

TECHNICAL MANUAL

ELECTRIC POWER PLANT DESIGN

HEADQUARTERS, DEPARTMENT OF THE ARMY
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CHAPTER 1

INTRODUCTION

1-1. Purpose

a. General: This manual provides engineering data and criteria for designing electric power plants where the size and characteristics of the electric power load and the economics of the particular facility justify on-site generation. Maximum size of plant considered in this manual is 30,000 kW.

b. References: A list of references used in this manual is contained in Appendix A. Additionally, a Bibliography is included identifying sources of material related to this document.

1-2. Design philosophy

a. General. Electric power plants fall into several categories and classes depending on the type of prime mover. Table 1-1 provides a general description of plant type and related capacity requirements. For purposes of this introduction Table 1-2 defines, in more detail, the diesel plant classes and operational characteristics; additional information is provided in Chapter 7. No similar categories have been developed for gas turbines. Finally, for purposes of this manual and to provide a quick scale for the plants under review here, several categories have been developed. These are shown in Table 1-3.

b. Reliability. Plant reliability standards will be equivalent to a 1-day generation forced outage in 10 years with equipment quality and redundancy selected during plant design to conform to this standard.

c. Maintenance. Power plant arrangement will permit reasonable access for operation and maintenance of equipment. Careful attention will be given to the arrangement of equipment, valves, mechanical specialties, and electrical devices so that rotors, tube bundles, inner valves, top works, strainers, contractors, relays, and like items can be maintained or replaced. Adequate platforms, stairs, handrails, and kickplates will be provided so that operators and maintenance personnel can function conveniently and safely.

d. Future expansion. The specific site selected for the power plant and the physical arrangement of the plant equipment, building, and support facilities such as coal and ash handling systems, coal storage, circulating water system, trackage, and access roads will be arranged insofar as practicable to allow for future expansion.

1-3. Design criteria

a. General requirements. The design will provide for a power plant which has the capacity to provide the quantity and type of electric power, steam and compressed air required. Many of the requirements discussed here are not applicable to each of the plant categories of Table 1-1. A general overview is provided in Table 1-4.

b. Electric power loads. The following information, as applicable, is required for design:

(1) Forecast of annual diversified peak load to be served by the project.

(2) Typical seasonal and daily load curves and load duration curves of the load to be served. Example curves are shown in Figures 1-1 and 1-2.

(3) If the plant is to operate interconnected with the local utility company, the designer will need information such as capacity, rates, metering, and interface switchgear requirements.

(4) If the plant is to operate in parallel with existing generation on the base, the designer will also need:

(a) An inventory of major existing generation equipment giving principal characteristics such as capacities, voltages, steam characteristics, back pressures, and like parameters.

(b) Incremental heat rates of existing boiler-turbine units, diesel generators, and combustion turbine generator units.

(c) Historical operating data for each existing generating unit giving energy generated, fuel consumption, steam exported, and other related information.

(5) Existing or recommended distribution voltage, generator voltage, and interconnecting substation voltages.

(6) If any of the above data as required for performing the detailed design is unavailable, the designer will develop this data.

c. Exports team loads.

(1) *General requirements.* If the plant will export steam, information similar to that required for electric power, as outlined in subparagraph c above, will be needed by the designer.

(2) *Coordination of steam and electric power loads.* To the greatest extent possible, peak, seasonal, and daily loads for steam will be coordinated with the electric power loads according to time of use.

Table 1-1. General Description of Type of Plant.

Category	Capacity	TYPE OF POWER	
		No Export Steam	With Export Steam
Primary	Adequate to meet all peacetime requirement.	<p>Purchased electric power to match electric load.</p> <p>Continuous duty diesel plant, Class "A" diesel.</p> <p>Straight condensing boilers and turbines matched in capacity as units; enough units so plant without largest unit can carry emergency load.</p>	<p>Purchased electric power and steam to match electric load plus supplementary boiler plant to match export steam load.</p> <p>Automatic back pressure steam plant plus automatic packaged firetube boiler to supplement requirements of export steam load.</p> <p>Automatic extraction steam plant boilers and turbines matched in capacity se units and enough units installed so that plant without largest unit can carry emergency load.</p>
Standby	<p>Adequate with prime source to match mobilization needs; or alone to supply emergency electric load and export steam load in case of primary source out age.</p> <p>Equal to primary source</p>	<p>Purchased electric power.</p> <p>Standby diesel plant, Class "B" diesel.</p> <p>Retired straight condensing plant.</p>	<p>Purchased electric power and steam to match electric power load plus supplementary boiler plant.</p> <p>Standby diesel plant with supplementary boiler plant.</p> <p>Retired automatic extraction steam plant.</p>
Emergency	To supply that part of emergency load that cannot be interrupted for more than 4 hours.	<p>Fixed emergency diesel plant, Class "C" diesel.</p> <p>Mobile utilities support equipment.</p>	<p>None.</p> <p>None.</p>

Table 1-2. Diesel Class and Operational Characteristics.

Class	Usage	Full Load Rating		Expected Operating Hours	
		Capability		Annually	First Ten Years
		Minimum Hours	Operating Period		
"A"	Continuous	8,000	Yearly	4,000 hours plus	40,000 hours plus
"B"	Standby	8,000	Yearly	1,000 to 4,000 hours	20,000 to 40,000 hours
"c"	Emergency	650	Monthly*	Under 1,000 hours	Under 10,000 hours

*Based on a 30-day month.

U.S. Army Corps of Engineers

Table-3. Plant Sizes.

Category	Size
Small	0 to 2,500 kW
Medium	2,500 kW to 10,000 kW
Large	10,000 kW to 30,000 kW

U.S. Army Corps of Engineers

Table-4. Design Criteria Requirements.

Class (Plant Category)	Electric Power Loads	Export St earn Loads	Fuel Source and Cost	Water Supply	Stack Emission	Waste Disposal
A (Primary)	A	A	A	A	A	A
B (Standby)	A	N/A	A	N/A	N/A	A
C (Emergency)	critical loads only	N/A	A	N/A	N/A	N/A

A= Applicable
 N/A = Not Applicable

Courtesy of Pope, Evans and Robbins (Non-Copyrighted)

This type of information is particularly important if the project involves cogeneration with the simultaneous production of electric power and steam.

d. Fuel source, and cost. The type, availability, and cost of fuel will be determined in the early stages of design; taking into account regulatory requirements that may affect fuel and fuel characteristics of the plant.

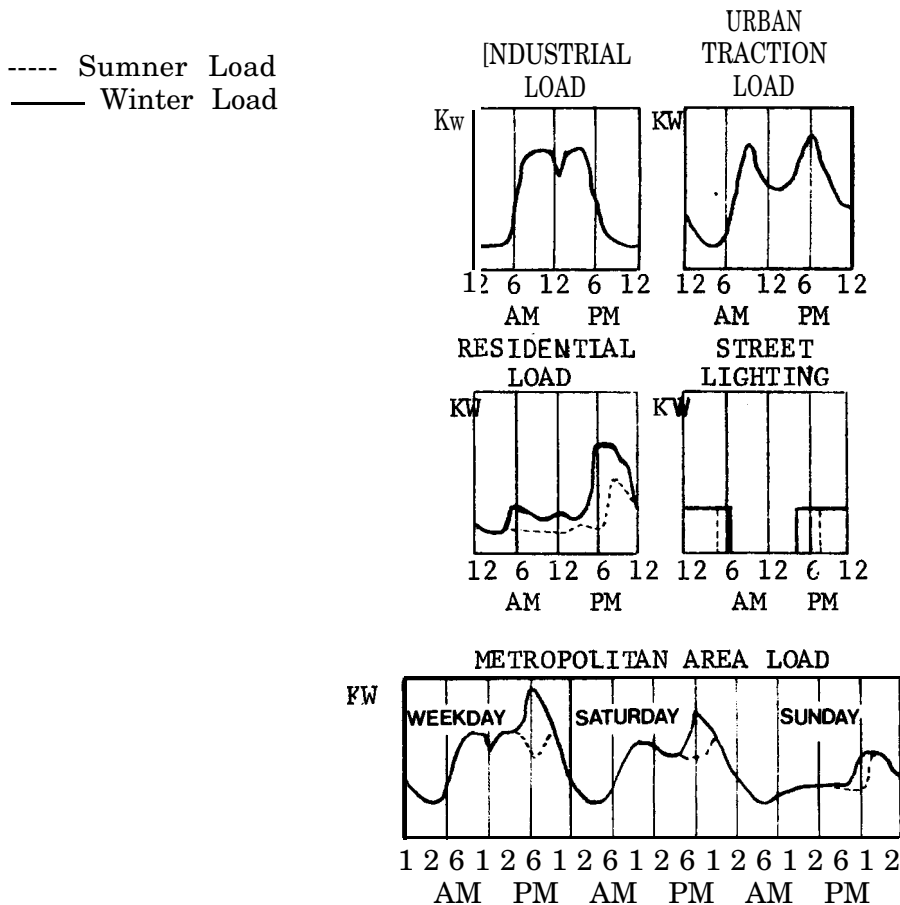
e. Water supply. Fresh water is required for thermal cycle makeup and for cooling tower or cooling pond makeup where once through water for heat rejection is unavailable or not usable because of regulatory constraints. Quantity of makeup will vary with the type of thermal cycle, amount of condensate return for any export steam, and the maximum heat rejection from the cycle. This heat rejection load usually will comprise the largest part of the makeup and will have the least stringent requirements for quality.

f. Stack emissions. A steam electric power plant

will be designed for the type of stack gas cleanup equipment which meets federal, state, and municipal emission requirements. For a solid fuel fired boiler, this will involve an electrostatic precipitator or bag house for particulate, and a scrubber for sulfur compounds unless fluidized bed combustion or compliance coal is employed. If design is based on compliance coal, the design will include space and other required provision for the installation of scrubber equipment. Boiler design will be specified as required for NO_x control.

g. Waste disposal.

(1) *Internal combustion plants.* Solid and liquid wastes from a diesel or combustion turbine generating station will be disposed of as follows: Miscellaneous oily wastes from storage tank areas and sumps will be directed to an API separator. Supplementary treating can be utilized if necessary to meet the applicable requirements for waste water discharge. For plants of size less than 1,000 kW, liquid



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Figure 1-1. Typical metropolitan area load curves.

oily wastes will be accumulated in sumps or small tanks for removal. Residues from filters and centrifuges will be similarly handled.

(2) *Steam electric stations.* For steam electric generating stations utilizing solid fuel, both solid and liquid wastes will be handled and disposed of in an environmentally acceptable manner. The wastes can be categorized generally as follows:

(a) *Solid wastes.* These include both bottom ash and fly ash from boilers.

(b) *Liquid wastes.* These include boiler blow-down, cooling tower blowdown, acid and caustic water treating wastes, coal pile runoff, and various contaminated wastes from chemical storage areas, sanitary sewage and yard areas.

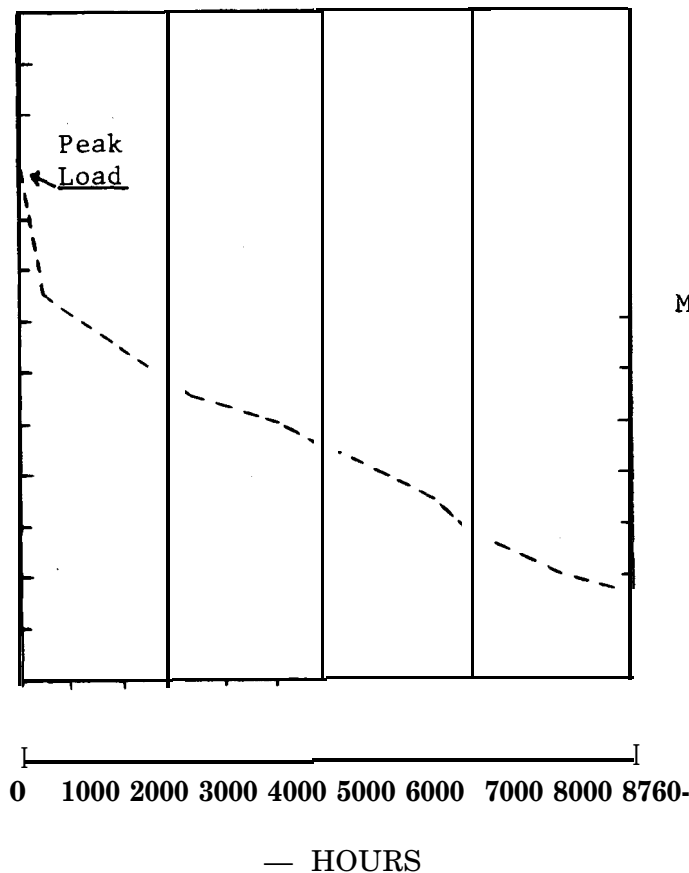
(h) *Other environmental considerations.* Other environmental considerations include noise control and aesthetic treatment of the project. The final location of the project within the site area will be reviewed in relation to its proximity to hospital and office areas and the civilian neighborhood, if applicable. Also, the general architectural design will be reviewed in terms of coordination and blending with

the style of surrounding buildings. Any anticipated noise or aesthetics problem will be resolved prior to the time that final site selection is approved.

1-4. Economic considerations

a. The selection of one particular type of design for a given application, when two or more types of design are known to be feasible, will be based on the results of an economic study in accordance with the requirements of DOD 4270.1-M and the National Energy Conservation Policy Act (Public Law 95-619, 9 Nov 1978).

b. Standards for economic studies are contained in AR 11-28 and AFR 178-1, respectively. Additional standards for design applications dealing with energy/fuel consuming elements of a facility are contained in the US Code of Federal Regulations, 20 CFR 436A. Clarification of the basic standards and guidelines for a particular application and supplementary standards which may be required for special cases may be obtained through normal channels from HQDA (DAEN-ECE-D), WASH DC 20314.



U.S. Army Corps of Engineers

Figure 1-2. Typical annual load duration curve.

CHAPTER 2

SITE AND CIVIL FACILITIES DESIGN

Section 1. SITE SELECTION

2-1. Introduction

Since the selection of a plant site has a significant influence on the design, construction and operating costs of a power plant, each potential plant site will be evaluated to determine which is the most economically feasible for the type of power plant being considered.

2-2. Environmental considerations

a. Rules and regulations. All power plant design, regardless of the type of power plant, must be in accordance with the rules and regulations which have been established by Federal, state and local governmental bodies.

b. Extraordinary design features. To meet various environmental regulations, it is often necessary to utilize design features that will greatly increase the cost of the power plant without increasing its efficiency. For example, the cost of the pollution control equipment that will be required for each site under consideration is one such item which must be carefully evaluated.

2-3. Water supply

a. General requirements. Water supply will be adequate to meet present and future plant requirements. The supply maybe available from a local municipal or privately owned system, or it may be necessary to utilize surface or subsurface sources.

b. Quality. Water quality and type of treatment required will be compatible with the type of power plant to be built.

c. Water rights. If water rights are required, it will be necessary to insure that an agreement for water rights provides sufficient quantity for present and future use.

d. Water wells. If the makeup to the closed system is from water wells, a study to determine water table information and well drawdown will be required. If this information is not available, test well studies must be made.

e. Once-through system. If the plant has a once through cooling system, the following will be determined:

(1) The limitations established by the appropriate regulatory bodies which must be met to ob-

tain a permit required to discharge heated water to the source.

(2) Maximum allowable temperature rise permissible as compared to system design parameters. If system design temperature rise exceeds permissible rise, a supplemental cooling system (cooling tower or spray pond) must be incorporated into the design.

(3) Maximum allowable temperature for river or lake after mixing of cooling system effluent with source. If mixed temperature is higher than allowable temperature, a supplemental cooling system must be added. It is possible to meet the conditions of (2) above and not meet the conditions in this subparagraph.

(4) If extensive or repetitive dredging of waterway will be necessary for plant operations.

(5) The historical maximum and minimum water level and flow readings. Check to see that adequate water supply is available at minimum flow and if site will flood at high level.

2-4. Fuel supply

Site selection will take into consideration fuel storage and the ingress and egress of fuel delivery equipment.

2-5. Physical characteristics

Selection of the site will be based on the availability of usable land for the plant, including yard structures, fuel handling facilities, and any future expansion. Other considerations that will be taken into account in site selection are:

- Soil information.
- Site drainage.
- Wind data.
- Seismic zone.
- Ingress and egress.

For economic purposes and operational efficiency, the plant site will be located as close to the load center as environmental conditions permit.

2-6. Economics

Where the choice of several sites exists, the final selection will be based on economics and engineering studies.

Section II. CIVIL FACILITIES, BUILDINGS, SAFETY, AND SECURITY

2-7. Soils investigation

An analysis of existing soils conditions will be made to determine the proper type of foundation. Soils data will include elevation of each boring, water table level, description of soil strata including the group symbol based on the Unified Soil Classification System, and penetration data (blow count). The soils report will include recommendations as to type of foundations for various purposes; excavation, dewatering and fill procedures; and suitability of on-site material for fill and earthen dikes including data on soft and organic materials, rock and other pertinent information as applicable.

2-8. Site development

a. Grading and drainage.

(1) *Basic criteria.* Determination of final grading and drainage scheme for a new power plant will be based on a number of considerations including size of property in relationship to the size of plant facilities, desirable location on site, and plant access based on topography. If the power plant is part of an overall complex, the grading and drainage will be compatible and integrated with the rest of the complex. To minimize cut and fill, plant facilities will be located on high ground and storm water drainage will be directed away from the plant. Assuming on site soils are suitable, grading should be based on balanced cut and fill volume to avoid hauling of excess fill material to offsite disposal and replacement with expensive new material.

(2) *Drainage.* Storm water drainage will be evaluated based on rainfall intensities, runoff characteristics of soil, facilities for receiving storm water discharge, and local regulations. Storm water drains or systems will not be integrated with sanitary drains and other contaminated water drainage systems.

(3) *Erosion prevention.* All graded areas will be stabilized to control erosion by designing shallow slopes to the greatest extent possible and by means of soil stabilization such as seeding, sod, stone, rip-rap and retaining walls.

b. Roadways.

(1) *Basic roadway requirements.* Layout of plant roadways will be based on volume and type of traffic, speed, and traffic patterns. Type of traffic or vehicle functions for power plants can be categorized as follows:

- Passenger cars for plant personnel.
- Passenger cars for visitors.
- Trucks for maintenance material deliveries.
- Trucks for fuel supply.

-Trucks for removal of ash, sludge and other waste materials.

(2) *Roadway material and width.* Aside from temporary construction roads, the last two categories described above will govern most roadway design, particularly if the plant is coal fired. Roadway material and thickness will be based on economic evaluations of feasible alternatives. Vehicular parking for plant personnel and visitors will be located in areas that will not interfere with the safe operation of the plant. Turning radii will be adequate to handle all vehicle categories. Refer to TM 5-803-5/NAVPAC P-960/AFM 88-43; TM 5-818-2/AFM 88-6, Chap. 4; TM 5-822-2/AFM 88-7, Chap. 7; TM 5-822-4/AFM 88-7, Chap. 4; TM 5-822-5/AFM 88-7, Chap. 3; TM 5-822-6/AFM 88-7, Chap. 1; TM 5-822-7/AFM 88-6, Chap. 8; and TM 5-822-8.

c. *Railroads.* If a railroad spur is selected to handle fuel supplies and material and equipment deliveries during construction or plant expansion, the design will be in accordance with American Railway Engineering Association standards. If coal is the fuel, spur layout will accommodate coal handling facilities including a storage track for empty cars. If liquid fuel is to be handled, unloading pumps and steam connections for tank car heaters may be required in frigid climates.

2-9. Buildings

a. Size and arrangement.

(1) *Steam plant.* Main building size and arrangement depend on the selected plant equipment and facilities including whether steam generators are indoor or outdoor type; coal bunker or silo arrangement; source of cooling water supply relative to the plant; the relationship of the switchyard to the plant; provisions for future expansion; and , aesthetic and environmental considerations. Generally, the main building will consist of a turbine bay with traveling crane; an auxiliary bay for feedwater heaters, pumps, and switchgear; a steam generator bay (or firing aisle for semi-outdoor units); and general spaces as may be required for machine shop, locker room, laboratory and office facilities. The general spaces will be located in an area that will not interfere with future plant expansion and isolated from main plant facilities to control noise. For very mild climates the turbine generator sets and steam generators may be outdoor type (in a weather protected, walk-in enclosure) although this arrangement presents special maintenance problems. If incorporated, the elevator will have access to the high-

est operating level of the steam generator (drum levels).

(2) *Diesel plant.* The requirements for a building housing a diesel generator plant are the same as for a steam turbine plant except that a steam generator bay is not required.

b. Architectural treatment.

(1) The architectural treatment will be developed to harmonize with the site conditions, both natural and manmade. Depending on location, the environmental compatibility may be the determining factor. In other cases the climate or user preference, tempered with aesthetic and economic factors, will dictate architectural treatment. Climate is a controlling factor in whether or not a total or partial closure is selected. Semi-outdoor construction with the bulk of the steam generator not enclosed in a boiler room is an acceptable design.

(2) For special circumstances, such as areas where extended periods of very high humidity, frequently combined with desert conditions giving rise to heavy dust and sand blasting action, indoor construction with pressurized ventilation will be required not only for the main building but also, generally, for the switchyard. Gas enclosed switchyard installations may be considered for such circumstances in lieu of that required above.

(3) Control rooms, offices, locker rooms, and some out-buildings will be enclosed regardless of enclosure selected for main building. Circulating water pumps may be installed in the open, except in the most severe climates. For semi-outdoor or outdoor stations, enclosures for switchgear and motor controls for the auxiliary power system will be enclosed in manufacturer supplied walk-in metal housings or site fabricated closures.

c. Structural design.

(1) *Building framing and turbine pedestals.* Thermal stations will be designed utilizing conventional structural steel for the main power station building and support of boiler. The pedestal for supporting the turbine generator (and turbine driven boiler feed pump if utilized) will be of reinforced concrete. Reinforced concrete on masonry construction may be used for the building framing (*not* for boiler framing); special concrete inserts or other provision must be made in such event for support of piping, trays and conduits. An economic evaluation will be made of these alternatives.

(2) *Exterior walls.* The exterior walls of most thermal power stations are constructed of insulated metal panels. However, concrete blocks, bricks, or other material may be used depending on the aesthetics and economics of the design.

(3) *Interior walls.* Concrete masonry blocks will be used for interior walls; however, some specialized

areas, such as for the control room enclosure and for offices, may utilize factory fabricated metal walls, fixed or moveable according to the application.

(4) *Roof decks.* Main building roof decks will be constructed of reinforced concrete or ribbed metal deck with built-up multi-ply roofing to provide waterproofing. Roofs will be sloped a minimum of 1/4-inch per foot for drainage.

(5) *Floors.* Except where grating or checkered plate is required for access or ventilation, all floors will be designed for reinforced concrete with a non-slip finish.

(6) *Live loads.* Buildings, structures and all portions thereof will be designed and constructed to support all live and dead loads without exceeding the allowable stresses of the selected materials in the structural members and connections. Typical live loads for power plant floors are as follows:

(a) Turbine generator floor	500 psf
(b) Basement and operating floors except turbine generator floor	200 psf
(c) Mezzanine, deaerator, and miscellaneous operating floors	200 psf
(d) Offices, laboratories, instrument shops, and other lightly loaded areas	100 psf

Live loads for actual design will be carefully reviewed for any special conditions and actual loads applicable.

(7) *Other loads.* In addition to the live and dead loads, the following loadings will be provided for:

(a) *Wind loading.* Building will be designed to resist the horizontal wind pressure available for the site on all surfaces exposed to the wind.

(b) *Seismic loading.* Buildings and other structures will be designed to resist seismic loading in accordance with the zone in which the building is located.

(c) *Equipment loading.* Equipment loads are furnished by the various manufacturers of each equipment item. In addition to equipment dead loads, impact loads, short circuit forces for generators, and other pertinent special loads prescribed by the equipment function or requirements will be included.

d. Foundation design.

(1) Foundations will be designed to safely support all structures, considering type of foundation and allowable bearing pressures. The two most common types of foundations are spread footings and pile type foundations, although "raft" type of other special approaches may be utilized for unusual circumstances.

(2) Pile type foundations require reinforced concrete pile caps and a system of reinforced concrete beams to tie the caps together. Pile load capabilities may be developed either in friction or point

bearing. The allowable load on piles will be determined by an approved formula or by a load test. Piles can be timber, concrete, rolled structural steel shape, steel pipe, or steel pipe concrete filled.

(3) Design of the reinforced concrete turbine generator or diesel set foundation, both mat and pedestal, will be such that the foundation is isolated from the main building foundations and structures by expansion joint material placed around its perimeter. The design will also insure that the resonance of the foundation at operating speed is avoided in order to prevent cracking of the foundation and damage to machines caused by resonant vibration. The foundation will be designed on the basis of deflection. The limits of deflection will be selected to avoid values of natural frequency by at least 30 percent above or 30 percent below operating speed.

(4) Vibration mounts or "floating floor" foundations where equipment or equipment foundation inertia blocks are separated from the main building floor by springs or precompressed material will generally not be used in power plants except for ventilation fans and other building service equipment. In these circumstances where such inertia blocks are considered necessary for equipment not normally so mounted, written justification will be included in the project design analysis supporting such a necessity.

(5) The location of turbine generators, diesel engine sets, boiler feed pumps, draft fans, compressors, and other high speed rotating equipment on elevated floors will be avoided because of the difficulty or impossibility of isolating equipment foundations from the building structure.

2-10. Safety.

a. Introduction. The safety features described in the following paragraphs will be incorporated into the power plant design to assist in maintaining a high level of personnel safety.

b. Design safety features. In designing a power plant, the following general recommendations on safety will be given attention:

(1) Equipment will be arranged with adequate access space for operation and for maintenance. Wherever possible, auxiliary equipment will be arranged for maintenance handling by the main turbine room crane. Where this is not feasible, mono-rails, wheeled trucks, or portable A-frames should be provided if disassembly of heavy pieces is required for maintenance.

(2) Safety guards will be provided on moving parts of all equipment.

(3) All valves, specialties, and devices needing manipulation by operators will be accessible without ladders, and preferably without using chain

wheels. This can be achieved by careful piping design, but some access platforms or remote mechanical operators may be necessary.

(4) Impact type handwheels will be used for high pressure valves and all large valves.

(5) Valve centers will be mounted approximately 7 feet above floors and platforms so that rising stems and bottom rims of handwheels will not be a hazard.

(6) Stairs with conventional riser-tread proportions will be used. Vertical ladders, installed only as a last resort, must have a safety cage if required by the Occupational Safety and Health Act (OSHA).

(7) All floors, gratings and checkered plates will have non-slip surfaces.

(8) No platform or walkway will be less than 3 feet wide.

(9) Toe plates, fitted closely to the edge of all floor openings, platforms and stairways, will be provided in all cases.

(10) Adequate piping and equipment drains to waste will be provided.

(11) All floors subject to washdown or leaks will be sloped to floor drains.

(12) All areas subject to lube oil or chemical spills will be provided with curbs and drains,

(13) If plant is of semi-outdoor or outdoor construction in a climate subject to freezing weather, weather protection will be provided for critical operating and maintenance areas such as the firing aisle, boiler steam drum ends and soot blower locations.

(14) Adequate illumination will be provided throughout the plant. Illumination will comply with requirements of the Illuminating Engineers Society (IES) Lighting Handbook, as implemented by DOD 4270.1-M.

(15) Comfort air conditioning will be provided throughout control rooms, laboratories, offices and similar spaces where operating and maintenance personnel spend considerable time.

(16) Mechanical supply and exhaust ventilation will be provided for all of the power plant equipment areas to alleviate operator fatigue and prevent accumulation of fumes and dust. Supply will be ducted to direct air to the lowest level of the power plant and to areas with large heat release such as the turbine or engine room and the boiler feed pump area. Evaporative cooling will be considered in low humidity areas. Ventilation air will be filtered and heated in the winter also, system air flow capacity should be capable of being reduced in the winter. Battery room will have separate exhaust fans to remove hydrogen emitted by batteries as covered in TM 5-811-2/AFM 88-9, Chap. 2.

(17) Noise level will be reduced to at least the

recommended maximum levels of OSHA. Use of fan silencers, compressor silencers, mufflers on internal combustion engines, and acoustical material is required as discussed in TM 5-805-4/AFM 88-37/NAVFAC DM-3.10 and TM 5-805-9/AFM 88-20/NAVFAC DM-3.14. Consideration should be given to locating forced draft fans in acoustically treated fan rooms since they are usually the largest noise source in a power plant. Control valves will be designed to limit noise emissions.

(18) A central vacuum cleaning system should be considered to permit easy maintenance of plant.

(19) Color schemes will be psychologically restful except where danger must be highlighted with special bright primary colors.

(20) Each equipment item will be clearly labelled in block letters identifying it both by equipment item number and name. A complete, coordinated system of pipe markers will be used for identification of each separate cycle and power plant service system. All switches, controls, and devices on all control panels will be labelled using the identical names shown on equipment or remote devices being controlled.

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CHAPTER 3

STEAM TURBINE POWER PLANT DESIGN

Section 1. TYPICAL PLANTS AND CYCLES

3-1. Introduction

a. Definition. The cycle of a steam power plant is the group of interconnected major equipment components selected for optimum thermodynamic characteristics, including pressure, temperatures and capacities, and integrated into a practical arrangement to serve the electrical (and sometimes by-product steam) requirements of a particular project. Selection of the optimum cycle depends upon plant size, cost of money, fuel costs, non-fuel operating costs, and maintenance costs.

b. Steam conditions. Typical cycles for the probable size and type of steam power plants at Army establishments will be supplied by superheated steam generated at pressures and temperatures between 600 psig (at 750 to 850°F) and 1450 psig (at 850 to 950° F). Reheat is never offered for turbine generators of less than 50 MW and, hence, is not applicable in this manual.

c. Steam turbine prime movers. The steam turbine prime mover, for rated capacity limits of 5000 kW to 30,000 kW, will be a multi-stage, multi-valve unit, either back pressure or condensing. Smaller turbines, especially under 1000 kW rated capacity, may be single stage units because of lower first cost and simplicity. Single stage turbines, either back pressure or condensing, are not equipped with extraction openings.

d. Back pressure turbines. Back pressure turbine units usually exhaust at pressures between 250 psig and 15 psig with one or two controlled or uncontrolled extractions. However, there is a significant price difference between controlled and uncontrolled extraction turbines, the former being more expensive. Controlled extraction is normally applied where the bleed steam is exported to process or district heat users.

e. Condensing turbines. Condensing units exhaust at pressures between 1 inch of mercury absolute (Hga) and 5 inches Hga, with up to two controlled, or up to five uncontrolled, extractions.

3-2. Plant function and purpose

a. Integration into general planning. General plant design parameters will be in accordance with overall criteria established in the feasibility study or

planning criteria on which the technical and economic feasibility is based. The sizes and characteristics of the loads to be supplied by the power plant, including peak loads, load factors, allowances for future growth, the requirements for reliability, and the criteria for fuel, energy, and general economy, will be determined or verified by the designer and approved by appropriate authority in advance of the final design for the project.

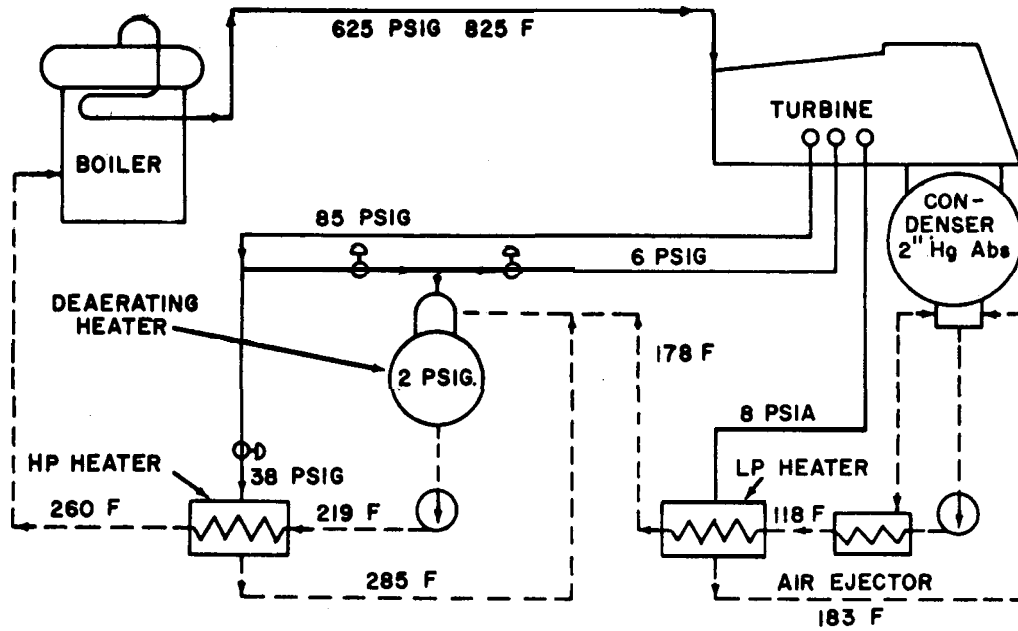
b. Selection of cycle conditions. Choice of steam conditions, types and sizes of steam generators and turbine prime movers, and extraction pressures depend on the function or purpose for which the plant is intended. Generally, these basic criteria should have already been established in the technical and economic feasibility studies, but if all such criteria have not been so established, the designer will select the parameters to suit the intended use.

c. Cooperation plants. Back pressure and controlled extraction/condensing cycles are attractive and applicable to a cogeneration plant, which is defined as a power plant simultaneously supplying either electric power or mechanical energy and heat energy (para. 3-4).

d. Simple condensing cycles. Straight condensing cycles, or condensing units with uncontrolled extractions are applicable to plants or situations where security or isolation from public utility power supply is more important than lowest power cost. Because of their higher heat rates and operating costs per unit output, it is not likely that simple condensing cycles will be economically justified for a military power plant application as compared with that associated with public utility 'purchased power costs. A schematic diagram of a simple condensing cycle is shown on Figure 3-1.

3-3. Steam power cycle economy

a. Introduction. Maximum overall efficiency and economy of a steam power cycle are the principal design criteria for plant selection and design. In general, better efficiency, or lower heat rate, is accompanied by higher costs for initial investment, operation and maintenance. However, more efficient cycles are more complex and may be less reliable per unit of capacity or investment cost than simpler and



NAVFAC DM3

Figure 3-1. Typical straight condensing cycle.

less efficient cycles. Efficiency characteristics can be listed as follows:

(1) Higher steam pressures and temperatures contribute to better, or lower, heat rates.

(2) For condensing cycles, lower back pressures increase efficiency except that for each particular turbine unit there is a crossover point where lowering back pressure further will commence to decrease efficiency because the incremental exhaust loss effect is greater than the incremental increase in available energy.

(3) The use of stage or regenerative feedwater cycles improves heat rates, with greater improvement corresponding to larger numbers of such heaters. In a regenerative cycle, there is also a thermodynamic crossover point where lowering of an extraction pressure causes less steam to flow through the extraction piping to the feedwater heaters, reducing the feedwater temperature. There is also a limit to the number of stages of extraction/feedwater heating which may be economically added to the cycle. This occurs when additional cycle efficiency no longer justifies the increased capital cost.

(4) Larger turbine generator units are generally more efficient than smaller units.

(5) Multi-stage and multi-valve turbines are more economical than single stage or single valve machines.

(6) Steam generators of more elaborate design, or with heat saving accessory equipment are more efficient.

b. *Heat rate units and definitions.* The economy or efficiency of a steam power plant cycle is ex-

pressed in terms of heat rate, which is total thermal input to the cycle divided by the electrical output of the units. Units are Btu/kWh.

(1) Conversion to cycle efficiency, as the ratio of output to input energy, may be made by dividing the heat content of one kWh, equivalent to 3412.14 Btu by the heat rate, as defined. Efficiencies are seldom used to express overall plant or cycle performance, although efficiencies of individual components, such as pumps or steam generators, are commonly used.

(2) Power cycle economy for particular plants or stations is sometimes expressed in terms of pounds of steam per kilowatt hour, but such a parameter is not readily comparable to other plants or cycles and omits steam generator efficiency.

(3) For mechanical drive turbines, heat rates are sometimes expressed in Btu per hp-hour, excluding losses for the driven machine. One horsepower hour is equivalent to 2544.43 Btu.

c. *Heat rate applications.* In relation to steam power plant cycles, several types or definitions of heat rates are used:

(1) The turbine heat rate for a regenerative turbine is defined as the heat consumption of the turbine in terms of "heat energy in steam" supplied by the steam generator, minus the "heat in the feedwater" as warmed by turbine extraction, divided by the electrical output at the generator terminals. This definition includes mechanical and electrical losses of the generator and turbine auxiliary systems, but excludes boiler inefficiencies and pumping losses and loads. The turbine heat rate is useful for

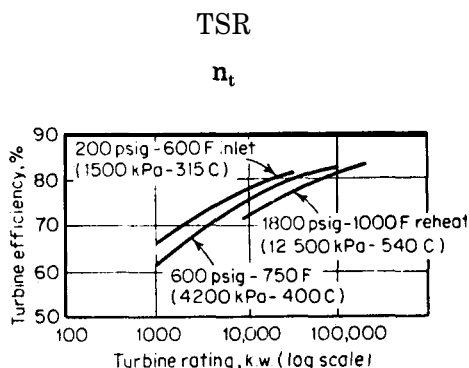
performing engineering and economic comparisons of various turbine designs. Table 3-1 provides theoretical turbine steam rates for typical steam throttle conditions. Actual steam rates are obtained by dividing the theoretical steam rate by the turbine efficiency. Typical turbine efficiencies are provided on Figure 3-2.

$$ASR =$$

where: ASR = actual steam rate (lb/kWh)
 TSR = theoretical steam rate (l/kWh)
 n_t = turbine efficiency

Turbine heat rate can be obtained by multiplying the actual steam rate by the enthalpy change across the turbine (throttle enthalpy - extraction or exhaust enthalpy).

where $C_t = ASR(h_1 - h_2)$
 C_t = turbine heat rate (Btu/kWh)
 ASR = actual steam rate lb/kWh
 h_1 = throttle enthalpy
 h_2 = extraction or exhaust enthalpy



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Figure 3-2. Turbine efficiencies vs. capacity.

(2) Plant heat rates include inefficiencies and losses external to the turbine generator, principally the inefficiencies of the steam generator and piping systems; cycle auxiliary losses inherent in power required for pumps and fans; and related energy uses such as for soot blowing, air compression, and similar services.

(3) Both turbine and plant heat rates, as above, are usually based on calculations of cycle performance at specified steady state loads and well defined, optimum operating conditions. Such heat rates are seldom achieved in practice except under controlled or test conditions.

(4) Plant operating heat rates are long term average actual heat rates and include other such losses and energy uses as non-cycle auxiliaries,

plant lighting, air conditioning and heating, general water supply, startup and shutdown losses, fuel deterioration losses, and related items. The gradual and inevitable deterioration of equipment, and failure to operate at optimum conditions, are reflected in plant operating heat rate data.

d. Plant economy calculations. Calculations, estimates, and predictions of steam plant performance will allow for all normal and expected losses and loads and should, therefore, reflect predictions of monthly or annual net operating heat rates and costs. Electric and district heating distribution losses are not usually charged to the power plant but should be recognized and allowed for in capacity and cost analyses. The designer is required to develop and optimize a cycle heat balance during the conceptual or preliminary design phase of the project. The heat balance depicts, on a simplified flow diagram of the cycle, all significant fluid mass flow rates, fluid pressures and temperatures, fluid enthalpies, electric power output, and calculated cycle heat rates based on these factors. A heat balance is usually developed for various increments of plant load (i.e., 25%, 50%, 75%, 100% and VWO (valves wide open)). Computer programs have been developed which can quickly optimize a particular cycle heat rate using iterative heat balance calculations. Use of such a program should be considered.

e. Cogeneration performance. There is no generally accepted method of defining the energy efficiency or heat rates of cogeneration cycles. Various methods are used, and any rational method is valid. The difference in value (per Btu) between prime energy (i.e., electric power) and secondary or low level energy (heating steam) should be recognized. Refer to discussion of cogeneration cycles below.

3-4. Cogeneration cycles

a. Definition. In steam power plant practice, cogeneration normally describes an arrangement whereby high pressure steam is passed through a turbine prime mover to produce electrical power, and thence from the turbine exhaust (or extraction) opening to a lower pressure steam (or heat) distribution system for general heating, refrigeration, or process use.

b. Common medium. Steam power cycles are particularly applicable to cogeneration situations because the actual cycle medium, steam, is also a convenient medium for area distribution of heat.

(1) The choice of the steam distribution pressure will be a balance between the costs of distribution which are slightly lower at high pressure, and the gain in electrical power output by selection of a lower turbine exhaust or extraction pressure.

(2) Often the early selection of a relatively low

Table 3-1. Theoretical Steam Rates for Typical Steam

Exhaust pressure in lb/g abs	Initial pressure, lb/in ² gage															
	150	250	400	600	600	850	900	900	1,200	250	1,250	1,450	1,450	1,800	2,400	
2.0	10.52	9.070	7.831	7.083	6.761	6.580	6.282	6.555	6.256	6.451	6.133	5.944	6.408	5.900	5.668	5.633
2.5	10.88	9.343	8.037	7.251	6.916	6.723	6.415	6.696	6.388	6.584	6.256	6.061	6.536	6.014	5.773	5.733
3.0	11.20	9.582	8.217	7.396	7.052	6.847	6.530	6.819	6.502	6.699	6.362	6.162	6.648	6.112	5.862	5.819
4.0	11.76	9.996	8.524	7.644	7.282	7.058	6.726	7.026	6.694	6.894	6.541	6.332	6.835	6.277	6.013	5.963
5	21.69	16.57	13.01	11.05	10.42	9.838	9.288	9.755	9.209	9.397	8.820	8.491	9.218	8.351	7.874	7.713
10	23.97	17.90	13.83	11.64	10.95	10.30	9.705	10.202	9.617	9.797	9.180	8.830	9.593	8.673	8.158	7.975
20	28.63	20.44	15.33	12.68	11.90	11.10	10.43	10.982	10.327	10.490	9.801	9.415	10.240	9.227	8.642	8.421
30	33.69	22.95	16.73	13.63	12.75	11.80	11.08	11.67	10.952	11.095	10.341	9.922	10.800	9.704	9.057	8.799
40	39.39	25.52	18.08	14.51	13.54	12.46	11.66	12.304	11.52	11.646	10.831	10.380	11.309	10.134	9.427	9.136
50	46.00	28.21	19.42	15.36	14.30	13.07	12.22	12.90	12.06	12.16	11.284	10.804	11.779	10.531	9.767	9.442
60	53.90	31.07	20.76	16.18	15.05	13.66	12.74	13.47	12.57	12.64	11.71	11.20	12.22	10.90	10.08	9.727
75	69.4	35.77	22.81	17.40	16.16	14.50	13.51	14.28	13.30	13.34	12.32	11.77	12.85	11.43	10.53	10.12
80	75.9	37.47	23.51	17.80	16.54	14.78	13.77	14.55	13.55	13.56	12.52	11.95	13.05	11.60	10.67	10.25
100	45.21	26.46	20.43	18.05	15.86	14.77	13.77	14.55	13.55	13.56	12.52	11.95	13.05	11.60	10.67	10.25
125	57.88	30.59	21.56	20.03	17.22	16.04	14.77	15.59	14.50	14.42	13.27	12.65	13.83	12.24	11.21	10.73
150	76.5	35.40	23.83	22.14	18.61	17.33	14.77	16.87	15.70	15.46	14.17	13.51	14.76	13.01	11.84	11.28
160	86.8	37.57	24.79	23.03	19.17	17.85	14.77	18.18	16.91	16.47	15.06	14.35	15.65	13.75	12.44	11.80
175	41.16	26.29	24.43	20.04	18.66	19.52	14.77	19.52	18.16	17.48	15.94	15.20	16.52	14.49	13.03	12.29
200	48.24	29.00	26.95	21.53	20.91	20.05	14.77	20.91	19.45	18.48	16.84	16.05	17.39	15.23	13.62	12.77
250	69.1	35.40	32.89	24.78	23.08	23.08	14.77	23.90	22.24	20.57	18.68	17.81	19.11	16.73	14.78	13.69
300	43.72	40.62	28.50	26.53	27.27	26.53	14.77	27.27	25.37	22.79	20.62	19.66	20.89	18.28	15.95	14.59
400	72.2	67.0	38.05	35.43	35.71	33.22	14.77	35.71	33.22	27.82	24.99	23.82	24.74	21.64	18.39	16.41
425	84.2	78.3	41.08	38.26	38.33	35.65	14.77	38.33	35.65	29.24	26.21	24.98	25.78	22.55	19.03	16.87
600	78.5	73.1	68.11	63.4	63.4	63.4	14.77	63.4	63.4	42.10	37.03	35.30	34.50	30.16	24.06	20.29

THE MATERIAL IN THIS TABLE IS ADAPTED FROM THEORETICAL STEAM RATE TABLES WITH THE PERMISSION OF THE PUBLISHER, THE AMERICAN SOCIETY OF MECHANICAL ENGINEERS.

steam distribution pressure is easily accommodated in the design of distribution and utilization systems, whereas the hasty selection of a relatively high steam distribution pressure may not be recognized as a distinct economic penalty on the steam power plant cycle.

(3) Hot water heat distribution may also be applicable as a district heating medium with the hot water being cooled in the utilization equipment and returned to the power plant for reheating in a heat exchange with exhaust (or extraction) steam.

c. Relative economy. When the exhaust (or extraction) steam from a cogeneration plant can be utilized for heating, refrigeration, or process purposes in reasonable phase with the required electric power load, there is a marked economy of fuel energy because the major condensing loss of the conventional steam power plant (Rankine) cycle is avoided. If a good balance can be attained, up to 75 percent of the total fuel energy can be utilized as compared with about 40 percent for the best and largest Rankine cycle plants and about 25 to 30 percent for small Rankine cycle systems.

d. Cycle types. The two major steam power cogeneration cycles, which may be combined in the same plant or establishment, are:

(1) *Back pressure cycle.* In this type of plant, the entire flow to the turbine is exhausted (or extracted) for heating steam use. This cycle is the more effective for heat economy and for relatively lower cost of turbine equipment, because the prime mover is smaller and simpler and requires no condenser and circulating water system. Back pressure turbine generators are limited in electrical output by the amount of exhaust steam required by the heat load and are often governed by the exhaust steam load. They, therefore, usually operate in electrical parallel with other generators.

(2) *Extraction-condensing cycles.* Where the electrical demand does not correspond to the heat demand, or where the electrical load must be carried at times of very low (or zero) heat demand, then condensing-controlled extraction steam turbine prime movers as shown in Figure 3-3 may be applicable. Such a turbine is arranged to carry a specified electrical capacity either by a simple condensing cycle or a combination of extraction and condensing. While very flexible, the extraction machine is relatively complicated, requires complete condensing and heat rejection equipment, and must always pass a critical minimum flow of steam to its condenser to cool the low pressure buckets.

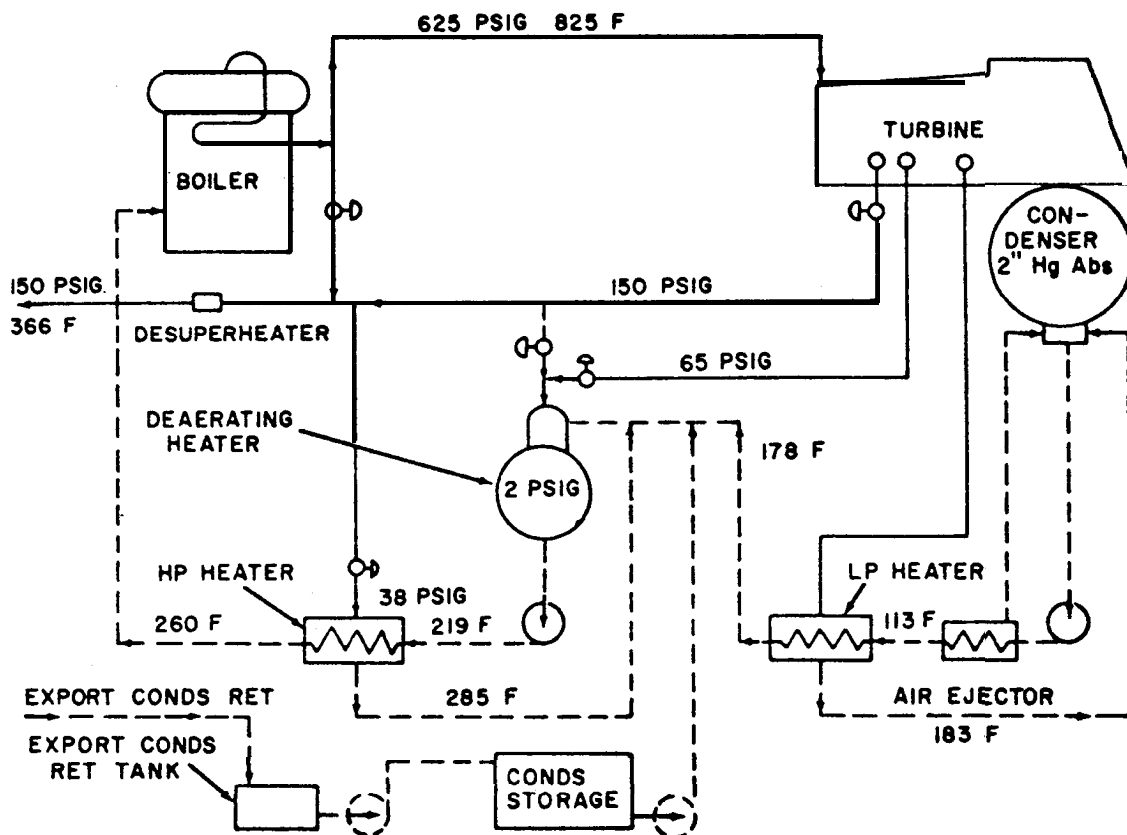


Figure 3-3. Typical condensing-controlled extinction cycle.

e. Criteria for cogeneration. For minimum economic feasibility, cogeneration cycles will meet the following criteria:

(1) *Load balance.* There should be a reasonably balanced relationship between the peak and normal requirements for electric power and heat. The peak/normal ratio should not exceed 2:1.

(2) *Load coincidence.* There should be a fairly high coincidence, not less than 70%, of time and quantity demands for electrical power and heat.

(3) *Size.* While there is no absolute minimum size of steam power plant which can be built for cogeneration, a conventional steam (cogeneration) plant will be practical and economical only above some minimum size or capacity, below which other types of cogeneration, diesel or gas turbine become more economical and convenient.

(4) *Distribution medium.* Any cogeneration plant will be more effective and economical if the heat distribution medium is chosen at the lowest possible steam pressure or lowest possible hot water temperature. The power energy delivered by the turbine is highest when the exhaust steam pressure is lowest. Substantial cycle improvement can be made by selecting an exhaust steam pressure of 40 psig rather than 125 psig, for example. Hot water heat distribution will also be considered where practical or convenient, because hot water temperatures of 200 to 240° F can be delivered with exhaust steam pressure as low as 20 to 50 psig. The balance between distribution system and heat exchanger costs, and power cycle effectiveness will be optimized.

3-5. Selection of cycle steam conditions

a. Balanced costs and economy. For a new or isolated plant, the choice of initial steam conditions should be a balance between enhanced operating economy at higher pressures and temperatures, and generally lower first costs and less difficult operation at lower pressures and temperatures. Realistic projections of future fuel costs may tend to justify higher pressures and temperatures, but such factors as lower availability, higher maintenance costs, more difficult operation, and more elaborate water treatment will also be considered.

b. Extension of existing plant. Where a new steam power plant is to be installed near an existing steam power or steam generation plant, careful consideration will be given to extending or paralleling the existing initial steam generating conditions. If existing steam generators are simply not usable in the new plant cycle, it may be appropriate to retire them or to retain them for emergency or standby service only. If boilers are retained for standby service only, steps will be taken in the project design for

protection against internal corrosion.

c. Special considerations. Where the special circumstances of the establishment to be served are significant factors in power cycle selection, the following considerations may apply:

(1) *Electrical isolation.* Where the proposed plant is not to be interconnected with any local electric utility service, the selection of a simpler, lower pressure plant may be indicated for easier operation and better reliability.

(2) *Geographic isolation.* Plants to be installed at great distances from sources of spare parts, maintenance services, and operating supplies may require special consideration of simplified cycles, redundant capacity and equipment, and highest practical reliability. Special maintenance tools and facilities may be required, the cost of which would be affected by the basic cycle design.

(3) *Weather conditions.* Plants to be installed under extreme weather conditions will require special consideration of weather protection, reliability, and redundancy. Heat rejection requires special design consideration in either very hot or very cold weather conditions. For arctic weather conditions, circulating hot water for the heat distribution medium has many advantages over steam, and the use of an antifreeze solution in lieu of pure water as a distribution medium should receive consideration.

3-6. Cycle equipment

a. General requirements. In addition to the prime movers, alternators, and steam generators, a complete power plant cycle includes a number of secondary elements which affect the economy and performance of the plant.

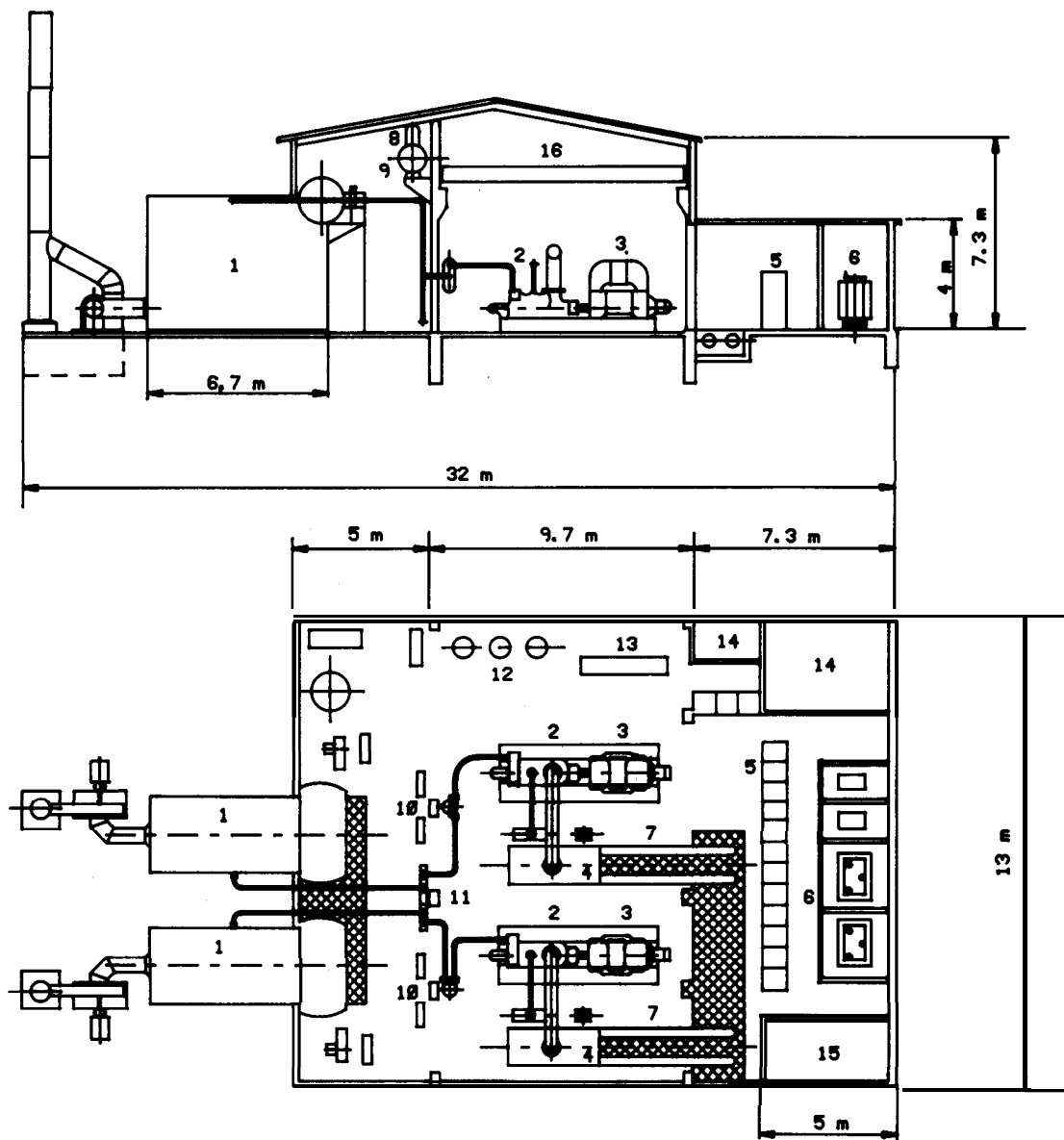
b. Major equipment. Refer to other parts of this manual for detailed information on steam turbine driven electric generators and steam generators.

c. Secondary cycle elements. Other equipment items affecting cycle performance, but subordinate to the steam generators and turbine generators, are also described in other parts of this chapter.

3-7. Steam power plant arrangement

a. General. Small units utilize the transverse arrangement in the turbine generator bay while the larger utility units are very long and require end-to-end arrangement of the turbine generators.

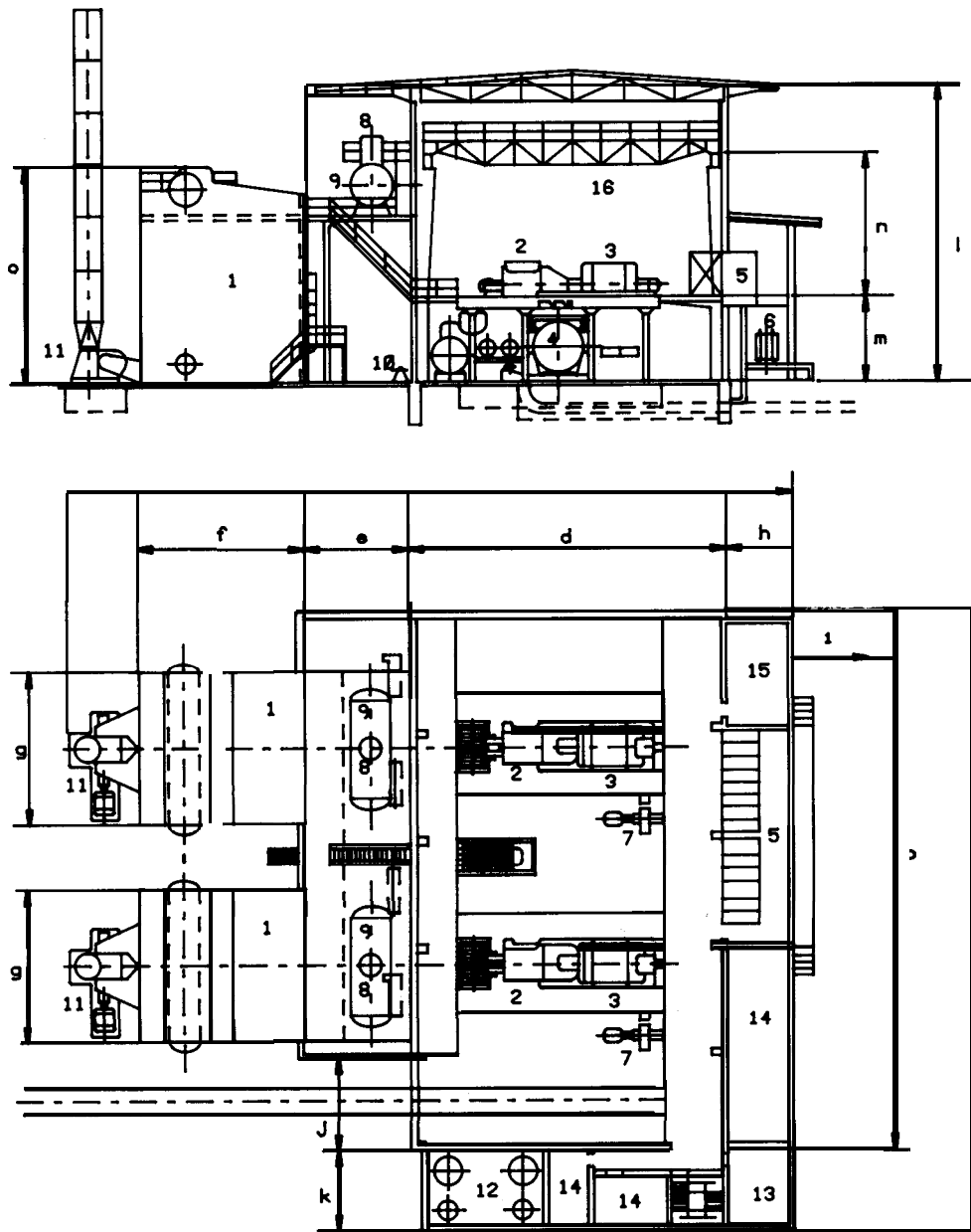
b. Typical small plants. Figures 3-4 and 3-6 show typical transverse small plant arrangements. Small units less than 5000 kW may have the condensers at the same level as the turbine generator for economy as shown in Figure 3-4. Figure 3-6 indicates the critical turbine room bay dimensions and the basic overall dimensions for the small power plants shown in Figure 3-5.



- | | | |
|-----------------------|-------------------------|-------------------------|
| 1 - BOILER, OIL-FIRED | 7 - COOLING WATER PIPES | 13 - START-UP DIESEL |
| 2 - TURBINE | 8 - DEAERATOR | 14 - STORE ROOM |
| 3 - GENERATOR | 9 - FEEDWATER TANK | 15 - OFFICE |
| 4 - CONDENSER | 10 - BOILER FEED PUMPS | 16 - TURBINE ROOM CRANE |
| 5 - SWITCHGEAR | 11 - STEAM MANIFOLD | |
| 6 - TRANSFORMERS | 12 - WATER TREATMENT | |

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Figure 3-4. Typical small 2-unit powerplant "A".



- | | | |
|-----------------------|------------------------|--------------------------|
| 1 - BOILER, OIL-FIRED | 7 - COOLING WATER PUMP | 13 - CHEMICAL LABORATORY |
| 2 - TURBINE | 8 - DEAERATOR | 14 - OFFICES |
| 3 - GENERATOR | 9 - FEEDWATER TANK | 15 - STORE ROOM |
| 4 - CONDENSER | 10 - BOILER FEED PUMPS | 16 - TURBINE HOUSE CRANE |
| 5 - SWITCHGEAR | 11 - INDUCED-DRAFT FAN | |
| 6 - TRANSFORMERS | 12 - WATER TREATMENT | |

NOTE: SEE TABLE IN FIG. 3-6 FOR DIMENSIONS.

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Figure 3-5. Typical small 2-unit power plant "B".

Section II. STEAM GENERATORS AND AUXILIARY SYSTEMS.

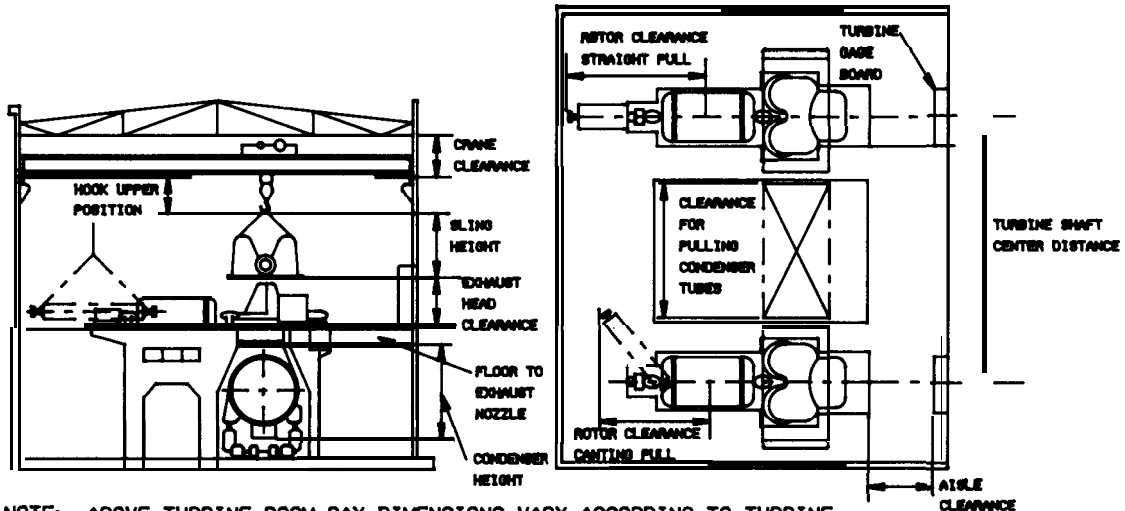
3-8. Steam generator conventional types and characteristics

a. *Introduction.* Number, size, and outlet steaming conditions of the steam generators will be as determined in planning studies and confirmed in the final project criteria prior to plant design activities. Note general criteria given in Section I of this chapter under discussion of typical plants and cycles.

b. *Types and classes.* Conventional steam genera-

tors for a steam power plant can be classified by type of fuel, by unit size, and by final steam condition. Units can also be classified by type of draft, by method of assembly, by degree of weather protection and by load factor application.

(1) *Fuel, general.* Type of fuel has a major impact on the general plant design in addition to the steam generator. Fuel selection may be dictated by considerations of policy and external circumstances



NOTE: ABOVE TURBINE ROOM BAY DIMENSIONS VARY ACCORDING TO TURBINE AND CONDENSER SUPPLIERS SELECTED.

DIMENSION	DIMENSIONS IN METERS			
	I 2x2.5 MW	II 2x4 MW	III 2x6.25 MW	IV 2x12.5 MW
a	24.5	26.5	28	36
b	32	34	36	43
c	20	22	23	31
d	12	13	14	16
e	5	5	5	6
f	8.3	9	9.3	11.3
g	3.6	5	5.7	7.5
h	3.5	3.5	3.7	3.7
i	1.2	1.2	1.2	1.2
j	5.5	5.5	5.5	5.5
k	4.5	4.5	5	5
l	11	12	13	17.5
m	3.5	3.5	3.7	5
n	4.5	5	6	8
o	9	9	10	11

NOTE: DIMENSIONS IN TABLE ARE APPLICABLE TO FIG. 3-5

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Figure 3-6. Critical turbine room bay and power plant "B" dimensions.

unrelated to plant costs, convenience, or location. Units designed for solid fuels (coal, lignite, or solid waste) or designed for combinations of solid, liquid, and gaseous fuel are larger and more complex than units designed for fuel oil or fuel gas only.

(2) *Fuel coal.* The qualities or characteristics of particular coal fuels having significant impact on steam generator design and arrangement are: heating value, ash content, ash fusion temperature, friability, grindability, moisture, and volatile content as shown in Table 3-2. For spreader stoker firing, the size, gradation, or mixture of particle sizes affect

stoker and grate selection, performance, and maintenance. For pulverized coal firing, grindability is a major consideration, and moisture content before and after local preparation must be considered. Coal burning equipment and related parts of the steam generator will be specified to match the specific characteristics of a preselected coal fuel as well as they can be determined at the time of design.

(3) *Unit sizes.* Larger numbers of smaller steam generators will tend to improve plant reliability and flexibility for maintenance. Smaller numbers of larger steam generators will result in lower first costs

Table 3-2. Fuel Characteristics.

Characteristic	Effects
<u>Coal</u>	
Ultimate analysis	Heat balance.
Proximate analysis:	
Moisture	Handling and efficiency loss.
Volatile matter.....	Ignition and theoretical air.
Ash.....	Freight, storage, handling, air pollution.
Ash fusion temp.....	Slagging, allowable heat release, allowable furnace exit gas temperature.
Heat value.....	Heat balance, fuel cost.
Friability	Handling and storage.
Grindability.....	Crushing and pulverizing.
Size consist	Crushing, segregation, and spreading over fuel bed.
Sulphur	Allowable temp. of metal contacting flue gas; removal from flue gas.
<u>Oil</u>	
Ultimate analysis	Heat balance.
Grade	Fuel cost.
Viscosity	Preheating, pumping, firing.
Specific gravity	Pumping and metering.
Flash point	Vapor locking of pump suction.
Heat value	Heat balance, fuel cost.
Sulphur	Allowable temp. of metal contacting flue gas; removal from flue gas.
<u>Gas</u>	
Ultimate analysis	Heat balance.
Type	Pressure, firing, fuel cost.
Specific gravity	Metering.
Heat value	Heat balance, fuel cost.
Sulphur :.....	Insignificant.

per unit of capacity and may permit the use of design features and arrangements not available on smaller units. Larger units are inherently more efficient, and will normally have more efficient draft fans, better steam temperature control, and better control of steam solids.

(4) *Final steam conditions.* Desired pressure and temperature of the superheater outlet steam (and to a lesser extent feedwater temperature) will have a marked effect on the design and cost of a steam generator. The higher the pressure the heavier the pressure parts, and the higher the steam temperature the greater the superheater surface area and the more costly the tube material. In addition to this, however, boiler natural circulation problems increase with higher pressures because the densities of the saturated water and steam approach each other. In consequence, higher pressure boilers require more height and generally are of different design than boilers of 200 psig and less as used for general space heating and process application.

(5) *Type of draft.*

(a) *Balanced draft.* Steam generators for electric generating stations are usually of the so called "balanced draft" type with both forced and induced draft fans. This type of draft system uses one or more forced draft fans to supply combustion air under pressure to the burners (or under the grate) and one or more induced draft fans to carry the hot combustion gases from the furnace to the atmosphere; a slightly negative pressure is maintained in the furnace by the induced draft fans so that any gas leakage will be into rather than out of the furnace. Natural draft will be utilized to take care of the chimney or stack resistance while the remainder of the draft friction from the furnace to the chimney entrance is handled by the induced draft fans.

(b) *Choice of draft.* Except for special cases such as for an overseas power plant in low cost fuel areas, balanced draft, steam generators will be specified for steam electric generating stations.

(6) *Method of assembly.* A major division of steam generators is made between packaged or factory assembled units and larger field erected units. Factory assembled units are usually designed for convenient shipment by railroad or motor truck, complete with pressure parts, supporting structure, and enclosure in one or a few assemblies. These units are characteristically bottom supported, while the larger and more complex power steam generators are field erected, usually top supported.

(7) *Degree of weather protection.* For all types and sizes of steam generators, a choice must be made between indoor, outdoor and semi-outdoor installation. An outdoor installation is usually less expensive in first cost which permits a reduced general

building construction costs. Aesthetic, environmental, or weather conditions may require indoor installation, although outdoors units have been used successfully in a variety of cold or otherwise hostile climates. In climates subject to cold weather, 30 °F. for 7 continuous days, outdoor units will require electrically or steam traced piping and appurtenances to prevent freezing. The firing aisle will be enclosed either as part of the main power plant building or as a separate weather protected enclosure; and the ends of the steam drum and retractable soot blowers will be enclosed and heated for operator convenience and maintenance.

(8) *Load factor application.* As with all parts of the plant cycle, the load factor on which the steam generator is to be operated affects design and cost factors. Units with load factors exceeding 50% will be selected and designed for relatively higher efficiencies, and more conservative parameters for furnace volume, heat transfer surface, and numbers and types of auxiliaries. Plants with load factors less than 50% will be served by relatively less expensive, smaller and less durable equipment.

3-9. Other steam generator characteristics

a. *Water tube and waterwell design.* Power plant boilers will be of the water welded or water cooled furnace types, in which the entire interior surface of the furnace is lined with steam generating heating surface in the form of closely spaced tubes usually all welded together in a gas tight enclosure.

b. *Superheated steam.* Depending on manufacturer's design some power boilers are designed to deliver superheated steam because of the requirements of the steam power cycle. A certain portion of the total boiler heating surface is arranged to add superheat energy to the steam flow. In superheater design, a balance of radiant and convective superheat surfaces will provide a reasonable superheat characteristic. With high pressure - high temperature turbine generators, it is usually desirable to provide superheat controls to obtain a flat characteristic down to at least 50 to 60 percent of load. This is done by installing excess superheat surface and then attemperating by means of spray water at the higher loads. In some instances, boilers are designed to obtain superheat control by means of tilting burners which change the heat absorption pattern in the steam generator, although supplementary attemperation is also provided with such a control system.

c. *Balanced heating surface and volumetric design parameters.* Steam generator design requires adequate and reasonable amounts of heating surface

and furnace volume for acceptable performance and longevity.

(1) *Evaporative heating surface.* For its rated capacity output, an adequate total of evaporative or steam generating heat transfer surface is required, which is usually a combination of furnace wall radiant surface and boiler convection surface. Balanced design will provide adequate but not excessive heat flux through such surfaces to insure effective circulation, steam generation and efficiency.

(2) *Superheater surface.* For the required heat transfer, temperature control and protection of metal parts, the superheater must be designed for a balance between total surface, total steam flow area, and relative exposure to radiant convection heat sources. Superheaters may be of the drainable or non-drainable types. Non-drainable types offer certain advantages of cost, simplicity, and arrangement, but are vulnerable to damage on startup. Therefore, units requiring frequent cycles of shutdown and startup operations should be considered for fully drainable superheaters. With some boiler designs this may not be possible.

(3) *Furnace volume.* For a given steam generator capacity rating, a larger furnace provides lower furnace temperatures, less probability of hot spots, and a lower heat flux through the larger furnace wall surface. Flame impingement and slagging, particularly with pulverized coal fuel, can be controlled or prevented with increased furnace size.

(4) *General criteria.* Steam generator design will specify conservative lower limits of total heating surface, furnace wall surface and furnace volume, as well as the limits of superheat temperature control range. Furnace volume and surfaces will be sized to insure trouble free operation.

(5) *Specific criteria.* Steam generator specifications set minimum requirements for Btu heat release per cubic foot of furnace volume, for Btu heat release per square foot of effective radiant heating surface and, in the case of spreader stokers, for Btu per square foot of grate. Such parameters are not set forth in this manual, however, because of the wide range of fuels which can affect these equipment design considerations. The establishment of arbitrary limitations which may handicap the geometry of furnace designs is inappropriate. Prior to setting furnace geometry parameters, and after the type and grade of fuel are established and the particular service conditions are determined, the power plant designer will consult boiler manufacturers to insure that steam generator specifications are capable of being met.

d. Single unit versus steam header system. For cogeneration plants, especially in isolated locations or for units of 10,000 kW and less, a parallel boiler or

steam header system may be more reliable and more economical than unit operation. Where a group of steam turbine prime movers of different types; i.e., one back pressure unit plus one condensing/extraction unit are installed together, overall economy can be enhanced by a header (or parallel) boiler arrangement.

3-10. Steam generator special types

a. Circulation. Water tube boilers will be specified to be of natural circulation. The exception to this rule is for wasteheat boilers which frequently are a special type of extended surface heat exchanger designed for forced circulation.

b. Fluidized bed combustion. The fluidized bed boiler has the ability to produce steam in an environmentally accepted manner in controlling the stack emission of sulfur oxides by absorption of sulfur in the fuel bed as well as nitrogen oxides because of its relatively low fire box temperature. The fluidized bed boiler is a viable alternative to a spreader stoker unit. A fluidized bed steam generator consists of a fluidized bed combustor with a more or less conventional steam generator which includes radiant and convection boiler heat transfer surfaces plus heat recovery equipment, draft fans, and the usual array of steam generator auxiliaries. A typical fluidized bed boiler is shown in Figure 3-7.

3-11. Major auxiliary systems.

a. Burners.

(1) *Oil burners.* Fuel oil is introduced through oil burners, which deliver finely divided or atomized liquid fuel in a suitable pattern for mixing with combustion air at the burner opening. Atomizing methods are classified as pressure or mechanical type, air atomizing and steam atomizing type. Pressure atomization is usually more economical but is also more complex and presents problems of control, poor turndown, operation and maintenance. The range of fuel flows obtainable is more limited with pressure atomization. Steam atomization is simple to operate, reliable, and has a wide range, but consumes a portion of the boiler steam output and adds moisture to the furnace gases. Generally, steam atomization will be used when makeup water is relatively inexpensive, and for smaller, lower pressure plants. Air atomization will be used for plants burning light liquid fuels, or when steam reacts adversely with the fuel, i.e., high sulfur oils.

(2) *Gas and coal burners.* Natural gas or pulverized coal will be delivered to the burner for mixing with combustion air supply at the burner opening. Pulverized coal will be delivered by heated, pressurized primary air.

(3) *Burner accessories.* Oil, gas and pulverized

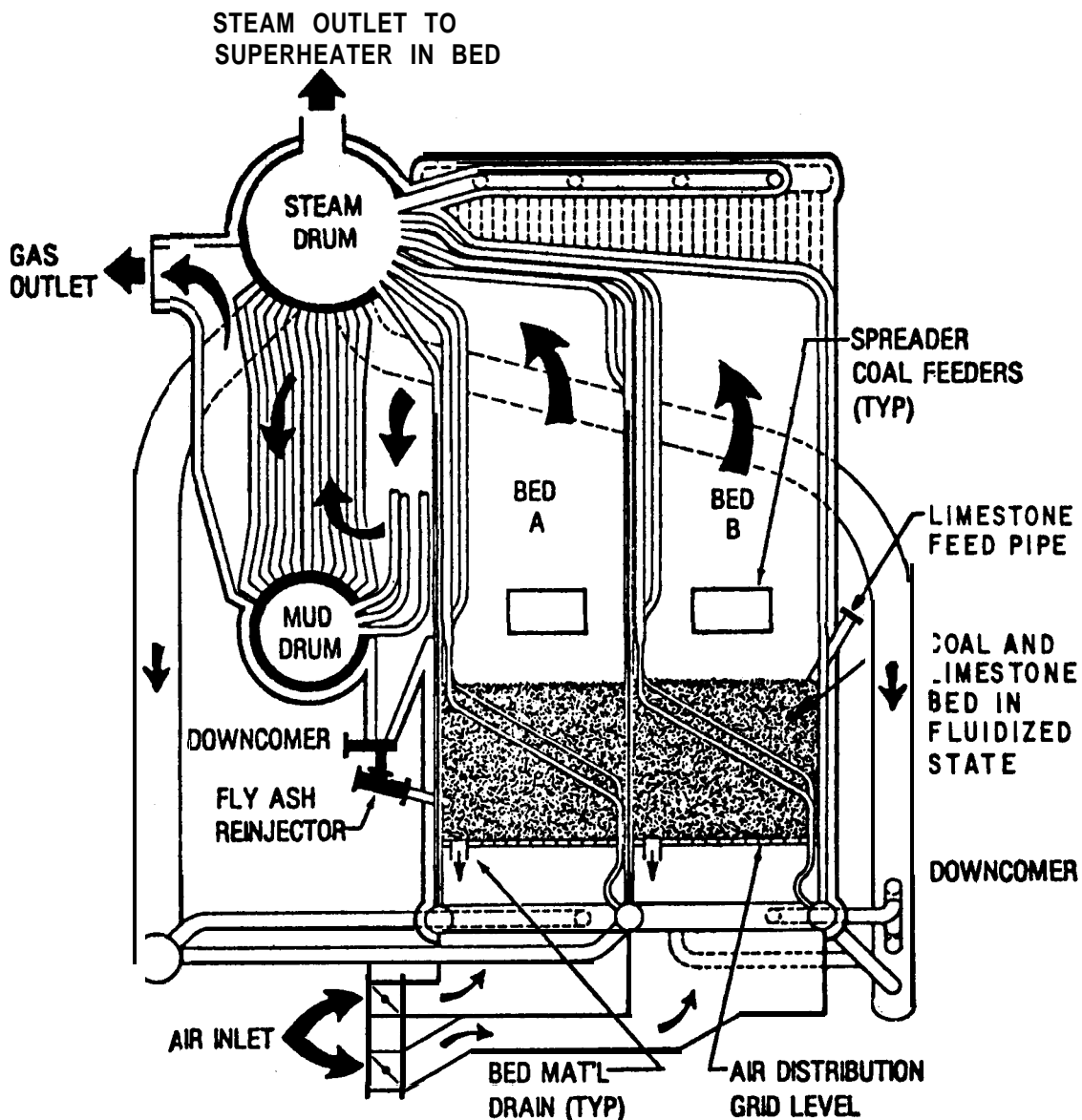
coal burners will be equipped with adjustable air guide registers designed to control and shape the air flow into the furnace. Some burner designs also provide for automatic insertion and withdrawal of varying size oil burner nozzles as load and operating conditions require.

(4) *Number of burners.* The number of burners required is a function both of load requirements and boiler manufacturer design. For the former, the individual burner turndown ratios per burner are provided in Table 3-3. Turndown ratios in excess of those listed can be achieved through the use of multiple burners. Manufacturer design limits capacity of each burner to that compatible with furnace flame and gas flow patterns, exposure and damage to

heating surfaces, and convenience of operation and control.

(5) *Burner management systems.* Plant safety practices require power plant fuel burners to be equipped with comprehensive burner control and safety systems to prevent unsafe or dangerous conditions which may lead to furnace explosions. The primary purpose of a burner management system is safety which is provided by interlocks, furnace purge cycles and fail safe devices.

b. *Pulverizes.* The pulverizers (mills) are an essential part of powdered coal burning equipment, and are usually located adjacent to the steam generator and burners, but in a position to receive coal by gravity from the coal silo. The coal pulverizers grind



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Figure 3-7. Fluidized bed combustion boiler.

and classify the coal fuel to specific particle sizes for rapid and efficient burning. Reliable and safe pulverizing equipment is essential for steam generator operation. Pulverized coal burning will not be specified for boilers smaller than 150,000 lb/hour.

c. Stokers and grates. For small and medium sized coal burning steam generators, less than 150,000 lb/hour, coal stokers or fluidized bed units will be used. For power boilers, spreader stokers with traveling grates are used. Other types of stokers (retort, underfeed, or overfeed types) are generally obsolete for power plant use except perhaps for special fuels such as anthracite.

(1) Spreader stokers typically deliver sized coal, with some proportion of fines, by throwing it into the furnace where part of the fuel burns in suspension and the balance falls to the traveling grate for burnout. Stoker fired units will have two or more spreader feeder units, each delivering fuel to its own separate grate area. Stoker fired units are less responsive to load changes because a large proportion of the fuel burns on the grate for long time periods (minutes). Where the plant demand is expected to in-

clude sudden load changes, pulverized coal feeders are to be used.

(2) Grate operation requires close and skillful operator attention, and overall plant performance is sensitive to fuel sizing and operator experience. Grates for stoker fired units occupy a large part of the furnace floor and must be integrated with ash removal and handling systems. A high proportion of stoker ash must be removed from the grates in a wide range of particle sizes and characteristics although some unburned carbon and fly ash is carried out of the furnace by the flue gas. In contrast, a larger proportion of pulverized coal ash leaves the furnace with the gas flow as finely divided particulate,

(3) Discharged ash is allowed to cool in the ash hopper at the end of the grate and is then sometimes put through a clinker grinder prior to removal in the vacuum ash handling system described elsewhere in this manual.

d. Draft fans, ducts and flues.

(1) *Draft fans.*

(a) Air delivery to the furnace and flue gas re-

Table 3-3. Individual Burner Turndown Ratios.

<u>Burner Type</u>	<u>Turndown Ratio</u>
NATURAL GM	
Spud or Ring Type	5:1 to 10:1
HEAVY FUEL OIL	
Steam Atomizing	5:1 to 10:1
Mechanical Atomizing	3:1 to 10:1
COAL	
Pulverized	3:1
Spreader-Stoker	2:1 to 3:1
Fluidized Bed (single bed)	2:1 to 3:1

removal will be provided by power driven draft fans designed for adequate volumes and pressures of air and gas flow. Typical theoretical air requirements are shown in Figure 3-8 to which must be added excess air which varies with type of firing, plus fan margins on both volumetric and pressure capacity for reliable full load operation. Oxygen and carbon dioxide in products of combustion for various amounts of excess air are also shown in Figure 3-8.

(b) Calculations of air and gas quantities and pressure drops are necessary. Since fans are heavy power consumers, for larger fans consideration should be given to the use of back pressure steam turbine drives for economy, reliability and their ability to provide speed variation. Multiple fans on each boiler unit will add to first costs but will provide more flexibility and reliability. Type of fan drives and number of fans will be considered for cost effectiveness. Fan speed will be conservatively selected, and silencers will be provided in those cases where noise by fans exceeds 80 decibels.

(c) Power plant steam generator units designed for coal or oil will use balanced draft design with both forced and induced draft fans arranged for closely controlled negative furnace pressure.

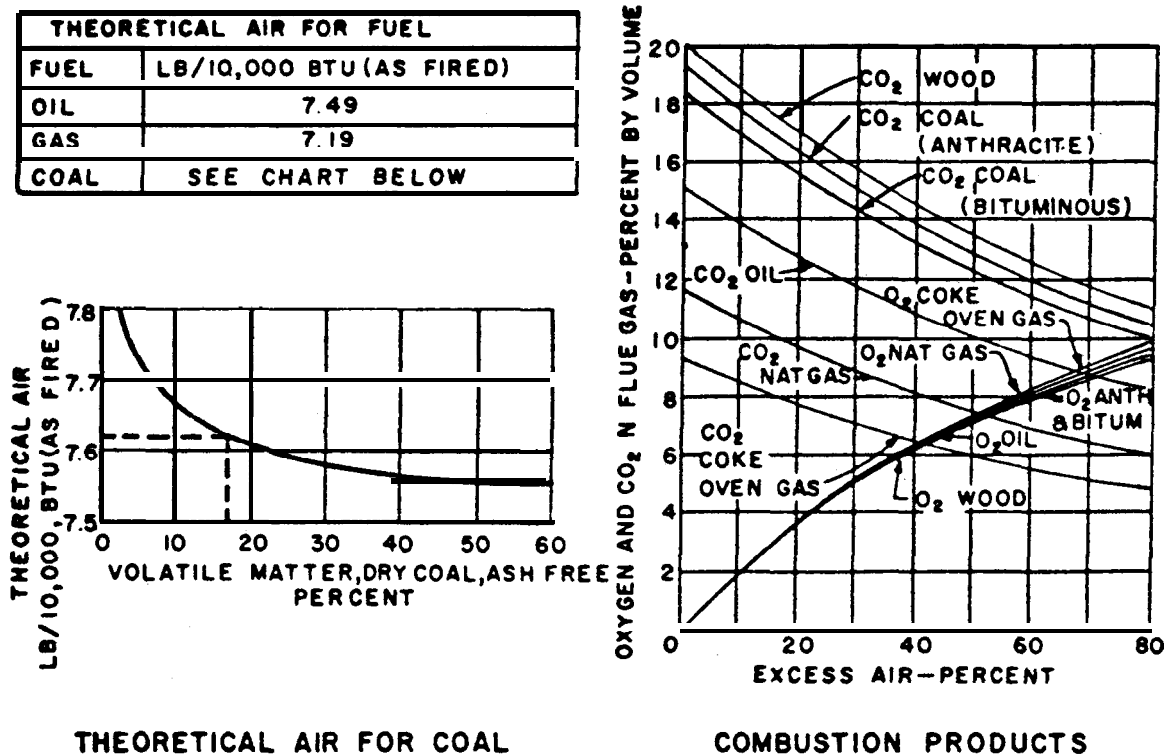
(2) *Ducts and flues.* Air ducts and gas flues will be adequate in size and structural strength and designed with provision for expansion, support, corro-

sion resistance and overall gas tightness. Adequate space and weight capacity will be allowed in overall plant arrangement to avoid awkward, noisy or marginal fan, duct and flue systems. Final steam generator design will insure that fan capacities (especially pressure) are matched properly to realistic air and gas path losses considering operation with dirty boilers and under abnormal operating conditions. Damper durability and control characteristics will be carefully designed; dampers used for control purposes will be of opposed blade construction.

e. Heat recovery. Overall design criteria require highest fuel efficiency for a power boiler; therefore, steam generators will be provided with heat recovery equipment of two principal types: air preheater and economizers.

(1) Efficiency effects. Both principal types of heat recovery equipment remove relatively low level heat from the flue gases prior to flue gas discharge to the atmosphere, using boiler fluid media (air or water) which can effectively absorb such low level energy. Such equipment adds to the cost, complexity and operational skills required, which will be balanced by the plant designer against the life cycle fuel savings.

(2) *Air preheater.* Simple tubular surface heaters will be specified for smaller units and the regenerative type heater for larger boilers. To mini-



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Figure 3-8. Theoretical air and combustion products.

mize corrosion and acid/moisture damage, especially with dirty and high sulphur fuels, special alloy steel will be used in the low temperature heat transfer surface (replaceable tubes or "baskets") of air preheater. Steam coil air heaters will be installed to maintain certain minimum inlet air (and metal) temperatures and thus protect the main preheater from corrosion at low loads or low ambient air temperatures. Figure 3-9 illustrates the usual range of minimum metal temperatures for heat recovery equipment.

(3) *Economizers.* Either an economizer or an air heater or a balanced selection of both as is usual in a power boiler will be provided, allowing also for turbine cycle feedwater stage heating.

f. Stacks.

(1) Delivery of flue gases to the atmosphere through a flue gas stack or chimney will be provided.

(2) Stacks and chimneys will be designed to discharge their gases without adverse local effects. Dispersion patterns and considerations will be treated during design.

(3) Stacks and chimneys will be sized with due regard to natural draft and stack friction with

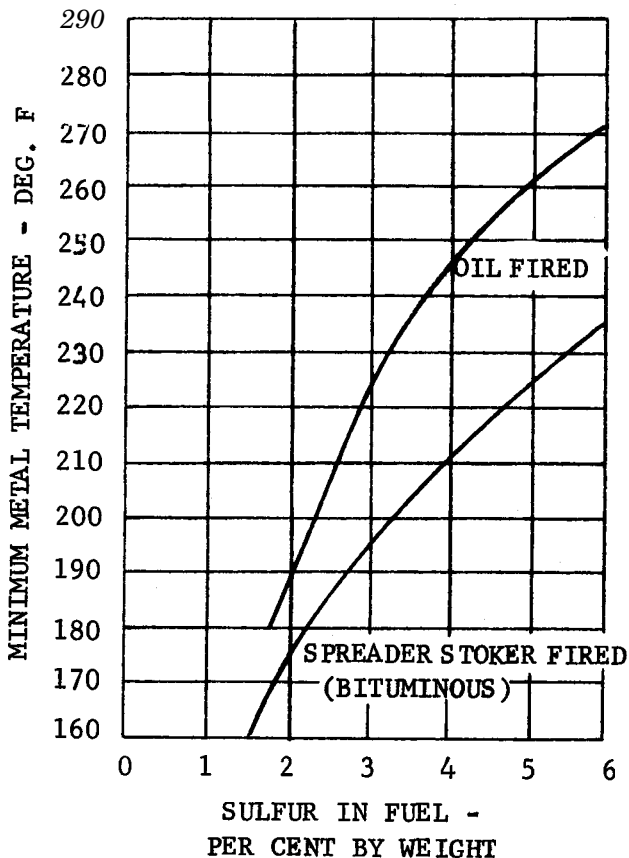
height sometimes limited by aesthetic or other non-economic considerations. Draft is a function of density difference between the hot stack gases and ambient air, and a number of formulas are available for calculating draft and friction. Utilize draft of the stack or chimney only to overcome friction within the chimney with the induced draft fan(s) supplying stack or chimney entrance. Maintain relatively high gas exit velocities (50 to 60 feet per second) to eject gases as high above ground level as possible. Reheat (usually by steam) will be provided if the gases are treated (and cooled) in a flue gas desulfurization scrubber prior to entering the stack to add buoyancy and prevent their settling to the ground after ejection to the atmosphere. Insure that downwash due to wind and building effects does not drive the flue gas to the ground.

g. Flue gas cleanup. The requirements for flue gas cleanup will be determined during design.

(1) *Design considerations.* The extent and nature of the air pollution problem will be analyzed prior to specifying the environmental control system for the steam generator. The system will meet all applicable requirements, and the application will be the most economically feasible method of accomplishment. All alternative solutions to the problem will be considered which will satisfy the given load and which will produce the least objectionable wastes. Plant design will be such as to accommodate future additions or modifications at minimum cost. Questions concerning unusual problems, unique applications or marginal and future requirements will be directed to the design agency having jurisdiction over the project. Table 3-4 shows the emission levels allowable under the National Ambient Air Quality Standards.

(2) *Particulate control.* Removal of flue gas particulate material is broadly divided into mechanical dust collectors, electrostatic precipitators, bag filters, and gas scrubbing systems. For power plants of the size range here considered estimated uncontrolled emission levels of various pollutants are shown in Table 3-5. Environmental regulations require control of particulate, sulfur oxides and nitrogen oxides. For reference purposes in this manual, typical control equipment performance is shown in Table 3-6, 3-7, 3-8, 3-9, 3-10 and 3-11. These only provide general guidance. The designer will refer to TM 5-815-1/AFR 19-6/NAVFAC DM-3.15 for details of this equipment and related computational requirements and design criteria.

(a) *Mechanical collectors.* For oil fired steam generators with output steaming capacities less than 200,000 pounds per hour, mechanical (centrifugal) type dust collectors may be effective and economical depending on the applicable emission stand-



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Figure 3-9. Minimum metal temperatures for boiler heat recovery equipment.

ards. For a coal fired boiler with a spreader stoker, a mechanical collector in series with an electrostatic precipitator or baghouse also might be considered. Performance requirements and technical environmental standards must be carefully matched, and ultimate performance warranties and tests require careful and explicit definitions. Collected dust from a mechanical collector containing a large proportion of combustibles may be reinfected into the furnace for final burnout; this will increase steam generator

efficiency slightly but also will increase collector dust loading and carryover. Ultimate collected dust material must be handled and disposed of systematically to avoid objectionable environmental effects.

(b) Electrostatic precipitators. For pulverized coal firing, adequate particulate control will require electrostatic precipitators (ESP). ESP systems are well developed and effective, but add substantial capital and maintenance costs. Very high percent-

CONTAMINANT	1-YEAR	24-HOURS ⁽¹⁾	MAXIMUM CONCENTRATION AVERAGED OVER ⁽¹⁾		
			8-HOURS	3-HOURS	1-HOUR
Sulfur dioxide as SO ₂					
primary	80 ug/m ³	80 ug/m ³	--	--	--
secondary	--	--	--	300 ug/m ³	--
Particulates					
primary	75 ug/m ³	260 ug/m ³	--	--	--
secondary	60 ug/m ³	150 ug/m ³	--	--	--
Carbon monoxide					
primary and secondary	--	--	10 mg/m ³	--	40 mg/m ³
Photochemical oxidants					
primary and secondary		--	--	--	40 mg/m ³
Hydrocarbons					
primary and secondary		--	--	160 ug/m ³	--
Nitrogen dioxide					
primary and secondary	100 ug/m ³	--	--	--	--
Lead					
Primary and secondary	1.5 ug/m ³ (2)	--	--	--	--

Notes: (1) Not to be exceeded more than once per year.
 (2) Averaged over a calendar quarter.

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Table 3-4. Emission Levels Allowable, National Ambient Air Quality Standards.

Table 3-5. Uncontrolled Emissions.

Pollutant	COAL FIRED (Lb of Pollutant/Ton of Coal)		OIL FIRED (Lb of Pollutant/1000 Gal)		NATURAL GAS (Lb of Pollutant/10 ⁶ F t ³)
	<u>Pulverized Coal Boilers</u>	<u>Stokers or FBC Boilers</u>	<u>Residual Oil</u>	<u>Distillate Oil</u>	
Particulate	16A ¹	13A ²	10S ³ + 3	2	5-15
Sulfur Oxides	38S ³	38S ³	159S ³	144S ³	0.6
Nitrogen Oxides	18	15	60		

1. The letter A indicates that the weight percentage of ash in the coal should be multiplied by the value given. Example: If the factor is 16 and the ash content is 10 percent, the particulate emissions before the control equipment would be 10 times 16, or 160 pounds of particulate per ton of coal.
2. Without fly ash reinfection. With fly ash reinfection use 20A.
3. S equals the sulfur content, use like the factor A (see Note 1 above) for estimate emissions.

U.S. Environmental Protection Agency

Table 3-6. Characteristics of Cyclones for Particulate Control.

<u>Type</u>	<u>Body Diameter (Feet)</u>	<u>Gas Flow Ft /min</u>	<u>Pressure Drop (In. H O)</u>	<u>Inlet Velocity Ft/Sec</u>	<u>Collection Efficiency (%)</u>	<u>Application</u>	<u>Other</u>
Conventional	4-12	1,000-20,000	.5-2	20-70	50-80	Material handling. Exhaust gas pre-cleaner.	Large headroom requirements. Limited to large coarse particles large grain loadings.
High efficiency single cyclone	Less than 3	100-2,000	2-6	50-70	80-85	Industrial boiler particulate control.	Smaller space requirement. Parallel arrangement, inlet vane flow controls needed continuous dust removal system purge operation.
Multicyclones	.5-1	30,000-100,000	3-6	50-70	90-95	Industrial and utility boiler Particulate control.	Plenums required. Problems: gas recirculation fouling. Continuous dust removal system, flow control.
Irrigated cyclone (wet) high efficiency single unit	less than 3	100-2,000	2-6	50	90-95	Boiler application (low sulfur fuel) (low gas temp.).	Water rate 5-15 gal/1,000 ft ³ /min. Corrosion resistant materials.

U.S. Army Corps of Engineers

Table 3-2! Characteristics of Scrubbers for Particulate Control.

<u>Scrubber Type</u>	<u>Energy Type</u>	<u>Pressure Drop In. H O</u>	<u>Gas Flow Ft /Min</u>	<u>Internal Velocity Ft/Sec</u>	<u>Particle Collection Efficiency</u>	<u>Water Usage Per 1000 Gal/Min</u>
Centrifugal Scrubber	Low Energy	3-8	1,000- 20,000	50-150	80	3-5
Impingement & Entrainment	Low Energy	4-20	500- 50,000	50-150	60-90	10-40
Venturi	High Energy	4-200	200- 150,000	200-600	95-99	5-7
Ejector Venturi	High Energy	10-50	500- 10,000	200-500	90-98	70-145

U.S. Army Corps of Engineers

Table 3-8. Characteristics of Electrostatic Precipitators (ESP) for Particulate Control.

Type	Operating Temperature °F	Resistivity at 300° F ohm-cm	Gas Flow Ft/Min	Pressure Drop In. of Water
Hot ESP	600+	Greater Than 10^2	100,000+	Less Than 1
Cold ESP	300	Less Than 10^6		
Wet ESP	300-	Greater Than 10^2 below 10^4		

U.S. Army Corps of Engineers

Table 3-9. Characteristics of Baghouses for Particulate Control.

<u>System Type</u>	<u>Pressure Loss (Inches of Water)</u>	<u>Efficiency</u>	<u>Cloth Type</u>	<u>Filter Ratio (cfm/ft Cloth Area)</u>	<u>Recommended Application</u>
Shaker	3-6	99+%	Woven	1-5	Dust with good filter cleaning properties, intermittent collection.
Reverse Flow	3-6	99+%	Woven	1-5	Dust with good filter cleaning properties, high temperature collection (incinerator fly-ash) with glass bags.
Pulse Jet	3-6	99+%	Felted	4-20	Efficient for coal and oil fly ash collection.
Reverse Jet	3-8	99+%	Felted	10-30	Collection of fine dusts and fumes.
Envelope	3-6	99+%	Woven	1-5	Collection of highly abrasive dust .

U.S. Army Corps of Engineers

Table 3-10. Characteristics of Flue-Gas Desulfurization Systems for Particulate Control.

<u>System Type</u>	<u>SO Removal Efficiency (%)</u>	<u>Pressure Drop (Inches of Water)</u>	<u>Recovery and Regeneration</u>	<u>Operational Reliability</u>	<u>Retrofit to Existing Installations</u>
1) Limestone Boiler Injection Type	30-40%	Less Than 6"	No Recovery of Limestone	High	Yea
2) Limestone, Scrubber Injection Type	30-40%	Greater Than 6"	No Recovery of Lime	High	Yea
3) Lime, Scrubber, Injection Type	90%+	Greater Than 6"	No Recovery of Lime	Low	Yea
4) Magnesium Oxide	90%+	Greater Than 6"	Recovery of MgO and Sulfuric Acid	Low	Yea
5) Wellman-Lord	90%+	Greater Than 6"	Recovery of NaSO ₃ and Elemental Sulfur	Unknown	
6) Catalytic oxidation	85%	May be as high as 24"	Recovery of 80% H ₂ SO ₄	Unknown	No
7) Single Alkali Systems	90%+	Tray Tower Pressure Drop 1.6-2.0 in. H ₂ O/tray, w/Venturi add 10-14 in. H ₂ O	Little Recovery of Sodium Carbonate	Unknown	Yea
8) Dual Alkali	90-95%+		Regeneration of Sodium Hydroxide and Sodium Sulfites	Unknown	Yea

U.S. Army Corps of Engineers

Table 3-11. Techniques for Nitrogen Oxide Control.

<u>Technique</u>	<u>Potential NO Reduction (%)</u>	<u>Advantages</u>	<u>Disadvantages</u>
Load Reduction		Easily implemented; no additional equipment required; reduced particulate and SO _x emissions.	Reduction in generating capacity; possible reduction in boiler thermal efficiency.
Low Excess Air Firing	15 to 40	Increased boiler thermal efficiency; possible reduction in particulate emissions may be combined with a load reduction to obtain additional NO _x emission decrease; reduction in high temperature corrosion and ash deposition.	A combustion control system which closely monitors and controls fuel/air ratios is required.
Two Stage Combustion			
Coal	30	---	Boiler windboxes must be designed for this application.
Oil	40	---	
Gas	50	---	Furnace corrosion and particulate emissions may increase.
Off-Stoichiometric Combustion			
Coal	45	---	Control of alternate fuel rich/and fuel lean burners may be a problem during transient load conditions.
Reduced Combustion Air Preheat	10-50	---	Not applicable to coal or oil fired units; reduction in boiler thermal efficiency; increase in exit gas volume and temperature; reduction in boiler load.
Flue Gas Recirculation	20-50	Possible improvement in combustion efficiency and reduction in particulate emissions.	Boiler windbox must be modified to handle the additional gas volume; ductwork, fans and Controls required.

ages of particulate removal can be attained (99 percent, plus) but precipitators are sensitive to ash composition, fuel additives, flue gas temperatures and moisture content, and even weather conditions. ESP's are frequently used with and ahead of flue gas washing and desulfurization systems. They may be either hot precipitators ahead of the air preheater in the gas path or cold precipitators after the air preheater. Hot precipitators are more expensive because of the larger volume of gas to be handled and temperature influence on materials. But they are sometimes necessary for low sulfur fuels where cold precipitators are relatively inefficient.

(c) *Bag filters.* Effective particulate removal may be obtained with bag filter systems or bag houses, which mechanically filter the gas by passage through specially designed filter fabric surfaces. Bag filters are especially effective on very fine particles, and at relatively low flue gas temperatures. They may be used to improve or upgrade other particulate collection systems such as centrifugal collectors. Also they are probably the most economic choice for most medium and small size coal fired steam generators.

(d) *Flue gas desulfurization.* While various gaseous pollutants are subject to environmental control and limitation, the pollutants which must be removed from the power plant flue gases are the oxides of sulfur (SO_2 and SO_3). Many flue gas desulfurization (FGD) scrubbing systems to control SO_2 and SO_3 stack emission have been installed and operated, with wide variations in effectiveness, reliability, longevity and cost. For small or medium sized power plants, FGD systems should be avoided if possible by the use of low sulfur fuel. If the parameters of the project indicate that a FGD system is required, adequate allowances for redundancy, capital cost, operating costs, space, and environmental impact will be made. Alternatively, a fluidized bed boiler (para. 3-10 c) may be a better economic choice for such a project.

(1) Wet scrubbers utilize either limestone, lime, or a combination of lime and soda ash as sorbents for the SO_2 and SO_3 in the boiler flue gas stream. A mixed slurry of the sorbent material is sprayed into the flue gas duct where it mixes with and wets the particulate in the gas stream. The SO_2 and SO_3 reacts with the calcium hydroxide of the slurry to form calcium sulfate. The gas then continues to a separator tower where the solids and excess solution settle and separate from the water vapor saturated gas stream which vents to the atmosphere through the boiler stack. Wet scrubbers permit the use of coal with a sulfur content as high as 5 percent.

(2) Dry scrubbers generally utilize a diluted solution of slaked lime slurry which is atomized by

compressed air and injected into the boiler flue gas stream. SO_2 and SO_3 in the flue gas is absorbed by the slurry droplets and reacts with the calcium hydroxide of the slurry to form calcium sulfite. Evaporation of the water in the slurry droplets occurs simultaneously with the reaction. The dry flue gas then travels to a bag filter system and then to the boiler stack. The bag filter system collects the boiler exit solid particles and the dried reaction products. Additional remaining SO_2 and SO_3 are removed by the flue gas filtering through the accumulation on the surface of the bag filters, Dry scrubbers permit the use of coal with a sulfur content as high as 3 percent.

(3) *Induced draft fan requirements.* Induced draft fans will be designed with sufficient capacity to produce the required flow while overcoming the static pressure losses associated with the ductwork, economizer, air preheater, and air pollution control equipment under all operating (clean and dirty) conditions.

(4) *Waste removal.* Flue gas cleanup systems usually produce substantial quantities of waste products, often much greater in mass than the substances actually removed from the exit gases. Design and arrangement must allow for dewatering and stabilization of FGD sludge, removal, storage and disposal of waste products with due regard for environmental impacts.

3-12. Minor auxiliary systems

Various minor auxiliary systems and components are vital parts of the steam generator.

a. *Piping and valves.* Various piping systems are defined as parts of the complete boiler (refer to the ASME Boiler Code), and must be designed for safe and effective service; this includes steam and feed-water piping, fuel piping, blowdown piping, safety and control valve piping, isolation valves, drips, drains and instrument connections.

b. *Controls and instruments.* Superheater and burner management controls are best purchased along with the steam generator so that there will be integrated steam temperature and burner systems.

c. *Soot blowers.* Continuous or frequent on line cleaning of furnace, boiler economizer, and air preheater heating surfaces is required to maintain performance and efficiency. Soot blower systems, steam or air operated, will be provided for this purpose. The selection of steam or air for soot blowing is an economic choice and will be evaluated in terms of steam and makeup water vs. compressed air costs with due allowance for capital and operating cost components.

Section III. FUEL HANDLING AND STORAGE SYSTEMS

3-13. Introduction

a. *Purpose.* Figure 3-10 is a block diagram illustrating the various steps and equipment required for a solid fuel storage and handling system.

b. *Fuels for consideration.* Equipment required for a system depends on the type of fuel or fuels burned. The three major types of fuels utilized for steam raising are gaseous, liquid and solid.

3-14. Typical fuel oil storage and handling system

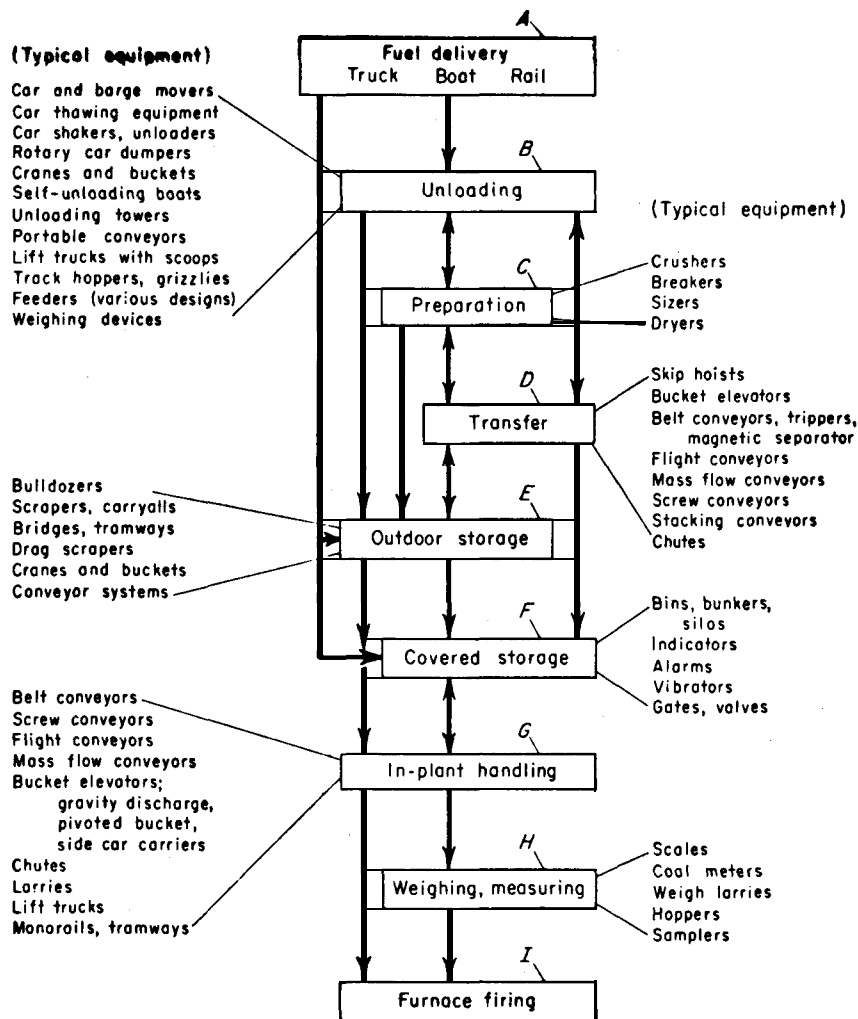
The usual power plant fuel oil storage and handling system includes:

a. *Unloading and storage.*

(1) Unloading pumps will be supplied, as required for the type of delivery system used, as part

of the power plant facilities. Time for unloading will be analyzed and unloading pump(s) optimized for the circumstances and oil quantities involved. Heavier fuel oils are loaded into transport tanks hot and cool during delivery. Steam supply for tank car heaters will be provided at the plant if it is expected that the temperature of the oil delivered will be below the 120 to 150°F. range.

(2) Storage of the fuel oil will be in two tanks so as to provide more versatility for tank cleanout inspection and repair. A minimum of 30 days storage capacity at maximum expected power plant load (maximum steaming capacity of all boilers with maximum expected turbine generator output and maximum export steam, if any) will be provided. Factors such as reliability of supply and whether



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Figure 3-10. Coal handling system diagram.

backup power is available from other sources may result in additional storage requirements. Space for future tanks will be allocated where additional boilers are planned, but storage capacity will not be provided initially.

(3) Storage tank(s) for heavy oils will be heated with a suction type heater, a continuous coil extending over the bottom of the tank, or a combination of both types of surfaces. Steam is usually the most economical heating medium although hot water can be considered depending on the temperatures at which low level heat is available in the power plant. Tank exterior insulation will be provided.

b. Fuel pumps and heaters.

(1) Fuel oil forwarding pumps to transfer oil from bulk storage to the burner pumps will be provided. Both forwarding and burner pumps should be selected with at least 10 percent excess capacity over maximum burning rate in the boilers. Sizing will consider additional pumps for future boilers and pressure requirements will be selected for pipe friction, control valves, heater pressure drops, and burners. A reasonable selection would be one pump per boiler with a common spare if the system is designed for a common supply to all boilers. For high pressure mechanical atomizing burners, each boiler may also have its own metering pump with spare.

(2) Pumps may be either centrifugal or positive displacement. Positive displacement pumps will be specified for the heavier fuel oils. Centrifugal pumps will be specified for crude oils. Where absolute reliability is required, a spare pump driven by a steam turbine with gear reducer will be used. For "black starts," or where a steam turbine may be inconvenient, a dc motor driver may be selected for use for relatively short periods.

(3) At least two fuel oil heaters will be used for reliability and to facilitate maintenance. Typical heater design for Bunker C! fuel oil will provide for temperature increases from 100 to 230° F using steam or hot water for heating medium.

c. Piping system.

(1) The piping system will be designed to maintain pressure by recirculating excess oil to the bulk storage tank. The burner pumps also will circulate back to the storage tank. A recirculation connection will be provided at each burner for startup. It will be manually valved and shut off after burner is successfully lit off and operating smoothly.

(2) Piping systems will be adapted to the type of burner utilized. Steam atomizing burners will have "blowback" connections to cleanse burners of fuel with steam on shutdown. Mechanical atomizing burner piping will be designed to suit the requirements of the burner.

d. Instruments and control. Instruments and

controls include combustion controls, burner management system, control valves and shut off valves.

3-15. Coal handling and storage systems

a. Available systems. The following principal systems will be used as appropriate for handling, storing and reclaiming coal:

(1) *Relatively small to intermediate system;* coal purchases sized and washed. A system with a track or truck (or combined track/truck) hopper, bucket elevator with feeder, coal silo, spouts and chutes, and a dust collecting system will be used. Elevator will be arranged to discharge via closed chute into one or two silos, or spouted to a ground pile for moving into dead storage by bulldozer. Reclaim from dead storage will be by means of bulldozer to track/truck hopper.

(2) *Intermediate system;* coal purchased sized and washed. This will be similar to the system described in (1) above but will use an enclosed skip hoist instead of a bucket elevator for conveying coal to top of silo.

(3) *Intermediate system alternatives.* For more than two boilers, an overbunker flight or belt conveyor will be used. If mine run, uncrushed coal proves economical, a crusher with feeder will be installed in association with the track/truck hopper.

(4) *Larger systems, usually with mine run coal.* A larger system will include track or truck (or combined track/truck) unloading hopper, separate dead storage reclaim hoppers, inclined belt conveyors with appropriate feeders, transfer towers, vibrating screens, magnetic separators, crusher(s), overbunker conveyor(s) with automatic tripper, weighing equipment, sampling equipment, silos, dust collecting system(s), fire protection, and like items. Where two or more types of coal are burned (e.g., high and low sulphur), blending facilities will be required.

(5) *For cold climates.* All systems, regardless of size, which receive coal by railroad will require car thawing facilities and car shakeouts for loosening frozen coal. These facilities will not be provided for truck unloading because truck runs are usually short.

b. Selection of handling capacity. Coal handling system capacity will be selected so that ultimate planned 24-hour coal consumption of the plant at maximum expected power plant load can be unloaded or reclaimed in not more than 7-1/2 hours, or within the time span of one shift after allowance of a 1/2-hour margin for preparation and cleanup time. The handling capacity should be calculated using the worst (lowest heating value) coal which may be burned in the future and a maximum steam capacity boiler efficiency at least 3 percent less than guaranteed by boiler manufacturer.

c. *Outdoor storage pile.* The size of the outdoor storage pile will be based on not less than 90 days of the ultimate planned 24-hour coal consumption of the plant at maximum expected power plant load. Some power plants, particularly existing plants which are being rehabilitated or expanded, will have outdoor space limitations or are situated so that it is environmentally inadvisable to have a substantial outdoor coal pile.

d. *Plant Storage.*

(1) For small or medium sized spreader stoker fired plants, grade mounted silo storage will be specified with a live storage shelf above and a reserve storage space below. Usually arranged with one silo per boiler and the silo located on the outside of the firing aisle opposite the boiler, the live storage shelf will be placed high enough so that the spout to the stoker hopper or coal scale above the hopper emerges at a point high enough for the spout angle to be not less than 60 degrees from the horizontal. The reserve storage below the live storage shelf will be arranged to recirculate back to the loading point of the elevator so that coal can be raised to the top of the live storage shelf as needed. Figure 3-11 shows a

typical bucket elevator grade mounted silo arrangement for a small or medium sized steam generating facility.

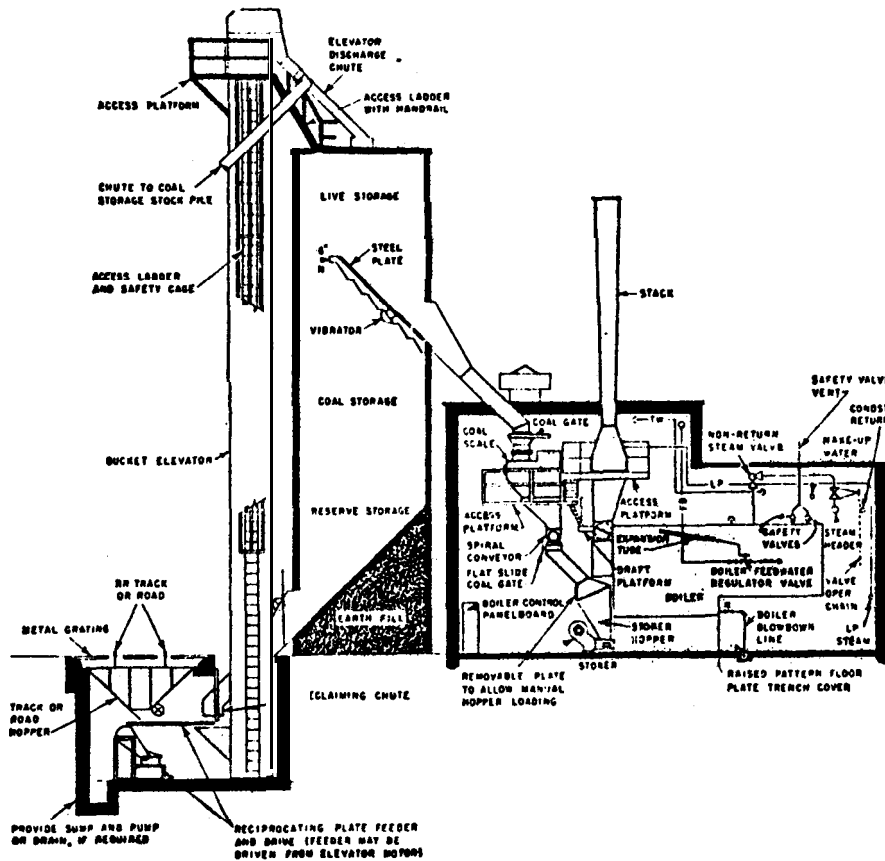
(2) For large sized spreader stoker fired plants, silo type overhead construction will be specified. It will be fabricated of structural steel or reinforced concrete with stainless steel lined conical bottoms.

(3) For small or medium sized plants combined live and reserve storage in the silo will be not less than 3 days at 60 percent of maximum expected load of the boiler(s) being supplied from the silo so that reserves from the outside storage pile need not be drawn upon during weekends when operating staff is reduced. For large sized plants this storage requirement will be 1 day.

e. *Equipment and systems.*

(1) *Bucket elevators.* Bucket elevators will be chain and bucket type. For relatively small installations the belt and bucket type is feasible although not as rugged as the chain and bucket type. Typical bucket elevator system is shown in Figure 3-11.

(2) *Skip hoists.* Because of the requirement for dust suppression and equipment closure dictated by



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Figure 3-11. Typical coal handling system for spreader stoker fired boiler (with bucket elevator).

environmental considerations, skip hoists will not be specified.

(3) *Belt conveyors.* Belt conveyors will be selected for speeds not in excess of 500 to 550 feet per minute. They will be specified with roller bearings for pulleys and idlers, with heavy duty belts, and with rugged helical or herringbone gear drive units.

(4) *Feeders.* Feeders are required to transfer coal at a uniform rate from each unloading and intermediate hopper to the conveyor. Such feeders will be of the reciprocating plate or vibrating pan type with single or variable speed drive. Reciprocating type feeders will be used for smaller installations; the vibrating type will be used for larger systems.

(5) *Miscellaneous.* The following items are required as noted

(a) Magnetic separators for removal of tramp iron from mine run coal.

(b) Weigh scale at each boiler and, for larger installations, for weighing in coal as received. Scales will be of the belt type with temperature compensated load cell. For very small installations, a low cost displacement type scale for each boiler will be used.

(c) Coal crusher for mine run coal; for large installations the crusher will be preceded by vibrating (scalping) screens for separating out and by-passing fines around the crusher.

(d) Traveling tripper for overbunker conveyor serving a number of bunkers in series.

(e) One or more coal samplers to check "as re-

ceived" and 'as fired" samples for large systems.

(f) Chutes, hoppers and skirts, as required, fabricated of continuously welded steel for dust tightness and with wearing surfaces lined with stainless steel. Vibrators and poke holes will be provided at all points subject to coal stoppage or hang-up.

(g) Car shakeout and a thaw shed for loosening frozen coal from railroad cars.

(h) Dust control systems as required throughout the coal handling areas. All handling equipment—hoppers, conveyors and galleries—will be enclosed in dust tight casings or building shells and provided with negative pressure ventilation complete with heated air supply, exhaust blowers, separators, and bag filters for removing dust from exhausted air. In addition, high dust concentration areas located outside which cannot be enclosed, such as unloading and reclaim hoppers, will be provided with spray type dust suppression equipment.

(i) Fire protection system of the sprinkler type.

(j) Freeze protection for any water piping located outdoors or in unheated closures as provided for dust suppression or fire protection systems.

(k) A vacuum cleaning system for maintenance of coal handling systems having galleries and equipment enclosures.

(l) System of controls for sequencing and monitoring entire coal handling system.

Section IV. ASH HANDLING SYSTEMS

3-16. Introduction

a. Background.

(1) Most gaseous fuels burn cleanly, and the amount of incombustible material is so small that it can be safely ignored. When liquid or solid fuel is fired in a boiler, however, the incombustible material, or ash, together with a small amount of unburned carbon chiefly in the form of soot or cinders, collects in the bottom of the furnace or is carried out in a lightweight, finely divided form usually known loosely as "fly ash." Collection of the bottom ash from combustion of coal has never been a problem as the ash is heavy and easily directed into hoppers which may be dry or filled with water,

(2) Current ash collection technology is capable of removing up to 99 percent or more of all fly ash from the furnace gases by utilizing a precipitator or baghouse, often in combination with a mechanical collector. Heavier fly ash particles collected from the boiler gas passages and mechanical collectors often have a high percentage of unburned carbon content, particularly in the case of spreader stoker fired boilers; this heavier material may be reinfected into the furnace to reduce unburned carbon losses and in-

crease efficiency, although this procedure does increase the dust loading on the collection equipment downstream of the last hopper from which such material is reinfected.

(3) It is mandatory to install precipitators or baghouses on all new coal fired boilers for final cleanup of the flue gases prior to their ejection to atmosphere. But in most regions of the United States, mechanical collectors alone are adequate for heavy oil fired boilers because of the conventionally low ash content of this type of fuel. An investigation is required, however, for each particular oil fired unit being considered.

b. *Purpose.* It is the purpose of the ash handling system to:

(1) Collect the bottom ash from coal-fired spreader stoker or AFBC boilers and to convey it dry by vacuum or hydraulically by liquid pressure to a temporary or permanent storage terminal. The latter may be a storage bin or silo for ultimate transfer to rail or truck for transport to a remote disposal area, or it maybe an on-site fill area or storage pond for the larger systems where the power plant site is

adequate and environmentally acceptable for this purpose.

(2) Collect fly ash and to convey it dry to temporary or permanent storage as described above for bottom ash. Fly ash, being very light, will be wetted and is mixed with bottom ash prior to disposal to prevent a severe dust problem.

3-17. Description of major components

a. Typical oil fired system. Oil fired boilers do not require any bottom ash removal facilities, since ash and unburned carbon are light and carried out with the furnace exit gas. A mechanical collector may be required for small or intermediate sized boilers having steaming rates of 200,000 pounds per hour or less. The fly ash from the gas passage and mechanical collector hoppers can usually be handled manually because of the small amount of fly ash (soot) collected. The soot from the fuel oil is greasy and can coagulate at atmospheric temperatures making it difficult to handle. To overcome this, hoppers should be heated with steam, hot water, or electric power. Hoppers will be equipped with an outlet valve having an air lock and a means of attaching disposable paper bags sized to permit manual handling. Each hopper will be selected so that it need not be evacuated more than once every few days. If boiler size and estimated soot/ash loading is such that manual handling becomes burdensome, a vacuum or hydraulic system as described below should be considered.

b. Typical ash handling system for small or intermediate sized coal fired boilers;

(1) Plant fuel burning rates and ash content of coal are critical in sizing the ash handling system. Sizing criteria will provide for selecting hoppers and handling equipment so that ash does not have to be removed more frequently than once each 8-hour shift using the highest ash content coal anticipated and with boiler at maximum continuous steaming capacity. For the smaller, non-automatic system it may be cost effective to select hoppers and equipment which will permit operating at 60 percent of maximum steam capacity for 3 days without removing ash to facilitate operating with a minimum weekend crew.

(2) For a typical military power plant, the most economical selection for both bottom and fly ash disposal is a vacuum type dry system with a steam jet

or mechanical exhauster for creating the vacuum (Figure 3-12). This typical plant would probably have a traveling grate spreader stoker, a mechanical collector, and a baghouse; in all likelihood, no on-site ash disposal area would be available.

(3) The ash system for the typical plant will include the following for each boiler:

(a) A refractory lined bottom ash hopper to receive the discharge from the traveling grate. A clinker grinder is not required for a spreader stoker although adequate poke holes should be incorporated into the outlet sections of the hopper.

(b) Gas passage fly ash hoppers as required by the boiler design for boiler proper, economizer, and air heater.

(c) Collector fly ash hoppers for the mechanical collector and baghouse.

(d) Air lock valves, one at each hopper outlet, manually or automatically operated as selected by the design engineer.

(4) And the following items are common to all boilers in the plant:

(a) Ash collecting piping fabricated of special hardened ferro-alloy to transfer bottom and fly ash to Storage.

(b) Vacuum producing equipment, steam or mechanical exhauster as may prove economical. For plants with substantial export steam and with low quality, relatively inexpensive makeup requirements, steam will be the choice. For plants with high quality, expensive makeup requirements, consideration should be given to the higher cost mechanical exhauster.

(c) Primary and secondary mechanical (centrifugal) separators and baghouse filter are used to clean the dust out of the ash handling system exhaust prior to discharge to the atmosphere. This equipment is mounted on top of the silo.

(d) Reinforced concrete or vitrified tile overhead silo with separator and air lock for loading silo with a "dustless" unloader designed to dampen ashes as they are unloaded into a truck or railroad car for transport to remote disposal.

(e) Automatic control system for sequencing operation of the system. Usually the manual initiation of such a system starts the exhauster and then removes bottom and fly ash from each separator collection point in a predetermined sequence. Ash unloading to vehicles is separately controlled.

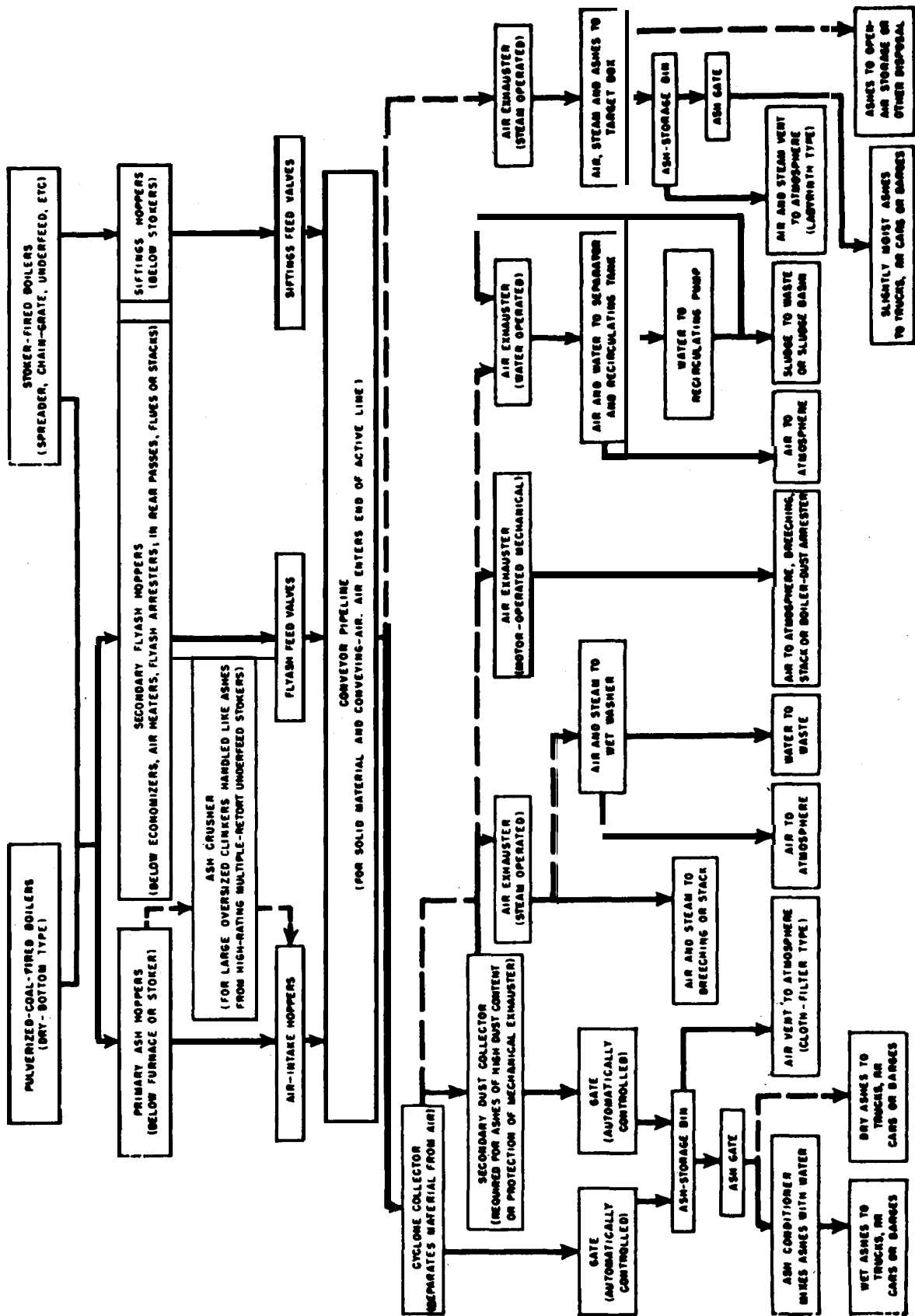
Section V. TURBINES AND AUXILIARY SYSTEMS

3-18. Turbine prime movers

The following paragraphs on turbine generators discuss size and other overall characteristics of the turbine generator set. For detailed discussion of the

generator and its associated electrical accessories, refer to Chapter 4.

a. Size and type ranges. Steam turbine generators for military installations will fall into the fol-



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Figure 3-12. Pneumatic ash handling systems—variations.

lowing size ranges:

(1) *Small turbine generators.* From 500 to about 2500 kW rated capacity, turbine generators will usually be single stage, geared units without extraction openings for either back pressure or condensing service. Rated condensing pressures for single stage turbines range from 3 to 6 inches Hga. Exhaust pressures for back pressure units in cogeneration service typically range from 15 psig to 250 psig.

(2) *Intermediate turbine generators.* From about 2500 to 10,000 kW rated capacity, turbine generators will be either multi-stage, multi-valve machines with two pole direct drive generators turning at 3600 rpm, or high speed turbines with gear reducers may also be used in this size range. Units are equipped with either uncontrolled or controlled (automatic) extraction openings. Below 4000 kW, there will be one or two openings with steam pressures up to 600 psig and 750°F. From 4000 kW to 10,000 kW, turbines will be provided with two to four uncontrolled extraction openings, or one or two automatic extraction openings. These turbines would have initial steam conditions from 600 psig to 1250 psig, and 750°F to 900°F. Typical initial steam conditions would be 600 psig, 825° For 850 psig, 900°F.

(3) *Large turbine generators.* In the capacity range 10,000 to 30,000 kW, turbine generators will be direct drive, multi-stage, multi-valve units. For electric power generator applications, from two to five uncontrolled extraction openings will be required for feedwater heating. In cogeneration applications which include the provision of process or heating steam along with power generation, one automatic extraction opening will be required for each level of processor heating steam pressure specified, along with uncontrolled extraction openings for feedwater heating. Initial steam conditions range up to 1450 psig and 950 °F with condensing pressures from 1 1/2 to 4 inches Hga.

b. Turbine features and accessories. In all size ranges, turbine generator sets are supplied by the manufacturer with basic accessories as follows:

(1) Generator with cooling system, excitation and voltage regulator, coupling, and speed reduction gear, if used.

(2) Turbine and generator (and gear) lubrication system including tank, pumps, piping, and controls.

(3) Load speed governor, emergency overspeed governor, and emergency inlet steam trip valve with related hydraulic piping.

(4) Full rigid base plate in small sizes or separate mounting sole plates for installation in concrete pedestal for larger units.

(5) Insulation and jacketing, instruments, turning gear and special tools.

3-19. Generators

For purposes of this section, it is noted that the generator must be mechanically compatible with the driving turbine, coupling, lubrication system, and vibration characteristics (see Chapter 4 for generator details).

3-20. Turbine features

a. General. Turbine construction may be generally classified as high or low pressure, single or multi-stage, back pressure on condensing, direct drive or gear reducer drive, and for electric generator or for mechanical drive service.

(1) *Shell pressures.* High or low pressure construction refers generally to the internal pressures to be contained by the main shell or casing parts.

(2) *Single vs. multi-stage.* Single or multi-stage designs are selected to suit the general size, enthalpy drops and performance requirements of the turbine. Multi-stage machines are much more expensive but are also considerably more efficient. Single stage machines are always less expensive, simpler and less efficient. They may have up to three velocity wheels of blading with reentry stationary vanes between wheels to improve efficiency. As casing pressure of single stage turbines are equal to exhaust pressures, the design of seals and bearings is relatively simple.

(3) *Back pressure vs. condensing.* Selection of a back pressure or a condensing turbine is dependent on the plant function and cycle parameters. (See Chapter 3, Section I for discussion of cycles.) Condensing machines are larger and more complex with high pressure and vacuum sealing provisions, steam condensers, stage feedwater heating, extensive lube oil systems and valve gear, and related auxiliary features.

(4) *Direct drive vs. geared sets.* Direct drive turbines generators turn the turbine shaft at generator speed. Units 2500 kW and larger are normally direct connected. Small, and especially single stage, turbines may be gear driven for compactness and for single stage economy. Gear reducers add complexity and energy losses to the turbine and should be used only after careful consideration of overall economy and reliability.

(5) *Mechanical drive.* Main turbine units in power plants drive electrical generators, although large pumps or air compressors may also be driven by large turbines. In this event, the turbines are called "mechanical drive" turbines. Mechanical drive turbines are usually variable speed units with special governing equipment to adapt to best economy balance between driver (turbine) and driven machine. Small auxiliary turbines for cycle pumps,

fans, or air compressor drives are usually single stage, back pressure, direct drive type designed for mechanical simplicity and reliability. Both constant speed and variable speed governors are used depending on the application.

b. Arrangement. Turbine generators are horizontal shaft type with horizontally split casings. Relatively small mechanical drive turbines may be built with vertical shafts. Turbine rotor shaft is usually supported in two sleeve type, self aligning bearings, sealed and protected from internal casing steam conditions. Output shaft is coupled to the shaft of the generator which is provided with its own enclosure but is always mounted on the same foundation as the turbine.

(1) *Balance.* Balanced and integrated design of the turbine, coupling and generator moving parts is important to successful operation, and freedom from torsional or lateral vibrations as well as prevention of expansion damage are essential.

(2) *Foundations.* Foundations and pedestals for turbine generators will be carefully designed to accommodate and protect the turbine generator, condenser, and associated equipment. Strength, mass, stiffness, and vibration characteristics must be considered. Most turbine generator pedestals in the United States are constructed of massive concrete.

3-21. Governing and control

a. Turbine generators speed/load control. Electrical generator output is in the form of synchronized ac electrical power, causing the generator and driving turbine to rotate at exactly the same speed (or frequency) as other synchronized generators connected into the common network. Basic speed/load governing equipment is designed to allow each unit to hold its own load steady at constant frequency, or to accept its share of load variations, as the common frequency rises and falls. Very small machines may use direct mechanical governors, but the bulk of the units will use either mechanical-hydraulic governing systems or electrohydraulic systems. Non-reheat condensing units 5000 kW and larger and back pressure units without automatic extraction will be equipped with mechanical-hydraulic governing. For automatic extraction units larger than 20,000 kW, governing will be specified either with a mechanical-hydraulic or an electro-hydraulic system.

b. Overspeed governors. All turbines require separate safety or overspeed governing systems to insure inlet steam interruption if the machine exceeds a safe speed for any reason. The emergency governor closes a specially designed stop valve which not only shuts off steam flow but also trips various safety devices to prevent overspeed by flash steam in-

duction through the turbine bleed (extraction) points.

c. Single and multi-valve arrangements. Whatever type of governor is used, it will modulate the turbine inlet valves to regulate steam flow and turbine output. For machines expected to operate extensively at low or partial loads, multi-valve arrangements improve economy. Single valve turbines, in general, have equal economy and efficiency at rated load, but lower part load efficiencies.

3-22. Turning gear

a. General. For turbines sized 10,000 kW and larger, a motor operated turning gear is required to prevent the bowing of the turbine rotor created by the temperature differential existing between the upper and lower turbine casings during the long period after shutdown in which the turbine cools down. The turbine cannot be restarted until it has completely cooled down without risk of damage to inter-state packing and decrease of turbine efficiency, causing delays in restarting. The turning gear is mounted at the exhaust end of the turbine and is used to turn the rotor at a speed of 1 to 4 rpm when the turbine is shut down in order to permit uniform cooling of the rotor. Turning gear is also used during startup to evenly warm up the rotor before rolling the turbine with steam and as a jacking device for turning the rotor as required for inspection and maintenance when the turbine is shut down.

b. Arrangement and controls. The turning gear will consist of a horizontal electric motor with a set of gear chains and a clutching arrangement which engages a gear ring on the shaft of the turbine. Its controls are arranged for local and/or remote starting and to automatically disengage when the turbine reaches a predetermined speed during startup with steam. It is also arranged to automatically engage when the turbine has been shut down and decelerated to a sufficiently slow speed. Indicating lights will be provided to indicate the disengaged or engaged status of the turning gear and an interlock provided to prevent the operation of the turning gear if the pressure in the turbine lubrication oil system is below a predetermined safe setting.

3-23. Lubrication systems

a. General. Every turbine and its driven machine or generator requires adequate lubricating oil supply including pressurization, filtration, oil cooling, and emergency provisions to insure lubrication in the event of a failure of main oil supply. For a typical turbine generator, an integrated lube oil storage tank with built in normal and emergency pumps is usually provided. Oil cooling may be by means of an

external or internal water cooled heat exchanger. Oil temperatures should be monitored and controlled, and heating may be required for startup.

b. Oil Pumps. Two full capacity main lube oil pumps will be provided. One will be directly driven from the turbine shaft for multi-stage machines. The second full size pump will be ac electric motor driven. An emergency dc motor driven or turbine-driven backup pump will be specified to allow orderly shutdown during normal startup and shutdown when the shaft driven pump cannot maintain pressure, or after main pump failure, or in the event of failure of the power supply to the ac electric motor driven pumps.

c. Filtration. Strainers and filters are necessary for the protection and longevity of lubricated parts. Filters and strainers should be arranged in pairs for on line cleaning, inspection, and maintenance. Larger turbine generator units are sometimes equipped with special off base lubrication systems to provide separate, high quality filtering.

3-24. Extraction features

a. Uncontrolled extraction systems. Uncontrolled bleed or extraction openings are merely nozzles in the turbine shell between stages through which relatively limited amounts of steam may be extracted for stage feedwater heating. Such openings add little to the turbine cost as compared with the cost of feedwater heaters, piping, and controls. Turbines so equipped are usually rated and will have efficiencies and performance based on normal extraction pressures and regenerative feedwater heating calculations. Uncontrolled extraction opening pressures will vary in proportion to turbine steam flow, and

extracted steam will not be used or routed to any substantial uses except for feedwater heating.

b. Automatic extraction. Controlled or automatic extraction turbines are more elaborate and equipped with variable internal orifices or valves to modulate internal steam flows so as to maintain extraction pressures within specified ranges. Automatic extraction machine governors provide automatic self-contained modulation of the internal flow orifices or valves, using hydraulic operators. Automatic extraction governing systems can also be adapted to respond to external controls or cycle parameters to permit extraction pressures to adjust to changing cycle conditions.

c. Extraction turbine selection. Any automatic extraction turbine is more expensive than its straight uncontrolled extraction counterpart of similar size, capacity and type; its selection and use require comprehensive planning studies and economic analysis for justification. Sometimes the same objective can be achieved by selecting two units, one of which is an uncontrolled extraction-condensing machine and the other a back pressure machine.

3-25. Instruments and special tools

a. Operating instruments. Each turbine will be equipped with appropriate instruments and alarms to monitor normal and abnormal operating conditions including speed, vibration, shell and rotor expansions, steam and metal temperatures, rotor straightness, turning gear operation, and various steam, oil and hydraulic system pressures.

b. Special tool. Particularly for larger machines, complete sets of special tools, lifting bars, and related special items are required for organized and effective erection and maintenance.

Section VI. CONDENSER AND CIRCULATING WATERSYSTEM

3-26. Introduction

a. Purpose.

(1) The primary purpose of a condenser and circulating water system is to remove the latent heat from the steam exhausted from the exhaust end of the steam turbine prime mover, and to transfer the latent heat so removed to the circulating water which is the medium for dissipating this heat to the atmosphere. A secondary purpose is to recover the condensate resulting from the phase change in the exhaust steam and to recirculate it as the working fluid in the cycle.

(2) Practically, these purposes are accomplished in two steps. In the first step, the condenser is supplied with circulating water which serves as a medium for absorbing the latent heat in the condensing exhaust steam. The source of this circulat-

ing water can be a natural body of water such as an ocean, a river, or a lake, or it can be from a recirculated source such as a cooling tower or cooling pond. In the second step, the heated circulating water is rejected to the natural body of water or recirculated source which, in turn, transfers the heat to the atmosphere, principally by evaporative cooling effect.

b. Equipment required—general. Equipment required for a system depends on the type of system utilized. There are two basic types of condensers: surface and direct contact.

There are also two basic types of cooling systems:

Once through; and

Recirculating type, including cooling ponds, mechanical draft cooling towers, natural draft cooling towers, or a combination of a pond and tower.

3-27. Description of major components

a. Surface condensers.

(1) *General description.* These units are designed as shell and tube heat exchangers. A surface condenser consists of a casing or shell with a chamber at each end called a "water box." Tube sheets separate the two water boxes from the center steam space. Banks of tubes connect the water boxes by piercing the tube sheets; the tubes essentially fill the shell or steam space. Circulating water pumps force the cooling (circulating) water through the water boxes and the connecting tubes. Uncontaminated condensate is recovered in surface condensers since the cooling water does not mix with the condensing steam. Steam pressure in a condenser (or vacuum) depends mainly on the flow rate and temperature of the cooling water and on the effectiveness of air removal equipment.

(2) *Passes and water boxes.*

(a) Tubing and water boxes may be arranged for single pass or two pass flow of water through the shell. In single pass units, water enters the water box at one end of the tubes, flows once through all the tubes in parallel, and leaves through the outlet water box at the opposite end of the tubes. In two pass units, water flows through the bottom half of the tubes (sometimes the top half) in one direction, reverses in the far end water box, and returns through the upper or lower half of the tubes to the near water box. Water enters and leaves through the near water box which is divided into two chambers by a horizontal plate. The far end water box is undivided to permit reversal of flow.

(b) For a relatively large cooling water source and low circulating water pump heads (hence low unit pumping energy costs), single pass units will be used. For limited cooling water supplies and high circulating water pump heads (hence high unit pumping energy costs), two pass condensers will be specified. In all cases, the overall condenser-circulating water system must be optimized by the designer to arrive at the best combination of condenser surface, temperature, vacuum, circulating water pumps, piping, and ultimate heat rejection equipment.

(c) Most large condensers, in addition to the inlet waterbox horizontal division, have vertical partitions to give two separate parallel flow paths through the shell. This permits taking half the condensing surface out of service for cleaning while water flows through the other half to keep the unit running at reduced load.

(3) *Hot well.* The hot well stores the condensate and keeps a net positive suction head on the condensate pumps. Hot well will have a capacity of at least 3 minutes maximum condensing load for surges and

to permit variations in level for the condensate control system.

(4) *Air removal offtakes.* One or more air offtakes in the steam space lead accumulating air to the air removal pump.

(5) *Tubes.*

(a) The tubes provide the heat transfer surface in the condenser are fastened into tube sheets, usually made of Muntz metal. Modern designs have tubes rolled into both tube sheets; for ultra-tightness, alloy steel tubes may be welded into tube sheets of appropriate material. Admiralty is the most common tube material and frequently is satisfactory for once through systems using fresh water and for recirculating systems. Tube material in the "off gas" section of the condenser should be stainless steel because of the highly corrosive effects of carbon dioxide and ammonia in the presence of moisture and oxygen. These gases are most concentrated in this section. Other typical condenser tube materials include:

- (1) Cupronickel
- (2) Aluminum bronze
- (3) Aluminum brass
- (4) Various grades of stainless steel

(b) Condenser tube water velocities range from 6 to 9 feet per second (Table 3-12). Higher flow rates raise pumping power requirements and erode tubes at their entrances, thus shortening their life expectancy. Lower velocities are inefficient from a heat transfer point of view. Tubes are generally installed with an upwardly bowed arc. This provides for thermal expansion, aids drainage in a shutdown condenser, and helps prevent tube vibration.

(b) *Direct contact condensers.* Direct contact condensers will not be specified.

c. *Condenser auxiliaries.*

(1) *General.* A condenser needs equipment and conduits to move cooling water through the tubes, remove air from the steam space, and extract condensate from the hotwell. Such equipment and conduits will include:

- (a) Circulating water pumps.
- (b) Condensate or hotwell pumps.
- (c) Air removal equipment and piping.
- (d) Priming ejectors.
- (e) Atmospheric relief valve.

(f) *Inlet water* tunnel, piping, canal, or combination of these conduits.

(g) *Discharge water* tunnel, piping or canal, or combination of these conduits.

(2) *Circulating water pumps.* A condenser uses 75 to 100 pounds of circulating water per pound of steam condensed. Hence, large units need substantial water flows; to keep pump work to a minimum, top of condenser water boxes in a closed system will

Table 3-12. Condenser Tube Design Velocities.

Material	Design Velocities fps		
	Fresh Water	Brackish Water	Salt Water
Admiralty Metal	7.0	(1)	(1)
Aluminum Brass ⁽²⁾	8.0	7.0	7.0
Copper-Nickel Alloys:			
90-10	8.0	8.0	7.0 to 7.5
80-20	8.0	8.0	7.0 to 7.5
70-30	9.0	9.0	8.0 to 8.5
Stainless Steel	9.0 to 9.5	8 . 0 ⁽³⁾	8 . 0 ⁽³⁾
Aluminum ⁽⁴⁾	8.0	7.0	6.8

NOTES :

- (1) Not normally used, but if used, velocity shall not exceed 6.0 fps.
- (2) For salt and brackish water, velocities in excess of 6.8 fps are not recommended.
- (3) Minimum velocity of 5.5 fps to prevent chloride attack.
- (4) Not recommended for circulating water containing high concentration of heavy metal salts.

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not be higher than approximately 27 feet above minimum water source level which permits siphon operation without imposing static head. With a siphon system, air bubbles tend to migrate to the top of the system and must be removed with vacuum-producing equipment. The circulating pumps then need to develop only enough head to overcome the flow resistance of the circulating water circuit. Circulating pumps for condensers are generally of the centrifugal type for horizontal pumps, and either mixed flow or propeller type for vertical pumps. Vertical pumps will be specified because of their adaptability for intake structures and their ability to handle high capacities at relatively low heads. Pump material will be selected for long life.

(3) *Condensate pumps.* Condensate (or hotwell)

pumps handle much smaller flows than the circulating water pumps. They must develop heads to push water through atmospheric pressure, pipe and control valve friction, closed heater water circuit friction, and the elevation of the deaerator storage tank. These pumps take suction at low pressure of two inches Hg absolute or less and handle water at saturation temperature; to prevent flashing of the condensate, they are mounted below the hotwell to receive a net positive suction head. Modern vertical "can" type pumps will be used. Specially designed pump glands prevent air leakage into the condensate, and vents from the pump connecting to the vapor space in the condenser prevent vapor binding.

(4) *Spare pumps.* Two 100 percent pumps for both circulating water and condensate service will

be specified. If the circulating water system serves more than one condenser, there will be one circulating pump per condenser with an extra pump as a common spare. Condensate pump capacity will be sized to handle the maximum condenser load under any condition of operation (e.g., with automatic extraction to heating or process shutoff and including all feedwater heater drains and miscellaneous drips received by the condenser.)

(5) *Air removal.*

(a) Non-condensable gases such as air, carbon dioxide, and hydrogen migrate continuously into the steam space of a condenser inasmuch as it is the lowest pressure region in the cycle. These gases may enter through leakage at glands, valve bonnets, porous walls, or may be in the throttle steam. Those gases not dissolved by the condensate diffuse throughout the steam space of the condenser. As these gases accumulate, their partial pressure raises the condenser total pressure and hence decreases efficiency of the turbine because of loss of available energy. The total condenser pressure is:

$$P_c = P_s + P_a$$

where P_s = steam saturation pressure corresponding to steam temperature

$$P_a = \text{air pressure (moisture free)}$$

This equation shows that air leakage must be removed constantly to maintain lowest possible vacuum for the equipment selected and the particular exhaust steam loading. In removing this air, it will always have some entrained vapor. Because of its subatmospheric pressure, the mixture must be compressed for discharge to atmosphere.

(b) Although the mass of air leakage to the condenser may be relatively small because of its very low pressure, its removal requires handling of a large volume by the air removal equipment. The air offtakes withdraw the air-vapor moisture from the steam space over a cold section of the condenser tubes or through an external cooler, which condenses part of the moisture and increases the air-to-steam ratio. Steam jets or mechanical vacuum pumps receive the mixture and compress it to atmosphere pressure.

(6) Condenser cleanliness. Surface condenser performance depends greatly on the cleanliness of the tube water side heat transfer surface. When dirty fresh water or sea water is used in the circulating water system, automatic backflush or mechanical cleaning systems will be specified for on line cleaning of the interior condenser tube surfaces.

d. Circulating water system—once through

(1) *System components.* A typical once through circulating water system, shown in figure 3-13, consists of the following components:

- (a) Intake structure.
- (b) Discharge, or outfall.
- (c) Trash racks.
- (d) Traveling screens.
- (e) Circulating water pumps.
- (f) Circulating water pump structure (indoor or outdoor).
- (g) Circulating water canals, tunnels, and pipework.

(2) *System operation.*

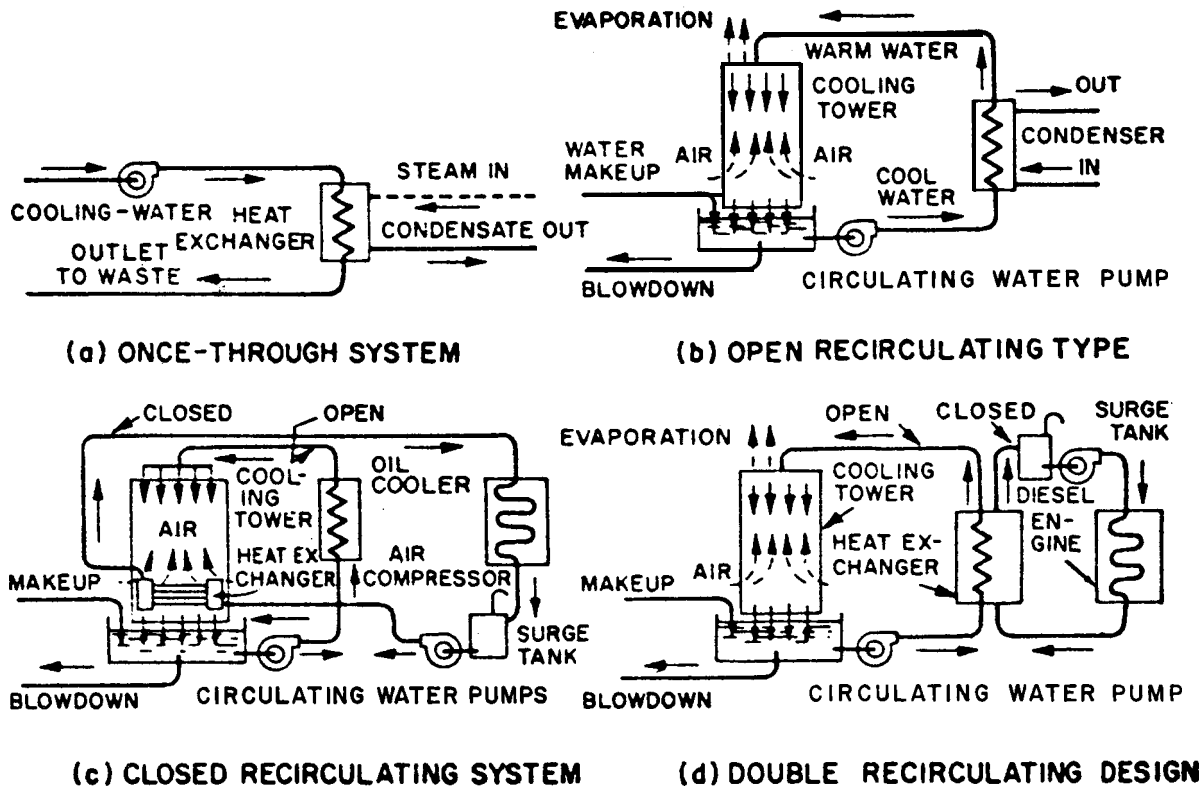
(a) The circulating water system functions as follows. Water from an ocean, river, lake, or pond flows either directly from the source to the circulating water structure or through conduits which bring water from offshore; the inlet conduits discharge into a common plenum which is part of the circulating water pump structure. Water flows through bar trash racks which protect the traveling screens from damage by heavy debris and then through traveling screens where smaller debris is removed. For large systems, a motor operated trash rake can be installed to clear the bar trash racks of heavy debris. In case the traveling screens become clogged, or to prevent clogging, they are periodically backwashes by a high pressure water jet system. The backwash is returned to the ocean or other body of water. Each separate screen well is provided with stop logs and sluice gates to allow dewatering for maintenance purposes.

(b) The water for each screen flows to the suction of the circulating water pumps. For small systems, two 100-percent capacity pumps will be selected while for larger systems, three 50-percent pumps will be used. At least one pump is required for standby. Each pump will be equipped with a motorized butterfly valve for isolation purposes. The pumps discharge into a common circulating water tunnel or supply pipe which may feed one or more condensers. Also, a branch line delivers water to the booster pumps serving the closed cooling water exchangers.

(c) Both inlet and outlet water boxes of the main condensers will be equipped with butterfly valves for isolation purposes and expansion joints. As mentioned above, the system may have the capability to reverse flow in each of the condenser halves for cleaning the tubes. The frequency and duration of the condenser reverse flow or back wash operation is dictated by operating experience.

(d) The warmed circulating water from the condensers and closed cooling water exchangers is discharged to the ocean, river, lake, or pond via a common discharge tunnel.

(3) *Circulating water pump setting.* The circulating water pumps are designed to remain operable with the water level at the lowest anticipated eleva-



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Figure 3-13. Types of circulating water systems.

tion of the selected source. This level is a function of the neap tide for an ocean source and seasonal level variations for a natural lake or river. Cooling ponds are usually man-made with the level controlled within modest limits. The pump motors and valve motor operators will be located so that no electrical parts will be immersed in water at the highest anticipated elevation of the water source.

(4) *System pressure control.* On shutdown of a circulating water pump, water hammer is avoided by ensuring that the pumps coast down as the pump isolation valves close. System hydraulics, circulating pump coastdown times, and system isolation valve closing times must be analyzed to preclude damage to the system due to water hammer. The condenser tubes and water boxes are to be designed for a pressure of approximately 25 psig which is well above the ordinary maximum discharge pressure of the circulating water pumps, but all equipment must be protected against surge pressures caused by sudden collapse of system pressure.

(5) *Inspection and testing.* All active components of the circulating water system will be accessible for inspection during station operation.

e. *Circulating water system—recirculating type*

(1) *General discussion.*

(a) With a once-through system, the evaporative losses responsible for rejecting heat to the atmosphere occur in the natural body of water as the warmed circulating water is mixed with the residual water and is cooled over a period of time by evaporation and conduction heat transfer. With a recirculation system, the same water constantly circulates; evaporative losses responsible for rejecting heat to the atmosphere occur in the cooling equipment and must be replenished at the power plant site. Recirculating systems can utilize one of the following for heat rejection:

- (1) A natural draft, hyperbolic cooling tower.
- (2) A mechanical draft cooling tower, usually induced draft.
- (3) A spray pond with a network of piping serving banks of spray nozzles.

(b) Very large, man-made ponds which take advantage of natural evaporative cooling may be considered as "recirculating" systems, although for design purposes of the circulating water system

they are once through and hence considered as such in paragraph *d* above.

(c) To avoid fogging and plumes which are characteristic of cooling towers under certain atmospheric conditions in humid climates, so called wet-dry cooling towers may be used. These towers use a combination of finned heat transfer surface and evaporative cooling to eliminate the fog and visible plume. The wet-dry types of towers are expensive and not considered in this manual. Hyperbolic towers also are expensive and are not applicable to units less than 300-500 M W; while spray ponds have limited application (for smaller units) because of the large ground area required and the problem of excessive drift. Therefore, the following descriptive material applies only to conventional induced draft cooling towers which, except for very special circumstances, will be the choice for a military power plant requiring a recirculating type system.

(2) *System components.* A typical recirculating system with a mechanical draft cooling tower consists of the following components:

(a) Intake structure which is usually an extension of the cooling tower basin.

(b) Circulating water pumps.

(c) Circulating water piping or tunnels to condensers and from condensers to top of cooling tower.

(d) Cooling tower with makeup and blowdown systems.

(3) *System operation.*

(a) The recirculating system functions as follows. Cooled water from the tower basin is directed to the circulating water pump pit. The pit is similar to the intake structure for a once through system except it is much simpler because trash racks or traveling screens are not required, and the pit setting can be designed without reference to levels of a natural body of water. The circulating water pumps pressure the water and direct it to the condensers through the circulating water discharge piping. A stream of circulating water is taken off from the main condenser supply and by means of booster pumps further pressurized as required for bearing cooling, generator cooling, and turbine generator oil cooling. From the outlet of the condensers and miscellaneous cooling services, the warmed circulating water is directed to the top of the cooling tower for rejection of heat to the atmosphere.

(b) Circulating water pump and condenser valving is similar to that described for a typical once-through system, but no automatic back flushing or mechanical cleaning system is required for the condenser. Also, due to the higher pumping

heads commonly required for elevating water to the top of the tower and the break in water pressure at that point which precludes a siphon, higher pressure

ratings for the pumps and condensers will be specified.

(4) *Cooling tower design.*

(a) In an induced draft mechanical cooling tower, atmospheric air enters the louvers at the bottom perimeter of the tower, flows up through the fill, usually counterflow to the falling water drop lets, and is ejected to the atmosphere in saturated condition thus carrying off the operating load of heat picked up in the condenser. Placement and arrangement of the tower or towers on the power station site will be carefully planned to avoid recirculation of saturated air back into the tower intake and to prevent drift from the tower depositing on electrical buses and equipment in the switchyard, roadways and other areas where the drift could be detrimental.

(b) Hot circulating water from the condenser enters the distribution header at the top of the tower. In conventional towers about 75 percent of the cooling takes place by evaporation and the remainder by heat conduction; the ratio depends on the humidity of the entering air and various factors.

(5) *Cooling tower performance.* The principal performance factor of a cooling tower is its approach to the wet bulb temperature; this is the difference between the cold water temperature leaving the tower and the wet bulb temperature of the entering air. The smaller the approach, the more efficient and expensive the tower. Another critical factor is the cooling range. This is the difference between the hot water temperature entering the tower and the cold water temperature leaving it is essentially the same as the circulating water temperature rise in the condenser. Practically, tower approaches are 8 to 15°F with ranges of 18 to 22°F. Selection of approach and range for a tower is the subject for an economic optimization which should include simultaneous selection of the condensers as these two major items of equipment are interdependent.

(6) *Cooling tower makeup.*

(a) Makeup must be continuously added to the tower collecting basin to replace water lost by evaporation and drift. In many cases, the makeup water must be softened to prevent scaling of heat transfer surfaces; this will be accomplished by means of cold lime softening. Also the circulating water must be treated with bioxides and inhibitors while in use to kill algae, preserve the fill, and prevent metal corrosion and fouling. Algae control is accomplished by means of chlorine injection; acid and phosphate feeds are used for pH control and to keep heat surfaces clean.

(b) The circulating water system must be blown down periodically to remove the accumulated solid concentrated by evaporation.

3-28. Environmental concerns

a. Possible problems. Some of the environmental concerns which have an impact on various types of power plant waste heat rejection systems are as follows:

- (1) Compatibility of circulating water system with type of land use allocated to the surrounding area of the power plant.
- (2) Atmospheric ground level fogging from cooling tower.
- (3) Cooling tower plumes.
- (4) Ice formation on adjacent roads, buildings and structures in the winter.
- (5) Noise from cooling tower fans and circulating water pumps.
- (6) Salts deposition on the contiguous countryside as the evaporated water from the tower is absorbed in the atmosphere and the entrained chemicals injected in the circulating water system fallout.
- (7) Effect on aquatic life for once through systems:

- (a) Entrapment or fish kill.
- (b) Migration of aquatic life.
- (c) Thermal discharge.
- (d) Chemical discharge.
- (e) Effect of plankton.
- (8) Effect on animal and bird life.
- (9) Possible obstruction to aircraft (usually only a problem for tall hyperbolic towers).
- (10) Obstruction to ship and boat navigation (for once through system intakes or navigable streams or bodies of water).

b. Solutions to problems. Judicious selection of the type of circulating water system and optimum orientation of the power plant at the site can minimize these problems. However, many military projects will involve cogeneration facilities which may require use of existing areas where construction of cooling towers may present serious on base problems and, hence, will require innovative design solutions.

Section VII. FEEDWATER SYSTEM

3-29. Feedwater heaters

a. Open type—deaerators.

(1) *Purpose.* Open type feedwater heaters are used primarily to reduce feedwater oxygen and other noncondensable gases to essentially zero and thus decrease corrosion in the boiler and boiler feed system. Secondly, they are used to increase thermal efficiency as part of the regenerative feedwater heating cycle.

(2) *Types.*

(a) There are two basic types of open deaerating heaters used in steam power plants—tray type and spray type. The tray or combination spray/tray type unit will be used. In plants where heater tray maintenance could be a problem, or where the feedwater has a high solids content or is corrosive, a spray type deaerator will be considered.

(b) All types of deaerators will have internal or external vent condensers, the internal parts of which will be protected from corrosive gases and oxidation by chloride stress resistant stainless steel.

(c) In cogeneration plants where large amounts of raw water makeup are required, a deaerating hot process softener will be selected depending on the steam conditions and the type of raw water being treated (Section IX, paragraph 3-38 and 3-39).

(3) *Location.* The deaerating heater should be located to maintain a pressure higher than the NPSH required by the boiler feed pumps under all conditions of operation. This means providing a margin of static head to compensate for sudden fall

off in deaerator pressure under an upset condition. Access will be provided for heater maintenance and for reading and maintaining heater instrumentation.

(4) *Design criteria.*

(a) Deaerating heaters and storage tanks will comply with the latest revisions of the following standards:

- (1) ASME Unified Pressure Vessel Code.
- (2) ASME Power Test Code for Deaerators.
- (3) Heat Exchanger Institute (HE I).
- (4) American National Standards Institute (ANSI).

(b) Steam pressure to the deaerating heater will not be less than three psig.

(c) Feedwater leaving the deaerator will contain no more than 0.005 cc/liter of oxygen and zero residual carbon dioxide. Residual content of the dissolved gases will be consistent with their relative volatility and ionization.

(d) Deaerator storage capacity will be not less than ten minutes in terms of maximum design flow through the unit.

(e) Deaerator will have an internal or external oil separator if the steam supply may contain oil, such as from a reciprocating steam engine.

(f) Deaerating heater will be provided with the following minimum instrumentation: relief valve, thermometer, thermocouple and test well at feedwater inlet and outlet, and steam inlet; pressure gauge at feedwater and steam inlets; and a level control system (paragraph c).

b. Closed type.

(1) *Purpose.* along with the deaerating heater, closed feedwater heaters are used in a regenerative feedwater cycle to increase thermal efficiency and thus provide fuel savings. An economic evaluation will be made to determine the number of stages of feedwater heating to be incorporated into the cycle. Condensing type steam turbine units often have both low pressure heaters (suction side of the boiler feed pumps) and high pressure heaters (on the discharge side of the feed pumps). The economic analysis of the heaters should consider a desuperheater section when there is a high degree of superheat in the steam to the heater and an internal or external drain cooler (using entering condensate or boiler feedwater) to reduce drains below steam saturation temperature.

(2) *Type.* The feedwater heaters will be of the U-tube type.

(3) *Location.* Heaters will be located to allow easy access for reading and maintaining heater instrumentation and for pulling the tube bundle or heater shell. High pressure heaters will be located to provide the best economic balance of high pressure feedwater piping, steam piping and heater drain piping.

(4) *Design criteria*

(a) Heaters will comply with the latest revisions of the following standards:

(1) ASME Unfired Pressure Vessel Code.

(2) ASME Power Test Code for Feedwater Heaters.

(3) Tubular Exchanger Manufacturers Association (TEMA).

(4) Heat Exchanger Institute (HE I).

(5) American National Standards Institute (ANSI).

(b) Each feedwater heater will be provided with the following minimum instrumentation: shell and tube relief valves; thermometer, thermocouple and test well at feedwater inlet and outlet; steam inlet and drain outlet; pressure gauge at feedwater inlet and outlet, and steam inlet; and level control system.

c. Level control systems.

(1) *Purpose.* Level control systems are required for all open and closed feedwater heaters to assure efficient operation of each heater and provide for protection of other related power plant equipment. The level control system for the feedwater heaters is an integrated part of a plant cycle level control system which includes the condenser hotwell and the boiler level controls, and must be designed with this in mind. This paragraph sets forth design criteria which are essential to a feedwater heater level control system. Modifications may be required to fit the

actual plant cycle.

(2) *Closed feedwater heaters.*

(a) Closed feedwater heater drains are usually cascaded to the next lowest stage feedwater heater or to the condenser. A normal and emergency drain line from each heater will be provided. At high loads with high extraction steam pressure, the normal heater drain valve cascades drain to the next lowest stage heater to control its own heater level. At low loads with lower extraction steam pressure and lower pressure differential between successive heaters, sufficient pressure may not be available to allow the drains to flow to the next lowest stage heater. In this case, an emergency drain valve will be provided to cascade to a lower stage heater or to the condenser to hold the predetermined level.

(b) The following minimum instrumentation will be supplied to provide adequate level control at each heater: gauge glass; level controller to modulate normal drain line control valve (if emergency drain line control valve is used, controller must have a split range); and high water level alarm switch.

(3) *Open feedwater heaters-deaerators.* The following minimum instrumentation will be supplied to provide adequate level control at the heater: gauge glass, level controller to control feedwater inlet control valve (if more than one feedwater inlet source, controller must have a split range); low water level alarm switch; "low-low" water level alarm switch to sound alarm and trip boiler feed pumps, or other pumps taking suction from heater; high water level alarm switch; and "high-high" water level controller to remove water from the deaerator to the condenser or flash tank, or to divert feedwater away from the deaerator by opening a diverting valve to dump water from the feedwater line to the condenser or condensate storage tank.

(4) *Reference.* The following papers should be consulted in designing feedwater level control systems, particularly in regard to the prevention of water induction through extraction piping

(a) ASMD Standard TWDP-1, July 1972, "Recommended Practices for the Prevention of Water Damage to Steam Turbines Used for Electric Power Generation (Part 1- Fossil Fueled Plants)."

(b) General Electric Company Standard GEK-25504, Revision D, "Design and Operating Recommendations to Minimize Water Induction in Large Steam Turbines."

(c) Westinghouse Standard, "Recommendation to Minimize Water Damage to Steam Turbines."

3-30. Boiler feed pumps.

a. General. Boiler feed pumps are used to pressur-

ize water from the deaerating feedwater heater or deaerating hot process softener and feed it through any high pressure closed feedwater heaters to the boiler inlet. Discharge from the boiler superheated steam in order to maintain proper main steam temperature to the steam turbine generator.

b. Types. There are two types of centrifugal multi-stage boiler feed pumps commonly used in steam power plants—horizontally split case and barrel type with horizontal or vertical (segmented) split inner case. The horizontal split case type will be used on boilers with rated outlet pressures up to 900 psig. Barrel type pumps will be used on boilers with rated outlet pressure in excess of 900 psig.

c. Number of pumps. In all cases, at least one spare feed pump will be provided.

(1) For power plants where one battery of boiler feed pumps feeds one boiler.

(a) If the boiler is base loaded most of the time at a high load factor, then use two pumps each at 110-125 percent of boiler maximum steaming capacity.

(b) If the boiler is subject to daily wide range load swings, use three pumps at 55-62.5 percent of boiler maximum steaming capacity. With this arrangement, two pumps are operated in parallel between 50 and 100 percent boiler output, but only one pump is operated below 50 percent capacity. This arrangement allows for pump operation in its most efficient range and also permits a greater degree of flexibility.

(2) For power plants where one battery of pump feeds more than one boiler through a header system, the number of pumps and rating will be chosen to provide optimum operating efficiency and capital costs. At least three 55-62.5 percent pumps should be selected based on maximum steaming capacity of all boilers served by the battery to provide the flexibility required for a wide range of total feedwater flows.

d. Location. The boiler feed pumps will be located at the lowest plant level with the deaerating heater or softener elevated sufficiently to maintain pump suction pressure higher than the required NPSH of the pump under all operating conditions. This means a substantial margin over the theoretically calculated requirements to provide for pressures collapses in the deaerator under abnormal operating conditions. Deaerator level will never be decreased for structural or aesthetic reasons, and suction pipe connecting deaerator to boiler feed pumps should be sized so that friction loss is negligible.

e. Recirculation control system.

(1) To prevent overheating and pump damage, each boiler feed pump will have its own recirculation control system to maintain minimum pump flow

whenever the pump is in operation. The control system will consist of

(a) Flow element to be installed in the pump suction line.

(b) Flow controller.

(c) Flow control valve.

(d) Breakdown orifice.

(2) Whenever the pump flow decreases to minimum required flow, as measured by the flow element in the suction line, the flow controller will be designed to open the flow control valve to maintain minimum pump flow. The recirculation line will be discharge to the deaerator. A breakdown orifice will be installed in the recirculation line just before it enters the deaerator to reduce the pressure from boiler feed pump discharge level to deaerator operating pressure.

f. Design criteria.

(1) Boiler feed pumps will comply with the latest revisions of the following standards:

(a) Hydraulics Institute (HI).

(b) American National Standards Institute (ANSI).

(2) Pump head characteristics will be maximum at zero flow with continuously decreasing head as flow increases to insure stable operation of one pump, or multiple pumps in parallel, at all loads.

(3) Pumps will operate quietly at all loads without internal flashing and operate continuously without overheating or objectionable noises at minimum recirculation flow.

(4) Provision will be made in pump design for expansion of

(a) Casing and rotor relative to one another.

(b) Casing relative to the base.

(c) Pump rotor relative to the shaft of the driver.

(d) Inner and outer casing for double casing pumps.

(5) All rotating parts will be balanced statically and dynamically for all speeds.

(6) Pump design will provide axial as well as radial balance of the rotor at all outputs.

(7) One end of the pump shaft will be accessible for portable tachometer measurements.

(8) Each pump will be provided with a pump warmup system so that when it is used as a standby it can be hot, ready for quick startup. This is done by connecting a small bleed line and orifice from the common discharge header to the pump discharge inside of the stop and check valve. Hot water can then flow back through the pump and open suction valve to the common suction header, thus keeping the pump at operating temperature.

(9) Pump will be designed so that it will start safely from a cold start to full load in 60 seconds in

an emergency, although it will normally be warmed before starting as described above.

(10) Other design criteria should be as forth in Military Specification MIL-P-17552D.

g. Pump drives. For military plants, one steam turbine driven pump may be justified under certain conditions; e.g., if the plant is isolated, or if it is a cogeneration plant or there is otherwise a need for substantial quantities of exhaust steam. Usually, however, adequate reliability can be incorporated into the feed pumps by other means, and from a plant efficiency point of view it is always better to bleed steam from the prime mover(s) rather than to use steam from an inefficient mechanical drive turbine.

3-31. Feedwater supply

a. General description.

(1) In general terms, the feedwater supply includes the condensate system as well as the boiler feed system.

(2) The condensate system includes the condensate pumps, condensate piping, low pressure closed heaters, deaerator, and condensate system level and makeup controls. Cycle makeup may be introduced either into the condenser hotwell or the deaerator. For large quantities of makeup as in cogeneration plants, the deaerator maybe preferred as it contains a larger surge volume. The condenser, however, is better for this purpose when makeup is of high purity and corrosive (demineralized and undeaerated). With this arrangement, corrosive demineralized water can be deaerated in the condenser hotwell; the excess not immediately required for cycle makeup is extracted and pumped to an atmospheric storage tank where it will be passive in its deaerated state. As hotwell condensate is at a much lower temperature than deaerator condensate, the heat loss in the atmospheric storage tank is much less with this arrangement.

(3) The feedwater system includes the boiler feed pumps, high pressure closed heaters, boiler feed suction and discharge piping, feedwater level controls for the boiler, and boiler desuperheater water supply with its piping and controls.

b. Unit vs. common system. Multiple unit cogeneration plants producing export steam as well as electric will always have ties for the high pressure

steam, the extraction steam, and the high pressure feedwater system. If there are low pressure closed heaters incorporated into the prime movers, the condensate system usually remains independent for each such prime mover; however, the deaerator and boiler feed pumps are frequently common for all boilers although paralleling of independent high pressure heater trains (if part of the cycle) on the feedwater side maybe incorporated if high pressure bleeds on the primer movers are uncontrolled. Each cogeneration feedwater system must carefully be designed to suit the basic parameters of the cycle. Level control problems can become complex, particularly if the cycle includes multiple deaerators operating in parallel.

c. Feedwater controls. Condensate pumps, boiler feed pumps, deaerator, and closed feedwater heaters are described as equipment items under other headings in this manual. Feedwater system controls will consist of the following

(1) Condenser hotwell level controls which control hotwell level by recirculating condensate from the condensate pump discharge to the hotwell, by extracting excess fluid from the cycle and pumping it to atmospheric condensate storage (surge) tanks, and by introducing makeup (usually from the same condensate storage tanks) into the hotwell to replenish cycle fluid.

(2) Condensate pump minimum flow controls to recirculate sufficient condensate back to the condenser hotwell to prevent condensate pumps from overheating.

(3) Deaerator level controls to regulate amount of condensate transferred from condenser hotwell to deaerator and, in an emergency, to overflow excess water in the deaerator storage tank to the condensate storage tank(s).

(4) Numerous different control systems are possible for all three of the above categories. Regardless of the method selected, the hotwell and the deaerator level controls must be closely coordinated and integrated because the hotwell and deaerator tank are both surge vessels in the same fluid system.

(5) Other details on instruments and controls for the feedwater supply are described under Section 1 of Chapter 5, Instruments and Controls.

Section VIII. SERVICE WATER AND CLOSED COOLING SYSTEMS

3-32. Introduction

a. Definitions and purposes. Service water supply systems and subsystems can be categorized as follows:

(1) For stations with salt circulating water or

heavily contaminated or sedimented fresh circulating water.

(a) Most power stations, other than those with cooling towers, fall into this category. Circulating water booster pumps increase the pressure of a (small) part of the circulating water to a level ade-

quate to circulate through closed cooling water exchangers. If the source is fresh water, these pumps may also supply water to the water treating system. Supplementary sources of water such as the area public water supply or well water may be used for potable use and/or as a supply to the water treating system. In some cases, particularly for larger stations, the service water system may have its pumps divorced from the circulating water pumps to provide more flexibility and reliability.

(b) The closed cooling water exchangers transfer rejected heat from the turbine generator lube oil and generator air (or hydrogen) coolers, bearings and incidental use to the circulating water side-stream pressurized by the booster pumps. The medium used for this transfer is cycle condensate which recirculates between the closed cooling exchangers and the ultimate equipment where heat is removed. This closed cooling cycle has its own circulating (closed cooling water) pumps, expansion tank and temperature controls.

(2) For stations with cooling towers. Circulating water booster pumps (or separate service water pumps) may also be used for this type of power plant. In the case of cooling tower systems, however, the treated cooling tower circulating water can be used directly in the turbine generator lube oil and generator air (or hydrogen) coolers and various other services where a condensate quality cooling medium is unnecessary. This substantially reduces the size of a closed cooling system because the turbine generator auxiliary cooling requirements are the largest heat rejection load other than that required for the main condenser. If a closed cooling system is used for a station with a cooling tower, it should be designed to serve equipment such as air compressor cylinder jackets and after coolers, excitation system coolers, hydraulic system fluid coolers, boiler TV cameras, and other similar more or less delicate service. If available, city water, high quality well water, or other clean water source might be used for this delicate equipment cooling service and thus eliminate the closed cooling water system.

b. Equipment required—general. Equipment required for each system is as follows:

(1) Service water system

(a) Circulating water booster pumps (or separate service water pumps).

(b) Piping components, valves, specialties and instrumentation.

(2) Closed cooling water system.

(a) Closed cooling water circulating pumps.

(b) Closed cooling water heat exchangers.

(c) Expansion tank.

(d) Piping components, valves, specialties and instrumentation. Adequate instrumentation

(thermometers, pressure gages, and flow indicators) should be incorporated into the system to allow monitoring of equipment cooling.

3-33. Description of major components

a. Service water system.

(1) *Circulating water booster (or service water) pumps.* These pumps are motor driven, horizontal (or vertical) centrifugal type. Either two 100-percent or three 50-percent pumps will be selected for this duty. Three pumps provide more flexibility; depending upon heat rejection load and desired water temperature, one pump or two pumps can be operated with the third pump standing by as a spare. A pressure switch on the common discharge line alarms high pressure, and in the case of the booster pumps a pressure switch on the suction header or interlocks with the circulating water pumps provides permissive to prevent starting the pumps unless the circulating water system is in operation.

(2) *Temperature control.* In the event the system serves heat rejection loads directly, temperature control for each equipment where heat is removed will be by means of either automatic or manually controlled valves installed on the cooling water discharge line from each piece of equipment, or by using a by-pass arrangement to pass variable amounts of water through the equipment without upsetting system hydraulic balance.

b. Closed cooling water system.

(1) *Closed cooling water pumps.* The closed cooling water pumps will be motor driven, horizontal, end suction, centrifugal type with two 100-percent or three 50-percent pumps as recommended for the pumps described in *a* above.

(2) *Closed cooling water heat exchangers.* The closed cooling water exchangers will be horizontal shell and tube test exchangers with the treated plant cycle condensate on the shell side and circulating (service) water on the tube side. Two 100-percent capacity exchangers will be selected for this service, although three 50-percent units may be selected for large systems.

(3) *Temperature control.* Temperature control for each equipment item rejecting heat will be similar to that described above for the service water system.

3-34. Description of systems

a. Service water system.

(1) The service water system heat load is the sum of the heat loads for the closed cooling water system and any other station auxiliary systems which may be included. The system is designed to maintain the closed cooling water system supply temperature at 95° F or less during normal operation

with maximum heat rejection load. The system will also be capable of being controlled or manually adjusted so that a minimum closed cooling water supply temperature of approximately 55 °F can be maintained with the ultimate heat sink at its lowest temperature and minimum head load on the closed cooling water system. The service water system will be designed with adequate backup and other reliability features to provide the required cooling to components as necessary for emergency shutdown of the plant. In the case of a system with circulating water booster pumps, this may mean a crossover from a city or well water system or a special small circulating water pump.

(2) Where cooling towers are utilized, means will be provided at the cooling tower basin to permit the service water system to remain in operation while the cooling tower is down for maintenance or repairs.

(3) The system will be designed such that operational transients (e.g., pump startup or water hammer due to power failure) do not cause adverse effects in the system. Where necessary, suitable valving or surge control devices will be provided.

b. Closed cooling water system.

(1) The closed cooling water coolant temperature is maintained at a constant value by automatic control of the service water flow through the heat exchanger. This is achieved by control valve modulation of the heat exchanger by-pass flow. All equipment cooled by the cooling system is individually temperature controlled by either manual or automatic valves on the coolant discharge from, or by by-pass control around each piece of equipment. The quantity of coolant in the system is automatically maintained at a predetermined level in the expansion tank by means of a level controller which operates a control valve supplying makeup from the cycle condensate system. The head tank is provided with an emergency overflow. On a failure of a running closed cooling water pump, it is usual to pro-

vide means to start a standby pump automatically.

(2) The system will be designed to ensure adequate heat removal based on the assumption that all service equipment will be operating at maximum design conditions.

3-35. Arrangement

a. Service water system. The circulating water booster pumps will be located as close as possible to the cooling load center which generally will be near the turbine generator units. All service water piping located in the yard will be buried below the frost line.

b. Closed cooling water system. The closed cooling water system exchangers will be located near the turbine generators.

3-36. Reliability of systems

It is of utmost importance that the service and closed cooling water systems be maintained in service during emergency conditions. In the event power from the normal auxiliary source is lost, the motor driven pumps and electrically actuated devices will be automatically supplied by the emergency power source (Chapter 4, Section VII). Each standby pump will be designed for manual or automatic startup upon loss of an operating pump with suitable alarms incorporated to warn operators of loss of pressure in either system.

3-37. Testing

The systems will be designed to allow appropriate initial and periodic testing to:

u. Permit initial hydrostatic testing as required in the ASME Boiler and Pressure Vessel Code.

b. Assure the operability and the performance of the active components of the system.

c. Permit testing of individual components or subsystems such that plant safety is not impaired and that undesirable transients are not present.

Section IX. WATER CONDITIONING SYSTEMS

3-38. Water Conditioning Selection

a. Purpose.

(1) All naturally occurring waters, whether surface water or well water, contain dissolved and possibly suspended impurities (solids) which may be injurious to steam boiler operation and cooling water service. Fresh water makeup to a cooling tower, depending on its quality, usually requires little or no pretreatment. Fresh water makeup to a boiler system ranges from possibly no pretreatment (in the case of soft well water used in low pressure boiler) to ultra-purification required for a typical high pres-

sure boiler used in power generation.

(2) The purpose of the water conditioning systems is to purify or condition raw water to the required quality for all phases of power plant operation. Today, most high pressure boilers (600 psig or above) require high quality makeup water which is usually produced by ion exchange techniques. To reduce the undesirable concentrations of turbidity and organic matter found in most surface waters, the raw water will normally be clarified by coagulation and filtration for pretreatment prior to passing to the ion exchangers (demineralizers). Such pretreat-

ment, which may also include some degree of softening, will normally be adequate without further treatment for cooling tower makeup and other general plant use.

b. Methods of conditioning.

(1) Water conditioning can be generally categorized as 'external' treatment or 'internal' treatment. External treatment clarifies, softens, or purifies raw water prior to introducing it into the power plant fluid streams (the boiler feed water, cooling tower system, and process water) or prior to utilizing it for potable or general washup purposes. Internal treatment methods introduce chemicals directly into the power plant fluid stream where they counteract or moderate the undesirable effects of water impurities. Blowdown is used in the evaporative processes to control the increased concentration of dissolved and suspended solids at manageable levels.

(2) Some of the methods of water conditioning are as follows:

- (a) Removal of suspended matter by sedimentation, coagulation, and filtration (clarification).
- (b) Deaeration and degasification for removal of gases.
- (c) Cold or hot lime softening.
- (d) Sodium zeolite ion exchange.
- (f) Chloride cycle dealkalization.
- (g) Demineralization (ultimate ion exchange).
- (h) Internal chemical treatment.
- (i) Blowdown to remove sludge and concentration buildups.

c. Treatment Selection. Tables 3-13, 3-14, and 3-15 provide general guidelines for selection of treatment methodologies. The choice among these is an economic one depending vitally on the actual constituents of the incoming water. The designer will make a thorough life cycle of these techniques in conjunction with the plant data. Water treatment experts and manufacturer experience data will be called upon.

Section X. COMPRESSED AIR SYSTEMS

3-39. Introduction

a. Purpose. The purpose of the compressed air systems is to provide all the compressed air requirements throughout the power plant. The compressed air systems will include service air and instrument air systems.

b. Equipment required-general. Equipment required for a compressed air system is shown in Figures 3-14 and 3-15. Each system will include

- (1) Air compressors.
- (2) Air aftercoolers.
- (3) Air receiver.
- (4) Air dryer (usually for instrument air system only).
- (5) Piping, valves and instrumentation.

c. Equipment served by the compressed air systems.

- (1) Service (or plant) air system for operation of tools, blowing and cleaning.
- (2) Instrument air system for instrument and control purposes.
- (3) Soot blower air system for boiler soot blowing operations.

3-40. Description of major components

a. Air compressors. Typical service and instrument air compressor? for power plant service are single or two stage, reciprocating piston type with electric motor drive, usually rated for 90 to 125 psig discharge pressure. They may be vertical or horizontal and, for instrument air service, always have oilless pistons and cylinders to eliminate oil carryover.

Non-lubricated design for service air as well as instrument air will be specified so that when the former is used for backup of the latter, oil carryover will not be a problem. Slow speed horizontal units for service and instrument air will be used. Soot blower service requirements call for pressures which require multi-stage design. The inlet air filter-silencer will be a replaceable dry felt cartridge type. Each compressor will have completely separate and independent controls. The compressor controls will permit either constant speed-unloaded cylinder control or automatic start-stop control. Means will be provided *in* a multi-compressor system for selection of the 'lead' compressor.

b. Air aftercooler. The air aftercooler for each compressor will be of the shell and tube type, designed to handle the maximum rated output of the compressor. Water cooling is provided except for relatively small units which may be air cooled. Water for cooling is condensate from the closed cooling system which is routed counter-flow to the air through the aftercooler, and then through the cylinder jackets. Standard aftercoolers are rated for 95 °F. maximum inlet cooling water. Permissive can be installed to prevent compressor startup unless cooling water is available and to shut compressor down or sound an alarm (or both) on failure of water when unit is in operation.

c. Air receiver. Each compressor will have its own receiver equipped with an automatic drainer for removal of water.

d. Instrument air dryer. The instrument air dryer

Table 3-13. General Guide for Raw Water Treatment of Boiler Makeup

<u>Steam Pressure (psig)</u>	<u>Silica reg./l.</u>	<u>Alkalinity reg./l. (as CaCO₃)</u>	<u>Water Treatment</u>
up to 450	Under 15	Under 50 Over 50	Sodium ion exchange. Hot lime-hot zeolite, or cold lime zeolite, or hot lime soda, or sodium ion exchange plus chloride anion exchange.
	Over 15	Over 50	Hot lime-hot zeolite, or cold lime-zeolite, or hot lime soda.
450 to 600	Under 5	Under 50	Sodium ion exchange plus chloride anion exchange, or hot lime-hot zeolite.
		Over 50	Sodium plus hydrogen ion exchange, or cold lime- zeolite or hot lime-hot zeolite.
	Above 5		Demineralizer, or hot lime-hot zeolite.
600 to 1000	----- Any Water -----		Demineralizer.
1000 & Higher	----- Any Water -----		Demineralizer.

NOTES :

- (1) Guide is based on boiler water concentrations recommended in the American Boiler and Affiliated Industries "Manual of Industry Standards and Engineering Information."
- (2) Add filters when turbidity exceeds 10mg./l.
- (3) See Table 3-15 for effectiveness of treatments.
- (4) reg./l. = p.p.m.

Source: Adapted from NAVFAC DM3

Table 3-14. Internal Chemical Treatment.

<u>Corrosive Treatment Required</u>	<u>Chemical</u>
Maintenance of feedwater pH and boiler water alkalinity for scale and corrosion control.	Caustic Soda Soda Ash Sulfuric Acid
Prevention of boiler scale by internal softening of the boiler water.	Phosphates Soda Ash Sodium Aluminate Alginates Sodium Silicate
Conditioning of boiler sludge to prevent adherence to internal boiler surfaces.	Tannins Lignin Derivatives Starch Glucose Derivatives
Prevention of scale from hot water in pipelines, stage heaters, and economizers.	Polyphosphates Tannins Lignin Derivatives Glucose Derivatives
Prevention of oxygen corrosion by chemical deaeration of boiler feedwater.	Sulfites Tannins Ferrus hydroxide Glucose Derivatives Hydrazine Ammonia
Prevention of corrosion by protective film formation.	Tannins Lignin Derivatives Glucose Derivatives
Prevention of corrosion by condensate.	Amine Compounds Ammonia
Prevention of foam in boiler water.	Polyamides Polyalkylene Glycols
Inhibition of caustic embrittlement.	Sodium Sulfate Phosphates Tannins Nitrates

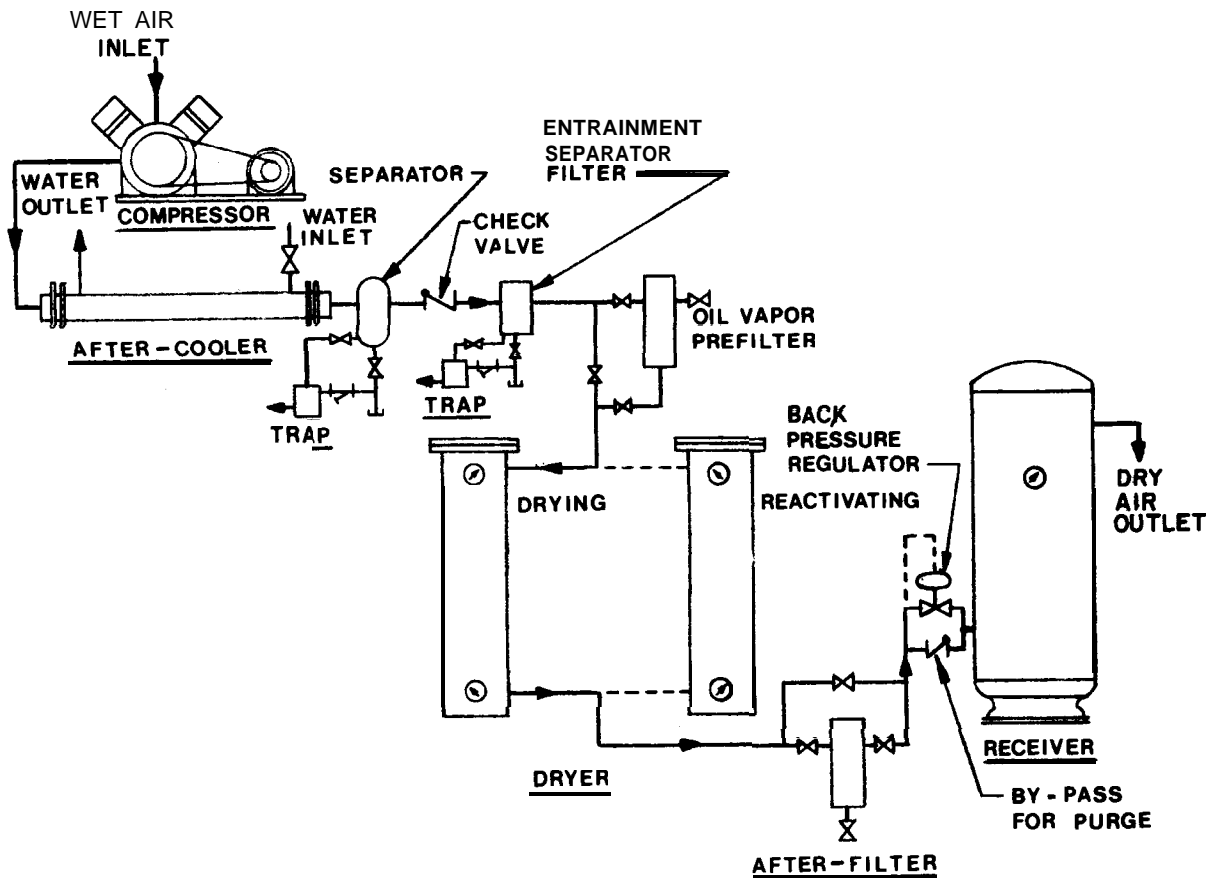
U.S. Army Corps of Engineers

Table 3-15. Effectiveness of Water Treatment

<u>Treatment</u>	<u>Average Analysis of Effluent</u>				
	<u>Hardness</u> (as CaCO) <u>mg./l.</u>	<u>Alkalinity</u> (as CaCO) <u>mg./l.</u>	<u>co</u> <u>mg./l.</u> <u>in Steam</u>	<u>Dissolved</u> <u>Solids</u> <u>mg./l.</u>	<u>Silica</u> <u>mg./l.</u>
Cold Lime-Zeolite	0 to 2	75	Medium High	Reduced	8
Hot Lime Soda	17 to 25	35 to 50	Medium High	Reduced	3
Hot Lime-Hot Zeolite	0 to 2	20 to 25	Low	Reduced	3
Sodium Zeolite	0 to 2	Unchanged	Low to High	Unchanged	Unchanged
Sodium Plus Hydrogen Zeolite	0 to 2	10 to 30	Low	Reduced	Unchanged
Sodium Zeolite Plus Chloride Anion Exchanger	0 to 2	15 to 35	Low	Unchanged	Unchanged
Demineralizer	0 to 2	0 to 2	0 to 5	0 to 5	Below 0.15
Evaporator	0 to 2	0 to 2	0 to 5	0 to 5	Below 0.15

NOTE: (1) mg./l. = p.p.m.

Source: NAWFAC DM3



Courtesy of Pope, Evans and Robbins (Non-Copyrighted)

Figure 3-14. Typical compressed air system.

will be of the automatic heat reactivating, dual chamber, chemical desiccant, downflow type. It will contain a prefilter and afterfilter to limit particulate size in the outlet dried air. Reactivating heat will be provided by steam heaters.

3-41. Description of systems

a. *General.* The service (or plant) air and the instrument air systems may have separate or common compressors. Regardless of compressor arrangement, service and instrument air systems will each have their own air receivers. There will be isolation in the piping system to prevent upsets in the service air system from carrying over into the vital instrument air system.

b. *Service air system.* The service air system capacity will meet normal system usage with one compressor out of service. System capacity will include emergency instrument air requirements as well as service air requirements for maintenance during plant operation. Service air supply will in-

clude work shops, laboratory, air hose stations for maintenance use, and like items. Air hose stations should be spaced so that air is available at each piece of equipment by using an air hose no longer than 75 feet. Exceptions to this will be as follows:

(1) The turbine operating floor will have service air stations every 50 feet to handle air wrenches used to tension the turbine hood bolts.

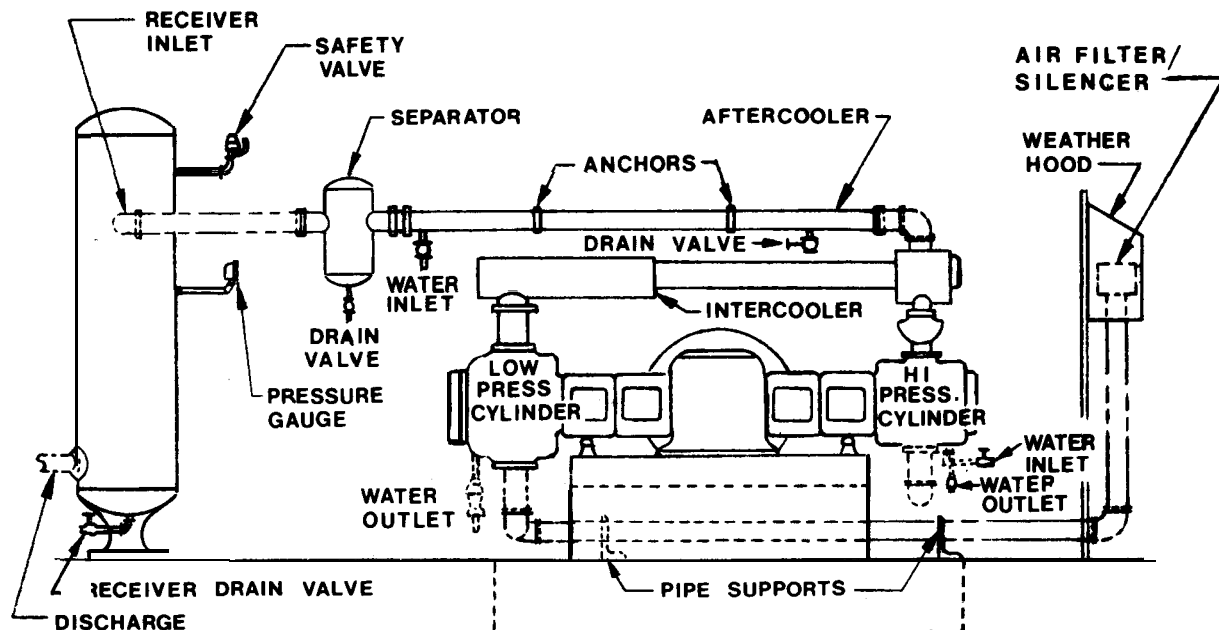
(2) No service air stations are required in the control room and in areas devoted solely to switch-gear and motor control centers.

(3) Service air stations will be provided inside buildings at doors where equipment or supplies may be brought in or out.

c. *Instrument air system.* A detailed analysis will be performed to determine system requirements. The analysis will be based on:

(1) The number of air operated valves and dampers included in the mechanical systems.

(2) The number of air transmitters, controllers and converters.



Courtesy of Pope, Evans and Robbins (Non-Copyrighted)

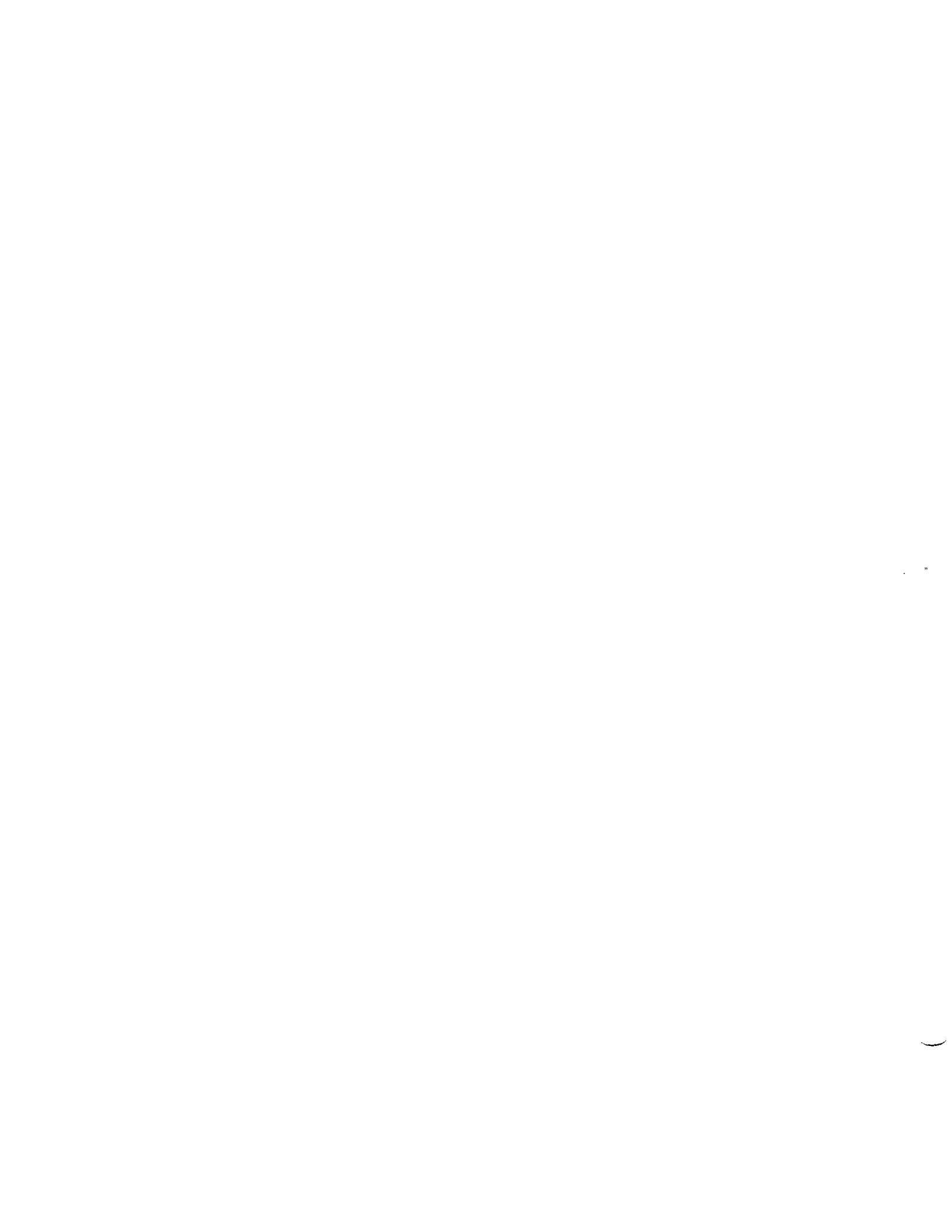
Figure 3-15. Typical arrangement of air compressor and accessories.

(3) A list of another estimated air usage not included in the above items.

d. Piping system.

(1) *Headers.* Each separate system will have a looped header to distribute the compressed air, and for large stations a looped header will be provided at each of the floor levels.

(2) *Instrument air reserve.* In instances where short term, large volume air flow is required, local air receivers can be considered to meet such needs and thereby eliminate installation of excessive compressor capacity. However, compressor must be sized to recharge the receivers while continuing to supply normal air demands.



CHAPTER 4

GENERATOR AND ELECTRICAL FACILITIES DESIGN

Section 1. TYPICAL VOLTAGE RATINGS AND SYSTEMS “

4-1. Voltages

a. General. Refer to ANSI Standard C84. 1 for voltage ratings for 60 Hz electric power systems and equipment. In addition, the standard lists applicable motor and motor control nameplate voltage ranges up to nominal system voltages of 13.8 kV.

b. Generators. Terminal voltage ratings for power plant generators depend on the size of the generators and their application. Generally, the larger the generator, the higher the voltage. Generators for a power plant serving an Army installation will be in the range from 4160 volts to 13.8 kV to suit the size of the unit and primary distribution system voltage. Generators in this size range will be offered by the manufacturer in accordance with its design, and it would be difficult and expensive to get a different voltage rating. Insofar as possible, the generator voltage should match the distribution voltage to avoid the installation of a transformer between the generator and the distribution system.

c. Power plant station service power systems.

(1) Voltages for station service power supply within steam electric generating stations are related to motor size and, to a lesser extent, distances of cable runs. Motor sizes for draft fans and boiler feed pumps usually control the selection of the highest station service power voltage level. Rules for selecting motor voltage are not rigid but are based on relative costs. For instance, if there is only one motor larger than 200 hp and it is, say, only 300 hp, it might be a good choice to select this one larger motor for 460 volts so that the entire auxiliary power system can be designed at the lower voltage.

(2) Station service power requirements for combustion turbine and internal combustion engine generating plants are such that 208 or 480 volts will be used.

d. Distribution system. The primary distribution system for an Army installation with central in-house generation should be selected in accordance with TM 5-811 -1/AFM 88-9.

4-2. Station service power systems.

a. General. Two types of station service power systems are generally in use in steam electric plants and are discussed herein. They are designated as a

common bus system and a unit system. The distinction is based on the relationship between the generating unit and the auxiliary transformer supplying power for its auxiliary equipment.

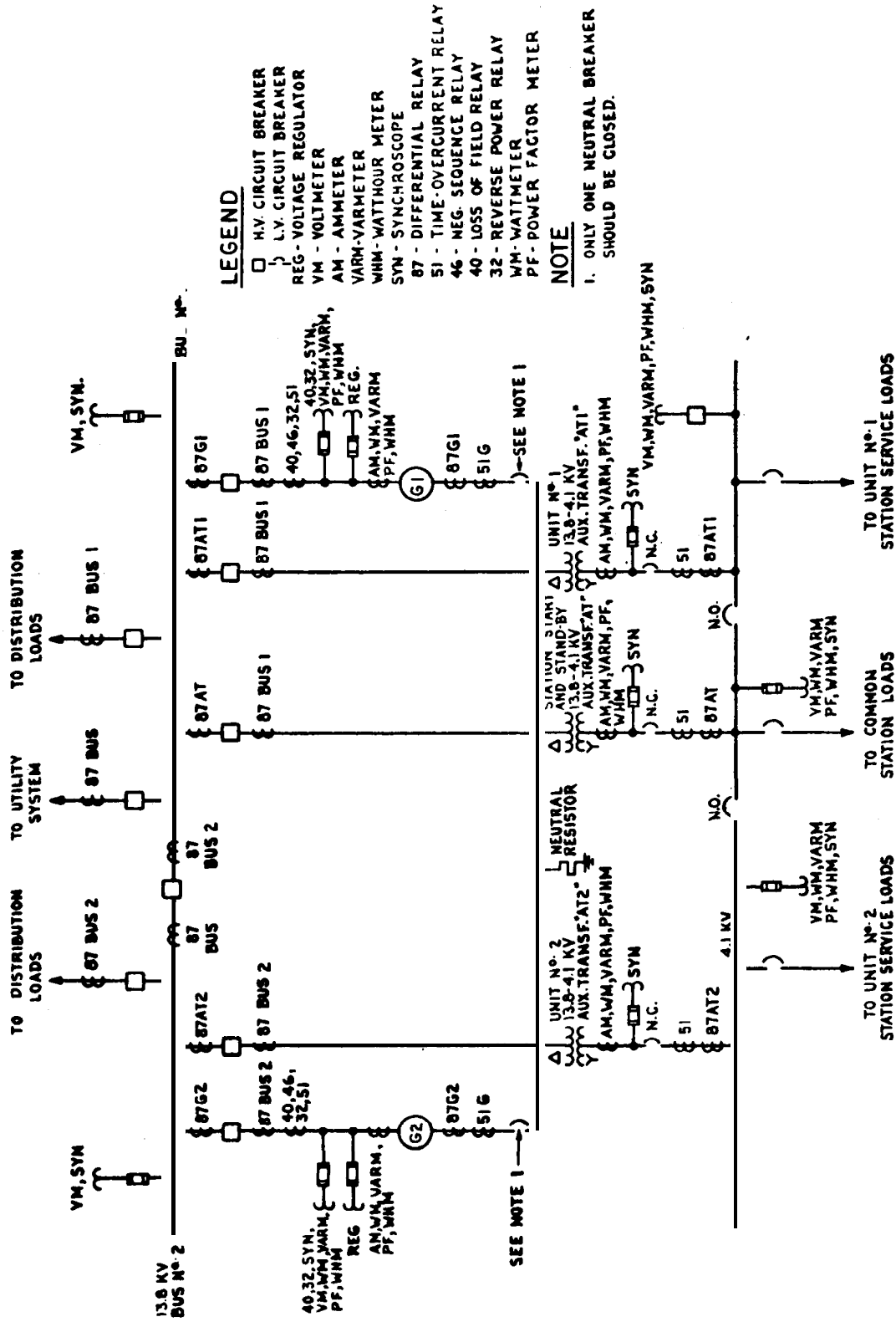
(1) In the common bus system the auxiliary transformer will be connected through a circuit breaker to a bus supplied by a number of units and other sources so that the supply has no relationship to the generating unit whose auxiliary equipment is being served. In the unit system the auxiliary transformer will be connected solidly to the generator leads and is switched with the generator. In either case, the auxiliary equipment for each generating unit usually will be supplied by a separate transformer with appropriate interconnections between the secondary side of the transformers.

(2) The unit type system has the disadvantage that its station service power requirements must be supplied by a startup transformer until the generating unit is synchronized with the system. This startup transformer also serves as the backup supply in case of transformer failure. This arrangement requires that the station service power supply be transferred from the startup source to the unit source with the auxiliary equipment in operation as apart of the procedure of starting the unit.

(3) The advantages of the unit system are that it reduces the number of breakers required and that its source of energy is the rotating generating unit so that, in case of system trouble, the generating unit and its auxiliaries can easily be isolated from the rest of the system. For application to Army installations, the advantage of switching the generator and its auxiliary transformer as a unit is not very important, so the common bus system will normally be used.

b. Common bus system. In this system, generators will be connected to a common bus and the auxiliary transformers for all generating units will be fed from that common bus. This bus may have one or more other power sources to serve for station startup.

(1) Figure 4-1 is a typical one-line diagram for such a system. This type system will be used for diesel generating plants with all station service supplied by two station service transformers with no



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Figure 4-1. Station connections two unit stations—common bus arrangement.

isolation between auxiliaries for different generating units. It also will be used for steam turbine and gas turbine generating plants. For steam turbine generating plants the auxiliary loads for each unit in the plant will be isolated on a separate bus fed by a separate transformer. A standby transformer is included and it serves the loads common to all units such as building services.

(2) The buses supplying the auxiliaries for the several units will be operated isolated to minimize fault current and permit use of lower interrupting rating on the feeder breakers. Provision will be made for the standby transformer to supply any auxiliary bus.

c. Unit type system.

(1) The unit type station service power system will be used for a steam electric or combustion turbine generating station serving a utility transmission network. It will not be, as a rule, used for a diesel generating station of any kind since the station service power requirements are minimal.

(2) The distinguishing feature of a unit type station power system is that the generator and unit auxiliary transformer are permanently connected together at generator voltage and the station service power requirements for that generating unit, including boiler and turbine requirements, are normally supplied by the auxiliary transformer connected to the generator leads. This is shown in Figure 4-2. If the unit is to be connected to a system voltage that is higher than the generator voltage, the unit concept can be extended to include the step-up transformer by tying its low side solidly to the generator leads and using the high side breaker for synchronizing the generator to the system. This arrangement is shown in Figure 4-3.

d. Station service switchgear. A station service switchgear lineup will be connected to the low side of the auxiliary transformer; air circuit breakers will be used for control of large auxiliary motors such as boiler feed pumps, fans and circulating water pumps which use the highest station service voltage, and for distribution of power to various unit substations and motor control centers to serve the remaining station service requirements. Figure 4-4 is a typical

one-line diagram of this arrangement. If the highest level of auxiliary voltage required is more than 480 volts, say 4.16 kV, the auxiliary switchgear air circuit breakers will only serve motors 250 hp and larger and feeders to unit substations. Each unit substation will include a transformer to reduce voltage from the highest auxiliary power level to 480 volts together with air circuit breakers in a lineup for starting of motors 100 to 200 hp and for serving 480-volt motor control centers. The motor control centers will include combination starters and feeders breakers to serve motors less than 100 hp and other small auxiliary circuits such as power panels.

e. Startup auxiliary transformer. In addition to the above items, the unit auxiliary type system will incorporate a "common" or "startup" arrangement which will consist of a startup and standby auxiliary transformer connected to the switchyard bus or other reliable source, plus a low voltage switchgear and motor control center arrangement similar to that described above for the unit auxiliary system. The common bus system may have a similar arrangement for the standby transformer.

(1) This common system has three principal functions:

(a) To provide a source of normal power for power plant equipment and services which are common to all units; e.g., water treating system, coal and ash handling equipment, air compressors, lighting, shops and similar items.

(b) To provide backup to each auxiliary power system segment if the transformer supplying that segment fails or is being maintained.

(c) In the case of the unit system, to provide startup power to each unit auxiliary power system until the generator is up to speed and voltage and is synchronized with the distribution system.

(2) The startup and standby transformer and switchgear will be sized to accomplish the above three functions and, in addition, to allow for possible future additions to the plant. Interconnections will be provided between the common and unit switchgear. Appropriate interlocks will be included so that no more than one auxiliary transformer can feed any switchgear bus at one time.

Section II. GENERATORS

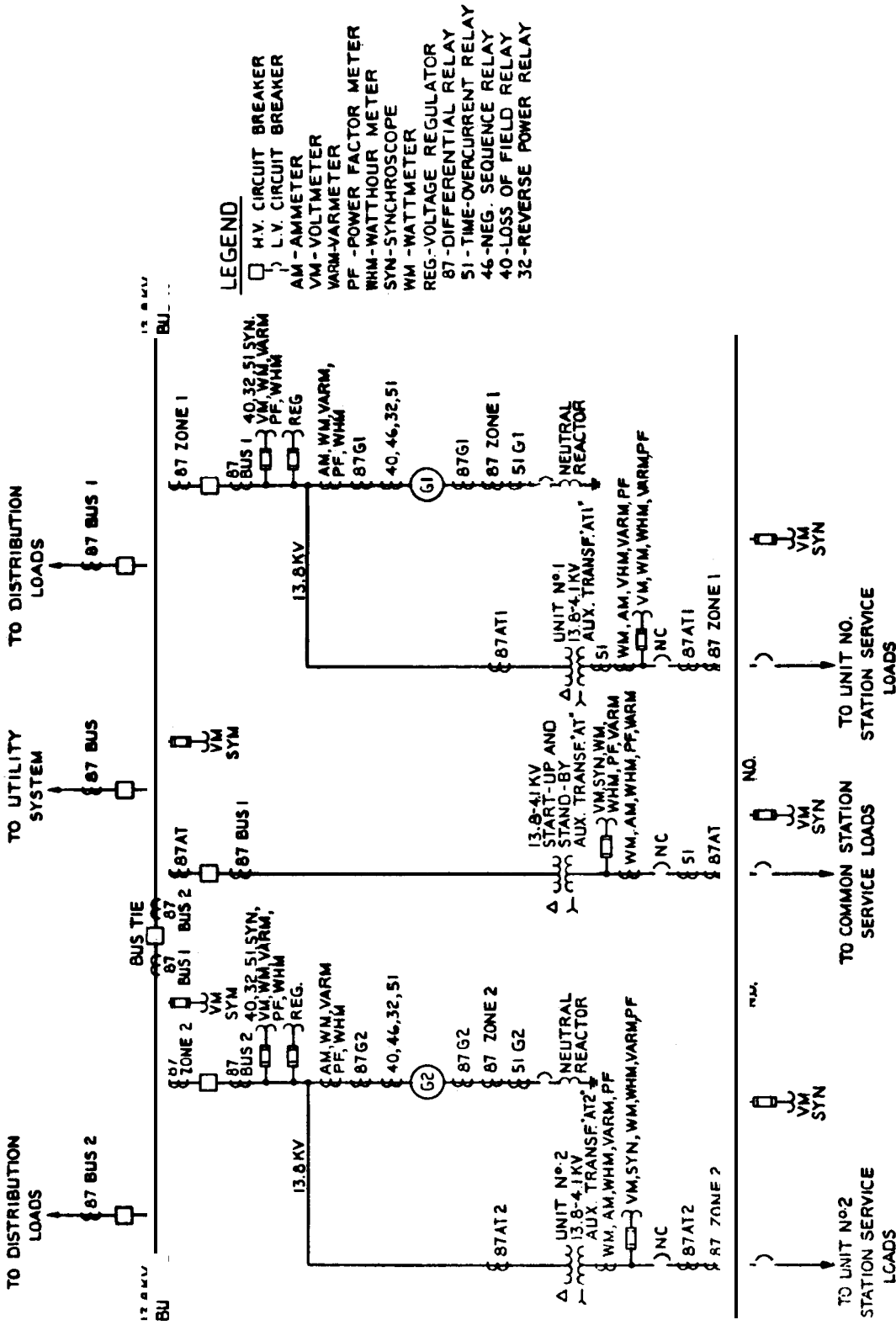
4-3. General types and standards

a. Type. Generators for power plant service can be generally grouped according to service and size.

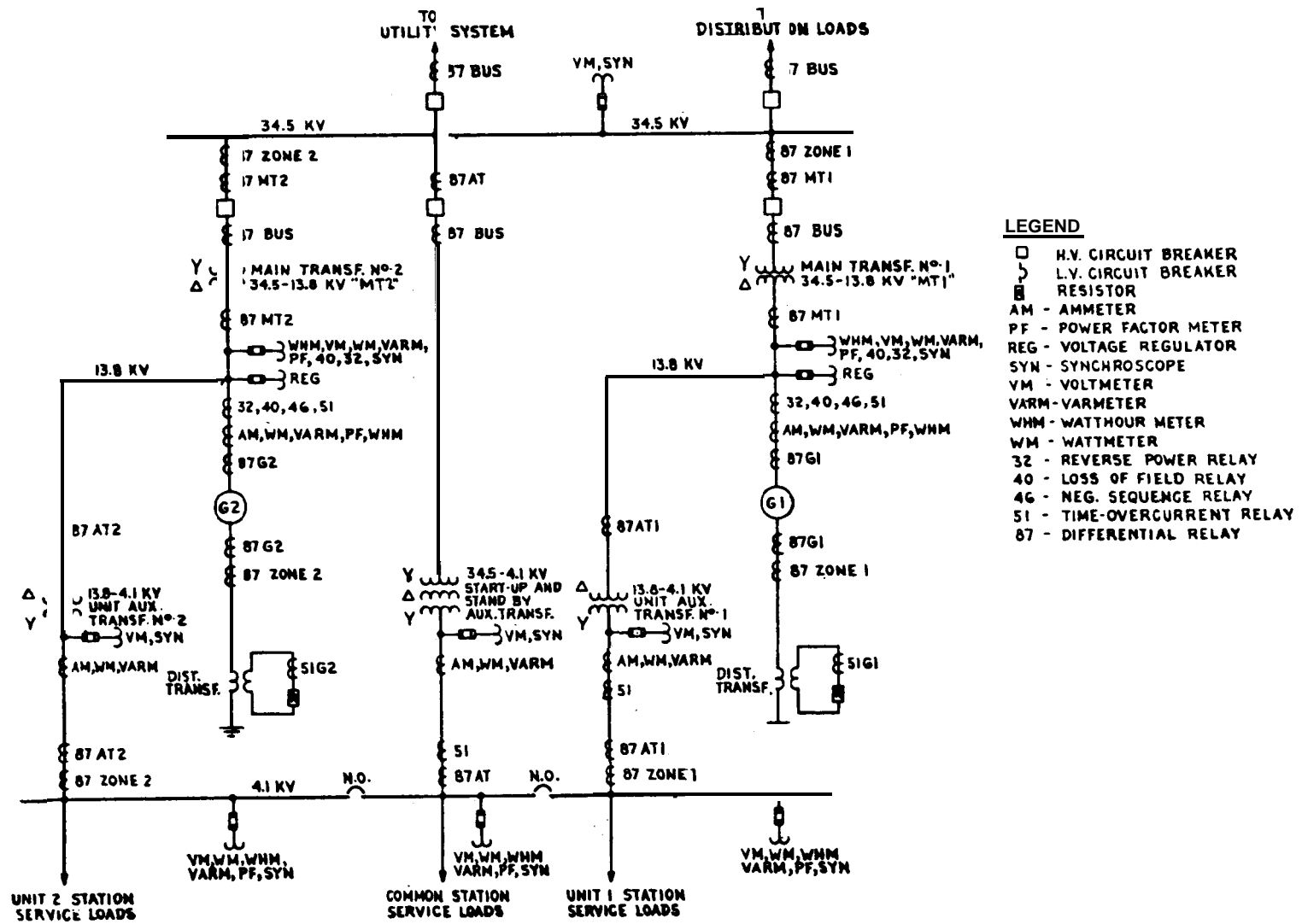
(1) Generators for steam turbine service rated 5000-32,000 kVA, are revolving field, non-salient, two-pole, totally enclosed, air cooled with water cooling for air coolers, direct connected, 3600 rpm for 60 Hz frequency (sometimes connected through

a gear reducer up to 10,000 kVA or more). Self-ventilation is provided for generators larger than 5000 kVA by some manufacturers, but this is not recommended for steam power plant service.

(2) Similar generators rated 5000 kVA and below are revolving field, non-salient or salient pole, self-ventilated, open drip-proof type, sometimes connected through a gear reducer to the turbine

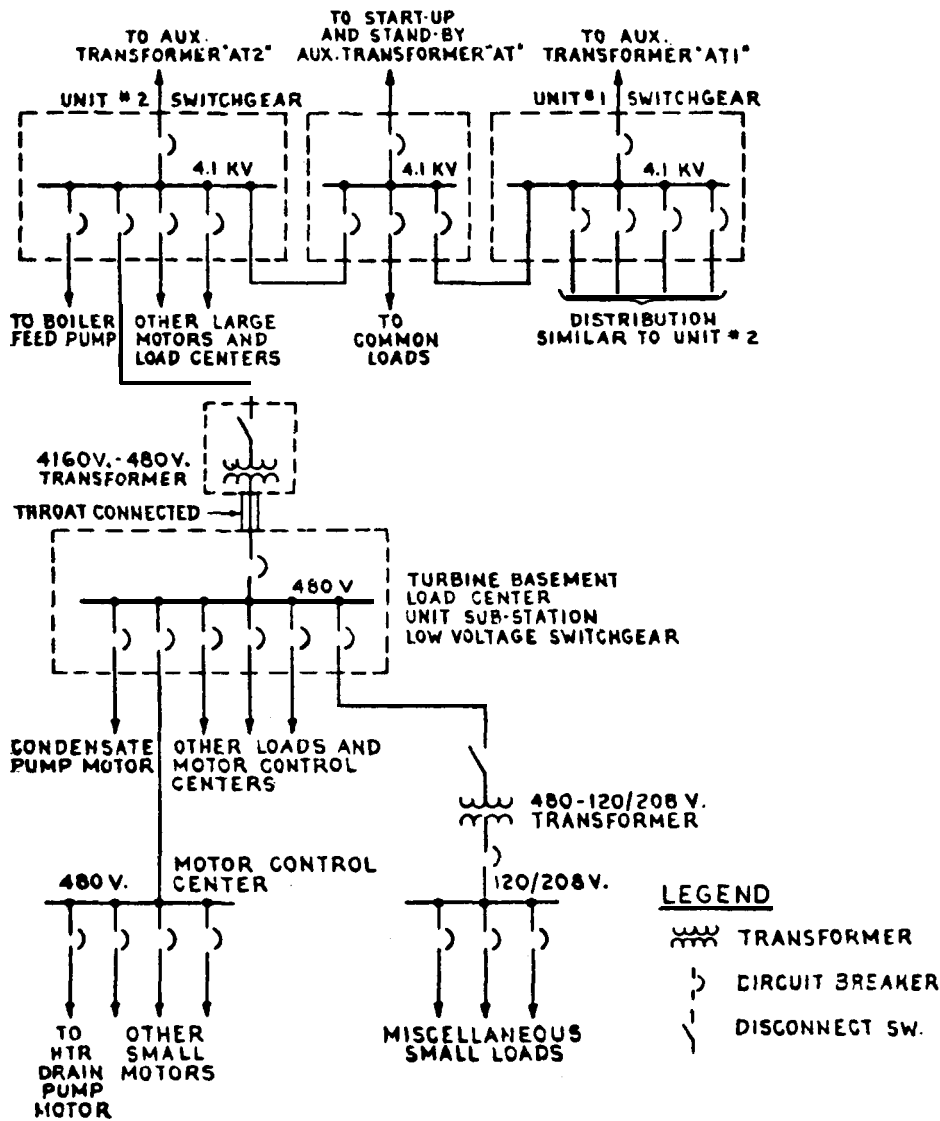


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Figure 4-3. Station connections, two unit station unit arrangement-distribution voltage higher than generation.



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Figure 4-4. One-line diagram—typical station service power system.

with the number of poles dependent on the speed selected which is the result of an economic evaluation by the manufacturer to optimize the best combination of turbine, gear and generator.

(3) Generators for gas turbine service are revolving field, non-salient or salient pole, self-ventilated, open drip-proof type, sometimes connected through a gear reducer, depending on manufacturer's gas turbine design speed, to the gas turbine power takeoff shaft. Non-salient pole generators are two-pole, 3600 rpm for 60 Hz, although manufacturers of machines smaller than 1500 kVA may utilize 1800 rpm, four-pole, or 1200 rpm, six-pole, salient

pole generators. Generators may be obtained totally enclosed with water cooling if desired because of high ambient temperatures or polluted atmosphere.

(4) Generators for diesel service are revolving field, salient pole, air cooled, open type, direct connected, and with amortisseur windings to dampen pulsating engine torque. Number of poles is six or more to match low speeds typical of diesels,

b. *Standards.* Generators will meet the requirements of ANSI C50. 10, C50. 13 and C50.14 is applicable as well as the requirements of NEMA SM 12 and SM 13.

(1) ANSI C84.1 designates standard voltages

as discussed in section I.

(2) Generator kVA rating for steam turbine generating units is standardized as a multiplier of the turbine kW rating. Turbine rating for a condensing steam turbine with controlled extraction for feedwater heating is the kW output at design initial steam conditions, 3.5-inches hg absolute exhaust pressure, three percent cycle makeup, and all feedwater heaters in service. Turbine rating for a non-condensing turbine without controlled or uncontrolled extraction is based on output at design initial steam conditions and design exhaust pressure. Turbine standard ratings for automatic extraction units are based on design initial steam conditions and exhaust pressure with zero extraction while maintaining rated extraction pressure. However, automatic extraction turbine ratings are complicated by the unique steam extraction requirements for each machine specified. For air cooled generators up to 15,625 kVA, the multiplier is 1.25 times the turbine rating, and for 18,750 kVA air cooled and hydrogen cooled generators, 1.20. These ratings are for water cooled generators with 95 °F maximum inlet water to the generator air or hydrogen coolers. Open, self-ventilated generator rating varies with ambient air temperature; standard rating usually is at 104° F ambient.

(3) Generator ratings for gas turbine generating units are selected in accordance with ANSI Standards which require the generator rating to be the base capacity which, in turn, must be equal to or greater than the base rating of the turbine over a specified range of inlet temperatures. Non-standard generator ratings can be obtained at an additional price.

(4) Power factor ratings of steam turbine driven generators are 0.80 for ratings up to 15,625 kVA and 0.85 for 17,650 kVA air cooled and 25,600 kVA to 32,000 kVA air/water cooled units. Standard power factor ratings for gas turbine driven air cooled generators usually are 0.80 for machines up to 9375 kVA and 0.90 for 12,500 to 32,000 kVA. Changes in air density, however, do not affect the capability of the turbine and generator to the same extent so that kW based on standard conditions and generator kVA ratings show various relationships. Power factors of large hydrogen cooled machines are standardized at 0.90. Power factor for salient pole generators is usually 0.80. Power factor lower than standard, with increased kVA rating, can be obtained at an extra price.

(5) Generator short circuit ratio is a rough indication of generator stability; the higher the short circuit ratio, the more stable the generator under transient system load changes or faults. However, fast acting voltage regulation can also assist in

achieving generator stability without the heavy expense associated with the high cost of building high short circuit ratios into the generator. Generators have standard short circuit ratios of 0.58 at rated kVA and power factor. If a generator has a fast acting voltage regulator and a high ceiling voltage static excitation system, this standard short circuit ratio should be adequate even under severe system disturbance conditions. Higher short circuit ratios are available at extra cost to provide more stability for unduly fluctuating loads which may be anticipated in the system to be served.

(6) Maximum winding temperature, at rated load for standard generators, is predicated on operation at or below a maximum elevation of 3300 feet; this may be upgraded for higher altitudes at an additional price.

4-4. Features and accessories

The following features and accessories are available in accordance with NEMA standards SM 12 and SM 13 and will be specified as applicable for each generator.

a. Voltage variations. Unit will operate with voltage variations of plus or minus 5 percent of rated voltage at rated kVA, power factor and frequency, but not necessarily in accordance with the standards of performance established for operation at rated voltage; i.e., losses and temperature rises may exceed standard values when operation is not at rated voltage.

b. Thermal variations.

(1) Starting from stabilized temperatures and rated conditions, the armature will be capable of operating, with balanced current, at 130 percent of its rated current for 1 minute not more than twice a year; and the field winding will be capable of operating at 125 percent of rated load field voltage for 1 minute not more than twice a year.

(2) The generator will be capable of withstanding, without injury, the thermal effects of unbalanced faults at the machine terminals, including the decaying effects of field current and dc component of stator current for times up to 120 seconds, provided the integrated product of generator negative phase sequence current squared and time (I_2^2t) does not exceed 30. Negative phase sequence current is expressed in per unit of rated stator current, and time in seconds. The thermal effect of unbalanced faults at the machine terminals includes the decaying effects of field current where protection is provided by reducing field current (such as with an exciter field breaker or equivalent) and dc component of the stator current.

c. Mechanical withstand. Generator will be capable of withstanding without mechanical injury any

type of short circuit at its terminals for times not exceeding its short time thermal capabilities at rated kVA and power factor with 5 percent over rated voltage, provided that maximum phase current is limited externally to the maximum current obtained from the three-phase fault. Stator windings must withstand a normal high potential test and show no abnormal deformation or damage to the coils and connections.

d. Excitation voltage. Excitation system will be wide range stabilized to permit stable operation down to 25 percent of rated excitation voltage on manual control. Excitation ceiling voltage on manual control will not be less than 120 percent of rated exciter voltage when operating with a load resistance equal to the generator field resistance, and excitation system will be capable of supplying this ceiling voltage for not less than 1 minute. These criteria, as set for manual control, will permit operation when on automatic control. Exciter response ratio as defined in ANSI/IEEE 100 will not be less than 0.50.

e. Wave shape. Deviation factor of the open circuit terminal voltage wave will not exceed 10 percent.

f. Telephone influence factor. The balanced telephone influence factor (TIF) and the residual component TIF will meet the applicable requirements of ANSI C50.13.

4-5. Excitation systems

Rotating commutator exciters as a source of dc power for the ac generator field generally have been replaced by silicon diode power rectifier systems of the static or brushless type.

a. A typical brushless system includes a rotating permanent magnet pilot exciter with the stator connected through the excitation switchgear to the stationary field of an ac exciter with rotating armature and a rotating silicon diode rectifier assembly, which in turn is connected to the rotating field of the generator. This arrangement eliminates both the commutator and the collector rings. Also, part of the system is a solid state automatic voltage regulator, a means of manual voltage regulation, and necessary control devices for mounting on a remote panel. The exciter rotating parts and the diodes are mounted on the generator shaft; viewing during operation must utilize a strobe light.

b. A typical static system includes a three-phase excitation potential transformer, three single-phase current transformers, an excitation cubicle with field breaker and discharge resistor, one automatic and one manual static thyristor type voltage regulators, a full wave static rectifier, necessary devices for mounting on a remote panel, and a collector assembly for connection to the generator field.

Section III. GENERATOR LEADS AND SWITCHYARD

4-6. General

The connection of the generating units to the distribution system can take one of the following patterns:

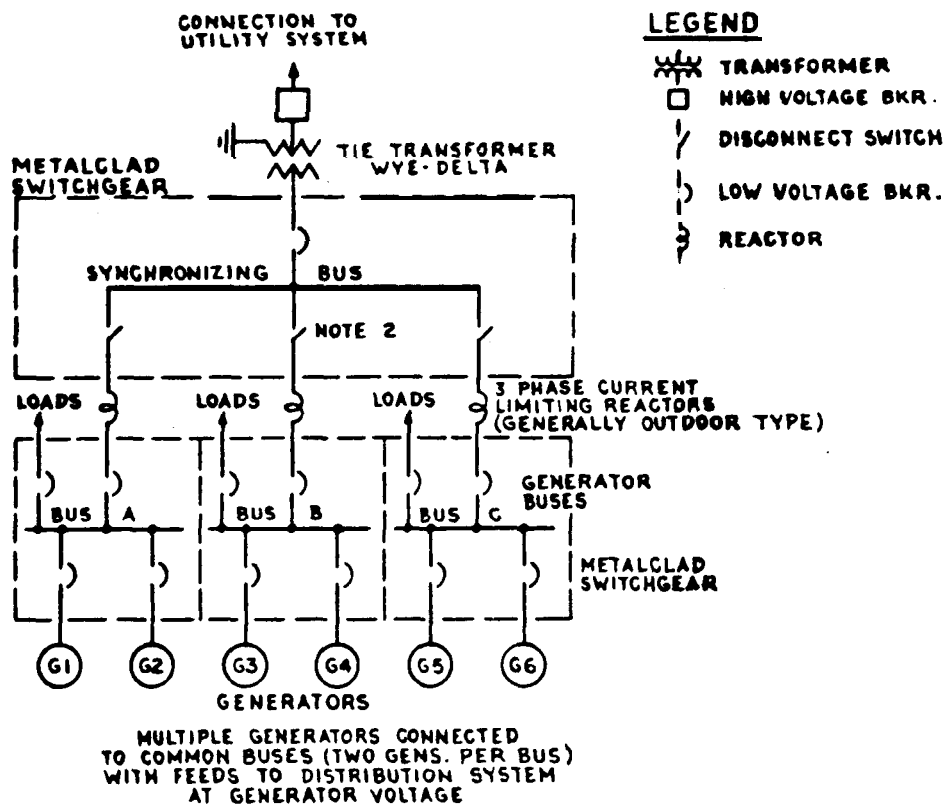
a. With the common bus system, the generators are all connected to the same bus with the distribution feeders. If this bus operates at a voltage of 4.16 kV, this arrangement is suitable up to approximately 10,000 kVA. If the bus operates at a voltage of 13.8 kV, this arrangement is the best for stations up to about 25,000 or 32,000 kVA. For larger stations, the fault duty on the common bus reaches a level that requires more expensive feeder breakers and the bus should be split.

b. The bus and switchgear will be in the form of a factory fabricated metal clad switchgear as shown in Figure 4-1. For plants with multiple generators and outgoing circuits, the bus will be split for reliability using a bus tie breaker to permit separation of approximately one-half of the generators and lines on each side of the split.

c. A limiting factor of the common type bus system is the interrupting capacity of the switchgear. The switchgear breakers will be capable of inter-

rupting the maximum possible fault current that will flow through them to a fault. In the event that the possible fault current exceeds the interrupting capacity of the available breakers, a synchronizing bus with current limiting reactors will be required. Switching arrangement selected will be adequate to handle the maximum calculated short circuit currents which can be developed under any operating routine that can occur. All possible sources of fault current; i.e., generators, motors and outside utility sources, will be considered when calculating short circuit currents. In order to clear a fault, all sources will be disconnected. Figure 4-5 shows, in simplified single line format, a typical synchronizing bus arrangement. The interrupting capacity of the breakers in the switchgear for each set of generators is limited to the contribution to a fault from the generators connected to that bus section plus the contribution from the synchronizing bus and large (load) motors. Since the contribution from generators connected to other bus sections must flow through two reactors in series fault current will be reduced materially.

d. If the plant is 20,000 kVA or larger and the



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Figure 4-5. Typical synchronizing bus.

area covered by the distribution system requires distribution feeders in excess of 2 miles, it may be advantageous to connect the generators to a higher voltage bus and feed several distribution substations from that bus with step-down substation transformers at each distribution substation as shown in Figure 4-3.

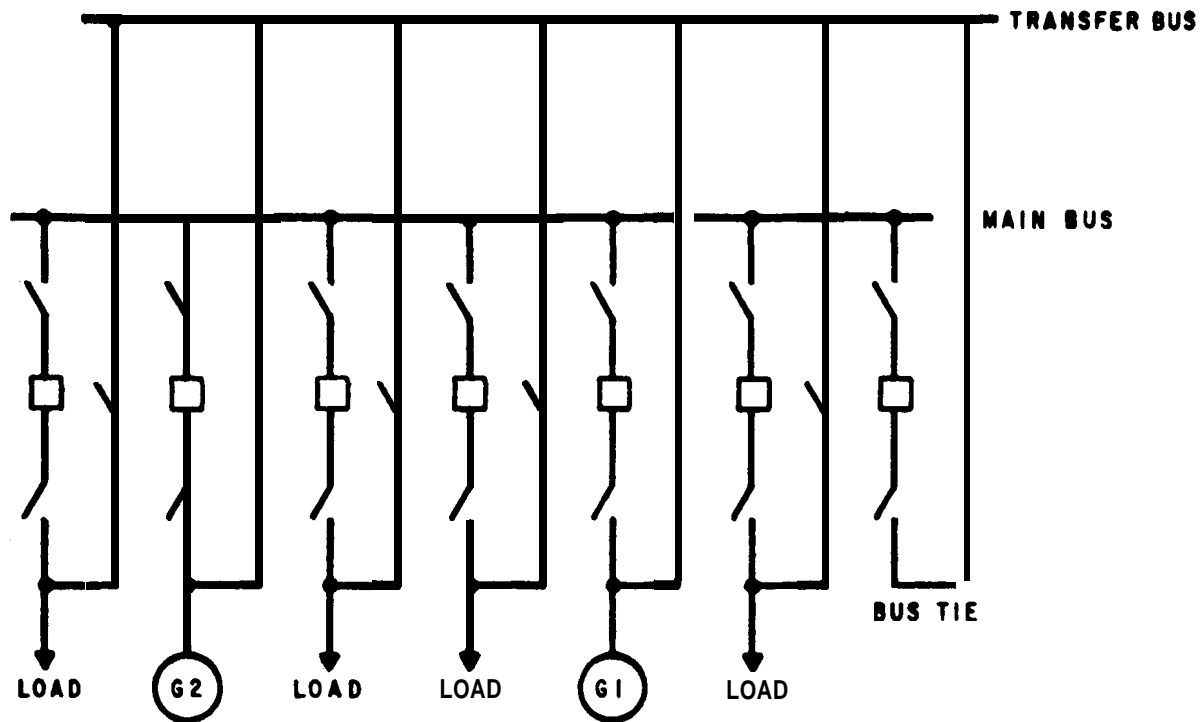
e. The configuration of the high voltage bus will be selected for reliability and economy. Alternative bus arrangements include main and transfer bus, ring bus and breaker and a half schemes. The main and transfer arrangement, shown in Figure 4-6, is the lowest cost alternative but is subject to loss of all circuits due to a bus fault. The ring bus arrangement, shown in Figure 4-7, costs only slightly more than the main and transfer bus arrangement and eliminates the possibility of losing all circuits from a bus fault since each bus section is included in the protected area of its circuit. Normally it will not be

used with more than eight bus sections because of the possibility of simultaneous outages resulting in the bus being split into two parts. The breaker and a half arrangement, shown in Figure 4-8, is the highest cost alternative and provides the highest reliability without limitation on the number of circuits.

4-7. Generator leads

a. Cable.

(1) Connections between the generator and switchgear bus where distribution is at generator voltage, and between generator and stepup transformer where distribution is at 34.5 kV and higher, will be by means of cable or bus duct. In most instances more than one cable per phase will be necessary to handle the current up to a practical maximum of four conductors per phase. Generally, cable installations will be provided for generator capacities up to 25 MVA. For larger units, bus ducts will



LEGEND

— [square symbol] — **CIRCUIT BREAKER WITH TWO DISCONNECT SWITCHES**

— [diagonal line symbol] — **DISCONNECT SWITCH**

⊙ **GENERATOR**

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Figure 4-6. Typical main and transfer bus.

be evaluated as an alternative.

(2) The power cables will be run in a cable tray, separate from the control cable tray; in steel conduit; suspended from ceiling or on wall hangers; or in ducts depending on the installation requirements.

(3) Cable terminations will be made by means of potheads where lead covered cable is applied, or by compression lugs where neoprene or similarly jacketed cables are used. Stress cones will be used at 4.16 kV and above.

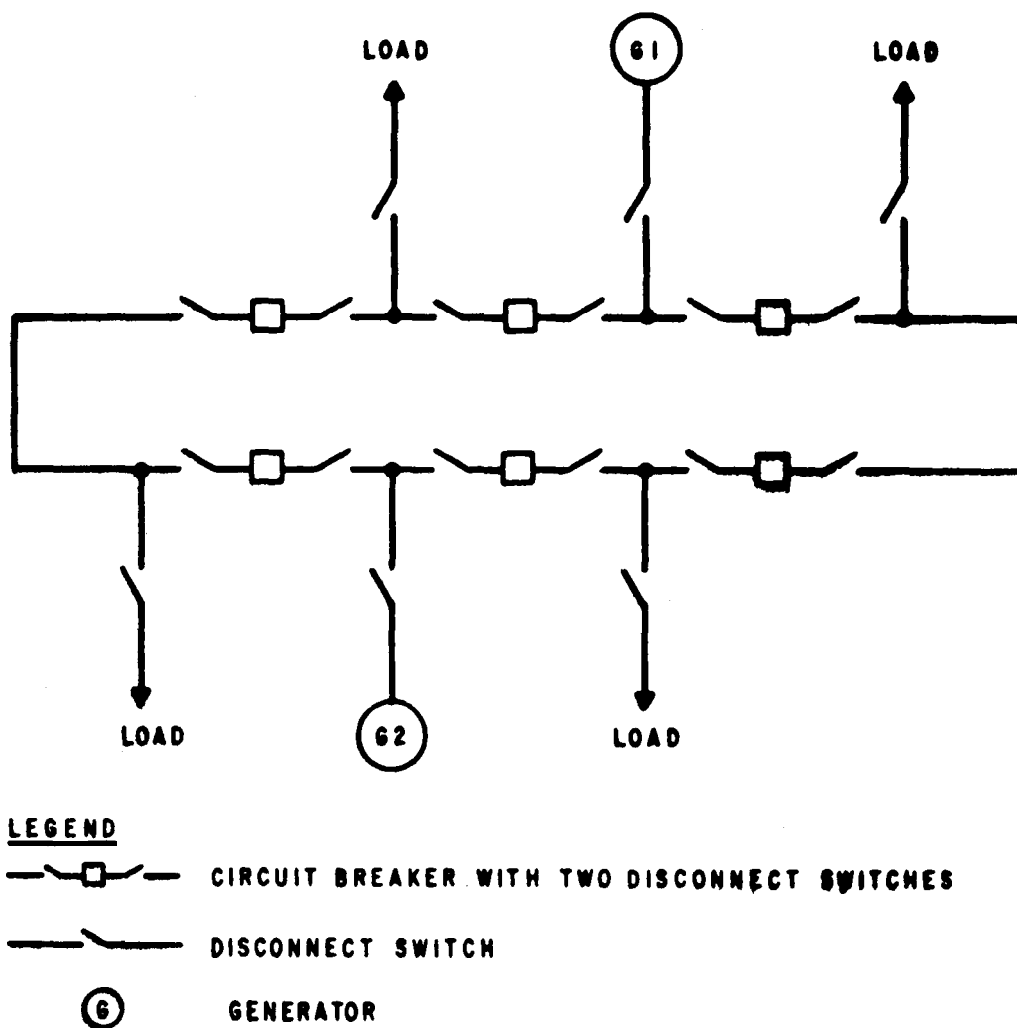
(4) For most applications utilizing conduit, cross-linked polyethylene with approved type filler or ethylene-propylene cables will be used. For applications where cables will be suspended from hangers or placed in tray, armored cable will be used to provide physical protection. If the cable current rating does not exceed 400 amperes, the three phases will

be tri-plexed; i.e., all run in one steel armored enclosure. In the event that single phase cables are required, the armor will be nonmagnetic.

(5) In no event should the current carrying capacity of the power cables emanating from the generator be a limiting factor on turbine generator output. As a rule of thumb, the cable current carrying capacity will be at least 1.25 times the current associated with kVA capacity of the generator (not the kW rating of the turbine).

b. Segregated phase bus.

(1) For gas turbine generator installations the connections from the generator to the side wall or roof of the gas turbine generator enclosure will have been made by the manufacturer in segregated phase bus configuration. The three phase conductors will be flat copper bus, either in single or multiple con-



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Figure 4-7. Typical ring bus.

ductor per phase pattern. External connection to switchgear or transformer will be by means of segregated phase bus or cable. In the segregated phase bus, the three bare bus-phases will be physically separated by non-magnetic barriers with a single enclosure around the three buses.

(2) For applications involving an outdoor gas turbine generator for which a relatively small lineup of outdoor metal clad switchgear is required to handle the distribution system, segregated phase bus will be used. For multiple gas turbine generator installations, the switchgear will be of indoor construction and installed in a control/switchgear building. For these installations, the several generators will be connected to the switchgear via cables.

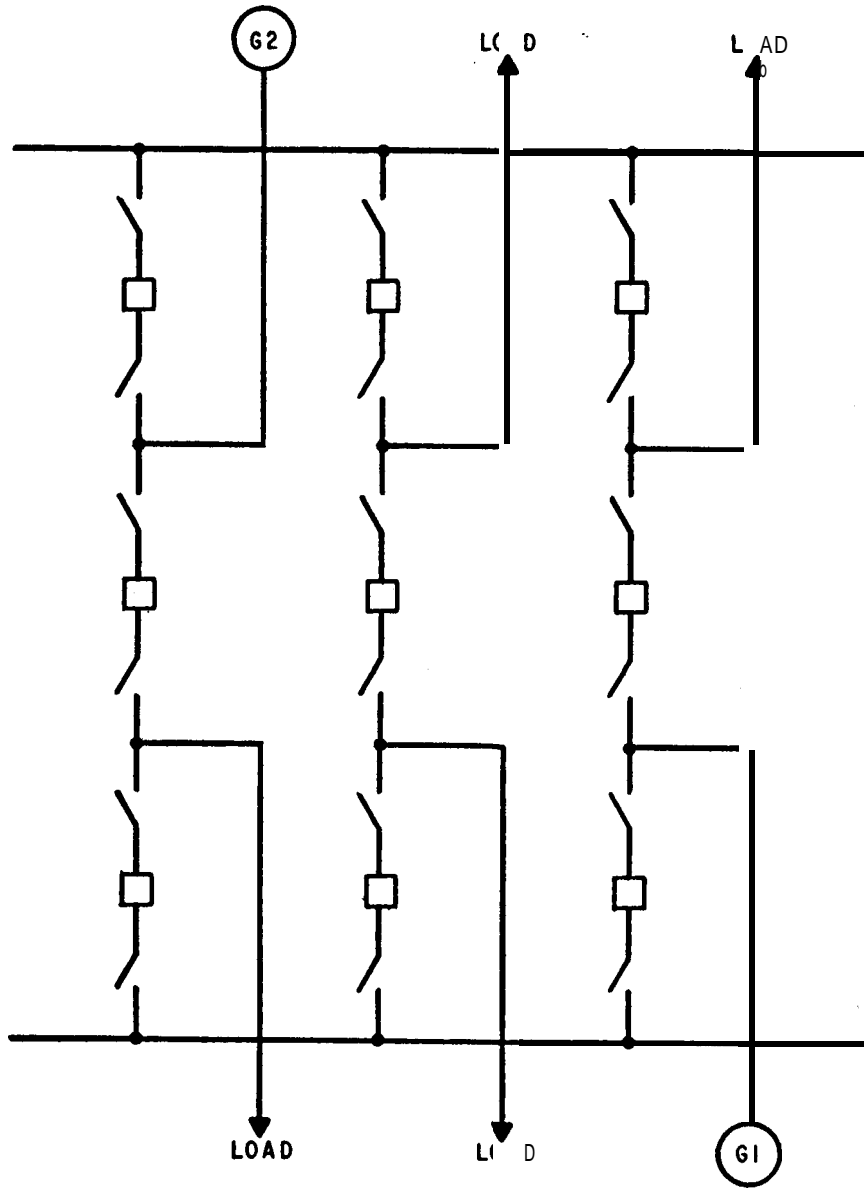
(3) Segregated bus current ratings may follow the rule of thumb set forth above for generator ca-

bles but final selection will be based on expected field conditions.


c. Isolated phase bus.

(1) For steam turbine generator ratings of 25 MVA and above, the use of isolated phase bus for connection from generator to stepup transformer will be used. At such generator ratings, distribution seldom is made at generator voltage. An isolated phase bus system, utilizing individual phase copper or aluminum, hollow square or round bus on insulators in individual non-magnetic bus enclosures, provides maximum reliability by minimizing the possibility of phase-to-ground or phase-to-phase faults.

(2) Isolated phase bus current ratings should follow the rule of thumb set forth above for generator cables.



LEGEND

—  — CIRCUIT BREAKER WITH TWO DISCONNECT SWITCHES

—  — DISCONNECT SWITCH

⊙ GENERATOR

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Figure 4-8. Typical breaker and a half bus.

4-8. Switchyard

a. *Outdoor vs. indoor.* With normal atmospheric conditions, switchyards will be of the outdoor type as described below. It is possible that a plant will be located on a tropical desert area where alternate sand blasting and corrosion or contamination is a problem or in an arctic area where icing is a problem. In such an event, an indoor switchyard or installation employing totally enclosed metal clad switchgear with SF6 insulation will be provided.

b. Structures and buses.

(1) In the event distribution for a large installation is at higher than generator voltage; e.g., 34.5 kV, or in the event an interconnection with a local utility is necessary, a switchyard will be required. The switching structure will be erected to support the bus insulators, disconnecting switches, potential and current transformers, and the terminations for the generator stepup transformer and transmission lines.

(2) Structures of galvanized steel or aluminum are most often used. Where the switchyard is located close to an ocean, the salt laden atmosphere may be extremely corrosive to aluminum requiring the use of galvanized steel.

(3) Either copper or aluminum, tubular buses will be employed depending upon the atmosphere, with aluminum generally being less expensive. Copper bus connections will be bolted; aluminum connections must be welded. Special procedures are required for aluminum welding, and care should be taken to assure that welders certified for this type of welding are available. For isolated or overseas establishments, only copper buses should be used. A corrosive atmosphere will preclude the use of aluminum.

c. Disconnect switches; insulators

(1) Two three-phase disconnect switches will be used for each oil circuit breaker, one on each side of the breaker. If the ring bus arrangement is used, a disconnect switch will also be used in the circuit take-off so the ring can be reclosed with the circuit out for maintenance. If only one bus is used, a disconnect switch will be installed as a by-pass around the circuit breaker so it can be maintained.

(2) Line disconnect switches at all voltage ratings will have arcing horns. Above 69 kV, all disconnect switches will have arcing horns.

(3) Current carrying capacity of each disconnect switch will be at least 25 percent above that of the line or transformer to which it is connected. The switches are available in 600, 1200 and 2000 ampere ratings.

(4) Voltage ratings of switches and bus support insulators will match the system voltage. In par-

ticularly polluted atmospheres, the next higher voltage rating than that of the system will be used. In some instances, the manufacturer can furnish current carrying parts designed for the system voltage and will increase phase spacing and insulator stack length to the next higher voltage rating in order to increase the leakage paths in the polluted atmosphere. In such installations, the normal relationship between flashover across the open switch and flashover to ground must be maintained.

(5) All disconnect switches will be operable from ground level by means of either a lever or rotating crank mechanism. The crank type mechanism is preferred because it is more positive and takes less strength to operate. Operating mechanisms will be capable of being locked by padlock in both the open and closed positions. A switchplate will be provided at each operating mechanism for the operator to stand on when operating the switch. Each plate will be approximately 2 feet, 6 inches wide by 4 feet long, made of galvanized steel, and with two ground lugs permanently attached to the underside of each plate on the side next to the operating mechanism. The switchplates will be connected to the operating handle and to the switchyard ground grid at two separate points by means of a 2/0 stranded bare copper wire.

d. Oil circuit breakers.

(1) For outdoor service, from nominal 13.8 kV through 69 kV, single tank oil circuit breakers (ocb's) having one operating mechanism attached to the tank will be used. Above 69 kV, three tanks are used, all permanently mounted on a single channel base, with a single operating mechanism attached to one of the end tanks.

(2) Operating mechanisms can be spring charged using a motor to charge the spring, pneumatic employing a motor driven compressor in each operating mechanism; or pneudraulic, a combination pneumatic and hydraulic mechanism. The 69 kV and below applications utilize the spring charged mechanism because of lower cost while above 69 kV, either of the other two work satisfactorily. Both an ac and a dc auxiliary source must be made available to each breaker operating mechanism.

(3) Up to two doughnut type multi-ratio current transformers (600:5, with taps; or 1200:5, with taps) can be obtained on each bushing. These are mounted inside the tanks with all leads brought to terminal blocks in the mechanism cabinets. Since it is a major task to add current transformers, the two will be purchased initially for each bushing.

(4) A considerable range of both current carrying and current interrupting capacity is available for each system operating voltage level. Careful study must be made of the continuous load current

and fault current requirements before selecting oil circuit breakers. Short circuit calculations must be made for any power system, but for extensive power systems operating in parallel with a utility, a system study will be performed prior to selecting the oil circuit breakers. Power networks analyzers or computer programs will be utilized in such work.

e. Potential and current transformers.

(1) For power systems through 69 kV, potential transformers are generally used to provide voltages in the 69- and 120-volt ranges for voltmeters, wattmeters, varmeters, watt-hour meters, power factor meters, synchrosopes, various recorders, and for certain protective relays and controls. Above 69 kV, the cost becomes prohibitive and capacitor potential devices are used. The latter do not have as much volt-ampere capacity as potential transformers so care must be taken not to overload the potential devices by placing too many instruments or devices in the circuit.

(2) Both the potential transformers (pt's) and capacitor potential devices (cpd's) will be purchased with dual 120 volt secondaries, each tapped at 69 volts for circuit flexibility. All should be for single phase-to-ground application on the high voltage side.

(3) Three line-to-ground pt's or cpd's will be employed on each main high voltage bus. Generally, only one pt or cpd is needed on each feeder for synchronizing or hot line indication; but for ties to the outside utility or for special energy metering for billing purposes or other energy accounting, or for relaying, three devices will be necessary.

(4) Current transformers (ct's) of the through type, where the primary winding is connected in the circuit, will seldom be used. In the usual case, there are sufficient bushing type ct's in the oil circuit breakers and power transformers. Multi-ratio units will be employed, as described under *d* above, for control, indication and protective relaying. Should billing metering be needed, more accurate metering type bushing type ct's will be used.

(5) Current transformer ratios do not necessarily have a direct relationship with the continuous current capacity of the circuit breaker or transformer bushing on which they are mounted. The high current portion of the ratio should be selected so that the circuit full load current will be approximately 70-80 percent of instrument full scale for best accuracy. Ratios for protective relaying will be specially selected to fill the particular relays being applied.

(6) Joint use of a particular set of ct's for both instrumentation and protective relaying will be avoided because the two ratio requirements may be different and testing or repair of instrument circuits may require those circuits to be out of service for a

time. Power circuits can be operated for extended periods with a part of the instrumentation and metering out of service; they should not be operated for extended periods without the protective devices.

f. Duct system.

(1) Except as otherwise described herein, duct systems will be in accordance with TM 5-811-1/AFM 88-9.

(2) Power and control cables will be run in underground conduit in a concrete duct system between the generating station and switchyard; the two types of cable may be run in the same duct bank but in separate conduits. If in the same duct bank, the manholes will be divided with a concrete barrier between the power and control cable sections. The main power cables will be run in their own duct system and will terminate at the power transformers which are usually placed in a single row.

(3) At the point of entrance into the switchyard, the control cable duct system will empty into a concrete cable trench system, either poured in place or assembled from prefabricated runs. The U-shaped trench will be of sufficient size in width and depth to accommodate control and auxiliary power cables for present transformers, breakers, disconnect switches, pt's and ct's, ac and dc auxiliary power cables and lighting circuits, plus provision of at least 25 percent for expansion of the switchyard.

(4) Checkered plate or sectionalized prefabricated concrete covers will be placed on the trench, complete with holes or tilt-up recessed handles for assistance in removal of each cover section.

(5) Control cables will be run through sleeves from the trench then through galvanized steel conduit buried 18 inches deep to the point of rising to the circuit breaker mechanism housing or other termination. Risers will be attached securely to the terminating device.

g. Ac and dc distribution. One or more 120/208 Vat, 24 or 40 circuit distribution panelboards and one 125 Vdc, 24-circuit distribution panel will be provided in weatherproof enclosures in a central location in the switchyard. Oil circuit breakers require 125 Vdc for closing, tripping and indication. Compressor motors or spring winding motors for the oil circuit breakers will require 120 or 208 volts ac, as will the radiator cooling fans for the power transformers. Strip heaters for the ocb transformer mechanism housings will operate at 208 Vat. Lighting circuits will require 120 Vat. Weatherproof, grounding type convenience outlets at 120 volts and 208 volts will be provided for electrically operated tools and maintenance equipment needed to maintain the switchyard.

h. Grading and fencing.

(1) The entire switchyard area will be at the

same grade except for enough slope to provide drainage. The concrete pads and foundations for all ocb's and transformers; for all bus, pt and ct supporting structures; and for the switchyard structures will be designed for the same top elevation, and final rough grade will set some 9 inches below top of concrete.

(2) Three inches of coarse gravel and 3 inches of fine gravel will be provided on the rough grade which will allow the top of the concrete to be exposed 3 inches above the final crushed rock grade. The rough grade will be sloped at 1 inch per hundred feet to provide drainage, but the final crushed rock course will be dead level. Crushed rock will extend 3 feet outside the fence line.

(3) All concrete foundations will have a 1-inch, 45-degree chamfer so the edges will not chip.

(4) An 8-foot galvanized steel chain link fence with round line and corner posts will enclose the entire substation. The fence will be angle braced in both directions. End posts for personnel and vehicle gates will be similarly braced. Posts will be mounted in poured concrete footings, having the top cap rounded for drainage.

(5) Two 36-inch wide personnel gates will be placed in diagonally opposite locations; one located for convenience for operator and maintenance regular access, and the other to provide an emergency exit. The gate for regular access will be padlockable. The emergency exit gate will not be padlocked but will be openable only from inside the switchyard by means of removing a drop-in pin; the pin will be so barred that it cannot be removed from outside the fence. This panic hardware will be designed for instant, easy removal in the event use of the emergency exit is necessary.

(6) A double hung, padlockable vehicle gate will be installed; each section will be 8 feet in width to provide adequate room for transformer removal and line truck entrance and egress.

(7) If local codes will permit, a three-strand barbed wire security extension, facing outward at 45 degrees, will be mounted on top of the fence and gates.

i. Grounding.

(1) A grounding grid, buried approximately 2 feet below rough grade level will be installed prior to installation of cable ducts, cable trenches and crushed rock, but simultaneously with the installation of switchyard structure, ocb, and transformer footings.

(2) The main rectangular grid will be looped around the perimeter of the yard and composed of 500 MCM bare stranded tinned copper cable. From

the perimeter, cross-connections from side to side and end to end will be 250 MCM stranded tinned copper cable on 10- to 12-foot spacing in accordance with TM 5-811-1/AFM 88-9. Taps will be made to each vertical bay column of the switchyard structure, to every pt and ct and bus support structure, to every ocb and transformer, and to every disconnect switch structure with 4/0 stranded tinned copper conductor. Two taps will be run to each circuit breaker and power transformer from different 250 MCM cross-connections.

(3) Taps will extend outward from the 500 MCM perimeter cable to a fence rectangular loop with taps at no more than 40-foot centers. This loop will be run parallel to the fence, 2 feet outside the fence line, and the fence loop will be tapped every 20-feet via 2/0 stranded tinned copper taps securely bolted to the fence fabric near the top rail. Flexible tinned copper ground straps will be installed across the hinge point at each swinging gate.

(4) At least two 500 MCM bare-stranded, tinned copper cables will be connected via direct burial to the generating station ground grid. Connection will be made to opposite ends of the switchyard 500 MCM loop and to widely separated points at the generating station grid.

(5) Ground rods, at least 8 feet long, 3/4-inch diameter, will be driven at each main grid intersection point and at 20-foot centers along the fence loop to a depth of 13 inches above the intersection about 17 inches below rough grade.

(6) Every grid intersection and every ground rod connection to both grids will be exothermic welded using appropriate molds.

(7) The ground grid system described above will suffice for most Army establishments except in particularly rocky areas or in the Southwest desert states. Target is to obtain not greater than five ohms ground resistance. In rocky or desert areas, special connections of the switchyard grid to remote grounding pits via drilled holes perhaps 200 feet deep or grids buried in remote stream beds may be necessary. NOTE: TM 5-811-1 describes a grading, fencing and grounding system in considerable detail for station and substation applications where power is purchased from a utility or small generators are installed. The intent herein is to provide for the additional requirements for a larger (5000-30,000 kW) generating station stepup switchyard which permits connection to a distribution system and interconnection with an outside utility system. The system herein described is a "heavy duty" system. TM 5-811-UAFM 88-9 will be followed for detail not described herein.

Section IV. TRANSFORMERS

4-9. Generator stepup transformer

The stepup transformer will be in accordance with ANSI Standard C 57.12.10 and will include the following optional features.

a. Rating.

(1) The generator stepup transformer kVA rating for boiler-turbine-generator "unit type" power plants will depend upon the generator kVA rating which, in turn, is dependent upon the prime mover ratings. In any event, the transformer kVA rating will be selected so that it is not the limiting factor for station output.

(2) As a rule of thumb, the top kVA rating will be selected to be approximately 115-120 percent of the KVA rating of the generator. Since the generator unit auxiliary transformer load is tapped off between the generator and stepup transformer and will amount to about 6 percent of the generator rating, the operating margin for the stepup transformer will be on the order of 20-25 percent. This will permit making full use of the margin the turbine generator manufacturer must build in, in order to meet his guarantees.

(3) If the load served is expected to be quite constant and the generator will be operating at a high load factor, it should be cost effective to obtain an FOA (forced oil/air cooled) transformer. Pumps and fans are on whenever the transformer is energized. If, on the other hand, a widely varying load is expected, it may be cost effective to obtain a dual rated transformer OA/FA, or even triple rated OA/FA/FA having two increments of fan cooling as well as a self-cooled rating. The top rating would coordinate with the generator rating but fans would shut down when the unit is operating at partial load. The resulting rating of the turbine, generator and stepup transformer for typical unit might be:

Turbine	25,000 kW
Generator	31,250 kVA at 0.8 PF
Transformer	35,000 kVA at OA/FA/FA rating

(4) Voltage of the high side will match the nominal operating voltage desired for the distribution system, such as 34.5 kV; and for the low side will match the generator voltage, such as 13.8 kV. High voltage side will have two 2 1/2 percent full capacity taps above and "below rated voltage."

b. Control.

(1) Both the fan and pump systems will operate on 208 volts, 60 Hz, single phase. The control system will provide automatic throwover from dual 208 volt sources with one being preferred and the other alternate; either may be selected as preferred via a selector switch. Sources will be run from separate

auxiliary power sources within the plant.

(2) The transformer alarms will be connected to the plant annunciator system and will require 125 Vdc for the alarm system auxiliary relays. Protective devices, which will be mounted in the transformer with control and indication leads run by the transformer manufacturer to the control cabinet, are as follows:

(a) Oil low level gauge with alarm contacts.

(b) Top oil temperature indicator with alarm contacts.

(c) Winding hot spot oil temperature indicator with two or more sets of electrically independent control and alarm contacts, the number depending on whether unit is FOA, O/FA, or OA/FA/FA.

(d) Sudden gas pressure Buchholz type relay with alarm contacts and external reset button.

(e) Pressure relief device with alarm contacts and with operation indicator clearly visible from ground level.

(f) Pressure/vacuum gauge with electrically independent high and low alarm contacts; gauge to be visible from ground level.

(g) Full set of thermally protected molded case circuit breakers and auxiliary control and alarm relays for denoting

-Loss of preferred fan pump power source.

-Automatic throwover of fan and pump sources one or two.

-Loss of control power.

(3) The control compartment will have a dual hinged door readily accessible from finished grade level; bottom of compartment will be about 3 feet above grade. Thermostat and heaters will be provided,

c. *Miscellaneous.* Miscellaneous items that will be included are as follows:

(1) Control of the fixed high side winding taps will be accessible to a person standing on the ground. The control device will permit padlocking with the selected tap position clearly visible.

(2) Base of transformer will be on I-beams suitable for skidding the transformer in any direction.

(3) Two 600-5 or 1200-5 multi-ratio bushing ct's will be provided on each of the high side and low side bushings with all leads brought to terminal blocks in the control cabinet.

(4) One 600-5, or lesser high current rating, bushing ct will be provided on the high side neutral bushing with leads brought to a terminal block in the control compartment.

4-10. Auxiliary transformers

a. Rating.

(1) As a rule of thumb, the unit auxiliary transformer for a steam electric station will have a kVA rating on the order of 6 to 10 percent of the generator maximum kVA rating. The percent goes down slightly as generator kVA goes up and coal fired plants have highest auxiliary power requirements while gas fired plants have the least. The actual rating specified for an installation will be determined from the expected station service loads developed by the design. The station startup and standby auxiliary transformer for plants having a unit system will have a kVA rating on the order of 150 percent of a unit auxiliary transformer— say 10 to 12 percent of the maximum generator kVA. The additional capacity is required because the transformer acts as 100 percent spare for the unit auxiliary transformer for each of one or more generators, while also serving a number of common plant loads normally fed from this source. If the auxiliary power system is not on the unit basis; i.e., if two or more auxiliary transformers are fed from the station bus, sizing of the auxiliary transformer will take into account the auxiliary power loads for all units in the station plus all common plant loads. The sizing of auxiliary transformers, in any case, will be subject to an analysis of all loads served under any set of startup, operating, or shutdown conditions with reasonable assumed transformer outages and will include a minimum of 10 percent for future load additions.

(2) Auxiliary transformer voltage ratings will be compatible with the switchyard voltage and the auxiliary switchgear voltages. Two 2 1/2 percent taps above and below rated voltage on the high voltage side will be included for each transformer.

b. Control.

(1) One step of fan control is commonly provided, resulting in an OA/FA rating. Fan control for auxiliary transformers will be similar to that described for the generator stepup transformer, except that it is not necessary to provide for dual power sources to the fans. Since the unit auxiliary and the station auxiliary transformers can essentially furnish power for the same services, each transformer serves as a spare for the other. Also, if a fan source fails, the transformer it serves can still be operated continuously at the base self-cooled rating.

(2) The protective devices and alarms will be identical to those of the generator stepup transformer.

(3) The control compartment will be similar to that of the generator stepup transformer.

c. Miscellaneous. The miscellaneous items will be similar to those for the generator stepup transformer, except that only one set of multi-ratio bushing ct's need be provided on each of the high and low side bushings.

4-11. Unit substation transformer

a. Definition. The phrase "unit substation" is used to denote a unit of equipment comprising a transformer and low-side switchgear designed and factory assembled as a single piece of equipment. It is used herein to denote an intermediate voltage reducing station fed by one or two circuits from the auxiliary switchgear and, in turn, serving a number of large motors or motor control centers. The breakers will have lower ratings than those in the auxiliary switchgear but higher ratings than those in the motor control centers. The transformer in the "unit substation" is referred to as a "unit substation transformer."

(1) The term "unit auxiliary transformer" is used to denote the transformer connected to the generator leads that provides power for the auxiliaries of the unit to which it is connected. It feeds the "auxiliary switchgear" for that unit.

(2) The "unit stepup transformer" designates the stepup transformer that is connected permanently to the generator terminals and connects that generator to the distribution system.

b. Rating. For steam electric stations there will be a minimum of two unit substations per turbine installation so that each can be located near an area load center to minimize the lengths of cables serving the various low voltage loads. The kVA rating of the transformer in each unit substation will be sufficient to handle the full kVA of the connected load, including the starting kVA of the largest motor fed from the center, plus approximately 15 percent for future load additions. For diesel engine or gas turbine installations, these unit substations may not be required or one such unit substation may serve more than one generating unit.

c. Control. No fans or pumps are required and thus no control voltage need be brought to the transformer.

d. Alarms. Protective devices will be mounted on the transformer with alarm leads run to an easily accessible terminal board. Devices will include a winding hot spot temperature indicator having two alarm stages for two temperature levels with electrically independent alarm contacts. On occasion, it will be found that design and construction of the unit substation transformer and its physically attached 480-volt switchgear may require the ground indication pt's and their ground indicating lamps to be mounted within and on the transformer ventilated enclosure. In this event, the ground alarm relays will be mounted in a readily accessible portion of the enclosure with leads brought to terminal blocks for external connection to the control room annunciator.

Section V. Protective RELAYS AND METERING

4-12. Generator, stepup transformer and switchyard relaying

a. General. Selection of relays and coordination of their settings so that the correct circuit breaker trips when it is supposed to, and does not trip when it is not supposed to is a subject too broad to be covered herein. For the purpose of this document the listings below will set forth those protective relay types which will be considered.

b. Generator relaying. Each generator will be provided with the following protective relays:

- Three – Generator differential relays (ANSI Device 87)
- One – Lockout relay, electrical trip, hand reset (ANSI Device 86)
- One – Loss of field relay (ANSI Device 40)
- One – Negative sequence relay (ANSI Device 46)
- One – Reverse power relay (ANSI Device 32)
- One – Generator field ground relay (ANSI Device 64)
- Three – Phase time overcurrent relays, voltage restrained (ANSI Device 51V)
- One – Ground overcurrent relay in the generator neutral (ANSI Device 51G)

Although not a part of the ANSI device identification system, generator relay numbers are frequently suffixed with a letter-number sequence such as "G1". For instance, differential relays for generator 1 would be 87G 1 and for generator 2 would be 87G2.

c. Relay functions.

(1) It is usual practice in relay application to provide two separate relays that will be activated by a fault at any point on the system. In the case of a generating unit with an extended zone of differential protection including generator, feeder, auxiliary transformer, stepup transformer and circuit breaker, it is also common practice to use a dedicated zone of differential protection for the generator as backup protection.

(2) The lockout relay (ANSI device 86) is a hand reset device to control equipment when it is desired to have the operator take some positive action before returning the controlled equipment to its normal position.

(3) If a unit operating in parallel with other units or a utility system loses its excitation, it will draw excessive reactive kVA from the system, which may cause other difficulties in the system or may cause overloads in the generator. The loss of field relays (ANSI device 40) will sense this situation and initiate a safe shutdown.

(4) Negative sequence currents flowing in a generator armature will cause double frequency magnetic flux linkages in the rotor and may cause sur-

face heating of the rotor. The generator is designed to accept a specified amount of this current continually and higher amounts for short periods within a specified integrated time-current square (I_2^2t) limit. The negative sequence relay (ANSI device 46) is to remove the unit from service if these limits are exceeded.

(5) The reverse power relay (ANSI device 32) is used to trip the generator from the system in case it starts drawing power from the system and driving its primemover.

(6) A ground on the generator field circuits is not serious as long as only one ground exists. However, a second ground could cause destructive vibrations in the unit due to unbalanced magnetic forces. The generator field ground relay (ANSI device 64) is used to detect the first ground so the unit can be shut down or the condition corrected before a second ground occurs.

(7) The phase time-overcurrent relays (ANSI device 51) are used for overload protection to protect the generator from faults occurring on the system.

(8) The ground overcurrent relay (ANSI 51G) in the generator neutral is used to confirm that a ground fault exists before other ground relays can operate, thus preventing false trips due to unbalances in circuit transformer circuits.

d. Power transformer relaying. Each stepup transformer will be provided with the following protective relays:

(1) Three – Transformer differential relays (ANSI Device 87).

(2) One–Transformer neutral time over-current relay to be used as a ground fault detector relay (ANSI Device 51G)

(3) One–Transformer sudden gas pressure relay. This device is specified and furnished as part of the transformer (ANSI Device 63).

(4) For application in a "unit system" where the generator, the stepup transformer, and the auxiliary transformer are connected together permanently, an additional differential relay zone is established comprising the three items of equipment and the connections between them. This requires three additional differential relays, one for each phase, shown as Zone 1 in Figure 4-3.

e. Auxiliary transformer relaying. These transformers will each be provided with the following protective relays:

(1) Three–Transformer differential relays (ANSI Device 87)

(2) One–Lockout relay (ANSI Device 86)

(3) One–Transformer neutral time overcurrent

relay to be used as a fault detector relay (ANSI Device 51G)

(4) One-Transformer sudden gas pressure relay (ANSI Device 63).

f. Switchyard bus relaying. Each section of the switchyard bus will be provided with bus differential relaying if the size of the installation, say 25,000 kW or more, requires high speed clearing of bus faults.

g. Distribution feeder relaying. Whether feeders emanate from the switchyard bus at, say 34.5kV, or from the generator bus at 13.8 kV, the following relays will be provided for each circuit:

(1) Three-Phase time overcurrent relays with instantaneous element (ANSI Device 50/5 1).

(2) One-Residual ground time overcurrent relay with instantaneous element (ANSI Device 50/51 N).

h. Ties to utility. Relaying of tie lines to the utility company must be coordinated with that utility and the utility will have its own standards which must be met. For short connections, less than 10 miles, pilot wire relaying is often used (ANSI device 87PW). For longer connections, phase directional distance and ground distance relays are often used (ANSI device 21 and 21 G). Various auxiliary relays will also be required. Refer to the utility for these tie line protective relaying requirements.

4-13. Switchgear and MCC protection

a. Medium voltage switchgear (4160 volt system).

(1) The incoming line breaker will be provided with: Three-Phase time overcurrent relays set high enough to provide protection against bus faults on the switchgear bus and not to cause tripping on feeder faults (ANSI Device 50/51).

(2) Each transformer feeder will be provided with:

(a) Three-Phase time overcurrent relays with instantaneous trip attachments (ANSI Device 50/51).

(b) One-Residual ground time overcurrent relay with instantaneous trip attachment (ANSI Device 50N/51N).

(3) Each motor feeder will be provided with:

(a) Three-Phase time overcurrent relay (ANSI Device 50/51).

(b) One-Replica type overcurrent relay (ANSI Device 49) (to match motor characteristic heating curves).

(4) Each bus tie will be provided with: Three-Phase time overcurrent relays (ANSI Device 50).

b. Unit substation switchgear protection (480 volt system). Breakers in the 480-volt substations utilize direct acting trip devices. These devices will be provided as follows:

(1) Incoming line: three-long time and short time elements.

(2) Motor control center feeders: three-long time and short time elements.

(3) Motor feeders: three-long time and instantaneous elements.

c. Motor control center protection (480-volt system). Because of the lower rating, breakers will be molded case type employing thermal/magnetic elements for protection on direct feeders. Combination starters will employ three thermal protective heater type elements in conjunction with the starter.

4-14. Instrumentation and metering

The following instruments will be mounted on the control board in the operating room to provide the operator with information needed for operations:

a. Generator.

(1) Ammeter with phase selector switch

(2) Voltmeter with phase selector switch

(3) Wattmeter

(4) Varmeter

(5) Power factor meter

(6) Frequency meter

(7) Temperature meter with selector switch for stator temperature detectors

(8) D.C. voltmeter for excitation voltage

(9) D.C. ammeter for field current

b. Stepup transformer.

(1) Voltmeter on high voltage side with selector switch

(2) Ammeter with selector switch

(3) Wattmeter

(4) Varmeter

(5) Power factor meter

c. Auxiliary transformer.

(1) Voltmeter on low voltage side with selector switch

(2) Ammeter with selector switch

(3) Wattmeter

(4) Varmeter

(5) Power factor meter

d. Common.

(1) Voltmeter with selector switch for each bus

(2) Synchroscope

e. Integrating meters. The following integrating meters will be provided but need not be mounted on the control board:

(1) Generator output watt-hour meter

(2) Auxiliary transformer watt-hour meter for each auxiliary transformer.

f. Miscellaneous. For units rated 20,000 kW or larger, a turbine-generator trip recorder will be provided but not necessarily mounted on the control board. This is for use in analyzing equipment failures and shutdowns.

Section VI. STATION SERVICE POWER SYSTEMS

4-15. General requirements

a. Scope. The power plant station service electrical system will consist of the following

(1) For steam turbine plants of about 20,000 kW or larger, a medium voltage (4.16 kV) distribution system utilizing outdoor oil filled auxiliary power transformers and indoor metal clad drawout type switchgear assemblies. Usually a medium voltage level of 4.16 kV is not required until generator unit sizes reach approximately 20 MW. A 4.16 kV system may be grounded permitting the use of phase and ground protective relays.

(2) A low voltage (480-volt and 208/120-volt) distribution system, unit substation assemblies, and also motor control centers containing combination starters and feeder breakers.

(3) Station power requirements are smaller for combustion gas turbine units and diesel engine driven generators. For the combustion gas turbine plant, a starting transformer capable of supplying the starting motors is required if the turbine is motor started, but may serve more than one unit. For diesel plants a single 480-volt power supply with appropriate standby provisions is adequate for all units.

b. Operating conditions and redundancy. The station service system will be designed to be operational during station startup, normal operation and normal shutdown. Redundancy will be provided to permit operation of the plant at full or reduced output during a component failure of those portions of the system having two or more *similar* equipments.

c. Switchgear and motor control center location. Switchgear inside the power plant will be located so as to minimize the requirements for conduit to be embedded in the grade floor slab. In steam electric plants it will generally be convenient to have one or more motor control centers at grade with top entrance of control and power cables. The 4160-volt switchgear and 480-volt unit substation will preferably be located on upper floor levels for maximum convenience in routing power cables; control and power cables can thus enter from either above or below. The 480-volt switchgear in combustion gas turbine or diesel plants will be at ground level.

4-16. Auxiliary power transformers

a. Type. The auxiliary power transformers will be oil filled, outdoor type, having both natural and forced air cooled ratings.

b. Taps. Four full capacity taps for deenergized tap changing will be provided on the high voltage side, in two 2 1/2 percent increments above and below rated voltage.

c. Impedance.

(1) Impedance should be selected so that the voltage drop during starting of the largest motor on an otherwise fully loaded bus will not reduce motor terminal voltage below 85 percent of the nominal bus voltage to assure successful motor starting under adverse conditions and so that the symmetrical short circuit current on the low voltage side will not exceed 48 kA using 4160 volt rated switchgear or 41 kA for 4.16 kV system where 2400 volt switchgear is to be used. This permits using breakers having an interrupting rating of 350 MVA for 4160 volts switchgear or 300 MVA for 2400 volt switchgear.

(2) Meeting these criteria is possible for units of the size contemplated herein. If the voltage drop when starting the largest motor exceeds the criterion with the fault current limited as indicated, alternative motor designs and reduced voltage starting for the largest motor or alternative drives for that load, will be investigated.

d. Transformer connections.

(1) With the unit system, the turbine generator unit auxiliary transformers will be 13.8 kV delta to 4.16 kV wye. If the startup and standby auxiliary transformer is fed from a bus to which the generator is connected through a delta-wye transformation, it must be wye-wye with a delta tertiary. The wye-wye connection is necessary to get the correct phase relationship for the two possible sources to the 4160 volt buses. Voltage phase relationships must be considered whenever different voltage sources are in parallel. For wye-wye or delta-delta transformer connections, there is no phase shift between the primary and secondary voltages. However, for delta-wye or wye-delta transformer connections, the primary and secondary voltage will be 30 degrees out of phase in either a leading or lagging relationship. With the correct arrangement of transformers it will be possible to establish correct phase angles for paralleling voltages from different sources. Figures 4-1, 4-2 and 4-3 illustrate the typical phase relationships for power station generators and transformers.

(2) Where more than one generator is installed, a single startup and standby auxiliary transformer is sufficient. The low side will be connected through suitable switches to each of the sections of medium voltage switchgear,

4-17. 4160 volt switchgear

a. Type. The 4160 volt assemblies will be indoor metal clad, drawout type employing breakers having a symmetrical interrupting rating of 48 kA and

with copper or aluminum buses braced to withstand the corresponding 350 MVA short circuit. Quantity of breakers will be determined to handle incoming transformer, large motors above 200 hp and transformer feeds to the 480 volt unit substations.

b. Cable entrance. Power and control cable entrance from above or below the gear will depend on final locations in the power plant.

c. Relaying. Appropriate protective relaying will be applied to each incoming and outgoing circuit as discussed in paragraph 4- 13a above.

4-18. 480 volt unit substations

a. General arrangement. The unit substation as defined in subparagraph 4-1 la, or power centers, employ a 4160-480 volt transformer close coupled to a section of 480 volt switchgear. Switchgear portion will utilize drawout breakers and have breakers and buses braced to interrupt and withstand, respectively, a short circuit of 42 kA, symmetrical. Buses may be of aluminum or copper.

b. Loads served. The unit substations will serve as sources for 480-volt auxiliary motor loads between 75 and 200 horsepower, and also serve as supply to the 480-volt motor control centers.

c. Cable entrance. Power and control cable entrance from above or below will depend on final location in the station.

d. Trip devices. Direct acting trip devices will be applied to match the appropriate transformer or motor feeder load and fault characteristics as discussed in paragraph 4- 13b above.

4-19. 480-volt motor control centers

a. General arrangement. Motor control centers (MCC'S) will utilize plug-in type circuit breakers and combination starters in either a front only or a back-to-back free standing construction, depending on space limitations. Main bus, starters and breakers will be braced to withstand a short circuit of 22 kA, symmetrical. A power panel transformer and feeder breaker, complete with a 120/208 volt power panel and its own main breaker, may be built into the MCC.

b. Current limiting reactors. Dry type three phase reactors, when necessary, will be located in a vertical section of the MCC's to reduce the available short circuit at the 480-volt unit substations to 22 kA at the MCC's. Each system will be investigated to determine the necessity for these current limiting reactors; cable reactance will play an important part in determining the necessity for reactors.

c. Location. The several motor control centers will be strategically located in the power plant to serve most of the plant auxiliary motor loads, lighting transformers, motor operated devices, welding

receptacle system and the like. Loads should be grouped in such a manner as to result in relatively short feeder runs from the centers, and also to facilitate alternate power sources to vital services.

d. Cable space. Connection to the MCC's will be via overhead cable tray, and thus the top horizontal section of the MCC will incorporate ample cable training space. Control and power leads will terminate in each compartment. The MCC's can be designed with all external connections brought by the manufacturer to terminal blocks in the top or bottom horizontal compartments, at added expense.

e. Enclosures. Table 4-1 lists standard MCC enclosures. Type 2, drip tight, will be specified for all indoor power plant applicants; Type 3, weather resistant, for outdoor service. The other types listed in Table 4-1 should be used when applicable.

4-20. Foundations

a. Transformers. The outdoor auxiliary power transformers will be placed on individual reinforced concrete pads.

b. Medium voltages switchgear. The medium voltage switchgear assemblies will be mounted on flush embedded floor channels furnished by the switchgear manufacturer prior to shipment of the gear.

c. Unit substations and motor control centers. 480-volt unit substation transformers and switchgear, and all MCC's will be mounted on chamfered concrete pads at least 3 inches above finished floor grade. Foundations will be drilled for clinch anchors after the foundation has been poured and set; the anchor placement will be in accordance with the switchgear manufacturer's recommendation.

4-21. Grounding

A minimum 1/4-inch by 2-inch copper ground bus will be incorporated within the lower rear of each section of switchgear and MCC. Each ground bus will be connected to the station ground grid with two 4/0 stranded copper cables.

4-22. Conduit and tray systems

a. Power cables. Power cables will generally be run in galvanized rigid steel conduit to the motor and switchgear terminations, although a ladder type galvanized steel cable tray system having adequate support may be used with conduit runouts from trays to terminations.

b. Control cables. Control cables will be run in an expanded metal galvanized steel overhead tray system wherever possible. Adequate support will be provided to avoid sagging. Exit from the tray will be via rigid steel conduit.

c. Grounding. Every cable tray length (i.e., each construction section) will be grounded by bolting to

Table 4-1. Standard Motor Control Center Enclosures.

NEMA Classification	Comments
Type 1: General purpose	A sheet metal case designed primarily to protect against accidental contact with the control mechanism.
Type 1: Gasketed	The general purpose enclosure with gasketed door or cover.
Type 2: Drip tight	Similar to Type 1 with the addition of drip shields or the equivalent.
Type 3: Weather-resistant	Designed to provide protection against weather hazards such as rain and sleet.
Type 4: Watertight	Designed to meet the hose test described in NEMA Definition 1C-1.2.6B.
Type 7: Hazardous locations, Class 1, Air break.....	Enclosures designed to meet the application requirements of the NEC for the indicated specific classes of hazardous locations.
Type 9: Hazardous locations, Class 2, Groups F & G.	
Type 9-C: Hazardous locations, Class 2, Group E.	
Type 12: Industrial use	A sheet metal case designed with welded corners and no knockouts to meet the Joint Industry Conference standards for use where it is desired to exclude dust, lint, fibers and fillings, and oil or coolant seepage.

Source: NAVFAC DM3

a stranded bare copper ground cable which will be run throughout the tray system. The tray cable itself will be tapped to the plant ground grid at each building column. Basic tray cable will be 4/0 bare stranded copper with connections to station taps of minimum 2/0 copper.

4-23. Distribution outside the power plant

Electrical distribution system for the installation outside of the power plant is covered in TM 5-811-11AFM88-9.

Section VII. EMERGENCY POWER SYSTEM

4-24. Battery and charger

a. General requirements. The dc system, consisting of a station battery, chargers and dc distribution panels, provides a continuous and reliable source of dc control voltage for system protection during normal operation and for emergency shutdown of the power plant. Battery will be nominal 125 volts, mounted on wooden racks or metal racks with PVC covers on the metal supporting surfaces. Lead calcurn cells having pasted plates Plante or other suitable cells will be considered for use.

b. Duty cycle. Required capacity will be calculated on an 8-hour duty cycle basis taking into account all normal and emergency loads. The duty cycle will meet the requirements of the steam generator burner control system, emergency cooling systems, control benchboard, relays and instrument panels, emergency lighting system, and all close/trip functions of the medium voltage and 480-volt circuit breaker systems. In addition, the following emergency functions shall be included in the duty cycle:

(1) Simultaneously close all normally open breakers and trip 40 percent of all normally closed breakers during the first minute of the duty cycle; during the last minute, simultaneously trip all main and tie breakers on the medium voltage system.

(2) One hour (first hour) running of the turbine generator emergency lube oil pump motor and, for hydrogen cooled units, 3-hour running of the emergency seal oil pump motor.

(3) One hour (first hour) running of the backup turning gear motor, if applicable.

c. Battery chargers.

(1) Two chargers capable of maintaining a 2.17 the proper float and equalizing voltage on the battery will be provided. Each charger will be capable of restoring the station battery to full charge in 12 hours after emergency service discharge. Also, each unit will be capable of meeting 50 percent of the total dc demand including charging current taken by the discharged battery during normal conditions. Note: Equalizing voltage application will subject coils and indicating lamps to voltages above the nominal 125-volt dc system level. These devices, however, will accept 20 percent overvoltage continu-

ously. To assure, however, that the manufacturer of all dc operated devices is aware of the source of dc system voltage, the various equipment specifications will advise that the nominal system voltage will be 125 volts but will have an equalizing charge applied periodically.

(2) Appurtenances. The following instruments and devices will be supplied for each charger:

(a) Relay to recognize loss of ac supply.

(b) Ac voltage with selector switch.

(c) Dc ground detection system with test device.

(d) Relay to recognize loss of dc output.

(e) Relay to alarm on high dc voltage.

(f) Relay to alarm on low dc voltage.

(g) Dc voltmeter.

(h) Dc ammeter with shunt.

d. Battery room. Only the battery will be located in a ventilated battery room, which will be in accordance with TM 5-811-2. The chargers maybe wall or floor mounted, together with the main dc distribution panel, immediately outside the battery room.

e. DC distribution panel. The distribution panel will utilize molded case circuit breakers or fuses selected to coordinate with dc breakers furnished in control panels and switchgear. The breakers will be equipped with thermal magnetic trip devices, and for 20 kA dc interrupting rating.

4-25. Emergency ac system

Those portions of the station service load that must be operable for a safe shutdown of the unit, or that are required for protection of the unit during shutdown, will be fed from a separate 480-volt unit emergency power bus. A suitable emergency diesel engine driven generator will be installed and arranged to start automatically and carry these loads if the normal source of power to this bus is lost. The loads fed from this bus might include such things as emergency lighting, communication system, battery charger, boiler control system, burner control system, control boards, annunciator, recorders and instrumentation. Design of these systems will provide for them to return to operation after a brief power outage.

Section VIII. MOTORS

4-26. General

Motors inside the power plant require drip proof enclosures, while outside the plant totally enclosed fan cooled motors are used. For induced draft and forced draft, and outdoor fan motors in the larger sizes, a

weatherproof construction employing labyrinth type enclosures for air circulation will be applied. All motors will be capable of starting at 85 percent nameplate voltage.

4-27. Insulation

a. *4000-volt motors.* Motors at this voltage will be three phase, 60 Hz, have Class B insulation for 80 C. rise above 40 C. ambient, and with 1.0 service factor.

b. *460-volt motors.* These motors will be three phase, 60 Hz, have Class B insulation for 80 C. rise, or Class F for 95 C. rise, above 40 C. ambient, and with 1.0 service factor.

c. *115-volt motors.* These motors will be one phase, 60 Hz, with Class B insulation for 80 C. rise above 40 C. ambient, and with 1.25 service factor.

4-28. Horsepower

It is seldom necessary to specify motor horsepower if the motor is purchased with the driven equipment as is the usual case with military projects. In almost every instance, the load required by the pump, fan, or other driven equipment sets the motor horsepower and characteristics—thus the specification is written to require manufacturer of the driven machine to furnish a motor of proper horsepower and characteristics to perform the intended function.

4-29. Grounding

Every motor will be connected to the station ground grid via a bolted connection to a stranded copper tap. Single phase motors may be grounded with #6 AWG bare wire; to 75 horsepower, three phase with #2 AWG bare stranded copper cable; and to 200 hp, three phase, with 2/0 bare stranded copper wire.

Above 200 horsepower, three phase, 4/0 bare stranded copper wire will be used for the ground connection.

4-30. Conduit

Motor power cables will be run in rigid steel galvanized conduit to a point approximately 18 inches from the motor termination or pull box. The last 18 inches, approximately, will be flexible conduit with PVC weatherproof jacket. Firm support will be given the rigid conduit at the point of transition to the flexible conduit.

4-31. Cable

In selecting motor cable for small motors on a high capacity station service power system, the cable size is seldom set by the motor full load current. Manufacturer's curves showing copper temperature melting values for high short circuit currents for a specific time duration must be consulted; the cable may need to be appreciably larger than required by motor full load current.

4-32. Motor details

It is important to specify enclosure type, special high temperature or other ambient conditions and similar data which is unique to the particular application. Also the type of motor, whether squirrel cage, wound rotor or synchronous, and power supply characteristics including voltage, frequency, and phases must be specified.

Section IX. COMMUNICATION SYSTEMS

4-33. Intraplant communications

a. *General requirements.* Installation of a high quality voice communication system in a power plant and in the immediate vicinity of the plant is vital to successful and efficient startup, operation and maintenance. The communications system selected will be designed for operation in a noisy environment.

b. *Functional description.* A description of the features of an intraplant communication system is given below.

(1) A page-talk party line system will be required.

(2) If a conversation is in process on the party line when a page is initiated, the paging party will instruct the party paged to respond on the "page" system. This second conversation will be carried on over the page system—that is, both parties will be heard on all speakers, except that the speakers nearest the four or more handsets in use will be muted.

(3) If a party wishes to break into a private conversation, all he will do is lift his handset and break

into the private conversation already taking place. Any number of parties will be able to participate in the "private conversation" because the private system is a party line system.

(4) Additional handsets and speakers can be added to the basic system as the power plant or outdoor areas are expanded.

c. *Handsets.*

(1) Except for handsets at desks in offices or operating rooms, the indoor handsets in the power plant will be hook switch mounted in a metal enclosure having a hinged door. They will be mounted on building columns approximately 5 feet above the floor. In particularly noisy areas, e.g., in the boiler feed pump and draft fan areas, the handsets will be of the noise canceling types.

(2) Desk type handsets will be furnished either for table top use or in "wall-mounting" hook switch type for mounting on the side of a desk. The hook switch wall mounting will also be used at various control boards for ease of use by the plant control room operators.

(3) Outdoor handsets will be hook switch mounted in a weatherproof enclosure having a hinged door. They will be mounted on the switchyard structure or other structure five feet above final grade.

(4) Flexible coil spring type cords will be supplied with each handset to permit freedom of movement by the caller. In the control room provide extra long cords. The spacing depends upon the operating

area configuration but a handset will be readily available to any operator performing an operating function.

d. Speakers.

(1) Speakers for general indoor use will be of relatively small trumpet type and will be weatherproof for durability. They will be mounted on building columns about 10 feet above floor level with spacing as indicated in Table 4-2.

Table 4-2. Suggested Locations for Intraplant Communication Systems Devices.

<u>For</u>	<u>Speakers</u>	<u>Handsets</u>
Control Room	Two ceiling speakers.	Desk set on operator's desk; handsets spaced about 10-feet apart on control benchboards and on each isolated control panel.
Offices	Ceiling speaker in Sup't. and Assistant Sup't. offices.	Desk set in each office.
Locker Room	Wall speaker in locker room.	Wall handset in locker room.
Plant	Column mounted speakers as necessary to provide coverage of work areas. The required spacing will depend upon plant layout, equipment location and noise levels.	Column mounted handsets, as necessary to provide convenient access.
Switchyard	Minimum two structure mounted speakers at diagonally opposite corner of structure.	Minimum two structure mounted handsets at quarter points on longitudinal centerline of structure.
Cooling tower area	Speaker mounted on cooling tower auxiliary building facing tower.	Two handsets; one inside auxiliary building; one mounted on outside wall.
Fuel oil unloading area (or coal handling area)	Minimum two speakers on structures (one inside crusher house).	One handset near pump area (one handset inside grade door or crusher house).
Gate house (if power plant area is fenced)	Speaker on outside of gate house.	One handset outside fence, at personnel or vehicle gate.

Note: Speakers and handsets for inside-the-power plant coverage will be provided at every floor and mezzanine level from basement to uppermost boiler platform.

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(2) Speakers for outdoor use will be large trumpet type, weatherproof. They will be mounted on the switchyard structure or other structure about 15 feet above final finished grade.

(3) In the control room, two flush mounted speakers will be installed in the ceiling. A wall mounted speaker in wooden enclosure will be provided for the plant superintendent's office, training room or other similar location.

e. Power supply.

(1) Power supply will be 120 Vat, 60 Hz, single phase as supplied from the emergency power supply. The single phase conductors will be run in their own conduit system. It is vital to have the plant communication system operable under all normal and emergency conditions.

(2) The manufacturer will be consulted regarding type of power supply cable, as well as type, shielding, and routing of the communication pair conductors.

f. Device locations, general. Proper selection and planning for location of components is necessary to ensure adequate coverage. Alignment of speakers is important so as to avoid interference and feedback.

It is not necessary to have a speaker and a handset mounted near to one another. Speakers will be positioned to provide "page" coverage; handsets will be placed for convenience of access. For example, a speaker may be mounted outdoors to cover a tank area, while the nearest handset may be conveniently located immediately inside the plant or auxiliary building adjacent to the door giving access to the tanks.

g. Suggested device locations. Table 4-2 shows suggested locations for the various intraplant communication systems devices.

4-34. Telephone communications

At least one normal telephone desk set will be provided in the central control room for contact by the operators with the outside world and for contact with the utility company in the event of parallel operation. For those instances when the power plant is connected into a power pool grid, a direct telephone connection between the control room and the pool or connected utility dispatcher will also be provided.

CHAPTER 5

GENERAL POWER PLANT FACILITIES DESIGN

Section I. INSTRUMENTS AND CONTROL SYSTEMS

5-1. General

Input adjustments will be designed to be delegated to automatic control systems except during startup, shutdown, and abnormal operating conditions when the operator displaces or overrides automatic control functions.

5-2. Control panels

a. Types and selection.

(1) *General types.* Control panels used in power plants may be free standing or mounted on a wall or column, as appropriate.

(2) *Central control panel selection.* Control panels for use in central control rooms will be enclosed and of the dual switchboard, duplex switchboard, dual benchboard, control benchboard, or control desk type depending upon the size of the plant and complexity of the instruments and controls to be mounted. When control panels have complex wiring (piping and devices mounted in the interior) the vertical panel section will be provided with rear or walk-in access for ease in erection and maintenance. Frequently the floor of the walk-in space is dropped .2 or 3 feet below the raised control room floor to simplify cable and tubing entrance to the panel interior and to increase space for terminals. A dropped floor will be provided for proper access to any benchboard section of a panel. The shape of the panel will be selected using the following criteria:

(a) Space availability in the control room.

(b) Number of controls and instruments to be mounted.

(c) Visibility of the controls and instruments by the plant operators.

(d) Grouping and interrelationship of the controls and instruments for ease of operation and avoidance of operating error.

b. Location of panels.

(1) *Control room.* The various panels located in the central control room will be arranged to minimize operator wasted motion. In a unitized power plant (one without a header system), provide a boiler-turbine mechanical panel (or section) for each unit with separate common panel(s) to accommodate compressed air, circulating water, service water and like system which may pertain to more than one

unit. Coal handling, ash handling and water treating panels will not be located in the central control room unless the plant is small and the operating crew may be reduced by such additional centralizing. If the plant has a header system which is not conducive to boiler-turbine panels, group controls and instruments into a boiler panel for all boilers and a turbine generator panel for all turbines whenever practicable. Usually, a separate electrical panel with mimic bus for the generators and switchgear and switchyard, if applicable, will be provided regardless of whether the mechanical instruments are grouped on a unit basis or a header basis.

(2) *Local panels.* These will be mounted as close to the equipment (or process) they are controlling as is practical.

c. *Instrument selection and arrangement on panels.* Selection and arrangement of the various controls, instruments and devices on the panels will be generally in accordance with the guidelines of Tables 5-1,5 -2,5-3 and 5-4, and the following

(1) *Items.* Mechanical items will be grouped by basic function (i.e., turbine, boiler, condensate, feed-water, circulating water, service water and like systems), Burner management controls will be obtained as an "insert" or subpanel which can be incorporated into the boiler grouping of controls and instruments. Such an insert may include remote lightoff and startup of burners if desired. Electrical items will be grouped by generator, voltage regulator, switchgear and like equipment items in a manner which is easily incorporated into a mimic bus.

(2) *Readability.* Instruments which require operator observation will be located not higher than 6 1/2 feet nor lower than 3 feet above the floor for easy readability.

(3) *Controls, switches and devices.* Those controls, switches and other devices which require manipulation by the operators will be easily accessible and will be located on a bench or desk wherever practicable.

(4) *Indicators versus recorders.* Indicators will be provided where an instantaneous reading of cycle thermodynamic or physical parameters suffices as a check of proper system operation. When a permanent record of plant parameters is desired for eco-

Table 5-1. List of Typical Instruments and Devices to be Provided for Boiler Turbine Mechanical Panel

Measurement or Device	Primary Element		Instrument or Device on Panel
	Fluid	Location	
Pressure	Steam	Boiler drum	Indicator
	Steam	Boiler atomizing steam	Indicator
	Steam	Turbine Throttle	Indicator
	Steam	Deaerator steam space	Indicator
	Feedwater	BFP discharge	Indicator
	Condensate	Cond. pump discharge	Indicator
	Fuel gas	Boiler burners	Indicator
	Fuel gas	Igniter	Indicator
	Fuel gas	Boiler burners	Indicator
	Flue gas	Draft points⁽¹⁾	Indicator
	Lube Oil	Turbine generator	Indicator
	Vacuum	Condenser	Indicator
Temperature	Steam	Turbine throttle	Indicator
	Steam	Boiler superheater outlet	Recorder
	Steam	Turbine extraction steam	Recorder
	Air-flue gas	Boiler draft system	Recorder⁽²⁾
	Lube Oil	Turbine generator	Recorder
Flow	Steam	Boiler main steam	Recorder & totalizer
	Air	Boiler FD fan discharge	Recorder
	CO ₂	Boiler flue⁽³⁾	Recorder
	Feedwater	Boiler main supply	Recorder
	Feedwater	Boiler Attemperator	Recorder
	Fuel gas	Boiler burner supply	Recorder & totalizer
	Fuel oil	Boiler burner supply	Recorder & totalizer

- Notes:
- (1) Including FD fan discharge, air inlet & outlet to air preheater, windbox, furnace draft, inlet & outlet to economizer, gas inlet and outlet to air preheater, overfire or primary air pressure, and ID fan discharge.
 - (2) Multi-point electronic type to track air and gas temperatures through the unit.
 - (3) May be used for combustion controls instead of steam flow-air flow.
 - (4) Usually in condensate system, boiler feed system and process returns.

Table 5-1. List of Typical Instruments and Devices to be Provided for Boiler Turbine Mechanical Panel. (Continued)

Measurement or Device	Primary Element		Instrument or Device on Panel
	Fluid	Location	
Level	Feedwater Condensate Coal	Boiler drum Deaerator, Condenser Hotwell Bunker	Recorder Recorder Indicator or pilot lights
Conductivity	Condensate	Cells as required ⁽⁴⁾	Recorder
Manual-automatic stations	--	Combustion control system, condensate and feedwater control systems, steam attemperator, and as required	Each station
Motor control switches	--	Starters for draft fans, BF pumps, condensate pumps, vacuum pumps, fuel pumps, lube oil pumps, turning gear, turbine governor and like items	Each switch
Ammeters	--	Major motors (high voltage): draft fans, BF pumps	Indicator
Alarms	--	Points as selected for safe operation	Annunciator section for boiler turbine panel
Burner Management	--	Boiler burner system	Insert on boiler-turbine panel
Indicating	-	As required to start up and monitor boiler and turbine.	Each light

Notes: See first page of Table.

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Table 5-2. List of Typical Instruments and Devices to be Provided for Common Services Mechanical Panel

Measurement or Device	Primary Element		Instrument or Device on Panel
	Fluid	Location	
Pressure	Steam	Main steam header ⁽¹⁾	Recorder
	Steam	Extraction steam header(1)	Indicator
	Fuel gas	Supply to plant	Indicator
	Fuel oil	supply	Indicator
	Fuel oil	Burner pump discharge	Indicator
	Circ. water	Discharge header	Indicator
	Water	Service water	Indicator
	Water	Closed cooling water	Indicator
	Water	Fire system	Indicator
	Air	Instrument air	Indicator
	Air	Service air	Indicator
	Air	Atmosphere	Barometer
Temperature	Steam	Extraction steam header(1)	Indicator
	Fuel Oil	supply	Indicator
	Various	As required	Recorder⁽²⁾
Viscosity Flow	Fuel oil	Pump and heater sets	Recorder Recorder & totalizer Recorder & totalizer
	Steam	Turbine throttle⁽¹⁾	
	Steam	Extraction to process	
	Fuel gas	Supply to plant	
Level	Fuel oil	Tank(s)	Indicator
	Condensate	Tank(s)	Indicator
Manual-automatic stations	--	Pressure reducing station, misc. air operated devices	Each station
Motor control switches	--	CW pumps, cooling tower fans, air compressors, condensate transfer pumps, service water pumps, fuel transfer pumps, and like items	Each switch

Notes: (1) For header systems only
(2) Multi-point electronic type

Table 6-2, List of Typical Instruments and Devices to be provided for Common Services Mechanical Panel. (Continued)

Measurement or Device	Primary Element		Instrument or Device on Panel
	Fluid	Location	
Ammeter	-	Major (high voltage) motors; CW pumps, cooling tower fans	Indicator
Alarms	--	Points as selected for safe operation	Annunciator section for common panel
Indicating	--	As required to start-up and monitor principal common systems	Each light

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nomic or engineering accountability purposes, recorders will be provided.

d. Ventilation. All panels which house heat producing instruments will be ventilated or air conditioned to prevent overheating of the instruments. For panel-in the central control room, this will be accomplished by having a filtered air intake and mechanical exhaust arrangement to circulate cool air from the air conditioned control room through each enclosed panel wherever practicable. Local panels, as a rule, have only gages and other devices which emit little heat and do not require special ventilation.

e. Illumination. In a central control room, the best illumination is a "light ceiling" with diffuser type suspended panels to give a shadowless, even level of lighting throughout the control room. Levels of illumination at bench tops of 75-foot candles, plus or minus 10-foot candles, will be provided. However, caution must be used when designing lighting for control rooms utilizing electronic digital controls with cathode ray tube (CRT) display as excessive illumination tends to wash out displays. In areas with electronic digital controls with CRT displays, the level of general illumination will be maintained at 15- to 25-foot candles. Local panel illumination will be accomplished by means of a canopy built into the top of the panel. Local switch control will be provided at each canopy light.

5-3. Automatic control systems

a. Types. Control systems and instruments may be pneumatic, ac or dc electronic, electronic digital, combination pneumatic and electronic, or hydraulic.

Mechanical-hydraulic and electro-hydraulic systems will be utilized in connection with turbine generator speed governing control systems. Pneumatic controls will be used for power plant units of 30 MW or less. Applications include: combustion control, feedwater regulation, desuperheating and pressure reducing station control, heater drain control, and boiler feed recirculation control. Pneumatic systems are economical, reliable, and provide smooth, modulating type of operation. For plants where the arrangement is dispersed and precision is required, electronic controls and instruments will be provided in lieu of the pneumatic type because of the sluggishness of pneumatic response where long distances are involved. Electronic digital controls have recently become economically competitive with analog pneumatic and electronic controls and offer the advantage of "soft-wired" control logic and programmable versatility. With electronic controls it is required to use pneumatically operated valves with transducers to convert the electronic signals to pneumatic at the pneumatic valve operator.

b. Combustion controls. Combustion controls for steam generators will be based on the conventional indirect method of maintaining steam pressure. Systems will be of the fully metering type, designed to hold steam pressure within plus or minus 1 percent of the controller setting with load changes of 5 percent per minute; under the same rate of load change, excess air will be maintained at plus or minus 2 percent of the control setting. (*Note:* With stoker fired boilers having limited heat inputs from suspension heat release, the tolerances on steam pressure will be greater than 1 percent.)

Table 5-3. List of Typical Instruments and Devices to be Provided for Electrical (Generator and Switchgear) Panel

Measurement or Device	Instrument or Device on Panel	Notes
For Each Generator		
Generator gross output	Wattmeter	--
Power Factor	P.F. Meter	
Generator ac current	AC ammeter	--
Generator ac volts	AC voltmeter	--
Generator dc current	DC ammeter	--
Generator dc volts	DC voltmeter	--
Generator ac current (for individual phases)	AC ammeter control switch	For phase measurement selection --
Generator ac volts (for individual phases)	AC voltmeter control switch	For phase measurement selection --
Generator synchronizing	Synchronizing control switch	
Generator synchronizing	Separate panel section	Incl. synch. lamps and meters for incoming and running indication
Oil circuit breaker trip	OCB control switch	If step-up transformation included
Generator field breaker	Field breaker control switch	--
Voltage regulator	Voltage reg. transfer voltmeter	
Voltage regulator	Manual voltage regulator	--
Voltage regulator	Auto. voltage reg. adjuster	--
Voltage regulator	Voltage reg. transfer switch	--
Unit governor	Governor control switch, raise-lower	--
Unit trip	Trip pushbutton	--
Unit reset	Reset pushbutton	--
Unit speed	Speed indicator	--
Unit temperatures	Electronic recorder	For turbine and generator temperatures
Generator alarms	Annunciator	With test and reset pushbuttons
Miscellaneous	Indicating lights	For switches and as required
Supervisory	Recorders	Vibration, eccentricity

Table 5-3. List of Typical Instruments and Devices to be Provided for Electrical (Generator and Switchgear) Panel. (Continued)

<u>Measurement or Device</u>	<u>Instrument or Device on Panel</u>	<u>Notes</u>
For Switchgear		
2.4 or 4.16 kV unit switchgear	Breaker control switch	If higher plant auxiliary voltage required
2.4 or 4.16 kV common switchgear	Breaker control switch	If required
2.4 or 4.16 kV feeders	Breaker control switches	For plant auxiliaries and/or for outside distribution circuits as required.
480 V unit switchgear	Breaker control switch	
480 V common switchgear	Breaker control switch	
480 V feeders	Breaker control switches	For plant auxiliaries as required
Switchgear ac current	AC ammeters	One for each switchgear with switch
Switchgear ac volts	AC voltmeters	One for each switchgear with switch
Switchgear alarms	Annunciator	With test and reset push-buttons
Miscellaneous	Indicating lights	For switches and as required
Intraplant communication	Telephone handset	

- Notes: (1) If a high voltage switchyard is required a separate panel may be required.
- (2) For relays see Chapter 4, Section V; generator and auxiliary power relays may be mounted on the back of the generator walk-in bench-board or on a separate panel.

Table 5-4. List of Typical Instruments and Devices to be Provided for Diesel Mechanical Panel

Measurement or Device	Primary Element		Instrument or Device on Panel
	Fluid	Location	
Pressure	Fuel gas	Supply to engine	Indicator
	Fuel oil	Supply to engine	Indicator
	Lube oil	Supply to engine	Indicator
	Lube oil	supply to turbocharger	Indicator
	Comb. air	Turbocharger discharge	Indicator
	Comb. air	Filter downstream	Indicator
	Cooling water	Pump discharge	Indicator
	Starting air	Air receiver	Indicator
Temperature	Exhaust	Each cylinder and combined exhaust	Indicator(1)
	Cooling water	Supply to engine	Indicator
	Cooling water	Return from engine	Indicator
Level	Jacket water	Surge tank	Indicator
	Lube Oil	Sump tank	Indicator
	Fuel	Bulk storage tank	Indicator
	Fuel	Day Tank	Indicator
Motor control switches (or pushbuttons)	-	Jacket water pumps, radiator (or cooling tower) fans, fuel oil pumps, centrifuges, and like auxiliaries	Each switch
Alarms	--	Low lube oil pressure, low jacket water pressure, high lube oil temperature, high jacket water temperature, high and low day tank levels	Annunciator

Notes: (1) With selector switch.

c. Feedwater regulation. A three element feedwater regulator system will be provided for steam power plant service. Such a system balances feedwater input to steam output subject to correction for drum level deviations caused by operating pressure variations (drum swell).

d. Attenuator control system. Each power plant steam generator will have superheat (attenuator) controls to maintain superheat within the limits required for protection of the turbine metal parts against thermal stress and for preventing excessive reduction in part load turbine efficiency. Injection of desuperheating water (which must be high purity water, such as condensate) will be done between stages of the boiler superheater to reduce chances of water carryover to the turbine. An attenuator system having a controller with a fast response, derivative feature will be provided. This type of controller anticipates the magnitude of system deviations from the control set point in accordance with the rate of change of superheat temperature. Automatic positive shutoff valve(s) will be provided in the desuperheating water supply line upstream of the desuperheater control valve to prevent dribbling of water to the desuperheater when the controls are not calling for spray water.

e. Closed heater drain controls. Although it is thermodynamically preferable to pump the drains from each feedwater heater forward into the condensate or feedwater stream exiting from the heater, the expense and general unreliability of the low NPSH pumps required for this type of drain service will normally preclude such a design. Accordingly, the drains from each heater will normally be cascaded to the next lower pressure heater through a level control valve. The valve will be located as closely as possible to the lower pressure heater due to the flashing which occurs because of the pressure reduction at the outlet of the level control valve. Each heater will be provided with two level control valves. The secondary valve only functions on startup, on malfunction of the normal valve, or sometimes during light loads when pressure differential between heaters being cascaded becomes very small. The secondary valve frequently discharges directly to the condenser. Such a complexity of controls for heater drains is necessary to assist in preventing problems and turbine damage caused by turbine water induction. Water induction occurs when feedwater header tubes or level control valves fail, causing water to backup into the turbine through the extraction steam piping. Refer to Chapter 3, Section VII.

f. Boiler feed recirculation controls. An automatic recirculation system will be installed for each pump to bypass a minimum amount of feedwater back to

the deaerator at low loads for protection against boiler feed pump overheating. A flow signal from the suction of each pump will be used to sense the preset minimum safe pump flow. This low flow signal will open an automatic recirculation valve located in the piping run from the pump discharge to the deaerator. This recirculation line poses minimum flow through a breakdown orifice for pressure reduction to the deaerator. The breakdown orifice will be located as closely as possible to the deaerator because flashing occurs downstream. When pump suction flow increases to a preselected amount in excess of pump minimum flow, the recirculation valve closes. The operator will be able to open the recirculation valve manually with a selector switch on the control panel. Designs will be such as to preclude accidental closing of the valve manually. Such an operator error could cause flow to drop below the safe level quickly, destroying high pressure pumps.

g. Other control systems. Desuperheating, pressure reducing, fuel oil heating, and other miscellaneous power plant control systems will be provided as appropriate. Direct acting valves will not be used. Control valves will be equipped with a matching valve operator for positive opening and closing action. Deaerator and hotwell level control systems are described in Chapter 3, Section VII.

5-4. Monitoring instruments

a. Types.

(1) Control system components will include sensing devices for primary fluids plus transmitters, transducers, relays, controllers, manual-automatic stations, and various special devices. Table 5-5 lists sensing elements for controls and instruments. Instruments generally fall into two classifications—direct reading and remote reading.

(2) Direct reading instruments (e.g., thermometers, pressure gages, and manometers) will be mounted on local panels, or directly on the process piping or equipment if at an accessible location. Locally mounted thermometers will be of the conventional mercury type or of the more easily read (but less accurate) dial type. Type selected will depend on accuracy required. Pressure gages for steam or water service will be of the Bourdon tube type.

(3) Remote reading instruments (recorders, integrators, indicators and electrical meters) will be mounted on panels in the central control room. These instruments will have pneumatic or electronic transmission circuits. Sometimes the same transmitters utilized for control system service can be utilized for the pertinent remote reading instrument, although for vital services, such as drum level, an independent level transmitter will be used for the remote level indicator.

Table 5-5. Sensing Elements for Controls and Instruments.

Element	Type		Common Applications	
	Type	Batch	Control	Instrument
Flow	Mechanical	Batch	Filling containers	Weigh Scale
	Totalizing			Totalizing positive displacement water and gas meters
	Variable differential pressure with constant area	Continuous and totalizing	Proportioning large flows	Orifice, flow nozzle, and nozzle meters
	Variable differential pressure with variable area	Combustion	Air or gas flow	Control valves
	Constant differential pressure with variable area	Tapered tube and float	Proportioning small flows	Rotameter
	Variable differential	Pitot tube Velocity	Air or gas flow	Dampers
Variable velocity anemometer	Electric resistance of hot wire affected by velocity of flow	---	Potentiometer	

Table 5-5. Sensing Elements for Controls and Instruments. (Continued)

Element	Type		Common Applications	
			Control	Instrument
Motion	Centrifugal	--	Speed governs	Tachometer
	Vibrating reed	--	Speed governs	Tachometer
	Relative motion	--	--	Stroboscope
	Photo-electric cell	--	Limit control	Counter
Chemical	Flue gas analysis	--	Combustion control	Orsat
	Water analysis	--	Water treatment	--
	Fuel analysis	--	--	--
Physical	Specific gravity	--	--	Hydrometer for liquids
	Weight	--	--	Scales for solids
	Humidity	--	--	Hygrometer
	Smoke density	--	--	Ringelman chart
	Gas density	--	Combustion	CO ₂ meter
	Heat	Combination of water flow and temperature differential	Combustion	Btu meter
Electric and electronic	Photo-conductivity		Flame safe-guard	Photo-electric cell Smoke density
	Electric conductivity	Probes	Alarm	pH of water Oil in condensate

Source: NAVFAC DM3

Table 5-5. Sensing Elements for Controls and Instruments. (Continued)

Element	Type	Common Applications		
			Control	Instrument
Pressure	Mechanical	Bourdon tube	Pressure, draft and vacuum regulators	Pressure gage Low pressure, draft and vacuum gages Barometer
		Bellows or diaphragm Manometers		
	Variable electric resistance due to strain	Pressure transducer	Process pressure regulator	Potentiom. 100 to 50,000 psi
	Variable electric resistance due to vacuum	Thermocouple	Vacuum regulator	High vacuum 1-7000 microns Hg
Level	Visual	Vacuum tube	Vacuum regulator	High-vacuum down to 0.1 micron Hg
		- -	- -	Gage stick Transparent tube
	Float	Buoyant float	Mechanical level regulator	Tape connected to float
		Displacement	Pneumatic float regulator	Torque
Differential pressure	Manometer	Level regulator	Remote level gage	
Hydrostatic	Diaphragm in tank bottom	Level regulator	Tank levels with viscous fluids	

Table 5-5. Sensing Elements for Controls and Instruments. (Continued)

Element	Type	Common Applications		
		Control	Instrument	
Temperature	Solid expansion	Bimetal	On-off thermostats	Dial therm. - 100 to 1000 F
	Fluid expansion	Mercury or alcohol	- -	Glass therm.- 38 to 750 F
		Mercury in coil	Temperature regulators	Dial therm. - 38 to 1000 F
		Organic liquid		125 to 500 F
		Organic vapor liquid		- 40 to 600 F
	Gas	- 400 to 1000 F		
	Thermocouple	Copper-constantan	Temperature regulators	Low voltage - 300 to 600 F
		Iron-constantan		0 to 1400 F
		Chromel-alumel		600 to 2100 F
		Plat.-plat. rhodium		1300 to 3000 F
Elec. resistance of metals	Copper	Temperature regulators	Potentiom. - 40 to 250 F	
	Nickel		- 300 to 600 F	
	Platinum		- 300 to 1800 F	
Optical Pyrometer	Comparative radiant energy	- -	Potentiom. - 800 to 5200 F	
Radiation pyrometer	Radiant energy on thermocouples	Flame safeguard Surface temperature regulation	Potentiom. - 200 to 7000 F	
Fusion	- -	- -	Pyrom.cones -1600 to 3600 F	
			Crayons - 100 to 800 F	

(4) Panel mounted receiver gages for pressure, temperature, level and draft will be of the miniature, vertical indicating type which can be arranged in convenient lineups on the panel and are easy to read.

(5) Recorders will be of the miniature type, except for multi-point electronic dot printing recorders which will be full size.

b. Selection. The monitoring instruments for any control system will be selected to provide the necessary information required for the control room operator to be informed at all times on how the controlled system is functioning, on vital process trends, and on other essential information so that corrective action can be taken as required.

5-5. Alarm and annunciator systems

a. Purpose. The annunciator system supplements the operator's physical senses and notifies him both

audibly and visually when trouble occurs so that proper steps can be taken to correct the problem.

b. General. The alarm system will be both audible and visual. The sounding of the alarm will alert the operators that a problem exists and the visual light in the pertinent annunciator window will identify the problem. Annunciator systems shall provide for the visual display to be distinguishable between new alarms and previous alarms already acknowledged by the operator pushing a button provided for this purpose. New alarms will be signified by a flashing light, whereas acknowledged alarms will be signified by a steady light. Alarm windows will be arranged and grouped on vertical, upper panel sections with corresponding control stations and operating switches within easy reach of the operator at all times. Critical or potentially dangerous alarms will be a different color from standard alarms for rapid operator identification and response.

Section II. HEATING; VENTILATING AND AIR CONDITIONING SYSTEMS

5-6. introduction

This section sets forth general criteria for design of space conditioning systems for a power plant.

5-7. Operations areas

a. Enclosed general operating areas.

(1) *Ventilation supply.* Provide mechanical ventilation for fresh air supply to, as well as exhaust from, the main operating areas. A filtered outside air supply, with heating coils and recirculation option for winter use, will be provided. Supply fans will be selected so that indoor temperature does not rise more than 15°F. above the ambient outdoor air design temperature, and to maintain a slight positive inside pressure with all exhaust fans operating at maximum speed. Ventilation system design will take into account any indoor air intakes for boiler forced draft fans, which can be designed to draw warm air from near the roof of the plant. Supply air will be directed through a duct system to the lowest levels of the plant with particular emphasis on furnishing large air quantities to "hot spots." The turbine room will receive a substantial quantity of fresh air, supplemented by air from lower levels rising through operating floor gratings. For hot, dry climates, evaporative cooling of ventilation air supply will be provided.

(2) *Ventilation exhaust.* Exhaust fans with at least two speeds are switched so that individual fan and fan speed can be selected according to air quantity desired will be provided. Battery rooms will have separate exhaust systems designed in accordance with TM 5-811-21AFM 88-9/2. It may be economical to remove heat from hot spots with local

ducted exhaust systems to prevent heat from being carried into other areas. All exhaust and supply openings will be provided with power operated dampers, bird screens, and means for preventing entrance of rain, sleet and snow.

(3) *Heating.* As much heating as practicable will be supplied via the central ventilation supply system, which will be designed so that maximum design air flow can be reduced to a minimum required for winter operation. Heat supplied by the ventilation system will be supplemented as required by unit heaters and radiation. Heating system design for ventilation and other space heating equipment will be selected to maintain a minimum plant indoor temperature of 55°F. and an office, control room and laboratory area temperature of 68°F.

b. Control room.

(1) The central control room is the operating center of a power plant and will be air conditioned (i.e., temperature control, humidity control and air filtration) for the purpose of human comfort and to protect equipment such as relays, meters and computers. Unattended control rooms may not require comfort conditions but have temperature limits as required by the equipment housed in the room. Control system component manufacturers will be consulted to determine the operating environment required for equipment reliability.

(2) Intermediate season cooling using 100 percent outside air for an economizer cycle or enthalpy control will be life cycle cost analyzed.

5-8. Service areas

a. Toilets, locker rooms and lunch rooms.

(1) Toilets will be exhausted to maintain a negative pressure relative to adjacent areas. All exhaust outlets from a toilet will be a minimum of 15 feet from any supply inlet to prevent short circuiting of air. Toilet exhaust will be combined with a locker room exhaust but not with any other exhaust.

(2) Locker rooms will be exhausted according to the applicable codes and supplied by a heated air supply.

(3) Lunch rooms will be furnished with recirculation heating systems to meet applicable codes; exhaust will be installed. System will be independent

of other systems to prevent recirculation of food odors to other spaces.

b. Shops and maintenance rooms. All shops and maintenance rooms will be ventilated according to applicable codes. Welding and painting areas will be exhausted. Heating will be provided by means of unit heaters sized to maintain a maximum of 68 °F. on the coldest winter design day.

c. Offices and laboratories. All offices and laboratories will be air conditioned for human comfort in accordance with TM 5-810-1/AFM 88-8/1. Exhaust will be provided where required for laboratory hoods or other special purposes.

Section III. POWER AND SERVICE PIPING SYSTEMS

5-9. introduction

a. General. Power plant piping systems, designed to transfer a variety of fluids (steam, water, compressed air, fuel oil, lube oil, natural gas) at pressures ranging from full vacuum to thousands of psi, will be engineered for structural integrity and economy of fluid system construction and operation.

b. Design considerations. Piping systems will be designed to conform to the standards listed in Table 5-6. ASME Boiler Pressure Vessel Code Section I governs the design of boiler piping, usually up to the second isolation valve. ANSI B31.1, Code for Pressure Power Piping governs the pressure boundary requirements of most other plant piping (excluding plumbing and drainage piping). Each of these codes provides a detailed description of its scope and limitations.

5-10. Piping design fundamentals

Design of piping system will conform to the following procedure:

a. Select pipe sizes, materials and wall thickness (pipe schedule). Design for the maximum pressure and temperature the piping will experience during either operation or upset conditions. Follow appropriate sections of ASME Section I and ANSI B31.1. Other requirements for welding qualification and pressure vessel design are set forth in ASME Sections VIII and IX. Specify hydrostatic pressure testing requirements in accordance with the codes. Select flow velocities for overall economy.

b. Select piping components and end connections for equipment.

c. Route piping. Make runs as simple and direct as possible. Allow for maintenance space and access to equipment. Do not allow piping to encroach on aisles and walkways. Inspect for interferences with structures, ductwork, equipment and electric services.

d. Include provisions for drainage and venting of all pipe lines.

e. Design pipe supports, restraints and anchors, using accepted procedures for thermal expansion stress analysis. The stress analysis will consider simultaneous application of seismic loads, where applicable. Computer analysis will be used for major three plane piping systems with multiple anchors.

5-11. Specific system design considerations

a. Steam piping. In all steam systems, provisions will be made for draining of condensate before startup, during operation and after shutdown. Steam traps will be connected to low points of the pipelines. Small bore bypass piping will be provided around block valves on large, high pressure lines to permit warming before startup.

b. Circulating water piping. Reinforced plastic piping will be used for salt or brackish water service whenever practicable.

c. Fuel oil piping. Fuel oil piping will be designed with relief valves between all block valves to protect against pipe rupture due to thermal expansion of the oil. Fuel oil piping will be designed in accordance with National Fire Protection Association (NFPA) standards and ANSI B31. Piping subject to vibration (such as engine service) will be socket or butt welded, although flared tubing may be used for small lines under 1/2 inch.

d. Insulation. Insulate all lines containing fluids above 120°F. so that insulation surface temperatures remain below 120°F. at 80°F. still air ambient. Provide anti-sweat insulation for all lines which operate below ambient temperatures. Protect all insulation against weather (or wash down water if indoors) and mechanical abuse.

Table 5-7. Characteristics of Thermal Insulations. (Continued)

Form	Material (Composition)	Accepted Max.Temp. For Use °F ⁽¹⁾	Density lb./cu. ft.	K = Typical Conductivity at Mean Temp. °F (Btu/H/ft ² /° per inch)							
				40	70	100	200	300	500	700	900
Pipe Insu- lation (con'd)	Plastics (foamed)	175	1-6	0.26	0.28	0.31	--	--	--	--	--
	Rubber (foamed)	150	5	0.23	0.24	0.25	--	--	--	--	--
	Vegetable and animal fiber:										
	Wool felt	180	20	0.29	0.31	0.33	--	--	--	--	--
	Hair felt or hair felt plus jute	180	10	0.27	0.28	0.30	--	--	--	--	--
Insu- lating cement	85% magnesia	600	18	--	--	0.46	0.52	0.58	--	--	--
	Mineral wool (rock, slag or glass):										
	With colloidal clay binder	1800	24-30	--	--	0.49	--	0.61	0.73	0.83	--

NOTES: (1) These temperatures are generally as maximum. When operating temperature approaches these limits the manufacturer's recommendations should be followed.

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Table 5-6. Piping Codes and Standards for Power Plants. (Continued)

<u>Sponsor</u>	<u>Identification</u>	<u>Title</u>	<u>Coverage</u>
ANSI	B36 series	Iron and steel pipe	Materials and dimensions.
	B16 series and G37.1	Pipe, flanges and fittings	Materials, dimensions, stresses and temperature-pressure ratings.
	B18 series	Bolts and nuts	Bolted connections.
ASTM	--	Testing materials	Physical properties of materials specified in above ASME and ANSI standards.
Major equipment manufacturers (turbines, pumps, heat exchangers, etc.)	--	--	Allowable reactions and movements on nozzles from piping.

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Section IV. THERMAL INSULATION AND FREEZE PROTECTION

5-12. Introduction

Applications. Thermal insulations are used for the following purposes:

- Limit useful heat losses.
- Personnel burn protection.
- Limit heat gains where cold is desired.
- Prevent icing and condensation.
- Freeze protection.

5-13. Insulation design

The principal elements of insulation system design and specification areas follows:

a. Selection of surfaces. Define and list the various surfaces, piping, vessels, ductwork, and machinery for which insulation is needed including lengths, areas and temperatures.

b. Insulation systems. For each class or type of surface select an appropriate insulation system: bulk insulation material and miscellaneous materials, coverings, and like items.

c. Economical thickness. Based on the above data, select the economical or necessary thickness of insulation for each class or type of surface.

5-14. Insulation materials

a. Bulk material. Refer to Table 5-7 for nomenclature and characteristics of conventional thermal insulations.

b. Restrictions on asbestos. Asbestos insulation, or insulations containing loose, fibrous, or free asbestos are not to be used.

c. Maximum temperatures. Each type of insulation is suitable for use at a specified maximum temperature. Design will be such that those maximums will not be approached closely in ordinary applications. All high temperature insulations are more expensive and more fragile than lower temperature products and, in general, the least expensive material which is suitable for the temperature exposure will be selected. Where substantial total insulation thicknesses of 6 inches or more are required, economics may be realized by using two layers of different materials using high temperature material close to the hot surface with cheaper low temperature material on the cold side.

d. Prefabricated insulation. A major part of total insulation cost is field labor for cutting, fitting and

Table 5-7. Characteristics of Thermal Insulations.

Form	Material (Composition)	Accepted Max.Temp. For Use °F(1)	Density lb./cu. ft.	K = Typical Conductivity at Mean Temp. °F (Btu/H/ft ² /°F per inch)								
				40	70	100	200	300	500	700	900	
Blanket	Mineral wool (rock, slag, or glass):											
	Metal reinforced	1200	6-15	--	--	0.29	0.35	0.42	0.56	--	--	
	Felt-flexible type	450	0.5-3	0.23	0.25	0.26	0.34	0.45	--	--	--	
	Felt-semi-rigid type	450	2-8	0.24	0.25	0.27	0.35	0.44	--	--	--	
	Vegetable and animal fiber:											
	Hair felt or hair felt plus jute	180	10	0.27	0.28	0.30	--	--	--	--	--	
	Blocks and boards	Calcium silicate	1200	11	--	--	0.33	0.38	0.43	0.53	0.64	0.75
		Cellular glass	800	9	0.37	0.39	0.41	0.43	0.55	--	--	--
		Corkboard (without added binder)	200	6.5-8	0.26	0.27	--	--	--	--	--	--
		Diatomaceous silica	1500	22	--	--	--	--	--	0.60	0.64	0.68
		1900	25	--	--	--	--	--	--	--	--	
85% magnesia		600	11-14	--	--	0.35	0.38	0.42	0.46	--	--	
Mineral wool (rock, slag or glass):												
Low temp. (asphalt or resin bonded)		200	6-18	0.28	0.29	0.30	--	--	--	--	--	
High temp.-(resin bonded) -(inorganic binder)	600 1600	6-10 16-24	-- --	-- --	0.28 0.34	0.35 0.39	0.43 0.44	-- 0.54	-- 0.64	-- --		
Plastics (foamed)	175	1.6	0.26	0.28	0.30	--	--	--	--	--		
Rubber (foamed)	150	5	0.23	0.24	0.25	--	--	--	--	--		

Table 5-7. Characteristics of Thermal Insulations. (Continued)

Form	Material (Composition)	Accepted Max. Temp. For Use °F(1)	Density lb./cu. ft.	K = Typical Conductivity at Mean Temp. °F (Btu/H/ft ² /° per inch)										
				40	70	100	200	300	500	700	900			
Pipe Insu- lation	Asbestos:													
	Molded amosite and binder	1200	16	--	--	0.33	0.38	0.43	0.53	--	--			
	Laminated asbestos paper	700	30	--	--	0.40	0.45	0.50	0.60	--	--			
	Corrugated and laminated asbestos paper:													
	4 ply per in.	300	11-13	--	0.54	0.57	0.62	0.80	--	--	--			
	6 ply per in.	300	15-17	--	0.49	0.51	0.59	0.69	--	--	--			
	8 ply per in.	300	18-20	--	0.47	0.49	0.57	0.65	--	--	--			
	Calcium silicate	1200	11	--	--	0.36	0.40	0.44	0.55	--	--			
	Cellular glass	800	9	0.37	0.39	0.41	0.48	0.55	--	--	--			
	Cork (without added binder)	200	7-10	0.27	0.28	0.29	0.30	--	--	--	--			
	Diatomaceous silica	1500	22	--	--	--	--	--	0.64	0.66	0.71			
		1900	25	--	--	--	--	--	0.70	0.75	0.80			
	85% magnesia	600	11-14	--	--	0.39	0.42	0.45	0.51	--	--			
	Mineral wool (rock, slag or glass):													
	Low temp. (asphalt or resin bonded)	200	15	0.28	0.30	0.33	0.39	--	--	--	--			
Low temp. (fine fiber resin bonded)	450	3	0.22	0.23	0.24	0.27	0.31	--	--	--				
High temp. blanket-type (metal reinforced)	1200	6-15	--	--	0.29	0.36	0.42	0.56	--	--				

Table 5-7. Characteristics of Thermal Insulations. (Continued)

Form	Material (Composition)	Accepted Max.Temp. For Use °F ⁽¹⁾	Density lb./cu. ft.	K = Typical Conductivity at Mean Temp. °F (Btu/H/ft ² /° per inch)							
				40	70	100	200	300	500	700	900
Pipe Insu- lation (con'd)	Plastics (foamed)	175	1-6	0.26	0.28	0.31	--	--	--	--	--
	Rubber (foamed)	150	5	0.23	0.24	0.25	--	--	--	--	--
	Vegetable and animal fiber:										
	Wool felt	180	20	0.29	0.31	0.33	--	--	--	--	--
	Hair felt or hair felt plus jute	180	10	0.27	0.28	0.30	--	--	--	--	--
Insu- lating cement	85% magnesia	600	18	--	--	0.46	0.52	0.58	--	--	--
	Mineral wool (rock, slag or glass):										
	With colloidal clay binder	1800	24-30	--	--	0.49	--	0.61	0.73	0.83	--

NOTES: (1) These temperatures are generally as maximum. When operating temperature approaches these limits the manufacturer's recommendations should be followed.

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installation. For large areas or long piping runs, substantial savings may be realized by factory forming, cutting or covering. Valves and pipe fittings, especially large ones, may be economically insulated with factory made prefabricated shapes. Equipment requiring periodic servicing will be equipped with removable, reusable insulation.

e. Miscellaneous materials. Complete insulation systems include accessory materials such as fasteners, adhesives, reinforcing wire meshes and screens, bandings and binder wires, coverings or laggings, and finishes. All insulations will be sealed or closed at joints and should be arranged to accommodate differential expansions between piping or metal structures and insulations.

f. Cold surface materials. Cold surface insulation materials will be selected primarily for high resistance to moisture penetration and damage, and for avoidance of corrosion where wet insulation materials may contact metal surfaces. Foamed plastics or rubber and cellular (or foamed) glass materials will be used wherever practicable.

5-15. Control of useful heat losses

a. General. Control of losses of useful heat is the most important function of insulations. Substantial investments for thermal insulation warrants careful selection and design.

b. Durability and deterioration. Most conventional insulating materials are relatively soft and fragile and are subject to progressive deterioration and loss of effectiveness with the passage of time. Insulation assemblies which must be removed for maintenance or which are subject to frequent contact with tools, operating equipment and personnel, or are subject to shock or vibration, will be designed for maximum resistance to these forces.

5-16. Safety insulation

a. General Insulation for personnel protection or safety purposes will be used to cover dangerously hot surfaces to avoid accidental contact, where heat loss is not itself an important criteria.

b. General safety criteria. Safety or burn protection insulations will be selected to insure that outside insulation surfaces do not exceed a reasonably safe maximum, such as 140 °F.

c. Other criteria Close fitting or sealing of safety insulation is not required. Metal jacketing will be avoided due to its high conductivity in contact with the human body.

5-17. Cold surface insulation

a. Applications. Insulations for cold surfaces will be applied to refrigeration equipment, piping and ductwork, cold water piping, and to air ducts bring-

ing outside air into power plants and HVAC systems.

b. Criteria. In most cases, cold surface insulations will be selected to prevent icing or condensation. Extra insulation thickness is not normally economical for heat absorption control.

5-18. Economic thickness

a. General. Economic thickness of an insulation material (ETI) is a calculated parameter in which the owning costs of greater or lesser thicknesses are compared with the relative values of heat energy which might be saved by such various thicknesses. The method is applicable only to systems which are installed to save useful heat (or refrigeration) and does not apply to safety insulation or anti-sweat (condensation) materials.

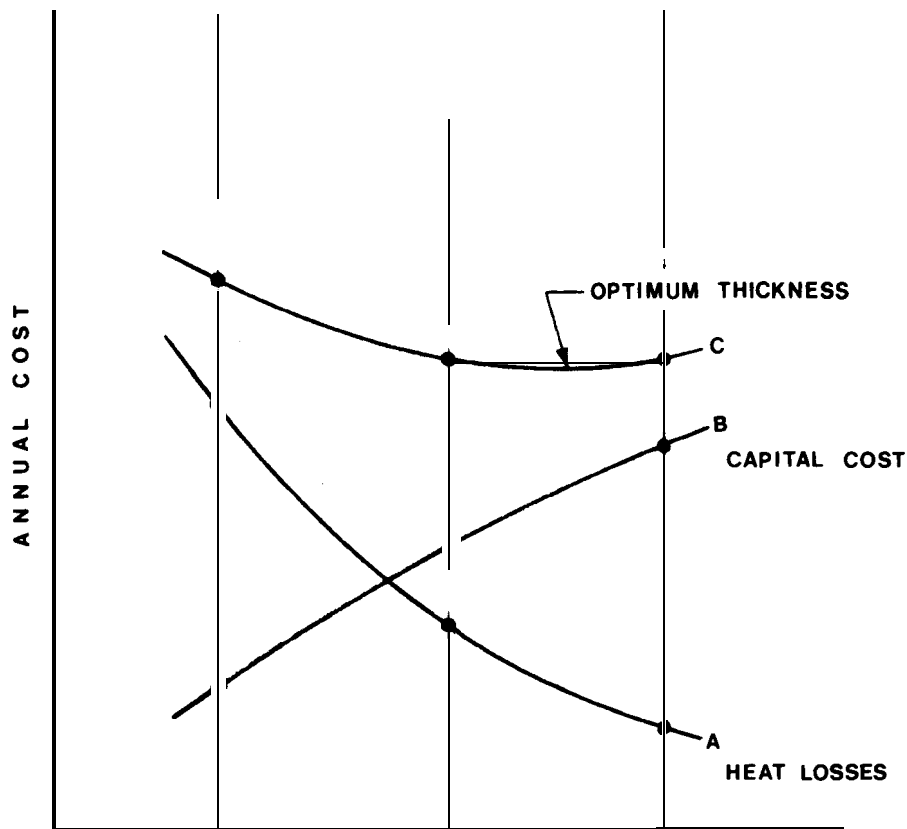
b. Economic criteria. The general principle of ETI calculations is that the most economical thickness of a group or set of thicknesses is that one for which the annual sum of owning costs and heat loss costs is a minimum. Generally, thicker insulations will represent higher owning costs and lower heat loss costs. The range of thicknesses selected for calculation will indicate at least one uneconomical thickness on each side of the indicated ETI. Refer to Figure 5-1 for a generalized plot of an ETI solution.

c. Required data. The calculations of ETI for a particular insulation application involves routine calculations of costs for a group of different thicknesses. While calculations are readily performed by computers, the required input data are relatively complex and will include energy or fuel prices with allowance for future changes, relative values of particular heat sources or losses, depreciation and money cost rates, costs of complete installed insulation systems, conductivities, temperatures, air velocities and operating hours. Standard programs are available for routine calculations but must be used with care. The most uncertain data will be the installed costs of alternative insulation systems and thicknesses. Assumptions and estimates of such costs will be as accurate as possible. Refer to the publications and program systems of the Thermal Insulation Manufacturers Association (TIMA) and of leading insulation manufacturers.

5-19. Freeze protection

a. Application. Freeze protection systems are combinations of insulation and heat source materials arranged to supply heat to exposed piping or equipment to prevent freezing in cold weather.

b. Insulation materials. Conventional insulation materials will be used and selected for general heat loss control purposes in addition to freeze protection. Insulation will be such as not to be damaged by



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Figure 5-1. Economical thickness for heat insulation (typical curves).

the heat source or by extended exposure to weather and moisture.

c. *Design criteria.* In general, the insulation for a freeze protection system will be selected for maximum overall coldest ambient temperatures. Allowance for wind conditions will be made.

d. Heat sources. Electrical heating tape will gen-

erally be used to supply the correct heat flow to the protected surface. Steam and hot water tracing may also be used with provisions to avoid loss of steam or water. In either case, the required heat supply will be sufficient to meet the heat loss of the insulation under the combination of design ambient and pipe line surface temperature.

Section V. CORROSION PROTECTION

5-20. General remarks

The need for corrosion protection will be investigated. Cycle fluids will be analyzed to determine treatment or if addition of corrosion inhibitors is required. Corrosion protection of items external to the

cycle is generally accomplished by more conventional methods such as:

- u. Selection of corrosion resistant materials.
- b. Protective coatings.
- c. Cathodic protection.

Section VI. FIRE PROTECTION

5-21. Introduction

Fire protection will be provided in order to safeguard the equipment and personnel. Various systems will be installed as required to suit the particu-

lar type of fire which can occur in the station. This manual discusses various fire protection systems and their general application in power plants. Reference will be made to TM 5-812-1 for specific re-

quirements for military installations. Further details may be found in the National Fire Protection Association (NFPA) Codes and Standards.

5-22. Design considerations

a. Areas and equipment to be protected. The following are some of the major areas which will be investigated to determine the need for installing fire protection facilities.

- (1) Main and auxiliary transformers.
- (2) Turbine lubricating oil system including the oil reservoir, oil, cooler, storage tanks, pumps and the turbine and generator bearings.
- (3) Generator hydrogen cooling system including control panels, seal oil unit, hydrogen bottles and the purification unit.
- (4) Coal storage bunkers, fuel oil storage tanks and the burner front of the steam generator.
- (5) Emergency diesel generator and its oil storage tank.
- (6) Office and records rooms.
- (7) Control room.
- (8) Relay, computer, switchgear and battery rooms.
- (9) Shops, warehouses, garages and laboratories.
- (10) Personnel locker rooms, lunch rooms and toilets.

b. Types of systems. The following is a brief description of the various types of systems and their general application.

(1) *Water spray and deluge system.* This type of system consists of open type sprinkler heads attached to a network of dry (not water filled) piping which is automatically controlled by a fully supervised fire detection system which also serves as a fire alarm system. When a fire is detected, an automatic deluge valve is tripped open, admitting water to the system to discharge through all of the sprinkler heads. The system may be subdivided into separately controlled headers, depending on the area to be covered and the number of sprinkler heads required. The usual pressure required at the sprinkler heads is about 175 psi and the piping should be properly sized accordingly. A water spray deluge sprinkler system will be provided where required in open areas and areas requiring the protection of the piping from freezing, such as the steam generator burner fronts; the generator hydrogen system; the main and auxiliary transformers; and unheated shops, garages, warehouses and laboratories.

(2) *Water spray pre-action and deluge system.* This type of system is similar to the above water spray deluge system, except that it contains closed type sprinkler heads which only discharges water through those sprinklers whose fixed temperature

elements have been opened by the heat from a fire. This system will be utilized for the turbine and generator bearings and for the above water spray deluge sprinkler system areas where more localized control is desired.

(3) *Wet pipe sprinkler systems.* This wet pipe system utilizes a water filled piping system connected to a water supply and is equipped with sprinklers having fixed temperature elements which each open individually when exposed to a high temperature due to a fire. The areas where wet pipe sprinkler systems will be used are heated shops, garages, warehouses, laboratories, offices, record rooms, locker rooms, lunch rooms and toilets.

(4) *Foam extinguishing systems.* Foam fire extinguishing systems utilize a foam producing solution which is distributed by pipes equipped with spray nozzles or a fuel tank foam entry chamber for discharging the foam and spreading it over the area to be protected. It is principally used to form a coherent floating blanket over flammable and combustible liquids which extinguish (or prevent) a fire by excluding air and cooling the fuel. The foam is usually generated by mixing proportionate amounts of 3% double strength, low expansion standard foam concentrate using either a suitably arranged induction device with (or without) a foam storage-proportioning tank to mix the foam concentrate with a water stream from a fire water header. A specially designed hand play pipe, tank foam chamber or open sprinklers aspirate the air to form the foam to blanket the area to be protected. The deluge water entry valve to the system may be manually or automatically opened. Foam systems will be installed in power plants to protect fuel oil areas, lubricating oil systems, and hydrogen seal oil systems.

(5) *Carbon dioxide extinguishing systems.* This type of system usually consists of a truck filled low pressure refrigerated liquid carbon dioxide storage tank with temperature sensing controls to permit the automatic injection of permanently pipe carbon dioxide into areas to be protected. The system usually includes warning alarms to alert personnel whenever carbon dioxide is being injected into an actuated area. Carbon dioxide extinguishing systems of this total flooding type will be utilized to extinguish coal bunker fires and for electrical hazard areas such as in battery rooms, electrical relay rooms, switchgear rooms, computer rooms and within electrical cabinets.

(6) *Halogenated fire extinguishing systems.* This type of system utilizes specially designed removable and rechargeable storage containers containing liquid Halon at ambient temperature which is superpressurized with dry nitrogen up to 600 psig

pressure. These manifolded containers are located as closely as possible to the hazards they protect and include connecting piping and discharge nozzles. There are two types of systems. The total flooding system is arranged to discharge into, and fill to the proper concentration, an enclosed space or an enclosure about the hazard. The local application system is arranged to discharge directly onto the burning material. Either system may be arranged to protect one or more hazards or groups of hazards by so arranging the piping and valves and may be manually or automatically actuated. Halon is a colorless and odorless gas with a density of approximately five times that of air, and these systems must include warning alarms to alert personnel whenever the gas is being ejected. However, personnel maybe exposed to Halon vapors in low concentrations for brief periods without serious risk. The principal application of Halon extinguishing systems is where an electrically nonconductive medium is essential or desired or where the cleanup of other media presents a problem, such as in control rooms, computer rooms, chemical laboratories and within electrical panels.

c. Automatic fire detectors. All fire protection systems will normally be automatically alarmed and

actuated; however, some special conditions may require manual actuation on an alarm indication. A manual actuation will be included to provide for emergencies arising from the malfunction of an automatic system. The primary element of any fire protection system is the fire detection sensing device which is actuated by heat detectors which detect abnormally high temperature or rate-of-temperature rise, or smoke detectors which are sensitive to the visible or invisible particles of combustion. The ionization type of smoke detector belongs in this category.

5-23. Support facilities

To support the fire protection water systems, an assured supply of water at an appropriate pressure is necessary. This water supply will be provided from an underground fire water hydrant system main if one is available in the area and/or by means of an elevated head storage tank or by fire pumps which take their suction from a low level storage tank. For cases where the water supply pressure is inadequate to fill the tank, fill pumps will be provided. Fire pumps will be electric motor driven, except that at least one should be of the engine driven or of the dual drive type.

CHAPTER 6

GAS TURBINE POWER PLANT DESIGN

6-1. General

Gas turbines find only limited application as prime movers for power generation at military facilities. This is because gas turbine generators typically have significantly higher heat rates than steam turbine or diesel power plants; their higher fuel costs quickly outweigh their initial advantages in most applications. Applications to be evaluated include:

a. Supplying relatively large power requirements in a facility where space is at a significant premium—such as hardened structure.

b. Mobile, temporary or difficult access site—such as a troop support or line of sight station.

c. Peak shaving, in conjunction with a more efficient generating station.

d. Emergency power, where a gas turbine's light weight and relatively vibration-free operation are of greater importance than fuel consumption over short periods of operation. However, the starting time of gas turbines may not be suitable for a given application.

e. Combined cycle or cogeneration power plants where turbine exhaust waste heat can be economically used to generate additional power and thermal energy for process or space heating.

6-2. Turbine-generator selection

a. Packaged plants. Gas turbines are normally purchased as complete, packaged power plants. With few exceptions, only simple cycle turbines are applicable to military installations. Therefore, the remainder of this chapter focuses on the simple cycle configuration. The packaged gas turbine power plant will include the prime mover, combustion system, starting system, generator, auxiliary switchgear and all turbine support equipment required for operation. This equipment is usually "skid" or base mounted. The only "off base" or additional auxiliaries normally required to supplement the package are the fuel oil storage tanks, transfer pumps and oil receiving station, distribution switchgear, step up transformer and switchyard, as required.

(1) Selection of unit size requires establishment of plant loading and the number of units required for reliability and turndown. Wide gaps in the standard equipment capacity ratings available may force re-

consideration of the number of units or the total plant capacity,

(2) Initial selection of the gas turbine unit begins using the International Standards Organization (ISO) rating provided on the manufacturer's data sheets. This is a power rating at design speed and at sea level with an ambient temperature of 59°F (15°C). The ISO rating considers inlet and outlet losses to be zero. Initially, ISO ratings will be reduced 15 percent for typical applications, which will further be refined to reflect actual site and installation conditions. The four variables which will be considered in unit rating are:

- (a) Elevation.
- (b) Ambient temperature.
- (c) Inlet losses.
- (d) Exhaust losses.

The following subsections define the impact of each of these variables.

b. Elevation. For a specific site, the ISO rating reduction due to site altitude is read directly from an altitude correction curve published by the various manufacturers. There is little difference in such curves. For mobile units, the effect of possible site altitudes will be evaluated. The operating altitude will be used to determine the unit rating.

c. Temperature. Site temperature data will be obtained from TM 5-785. The design temperature selected is normally the 2 1/2 percent dry bulb temperature, although the timing of the load curve peak will also be considered. Unless the choice of equipment is tight, there is usually sufficient overload capability to carry the unit during the 2 1/2 percent time of higher temperature. Another temperature related selection parameter is icing. Icing is caused when the right combination of temperature and humidity levels occurs, and is manifested by ice formation on the downstream side of the inlet filters or at the compressors bell mouth intake. Chunks of ice can be sucked in the compressor with possible blade damage resulting. Icing occurs when ambient temperatures are in the 35 to 42°F. range and relative humidity is high. This problem will be avoided by recirculating hot air from the compressor discharge to the filter inlet, either manually or automatically. This causes some loss of turbine efficiency.

d. Inlet losses. Inlet losses are a critical performance variable, and one over which the designer has

considerable control. Increases in the inlet air friction cause a significant reduction in power output. The total inlet pressure loss will not exceed 2 inches of water and will be as close to zero as space limitations and economics will permit. Additional ductwork costs will be quickly amortized by operating fuel savings. Dust, rain, sand and snow will be prevented from entering the combustion air inlet of the engine. Inlet air filter design will preclude entrance of these contaminants with minimal pressure loss. The air inlet will be located to preclude ingestion of combustion products from other turbines or a nearby boiler plant, or hot, humid discharge from any cooling towers.

e. Outlet losses. Outlet friction losses also result in a decrease of turbine-generator output and will be accounted for in the unit design. The major factor in outlet losses is the requirement to attenuate noise. More effective silencers typically have higher pressure losses. Exhaust back pressure has a smaller overall effect on performance than inlet losses but will be kept as low as possible, and will be less than 6 inches of water. Since increasing exhaust silencer size costs considerably more than ductwork design improvements, the return on investment for a low pressure loss exhaust is significantly longer.

6-3. Fuels

Each manufacturer has his own specification on fuel acceptable for his turbine. The high grade liquid fuels such as Diesel No. 1 or 2 and JP-4 or JP-5 will likely be acceptable to all manufacturers. Use of heavier oils is possible with a specially designed turbine. The heavy oil will have to be cleaned up to reduce corrosive salts of sodium, potassium, vanadium, and sulfur—all of which will elevate the cost of the fuel. Storage and handling at the site will also be more costly, particularly if a heavy oil such as No. 6 was involved because of the heating requirement. No. 4 oil will increase transfer pumping costs a bit but, except in extremely cold regions, would not require heating.

6-4. Plant arrangement

a. General. Turbine generator units are frequently sold as complete packages which include all components necessary to operate, ready for connection to the fuel supply and electrical distribution system. This presents the advantages of faster lead time, well matched components and single point of performance responsibility.

b. Outdoor vs. indoor.

(1) *Outdoor.* Outdoor units can be divided into two sub-types.

(a) The package power plant unit is supplied with the principal components of the unit factory as-

sembled into three or more skid mounted modules, each with its own weatherproof housing the separate modules have wiring splits, piping connections, and housing flanges arranged so that the modules may be quickly assembled into a unit on a reinforced concrete pad in the field. Supplementing these main modules are the inlet and exhaust ducts, inlet silencer and filters, exhaust silencer, fuel tanks, unit fuel skid, and unit auxiliary transformer which are connected by piping and cables to the main assembly after placing on separate foundation as may be required.

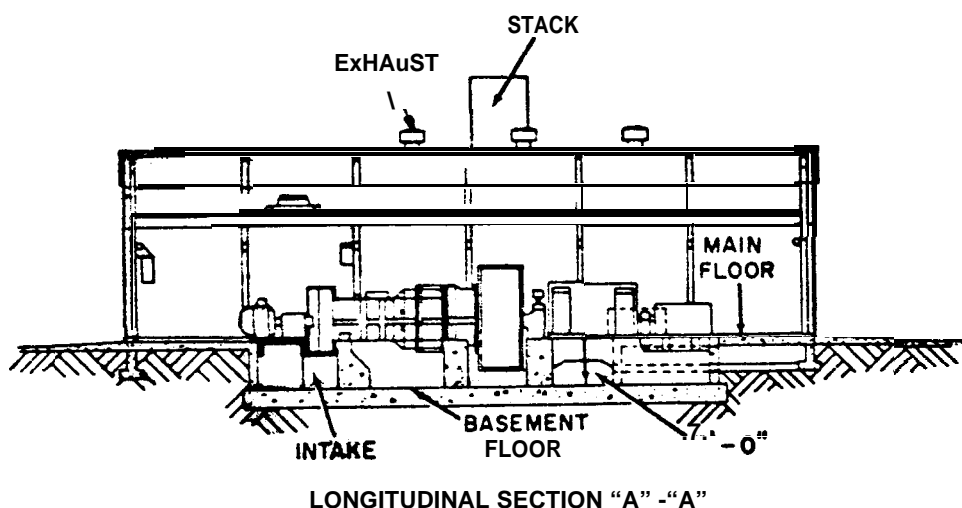
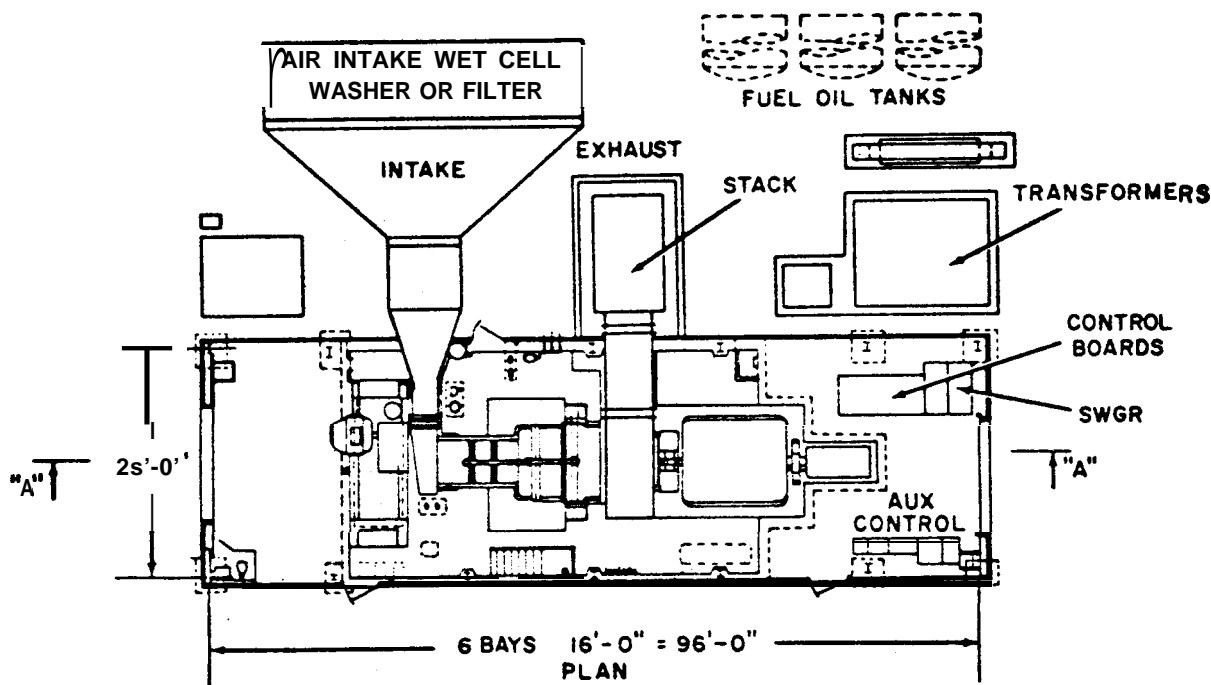
(b) The other outdoor sub-type is a similar package unit except that the weatherproof housing is shipped knocked down and is, in effect, a prefabricated building for quick field assembly into a closure for the main power plant components.

(c) Outdoor units to be provided with all components, auxiliaries and controls assembled in all-weather metal enclosures and furnished complete for operation will be specified for Class "B" and "C" power plants having a 5-year anticipated life and requiring not more than four generating units.

(2) *Indoor.* An indoor type unit will have the compressor-turbine-generator mounted at grade floor level of the building on a pad, or possibly raised above or lowered below grade floor level to provide space for installation of ducts, piping and cabling. Inlet and exhaust ducts will be routed to the outside through the side wall or the roof; the side wall is usually preferable for this so that the turbine room crane can have full longitudinal travel in the turbine generator bay. Filters and silencers may be inside or outside. All heat rejection equipment will be mounted outside while fuel oil skids may be inside or outside. Unit and distribution switchgear and motor control centers will be indoors as in a conventional steam power plant. Figure 6-1 shows a typical indoor unit installation with the prime mover mounted below grade floor level.

6-5. Waste heat recovery

Waste heat recovery will be used wherever cost effective. If the turbine unit is to be used only intermittently, the capital cost of heat recovery must be kept down in order to be considered at all. Add-on or sidestream coils might provide a temporary hot water supply for the period of operation—for one example. Care must be exercised due to the high exhaust gas temperature. It may prove feasible to flash steam through the jacket of a small heat exchanger. In the event that a long term operation is indicated, the cost trade off for heat recovery equipment is enhanced, but still must be considered as an auxiliary system. It will take a sizable yearly load to justify an exhaust gas heat recovery boiler.



NAVFAC DMS

Figure 6-1. Typical indoor simple cycle gas turbine generator power plant.

Turbine efficiency loss due to back pressure is also a factor to be considered.

6-6. Equipment and auxiliary systems

a. General. The gas turbine package is a complete power plant requiring only adequate site preparation, foundations, and support facilities including fuel storage and forwarding system, distribution **switchgear**, stepup transformer, and switchyard. If the fuel to be fired is a residual oil, a fuel washing and treating plant is also required.

b. References. Chapter 4 sets forth guidelines for the design of the electrical facilities required for a

gas turbine power plant, including the generator, **switchgear**, switchyard, transformers, relays and controls. Chapter 2 describes the pertinent civil facilities.

c. Scope. The scope of a package gas turbine generator for purchase from the manufacturer will include the following

- (1) Compressor and turbine with fuel and combustion system, lube oil system, turning gear, governor, and other auxiliaries and accessories.
- (2) Reduction gear.
- (3) Generator and excitation system.

TM 5-811-6

(4) AC auxiliary power system including switchgear and motor controls.

(5) DC power system including battery, charger, and inverter if required.

(6) External heat rejection equipment if required.

(7) All mechanical and electrical controls.

(8) Diesel engine or electric motor starting system.

(9) Unit fuel skid (may be purchased separately if desired).

(10) Intake and exhaust ducts.

(11) Intake air filters.

(12) Acoustical treatment for intake and exhaust ducts and for machinery.

(13) Weatherproof housing option with appropriate lighting, heating, ventilating, air conditioning and fire protection systems.

CHAPTER 7

DIESEL ENGINE POWER PLANT DESIGN

Section I. DIESEL ENGINE-GENERATORS

7-1. Engines

a. Diesel engines have higher thermal efficiencies than other commercial prime movers of comparable size. Diesel engine-generators are applicable to electric loads, from about 10 to 5000 kilowatts. Diesel-engine-driven electric generator sets are divided into three general categories based on application as follows:

(1) *Class A:* Diesel-electric generator sets for stationary power plants generating prime power continuously at full nameplate kW rating as the sole source of electric power.

(2) *Class B:* Diesel-electric generators sets for stationary power plants generating power on a standby basis for extended periods of time where months of continuous operation at full nameplate kW rating are anticipated.

(3) *Class C:* Diesel-electric generator sets for stationary power plants generating power on an emergency basis for short periods of time at full nameplate kW rating where days of continuous operation are anticipated.

b. Diesel engines normally will be supplied as skid mounted packaged systems. For multiple-unit procurement, matched engine-generator sets will be provided for units of 2500kW electrical output or less. For larger units, investigate the overall economics and practicality of purchasing the generators separately, recognizing that the capability for reliable operation and performance of the units are sacrificed if engine and generator are bought from two sources.

c. Engines and engine-generator sets are normally provided with the primary subsystems necessary for engine operation, such as:

- (1) Starting system.
- (2) Fuel supply and injection system.
- (3) Lubrication system and oil cooling.
- (4) Primary (engine) cooling system.
- (5) Speed control (governor) system.
- (6) Required instrumentation.

d. The designer must provide for the following

- (1) Intake air.

- (2) Exhaust and exhaust silencing.
 - (3) Source of secondary cooling (heat sink).
 - (4) Engine foundation and vibration isolation.
 - (5) Fuel storage, transfer and supply to the engine.
 - (6) Electrical switchgear, stepup transformer, if required, and connection to distribution wiring.
 - (7) Facilities for engine maintenance, such as cranes, hoists and disassembly space.
 - (8) Compressed air system for starting, if required.
- e.* Generator design criteria are provided in Chapter 4.

7-2. Fuel selection

A fuel selection is normally made according to availability and economic criteria during the conceptual design. Fuels are specified according to ASTM, Federal and military specifications and include:

a. ASTM Grades 1-D, 2-D, and 4-D as specified by ASTM D 975. These fuels are similar to No. 1, No. 2 and No. 4 heating oils.

b. Federal Specification Grades DF-A and DF-2 (see Federal Specification VV-F-800). These specifications parallel ASTM Grades 1-D and 2-D, respectively.

c. Jet Fuel Grade JP-5 (Military Specification MIL-T-5624).

d. Marine Diesel (Military Specification MIL-F-16884). Marine Diesel is close to ASTM No. 2-D, although requirements differ somewhat.

e. ASTM No. 6, or its Federal equivalent, or Navy special may be specified for engines in excess of 2000 kW if economics permit. Fuel selection must be closely coordinated with the requirements of the engine manufacturer. The No. 2-D or DF-2 fuels are most common. If fuel is stored at ambient temperatures below 20°F., No. 1-D or DF-A (arctic fuel) should be considered. ASTM No. 4-D or No. 6 are residual oil blends which require preheating prior to burning. Fuel oil storage and handling equipment and the engine itself will be specifically designed for burning these viscous fuel oils.

Section II. BALANCE OF PLANT SYSTEMS

7-3. General

Balance of plant systems are those which must be provided and interfaced with a packaged diesel or diesel-generator set to provide an operational generating unit.

7-4. Cooling systems

a. Water-to-water systems. Jacket water and lube oil cooling heat exchangers are cooled by a secondary circulating water system. Normally, a recirculating system will be used. Heat is dissipated to the atmosphere through an evaporative, mechanical-draft cooling tower. If the plant is located on or near a body of water, once-through circulating water will be evaluated. Bidders will be informed of the type and source of secondary water used so heat exchangers can be designed for their intended service.

b. Water-to-air systems. Water-to-air systems will be restricted to small engines. If an integral (skid mounted) radiator is used, sufficient cooling air will be provided. Outside air may be ducted to the radiator air inlet. Ductwork will be designed for minimum pressure loss. The cooling fan(s) will be checked for adequate flow (cfm) and static pressure under the intended service. Air leaving the radiator normally goes to the engine room and is exhausted. Cooling air inlets will be equipped with automatic dampers and bird screens.

7-5. Combustion air intake and exhaust systems

a. Purpose. The functions of the intake and exhaust systems are to deliver clean combustion air to the engine and dispose of the exhaust quietly with the minimum loss of performance.

b. Intake. The air intake system usually consists of air intake duct or pipe appropriately supported, a silencer, an air cleaner, and flexible connections as required. This arrangement permits location of area of air intake beyond the immediate vicinity of the engine, provides for the reduction of noise from intake air flow, and protects vital engine parts against airborne impurities. The air intake will be designed to be short and direct and economically sized for minimum friction loss. The air filter will be designed for the expected dust loading, simple maintenance, and low pressure drop. Oil bath or dry filter element air cleaners will be provided. The air filter and silencer may be combined.

c. Exhaust. The exhaust system consists of a muffler and connecting piping to the atmosphere with suitable expansion joints, insulation, and supports. In cogeneration plants, it also provides for utilization of exhaust heat energy by incorporating

a waste heat boiler which can be used for space heating, absorption refrigeration, or other useful purpose. This boiler produces steam in parallel with the vapor phase cooling system. The exhaust silencer attenuates exhaust gas pulsations (noise), arrests sparks, and in some cases recovers waste heat. The muffler design will provide the required sound attenuation with minimum pressure loss.

7-6. Fuel storage and handling

a. Storage requirements.

(1) Aboveground fuel storage tanks with a minimum capacity for 30 days continuous operation will be provided for continuous and standby duty plants. Fuel storage shall be designed to the requirements of NFPA 30. A tank with 3 day storage capacity will be provided for emergency duty plants.

(2) For continuous duty plants, provide a day tank for each engine. The tank will provide a 4-hour storage capacity at maximum load. The tank will be filled by automatic level controls and transfer pumps. Standby plants will be provided with day tanks of sufficient capacity to permit manual filling once per shift (10-hour capacity). No separate day tank is required for emergency plants.

b. Fuel handling. Provide unloading pumps if fuel is to be delivered by rail car or barge. Most fuel tank trucks are equipped with pumps. Provide transfer pumps capable of filling the day tank in less than 1/2 hour when the engine is operating at maximum load. Duplex pumps, valved so that one can operate while the other is on standby, will be provided for reliability. Pipeline strainers and filters will be provided to protect the fuel pumps and engine injectors from dirt. Strainers and filters will not pass particles larger than half the injector nozzle opening.

7-7. Engine room ventilation

About 8 percent of the heating value of the fuel consumed by the engine is radiated to the surrounding air. It is essential that provision be made for removal of this heat. Engine room temperature rise should be limited to 15°F. For engines with wall mounted or ducted radiators, radiator fans may be sufficient if adequate exhaust or air relief is provided. If engines are equipped with water cooled heat exchangers, a separate ventilation system will be provided. The approximate ventilation rate may be determined by the following formula:

$$C F M = \frac{1,000 \times HP}{T}$$

where:

HP = maximum engine horsepower
T = allowable temperature rise, 'F.

Provision will be made to allow for reducing the air flow during the cooler months so as not to over-cool

the engine room; however, jacket water cooling will remain within recommended limits at all times.

Section III. FOUNDATIONS AND BUILDING

7-8. General

Chapter 2 should be consulted for the civil facilities design criteria associated with a diesel power plant. This section amplifies the civil engineering aspects directly applicable to the diesel plant.

7-9. Engine foundation

a. Design considerations.

(1) The foundation will have the required mass and base area, assuming installation on firm soil and the use of high quality concrete. Before final details of the foundation design are established by the designer, the bearing capacity and suitability of the soil on which the foundation will rest will be determined. Modification of the manufacturer's recommended foundation may be required to meet special requirements of local conditions. Modifications required may include:

(a) Adjustment of the mass.

(b) Additional reinforcing steel.

(c) Use of a reinforced mat under the regular foundation.

(d) Support of the foundation on piles. Piling may require bracing against horizontal displacement.

(2) The engine foundation will extend below the footings of the building and the foundation will be completely isolated from the walls and floors of the building. The foundation block will be cast in a single, continuous pour. If a base mat is used, it will be cast in a separate continuous pour and be provided with vertical re-bars extending up into the foundation block.

b. Vibration mounts.

(1) For small engine installations where there is a possibility of transmission of vibration to adjacent areas, the engine foundations will be adequately insulated by gravel, or the engine mounted on vibration insulating material or devices. Vibration mounts for larger engines become impractical and foundation mass must be provided accordingly.

(2) Skid mounted generating units will be supplied with skids of sufficient strength and rigidity to maintain proper alignment between the engine and the generator. Vibration isolators, either of the adjustable spring or rubber pad type, will be placed between the unit skid and the foundation block to minimize the transmission of vibrations.

7-10. Building

a. Location.

(1) A diesel engine power plant has few limitations regarding location. Aesthetically, an architecturally attractive building can enclose the equipment if required. Fuel can be stored underground if appearance so dictates. Proper exhaust and intake air silencing can eliminate all objectionable noise. Air and water pollution problems are minimal with most recommended fuels.

(2) Consider the relative importance of the following when selecting a plant site:

(a) Proximity to the center of power demand.

(b) Economical delivery of fuel.

(c) Cost of property.

(d) Suitability of soil for building and machinery foundations.

(e) Space available for future expansion.

(f) Proximity to potential users of engine waste heat.

(g) Availability of water supply for cooling systems.

b. Arrangement.

(1) In designing the power plant building, a general arrangement or plant layout will be designed for the major components. The arrangement will facilitate installation, maintenance and future plant expansion. Ample space shall be provided around each unit to create an attractive overall appearance and simplify maintenance for engines and auxiliary equipment.

(2) In addition to the basic equipment arrangement, provide for the location of the following, as required by the project scope:

(a) Office space.

(b) Lunchroom and toilet facilities.

(c) Engine panels, plant and distribution switchgear, and a central control board (Chapter 5, Section I).

(d) Cooling system including pumps and heat exchangers.

(e) Lube oil filters and, for heavier fuels, fuel oil processing equipment such as centrifuges.

(f) Tools and operating supplies storage.

(g) Facilities for maintenance.

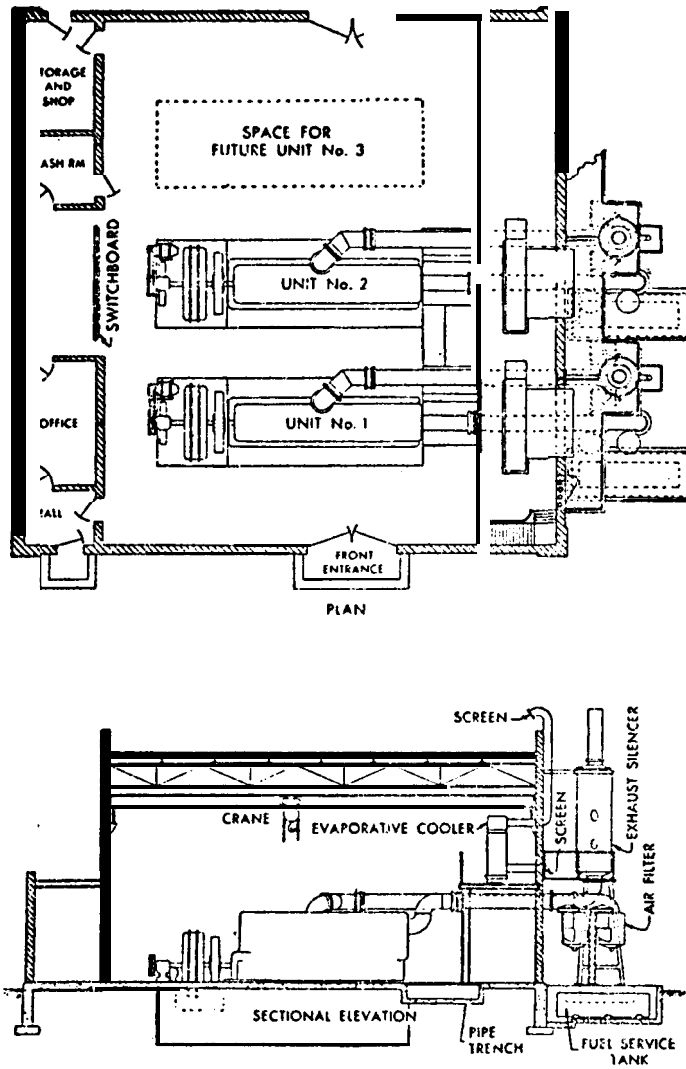
(h) Heat recovery equipment, if included.

(3) The main units should usually be lined up in parallel, perpendicular to the long axis of the engine room thus making unlimited future expansion easy

and economical. The engine bay will be high enough for a motorized, overhead traveling crane. The crane, if economically feasible, will be sized for maintenance only. The switchgear will be located at the generator end of each unit, permitting the shortest

possible wiring between the switchgear and generators. The switchgear may be enclosed in a separate room or maybe a part of the main engine bay.

(4) A typical small two-unit diesel power plant arrangement is shown in Figure 7-1.



U.S. Army Corps of Engineers

Figure 7-1. Typical diesel generator power plant.

CHAPTER 8

COMBINED CYCLE POWER PLANTS

Section 1. TYPICAL PLANTS AND CYCLES

8-1. Introduction

a. Definition. In general usage the term ‘combined cycle power plant’ describes the combination of gas turbine generator(s) (Brayton cycle) with turbine exhaust waste heat boiler(s) and steam turbine generator(s) (Rankine cycle) for the production of electric power. If the steam from the waste heat boiler is used for process or space heating, the term “co-generation” is the more correct terminology (simultaneous production of electric and heat energy).

b. General description.

(1) Simple cycle gas turbine generators, when operated as independent electric power producers, are relatively inefficient with net heat rates at full load of over 15,000 Btu per kilowatt-hour. Consequently, simple cycle gas turbine generators will be used only for peaking or standby service when fuel economy is of small importance.

(2) Condensing steam turbine generators have full load heat rates of over 13,000 Btu per kilowatt-hour and are relatively expensive to install and operate. The efficiency of such units is poor compared to the 8500 to 9000 Btu per kilowatt-hour heat rates typical of a large, fossil fuel fired utility generating station.

(3) The gas turbine exhausts relatively large quantities of gases at temperatures over 900 °F. In combined cycle operation, then, the exhaust gases from each gas turbine will be ducted to a waste heat boiler. The heat in these gases, ordinarily exhausted to the atmosphere, generates high pressure superheated steam. This steam will be piped to a steam turbine generator. The resulting “combined cycle” heat rate is in the 8500 to 10,500 Btu per net kilowatt-hour range, or roughly one-third less than a simple cycle gas turbine generator.

(4) The disadvantage of the combined cycle is that natural gas and light distillate fuels required for low maintenance operation of a gas turbine are

expensive. Heavier distillates and residual oils are also expensive as compared to coal.

8-2. Plant details

a. Unfired boiler operation. For turbines burning natural gas or light distillate oil, the boiler will be of the compact, extended surface design with either natural or forced circulation with steam generated at approximately 650 psig and 825°F. The addition of the waste heat boiler-steam turbine generator combinations increases power output over the simple gas turbine.

b. Fired boiler operation. The exhaust from a gas turbine contains large amounts of excess air. This exhaust has an oxygen content close to fresh air, and will be utilized as preheated combustion air for supplementary fuel firing. Supplementary fuel firing permits increasing steaming of the waste heat boiler. Burners will be installed between the gas turbine exhaust and the waste boiler to elevate the exhaust gases to the heat absorption limitations of the waste heat boiler. Supplementary burners also permit generation when the gas turbine is out of service.

c. Other types of combined cycle plants. Variations of combined cycle plants areas follows:

(1) Back pressure operation of the steam turbine. This may include either unfired or fired boiler operation. The steam turbine used is a non-condensing machine with all of the exhaust steam utilized for heating or process at a lower pressure level.

(2) Controlled (automatic) extraction operation of the steam turbine. This may also include either unfired or fired boiler operation. A controlled extraction steam turbine permits extraction steam flow to be matched to the steam demand. Varying amounts of steam can be used for heating or process purposes. Steam not extracted is condensed. This type of steam turbine will only be used when electrical requirements are very large (see Chapter 1).

Section II. GENERAL DESIGN PARAMETERS

8-3. Background

A combined cycle power plant is essentially comprised of standard equipment derived from both gas

turbine and steam turbine power plants. The waste heat boiler is different in design, however, from a normal fossil fueled boiler. Feedwater heating is

usually less complex. Power plant controls must take into account the simultaneous operation of gas turbine, boiler and steam turbine.

8-4. Design approach

a. Operating differences. The following items should be given consideration:

(1) *Turndown.* Gas turbine mass flows are fairly constant, but exhaust temperature falls off rapidly as load is reduced. Therefore, decreasing amounts of steam are generated in the waste heat boiler. Variations in gas turbine generator output affect the output from the steam turbine generator unless supplementary fuel is fired to adjust the temperature. Supplementary fuel firing, however, decreases combined cycle efficiency because of the increased boiler stack gas losses associated with the constant mass flow of the turbine.

(2) *Exhaust gas flows.* For the same amount of steam produced, gas flows through a combined cycle boiler are always much higher than for a fuel fired boiler.

(3) *Feedwater temperatures.* With a combined cycle plan, no air preheater is needed for the boiler. Hence, the only way to reduce final stack gas exit temperature to a sufficiently low (efficient) level is to absorb the heat in the feedwater with economizer recovery equipment. Inlet feedwater temperature must be limited (usually to about 250°F) to do this.

b. Approaches to specialized problems:

(1) *Load following.* Methods of varying loads for a combined cycle include:

(a) Varying amount of fuel to a gas turbine will decrease efficiency quickly as output is reduced from full load because of the steep heat rate curve of the gas turbine and the multiplying effect on the steam turbine. Also, steam temperature can rapidly fall below the recommended limit for the steam turbine.

(b) Some supplementary firing may be used for a combined cycle power plant full load. Supplementary firing is cut back as the load decreases; if load decreases below combined output when supplementary firing is zero, fuel to the gas turbine is also cut back. This will give somewhat less efficiency at combined cycle full load and a best efficiency point at less than full load; i.e., at 100 percent waste heat operation with full load on the gas turbine.

(c) Use of a multiple gas turbine coupled with a waste heat boiler will give the widest load range with minimum efficiency penalty. Individual gas turbine-waste heat units can be shut down as the

load decreases with load-following between shut-down steps by any or both of the above methods.

(d) Installation of gas dampers to bypass variable amounts of gas from turbine exhaust directly to atmosphere. With this method, gas turbine exhaust and steam temperatures can be maintained while steam flow to steam turbine generator is decreased as is the load. This has the added advantage that if both atmospheric bypass and boiler dampers are installed, the gas turbine can operate while the steam turbine is down for maintenance. Also, if full fuel firing for the boiler is installed along with a standby forced draft fan, steam can be produced from the boiler while the gas turbine is out for maintenance. This plan allows the greatest flexibility when there is only one gas turbine-boiler-steam turbine train. It does introduce equipment and control complication and is more costly; and efficiency decreases as greater quantities of exhaust gas are by passed to atmosphere.

(2) *Boiler design.*

(a) Waste heat boilers must be designed for the greater gas flows and lower temperature differentials inherent in combined cycle operation. If a standby forced draft fan is installed, the fan must be carefully sized. Gas turbine full load flow rates need not be maintained,

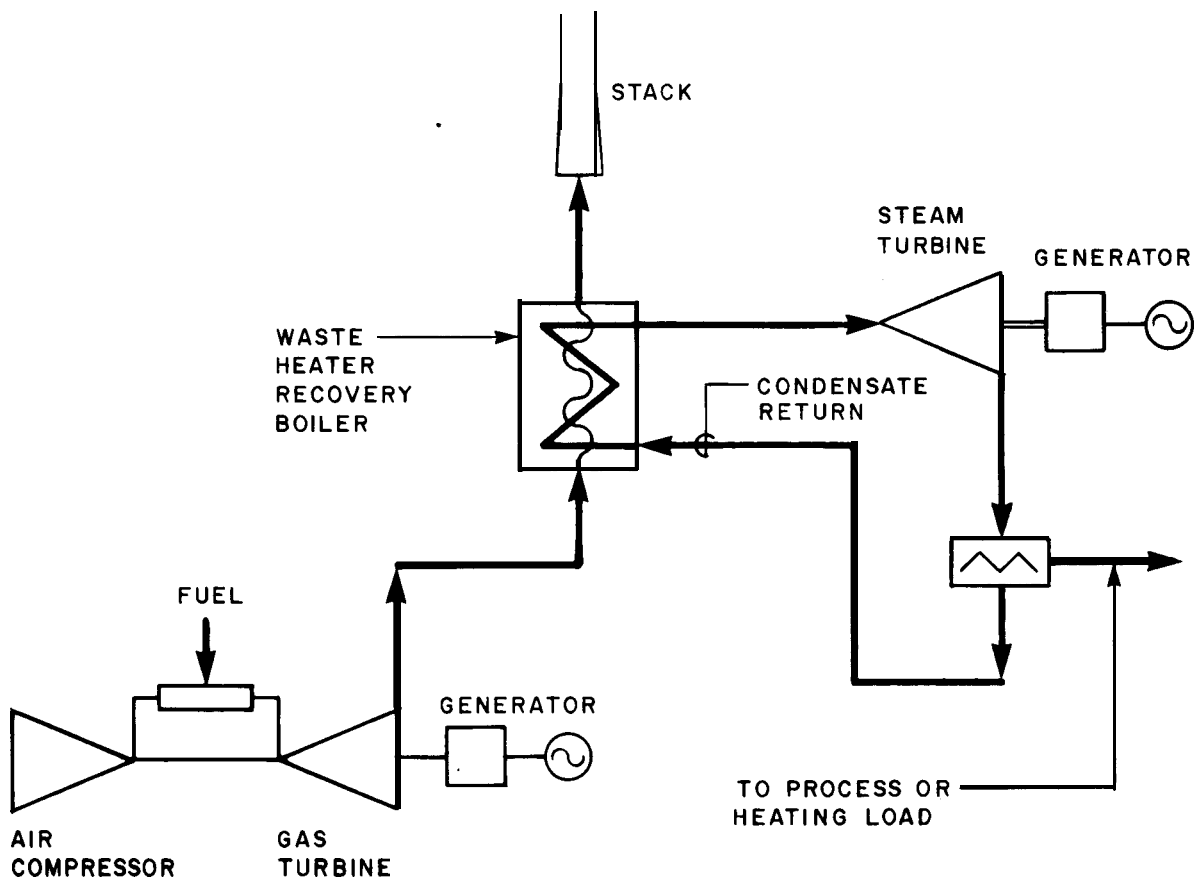
(b) If the fuel to be fired, either in the gas turbine or as supplementary fuel, is residual oil, bare tubes should be used in the boiler with extended surface tubes used in the economizer only. This increases the boiler cost substantially but will preclude tube pass blockages. Soot blowers are required for heavy oil fired units.

(3) *Feedwater heating and affect on steam generator design.*

(a) Because of the requirement for relatively low temperature feedwater to the combined cycle boiler, usually only one or two stages of feedwater heating are needed. In some cycles, separate economizer circuits in the steam generator are used to heat and deaerate feewater while reducing boiler exit gas to an efficient low level.

(b) For use in military installations, only co-generation combined cycles will be installed. A typical cycle diagram is shown in Figure 8-1.

(4) *Combined cycle controls.* There is a wide variation in the controls required for a combined cycle unit which, of course, are dependent on the type of unit installed. Many manufacturers have developed their own automated control systems to suit the standardized equipment array which they have developed.



Courtesy of Pope, Evans and Robbins (Non-Copyrighted)

Figure 8-1. Combined cycle diagram.

APPENDIX A

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- C84.1 Voltage Ratings for Electrical Power Systems and Equipment.

American Society of Mechanical Engineers, 345 East 47th Street, New York, N.Y. 10017

- ASME Code ASME Boiler and Pressure Code: Section I, Power Boilers; Section II, Material Specifications; Section VIII, Pressure Vessels; Section IX, Welding and Brazing Qualifications.
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