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APPLICATION OF EL PASO ELECTRIC COMPANY TO CHANGE RATES	§ § §	BEFORE THE STATE OFFICE OF ADMINISTRATIVE HEARINGS

EL PASO ELECTRIC COMPANY'S RESPONSE TO FREEPORT-MCMORAN, INC'S FIFTH REQUEST FOR INFORMATION QUESTION NOS. FMI 5-1 THROUGH FMI 5-4

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DECEMBER 2, 2021

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FMI 5-1:

The following Interrogatory pertains to the Rebuttal Testimony of Paul M. Norman.

Referring to pages 6 and 7, provide all authoritative references that the Hoebel factor is primarily applicable to distribution conductors.

RESPONSE:

The most referenced source used by Mr. Normand is McGraw-Hill 15th Edition of "Standard Handbook for Electrical Engineers." An excerpt from that publication is attached, FMI 5-1, Attachment 1, representing Distribution System Losses (Section 18.28).

The most authoritative reference for losses on the El Paso Electric Company power system is by mathematically modelling the transmission network and calculating losses at peak, intermediate, and low load levels by season which was undertaken. In this manner, we know the losses at a multitude of high and low load levels and all load levels and associated losses in between.

The Hoebel factor is primarily used to explain distribution losses only, and it is mathematically impossible to represent transmission network losses as explained in Normand Rebuttal, page 8, lines 20 – 30.

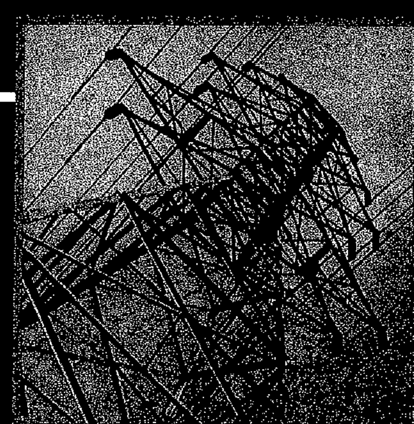
The second article, FMI 5-1, Attachment 2, is authored by H. F. Hoebel where he discusses the development of the loss relationship related to distribution only.

Preparer: Paul M. Normand — Title: Principal, Management Applications Consulting, Inc.

Sponsor: Paul M. Normand — Title: Principal, Management Applications Consulting, Inc.

STANDARD HANDBOOK FOR

Electrical Engineers



Manufacturer *A* switch would be the overall lowest cost and would be the better deal provided the capability and reliability of the two switches are equivalent.

18.28 DISTRIBUTION SYSTEM LOSSES

About 8% of the total output of a large power system is lost or unaccounted for. Much of this loss is in the distribution system. Since investment must be made in facilities to supply these losses, they should be an important consideration in the engineering design of the system. A knowledge of their magnitude is essential and they should not be omitted from overall comparisons of alternative facilities without a study of each specific situation.

Line Losses. The line losses, which are the sum of the I^2R, or resistance losses, can be easily found when the currents at peak load are known. Simplifying assumptions often can be made in making these calculations. For instance, if the load can be considered as being uniformly distributed, the losses are the same as if the total load were concentrated at a point one-third of the way out on the feeder.

Transformer Losses. Transformers have a no-load loss as well as a load loss. The transformer no-load loss is independent of load, whereas the load loss will vary as the square of the current. These losses for distribution transformers are usually published as no-load and total loss when the transformer is operating at rated voltage and rated kVA. The load loss at full-load current is the difference between total and no-load losses.

Working Principles. The problem of converting kWh of lost energy to dollars and cents has resulted in considerable controversy among system operators because of the difficulty of determining the value of the energy. It is not the purpose of this handbook to take sides in the controversy but rather to show the principles involved so that engineers will be able to evaluate losses using appropriate system costs.

The cost of supplying losses can be broken down into two major parts:

1. Energy component, or production cost to generate kWh losses
2. Demand component, or annual costs associated with system investment required to supply the peak kW of loss

The two components of cost usually are combined into a single figure either in terms of cents per kilowatthour of total energy loss or as dollars per kilowatt of peak loss. Expressing losses in terms of dollars per kilowatt is usually called *capitalized* cost of losses, and it has some advantage in that it shows directly the amount of money that could be economically spent to save 1 kW of loss. However, the expression of cost of losses in cents per kilowatthour is usually a more convenient form to use in most engineering studies.

The cost of losses depends on the point in the system at which they occur. The farther out on the system, the greater value losses have. One kilowatt of loss saved on the secondary system is worth more than 1 kW loss at generation because of the cumulative effect of increments of losses as they pass through various elements of the system.

In calculating loss, present-day or future cost of system investment should be used. The primary interest is to find the incremental investment, in dollars, required to supply an incremental load in kilowatts.

Opinions differ widely as to the degree to which the demand component of losses shall be evaluated. This ranges all the way from the dollar cost per kilowatt for future system expansion to no value at all for this component. The great majority of utility engineers prefer to assign full value to the demand component of losses.

Responsibility Factor. Owing to diversity between classes of loads (i.e., residential, industrial, etc.) on a distribution system, peak loads on distribution, transmission, and generation usually do not

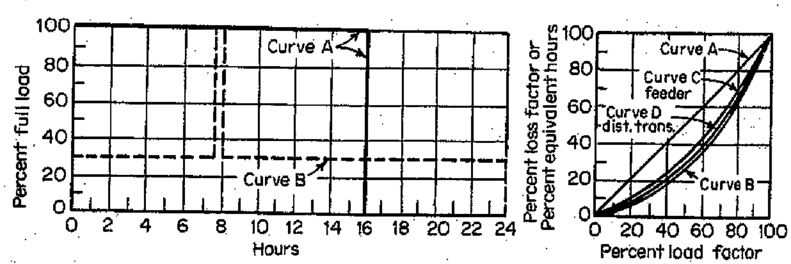


FIGURE 18-67 Relationship between load factor and loss factor or equivalent hours.

occur at the same time. Therefore, a loss which contributes 1 kW to the distribution system peak might contribute less than this to transmission and production plant peak because its maximum does not occur at the same time as the transmission or generation peak. This introduces *peak responsibility factors* used for evaluating cost of losses in various parts of the system.

Loss Factor. If the peak conductor losses of line or transformer have been calculated, it will still be necessary to know the loss factor or percent equivalent hours before it is possible to calculate the actual losses over a period of time. *Loss factor* is usually defined as the ratio of the average power loss, over a designated period of time, to the maximum loss occurring in that period. The term can refer to any part or all of the electric system. It is sometimes referred to as the *load factor of the losses.*

A corollary to loss factor is the term *equivalent hours.* This is defined as the number of hours per day, week, month, or year of peak load necessary to give the same total kilowatthours of loss as that produced by the actual variable load over the selected period of time. The period of time for distribution studies is usually 1 year, and it is obvious that *percent equivalent hours* has the same meaning as the term *percent loss factor.*

Relation Between Loss Factor and Load Factor. Definitions of *loss factor* and *load factor* are quite similar. (*Load factor* is defined as the ratio of average power demand over a stipulated period of time to the peak or maximum demand for that same interval.) Care should be taken that the latter is not used in place of loss factor when considering system losses. There is a relationship between the two factors which depends on the shape of the load curve. Because resistance losses vary as the square of the load, it can be shown that the value of loss factor can vary between the extreme limits of load factor and load factor squared. A number of typical load curves have been studied to determine this relationship for distribution feeders and distribution transformers. The relation is shown in Fig. 18-67. Note that loss factor is always less than load factor except where they are both unity, as would be the case for transformer core losses. The relationship between load factor and loss factor at the distribution transformer can be expressed by the empirical formula

$$\text{Loss factor} = 0.15 \text{ load factor} + 0.85 (\text{load factor})^2$$

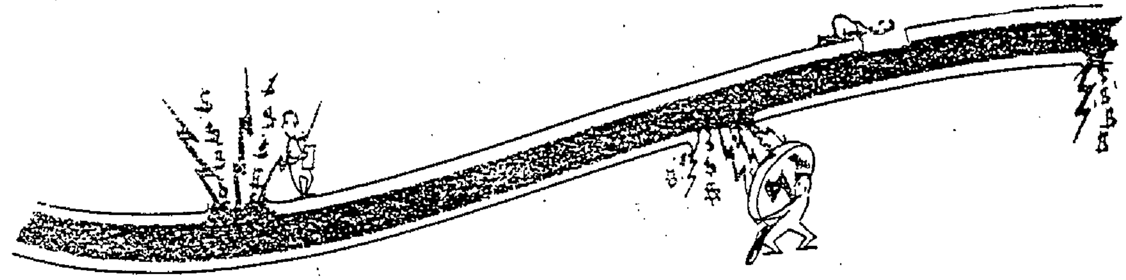
It should be noted that when the shape of the load curve is known or can be reasonably estimated, the loss factor should be calculated directly and not determined by the empirical formula.

Cost of Losses. The two parts of the cost to supply losses are as follows:

$$\text{Energy component} = 8760 F_L E$$

$$\text{Demand component} = F_S P$$

where F_L = loss factor of load
E = cost of energy, dollars/kWh
F_S = responsibility factor
P = annual cost of system capacity, dollars/kW · year



COST OF ELECTRIC DISTRIBUTION LOSSES

Although losses in a particular case may be small, summation of such losses over a period of time can have a pronounced effect on system investment; a clear understanding of their value based on present-day costs should be obtained.

By H. F. HOEBEL,
Manager, Canton Engineering Office, American Electric Power Service Corporation

ABOUT TEN PERCENT of the total output of a large power system is lost or unaccounted for. Since investment must be made in facilities to supply these losses, they should be an important consideration in the engineering design of the system. A knowledge of their magnitude is essential and they should not be omitted from over-all comparisons without a study of each specific situation, even though in certain cases cost of losses is small in comparison with other factors involved in an economic study and may have little effect on the ultimate solution.

There has been a rather wide difference of opinion among utility engineers as to the proper method of evaluating losses and, regardless of the method employed, it is difficult to determine such costs exactly. However, a high degree of accuracy is not essential and certain assumptions can usually be made in order to reduce calculations without affecting validity of results. An approximation based on sound reasoning is certainly better than a guess. For that reason the more important principles used in evaluating losses are discussed and some values of these losses are developed on the basis of present-day costs. These values need not be re-determined for each individual problem but only reviewed occasionally in the light of changing economic conditions.

The discussion is confined to three components of the distribution system: secondary lines, distribution transformers, and primary lines. However, the principles outlined are applicable to any portion of the electric system from the generator to the customer's appliance.

Working Principles

The cost of supplying losses can be broken down into two major parts:

1. Energy component, or production cost to generate kwh losses.

2. Demand component, or annual costs associated with system investment required to supply the peak kw of loss.

The two components of cost are usually combined in a single figure either in terms of cents per kwh of total loss or as dollars per kw of peak loss. Either combination involves a consideration of the term "loss factor" which is developed later in the text. Expressing losses in terms of dollars per kw is usually called "capitalized" cost of losses and it has some advantages in that it shows directly the amount of money a company should be willing to spend to save one kw of loss. In some specific cases, such as evaluating transformer losses, it may be simpler to capitalize the losses and then add this cost directly to the cost of the transformer for making comparisons between various units. However, the expression of cost of losses in cents per kwh is usually a more convenient form to use in most engineering studies.

Evaluating losses in terms of revenue, i.e., at the price received for useful energy, is erroneous. Demand and energy components of customers' usage are entirely independent of losses and there is, therefore, no reduction or increase in kwh sales which can be attributed to incremental loss. Such an evaluation might have some merit on a system where supply is strictly limited and demand is greater than supply, but this is not a realistic situation.

It should be apparent that cost of losses depends on the point in the system at which they occur. The further out on the system, or the closer to the customer, the higher the cost becomes because system investment per kw increases with a corresponding increase in the demand component. Secondary losses cost more to supply than primary losses. Or, expressed another way, savings made by a one-kw reduction in losses at an outlying point on the system are greater than that made by the same one-kw reduction at a point near the generating station.

In calculating cost of losses it is important to use present-day (or estimated future) system investment costs per kw for added capacity rather than average cost of existing plant in service. Cost of plant in service cannot be affected by any presently proposed changes in losses; these can only affect future added investment. Since losses are an incremental kind of load, system investment required to supply them cannot be determined by dividing total plant investment by peak load for the particular year under consideration.

The primary interest is to find the incremental investment, in dollars, required to supply an incremental load, in kw. Experience thus far has shown that these costs are less than the average cost per kw to supply total system load.

Use Of Demand Component

The great majority of utility engineers prefer to assign full value to the demand component of losses. This is sound economically and it is the basis used in this study. Proper consideration, of course, must be given to such factors as peak responsibility, intermediate losses, reserve capacity, and diversity. Assignment of full value to demand is valid on any growing system where losses contribute to peak demand on one or more parts of the system. This is a fair assumption in the case of most present-day systems.

Although losses in a particular case may be small, summation of such losses over a period of time can have a pronounced effect on system investment. For example, assume that present-day installed cost of generating plant capacity is approximately $135 per kw. If the loss at the time of system peak is reduced by one kw in an overhead line or a transformer winding, it increases the available output by one kw plus losses on this one kw back to the source. Unless generating capacity is over-built for many years to come, then, value of the one-kw reduction in loss out on the system is at least $135.

Diversity, Reserve Capacity, And Cumulative Losses

Due to diversity, a loss which contributes one kw to the distribution system peak might contribute something less than this to transmission and production plant peak because its maximum does not occur at the same time as the transmission or plant peak. This introduces "peak responsibility factors" used for evaluating cost of losses in various parts of the system. Peak responsibility applies not only to system peak but to one or more elements of the total system. While this method has certain limitations, it is the simplest to apply with information available and any slight additional accuracy obtained by more refined methods is not warranted.

Reasonable values of peak responsibility factors based on experience with typical circuits and lines are listed below under "Assumptions." These factors for distribution losses vary from time to time and with different types of loads. However, little error is introduced by using estimated average values for these factors when determining working figures for cost of losses which can be applied to all distribution lines on the system.

The investment in the system for one kw of peak loss should include a normal allowance for reserve. The simplest way to introduce this is to assume a reserve capacity equal to a fixed percentage of peak load. It has been assumed in this study that this allowance should be applied to production plant investment only, and that a reasonable figure is 15 percent.

The values of the demand and energy components should also include the cumulative effect of increments of losses, or "losses on losses," as they pass through various elements of the system. Reasonable values for these components are listed under "Assumptions."

Loss Factor

Loss factor is usually defined as the ratio of the average power loss, over a designated period of time, to the maximum loss occurring in that period. The term can refer to any part or all of the electric system. It is sometimes referred to as the "load factor of the losses." It can also be defined as the ratio of the total actual kwh of loss to the kwh of loss there would have been if full load had continued throughout the period under study.

A corollary to loss factor is the term "equivalent hours." This is defined as the number of hours per day, week, month, or year of peak load necessary to give the same total kwh of loss as that produced by the actual variable load over the selected period of time. The period of time for distribution studies is usually one year, and it is obvious that:

Annual equivalent hours = loss factor $\times$ 8760.

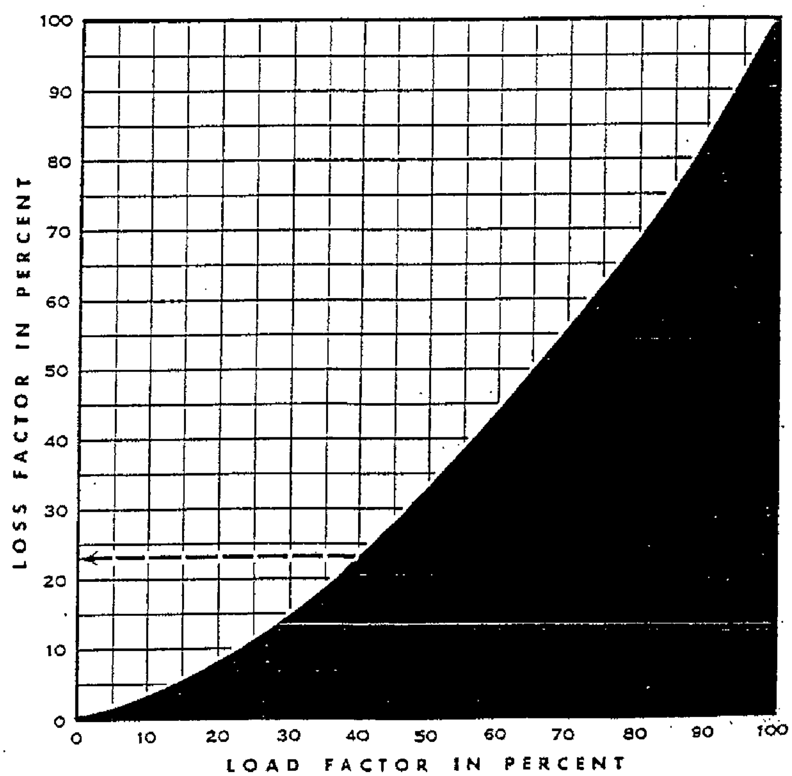
"Percent equivalent hours" has the same meaning as the term "Percent loss factor."

Cost of losses can be combined into one figure and expressed in cents per kwh as follows:

Let E = Energy or production cost per kwh of loss

D = Annual demand cost per kw

Fig. 1—Relation between load factor and loss factor for typical distribution loads. To find annual loss in kwh, multiply the loss factor by the kw loss at peak load by 8760 hours per year.



of loss

C = Combined cost per kwh of loss

kwh of annual loss = kw of loss × loss factor × 8760.

Then, annual cost of losses = E × kwh + D × kw
= E × kw × loss factor × 8760 + D × kw

Also, annual cost of losses =
C × kwh =
C × kw × loss factor × 8760

It is, therefore, evident that:

$$C = \frac{D}{\text{loss factor} \times 8760} + E$$

Loss Factor And Load Factor

Definitions of "loss factor" and "load factor" are quite similar, and the latter is sometimes incorrectly used in place of loss factor when considering system losses. There is, however, a relationship between the two factors which is dependent upon the shape of the load curve. Because resistance losses vary as the square of the load, it can be shown that the value of loss factor can vary between the extreme limits of load factor and (load factor)^2.

A number of typical load curves experienced on a large system have been studied to determine this relationship. Results are shown in Fig. 1. Load curves studied were taken on both distribution circuits and stations with various types of loads and widely varying load factors. The curve in Fig. 1 may be used for either line losses or transformer copper loss; note that loss factor is always less than load factor except where they are both unity, as would be the case for transformer core losses. The relationship between load factor and loss factor can be approximately expressed by the empirical formula:

Loss factor = 0.7 (load factor)^2 + 0.3 (load factor)

Assumptions

To develop a numerical illustration of the method used in arriving at the values of electric distribution losses, the following assumptions have been made:

1. The incremental cost of system investment which is proportional to demand is as follows: production plant—$135/kw; transmission and stations—$78/kva; primary distribution—$20/kva; distribution transformers—$24/kva; secondary distribution—$18/kva.

Except for production plant, incremental costs given above are quite different from average costs of plant in service.

2. Annual fixed charges on investment are assumed to be 14.5 percent. This includes return on investment, federal income tax, depreciation reserve, property taxes, insurance and miscellaneous general expenses. It does *not* include any provision for operation and maintenance.

3. The assumed value of 14.5 percent is directly applicable to production plant investment since operation and maintenance charges for production plant are included in the energy charge. It may also be applied to all other parts of the system if operation and maintenance costs are separately estimated. While such costs are usually not a fixed percentage of plant investment, they are assumed to amount to three percent of investment in order to arrive at the total cost of losses. This results in an annual fixed charge rate of 17.5 percent, including operation and maintenance expenses.

4. Energy cost is assumed at 2½ mills ($0.0025) per kwh.

5. Reserve capacity is taken at 15 percent of production plant demand investment.

6. Percent losses (on the losses) in passing through the various parts of the system are assumed as follows: transmission and station—7%; primary distribution—3% transformers—2%; secondary distribution—2%; total—14%.

The above figures indicate, for example, that one kw of secondary copper loss amounts to 1.02 kw at the secondary side of the distribution transformer, 1.04 kw at the primary side of the distribution transformer, 1.07 kw at the distribution station and 1.14 kw at the generating station.

7. Peak responsibility factors for distribution losses are as follows:

	Losses		
	Primary	Transformer	Secondary
To production plant (system) peak	0.58	0.56	0.56
To transmission and station peak	0.60	0.58	0.58
To primary peak	1.00	0.85	0.85
To transformer peak	......	1.00	1.00
To secondary peak	......	......	1.00

Peak responsibility factors for losses on any part of the distribution system will vary somewhat with the load factor of the load. The values given above are reasonable figures for typical loads encountered on distribution circuits. They should not be used for extremely high load factors. For load factors close to 100 percent use peak responsibility factors of unity on all components of the system. It is apparent that transformer core losses, for example, which have both a load factor and loss factor of 100 percent must contribute to the peak load on all parts of the system.

Computation Of Loss Energy Cost

On the basis of the above assumptions, the following example will illustrate the method used in calculating the cost of losses in cents per kwh. Determine typical distribution transformer copper loss at a load factor of 40 percent. From Fig. 1, this results in a loss factor of 23 percent.

A. Value of energy used in overcoming losses (production cost) = $0.0025 /kwh × loss allowance = $0.0025 × 1.12 = $0.0028 at the transformer

B. Annual cost of investment in system per kw peak load (investment per kw × fixed charges × peak responsibility factor × loss allowance × reserve factor)

1. Production plant
   $135 × 0.145 × 0.56 × 1.12 × 1.15 = $14.12
2. Transmission and stations
   $78 × 0.175 × 0.58 × 1.12 = 8.87
3. Primary
   $20 × 0.175 × 0.85 × 1.05 = 3.12
4. Transformers
   $24 × 0.175 × 1.00 × 1.02 = 4.28

   Annual demand cost per kw = $30.39

C. Cost of losses per kwh =

$$\frac{D}{\text{loss factor} \times 8760} + E = \frac{30.39}{0.23 \times 8760} + 0.0028 = 0.0152 + 0.0028 =$$

$0.0180 per kwh

(See Fig. 2, which indicates cost of 1.80 cents per kwh for distribution transformer copper loss at 23 percent loss factor.)

Relation Between Loss Factor and Cost of Losses

Using the method outlined above, Fig. 2 has been developed to give the relationship between cost of distribution losses (in cents per kwh) and loss factor. Separate curves are shown for secondary system losses, distribution transformer losses and primary system losses.

Attachment FM 5-1-2

Summary

The final results of this study are shown in Fig. 2. Inasmuch as this study is based on present-day costs it could be concluded that values given for cost of losses are conservative and acceptable.

In order to use this data it is necessary to know only the load factor of the load and the total annual kwh of losses. The loss factor for the corresponding load factor can be obtained directly from Fig. 1, and Fig. 2 will then give the corresponding value, in cents per kwh, for the losses. The total annual kwh of losses can be easily determined from Fig. 1 by multiplying the kw loss at peak load by 8760, and the result by the loss factor.

In determining the annual loss factor on a primary distribution line, for example, it is desirable to use a composite, or weighted average, of this factor by proper consideration of the loss factor for typical week-days, Sundays and holidays in both winter and summer. Based on a recent study of a number of distribution load curves, values of annual loss factors within the following ranges can be expected for the various types of circuits listed.

Residential	—0.30 to 0.40
Commerical	—0.35 to 0.45
Rural	—0.20 to 0.30
Industrial	—0.40 to 0.50
General Purpose (Mixed)	—0.33 to 0.43

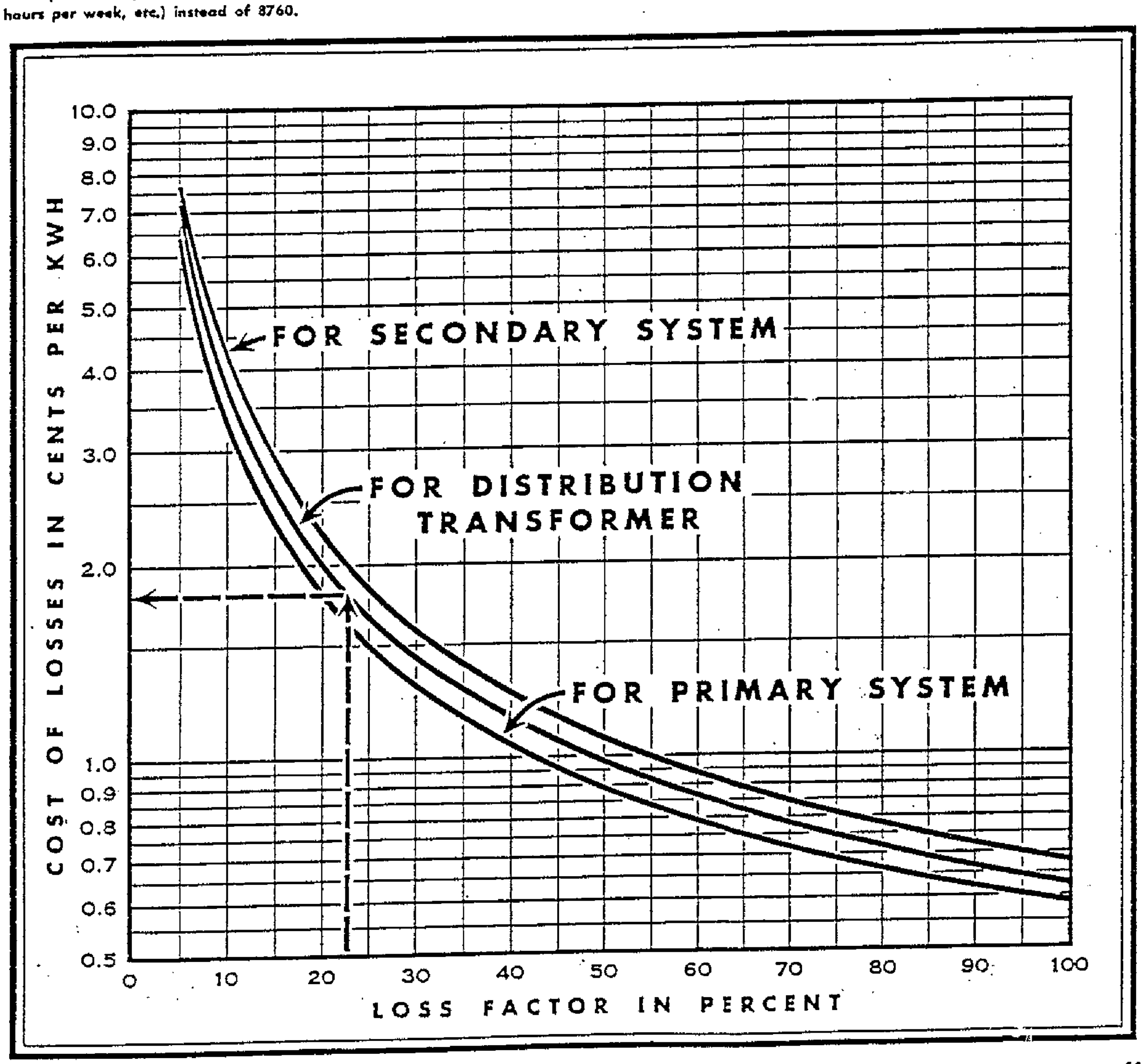
Transformer losses should be considered as consisting of two independent parts:

a. Core loss, which is a constant 24 hours per day loss independent of the amount of load carried. It has 100 percent load factor and 100 percent loss factor.

b. Copper loss, a loss which varies with the load the same as the loss in the line.

Much work has been done, and published, on the development of charts and simplifier formulae which are useful in the determination of peak kw of loss for various conditions of loads, size of conductors, voltages and power-factors. In most cases the computation of peak loss kw is relatively simple.

Fig. 2—Typical costs of electric distribution losses for various loss factors. Use loss factor from Fig. 1. To determine annual cost, multiply appropriate cents per kwh by total annual kwh of losses, also from Fig. 1. For other time periods, use kwh losses for the period (730 hours per month, 168 hours per week, etc.) instead of 8760.



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EL PASO ELECTRIC COMPANY'S RESPONSE TO
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QUESTION NOS. FMI 5-1 THROUGH FMI 5-4

FMI 5-2:

The following Interrogatory pertains to the Rebuttal Testimony of George Novela.

Referring to pages 5-6, please state whether EPE's 15% reserve margin is quantified based on projected system capacity and projected system load at the time of the annual system peak or during the average of the four projected summer system peaks.

RESPONSE:

Historically, EPE has used a 15% planning reserve margin over the projected annual peak load (not a historical peak); however, in the recent 2021 New Mexico Integrated Resource Plan filing, EPE has shifted to the use of the loss of load expectation for all hours of the year and the reserve margin to establish loss of load expectation over all hours, not just the peak hour. EPE intends to use the loss of load expectation methodology going forward.

Preparer:	Enedina Soto	Title:	Manager – Load Research & Data Analytics
Sponsor:	George Novela David C. Hawkins	Title:	Director – Economic and Rate Research Vice President – Strategy & Sustainability

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FMI 5-3:

The following Interrogatory pertains to the Rebuttal Testimony of Manuel Carrasco.

Referring to page 14, line 25 through page 15, line 2, please explain whether the reference to the Rate 15 revenue requirement assumes that FMI's monthly firm demand is 7,500 kW or 5,000 kW.

RESPONSE:

The Rate 15 revenue requirement is based on FMI’s monthly firm demand during the test year of 7,500 kW.

Preparer: Manuel Carrasco Title: Manager – Rate Research

Sponsor: Manuel Carrasco Title: Manager – Rate Research

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FMI 5-4:

The following Interrogatory pertains to the Rebuttal Testimony of Manuel Carrasco.

If FMI were to adjust its firm demand to 5,000 kW, shouldn't its firm revenue requirement be based on 5,000 kW and not 7,500 kW? Please explain why or why not.

RESPONSE:

No. FMI's request to adjust its firm demand from 7,500 kW to 5,000 kW is an adjustment that is significantly outside the 2020 historical test year. Furthermore, that adjustment was not known and measurable when EPE developed its revenue requirement in this proceeding, therefore, the Rate 15 revenue requirement is based on the 7,500 kW firm demand.

An amendment to FMI's interconnection agreement and power service contract with the lower firm demand amount of 5,000 kW has not yet occurred.

Preparer: Manuel Carrasco Title: Manager – Rate Research

Sponsor: Manuel Carrasco Title: Manager – Rate Research