
Gas turbine combined cycle power plants — Thermal performance tests

*Turbines à gaz — Centrales à cycle combiné — Essais de performance
thermique*

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Foreword

ISO (the International Organization for Standardization) is a worldwide federation of national standards bodies (ISO member bodies). The work of preparing International Standards is normally carried out through ISO technical committees. Each member body interested in a subject for which a technical committee has been established has the right to be represented on that committee. International organizations, governmental and non-governmental, in liaison with ISO, also take part in the work. ISO collaborates closely with the International Electrotechnical Commission (IEC) on all matters of electrotechnical standardization.

The procedures used to develop this document and those intended for its further maintenance are described in the ISO/IEC Directives, Part 1. In particular the different approval criteria needed for the different types of ISO documents should be noted. This document was drafted in accordance with the editorial rules of the ISO/IEC Directives, Part 2 (see www.iso.org/directives).

Attention is drawn to the possibility that some of the elements of this document may be the subject of patent rights. ISO shall not be held responsible for identifying any or all such patent rights. Details of any patent rights identified during the development of the document will be in the Introduction and/or on the ISO list of patent declarations received (see www.iso.org/patents).

Any trade name used in this document is information given for the convenience of users and does not constitute an endorsement.

For an explanation on the voluntary nature of standards, the meaning of ISO specific terms and expressions related to conformity assessment, as well as information about ISO's adherence to the World Trade Organization (WTO) principles in the Technical Barriers to Trade (TBT) see the following URL: www.iso.org/iso/foreword.html.

This document was prepared by Technical Committee ISO/TC 192, *Gas turbines*.

Introduction

This document specifies standard rules for preparing, conducting, evaluating and reporting thermal performance tests in order to determine and/or verify the power output, the thermal efficiency (heat rate) and/or other performance test parameters for gas turbine driven combined cycle power plants. It provides information on methods of measurement considering uncertainties and on methods for corrected results obtained under test conditions in order to compare to guaranteed or specified conditions.

The objective of testing conducted per this document is to determine combined cycle thermal performance characteristics in accordance with any previously drawn up agreements such as the purchase agreements, test criteria documents, engineering, procurement and construction (EPC) requirements, power purchase agreements, power and water purchase agreements, contractual services agreements.

The document also provides guidelines for comparative tests designed to check performance differentials of the combined cycle and cogeneration power plants, for testing before and after modifications, upgrades or overhauls. Improvements to achieve additional performance of the combined cycle may include modification/substitutions of main components and additions of components inside test boundary. This comparative testing philosophy may also be used for “periodic testing” of the plant in order to monitor overall plant performance degradation, while giving due consideration to the relative testing uncertainty.

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Gas turbine combined cycle power plants — Thermal performance tests

1 Scope

This document specifies standard rules for preparing, conducting, evaluating and reporting thermal performance tests on combined cycle and cogeneration power plants driven by gas turbines for base and part load operation with or without supplementary firing.

This document is applicable to

- thermal performance tests for general information,
- thermal acceptance tests for determining the performance of the combined cycle plant in relation to a contractual guarantee, and
- comparative tests designed to check the performance differentials of the combined cycle and cogeneration power plants, for testing before and after modifications, upgrades or overhauls.

It can be used to determine the following thermal performance test goals and expected values, under specific operating and reference conditions within defined test boundaries:

- electrical power output;
- heat rate or thermal efficiency;
- process steam and/or district heat w/o generation of electrical power output by means of a steam turbine.

This document does not apply to individual equipment component testing, which is covered by corresponding standards.

It is not intended to be applied to the following test goals:

- environmental testing for example emissions, noise;
- vibration testing;
- operational testing;
- absolute or comparative performance of specific components of the combined cycle covered by dedicated standards (e.g. gas turbines).

2 Normative references

The following documents are referred to in the text in such a way that some or all of their content constitutes requirements of this document. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments) applies.

ISO 2314:2009, *Gas turbines — Acceptance tests*

ISO 3675, *Crude petroleum and liquid petroleum products — Laboratory determination of density — Hydrometer method*

ISO 5167 (all parts), *Measurement of fluid flow by means of pressure differential devices inserted in circular cross-section conduits running in full*

ISO 6974-1, *Natural gas — Determination of composition and associated uncertainty by gas chromatography — Part 1: General guidelines and calculation of composition*

ISO 6975, *Natural gas — Extended analysis — Gas-chromatographic method*

ISO 6976, *Natural gas — Calculation of calorific values, density, relative density and Wobbe indices from composition*

ISO 9951, *Measurement of gas flow in closed conduits — Turbine meters*

ISO 10715:1997, *Natural gas — Sampling guidelines*

ISO 10790, *Measurement of fluid flow in closed conduits — Guidance to the selection, installation and use of Coriolis flowmeters (mass flow, density and volume flow measurements)*

ISO 12185, *Crude petroleum and petroleum products — Determination of density — Oscillating U-tube method*

ISO 12213-2, *Natural gas — Calculation of compression factor — Part 2: Calculation using molar-composition analysis*

ISO 17089-1, *Measurement of fluid flow in closed conduits — Ultrasonic meters for gas — Part 1: Meters for custody transfer and allocation measurement*

ISO 20765-1, *Natural gas — Calculation of thermodynamic properties — Part 1: Gas phase properties for transmission and distribution applications*

ISO/IEC 17025, *General requirements for the competence of testing and calibration laboratories*

ASTM D1945, *Standard Test Method for Analysis of Natural Gas by Gas Chromatography*

ASTM D4052, *Standard Test Method for Density, Relative Density, and API Gravity of Liquids by Digital Density Meter*

ASTM D4809, *Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter*

ASTM D4868, *Standard Test Method for Estimation of Net and Gross Heat of Combustion of Burner and Diesel Fuels*

DIN 51900-1, *Testing of solid and liquid fuels — Determination of gross calorific value by the bomb calorimeter and calculation of net calorific value — Part 1: Principles, apparatus, methods*

3 Terms and definitions

For the purposes of this document, the following terms and definitions apply.

ISO and IEC maintain terminological databases for use in standardization at the following addresses:

- IEC Electropedia: available at <http://www.electropedia.org/>
- ISO Online browsing platform: available at <http://www.iso.org/obp>

3.1

absolute test

test carried out in order to prove an absolute guarantee or an absolute expected performance

3.2

comparative test

test carried out in order to prove a relative change or improvement of performance

EXAMPLE For retrofits.

3.3**performance test**

means test of performance of power output, efficiency or heat rate, heat duty, process steam mass flows, etc., as specified

EXAMPLE Performance tests could be specified in contractual agreements.

3.4**preliminary test**

test or tests in advance of the actual *performance test* (3.3) to check the complete measuring system and main components to verify that the power plant is in a suitable condition before conducting the actual performance test

3.5**simple cycle**

thermodynamic cycle consisting only of successive compression, combustion and expansion

Note 1 to entry: Generation of electrical *power* (3.16) output driven only from a *gas turbine* (3.29) or from the gas turbine in *combined cycle* (3.28) using a bypass stack. The working fluid enters the gas turbine from the atmosphere and is discharged into the atmosphere.

[SOURCE: ISO 11086:1996, 1.8, modified.]

3.6**open cycle**

combined cycle (3.28) with the steam turbine bypassed in which the working fluid enters the gas turbine from the atmosphere and is discharged through a heat recovery steam generator stack into the atmosphere

Note 1 to entry: The generation of electrical power output in a *combined cycle* (3.28) plant operating in open cycle is provided only from the gas turbine, as the steam turbine is bypassed.

3.7**test boundary**

imaginary boundary drawn encompassing the major equipment included in the test scope

3.8**heat duty**

thermal net/gross output produced from the *combined cycle* (3.28) plant

3.9**heat rate****HR**

ratio of the fuel energy supplied per unit time to the electrical power produced

Note 1 to entry: Inverse of thermal efficiency.

Note 2 to entry: The heat rate is expressed in units of kilojoules per kilowatt hour.

[SOURCE: ISO 11086:1996, 5.31, modified.]

3.10**heating value****calorific value****specific energy**

amount of heat released by the complete combustion in air of a specific quantity of gas or liquid fuel when the reaction takes place at constant pressure

Note 1 to entry: If the combustion products accounted for are only in the gaseous state, the value is called lower heating value (LHV) or inferior calorific value or net heating value. If the combustion products are gaseous with the exception of water, which is in liquid state, the value is called higher heating value (HHV) or superior calorific value or gross heating value at 15 °C for natural gas fuel.

Note 2 to entry: HHV at constant volume and a reference temperature of 15 °C shall be determined by means of a bomb calorimeter method. Then LHV at constant volume is found by calculation deducting the latent heat of the calculated amount of water vapour produced from the measured hydrogen content of the fuel.

3.11

high pressure

HP

highest pressure level of the working fluid

3.12

intermediate pressure

IP

medium pressure level of the working fluid

3.13

low pressure

LP

lowest pressure level of the working fluid

3.14

mechanical loss

reduction of power output due to bearing and windage losses of gas and steam turbine rotors

[SOURCE: ISO 11086:1996 5.34, modified.]

3.15

hot water

host that can accept or supply energy (non-fuel) to a cycle

3.16

power

quantity expressed in terms of mechanical shaft power at the turbine coupling or electrical power of the turbine-generator

3.17

primary variable

value that is measured and used for calculation and correction of test results

3.18

process steam

host that can accept or supply energy (non-fuel) to the cycle

EXAMPLE District heating, steam consumers (refinery, pulp and paper industries, petrochemical industries), steam producers (auxiliary boilers, steam from other power plant blocks), etc.

3.19

secondary variable

value that is measured but that will not be used for calculation of the results

Note 1 to entry: These variables are measured to ensure that the required test conditions are not violated and to provide information for future use.

3.20

standard reference condition

condition for the ambient air or intake air at the compressor flange (alternatively, the compressor intake flare) equal to

- absolute pressure of 101,325 kPa (1,01325 bar; 760 mmHg),
- temperature of 15 °C, and
- relative humidity of 60 %

Note 1 to entry: The conditions are defined in ISO 2533.

Note 2 to entry: In the case of the closed cycle, the standard conditions for the air heater are 15 °C and 101,325 kPa for the ambient atmospheric air.

Note 3 to entry: An inlet water temperature of 15 °C applies if cooling of the working fluid is used.

Note 4 to entry: These reference conditions may be different if otherwise agreed in contractual documents or agreements.

3.21

thermal efficiency

ratio of electrical *power* (3.16) output to the heat consumption

Note 1 to entry: Inverse of heat rate.

Note 2 to entry: It can be based on lower or higher heating value.

[SOURCE: ISO 3977-1:1997, 2.3.4, modified.]

3.22

total efficiency

ratio of the sum of electrical *power* (3.16) output and *thermal output* (3.23) to the heat consumption

3.23

thermal output

energy as *process steam* (3.18), *hot water* (3.15) or other export of thermal energy from the cycle

3.24

thermal performance guarantee

guaranteed value for net/gross *power* (3.16) output, net/gross *heat rate* (3.9), or net/gross *thermal efficiency* (3.21), *process steam* (3.18) mass flows and/or *heat duty* (3.8)

3.25

tolerance

allowed deviation from a specific requirement

Note 1 to entry: To define in contractual agreements.

3.26

uncertainty

parameter associated with the result of a measurement, which characterises the dispersion of the values that can reasonably be attributed to the measurand

Note 1 to entry: The determination of the quality of a measurement that can be expressed with the uncertainty of the test result is of fundamental importance in any field of measuring and testing. A measure to quantify such quality is the uncertainty of measurement. The shortened term “uncertainty” is used for simplicity in this document.

Note 2 to entry: The expression “accuracy of measurement” (closeness of the agreement between the result of a measurement and the value of the measurand), commonly abbreviated as “accuracy,” is not associated with numbers and is not used as a quantitative term.

3.27

cogeneration power plant

gas turbine based power plant which delivers both electricity and heat

Note 1 to entry: Heat can be delivered in form of process steam or hot water/district heat water to one or more external consumers. The plant can include a steam turbine, but can also deliver the steam or hot water produced in the heat recovery steam generator or waste heat recovery unit direct to the external consumer.

3.28

combined cycle

CC

thermodynamic cycle employing the combination of a gas turbine cycle with a steam or other fluid Rankine cycle

[SOURCE: ISO 11086:1996, 1.12]

3.29

gas turbine

GT

rotary engine that converts fuel thermal energy into mechanical work

Note 1 to entry: It consists of one or several rotating compressors, a thermal device(s) that heats the working fluid, one or several turbines, a control system and essential auxiliary equipment. Any heat exchangers (excluding waste exhaust heat recovery exchangers) in the main working fluid circuit are considered to be part of the gas turbine.

[SOURCE: ISO 3977-1:1997, 2.1, modified.]

3.30

heat recovery steam generator

HRSG

energy recovery heat exchanger that produces *process steam* ([3.18](#)) and/or drives a steam turbine

Note 1 to entry: It may contain provisions for supplementary firing.

3.31

multi-shaft combined cycle

combined cycle ([3.28](#)) in which the useful power output from the cycle is taken from more than one shaft

[SOURCE: ISO 11086:1996, 26.7, modified.]

3.32

single shaft combined cycle

combined cycle ([3.28](#)) in which the useful *power* ([3.16](#)) output from the cycle is taken from one shaft

[SOURCE: ISO 11086:1996, 26.6]

3.33

steam turbine

ST

rotary engine in which the kinetic energy of a moving fluid (steam) is converted into mechanical energy by causing a bladed rotor to rotate

3.34

waste heat recovery unit

WHRU

heat exchanger to deliver hot fluid (not gas) where there is no change of phase to the working fluid, which is commonly a water/glycol blend

4 Symbols and units

For the purposes of this document, the symbols and units shown in [Table 1](#) apply.

Table 1 — Global symbols

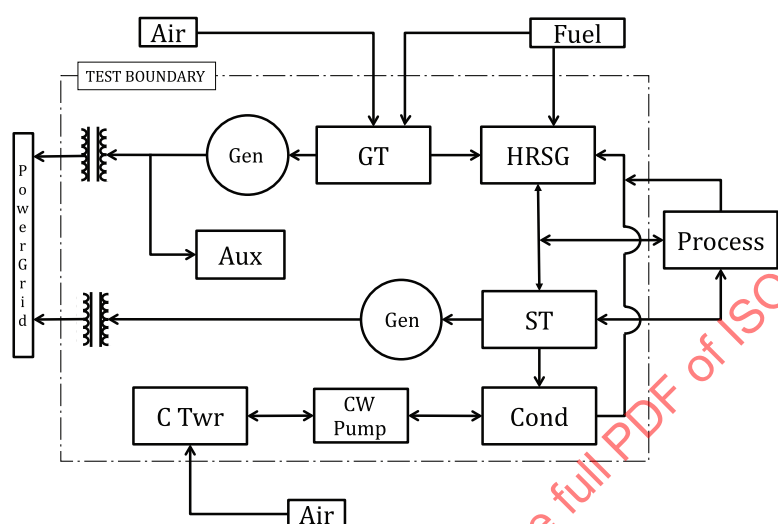
Symbol	Definition	SI unit
AC_{Pi}	Additive correction (i) for measured power output	kW
AC_{Qi}	Additive correction (i) for measured fuel heat input	kW
BRC	Base reference conditions (guarantee conditions)	–
C_P	Global correction for power output	–
C_Q	Global correction for fuel heat consumption	–
HR_{corr}	Net or gross heat rate of the combined cycle based on fuel lower or higher heating value and corrected to base reference conditions	kJ/kWh
$HR_{elec, meas}$	Heat rate of the combined cycle based on measured electrical power output and measured fuel lower or higher heating value	kJ/kWh
$HR_{total, meas}$	Heat rate of the combined cycle based on measured electrical power output, measured thermal output and measured fuel lower or higher heating	kJ/kWh
h_f	Specific enthalpy of fuel at temperature entering in the heat source	kJ/kg
h_0	Specific enthalpy of fuel at standard reference conditions 15 °C / 1.01325 bar	kJ/kg
$\dot{m}_{CW}$	Cooling water mass flow	kg/s
$\dot{m}_{fuel}$	Fuel mass flow	kg/s
$\dot{m}_{process}$	Process steam or hot water mass flow	kg/s
MC_{Pi}	Multiplicative correction (i) for measured power output	–
MC_{Qi}	Multiplicative correction (i) for measured fuel heat input	–
P_{CC}	Gross or net power output of the combined cycle	kW
P_{corr}	Gross or net power output corrected to base reference conditions	kW
$P_{gross, meas}$	Measured gross power output	kW
$P_{net, meas}$	Measured net power output	kW
PF	Power factor	–
P_{GT}	Gas turbine power output	kW
P_{PL}	Part load power output of combined cycle	kW
$P_{PL, GT}$	Part load power output of gas turbine	kW
P_{ST}	Steam turbine power output	kW
Q_{CC}	Corrected heat input of the combined cycle	kW
Q_{meas}	Measured heat input	kJ/s
η_{corr}	Net or gross thermal efficiency of the combined cycle based on fuel lower or higher heating value and corrected to base reference conditions	%
$\eta_{elec, meas}$	Thermal electrical efficiency of the combined cycle based on measured electrical power output and measured fuel lower or higher heating value	%
$\eta_{total, meas}$	Thermal total efficiency of the combined cycle based on measured electrical power output, measured thermal output and measured fuel lower or higher heating value	%

5 Test boundary

The concept of a test boundary identifies the scope of hardware within the combined cycle power plant subject to thermal performance testing while considering the reference conditions used to establish the performance parameters (i.e. heat/power output, efficiency or heat rate). It provides the basis for the definition and layout of instrumentation required to determine the energy streams crossing the test boundary. It also determines the actual conditions during testing for correcting the test results to reference conditions.

A combined cycle power plant can have a range of equipment within the plant boundary. Depending on the scope of supply, and the understanding between parties, either the entire plant or only a portion of the plant including gas turbine(s) within the test boundary can be tested. This document provides flexibility in terms of the test boundary, and hence, the test boundary is typically defined along with the base reference conditions that are used to specify the performance parameters.

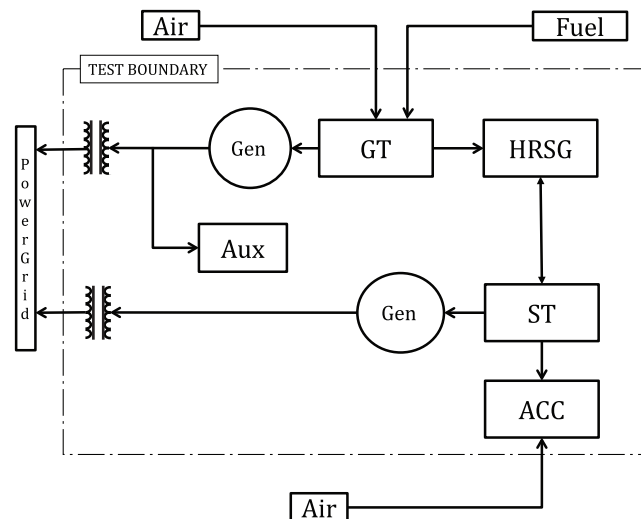
Figures (1) to (7) provide a range of applicable test boundaries. The users of this document should recognize that the test boundaries provided herein are for reference only, and that the actual test boundaries can vary depending on the plant design and the contractually guaranteed scope of supply.



Key

ACC	air cooled condenser(s)	GT	gas turbine(s)
Aux	auxiliary consumption	HRSG	heat recovery steam generator(s)
C Twr	cooling tower(s)	Process	heat in form of process steam or hot water / district heat
Cond	condenser(s)	ST	steam turbine(s)
CW Pump	circulation water pump(s)	WHRU	waste heat recovery unit(s)
Gen	generator(s)		

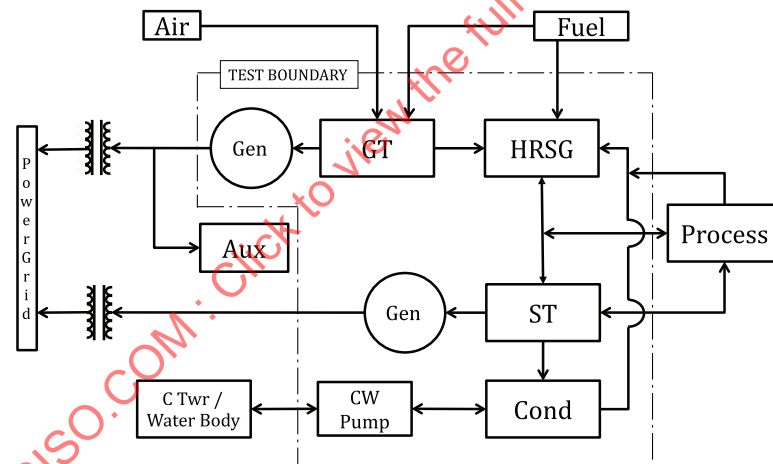
Figure 1 — Combined cycle plant test boundary: sample 1, overall plant test boundary for multi-shaft configuration with process steam and duct firing (e.g. turnkey project)



Key

See [Figure 1](#).

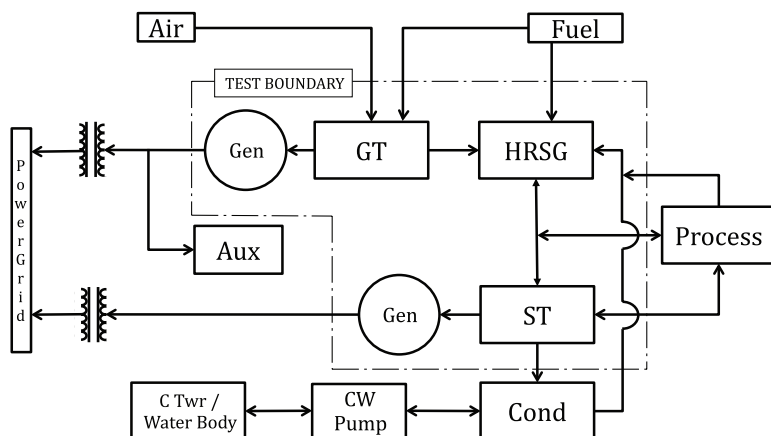
Figure 2 — Combined cycle plant test boundary: sample 2, typical overall plant test boundary with water steam cycle operated in condensing mode (e.g. turnkey project)



Key

See [Figure 1](#).

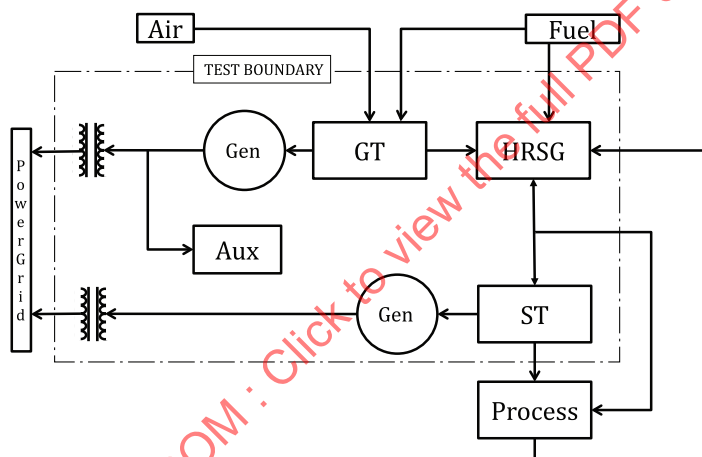
Figure 3 — Combined cycle plant test boundary: sample 3, test boundary including gross power output and gross efficiency (e.g. power island project)



Key

See [Figure 1](#).

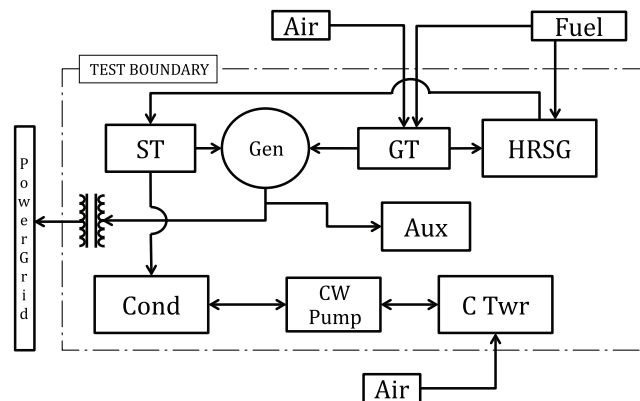
Figure 4 — Combined cycle plant test boundary: sample 4, test boundary including condenser pressure as primary variable for gross power output and gross efficiency



Key

See [Figure 1](#).

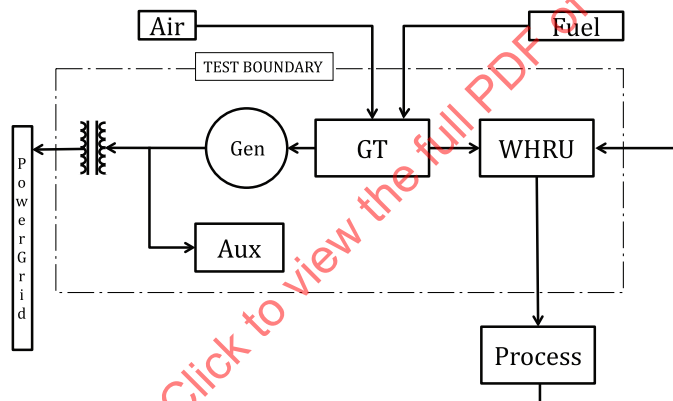
Figure 5 — Combined cycle plant test boundary: sample 5, Overall plant test boundary including back pressure steam turbine(s) for generation of process steam



Key

See [Figure 1](#).

Figure 6 — Combined cycle plant test boundary: sample 6, overall plant test boundary for single shaft configuration (e.g. turnkey project)



Key

See [Figure 1](#).

Figure 7 — Cogeneration plant test boundary: sample 7, gas turbine combined cycle plant with waste heat recovery unit for generation of hot water or process steam

6 Preparation for test

6.1 General

Thermal performance testing requires specific and detailed preparations. Since the purpose of such tests varies depending on the equipment, site conditions and contractual scope, it is crucial that a dedicated test procedure document is established and agreed well in advance of the planned test date. The procedure document should be developed in accordance with this document and approved by all responsible parties. Sufficient time to development the final procedure should be considered to allow the parties involved for addressing comments. A clear determination of the equipment boundaries, associated instrumentation and correction methodology shall avoid any potential disagreements after the test.

6.2 Performance degradation

The thermal performance degradation of combined cycle equipment during operation is an existing phenomenon. This is associated with effects of fouling, erosion, wear and tear of gas turbine components, as well as those of the water/steam cycle equipment.

Thermal performance tests should be carried out immediately after the completion of the commissioning. However, agreement to apply degradation corrections to the performance test results is strictly a commercial issue between the parties and beyond the scope of this document.

In most cases, the combined cycle thermal performance guarantees are made based on “new and clean” equipment conditions. The contractual agreements between the parties should define the period when the equipment is considered as new and clean and state if performance corrections are permitted, when equipment is tested beyond this period.

The detailed methodology on how to apply degradation correction may be derived from comparative tests or predictive degradation curves.

6.3 Measurement classification

Measurements of variables used in calculation of test results are considered primary variables. These measurements directly relate to the boundary conditions and require instrumentation accuracy in accordance with this document.

Measurements of variables that are not included in the calculation and correction of the results but provide indication that the required test conditions are met will be designated as secondary variables. Examples of these variables are gas turbine exhaust temperature or steam turbine inlet pressure and temperature. Instruments used for secondary measurements may require field verification against suitable calibrated instruments (i.e. loop checks using portable calibration equipment). In this case, the recommended calibration tolerance is 0,25 % of the measurement span or 0,5 K, and the reference device should be such that it provides an accuracy ratio greater than 4 versus a field instrument.

6.4 Design and construction phase recommendations

The following recommendations should be considered when establishing the requirements for instrumentation accuracy, calibration, documentation and location of permanent and temporary instrumentation to be used for any thermal performance test.

- a) Suitable access and isolation capability for permanently installed instrumentation and temporary test provisions, such as fuel sampling tapping point and fuel flow measurement should be taken into account in the design, as this will reduce manpower and downtime required during the preparations for testing.
- b) If permanently installed instrumentation is to be used during the test, the requirements of [Table 4](#) should be implemented if possible during early stages of the design. The ability to conduct post-test calibrations or to substitute with temporary instrumentation should also be considered. The signal processing and data logging should also meet the requirements of this document. If the permanently installed instrumentation has a local readout, then the display shall be in such a position that reading the display is convenient for the reader or inspector (especially flow devices). This is also applicable for the attached name plate identifications.
- c) In the case of precision power measurement for testing, it is recommended that current and voltage transformers in accordance with [6.7.2.3](#) are installed for the performance tests. The burden of the measuring transformers should be measured and recorded to check if the load is inside the calibration range.
- d) For temporary installed instrumentation, the design should allow for connections and spools sections, pressure connections, thermowells and electrical tie-ins. All tapping points for pressure transmitter and differential pressure transmitter connection including required isolating valves shall be made available for installing temporary precision test instrumentation. This also applies

to the provision of free thermowells and power meter connections for testing purposes. All test instrument tapping points for connection of temporary precision test instrumentation need to be serviceable and accessible. Where possible these should be located such that scaffolding is not required for access. Suitable and correct isolation valves should be provided to allow safe connection and removal of static and differential pressure transducers for the performance test.

- e) Flow meters used for performance testing shall be designed, manufactured and located in a suitable straight section with sufficient upstream and downstream lengths to ensure conformity with the test codes. To meet the required flow meters measurement uncertainty limits, use of flow straighteners is recommended. Flow meters should ideally be of flanged construction (if pressure line allows it) so that they can be removed for calibration and if necessary replaced. A removal spool piece is recommended and should be inserted during all commissioning activities to prevent damage to the flow devices. In any case the flow element installation shall occur after any acid cleaning, as well as gas or steam blows, since those activities could have negative impact on the uncertainty and/or could easily invalidate calibration data on meters.
- f) The instrumentation layout should allow for contingency in duplicating and validating measurements used for determination of performance test results. This should be the case for power measurement and fuel flow in particular.
- g) Instrument loops should minimize signal interference and measurement error. If instrument transformers are used, adequate wire size should be used to reduce voltage drops.
- h) The design of the plant should consider accessible installation and provisions for air inlet temperatures (e.g. downstream chillers or evaporative coolers) and steam turbine exhaust pressures, as well as gas turbine (GT) exhaust, heat recovery steam generator (HRSG) module and HRSG stack temperatures and pressure measurements.

6.5 Test procedure

The performance test shall be conducted based on a test procedure developed to provide detailed guidance for the test preparation and execution as well as evaluation. This test procedure document supplements the contract obligations and clarifies particular contract issues. It shall provide the course of action for conducting the test, as well as methods of measurement and the method used for correcting the results from test conditions to reference conditions, or any other criteria set out in the contract. Prior to the execution, the test procedure shall be agreed upon by all the relevant parties to the test.

The following topics are strongly recommended to be included within the test procedure (unless known to be not applicable) in order to ensure highest possible quality of test preparation and execution.

- a) Brief description of the plant.
- b) Base reference conditions, guarantees or expected values.
- c) Required operating conditions and control conditions, e.g. load settings, power augmentation system conditions, supplementary firing conditions, gas turbine inlet cooling or heating conditions, district heating and process steam conditions, air cooled condenser or cooling tower (wet mode or dry mode), allowable range of fuel conditions (constituents and heating value).
- d) Responsibilities of test participants.
- e) The criteria for conformity with guarantees.
- f) Schematic diagram of the cycle, showing test boundary/envelope and test measurement points.
- g) A schedule for instrumentation including type, location, calibration requirements and systematic uncertainty.
- h) Requirements for the stabilization period prior to the test commencement and stability criteria during the test based on [Table 8](#).

- i) Details concerning fuel handling, including a procedure for fuel samples collection, handling, method of analysis, laboratories for fuel analyses, frequency of sampling, as well as the distribution of duplicate fuel samples for each party, including a set of samples to be kept in case of additional analysis. On site gas chromatograph equipment for gas analysis may be used, if it meets the accuracy requirements of [Table 4](#).
- j) A cycle isolation list showing the position of valves required for the performance tests. This should include details of the normal operating position of plant valves (open/closed) and the position required during the performance test. Ideally the list should be prepared in table format so that it can be used as a check sheet during the performance test.
- k) Number of auxiliary consumers in service (pumps, compressors, etc.) and auxiliary load line-up.
- l) A list of the inspections required ahead of the performance test. It is envisaged that this will include inlet guide vane (IGV) angle checks, IGVs hand cleaning, visual inspections to check the cleanliness of the gas turbine compressor and IGV blades. For new plants, the major components should be in a clean and undamaged condition.
- m) Number of test runs and duration of each run.
- n) Frequency of data acquisition, data acceptance and rejection criteria.
- o) Optional template for manual readings where found necessary.
- p) Numerical values from tables (considering interpolation), curves or algorithms for correction under conditions differing from the specified conditions. The curves or algorithms, however, can be replaced by a computing model to be used for the correction from the reference conditions in line with [8.2](#) with agreement of the relevant parties involved. In case of correction curves it is advised that a sufficient order for each polynomial formula is provided to achieve accurate results and that 6 decimal places in scientific format may be considered, i.e. $y = a_n \cdot x^n + \dots + a_2 \cdot x^2 + a_1 \cdot x + a_0$, where constants a_i are in the format 0,000 000E ± 00.
- q) Method of combining test runs to calculate the final test result.
- r) Requirements for data storage, document retention, data and test report distribution.
- s) Method for agreeing and documenting any modification to test procedure.
- t) Method for documenting the control parameters during the test.
- u) Method for recording observations and deviations before, during or after test.
- v) Pre-test uncertainty analysis based on systematic uncertainties of the instrumentation (see [6.10](#)) and typical random uncertainties to check the requirements of [Table 4](#).

6.6 Field preparations for the performance test

Prior to the tests, the plant shall be placed at the disposal of the equipment supplier, the original equipment manufacturer (OEM) or engineering, procurement and construction (EPC) responsible for examination and cleaning (approval from load dispatch centres or other relevant parties involved might be considered). All parties to the test shall be given timely notification, to allow them the necessary time to respond and to prepare personnel, equipment or documentation. Updated information should be provided, as it becomes available.

In addition to following the test procedure, the testing parties should do as follows.

- a) Conduct a survey of all the components within the combined cycle plant in order to identify any deficiencies in equipment or process that might affect the performance test and to confirm that all components are ready for the performance test.
- b) Audit electrical power output measurement, inspect condition of the devices and check for possible consistency with other existing station power measurements.

- c) Audit the fuel flow measuring system, inspect condition of the devices and check for possible consistency with other existing station fuel flow measurements.
- d) Conduct gas turbine checks and preparation in accordance with ISO 2314. This applies in particular to the gas turbine compressor blades, inlet guide vanes (IGVs) and compressor inlet which should be visually inspected and cleaned (off line washing with previous hand washing, if necessary) unless only limited running, from a known clean condition, has been undertaken before the test.
- e) Prior to the commencement of tests, obtain valid calibration certificates for all temporary and station instruments used for primary variables.
- f) If certified instrumentation is not installed for secondary variables, conduct field calibration checks of secondary variables against reference calibrated instruments. These should be done considering the full loop against the calculated engineering value in the control system. Certificates of reference instruments used shall be made available. Typical secondary variables are listed in [Annex A](#).
- g) Verify instrument setup: location and proper installation of all relevant temporary and station instruments.
- h) Verify data acquisition setup: monitoring relevant parameters, frequency of data collection, remove any data filters (dead bands).
- i) Verify certificates and validity of calibrations for all primary variables, as per the requirement of this document. Also, crosscheck them against the nameplates and serial numbers of test equipment and instrumentation.
- j) Confirm adequate controls and operation modes of the plant (e.g. anti-icing, gas turbine inlet conditioning, process steam extractions, district heating, cooling tower or air cooled condenser). Also, agree on how to document their state during the test.
- k) Verify calibration and settings of station instrumentation and valves, in order to produce conditions as close as possible to the reference conditions. Also agree on how to document their state during the test.
- l) Obtain data sheets and calibration certificates of station flow elements (if available) including distributed control system (DCS) calculation methods.
- m) Record and determine dimensions and physical conditions of any part (vessels, piping, orifices, etc.) of the plant required for calculations or other test purposes.
- n) Finalize the detailed test programme document, including tests sequence, durations and load requirements.
- o) Obtain a recent fuel analysis (with fuel density and lower or higher heating value) or fuel composition to ensure that the fuel characteristics are as expected.
- p) Identify the names of the laboratories for fuel analyses.
- q) Appoint a test director from the conducting party, who will oversee and lead the test programme.
- r) Ensure that a suitable number of personnel are available to support equipment installation and preparation activities. Also, if needed, for collecting the test data.
- s) Implement an effective communication system to indicate the starting and the end of the tests and to inform all personal involved in recording of manual readings when to take each value.
- t) Finalize a cycle isolation list, getting agreement with plant operations and operator support for conducting cycle isolation. It is recommended to separate the isolation in all electrically operated valves (these can be checked from the control room ahead of tests), all valves that are closed for normal operation and closed for the performance tests and all valves that are open for normal plant operation and closed for the performance test. These valves are normally closed before the start of the test.

- u) Finalize auxiliary load line-up list, confirming support from plant operations.
- v) Conduct a condenser vacuum drop test (if applicable) by means of shutdown of vacuum system of the condenser, e.g. for 10 min. The vacuum slope in mbar/min should be in the expected range of condenser supplier, e.g. 1 mbar/min. A visual inspection of tube condition bypass gap baffle can be conducted under field preparations. These checks can be conducted under commissioning tests to avoid unnecessary delays during a test programme.
- w) Perform inspection of evaporative coolers or chillers, i.e. under field preparations.
- x) Conduct preliminary test runs.
- y) Record and agree in writing any deviations to the preparations specified in the test procedure.
- z) Prepare a list of representatives and contact details of those involved in testing.

6.7 Instruments and measuring methods

6.7.1 General

This subclause describes the instruments, methods and precautions to be employed when testing combined cycle power plants in accordance with this document. Where there is no specification concerning the instruments and the measurement method used, these shall be subject to agreement by the parties to the test.

The use of advanced electronic instruments and devices together with a computer controlled data recording and processing system is preferred in respect of achieving test data and results with the highest level of accuracy. However, manual recording of analogue instruments is allowed in cases where non-electronic instrumentation is used.

The instruments and measuring methods mentioned and described hereafter are state of the art and commonly employed at the time this document is published; however, new technology and methods of measurement may be adopted for performance testing as they are available provided they comply with the requirements for the maximum uncertainties specified herein.

Instruments, devices and measurements shall be employed in accordance with relevant International Standards, unless otherwise agreed.

6.7.2 Electrical power measurement

6.7.2.1 General

The metering method of the electrical power, preferably the three-watt meter method, depends on the various types of the power generating and distributing arrangements, which typically are three-phase systems with Delta generator connection in three-wire configuration or Star generator connection in four-wire configuration.

In order to select the appropriate metering equipment and define the corresponding instrument transformer connection the particular site configuration shall be reviewed during planning and preparation of the test, in accordance with IEC or other recognized standards.

6.7.2.2 Power metering equipment

For the measurement of the active power output, single-phase or poly-phase precision Watt or Watt-hour meters of accuracy class of 0,2 % or better shall be used, in accordance with [Table 4](#). If the power meter is not equipped with an integrated feature to measure the power factor, the reactive power shall be recorded with a Var or Var-hour meter of an accuracy class of 0,5 % or better.

In cases where excitation and/or auxiliary power, branched off the main generator bus duct, is metered to determine the net electrical output based on gross power measurement, the accuracy of the

corresponding Watt or Watt-hour-meter shall have an accuracy class of 3 % or better in accordance with [Table 4](#).

If a Watt meter is being used to measure the active power output, the instantaneous active power shall be measured frequently during a test run and averaged over the test run period to determine average power (kilowatts) during the test. In this case the measurement frequency shall not be less than once every 30 s. Conversely, auxiliary power or power factor measurements done via Watt meter and Var meter, respectively, can be done every 60 s.

Power output metering equipment used for testing shall be calibrated against reference standards traceable to recognized International Standards. The calibrations shall be made in such a manner that the expected tests load, voltage, power factor and frequency conditions are covered.

Preferably portable test instruments, properly calibrated in a laboratory, shall be used. However, switchboard instruments may be used by mutual consent of the parties and provided that the requirements given in this document are fulfilled.

6.7.2.3 Instrument transformers

For power output metering, correctly rated and calibrated voltage and current transformers of 0,2 % accuracy class or better shall be used, in accordance with [Table 4](#). The respective instrument transformers shall be designed solely for metering purpose with no unknown burden other than that of test instrument and leads, i.e. protective relay or voltage regulator devices shall not be connected to the transformers. In certain cases, an exception to the minimum accuracy class requirement can be made depending on country regulations and the standard used to devise the instrument transformer.

The calibrations shall cover the expected field test conditions such as voltage, current, turn ratio, phase angle and expected burden.

The connecting leads between meter and instrument transformer shall be arranged so that effects such as inductance, voltage drop or any other cause are minimized. Twisted and shielded pairs for current leads which are reducing the impact of inductance and voltage drop may be minimized by choosing appropriate wire gauge and resistance considering wire length and load of voltage transformer.

6.7.2.4 Speed measurement

Since the influence of shaft speed to the combined cycle performance mainly depends on the gas turbine behaviour refer to ISO 2314:2009, 6.4.6 for the requirements regarding speed measurements.

6.7.3 Flow measurements

6.7.3.1 General

Since each energy stream shall be determined with reference to the point at which it crosses the test boundary, the choice of the test boundary can have a significant impact on the test results. An example might be the inclusion or exclusion of a fuel pre-heater.

Each measurement variable of a flow device, such as static/differential pressure, temperature, pulses and fluid properties, shall be recorded individually to allow intrinsic calculation of the mass flow rate. Therefore, flow computer or other control system calculated flow values are not to be used as they are usually not in conformance with the requirements of this document.

6.7.3.2 Gaseous fuel flow measurement

The fuel flow per unit of time (flow rate) of gaseous fuels shall be determined by one of the following.

- a) Turbine type flow meter, in accordance with ISO 9951.
- b) Differential pressure device, in accordance with ISO 5167 (all parts).

- c) Coriolis meter, in accordance with ISO 10790.
- d) Ultrasonic flow meter, in accordance with ISO 17089-1.

The fuel flow meter specified shall meet the applicable requirements of a recognized international or national standard.

Accurate gas analysis during the calibration is mandatory for fuel flow meters which measurements depend directly from the gas properties (e.g. coriolis meter).

Other flow meters covered by a recognized international or national standard, and meeting the uncertainty requirements of this document, can also be used.

Meters shall be selected to meet uncertainty requirements of this document, in accordance with [Table 4](#).

The computation of the actual fuel mass flows at test conditions is based on the formulae outlined in respective standards, in conjunction with ISO 6976 for the determination of the gas density and ISO 12213-2 for gas compressibility.

6.7.3.3 Liquid fuel flow measurement

It is recommended to measure the liquid fuel flow by means of following meters.

- a) Nozzle, orifice or venturi flow section, in accordance with ISO 5167 (all parts).
- b) Ultrasonic flow meter, in accordance with ISO 12242.
- c) Coriolis flow meter, in accordance with ISO 10790.

Other flow devices such as positive displacement flow meters are also permitted, as long as they meet the requirements of [Table 4](#) and are calibrated and installed per recognized standards.

6.7.3.4 Water/steam flow measurement

Depending on the plant configuration and equipment scope, several steam or water flows can cross the boundary at different points, such as condenser cooling water flow, process steam/water, GT steam/water injection and GT inlet heating and cooling flows.

For better accuracy, feed water measurements are preferred for determining downstream steam flows, instead of direct measurement of steam flow.

In the case of spray water injection used to control the final steam temperature, a heat balance around the attemperator can be done, using measurements of steam and water temperatures, pressures and feed water flow.

Water and steam flows can be measured with nozzle, orifice or venturi flow section in accordance with ISO 5167 (all parts), an ultrasonic flow meter in accordance with ISO 12242, or a Coriolis flow meter in accordance with ISO 10790. Other flow devices are also permitted, as long as they meet the requirements of [Table 4](#) and are calibrated and installed per recognized standards.

6.7.4 Temperature measurements

6.7.4.1 General

This subclause presents requirements and guidance regarding the measurement of temperature. It also discusses applicable temperature measurement devices, calibration of temperature measurement devices, and application of temperature devices.

6.7.4.2 Acceptable temperature measurement devices

- Thermocouples in accordance with IEC 60584 (all parts) may be used to measure temperature of any fluid above 150 °C. The maximum temperature is dependent on the type of thermocouple and sheath material used. The thermocouple is a differential-type device. The thermocouple measures the difference between the measurement location in question and a reference temperature (cold junction). The greater this difference, the higher the signal from the thermocouple. Therefore, below 150 °C the signal becomes low and subject to induced noise causing inaccuracy. It is recommended to measure the temperature of any fluid above 150 °C.
- Resistance temperature devices (RTD) in accordance with IEC 60751 may be used to measure temperature from any low temperature to the highest temperature recommended by the RTD manufacturer. It is recommended to measure the temperature of any fluid below 250 °C.
- Other temperature measuring devices such as thermistors and liquid in-glass thermometers may also be used provided they are properly calibrated with uncertainty in compliance with the limits given in this document.

6.7.4.3 Required accuracy

Unless otherwise indicated for specific requirements, all instruments used to measure primary variables shall have an allowable uncertainty in accordance with [Table 4](#) that considers different classes of accuracy for each variable measured depending on its sensitivity on the results. It shall be noted that instrument's accuracy shall be combined with the number of installed instruments and the number of readings to obtain the overall measurement uncertainty.

6.7.4.4 Ambient air temperature at gas turbine inlet

6.7.4.4.1 Air inlet duct

Instruments required for the measurement of the air temperature shall be installed at the location where the air stream is crossing the specified test boundary, typically at the filter house of the air inlet duct. Special care is required for the protection and shielding of the temperature probes from solar and other radiation sources and when the air flow across the sensing element is higher than 10 m/s.

In case of multiple gas turbine units, installed in one or more rows or staggered, with or without evaporative cooling systems (within the inlet air system) every effort shall be taken to find the most representative and accurate location(s) for the determination of the weighted average of the air temperature, where the test boundary is entered.

The number of instruments shall depend on the shape and the size of the air filter system inlet area. The temperature shall be measured with an amount of instruments uniformly distributed over the cross sectional area of the inlet.

The recommended number of temperature sensors for measurement of air temperature at the inlet to each gas turbine can be determined using [Formula \(1\)](#). A minimum of two temperature sensors shall be installed at the inlet to each gas turbine.

$$n = INT(0,3 \times A^{0,64}) \quad (1)$$

where

A is the total area of air inlet, in m²;

n is the recommended number of temperature sensors;

INT is the integer function that returns the nearest integer number in accordance with ISO/IEC/IEEE 60559.

In cases where temperature variation limits specified in [Table 4](#) are exceeded, the root cause, such as plant equipment producing hot streams directed towards the air inlet duct, shall be investigated and where possible eliminated. In cases where a non-homogeneous temperature profile exists over the inlet section, the number of probes shall be increased accordingly.

6.7.4.4.2 Compressor inlet

The air temperature at the compressor inlet may be used in case of application with fogging, anti-icing, chillers or other GT inlet air conditioning equipment. At least four sensors should be installed; however, if this is not applicable to the gas turbine design (e.g. for small gas turbines) then as many sensors shall be installed as the design allows in order to calculate the mean value.

If the temperature is measured at a location where the air velocity is higher than 20 m/s, the measured temperature shall be corrected with the computed dynamic portion of the total temperature using the calculated air velocity shown in [Formula \(2\)](#):

$$T_0 = T + \frac{v^2}{2c_p} \quad (2)$$

where

T_0 is the corrected air temperature in K;

T is the measured air temperature in K;

v is the air velocity in m/s;

c_p is the specific heat at constant pressure in J/(kg K).

In cases where there are applications such as evaporative cooling, fogging, anti-icing, chillers or other inlet air conditioning equipment in operation upstream of inlet air temperature measurements at test boundary, care should be taken for the selection of the measurement location(s) in order to prevent sub-cooling of the temperature element(s) by water droplet impingement.

6.7.4.5 Ambient air temperature at air cooled condenser inlet

A sufficient number of temperature sensors to measure the cooling air temperature shall be installed within the air inlet zone between the fan platform supports in order to have a temperature traverse arrangement. It is recommended at least one temperature measuring point per two fans; the height of the measuring point should be at the half of the height of the air entering section the condenser (meaning midway between the fan inlet and the air entering point of the condenser). Care should be taken to avoid the measurement being affected by thermal radiation or other heat sources. Suitable access for installation of temperature sensors should be considered in the design as this will reduce manpower and downtime required during the preparations for testing.

The temperature-sensitive element shall be calibrated in accordance with the requirements stated in [6.10](#). The calibration shall be at least beyond (± 5 K) of the expected temperature extremes during the test.

6.7.4.6 Ambient air temperature at cooling tower inlet

The measurement of inlet air wet-bulb temperature is possible instead of dry bulb and relative humidity as long as the instrumentation fulfils the required uncertainty for relative humidity (see [6.7.5](#) and [6.11](#)). The recommended instrumentation for measurement of wet-bulb temperatures is a mechanically aspirated instrument or psychrometer that meets the following requirements.

- The temperature-sensitive element shall be calibrated in accordance with the requirements reported in [6.11](#). The calibration shall be at least beyond (± 5 K) of the expected temperature extremes during the test.

- Temperature-sensitive elements shall be shielded from the sun or from any other source of radiant heat. The innermost shield shall be essentially at the dry-bulb temperature.
- The temperature-sensitive element shall be covered with a wick that is continuously fed from a reservoir of distilled or demineralized water (the temperature of the water used to wet the wick shall be at approximately the wet-bulb temperature being measured).
- The air velocity over the temperature-sensitive element shall be below 5 m/s.

The dry-bulb temperature shall be measured under the same conditions as the wet-bulb temperature without the wick and water supply.

For the measurement of inlet wet-bulb temperature, the instruments shall be located about 1,5 m outside the air intake(s); if recirculation affects the measurement, this distance should be increased.

The recommended total number of wet-bulb instrument stations for the overall performance test in combined cycle plants can be estimated as shown in [Formula \(3\)](#). A minimum of two wet-bulb temperatures shall be used.

$$n = INT(0,325 \times A^{0,33}) \quad (3)$$

where

A is the area of total air inlets in m²;

n is the minimum number of wet-bulb instruments;

INT is the integer function that returns the nearest integer number in accordance with ISO/IEC/IEEE 60559.

6.7.4.7 Cooling water temperature at condenser inlet

Depending on the definition of the test boundary for the combined cycle power plant, cooling water temperature at condenser inlet can either be a primary variable or a secondary variable. In the first case, recommendations of this document should be considered; otherwise, and in particular if no adequate dedicated tapping points are available, station instruments may be used, even if it is important to have a proper understanding of the condensing system when determining the readiness of the equipment for testing.

The cooling water at the condenser inlet is generally well mixed, so one temperature measuring device per each cooling water inlet conduit is sufficient. The temperature measuring devices should be installed with different angulation respect to the pipe and with sufficient depth (at least 150 mm depth for pipe diameters > 300 mm). A discrepancy in excess of 0,5 K between simultaneous readings should be investigated.

6.7.4.8 Fuel temperature

Fuel temperature has a strong effect on test results related to efficiency/heat rate; it may necessary for this to be measured at two different locations:

- close to the flow meter for the calculation of the fuel density (in conjunction with the fuel pressure for gas fuel) and, if applicable, for liquid fuel return;
- at the test boundary for the determination of the sensible heat (if applicable as correction to reference conditions).

In the first case, requirements of the flow meter for the position of the tapping point shall be considered.

6.7.4.9 Process water temperature and district heating

In combined cycle power plants with cogeneration, the return and forward temperature of the district heating, water is very sensitive to the results (since the water mass flow normally is very large). Therefore, special care should be used in this measurement and low uncertainty devices should be installed.

Measurement of the district heating return water temperature (e.g. at the inlet of the heat exchanger) should be made upstream the heat exchanger. However, this kind of measure usually does not present problem of stratification, and therefore at least two temperature locations should be used.

Measurement of the district heating forward water temperature (e.g. at the outlet of the heat exchanger) should be made downstream from the heat exchanger, where the flow is well mixed and the temperature is uniform. Measurement should be made after a bend to ensure better mixing; adding mixing plates can also be considered. This location is acceptable if the district heating water does not mix with any other flow.

If a well-mixed location can be found, four temperature locations are acceptable. Otherwise, the outlet temperature shall be determined from an array of temperature locations at the outlet of the heat exchanger but in no case less than four for each exhaust annulus. A discrepancy in excess of 0,3 K between simultaneous readings should be investigated.

6.7.4.10 Process steam temperature

In standard applications of combined cycle power plants with cogeneration, process steam temperature is very sensitive to the results.

Location of temperature measurements for enthalpy and density determination shall be selected as close as practicable to the points at which the corresponding pressures are to be measured and in any case at or close to the defined test boundary.

Thermowells should be located at least 5 pipe diameters downstream from throttling devices. The minimum number of thermowells should be in accordance with [Table 4](#) and installed preferably at least 45° apart measured circumferentially. Temperature differences caused by stratification shall be minimized by locating the temperature sensor sufficiently downstream of source like spray water injections.

6.7.4.11 Other temperature measurements of secondary variables

To measure any temperature related to secondary variables (e.g. between consortium partners), such as gas turbine exhaust temperature, steam/water flow temperature from/to the HRSG/steam turbine, the respective standard for the equipment shall be used for location and installation details.

6.7.5 Relative humidity measurements

The moisture content of the air entering the test boundary shall be measured, and an instrument with the capability to determine relative humidity within an uncertainty of 2 % points or better shall be used.

In case of multiple gas turbine units, installed in one or more rows or staggered, with or without evaporative cooling systems or chiller/fogger systems (within the inlet air system) every effort shall be taken to find the most representative and accurate location(s) for the determination of the ambient air temperature and relative humidity, where the test boundary is entered.

The relative humidity may be determined with direct measurement using a hygrometer or with measurement of wet and dry bulb temperature, barometric pressure and calculating the relative humidity by means of psychrometric charts, tables or algorithms.

6.7.6 Pressure measurements

6.7.6.1 General

This subclause presents requirements and guidance regarding the measurement of pressure.

Preferably, calibrated electronic pressure transducers based on sensing technology such as piezo, capacitive, etc. with temperature compensation shall be used to ensure highest level of measurement accuracy.

The methodology, number and type of instruments used for the measurement of a pressure shall be carefully evaluated considering magnitude and range of parameter, accuracy requirement as well as specific flow dynamics and design of equipment.

Attention shall be paid to location and installation of pressure instruments in a manner that no additional errors induced by environmental conditions such as radiation, vibration, etc. or leakage of pipe and fitting increase the uncertainty of the reading.

A review should be performed of the water leg correction necessary for accurate process variable measurement. If this has already been applied in the pressure transducer the water leg correction shall be taken account in the reported measurement.

6.7.6.2 Required accuracy

Primary variables should be measured with instruments with an allowable uncertainty in accordance with [Table 4](#) that considers different classes of accuracy for each variable measured depending on its sensitivity on the results. It shall be noted that instrument accuracy shall be combined with the number of installed instruments and the number of readings to obtain the overall measuring uncertainty. These pressure transmitters should be used within the temperature compensated ranges.

Secondary variables can be measured with any type of pressure transmitter. On a case-by-case basis the secondary variables may be field checked to achieve accuracy requirements.

6.7.6.3 Barometric pressure

The absolute atmospheric pressure as primary variable shall be measured with a calibrated absolute pressure transmitter. The instrument shall be located outside of any closed containment in a stable and protected environment at an elevation equal to the centreline of the gas turbine shaft.

Other barometric pressure measurements used for calculation of absolute pressure values in combination with gauge pressure transmitters should be installed at the same elevation to avoid additional level altitude correction.

Barometric pressures from local weather stations shall not be used.

6.7.6.4 Fuel gas pressure

Fuel pressure has a significant impact on test results related to efficiency/heat rate; it may need to be measured at two different locations:

- close to the flow meter, for the calculation of the fuel density (in conjunction with the fuel temperature for gas fuel);
- at the test boundary for the determination of the sensible heat (if applicable as correction to reference conditions).

In the first case the location of the pressure transmitter shall be upstream, and as close as possible, to the flow meter (or at the designated connection requirements of the flow meter).

6.7.6.5 Process steam pressure

The steam pressure shall be measured at the test process boundary with at least one pressure transmitter with the maximum allowable uncertainty as specified in this document (see [Table 4](#)).

6.7.6.6 Other pressure measurements of secondary variables

To measure any pressure related to secondary variables, such as gas turbine compressor inlet and outlet pressure, steam/water flow pressure from/to the HRSG/steam turbine, the respective standard for the equipment shall be used for location and installation details.

6.7.6.7 Steam turbine exhaust static pressure

Depending on the definition of the test boundary for the combined cycle power plant, steam turbine exhaust static pressure can either be a primary variable or a secondary variable. Regardless of whether it is a primary or a secondary variable, it is important to have a proper understanding of the vacuum system when determining the readiness of the equipment for testing. As such, a dedicated subclause has been provided in this document to outline the requirements for making this critical measurement.

Steam condensing turbine exhaust pressure measurements are pressure measurements below atmospheric pressure. These measurements should be taken with absolute pressure transmitters with a maximum calibration range that can make a zero point measurement. If gauge pressure transmitters are used the requirements of [6.7.6.3](#) shall be considered.

Atmospheric pressure measurements shall be measured with absolute pressure transmitters (see [6.7.6.3](#)).

All vacuum measurement sensing lines shall slope upward from the source to the instrument. All sensing lines in steam or water service shall be purged with a minute amount of air or nitrogen to deter water legs from forming. If measurement values show a plausible and stable pressure level during the signal checks (free from water) this step can be performed one time shortly before the test campaign starts otherwise it is recommended to repeat this step shortly before each test.

A purge system should be used that isolates the purge gas during measurement of the process. A continuous purge system may be used; however, it shall be regulated to have no influence on the reading. Prior to the test period, readings from all purged instrumentation should be taken successively with the purge on and with the purge off to prove that the purge air has no influence.

Once transmitters are connected to process, a leak check shall be conducted. The leak check is performed by first isolating the purge system and then isolating the source. If the sensing line has no leaks, the instrument reading will not change.

Atmospheric pressure transmitters should be installed in the same general area and elevation of the gauge pressure transmitters and should be protected from air currents that could influence the measurements.

The exhaust static pressure of a condensing turbine shall be measured at the exhaust joint or exhaust duct of the steam turbine. In cases where the condenser pressure is regarded as a primary variable a minimum number of two stations per one exhaust annulus shall be used. A discrepancy in excess of 3 mbar between simultaneous readings should be investigated.

A possible way to investigate vacuum measurements problems is to match readings with the saturation pressure relative to the condensate temperature (in hotwell) that is generally available.

Pressure connections should be carried to the interior of the conduit and be provided with basket tips or guide plates. Basket tips are preferred. If the exhaust is provided with ribs or braces traversing the stream space, some of the instrument piping connections may pass through them with the opening flush and normal to the surface of the rib. The terminals of the exhaust pressure instrument connections shall be distributed over the entire exhaust-conduit area and located so that they will be centred, as closely as practicable, in equal areas. The basket tips should be installed at a 45° angle. Alternatively, guide

plates may be used and should be arranged so that the steam flow is perpendicular to the pressure tap. Careful attention shall be given to the location of basket tips and guide plates because pressures at certain points at the exhaust joint may be influenced by local high steam velocities.

6.7.6.8 Differential pressure measurements

Differential pressure transmitters are installed preferably using a five-way manifold as it eliminates the possibility of leakage past the equalizing valve, a frequent source of error.

Once the instrument is installed in the field, the differential pressure shall be equalized and a zero value read. This zero bias shall be subtracted from the test-measured differential pressure. During test preparations or during the test, the vent shall be checked to ensure the equalizing valves are not leaking, and shall be noted in the test report.

6.7.7 Data acquisition system

The use of an electronic data recording system in favour of manual recording is strongly recommended for two reasons: the avoidance of personal bias in reading analogue instruments; and the higher sampling rate which allows a reduction of the uncertainty component caused by random effects.

When considering the accuracy of a measurement, the accuracy of the entire measurement loop shall be considered. This includes the instrument and the signal conditioning loop or process. Ideally, when an instrument is calibrated it shall be connected to the position on the data collection system employed during the test. When this is impractical, the minimum requirement shall be to have each piece of equipment in the measurement loop individually calibrated. Spot checks of the measurement loop shall be allowed to the parties of the test, in order to verify that the combined accuracy is within expected value.

The recording system shall have the ability to store the data of the primary electronic (typically analogue) signal generated by the instrument as well as the data of the corresponding signal transformed into engineering units to allow post test data verification or correction.

Data acquisition systems converting primary analogue signals into digital signals using A-D converters shall have a resolution of 14 bit (equal to 0,006 % of range) or better. Also, any dead band restraints variables shall be minimized such that all data signals received during the test are captured. This can be a particular concern when using plant measurement and control systems.

All instruments and cables of an electronic data recording system should have a grounded shield to drain any inducted currents from nearby electrical equipment. All signal cables should be installed away from electromagnetic force (EMF)-producing devices such as motors, generators, electrical conduit, and electrical service panels.

6.7.8 Wind velocity

Wind velocity shall be measured with a cup anemometer and the maximum allowable uncertainty shall be in accordance with [Table 4](#).

For air cooled condenser (ACC) applications, wind velocity should be measured at an elevation equal to 1 m above the upper edge of the condenser. Care should be taken that the measurement is not spoiled by other factors such as the air mass flow, buildings, etc.

For cooling towers applications, wind velocity should be measured in an open and undisturbed location windward of the equipment, at a height equal to the mean height of the air inlet. The distance of this location from the equipment should be within the range of 30 m to 90 m and the position should be agreed by the parties.

6.7.9 Storage vessel levels

In standard applications of combined cycle power plants storage vessel (drum) levels should be considered a secondary variable. However, it is very important to check the stability of the water/steam

cycle conditions and to evaluate the cycle losses that shall be checked under an acceptable threshold value before the test (refer to 7.2 and 7.3). Considering the complexity in installing a temporary storage vessel level measuring device, station instruments can be used.

6.7.10 Data sampling

It is strongly recommended to record automatically all readings (raw and physical values) from temporary instruments by means of a dedicated data acquisition system.

The recording system shall have the ability to store the data of the primary electronic (typically analogue) signal generated by the instrument as well as the data of the corresponding signal transformed into engineering units to allow post test data verification or correction.

This dedicated electronic data acquisition system can be used to collect the signals from pressure transmitters, temperature measuring devices, power analyser, ambient relative humidity, wind speed, frequency signals of fuel gas turbine meters, etc. The system should automatically convert the electrical signals from the field to engineering units taking into account the calibration curves, water legs, zero shift and cold junction compensation if necessary. The system shall be always transparent and feasible for checks to all relevant parties involved in order to reproduce the physical measured values from the raw values any time.

Where manual readings are unavoidable, log sheets will be prepared and arranged such that the number of personnel required during the performance test is minimized.

For any variables considered the frequency of reading shall be at least 60 s except for the following cases.

- The gaseous fuel, which shall be sampled every 30 min using gas sample containers. If an online gas chromatograph is available the frequency of data collection can be increased to 15 min (other requirements related to fuel sampling are reported in 6.8.2). If there are significant changes in gas composition, then taking additional samples as necessary should be considered.
- Any primary variable collected manually, which can be sampled every 5 min if the stability has been checked prior to the test or every minute if the trend shows variations close to the acceptable limits.
- Any secondary variables collected manually, which can be sampled every 5 min.

6.8 Determination of fuel properties

6.8.1 General

The calculation of fuel properties for gaseous fuels and liquid fuels: lower heating value, higher heating value, density, compressibility factor, etc. shall be in accordance with Table 2.

Table 2 — Fuel properties requirements

Properties	Comment	Applicable standard
Fuel gas composition	Up to C6+ or C16 (for higher hydrocarbons)	ISO 6974-1 ISO 6975 for extended analysis
Fuel gas density	Based on measurement of gas temperature, gas pressure and actual molar fuel gas composition	ISO 6976
Fuel gas compression factor	Based on measurement of gas temperature, gas pressure and actual molar fuel gas composition	ISO 12213-2
Fuel gas lower/higher heating value (LHV/HHV)	Reference temperature of 15 °C	ISO 6976

Table 2 (continued)

Properties	Comment	Applicable standard
Density of crude or liquid petroleum fuel	The actual density at test conditions shall be determined by interpolating between the analysis results using the measured fuel temperature	ISO 3675 ISO 12185 (digital)
Heating value of crude or liquid petroleum fuel		ASTM D4868 or DIN 51900-1
Fuel sensible heat = $h_f - h_0$	h_0 as function of reference temperature and pressure 15 °C, 1,013 25 bar	c_p (specific heat) calculation for natural gas in accordance with ISO 20765-1; for liquid fuel in accordance with ISO 2314:2009, Table 4

6.8.2 Tests on fuel gas

Fuel gas samples shall be taken in accordance with ISO 10715.

For thermal performance tests: as a minimum, one sample shall be taken at the beginning, one in the middle and one at the end of each performance test run with natural gas in combined cycle operation. The sampling frequency requirement stated in 6.7.10 shall also be taken into account. The sampling point should be preferably upstream of the measuring device and after the filter/knockout vessel.

One set of three samples composed of one sample taken at the start, one sample taken in the middle and one sample taken at the end of each test will be analysed by an internationally certified independent laboratory for gaseous fuels. This analysis will be used for calculation of the performance test results.

A complete set of back-up samples should be obtained. Parties involved in the test may agree to take additional samples, as per contract requirements or otherwise. In this case several containers can be installed in line to distribute the agreed number of samples to the parties involved (e.g. one set of samples for client, one set of samples for supplier and one set of samples for arbitrary purposes).

The fuel gas samples shall be analysed in accordance with ISO 6974-1 or ASTM D1945 by laboratories fulfilling the requirements of ISO/IEC 17025.

- Repeatability less than 0,1 % for mol fractions higher than 50 % (e.g. CH₄).
- Reaction time shall be known and minimized.
- Air conditioned installation.
- Calibrated with certified calibration gases; calibration gases shall cover the expected fuel gas composition. Analysis shall cover the fuel components up to C6+ (C6 and higher as combined) and the inorganic components N₂, CO₂, H₂S. Some cases require long analysis to get hydrocarbons.

In extension to ISO 10715:1997, Annex E a back pressure regulator should be used after the last gas sample to keep the sample line pressure, e.g. 5 bar below gas pressure in order to prevent heavy-hydrocarbon condensation in the sample container(s).

6.8.3 Tests on liquid fuel

Fuel oil sampling shall be taken as close as possible to the test boundary taking into account the gap due to time shift between sampling point and test run period. The sampling point should be preferably upstream of the measuring device and after filter.

For thermal performance tests: one sample shall be taken at the beginning, one in the middle and one at the end of each test run.

For distillate oil of low viscosity, when oil is supplied from the same tank for the entire duration of the test, the three samples shall be mixed at the end of the test and equally divided in at least one mixed sample for analysis. For all other cases, each sample should be analysed separately.

A complete set of back-up samples should be obtained. Parties involved in the test may agree to take additional samples, per contract requirements or other (e.g. one set of samples for client, one set of samples for supplier and one set of samples for arbitrary purposes).

The fuel oil samples shall be analysed in accordance with DIN 51900-1, ISO 12185, ISO 3675 or ASTM D4868, ASTM D4052, ASTM D4809 by laboratories fulfilling the requirements of ISO/IEC 17025.

The following values shall be determined for performance test evaluation.

- The lower and the higher heating value.
- The density at 15 °C, 30 °C and e.g. 45 °C (kg/m³). The choice of lowest and highest temperature shall cover the tested range.
- The kinematic viscosity at 15 °C, 30 °C and e.g. 45 °C (mm²/s). The choice of lowest and highest temperature shall cover the tested range.
- The sulfur total mass fraction.
- The carbon total mass fraction.
- The hydrogen total mass fraction.
- The oxygen total mass fraction.
- The nitrogen total mass fraction.

6.9 Determination of cooling water flow into the condenser

6.9.1 General

If the condenser inlet cooling water mass flow is required for correction reasons, the cooling water mass flow can be determined by one of three methods as outlined in [6.9.2](#), [6.9.3](#) and [6.9.4](#).

- a) An energy balance method (in case of multi-shaft and single shaft units with clutch).
- b) Using cooling water pump performance curves.
- c) Direct flow measurement.

The method to be employed for determining the cooling water flow should be chosen based on the information available to employ a given method and the uncertainty associated with the method. It is preferable to use a method that entails lowest uncertainty. The energy balance and pump curve methods are described in more detail below.

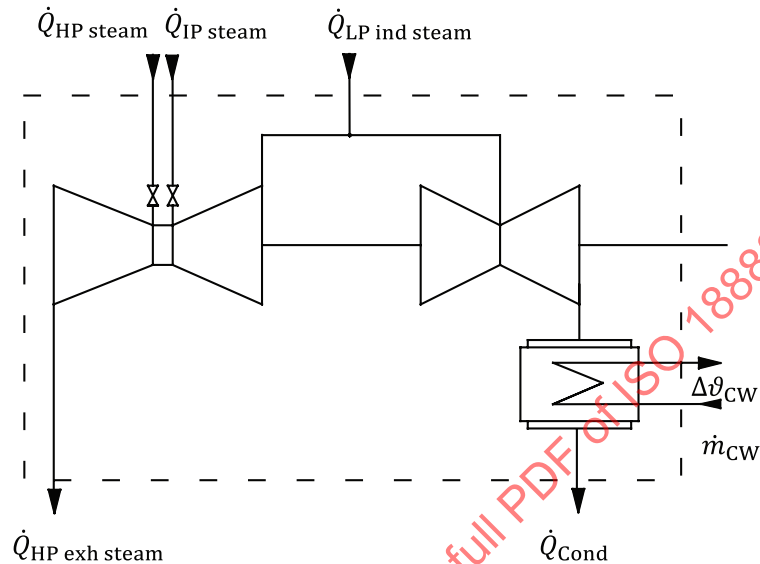
6.9.2 Energy balance method

When employing the energy balance method, the measured heat input into the steam turbine (e.g. for a plant with one, two or three pressure stages HRSGs) requires utilization of more instrumentation within the water/steam cycle and, as such, will be affected by the accuracy of these measurements, in particular water/steam flow measurements and cooling water inlet and outlet temperatures. In general, [Formula \(8\)](#) may be used for determining the cooling water flow. Note that the formula for a given plant configuration will have to be tailored based on the specific configuration for that particular plant. An example of a test boundary for the application of the energy balance method is shown in [Figure 8](#).

The input heat of the steam turbine can be determined for a three pressure stage HRSG as shown in [Formula \(4\)](#):

$$\dot{Q}_{\text{input,ST}} = \dot{Q}_{\text{HP steam}} - \dot{Q}_{\text{HP exh steam}} + \dot{Q}_{\text{IP steam}} + \dot{Q}_{\text{LP ind steam}} - \dot{Q}_{\text{Cond}} \quad (4)$$

where



- $\dot{Q}_{\text{input,ST}}$ is the heat input energy of steam turbine, in kJ/s;
- $\dot{Q}_{\text{HP steam}}$ is the heat energy (mass flow $\times$ spec. enthalpy) upstream high pressure turbine, in kJ/s;
- $\dot{Q}_{\text{HP exh steam}}$ is the heat energy (mass flow $\times$ spec. enthalpy) downstream high pressure turbine, in kJ/s;
- $\dot{Q}_{\text{IP steam}}$ is the heat energy (mass flow $\times$ spec. enthalpy) upstream intermediate pressure turbine, in kJ/s;
- $\dot{Q}_{\text{LP ind steam}}$ is the heat energy (mass flow $\times$ spec. enthalpy) of low pressure induction steam, in kJ/s;
- $\dot{Q}_{\text{Cond}}$ is the heat energy (mass flow $\times$ spec. enthalpy) of main condensate downstream of hotwell, in kJ/s.

Figure 8 — Example of test boundary for cooling water mass flow calculation by means of an energy balance

For a steam turbine in single shaft configuration the shaft power output ($P_{\text{ST shaft}}$) can be calculated from the combined cycle gross power output P_{CC} (measured by means of one test in combined cycle, CC, operation), the gas turbine gross power output P_{GT} (measured by means of an additional test in simple or open cycle operation immediately after the CC test and corrected to combined cycle test conditions), the mechanical losses P_{ML} and the determined generator efficiencies η_{gen} . See [Formula \(5\)](#):

$$P_{\text{ST shaft}} = \left[\frac{P_{\text{CC, gross}}}{\eta_{\text{gen, CC}}} \cdot 100\% - \frac{P_{\text{GT, gross}}}{\eta_{\text{gen, GT}}} \cdot 100\% \right] + P_{\text{ML}} \quad (5)$$

where

- $P_{ST\text{ shaft}}$ is the shaft power output of steam turbine, in kW;
- $P_{CC, gross}$ is the gross power output of combined cycle at generator terminals, in kW (considering exciter losses if necessary);
- $P_{GT, gross}$ is the gross power output of gas turbine at generator terminals, in kW (considering exciter losses if necessary);
- P_{ML} are the mechanical losses, in kW;
- $\eta_{gen, CC}$ is the generator efficiency during the combined cycle performance test, in %;
- $\eta_{gen, GT}$ is the generator efficiency during the gas turbine performance test, in %.

In single shaft plants where it is not possible to obtain a direct measurement of the gas turbine power output by means of conducting an additional simple or open cycle test, alternative approaches can be employed, such as the following.

- Assuming a reference value for steam turbine section efficiency in energy balance calculation.
- Direct measurement of cooling water flow from an installed flow meter.
- Determination of flow by measuring the cooling water pump head and using pump characteristic curves of head against flow to find the cooling water pump flow (pump performance curve at the calculated total head: refer to ISO 9906).

For a steam turbine in multi-shaft configuration the shaft power output ($P_{ST\text{ shaft}}$) can be calculated from the measured gross power output of the steam turbine, the mechanical losses and the determined generator efficiency. See [Formula \(6\)](#):

$$P_{ST\text{ shaft}} = \left[\frac{P_{ST, gross}}{\eta_{gen, ST}} \cdot 100\% \right] + P_{ML} \quad (6)$$

where

- $P_{ST, gross}$ is the gross power output of steam turbine at generator terminals, in kW;
- $\eta_{gen, ST}$ is the generator efficiency of steam turbine during the performance test, in %;
- P_{ML} are the mechanical losses, in kW.

The circulating water inlet and outlet temperature difference can be determined as shown in [Formula \(7\)](#):

$$\Delta\vartheta_{CW} = \vartheta_{CWoutlet} - \vartheta_{CWinlet} \quad (7)$$

where

- $\vartheta_{CWoutlet}$ is the cooling water temperature downstream condenser, in °C;
- $\vartheta_{CWinlet}$ is the cooling water temperature upstream condenser, in °C.

The heat balance for the circulation water mass flow upstream the condenser $\dot{m}_{CW}$, in kg/s, will be as shown in [Formula \(8\)](#):

$$\dot{m}_{CW} = \frac{\dot{Q}_{input, ST} - P_{ST shaft}}{c_p \times \Delta \vartheta_{CW}} \quad (8)$$

where

$\dot{Q}_{input, ST}$ is the heat input energy of steam turbine, in kJ/s;

$P_{ST shaft}$ is the shaft power output of steam turbine, in kW;

c_p is the specific heat capacity as function of the average temperature $\frac{\vartheta_{CW outlet} + \vartheta_{CW inlet}}{2}$, in kJ/(kg K).

In case of cooling by means of seawater the salt content shall be analysed and considered for calculation of c_p .

If the test boundary requires correction to base reference conditions including cooling water inlet temperature and cooling water inlet mass flow to the condenser (e.g. in case that cooling water pumps are outside the test boundary) the correction to base reference conditions can be made by means of a corrected cooling water temperature (instead AC_{P14} and AC_{Q14} of [8.2.4](#)), as shown in [Formula \(9\)](#):

$$\vartheta_{CW inlet, equiv} = \vartheta_{CW outlet, meas} - \frac{\dot{m}_{CW}}{\dot{m}_{CW, ref}} \times (\vartheta_{CW outlet, meas} - \vartheta_{CW inlet, meas}) \quad (9)$$

where

$\vartheta_{CW inlet, equiv}$ is the equivalent cooling water inlet temperature, in °C;

$\vartheta_{CW inlet, meas}$ is the measured inlet cooling water temperature (upstream condenser), in °C;

$\vartheta_{CW outlet, meas}$ is the measured outlet cooling water temperature (downstream condenser), in °C;

$\dot{m}_{CW}$ is the determined cooling water flow into the condenser, in kg/s. See [Formula \(8\)](#);

$\dot{m}_{CW, ref}$ is the cooling water flow at reference conditions, in kg/s.

6.9.3 Cooling water pump performance curves

In general, the pump performance curve package typically includes a “head vs. capacity” curve, which relates the measured head across the pump with the associated flow rate through the pump. In order to use this method of determining cooling water flow, it is essential to use the pump performance curve that has been developed for the specific pump by means of testing (either factory tested or field tested in a controlled environment). In the event that a generic pump curve representing the general performance characteristic of the pump (e.g. generic performance curve for a given model of pump), then the resulting flow will have high uncertainty associated with it, which will need to be accounted for in the uncertainty calculations. Using the performance curves, along with the measured head, the water flow rate through the pump can be estimated.

The head across the pump may be determined as shown in [Formula \(10\)](#):

$$\text{Head} = h_{\text{pump}} = h_{\text{discharge}} + h_{\text{elevation}} + h_{\text{velocity}} \quad (10)$$

where

- $h_{\text{discharge}}$ is the head corresponding to the pressure measured at the discharge of the pump, in m;
- $h_{\text{elevation}}$ is the head corresponding to the elevation of the pump discharge from the water surface level, in m;
- h_{velocity} is the head corresponding to the velocity (kinetic energy) at the discharge of the pump, in m.

Once the head is determined, the flow through the pump can be obtained from the “head vs. capacity” curve. In most cases, the cooling water pumps supply water not only to the condenser, but also to auxiliary cooling equipment. In such cases, the flow to the auxiliary cooling system shall be determined and subtracted from the estimated pump cooling water flow in order to determine the cooling water flow to the condenser, which increases the uncertainty involved with this calculation method. Additional uncertainty associated with the auxiliary systems will need to be accounted for in the uncertainty calculations.

6.9.4 Direct flow measurement

Direct flow measurements of cooling mass flow can be performed using ultrasonic or pitot tube flow measuring devices.

Due to the large pipe diameters of the cooling water pipes these measurements can be afflicted with large measuring uncertainties.

6.10 Measurement uncertainties

The purpose of conducting test uncertainty analysis is to check the quality of the test. The outcome is a range of values, usually expressed as the measured test results plus or minus a certain percentage, within which the true test results should lie.

The application and the use of overall uncertainty figures to the final performance test results are outside the scope of this document, as these are primarily contractual considerations and rationalization should be agreed prior to the tests.

Each value entering into the computation of the test results is liable to some degree of uncertainty, depending on the quality of the measuring instruments and the conditions of the measurement. The test result is therefore subject to a degree of uncertainty depending on the combined effect of all the errors of measurement.

The uncertainty of any measurement can be assessed as follows:

- a) from measuring recommendations and standards;
- b) from the accuracy classes of the measuring instrument or measurement chain;
- c) from the accuracy of calibration of measuring instrument of transducer;
- d) from the influence of unavoidable installation uncertainty; which is introduced due to actual installation outside laboratory conditions. Loop calibration can be used to consider installation uncertainties as systematic uncertainties within the signal path, see [Table 3](#);
- e) from general measurement experience;
- f) from fluctuation general conditions.

Table 3 — Indicative method to minimize systematic installation uncertainty

Method	Recommendations
Calibrated temperatures in thermo-wells	— Assurance that thermocouple or resistance temperature devices (RTD) is inserted properly in the thermowell.
Calibrated pressures and differential pressures	— Zero point measurement before thermal performance tests should be measured and the offset from calibration zero point should be corrected. — Check if pressure line calibration is required depending of transmitter type. — Consider as exactly as possible the correction for water leg (if applicable).
Calibrated barometric pressures	— Consideration of possible transmitter drifts due to location in high ambient temperatures areas. — Position of barometric pressure transmitters at the same level as the GT shaft.

Due to the many variables involved, the assessment of the measuring uncertainty shall be made by calculation on a case-by-case basis.

The total absolute uncertainty, U , of one measurement i will be built as sum of square root of the uncertainty portions of systematic and random uncertainties, as shown in [Formulae \(11\)](#) and [\(12\)](#):

$$U_i = \sqrt{U_{\text{systematic},i}^2 + U_{\text{random},i}^2} = \sqrt{\left(U_{\text{calib},i}^2 + U_{\text{install},i}^2 \right)_{\text{systematic}} + U_{\text{random},i}^2} \quad (11)$$

$$u_i(\bar{x}_i) = \frac{U_i}{\bar{x}_i} \cdot 100 \quad (12)$$

where

$\bar{x}_i$ is the mean absolute value of measurement i ;

$u_i(\bar{x}_i)$ is the relative total uncertainty of mean value $\bar{x}_i$;

$U_{\text{systematic},i}$ is the absolute systematic uncertainty of $\bar{x}_i$ at 95 % CI (confidence level)/Type B uncertainty in accordance with ISO 2314:2009;

$U_{\text{calb},i}$ is the absolute calibration uncertainty of $\bar{x}_i$;

$U_{\text{install},i}$ is the absolute installation uncertainty of $\bar{x}_i$;

$U_{\text{random},i}$ is the absolute random uncertainty of $\bar{x}_i$ / Type A uncertainty as in accordance with ISO 2314:2009.

The random uncertainty is determined as shown in [Formula \(13\)](#).

$$U_{\text{random},i} = k \times \frac{\bar{\sigma}_i}{\sqrt{N}} \quad (13)$$

where

$k = 1,96$ is the 95 % CI (confidence level);

$\bar{\sigma}_i$ is the standard deviation of mean value $\bar{x}_i$;

N is the number of readings.

This document uses the same philosophy as ISO 2314:2009, Annex A, where the total uncertainty is calculated from the root sum square of the systematic and random uncertainties.

The impact of spatial effects to the total uncertainty can be accounted for in the installation uncertainty term.

For a function $y = f(\bar{x}_i)$ the uncorrelated uncertainty is calculated as shown in [Formula \(14\)](#):

$$U_C(y) = \sqrt{\sum_{i=1}^N \left[\frac{\partial f}{\partial \bar{x}_i} \right]^2 U^2(\bar{x}_i)} \quad (14)$$

And correlated input quantities are calculated as shown in [Formula \(15\)](#):

$$U_C(y) = \sqrt{\sum_{i=1}^N \left[\frac{\partial f}{\partial \bar{x}_i} \right]^2 U^2(\bar{x}_i) + 2 \sum_{i=1}^{N-1} \sum_{j=i+1}^N \frac{\partial f}{\partial \bar{x}_i} \frac{\partial f}{\partial \bar{x}_j} r(\bar{x}_i, \bar{x}_j) U(\bar{x}_i) U(\bar{x}_j)} \quad (15)$$

where $r(\bar{x}_i, \bar{x}_j)$ is the correlation coefficient between $\bar{x}_i$ and $\bar{x}_j$, and

with $-1 \leq r(\bar{x}_i, \bar{x}_j) \leq +1$ (or $r(\bar{x}_i, \bar{x}_j) = 0$ for independent relation between $\bar{x}_i$ and $\bar{x}_j$).

The expression $\left| \frac{\partial f}{\partial \bar{x}_i} \right| \approx \left| \frac{f(\bar{x}_{i,o}) - f(\bar{x}_{i,o} + \delta)}{\delta} \right|$ is the sensitivity coefficient.

6.11 Maximum allowable uncertainties

In order achieve test results with highest possible accuracy the maximum permissible uncertainties of measuring instruments in accordance with [Table 4](#) shall be fulfilled.

Table 4 — Maximum allowable uncertainty of instrumentation for primary variables

Primary variables: individual instrument or parameter	Max. uncertainty	Min. number of stations	Notes
Barometric pressure	$\pm 0,05$ %	2	
Ambient temperature at GT	$\pm 0,2$ K	$INT(0,3 \times A^{0,64})$ or 2 per inlet, whichever is higher	A = Area of total inlets m^2
Ambient relative humidity at GT	$\pm 2,0$ % points	1	
Ambient temperature at cooling tower	$\pm 0,2$ K	$INT(0,325 \times A^{0,33})$ or 2, whichever is higher	A = Area of total inlets m^2
Ambient temperature at air cooled condenser	$\pm 0,2$ %	one temperature measuring point per two fans	
Electrical power meter	$\pm 0,2$ %	1	Measurement of gross or net power output
Current transformer	$\pm 0,2$ % ^a	1	Measurement of gross or net power output

^a Accuracy class: in certain cases an exception to the accuracy class requirement can be allowed for specific country regulations.

Table 4 (continued)

Primary variables: individual instrument or parameter	Max. uncertainty	Min. number of stations	Notes
Voltage transformer	$\pm 0,2 \%$ ^a	1	Measurement of gross or net power output
Electrical power meter (aux)	$\pm 3,0 \%$	1	Measurement of auxiliary power consumption
Current transformer (aux)	$\pm 0,5 \%$	1	Measurement of auxiliary power consumption
Voltage transformer (aux)	$\pm 0,5 \%$	1	Measurement of auxiliary power consumption
Grid frequency/shaft speed	$\pm 0,25 \%$	1	
Gas fuel pressure	$\pm 0,25 \%$	1	
Fuel temperature	$\pm 0,2 \text{ K}$	1	
Fuel mass flow	$\pm 0,5 \%$	1	Min. 2 differential pressure transmitters in case of throttling device
Oil fuel heating value	$\pm 1,0 \%$	1	
Gas fuel heating value	$\pm 0,5 \%$	1	
Process steam temperature	$\pm 1,0 \text{ K}$	2	
Process steam pressure	$\pm 0,3 \%$	1	
Process water temperature	$\pm 1,0 \text{ K}$	2	
Steam/water mass flow	$\pm 0,5 \%$	1	Min. 2 differential pressure transmitters in case of throttling device
ST backpressure	$\pm 0,05 \%$	4	
Condenser cooling inlet water temperature	$\pm 0,2 \text{ K}$	1	
Condenser cooling water mass flow	$\pm 4,0 \%$	1	See 6.9.1
Wind velocity	$\pm 1,5 \%$	1	
^a Accuracy class: in certain cases an exception to the accuracy class requirement can be allowed for specific country regulations.			

6.12 Calibration

All special temporarily installed instruments shall be strictly controlled and calibrated at the intervals specified. This calibration shall be carried out in calibration laboratories that are certified e.g. in accordance with ISO/IEC 17025 or equivalent to a relevant International Standard. Traceability shall be in accordance with ISO/IEC 17025. Each measuring and recording instrument shall be provided with a valid calibration certificate. The calibration certificates of the temporary installed, measuring and recording instruments shall be provided to all concerned parties before starting the performance test.

This document does not restrict the duration for which the calibration of an instrument is valid. The validity of the calibration of measuring and recording equipment should be defined by technical judgement based on handling, the required accuracy of the instruments, environmental criteria, stability of instrumentation, practical applications in accordance with project schedules, checks on site by means of zero point measurements for pressure transmitters or reference temperatures. In addition, certified calibration laboratories can be asked for guidance on the definition of the validity of the calibrations. The applicable instrumentation should be subject to special care in order to prevent damages and effects on calibration.

7 Execution of test

7.1 Base reference conditions

7.1.1 General

The base reference conditions are the conditions at which the performance parameters are specified. These conditions are dictated by the applicable test boundary and adjustments are made to the performance parameters for any deviations between the test measured boundary conditions and the base reference conditions. Reasonable effort should be made to conduct the test at these base reference conditions or as close as possible to the base reference conditions in order to minimize the effect of corrections. Table 5 provides a general list of the typical base reference conditions applicable for a variety of combined cycle and co-generation power plants. Note that the test objectives define the test boundary conditions, which, in turn, define the applicable base reference conditions. As such, not all parameters listed in Table 5 will be applicable for a given combined cycle power plant.

Table 5 — Typical base reference conditions

Base reference parameter	Units ^a
Ambient temperature	°C
Ambient pressure	bar
Ambient relative humidity	%
Grid frequency (or speed)	Hz
Power factor (cos ϕ)	—
Fuel composition (C/H ratio)	mol% or mass%
Heating value	kJ/kg
Fuel supply temperature	°C
Thermal export energy (in the form of steam or water)	kJ/s
Thermal export steam pressure (absolute)	bar
Secondary heat input	kJ/s
Process return / make up temperature	°C
Boiler blowdown	kg/s
Condenser pressure (absolute)	bar
Circulating cooling water temperature	°C
Circulating cooling water flow	kg/s
Air heat sink temperature ^b	°C
Wind velocity ^c	m/s
Make-up water	kg/s
Auxiliary load ^d	kW
^a Recommended units of measure in SI. Parties involved in the test may choose to use different set of units.	
^b For combined cycle power plants with air cooled condenser within the test boundary, the air heat sink temperature would be the ambient dry bulb temperature measured at the air cooled condenser. For combined cycle power plants with cooling tower within the test boundary, the air heat sink temperature would be the ambient wet bulb temperature measured at the cooling tower.	
^c For plants with air cooled condensers within the test boundary, all reasonable efforts shall be made to conduct the test with wind velocity below 5 m/s, unless wind conditions at the site are predominately higher than 5 m/s, in which case efforts should be made to undertake the test at typical site conditions. As long as the wind velocity is complies with these requirements, this document does not require the application of a correction for wind velocity.	
^d Out of scope auxiliary loads.	

7.1.2 Specified gaseous fuel

In case of natural gas, a typical list of fuel gas components is shown in [Table 6](#). The mol% of the individual gas components shall be the same as specified in the contract documents. For special gaseous fuels other than natural gas (for example: synthetic gas), the appropriate gas composition shall be specified. The fuel heating value shall be determined based on ISO 6976 at reference conditions of 15 °C and 101,325 kPa.

Table 6 — Fuel gas composition

Fuel gas component	Symbol
Methane	CH ₄
Ethane	C ₂ H ₆
Propane	C ₃ H ₈
iso-Butane	i-C ₄ H ₁₀
n-Butane	n-C ₄ H ₁₀
iso-Pentane	i-C ₅ H ₁₂
n-Pentane	n-C ₅ H ₁₂
neo-Pentane	C ₅ H ₁₂ NEO
Hexane+	C ₆ H ₁₄ +
Nitrogen	N ₂
Argon	Ar
Oxygen	O ₂
Carbon dioxide	CO ₂
Carbon monoxide	CO
Moisture	H ₂ O
Hydrogen	H ₂
Helium	He
Hydrogen sulphide	H ₂ S

The C/H ratio shall be calculated based on the composition given above.

7.1.3 Specified liquid fuel

The base reference conditions should specify the type of liquid fuel and its heating value. Typical fuel oil analysis should include the characteristics shown in [Table 7](#).

Table 7 — Liquid fuel characteristics

Description	Unit
Calorific value of fuel at 15 °C	kJ/kg
Density at 15 °C	kg/m ³
Specific gravity at 15 °C	-
Sulfur, total	mass %
Carbon, total	mass %
Hydrogen	mass %
Oxygen	mass %
Nitrogen	mass %
C/H ratio w/o CO ₂	mass % / mass %

7.2 Preliminary test

Preliminary test runs are recommended. This will be an opportunity for confirming that the power plant and main equipment are in suitable condition for the performance test, as well as verifying complete data logging system, cycle isolation, and auxiliary load line-up and provides a “training” opportunity for all parties involved in the performance tests. The preliminary test(s) should be conducted close to the guaranteed or specified conditions.

The performance test can only be started after having checked the correct arrangement of the thermal cycle, the correct functioning of the measuring instruments and equipment. Additional preliminary tests may be conducted.

In case of single shaft configuration of the combined cycle power plant, the gas turbine and steam turbine power outputs cannot be measured directly. If there is a clutch for disengaging one turbine from the other, individual power output contributions can be determined testing sequentially, in engaged and disengaged mode (e.g. if a clutch is provided, the steam turbine can be disengaged to determine the performance of the gas turbine in open cycle).

In this case the recommendation is to conduct the combined cycle (CC) test first as the steam turbine will take time for heating and achieving stability. After the CC test is completed, the steam turbine can be disengaged and the gas turbine open cycle (OC) test conducted. Both CC and OC tests should be conducted on the same day and with similar ambient conditions and power factor.

The normal method for disengaging the steam turbine would involve reducing the CC load from base load before the clutch is disengaged. The GT load is then increased back to base load. A suitable period of time to allow GT stabilization is necessary before the GT open cycle test can commence.

7.3 Performance test

Having adjusted the system as close as possible to the base reference conditions to minimize the corrections used, the operation load of the plant shall be kept for stabilization of the combined cycle (see [Table 8](#)).

Stable plant conditions should be maintained during the performance test; [Table 8](#) provides guidance on the allowable limits for deviations in test parameters. If stable conditions are not achieved during the performance test, the test duration can be shortened to select a suitable period when the stability criteria were achieved. Available fuel sampling should be considered if a shortened duration is taken. This would need to be agreed by all parties. If a stable period cannot be determined the tests should be rejected and would need to be repeated.

A test run is stopped when the requirements for a complete test run have been satisfied. These requirements are as follows.

- Duration equal or greater than 1 (one) hour per test run.
- Plant operation at base load and part load on the correct cycle for performance test, upon which the guarantees or specified conditions have been calculated.
- A sufficient number of readings have been taken within the test run to yield minimal random uncertainty.
 - Number of readings during test run from data acquisition system for primary variables ≥ 60 .
 - Number of readings during test run from handwritten data ≥ 12 .
- Fuel sampling completed.

The amount of cycle losses within the water/steam cycle (unaccounted-for leakages) should be in accordance with IEC 60953-2, which are in the expected range of 0,5 % of high pressure steam mass flow at full load.

7.4 Duration of test runs

Unless there is a specific contractual stipulation indicating otherwise, one test run of 60 min duration shall be conducted for each guaranteed or specified load point.

7.5 Auxiliary equipment operation

The responsibility for the equipment influencing the auxiliary power consumption is specific to each project. In general, only the auxiliary power consumption of the equipment that is in continuous operation and absolutely necessary for power generation would be taken into account. The measuring procedures shall therefore be adapted to specified conditions or guarantee cases. Intermittent or outside test run operation of auxiliary equipment shall be accounted for.

The preferable method recommended in this document is to measure the auxiliary total load at the unit auxiliary transformers (not necessarily at each auxiliary component) at high voltage side of auxiliary transformers. Provision of voltage transformers (VTs) (accuracy class 0,5 or better) and current transformers (CTs) (accuracy class 0,5 or better) should be available.

For an example auxiliary consumption measuring test points, see [Figure 9](#).

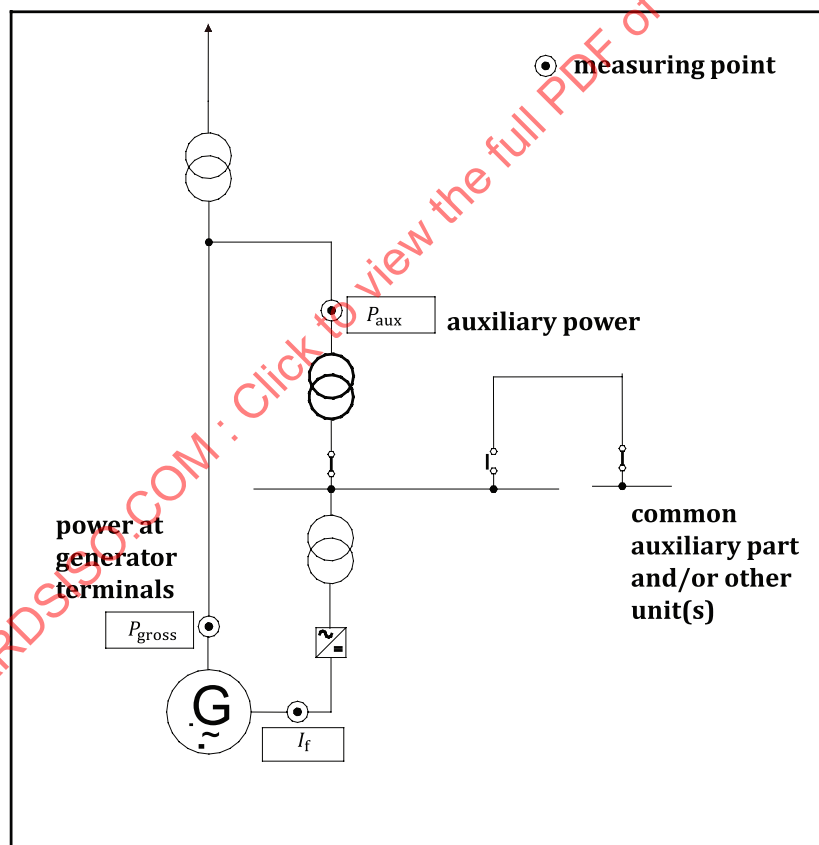


Figure 9 — Example of single line diagram for auxiliary consumption

7.6 Tests with inlet air heating system

If contracts require tests with “inlet air heating system ON” the compressor inlet air temperature is inside the test boundary and shall not be considered for performance correction. However, if the performance of the combined cycle will be affected due to effectiveness deviation from design of the heating system and not by the gas turbine performance itself an additional test with the inlet air heating

system out of service is recommended. This additional test gives the opportunity to allocate a technical reason for a possible performance deviation of the combined cycle from expected or guaranteed values.

In case the performance test boundary requires measurements of compressor inlet temperature downstream of the heating system, the number of temperature measurements shall be optimized in such way that stratification of compressor inlet temperature can be detected with acceptable uncertainty. In any case the uncertainty of the corrected power output and corrected performance of the combined cycle plant increases and requires engineering estimation.

If the thermal performance guarantees are based on performance operation conditions without the heating system in operation the anti-icing system should be deactivated. If there is no possibility to switch the heating system off and the performance test has to be carried out, agreement regarding additional tolerances due to increased uncertainty should be considered.

7.7 Tests with inlet air cooling system

The performance test should be conducted consistent with the base reference conditions. If the base reference conditions include operation of the evaporative coolers, foggers or chillers then the test should be conducted with the respective air cooling system operation, provided the ambient conditions are conducive to operating the cooling system.

If the ambient conditions are such that e.g. the evaporative coolers cannot be operated due to normal operational restrictions as per manufacturer operational guidelines then the test may be conducted with the evaporative coolers out of service and the appropriate correction curves may be used to adjust the test results. Alternatively, the test may be conducted when the ambient conditions are conducive to evaporative cooler operation.

7.8 Maximum permissible variation in operation conditions

Each observation of an operating condition shall not vary from the reported test average by more than the amount specified in the following table. Although the listed parameters are not independent, no single figure of [Table 8](#) shall be exceeded during a test run.

In case that, during the test run, some observations of an operating condition vary beyond the permissible limits prescribed in [Table 8](#), the test run can be rejected. However, if the fluctuation is limited in time and amplitude, it can be agreed between parties to discard those readings showing excessive deviations and to accept the test.

Table 8 — Maximum permissible variations in operating conditions

No.	Parameters	Measured value vs. test run average	Test run average vs. design or rated conditions ^b
1	Power output	±1 %	
2	Power factor at generator(s)	±2 %	
3	Frequency at generator(s)/rotating speed	±1 %	±1 %
4	Temperature of gas ^a or liquid fuel, as supplied to the plant	±3 K	
5	Gaseous fuel pressure	±1 %	
6	Specific energy of fuel ^a	±2 %	acc. to GT specifications
7	Fuel mass flow	±1 %	
^a For gaseous fuels other than natural gas, the allowable variation shall be specified by prior agreement. ^b Difference between the base reference condition and the average tested condition of a parameter. ^c Storage vessel levels (usually as parameters inside the test boundary) do not have requirements for permissible variation. However, it is recommended to observe all storage levels during stabilization and during the test period for identifying and correctly evaluating unaccountable cycle leakages.			

Table 8 (continued)

No.	Parameters	Measured value vs. test run average	Test run average vs. design or rated conditions ^b
8	Barometric pressure	±0,5 %	
9	Ambient dry bulb temperature at GT inlet and heat sink	±2 K	
10	Ambient wet bulb temperature at heat sink	±2 K	
11	Wind velocity	–	< 5 m/s
12	Process steam/water flows	±5 %	±10 %
13	Process steam/water temperatures	±3 K	
14	Condenser cooling water flow	±15 %	±7,5 %
15	Condenser cooling water inlet temperature	±1 K	±10 K
16	Steam exhaust pressure for back pressure turbines (if applicable)	±5 %	
17	Storage vessel levels ^c	stability check by monitoring - uniformly continuous threshold during stabilization and test period	
^a For gaseous fuels other than natural gas, the allowable variation shall be specified by prior agreement.			
^b Difference between the base reference condition and the average tested condition of a parameter.			
^c Storage vessel levels (usually as parameters inside the test boundary) do not have requirements for permissible variation. However, it is recommended to observe all storage levels during stabilization and during the test period for identifying and correctly evaluating unaccountable cycle leakages.			

8 Calculation of results for absolute test

8.1 General

The corrected performance (power output, heat consumption and heat rate or efficiency) is determined using the averaged or integrated values from data measured during each single test run and applying corrections as presented in this document.

8.2 Correction to base reference conditions

8.2.1 General

The performance parameters for a combined cycle power plant are typically defined at a set of base reference conditions, as explained in 7.1. However, the practical limitations of conducting a thermal performance test will cause the boundary conditions measured at the time of the test to be different from the pre-defined base reference conditions. In order to compare the specified performance with the actual test measured performance of the plant, it is essential to adjust the measured performance parameters (i.e. power output, heat rate and/or heat consumption) for the differences between the base reference boundary conditions and the test measured boundary conditions. These adjusted performance parameters are called “corrected” parameters. This adjustment may be achieved by means of a set of correction terms or by means of an equivalent thermodynamic model representative of the plant. The correction curves should depict the adjustment to be applied to the performance parameter.

This document recommends two approaches in order to determine the corrected performance of the combined cycle power plant:

- correction curve based approach, wherein a set of correction curves are used to determine the corrected performance;
- model based approach, wherein a model representative of the plant is used to determine the corrected performance.

8.2.2 Correction curves based correction approach

The following formulae should be used to determine the corrected performance of combined cycle power plants.

To calculate the corrected power output, in kW, use [Formula \(16\)](#):

$$P_{\text{corr}} = (P_{\text{meas}} \times MC_{P1}) + \sum_{i=2}^{17} AC_{Pi} \quad (16)$$

where P_{meas} is the power output determined by means of measurements in accordance with the test boundary, in kW, e.g. see [Formulae \(20\)](#), [\(21\)](#) or [\(23\)](#), [\(24\)](#).

To calculate the corrected heat consumption, in kJ/s, use [Formula \(17\)](#):

$$Q_{\text{corr}} = (Q_{\text{meas}} \times MC_{Q1}) + \sum_{i=2}^{17} AC_{Qi} \quad (17)$$

For corrected heat rate, in kJ/kWh, use [Formula \(18\)](#):

$$HR_{\text{corr}} = \frac{(Q_{\text{corr}})}{(P_{\text{corr}})} \cdot 3\,600 \quad (18)$$

For corrected efficiency, in %, use [Formula \(19\)](#):

$$\eta_{\text{corr}} = \frac{(P_{\text{corr}})}{(Q_{\text{corr}})} \cdot 100\% \quad (19)$$

The correction terms are discussed in further detail in [8.2.4](#) and [8.2.5](#). For definitions of the applied symbols and corresponding technical units, see [Table 1](#). It should, however, be noted that the multiplicative correction is applied prior to the application of the additive corrections.

The correction curves are typically generated using a thermodynamic heat balance model of the combined cycle plant by varying each boundary parameter at a time while holding the remaining boundary parameters at base reference values. Due to the inherent inter-dependencies between all the boundary parameters, certain boundary parameters may have prominent secondary influence from other boundary parameters. In order to capture the secondary effects of inter-dependent boundary parameters, a family of curves shall be generated for such affected boundary parameters. The range of the correction curves should encompass the expected boundary conditions at the time of the test. This document does not recommend extrapolating the correction curves. In the event that the actual test conditions are outside the range then the model shall be re-run. The curves may be presented as either formulae (e.g. polynomials, logarithmic) or in a tabular format. In the event that a tabular format is presented, sufficient level of detail should be introduced in the tables such that the behaviour of the plant is accurately captured, and the parties involved should agree on the interpolation routine used to determine the correction terms from the tables.

The correction curves may be plotted as either additive terms or as multiplicative terms. However, the application of the corrections shall be in accordance with [Table 9](#) and with [Formulae \(16\)](#) and [\(17\)](#). An example for clarification is as follows: the ambient temperature correction curve for power output may be plotted as a multiplicative correction curve; however, when applying the correction to the measured power, the multiplicative correction should be converted into an additive correction prior to applying the correction to the measurement. In this example, the multiplicative correction from the ambient temperature correction curve should not be applied directly to the measured output without converting it to an additive correction term. In such situations, the test procedure should include information on converting a multiplicative correction term to an additive and vice versa.

The model used for generating the correction curves should, as far as is practical, be finalized prior to the thermal performance test programme after procurement of all hardware to be installed and

after final control specifications of the systems are available. A detailed study^[12] of the correction method demonstrated that, as long as the plant behaves exactly as predicted by the corresponding thermodynamic model, the curve based approach results are typically within 0,2 % (95 % confidence interval) of the corresponding results obtained from a model based approach, with a maximum observed error of 0,4 % in the population used in the detailed study. If the actual performance levels of the plant equipment differ from the model predictions, then the maximum observed errors could be higher. If the boundary conditions during the test require very large corrections that also point in the same direction for the majority of parameters, the error introduced with the correction curve methodology can be significantly higher. This method uncertainty should be accounted for in the test uncertainty calculations. The model based approach is considered to be more precise relative to a correction curve based approach (see 8.2.3).

The correction curves based approach has the primary advantage of providing a visual representation of the magnitude and direction of the correction terms, which enables the parties involved in the test to easily understand the plant behaviour across the range of boundary conditions.

8.2.3 Thermodynamic heat balance model based correction approach

The primary limitation associated with a correction curve based approach is its limited ability to capture the inherent inter-dependencies between the relevant boundary parameters. It is possible to isolate the secondary effects when generating the correction curves; however, any higher order inter-dependencies between the correction terms cannot be captured by correction curves in a simplistic manner. The use of a representative thermodynamic heat balance model to adjust the performance parameters from the test measured boundary conditions to the base reference boundary conditions alleviates errors associated with the higher order inter-dependencies between the boundary parameters, which are not captured by the correction curves. When using a model based approach, all the corrections to base reference conditions collapse into a single correction term. The boundary parameters that are altered in order to obtain the correction to base reference conditions, however, remain the same as the boundary parameters applicable for the correction curve based approach. As such, the formulations provided in 8.2.2 are still applicable.

Using a model based approach provides two added advantages over using a curve based approach. First, it eliminates the necessity of creating correction curves, which is a labour intensive process of running the thermodynamic model multiple times in order to identify inter-dependencies of related boundary variables and then creating families of correction curves. Second, since the method automatically captures all of the inherent inter-dependencies between boundary parameters, the method inherently eliminates the possibility of potentially missing any inter-dependencies when generating the correction curves.

The representative model used for correcting the performance from test conditions to reference conditions should, as far as is practical, be finalized prior to the thermal performance test programme after procurement of all hardware to be installed and final control specifications of the systems are available. In as far as is practical, a provision should be made to input the final control settings of key controlling parameters into the thermodynamic heat balance model of the plant in order to ensure that the actual behaviour of the plant is captured when generating the single correction. A detailed study^[12] of the correction method demonstrated that, as long as the plant behaves exactly as predicted by the corresponding thermodynamic model, the model based approach results are closer to 0,1 % (95 % confidence interval) or better. If the actual performance levels of the plant equipment differ from the model predictions, then the maximum observed errors could be higher. This method uncertainty should be accounted for in the test uncertainty calculations.

The correction by means of the thermodynamic model is also recommended for combined cycle plants with process steam and/or district heat (cogeneration combined cycle plants).

The model shall be representative of the plant being tested and should be in a programme format that can be easily executed by all involved parties on their operating systems. Applicable documentation, required to execute the model and confirm its validity shall be provided to the involved parties. Furthermore, limitations of the licence for using the model, if any, in terms of time or scope, shall not have any impact for both parties to evaluate the performance test. The model has to be frozen and documented with test cases for verification.

The following procedure may be applied between the parties involved in cases of agreement for correction by means of the model based approach.

- a) Preparation for documentation: development of sufficient heat balance diagrams in advance of the performance test including variations of primary values which can be expected during the performance test.
- b) Execution: immediately after the test run the correction should be performed using the same model followed by a recalculation of the documented heat balance diagrams (fixed during the preparation) under the witness of the relevant parties involved (preliminary calculation).
- c) Reporting: development of a final report including checked input parameters using the same model. Deviations in results from preliminary calculation shall be technically justified (e.g. due to final fuel analysis).

8.2.4 Boundary parameters for correction

Regardless of the correction approach used, the boundary parameters for which correction to base reference conditions may be applied are summarized in [Table 9](#).

Additional corrections, beyond those summarized in the table, may be applicable for certain types of plant layouts. As such, the introduction of additional correction parameters is not prohibited provided that their application can be technically justified.

Table 9 — Summary of applicable correction to base reference conditions

Corrections ^{e, f}		Type of correction (additive/multiplicative)	Boundary parameter requiring correction and type of boundary parameter (controllable/uncontrollable)	Comments
Power output	Fuel heat input			
MC_{P1}	MC_{Q1}	Multiplicative ^a	Ambient pressure (uncontrollable)	Ambient pressure measured at the vicinity of the primary rotating equipment (e.g. gas turbine centre-line).
AC_{P2}	AC_{Q2}	Additive	Ambient temperature (uncontrollable)	Air temperature measured at the inlet to the primary rotating equipment (e.g. gas turbine inlet).
AC_{P3}	AC_{Q3}	Additive	Ambient relative humidity (uncontrollable)	Ambient air relative humidity measured at the inlet to the primary rotating equipment (e.g. gas turbine inlet).
AC_{P4}	AC_{Q4}	Additive	Fuel supply temperature correction (uncontrollable)	At the test boundary.
AC_{P5}	AC_{Q5}	Additive	Fuel composition (uncontrollable)	Accounts for differences between test fuel composition and reference fuel composition. This correction is multivariate and varies by fuel.

^a This document recommends ambient pressure correction to be treated as a multiplicative correction term; however, users of this document have the option to treat it as an additive correction term.

^b AC_{P7} and AC_{Q7} are typically used together.

^c This document recommends performance degradation correction to be treated as an additive correction term; however, users of this document have the option to treat it as a multiplicative correction term.

^d The contractual agreements between the parties should define the period when the equipment is considered as new and clean and state if performance corrections due to degradation are permitted, when equipment is tested beyond this period.

^e For correction terms 9 to 16, for a given correction i , usually either AC_{Pi} or AC_{Qi} will be used, but not both.

^f For correction terms 12 to 16, not all corrections will apply at the same time. Depending on the test boundary, certain corrections will not apply.

Table 9 (continued)

Corrections ^{e, f}		Type of correction (additive/multiplicative)	Boundary parameter requiring correction and type of boundary parameter (controllable/uncontrollable)	Comments
Power output	Fuel heat input			
AC_{P6}	AC_{Q6}	Additive	Grid frequency (uncontrollable)	Correction shall be weighted in case of multiple generators.
AC_{P7}^b	AC_{Q7}^b	Additive	Measured power output different from target power output (controllable)	Used to account for differences between measured power output and target power output. Applicable for part load combined cycle tests and tests with supplementary firing in operation.
AC_{P8}	AC_{Q8}	Additive ^c	Performance degradation ^d (uncontrollable)	Refer to 6.2.
AC_{P9}	—	Additive	Power factor (controllable)	Accounts for differences in the measured and base reference power factor. Typically determined based on the power factor measured at generator terminals (e.g. see Annex C).
AC_{P10}	AC_{Q10}	Additive	Thermal efflux (controllable)	Energy leaving test boundary in the form of steam and/or water that has an impact on power generation (e.g. process extraction, blowdown flows, drain leakages).
AC_{P11}	AC_{Q11}	Additive	Secondary heat inputs (uncontrollable)	Energy entering or leaving the cycle in the form of steam and/or water. (e.g. Process return water, make-up temperature, steam supplied from external source).
AC_{P12}	AC_{Q12}	Additive	Low pressure steam turbine exhaust pressure (uncontrollable)	Applicable when the heat sink system is excluded from the test boundary.
AC_{P13}	AC_{Q13}	Additive	Cooling water temperature at the inlet to the condenser (uncontrollable)	Used in cases wherein the condenser is the heat sink boundary, with cooling water crossing the boundary.
AC_{P14}	AC_{Q14}	Additive	Cooling water flow at the inlet to the condenser (uncontrollable)	Used in cases wherein the condenser is the heat sink boundary, with cooling water crossing the boundary. Cannot be used if the cooling water pumps are in the test boundary (optional Formula (9) can replace this correction).

^a This document recommends ambient pressure correction to be treated as a multiplicative correction term; however, users of this document have the option to treat it as an additive correction term.

^b AC_{P7} and AC_{Q7} are typically used together.

^c This document recommends performance degradation correction to be treated as an additive correction term; however, users of this document have the option to treat it as a multiplicative correction term.

^d The contractual agreements between the parties should define the period when the equipment is considered as new and clean and state if performance corrections due to degradation are permitted, when equipment is tested beyond this period.

^e For correction terms 9 to 16, for a given correction i , usually either AC_{Pi} or AC_{Qi} will be used, but not both.

^f For correction terms 12 to 16, not all corrections will apply at the same time. Depending on the test boundary, certain corrections will not apply.

Table 9 (continued)

Corrections ^{e, f}		Type of correction (additive/multiplicative)	Boundary parameter requiring correction and type of boundary parameter (controllable/uncontrollable)	Comments
Power output	Fuel heat input			
AC_{P15}	AC_{Q15}	Additive	Air temperature at inlet to the cooling tower or the air-cooled condenser (uncontrollable)	Captures the effect of ambient conditions at the cooling tower or air-cooled condenser.
AC_{P16}	AC_{Q16}	Additive	Wind velocity at inlet to the air-cooled condenser (uncontrollable)	Used for plants with air-cooled condenser when wind velocity is above 5 m/s.
AC_{P17}	AC_{Q17}	Additive	Auxiliary loads or excess auxiliary loads, thermal and electrical (controllable)	Used to account for irregular, cyclical, intermittent, or auxiliary loads not included in the base reference conditions.
^a This document recommends ambient pressure correction to be treated as a multiplicative correction term; however, users of this document have the option to treat it as an additive correction term. ^b AC_{P7} and AC_{Q7} are typically used together. ^c This document recommends performance degradation correction to be treated as an additive correction term; however, users of this document have the option to treat it as a multiplicative correction term. ^d The contractual agreements between the parties should define the period when the equipment is considered as new and clean and state if performance corrections due to degradation are permitted, when equipment is tested beyond this period. ^e For correction terms 9 to 16, for a given correction i, usually either AC_{Pi} or AC_{Qi} will be used, but not both. ^f For correction terms 12 to 16, not all corrections will apply at the same time. Depending on the test boundary, certain corrections will not apply.				

8.2.5 Description of corrections to base reference conditions

8.2.5.1 General

A more detailed description of the test boundary correction terms is summarized in 8.2.4 and their applicability is explained in 8.2.5.2 to 8.2.5.18. This document does not recommend the application of all listed corrections in Table 9 and instead proposes that these be agreed between the parties.

8.2.5.2 Ambient pressure (MC_{P1} , MC_{Q1})

The ambient pressure measured at the centre-line of the primary rotating equipment (i.e. gas turbine) within the combined cycle power plant has a significant and direct influence on the performance of the plant. In particular, the impact of ambient pressure is a linear one-to-one influence on the power output and the fuel input to the combined cycle plant. As such, the effect of ambient pressure on the combined cycle plant is treated as a multiplicative correction term.

8.2.5.3 Ambient temperature correction (AC_{P2} , AC_{Q2})

The ambient temperature at the inlet to the primary rotating equipment in the combined cycle plant has a significant influence on the plant performance parameters. Typically, the ambient air dry bulb temperature is measured at the inlet filter house of the gas turbine.

8.2.5.4 Ambient relative humidity correction (AC_{P3} , AC_{Q3})

The ambient relative humidity measured at the inlet to the primary rotating equipment, typically in the gas turbine inlet filter house, has an appreciable effect on the combined cycle plant output and heat consumption. In particular, when a plant is equipped with an inlet cooling system, such as an

evaporative cooler or an inlet fogging system, the influence can be significant. Typically, this curve is provided as a family of curves at various ambient temperatures

8.2.5.5 Fuel supply temperature correction (AC_{P4} , AC_{Q4})

This correction accounts for deviations between the fuel supply temperature at the test boundary and the corresponding base reference fuel supply temperature. Typically, the fuel temperature is measured upstream of any conditioning device such as pre-heating. However, there may be situations where in the test boundary measurement is required excluding fuel pre-heating (such as a dew point heater).

8.2.5.6 Fuel composition correction (AC_{P5} , AC_{Q5})

This correction adjusts the plant performance parameters for deviations between the base reference fuel composition and the test measured fuel composition. The test fuel composition is typically obtained by taking fuel samples at pre-determined intervals during the test and having a laboratory analyse the samples.

8.2.5.7 Grid frequency correction (AC_{P6} , AC_{Q6})

This correction accounts for the performance impact perceived by the turbine generators when the grid frequency deviates from the base reference frequency. Plant performance is very sensitive to changes in frequency, therefore the tests should be conducted when the grid frequency is most stable.

8.2.5.8 Measured power different from target power (AC_{P7} , AC_{Q7})

When the objective of the test is to operate a combined cycle plant at a predetermined power output by varying the gas turbine load (e.g. part load tests) or varying supplementary firing (e.g. duct fired tests), due to practical limitations, the test measured output will never be exactly equal to the desired target power output. In such situations, the AC_{P7} correction is used to adjust the measured power output to the target power output. While doing so, the plant heat rate and heat consumption will be affected. As such, the AC_{Q7} correction should be used to adjust the plant heat consumption, whenever the AC_{P7} correction is used. These corrections shall always both be used together. See [Clause 9](#) on part load testing of combined cycle plants.

8.2.5.9 Performance degradation (AC_{P8} , AC_{Q8})

Refer to [6.2](#).

8.2.5.10 Power factor correction (AC_{P9})

As the power factor deviates from the base reference power factor, the losses in the generator change. The power factor at which a generator operates is typically dictated by grid demand. In situations where the power factor cannot be set equal to the base reference value, an appropriate correction should be applied in order to correct the performance from the test measured power factor to the base reference value. Typically, this correction is applied on a per-generator basis, and the summation of all the corrections to each generator equals AC_{P9} (see [Annex C](#)). In certain rare cases (e.g. "flat-rated" plants), it is possible that the power factor adjustment may be applied to the fuel input instead of the power output. In such rare cases, the correction should only be applied to the heat input and not to the power output.

8.2.5.11 Thermal efflux correction (AC_{P10} , AC_{Q10})

Steam and/or water energy leaving a combined cycle power plant test boundary is referred to as thermal efflux. Power output and heat rate are typically specified at a base reference thermal efflux. Given that actual operating conditions also due to external parameters will cause the actual thermal efflux to be different from the base reference thermal efflux, it becomes essential to adjust the power output and heat consumption for differences between the base reference thermal efflux and the thermal efflux measured at the time of the thermal performance test.

Thermal efflux includes, but is not limited to, the following.

- a) Water/steam energy exported out from the plant test boundary for purposes other than power generation (e.g. process plant, district heating, desalination). The correction for this thermal efflux case can be only considered in conjunction with the generation of electrical power output by means of a steam turbine. Otherwise this thermal efflux should be regarded as an expected or a guaranteed value (see example in [Figure 7](#)).
- b) Water/steam blowdown from the drums in the steam generator.
- c) Water/steam passing drain valves that cannot, otherwise, be isolated.

Combined cycle power plants equipped with the ability to supply steam and/or water energy to an external customer are typically referred to as cogeneration power plants and can have varying levels of thermal efflux. In such situations, each thermal efflux should be defined and the corresponding base reference value should be provided. If the process return energy is included in the formula used to calculate net thermal efflux from the cycle, the correction term AC_{P11} (or AC_{Q11}), which is for secondary heat inputs into the cycle (see below), should not be used so as to avoid “double-correction”.

For combined cycle power plants wherein the base reference conditions include a non-zero blowdown flow, the test should be conducted at zero blowdown flow and a blowdown correction curve should be used to correct the test results from zero blowdown flow to the base reference blowdown flow. This is due to the practical limitations involved with measuring blowdown flows. The unaccounted-for leakages should be in accordance with IEC 60953-2.

In order to be able to determine the true thermal performance of a combined cycle plant, it is essential to properly isolate the Rankine cycle portion of the plant to ensure that all steam passes through the steam turbine. In situations where it is not possible to attain the desired level of cycle isolation, the test programme should be temporarily halted and cycle isolation issues should be identified and addressed prior to continuing with the test programme. Alternatively, the concerned parties may choose to proceed with the test programme by agreeing to an appropriate correction for the inability to attain desired levels of cycle isolation. If this is the case, the correction will be treated as thermal efflux correction.

After the conduction of the test, the test results should be corrected for deviations from base reference condition for each thermal efflux term. The summation of all these corrections will equal AC_{P10} (or AC_{Q10}).

8.2.5.12 Secondary heat input (AC_{P11} , AC_{Q11})

Any thermal heat input into the plant test boundary besides the primary fuel is considered as secondary heat inputs to the cycle. Examples include make-up water, steam supply from an external source, low level external heat recovery. This correction may be used to represent the return portion of a thermal efflux in a cogeneration application. In the event that the return portion is included in AC_{P10} (or AC_{Q10}) then this correction will not apply.

8.2.5.13 Low pressure steam turbine exhaust pressure (AC_{P12} , AC_{Q12})

This correction applies when the test boundary terminates at the exhaust of the low pressure steam turbine. The condenser and the rest of the sink system are typically excluded from the test boundary. For this particular situation, the correction is applied to the plant performance parameters based on the pressure measured at the exhaust end of the low pressure steam turbine.

8.2.5.14 Cooling water temperature at the inlet to the condenser (AC_{P13} , AC_{Q13})

The temperature of the circulating cooling water supplied to a surface condenser has an influence on the condenser pressure and hence the steam turbine output. When the test boundary includes the surface condenser and the base reference conditions call for a reference cooling water temperature at the inlet to the surface condenser, a correction is applied in order to account for deviations between the measured cooling water temperature and the corresponding reference value. Example situations

include plants where cooling water is supplied from a water body such as a sea, river, lake or a pond. The temperature is measured as close as possible to the condenser, upstream of the condenser water-box.

8.2.5.15 Cooling water flow at the inlet to the condenser (AC_{P14} , AC_{Q14})

For plants where the surface condenser is within the test boundary, while the circulating cooling water pumps and cooling towers (if applicable) are excluded from the test boundary, a correction can be applied to account for deviations between the base reference circulating cooling water flow rate and the actual circulating cooling water flow rate. The circulating cooling water flow determination is addressed in 6.9. This correction should not be applied when the circulating cooling water pumps are within the test boundary.

In case of cooling by means of seawater the salt content should be analysed and considered for calculation of results.

8.2.5.16 Air temperature at inlet to the cooling tower or the air-cooled condenser (AC_{P15} , AC_{Q15})

Normally, the variation of the heat sink performance as a function of ambient conditions is captured in the overall plant ambient correction curves (AC_{P2} , AC_{Q2} , AC_{P3} , AC_{Q3}). However, it should be recognized that the physical layout of a combined cycle power plant results in spatial variation of ambient conditions throughout the plant. When the test boundary includes cooling tower(s) or air-cooled condenser(s), due consideration should be given for differences in ambient air temperatures between inlet to the gas turbine and inlet to the heat sink system. In case of a wet cooling tower, the inlet wet bulb temperature is considered as the influencing factor while for an air cooled condenser, the dry bulb temperature is considered as the influencing factor. Typically, this correction is provided as a family of curves with respect to the ambient dry bulb or wet bulb temperatures.

8.2.5.17 Wind velocity at inlet to the air-cooled condenser (AC_{P16} , AC_{Q16})

Correction is applicable only for plants where the test boundary includes an air-cooled condenser. Wind velocity has a perceivable influence on the performance of the air-cooled condenser, and hence on the steam turbine output. This correction can only be applied when the measured wind velocity is above 5 m/s. If wind velocity exceeds 5 m/s or if there are peaks above 6 m/s for 20 times (or more) within the test period the test should be re-scheduled (subject to agree between the parties).

8.2.5.18 Thermal and electrical auxiliary loads or excess auxiliary loads (AC_{P17} , AC_{Q17})

This correction is meant to capture irregular operation of auxiliary equipment and/or situations where the power metering does not occur exactly at the intended test boundary.

Irregular operation of auxiliary equipment includes situations wherein auxiliary equipment is included in the test boundary, but was not operational during the test or vice versa. For certain situations wherein the operation of auxiliary equipment is dictated by the operating conditions at the time of the test, this correction may be included in the respective boundary condition correction curve. For example, for certain HRSG designs, the LP economizer may include a recirculation pump that may or may not be in operation depending on the ambient conditions and/or condenser pressure. In such a case, the operation of the pump is typically included in the ambient correction curves and a dedicated AC_{P17} correction is not applied.

When it is not practical to measure power at the test boundary, provisions at the generator terminals may be used to measure the plant gross power output. In order to determine the power at the test boundary, the auxiliary power, line/bus duct losses and transformer losses should then be subtracted from this gross power output measurement. In such situations, the plant auxiliary power and transformer losses may be treated as AC_{P17} corrections.

8.3 Power output for combined cycle overall test

8.3.1 Measured power output

Calibrated power meters (three-phase four-wire or three-phase three-wire system) shall be used to measure the three-phase power. The power meters shall be wired through a test plug if available to station current transformers and station voltage transformers that are normally used for station or tariff metering.

Some country codes dictate that temporary power meters can only be connected to the check meter. Refer also to [6.7.2.3](#).

The definition of electrical power output to be verified may be given at different stations as indicated in [Figure 10](#) and [Table 10](#) depending on the test boundary stipulated by contractual scope or guarantee definition, etc. The power may be measured at any station if properly equipped with adequate transformers and in conformance with the requirements of this document.

It is to be noted that design and nomenclature may be different to the terms used by gas turbine manufacturers.

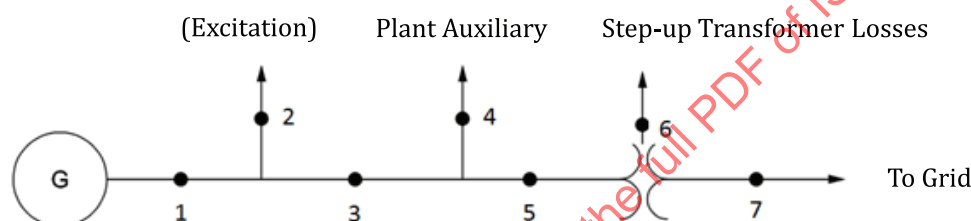


Figure 10 — Stations definition of electrical power

Table 10 — Station definitions for electric power measurement

Station	Description of measurement
1	Gross electrical power at generator terminals. In case of dynamic excitation of the generator this power corresponds with the power at station 3.
2	Excitation power (static exciters).
3	Gross electrical power output (minus excitation power for static exciters).
4	Plant auxiliary consumption.
5	Net electrical power low voltage side.
6	Step-up transformer losses.
7	Net electrical power output high voltage side.

The net power output can be expressed for static exciters as shown in [Formula \(20\)](#):

$$P_{\text{net}} = P_{\text{gross, meas}} - P_{\text{Exc.}} - P_{\text{aux, loss, SUM}} \quad (20)$$

And for dynamic exciters as shown in [Formula \(21\)](#):

$$P_{\text{net}} = P_{\text{gross, meas}} - P_{\text{aux, loss, SUM}} \quad (21)$$

where

- $P_{\text{gross, meas}}$ is the measured active power at generator terminals, in kW;
- $P_{\text{Exc.}}$ is the field current (exciter) losses in accordance with [Table C.2](#) step 25, in kW;
- $P_{\text{aux,loss,SUM}}$ is the sum of auxiliary power and losses, in kW.

The sum of auxiliary power and losses is shown in [Formula \(22\)](#):

$$P_{\text{aux,loss,SUM}} = P_{\text{aux}} + P_{\text{L,BD}} + P_{0,\text{TR,BAT}} + P_{\text{SC,TR,BAT}} + P_{\text{cable losses}} \quad (22)$$

where

- P_{aux} is the total auxiliary power of test boundary, in kW;
- $P_{\text{L,BD}}$ is the bus duct losses low voltage (LV) side, in kW;
- $P_{0,\text{TR,BAT}}$ is the no-load losses of transformer, in kW;
- $P_{\text{SC,TR,BAT}}$ is the losses of transformer, in kW;
- $P_{\text{cable losses}}$ is the cable losses from step-up transformer up to the electrical delivery point high voltage (HV) side (line losses), in kW. Depending on the test boundary, this term may be zero.

If the net power output is measured at the high voltage side, which is identical with the contractually defined reference or guaranteed power output, the measurement result can be directly used for correction to thermodynamic reference conditions as shown in [Formula \(23\)](#):

$$P_{\text{net}} = P_{\text{net, meas}} + P_{\text{cable losses}} \quad (23)$$

where

- $P_{\text{net, meas}}$ is the net power output at tariff meter, in kW;
- $P_{\text{cable losses}}$ is the cable losses from step-up transformer up to the electrical delivery point high voltage (HV) side (line losses), in kW. Depending on the test boundary, this term may be zero.

The total net power output for the combined cycle plant can be determined as shown in [Formula \(24\)](#):

$$P_{\text{net}} = \sum_{i=1}^n P_{\text{net } i} \quad (24)$$

where

- i is an individual generator;
- n is the total number of generators of the test boundary.

8.3.2 Power output corrected to nominal power factor

The power factor (PF), in general, can be determined using [Formula \(25\)](#):

$$PF = \frac{P_{\text{active}}}{\sqrt{P_{\text{active}}^2 + P_{\text{reactive}}^2}} \quad (25)$$

where

P_{active} is the active power output, in kW;

P_{reactive} is the reactive power output, in kVAR.

The correction for power factor, outlined in [8.2.5.10](#), can be obtained using generator loss curves for the generators in the power plant. In situations wherein a more detailed determination of the power factor correction is desired or available, the formulation outlined in [Annex C](#) should be employed.

8.3.3 Corrected power output

Power output is affected by various factors during the conduct of a performance test. Some of these factors are controllable by normal plant operations, while others cannot be influenced by the plant operation and are hence termed as uncontrollable factors. Due to this inherent nature of a performance test, it is necessary to correct the measured performance for differences between the test conditions and the corresponding base reference conditions.

In case of a correction curve based correction approach the corrected electrical power output will be determined using [Formula \(16\)](#). It should, however, be noted that not all corrections will necessarily be applied to every test. Depending on the test boundary applicable for a given test, certain factors will apply, while the rest of the factors will not apply. Typically, the applicability of corrections is defined by the applicable base reference conditions.

In case of application of the model based approach the corrected power output is expressed as shown in [Formula \(26\)](#):

$$P_{\text{corr}} = (P_{\text{meas}}) \times (C_p) \quad (26)$$

where

$$C_p = \frac{P_{\text{ref}}}{P_{\text{cal}}}$$

C_p is the global correction calculated by the thermodynamic plant model (model based approach);

P_{ref} is the calculated power output under base reference conditions, in kW; this value is equivalent to the guaranteed power output or to the expected power output at BRC;

P_{cal} is the calculated power output under measured conditions, in kW;

P_{meas} is the power output determined based on measurements in accordance with the specific test boundary, e.g. by means of [Formula \(20\)](#) or [\(21\)](#) or [\(23\)](#) or [\(24\)](#), in kW.

8.4 Heat rate for combined cycle overall test

8.4.1 Measured heat rate/measured thermal efficiency

The heat rate and/or efficiency for a combined cycle plant including gas turbine(s) can be defined either on lower heating value basis or higher heating value basis. The base reference conditions will clearly define the basis for the fuel gas heating value.

The heat rate, in kJ/kWh, for the combined cycle power plant is calculated as shown in [Formula \(27\)](#):

$$HR_{\text{meas}} = \frac{(Q_{\text{meas}})}{(P_{\text{meas}})} \cdot 3\,600 \quad (27)$$

The efficiency, in %, for the combined cycle power plant is calculated as shown in [Formula \(28\)](#):

$$\eta_{\text{meas}} = \frac{(P_{\text{meas}})}{(Q_{\text{meas}})} \cdot 100 \% \quad (28)$$

where

P_{meas} is the electrical power at the test boundary, in kW;

Q_{meas} is the heat consumption of fuel input into the test boundary, in kJ/s. This includes the heat consumption of the gas turbines and, where applicable, the heat consumption of the supplementary firing in the HRSG.

The fuel flow and heating value can be measured using the instruments and methods outlined in [6.7.3.2](#), [6.7.3.3](#), [6.8.2](#) and [6.8.3](#). In general, the fuel flow should be measured as close as possible to the equipment consuming the fuel (e.g. the fuel flow to the gas turbine should be measured using a measuring device that is installed as close as possible to the gas turbine, while the fuel flow to the HRSG equipped with supplementary firing should be measured as close as possible to the HRSG).

If additional fuel consumption within the test boundary e.g. dew point heaters, etc. has to be considered, the fuel flow shall be measured at the plant entry (boundary) to account for these consumers.

8.4.2 Corrected heat rate / corrected thermal efficiency

[Formulae \(18\)](#) to [\(19\)](#) are used to calculate the corrected heat rate and thermal efficiency. Depending on the plant layout and the test boundary, the generic formulation should be modified such that it fits the test situation. Calculation of part load corrected heat rate/corrected thermal efficiency is addressed separately in [Clause 9](#).

When a model based approach is employed to determine the corrected heat rate, the calculations are performed in two steps. First, the corrected heat consumption (Q_{corr}) is calculated as shown in [Formula \(29\)](#), followed by calculation of the corrected heat rate (HR_{corr}):

$$Q_{\text{corr}} = (Q_{\text{meas}}) \times (C_Q) \quad (29)$$

$$C_Q = \frac{Q_{\text{ref}}}{Q_{\text{cal}}}$$

where

- C_Q is the global heat consumption correction calculated using the thermodynamic plant model (model based approach);
- Q_{ref} is the calculated heat consumption under base reference conditions, in kJ/s;
- Q_{cal} is the calculated heat consumption under measured conditions, in kJ/s.
- Q_{meas} is the heat consumption of fuel input into the test boundary, in kJ/s. This includes the heat consumption of the gas turbines and, where applicable, the heat consumption of the supplementary firing in the HRSG.

The corrected heat rate (HR_{corr}) is shown in [Formula \(30\)](#):

$$HR_{\text{corr}} = \frac{(Q_{\text{corr}})}{(P_{\text{corr}})} \cdot 3\,600 \quad (30)$$

where P_{corr} is the corrected power output determined using the model based approach under [8.3.3](#), in kW.

8.5 Power output of steam turbine determination for combined cycle in single shaft configuration

For single shaft plants equipped with a clutch mechanism to operate the gas turbine in simple or open cycle without engaging the steam turbine, the gross power output ($P_{\text{ST,gross}}$) can be calculated from the gross power output measurement obtained by means of a combined cycle test and a gross power output measurement from an additional simple cycle test, if feasible according to [Formula \(31\)](#):

$$P_{\text{ST,gross}} = P_{\text{CC,gross}} - P_{\text{GT,gross corr to CC cond}} \times \frac{\eta_{\text{Gen,CC}}}{\eta_{\text{Gen,GT}}} \quad (31)$$

where

- $P_{\text{CC,gross}}$ is the measured combined cycle gross power output, in kW;
- $P_{\text{GT,gross corr to CC cond}}$ is the measured gas turbine gross power output corrected to combined cycle test conditions, in kW;
- $\eta_{\text{Gen,CC}}$ is the generator efficiency during CC test, in %;
- $\eta_{\text{Gen,GT}}$ is the generator efficiency during GT test, in %.

9 Part load tests

9.1 General

The part load test philosophy outlined in this subclause can be used to determine the following:

- corrected part load output;
- corrected part load heat rate (or efficiency);
- corrected part load heat consumption.

Any of the above mentioned parameters can be specified at a set of base reference conditions corresponding to a particular part load condition, expressed as a fraction of plant baseload output or gas turbine baseload output (or also expressed at either an absolute CC part load output, or absolute GT

part load output). Typical part load operation of a combined cycle plant entails the gas turbine control system modulating the gas turbine inlet guide vanes (IGVs) and/or the fuel valves, with the rest of the plant following suit, in order to reach the desired plant power output. Since it is not always possible to conduct the test at the exact reference conditions and the exact target load fraction (or absolute target part load), the practical limitations of conducting such a test make it necessary to not only correct the measured part load performance to specified reference boundary conditions, but to also adjust the corrected performance for any deviation between the actual percent of base load (or actual absolute part load) at which the test is ultimately conducted and the intended target percent load (or absolute target load).

In general, it is expected that a part load test will have a higher uncertainty as compared to a base load test of the same plant.

The part load test methodology presented herein is based on the following assumptions.

- The desired combined cycle part load set point will be operated so that the control system regulates the IGVs and the fuel supply automatically.
- A baseload thermal performance test, in accordance with this document, is conducted prior to the part load test programme. The baseload test is used to determine the baseload corrected output, which is required to determine the target part load output if fraction of base load is required.
- A complete set of part load correction curves for the desired part load percent condition of the specific cycle or a thermal model is available and valid for the operating envelope.

9.2 Test set up and conduct

Since the part load heat rate is specified at a given set of reference conditions that includes the part load power fraction (or absolute part load), it becomes essential that the test is set up such that the power output targeted during the test is consistent with the intended target part load fraction (or absolute part load) at the specified base reference conditions. The required part load power output target can be calculated by using the corrected output from the baseload test and the expected boundary conditions at the time of the part load test. As such, the baseload tests should be completed prior to the conduct of part load tests.

The desired target test load should be determined based on the target combined cycle part load fraction (or based on the absolute target part load) at the specified reference conditions using the following formulae.

First, calculate the part load output target at the specified reference conditions in case that the target part load is a fraction of the base load, as shown in [Formula \(32\)](#):

$$P_{PL,target,ref} = f_{PL} \times P_{CC,corr} \quad (32)$$

where

$P_{PL,target,ref}$	is the combined cycle target part load power output at the specified reference conditions, in kW, if part load requirement is in % of base load;
f_{PL}	is the combined cycle target part load fraction at the specified reference conditions;
$P_{CC,corr}$	is the combined cycle corrected baseload output from the baseload test, in kW.

Next, determine the part load power output target at the testing conditions by reverse application of part load corrections as shown in [Formula \(33\)](#):

$$P_{PL,target,test} = \frac{P_{PL,target,ref} - \sum_{i=2}^{17} AC_{Pi}}{MC_{P1}} \quad (33)$$

where

- $P_{PL,target,test}$ is the combined cycle part load power output target at the test conditions, in kW;
- $P_{PL,target,ref}$ is the combined cycle part load power output target at the specified reference conditions, in kW;
- MC_{P1} is the combined cycle part load multiplicative correction based on the expected boundary conditions at the time of the part load test;
- AC_{Pi} are the combined cycle part load additive corrections based on the expected boundary conditions at the time of the part load test in kW. Non-applicable corrections should be set equal to zero.

In situations wherein the target part load fraction is specified as a fraction of the baseload gas turbine output, gas turbine-specific output correction curves will be required and [Formulae \(32\)](#) and [\(33\)](#) are updated, as shown in [Formula \(34\)](#):

$$P_{PL,target,ref_x} = f_{PL,GT} \times P_{GT,corr_x} \quad (34)$$

where

- $P_{PL,target,ref_x}$ is the target part load at the specified reference conditions for gas turbine “x”, in kW;
- $f_{PL,GT}$ is the target gas turbine part load fraction at the specified reference conditions;
- $P_{GT,corr_x}$ is the gas turbine “x” corrected baseload output from the CC baseload test, in kW.

The part load power output target at the testing conditions based on gas turbine part load can be determined as shown in [Formula \(35\)](#):

$$P_{PL,target,test_x} = \frac{P_{PL,target,ref_x} - \sum_{i=2}^9 AC_{Pi}}{MC_{P1}} \quad (35)$$

where

- $P_{PL,target,test_x}$ is the gas turbine “x” part load target at the test conditions, in kW;
- $P_{PL,target,ref_x}$ is the target part load at the specified reference conditions for gas turbine “x”, in kW;
- MC_{P1} is the gas turbine part load multiplicative correction factor based on the expected boundary conditions at the time of the part load test;
- AC_{Pi} are the gas turbine part load additive correction factors based on the expected boundary conditions at the time of the part load test in kW. Non-applicable corrections should be set equal to zero.

In cases wherein the gas turbines in the combined cycle plant are identical models, the test target load can be calculated as an average part load target, and all the gas turbines can be loaded up equally.

Once the test part load power output target is established, the combined cycle plant should be set and operated at this desired target power output. The required target can be achieved by loading the gas turbine(s) in such a manner so that the plant (or gas turbine) output at the test boundary location is as close as possible to the target part load output at test conditions ($P_{PL,target_test}$).

In order to minimize the application of corrections, it is advisable to conduct the part load heat rate tests at the specified reference conditions or as close to those conditions as possible or practical. For example, when executing a specified 75 % target part load test, it is desirable to set the plant exactly at this target. However, this may not be achievable because of continuous changes in ambient conditions, fuel composition, power factor, and other external parameters. A maximum deviation of 2,5 % from the target plant part load at specified conditions is acceptable with minor impact to the test results.

The test boundary conditions should be monitored continuously for the duration of the test. As long as the test boundary parameters are fairly steady for the duration of the test, the target part load for the test run will remain unchanged. However, any significant variation in a boundary condition will cause a corresponding variation in the target part load. As far as is practical, the part load test should be conducted at a time when the boundary conditions are as stable as possible to avoid any significant changes in the target part load for the duration of the test. Test runs wherein steep step changes occur in the uncontrollable boundary parameters during the test run shall be avoided.

9.3 Correction method for part loads

The general correction formulation outlined in 8.2.2 can be adopted to calculate part load performance. However, due to the practical limitations associated with the conduct of part load test, special consideration needs to be given for adjusting the test measured output and heat rate (or efficiency) for differences between the targeted test load and the actual test load. The load fraction has a bivariate characteristic with respect to the ambient temperature when plotted against the corresponding heat rate fraction. Since part load testing requires an adjustment to the measured output and/or heat rate for variations in the load from the targeted load, it is essential that this correction curve be generated as a bivariate function of ambient temperature.

Given the nature of part load testing, correction curves can be generated in two different manners. One method is to generate the curves by holding a constant the IGVs for all the correction curves, while the other method is to hold a constant part load fraction while generating the correction curves. Both methods yield similar results.

For combined cycle part loads controlled by means of gas turbine inlet guide vanes modulation, the ambient temperature correction and the load correction can be plotted in a single chart, as a trivariate with the inlet guide vanes angle. This method simplifies the process of creating correction curves and the process of applying the correction terms. Alternatively, two separate correction curves (the traditional ambient temperature correction curve and the load correction curve, which is a bivariate with ambient temperature) can be used to arrive at the same result.

10 Calculation of results for comparative test

10.1 General

The main objective of a comparative test is to measure the change in performance of the combined cycle power plant (or a combined cycle package) due to degradation or plant/components upgrades or modifications.

10.2 Comparative performance test uncertainty

For comparative performance testing a limit for the uncertainty of the test result should be defined.

It is recommended that the uncertainty of the comparative performance test result, expressed as the uncertainty of the difference, should be no greater than 10 % of the expected change in performance

(the parties can also assess a different threshold value due to the complexity of testing and/or the entity of the change in performance). Both pre- and post-test uncertainty calculations are required.

For comparative performance tests, the uncertainty is more complex than for absolute performance tests since the target result is the difference in performance rather than the absolute level. The comparative test uncertainty is strongly affected by whether or not the same instrumentation is used for both before and after tests, and by the sensitivities of results. As such, due consideration should be given to how the sensitivities are established and what instrumentation is chosen for the testing programme. Thus, the uncertainty values can have considerable variation.

During the preparation phase, the parties should agree beforehand whether a test can be designed with an uncertainty that is significantly lower than the expected performance benefit. In some cases as-tested uncertainty may be a value as large or larger than the performance benefit to be verified resulting in an inconclusive test. In addition, the parties should realize that a cost/benefit analysis of the modification and its comparative test should determine the scope, cost and required accuracy of the test.

A sample of the evaluation of the uncertainty calculation is reported in [Annex B](#).

10.3 Preparation for comparative test

10.3.1 Instrumentation

Typically, a comparative test conducted using the same test instrumentation for the pre- and post-tests will result in comparative test results with lower uncertainty. By using the same instrumentation, it is deemed that the systematic error for instruments used for both tests, if not affected by drift or recalibrated, will approach zero for most cases. The same instrumentation should be used for pre- and post-tests, but the use of different sets of instrumentation may be used provided they are calibrated to the same standards.

Agreement shall be reached on the type of instrumentation (e.g. existing station instrumentation, test grade instrumentation, and/or calibrated to known standards or not) that will be used for the test. Permanently installed plant instrumentation can be used for a comparative test due to the potential for reduced effect of systematic error in the uncertainty of performance differences. The reduced effect of systematic error is achieved by using the same instruments in both the pre- and post-modification tests, provided also that the systematic errors are known to remain constant in both pre- and post-tests. In order to ensure that that systematic errors associated with permanently installed plant instrumentation stay constant between the pre- and post-tests, the plant instrumentation used for comparative testing shall be calibrated before the pre-test and field verified using calibrated standards prior to the post-tests. If any drift is observed, then the associated uncertainty should be captured.

In some instruments systematic errors may not remain constant. Drift and sensitivity to ambient conditions may be reasons for changing systematic error. To overcome this change in systematic error, it may be necessary to upgrade some instruments prior to pre-test. Re-calibration or other maintenance of instruments during the outage would be a cause for systematic error to change and should be avoided. Care shall be taken with instruments that will be removed during the outage that they be replaced and used in the same manner in which they were used in the pre-test.

In particular, flow elements used to measure fuel input should not be cleaned or replaced during the outage. Any maintenance operation should be done before the pre-modification test if the target of the test is to measure the change in performance due to upgrades of modifications.

10.3.2 Preliminary activities and plant settings

It is common to do restorative action in multiple parts of the combined cycle power plants while it is in an outage period. Examples of restorative action include special cleaning of the gas turbine compressor and replacement of inlet filters or damaged gas parts, washing and checks on air cooled condenser fan, cleaning of bundles of surface condenser, and checks for leakages in boiler and vacuum system. The parties need to recognize the value of this additional restorative work, if out of the boundary of the