ASME PTC 19.6-2018

Electrical Power Measurements

Performance Test Codes

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AN AMERICAN NATIONAL STANDARD

The American Society of Mechanical Engineers

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AN AMERICAN NATIONAL STANDARD

The American Society of Mechanical Engineers

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NOTICE

All Performance Test Codes must adhere to the requirements of ASME PTC 1, General Instructions. The following information is based on that document and is included here for emphasis and for the convenience of the user of this 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 with 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 with the contractual guarantees. It is beyond the scope of any Code to determine or interpret how such comparisons shall be made.

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FOREWORD

At the suggestion of members of the Rotating Machinery Committee of the American Institute of Electrical Engineers (AIEE), the Instruments and Measurements Committee voted, in 1950, the appointment of a subcommittee for preparing a master Test Code for electrical measurements in power circuits.

Material was gathered from Part 6 of the ASME Power Test Code Supplement on instruments and apparatuses of 1934, AIEE Test Code 502 on single-phase motors, and Test Code 503 on synchronous machines. Other codes of the AIEE were reviewed, and much new material was added. All of this information was compiled and revised for the 1955 edition of ASME PTC 19.6 on electrical measurements in power circuits.

Since 1955, many ASME Performance Test Codes have been written or revised that require the accurate determination of power. Due to advances in power metering technology, these newer codes include many additional metering requirements not included in ASME PTC 19.6-1955. In addition, many fundamental techniques of power metering, use of instrument transformers, and methods for correcting for installation effects had lost emphasis or were not well understood by the more recent generation of Performance Test Code users and committee members.

Therefore, in 2002, a new ASME PTC 19.6 Committee was formed, and an initial organizational meeting was held on July 30, 2002, at ASME headquarters in New York with the intent to modernize the Supplement while simplifying, illustrating, and emphasizing techniques that are required primarily in the measurement of electrical power.

The intent of the reactivated PTC 19.6 Committee was to produce an instrument and apparatus supplement that could be wholly referenced by the equipment/system PTCs and reduce the need for the other ASME Performance Test Code committees to develop unique sections on electrical power measurement. However, it is not the intent of this revised Supplement to supersede the guidance or requirements of any IEEE code. Rather, this revised edition of ASME PTC 19.6 is intended solely to provide assistance and guidance for the accurate measurement and determination of electrical power as it applies to ASME PTC tests.

The ASME Board on Standardization and Testing approved this Code on November 20, 2017, and the ANSI Board of Standards Review approved it as an American National Standard on February 27, 2018.

ACKNOWLEDGMENT: The preparation of this Supplement required several years, and some previous members of the committee were not active at the time of its publication. The committee chair would therefore like to recognize and thank the following individuals for their significant contributions to the development of this Supplement:

M. Bearden, Landis + Gyr
T. Crawley, Southern Co.
B. Gatheridge, Yokogawa Corporation of America
A. Iskandrani, Siemens Power Corp.
R. Nadi, GE Co.
G. Osolsobe, former ASME staff
L. Penna, MD&A Turbines

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R. R. Priestley, *Honorary Member,* Consultant
R. E. Sommerlad, *Honorary Member,* Consultant

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T. Wheelock, McHale & Associates, Inc.
B. James, *Contributing Member*, Southern California Edison

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

Subject: Cite the applicable paragraph number(s) and the topic of the inquiry in one or two words.

Edition: Cite the applicable edition of the Code for which the interpretation is being requested.

Question: Phrase the question as a request for an interpretation of a specific requirement suitable for general understanding and use, not as a request for an approval of a proprietary design or situation. Please provide a condensed and precise question, composed in such a way that a "yes" or "no" reply is acceptable.

Proposed Reply(ies): Provide a proposed reply(ies) in the form of "Yes" or "No," with explanation as needed. If entering replies to more than one question, please number the questions and replies.

Background Information: Provide the Committee with any background information that will assist the Committee in understanding the inquiry. The Inquirer may also include any plans or drawings that are necessary to explain the question; however, they should not contain proprietary names or information.

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

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Moreover, ASME does not act as a consultant for specific engineering problems or for the general application or understanding of the Code requirements. If, based on the inquiry information submitted, it is the opinion of the Committee that the Inquirer should seek assistance, the inquiry will be returned with the recommendation that such assistance be obtained.

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INTRODUCTION

Many ASME Performance Test Codes require the determination of electrical power in order to evaluate the performance of a power generating system, the power produced by a large piece of mechanical equipment, or the power consumed by auxiliary equipment. IEEE 120 and C57.13 contain details for measurement of electrical properties and the application of instrument transformers. These IEEE standards are very thorough and cover measurements of voltage, current, power, power factor, frequency, impedance, magnetic quantities, and ancillary equipment. However, during many ASME performance tests, power is the main quantity of interest. In addition, specific corrections for electrical generator power output to reference operating conditions are necessary for many ASME performance tests.

It is not the intent of this Supplement to supersede the guidance or requirements of any IEEE standard. The intent is simply to emphasize and simplify the requirements for these measurements as they apply to ASME Performance Test Code tests and to provide a common document that can be referred to by all ASME Performance Test Codes.

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Section 1
Object and Scope

1-1 OBJECT

It is the purpose of this Supplement to give instructions and guidance for the accurate determination of electrical power quantities that are commonly needed in support of ASME Performance Test Codes. The choice of method and instruments to be used, required calculations, and corrections to be applied in any given case depend on the requirements of the PTC referencing this Supplement, considering the purpose of the measurement, uncertainty required, and nature of the circuit to be measured.

1-2 SCOPE

The methods given herein include direct and indirect determinations of active power (watts), reactive power (vars), and power factor produced or consumed in alternating-current single-phase and polyphase electrical circuits, electrical generators, power transformers, and motors. This Supplement does not include such measurements of fundamental electrical properties as voltage, current, frequency, resistance, and impedance, except as needed to support the objectives of this Supplement.

1-3 TEST UNCERTAINTY

This Supplement emphasizes the methods and instrumentation required to obtain measurement results with the lowest practical uncertainty based on current engineering knowledge, taking into account measurement costs and the value of information obtained from the measurement. Test uncertainty is principally influenced by the quality and calibration of the instruments, experience and judgment of the test personnel, and stability and characteristics of the power system. When estimating the systematic uncertainty of a power measurement, an uncertainty analysis shall be conducted to identify the potential sources of uncertainty, how these were estimated, and a list of all assumptions made that support the estimates presented.

Table 1-3-1 presents the requirements for the active power measurement uncertainty for three classes of measurements designated as Class A, B, or C. For the Class A measurements (high quality, minimum uncertainty), the uncertainty can be restricted to a narrow band. For the Classes B and C, a range of uncertainties can occur depending on the instrumentation selected and the other factors mentioned above. Class B has two options, depending on the calibration and burden data available. Other options may be applicable for exceptions to best practices, provided the uncertainty requirements are met for Class B.

Table 1-3-1 Class Requirements for Active Power Measurement Uncertainty

Class/Purpose	Requirements	Uncertainty, %
A (best practices)	Calibrated watt or watt-hour meter, VTs, and CTs with corrections	0.2 or better
B	Calibrated watt or watt-hour meter, with exceptions to best practices for burden correction, and VTs and CTs calibration as shown in B1 and B2	0.2–0.35
B1	Exception: type test information on CTs	0.2–0.3
B2	Exception: type test information on CTs, VTs, and estimated burden	0.25–0.35
C (low-voltage)	Clamp-on and direct metering	2–5

GENERAL NOTE: VT = voltage transformer; CT = current transformer.

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For cases of monitoring or comparative testing, where the same instruments are used for both initial and later tests, absolute measurement is not the goal of the test. In these cases, the relative uncertainty is the uncertainty of the difference between the previous reading and the current one or between the before and after tests of an equipment rebuild or modification. In these cases, Performance Test Codes that reference this Supplement may allow the use of a measurement that does not meet the requirements of Class A, B, or C, if it is demonstrated that the systematic uncertainties are correlated and essentially cancel out, thus resulting in a low measurement uncertainty.

The sections of this Supplement describe various combinations of instruments available for use in the measurement of electrical power and their calibration and application requirements. The specific test uncertainty for each combination of instruments can be determined by the procedures outlined in Section 7.

1-4 OTHER REQUIREMENTS AND REFERENCES

1-4.1 Other Requirements

The applicable provisions of ASME PTC 1 are a mandatory part of this Supplement. It should be reviewed and followed when preparing the procedure for electrical power measurements.

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

1-4.2 References

This Supplement relies on many references for test procedures and data, such as ASME, IEEE, etc. The parties shall agree to use other recognized international sources for these procedures and data, including applicable revisions. The following publications form a part of this Supplement to the extent specified herein. Unless otherwise indicated, the latest edition shall apply.

ASME PTC 1, General Instructions
ASME PTC 2, Definitions and Values
ASME PTC 19.1, Test Uncertainty
Publisher: The American Society of Mechanical Engineers (ASME), Two Park Avenue, New York, NY 10016-5990 (www.asme.org)

IEEE 120-1989, IEEE Master Test Guide for Electrical Measurements in Power Circuits
IEEE C12.1, Code for Electricity Metering
IEEE C57.12.90, Standard Test Code for Liquid-Immersed Distribution, Power, and Regulating Transformers
IEEE C57.13-2016, Requirements for Instrument Transformers
Publisher: Institute of Electrical and Electronics Engineers, Inc. (IEEE), 445 Hoes Lane, Piscataway, NJ 08854 (www.ieee.org)

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Section 2
Definitions and Descriptions of Terms

2-1 GENERAL

Terms provided in this Section are confined to those for which clarification is considered to improve the user's grasp of intent.

2-2 DEFINITIONS

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

accuracy class: guaranteed worst-case accuracy for all devices of a particular type, model, or design over their intended operating range. Usually refers to meters and instrument transformers. Accuracy of individual units may be much better than the class accuracy, but testing is required to discover the actual value.

active power [expressed in watts (W)]: amount of power delivered to the resistive component of a load. Active power is the only power that can perform useful work. In a DC circuit, active power is volts multiplied by amps. In an AC circuit with sinusoidal waveforms, active power is RMS volts multiplied by RMS amps and the cosine of the phase difference between them. (See *apparent power* and *reactive power*.)

apparent power [expressed in volt-amperes (VA)]: total power that is delivered to a circuit that contains both resistive and reactive loads. Apparent power is the square root of the sum of the squares of the active and reactive powers. (See *active power* and *reactive power*.)

burden (instrument transformer): load connected to the secondary winding of an instrument transformer that determines the active and reactive power at the secondary terminals. The burden is expressed either as total ohms impedance with the effective resistance and reactance components or as the total volt-amperes and power factor at the specified value of current or voltage and frequency.

calibration: 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. Data gathered during calibration may be used to establish correction or uncertainty factors. Alternately, for an instrument, the development of documentation that will show the difference between the Code and the instrument and the uncertainty of doing the comparison.

current transformer (CT): instrument transformer that is used to reduce a high current to a proportionately lower current that may be safely applied to a measuring instrument.

energy [expressed in watt-hours (Wh)]: integral of active power with respect to time. One watt of power delivered continuously for 1 h delivers 1 Wh of energy.

instrument transformer: transformer that is intended to reproduce in its secondary circuit, in a definite and known proportion, the current or voltage of its primary circuit with the phase relations substantially preserved. An instrument transformer is used to convert potentially dangerous voltage or current levels to a safer level suitable for a measuring instrument.

marked ratio: ratio of a transformer's rated primary value to the rated secondary value as stated on the nameplate.

phase-angle correction factor (PACF): ratio of the true power factor to the measured power factor. The phase-angle correction factor corrects for the phase displacement of the secondary current or voltage, or both, due to the instrument transformer phase angle(s).

phase angle of an instrument transformer (PA): phase displacement, in minutes of arc or radians, between the primary and secondary values. The phase angle of a current transformer is designated by the Greek letter β and is positive when the current leaving the identified secondary terminal leads the current entering the identified primary terminal. The phase angle of a voltage transformer is designated by the Greek letter γ and is positive when the secondary voltage leads the corresponding primary voltage.

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polarity: arrangement of test connections to a circuit that permits correct determination of the direction of power flow. In an AC circuit, power is regarded as being "delivered" to the load when instantaneous current flows into the load for positive instantaneous voltage swings and out of the load for negative instantaneous voltage. Instrument transformers are marked to allow correct polarity to be maintained. In general, if the marked primary terminals are connected to a phase voltage (for a VT) or toward the generator (for a CT) and the marked secondary terminals are connected to the phase voltage or line side current terminals on the instrument, the polarity will be correct for power measurements.

power factor: ratio of the active power to the apparent power in a circuit; the cosine of the phase angle between sinusoidal voltage and current in an AC circuit. Power factor can never exceed 1.0.

primary winding (instrument transformer): transformer winding intended for connection to the circuit to be measured or controlled.

random error: the portion of total error that varies randomly in repeated measurements of the true value throughout a test process.

ratio correction factor (RCF): ratio of the true ratio to the marked ratio on an instrument transformer. The primary current or voltage is equal to the secondary current or voltage multiplied by the marked ratio times the ratio correction factor.

reactive power [expressed in volt-amperes reactive (var)]: amount of power delivered to the reactive component of a load. Reactive components cause a phase shift between voltage and current in an AC circuit. In an AC circuit with sinusoidal waveforms, reactive power is RMS volts multiplied by RMS amps and the sine of the phase shift. (See *active power* and *apparent power*.)

secondary winding (instrument transformer): winding of a transformer that is intended for connection to the measuring, protection, or control device.

systematic error: the portion of total error that remains constant in repeated measurements of the true value throughout a test process. Also called bias error.

traceable: records are available demonstrating that an instrument's calibration has been performed against an ultimate reference maintained by the National Institute for Standards and Technology (NIST) or against a standard that is traceable to an NIST reference.

transformer correction factor (TCF): ratio of the true watts or watt-hours to the measured secondary watts or watt-hours divided by the marked ratio.

NOTE: The transformer correction factor for a current or voltage transformer is the ratio correction factor multiplied by the phase-angle correction factor for a specified primary circuit power factor. The true primary watts or watt-hours are equal to the watts or watt-hours measured multiplied by the transformer correction factor and the marked ratio. The true primary watts or watt-hours, when measured using both current and voltage transformers, are equal to the current transformer ratio correction factor multiplied by the voltage transformer ratio correction factor multiplied by the marked ratios of the current and voltage transformers multiplied by the observed watts or watt-hours. It is usually sufficiently accurate to calculate true watts or watt-hours as equal to the product of the two transformer correction factors multiplied by the marked ratios multiplied by the observed watts or watt-hours (from IEEE C57.13).

true ratio: ratio of the root-mean-square (rms) primary voltage or current to the rms secondary voltage or current in a transformer under specified conditions. This is the value that results from application of correction factors and may be different than the marked ratio or nominal ratio.

turns ratio of a current transformer: ratio of the secondary winding turns to the primary winding turns. This may not be the same as the marked ratio or nominal ratio.

turns ratio of a voltage transformer: ratio of the primary winding turns to the secondary winding turns. This may not be the same as the marked ratio or nominal ratio.

uncertainty (U): the interval about the measurement or result that contains the true value for the measured quantity for a given confidence level.

verification: confirmation that the instrument meets the technical specifications claimed by the manufacturer.

voltage transformer (VT): instrument transformer that is used to reduce a high voltage to a proportionately lower voltage that may be safely applied to a measuring instrument.

NOTE: Voltage transformers are commonly referred to as potential transformers (PTs), although in this Supplement they are always referred to as voltage transformers (VTs).

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Table 2-2.1-1 Symbols

Symbol	Description	Units
B	Burden	VA
CT	Current transformer	...
CTRCF	Current transformer ratio correction factor	...
CTTR	Current transformer turns ratio	...
I	Current	A
P	Power	kW
PACF	Phase-angle correction factor	...
PF	Power factor	...
Pvar	Primary side reactive power	kvar
PW	Primary side active power	kW
RCF	Ratio correction factor	...
Svar	Secondary side reactive power	var [Note (1)]
SW	Secondary side active power	W
V	Voltage	V
VA	Volt-amperes	VA
VT	Voltage transformer	...
VTRCF	Voltage transformer ratio correction factor	...
VTTR	Voltage transformer turns ratio	...
VTVD	VT circuit voltage drop	V
VTVDCF	Voltage transformer circuit voltage drop correction factor	...
W	Active power	W
α	Wattmeter phase-angle error	deg
β	CT phase-angle error	deg
γ	Phase angle	rad
γ_c	VT phase-angle error	deg
Θ	Phase angle	deg

NOTE: (1) var = volt-ampere reactive.

2-2.1 Symbols and Subscripts

Symbols used in this Supplement are listed in Table 2-2.1-1. Subscripts used in this Supplement are listed in Table 2-2.1-2.

Listed in Table 2-2.1-2 are the principal subscripts used in Sections 1 through 7 and Nonmandatory Appendix A. Subscripts in subsection 6-3 and Nonmandatory Appendix B are not included as they are specific to the calculations in those sections and are sufficiently defined therein.

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Table 2-2.1-2 Subscripts

Subscript	Description
0	Zero burden point
c	Actual burden point
d	Difference
exc	Exciter
field	Field V or I
gp	Gross power
i	Individual measurement or parameter
m	Motor
rect	Rectifier
s	Indicated
t	Total, for power or vars Upper burden point, for correction factors
vt	VT parameter
x	Per phase, in power calculation Standard deviation, for uncertain calculations
$\bar{x}$	Random or systematic standard uncertainty

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Section 3
Power System Measurement Techniques

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3-1 INTRODUCTION

Electrical system parameters commonly required for the execution of ASME PTCs include gross electrical output, power factor, exciter power, power to other auxiliary system electrical loads, and associated power-factor values. This Section provides guidance and requirements for the determination of these parameters. IEEE 120-1989 should be consulted for additional information and measurement requirements of other documents not included in this Supplement.

The number of conductors involved and metering elements required for common power circuits encountered during an ASME performance test are as follows:

(a) *two-wire systems*: one single-element meter

(b) *three-wire systems*: two single-element meters or one two-element meter

(c) *four-wire systems*: three single-element meters or one three-element meter

Details of these circuits and their metering methods are as indicated in the remainder of this Section.

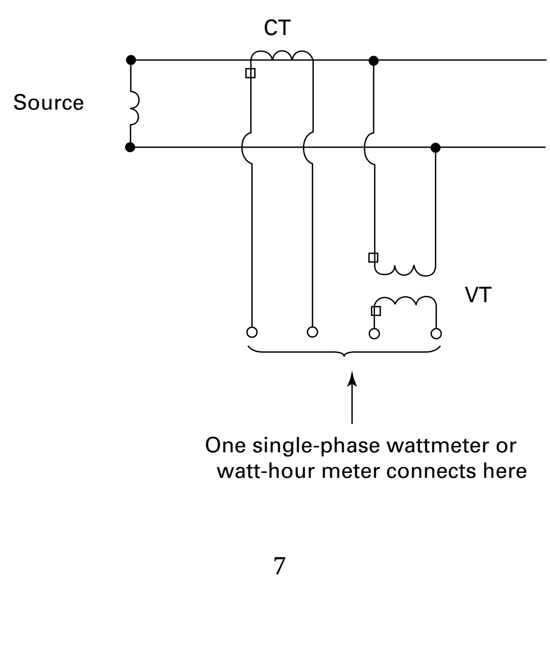
3-2 SINGLE-PHASE, TWO-WIRE POWER SYSTEMS

Figure 3-2-1 shows a simple two-wire system where the two conductors may come from any source, such as any two phases of an electric generator or a motor control center. Power in this circuit can be measured using only one metering element. This is a common application where separate transducers or metering elements are used to measure the power in single phases of a three-phase power circuit. It may also be used for a phase-to-phase or phase-to-neutral power measurement. In this case, the potential difference between the two conductors and the current in only one conductor is necessary for the calculation of power. Single-element meters may also meter the phase angle or power factor between the voltage and current in this system.

3-3 THREE-PHASE, THREE-WIRE POWER SYSTEMS

(a) *Delta-Connected Generator*. As shown in Figure 3-3-1, illustration (a), in this arrangement, the three phases on the generator are arranged in a series so that the three conductors come from the connection between each phase. In this case, the generator is connected directly to a transformer with a delta primary winding, and load distribution is made on the

Figure 3-2-1 Single-Phase, Two-Wire Power Measurement



secondary grounded-wye side of the transformer. Any zero sequence 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. In fact, the existence of any significant current in the generator neutral would indicate a ground fault in the generator stator, generator bus, primary winding of the generator transformer, or the primary winding of a unit auxiliary transformer (when used). This would result in a protective trip of the generator.

(b) Wye-Connected Generator With High Impendence Ground. As shown in Figure 3-3-1, illustration (b), in this arrangement, the three phases of the generator are connected to a neutral point that is grounded using a high impedance neutral grounding device. In this case, the generator is typically connected to a three-wire load distribution bus, and the loads are connected either phase-to-phase or three-phase delta. The grounding device is typically sized to carry 400 A to 2 000 A of fault current. Since no line-to-ground loads are connected, any significant current in the generator neutral would be abnormal and result in a protective trip of the generator.

Examples of three-wire power generation systems are shown in Figure 3-3-1. Descriptions of various three-wire power systems are as follows:

(1) where generator output (gross generation) is desired from a delta-connected generator. In this case, no neutral or fourth wire is available.

(2) where generator output is desired from a wye-connected generator with a high impedance neutral grounding device.

(3) other three-wire systems, such as the less common example of an ungrounded wye generator used with a delta-wye-grounded transformer.

Regardless of the type of three-wire system or generator arrangement, power in any of these systems can be measured using two metering elements. The power can be stepped down to measureable values using two voltage transformers (VTs) connected in an Open Delta arrangement and two current transformers (CTs). The Open Delta metering system can be used for either a delta- or wye-connected generator as shown in Figure 3-3-1, illustrations (a) and (b). These instrument transformers supply inputs to either two watt/varmeters, two watt-hour/var-hour meters, a two-element watt/varmeter, or a two-element watt-hour/var-hour meter.

3-4 THREE-PHASE, FOUR-WIRE POWER SYSTEMS

There are two types of four-wire power systems. Descriptions of these four-wire power systems are as follows:

(a) Wye-Connected Generator With Low Impedance Ground. As shown in Figure 3-4-1, in this arrangement, generator output is conducted from a wye-connected generator with a solid or low impedance ground where unbalance (zero sequence load) current can flow continuously through this fourth wire.

(b) Other Four-Wire Systems. These would include where net plant generation is measured somewhere other than at the generator, such as the four-wire grounded wye high side of a step-up transformer.

Power in four-wire systems must be measured using three metering elements. In addition, power for all of the three-wire systems described in subsection 3-3 can also be measured using this three-element approach.

The measurement of power and energy in a four-wire power system is made using three VTs and CTs as shown in Figure 3-4-1. These instrument transformers supply inputs to either three watt/varmeters, three watt-hour/var-hour meters, a three-element watt/varmeter, or a three-element watt-hour/var-hour meter.

3-5 CALCULATION OF PRIMARY ACTIVE AND REACTIVE POWER

Test power meters actually only display watts or vars on the secondary side of the VTs and CTs, based on the voltages and currents supplied by the VTs and CTs. Paragraphs 3-5.1 and 3-5.2 illustrate the methods used to convert these readings to what actually exists on the primary side of the generator bus and how to apply the transformer corrections.

3-5.1 Primary Watts

(a) To convert the power displayed or recorded by the wattmeter to what actually exists on the primary side of the instrument transformer, multiply the secondary side readings by the VT and CT turns ratios, apply the correction factors, and convert to kilowatts as follows for each phase:

$$PW_x = \frac{SW_x \times VTTR_x \times CTTR_x \times VTRCF_x \times VTVDCF_x \times CTRCF_x \times PACF_x}{1\,000}$$

where

1 000 = conversion factor from watts to kilowatts

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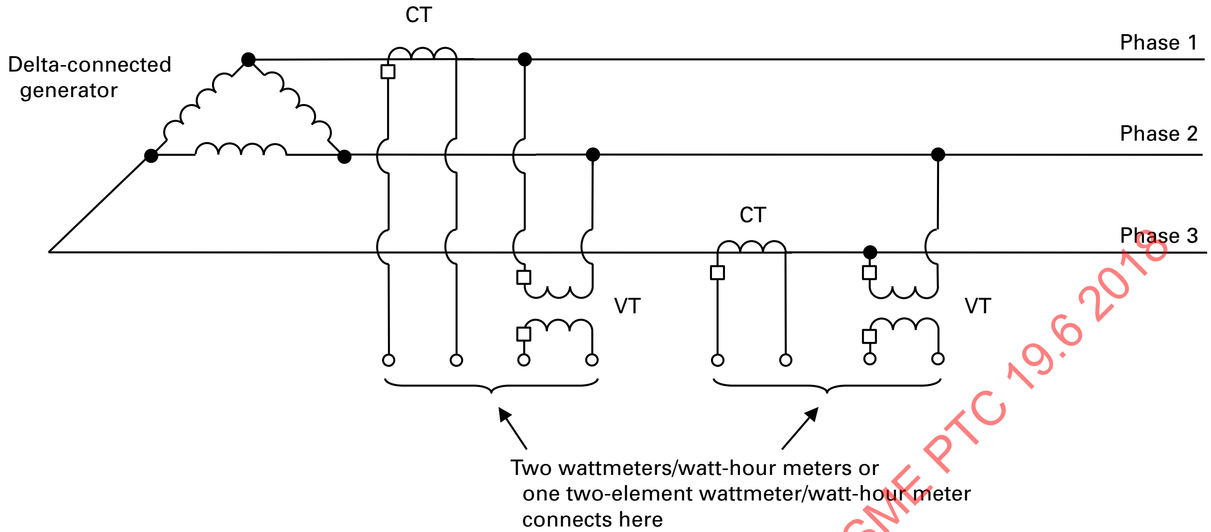
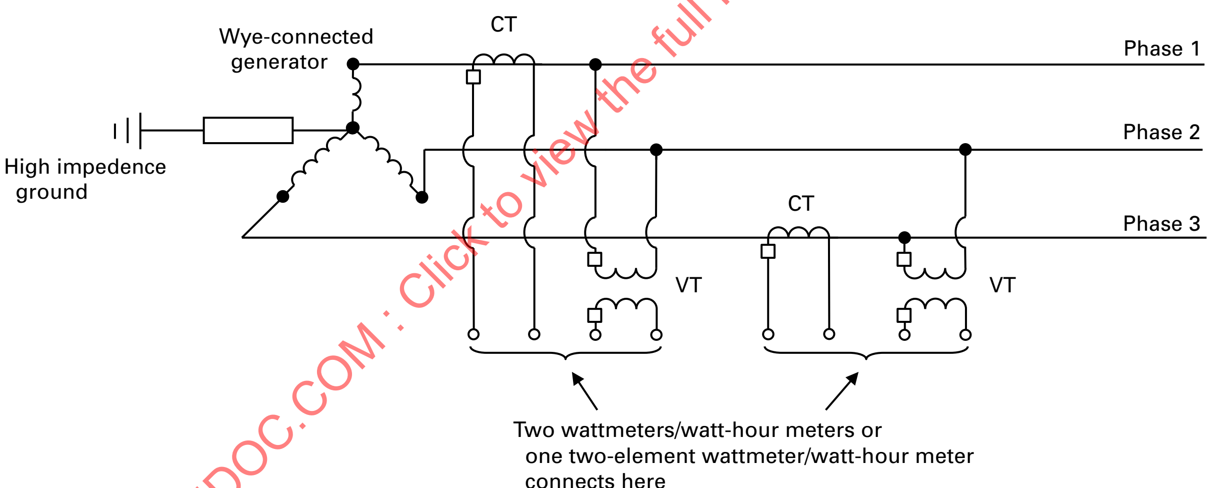
Figure 3-3-1 Three-Phase, Three-Wire Generators



(a) Delta Generator



(b) Wye Generator

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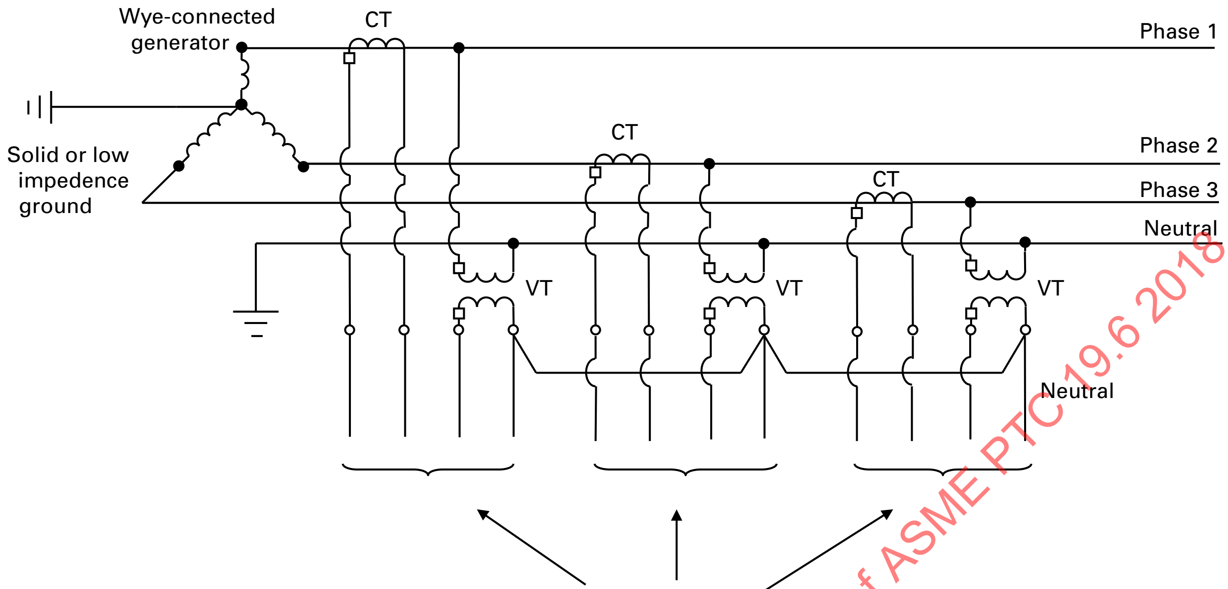
Figure 3-4-1 Three-Phase, Four-Wire Wye Generator



$CTRCF_x$ = current transformer ratio correction factor
$CTTR_x$ = current transformer turns ratio
$PACF_x$ = phase-angle correction factor
PW_x = calculated power on the primary (high-voltage) side of the voltage and current transformers, kW
SW_x = measured watts on the secondary (low-voltage) side of the voltage and current transformers, W
$VTRCF_x$ = voltage transformer ratio correction factor
$VTTR_x$ = voltage transformer turns ratio
$VTVDCF_x$ = voltage transformer circuit voltage drop correction factor

(b) The equation in (a) yields the primary watts for phase x. To determine the total power output of the generator, sum the active power measured on each phase as follows:

(1) Three-Element Measurements (Three-Phase, Four-Wire)

$$PW_t = PW_{1-N} + PW_{2-N} + PW_{3-N}$$

(2) Two-Element Measurements (Three-Phase, Three-Wire)

$$PW_t = PW_{1-2} + PW_{3-2}$$

where

PW_t = total gross generator output on primary (high) side of voltage and current transformers, kW
PW_{1-N} = phase 1 power measured using voltage difference between phase 1 and neutral, and current in phase 1, kW
PW_{2-N} = phase 2 power measured using voltage difference between phase 2 and neutral, and current in phase 2, kW
PW_{3-N} = phase 3 power measured using voltage difference between phase 3 and neutral, and current in phase 3, kW
PW_{1-2} = phase 1 power measured using voltage difference between phases 1 and 2, and current in phase 1, kW
PW_{3-2} = phase 3 power measured using voltage difference between phases 3 and 2, and current in phase 3, kW

3-5.2 Primary Vars

(a) The methods used to measure vars are similar to those used to measure watts. To convert the measured vars on the secondary side to the reactive power on the primary side per phase, multiply the secondary readings by the VT and CT turns ratios, apply the transformer corrections, and convert to kilovars.

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$$Pvar_x = \frac{Svar_x \times VTTR_x \times CTTR_x \times VTRCF_x \times VTVDCF_x \times CTRCF_x \times PACF_x}{1\,000}$$

where

1 000 = conversion factor from vars to kvars
$CTRCF_x$ = current transformer ratio correction factor
$CTTR_x$ = current transformer turns ratio
$PACF_x$ = phase-angle correction factor
$Pvar_x$ = calculated vars on the primary (high-voltage) side of the voltage and current transformers, kvar
$Svar_x$ = measured vars on the secondary (low-voltage) side of the voltage and current transformers, var
$VTRCF_x$ = voltage transformer ratio correction factor
$VTTR_x$ = voltage transformer turns ratio
$VTVDCF_x$ = voltage transformer circuit voltage drop correction factor

(b) The equation in (a) yields the primary vars for a single phase. To determine the total power output of the generator, sum the reactive power measured on each phase as follows:

(1) Three-Element Measurements (Three-Phase, Four-Wire):

$$Pvar_t = Pvar_{1-\mathrm{N}} + Pvar_{2-\mathrm{N}} + Pvar_{3-\mathrm{N}}$$

(2) Two-Element Measurements (Three-Phase, Three-Wire):

$$Pvar_t = Pvar_{1-2} + Pvar_{3-2}$$

where

$Pvar_t$ = total gross generator vars on primary (high) side of voltage and current transformers, kvar
$Pvar_{1-\mathrm{N}}$ = phase 1 vars measured using voltage difference between phase 1 and neutral, and current in phase 1, kvar
$Pvar_{2-\mathrm{N}}$ = phase 2 vars measured using voltage difference between phase 2 and neutral, and current in phase 2, kvar
$Pvar_{3-\mathrm{N}}$ = phase 3 vars measured using voltage difference between phase 3 and neutral, and current in phase 3, kvar
$Pvar_{1-2}$ = phase 1 vars measured using voltage difference between phases 1 and 2, and current in phase 1, kvar
$Pvar_{3-2}$ = phase 3 vars measured using voltage difference between phases 3 and 2, and current in phase 3, kvar

3-6 POWER FACTOR

Power factor can be measured directly using a multifunction power analyzer or calculated from measurements of apparent power, active power, RMS voltage, RMS current, and vars as in paras. 3-6.1 and 3-6.2.

3-6.1 Three-Phase, Three-Wire Power System

(a) Calculation From Active and Reactive Power. The most accurate value of power factor can be calculated using the corrected primary side measurements of active and reactive power as follows:

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

where

PF = total power factor
vars_t = total vars
watts_t = total watts

If power factor is calculated using this method, direct measurement of reactive power is recommended using a varmeter. Power factor is then determined using the above equation.

(b) Estimation From Measured Phase-to-Phase Active Power Measurements. Alternatively, for balanced three-phase sinusoidal circuits, power factor may be calculated from the phase-to-phase power measurement using the following equation:

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

where

PF = total power factor
watts_{1-2} = true power phase 1 to 2
watts_{3-2} = true power phase 3 to 2

(c) Calculation From Active and Apparent Power. Power factor can also be calculated as the ratio of active power to apparent power (in volt-amperes) of the power system.

$$PF = \frac{\text{active power}}{\text{apparent power}}$$

If measurements of phase voltage and currents are available, the apparent power can be determined as follows:

(1) Balanced Three-Wire System

$$VA = \frac{\sqrt{3}}{2}(V_{1-2}A_1 + V_{3-2}A_3)$$

(2) Unbalanced or Balanced Three-Wire System

$$VA = \frac{\sqrt{3}}{3}(V_{1-2}A_1 + V_{2-3}A_2 + V_{3-1}A_3)$$

3-6.2 Three-Phase, Four-Wire Power Systems

As in the three-wire system, power factor for the four-wire power system can be measured directly using a multifunction power analyzer or calculated from measurements of active power, RMS voltage, RMS current, and vars using the following equation:

$$PF = \frac{\text{true power}}{\text{apparent power}} = \frac{\text{watts}_t}{VA_t} = \frac{\text{watts}_t}{\sqrt{\text{watts}_t^2 + \text{vars}_t^2}}$$

where

PF = total power factor
vars_t = total vars for three phases
VA_t = total volt-amps for three phases
watts_t = total watts for three phases

3-7 EXCITER POWER

The equations provided so far are typically used to determine the gross output from an electrical generator. If a requirement of the test is to determine total output of an entire generating unit or plant, then additional measurements are necessary. One common auxiliary component is the generator exciter. The amount of power supplied or consumed by the exciter may be needed in order to calculate what the net shaft mechanical output of the turbine shaft may be, or it may be needed for the calculation of the net power plant output.

The first thing that is needed is to determine the source of the power supplied to the exciter. On many turbines/generators, the mechanical power supplied to the exciter is supplied by the same turbine shaft that turns the main generator. In this case, the power measured at the generator terminals already includes the subtraction of the power supplied to the exciter. If the exciter is powered by current supplied from the main generator bus at a point between the generator terminals and gross electrical output metering CTs, the power supplied to the exciter is also already included in the gross power measurement. If the current is supplied from a point downstream of the metering CTs, then the power supplied to the exciter is not included in the gross power measurement and should be subtracted from the gross generator output in order to calculate the net generator output.

For exciters powered from the station auxiliary system, exciter power will be included in station auxiliary system power measurements, and a separate reading for the exciter may not be necessary (see subsection 3-8). The power supplied to the exciter can be determined using any of the methods in the following paragraphs.

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3-7.1 Derivation From Breaker Currents

Exciter power can be calculated from the AC current and voltage inputs to the exciter power transformer or breaker. Since this is a measure of the actual power that comes off of the main generator bus, it includes transformer and other losses, as well as actual exciter power.

$$P_{\text{exc}} = \frac{\sqrt{3} \times V \times I \times \text{PF}}{1\,000}$$

where

1 000 = conversion factor from watts to kilowatts
$\sqrt{3}$ = value that accounts for use of line-to-line voltage measurement on a three-phase system
I = average phase current, AC amp, at high side of exciter transformer
P_{exc} = exciter power, kW
PF = power factor
V = average line-to-line voltage, AC volts

The above assumes CTs are available at the high side of the exciter transformer. In some designs, the CTs are located at the low side of the exciter transformer. If so, the exciter transformer losses, both load and no-load losses, must be calculated using the transformer design loss data. The exciter losses would be computed using the above equation but with currents, voltages, and power factor measured at the low side of the exciter transformer.

Excitation systems employing rectifiers or pulse width modulation will cause nonsinusoidal (distorted) current and voltage waveforms that can increase the uncertainty in this power computation method. Power factor is especially difficult to measure with distorted waveforms. To minimize the error, measurements should be made with true RMS instruments, either analog or digital, with sufficient bandwidth (in the kilohertz range for an analog meter) or sample rate (tens or hundreds of thousands of samples per second for a digital meter) to handle the high frequency distortion components.

The excitation transformer itself can help reduce the current waveform distortion by acting as a low-pass filter. Voltage, current, and power factor measurements on the high side of the transformer will encounter less distortion. Also, the measurements will take into account the transformer losses that otherwise would be difficult to estimate accurately due to the distortion. This is the preferred method of determining exciter power since it measures the actual power coming from the generator bus.

Modern electronic polyphase power and energy meters, either portable or permanently installed, can simplify this process. Most use either digital sampling or analog multiplication with sufficient bandwidth to account for distortion products and compute the power in each phase of the three-phase circuit rather than use an average of the three phases.

3-7.2 Derivation From Field Voltage and Current

Power supplied to the exciter can be estimated by calculating the power output by the exciter and correcting for an assumed AC-to-DC conversion efficiency using the following equation:

$$P_{\text{exc}} = \frac{V_{\text{field}} \times I_{\text{field}}}{1\,000 \times \text{ACDC}}$$

where

1 000 = conversion factor from watts to kilowatts
ACDC = AC-to-DC conversion efficiency factor
I_{field} = field current, DC amps
P_{exc} = exciter power, kW
V_{field} = field voltage, VDC

The AC-to-DC conversion efficiency factor is approximately 0.975 but may vary. Contact the generator manufacturer or consult the design documentation for the correct factor.

This straightforward method eliminates the need to deal with distorted AC waveforms since all signals are DC. Losses in the exciter transformer must still be estimated, however, and in the presence of distorted waveforms will be higher than those computed from the transformer design loss data.

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3-7.3 Detailed Analysis of Exciter Load

The exciter system has three major points that consume power: the generator field winding, the rectifier, and the exciter power transformer.

$$P_{\mathrm{exc}} = P_{\mathrm{field}} + P_{\mathrm{rect}} + P_{\mathrm{xfmr}}$$

where

P_{exc} = exciter power, kW
P_{field} = generator field power, kW
P_{rect} = rectifier power, kW
P_{xfmr} = excitation transformer power loss, kW

Generator field power is easily calculated from the DC voltage and current applied to the field winding.

$$P_{\mathrm{field}} = \frac{V_{\mathrm{field}} \times I_{\mathrm{field}}}{1\,000}$$

where

1 000 = conversion factor from watts to kilowatts
I_{field} = field current, DC amps
P_{field} = generator field power, kW
V_{field} = field voltage, DC volts

Rectifier power is the power lost in the excitation rectifier. It is calculated from field current and the voltage drop of the rectifier. Rectifier voltage drop will vary from system to system. Consult the manufacturer for the correct voltage drop value.

$$P_{\mathrm{rect}} = \frac{I_{\mathrm{field}} \times V_{\mathrm{rect}}}{1\,000}$$

where

1 000 = conversion factor from watts to kilowatts
I_{field} = field current, DC amps
P_{rect} = rectifier power, kW
V_{rect} = rectifier voltage drop, DC volts

Excitation transformer power is the power lost in the excitation transformer. It is determined from the transformer manufacturer's test or design data for the transformer.

$$P_{xfmr} = P_{\mathrm{lossNL}} \times \left(\frac{V_{\mathrm{actualSec}}}{V_{\mathrm{ratedSec}}}\right)^2 + P_{\mathrm{lossFL}} \times \left(\frac{I_{\mathrm{actualSec}}}{I_{\mathrm{ratedSec}}}\right)^2$$

where

$I_{\mathrm{actualSec}}$ = transformer secondary current, amps, measured at secondary
I_{ratedSec} = transformer rated secondary current, amps, from transformer data
P_{lossFL} = transformer short circuit losses, kW, from transformer data (also called full-load losses)
P_{lossNL} = transformer no-load losses, kW, from transformer data
P_{xfmr} = excitation transformer power, kW
$V_{\mathrm{actualSec}}$ = transformer secondary voltage, V, measured at secondary
V_{ratedSec} = transformer rated secondary voltage, V, from transformer data

If the transformer primary voltage and current are available, the secondary voltage can be computed by dividing primary voltage by the transformer turns ratio. Similarly, the secondary current can be computed by multiplying the primary current by the turns ratio.

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3-8 AUXILIARY POWER

If net unit, total power plant output, or gross power output are desired, a correction should also be applied for power supplied to any other auxiliary equipment if the current is supplied from the main generator bus at a point after the generator gross electrical output metering CTs. This power can usually be metered at the breaker feeding the auxiliary bus using the following equation and inputs:

$$\mathrm{Aux} = \frac{\sqrt{3} \times V \times I \times \mathrm{PF}}{1\,000}$$

where

1 000 = conversion factor from watts to kilowatts
$\sqrt{3}$ = value that accounts for use of phase-to-phase voltage
Aux = auxiliary power, kW
I = average RMS phase current, amps
PF = power factor
V = average phase-to-phase voltage, V

For high accuracy measurements of auxiliary power, the same techniques and metering equipment used for main generator output measurements can be used.

3-9 ELECTRIC MOTOR POWER MEASUREMENT

Some ASME PTCs require the determination of power supplied to electric motors. When necessary, power supplied or consumed by electrical motors or low-voltage station service busses may be determined using the following methods.

3-9.1 Power Meter Method

A convenient method for determining the electrical power input to an electric motor is to use a portable power meter or power analyzer. This type of instrument will measure the motor input voltage and current simultaneously and calculate the true electrical power in watts or kilowatts.

The power analyzer can also provide other measurement parameters, such as VA, var, power factor, and frequency. Some power analyzers will permit measuring and displaying all three currents and voltages of a three-phase motor. This is very useful for checking the electrical balance condition of the motor.

When connecting the power meter to the motor circuit, follow the instrument manufacturer's wiring and connection diagrams. This is especially important for the three-phase connections. In most cases, the voltage and current measurement connections will need to be done without disconnecting the motor from the electrical circuit. Use extreme caution to ensure operator safety when making these connections.

(a) Voltage Connections. Before making the voltage connections, confirm the supply voltage rating and voltage measurement ranges of the power meter. Most power meters or power analyzers can make direct voltage measurements up to 600 V RMS or 1 000 V RMS. If the motor supply voltage is higher than the instrument measurement range, a VT will be required.

Voltage connections can usually be made at the motor supply bus or contractor/starter panel. (Connection at the motor terminal may not be possible due to safety considerations.) Make the voltage connections in accordance with the instrument manufacturer's instructions. For a three-phase, three-wire supply to a motor, connect the voltages in a line-to-line configuration. For a two-wattmeter measurement method, only two voltages will be needed. A typical voltage connection would be from A to B and C to B. If the power analyzer will measure all three voltages on a three-wire system, then connect all three, typically A to B, B to C, and C to A, or as indicated by the instrument manufacturer.

(b) Current Connections. A convenient and safe way to make the current measurements is to use a clamp-on or split-core CT with the power meter. CTs must be installed around the current carrying cables in a proper physical orientation. Clamp-on CTs often have an arrow to show the orientation from the line supply to the load. The arrow should point towards the load device being tested. Check the manufacturer's instructions for proper polarity markings and physical orientation.

If a clamp-on current probe is not used, the secondary output of a CT should be shorted or switched in using a sliding link when connecting the measuring instrument. Continuity through the meter should be verified before removing the short or opening the sliding link. Before disconnecting the measuring instrument, make sure the CT secondary is shorted or the sliding link is closed. Extremely high and dangerous voltages can develop inside a CT when the secondary is open circuit.

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Most stationary and split-core type CTs will have a shorting bar for the secondary output. Clamp-on CTs usually have an internal protection circuit.

For a two-wattmeter measurement method, only two currents will be needed. Follow the instrument manufacturer's wiring instructions for proper voltage and current phase connections. If possible, measure each phase current to check current balance to the motor.

Induction motors often have capacitor banks installed for power factor correction. It is important to make sure the voltages and currents being measured are the actual motor voltages and currents. If capacitors are used, make sure the voltages and currents are measured between the motor and capacitor bank.

If the motor is connected to a variable speed drive or variable frequency drive (VFD), it is important to use a power meter or power analyzer designed to make accurate measurements on this type of device. The voltage output of a VFD is a pulse width modulated (PWM) waveform. Both the voltage and current waveforms of a PWM-type inverter contain harmonic components to a high order. The power in a distorted waveform is the total sum of the products of the equivalent frequency or harmonic components in a given voltage/current waveform. The power meter or power analyzer must be capable of measuring all the high frequency components of the voltage and current waveforms. To do this, the power analyzer must have a digitizing rate fast enough to sample the high frequency components. A typical digitizing rate would be 100,000 samples per second. The bandwidth of the power analyzer should be 100 kHz or higher. Many general purpose power meters are designed to work on a sine wave only and will not make accurate measurements on a PWM-type waveform.

3-9.2 Calculated Method

When a power meter is not available, the input power of an electric motor can be estimated by making RMS voltage and current measurements. The measurements can be made with handheld instruments, such as clamp-on ammeters and multimeters, and a power factor meter is available. This method is not suitable if the motor is connected to a variable speed drive.

The three-phase input power to the motor can be calculated from the following equation:

$$P_m = \frac{\sqrt{3} \times V \times I \times \mathrm{PF}}{1\,000}$$

where

1 000 = conversion factor from watts to kilowatts
$\sqrt{3}$ = value that accounts for use of phase-to-phase voltage
I = average RMS phase current
PF = power factor, as a decimal
P_m = three-phase motor power in kW
V = average line-to-line RMS voltage

Measurement of V, I, and PF for all three phases should be made and the average values used for the calculation. This applies to the voltage, current, and power factor measurements. The voltage, current, and power factor measurements can usually be made at the motor starter supply bus or contractor/starter panel or breaker.

For an induction motor, the voltage measurements can be made with a true RMS handheld digital multimeter. Measure each line-to line voltage, and average the three readings.

Motor current can be measured with a clamp-on ammeter. Current measurements can usually be made by clamping the jaws of the ammeter around the cables at the motor starter box. It is important to make sure the current being measured is the actual motor current. If power factor correction capacitors are used, make sure the currents are measured between the motor and capacitor bank. Measure each of the phase currents and use the average value for calculating the motor power.

The accuracy of a clamp-on ammeter is typically based on its full-scale range. Therefore, always use a clamp-on ammeter with a range optimized for the actual current value being measured.

Sometimes the motor load may be fluctuating. In this case, the min/max current for each phase should be averaged. Some clamp-on ammeters have a min/max-averaging feature, which will simplify this measurement.

When using clamp-on ammeters, it is very important to make sure the jaws are completely closed and aligned properly. This is essential to ensure that the magnetic circuit of the CT is properly completed for the most accurate measurement. When clamping a cable with tight clearances, the jaws can stick partially open or be skewed. This can cause a considerable measurement error. Make sure the jaws are fully closed and aligned before making current measurements.

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If a power factor meter is available, it should be used to obtain an accurate value for the calculation. The power factor meter can be connected at the same locations as the power measurements. If power factor correction capacitors are used, make sure the power factor meter is connected between the motor and capacitor.

If a power factor meter is not available, the value for the power factor will need to be estimated. Typical values can usually be obtained from the motor manufacturer's data. An induction motor with a load of 50% to 100% will typically have a power factor of 0.8 to 0.85. This range could be used to make an estimated calculation of motor power when manufacturer's data is not available. The motor input current is usually a linear relationship to the motor power. Therefore, the measured current can be compared to the full load current rating of the motor, as indicated on the motor nameplate. This ratio of currents provides an indication of motor load. If the motor has less than a 50% load, this estimated value of the power factor cannot be used.

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Section 4
Power Meters

4-1 TYPES OF METERS

The following are the five types of electrical metering equipment that may be used to measure electrical energy:
(a) wattmeters
(b) watt-hour meters
(c) varmeters
(d) var-hour meters
(e) power factor meters

This metering equipment may be a single function measuring instrument or a multifunction precision power analyzer capable of making all of the measurements in one instrument. Single or polyphase metering equipment may be used. However, if polyphase equipment is used, it is recommended that the output from each phase be available.

4-2 CATEGORIES OF INSTRUMENTATION

This Section will classify instrumentation by accuracy and application. The instrumentation employed to measure a variable will have a different required accuracy depending upon the use of the measured variable and on how the measured variable affects the final result. For purposes of this discussion, variables include voltage, current, active apparent and reactive power and energy, power factor, and frequency.

4-2.1 Test Instruments

This category of instruments provides the highest accuracy measurements. They are typically installed only during the testing and calibrated prior to the testing. These could be single or multifunction instruments that measure any of the variables listed above. These instruments are the preferred source of measurements used to calculate ASME performance test results because they contribute the least uncertainty to the result.

4-2.2 Station Instruments

This category of instruments may include the permanently installed plant instrumentation if it is calibrated to the required accuracy level before testing. This could include station or unit gross generator output watt-hour meter, switchboard and panel meters, transducers, and other permanently installed plant metering. These instruments could be used as the source of measurements to calculate the performance test results if they contribute an acceptable level of uncertainty to the result. As with temporary test instruments, the output from these meters must be compensated for instrument transformer errors and line losses, either internally or externally using raw values.

4-2.3 Performance Monitoring Instruments

Since performance monitoring involves measuring the change in values, the absolute accuracy of instruments used for monitoring relative changes in electrical parameters is of less critical importance. Most systematic or bias errors in these measurements are typically consistent, so primarily, the random errors contribute to the uncertainty of the relative change in the measurement. In this case, plant transducers or other permanently installed instruments may be used for determining the change in electrical parameters from one time period to another, assuming that the following conditions are repeatable:
(a) load on the metering circuit
(b) environmental conditions surrounding the meter
(c) unchanged calibrations
(d) unchanged connection points and wiring to the meter
(e) no obvious drift shifts in meter output compared to other measurements of the same parameters

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4-2.4 Clamp-on Instruments

This category of instruments includes portable test devices that have a clamp-on current sensor and clip-on voltage connections. Handheld clamp-on meters and power quality analyzers fit into this category. These instruments are typically used for lower voltage applications (480 VAC to 4 160 VAC) when direct connection of current inputs to the power meter is unsafe or impractical or when a current transformer (CT) is not available. The electrical measurements may be made using a test quality power meter; however, due to the additional uncertainty of the current clamps, the overall uncertainty of the measured quantity will be significantly higher. These techniques could be used as the source of measurements to calculate auxiliary loads if they contribute an acceptable level of uncertainty to the result.

The clamp-on ammeter is based on the principle that a current-carrying wire produces a magnetic field, the strength of which is in direct proportion to the strength of the current. Clamp-on ammeters have a CT with "jaws" that can be opened and clamped around the current-carrying wire. The measuring circuit may be an analog-type meter using a moving coil iron-vane mechanism called a D'Arsonval movement. Other designs of clamp-on ammeters may have a digital readout. The digital instrument has an electronic circuit and a magnetic field detector device, such as a Hall-effect sensor to determine the field strength.

Typical accuracy of a clamp-on ammeter is about 2%. Elements that cause the reduced accuracy of this type of instrument are the split-core CT and the D'Arsonval movement or the Hall-effect magnetic field sensor.

4-2.5 Uncalibrated Instruments

This category of instruments may include permanently installed plant instrumentation or other portable instruments that have not been calibrated before testing. These instruments may be used for measured variables that do not enter into the calculation of the performance test result. These variables are measured throughout a test period to ensure that the required test conditions are not violated.

4-3 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 gross active generation should have an uncertainty equal to or less than 0.15% of reading. For Class A high-accuracy measurements, single-phase wattmeters are available that have an uncertainty equal to or less than 0.10% of reading. The output from the wattmeter should be sampled with a frequency high enough to attain an acceptable precision considering the variation of the power measured. A general guideline is a frequency of at least once every 15 sec.

4-4 WATT-HOUR METERS

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

For Class A high-accuracy measurements, single-phase wattmeters are available that have an uncertainty equal to or less than 0.10% of reading. Watt-hour meters measuring gross active generation should have an uncertainty equal to or less than 0.15% of reading.

The resolution of induction-type watt-hour meters is often so low that high inaccuracies can occur over a typical test period. Often, watt-hour meters will have an analog or digital output with a higher resolution that may be used to increase the resolution. Some watt-hour meters will often also have a pulse-type output that may be summed over time to determine an accurate total energy during the test period.

For disk-type watt-hour meters with no external output, the disk revolutions can be timed and counted during a test to increase resolution. Some electronic watt-hour meters also display blinking lights or LCD elements, which correspond to disk revolutions that can be timed to determine the generator electrical output.

Another technique for improving the precision of the watt-hour meter display is to accurately record the time between the incrementing of the watt-hour display. The method that should be used is as follows:

(a) Obtain a stopwatch with a precision of at least 0.1 s. (A precision of 0.01 s is preferred.)

(b) At the approximate start of the test period, start the stopwatch at the instant that the least significant digit of the watt-hour display increments.

(c) Record the watt-hour reading that the meter now displays. Be sure to record it before the display changes to the next number.

(d) Wait until approximately 1 min before the end of the test period.

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(e) Stop the stopwatch when the least significant digit of the watt-hour display increments. This is the total elapsed time during the test period. Record the time to as many significant figures as available.

(f) Record the watt-hour reading that the meter now displays. Again, be sure to record it before the display changes to the next number.

(g) Subtract the watt-hours recorded during the start of the test from the watt-hours recorded at the end of the test. This is the total watt-hours for the test period.

(h) Divide the total watt-hours by the elapsed time (in fractional hours). The result is the average watts during the test period.

NOTE: Some stopwatches roll over to whole seconds after 30 min or 1 h. It may be beneficial to record the final readings in the last few minutes before this amount of time has elapsed.

It also is recommended that instantaneous readings also be recorded periodically during the test period as backup data to determine the random uncertainty and verify the validity of the final result.

An electronic digitizing multifunction power analyzer with an integration function for watt-hour measurements could be used to overcome some of the limitations and inaccuracies of induction and disk-type watt-hour meters. This type of analyzer can provide an auto scale feature to provide high-resolution measurements. They can also provide very high-accuracy power measurements and high-accuracy timing function for accurate watt-hour calculations. In addition, an analog or digital output can be provided.

4-5 VARMETERS

Varmeters measure instantaneous reactive power. The instantaneous reactive power must be measured frequently during a test run and averaged over the test run period to determine average reactive power (kilovars) during the test. Should the total reactive electrical energy (kilovar-hours) be desired, the average power must be multiplied by the test duration in hours.

Varmeters measuring generator reactive power should have an uncertainty equal to or less than 0.5% of range. The output from the varmeters must be sampled with a frequency high enough to attain an acceptable precision. This is a function of the variation of the power measured. A general guideline is a frequency of at least once per minute. In any case, the resulting effect on power factor uncertainty should not exceed 0.005 PF.

4-6 VAR-HOUR METERS

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

Var-hour meters measuring generator output should have an uncertainty equal to or less than 0.5% of range. In any case, the resulting effect on power factor uncertainty should not exceed 0.005 PF.

The resolution of var-hour meter output is often so low that high inaccuracies can occur over a typical test period. The same methods described above for improving the precision of watt-hour meters may be employed for var-hour meters.

4-7 POWER FACTOR METERS

Power factor may be measured directly using a three-phase power factor transducer when balanced load and frequency conditions prevail. Power factor transducers should have an uncertainty equal to or less than 0.005 PF of the indicated power factor. An electronic multifunction power analyzer with a power factor measurement function may also be used. Certain types of power analyzers offer a function for measurement of total power factor on an unbalanced three-phase, three-wire system.

4-8 CALIBRATION

All measuring instrumentation should be calibrated in accordance with the manufacturer's specifications and procedures. Standard instruments and calibration sources should have a higher accuracy than the measuring instrument being calibrated. Typically, a standard instrument or calibration source should have an accuracy of at least four times greater than the instrument being calibrated; however, due to the extreme accuracy available in modern test instruments, it is often difficult to meet this criterion. In this case, where test and standard instrument accuracies are less than the four-to-one ratio, the combined uncertainty of the two instruments must meet the uncertainty requirements of the test measurement. The instruments should be calibrated against a standard instrument of the same type that is a wattmeter against a standard wattmeter or against a standard calibration source. All standard instruments and calibration sources should be under a primary calibration schedule and should have calibration records traceable to the National Institute of Standards

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and Technology (NIST), a recognized international or national standard organization, or defined natural physical (intrinsic) constants.

Calibration laboratories commonly include in their calibration process a comparison of the Test & Measurement Equipment (T&ME) to a standard. The test uncertainty ratio (TUR) is typically used and is the comparison between the accuracy of the unit under test (UUT) and the estimated calibration uncertainty. TUR includes other potential sources of error in the calibration process. A 4:1 TUR is the point to which most high-quality labs strive under certain quality standards. In some cases, a 4:1 TUR may be unachievable. Factors that could cause a situation where the TUR is <4:1 include availability of adequate standards and the technology of the respective T&ME is approaching the intrinsic level of the specific discipline.

For power meters that produce analog output, calibration shall include full-loop calibration from the source inputs to the output method that will be used during the test.

4-8.1 Wattmeter and Watt-Hour Meter Calibration

Wattmeter and watt-hour meters are calibrated by applying power through the test power meter and a power meter standard simultaneously. Should polyphase metering equipment be used, the output of each phase must be available, or the meter must be calibrated with all three phases simultaneously.

Electrical test instruments shall be calibrated before the test. It is recommended that the instruments be calibrated after the test in order to verify that the meter calibration has not drifted and that the uncertainty of the meter meets test requirements. In addition, post-test calibrations should be performed if the calibration has expired before the end of the test or if a problem is suspected to have developed during shipping or during the test.

Portable instruments shall be calibrated in a controlled laboratory environment. In calibrating a wattmeter or a watt-hour meter, first determine the ranges of voltage, current, and power factor over which the instrument must maintain its rated accuracy. Then provide high accuracy sources that establish all the combinations of these parameters needed to verify acceptable meter performance. The AC sources used for calibrating wattmeters and watt-hour meters must have known values of uncertainty for amplitude, frequency, and phase angle of the voltage and current. The AC sources used for calibration could be individual voltage and current standards as long as they have the capability of being synchronized together with a phase shifter. The other type of source is a multifunction calibrator that produces an internally synchronized voltage and current source. Polyphase meters, or metering systems, that cannot be verified to be made up of separate single-phase meters shall not be used unless they can be calibrated three-phase.

When calibrating watt-hour meters, an accurate source of time measurement must be included. The average output can be multiplied by the calibration time interval to compare against the watt-hour meter output.

Wattmeters should be calibrated and adjusted at the electrical line frequency specified by the instrument manufacturer. Often, the manufacturer of highly sensitive instruments will specify calibration and adjustment at some other frequency than line frequency in order to avoid any induced errors from electrical fields. These stray electrical fields could come from other instruments, power supplies, and lighting sources. After proper calibration and adjustment, a performance test of the wattmeter could be made at the electrical line frequency at which the tests will actually be performed.

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

4-8.2 Varmeter and Var-Hour Meter Calibration

In order to calibrate a varmeter or var-hour meter, one must either have 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. A calibration source as specified above for wattmeters could be used for varmeter and var-hour meters.

Should a varmeter standard be employed, the procedure for calibration outlined above for wattmeters should be used. Should a wattmeter standard and VA and/or phase-angle meter be used, simultaneous measurements from the standard, phase-angle meter, and test instrument should be taken. The var level will be calculated from the average watts and phase angle.

Varmeter and power factor meters should be calibrated in accordance with the manufacturer's specifications. Manufacturers of varmeters, like some wattmeters, may specify calibration and adjustment at some other frequency than line frequency. Other types of varmeters may be particularly sensitive to frequency. In this case, the varmeter should be used within 0.5 Hz of the calibration frequency.

When calibrating var-hour meters, an accurate source of time measurement must be included. The average output can be multiplied by the calibration time interval to compare against the watt-hour meter output.

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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.

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Section 5
Instrument Transformers

5-1 PURPOSE

Connections and measurements of the voltage and current necessary for the determination of power are seldom made directly in high voltage and current circuits due to the magnitude and danger of the voltage and currents involved. Instrument transformers are used for the purpose of

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

(b) insulating the metering instruments from the high voltage that may exist on the circuit under test

Instrument transformer practice is described in detail in IEEE C57.13.

For a Class A or Class B power measurement, correctly rated current and voltage transformers (VTs) of at least 0.3% accuracy class (metering type) shall be used for the tests. When required, instrument transformers shall be calibrated for correction of ratio and phase-angle errors prior to the test over the ranges of voltage, current, and burden expected to be experienced during the test. Ratio correction factor corrections should be applied for the actual burdens that exist during the test. Actual volt-ampere (VA) burdens shall be determined either by calculation from lead impedances and the VA ratings of the connected meters or by direct measurement.

Instrument transformer accuracy ratings are typically specified in terms of accuracy class. Accuracy class for revenue metering is based on the requirement that the transformer correction factor of the VT or of the current transformer (CT) shall be within specified limits when the power factor (lagging) of the metered load has any value from 0.6 to 1.0 under specified conditions as established in IEEE C57.13. The limits of transformer correction factor for a standard 0.3% accuracy class VT (at 90% to 110% rated voltage) is 0.997 minimum and 1.003 maximum. The limits of transformer correction factor for a standard 0.3% accuracy class CT at 100% rated current is 0.997 minimum and 1.003 maximum and at 10% rated current is 0.994 minimum and 1.006 maximum.

For performance testing of newer plants, factory test calibration data of the instrument transformers may be used for determining the ratio and phase-angle correction factors. However, recalibration may be required if the CT or VT is subjected to abnormal operating conditions, particularly exposure to direct current, opened circuitry of a CT secondary, shorted circuitry of a VT secondary, and/or a primary ground fault condition. Further investigation should be performed if any of these events have occurred in order to verify that transformer characteristics have not changed.

The impedances in the transformer circuits must be constant during the test. Protective relay devices or voltage regulators shall not be connected to the CTs used for the test. When VTs are used for both protection and metering functions, the metering circuit shall be separately fused. Normal station instrumentation may be connected to the test transformers if the resulting total burden is known and within the rated burden of the instrument transformers for the range of calibration data.

5-2 VOLTAGE TRANSFORMERS

VTs measure either phase-to-phase voltage or phase-to-neutral voltage. The VTs serve to convert line or primary voltages (typically exceeding 480 V) 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 VT must be multiplied by a turns ratio to calculate the primary voltage that actually exists in the primary circuit.

VTs are available in several metering accuracy classes. For Class A or Class B power measurements, 0.3% accuracy class VTs or better shall be used. For Class A or Class B1 power measurements, each VT shall be calibrated per IEEE C57.13. Accuracy tests shall consist of ratio and phase-angle tests from approximately 90% to 110% of rated primary voltage, when energized at rated frequency with zero burden, and with the maximum standard burden for which the transformer is rated at its best accuracy class.

For Class B2 power measurements, 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 and that may have a different characteristic in a specific test.

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Corrections should also be applied for voltage drop from the VTs to the test meters. Methods for determining voltage drop and applying corrections for it are also discussed in subsection 5-7 with an example in Nonmandatory Appendix A.

5-3 CURRENT TRANSFORMERS

CTs measure current in each line of the circuit. The CTs convert the line or primary current (typically very high in kiloamps) to a lower secondary current safe for metering (typically 1 A to 5 A). For this reason, the secondary current measured by the CTs must be multiplied by a turns ratio to calculate the primary current that actually exists in the primary circuit.

CTs are available in several metering accuracy classes. CTs shall be operated within their rated burden range during the test and should be operated near 100% of rated current to minimize instrument error. For Class A or Class B power measurements, 0.3% or better accuracy class CTs shall be used. For Class A power measurements, each CT shall be calibrated per IEEE C57.13. Accuracy tests shall consist of a measurement of ratio and phase angle at approximately 100% and at 10% of rated current, when energized at rated frequency with zero burden, and with maximum standard burden for which the transformer is rated at its best accuracy class. The method of calibration shall permit the determination of turns ratio and phase angle to an uncertainty of at least ±0.1% and ±0.9 mrad (3 min), respectively.

For Class B1 or Class B2 power measurements, 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 and that may have a different characteristic in a specific test. Permanently installed CTs are almost exclusively used for ASME performance tests since it is impractical to install temporary test CTs in a typical generator isothermal bus.

Ratio and phase-angle correction factors are typically very small near rated current outputs for CTs; 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. If either correction factor is estimated to be less than 0.02%, it can be neglected but should be included in the test uncertainty analysis.

CAUTION: Lethal voltage will be developed at the CT secondary terminals if left open-circuited while energized.

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5-4 INSTRUMENT TRANSFORMER CONNECTIONS

For generator gross power measurements, connections for voltage- and current-measuring instruments shall be made on the generator side of step-up transformers as close to the generator terminals as possible. Current connections shall be made on the generator side of any external connections of the power circuit by which power can enter or leave this circuit.

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

In order to minimize the voltage drop in the secondary circuit, wire gage shall be chosen considering the length of wiring, load of the transformer circuit, and resistance of the safety fuses. The errors due to wiring resistance (including any fuses) shall always be taken into account, either by direct voltage drop measurement or calculation. A suggested method for determining these corrections is discussed in subsection 5-7. An example for applying the correction is shown in Nonmandatory Appendix A.

5-5 CALIBRATION REQUIREMENTS

For Class A measurements, instrument transformers shall be calibrated according to IEEE C57.13. The data obtained during calibration are used to correct for ratio and phase-angle errors as detailed below. Instrument transformers are passive devices that maintain their accuracies after initial calibration or factory tests, and periodic testing and recalibration are normally not necessary (see IEEE C12.1).

5-5.1 VT Calibration

For Class A or Class B power measurements, each VT shall be calibrated per IEEE C57.13. Accuracy tests shall consist of ratio and phase-angle tests from approximately 90% to 110% of rated primary voltage, when energized at a rated frequency with zero burden, and with the maximum standard burden for which the transformer is rated at its best accuracy class. The method of calibration shall permit the determination of turns ratio and phase angle to an uncertainty of at least ±0.1% and ±0.9 mrad (3 min), respectively. The calibration records should include a statement of the uncertainty of the measurement.

A NIST publication[1] indicates the IEEE C57.13 uncertainty figures are relatively modest uncertainties, with significantly lower calibration uncertainties for ratio correction factor and phase angle being achievable. Sources of error in the calibration of instrument transformers should be evaluated to determine the actual uncertainty associated with the ratio correction factor and phase angle. Sources of error for the calibration of VTs may include, but not limited to, bridge measurement, secondary voltage setting, burden setting, transformer self-heating, and capacitance ratio measurement.

Corrections for actual VT performance require that known transformer performance data be available at a minimum of two points. One set of data should be provided at zero burden and another provided at one other burden that is higher than the test burden.

NOTE: Standard rated burdens for VTs are designated as follows:

0 = 0 VA
W = 12.5 VA, PF = 0.10
X = 25.0 VA, PF = 0.70
M = 35.0 VA, PF = 0.20
Y = 75.0 VA, PF = 0.85
Z = 200.0 VA, PF = 0.85
ZZ = 400.0 VA, PF = 0.85

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Modern metering circuits used for performance measurements have very low burdens — typically no greater than 25 VA; therefore, for the purposes of performance testing, VTs with ratings as low as 75 VA should be sufficient. However, if existing station VTs are used for the test, these VTs may be rated as high as 200 VA. If permanent plant metering and instrumentation are connected during performance testing, the total burdens can be greater than 75 VA, especially on older installations.

As a minimum, the following data are required to define and correct VT performance:

(a) VT turns ratio
(b) VT secondary burden rating
(c) secondary volts
(d) ratio correction factor or error at 0 VA
(e) ratio correction factor or error at rated burden
(f) phase angle at 0 VA
(g) phase angle at rated burden

For a 0.3% accuracy class VT rated at 200 VA, typical ratio correction factors are in the neighborhood of 0.9975 at zero burden and 1.0025 at 200 VA. To be classified as a 0.3% accuracy class VT, the ratio correction factors at 0 VA and rated burdens must be between 0.997 and 1.003 and within a 0.3% accuracy class parallelogram. This is not the uncertainty but merely the accuracy class of the transformer. The uncertainty of the transformer can be calculated as shown in Section 7.

5-5.2 CT Calibration

Small errors exist in CT performance since part of the primary current required to magnetize the core is not available as a secondary side current. The amount of exciting current required depends on the magnetic flux required to force the secondary current through the secondary impedance. This current and subsequently the CT error would increase as the impedance of the secondary burden increases. However, in order to compensate for these core losses, the transformer may be compensated by including extra turns of wire to provide a zero ratio error at some particular value of current and burden. Similar compensation is made for phase-angle errors.

For Class A power measurements, each CT shall be calibrated per IEEE C57.13. Accuracy tests shall consist of a measurement of ratio and phase angle at approximately 100% and 10% of rated current, when energized at rated frequency with zero burden, and with maximum standard burden for which the transformer is rated at its best accuracy class. The method of calibration shall permit the determination of turns ratio and phase angle to an uncertainty of at least ±0.1% and ±0.9 mrad (3 min), respectively. The calibration records should include a statement of the uncertainty of the measurement.

Recalibration may be required if the CT is subjected to abnormal operating conditions, particularly exposure to direct current, opened circuitry of a CT secondary, or a primary ground fault condition. Further investigation should be performed if any of these events have occurred, to verify that transformer characteristics have not changed.

[1] NBS Measurement Services: A Calibration Service for Voltage Transformers and High-Voltage Capacitors, Special Publication 250-33, William E. Anderson, U.S. Department of Commerce, June 1998.

A NIST publication[2] indicates the IEEE C57.13 uncertainty figures are relatively modest uncertainties, with significantly lower calibration uncertainties for ratio correction factor and phase angle being achievable. Sources of error in the calibration of instrument transforms should be evaluated to determine the actual uncertainty associated with the ratio correction factor and phase angle. Sources of error for the calibration of CTs may include, but are not limited to, core magnetization, burden, transformer temperature, current value, primary winding position, and electromagnetic interference.

Corrections for actual CT performance require that known performance test data for ratio and phase angle or calibration curve at different secondary currents are available. In accordance with IEEE C57.13, test data will include a minimum of two points at 100% and 10% of the rated current and at maximum standard burden.

The standard rated burdens for metering class CTs are designated as follows, all at 0.9 power factor and corresponding to 5 A rated secondary current:

Symbol	Rated Burden
B-0.1	2.5 VA, 0.1 Ω burden
B-0.2	5.0 VA, 0.2 Ω burden
B-0.5	12.5 VA, 0.5 Ω burden
B-0.9	22.5 VA, 0.9 Ω burden
B-1.8	45.0 VA, 1.8 Ω burden

The typical burden rating of the CT for power plant application is B-1.8 or B-0.9.

The CT ratio for a generator circuit is normally selected with primary rated current very close to the circuit rating. Therefore, the accuracy and phase-angle test data at 100% rating of the CT could be used for estimating the correction factors and to allow for a difference in connected burden. To be classified as a 0.3% accuracy class CT, the correction factors at 100% rated current must be between 0.997 and 1.003. This does not mean that the uncertainty of the current produced by the transformer has an uncertainty of 0.3%. It simply means that the error of the current will not exceed 0.3% if no corrections are applied for its known characteristics or calibration data.

CT burdens required for correction of CT ratio correction factors during performance tests are usually determined online by measurement of the percentage of rated current using existing plant instrument primary side phase current displays. Typically, the CT ratio error is the same for all metering burdens above approximately 30% of rated current, so measurement of the actual burdens of the CT metering circuit is not necessary.

5-5.3 Ratio Error Modeling of Instrument Transformers[3]

Calibrations of instrument transformers according to IEEE C57.13 are usually performed in a shop or lab. However, CTs and VTs may also be calibrated in-situ, while the unit is off-line. Conventional testing methods apply a known signal on one side of a transformer and read the output signal on the other side. This can be time-consuming and require the injection or measurement of very high voltages or current.

Because of the difficulties of testing CTs in the field, specialized instrumentation and modelling methods are sometimes used for CT testing. The concept of modeling a CT requires the nameplate data on the CT and burdens of the primary and secondary circuitry, including the following:

(a) excitation current
(b) secondary current
(c) secondary core voltage
(d) main inductivity of the core
(e) magnetic losses of the core
(f) turns ratio
(g) wiring resistance
(h) resistance of the secondary turns
(i) resistance of the metering burden
(j) inductivity of the metering burden

Using a model, the effects of various currents and phase angles can be simulated, and predicted ratio correction factors can be calculated.

[2] NIST Measurement Services: A Calibration Service for Current Transformers, NIST Special Publication 250-36, John D. Ramboz and Oskars Petersons, U.S. Department of Commerce, June 1991.
[3] "A Revolution in Current Transformer Testing," Benton Vandiver, PowerGrid International, August 2012.

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5-6 CORRECTION OF VT ERRORS

Two methods are commonly used for the correction of installed characteristic data of VTs used in ASME performance testing. IEEE C57.13 provides detailed equations for the calculation of transformer corrections algebraically. Another method referred to as the “Farber method” exists, which determines the VT correction factors using a graphical approach. An example of this method is provided in Nonmandatory Appendix C.

This method is defined in “The Analytical and Graphical Determination of Complete Voltage Transformer Characteristics” by J. L. Settles, W. R. Farber, and E. E. Conner, published in February 1961. Each of these methods requires calibration characteristic data and the measurement of actual installed VA burden on the secondary side of the transformer.

If the actual calibration data for a particular VT is not available, typical VT calibration data for that type or model number of that VT may be used with higher uncertainty. Based on the GE Manual of Instrument Transformers, Operation Principles and Application Information (GET-97D), copyright 1950 by GE, the ratio correction factor may vary a maximum of ±0.002, and phase angle may vary a maximum of ±7 min from the typical curve values. Therefore, the uncertainty of using a typical ratio correction factor for an uncalibrated VT of the same type can be assumed to be 0.2%.

5-6.1 VT Burden Measurements

Determination of actual VT burdens requires the measurement of voltage, current, and phase angle between the voltage and current on each metering element. Each phase voltage and current across or through the secondary windings of the VT circuit should be made at a point near the VT secondary fuses or in the initial VT junction box, before any point where current may branch off to other circuits. Since the accurate measurements of current and phase angle require the introduction of meters in series with the current that may be supplied to unit controls, any inadvertent opening of the circuit during connection or use of these meters may cause a unit trip. To avoid this possibility, it is highly recommended that measurement of current be made with clamp-on meters and that corrections for phase angle and power factor be neglected. A sample uncertainty analysis using an assumed power factor of 0.85 rather than an actual power factor of 1.0 and a phase angle of −0.5 min instead of +0.5 min resulted in an error of only 0.006%. Therefore, the effect of this assumption on the overall test uncertainty will be minimal.

The number and method of voltage and current measurements depends on the type of power metering system being used. If the two-element method is being used, then voltage should be measured phase-to-phase, and current is only needed in two of the three phases. If the three-element method is being used, voltage must be measured for each phase-to-neutral and current measured in each phase.

Meters used to measure VT voltage should display true RMS AC voltage, have an accuracy of at least 1%, and a precision of at least 0.1 VAC. Expected voltages for phase-to-phase measurements are between 110 VAC and 120 VAC. Expected readings for phase-to-neutral voltages are between 67 VAC and 70 VAC.

Meters used to measure VT phase currents should have a very low range. Typical VT currents are between 0 AC amp and 0.25 AC amp per phase. As discussed above, it is highly recommended that a clamp on type current meter be used for these measurements. If a nonclamp on type of meter is used, check the current meter fuses and continuity through the current meter before inserting the meter in the VT circuit.

5-6.2 Analytical Calculation of VT Ratio and Phase-Angle Correction Factors

IEEE C57.13, section 8.1.12, provides the most precise method for correcting VT output for ratio correction factor and phase-angle displacement between primary and secondary volts. The equation provided for the determination of ratio correction factor at the performance test burden is as follows:

$$\mathrm{RCF}_c = \mathrm{RCF}_0 + \frac{B_c}{B_t}[\mathrm{RCF}_d \cos(\Theta_t - \Theta_c) + \gamma_d \sin(\Theta_t - \Theta_c)] \tag{5-6-1}$$

The equation provided for the determination of phase angle at the performance test burden is as follows:

$$\gamma_c = \gamma_0 + [B_c/B_t][\gamma_d \times \cos(\Theta_t - \Theta_c) - \mathrm{RCF}_d \times \sin(\Theta_t - \Theta_c)]$$

where

B_c = the burden at which RCF and PACF will be calculated for the performance test condition, VA
B_0 = zero burden, VA
B_t = the burden at the calibration test point (typically at VT rated burden at which RCF and PACF will be calculated for the performance test condition), VA
RCF_c = ratio correction factor at B_c

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RCF_d = $RCF_t - RCF_0$
RCF_0 = ratio correction factor at B_0
RCF_t = ratio correction factor at B_t (typically at rated burden)
Θ_t = power factor at B_t, deg
Θ_c = power factor at B_c, deg
γ_c = phase angle at B_c, rad
γ_d = $\gamma_t - \gamma_0$
γ_0 = phase angle at B_0, rad
γ_t = phase angle at B_t, rad

NOTE: If phase angles are in degrees, multiply by 0.000291 to convert to radians.
0.000291 = 1/3,438 rad/min
3,438 = minutes of angle in 1 rad

If the small deviations in power factor and phase angles between performance test burden and rated burden are neglected, the equation for ratio correction factor reduces to the following:

$$\mathrm{RCF}_c = \mathrm{RCF}_0 + \frac{B_c}{B_t}[\mathrm{RCF}_d\cos(0) + \gamma_d\sin(0)] \tag{5-6-2}$$

$$\mathrm{RCF}_c = \mathrm{RCF}_0 + \frac{B_c}{B_t}[\mathrm{RCF}_d \times 1 + \gamma_d \times 0] \tag{5-6-3}$$

$$\mathrm{RCF}_c = \mathrm{RCF}_0 + \frac{B_c}{B_t}[\mathrm{RCF}_d]$$

Substituting $RCF_t - RCF_0$ for RCF_d yields the following equation, which is simply a linear interpolation of the RCFs between the VT calibration test points at the rated burden and at zero burden, based on the burden at the performance test point:

$$\mathrm{RCF}_c = \mathrm{RCF}_0 + \frac{B_c}{B_t}[\mathrm{RCF}_t - \mathrm{RCF}_0]$$

If the small deviations in power factor and phase angle between performance test burden and rated burden are neglected, the equation for phase angle for the performance test burden reduces to the following:

$$\gamma_c = \gamma_0 + [B_c/B_t][\gamma_d\cos(0) - \mathrm{RCF}_d\sin(0)]$$

$$\gamma_c = \gamma_0 + [B_c/B_t]\gamma_d$$

Substituting $\gamma_t - \gamma_0$ for γ_d yields the equation

$$\gamma_c = \gamma_0 + (B_c/B_t) \times (\gamma_t - \gamma_0)$$

This is simply a linear interpolation of the phase angles between the VT calibration test points at rated and zero burdens, based on the burden at the performance test point.

VT phase-angle correction factor ($VTPACF_c$) is determined as follows:

$$\mathrm{VTPACF}_c = \cos\left(\Theta_{\mathrm{primary}} - \gamma_c\right)/\cos\left(\Theta_{\mathrm{primary}}\right)$$

where

$VTPACF_c$ = VT Phase-Angle Correction Factor at B_c
$\Theta_{primary}$ = measured circuit's primary side power factor angle

Refer to Nonmandatory Appendix A for a sample calculation.

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5-7 VOLTAGE DROP CORRECTIONS FOR VT SECONDARY CIRCUITS

Voltage supplied to each test metering element shall also be corrected for voltage drops from the VTs to the test meters. Voltage measurements should be made to a reading resolution of 0.01 V or better using two AC RMS voltmeters with an accuracy of at least 0.05 V AC each or better. For three-phase, four-wire, three-element metering circuits, voltages should be measured from each phase to neutral. For three-phase, three-wire, two-element circuits, voltages should be measured from phase to phase. A procedure for determining the voltage drop correction factor for each phase is as follows:

Step 1. Connect two test voltmeters to the same voltage source, and determine the offset between the two meters. Take readings simultaneously, and integrate or average at least ten readings over a minimum of 1 min. The voltage offset is equal to the higher of the two meter displays less the display of the lower meter. Tag the higher reading meter.

Step 2. Measure the voltage at the secondary outputs of the VT and the voltage at the input to the test meter simultaneously, using the two meters. Integrate or average at least ten readings over a minimum of 1 min.

Step 3. Subtract the voltmeter offset readings taken with the higher reading meter to obtain the corrected voltage at that location.

Step 4. Subtract the corrected integrated/average voltage at the meter from the voltage at the VT to obtain the voltage drop.

Step 5. The voltage drop correction factor is equal to the ratio of the voltage at the VT divided by the voltage at the meter.

NOTE: The voltage drop correction factor must be a number equal to or greater than 1.0. If the indicated voltage drop correction factor is less than 1.0, there is a problem with the readings. If the voltage drop is less than the combined uncertainty of the meters, assume a voltage drop correction factor of 1.0. Otherwise, attempt to determine the cause of the problem, and repeat the measurements.

The corrected watts and vars for the tested phase are equal to the meter output multiplied by the correction factor. An example calculation is shown in Nonmandatory Appendix A, Table A-3.7-1.

5-8 CORRECTION OF IRON-CORE CT ERRORS

As discussed earlier, errors in CT performance may exist due to core excitation current that varies with actual secondary burdens. Compensation may be included to produce zero correction factors at a rated burden. Actual secondary burden is generally constant with load so the amount of current required for excitation is also constant. Therefore, as total current increases, the error due to excitation current becomes less significant. If the actual secondary burden is close to the rated burden, the ratio error can be assumed to be zero (CTRCF = 1.0). If actual burden is different from rated, the ratio error should be read off of the calibration curve.

IEEE C57.13 for instrument transformers contains several methods for calibrating CTs in which the maximum uncertainties allowed are ±0.1% for ratio correction factors and ±0.9 mrad (3 min) for phase-angle error. If the CTs are calibrated and corrections are applied for ratio correction factor as discussed above, the maximum uncertainty of the current inputs to a power meter used for an ASME performance test should not exceed the uncertainty of the CT calibrations as shown above.

If typical CT-type calibration data are used, the variation of calibration corrections for a sample of meters of this type should be used as an added uncertainty. Based on the GE Manual of Instrument Transformers, Operation Principles and Application Information (GET-97A), copyright 1950 by GE, the ratio correction factor may vary ±0.002, and phase angle may vary ±7 min from the curve values. Therefore, the uncertainty of using a typical ratio correction factor for an uncalibrated CT of the same type can be assumed to be 0.2%.

5-8.1 Calculation of CT Phase-Angle Correction Factors

If higher precision is desired, the CT phase-angle (β) data that are available from the factory tests may be used for estimating the CT phase-angle correction factor ($CTPACF_c$).

$$\mathrm{CTPACF}_c = \cos\left(\Theta_{\mathrm{primary}} + \beta\right)/\cos\left(\Theta_{\mathrm{primary}}\right)$$

where

CTPACF_c = CT phase-angle correction factor at B_c

$\Theta_{\mathrm{primary}}$ = measured circuit's primary side power factor angle

Refer to Nonmandatory Appendix A for a sample calculation.

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5-8.2 Demagnetization

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

5-9 CALCULATION OF PHASE-ANGLE CORRECTION FACTORS

The use of instrument transformers creates a phase-angle shift between primary and secondary values of voltage and current. This causes a displacement between the power factor measured on the secondary side of instrument transformers and the true power factor. If significant, a phase-angle correction factor should be applied for this error. The error in VT phase-angle is represented by the Greek letter γ and is positive when the voltage across designated secondary terminals leads the voltage across the corresponding terminals on the primary side. This represents the phase shift between the voltage phase angle on the secondary side of the VT versus the actual voltage phase angle on the high voltage side. The CT will also introduce a phase shift error. The error in CT phase angle is designated by the Greek letter β and is positive when the current leaving a designated secondary terminal leads the current entering the corresponding primary side terminal. The power meter will also introduce a phase shift error, designated by the Greek letter α.

The true phase angle, Θ, between the primary current and primary voltage is obtained by adding the phase-angle errors of the power meter, VT, and CT to the indicated phase angle, Θ_s, as follows:

$$\Theta = \Theta_s - \alpha + \beta - \gamma$$

Power factor on the primary side of the instrument transformers is calculated as follows:

$$\mathrm{PF} = \cos(\Theta) - \cos(\Theta_s - \alpha + \beta - \gamma)$$

For each phase, the phase-angle correction factor is calculated as follows:

$$\mathrm{PACF} = \frac{\cos\left(\Theta_s - \alpha + \beta - \gamma\right)}{\cos\Theta_s}$$

5-10 PRECAUTIONS IN THE USE OF INSTRUMENT TRANSFORMERS

Extreme care should also be used when connecting generation metering to plant voltage and CT circuits. Connections should preferably be made when the unit is off-line. If connection or disconnection of test metering is to be made when the unit is on-line, provisions should be made to prevent opening of the current circuit and shorting of voltage circuits. The use of test blocks, sliding link terminal strips, or knife switches are recommended. Shorting or opening of inputs to plant metering while the unit is on-line may cause a unit trip.

5-11 UTILIZATION OF STATION INSTRUMENT TRANSFORMERS

Existing station voltage or CTs may be used for the test if they meet the requirements of this Supplement.

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Section 6
Net Power Output

6-1 INTRODUCTION

If a test requires obtaining a net active or reactive power value for an electrical power generating unit, the total unit power can be measured directly or calculated by measuring the gross electrical active and reactive power of all generators involved and by subtracting all auxiliary active and reactive power consumed by the unit. This Section provides guidance for either the direct measurement or the calculation of these values at a remote delivery point located on the high side of the main power transformers.

6-2 DIRECT MEASUREMENT OF NET POWER

Transmission line voltages may be as high as 750 kV. Nevertheless, it is possible to directly measure net active and reactive power supplied to a remote delivery point using high-voltage instrument transformers. If instrument transformers do exist at this point, active and reactive power can be measured on the low voltage secondary side of these transformers using the same technique discussed in Section 3. These types of instrument transformers are very expensive but do provide a direct measurement of power delivered to the remote point. No corrections for power transformer or transmission line losses are necessary.

NOTE: In many cases, a remote delivery point includes separate lines for the receipt of power produced by the power plant and the delivery of station service power to the power plant. In this case, both delivered and received power should be determined, and the net power is calculated by subtracting the power delivered to the plant from the power received from the plant.

6-3 CALCULATION OF NET POWER

Net power supplied to a remote delivery point can also be calculated from gross power and gross station service readings measured on the low side of main and auxiliary power transformers. In this case, gross power outputs and auxiliary power inputs must be corrected for transformer and transmission line losses as discussed below. Net power delivered to the remote delivery point is calculated by subtracting the station service leaving the delivery point from the sum of the gross generator power received at the remote delivery point.

6-3.1 Power Transformer Losses

Since the power loss for the step-up/down transformers cannot be accurately measured in the field but only calculated, it is necessary to use the results of the transformer performance tests conducted in the factory. Normally, the factory tests determining the power loss are conducted at 0% and 100% rated load of the transformer and at various voltages. To calculate the actual power loss during the test in the field, values of the voltage and current at the high side of the transformer should be measured and recorded. The corrections are done using the methodology described in IEEE C57.12.90.

The losses through a transformer are determined by the following equation:

$$\mathrm{Loss}_{\mathrm{TOTAL}} = \mathrm{Loss}_{\mathrm{NO\text{-}LOAD}} + \mathrm{Loss}_{\mathrm{LOAD}}$$

where

$\mathrm{Loss}_{\mathrm{LOAD}}$ = transformer load losses, kW
$\mathrm{Loss}_{\mathrm{NO\text{-}LOAD}}$ = transformer no-load losses, kW
$\mathrm{Loss}_{\mathrm{TOTAL}}$ = total transformer losses, kW

$\mathrm{Loss}_{\mathrm{NO\text{-}LOAD}}$ is determined from the factory shop test report; it is a constant value.

The load losses of a transformer are determined as follows:

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$$\mathrm{Loss}_{\mathrm{LOAD}} = L_{1\,\mathrm{CORR}} + L_{2\,\mathrm{CORR}}$$

where

$L_{1\ \mathrm{CORR}}$ = I^2R losses, corrected to reference conditions, kW
$L_{2\ \mathrm{CORR}}$ = stray load losses, corrected to reference conditions, kW

The load losses vary with winding temperature, oil temperature, ambient conditions, voltage, and load. Therefore, the values for the load losses taken from the shop test report need to be corrected. The following equation, derived from IEEE C57.12.90, corrects for these conditions:

$$L_{1\,\mathrm{CORR}} = L_1 \times n \times K \times \left(\frac{T_K + T_M}{T_K + T_R}\right)\left(\frac{T_K + T_{MC}}{T_K + T_M}\right)$$

$$L_{2\,\mathrm{CORR}} = L_2 \times n \times K \times \left(\frac{T_K + T_R}{T_K + T_M}\right)\left(\frac{T_K + T_M}{T_K + T_{MC}}\right)$$

where

K = voltage correction ratio, dimensionless
L_1 = I^2R losses from factory test report at rated load with rated winding temperature (T_R), kW
L_2 = stray load losses from factory test report at rated load and rated winding temperature (T_R), kW
n = load correction ratio, dimensionless
T_K = transformer material correction factor (copper = 234.5°C)
T_M = average winding temperature at prevailing ambient temperature from calculation below, °C
T_{MC} = average winding temperature, corrected to reference ambient temperature from calculation below, °C
T_R = rated winding temperature from factory test report, °C

To determine n and K, use the following equations:

$$n = \left(\frac{\text{test load}}{\text{rated load}}\right)^2$$

$$K = \left(\frac{\text{rated voltage}}{\text{test voltage}}\right)^2$$

The test load (kVA) and test voltage (V) are determined from the power and voltage measurements, collected as test data. The rated load (kVA) and rated voltage (V) are from the factory test reports. Rated voltage is a phase-to-phase value, so a cube-root factor is applied to the measured phase to ground voltage measurement.

$$\text{test load} = \left(\frac{P_{\mathrm{MEAS}}}{\mathrm{PF}_{\mathrm{MEAS}}}\right) - \left(\frac{P_{\mathrm{LINE\ LOSS}} + P_{\mathrm{AUX\ MEAS}}}{\mathrm{PF}_{\mathrm{MEAS}}}\right)$$

where

$P_{\mathrm{AUX\ MEAS}}$ = measured auxiliary loads, if any, between power measurement and low side of the transformer, kW
$P_{\mathrm{LINE\ LOSS}}$ = line losses between power measurement and low side of the transformer, kW
P_{MEAS} = measured power at the generator terminals, kW
$\mathrm{PF}_{\mathrm{MEAS}}$ = generator power factor at test conditions, dimensionless

$$\text{test voltage} = V_{\mathrm{MEAS}} \times \text{VT Ratio} \times \sqrt{3}$$

where

V_{MEAS} = measured secondary voltage at the low side of the transformer, adjusted for meter errors as necessary (phase-to-ground), kV
VT Ratio = from instrument transformer design data

To determine the average winding temperature, T_M, use the following equation (from IEEE C57.12.90):

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$$T_M = T_C + T_{OM}$$

where

T_C = corrected difference between average winding temperature and the oil temperature measured in the filled oil thermometer pocket, °C

T_{OM} = measured oil temperature measured in the filled oil thermometer pocket, °C

T_C is determined by the following equation:

$$T_C = T_O \times \left(\frac{\text{test load}}{\text{rated load}}\right)^{2m}$$

where

m = 1.0 for main step-up transformer
= 0.8 for auxiliary transformer

T_O = measured difference between average winding temperature (from factory test report) and the oil temperature measured in the filled oil thermometer pocket at rated load (from factory test report), °C

The average winding temperature is measured between the high- and low-voltage winding.

To determine the winding temperature, corrected for differences in ambient temperature (T_{MC}), the following equations are used:

$$T_{MC} = T_M + (T_A - T_{AM})$$

where

T_A = ambient temperature at rated conditions (conditions upon which transformer losses are based, from factory test report), °C

T_{AM} = measured ambient temperature, °C

6-3.2 Line Losses

Line losses are conductor losses from the main transformer high voltage terminals to the switchyard interface point. In addition, there are conductor losses in the bus connection from the generator terminals to the main transformer low voltage terminals. The method for calculating the losses is specified in paras. 6-3.2.1, 6-3.2.2, and 6-3.2.3.

6-3.2.1 Line Losses From Main Transformer High-Voltage Terminals to the Switchyard Interface Point

$$P_{\text{LINE LOSSES}} = \frac{3(I_L^2 \times R_L)}{1\,000}$$

where

I_L = average RMS line or phase current on the high side of the main transformer

$P_{\text{LINE LOSSES}}$ = three-phase line losses, kW

R_L = average resistance of each line or phase conductor(s)

The resistance of the conductor is determined from the manufacturer's data for the selected conductor size and the length of the transmission line. The temperature effect of the conductor resistance from the manufacturer's reference temperature data to the actual operating temperature is relatively small and can be neglected. However, if temperature correction is desired, determine the conductor resistance at the conductor actual operating temperature (at the average operating current and site ambient temperature) from the manufacturer data for the conductor.

6-3.2.2 Bus Losses From the Generator Terminals to the Low-Voltage Terminals of the Main Transformer. The bus losses are calculated by a method similar to that for line losses described in para. 6-3.2.1. The bus duct configuration consists of a conductor in metallic enclosures. The bus duct losses are due to both conductor loss and enclosure loss. The manufacturer of the bus duct normally provides the resistance and loss per unit length of the conductor and of the enclosure at the specified operating current(s). The operating current is the average of the measured generator phase current.

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6-3.2.3 Sample Calculations

(a) Line losses from the main transformer high voltage terminals to the remote delivery point are calculated from the following equation:

$$P_{\text{LINE LOSSES}} = \frac{3(I_L^2 \times R_L)}{1\,000}$$

where

I_L = average RMS line or phase current on the high side of the main transformer
$P_{\text{LINE LOSSES}}$ = three-phase line losses, kW
R_L = average resistance of each line or phase conductor(s)

(1) Typical conductor resistance data are as follows:

(-a) 0.1172 Ω/mile at 25°C, or 0.1172 (100/5,280) = 0.0022197 Ω/100 ft.

(-b) 0.1398 Ω/mile at 75°C, or 0.1398 (100/5,280) = 0.0026477 Ω/100 ft.

(-c) For conductor temperatures between 25°C and 75°C, the resistance value could be linearly extrapolated. For example, conductor resistance at 50°C is 0.0022197 + [(0.0026477 − 0.0022197)/(75 − 25)] × (50 − 25) = 0.0022197 + 0.000314 = 0.0024337 Ω/100 ft

(2) For an average RMS line current of 800 A, the line losses determined from the equation in (a) and the data in (1)(-a) through (1)(-c) are the following:

(-a) at 25°C conductor temperature = 4.261 kW/100 ft of three-phase lines

(-b) at 75°C conductor temperature = 5.083 kW/100 ft of three-phase lines

(-c) at 50°C conductor temperature = 4.673 kW/100 ft of three-phase lines

(b) Bus losses from the generator terminals to the low-voltage terminals of the main transformer are calculated as follows:

(1) The following table shows the losses attributed to resistances in the conductor and enclosure. The *R* values are supplied by the manufacturer.

Data Type	Resistance, *R*, μΩ/ft	Current, *I*, A	Duct Length, *L*, ft	Loss [(I^2 × *R* × *L*)/1 000], kW
Conductor	1.0517	11 000	100	12.725
Enclosure	0.645	11 000	100	7.805
Total loss per phase	...	...	...	20.53

(2) For a three-phase system, the loss would be 20.53 × 3 = 61.6 kW for the assumed 11,000-A current and 100-ft length.

NOTE: The enclosure losses are due to the induced current from the conductor and depend on the geometry of the conductors and enclosures. The manufacturer of the bus duct normally provides the conductor and enclosure loss/resistance data to determine the bus duct losses at specified operating currents and length of the bus duct installation, as illustrated above.

6-4 NET PLANT POWER FACTOR

Net plant power factor can be measured directly or calculated from the net active and reactive power values determined either measured directly or calculated as discussed above. If measured directly, net plant power factor can be determined using the same techniques discussed in subsection 3-6 by connection to the high-voltage instrument transformer used for the direct measurement of active power. If calculated from gross low side measurements of active and reactive power, net plant power factor should be calculated using the net high side values of active and reactive power as delivered to the remote delivery point, using the same equations as shown in subsection 3-6; however, the net vars on the high side of the main power transformer should be corrected for transformer losses as discussed below.

6-5 POWER RELATIONSHIPS BETWEEN PRIMARY AND SECONDARY WINDINGS OF MAIN POWER TRANSFORMER

The turns ratio of the main power transformer affects the current as well as the voltage. If the voltage is doubled in the secondary, the current is halved in the secondary. Therefore, all the power delivered to the primary of the main transformer by the generator source is also delivered to the load by the secondary minus whatever power is consumed by the transformer in the form of losses. There are three different types of losses in a transformer. One is copper loss, or I^2R loss.

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This is the loss due to the DC resistance in the primary and secondary windings. The other losses are due to eddy currents and hysteresis in the core. All of these losses are the result of electrical energy being converted to heat energy.

$$P_S = P_P - P_L$$

where
P_L = power loss in the transformer
P_P = power delivered to the primary by the generator source
P_S = power delivered to the load by the secondary

The efficiency of a transformer is simply the ratio of the output power to the input power.

$$T_e = \frac{P_{\text{out}}}{P_{\text{in}}} \times 100$$

where
P_{in} = total input power to the transformer
P_{out} = total output power delivered to the load
T_e = transformer efficiency, %

Large commercial power line transformers typically have an efficiency of 99.7% or better.

Power factor or vars on the high side based on measurements on the low side can be determined based on the following two characteristics:

(a) The power on the high side will be less due to the transformer losses.

(b) The VA on the high side is unchanged from the VA on the low side.

Begin by measuring the input power and input vars to main power transformer on the low-voltage side using an appropriate wattmeter and varmeter. Then calculate the output power of the main power transformer.

$$P_{\text{out}} = P_{\text{in}} \times T_e/100$$

Use the actual value for transformer efficiency of the main power transformer if it is available. If it is not available, use an estimated value of 99.7% or higher.

Calculate the total input power factor using the total watt and var values.

$$\text{PF}_{\text{in}} = P_{\text{in}}/\sqrt{(P_{\text{in}})^2 + (\text{var}_{\text{in}})^2} = P_{\text{in}}/\text{VA}_{\text{in}}$$

Next, calculate the total input VA from the known values of total watts and PF.

$$\text{VA}_{\text{in}} = P_{\text{in}}/\text{PF}_{\text{in}}$$

Given that the volt-amps across the transformer is unchanged, yields the following:

$$\text{VA}_{\text{in}} = \text{VA}_{\text{out}}$$

Calculate the output power factor.

$$\text{PF}_{\text{out}} = P_{\text{out}}/\text{VA}_{\text{out}}$$

Calculate output var.

$$\text{var}_{\text{out}} = \sqrt{(\text{VA}_{\text{out}})^2 - (P_{\text{out}})^2}$$

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Section 7
Test Uncertainty

7-1 UNCERTAINTY CALCULATION REQUIREMENTS

All uncertainty estimates shall be made in accordance with the definitions and procedures presented in ASME PTC 19.1, Test Uncertainty. The necessary inputs and calculations are summarized in the following paragraphs.

7-1.1 Uncertainty of the Result, U_R

The PTC uncertainty requirement is for estimates to be made at the 95% confidence level, which means that there is a 95% probability that the true test result lies within a $\pm U_R$ band around the test point. For most cases with a sufficient number of data points, the expanded uncertainty, U_R, equals $2u_R$, where $u_R = (b_R{}^2 + s_R{}^2)^{0.5}$.

(a) b_R = systematic standard uncertainty of the result

$$b_R = \left[\sum_{i=1}^{I}\left(\theta_i b_{\overline{X}_i}\right)^2\right]^{1/2}$$

(b) s_R = random standard uncertainty of the result

$$s_R = \left[\sum_{i=1}^{I}\left(\theta_i s_{\overline{X}_i}\right)^2\right]^{1/2}$$

7-1.2 Sensitivity, Θ

Sensitivity is the instantaneous rate of change in a result due to the change in a parameter. It may be determined by one of two methods.

7-1.2.1 Analytical Determination of Sensitivity. If there is a known relationship between the result, R, and its parameters, X_i [$R = f(X_1, X_2$, etc.)], then the sensitivity can be calculated by partial differentiation. Thus

$$\Theta = \delta R/\delta X_i$$

7-1.2.2 Numerical Determination of Sensitivity. Each parameter in the data may be incremented a small amount to determine its effect on the result. In this case

$$\Theta = \Delta R/\Delta X_i$$

ΔX_i should be as small as possible to avoid large nonlinear effects, and it is advisable to do both plus and minus ΔX_i to assess the nonlinearity.

7-1.2.3 Relative Sensitivity. Since normally the uncertainty is a percent of the result and parameter uncertainties are provided as percentages, relative sensitivities are calculated as shown in the following example:

$$\text{Relative numerical } \Theta = (\Delta R/R)/(\Delta X_i/X_i) = (X_i/R)(\Delta R/\Delta X_i)$$

7-1.3 Systematic Standard Uncertainty

Systematic uncertainties are estimates made to account for fixed errors in the measurement that remain after calibration. These are made at the 95% confidence level where $B_{\overline{x}}$, the expanded systematic standard uncertainty, is equal to $2B_{\overline{x}}$. For each measurement, the individual contributing systematic uncertainties are combined to determine $B_{\overline{x}}$ by the root sum squared method.

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$$B_{\overline{x}} = \left[\sum B_{\overline{x}_i}{}^2\right]^{0.5}$$

7-1.4 Random Standard Uncertainty

Parameter measurements are influenced by several random error sources. This data scatter is evaluated by calculating the standard deviation (STD), s_x, normally done by the data acquisition system. The random standard uncertainty, $s_{\overline{x}}$, is the STD of the mean, or

$$s_{\overline{x}} = \frac{s_x}{\sqrt{N}} \tag{7-1-1}$$

where

N = number of measurements (number of instruments multiplied by the number of readings)

7-1.5 Other Considerations

Two important effects, correlation and degrees of freedom, need to be evaluated, and ASME PTC 19.1 should be consulted to assess them properly.

7-1.5.1 Correlation. The estimates for systematic uncertainties must consider the relationship among the instruments used to measure the parameter. If they are all independent, which means they are not produced in the same batch at the same factory, or are not calibrated against the same standard, etc., then the calculations proceed as outlined above. If, however, the instruments are related, then the estimates for the systematic standard uncertainty must be modified. Since this is a likely occurrence (e.g., VTs and CTs from the same batch, calibrated against the same standard), then the value of b_{R} is given by

$$b_{\mathrm{R}} = \left[\left(\theta_1 b_{\overline{x}_1}\right)^2 + \left(\theta_2 b_{\overline{x}_2}\right)^2 + \left(\theta_3 b_{\overline{x}_3}\right)^2 + 2\theta_1\theta_2 b_{\overline{x}_1\overline{x}_2} + 2\theta_1\theta_3 b_{\overline{x}_1\overline{x}_3} + 2\theta_2\theta_3 b_{\overline{x}_2\overline{x}_3}\right]^{1/2} \tag{7-1-2}$$

The sample calculation for test uncertainty shown later in this section illustrates this procedure.

7-1.5.2 Degrees of Freedom. The use of "2" to obtain the expanded systematic or expanded random uncertainty assumes that a sufficient number of measurements has been made, nominally at least 30. If this number is considerably less than 30, then ASME PTC 19.1 should be consulted to properly apply the Student's t factor. For the systematic case, which is based on best estimates, as a practical matter, there is uncertainty in these estimates, and concern whether "2" is really "2.2" may not be justified. Therefore, if the degrees of freedom are at least 10, the use of "2" should be acceptable.

7-2 POWER UNCERTAINTY CALCULATION

As shown in subsection 3-5, the power in each of the three phases, in kilowatts, is calculated from the following:

$$\mathrm{PW}_x = \frac{\mathrm{SW}_x \times \mathrm{VTTR}_x \times \mathrm{CTTR}_x \times \mathrm{VTRCF}_x \times \mathrm{VTVDCF}_x \times \mathrm{CTRCF}_x \times \mathrm{PACF}_x}{1\,000}$$

where

1 000 = conversion factor from watts to kilowatts
CTRCF_x = current transformer ratio correction factor
CTTR_x = current transformer turns ratio
PACF_x = phase-angle correction factor
PW_x = calculated watts on the primary (high voltage) side of the voltage and current transformers, kW
SW_x = measured watts on the secondary (low voltage) side of the voltage and current transformers, W
VTRCF_x = voltage transformer ratio correction factor
VTTR_x = voltage transformer turns ratio
VTVDCF_x = voltage transformer circuit voltage drop correction factor

VTRCF_x is calculated from the VT calibration data, using the following simplified equation:

$$\mathrm{VTRCF}_x = \mathrm{RCF}_0 + (B_c/B_t)\mathrm{RCF}_d$$

VTVDCF_x comes from the voltage drop measurements and the following equation:

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$$\mathrm{VTVDCF}_x = 1 + \mathrm{VTVD}/\mathrm{V1}_t$$

CTRCF_x is obtained from the CT calibration curve.

PACF_x corrects the phase shift and is calculated by the following equation:

$$\mathrm{PACF}_x = \cos(\Theta_s - \alpha + \beta - \gamma)/\cos(\Theta_s)$$

It is possible to differentiate each of these equations to determine the sensitivity of each of the variable's effect on the correction factor and then estimate a systematic uncertainty for each one. However, since normally these correction factors are quite small, this laborious effort is not justified considering the much larger uncertainties associated with the instrument transformers and power metering. An examination of each of the correction factors provides some guidance on its contribution to the measured power uncertainty.

(a) VTRCF: Inputs are low side volts and amps, measured very accurately in the wattmeter circuit; phase-angle error, very small (in minutes); and calibration data. The uncertainty in the VTRCF is covered by the VT uncertainty. (Refer to Nonmandatory Appendix D.)

(b) VTVDCF: The correction is in the fourth decimal place, so any error would be insignificant.

(c) CTRCF: This correction is covered by the CT uncertainty. (Refer to Nonmandatory Appendix D.)

(d) PACF: The major input is the wattmeter reading, covered by its uncertainty. The other angle measurements are very small, with the result that the correction factor is also very small.

The application of the correction factors to accurately calculate the gross power (GP) is absolutely critical. However, since the VTVDCF and PACF have negligible impact, the calculation for gross power uncertainty can be based on the following summation of the power of the three phases:

$$\mathrm{GP} = \sum_{i=1}^{3} (P_i \times CT_i \times VT_i)$$

7-2.1 Systematic Uncertainty and Correlation

Typically, the wattmeters and the VTs and CTs have each come from a single source and were calibrated against the same standard. Therefore, the systematic errors are correlated, and eq. (7-1-2) applies.

$${B_{gp}}^2 = \sum_{i=1}^{3} \left(\Theta_i B_{P_i}\right)^2 + 2\sum_{i=1}^{2} \sum_{k=i+1}^{3} \Theta_i \Theta_k B_{ik}$$

As an example, assume the following uncertainties:

(a) 0.1% for calibrated wattmeters. Typically, the quoted accuracy is 0.04% of reading plus 0.04% of range. As long as the reading is 75% of range or higher, the 0.1% can be met.

(b) 0.1% for VTs, which must be calibrated.

(c) 0.15% for CTs. This level can be achieved by obtaining a type calibration for the lot of 0.3% accuracy transformers or purchasing 0.15% class transformers.

Refer to Nonmandatory Appendix D for guidance in determining the uncertainties of instrument transformers.

With Θ = 1/3, since the phase powers are essentially equal, then

$$\begin{aligned}{B_{gp}}^2 = \Big[&3\left(\Theta B_p\right)^2 + 3(\Theta B_{\mathrm{VT}})^2 + 3(\Theta B_{\mathrm{CT}})^2 + 2\Big(\Theta_1\Theta_2 B_{p1}B_{p2} + \Theta_1\Theta_3 B_{p1}B_{p3} + \Theta_2\Theta_3 B_{p2}B_{p3} + \Theta_1\Theta_2 B_{\mathrm{VT1}}B_{\mathrm{VT2}} \\ &+ \Theta_1\Theta_3 B_{\mathrm{VT1}}B_{\mathrm{VT3}} + \Theta_2\Theta_3 B_{\mathrm{VT2}}B_{\mathrm{VT3}} + \Theta_1\Theta_2 B_{\mathrm{CT1}}B_{\mathrm{CT2}} + \Theta_1\Theta_3 B_{\mathrm{CT1}}B_{\mathrm{CT3}} + \Theta_2\Theta_3 B_{\mathrm{CT2}}B_{\mathrm{CT3}}\Big)\Big]\end{aligned}$$

and

$$B_{gp} = 0.206\%$$

If they were not correlated, B_{gp} would be 0.119%, which is $0.206/\sqrt{3}$. This significant reduction would likely be expensive and complicated to implement and normally not justified.

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Table 7-2.3-1 Typical Gross Power Uncertainties for Test Classes

Test Class	Instrument Uncertainty			U_{gp}
	Wattmeter	VT	CT	
A	0.075	0.102	0.113	0.170
B1	0.100	0.103	0.146	0.205
B2	0.100	0.147	0.173	0.248

7-2.2 Random Standard Uncertainty

With wattmeters, multiple readings are taken during the test, and a value for $s_{\bar{x}}$ can be calculated. With watt-hour meters, only one summation is obtained at the end of the test, and the time measurement required to calculate watts should be accurate enough not to contribute any additional uncertainty. A 0.1-s error in a 30-min run would be 0.0056%. For this example, with wattmeters, the value of s_{gp} is determined as follows:

(a) The STDs for each phase of the test, as calculated by the data acquisition system, and the number of readings, N, are used to determine $s_{\bar{x}i}$.

Phase	STD, %	N	$s_{\bar{x}i} = STD/\sqrt{N}$
1	0.51	60	0.066
2	0.36	60	0.046
3	0.43	60	0.056

(b) The $s_{\bar{x}i}$ values are used to calculate s_{gp}.

$$s_{gp} = \left[\sum \left(\Theta_i s_{\bar{x}_i}\right)^2\right]^{0.5} = 0.033\%$$

7-2.3 Gross Power Uncertainty

B_{gp} was determined on the 95% confidence level, and $2s_{gp}$ would be needed to calculate the expanded gross power uncertainty, U_{gp}.

$$U_{gp} = \left({B_{gp}}^2 + 2{s_{gp}}^2\right)^{0.5} = \left[0.206^2 + (2 \times 0.033)^2\right]^{0.5} = 0.216\%$$

Using this calculation method, typical gross power uncertainties for the three classes of tests can be determined (see Table 7-2.3-1). The random contribution has been neglected.

7-2.4 Corrected Gross Power Uncertainty

For corrected power, the example defines corrections for power factor-related generator loss, hydrogen purity, and hydrogen pressure. The sensitivities, θ', for these corrections are determined using the procedure in para. 7-1.2.3 and are listed in Table 7-2.4-1. A relative uncertainty, U, for each was assumed to be 1%, principally due to the ability to obtain data from the curves.

The uncertainty of the corrected power can now be calculated by the RSS value of the ($\theta' \times U$) products above plus that for the Class A gross power (0.170%). The result is U_{cgp} = 0.171%.

The magnitude of the corrections would suggest that their impact on the overall power uncertainty would be minimal. However, the method is presented so cases where corrections are more significant can be properly evaluated.

The calculation of corrected gross power uncertainty shown here is intended to be an illustration of the calculation process. Actual performance testing will use instruments with varying quality, calibration records, and random uncertainties, leading to different U_{cgp} than in this example.

Table 7-2.4-1 Gross Power Correction Uncertainties

Correction	ΔR, kW	R, kW	ΔX	X	θ'	U
Generator loss	600	210 474	0.135 PF	0.985	0.0208	1%
Hydrogen pressure	10	210 474	14 kPa	414	0.00141	1%
Hydrogen purity	65	210 474	0.36 lb/ft^3	4.10	0.0035	1%

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7-3 UNCERTAINTY CONSIDERATIONS

The uncertainty calculations indicate that achieving the levels specified in subsection 1-3 should not be a problem, as long as proper attention is paid to the instrument transformer calibration or type information and the measurement or estimation of the burdens.

In addition to the basic uncertainties related to the instrument's ability to read the true value, there are other secondary factors that may influence the total systematic uncertainty. Among these are the following:

(a) range and percentage of reading
(b) drift
(c) ability to read instrument
(d) harmonics
(e) temperature changes
(f) age

Most of these effects are difficult to quantify; best engineering judgment would be needed to assign an uncertainty value. For a Class A test, selection and calibration of the instruments should eliminate any significant contribution from these effects. For other tests, the parties to the test should agree upon which effects need to be evaluated and assign B_{px} values for each to be included in the overall systematic uncertainty estimate.

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NONMANDATORY APPENDIX A SAMPLE CALCULATION OF CLASS A GROSS GENERATOR OUTPUT DERIVED FROM THREE-PHASE SECONDARY MEASUREMENTS

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A-1 INTRODUCTION

In this sample calculation, gross generator electrical output will be determined for the power plant configuration shown in Figure A-1-1. The electrical output of this plant is produced by a hydrogen-cooled generator rated at 250 MVA, 0.85 PF, and 18 kV. Power from the generator is provided to a 230-kV switchyard through a main power step-up transformer over a 0.6-mile overhead transmission line. Power to plant auxiliary loads and the generator exciter are provided by an auxiliary power transformer connected to the main generator bus. Auxiliary loads of 480 V are served through the 4 160-V bus by another step-down transformer.

For this example calculation, many of the tabulated numbers have been rounded off, which results in some slight differences in the results that were calculated on a spreadsheet with no roundoff. Since the corrections are small, it is important not to make any roundoffs until the final values are obtained.

In the event the gross generator electrical output is required to be corrected to design, rated, or guaranteed operating conditions for evaluation of turbine/generator or overall unit performance, refer to Nonmandatory Appendix B for methods that can be used for this analysis.

A-2 GENERATOR OUTPUT METERING REQUIREMENTS

The electrical diagram shown in Figure A-1-1 represents a three-phase power system with a high impedance ground, similar to the system shown in Figure 3-3-1, illustration (b). According to Blondel's theorem, a minimum of two metering elements are required to measure power for this type of system. However, if two metering elements were used, current inputs on only two of the three phases would be obtained. In order to obtain the most complete set of data on all phases, the three-element method was used for the test, as allowed in subsection 3-4.

The existing plant 0.3% accuracy class voltage transformers (VTs) were used for the test since they were calibrated before installation and calibration data were available on their particular performance. The existing VTs are connected in a grounded wye configuration so each meter element was connected in a phase-to-neutral configuration.

The existing plant 0.3% accuracy class current transformers (CTs) were used since they were of a type that had a predictable performance, even though actual calibration data were not available for each particular CT.

Data that will be used in this sample calculation are shown in Table A-2-1.

A-3 CORRECTIONS FOR INSTRUMENT TRANSFORMER BURDENS AND WIRING LOSSES

The measurements and calculations used for ratio corrections, phase-angle errors, and VT wiring voltage drops are described in this Section.

Table A-2-1 Sample Wattmeter Data

Parameter	Symbol	Phase 1-N	Phase 2-N	Phase 3-N	Total
Secondary vars at meter, vars	Svar	36.35	44.68	42.18	123.21
Calculated primary side Current, A	I	3 909	4 021	3 954	...
Marked VT turns ratio, ratio	VTTR	150	150	150	...
Marked CT turns ratio, ratio	CTTR	2 000	2 000	2 000	...

Figure A-1-1 Example Electrical Single-Line Schematic

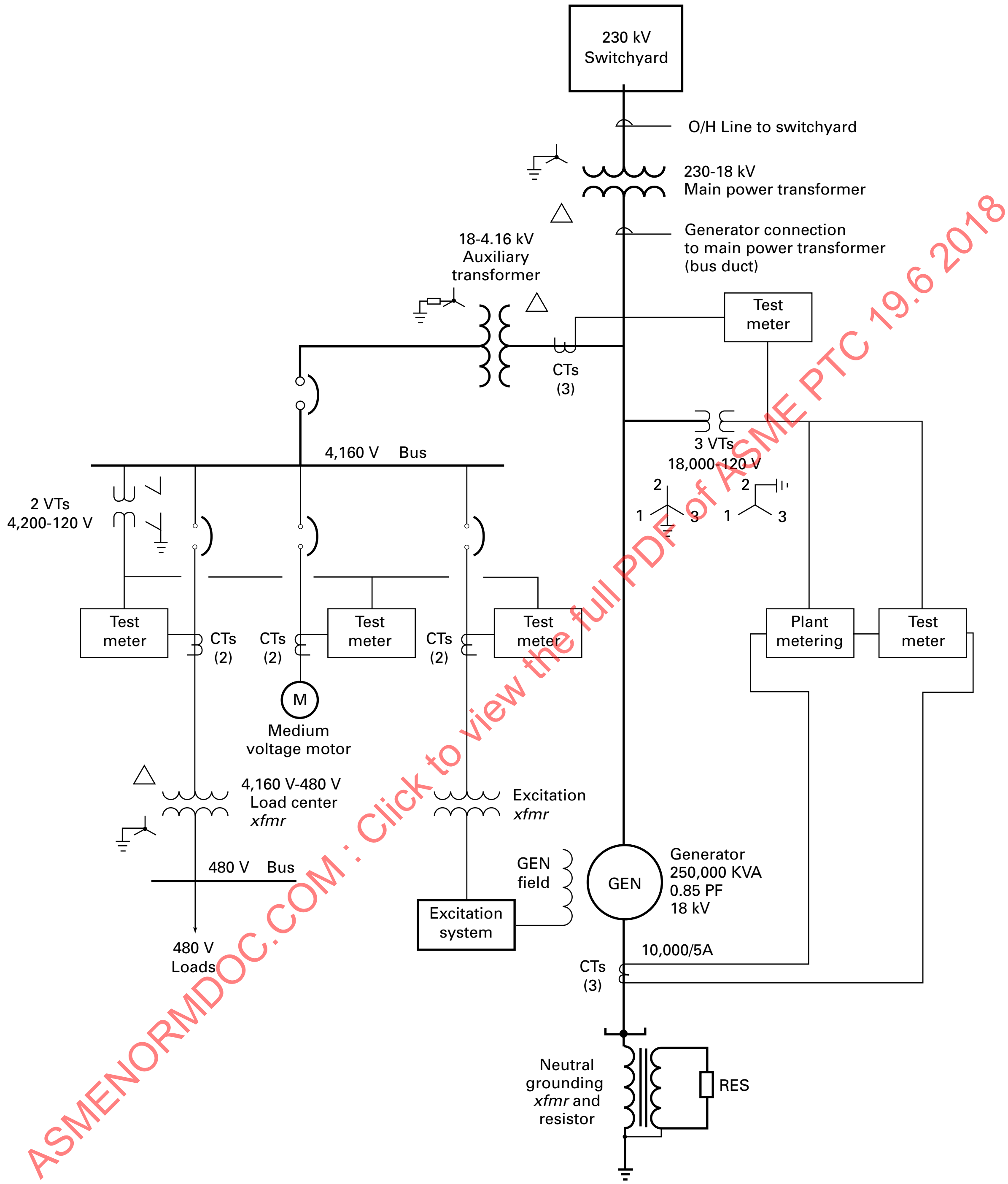

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Table A-3.1-1 Example VT Burden Measurement Data

Parameter	Symbol	Phase 1	Phase 2	Phase 3
Voltage (measured), VAC	V_s	69.28	68.95	69.63
Current (measured), mA	I_{vt}	260	25	310
Actual burden ($V_s \times I_{vt}$/1 000), VA	B_c	18.01	1.72	21.59
Power factor (assumed), ratio	PF_{vt}	0.85	0.85	0.85
Phase angle [arccos (PF_{vt})], deg	Θ_c	31.7883	31.7883	31.7883

A-3.1 VT Burden Measurements

Prior to the tests, voltage and current measurements were made on the secondary side of each phase of the VT circuits to determine the actual burden on each VT. Voltage measurements were made from phase to neutral on each phase using a true RMS AC voltmeter. Due to the danger of opening the VT circuit, and possible tripping the unit generator, current measurements were made using a low range (0 mA to 1 000 mA) clamp-on current meter. Power factor (PF_{vt}) of each phase was not measured for the same reason and was assumed to be 0.85.

Table A-3.1-1 shows burden measurement data obtained for the VT circuit, and Table A-3.1-2 shows the calibration data originally supplied with the VTs.

A-3.2 VT Ratio Correction Factors

VT ratio correction factors (VTRCF) for each phase were calculated using the following equation from eq. (5-6-1):

$$\mathrm{RCF}_c = \mathrm{RCF}_0 + \frac{B_c}{B_t}[\mathrm{RCF}_d \cos(\Theta_t - \Theta_c) + 0.000291\,\gamma_d \sin(\Theta_t - \Theta_c)]$$

where

0.000291 = 1/3,438
3,438 = minutes of angle in one radian (180 × 60/π)
B_c = actual burden at which the RCF will be calculated, VA
B_0 = zero burden, VA
B_t = burden at the upper calibration test point, VA
RCF_c = ratio correction factor to be calculated at actual burden
RCF_d = $\mathrm{RCF}_t - \mathrm{RCF}_0$
RCF_0 = ratio correction factor at the zero burden calibration test point (from calibration data)
RCF_t = ratio correction factor at the upper calibration test point burden (from the calibration data)
Θ_t = phase angle (deg) at the upper calibration test point (standard Z burden test point)
= arccos (0.85)
= 31.78833 deg
Θ_c = phase angle at the actual power factor (PF_{vt}) at which the RCF will be calculated
= arccos (PF_{vt})
= arccos (0.85)
= 31.78833 deg
γ_d = $\gamma_t - \gamma_0$
γ_0 = phase-angle error (min) at the zero calibration test point, from the calibration data
γ_t = phase-angle error (min) at the upper range calibration test point, from the calibration data

Table A-3.1-2 Example VT Calibration Data

Parameter	Symbol	Phase 1	Phase 2	Phase 3
Burden at calibration zero point, VA	B_0	0	0	0
Burden at upper cal. test point, VA	B_t	200	200	200
Power factor at upper calibration test point, ratio	PF_t	0.85	0.85	0.85
Phase angle at upper calibration test point, deg	Θ_t	31.78833	31.78833	31.78833
RCF at B_0, ratio	RCF_0	0.9979	0.9982	0.9978
RCF at B_t, ratio	RCF_t	1.00105	1.00104	1.00110
Phase-angle error at B_0, min	γ_0	0.5	0.4	0.5
Phase-angle error at B_t, min	γ_t	−0.46	−0.44	−0.49

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Table A-3.2-1 VT and CT Ratio and Phase-Angle Correction Factor Results

Correction Factors	Symbol	Phase 1	Phase 2	Phase 3
VT Correction Factors				
VT ratio correction factor, min	VTRCF	0.998184	0.998224	0.998156
VT phase-angle error, min	γ_c	0.4136	0.3928	0.3931
CT Correction Factors				
CT percent of primary rated current, %	…	39%	40%	40%
CT ratio correction factor (from calibration curve), min	CTRCF	1.00017	1.00017	1.00017
CT phase-angle error (from CT calibration curve), min	β	0.50	0.50	0.50
Phase-Angle Correction Factors				
Phase angle (at measured secondary power factor), deg	Θ_s	8.92215	10.7348	10.1986
Wattmeter phase-angle error (assumed), deg	α	0.0	0.0	0.0
CT phase-angle error (in minutes from above/60), deg	β	0.008333	0.008333	0.008333
VT phase-angle error (in minutes from above/60), deg	γ_c	0.006893	0.006547	0.006552
True power factor angle ($\Theta_s - \alpha + \beta - \gamma_c$), deg	Θ	8.9236	10.7365	10.2004
Phase-angle correction factor, deg	PACF	0.999996	0.999994	0.999994

The ratio correction factor RCF_c can now be calculated.

$$\begin{aligned}\mathrm{RCF}_c &= \mathrm{RCF}_0 + (B_c/B_t) \times [(\mathrm{RCF}_d \times \cos(31.78833 - 31.78833) + 0.000291 \times \gamma_d \times \sin(31.78833 - 31.78833)] \\ &= \mathrm{RCF}_0 + (B_c/B_t) \times [\mathrm{RCF}_d \times \cos(0) + 0.000291 \times \gamma_d \times \sin(0)]\end{aligned}$$

For phase 1, the RCF_c value is 0.998184.

Results for the VT ratio correction factors for all phases are shown in Table A-3.2-1.

A-3.3 VT Phase-Angle Error

The calculated VT phase-angle errors (γ_c) at the measured burdens are calculated as follows. A sample calculation for the phase-angle error for phase 1 is shown below:

$$\begin{aligned}\gamma_c &= \gamma_0 + (B_c/B_t)(\gamma_t - \gamma_0) \\ &= 0.5 + (0.09005)(-0.46 - 0.5) \\ &= 0.5 - 0.08645 \\ &= 0.4136 \text{ min (or 0.006893 deg)}\end{aligned}$$

A-3.4 CT Ratio Correction Factors

As explained earlier, existing plant CTs were used for the test, and typical "type" calibration data were used for their analysis. Example calibration test data plots for the type of CTs used are shown in Figures A-3.4-1 and A-3.4-2.

Due to the insensitivity of CT correction factors to the magnitude of the current and the danger of accidentally opening the CT circuit in any attempts to measure the current, the primary current from the test is in kilowatts, vars, and voltage. The primary current was calculated to be about 4 000 A, or 40% of rated current, and the CT ratio correction factors (CTRCFs) of 1.00017 are obtained from Figure A-3.4-1.

A-3.5 CT Phase-Angle Error

CT phase-angle errors can be read directly off of the calibration curve shown in Figure A-3.4-2. Using the 40% primary current, CT phase-angle errors (β) of +0.5 min are obtained for each phase from Figure A-3.4-2.

A-3.6 Phase-Angle Correction Factors

Using the phase-angle errors determined above, the primary side phase angle (Θ) between the current and voltage for each phase are calculated, as shown in the following example for phase 1:

$$\begin{aligned}\Theta &= \Theta_s - \alpha + \beta - \gamma_c \\ &= (8.922151 - 0 + 0.008333 - 0.006893) \\ &= 8.92359 \text{ deg}\end{aligned}$$

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where

α = wattmeter phase-angle error, assumed equal to zero, deg

β = CT phase-angle error, deg

Θ = true primary side phase angle, deg

Θ_s = measured secondary side phase angle, deg

γ_c = VT phase-angle error, deg

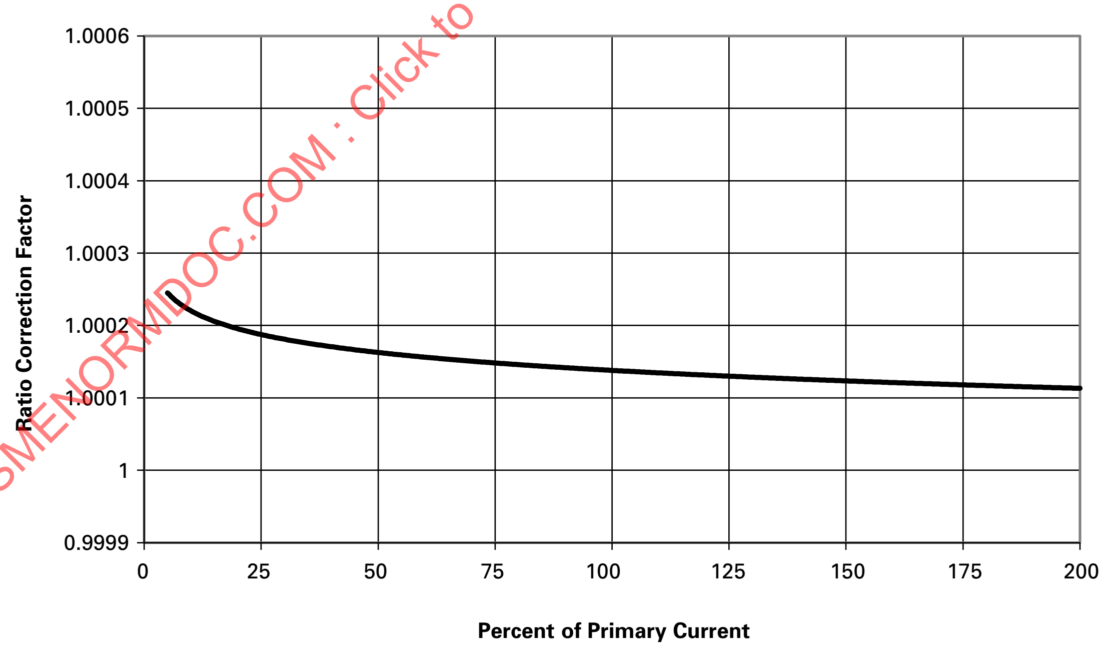
The phase-angle correction factor (PACF) is calculated as illustrated below for phase 1:

$$\begin{aligned} \text{PACF} &= \text{PF}/\text{PF}_s \\ &= \cos\Theta/\cos\Theta_s \\ &= \cos(8.92359)/\cos(8.922151) \\ &= 0.999996 \end{aligned}$$

A-3.7 VT Voltage Drop Corrections

The test wattmeters were located in a remote panel; therefore, there may be a voltage drop from the VT to the actual test watt transducers. Table A-3.7-1 shows example measurements made using two true RMS AC voltmeters. The first step was to record the voltage measured by both meters at a common location and to determine an offset difference between the two meters. Voltmeter 1 was then left at the VT location, and Voltmeter 2 was moved to the wattmeter location. Voltage measurements of 30 sec were then made between each phase to neutral simultaneously at each location and then averaged. The readings at the wattmeters were corrected for the meter offset and subtracted from the readings at the VTs. The differences between the readings were found to be 0.02, 0.04, and 0.06 VAC. Since the voltage at the wattmeters is lower than at the VTs, the recorded watts and vars will be low, and a VT voltage drop correction factor (VTVDCF) larger than one will be applied to convert the watt and var readings at the wattmeter location to what it would have been had the meters been directly connected to the VTs.

Figure A-3.4-1 Sample CT Ratio Correction Factor Curve



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