Because these networks may represent very large loads, their size and capacity may have to be limited to such values as can be successfully handled by the generating or other power sources should they become entirely deenergized for any reason. When they are deenergized for any length of time, the inrush currents are very large, as diversity among consumers may be lost, and this may be the limiting factor in restricting the size and capacity of such networks.

Voltages

For all types of service, primary voltages are becoming higher. Original feeder primary voltages of about 1000 V have climbed to nominal 2400, 4160, 7620, 13,800, 23,000, and 46,000 V. Moreover, primary feeders that originally operated as single-phase and two-phase circuits are all now essentially three-phase circuits; even those originally operated as delta ungrounded circuits are now converted to wye systems, with their neutral common to the secondary neutral conductor and grounded.

Secondary voltages have changed from nominal 110/220 V single-phase values to those now operating at 120/240 V single-phase and 120/208 or 120/240 V for three-phase circuits, the 120-V utilization being applied to lighting and small-motor loads while the 208- and 240-V three-phase values are applied to larger-motor loads. More recently, secondary systems have employed utilization voltage values of 277 and 480 V, with fluorescent lighting operating single-phase at 277 V and larger motors operating at a three-phase 480 V. To supply some lighting and small motors single-phase at 120 V, autotransformers of small capacity are employed to step down the 277 V to 120 V.

Secondary voltages and connections will be explored further in discussing transformers and transformer connections.

OVERHEAD VERSUS UNDERGROUND

Although the original distribution system pioneered by Thomas Edison was a direct current low-voltage system installed underground, the widespread expansion of electric systems was based principally on the adoption of alternating current (through the application of transformers) and the very economic overhead type of construction.

While the chief limitation to the adoption of underground systems is economic, there are other reasons that argue against its selection. The necessity for ducts, for manholes, and for cables that require expensive insulation and lead sheaths, short pulls, and a relatively large number of splices, and the special requirements to make equipment waterproof and safe for installation underground all tend to make investment costs several times as great as for overhead systems of comparable characteristics.

Where loads become so great, however, that the number of pole lines and the congestion of conductors on such lines become impractical from safety, operational, and appearance viewpoints, there is no alternative but to place the lines underground. In such areas, traffic conditions are usually so severe that difficulty is experienced in building and maintaining overhead systems; moreover, the heavy traffic itself presents additional hazards from vehicles striking the poles.

While an underground system is not exposed to damage and interruptions from storms, traffic, etc., on the other hand, when trouble does occur, it is very much more difficult and time-consuming to locate and repair than in the overhead system. For this reason, additional provisions and expenditures are made for maintaining service reliability; these include duplicate facilities, throwover schemes, networks, etc. Also, the lesser ability for heat radiation in an underground system does not permit the loading and overloading of conductors and equipment possible with overhead systems.

With plastics taking over the functions of insulation and sheathing in underground cables, and the ability of these materials to be buried directly in the ground, the economic advantage of overhead systems, though still favorable, is markedly reduced. The recent greater emphasis on environment (appearance) also has contributed to a greater pressure for underground installations. Overhead systems will, however, prevail to a very great extent for some time, and will be in almost exclusive use in rural areas.

ELECTRICAL DISTRIBUTION ENGINEERING

2ND EDITION

by

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Published by
THE FAIRMONT PRESS, INC.
700 Indian Trail
Lilburn, GA 30247

Library of Congress Cataloging-in-Publication Data

Pansini, Anthony J.
Electrical distribution engineering / by Anthony J. Pansini. --
2nd ed.
p. cm.
Includes index.
ISBN 0-88173-121-8
1. Electric power distribution. I. Title.
TK3001.P28 1991 621.319--dc20 91-19393
CIP

Electrical Distribution Engineering / By Anthony J. Pansini.
2nd Edition.

Printed in the United States of America

10 9 8 7 6 5 4 3 2

ISBN 0-88173-121-8 FP

ISBN 0-13-251133-9 PH

While every effort is made to provide dependable information, the publisher, authors, and editors cannot be held responsible for any errors or omissions.

Distributed by Prentice-Hall, Inc.
A Simon & Schuster Company
Englewood Cliffs, NJ 07632

Prentice-Hall International (UK) Limited, London
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Prentice-Hall Canada Inc., Toronto
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Prentice-Hall of Japan, Inc., Tokyo
Simon & Schuster Asia Pte. Ltd., Singapore
Editora Prentice-Hall do Brasil, Ltda., Rio de Janeiro

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PREFACE TO THE SECOND EDITION

In the decade since the first edition made its appearance, events have caused the electric utility industry to reevaluate its goals as well as its position in society. Technical developments, together with substantial changes in the financial and environmental climates, aggravated by spiralling costs of fuel, have forced utility engineers to seek means of achieving greater efficiency and economy in the planning, design, construction, maintenance and operation of their electrical systems. Their long time philosophy of "reliable service at low cost" no longer adequately interprets the goals of the enterprise. While still an important incentive, engineers must pay greater attention to the financial and social problems affecting the society of which they are a part. This second edition discusses the changes that affect the distribution systems.

Distribution engineers have had to expand their scope and responsibilities beyond the traditional mechanical, electrical and economic considerations. Their new responsibilities now encompass the consumer's operations and intrude into the fields of generation and system operations as well as in that of public relations. The closer cooperation between distribution engineers and consumers' consultants has resulted in an effective amalgamation of the two disciplines.

In determining the physical plant necessary to supply consumers loads, distribution engineers not only meet the electrical and mechanical requirements according to Kelvin's Law, but must modify them to meet the constraints imposed by the availability of financial resources. And further modification that may be necessary to meet the environmental demands, varying from area to area, that must be met to maintain that priceless commodity in business dealings, the good will of the consumer, the community and the general public.

Like almost every other industry, the utility industry has felt the shock waves generated by the explosive developments in the world of electronics and computers.

PART ONE

THE DISTRIBUTION SYSTEM

CHAPTER 1

THE DISTRIBUTION SYSTEM: DESCRIPTION

Although there is no "typical" electric power system, a diagram including the several components that are usually to be found in the makeup of such a system is shown in Fig. 1-1; particular attention should be paid to those elements which will make up the component under discussion, the distribution system.

While the energy flow is obviously from the power generating plant to the consumer, it may be more informative for our purposes to reverse the direction of observation and consider events from the consumer back to the generating source.

Energy is consumed by users at a nominal utilization voltage that may range generally (in the United States) from 110 to 125 V, and from 220 to 250 V (for some large commercial and industrial users, the nominal figures are 277 and 480 V). It flows through a metering device that determines the billing for the consumer, but which may also serve to obtain data useful later for planning, design, and operating purposes. The metering equipment usually includes a means of disconnecting the consumer from the incoming supply should this become necessary for any reason.

The energy flows through conductors to the meter from the secondary mains (if any); these conductors are referred to as the consumer's *service*, or sometimes also as the *service drop*.

Several services are connected to the secondary mains; the secondary mains now serve as a path to the several services from the distribution transformers which supply them.

At the transformer, the voltage of the energy being delivered is reduced to the utilization voltage values mentioned earlier from higher *primary* line voltages that may range from 2200 V to as high as 46,000 V.

The transformer is protected from overloads and faults by fuses or so-called

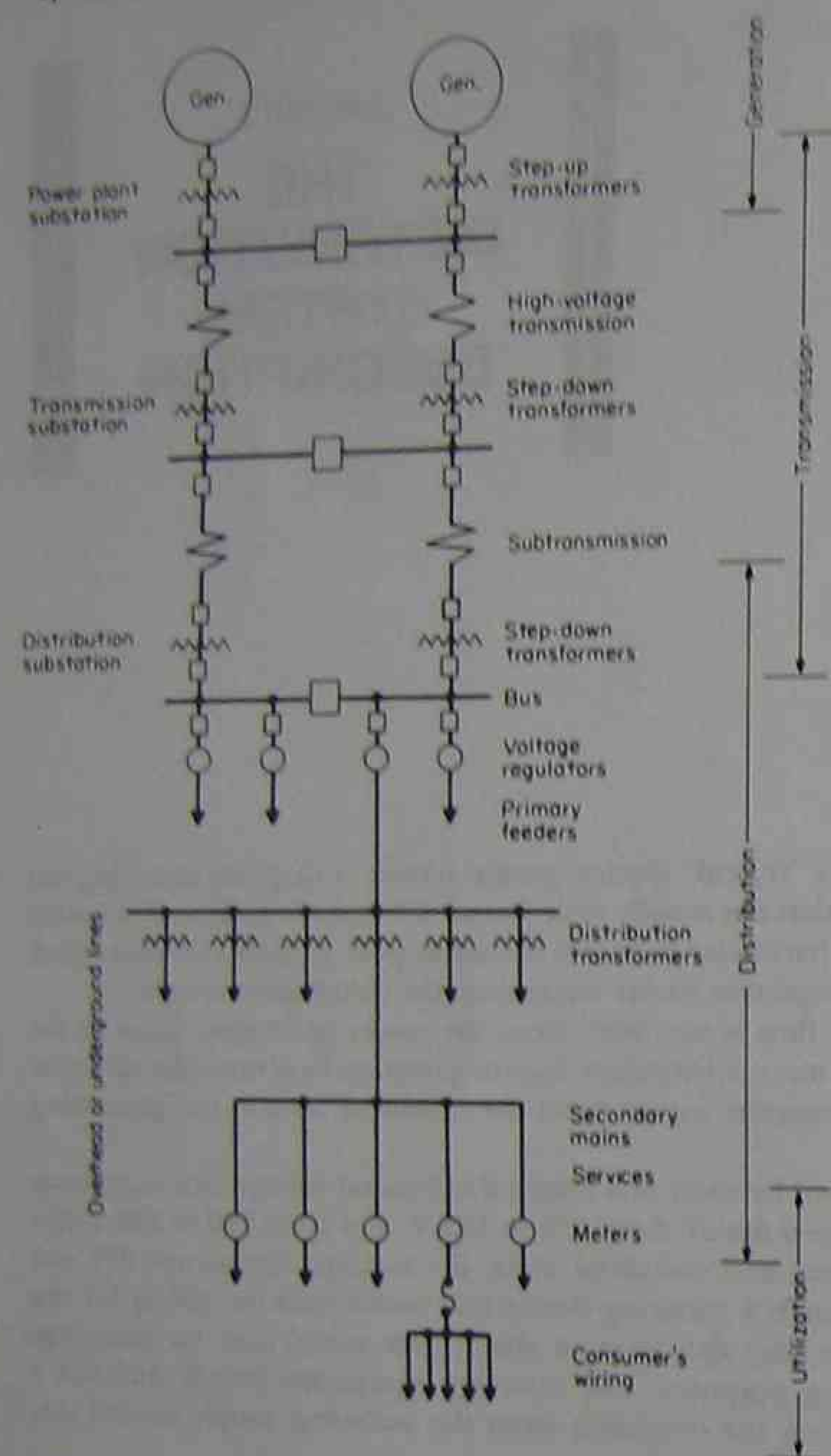


FIG. 1-1 Typical electric system showing operational divisions. Note overlap of divisions.

weak links on the high-voltage side; the latter also usually include circuit-breaking devices on the low-voltage side. These operate to disconnect the transformer in the event of overloads or faults. The circuit breakers (where they exist) on the secondary, or low-voltage, side operate only if the condition is caused by faults or overloads in the secondary mains, services, or consumers' premises; the primary fuse or weak link in addition operates in the event of a failure within the transformer itself.

If the transformer is situated on an overhead system, it is also protected from lightning or line voltage surges by a surge arrester, which drains the voltage surge to ground before it can do damage to the transformer.

The transformer is connected to the primary circuit, which may be a lateral or spur consisting of one phase of the usual three-phase primary main. This is done usually through a *line* or *sectionalizing fuse*, whose function is to disconnect the lateral from the main in the event of fault or overload in the lateral. The lateral conductors carry the sum of the energy components flowing through each of the transformers, which represent not only the energy used by the consumers connected thereto, but also the energy lost in the lines and transformers to that point.

The three-phase main may consist of several three-phase branches connected together, sometimes through other line or sectionalizing fuses, but sometimes also through switches. Each of the branches may have several single-phase laterals connected to it through line or sectionalizing fuses.

Where single-phase or three-phase overhead lines run for any considerable distance without distribution transformer installations connected to them, surge arresters may be installed on the lines for protection, as described earlier.

Some three-phase laterals may sometimes also be connected to the three-phase main through *circuit reclosers*. The recloser acts to disconnect the lateral from the main should a fault occur on the lateral, much as a line or sectionalizing fuse. However, it acts to reconnect the lateral to the main, reenergizing it one or more times after a time delay in a predetermined sequence before remaining open permanently. This is done so that a fault which may be only of a temporary nature, such as a tree limb falling on the line, will not cause a prolonged interruption of service to the consumers connected to the lateral.

The three-phase mains emanate from a *distribution substation*, supplied from a *bus* in that station. The three-phase mains, usually referred to as a *circuit* or *feeder*, are connected to the bus through a protective circuit breaker and sometimes a voltage regulator. The voltage regulator is usually a modified form of transformer and serves to maintain outgoing voltage within a predetermined band or range on the circuit or feeder as its load varies. It is sometimes placed electrically in the substation circuit so that it regulates the voltage of the entire bus rather than a single outgoing circuit or feeder, and sometimes along the route of a feeder for partial feeder regulation. The circuit breaker in the feeder acts to disconnect that feeder from the bus in the event of overload or fault on the outgoing or distribution feeder.

The substation bus usually supplies several distribution feeders and carries the sum of the energy supplied to each of the distribution feeders connected to it. In turn, the bus is supplied through one or more transformers and associated circuit breaker protection. These substation transformers step down the voltage of their supply circuit, usually called the *subtransmission* system, which operates at voltages usually from 23,000 to 138,000 V.

The subtransmission systems may supply several distribution substations and may act as *tie feeders* between two or more substations that are either of the *bulk power* or *transmission* type or of the distribution type. They may also be tapped to supply some distribution load, usually through a circuit breaker, for a single consumer, generally an industrial plant or a commercial consumer having a substantially large load.

The transmission or bulk power substation serves much the same purposes as a distribution substation, except that, as the name implies, it handles much greater amounts of energy: the sum of the energy individually supplied to the subtransmission lines and associated distribution substations and losses. Voltages at the transmission substations are reduced to outgoing subtransmission line voltages from transmission voltages that may range from 69,000 to upwards of 750,000 V.

The transmission lines usually emanate from another substation associated with a power generating plant. This last substation operates in much the same manner as other substations, but serves to step up to transmission line voltage values the voltages produced by the generators. Because of material and insulation limitations, generator voltages may range from a few thousand volts for older and smaller units to some 20,000 volts for more recent, larger ones. Both buses and transformers in these substations are protected by circuit breakers, surge arresters, and other protective devices.

In all the systems described, conductors should be large enough that the energy loss in them will not be excessive, nor the loss in voltage so great that normal nominal voltage ranges at the consumers' services cannot be maintained.

In some instances, voltage regulators and capacitors are installed at strategic points on overhead primary circuits as a means of compensating for voltage drops or losses, and incidentally help in holding down energy losses in the conductors.

In many of the distribution system arrangements, some of the several elements between the generating plant and the consumer may not be necessary. In a relatively small area, such as a small town, that is served by a power plant situated in or very near the service area, the distribution feeder may emanate directly from the power plant bus, and all other elements may be eliminated, as indicated in Fig. 1-2. This is perhaps one extreme; in many other instances only some of the other elements may not be necessary; e.g., a similar small area somewhat distant from the generating plant may find it necessary to install a distribution substation supplied by a transmission line of appropriate voltage only.

In the case of areas of high load density and rather severe service reliability requirements, the distribution system becomes more complex and more expensive. The several secondary mains to which the consumers' services are connected may all be connected into a mesh or network. The transformers supplying these

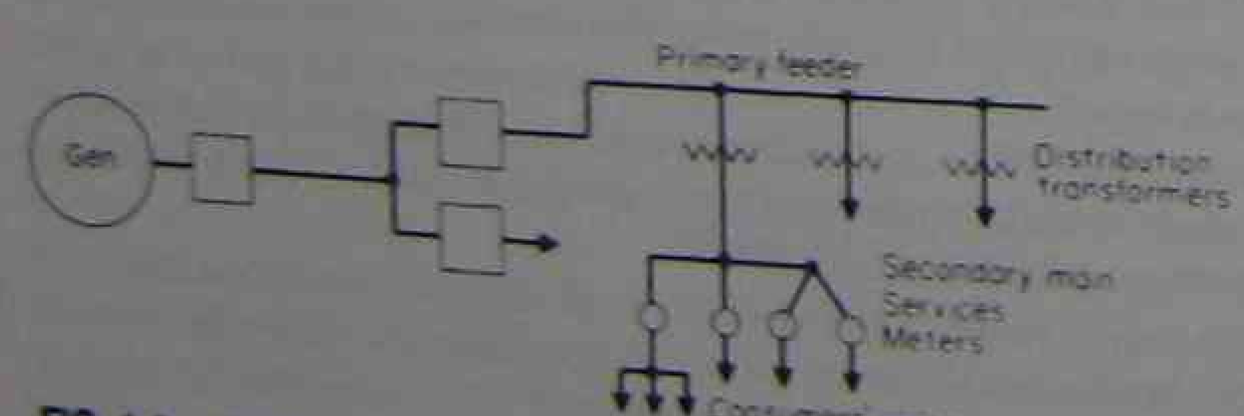


FIG. 1-2 "Abbreviated" electric system.

secondary mains or network are supplied from several different primary feeders, so that if one or more of these feeders is out of service for any reason, the secondary network is supplied from the remaining ones and service to the consumers is not interrupted. To prevent a feeding-back from the energized secondary network through the transformers connected to feeders out of service (thereby energizing the primary and creating unsafe conditions), automatically operated circuit breakers, called *network protectors*, are connected between the secondary network and the secondary of the transformers; these open when the direction of energy flow is reversed.

The two examples cited here are perhaps the two extremes in the design of distribution systems, the first the simplest, the latter the most complex. There are many variations in between these, and the basic ones will be described in their appropriate places.

Only distribution systems, however, will be the subject of further description and discussion in this book. In general, these include the distribution substation, primary feeders, transformers, secondary mains, services, and other elements between the substation and the consumers' points of service.

CHAPTER 2

DISTRIBUTION SYSTEM CONSIDERATIONS

In determining the design of distribution systems, three broad classifications of choices need to be considered:

1. The type of electric system: dc or ac, and if ac, single-phase or polyphase.
2. The type of delivery system: radial, loop, or network. Radial systems include duplicate and throwover systems.
3. The type of construction: overhead or underground.

DESIRED FEATURES

Electrical energy may be distributed over two or more wires. The principal features desired are safety; smooth and even flow of power, as far as is practical; and economy.

Safety

The safety factor usually requires a voltage low enough to be safe when the electric energy is utilized by the ordinary consumer.

Smooth and Even Flow of Power

A steady, uniform, nonfluctuating flow of power is highly desirable, both for lighting and for the operation of motors for power purposes. Although a direct current system fills these requirements admirably, it is limited in the distance over which it can economically supply power at utilization voltage.

Alternating current systems deliver power in a fluctuating manner following the cyclic variations of the voltage generated. Such fluctuations of power are not objectionable for heating, lighting, and small motors, but are not entirely satisfactory for the operation of some devices such as large motors, which must deliver mechanical power steadily and therefore require a steady input of electric power. This may be done by supplying electricity to the motors by two or three circuits, each supplying a portion of the power, whose fluctuations are purposely made not to occur at the same time, thereby decreasing or damping out the effect of the fluctuations. These two or three separate alternating current circuits (each often referred to as a single-phase circuit) are combined into one polyphase (two- or three-phase) circuit. The voltages for polyphase circuits or systems are supplied from polyphase generators.

Economy

The third factor requires the minimum use of conductors for delivery of electric energy. This usually calls for the use of higher voltages where conditions permit and the elimination of some conductors by providing a common return path for two or more circuits.

TYPES OF ELECTRIC SYSTEMS

Direct Current Systems

Direct current systems usually consist of two or three wires. Although such distribution systems are no longer employed, except in very special instances, older ones now exist and will continue to exist for some time. Direct current systems are essentially the same as single-phase ac systems of two or three wires; the same discussion for those systems also applies to dc systems.

Alternating Current Single-Phase Systems

Two-Wire Systems The simplest and oldest circuit consists of two conductors between which a relatively constant voltage is maintained, with the load connected between the two conductors; refer to Fig. 2-1.

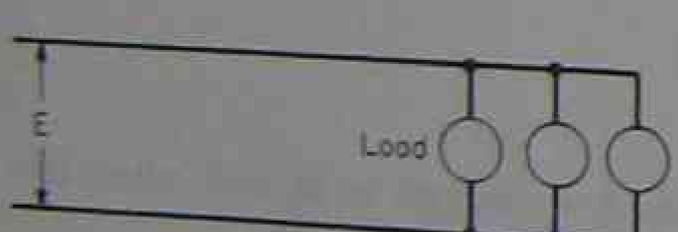


FIG. 2-1 AC single-phase two-wire system.

In almost all cases, one conductor is grounded. The grounding of one conductor, usually called the *neutral*, is basically a safety measure. Should the live conductor come in contact accidentally with the neutral conductor, the voltage of the live conductor will be dissipated throughout a relatively large body of earth and thereby rendered harmless.

In calculating power (I^2R) losses in the conductors, the resistance of the conductors must be considered. In the case of the neutral conductor, because the ground, in parallel with the conductor, reduces the effective resistance, the "return" current will divide between the conductor and ground in inverse proportion to their resistances. Thus the I^2R loss in the neutral conductor will be lower than that in the live conductor; the I^2R loss in the earth may, for practical purposes, be disregarded.

In calculating voltage drop in the circuits, both the resistance and reactance of the two conductors must be considered. (In dc circuits, reactance does not exist during normal flow of current.) This combination of reactance and resistance, known as impedance, is measured in ohms (Ω). Because the current in the grounded neutral conductor may be less than the current in the live conductor, the voltage drop in the neutral conductor may also be less.

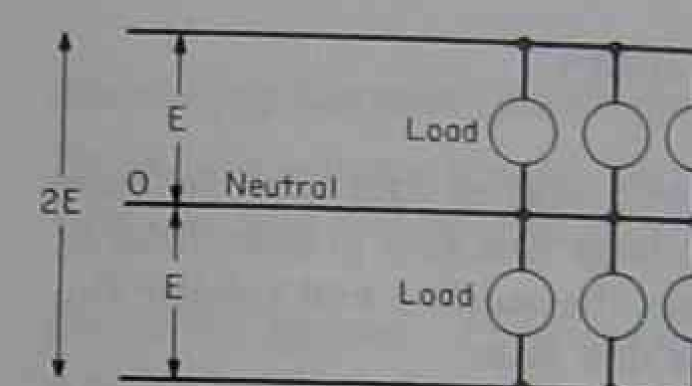


FIG. 2-2 AC single-phase three-wire system.

Three-Wire Systems Essentially the three-wire system is a combination of two two-wire systems with a single wire serving as the neutral of each of the two-wire systems. At a given instant, if one of the live conductors is E volts (say 120 V) "above" the neutral, the other live conductor will be E volts (120 V) "below" the neutral, and the voltage between the two live (or outside) conductors will be $2E$ (240 V). Refer to Fig. 2-2.

If the load is balanced between the two (two-wire) systems, the common neutral conductor carries no current and the system acts as a two-wire system at twice the voltage of the component system; each unit of load (such as a lamp) of one component system is in series with a similar unit of the other system. If the load is not balanced, the neutral conductor carries a current equal to the difference between the currents in the outside conductors. Here again, the neutral conductor is usually connected to ground.

For a balanced system, power loss and voltage drop are determined in the same way as for a two-wire circuit consisting of the outside conductors; the neutral is neglected.

Where the loads on the two portions of the three-wire circuit are unbalanced, voltages at the utilization or receiving ends may be different. These are shown schematically in Fig. 2-3. Let the distance between the dashed lines represent the voltage. There will be a voltage drop, with reference to the neutral, in each of the conductors 1 and 2. The neutral conductor will carry the difference in currents, that is, $I_2 - I_1$, or I_n. This current in the neutral conductor will produce a voltage drop in that conductor, as indicated in Fig. 2-3. The result will be a

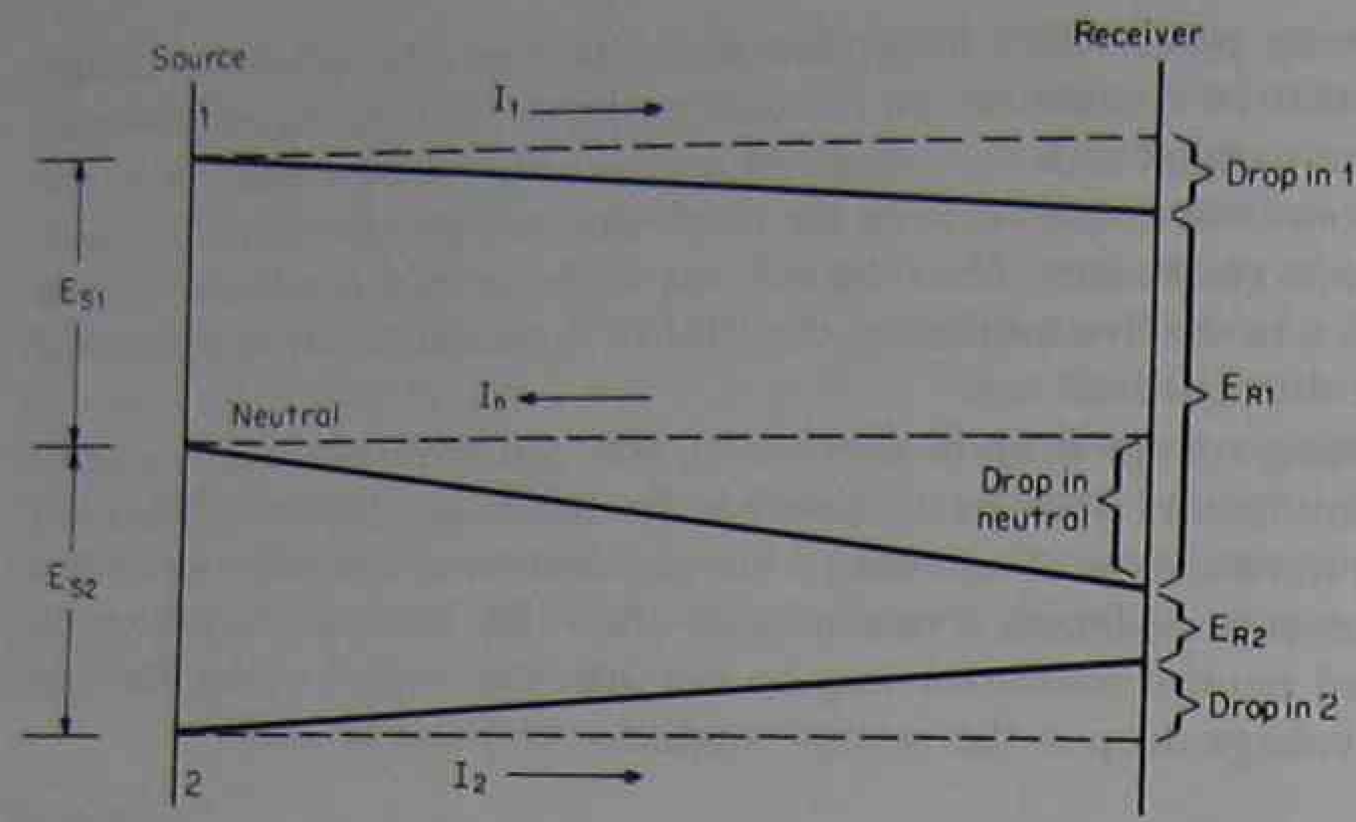


FIG. 2-3 Unbalanced load—single-phase three-wire system.

much larger drop in voltage between conductor 2 and neutral than between conductor 1 and neutral. If the unbalance is so large that I_n is greater than I_1, the receiving end voltage E_{R1} will be greater than the sending end voltage E_{S1}, and there will be an actual rise in voltage across that side.

The limiting case occurs when $I_1 = 0$ and $I_n = I_2$. In that case, all the load is carried on side 2; the rise in voltage on side 1 will be half as much as the drop in voltage on the loaded side 2. However, if an equal load is now added to side 1, the loads in both parts of the circuit will be balanced and I_n will equal 0. The drop in voltage between conductor 2 and the neutral will be reduced to half that obtained with the load on side 2 only, although the load now supplied is doubled.

Voltage drops in the conductors will depend on the currents flowing in them and their impedances. The power loss in each conductor (I^2R) will depend on the current flowing in it and its resistance.

In all of this discussion, the size of the neutral has been assumed to be the same as the live or outside conductors.

Series Systems The series type of circuit is used chiefly for street lighting and, although being rapidly replaced by multiple-circuit lighting, nevertheless still exists in substantial numbers. It consists of a single-conductor loop in which the current is maintained at a constant value, the loads connected in series; see Fig. 2-4. The voltage between the conductors at the source or at any other point depends on the amount of load connected beyond that point. The voltage at the source is equal to the vectorial sum of the voltages across the various loads and the voltage drop in the conductor.

The voltage drop in each section of the conductor depends on the current flowing in it (which is constant in value) and the impedance of that section of the conductor.

The power supplied the circuit equals the sum of the power for the individual units of load and the line losses. Power loss in each section of the conductor will

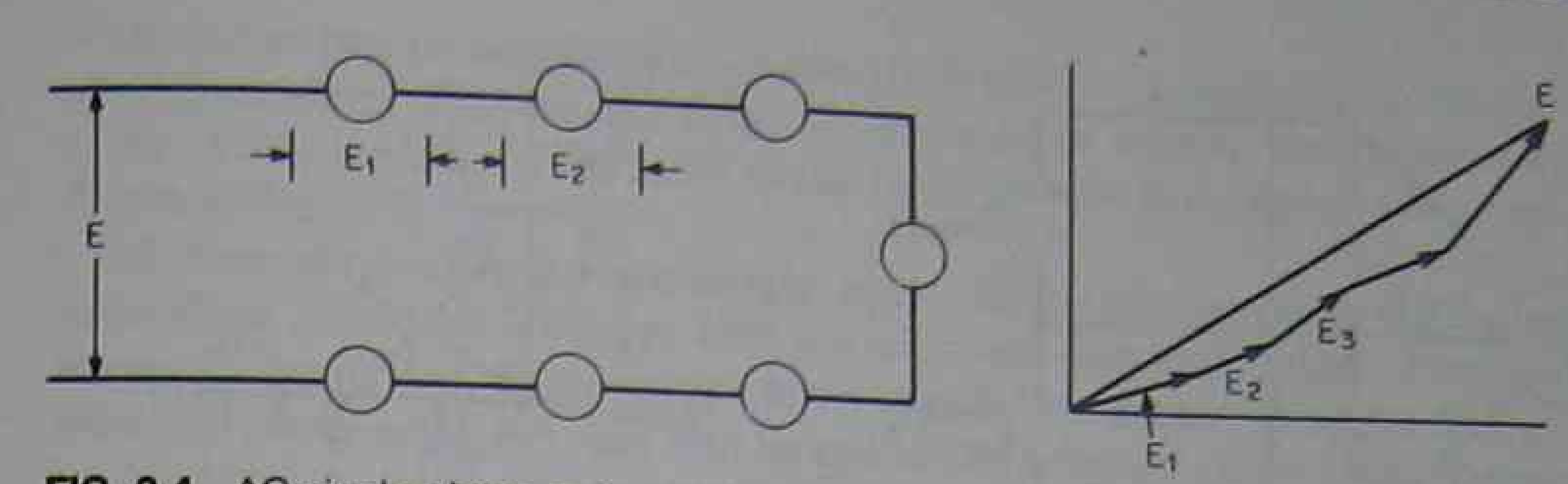


FIG. 2-4 AC single-phase series system and voltage vector diagram.

depend on the current (squared) and the resistance of that section of the conductor.

Alternating Current Two-Phase Systems

Two-phase systems are rapidly becoming obsolete, but a good number of them exist and may continue to exist for some time.

Four-Wire Systems The four-wire system consists of two single-phase two-wire systems in which the voltage in one system is 90° out of phase with the voltage in the other system, both usually supplied from the same generator. Refer to Fig. 2-5.

In determining the power, power loss, and voltage drops in such a system, the values are calculated as for two separate single-phase two-wire systems.

Three-Wire Systems The three-wire system is equivalent to a four-wire two-phase system, with one wire (the neutral) made common to both phases; refer to Fig. 2-6. The current in the outside or phase wires is the same as in the four-wire system; the current in the common wire is the vector sum of these currents but opposite in phase. When the load is exactly balanced in the two phases, these currents are equal and 90° out of phase with each other and the resultant neutral current is equal to $\sqrt{2}$ or 1.41 times the phase current.

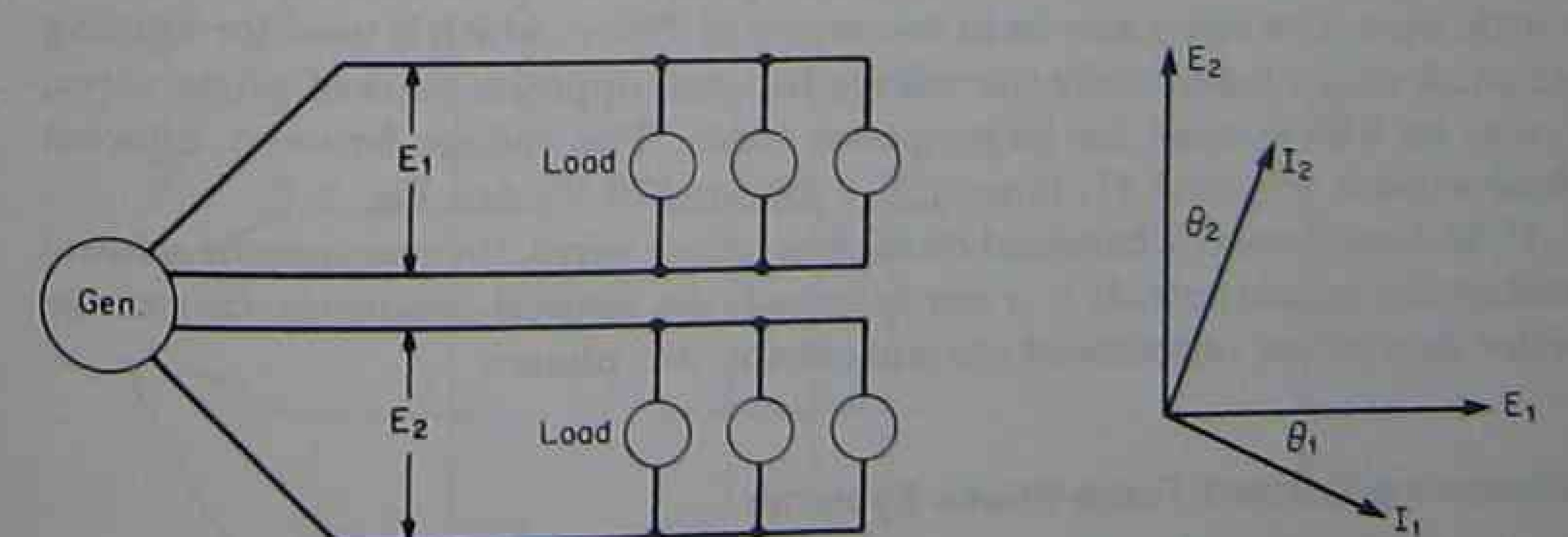


FIG. 2-5 AC two-phase four-wire system and vector diagram.

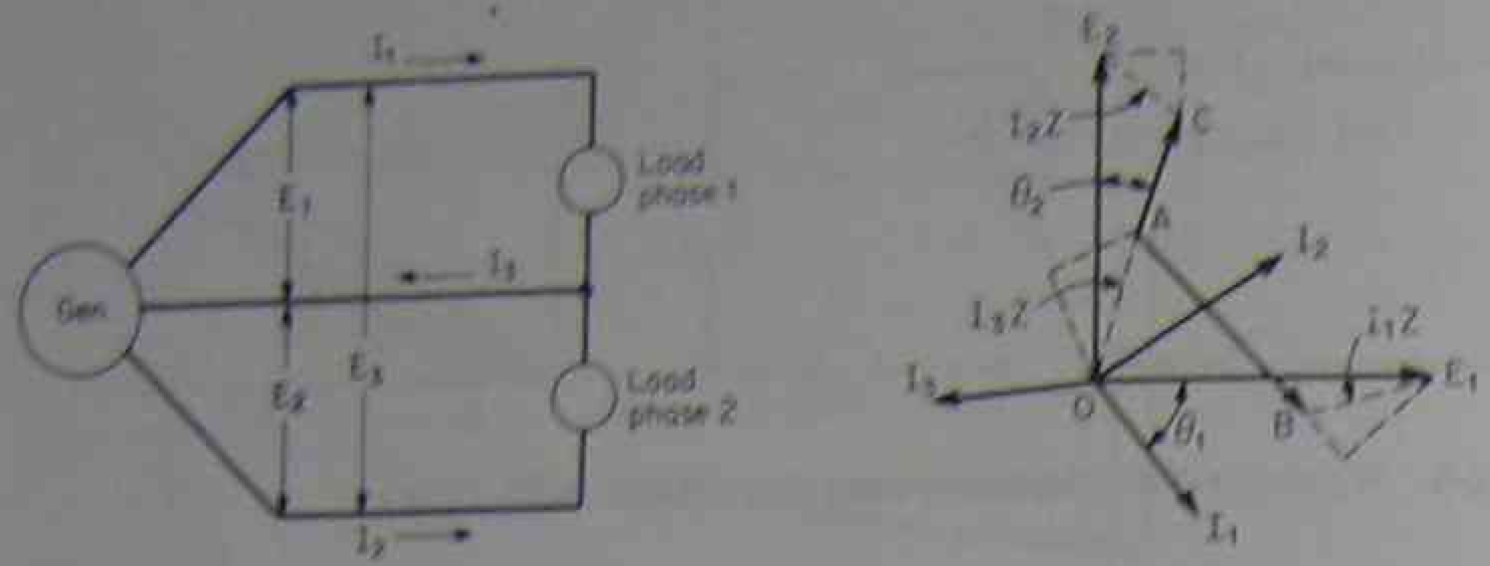


FIG. 2-6 AC two-phase three-wire system and vector diagram.

The voltage between phase wires and common wire is the normal phase voltage, and, neglecting the difference in neutral IR drop, the same as in the four-wire system. The voltage between phase wires is equal to $\sqrt{2}$ or 1.41 times that voltage.

The power delivered is equal to the sum of the powers delivered by the two phases. The power loss is equal to the sum of the power losses in each of the three wires.

The voltage drop is affected by the distortion of the phase relation caused by the larger current in the third or common wire. In Fig. 2-6, if E_1 and E_2 are the phase voltages at the source and I_1 and I_2 the corresponding phase currents (assuming balanced loading), I_3 is the current in the common wire. The voltage (IZ) drops in the two conductors, subtracted vectorially from the source voltages E_1 and E_2, give the resultant voltages at the receiver of AB for phase 1 and AC for phase 2. The voltage drop numerically is equal to $E_1 - AB$ for phase 1, and $E_2 - AC$ for phase 2. It is apparent that these voltage drops are unequal and that the action of the current in the common wire is to distort the relations between the voltages and currents—the effect shown in Fig. 2-6 is exaggerated for illustration.

Five-Wire Systems The five-wire system is equivalent to a two-phase four-wire system with the midpoint of both phases brought out and joined in a fifth wire. The voltage is of the same value from any phase wire to the common neutral, or fifth, wire. The value may be in the nature of 120 V, which is used for lighting and small motor loads, while the voltage between opposite pairs of phase wires, E, may be 240 V, used for larger-power loads. The voltage between adjacent phase wires is $\sqrt{2}$, or 1.41, times 120 V (about 170 V). See Fig. 2-7.

If the load is exactly balanced on all four phase wires, the common or neutral wire carries no current. If it is not balanced, the neutral conductor carries the vector sum of the unbalanced currents in the two phases.

Alternating Current Three-Phase Systems

Four-Wire Systems The three-phase four-wire system is perhaps the most widely used. It is equivalent to three single-phase two-wire systems supplied from the same generator. The voltage of each phase is 120° out of phase with the voltages

of the other two phases, but one conductor is used as a common conductor for all of the system. The current I_n in that common or neutral conductor is equal to the vector sum of the currents in the three phases, but opposite in phase, as shown in Fig. 2-8.

If these three currents are nearly equal, the neutral current will be small, since these phase currents are 120° out of phase with each other. The neutral is usually grounded. Single-phase loads may be connected between one phase wire and the neutral, but may also be connected between phase wires if desired. In this latter instance, the voltage is $\sqrt{3}$ or 1.73 times the line-to-neutral voltage E. Three-phase loads may have each of the separate phases connected to the three phase conductors and the neutral, or the separate phases may be connected to the three phase conductors only.

Power delivered is equal to the sum of the powers in each of the three phases. Power loss is equal to the sum of the I^2R losses in all four wires.

The voltage drop in each phase is affected by the distortion of the phase relations due to voltage drop caused by the current in the neutral conductor. This is not so, however, when the neutral conductor is grounded at both the sending and receiving ends, in which case the neutral drop is theoretically zero, the current returning through ground. The voltage drop may be obtained vectorially by applying the impedance drop of each phase to its voltage. The neutral point is shifted from O to A by the voltage drop in the neutral conductor and the resulting voltages at the receiver are shown by E_{1R}, E_{2R}, and E_{3R}. The voltage drops in each phase are numerically equal to the difference in length between E_{1S} and E_{1R}, E_{2S} and E_{2R}, and E_{3S} and E_{3R}. The effects of the distortion due to voltage drop in the neutral conductors are exaggerated in Fig. 2-8 for illustration.

Three-Wire Systems If the load is equally balanced on the three phases of a four-wire system, the neutral carries no current and hence could be removed, making a three-wire system. It is not necessary, however, that the load be exactly balanced on a three-wire system.

Considering balanced loads, on a three-phase three-wire system, a three-phase load may be connected with each phase connected between two phase wires—a

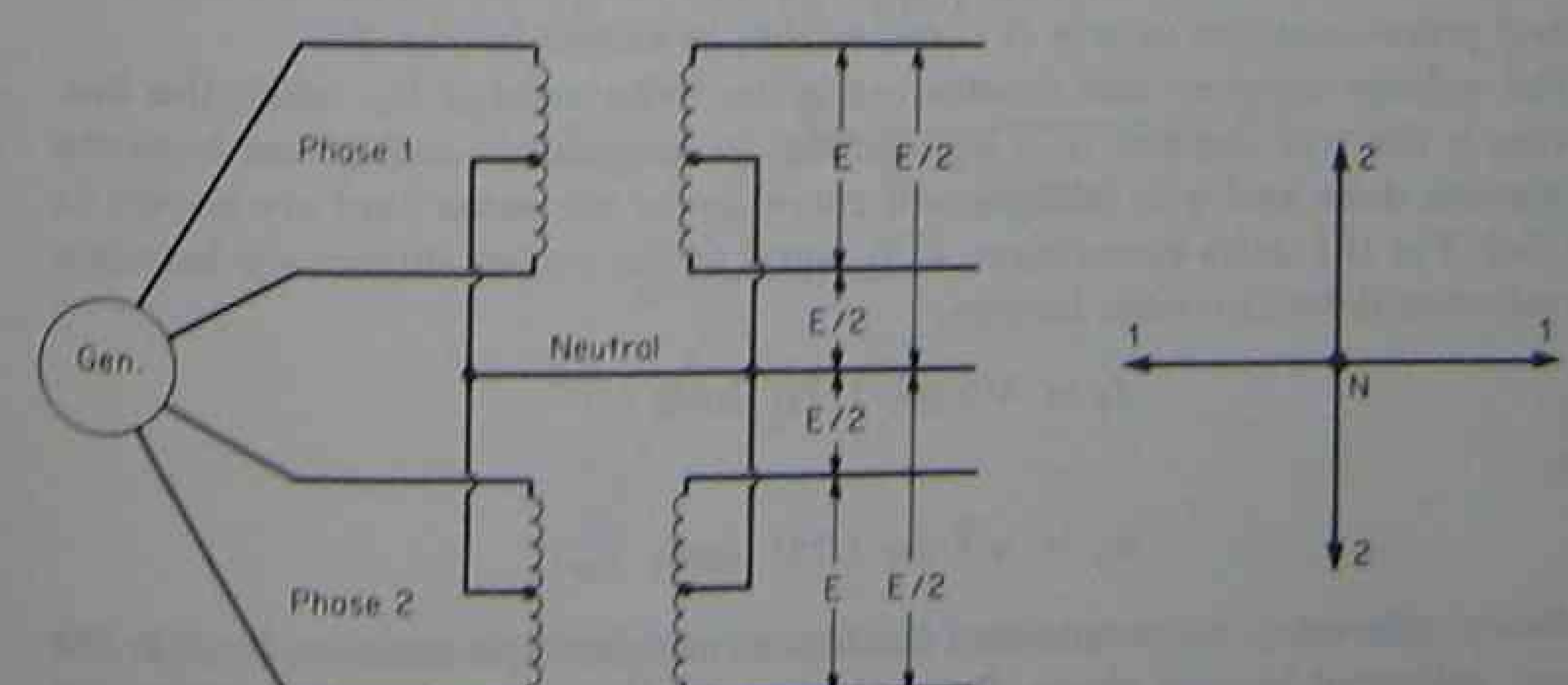


FIG. 2-7 AC two-phase five-wire system and vector diagram.

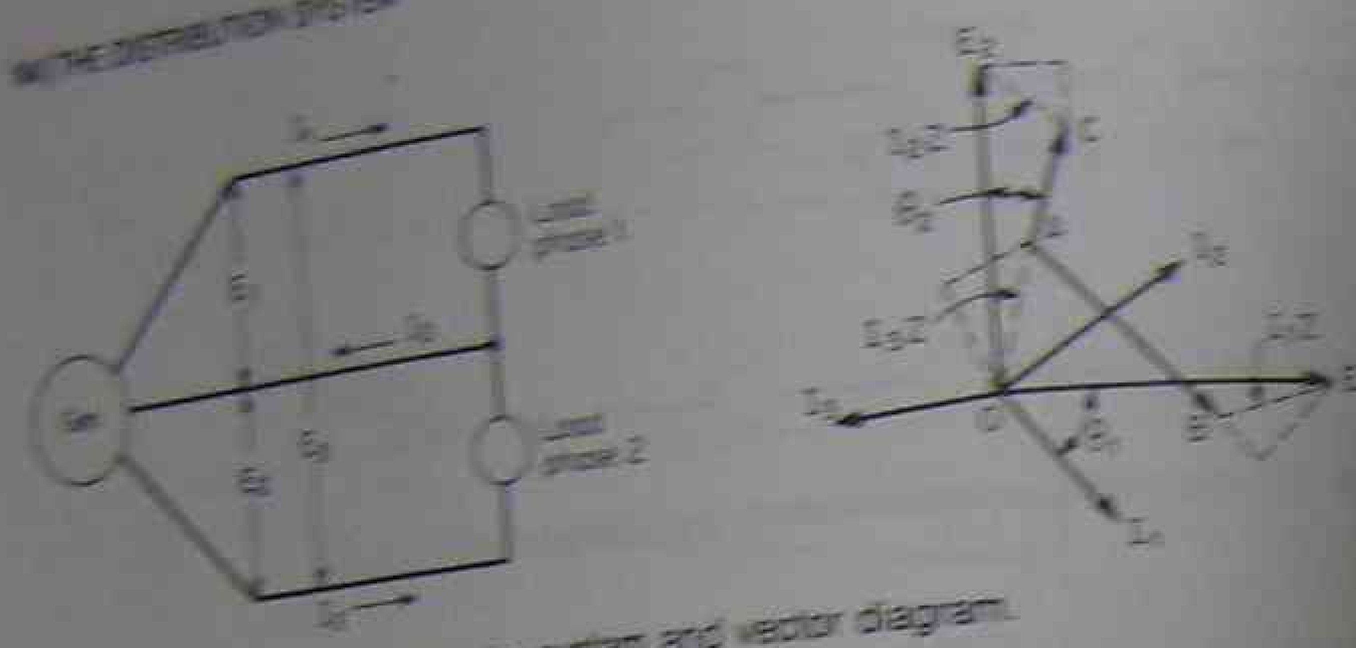


FIG. 2-6 AC two-phase three-wire system and vector diagram.

The voltage between phase wires and common wire is the normal phase voltage, and, neglecting the difference in neutral IR drop, the same as in the four-wire system. The voltage between phase wires is equal to $\sqrt{2}$ or 1.41 times that voltage.

The power delivered is equal to the sum of the powers delivered by the two phases. The power loss is equal to the sum of the power losses in each of the three wires.

The voltage drop is affected by the distortion of the phase relation caused by the larger current in the third or common wire. In Fig. 2-6, if E_1 and E_2 are the phase voltages at the source and I_1 and I_2 the corresponding phase currents (assuming balanced loading), I_3 is the current in the common wire. The voltage (IZ) drops in the two conductors, subtracted vectorially from the source voltages E_1 and E_2, give the resultant voltages at the receiver of AB for phase 1 and A… for phase 2. The voltage drop numerically is equal to $E_1 - AB$ for phase 1, an… $E_2 - AC$ for phase 2. It is apparent that these voltage drops are unequal a… that the action of the current in the common wire is to distort the rela… between the voltages and currents—the effect shown in Fig. 2-6 is exagger… for illustration.

Five-Wire Systems The five-wire system is equivalent to a two-phase fo… system with the midpoint of both phases brought out and joined in a fi… The voltage is of the same value from any phase wire to the common… or fifth, wire. The value may be in the nature of 120 V, which is used f… and small motor loads, while the voltage between opposite pairs of p… E_t may be 240 V, used for larger-power loads. The voltage betwe… phase wires is $\sqrt{2}$, or 1.41, times 120 V (about 170 V). See Fig. 2-…

If the load is exactly balanced on all four phase wires, the … wire carries no current. If it is not balanc… vector sum of the unbala…

Alternating Curre…

Four-Wire Syste… … used. It is equi… same generat…

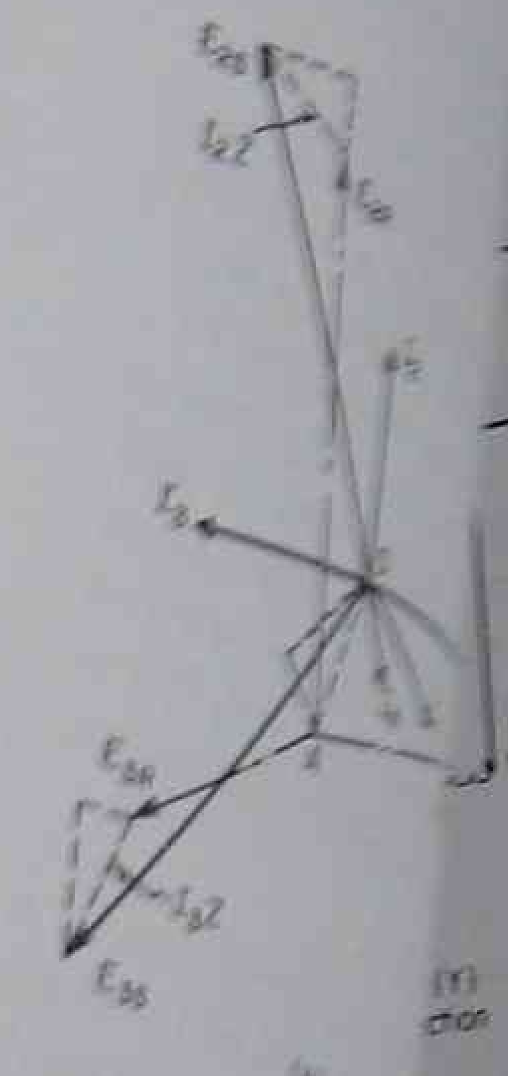


FIG. 2-8 (a) AC three-phase … current vector diagram.

delta (Δ) connection—or … neutral point—the star or w…

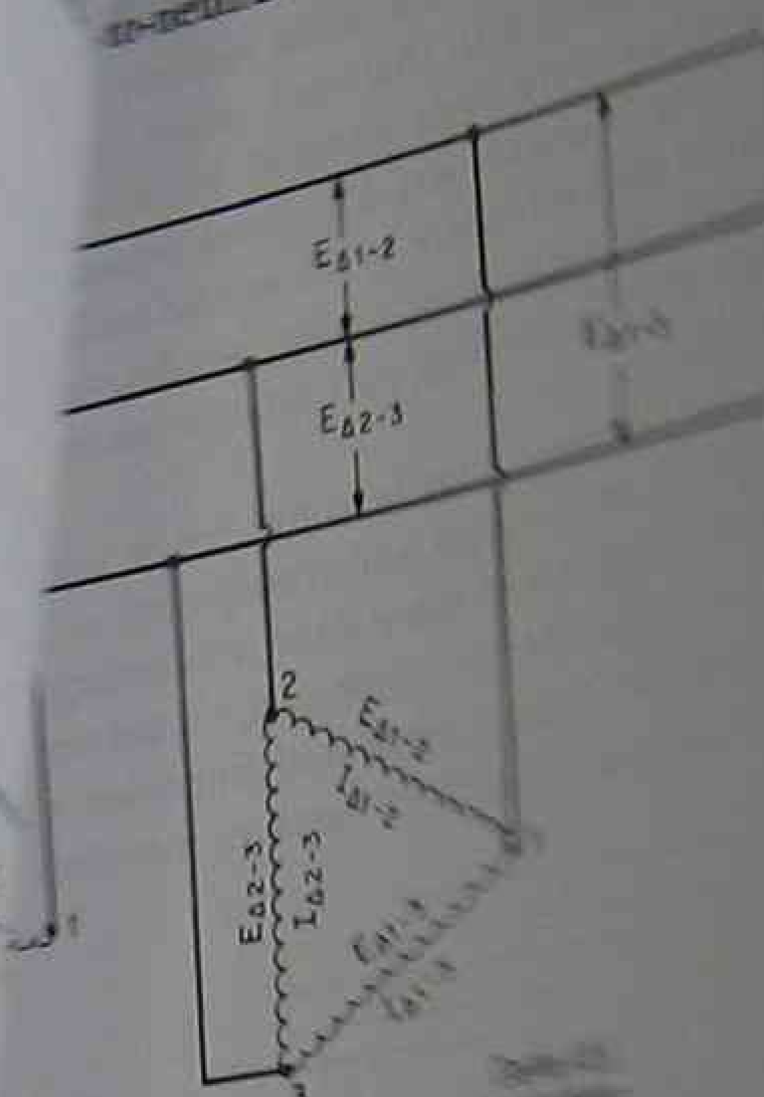
The voltage between lin… current is the wye curren… the various delta and wye volta… Fig. 2-9. For the delta connec… the adjacent delta currents be…

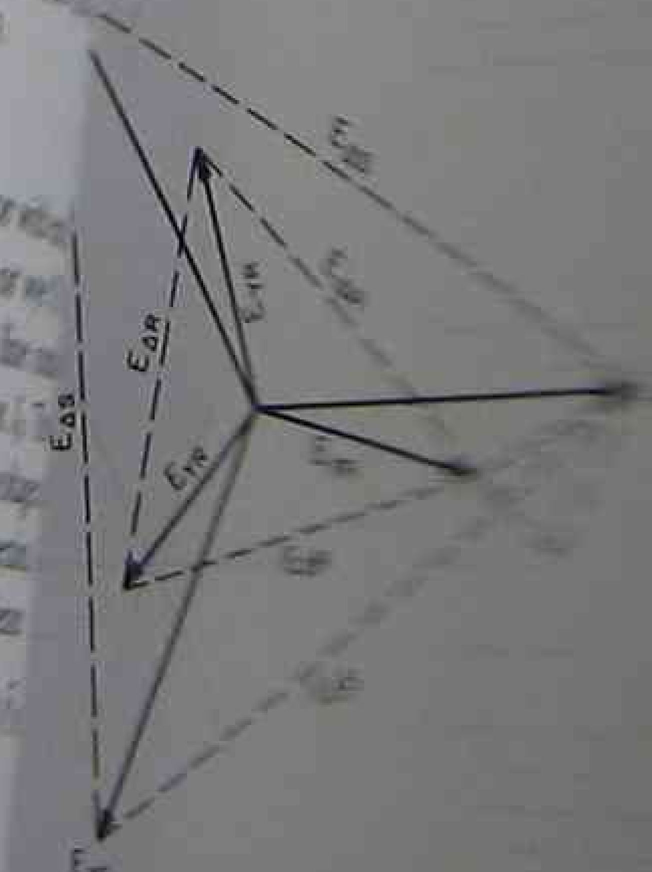
and

Power delivered, when balanced … power delivered by one phase …

…ss, it is 3 times the power loss in …

…d in the wye (Y) voltages, may be … in one conductor vectorially to E_Y, … same thing is done in determining … dered. If $E_{\Delta 1}$ is the voltage between … -to-neutral voltage, the drop due to





…hase three-wire system and …

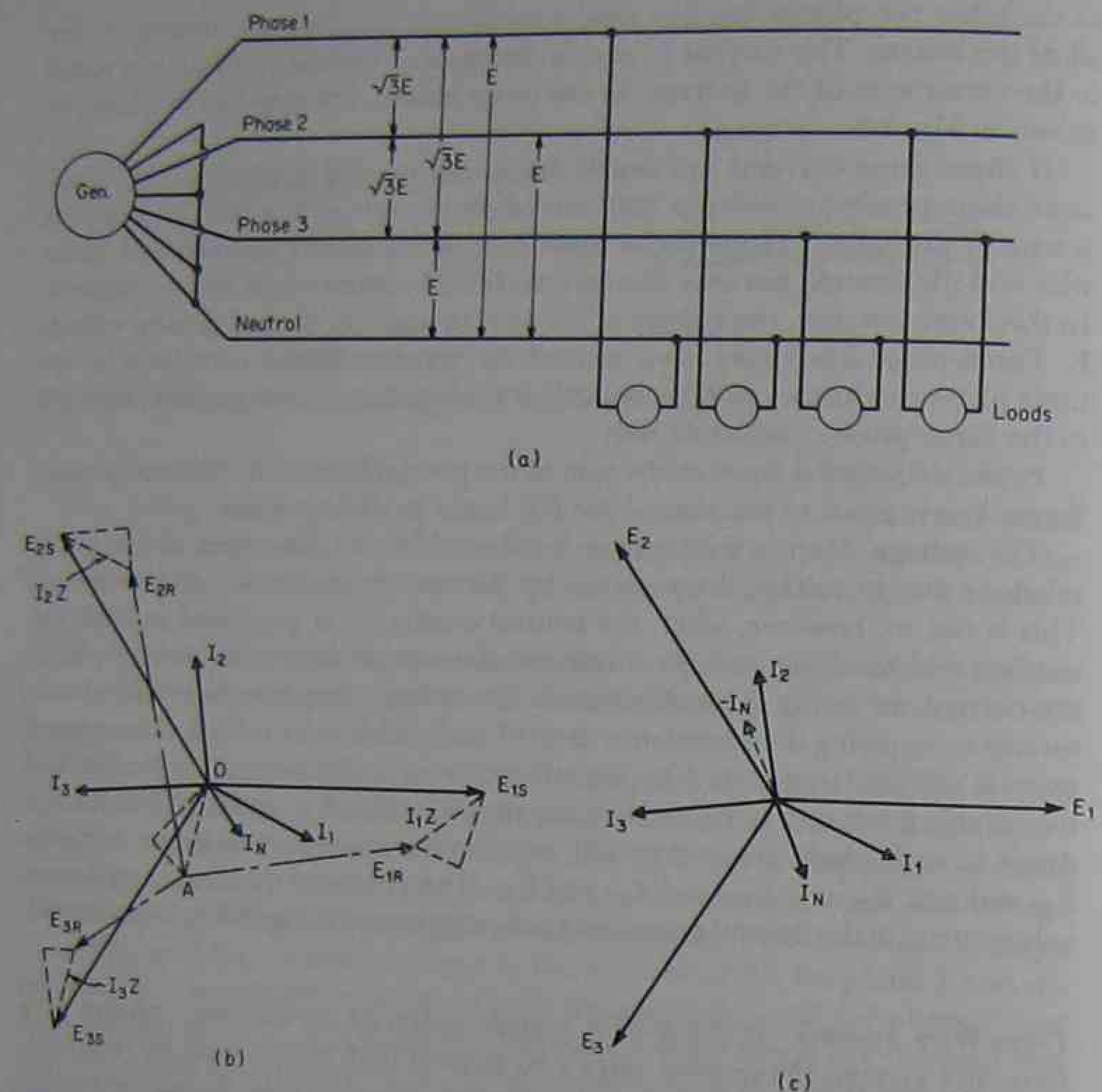


FIG. 2-8 (a) AC three-phase four-wire system; (b) voltage and current vector diagram; (c) current vector diagram.

delta (Δ) connection—or with each phase between one phase wire and a common neutral point—the star or wye (*Y*) connection, as shown in Fig. 2-9.

The voltage between line conductors is the delta voltage E_Δ, while the line current is the wye current I_Y. The relations in magnitude and phase between the various delta and wye voltages and currents for the same load are shown in Fig. 2-9. For the delta connection, I_Y is equal to the vector difference between the adjacent delta currents; hence:

$$I_Y = \sqrt{3} \text{ (or 1.73) times } I$$

and

$$E_\Delta = \sqrt{3} \text{ (or 1.73) times } E_Y$$

Power delivered, when balanced loads are considered, is equal to 3 times the power delivered by one phase. Power loss is equal to the sum of the losses in

each phase, or when balanced conditions exist, it is 3 times the power loss in any one phase.

The voltage drop in each phase, referred to the wye (*Y*) voltages, may be determined by adding the impedance drop in one conductor vectorially to E_Y, when balanced loads are considered. The same thing is done in determining voltages where unbalanced loads are considered. If $E_{\Delta S}$ is the voltage between phases at the source and E_{YS} the phase-to-neutral voltage, the drop due to

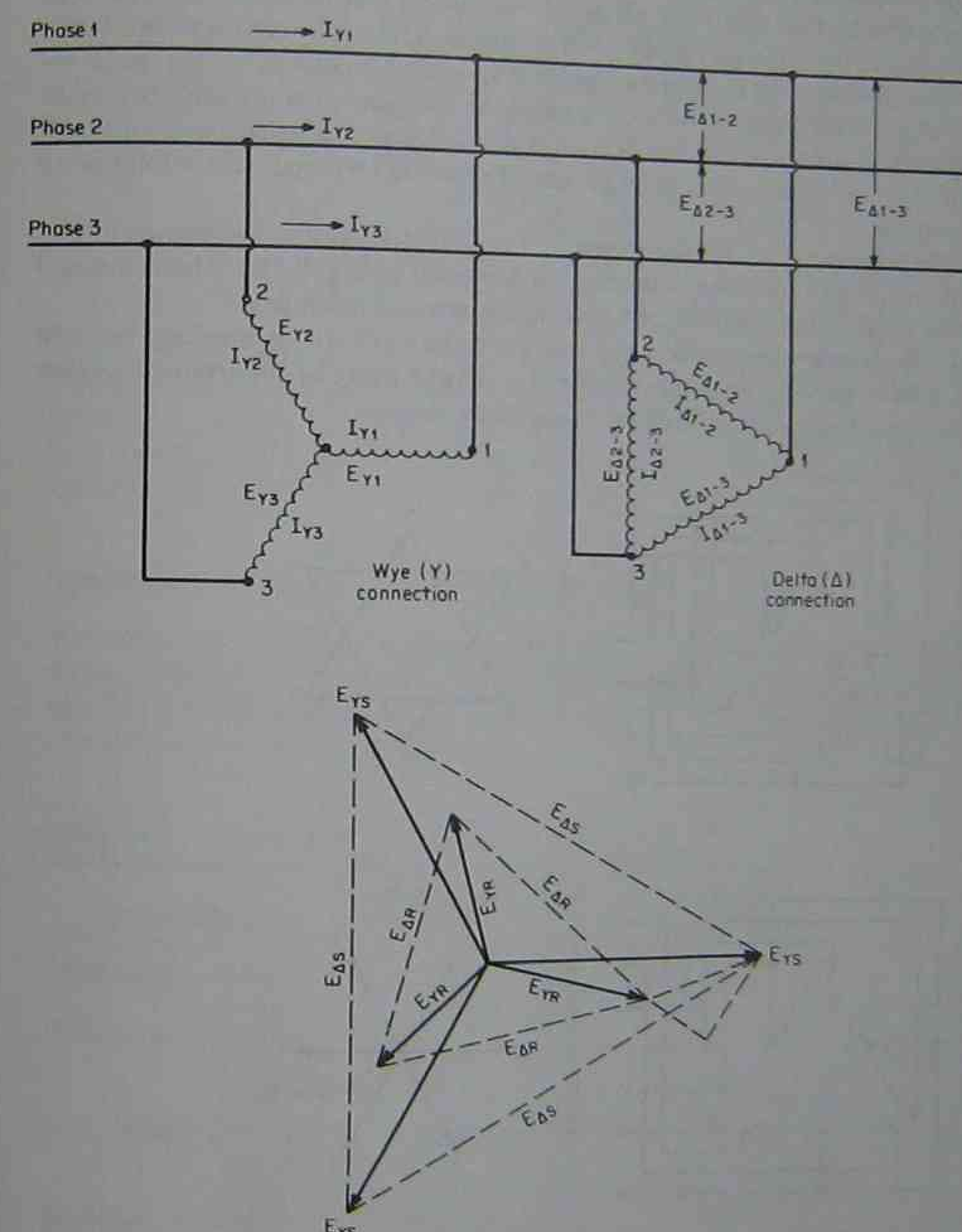


FIG. 2-9 AC three-phase three-wire system and voltage vector diagrams (current vector not shown).

conductor impedance, IZ, is subtracted vectorially from E_{YS} for each of the three phases, and the resulting voltages between phases at the receiving end ($E_{\Delta R}$) are obtained. The effects shown in the vector diagram of Fig. 2-9 are exaggerated for illustration.

Alternating Current Six-Phase Systems

Six-Wire Systems Six-phase systems consist essentially of two three-phase systems connected so that each phase of one system will be displaced 180° with reference to the same phase of the other system. These may consist of two banks of three transformers connected separately with the polarity of one bank reversed with reference to the second bank; or one bank of transformers may be employed, with the secondary windings divided into two equal parts and both ends of each winding part brought out to separate terminals (for a total of 12 terminals).

The windings may be connected in a double-delta fashion as shown in Fig. 2-10*a*, or in a double-wye arrangement as shown in Fig. 2-10*b*. The associated vector diagrams of the voltage relationships are also indicated.

In the double-wye connection, it is not necessary to have the windings brought out to 12 terminals; the neutral connection may be made by connecting together the midtap from each of the three secondary windings.

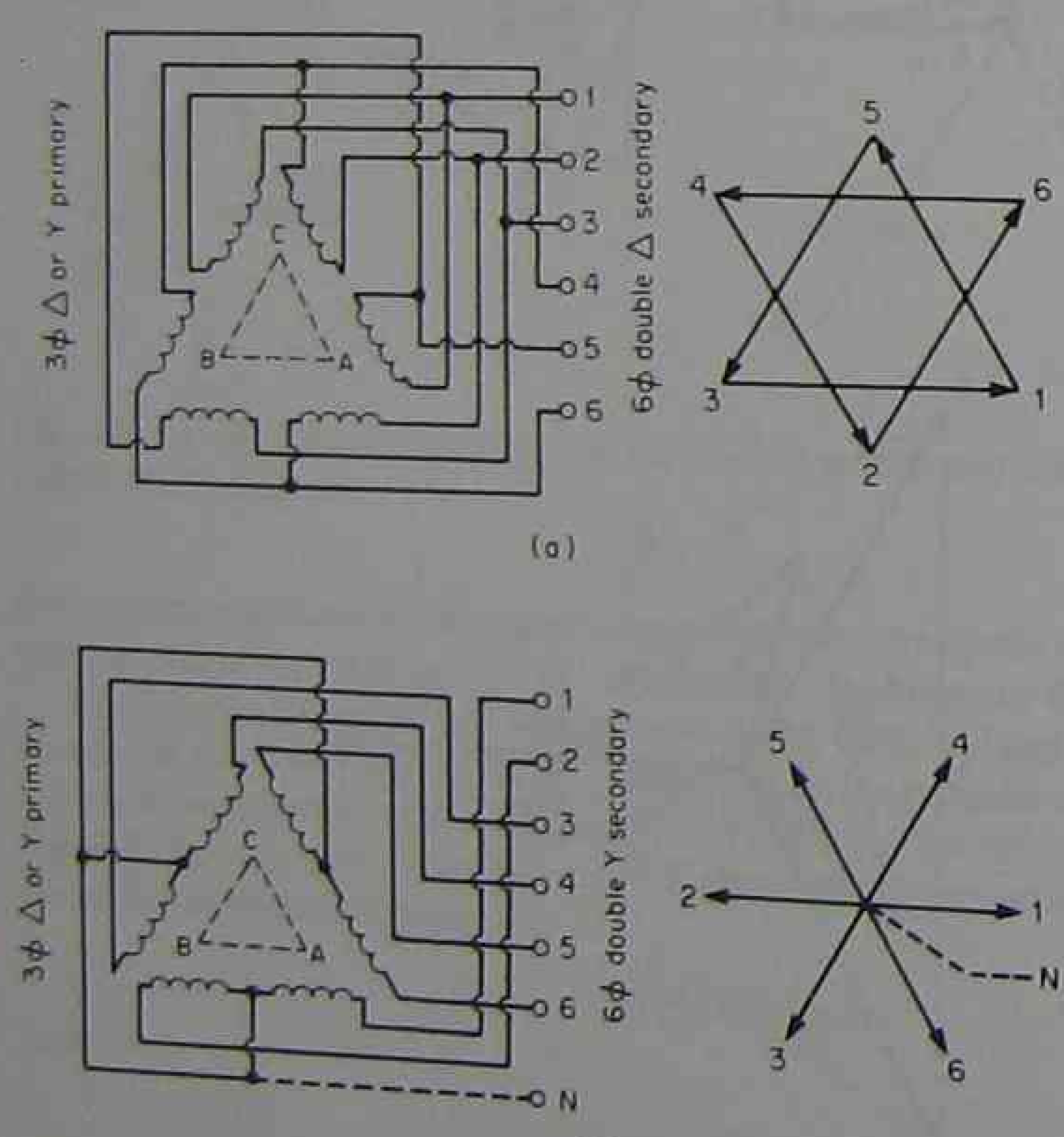


FIG. 2-10 AC six-phase six-wire double-delta system (*a*), AC six-phase six-wire (and seven-wire) double-wye system (*b*), and voltage vector diagrams.

Such systems are almost exclusively used in supplying rectifiers or synchronous converters to serve direct current loads; the synchronous converter also aids in improving power factor on the alternating current supply system.

Seven-Wire Systems A seventh, or neutral, wire may be brought out from the common junction of the double-wye connection, as indicated by the dashed line in Fig. 2-10*b*.

The seven-wire system may be used for distribution purposes, with the neutral connected to other common neutral systems. The disadvantage of the additional conductor is balanced against two major advantages:

1. The ability to serve single-phase loads from a source of higher voltage, i.e., twice the line-to-neutral voltage, compared with 1.73 times the line-to-neutral voltage in a three-phase system.
2. Reduction in overall line losses, as each conductor will carry only one-sixth of the load, compared with one-third in a three-phase system—only half the load per conductor in a three-phase system. The losses, therefore, will be one-quarter those in a three-phase (three- or four-wire balanced) system.

The overall savings in fuel costs for supplying the lesser losses may exceed the increased carrying charges associated with the additional conductors. The improved voltage in supplying three-phase delta (power) loads from such a system also contributes to its acceptability. As fuel and operating costs increase, such systems may find wider application.

Comparison Between Alternating Current Systems

A comparison of efficiencies for the several alternating current systems, assuming the same (balanced) loads, the same voltage between conductors, and the same conductor size is summarized in Table 2-1, which uses a single-phase two-wire circuit as a basis for comparison.

TABLE 2-1 COMPARATIVE EFFICIENCIES OF AC SYSTEMS

Type of ac system		*Amount of conductor*	*Power loss*	*Voltage drop (approximate)*
Single-phase	2-wire	1.0	1.00	1.00
	3-wire	1.5	0.25	0.25
Two-phase	3-wire	1.5	0.50	0.50
	4-wire	2.0	0.25	0.25
	5-wire	2.5	0.25	0.25
Three-phase	3-wire*	1.5	0.167	0.167
	3-wire**	1.5	0.50	0.50
	4-wire*	2.0	0.167	0.167
Six-phase	6-wire	3.0	0.042	0.042
	7-wire	3.5	0.042	0.042

*Wye (Y) voltage same as single-phase.

**Delta (Δ) voltage same as single-phase.

TYPES OF DELIVERY SYSTEMS

The delivery of electric energy from the generating plant to the consumer may consist of several more or less distinct parts that are nevertheless somewhat interrelated, described generally in Chap. 1. The part considered "distribution," i.e., from the bulk supply substation to the meter at the consumer's premises, can be conveniently divided into two subdivisions:

1. Primary distribution, which carries the load at higher than utilization voltages from the substation (or other source) to the point where the voltage is stepped down to the value at which the energy is utilized by the consumer.
2. Secondary distribution, which includes that part of the system operating at utilization voltages, up to the meter at the consumer's premises.

Primary Distribution

Primary distribution systems include three basic types:

1. Radial systems, including duplicate and throwover systems
2. Loop systems, including both open and closed loops
3. Primary network systems

Radial Systems The radial-type system is the simplest and the one most commonly used. It comprises separate feeders or circuits "radiating" out of the substation or source, each feeder usually serving a given area. The feeder may be considered as consisting of a main or trunk portion from which there radiate spurs or laterals to which distribution transformers are connected, as illustrated in Fig. 2-11.

The spurs or laterals are usually connected to the primary main through fuses, so that a fault on the lateral will not cause an interruption to the entire

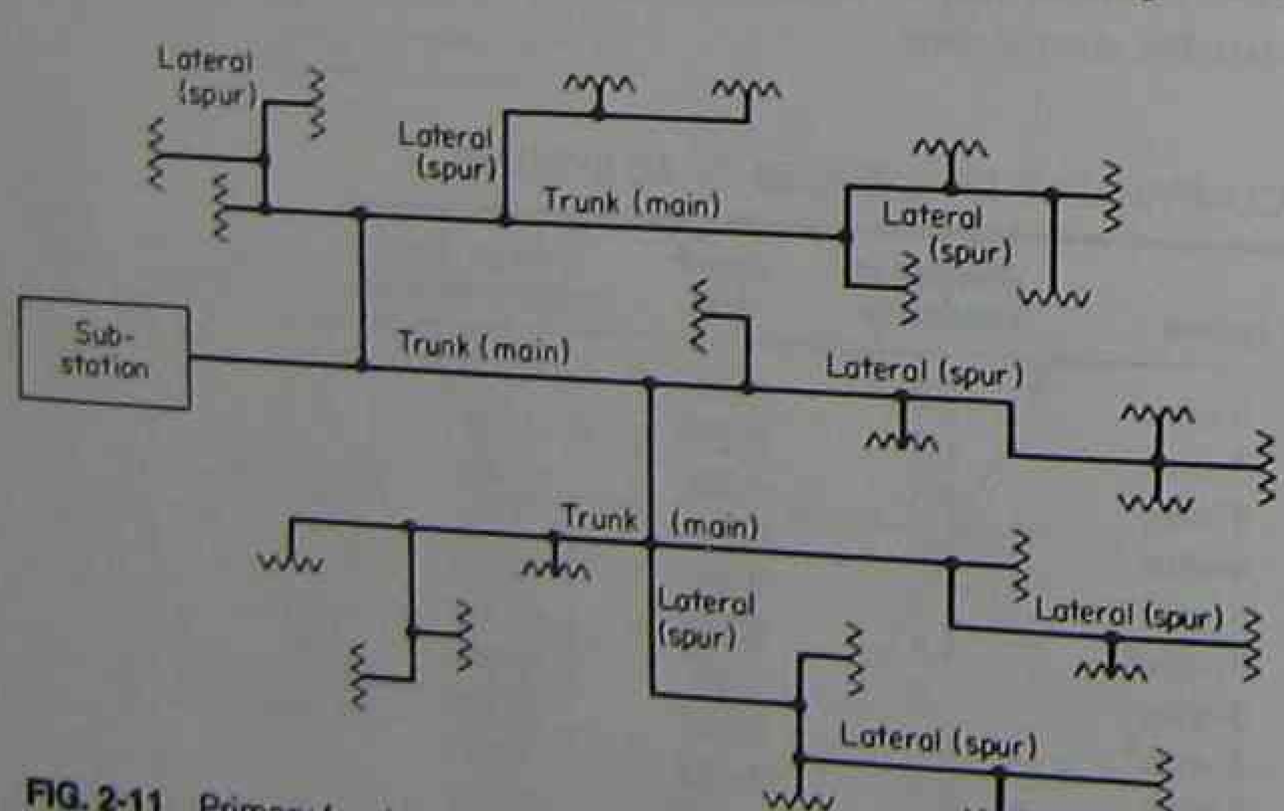


FIG. 2-11 Primary feeder schematic diagram showing trunk or main feeds and laterals or spurs.

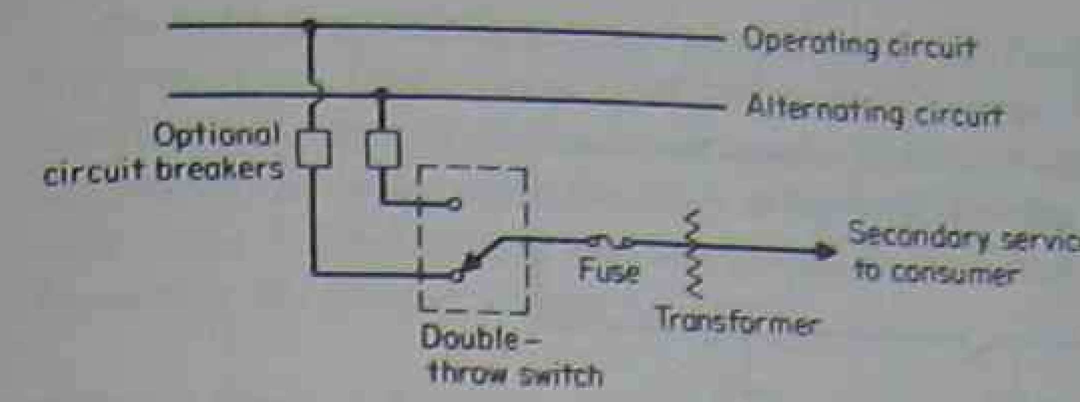


FIG. 2-12 Schematic diagram of alternate feed–throwover arrangement for critical consumers.

feeder. Should the fuse fail to clear the line, or should a fault develop on the feeder main, the circuit breaker back at the substation or source will open and the entire feeder will be deenergized.

To hold down the extent and duration of interruptions, provisions are made to sectionalize the feeder so that unfaulted portions may be reenergized as quickly as practical. To maximize such reenergization, emergency ties to adjacent feeders are incorporated in the design and construction; thus each part of a feeder not in trouble can be tied to an adjacent feeder. Often spare capacity is provided for in the feeders to prevent overload when parts of an adjacent feeder in trouble are connected to them. In many cases, there may be enough diversity between loads on adjacent feeders to require no extra capacity to be installed for these emergencies.

Supply to hospitals, military establishments, and other sensitive consumers may not be capable of tolerating any long interruption. In such cases, a second feeder (or additional feeders) may be provided, sometimes located along a separate route, to provide another, separate alternative source of supply. Switching from the normal to the alternative feeder may be accomplished by a throwover switching arrangement (which may be a circuit breaker) that may be operated manually or automatically. In many cases, two separate circuit breakers, one on each feeder, with electrical interlocks (to prevent connecting a good feeder to the one in trouble), are employed with automatic throwover control by relays. See Fig. 2-12.

Loop Systems Another means of restricting the duration of interruption employs feeders designed as loops, which essentially provide a two-way primary feed for critical consumers. Here, should the supply from one direction fail, the entire load of the feeder may be carried from the other end, but sufficient spare capacity must be provided in the feeder. This type of system may be operated with the loop normally open or with the loop normally closed.

Open Loop In the open-loop system, the several sections of the feeder are connected together through disconnecting devices, with the loads connected to the several sections, and both ends of the feeder connected to the supply. At a predetermined point in the feeder, the disconnecting device is intentionally left open. Essentially, this constitutes two feeders whose ends are separated by a

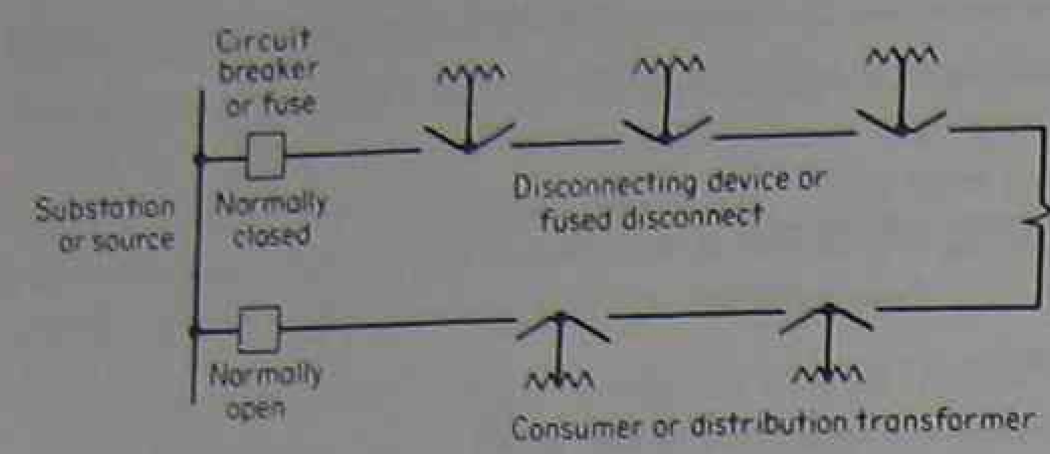


FIG. 2-13 Open-loop circuit schematic diagram.

disconnecting device, which may be a fuse, switch, or circuit breaker. See Fig. 2-13.

In the event of a fault, the section of the primary on which the fault occurs can be disconnected at both its ends and service reestablished to the unfaulted portions by closing the loop at the point where it is normally left open, and reclosing the breaker at the substation (or supply source) on the other, unfaulted portion of the feeder.

Such loops are not normally closed, since a fault would cause the breakers (or fuses) at both ends to open, leaving the entire feeder deenergized and no knowledge of where the fault has occurred. The disconnecting devices between sections are manually operated and may be relatively inexpensive fuses, cutouts, or switches.

Closed Loop Where a greater degree of reliability is desired, the feeder may be operated as a closed loop. Here, the disconnecting devices are usually the more expensive circuit breakers. The breakers are actuated by relays, which operate to open only the circuit breakers on each end of the faulted section, leaving the remaining portion of the entire feeder energized. In many instances, proper relay operation can only be achieved by means of pilot wires which run from circuit breaker to circuit breaker and are costly to install and maintain; in some instances these pilot wires may be rented telephone circuits. See Fig. 2-14.

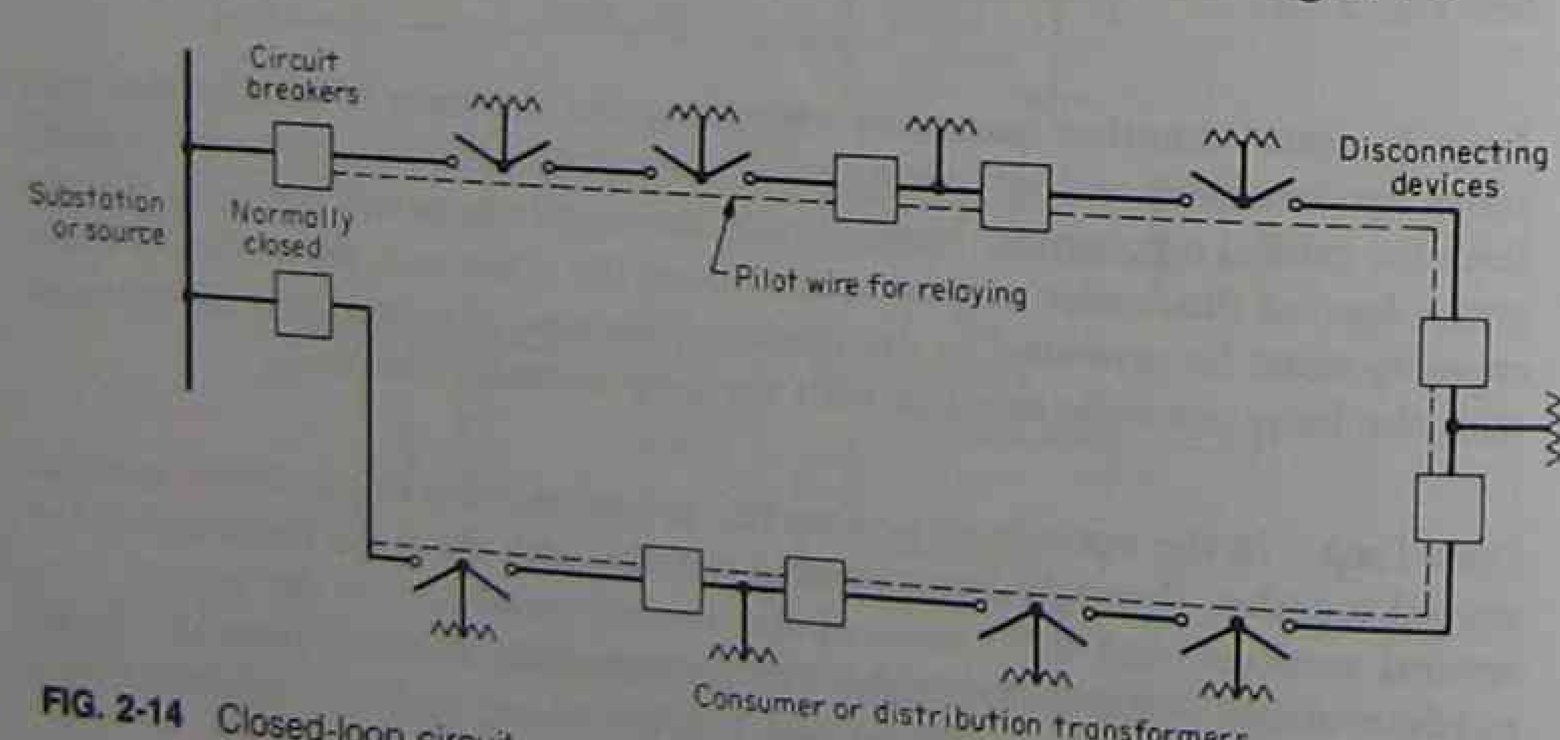


FIG. 2-14 Closed-loop circuit.

To hold down costs, circuit breakers may be installed only between certain sections of the feeder loop, and ordinary, less expensive disconnecting devices installed between the intermediate sections. A fault will then deenergize several sections of the loop; when the fault is located, the disconnecting devices on both ends of the faulted section may be opened and the unfaulted sections reenergized by closing the proper circuit breakers.

Primary Network Systems Although economic studies indicated that under some conditions the primary network may be less expensive and more reliable than some variations of the radial system, relatively few primary network systems have been put into actual operation and only a few still remain in service.

This system is formed by tying together primary mains ordinarily found in radial systems to form a mesh or grid. The grid is supplied by a number of power transformers supplied in turn from subtransmission and transmission lines at higher voltages. A circuit breaker between the transformer and grid, controlled by reverse-current and automatic reclosing relays, protects the primary network from feeding fault current through the transformer when faults occur on the supply subtransmission or transmission lines. Faults on sections of the primaries constituting the grid are isolated by circuit breakers and fuses. See Fig. 2-15.

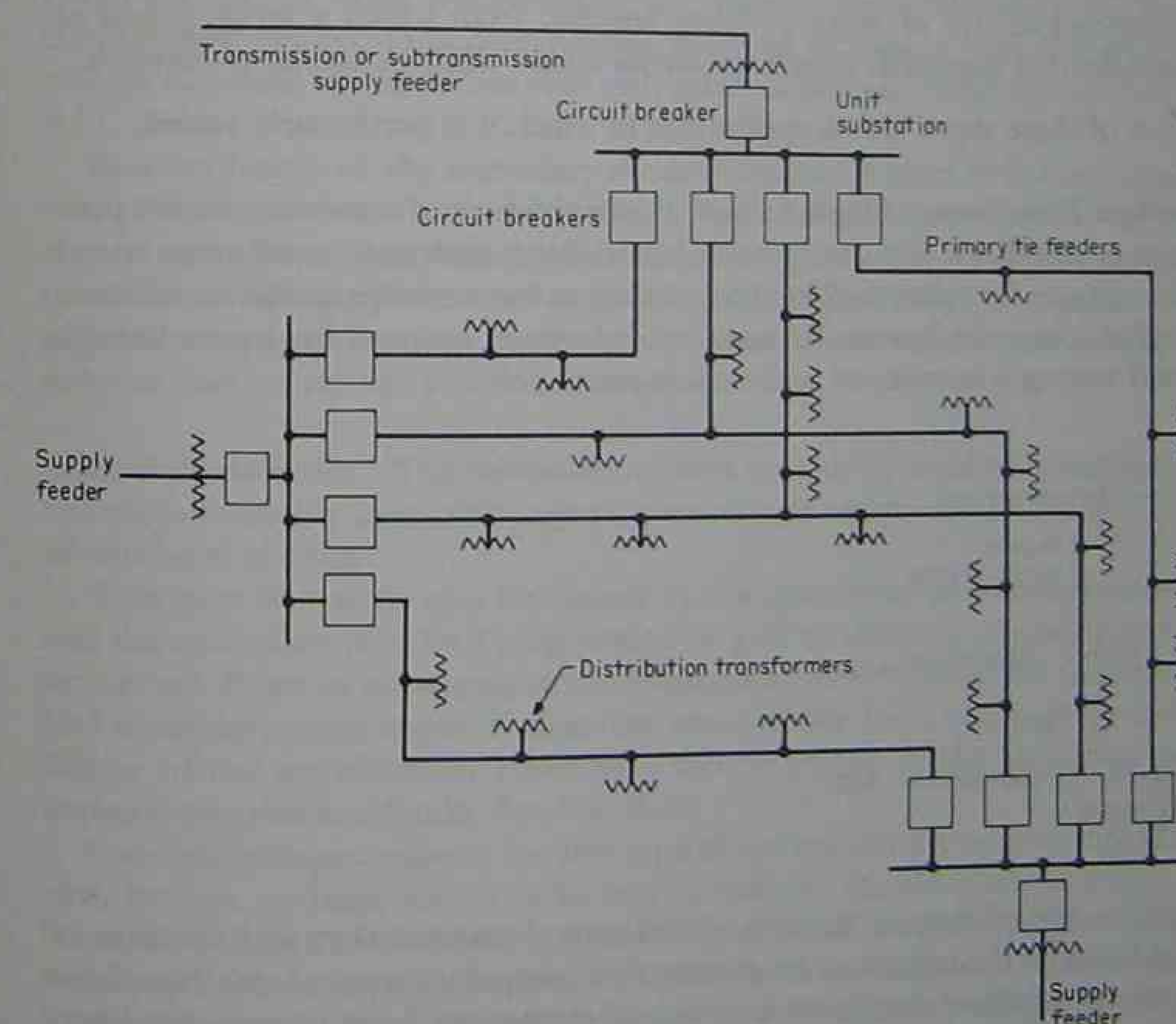


FIG. 2-15 Primary network. Sectionalizing devices on feeders not shown.

This type of system eliminates the conventional substation and long primary trunk feeders, replacing them with a greater number of "unit" substations strategically placed throughout the network. The additional sites necessary are often difficult to obtain. Moreover, difficulty is experienced in maintaining proper operation of the voltage regulators (where they exist) on the primary feeders when interconnected.

Secondary Distribution

Secondary distribution systems operate at relatively low utilization voltages and, like primary systems, involve considerations of service reliability and voltage regulation. The secondary system may be of four general types:

1. An individual transformer for each consumer; i.e., a single service from each transformer.
2. A common secondary main associated with one transformer from which a group of consumers is supplied.
3. A continuous secondary main associated with two or more transformers, connected to the same primary feeder, from which a group of consumers is supplied. This is sometimes known as *banking* of transformer secondaries.
4. A continuous secondary main or grid fed by a number of transformers, connected to two or more primary feeders, from which a large group of consumers is supplied. This is known as a *low-voltage* or *secondary* network.

Each of these types has its application to which it is particularly suited.

Individual Transformer–Single Service Individual-transformer service is applicable to certain loads that are more or less isolated, such as in rural areas where consumers are far apart and long secondary mains are impractical, or where a particular consumer has an extraordinarily large or unusual load even though situated among a number of ordinary consumers.

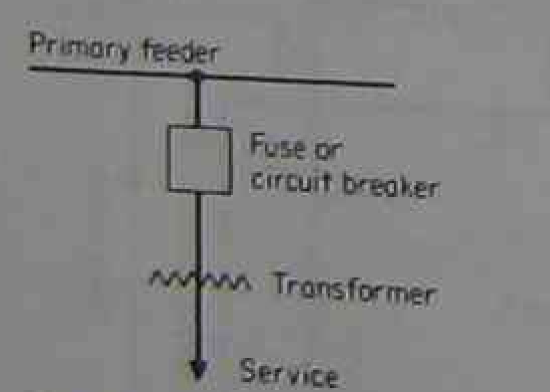


FIG. 2-16 Single-service secondary supply.

In this type of system, the cost of the several transformers and the sum of power losses in the units may be greater (for comparative purposes) than those for one transformer supplying a group of consumers from its associated secondary main. The diversity among consumers' loads and demands permits a

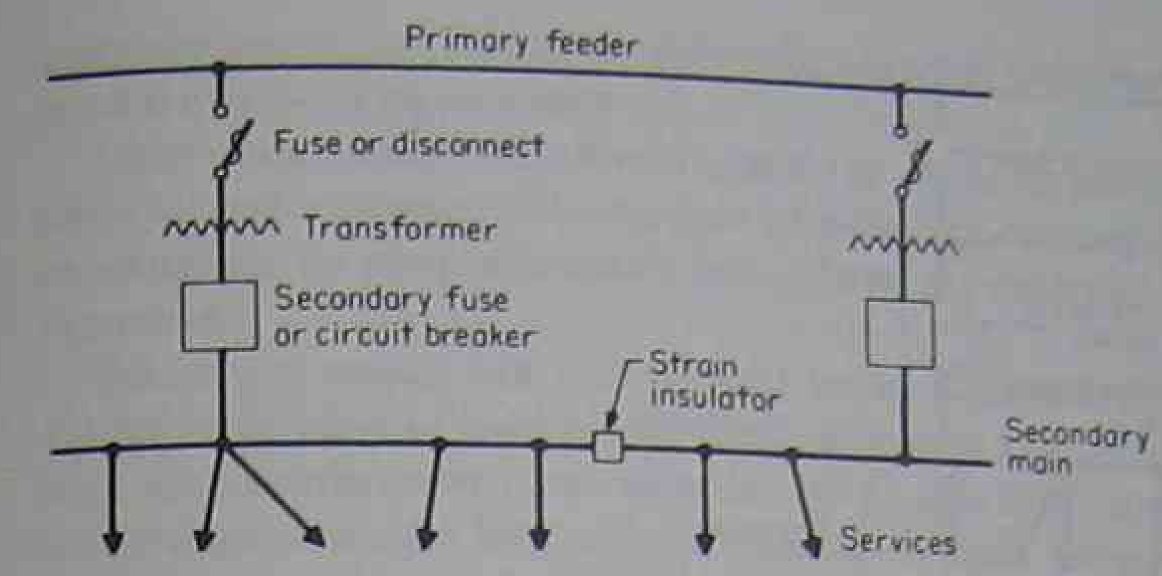


FIG. 2-17 Common-secondary-main supply.

transformer of smaller capacity than the capacity of the sum of the individual transformers to be installed. On the other hand, the cost and losses in the secondary main are obviated, as is also the voltage drop in the main. Where low voltage may be undesirable for a particular consumer, it may be well to apply this type of service to the one consumer. Refer to Fig. 2-16.

Common Secondary Main Perhaps the most common type of secondary system in use employs a common secondary main. It takes advantage of diversity between consumers' loads and demands, as indicated above. Moreover, the larger transformer can accommodate starting currents of motors with less resulting voltage dip than would be the case with small individual transformers. See Fig. 2-17.

In many instances, the secondary mains installed are more or less continuous, but cut into sections insulated from each other as conditions require. As loads change or increase, the position of these division points may be readily changed, sometimes holding off the need to install additional transformer capacity. Also, additional separate sections can be created and a new transformer installed to serve as load or voltage conditions require.

Banked Secondaries The secondary system employing banked secondaries is not very commonly used, although such installations exist and are usually limited to overhead systems.

This type of system may be viewed as a single-feeder low-voltage network, and the secondary may be a long section or grid to which the transformers are connected. Fuses or automatic circuit breakers located between the transformer and secondary main serve to clear the transformer from the bank in case of failure of the transformer. Fuses may also be placed in the secondary main between transformer banks. See Fig. 2-18.

Some advantages claimed for this type of system include uninterrupted service, though perhaps with a reduction in voltage, should a transformer fail; better distribution of load among transformers; better normal voltage conditions resulting from such load distribution; an ability to accommodate load increases by changing only one or some of the transformers, or by installing a new transformer at some intermediate location without disturbing the existing arrange-

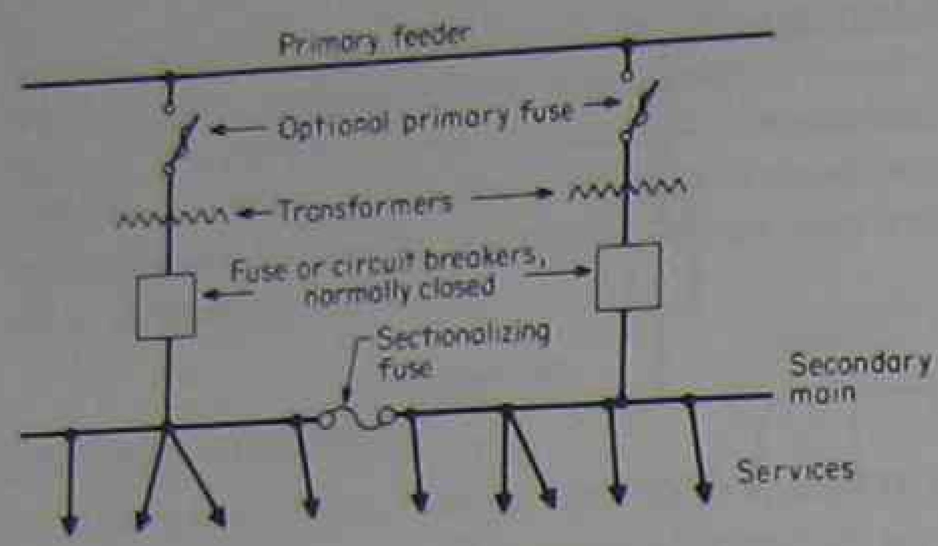


FIG. 2-18 Banked secondary supply.

ment; the possibility that diversity between demands on adjacent transformers will reduce the total transformer load; more capacity available for inrush currents that may cause flicker; and more capacity as well to burn secondary faults clear.

Some disadvantages associated with this type of system are as follows: should one transformer fail, the additional loads imposed on adjacent units may cause them to fail, and in turn their loads would cause still other transformers to fail (this is known as *cascading*); the transformers banked must have very nearly the same impedance and other characteristics, or the loads will not be distributed equitably among them; and sufficient reserve capacity must be provided to carry emergency loads safely, obviating the savings possible from the diversity of the demands on the several transformers.

Banked secondaries, while providing for failure of transformers, do not provide against faults on the primary main or feeder. Further, a hazard on any transformer disconnected for any reason may result from a back feed if the secondary energizes the primary (which may have been considered safe).

Secondary Networks Secondary networks at present provide the highest degree of service reliability and serve areas of high load density, where revenues justify their cost and where this kind of reliability is imperative. In some instances, a single consumer may be supplied from this type of system by what are known as *spot networks*.

In general, the secondary network is created by connecting together the secondary mains fed from transformers supplied by two or more primary feeders. Automatically operated circuit breakers in the secondary connection between the transformer and the secondary mains, known as *network protectors*, serve to disconnect the transformer from the network when its primary feeder is deenergized; this prevents a back feed from the secondary into the primary feeder. This is especially important for safety when the primary feeder is deenergized from fault or other cause. The circuit breaker or protector is backed up by a fuse so that, should the protector fail to operate, the fuse will blow and disconnect the transformer from the secondary mains. See Fig. 2-19.

The number of primary feeders supplying a network is very important. With only two feeders, only one feeder may be out of service at a time, and there must be sufficient spare transformer capacity available so as not to overload the

units remaining in service; therefore this type of network is sometimes referred to as a *single-contingency* network.

Most networks are supplied from three or more primary feeders, where the network can operate with the loss of two feeders and the spare transformer capacity can be proportionately less. These are referred to as *second-contingency* networks.

Secondary mains not only should be so designed that they provide for an equitable division of load between transformers and for good voltage regulation with all transformers in service, but they also must do so when some of the transformers are no longer in service when their primary feeders are deenergized. They must also be able to divide fault current properly among the transformers, and must provide for burning faults clear at any point while interrupting service to a minimum number of consumers; this often limits the size of secondary mains, usually to less than 500 cmil × 10^3, so that when additional secondary main capacity is required, two or more smaller size conductors have to be paralleled. In some networks, where insufficient fault current might cause long sections of secondary mains to be destroyed before the fault is burned clear, sections of secondary mains are fused at each end.

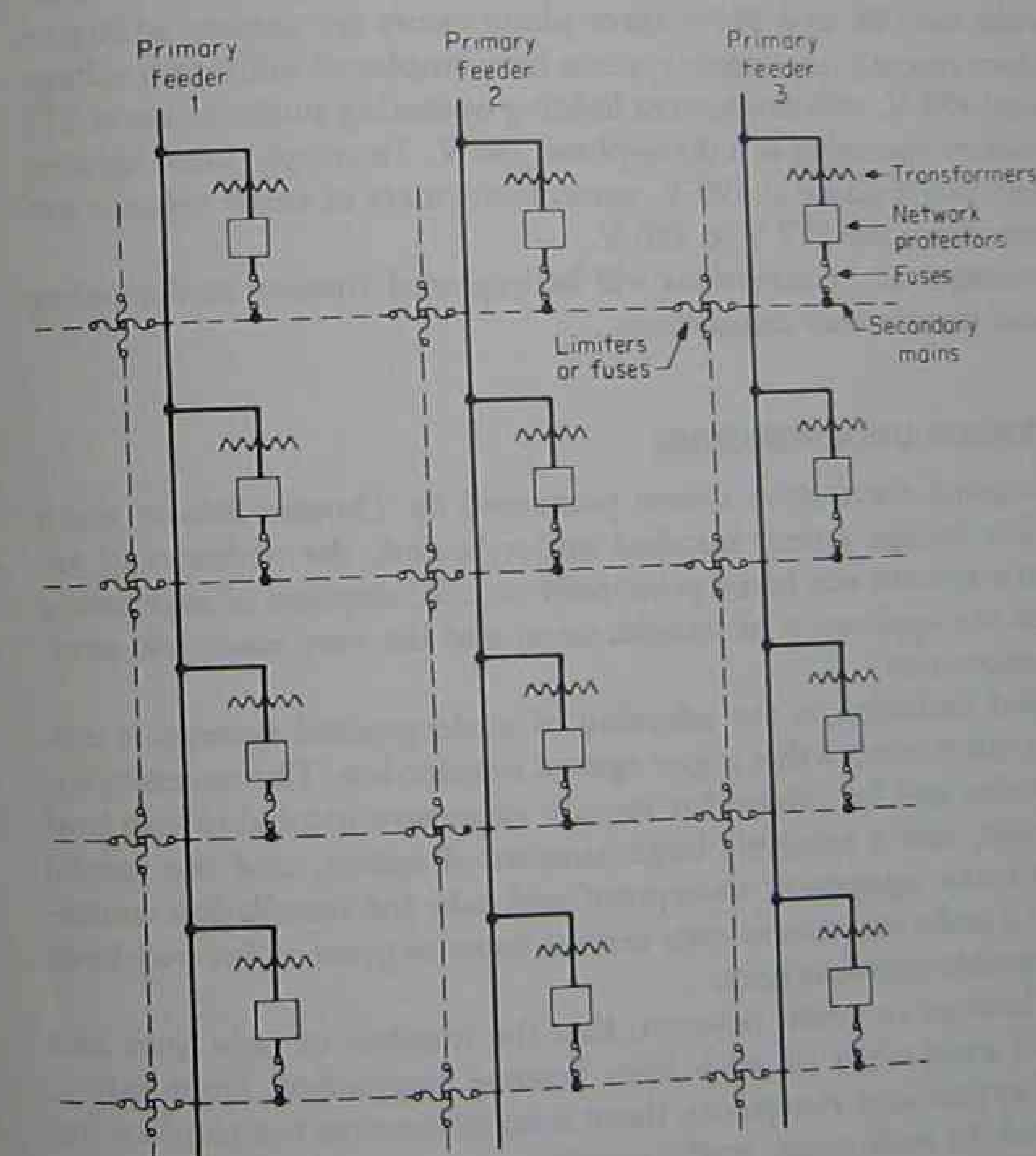


FIG. 2-19 Low-voltage secondary network.

Utility Problems

The utility generally must meet seasonal and daily load peaks, peaks of relatively short duration. Generation, transmission, and distribution facilities must be provided to meet these demands.

Generation Utilities generally have three levels of power generation equipment: base-load units, usually the newest and most highly efficient (as well as the most expensive); midrange units, which are less efficient and are perhaps the most recent of older generation facilities; and units generally operated as peak units, the least efficient and usually the oldest, but sometimes new units specifically designed for this short-term purpose. Controlling system demands, therefore, results in lessened need to operate the least efficient units and, in the long term, defers the addition of the most expensive newest units.

Transmission Transmission lines are the bulk carriers of electrical energy, and fall into the same category as generators as far as investment is concerned. Here, too, the older and less efficient transmission lines, usually those operating at lower voltages than the newest lines, constitute part of the transmission network, including those facilities needed to ensure continuity of adequate service in contingencies. Controlling system demands will not only result in lowered I^2R losses, as indicated previously, but will also defer, if not make unnecessary, the installation of new and expensive transmission lines.

Distribution The same general observations concerning transmission lines also apply to distribution circuits. Additional distribution facilities (including substations) and conversions or construction at higher voltages can be deferred if the system demands can be controlled.

In the case of distribution facilities, however, a problem arises as to the rating of equipment, particularly transformers. The rating of such equipment, though nominally predicated on its current-carrying ability, is actually based on the allowable temperature at which insulation may be subject to failure. This temperature is a function not only of the heat caused by the losses (copper and iron) developed within the unit, but also of the duration of the developed heat. The control of demands on the distribution system will, on the one hand, reduce the maximum values of heat applied (as noted previously), but on the other, may reduce the thermal margin of safety resulting from the duration of the heating cycles. In some instances, no doubt, the net overall effect may be negligible; in others, especially during periods of prolonged hot ambient temperatures, such as exist in summertime, the net overall effect may be appreciable. Units so affected should, therefore, be closely monitored.

CONCLUSION

The need for conservation of investment capital and use of energy resources indicates the desirability of operating practices that no longer separate the distribution system from other parts of electrical system operations. Moreover,

electronic and miniaturization advances make practical the integration and automatic management of such operations. These may be listed as:

1. Load management for conservation and improved overall system efficiency. This may include the direct control of consumer loads (and energy storage where practical), and other means to alter the shape of the utility system load curve.
2. Alternative energy resource management to control utility- or consumer-owned generation which will integrate with the distribution system.
3. Distribution system management during normal and contingency operation, including reporting of interruptions, sectionalizing and reconfiguration of circuits, remote operation of equipment, load monitoring and reactive power (VAR and capacitors) control, and even remote meter reading for revenue billing purposes.
4. Integrated systemwide control to provide for overall system operation during periods of widespread emergencies.

The distribution engineer, to a greater degree, must take into account the impact of these integrated operations on planning and design practices.

CONCLUSION

These are only a few examples in which recommendations based solely on tangible technical considerations may be overridden by nontechnical considerations influencing the design of the distribution finally selected.

The distribution engineer, therefore, must not only be aware of new and improved materials and equipment, but must be cognizant of changes in codes, regulations, and construction and maintenance standards and practices. Many of these are brought about by the development of new methods as well as new materials and equipment; many are also influenced by the changing public expectations resulting from changing social values and economic conditions. Indeed, the engineer must not only keep abreast of such changes, but should be an active contributor to them.

In selecting each item and designating its place in the distribution system, the engineer must examine step by step its impact on safety, service quality, and economic results before making a final determination and issuing orders to the field.

CHAPTER 15

OPERATING CONSIDERATIONS

INTRODUCTION

There are yet other requirements which the design of distribution systems must meet, other than those of meeting the consumer's and community's needs and desires. The additional requirements, in the main, have arisen from the changing national economic and energy situations. Collected under the general subject of operating requirements are the installation and arrangement of facilities to achieve a better quality of service, but also a more efficient distribution system and a more economical overall electric system from the generating plant to the consumer's premises.

The operations may be classified into four specific functions and may be listed under simplified headings:

1. Quality of service
2. Load shedding
3. Cogeneration
4. Demand control (or peak suppression)

These are somewhat interrelated, and all involve the distribution system.

QUALITY OF SERVICE

Operations involving the improvement of quality of service to the consumer have been discussed in previous chapters, and include measures to:

1. Isolate faults and restore service to the unfaulted portion of the distribution system

2. Transfer loads between phases or between circuits to relieve overloads or potential overloads, and improve voltage conditions
3. Switch on and off capacitors installed out on the distribution feeders (and in the substations) to improve power factor, reducing the value of current flowing and releasing capacity of distribution facilities, with resultant voltage improvement
4. Enable portions of the distribution system, including the substation portion, to be deenergized for construction and maintenance purposes without affecting the remaining portion of the circuit

Designs of distribution systems include provisions for carrying out these operations by means of suitable circuit extensions and switches. With the development of electronic and miniaturized systems of control and communication, many of these operations, generally performed manually and sometimes with a significant lapse of time, may now be performed automatically almost instantaneously.

LOAD SHEDDING

Why

The need for load shedding stems from two general causes, usually unforeseen:

1. Lack of sufficient power supply
2. Lack of sufficient transmission or distribution load-carrying ability

These conditions may come about from:

1. Load growth faster than the construction of new facilities can be accomplished
2. Abnormally high unforeseen demands that are created by unusual seasonal changes or by some special events that cause a significant loss in diversity of consumers' loads
3. Failure or overload in some element or elements of the supply facilities; e.g., transmission line failure, substation transformer failure, etc., for a prolonged period.

How

In this context, load shedding implies decreasing the load on the substation bus, substation transformer, or incoming transmission line. This may be accomplished in two basic ways:

1. Voltage reduction
2. "Brownout," or periodic disconnecting of feeders for relatively short periods of time on a predetermined schedule

In rare instances is resort had to the employment of both of these methods at the same time.

Voltage Reduction Voltage reduction may be accomplished by manipulating voltage regulators at the substation on individual feeders, or on the substation bus, where the substation's voltage is so regulated. Voltages may be reduced by steps according to the amount of load shedding required. In circuits that supply essentially lighting or unity power factor loads, a 1 percent voltage drop results in almost a 1 percent drop in load.

Steps may be 1 or 2 percentage points each to a maximum of about 8 percent; more often, however, voltage is lowered in two steps, (say) 5 percent and 8 percent.

Lowering voltage beyond this 8 percent value may prove self-defeating as light output from incandescent lamps decreases to the point where additional lighting may be turned on. Fluorescent lighting is also affected as maintenance of the electron flow in the fluorescent tube becomes tenuous. Power loads usually continue to operate satisfactorily at the lower voltage, drawing more current, so that they have little effect on load reduction. This increase in current, however, may cause overheating, loss of torque, and other undesirable conditions to take place.

In some instances, the lowering of voltage may take place on the transmission or subtransmission incoming supply circuit or circuits when they are equipped with voltage regulators at the sending ends. In this event, the voltage regulators on the distribution feeders (or on the distribution feeder bus) at the substation may have to be blocked in a fixed or neutral position so as not to negate the effect of the reduced voltage on the incoming supply.

Regulators installed in the field on portions of primary circuits, for practical reasons, are usually left alone and allowed to travel to their maximum position if necessary. The relatively small amounts of load that can be shed by attending to these units is often not worth the effort necessary to adjust them to nonautomatic operation at the start and to return them to automatic operation at the end of a usually short period of time.

Distribution System Problems Where distribution feeders are deliberately designed to accommodate such lowering of voltage below normal values, it may be necessary to reinforce or provide for some consumers, usually at the ends of primary circuits. These may have a sufficiently low normal voltage that the additional drop may cause damage to some of their connected loads. In most cases, provision involves the shortening of secondary mains and the more closely spaced installation of transformers; also, taps may be set for a lower (or the lowest) ratio of transformation. Sometimes, the installation of a booster transformer in those farthest sections of the primary circuit will accomplish the purpose. In any event, this feature requires investigation and the taking of necessary measures preferably before the need for such voltage reduction to shed load is placed in effect.

Where the need for voltage reduction stems only from some deficiency in the distribution system, that deficiency should be identified and removed as quickly as possible; such a need might occur in the case of overloads in an outgoing underground cable supplying a feeder where the cable carries too great a load under normal conditions, or under contingency conditions where it may be called upon to carry the load of an additional circuit or circuits, or parts of them.

Low-Voltage Network Where the feeders supply a low-voltage secondary network, extreme care must be exercised in lowering the voltage on the supply primary feeders. Operation of the regulators must be coordinated so that the voltage on each of the feeders is lowered as simultaneously as practical to prevent opening of network protectors on the feeder if its voltage alone is lowered. In turn, the additional load picked up by the feeder or feeders whose voltage is not lowered may cause "hunting" between the protectors of the several feeders, or may cause feeders to trip from overloads in a cascading effect that would shut down the network. In some instances, the overcurrent relays on the feeder circuit breakers may be blocked to prevent feeders from tripping from temporary overloads until all the regulators have been adjusted and locked in at the desired lowered voltage level. If the voltage lowering operation is to be a relatively frequent occurrence, relay settings on the network protectors in the field may be made sufficiently insensitive to keep the protectors from hunting and the feeders from cascading out.

Brownout

Brownout is a procedure in which feeders are taken out of service for a relatively short period of time on a predetermined basis, usually one at a time, to reduce the demand on the substation supply transformers or on the facilities back to the generating station. Critical loads, such as hospitals and military bases, are usually supplied from two sources with double-throw facilities to accomplish a switchover to an energized source, either manually or automatically. Where this arrangement does not exist, it may be necessary to sectionalize that portion of a feeder supplying such critical loads, connecting it to an energized feeder when its normal supply feeder is deenergized. In some instances, where more than one critical load may exist on a feeder, that feeder may be exempt from the brownout procedure. Feeders supplying low-voltage networks are usually exempt as the load dropped by them in such an operation would be picked up by the others supplying the network, and the net reduction in load would be very nearly zero.

COGENERATION

Why

Basically, cogeneration involves the interconnection of consumers' generation to the utility's distribution system. Changing energy and economic conditions have made such interconnections feasible in many instances, and, in some areas, mandated by law (e.g., Texas). Large users of steam and hot water have found it economically desirable to generate electricity and use the "waste" heat to meet their steam and hot water requirements. The electricity so produced that they do not use themselves is sold to the utility, usually at an advantageous rate. This

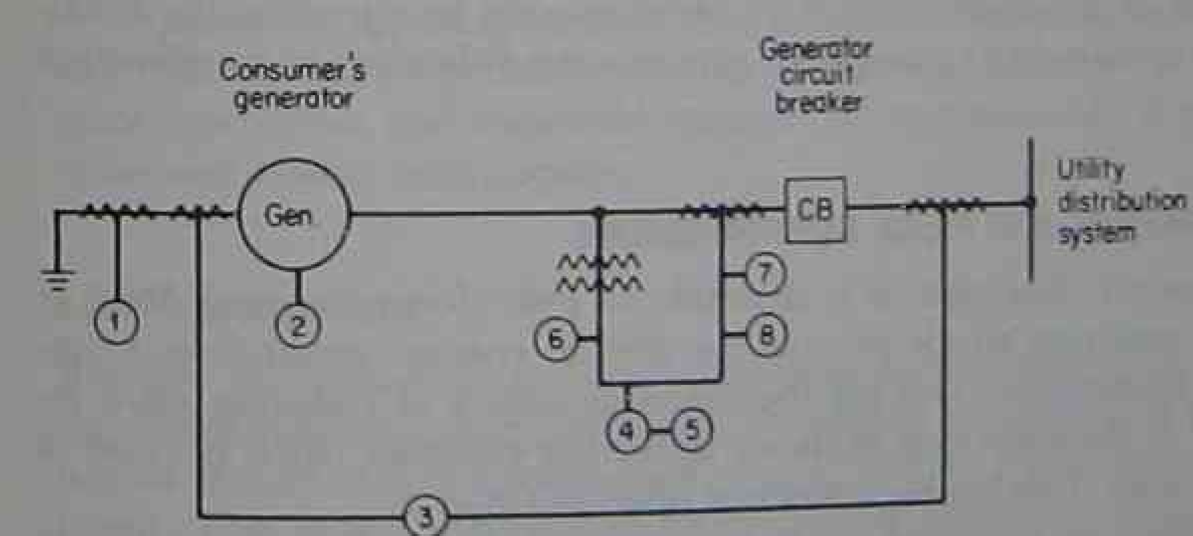
is because regulatory guidelines tend to favor a rate paid for power purchased by a utility (the avoidable cost to produce power) to be based on the utility's *least* efficient power plant, whereas the cost of power to a utility consumer is usually based on an *average* cost to produce power.

Paralleling the Systems

Paralleling the consumer's generation facilities with those of the utility requires that additional protection equipment be installed at the cogenerator's facilities. The principal features of this additional protection include:

1. Automatic synchronizing of the generator output with the utility
2. Relaying to prevent the closing of the circuit breaker to the utility system until the cogenerator's generator is open, for protection of that generator
3. Relaying to open the circuit breaker to the utility system on loss of power in the utility system
4. Relaying to open the circuit breaker to the utility system on a ground fault on the utility system
5. Relaying to control the cogenerator's generator circuit breaker to provide generator overcurrent protection, phase current balance protection, reverse power protection, under- and over-frequency protection, and under- and overvoltage protection
6. Control of engine governor equipment for speed, generator phase match, and generator load

The electrical connections and indicated protection are shown on the one-line diagram in Fig. 15-1.



KEY

1. Ground relay
2. Generator governor
3. Differential protective relay
4. Frequency meter and relay
5. Synchronizing device
6. Undervoltage relay
7. Time-overcurrent relay
8. Directional power relay

FIG. 15-1 One-line diagram showing protection relaying for consumer cogeneration unit.

Modes of Operation

There are several load relationships that may exist between the cogenerator and the utility:

1. The cogenerator always supplying power at a constant rate; i.e., the cogenerator supplying a part of the utility's base load
2. The cogenerator always supplying power in variable amounts, fluctuating with the consumer's needs; i.e., the cogenerator supplying only a marginal part of the utility's load
3. The cogenerator and the utility both supplying the consumer's requirements on a normal or contingency basis
4. The utility supplying all of the consumer's requirements on a contingency basis

The Distribution System

The variation in the modes of operation not only may affect the settings applied to the protective relays, but may influence the design of the utility's distribution system. Obviously, the distribution facilities required will vary with the mode of operation, and the problem of maintaining voltage within acceptable limits as conditions change (e.g., from mode 1 to mode 4 above) may tax the engineer's ingenuity.

The wide variations that may take place in voltage profiles and current distribution in the distribution circuit to which the cogenerator is connected may require rearrangement of the circuit configuration to maintain safe and acceptable standards of electricity supply. These may require the installation of additional switching facilities to achieve desired sectionalization and rearrangement; preferably the switches should be automatically operated. Moreover, as generators are usually under control of one operating group while the distribution system is controlled by a separate group, some difficulties in coordination may arise.

DEMAND CONTROL (OR PEAK SUPPRESSION)

From an economic viewpoint, it is desirable to hold down the peak load or maximum demands on all the parts of the electric system—generation, transmission, and distribution. This has the desirable effects of reducing plant investment and at the same time reducing operating expenses (fuel) because of reduced I^2R losses. This has been touched upon in Chap. 8.

Load shedding as described above is a form of demand control or peak suppression, but is associated with contingencies usually of a temporary nature; demand control applies to a permanent reduction in maximum demands as a normal condition.

Basic Concept

For a utility, the most efficient use of its facilities, from an investment point of view, is to use them throughout their lifetimes at maximum loads. By definition,

if this were done, the load factor for the facilities would be 100 percent. This does not occur, because some consumer loads are not always required and are turned off. The closer the utility can approach 100 percent load factor, however, the better the investment can be utilized, and the lower a unit of output can be priced.

The load factor concept in supplying a given load applies equally well whether it is applied to the utility itself or to a single consumer. For example, it is not unusual for a utility to have an annual load factor of 50 to 60 percent because of seasonal air-conditioning loads; this implies that a great part of the facilities used to meet summer peak demands will remain idle the rest of the year.

Typical load factors range from less than 20 percent for some residences to over 90 percent for some industrial plants (like some manufacturing plants having large air-filtering installations). In between, office buildings typically may have load factors of 20 to 30 percent and large, three-shift manufacturing plants 70 to 80 percent. Small to medium industries may have load factors ranging from 20 to 70 percent.

Conservation

Demand control is also a conservation measure, as it will substantially reduce losses, in both the utility's and the consumer's facilities. These reductions will be reflected in fuel consumption at the utility's generating plants and in both demand and energy charges (including fuel adjustment charges) in the consumer's bill.

Although the total overall consumption by a consumer may remain the same, the leveling of demands will decrease the *maximum* current flow, though the *reduced* current flow may continue for a longer period of time. As losses (I^2R) vary as the square of the current, the lower current should result in a substantial reduction in the total energy requirements of the consumer.

Experience has also indicated that reviews for reducing demand often discover unnecessary operation of some equipment, and result in elimination of some operations and improved methods of operation—all of which result in decreased energy consumption.

Load Management

Basically, to reduce the demand on its facilities, the utility must seek to reduce the individual consumers' demands. Preferably, the individual consumers' demands should also be coordinated so as to achieve a minimum coincident demand. This latter feature is more difficult of attainment than the first, as it involves cooperation not only between the utility and the consumer, but among a number of consumers as well. Methods for reducing demands differ for large consumers, such as industrial plants, and for small consumers, such as residences; both, however, employ rate incentives.

Large Consumers For large consumers this subject was touched upon in Chap. 8, in connection with the demand metering of large consumers and their role in schemes employed for reducing consumer demands. This is important to the consumer, as utility rates include demand charges based on the registered maximum demand. The timing impulses from the demand meter are used in several schemes to hold down demands to predetermined values.

To reduce demand requires that nonessential load peaks be reduced or eliminated. Loads are analyzed into several categories:

1. Those that are essential, that cannot be turned off without affecting safety and operations.
2. Those that may be curtailed or turned off for relatively short periods of time without being noticed (e.g., 10 min out of each hour); they may be programmed to be shut off sequentially for predetermined periods of time.
3. Those that may be deferred, put off to some random off-peak time which may differ from day to day (or other period).
4. Those which may be conveniently rescheduled regularly to off-peak periods.

Typical examples of such categories for large industrial consumers are shown in Table 15-1.

Load Cycling Cycling involves the turning off and on of individual loads or groups of loads. How long they can be turned off and how often is predetermined, and the off-on times are staggered so that a minimum number of such loads are on at any one time to achieve the smallest practical maximum demand.

TABLE 15-1 TYPICAL CATEGORIES OF LARGE CONSUMER LOADS

Category	*Examples*
Essential	Lighting (some)
	Elevators
	Production equipment (some)
	Ventilators (some)
	Pumps (some)
Curtailable	Air conditioners
	Heaters
	Ventilators
	Refrigerators
	Water pumps
	Ovens
Deferable	Coolers
	Air compressors
	Water heaters
	Equipment testing
Reschedulable	Electric furnace
	Process ovens
	Incinerators
	Trash compactors
	Battery chargers

Most automatic demand-control systems employ load cycling and involve some technique of demand forecasting to determine when loads should be turned off and on. All are based on the consumer's actual consumption, and its rate compared to some predetermined ideal rate. Several methods of obtaining the comparison have been devised yielding different degrees of accuracy and precision; these will not be further detailed as they are not within the scope of this book. Almost all employ pulses obtained from the utility's demand meter for matching the demand under consideration with that being recorded by the demand meter. Demand-control equipment also acts to control "average" maximum demands, leaving the utility still needing to meet the actual or peak maximum demand.

Demand control usually leads to increased off-on switching of equipment. Care must be taken, therefore, to ensure that thermal overloads and mechanical failure of switching devices do not occur because of short cycling of equipment.

Small Consumers Most small consumers are residential consumers whose demand is not usually metered. Efforts by the utility to hold down their demands are limited almost to promotional rates which, for practical purposes, cannot be policed. More and more, however, utilities are installing demand meters or clocking devices connected to the larger loads, such as hot water heaters, dish and clothes washers, etc. Consumers are thereby encouraged to install small computer-actuated devices for controlling the turning off and on of such loads; these include supplementary time delays so that the initial inrush currents on the various appliances will not (because of possible loss of diversity) all occur simultaneously, causing service interruption and possible damage to the appliance.

Thermal devices have been developed for storing cold and heat during off-peak periods to be used during periods of electrical peaks. Such devices are also beyond the scope of this book.

Load Management Control

A number of utilities have assumed control of devices that will switch off loads on their system automatically when undesirable demand levels are being reached. This involves the identification of noncritical loads that can be placed under the control of the utility with agreed-upon constraints regarding maximum time to be left off. Agreements with consumers include favorable "interruptible" rate schedules. These may be controlled by means of signals transmitted by radio, carrier, or telephone communication. (Similar means of communication are also employed in small residential consumers, mentioned earlier.)

Costs for such demand-control installations are sometimes shared with the (large) consumer, where the same equipment is also used to control the consumer's maximum demand. This demands an almost continuous review to ascertain that a target value set up by the consumer will not run afoul of that set up by the utility.

Capacitors

As mentioned earlier, banks of capacitors may be connected to the high-voltage incoming bus in connection with voltage regulation and increasing the capacity or capability of the substation to supply load. All or portions of these banks may be switched on and off to provide flexibility in maintaining voltage regulation and power factors. This is done with one or more circuit breakers, and arresters or other protective devices as indicated.

Transformers

Substation transformers may consist of three-phase units or banks of three single-phase units. The size of these individual installations may range from 150 kVA (three-phase) in small rural stations to upwards of 25,000 kVA at larger urban and suburban substations. Their impedances are generally low, restricting unregulated voltage variations at the bus to a few percent, except where fault current levels are high. In this case, transformer impedances are increased to limit fault current duty to design limits.

The impedances of the transformer banks in a station should match each other as closely as practical to have the banks share the load as equally as practical.

The transformers may be connected in a delta or wye pattern, on both the incoming high-voltage (subtransmission) side and the outgoing low-voltage (primary circuit) side. The transformers are ordinarily of the two-winding standard type, operating much as the distribution transformers.

For many reasons, including the random and nonuniform movement of the molecules in the core of the transformer, the alternating magnetic field that is set up may be distorted, producing serrated sine waves on both sides of the transformer. These serrations can be broken down into a series of harmonics or waves with frequencies of 3, 5, 7, etc., times the basic frequency (usually 60 cycles per second). If the transformers have a ground on either side, the harmonics or fluctuations flow to ground and the original sine wave essentially remains undistorted. If the windings are connected in delta fashion, these fluctuations circulate around the delta, filtering out the harmonics and eliminating them from the sine wave formed in the windings; however, they do cause some unnecessary heating.

Where the transformer windings are connected in a wye arrangement *without* a ground or neutral back to the source, the harmonics may be particularly bothersome. To overcome these, each of the single-phase transformations (singly or within a three-phase unit) is provided with a third, small-capacity winding; the three such windings are connected in delta (even though the main primary and secondary windings are connected in wye). The delta thus formed allows the harmonics to circulate within it, producing a little heat but essentially filtering them out, so that the sine wave produced on both the high and low sides of the transformer will be a more pure sine wave.

Low-Side Bus Arrangements

The low sides of the transformers are connected to their buses usually through circuit breakers. Several configurations are shown in Fig. 4-9. Some provision is

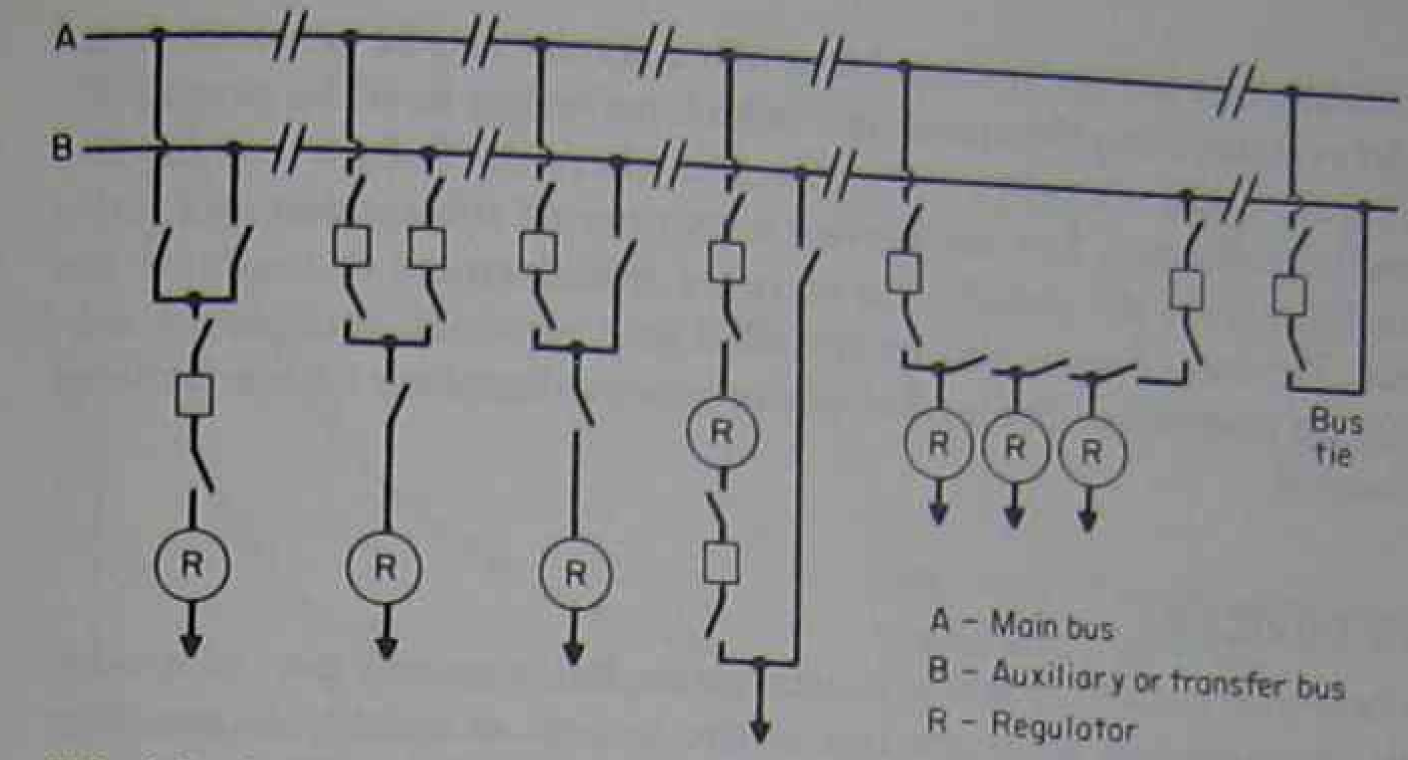


FIG. 4-9 Arrangement of distribution feeder buses at substations (see also Fig. 4-8).

usually made for permitting circuit breakers, switches, regulators, and other devices to be taken out of service for maintenance or for other reasons without causing an interruption to the outgoing distribution feeders. Each of the outgoing distribution feeders is usually equipped with its own circuit breaker. The relays operating these, as well as the transformer high-side circuit breakers, and the capacitors (if any) are coordinated so that only the proper circuit breaker will operate to clear a fault that may occur on some portion of the system; this is considered in more detail on pages 92 to 96.

Voltage Regulators

Each distribution feeder may have its voltage individually regulated, employing three single-phase regulators or one three-phase regulator. If all of the distribution feeders have approximately the same load cycles and voltage regulation (even if corrected by capacitors, field regulators, or other means out on the feeder) the bus to which they are connected may be regulated in place of individual feeder regulators. While this calls for a certain amount of compromise, it may prove economical in many instances.

Mobile Substations

Substations are often designed for three single-phase transformers so that, where they are connected in delta on the incoming side, they can operate in open delta in the event of failure of one of the units. In some instances, a spare single-phase transformer is installed at the substation so that, in the event of failure of one of the transformers, a replacement can be made readily.

With the advent of lighter transformers and improved transportation equipment, it has proven practical to mount a three-phase transformer and associated switching and surge arresters on a trailer especially designed for that purpose. Such a mobile substation can be readily transported to a substation where a failure has occurred. The terminal arrangements of both the mobile substation may impose a high voltage on the low side and on the loads connected thereto. The low-voltage side may be insulated to withstand the higher voltage, but the connected loads may not be so protected.

The autotransformer generally has a comparatively lower impedance, which may cause greater fault currents to flow through it during a contingency. The autotransformer, therefore, must be built very ruggedly to withstand the greater mechanical stresses produced, or else external impedances should be connected in the circuit to limit the magnitude of the fault currents, or both should be done in some combination.

Autotransformers may be used on both single-phase and polyphase circuits, as indicated previously. Voltage regulators of both the induction and TCUL types are autotransformers in principle.

Ratings and Temperature

The rating of any piece of electrical equipment is limited by the maximum permissible temperature in any of its components. For transformers, an additional consideration is the permissible voltage drop through the unit.

The maximum temperature generally accepted is that beyond which the insulation is apt to be damaged. Standards set by engineering and manufacturing groups specify an allowable temperature rise of 55°C above an ambient of 40°C, based on the average temperature of the windings; allowing a 10°C difference between "hot spot" and average temperatures in the windings, a maximum temperature of 105°C is indicated. This value is well below the temperature at which insulation fails, providing a large factor of safety.

Transformers are rated in volt-amperes (or kVA) rather than watts. Since the characteristics of the circuit and its loads affect the power factor of the power being transformed, a poor power factor can cause a large current flow in the coils of the transformer, producing losses and heat, with relatively little actual power delivered. The rating that takes into account the current flow and the voltage applied is the volt-ampere rating.

The rating is based on the current the transformer will carry *continuously* without exceeding the temperature rise limitations. In selecting a transformer to accommodate a load, other factors besides the maximum value of the load must be taken into consideration. Load duration and cyclic variations; the variations in ambient temperatures, especially because of latitudes and seasons; weather patterns of rain, snow, and ice; the age and condition of the transformer and its components—these are all factors that influence how much a transformer may be loaded with respect to its rating. Moreover, since transformers are not tailored to fit the load but are manufactured in standard sizes, there is normally a margin of transformer capacity available for supplying loads above the rating of the transformer for short periods of time.

Transformer Sizes

Standard sizes of distribution transformers change from time to time as economics and situations change. Kilovolt-ampere capacities presently in greatest use include:

Single-phase units: 10, 25, $37\frac{1}{2}$, 50, 100, 167, 250, 333, and 500 kVA. Older units that still exist in service include 1, $1\frac{1}{2}$, 3, 5, $7\frac{1}{2}$, 15, 75, 150, and 200 kVA.

Three-phase units: 75, 150, 300, 500, 1000, and 3000 kVA. Other, older units still in service include 5, $7\frac{1}{2}$, 10, 15, 25, 50, 100, 200, and 450 kVA.

Voltage Ratings

Standards of voltage ratings, on both the primary and secondary sides, as well as the numerical and percentage voltage variations above and below nominal voltage ratings, are specified in the selection of taps included in the primary winding of the transformer; these, too, are subject to revision from time to time in response to changing requirements.

SUBSTATIONS

Location versus Distribution Voltage

Perhaps the first consideration regarding a distribution substation is its location. In general, it should be situated as close to the load center to be served as practical. This implies that all loads can be served without undue voltage regulation, including future loads that can be expected in a reasonable period of time. The difficulty in obtaining substation sites is an important factor in selecting the distribution voltage, both in original designs and in later conversions.

The higher the distribution voltage, the farther apart substations may be located, but they also become larger in capacity and in the number of customers served. Thus, the problem of the number and location of distribution substations involves not only the study of transmission and subtransmission designs, but more emphasis on service reliability and consideration of additional costs that may be justified. The subjects of sectionalizing, field-installed voltage regulators and reclosers, capacitors, and ties to adjacent sources are discussed elsewhere, but are pertinent to the problem.

Supply Feeders and Circuit Breaker Requirements

The number and sources of supply subtransmission feeders to the distribution substation will depend not only on the load to be served, but also on the degree of service reliability sought. Some rural substations may be supplied from only one subtransmission feeder, while substations serving urban and suburban areas have a minimum of two supply feeders and may have several more. Each additional incoming feeder, however, adds to the bus and switching requirements, including auxiliary devices for their protection, all of which add to costs.

Circuit Breaker Arrangements

Some basic arrangements of incoming high-voltage circuit breakers and transformers are shown in Fig. 4-8. Each scheme progressively adds to the reliability of service to the substation and the loads it supplies. For example, in scheme *a*,

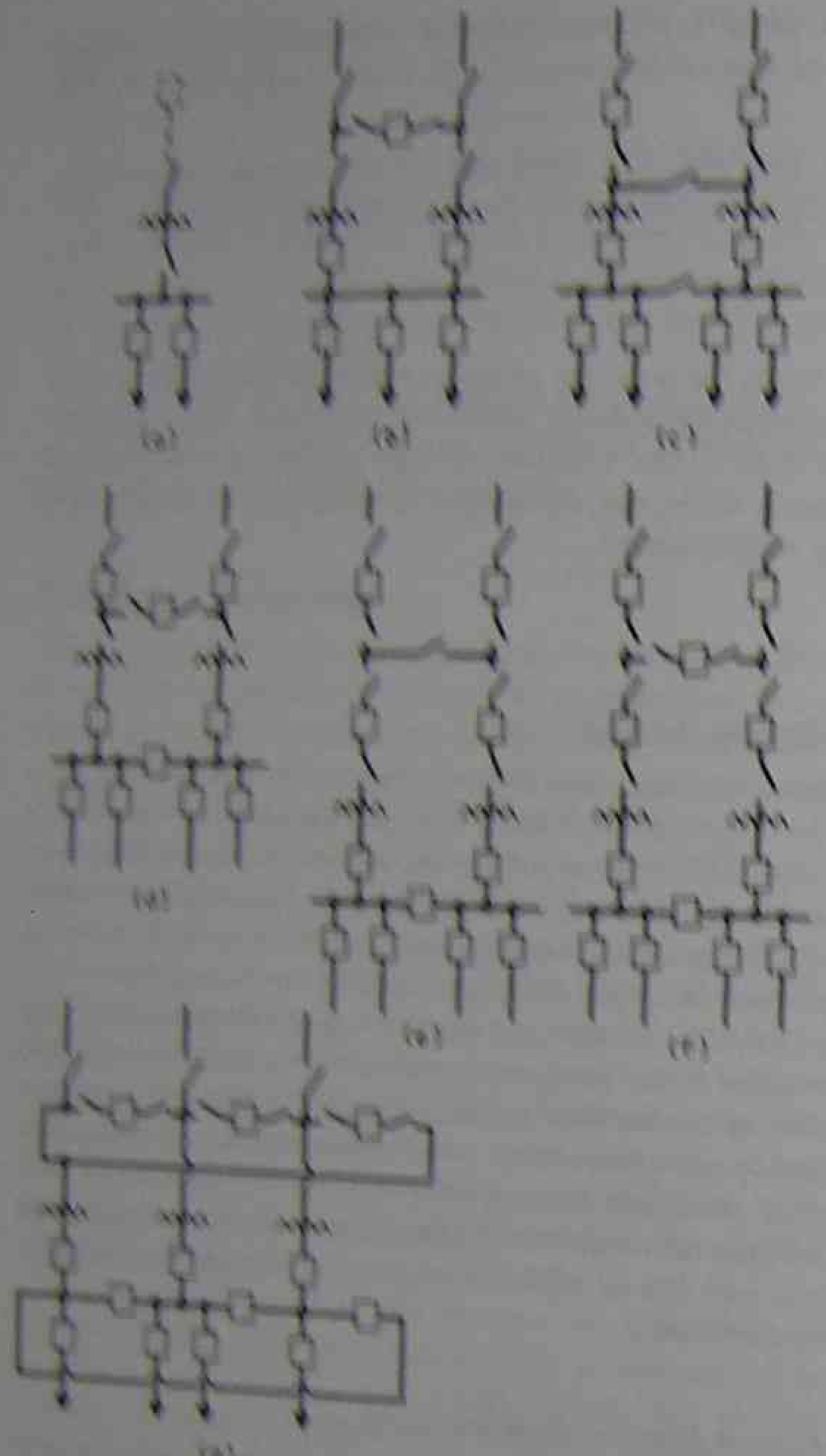


FIG. 4-8 Incoming feeder circuit breaker arrangements.

a failure on the transmission line or substation transformer or bus will trip the breaker back at the transmission source, and service may not be restored until the fault is *found and repaired;* in scheme *b*, such failures will trip the circuit breaker, but service can be restored as soon as the fault is *isolated;* in schemes *c*, *d*, *e*, *f*, and *g* (the last incorporating a ring bus), failures on the incoming transmission lines, transformers, or high-voltage circuit breaker will not interrupt (except for a short time or momentarily) the supply to the bus serving distribution

feeders. Since the cost of high-voltage circuit breakers, together with their accessories, is often as great as or greater than the cost of the transformers with which they may be associated, it is essential that the cost of additional circuit breakers not outweigh the protective advantages gained. It may prove desirable that a minimum number of circuit breakers be installed initially and others added as deemed necessary for any improvement in service reliability that time, increments of load, and customers' requirements may indicate.

Interrupting Duty

The circuit breakers must not only interrupt the normal load current, but must be mechanically able to withstand the forces resulting from the large magnetic fields created by the fault current flowing through them. Since the field will depend on the magnitude of the fault current, which in turn also depends on the voltage of the circuit, the stresses that must be accommodated depend on both of these values. A circuit breaker, therefore, is rated not only on its applied voltage and normal current-carrying capacity, but on its interrupting ability, expressed in volt-amperes (or kVA or MVA); for example, 100-A, 35-kV, or 50,000-kVA interrupting "duty" or capability.

Insulation Coordination—BIL

Circuit breakers and other equipment are subject to high-voltage surges resulting from lightning or switching operations, and the insulation of their energized parts must be capable of withstanding them. Lightning or surge arresters are installed on the conductors and buses of each phase as close to the circuit breakers as practical, with the intent of draining off the voltage surge to ground before it reaches the breaker.

To provide adequate insulation economically and to restrict and localize possible damage to the circuit breaker, the insulation provided for the several parts is coordinated. Internal parts are insulated as equally as practical, but their insulation is generally stronger than that of the bushings, which in turn is stronger than that of the "discharge" point of the associated arrester. Thus, a surge not drained to ground by the arrester will next tend to flash over at the bushings, outside the tank, where damage would be confined, comparatively light, and easier to repair. In general, the insulation of the weakest point in the circuit breaker should be weaker by such a margin as to ensure it will break down before the insulation of the principal equipment it is protecting.

The coordination of insulation requires the establishment of a basic insulation level (BIL) above which the insulation of the component parts of the system should be maintained, and below which lightning or surge arresters and other protective devices operate. This is discussed further in connection with protective devices.

Substation transformers also have their insulation coordinated with that of associated circuit breakers, buses, and other devices.