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Fossil Fuel Plant Steam Temperature Control System — Drum Type

ANSI/ISA-S77.44, Fossil Fuel Power Plant Steam Temperature Control System — Drum Type

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Preface

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The ISA Standards and Practices Department is aware of the growing need for attention to the metric system of units in general, and the International System of Units (SI) in particular, in the preparation of instrumentation standards, recommended practices, and technical reports. The Department is further aware of the benefits to USA users of ISA standards of incorporating suitable references to the SI (and the metric system) in their business and professional dealings with other countries. Toward this end, this Department will endeavor to introduce SI-acceptable metric units in all new and revised standards to the greatest extent possible. *The Metric Practice Guide*, which has been published by the Institute of Electrical and Electronics Engineers as ANSI/IEEE Std. 268-1992, and future revisions, will be the reference guide for definitions, symbols, abbreviations, and conversion factors. Certain metric units that are not a part of the SI system are in common accepted use. This standard uses bar as a pressure measurement that is convertible to kilopascals by multiplying by 100.

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This standard is part of a series of standards resulting from the efforts of ISA-SP77.40, Boiler Controls. It should be used in conjunction with the other SP77 series of standards for safe, reliable, and efficient design, construction, operation, and maintenance of fossil-fired power plants. It is not intended that this standard establish any procedures or practices that are contrary to any other standard in the series.

A variety of steam temperature control systems have been developed and used over the years to maintain steam temperature within limits and at the required setpoint. This standard is intended to establish minimum requirements for steam temperature control.

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1 Scope

The scope of this standard addresses the major steam temperature control subsystems in boilers with steaming capacities of 200,000 lb/hr (25 kg/s) or greater. These subsystems include, but are not limited to, superheat temperature control and reheat temperature control. Specifically excluded from consideration are turbine bypass control, motor control logic, combustion control, sootblower control, and controls associated with fluidized bed- and stoker-fired furnace combustion units.

2 Purpose

The purpose of this standard is to establish the minimum requirements for the functional design specification of steam temperature control systems for drum-type fossil fuel power plant boilers.

3 Definitions

3.1 attemperator: A mechanical device used for maintaining and controlling the temperature of superheated steam.

3.2 attemperator (direct contact type): A mechanical device in which the steam and the cooling medium (water) are mixed.

3.3 boiler: The entire vessel in which steam or other vapor is generated for use external to the vessel. This includes the furnace, consisting of waterwall tubes; the firebox area, including burners and dampers; the convection area, consisting of any superheater, reheater, economizer sections or any combination thereof, as well as drums and headers.

3.4 cascade control system: A control system in which the output of one controller (the outer loop) is the setpoint for another controller (the inner loop). The outer loop is normally a slow responding process as compared to the inner loop.

3.5 control: Maintaining a desired setpoint of steam temperature during operation.

3.6 control loop: A combination of field devices and control functions arranged so that a control variable is compared to a setpoint and returns to the process in the form of a manipulated variable.

3.7 controller: A manual or automatic device or system of devices used to regulate the boiler steam temperatures within defined parameters as set forth by a turbine/boiler manufacturer.

3.8 desuperheater: See 3.2 attemperator.

3.9 deviation: The difference between the loop setpoint and the process variable.

3.10 error: See 3.9 deviation.

3.11 feedback: A signal produced by a measuring device that is proportional to the magnitude of a controlled variable or position of a control element.

3.12 final control element: The component of a control system (such as a control valve) that directly regulates the flow of energy or material to or from the process.

3.13 fuel trip: The automatic shutoff of a specific fuel as the result of an interlock or operator action.

3.14 gas pass: An arrangement in which the convection banks of a boiler are separated by gas-tight baffles into two or more parallel gas paths isolating portions of the superheater and reheater surfaces. The proportion of total gas flow through each gas pass may be varied by regulating dampers.

3.15 gas recirculation: A method by which gas from the boiler, economizer, or air heater outlet is reintroduced to the furnace by means of a fan(s), duct(s), or both.

3.16 integral control action: An action in which the controller's output is proportional to the time integral of the error input. When used in combination with proportional action, it previously was called reset action.

3.17 integral windup: The saturation of the integral controller output in the presence of a continuous error, which may cause unacceptable response in returning the process to its setpoint within acceptable limits of time and overshoot.

3.18 interlock: A device or group of devices (hardware or software) arranged to sense a limit or off-limit condition, or improper sequence of events, and to shut down the offending or related piece of equipment, or to prevent proceeding in an improper sequence in order to avoid an undesirable condition.

3.19 intermediate (platen) superheater: A heating surface receiving steam from the primary superheater located between the primary and secondary superheater. (See Figure C.1b.)

3.20 linearity: The nearness with which the plot of a signal or other variable plotted against a prescribed linear scale approximates a straight line.

3.21 master fuel trip (MFT): (See 3.13 fuel trip.) An event resulting in the rapid shutoff of all fuel.

3.22 primary air: Combustion air that enters the fuel-burning zone and directly supports initial combustion. On pulverized coal-fired units, the primary air is used to transport the coal from the pulverizers to the burners.

3.23 primary (convection or initial) superheater: A heating surface receiving steam from the drum. (See Figures C.1a and C.1b.)

3.24 reheater: A heating surface receiving steam returning to the boiler from the high-pressure turbine exit.

3.25 secondary air: Combustion air introduced on the edge of the burning zone to supplement the primary air for support of the combustion process.

3.26 secondary (radiant or final) superheater: A heating surface receiving steam from either the primary or intermediate superheater. (See Figures C.1a or C.1b.)

3.27 setpoint: The desired operating value of the process variable.

3.28 superheater: A bank of heating surface tubes contained within a boiler, and to which heat is applied to elevate the steam temperature to a desired value above saturation.

3.29 trip: The automatic removal from operation of specific equipment or the automatic discontinuance of a process action or condition as the result of an interlock or operator action.

3.30 transient correction: A control action specifically applied to minimize any process error resulting from a temporary process change; e.g., temperature control action applied to counter the effects of over- or under-firing during load changes.

4 Minimum design requirements for a superheat steam temperature control system

The control system shall meet all operational requirements and properly interface with the process. To accomplish these objectives, the following minimum system design requirements are defined as:

a) Process measurement requirements
b) Control and logic requirements
c) Final control element requirements
d) System reliability and availability
e) Alarm requirements
f) Operator interface

4.1 Process measurement requirements

4.1.1 Instrument installations for superheat steam temperature control

Instruments should be installed as close as is practical to the source of the measurement, with consideration being given to excessive vibration, temperature, and accessibility for periodic maintenance.

Recommendations for the location of instrument and control equipment connections can be found in the joint publication by Scientific Apparatus Makers Association (SAMA) and American Boiler Manufacturers Association (ABMA), "Recommendations for Location of Instrument and Control Connections for the Operation and Control of Watertube Boilers."

Thermowell installations for temperature measurements shall meet the requirements of ANSI/ASME B31.1, Section 1, "ASME Code for Pressure Piping."

Thermowell installations shall consider location, mounting, and velocity criteria in making a proper interface with the process.

Separate isolation valves and impulse lines shall be provided for head-type instrumentation.

4.1.2 Process measurements for superheat steam temperature control

Process measurements for superheat temperature control are listed as follows. For location of these measurements see Figures C.1a and C.1b.

4.1.2.1 Secondary (final) superheater outlet steam temperature measurement

A temperature measurement, taken at the outlet of the secondary (final) superheater, is required for single-element, two-element, and three-element superheat steam temperature control strategies when the typical arrangement locates the attemperator between superheater sections.

4.1.2.2 Secondary superheater inlet temperature measurement

A temperature measurement, taken at the attemperator outlet(s) for single-stage or two-stage attemperation and followed by a superheater section, is required as the secondary variable in a three-element control strategy.

4.1.2.3 Intermediate inlet temperature measurement

A temperature measurement, taken at the intermediate superheater inlet (or outlet of the first stage attemperator of two-stage attemperation), is required as the secondary variable in a three-element control strategy.

4.1.2.4 Intermediate outlet temperature measurement

A temperature measurement, taken at the outlet of the intermediate superheater section before the second stage attemperator, is required in a two-stage attemperator control strategy.

4.1.2.5 Intermediate inlet pressure measurement

A pressure measurement is required in a two-stage attemperator control strategy to prevent saturation following first-stage spray attemperation. Typically, this pressure is measured at the inlet of the intermediate superheater; however, drum pressure may be used also.

4.1.2.6 Attemperator spray water-flow measurement

An attemperator spray water mass flow signal provides an alternative to the use of the attemperator outlet steam temperature as the secondary variable in a three-element control strategy.

4.2 Control and logic requirements

The function of the superheat temperature control system is to maintain superheat steam temperature within the boiler manufacturer's specified limits. Generally, the goal is to obtain a specified final superheat steam temperature over the specified boiler-load range. Control strategy must be based on the particular control mechanisms used and the boiler manufacturer's philosophy for controlling steam temperature. Although the strategies describe the use of conventional PID control techniques, it is not the intention to preclude the use of advanced control strategies.

For the control of superheat steam temperature, this standard addresses single-stage attemperation and two-stage attemperation. For typical boiler superheater attemperation arrangements, see Figures C.1a and C.1b.

4.2.1 Single-stage attemperation

Single-stage attemperation refers to the boiler design that provides a single location for the introduction of spray water for the regulation of steam temperature. This application is typical of boilers with only a single superheat section or two superheater sections in series, commonly called the primary and secondary superheaters. It is normal to have the spray attemperation take place in the headers between the two superheater sections or occasionally at the superheater outlet. Note that a single attemperation location does not necessarily refer to a single set of spray equipment.

4.2.1.1 Single-element steam temperature control

Single-element steam temperature control is the minimum control strategy required to regulate the steam temperature leaving the boiler and should be used only in applications with slow load changes; e.g., building heating system or where constant steam temperature is not critical.

Referring to Figure C.2, final steam temperature is measured and compared to a setpoint with the result used to regulate the spray valve(s).

4.2.1.2 Two-element steam temperature control

Two-element steam temperature control strategy should be used only in applications with slow to moderate load changes or with steady spray water pressure supply and fixed steam pressure applications.

Referring to Figure C.3, two-element steam temperature control adds a feed-forward signal and a transient correction signal to the single-element control described in 4.2.1.1. As a minimum, the feed-forward signal is derived from a load index (or indices). This feed-forward signal should recognize all major influences on steam temperature, including adjustments to heat distribution within the boiler.

4.2.1.3 Three-element steam temperature control

Three-element steam temperature control strategy should be used in applications with rapidly changing loads, with variable steam pressures or with variable spray water pressure supplies.

The three-element control strategy is applicable only when attemperation takes place between two superheater sections.

Referring to Figure C.4, three-element steam temperature control adds a cascade control arrangement to the two-element control strategy described in 4.2.1.2 for the control of the spray valve. The two-element control strategy acts as the setpoint development for the inner control loop of the cascade control arrangement. The process variable for the inner control loop is a monitor of the spray action. Although steam temperature immediately after the attemperation is the preferred process variable, spray water flow also may be used. As a minimum, the feed-forward signal is derived from a load index (or indices). This feed-forward signal should recognize all major influences on steam temperature, including adjustments to heat distribution within the boiler.

For variable pressure operation, a suitable feedforward shall be provided to reflect the influence of changes in the thermodynamic properties of steam on the final steam temperature.

4.2.2 Two-stage attemperation

Two-stage attemperation refers to the boiler design when spray attemperation is applied at two different locations, typically between the primary and intermediate superheaters and also between the intermediate and secondary superheaters. There are two common approaches to controlling a two-stage attemperation system—independent systems or coupled systems. Consideration should be given to the boiler manufacturer's recommendations when selecting a control strategy.

4.2.2.1 Independent two-stage control

In the independent system, the first-stage attemperator is used to control the outlet temperature of the intermediate superheater. The second-stage attemperator is used to control the final outlet temperature. Referring to Figure C.2, the setpoint for the first-stage control loop usually is a fixed value dependent on the metal temperature limits of the intermediate superheater. A single-element control is the minimum system required for the first stage. Referring to Figure C.4, the setpoint for the second-stage control loop is operator set. A cascade control scheme using final outlet temperature as the primary process variable and either the second-stage attemperator outlet temperature or spray water flow as the secondary process variable is the minimum system required for controlling the final outlet temperature.

Feed-forward signals usually are required to obtain satisfactory transient control performance from a steam temperature control loop. In the independent strategy, the feed-forward signals are used only on the final outlet temperature control loop, where they are added to the outlet of the primary controller. The exact arrangement of the feedforward signals must be determined on a case-by-case basis. As a minimum, the feedforward signal is derived from a load index (or indices). This feedforward signal should recognize all major influences on steam temperature, including adjustments to heat distribution within the boiler. Some common feedforward signals include load index, heat distribution signals (fuel nozzle tilt positions), fuel flow, and air flow.

4.2.2.2 Coupled two-stage control

In the coupled two-stage control strategy, the total spray attemperator demand is distributed between both stages of attemperation. Referring to Figure C.5, three-element control in the minimum system is required for the coupled two-stage attemperation to maintain the superheat steam temperature setpoint. The load index (or indices) feedforward signal is summed with a transient signal(s) and a final steam temperature feedback controller signal to develop a total spray attemperator demand. This feedforward signal should recognize all major influences on steam temperature, including adjustments to heat distribution within the boiler.

The individual spray attemperator demand is distributed between both stages of attemperation. The individual spray demands are developed from the spray distribution and coordination control strategy as determined from the boiler manufacturer's recommendations and specifications or as process constraints dictate. Both valves shall participate during transient boiler operation to minimize temperature excursions.

The intermediate (platen) spray demand shall protect the intermediate (platen) superheater from going into saturation at the inlet and from high temperature at the outlet. The control system must coordinate the intermediate (platen) spray demand and the secondary spray demand to minimize recorrection from the final steam temperature controller.

4.2.2.3 Saturation protection

Regardless of which type two-stage control strategy is used, logic shall be provided to prevent the outlet of either the intermediate (platen) or the secondary attemperator from reaching a saturated condition. In some cases the spray system may not be capable of delivering enough spray flow to reach saturation. In such cases, no logic is required.

4.2.3 Attemperator spray and block valve logic

A spray water block valve(s) should be furnished to provide tight shutoff to prevent water leakage past the spray control valve and to provide backup in the event that the spray control valve fails to close when required. The arrangement is such that each spray valve may have its own dedicated block valve, or several valves may share a common block valve.

A sequence control logic shall be provided for block valve operation to preserve its tight shutoff ability. The following permissives shall be satisfied before spray and block valves are opened:

a) The turbine trip logic is reset.
b) The load is greater than the preset amount.
c) The spray demand is greater than the preset amount (to minimize valve wear).

The attemperator spray water block valve logic shall open the block valve to its full open position prior to the initial opening of its associated modulating attemperator spray control valve(s). The block valve logic shall close the block valve after its associated modulating attemperator spray control valve(s) is fully closed. The block valve logic shall help reduce repeated opening and closing of the block valve when operating near minimum spray conditions. Provisions shall be made to override the sequence logic and trip close of both the block and spray valves in the event of a turbine trip (or master fuel trip when the master fuel trip does not initiate a turbine trip) to minimize the possibility of water carryover as the unit is shut down.

For further information on preventive design and operating measures, refer to ANSI/ASME TDP-1, *Recommended Practices for the Prevention of Water Damage to Steam Turbines Used in Electric Power Generation, Fossil Fueled Plants.*

4.2.4 Automatic tracking

Automatic tracking shall be provided such that any control mode transfer is accomplished without a sudden process upset.

4.2.5 Integral windup prevention

Means shall be provided with the superheater outlet steam temperature control strategy to prevent integral windup of the steam temperature controller when the boiler load is below that of the superheat steam temperature control range or when the final control element is at a limit (full open or full closed).

4.3 Final control element requirements

All final temperature control elements shall be designed to fail safe on loss of demand signal or control power (i.e., close or lock in place). The fail-safe position shall be determined by the user based on the specific application and the recommendations from the boiler/turbine supplier. The final control element should have the capability to be characterized to linearize the process.

4.4 System reliability and availability

As a minimum criteria, the design basis of the steam temperature's control system shall include

a) maximum unit load/temperature control capability;
b) normal operating load range;
c) anticipated load changes (transients); and

d) unit design characteristics, including spray water pressure and capacity for attemperation.

4.5 Minimum alarm requirements

Minimum alarm requirements shall include the following information:

a) High final superheater outlet steam temperature

b) Low final superheater outlet steam temperature

c) High differential header temperature between parallel paths of the final superheater (if applicable)

d) Low intermediate superheater inlet steam temperature (two-stage attemperation and saturation protection)

e) High intermediate superheater outlet steam temperature (two-stage attemperation and tube metal protection)

f) Loss of control power

g) Loss of final drive power

h) Control loop trip-to-manual

4.6 Operator interface

4.6.1 Operation information

The following information used in the superheat steam temperature control system shall be made available to the operator:

a) Final superheater outlet steam temperature (per outlet)

b) Final superheater outlet steam temperature setpoint

c) Intermediate superheater inlet temperature(s) or attemperator spray flow measurement (two-stage attemperation)

d) Intermediate superheater outlet temperature (two-stage attemperation)

e) Secondary superheater inlet steam temperature(s) or attemperator spray flow measurement

f) All alarms

g) Automatic/manual control loop status

In addition to the above, the final control element(s) position should be made available to the operator.

4.6.2 Operator control functions

The control system shall include capabilities for the automatic/manual control of each individual final device with the exception of block valves.

The control system shall include capabilities for the operator to control and adjust the final superheater outlet steam temperature setpoint. Consideration should be given to setpoint limits, which should not be accessible to the operator.

5 Minimum design requirements for a reheat steam temperature control system

The control system shall meet all operational requirements and shall properly interface with the process. To accomplish these objectives, the minimum system design requirements listed in Section 4 are defined as follows.

5.1 Process measurement requirements

5.1.1 Instrument installation for reheat steam temperature control

Instrument installation shall comply with the requirements and recommendations presented in 4.1.1.

5.1.2 Reheat steam temperature measurement

A temperature measurement, taken at the outlet of the final reheater, is required for single-element and two-element reheat steam temperature control strategies for modulation of the reheat steam temperature control mechanisms provided by the boiler manufacturer.

5.2 Control and logic requirements

The function of the reheat steam temperature control system is to maintain reheat steam temperature, leaving the boiler within manufacturer's specified limits. The strategy must be based on the particular mechanism(s) used and the boiler manufacturer's philosophy for controlling reheat steam temperature. The control mechanism(s) that are operated by the reheat steam temperature control equipment may involve the fire-side or the water-side of the boiler, or a combination of both. Although the strategies describe the use of conventional PID control techniques, it is not the intention to preclude the use of advanced control strategies.

This standard addresses the following means or mechanisms employed for the control of reheat steam temperature:

a) Fuel nozzle tilts
b) Flue gas pass dampers
c) Flue gas recirculation
d) Compartmented windbox
e) Single-stage spray water attemperation

5.2.1 Fuel nozzle tilts

Fuel nozzle tilts are a means of altering the distribution of heat in a furnace to effect changes in reheater and superheater outlet steam temperatures. Generally, the fuel nozzle tilts are mounted in the furnace corners and can be tilted up or down from horizontal. Lowering the fuel nozzle tilts increases furnace heat absorption, which in turn lowers the flue gas temperature as it enters the reheater and the superheater. Raising the fuel nozzle tilts has the opposite effect. Fuel nozzle tilts usually are operated in parallel, although biasing of individual corners may be included and incorporated in the control strategy employed.

Referring to Figure C.6, two-element control (reheat temperature control with feedforward) is the minimum system requirement for the fuel nozzle tilt arrangement to maintain the reheat steam temperature setpoint. The load index feedforward signal is summed with transient correction signals and a reheat temperature controller to develop a fuel nozzle tilt demand.

Fuel nozzle tilts may also be used to control superheater steam temperature in accordance with the boiler manufacturer's recommendation.

Single-stage spray water attemperation is provided to supplement the normal control of reheat steam temperature. (See 5.2.5.)

5.2.2 Flue gas pass dampers

This section describes the approach of controlling reheat temperature with flue gas pass dampers to distribute the flue gas between the superheater and the reheater.

The pass damper demand shall be indexed to position the two pass dampers in opposite directions. During start-up and at low loads, the reheat pass damper will normally be wide open, and the superheat pass damper will be at a minimum position and will approach full open while the reheat pass damper closes to its minimum position as the load is increased. The relationship of the damper positions is such that the differential pressure across the pass damper remains relatively constant.

Referring to Figure C.7, two-element control (reheat temperature control with feedforward) is the minimum system requirement for the flue gas pass damper arrangement to maintain the reheat steam temperature setpoint. The load index feedforward signal is summed with transient correction signals and a reheat temperature controller to develop a flue gas pass damper demand.

Single-stage spray water attemperation is provided to supplement the normal control of reheat steam temperature. (See 5.2.5.)

5.2.3 Flue gas recirculation

Flue gas recirculation is a means of altering the distribution of heat within a furnace to effect changes in reheater outlet steam temperature. Typically, at low loads, gas recirculation is high to assist in achieving reheat temperature. At high loads, gas recirculation is reduced to its minimum value. Generally, the recirculation of flue gas is introduced into the furnace hoppers for temperature control. For some boiler designs, flue gas recirculation is introduced in the furnace air foil and combination of air foil and hoppers for control of temperature and NO_x. (See Annex B.7.)

Referring to Figure C.8, two-element control (reheat temperature control with feedforward) is the minimum system requirement for the gas recirculation to maintain reheat temperature at the setpoint. The load index feedforward signal is summed with transient correction signals and a reheat temperature controller signal to develop a flue gas damper demand. Gas recirculation control damper demand shall be constrained by a current limiting program to keep the fan current within acceptable limits. Safety interlocks, such as furnace purge, need to be considered but are not addressed by this standard.

An alternate arrangement for the application of gas recirculation is as a supplement to the normal temperature control. When used in conjunction with fuel nozzle tilt control (see 5.2.1), gas recirculation may be applied to maintain the fuel nozzles in their horizontal position. When used in conjunction with flue pass damper control (see 5.2.2), the gas recirculation is used to maintain the pass dampers in a regulating range at low loads.

Single-stage water attemperation is provided to supplement the normal control of reheat steam temperature. (See 5.2.5.)

5.2.4 Compartmented windbox

This section describes the approach of controlling reheat temperature in a compartmented boiler with excess air and mill biasing. The system is designed so that the mill bias increases the firing rate of the upper elevations. The excess air portion is designed to sequentially add air into compartments. Loading of air to the bottom compartment is done first during load increases for the greatest effect to reheat temperature. Also, to keep the formation of nitrous oxide (NO_x) at a minimum, the excess air is first introduced in the idle compartments, then through the active compartments.

Referring to Figure C.9, three-element control is the minimum system requirement for the mill biasing and excess air to maintain reheat temperature setpoint. The system is designed to program the total air flow with the load-index demand. This program is then trimmed from the reheat temperature error and limited by the maximum allowable total air flow. The air-flow demand is compared to the total boiler air flow plus the air-flow equivalent of mill biasing to modulate the mill biasing and excess air through the compartments. At low loads, the control system sequences the bias to the mill firing first, then to excess air. As load increases, the excess air bias is reduced first, followed by mill bias.

Single-stage spray water attemperation is provided to supplement the normal control of reheat steam temperature. (See 5.2.5.)

5.2.5 Single-stage spray water attemperation

The use of spray water attemperators is a method of controlling reheater outlet steam temperature. Water is sprayed into the superheated steam to lower its temperature. Temperature control is achieved by varying the water flow.

Since water injection into the reheater will lower the overall unit thermal efficiency, spray-water attemperation normally is employed as a secondary means of reheat steam temperature control in combination with other control mechanisms.

Single-stage spray water attemperation is often combined with one of the other aforementioned means of controlling reheat steam temperature. When combined with fuel nozzle tilts, flue gas pass dampers, flue gas recirculation, and excess air, single-stage spray water attemperation reduces cycle efficiency and is effective only in reducing temperature. In such cases, other means shall be employed in the control strategy to limit the use of spray-water attemperation and to maximize the use of these other means of final reheater outlet steam temperature control. One method of accomplishing this control strategy is to introduce a positive offset [e.g., +10°F (+5.5°C)], into the temperature setpoint for the reheat spray control. Temperature setpoint offset also minimizes the possibility of process oscillation. The boiler manufacturer's recommendations should be followed in the implementation of combined control strategies.

5.2.5.1 Single-element reheat steam temperature control

Single-element steam temperature control is the minimum control strategy for reheat steam temperature leaving the boiler and shall be used only for applications where reheat spray is the secondary means of reheat temperature control.

Referring to Figure C.10, steam temperature is measured and compared to a setpoint. The setpoint bias in Figures C.6 – C.9, which is used to slightly increase the setpoint above the setpoint of the primary controlling mechanism, is summed with the reheat temperature error to develop the final error signal. Proportional and integral control action, along with an automatic/manual station function, completes the control scheme to regulate the valve.

5.2.5.2 Two- and three-element reheat steam temperature control

Two- and three-element steam temperature control strategy should be used in applications

a) where reheat spray is the primary method of reheat temperature control;
b) with variable steam pressures; and
c) with variable spray water pressure supplies.

Refer to 4.2.1.2 and 4.2.1.3 for two-element and three-element control strategies, respectively.

5.2.6 Attemperator spray water block valve logic

The requirements and criteria for reheater spray block valve logic is the same as for superheater block valves and is described in 4.2.3.

5.2.7 Automatic tracking

Automatic tracking shall be provided such that any control mode transfer is accomplished without a sudden process upset.

5.2.8 Integral windup prevention

Means shall be provided with the reheater outlet reheat steam temperature control strategy to prevent integral windup of the reheat steam temperature controller when the boiler load is below that of the reheat steam temperature control range or when the final control element is at a limit (full open or full closed.)

5.3 Final control element requirements

All final control elements shall be designed to fail safe on loss of demand signal or motive power (e.g., open, close, or lock in place). The fail-safe position shall be determined by the user, based on the specific application and the recommendation of the boiler/turbine supplier. The final control element should have the capability to be characterized to linearize the process.

5.4 System reliability and availability

As a minimum criteria, the system design of the steam temperature's control system shall include

a) maximum unit load/temperature control capability;
b) normal operating load range;
c) anticipated load changes (transients); and
d) unit design characteristics, including spray water pressure and capacity for attemperation.

5.5 Minimum alarm requirements

Minimum alarm requirements shall include

a) high reheater steam temperature;
b) loss of control power;
c) loss of final drive power; and
d) control loop trip-to-manual.

5.6 Operator interface

5.6.1 Operator information

The following information used in the reheat steam temperature control system shall be made available to the operator:

a) Final reheater outlet steam temperature (per each outlet)
b) Final reheater outlet steam temperature setpoint
c) All alarms
d) Automatic/manual control loop status

In addition to the preceding list, the final control element's (elements') position should be made available to the operator.

5.6.2 Operator control functions

The control system shall include capabilities for the automatic/manual control of each individual final control element with the exception of the fuel nozzle tilt final-control element, which may be operated in parallel, and the block valves, which do not require an automatic/manual station.

The control system shall include capabilities for the operator to control and adjust the final reheater outlet steam temperature setpoint. Consideration should be given to the setpoint limits that would be accessible to the operator.

Annex A — References

AMERICAN BOILER MANUFACTURERS ASSOCIATION (ABMA)

Recommendations for Location of Instrument and Control Connections for the Operation and Control of Watertube Boilers

SAMA/ABMA/IGCI's recommended Standard: Instrument Connections Manual, jointly published by the Scientific Apparatus Makers Association, the American Boiler Manufacturers Association, and Industrial Gas Cleaning Institute, Inc., 1981.

Available from: **ABMA**
950 North Glebe Rd., Suite 180
Arlington, VA 22203 Tel. (703) 522-7350

or

IGIC
700 North Fairfax St., Suite 304
Alexandria, VA. 22314 Tel. (202) 457-0911

AMERICAN SOCIETY OF MECHANICAL ENGINEERS (ASME)

Section 1-1983	Boiler and Pressure Vessel Code
MFC-2M-1983	Measurement Uncertainty for Fluid Flow in Closed Circuits
ANSI/ASME TDP-1-1985	Recommended Practices for the Prevention of Water Damage to Steam Turbines Used for Electric Power Generation, Fossil Fueled Plants

Available from: **ASME**
345 East 47 St.
New York, N.Y. 10017 Tel. (212) 705-7722

INSTITUTE OF ELECTRICAL AND ELECTRONICS ENGINEERS (IEEE)

ANSI/IEEE Std 268-1982 Metric Practice

Available from: **IEEE**
345 East 47th Street
New York, NY 10017 Tel. (800) 678-4333

ISA — THE INTERNATIONAL SOCIETY FOR MEASUREMENT AND CONTROL

ANSI/ISA-S5.1-1984 (R1992)	Instrumentation Symbols and Identification
ANSI/ISA-S5.4-1976 (R-1981)	Instrument Loop Diagrams
ANSI/ISA-S51.1-1979	Process Instrumentation Terminology
PMC 20.1-1973	Process Measurement and Control Terminology[1]
PMC 22.1-1981	Functional Diagramming of Instruments and Control Systems[1]

Available from: **ISA**
67 Alexander Drive
P.O. Box 12277
Research Triangle Park, NC 27709 Tel. (919) 549-8411

MISCELLANEOUS

Steam — Its Generation and Use, 40th ed.; The Babcock & Wilcox Company; 20 S Van Buren Ave.; P.O. Box 351; Barberton, OH. 44203-0351

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Combustion: Fossil Power Systems, 3rd ed.; Singer, Joseph G.; Combustion Engineering Inc.; 1000 Prospect Hill Rd.; Windsor, CT. 06095; 1981

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Annex B — Steam temperature control

B.1 Purpose

The purpose of this annex is to provide tutorial information on the philosophy underlying this standard and to assist the user of this standard in specifying and applying steam temperature control schemes. This annex is included for information purposes only and is not part of ANSI/ISA-S77.44-1994.

B.2 Requirements

B.2.1 Design specification requirement

To adequately specify a steam temperature control strategy, the following three fundamental questions must be addressed:

a) What are the anticipated process operational requirements—e.g., steady-state or cyclic operations, rates-of-change, etc.?

b) What equipment and operating parameters are required to properly interface the control system?

c) What characteristics must the control system possess to maintain the desired performance?

d) What are the boiler-design characteristics in the heat absorption pattern of the economizer, steam generation (water-wall), and the steam superheating (superheater and reheater)?

The extent to which these questions are answered will directly determine how well the control system is fitted to the design and operating requirements. A misapplication, at the least, could result in poor operating performance and, at the worst, could result in extensive boiler damage. The following is intended to supplement good engineering judgment with a consistent means of communicating design requirements to suppliers, designers, and constructors.

B.2.2 Summary of process performance requirements

A significant factor to consider in boiler control system selection is the heat absorption pattern in each steam generation (water wall and economizer) and steam superheater. Different boiler designs are used to properly balance the list absorption between the steam generation and steam super listing as well as the heat distribution requirements between the superheater and reheater sections.

When the superheater and reheater surfaces are designed to provide full load temperature at control load, resulting in excessive steam temperatures at full load, the following control means are provided for achieving the desired balance between steam generation and steam superheating over the load range:

a) Spray atttemperation

b) Gas by-pass and damper control

c) Burner manipulation

d) A combination of the above is often needed to control superheat and reheat temperature independently.

When the superheat and reheat surfaces are designed to provide full load temperature only near full load, the following means are provided to increase the balance toward superheating and/or reheating as the load is reduced:

a) Increase excess air at reduced load

b) Burner manipulation

c) Gas recirculation

d) Gas by-pass and damper control (for distribution between superheat and reheat absorption)

e) A combination of the above is often needed to control superheat and reheat temperature independently

A second significant factor in steam temperature control system selection is the intended boiler usage. Since the operating requirements of the boiler define the required control system capabilities, design specifications must address the following unit characteristics:

a) Unit load/steaming capacity
b) Normal operating load range
c) Anticipated load changes (transients)
d) Start-up and shutdown frequency

A complete description of the anticipated load characteristics will allow the engineer/supplier to properly evaluate the system and to propose a control strategy. When the control strategy is preselected, these characteristics still should be defined as part of the design basis.

Table B.1 provides a general comparison of typical control systems for specification development and evaluation. This table is not intended to be all-inclusive; rather, it is a summary of commonly used control strategies. The important conclusion to be drawn from the table is that all control systems are not the same, and, therefore, selection of a specific system requires careful consideration of design parameters.

Table B.1 — Summary of typical control systems

Process Prerequisites	Single-Element	Two-Element	Three-Element
	Slow load changes or constant final steam temperature not critical	**Slow to moderate load changes or steady spray water pressure supply or fixed final steam temperature**	**Rapidly changing loads, variable spray water supply or variable final steam temperature**
Steady-state operability	Good	Good	Good
Transient operability	Poor	Good	Good
Response to load change	Slow	Fast	Fast
Control system type	Feedback	Feedback and Feedforward	Feedback, Feedforward, and Cascade
Process measurement requirements	Final steam temperature	Final steam temperature and feedforward signal	Secondary Superheater (SSH) inlet temperature or attempt flow and final steam temperature
Potential for excessive temperature deviation during load change	Probable	Dependent on final drive linearity and repeatability through the load range	Minimal

B.2.3 System description and interface requirements

To achieve the desired performance objectives, the control system interface with the process must be considered carefully. At a minimum, a detailed process description should be provided that includes

a) a specification for all process design parameters such as temperature, pressures, and normal flows;

b) final drive descriptions of sufficient detail that a control strategy can be selected to provide appropriate control action;

c) existing process measurement interfaces, dimension sketches or diagrams. All measurements should be taken where vibrations, pulsations, and other flow disturbances are at a minimum;

d) a description of available electrical power and pneumatic supplies;

e) control interlocks, setpoints, and alarm points; and

f) instrument loop diagrams as defined by ISA-S5.4, 1976 (R1981).

B.3 Principles and methods of steam temperature control

B.3.1 Steam temperature feedback control

A typical boiler arrangement is one where the spray attemperation takes place between the primary and secondary superheaters. With this arrangement, a large process time lag exists between the introduction of spray water and the detection and stabilization of exit steam temperature. A final steam temperature is used as the feedback measurement for control.

B.3.2 Load index development

The load index feedforward may be steam flow, air flow, or other measures of boiler load. Air flow offers the advantage of including excess combustion air requirements as a part of the load index signal. The load index feedforward signal is summed with the output signal from the steam temperature controller.

B.3.3 Transient correction signal development

A steam temperature transient correction is a signal that is applied to the normal steam temperature control strategy to counter the impact of a transient process change. An example of a transient process change, and the most typical, would be overfiring or underfiring. Overfiring and underfiring are considered transients because they are not required to maintain a steady-state condition. A steam temperature transient correction recognizes the impact of a transient on the final steam temperature and attempts to minimize this impact.

Probably the best way to describe this action is to consider an example. Assuming that a load increase is occurring, the firing rate will increase to meet the new load setting and will increase even more to assist in achieving the new energy storage level in the unit. This additional firing is referred to as overfiring, and once the unit's energy level is satisfied, it will be removed. Since the overfiring is only temporary, it is considered a transient condition. Assuming that no transient correction is made, the new load setting will require an adjustment to the steam temperature control, which normally is satisfied through feedforward action. The overfiring would cause the steam temperature to increase, and the steam temperature controller would react to counter the temperature excursion by increasing the spray.

When the overfiring is removed, the steam temperature would drop because excess spray exists. The excess spray would then cause the steam temperature controller to reduce the spray flow. The end results are a longer time period to reach steady-state conditions and a greater deviation versus time. A transient correction would recognize when overfiring is occurring and bias the controls to increase the spray to help minimize the temperature excursion and to prevent the temperature controller from integrating a temperature error over time. Ideally, no temperature transient would occur; thus steady state is achieved more quickly, and the temperature deviation versus time will be reduced.

The actual transient correction for overfiring or underfiring is a function of the overall control strategy. One approach is to use the throttle pressure error as the source for the transient correction. Throttle pressure error is scaled and summed with other feedforward signals.

B.4 Saturation protection/water induction

Steam temperature control maintains final steam temperature by injecting water before the final superheater section. This design may create excessive water accumulation in the steam generator due to overspraying or leakage. Excessive water will lower the steam temperature to saturation, forming water droplets in the downstream piping. Spraying into saturation also will cause loss of control of the inner loop.

Therefore, the recommendation of ANSI/ASME TDP-1-1985 for the prevention of water damage to the steam turbine should be considered in the design of steam temperature control. The following control functions should be provided for the prevention of water induction:

a) Close the block valve and the spray control valve on the turbine trip (or master fuel trip where a main fuel trip does not initiate turbine trip).

b) Close the block valve after the spray control valve is closed.

c) Close the block and the spray control valves when unit load is below predetermined point.

d) Block the reset action of the control system that is calling for spray control valve opening until all other permissives are cleared to allow the spray control valve to open.

e) Provide a remote manual station function for the control spray water valves.

For two-stage attemperator arrangements, provisions should be made in the control system design to prevent the steam entering the intermediate superheater from reaching saturation conditions. This should be accomplished by coordinating the spray flow to the two attemperators in accordance with the boiler manufacturers's recommendations.

B.5 Two-stage attemperation

Two-stage attemperation is provided in a boiler for one or both of the following reasons: first, the quantity of spray flow required is so great that a single attemperator would have saturated steam at its outlet; second, the metal temperature in one of the intermediate superheater sections would be above the allowable design temperature unless the inlet temperature of that section is controlled by spray.

Control of two-stage attemperators is more complex than a single attemperator because the action of the first spray stage affects the second stage. The coupling of the two stages makes tuning any control strategy more difficult.

One consideration in developing an appropriate strategy is the difference in the time responses of the first-stage spray and the second-stage spray. Since the second-stage spray is closer to the outlet of the boiler, its effect on the outlet temperature is faster than the first-stage spray. Better dynamic response of the final outlet temperature is possible if the second-stage spray is the main control parameter for the final temperature.

B.6 Use of cascade spray valve control

In a cascade control strategy, when the output of one controller is used to manipulate the setpoint of another, the two controllers are said to be cascaded. Although each controller will have its own measurement input, only the primary controller (outer loop) can have an independent setpoint, and only the secondary controller (inner loop) has an output to the process.

Steam temperature control strategies assume a predictable relationship between the spray water control valve position and the spray water flow. If this is not the case, a cascade spray water flow control strategy should be considered. With the cascade control strategy, the output of the temperature controller establishes the required spray flow setpoint for the spray water flow controller. In the cascade control arrangement, the temperature controller is the primary controller, and the spray flow controller is the secondary controller.

B.7 No_X control

The nitrogen and oxygen in the combustion air and fuel form oxides of nitrogen (No_x) during the combustion process. The rate of No_X formation is dependent on high temperature, stoichiometric conditions, resident combustion time, and the amount of nitrogen in the fuel. To suppress the formation of No_x, the combustion conditions and control strategy must be altered to decrease the O_2 level at the flame zone, stage combustion, or both, and to decrease combustion gas temperature in the furnace, and hence, the time of exposure of the products of combustion to high temperature.

Air that bypasses the burner combustion can suppress the formation of No_x by reducing the O_2 level and temperature at the primary combustion zone. This option is possible if the boiler design allows the use of burner out-of-service or overfire air ports, or both to achieve the second stage of combustion. The out-of-service burners and overfire air ports provide means of introducing staged combustion air downstream of the furnace combustion zone. Excess air used for steam temperature control also must bypass the burner combustion zone.

Flue gas recirculation can suppress the formation of No_x by reducing the combustion temperature if the boiler design allows introduction of flue gas recirculation into the secondary air stream.

Flue gas recirculation can be used for suppressing the formation of No_X and controlling reheat steam temperatures if the boiler design allows the introduction of flue gas recirculation into both the secondary air stream and the furnace hopper. These boilers have a gas recirculation distribution damper for regulating the gas recirculation flow path.

B.8 Redundancy

Redundancy is employed when system reliability will be seriously affected by a component failure. Redundancy also permits on-line maintenance of components. For maximum availability, redundancy should always be considered. Deviation alarms and automatic failure detection/ transfer should be considered, in order to maximize the usefulness of the application of redundancy.

B.9 Reset windup prevention

Any control loop in which the controller has integral action and the final control element is likely to be fully open or fully closed during routine plant operation should have a provision to prevent reset windup. Steam temperature controls frequently fall into this category because boiler designers usually try to minimize the amount of spray flow required throughout the load range. This frequently leads to times when the spray valve is fully closed during normal operation and, therefore, to the need to reset windup prevention.

For conventional single-element control loops, reset windup prevention is relatively simple to implement. As soon as the final control element reaches one of its endpoints of travel (0% closed or 100% open), the integral (reset) action or the entire controller is disabled. For a simple control loop, the integral limits on the final control element correspond to the high and low limits on the controller output. Most controllers have automatic reset windup prevention when the controller output reaches a limit. Provided everything is calibrated correctly, the reset windup prevention will begin when the final control element reaches a travel limit.

For a three-element or cascade control loop, reset windup prevention becomes slightly more complicated. Now there are two controllers that must both stop integrating to prevent reset windup. The inner or secondary controller operates the same as a single-element controller described above. The primary controller must also have its integral or reset action disabled when the final control element reaches a limit. The output of the primary controller is not always at the same value when the final control element reaches a limit, so a different mechanism must be used to implement the windup prevention.

On pneumatic and analog electronic controllers, it may not be practical to implement a reset windup prevention scheme such as is required in this situation. On a digital system, however, there are several ways to do this. The integral gain of the controller may be adaptively tuned to zero when the limit is reached or the high or low limit of the controller may be adjusted to the controller output value when the limit is reached. This prevents the primary controller from winding up the setpoint for the secondary controller when the final control element is at a limit.

Annex C — Figures

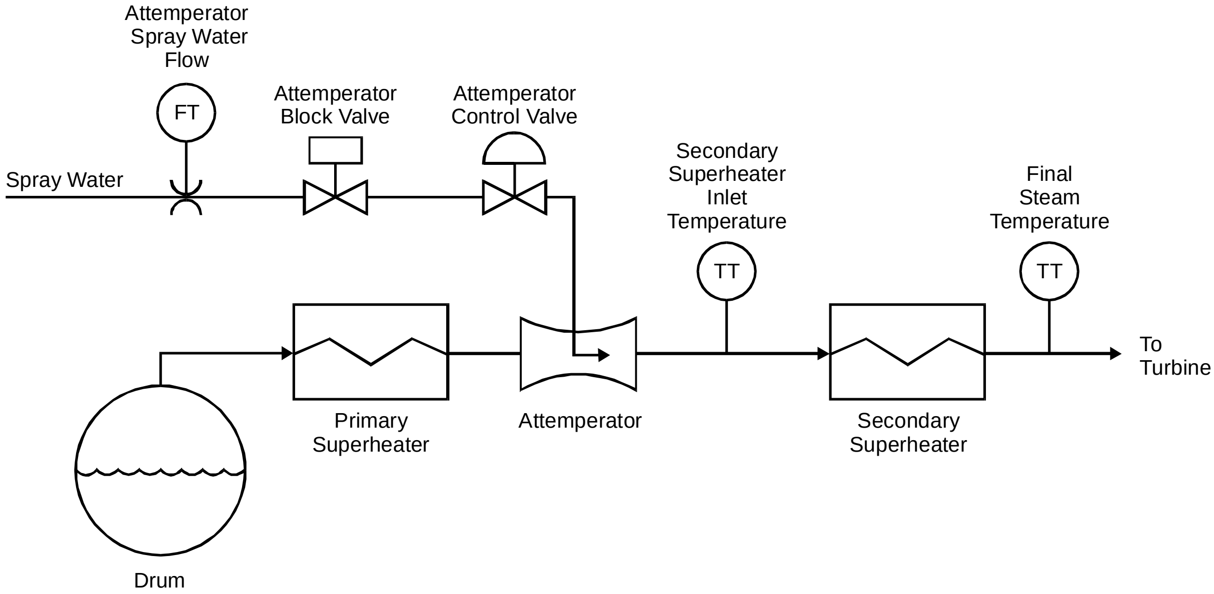


Figure C.1a — Typical superheater single-stage attemperator arrangement

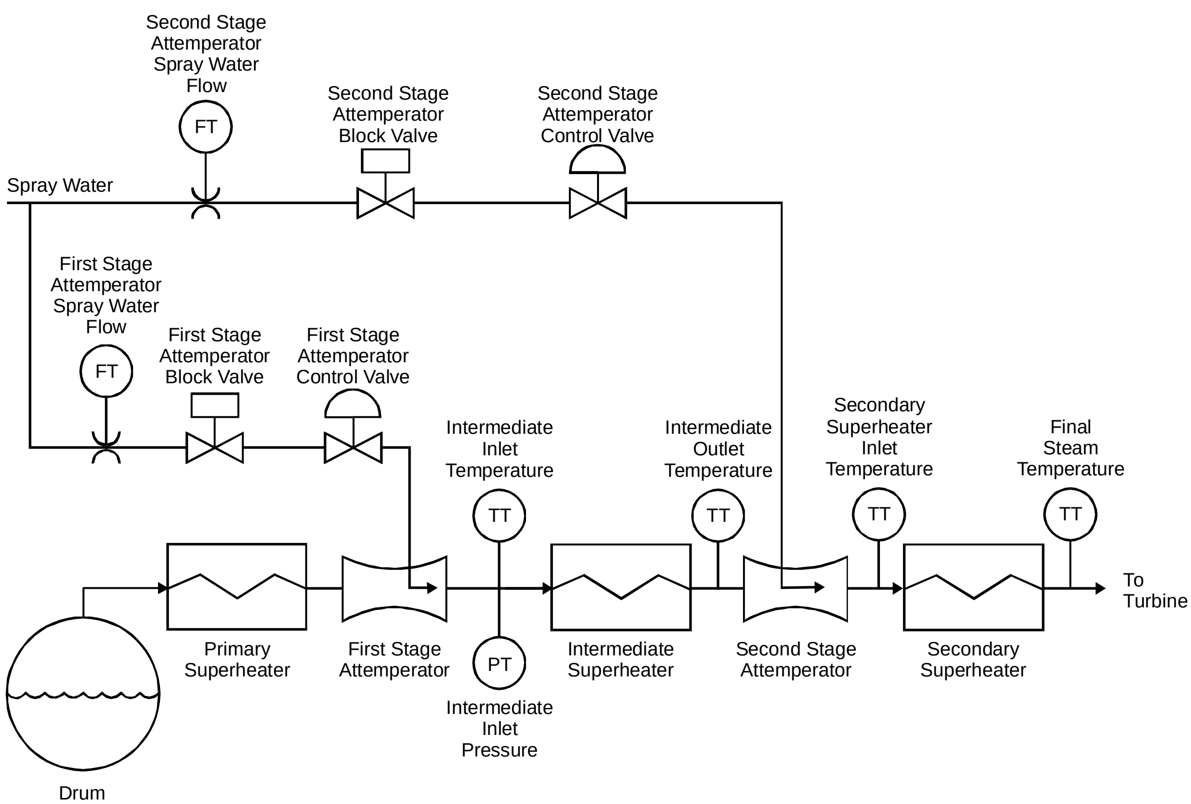


Figure C.1b — Typical superheater two-stage attemperator arrangement

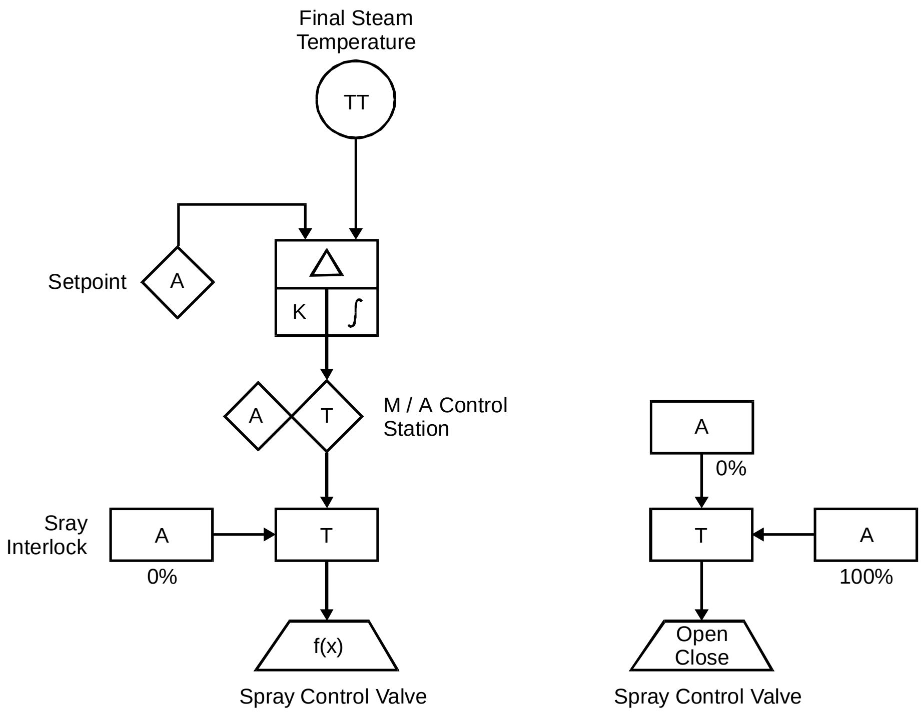


Figure C.2 — Typical single-element superheat steam temperature control

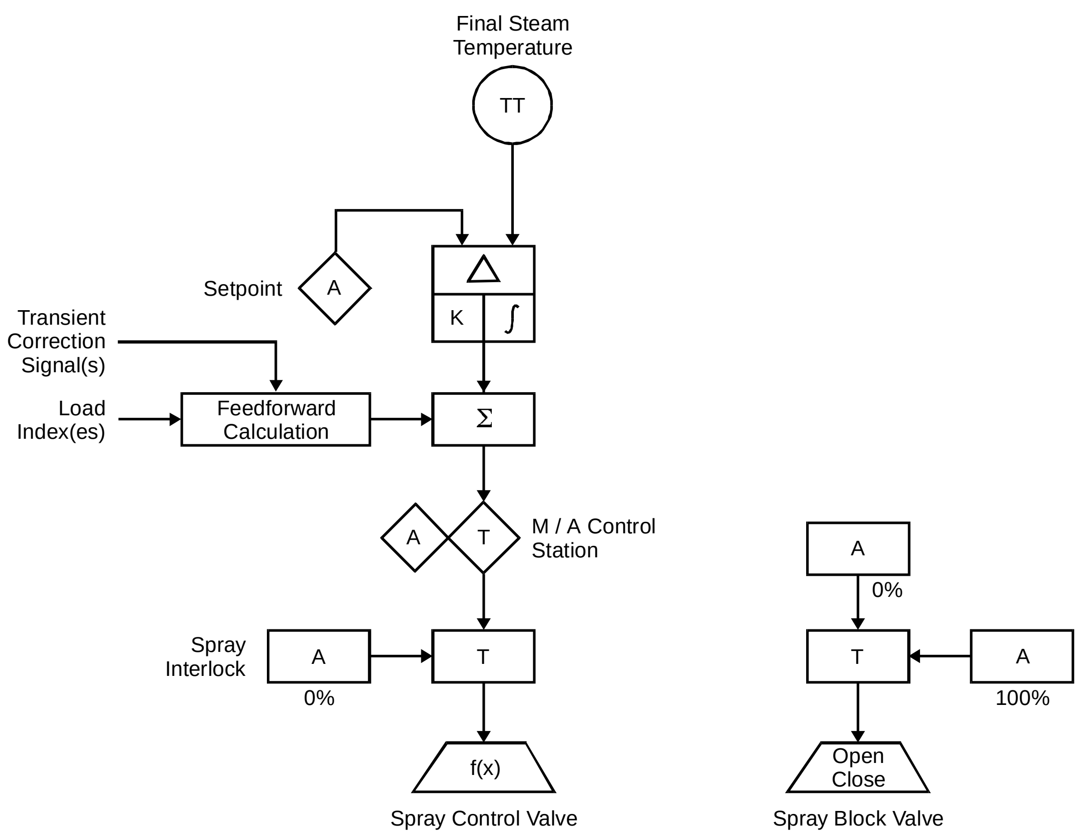
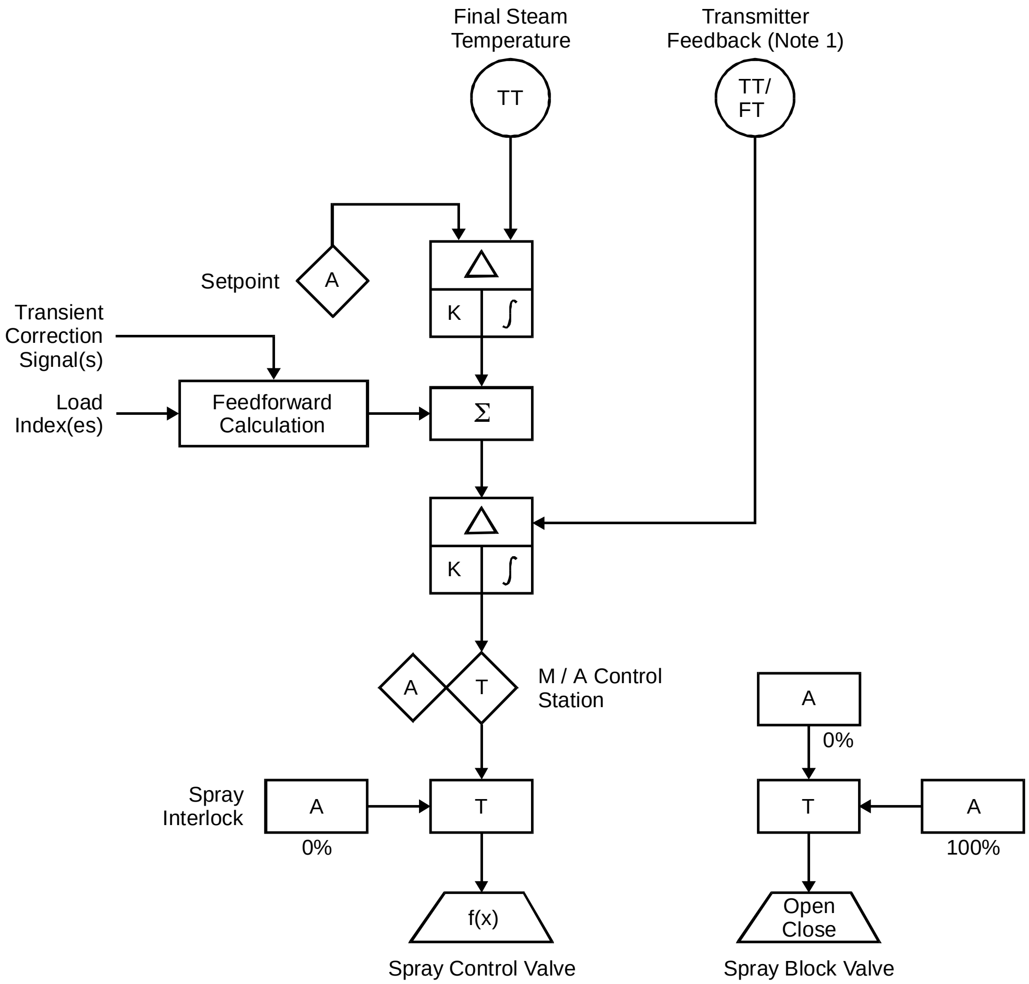
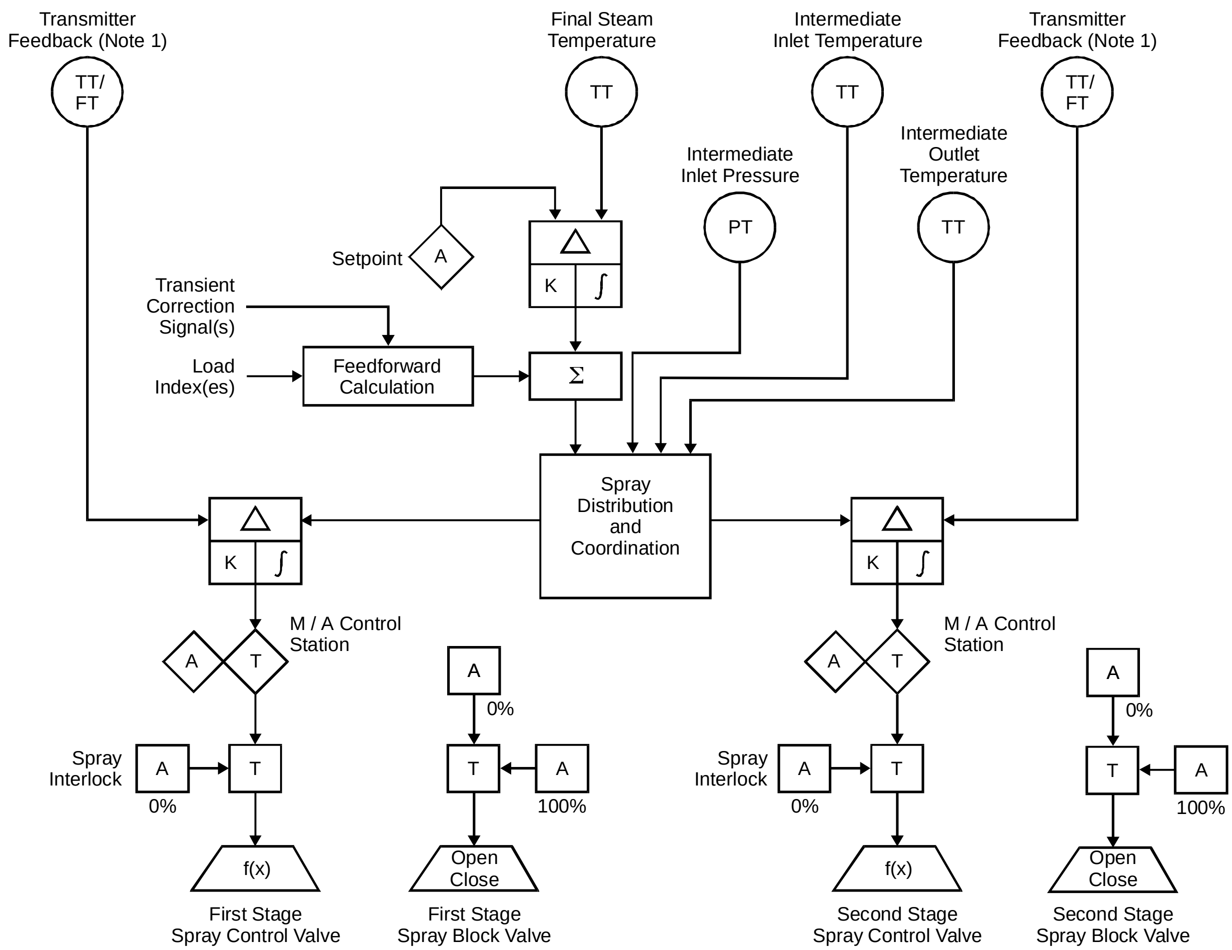


Figure C.3 — Typical two-element superheat steam temperature control



Note: 1. Attemperator Outlet Temperature or Spray Flow

Figure C.4 — Typical three-element superheat steam temperature control



Note: 1. First and Second Stage Attemperator Outlet Temperature or Spray Flow.

Figure C.5 — Typical two-stage attemperation superheat steam temperature control

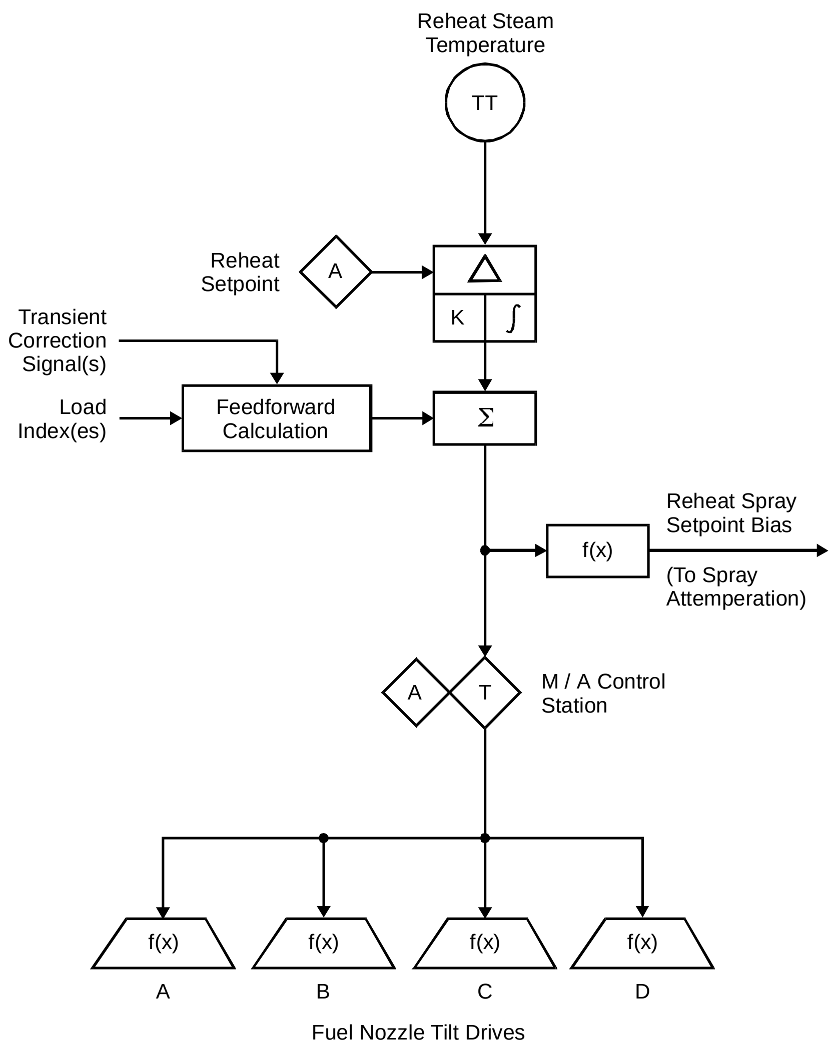


Figure C.6 — Typical two-element fuel nozzle tilt control

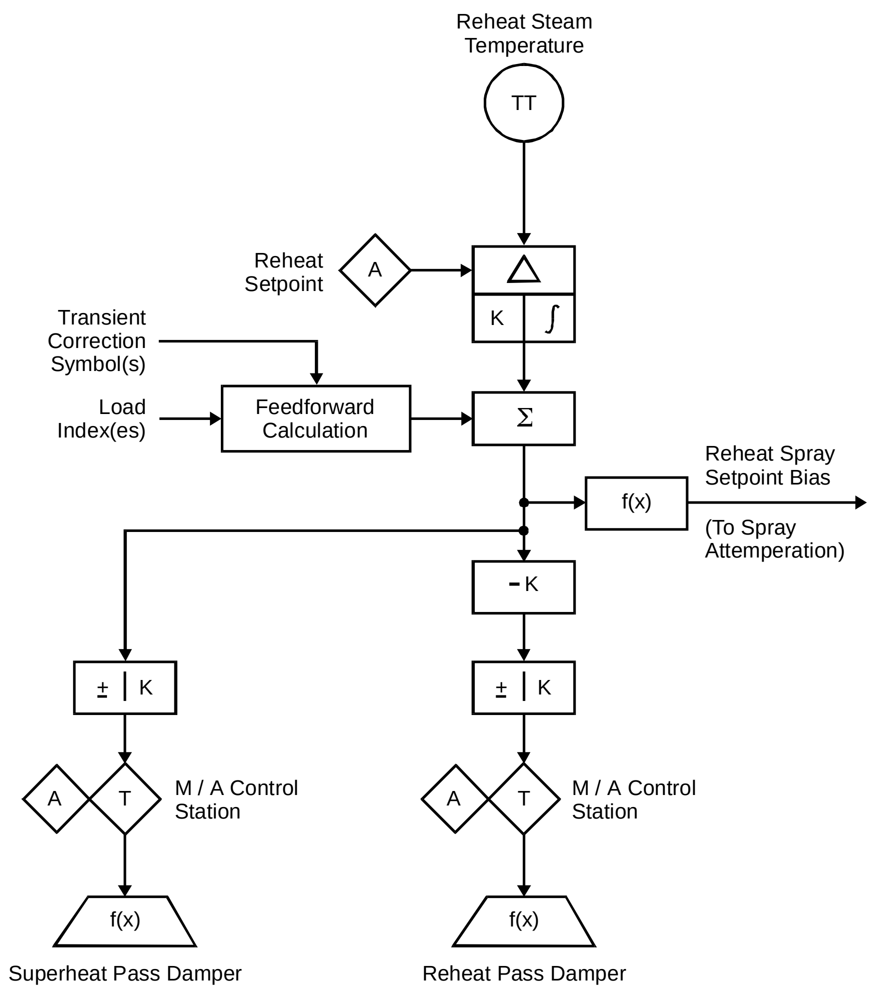


Figure C.7 — Typical two-element flue gas pass damper control

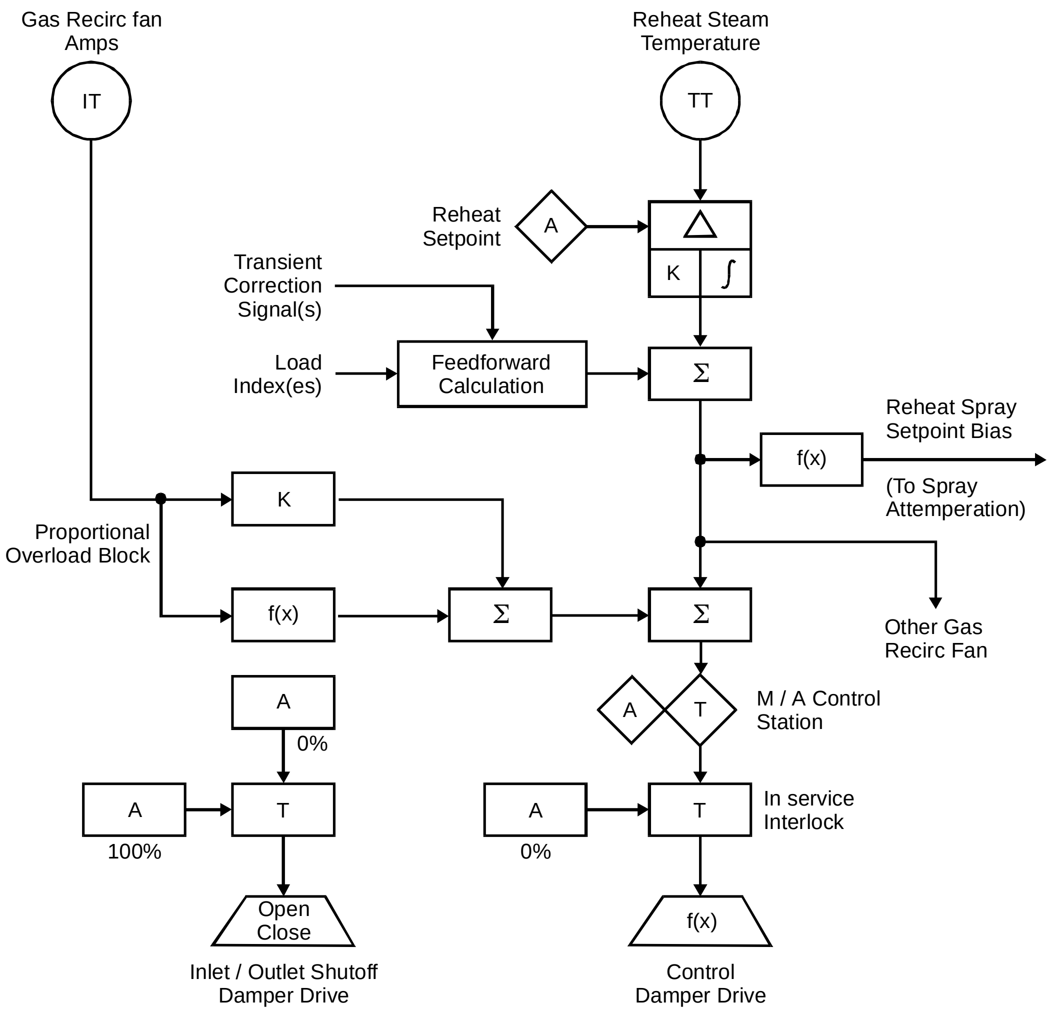


Figure C.8 — Typical two-element flue gas recirculation control

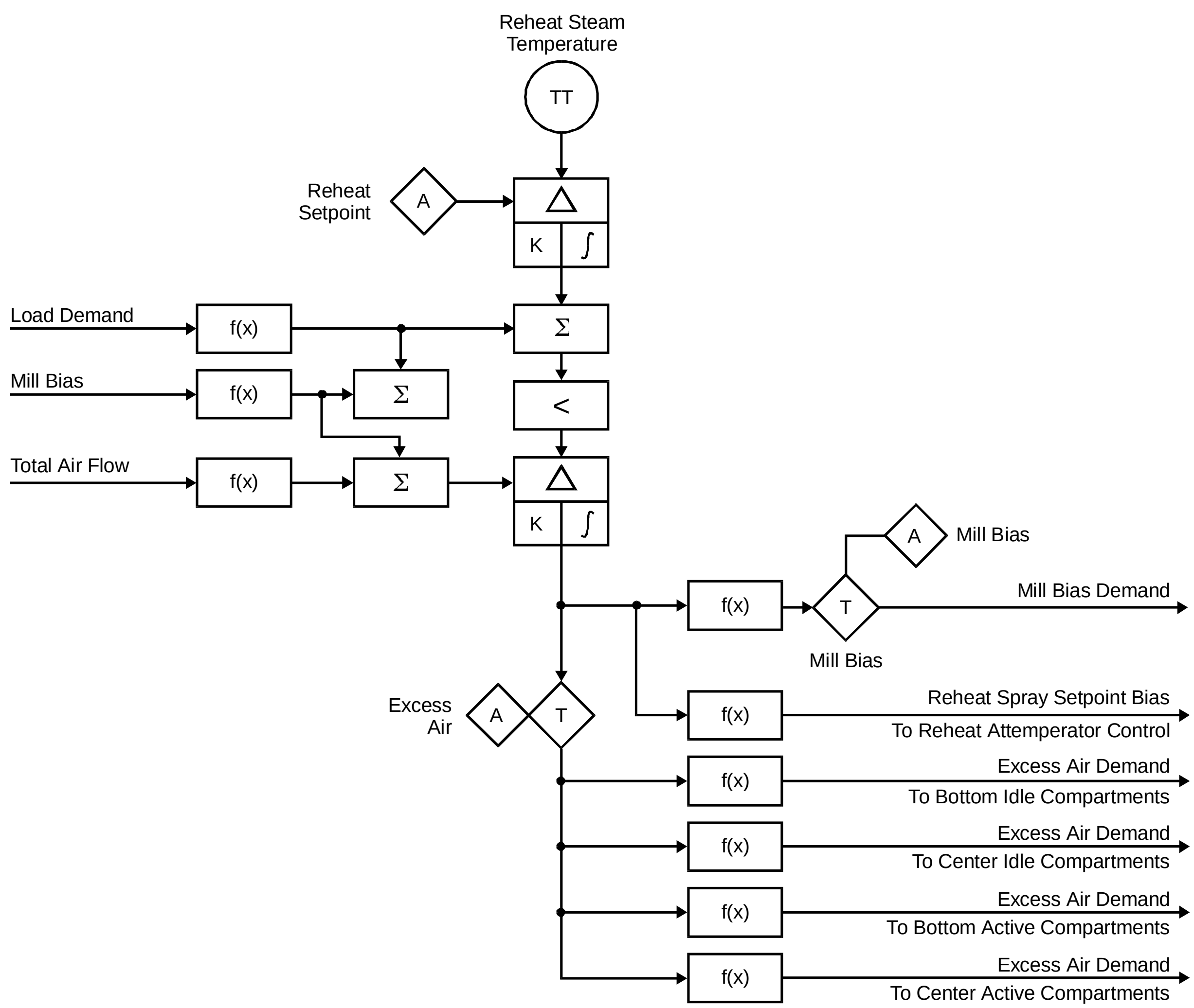


Figure C.9 — Typical compartmented windbox temperature control

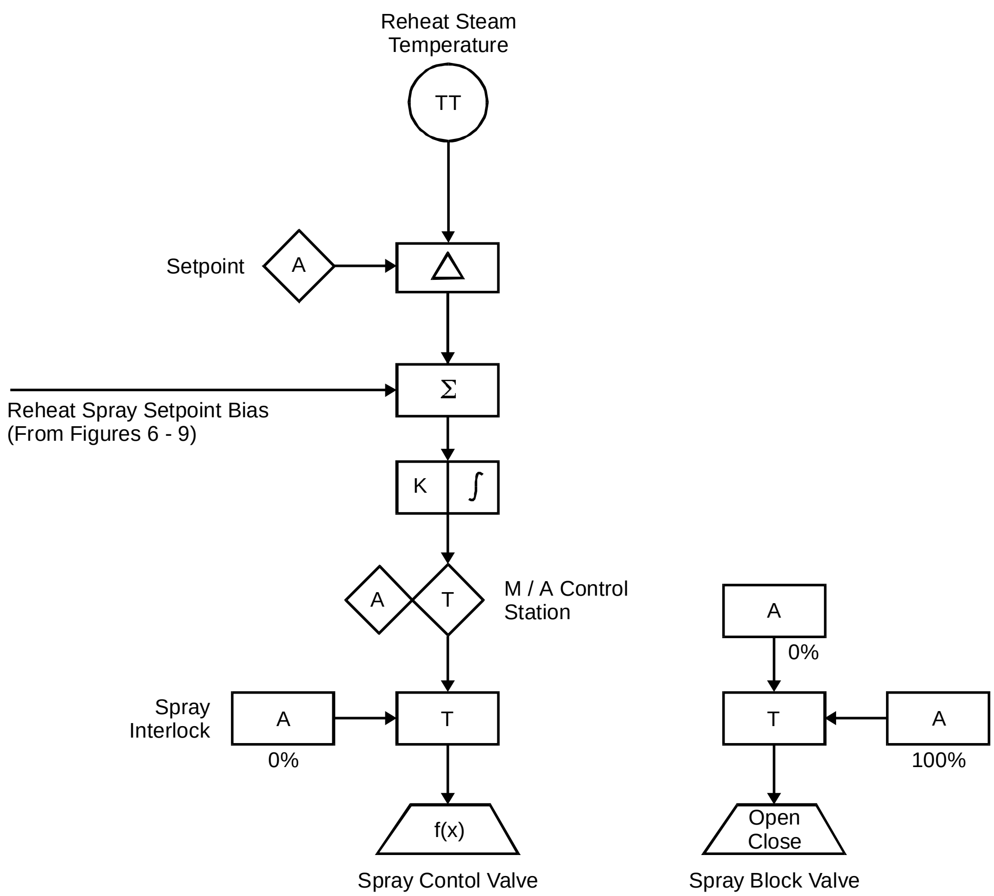


Figure C.10 — Typical single-element reheat steam temperature control

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