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I am submitting herewith a thesis written by Leonard E. Leech entitled "Simplified Reliability Calculations for Distribution Systems." I recommend that it be accepted for nine quarter hours of credit in partial fulfillment of the requirements for the degree of Master of Science, with a major in Electrical Engineering.

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SIMPLIFIED RELIABILITY CALCULATIONS FOR DISTRIBUTION SYSTEMS

A Thesis

Presented to

the Graduate Council of

The University of Tennessee, Knoxville

In Partial Fulfillment

of the Requirements for the Degree

Master of Science

Leonard E. Leech

December 1977

1346227

ABSTRACT

The object of this thesis was to develop a simplified method for analyzing power substation designs on a reliability versus cost basis and to apply this method to an existing system. The system to which this was applied is the Nashville Electric Service 161kV to 23.9kV distribution system.

Three substation designs were selected as applicable to this system and a probability model for these was developed using the conditional probability equation and the approximate method of combining system probabilities. A 69kV design that has given acceptable service for many years was also analyzed for reference.

Data for use in these models was compiled and includes 69kV and 161kV transmission line outage rates and durations and data applicable to 23.9kV, 69kV and 161kV substation components.

Although the results of this study indicate that a Main and Transfer Bus design with oil circuit breaker similar to existing 69kV designs offers the only improvement in reliability some savings can be effected by using a design with motor operated switching but with marginal decrease in reliability.

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CHAPTER I

INTRODUCTION

Substation designs have developed over the history of the power industry that offer various options to the engineer relative to operating flexibility and cost. Once the need for a station is established, the engineer must determine its initial and ultimate requirements. These include the installed KVA, operating voltage, number of possible incoming and outgoing feeders, and finally the bus configuration to be used.

At generating stations, many of these factors are affected by the amount of on-site generation available. At transmission and distribution stations, however, the load requirements become an influencing factor. Once the substation size and voltage have been determined, the bus configuration selection must be made. It is a difficult choice since it affects the service continuity to the customers. Sophisticated bus configurations with their associated switches, circuit breakers, etc., add to the cost of construction, but improve the continuity of service by some amount.

This thesis has compared three 161kV and one 69kV substation bus configurations on a reliability vs. cost basis. The reliability was determined through application of the approximate method of analysis. This method assumes that the times to failure (reciprocal of the failure rate) and outage durations are exponentially distributed. The approximate method was chosen because a

relative reliability between designs was required rather than an accurate projection of the failure rate. The approximate method also does not require the use of a digital computer to evaluate the system reliability. This is especially important to an engineer that cannot invest the necessary time in more sophisticated techniques or who does not have the required computer programs or facilities available.

Due to economic considerations, efforts are made to standardize designs as much as possible. With the exception of the 69kV substation, all 161kV cases considered were based on a design that allows expansion from simple to more complex arrangements with a minimum of difficulty.

The substation size and operating voltages were based on applications that exist on the Nashville Electric System (see plate 1). This system covers a 625 square mile area. It consists of an inter-connected 69kV subtransmission network serving more than 45 distribution substations totaling in excess of 2600 MVA of transformer capacity. The system receives power from the TVA at four major feedpoints at 69kV with a total 161kV-69kV transformer capacity of 2300 MVA and additional limited 69kV supply from the Old Hickory and Percy Priest Hydroelectric Plants.

Projected load growth for 1980 approximates 240-MW. This means additional feedpoints will be needed to supply the system and provide enough redundancy for transformer bank-out contingencies.

Subsequent growth of the 69kV system, if pursued, will dictate that application of current limiting reactors, circuit breaker replacements or that division of the network be accomplished to provide for the increased short circuit currents.

A decision to utilize an existing 161kV network in a subtransmission voltage conversion therefore is attractive. This coupled with a lease-purchase of existing TVA owned 161-69kV transformations provides NES with its future pattern of growth.

Even though the 69kV system has approached its practical limitations, a need to establish an acceptable level of goodness of service was needed. A 69kV standard substation design that has given adequate service was analyzed for reference in evaluating various options for the 161kV designs.

CHAPTER II

POWER SYSTEM RELIABILITY

Investigation of power system reliability is an investigation of situations involving uncertainty. The likelihood that power apparatus will be available to perform its functions in the power system is uncertain and the amount of time required to restore apparatus to service after a forced outage is also a source of uncertainty. In dealing with uncertainty, probability models and methods are used. One definition of probability is as follows:

> The probability P(A) of an event A is the relative frequency with which event A occurs in a continuing series of very many trails or observations under constant conditions.

If event A occurs N_A times out of n trials then $\hat{P}(A) = N_A/m$ where $\hat{P}(A)$ is the observed relative frequency of event A and the symbol ($\wedge$) indicates that the quantity is an estimate.

"Reliability" may be defined as follows (4):

> Reliability: The probability that an item will perform its intended function for a specified interval under stated conditions.

Another definition as found in Volume II of the FPC report on Prevention of Power Failures is (4):

> Reliability is the degree of assurance of a bulk power supply in delivering electricity to major points of distribution.

Events that cannot occur together are termed "mutually exclusive" or "disjoint" events. In this study events such as

"long outages" and "short outages" as shown in Table VII, Appendix C for a particular piece of equipment are obviously "mutually exclusive" since they cannot occur simultaneously. An assumption that is often made, as is made in this study, is that if an element in a series portion of a system fails, the remainder of this series portion of the system becomes deenergized and the chance of failure of other elements in series goes to zero. The chance of failure, called the forced outage rate or "F.O.R." is determined as follows (1)

F.O.R. = (Time on forced outage)/(Time exposed to forced outage)

Where: Time exposed to forced outage = (Time on forced outage) + (Operating time)

If the occurrence of an event does not affect the probability of another event then the two events are termed "independent." This assumption is made regarding events in this study.

Investigation of power system reliability requires construction of a model in which each circuit element is represented by its individual probability for the event of failure. In order to determine the reliability of the complete system, laws must be established that define how to combine the probabilities of the basic events.

If two or more events are mutually exclusive, the probability of occurrence of at least one of the two events will be the sum

of the individual event probabilities, hence for i events $P(A_1 + A_2 \ldots + A_i) = P(A_1) + P(A_2) + \ldots + P(A_i)$. This is referred to as the Addition Law for Mutually Exclusive Events.

If two events are not necessarily mutually exclusive, this equation must be modified to cover the situation when $P(A_1$ and $A_2) \neq 0$ hence

$$P(A_1 + A_2) = P(A_1) + P(A_2) - P(A_1A_2)$$

The probability of occurrence of an event S that is dependent upon the knowledge that an event H has occurred is called the conditional probability of S given H and is defined as $P(S/H) = P(HS)/P(H)$.

The probability of occurrence of both S and H, P(HS) is:

$$P(HS) = P(H)P(S/H) = P(S)P(H/S)$$

If, however, events H and S are independent:

$$P(HS) = P(H)P(S)$$

This is termed the Product Law for Independent Events.

Consider two events S and H. Event S can be described by:

$$S = SH + S\bar{H}$$

Then: $P(S) = P(S/H)P(H) + P(S/\bar{H})P(\bar{H})$

This equation can be utilized to cover any number of mutually exclusive exhaustive "conditioning" events (H_i).

$$\text{Hence: } P(S) = \sum_{i=1}^{n} P(S/H_i)\ (H_i)$$

The "conditioning" events (H_i) must be both mutually exclusive and exhaustive. It is not necessary that event S have a probability of occurrence for every situation. That is, it is possible for some situation $P(SH_i) = 0$.

Application of the fundamental laws of probability to a complex system is best begun with a two component system. First, however, consider a single component with a probability of the up state of P(0) and down state of P(1). Let us also assume that the unit has a failure rate of λ and a repair rate of u.

$$P(0) = \frac{u}{\lambda + u} \quad \text{and} \quad P(1) = \frac{\lambda}{\lambda + u}$$

The cycle time t or Mean Time Between Failure (MTBF) will be the sum of the mean repair time and the mean time to failure

$$t = \frac{1}{u} + \frac{1}{\lambda}$$

Let $m = 1/\lambda$ = mean time to failure

$f = 1/t$ = cycle frequency

$r = 1/u$ = mean repair time

$t = m + r$

Then: $P(0) = u/(\lambda + u) = m/(r + m) = m/t = 1/(\lambda)(t)$

$= f/X$

And: $P(1) = \lambda/(\lambda + u) = r/(r + m) = r/t = 1/(u)(t)$

$= f/u$

Hence: $f = P(0)(\lambda) = P(1)(u)$

The individual components repair times are assumed to be exponentially distributed (Appendix B).

For two components in series, the state-space diagram shown in figure 1 exists.

The probability of the system being in the up state (success) is dependent upon both systems being up simultaneously. Let $P_1(0)$ and $P_1(1)$ represent the probability of system component 1 being up and down respectively and $P_2(0)$ and $P_2(1)$ the probability of component 2 being up and down respectively.

Then, by the product law of probability

$$P(\text{System Success}) = P_1(0)P_2(0)$$

$$= (u_1/u_1 + \lambda_1)\ (u_2/u_2 + \lambda_2)$$

We wish to represent this two component series system with a single equivalent component with $\lambda = \lambda_{es}$ and $u = u_{es}$ therefore:

$$\lambda_{es}/u_{es} + \lambda_{es} = (u_1/u_1 + \lambda_1)\ (u_2/u_2 + \lambda_2)$$

and since the failure rates are exponentially distributed:

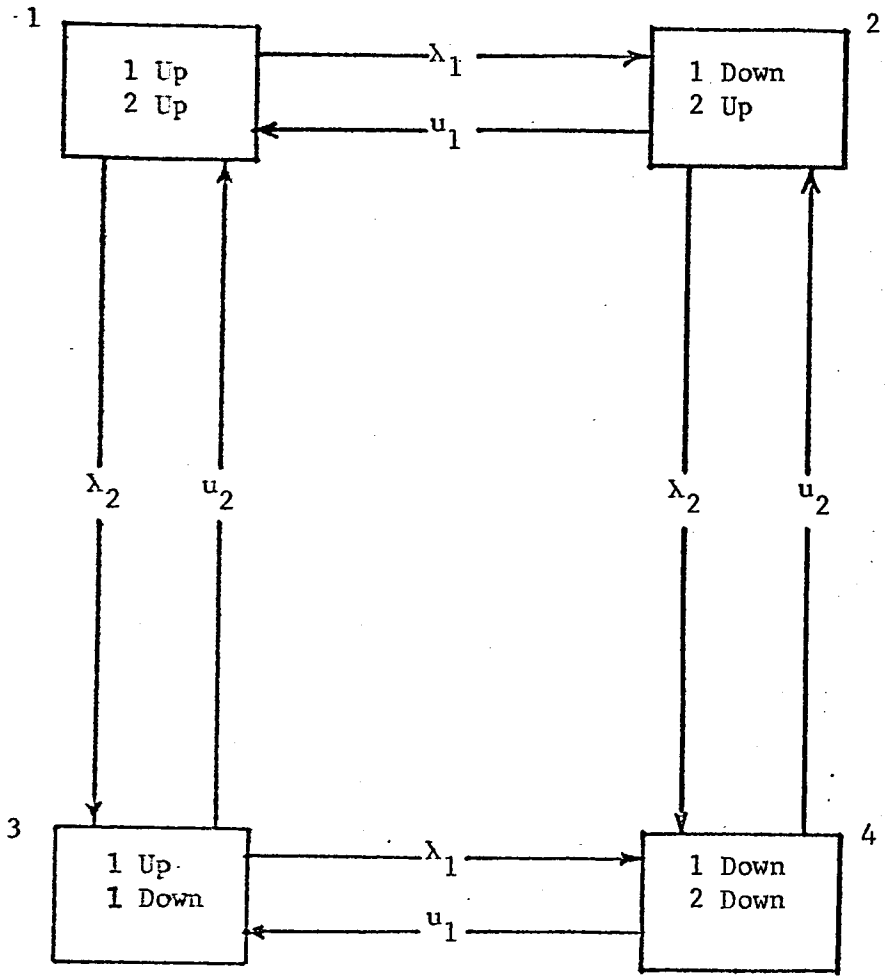


Figure 1. State Space Diagram for A Two Component System.

$$\lambda_s = \lambda_1 + \lambda_2$$

and $$r_s = 1/u_s = (\lambda_1 r_1 + \lambda_2 r_2 + \lambda_1 \lambda_2 r_1 r_2)/(\lambda_1 + \lambda_2)$$

Since for most cases $\lambda_1 \lambda_2 r_1 r_2 << \lambda_1 r_1$ or $\lambda_2 r_2$

$$r_s = \frac{\lambda_1 r_1 + \lambda_2 r_2}{\lambda_1 + \lambda_2}$$

For a two component parallel system, it is desired to develop an equivalent component. With components in parallel, it is assumed that system failure is achieved only if both components are inoperable. In this case, the product law of probability states:

$$P(\text{System Failure}) = P_1(1) P_2(1)$$

$$= (\lambda_1/\lambda_1 + u_1)(\lambda_2/\lambda_2 + u_2)$$

For a single equivalent component that could replace the parallel components with a $\lambda = \lambda_{ep}$ and $u = u_{ep}$

$$u_{ep} = u_1 + u_2$$

$$r_{ep} = \frac{1}{u_1 + u_2} = \frac{r_1 r_2}{r_1 + r_2}$$

Therefore: $\lambda_{ep} = \lambda_1 \lambda_2 (r_1 + r_2)/1 + \lambda_1 R_1 + \lambda_2 r_2$

If $\lambda_1 r_1$ and $\lambda_2 r_2 \prec\prec 1$

Then $\lambda_{ep} = \lambda_1 \lambda_2 (r_1 + r_2)$

These basic relationships for equivalent models combined with the conditional probability relationship were used in the following chapters to reduce complex networks to an equivalent model for which λ was determined. These relationships are summarized in Appendix A.

Some systems for which the composite reliability is desired to be calculated are arranged such that series-parallel reductions cannot be effected. The H or "ladder" type system is such a system. Consider the six component ladder type system in figure 2.

If the occurrence of an event S is dependent upon a number of mutually exclusive events H_i then as previously established:

$$P(S) = \sum_{i=1}^{j} P(S/H_i) P(H_i)$$

Therefore, if event S is defined as system success; and Hx and Hy designate success and failure respectively for component H.

P(System Success) = P(System Success if H is good) P(Hx)
+ P(System Success if H is bad) P(Hy)

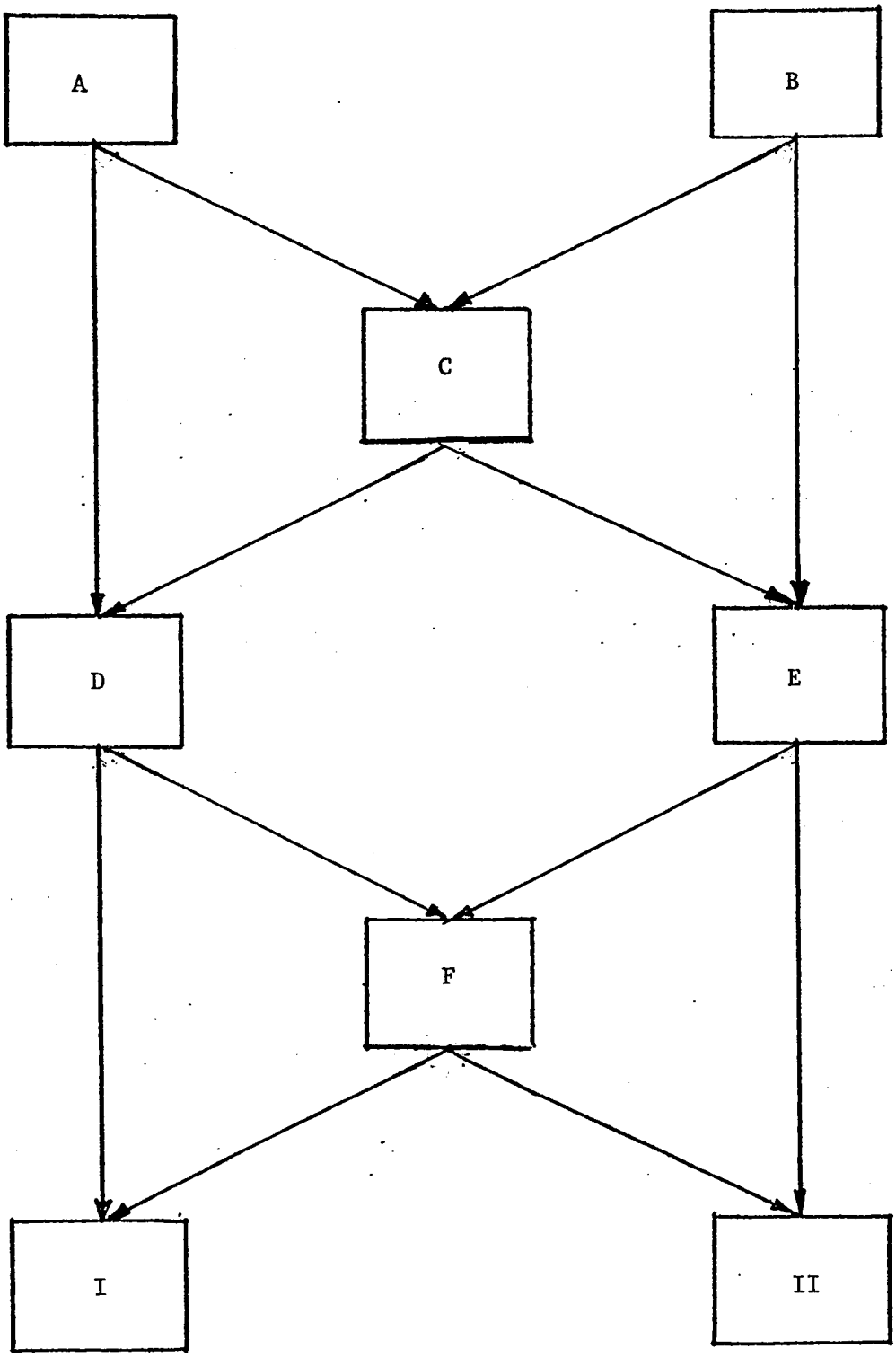


Figure 2. Ladder Diagram For A 6 Component System.

Applying this relationship to the six component system and using the equivalent model parameters λ and r:

CONSIDER NODE I:

$$R(S) = R_s(\text{C UP})\ R_C + R_S\ (\text{C DOWN})\ Q_C$$

(IF A IS UP)

$$R_{SIX} = e\text{EXP}(-t)\ (\lambda_D(\lambda_E + \lambda_F)(r_D + \frac{\lambda_E r_E + \lambda_F r_F}{\lambda_E + \lambda_F}) + \lambda_C) + \ldots$$

$$\ldots + e\text{EXP}(-t)\ (\lambda_D(\lambda_B + \lambda_E + \lambda_F)\ (r_D + \frac{\lambda_B r_B + \lambda_E r_E + \lambda_F r_F}{\lambda_B + \lambda_E + \lambda_F}) + \ldots$$

$$\ldots - e\text{EXP}(-t)\ (\lambda_B(\lambda_B + \lambda_E + \lambda_F)\ (r_D + \frac{\lambda_B r_B + \lambda_E r_E + \lambda_F r_F}{\lambda_B + \lambda_E + \lambda_F}) + \lambda_C)$$

(IF A IS DOWN)

$$R_{SIY} = e\text{EXP}(-t)\left(\lambda_B + (\lambda_E + \lambda_F)(\lambda_D)\left[\left(\frac{\lambda_E r_E + \lambda_F r_F}{\lambda_E + \lambda_F}\right) + r_D\right]\right) + \lambda_C) + \ldots$$

$$\ldots + e\text{EXP}(-t)(\lambda_B + \lambda_E + \lambda_F) - e\text{EXP}(-t)(\lambda_B + \lambda_E + \lambda_F + \lambda_C)$$

$$R_{SI} = R_S \text{ at Node I} = (R_{SIX})(R_A) + (R_{SIY})(Q_A)$$

CONSIDER NODE II

$$R_{SII} = R_S(\text{C UP})R_C + R_S(\text{C DOWN})Q_C$$

(IF A IS UP)

$$R_{SIIX} = eEXP(-t)\left[\lambda_E(\lambda_D + \lambda_F)\left(r_E + \frac{\lambda_D r_D + \lambda_F r_F}{\lambda_D + \lambda_F}\right) + \lambda_C\right] + \ldots$$

$$\ldots + eEXP(-t)\left((\lambda_D + \lambda_F)(\lambda_B + \lambda_E)\left(\frac{\lambda_D r_D + \lambda_F r_F}{\lambda_D + \lambda_F} + \frac{\lambda_B r_B + \lambda_E r_E}{\lambda_B + \lambda_E}\right)\right) + \ldots$$

$$\ldots - eEXP(-t)\left((\lambda_D + \lambda_F)(\lambda_B + \lambda_E)\left(\frac{\lambda_D r_D + \lambda_F r_F}{\lambda_D + \lambda_F} + \frac{\lambda_B r_B + \lambda_E r_E}{\lambda_B + \lambda_E}\right) + \lambda_C\right)$$

(IF A IS DOWN)

$$R_{SIIY} = eEXP(-t)\left(\lambda_B + (\lambda_D + \lambda_F)(\lambda_E)\left(\frac{\lambda_D r_D + \lambda_F r_F}{\lambda_D + \lambda_F} + r_E\right) + \lambda_C\right) + \ldots$$

$$+ eEXP(-t)(\lambda_B + \lambda_E) - eEXP(-t)(\lambda_B + \lambda_E + \lambda_C)$$

$$R_{SII} = (R_{SIIX})(R_A) + (R_{SIIY})(Q_A)$$

The equivalent failure rate for t = one year at Node I and II, are

$$\lambda_I = \ln R_{SI}$$

$$\lambda_{II} = \ln R_{SII}$$

CHAPTER III

DEVELOPMENT OF BASE DATA

The major problem in initiating any type of reliability study is the accumulation of viable data for inclusion therein. Data required for this study include:

69kV Transmission Line Outage Rates
161kV Transmission Line Outage Rates
69kV Substation Component Outage Rate
161kV Substation Component Outage Rate
69kV Transmission Line Repair Times
161kV Transmission Line Repair Times
69kV Substation Component Outage Durations
161kV Substation Component Outage Durations

The following assumptions are made regarding all forced outage rates.

1. Times to failure and repair times are exponentially distributed..

2. Repair times for circuit components are short in comparison to time to failure.

The following assumptions are made regarding all maintenance outage rates.

1. Maintenance outage durations are exponentially distributed.

2. Maintenance is not performed if other components will experience an overload as a result.

3. Maintenance outages occur at random.

69kV Line Outage Rates and Durations

Line outage rates and repair times for a typical 69kV Line were obtained by researching NES System Operating Reports (See Figure 15, Appendix C), for the time period extending from July 1, 1974 to July 1, 1975. Line outages and subsequent repair times were separated into two categories.

A. Forced Outages: Forced outages of all types were included. These consist of:

   (1) Transient Outages such as a relay operation followed by a successful automatic reclose. (Only one automatic reclose attempt is used on NES 69kV Network Lines.)

   (2) Short Time Outages, such as those terminated by a successful operator test by Control Switch or Supervisory Control.

   (3) Persistent Forced Outages that result in extended outage durations while repairs are made.

B. Scheduled Maintenance Outages that occur when a line is deliberately removed from service due to a need to made repairs on line hardware, poles, etc., or a need to move a section of the line because of changes in the right-of-way.

The forced outage data includes all weather conditions and represents a composite failure rate. The failure rate was computed as follows:

$$\hat{b} = \sum Y / \sum X$$

Where : $\hat{b}$ = Failures per mile per year

$\sum Y$ = Total number of outages

$\sum X$ = Total number of miles of line considered in the sample time period.

The average length of 69kV Line for the NES System was calculated to be 3.67 miles. This resulted in an annual outage rate for the average 69kV Line of .575 outages/year for forced outages and 2.123 outages/year for scheduled maintenance.

The average duration of outages was calculated as follows:

$$r = \sum_{i=1}^{n} t_i / n$$

Where: t_i = Total duration of the i th outage.

n = Number of outages

The average duration for forced outages computed to be 28.54 minutes/year and for scheduled outages 253.3 minutes/year.

161kV Outage Rates and Durations

Since no NES 161kV System has existed in the past, it was necessary to research TVA records for data relative to Central Zone operating experience. Four years of operating history were available extending from 1968 through 1971. The outage rate per 100 miles of line was averaged over this time period to be 2.89 faults/100 mi. The average length of the lines being considered

in the NES area is 25.55 miles. This leads to a forced outage rate projection of .7384 outages per year.

No data was available from the TVA for 161kV maintenance. Maintenance figures were derived from the Texas Electric Service System 138 kV data (2) using the 25.55 mile average length of line. This is felt to be acceptable since the right of ways for 138kV lines should differ little from those for 161kV lines and are not as subject to routine modifications such as those experienced at 69kV. Maintenance of 138kV Towers and Hardware, etc., is not expected to be that much different from 161kV equipment.

This data gives a maintenance outage rate of 2.6986 outages/year with an average duration of 540 minutes.

161kV and 69kV Substation Component Outage Rates

Very little data were available for substation equipment from NES or TVA records. The data contained in reference (2) were used to supply this information. Tables V, VI, VII and VIII, Appendix C, are copies of the data from reference (2). Applicable failure rates and durations were chosen from these tables and combined according to the following equations.

$$\lambda = \lambda_{Ta} + \lambda_{Tb} + \lambda_{Pa} + \lambda_{Pb}$$

Where: λ = Forced Outage Rate in Outages/Unit/Year
λ_{Ta} = Transient-cause Forced Outage Rate Due to Faults
λ_{Tb} = Transient-cause Forced Outage Rate Due to False Trips
X_{Pa} = Persistent Cause Forced Outage Rate Due to Faults
X_{Pb} = Persistent Cause Forced Outage Rate Due to False Trips

$$r = \frac{(\sum \lambda_a) r_a + (\sum \lambda_b) r_b}{\lambda_a + \lambda_b}$$

Where: r = Estimate of mean duration of forced outages in minutes
r_a = Mean duration of outages due to faults
r_b = Mean duration of outages due to false trips
$\lambda_a = \lambda_{Ta} + \lambda_{Pa}$
$\lambda_b = \lambda_{Tb} = \lambda_{Pb}$

$$\lambda' = \lambda'_a + \lambda'_b$$

Where: λ' = Scheduled Outage rates in Outages/Unit/Year
λ'_a = Scheduled Short Outage Rate
λ'_b = Scheduled Long Outage Rate

$$= \frac{(\sum \lambda'_a) r'_a + (\sum \lambda'_b) r'_b}{\lambda_a + \lambda_b}$$

Where: r' = Estimate of mean duration of maintenance outages in minutes
r_a' = Mean duration of short maintenance outages
r_b' = Mean duration of long outages

The data from reference (2) combined using these relationships is assembled in Tables I, II, III, and IV.

TABLE I

COMPOSITE SUBSTATION COMPONENT FORCED OUTAGE RATES

Component	FORCED OUTAGE RATES--OUTAGES/UNIT/YEAR Transient-Cause $\lambda_{Ta,Tb}$	Persistent-Cause $\lambda_{Pa,Pb}$	Equivalent Forced Outage Rates λ^*
138/dist. transformer	0.0^2641	0.0705	.0769
69/dist. transformer		0.0304	.0304
138-kV circuit breaker			
a Faults	0	0.0^2181	.0832
b False trips	0.0615	0.0199	
69-kV circuit breaker			
a Faults	0.0^2121	0.0^2484	.0821
b False trips	0.0652	0.0109	
Distribution circuit breaker			
a Faults	0.0^2_2161	0.0^2_2801	.0187
b False trips	0.0^2641	0.0^2268	
138kV Bus	0.0^2_2774	0.0^2_2258	.0103
69-kV Bus	0.0^2629	0.0^2228	.0085
Distribution bus	0.0145	0.0200	.0345
138-kV air switch	0.0^2_2160		.0016
69-kV air switch	0.0^2565	0.0^3942	.0066

*$\lambda = \lambda_{Ta} + \lambda_{Tb} + \lambda_{Pa} + \lambda_{Pb}$

TABLE II

COMPOSITE SUBSTATION COMPONENT PERSISTENT FORCED OUTAGE DURATION AND SWITCHING TIME STATISTICS

Component	Estimate of Mean Duration, Min.. r, r_a, r_b	r^*
138/dist. transformer	$r = 150$	150
69/dist. transformer	$r = 135$	135
138-kV circuit breaker		
Faults	$r_a = 425$	131.5
False	$r_b = 125$	
69-kV circuit breaker		
Faults	$r_a = 426$	147
False	$r_b = 125$	
Distribution circuit breaker		
Faults	$r_a = 334$	201.6
False trips	$r_b = 62$	
138- or 69-kV bus	$r = 221$	221
Distribution bus	$r = 117$	117
69-kV air switch	$r = 162$	162
Distribution bus regulator		
Repair	$r = 1264$	1264
Bypass	$r = 105$	105
69-kV Transmission		
Manual switching time	$r = 34$	34
69-kV transformer fuse		
Replacement time	$r = 171$	171

* $r = \dfrac{(\sum\lambda_a)r_a + (\sum\lambda_b)r_b}{\sum\lambda_a + \sum\lambda_b}$

TABLE III

COMPOSITE SUBSTATION COMPONENT SCHEDULED OUTAGE RATES

Component	Scheduled Outage Rates Outages/Unit/Year $\lambda'_{a,b}$	Equivalent Scheduled Outage Rates λ'^{*}
138/69-kV transformer		
a Short outages	1.028	
b Long outages	0.079	
138/dist. transformer		
a Short outages	0.720	.9190
b Long outages	0.199	
69/dist. transformer		
a Short outages	0.259	.2920
b Long outages	0.0326	
138-kV circuit breaker		
a Short outages	0.662	.6982
b Long outages	0.0362	
69-kV circuit breaker		
All outages	0.414	.414
138-kV bus		
a Short outages	0.0943	.10314
b Long outages	$0.0^{2}884$	
69-kV bus		
a Short outages	0.0291	.0302
b Long outages	$0.0^{2}110$	
Distribution bus		
a Short outages	0.0497	.0600
b Long outages	0.0103	
138-kV air switch		
All outages	0.0109	.0109
69-kV air switch		
All outages	0.0373	.0373
Distribution circuit breaker		
(Assumed)	0.414	0.0414

* $\lambda' = \lambda'_{a} + \lambda'_{b}$

TABLE IV

COMPOSITE SUBSTATION COMPONENT SCHEDULED OUTAGE DURATION STATISTICS

Component	Estimate of Mean Duration, Min. r'_a, r'_b	r^*
138-dist. transformer		
Short outages	$r'_a = 236$	3807.6
Long outages	$r'_b = 16730$	
69/dist. transformer		
Short outages	$r'_a = 213$	1973
Long outages	$r'_b = 15957$	
138-kV circuit breaker		
Short outages	$r'_a = 178$	280.66
Long outages	$r'_b = 2158$	
69-kV circuit breaker		
All outages	$r' = 157$	
138-kV bus		
Short outages	$r'_a = 257$	424.8
Long outages	$r'_b = 6037$	
69-kV bus		
Short outages	$r'_a = 262$	492
Long outages	$r'_b = 6602$	
Distribution bus		
Short outages	$r'_a = 269$	1605
Long outages	$r'_b = 8051$	
138-kV air switch		
All outages	$r' = 259$	259
69-kV air switch		
All outages	$r' = 74$	74

$$*r' = \frac{(\sum\lambda'_a)r'_a + (\sum\lambda'_b)r'_b}{\sum\lambda'_a + \sum\lambda'_b}$$

CHAPTER IV

SYSTEM MODELS

Selecting bus configurations for inclusion in a reliability study involves examination of all possible schemes and subsequent rejection of those not applicable for the system to which the chosen scheme is to be applied. This thesis concentrated on application to situations existing on the Nashville Electric Service System. A bus configuration that can be "switched" in a matter similar to those used in stations existing on the system will cause less difficulty from an operating standpoint. A design that can be expanded from one bus configuration to a more complex one with a minimum of down-time and expense is attractive since it will serve a radial distribution system that is not totally redundant from other sources. These types of constraints rule out such arrangements as 161kV "ring-bus" and "breaker and a half" schemes because of structural arrangement. Sophisticated bus schemes such as the "Z-bus" were considered too expensive for a distribution application. This leaves the following designs as applicable on the 161kV system.

A. "TAPPED LINE"

B. "MAIN AND TRANSFER BUS WITH MOTOR OPERATED DISCONNECT SWITCHES"

C. "MAIN AND TRANSFER BUS WITH OIL CIRCUIT BREAKERS"

In addition to the above, a "69kV MAIN BUS WITH-NO TRANSFER" configuration was analyzed, (Figure 16 Appendix C). Although

69kV substation design is not the subject of this study, some standard level of reliability must be established as a reference. This 69kV substation design has proven adequate in the past and therefore represents an entirely adequate design from a reliability standpoint.

The 69kV Main Bus With-no Transfer Configuration

The system in Figure 16 Appendix C was redrawn as shown in Figure 3 and subsequent series-parallel reductions made. These series-parallel reductions produced the system shown in Figure 4.

The system was reduced from that in Figure 4 using the probabilistic approach. Since the system is fully redundant, the non inclusion of maintenance outages was not considered to be a large source of error. The outage rate derived from this analysis is .1181 outages per year, which is a very low outage rate.

The 161kV Tapped Line Configuration

The most simple installation that can be made to provide 161kV to 23.9kV transformation service is the tapped line configuration. This configuration is illustrated in Figure 5. In this configuration, the substation is totally dependent upon the entire length of line and the series components for reliability. In the event of a substation failure, the station can, however,

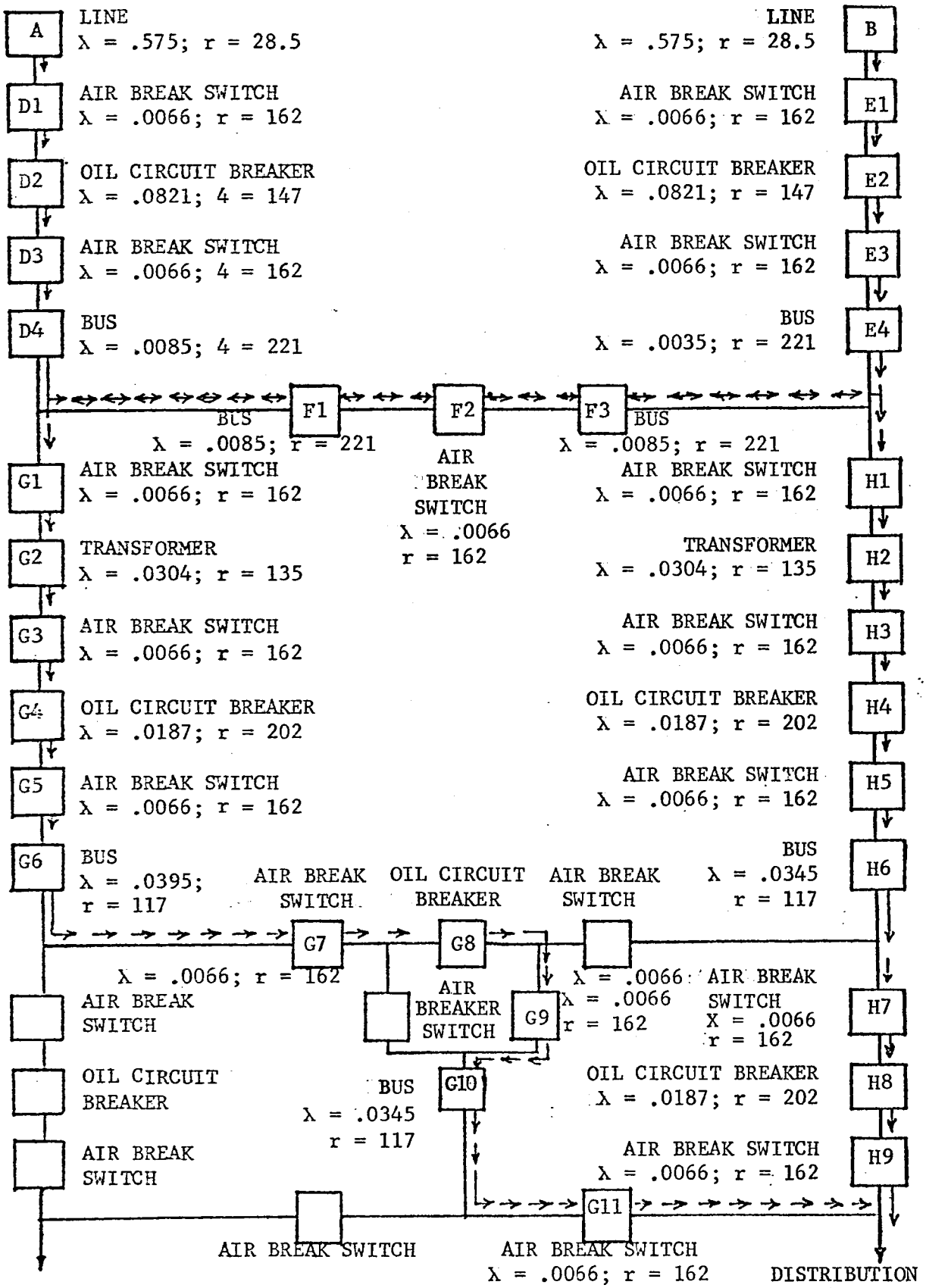


Figure 3. System Block Diagram - 69-kV Main Bus.

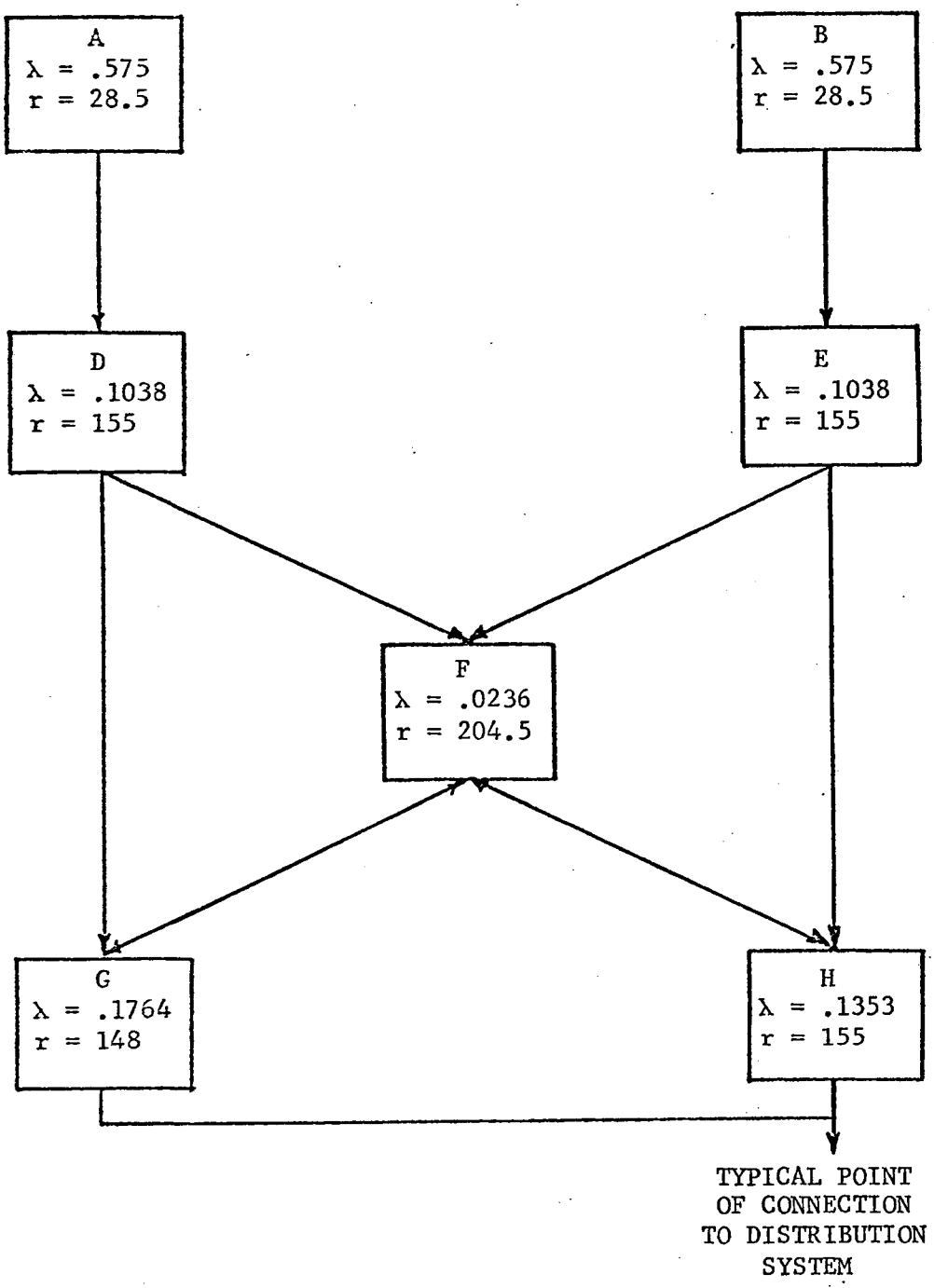


Figure 4. Equivalent System Diagram - 69-kV Main Bus Configuration.

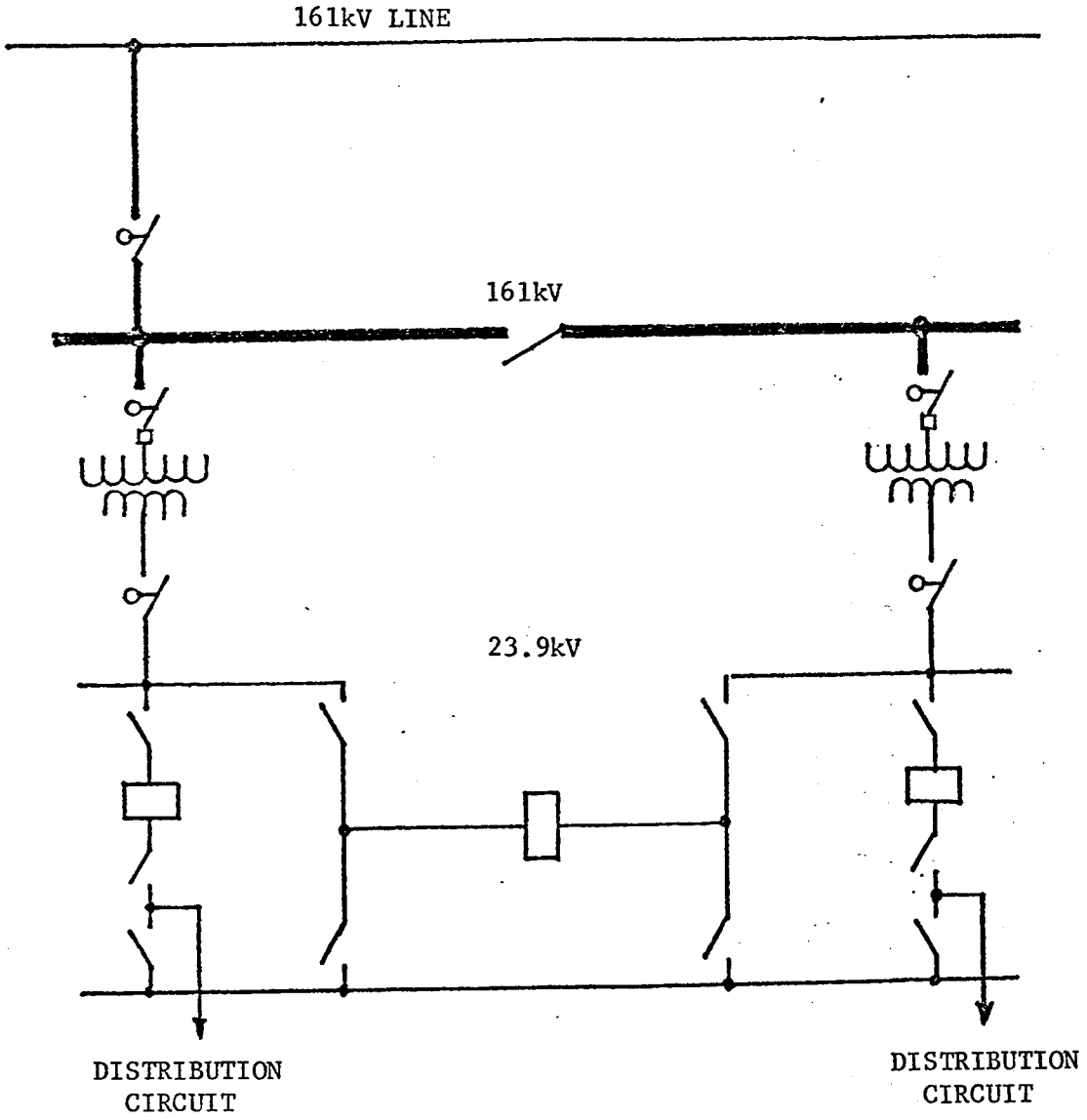


Figure 5. One Line Diagram of a Proposed Tapped Line Configuration.

be sectionalized from the line so that the line is made available for other system load.

In the analysis, each substation component was replaced with a block showing the outage rates and durations for each and assembled into the equivalent system shown in Figure 6.

The system was then reduced to the equivalent system shown in Figure 7, using the relationships in Appendix A for forced and maintenance outages.

The resulting system outage rate was determined to be .750371 outages/year using forced outages and 2.7228 outages/year due to maintenance. The outage rates are those present at a typical point of connection to a distribution circuit.

It is likely that the maintenance figure calculated is highly pessimistic since scheduled maintenance on the line, tap section, disconnect switches or 161kV main bus would probably be done at a time that loading conditions would permit transfer of all of the station load to another source via the distribution system. If system loading reaches a point that this opportunity does not present itself then the forced outage rate and the maintenance outage rate must be combined. This yields a combined outage rate approaching 3.566 outages per year. This is a totally unacceptable figure.

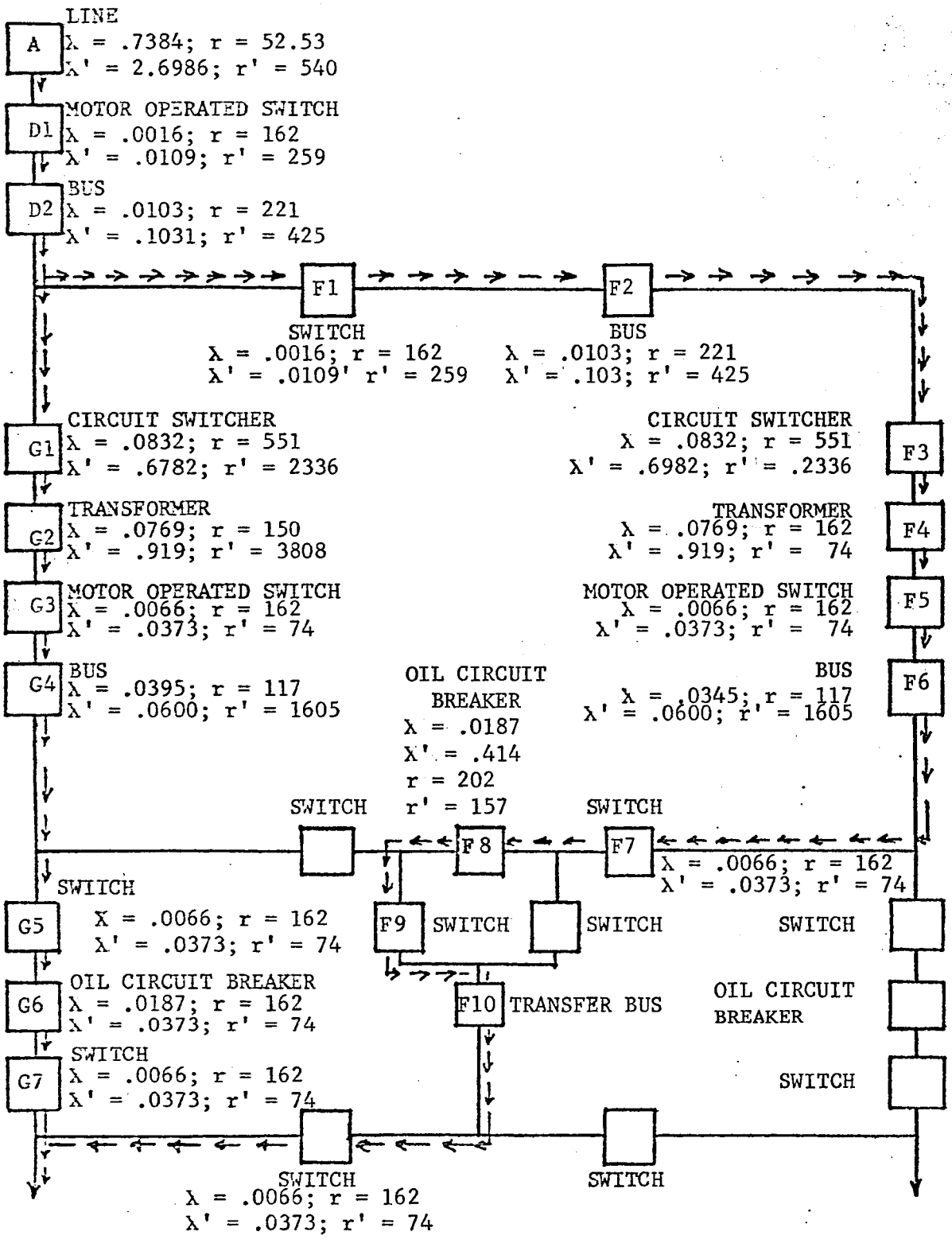
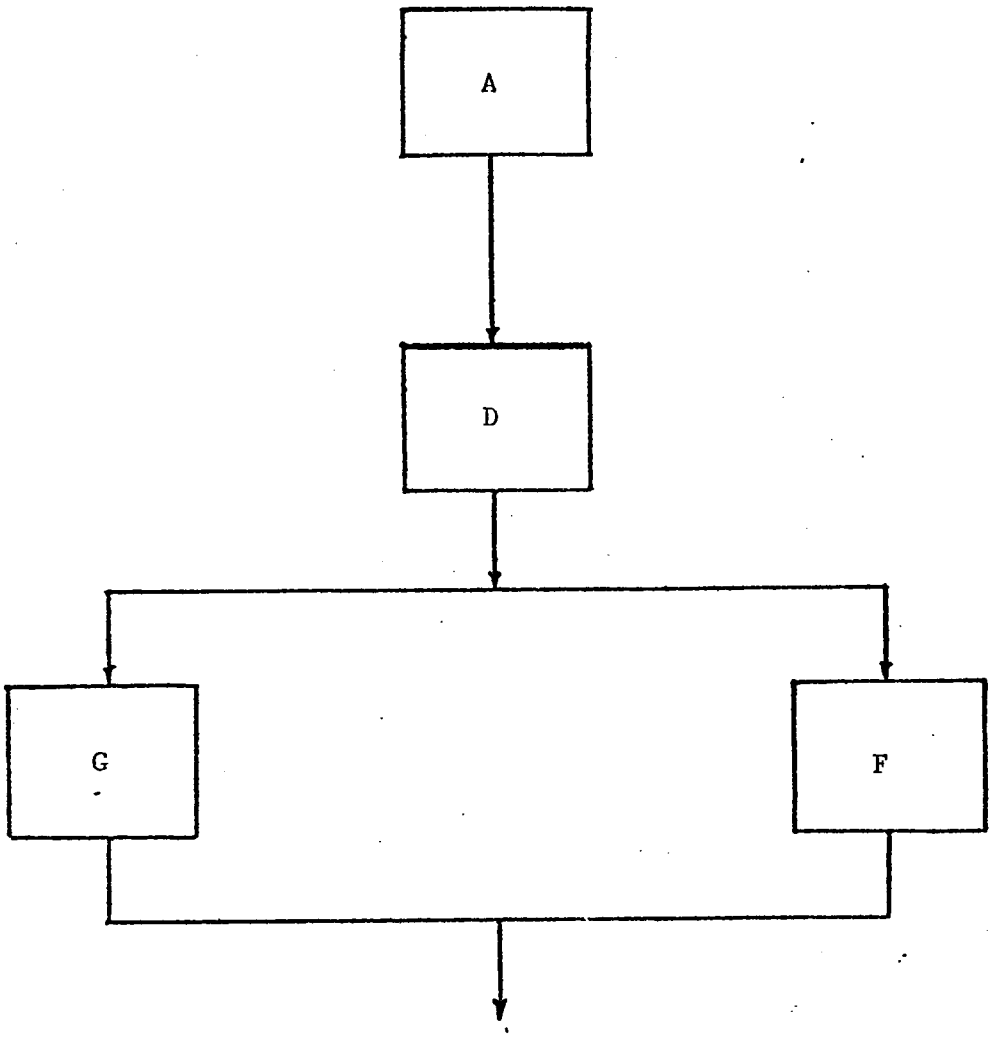


Figure 6. System Block Diagram - Proposed 161-kV Tapped Line Configuration.



$\lambda_A = .7384$	$r_A = 52.53$ min.	$\lambda'_A = 2.6986$	$r'_A = 540$ min.
$\lambda_P = .0119$	$r_B = 213$ min.	$\lambda'_D = .1190$	$r'_B = 3.23$ min.
$\lambda_F = .2450$	$r_F = 289.5$ min.	$\lambda'_F = 2.2243$	$r'_F = 2386$ min.
$\lambda_G = .2742$	$r_G = 268$ min.	$\lambda'_G = 2.3004$	$r'_G = 2347$ min.

Figure 7. Equivalent System Diagram - Proposed 161-kV Tapped Line Configuration.

The 161kV Main and Transfer with Motor Operated Disconnect Switch Configuration

The need for sectionalization of line sections that are either faulted or undergoing scheduled maintenance is desirable as shown by the analysis of the 161kV Tapped Line Configuration. Disconnect switches can be employed in the configuration shown in Figure 8 to effect this sectionalization. In order to keep the down time to a minimum, these switches are motor operated and controlled remotely by supervisory control. This configuration makes the station totally redundant with the exception of transient forced outages. Any 161,V fault will bring the total system down. However, sectionalizing times should be very short and service restored in a few minutes.

This system is reasonably complex from a reliability standpoint and does not lend itself to complete analysis using the series-parallel reductions of the approximate method.

The outage rate for a typical connection to the distribution system was calculated using a probabilistic approach after all possible series-parallel combinations had been made. (See pp. 50 Ref. 1). This type of analysis does not provide for calculation of outage durations and as such does not include the effect of maintenance on outage rates. Unlike the tapped line configuration, this system is totally redundant and maintenance outages should not affect the total outage rate significantly.

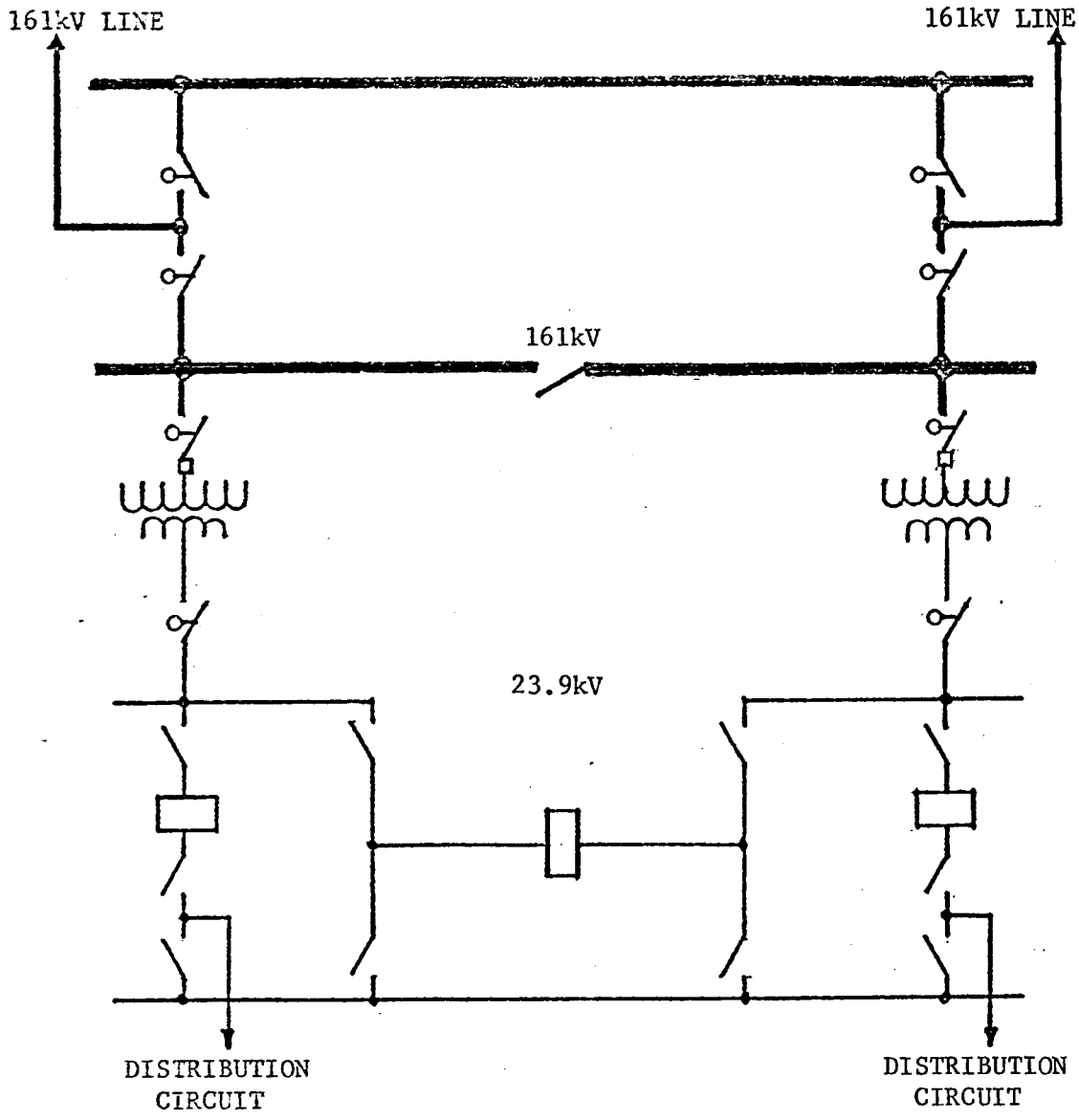


Figure 8. One Line Diagram 161kV Main and Transfer with Motor Operated Disconnect Switches.

The system diagram was assembled into an equivalent block diagram (Figure 9) for reduction using the relationships in Appendix A. After completion of this reduction the system became as shown in Figure 10.

At this point, the ability to make series-parallel reductions disappears and the relationship developed in Chapter II is required to reduce the system to its equivalent total.

These calculations give an equivalent outage rate of .8113 outages/year.

The 161kV Main and Transfer Configuration with Oil Circuit Breakers

If improvement of the reliability of the system over that offered by the Main and Transfer with Motor Operated Disconnects is desired, the use of oil circuit breakers to speed up sectionalization of line faults as shown in Figure 11 is applied. This, in effect, makes the system tie to two independent lines since a fault on one line section should not cause operation of the other. It is assumed for this study that the station is constructed at the mid-point of an average line-length section and therefore the source outage rate is reduced to one half that used in the analysis of the other 161kV arrangements. This also assumes that the outage rate is proportional to line length.

As in the previous cases, the system one-line diagram was converted to an equivalent block diagram as shown in Figure 12.

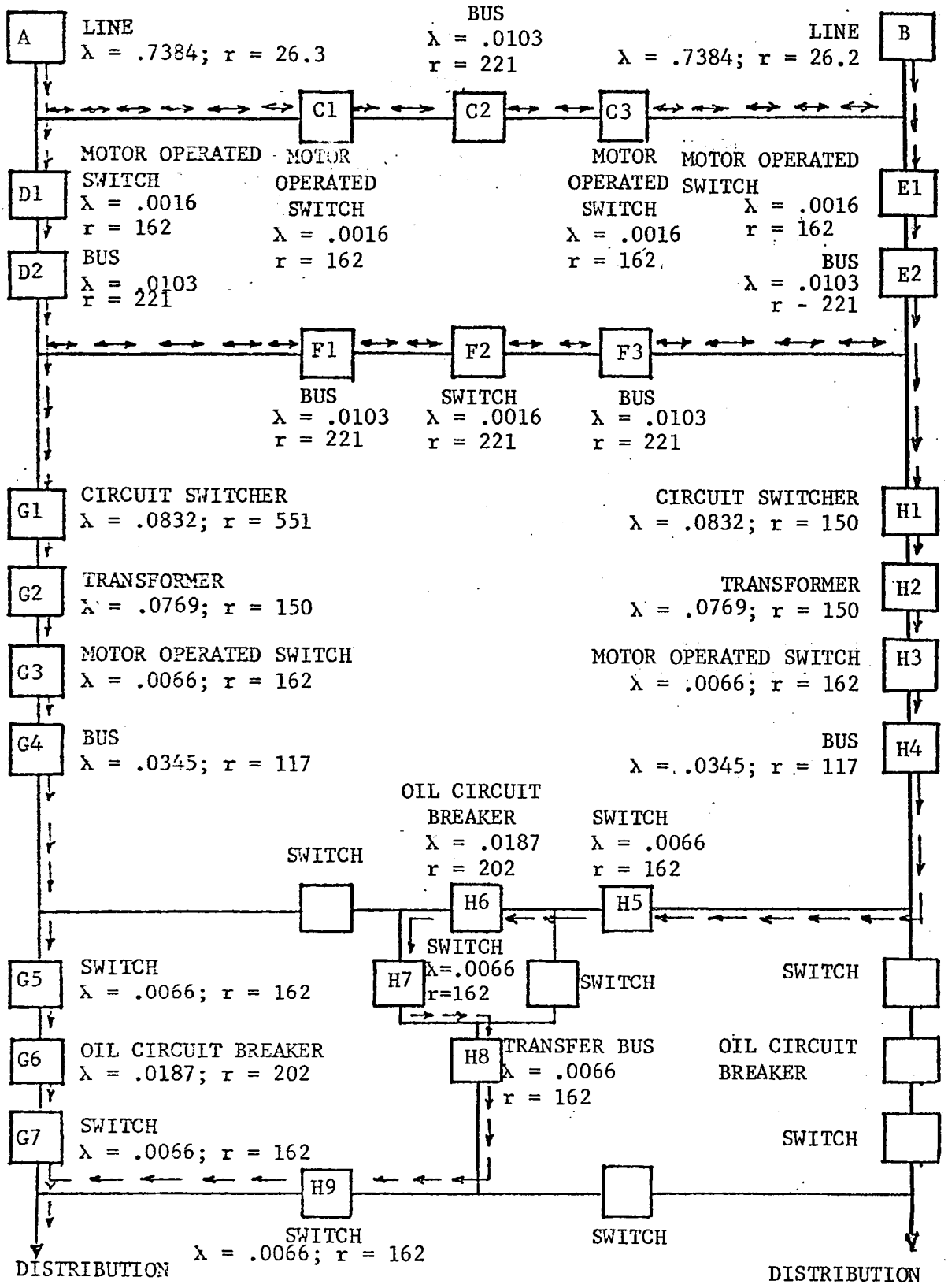


Figure 9. System Block Diagram - 161-kV Main Bus and Transfer with Motor Operated Disconnect Switches.

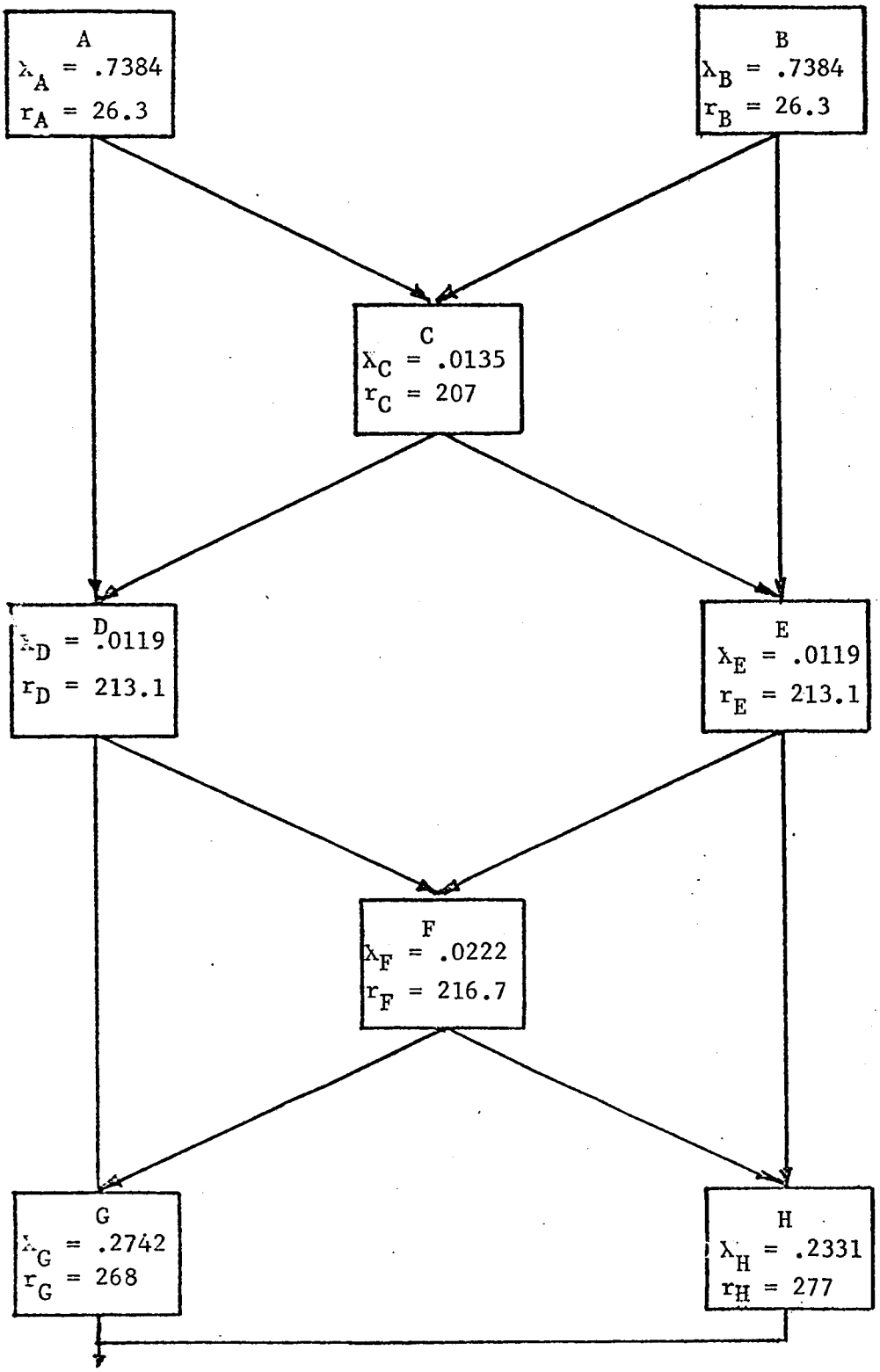


Figure 10. Equivalent System Diagram - 161-kV Main and Transfer with Motor Operated Disconnect Switches.

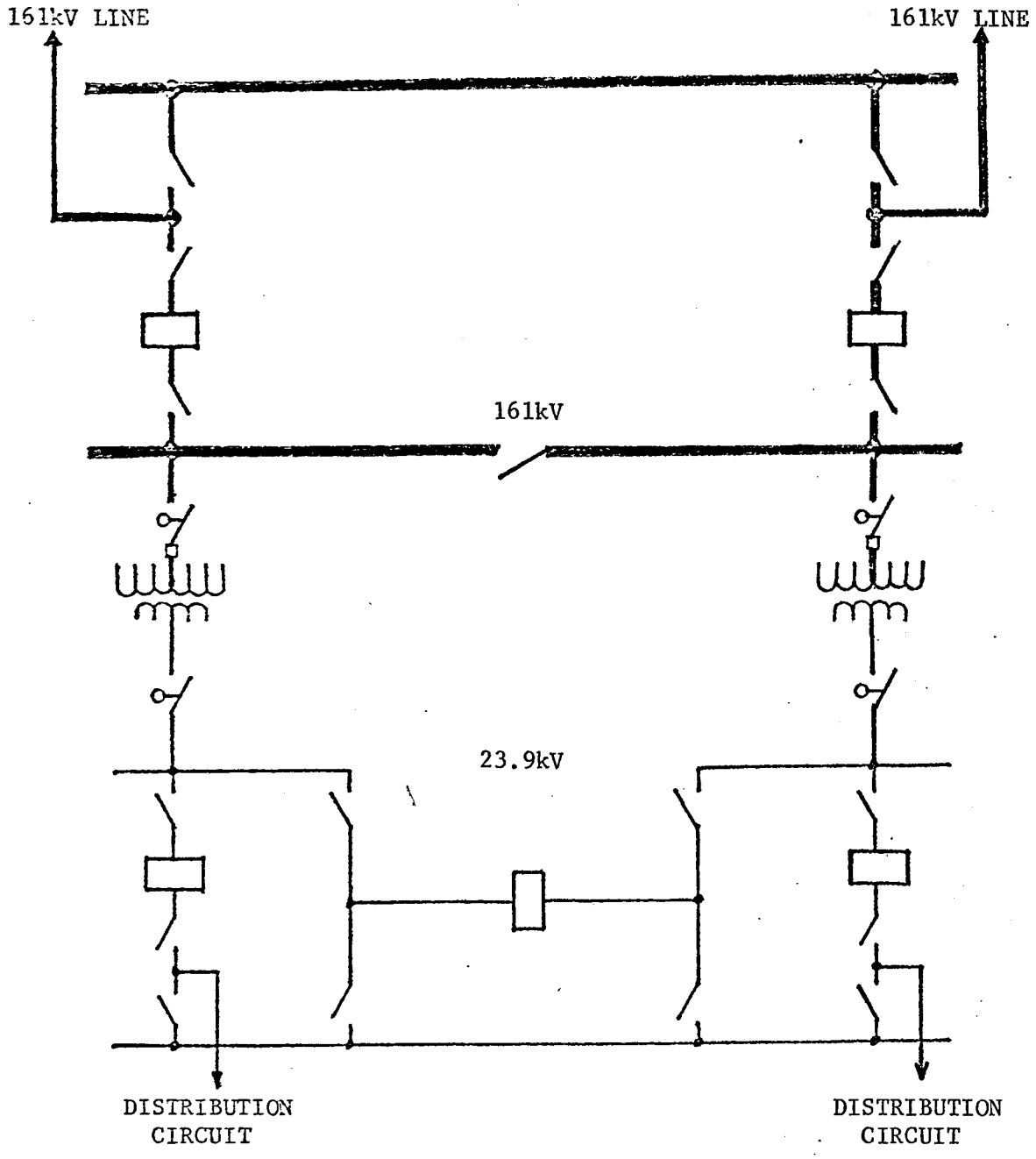


Figure 11. One Line Diagram of a 161-kV Main and Transfer Bus With Oil Circuit Breakers.

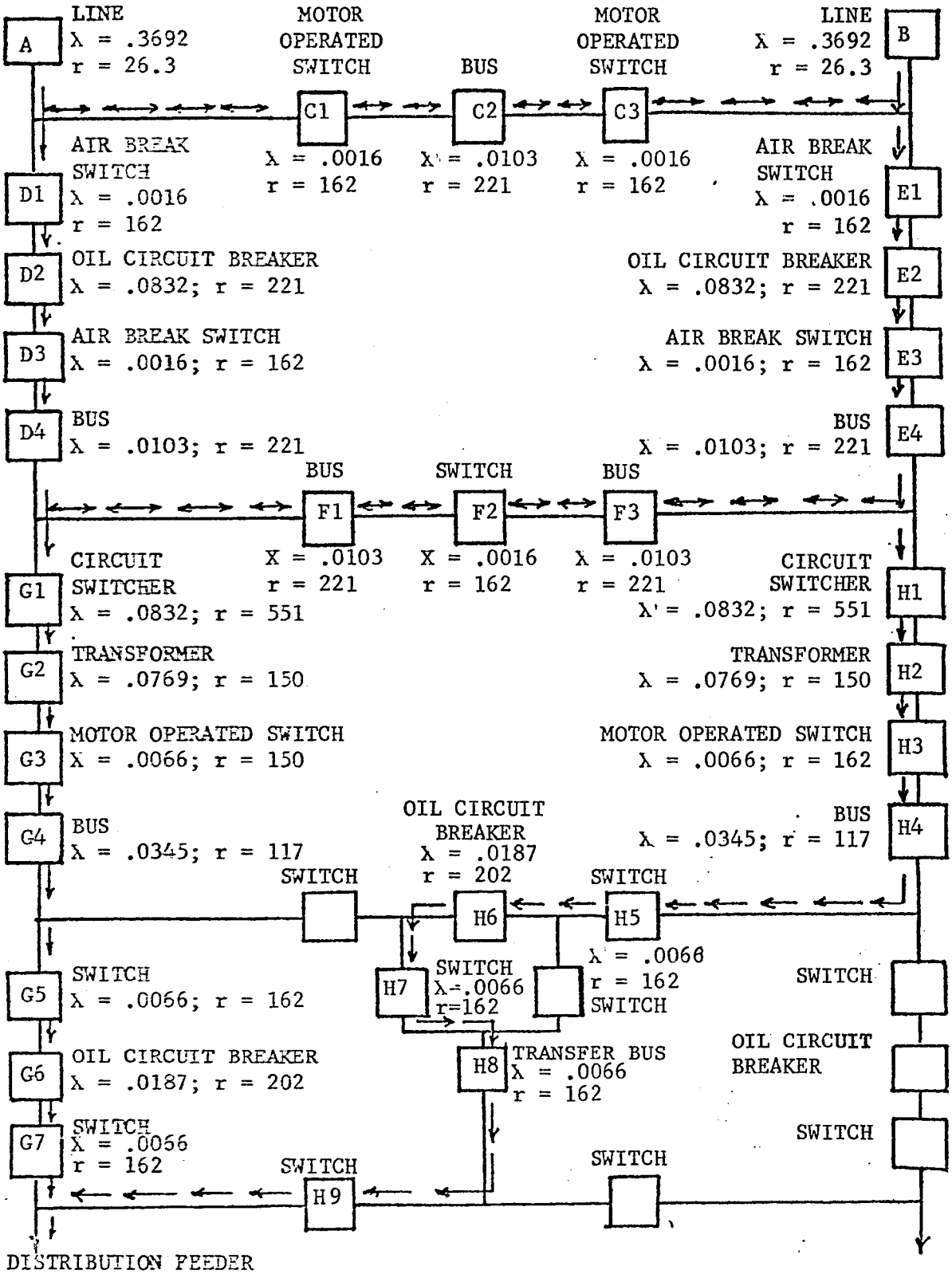


Figure 12. System Block Diagram - 161-kV Main and Transfer Bus with Oil Circuit Breakers.

Subsequent reductions of this system through the use of the relations in Appendix A are shown in Figure 13.

Since no further series-parallel reductions could be made, the relationships developed in Chapter II were applied.

Since this system is fully redundant, the absence of inclusion of maintenance outages should not significantly affect the net outage rate of the system.

The total equivalent outage rate for this system neglecting maintenance outages is .0928 outages/year.

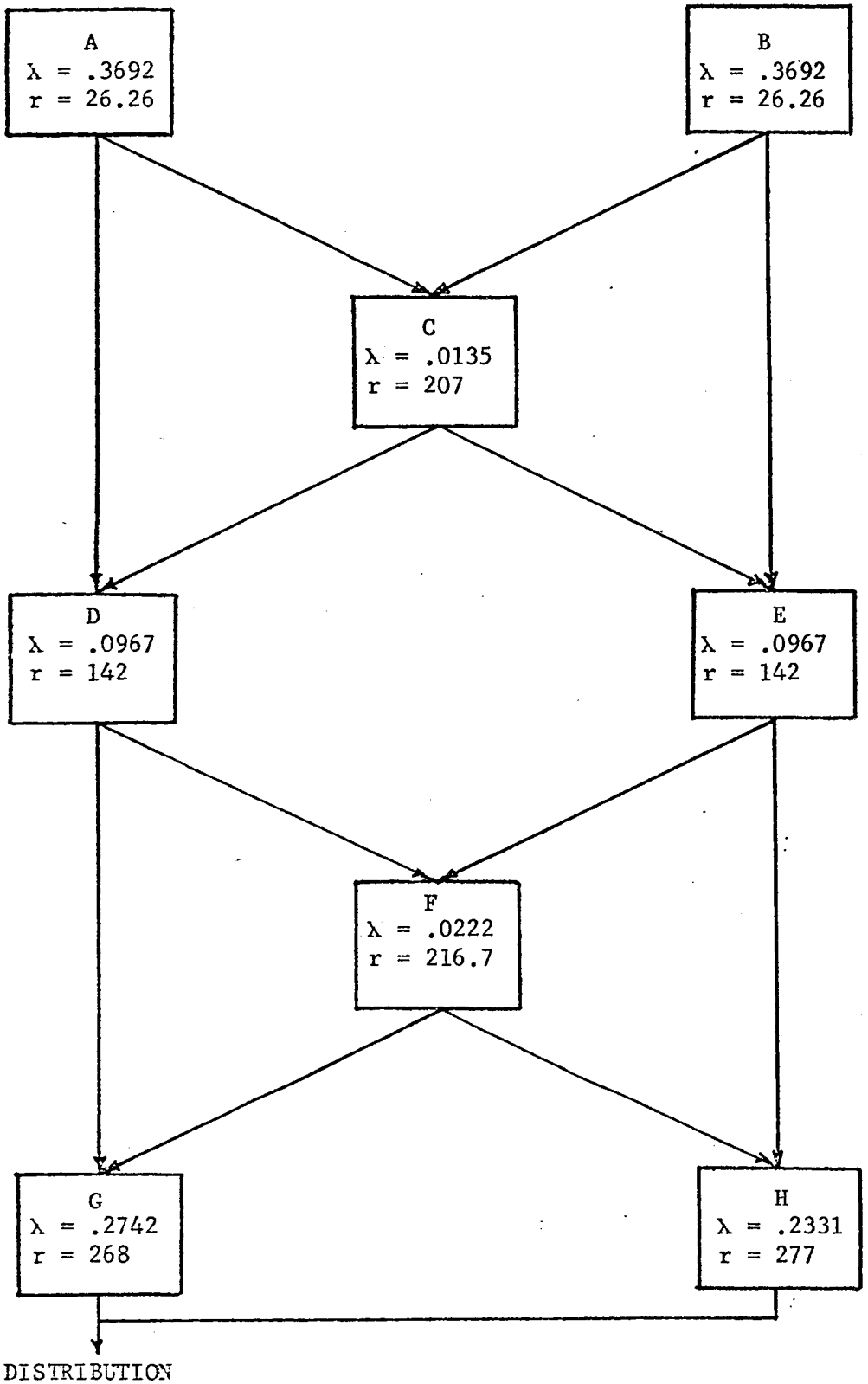


Figure 13. Equivalent System Diagram - 161-kV Main and Transfer With Oil Circuit Breakers.

CHAPTER V

CONCLUSIONS

This study was made using actual field obtained data for equipment and transmission lines and not hypothetical data. Improvement in accuracy could have been obtained if a larger sampling had been available. This is a contining problem in performing any type of reliability analysis. More recently, power companies have started to realize the potential savings in plant investment that can be made by prudent examination of reliability studies. Continuing accumulation of data will provide better data for future studies. Since a comparative analysis of various bus configuration rather than an actual prediction of outage rates was the object of this study, errors caused by small sample space should be minimal.

Since this is a cost vs. reliability comparison the substation cost must be made as accurately as possible. The 23.9kV portions of each configuration are almost identical. The primary difference in the cost of the 161kV design versus an equivalent 69kV design is the higher cost of transformers and circuit breakers for 161kV. The basic cost of steel and insulation contribute only a marginal amount to the cost. The cost estimates were made using 1977 cost data and include all materials, labor cost, and typical overhead expenses. It should be borne in mind that, in practice, there are other considerations that should be

made regarding cost of installation. Among these is the potentially large cost of building a 69kV or 161kV line to the site. Another is the impact on system network loading that could require line additions or bundling of existing lines on the system.

Substation Costs were determined to be as follows:

a. 69kV Main and Transfer ---------- $1,200,000

b. 161kV Tapped Line ---------- $1,450,000

c. 161kV Main and Transfer with Motor Operated Disconnect Switches ---------- $1,500,000

d. 161kV Main and Transfer with Oil Circuit Breakers ---------- $1,700,000

This cost data is illustrated in Figure 14, along with the equivalent forced outage rate λ for each case.

As can be seen from this diagram, with the exception of the "Tapped Line" arrangement, all designs offered less than .9 outages per year due to substation and supply line outages. The total outage to the customers served by one of these stations will be higher than this, however, due to the additional outages experienced by the distribution circuit that serves his location. This thesis analyzed the substation design only. This is acceptable because the distribution circuit outage rate will be common to all designs from the customer's standpoint. Addition of distribution circuit outages to the station outage rates obtained should indicate that any of the designs are applicable with the exception that the possibility of maintenance outages that must

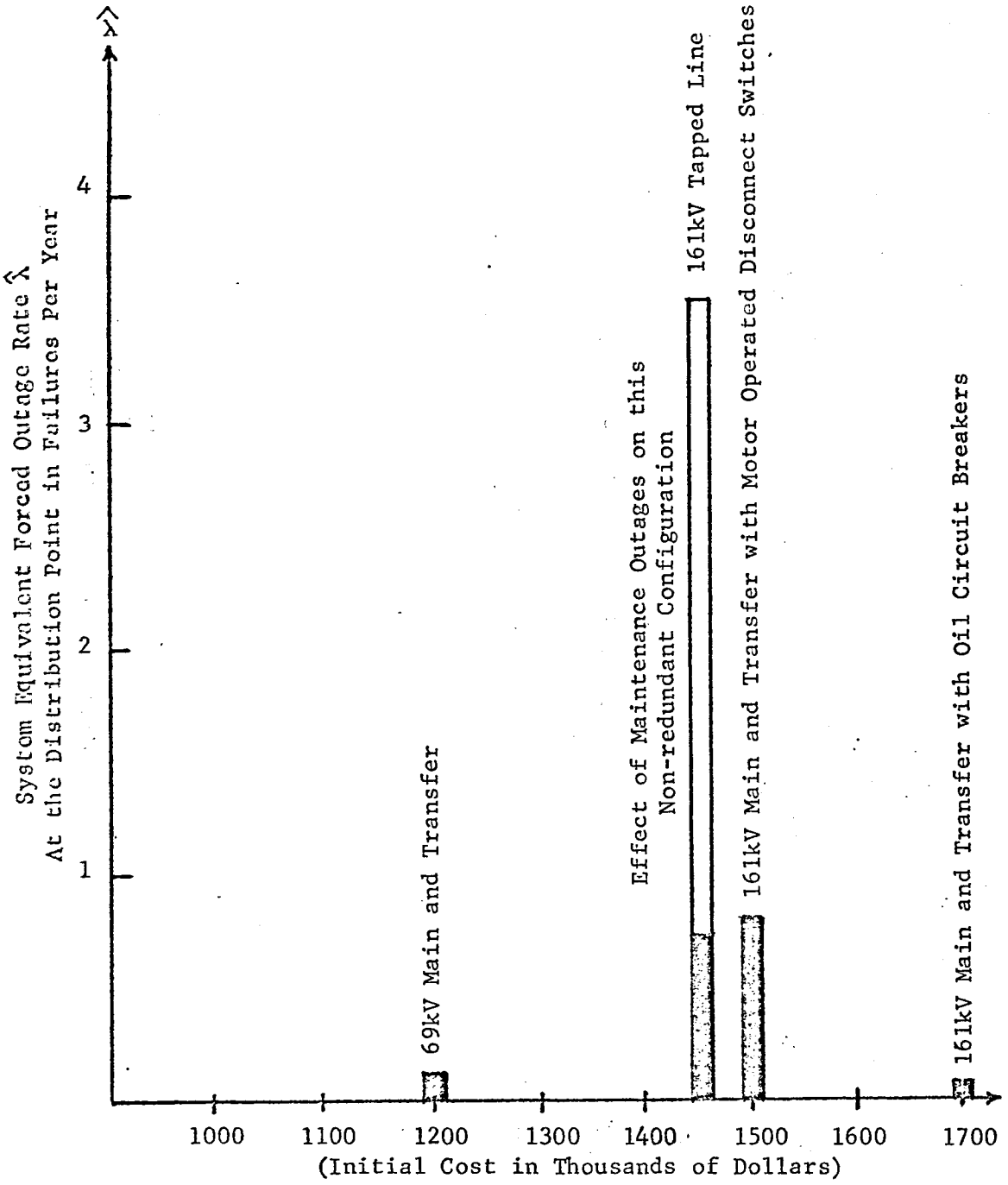


Figure 14. Cost vs. Reliability Bar Graph.

be considered in the "Tapped Line" case will make this design not applicable when the distribution load is not transferable to other sources such as mobile transformers or other stations. The "161kV Main and Transfer With Circuit Breakers" is the only design offering more reliability than the previous 69kV station design. This design, however, is 14 percent higher in initial cost than the "161kV Main and Transfer With Motor Operated Disconnect Switches" arrangement and carries with it higher yearly maintenance costs and more complication in operation. In view of this and the fact that the range of outage rates is basically low and a customer will incur the additional distribution circuit outages which will be even more of a factor relating to goodness of service, it is probable that selection of the "161kV Main and Transfer With Motor Operated Switch" design would be made.

In conclusion, a simple model has been developed as shown on page 12. Utilizing this model, two specific system configurations were analyzed. This model was limited to six components in a ladder type configuration. In addition, two other models were analyzed using similar but simpler models. The use of this type model is applicable to hand calculation and does not require the use of a digital computer. Use of the model developed permits optimization of cost of substation design.

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BIBLIOGRAPHY

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APPENDIXES

APPENDIX A

RELATIONSHIPS FOR COMBINING SERIES AND PARALLEL ELEMENTS OF A SERIES

The relationships for combining series elements of a system is given by the product, law of reliabilities. If there are n components in series, the reliability of the system is:

$$R_s = R_1 \cdot R_2 \ldots R_n = \sum_{i=1}^{n} R_i$$

If the components in the system are operating in their useful life period in a constant failure rate environment, then the reliability of a component as a function of time is:

$$R(t) = e^{-\lambda t}$$

The series system reliability is:

$$R_s(t) = e^{-\sum_{i=1}^{n} \lambda_i t}$$

In a parallel system that is redundant, the system reliability is related to the product law of unreliabilities:

$$Q_s = \prod_{i=1}^{n} Q_i$$

Where Q_s is the unreliability of the system. The system reliability R_s for an n component system is given by:

$$R_s = 1 - \prod_{i=1}^{n} Q_i$$

For a two component system:

$$R_s = 1 - Q_s = R_1 + R_2 - R_1R_2$$

If component down times R_i' are known, they may be included in the parallel reductions of the equivalent model parameter using the following equations:

Series System

$$r_s = \sum_{i=1}^{n} \lambda_i r_i / \sum_{i=1}^{n} \lambda_i, \quad \lambda_s = \sum_{i=1}^{n} \lambda_i$$

Parallel Two Component System

$$\lambda_p = \lambda_1\lambda_2(r_1 + r_2)$$

APPENDIX B

THE EXPONENTIAL DISTRIBUTION

The numerical value of the operating time to failure and the duration of time for repair for power equipment are examples of random variables. One of the ways to specify the probability law of a random variable is through the use of a distribution function. For random variable X the distribution as a function of t is $F(t) = P(X \leq t)$. The event that the observed value of X is less than or equal to t is defined by $(X \leq t)$.

The most commonly used distribution in power system reliability studies is the exponential distribution.

$$F(t) = 1 - e^{-\lambda t} \qquad t > 0$$

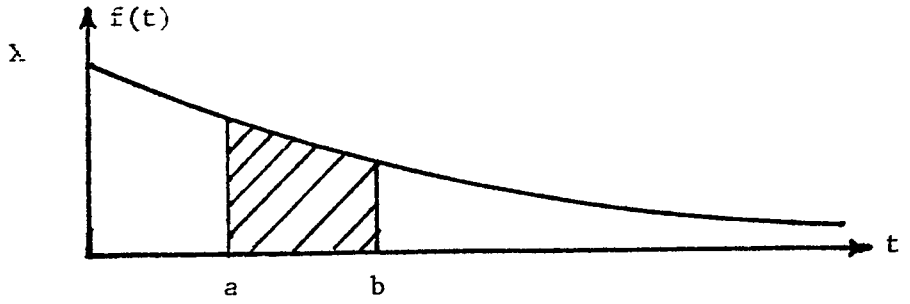
If F(t) is the probability of the event of failure by the time t then the reliability, or probability of success, will be $1 - F(t)$ or $R(t) = e^{-\lambda t}$.

In order to understand the validity of use of the exponential distribution for power system analysis, let us proceed as follows:

The exponential probability density function is obtained by differentiating the exponential distribution function:

$$f(t) = dF(t)/dt = \lambda e^{-\lambda t} \qquad t > 0$$

This function appears as follows



The probability that the event X occurs between a and b is obtained by integrating over the interval a to b. Hence

$$P(a \leq X \leq b) = \int_a^b F(t)dt.$$

If F(t) is the probability of failure, the reliability or probability of survival R(t) is: $R(t) = 1 - F(t)$.

$$\frac{dR(t)}{dt} = d(1 - F(t)) = - F(t)$$

F(t) being the failure density function.

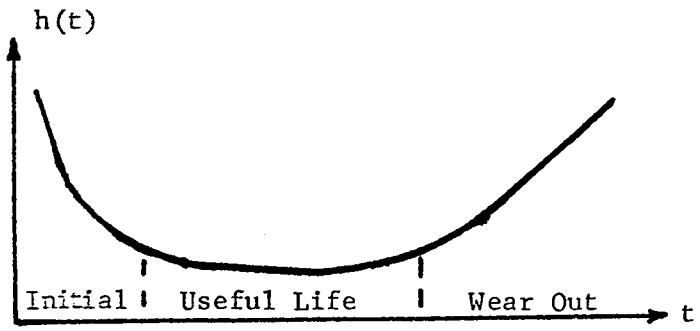
Let $h(t) = \frac{f(t)}{R(t)}$. Then $h(t) = \frac{-dR(t)}{R(t)dt}$ and $h(t)dt = \frac{-dR(t)}{1 - F(t)}$.

The instantaneous hazard rate, h(t), approximates the conditional probability that a unit that has survived till time t will fail in the next time period dt.

For the exponential distribution

$$h(t) = \frac{\lambda e^{-\lambda t}}{1 - (1 - e^{-\lambda t})} = \lambda$$

For this case, the failure rate is constant and equals λ. This property is valid for devices that operate in the "useful life" or flat portion of the "bathtub hazard rate characteristic."



This is a common operating interval for power system equipment.

A convenient property of the exponential distribution is that an estimate of the parameter λ can be made by simply dividing the number of failures, n, experienced in time t by t. Hence:

$$\hat{\lambda} = n/t$$

APPENDIX C

MAPS AND FIGURES

TABLE V

SUBSTATION COMPONENT FORCED OUTAGE RATES

Component	Forced Outage Rates-Outages/Unit/Year						Number Outages Observed		Unit-Years of Exposure T
	Transient-Cause			Persistent-Cause					
	λ_{L*}	$\hat{\lambda}$	λ_{U*}	λ_{L*}	$\hat{\lambda}$	λ_{U*}	Per-sistent	Tran-sient	
138/69-kV transformer	0.0116	0.0340	0.0779	0.0168	0.0425	0.0895	5	4	117
138/dist. transformer	0.0000330	0.000641	0.0304	0.0394	0.0705	0.1170	11	1	156
69/dist. transformer		0		0.0216	0.0304		28	0	920
138-kV circuit Breaker									
Faults		0		0.00000932	0.000181	0.000857	1	0	552
False trips	0.0452	0.0615	0.0819	0.0111	0.0199	0.0329	11	34	552
69-kV circuit Breaker									
Faults	0.00000621	0.000121	0.000574	0.000165	0.000484	0.0111	4	1	827
False trips	0.0515	0.0652	0.0817	0.000567	0.0109	0.0190	9	54	827

TABLE V (continued)

Component	Forced Outage Rates-Outages/Unit/Year: Transient-Cuase λ_{L*}	Transient-Cuase $\hat{\lambda}$	Transient-Cuase λ_{U*}	Persistent-Cause λ_{L*}	Persistent-Cause $\hat{\lambda}$	Persistent-Cause λ_{U*}	Number Outages Observed: Per-sistent	Number Outages Observed: Tran-sient	Unit-Years of Exposure T
Distribution Circuit Breaker									
Faults	0.0000439	0.000161	0.000415	0.000495	0.000801	0.0124	15	3	1870
False trips	0.000369	0.000641	0.0104	0.000105	0.000268	0.000561	5	12	1870
138-kV bus**	0.000404	0.000774	0.0135	0.0000705	0.000258	0.000666	3	9	1162
69-kV bus**	0.000425	0.000629	0.000896	0.000114	0.000228	0.000413	8	22	3500
Distribution bus	0.000914	0.0145	0.0221	0.0136	0.0200	0.0286	22	15	1101
138-kV air switch	0.0000437	0.000160	0.000414		0		0	3	1873
69-kV air switch	0.000389	0.000565	0.000794	0.0000321	0.0000942	0.000215	4	24	4250
Distribution bus regulator		0		0.0195	0.0357	0.0605	10	0	280

*Upper and lower limits of 90 percent confidence interval for one unit is λ.
**One unit is one termination on bus.

TABLE VI

SUBSTATION COMPONENT PERSISTENT FORCED OUTAGE DURATION AND SWITCHING TIME STATISTICS

Component	Estimate of Mean Duration, Min. r	90 Percent Confidence Limits, Min. r_L	r_U	Number Data Points n	Sum of Durations, Min. $\sum t_i$	$\sum t_i^2 \times 10^6$
138/69-kV transformer	517	266	1515	4	2068	143.916
128/dist. transformer	150	93	287	9	1347	22.097
16/dist. transformer	135	101	191	27	3645	88.307
138- or 69-kV circuit breaker						
Faults	426	233	1082	5	2133	146.359
False trips	125	89	188	20	2489	107.109
Distribution circuit breaker						
Faults	334	213	613	10	3343	159.125
False trips	62	32	181	4	247	2.793
138- or 69-kV bus	221	144	396	11	2434	171.387
Distribution bus	117	85	173	22	2574	45.848

TABLE VI (continued)

Component	Estimate of Mean Duration, Min. r	90 Percent Confidence Limits, Min. r_L	r_U	Number Data Points n	Sum of Durations, Min. $\sum t_i$	$\sum t_i^2 \times 10^6$
69-kV air switch	162	84	475	4	646	12.158
Distribution bus regulator						
Repair	1264	652	3700	4	5055	1,001.765
Bypass	105	62	223	7	734	10.758
69-kV transmission						
Manual switching time	34	25	49	23	773	5.417
69-kV transformer fuse						
Replacement time	171	93	433	5	853	23.380

TABLE VII

SUBSTATION COMPONENT SCHEDULED OUTAGE RATES

Component	Scheduled Outage Rates, Outages/Unit/Year λ_L*	$\hat{\lambda}$	λ_U*	Number Outages Observed	Unit-Years of Exposure
138/69-kV transformer					
Short outages	0.827	1.028	1.243	65	63.2
Long outages	0.0312	0.079	0.145	5	63.2
138/dist. transformer					
Short outages	0.590	0.720	0.859	76	105.6
Long outages	0.133	0.199	0.275	21	105.6
69/dist. transformer					
Short outages	0.221	0.259	0.300	127	489.8
Long outages	0.0205	0.0326	0.0471	16	489.8
138-kV circuit breaker					
Short outages	0.541	0.662	0.792	73	110.3
Long outages	0.0124	0.0362	0.0701	4	110.3
69-kV circuit breaker					
All outages	0.332	0.414	0.504	61	147.2

TABLE VII (continued)

Component	Scheduled Outage Rates, Outages/Unit/Year λ_L*	$\hat{\lambda}$	λ_U*	Number Outages Observed	Unit-Years of Exposure
138-kV bus**					
Short outages	0.0760	0.0943	0.114	64	678.7
Long outages	0.000386	0.000884	0.0155	6	678.7
69-kV bus**					
Short outages	0.0228	0.0291	0.0359	53	1821.6
Long outages	0.0000195	0.000110	0.000260	2	1821.6
Distribution bus					
Short outages	0.0356	0.0497	0.0659	29	583.7
Long outages	0.000449	0.0103	0.0180	6	583.7
138-kV air switch					
All outages	0.000372	0.0109	0.0211	4	367.0
69-kV air switch					
All outages	0.0265	0.0373	0.0496	28	751.0

* Upper and lower limits of 90 percent confidence interval for λ.
** One unit is one termination on bus.

TABLE VIII

SUBSTATION COMPONENT SCHEDULED OUTAGE DURATION STATISTICS

Component	Estimate of Mean Duration, Min. r	90 Percent Confidence Limits, Min. r_L	r_U	Number Data Points n	Sum of Durations, Min. $\sum t_i \times 10^4$	$\sum t_i^2 \times 10^6$
138/69-kV transformer						
Short outages	318	270	366	65	2.069	10.057
Long outages	4092	42	8142	5	2.046	155.900
138/dist. transformer						
Short outages	236	199	273	76	1.794	7.036
Long outages	16,730	5610	27,850	21	35.162	23.408
69/dist. transformer						
Short outages	213	188	238	127	2.704	9.495
Long outages	15,957	8346	23,566	16	25.309	5,209.654
138/kV circuit breaker						
Short outages	178	151	206	73	1.303	3.757
Long outages	2158	1308	3008	4	0.863	20.191
69-kV circuit breaker						
All outages	157	127	188	61	0.960	2.731

TABLE VIII (continued)

	Estimate of Mean Duration, Min.	90 Percent Confidence Limits, Min.		Number Data Points	Sum of Durations, Min.	
	r	r_L	r_U	n	$\sum t_i \times 10^4$	$\sum t_i^2 \times 10^6$
138-kV bus						
Short outages	257	218	297	64	1.647	6.550
Long outages	6037	757	11,317	6	3.622	427.552
69-kV bus						
Short outages	262	218	306	53	1.388	5.580
Long outages	6602	0	22,212	2	1.321	99.452
Distribution bus						
Short outages	269	204	334	29	0.779	3.283
Long outages	8051	1825	14,275	6	4.830	678.993
138/kV air switch						
All outages	259	111	407	4	0.104	0.316
69-kV air switch						
All outages	74	41	107	28	0.207	0.434

System Operating Report

Wednesday, January 29, 1975

TVA, Nashville area: Normal.

NES Systems:

Demand	South	- 69.0 KV -	95,200 KW
		13.8 KV -	38,300
	West	- 69.0 KV -	140,000
		13.8 KV -	29,000
	Radnor	- 69.0 KV -	143,000
		13.8 KV -	27,000
	North	- 69.0 KV -	180,000
	O.H. Dam	- 69,0 KV -	96,000
	P.P. Dam	- 69.0 KV -	30,000
	Total		778,500 KW at 6:00 p.m. (60°)

Energy: 14,873,000 KWH
289,961,000 KWH - month to date.

Weather: Partly cloudy - showers in the morning.
Temperature - Max. 76°, Min. 44°

69.0 KV

Operations: The East-Finn Street Circuit was out of service five minutes at 1:13 p.m. to check for radio interference. The South-Elm Hill Circuit was interrupted by pilot wire and ground (I & T)relays; the two South-Finn Street Lines by ground (T) relay at Finn Street; The No. 1 South-Battlefield Circuit by ground (T) relay at Battlefield; and the South-Central Line by ground (T) relay at Central, at 11:12 p.m. when a static wire bracket pulled off of a pole on Fesslers Lane just off of Lebanon Road - causing a static wire to fall into the conductors of the South-Elm Hill Circuit. All of these circuits, except the Elm Hill Line, reclosed instantaneously, and the Elm Hill Line was closed at 11:46 p.m.

Bus Voltage: All stations were normal.

Figure 15. Typical NES Operating Report.

13.8 KV and 23.9 KV

Disturbances: None.

Major Interruptions: None.

Miscellaneous Notes:

7:47 a.m.	Tenth Avenue	Circuits R21T and R29T were cleared until 5:18 p.m. to transfer the transformer in Vault 2118 to Vault 2919. (R21T was left cleared after transferring the load to R29T). The old National Life Building is now served from R28T, with R29T the alternate feed - without automatic controls.
10:37 a.m.	Central	Network Circuit U-8 was de-energized for thirteen minutes to reconnect a loose wire in Vault 811.
1:45 p.m.	South	SW 2194 was removed from the No. 11 Circuit.
4:24 p.m.	East	B13B was cleared to replace a compressor motor.
7:05 p.m.	Finn Street	One fuse on Pole 8625-110 in the No. 8 Circuit, which opened about 6:05 p.m. when tree limbs which were being cut fell into the conductors, was replaced.

Figure 15. (continued)

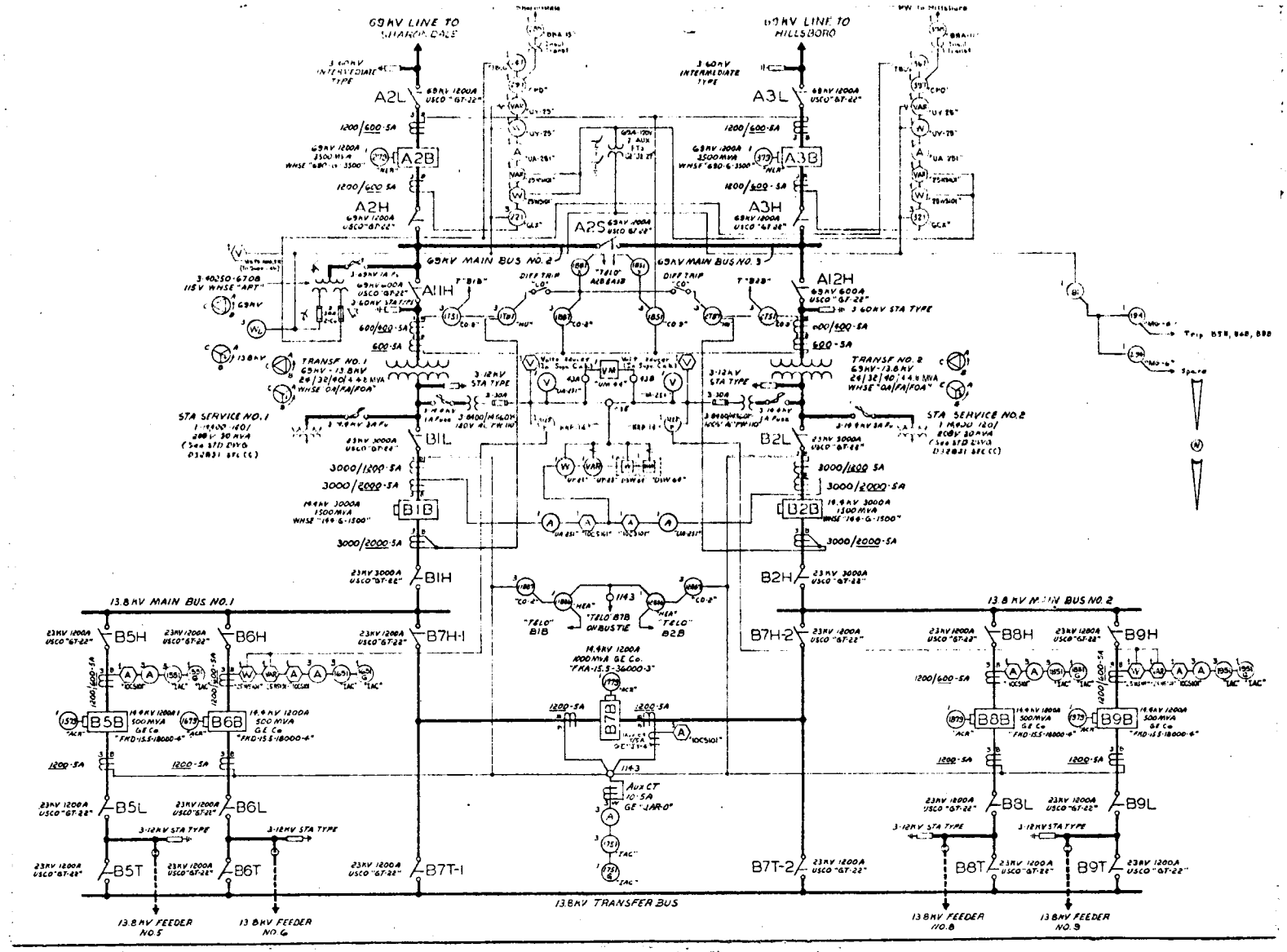
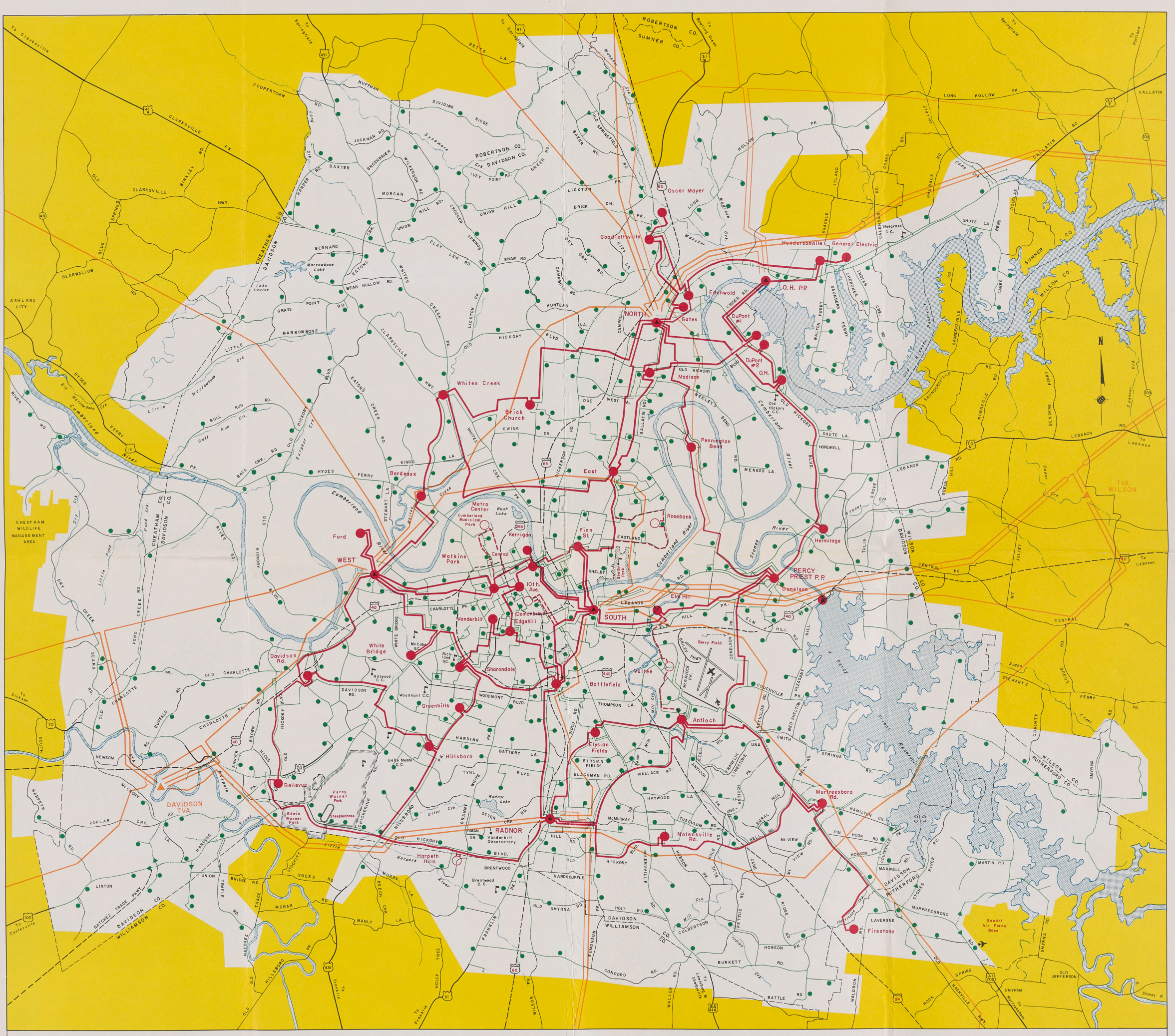


Figure 16. 69kV Main Bus With No Transfer Configuration.

VITA

Leonard Early Leech was born in Nashville, Tennessee, on July 13, 1942. He attended Dickson County Elementary and High Schools and graduated in 1960. He entered the Tennessee Polytechnic Institute in September, 1960, and received a Bachelor of Science degree in Electrical Engineering in June, 1964. He entered the University of Tennessee Nashville Graduate School in September, 1972, in the Engineering Administration program and transferred to Electrical Engineering program in March of 1975 to study toward a Master of Science degree. He received this degree in December, 1977. He is a registered Professional Engineer in the State of Tennessee.


Goodlettsville
Oscar Mayer
Hendersonville
General Electric
Edenwold
O.H. P.P.
Gates
DuPont #1
DuPont #2
O.H.
NORTH
Madison
Whites Creek
Brick Church
Pennington Bend
East
Bordeaux
Metro Center
Cumberland Municipal Park
Bush Lake
Rosebank
Finn St.
Kerrigan
Central
Ford
WEST
Watkins Park
10th Ave.
Demonbreun
Edgehill
Vanderbilt
SOUTH
Elm Hill
Hermitage
PERCY PRIEST P.P.
Donelson
Berry Field
White Bridge
Davidson Rd.
McCabe G.C.
Richland G.C.
Hillwood C.C.
Woodmont C.C.
Sharondale
Greenhills
Battlefield
Vultee
Antioch
Elysian Fields
Hillsboro
Bellevue
Bells Meade C.C.
Percy Warner Park
Edwin Warner Park
Steeplechase
DAVIDSON TVA
RADNOR
Vanderbilt Observatory
Harpeth Hills
Brentwood C.C.
Nolensville Rd.
Murfreesboro Rd.
Firestone
Sewart Air Force Base
Old Hickory C.C.
Bluegrass C.C.
CHEATHAM WILDLIFE MANAGEMENT AREA
ASHLAND CITY
Marrowbone Lake
Lake Louise
ROBERTSON CO.
SUMNER CO.
DAVIDSON CO.
CHEATHAM CO.
WILSON CO.
WILLIAMSON CO.
RUTHERFORD CO.
TVA WILSON
Cumberland River
Old Hickory Lake
J. Percy Priest Reservoir
Stones River
Harpeth River
Little Harpeth River
Big Marrowbone Creek
Little Marrowbone Creek
Bull Run Creek
Sulphur Creek
Dry Creek
Pond Creek
Little Pond Creek
Mansker Creek
Drake Br.
Rhubarb Creek
Spencer Creek
Goose Creek
Station Camp Creek
Indian Creek
Otter Creek
Granny White Creek
Radnor Lake
Mill Creek
Hurricane Creek
Stones River
Spring Hill
Nashville
Franklin
Murfreesboro
Springfield
Clarksville
Bowling Green
Portland
Lebanon
Gallatin
Dickson
Centerville
Columbia
Shelbyville
Smyrna
Old Jefferson
Laverne
Lavergne
Antioch
Una
Priest Reservoir
Old Hickory Reservoir
Percy Priest Reservoir
Cheatham Wildlife Management Area
Natchez Trace Pkwy
Old Hickory Blvd.
Nashville By-Pass
Central Pk.
Long Hollow Pk.
Dickerson Pk.
Gallatin Rd.
Nolensville Pk.
Murfreesboro Pk.
Franklin Pk.
Hillsboro Pk.
Charlotte Pk.
Clarksville Pk.
Lickton Pk.
Whites Creek Pk.
Hickory Blvd.
Harding Pl.
Harding Rd.
Old Hickory Blvd.
Nashville By-Pass
Old Hickory
Hickory Blvd.
Old Hickory Blvd.
Old Hickory
Old Hickory
Old Hickory