API RP 550

7 (47)

MANUAL
ON
INSTALLATION OF REFINERY INSTRUMENTS AND CONTROL SYSTEMS

PART IV—STEAM GENERATORS

FIRST EDITION
1975

A

MANUAL
ON
INSTALLATION OF REFINERY INSTRUMENTS AND CONTROL SYSTEMS

PART IV—STEAM GENERATORS

FIRST EDITION
1975

Up todate as at
June 1984

AMERICAN PETROLEUM INSTITUTE
Refining Department
2101 L Street Northwest
Washington, D.C. 20037

Price: $3.00

MANUAL
ON
INSTALLATION OF REFINERY INSTRUMENTS AND CONTROL SYSTEMS

PART IV—STEAM GENERATORS

FIRST EDITION
1975

FOREWORD

This is the fourth part of the manual and represents the latest suggested or generally used practices in the installation of the kinds of devices covered in Parts I and II as they apply to the measurement and control of steam generators.

Part IV covers recommended practices that specifically apply to instrument and control system installations for steam generation facilities in petroleum refinery and other hydrocarbon processing plants. The installation of primary measuring instruments, control systems, alarm and shutdown systems, and automatic startup and shutdown systems are discussed for steam generators, carbon monoxide or waste gas steam generators, gas turbine exhaust fired steam generators, and unfired waste heat steam generators.

Successful instrumentation depends upon a workable arrangement that incorporates the simplest systems and devices that will satisfy specified requirements. Schedules, drawings, sketches, and other data should be provided in sufficient amounts to enable the constructor to install the equipment in the desired manner. The various industry codes and standards and the laws and rulings of regulating bodies should be followed where applicable.

For maximum plant personnel safety, it is recommended that transmission systems be employed to eliminate the piping of hydrocarbons, acids, and other hazardous or noxious materials to the instruments in the control rooms.

The instrument installations should be carefully analyzed for good operation. The various components must be accessible for efficient maintenance, free of vibration, and certain of these elements should be located for convenient readability. Orifices, control valves, transmitters, thermocouples, level gages, and local controllers, as well as analyzer sample points, should, in general, be readily accessible from grade permanent platforms, or fixed ladders. In this manual special consideration is given to the location, accessibility, and readability of the elements.

Proper installation is essential in order to utilize the full capabilities that are built into the instrument systems and to realize the greatest return on the investment. In many instances, the instrument difficulties encountered have been traced to incorrect installation.

This part of the manual has been written as a general guide for designing and installing operable, safe, and efficient instrument and control systems for steam generators in petroleum refineries and related plants. It is intended to be used as a complement to Parts I and II of the manual. As such, it should be useful to design engineers, instrument construction and maintenance personnel, and process operators. It is no substitute for experience and proficiency in these fields, although it will be a help in achieving such experience and proficiency. Because of the lack of uniformity in the design and requirements of these processes, the complete instrumentation and control system must be studied to determine if it will enable the unit to be operated, started up, and shut down satisfactorily and safely.

T[illegible] are many specific features of these installations that require special attention [illegible]rder to assure safe and efficient operation of the plant and to ensure that the p[illegible]t can be started up or shut down with safety to the operating personnel and without damage to the equipment or to the processes that it serves. Special effort has been made to point out pitfalls in these installations but only a general guide can be established. Those concerned with the general installation will find it necessary to think through the function of each installation for each probable operating condition.

Background information is presented to show the reasons for customary installations. This has necessitated discussion of the processes, instrument application, and instrument design. For this reason, Part IV of the manual is organized with the different processes as the major headings and the types of measurement or control function as subheadings under these processes.

There are enough unique instrumentation and control problems in these systems to require treatment separate from process control on refinery units. In the past, combustion control has developed along a path that has been considerably divergent from the development of process control. Consequently, process operators and instrument mechanics have required special training to handle the steam generator instrumentation that has been integrated with the process unit control centers. Control system design engineers familiar with one kind of plant have usually not felt proficient with the other. Actually, many of the differences are more apparent than real. For this reason, the specific problems, differences, and similarities in the installation of these instruments and control systems are discussed.

The features of instruments and control systems that are covered sufficiently elsewhere in the manual are not covered in this section. Therefore, frequent reference is made to Parts I and II of the manual.

The steam generation facilities must be considered as an integral part of the refinery or process plant. These facilities cannot be considered separately even from the safety shutdown standpoint because a steam supply failure to some processes may be more dangerous to more personnel and equipment than taking a low level risk with the steam generation facilities by not shutting down on certain upsets. The overall view should include all risks due to direct process upsets, shutdown and startup of affected processes, and loss of essential utilities such as fire water, as well as what might happen to the steam generation facilities.

PREFACE

This section is one of a series which make up RP 550, Manual on Installation of Refinery Instruments and Control Systems. RP 550 is composed of four parts:

PART I	PROCESS INSTRUMENTATION AND CONTROL
PART II	PROCESS STREAM ANALYZERS
PART III	FIRED HEATERS AND INERT GAS GENERATORS
PART IV	STEAM GENERATORS

Part I assays the installation of the more commonly used measuring and control instruments, as well as protective devices and related accessories; Part II presents a detailed discussion of process stream analyzers; Part III covers installation requirements for instruments for fired heaters and inert gas generators; and Part IV covers installation requirements for steam generators. These discussions are supported by detailed information and illustrations to facilitate application of the recommendations.

This manual is based on the accumulated knowledge and experience of engineers in the petroleum industry. Its purpose is to aid in the installation of the more generally used measuring and control instruments and related accessories in order to achieve safe, continuous, accurate, and efficient operation with minimum maintenance. Although the information contained herein has been prepared primarily for petroleum refineries, much of it is applicable without change to chemical plants, gasoline plants, and similar installations.

Acknowledgment is made of the work of all the engineers and operating and maintenance personnel who, through years of study, observation, invention, and sometimes trial and error, have contributed to the technology of instrumentation and control of steam generators.

The information contained in this publication does not constitute, and should not be construed to be, a code of rules or regulations. Furthermore, it does not grant the right, by implication or otherwise, for manufacture, sale, or use in connection with any method, apparatus, or product covered by letters patent; nor does it ensure anyone against liability for infringement of letters patent.

Users of this manual are reminded that, in the rapidly advancing field of instrumentation, no publication of this type can be complete, nor can any written document be substituted for qualified engineering analysis. Furthermore, federal, state, and local regulations should be consulted.

Certain instruments are not covered herein because of their very specialized nature and limited use. When one of these devices (or classes of devices) gains general usage, and when installation reaches a fair degree of standardization, this manual will be revised to incorporate such additional information.

Suggested revisions are invited and should be submitted to the Director of Refining, American Petroleum Institute, 1801 K Street, N.W., Washington, D.C. 20006.

CONTENTS

PAGE

PAGE

PART IV—STEAM GENERATORS

SECTION 1—STEAM GENERATORS

1.1 Scope

This section covers instrumentation and control systems generally applicable to steam-generating units in petroleum processing plants. Measurements, control systems, protective instrumentation, and programmed burner ignition systems are discussed. This discussion applies to steam-generating units of either the field-erected or shop-fabricated design having a pressurized (forced-draft) type furnace with integral burners. Although such units may be fired with several types of fuel, only the gas and liquid fuels are covered.

1.2 Measurements

Many operating variables on a steam generator must be measured so that it may be operated as required by both external and internal conditions. These measurements may be necessary either for operator guidance, manual control, automatic control, safety alarms, safety shutdown, automatic light-off, accounting, economical load distribution, or any combination of these. The measurements for automatic control and safety devices are predominant and most important. For this reason, the installation of measuring devices that will perform accurately and continuously will be considered before discussing the systems that are actuated by these measurements.

The measurements required on a steam generator will vary with the conditions under which the unit must operate. The growing complexity of steam-generating units and their connected systems is promoting the need for an increased number of measurements and emphasizing the need for careful coordination of these measurements with the overall design and functional objectives of the unit. Special consideration should be given to measurements necessary to meet plant and insurance safety practices along with mandatory measurements required by state, federal, and local codes that apply to the locale in which the equipment is installed.

Most modern measurement and control systems for steam-generation units utilize a central control panel. There is generally a local indication of some measurements that are used for local operation. Many of these local indicators are normally furnished as a part of the basic steam-generator package.

Transmitters should be installed as close as practical to the source of the measurement with consideration being given to excessive vibration, temperature, and access for periodic maintenance. Suggestions for the location of instrument and control equipment connections can be found in SAMA—ABMA* "Recommendations for Location of Instrument and Control Connections for the Operation and Control of Watertube Boilers."

1.2.1 WATER LEVEL IN STEAM DRUM

The water level in a steam drum is controlled by regulating the feedwater flow and is normally measured and recorded using a differential pressure type level transmitter or an external cage displacement type level transmitter. Separate indication of the water level is required by the ASME† Boiler and Pressure Vessel Code. This code should be referred to before installing either local or remote level indicators.

Refer to Figure 1-1 for a typical differential pressure type level transmitter installation. It is recommended that the condensate reservoir be added to the top leg above 800 pounds per square inch gage (psig). Density compensation should be considered. Refer to RP 550, Part I, Section 2 for installation of the displacer type level transmitter.

1.2.2 STEAM PRESSURE

1.2.2.1 Header Pressure

Header pressure is required for control and operator guidance and normally recorded on a panel. On multiple steam generators, this is the pressure of the common header for the steam generators. Where it is used for control, some users install dual transmitters, one of which may go to the master gage under normal conditions. Refer to RP 550, Part I, Section 4 for installations.

1.2.2.2 Drum Pressure

Drum pressure is required for operator guidance and is normally indicated but sometimes recorded on the steam-generator panel. This pressure is the operating pressure of the individual steam drum. Refer to RP 550, Part I, Section 4 for installation.

---

*As recommended by the Recorder-Controller Section of the Scientific Apparatus Makers Association and the American Boiler Manufacturers Association. Available through Process Measurement and Control Section, SAMA, 370 Lexington Avenue, New York, NY 10017.

†American Society of Mechanical Engineers, 345 East 47th Street, New York, NY 10017.

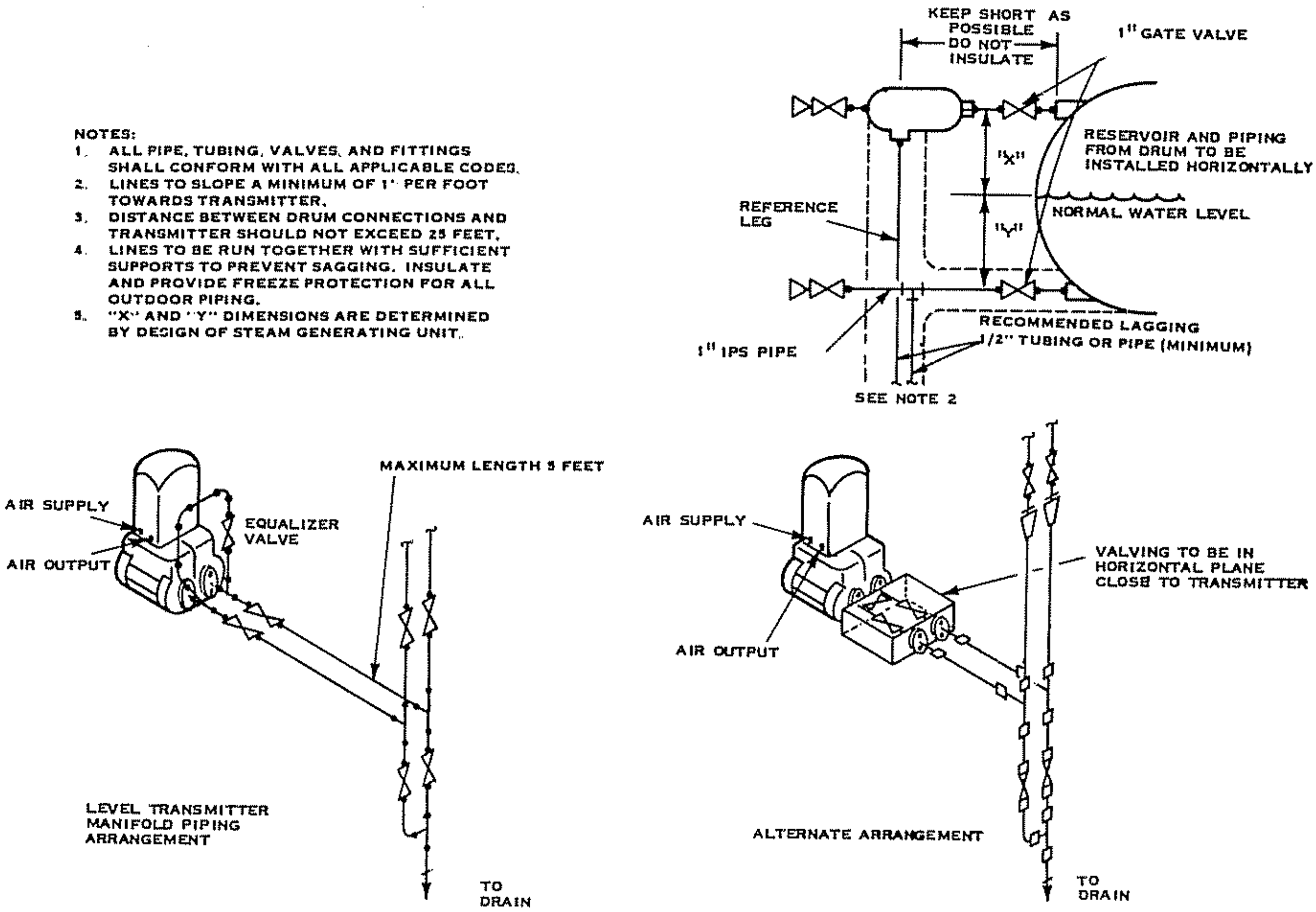


Figure 1-1—Typical Installation Drum-Level Transmitter Differential Pressure Type

1.2.3 FEEDWATER PRESSURE

Feedwater pressure is required for operator guidance and control. It is normally indicated and recorded on the steam-generator panel. On multiple steam-generator installations with common feedwater piping systems feedwater header pressure is sometimes regulated at some fixed value above the highest drum pressure. Refer to RP 550, Part I, Section 4 for installation.

1.2.4 SUPERHEATED STEAM TEMPERATURE

Superheated steam temperature is required for operator guidance and control. When control is used, it is primarily to prevent overheating the superheater and to assure safe conditions of auxiliary equipment. A resistance bulb, thermocouple, or filled thermal system can be used. The type of well and its immersion should be carefully selected and a special tapered well should be considered for high pressure and high velocity service. Tapered wells should be designed for the particular installation to prevent cracking from metal fatigue caused by the wells vibrating at their natural frequency.* For installation of temperature measuring devices, refer to RP 550, Part I, Section 3. Typically, wells in superheated steam service are welded in place.

1.2.5 DRAFT PRESSURE OF GASES AND AIR ENTERING OR LEAVING THE VARIOUS SECTIONS

Draft pressure is normally used for operator guidance. Diaphragm-type gages are usually used on these low pressures. The draft transmitter range should be sufficiently wide to cover unusual conditions. Sensing lines must be designed to assure fast response to small changes. Purge systems to prevent plugging may be necessary and, if used, care must be taken in this arrangement to be certain the gage is not subjected to purge pressures. Refer to RP 550, Part III, Section 1 for installation.

*J. W. Murdock, "Power Test Code Thermometer Wells," *ASME Trans. J. Power Eng.*, 403-16, October (1959).

1.2.6 FUEL PRESSURE

1.2.6.1 Using Gas as the Fuel

When using gas as the fuel, main header pressure is normally measured and transmitted to the control board. The main header pressure is taken downstream from the master regulator to the fuel system. Pressure to the burners is also measured and transmitted to the control board. This measurement is made downstream of the fuel control valve. Sometimes pressure indication is desired between the burner and the burner cock. These, if desired, are normally furnished by the steam-generator manufacturer. For installation, refer to RP 550, Part I, Section 4.

1.2.6.2 Using Oil as the Fuel

When using oil as the fuel, Paragraph 1.3.6.1 applies except that a pressure-regulating valve is used on the discharge of the pump to regulate the maximum pressure. In a system where oil is recirculated and only part is going to the users, it is necessary to control the system pressure. This is done to properly proportion the flow to the burner and the return line. Refer to Figures 1-2 and 1-3 for a typical fuel oil piping system. In many installations, steam-atomizing oil burners are employed. This is primarily a function of burner design. When steam atomization is used, it is usually necessary to control differential pressure between the fuel and the steam. Refer to Figure 1-4. However, some burners require a constant pressure.

For installation of pressure measuring devices, refer to RP 550, Part I, Section 4. When using heavy oils for fuel, consideration should be given to heat tracing or seals if climatic conditions can cause a possible problem. For installing heat tracing or seals, refer to RP 550, Part I, Section 8; for further information on application of seals, refer to RP 550, Part I, Section 4.

1.2.7 ANALYSIS

1.2.7.1 Oxygen

In order to establish and maintain the efficiency and safety of the combustion process, excess air is an important measurement. A combustion control system is continually adjusting the fuel feed to meet the varying load requirements and maintaining a correct proportion of air to burn the amount of fuel that is being fed at any time. To obtain a good measurement relating to the quality of combustion, samples should be taken as near as possible to the point where combustion is completed. This will minimize air leakage that will tend to dilute the sample. To obtain the percent oxygen in the flue gases, an oxygen analyzer is used. The analyzer may be used for recording, indicating, alarm, or control. If control is used, high-low limit relays should be installed. Some users limit the corrective control action to ± 5 percent of maximum air flow in the event of analyzer failure. Refer to RP 550, Part II, Section 19 for installation.

1.2.7.2 British Thermal Unit (Btu) Measurement

In some installations it is desirable to know the heating value of the fuel gas. In general, this measurement would be made on the plant fuel gas system rather than at the individual heater. It may be measured directly or inferentially.

Direct Btu measurement may be made with at least two types of continuous calorimeters. In one type, a measured amount of gas is continuously burned with a measured volume of air. The temperature of the products of combustion is compared with the air and gas temperature to obtain the Btu value. The other type comprises an atmospheric pressure constant flow regulator and a bimetal chimney with mechanical linkage to a recorder pen. The regulated flow of gas is burned in the bimetal chimney that has a constant heat loss. The mechanical linkage measures the differential expansion between the chimney elements and positions a pen or pointer. This differential expansion is proportional to the Btu content of the gas.

Probably the simplest inferential Btu measurement is direct density measurement of the gas. Refer to RP 550, Part II, Section 21 for installation of densitometers. The gas density can be correlated to heating value by laboratory calorimetery or by gas analyses and reference tables. Accurate correlation is difficult if the gas composition varies widely.

Probably the most sophisticated system is to use a gas chromatograph with its output fed directly to a computer programmed to calculate the heating value from the analysis.

1.2.7.3 Smoke Measurement

In some installations, smoke detectors are required. The equipment monitors smoke density by observation of a light beam projected across the flue. These instruments are usually comprised of a light source opposite a bolometer or a photo-electric detector with appropriate readout equipment. As the light source is obscured, higher smoke density is indicated. Provisions must be made to keep the lens of both the light source and bolometer clean and cool. Otherwise, the reading will be too high. Air purging over the lenses may be required.

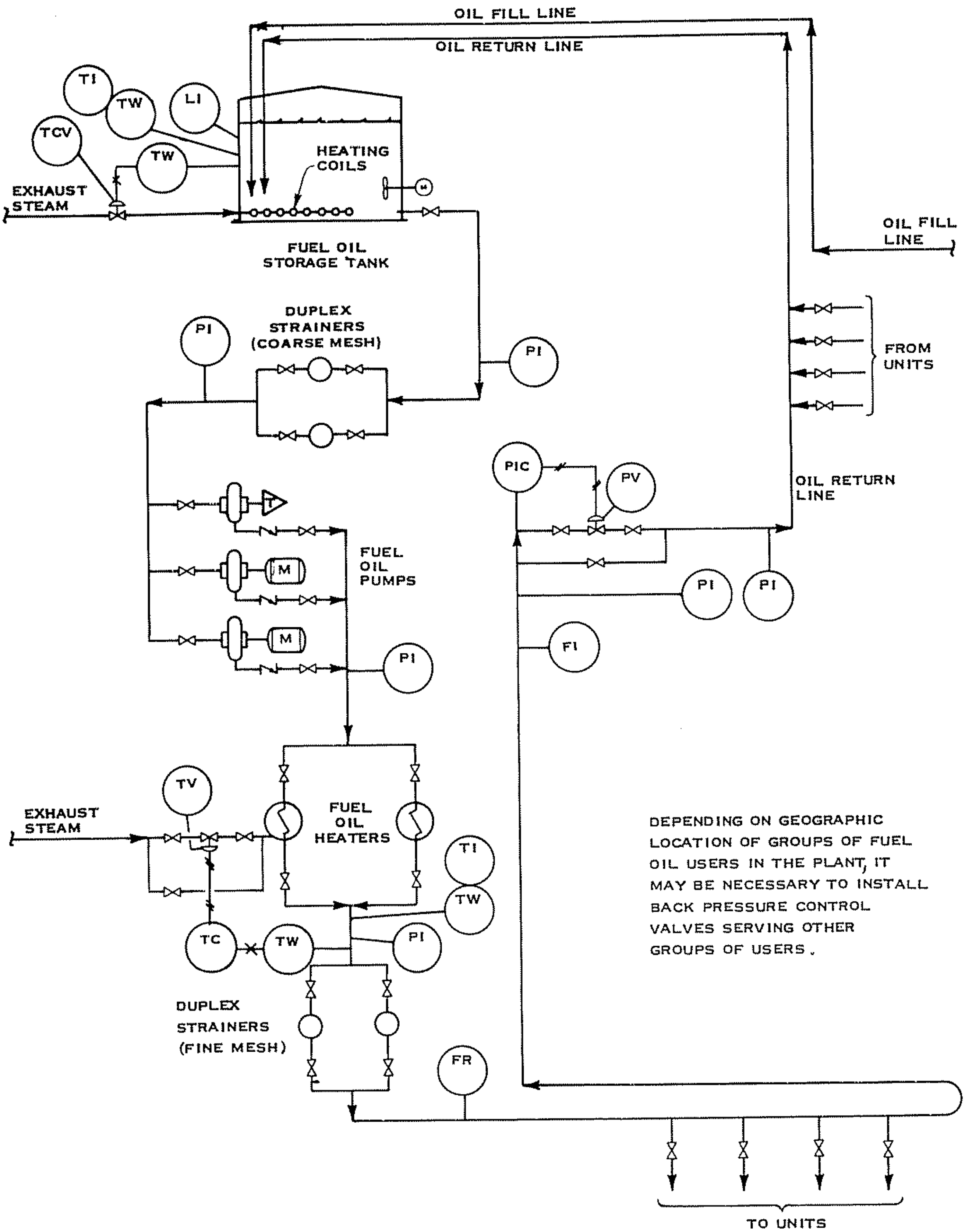


Figure 1-2—A Typical Plant Fuel Oil Circulating System

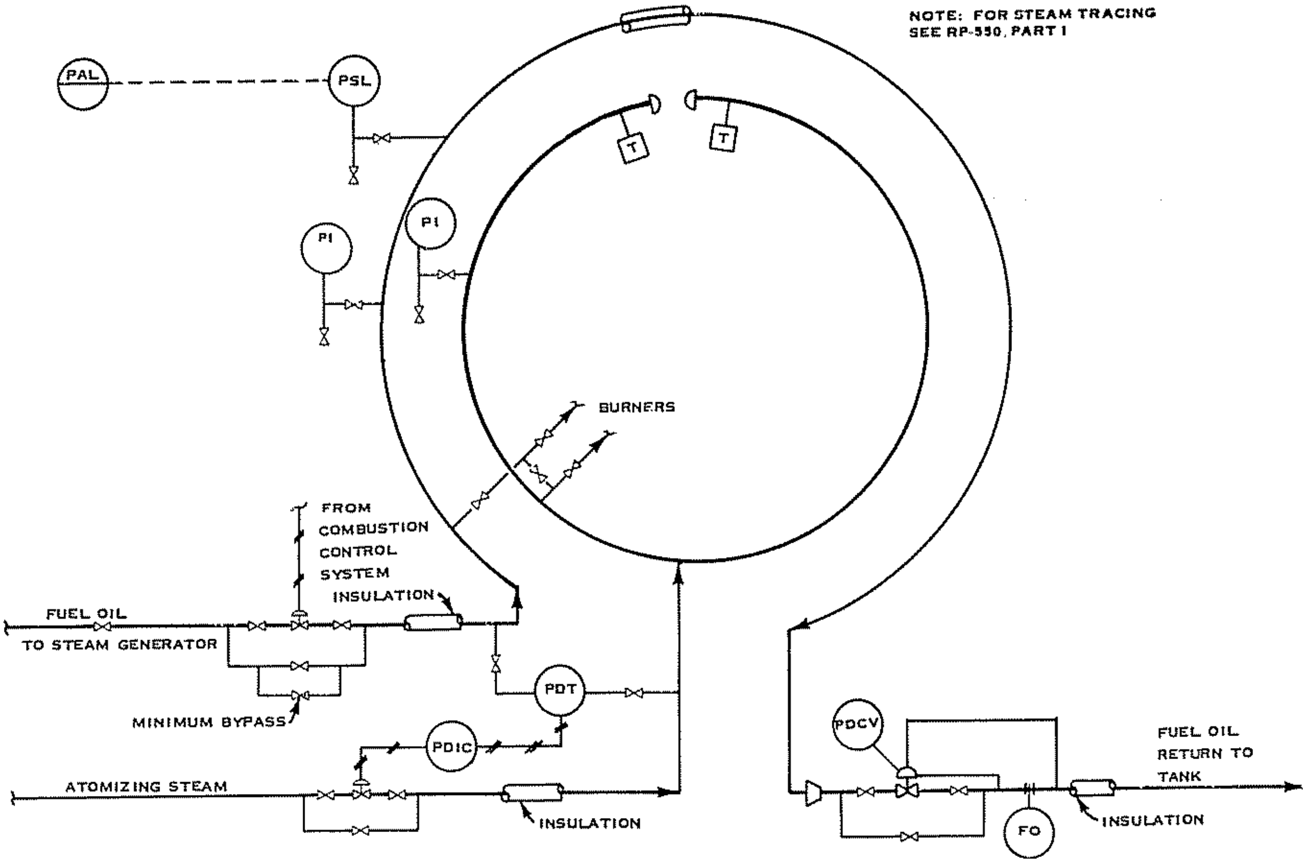


Figure 1-3—Typical Steam Generator Fuel Oil Circulation System

1.2.7.4 Sulfur Dioxide (SO_2)

Sulfur dioxide measurement should be considered. In some installations, sulfur dioxide analyzers are required.

1.2.7.5 Nitrogen Oxides (NO_x)

Nitrogen oxide measurement should be considered. In some installations, nitrogen oxide analysers are required.

1.2.7.6 Combustibles

This measurement should be considered.

1.2.8 FEEDWATER TEMPERATURE

Feedwater temperature can be detected by using a thermal system, resistance measurement, or thermocouple measurement, and is normally recorded. High feedwater temperature can cause flashing through the pumps and primary flow elements and in some installations may cause circulation problems leading to damage. Refer to RP 550, Part I, Section 3 for installation.

1.2.9 FLUE GAS TEMPERATURE

Flue gas temperature measurement can be made by using an averaging-type preformed capillary (see Figure 1-5), a "sausage"-type flue gas bulb (see Figure 1-6), or one or more thermocouples (see Figure 1-7) placed in the duct. For thermocouple installation, refer to RP 550, Part I, Section 3. Minimum flue gas temperature is a function of equipment design. For recommended arrangements of temperature and gas sampling connections to steam-generator settings and ducts, refer to SAMA-ABMA recommended standard instrument connections.

Because of the sulfur present in most fuel oils, excessive corrosion and plugging of air heater and precipitator elements results in objectionably high annual maintenance costs when exit gases are cooled beyond their dew point. Some technique is generally used to assure that flue gases are not cooled below their dew point. This can be accomplished by preheating the air (using steam) by cold air bypass, or by flue gas recirculation. The actual determination of the flue gas dew point is very difficult and generally not considered for measurement. For some high sulfur fuel oils the flue gas temperature may need to run as high as 400 degrees Fahrenheit.

1.2.10 AIR TEMPERATURE

If desired, the same measurement can be made for air temperature as for flue gas temperature. In many applications, it is unmeasured and uncontrolled. However, when an air heater is used, air temperature is measured to hold it above a predetermined minimum value to maintain flue gas temperature from the air heater above the dew point.

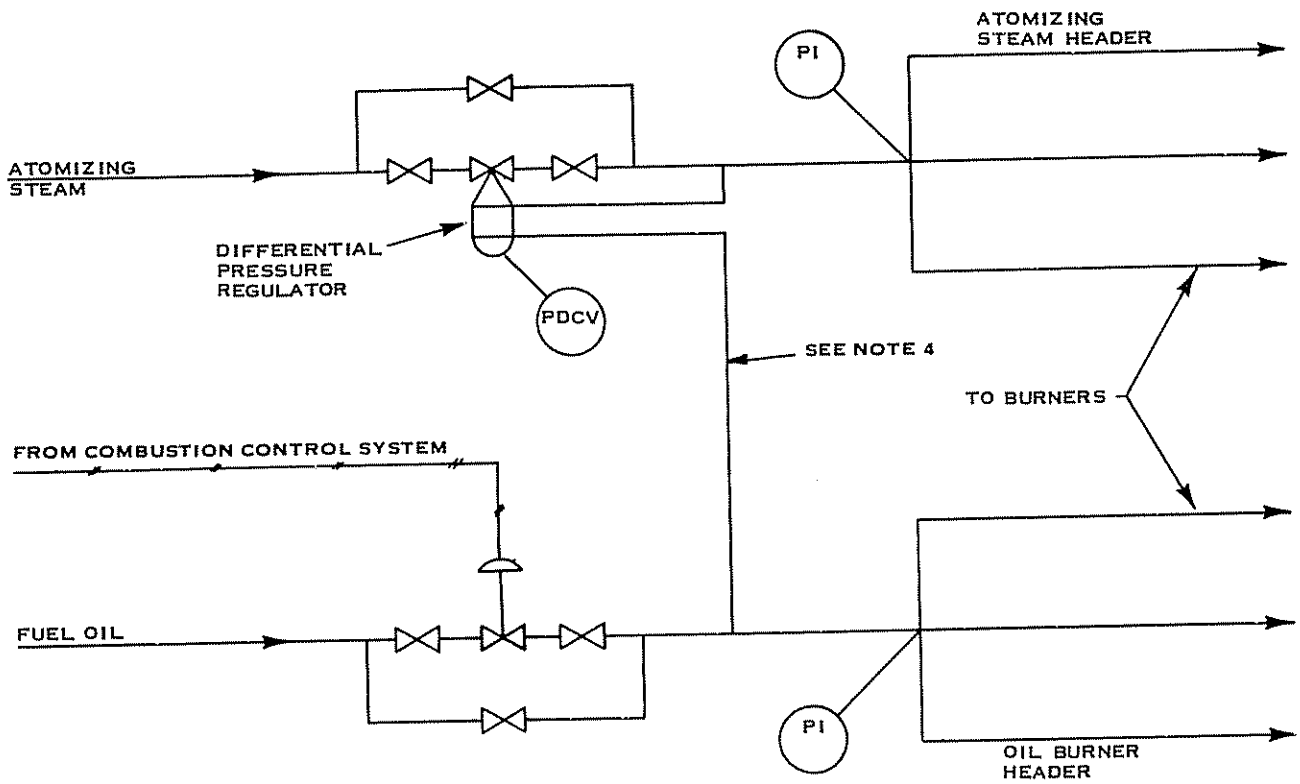
1.2.11 FUEL TEMPERATURE

1.2.11.1 Fuel Gas Temperature

Fuel gas temperature is not normally considered. Where liquid carryover may be a problem, external means should be provided to knock out the liquid or heat the gas to a temperature above its dew point.

1.2.11.2 Fuel Oil Temperature

Fuel oil temperature is usually measured and sometimes controlled. The measurement is generally made using a thermocouple, filled thermal system, or resistance bulb. The oil temperature required is dependent on the grade of oil being used. In the worst conditions (when using Bunker C or other heavy fuel), too low a temperature can cause a poor or dirty flame. Too high a temperature can cause carbonization of the burner tip.



NOTES:

1. DIFFERENTIAL PRESSURE REGULATOR SHOULD BE DOUBLE METALLIC DIAPHRAGM TYPE TO REDUCE POSSIBILITY OF CONTAMINATION OF STEAM SYSTEM BECAUSE OF RUPTURED DIAPHRAGM. TRANSMITTER TYPE SYSTEM MAY BE USED.
2. PNEUMATIC SYSTEM SHOWN MAY BE ELECTRONIC.
3. STEAM PRESSURE IS USUALLY MAINTAINED 10-20 PSI ABOVE OIL PRESSURE.
4. THIS LINE SHOULD NOT EXCEED 15 FEET. FOR STEAM TRACING, SEE RP-550, PART I.

Figure 1-4—Schematic Diagram of Typical Installation of Differential Pressure Regulator for Fuel Oil Atomizing Steam

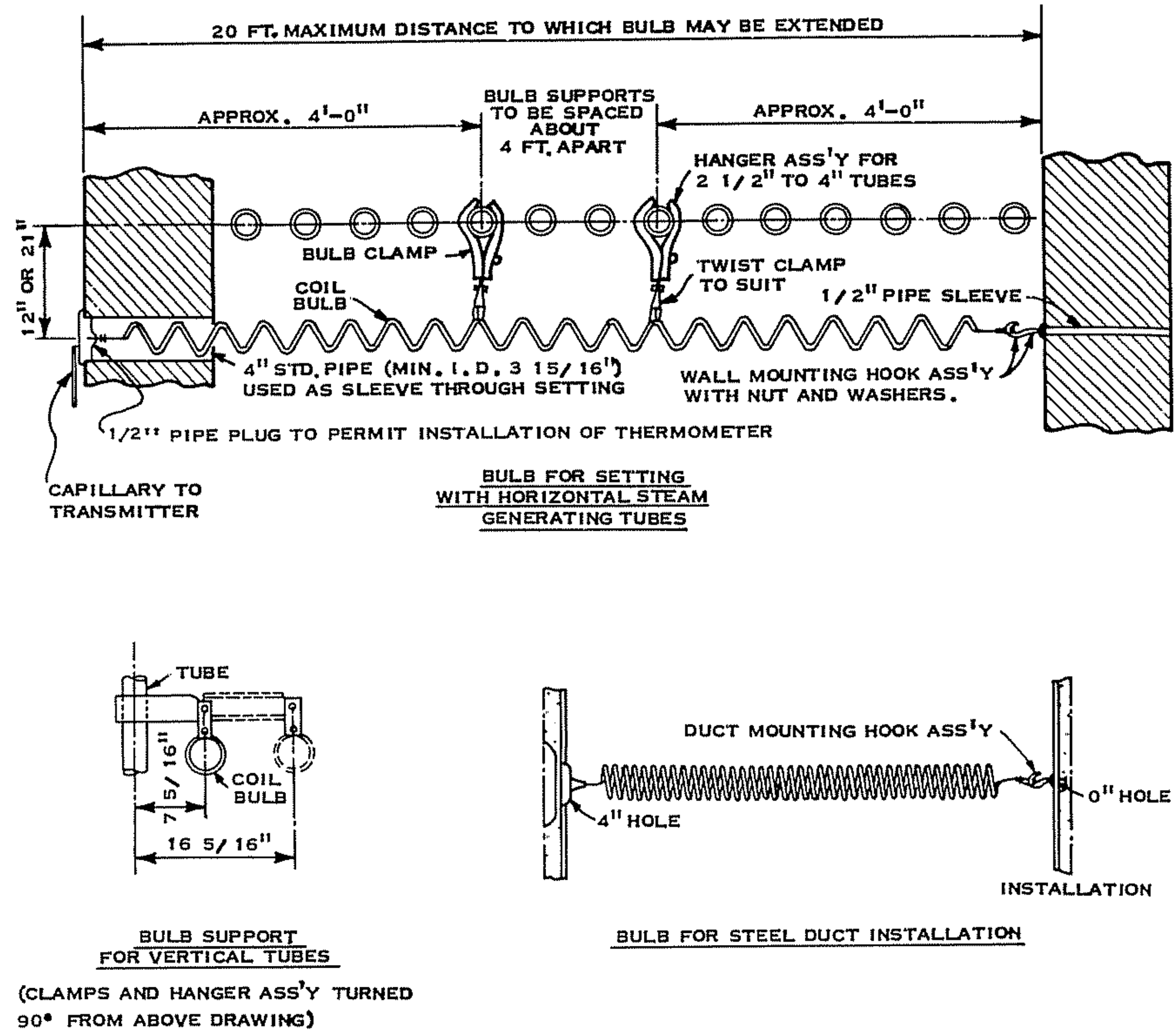


Figure 1-5—Coil-Type Bulb for Flue Gas Average Temperature Measurement

1.2.12 FUEL FLOW

1.2.12.1 Gas Flow

Gas flow measurement is generally made by using an orifice meter run and a differential pressure type flow transmitter. Of primary interest is the establishment of an output from the gas flow transmitter proportional to Btu input as nearly as possible. As long as pressure and/or temperature and heating value remain constant, the differential pressure-Btu relationship is achieved. If variation in temperature and/or pressure can be expected, compensation for the variations will result in an improvement of the combustion control.

As in any differential pressure approach to flow measurement, due regard must be given to the rangeability limitation. Some steam generators are expected to stay on full automatic control over a load range of 10:1. The relative insensitiveness to small flow changes at low ranges may turn out to be the limiting factor in establishing the minimum load point to which a steam-generator may be operated satisfactorily and safely on full automatic. In such cases a second flow meter can be used or turbine meters may be considered.

For installation of differential pressure transmitters, refer to RP 550, Part I, Section 1. If compensation is used, refer to RP 550, Part I, Section 3 for temperature

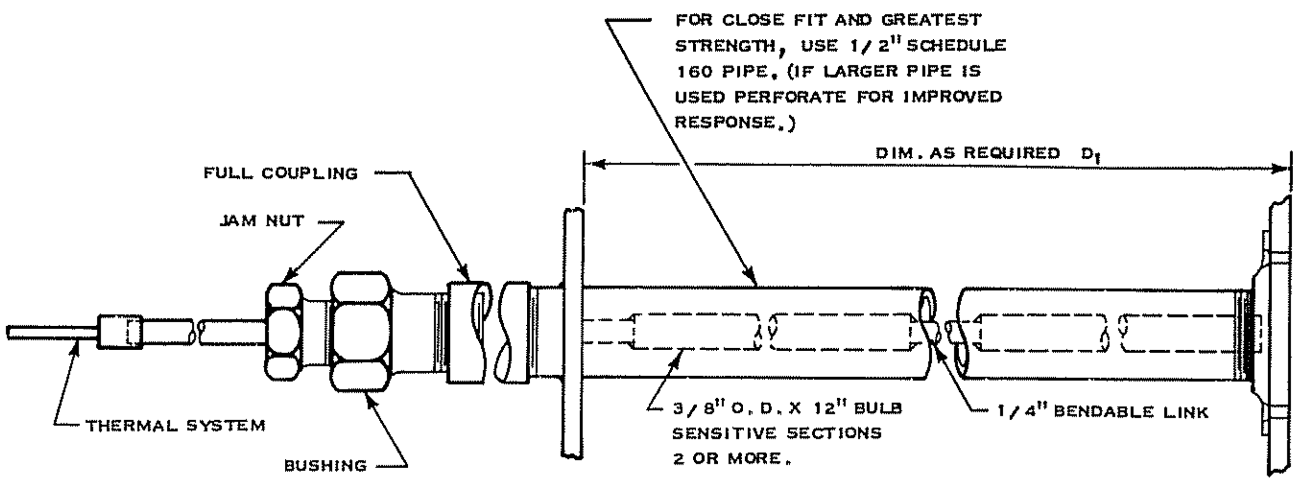


Figure 1-6—Sausage-Type Class 3 Bulb Installation for Flue Gas Average Temperature Measurement

measurement installation and RP 550, Part I, Section 4 for pressure measurement installation.

1.2.12.2 Oil Flow

Oil flow measurement is generally made by using an orifice meter run and a differential pressure type flow transmitter. When heavier fuel oils are used, a quadrant edge orifice should be considered. Oil flow measurements will introduce problems in addition to those covered under gas flow. Viscosity variation, even when the temperature of the oil is controlled at the point of measurement, will change the differential pressure-Btu relationship. When heavy fuels are used, it may be necessary to use transmitters, such as target meters, area meters, or positive displacement meters. The type of meter selected is dictated by the viscosity and dirt in the fuel being measured and accuracy required. For installation, refer to RP 550, Part I, Section 1.

1.2.12.3 Multiple Fuels

Obtaining a reasonable measurement of heat input when burning a combination of measured fuels (oil and gas) requires linearization and scaling before totalizing. The totalizer should represent Btu input. Therefore, each fuel flow transmitter should have its range determined in Btu's (pounds per hour times heating value). The totalizer gain should be adjusted to assure that incremental change in any fuel flow transmitter will produce a totalizer output proportional to actual change in Btu's.

1.2.13 STEAM FLOW

Steam flow is generally measured with a differential pressure type flow transmitter. The primary device for this measurement may be either an orifice plate or a flow nozzle. Generally the beta ratio is the major consideration for making the decision. Pressure recovery through the device may also be a consideration on some installations. On high-pressure steam generators the flow differentials that are used may need to be higher than 100 inches of water (the most common range in refinery process units). Refer to RP 550, Part I, Section 1 for installation of flow measuring devices.

1.2.14 FEEDWATER FLOW

Feedwater flow measurement is generally made by using an orifice meter run and a differential pressure type flow transmitter. For installation, refer to RP 550, Part I, Section 1.

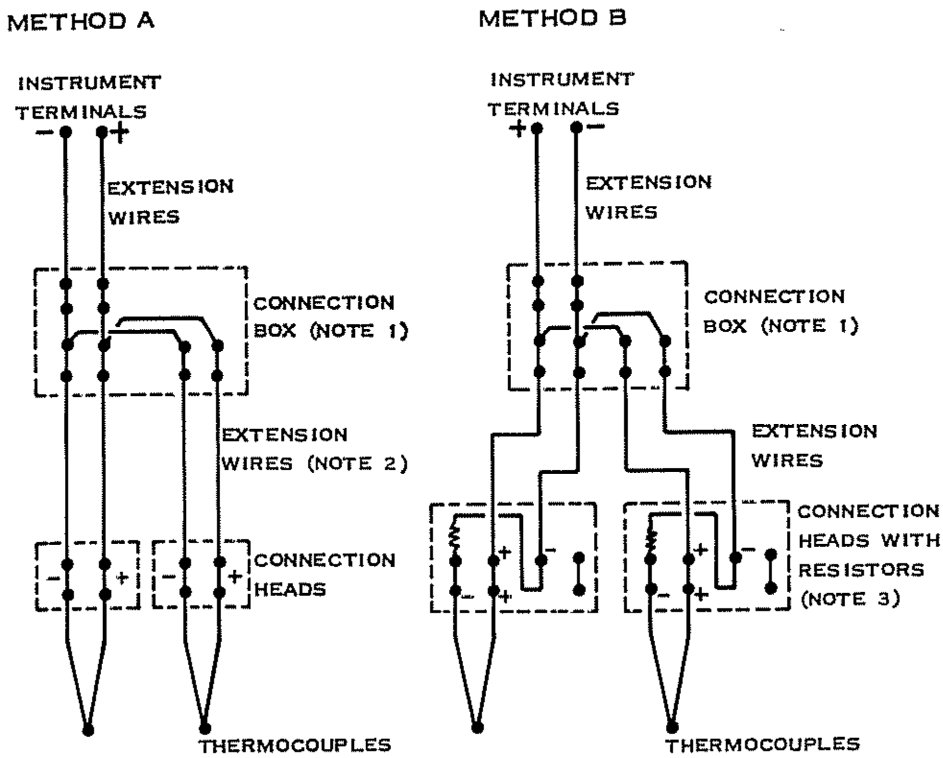
1.2.15 AIR FLOW

Air flow is one of the more critical measurements, is generally relative rather than absolute, and often creates a problem of obtaining a desirable signal. Some ways of obtaining this signal are:

1. Primary element for differential pressure transmitter in force draft (FD) duct system (probably the most desirable).
2. Differential across the steam generator (furnace to uptake). Avoid this measurement when soot blowers are installed. The operation of the soot blower will change the differential across the setting, thus affecting the combustion control system.
3. Differential pressure across the air heater. Careful consideration should be given to possible air leakage or soot blower effect if measurement is on the flue gas side.

1.2.16 FIRING CONDITIONS AT THE BURNERS

Stability of the fire conditions is most important and it is normally detected by visual observation. Instability



NOTE 1. CONDULET BOX
NOTE 2. DUPLEX EXTENSION WIRES TO BE OF EQUAL RESISTANCE - SAME LENGTHS.
NOTE 3. CONNECTION HEAD WITH 1500 OHM RESISTOR - PERMITS USE OF DIFFERENT LENGTHS OF EXTENSION WIRES.

TO MEASURE AVERAGE TEMPERATURE THERMOCOUPLES ARE CONNECTED IN PARALLEL. FOR ACCURATE MEASUREMENT, THE RESISTANCES OF ALL THERMOCOUPLES, INCLUDING EXTENSION WIRES, SHOULD BE THE SAME. IN ORDER TO PREVENT THE FLOW OF CURRENT THROUGH A GROUND LOOP, THE THERMOCOUPLES SHOULD NOT BE GROUNDED. OF COURSE, ALL THERMOCOUPLES MUST BE OF THE SAME TYPE AND MUST BE CONNECTED BY THE CORRECT EXTENSION WIRES.

A SUGGESTED METHOD OF WIRING IS TO USE AN EXTERNAL CONNECTION BOX PLACED IN A CONVENIENT LOCATION. TO OBTAIN EQUAL RESISTANCES, MAKE ALL EXTENSION WIRES BETWEEN THERMOCOUPLES AND CONNECTION BOX THE SAME LENGTH, COILING UP THE EXCESS LEADS TO THE NEARER COUPLES. AN ALTERNATIVE METHOD IS TO INCORPORATE A 1500-OHM RESISTOR IN SERIES WITH THE THERMOCOUPLE, SO THAT MINOR DIFFERENCES IN RESISTANCE OF THE THERMOCOUPLE EXTENSION WIRES HAVE NEGLIGIBLE EFFECT. IN THE CONNECTION BOX, CONNECT ALL TERMINALS OF EACH POLARITY IN COMMON, AND RUN A COMMON PAIR OF EXTENSION WIRES TO THE INSTRUMENT TERMINAL PANEL.

Figure 1-7—Average Temperature Measurement with Thermocouples

can be caused by the following:

1. Low oil temperature.
2. Low fuel pressure. A force balance or motion balance pressure transmitter can be used. On oil service, the transmitter should be mounted as close as possible to the pressure tap. Consideration should be given to using a narrow range instrument with overrange protection.
3. Excess air too high or too low. This can be detected from the air flow-fuel flow recorder or from the oxygen recorder.
4. Improper burner adjustments. Observation of the

flame pattern should detect poor adjustment.

5. Improper register settings that will give an improper flame pattern.

6. Water in fuel oil.

7. Poor atomization of oil because of wet steam, low steam pressure, and the like.

8. Dirty, carbonized, or worn burners.

9. Change in fuel composition that exceeds the range of the burner design, such as severe changes in hydrogen or inert gas content and liquids in gaseous fuels.

Flame safety systems play an important role in monitoring the flame. Refer to Paragraph 1.5.

1.2.17 STEAM GENERATOR FEEDWATER QUALITY

The quality of feedwater is important for good operation since impurities may cause scale formation, corrosion, carryover, and embrittlement. Since the purity of natural water sources and refinery condensate return streams varies widely, different types of treatment may be required for units operating at different pressures.

A full discussion of the problems of steam generator feedwater treatment is considered beyond the scope of this manual. However, for any given installation, certain water quality conditions are normally monitored during operation. Some of these conditions are monitored by either manual or automatic wet chemistry titration methods, while others are monitored using physical or electrical properties.

Some of the feedwater quality measurements are pH, conductivity, turbidity, and dissolved oxygen. Where such measurements are made, additional information on installation can be obtained from RP 550, Part II. In some cases covering specialized measurement equipment, it is suggested that the manufacturers of this type of equipment be contacted for recommendations.

1.3 Control Systems

The following paragraphs cover combustion control, feedwater control, and blowdown control of steam generating units utilizing the pressurized (forced draft) type furnace and operating independently, in parallel, or "base-loaded." The fuel-flow/air-flow type combustion control system will be described. Single-element, two-element, and three-element feedwater control systems will be discussed, as well as intermittent and continuous blowdown.

The function of the control system is to provide a means for automatically or manually regulating the steam generating unit, including auxiliaries, and to produce steam at the desired pressure, temperature, and purity, as required by plant load conditions and in accordance with normal safety practices.

The control system must be adequate to cover all operating conditions of the steam generator during startup, normal operation, shutdown, and all possible emergencies. It should be capable of maintaining the required pre-set header pressure, drum level, and fuel/air ratio for safe and efficient firing. Provision should be included for indication and convenient operator adjustment of all necessary set points from the main control panel. Depending on the user's preference, certain variables may also be duplicated on an auxiliary local panel for use during startup and operation.

The system should provide means for manual control of each final control device (control valve, fan damper, and so forth). Some users prefer to use the "manual" position of the respective control station; others prefer to install a separate panel-mounted, manual-automatic station.

1.3.1 COMBUSTION

1.3.1.1 General

Because it is necessary to maintain a steady pressure in the plant steam distribution system, it is normal practice to use steam header pressure as the basic criterion for combustion control. Steam header pressure is measured and transmitted to the master steam-pressure controller and the output pressure from this controller establishes the control point setting of the fuel and air flow controllers. See Figure 1-8.

Air-flow and fuel-flow control systems are interconnected to adjust air flow automatically to changes in fuel flow. This interconnection operates to reduce the fuel valve setting to correspond to the combustion air available and thus prevents unsafe firing conditions if air flow is insufficient.

1.3.1.2 Master Pressure Control

The key measurement for steam generator control, that relates to variation in demand, is made by the master pressure controller. It detects the pressure in the main steam header and compares it with the set pressure. By means of its output signal, varying in accordance with changes in steam header pressure (an indication of variations in plant load), the master pressure controller serves as the primary control of one or more units.

Some users install dual header pressure transmitters with their outputs fed into a selector switch. When the operating transmitter develops trouble, the output of the other can be switched to the master pressure controller. The dual transmitter installation also permits

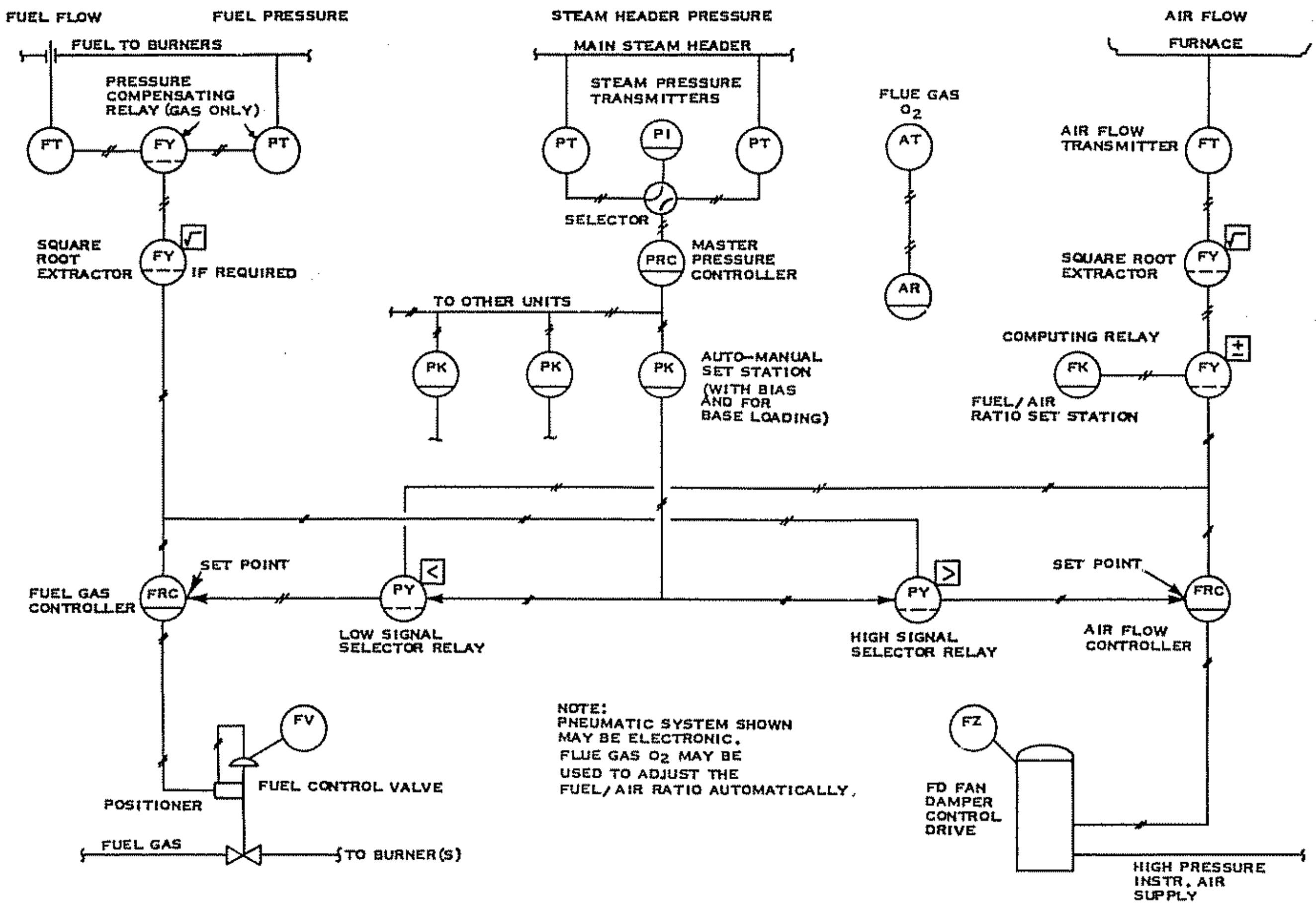


Figure 1-8—Combustion Control System

blowing down and cleaning pressure leads without interrupting operations. In some installations, the second transmitter is used to transmit to a board-mounted pressure indicator and is completely independent of the master pressure control system. Also, some users install dual pressure taps for a single transmitter so that lead lines can be blown down and unplugged.

1.3.1.3 Parallel and Baseload Operation

When two or more units are operated in parallel, they may share the total load in various proportions. In order to divide the total load, the output signal of the master pressure controller is fed into a loading station provided for each generator. This instrument allows the operator to bias the master pressure controller output signal and thus to allocate the desired portion of the total load to each unit. It also permits operating the generator base-loaded on manual control.

Often, where plant operating practices permit, economical operation is obtained when the most efficient unit is operated on manual control (that is, with the master pressure controller signal blocked off) with a substantial but steady baseload, while the remaining units operate with swinging loads, taking up the load changes automatically. The steam generating rate on the base-loaded (manually controlled) unit is adjusted as necessary so that the units on automatic control remain within satisfactory steaming range. In some instances it may be desirable to operate a steam generating unit base-loaded on flow control. Under this method of operation, the steam flow transmitter output (corrected for static pressure) is fed to a flow controller that is manually switched into service when baseload operation is required. It should be noted that the flow controller can be momentarily upset by load changes when they are large enough to cause significant pressure changes in the main steam header. For example, an increase in load will cause header pressure to drop. This results in a transient increase in steam flow from the steam generator to the header, so the initial response of the flow controller will be to reduce firing at a time when the steam generators that maintain header pressure are increasing the firing rate. See Figure 1-9.

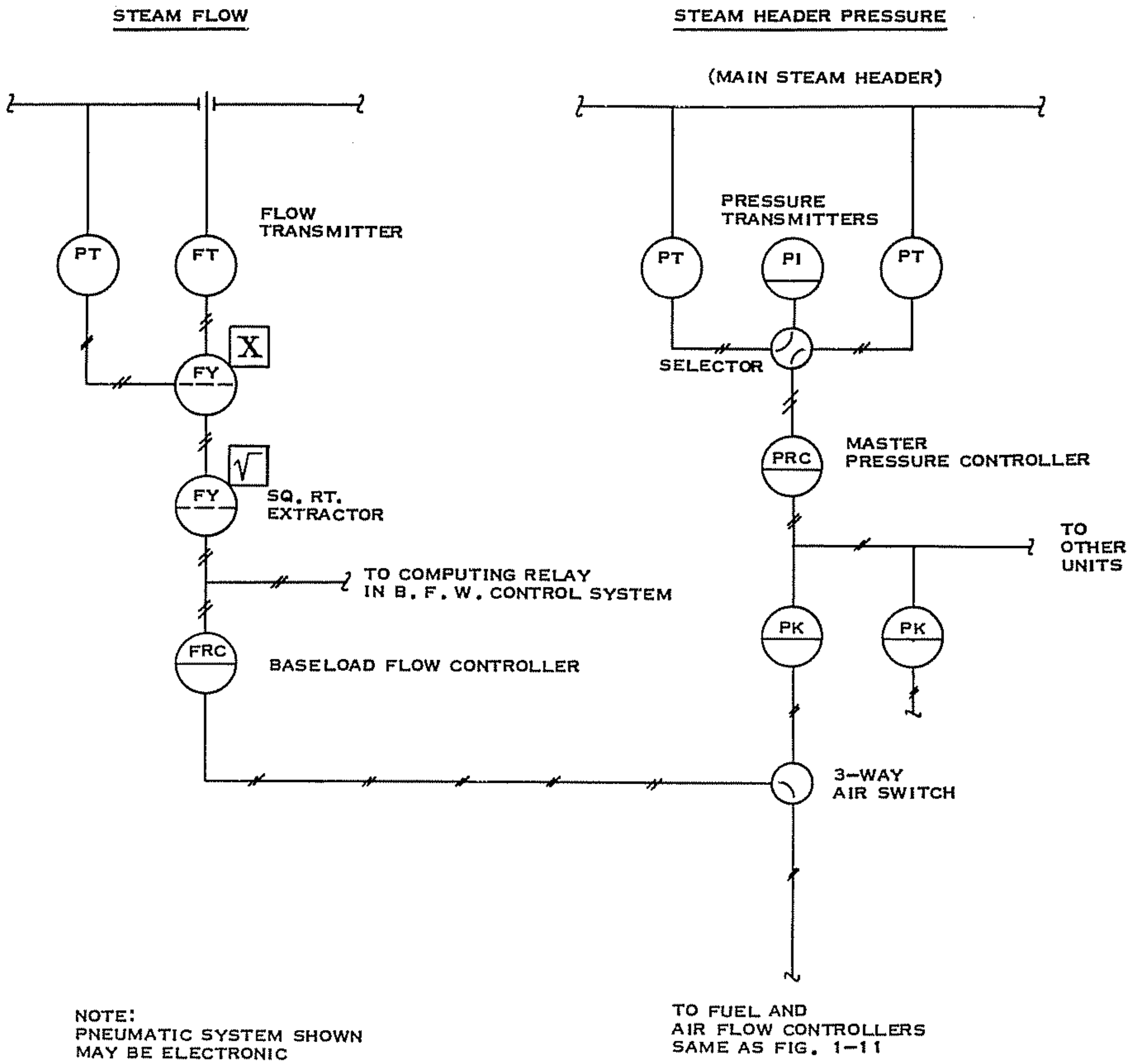


Figure 1-9—Baseload on Flow Control

1.3.1.4 Fuel-Flow/Air-Flow Control

The problem of automatically regulating the relationship between fuel and air is primarily one of achieving a repeatable measurement of fuel and air input to the furnace and then adjusting the supply of either fuel or air to obtain the proper combustion conditions.

The control method used must be such that the proper proportion can be achieved regardless of whether or not one or more fuels are being burned. Furthermore the proper proportion must be maintained over the full range of generator operation.

Fuel/air mixtures must be proportional to maintain stable combustion conditions at the burners and to maintain the fuel/air ratio desired for efficient performance at constant output temperature and pressure within the limits of the generator design. The required proportion varies with the type (Btu content per pound and carbon hydrogen ratio of fuel). The optimum in fuel-flow/air-flow control is achieved when just enough excess air is supplied to ensure the complete mixing and burning of the fuel required. Any air quantity above this amount results in a loss of efficiency due to the heat absorbed by the unused air. Air below this amount will cause loss of efficiency due to the loss of heat that results from incomplete combustion of fuel. However, a more important consideration is that firing under conditions of incomplete combustion can lead to the formation of hazardous (explosive) mixtures within the furnace. The control system should not allow the air/fuel ratio to get so low that the addition of air to the products of combustion after loss of fuel could form an explosive mixture.

One recommended method for controlling fuel gas and air flow is shown in Figure 1-8. In this system, fuel flow and air flow are controlled in parallel, with the control signals interconnected, so that excess air is always maintained during load changes. The combined action of the signal selector relays operates to maintain excess air during periods of increasing loads and operates to limit fuel flow to correspond to available air during periods of decreasing loads. These functions minimize the possibility of firing with an extreme deficiency of combustion air during rapid load changes or sudden loss of fan capacity.

1.3.1.5 Fuel Gas Compensation

The supply pressure of plant fuel gases may fluctuate. Because of this, some users make provision for automatic compensation for such changes. One method is shown in Figure 1-8. In this method, fuel gas pressure is measured and the transmitter output signal is fed to a computing relay.

The fuel gas control valve is usually equipped with bypass piping with a self-actuated regulator set to maintain the necessary minimum fuel gas header pressure. (This will ensure minimum flow through each burner.) The bypass regulator allows one operator to light off burners in succession without readjusting the fuel gas control valve. It also compensates for fuel supply pressure variations. Thus it contributes to safer lightoffs and reduces the occurrence of flameouts. However, in single burner installations, a fixed bypass valve or a hand jack is used to set minimum valve openings so that the combustion controls cannot reduce fuel gas flow to the point of flame failure.

When plant fuels fluctuate in Btu content, provision should be made for adjusting the fuel-flow/air-flow ratio to compensate for such changes. This may be achieved by adjusting the fuel/air ratio setting to the computing relay shown in Figure 1-8. This relay is also used to compensate for changes in atmospheric air temperature. Operator adjustment of the fuel/air ratio is based on changes in the oxygen content of stack gases as monitored by the flue gas analysis.

1.3.1.6 Fuel Oil Control

In installations using fuel oil only, the combustion control system is the same as for fuel gas as shown in Figure 1-8 except that pressure compensation is not required.

A typical piping arrangement for firing fuel oil and fuel gas in combination is shown in Figure 1-10. A typical control system for combination fuel firing is shown in Figures 1-11 and 1-12 with SAMA symbols. Figure 1-13 shows the SAMA legend. In this system the fuel gas flow is added to the fuel oil flow by a summing relay. This output signal is then transmitted to the fuel controller and to the combustion air interlock. The signal to the controller confirms that the total heat being released is the same as that called for by the set point, and the signal to the combustion air interlock insures that combustion air meets the minimum requirements for complete combustion. The signals from the transmitter must be linear or linearized by square root extractors, so the total number of heat units (Btu) measured remains reasonably constant when the ratio of the fuel gas to the fuel oil is changed. In this system the firing rate demand signal may be assigned all to one fuel or the other or it may be proportioned between the two fuels in a relationship determined by the operator. The firing ratio demand from the low selector is transmitted first to the bias or ratio station for the primary fuel. A bias station here would provide for a constant firing rate of the oil (as set by the operator) at any load. A ratio station here would provide for a constant ratio of firing rate demand by the subtraction unit. Any difference due to an operator setting negative bias or a ratio setting less than one appears as a demand for oil. Assume that a ratio station is provided, which is the usual case. If the operator desires to fire all gas, he merely sets the ratio station in a ratio of one. The firing rate demand signal then is transmitted unaltered to the gas valve and the demand for oil calculated by the subtraction unit remains at zero. If the operator desires to fire all oil, the gas is shut down and its demand is zero. The subtraction unit then transmits the firing rate demand signal unaltered to the oil valve since zero is subtracted from it. If the operator desires to fire equal amounts of both fuels, he sets a ratio of 0.5. The output from the station is then 50 percent of the input and the difference is calculated by the subtraction unit as the demand signal for oil.

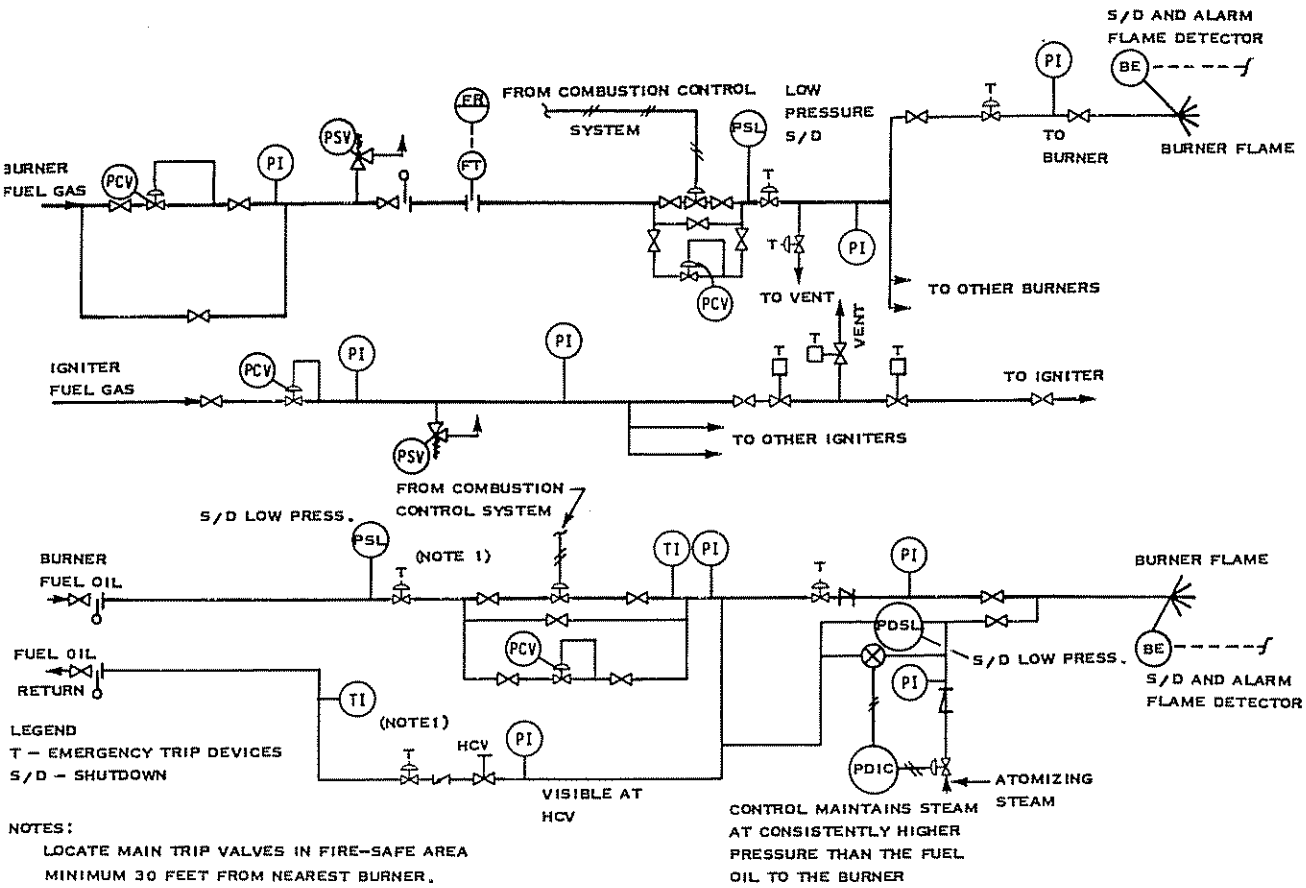


Figure 1-10—Typical Piping and Instrument Schematic for Combination Fuel Firing

In installations where fuel oil is used for supplemental firing, the fuel oil control valve may be manually loaded and load swings are controlled by the fuel gas control system. When this system is used, the operator must manually correct the fuel/air ratio.

For control of atomizing steam, a differential pressure control system is installed to maintain the required atomizing steam pressure. Installation details for the atomizing steam control system are shown in Figure 1-4.

1.3.1.7 Control of Excess Air

If the correct fuel/air ratio is to be maintained at all times, a suitable combustion guide is essential. The percentage of oxygen in the flue gases is a function of excess air. Sufficient excess air must be maintained at all times to assure complete combustion and safe operating conditions with due allowance for fluctuations in fuel gas composition. At the same time, the amount of excess air must be limited as it carries heat out of the furnace and lowers efficiency. A continuous measurement of the oxygen content of the flue gases provides the most satisfactory analysis, especially when the hydrogen/carbon ratio of the fuel may be varying.

Ultimately, the desired air flow for any given fuel quantity must be established on the basis of actual furnace conditions as determined by flue gas analysis. The desired relationship between the position of the control element and the output signal from the master pressure controller can be adjusted by the computing relay shown in Figure 1-8. This can give the air flow measurement the characteristic of causing increased amounts of excess air at lower loads. These adjustments are made during load tests of the steam generating unit.

The correct fuel/air ratio may be manually set by the operator using the oxygen analyzer-recorder as a guide, or automatically controlled by the oxygen analyzer. If automatic control is used, high/low limit relays should be installed. Some users limit the corrective control action to ±5 percent of the maximum air flow in the event of analyzer failure.

For information concerning installation of oxygen analyzers, see RP 550, Part II, Section 19.

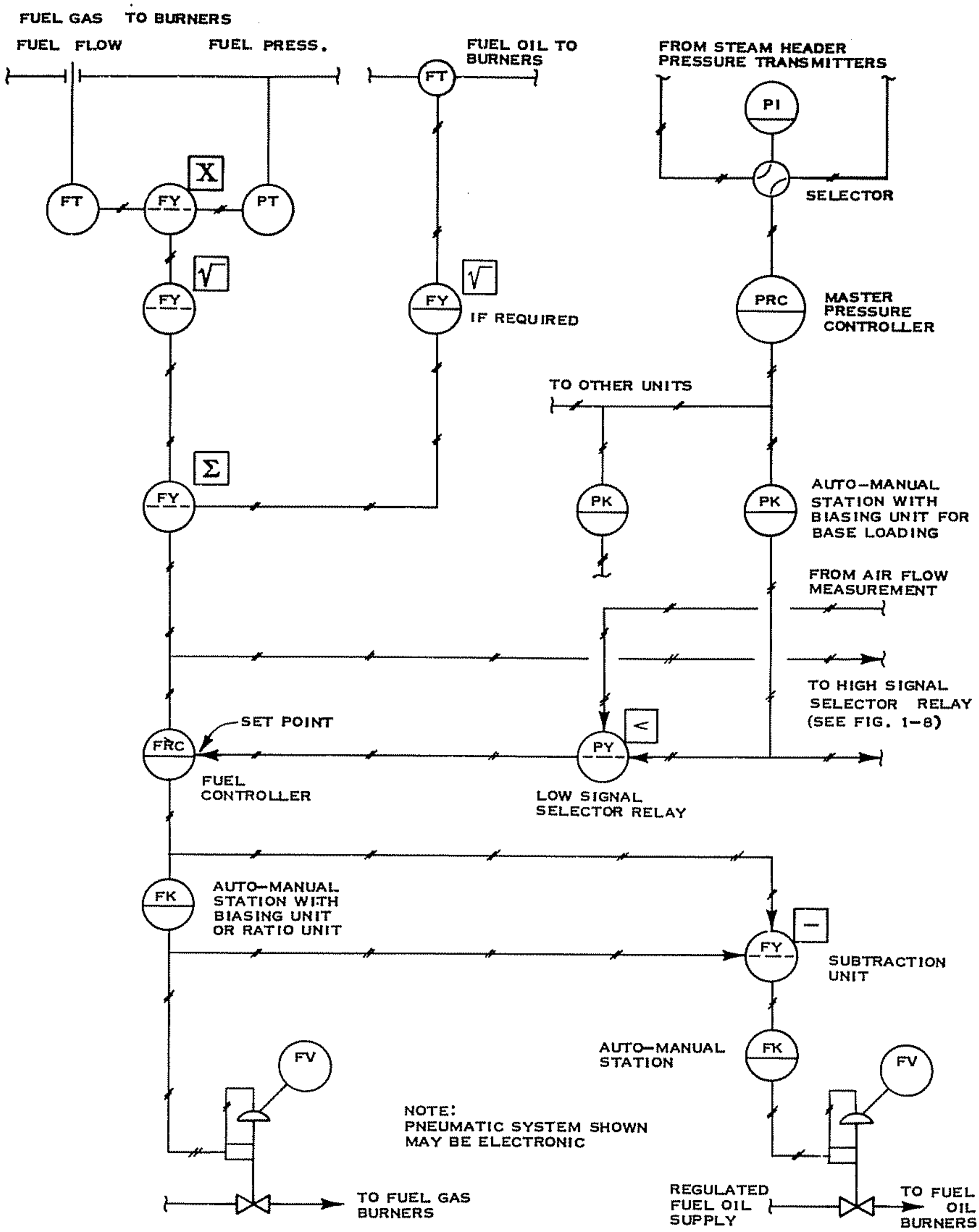


Figure 1-11—Combination Control System—Fuel Gas and Fuel Oil for Combination Firing on Automatic Control or One Fuel on Manual Control

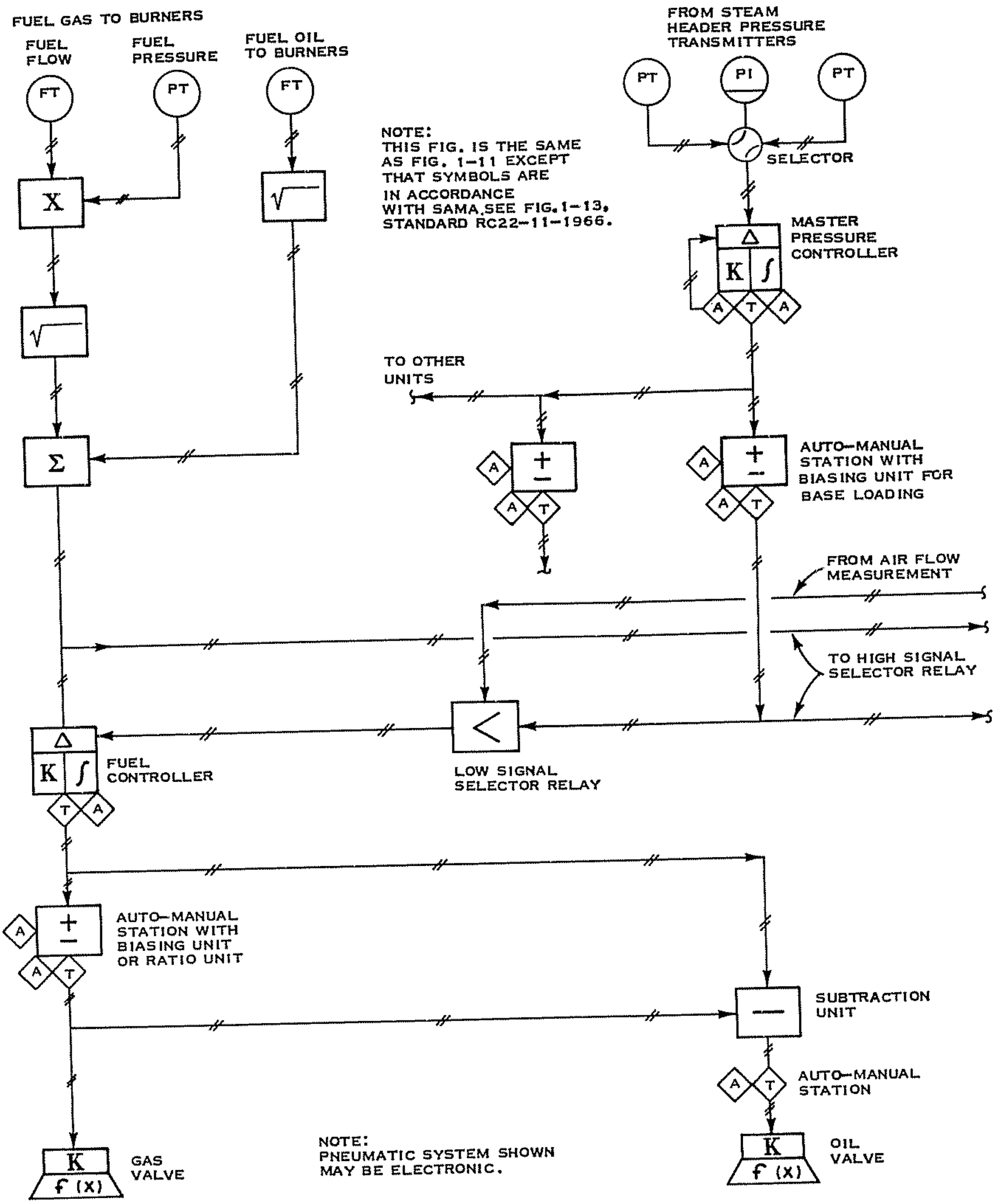


Figure 1-12—Combination Control System—Fuel Gas and Fuel Oil for Combination Firing on Automatic Control or One Fuel on Manual Control

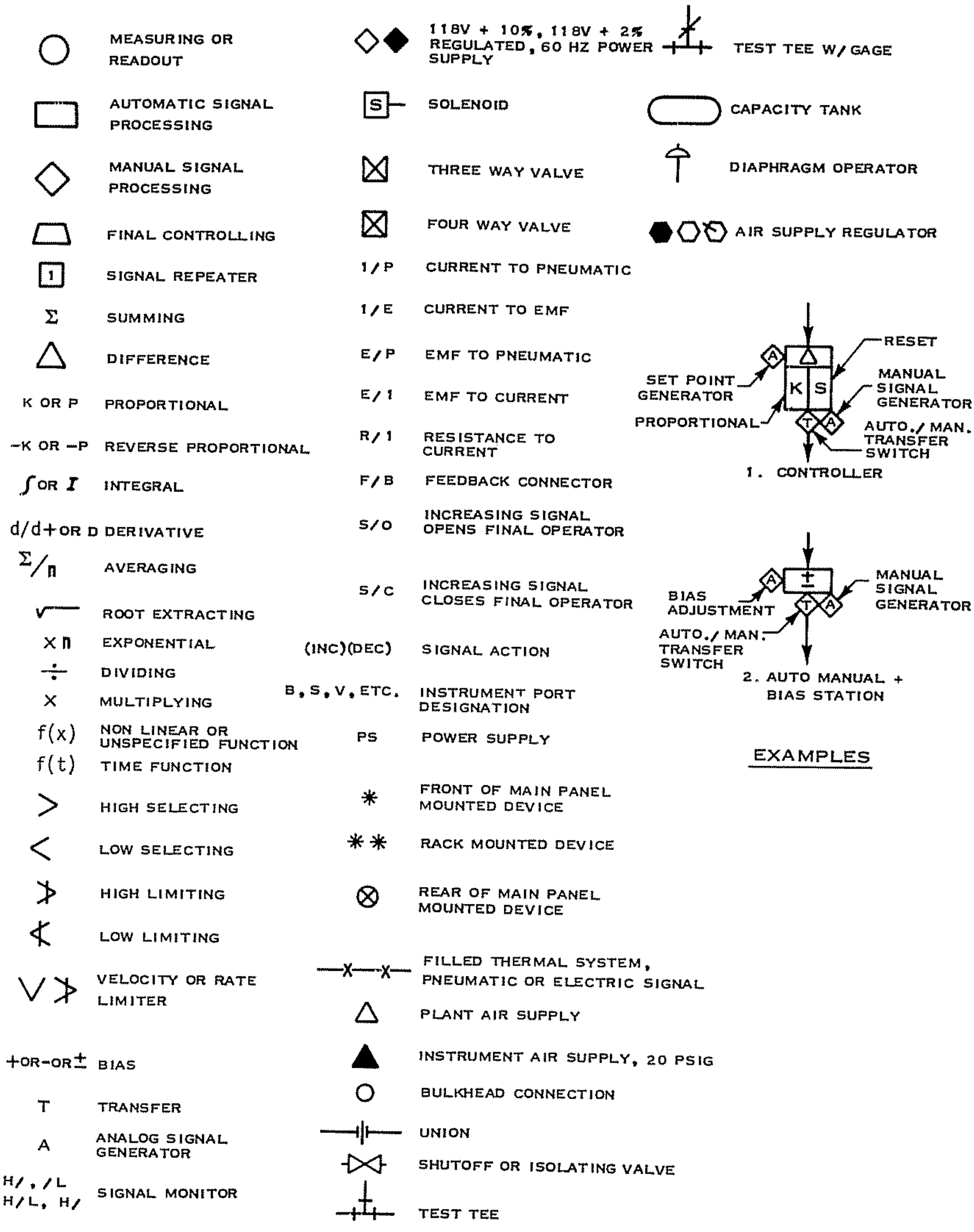


Figure 1-13—SAMA/ABMA Legend

1.3.2 FEEDWATER

1.3.2.1 Single-Element Feedwater Control

The basic feedwater control system is the "single-element" type, so called because only one variable, water level in the steam drum, is measured. Drum level is measured by either displacement or differential pressure type level sensors and is controlled either locally or remotely. A typical installation of a single-element level control is shown in Figure 1-14.

Single-element control is used for units operating under moderate evaporation rates without excessive load swings. The disadvantage of single-element control is that it recognizes only drum water level and thus may initiate control changes that are actually counter to the load change, due to swell and shrink effects.

Although single-element systems are installed on some generators operating at capacities up to 150,000 pounds per hour, they are more generally used on steam-generating units operating at fairly low pressures (250 pounds per square inch gage or less) and at steam rates of 100,000 pounds per hour or less, and at relatively constant load.

1.3.2.2 Two-Element Feedwater Control

Two-element (drum level-steam flow) systems are not generally used in fired steam generating units.

1.3.2.3 Three-Element Feedwater Control

Accurate and dependable feedwater control is necessary for safe operation of modern steam generators, which usually combine a high steaming rate with a small drum capacity. The total volume of water in the unit is small compared with the throughput, and there is insufficient capacity to protect the unit during rapid changes in steaming rates without proper controls.

With such steam generators, feedwater control cannot be based on level measurement alone because of "swell" that occurs when the steaming rate is suddenly increased and the drum pressure decreases. This produces a greater volume of steam in the tubes and the water is displaced into the drum. Level control alone would shut down on the water feed rate so quickly that a violent cycle could be started. Shrink occurs when the steam rate suddenly decreases and the pressure increases, collapsing some of the steam bubbles in the drum and tubes and thus causing a drop in level. To minimize the effects of shrink and swell and variations in feedwater pressure, it is normal practice to install the three-element feedwater control system, operating in accordance with the variations in feedwater flow, steam flow, and drum level, with corrections made automatically for variations in blowdown. The three-element system of steam flow, feedwater flow, and drum-level measurements shown in Figure 1-15 maintains the drum level within safe limits, even during rapid swings in load, by holding a definite steam/feedwater relationship. With this system, feedwater flow is matched against steam flow (for each pound of steam used a pound of feedwater is immediately added) and the material balance is adjusted by drum level feedback to maintain close level control. If for any reason (such as intermittent blowdown) the correct drum level is not maintained, the steam/feedwater relationship is automatically changed by the drum level controller ("proportional plus reset" type).

Linear signals are generally used for transmission of steam and feedwater flow variables. They are normally considered desirable for stable operation over the full range of instrument operation required by the wide variations in load conditions experienced in steam generator control. Linear signals are obtained by installing linear transmitters or by installing square root extractors to linearize the output of differential type transmitters. The primary consideration is that the flow signals must be compatible.

In some plant installations, the main steam header pressure may be subject to wide fluctuations, perhaps as much as ten percent. Consideration should be given to the effect such variations will have on the steam flow transmission signal as well as on the drum level signal.

For the recommended practice for the installation of drum level, steam flow, and feedwater flow transmitters, see Figure 1-1 and RP 550, Part I, Sections 1 and 2.

1.3.3 BLOWDOWN

1.3.3.1 General

The primary purpose of blowdown is to control the solids concentration of the water in the steam generator. Proper blowdown control will prevent scale formation on heat transfer surfaces, limit the amount of silica vaporized with the steam, limit the solids content of the steam leaving the steam drum, and assure a maximum benefit from water treatment chemicals.

There are two types of blowdown: intermittent manual blowdown and continuous blowdown, both of which are required.

1.3.3.2 Intermittent Blowdown

Intermittent blowdown is accomplished by manual operation of specially designed, tandem-seated, erosion-resistant valves located at the low points of the unit. The frequency of manual operation is determined by the feedwater quality and the chemical treating agents used.

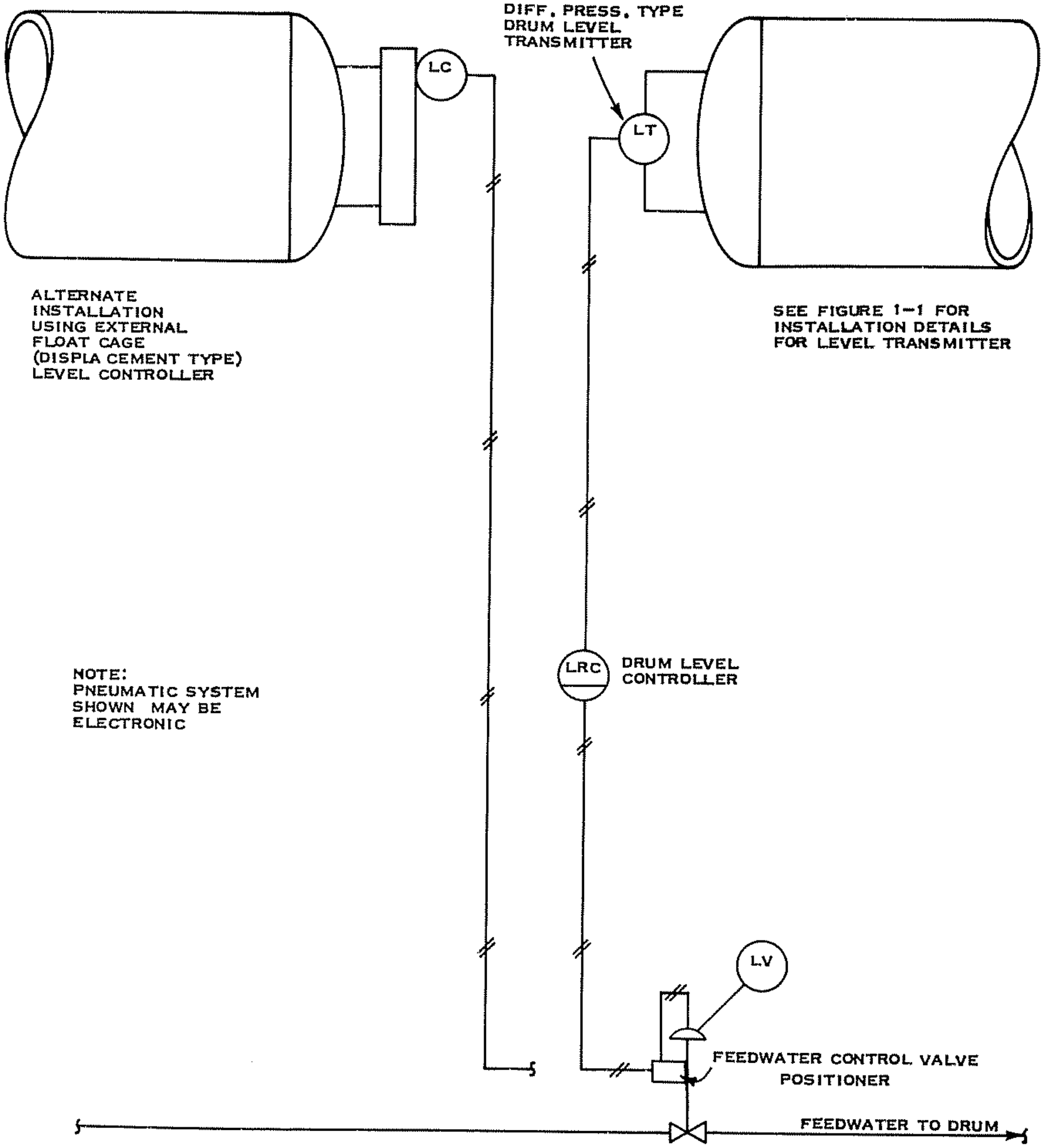


Figure 1-14—Single-Element Feedwater Control System

1.3.3.3 Continuous Blowdown

Continuous blowdown allows withdrawal of solids-bearing water from the steam drum at a rate proportional to the buildup of solids in the drum. When the limiting concentration of solids has been determined for the operating conditions of the unit, enough water must be withdrawn to hold the concentration within a predetermined range.

In many installations, the continuous blowdown rate is adjusted by manual operation of the blowdown

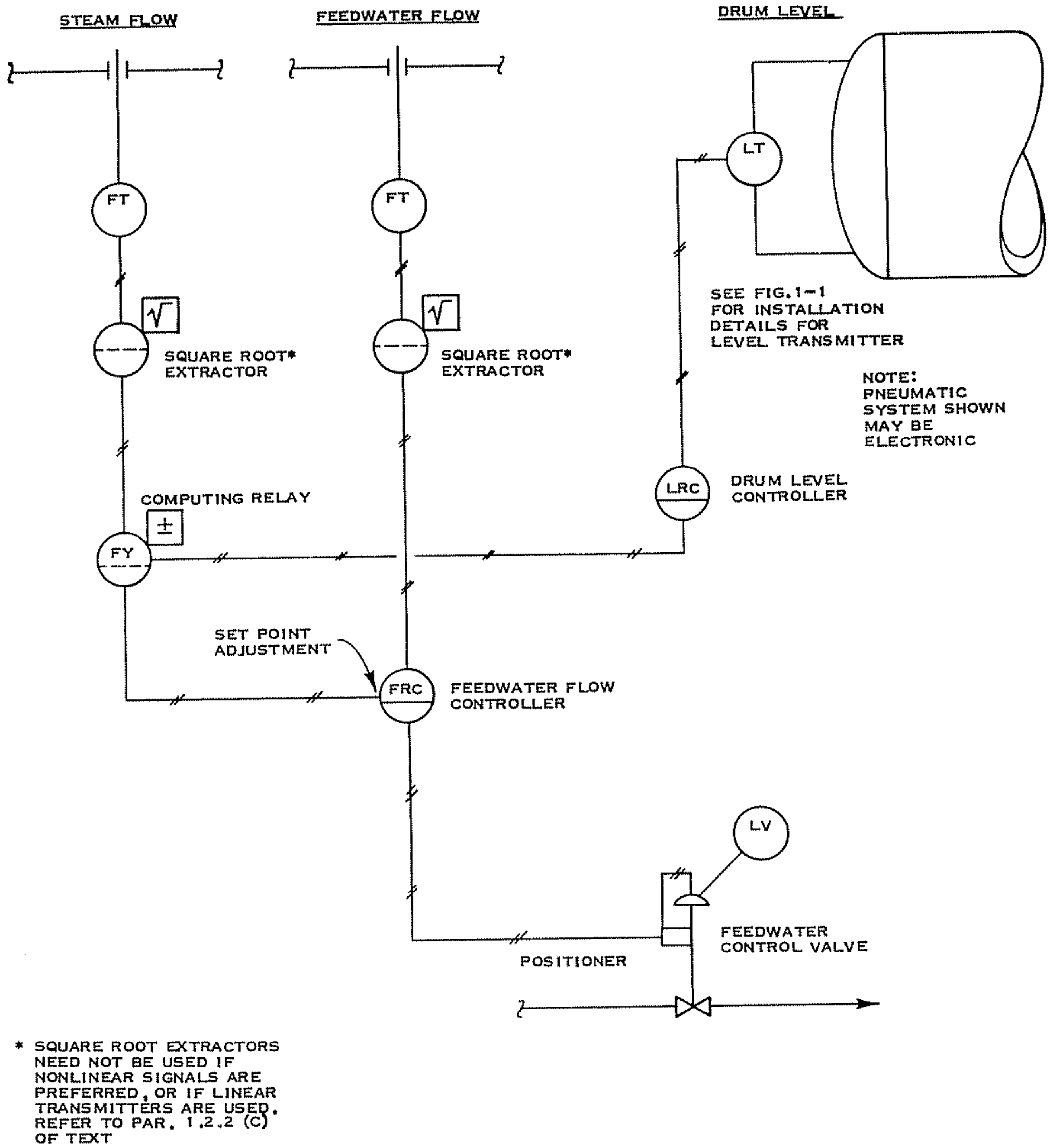


Figure 1-15—Three-Element Feedwater Control System

control valve. The amount of adjustment is determined by measurement of the electrolytic conductivity of the blowdown water by means of a continuous conductivity analyzer, or by measurement of steam purity by means of a continuous sodium analyzer. An alternate method is by periodic testing by wet chemistry analysis.

Blowdown may be controlled automatically by use of a ratio controller to proportion blowdown flow rate to feedwater flow rate. Continuous conductivity measurement should be used as a guide to adjust the ratio. See Figure 1-16.

Some installations utilize continuous conductivity measurement and automatic adjustment of the blowdown control valve to correct for changes in the solids concentration. Any change in conductivity of the blowdown water causes an appropriate decrease or increase in the rate of continuous blowdown. See Figure 1-17.

1.3.4 SOOT BLOWERS

Soot blowers can be manual or automatic. If automatic, the controls are usually provided by the vendor of the equipment.

Soot blowers, if required by the quality of the fuel, are normally provided in the tube banks of fired steam generators to prolong onstream time and maintain thermal efficiency by preventing buildup of soot or other foreign deposits. They may be either rotary or retractable. Consideration should be given during design to their number and location to make sure that all tubes can be reached for cleaning. Also, the steam pressure used for blowing should be selected so that it is high enough to give sufficient cleaning velocity without causing undue erosion. Soot blower operation can be automatically sequenced to reduce operator requirements and to reduce sudden, large demands on the steam system. Refer to Paragraph 1.2.15 for possible combustion control upsets due to soot blowing. Also, precautions should be taken to protect other instrumentation, such as sampling systems of analyzers, during soot blowing.

1.4 Protective Instrumentation

The purpose of protective instrumentation is to bring specific conditions to the attention of the operator (such as equipment malfunction, hazardous conditions, or misoperation), to assure that operating events occur in the proper order, and to initiate trip devices when approaching an unsafe operating condition. How elaborate these systems need be depends on several factors. These factors include the operating conditions under which the steam generator must function, the type and size of the unit, the fuel and air supply equipment and arrangement, burner capabilities, type and reliability of the fuel supply, the location of the burners in relation to the control center, and all applicable codes and regulations.

Since the availability of steam is usually critical for a process, the steam generator should be kept on line as long as possible consistent with overall plant safety considerations. This means that a variable that could give rise to unsafe conditions should be continuously monitored and checked against predetermined limits. These limits should leave considerable margin between the alarm valve and the valve at which a hazardous condition could arise.

An alarm should operate when a limit has been reached so that the operator can take corrective action at once. If he has failed to do so, or if he has not taken enough action on essential variables, and the variable continues to approach an unsafe value, an automatic trip-out should operate to shut down part or all of the steam generator.

The components of an alarm and/or shutdown system may be mechanical, pneumatic, electric, or a combination of all three. The entire system should have provisions for adequate onstream testing to ensure automatic operation when required. See Paragraph 1.4.4.

Installation of alarm and electric interlock systems are subject to the same considerations with regard to environment, power supply, physical mounting, and function, as associated with other electrical equipment. Refer to RP 550, Part I, Section 13 for installation practices.

1.4.1 ANNUNCIATORS AND ALARM LIGHTS

Annunciators and alarm lights, both visual and audible, are provided primarily for safety considerations, but also to alert an operator and give him immediate information on the status of the steam generating unit at any instant. Thus he will have an early warning in the event of malfunction of any piece of equipment or important off-limit operating variable, and he will be able to take faster corrective action to keep the unit on stream.

Annunciator and alarm equipment is available in a wide variety of physical designs and sequences. The "first out" sequence aids in troubleshooting and determining the first fault where various monitored functions are interlocked. This feature can light only the initiating trip or it can light all shutdown trips, but it keeps the initiating trip flashing. In addition, the annunciator should indicate all other pertinent steam generator parameters that deviate from normal. Variables that frequently require alarms are:

1. *High and low steam drum water level.* Low drum level is a safety consideration in steam generator operation. Dangerous overpressures, with possible explosions, could result if firing is unchecked with no water in the steam drum and then water added. Damage to the steam generator is always a possibility with little

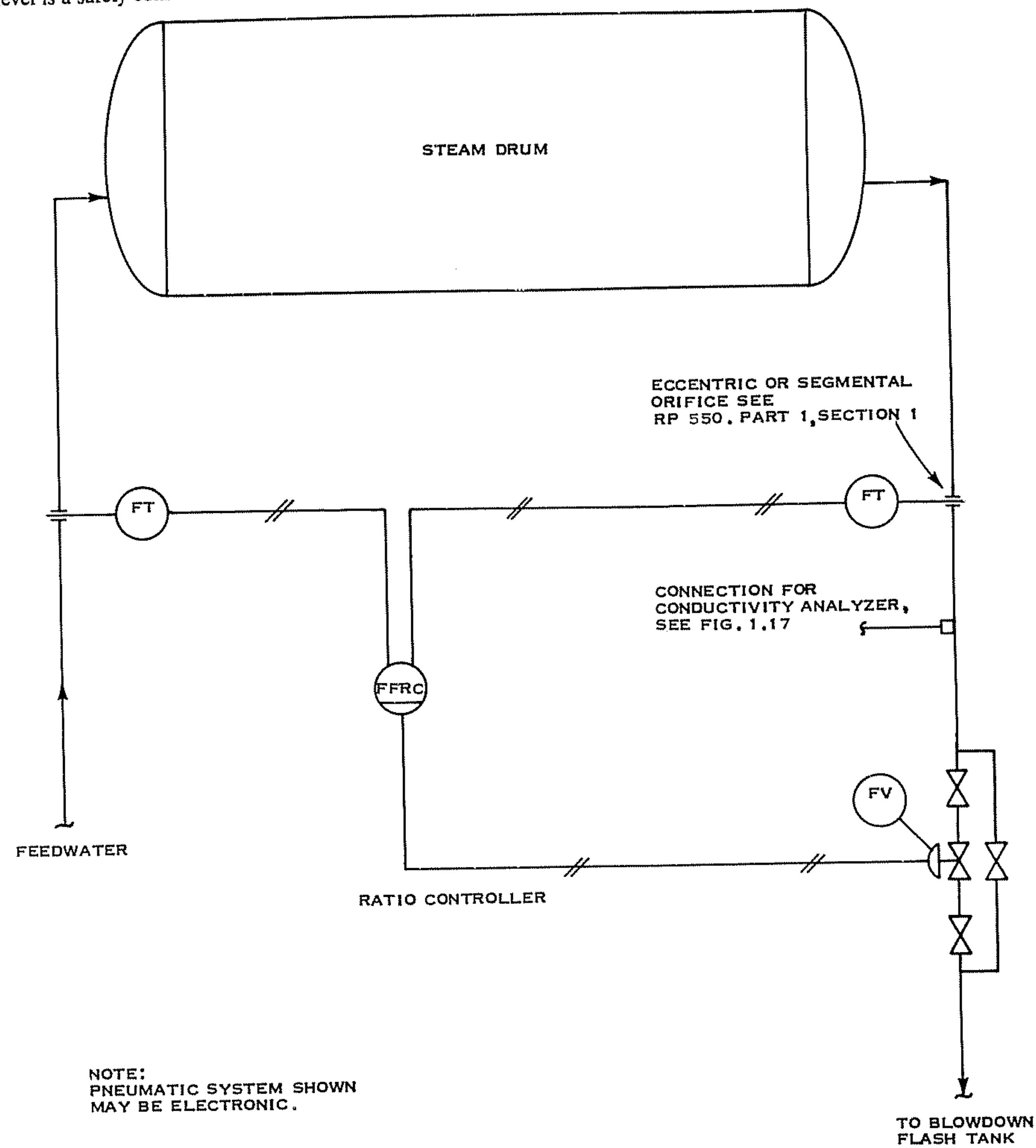


Figure 1-16—Automatic Blowdown Control, Feedwater Flow Ratio

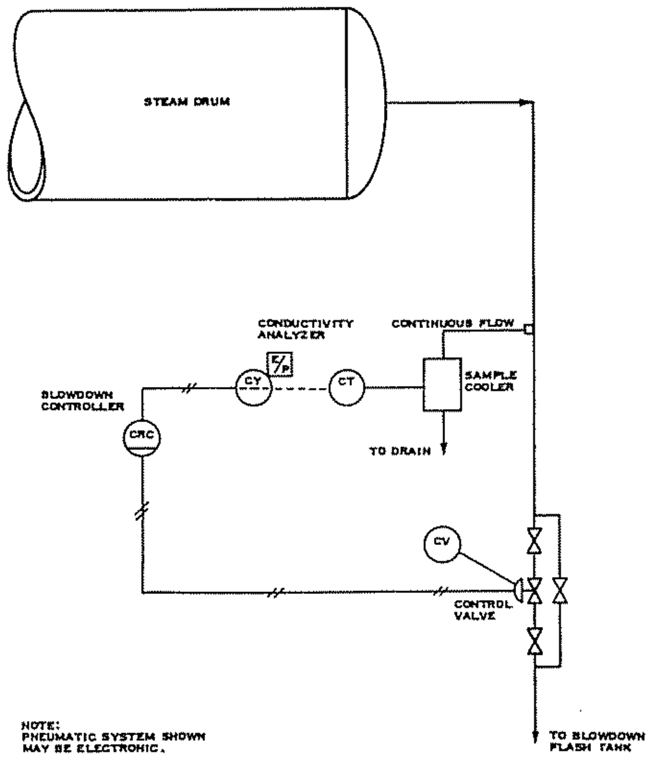


Figure 1-17—Automatic Blowdown Control, Conductivity

or no water in the drum. A high drum level may allow water carryover into the steam disengaging area, which in turn will lower the steam drum pressure or allow carryover into the steam header that can harm operating equipment, such as steam turbines. Superheater fouling can also occur from water carryover.

2. *Low feedwater pressure or loss of feedwater flow.* These variables generally indicate loss of feedwater to the drum. This will give advance warning to the operator of impending low drum level if allowed to go unchecked.

3. *Low pressure differential between feedwater and steam drum pressures.* Too low a pressure indicates the feedwater pressure is insufficient to permit feedwater to enter the drum.

4. *High and/or low fuel oil supply temperature.* When burning heavy fuel oil, burner tips will frequently plug if temperature is not maintained. In addition, the firebox efficiencies are dependent on maintaining the temperature limits of the liquid fuel oil supply.

5 *High and/or low fuel oil supply pressure.* Burner tips are fixed orifices and, therefore, flow is dependent upon the drop across the tip. A fuel pressure alarm will give the operator advance notice that fuel to the firebox may be changing, even though fuel demand has not changed. For example, a high limit pressure alarm could indicate that burner tips were fouling and therefore fuel demand was not being met or that potentially too much fuel was being supplied to the furnace through the burners.

6. *Atomizing media low pressure differential.* The atomizing media normally steam- or air-retards polymerization of hydrocarbon and assists in breaking the oil into a fine mist for more complete combustion. The loss of atomizing steam-oil pressure differential (when steam atomizing burners are used) can result in unsafe conditions.

7. *Low fuel gas pressure in burner header.* If fuel gas pressure falls to a point approaching unstable burner operation, an alarm should be actuated.

8. *High fuel pressure.* Overfiring or flameout may result from high fuel pressure. In systems where overpressure may be a problem, an alarm should be provided.

9. *Low pilot gas supply pressure.* Pilot gas is used to ignite the burners. It is sometimes used only for lightoff, in which case it is an interrupted (igniter) pilot since it is shut down after lightoff. In other cases, it is used as a continuous pilot to prevent a flameout in the firebox.

10. *Low forced draft fan differential pressure.* The operating forced draft fan differential pressure is often measured and alarmed to indicate the loss of a large quantity of combustion air.

11. *High pressure in combustion chamber.* An alarm for this variable should be provided when a balanced draft system is used. This could indicate induced draft fan failure or malfunction of dampers.

12. *Loss of air preheater drive.* The loss of air preheater drive results in decreased steam generator efficiency and can cause mechanical damage to the preheater. An alarm or alternate power source should be provided.

13. *Loss of main burner flame.* This condition should be alarmed from a flame detection device. Loss of steam production will occur and flame failure could result in a dangerous firebox condition. See Paragraphs 1.4.3.1,5 and 1.5.4 regarding the use and description of flame detection devices.

14. *Loss of pilot flame.* In an installation that uses a continuous pilot, flame detection alarms are generally provided. Paragraph 1.4.3.1,5 describes flame detection devices and their use.

15. *Instrument air low pressure.* This condition should be measured and alarmed to indicate the possibility of a combustion control upset or a complete unit shutdown.

16. *Loss of electric power.* All sources of power for interlock and control should be sensed and alarmed. Each source of power should be annunciated separately and by a reliable power source.

17. *Oxygen high or low.* These conditions should be alarmed to indicate possible combustion control problems that could develop into hazardous conditions.

18. *Combustibles high.* Steam generators in which the fuel supply is subject to extreme Btu fluctuations are often equipped with a combustible analyzer and alarm. This device warns the operator when combustibles reach a hazardous level.

19. *High flue gas temperature.* An alarm for high temperature of the flue gas could indicate too much fuel or that the combustion controls are not functioning properly. The consequence could be loss of steam tubes or superheater tubes, baffle failure, or other failure in the breaching or stack.

1.4.2 SAFETY SHUTDOWN SYSTEMS

Some of the alarm variables listed in Paragraph 1.4.1 are used to shut down (trip) a minimum amount of equipment in a safe sequence upon reaching conditions that jeopardize the safety of personnel or equipment. The specific safeguards required are subject to careful analysis of the steam generator functional components and its control system. Careful attention should be given to the installation of shutdown devices and associated electrical and instrument air supplies in order to ensure adequate equipment and personnel protection and to minimize nuisance shutdowns. On loss of electrical power and instrument air, it is essential that the control system, as well as the safety shutdown system, assume a condition that has been determined most favorable for overall plant safety. If overall safety is to be accomplished, each component in a control loop must assume a predetermined safe condition. A majority of refinery steam generating units utilize safety shutdown systems designed to close fuel valves on loss of electrical and instrument air supplies. The fuel valves should not open until manually reset.

Some of the variables selected for automatic trip are:

1. *Low fuel gas or fuel oil burner pressure.* If the fuel gas or fuel oil pressure decreases below the minimum pressure required for flame stability, an automatic trip of that fuel should occur. In the case of a multiple burner unit, when the last burner valve closes, the main fuel supply valve should close and should require a purge sequence before it can be opened again.

2. *Burner pressure high.* This variable should be considered for a fuel trip depending on the burner capabilities and the configuration of the fuel supply system. Fuel pressure transients from cutting burners in and out of service or failure of the supply pressure regulator might exceed burner limits for stable flame. A full capacity relief valve on the burner header, vented to a safe location, will eliminate the need for this fuel trip.

3. *Atomizing steam low differential pressure.* Loss of atomizing steam/oil differential pressure (when steam atomizing burners are used) can result in unsafe conditions.

4. *Loss of combustion air.* The loss of all forced draft (FD) or all induced draft (ID) fans should operate the master fuel trip to protect against the loss of large quantities of combustion air. The loss of one FD or ID fan can sometimes be handled by the combustion control system fuel/air ratio control system.

5. *Low water level.* A steam drum water level below the emergency low level should result in automatic fuel trip.

6. *Loss of electrical power.* Where electrical safety shutdown devices are installed, a loss of electrical power will automatically shut down the normally energized system. Normally deenergized systems, on the other hand, will not shut down the system on power failure but will become inoperative during the power outage.

7. *Loss of instrument air.* The loss of instrument air will usually close the firing control valve and interrupt fuel flow. In this case, the fuel safety valve should trip. An exception to this is that the system need not be shut down if such loss closes only the fuel control valve and if the control valve has a bypass regulator.

8. *Emergency trip switch.* Depending on the equipment location in relation to the control center, one or more emergency trip switches should be considered for operator use.

9. *Loss of flame.* Loss of flame at an individual burner should shut down that burner only. Loss of flame at all burners should result in automatic main fuel trip.

See Figure 1-10 for typical piping arrangements for emergency trip devices.

1.4.3 ALARM AND SHUTDOWN DEVICES

1.4.3.1

Shutdown signals should originate from their own process taps and be completely isolated from other measurement and control equipment. This would then preclude shutting down the steam generating equipment by upsetting a shutdown device while routinely blowing down or servicing other process instrumentation.

Some of the more common devices for alarm and shutdown functions include (but are not limited to):

1. Ball float displacer or electrode type transducers for drum high and/or low alarm or for shutdown. In some installations, a time delay is provided to eliminate nuisance shutdowns due to the shrinking and swelling effect that takes place within the drum during large steam load changes. A spring-loaded bypass switch located at the blowdown valve is a method frequently used to operate an electrical cutout switch for the shutdown devices during the blowdown period. In this manner, one hand can depress the switch button, leaving the other hand free to manipulate the blowdown valve. As soon as an operator removes his hand from the switch, full shutdown integrity is restored.

2. A pressure differential switch with the pressure impulse taps located across the forced draft fan rotor or inlet scroll as a means of detecting a loss of primary air flow.

3. A pressure differential or flow switch for detecting low air flow through the air duct.

4. Separate high-pressure or low-pressure switches for fuel supply to the burners.

5. The most widely used flame detector (and the one preferred) is the ultraviolet detector that senses the loss in ultraviolet energy when no flame is present and generates an appropriate signal for alarm or shutdown.

1.4.3.2

It is difficult to keep flame detectors sighted on the flame at all times due to a changing flame pattern or due to the sighting lens becoming coated with dust or soot unless certain precautions are taken. Malfunctions due to dust and soot deposits can be minimized by providing a continuous purge of clean dry air or inert gas to keep the lens clean. It is essential that the burner or steam generator manufacturer or both locate the detector so that the flame can be seen under all conditions.

The following items should be considered for flame detector installations:

1. The function of a flame detector is to give an on-off signal indicating that a flame is present or not present. It does not give a signal relative to flame quality or quantity.

2. Most flame detectors have a built-in time delay that is adjustable. This delay should be known by the user and reduced if undesirable. The normal time delay is one to four seconds.

3. The mounting base should be designed so that the flame scanning angle can be adjusted. It is good practice to have at least one alternative base for locating a flame detector.

4. Oil flames are usually more difficult to detect than gas flames. This is especially true for ultraviolet type detectors. Various extension type detector holders are available to make better sighting possible.

5. Many detectors will require purge air to keep the detection tube temperature at safe limits and to keep the sight glass free of dirt. The detector should be located to keep dirt from falling on to the detector lens or sight glass.

6. If the ignitor flame and main flame are to be monitored individually, two detectors per burner are required. They must be sighted to monitor only the desired flame and they may require shutters or orifices to reduce viewing angles. They must be shielded so that they will not be actuated by the ignitor spark.

7. On pressurized furnaces, purge air and a gate valve are recommended for sealing in furnace gases when a flame detector is removed.

8. The system design and quality of all other components should be investigated.

9. The recommendations of the flame detector manufacturer should be considered carefully.

10. A permanently installed meter is recommended for monitoring the output of each sensor. Such meters are helpful in sighting and also should give an early warning of possible failure.

11. Many times two units per burner are provided, each sighted on the pilot and main burner flames. Both units must then "confirm" that there is truly a flameout before initiating any action.

12. Flame detectors with automatic self-checking features are preferred.

1.4.3.3

In some cases, dual installations are provided for all variables associated with the shutdown systems. Both devices measuring the same variable must then indicate the off-limit before a shutdown is initiated. In this manner, nuisance shutdowns are avoided while the required safety precautions are still observed.

Take-off connections for "alarm only" functions are sometimes taken from the combustion control equipment. However, it is recommended that each instance be reviewed separately, since the servicing of the combustion control instrumentation may negate the alarm function.

Power failures or accidental grounding of wires can lead to unsafe conditions or to unwanted shutdowns. By following good design practices, these effects can be detected and minimized or eliminated.

Alarm systems generally use normally closed contacts, opening to alarm.

Power outages and voltage dips can be overcome or minimized by providing a "no-break" or backup power supply. A transfer of power from one source to an alternate must be fast enough to ensure that holding relays and solenoid valves will not drop out. Backup power is treated more fully in RP 540* and RP 550, Part I, Section 11.

1.4.4 INTERLOCKS

Interlock systems are provided to prevent operation under any and all potentially unsafe operating conditions. Interlocks are associated with both a starting up procedure (refer to Paragraph 1.5) and with an orderly shutdown sequence.

An interlock can be dependent upon a single variable's being outside of preset limits or upon more than one off-limit variable before action is initiated. Interlock is defined in NFPA Standard 85B† as: "Interlock—A device or group of devices 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 a hazardous condition."

1.4.5 TESTING OF SHUTDOWN DEVICES AND SYSTEMS

To ensure proper operation of a safety shutdown system after long periods of normal equipment operation, a regularly scheduled (1 to 3 months) onstream testing procedure is recommended. Test procedures should be reviewed carefully to prevent plant shutdowns or the disablement of the safety systems during plant operation.

Flame detectors with self-checking features built in are preferred over any scheduled testing program of these devices. Sensor switch contacts for low level shutdown, forced draft pressure, loss of forced draft fan, and so forth can be checked with spring return bypass switches that bypass the shutdown contacts and not the alarm contacts. Then, by manually operating the field switch, the operation of the shutdown loop can be checked. Sometimes a key switch is used with an alarm display to indicate when the shutdown system is inoperable. In this manner, one individual could test the full system.

If a bypass valve is provided, such as a fuel bypass, it is desirable to put that variable on hand control at the valve and check out the entire loop, including the operation of the control valve.

It should be stressed that the integrity of the system is protected only as long as there is proper and periodic maintenance and testing of the entire system. Refer to RP 550, Part I, Section 13.

1.5 Programmed Ignition Systems

The main purpose of programmed ignition systems is to eliminate the hazard of lighting off fired steam generators.

Whether the sequence of events is to be initiated manually or automatically must be determined when the system is designed.

The majority of furnace firebox explosions occur during burner ignition. Programmed ignition systems are designed to minimize this hazard. Relatively few explosions occur during initial burner ignition when a new steam generator is being first started up. The most likely time for an explosion is from two to five years after initial startup. The circumstances that lead to an explosion are often triggered by an unexpected flameout during normal operation. While hurriedly trying to get the steam generator back on the line, human mistakes are sometimes made. It is during this sort of burner ignition that the programmed system is most beneficial.

1.5.1 DESIGN FOR ON-LINE TESTING

To be certain that a programmed ignition system will perform properly during an unexpected emergency, it must receive regular preventive maintenance. This requires that the system be designed so that it can be checked safely at any time, without disturbing steam generator operation. This, in turn, requires a bypass switching arrangement. A key operated bypass switch with a local warning light and a remote alarm can be provided to prevent and detect unauthorized bypassing.

Recommended Practice for Electrical Installations in Petroleum Processing Plants, 2nd edition, American Petroleum Institute, 1801 K Street, N.W., Washington, D.C. 20006.

†*Explosion Prevention, Multiple Burner Boiler-Furnaces, Gas Fired*, National Fire Protection Association, 470 Atlantic Avenue, Boston, Mass. 02110.

1.5.2 COMPONENTS AND INSTALLATION

The electrical components in a programmed ignition system are: timers, solenoid valves, pressure switches, relays, flame detectors, ignitor and transformer, alarms, indicating lights, and switches. Usually a small panel is provided for the last three items. Additional components consist of pressure regulators, plug cocks or ball valves, gate valves, and the like. The recommended installation practices given in RP 540 and RP 550 should be followed when installing these components. In addition to a sound mechanical installation, the equipment location relative to the main operating control panel and the burners and any valves that need to be operated must be carefully considered. If the installation is out of doors, a weatherproof air (instrument air) purged junction box is usually sufficient protection for the electrical components. Depending on the steam generator design and size and on the purge cycle time, the operator will have a sequence of steps to follow. A typical schematic for a programmed gas-oil burner ignition system is shown in Figure 1-18.

1.5.3 SEQUENCE OF OPERATIONS

1.5.3.1

The first step in a typical burner lightoff sequence entails the operator's starting the forced draft fan to purge the firebox. A light on the burner panel indicates that the air flow is sufficient for purge requirements.

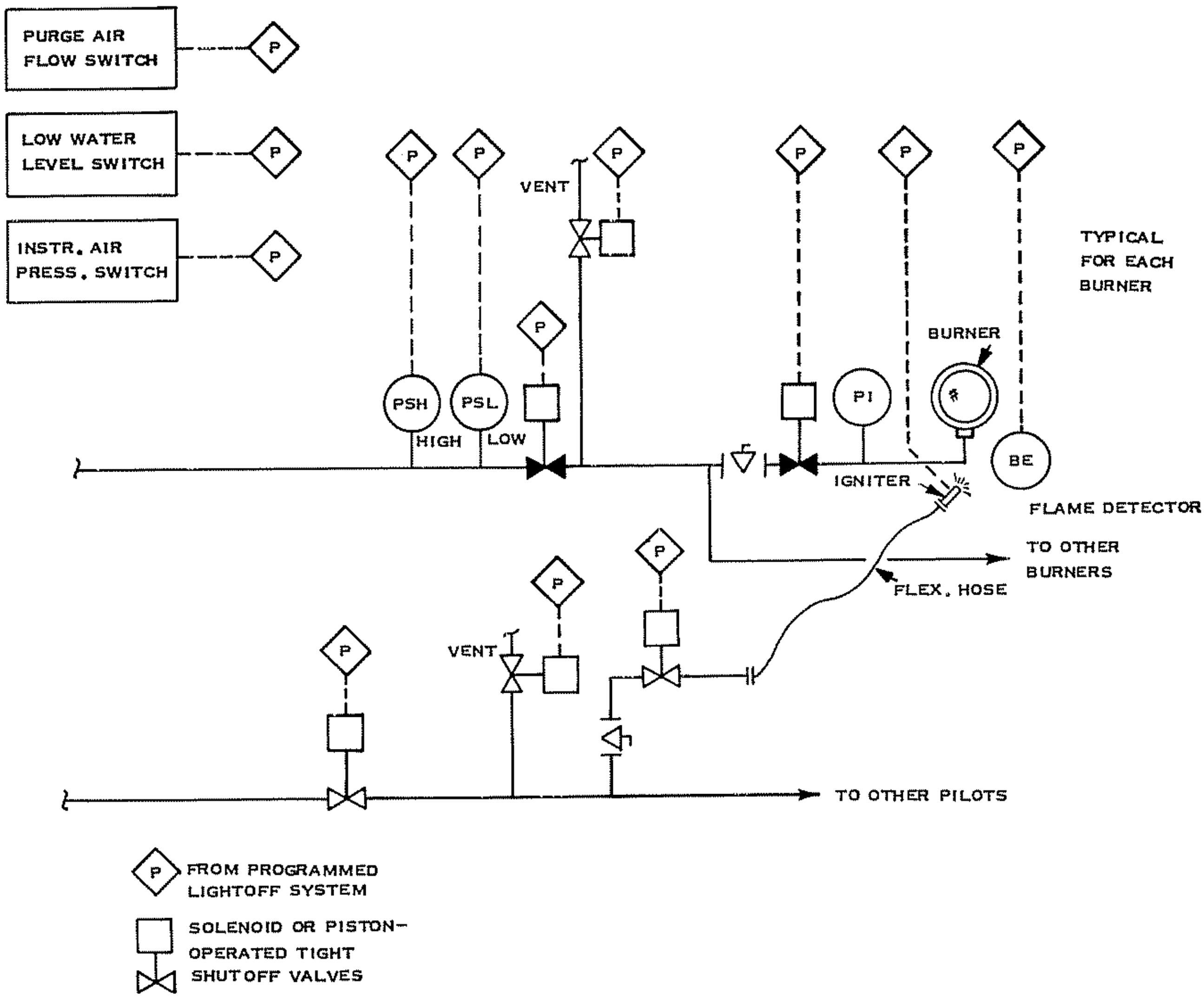


Figure 1-18—Typical Gas Burner Piping with Programmed Lightoff System for Multiple Burner Steam Generator

1.5.3.2

In the second step the operator closes a "purge start" switch. If the main fuel and individual burner automatic valves are closed (limit switch), the purge timer will start. The timer assures that the purge time will be sufficient to purge the furnace of all combustible gases. The purge air flow must not be less than 25 percent of full load air flow for a continuous period of not less than five minutes and must provide at least five volume changes. If any of these or other required conditions should deviate from safe limits at any time before ignition, the sequence must be restarted.

1.5.3.3

In the third step (after the purge is completed) a "ready" light comes on indicating not only that the purge is completed but that all other steam generator interlock devices are satisfied and a burner is ready to be lighted. After the "ready" light comes on, the burner must be lighted within a specified time limit (usually about five minutes) or the purge must be repeated.

1.5.3.4

As a fourth step, the air flow should be adjusted to the amount required for ignition. This should not be less than 25 percent of the maximum amount. Air flow cutback would be programmed into the lightoff system so that air flow dampers are automatically cut back at the end of the purge cycle. Some furnace suppliers recommend that the entire purge be performed at a low air flow (about 25 percent of maximum). This avoids the necessity of damper cutback at the end of the purge, but it has the disadvantage of requiring a long purge time. However, purge rate and time must be of sufficient magnitude to assure the purging of all combustibles from dead areas in the firebox.

1.5.3.5

The fifth procedure requires that the operator adjust the air register or damper on the burner selected for lighting to the position recommended by the manufacturer. He then closes the "burner start switch." This actuates a burner timer that regulates the valve opening sequence of ignitor and main burner ignition.

1.5.3.6

The sixth (and last) sequence of operations should be very carefully worked out during the design stages with the system supplier. The exact order and number of operations may vary depending on the user's safety and manpower requirements. It is normal to have the system designed so that one man can perform the operation. Some of the things that must be determined are:

1. The amount of time allowed between the end of purge and burner ignition.

2. Will it be a one-man operation?

3. After the burner timer starts, how many things does the operator have to do before a burner is lighted? The system could be completely automatic so that the operator has nothing further to do after he closes the burner timer switch. However, in practice it has been found that the preferred procedure is to have the operator at the burner platform with his hand on the final fuel valve lever. He permits the pilot to light automatically and then opens the main fuel valve by hand to ignite the main burner. Assuming none of the automatic valves or timing sequences are disturbed, having an operator open the final fuel valve when he sees the pilot flame should add to the safety of the procedure.

4. How many seconds should the ignition arc and the pilot gas stay on? The normal time is about 20 seconds for the arc. Pilot shutoff valves must close 10 seconds after opening unless a flame is established.

5. After the flame detector proves that the pilot flame is on, how many seconds until the main fuel valve opens? The normal time is about two seconds.

6. How many seconds does the main fuel valve stay open and the pilot flame stay on together? The normal time is about five seconds. If the main burner is not on when the pilot flame goes off, then the main flame detector must shut down the system.

7. How many and what type of flame detectors are to be used? Are they properly sighted and protected? One flame detector per burner is usually sufficient. Dual flame detectors in parallel operation can prevent unnecessary shutdowns. See Paragraph 1.4.3.1, 5. They can be sighted to detect the pilot flame and the main burner flame or both. This should be considered early in the design of the burner system.

8. What are the fuel conditions? If plant fuel gas is to be used for ignition fuel, will the pilot function properly at the varying conditions possible? If not, it is necessary to have a separate source of liquefied petroleum gas (LPG) or natural gas for the pilot.

9. Are the interlocks arranged logically? What are the chances of unnecessary shutdowns caused by inter-

lock switches set too conservatively? A system that is overly sensitive or one that consistently causes many abortive starts is more of a hazard than a completely manual system.

10. Is the system arranged so that the operator can perform all required functions at the burner panel?

11. Are all interlocks in the system actuated by the correct sensing elements? For example, the closing of a contact in the fan motor circuit does not assure that the furnace is actually being purged. Dampers and registers could be closed. Purge air flow should be determined by differential pressure measurement of flow, not by proving that the fan is running or by measuring windbox pressure.

12. Many steam generators fire either all gas, all oil, or a combination of both. The system should be designed so that either the gas or oil burner can be ignited from the same pilot. The same timing sequence is usually used. Of course, different interlocks are needed for the oil burner. It is normal to prove that oil pressure is sufficient and steam/oil atomization differential pressure is correct, in addition to the other interlocks previously mentioned.

1.5.4 FLAME DETECTORS

The flame detector, although important, should not be considered the single most critical component in the system. The provision of ignitors and burners capable of dependable lightoff and stable flames is the most important consideration. Refer to Paragraph 1.4.3.1,5.

1.5.5 POWER SUPPLIES

Flame safeguard systems usually require AC power and are sensitive to variations in the voltage and frequency of the power supply. Many systems have relays that are kept energized through their own contacts. Many systems have timers that are held in fixed positions by energized coils. It is not unusual for sensitive relays in these systems to drop out in eight milliseconds (½ cycle) after power is removed from the system.

To assure that steam generators with flame safeguard systems do not shut down during power outages, dips, or transfers, the flame safeguard system should be continuously fed by the most reliable power supply. If a backup supply is used, the transfer to backup power must be nearly instantaneous (less than eight milliseconds). Conventional electromechanical transfer switches are not this fast. Static switching may be used but can be quite costly and may introduce other problems.

When using an inverter power supply, the recommended method of installation is to have the inverter continually connected to the flame safeguard system. For backup power, plant AC is used. The electrical load of a typical four burner flame safeguard system may be from two to six amperes during operation.

Probably the most reliable system is one that uses two flame detectors for each burner, with each flame detector supplied from a different power source. With this arrangement, one detector on each burner would be supplied from utility power, for example, while the second detector on each burner would be supplied from an inverter system. The shutdown system would then be designed so that both detectors must indicate a loss of flame before causing a trip. Refer to Paragraph 1.4.3.

SECTION 2—CARBON MONOXIDE OR WASTE GAS STEAM GENERATORS

2.1 Scope

This section covers instruments and control information unique to carbon monoxide (CO) waste gas steam generators (converters).

A CO steam generator is designed to recover the heat energy from waste process gases. These gases are usually at high temperatures and contain combustible carbon monoxide. Thus, there is available both sensible heat and heat of combustion.

CO steam generators are designed with either hot refractory fireboxes or waterwall tubes. The waterwall design offers improved steam generation efficiency and longer refractory life and requires less ground space. The hot firebox design has several features necessary to satisfy some plant operating requirements. The hot refractory will provide better ignition stability during extreme load changes. This design will also handle wider variations in carbon monoxide temperatures and flow rates that can be especially important when the carbon monoxide-bearing gases are supplied at temperatures below 600 degrees Fahrenheit. Because of the higher temperature firebox, cleaner burning can be obtained, thereby decreasing some of the objectionable components in the flue gases that cause air pollution problems.

Since the CO steam generator must accept the waste gases as they come from the process unit, the operation of the cracking unit directly affects the operation of the steam generating unit. The control system must be designed to insure continuity of operation during irregular or emergency operations of the process unit and must be able to handle disturbances in the plant steam system. A CO or waste gas steam generator may have three basic functions requiring different modes of operation:

1. To serve as an incinerator for the upstream processing unit by burning the carbon monoxide and other combustibles. This requires sufficient supplementary fuel and air for complete combustion. The Btu output for this type of unit will vary directly with the Btu content of the fuels.

2. To burn waste gases with sufficient supplementary fuel to maintain a constant Btu output.

3. To serve as a variable Btu output unit while completely burning the waste gases and sufficient supplementary fuel to meet steam demand.

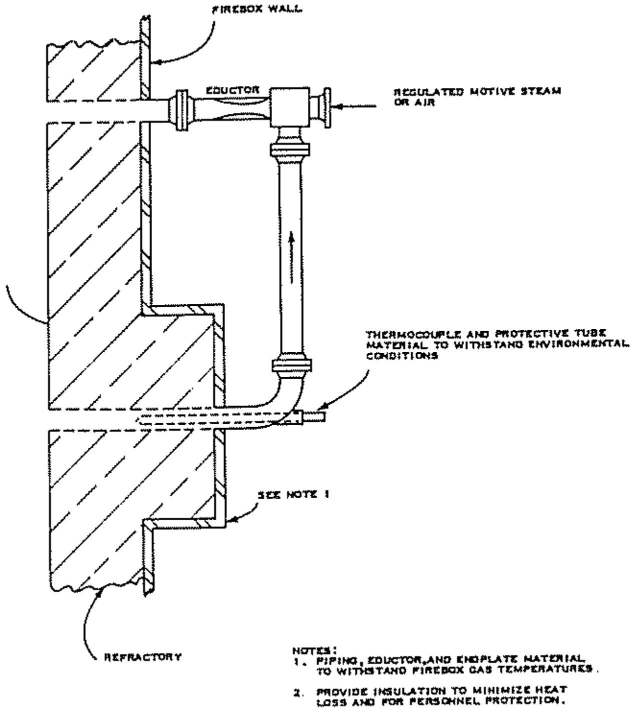


Figure 2-1—Firebox Temperature Measurement

2.2 Measurements

The measurements required for the CO converter will vary with the conditions under which the unit will be operated. Normally, the measurements are the same as for conventional steam generators. See Paragraph 1.2. Special measurements unique to CO converters are:

1. A reliable firebox temperature measurement. Carbon monoxide gases are maintained in combustion at approximately 1,500 degrees Fahrenheit; therefore, an adiabatic firebox temperature of approximately 1,800 degrees Fahrenheit should be maintained to allow a margin for control during process upsets. This measurement is usually made with a carefully located, special thermocouple and protecting tube that must be designed to operate in high temperature and oxidizing atmospheres. To reduce the effects of radiation and to obtain a true gas temperature, the thermocouples are sometimes located in hot gases educted from the firebox. See Figure 2-1 for typical installation. The firebox temperature is usually recorded and alarmed, high and low, to alert the operator to abnormal conditions.

2. A reliable measurement of oxygen in the flue gas. Usually, the CO converter serves as an incinerator burning waste gases with variable amounts of carbon monoxide, hydrocarbon vapors, oxygen, and supplementary fuel. At other times, it may burn only supplementary fuel. These variations make it impractical to set up a fuel/air relationship as is done for conventionally fired units. Because of this variable relationship when firing multiple fuels simultaneously, it is necessary to determine directly the amount of excess oxygen leaving the unit. Realistic flue gas oxygen levels, based on experience, are from about three percent for the combination fuels to about ten percent for total supplementary fuel. The higher oxygen level is normally required when firing supplementary fuel to protect the firebox refractory from excessive temperatures. Also, the increased oxygen provides a means of maintaining a mass flow rate of gases through the steam generator for a heat transfer similar to that for carbon monoxide firing. These percentages are commonly determined by a continuous oxygen analyzer that can be adapted to indicate, record, control, alarm, or any combination as required by the user. See RP 550, Part II, Section 19 for installation practices.

3. Flow rate determination of the carbon monoxide bearing gases to the steam generator is sometimes desired for operator information. As this stream is usually high in particulate matter, some users derive

the flow by inference from the air rate to the carbon monoxide generating source. Another method sometimes employed is to measure the stream directly with a Pitot-Venturi or other type of insertion flow element. See RP 550, Part I, Section 1 for the recommended practices for such installations.

2.3 Control Systems

The function of the carbon monoxide steam generator control system is to provide a means of automatically or manually regulating the steam generating unit to burn completely the carbon monoxide gases under varying operating conditions and to maintain a safe, stable operation. The control scheme will depend on the operating conditions under which the unit must function. In selecting a system, consideration should be given to the following:

1. Variations in carbon monoxide gas flow to the converter.
2. Variations in sensible heat in the waste gases.
3. Abnormal conditions due to catalyst carryover and moisture entrainment.
4. Any condition that will cause a fast change in the Btu value of the carbon monoxide gases or supplementary fuel.
5. Function of the unit in the plant steam system.
6. Disturbances in the plant steam system during abnormal operations.
7. Disposal of waste gases during steam generator upset.

2.3.1 COMBUSTION

For the basic concepts to be considered in the design of a steam generator combustion control system, see Paragraph 1.4.1. The combustion control scheme is usually designed to accomplish one or more of the three basic CO converter functions in the following manner:

1. When used as an incinerator for the upstream processing unit. This operation requires the least complex control system. The normal practice is to base-load the supplemental fuel. Then, by measuring the quantities of supplemental fuel, compensating for the oxygen demand of the carbon monoxide gas, and measuring combustion air, the desired fuel/air ratio can be established by manipulating the air flow. Air flow may be regulated by either manually loading the positioner on the dampers of the forced draft fan or (as is often done) the dampers may be positioned automatically by the fuel/air ratio controller. The ratio may be adjusted manually or biased automatically from a flue gas oxygen analyzer. Usually the oxygen controller will include high and low limits to maintain the air within preset limits. See Figure 2-2.

A steam-flow/air-flow combustion control system is often used when the normal operation of the steam generator requires the burning of variable Btu fuels and variable amounts of carbon monoxide in waste gases. If the sensible heat input is relatively constant, the steam flow can be used as a measure of the Btu output from the steam generator. Thus, by manipulating the steam-flow/air-flow ratio controller, the desired fuel/air ratio can be established. The remainder of the system may be arranged the same as the fuel-flow/air-flow type of control. See Figure 2-3.

2. When the converter is used to burn waste gases while producing steam at a constant rate. The master control signal for this type of operation is usually from a flow controller in the steam output from the steam generator. When using this control scheme, care must be exercised to prevent pressure disturbances in the steam system. Otherwise it will be necessary to provide pressure compensation for the steam flow measurement. Sometimes a pressure controller is incorporated to override the flow controller in case the pressure gets out of preset limits. Normally the fuel/air ratio is automatically controlled, with the ratio adjusted manually or biased automatically from an oxygen analyzer in the flue gas. See Figure 2-2 for a typical system.

3. When used as a power steam generator burning carbon monoxide gases and supplementary fuel, regulated to maintain steam header pressure. In this case, the master control signal will originate with the steam header pressure controller. The remainder of the combustion control system may be the same as for the constant rate CO converter. See Figure 2-4 for a typical system.

2.3.2 FEEDWATER

For the basic concepts to be considered in the design of a steam generator feedwater control system, see Paragraph 1.3.2.

The drum level of a carbon monoxide converter is exposed to severe disturbances by the abnormal operation of the processing equipment furnishing the carbon monoxide gases. These disturbances can enter the converter as sizable carbon monoxide volume swings that represent large, input heat surges. Since there is seldom any means of control over such disturbances, careful consideration should be given during design to the total water holdup in the converter and to the drum volume. For a given steam production rate, the hot firebox unit (because of its large pumparound lines) will have a greater volume of water holdup than the waterwall type converter. Aside from the converter design considerations, the instrumentation for controlling drum level must be responsive to normal operating load changes. Usually a three-element feedwater control system is required. Since this system employs steam flow as a continuous load index, disturbances in the header should be minimized or the measurement should be compensated for pressure. Otherwise, pressure surges will appear as false load changes, resulting in reverse corrective action by the control system.

2.3.3 BLOWDOWN

For information concerning steam generator blowdown systems, see Paragraph 1.3.3.

2.3.4 AUXILIARY

2.3.4.1 Firebox Temperature Limits

Normally a CO converter is required to operate under varying operating conditions and steam demands. Therefore, under low steam loads, low firebox temperature limits are often provided. Sometimes the steam generator design or method of control will require a maximum temperature limit. These limits may be achieved by one of the following methods:

1. Minimum temperature is often provided by limiting the supplementary fuel control valve for minimum travel. Maximum travel may be limited for the high temperature limit. Consideration must be given to disposal of excess steam during low load conditions.

2. Some users provide a minimum burner pressure regulator around the control valve for the supplementary fuel. The regulator is preset to guarantee a stable, minimum flame at the burners or to maintain a minimum firebox temperature. In this case, consideration must be given to excess steam production under low steam demands.

3. A total steam flow controller is often used as an override to maintain a safe firebox temperature. The controller can be used as a maximum temperature limiter by overriding the controls to limit steam pro-

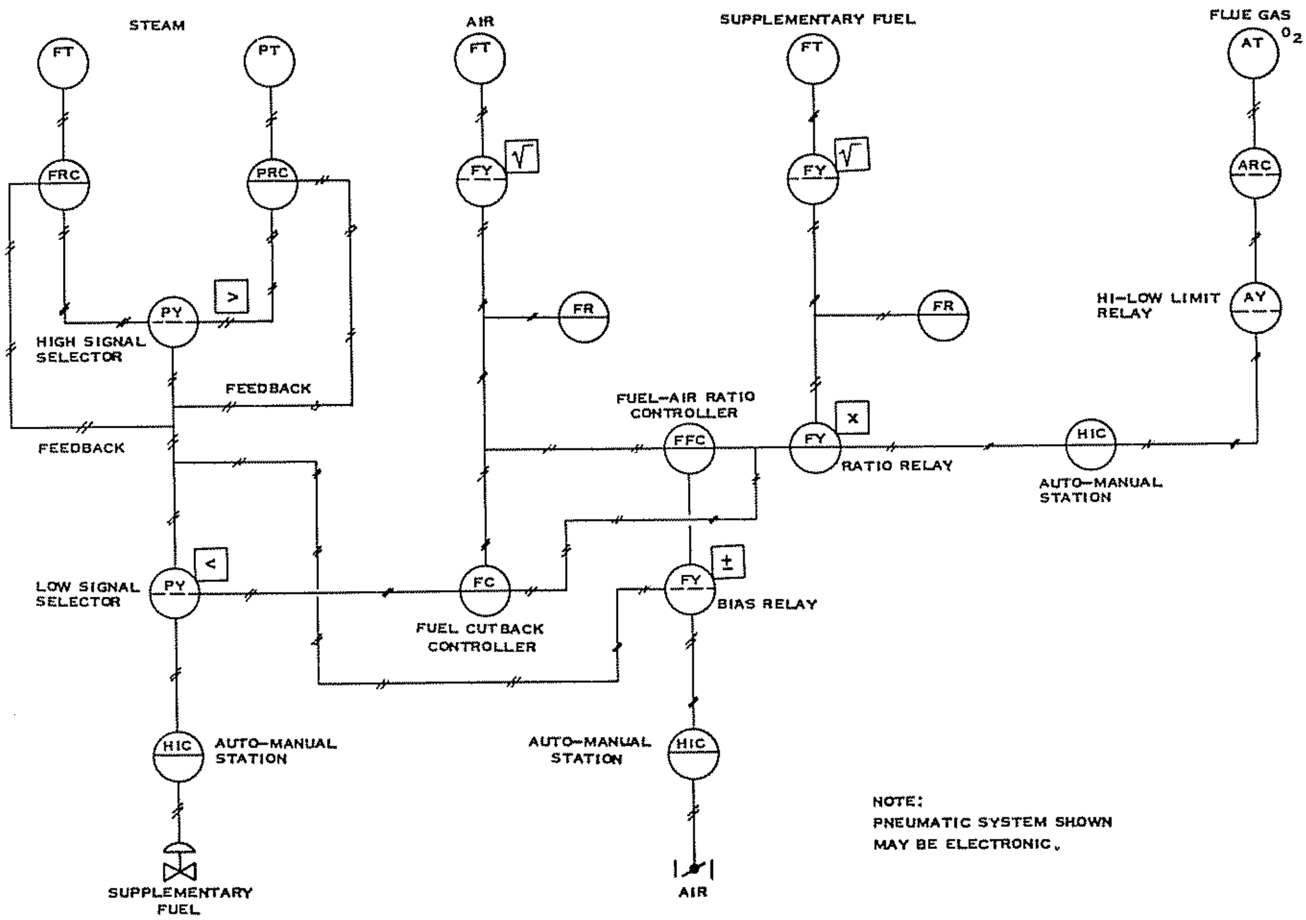


Figure 2-2—Constant Steam Flow with Low Pressure Override and Automatic Air Control

duction. It can also be used as a minimum temperature limiter by venting excess steam to other systems or to the atmosphere.

2.3.4.2 Forced Draft Fans

When two forced draft fans are provided, each may be capable of supplying the combustion air for the maximum load. In such cases, controls may be provided to automatically bring the spare into service in case of failure of the primary unit. These controls should also provide a means to temporarily reduce the supplementary fuel until the air flow is reestablished. This is often accomplished by installing an impulse relay in the control air line to the fuel control valve. It is good practice to also install a time delay device to shut off the supplementary fuel should the air flow fail to recover.

Flow of combustion air is normally controlled by modulating dampers. Shutoff dampers are also provided to minimize the hazard of back flow of the hot firebox gases when loss of forced draft occurs. Injection of steam or air into the duct between the dampers will furnish a seal against the hot gases and provide cooling for the equipment. When using a steam seal, care must be exercised to provide sufficient steam for a seal without overpressuring the equipment. If the converter utilizes an air blower in continuous operation for other purposes, seal air may be taken from the same system if pressure and volume permit. See Figure 2-5.

2.3.4.3 Admission and Removal of Carbon Monoxide

To permit independent operation of the CO steam generator and the waste gas system, several methods can be employed to bypass the carbon monoxide-rich gases to the stack. In cases where these gases are at high temperatures that could cause afterburning, consideration should be given to steam- or water-quenching to prevent damage to the stack or ductwork. Water seal tanks are frequently used to direct the waste gases to either the converter or to the stack. See Figure 2-6.

With this arrangement, two seal tanks are used to divert the gases by maintaining a water seal in the appropriate tank. A small, continuous overflow is normally used to maintain the seal level because this method will also prevent a buildup of dissolved gases in the water that would be quite corrosive. The rate of overflow is adjusted to hold the level and to keep the pH value of the water at not less than seven. On installations where the waste gases are above 700 degrees Fahrenheit, water sprays are sometimes installed in the top of the seal tanks.

A combination of both seal tanks and butterfly valves is sometimes used for diverting the waste gases. See Figure 2-7.

This arrangement has the advantage over seal tanks alone in that it minimizes shock to the steam generation equipment during admission or rejection of the gases to the steam generator. With this installation, the butterflies are used to introduce or remove the waste gases step by step.

Some installations use butterfly valves. Such an arrangement normally employs two control valves with one located in the stack and the other in the inlet duct to the steam generator. Hand loaders are commonly used to remotely position the valves.

2.3.4.4 Soot Blowers

Soot blowers are normally provided in the tube banks of waste gas converters to prolong onstream

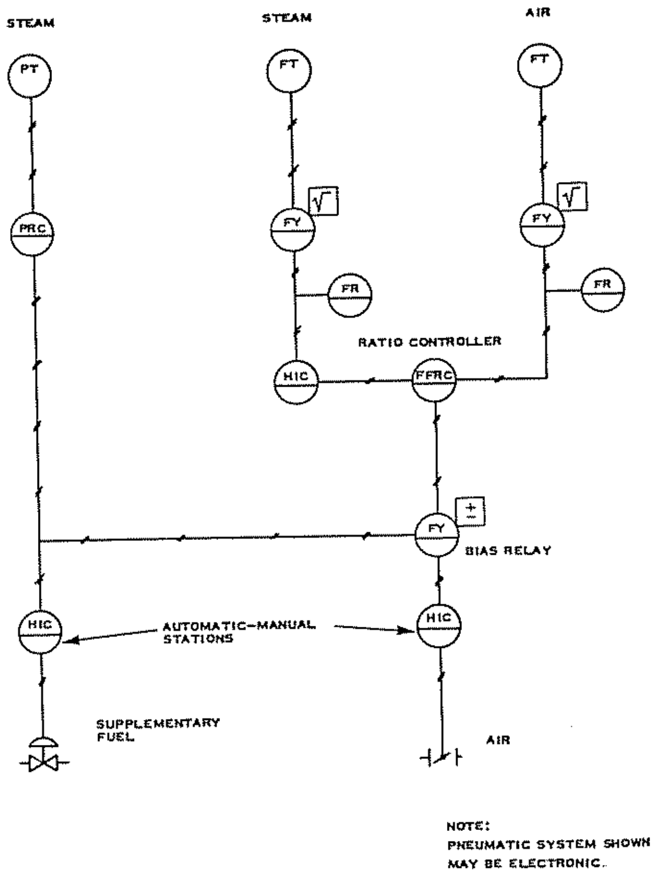


Figure 2-3—Steam Flow—Airflow

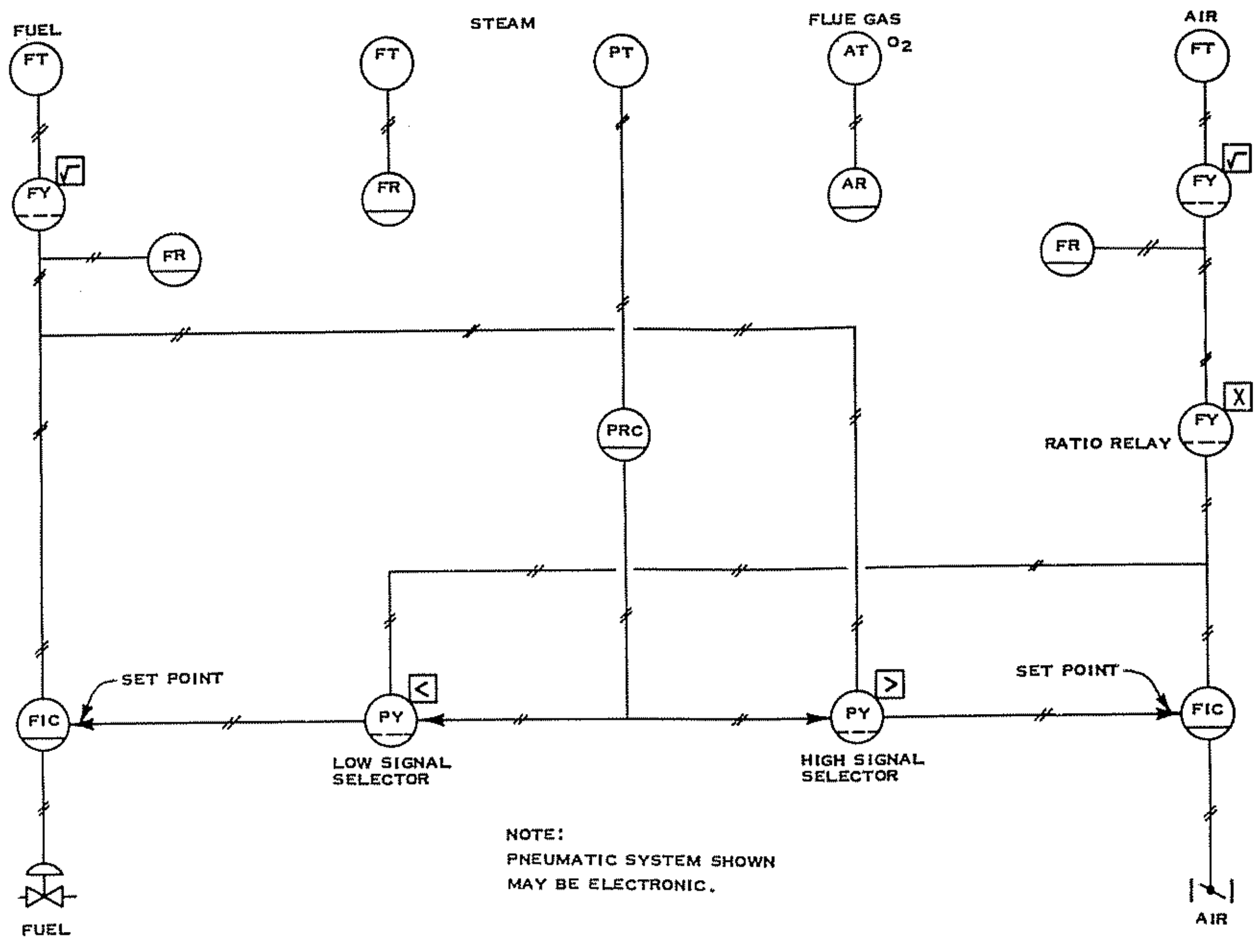


Figure 2-4—Steam Header Pressure Control

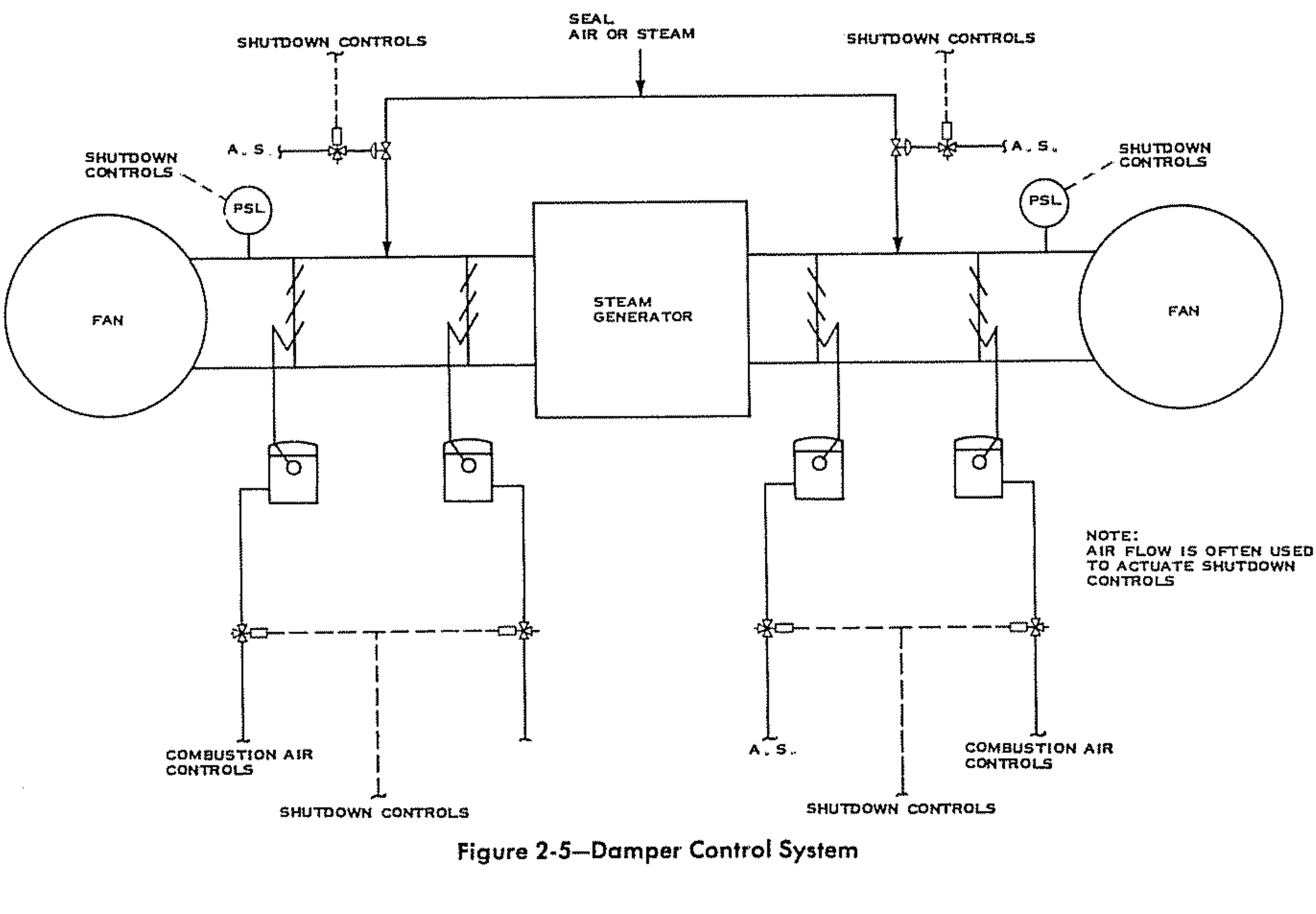


Figure 2-5—Damper Control System

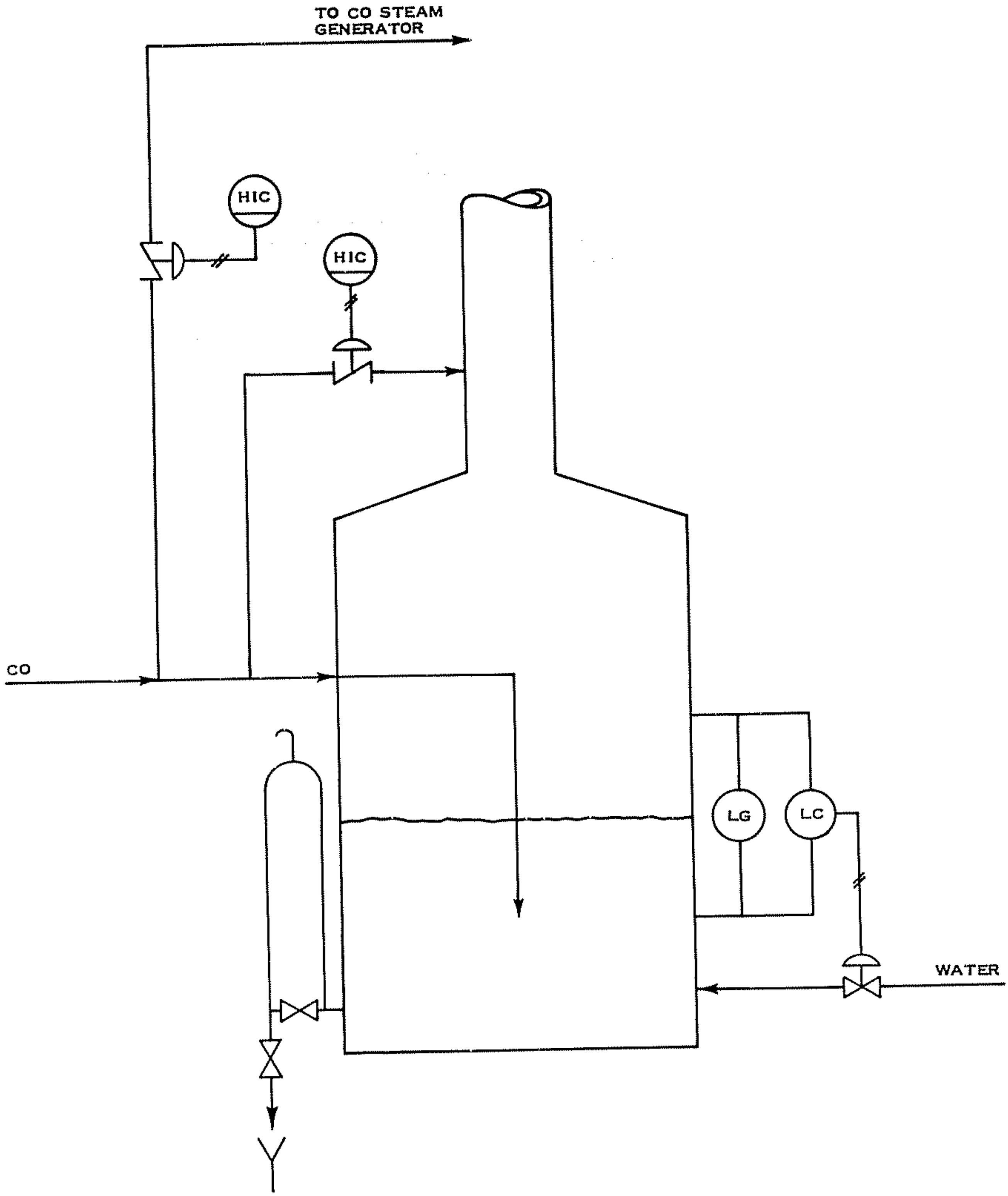


Figure 2-7—Water Seal Tank and Butterfly Valves

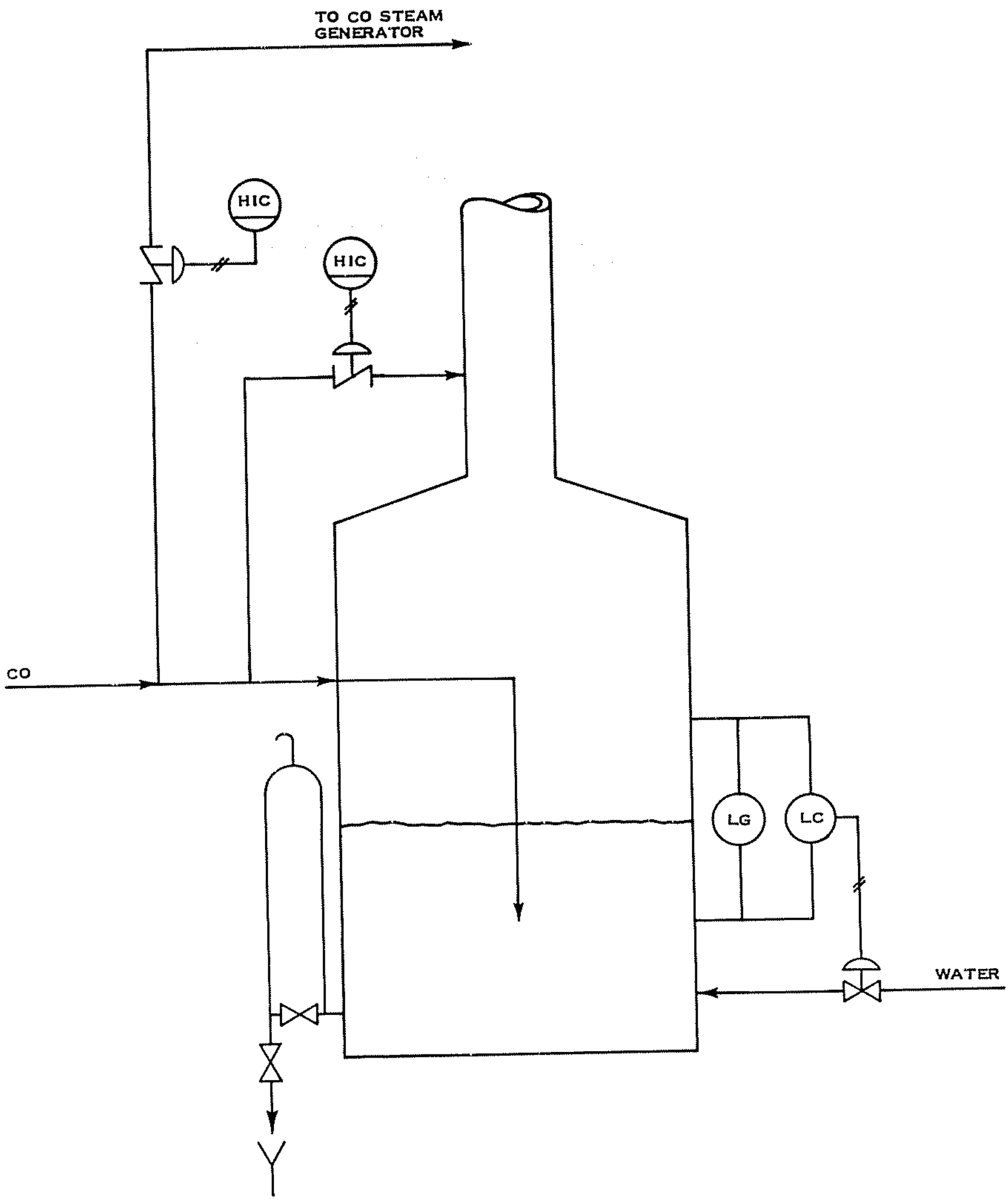


Figure 2-7—Water Seal Tank and Butterfly Valves

SECTION 3—GAS TURBINE EXHAUST FIRED STEAM GENERATORS

3.1 Scope

This section covers instrumentation and control information unique to steam generators that use the oxygen in a gas turbine exhaust for combustion. The gas turbine has found wide industrial application in driving compressors, pumps, and electric generators. Oftentimes they are integrated with steam generating facilities by utilizing their hot exhaust gases as combustion air. Such integrated packages are frequently referred to as combined cycle units.

A combined cycle unit is designed to recover the heat energy in the exhaust gases from a gas turbine. These gases are usually at 800 to 900 degrees Fahrenheit and contain from 17 to 18 percent oxygen, resulting from the excess air levels required to prevent overheating of the turbine blades. Thus they are ideally suited for use as the combustion air for a steam generator. Use of preheated air will speed up combustion at all steam generator loads, improve combustion at low loads, and increase overall efficiency. For each 100 degrees Fahrenheit rise in combustion air temperature, the steam generator efficiency will increase approximately two percent.

The steam generator-gas turbine package must satisfy process conditions and there are numerous design arrangements. In almost all cases, however, there will be an auxiliary source of combustion air with decoupling controls to permit independent operation of the steam generator and the gas turbine. This source of auxiliary air is usually a forced draft fan the discharge from which is regulated by control dampers. Proper bearing lubrication is of added significance on these dampers as they frequently remain closed for extended periods of time. The fan may be operated in one of three ways:

1. The fan may normally remain down and be placed on line only when needed.

2. The fan may operate continuously against closed dampers to be readily available when needed. In such cases, it is the usual practice to vent about ten percent of the discharge to keep the fan from overheating.

3. The fan may be used to supplement the combustion air requirements by using it as a trimmer. This type of operation is necessary on combined cycle units that have an insufficient quantity of turbine exhaust gases to satisfy the steam generator design requirements.

3.2 Measurements

The measurements required for a combined cycle unit will vary with the conditions under which it is operated. Normally, they are the same as for conventional steam generators, plus those for decoupling and system integration. See Paragraph 1.2.

Characteristic measurements include the following:

1. Flue Gas Oxygen Content

To permit compensation for differences in available oxygen between turbine exhaust and fresh air, a reliable measurement of oxygen in the steam generator flue gas is usually required. Minimum excess oxygen requirements for combined cycle units will be the same as for other fired steam generators, although higher maximums are generally acceptable. The flue gas oxygen content is commonly measured by a continuous oxygen analyzer that may be adapted to indicate, record, control, alarm, or any combination as required by the user. See RP 550, Part II, Section 19 for installation practices.

2. Combustion Air Flow

In addition to being required for most combustion control systems, the measurement of air flow rate in a combined cycle unit provides operator guidance when manually switching between fresh air and turbine exhaust. Several common methods of obtaining this measurement are given in Paragraph 1.2.14.

3. Air Duct Pressure

Pressure in the combustion air duct is frequently measured to enable the operator to guard against excessive back pressure against the turbine and overpressure in the ductwork. For pressure measurement installation practices, see RP 550, Part I, Section 4.

3.3 Control Systems

As the steam generator portion of a combined cycle unit is usually of conventional design, the control information given in Paragraph 1.4 is generally applicable. However, the use of turbine exhaust for preheated combustion air often adds to the control system complexity. Depending on the function of the steam generator in the process scheme, the control system may provide automatic or remote-manual switching to fresh air for continuity of operation. In addition, the combustion air signal to the firing controls is often compensated automatically in order to correct for differences in available oxygen and Btu content of the two air sources. See Figure 3-1. Although the number of gas turbines and steam generators in a combined cycle unit may vary, the control systems discussed in this section for a single turbine–single steam generator package may be expanded to satisfy other arrangements. For a typical arrangement, see Figure 3-2.

3.3.1 DECOUPLING CONTROLS

It is imperative that careful consideration be given to the function of the steam generator in the process scheme when designing the decoupling control system. When the gas turbine trips, the switch to auxiliary air should be made smoothly and safely, with particular attention given to see that the fires in the steam generator are not extinguished by sudden air surges.

Decoupling is complicated by dynamic changes that occur at the time the air switch is made. First, replacement of hot air with cold air affects the instantaneous heat transfer rate in the steam generator. Thus there is at least a momentary sag in steam production. Second, the steam load may change, either up or down, on loss of the gas turbine. These two factors impose severe dynamic requirements on the decoupling control system.

Operation of the decoupling controls is normally initiated by any one of the various shutdown devices on the gas turbine. When actuated, the system should respond to automatically place the forced draft fan on line. As there are time lags involved that depend upon the normal operating status of the fan and damper positions, the switch is usually accompanied by a dip in air flow. Therefore, to maintain safe combustion conditions, the control system shown in Figure 1-9 and discussed in Paragraph 1.3.1, 4 is required. It is also good practice to install a time delay device

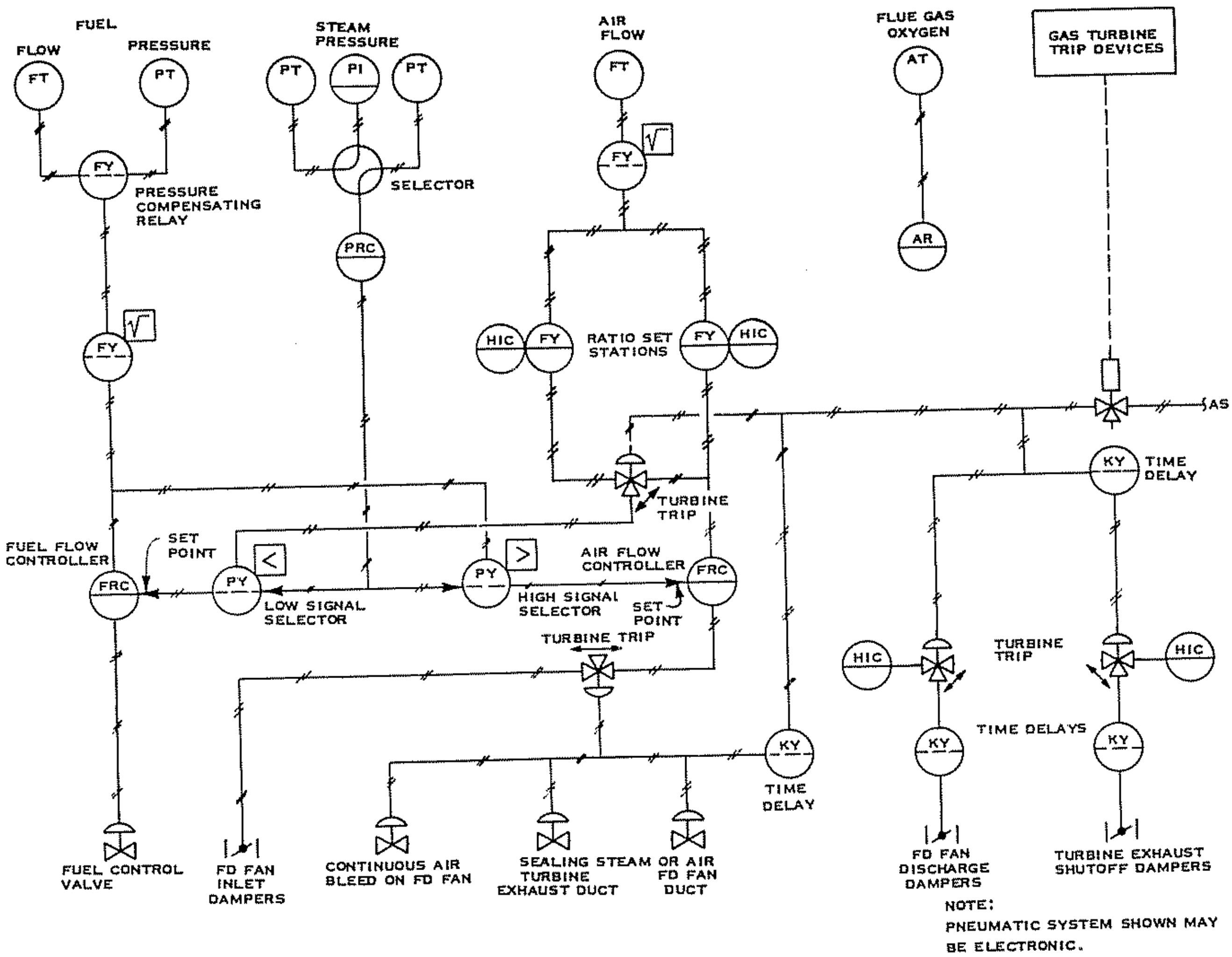


Figure 3-1—Gas Turbine Exhaust Fired Steam Generator

to shut off the fuel should the air flow fail to recover. A typical decoupling control system is shown in Figure 3-1.

3.3.2 COUPLING CONTROLS

Switching of steam generator combustion from fresh air to gas turbine exhaust is usually an operator function. Equipment is normally provided for remote-manual operation.

3.3.3 TURBINE EXHAUST BYPASS CONTROL

To permit operation of the gas turbine when the steam generator is down, dampers are usually installed in the air duct to bypass the turbine exhaust to a vent stack. Normally these dampers are actuated by a pressure controller in the duct so that the system also functions to prevent excessive back pressure against the turbine and to protect the ductwork against damage from overpressure.

For added safety, some users limit the maximum permissible duct pressure by the use of a liquid seal in the bottom of the stack. See Figure 2-7.

3.4 Protective Instrumentation

3.4.1 ALARMS

For general information concerning steam generator alarm systems, see Paragraph 1.4.1.

Additional alarms often provided for a combined cycle unit are:

1. Gas turbine tripout.
2. High exhaust gas temperature.
3. Low exhaust gas pressure.
4. High exhaust gas pressure.
5. Forced draft fan failure.
6. Low combustion air flow.
7. Low oxygen in steam generator flue gas.

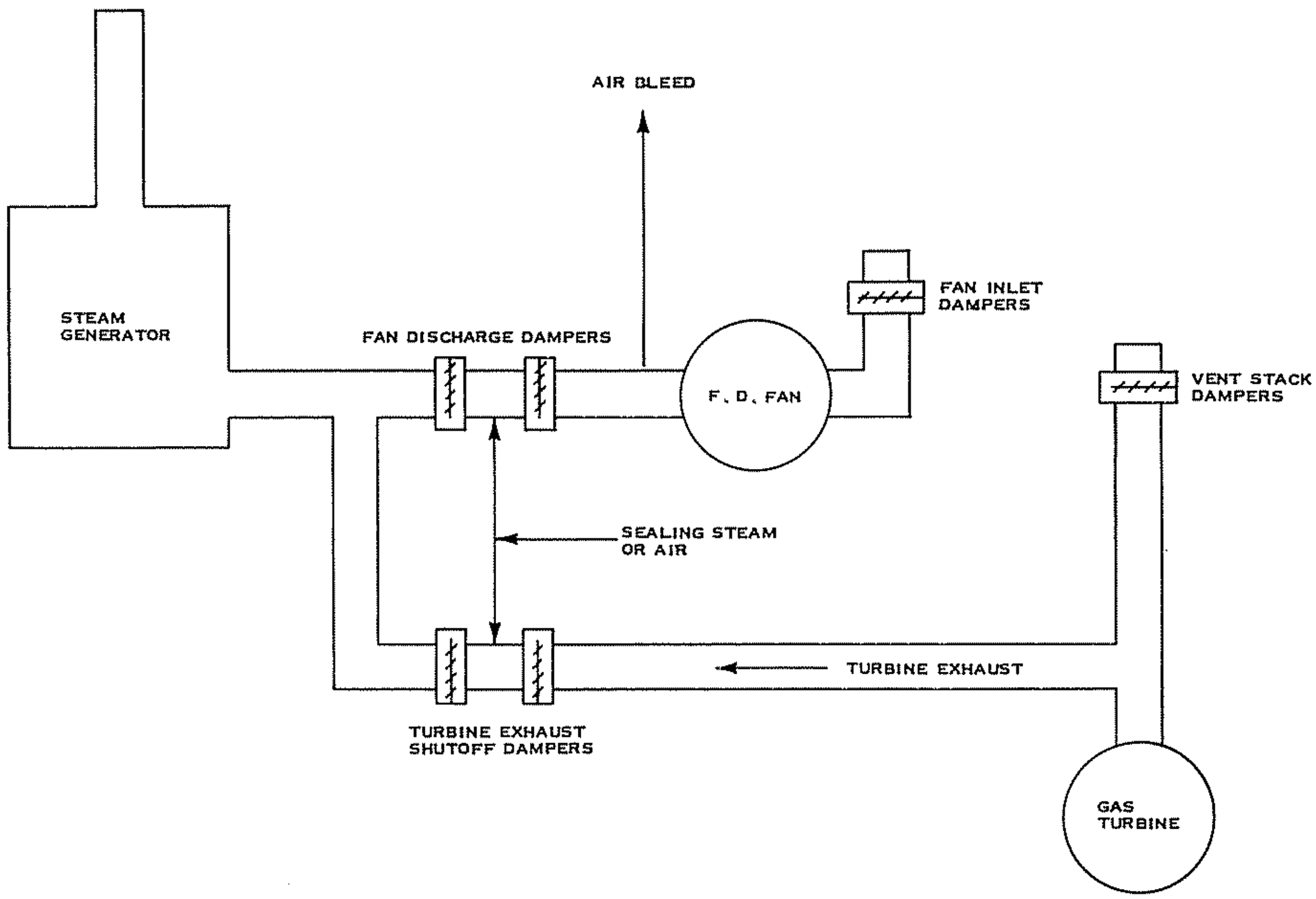


Figure 3-2—Typical Combined Cycle Unit

3.4.2 SHUTDOWN DEVICES

For general information concerning steam generator shutdown devices, see Paragraph 1.4.2.

Shutdown systems often required, and unique to combined cycle units, are those that:

1. Provide a means for uninterrupted turbine operation in case of emergency shutdown of the steam generator. See Figure 3-2.

2. Provide a system for uninterrupted steam generator operation when switching from gas-fired turbine exhaust to fresh air for combustion. The system is normally integrated with the turbine shutdown system. See Figure 3-1.

3. Provide a means for injection of sealing air or steam into ductwork between the dampers when forced draft fans are shut down. See Figure 3-1.

SECTION 4—UNFIRED WASTE HEAT STEAM GENERATORS

4.1 Scope

This section covers instrumentation and control information for steam generators that are designed to utilize the waste heat in process streams or in exhaust gases from turbines, furnaces, catalyst regenerators, or similar equipment.

A waste heat steam generator is normally used to cool process streams or waste gases, while producing steam as a byproduct. As there are numerous arrangements of such generators, each installation must be custom designed to satisfy process requirements. Generator design, however, will depend upon the chemical nature of the waste gases, their temperature, pressure, and cleanliness, and on the degree of cooling desired.

4.2 Measurements

Since there is normally no control over the heat input to waste heat steam generators, few measurements are required. Usual measurements are:

1. Total steam production. For flow meter installation practices, see RP 550, Part I, Section 2.

2. Drum level. For level measurement installation practices, see RP 550, Part I, Section 2.

3. Heating medium or process temperature. For temperature measurement practices, see RP 550, Part I, Section 3.

Depending upon individual requirements and arrangements, other measurements may be necessary to assure stable operation of either the process or steam system. See Paragraph 1.2.

4.3 Control Systems

Other than controls to assure an adequate supply of properly treated feedwater, the only controls usually employed on waste heat steam generators are those for drum level. Additional controls are sometimes provided to satisfy process requirements.

4.3.1 DRUM LEVEL

For the basic concepts to be considered in the design of a steam generator feedwater control system, see Paragraph 1.3.2.

The drum level of a waste heat steam generator is exposed to disturbances from both the process and the steam header. If the magnitude and the frequency of these disturbances are such that steam quality can be maintained, a simple level controller may be sufficient if feedwater pressure is constant. However, as there is seldom any means to control steam production, the drum level control of waste heat steam generators is often very difficult. Usually a two- or three-element feedwater control system is required. In selecting the level control scheme for any given installation, careful consideration should be given to the following:

1. Steam rate or quality variations (steam header disturbances).

2. Input heat surges (process disturbances).

3. Drum size.

4. Requirements for operator attention.

5. ASME regulations.

4.3.2 HEAT INPUT

There is usually no control over the heat input to a waste heat steam generator. Controls are sometimes provided, however, when it is desired to either control the heating medium temperature from the generator or to control steam production. Systems for controlling the heat input depend upon steam or process requirements and the complexity of the steam generating equipment. Normally, control is achieved by bypassing a controlled portion of the heating medium around the waste heat steam generator. A typical heating medium temperature control system is shown in Figure 4-1.

4.3.3 STEAM TEMPERATURE

On waste heat steam generators that are followed by superheater sections, it is often necessary to control the steam temperature. Usually this is achieved by introducing a controlled amount of saturated steam or condensate into the superheater outlet to maintain the desired superheat temperature to the main header.

4.3.4 PRESSURE

The waste heat steam generator pressure is usually maintained by the steam system into which it produces. However, the steam drum is sometimes operated at a higher pressure to produce superheated steam into the system. In such cases, a simple back pressure control is normally provided.

4.3.5 BLOWDOWN

Blowdown is usually manual. See Paragraph 1.3.3.

4.4 Protective Instrumentation—Alarms

Usually, the only alarms provided on waste heat steam generators are those for high and low drum level. However, depending upon the complexity of the waste heat system, other alarms are sometimes provided to alert the operator to abnormal conditions. The more common ones include:

1. Flow alarms on recirculating systems.
2. High temperature alarms on superheated steam.
3. Leakage between heat exchange streams.

For general information concerning steam generator alarm systems, see Paragraph 1.4.1.

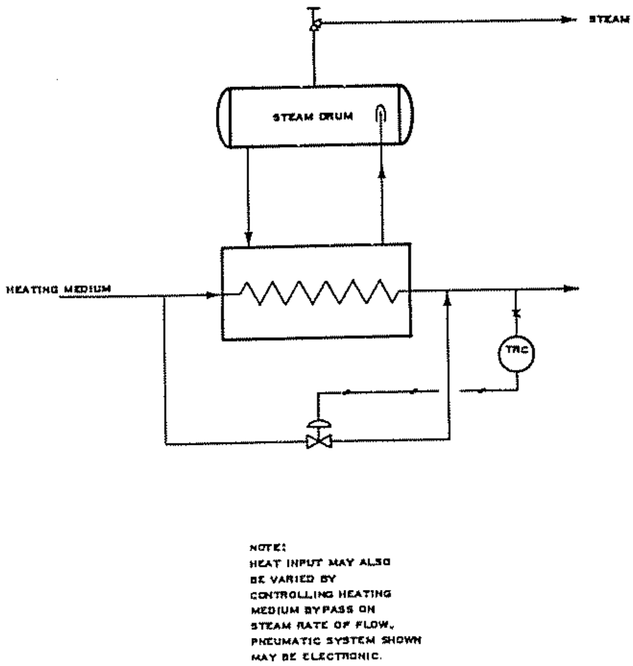


Figure 4-1—Heating Medium Temperature Control System