SECTION 1 — OBJECT AND SCOPE

1.1 OBJECT

This Code provides procedures for the accurate testing of steam turbines. It is recommended for use in conducting acceptance tests of steam turbines and for any other situation in which performance levels must be determined with minimum uncertainty. It is the intent of this Code that accurate instrumentation and best possible measurement techniques be used to determine the performance. In planning and running the test, the parties must strive to follow the Code procedures as closely as possible to achieve the lowest level of uncertainty.

1.2 SCOPE

This Code may be used for testing of steam turbines operating either with a significant amount of superheat in the initial steam (typically fossil-fueled units) or predominantly within the moisture region (typically nuclear-fueled units).

This Code contains rules and procedures for the conduct and reporting of steam turbine testing, including mandatory requirements for pretest arrangements, instruments to be employed, their application and methods of measurement, testing techniques, and methods of calculation of test results. The performance parameters which may be determined from a Code test include:

(a) heat rate
(b) generator output
(c) steam flow
(d) steam rate
(e) feedwater flow

It also contains procedures and techniques required to determine enthalpy values within the moisture region and modifications necessary to permit testing within the restrictions of radiological safety requirements in nuclear plants.

1.3 FULL-SCALE AND ALTERNATIVE TESTS

Two steam turbine testing procedures are presented. For either procedure, primary flow may be measured either in the condensate line or in the feedwater line downstream of the final feedwater heater. The parties may agree to variations between the full-scale and alternative tests as long as the philosophy of minimum uncertainty is followed in detail.

1.3.1 Full-scale test. The full-scale test requires extensive thermal cycle measurements and calculations which provide detailed information about the turbine HP, IP, and LP individual component performance. A full-scale test will produce results with a minimum uncertainty.

1.3.2 The full-scale test with condensate flow measurement is recommended for conducting acceptance tests of fossil unit steam turbines. Without prior written agreement between the parties to an acceptance test, this procedure shall be used.

1.3.3 Alternative test. The alternative test relies on fewer measurements and makes greater use of correction curves for cycle adjustments and heater performance with resultant cost savings over the full-scale test. The test uncertainty is slightly increased compared with the full-scale test. For a nuclear unit, the alternative test with feedwater flow measurement may be preferred depending on the turbine cycle design. Use of this procedure requires agreement between the parties to an acceptance test.

1.3.4 The data from the alternative test procedure may produce a slightly higher uncertainty in results, particularly if there is substantial divergence between the test and the specified cycle. The parties to the test must agree on a course of action if the turbine fails to meet specified performance. The alternative test may not provide the information necessary to determine individual component performance compared to expected because only those measurements needed to calculate test heat rate and to permit comparison to specific conditions are required. It is recommended that all provisions and source connections for a full-scale test be included in the design of the cycle, should such a test be required at a later time and to facilitate individual turbine component performance testing.

1.4 CONFORMANCE TO CODE

1.4.1 Other procedures and instrumentation may be used only if they have demonstrated accuracy equivalent to that required by this Code. Only the relevant portion of this Code need apply to any individual case.

1.4.2 The tests should be conducted with the strictest possible adherence to the provisions of this Code. However, equipment limitations may dictate that the parties cannot comply with one or more Code requirements because of a conflict with another condition specified by the Code. In such cases, agreement between the parties is necessary. The agreement shall conform to the intent of the Code as closely as possible. The agreement should provide details for handling departures from specific Code requirements.

1.4.3 Any departure from Code requirements must be agreed upon in writing and must conform to the intent of the Code. In the absence of written agreement, the Code requirements shall be mandatory.

1.4.4 Uncertainty of Code Test. The results of a full-scale Code test, expressed as a heat rate, for a typical fossil fuel reheat cycle unit have an uncertainty of about $\frac{1}{4}$ percent compared to an uncertainty of about $\frac{1}{3}$ percent for the alternative test. Test results for steam turbines operating predominantly within the moisture region have uncertainties of about $\frac{3}{8}$ percent and $\frac{1}{2}$ percent, respectively. Values of uncertainty will be affected by cycle configuration and equipment type and may be significantly higher. Section 9 discusses the rationale for heat rate uncertainty and demonstrates examples of uncertainty calculations in Tables 9.1–9.4

1.4.5 A post-test uncertainty analysis performed according to procedures as described in PTC 19.1 is recommended. However, a post-test uncertainty analysis may be made optional upon agreement by the parties that a test adhered to all instrumentation requirements and procedures contained in this Code.

1.4.6 Code instrumentation and procedures may not always be economically feasible or physically possible for specific turbine acceptance tests. In these cases, the intent of the Code cannot be met, and PTC 6 Report should be consulted for guidance in designing the test and calculating the test uncertainty.

1.5 ADDITIONAL REQUIREMENTS AND REFERENCES

1.5.1 The provisions of the Code on General Instructions, PTC 1, are a mandatory part of this Code. PTC 1 should be studied and followed in detail when preparing the procedure for testing a specific steam turbine.

1.5.2 The Code on Definitions and Values, PTC 2, defines certain technical terms and numerical constants which are used throughout this Code. Unless otherwise specified in this Code, instrumentation should comply with the appropriate sections of Supplements on Instruments and Apparatus, PTC 19 series.

1.5.3 An Appendix to this Code, PTC 6A, published separately, gives numerical examples of various calculations of test results.

SECTION 3 — GUIDING PRINCIPLES

3.1 PLANNING FOR TEST

3.1.1 Requirements for Agreements. The parties to any test under this Code shall reach definite agreement on the specific objective of the test and on the method of operation. This agreement shall reflect the intent of any applicable contract or specification. Any specified or contract operating conditions or specified performance pertinent to the objective of the test shall be ascertained. Unless the alternative test procedures are specified, full-scale test procedures shall be used. Omissions or ambiguities about any of the conditions must be eliminated or their values or intent agreed upon before the test is started. The cycle arrangement, operating conditions, and testing procedures shall be established during the agreement on test methods.

3.2 ITEMS ON WHICH AGREEMENT SHALL BE REACHED

3.2.1 The following is a list of typical items upon which agreement shall be reached during the engineering phase of a new unit or modification of an existing unit.

(a) objective of test and methods of operation

(b) the intent of any contract or specifications as to use of the alternative test procedure which must include a review of specified heat cycle and final expected values (refer to para. 3.4.1)

(c) the intent of any contract or specifications as to timing of test, operating conditions, and guarantees, including definitions of heat rate, method of comparing test results with guarantee and responsibility for the preparation of test report(s)

(d) location of, and piping arrangement around, primary flow measuring device(s) on which test calculations are to be based (see paras. 4.9.1–4.9.7)

(e) location and type of secondary flow measuring devices and provisions for calibration, including temporary piping for in-place calibration, if required

(f) number and location of valves or other means required to ensure that no unaccounted-for flow enters or leaves the test cycle or bypasses any cycle component. (In a nuclear plant, particular note must be taken of make-up lines and emergency valving that may not be blocked off and for which accounting must be made. (see Subsection 3.5.8)

(g) method of handling leakage flows, orificed continuous drain flows, continuous blowdowns, etc. to avoid complications in testing or the introduction of errors

(h) method of complying with the criteria and recommendation of ASME Standard No. TDP-1, Parts 1 and 2, "Recommended Practices for the Prevention of Water Damage to Steam Turbines Used for Electric Power Generation" as related to handling of, or accounting for, drain flows

(i) means of measuring pump-shaft seal and leakage flows

(j) number and location of temperature wells and pressure connections

(k) number and location of duplicate instrument connections required to ensure correct measurements at critical points

(l) calibration and connection of instrument transformers to be used for measuring electrical output

(m) where a plant computer is used for data acquisition, provisions for total-system, in-place calibration of station instrumentation and computer (Calibration should include comparison of known inputs to the output of the computer.)

(n) method of determining the differential pressure across control valve(s) to satisfy the provisions of paras. 3.13.2 and 3.13.4 (Pressure tap should be provided immediately upstream and downstream of the last control valve(s) to open.)

(o) method of determining steam quality including sampling technique as required (The recommended methods are tracer, heater-drain flow measurements, and calorimeter method.)

(p) responsibility for obtaining a license for radioactive tracer and method of shipping, receiving, handling, storing, and using both the tracer and its associated equipment

(q) level of undue deterioration at which the acceptance test will be postponed until after the first internal inspection

(r) method of establishing the efficiency of the feedwater pump turbine, if required

(s) criteria for instrument recalibration after the test

3.2.2 The following is a list of typical items upon which agreement shall be reached prior to conducting the test:

(a) procedure for determining the condition of the turbine prior to the test (see paras. 3.3.1, 3.3.2, and 3.4.5)

(b) location, type, and calibration of instruments (see para. 3.10.1)

(c) methods of measurement not established in (b)

(d) isolation of cycle during test (see Subsection 3.5)

(e) method of detecting excessive feedwater-heater leakage (see para. 4.16.6)

(f) means for maintaining constant test conditions (see paras. 3.8.1 and 3.8.2)

(g) method of isolating or arresting control valve action such as those caused by variations in combustion-control systems signal, electrical system, etc.

(h) operating conditions at which tests are to be conducted including, but not limited to, the loads, valve settings, or valve points to be used for each run (see paras. 3.8.3 and 3.13)

(i) position of manually and automatically operated valves (see para. 3.8.9)

(j) frequency of observations (see para. 3.9.2)

(k) number of test runs at the same test point (see paras. 3.7.1 and 3.7.2)

(l) duration of test runs (see para. 3.9.2)

(m) duration of operation at test load before readings are commenced (see para. 3.8.1)

(n) computer or data acquisition system to be used for test data acquisition and analysis

(o) arrangements for data acquisition and analysis, including calibration of data acquisition system

(p) procedures and format for recording data

(q) organization and training of test personnel and identification of the responsibility for the test (see paras. 3.4.2, 3.4.3, and 3.4.5)

(r) procedures for calculating test results

(s) curves to correct for measured generator output for deviations from specified power factor and specified hydrogen pressure

(t) corrections for deviation of test steam conditions from those specified (see Subsection 3.12)

(u) curves to correct test heat rate to specified cycle conditions (alternative test only)

(v) method of conducting test runs to determine the value of any correction factors (see para. 3.4.5 and Subsection 3.12)

(w) method of handling deviations beyond the stated permissible levels as a result of a mismatch between test timing and seasonal effects on operating conditions

(x) where a nuclear unit is involved, all test plans must reflect compliance with the technical specification for that unit

(y) load limitations caused by licensing considerations (nuclear steam-supply limitations, or otherwise) which prevent attainment of full power within a practical time period

(z) deviations from test arrangements and test procedures that may be required due to a radioactive environment in the testing area

3.3 TIMING OF ACCEPTANCE TEST

3.3.1 The acceptance test should be scheduled as soon as practicable, preferably within eight weeks, after the turbine is first put into initial operation under load. This allows for detailed planning, material procurement, instrument acquisition, preparation, shipment, controls adjustment, preliminary tests, and detection and correction of problems with the unit. The tests should be conducted if no serious operating difficulty has been experienced and there is reasonable assurance the unit is free of deposits and undamaged.

It is the intent during this period to minimize performance deterioration and risk of damage to the turbine. Enthalpy drop tests or preliminary tests should be made during this period to monitor the performance of turbine sections operating entirely in the superheat region. However, enthalpy drop tests do not provide performance for turbine sections with a wet exhaust. Therefore, it is imperative to conduct the acceptance test as soon as possible.

In any event, if the enthalpy drop tests show undue deterioration, or if plant conditions delay the tests for more than four months after initial operation, the acceptance test should be postponed until immediately following the first internal inspection, provided that any deficiencies in the turbine generator affecting performance have been corrected during the inspection period. Except with written agreement to the contrary, the acceptance test shall take place within the warranty period specified in the contract. Adjusting of heat rate test results to start-up enthalpy drop efficiencies or for the effects of aging are not permitted by this Code.

In lieu of an internal inspection, the following methods may be used prior to the acceptance test to establish the approximate condition of the turbine:

(a) For turbines using superheated steam, a comparison between enthalpy-drop efficiency tests conducted immediately after the start-up and again immediately before the test. (See para. 3.3.2.)

(b) By running preliminary tests. For turbines operating predominantly in the moisture region, this may be the only applicable method.

(c) By a combination of these methods.

If the turbine is shut down prior to the test, an inspection of all accessible parts is desirable. The parties to the test must agree as to the action to be taken on evidence of deterioration.

3.3.2 Performance Bench Mark Determinations. It is desirable that a performance bench mark be established immediately after the turbine is first placed in service, so that, should the Code test be delayed past eight weeks, there can be reasonable assurance that the turbine has not been damaged or become fouled with deposits during the intervening period of operation. (See para. 3.3.1.) For turbines operating in the superheated steam region, the internal efficiency (actual enthalpy drop divided by the isentropic drop) of each turbine element should be determined by measurement of the pressure and temperature of the steam entering and leaving the section. These measurements should be made with all control valves fully open. The instrumentation to be used for the benchmark testing shall meet the same accuracy and calibration requirements specified for Code test measurements.

Unlike the intermediate-pressure turbine section, for which efficiency is substantially constant over a wide range of steam flow, the efficiency of the high-pressure section is affected by the position of the control valves. If it is not possible to bring the turbine up to full load immediately after initial start-up, the internal efficiency test should be made by reducing the throttle steam pressure sufficiently to permit operation with fully-open control valves without exceeding limitations on output. The internal efficiencies of all turbine sections measured under these conditions will then be compared with tests run with design steam pressures and fully open control valves. Steam pressure and temperature measurements (or test data) should be supplemented with output measurements to provide data on the low-pressure section of the turbine. With some stages operating in the wet steam region the low pressure section cannot be checked by internal efficiency measurements.

When a turbine has wet steam exhausting from all sections (such as a turbine with a nuclear steam supply), it is not possible to use an enthalpy-drop efficiency test to establish benchmark performance. If a preliminary heat rate test can be performed, this would be an excellent method to establish benchmark performance. If this is not practical, however, it is recommended that a "capacity" test be conducted at the licensed thermal output of the nuclear steam supply system. In a capacity test, cycle conditions are stabilized and electrical output of the generator is carefully measured, together with all cycle conditions which affect performance, such as initial and condenser pressure. Generator output is corrected for differences in cycle conditions from their nominal values using appropriate correction factor curves. It is also corrected for any difference between measured and licensed reactor thermal output, assuming electrical output is proportional to reactor thermal output. This corrected electrical output can then be used as a benchmark, since it can be compared to an electrical output derived in exactly the same way at the time of the test. The accuracy of this procedure depends upon the repeatability of electrical output and reactor thermal output. Since this capacity test is performed with a measured heat input, it is analogous to a simplified heat rate test; therefore, it is necessary to isolate the cycle to achieve an accurate determination of any deterioration.

3.4 GENERAL TEST REQUIREMENTS

3.4.1 Various methods are presented in the Code for conducting certain details of the test and for computing the results. The test report shall state which alternatives have been employed. (See Section 6.) Since the alternative method requires fewer measurements, it is important that cycle components operate close to specified conditions. If not, appropriate corrections must be developed reflecting test conditions to minimize the uncertainty.

3.4.2 The parties to the test may designate a person to direct the test and to serve as mediator in event of disputes as to the accuracy of observations, conditions, or methods of operation.

3.4.3 Designated representatives of the parties to the test shall be present to verify that the test is conducted in accordance with this Code and the arrangements made prior to the test.

3.4.4 Provisions shall be made for all precautions specified in Section 4 for respective measurements.

Provisions for cycle isolation shall be made in accordance with Subsection 3.5.

3.4.5 Preliminary tests may be run for the purpose of:

(a) determining whether the turbine and plant are in a suitable condition for the conduct of the test (see paras. 3.3.1 and 3.3.2)

(b) checking all instruments

(c) training personnel

(d) establishing valve points

(e) determining corrections for deviation of conditions from specified

(f) confirming cycle isolation

3.4.6 Test Data. Unless an agreement is reached to the contrary, records shall be kept of all test data before the application of any calibration factors, corrections, conversions, or statistical analysis. A copy of the original records shall become the property of each of the principal parties to the test. No original data may be erased or deleted.

3.5 ISOLATION OF THE CYCLE

3.5.1 General. The accuracy of the test results depends on the isolation of the system. Cycle isolation is equally important to both the full-scale and alternative procedures. Extraneous flows should be isolated, if possible, to eliminate errors. Extraneous flows for equipment that is included in the contract cycle should be isolated only with mutual agreement by the parties. If there is any doubt about the ability to isolate extraneous flows during the test, preparations shall be made prior to the test to measure the flows.

3.5.2 The equipment and flows to be isolated and the method to accomplish this should be outlined well ahead of the initial operation date of the turbine.

3.5.3 External Isolation. External isolation deals with flows which enter or leave the turbine cycle, such as condensate make-up or boiler blowdown flow. This system isolation shall be effected so that the difference between the sums of the measured storage changes and the entering and leaving flows (the unaccounted-for leakage) is minimized. The unaccounted-for leakage shall not exceed 0.1 percent of the test throttle flow at full load. Excessive unaccounted-for leakages shall be eliminated before continuing the test. Water storage in the condenser, deaerating and other extraction feedwater heaters, steam generator drum(s), moisture separators, and any other storage points within the cycle are to be taken into account.

3.5.4 Internal Isolation. Internal isolation deals with flows which do not enter or leave the turbine cycle but which may bypass the component they were designed to go through. Examples of such flows are steam line drain flows to the condenser or feedwater heater bypass flows. Internal isolation cannot be verified by the inventory summation method discussed above. The isolation procedure given in paras. 3.5.6 and 3.5.8 must be followed to verify internal isolation.

3.5.5 Flows That Shall Be Isolated. The following list includes items of equipment and extraneous flows that shall be isolated:

(a) large-volume storage tanks not directly in the cycle

(b) evaporators and allied equipment such as evaporator condenser and evaporator preheaters

(c) bypass systems and auxiliary steam lines for starting

(d) bypass lines for primary flow measuring devices

(e) turbine sprays

(f) drain lines on stop, intercept, and control valves

(g) drain lines on main steam, cold reheat, hot reheat, and extraction steam piping

(h) interconnecting lines to other units

(i) demineralizing equipment. Isolation of demineralizing equipment does not necessarily mean removing the equipment from the cycle. (It does, however, mean that all ties with other units must be isolated and such components as recirculating lines that affect the primary flow measurement must be isolated or the flows measured.)

(j) chemical feed equipment using condensate

(k) steam generator fill lines

(l) steam generator vents

(m) steam-operated soot blowers

(n) condensate and feedwater flow bypassing heaters

(o) heater drain bypasses

(p) heater shell drains

(q) heater water-box vents

(r) hogging jets

(s) condenser water-box priming vents

(t) steam or water lines for station heating

(u) steam or water lines installed for water washing the turbine

3.5.6 Flows That Shall Be Isolated or Measured. Extraneous flows which enter or leave the cycle or bypass a component in such a manner that if ignored will cause an error in the flows through the turbine shall be isolated or measured. Typical of such flows are:

(a) boiler-fire-door cooling flow and boiler-slag-tap cooling-coil flow

(b) sealing and gland cooling flow on the following (both supply and return):

(1) condensate pumps

(2) feedwater pumps

(3) boiler or reactor-water circulating pumps

(4) heater drain pumps when not self-sealed

(5) turbines for turbine-driven pumps

(6) reactor control-rod drive flows

(c) desuperheating water flow

(d) feedwater pump minimum-flow lines and balance drum flow when the piping is arranged to allow recirculation of the flow through the primary flow element

(e) steam for fuel oil atomization and heating

(f) steam generator blowdowns

(g) turbine water-seal flows

(h) desuperheating water for turbine cooling steam

(i) emergency blowdown valve or turbine-packing leakage and sealing steam

(j) turbine water-seal overflows

(k) steam, other than packing leakage steam, to the steam-seal regulating valve

(l) make-up water, if necessary

(m) pegging or sparging steam (such as higher-stage extraction at low loads) for low pressure operation of deaerator

(n) heater shell vents are to be closed, if possible, and if not possible, shall be throttled to a minimum

(o) deaerator overflow line

(p) deaerator vents shall be throttled to a minimum

(q) water leakage into any water-sealed flanges, such as water-sealed vacuum breakers

(r) pump-seal leakage leaving the system

(s) automatic extraction steam for industrial use

(t) continuous drains from wet-steam turbine casings and connection lines

(u) subcooled moisture used for moisture separator or reheater coil-drain cooling

(v) reactor core spray

(w) heater-blanketing steam lines

(x) water and steam sampling equipment. If it is impossible to isolate water and steam sampling equipment and if the sampling flow is significant, it shall be measured.

(y) steam to air preheaters

3.5.7 For the full scale test, when it is impossible to measure shaft packing leakage, valve-stem leakage, internal turbine leakage, and turbine drain flows, it will be necessary to use calculated values. For the alternative procedure, calculated values may be used in lieu of measured values.

3.5.8 Methods of Isolating. The following methods are suggested for isolating or verifying isolation of miscellaneous equipment and extraneous flows from the primary feedwater cycle:

(a) use of double valves and telltales

(b) use of blank flanges

(c) use of blank between two flanges

(d) removal of spool piece for visual inspection

(e) visual inspection for steam blowing to atmosphere from such sources as safety valves and valve-stem packings

(f) use of a closed valve which is known to be leak-proof (test witnessed by both parties) and is not operated prior to or during test

(g) tracer indicator of presence of leakage

(h) for steam lines terminating at the condenser, pipe surface temperature indication

(i) for bypass lines around feedwater heaters, temperature measurement of condensate/feedwater before and after the bypass lines tee into the condensate/feedwater lines

(j) temperature measurement for situations other than described in (h) and (i) (acceptable only under certain conditions with mutual agreement necessary)

(k) acoustic techniques, with mutual agreement

3.6 LOCATION OF TURBINE VALVE POINTS

3.6.1 The method used to establish turbine valve points depends on valve point definition. A valve point may be established in terms of high pressure turbine efficiency, certain measured turbine pressures, or valve-stem positions. The turbine is then tested accordingly.

3.6.2 For units with a high pressure section operating entirely in the superheat region, a valve point may be located by finding a point of local maximum high pressure section efficiency. To do this, the flow to the unit is changed in small increments throughout a range which includes the valve point. At each flow increment, pressure and temperature measurements are taken at both inlet and exhaust so that high pressure section efficiency can be derived. A local maximum efficiency will be evident, provided suitable instruments and test procedures have been used. During testing, a parameter which varies with flow (such as control valve position(s), or pressure ratio across either the first stage or the complete high pressure section) should also be recorded so the valve point can be readily set during the test series.

3.6.3 A valve point established in terms of pressures is found by measuring pressure at a tap provided for each steam admission zone served by a valve. While the valve remains closed, the pressure in this zone will be nearly the same as the first stage pressure of the turbine. As the valve opens, the difference between these two pressures will gradually change and the zone pressure will rise above the first stage pressure.

3.6.4 A valve point established in terms of valve stem position is found by taking the appropriate measurements during operation.

3.6.5 If valve points are located prior to the start of the test series, time and labor can be saved during the tests.

3.6.6 Valve points are numbered consecutively from the minimum arc of admission. For example, consider a machine with four control valves designed such that the first two valves open together. The first valve point occurs where the third valve is about to open, and the second valve point occurs where the fourth valve is about to open.

3.7 NUMBER OF TEST RUNS

3.7.1 Recommended Test. As a minimum, duplicate test runs should be performed at valves-wide-open and at two part load points. Duplicate test runs at the same operating condition reduce the random error component of uncertainty. The part-load tests should be performed at valve points to ensure that duplicate test runs are at the same conditions. The test series should begin and end with the same valve point test run, preferably the valves-wide-open test run.

Consecutive tests should not be performed at the same load without changing valve positions and breaking isolation. It may be necessary to break isolation to maintain hotwell level during the load change. Load change should be at least to the next higher, or lower, valve point, or, for full-arc admission turbines, at least 15 percent of load.

The criteria of para. 3.7.2 are to verify that operating conditions during duplicate test runs are correct, provided that changes in load and isolation are made between these duplicate runs. If the criteria are not met, according to PTC 1-1991, subpart P, para. 4.16, the parties to the test may eliminate the test runs by mutual agreement. The criteria are to verify correct operating conditions and are not to determine statistical outliers.

The heat rate differences used are based on experience and do not relate directly to uncertainties in Tables 9.1-9.4.

3.7.2 Duplicate Test Runs. The requirements of this Code for agreement between the results of duplicate test runs are illustrated by several hypothetical sequences of test results in examples (a) through (g) below. When two test runs are conducted at the same test point, the corrected test heat rates shall agree within 0.25 percent. Thus, neither test differs from the average by more than one-half this amount or 0.125 percent. Units for the heat rates in the following are Btu/kWhr.

(a) 2 test runs within 0.25%
8009
7991
use average = 8000

If the two test runs differ by more than 0.25 percent, additional test runs are required at the same test point until the corrected heat rates of at least two test runs agree within the 0.25 percent. If more than one pair of test runs meets the 0.25 percent criterion, then the pair that most closely falls on the locus curve of the corrected test heat rates from other test points shall be accepted. Alternatively, another test run may be made.

(b) 3 test runs with third outside range of other two
8010 > 0.25% from nearest one
7988
7980
use average of last two = 7984

(c) 3 test runs agree with third test run between other two
8015
7985 > 0.25% from first one
8000
use average from third test (8000)
in a pair that best fits locus curve

(d) 3 tests runs with third test run between other two, followed by a fourth test run
8011 > 0.25% from nearest one
7979
7988
7983
use average of last three = 7983

If no two corrected heat rates fall within 0.25 percent of each other after three test runs have been made at the same test point, the test procedure and instrumentation must be carefully reviewed to determine and correct the cause before proceeding to run more test runs.

(e) 3 test runs with no pair within 0.25%

8021
8000
7979
find cause before proceeding

At any one test point, all corrected test heat rates falling within 0.125 percent of their average shall be accepted.

(f) 4 tests with close grouping

8010
8005
8012
8000
use average of all four = 8007,
since each is within 0.125%
of their average.

3.8 TESTING CONDITIONS

3.8.1 Constancy of Test Conditions. Preparatory to any test run, the turbine and all associated equipment shall be operated for a sufficient time to attain steady-state condition. Steady-state conditions shall have been attained when the criteria of para. 3.8.3 are met.

When a tracer is used for determining steam quality, the injection period should commence sufficiently prior to the start of the test run to attain equilibrium. As a guide, it may be conservatively expected that equilibrium is attained when a time period, equal to twice the calculated transit time through the longest injection line plus the longest sample line following the commencement of injection, has passed. For the purpose of this Code, equilibrium shall have been attained when the concentration of tracer in two consecutive samples taken during the test at a 30-minute interval differ by no more than 3 percent from one another.

3.8.2 Appropriate means shall be employed for securing constant load. This may be accomplished by blocking the valve-gear or control valve travel in the opening direction at the desired load, leaving the control valves free to move in the closing direction in the event of upsets or emergency situations. While the machine is so operating, it will be unable to carry more load than that for which the valve-gear or control valves are blocked, but will regulate the turbine at a slightly higher speed in the event of loss of load.

3.8.3 Operating Conditions. Every effort shall be made to run the tests under specified operating conditions, or as close to specified operating conditions as possible in order to avoid the application of corrections to test results, or minimize the magnitude of the corrections. In addition, variations in any condition that may influence the results of the test, shall be made as nearly constant as practicable before the test begins and shall be so maintained throughout the test. Steam generator and turbine controls shall be fine-tuned prior to the test to minimize deviation of variables. Table 3.1 lists the permissible deviation of variables prescribed with the exceptions as noted in para. 3.8.11. A slow change in variables, or "drift," during the test run, will frequently occur in addition to the fluctuations addressed in Table 3.1. For some key parameters, "drift" should be limited to 50 percent of the permissible deviations presented in Table 3.1 for the average of the test conditions from design or rated conditions. These key parameters are initial steam pressure, initial and reheat steam temperature, exhaust pressure, output, and speed. Operating within the limits of Table 3.1 is especially important for the alternative test, since more correction curves are used than in the full-scale test.

3.8.4 Hydrogen purity should be maximized to decrease windage loss, improve heat transfer, and for safety reasons. Operating manuals specify a minimum hydrogen purity, with safety as the primary consideration. For instances where hydrogen purity is below the manufacturer's specified value, the test should be postponed until the purity can be brought to the specified value. Improvement is usually easy to achieve and should not impose undue hardship on the parties to the test. The hydrogen purity instrumentation should be checked to ensure correct indication.

3.8.5 The turbine and its cycle shall be in normal operation during the test, except for cycle isolation, (see Subsection 3.5). Except as provided in para. 3.8.2, no special adjustments shall be made to the turbine that are inappropriate for normal and continuous operation.

3.8.6 The turbine shaft-sealing system, if controlled, shall be adjusted to normal operating conditions during a test and arrangement made to measure any flow outward or inward that will influence test results.

TABLE 3.1
PERMISSIBLE DEVIATION OF VARIABLES

Variable	*Permissible Deviation for the Average of the Test Conditions from Design or Rated Conditions	**Permissible Fluctuations During Any Test Run
(a) Initial steam pressure	±3.0% of the absolute pressure	±0.25% of the absolute pressure or 5.0 psi (34.5 kPa), whichever is larger
(b) Initial and reheat steam temperature	±15°F (8K) when superheat is 27°–50°F (15–30K); ±30°F (16K) when superheat is in excess of 50°F (30K)	±4°F (2K) where superheat is 27°–50°F (15–30K); ±7°F (4K) where superheat is in excess of 50°F (30K)
(c) Initial steam quality	±0.5 percentage points of quality for turbines with wet throttle steam	±0.1 percentage points of quality for turbines with wet throttle steam
(d) Primary flow	Not specified	Refer to para. 4.10.1
(e) Secondary flows	±5.0% × (primary flow)/(secondary flow)	Same as (d) × (primary flow)/(secondary flow)
(f) Pressure drop through fossil unit reheater	±50.0%	
(g) Extraction pressures	±5.0%	
(h) Extraction flows***	±5.0%	
(i) Temperature of feed water leaving final heater	±10°F (6K)	
(j) Exhaust pressure****	±0.05 psi (0.34 kPa) or ±2.5% of the absolute pressure, whichever is larger	±0.02 psi (0.14 kPa) or ±1. 0% of the absolute pressure, whichever is larger
(k) Load	Refer to para. 3.13.5	±0.25%
(l) Voltage	±5.0%	
(m) Power factor	Not specified	±1.0%
(n) Speed	±5.0%	±0.25%
(o) Aggregate isentropic enthalpy drop of anyone of the sections of an automatic-extraction turbine	±10.0%	

* In any event, the manufacturer's allowable variations in pressure temperature and speed are not to be exceeded, unless specifically agreed to before the test.

** Fluctuations would be indicated by scatter in the data (refer to para. 3.9.2).

*** When steam is extracted for feedwater heaters, the extraction pressures (which are fixed by the turbine design and flow conditions) may deviate from expected values by a few percent. This normally has a negligible effect upon the overall performance. It shall be ascertained that such deviations as do exist are not due to malfunctioning of feedwater heaters. If large deviations persist, agreement must be reached as to the course to be followed.

****If it is not practicable to obtain design or rated exhaust pressure, the test may be conducted by agreement at another exhaust pressure, and either party may require that the exhaust pressure correction curve be verified by test.

3.8.7 During any heat rate, steam rate, or capacity determination of a constant-speed turbine, the turbine shall be operated at specified speed.

3.8.8 Permissible Adjustments. To attain specified operating conditions it is permissible to:

(a) Lower initial pressure. If this is accomplished by throttling the initial steam supply, it must be done not less than 10 pipe diameters upstream from the point at which the initial steam pressure and temperature are measured.

(b) Adjust exhaust pressure. This may possibly be done by bleeding air into the suction of the air removal equipment, by removing some air removal equipment from service, or by reducing cooling capacity. Hotwell conductivity should be closely monitored if these adjustments are made.

3.8.9 Valve Positions. Nozzle, bypass, extraction, and secondary flow valves to or from the turbine, if provided, shall be in the position contemplated by the specified performance. If the specification is not clear in this respect, or if any of these valve positions cannot be attained, the parties to the test shall agree as to the intent.

3.8.10 Measurements of feedwater heater and condenser circulating water leakage are not required, but these components should be checked for excessive leakage. This check is particularly important on feedwater heaters where leakage would affect the determination of primary flow or reheater flow.

3.8.11 Deviations. Deviations of variables in excess of the limits prescribed in Table 3.1, or as otherwise agreed upon, may occur during a test run. If such deviations are observed during the test run, the cause shall be eliminated and the test continued, if possible, until all variables are within the specified limits for the planned duration of the test run.

If the cause of the deviations cannot be eliminated during the test run, or if deviations are discovered during computation of results from a completed test run, that run shall be rejected in whole, or in part, and repeated as necessary after the cause of the deviations has been eliminated, except in the case of initial steam pressure and initial and reheat steam temperature.

If the initial steam pressure, initial steam temperature, or reheat steam temperature exceed the maximum permissible deviation indicated in Table 3.1, the correction factors for these variables must be calculated for the specific cycle being considered and used in place of the standard steam conditions corrections normally provided with the turbine.

Any rejected portions of the test run shall not be used in computing the overall averages. The results of that test run will then be deemed acceptable provided:

(a) valid periods aggregate to one hour or more,

(b) quantity of readings obtained during the valid period satisfies the criteria of paras. 3.9.1 through 3.9.5, and

(c) selected time periods do not include generation changes, level changes, or any integrated data from any part of the invalid periods.

3.9 FREQUENCY OF OBSERVATIONS AND DURATIONS OF TEST

3.9.1 Frequency of Observations. For steam rate or heat rate tests, output observations from indicating meters and differentials on flow meters for primary flow shall be made at intervals no greater than one minute. Other important measurements shall be made at no greater than five-minute intervals. Integrating meters and water levels shall be read at intervals not exceeding 10 minutes.

3.9.2 Duration of Test Runs. This Code recommends a minimum steady-state test run of two-hour duration for each load point. Although high speed data acquisition systems may permit enough readings to be taken in less than two hours to satisfy other requirements, the two-hour minimum is recommended to verify cycle isolation. In any case the length of the test period for which readings are averaged shall be at least as long as the period which corresponds to N_R from Fig. 3.1. N_R is the required number of readings whose averaged scatter will affect the test results by an uncertainty no larger than 0.05 percent. Table 3.2 contains the percentage coefficients to be used to calculate $\overline{Z}$, the abscissa on Fig. 3.1.

3.9.3 Number of Readings Available. During a test run, after several readings have been recorded and their scatter established, Fig. 3.1 may be used to determine how many readings are needed to comply with the 0.05 percent effect of the scatter on the results or to determine if improvements are needed in the instrumentation or in the control of test conditions.

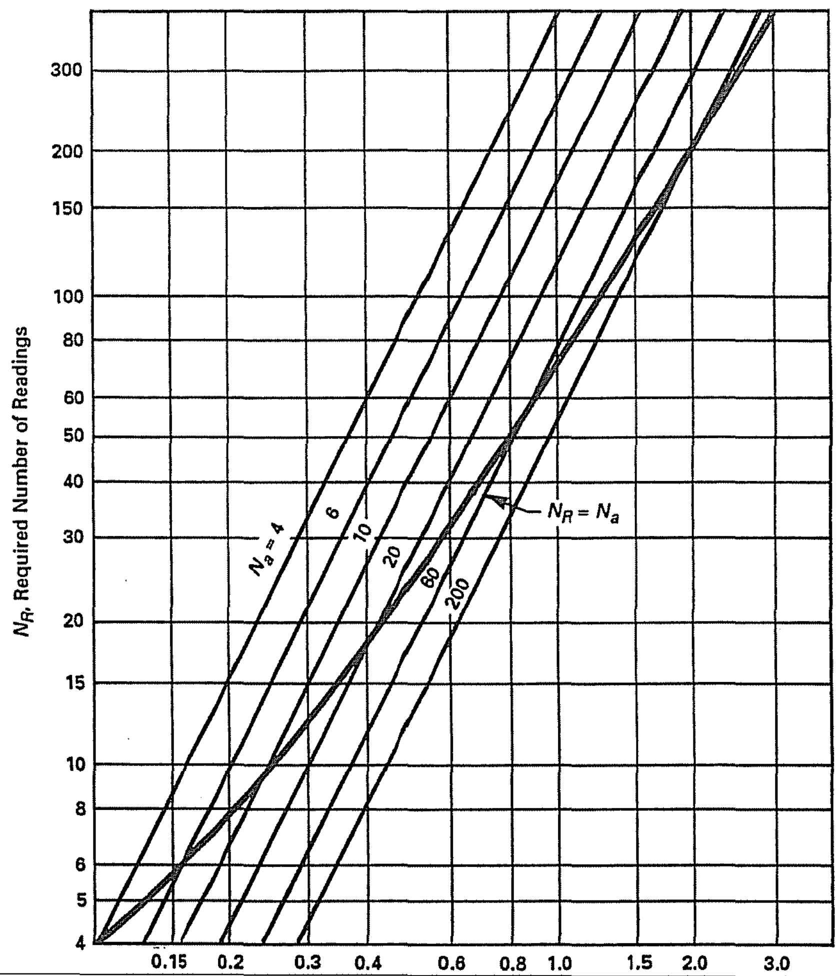
3.9.4 Illustrations and Derivation. Section 7 in this Code presents illustrations for the use of Fig. 3.1 as well as its derivation. A method is also presented and illustrated for estimating the uncertainty of a test based on all the readings of a specific type that are used to calculate the test results. A comprehensive treatment of calculation of uncertainty is presented in PTC 19.1.

3.9.5 Only such observations and measurements need be made as apply and are necessary to attain the objective of the test. In the case of the alternative test, additional measurements beyond those required may be desirable to aid in the analysis of test results.

3.10 CALIBRATION OF INSTRUMENTS

3.10.1 All measuring instruments shall be accurate and reliable and shall be calibrated as required in compliance with criteria given in Section 4. Calibration standards shall be traceable to those maintained by the National Institute of Standards and Technology.

The ratio of the accuracy of the measuring standard compared to the instrument being calibrated is re-



$$\overline{Z} = \frac{100 \times \theta_1(I_{max} - I_{min})}{0.5(I_{max} + I_{min})} \text{ or } \theta_2(I_{max} - I_{min}), \text{ in percent}$$

NOTES: $\overline{Z}$ = percentage effect of instrument reading range on the test results
N_a = number of readings available whose maximum and minimum values are used to determine Z
I = instrument readings in engineering units
θ_1 = factor from Table 3.2, effect per percent of reading
θ_2 = factor from Table 3.2, effect per unit of reading

FIG. 3.1 REQUIRED NUMBER OF READINGS (N_R) CORRESPONDING TO 0.05% EFFECT ON THE TEST RESULTS DUE TO SCATTER

TABLE 3.2
DEFINITIONS AND NOTES TO FIGURE 3.1

(A) θ_1, θ_2 INFLUENCE FACTORS FOR CALCULATIONS $\overline{Z}$, THE ABSCISSA OF FIG. 3.1

Notes:

(1) θ_1 is expressed as percent effect per percent of instrument reading.

(2) θ_2 is expressed as percent effect per unit of instrument reading.

(3) θ_1', θ_2' are the slopes of the correction-factor curves.

(4) θ_1'' or θ_2'' are used to take into account the effect of the instrument-reading range for fluctuation in measurements used to establish any enthalpy appearing in the heat rate equation. For θ_1'' or θ_2'' values use the applicable Figs. 7.2, 7.3, 7.4 or 7.5 after converting the ordinate to percentage effect per percent of absolute pressure or absolute temperature for θ_1'' or percent effect per unit of reading for θ_2''.

Type of Data	θ_1	θ_2
(1) Power	1.0	. . .
(2) Flow by Volumetric Weigh Tanks	1.0	. . .
(3) Flow by Flow-Nozzle Differentials	0.5	. . .
(4) Steam Pressure and Temperature	$\theta_1' + \theta_1''$	$\theta_2' + \theta_2''$
(5) Feedwater Temperature	. . .	θ_2''
(6) Exhaust Pressure	θ_1'	θ_2'

(B) FOR COMBINING TYPES OF DATA

Type of Data	Combined
(1) Average of n columns of similar readings such as 4 exhaust-pressure taps	$\overline{Z}_n = \dfrac{\sqrt{\sum \frac{\overline{Z}_i^2}{n}}}{\sqrt{n}} = \dfrac{1}{n}\sqrt{\sum \overline{Z}_i^2}$
(2) Total effect of m types of readings with the same time interval between readings, such as load and flow, or pressure and temperature	$\overline{Z}_m = \sqrt{\sum \overline{Z}_n^2}$

NOTES:
(1) $\overline{Z}$ is the percentage effect the instrument readings range (maximum reading – minimum reading) has on the test results.
(2) Subscript i refers to columns of individual measurements.

ferred to as accuracy ratio. Wherever achievable, an accuracy ratio of 10:1 is desirable for calibration work. Extremely accurate instruments approaching the accuracy of the measuring standard may have a ratio of 4:1.

Consideration shall be given to the environment in which the calibration takes place. Even under laboratory conditions, the quantity being measured and the instruments obtaining the measured value can be influenced by vibration, magnetic fields, ambient temperature, changes in local acceleration due to gravity, fluctuation, instability of the voltage source, and other variables.

A calibration should cover the range for which the instrument is used. The increment between calibration points and the method of interpolation between these points shall be selected so as to attain the lowest possible calibration uncertainty.

For each calibration point, a deviation may be found between the value measured by the instrument to be calibrated and the calibration standard. A plot or table of deviation versus instrument measurement is then used to determine the amount of correction to be applied to a test measurement. Calibration results also may take the form of instrument output at a known value of input as determined by the calibration standard. From this, a conversion equation can be developed for the instrument.

The calibration report should include the identification of the calibration equipment and instruments, a description of the calibration process, a statement of uncertainty of the measuring standard, and a tabulation of the recorded calibration data. The report should be signed by a responsible representative of the calibration laboratory. Where appropriate, calibration shall be performed with test instruments installed in place for the test and all calibrations shall be available prior to the test.

In-place calibration of station instrumentation is necessary when secondary flow measurements are made by a permanently installed flow element for which calibration is required or where station instruments and a computer are used for test data acquisition.

Installation of all test instrumentation shall comply with all applicable criteria of Section 4. Instruments subject to failure or breakage in service should be duplicated by reserve instruments, properly calibrated, and ready to be placed in service without delay.

3.11 STEAM PRESSURE AND TEMPERATURE MEASUREMENTS

3.11.1 Extraction pressure and temperature measurements, when required, should be made both at the turbine end and the feedwater heater end of the extraction piping for feedwater heaters located outside the condenser neck. Source connections in the intermediate pressure to low pressure crossover pipe or in the low pressure turbine bowl may be used as a common point for intermediate pressure section and low pressure section efficiency determinations. Paragraphs 4.17.21 and 4.18.3 should be consulted for guidance in selecting locations for pressure taps and thermowells.

3.11.2 Steam enthalpy shall be determined from temperature and pressure measurements only when the steam is superheated at least 27°F (15K).

3.11.3 Thermodynamic Properties. Except with written agreements to the contrary, the latest edition of the ASME Steam Tables, "Thermodynamic and Transport Properties of Steam" and its enthalpy-entropy diagram (Mollier chart), shall be used in the calculation of test results. When computers are used, they may link to compiled versions of the source code as supplied with the steam tables. Otherwise, they shall be programmed in accordance with the 1967 International Formulations for Industrial Use.

3.12 CORRECTIONS

3.12.1 Corrections shall be applied to the test results for any deviations of the test conditions from those specified. Correction factors may be in the form of curves or numerical values. The method of applying corrections shall be carried out as required in Section 5. Thermal losses associated with unlagged heaters and connecting piping located in the condenser neck shall be considered cycle losses, not turbine losses.

3.12.2 The numerical values of corrections shall be agreed upon prior to the test. Auxiliary tests may be run for the purpose of verifying the value of certain correction factors. Any such special tests shall be completely described in the test report, as to the methods employed and the results obtained. (See paras. 3.4.5 and 3.8.11 and Section 5.)

3.13 METHODS OF COMPARING TEST RESULTS

3.13.1 The method of comparing test results to the specified performance shall be agreed upon by both parties prior to the test. The following are different methods that can be utilized to make these comparisons.

3.13.2 Valve Point Basis. If the specified performance is based on valve points, then a locus curve can be drawn through the specified performance points for comparison with another locus curve drawn through the corrected test heat rates conducted at valve points. Test results may be compared with the specified performance by reading the difference between the two locus curves at the specified kilowatt load(s). Alternatively, the comparison may be made at the test valve-point loads. In any case, the provisions and intent of the contract must be met.

There may be instances when regulatory restrictions limit operation of a unit to loads below the valves-wide-open point. In such cases it is necessary to apply a correction for operating on a valve loop so that the test heat rate at the highest permissible test load may be included on the curve of corrected test heat rates.

It is recommended that the highest test load be as close to the valves-wide-open load as possible to keep the valve loop correction to a minimum. Testing at reduced steam generator pressure is recommended, where practical, to minimize the loop correction.

The following approach is recommended:

(a) Establish by test the pressure drop across the last control valve(s) to open in valves-wide-open operation. Steam generator pressure may be reduced to open the last valve(s). If this is not possible, use the design pressure drop for the last control valve(s), when fully open.

(b) Measure the pressure drop across the last control valve(s) to open during the highest load test.

(c) Apply the following equation to obtain the percentage heat rate correction:

$$\text{Percent } \Delta HR = \frac{w_n}{w_{mo}} \left(\frac{\Delta p_{mo} - \Delta p_{vwo}}{p_t} \right) 100k$$

where subscript *mo* indicates highest load test, and

$\dfrac{w_n}{w_{mo}} =$ the ratio of flow through the final valve(s) to total flow during the highest load test (decimal fraction of total flow being subjected to extra throttling.)

$\dfrac{\Delta p_{mo} - \Delta p_{vwo}}{P_t} =$ the ratio of (1) the difference between pressure drop across the final valve(s) during the highest load test and the pressure drop across the same valve(s) at valves-wide-open conditions, to (2) throttle pressure (extra pressure drop due to final valve(s) not being wide open.)

k= the percentage effect on heat rate for a 1 percent change in pressure drop

P_t= absolute throttle pressure

k= 0.15 for turbines with nuclear steam supply operating predominantly in the moisture region.

k= 0.10 for turbines operating predominantly in the superheat region.

k values for other types of turbines should be obtained from the manufacturer.

3.13.3 Mean-of-the-Valve-Loop Basis. If the specified performance is based on mean of the valve loops, it may be convenient to convert to the valve-point basis, and the correction curves for this conversion shall be furnished by the manufacturer. However, if there is any doubt as to their accuracy, enthalpy drop or other efficiency tests can be run to establish the difference between the valve-point curve and the mean-of-the-valve-loop curve.

3.13.4 Throttled Valve(s) Basis. For machines with a single valve or multiple valves operating in unison, each test heat rate should be compared to design heat rate at the same percent of valves-wide-open load. This can best be done by including a test at the valves-wide-open load. Therefore, this is the preferred condition. However, some units cannot be tested with valves wide open. In these cases, it is necessary to predict the test valves-wide-open load using the available test information given below. It is recommended that the highest test load be at least 95 percent of the load corresponding to rated flow at specified steam conditions and cycle arrangement in order to minimize uncertainty in the extrapolation method. The following approach is recommended:

(a) Establish the relationship between the test throttle flow vs. first stage inlet (bowl) pressure over as much of the load range as possible. See Fig. 3.2. Correct the throttle flow from the test throttle steam conditions to the specified throttle steam conditions at valves wide open as shown in para. 5.4.2. The first stage inlet (bowl) pressure must be corrected to specified throttle pressure at valves wide open as follows:

$$p_c = p_o \times \frac{p_s}{p_t}.$$

where

p_c= corrected first stage inlet (bowl) absolute pressure

p_o= test first stage inlet (bowl) absolute press

p_s= specified throttle absolute pressure

p_t= test throttle absolute pressure

(b) In tests of light water reactor (LWR) cycles with reheat, the use of the alternative procedure may not provide sufficient data to establish the turbine throttle flow, particularly if the main steam flow to the reheater is not measured. In such tests, one of the following procedures may be used by agreement of the parties to the test:

(1) Determine the main steam flow to the reheater with available plant instrumentation or;

(2) Conduct calibration tests, without the reheater in service, of the first stage pressure versus throttle flow, and correct the flow using manufacturer's data to obtain the throttle flow during tests with the reheater in the cycle.

If either of these procedures cannot be implemented, then;

(3) Use the design values for the reheater flow and subtract this value from the total flow to obtain the throttle flow for each test point.

(c) Using the above relationship, extrapolate to a throttle flow which would exist at the valves-wide-

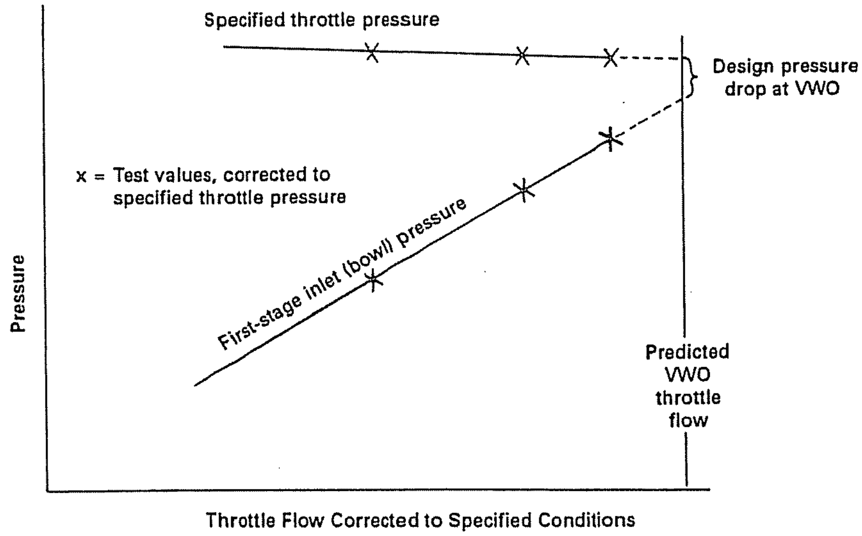


FIG. 3.2 CORRECTED FIRST STAGE INLET (BOWL) PRESSURE VS. CORRECTED THROTTLE FLOW FOR USE IN DETERMINING PREDICTED VWO THROTTLE FLOW

open point, using the design pressure drop from the throttle inlet to first stage inlet (bowl) at valves wide open.

(d) Determine the valves-wide-open load by establishing a curve of corrected throttle flow vs. corrected test load. See Fig. 3.3. Extrapolate to valves-wide-open flow (from item 2) using the slope of the corresponding curves derived from design heat balances as a reference.

(e) The percent of valves-wide-open load for any test point can be determined using the extrapolated valves-wide-open load.

3.13.5 Specified Load Basis. During steam rate or heat rate tests at specified loads, it shall be permissible to adjust the load of the test so that when all corrections have been applied, the corrected load will be within five percent of the load specified for the test. The test results may be reported at a load within this percentage.

The load correction may be applied only when guarantees are made at specified loads and when the valve point or mean-of-the-valve-loop comparisons cannot be utilized.

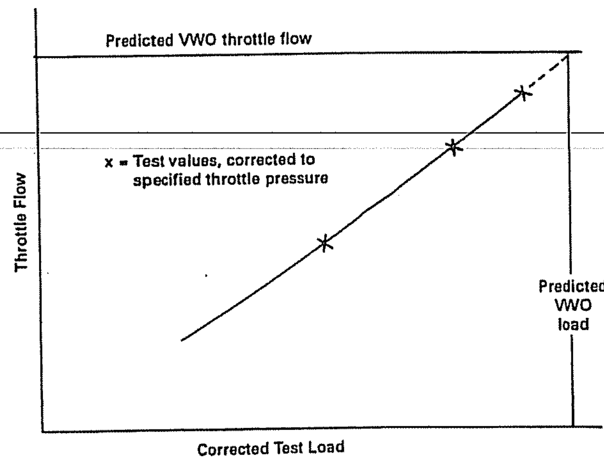


FIG. 3.3 CORRECTED THROTTLE FLOW VS. CORRECTED TEST LOAD FOR USE IN DETERMINING PREDICTED VWO LOAD

3.14 TOLERANCES

3.14.1 Tolerances are contractual adjustments to test results or to guarantees and are beyond the scope of this Code. Allowances for test uncertainties shall not be applied to the test results when a test is run in accordance with this Code. The test results shall be reported as calculated from test observations with only such corrections as are provided for in this Code.

SECTION 4 — INSTRUMENTS AND METHODS OF MEASUREMENT

4.1 GENERAL

4.1.1 In the absence of special agreements to the contrary, this Code presents the mandatory requirements for instruments, methods, and precautions which shall be employed. It emphasizes the use of advanced instrument systems, such as those using electronic devices or mass flow techniques, that are suitable for use with digital systems. The Supplements on Instruments and Apparatus, PTC 19 series, provide general and authoritative information concerning instruments and their use and should be consulted if sufficient information is not included in this Code.

4.1.2 Duplicate Instrumentation. This Code specifies duplicate instrumentation for measuring certain types of data that are critical to the test results; such data may include flow nozzle pressure differentials and steam temperatures. Other data, such as exhaust pressures, vary over the region involved; the several measurements required confirm each other by their pattern from test point to test point. Beyond these, duplication of many types of instrumentation should be seriously considered to assure successful use of the instruments or to detect trouble, and to gain the significant reduction of the uncertainty of the average of the duplicating instruments relative to that of a single instrument. Refer to Figs. 4.11a–4.11e.

4.1.3 Equivalent Instrumentation. By mutual agreement of the parties to the test, manual instrument systems as described herein may be used as an alternative to the advanced instrument systems specified by this Code.

4.1.4 Use of Mercury in Instrumentation. Certain manual instrumentation systems require the use of indicating fluids to indicate pressure or differential pressure. Historically, mercury is one of the fluids commonly used for this purpose. Mercury will alloy with many other metals such as copper, lead, tin, bronze, and Monel and their alloys. There is evidence that Inconel alloys, zircaloy, and certain stainless steels are also sensitive to mercury. These materials are used extensively in the construction of various nuclear steam supply system components that come in contact with feedwater returned from the turbine cycle.

Mercury constitutes a hazard to light-water cooled and moderated nuclear steam supply systems if introduced into the feedwater stream. If the use of mercury cannot be avoided in pressure measuring instruments, the following precautions are recommended:

(a) Keep valves to test instruments closed except during test runs.

(b) Install quick-closing solenoid valves in test instrument sensing lines to close automatically on systems upsets.

(c) Employ double mercury traps.

(d) Locate primary flow element in the low pressure part of the feedwater cycle where it is more remote from the nuclear steam supply system (see para. 4.9.1).

Mercury metal and compounds of mercury may cause dangerous environmental problems. The relatively high vapor pressure of mercury presents a serious health hazard if spillage occurs. Extreme care is necessary and strict adherence must be given to all applicable regulations concerning mercury. If the risk of using mercury-filled manometers is judged unacceptable by one or both parties to the test, regardless of the degree of precaution exercised, the parties may employ advanced instrument systems (such as those employing certain high sensitivity differential-pressure transducers) in accordance with paras. 4.1.1 and 4.8.1 of this Code.

4.1.5 Necessary Instruments. The instruments generally required for a Code test of a steam turbine are listed below and are for check purposes only:

(a) for a mechanical-drive turbine, a dynamometer of a type suitable to the turbine and to the circumstances of the test, see Subsection 4.2

(b) for a turbine-generator, instruments for the measurements of the electrical output and power for excitation, if separately supplied, and for other turbine-

generator auxiliary services, see Subsections 4.4 through 4.7

(c) for determining condenser leakage, instruments required for using tracer techniques, electrolytic or other measuring means refer to PTC 12.2, Surface Steam Condensers

(d) for the location and type of test instrumentation required for full scale testing of a typical unit, see Fig. 4.11(a) to Fig. 4.11(c) and Subsection 4.8 through para. 4.19.1.8

(e) for the location and type of test instrumentation required for the alternative test with final feedwater flow measurement, see Fig. 4.11(d) to Fig. 4.11(e) and Subsection 4.8 through para. 4.19.1.8

(f) for measurement of speed, see Subsection 4.20.

4.1.6 Measuring Devices with Digital Outputs. To minimize uncertainty, it is recommended that measurement signals should be converted from analog to digital only once. Therefore, if a measuring device has a digital output, this digital signal should be transmitted to a data logger rather than use an analog converter.

4.2 MEASUREMENT OF MECHANICAL OUTPUT

4.2.1 Recommended Measurement Methods. Absorption dynamometers (reaction torque measurement systems) or transmission dynamometers (shaft torque meters) shall be used to measure mechanical output of prime movers which can be an auxiliary turbine, turbine generator shaft, or electric motor. These measurement systems are described in detail in PTC 19.7 on "Measurement of Shaft Horsepower."

The direct method for measuring power, utilizing a dynamometer or a torque meter, involves determination of the variables in the following equation:

For power expressed in SI units

$$P = NT$$

where

P = power, watts (W)
N = rotational speed, rad/sec
T = torque, newton–meters

For power expressed in U.S. customary units

$$P = \frac{2\pi NT}{33000}$$

where

P = power, horsepower (hp)
N = rotational speed, (rpm)
T = torque, foot-pounds (ft lbf)

Rotational speed measurement is discussed in Subsection 4.20.

For shaft power measurement when the prime mover is driving a connected load, such as required for a feedwater pump drive turbine in an acceptance test, the transmission dynamometer (shaft torque meter) is recommended. Absorption dynamometers (reaction torque measurement systems) absorb the primer mover power output and cannot be used while simultaneously driving a connected load.

Either surface strain shaft torque meters or angular displacement shaft torque meters which are compatible for use in either computerized data recording systems or for use with electronic digital indicators should be used.

For shaft power measurement of a mechanical drive turbine that can be tested without its connected load, an absorption dynamometer (reaction torque measurement system) can be used. Such a test might occur when a mechanical drive turbine is tested independently of a turbine-generator acceptance test.

Precautions must be taken in the construction and use of torque meters to ensure accuracy. The torque meter shall be accurate within 1 percent of torque. Torque meter readings shall be taken with the frequency indicated in Subsection 3.9 and shall not exceed the permissible deviations shown in Table 3.1. Because power is proportional to speed, speed shall be accurately determined in accordance with Subsection 4.20.

4.2.2 Transmission Dynamometers (Shaft torque meter). Transmission dynamometers shall be calibrated before and after the test series with the torsional member at approximately the same temperature as expected during the test. The calibration shall be conducted with the torsion indicating device in place, taking care not to introduce any bending moments in the torque meter shaft. One such method of calibration is shown in PTC 19.7. Recordings of the indicator shall be made with a series of increasing loads and then with a series of decreasing loads, with the precaution that during the recording of each series of readings the loads shall not be reversed. The calculation of output shall be based on the average of the increasing and decreasing readings. If the difference in readings between increasing and decreasing loads exceeds 0.2 percent of the load, the dynamometer shall be deemed unsatisfactory.

The shaft torque meter may be either a special coupling spacer, installed only during the test, that connects the prime mover shaft to the connected load or it may be a permanently installed part of either the prime mover shaft or the connected load shaft.

To minimize potential error, the shaft torque meter capacity range should be approximately equal to but slightly greater than the torque range of the prime mover.

Temperature compensation in the electronic circuit is recommended to minimize errors that could occur if the test is conducted at temperatures different from the temperature that existed when the torque meter was calibrated.

4.2.3 Absorption Dynamometers (Reaction torque system). Absorption dynamometers are preferably arranged so that the reaction due to friction of any bearings that are essentially a part of the dynamometer will be automatically included in the dynamometer readings. Otherwise the parties to the test shall agree upon an allowance for these losses which shall be stated in the test report.

4.2.4 Precautionary Measures for Absorption Dynamometers. In the case of absorption dynamometers, care must be taken so that no external forces are applied which may introduce errors. The operating fluid of water brakes and cooling air of electric absorption dynamometers shall enter and leave in the radial or axial direction. There shall be no sensible fluid velocities external to the essential brake parts that have any tangential components. Hose connections, if employed, shall cause no sensible force in the tangential direction. If automatic valves are employed to regulate operating fluid flow by means of movement of the stationary dynamometer element, these valves shall have their resistance to motion equal in both directions. Dashpots employed to dampen oscillation shall also have their resistance to motion equal in both directions. Other precautions for specific types of absorption dynamometers are detailed in PTC 19.7.

4.2.5 Absorption dynamometers shall be carefully examined before and after the test and zero scale readings taken. The output shall be determined as shown in PTC 19.7.

4.3 MEASUREMENT OF FEEDWATER PUMP POWER

4.3.1 General. Any thermal energy that is either added to or removed from the turbine cycle by the feedwater pump or its associated auxiliary systems shall be measured and properly accounted for in the turbine heat rate calculations (see paras. 5.7.1 and 5.7.2). The following types of feedwater pump drives can be used: auxiliary turbine drives, motor, and turbine-generator shaft drives.

Regardless of the type of feedwater pump drive that is used, the feedwater pump power can be determined by either of the following methods:

(a) pump shaft power calculated from measured shaft torque and speed (see Subsection 4.2 for torque measurement and Subsection 4.20 for speed measurement)

(b) pump power calculated by an energy balance around the pump using measured fluid flow rates, temperature, and pressure of all fluids that enter and leave the feedwater pumps (see para. 4.3.5). The energy balance method is described in this Section.

4.3.1.1 For auxiliary turbine driven feedwater pumps, it is also necessary to determine the thermal energy that is extracted from the turbine cycle. This can be accomplished by one of the following methods:

(a) measurement of flow rate, pressure, and necessary measurements to obtain enthalpy of steam that enters and leaves the auxiliary turbine (see Subsection 4.12 and para. 4.16.3)

(b) shaft power calculated from measured torque and speed and then divided by the efficiency of the auxiliary turbine to obtain the energy removed from the turbine cycle

Method *(b)* requires the use of the manufacturer's predicted turbine efficiency and must be agreed to by all parties to the test, especially if the auxiliary turbine is being acceptance tested concurrently with the turbine-generator.

4.3.2 Typical Instrumentation for Pump Power by Energy Balance Method. Fig. 4.1 shows the typical instrumentation for measurement of feedwater pump power and is representative of feedwater pumps that have a speed changer and hydraulic coupling. The prime mover could be an auxiliary turbine, motor drive, or turbine generator shaft drive. The hydraulic coupling and speed changer are not commonly used with all three types of feedwater pump drives. However, in some situations they may be used. Therefore, the following text describes thermody-

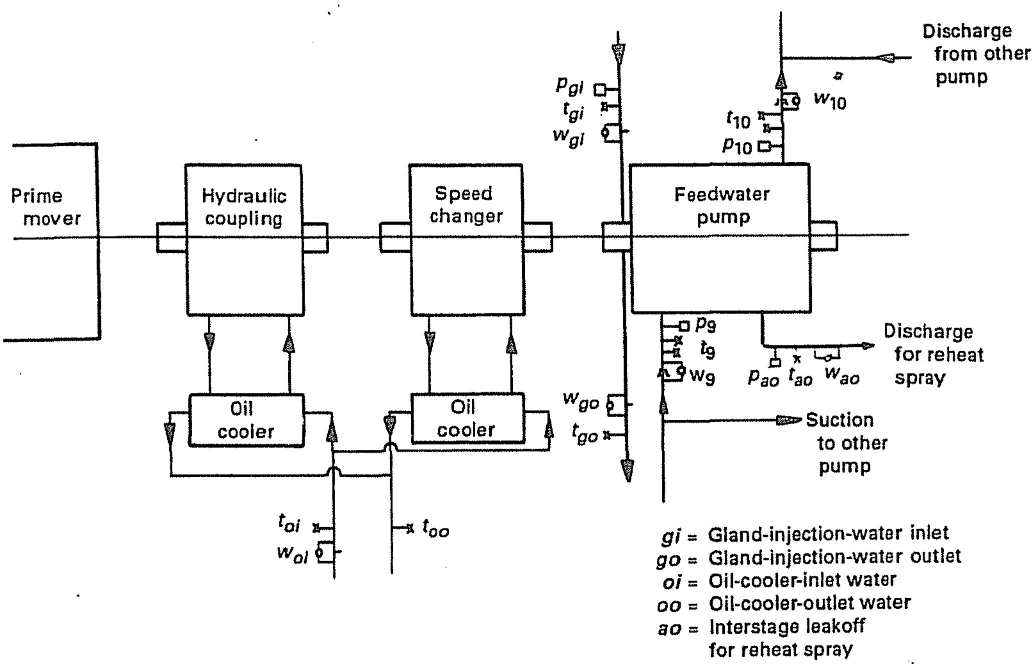


FIG. 4.1 TYPICAL INSTRUMENTATION FOR MEASUREMENT OF FEEDWATER PUMP POWER

namic property measurements and calculations for the most general situation.

4.3.3 Turbine-Generator Shaft Driven Pumps. When feedwater pumps are driven from the turbine generator shaft, the measurements described below must be made as accurately as possible to determine the power supplied by the turbine(s) for driving pump(s) and any associated hydraulic coupling(s) and/or speed increaser(s).

4.3.4 Required Measurements. The power transmitting oil for the hydraulic coupling and lubricating oil for the pump, speed changer, and hydraulic coupling is cooled in heat exchangers using water as a cooling medium (see Fig. 4.1). Changes in instrumentation requirements resulting from any variation in this arrangement shall be agreed upon prior to the test. The illustration on Fig. 4.1 is for one pump but the same measurements will be necessary for each pump in service. In some cases it may not be practical to measure the individual water flow through each pump or the injection water flows to and from each pump. In such cases, the power for each individual pump cannot be accurately determined. However, the total power consumed by the feedwater pumps in service is all that is needed for an overall test.

The temperature, pressure, and flow measurements should be of such accuracy that the effect on the overall test result shall be less than 0.1 percent. The measurements requiring the most care are the temperatures of the feedwater entering and leaving the pump (t_9 and t_{10}) if feedwater pump power is determined as described in para. 4.3.5. These temperatures may be measured by two or more precision resistance thermometers and precision bridges or a difference resistance bridge (see Subsection 4.18). The individual measurements for each location shall agree within 0.2°F (0.1 K). Alternatively, the temperature differences between pump discharge and suction may be measured by multiple junction differential thermocouple devices and precision millivolt instruments.

4.3.5 Calculations. The calculations shown below closely follow PTC 8.2 on "Centrifugal Pumps."

The power taken from the prime mover shaft is the sum of the power equivalent of the enthalpy rise of the water flow through the pump, the power used in bearing losses, gear losses, and hydraulic coupling losses, and the power equivalent of the radiation losses.

The power equivalent of the enthalpy rise of the water ($P_{\text{enthalpy rise}}$) is:

$$P_{\text{enthalpy rise}} = \frac{w_9(h_{10} - h_9) - w_{ao}(h_{10} - h_{ao}) + w_{gi}(h_{10} - h_{gi}) - w_{go}(h_{10} - h_{go})}{K}$$

where K is a constant depending on the units of P, w, and h.
(See Section 2 and Fig. 4.1 for nomenclature).

If P is in kW, w in kg/s and h in kJ/kg, then $K = 1$
If P is in Kw, w in kg/h and h in Kj/kg, then $K = 3600$
If P is in Kw, w in lbm/hr and h in Btu/lbm, then $K = 3412.14$

The power equivalent of the bearing, gear, and hydraulic coupling heat losses ($P_{\text{heat losses}}$), as determined from the heat absorbed by the oil cooling water is:

$$P_{\text{heat losses}} = \frac{w_{oi}(h_{oo} - h_{oi})}{K}$$

Determination of water flow at the pump discharge will vary, depending on whether the main flow measurement nozzle is located in the pump suction or pump discharge piping. If the nozzle is located in the suction piping, the pump discharge flow rate (w_{10}) is:

Pump discharge flow rate =

$$w_{10} = w_9 + w_{gi} - w_{go} - w_{ao}$$

The power equivalent of the radiation losses ($P_{\text{radiation losses}}$) can be calculated or estimated, but the amount of this loss may be negligible (refer to PTC 10 on "Compressors and Exhausters" for the method of calculating this loss).

The pump shaft power (P) is:

$$P = P_{\text{enthalpy rise}} + P_{\text{heat losses}} + P_{\text{radiation losses}}$$

4.3.6 Alternative Calculations. Another method of determining pump shaft power involves pump efficiency curves. Water horsepower (Whp) is determined from these measurements and then divided by expected pump efficiency to obtain pump shaft power.

The basic equations for pump shaft power are:

$$kW = \frac{(Whp)0.746}{\eta}$$

$$kW = \frac{(Q\gamma H)0.746}{550\eta}$$

where

η = pump efficiency from curve
Q = volumetric flow rate at pump discharge, ft^3/sec (m^3/s)
γ = specific weight, lbf/ft^3 (N/m^3)
H = pump total discharge head minus total suction head, ft (m)

Measurements and calculations of water horsepower are detailed in PTC 8.2.

Other losses, such as hydraulic coupling losses, speed changer losses, seal flows, radiation, and spray water takeoffs must also be accounted for as described in para. 4.3.5. Refer to Fig. 4.1 for these items.

An ordinary pump characteristic curve supplied with the pump has two major limitations. First, the efficiency versus capacity curve is valid at only one point because it is plotted at constant speed and many feedwater pumps run at variable speed. One should obtain the variable speed efficiency versus capacity curve prior to using this method.

Second, if the pump is operating at off design speed during the test, the pump efficiency is usually different from predicted efficiency by a small amount. Hence, test speed should be within two percent of design speed in order that pump power can be determined as accurately as possible.

4.4 MEASUREMENT OF ELECTRICAL POWER

4.4.1 General Requirements for A-C Generators. It is recommended that the power output of an a-c generator be measured by sufficient instrumentation to ensure that accurate metering (i.e., no uncertainty is introduced due to the metering method) will be provided under all conditions of load power factor and load unbalance.

Generator loss curves provided by the manufacturer may require either the kilovolt-ampere (kVA) output or kilowatt output and power factor of the generator to determine the generator loss at specified hydrogen pressure.

4.4.2 Recommended Metering Connection Methods. The recommended metering methods that achieve accurate metering for three-phase systems are as follows:

(a) four-wire generator connections — three single-phase meters

(b) three-wire generator connections — two single-phase meters

Refer to para. 4.5.1, below, for further discussion.

The necessity for the recommended metering methods is discussed in the following paragraphs.

4.4.3 Blondel's Theorem for the measurement of electrical power or energy states that in an electrical system of N conductors, N-1 metering elements are required to measure the true power or energy of the system. It is evident, then, that the electrical connections of the generator to the system govern the selection of the metering system.

Connections for three-phase generating systems can be divided into the following two general categories:

(a) three-wire connections with no neutral return to the generating source

(b) four-wire connections with the fourth wire acting as a neutral current return path to the generator

4.4.4 The following describes different types of three-wire and four-wire generator connections that are used

4.4.4.1 Three-Wire System. A common three-wire system is a wye connected generator with a high impedance neutral grounding device. The generator is connected directly to a transformer with a delta primary winding and load distribution is made on the secondary, grounded-wye, side of the transformer. [See Fig. 4.2(a).] Load unbalances on the load distribution side of the generator transformer are seen as neutral current in the grounded wye connection. However, on the generator-side of the transformer, the neutral current is effectively filtered out due to the delta winding and a neutral conductor is not required.

Another type of three-wire system utilizes a wye connected generator with a low impedance neutral grounding resistor. The generator is connected to a three-wire load distribution bus and the loads are connected either phase to phase, single phase, or three phase delta. The grounding resistor is sized to carry 400 to 2000 amperes fault current.

An ungrounded wye generator is less common than the high impedance grounded-wye generator, but when used with a delta-wye grounded transformer, it is also an example of a three-wire generator connection. [See Fig. 4.2(a).]

A final example of a three-wire generator connection is the delta connected generator. The delta connected generator has no neutral connection to facilitate a neutral conductor; hence, it can be connected only in a three-wire connection. [see Fig. 4.2(b).]

4.4.4.2 Four-Wire System. Four-wire generator connections can be made only with a wye connected generator with the generator neutral either solidly grounded or, more typically, grounded through an impedance. Load distribution is made at generator voltage rather than being separated from the generator by a delta-wye transformer. This type of connection has a separate fourth conductor which directly connects the generator neutral (or neutral grounding device) with the neutral of the connected loads. [see Fig. 4.2(c).]

For the generating system connections described in the preceding paragraphs, accurate metering will be provided under all conditions of load power factor and load unbalance by application of the recommended metering methods, which were described in para. 4.4.2.

A typical instrument connection diagram is shown on Fig. 4.2(d).

4.4.5 Alternative Metering Connection Methods. Alternative metering methods that may be used by mutual agreement between all test parties are described in PTC 6 Report. However, the uncertainty of the power measurement with the alternative metering methods will be greater than that of the recommended metering methods.

4.4.6 Meter Connections. Connections for voltage and current measuring instruments shall be made on the generator side of the step-up transformer(s) as close to the generator terminals as possible. Current connections shall be made on the generator side of any external connections of the power circuit by which power can enter or leave this circuit.

4.4.7 Excitation Power Measurement. If the excitation or auxiliary systems receive power from the generator, then either it must be separately metered or the generator power metered beyond the excitation connections but ahead of any auxiliary power connections.

Electrical power separately supplied to produce either excitation or any other service to the turbine generator unit, not specifically covered by agreement of the parties to the test, shall be measured at the

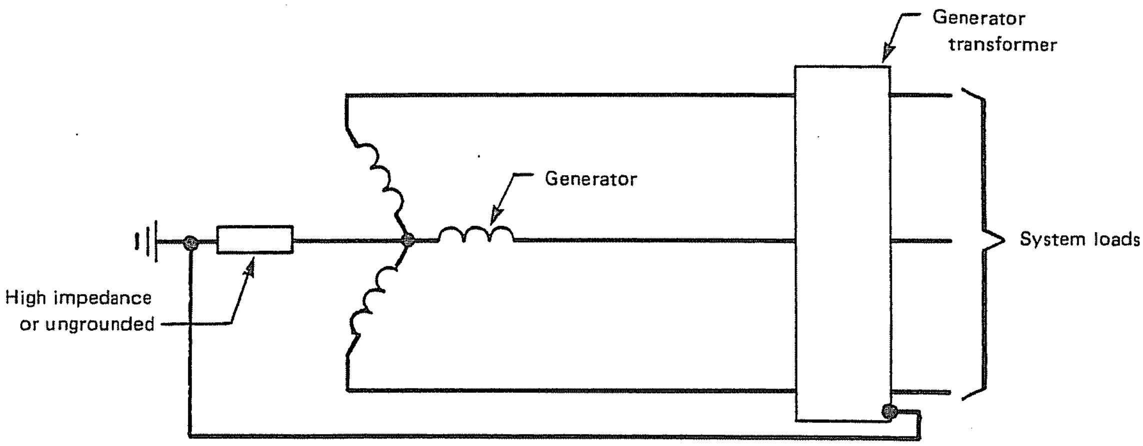


FIG. 4.2(a) WYE GENERATOR — 3-PHASE, 3-WIRE

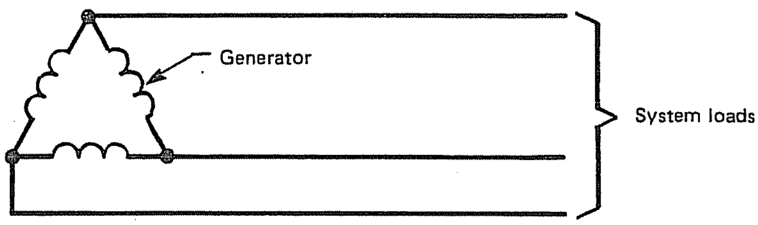


FIG. 4.2(b) DELTA GENERATOR — 3-PHASE, 3-WIRE

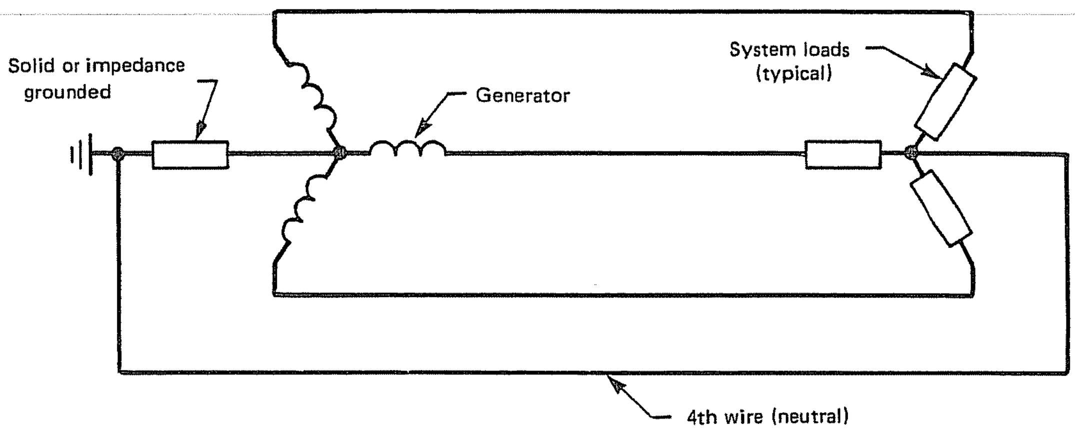
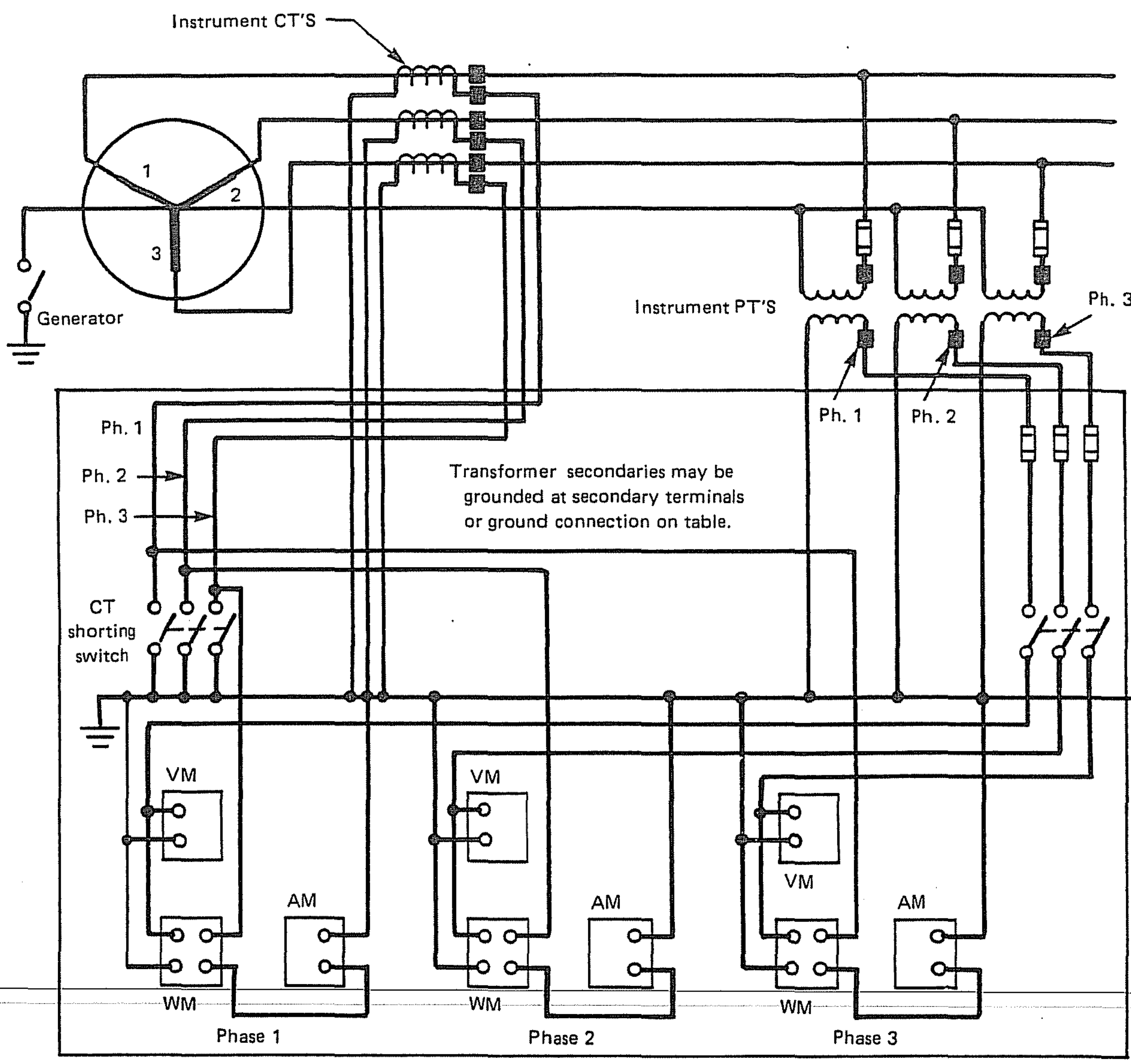


FIG. 4.2(c) WYE GENERATOR — 3-PHASE, 4-WIRE



VM — Voltmeter
AM — Ammeter
WM — Wattmeter
CT — Current transformer
PT — Potential transformer
▪ — Polarity mark
▯ — Fuse

FIG. 4.2(d) TYPICAL CONNECTIONS FOR MEASURING ELECTRIC POWER OUTPUT BY THE THREE-WATTMETER METHOD

point of supply to the auxiliary apparatus producing the excitation or other service.

4.4.8 D-C Generator Power Measurement. Power output of d-c generators shall be measured by the d-c voltmeter-ammeter method. Connections for voltage and current measuring devices shall be made on the generator side of any connections to the power circuit by which power can enter or leave this circuit and as close to the generator terminals as physically possible.

4.4.9 Guidance for Power Measurement. ANSI/IEEE Std 120, Master Test Guide for Electrical Measurements in Power Circuits, contains detailed information on the construction and use of electrical measurement equipment and instructions for measurement of electrical quantities.

4.5 A-C GENERATOR TEST INSTRUMENTS

4.5.1 Test Instruments. Active power or energy (kilowatts/kilowatt hours) shall be measured by precision watt/watthour meters (uncertainty of $\pm$ 0.10 percent of reading for power factors $\geq$ 0.8). The reactive power (kilovars) shall be measured either by a var transducer (uncertainty of $\pm$ 0.20 percent of range) or calculated from measurements of voltage and current. The active power, and either voltage and current, or the reactive power of each required phase, as described in paras. 4.4.2 through 4.4.4, shall be measured.

As an alternative to active and reactive power measurements of each phase, polyphase precision watt/watthour transducers and polyphase precision var/varhour transducers may be used. For four-wire generator connections, three-element polyphase transducers are required. For three-wire generator connections, two-element polyphase transducers may be used. The metering uncertainty with the polyphase transducers must be equivalent to the combined metering uncertainty of the single-phase meters and calibrated per para. 4.7.2.

As noted in para. 4.1.6, any power measuring device with digital outputs should not use analog converters for signal transmission to data loggers.

The power output measurement instruments shall be calibrated before and after the tests. The laboratory(ies) and standard(s) used for the calibrations shall be mutually agreed upon by the parties to the test. It is required that the instruments have their best operating characteristics over the range of values that will occur during the tests.

Extreme care must be exercised in the transportation of calibrated portable instruments. The instruments should be located in an area as free of stray electrostatic and magnetic fields as possible. Where watthour meters are used, a suitable timing device shall be provided to accurately determine the times for the number of disc revolutions or pulse counts recorded during the predetermined test time period, to one part in four thousand.

4.5.2 Instrument Transformers. Correctly rated current and potential transformers of the 0.3 percent accuracy class (metering type) shall be used for the tests. Transformers shall be calibrated for ratio and phase angle prior to the test over the ranges of voltage, current, and burden expected to be experienced during the test. Burdens shall be determined from instrument nameplate data and by measurement of lead resistance or by measurement of the volt-amperes or the secondary impedance and must be constant during the test. Protective relay devices or voltage regulators shall not be connected to the instrument transformers used for the test. Normal station instrumentation may be connected to the test transformers if the resulting total burden is known and is within the range of calibration data.

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

4.5.2.2 Precautions for Potential Transformers. Potential transformers may have either one or two secondary windings; however, one secondary winding is the most common arrangement. If potential transformers with two secondary windings are used, the total burden on the two secondary windings must be less than or equal to the total allowable burden of the two windings and the burden on each winding must be less than or equal to the allowable burden of each winding. Failure to observe the above precautions will introduce increased uncertainty in the measurement of electrical potential.

4.5.3 Instrument Connections. Test instruments shall be connected into the lines from the generator as near to the generator terminals as practical, and on the generator side of any external connections by which power can enter or leave the generator circuit. Instruments should be connected as shown

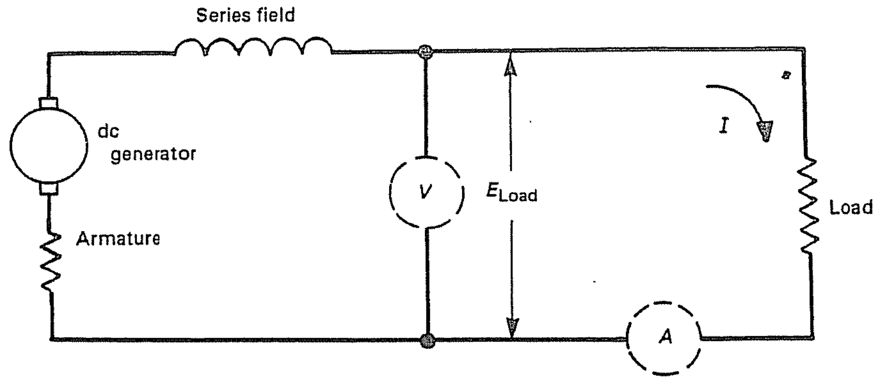


FIG. 4.2(e) DIRECT CURRENT SERIES GENERATOR

on connection diagrams given in ANSI/IEEE Std 120. Guidance on the use of computer-compatible instruments is provided in PTC 19.22, Digital Systems.

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

The wiring influence of the voltage circuit shall not cause a significant error in the measured power output. Wire gauge shall be chosen considering the length of wiring and a given load of the potential transformers, taking into account the resistance of the safety fuses to be used in the voltage circuit. The errors due to wiring resistance (including fuses) shall always be taken into account.

4.5.4 Excitation and Auxiliary Service. Test instruments for measurement of the excitation and auxiliary power services shall be the same type as described in para. 4.5.1 above.

4.6 D-C GENERATOR TEST INSTRUMENTS

4.6.1 Instruments. Portable indicating d-c ammeters (with shunts if required) and d-c voltmeters of the 0.25 percent accuracy class shall be used. Ammeter shunts shall be calibrated prior to installation.

Typical instrument locations are shown in Figs. 4.2(e), 4.2(f), 4.2(g) for a direct current series generator, a direct current shunt generator, and a direct current short-shunt compound generator, respectively. The power output and efficiency of each of the three types of direct current generators is calculated as follows.

D-C Series Generator and D-C Shunt Generator:

$$P_E = (I_L \times E_F) + (I_L \times E_A)$$

$$P_o = I_L \times E_L$$

$$\eta_{Gen} = (1 - [(P_E + P_M)/(P_E + P_M + P_o)]) \times 100$$

D-C Short-Shunt Compound Generator:

$$P_E = (I_{Sh\,Fld} \times E_{Sh\,Fld}) + (I_A \times E_A) + (I_L \times E_{Series\,Fld})$$

$$P_o = I_L \times E_L$$

$$\eta_{gen} = (1 - [(P_E + P_M)/(P_E + P_M + P_o)]) \times 100$$

where

P_E = power expended in generator
P_M = mechanical power loss = windage and bearing loss
P_o = power output
η_{gen} = generator efficiency
I_L = load current
$I_{Sh\,Fld}$ = shunt field current
I_A = armature current
E_F = field voltage
E_A = armature voltage
E_L = load voltage

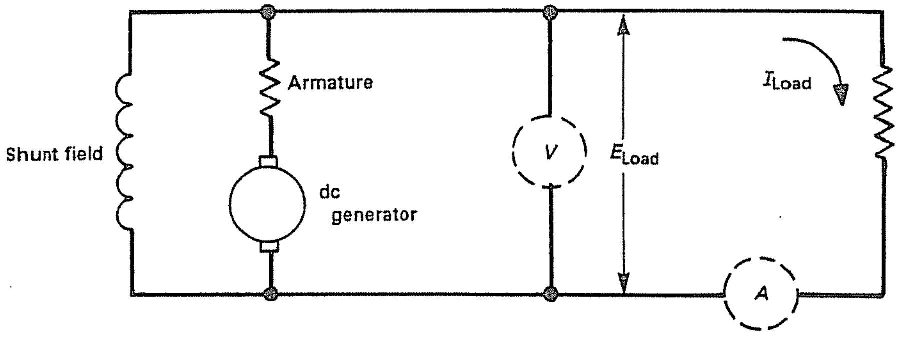


FIG. 4.2(f) DIRECT CURRENT SHUNT GENERATOR

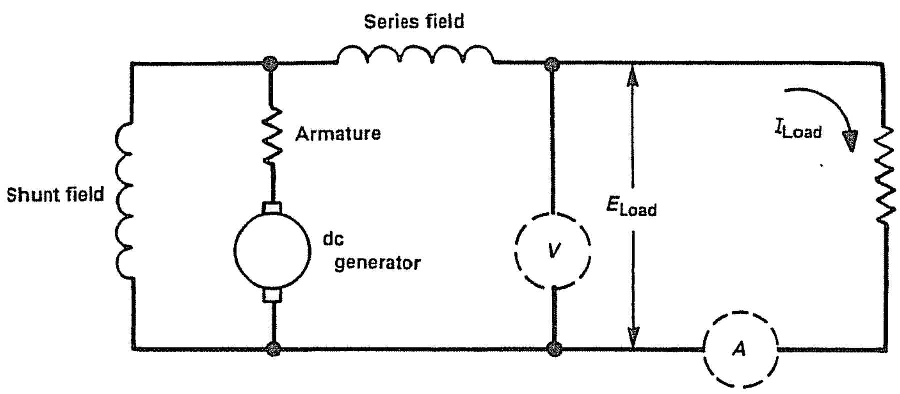


FIG. 4.2(g) DIRECT CURRENT SHORT-SHUNT COMPOUND GENERATOR

$E_{Sh\ Fld}$ = shunt field voltage
$E_{Series\ Fld}$ = series field voltage

4.6.2 Excitation and Auxiliary Service. Test instruments for measurement of the excitation and auxiliary power services may be of the switchboard type if their contribution to the test uncertainty will be less than ±0.03 percent. Otherwise, portable instruments of the 0.25 percent accuracy class shall be used.

4.7 CALIBRATION OF ELECTRICAL INSTRUMENTS

4.7.1 Standards. The electrical test instruments used for measuring the gross electrical output of the generator shall be calibrated against secondary standards traceable to a recognized national standards laboratory such as the National Institute of Standards and Technology under laboratory conditions that approximate the expected test site conditions.

4.7.2 Procedures. Electrical test instruments shall be calibrated immediately before and after the turbine generator test series. Portable instruments shall be calibrated in a laboratory. The value of the voltage maintained on the potential circuit of the instruments during calibration shall cover the range of expected test values. Switchboard instruments, if used by mutual consent of all test parties, shall be calibrated in place. Polyphase meters, or metering systems which cannot be verified to be separate single-phase meters, shall not be used unless they can be calibrated three phase.

4.8 PRIMARY FLOW MEASUREMENT

4.8.1 The accurate determination of primary flow to the turbine is necessary to compute turbine heat rate or steam rate if the results are to be considered as a basis for turbine acceptance. Recognizing the limitations presented herein, this Code recommends measurement of water flow in the feedwater cycle. Extreme care must be taken to obtain the high order of accuracy necessary in primary water-flow measurement. Any deviation from the requirements set forth in the following paragraphs may result in an increase in uncertainty. All known errors must be reduced so that their individual effect is less than 0.05 percent of the primary flow to be measured.

4.8.2 Measurement of Water Flow. While weighing of water can be the most accurate method of measuring flow, it is seldom practical or economical to employ weigh tanks or volumetric tanks for testing of the large units installed in modern power plants. The usual method of determining flow is with a differential pressure producing device. Two sets of pressure taps and a differential pressure instrument for each set of taps will be used.

4.8.3 Recommended Method. Excellent results have been obtained using low beta-ratio throat-tap nozzles and, for this reason, this Code recommends that they be used. The stringent requirements for the recommended primary flow device contained in this Code are based on experience with the low beta-ratio throat-tap nozzles installed in 4 in. to 28 in. flow sections. Larger flow sections may be used provided they can be calibrated in accordance with paras. 4.8.13 and 4.8.14.

4.8.4 Flow Section. Throat-tap nozzles are recommended for measurement of primary flow provided they comply with the following requirements:

(a) The beta-ratio (*d/D*) is limited to the range of 0.25 to 0.50.

(b) The test flow section shall be calibrated (see paras. 4.8.13, 4.8.14, and 4.8.15). The flow section is comprised of the primary element, including the diffusing section, if used, and the upstream and downstream pipe sections. The upstream pipe section shall be a minimum of 20 diameters of straight pipe and include a flow straightener installed at least 16 pipe diameters upstream of the primary element.

The preferred flow straightener utilizes a low pressure drop perforated or tubed plate with a nonuniform hole distribution. The geometry of the design is shown in Fig. 4.5 and hole coordinates are specified in Table 4.1. The design and hole coordinates are identical for both the perforated and the tubed plate straightener. The upstream side of the holes must be beveled in all cases. The straightener is located between 2 and 4 diameters downstream of the test flow section inlet, as shown in Fig. 4.3a.

An alternative is a perforated-plate flow straightener, as shown in PTC 19.5. However, because it is likely to have a higher pressure drop, there is an increased chance of cavitation in the nozzle during calibration which may limit the maximum Reynolds Number achieved.

Another design, utilizing a bundle of at least 50 tubes 2D long (see Fig. 4.3b) has been used extensively. Recent data indicates that this design may not necessarily eliminate flow swirl. Its use may, therefore, introduce an added measurement uncertainty.

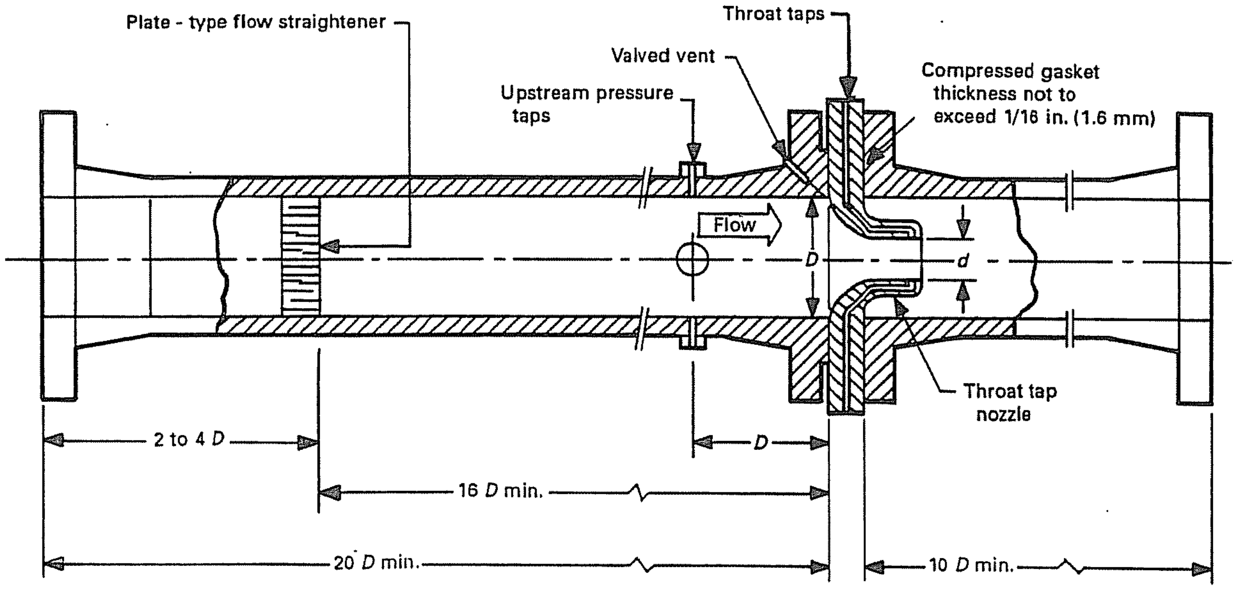
Other types of flow straighteners may be used if their ability to remove swirl and distortion from the upstream flow has been demonstrated.

(c) The primary flow element and its flow section shall be known to be clean (see para. 4.8.18) and undamaged throughout the test period. This shall be determined by inspection as soon as possible before and after the test. The location of the primary flow section in the cycle, its physical configuration, and the technique which is employed to obtain the flow measurements are critical and are discussed in subsequent paragraphs.

4.8.5 PTC 19.5 contains a description of the low-beta-ratio throat-tap nozzle; however, additional information is included in the following paragraphs which applies specifically to throat-tap nozzles used for steam turbine testing.

PTC 19.5 also contains procedures for calculating the flow of water through a throat-tap nozzle using measured values of pressure differential between an in-line set of upstream and throat taps.

4.8.6 Design and Manufacture. Because of the high degree of accuracy necessary, the following requirements are given in regard to the design and manufacture of throat-tap nozzles for primary flow measurement. Fig. 4.4 of this Code and PTC 19.5 show examples of a long-radius, low beta-ratio nozzle shapes with throat taps that satisfy these requirements. It is recommended that this nozzle be manufactured with four throat taps, located 90 deg. apart.



NOTE: No obstruction, such as thermocouple wells, backing rings, etc. are permitted.

FIG. 4.3(a) PRIMARY-FLOW SECTION WITH PLATE-TYPE FLOW STRAIGHTENER (RECOMMENDED)

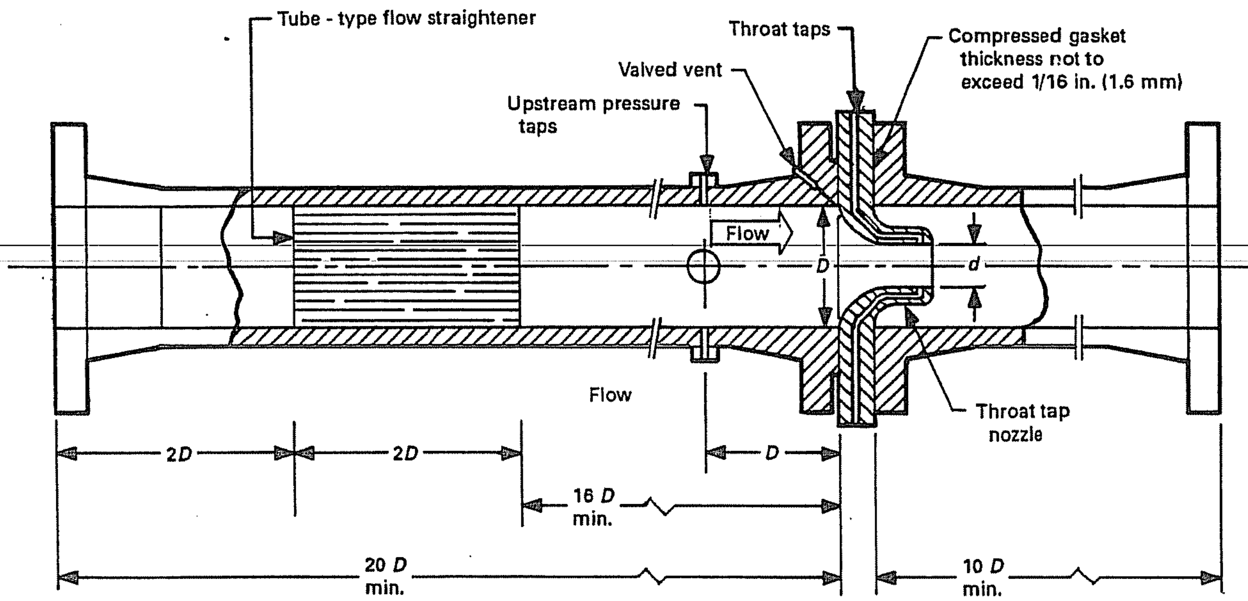


FIG. 4.3(b) PRIMARY-FLOW SECTION WITH TUBE-TYPE FLOW STRAIGHTENER

NOTE: No obstruction, such as thermocouple wells, backing rings, etc. are permitted.
These figures are diagrammatic and are not intended to represent details of actual construction.

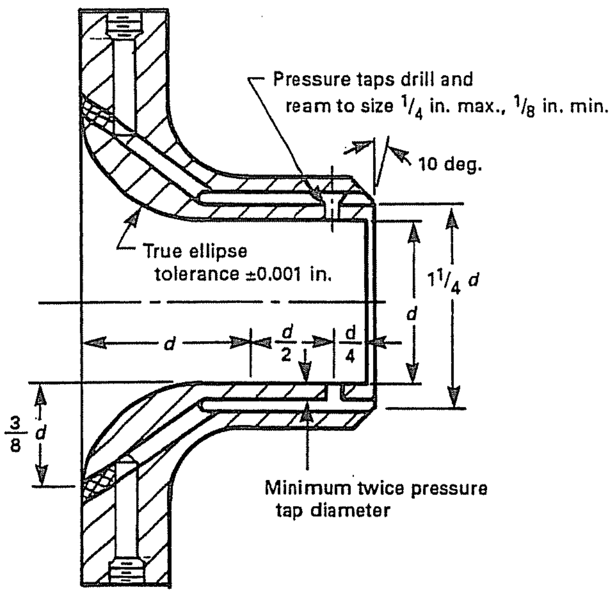
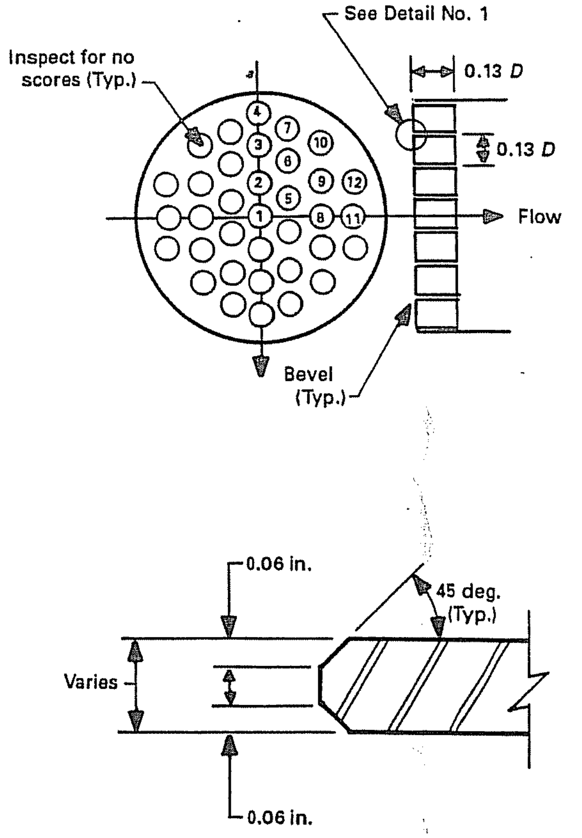


FIG. 4.4 THROAT-TAP FLOW NOZZLE

Great care must be taken in the manufacture and inspection of throat-tap nozzles, particularly in regard to the geometry of the nozzle and the downstream pressure taps; otherwise, difficulties meeting the calibration criteria may occur. This is particularly true when the flow section is welded together, since problems with calibration will not be evident until after the nozzle has been welded into the upstream and downstream pipe sections. Any required rework of the nozzle would obviously be much more difficult than with a flanged construction.



(This figure is diagrammatic and is not intended to represent details of actual construction.)

(No Scale)

FIG. 4.5 PERFORATED OR TUBED PLATE FLOW STRAIGHTENER WITH NON-UNIFORM HOLE DISTRIBUTION

4.8.7 The entrance provided by the low-beta-ratio profile gives a favorable pressure gradient so that the boundary layer will be very thin in the throat section and there will be no flow separations. The area in the plane of the throat taps shall be used in the coefficient calculation. The nozzle shall be made from a corrosion-resistant material with known thermal expansion coefficient and its surface shall be free of all burrs, scratches, imperfections, or ripples. The surface should be either "hydraulically smooth" or 16 micro inches, whichever is smoother. For turbulent boundary layers, the surface is "hydraulically smooth" when protuberances are contained within the laminar sublayer. Figure 4.6 presents the surface finish necessary to be hydraulically smooth as a function of throat diameter and the maximum throat Reynolds number achieved during either test or calibration.

TABLE 4.1
HOLE COORDINATES FOR PERFORATED OR TUBED PLATE

No.	X-axis	Y-axis
1	0	0
2	0	0.142 D
3	0	0.283 D
4	0	0.423 D
5	0.129 D	0.078 D
6	0.134 D	0.225 D
7	0.156 D	0.381 D
8	0.252 D	0
9	0.255 D	0.146 D
10	0.288 D	0.288 D
11	0.396 D	0
12	0.400 D	0.151 D

(D: pipe inside diameter)

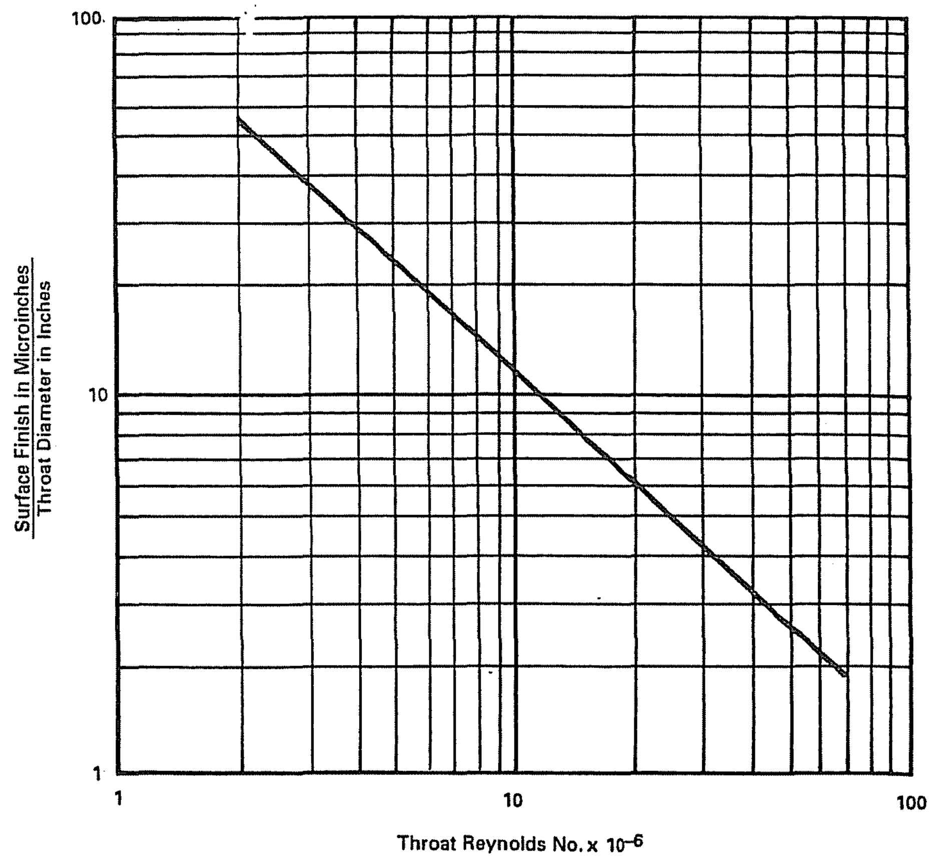


FIG. 4.6 THROAT-TAP NOZZLE REQUIRED SURFACE FINISH TO PRODUCE A HYDRAULICALLY SMOOTH SURFACE

4.8.8 In order to minimize instrument bias error, the nozzle throat diameter should be selected to give the maximum deflection possible, considering both the available pumping head and the instrument range. The transducer or manometer range should be selected to allow for fluctuations and for maximum flow which may be encountered. The nozzle shall not be used to measure flow when the differential pressure is less than 1000 times the reading error, or 2.5 psi (17.2 kPa), whichever is larger. When it is necessary to measure flow over a larger range than can be obtained by complying with this requirement, it is permissible to use additional nozzles with different throat diameters. These nozzles should be sized so that one of the test points can be run with each nozzle.

When measuring large flows the nozzle is sometimes sized to give large pressure differentials with correspondingly large unrecoverable losses. A large pressure drop may prevent normal operation of the plant and will represent a penalty in cycle efficiency which may be unacceptable if the nozzle is to be installed for a significant period of time. This loss can be reduced by about 70 percent by installing a diffuser downstream of the nozzle as shown in Fig. 4.7a. This figure is for a typical diffusing cone installation showing flow-path requirements and is not intended to show details of mechanical design. A cylindrical section of length $d/2$ preceding the diffuser is necessary in order not to change the flow coefficient. Care should be taken to see that the cylindrical section of the diffusing element does not protrude into the flow from the throat of the nozzle and that the gap between nozzle and cylindrical section is less than 0.050 inch. The calibration must be made with the diffusing section in place. It is recommended that the diffuser material have the same expansion characteristics as the nozzle.

A secondary benefit of a diffusing cone may occur during calibration. With a reduced unrecoverable pressure loss, the calibration facility may be able to achieve a higher Reynolds number.

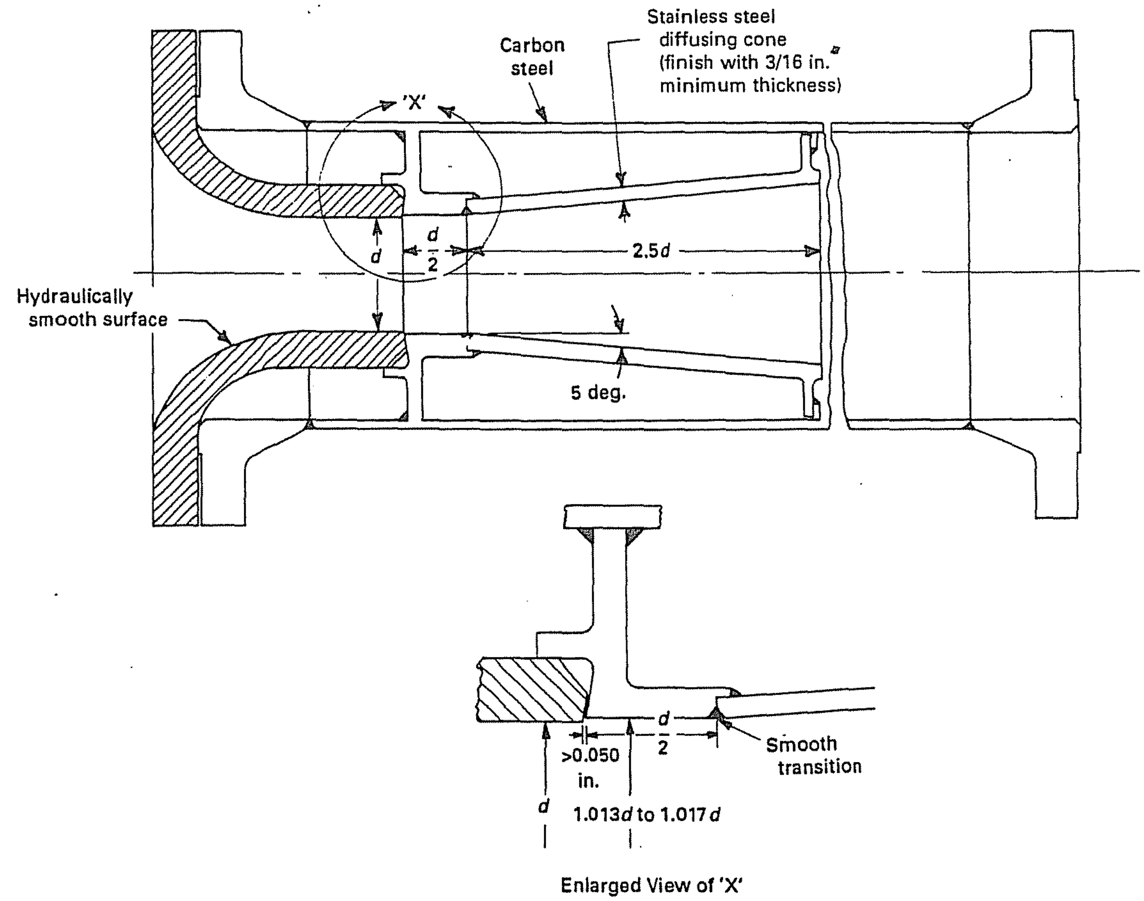


FIG. 4.7(a) THROAT-TAP NOZZLE WITH OPTIONAL DIFFUSING CONE

4.8.9 Pressure Taps. The pressure taps shall be between $^1/_8$ in. (3 mm) and $^1/_4$ in. (6 mm) in diameter and at least two pressure-tap diameters deep. They shall be machined perpendicular to the surface, shall have sharp corners, and shall be free from burrs and scratches. The downstream pressure taps shall be machined in the throat of the nozzle in order to decrease the effect of downstream disturbances on this pressure measurement. They shall be drilled and reamed previous to the final boring and polishing of the throat. A plug with a press fit is then inserted in the hole. The final boring and polishing operation should be done after the insertion of the plug. The plug should be made with provisions for pulling it out of the hole after the polishing and machining is completed. After removal of this plug, any slight burr which might be left on the edge of the hole may be removed by using a tapered piece of hardwood such as maple to roll around the tap edges. The upstream taps shall be carefully made and shall be located one inside-pipe diameter upstream from the nozzle entrance.

4.8.10 Pipe Section. The pipe on either side of the flow nozzle shall be smooth, free from rust, scale, and blisters. For the upstream pipe section, the inside diameter measured at four points at any cross-section shall not differ by more than 0.2 percent. Checks on concentricity should include planes 0.5, 1.0, and 2.0 times the pipe inside diameter upstream from the nozzle inlet. The average inside diameter at different cross-sections shall not differ by more than one percent. The allowable variations in inside diameter for the downstream pipe shall be twice those for the upstream pipe section. (See Fig. 4.7b.)

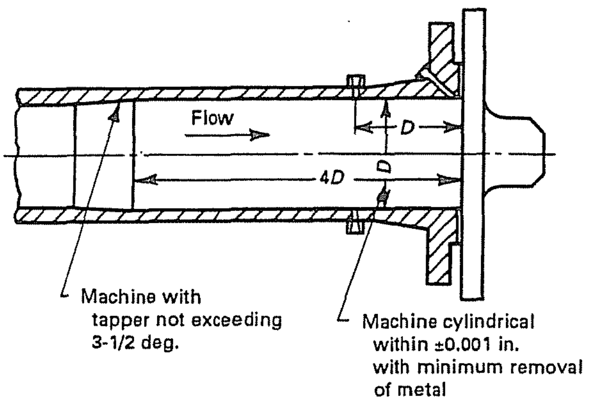


FIG. 4.7(b) BORING IN FLOW SECTION UPSTREAM OF NOZZLE

To achieve compliance with pipe inside diameter limits, the upstream pipe may have to be bored for a length equal to 4D and then tapered at 3.5 deg. to the untouched pipe ID.

4.8.11 Flanged Assemblies. Flanged assemblies are normally used with relatively low pressures such as when the flow element is in the condensate line upstream of the main feed pump. This arrangement is associated with the recommended procedure for the full scale test. The flow nozzle shall be centered in the pipe within $^1/_{32}$ in. (0.8 mm) of the pipe axis.

If the flow section is downstream of the main feed pumps where it is subject to high pressure levels, flanges should conform with the pressure-temperature rating in ANSI B16.5. Considerations such as the cost of the flanges, the cost of moving them into place, and the added cost of pipe hangers may make it desirable to use a welded assembly. See para. 4.8.12.

When the flow section is assembled with flanged connections, the pipe joints at the flow nozzle shall have the inner bores square with the faces of the flanges. The gap between the nozzle flange and the pipe flange shall not exceed $^1/_{16}$ in. (1.6 mm). The gaskets shall not extend within the pipe.

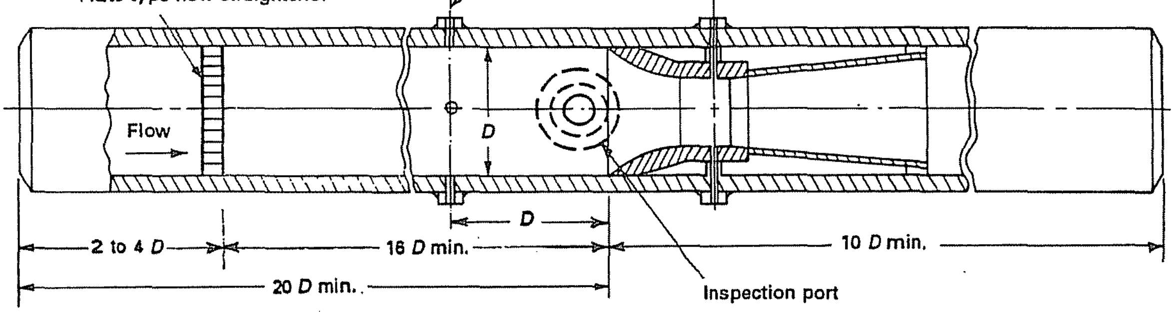
Flanges adjacent to the nozzle should be provided with dowels or other means to ensure that all components of the complete flow section are always assembled in exactly the same relative locations as when it was calibrated. Some methods of manufacture may subject the nozzle throat to distortion due to thermally induced stress. This could be caused by the difference in linear expansion coefficients for the different materials of the components. To reduce the possibility of thermal distortion of the nozzle, it is desirable that the pipe and the flanges of the flow section adjacent to the nozzle be made of a material having the same coefficient of expansion as the nozzle.

To avoid damage to the nozzle during flushing that normally precedes the initial startup of the plant, it is recommended that the flow section be installed after flushing.

4.8.12 Welded Assembly. If the flow section is downstream of the main feed pumps where it is subject to high pressure levels, it may be welded together and then be welded in the station piping after the piping has been flushed. A typical such flow section is shown in Fig. 4.8. To meet the requirement of inspecting the nozzle both before and after a test, a welded flow section shall include a plugged inspection port immediately upstream of the nozzle. The orientation of the inspection port will be determined by the ease of inspection, ease of cleaning, and other design considerations. An example of such an inspection port is shown in Fig. 4.9. The inside diameter of the inspection port should be at least 4 in. (100 mm) to allow easy access and nozzle cleaning if required.

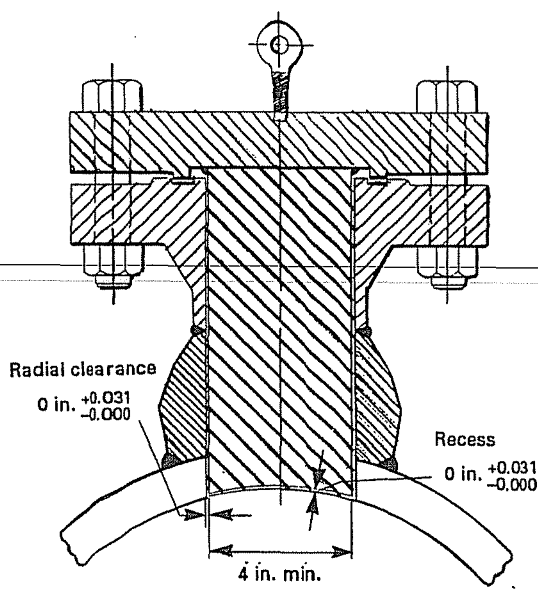
The inspection device (typically a fiber optic device) shall not damage the sharp edges of the inspection hole or the surface of the nozzle, particularly around the taps. The plug must be undamaged and the contour of the plug must be properly aligned to preserve the flow profile of the water. A plug radial clearance of up to $^1/_{32}$ in. (0.8 mm) will be acceptable. A recess (i.e., distance from the end of the plug to the inside diameter of the pipe) of up to $^1/_{32}$ in. (0.8 mm) is acceptable. The plug must not protrude into the pipe.

For flow sections welded into the feedwater pipe, the flow nozzle must be constructed of a corrosion resistant material if the pipe is subject to chemical cleaning. The cleaning of the flow test section can be accomplished by the use of very high pressure water jet devices. In the design of the plant, the design of available cleaning devices should be reviewed and the practicality of performing the cleaning through the inspection port should be evaluated. It may be advisable to install a special port downstream of the downstream pipe section specifically for the introduction of a high pressure water cleaning device.



(This figure is diagrammatic and is not intended to represent details of actual construction)

FIG. 4.8 PRIMARY FLOW SECTION FOR WELDED ASSEMBLY



NOTE: The orientation of the access port on the pipe is determined by the designer. See para. 4.8.12.

FIG. 4.9 INSPECTION PORT ASSEMBLY

If, after installation, inspection reveals damage to the flow nozzle or to its throat taps, such damage may be remedied through the access provided by the inspection opening. This would depend on the type and extent of the damage, and would call for consultation and agreement between the parties to the test.

Precaution should be taken to avoid nozzle throat distortion in service due to use of materials with dissimilar thermal expansion characteristics.

4.8.13 Calibration. Experience shows that the coefficient of discharge cannot be satisfactorily predicted and, therefore, it is necessary to calibrate the flow section. This calibration should be undertaken only at recognized facilities under conditions similar to those in the actual installation. Care must be exercised in the selection of the calibration facility and in the analysis of the calibration data to assure that the single-point accuracy necessary to establish the slope of the calibration curve is attained. The physical construction of the piping in the calibrating setup should be similar to that in the test setup from the standpoint of pipe configuration, immediately upstream and downstream of the flow-measuring section. Also, the Reynolds number, water temperature, and other flow conditions should be as close to test conditions as possible. The calibration should preferably consist of at least 20 acceptable points over a wide range of Reynolds numbers. If repeat calibration points at the same Reynolds number

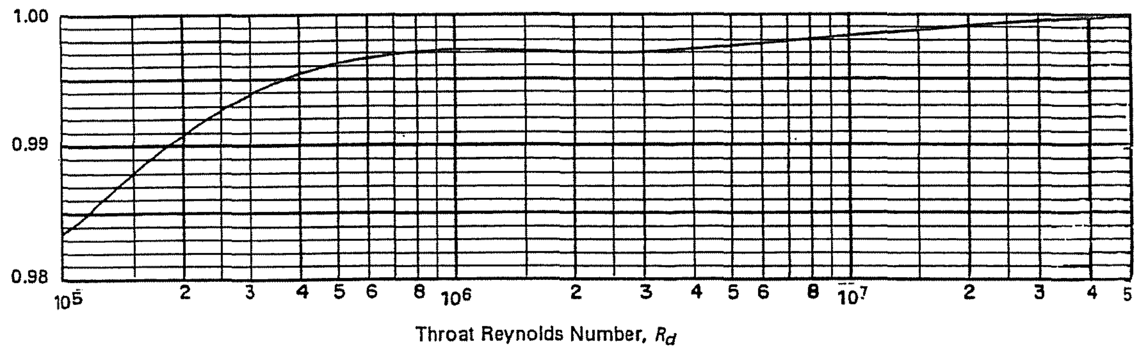


FIG. 4.10 REFERENCE CURVE FOR NOZZLE CALIBRATION

differ by more than 0.1 percent, an additional calibration point at the same Reynolds number is recommended. When it is not possible to calibrate at test Reynolds number, it is permissible to extrapolate the calibration curve as described in para. 4.8.16. Since the effect of the transition region becomes increasingly smaller as Reynolds number rises, this Code recommends that the value of the coefficient be established at highest Reynolds number possible so that this effect is minimal. All four tap sets should be calibrated. For the test, select the two tap sets that most closely comply with first, the calibration criteria (see paras. 4.8.13, 4.8.14, and 4.8.15) and second, with the guidelines in Fig. 4.13. If the calibration of the flow section does not comply with para. 4.8.14, the nozzle should be carefully inspected as described in para. 4.8.7, corrected, if necessary, and the flow section recalibrated. If the recalibration still does not comply with para. 4.8.14, the flow section should again be recalibrated using different facilities. In the event different facilities are not available, the parties to the test must agree on the course of action before the test is started.

4.8.14 Compliance with the requirements of paras. 4.8.4 through 4.8.12 is determined by the shape of the coefficient of discharge, C, versus Reynolds number curve established by calibration. For each set of selected taps, the calibration curve (not necessarily each individual point) shall be within 0.25 percent of the reference curve (see reference curve Fig. 4.10 and Table 4.2) and shall have the same slope as the reference curve (see para. 4.8.15). The reference curve shown in Fig. 4.10 was derived from a detailed boundary layer analysis and corroborated later by a study yielding the expression given in Table 4.2.

TABLE 4.2
REFERENCE NOZZLE COEFFICIENTS OF DISCHARGE DERIVED FROM THE EXPRESSION $C = 1.0054 - 0.185\ R_d^{-0.2}\ [1 - 361{,}239/R_d]^{0.8}$, WHICH REASONABLY MATCH THE REFERENCE CURVE SHOWN IN FIG. 4.10

Throat Reynolds Number–MILLIONS	Coefficient of Discharge, C
1.0	0.9972
2.0	0.9967
3.0	0.9969
4.0	0.9972
5.0	0.9974
6.0	0.9976
8.0	0.9980
10.0	0.9982
20.0	0.9991
30.0	0.9995
40.0	0.9999
50.0	1.0001

The equation, discussed in para. 4.15, is a description of the coefficient of discharge, C, of a throat-tap device throughout the entire range of Reynolds numbers of interest.

4.8.15 Evaluation of Laboratory Calibration Data. The recommended method for determining if the calibration data of a throat-tap nozzle is satisfactory, i.e. can be extrapolated parallel to the reference curve as required in para. 4.8.14, is as follows:

Make multiple solutions of an equation of the form

$$C = C_x - 0.185\, R_d^{-0.2}\, (1 - 361{,}239/R_d)^{0.8}$$

This is done by substituting the measured value of the coefficient of discharge of each calibration point with a Reynolds number greater than one million into the above equation as C and evaluating for C_x. Three criteria must be satisfied for the nozzle calibration to be accepted as satisfactory.

4.8.15.1 Average Value. The average value of C_x must equal 1.0054 ± 0.0025 (therefore, $1.0079 \geq C_x \geq 1.0029$).

4.8.15.2 Reynolds Number Independence. The values of C_x must show no dependence on R_d. This is determined by an unconstrained linear regression of C_x (least squares fit) represented by the equation $C_x = a + bR_d$. The standard deviation of the slope, $s(b)$, is calculated and the 95% confidence limits for b are given by $b \pm ts(b)$ where t is the value of Student's t for $n - 2$ deg. of freedom. If these limits include zero, the values of C_x are considered to be R_d independent.

Guidance on performing regression analysis may be found in PTC 19.1, in texts on statistical analysis, and in ISO 7066-1 1989, "Assessment of Uncertainty in the Calibration and Use of Flow Measurement Devices — Part 1. Linear Calibration Relationships."

4.8.15.3 Scatter of Calibration Data. The confidence interval of the C_x data for 95 percent confidence level should not exceed 0.0006 (±0.0003 from the average C_x). If this is not achieved with the recommended 20 calibration points, it will be necessary to collect additional calibration points.

4.8.16 Extrapolation. When an extrapolation of calibrated data to higher Reynolds numbers is required, as permitted by para. 4.8.13, that extrapolation shall be made by solving for C at test Reynolds number in the equation in para. 4.8.15 with C_x equal to the average value determined for the set of calibration data being used. This method provides a precise and repeatable means for determining a coefficient of discharge beyond the upper limit of the calibration range. This method results in a calibration curve that closely parallels the reference curve in Fig. 4.10.

4.8.17 Transition Region. At low throat Reynolds numbers the nozzle boundary layer is laminar; at high throat Reynolds numbers it is turbulent. In between these two regions is a zone called the transition region. Figs. 4.10 and Table 4.2 indicate that for Reynolds numbers between 1.0 and 4.0 million, nozzles described in this Code are noticeably affected by the transition of the boundary layer. However, experience has shown that for any given nozzle, coefficients in this region are repeatable within laboratory precision. Therefore, the coefficient of discharge in this region is stable and usable for any calibrated nozzle that meets the evaluation criteria in para. 4.8.15. It is recommended that nozzles be sized to produce throat Reynolds numbers beyond this range if possible and extrapolation be performed as described in para. 4.8.16. If there is excessive scatter in the calibration data, the nozzle should be inspected, reworked, and recalibrated. If scatter is still present, another nozzle shall be used for the test.

4.8.18 Deposits. A slight iron-oxide film on the nozzle surface will usually collect during the test. If film thickness is less than $0.0002d$, and uniformly deposited, its effect on the uncertainty of the flow measurement will be negligible. If the thickness of the deposit exceeds this value, or if the nature of the deposit is nonuniform and the surface appears rough, either of two procedures may be followed:

(a) the nozzle may be cleaned using commercial cleaning agents or fine rubbing compounds not harmful to the nozzle and the test repeated; or

(b) the flow measuring section may be recalibrated and if the calibration change is judged to be insignificant by the parties to the test, they should agree on the action to be taken.

Care must be taken not to disturb the deposit before recalibration. If the calibration is significantly different from the calibration prior to the test, it is necessary that another set of runs be made under deposit-free conditions. The test results cannot be adjusted, since it is usually impossible to determine when the deposit formed on the nozzle.

Removable flow sections should be installed, at a practicable time, to minimize the interval between installation and test dates.

4.9 INSTALLATION OF FLOW SECTION

4.9.1 Recommended Cycle Locations. As stated in paras. 1.3.1 and 1.3.2, this Code provides a choice for the location of the primary flow measurement. Variations in flow measurement locations may be used by agreement between the parties to the test provided precautions are taken to eliminate heater leakage and recirculation flows and appropriate instrumentation is installed.

Figures 4.11(a) through 4.11(e) show the location of flow instrumentation in typical cycles. While these diagrams show only single strings of heaters, two or three strings are commonly used with the larger sized turbine-generator units. For cycles of large units and particularly those with nuclear steam-supply systems, two or more flow measuring devices may be used in parallel at each primary flow location.

4.9.2 Condensate Flow Section

(a) For units with high pressure feedwater heaters supplied with superheated extraction steam, see Fig. 4.11(a). If the feedwater cycle has a deaerator, it is recommended that condensate flow entering it be measured as primary flow. This eliminates the possibility of any heater tube leakage recirculating through the flow measuring device.

If the feedwater cycle has no deaerator but does have a heater with pumped-ahead drains immediately upstream of the feedwater pump, it is recommended that the condensate flow entering this heater be measured. Again, there is no possibility of heater tube leakage recirculating through the flow measuring device.

If the feedwater cycle has no deaerator and no pumped-ahead heater drains immediately upstream of the feedwater pump, it is recommended that condensate flow be measured downstream of the low pressure heaters, and upstream of the feedwater pump. If the absence of high pressure heater leakage is not verified by use of a suitable tracer or other technique, it will be necessary to measure the total drain flow from the high pressure heaters for comparison with the sum of the extraction flows from these heaters as calculated by heat balance. The difference between these values is the amount of suspected high pressure heater leakage.

The preceding primary flow locations were selected to improve the accuracy of the measurement by (1) avoiding difficulties associated with use of flanged joints in high pressure piping, (2) taking advantage of lower water temperatures that minimize the added uncertainty associated with the extrapolation of the coefficient-of-discharge curve and (3) avoiding the lower temperatures in the cycle where the transition region may cause higher uncertainty in the coefficient of discharge.

(b) For units with high pressure feedwater heaters supplied with wet extraction steam, see Fig. 4.11(b) and (c). If the feedwater cycle has a heater with pumped-ahead drains upstream of the feedwater pump (Fig. 4.11(b)), it is recommended that the condensate flow and the heater drain flow both be measured immediately upstream of the point where they mix and the sum of the two flows be used as primary flow, provided that the absence of heater leakage is verified by use of a suitable tracer technique. Otherwise, the feedwater flow from the highest pressure heater also must be measured for comparison with the primary flow with adjustment for feedwater pump injection and leak-off flows. The difference between these values is the amount of suspected high pressure heater leakage.

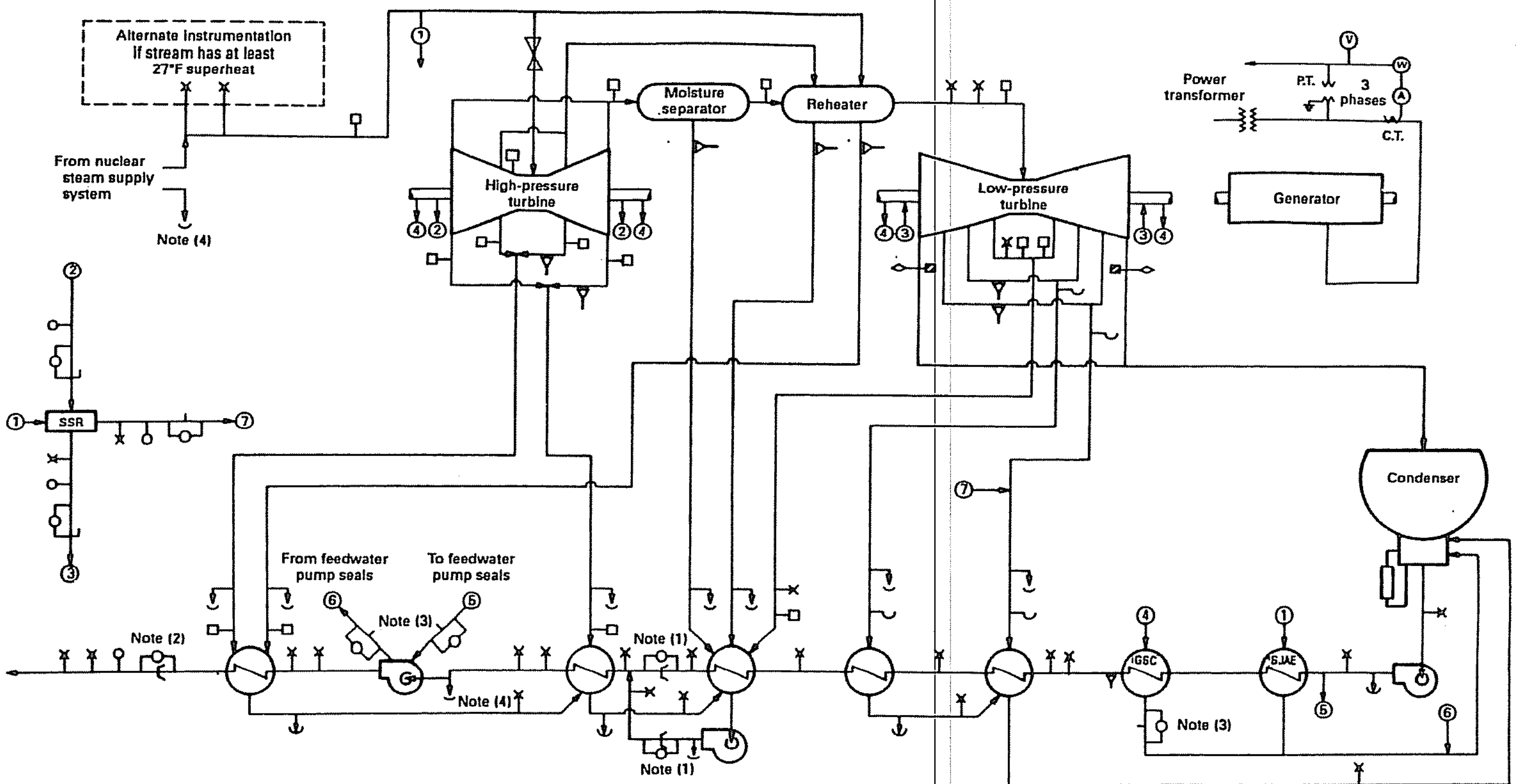
If the feedwater cycle has only heaters with drains cascading to the condenser [Fig. 4.11(c)], it is recommended that feedwater pump suction flow be measured, provided that the absence of heater leakage is verified by use of a suitable tracer technique. Otherwise, feedwater flow from the highest pressure heater must be measured for determination of suspected water leakage, as in the case of the intermediate pumped-ahead-heater cycle. When measuring feedwater pump suction flow, use of a metering pressure drop that infringes on the pump required minimum NPSH should be avoided.

(c) Before aborting or discarding a test because of suspected high heater leakage (see para. 3.8.10), the isolation of the cycle should be rechecked, the calibration curves of the flow measuring devices should be investigated, and the possibility of error in the final feedwater or heater drain flow measurements should be considered.

4.9.3 Feedwater Flow Section. The primary flow measuring device is installed, perhaps welded, in the feedwater line, downstream of the highest pressure heater, so that it directly measures feedwater flow to the steam generator.

4.9.4 To minimize the difficulty of obtaining steady flow, the flow measuring device should not be located at a pump discharge. Advantage should be taken of the damping effect of any existing heat exchangers and long lengths of pipe in the cycle in locating the flow measuring device. The flow measuring device should also be located to eliminate the effects of recirculating and bypassing flows. If this is not possible, extraneous flows shall be measured with sufficient accuracy so that the effect on primary flow uncertainty is less than ±0.05 percent.

4.9.5 The installation of the flow measuring section in a horizontal run is recommended. To minimize the effects of distortion due to thermal expansion



= Temperature measurement

= Pressure measurement

= Pressure measurement

Refer to para. 4.1.3 regarding caution on use of mercury:

= Pressure measurement

= Orifice and differential pressure measurement

= Nozzle or venturi and differential pressure measurement

= Impact and static taps with pressure measurement

= Absolute-pressure gage

= Basket tips in exhaust hood

= Tracer injection

= Water sample

= Level

W = Wattmeter

A = Ammeter

V = Voltmeter

GSC = Gland-steam condenser

SJAE = Steam-jet-air ejector

SSR = Steam-seal regulator

C.T. = Current transformer

P.T. = Potential transformer

NOTES:

(1) Recommended primary flow measurement when heater leakage is measured by tracer.

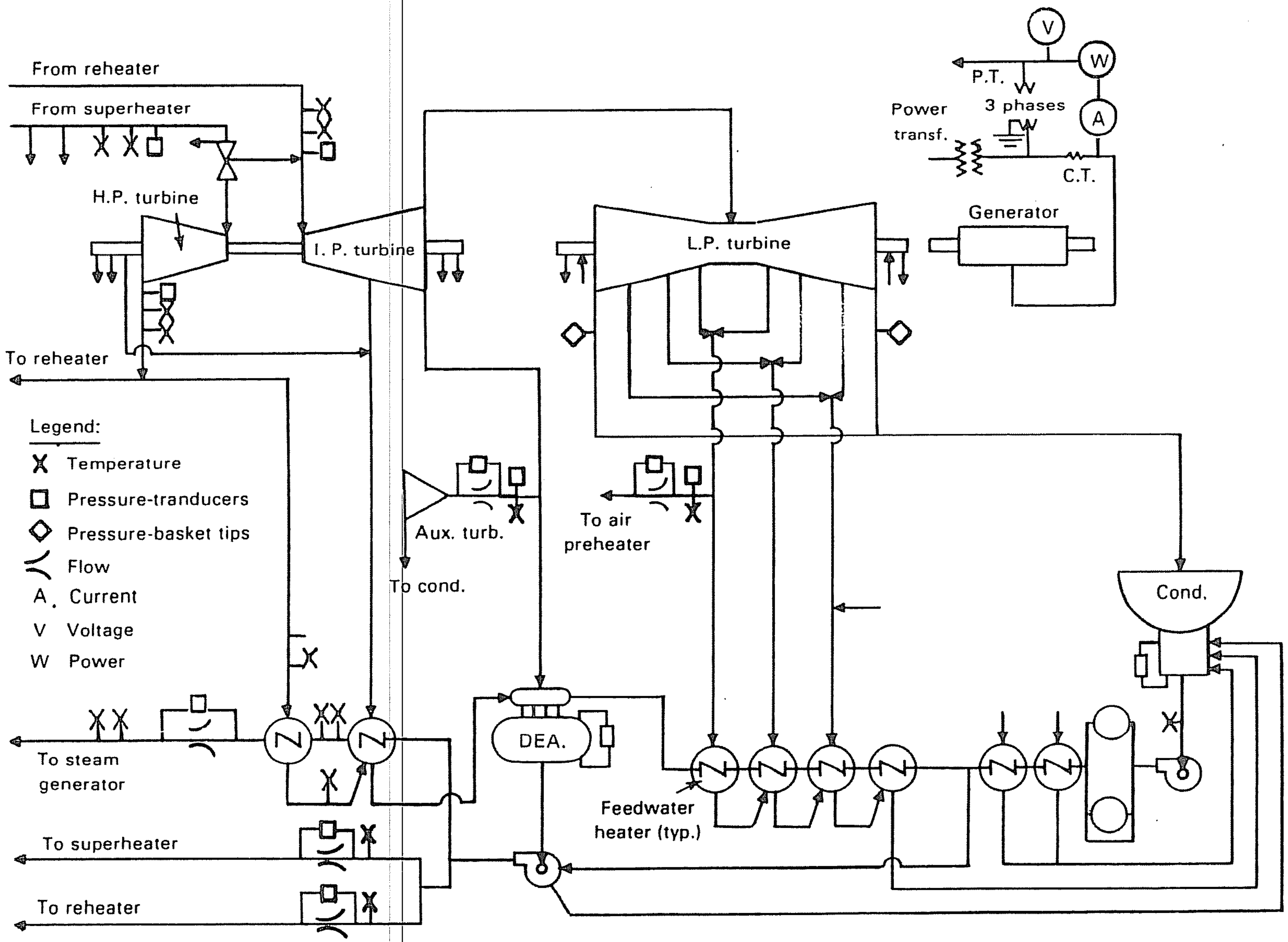
(2) Recommended alternate primary flow measurement. See para. 4.8.4 (c) for inspection requirements.

(3) A calibrated turbine meter may be used where flashing might otherwise be a problem or where flow rate is less than 5% of primary flow.

(4) Omit water sample if main steam has at least 27°F superheat.

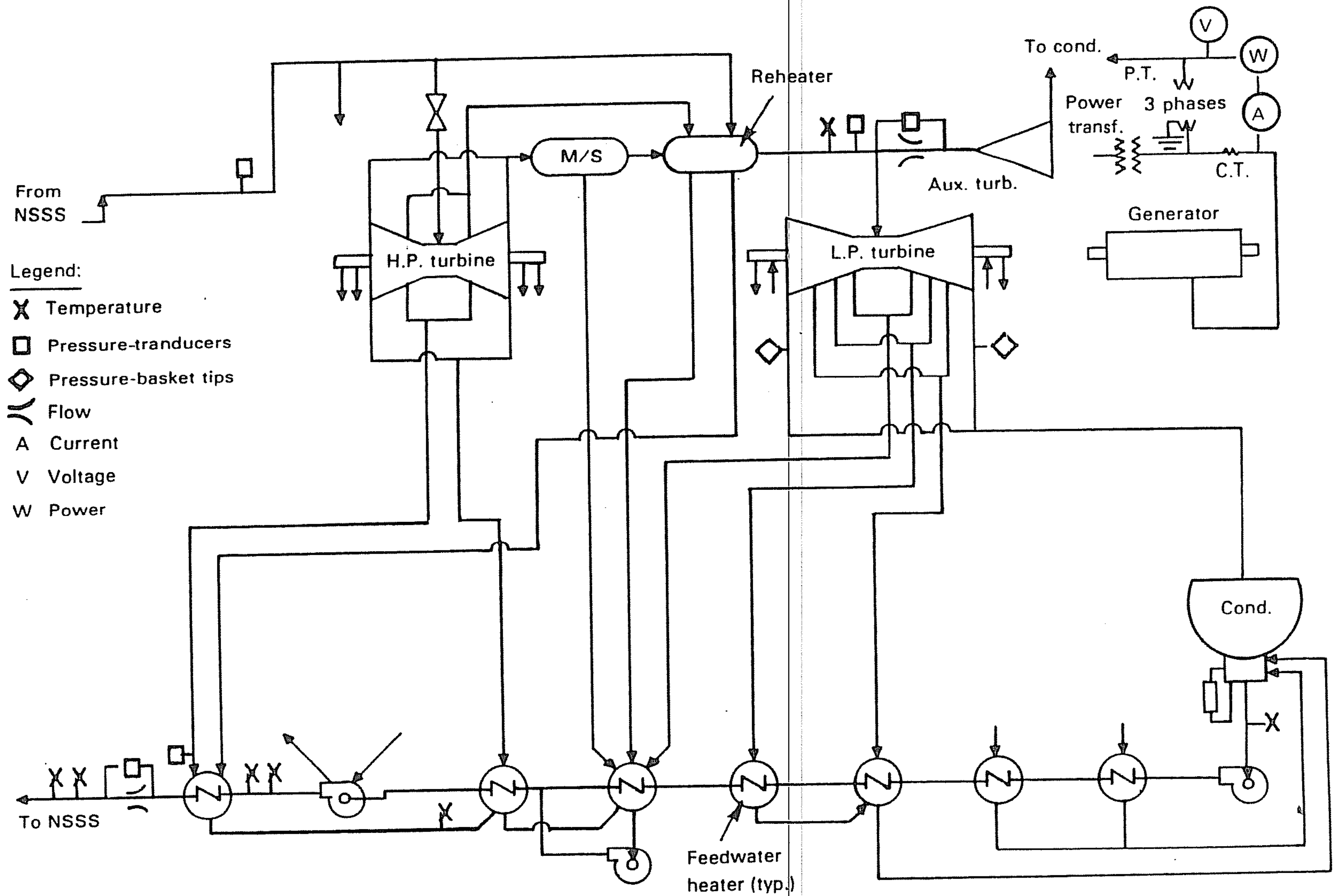
(5) Specific flow measuring primary elements are suggested for guidance. Alternate flow elements are permissible provided the final measurement has no higher uncertainty than the best attainable with the specified primary element.

FIG. 4.11(c) LOCATION AND TYPE OF TEST INSTRUMENTATION (HEATER DRAINS PUMPED FORWARD; TRACER TECHNIQUE FOR FLOW MEASUREMENT)



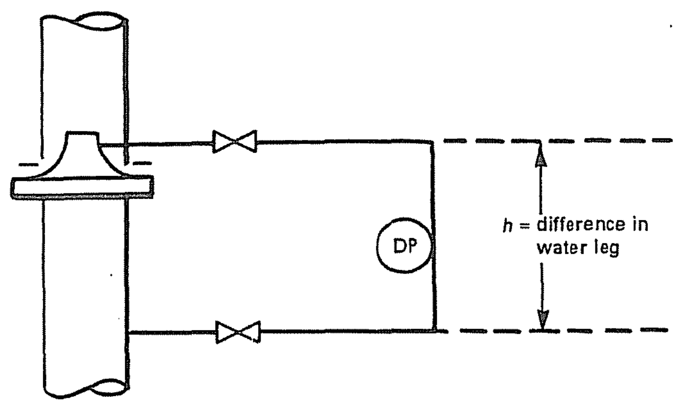
NOTE: High-accuracy instrumentation is shown in color.

FIG. 4.11(d) LOCATION AND TYPE OF TEST INSTRUMENTATION FOR ALTERNATIVE TEST PROCEDURE — FOSSIL



NOTE: High-accuracy instrumentation is shown in color.

FIG. 4.11(e) LOCATION AND TYPE OF TEST INSTRUMENTATION FOR ALTERNATIVE TEST PROCEDURE — NUCLEAR



For upward flow:
$\Delta p_{true} = \Delta p_{meas.} + (\rho_{amb} - \rho_{pipe}) (\frac{g}{g_o}) h$

For downward flow:
$\Delta p_{true} = \Delta p_{meas.} - (\rho_{amb} - \rho_{pipe}) (\frac{g}{g_o}) h$

FIG. 4.12 WATER LEG CORRECTION FOR FLOW MEASUREMENT

and nozzle-coefficient extrapolation due to higher Reynolds numbers, flow nozzle locations having water temperatures below 300°F (422K) are preferred. However, flow nozzles located downstream of the highest pressure heater are acceptable if they are designed in accordance with this Code, see paras. 4.8.6 through 4.8.18.

4.9.6 When the flow measuring device is installed such that the upstream and downstream tap locations are at different elevations, it is necessary to correct for water leg differences between the tap elevations caused by the difference in density of the water in the flow section and the water in the pressure sensing lines. (See Fig. 4.12.)

4.9.7 If the only two acceptable sets of taps are 90 deg. apart instead of the recommended 180 deg. apart in a horizontal pipe, one set should be located at the horizontal axis of the pipe. (See Fig. 4.13.). If the other set of taps has the upstream and downstream taps connected to the pipe at different elevations, special attention to insulation must be given to minimize any specific weight differences between the water flowing through the pipe and the water in the pressure tap lines. (See para. 4.9.6 and Fig. 4.12.) If the flow section is located in a vertical pipe, any tap configuration is acceptable. See para. 4.9.6 for further discussion of necessary water leg correction for taps at different elevations.

4.10 FLOW CHARACTERISTICS

4.10.1 Flow measurements shall not be undertaken unless the flow is steady or fluctuates only slightly with time. The permissible fluctuation is ±1 percent of the differential pressure for fluctuations with a frequency greater than twice the frequency of successive readings and ±4 percent for smaller frequencies. Fluctuations in the flow shall be suppressed before the beginning of a test by very careful adjustment of flow and level controls or by introducing a combination of conductance, such as pump recirculation, and resistance, such as throttling the pump discharge, in the line between the pulsation sources and the flow measuring device. Damping devices on instruments do not eliminate errors due to pulsations and, therefore, shall not be used. If the pulsations exceed the above values after every effort has been made to suppress them, mutual agreement is required before the test can proceed.

4.10.2 In passing through the flow measuring device, the water shall not flash into steam. The minimum throat static pressure shall be higher than

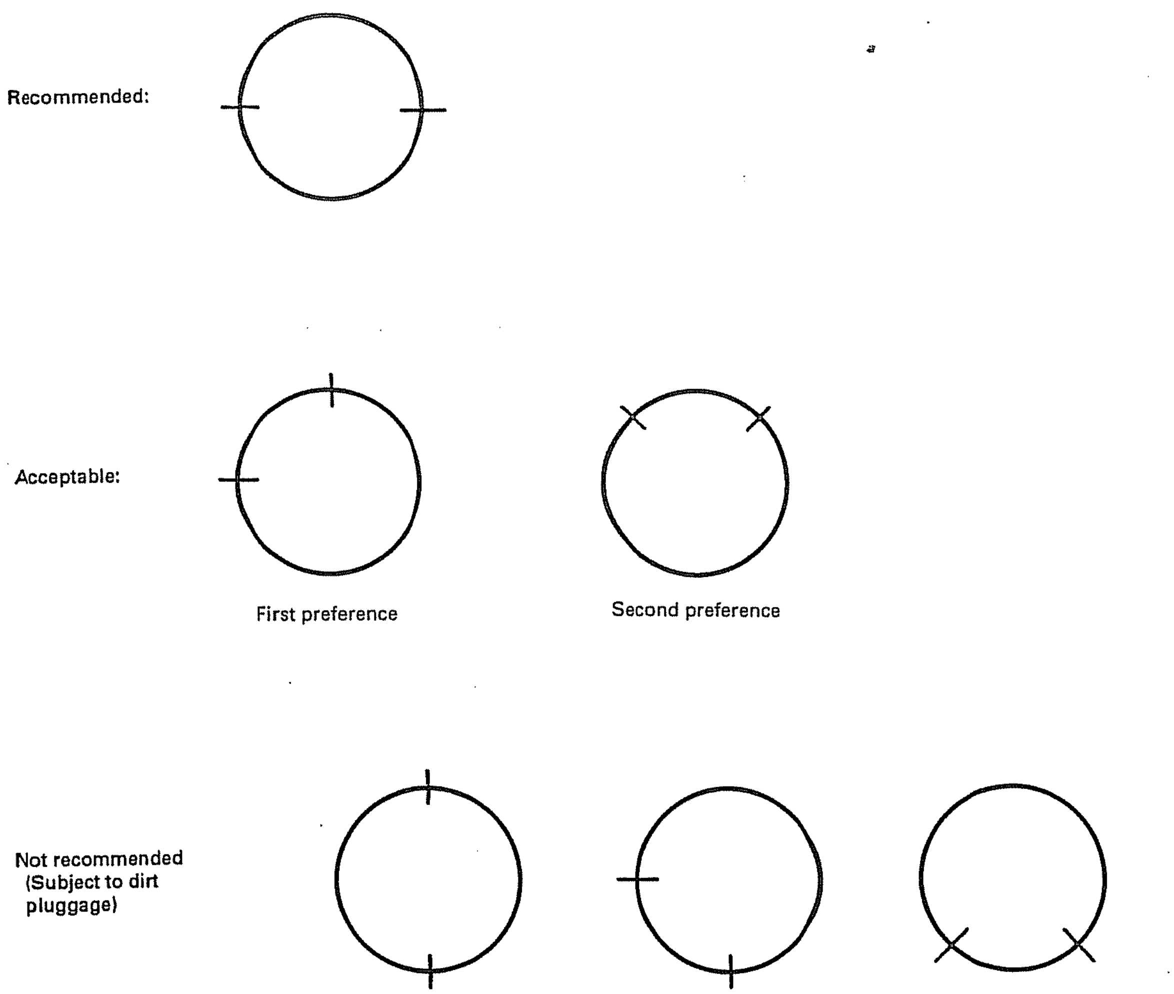


FIG. 4.13 FLOW ELEMENT TAP LOCATIONS FOR HORIZONTAL PIPES
~~(See para. 4.9.7)~~

the saturation pressure corresponding to the temperature of the flowing water by at least 20 percent of the throat velocity head, as required per para. 4.16.2, to avoid cavitation.

4.11 OTHER FLOW MEASURING DEVICES

4.11.1 Information relative to the construction, calibration, and installation of other flow-measuring devices is described in PTC 19.5. Although these devices are not recommended for the measurement of primary flow, they may be used provided they conform to the general requirements of paras. 4.8.4 and 4.8.14 with the following exceptions:

(a) For the requirement stated in para. 4.8.4(a), the beta-ratio shall be limited to the range 0.25 to 0.50 for wall-tap nozzles and venturis and 0.30 to 0.60 for orifices.

(b) For the requirement stated in para. 4.8.14, the appropriate reference coefficient for the actual device given in PTC 19.5 shall be used. The parties to a test should become familiar with the contents of PTC 19.5 regarding these devices.

4.12 MEASUREMENT OF STEAM FLOW

4.12.1 To measure the primary steam flow directly, the requirements for accurate steam flow measure-