American National Standard

Fossil Fuel Power Plant
Unit/Plant Demand Development (Drum Type)
ISA-S77.43 — Fossil Fuel Power Plant Unit/Plant Demand Development (Drum Type)

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1 Purpose

The purpose of this Standard is to establish the minimum requirements for the functional design specifications of unit/plant demand development for control systems for drum-type fossil-fueled power plant boilers.

2 Scope

The scope of this Standard is to address the unit/plant demand development subsystem for boilers with steaming capacities of 200,000 lbs/hr (25 kg/s) or greater. This subsystem includes firing rate demand development, throttle/header pressure control, and unit megawatt/steam flow control as applicable.

This Standard will address two types of process applications:

1) a single boiler supplying a single turbine, typical of an electric utility power plant; and
2) a single boiler or multiple boilers supplying a common distribution header, typical of an industrial power plant.

Specifically excluded from consideration are:

1) dispatch control;
2) turbine/generator control (other than turbine demand);
3) combustion controls (covered separately by ISA-S77.41, Fossil Fuel Power Plant Boiler Combustion Controls);
4) steam distribution control systems;
5) economic loading of boilers; and
6) fluidized bed boilers.

3 Definitions

The following definitions are included to clarify their use in this Standard and may not correspond to the use of the word in other texts. For other definitions, reference ANSI/ISA-S51.1, “Process Instrumentation Terminology.”

alarm: An indication used to alert an operator about an abnormal condition.

boiler: The entire vessel in which steam or other vapor is generated for use external to itself, including the furnace, consisting of waterwall tubes; the firebox area (including burners and dampers); the convection area, consisting of any superheater, reheater, and/or economizer sections; and drums and headers.
**boiler follow mode:** Mode of boiler control where the boiler responds to an energy demand requirement and controls boiler pressure by regulating boiler inputs.

**boiler follow system:** A type of boiler control system in which the boiler inputs are adjusted to control the steam pressure out of the boiler.

**coordinated control mode:** A mode of boiler/turbine control that provides for the parallel operation of the boiler and the turbine as a unit to match generation to demand while maintaining boiler/turbine balance.

**coordinated control system:** A type of boiler and turbine control system in which both the turbine inlet valves and the boiler inputs are adjusted together to simultaneously regulate the turbine load and the boiler output pressure.

**controller:** Any manual or automatic device or system of devices used to regulate a process within defined parameters. If automatic, the device or system responds to variations in a process variable.

**differential pressure flow element:** A measuring element that is inserted in a process flow path and used to create a pressure drop that is proportional to the square of the rate of flow.

**firing rate:** The rate of fuel combustion in a boiler.

**first-stage pressure:** The pressure within a steam turbine at the point where the steam exits the first row of turbine blades. The pressure at this point is closely proportional to the flow rate of steam through the turbine. First-stage pressure is also referred to as impulse pressure.

**frequency:** An electrical measurement of the number of cycles in a given period of time that an electrical current oscillates. In the United States, the electrical system operates at a frequency of sixty Hertz (cycles/sec).

**load:** The rate of energy output, usually expressed as lb/hr (kg/s) of steam or megawatts of electrical generation.

**load dispatch:** A remotely developed signal transmitted to an electric generating unit's control system for the development of that unit's net generation requirement.

**load index:** Signal representative of desired output energy flow rate.

**mass steam flow:** The mass flow rate of steam from the boiler derived either from direct process measurements and/or calculations from other parameters. If volumetric steam flow rate measuring techniques are employed, the measured (indicated) flow shall be compensated for flowing steam density to determine the true mass steam flow rate.

**megawatt:** A unit of power measurement equal to one million watts. Turbine/generator capability is usually expressed in megawatts.

**mode (submode):** A particular operating state of a control system such as manual, automatic, remote, coordinated, etc. A mode is usually designed to achieve a desired control strategy.

**redundant (redundancy):** Duplication or repetition of elements in electronic or mechanical equipment to provide alternative functional channels in case of failure.

**regenerative:** A quality of signal that feeds back on itself, causing control system instability.

**runback:** An action by the boiler control system initiated by the loss of selected auxiliary equipment, which limits the capabilities of the unit to sustain the existing load. Upon runback initiation, the boiler demand signal is reduced at a preset rate to a level that the remaining auxiliaries are capable of supporting.

**NOTE:** Auxiliary equipment can be part of the boiler, turbine, and/or the balance of plant.
**rundown (runup):** An action by the boiler control system initiated by an undesirable operating condition, i.e., fuel/air limit (cross-limiting), temperature limits, etc. Upon rundown (runup) initiation, the boiler demand signal is reduced (increased) in a controlled manner until the undesirable operating condition is eliminated.

**shall, should, and may:** The word "shall" is to be understood as a requirement, the word "should" as a recommendation, and the word "may" as permissive, neither mandatory nor recommended.

**steam header:** Pipe in which steam output from multiple boilers is collected and then distributed to various steam loads.

**tracking:** Forcing an inactive control function to follow the active control function so that upon a mode transfer, no process upset occurs.

**turbine:** A machine that converts energy from a moving fluid into rotating mechanical energy to drive a load. In a power plant, a turbine converts energy in the steam into mechanical energy to drive an electric generator (the load) or an auxiliary, such as a boiler feedpump.

**turbine governor valves:** The primary control valves used to regulate the flow of steam through the turbine during normal operation.

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### 4 Minimum design requirements for unit/plant demand development control systems

The unit/plant demand development portion of the total plant control system shall meet the operational requirements of the plant and shall correctly interface with the process to provide accurate, safe, and efficient plant control. To accomplish these objectives, the following requirements are defined as the minimum acceptable design.

#### 4.1 Process measurement requirements

**4.1.1 Instrument installation for unit/plant demand development**

4.1.1.1 Process-sensing devices should be installed as close as practical to the source of the measurement with appropriate design to prevent excessive vibration and temperature and to provide access for periodic maintenance. Recommendation for the location of instrument and control equipment connections can be found in "Recommended Instrument Connections," published by SAMA, ABMA, and IGCI.

4.1.1.2 If instruments require impulse lines, then separate isolation valves and impulse lines shall be provided for each instrument.

**4.1.2 Measurement and conditioning**

4.1.2.1 Measurement filtering

Filtering techniques used to condition process measurements shall not compromise the speed of response of control.
4.1.3 Process measurements

4.1.3.1 Steam pressure measurement
An appropriate steam pressure measurement shall be provided for control. This may be steam header pressure, throttle pressure, or drum pressure, as required by the application.

4.1.3.2 Boiler output energy flow measurement

4.1.3.2.1 Boiler output energy flow may be used in the demand development calculation. Energy flow may be calculated or measured in several different manners including but not limited to: measurement of boiler output steam flow, measurement of turbine first-stage (impulse) pressure, or calculation of turbine governor valve(s) position.

4.1.3.2.2 If a differential pressure flow element is used for the steam flow measurement, it shall be pressure and temperature compensated to determine the mass steam flow.

4.1.3.3 Megawatt and frequency measurement
For coordinated systems (4.2.2), megawatts and frequency measurements shall be provided, if not a part of the turbine control system.

4.1.4 Measurement redundancy

4.1.4.1 The following process measurements shall be redundant:
1) steam pressure; and
2) boiler output energy flow.

4.1.4.2 When two measurements are employed, excessive deviation between the measurements shall be alarmed and the affected portion of the control system automatically transferred to manual.

4.1.4.3 When three measurements are employed, the median measurement shall be used for control and excessive deviation between each measurement, and the median shall be alarmed.

4.2 Control and logic requirements

4.2.1 Boiler follow system

4.2.1.1 Single boiler units

4.2.1.1.1 Single-element control (header or throttle pressure control only) is the minimum boiler follow system required to match steam production to steam needs for the following applications:
1) process of relatively slow load changes (e.g., building heating system); and
2) process where constant steam pressure is not critical.

4.2.1.1.2 The single-element boiler following system (Figure 1) requires a steam pressure signal and a setpoint. The steam pressure is compared to a setpoint to determine if steam generation matches demand. If not matching, an error will exist that, through the pressure controller, will generate a change in boiler load demand.
4.2.1.1.3 Two-element control (pressure control with load index feedforward) is the minimum boiler follow system required to match steam production to steam needs for the following applications:

1) process with frequent or rapid load changes; and
2) process where constant steam pressure is critical.

4.2.1.1.4 The two-element boiler follow system (Figure 2) requires a steam pressure signal, a load index signal, and a steam pressure setpoint. The load index is trimmed by a steam pressure controller or its functional equivalent to develop a boiler load demand. The load index signal shall not be affected by boiler disturbances (i.e., be nonregenerative).

The steam pressure is compared to a setpoint to determine if steam generation matches demand. If not matching, an error will exist that, through a pressure controller, will trim the boiler load demand.
4.2.1.2 Multiple boiler units

4.2.1.2.1 This section describes several approaches for the development of an individual boiler firing rate when multiple boilers are providing steam to a header. In such a system, steam from multiple sources is distributed to multiple users. It is not generally possible to coordinate the users and suppliers. Thus, the suppliers of steam are resigned to be used in a following mode of operation.

4.2.1.2.2 Single-element control (pressure control only) is the minimum boiler follow system required to match steam production to steam needs for the following applications:

1) processes of relatively slow load changes (e.g., building heating systems); and
2) processes in which constant steam pressure is not critical.
4.2.1.2.3 The single-element boiler following system (Figure 3) requires a steam header pressure signal and a setpoint. The steam header pressure is compared to the set point to determine if steam generation is matching demand. If not matching, an error will exist that, through the pressure controller, will generate a change in plant master load demand.

Figure 3: Typical single-element plant master control system for use with multiple boilers on a common steam header (functional control diagram)

4.2.1.2.4 Two-element control (pressure control with load index feedforward) is the minimum boiler follow system required to match steam production to steam needs for the following applications:

1) processes with frequent or rapid load changes; and
2) processes in which constant steam pressure is critical.
4.2.1.2.5 The two-element boiler follow system (Figure 4) requires a steam header pressure signal, a cumulative load index signal, and a steam header pressure setpoint. The cumulative load index is trimmed by a steam pressure controller to develop a plant master load demand. The load index signal shall not be affected by boiler disturbances (i.e., be nonregenerative). The steam header pressure is compared to a setpoint to determine if steam generation is matching demand. If not matching, an error will exist that, through a pressure controller, will trim the plant master load demand. See 4.2.1.1.4.

Figure 4: Typical two-element plant master control system for use with multiple boilers on a common steam header (functional control diagram)

4.2.1.2.6 When the load demand to one of the boilers is changed by biasing or manual action, the load demand to each of the other boilers on automatic shall compensate in correct proportion to maintain the overall plant load demand and thereby minimize the process upset.

4.2.2 Coordinated system
A coordinated system is a type of boiler and turbine control system in which both the turbine inlet valves and the boiler inputs are adjusted together to simultaneously regulate the turbine load and
the boiler output pressure. Coordinated control is usually applied to units that consist of a single boiler and single turbine.

The unit demand development subsystem (Figure 5) shall provide boiler energy demand and turbine demand to achieve the following control objectives:

1) match generation to demand;
2) match boiler energy demand to turbine steam demand to maintain throttle pressure at desired setpoint;
3) coordinate the operation of the boiler and the turbine under normal operating conditions and under emergency or limiting conditions for either boiler or turbine; and
4) provide unit master control for the operator, encompassing both boiler and turbine operation from a single interface.

Figure 5: Typical coordinated system (functional control diagram)
4.2.2.1 Coordinated system requirements

1) The unit demand development subsystem shall match generation to demand by using closed-loop control to make the total megawatt output equal to the total megawatts required of the unit.

2) The unit demand development subsystem shall maintain boiler turbine energy balance by controlling throttle pressure to its desired setpoint.

3) The unit demand development subsystem shall have the ability to recognize boiler and turbine capability limitations. It shall adjust and/or limit boiler and turbine demands to be within the capabilities of the supporting auxiliary equipment.

The adjustment or limiting of boiler and turbine demands shall recognize, as a minimum, the following equipment limitations:

   a) excessive flow errors in the fuel, air, and feedwater control loops; and

   b) loss of capabilities of external equipment that support boiler or turbine operation (e.g., stator cooling water loss).

4) The unit demand development subsystem shall provide a consolidated operator interface for boiler and turbine control and indication functions. Consideration shall be given to the features of the external turbine controls.

4.2.2.2 Unit master functions

Generation demand shall be established either manually or from a signal from the load dispatch system. This demand shall be constrained by maximum/minimum generation limits and generation maximum rate of change limits as appropriate to the particular boiler turbine unit and the auxiliaries in service. Provision shall be included, if necessary, to compensate for system frequency (turbine speed) variations so as not to interfere with normal turbine governor action. Permissives shall be included to determine the validity of the signal from the load dispatch system before it is accepted by the unit master system.

4.2.2.3 Turbine demand

The turbine demand shall be fully coordinated with the boiler and shall be restricted when boiler capability is limited.

The turbine demand shall be compatible with and shall not duplicate the functions of the external turbine control system (such as stage pressure feedback loop). The turbine stage pressure or megawatt feedback control may be active only when the coordinated mode or boiler follow mode is active.

4.2.2.4 Boiler demand

The boiler demand shall establish the primary demand for fuel and air flow controls as covered by SP77.41, Combustion Controls. This demand shall be fully coordinated with the turbine and shall be restricted when turbine capability is limited.

4.2.3 System tracking

Automatic tracking shall be provided such that any control mode transfer is accomplished without process upset.
4.3 Minimum alarm requirements
Minimum alarm requirements shall be the alarms listed below. Unless otherwise stated, all hardware alarms apply only to hardware associated with the unit/plant demand development system.

4.3.1 Process alarms
1) loss of capability of external equipment that supports boiler and/or turbine operation;
2) excessive steam pressure deviation from setpoint;
3) load at minimum or maximum limit; and
4) excessive flow errors in the fuel, air, and feedwater flow loops.

4.3.2 Hardware alarms
1) loss of control power;
2) control loop trip to manual;
3) loss of control transmitter or associated signal conditioning unit;
4) redundant transmitter deviation alarm;
5) loss of redundant components; and
6) invalid load dispatch signal detected.

4.4 Operator interface
4.4.1 Operator information
4.4.1.1 Boiler follow systems
4.4.1.1.1 The following information used in the unit/plant demand development control system shall be made available to the operator:
1) main steam pressure;
2) main steam pressure setpoint;
3) steam flow (on a per boiler basis);
4) all alarms;
5) automatic/manual control loop status;
6) output demand to boiler combustion controls;
7) boiler biasing (if multiple boilers are used); and
8) minimum and maximum load limits (if provided).
4.4.1.1.2 In addition to the above, information related to main steam temperature (on a per boiler basis) should be made available to the operator.

4.4.1.2 Boiler/turbine coordinated systems

4.4.1.2.1 The following information used in the unit/plant demand development control system shall be made available to the operator:

1) main steam pressure;
2) main steam pressure setpoint;
3) gross megawatts;
4) load (MW) setpoint;
5) all alarms;
6) automatic/manual control loop status;
7) output demand to boiler combustion controls;
8) output demand to turbine governor valve controls (if available);
9) maximum and minimum generation limits;
10) generation maximum rate of change limit; and
11) steam flow.

4.4.1.2.2 In addition to the above, the following information should be made available to the operator:

1) runback/rundown status;
2) load hold status;
3) load control status (local or remote); and
4) current operating mode.

4.4.2 Operator control functions

4.4.2.1 Boiler follow systems

4.4.2.1.1 The control system shall include capabilities for the automatic/manual control of the boiler demand signal to the boiler combustion controls (boiler master station).

4.4.2.1.2 The control system shall include capabilities for the operator to control/adjust the following:

1) main steam pressure setpoint; and
2) biasing of boilers (in multi-boiler applications).

4.4.2.2 Boiler/turbine coordinated systems

4.4.2.2.1 The control system shall include capabilities for the automatic/manual control of the following:

1) boiler demand signal to the boiler combustion controls (boiler master station); and
2) turbine demand signal to the turbine governor valves control system (or governor valve interface).

4.4.2.2.2 The control system shall include capabilities for the operator to control/adjust the following:

1) load (MW) setpoint;
2) minimum load (MW) limit;
3) maximum load (MW) limit;
4) rate (load change) limit;
5) throttle pressure setpoint; and
6) mode of operation.

Appendix A

unit operating modes: The boiler follow system includes two basic operating modes, "manual" and "boiler follow." The coordinated system includes the two basic operating modes, "manual" and "boiler follow," and two additional operating modes, "turbine follow" and "coordinated." The different modes provide alternate methods for the operator to establish the energy output and/or energy balance of the unit/plant.

manual mode: The manual mode allows the operator to regulate the energy output of the unit/plant manually. All demand development controls are in manual, and no energy output or energy balance regulation is provided.

boiler follow mode: In boiler follow mode, the energy output of the unit is established from external sources (turbine, building heating system, process steam users, etc.). The boiler is in automatic, and the unit/plant demand development system establishes the boiler demand and maintains the steam pressure (or steam header pressure) of the unit/plant at the setpoint by regulating the boiler inputs.

turbine follow mode: In turbine follow mode, the energy output of the unit is established by the existing boiler inputs. The turbine is in automatic, and the unit demand development system establishes the turbine demand and maintains the steam pressure of the unit at setpoint by regulating the turbine control valves.

coordinated mode: In coordinated mode the energy output of the unit is established by generation demand. Both the turbine and boiler are in automatic, and the unit demand development system establishes the turbine and boiler demands signals to simultaneously regulate the energy output and energy balance of the unit. The generation demand may be established by the unit operator or from the load dispatch system.

load dispatch system: A power plant's electric generation is interconnected with the generation of other units as part of a regional system for reliability and economic benefits. A regional load dispatch system continuously monitors system frequency and schedules network interchange of energy. The load dispatch system satisfies both of these criteria by changing the demand for electrical output from each generating unit. Each unit receives, via a telemetering channel, a net
generation requirement. The unit demand development system should provide conversion, validation, and selection of the load dispatch generation demand signal (as required).

The unit demand development system establishes permissives before the load dispatch system can establish the unit's generation demand. The unit must be operating within the normal range of the boiler and its auxiliaries without an active runback or rundown. Selection of the load dispatch mode will permit the signal from the load dispatch system to be accepted by the unit demand development system.

Validation of the load dispatch signal protects the control system from operating on an incorrect signal. Identification of an incorrect signal shall inhibit further change in the generation demand, reject the load dispatch mode, and alert the operator.

The load dispatch signal shall be inhibited when actual unit operating limits have been reached. High load limit, low load limit, and rate of change limit protect the boiler and its auxiliaries from damage. The generation demand, determined by the unit demand development system, shall be compared to the unit's limits. Upon reaching a unit limit, the generation demand signal shall be limited and the operator alerted.

**nonregenerative load index:** A nonregenerative load index is a signal that is representative of desired output energy flow rate and does not feed back on itself to cause control system instability. A typical condition application requirement for a load index signal that is nonregenerative is the boiler energy demand signal. The boiler energy demand signal should represent the actual energy requirement imposed by the turbine (or whatever the steam load may be) on the boiler. This signal should reflect only the changes in energy demand requirement and should not be affected by boiler disturbances such as changes in fuel quality.

An example of a regenerative load index is the use of steam flow as a load index or feedforward to the boiler control. If the source of the change of steam flow is the turbine throttle valves, the correct feedforward information is provided to the boiler controls. However, if the change in steam flow is due to a boiler disturbance, the effect is regenerative. For example, if fuel quality decreases, steam flow will decrease, which will result in a lower steam flow feedforward and which, in turn, will call for further reduction of fuel flow.

Examples of nonregenerative load indices include a calculated desired output or calculated turbine throttle valve opening. Either of these indices will be unaffected by any disturbance that may occur within the boiler and, hence, are nonregenerative.

**frequency correction:** The turbine governor is responsible for controlling turbine speed when the generator is not connected to a large electrical grid. When the generator is connected to a large electrical grid, the turbine speed cannot change independently of the system frequency. The role of the governor then changes to one in which it automatically adjusts the turbine load if the system frequency deviates from its desired value. If the system frequency is changing, there is a mismatch in the electrical system between the load on the system and the generation in the system. The turbine governor controls the mismatch by automatically increasing generation if frequency is low and decreasing generation if frequency is high.

When a significant frequency upset occurs in a power system, it may last for many seconds or even a minute. It is important during these long upsets that the turbine load reference not be changed by the operator or the coordinated control system. If the coordinated control system has a feedback control loop on megawatts, first-stage pressure, or turbine valve position, any time one of these parameters changes the control loop will automatically try to bring the parameter back to its original value. If these loops are in service during a frequency upset, they will change the turbine load reference, which counteracts the frequency correction action of the turbine governor. To prevent this from happening, the coordinated control system must adjust its demand to the turbine governor so that it tracks the normal frequency correction of the governor.
As an example, suppose a coordinated control system has a feedback loop in service controlling megawatts when a 1% system frequency upset occurs. Most turbine governors have a speed regulation of 5% (gain = 20), so if the frequency changes 1%, the turbine generation changes 20%. The coordinated control system must also sense the 1% speed change and must change the megawatt demand by 20%. This keeps the coordinated system in track with the turbine governor and prevents it from overriding the normal frequency correction action of the governor.

**runbacks, runups, rundowns, and directional blocking:** Runbacks, runups, and directional blocking are terms used to describe various control system automatic actions and responses to upsets that occur within the plant and to situations in which the controlled process variable (or variable relationships) exceed pre-established limits.

**runbacks:** Following the loss of any major auxiliary, the boiler/turbine unit must be rapidly driven in a controlled manner to a load that can be sustained without that auxiliary in service. Runbacks are provided for this purpose. Each runback has an associated load target and rate of load change to achieve the load target. In addition, some control systems will change the mode of control (i.e., boiler follow, turbine follow, or coordinated) to best achieve effective control during this event. Runbacks initiated from fuel-, air-, or gas-handling equipment can often be handled best by placing load control in the turbine follow mode and ramping the boiler demand signal down to the level that the remaining auxiliaries can support. In this manner, throttle pressure would be controlled by the turbine, and no additional upsets would be introduced into the equipment that caused the runback. Runbacks initiated from feedwater or the turbine can often be best handled by placing control in the boiler follow mode and ramping the demand to the turbine governing valves down to the pre-established level that the remaining auxiliaries can support. This would reduce any further upsets in the feedwater and turbine subsystems.

**runups and rundowns:** Runups and rundowns are responses by the boiler control system initiated generally by an unsafe operating condition. One example is the existence of a generator stator high temperature. The unit demand will be increased or decreased at a pre-established rate until the condition that initiated the runup or rundown clears. Often, runups and rundowns are employed when a minimum or maximum limit is reached in conjunction with process input deviation (such as forced draft fans at maximum and air flow less than demand).

**directional blocking:** Directional blocking is a term used to describe a control system response to a situation in which a major auxiliary subsystem reaches a preset maximum or minimum limit. When this occurs, the control system will block any additional increases or decreases in unit load demand. Directional blocking may also be used when process variables exceed pre-established limits.
Appendix B  References

1) ANSI/ISA-S5.1-1984, “Instrumentation Symbols and Identification,” ISA.


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