2 + (IRE)^2 + (LFE)^2 + (AE)^2}$$

The total power meter uncertainties are presented in Table F-15.6-1.

In addition to the power meter uncertainty calculated in Table F-15.6-1, there are additional uncertainty sources by the current and potential transformers that contribute to the total power measurement uncertainty. The transformers introduce errors in the power measurement through transformer ratio variations and phase displacements between the primary and secondary voltages.

The potential and current transformers used in this metering system were not calibrated prior to installation. There is no information regarding the base reference uncertainty of the transformers or the effects of elemental uncertainty sources on which to base a detailed uncertainty analysis of the transformers. The metering accuracy class is given as 0.3% for all potential and current transformers. The accuracy class of a measuring instrument is a statement that the device meets certain metrological requirements that are intended to keep errors within specified limits. Hence, the accuracy class represents the maximum error of the transformer at specified burdens.

In the power industry, it has become common to assemble metering and instrumentation systems using components of a certain "accuracy class." From this approach, it has been common to draw the unjustified conclusion that the device accuracy is equal to the accuracy class. It is likely that this conclusion is wrong and that the actual uncertainty is lower than the accuracy class. The only way to know the actual uncertainty is to perform a detailed error analysis.

During this test the stated burdens were not exceeded for the potential nor current transformers, so it can be said that additional error introduced by excess burden was not present. A detailed uncertainty analysis of the potential and current transformers at the as-tested conditions may result in a lower uncertainty result; however, due to the lack of information provided for the transformers, the more conservative estimate of 0.3% uncertainty will be used.

Table F-15.6-2 Total Transformer Uncertainty

Measurement Location	Total Performance Specification Uncertainty (% of Reading)
Potential transformers	$\pm\sqrt{(0.3)^2 + (0)^2 + (0)^2 + (0)^2 + (0)^2} = \pm 0.3\%$
Current transformers	$\pm\sqrt{(0.3)^2 + (0)^2 + (0)^2 + (0)^2 + (0)^2} = \pm 0.3\%$

Table F-15.6-3 Total Power Systematic Measurement Uncertainty

Measurement Location	Total Performance Specification Uncertainty (% of Reading)
CTG 1 export line net power output	$\pm\sqrt{(0.104)^2 + (0.3)^2 + (0.3)^2} = \pm 0.437\%$
CTG 2 export line net power output	$\pm\sqrt{(0.102)^2 + (0.3)^2 + (0.3)^2} = \pm 0.436\%$
STG export line net power output	$\pm\sqrt{(0.109)^2 + (0.3)^2 + (0.3)^2} = \pm 0.438\%$

For the purpose of this analysis, the sources of uncertainty identified for the current and potential transformers used in the execution of this test are as follows:

(a) Transformer Stated Accuracy (RU/CU). As discussed above, the transformers were not calibrated and base reference uncertainty for the transformers was unknown; therefore, the conservative estimate of 0.3% uncertainty will be used.

(b) Exciting Current of the Transformer Effect (ECE). The exciting current of the transformers was within the required range of values so that no additional uncertainty was contributed by this effect.

(c) Percentage of Rated Voltage or Current Effect (PRE). The potential and current transformers were used at 100% of rated voltage and 100% of rated current, respectively. No additional uncertainty was contributed by this effect.

(d) Power Factor of the Electrical System Load Effect (PFE). The power factor of the electrical system load was near unity. No additional uncertainty was contributed by this effect.

(e) Burden of the Devices Connected to the Secondary Windings Effect (BE). The rated burdens were not exceeded. No additional uncertainty was contributed by this effect.

With each source of error identified, categorized, and estimated, the total performance specification can be determined by root-sum squaring the individual contributors since they are uncorrelated. The general equation is as follows:

$$\text{Total Transformer Uncertainty} = \pm\sqrt{(RU/CU)^2 + (ECE)^2 + (PRE)^2 + (PFE)^2 + (BE)^2}$$

The total transformer uncertainties are presented in Table F-15.6-2.

With the sources of error due to the power meters (PME), potential transformers (PTE), and current transformers (CTE) identified and estimated, the total systematic uncertainty of the power measurements can be determined by root-sum squaring the individual contributors since they are uncorrelated. The general equation is as follows:

$$\text{Total Power Systematic Measurement Uncertainty} = \pm\sqrt{(PME)^2 + (PTE)^2 + (CTE)^2}$$

NOTE: As stated earlier, the instruments are correlated by their ties to the same manufacturer. Therefore, correlated uncertainty must be applied to the PTE and CTE uncertainties in accordance with eq. (8-1.4) of ASME PTC 19.1. However, if the same accuracy class is being used for each of the components, then algebraically the correlated uncertainty equation equals the accuracy class.

The total power systematic measurement uncertainties are presented in Table F-15.6-3.

F-16 FUEL ANALYSIS/HEATING VALUE/COMPRESSIBILITY/MOISTURE CONTENT SYSTEMATIC UNCERTAINTY ANALYSIS

The constituent analyses of the natural gas fuel samples were made by a certified laboratory using a gas chromatograph following the methods outlined in ASTM D1945 and ISO 6974. The laboratory stated that they calibrated the chromatograph with calibration gases traceable to NIST or equivalent organizations. An audit of the methodology, equipment, procedures, and calibration standards was conducted to identify the sources of uncertainty and verify the laboratory claims.

The laboratory performing the analyses utilizes detailed written procedures for performing the constituent analysis. The laboratory is an American Society for Testing and Materials (ASTM) member laboratory and holds accreditations from the American Association of Laboratory Accreditation (A2LA) and the American National Standards Institute Registrar Accreditation Board (ANSI RAB). The lab also is an ISO 17025 registered company.

The calibration gases used by the lab to calibrate the gas chromatograph were from a commercial specialty gas company. The methods and practices that the commercial specialty gas company uses to develop their calibration gas blends are in compliance with following agencies: U.S. Environmental Protection Agency (EPA), ASTM International (formerly American Society for Testing and Materials), American National Standards Institute (ANSI), Gas Processors Association (GPA), and Compressed Gas Association (CGA). The commercial specialty gas company uses internal and external audits to ensure compliance with the various agency programs.

In addition, the commercial specialty gas company participates in the National Institute of Standards and Technology (NIST) Traceable Reference Materials (NTRM) program. This program was originally established in 1990 to provide users of gas chromatographs, who analyze emissions, with a means to accurately analyze pollutants and exhaust gases for the EPA. But since that time, the program has been extended to cover the hydrocarbon blends.

Under the NTRM, commercial vendors produce certified gas standard blends that are distributed by NIST. NIST does prepare its own reference gases and can supply gravimetrically produced calibration gases that contain methane, ethane, propane, and diluents. Heavier hydrocarbon blends are not available from NIST, thus direct NIST traceability only exists for this range of gases. For heavier hydrocarbons, members of the NTRM program blend gases and verify them with a combination of gravimetric and statistical combinations of multiple gas chromatograph analyses. Using this approach, the program allows hydrocarbon blends of interest to the natural gas community to have indirect traceability in butane and heavier hydrocarbons. For typical blends from commercial specialty gas companies participating in this program, composition uncertainties of less than 1% of value or less, at the 95% confidence level, are routinely attainable in hydrocarbon components from methane through isobutene and normal butane. For heavier hydrocarbons, the expected uncertainty is 2% of value or less, at the 95% confidence level.

It was determined from the audit that the laboratory and their gas vendors are following practices that yield results of the highest level of accuracy based on current engineering knowledge, taking into account costs and the value of information obtained; thus, they are in compliance with the philosophies of ASME PTC 1-2004.

For the purpose of this analysis, the sources of uncertainty identified for the constituent analyses by gas chromatograph are as follows:

(a) Calibration Gas Composition Uncertainty (CGCU)
(b) Chromatograph Method Effect (CME)
(c) Gas Sampling Method Effect (GSME)

Each source of uncertainty was studied individually before root-sum squaring into a combined performance specification as shown in paras. F-16.1 through F-16.3.

F-16.1 Calibration Gas Composition Uncertainty (CGCU)

The gas chromatograph was calibrated using calibration standard gases that were blended by a specialty gas company. The gas company utilized gas chromatography as their primary method to validate mixtures and utilized gravimetric analysis as a verification check on the gas chromatograph analysis on a periodic basis. The specialty gas company also utilized proper material handling and storage techniques so to avoid undesired heavy hydrocarbon settling and contamination. Through these practices, the specialty gas company provided certificates of uncertainty for the calibration gas as shown in Table F-16.1-1.

The certified uncertainty constitutes the calibration gas composition uncertainty for each constituent.

F-16.2 Chromatograph Method Effect (CME)

The methods employed by the laboratory for determination of composition are in accordance with ASTM D1945 and ISO 6974. The laboratory provided statements of compliance with the repeatability and reproducibility limits stated in ASTM D1945 yet did not provide data demonstrating the level of compliance. In absence of this information, the uncertainty must be evaluated using repeatability, reproducibility, and trueness information (ISO/TS 21748).

Table F-16.1-1 Calibration Gas Uncertainty

Component	Mole %	U_{95} (% Relative)
Methane (xCH_4)	95.406	0.31
Ethane (xCH_2)	2.132	0.21
Propane (xCH_3)	0.282	0.79
Iso-butane ($xICH_4$)	0.041	0.71
N-butane ($xNCH_4$)	0.052	0.81
Iso-pentane ($xICH_5$)	0.02	1.48
N-pentane ($xNCH_5$)	0.02	1.62
N-hexane (xCH_6)	0.0042	1.94
Carbon dioxide (xCO_2)	0.792	0.73
Nitrogen (xN_2)	0.821	0.71
Oxygen (xO_2)	0.001	2.2
Hydrogen (xH_2)	0.4	0.72
Total	100.000	. . .

NOTE: ASME PTC 19.1 does not provide a definition of trueness. It does, however, state in Section 1 that it has attempted to harmonize with International Organization for Standardization (ISO) Guide to the Expression of Uncertainty in Measurement (GUM). Since ASME PTC 19.1 does not directly handle the determination of uncertainty using repeatability, reproducibility, and trueness information, use of ISO/TS 21748 was utilized to demonstrate the proper approach to estimating uncertainty with this type of information. ISO defines trueness as the closeness of agreement between the average value obtained from a large set of test results and an accepted reference value. The measure of trueness is normally expressed in terms of bias.

This technique covered by ISO/TS 21748 is acceptable if the following criterions are met:

(a) Criterion 1. Estimates of the repeatability, reproducibility, and trueness are available from published information about the method used.

(b) Fulfillment 1. ASTM D1945 provides repeatability and reproducibility information. Trueness and bias information is not provided. A generic published statement of trueness or bias can not be provided since this quantity depends on the uncertainty associated with the reference standard (calibration gas). The uncertainty associated with constituent analysis of the calibration gas will be used to represent the trueness.

(c) Criterion 2. The laboratory can establish whether the bias for the measurements is within that expected on the basis of the criterion of Criterion 1.

(d) Fulfillment 2. Since there is no trueness or bias statement for the method, the lab cannot establish this point. However, this ISO/TS 21748 method is still valid since we will be using the calibration gas bias statements to demonstrate this quantity.

(e) Criterion 3. The laboratory can establish whether the precision attained by current measurements is within that expected on the basis of the repeatability and reproducibility estimates of Criterion 1.

(f) Fulfillment 3. The laboratory produced statements that the precision attained is within that expected on the basis of the repeatability and reproducibility statements of the method.

(g) Criterion 4. The laboratory can identify any influences on the measurement that were not adequately covered in the studies referenced in Criterion 1, and quantify the variance that could arise from these effects, taking into account the sensitivity coefficients and the uncertainties for each influence.

(h) Fulfillment 4. The laboratory stated that the device is used under controlled laboratory conditions and that there are no additional influences on the device.

With the criterions met, the uncertainty can be estimated by combining the reproducibility estimate with the uncertainty associated with trueness and the effects of additional influences to form a combined uncertainty estimate.

The published reproducibility numbers provided in ASTM D1945 are displayed in the Reproducibility Column of Table F-16.2-1. Following the standard laid out by ASTM E177-04$^{\epsilon 1}$, the repeatability limit, r, and reproducibility limit, R, are calculated by

$$r = 1.96\sqrt{2} * s_r$$

where

s_r = the repeatability standard deviation

and

$$R = 1.96\sqrt{2} * s_R$$

Table F-16.2-1 Converted ASTM D1945 Reproducibility

Component, mol %	Reproducibility, mol %	Converted Reproducibility, mol %
0 to 0.1	0.02	0.0141
0.1 to 1.0	0.07	0.0495
1.0 to 5.0	0.10	0.0707
5.0 to 10	0.12	0.0849
Over 10	0.15	0.1061

where

s_r = the repeatability standard deviation

The 1.96 reflects the 95% limit for an infinite sample size. The reproducibility s_R includes s_r. Since s_r is based on same operator, same equipment, same time, it includes the variability within a lab due to differences in operator-equipment-time. It also includes the between-laboratory variability and any differences in material properties, environment, etc. In order to conform to the standard of ISO/TS 21748 and ASME PTC 19.1, the $\sqrt{2}$ term must be divided out of the above equations. This results in the converted reproducibility column in Table F-16.2-1.

This information can be translated into the following uncertainty component statements for each constituent by dividing by the actual constituent concentration in each range, thus deriving a relative basis value.

During the test, a fuel sample was taken at the beginning, middle, and end of each test run. The constituents from each sample were averaged to determine an average fuel constituent analysis over each of the test periods. Since each fuel constituent analysis is determined with the same laboratory equipment, the reproducibility quantities will be treated as correlated. To simulate this correlation, the reproducibility numbers will be applied directly to the averaged constituents, thus avoiding the additional mathematics of applying to the individual analysis constituents and combining with an expanded Taylor series analysis. (Please see Nonmandatory Appendix C of ASME PTC 19.1 for more details.) The reproducibility values may be applied to each fuel analysis and combined while accounting for the correlation terms, and the same result would be achieved. With this said, the relative reproducibility is given in Tables F-16.2-2 and F-16.2-3.

F-16.3 Gas Sampling Method Effect (GSME)

The gas samples were collected in strict accordance with GPA 2166. The bottles were washed and vacuum purged prior to collection of samples. The samples were collected downstream of the plant's moisture separator/filter unit and the fuel was not heated. The pressure, temperature, and measurement location during the sample collection does not facilitate the presence of condensed liquids. With the sampling probe being at centerline of the pipe, wall buildup contamination was avoided. The sample cylinders were not exposed to extreme temperature changes during transportation to the lab to induce drop out of hydrocarbons. The sample cylinders and connecting valves are of nonreactive or absorbing materials, so as to avoid altering the composition. With all of these steps taken, no additional uncertainty due to sampling methods was present and the gas sampling method uncertainty will be estimated to be zero.

With each source of error identified, categorized, and estimated for the fuel constituents, the total fuel constituent performance specification can be determined by root-sum squaring the individual contributors since they are uncorrelated. The general equation is as follows:

$$\text{Total Fuel Constituent Performance Specification Uncertainty} = \pm\sqrt{(\text{CGCU})^2 + (\text{CME})^2 + (\text{GSME})^2}$$

The fuel constituent element uncertainties are presented in Tables F-16.3-1, F-16.3-2, F-16.3-3, and F-16.3-4 for Tests 1, 2, 3, and 4, respectively.

The heating value for each averaged gas analysis is calculated using ASTM D3588 methodology. The order of precedence for stated ideal gas heating property values used in the execution of the ASTM D3588 calculation method for each component is taken from GPA 2145, then ASTM D3588 and then GPSA Engineering Data Book. ASTM D3588 states that the uncertainty (twice the standard deviation) of the ideal gas heating values of components should be 0.03%. With this being stated, the method uncertainty associated with ASTM D3588 calculation of heating value is 0.03%.

The compressibility for each averaged gas analysis is calculated using methods outlined in AGA Report No. 8 utilizing the Detail Characterization Method (input of individual gas constituents). Per AGA Report No. 8, the

Table F-16.2-2 Relative Reproducibility for Test 1 and Test 2

	Test 1			Test 2		
		Reproducibility			Reproducibility	
Constituent	Average Mole %	Mole %	% Relative	Average Mole %	Mole %	% Relative
Methane (xCH_4)	96.0933	0.1061	0.1104	96.0667	0.1061	0.1104
Ethane (xCH_2)	1.9667	0.0707	3.5955	1.9700	0.0707	3.5894
Propane (xCH_3)	0.3033	0.0495	16.3178	0.3267	0.0495	15.1523
Iso-butane ($xICH_4$)	0.0767	0.0141	18.4463	0.0567	0.0141	24.9567
N-butane ($xNCH_4$)	0.0567	0.0141	24.9567	0.0667	0.0141	21.2132
Iso-pentane ($xICH_5$)	0.0300	0.0141	47.1405	0.0167	0.0141	84.8528
N-pentane ($xNCH_5$)	0.0167	0.0141	84.8528	0.0100	0.0141	141.4214
N-hexane (xCH_6)	0.0033	0.0141	424.2641	0.0100	0.0141	141.4214
N-heptane (xCH_7)	0.0000	0.0141	. . .	0.0000	0.0141	. . .
N-octane (xCH_8)	0.0000	0.0141	. . .	0.0000	0.0141	. . .
Nonane (xCH_9)	0.0000	0.0141	. . .	0.0000	0.0141	. . .
Decane (xCH_{10})	0.0000	0.0141	. . .	0.0000	0.0141	. . .
Carbon dioxide (xCO_2)	0.6867	0.0495	7.2084	0.6933	0.0495	7.1391
Nitrogen (xN_2)	0.7367	0.0495	6.7191	0.7533	0.0495	6.5705
Oxygen (xO_2)	0.0100	0.0141	141.4214	0.0100	0.0141	141.4214
Helium (xHe)	0.0200	0.0141	70.7107	0.0200	0.0141	70.7107
Hydrogen (xH_2)	0.0000	0.0141	. . .	0.0000	0.0141	. . .
Carbon monoxide (xCO)	0.0000	0.0141	. . .	0.0000	0.0141	. . .
Hydrogen sulfide (xH_2S)	0.0000	0.0141	. . .	0.0000	0.0141	. . .
Water (xH_2O)	0.0000	0.0141	. . .	0.0000	0.0141	. . .
Total	100.0000	. . .	. . .	100.0000	. . .	. . .

Table F-16.2-3 Relative Reproducibility for Test 3 and Test 4

	Test 3			Test 4		
		Reproducibility			Reproducibility	
Constituent	Average Mole %	Mole %	% Relative	Average Mole %	Mole %	% Relative
Methane (xCH_4)	96.0500	0.1061	0.1104	96.0533	0.1061	0.1104
Ethane (xCH_2)	1.9800	0.0707	3.5712	1.9800	0.0707	3.5712
Propane (xCH_3)	0.3300	0.0495	14.9992	0.3233	0.0495	15.3085
Iso-butane ($xICH_4$)	0.0600	0.0141	23.5702	0.0667	0.0141	21.2132
N-butane ($xNCH_4$)	0.0733	0.0141	19.2847	0.0700	0.0141	20.2031
Iso-pentane ($xICH_5$)	0.0167	0.0141	84.8528	0.0200	0.0141	70.7107
N-pentane ($xNCH_5$)	0.0100	0.0141	141.4214	0.0133	0.0141	106.0660
N-hexane (xCH_6)	0.0100	0.0141	141.4214	0.0100	0.0141	141.4214
N-heptane (xCH_7)	0.0000	0.0141	0.0000	0.0141	. . .	. . .
N-octane (xCH_8)	0.0000	0.0141	0.0000	0.0141	. . .	. . .
Nonane (xCH_9)	0.0000	0.0141	0.0000	0.0141	. . .	. . .
Decane (xCH_{10})	0.0000	0.0141	0.0000	0.0141	. . .	. . .
Carbon dioxide (xCO_2)	0.6900	0.0495	7.1735	0.6833	0.0495	7.2435
Nitrogen (xN_2)	0.7467	0.0495	6.6291	0.7467	0.0495	6.6291
Oxygen (xO_2)	0.0100	0.0141	141.4214	0.0067	0.0141	212.1320
Helium (xHe)	0.0200	0.0141	70.7107	0.0200	0.0141	70.7107
Hydrogen (xH_2)	0.0033	0.0141	424.2641	0.0067	0.0141	212.1320
Carbon monoxide (xCO)	0.0000	0.0141	0.0000	0.0141	. . .	. . .
Hydrogen sulfide (xH_2S)	0.0000	0.0141	0.0000	0.0141	. . .	. . .
Water (xH_2O)	0.0000	0.0141	0.0000	0.0141	. . .	. . .
Total	100.0000	100.0000	. . .	. . .	. . .	. . .

Table F-16.3-1 Total Fuel Constituent Performance Specification Uncertainty for Test 1

	Test 1				
Constituent	Average Mole %	CGCU % (Rel)	CME % (Rel)	GSME % (Rel)	Total % (Rel)
Methane (xCH_4)	96.0933	0.3100	0.1104	0.0000	0.3291
Ethane (xCH_2)	1.9667	0.2100	3.5955	0.0000	3.6016
Propane (xCH_3)	0.3033	0.7900	16.3178	0.0000	16.3370
Iso-butane ($xICH_4$)	0.0767	0.7100	18.4463	0.0000	18.4599
N-butane ($xNCH_4$)	0.0567	0.8100	24.9567	0.0000	24.9699
Iso-pentane ($xICH_5$)	0.0300	1.4800	47.1405	0.0000	47.1637
N-pentane ($xNCH_5$)	0.0167	1.6200	84.8528	0.0000	84.8683
N-hexane (xCH_6)	0.0033	1.9400	424.2641	0.0000	424.2685
N-heptane (xCH_7)	0.0000	. . .	. . .	. . .	. . .
N-octane (xCH_8)	0.0000	. . .	. . .	. . .	. . .
Nonane (xCH_9)	0.0000	. . .	. . .	. . .	. . .
Decane (xCH_{10})	0.0000	. . .	. . .	. . .	. . .
Carbon dioxide (xCO_2)	0.6867	0.7300	7.2084	0.0000	7.2452
Nitrogen (xN_2)	0.7367	0.7100	6.7191	0.0000	6.7565
Oxygen (xO_2)	0.0100	2.2000	141.4214	0.0000	141.4385
Helium (xHe)	0.0200	0.7200	70.7107	0.0000	70.7143
Hydrogen (xH_2)	0.0000	0.4000	. . .	0.0000	0.4000
Carbon monoxide (xCO)	0.0000	. . .	. . .	. . .	. . .
Hydrogen sulfide (xH_2S)	0.0000	. . .	. . .	. . .	. . .
Water (xH_2O)	0.0000	. . .	. . .	. . .	. . .
Total	100.0000	. . .	. . .	. . .	. . .

Table F-16.3-2 Total Fuel Constituent Performance Specification Uncertainty for Test 2

	Test 2				
Constituent	Average Mole %	CGCU % (Rel)	CME % (Rel)	GSME % (Rel)	Total % (Rel)
Methane (xCH_4)	96.0667	0.3100	0.1104	0.0000	0.3291
Ethane (xCH_2)	1.9700	0.2100	3.5894	0.0000	3.5955
Propane (xCH_3)	0.3267	0.7900	15.1523	0.0000	15.1729
Iso-butane ($xICH_4$)	0.0567	0.7100	24.9567	0.0000	24.9668
N-butane ($xNCH_4$)	0.0667	0.8100	21.2132	0.0000	21.2287
Iso-pentane ($xICH_5$)	0.0167	1.4800	84.8528	0.0000	84.8657
N-pentane ($xNCH_5$)	0.0100	1.6200	141.4214	0.0000	141.4306
N-hexane (xCH_6)	0.0100	1.9400	141.4214	0.0000	141.4347
N-heptane (xCH_7)	0.0000	. . .	. . .	. . .	. . .
N-octane (xCH_8)	0.0000	. . .	. . .	. . .	. . .
Nonane (xCH_9)	0.0000	. . .	. . .	. . .	. . .
Decane (xCH_{10})	0.0000	. . .	. . .	. . .	. . .
Carbon dioxide (xCO_2)	0.6933	0.7300	7.1391	0.0000	7.1763
Nitrogen (xN_2)	0.7533	0.7100	6.5705	0.0000	6.6087
Oxygen (xO_2)	0.0100	2.2000	141.4214	0.0000	141.4385
Helium (xHe)	0.0200	0.7200	70.7107	0.0000	70.7143
Hydrogen (xH_2)	0.0000	0.4000	. . .	0.0000	0.4000
Carbon monoxide (xCO)	0.0000	. . .	. . .	. . .	. . .
Hydrogen sulfide (xH_2S)	0.0000	. . .	. . .	. . .	. . .
Water (xH_2O)	0.0000	. . .	. . .	. . .	. . .
Total	100.0000	. . .	. . .	. . .	. . .

Table F-16.3-3 Total Fuel Constituent Performance Specification Uncertainty for Test 3

Constituent	Test 3				
	Average Mole %	CGCU % (Rel)	CME % (Rel)	GSME % (Rel)	Total % (Rel)
Methane (xCH_4)	96.0500	0.3100	0.1104	0.0000	0.3291
Ethane (xCH_2)	1.9800	0.2100	3.5712	0.0000	3.5774
Propane (xCH_3)	0.3300	0.7900	14.9992	0.0000	15.0200
Iso-butane ($xICH_4$)	0.0600	0.7100	23.5702	0.0000	23.5809
N-butane ($xNCH_4$)	0.0733	0.8100	19.2847	0.0000	19.3017
Iso-pentane ($xICH_5$)	0.0167	1.4800	84.8528	0.0000	84.8657
N-pentane ($xNCH_5$)	0.0100	1.6200	141.4214	0.0000	141.4306
N-hexane (xCH_6)	0.0100	1.9400	141.4214	0.0000	141.4347
N-heptane (xCH_7)	0.0000	. . .	. . .	. . .	. . .
N-octane (xCH_8)	0.0000	. . .	. . .	. . .	. . .
Nonane (xCH_9)	0.0000	. . .	. . .	. . .	. . .
Decane (xCH_{10})	0.0000	. . .	. . .	. . .	. . .
Carbon dioxide (xCO_2)	0.6900	0.7300	7.1735	0.0000	7.2106
Nitrogen (xN_2)	0.7467	0.7100	6.6291	0.0000	6.6670
Oxygen (xO_2)	0.0100	2.2000	141.4214	0.0000	141.4385
Helium (xHe)	0.0200	0.7200	70.7107	0.0000	70.7143
Hydrogen (xH_2)	0.0033	0.4000	424.2641	0.0000	424.2643
Carbon monoxide (xCO)	0.0000	. . .	. . .	. . .	. . .
Hydrogen sulfide (xH_2S)	0.0000	. . .	. . .	. . .	. . .
Water (xH_2O)	0.0000	. . .	. . .	. . .	. . .
Total	100.0000	. . .	. . .	. . .	. . .

Table F-16.3-4 Total Fuel Constituent Performance Specification Uncertainty for Test 4

Constituent	Test 4				
	Average Mole %	CGCU % (Rel)	CME % (Rel)	GSME % (Rel)	Total % (Rel)
Methane (xCH_4)	96.0533	0.3100	0.1104	0.0000	0.3291
Ethane (xCH_2)	1.9800	0.2100	3.5712	0.0000	3.5774
Propane (xCH_3)	0.3233	0.7900	15.3085	0.0000	15.3289
Iso-butane ($xICH_4$)	0.0667	0.7100	21.2132	0.0000	21.2251
N-butane ($xNCH_4$)	0.0700	0.8100	20.2031	0.0000	20.2193
Iso-pentane ($xICH_5$)	0.0200	1.4800	70.7107	0.0000	70.7262
N-pentane ($xNCH_5$)	0.0133	1.6200	106.0660	0.0000	106.0784
N-hexane (xCH_6)	0.0100	1.9400	141.4214	0.0000	141.4347
N-heptane (xCH_7)	0.0000	. . .	. . .	. . .	. . .
N-octane (xCH_8)	0.0000	. . .	. . .	. . .	. . .
Nonane (xCH_9)	0.0000	. . .	. . .	. . .	. . .
Decane (xCH_{10})	0.0000	. . .	. . .	. . .	. . .
Carbon dioxide (xCO_2)	0.6833	0.7300	7.2435	0.0000	7.2802
Nitrogen (xN_2)	0.7467	0.7100	6.6291	0.0000	6.6670
Oxygen (xO_2)	0.0067	2.2000	212.1320	0.0000	212.1434
Helium (xHe)	0.0200	0.7200	70.7107	0.0000	70.7143
Hydrogen (xH_2)	0.0067	0.4000	212.1320	0.0000	212.1324
Carbon monoxide (xCO)	0.0000	. . .	. . .	. . .	. . .
Hydrogen sulfide (xH_2S)	0.0000	. . .	. . .	. . .	. . .
Water (xH_2O)	0.0000	. . .	. . .	. . .	. . .
Total	100.0000	. . .	. . .	. . .	. . .

targeted uncertainty associated with natural gas compressibility factors using the Detail Characterization Method for pressures between 0 MPa to 12 MPa (0 psia to 1,750 psia) and temperatures between −8°C to 62°C (17°F to 143°F) is 0.1%. With this being stated, the method uncertainty associated with the AGA Report No. 8 determined compressibility is 0.1%.

The moisture content of the gas was deemed negligible due to the sampling location and prior fuel sampling analysis conducted in accordance with ASTM D1142 showed undetectable moisture. With this information, the fuel was considered dry and treated as such. For this example, uncertainty associated with the moisture content is excluded since the gas analysis is considered dry.

F-17 PLANT FUEL FLOW SYSTEMATIC UNCERTAINTY

The plant fuel flow was measured using an orifice flow section built and calibrated in strict compliance with Section 4 of ASME PTC 19.5. The flow section was installed in process piping free of any influencing upstream obstructions so to avoid additional uncertainty effects due to installation location. The calibration was performed in a water facility within the same range of Reynold's Numbers as seen in actual operation so no extrapolation of the calibration was necessary. The expanded uncertainty statement at a 95% confidence level from the calibration facility is 0.25% relative basis for the stated discharge coefficient.

As per para. 3.1.1 of ASME PTC 19.5, the basic flow equation utilized to derive the natural gas fuel mass flow rate is

$$q_m = n\,\frac{\pi}{4}\,d^2 C \epsilon \sqrt{\frac{2\rho(\Delta P)g_c}{1-\beta^4}}$$

In SI units

$$g_c = 1.0$$

$$n = 1.0\left(\frac{\text{kg}}{\text{m}\cdot\text{s}^2\cdot\text{Pa}}\right)^{0.5}$$

In U.S. Customary units

$$g_c = 32.1740486\,\frac{\text{lbm}\cdot\text{ft}}{\text{lbf}\cdot\text{s}^2}$$

$$n = 300.0\,\frac{\text{ft}^2}{\text{s}^2}\left(\frac{\text{in.}^2}{\text{ft}^2}\cdot\frac{\text{s}^2}{\text{hr}^2}\right)^{0.5}$$

where

C = coefficient of discharge (per calibration)
d = orifice plate bore diameter (per ASME PTC 19.5. Table 3.1), m (in.)
g_c = proportionally constant, 32.174086 lbm-ft/lbf-sec^2, or 1.0 dimensionless for SI measurements
n = units conversion factor for general equation for flow through a differential pressure class meter, 1 (kg/m-s^2-Pa)$^{1/2}$ for SI measurement
q_m = natural gas fuel mass flow rate [per ASME PTC 19.5, eq. (3.1.1)], kg/s (lbm/sec)
β = ratio of the orifice plate bore diameter to the upstream internal pipe diameter, $\beta = d/D$
ΔP = differential pressure (per ASME PTC 19.5, Table 3.1), Pa (lbf/in.^{2})
ϵ = upstream expansion factor [per ASME PTC 19.5, eq. (3.8.2)]
ρ = upstream density of flowing fluid (per ASME PTC 19.5 Table 3.1), kg/m^3 (lbm/ft^3)

The systematic uncertainty for the fuel flow is estimated as the square root of the quadrature sum (square root of the sum of the squares) of the systematic uncertainties associated with the pertinent variables.

$$W_{FG} = f\,(C, \epsilon, d, \Delta P, \rho, \beta)$$

However, since the flow section was calibrated, the systematic uncertainty of the orifice plate bore diameter, d, the pipe diameter, D, and the ratio of the orifice plate bore diameter to the upstream internal pipe diameter, β, are contained within the systematic uncertainty value of the discharge coefficient. Since the calibration process utilizes these dimensions in the determination of differential pressure to flow, the uncertainty associated with those dimensions are integral in the discharge coefficient uncertainty statement of the lab. Therefore, the systematic uncertainty for the fuel flow is the square root of the quadrature sum (square root of the sum of the squares) of the systematic uncertainties associated with the remaining pertinent variables as follows:

$$W_{FG} = f(C, \epsilon, \Delta P, \rho)$$

The systematic uncertainty associated with the discharge coefficient C is taken to be that of the expanded uncertainty statement of 0.25% relative basis from the calibration facility at a 95% confidence level. The systematic uncertainty associated with the expansion coefficient is determined using the equation from subsection 4-10 of ASME PTC 19.5 of $U_\epsilon/\epsilon = 4(\Delta P/P)$. The systematic uncertainty associated with ΔP is taken from the test instrumentation systematic uncertainty analysis given in subsection F-12. The uncertainty contribution associated with the density is found by analyzing the systematic uncertainty associated with the fuel pressure, the fuel temperature, the fuel constituent analysis, and the compressibility factor method uncertainty. The predicted fuel flow uncertainty is provided in Tables F-17-1 through F-17-12. As a point of reference, subsections F-22 through F-26 outline how to similarly determine the total uncertainty for the fuel flow.

F-18 INSTRUMENT SYSTEMATIC UNCERTAINTY

The instrument systematic uncertainty is calculated within the spreadsheet and is dependent upon what type of accuracy the collected data was reported in. In order to conform to the ASME PTC 19.1, all uncertainties must be converted to an absolute uncertainty. If the measurement made was absolute, the instrument systematic uncertainty is taken as reported. If the uncertainty is reported to be within a certain percentage of reading, it is converted to absolute by taking the reported instrument accuracy, dividing by 100, and multiplying by the mean test value of the desired parameter.

Conversion from percent of reading to absolute instrument uncertainty is as follows:

$$B_{\text{inst}} = \frac{\text{Percent of Reading}}{100} * \bar{x}$$

If the instrument uncertainty is based off a percentage of span, the uncertainty is converted to an absolute uncertainty by dividing the instrument's accuracy by 100 and multiplying it by the length of the span.

Conversion from percent of span to absolute systematic uncertainty is as follows:

$$B_{\text{inst}} = \frac{\text{Percent of Span}}{100} * (x_{\max} - x_{\min})$$

All instrument systematic uncertainties reported in Tables F-17-1 through F-17-12 are absolute.

F-19 SENSITIVITY ANALYSIS

To combine total measurement uncertainty of all of the measurement parameters into an overall uncertainty of the test result, the sensitivity of the result to changes in each of the parameters must be determined. ASME PTC 19.1 defines sensitivity as the ratio of the change in a result to a unit change in a parameter. Sensitivity coefficients may be determined through analytical or numerical analysis as follows:

$$\text{Analytical Form: } \theta_{R,P_i} = \frac{\partial R}{\partial \overline{X}_i} \qquad \text{Numerical Form: } \theta_{R,P_i} \approx \frac{\Delta R}{\Delta \overline{X}_i}$$

where

R = corrected result

$\bar{X}_i$ = measurement parameter

$\theta_{R,\,Pi}$ = sensitivity coefficient for the corrected result with respect to a measurement parameter

For this test, the sensitivity of the corrected net electrical output and net heat rate to each measured parameter was determined by numerical methods. The spreadsheet that was used to calculate the corrected test results was used to increment each measured value individually so that the corresponding change in corrected results could be determined. The ratio of the change in corrected result to the change in the measurement value is the absolute sensitivity coefficient. As specified in para. 7-2.2 of ASME PTC 19.1, the increment in the measured value used to

Table F-17-1 Plant Fuel Flow Post-test Systematic Uncertainty Analysis (Test Run 1)

Post-test (Absolute Basis, SI Units) (95% Confidence Level)	Fuel Flow 67 865 kg/h				
	Test Value		Systematic Uncertainty		
	Mean, $\bar{X}$	Units	Instrument Systematic Uncertainty, B_{inst}	Absolute Sensitivity, θ	Systematic Uncertainty of Fuel Flow, $U_{F1,SYS}$, kg/h
Fuel Flow Data					
Plant supply fuel flow differential pressure	542.14	cm H_2O	0.381	61.07	23.266
Plant supply fuel flowing pressure	17.64	bara	0.023	2 035.97	46.043
Plant supply fuel flowing temperature	16.76	°C	0.056	−130.34	−7.241
Orifice flowmeter calibration uncertainty (PTC 19.5)	. . .	. . .	. . .	. . .	169.663
Expansion factor method uncertainty (AGA 3)	. . .	. . .	. . .	. . .	81.747
Compressibility factor method uncertainty (AGA 8)	. . .	. . .	. . .	. . .	33.933
Fuel Analysis Data					
Methane (xCH_4)	96.0933	Mole %	0.316	−15.48	−4.895
Ethane (xCH_2)	1.9667	Mole %	0.071	295.67	20.943
Propane (xCH_3)	0.3033	Mole %	0.050	601.67	29.816
Iso-butane ($xICH_4$)	0.0767	Mole %	0.014	909.81	12.876
N-butane ($xNCH_4$)	0.0567	Mole %	0.014	906.77	12.830
Iso-pentane ($xICH_5$)	0.0300	Mole %	0.014	1 212.70	17.159
N-pentane ($xNCH_5$)	0.0167	Mole %	0.014	1 216.10	17.201
N-hexane (xCH_6)	0.0033	Mole %	0.014	1 550.68	21.930
N-heptane (xCH_7)	0.0000	Mole %	0.000	0.00	0.000
N-octane (xCH_8)	0.0000	Mole %	0.000	0.00	0.000
Nonane (xCH_9)	0.0000	Mole %	0.000	0.00	0.000
Decane (xCH_{10})	0.0000	Mole %	0.000	0.00	0.000
Carbon dioxide (xCO_2)	0.6867	Mole %	0.050	563.21	28.020
Nitrogen (xN_2)	0.7367	Mole %	0.050	212.81	10.592
Oxygen (xO_2)	0.0100	Mole %	0.014	298.62	4.224
Helium (xHe)	0.0200	Mole %	0.014	−295.63	−4.181
Hydrogen (xH_2)	0.0000	Mole %	0.000	0.00	0.000
Carbon monoxide (xCO)	0.0000	Mole %	0.000	0.00	0.000
Hydrogen sulfide (xH_2S)	0.0000	Mole %	0.000	0.00	0.000
Water (xH_2O)	0.0000	Mole %	0.000	0.00	0.000

RSS	207.41
Post-test Fuel Flow Uncertainty	
0.31%	

Table F-17-2 Plant Fuel Flow Post-test Systematic Uncertainty Analysis (Test Run 2)

Post-test (Absolute Basis, SI Units) (95% Confidence Level)	Fuel Flow 68 017 kg/h				
	Test Value		Systematic Uncertainty		
	Mean, $\bar{X}$	Units	Instrument Systematic Uncertainty, B_{inst}	Absolute Sensitivity, θ	Systematic Uncertainty of Fuel Flow, $U_{F2,SYS}$, kg/h
Fuel Flow Data					
Plant supply fuel flow differential pressure	545.40	cm H_2O	0.381	60.83	23.175
Plant supply fuel flowing pressure	17.61	bara	0.023	2 044.31	46.232
Plant supply fuel flowing temperature	16.64	°C	0.056	−130.67	−7.259
Orifice flowmeter calibration uncertainty (PTC 19.5)	. . .	. . .	. . .	. . .	170.044
Expansion factor method uncertainty (AGA 3)	. . .	. . .	. . .	. . .	82.563
Compressibility factor method uncertainty (AGA 8)	. . .	. . .	. . .	. . .	34.009
Fuel Analysis Data					
Methane (xCH_4)	96.0667	Mole %	0.316	−15.51	−4.903
Ethane (xCH_2)	1.9700	Mole %	0.071	296.32	20.989
Propane (xCH_3)	0.3267	Mole %	0.050	602.98	29.887
Iso-butane ($xICH_4$)	0.0567	Mole %	0.014	911.79	12.900
N-butane ($xNCH_4$)	0.0667	Mole %	0.014	908.75	12.861
Iso-pentane ($xICH_5$)	0.0167	Mole %	0.014	1 215.34	17.190
N-pentane ($xNCH_5$)	0.0100	Mole %	0.014	1 218.75	17.237
N-hexane (xCH_6)	0.0100	Mole %	0.014	1 554.05	21.980
N-heptane (xCH_7)	0.0000	Mole %	0.000	0.00	0.000
N-octane (xCH_8)	0.0000	Mole %	0.000	0.00	0.000
Nonane (xCH_9)	0.0000	Mole %	0.000	0.00	0.000
Decane (xCH_{10})	0.0000	Mole %	0.000	0.00	0.000
Carbon dioxide (xCO_2)	0.6933	Mole %	0.050	564.48	28.086
Nitrogen (xN_2)	0.7533	Mole %	0.050	213.30	10.620
Oxygen (xO_2)	0.0100	Mole %	0.014	299.30	4.233
Helium (xHe)	0.0200	Mole %	0.014	−296.26	−4.190
Hydrogen (xH_2)	0.0000	Mole %	0.000	0.00	0.000
Carbon monoxide (xCO)	0.0000	Mole %	0.000	0.00	0.000
Hydrogen sulfide (xH_2S)	0.0000	Mole %	0.000	0.00	0.000
Water (xH_2O)	0.0000	Mole %	0.000	0.00	0.000

RSS	208.13
Post-test Fuel Flow Uncertainty	
0.31%	

Table F-17-3 Plant Fuel Flow Post-test Systematic Uncertainty Analysis (Test Run 3)

Post-test (Absolute Basis, SI Units) (95% Confidence Level)	Fuel Flow 67 831 kg/h				
			Systematic Uncertainty		
	Test Value		Instrument Systematic Uncertainty,	Absolute Sensitivity,	Systematic Uncertainty of Fuel Flow,
	Mean, $\bar{X}$	Units	B_{inst}	θ	$U_{F3,SYS}$, kg/h
Fuel Flow Data					
Plant supply fuel flow differential pressure	542.34	cm H_2O	0.381	61.01	23.245
Plant supply fuel flowing pressure	17.59	bara	0.023	2 040.17	46.138
Plant supply fuel flowing temperature	16.51	°C	0.056	−130.39	−7.244
Orifice flowmeter calibration uncertainty (PTC 19.5)	. . .	. . .	. . .	. . .	169.578
Expansion factor method uncertainty (AGA 3)	. . .	. . .	. . .	. . .	81.936
Compressibility factor method uncertainty (AGA 8)	. . .	. . .	. . .	. . .	33.916
Fuel Analysis Data					
Methane (xCH_4)	96.0500	Mole %	0.316	−15.56	−4.920
Ethane (xCH_2)	1.9800	Mole %	0.071	295.37	20.922
Propane (xCH_3)	0.3300	Mole %	0.050	601.15	29.797
Iso-butane ($xICH_4$)	0.0600	Mole %	0.014	909.08	12.862
N-butane ($xNCH_4$)	0.0733	Mole %	0.014	906.05	12.825
Iso-pentane ($xICH_5$)	0.0167	Mole %	0.014	1 211.76	17.139
N-pentane ($xNCH_5$)	0.0100	Mole %	0.014	1 215.17	17.186
N-hexane (xCH_6)	0.0100	Mole %	0.014	1 549.52	21.916
N-heptane (xCH_7)	0.0000	Mole %	0.000	0.00	0.000
N-octane (xCH_8)	0.0000	Mole %	0.000	0.00	0.000
Nonane (xCH_9)	0.0000	Mole %	0.000	0.00	0.000
Decane (xCH_{10})	0.0000	Mole %	0.000	0.00	0.000
Carbon dioxide (xCO_2)	0.6900	Mole %	0.050	562.71	27.996
Nitrogen (xN_2)	0.7467	Mole %	0.050	212.55	10.581
Oxygen (xO_2)	0.0100	Mole %	0.014	298.29	4.219
Helium (xHe)	0.0200	Mole %	0.014	−295.52	−4.180
Hydrogen (xH_2)	0.0033	Mole %	0.014	−327.41	−4.630
Carbon monoxide (xCO)	0.0000	Mole %	0.000	0.00	0.000
Hydrogen sulfide (xH_2S)	0.0000	Mole %	0.000	0.00	0.000
Water (xH_2O)	0.0000	Mole %	0.000	0.00	0.000

RSS	207.47
Post-test Fuel Flow Uncertainty	
0.31%	

Table F-17-4 Plant Fuel Flow Post-test Systematic Uncertainty Analysis (Test Run 4)

Post-test (Absolute Basis, SI Units) (95% Confidence Level)	Test Value: Mean, $\bar{X}$	Test Value: Units	Instrument Systematic Uncertainty, B_{inst}	Absolute Sensitivity, θ	Systematic Uncertainty of Fuel Flow, $U_{F4,SYS}$, kg/h
	Fuel Flow 67 766 kg/h		Systematic Uncertainty		
Fuel Flow Data					
Plant supply fuel flow differential pressure	541.63	cm H_2O	0.381	61.03	23.253
Plant supply fuel flowing pressure	17.58	bara	0.023	2 039.83	46.130
Plant supply fuel flowing temperature	16.46	°C	0.056	−130.29	−7.238
Orifice flowmeter calibration uncertainty (PTC 19.5)	. . .	. . .	. . .	. . .	169.417
Expansion factor method uncertainty (AGA 3)	. . .	. . .	. . .	. . .	81.816
Compressibility factor method uncertainty (AGA 8)	. . .	. . .	. . .	. . .	33.883
Fuel Analysis Data					
Methane (xCH_4)	96.0533	Mole %	0.316	−15.56	−4.919
Ethane (xCH_2)	1.9800	Mole %	0.071	295.06	20.900
Propane (xCH_3)	0.3233	Mole %	0.050	600.55	29.765
Iso-butane ($xICH_4$)	0.0667	Mole %	0.014	908.17	12.851
N-butane ($xNCH_4$)	0.0700	Mole %	0.014	905.15	12.811
Iso-pentane ($xICH_5$)	0.0200	Mole %	0.014	1 210.57	17.124
N-pentane ($xNCH_5$)	0.0133	Mole %	0.014	1 213.97	17.170
N-hexane (xCH_6)	0.0100	Mole %	0.014	1 547.98	21.894
N-heptane (xCH_7)	0.0000	Mole %	0.000	0.00	0.000
N-octane (xCH_8)	0.0000	Mole %	0.000	0.00	0.000
Nonane (xCH_9)	0.0000	Mole %	0.000	0.00	0.000
Decane (xCH_{10})	0.0000	Mole %	0.000	0.00	0.000
Carbon dioxide (xCO_2)	0.6833	Mole %	0.050	562.14	27.965
Nitrogen (xN_2)	0.7467	Mole %	0.050	212.33	10.570
Oxygen (xO_2)	0.0067	Mole %	0.014	297.99	4.214
Helium (xHe)	0.0200	Mole %	0.014	−295.24	−4.175
Hydrogen (xH_2)	0.0067	Mole %	0.014	−327.09	−4.626
Carbon monoxide (xCO)	0.0000	Mole %	0.000	0.00	0.000
Hydrogen sulfide (xH_2S)	0.0000	Mole %	0.000	0.00	0.000
Water (xH_2O)	0.0000	Mole %	0.000	0.00	0.000

RSS	207.27
Post-test Fuel Flow Uncertainty	
0.31%	

Table F-17-5 Plant Fuel Flow Post-test Systematic Uncertainty Analysis (Test Run 1)

	Fuel Flow 149.62 KPPH				
			Systematic Uncertainty		
Post-test (Absolute Basis, English Units) (95% Confidence Level)	Test Value: Mean, $\bar{X}$	Test Value: Units	Instrument Systematic Uncertainty, B_{inst}	Absolute Sensitivity, θ	Systematic Uncertainty of Fuel Flow, $U_{F1,SYS}$, KPPH
Fuel Flow Data					
Plant supply fuel flow differential pressure	213.44	in. H_2O	0.150	0.34	0.051
Plant supply fuel flowing pressure	255.81	psia	0.328	0.31	0.102
Plant supply fuel flowing temperature	62.16	°F	0.100	−0.16	−0.016
Orifice flowmeter calibration uncertainty (PTC 19.5)	. . .	. . .	. . .	. . .	0.374
Expansion factor method uncertainty (AGA 3)	. . .	. . .	. . .	. . .	0.180
Compressibility factor method uncertainty (AGA 8)	. . .	. . .	. . .	. . .	0.075
Fuel Analysis Data					
Methane (xCH_4)	96.0933	Mole %	0.316	−0.03	−0.011
Ethane (xCH_2)	1.9667	Mole %	0.071	0.65	0.046
Propane (xCH_3)	0.3033	Mole %	0.050	1.33	0.066
Iso-butane ($xICH_4$)	0.0767	Mole %	0.014	2.01	0.028
N-butane ($xNCH_4$)	0.0567	Mole %	0.014	2.00	0.028
Iso-pentane ($xICH_5$)	0.0300	Mole %	0.014	2.67	0.038
N-pentane ($xNCH_5$)	0.0167	Mole %	0.014	2.68	0.038
N-hexane (xCH_6)	0.0033	Mole %	0.014	3.42	0.048
N-heptane (xCH_7)	0.0000	Mole %	0.000	0.00	0.000
N-octane (xCH_8)	0.0000	Mole %	0.000	0.00	0.000
Nonane (xCH_9)	0.0000	Mole %	0.000	0.00	0.000
Decane (xCH_{10})	0.0000	Mole %	0.000	0.00	0.000
Carbon dioxide (xCO_2)	0.6867	Mole %	0.050	1.24	0.062
Nitrogen (xN_2)	0.7367	Mole %	0.050	0.47	0.023
Oxygen (xO_2)	0.0100	Mole %	0.014	0.66	0.009
Helium (xHe)	0.0200	Mole %	0.014	−0.65	−0.009
Hydrogen (xH_2)	0.0000	Mole %	0.000	0.00	0.000
Carbon monoxide (xCO)	0.0000	Mole %	0.000	0.00	0.000
Hydrogen sulfide (xH_2S)	0.0000	Mole %	0.000	0.00	0.000
Water (xH_2O)	0.0000	Mole %	0.000	0.00	0.000
				RSS	0.46

Post-test Fuel Flow Uncertainty
0.31%

Table F-17-6 Plant Fuel Flow Post-test Systematic Uncertainty Analysis (Test Run 2)

Post-test (Absolute Basis, U.S. Customary Units) (95% Confidence Level)	Fuel Flow 149.95 KPPH — Test Value: Mean, $\bar{X}$	Test Value: Units	Systematic Uncertainty: Instrument Systematic Uncertainty, B_{inst}	Systematic Uncertainty: Absolute Sensitivity, θ	Systematic Uncertainty: Systematic Uncertainty of Fuel Flow, $U_{F2,SYS}$, KPPH
Fuel Flow Data					
Plant supply fuel flow differential pressure	214.72	in. H_2O	0.150	0.34	0.051
Plant supply fuel flowing pressure	255.38	psia	0.328	0.31	0.102
Plant supply fuel flowing temperature	61.95	°F	0.100	−0.16	−0.016
Orifice flowmeter calibration uncertainty (PTC 19.5)	. . .	. . .	. . .	. . .	0.375
Expansion factor method uncertainty (AGA 3)	. . .	. . .	. . .	. . .	0.182
Compressibility factor method uncertainty (AGA 8)	. . .	. . .	. . .	. . .	0.075
Fuel Analysis Data					
Methane (xCH_4)	96.0667	Mole %	0.316	−0.03	−0.011
Ethane (xCH_2)	1.9700	Mole %	0.071	0.65	0.046
Propane (xCH_3)	0.3267	Mole %	0.050	1.33	0.066
Iso-butane ($xICH_4$)	0.0567	Mole %	0.014	2.01	0.028
N-butane ($xNCH_4$)	0.0667	Mole %	0.014	2.00	0.028
Iso-pentane ($xICH_5$)	0.0167	Mole %	0.014	2.68	0.038
N-pentane ($xNCH_5$)	0.0100	Mole %	0.014	2.69	0.038
N-hexane (xCH_6)	0.0100	Mole %	0.014	3.43	0.048
N-heptane (xCH_7)	0.0000	Mole %	0.000	0.00	0.000
N-octane (xCH_8)	0.0000	Mole %	0.000	0.00	0.000
Nonane (xCH_9)	0.0000	Mole %	0.000	0.00	0.000
Decane (xCH_{10})	0.0000	Mole %	0.000	0.00	0.000
Carbon dioxide (xCO_2)	0.6933	Mole %	0.050	1.24	0.062
Nitrogen (xN_2)	0.7533	Mole %	0.050	0.47	0.023
Oxygen (xO_2)	0.0100	Mole %	0.014	0.66	0.009
Helium (xHe)	0.0200	Mole %	0.014	−0.65	−0.009
Hydrogen (xH_2)	0.0000	Mole %	0.000	0.00	0.000
Carbon monoxide (xCO)	0.0000	Mole %	0.000	0.00	0.000
Hydrogen sulfide (xH_2S)	0.0000	Mole %	0.000	0.00	0.000
Water (xH_2O)	0.0000	Mole %	0.000	0.00	0.000
				RSS	0.46
				Post-test Fuel Flow Uncertainty	0.31%

Table F-17-7 Plant Fuel Flow Post-test Systematic Uncertainty Analysis (Test Run 3)

Post-test (Absolute Basis, U.S. Customary Units) (95% Confidence Level)	Fuel Flow 149.54 KPPH				
	Test Value		Systematic Uncertainty		
	Mean, $\bar{X}$	Units	Instrument Systematic Uncertainty, B_{inst}	Absolute Sensitivity, θ	Systematic Uncertainty of Fuel Flow, $U_{F3,SYS}$, KPPH
Fuel Flow Data					
Plant supply fuel flow differential pressure	213.52	in. H_2O	0.150	0.34	0.051
Plant supply fuel flowing pressure	255.19	psia	0.328	0.31	0.102
Plant supply fuel flowing temperature	61.71	°F	0.100	−0.16	−0.016
Orifice flowmeter calibration uncertainty (PTC 19.5)	. . .	. . .	. . .	. . .	0.374
Expansion factor method uncertainty (AGA 3)	. . .	. . .	. . .	. . .	0.181
Compressibility factor method uncertainty (AGA 8)	. . .	. . .	. . .	. . .	0.075
Fuel Analysis Data					
Methane (xCH_4)	96.0500	Mole %	0.316	−0.03	−0.011
Ethane (xCH_2)	1.9800	Mole %	0.071	0.65	0.046
Propane (xCH_3)	0.3300	Mole %	0.050	1.33	0.066
Iso-butane ($xICH_4$)	0.0600	Mole %	0.014	2.00	0.028
N-butane ($xNCH_4$)	0.0733	Mole %	0.014	2.00	0.028
Iso-pentane ($xICH_5$)	0.0167	Mole %	0.014	2.67	0.038
N-pentane ($xNCH_5$)	0.0100	Mole %	0.014	2.68	0.038
N-hexane (xCH_6)	0.0100	Mole %	0.014	3.42	0.048
N-heptane (xCH_7)	0.0000	Mole %	0.000	0.00	0.000
N-octane (xCH_8)	0.0000	Mole %	0.000	0.00	0.000
Nonane (xCH_9)	0.0000	Mole %	0.000	0.00	0.000
Decane (xCH_{10})	0.0000	Mole %	0.000	0.00	0.000
Carbon dioxide (xCO_2)	0.6900	Mole %	0.050	1.24	0.062
Nitrogen (xN_2)	0.7467	Mole %	0.050	0.47	0.023
Oxygen (xO_2)	0.0100	Mole %	0.014	0.66	0.009
Helium (xHe)	0.0200	Mole %	0.014	−0.65	−0.009
Hydrogen (xH_2)	0.0033	Mole %	0.014	−0.72	−0.010
Carbon monoxide (xCO)	0.0000	Mole %	0.000	0.00	0.000
Hydrogen sulfide (xH_2S)	0.0000	Mole %	0.000	0.00	0.000
Water (xH_2O)	0.0000	Mole %	0.000	0.00	0.000

RSS	0.46
Post-test Fuel Flow Uncertainty	
0.31%	

Table F-17-8 Plant Fuel Flow Post-test Systematic Uncertainty Analysis (Test Run 4)

Post-test (Absolute Basis, U.S. Customary Units) (95% Confidence Level)	Fuel Flow 149.40 KPPH				
	Test Value		Systematic Uncertainty		
	Mean, $\bar{X}$	Units	Instrument Systematic Uncertainty, B_{inst}	Absolute Sensitivity, θ	Systematic Uncertainty of Fuel Flow, $U_{F4,SYS}$, KPPH
Fuel Flow Data					
Plant supply fuel flow differential pressure	213.24	in. H_2O	0.150	0.34	0.051
Plant supply fuel flowing pressure	254.99	psia	0.328	0.31	0.102
Plant supply fuel flowing temperature	61.63	°F	0.100	−0.16	−0.016
Orifice flowmeter calibration uncertainty (PTC 19.5)	. . .	. . .	. . .	. . .	0.373
Expansion factor method uncertainty (AGA 3)	. . .	. . .	. . .	. . .	0.180
Compressibility factor method uncertainty (AGA 8)	. . .	. . .	. . .	. . .	0.075
Fuel Analysis Data					
Methane (xCH_4)	96.0533	Mole %	0.316	−0.03	−0.011
Ethane (xCH_2)	1.9800	Mole %	0.071	0.65	0.046
Propane (xCH_3)	0.3233	Mole %	0.050	1.32	0.066
Iso-butane ($xICH_4$)	0.0667	Mole %	0.014	2.00	0.028
N-butane ($xNCH_4$)	0.0700	Mole %	0.014	2.00	0.028
Iso-pentane ($xICH_5$)	0.0200	Mole %	0.014	2.67	0.038
N-pentane ($xNCH_5$)	0.0133	Mole %	0.014	2.68	0.038
N-hexane (xCH_6)	0.0100	Mole %	0.014	3.41	0.048
N-heptane (xCH_7)	0.0000	Mole %	0.000	0.00	0.000
N-octane (xCH_8)	0.0000	Mole %	0.000	0.00	0.000
Nonane (xCH_9)	0.0000	Mole %	0.000	0.00	0.000
Decane (xCH_{10})	0.0000	Mole %	0.000	0.00	0.000
Carbon dioxide (xCO_2)	0.6833	Mole %	0.050	1.24	0.062
Nitrogen (xN_2)	0.7467	Mole %	0.050	0.47	0.023
Oxygen (xO_2)	0.0067	Mole %	0.014	0.66	0.009
Helium (xHe)	0.0200	Mole %	0.014	−0.65	−0.009
Hydrogen (xH_2)	0.0067	Mole %	0.014	−0.72	−0.010
Carbon monoxide (xCO)	0.0000	Mole %	0.000	0.00	0.000
Hydrogen sulfide (xH_2S)	0.0000	Mole %	0.000	0.00	0.000
Water (xH_2O)	0.0000	Mole %	0.000	0.00	0.000

RSS	0.46
Post-test Fuel Flow Uncertainty	
0.31%	