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**Evaluation of Higher Distribution
and/or Utilization Voltages**
Fourth Interim Report (August 1980)
Assessment of
Optimum Distribution Configuration

MASTER

Published April 1981

Prepared for:

U.S. Department of Energy

Assistant Secretary for Conservation and Renewable Energy
Division of Electric Energy Systems

Under Contract No. AC01-78 ET 20505

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U.S. Department of Energy
Assistant Secretary for Conservation and Renewable Energy
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PREFACE

This interim report provides documentation on the fourth task, Assessment of Optimum Distribution Configuration, of DOE Contract No. ET-78-C-01-2866, Evaluation of Higher Distribution and/or Utilization Voltages. The work performed under this task includes the development of a computer model for assessment of "life cycle" costs for the distribution and utilization systems, the development of an optimization algorithm to enable distribution system configuration optimization and a net energy analysis to determine potential net energy savings. Input data for this task derive from Task 3. The major output of this task is a documented computer code.

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1. ELECTRIC SYSTEM MODELING

A model of electric energy system primary and secondary distribution systems and end-use elements is developed herein. The purpose of the model is to permit a comparative economic analysis between alternative system configurations and to facilitate optimization of the system configuration with respect to a number of design parameters such as primary and secondary voltages, conductor sizes, number of customers per distribution transformer and so on. The model accounts for such things as voltage regulation, reliability, voltage flicker, load profile, losses and dynamic properties of the system such as load growth, changing costs of energy, load profile changes and so on. The model is divided into two principal submodels, a distribution system model and a utilization system model.

The distribution system model is based on the results of two preliminary development phases. The first phase consists of component and system design-point studies. The second phase consists of combining models of components into a system model in accordance with procedures governing the choice, timing and operation of the distribution system for the supply of evolving load.

Discussion is focused first on the initial phase of the modeling of distribution system development and performance, the component and system design-point studies.

1.1 Design-Point Studies

Focusing first on the components of the distribution system, and then on the combination of these components into a system, the design-point studies provide the foundation for a valid system model. These studies provide a systematic means of assembling relevant knowledge and experience on system design, specification of components and evaluation of costs and energy losses.

The work was performed by the in-house Electrical Engineering Division of the Philadelphia Electric Company (PECO). This division brought to the design-point studies (1) recent experience with primary voltage conversions from 4 to 13 kV and 4 to 34 kV, (2) a working relationship with manufacturers of distribution-class equipment and (3) extensive experience with the design, operation and maintenance of distribution substations and circuits.

1.1.1 Component Design-Point Studies

The component design-point studies provide parametric capital and operating and maintenance costs for each component or component ensemble found in an aerial or underground distribution system. The parametric costs are provided for each component over the range of voltage and current ratings required by the distribution system model.

In addition to cost data, the component studies quantify fixed and variable energy losses as a function of component voltage and current rating. The components in which significant losses occur are the substation power transformer, the distribution (primary to secondary) transformer, and all wire or cable in the primary and secondary distribution circuits, including the customers' service connections.

Component Costs and Losses

Component costs and losses for the relevant range of component types and ratings were taken from PECO experience for voltages of 13 kV and 34 kV, and from PECO judgment following consultation with equipment manufacturers for 69 kV. Costs are quoted in 1979 dollars.

Components not available for primary voltages greater than 34 kV are load-break elbows and distribution-class surge arresters. All other distribution components are currently available. Because of a low demand for such components,

however, costs rise steeply for voltages greater than 34 kV. This is the case for aluminum underground cable, distribution transformers, disconnecting switches, cutouts and fuseholders.

Component Insulation Requirement

The basic impulse level (BIL) for component insulation was chosen in accordance with industry practice. These are given in Table 1.1. The use of 250 kV BIL equipment on 69 kV circuits will provide a protection margin of at least 20% as outlined in ANSI 62.2 entitled "USA Standard Guide for Application of Valve-Type Lightning Arresters for Alternating Current Systems." Allowance is made for exceptional circumstances such as abnormally steep impulse currents and aged insulation.

Cable Rating Calculations

Underground cable ratings are calculated for each size of cable used in a circuit and are compared to the expected peak loads for these cables. An overload will signal an infeasible condition.

Factors considered when calculating a rating are the ambient earth temperature, number of cables in a trench, cable spacing, duct or earth burial, cable size, cable voltage and the load profile expected for the peak day.

The load shape is represented by a daily loss factor. This factor is the ratio of average loss during the day to the peak loss during the day. The daily loss factor, DLF, used in the computer model is given by

$$DLF(N) = .50 - .33/N$$

This is based on a regression analysis of samples from a PECO survey of hourly residential electric load taken in 1975. N is the number of residential customers served by the cable.

TABLE 1.1. REPRESENTATIVE COMPONENT BIL			
NOMINAL VOLTAGE (PHASE-TO-PHASE)	BASIC IMPULSE LEVEL OF INSULATION (PHASE-TO-PHASE) kV		
kV	AERIAL OPEN WIRE	CABLE	EQUIPMENT
13	500	110	95
34	500	200	150
69	600	350	250

The above factors are used to calculate the maximum peak current which can be sustained without reaching the point of thermal saturation (55° C) in the surrounding earth. If that temperature is reached, then heat will build up in the cable and may cause an insulation failure.

Component Ensembles

In many cases components are grouped into ensembles which commonly are found in the distribution system. These ensembles are identified as the duct bank, the aerial support structure, the terminal pole and the distribution transformer. The reader is referred to circuit item descriptions in Appendix A for the definition of these component ensembles.

Component Carrying Charges

Associated with each component is a book and tax life, and a mortality dispersion. These are used (in conjunction with the corporate tax rate, cost of money, the allowable depreciation schedule and a discount rate) to compute a capital carrying charge rate. The carrying charge rate associated with a particular component converts capital cost into a levelized annual capital revenue require-

ment. Capital cost is then combined with operating and maintenance costs to obtain the total annual revenue requirement associated with that component.

Differences in book and tax life, and mortality dispersion result in six different carrying charge rates in use for components of the distribution system. The components and associated carrying charge data are summarized in Table 1.2.

Component Models

The regression models for all system components are developed from the parametric cost and loss values provided by the component design-point studies. These models are presented in the Third Interim Report.* The cost and loss values supporting these models is presented in Appendix A of this report. The component descriptions and cost data of Appendix A are used in the system design-point studies discussed in the next section and illustrated in Appendix B.

1.1.2 System Design-Point Studies

The system design-point studies are performed to observe the procedure for designing a circuit, the considerations that enter into this procedure and the significant cost elements found in the resulting design. They are to be used to assist in verification of the computer model. These studies are intended also to identify any special problems and costs that may be encountered as primary and secondary voltages are increased above 34 kV and 120/240 V respectively.

System design-point studies were performed for each of the two basic subsystems of the distribution system; the distribution circuit and the distribution substation. Samples of these studies are presented in Appendix B. The details and findings of these studies are discussed below.

*Third Interim Report, "Analysis of Individual Component Cost and/or Energy Efficiencies," October 26, 1979.

TABLE 1.2 COMPONENT CARRYING CHARGE RATES

COMPONENTS	TAX LIFE, YRS	BOOK LIFE, YRS	MORTALITY DISPERSION*	ANNUAL CARRYING CHARGE RATE**
TRANSFORMERS	24	25	R1	.0752
OVERHEAD CONDUCTORS AND DEVICES	24	30	L0.5	.0732
POLES, TOWERS AND FIXTURES	24	35	L0.5	.0725
UNDERGROUND CON- DUCTORS AND DE- VICES	24	40	L1	.0707
STATION EQUIPMENT	24	40	R1.5	.0628
UNDERGROUND CIRCUIT	24	50	R4	.0554

*THESE CODES REFER TO LEFT OR RIGHT MODEL STANDARD IOWA MORTALITY DISTRIBUTIONS WITH VARYING DEGREES OF KURTOSIS. REF: R. WINFREY, DEPRECIATION OF GROUP PROPERTIES, BULLETIN 155, IOWA ENGINEERING EXPERIMENT STATION, 1942.

**ASSUMING A CORPORATE TAX RATE OF 51.7%, A WEIGHTED AVERAGE COST OF MONEY OF 2.5% AND A DISCOUNT RATE OF 2%.

1.1.2.1 Studies of the Distribution Circuit

As the basis for a design-point study of a residential distribution circuit, the following system and load information is specified:

System:

- Circuit configuration (layout)
- Construction type (aerial/underground)
- Primary and secondary voltage
- Normal rating of the circuit

Load:

- Individual residential peak demand
- Peak diversification function
- Residential lot size

These are now discussed individually.

Circuit Configuration

For use in the computer model, two possible rectangular circuit configurations were considered as representative of actual practice for the supply of residential areas with lattice street layout. These are illustrated in Figures 1.1 and 1.2.

Circuit configuration A is characterized by a distance between adjacent laterals which may exceed the reach of a secondary circuit. Single- or three-phase fused spurs extend between the laterals. Distribution transformers tap the spurs. Secondary circuits run parallel to these spurs using the same utility poles or underground trenches.

Configuration B has laterals which are likely to be more closely spaced than those of Configuration A. The area between these laterals, however, is reached by secondary circuits emanating from distribution transformers located on the laterals.

Circuit Configuration B is used in the computer model. This decision is based on design-point studies on the two configurations for a variety of primary voltages and area load densities. Results indicate a significant cost advantage of Configuration B over A. Furthermore, Configuration B allows a trade-off between area coverage of primary and secondary circuits. That is, as secondary voltage is increased, secondary reach will increase and thus the distance between primary laterals will increase. The result is fewer primary laterals required to supply a given area.

FIGURE 1.1 CONFIGURATION A: PRIMARY SPURS BETWEEN LATERALS

FIGURE 1.2 CONFIGURATION B: SECONDARY CIRCUITS BETWEEN LATERALS

Construction Type

A circuit may be aerial, underground or a mixture of the two construction types. In all cases the feeder from the substation is assumed to be underground. The possible hybrids of aerial and underground considered in the design-point studies are limited to the following possibilities:

1. Underground residential service connections only
2. Underground secondary systems only
3. Underground primary laterals and secondary systems with an aerial primary main.

Primary and Secondary Voltage

Primary voltages considered in the design-point studies are 13, 34 and 69 kV. Secondary voltages are: 120/240 V, 1-phase; 120/208 V, 3-phase; 240/480 V, 1-phase; and 480/960 V, 1-phase.

Normal Current Rating

The normal current rating of the substation supply/circuit feeder is chosen to be 400 amps for all primary voltages. This is in coordination with the substation design-point studies. This rating provides the circuit with normal capacities of 9.0, 23.6 and 47.8 MVA for primary voltages of 13, 34 and 69 kV respectively.

Residential Load and Its Description

The peak demand of a single residence is assumed to be uniform over the entire area served by a single circuit. A peak diversification function, D , is used to compute the coincident peak, $CP(N)$, of a group of N residences according to the following formula:

$$CP(N) = D(N) \times P \times N$$

where P is the peak demand of the typical single residence. The peak diversification function is:

$$D(N) = \frac{.9827}{N} + .3439$$

which was obtained from a regression of values taken from a sample of residential load data.* Nichel and Braunstein** report diversification functions calculated from a number of samples of residential data.

To complete the description of the residential load served by a circuit (for the purpose of a design-point study), the residential lot dimensions must be specified. Lot dimensions are also assumed to be uniform over the area covered by a circuit. Lot depth is assumed to include one-half the width of the street in front. Lot width is assumed to include a portion of an adjacent cross-street. The result of the latter two assumptions is that specific street details are neglected in the circuit studies.

Table 1.3 describes the different residential loads used in the circuit studies.

Results of Circuit Design-Point Studies

Two kinds of results grow out of the circuit design-point studies; those that impact directly on model design and those which identify considerations that must accompany a move to higher primary and/or secondary voltages. The results that affect model design include observations on:

1. Circuit configuration
2. Circuit design procedure
3. Circuit design constraints
4. Assumptions for simplifying the model.

The considerations arising out of the studies that do not directly affect model design include questions whose resolution require pilot programs and experimentation. These concern the topics of:

* Sander, Barbara M., "Forecasting Residential Energy Demand: A Key to Distribution Planning," Paper A77 642-2 presented at IEEE Summer Power Meeting, 1977.

** Nichel, D.L. and H.R. Braunstein, "Distribution Transformer Loss Variations, II: Load Characteristics and System Cost Parameters," Paper F80 248-5, presented at IEEE Winter Power Meeting, February 1980.

TABLE 1.3 RESIDENTIAL LOADS USED IN CIRCUIT STUDIES			
INDIVIDUAL RESIDENTIAL PEAK (kVA)	LOT DIMENSIONS (FT)		APPROXIMATE LOAD DENSITY (MVA/SQ. MI.)
	WIDTH	DEPTH	
6.4	250	250	1
6.4	100	150	4
6.4	80	185	4
6.4	20	180	16
19.2	75	150	16
38.4	75	150	32

1. Adequacy of reliability criteria
2. Ferroresonance and its mitigation
3. Aesthetic considerations
4. Safety considerations.

The findings of the circuit design-point studies are now discussed in more detail.

Circuit Configuration

As stated in the previous section, preliminary studies established circuit Configuration B, illustrated in Figure 1.2, as generally less costly than alternative designs. It is a realistic design with ample sectionalization and transfer capability for maintaining service reliability as circuit capacity and coverage increase. Its development and operation are readily simulated. Subject to optimization are the numbers of laterals, the reach and capacity of the secondary circuits (and thus the distance between adjacent laterals), the length of the laterals and the length of the primary main. Conductor sizes for the feeder, the primary main, the primary

laterals, the secondary main and the customers service connection may also be varied. Configuration B appears to be appropriate for comparing the costs and losses of one combination of primary and secondary voltages with another.

Circuit Design Procedure

The approach to specifying circuit components begins with the establishment of a feasible secondary circuit design. Secondary length and conductor size and customer service connection are chosen to avoid excessive voltage drop, intolerable lamp flicker and currents greater than conductor thermal ratings.

The peak demand of the feasible secondary circuit establishes the nameplate rating of the distribution transformer. Typically, the initial loading on a transformer will be 90 to 100 percent of its nameplate rating. The transformer will be replaced by one of greater capacity when its load reaches a level between 140 to 180 percent of nameplate rating.

Whereas the length of the secondary circuit establishes the distance between adjacent primary laterals (in a circuit of Configuration B), the length of these laterals is arbitrary. The coverage of the circuit in the design-point study is chosen to load the circuit to its normal rating (400 amps). Therefore, for a given lateral length, the number of laterals may be calculated since their spacing is known. Alternatively, if the number of laterals is specified, their length may be calculated. The number of laterals and their spacing dictates the length of the primary main. The underground circuit feeder connecting the substation and primary main is logically taken as proportional to the square root of the area served by the circuit. The length of the lateral may be constrained by reliability considerations as are the number and types of sectionalizing switches that are needed. This is discussed in a later section under the topic of circuit reliability.

The conductor size employed in the lateral is checked for adequate thermal rating as are the conductors used in the primary main and circuit feeder. As it is assumed that the voltage at the circuit end of feeder is maintained at the high end of the range of allowable voltage variation by the substation LTC transformer, the voltage drop from this point to the most remote distribution transformer is calculated. In a feasible design this voltage drop may not exceed a maximum value allotted to the primary circuit. Similarly the voltage drops under peak loading may not exceed the specified maximum allotments for the distribution transformer, secondary circuit and service connection respectively.

Once the secondary length, the number and length of laterals and conductor sizes have been specified, a complete bill of materials for the circuit is written. From this and the data developed in the component design-point studies, the total capital cost of the circuit may be calculated.

Circuit Design Constraints

As mentioned in the previous discussion on circuit design procedure, there are four constraints that a feasible circuit design must satisfy under normal conditions.

1. No conductor will be thermally overloaded.
2. Voltage at the customer's meter will remain within a specified range of its nominal level.
3. Voltage fluctuation due to motor starting will be tolerable to the customer.
4. Continuity of service will not deviate noticeably from customer's expectations.

Conductor Thermal Rating

The choice of a circuit conductor must ensure that normal anticipated current levels will not exceed the conductor's thermal rating. This is a concern especially for insulated cable where insulation both limits heat dissipation and is subject to thermal damage.

As energy costs increase and generation costs escalate, however, utilities are justifying the use of larger conductors to reduce energy losses. Larger cables increase thermal rating and thus reduce the concern with cable overloads. Emergency load pick-up capability of circuits is an added benefit of the increased ratings accompanying economic conductor sizing, improving the reliability of the distribution system.

Limited Voltage Variation

The voltage at the customer's meter is to be maintained within a specified range of a nominal value. Currently, for a nominal voltage of 120 V, variations are limited to $\pm 5\%$ of nominal (114 V to 126 V). It has been proposed that this range be reduced to $117 \text{ V} \pm 2.5\%$, or 114 V to 120 V, to conserve energy. It appears, however, that the narrower range of allowable voltage variation may have a counterproductive effect since it will result in (1) increased distribution system cost, and (2) eventual compensation in the design of end-use devices to meet performance requirements.

The specified constraint on service voltage is satisfied, in practice, by allocating the voltage drop to the different portions of the circuit. That is, the point where the feeder meets the primary main is allowed a certain variation, with maximum voltage drop allowances also specified for the primary circuit, distribution transformer, secondary circuit and customer service connection. Typical allowances are:

Feeder	1.0%
Primary	4.0%
Distribution Transformer	2.5%
Secondary	2.0%
Service Connection	<u>0.5%</u>
Total	10%

The circuit design specifies circuit length and conductor size so that the worst-case voltage drop for any subsystem does not exceed the maximum allowable drop.

The PECO design-point studies found that circuit capacitors were not required if the primary feeder voltage is regulated. Power factor correction would be done with capacitors located at the substation. It is recognized, however, that investment in capacitors trades off with savings in losses and increased wire size. Consequently capacitors may be applied in the computer model as is discussed later.

Tolerable Voltage Fluctuation

Due to locked rotor currents considerably higher than normal running currents, starts of large residential motors (2 to 5 hp) can cause voltage dips perceptible as lamp flicker and momentary TV picture shrinkage. The frequency of such flicker is primarily dependent on the number of customers with such motors on a secondary circuit and the frequency with which these motors start. The magnitude of the voltage dip governs whether or not it is perceptible and is dependent on (1) the size of the larger motors in common use, (2) the secondary/utilization voltage, (3) impedance of the distribution transformer, (4) impedance of the secondary circuit (conductor size and length), and (5) impedance of the customer's service connection (where only conductor size is controllable).

Tolerable levels of voltage fluctuation are a function of frequency and magnitude of lamp flicker. The subjective thresholds of irritability have been determined from customer surveys and controlled experiment by various utilities. Typical irritability curves have been published by Westinghouse* and General Electric.**

*Electric Utility Engineering Reference Book: Distribution Systems, Westinghouse Electric Corp., East Pittsburgh, Pennsylvania, 1965, p. 347.

**Distribution Data Book, General Electric Co., GET-1008K, p. 48.

In a design-point study for a given secondary voltage, when lamp flicker is assessed as irritable, either secondary wire size is increased or the number of customers on a secondary circuit is reduced, or both, until frequency/magnitude becomes tolerable.

Consistent Level of Availability of Service

Currently, in the United States, most electric utilities employ primary voltages falling in the range of 4 kV to 15 kV. Customers have become accustomed to service of high reliability. Average annual unavailability per customer varies usually in the range of one to two hours per year.

As primary voltage is increased, circuit capacity and, therefore, area coverage per circuit also increases. An increased exposure to fault results. When a fault does occur on a circuit with higher primary voltage, a larger block of load may be interrupted. Therefore, as voltage increases, steps are taken to maintain the same level of service continuity to the average customer as he is accustomed to at the lower voltage. Service continuity is quantified in terms of average annual unavailability of service to a customer.

This objective is achieved with fuses to interrupt faults locally and sectionalizing switches to isolate faulted primary sections so that service may be restored to adjacent unfaulted sections promptly before repairs are made. Sectionalization may be performed manually by a trouble crew or remotely by a central operator and/or computer using supervisory control and remote fault sensors.

The following guidelines are used in placing fuses and sectionalizing switches in a circuit with primary voltage above 4 kV. First, the maximum amount of load that may remain unserved while repairs are made is defined. Using an unsectionalized 4 kV circuit as a reference, this amount is the capacity of the 4 kV circuit, say 1.8 MVA. A circuit of higher voltage is sectionalized so that, following the

clearance of a fault, manual switching would ensure that no more than 1.8 MVA would remain unserved during the repair time. If manual switching is performed quickly (within 20-30 minutes of fault clearance), the customers served by the circuit will experience an annual unavailability similar to those served by a 4 kV circuit.

A fault on the primary main of a circuit of Configuration B, Figure 1.2, would require interruption of the entire circuit. With primary voltages greater than 15 kV, such action may contribute excessively to customer unavailability, even if the fault were isolated and service restored to healthy sections within 20 minutes. Automated or supervisory controlled sectionalization is then required. The objective is to isolate the fault quickly (in 5 minutes or less) with automated switching. The automated sectionalization thus limits the unserved load to approximately the capacity of a 13 kV circuit (say 7.2 MVA) or about four 1.8 MVA sections. A trouble crew would then be dispatched to isolate the fault (and, therefore, the interruption) to a 1.8 MVA section using manual switching. Consistent with automated sectionalization, the load on a fused lateral may not exceed 7.2 MVA if it has four sections and a normally-open transfer switch.

It should be noted that, in the above discussion, interrupted circuit capacity expressed in MVA is assumed proportional to interrupted number of customers. This is not entirely correct, since the average peak demand for a residential customer may vary among residential areas. That is, similar faults on similar circuits serving different areas may interrupt a different number of customers. Ross, et al.* suggests using number of customers directly; the authors agree.

* Ross, D.W., A.I. Cohen, M. Carson, "Methods for Evaluating Reliability Benefits of Distribution Automation," paper presented at 7th Annual Engineering Conference on Reliability for the Electric Power Industry, Madison, Wisconsin, April 29-30, 1980.

Figure 1.3 summarizes the above discussion in terms of number of customers. Consistent average annual availability is ensured as primary voltage is increased by maintaining the same area under the customers-interrupted-versus-time curve.

Assumptions for Simplifying the Model

In the course of the circuit design-point studies, a number of assumptions, useful in modeling the design procedure, were identified. These included:

1. The use of component ensembles such as the support structure, terminal pole and the distribution transformer. This simplifies bookkeeping in the itemization of yearly component additions and evaluation of capital costs.
2. A rule for transformer sizing. That is, transformer nameplate rating is chosen such that initial load is some percentage of this rating (90-100%) and transformer change-out is performed when load is some other percentage of rating (140-180%).
3. Manual and automated sectionalization as a means for maintaining consistent service availability as circuit capacity increase. This is discussed in the previous section.

A number of other less significant assumptions arose in the circuit studies. These are generally considered to constitute the modeling approach and philosophy reflected in this work.

Adequacy of Reliability Criteria

Under the topic of circuit design constraints, the need to maintain a consistent level of availability of service is discussed. The specific constraint in use states that the average annual unavailability of service to a customer shall not increase as circuit capacity increases. Unavailability of service is limited by adding manual and automated sectionalizing capability. It is uncertain, however, that average annual unavailability is an adequate measure of reliability of service. Customers may perceive an objectionable change in service reliability even though average unavailability may have remained the same.

FIGURE 1.3 RELIABILITY REQUIREMENTS--DISTRIBUTION CHART

Average annual unavailability, U , for a circuit is given by the number of customer-minutes interrupted during the year divided by the number of customers served by the circuit. That is,

$$U = \frac{n_c}{\sum_{i=1}^n} N_i d_i / N_T$$

where n_c is the number of interruption conditions for the circuit during the year, N_i is the number of customers interrupted during the i^{th} condition, d_i is the duration in minutes of the i^{th} condition and N_T is the total number of customers served by the circuit. It should be noted that differences in frequency and average duration of interruption may occur for the same level of availability. That is, equal

unavailability may result from a few outages, each of extended duration, as from many outages, each of shorter duration.

Circuits with increased capacity and greater sectionalization capability may maintain a consistent service availability, but will most likely manifest an increased average frequency of interruption. Whether or not this increase is significant enough to be noticed and objected to by the customer is not yet known. (This same issue also exists on the question of the relative adequacy of a spot network versus primary (or secondary) selective supply to a commercial or industrial customer). How detrimental or irritating are momentary interruptions? Before this question can be answered, more experience with less expensive distribution schemes that result in occasional momentary interruptions is needed to compare their effectiveness with that of more expensive schemes (with equivalent unavailability) which result in fewer momentary interruptions.

If rapid fault isolation and service restoration by circuit reconfiguration (following fault clearance) is unacceptable, the alternative is local fault clearance. This would require fault-interrupting sectionalizers coordinated by a sophisticated monitoring and control system. The added expense would be significant.

A second issue, yet to be resolved, concerns the design and reliability of the monitoring and control system intended to perform the remote fault location and circuit switching. The cost of an adequately reliable system is uncertain and will require experimentation and experience before it can be satisfactorily estimated. This issue has been avoided in this study with the assumption that a reliable two-way communications system already exists as does a central human dispatcher.

Ferroresonance and Its Amelioration

Another area of concern that was encountered in the context of the design-point studies was ferroresonance. No specific actions were taken in the studies to

mitigate against its occurrence. The most effective responses require experimentation and will be those which give the most economic, workable solution.

In a distribution system, the capacitance of high voltage shielded cables connected to the windings of three-phase transformers with common iron core materials form a resonant electric circuit. When one phase of a three-phase transformer is energized, the magnetic coupling through the common core establishes voltages in the unenergized windings. If the winding inductance equals the cable capacitance, then current flow will be limited only by the circuit resistance. High current flowing through the transformer inductance will develop a high voltage that is detrimental to system operation.

With higher distribution voltage systems, the probability of experiencing ferroresonant circuit conditions increases. To reduce this probability, certain design features should be considered.

1. Use three-phase switching to energize three-phase distribution transformers.
2. Switch at transformer terminals if single-phase switching is required.
3. Limit the length of cable that is connected to three-phase transformers.
4. Combine single-phase transformers to provide three-phase grounded wye-wye service.
5. Use grounded wye-wye connected three-phase transformers with a five-legged transformer core.
6. Keep a minimum of 5 percent load connected to the transformer during switching operations. This load should not be phase-sensitive.

Aesthetic Considerations

In developing the design for the support structure for aerial primary voltages higher than 34 kV, the question of public acceptance on an aesthetic basis was discussed. Compared to 34 kV structures, the greater clearances in the pole-top configuration and a resulting taller pole for 69 kV may be noticeable only to the

informed observer. Refer to Appendix A, Item 6, Figure A.1 for relative dimensions. Larger distribution transformers due to increased insulation requirements are also likely to go unnoticed.

Aerial construction is preferred from the utility point of view. It costs less than underground, it is more accessible for detection and repair of faults, it may be repaired or maintained while energized, and it has a higher thermal rating for normal and emergency loading. There is, however, a trend toward underground in residential areas. For instance, Pennsylvania state law requires underground distribution facilities in residential developments of five or more houses. If the circuit is underground there will be no difference in appearance between 13 kV and 69 kV primary distribution facilities.

Safety Considerations

Aerial primary distribution facilities are equally safe for the public whether the voltage is 13, 34 or 69 kV. Utility repair and maintenance crews have developed safe practices for working on these facilities while energized. PECO linemen use insulated gloves for 13 kV, but are required by state law to use hot-sticks for all voltages above 15 kV. The grounded static line does complicate live-line maintenance, but no problem is anticipated that cannot be overcome through the development of work procedures and the judicious use of available tools and equipment.

Underground facilities are generally inaccessible by the public (with the exception of back-hoe operators) and are, therefore, safer than aerial facilities. De-energization is required for maintenance and repair so that no additional hazards are imposed on utility crews as primary voltage is increased.

Secondary voltages of 480 V and above present a hazard from undetected arcing faults. Such faults may have impedances indistinguishable from normal load

impedances. If not detected, an arcing fault imposes the threat of fire and significant equipment damage. Experience with such faults in connection with secondary spot networks has suggested, in some cases, the use of thermal or smoke detecting devices for protection. The possibility of sustained arcing faults is a significant reason for not adopting a secondary/utilization voltage of 480 V or above.

1.1.2.2 Studies of the Distribution Substation

Substation costs account for approximately 15 percent of the total capital cost of the distribution system. Cost savings may result from choosing substation capacity in accordance with estimates of present demand and forecasted growth of the surrounding region and considering specific transmission lines already existing in the area as possible bulk-power supplies. Alternatively, a standard substation design may be used and savings of a different kind realized.

Standardization provides advantages such as better estimates of construction costs, lower equipment costs through the purchase of large-lot quantities, fewer spare components to cover equipment failures, lower operating and maintenance costs through standardization of work procedures and use of specialized test equipment. Finally, a standard design may provide capital savings by allowing a coordinated choice of substation components.

In the substation studies supporting the modeling of the distribution system, the latter approach (standardized design) was chosen. As a consequence, the specific characteristics of surrounding load and the existing transmission system need not be considered in the optimal choice of primary voltage. The distribution system model need not, therefore, optimize substation size nor generalize system-specific transmission system characteristics. The emphasis is thus placed on optimizing circuit design for given primary and secondary voltages. The model will

still include a reasonable estimate of the contribution of the substation to distribution system costs and losses.

The standard substation design adopted in this study is configured according to a "unit concept." Introduced in the Second Interim Report^{*} its description and features are reviewed in the next section.

Capital, operating and maintenance costs for substations supplied by 230 kV transmission and serving primary distribution circuits at 13, 34 and 69 kV are developed. The specific details and results of these studies are presented in Appendix B. As illustrated in Figure 1.4 for each voltage, two substation capacities are considered to reflect economies of scale. In the computer model, either the single-breaker/three-circuit or the double-breaker/four-circuit design may be selected for evaluation. Thus the impact of substation size on selection of optimal voltage for primary distribution (for an area of specified load characteristics) may be assessed.

Substation Configuration (Unit Concept)

The substation designed according to the unit concept specifies the reactance of the power transformer so that maximum available fault current is limited to about 15 kA (or well within the fault-interrupting capacity of the standard low-side circuit breaker with 1200A normal rating). Furthermore, the capacity of the transformer is chosen so that full-load, low-side current is 1200A (matching the normal rating of the circuit breaker). This capacity is divided into three 400A circuit feeders. Each feeder is switched by a motor-operated disconnecting switch. When a fault occurs on any one of the three circuits, the circuit breaker opens

^{*}Second Interim Report, Identification of Components and Parameters for Cost and Energy-Efficiency Analysis, March 30, 1979.

34 kV

SAME ARRANGEMENTS AS ABOVE WITH TRANSFORMERS RATED:

SINGLE BREAKER

75 MVA, $X = 9\%$

TWO BREAKERS

150 MVA, $X = 10\%$

69 kV

SAME ARRANGEMENTS AS FOR 13 kV WITH TRANSFORMERS RATED:

SINGLE BREAKER

150 MVA, $X = 9\%$

TWO BREAKERS

300 MVA, $X = 10\%$

FIGURE 1.4 SUBSTATION CONFIGURATION (UNIT CONCEPT)

momentarily and recloses after the switch for the faulted circuit has opened. This switching sequence is completed in less than one second.

It should be noted that transformers with the desired reactances indicated in Figure 1.4 are found in manufacturers' standard catalogs. The transformers, with tap changing under load, are capable of maintaining favored voltage under the full range of circuit loadings.

When two circuit breakers are used, the transformer reactance still limits maximum available fault current to 15 kA and has capacity sufficient to supply 2400A demand at the low-side (primary distribution) voltage. A summary of results of the design-point studies for these substations and one detailed example are found in Appendix B.

The momentary interruption of all three circuits required to clear a fault on any one circuit may not be tolerable with higher-voltage, higher-capacity circuits. Design-point studies were also made for substation designs in which the motor operated disconnects are replaced by circuit breakers. The resulting substation configuration is shown in Figure B.3 in Appendix B. Costs for the 34 and 69 kV designs resulting from this deviation from the unit concept are given under the cases C-1 through F-1 in Table B.1. It should be noted that the computer model provides costs only for the designs using the unit concept.

1.2 General Distribution/Utilization System Model

Coincident with the system design-point studies, work on the system model formulation was underway. The objective in system modeling was to provide a means for choosing the primary and secondary distribution voltages to minimize revenue requirements for utilities and, therefore, customers' electricity bills. This involved, for any particular year, minimizing the sum of the carrying charges for capital plant and expenses associated with system operation, maintenance and energy losses.

Two approaches to system modeling were considered. The first approach was to formulate circuit design as a problem in constrained optimization. That is, circuit design was considered as an optimal power flow problem, where the control variables, in addition to primary and secondary voltages, included all relevant circuit design parameters. The objective was to find the minimum cost combination of voltages and system design parameters to provide a feasible supply for a residential area of specified load characteristics.

The second approach was to develop a model which would evaluate system costs and losses for specified primary and secondary voltages, and specified system design parameters. These variables were then systematically varied until minimum system cost was observed.

The theoretical basis for the first approach (the optimal power flow) was developed and is presented in Appendix C. Since the approach was an extension of the nonlinear optimal power flow formulation, it would be prone to solution-convergence problems currently encountered with optimal power flow. Anticipated difficulties with the solution were considered likely to consume considerable time, thus the decision was made to abandon this approach and opt for the alternate.

The second approach is similar to previous work on evaluating the merits of higher primary and secondary distribution voltages. This approach provides estimates of system costs and losses (associated with the supply of a specified load) for given system design parameters. It improves over previous work, however, by including the dynamic effects of system and load development over a period of time (e.g., 30 years). In addition, considerable refinements on estimation of energy losses are made. These and other features of the model developed in this project are discussed later in this section.

Model Description

The distribution/utilization system model developed herein consists of two major submodels: a dynamic substation service area model and a customer model. The substation service area model is based upon the standardized unit substation concept. This concept is shown in Figure 1.4. The substation is sized for efficient use of a 1200A breaker with a transformer impedance chosen to limit fault current to 15 kA without cost penalty or voltage regulation problems. The substation is designed to feed three 400A circuits individually isolated using fast disconnect switches. Alternatively, the unit substation may be designed for efficient use of a 2400 amp breaker supplying six 400A circuits.

The substation service area fed by each of the circuits from the substation is shown conceptually in Figure 1.5. The substation circuit feeds a primary main.

$$\text{SECONDARY LENGTH} = \frac{\text{MAX. NO. SERVICE DROPS PER SECONDARY}}{2} \times \text{LOT WIDTH}$$

$$\begin{aligned} \text{SERVICE AREA WIDTH} &= 2 \times \text{LATERAL LENGTH} \\ &= 2 \times \text{MAX. NO. SECONDARIES PER LATERAL} \times \text{LOT DEPTH} \end{aligned}$$

$$\text{SERVICE AREA LENGTH} = \text{MAX. NO. LATERAL PAIRS} \times \text{SECONDARY LENGTH}$$

FIGURE 1.5 SUBSTATION SERVICE AREA

Off of the primary main are laterals on which the distribution transformers are connected. The distribution transformer feeds a secondary distribution circuit with service drops in groups of four. For reliability purposes, the primary main and laterals can be switched into adjacent substation service areas. The physical dimensions of the substation service area and the secondary lengths are given by the equations shown in Figure 1.5.

In order to account for the dynamic characteristics of a substation service area (i.e., growth) two new system parameters are defined. The first, shown in Figure 1.6, is referred to as the Fullness Factor. The Fullness Factor is the fraction of lots in the service area which have load. Typically the Fullness Factor will grow over time. The Fullness Factor relates to the number of components of

FIGURE 1.6 FULLNESS FACTOR

the i th type, N_i , through the second parameter which is referred to as the Homogeneity Factor, H , shown in Figure 1.7. The Homogeneity Factor relates the extent to which the occupied areas of the service area are uniformly distributed throughout the service area as opposed to being confined to compact locations within the service area. In so doing, the Homogeneity Factor provides a relationship between the Fullness Factor and the number of each type of component required to serve the load. The number of the i th type of component, N_i , is given in terms of the maximum number of components, $N_{\max i}$, that would be required if the service area were totally filled, the Fullness Factor and the Homogeneity Factor for that particular component. Typical Homogeneity Factors are as follows: for the main, $H = 1$; for service connections, $H = 0$; and for secondaries and laterals, H is between 0 and 1.

The advantages of the Fullness and Homogeneity Factors are that they provide a means for analyzing the effects of load growth over time within a substation service area without being specific as to the location of specific elements of load. Using these factors, one determines year-by-year over a study

$$H_i = \frac{\left(\text{NO. OF COMPONENTS} \right)_i - \left(\text{MIN. POSSIBLE NO. OF COMPONENTS TO SERVE LOAD} \right)_i}{\left(\text{MAX. NO. OF COMPONENTS} \right)_i - \left(\text{MIN. POSSIBLE NO. OF COMPONENTS TO SERVE LOAD} \right)_i}$$

$$N_i(t) = N_{\text{MAX}i} [F(t) + H_i(1 - F(t))]$$

FIGURE 1.7 HOMOGENEITY FACTORS

period the number of components of each type necessary to serve the load. It is then possible to account for their capital and operating and maintenance costs during the period of time which each is required.

In using Fullness and Homogeneity Factors, it is assumed that capital costs and operating and maintenance costs are independent of the equipment location. It is furthermore assumed in the model that equipment is not removed after its installation. Equipment which is installed is sized at installation to handle at least the maximum load and it is, in general, not changed out as load increases. There is one exception to this assumption in the model and that is the distribution transformer. There is provision in the model to allow for changeout of the distribution transformer as load increases.

One practical problem does exist as a result of this approach. That problem is that losses do depend on system geometry. Thus, for computation of losses, it is

assumed that the load is spread evenly across the various subsystems (secondary distribution circuit, lateral and main/feeder).

In addition to load growth in the service area, the distribution/utilization system model also accounts for voltage control, voltage flicker and reliability. The model also provides for loss evaluation.

Voltage control is obtained at the substation level through the use of a tap-change-under-load (TCUL) transformer and in the remainder of the substation area by means of wire size choice, length of secondary and, if necessary, by means of switched capacitors located on laterals. If they are required, the capacitors are sized using an AC power flow simulation.

Voltage flicker arising from locked rotor currents of larger motors is controlled to prevent irritability. The frequency and average magnitude of voltage fluctuation is calculated for the customer on the end of the secondary circuit. The average flicker magnitude for this individual is then computed and a tolerable frequency is obtained from a standard flicker irritability curve. If the flicker frequency exceeds the tolerable frequency, the secondary circuit is reduced in length and/or the wire size increased.

The objective of reliability control within the model is to assure that the amount of load that might be dropped for more than a few minutes does not exceed a specified amount. Figure 1.3 shows how reliability constraints are interpreted. The numbers N_1 and N_2 are specified as input to the model and the model develops the number of sectionalized switches and other equipments necessary to isolate faulted sections as necessary to meet these constraints.

The model provides for year-by-year computation of energy losses. This is done by means of a single-phase AC power flow simulation. This simulation assumes balanced loads on the main and feeder as well as the secondary, if it is

three-phase. (It will be explained later that the load flow is not used to calculate the losses on laterals). Since a major imbalance can only occur on the main and since its losses are relatively small this assumption is acceptable. Annual energy losses for subsystems are estimated by first calculating the peak loss on a subsystem at its own diversity factor (which is a function of the number of customers on the subsystem) with either the load flow model or by explicit calculation. This PL is then converted to annual energy loss by the equation:

$$EL = PL \times \text{Loss Factor (No. of Customers on Subsystem)} \times 8760$$

The loss factor used is also a function of the number of customers served.

The demand loss is estimated for the entire circuit at its annual peak load using the load flow simulation. The demand loss is taken equal to the swing bus generation for the main/feeder model minus the coincident customer peak load. The cost of energy loss per kilowatt hour is taken as a weighted average of the marginal cost of energy per kilowatt hour during a year. The weights are the squared values of the per unit peak load occurring at the various values of marginal cost. The cost of demand loss is taken as the cost per kilowatt of buying or selling capacity for a year over available interconnecting transmission.

The customer model is shown in Figure 1.8. Customer peak load is specified as a function of time and the customer's load profile is accounted for by specifying the diversity factor and the loss factor. These factors provide the flexibility necessary in order to be able to examine changes in load profile or customer peak loads. Incorporated in these capabilities is the ability to examine issues relating to dispersed generation and dispersed energy storage.

The measure of performance assumed by the model is the present value of utility revenue requirements plus the customer costs over a given study period per unit area served. The utility revenue requirements account for such things as

CUSTOMER PEAK LOAD

CUSTOMER POWER FACTOR--0.85 TYPICAL

DIVERSITY FACTOR

$$\text{DIVFAC}(n) = \frac{\sum_{j=1,8760}^{\text{MAX}} \left\{ \sum_{i \in A_n} s_{ij} \right\}}{\sum_{i \in A_n} \left\{ \sum_{j=1,8760}^{\text{MAX}} s_{ij} \right\}}$$

LOSS FACTOR

$$\text{LOSFAC}(n) = \frac{1}{8760} \frac{\sum_{i \in A_n} \sum_{j=1}^{8760} s_{ij}^2}{\sum_{j=1,8760}^{\text{MAX}} \left\{ \sum_{i \in A_n} s_{ij}^2 \right\}}$$

FIGURE 1.8 CUSTOMER MODEL

capital, operating and maintenance, taxes, cost of losses and equipment lifetime and lifetime dispersion characteristics. Costs for all equipments are entered in the computations as levelized annuities. The process of levelization is illustrated in Figure 1.9. Customer-related costs are accounted for in a similar manner, taking into account cost of equipment and the cost savings due to reduced losses as a function of increased secondary voltages. The reader is referenced to the Third Interim Report* for detailed documentation of the customer's cost models.

*Third Interim Report, "Analysis of Individual Component Costs and/or Energy Efficiencies," October 26, 1979.

$$PV = \sum_{\ell=1}^{\ell_L} \frac{1}{(1+r)^\ell} \left\{ \sum_{\substack{\text{ALL} \\ \text{SYSTEM} \\ \text{COMPONENTS} \\ j}} N_{j\ell} \times \left(\text{LEVELIZED ANNUAL COST} \right)_\ell + \left(\text{COST OF LOSSES} \right)_\ell \right\}$$

FIGURE 1.9 PRESENT VALUE OF REVENUE REQUIREMENTS

2. SYSTEM DESIGN OPTIMIZATION

The optimization of system design parameters makes use of the relative independence of the system design variables, voltages and conductor sizes. This independence was observed to exist while exercising the program to perform parametric studies and model validation. Variation of one variable had no significant effect on the optimum value for any other variable. Because of this independence, it is not necessary to use a multidimensional gradient search technique to find the optimum design. Instead, a one-dimensional Fibonacci search of each parameter to be optimized is conducted and the optimum parameters so found constitute essentially the optimum design. (If desired, repetitive application of this search technique may slightly refine the optimum design thus found). A Fibonacci search is used because of its efficiency and ease of program implementation.

The optimization method requires the user to specify the variables to be optimized, the upper and lower bounds of acceptable variable values for each variable and the maximum acceptable error allowed for each variable's optimum value.

The Fibonacci search is designed so that the error in the best value found for the independent variable after n experimental evaluations of the objective function is no greater than a fraction of the variable span equal to $\frac{1}{F_n}$. F_n is the n^{th} Fibonacci number, where $F_0 = F_1 = 1$ and $F_n = F_{(n-1)} + F_{(n-2)}$. Thus if the optimum value of X should have an error less than 1 percent of the span of X , 11 evaluations of the function must be made.

The number of function evaluations to be performed is calculated by comparing the fraction (acceptable variable error)/(variable span) with the reciprocal of successive Fibonacci numbers until the reciprocal is smaller than the fraction. The number of evaluations is equal to the n of the Fibonacci number F_n which first satisfies the above comparison.

The Fibonacci search continually reduces the span of the independent variable being searched on each evaluation of the objective function. If a new minimum is not reached, then the new value of the independent variable replaces either the previous upper bound or the previous lower bound of the variable span. If a new minimum is reached, then the value of the independent variable corresponding to the previous minimum replaces either the previous upper or lower bound of the variable span. In either case the next value of the independent variable is chosen to be symmetrically opposite to the current best value of the independent variable within the remaining variable span (i.e., if the minimum X is 5 units from the upper bound, then the new X will be 5 units from the lower bound).

This search is continued for n evaluations of the objective function and at that point the value of the independent variable yielding the lowest value of the objective function is used as the optimum value.

The initial value of the independent variable is chosen to be equal to the lower bound plus a fraction of the variable span. The fraction is the ratio $\frac{F_n}{F_{(n-2)}}$.

Each variable specified for optimization by the user is optimized in the order specified. As each optimal value is found, it replaces the initial value specified for that variable. After the last variable is optimized and its new value is used to replace the initial guess at that variable, the optimized design parameters are used in an evaluation of system costs. A detailed output of the annual capital and energy requirements and costs is produced for the optimal system.

3. POTENTIAL ENERGY SAVINGS

An important potential rationale for increased distribution/utilization voltages is energy conservation in the form of reduced losses and lower energy requirements for the manufacture, installation and maintenance of distribution system components. This section presents a model for the net energy comparison of different distribution system designs. The model is given in a general form and is intended to be used in conjunction with the distribution/utilization system model. A sample calculation is presented, using outputs of the model together with estimates of the energy content of various components.

Prior to proceeding one should be warned that there is some question as to the value of such an analysis for decision making, relative to a proper economic analysis, since the value of energy consumed by the system is embedded within the cost estimates of an economic analysis. However, an energy analysis can give insight into the relative energy efficiencies of competing designs, independent of current or projected prices for various forms of energy, which may be distorted by market imperfections or government policy. Of course it should be understood that the energy values given here are only crude approximations. In searching the literature for information on the energy required for certain basic components, a considerable discrepancy between estimates was not uncommon, as much as 20 to 30 percent or more. Also, data from different sources tend to be based on different assumptions, and there are some inconsistencies and inaccuracies involved in combining these data into a single estimate.

Aside from data, there are many unresolved issues relevant to net energy analysis. These are parallel to issues that have arisen in economics and which have

been addressed over the past century or so. First is the issue of the time value of energy. Is a kilowatt-hour consumed today worth more than a kilowatt-hour consumed ten years from today? How should a net energy analysis compare energy investments made across time? A second issue is quality of energy. How should electric energy losses be compared to process heat requirements? A kilowatt-hour of one is not equal to a kilowatt-hour of the other. How should requirements on different fuels be considered? Should the energy content of petroleum be considered in calculating the net energy requirements of petroleum-based insulation materials? Finally, what should be counted as "net energy:" the energy input to the mining, refining, transportation, forming, machining? What about capital plant, transportation for workers, additional food that workers consume due to working, the energy cost of growing that food, etc., etc.? No well established procedures or conventions exist. Thus, it is little wonder that net energy cost estimates vary widely depending upon assumptions of the particular analysis.

3.1 General Form of the Model

The analysis of changes in energy requirements due to changes in distribution and utilization voltages includes consideration of the distribution substation, the primary distribution circuit, the distribution transformer, the secondary distribution circuit and the customer's utilization system. Three basic types of circuit design are allowed:

- All underground
- All aerial
- Aerial primary main with underground laterals and secondaries.

A single substation service area is used as the basis for comparison of different voltages. Since it is assumed that the area has a uniform load density, an appropriate measure of change in energy consumption is kilowatt-hours per square

mile of service area (by assumption equivalent to energy consumption per MW of load). This allows the fact that at higher voltages a given substation can serve a larger area to be properly accounted for in the energy analysis.

The accounting of energy requirements, since it involves "capital" energy expenditures for equipment, should cover a time period comparable to the useful lifetime of the equipment involved. In the sample calculations a 30-year period is used to agree with the distribution/utilization system model output.

As noted above, expressing energy consumption as a function of time immediately raises the issues of whether to discount energy to be consumed in the future, and if so, at what rate. How should a kilowatt-hour saved today be compared with a kilowatt-hour saved 20 years from now? In the general model a discount rate is included, but its value is not specified. Thus, setting the rate equal to zero will include the case where no discounting is made, and energy is accounted for equally no matter when it is consumed.

There are two major categories of energy consumption by the distribution system, analogous to operating and capital costs: the energy losses within system components and the energy invested in the materials, manufacture and installation of components. Losses are the larger component of energy consumption, and consist primarily of I^2R losses and also transformer core (no-load) losses. The losses tend to decrease as voltages increase (other things held constant), since the current needed to supply a given amount of power decreases.

Except for the distribution substation, the numbers of components per square mile of service area will generally remain constant as voltage levels vary. Some additional components may be required at higher voltages (particularly in the utilization system, e.g., an autotransformer). In general, however, the energy requirements for installation and maintenance per square mile of service area will not vary greatly with voltage level, again with the exception of the substation.

A general model for the computation of the difference in discounted energy consumption per square mile of service area between two candidate system configurations is the following:

$$\Delta E = \frac{1}{A_1} \sum_{t=1}^T \left[\frac{1}{(1+r)^t} \sum_{j=1}^J (L_{jt}^1 + E_{jt}^1) \right] - \frac{1}{A_2} \sum_{t=1}^T \left[\frac{1}{(1+r)^t} \sum_{j=1}^J (L_{jt}^2 + E_{jt}^2) \right]$$

$$= \sum_{t=1}^T \left[\frac{1}{(1+r)^t} \sum_{j=1}^J \left[\frac{1}{A_1} (L_{jt}^1 + E_{jt}^1) - \frac{1}{A_2} (L_{jt}^2 + E_{jt}^2) \right] \right]$$

where

$j = 1, 2, \dots, J$	indexes types of distribution system components
$t = 1, 2, \dots, T$	indexes years
A_1	size of service area for Configuration 1
A_2	size of service area for Configuration 2
r	discount rate
L_{jt}^1, L_{jt}^2	energy losses in component type j during year t for cases 1 and 2 respectively
E_{jt}^1, E_{jt}^2	capital energy requirements for component type j during year t for cases 1 and 2 respectively.

Note that in general this model provides only comparative net energy costs between alternative system configurations. Absolute measures of net energy costs are obtained only if j ranges over all system components.

Let n_{jt}^1, n_{jt}^2 represent the number of components of type j (or number of feet for conductors, etc.) installed in year t under cases 1 and 2 respectively. Then the energy terms above can be represented as $E_{jt}^k = \alpha_j^k n_{jt}^k$ for $k = 1, 2$, where α_j^k is the energy requirement for one unit of component type j under the system design for case k . The distribution/utilization system model has as output, in addition to costs, the values of A_k, L_{jt}^k, n_{jt}^k for all k, j, t . All that remains, besides the choice of a discount rate r , is the determination of the energy requirements coefficients

α_j^k , the amount of energy required to manufacture, install and maintain one unit of component type j for design case k .

3.2 Components of the Distribution/Utilization System

The types of components which are present in a system design depend upon the design type (underground, aerial or hybrid) as well as the distribution and utilization voltages. A list of the major system components is given in Table 3.1. Most of the energy losses occur in the conductors (cable, wire) transformers and end use devices.

For capital energy expenditures, there are three effects to consider. As the voltages increase, a given component can supply more load, so that the service area can increase, reducing the number of components of that type per square mile of service area. This applies particularly to the distribution substation. Second, the design of a component may change. Transformers, conductor size and insulation thickness in cables, and possibly size of pole insulators, are most significant in terms of the amount of energy involved. And finally, higher voltages may require components which were not needed at lower voltages. For example, the bulk of the change in energy requirements for customer components as utilization voltage increases comes from the need for an autotransformer. There are some components, e.g., poles, whose design is essentially independent of voltage and whose number per square mile of service area is relatively constant, so their energy content has no effect on the change in energy required per square mile of service area as voltages increase.

3.3 Capital Energy Analysis--Methodology and Models

Two commonly used methodologies for energy analysis are process analysis and input/output analysis [1, 2].*

* See references at the end of this section.

TABLE 3.1 COMPONENTS	
<u>DISTRIBUTION SUBSTATION</u>	
BUS & BARE CABLE	LOAD-INTERRUPTERS
STRUCTURES	TRANSFORMERS (LTC)*
INSULATORS	SURGE ARRESTERS
CIRCUIT BREAKERS*	PROTECTIVE RELAYS
DISCONNECTING SWITCHES	
<u>PRIMARY CIRCUIT</u>	
CABLE & TERMINATORS*	DISCONNECTS, SWITCHES, CUTOUTS
CONDUIT, MANHOLES, VAULTS	TRANSFORMERS*
WIRE & CONNECTORS	SURGE ARRESTERS*
SUPPORT STRUCTURES (POLES, CROSSARMS, INSULATORS*)	CAPACITORS*
RECLOSERS & SECTIONALIZERS*	
<u>SECONDARY CIRCUIT</u>	
CABLE*	SUPPORT STRUCTURES
WIRE & CONNECTORS	
<u>CUSTOMER COMPONENTS</u>	
METER	CIRCUITS*
POTENTIAL TRANSFORMER*	SWITCHES
CIRCUIT BREAKERS*	GROUND FAULT CIRCUIT INTERRUPTERS
AUTOTRANSFORMERS*	OUTLETS*
<u>END-USE ELEMENTS</u>	
MOTORS*	RESISTIVE LOAD
*DESIGN STRONGLY INFLUENCED BY VOLTAGE LEVEL	

accurate method, involving a breakdown of materials usage, step-by-step manufacturing processes and installation procedures for each component, and determination of the energy required at each step and for each material. Input/output analysis involves consideration of interactions between sectors of the economy and translation of flows of goods and services into energy terms. The basic result is an energy-to-cost ratio for each sector which allows a cost analysis to be translated into an energy analysis. Thus, input/output analysis is an aggregate, "macro" approach while process analysis is a more detailed, "micro" approach.

In the present case a combination of the two methods is used. A detailed process analysis is a significant undertaking, especially for manufactured goods as

complex as power distribution system components [3]. Such estimates which are available from the literature have been used in this study and, in addition, an effort has been made to obtain accurate estimates for the most significant components, that is, transformers and cables. For the remainder of the system, the input/output method has been used to translate the cost outputs of the distribution/utilization model into energy terms.

Some relevant energy/cost ratios are given in Table 3.2. The numbers are derived from a study of the energy inputs for constructing power plants [4], adjusted for inflation in the appropriate sector of the economy. (Additional information on energy content of distribution transformers may be found in [3].)

The data used to compute the energy content of various sizes of cable are derived from Reference 5. Given the energy content of copper, aluminum [5, 6] and various insulation materials, the energy content per foot of cable is computed from the specifications for various sizes of cable. The results are shown in Tables 3.3 and 3.4.

TABLE 3.2 ENERGY/COST RATIOS	
INDUSTRIAL CLASSIFICATION	ENERGY/COST RATIO 10^4 BTU/\$1979
NEW CONSTRUCTION (OTHER)	3.65
MAINTENANCE/REPAIR CONSTRUCTION	3.44
MISC. FABRICATED WIRE PRODUCTS	8.66
POWER TRANSMISSION EQUIPMENT	3.96
TRANSFORMERS	4.85
SWITCHGEAR & SWITCHBOARDS	2.92
MOTORS & GENERATORS	3.91
ELECTRICAL INDUSTRIAL APPARATUS	4.23
ELECTRICAL EQUIPMENT	3.69

TABLE 3.3 CONDUCTORS

ALUMINUM: (BASED ON AN ENERGY CONTENT FOR DRAWN AND STRANDED WIRE OF
 1.14×10^5 BTU/LB)

$$\text{BTU PER 100 FT} = 10,696 \times \text{SIZE (K C MILS)} \times \# \text{ WIRES IN CABLE}$$

COPPER: (BASED ON ENERGY CONTENT OF 4.64×10^4 BTU/LB)

$$\text{BTU PER 100 FT} = 14,389 \times \text{SIZE (KCM)} \times \# \text{ WIRES IN CABLE}$$

TABLE 3.4 INSULATION

INSULATING MATERIAL POLYETHYLENE = ENERGY CONTENT OF 3.51×10^4 BTU/LB

PRIMARY CIRCUITS (UNDERGROUND):

$$10^3 \text{ BTU PER 100 FT} = 8.15 + 3.33 V_{PR} + 0.34 V_{PR}^2 + 6.754 \sqrt{S} + 1.38 V_{PR} \times \sqrt{S}$$

WHERE V_{PR} IS PRIMARY VOLTAGE IN KV

S IS CONDUCTOR SIZE IN KCM

SECONDARY UNITS:

SECONDARY VOLTAGE

10^3 BTU PER 100 FT

LESS THAN 212 V

$$28.14 + 12.55 \sqrt{S}$$

212 V to 350 V

$$39.69 + 14.90 \sqrt{S}$$

GREATER THAN 350 V

$$53.21 + 17.26 \sqrt{S}$$

The energy content of other components of the distribution system are calculated from energy/cost ratios (Table 3.2). Energy requirements for installation of aerial cables and support structures are constant per unit service area and relatively insensitive to voltage level. Other installation costs are computed from energy/cost ratios for general construction.

Finally, consideration should be given to the end-use elements of the customer, consisting primarily of motors and resistive load. Although motors need to be redesigned for higher voltages, the energy content stays roughly constant. The wire size decreases proportional to voltage increase, but the number of turns required increases by the same proportion, so that the amount of conductor required is roughly the same, and the energy effects of other design changes are essentially negligible in comparison with other portions of the distribution system. Also there is probably some effect of changed utilization voltages on appliance lifetimes, but the effects are not likely to be significant in relation to the overall system. The most significant effect of increased utilization voltage on capital energy required seems to be in the need for autotransformers.

3.4 Sample Calculation

The results of a sample calculation are presented for comparison of the 13 kV and 69 kV primary systems. The secondary voltage is the same for both systems, and the load density increases from 16 MVA per square mile to 32 MVA per square mile over 30 years. The comparison is made only for year 1 below, with capital energy requirements converted to a yearly basis according to the equipment lifetime and assuming no salvage value and a 2 percent discount rate.

For those components for which the energy/cost ratio is used to determine energy requirements, the starting point is the unit cost. This cost is multiplied by the number of such components in the optimal system. The total cost is then

multiplied by the appropriate energy/cost ratio and then annuitized and divided by the service area of the circuit. The result is in units of 10^6 Btu per square mile per year. For other components the capital energy requirements are a function of the component size and design. The results are given in Table 3.5.

In order to compare capital energy inputs to system losses, it is necessary to convert kilowatt-hours lost in the distribution system into the amount of thermal energy required as input to the generators. The value used here is 10,500 Btu/kWh of electricity, an efficiency of 32.5 percent for converting thermal energy into electricity. The results are shown in Table 3.6.

Note that the distribution transformers have a dominant effect on energy requirements, both in terms of energy losses (primarily core losses) and capital energy. The capital energy requirements are calculated as proportional to costs, which indicates a need for careful analysis of transformer costs at higher voltages and also sensitivity analysis on transformer costs. The result that the majority of system energy losses are core losses is partially due to the assumption that relatively high-loss transformers will be used. This is an example of why an economic analysis is generally superior to an analysis based strictly on energy. There is a tradeoff between transformer cost and losses, and in determining the optimum design it is important to reflect the fact that much of the core loss occurs at off-peak hours, when a kilowatt-hour is worth less than at peak times.

Capital energy requirements for the remaining components decrease substantially at the higher voltage level, primarily due to the larger area served by a single substation (0.24 square miles at 13 kV vs. 1.4 square miles at 69 kV).

3.5 Summary of the Energy Analysis

A model is presented for determining the discounted net change in energy requirements within the distribution system at various voltages. Losses within

TABLE 3.5A CAPITAL ENERGY REQUIREMENTS (13 KV 16-32 MVA/MI ² , AREA = 0.24 MI ²)					
COMPONENT	UNIT COST	NUMBER	SIZE (KCM)	ENERGY/COST [*] RATIO	ANNUALIZED ^{**} ENERGY
SUBSTATION TRANSFORMERS	697,100.00	0.333		4.85	2,399.0
SUBSTATION CIRCUIT BREAKERS	52,100.00	0.333		3.96	104.5
MISCELLANEOUS SUBSTATION ITEMS	721,850.00	0.333		3.96	1,448.0
SUBSTATION RELAY AND INSTRUMENT TRANSFORMER PACKAGES	15,820.00	0.333		4.23	34.0
SUBSTATION LOAD INTERRUPTER AND DISCONNECT PACKAGES	100,650.00	0.333		3.96	246.6
TERMINAL POLES	3,312.00	1.000		3.96	21.8
SWITCHED MANHOLES	8,799.00	1.000		3.65	42.6
THREE-PHASE OIL SWITCHES	22,640.00	1.000		3.96	136.5
MAIN CONDUCTORS (100')	120.00	30.000	400		105.0
MAIN AERIAL SUPPORT FACILITIES (100')	2,007.00	30.000		3.65	366.1
MAIN FEEDER CABLE (100')	1,366.00	27.457	695		241.2
CONDUIT (100')	6,132.00	27.457		3.65	814.6
SUBSTATION SURGE ARRESTORS	420.00	4.000		3.96	12.4
STRAIGHT MANHOLES	8,799.00	3.432		3.65	146.1
LATERAL CONDUCTOR (100')	46.17	99.337	326		128.7
LATERAL AERIAL SUPPORT FACILITIES (100')	1,451.00	99.337		3.65	876.6
SECONDARY AERIAL SUPPORT FACILITIES (100')	433.00	321.720		3.65	847.1
SECONDARY CONDUCTOR (100')	289.84	344.700	446		1,610.0
SERVICE DROP (100')	149.00	388.200	98		259.8
SECONDARY TRANSFORMERS	2,489.00	57.450		4.85	1,477.7
REMOTE CONTROLLED AERIAL OR UNDERGROUND SWITCHES	7,236.00	1.472		3.96	78.5
FUSED CUTOUTS OR PAD MOUNTED SWITCHES	140.00	8.830		3.96	9.1
AERIAL DISCONNECTS OR PAD MOUNTED SWITCHES	137.00	4.415		3.96	4.4
TOTAL ENERGY					11,410.0
[*] 10 ⁴ BTU/\$1979 ^{**} 10 ⁶ BTU PER YEAR PER MI ²					

TABLE 3.5B CAPITAL ENERGY REQUIREMENTS (69 kV 16-32 MVA/MI ² , AREA = 1.4 MI ²)					
COMPONENT	UNIT COST	NUMBER	SIZE (KCM)	ENERGY/COST [*] RATIO	ANNUALIZED ENERGY ^{**}
SUBSTATION TRANSFORMERS	1,786,757.00	0.333		4.85	1,055.0
SUBSTATION CIRCUIT BREAKERS	83,762.00	0.333		3.96	28.8
MISCELLANEOUS SUBSTATION ITEMS	911,170.00	0.333		3.96	313.7
SUBSTATION RELAY AND INSTRUMENT TRANSFORMER PACKAGES	93,318.00	0.333		4.23	34.3
SUBSTATION LOAD INTERRUPTER AND DISCONNECT PACKAGES	197,266.00	0.333		3.96	82.9
TERMINAL POLES	7,008.00	1.000		3.96	7.9
SWITCHED MANHOLES	69,549.00	1.000		3.65	57.7
THREE-PHASE OIL SWITCHES	108,498.00	1.000		3.96	112.2
MAIN CONDUCTORS (100')	102.60	30.000	349		14.3
MAIN AERIAL SUPPORT FACILITIES (100')	2,082.50	30.000		3.65	65.2
MAIN FEEDER CABLE (100')	5,000.00	63.256	764		235.7
CONDUIT (100')	12,053.00	63.256		3.65	632.9
SUBSTATION SURGE ARRESTORS	1,335.00	4.000		3.96	6.7
STRAIGHT MANHOLES	36,335.00	7.907		3.65	238.5
LATERAL CONDUCTOR (100')	50.00	576.157	384		151.0
LATERAL AERIAL SUPPORT FACILITIES (100')	1,526.00	576.157		3.65	917.7
SECONDARY AERIAL SUPPORT FACILITIES (100')	433.00	1,976.280		3.65	892.9
SECONDARY CONDUCTOR (100')	288.20	1,999.260	443		962.3
SERVICE DROP (100')	151.00	2,251.570	103		270.8
SECONDARY TRANSFORMERS	14,844.00	333.210		4.85	8,771.0
REMOTE CONTROLLED AREIAL OR UNDERGROUND SWITCHES	17,713.00	17.660		3.96	395.0
FUSED CUTOUTS OR PAD MOUNTED SWITCHES		0.000		3.96	0.0
AERIAL DISCONNECTS OR PAD MOUNTED SWITCHES	448.40	26.490		3.96	15.0
TOTAL ENERGY					15,261.0
[*] 10 ⁴ BTU/\$1979 ^{**} 10 ⁶ BTU PER YEAR PER MI ²					

TABLE 3.6 ENERGY PER UNIT AREA IN YEAR 1 (10^6 BTU)			
COMPONENT OF TOTAL	13 kV	69 kV	13 kV-69 kV
DISTRIBUTION TRANSFORMER CAPITAL ENERGY	1,479	8,771	-7,292
OTHER CAPITAL ENERGY	<u>9,931</u>	<u>6,490</u>	<u>+3,441</u>
TOTAL CAPITAL ENERGY	11,410	15,261	-3,851
I^2R LOSSES	4,776	4,294	482
DISTRIBUTION TRANSFORMER CORE LOSSES	<u>8,088</u>	<u>9,051</u>	<u>-963</u>
TOTAL ENERGY LOSSES	<u>12,864</u>	<u>13,345</u>	<u>-481</u>
TOTAL ENERGY REQUIREMENTS	<u>24,284</u>	<u>28,606</u>	<u>-4,322</u>

components and the capital energy required to manufacture and install components are included in the model. Outputs (from the distribution/utilization system model) of energy losses and number, types and costs of components are used as inputs, together with results of detailed energy analyses from the literature and energy/cost ratios derived from input/output analysis.

In general the capital energy required to construct the distribution system, annualized to a yearly basis, is of the same order of magnitude as the energy (thermal equivalent) lost in the system. In the sample calculation of the previous section, the small savings in I^2R losses in going from 13 kV to 69 kV, and the larger savings in capital energy for the substation due to larger service area, are outweighed by the increased transformer core losses and the capital energy for the larger transformers themselves. The strong influence of the characteristics of distribution transformers on the energy analysis implies a need for better data and additional sensitivity analysis for this particular component.

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4. ELECTRIC DISTRIBUTION/UTILIZATION SYSTEM COST ANALYSIS MODEL

This section provides a description of the distribution/utilization system model and describes its capabilities and use. The model logic is provided first. Then a user's guide is given.

4.1 Model Logic

The model main routine logic is presented in Figure 4.1. First the input routine is called which reads in the data values for all variables. The next section initializes the control variables (those which can be optimized) to the values read in by the input routine.

The following section reads in the names of any variables which are to be optimized. For each variable the lower and upper bounds on the variables are read in along with the maximum error permitted between the calculated optimum and the true optimum.

After the optimizing variables have been read, the CUSTPK array of data representing annual growth rates must be stored in an array CSPKSV so that the initial values of CUSTPK will be available for successive iterations in the optimization process. The initial values of CUSTPK are destroyed during an iteration.

After the values of CUSTPK have been saved, the program checks to see if any variables are to be optimized. If there are no optimization variables, then the system development and cost evaluation routine FOFX is called and the annual system development and costs are calculated along with a total present worth cost per square mile for the distribution circuit capital and losses as well as the customer system capital and losses for the period of time specified.

FIGURE 4.1 MAIN ROUTINE LOGIC

If there are variables to optimize, a do loop is entered which will call routine FBSRCH for each of the optimizing variables. After each variable has been optimized the routine FOFX is called to evaluate the system design and cost.

The FBSRCH routine is shown in Figure 4.2. This routine performs a Fibonacci search of the span defined by the variable upper and lower bounds specified in the optimization data such that the optimal variable value calculated is guaranteed to differ from the true optimum by no more than the maximum error specified in the optimization data.

The routine starts by calculating the initially defined variable span and setting the first two Fibonacci numbers. Next the routine enters a loop which calculates successive Fibonacci numbers. In this loop a comparison is made to determine which Fibonacci number F_n has an n large enough so that n iterations will guarantee that the error in the optimal value will be no greater than the maximum permissible error. If a satisfactory F_n has not been found by $n = 16$, then

FIGURE 4.2 FBSRCH ROUTINE LOGIC

16 iterations are chosen since this corresponds to an error of $1/987$ of the initial span of the variable and is considered to be good enough.

Once the number of iterations has been determined, the starting point for the search must be calculated. This point should be a fraction of the span length added to the lower bound on the variable. The fraction is equal to the ratio of the Fibonacci number F_n divided by the Fibonacci number $F_{(n+2)}$, where n is the number of iterations, $F_1 = 1$, $F_2 = 1$ and $F_i = F_{(i-1)} + F_{(i-2)}$.

After determining the first value of X , the routine FOFX must be called to evaluate the objective function, $F(X)$, for the X just calculated. This initial value of the objective function is stored in OLDTOT and FMIN. The value of X is stored in XSAV and XMINF. The final values of XMINF and FMIN will be the optimal value of X and its corresponding objective function value.

Next the second value of X must be calculated. Each new value of X must be located in the portion of the span remaining to be searched so that it is symmetric with the most optimal value of X found up to that iteration. Therefore the second value of X is located as far from the span upper bound as the initial value of X was located from the lower bound.

Once the second X value has been calculated, a loop is entered which evaluates the objective function for the current value of X . It then compares the new value of the objective function with the minimum value previously found. If a lower value has been found then it and its corresponding X -value replace the previous best values and the span bounds are adjusted to narrow in on the current minimum. If the previous minimum is still lower than the new objective function value, it is retained and the span bounds are adjusted to narrow in on it.

At the end of the iteration loop, the value of X for the minimum objective function value is used to replace the value of that variable in the base data. The routine then returns to the main routine.

The FOFX routine logic is presented in Figure 4.3. FOFX simulates the development and operation of primary and secondary distribution circuits and associated substation capacity, and the end-use elements for a given set of input data. FOFX takes a set of data as input and calculates the number of components required for a circuit area each year for a number of years specified by the user. The losses on the circuit are also calculated for each year of circuit evolution. Finally the present worth of the component and loss costs is summed up for each year and divided by the number of square miles in the circuit area to calculate the objective function.

When FOFX is called, the first thing done is to set the values of the control variables to those values passed from the FBSRCH routine or the main routine. Next the RESET routine is called for the purpose of recalculating the impedances based on the new conductor sizes and setting any array values to zero where required.

After that a routine named RESLD is called which adjusts the value of a single residential load. The input data load assumes 120 volts, single-phase load. If a different voltage or if three-phase is used, the effect of this change on house load is determined and the house load is adjusted accordingly.

Next a routine named PKYR is called to determine peak years for the total circuit and the secondary circuits. These years could be different if load management were to reduce the single customer peak demand over time while more customers were added.

Once the peak years have been determined, these years will be used in sizing the circuit and making voltage drop and voltage flicker checks. PKYR also determines in which years (if any) that distribution transformers should be changed-out for larger transformers. The nameplate rating of the initially installed transformers is calculated in PKYR.

FIGURE 4.3 FOFX ROUTINE LOGIC

After PKYR, the RATCHK routine is called. RATCHK calculates the cable ratings for the circuit. If an underground case is being run, the routine checks the service drop cable rating against its maximum expected load. If an overloaded service drop cable is found, the program branches to a statement which sets the objective function to 10^{60} and returns. An error message detailing the problem is printed out.

If no overload is encountered, a routine named SECMOD is called which develops a secondary load flow model. This model is used to check the voltage drop on the secondary for the secondary peak year. It also compares the peak secondary load with the rating of the secondary cable for underground cases. If an overload exists, an error message is printed.

If a secondary cable overload is found, the program branches to a statement which sets the objective function to 10^{60} and returns. If no overload is encountered, BUMPS is called.

BUMPS calculates the frequency of each possible magnitude of voltage bump experienced by a secondary customer on a secondary circuit. It then checks the frequency associated with each magnitude against an irritability curve to determine if the secondary circuit is feasible as designed. If it is not, a branch is made to set the objective function to 10^{60} and return. The secondary circuit must then either be reduced in length or have its conductor size increased.

If the circuit is feasible, routine DIM is entered. DIM calculates the dimensions of the circuit needed for the peak year. It also calculates the maximum number of each type of component which will be required for a fully developed circuit.

Next the program calls routine RELCOM to calculate the number of reliability related components per circuit and per lateral needed to limit the

amount of load dropped for any extended period of time to a specified value, CRITLD.

At this point the SYSMOD routine is called. SYSMOD sets up loadflow models for the secondary, lateral, main/feeder and total circuit systems. The total circuit model is used within the routine to determine any low voltage points. The routine then adds capacitors in increments until the low voltage problems are overcome. If it is an underground case, the ratings on the lateral and main cables are checked for an overload. The feeder cable rating is checked for an overload in any case.

If any cable is overloaded, a message is printed and the program branches to set the objective function to 10^{60} and then returns. If no overloads are encountered, a loop, executed once for each study year, is entered. Three routines are called in the loop.

First NOCOM is called to calculate the number of components required for each year to supply the circuit load. These data are used when calculating the annual capital cost.

The second routine is SYSLOS. In SYSLOS the annual I^2R loss, transformer core loss and peak demand losses are calculated either with the loadflow models or algebraically. The appropriate coincidence and loss factors (which depend on number of customers served) are considered for each subsystem (e.g., secondary, lateral, etc.) in calculating the total system loss. The current-year circuit load and system development are also considered.

The last routine called is COSTS. In COSTS the per unit cost of each type of component is calculated and combined with the number of units passed from NOCOM to calculate each year's levelized capital cost in present worth terms. In COSTS a check is made to determine if a transformer change-out is needed for the

current year. When it is, the transformer cost is reevaluated based on the larger size and is used to replace the previous cost. Also, a present worth cost of changing-out the existing transformers is added to the cumulative system cost. Each year's present worth loss cost is then added to the capital cost, with the actual losses being passed from SYSLOS. Finally the number of customer components and their costs in present worth terms is calculated and added to the accumulated system cost, along with the capital and loss costs.

For each year a summary of the numbers of components, losses and associated present worth levelized costs accumulated by the present year is printed. In the last year the accumulated cost during the circuit life is normalized by dividing it by the number of square miles per circuit. This value is then used for the objective function which is returned either to FBSRCH or the main routine. If FBSRCH was the calling routine, all output other than error messages and the value of the object function is suppressed.

4.2 Program Users' Guide

The Electric Distribution/Utilization System Cost Analysis Model (EDUSCAM) calculates the cumulative present worth of the annual capital carrying charges, expenses and losses on the distribution system defined by the user for a number of years specified by the user.

The EDUSCAM has an optional optimization routine which will calculate the most economic set of system design parameters for a given set of load model parameters.

Three types of input parameters must be specified when executing EDUSCAM. These are identified as system design (SD) parameters, load model (LM) parameters and miscellaneous system (MS) parameters. When the optimization routine is used, only the SD parameters or a subset of SD parameters are

optimized. The LM and MS parameters are the base for which the SD parameters are optimized. The objective function is the cumulative present worth cost of the system.

The parameters for each group are specified below along with allowable value ranges and comments.

System Design Parameters

C1-C4 The objective function for a run is a present worth sum having the form:

$$\begin{aligned} \text{OBJECT} = & C1 * \text{CAPITAL COSTS} \\ & + C2 * \text{ENERGY COSTS} \\ & + C3 * \text{CUSTOMER CAPITAL COSTS} \\ & - C4 * \text{CUSTOMER ENERGY COST SAVINGS} \end{aligned}$$

This form provides the user with the ability to vary the objective function if so desired. For a normal run, the value of each of the coefficients C1 through C4 should be set to 1. Cost components can be removed from the objective function by setting the respective coefficient to 0.

CSFEED The circuit feeder cable size in KCMIL. Must be specified for aerial or underground systems.

There are minimum cable sizes which can be used at different voltages because of the excessive electric fields in the corona which would occur at lower sizes. The equation specifying the lowest allowable cable sizes in KCMIL as a function of primary phase-to-phase voltage in KV is:

$$\text{MINIMUM SIZE} = .1776 \times VP^2 - 6.878 \times VP + 129.2$$

$$\text{Value Range: } 0 < \text{CSFEED} \leq 1000$$

CSMAIN The circuit main cable size in KCMIL. Must be specified for underground systems.

$$\text{Value Range: } 0 < \text{CSMAIN} \leq 1000$$

CSPRIM The circuit lateral cable size in KCMIL. Must be specified for underground systems.

$$\text{Value Range: } 0 < \text{CSPRIM} \leq 1000$$

CSSEC The circuit secondary cable size in KCMIL. Must be specified for underground systems.

Value Range: $0 < \text{CSSEC} \leq 1000$

CSSERV The circuit secondary service cable size in KCMIL. Must be specified for underground systems.

Value Range: $0 < \text{CSSERV} \leq 1000$

NCUSTS The maximum possible number of customers which can be supplied by a secondary distribution transformer. Must be specified. NCUSTS is restricted to be a multiple of 4. If the MS parameter NX is equal to 1, any multiple of 4 greater than 0 is allowed. If NX is equal to 2, only odd multiples of 4 are allowed. If the voltage drop on the secondary is greater than permissible, the value of NCUSTS must be reduced or the wire size for the secondary must be increased.

NLATPR The number of lateral pairs on the circuit main. Must be specified. NLATPR must be an odd number.

VOLTHI The upper value of allowable secondary voltages in kV. Must be specified. Must be greater than or equal to VS. Must be greater than VOLTLO.

VOLTLO The lower value of allowable secondary voltages in kV. Must be specified. Must be less than or equal to VS. Must be less than VOLTHI.

VP The primary voltage in kV. Must be specified.

Value Range: $13 \leq \text{VP} \leq 69$

VS The secondary voltage in kV. Must be specified.

Value Range: $.12 \leq \text{VS} \leq .48$

WSLAT The circuit lateral wire size specified in KCMIL. Must be specified for aerial systems.

Value Range: $0 < \text{WSLAT} \leq 1000$

WSPRIM The circuit main wire size specified in KCMIL. Must be specified for aerial systems.

Value Range: $0 < \text{WSPRIM} \leq 1000$

WSSEC The circuit secondary wire size specified in KCMIL. Must be specified for aerial circuits.

Value Range: $0 > \text{WSSEC} \leq 1000$

WSSERV The circuit secondary service drop wire size in KCMIL. Must be specified for aerial circuits.

Value Range: $0 \leq \text{WSSERV} \leq 1000$

Load Model Parameters

CUSTPK An array storing the yearly growth factors which will be applied to a single house load. Growth factor for the i th year is the ratio of a house load in year i divided by a house load in year $(i-1)$. Values of CUSTPK (i) must be specified for every year of the study except for the first year. The program will internally replace each value of CUSTPK (i) with the calculated house load for each year.

DFAC An array storing the yearly coincidence factors between a house peak load and a house load at system peak. Values of DFAC(i) must be specified for every year i of the study.

This program calculates coincidence factors as a function of the number of customers (X) served by a piece of equipment. The equation for this curve is hardcoded into the program. DFAC(i) is used to scale the basic equation for the i th year. The equation used is:

$$\text{COINCIDENCE FACTOR} = 0.47482 + 0.52518/X.$$

This equation was determined by sampling different numbers of residential load profiles obtained during a Philadelphia Electric Company 1977 load survey and fitting the composite coincidence factors for different numbers of customers to a regression curve.

Value Range: $0 < \text{DFAC}(i) \leq 1$

DLF An array storing the peak daily loss factor for each year for a system of secondary distribution customers. This is used for cable rating calculations. Values of DLF(i) must be specified for each study year i . Values of DLF(i) are equal to the ratio of the average loss during a peak day load cycle to the peak loss for that day.

Value Range: $0 < \text{DLF}(i) \leq 1$

DLOT The lot depth for a single residence in feet.

F An array storing the yearly fullness factors for each year of the study. F(i) is equal to the ratio of actual occupied house lots on a circuit to the maximum number of house lots on a circuit. Circuit load density is a function of F, DFAC, CUSTPK and HSLOAD (defined later).

HLAT The lateral homogeneity factor. HLAT describes the density of occupied lots per lateral for the circuit area. HLAT is equal to the ratio A/B . A is the difference between the actual number of laterals required to serve an area and the minimum number required if all of the

house lots were packed together. B is the difference between the maximum possible number of laterals in the circuit area and the minimum possible number.

HP The horsepower rating of the largest motor in a house.

<u>Motor Type</u>	<u>Value Range</u>
Capacitor	0.25 - 5.00 HP
Split Phase	0.05 - 0.75 HP
Three Phase	0.50 - 5.00 HP

HSEC The secondary homogeneity factor. HSEC describes the density of occupied lots per secondary circuit for the circuit area. HSEC is the ratio A/B. A is the difference between the actual number of secondaries required to serve an area and the minimum number required if all of the house lots were packed together. B is the difference between the maximum possible number of secondaries in the circuit area and the minimum possible number.

HSLOAD The noncoincident peak house load in the first study year in kVA. (Assumes 120 volt secondary voltage).

IDUS Code for the type of motor with a horsepower rating of HP.

<u>IDUS</u>	<u>Motor Type</u>
1	Capacitor
2	Split Phase
3	Three Phase

NSTART The number of motor starts per house for the largest house motor.

POWFAC The power factor for the circuit load.

WLOT The lot width for a single residence in feet.

YLF An array storing the yearly loss factor for each year for a system of secondary distribution customers. This is used for loss calculations. Values of YLF(i) are equal to the ratio of the average loss during a year i to the peak loss for that year.

The program calculates loss factors as a function of the number of customers (X) served by a piece of equipment. The equation for this curve is hardcoded into the program. YLF(i) is used to scale the basic equation for the ith year. The equation used is:

$$\text{YEARLY LOSS FACTOR} = 0.14836 - 0.10958/X$$

This equation was determined by sampling different numbers of residential load profiles obtained during a Philadelphia Electric Company 1977 load survey and fitting the composite loss factors for different numbers of customers to a regression curve.

Value Range: $0 < YLF(i) \leq 1$

Miscellaneous System Parameters

CAPRAT The capacity to rating ratio used in determining the capacity for a secondary distribution transformer from its nameplate rating.

Value Range: Typically less than two.

CAPSIZ The rating of a circuit capacitor in kvar.

Suggested Value: Approximately 100.

CC1-CC6 The carrying charge rates for different types of equipment.

CC1 = 0.075197

CC2 = 0.073214

CC3 = 0.0725414

CC4 = 0.0707101

CC5 = 0.0628048

CC6 = 0.055407.

These rates are real carrying charge rates where inflationary effects have been removed.

CD An array storing the annual dollar cost for each study year of one kilowatt of demand loss.

CIRRRAT The maximum ampere load for one circuit. $CIRRRAT = 1200/\text{number of circuits per substation transformer (for NUMB} = 1)$.

CRITLD The critical amount of load in kVA which is the maximum that the utility is willing to drop for a period greater than a few minutes.

DTZ The typical percent of nameplate impedance for a utility's secondary distribution transformers.

Value Range: $0 < DTZ \leq 100$.

FEC An array storing the dollar per kilowatt-hour cost of fixed energy losses for each year of the study. These losses are constant losses associated with transformer cores and capacitors.

- LFDEBUG** A logical flag which produces (= .TRUE.) or suppresses (= .FALSE.) the standard load flow outputs for each load flow run completed during program execution.
- NCAP** The number of capacitors to be placed along each circuit lateral.
Value Range: $NCAP \geq 1$.
- NCODE** A code indicating whether an aerial (NCODE = 0) or an underground (NCODE = 1) circuit is to be modeled.
- NPHI** A code indicating whether the secondary lines for the circuit are single-phase (NPHI = 0) or three-phase (NPHI = 1).
- NUMB** A code indicating whether a 1200 ampere substation transformer (NUMB = 1) or a 2400 ampere substation transformer is to be modeled.
- NX** Number of houses on one side of the street supplied from a single point on a secondary circuit. NX = 1 or 2. For underground NX = 1.
- NYEAR** The number of years for a study.
Suggested Value: 30
- R** The real interest rate (corrected for inflation).
Suggested Value: 0.02
- TA** The earth ambient temperature in degrees centigrade.
Middle Atlantic Region Value: 23.
- VBUFF** The per-unit voltage drop reserved for areas of the circuit other than the secondary system.
Value Range: $0.01 < VBUFF < \text{Maximum per-unit voltage drop}$.
- VC** The convenience outlet voltage in kV.
Value Range: $0.12 \leq VC \leq 0.24$.
- VEC** An array storing the dollar per kilowatt-hour cost of I^2R energy losses for each year of the study.

Base Data Format

The base data input data for the EDUSCAM consists of card images defining the initial values for each of the System Design Parameters, Load Model Parameters and Miscellaneous System Parameters.

The first data card consists of the characters &DATAIN starting in column two of the data card. The remainder of this card should be left blank.

This card is followed by data items separated by commas. Each data item has one of the following forms:

Symbolic name = constant,

or

Array name = set of constants (separated by commas).

The symbolic name may be an array element name or a variable name. The constant may be integer, real or logical. Subscripts for array element names must be integer constants.

For array initialization, the set of constants consists of integer constants, real constants or logical (.TRUE. or .FALSE.) constants. The number of constants must be less than or equal to the number of elements in the array. Successive occurrences of the same constant can be represented in the form k*constant, where k is a nonzero integer constant specifying the number of times the constant is to occur.

The order of occurrence of the array names and variable names in the input data is not significant. However, it is strongly recommended that the array and variables names be entered alphabetically to facilitate locating the array or variable within the input data should it be desired to change its initial value(s) for subsequent runs.

Each card image must contain a blank in column one followed by a complete variable name or array name following by an equal sign (=) followed by a constant or set of constants. A comma (,) must immediately follow the last constant on the card. Embedded blanks are not permitted in names or constants. Trailing blanks after integers and exponents are treated as zeros. It is strongly recommended that

each card contain only one data item, i.e., the initialization for only one variable or array.

The end of the base data is signalled by a card containing the characters &END starting in column two of the data card. All other columns should remain blank.

Optional Optimization Feature

The optional optimization feature in DSCAP is invoked by including additional data cards after the &END card which signals the end of the base data. These cards each specify one control variable which will be optimized using a one-dimensional Fibonacci search.

Only variables with a continuous nature and which do not cause concomitant changes in other variables may be optimized. Specifically, the allowable control variables names which may appear on the optional optimization data cards are: CSFEED, CSMAIN, CSPRIM, CSSEC, CSSERV, HSLOAD, VP, WSLAT, WSPRIM, WSSEC and WSSERV. Any other variables (e.g., NCUSTS, NLATPR) must be varied in successive runs by changing their initial values in the base data.

The format for the optional optimization data cards is as follows:

Columns 1- 6: Control Variable Name

Columns 11-20: Minimum Allowable Value of Control Variable

Columns 21-30: Maximum Allowable Value in Control Variable

Columns 31-40: Maximum Allowable Error in Control Variable.

No implied decimal points are assumed for the numeric fields.

Optimization of each of the control variables specified will be performed in sequence in the order in which the control variables appear on the optional optimization data cards.

It is suggested that if the secondary wire size WSSEC is to appear as a control variable for optimization, it should appear on the first optimization data card so that any infeasible voltage condition which might occur on the secondary can be overcome. Otherwise this infeasible condition will result in errors in variables optimized prior to the secondary wire size.

After secondary wire size, the primary voltage VP is recommended as the next variable to be optimized. After that, order is unimportant.

NOTE: Initial values for all control variables should appear in the base data. This is particularly important when several control variables are to be optimized in a single run. The initial values specified in the base data are used during the optimization process. Each control variable will retain the initial value specified in the base data until optimization is performed for that variable. Once optimization has been performed for a control variable, the optimal value found for that variable will be used during the optimization process for the remaining control variables specified.

When no optional optimization control cards are included as part of the input data, the program will evaluate the objective function for the system defined by the values specified in the base data.

JCL for Executing the EDUSCAM Program

The Job Control Cards (JCL) required to run the EDUSCAM program are shown below:

//jobname	JOB	(accounting information)
//	EXEC	PGM=DSCAP
//STEPLIB	DD	DSN=SP.TESTING.LOADLIB,DISP=SHR
//FT02F001	DD	UNIT=SYSDA,DISP=(NEW,DELETE),
//		SPACE=(3600,100)
//FT05F001	DD	UNIT=SYSDA,DISP=(NEW,DELETE),
//		SPACE=(800,(200,50),RLSE),
//		DCB=(RECFM=FB,BLKSIZE=800,LRECL=80)
//FT06F001	DD	SYSOUT=A
//FT15F001	dd	*

```
      .  
      .  
      .  
[ d a t a ]  
      .  
      .  
      .
```

```
//
```

There follows a listing of typical input data cards and example outputs.

LISTING OF INPUT DATA CARDS

TIME 13:29:04 DATE 08/11/80

0...0...1...1...2...2...3...3...4...4...5...5...6...6...7...7...8
 1234567890123456789012345678901234567890123456789012345678901234567890

&DATAIN

AUTOFX = 0.,

CAPRAT = 1.60,

CAPSIZ = 100.,

C1 = 1

C2 = 1

C3 = 1

C4 = 1

CC1 = 0.751970E-1,

CC2 = 0.732140E-1,

CC3 = 0.725414E-1,

CC4 = 0.707101E-1,

CC5 = 0.628048E-1,

CC6 = 0.554070E-1,

CD = 50 * 30.,

CIRRAT = 400.,

CRITLD = 6000.,

CSFEED = 665.,

CSMAIN = 160.,

CSPRIM = 125.,

CSSEC = 565.,

CSSERV = 90.,

CUSTPK = 50 * 1.010,

DFAC = 50 * 0.47535,

DLF = 50 * 0.49967,

DLOT = 150.,

DTZ = 1.8,

F(1) = .61,

F(2) = .62,

F(3) = .63,

F(4) = .64,

F(5) = .65,

F(6) = .66,

F(7) = .67,

F(8) = .68,

F(9) = .69,

F(10) = .70,

F(11) = .71,

F(12) = .72,

F(13) = .73,

F(14) = .74,

F(15) = .75,

F(16) = .76,

F(17) = .77,

F(18) = .78,

F(19) = .79,

F(20) = .80,

F(21) = .81,

F(22) = .82,

F(23) = .83,

MODEL INPUT

FOR A 30-YEAR STUDY OF AN AREA HAVING
 A FIRST-YEAR LOAD DENSITY OF 8 MVA PER
 SQUARE MILE AND A FINAL-YEAR LOAD DEN-
 SITY OF 16 MVA PER SQUARE MILE.

THE VARIABLE DEFINITIONS ARE FOUND IN
 THE USERS GUIDE.

THE CARRYING CHARGE RATES CC1-CC6 ARE
 CALCULATED ACCORDING TO THE METHOD
 DEFINED IN THE THIRD INTERIM REPORT,
 APPENDIX A. 2% REAL INTEREST RATE IS
 USED.

0...0...1...1...2...2...3...3...4...4...5...5...6...6...7...7...8
 1234567890123456789012345678901234567890123456789012345678901234567890

LISTING OF INPUT DATA CARDS

TIME 13:29:04 DATE 08/11/80

0...0...1...1...2...2...3...3...4...4...5...5...6...6...7...7...8
 1234567890123456789012345678901234567890123456789012345678901234567890

F(24) = .84,
 F(25) = .85,
 F(26) = .86,
 F(27) = .87,
 F(28) = .88,
 F(29) = .89,
 F(30) = .90,
 FEC = 50 * 0.04,
 FEEDRL = 8400.,
 HLAT = 0.7,
 HP = 2.0,
 HSEC = 0.4,
 HSLOAD = 11.3,
 IDUS = 1,
 LFDSUG = .FALSE.,
 NCAP = 2,
 NCODE = 0,
 NCUSTS = 16,
 NLATPR = 5,
 NPHI = 0,
 NSTART = 4,
 NUMB = 1,
 NX = 1,
 NYEAR = 30,
 POWFAC = 0.90,
 R = 0.02,
 TA = 23.,
 VBUFF = 0.03,
 VC = 0.12,
 VEC = 50 * 0.05,
 VOLTHI = 0.126,
 VOLTLO = 0.114,
 VP = 35.0000,
 VS = 0.12,
 WLOT = 75.,
 WSLAT = 300.,
 WSPRIM = 400.0000,
 WSSEC = 400.0000,
 WSSERV = 120.0000,
 YLF = 50 * 0.14825

MODEL INPUT
 CONTINUED

THE VARIABLES SPECIFIED IN THE OPTI-
 MIZATION INPUT BELOW WILL BE OPTI-
 MIZED IN THE ORDER THEY ARE ENTERED.
 THE FIRST NUMERIC FIELD SPECIFIES THE
 LOWER LIMIT ON ACCEPTABLE VARIABLE
 VALUE USED IN THE SINGLE-DIMENSIONAL
 FIBONACCI SEARCH. THE SECOND FIELD IS
 THE UPPER LIMIT. THE THIRD FIELD IS
 THE MAXIMUM ERROR TOLERANCE FOR THE
 OPTIMIZED VARIABLE VALUE. THE TRUE
 OPTIMUM WILL DIFFER FROM THE CALCUL-
 ATED OPTIMUM BY LESS THAN THIS
 AMOUNT.

END
 WSSEC 0. 1000. 40.
 WSSERV 0. 1000. 40.
 VP 13. 69. 2.
 CSFEED 0. 1000. 40.
 WSPRIM 0. 1000. 40.
 WSLAT 0. 1000. 40.

OPTIMIZATION INPUT

0...0...1...1...2...2...3...3...4...4...5...5...6...6...7...7...8
 1234567890123456789012345678901234567890123456789012345678901234567890

ENTERING FOFX

CSFEED = 665.0000
 CSMAIN = 160.0000
 CSPRIM = 125.0000
 CSSEC = 565.0000
 CSSERV = 90.0000
 HSLOAD = 11.3000
 VOLTHI = 0.1260
 VOLTLO = 0.1140
 VP = 35.0000
 VS = 0.1200
 WSLAT = 300.0000
 WSPRIM = 400.0000
 WSSEC = 382.0222
 WSSERV = 120.0000

INITIAL VALUES OF VARIABLES WHICH MAY
 BE SUBJECT TO OPTIMIZATION

THIS IS THE NAMEPLATE RATING FOR A
 SECONDARY DISTRIBUTION TRANSFORMER
 INSTALLED IN THE FIRST YEAR. THIS
 SIZE WILL BE CHANGED-OUT IN A FUTURE
 YEAR IF LOAD GROWTH MAKES IT NECES-
 SARY.

THE CIRCUIT PEAK YEAR IS 30 } THE YEARS WHEN PRIMARY AND SECONDARY
 THE SECONDARY PEAK YEAR IS 30 } CIRCUIT PEAKS OCCUR
 THE DISTRIBUTION TRANSFORMER NAMEPLATE RATING IS 73.1 KVA

CIRCUIT AREA = 1.45 SQUARE MILES
 CIRCUIT LENGTH = 3000.00 FEET
 CIRCUIT WIDTH = 13500.00 FEET
 MAXIMUM NUMBER OF CUSTOMERS IN THE CIRCUIT AREA IS 3600

CIRCUIT DIMENSIONS

THE DISTRIBUTION TRANSFORMER CORE LOSS IS 0.26 KW } THIS CORE LOSS AS WELL AS THE TRANS-
 FORMER IMPEDANCE IS UPDATED IF A
 CHANGE-OUT IS NECESSARY

THE PRESENT WORTH COST OF A CIRCUIT PER SQUARE MILE IS 7181307.00

THE CAPITAL PORTION IS 4633749.00
 THE CUSTOMER PORTION IS 1180799.00
 THE ENERGY PORTION IS 1366768.00
 CUSTOMER DOLLAR SAVINGS 8.08

CUSTOMER ENERGY SAVINGS 280.02 KWH
 FBSRCH - ITERATION 1: XLB= 0.0 X= 382.0222 XUB= 1000.0000 FOFX = 7181307.00

THE PER SQUARE MILE COST OF THE CIRCUIT
 AND ITS SHARE OF THE SUBSTATION IS
 PRINTED HERE. THIS IS A CUMULATIVE
 PRESENT WORTH COST. IT IS SUBDIVIDED
 INTO UTILITY CAPITAL, CUSTOMER CAPI-
 TAL, UTILITY LOSS AND CUSTOMER LOSS
 COSTS. THE CUSTOMER LOSSES ARE THE
 INCREMENTAL LOSSES CAUSED BY SECON-
 DARY VOLTAGES DIFFERENT FROM
 120 VOLTS/SINGLE PHASE. THE SMALL
 VALUES SHOWN FOR THIS 120 VOLT CASE
 ARE DUE TO ROUND OFF ERROR.

THE RESULTS OF THIS PAGE WERE ITERA-
 TION 1 OF THE SEARCH BEING MADE OF THE
 DEFINED RANGE FOR WSSEC TO FIND AN OP-
 TIMUM VALUE. THE CURRENT ITERATION
 LOWER AND UPPER BOUNDS AS WELL AS THE
 CURRENT VALUE OF THE SEARCH VARIABLE
 (WSSEC) ARE SPECIFIED. THE VALUE OF
 THE OBJECTIVE FUNCTION FOUND FOR THIS
 VALUE OF WSSEC IS ALSO SPECIFIED.

ENTERING FOFX

CSFEED =	665.0000	
CSMAIN =	160.0000	
CSPRIM =	125.0000	CONTROL VARIABLE VALUES UPON ENTERING
CSSEC =	565.0000	SECOND ITERATION. WSSEC CURRENTLY
CSSECV =	90.0000	BEING OPTIMIZED.
MSLOAD =	11.3000	
VOLTHI =	0.1260	
VOLTLO =	0.1140	
VP =	35.0000	
VS =	0.1200	
MSLAT =	300.0000	
MSPRIM =	400.0000	
MSSEC =	617.9778	
MSSECV =	120.0000	

THE CIRCUIT PEAK YEAR IS 30
 THE SECONDARY PEAK YEAR IS 30
 THE DISTRIBUTION TRANSFORMER NAMEPLATE RATING IS 73.1 KVA

CIRCUIT AREA = 1.45 SQUARE MILES
 CIRCUIT LENGTH = 3000.00 FEET
 CIRCUIT WIDTH = 13500.00 FEET
 MAXIMUM NUMBER OF CUSTOMERS IN THE CIRCUIT AREA IS 3600

THE DISTRIBUTION TRANSFORMER CORE LOSS IS 0.26 KW

THE PRESENT WORTH COST OF A CIRCUIT PER SQUARE MILE IS 7201775.00

THE CAPITAL PORTION IS	4778526.00				
THE CUSTOMER PORTION IS	1180799.00				
THE ENERGY PORTION IS	1242459.00				
CUSTOMER DOLLAR SAVINGS	8.08				
CUSTOMER ENERGY SAVINGS	280.02 KWH				
FBSRCH - ITERATION 2: XLB=	0.0	X=	617.9778	XUB=	1000.0000 FOFX = 7201775.00

THIS IS THE SECOND ITERATION IN THE SEARCH OF WSSEC FOR AN OPTIMUM. BECAUSE THE VALUE OF THE OBJECTIVE FUNCTION IS GREATER THAN FOR ITERATION 1, THE VALUE OF THE UPPER BOUND (1000) WILL BE REPLACED WITH THIS ITERATION'S VALUE OF THE SEARCH VARIABLE (617.9778). IN SUCCESSIVE ITERATIONS THE BOUNDS WILL BE FURTHER NARROWED AS THE ROUTING NARROWS IN ON THE OPTIMUM.

ENTERING FOFX

CSFEED = 665.0000
 CSMAN = 160.0000
 CSFRM = 125.0000
 CSSEC = 565.0000
 CSSERV = 90.0000
 HSLD = 11.3000
 VOLTHI = 0.1260
 VOLTLO = 0.1140
 VP = 35.0000
 VS = 0.1200
 WSLAT = 300.0000
 WSPRM = 400.0000
 WSSEC = 449.4446
 WSSERV = 120.0000

THIS PAGE IS THE OUTPUT OF THE EIGHTH AND LAST ITERATION FOR DETERMINING THE OPTIMUM VALUE OF WSSEC. WITH THE RANGE AND ERROR TOLERANCE SPECIFIED FOR WSSEC, EIGHT ITERATIONS ARE REQUIRED TO GUARANTEE THAT THE OPTIMUM FOUND IN THE SEARCH DOES NOT DIFFER FROM THE TRUE OPTIMUM BY MORE THAN THE ERROR TOLERANCE OF 40 SPECIFIED AS INPUT.

THE CIRCUIT PEAK YEAR IS 30
 THE SECONDARY PEAK YEAR IS 30
 THE DISTRIBUTION TRANSFORMER NAMEPLATE RATING IS 73.1 KVA

CIRCUIT AREA = 1.45 SQUARE MILES
 CIRCUIT LENGTH = 3000.00 FEET
 CIRCUIT WIDTH = 13500.00 FEET
 MAXIMUM NUMBER OF CUSTOMERS IN THE CIRCUIT AREA IS 3600

THE DISTRIBUTION TRANSFORMER CORE LOSS IS 0.26 KW

THE PRESENT WORTH COST OF A CIRCUIT PER SQUARE MILE IS 7173476.00

THE CAPITAL PORTION IS 4675118.00
 THE CUSTOMER PORTION IS 1180799.00
 THE ENERGY PORTION IS 1317568.00
 CUSTOMER DOLLAR SAVINGS 8.08
 CUSTOMER ENERGY SAVINGS 280.02 KWH
 FBSRCH - ITERATION 8: XLB= 415.7334 X= 449.4446 XUB= 471.9111 FOFX = 7173476.00

X FOR MINIMUM = 449.4446 FOFX= 7173476.00 }

THE OPTIMUM SEARCH VARIABLE AND THE ASSOCIATED VALUE OF THE OBJECTIVE FUNCTION (CIRCUIT COST PER SQUARE MILE) ARE PRINTED. NOTICE THAT THE OPTIMUM OF THE SEARCH VARIABLE IS THE SAME AS THE EIGHTH ITERATION VALUE (449.4446). THIS IS NOT ALWAYS SO. SOMETIMES THE OPTIMUM VALUE OF THE SEARCH VARIABLE WILL BE FOUND IN AN EARLIER ITERATION.

ENTERING FOFX

CSFEED = 665.0000
 CSMAN = 160.0000
 CSPRIM = 125.0000
 CSSEC = 565.0000
 CSSERV = 90.0000
 WSLoad = 11.3000
 VOLTBI = 0.1260
 VOLTLO = 0.1140
 VPI = 35.0000
 VS = 0.1200
 WSLAT = 300.0000
 WSPRIM = 400.0000
 WSSEC = 449.4446
 WSSERV = 382.0222

THIS IS THE FIRST ITERATION OF THE
 SEARCH FOR THE OPTIMUM VALUE OF WSSERV
 (THE SECOND CONTROL VARIABLE ENTERED
 AS INPUT). NOTICE THAT THE ORIGINAL
 VALUE OF 400 FOR WSSEC HAS BEEN
 REPLACED BY THE OPTIMUM FOUND FOR
 WSSEC. AS EACH SEARCH IS COMPLETED
 THE OPTIMUM FOUND REPLACES THE
 INITIAL GUESS. BECAUSE OF THE RANGES
 AND ERROR TOLERANCES DEFINED, EACH
 VARIABLE SEARCH IN THIS RUN TAKES
 EIGHT ITERATIONS.

THE CIRCUIT PEAK YEAR IS 30
 THE SECONDARY PEAK YEAR IS 30
 THE DISTRIBUTION TRANSFORMER NAMEPLATE RATING IS 73.1 KVA

CIRCUIT AREA = 1.45 SQUARE MILES
 CIRCUIT LENGTH = 3000.00 FEET
 CIRCUIT WIDTH = 13500.00 FEET
 MAXIMUM NUMBER OF CUSTOMERS IN THE CIRCUIT AREA IS 3600

THE DISTRIBUTION TRANSFORMER CORE LOSS IS 0.26 KW

THE PRESENT WORTH COST OF A CIRCUIT PER SQUARE MILE IS 7374635.00

THE CAPITAL PORTION IS	4932857.00				
THE CUSTOMER PORTION IS	1180799.00				
THE ENERGY PORTION IS	1260988.00				
CUSTOMER DOLLAR SAVINGS	8.08				
CUSTOMER ENERGY SAVINGS	280.02 KWH				
FBSRCH - ITERATION 1: XLB=	0.0	X=	382.0222	XLB=	1000.0000 FOFX = 7374635.00

THE MINIMUM VALUE OF THE OBJECTIVE FUNCTION FOUND IS 0.71304400E+07

CSFEED = 764.0444
 CSMAIN = 160.0000
 CS PRIM = 125.0000
 CSSEC = 565.0000
 CSSERV = 90.0000
 HSLOAD = 11.3000
 VOLTHI = 0.1260
 VOLTLO = 0.1140
 VP = 31.2473
 VS = 0.1200
 WSLAT = 415.7334
 WSPRIM = 741.5779
 WSSEC = 449.4446
 WSSERV = 112.3555

THIS PAGE IS PRINTED AFTER ALL OF THE
 VARIABLE SEARCHES ARE COMPLETED. THE
 CIRCUIT COST PER SQUARE MILE FOR THE
 OPTIMUM CASE AND THE OPTIMUM SEARCH
 VARIABLES ARE PRINTED.

ENTERING FOFX

CSFEED = 764.0444
 CSMAIN = 160.0000
 CS PRIM = 125.0000
 CSSEC = 565.0000
 CSSERV = 90.0000
 HSLOAD = 11.3000
 VOLTHI = 0.1260
 VOLTLO = 0.1140
 VP = 31.2473
 VS = 0.1200
 WSLAT = 415.7334
 WSPRIM = 741.5779
 WSSEC = 449.4446
 WSSERV = 112.3555

ONCE THE OPTIMUM HAS BEEN FOUND THE
 FOLLOWING DETAILED COST EVALUATION
 OUTPUT FOR IT IS PRODUCED. THE OPTI-
 MIZED INPUT DATA TO THIS CASE IS
 PRINTED ALONG WITH THE PRIMARY AND
 SECONDARY CIRCUIT PEAK YEARS, THE
 SECONDARY TRANSFORMER NAMEPLATE
 RATING FOR TRANSFORMERS INSTALLED IN
 THE FIRST YEAR, THE CIRCUIT DIMEN-
 SIONS AND THE SECONDARY TRANSFORMER
 CORE LOSS.

THE CIRCUIT PEAK YEAR IS 30
 THE SECONDARY PEAK YEAR IS 30
 THE DISTRIBUTION TRANSFORMER NAMEPLATE RATING IS 73.1 KVA

CIRCUIT AREA = 1.26 SQUARE MILES
 CIRCUIT LENGTH = 3000.00 FEET
 CIRCUIT WIDTH = 11700.00 FEET
 MAXIMUM NUMBER OF CUSTOMERS IN THE CIRCUIT AREA IS 3120

THE DISTRIBUTION TRANSFORMER CORE LOSS IS 0.26 KW

FOR YEAR = 1 THE FOLLOWING NUMBER OF COMPONENTS PER CIRCUIT MUST BE IN SERVICE:

	COST
0.333 SUBSTATION TRANSFORMERS	81562.81
0.333 SUBSTATION CIRCUIT BREAKERS	3633.18
0.333 MISCELLANEOUS SUBSTATION ITEMS	51517.91
0.333 SUBSTATION RELAY AND INSTRUMENT TRANSFORMER PACKAGES	3705.23
0.333 SUBSTATION LOAD INTERRUPTER AND DISCONNECT PACKAGES	7749.62
1.000 TERMINAL POLES	343.52
1.000 SWITCHED MANHOLES	2057.51
1.000 THREE-PHASE OIL SWITCHES	2721.93
30.000 MAIN CONDUCTORS (PER 100 CIRCUIT FEET)	12.96
30.000 MAIN AERIAL SUPPORT FACILITIES (PER 100 CIRCUIT FEET)	147.37
60.200 MAIN FEEDER CABLE (PER 100 CIRCUIT FEET)	102.10
60.200 CONDUIT (PER 100 CIRCUIT FEET)	353.38
4.000 SUBSTATION SURGE ARRESTORS	53.94
7.525 STRAIGHT MANHOLES	1111.19
516.555 LATERAL CONDUCTOR (PER 100 CIRCUIT FEET)	3.80
516.555 LATERAL AERIAL SUPPORT FACILITIES (PER 100 CIRCUIT FEET)	107.04
873.240 SECONDARY AERIAL SUPPORT FACILITIES (PER 100 CIRCUIT FEET)	31.41
896.220 SECONDARY CONDUCTOR (PER 100 CIRCUIT FEET)	21.34
1595.821 SERVICE DROP (PER 100 CIRCUIT FEET)	11.31
149.370 SECONDARY TRANSFORMERS	157.92
4.415 REMOTE CONTROLLED AERIAL OR UNDERGROUND SWITCHES	690.60
8.830 FUSED CUTOUPS OR PAD MOUNTED SWITCHES	15.19
13.245 AERIAL DISCONNECTS OR PAD MOUNTED SWITCHES	13.12
8.830 LATERALS	

FOR THE FIRST YEAR THE NUMBER OF EACH TYPE OF COMPONENT REQUIRED FOR THE CIRCUIT AND THE LEVELIZED ANNUAL COST FOR ONE OF THAT TYPE OF COMPONENT IS PRINTED.

THE NUMBER OF CUSTOMERS ON THE CIRCUIT IN YEAR 1 IS 1903.2 } THE CURRENT YEAR NUMBER OF CUSTOMERS
THE NUMBER OF CUSTOMERS PER DISTRIBUTION TRANSFORMER IS 12.7 } PER CIRCUIT AND TRANSFORMER ARE PRINTED.

THE CIRCUIT LOSSES ON A PER SQUARE MILE BASIS ARE:

32682.2 KWH	TOTAL SERVICE DROP ENERGY LOSS	} ANNUAL ENERGY LOSSES AND PEAK DEMAND LOSS ARE PRINTED. THESE LOSSES ARE BASED ON THE CURRENT SYSTEM LOAD AND CONFIGURATION.
94632.6 KWH	TOTAL SECONDARY WIRE LOSS	
121275.4 KWH	DISTRIBUTION TRANSFORMER I**2 R LOSSES	
5018.0 KWH	TOTAL LATERAL LOSS	
19188.1 KWH	TOTAL MAIN AND FEEDER LOSS	
272816.2 KWH	ANNUAL I**2 R ENERGY LOSS	
267672.4 KWH	DISTRIBUTION TRANSFORMER CORE LOSSES	
214. KW	PEAK DEMAND LOSS	

THE PEAK SUBSTATION TRANSFORMER LOAD IS 32. MVA } THIS LOAD IS USED TO CALCULATE THE SUBSTATION TRANSFORMER LOSS.

***** SYSTEM COST FOR YEAR 1 IS 342287.69
ECOST = 40723.25
DCOST = 9636.43
TCOST = 28.74
STI2R = 86.08
STCL = 54.98

THE CUMULATIVE PRESENT WORTH OF THE CAPITAL CARRYING CHARGES AND THE SYSTEM LOSSES ARE PRINTED HERE. THE ENERGY (ECOST) AND DEMAND (DCOST) PORTIONS OF THIS COST ARE LISTED. ALSO LISTED IS LEVELIZED COST OF RESIDENTIAL ELECTRICAL EQUIPMENT FOR ONE CUSTOMER (TCOST). STI2R IS THE CURRENT YEAR SUBSTATION TRANSFORMER PEAK I**2 LOSS. STCL IS THE SUBSTATION TRANSFORMER CORE LOSS.

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FOR YEAR = 2 THE FOLLOWING NUMBER OF COMPONENTS PER CIRCUIT MUST BE IN SERVICE:

	COST
0.333 SUBSTATION TRANSFORMERS	81562.81
0.333 SUBSTATION CIRCUIT BREAKERS	3633.18
0.333 MISCELLANEOUS SUBSTATION ITEMS	51517.91
0.333 SUBSTATION RELAY AND INSTRUMENT TRANSFORMER PACKAGES	3705.23
0.333 SUBSTATION LOAD INTERRUPTER AND DISCONNECT PACKAGES	7749.62
1.000 TERMINAL POLES	343.52
1.000 SWITCHED MANHOLES	2057.51
1.000 THREE-PHASE OIL SWITCHES	2721.93
30.000 MAIN CONDUCTORS (PER 100 CIRCUIT FEET)	12.96
30.000 MAIN AERIAL SUPPORT FACILITIES (PER 100 CIRCUIT FEET)	147.37
60.200 MAIN FEEDER CABLE (PER 100 CIRCUIT FEET)	102.10
60.200 CONDUIT (PER 100 CIRCUIT FEET)	353.38
4.000 SUBSTATION SURGE ARRESTORS	53.94
7.525 STRAIGHT MANHOLES	1111.19
518.310 LATERAL CONDUCTOR (PER 100 CIRCUIT FEET)	3.80
518.310 LATERAL AERIAL SUPPORT FACILITIES (PER 100 CIRCUIT FEET)	107.04
880.080 SECONDARY AERIAL SUPPORT FACILITIES (PER 100 CIRCUIT FEET)	31.41
903.240 SECONDARY CONDUCTOR (PER 100 CIRCUIT FEET)	21.34
1622.043 SERVICE DROP (PER 100 CIRCUIT FEET)	11.31
150.540 SECONDARY TRANSFORMERS	157.92
4.430 REMOTE CONTROLLED AERIAL OR UNDERGROUND SWITCHES	690.60
8.860 FUSED CUTOUPS OR PAD MOUNTED SWITCHES	15.19
13.290 AERIAL DISCONNECTS OR PAD MOUNTED SWITCHES	13.12
8.860 LATERALS	

THE NUMBER OF CUSTOMERS ON THE CIRCUIT IN YEAR 2 IS 1934.4
 THE NUMBER OF CUSTOMERS PER DISTRIBUTION TRANSFORMER IS 12.8

THE CIRCUIT LOSSES ON A PER SQUARE MILE BASIS ARE:

33885.7 KWH	TOTAL SERVICE DROP ENERGY LOSS
98686.5 KWH	TOTAL SECONDARY WIRE LOSS
126749.9 KWH	DISTRIBUTION TRANSFORMER I**2 R LOSSES
5274.4 KWH	TOTAL LATERAL LOSS
20104.2 KWH	TOTAL MAIN AND FEEDER LOSS

FOR EACH SUCCESSIVE YEAR THE QUANTITIES CALCULATED FOR THE FIRST YEAR ARE REEVALUATED TO REFLECT CURRENT CIRCUIT DEVELOPMENT AND LOAD LEVEL.

284700.3 KWH	ANNUAL I**2 R ENERGY LOSS
269769.1 KWH	DISTRIBUTION TRANSFORMER CORE LOSSES

222. KW PEAK DEMAND LOSS

THE PEAK SUBSTATION TRANSFORMER LOAD IS 32. MVA

***** SYSTEM COST FOR YEAR 2 IS	681014.25	} THE COST IS THE CUMULATIVE PRESENT WORTH CIRCUIT COST.
ECOST =	41679.60	
DCOST =	10010.21	
TCOST =	28.74	
STI2R =	90.82	
STCL =	54.98	

FOR YEAR = 30 THE FOLLOWING NUMBER OF COMPONENTS PER CIRCUIT MUST BE IN SERVICE:

	COST
0.333 SUBSTATION TRANSFORMERS	81562.81
0.333 SUBSTATION CIRCUIT BREAKERS	3633.18
0.333 MISCELLANEOUS SUBSTATION ITEMS	51517.91
0.333 SUBSTATION RELAY AND INSTRUMENT TRANSFORMER PACKAGES	3705.23
0.333 SUBSTATION LOAD INTERRUPTER AND DISCONNECT PACKAGES	7749.62
1.000 TERMINAL POLES	343.52
1.000 SWITCHED MANHOLES	2057.51
1.000 THREE-PHASE OIL SWITCHES	2721.93
30.000 MAIN CONDUCTORS (PER 100 CIRCUIT FEET)	12.96
30.000 MAIN AERIAL SUPPORT FACILITIES (PER 100 CIRCUIT FEET)	147.37
60.200 MAIN FEEDER CABLE (PER 100 CIRCUIT FEET)	102.10
60.200 CONDUIT (PER 100 CIRCUIT FEET)	353.38
4.000 SUBSTATION SURGE ARRESTORS	53.94
7.525 STRAIGHT MANHOLES	1111.19
567.450 LATERAL CONDUCTOR (PER 100 CIRCUIT FEET)	3.80
567.450 LATERAL AERIAL SUPPORT FACILITIES (PER 100 CIRCUIT FEET)	107.04
1071.600 SECONDARY AERIAL SUPPORT FACILITIES (PER 100 CIRCUIT FEET)	31.41
1099.800 SECONDARY CONDUCTOR (PER 100 CIRCUIT FEET)	21.34
2354.579 SERVICE DROP (PER 100 CIRCUIT FEET)	11.31
183.300 SECONDARY TRANSFORMERS	157.92 IN PREVIOUS YEAR → [217.91]
4.850 REMOTE CONTROLLED AERIAL OR UNDERGROUND SWITCHES	690.60
9.700 FUSED CUTOUPS OR PAD MOUNTED SWITCHES	15.19
14.550 AERIAL DISCONNECTS OR PAD MOUNTED SWITCHES	13.12
9.700 LATERALS	

THE NUMBER OF CUSTOMERS ON THE CIRCUIT IN YEAR 30 IS 2808.0
 THE NUMBER OF CUSTOMERS PER DISTRIBUTION TRANSFORMER IS 15.3

THE CIRCUIT LOSSES ON A PER SQUARE MILE BASIS ARE:

85875.2 KWH	TOTAL SERVICE DROP ENERGY LOSS
293589.1 KWH	TOTAL SECONDARY WIRE LOSS
238407.6 KWH	DISTRIBUTION TRANSFORMER I**2 R LOSSES
17908.5 KWH	TOTAL LATERAL LOSS
73580.2 KWH	TOTAL MAIN AND FEEDER LOSS
709360.5 KWH	ANNUAL I**2 R ENERGY LOSS
460863.4 KWH	DISTRIBUTION TRANSFORMER CORE LOSSES
538. KW	PEAK DEMAND LOSS

THE PEAK SUBSTATION TRANSFORMER LOAD IS 63. MVA

***** SYSTEM COST FOR YEAR 30 IS 8977496.00
 ECOST = 83535.12
 DCOST = 24524.87
 TCOST = 28.74
 STI2R = 341.11
 STCL = 54.98

THIS IS THE FINAL YEAR'S CIRCUIT COST EVALUATION SUMMARY. COINCIDENTALLY, THIS IS THE FIRST YEAR IN WHICH SECONDARY CIRCUIT LOAD HAS REACHED A LEVEL WHICH NECESSITATES THE CHANGING-OUT OF THE ORIGINAL SECONDARY TRANSFORMERS. NOTICE THAT THE LEVELIZED COST OPPOSITE THE SECONDARY TRANSFORMER LINE HAS INCREASED FOR THIS YEAR. ALSO, A ONE-TIME PRESENT WORTH CHANGE-OUT EXPENSE HAS BEEN ADDED TO THE CUMULATIVE SYSTEM COST. THE TRANSFORMERS ARE INITIALLY INSTALLED WITH A NAMEPLATE RATING EQUAL TO THE PEAK LOAD IN THE FIRST YEAR THAT MUST BE SUPPLIED. WHEN THE LOAD BECOMES GREATER THAN $CAPRAT \times (NAMEPLATE RATING)$, THEY ARE CHANGED-OUT FOR NEW TRANSFORMERS HAVING A NAMEPLATE EQUAL TO THE CURRENT YEAR'S PEAK LOAD.

THE PRESENT WORTH COST OF A CIRCUIT PER SQUARE MILE IS

7130433.00

THE CAPITAL PORTION IS	4630069.00
THE CUSTOMER PORTION IS	1180799.00
THE ENERGY PORTION IS	1319574.00
CUSTOMER DOLLAR SAVINGS	8.08
CUSTOMER ENERGY SAVINGS	280.02 KWH

THIS LAST SHEET SUMMARIZES THE PER SQUARE MILE CIRCUIT COSTS AND ITS DIFFERENT COMPONENTS FOR THE OPTIMIZED CIRCUIT.

ONLY 12 OF A TOTAL OF 83 PAGES OF OUTPUT HAVE BEEN PRESENTED HERE, BUT THE MISSING PAGES FOLLOW THE SAME FORMAT AS THOSE PRESENTED.

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5. EXAMPLE RUNS

5.1 Model Verification

From the first day that a system cost could be calculated with the EDUSCAM Program, it has been exercised extensively. The studies run have been run as much to debug the program as to find useful results. By closely analyzing the results of the earlier studies, a number of problem areas were identified and corrected.

The first major problem encountered was a numerical significance problem with the load flow program used to evaluate losses and voltage drop. The losses being solved were quite small compared to the amount of load being modeled (on the order of about 2 percent) and the error observed for the losses was unacceptable. By performing the load flow calculations using double precision arithmetic and by changing the assumed MVA base depending on whether a system or a secondary circuit was being modeled, this accuracy problem was solved for all of the load flow models with the exception of the model used to evaluate lateral losses. In that case the magnitude of the loss was so small compared to the load being modeled (on the order of 0.02 percent) that an iterative technique could not converge to the proper answer. Therefore the load flow model was abandoned for lateral loss calculation and was replaced with an I^2R formula calculation of lateral loss for each lateral segment. An assumption of a constant voltage for determining each lateral segment's current was deemed acceptable because of the virtually flat voltage profile found to exist on these laterals.

The next major problem encountered was the implementation of an optimization routine. A conjugate-gradient routine was modified to fit the problem being modeled in EDUSCAM. Upon using the modified routine it was found that an

excessive number of iterations were required to reach an optimum. In searching for a less costly alternative, it was noted that for the "hand optimized" cases which had been done up to that time, the optimum value of one variable was not significantly affected by the values of the other variables (we will return to the importance of this later). This is better understood by considering how the "hand optimization" was done.

It was desired to find some near-to-optimal system design parameters (e.g., voltages, conductor sizes, etc.) for an aerial and underground case where, for each case the costs of the losses would first have the current values and then have double the current values.

The optima were found by optimizing one variable with a one dimensional search. This involved running a case, changing the variable, running the new case, and adjusting the variable until an apparent optimum had been found. Then, while the first variable retained its "optimal" value, the procedure would be repeated for the next variable. After each variable in turn had been optimized, the process was started again with the first variable to see what effect the changed variable values would have. However, no improvement in the objective function was obtained by permuting each variable in turn above and below their current values. The exception to this was the secondary wire and service drop wires which, for the lower energy cost cases, were voltage limited. These wires could not have their wire sizes reduced without violating the voltage drop criteria. However, if one were raised while the other were lowered, then the voltage criteria could be satisfied. Various combinations of wire sizes were tried until an apparently optimum combination was found.

In view of the apparent independence of variables, a method of sequential, one-dimensional Fibonacci searches was substituted for the conjugate-gradient

method. This optimization method, while still expensive, was better than an order of magnitude faster than the conjugate-gradient method. The new method would require that the secondary wire size be optimized first so that a feasible wire size would be assured by the time the other variables were being optimized. Further, if it were found that the secondary wire sizes were voltage limited, then the starting value of the service drop wire size should be altered a few times to see what combination of secondary and service drop wire sizes give the best result. Note that because of the independence of the other wire sizes, only the secondary and service drop wire sizes need be reoptimized.

The only problem encountered during implementation of the optimization routine was that certain arrays had to be reinitialized for each iteration and the impedance values calculated at the beginning of the program had to be moved into the optimization loop so that they would be recalculated for each iteration.

After the optimization routine was implemented, a comparison was made. The output of an optimized system starting from the same point as one of the manually optimized systems and the output of the manually optimized system were compared and found to be in close agreement.

Once the optimization routine was up and running, no anomalous results were obtained during the many optimization runs.

5.2 Case Studies

The results of 12 optimized cases are presented in this section. A number of other cases were run during the debugging stage of the program which had errors in them, but which still provided qualitative information. The conclusions drawn are based on the cases presented here and the qualitative information gained in those other cases.

The main conclusions which draw upon cases not reproduced here are the conclusions about the economics of secondary voltages above 120 volts and of three-phase secondaries. It was observed that voltages of more than 120 volts or three-phase on the secondary were too expensive to the customer. Even though losses and conductor sizes on the utility secondary wires decreased, the cost of customer meters, circuit breaker panels and auto transformers increased by much more than the utility system costs decreased. Unless the components can be greatly reduced in cost, there is little chance that three-phase or higher secondary voltages can be justified. It is worth nothing though that if the customer costs were ignored and only utility costs were considered, 240 volts appears to be better than 120 volts for the moderate growth and load density cases examined.

One case showing the combined effects of three-phase and 480 volts on the secondary is presented to illustrate just how much more expensive that type of circuit would be than a conventional circuit.

The first four cases presented were run to determine the effects of energy and demand loss costs on optimal circuit design. Two aerial and two underground cases were run where for each pair the loss costs used were set at current values for one case and twice current values for the other case. These cases are identified as follows:

- Case 1: Aerial, low loss cost
- Case 2: Aerial, high loss cost
- Case 3: Underground, low loss cost
- Case 4: Underground, high loss cost.

For all four cases the load density ran from 2 MVA per square mile in the first year to 8 MVA per square mile in the 30th (last) year. The loss costs used for current values are:

Demand loss	= \$30 per kW per year
I^2R energy loss	= \$0.05 per kWh
Nonvarying energy loss	= \$0.04 per kWh.

The optimized parameters for these cases are presented in Table 5.1.

These results agree with the intuitive results one might hypothesize for these cases. For both aerial and underground systems, an increase in loss costs causes an increase in conductor size and primary voltage. The underground voltage is slightly lower than the aerial voltage, reflecting the increased cost of insulation as voltage increases. The primary main and lateral wire sizes are larger than for the corresponding cable sizes because the rate of change of costs with respect to conductor size for these cables is greater than it is for the aerial wires. The reverse is true of the marginal costs for secondary cables and wires; therefore the secondary cable sizes are larger than the corresponding aerial wire sizes. Finally, the underground system cost is greater than the cost of the aerial system, which is no surprise at all.

The remaining eight cases were run to examine the relationship between optimal primary voltage and the underlying load density and load growth rate. Also, one case was run to show the high cost of a circuit when three-phase, higher voltage secondaries are used.

The cases and their resultant primary voltages and costs per square mile are listed in Tables 5.2 and 5.3. The primary voltages and costs per square mile calculated for the cases in Table 5.2 are summarized in Table 5.3. These results indicate that an increase in load density leads to an increase in optimal primary voltage. Furthermore, Cases 4, 5 and 6 indicate that the growth rate has only a small effect on the optimal primary voltage. Finally, Cases 3 and 8 indicate that both three-phase secondaries and higher secondary voltages are more expensive.

TABLE 5.1 EXAMPLE RESULTS				
PARAMETER	CASE 1	CASE 2	CASE 3	CASE 4
PRIMARY VOLTAGE	32.3 kV	32.6 kV	31.7 kV	30.8 kV
NUMBER OF CUSTOMERS PER SECONDARY BANK	16	16	16	20
NUMBER OF LATERAL PAIRS	5	5	5	5
FEEDER CABLE SIZE	655 KCMIL	790 KCMIL	790 KCMIL	665 KCMIL
LATERAL CABLE/ WIRE SIZE	300 KCMIL	415 KCMIL	250 KCMIL	160 KCMIL
PRIMARY MAIN CABLE/ WIRE SIZE	400 KCMIL	530 KCMIL	170 KCMIL	125 KCMIL
SECONDARY CABLE/ WIRE SIZE	385 KCMIL	520 KCMIL	660 KCMIL	565 KCMIL
SERVICE DROP CABLE/ WIRE SIZE	80 KCMIL	115 KCMIL	125 KCMIL	95 KCMIL
UTILITY COST/MILE ²	\$2,950,000	\$3,081,000	\$3,985,000	\$3,829,000
CUSTOMER COST/MILE ²	\$ 553,000	\$ 553,000	\$ 553,000	\$ 553,000
LOST COST/MILE ²	\$ 670,000	\$1,185,000	\$1,124,000	\$ 672,000

TABLE 5.2 EXAMPLE RESULTS				
CASE	LOAD DENSITY		SECONDARY PHASES	SECONDARY VOLTAGE (V)
	1ST YEAR (MVA/MI ²)	30TH YEAR (MVA/MI ²)		
5	0.5	1.0	1	120
6	2.0	4.0	1	120
7	8.0	16.0	1	120
8	1.1	32.0	1	120
9	16.0	32.0	1	120
10	32.0	32.0	1	120
11	9.5	38.8	1	120
12	8.0	16.0	3	480

TABLE 5.3 EXAMPLE RESULTS		
CASE	PRIMARY VOLTAGE (kV)	COST/MILE ² (\$)
5	27.9	1,670,000
6	26.7	3,925,000
7	31.1	7,266,000
8	35.7	7,451,368
9	36.3	10,319,960
10	35.0	12,557,558
11	35.2	12,014,000
12	28.8	24,356,000

The lower primary voltage for the three phase 480 V case is due to the higher cost of the secondary distribution transformers. The costs of these transformers increases with primary voltage and, because of the higher basic cost for them in Case 8 compared to Case 3, the voltage at which the increasing capital cost just balances the decreasing loss costs is reached at a lower primary voltage. In no case were capacitors required. Apparently the larger conductor sizes installed because of loss economics prevented the voltage drop on the primaries from ever becoming large enough to require correction.

One additional observation derived from these parameter studies is that the optimal primary voltages all cluster around the low 30 kV range. This probably reflects the fact that efficiently mass produced equipment at voltages of 30 kV and below were made more economically than equipment made for voltages closer to 69 kV. If the cost models more accurately reflect the cost of mass produced 69 kV equipment, then perhaps even higher optimal primary voltages would likely be recommended.

Plots of the circuit cost per square mile versus load density and optimal primary voltage versus load density for the seven single phase cases appear in Figures 5.1 and 5.2.

FIGURE 5.1 CIRCUIT COST VS. LOAD DENSITY

FIGURE 5.2 CIRCUIT PRIMARY VOLTAGE VS. LOAD DENSITY

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APPENDIX A

RESULTS OF COMPONENT DESIGN-POINT STUDIES

Sample cost and energy loss data are presented for each component and component ensemble of the distribution system. The ensemble descriptions are presented with each component study. Material costs are manufacturer's list costs for 1979. Installation and maintenance costs are based on PECO's labor rate for 1979.

A.1 Cost Data for Components of the Distribution Circuit

The following data are referenced by the system design point studies, examples of which are presented in Appendix B. The 18 circuit components are listed in Table A.1. In the component descriptions the numbers shown in parenthesis refer to the applicable PECO electric construction standards.

TABLE A.1 DISTRIBUTION CIRCUIT COMPONENTS

ITEM NUMBER	DESCRIPTION
1	ALUMINUM PRIMARY UNDERGROUND CABLE
2	INSTALLED CONDUIT
3	INSTALLED MANHOLE
4	3 PHASE UNDERGROUND SWITCH
5*	TERMINAL POLE (AERIAL-UNDERGROUND)
6*	SUPPORT STRUCTURE
7*	BARE ALUMINUM PRIMARY OVERHEAD WIRE
8	AERIAL DISCONNECTING SWITCH
9	AERIAL FUSED CUTOUT
10*	ALUMINUM SECONDARY OVERHEAD WIRE
11*	AERIAL AND UNDERGROUND DISTRIBUTION TRANSFORMER
12	AERIAL SECONDARY SERVICE WIRE
13*	3 PHASE CIRCUIT CAPACITOR
14	3 PHASE AERIAL SWITCH
15	SURGE ARRESTOR
16*	AERIAL RECLOSER
17	ALUMINUM SECONDARY UNDERGROUND CABLE
18*	3 PHASE PADMOUNTED SWITCH
* INDICATES COMPONENT ENSEMBLE	

Item #1Aluminum Underground Cable (Primary Voltages)/100'

Voltage kV	# Phases	Cable Size kcmil (AL)	Cable Cost Only	Installation Cost Only	
				In Duct	Direct Burial
13	1	1-66	\$ 60.00	\$ 400.00	\$ 668.00
13	3	1-66	180.00	504.00	1,004.00
13	1	1-400	210.00	500.00	900.00
13	3	3-400	630.00	674.00	1,324.00
13	1	1-750	290.00	600.00	1,000.00
13	3	3-750	810.00	756.00	1,500.00
34	1	1-105	118.00	400.00	668.00
34	3	3-105	354.00	504.00	1,004.00
34	1	1-212	190.00	400.00	668.00
34	3	3-212	570.00	504.00	1,004.00
34	1	1-750	320.00	600.00	1,000.00
34	3	3-750	960.00	756.00	1,500.00
34	1	1-1,500	430.00	775.00	1,200.00
34	3	3-1,500	1,290.00	925.00	1,700.00
69	1	1-500	1,100.00	1,300.00	2,500.00
69	3	3-500	3,300.00	1,500.00	3,000.00
69	1	1-750	1,200.00	1,300.00	2,500.00
69	3	3-750	3,600.00	1,500.00	3,000.00
69	3	1-1,000	1,300.00	1,300.00	2,500.00
69	3	3-1,000	3,900.00	1,500.00	3,000.00
69	1	1-2,000	1,700.00	1,300.00	2,500.00
69	3	3-2,000	5,400.00	1,500.00	3,000.00

There are minimum cable sizes which can be used at different voltages because of the excessive electric fields in the corona which would occur at lower sizes. The equation specifying the lowest allowable cable size (in kcmil) as a function of primary phase-to-phase voltage in kV is

$$\text{Minimum size} = .1776 \times VP^2 - 6.878 \times VP + 129.2$$

Item #2Installed Conduit--13 kV & 34 kV/100'

<u>Encased in Concrete (S-2126)</u>	<u>Center City</u>	<u>Other Areas</u>
4 - 4-1/2" Ducts per Bank	\$12,600.00	\$ 7,100.00
8 - 4-1/2" Ducts per Bank	17,000.00	9,900.00
12 - 4-1/2" Ducts per Bank	21,500.00	12,100.00

In Earth

2 - 4-1/2" Ducts per Bank	8,200.00	5,500.00
2 - 6-1/2" Ducts per Bank	9,000.00	6,000.00

Installed Conduit--69 kV/100'

<u>Encased in Concrete</u>	<u>Center City</u>	<u>Other Areas</u>
4 - 8" Ducts per Bank	\$22,700.00	\$12,900.00
8 - 8" Ducts per Bank	30,600.00	17,800.00
12 - 8" Ducts per Bank	38,700.00	21,800.00

In Earth

2 - 8" Ducts per Bank	14,800.00	9,900.00
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NOTES

- (a) LUMBER OR REINFORCING RODS SHOULD BE INSTALLED ACROSS TRENCH DIRECTLY ABOVE DUCT SPACERS EVERY 6'-0" TO PREVENT CONDUIT FROM FLOATING DURING CONCRETE POUR.
- (b) BOTTOM TYPE SPACER (ITEM #2) SHOULD BE USED AS TOP SPACER. ATTACH TO VERTICALLY ADJACENT SPACER USING ADAPTER (ITEM #4). CONCRETE LEVEL SHOULD BE 4" MIN ABOVE TOP OF CONDUITS.
- (c) FOR CHANGE OF CONFIGURATION SEE S-2127.
- (d) FOR NEUTRAL WIRE INSTALLATION SEE S-2107.
- (e) FOR COUPLING INSTALLATION SEE S-2121-A (FIBER), S-2121-B (PLASTIC), OR S-2121-C (SPLIT PLASTIC).

REFERENCES

CONCRETE	S-2070, 2074
NEUTRAL WIRE INSTALLATION	S-2107
CONDUIT ASSEMBLY	S-2121-A, B & C
CHANGE OF CONFIGURATION - 4 DUCT BANK	S-2127
SPLIT PLASTIC DUCT INSTALLATION	S-2141

TABLE I
CONDUIT CODE NUMBERS

	4 1/2"	5"
PLASTIC	-	129-14204
FIBER	142-14974	142-14975

BILL OF MATERIAL (QUANTITY PER 4' OF DUCT BANK)

ITEM	CODE NO	DESCRIPTION	4 1/2" DT	5" DT	4 1/2" DT	5" DT	4 1/2" DT	5" DT
1	W2-64939	SPACER, INTERMEDIATE, 5"	2	2	3	3	-	-
2	W2-64940	SPACER, BOTTOM, 5"	4	4	2	2	8	8
3	S-2070, 2074	CONCRETE, 2000 lb. CU YD	1/3	1/3	1/3	1/3	1/3	1/3
4	W2-64949	ADAPTER, SPACER	4	4	2	2	8	8
5	SEE TABLE I	CONDUIT	16	16	16	16	16	16

CONDUIT INSTALLATION - 4 DUCT BANK
NORMAL CONFIGURATIONS10-78
10-77
10-76

PHILADELPHIA ELECTRIC CO.

ELEC. CONST. STD'S.

S-2126

Item #3Installed Manhole--Maximum Distance Between Manholes = 1,000'

1. <u>13 & 34 kV</u>	<u>Center City</u>	<u>Other Areas</u>
3 Way	\$28,600.00	\$19,300.00
4 Way (S-2271)	31,900.00	22,000.00
Straight	18,200.00	12,100.00
Switch (13 kV)	7,700.00	5,500.00
Switch (34 kV)	34,800.00	24,000.00
2. <u>69 kV</u>	<u>Center City</u>	<u>Other Areas</u>
3 Way	\$45,800.00	\$30,900.00
4 Way	51,000.00	35,200.00
Straight	29,100.00	19,400.00
Switch	55,700.00	38,400.00

Item #43 Phase Underground Switches (Excluding Manhole)

<u>Voltage (kV)</u>	<u>Capital and Installation Cost</u>
13	\$ 9,500.00
34	26,000.00
69	73,500.00

Item #5Terminal Poles, Aerial-Underground (Including pole, crossarms, insulation, cable terminators, surge arrester, length of cable and aerial cutouts)

<u>Voltage (kV)</u>	<u>Capital + Installation Cost 3 Phase</u>	<u>Capital + Installation Cost 1 Phase</u>
13 (S-5176)	\$3,700.00	\$2,700.00
34	5,200.00	3,600.00
69	7,200.00	5,200.00

SECTION A-A
NOTES

- (a) CONCRETE TO BE 3000 PSI AT 28 DAYS. SEE STD'S. 2070 & 2073.
 (b) FOR CEMENT MORTAR, SEE STD. 2080.
 (c) REINFORCING BARS TO BE GRADE NO. DO NOT PLACE REINFORCING RODS BETWEEN DUCTS.
 (d) LAP FOR REINFORCING BARS-24 DIAMETERS, 12" MIN.
 (e) USE 10" FRAME IN TRAFFIC AREAS.
 (f) NOTIFY ELECTRICAL ENGINEERING IF COVER IS LESS THAN 1'-0" OR MORE THAN 4'-0".
 (g) LOCATION OF BACK SUPPORT INSERTS.
 (h) MANHOLE MUST SET 48 HOURS BEFORE STRIPPING FORM.

REFERENCES

CONCRETE STRENGTH, FOUR-INCH SLUMP	S-2070, 2073
CEMENT MORTAR FOR MASONRY WORK	S-2080
GROUND ROD INSTALLATION IN MANHOLES	S-2214
MANHOLE SLUMP INSTALLATION	S-2218
DETAIL OF DUCT REFERENCES	S-2219

BILL OF MATERIAL

ITEM	CODE NO.	DESCRIPTION	QUANTITY
1	S-2070 & S-2073	CONCRETE 3000	SEE TABLE
2	139-3630	ANCHOR, CABLE PULLING	8
3	199-66419	ROC, CONCRETE REINFORCING, 1/2" x 20"	SEE TABLE
4	199-66422	ROC, CONCRETE REINFORCING, 3/4" x 20"	SEE TABLE
5	{ 139-29401 139-29415 }	FRAME, MH, 3' x 3' x 10"	1
6	139-16905	LID, SUMP, 10"	1
7	139-10601	TY-CHAIR, 3/4"	85
8	119-76923	WIRE, 16 GAUGE, BLACK IRON, SOFT DR	100'
9	139-55202	RING, MH FRAME, 31" DIA	1
10	139-42202	LID, MH, SOLID, CST IR, 31" x 1 1/4"	1
11	199-36018	INSERT, 1/2" BOLTS	32
12	199-06704	BRICK, RED, 2 1/4" x 3 1/4" x 8 1/4"	56
13	138-62503	ROC, GROUND, 3/8" x 16 COPPERWELD	1
14	139-72418	TUBE, SUMP, MH, 10" ID x 12" LONG	1

DESCRIPTION	DUCTS	DIM "X"	DIM "Y"	CONCRETE YD ³	REINFORCING STEEL, FT #4	REINFORCING STEEL, FT #6
15'-5" x 15'-5" x 7'-0" 4 WAY M.H.	8	7'-0"	4'-0"	16	720	1760
15'-5" x 15'-5" x 8'-0" 4 WAY M.H.	10	8'-0"	5'-0"	17	775	1835
15'-5" x 15'-5" x 9'-0" 4 WAY M.H.	12	9'-0"	6'-0"	18	825	1870

MATERIAL QUANTITIES INCLUDE 10% EXTRA

FIELDCAST 4 WAY MANHOLE FOR 2 WIDE DUCT BANK

S-2271

PHILADELPHIA ELECTRIC CO.

ELEC. CONST. STD'S.

RE 5-74
5-74
5-74

Item #6Pole-Top Configuration

Present lightning-protection practice usually consists of placing surge arresters on all transformers, switches, capacitors, cable terminations, etc. This method of protection often results in line insulator flashover which, about one-half of the time, is sustained and requires interruption by a breaker (recloser) or a fuse. The operation of a protective device thus results in a momentary or extended interruption to customers on the circuit. Because of the greater capacity of higher-voltage primary distribution circuits, a shield wire is recommended to reduce circuit interruptions initiated by lightening. The resulting pole-top configuration is illustrated in Figure A.1.

When a shield angle of 30 degrees or less is used, practically all strokes will be intercepted by the shield wire. The shield wire should have a minimum of four connections to ground per mile. Increasing the connections to ground reduces the number of lightening interruptions expected to occur. Performance of lines with shield wires on the PECO system is estimated as follows using the PECO region's isokeraunic level.

	Lightning Interruptions Per Year Per 100 Miles of 34 kV Aerial Circuit
No shield wire	25
Shield wire with 4 ground connections per mile	8
6 ground connections per mile	6

NOTES

- (a) MINIMUM BENDING RADIUS 20'
 (b) KEEP TAPS SHORT AND REMOVE 1" OF WIRE COVERING BEYOND CLAMPS
 (c) DRILL TWO 1/16" HOLES IN POLE 8" APART FOR GAIN
 (d) BRING OUT UNDERGROUND CABLE NEUTRAL OF DUCT BANK NEUTRAL AT THIS POINT AND ATTACH DIRECTLY TO AERIAL NEUTRAL
 (e) REFER TO S-5175 FOR POLE TOP CONSTRUCTION OF THRU GOING AERIAL LINE
 (f) REFER TO S-5173 AND S-5174 FOR POLE TOP CONSTRUCTION IF CUTOUTS ARE REQUIRED

CONNECTION	CODE	TOOL	INDEX	DIE CAT NO	QUANTITY
2" STR TERM LUG	132-14121	Y 35	UNOC	U26PT	4
4" O SOL AL TERM LUG	132-14873	MO 6	249	W249	5
		Y 34	249	A249	3
		Y 35	249	U249	3
		CA700	249	CAB249	5

REFERENCES

GROUNDING INSTALLATION AT POLE	S-1131
POLE BOLDING INSTALLATION	S-1172
HEAVYWEAL CONDUIT INSTALLATION & EXTENSION	S-2135
TO TERMINAL POLE	S-2320
CABLE DATA	S-5103
BUYING, 13KV DIST	S-5103
TERMINAL FOR 750 kcmil ALUM RUBBER OR PLASTIC INSULATED CABLE	S-5193

BILL OF MATERIAL

ITEM	CODE NO	DESCRIPTION	QUANTITY
1	132-00686	CROSSARM, # 8	4
2	138-69178	SWITCH, DISC, 15KV 60CA	3
3	138-00725	ARRESTER, LIGHTNING, SKYBLUE, 10KV	3
4	138-71056	TERMINAL, F/750 KCMIL, 15KV AL CBL	3
5	132-57256	SCREW, LAG, 1/2" x 3 1/2" GALV	2
6	132-76017	WASHER, ROUND, FLAT, 1/2" GALV	2
7	132-33407	GRIP BASKET, BEAVE, F/1 1/2" - 1 3/4" CABLE	3
8	125-	CABLE, 15KV, RUBBER OR PLASTIC	+
9	132-05932	BRACKET, EXT, 12" F/LASHEE, SECONDARY	+
10	SIZE REC	CONNECTOR, COMPRESSION, TAP	+
11	135-79579	WIRE, # 4/0 SOL AL CLPE COVERED	+
12	132-14807	CONNECTOR, TAP, VISE, TYPE, # 2/0 STR CU	+
13	138-05818	BRACKET, MNTG, F/750 KCMIL, TERM	+
14	135-79565	WIRE, # 4 SOL CU CLPE COVERED	+
15	132-44754	MOLDING, STEEL, 1/2" x 1 1/2"	1
16	132-44749	MOLDING, PLASTIC, 3 1/2"	+
17	132-67413	SUPPORT, STL, F/3 1/2" PLASTIC MLDG	+
18	138-65605	STAPLE, 1/2" x 2" GALV	+
19	132-44750	MOLDING, PLASTIC, 1/2"	+
20	132-31005	GAIN, CROSSARM	2
21	132-14121	TERMINAL, LUG, COMP, SLOTTED, # 2/0 STR CU	6
22	132-05444	BOLT, MACHINE, 1/2" x 6" GALV	16
23	135-76806	WIRE, # 2 SOL BARE, AL, 1/2"	+
24	132-52049	CHANNEL, BACKING, F/STEEL, MLDG	1
25	135-08112	WIRE, # 2/0 STR BARE COPPER	+
26	132-05399	BOLT, MACHINE, 1/2" x 1 1/2" GALV	18
27	132-14873	TERM, LUG, ALUM, 4/0 SOLID	3
28	132-76002	WASHER, LOCK, SPLIT, 1/2"	18
29	132-57262	SCREW, LAG, 3/8" x 3" GALV	8

* AS REQUIRED

30 TERMINAL POLE FOR 750 kcmil RUBBER OR PLASTIC
 INSULATED CABLE WITH 600 AMP. SWITCHES
 13KV. DIST.

PHILADELPHIA ELECTRIC CO.
 ELEC. CONST. STD'S. S-5176

ELEC. CONST. STD'S. S-5176

FIGURE A.1 RECOMMENDED CONFIGURATION--69 kV DISTRIBUTION CCT

Item #6A (S-6105A)Support Structure

Installed cost of aerial line support structures including poles, crossarms, hardware, static, primary and secondary conductor installations (but not the cost of the conductors) per 100 feet of line and based on pole heights of 55 feet for 69 kV, 50 feet for 34 kV and 45 feet for 13 kV construction with spacings in all cases of 150 feet between poles.

<u>Voltage (kV)</u>	<u># Phases</u>	<u>Primary Wire Size kcmil/ Phase</u>	<u>Capital Cost + Installation</u>
13	1	106, 212, 556	\$1,208.00
13	3	795 & 954	1,751.00
34	1	106,212,556	1,234.00
34	3	795 & 954	1,788.00
69	1	106,212,556	1,270.00
69	3	795 & 954	1,841.00

Item #6BSupport Structure

Installed costs of aerial line support structures including poles, hardware and secondary conductor installation (but not the cost of the conductor) per 100 feet of line and based on pole height of 35 feet with spacings of 150 feet between poles.

<u>Voltage</u>	<u># Phases</u>	<u>Secondary Wire Size kcmil</u>	<u>Capital Cost + Installation</u>
Secondary Only	1	212, 556, 795 & 954	\$435.00

Item #7

Basic Aluminum Primary Overhead Wire Including phase work(s), static and neutral: (Cost of installation is provided for in Item #6A, aerial support structures)

<u>Wire Size</u> <u>kcmil/</u> <u>Phase</u>	<u>1 Phase</u> <u>Conductor</u> <u>Cost Only/</u> <u>100 Feet</u>	<u>3 Phase</u> <u>Conductor</u> <u>Cost Only/</u> <u>100 Feet</u>
106	\$31.00	\$ 51.00
212	40.00	79.00
556	61.00	139.00
795	76.00	187.00
954	86.00	218.00

FIGURE A.2 TANGENT STRUCTURE, 13 kV, 34 kV & 69 kV DISTRIBUTION

Item #8Disconnect Aerial (Excluding cost of pole)

<u>Voltage (kV)</u>	<u># Phases</u>	<u>Capital + Installation Aerial</u>
13	1	\$ 137.00
13 (S-5142A)	3	410.00
34	1	200.00
34	3	600.00
69	1	450.00
69	3	1,350.00

Item #9Fused Cutout Aerial (Excluding cost of pole)

<u>Voltage (kV)</u>	<u># Phases</u>	<u>Capital + Installation Aerial</u>
13	1	\$ 140.00
13 (S-5142A)	3	420.00
34	1	234.00
34	3	700.00
69	1	517.00
69	3	1,550.00

Item #10

Aluminum Secondary Overhead Wire (Cost of installation is provided for in Items #6A and #6B--aerial support structures)

<u>Wire Size kcmil 1 Phase</u>	<u>1 Phase Conductor Cost (2 Polarities & 1 Neutral)/ 100 Feet</u>	<u>3 Phase Conductor Cost (3 Polarities & 1 Neutral)/ 100 Feet</u>
212	\$184.00	\$258.00
556	331.00	478.00
795	459.00	670.00
954	536.00	786.00

NOTES

- (a) DRILL TWO 11/16" HOLES IN POLE 8" APART
 (b) USE A POLE STEP AS A BLADE HANGER
 (c) REMOVE WIRE COVERING FOR INSTALLATION OF CONNECTORS OR JUMPERS ON ALL PHASES
 (d) MAINTAIN A MINIMUM OF 12" BETWEEN ENERGIZED PART OF INSULATOR AND TAP WIRE

REFERENCES

ALUMINUM & ACSR DEADENDS.....S-10518
 INSULATOR TIES.....S-10550
 COMPRESSION TAP CONNECTORS.....S-10599

BILL OF MATERIAL

ITEM	CODE NO.	DESCRIPTION	QUANTITY
1	137-36627	INSULATOR, PIN TYPE,	3
2	132-66903	PIN, POLE TOP	1
3	132-00686	CROSSARM, # 8	1
4	132-05924	BRACKET, CUTOUT, POLE MOUNTING	1
5	{ 138-17067 138-17069 }	CUTOUT, 7.8KV-100A FUSE CUTOUT, 7.8KV-300A BLADE	3
6	132-52035	PIN, STEEL LEAD TOP	2
7	AS REQ	CLAMP, STRAIGHT LINE	6
8	137-36629	INSULATOR, SUSPENSION, 4 1/4"	6
9	135-79579	WIRE, # 4/0 ALUM SOL COV	AS REQ
10	132-42233	LINK, CHAIN, FIGURE 8	3
11	132-31005	GAIN, CROSSARM	1
12	AS REQ	BOLT, MACHINE 5/8"	1
13	132-05414	BOLT, MACHINE, 1/2" X 6"	2
14	132-64905	POLE STEP	1
15	132-05932	BRACKET, EXTENSION FOR LASHED SECONDARIES	1
16	RE-05936	BRACKET, END ARM, MOUNTING	2

3-PHASE SECTIONALIZING 13 KV. DIST.

PHILADELPHIA ELECTRIC CO. ELEC. CONST. STD'S. S-5142-A

Item #11

Distribution Transformer

Aerial installation includes the cost of transformer, fused cutout, surge arrester and installation, but not the cost of the pole.

Underground installation includes the cost of transformer, pad, elbows and insulation.

Primary Voltage (kV)	Secondary Voltage (V)	Nameplate Rating (kVA)	<u>Cost (\$)</u>		<u>Installation Cost (\$)</u>		<u>Cost (\$)</u>		<u>Installation Cost (\$)</u>	
			<u>Aerial</u>		<u>Underground</u>		<u>Aerial</u>		<u>Underground</u>	
			<u>1 Phase</u>	<u>3 Phase</u>	<u>1 Phase</u>	<u>3 Phase</u>	<u>1 Phase</u>	<u>3 Phase</u>	<u>1 Phase</u>	<u>3 Phase</u>
13 (S-5151,	120	75	1,250	2,000	1,000	1,900	560	935	676	1,257
13 S-5157,	120	100	1,450	2,350	1,150	2,100	560	935	676	1,257
13 S-5165)	120	167	2,050	3,450	1,450	2,350	560	935	676	1,257
13	240	75	1,350	2,400	1,200	1,950	560	935	676	1,257
13	240	100	1,500	2,650	1,350	2,150	560	935	676	1,257
13	240	167	2,000	3,250	1,700	2,400	560	935	676	1,257
13	480	75	1,450	2,400	1,300	2,000	560	935	676	1,257
13	480	100	1,700	2,850	1,500	2,200	560	935	676	1,257
13	480	167	2,350	3,900	1,850	2,450	560	935	676	1,257
35 (S-6161B,	120	75	1,600	2,650	1,200	2,400	926	1,546	1,006	1,680
35 S-6181-A)	120	100	1,900	3,150	1,350	2,600	926	1,546	1,006	1,680
35	120	167	2,450	4,100	1,750	2,950	926	1,546	1,006	1,680
35	240	75	2,400	4,000	1,300	2,450	926	1,546	1,006	1,680
35	240	100	2,600	4,300	1,500	2,650	926	1,546	1,006	1,680
35	240	167	2,900	4,850	1,950	3,000	926	1,546	1,006	1,680
35	480	75	2,550	4,250	1,350	2,500	926	1,546	1,006	1,680
35	480	100	2,750	4,600	1,550	2,750	926	1,546	1,006	1,680
35	480	167	3,050	5,100	1,950	3,050	926	1,546	1,006	1,680
69	120	75	11,400	14,900	8,550	13,450	1,807	3,943	1,950	4,100
69	120	100	12,400	16,300	9,300	14,650	1,807	3,943	1,950	4,100
69	120	167	14,600	19,150	10,950	17,250	1,807	3,943	1,950	4,100
69	240	75	11,400	14,900	8,550	13,450	1,807	3,943	1,950	4,100
69	240	100	12,400	16,300	9,300	14,650	1,807	3,943	1,950	4,100
69	240	167	14,600	19,150	10,950	17,250	1,807	3,943	1,950	4,100
69	480	75	11,400	14,900	8,550	13,450	1,807	3,943	1,950	4,100
69	480	100	12,400	16,300	9,300	14,650	1,807	3,943	1,950	4,100
69	480	167	14,600	19,150	10,950	17,250	1,807	3,943	1,950	4,100

NOTES

- (a) REMOVE 18" OF WIRE COVERING BEYOND END OF TIE WIRE.
- (b) INSTALL MOUNTING BRACKET TOUCHING BRACE.
- (c) LIGHTNING ARRESTER SHOULD BE RELOCATED AS SHOWN TO SUPPORT THE LEAD TO CUTOFF ON OUTSIDE PHASE.
- (d) PREFERRED SECONDARY LOCATION IS BELOW TRANSFORMER ON SAME SIDE AS CUTOFF AND TRANSFORMER LIGHTNING ARRESTER.
- (e) USE TWO SECONDARY LEADS FROM EACH POLARITY BUSHING OF 75 & 100 KVA TRANSFORMERS USE FOUR LEADS FROM EACH POLARITY ON 167 KVA TRANSFORMERS
- (f) WIRE IS CONTINUOUS THROUGH DOUBLE EYE BOLTS TO FORM TWO LEADS
- (g) APPLY 6 LAYERS AT 1/2 LAP OF HIGH VOLTAGE SPLICING TAPE (ITEM 18) OVER ENTIRE CONNECTION

REFERENCES

LUG TERMINATION OF ALUM. CONDUCTORS	S-1058
GROUNDING INSTALLATION AT POLES	S-1131
2ND V. SERIAL CABLE	S-1324
13 KV DISTRIBUTION FUSING PRACTICE	S-5101
TANGENT STRUCTURES	S-5121

BILL OF MATERIAL

ITEM	CODE NO	DESCRIPTION	QUANTITY
1		TRANSFORMER, 13 KV SINGLE PHASE (CONVENTIONAL)	1
2	138-17067	CUTOFF, OPEN 7.8KV 100A	1
3	AS REC	CONNECTOR TAP, COMPRESSION	AS REC
4	135-7958C	WIRE, #2 STRANDED ALUMINUM, COV.	AS REC
5	135-7956S	WIRE, #4 COPPER, SOLID, COV.	AS REC
6	137-36627	INSULATOR, PIN TYPE	3
7	132-66903	PIN, POLE TOP	1
8	132-00686	CROSSARM, #8	1
9	132-05932	BRACKET, EXTENSION FOR LASHED SECONDARY	1
10	135-79579	WIRE, #4 0 SOLID ALUMINUM COV.	AS REC
11	AS REC	CONNECTOR TAP, VISE TYPE	AS REC
12	132-44750	MOLDING, PLASTIC 1 2"	AS REC
13	132-14005	COVER, INSULATING BOLT END	2
14	132-14977	LUG, TERMINAL, 4 0 SOL ALUM	9
15	132-05403	BOLT, MACHINE, 1 2" X 2" GALV	10
16	132-76017	BASHER, 1 2" FLAT, GALV.	10
17	132-76008	LOCKWASHER, 1 2", GALV.	10
18	199-70130	TAPE, HIGH VOLTAGE, SPLICING	AS REC

SINGLE PHASE CONVENTIONAL TRANSFORMER INSTALLATION 13 KV. DIST.

S-5151 PHILADELPHIA ELECTRIC CO. ELEC. CONST. STD'S

NOTES

- (a) INSTALL #4 BARE COPPER WIRE FOR GROUNDING. PROVIDE 12" MIN.
B MAX. CON. EXTEND TO GROUND ROD.
- (b) LEAVE 2 FEET MINIMUM OF SECONDARY CABLE SLACK WITHIN PAD.
- (c) LEVEL PAD BEFORE INSTALLING TRANSFORMER.
- (d) LEAVE ONE COIL OF CABLE IN BOTTOM OF BOX PAD AND SUFFICIENT SLACK
IN CONCENTRIC NEUTRAL TO PERMIT OPERATION OF ELBOW TERMINATOR
- (e) CABLES MAY ENTER OR EXIT PAD IN ANY DIRECTION.
- (f) CURRENT LIMITING FUSE HOLDER WITH REPLACEABLE FUSE.
- (g) USE HOLD DOWN CLIPS, 132-13012, WHEN NOT PROVIDED WITH
TRANSFORMER.

REFERENCES

FUSING PRACTICE FOR 13KV DISTRIBUTION SYSTEM _____ S-5101
 COMPRESSION AND WEDGE TYPE CONNECTORS FOR URD _____ S-5510
 INSTALLATION OF 13KV., 200 AMP. LOADBREAK ELBOW _____ S-5525 A, B, C & D
 TERMINATORS _____ S-5524
 FAULT INDICATOR _____ S-5524

BILL OF MATERIAL

ITEM	CODE NO.	DESCRIPTION	QUANTITY
1	133-	TRANSFORMER	
2	138-36255	ELBOW, 15KV, MOLDED RUBBER, LB. #2 C.B.	2
3	138-36260	ELBOW, 15KV, MOLDED RUBBER, LB. 1/0 AL	2
4	135-76852	WIRE, #2 SOL CU BARE, SD TIE	4
5	138-52501	ROD, GROUND, 5/8" X 10', POINTED	1
6	138-12500	CLAMP, 5/8" GROUND ROD	1
7	132-14959	CONN. TERM. LUG, COMP. #2 STR. CU.	1
8	132-14608	CONNECTOR, VISE TYPE, TAP. CU. 2/0 SOL	1
9	135-76855	WIRE, #4 SOL CU. BARE, SD TIE	4
10	139-50618	PAD, TRANSF. 43" X 37 1/2", FIBERGLASS	1
11	139-36002	INDICATOR, FAULT, .580 TO 1.25" CBL	1
12	132-05403	BOLT, MACHINE, 1/2" X 2", GALV.	4
13	132-76017	WASHER, ROUND, FLAT, 1/2" GALV.	4
14	132-76008	WASHER, LOCK, SPLIT, 1/2" GALV.	4
15	132-05382	BOLT, MACHINE, 3/8" X 1 1/2", GALV.	2
16	132-76019	WASHER, ROUND, FLAT, 3/8" GALV.	2
17	132-14966	CONN. TAP, COMP. CU. #2 STR (CU URD CBL)	1
	132-14930	CONN. TAP, COMP. CU. #4 STR (AL URD CBL)	1
	132-14609	CONNECTOR, VISE TYPE, TAP. CU. #4 SOL	1

* AS REQUIRED

10 PADMOUNT TRANSFORMER INSTALLATION 13 KV DISTRIBUTION DEAD FRONT

S-5157

PHILADELPHIA ELECTRIC CO.

ELEC. CONST. STD'S.

1-75
9-77

NOTES

- (a) MINIMUM BENDING RADIUS OF CABLE IS 12"
 (b) POSITION TRANSFORMER SO PRIMARY AND SECONDARY COMPARTMENTS ARE LOCATED OVER RESPECTIVE DUCTS
 (c) SEE S-1006/2006 FOR CONCRETE PAD, GROUNDING AND GUARD POST DETAILS

REFERENCES

CONCRETE PAD & GROUNDING FOR 3- ϕ DISTRIBUTION TRANSFORMERS—S-1006/2006
 PS CONE TERMINATION OF POLYETHYLENE INSUL CONCENTRIC
 NEUTRAL CABLE IN PAD MOUNTED EQUIPMENT—S-5196 A,B & C
 COMPRESSION CONNECTORS FOR URD—S-5510

BILL OF MATERIAL

ITEM	CODE NO	DESCRIPTION	QUANTITY
1	133-	TRANSFORMER, PADMOUNT, 3 ϕ	1
2	138-15330	CONE, STRESS, F/#2 STR, C/A,CBL, 15KV	3
3	132-05403	BOLT, MACHINE, 1/2" X 2", GALV	*
4	135-76852	WIRE #2 SOL CU, BARE, SD TIE	8
5	134-52501	ROL GROUND, 5" X 10", POINTED	1
6	136-12597	CLAMP, 5" GROUND ROD	1
7	132-14959	COMP, TERM LUG, COMP #2 STR CU	3
8	SIZE REQ	CONNECTOR, TAP, VISE TYPE, CU	1
9	139-47925	PACKING, OAK, 1/2"	*
10	199-1264F	COMPOUND SEALING, DUCT	*
11	135-76855	WIRE #4 SOL CU, BARE, SD TIE	*
12	*	CONDUIT METERING, 1/2" MINIMUM ID	*
13	*	BUSHING INSULATED	*
14	132-76017	WASHER ROUND, FLAT, 1/2" GALV	*
15	132-76006	WASHER LOCK, SPLIT, 1/2" GALV	*
* AS REQUIRED			

3 ϕ PAD MOUNTED TRANSFORMER INST.
 13 KV. DIST.

S-5165 PHILADELPHIA ELECTRIC CO. ELEC. CONST. STD'S 3-5-2

SINGLE PHASE TRANSFORMER INSTALLATION

34 KV DIST.

PHILADELPHIA ELECTRIC CO.

ELEC. CONST. STD'S S-6161-B

TYPICAL HIGH-VOLTAGE CABLE RACKING AND
GROUNDING DETAIL

COMPRESSION AND WEDGE TYPE CONNECTORS FOR URD _____ S-5510
FAULT INDICATOR _____ S-5524
RTE 20 KV, 200 AMP. LOADERS AND ELBOW TERMINATOR _____ S-6525

- (d) INSTALL #6 BARE COPPER WIRE PER GROUNDING PROVIDED 1/2 IN. TO 18 IN. MAX COVER EXTENT TO GROUND ROD IS AVAILABLE. IF NOT EXTEND TO GROUND CONNECTION IN SECOND COMPARTMENT. (SEE NOTE 1)
- (e) LEAVE 2 FEET MIN. OF EXCESS WIRE IN SECOND COMPARTMENT WHEN WLD
- (f) TRANSFORMERS MAY BE EQUIPPED WITH A HIGH VOLTAGE SWITCH AND REMOVABLE FUSE.
- (g) LEVEL PAD BEFORE INSTALLING TRANSFORMER
- (h) LEAVE ONE COIL OF CABLE IN BOTTOM OF BOX PAD AND SUFFICIENT SLACK IN CONCENTRIC NEUTRAL TO PERMIT OPERATION OF 1/4 IN. LEMINATOR
- (i) CABLE MAY ENTER OR EXIT PAD IN ANY DIRECTION
- (j) USE HOLD DOWN CLIPS, 132-13012, WHEN NOT PROVIDED WITH TRANSFORMER
- (k) INSTALL FAULT INDICATOR ON LOAD SIDE CABLE
- (l) ARRESTER/ELBOW TO BE INSTALLED ON W/8 BUSHING ON LAST TRANSFORMER
- (m) ATTACH FLEXIBLE GROUND LEAD OF ARRESTER ASSEMBLY (FACTORY SUPPLIED) TO GROUND BY THREADING GROUND PLUG INTO AN UNOCCUPIED GROUNDING NUT OF ATTACH LEAD TO GROUND BUS USING ITEM 7.
- (n) A GROUND ROD IS NOT REQUIRED IF THERE IS A MINIMUM TOTAL LENGTH OF 100' OF CONCENTRIC NEUTRAL CABLE IN CONTACT WITH THE EARTH ADJACENT TO THE BOX PAD IF A GROUND ROD IS REQUIRED BUT CANNOT BE INSTALLED DUE TO SOIL CONDITIONS. INSTALL 100' OF #6 BARE COPPER WIRE (ITEM 8) IN EARTH TO A DEPTH NOT LESS THAN 18" THE WIRE MAY BE A SINGLE 100' STRAIGHT OR TWO 50' LENGTHS OF JOINTED STRAIGHT LENGTHS ADJACENT TO EACH OTHER. CONDITIONS A MINIMUM SEPARATION OF 4 IN. MUST BE MAINTAINED BETWEEN RODS. LENGTH OF WIRE EXTENT TO GROUND CONNECTION IN SECOND COMPARTMENT

ITEM	CODE NO.	DESCRIPTION	QUANTITY
1	131	TRANSFORMER	
2	135-32355	WIRE #20 ALUM. WOLDED REBAR, LB./CAL.	2
3	135-76855	ELECT. WIRE #12, 300 FT. BARF 50 FT.	2
4	135-0585	ACRO. DRUM, 55 GAL. POINTED	2
5	136-12501	CLAMP, 5/8" DRUM, ROD	2
6	132-14955	CONN. TERM. LUG, COMP. #1 STR. C	2
7	131-14626	CONCRETE TAP, 1/2" DIA. 10 FT. L.	2
8	135-76855	WIRE #4, 300 FT. BARF 50 FT.	2
9	136-50616	PAC. TRANS. NO. 41575, FIBERGLASS	2
10	136-36001	INDICATOR, FAULT, 55 G. 25 DB.	2
11	125-29335	CABLE, 1/2" DIA. 100 FT. AL. CLPE	2
12	131-05411	BOL. WASHING, 1/2" DIA. GAL.	2
13	132-76855	WIRE, 1/2" DIA. 100 FT. BARF 50 FT.	2
14	132-76855	WIRE, 1/2" DIA. 100 FT. BARF 50 FT.	2
15	132-05182	BOL. WASHING, 1/2" DIA. GAL.	2
16	131-76855	WIRE, 1/2" DIA. 100 FT. BARF 50 FT.	2
17	132-14966	CONNECTOR, TAP, 1/2" DIA. 10 FT. L.	2
18	131-14626	CONCRETE TAP, 1/2" DIA. 10 FT. L.	2
19	136-0086	ARRESTER/ELBOW, 2" DIA.	2
20	128-0109	BARF, TAP, 1/2" DIA. 10 FT. L.	2

CODE NO.	DESCRIPTION
138-2987	FUSE, 5A, 250V, 1/4" (1/4")

34 KV. DISTRIBUTION-DEAD FRONT

S-6181-A PHILADELPHIA ELECTRIC CO.

ELEC. CONST. STD'S.		ORDIN.
4-74		4-74
2-75		2-75
3-77		3-77
3-78		3-78
1-79		1-79

RDNR
4-74
2-75
9 77
9-78
4 79

Item #12Aerial Secondary Services

1. Installation cost per 100 feet (less cost of conductor)

1 Phase or 3 Phase	)	
120/240V	)	
240/480V	)	\$100.00
480/960V	)	
555/960V	)	

2. Conductor cost per 100 feet

- A. 120/240V 1 Phase
 120/208V 3 Phase
 240/480V 1 Phase
 277/480V 3 Phase

<u>Size</u> <u>kcmil</u>	<u>1 Phase</u> <u>Triplex</u>	<u>3 Phase</u> <u>Quadraplex</u>
42	\$27.00	\$35.00
106	52.00	67.00
212	72.00	--

- B. 480/960V 1 Phase
 555/960V 3 Phase

<u>Size</u> <u>kcmil</u>	<u>1 Phase</u> <u>Triplex</u>	<u>3 Phase</u> <u>Quadraplex</u>
42	\$29.00	\$38.00
106	56.00	72.00

Item #13

3 Phase Circuit Capacitor (Aerial does not include pole--underground does not include manhole.)

Voltage (kV)	3 Phase Capacitor Size (kVAR)	<u>Aerial</u> Cap. Cost + Instal.		<u>Underground</u> Cap. Cost + Instal.	
		<u>Fixed</u>	<u>Switched</u>	<u>Fixed</u>	<u>Switched</u>
13	1,350	\$4,200	\$4,600	\$ 5,200	\$ 5,700
13	1,800	4,700	5,100	5,900	6,400
13	2,400	5,900	6,400	7,400	8,000
36	1,350	4,300	5,000	5,400	6,300
36	1,800	4,800	5,500	6,000	6,900
36	2,400	6,100	6,800	7,600	8,500
69	1,350	6,800	6,700	7,300	8,400
69	1,800	6,500	7,400	8,100	9,300
69	2,400	8,200	9,299	10,300	11,500

Item #14

Aerial Switch--3 Phase (Excluding pole)

Voltage (kV)	Rating (A)	Installed Cost Excluding Pole
13	600	\$ 3,500.00
34 (S-1533-B)	600	5,100.00
69	600	17,000.00

Item #15

Surge Arrester (Excluding pole)

Voltage (kV)	Capital 3 Phase Cost
13	\$ 130.00
34	350.00
69	1,240.00

Item #16

Aerial Recloser Accessories and Relay Package (Excluding pole)

Voltage (kV)	Installed Cost Excluding Pole
13	\$ 8,440.00
34	11,925.00
69	20,775.00

Item #17

Aluminum Underground Cable
 (Secondary Voltages--Main and Service)/100 Feet

	Cable Size <u>kcmil</u>	Cable Cost <u>Only</u>	<u>Installation Cost</u>	
			<u>Direct Burial</u>	<u>Installed with Primary Cable</u>
Voltage-120/208 & 277/480 Phase - 3 Wires - 4				
	4-66	\$ 77.00	\$600.00	\$150.00
	4-133	116.00	600.00	150.00
	4-212	138.00	600.00	150.00
	4-350	333.00	600.00	150.00
	4-500	372.00	600.00	150.00
	4-1,000	584.00	600.00	150.00
Voltage-555/960 Phase - 3 Wires - 4				
	4-66	165.00	600.00	150.00
	4-133	319.00	600.00	150.00
	4-212	400.00	600.00	150.00
	4-350	700.00	600.00	150.00
	4-500	1,000.00	600.00	150.00
	4-1,000	1,400.00	600.00	150.00
Voltage-120/240 & 240/480 Phase - 1 Wires - 3				
	3-66	58.00	600.00	150.00
	3-133	87.00	600.00	150.00
	3-212	104.00	600.00	150.00
	3-350	250.00	600.00	150.00
	3-500	280.00	600.00	150.00
	3-750	400.00	600.00	150.00
	3-1,000	519.00	600.00	150.00
Voltage-480/960 Phase - 1 Wires - 3				
	3-66	124.00	600.00	150.00
	3-133	240.00	600.00	150.00
	3-212	300.00	600.00	150.00
	3-350	510.00	600.00	150.00
	3-500	750.00	600.00	150.00
	3-1,000	1,050.00	600.00	150.00

Item #18

3 Phase
Padmounted Switch with 600A
Mains & 2 Fused 200A Taps
(Including Cost of Pad)

<u>Voltage (kV)</u>	<u>Capital + Installation Cost</u>
13 (S-5167-B)	\$ 8,600.00
34	24,100.00
69	43,700.00

FUSE CODE NUMBERS	
SIZE	CODE NO.
65E	130-29844
125E	130-29826

BILL OF MATERIAL

ITEM	CODE NO.	DESCRIPTION	QUANTITY			
			1 TAP SWITCH	2 TAP SWITCH	2 TAP SWITCH	2 TAP SWITCH
1	130-22214	ENCL. SW. 1 FUSD TAP. POINT. 15KV. 3 PH	1	1	1	1
1	130-22215	ENCL. SW. 2 FUSD TAP. POINT. 15KV. 3 PH	-	-	-	-
2	SEE TABLE	FUSE, POWER, 144 KV SOL	3	3	6	6
3	135-76852	WIRE, 2 SOL. CU. BARE. SD. TIE	18'	18'	24'	24'
4	135-76855	WIRE, 4 SOL. CU. BARE. SD. TIE	130'	130'	140'	140'
5	139-50624	PAD, SITHGR. 65" x 69 1/2", FIBERGLASS	1	1	1	1
6	130-52501	ROD GROUND, 5/8" x 10' POINTED	1	1	1	1
7	130-12500	CLAMP, 5/8" GROUND ROD	1	1	1	1
8	132-14959	TERMINAL, LUG, 2 STR. CU.	4	4	4	4
9	132-14966	CONN. TAP. COMP. 2 STR. CU.	2	5	2	8
10	132-14930	CONN. TAP. COMP. 6 SOL. 4 STR. CU.	3	-	6	-

REFERENCES

LUG TERMINATION OF ALUMINUM CONDUCTORS	S-1058
WRO FUSE SELECTION	S-1404
ALUMINUM COMPRESSION CONNECTORS FOR INSULATED CONDUCTORS	S-2010
P.C. CONE TERMINATION OF 13 KV 750 KCMIL AL. CABLE IN PAD MOUNTED EQUIPMENT	S-2647/5199
PHASE DIAGRAMS FOR 15 KV PAD MOUNTED SWITCH FUSE GEAR	S-5167-C
P.C. CONE TERMINATION OF 13 KV INSULATED CONCENTRIC NEUTRAL CABLE IN PAD MOUNTED EQUIPMENT	S-5196-A,B,C
COMPRESSION AND WEDGE TYPE CONNECTORS FOR WRO	S-5510

COMPRESSION CONNECTOR DATA

SIZE	CODE NO.	TOOL	DIE	INCHES
#4 STR	132-14930	HD-6	B6	2
#2 STR	132-14966	HD-6	0	3
#2 SOL	132-14959	SI-4	H	4

3φ PAD MOUNTED FUSED SWITCH INSTALLATION 13KV. DIST.

S-5167-B PHILADELPHIA ELECTRIC CO.

ELEC. CONST. STD'S.

NOTES

- (a) IF POSSIBLE INSTALL BOX PAD (ITEM 5) ON UNDISTURBED EARTH
- (b) CABLES MAY ENTER OR EXIT BOX PAD IN ANY DIRECTION
- (c) INSTALL GROUND MAT USING #4 COPPER WIRE (ITEM 4) AS SHOWN. PROVIDE 12" MINIMUM / 18" MAXIMUM COVER. CONNECT TO GROUND ROD (ITEM 6) WITH GROUND ROD CLAMP
- (d) CONNECT CONCENTRIC NEUTRALS WITH #2 SOL COPPER WIRE (ITEM 3) AND TAP CONNECTOR (ITEM 9 OR 10). CONNECT #2 SOL COPPER TO GROUND PAD WITH TERMINAL LUG (ITEM 8).
- (e) EXTEND #2 SOL COPPER WIRE FROM GROUND ROD CLAMP AND CONNECT TO GROUND PAD AS SHOWN.
- (f) DASHED LINES INDICATE LOCATION OF SECOND SET OF TAPS IN 2 TAP SWITCH (CODE NO 138-22208)
- (g) A GROUND ROD IS NOT REQUIRED IF THERE IS A MINIMUM TOTAL LENGTH OF 100' OF CONCENTRIC NEUTRAL CABLE IN CONTACT WITH THE EARTH ADJACENT TO THE BOX PAD. IF A GROUND ROD IS REQUIRED AND CANNOT BE INSTALLED DUE TO SOIL CONDITIONS, INSTALL 100' OF #4 BARE SOL COPPER WIRE IN EARTH AT A DEPTH NOT LESS THAN 18". THE WIRE MAY BE A SINGLE 100' LENGTH OR A COMBINATION OF SHORTER STRAIGHT LENGTHS ARRANGED TO SUIT FIELD CONDITIONS. A MINIMUM SEPARATION OF 2' MUST BE MAINTAINED BETWEEN PARALLEL LENGTHS OF WIRE.

3φ PAD MOUNTED FUSED SWITCH INSTALLATION 13 KV. DIST.

PHILADELPHIA ELECTRIC CO.

ELEC. CONST. STD'S

S-5167-B
PAGE 2 OF 2

A.2 Loss Data for Circuit Components

Distribution Transformer Loss Data

I^2R losses are calculated using transformer impedances of 1.8 percent. Core losses are calculated with a regression equation fit to the data below.

Core Losses (Watts)

Primary Voltage (kV)	Secondary Voltage (V)	Nameplate Rating (kVA)	<u>Aerial</u>		<u>Underground</u>	
			<u>1 Phase</u>	<u>3 Phase</u>	<u>1 Phase</u>	<u>3 Phase</u>
13	120	75	240	365	1,000	1,420
13	120	100	300	470	1,230	2,200
13	120	167	530	590	2,250	2,480
13	240	75	250	390	1,030	1,440
13	240	100	310	490	1,270	2,230
13	240	167	540	610	2,280	2,510
13	480	75	280	390	1,070	1,460
13	480	100	340	500	1,300	2,250
13	480	167	590	620	2,320	2,530
35	120	75	270	380	1,070	1,530
35	120	100	340	480	1,370	2,390
35	120	167	490	610	2,250	2,680
35	240	75	290	400	1,110	1,550
35	240	100	370	500	1,410	2,420
35	240	167	500	640	2,290	2,720
35	480	75	310	410	1,160	1,570
35	480	100	390	520	1,450	2,440
35	480	167	530	650	2,310	2,740
69	120	75	270	400	1,290	1,740
69	120	100	340	510	1,600	2,710
69	120	167	590	650	2,920	3,050
69	240	75	280	420	1,330	1,770
69	240	100	350	530	1,640	2,750
69	240	167	610	670	2,960	3,090
69	480	75	310	430	1,380	1,790
69	480	100	380	550	1,680	2,770
69	480	167	650	680	3,010	3,110

Conductor Losses

Conductor losses are based on conductor impedances calculated as follows.

Conductor resistance (in ohms) is approximated by

$$R = \frac{1.9234}{(\text{conductor area in kcmil})}$$

This closely approximates the resistances found in the tables.

Conductor reactance is calculated in ohms per mile using the well-known formula*

$$X = .2794 \log_{10} \left(\frac{\text{GMD}}{\text{GMR}} \right)$$

where GMD is the geometric mean diameter between the conductors and GMR is the geometric mean radius of one conductor. Formulas for GMD and GMR which depend on voltage and conductor area for both aerial wire and underground cable were fit to tabulated data and substituted into the formula for X where appropriate so that X could be calculated as a function of wire size and primary or secondary voltage. Cable dielectric losses are calculated in watts/conductor foot (W_d) with the equation

$$W_d = \frac{0.00276 E^2 \epsilon_r \times \cos \phi}{\log_{10} \left(\frac{2T + D_c}{D_c} \right)}$$

E = Line-to-line neutral voltage in kV

ϵ_r = Constant = 2.5 for cross linked polyethylene

$\cos \phi$ = Insulation power factor = 0.008 for cross linked polyethylene

T = Insulation thickness in mils

D_c = Conductor diameter in mils

A.3 Cost Data for Components of the Distribution Substation

Capital, operating and maintenance costs for substation components are reported as part of the system design-point studies for the substation. The reader is therefore referred to Appendix B for this information.

* W. D. Stevenson, Elements of Power System Analysis, McGraw-Hill, 1962, p. 39.

A.4 Loss Data for Substation Power Transformers

Table A.2 gives representative core loss and full-load copper loss for substation power transformers with high-side voltage rating of 225 kV. Transformer cooling fans also contribute to transformer operating cost. Refer to Appendix B, Table B.5, where such costs are included as part of the calculation of substation yearly electrical consumption.

TABLE A.2 PECO TRANSFORMER LOSSES--SELECTED TRANSFORMERS ALL HIGH SIDE VOLTAGE RATINGS 225 kV

SAMPLE NO.	PECO LOCATION	YEAR PURCH.	% Z OF N.P.	P.U. R*	MVA RATING	MFR	LOW VOLTAGE kV	CORE LOSS (WATTS)	I ² R F.L. LOSS (WATTS)	TOTAL LOSS @ F.L. (WATTS)	DB LEVEL
1	ISLAND RD. #6	1972	12.78	.00403	104**	G.E.	69	56,480	436,080	492,560	75
2	SCHUYLKILL #8	1969	15.08	.00140	208**	G.E.	69	149,400	604,400	753,800	75
3	SCHUYLKILL #7	1967	14.90	.00179	208**	A-C	69	184,000	773,500	957,500	87
4	N. PHILA. #7	1973	13.14	.00928	69**	G.E.	69	50,900	442,000	492,900	70
5	N. PHILA. #8	1973	13.03	.00928	69	G.E.	69	50,900	442,000	492,900	70
6	PLNBRK. #2	1973	21.42	.00280	150	G.E.	35	77,950	630,220	708,170	70
7	PLNBRK. #3	1973	21.50	.00286	150	G.E.	35	82,510	643,020	725,530	70
8	N. WALES #1	1969	14.87	.00641	80	MCGRAW	35	56,672	410,542	467,214	70
9	JENKINTOWN #2	1966	15.00	.00670	80	WEST.	35	97,533	428,856	526,389	70
10	CONCORD #1	1967	14.35	.00721	80	MOLONY	35	95,200	461,200	556,400	82
11	NOTINGHAM #2	1959	13.20	.0194	40	A-C	34.5	56,080	310,880	336,960	N.D.
12	COLORA #1	1969	14.02	.0154	40	WEST.	35	44,888	246,785	291,673	65
13	CLAY #2	1963	13.70	.0167	40	PENNA.	34	50,242	267,079	317,321	N.D.
14	GRAYS FRY. #1	1969	14.70	.00991	55	A-C	14.2	53,500	299,900	353,400	65
15	GRAYS FRY. #3	1969	14.70	.0101	55	A-C	14.2	52,800	304,300	357,100	65
16	PLY. MTG. #11	1972	14.69	.0128	55	MCGRAW	14.2	42,496	386,570	429,066	65
17	PLY. MTG. #13	1972	14.73	.0127	55	MCGRAW	14.2	43,180	384,482	427,662	65
18	MACDADE #1	1969	14.70	.00985	55	A-C	14.2	52,800	298,100	350,900	65
19	BALA #4	1967	14.90	.0127	55	G.E.	14.2	44,600	385,000	429,600	55
20	BALA #6	1967	14.90	.0127	55	G.E.	14.2	44,600	385,000	429,600	55
21	JENKINTOWN #11	1967	15.10	.0120	55	WEST.	14.2	69,556	363,517	433,073	65
22	JENKINTOWN #13	1967	15.05	.0120	55	WEST.	14.2	69,556	363,517	433,073	65
23	PARRISH #1	1967	15.02	.0120	55	WEST.	14.2	69,556	363,517	433,073	65
24	PARISH #2	1970	14.34	.0128	55	MCGRAW	14.2	44,420	387,860	432,280	65
25	EDDYSTONE #3	1971	8.81	.00057	493	G.E.	23.4	197,200	1,385,000	1,582,000	88

* PER UNIT RESISTANCE = $\frac{M \text{ WATTS LOSS } I^2 R \text{ F-L}}{(I_{pu})^2 (MVA \text{ TRANSF})} \times \frac{(100 \text{ MVA BASE})}{(\text{TRANSF. MVA BASE})}$ on 100 MVA BASE.

** AUTO TRANSFORMER DERATED TO TWO WINDING TRANSFORMER BY CORATIO FACTOR $.6933 \frac{E_1 - E_2}{E_1}$.

APPENDIX B

Sample Design-Point Studies for
the Distribution Substation and the Distribution CircuitSubstation Design-Point Studies

The results of the substation system design-point studies are summarized in Table B.1. Cost of designs A through F and C-1 to F-1 are given. The single-line and equipment arrangement diagrams for these designs are illustrated in Figures B.1 through B.5. Table B.2 summarizes annual substation operating and maintenance costs for the designs considered.

The substation component design-point studies are also summarized in Tables B.1 and B.2. The capital costs for each substation item for different voltages and capacities are itemized in Table B.1. Operating and maintenance costs are itemized in Table B.2.

The sample design-point study for Substation Design A is given in Tables B.3, B.4 and B.5. Table B.3 demonstrates development of capital costs for Design A. Tables B.4 and B.5 demonstrate the development of substation operating and maintenance costs.

TABLE B.1 SUMMARY OF SUBSTATION COST ESTIMATES										
ITEM	A 15 kV 20 MVA	B 15 kV 55 MVA	C 33 kV 75 MVA	C-1 33 kV 75 MVA*	D 33 kV 150 MVA	D-1 33 kV 150 MVA*	E 69 kV 150 MVA	E-1 69 kV 150 MVA*	F 69 kV 300 MVA	F-1 69 kV 300 MVA*
PROPERTY IMP.	200,000	300,000	200,000	200,000	350,000	350,000	230,000	230,000	400,000	400,000
FIXED COSTS	978,390	978,390	978,390	978,390	978,390	978,390	978,390	978,390	978,390	978,390
TRANSFORMER	818,400	930,600	1,130,800	1,130,800	1,562,000	1,562,000	1,789,700	1,789,700	2,684,000	2,684,000
CIRCUIT BKRS.	55,000	110,000	57,200	171,600	114,400	343,000	81,950	245,850	163,900	491,700
LOAD INTER.	57,000	114,000	57,650	0	115,300	0	104,775	0	209,550	0
DISCONNECTS W/GRD	47,700	111,900	47,700	64,200	111,900	128,400	79,037	114,300	196,400	220,200
INST. TRANSFORMERS	17,700	33,000	69,570	41,840	128,180	72,220	96,235	58,280	177,000	101,590
BUS SUPPORTS	5,140	14,135	5,140	5,140	14,135	10,280	6,800	6,800	18,700	13,600
BUS & CABLE	11,400	27,200	11,400	12,400	27,200	24,700	15,600	16,800	38,400	33,800
LIGHTNING ARR.	5,860	10,255	9,652	9,652	16,891	16,891	16,540	16,540	27,895	27,895
GROUNDING	70,000	90,000	70,000	70,000	90,000	90,000	70,000	70,000	90,000	90,000
LIGHTNING POLES	7,000	10,000	7,000	7,000	10,000	10,000	12,000	12,000	15,000	15,000
SUPERVISION	147,000	200,000	155,000	175,000	200,000	225,000	175,000	200,000	230,000	250,000
ENGINEERING	350,000	425,000	350,000	375,000	425,000	450,000	350,000	375,000	425,000	450,000
MISC.	4,000	8,459	9,576	6,903	18,641	12,409	13,518	9,842	26,200	17,688
TOTAL	2,774,590	3,362,939	3,159,078	3,247,925	4,162,037	4,273,490	4,019,545	4,123,502	5,680,435	5,773,863
\$/kVA	\$99.20	\$61.14	\$42.12	\$43.31	\$27.75	\$28.49	\$26.80	\$27.49	\$18.93	\$19.25
LAND REQUIREMENT (ACRES)	2.5	3.8	2.5	2.5	3.8	3.8	4.0	4.0	6.3	6.3
*THESE STATIONS HAVE NO MAIN C.B.'S AND USED C.B.'S AS LINE LOAD INTERRUPTERS

FIGURE B.1 SINGLE LINE DIAGRAM DISTRIBUTION SUBSTATION
 CONFIGURATIONS A, B, C, D, E, F

- 1 MAIN TRANSFORMER
- 2 OIL CIRCUIT BREAKERS
- 3 BUS SUPPORTS
- 4 DISC. W/GRD
- 5 TAKE OFF TOWERS
- 6 BUS SPANS
- 7 CABLE SPAND
- 8 MOTOR OPERATED
LOAD INTERRUPTER

CONTROL CAB.	6
DISC. SW W/GRD	4
BUS STRUCTURES	4
BUS SPANS	6
CABLE SPANS	6
T.O. TOWERS	3
DISC. SW STRUCT.	1
LOAD INT STRUCT.	3

CONFIGURATIONS

CONTROL CAB.	10
DISC. SW W/GB	10
BUS STRUCTURER	11
BUS SPANS	18
CABEL SPANS	11
TO TOWERS	6
DISC. SW ST	4
LOAD INT. ST.	6

FIGURE B.2 SUBSTATION CONFIGURATIONS A, B, C, D, E, F
EQUIPMENT ARRANGEMENT

FIGURE B.3 SINGLE LINE DAIGRAM DISTRIBUTION SUBSTATION CONFIGURATIONS C-1, D-1, E-1, F-1

- 1 MAIN TRANSFORMER
- 2 OIL CIRCUIT BREAKERS
- 3 BUS SUPPORTS
- 4 DISC. W/GRD
- 5 TAKE OFF TOWERS
- 6 BUS SPANS
- 7 CABLE SPANS

FIGURE B.4 SUBSTATION CONFIGURATIONS C-1, D-1, E-1, F-1
EQUIPMENT ARRANGEMENT

TO 220 kV BULK
TRANSMISSION SYSTEM

- 1 3-192 kV LIGHTNING ARRESTER
- 2 220 kV DISC. SW W/GRD.
- 3 220 kV LINE WAVE TRAP
- 4 220 kV SF₆ GAS C.B.
- 5 220 kV COUPLING CAPACITOR

TO TRANSFORMER
HIGH SIDE BUSHING

FIGURE B.5 SINGLE LINE DIAGRAM DISTRIBUTION SUBSTATION
220 kV LINE SECTION

TABLE B.2 SUBSTATION OPERATING AND MAINTENANCE YEARLY COSTS										
ITEM	A	B	C	C-1	D	D-1	E	E-1	F	F-1
	15 kV 28 MVA	15 kV 55 MVA	35 kV 75 MVA	35 kV 75 MVA*	35 kV 150 MVA*	35 kV 150 MVA*	69 kV 150 MVA*	69 kV 150 MVA	69 kV 300 MVA	69 kV 300 MVA*
APPARATUS MAINTENANCE										
CIRCUIT BKRS.	200	400	200	600	400	1,200	450	1,350	900	2,700
MOTOR OPER. L.I.	150	300	188	0	375	0	375	0	750	0
DISC. SW. W/GRD.	100	250	100	150	250	300	200	300	500	600
TRANSFORMER	250	250	250	250	250	250	250	250	250	250
GENERAL INSPECTIONS	12,000	13,200	12,000	12,000	13,200	13,200	12,000	12,000	13,200	13,200
SEWER & WATER	240	240	240	240	240	240	240	240	240	240
kWh	238,430	284,520	266,691	262,753	341,537	333,501	315,889	311,951	433,651	425,746
ELECTRICAL CONSUMP. (CONSTANT) \$	**	**	**	**	**	**	**	**	**	**
kWh	**	**	**	**	**	**	**	**	**	**
ELECTRICAL CONSUMP. \$ (LOAD DEPENDENT)	**	**	**	**	**	**	**	**	**	**
TOTAL	**	**	**	**	**	**	**	**	**	**
<p>*THESE STATIONS HAVE NO MAIN BREAKER AND USE BREAKERS AS LINE LOAD INTERRUPTERS. THIS CHART REPRESENTS DOLLARS PER YEAR.</p> <p>**THESE VALUES ARE CALCULATED IN THE COMPUTER MODEL.</p>										

TABLE B.3 15 kV 28 MVA DISTRIBUTION SUBSTATION DESIGN A

QUANTITY	DESCRIPTION	MATERIAL	LABOR	UNIT L. & M. COST	TOTAL
1	<u>PROPERTY IMPROVEMENTS</u>			200,000	200,000
	230 kV LINE SECTION			655,000	655,000
	<u>BUILDING CONSTRUCTION</u>				
	CONTROL HOUSE			36,000	36,000
	PLUMBING & DRAINAGE			37,000	37,000
	HVAC			12,000	12,000
	LIGHTING			2,400	2,400
	SURVEYING & TRANS.			6,400	6,400
	MISC.			9,400	9,400
					103,200
1	<u>STATION PRIMARY EQUIP.</u>				
	<u>MAIN TRANSFORMER</u>				
	28 MVA 230-13 kV TRANSFORMER	566,000	75,000		581,000
	TRANSFORMER FOUNDATION			10,000	10,000
	FIXED-WATER SPRAY SYS.			20,000	20,000
	TRANSFORMER COURT WALL & FND			70,000	70,000
	RELAYING			10,000	10,000
	SEC. WIRING			10,000	10,000
	RIGGING			10,000	10,000
	TESTING			13,000	13,000
	FIELD INSP.			20,000	20,000
	MISC.			74,000	74,000
					818,400
1	<u>MAIN OCB</u>				
	1200 AMP 22 KAIC OCB 15 kV	18,000	3,000		21,000
	FOUNDATION			3,000	3,000
	RIGGING			1,000	1,000
	RELAYING			7,000	7,000
	SEC. WIRING			6,000	6,000
	TESTING			6,000	6,000
	FIELD INSP.			6,000	6,000
	MISC.			5,000	5,000
					55,000
3	<u>LOAD INTERRUPTERS</u>				
	600 AMP CIRCUIT SWITCHER 15 kV	21,000	9,000		30,000
	SEC. WIRING			9,000	9,000
	SUPPORT STRUCTURES & FOUNDATIONS			4,500	4,500
	RIGGING			3,000	3,000
	FIELD INSP.			6,000	6,000
	MISC.			4,500	4,500
					57,000

TABLE B.3 15 kV, 28 MVA DISTRIBUTION SUBSTATION DESIGN A (CONTINUED)

QUANTITY	DESCRIPTION	MATERIAL	LABOR	UNIT L. & M. COST	TOTAL
	<u>DISCONNECT SWITCHES</u>				
11	600 AMP DISC. SW. W/GRD. BLADE 15 kV	19,000	8,000		27,000
1	SUPPORT STRUCTURES & FOUNDATIONS			1,500	1,500
3	TAKE-OFF TOWERS & FOUNDATIONS			19,200	19,200
12	LIGHTNING ARRESTERS 15 kV, 140 MH	3,060	2,800		5,860
12	VOLTAGE TRANSFORMERS 7,600 V-120 V, 240 MH	4,800	4,800		9,600
9	OUTDOOR CURRENT TRANSF. 600-515 kV, 180 MH	4,500	3,600		8,100
4	BUS SUPPORTS (STRUCTURE- INSULATOR FOUNDATIONS LABOR)			5,140	5,140
6	BUS SPANS (3φ) @ \$900			5,400	5,400
6	CABLE SPANS (3φ) @ \$1,000			6,000	6,000
	MISC.			4,000	4,000
	TOTAL STATION PRIMARY EQUIPMENT				1,980,400
	<u>MISCELLANEOUS</u>				
	STATION L&P			22,190	22,190
	ALARMS			2,000	2,000
	SUPERVISORY CONTROL			65,000	65,000
	STATION BATTERY			11,000	11,000
	CABLE & TRAYS			20,000	20,000
	GROUNDING			70,000	70,000
	LIGHTNING POLES			7,000	7,000
	STORES & TRANSP.			70,000	70,000
	OPERATING EQUIP.			30,000	30,000
	SUPERVISION			147,000	147,000
					444,190
	TOTAL PLANT				2,424,590
	ENGINEERING			350,000	350,000
	TOTAL COST				<u>2,774,590</u>

TABLE B.4 YEARLY OPERATING AND MAINTENANCE COSTS

<u>15</u> kV	<u>28</u> MVA	CONFIGURATION <u>A</u>
<u>1</u> C.B.'S x $\frac{\$200.00}{\text{YEAR}}$	=	<u>\$200</u>
<u>3</u> MOTOR OP. L.I. x $\frac{\$50.00}{\text{YEAR}}$	=	<u>150</u>
<u>4</u> DISC. SW. W/GRD. x $\frac{\$25.00}{\text{YEAR}}$	=	<u>100</u>
<u>1</u> TRANSFORMER x $\frac{\$250.00}{\text{YEAR}}$	=	<u>\$250</u>
TOTAL COMPONENT MAINTENANCE		<u>\$ 700</u>
GENERAL INSPECTION COSTS PER YEAR		<u>12,000</u>
WATER AND SEWER		<u>240</u>
TOTAL ELECTRICAL CONSUMPTION <u>238,430</u> kWh		<u>*</u>
(NONLOAD DEPENDENT) x _____ MILLS/kWh		<u>*</u>
LOAD DEPENDENT ELECTRICAL CONSUMPTION _____ kWh		<u>*</u>
x _____ MILLS/kWh		<u>*</u>
TOTAL OPERATING AND MAINTENANCE COSTS PER YEAR		<u>*</u>
* THESE VALUES ARE CALCULATED BY THE COMPUTER MODEL.		

TABLE B.5 SUBSTATION YEARLY ELECTRICAL CONSUMPTION, 15 kV, 28 MVA, CONFIGURATION A				
ITEM	kW DEMAND	HRS/DAY	kWh/DAY	kWh/YEAR
HIGH SIDE C.B.				
AIR COMP.	1.5	2	3	1,089
SF ₆ GAS COMP.	3.0	2	6	2,192
SF ₆ GAS HEATER	5.0	1,872.8 HRS/YEAR		9,359
LOW SIDE C.B.'S				
1 AIR COMP.	1.5	2	3	1,089
CONTROL CABINET HTRS. 6x700 WATT HTRS.	4.2	24	100.8	36,817
LIGHTING (SECURITY)	7.0	4,110 HRS/YEAR		28,700
MISC.	5.5	10	17	6,209
CONTROL HOUSE HVAC				
HEAT	30	1,500 HRS/YEAR		45,000
COOLING	30	1,200 HRS/YEAR		36,000
PRIMARY TRANSFORMER COOLERS $\frac{328 \text{ FULL LOAD LOSS} \times .05 \times 24 \times 365.25}{(\text{kW}) \quad 2} = 71,975$				
SUBTOTAL				= 238,430
SECONDARY TRANSFORMER COOLERS $\frac{328 \text{ FULL LOAD LOSS} \times .05 \times \text{#HRS @ 70\% N.P.}}{2 \quad \text{YEAR}} = *$				
TOTAL CONSUMPTION				= *
*CALCULATED WITHIN THE PROGRAM				

Circuit Design-Point Studies

The specifications of the circuit design-point studies performed are given in Table B.6. The design-point studies for Cases 2B and 2B-U are presented in detail as examples of what was done. In Case 2B the residential load is served by aerial primary and secondary circuits. Figure B.6 illustrates the resulting circuit layout. Table B.7 gives the bill of materials for Case 2B. In Case 2B-U, underground construction is used to serve the same load, using the same primary and secondary voltages. Figure B.7 shows the circuit layout for Case 2B-U while Table B.8 gives the bill of materials.

TABLE D.6 SPECIFICATIONS OF CIRCUIT DESIGN-POINT STUDIES PERFORMED									
CASE IDENT.	PRL VOLT. (kV)	SEC. VOLT. (V)	OVERHEAD OR UNDERGROUND	CONFIG. (A OR B)	INDIVIDUAL PEAK/DIVERSIFIED (kVA)	LOT DIM. (FT) W L		APPROX. DENSITY (MVA/mi ²)	CAPITAL COST (\$)
1A2*	13	120/240, 1- ϕ	OH	A*	6/2.2	250	250	1	\$11,968,757
1A1	13	120/240, 1- ϕ	OH	A	6/2.2	250	250	1	12,621,002
1B	13	120/240, 1- ϕ	OH	B	6/2.2	250	250	1	8,929,303
2B	13	120/240, 1- ϕ	OH	B	6/2.2	100	150	4	4,671,837
2A2*	13	120/240, 1- ϕ	OH	A*	6/2.2	100	150	4	5,891,520
2B-U	13	120/240, 1- ϕ	UG	B	6/2.2	100	150	4	7,044,884
4B	34	120/240, 1- ϕ	OH	B	6/2.2	250	250	1	17,834,570
5B	34	120/240, 1- ϕ	OH	B	18/6.6	75	150	16	4,314,136
6B	34	120/240, 1- ϕ	OH	A	36/13.2	75	150	32	3,104,598
<u>INITIAL STUDIES</u>									
1	13	120/240, 1- ϕ	OH	A	6/6	80	181.5	4	
2	13	120/240, 1- ϕ	OH	A	14.25/14.25	80	181.5	9.5	
3	13	120/240, 1- ϕ	UG	A	6/2.2	80	181.5	4	
4	34	120/208, 3- ϕ	OH	A	6/2.09	80	181.5	4	
5	69	480/960, 1- ϕ	UG	A	6.3/2.2	20	181.5	16	
*CIRCUIT CONFIGURATION A WITH ONLY ONE PAIR OF PRIMARY LATERALS (NO PRIMARY MAIN).

FIGURE B.6 CIRCUIT LAYOUT, AERIAL CASE 2B

TABLE B.7 BILL OF MATERIALS, CASE 2B

TABLE B.7 BILL OF MATERIALS, CASE 2B				
ITEM	DESCRIPTION	UNIT	\$COST/UNIT	COST \$
1	3-1X750AL 13KV CABLE IN, 1 DUCT CABLE INSTALLATION	240.0	810.00	194,400.
		240.0	756.00	181,440.
2	4 1/2" DUCTS IN EARTH 1/2 OF COST	240.0	$\frac{5,500.00}{2}$	660,000.
3	MANHOLES 13kv STRAIGHT 1/2 OF COST	24.0	$\frac{12,100.00}{2}$	145,200.
5	TERMINAL POLE A/U 13 kv 3 ϕ INCL. 3 ϕ AFR DISC.	1.0	3,700.00	3,700.
6	SUPPORT STRUCTURES 3 ϕ 1 ϕ 14,700' = 14,700' 2 ϕ USE 3 ϕ 7 ϕ 4,500' = $\frac{31,500'}{46,200'}$	462.0	1,751.00	808,962.
	1 ϕ SECD ONLY 15 x 14,700 = 220,500	2,205.0	435.00	959,175.
7	ALUM PRIM OH CONDUCTOR 212 3 ϕ 1 ϕ 14,700 106 2 ϕ USE 2-1 ϕ OR 2 x 7 x 4,500	146.9	79.00	11,613.
		630.0	31.00	19,530.
8	13 kv AERIAL DISCONNECT 3 ϕ 2 (FULL COST) 2 (1/2 COST) 1 ϕ 14 x 2 (1/2 COST)	2.0	410.00	820.
		2.0	205.00	410.
		28.0	59.00	1,932.
9	13kv FUBRD CUTOUT 14 14 x 2	28.0	140.00	3,920.
10	ALUM SEC OH CONDUCTOR 1 ϕ 795 15 x 7 x 2000 = 210,000	2,100.0	459.00	963,900.
11	1 ϕ OH TRANSFORMER 100 kVA 7 x 15 = 105	105.0	2,060.00	216,300.
12	AERIAL 1 ϕ TRIPLEX SERVICE 105 x 42 = 4,410 4410 x 50' = 220,500	4,410.	100.00	441,000.
		2,205.	27.00	59,535.
TOTAL CAPITAL COST				4,671,837.

FIGURE B.7 CIRCUIT LAYOUT, UNDERGROUND CASE 2B-U

TABLE B.8 BILL OF MATERIALS, CASE 2B-U

ITEM	DESCRIPTION	UNIT	\$COST/UNIT	COST \$
1	SAME AS IN CASE 2B			194,400.
2	" "			181,440.
3	" "			660,000.
1	3-1 x 750 13kVCA DIRECT BURIED			
	CABLE 6 x 2100 = 12,600'	126.0	810.00	102,060.
	INSTALLATION	126.0	1,500.00	189,000.
1	1-1 x 66 AL 13 kV DIRECT BURIED 7 x 4500 = 31,500			
	CABLE	315.0	60.00	18,900.
	INSTALLATION	315.0	668.00	210,430.
11	1φ URD TRANSFORMER 100 kVA 7 x 15	105.0	2,026.00	212,730.
17	1φ ALUM SEC DIR BURIED 3-1 x 750 AL CAS. 7 x 2 x 2000' x 15 = 420,000'	4,200.00	400.00	1,680,000.
	INSTALLATION-NOT WITH PRIM.	4,200.00	600.000	2,520,000.
17	1φ AL SMC D SERVICES- 66 105 x 42 = 4,410 4410 x 30' = 132,300'			
	INST DIR BURIED	1,323.0	600.00	793,800.
	CABLE	1,323.0	58.00	76,734.
18	3φ PAD MOUNTED FUBMD SWITCH	7.0	8,600.00	60,200.
TOTAL CAPITAL COST				7,044,884.

EXAMPLE CIRCUIT DESIGN-POINT STUDIES

Basic data for 13 kV supply, Cases 2B and 2B-U:

Approximate Density	4 MVA/sq. mi.
Lot Dimensions (Depth is from Center - Line of Street)	100' W x 150' D
Customer Peak Demand	6 kVA
Customer Diversified Peak	2.2 kVA
Approximate Residential Density	1,858 Lots/sq. mi.

Dimensions of Circuit Area, Cases 2B and 2B-U:

The length of the block is determined by the optimum conductor length, in this case 2,000'. 100' spaces are provided for cross streets.

Analysis of Secondary Voltage Drop, Case 2B:

Sec'd. V = 120/240 V 1 ϕ 3W.

Load/House = 2.2 KVA @ 80% P.F.

Lot Width = 100', Depth = 150'

Aerial Construction

What is maximum length of sec'd.? What size? (maximum voltage drop of main + serv. = 3%)

SIZE MAIN KCMIL	VOLTAGE DROP (VD) FACTOR %/kVA/100'	kVA LOAD ON MAIN	V.D., DIST.	%VD MAIN	%VD SERV.	%VD TOTAL	LOAD ON TRANSF kW	SEC'D. LENGTH OF BLOCK
795 AL	.011	44.0	550'	2.66	.31	2.97	92.4	2000'
556 AL	.014	39.6	500'	2.77	.31	3.08	83.6	1800'
212 AL	.040	22.0	300'	2.64	.31	2.95	48.4	1000'
954 AL	.010	44.0	550'	2.42	.31	2.73	92.4	2000'
66 AL	.102	6.0	50'	----	.31			

THE OPTIMUM CONDUCTOR TO BE USED IS 795 AL.

TRANSFORMER LOAD IS

44.0
44.0
4.4
<u>92.4</u> kVA

Analysis of Primary Voltage Drop and Circuit Loading, Case 2B:

SIZE MAIN KCMIL	VOLTAGE DROP (VD) FACTOR/ MVA/MI	MVA LOAD	%VD	LOAD	CONDUCTOR RATING	
					NORMAL	24 HR EMERG'Y
212 (3 ϕ)	$.4793 \times \frac{2100}{5280}$	4.23	.81	177A (OK)	380A	510A
"	$.4793 \times \frac{2100}{5280}$	2.82	.54			
"	$.4793 \times \frac{2100}{5280}$	1.41	.27			
106 (1 ϕ)	$2.240 \times \frac{1200}{5280}$	.658	.33 (OK) 1.95% (OK)		245A	275A

Analysis of Secondary Voltage Drop, Case 2B-U:

Sec'd. V = 120/240 V 1 ϕ 3W.

Load/House = 2.2 kVA @ 80% P.F.

Lot Width = 100', Depth = 150'

Underground Construction

What is maximum length of sec'd.? What size? (Maximum VD Main + Serv. = 3%)

SIZE MAIN KCMIL	VOLTAGE DROP (VD) FACTOR %/kVA/100'	kVA LOAD ON MAIN	VD DIST.	%VD MAIN	%VD SERV.
1000	.0101	46.2	50'	.24	
"	"	22.0	550'	1.22	
66	.102	6.0	30'	.18 1.64	.18
750	.0119	46.2	50'	.27	
"	"	22.0	550'	1.44	
66	.102	6.0	30'	.18 1.89 (OK)	
500	.0213	46.2	50'	.49	
"	"	22.0	550'	2.58	
66	.102	6.0	30'	.18 3.25 (NOT OK)	

Analysis of Primary Voltage Drop and Circuit Loading, Case 2B-U:

SIZE MAIN KCMIL	VD FACTOR MVA/MI	MVA LOAD	%VD	CABLE RATING		
				NORMAL	24 HR. EMER.	LOAD
750 3¢	$.491 \times \frac{2100}{5280}$	4.23	.83	560A	600A	176A
"	"	2.82	.55			
"	"	1.41	.28			
66 1¢	$4.122 \times \frac{1200}{5280}$	.658	$\frac{.62}{2.28}$ (OK)	125A	180A	82A

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APPENDIX C

Formulation of Optimal-Power-Flow Approach
to
Circuit Design Optimization*

The search for the primary and secondary voltages and other circuit design parameters that minimize cost while satisfying constraints on power flow and voltage variation may be considered a problem in constrained optimization. The cost function to be minimized is the utility's annual revenue requirement to meet a residential load of specified characteristics. The cost function includes components for capital carrying charge, operating and maintenance and energy losses. The constraints to be satisfied are the ac nodal power balance equalities, equipment current-carrying limits, limits on allowable voltage variation at various points in the circuit and the limits imposed by component availability.

An additional constraint imposed is that the circuit conforms to a specified configuration. Configuration A, illustrated in Figure 1.1, is chosen for the following discussion. Circuit design parameters subject to optimization may include primary and secondary voltages, circuit dimensions and conductor sizes.

This appendix is divided into two parts. Section C.1 addresses the modeling of variable circuit lengths. The problem is recognized that, as the length of a section of circuit (primary lateral, secondary main, etc.) increases, the number of load taps (nodes) increases. An equivalent circuit with a fixed number of nodes is introduced and its validity explored.

Section C.2 develops a model of the circuit with a fixed number of nodes. Section C.2 then derives (1) the analytical cost function to be minimized and,

*The formulation that follows was developed by Dr. R.G. Wasley of the Electrical Engineering Department of Drexel University while temporarily employed by Philadelphia Electric Co. during the summer of 1979.

(2) the analytical gradients of this cost function with respect to each design parameter to be optimized. The inequality constraints are presented and their enforcement in the solution process discussed. Section C.2 is concluded with a summary of the theoretical development presented in this appendix and a discussion of its implementation.

C.1 Equivalence Modeling of Variable Circuit Lengths

The distribution planning problem involves in part the determination of circuit lengths and, hence, the number of customers served per feeder within an overall optimization process. This means, however, that circuit length or number of customers served per feeder becomes a variable, introducing during adjustment a variable number of nodes from which customers are served. With increasing or decreasing numbers of nodes, the number of equations relating node quantities such as voltage and current must change, along with the dimensions of the system admittance matrix, for example. In consequence, the fact that the number of variables during the solution process is varying poses inherent formulation difficulties which are best avoided. A basis for avoiding such difficulties is described herein, where the objective is to always retain a fixed number of system nodes by a simple equivalencing technique as the system expands and contracts during optimization.

C.1.1 Equivalence Formulation

Consider the simple circuit of Figure C.1 in which several customers are fed from the midpoint at a level of S per unit of complex power. Power flow is from nodes 1 to 2. In effect we will consider elimination of the node at the midpoint by establishing an equivalent circuit taking the form of Figure C.2. The problem resemblance to the star-delta or $T - \Pi$ transformation of network theory.

FIGURE C.1 SINGLE SERVICE NODE

FIGURE C.2 DESIRED EQUIVALENT

For the circuit of Figure C.1 the following relationships for voltage and current are readily established:

$$E_1 = E_2 + Z(I_1 + I_2)$$

$$I_1 = (S/E)^* + I_2$$

Alternatively, we can write

$$\begin{bmatrix} E_1 \\ I_1 \end{bmatrix} = \begin{bmatrix} 1 + KZ & 2Z \\ K & 1 \end{bmatrix} \begin{bmatrix} E_2 \\ I_2 \end{bmatrix} \quad (1)$$

where

$$K = S^*/E^*E_2$$

Consideration of the circuit depicted in Figure C.2 also yields

$$E_1 = E_2 + Z^1(I_2 + S_2^*/E_2^*)$$

$$I_1 = S_1^*/E_1^* + S_2^*/E_2^* + I_2$$

Again, in matrix form we can write

$$\begin{bmatrix} E_1 \\ I_1 \end{bmatrix} = \begin{bmatrix} 1 + Z^1K_2 & Z^1 \\ K_1 + K_2 & 1 \end{bmatrix} \begin{bmatrix} E_2 \\ I_2 \end{bmatrix} \quad (2)$$

where

$$K_1 = S_1^*/E_1^*E_2$$

$$K_2 = S_2^*/E_2^*E_2$$

For equivalence between the circuits of Figures C.1 and C.2, it now follows from (1) and (2) that the following equalities must hold:

$$Z^1 = 2Z \quad (3)$$

$$Z^1K_2 = KZ \quad (4)$$

$$K = K_1 + K_2 \quad (5)$$

In particular, consideration of (3), (4) and (5) demands

$$K_1 = K_2 = K/2 \quad (6)$$

which in turn demands

$$S_1 = (S/2) E_1/E \quad (7)$$

$$S_2 = (S/2) E_2/E \quad (8)$$

Therefore, in summary, for equivalence between the circuits, (3), (7) and (8) must be satisfied.

C.1.2 Implementation

In achieving equivalence between the circuits of Figures C.1 and C.2 it should be clear that we can readily set $Z^1 = 2Z$. However, since the voltages E_1 , E_2 and E are not necessarily known a-priori, we are unable to use (7) and (8) exactly. There is the need for approximation.

As a first step, consideration of Figure C.1 leads to the relationships

$$E_1/E = 1 + ZI_1/E$$

$$E_2/E = 1 - ZI_2/E$$

so that a simple approximation based on a neglect of voltage drop yields

$$E_1/E \approx E_2/E \approx 1$$

In (7) and (8), this means that the midpoint power S of Figure C.1 is simply divided equally and each component placed at each terminal node so as to define the equivalent circuit of Figure C.2. This process is further illustrated in Figure C.3.

Accepting this approximation, the question now arises as to its application in the case of more than one service node. The procedure is illustrated in Figure C.4, where three intermediate service nodes are to be eliminated. There are different ways of proceeding but, in Figure C.4, the second step is the result of splitting the

FIGURE C.3 APPROXIMATE EQUIVALENCING

STEP #	1	A	B	C	4
1	0	S	S	S	0
2	0	$3S/2$	0	$3S/2$	0
3	$3S/4$	0	$3S/2$	0	$3S/4$
4	$3S/4$	$3S/4$	0	$3S/4$	$3S/4$
5	$9S/8$	0	$3S/4$	0	$9S/8$
6	$9S/8$	$3S/8$	0	$3S/8$	$9S/8$
7	$21S/16$	0	$3S/8$	0	$21S/16$
8	$21S/16$	$3S/16$	0	$3S/16$	$21S/16$
9	$45S/32$	0	$3S/16$	0	$45S/32$
10	$45S/32$	$3S/32$	0	$3S/32$	$45S/32$
11	$93S/64$	0	$3S/32$	0	$93S/64$
12	$93S/64$	$3S/64$	0	$3S/64$	$93S/64$
13	$189S/128$	0	$3S/64$	0	$189S/128$
14	$189S/128$	$3S/128$	0	$3S/128$	$189S/128$
15	$381S/256$	0	$3S/128$	0	$318S/256$
16	$381S/256$	$3S/256$	0	$3S/256$	$381S/256$
17	$765S/512$	0	$3S/512$	0	$765S/512$
18	$765S/512$	$3S/1024$	0	$3S/1024$	$765S/512$

FIGURE C.4 STEP-BY-STEP EQUIVALENCING PROCESS

demand at B and adding to the demands at A and C respectively. The third step results in splitting each new demand at A and C and placing the components at 1 and A and at C and 4 respectively. Continuing in this manner the tabulated results evolve so that, in the limit, the demands at A, B and C tend to be zero whilst the equivalent demands at 1 and 2 increase according to the converging series

$$(3S/2) \sum_{n=1}^{\infty} (1/2)^n = 3S/2$$

In fact, from this example, it can be deduced that the elimination of say N service nodes leads to the simple equivalent depicted in Figure C.5. Also note that, in the case of the approximate procedure so far discussed, the equivalencing of Figure C.3 is reversible. Thus the results deduced from Figure C.4 can be established much more readily on this basis as illustrated, for example, in Figure C.6.

C.1.3 Example of Exact Equivalent

To demonstrate the development of an exact equivalent, elimination of the three service nodes of Figure C.4 will be undertaken under no limiting assumptions. The basic multiplying factors as power is shifted from one node to another are indicated in Figure C.7 where the corresponding results of such operations are listed in the accompanying table step-by-step. The table is not complete, of course, but once the pattern is recognized it is readily seen that in the limit the powers extracted originally from nodes A, B and C are eliminated and replaced by the following powers at nodes 1 and 2 respectively:

$$\begin{aligned} S_1 &= (3S/2) [E_1/2E_A + E_1/3E_B + E_1/6E_C] \\ S_2 &= (3S/2) [E_2/2E_C + E_2/3E_B + E_2/6E_A] \end{aligned} \quad (9)$$

Insofar as practical implementation is concerned, it is clear that the exact equivalent cannot be applied for the same reasons discussed earlier. It is of

FIGURE C.5 APPROXIMATE EQUIVALENCING FOR ELIMINATING N SERVICE NODES

FIGURE C.6 USE OF $T \rightarrow \Pi$ AND $\Pi \rightarrow T$ EQUIVALENCING

STEP #	1	A	B	C	2
1	0	S	S	S	0
2	$SE_1/2E_A$	$SE_A/2E_B$	$SE_B \left(\frac{1}{E_A} + \frac{1}{E_C} \right) / 2$	$SE_C/2E_B$	$SE_2/2E_C$
3	$SE_1/2E_A + SE_1/4E_B$	$SE_A \left(\frac{1}{E_A} + \frac{1}{E_C} \right) / 4$	$S/2$	$SE_C \left(\frac{1}{E_A} + \frac{1}{E_C} \right) / 4$	$SE_2/2E_C + SE_2/4E_B$
4	$SE_1/2E_A (1+1/4)$ $SE_1/2E_B (1/2)$ $SE_1/2E_C (1/4)$	$SE_A/4E_B$	$SE_B \left(\frac{1}{E_A} + \frac{1}{E_C} \right) / 4$	$SE_C/4E_B$	$SE_2/2E_C (1+1/4)$ $SE_2/2E_B (1/2)$ $SE_2/2E_A (1/4)$
5	$SE_1/2E_A (1+1/4)$ $SE_1/2E_B (1/2+1/4)$ $SE_1/2E_C (1/4)$	$SE_A \left(\frac{1}{E_A} + \frac{1}{E_C} \right) / 8$	$-S/4$	$SE_C \left(\frac{1}{E_A} + \frac{1}{E_C} \right) / 8$	$SE_2/2E_C (1+1/4)$ $SE_2/2E_B (1/2+1/4)$ $SE_2/2E_A (1/4)$
6	$SE_1/2E_A (1+1/4+1/8)$ $SE_1/2E_B (1/2+1/4)$ $SE_1/2E_C (1/4+1/8)$	$SE_A/8E_B$	$SE_B \left(\frac{1}{E_A} + \frac{1}{E_C} \right) / 8$	$SE_C/8E_B$	$SE_2/2E_C (1+1/4+1/8)$ $SE_2/2E_B (1/2+1/4)$ $SE_2/2E_A (1/4+1/8)$
7	$SE_1/2E_A (1+1/4+1/8)$ $SE_1/2E_B (1/2+1/4+1/8)$ $SE_1/2E_C (1/4+1/8)$	$SE_A \left(\frac{1}{E_A} + \frac{1}{E_C} \right) / 16$	$S/8$	$SE_B \left(\frac{1}{E_A} + \frac{1}{E_C} \right) / 16$	$SE_2/2E_C (1+1/4+1/8)$ $SE_2/2E_B (1/2+1/4+1/8)$ $SE_2/2E_A (1/4+1/8)$
8	$SE_1/2E_A (1+1/4+1/8+1/16)$ $SE_1/2E_B (1/2+1/4+1/8+1/16)$ $SE_1/2E_C (1/4+1/8)$	$SE_A/16E_B$	$SE_B \left(\frac{1}{E_A} + \frac{1}{E_C} \right) / 16$	$SE_C/16E_B$	$SE_2/2E_C (1+1/4+1/8+1/16)$ $SE_2/2E_B (1/2+1/4+1/8+1/16)$ $SE_2/2E_A (1/4+1/8)$

FIGURE C.7 EXACT EQUIVALENCING EXAMPLE

interest, however, to consider the exact equivalence in order to obtain a basis for assessing the possible errors arising from the approximate equivalencing procedure which proves very easy to apply and is, in fact, the recommended procedure.

C.1.4 Example Results and Corresponding Errors

As a matter of demonstration, the approximate equivalencing procedure is applied to the case of an expanding secondary feeder. In effect load-flow results for the actual feeder and the corresponding equivalent feeder are compared so as to establish the levels of error to be expected. The secondary feeder is visualized in accordance with the schematic of Figure C.8. Thus, at the distribution transformer, it is assumed that two service drops exist and then, at equal spans out from the transformer, four service drops exist until at the end of the run only two customers are serviced. All customers except one of the latter are simply represented in terms of an effective load demand at the junction of the corresponding service drops and the secondary feeder. In the case of one of the last customers, however, the service drop circuit is also represented, allowing computation of the service voltage which will be lower than for any of the customers closer to the transformer. This critical voltage is made available so as to ensure it will be kept within limits.

For present purposes, no attempt is made to limit this voltage. The levels of loading are simply chosen to provide representative (or greater) voltage drops as the secondary feeder is expanded. Typically, the intermediate customer load demands would allow for diversity and the last customer (whose service voltage is monitored) would be considered under peak demand conditions. Hence, with reference to Figure C.8, S is the diversified load demand for each group of four customers served from the same pole, with $S' = S/2$ the diversified load demand for the two customers served from the distribution-transformer pole, i.e., the first

(A)

(B)

(C)

FIGURE C.8 EXPANDING SECONDARY FEEDER AND ITS APPROPRIATE EQUIVALENT REPRESENTATION

pole. The last two customers are represented by the demands S'' and S''' , the latter corresponding to the peak demand of the customer whose service voltage is to be monitored. Thus $S'' = S/4$ and S''' is taken to be of the order of 1.6 times greater. Pole spans are assumed equal so that Z is simply the effective impedance between poles, and Z' is taken as the impedance corresponding to the last-customer service connection.

Various case studies are provided in Figures C.9 through C.12, comparing the load-flow results from the corresponding exact and approximate representations of the system as more and more customers are supplied via feeder extension. Note that the impedances of the feeder and service drop conductors are decreased in stages as the secondary circuit expands so as to provide overall voltage drops which are not too excessive. Even so, it is noted that the drop of about 13% in Figure C.12 is rather extreme. Clearly a larger conductor size is still required, or else a higher secondary voltage, a problem which is a part of the optimization process.

In summary, the results indicate that very good agreement is obtained in terms of voltages (also see Figure C.13) as well as system input power demands. However, the small differences in the latter are the result of significant differences in the system losses when the corresponding exact and approximate cases are compared. Thus system losses are in error within the range 14% to 18%.

This order of error suggests the need for closer investigation of its possible impact on the overall design problem in which the cost of losses has to be factored into the total cost function to be minimized. Clearly the error also varies according to specific loading conditions and conductor sizes. Therefore it is desirable to establish an upper bound on the error, albeit on a system-wide basis. This task is a difficult one, however, and further complicated because the optimum system configuration is as yet unknown. Nevertheless, during the optimization

	INPUT REAL AND REACTIVE POWERS, P.U.	SYSTEM REAL AND REACTIVE LOSSES, P.U.	VOLTAGE AT NODE 4, P.U.
A	1.32, 0.91	0.019, 0.055	$0.951 \angle -2.2^\circ$
B	1.32, 0.90	0.016, 0.048	$0.951 \angle -2.2^\circ$

$$S = .6 + j.4 \text{ pu}$$

$$S' = S/2 = 0.3 + j0.2 \text{ pu}; S'' = S/4 = 0.15 + j0.1 \text{ pu}$$

$$S''' = 0.25 + j0.15 \text{ pu}$$

$$Z = 1.0 + j3.0 \text{ \%}; Z' = 1.0 + j2.0 \text{ \%}$$

FIGURE C.9 4 TO 3 NODE LOAD-FLOW COMPARISON

	INPUT REAL AND REACTIVE POWERS, P.U.	SYSTEM REAL AND REACTIVE LOSSES, P.U.	VOLTAGE AT NODE 5, P.U.
A	1.96, 1.44	0.064, 0.192	$0.895 \angle -4.7^\circ$
B	1.95, 1.41	0.054, 0.161	$0.892 \angle -4.8^\circ$

$$S' = S/2 = 0.3 + j0.2 \text{ pu}; S'' = S/4 = 0.15 + j0.1 \text{ pu}$$

$$S''' = 0.25 + j0.15 \text{ pu}$$

$$Z = 1.0 + j3.0 \%; Z' = 1.0 + j2.0 \%$$

FIGURE C.10 5 TO 3 NODE LOAD-FLOW COMPARISON

	INPUT REAL AND REACTIVE POWERS, P.U.	SYSTEM REAL AND REACTIVE LOSSES, P.U.	VOLTAGE AT NODE 6, P.U.
A	2.57, 1.86	0.071, 0.213	$0.912 \angle -3.9^\circ$
B	2.56, 1.83	0.058, 0.175	$0.910 \angle -4.0^\circ$

$$S' = S/2 = 0.3 + j0.2 \text{ pu}; S'' = S/4 = 0.15 + j0.1 \text{ pu}$$

$$S''' = 0.25 + j0.15 \text{ pu}$$

$$Z = 0.5 + j1.5 \text{ } \Omega; Z' = 0.5 + j1.0 \text{ } \Omega$$

FIGURE C.11 6 TO 3 NODE LOAD-FLOW COMPARISON

	INPUT REAL AND REACTIVE POWERS, P.U.	SYSTEM REAL AND REACTIVES LOSSES, P.U.	VOLTAGE AT NODE 9, P.U.
A	4.50, 3.45	0.199, 0.596	$0.866 \angle -6.0^\circ$
B	4.46, 3.34	0.164, 0.492	$0.860 \angle -6.1^\circ$

$$S' = S/2 = 0.3 + j0.2 \text{ pu}; S'' = S/4 = 0.15 + j0.1 \text{ pu}$$

$$S''' = 0.25 + j0.15 \text{ pu}$$

$$Z = 0.25 + j0.75 \text{ } \Omega; Z' = 0.25 + j0.5 \text{ } \Omega$$

FIGURE C.12 9 TO 3 NODE LOAD-FLOW COMPARISON

FIGURE C.13 VOLTAGE PROFILES

procedure (aimed at deriving a generic system configuration) it is proposed to assess the effect of uncertainty in the system-loss calculation by varying the weight given to its associated cost in the total cost function. Moreover it is believed that the effect of the error in system loss can be alleviated by applying a two-stage design process. In the first step the approximate equivalencing procedure will be applied so as to develop a generic system configuration whose number of nodes, in particular, will then be fixed. Thus, in the second step, the system can be modeled exactly without the need for equivalencing and a further refinement obtained by again optimizing the overall cost function. Of course the nature of the cost function will be somewhat different since some of the variables, such as feeder lengths, number of distribution transformers and breakdown in terms of basic elements, will have already been established from stage 1.

C.2 Problem Formulation and Solution Procedure

C.2.1 Development of System Model

It is proposed to develop a full ac model of the distribution system on the basis of which the real and reactive power balance equations for each node can be established. This model will then be used to compute a base case load-flow solution along with the associated cost of the corresponding system configuration and its operation. In addition an adjoint sensitivity method will allow generation of the gradient of the cost function with respect to those variables (control variables) which can be adjusted to achieve a better configuration. Thus, via control-variable adjustment using the gradient information, an iterative process of optimization will ensue.

As a first step let us consider the radial, primary system configuration of Figure C.14, where an underground cable from the substation feeds into a primary main, several laterals and numerous spurs. For present purposes, three-phase

FIGURE C.14. DISTRIBUTION SUBSTATION PRIMARY SYSTEM CONFIGURATION

circuits throughout will be assumed and each distribution transformer will be assumed loaded to the same extent. The secondary feeder arrangements are depicted in Figure C.15 along with the approximate model representation of each secondary feeder, in accordance with the procedure recommended in Section C.1. This model will be used to represent the most extreme secondary feeders from the substation infeed point only. Thus the most-distant customer service voltages will be made available for holding within specified limits. Otherwise the influence of all other secondary feeders will be reflected in their contributions to the total load on corresponding distribution transformers. The modeling process is further illustrated in Figure C.16, noting that the turns ratio is introduced because it is in effect a control variable related to the need to establish preferred voltage levels.

In order to represent intermediate spurs along any lateral, it is only necessary to introduce an appropriate effective demand at the corresponding spur/lateral junction. On this basis the approximate equivalencing method, described in Section C.1, can be applied once more in the manner illustrated in Figure C.17. Note that spur pairs and secondary-feeder pairs are in parallel respectively, so that further reduction is incorporated as shown.

At this stage most of the models for representing the complete system are available. In particular Figure C.18 shows one form of representation, noting that intermediate laterals are represented at their junction with the primary main by an effective power demand S_L . Further simplification is possible, however, by noting that corresponding nodes in upper and lower portions as well as corresponding nodes in left and right portions of Figure C.18 are in parallel. It is also necessary to introduce an equivalencing procedure for the variable number of nodes along the primary main, in a manner similar to that already used elsewhere in the system. In this regard it is noted that there are $2N_T$ distribution transformers between

(A) SECONDARY CONFIGURATION

(B) SECONDARY FEEDER REPRESENTATION

N_p - #SERVICE POLES PER DISTRIBUTION TRANSFORMER; S - DIVERSIFIED DEMAND PER 4 CUSTOMERS
 S_{pk} - LAST CUSTOMER PEAK DEMAND ; l_{sd} - LENGTH OF SERVICE CONNECTION
 Z_d - SERVICE DROP IMPEDANCE PER UNIT LENGTH ; l_{ss} - SPAN BETWEEN SERVICE POLES
 Z_s - SECONDARY FEEDER IMPEDANCE PER UNIT LENGTH ; l_s - LENGTH OF SECONDARY FEEDER

$$l_s = (N_p - 1)l_{ss} / 2$$

FIGURE C.15 SECONDARY CONFIGURATION AND MODELING

N_T - # DISTRIBUTION TRANSFORMERS PER SPUR; S_D - EFFECTIVE DEMAND PER INTERMEDIATE TRANSFORMER

Z_t - TRANSFORMER LEAKAGE IMPEDANCE

a - TRANSFORMER TURNS RATIO

Z_p - SPUR IMPEDANCE PER UNIT LENGTH

$$Z = a^2 (N_p - 1) Z_{r,ss} / 2$$

FIGURE C.16 SPUR AND SECONDARY MODELING

N_S - # SPUR-PAIRS PER LATERAL

ℓ_a - SPAN BETWEEN SPURS

Z_a - LATERAL IMPEDANCE PER UNIT LENGTH

S_p - EFFECTIVE DEMAND PER INTERMEDIATE SPAN

FIGURE C.17 LATERAL/SPURS/SECONDARIES MODEL

FIGURE C.18 OVERALL SYSTEM REPRESENTATION

laterals and $(N_L - 3)/2$ lateral-pairs between any last pair of laterals and the central lateral-pair, N_L , representing the total number of lateral-pairs. Consequently the equivalence modeling of the primary main is as shown in Figure C.19. Finally, taking account of paralleling, the reduced system representation is obtained as shown in Figure C.20.

C.2.2 Discussion

It is evident from Figure C.20 that the approximate equivalencing procedure has reduced the actual system to a fixed-node system in which, nevertheless, complete flexibility exists in terms of expansion facilities to establish a "best" system configuration. In essence there are just eight nodes but of course the complexity of the system relationships pertaining to the actual system are reflected in the dependency of the reduced system branch impedances and load demands on various control variables. The next stage of this report, in fact, is concerned with developing the method for optimizing the reduced system in terms of these control variables. Before proceeding, however, some preliminary discussions are in order.

As previously mentioned, the design process is to be undertaken in two stages because the reduced system of Figure C.20 is, after all, approximate. Even so, under the circumstances, the fundamental relationships between the system variables are retained as closely as possible. This suggests that optimization of the reduced system should at least determine the number of nodes and hence the number of different elements required by the best solution to the design problem. This generic configuration will then provide a basis for further refinement such as in primary and secondary conductor sizes and corresponding working voltages.

A point for specific discussion involves the underground feeder. To simplify matters at this stage it will be assumed that it is of fixed length and has the

FIGURE C.19 PRIMARY MAIN EQUIVALENCING
 N_L - # LATERAL PARTS PER PRIMARY MAIN

FIGURE C.20 REDUCED SYSTEM REPRESENTATION

capability of supplying 400 amps at any preferred voltage level. In effect its cost will be simply addressed as a function of voltage only. No consideration will be given to its sizing in terms of energy losses nor any associated voltage drop. These factors can be incorporated later. Node 1 of Figure C.20, therefore, will be taken as the voltage reference node, a node that can supply up to a maximum of 400A. The latter value is chosen on the basis that the substation is of unit form capable of supplying three underground feeders to corresponding service areas and that the associated circuit breaker is limited to a continuous rating of 1,200A.

For a given load demand per customer the 400A is clearly an important limit related to the extent of the ultimate service area which can be supplied at different voltages. Another important limit in this regard, but more importantly in terms of the form taken by the system configuration, is the lowest allowable service voltage. Typically the service voltage will be held within ± 5 percent of the nominal voltage with the latter a control variable. Other ranges of variation can be incorporated as desired, in particular it may be of interest to explore the effect of a much more restricted upper limit, say 0 percent, in accordance with regulations being adopted in California. It is worth noting that other elements to be incorporated in the optimizing procedure are capacitor banks. These will be introduced at the primary nodes of Figure C.20.

In developing the reduced system representation of Figure C.20, certain information was assumed such as distribution transformer loading S_D , spur loading S_p and lateral loading S_L . Consequently, it is necessary to provide appropriate values. Ignoring losses, for example, we may write

$$S_D = (N_p - 1)S \quad (10)$$

$$S_p = N_T S_D = N_T (N_p - 1)S \quad (11)$$

$$S_L = 2N_S S_p = 2N_S N_T (N_p - 1)S \quad (12)$$

so that all node demands can be expressed in terms of the control variables N_p (number of service poles per distribution transformer), N_T (number of distribution transformers per spur), N_S (number of spur-pairs per lateral) and N_L (see Figure C.20, number of lateral-pairs per primary main). In addition, of course, they depend upon the given diversified demand per four customers, S , where the four-customer service-pole concept is retained on practical grounds. Note that the above relationships could incorporate a multiplying factor (e.g., 1.05 or 1.1) in an attempt to account for losses. It is felt, however, that this is relatively unimportant in the first stage of the design process and, in consequence, will not be pursued further in this report.

As a matter of clarification it is also noted that certain distances defined in the process of developing Figure C.20 are assumed given. Thus ℓ_{sd} (length of service connection) is a given dependent upon lot size and street width. The span between service poles, ℓ_{ss} , is also a given dependent upon lot size. Similarly ℓ_a (span between spurs) is a given determined by typical distances between streets. On the other hand the length of a secondary feeder, ℓ_s , and hence the span between distribution transformers on a spur or the primary main, $2\ell_s$, can be written as

$$\ell_s = \frac{(N_p - 1)\ell_{ss}}{2} \quad (13)$$

In the light of the power demand and length relationships (10) through (13) some of the node demands and branch impedances of the reduced system (Figure C.20) can be rewritten. For completeness, the definitive expressions are summarized in Tables C.1 and C.2. In addition, Table C.3 lists all the variables

TABLE C.1 POWER DEMAND EXPRESSIONS	
NODE NUMBER	COMPLEX POWER DEMAND
1	$(N_p - 1)N_T(2N_S + 1)(N_L - 1)S$
2	$(N_p - 1)N_T[2N_S(N_L - 1) + (N_L - 5)]S$
3	$4(N_p - 1)N_T(N_S - 1)S$
4	$4(N_p - 1)N_T S$
5	$4(N_p - 1)(N_T - 2)S$
6	$4(N_p - 1)S$
7	$4(N_p - 2)S$
8	$16S_{pk}$

TABLE C.2 BRANCH IMPEDANCE EXPRESSIONS	
BRANCH	COMPLEX IMPEDANCE EXPRESSION
1-2	$(N_p - 1)N_T(N_L - 1)Z_m \ell_{ss} / 2$
2-3	$N_s Z_a \ell_a / 4$
3-4	$(N_p - 1)Z_p \ell_{ss} / 16$
4-5	$(N_p - 1)(N_T - 1)Z_p \ell_{ss} / 8$
5-6	$Z_t / 8$
6-7	$(N_p - 1)a^2 Z_s \ell_{ss} / 32$
7-8	$a^2 Z_d \ell_{sd} / 16$

TABLE C.3 LIST OF AVAILABLE CONTROL VARIABLES

SYMBOL	DESCRIPTION
N_p	SERVICE POLES/DISTRIBUTION TRANSF.
N_T	DISTRIBUTION TRANSFS./SPUR
N_S	SPUR-PAIRS/LATERAL
N_L	LATERAL-PAIRS/PRIMARY MAIN
Z_d	SERVICE DROP IMPEDANCE/LENGTH
Z_s	SECONDARY FEEDER IMPEDANCE/LENGTH
Z_p	SPUR IMPEDANCE/LENGTH
Z_a	LATERAL IMPEDANCE/LENGTH
Z_m	PRIMARY MAIN IMPEDANCE/LENGTH
Z_t	TRANSFORMER IMPEDANCE
a	TRANSFORMER TURNS RATIO

which are immediately available for control purposes, noting that further consideration has yet to be given to the details of the conductor and distribution transformer sizing problem, the capacitor bank locating and sizing problem and the primary and secondary voltage problem.

It is also worth noting that application of the reduced model of the system is limited by the following lower bounds on certain of the control variables:

1. $N_p \geq 3$, i.e., there must be at least three service poles per distribution transformer
2. $N_T \geq 2$, i.e., there must be at least two distribution transformers per spur
3. $N_S \geq 1$, i.e., there must be at least one spur-pair per lateral
4. $N_L \geq 3$, i.e., there must be at least three lateral-pairs per primary main.

For all practical purposes, however, these lower bounds are irrelevant.

Finally it is stressed that the model arrived at in Figure C.20 is representative of typical aerial configurations of radial type and, so far, is based on three-phase circuits throughout. Consequently the model must be reconsidered and modified, if necessary, to match specific requirements, e.g., the cases of single-phase spurs and underground cable or mixed systems, etc. Of course, by developing an optimization procedure for the case in hand, a useful learning process will be experienced. Moreover, it is necessary to first prove the feasibility of the proposed design procedure.

C.2.3 Nature of System Cost Function

The economic and energy efficient design of a unit substation service area involving one transformer feeding three independent circuits, and including the determination of preferred primary and secondary voltages, is to be based on

minimization of a total system cost function. Component-by-component, this function includes capital costs, installation costs and operating costs with the latter accounting for the costs of energy loss and demand loss components. Note that minimization is constrained by various imposed limits, e.g., voltage drop limits.

In any event the nature of the total cost function must be established in terms of the system variables and, of course, the values of any associated constants must be enumerated. In this regard component cost models have been developed and reported in the Third Interim Report. Effectively, from numerous design point studies, curving fitting procedures have generated general formulas for component cost functions in polynomial form. As far as this report is concerned, only the nature of these functions will be presented along with some relevant comments. It is also emphasized that the case of aerial configurations is addressed.

Taking the substation transformer, for example, the levelized annual cost has been found to have the form

$$C_{ST} = T_1 + T_2 V_p$$

where capital costs, installation costs and costs associated with routine maintenance testing, core losses and I^2R losses are incorporated T_1 and T_2 are constants and V_p is the primary distribution voltage. The design-point studies were based on a 230 kV subtransmission system and, in fact, they also indicate a dependence upon transformer MVA rating. For present purposes, however, a current rating of 1,200A is assumed so that the MVA rating in itself is a function of voltage.

If the capital costs of substation surge arresters (including costs of installation) are considered, the appropriate relationship is

$$C_{SA} = A_1 + A_2 V_p$$

in which the number of arresters (12 for the unit substation) must be incorporated. For arresters on the primary distribution circuit, however, the corresponding function is

$$C_{PA} = A'_1 + A'_2 V_p + A'_3 V_p^2$$

noting that the multiplying factor to be incorporated is simply three, corresponding to those at the underground feeder terminal pole. Arresters associated with distribution transformers are factored into transformer costs to be given later. Again it is noted that three-phase circuits are assumed throughout but that other arrangements could also be taken into consideration very readily.

Another component is the substation circuit breaker. Capital, installation and maintenance costs together yield

$$C_{SB} = B_1 + B_2 V_p + B_3 V_p^2$$

In addition one can lump together various costs associated with the substation which are miscellaneous in nature and dependent upon the number of transformers as well as voltage. In particular, for the unit substation comprising one transformer, we have

$$C_{SM} = M_1 + M_2 V_p$$

to also include the costs of associated energy and demand losses.

As far as substation protective equipment is concerned, the unit substation involves a cost function of the form

$$C_{SP} = P_1 + P_2 V_p + P_3 V_p^2$$

where the total package of current and voltage sensing relays and instrument transformers are included.

The cost function for each of the underground feeders out of the substation must reflect not only capital costs but also the costs of manholes, I^2R losses and, if necessary, ducts. Cable costs depend upon voltage, conductor size, number of phases, length and whether or not the cable is installed in ducts or simply buried directly. In particular, assuming a three-phase cable and a fixed conductor size, the appropriate relationship is

$$C_{cc} = C_1 + C_2 V_p + C_3 V_p^2$$

where conductor size, for present purposes, is to be fixed in accordance with the 400A current rating. Feeder length will also be fixed, say to one mile. A similar relationship has been obtained for manhole costs, i.e., those of a straight type, and any required duct work. In the case of a one mile feeder, for example, a consideration of cable pulling limits would indicate the need for four straight manholes. In addition, a manhole of switched type is relevant. For this type, design-point studies yield the cost function

$$C_{SW} = W_1 + W_2 V_p^{1/2}$$

The submersible underground switch to be installed in the switched manhole is an additional cost whose cost function (including installation) has been established as

$$C_{MS} = S_1 + S_2 V_p + S_3 V_p^2$$

For the I^2R losses, since conductor size and current are known, associated costs in terms of both energy and demand loss components are readily determined independently of voltage.

The underground cable feeding the aerial distribution system is also associated with a three-phase terminal pole. Hence, for this component the cost function takes the form

$$C_{TL} = L_1 + L_2 V_p + L_3 V_p^2$$

based on capital costs only since no other costs are involved.

For the aerial distribution system, the cost of support structures must be incorporated. On a three-phase basis, for example, it can be shown to have the form

$$C_{SR} = R_1 + R_2 V_p$$

In this expression, only the total length of primary circuit comprising the main, laterals and spurs is required, noting that secondary circuits share the same support facilities as primary spurs. More specifically, in terms of previously defined variables, the appropriate length of primary circuit is

$$N_L (2N_S + 1)(4N_T \ell_s + \ell_a)$$

Other components for which cost is dependent upon length are those associated with the different sizes of aerial conductor. In effect, depending upon the number of phases and material, the relationship has the form

$$C_{WG} = G_1 + G_2 W_s$$

where W_s denotes wire size. To include in each formula, however, are the multipliers corresponding to the total lengths of primary main and lateral spans, the primary spurs, the secondary feeders and the secondary service drops. Taking

each of these in turn the corresponding multipliers* are

$$4N_L N_T \ell_S + N_L (2N_S + 1) \ell_a \quad (\text{main \& laterals}) \quad (14)$$

$$8N_L N_S N_T \ell_S \quad (\text{spurs}) \quad (15)$$

$$4N_L (2N_S + 1) N_T \ell_S \quad (\text{secondaries}) \quad (16)$$

$$4N_L (2N_S + 1) N_T \ell_{SD} \quad (\text{service drops}) \quad (17)$$

Disconnect switches and fused cutouts are additional components to be considered. In the case of the unit substation, for example, the costs associated with these components can be written as

$$C_{SF} = F_1 + F_2 V_p + F_3 V_p^2$$

Similar relationships are appropriate for the same components on the primary distribution circuits. The question is, how many of these components are required? The number of fused cutouts depends upon the number of spurs, i.e., $4N_L N_S$, which for three-phase circuits has to be multiplied by a factor of three to obtain the desired quantity. In the case of disconnect switches, sectionalizing between spurs, similar sections of primary main and also between sections of the lateral feeders, the corresponding number is

$$(2N_S + 1)(2N_L - 1) + 3N_L$$

Again, assuming three-phase circuits throughout, this expression must also be multiplied by three. In deriving the expression, note that there are four disconnect-switch locations along each lateral pair but that the two at the ends are

* Note that main and lateral conductors are taken to be the same size, i.e., $Z_m = Z_a$.

shared between adjacent circuits, meaning that per lateral pair there are effectively three locations. A similar concept of sharing is applied to those disconnect switches located between the spurs and primary mains of adjacent circuits.

If, for the present, three-phase aerial type transformers are considered, the corresponding cost function is found to take the form

$$C_{DT} = D_1 + D_2 V_p + D_3 V_p + D_4 R_T + D_5 V_S^{1/2}$$

where R_T and V_S are additional variables referring to transformer rating and secondary voltage respectively. Moreover, $2(2N_S + 1)N_L N_T$ defines the total number of such transformers. Costs associated with transformer core and $I^2 R$ losses are also needed; both energy and demand components. The $I^2 R$ losses in particular will be taken into account as an integral part of the total primary/secondary system losses, as determined from a load-flow solution. Core losses, however, will be evaluated separately. The relevant relationship is

$$C_{DC} = D'_1 + D'_2 V_p + D'_3 R_T^{1/2} + D'_4 R_T^3 + D'_5 V_S^{1/2}$$

which should again allow for the total number of distribution transformers.

Since it is of interest to explore the influence of capacitor banks, as used for regulating purposes, corresponding cost functions must also be provided. In the case of a three-phase fixed capacitor bank of aerial type, for example, the appropriate cost function appears as

$$C_{CK} = K_1 + K_2 V_p + K_3 V_p^2 + K_4 C_K + K_5 C_K^2$$

where C_K is the capacitor bank rating, say in kVARs. As for the number of such banks to be used, this could be limited in accordance with current utility practice, i.e., by locating them where they are usually placed--in advance of the automated

design process--or else they could be defined to exist at, say, every primary node and subsequently sized on this basis.

Finally, as a matter of summary, Table C.4 lists the cost functions component-by-component along with appropriate comments and/or an indication of the multiplying factors to be incorporated. It must also be mentioned that the total cost function for the underground cable and its distribution circuit configuration is to be multiplied by a factor of three, because the unit substation feeds three such circuits.

Note that so far no allowance has been made for including automatic reclosing and sectionalizing schemes. On the other hand, to limit loss-of-service under fault conditions, such facilities may well be desirable, especially at the higher voltage levels where relatively large demands can be expected on a single circuit. Therefore, based on reliability concepts, there is the need to yet develop an appropriate strategy to be incorporated in the solution process.

C.2.4 Cost Function Gradient

Thus far a model of the distribution system has been established to provide relationships between all the system variables. Moreover a performance index in the form of a total cost function has been described as the basis for achieving optimization, i.e., it is required to drive the cost function to a minimum by adjusting the available control variables. Optimization is constrained of course by certain limiting conditions yet to be discussed in greater detail. Nevertheless, on achieving the minimum of the constrained cost function, the corresponding values of the control variables will provide the best system design.

At the outset it is appropriate to classify the system variables as dependent or independent variables with the latter control variables further classified according to their nature as either node or network type variables. In effect we

TABLE C.4 LEVELIZED ANNUAL COST FUNCTIONS		
SUBSTATION COMPONENTS		
COMPONENT	COST FUNCTION	COMMENTS
TRANSFORMER	$C_{ST} = T_1 + T_2 V_p$	1200A CURRENT RATING INCLUDES LOSSES
BREAKER	$C_{SB} = B_1 + B_2 V_p + B_3 V_p^2$	1200A CURRENT RATING
SWITCHES	$C_{SF} = F_1 + F_2 V_p + F_3 V_p^2$	PER UNIT SUBSTATION
PROTECTION	$C_{SP} = P_1 + P_2 V_p + P_3 V_p^2$	PER UNIT SUBSTATION
ARRESTERS	$C_{SA} = A_1 + A_2 V_p$	PER UNIT SUBSTATION
MISCELLANEOUS	$C_{SM} = M_1 + M_2 V_p$	CONSTRUCTION, BUILDINGS AUXILIARY EQUIPMENT, PLANT, ETC.

TABLE C.4 LEVELIZED ANNUAL COST FUNCTIONS (CONTINUED)		
UNDERGROUND CABLE COMPONENTS		
COMPONENT	COST FUNCTION	COMMENTS
CABLE	$C_{CC} = C_1 + C_2 V_p + C_3 V_p^2$	400A CURRENT RATING, 3-Ø DEPENDENT ON INSTALLA- TION & LENGTH
CONDUIT	$C_{DU} = U_1 + U_2 V_p + U_3 V_p^2$	DEPENDENT ON LENGTH BUT MAY NOT BE REQUIRED
MANHOLE (STRAIGHT)	$C_{MH} = H_1 + H_2 V_p + H_3 V_p^2$	DEPENDENT ON CABLE LENGTH, E.G., 4 PER MILE
MANHOLE (SWITCHED)	$C_{SW} = W_1 + W_2 V_p^{\frac{1}{2}}$	1 ONLY
3-Ø SWITCH	$C_{MS} = S_1 + S_2 V_p + S_3 V_p^2$	1 ONLY
LOSSES	$C_{CL} = I^2 R (N_1 + N_2)$	I AND R FIXED (FOR EXAMPLE) N_1 & N_2 CONVERSION OF ENERGY & DEMAND LOSSES
TERMINAL POLE	$C_{TL} = L_1 + L_2 V_p + L_3 V_p^2$	3-Ø CABLE/AERIAL JUNCTION
ARRESTERS	$C_{PA} = A_1' + A_2' V_p + A_3' V_p^2$	3 PER TERMINAL POLE

TABLE C.4 LEVELIZED ANNUAL COST FUNCTIONS (CONTINUED)

PRIMARY/SECONDARY SYSTEM COMPONENTS		
COMPONENT	COST FUNCTION	COMMENTS/MULTIPLYING FACTOR
SUPPORT STRUCTURES	$C_{SR} = R_1 + R_2 V_p$	$N_L (2N_S + 1) (4N_T^2 S + l_a)$
MAIN & LATERAL CONDUCTORS	$C_{WG}^{ml} = G_1 + G_2 W_S$	$4N_L N_T^2 S + N_L (2N_S + 1) l_a$
SPUR CONDUCTORS	$C_{WG}^{SP} = G_1 + G_2 W_S$	$8N_L N_S N_T^2 S$
SECONDARY CONDUCTORS	$C_{WG}^{SC} = G_1' + G_2' W_S$	$4N_L (2N_S + 1) N_T^2 S$
SERVICE DROP CONDUCTORS	$C_{WG}^{SD} = G_1' + G_2' W_S$	$4N_L (2N_S + 1) N_T^2 S_p$
FUSED CUTOUTS	$C_{FC} = F_1' + F_2' V_p + F_3' V_p^2$	$4N_L N_S$, ALSO x 3 FOR 3-Ø
DISCONNECTS	$C_{DS} = F_1'' + F_2'' V_p + F_3'' V_p^2$	$(2N_S + 1) (2N_L - 1) + 3N_L$, ALSO x 3 FOR 3-Ø
ARRESTERS	$C_{PA} = A_1' + A_2' V_p + A_3' V_p^2$	$3(4N_T N_S N_L + 1)$ for 3-Ø
DISTRIBUTION TRANSFORMER CAPITAL COSTS	$C_{DT} = D_1 = D_2 V_p + D_3 V_p^3 + D_4 R_T + D_5 V_S^{1/2}$	$2(2N_S + 1) N_L N_T$, 3-Ø AERIAL
DISTRIBUTION TRANSFORMER CORE LOSSES	$C_{DC} = D_1' + D_2' V_p + D_3' R_T^{1/2} + D_4' R_T^3 + D_5' V_S^{1/2}$	$2(2N_S + 1) N_L N_T$, N_1 & N_2 , 3-Ø
3-Ø FIXED CAPACITOR BANK	$C_{CK} = K_1 = K_2 V_p + K_3 V_p^2 + K_4 C_K + K_5 C_K^2$	VARIABLE NUMBER
SYSTEM LOSSES	$C_{SL} = \Delta P (N_1 + N_2)$	ΔP = INPUT-DEMAND INCLUDES DIST. TRANSF. LOSSES

may define a vector of dependent variables $\underline{x}$ and two vectors of independent control variables $\underline{u}$ and $\underline{\phi}$ respectively, where for the problem in hand

$$\underline{x}^T = [P_1, Q_1, \theta_1, V_1]$$

$$\underline{u}^T = [P_D, Q_D, \theta_D, V_D]$$

$$\underline{\phi}^T = [N_p, N_T, N_S, N_L, Z_d, Z_s, Z_p, Z_m, Z_t, a, \underline{C}_K]$$

with T denoting transposition.

The elements of $\underline{\phi}$ correspond to the network-type variables of Table C.3* except for the additional vector $\underline{C}_K$ which recognizes the possibility of having some capacitor banks installed, i.e., the number of elements in $\underline{C}_K$ depends on the number of nodes at which capacitors are located. In $\underline{x}$ and $\underline{u}$, P_1 , Q_1 , θ_1 and V_1 refer to the real power, reactive power, voltage angle and voltage magnitude variables associated with node 1 of Figure C.20. Similarly the vectors $\underline{P}_D$, $\underline{Q}_D$, $\underline{\theta}_D$ and $\underline{V}_D$ contain the corresponding power and voltage variables associated with the remaining nodes 2 through 8, noting that these nodes are load-type nodes, albeit of complex form owing to their relationship to certain network-type variables.** Node 1, on the other hand, is in essence the "slack or swing bus" of the system, as defined in the well-known load-flow problem.

If consideration is now given to the total cost function, it should be evident that the variables upon which it depends are either directly or indirectly related to those variables defining $\underline{x}$, $\underline{u}$ and $\underline{\phi}$. Thus, denoting the total cost function by C and

* Note that $Z_m = Z_a$ is assumed as in the cost function component, where main and lateral conductors are taken to be of the same size.

** Note that generator nodes, as required in transmission systems, can also be incorporated in the method but are not required here.

allowing for first-order perturbations in the system variables, we may write

$$\Delta C(\underline{x}, \underline{u}, \underline{\phi}) = \underline{C}_x^T \Delta \underline{x} + \underline{C}_u^T \Delta \underline{u} + \underline{C}_\phi^T \Delta \underline{\phi} \quad (18)$$

where $\underline{C}_x$, $\underline{C}_u$ and $\underline{C}_\phi$ represent appropriate partial derivations evaluated at some initial point $\underline{x}^0$, $\underline{u}^0$, $\underline{\phi}^0$. This implies that the cost function can be differentiated, a condition which is in fact satisfied. Note that the initial point in the space of all variables corresponds to an initial design, i.e., a starting point which is to be improved by adjusting the available control variables comprising $\underline{u}$ and $\underline{\phi}$.

To implement this optimizing procedure, therefore, we seek a form of (18) such that

$$\Delta C(\underline{x}, \underline{u}, \underline{\phi}) = \underline{\sigma}_u^T \Delta \underline{u} + \underline{\sigma}_\phi^T \Delta \underline{\phi} \quad (19)$$

where the sensitivity vectors $\underline{\sigma}_u$ and $\underline{\sigma}_\phi$ are introduced to define the gradient of the cost function in terms of the control variables only, viz.

$$\nabla \underline{C}^T = [\underline{\sigma}_u^T, \underline{\sigma}_\phi^T] \quad (20)$$

If the relationship of (19) can indeed be established, then it is noted that a gradient-directed search for the minimum cost can be applied. Acceptance of this approach, however, depends upon the development of an efficient and flexible algorithm for obtaining the sensitivity vectors $\underline{\sigma}_u$ and $\underline{\sigma}_\phi$, and hence the gradient of the cost function.

With this objective in mind, consider the power balance equations at each node k . Moreover, let an element of the nodal or bus admittance matrix of the system be denoted by

$$Y_{km} = G_{km} + jB_{km}$$

The nodal or bus injected powers (real and reactive) can now be written as

$$P_k = V_k \sum_{m=1}^n V_m (G_{km} \cos \theta_{km} + B_{km} \sin \theta_{km}) \quad (21)$$

$$Q_k = V_k \sum_{m=1}^n V_m (G_{km} \sin \theta_{km} - B_{km} \cos \theta_{km})$$

with n denoting the number of nodes (eight in the case of Figure C.20). Noting, however, that G_{km} and B_{km} can be written in terms of elements of ϕ , first order variable perturbations in (21) can be used to establish relationships expressed as

$$\begin{bmatrix} \Delta \underline{P} \\ \Delta \underline{Q} \end{bmatrix} = \begin{bmatrix} H & N \\ J & L \end{bmatrix} \begin{bmatrix} \Delta \underline{\theta} \\ \Delta \underline{V/V} \end{bmatrix} + \begin{bmatrix} \Delta \underline{P}_\phi \\ \Delta \underline{Q}_\phi \end{bmatrix} \quad (22)$$

where

$$\begin{aligned} H_{km} &= L_{km} = V_k V_m (G_{km} \sin \theta_{km} - B_{km} \cos \theta_{km}) & m \neq k \\ H_{kk} &= -B_{kk} V_k^2 - Q_k; L_{kk} = -B_{kk} V_k^2 + Q_k & m = k \\ N_{km} &= -J_{km} = V_k V_m (G_{km} \cos \theta_{km} + B_{km} \sin \theta_{km}) & m \neq k \\ N_{kk} &= G_{kk} V_k^2 + P_k; J_{kk} = -G_{kk} V_k^2 + P_k & m = k \end{aligned} \quad (23)$$

and

$$\begin{aligned} \Delta P_{\phi k} &= V_k \sum_{m=1}^n (V_m \cos \theta_{km} \Delta G_{km} + V_m \sin \theta_{km} \Delta B_{km}) \\ \Delta Q_{\phi k} &= V_k \sum_{m=1}^n (V_m \sin \theta_{km} \Delta G_{km} + V_m \cos \theta_{km} \Delta B_{km}) \end{aligned} \quad (24)$$

The sub-matrices H , N , J and L constitute the so-called Jacobian matrix for the complete system.

To continue, it now proves amenable to introduce and define the arbitrary relationship

$$\begin{bmatrix} \hat{\underline{P}} \\ \hat{\underline{Q}} \end{bmatrix} = \begin{bmatrix} \underline{H}^T & \underline{J}^T \\ \underline{N}^T & \underline{L}^T \end{bmatrix} \begin{bmatrix} \hat{\underline{\theta}} \\ \hat{\underline{V}} \end{bmatrix} \quad (25)$$

which can be used in (22) to obtain

$$\underline{\theta}^T \Delta \underline{P}_{-\phi} + \underline{V}^T \Delta \underline{Q}_{-\phi} = \hat{\underline{\theta}}^T \Delta \underline{P} + \hat{\underline{V}}^T \Delta \underline{Q} - \underline{\hat{P}}^T \Delta \underline{\theta} - \underline{\hat{Q}}^T (\Delta \underline{V} / \underline{V}) \quad (26)$$

Alternatively, by defining

$$\hat{\underline{u}}^T = [\hat{\theta}_1, \hat{V}_1, -\hat{P}_{-D}^T, -\hat{Q}_{-D}^T] \quad (27)$$

$$\hat{\underline{x}}^T = [\hat{P}_1, \hat{Q}_1, -\hat{\theta}_{-D}^T, -\hat{V}_{-D}^T] \quad (28)$$

and recognizing from (24) that the lhs of (26) takes the form

$$\hat{\underline{\theta}}^T \Delta \underline{P}_{-\phi} + \hat{\underline{V}}^T \Delta \underline{Q}_{-\phi} = \sum_{k=1}^n \sum_{m=1}^n (\sigma_{km}^G \Delta G_{km} + \sigma_{km}^B \Delta B_{km}) \quad (29)$$

where

$$\begin{aligned} \sigma_{km}^G &= (V_k V_m \cos \theta_{km}) \hat{\theta}_k + (V_k V_m \sin \theta_{km}) \hat{V}_k \\ \sigma_{km}^B &= (V_k V_m \sin \theta_{km}) \hat{\theta}_k + (V_k V_m \cos \theta_{km}) \hat{V}_k \end{aligned} \quad (30)$$

(26) can be written as

$$\sum_{k=1}^n \sum_{m=1}^n (\sigma_{km}^G \Delta G_{km} + \sigma_{km}^B \Delta B_{km}) = \hat{\underline{u}}^T \Delta \underline{x} - \hat{\underline{x}}^T \Delta \underline{u} \quad (31)$$

It is important to note that entries in $\Delta \underline{x}$ and $\Delta \underline{u}$ which refer to say V_k now take the form $\Delta V_k / V_k$. Consequently, this must be reflected in corresponding entries of $\underline{C}_x$ and $\underline{C}_u$.

The arbitrary nature of (31) can now be removed by setting

$$\hat{\underline{u}} = \underline{C}_x \quad (32)$$

Moreover, as already mentioned and to be detailed later, the lhs of (31), i.e., the ΔG_{km} and ΔB_{km} elements, can be expressed in terms of changes in the elements of the network-type variables, namely $\Delta \phi$. Thus, from (31) and (32)

$$\underline{C}_x^T \Delta \underline{x} = \hat{\underline{x}}^T \Delta \underline{u} + \hat{\underline{\phi}}^T \Delta \underline{\phi} \quad (33)$$

where we define

$$\hat{\underline{\phi}}^T \Delta \underline{\phi} = \sum_{k=1}^n \sum_{m=1}^n (\sigma_{km}^G \Delta G_{km} + \sigma_{km}^B \Delta B_{km}) \quad (34)$$

Using (33) in (18) it now follows that

$$\Delta C(\underline{x}, \underline{u}, \underline{\phi}) = (\hat{\underline{x}} + \underline{C}_u)^T \Delta \underline{u} + (\hat{\underline{\phi}} + \underline{C}_\phi)^T \Delta \underline{\phi} \quad (35)$$

to establish the desired result

$$\begin{aligned} \underline{\sigma} &= \hat{\underline{x}} + \underline{C}_u \\ \underline{\sigma}_\phi &= \hat{\underline{\phi}} + \underline{C}_\phi \end{aligned} \quad (36)$$

It is stressed once more that both $\underline{C}_x$ and $\underline{C}_u$ entries related to voltage magnitudes must be derived in terms of $\Delta V_k/V_k$ rather than ΔV_k . This is in keeping with the choice of Jacobian matrix in (22). As a matter of summary, it is also pointed out that a procedure has been outlined by means of which the gradient of the cost function can be obtained in terms of the control variables. Of course details concerning application have yet to be discussed in depth but, beforehand, the next section helps to further understand the concepts of the approach by considering some general aspects of implementation.

C.2.5 Overview of Gradient Computation

The definitive relationships of the adjoint-network approach to the computation of the cost function gradient are reviewed here in terms of practical implementation. The name adjoint-network arises because of the network relationship of (25) defining the relationship between the so-called adjoint variables constituting $\hat{\underline{u}}$ and $\hat{\underline{x}}$. Note that the approach is not limited to computation of the gradient of the particular cost function of interest. Other measures of system performance can be handled by simply redefining $\hat{\underline{u}}$, in a similar but different manner to (32).

Since $\hat{\underline{u}}$ is in fact specified according to the partial derivative $\underline{C}_x$, $\hat{\underline{u}}$ can be considered the input to the adjoint network and $\hat{\underline{x}}$ can be considered the response. Thus (25) must be rearranged so as to allow solution of $\hat{\underline{x}}$ given $\hat{\underline{u}}$. For this purpose we obtain from (25)

$$\begin{bmatrix} H_{DD}^T & J_{DD}^T \\ N_{DD}^T & L_{DD}^T \end{bmatrix} \begin{bmatrix} \hat{\underline{p}}_D \\ \hat{\underline{v}}_D \end{bmatrix} = \begin{bmatrix} \hat{\underline{p}}_D \\ \hat{\underline{q}}_D \end{bmatrix} - \begin{bmatrix} H_{ID}^T & J_{ID}^T \\ N_{ID}^T & L_{ID}^T \end{bmatrix} \begin{bmatrix} \hat{\underline{\theta}}_1 \\ \hat{\underline{v}}_1 \end{bmatrix} \quad (37)$$

$$\begin{bmatrix} \hat{\underline{p}}_1 \\ \hat{\underline{q}}_1 \end{bmatrix} = \begin{bmatrix} H_{11} & J_{11} \\ N_{11} & L_{11} \end{bmatrix} \begin{bmatrix} \hat{\underline{\theta}}_1 \\ \hat{\underline{v}}_1 \end{bmatrix} + \begin{bmatrix} H_{D1}^T & J_{D1}^T \\ N_{D1}^T & L_{D1}^T \end{bmatrix} \begin{bmatrix} \hat{\underline{\theta}}_D \\ \hat{\underline{v}}_D \end{bmatrix}$$

Alternatively, if we subdivide $\underline{u}$ and $\underline{x}$ in such a way as to define from (27) and (28) respectively

$$\underline{u}^T = [\underline{u}_1^T, \underline{u}_2^T] \quad ; \quad \underline{x}^T = [\underline{x}_1^T, \underline{x}_2^T]$$

where

$$\underline{u}_1^T = [\hat{\underline{\theta}}_1, \hat{\underline{v}}_1] \quad ; \quad \underline{u}_2^T = -[\hat{\underline{p}}_D^T, \hat{\underline{q}}_D^T] \quad (38)$$

$$\hat{\underline{x}}_1^T = [\hat{P}_1, \hat{Q}_1] \quad ; \quad \hat{\underline{x}}_2^T = -[\hat{\theta}_D^T, \hat{V}_D^T] \quad (39)$$

(37) takes the form

$$\begin{aligned} M_{\underline{x}} \hat{\underline{x}}_2 &= \hat{\underline{u}}_2 + M_{\underline{u}} \hat{\underline{u}}_1 \\ \hat{\underline{x}}_1 &= M_{\underline{u}} \hat{\underline{u}}_1 - M_{\underline{x}} \hat{\underline{x}}_2 \end{aligned} \quad (40)$$

with the M-matrices retaining the identity of corresponding matrices in (37).

The overall process to evaluate the gradient of the cost function at some point $\underline{x}^0, \underline{u}^0, \phi^0$ can now be described as follows:

1. Given $\underline{u}^0, \phi^0$ solve the ac load-flow problem to obtain $\underline{x}^0$
2. Compute the partial derivatives of the cost function, i.e., $\underline{C}_x, \underline{C}_u$ and $\underline{C}_\phi$, at $\underline{x}^0, \underline{u}^0, \phi^0$
3. Set $\hat{\underline{u}} = \underline{C}_x$ and solve (40) for $\hat{\underline{x}}$
4. Compute $\hat{\phi}$
5. Compute $\underline{\sigma}_u$ and $\underline{\sigma}_\phi$ in accordance with (36).

In following the above steps it should be clear that suitable expressions for $\underline{C}_x, \underline{C}_u$ and $\underline{C}_\phi$ are required and, of course, appropriate expressions for $\hat{\phi}$ elements which are functions of both adjoint variables and network variables. The next task, therefore, is to establish the necessary formulas for evaluation.

C.2.6 Partial Derivative Formulas

Implementing a gradient-directed search for minimum cost requires the gradient of the cost function. In particular, using the approach described in previous sections, it is necessary to evaluate the partial derivatives $\underline{C}_x, \underline{C}_u, \underline{C}_\phi$ and $\hat{\phi}$. For this purpose, therefore, formulas are developed in accordance with the following.

At the outset note that the cost function as summarized in Table C.4 is in essence a function of the variables V_p , V_s , R_T and W_s as well as N_L , N_T , N_S , N_p , P_l and C_k . The variables of the latter group are elements of $\underline{x}$ and $\underline{\phi}$ directly whereas the variables of the former group are not. This means that relationships between V_p , V_s , R_T and W_s and the actual solution variables must be established.

As for V_p , the nominal primary voltage, we may consider for example that $V_l = k_p V_p$ where k_p is a constant (say 1.05) since V_l is the voltage magnitude at node 1, the slack bus of Figure C.20, and as such can be used as a reference for voltages at all other nodes. Furthermore, since $V_p = a^2 V_s$ where V_s is the nominal secondary voltage, we have $V_l = k_p a^2 V_s$ as a basis for rewriting the expressions for those component cost functions dependent on V_s also.

In the case of W_s , the gauge or wire size of a particular conductor, we may write $W_s = \frac{w_c}{R_c}$ where w_c is a constant and R_c is the resistance of the corresponding conductor, i.e., the smaller the resistance, the larger the wire size because of the larger cross-sectional area. Of course resistance as the real part of impedance means that the cost function components dependent upon W_s can now be written as functions of z_d , z_s , z_p or z_m , as required.

In the case of transformer rating, R_T , it is suggested that the sum of the diversified demands fed from the transformer is taken. Thus, if each transformer is considered in terms of Figure C.15, we may write

$$R_T = (N_p - \frac{3}{2}) |S| + 2 |S_{pk}|$$

Alternatively, replacing S_{pk} by $\frac{S}{4}$, the recommended relationship for R_T becomes

$$R_T = k_T (N_p - 1) |S|$$

where k_T is introduced as an arbitrary constant to allow for some appropriate margin in accordance with designer preference.

Giving due consideration to the above remarks, it is not a straightforward matter to establish the partial derivatives of the component costs of Table C.4. The results are provided in Tables C.5 through C.7. Problem formulation, however, is not yet complete. For one thing it is noted that the complex power demand expressions of Table C.1 have not been recognized. This is a consequence of having allowed the injected powers at nodes 2 through 8 to be independent variables. To address this problem consider the following:

$$\underline{u}^T = [\underline{u}_1^T, \underline{u}_2^T] ; \quad \underline{\phi}^T = [\underline{\phi}_1^T, \underline{\phi}_2^T] \quad (41)$$

where

$$\underline{u}_1^T = [\theta_1, v_1] ; \quad \underline{u}_2^T = [\underline{P}_D^T, \underline{Q}_D^T] ; \quad \underline{\phi}_1^T = [N_p, N_T, N_S, N_L]$$

$$\underline{\phi}_2^T = [R_d, X_d, R_s, X_s, R_p, X_p, R_m, X_m, R_t, X_t, a, C_1, C_2, C_3, C_4, C_5]$$

$\underline{P}_D$ and $\underline{Q}_D$ are the arrays of real and reactive powers injected at nodes 2 through 8 and, as such, are the negatives of the real and imaginary components associated with the expressions of Table C.1. Thus, partial derivatives wrt $\underline{\phi}_1$ -elements can be obtained, allowing us to write

$$\Delta \underline{P}_D = P_{D\phi} \Delta \underline{\phi}_1 ; \quad \Delta \underline{Q}_D = Q_{D\phi} \Delta \underline{\phi}_1 \quad (42)$$

The expressions corresponding to the elements of the $P_{D\phi}$ and $Q_{D\phi}$ matrices are given in Table C.8.

TABLE C.5 DERIVATIVES WRT X							
SUBSTATION COMPONENTS							
COMPONENT		C_{ST}	C_{SB}	C_{SF}	C_{SP}	C_{SA}	C_{SM}
C_x	P_1	0	0	0	0	0	0
	Q_1	0	0	0	0	0	0
	θ_2	0	0	0	0	0	0
	V_2	0	0	0	0	0	0
	θ_3	0	0	0	0	0	0
	V_3	0	0	0	0	0	0
	θ_4	0	0	0	0	0	0
	V_4	0	0	0	0	0	0
	θ_5	0	0	0	0	0	0
	V_5	0	0	0	0	0	0
	θ_6	0	0	0	0	0	0
	V_6	0	0	0	0	0	0
	θ_7	0	0	0	0	0	0
	V_7	0	0	0	0	0	0
	θ_8	0	0	0	0	0	0
	V_8	0	0	0	0	0	0

TABLE C.5 DERIVATIVES WRT X (CONTINUED)									
UNDERGROUND CABLE COMPONENTS									
COMPONENT		C_{CC}	C_{DU}	C_{MN}	C_{SM}	C_{MS}	C_{CL}	C_{TL}	C_{PA}
C_x	P_1	0	0	0	0	0	0	0	0
	Q_1	0	0	0	0	0	0	0	0
	θ_2	0	0	0	0	0	0	0	0
	V_2	0	0	0	0	0	0	0	0
	θ_3	0	0	0	0	0	0	0	0
	V_3	0	0	0	0	0	0	0	0
	θ_4	0	0	0	0	0	0	0	0
	V_4	0	0	0	0	0	0	0	0
	θ_5	0	0	0	0	0	0	0	0
	V_5	0	0	0	0	0	0	0	0
	θ_6	0	0	0	0	0	0	0	0
	V_6	0	0	0	0	0	0	0	0
	θ_7	0	0	0	0	0	0	0	0
	V_7	0	0	0	0	0	0	0	0
	θ_8	0	0	0	0	0	0	0	0
	V_8	0	0	0	0	0	0	0	0

TABLE C.5 DERIVATIVES WRT X (CONTINUED)

PRIMARY/SECONDARY SYSTEM COMPONENTS												
COMPONENT		C_{SR}	C_{WG}^{mL}	C_{WG}^{SP}	C_{WG}^{SC}	C_{WG}^{sd}	C_{FC}	C_{DS}	C_{DT}	C_{DC}	C_{CK}	C_{SL}
C_x	P_1	0	0	0	0	0	0	0	0	0	0	0
	Q_1	0	0	0	0	0	0	0	0	0	0	0
	θ_2	0	0	0	0	0	0	0	0	0	0	0
	V_2	0	0	0	0	0	0	0	0	0	0	0
	θ_3	0	0	0	0	0	0	0	0	0	0	0
	V_3	0	0	0	0	0	0	0	0	0	0	0
	θ_4	0	0	0	0	0	0	0	0	0	0	0
	V_4	0	0	0	0	0	0	0	0	0	0	0
	θ_5	0	0	0	0	0	0	0	0	0	0	0
	V_5	0	0	0	0	0	0	0	0	0	0	0
	θ_6	0	0	0	0	0	0	0	0	0	0	0
	V_6	0	0	0	0	0	0	0	0	0	0	0
	θ_7	0	0	0	0	0	0	0	0	0	0	0
	V_7	0	0	0	0	0	0	0	0	0	0	0
	θ_8	0	0	0	0	0	0	0	0	0	0	0
	V_8	0	0	0	0	0	0	0	0	0	0	0

TABLE C.6 DERIVATIVES WRT. U							
SUBSTATION COMPONENTS							
COMPONENT		C_{ST}	C_{SB}	C_{SF}	C_{SP}	C_{SA}	C_{SM}
C_U	θ_1	0	0	0	0	0	0
	V_1	T_2	$B_2 + 2B_3 V_1$	$F_2 + 2F_3 V_1$	$P_2 + 2P_3 V_1$	A_2	M_2
	P_2	0	0	0	0	0	0
	Q_2	0	0	0	0	0	0
	P_3	0	0	0	0	0	0
	Q_3	0	0	0	0	0	0
	P_4	0	0	0	0	0	0
	Q_4	0	0	0	0	0	0
	P_5	0	0	0	0	0	0
	Q_5	0	0	0	0	0	0
	P_6	0	0	0	0	0	0
	Q_6	0	0	0	0	0	0
	P_7	0	0	0	0	0	0
	Q_7	0	0	0	0	0	0
	P_8	0	0	0	0	0	0
	Q_8	0	0	0	0	0	0

NB: $T_2 \rightarrow T_2/k_p$; $B_2 \rightarrow B_2/k_p$; $B_3 \rightarrow B_3/k_p^2$; $F_2 \rightarrow F_2/k_p$; $F_3 \rightarrow F_3/k_p^2$
 $P_2 \rightarrow P_2/k_p$; $P_3 \rightarrow P_3/k_p^2$; $A_2 \rightarrow A_2/k_p$; $M_2 \rightarrow M_2/k_p$

TABLE C.6 DERIVATIVES WRT U (CONTINUED)												
PRIMARY/SECONDARY SYSTEM COMPONENTS												
COMPONENT		C_{SR}	C_{ME}^{ME}	C_{MG}^{SD}	C_{MG}^{SC}	C_{MG}^{SD}	C_{FC}	C_{DS}	C_{DT}	C_{DC}	C_{CK}	C_{SL}
C_U	θ_1	0	0	0	0	0	0	0	0	0	0	0
	V_1	R_2	0	0	0	0	$F_2' + 2F_3'V_1$	$F_2'' + 2F_3''V_1$	0	0	$K_2 + 2K_3V_1$	0
	P_2	0	0	0	0	0	0	0	0	0	0	$N_1 + N_2$
	Q_2	0	0	0	0	0	0	0	0	0	0	0
	P_3	0	0	0	0	0	0	0	0	0	0	$N_1 + N_2$
	Q_3	0	0	0	0	0	0	0	0	0	0	0
	P_4	0	0	0	0	0	0	0	0	0	0	$N_1 + N_2$
	Q_4	0	0	0	0	0	0	0	0	0	0	0
	P_5	0	0	0	0	0	0	0	0	0	0	$N_1 + N_2$
	Q_5	0	0	0	0	0	0	0	0	0	0	0
	P_6	0	0	0	0	0	0	0	0	0	0	$N_1 + N_2$
	Q_6	0	0	0	0	0	0	0	0	0	0	0
	P_7	0	0	0	0	0	0	0	0	0	0	$N_1 + N_2$
	Q_7	0	0	0	0	0	0	0	0	0	0	0
	P_8	0	0	0	0	0	0	0	0	0	0	$N_1 + N_2$
	Q_8	0	0	0	0	0	0	0	0	0	0	0
MULTIPLIER		$N_L(2N_S+1) \times$ $(4N_T+L_S+L_B)$					$12N_LN_S$	$3(2N_S+1) \times$ $(2N_T-1)+9N_L$			5	

NB: $R_2 = R_2/k_p$; $F_2' = F_2'/k_p$; $F_3' = F_3'/k_p^2$; $F_2'' = F_2''/k_p$

$F_3'' = F_3''/k_p^2$; $K_2 = K_2/k_p$; $K_3 = K_3/k_p^2$

TABLE C.6 DERIVATIVES WRT U (CONTINUED)

UNDERGROUND CABLE COMPONENTS									
COMPONENT		C_{CC}	C_{DU}	C_{MH}	C_{SW}	C_{MS}	C_{CL}	C_{TL}	C_{PA}
C_U	θ_1	0	0	0		0	0	0	0
	V_1	$C_2 + 2C_3 V_1$	$U_2 + 2U_3 V_1$	$4(H_2 + 2H_3 V_1)$	$W_2 / 2V_1^{1/2}$	$S_2 + 2S_3 V_1$	0	$L_2 + 2L_3 V_1$	$3(A_2' + 2A_3' V_1)$
	P_2	0	0	0	0	0	0	0	0
	Q_2	0	0	0	0	0	0	0	0
	P_3	0	0	0	0	0	0	0	0
	Q_3	0	0	0	0	0	0	0	0
	P_4	0	0	0	0	0	0	0	0
	Q_4	0	0	0	0	0	0	0	0
	P_5	0	0	0	0	0	0	0	0
	Q_5	0	0	0	0	0	0	0	0
	P_6	0	0	0	0	0	0	0	0
	Q_6	0	0	0	0	0	0	0	0
	P_7	0	0	0	0	0	0	0	0
	Q_7	0	0	0	0	0	0	0	0
	P_8	0	0	0	0	0	0	0	0
	Q_8	0	0	0	0	0	0	0	0

NB: $C_2 \rightarrow C_2/k_p$; $C_3 \rightarrow C_3/k_p^2$; $U_2 \rightarrow U_2/k_p$; $U_3 \rightarrow U_3/k_p^2$; $H_2 \rightarrow H_2/k_p$; $H_3 \rightarrow H_3/k_p^2$

$W_2 \rightarrow W_2/k_p^{1/2}$; $S_2 \rightarrow S_2/k_p$; $S_3 \rightarrow S_3/k_p^2$; $L_2 \rightarrow L_2/k_p$; $L_3 \rightarrow L_3/k_p^2$; $A_2' \rightarrow A_2'/k_p$; $A_3' \rightarrow A_3'/k_p^2$

TABLE C.7 DERIVATIVES WRT θ							
SUBSTATION COMPONENTS							
COMPONENT		C_{ST}	C_{SB}	C_{SF}	C_{SP}	C_{SA}	C_{SM}
C_{θ}	N_p	0	0	0	0	0	0
	N_T	0	0	0	0	0	0
	N_S	0	0	0	0	0	0
	N_L	0	0	0	0	0	0
	R_d	0	0	0	0	0	0
	X_d	0	0	0	0	0	0
	R_S	0	0	0	0	0	0
	X_S	0	0	0	0	0	0
	R_p	0	0	0	0	0	0
	X_p	0	0	0	0	0	0
	R_m	0	0	0	0	0	0
	X_m	0	0	0	0	0	0
	R_t	0	0	0	0	0	0
	X_t	0	0	0	0	0	0
	a	0	0	0	0	0	0
	C_1	0	0	0	0	0	0
	C_2	0	0	0	0	0	0
	C_3	0	0	0	0	0	0
	C_4	0	0	0	0	0	0
	C_5	0	0	0	0	0	0

TABLE C.7 DERIVATIVES WRT θ (CONTINUED)

PRIMARY/SECONDARY SYSTEM COMPONENTS											
COMPONENT	C_{SR}	C_{MG}^{M1}	C_{MG}^{SP}	C_{MG}^{SC}	C_{MG}^{SD}	C_{FC}	C_{DS}	C_{DT}	C_{DC}	C_{CK}	C_{SL}^*
N_D (1)	$(2N_S+1)2N_L N_L^t$	$2N_L N_L^t$	$4N_L N_S N_L^t$	$(2N_S+1)2N_L N_L^t$	0	0	0			0	$(2N_S+1)2N_L N_L^t P$
N_T (1)	$(2N_S+1)4N_L^t$	$4N_L^t$	$8N_L N_S^t$	$(2N_S+1)4N_L^t$	$(2N_S+1)3N_L^t SD$	0	0			0	$(2N_S+1)2N_L^t \bar{P}$
N_S (1)	$2N_L(4N_T^t + t_a)$	$2N_L^t a$	$8N_L N_T^t$	$8N_L N_T^t$	$8N_L N_T^t SD$	$12N_L$	$6(2N_L-1)$			0	$4N_L N_L^t \bar{P}$
N_L (1)	$(2N_S+1)(4N_T^t + t_a)$	$4N_T^t + (2N_S+1)t_a$	$8N_S N_T^t$	$(2N_S+1)4N_T^t$	$(2N_S+1)4N_T^t SD$	$12N_S$	$6(2N_S+1)+9$			0	$(2N_S+1)2N_L^t \bar{P}$
N_D (2)	0	0	0	0	$-G_2' M_D / R_D^2$	0	0			0	0
I_D	0	0	0	0	0	0	0			0	0
N_S (2)	0	0	$-G_2' M_S / R_S^2$	0	0	0	0			0	0
I_S	0	0	0	0	0	0	0			0	0
N_D (2)	0	0	$-G_2' M_D / R_D^2$	0	0	0	0			0	0
I_D	0	0	0	0	0	0	0			0	0
N_M (2)	0	$-G_2' M_M / R_M^2$	0	0	0	0	0			0	0
I_M	0	0	0	0	0	0	0			0	0
N_L	0	0	0	0	0	0	0			0	0
I_L	0	0	0	0	0	0	0			0	0
a	0	0	0	0	0	0	0			0	0
C_1	0	0	0	0	0	0	0			$K_4 + 2N_S C_1$	0
C_2	0	0	0	0	0	0	0			$K_4 + 2N_S C_2$	0
C_3	0	0	0	0	0	0	0			$K_4 + 2N_S C_3$	0
C_4	0	0	0	0	0	0	0			$K_4 + 2N_S C_4$	0
C_5	0	0	0	0	0	0	0			$K_4 + 2N_S C_5$	0
MULTIPLIERS (1)	$N_1 - N_2 V_p$	$G_1 + G_2 M_M$	$G_1 + G_2 M_D$	$G_1 + G_2 M_S$	$G_1 + G_2 M_D$	$F_1' + F_2' V_p + F_3' V_p^2$	$F_1' + F_2' V_p + F_3' V_p^2$				$-(N_1 + N_2)$
(2)		$4N_L N_T^t + N_L (2N_S+1)t_a$	$8N_L N_S N_T^t$	$4N_L (2N_S+1)N_T^t$	$4N_L (2N_S+1)N_T^t SD$						

* $\bar{P} = (N_p - 2/2)P + 2P_{pk}$; $P = \text{re}(S)$; $P_{pk} = \text{re}(S_{pk})$

TABLE C.7 DERIVATIVES WRT θ (CONTINUED)

UNDERGROUND CABLE COMPONENTS									
COMPONENT		C_{CC}	C_{DU}	C_{MH}	C_{SW}	C_{MS}	C_{CL}	C_{TL}	C_{PA}
$1C_{\theta}$	N_p	0	0	0	0	0	0	0	0
	N_T	0	0	0	0	0	0	0	0
	N_S	0	0	0	0	0	0	0	0
	N_L	0	0	0	0	0	0	0	0
	R_d	0	0	0	0	0	0	0	0
	X_d	0	0	0	0	0	0	0	0
	R_S	0	0	0	0	0	0	0	0
	X_S	0	0	0	0	0	0	0	0
	R_p	0	0	0	0	0	0	0	0
	X_p	0	0	0	0	0	0	0	0
	R_m	0	0	0	0	0	0	0	0
	X_m	0	0	0	0	0	0	0	0
	R_t	0	0	0	0	0	0	0	0
	X_t	0	0	0	0	0	0	0	0
	a	0	0	0	0	0	0	0	0
	C_1	0	0	0	0	0	0	0	0
	C_2	0	0	0	0	0	0	0	0
	C_3	0	0	0	0	0	0	0	0
	C_4	0	0	0	0	0	0	0	0
	C_5	0	0	0	0	0	0	0	0

TABLE C.8 PARTIAL DERIVATIVE MATRICES $P_{D\theta}$ AND $Q_{D\theta}$				
NODE INJECTIONS	DERIVATIVES WITH RESPECT TO			
	N_p	N_T	N_S	N_L
P_2	$-N_T[2N_S(N_L-1)+(N_L-5)]P$	$-(N_p-1)[2N_S(N_L-1)+(N_L-5)]P$	$-(N_p-1)N_T2(N_L-1)P$	$-(N_p-1)N_T(2N_S+1)P$
P_3	$-4N_T(N_S-1)P$	$-4(N_p-1)(N_S-1)P$	$-4(N_p-1)N_TP$	0
P_4	$-4N_TP$	$-4(N_p-1)P$	0	0
P_5	$-4N_p(N_T-2)P$	$-4(N_p-1)P$	0	0
P_6	$-4P$	0	0	0
P_7	$-4P$	0	0	0
P_8	0	0	0	0
Q_2	$-N_T[2N_S(N_L-1)+(N_L-5)]Q$	$-(N_p-1)[2N_S(N_L-1)+(N_L-5)]Q$	$-(N_p-1)N_T2(N_L-1)Q$	$-(N_p-1)N_T(2N_S+1)Q$
Q_3	$-4N_T(N_S-1)Q$	$-4(N_p-1)(N_S-1)Q$	$-4(N_p-1)N_TQ$	0
Q_4	$-4N_TQ$	$-4(N_p-1)Q$	0	0
Q_5	$-4N_p(N_T-2)Q$	$-4(N_p-1)Q$	0	0
Q_6	$-4Q$	0	0	0
Q_7	$-4Q$	0	0	0
Q_8	0	0	0	0
$P = \text{re}(S); Q = \text{im}(S)$				

Let us also consider equation (35) and write it in the form

$$\begin{aligned} \Delta C(\underline{x}, \underline{u}, \underline{\phi}) = & (\hat{\underline{x}}_1 + \underline{C}_{u1})^T \Delta \underline{u}_1 + (\hat{\underline{x}}_2 + \underline{C}_{u2})^T \Delta \underline{u}_2 + (\hat{\underline{\phi}}_1 + \underline{C}_{\phi 1})^T \Delta \underline{\phi}_1 \\ & + (\hat{\underline{\phi}}_2 + \underline{C}_{\phi 2})^T \Delta \underline{\phi}_2 \end{aligned} \quad (43)$$

From (42), however, we have

$$\Delta \underline{u}_2^T = [\Delta \underline{\phi}_1^T, P_{D\phi}^T, \Delta \underline{\phi}_1^T, Q_{D\phi}^T] \quad (44)$$

which in (43), letting

$$\underline{C}_{u2}^T = [\underline{C}_{up}^T, \underline{C}_{uq}^T] \quad (45)$$

and using (39), yields

$$\begin{aligned} \Delta C(\underline{x}, \underline{u}, \underline{\phi}) = & (\hat{\underline{x}}_1 + \underline{C}_{u1})^T \Delta \underline{u}_1 + [(\underline{C}_{up} - \hat{\theta}_{-D})^T P_{D\phi} + (\underline{C}_{uq} - \hat{y}_D)^T Q_{D\phi} \\ & + (\hat{\underline{\phi}}_1 + \underline{C}_{\phi 1})^T] \Delta \underline{\phi}_1 + (\hat{\underline{\phi}}_2 + \underline{C}_{\phi 2})^T \Delta \underline{\phi}_2 \end{aligned} \quad (46)$$

Note also that, from Table C.6, $\underline{C}_{uq}$ is a null array and may therefore be deleted from (46).

The outcome of the above development is that the gradient of the cost function is now available in terms of the essential variables contained in $\underline{u}_1$ and $\underline{\phi}$. So that these are the variables to be controlled during a search for minimum cost, recognizing that changes in $\underline{\phi}_1$ -elements will in turn affect changes in $\underline{P}_D$ and $\underline{Q}_D$. It is also pointed out that (42) could be modified to reflect the possibility of investigating the sensitivity of the cost function to changes in customer load demands, i.e., changes in S and S_{pk} . Such facilities, however, will not be pursued further in this report. In addition, note that the demand expression associated with

node 1 of Figure C.20 (see Table C.1) need not be considered in the same way as those associated with nodes 2 through 8 because node 1 is the slack bus.

To be able to complete the gradient computation in accordance with (46), it yet remains to develop the formulas for enumerating the elements of $\hat{\phi}$. As a starting point, we have equation (34), viz.

$$\hat{\phi}^T \Delta \phi = \sum_{k=1}^n \sum_{m=1}^n (\sigma_{km}^G \Delta G_{km} + \sigma_{km}^B \Delta B_{km}) \quad (47)$$

where σ_{km}^G and σ_{km}^B are sensitivities with respect to the conductance and susceptance elements respectively of the system admittance matrix. These sensitivities, it is recalled, are functions of the adjoint variables $\hat{\theta}$ and $\hat{V}$; see equation (30). In using (47) the problem now is to express ΔG_{km} and ΔB_{km} in terms of $\Delta \phi$.

With this in mind, let us first define g_{km} and b_{km} as the components of branch admittance between any two nodes k and m of the distribution system. In particular, the system admittance matrix for the reduced system of Figure C.20 can be written in these terms as illustrated in Table C.9. Also in Table C.9, note that shunt susceptances such as b_k (applied at nodes 1 through 5) corresponding to capacitor banks are included.

Consideration of the admittance matrix structure readily indicates that, in general, we may write

$$\begin{aligned} \Delta G_{km} &= -\Delta g_{km} ; \quad \Delta B_{km} = -\Delta b_{km} \\ \Delta G_{kk} &= \sum_{n_{bk}} \Delta g_{km} ; \quad \Delta B_{kk} = \sum_{n_{bk}} \Delta b_{km} + \Delta b_k \end{aligned} \quad (48)$$

where $\sum_{n_{bk}}$ is used to denote summation over all branches connected to node k .

Hence, using (48) in (47), it is readily shown that

TABLE C.9 SYSTEM ADMITTANCE MATRIX							
$g_{12} + j(b_{12} \cdot b_1)$	$-g_{12} - jb_{12}$	0	0	0	0	0	0
$-g_{12} - jb_{12}$	$(g_{12} + g_{23}) + j(b_{12} \cdot b_{23} \cdot b_2)$	$-g_{23} - jb_{23}$	0	0	0	0	0
0	$-g_{23} - jb_{23}$	$(g_{23} + g_{34}) + j(b_{23} \cdot b_{34} \cdot b_3)$	$-g_{34} - jb_{34}$	0	0	0	0
0	0	$-g_{34} - jb_{34}$	$(g_{34} + g_{45}) + j(b_{34} \cdot b_{45} \cdot b_4)$	$-g_{45} - jb_{45}$	0	0	0
0	0	0	$-g_{45} - jb_{45}$	$(g_{45} + g_{56}) + j(b_{45} \cdot b_{56} \cdot b_5)$	$-g_{56} - jb_{56}$	0	0
0	0	0	0	$-g_{56} - jb_{56}$	$(g_{56} + g_{67}) + j(b_{56} \cdot b_{67} \cdot b_6)$	$-g_{67} - jb_{67}$	0
0	0	0	0	0	$-g_{67} - jb_{67}$	$(g_{67} + g_{78}) + j(b_{67} \cdot b_{78} \cdot b_7)$	$-g_{78} - jb_{78}$
0	0	0	0	0	0	$-g_{78} - jb_{78}$	$g_{78} + jb_{78}$

$$\begin{aligned} \hat{\Phi}^T \Delta \Phi = & \sum_{k=1}^{n_b} (\sigma_{kk}^G + \sigma_{mm}^G - \sigma_{km}^G - \sigma_{mk}^G) \Delta g_{km} \\ & + \sum_{k=1}^{n_b} (\sigma_{kk}^B + \sigma_{mm}^B - \sigma_{km}^B - \sigma_{mk}^B) \Delta b_{km} + \sum_{k=1}^n \sigma_{kk}^B \Delta b_k \end{aligned} \quad (49)$$

where n_b represents the total number of branches. Alternatively, if we let

$$\begin{aligned} g_\ell &= g_{km} \quad ; \quad b_\ell = b_{km} \quad ; \quad \sigma_k^C = \sigma_{kk}^B \\ \sigma_\ell^G &= \sigma_{kk}^G + \sigma_{mm}^G - \sigma_{km}^G - \sigma_{mk}^G \\ \sigma_\ell^B &= \sigma_{kk}^B + \sigma_{mm}^B - \sigma_{km}^B - \sigma_{mk}^B \end{aligned} \quad (50)$$

where ℓ runs from 1 through 7, (49) becomes

$$\hat{\Phi}^T \Delta \Phi = \sum_{\ell=1}^{n_b} (\sigma_\ell^G \Delta g_\ell + \sigma_\ell^B \Delta b_\ell) + \sum_{k=1}^n \sigma_k^C \Delta b_k \quad (51)$$

As a matter of convenience, derived formulas for σ_ℓ^G , σ_ℓ^B and σ_k^C are presented in Table C.10, as based on (30) and (50).

Thus far the $\Delta \Phi$ elements of (51) are related to branch and shunt admittance components. Referring to Table C.2, however, the controllable elements comprising Φ are grouped in complex impedance form. In effect, if R_ℓ and X_ℓ are used to represent the real and imaginary impedance components corresponding to any branch of Figure C.20, we may write

$$g_\ell = \frac{R_\ell}{(R_\ell^2 + X_\ell^2)} \quad ; \quad b_\ell = \frac{-X_\ell}{(R_\ell^2 + X_\ell^2)}$$

which in turn yield

$$\begin{aligned} \Delta g_\ell &= g_\ell^R \Delta R_\ell + g_\ell^X \Delta X_\ell \\ \Delta b_\ell &= b_\ell^R \Delta R_\ell + b_\ell^X \Delta X_\ell \end{aligned} \quad (52)$$

TABLE C.10 SENSITIVITY FACTORS	
SENSITIVITY FACTOR	FORMULA
σ_l^G	$v_k^2 \hat{\theta}_k + v_m^2 \hat{\theta}_m - v_k v_m [\cos \theta_{km} (\hat{\theta}_k + \hat{\theta}_m) + \sin \theta_{km} (\hat{v}_k - \hat{v}_m)]$
σ_l^B	$v_k^2 \hat{v}_k + v_m^2 \hat{v}_m - v_k v_m [\sin \theta_{km} (\hat{\theta}_k - \hat{\theta}_m) + \cos \theta_{km} (\hat{v}_k + \hat{v}_m)]$
σ_l^C	$v_k^2 \hat{v}_k$

where the partial derivatives are given by

$$\begin{aligned} g_{\ell}^R &= b_{\ell}^X = \frac{(X_{\ell}^2 - R_{\ell}^2)}{(R_{\ell}^2 + X_{\ell}^2)} \\ g_{\ell}^X &= -b_{\ell}^R = \frac{2X_{\ell} R_{\ell}}{(R_{\ell}^2 + X_{\ell}^2)} \end{aligned} \quad (53)$$

Using (52), (51) now becomes

$$\begin{aligned} \hat{\Phi}^T \Delta \Phi &= \sum_{i=1}^{n_b} [(\sigma_{\ell}^G g_{\ell}^R + \sigma_{\ell}^B b_{\ell}^R) \Delta R_{\ell} + (\sigma_{\ell}^G g_{\ell}^X + \sigma_{\ell}^B b_{\ell}^X) \Delta X_{\ell}] \\ &+ \sum_{k=1}^n \sigma_k^C \Delta b_k \end{aligned} \quad (54)$$

Finally, since $b_k = \omega C_k$ where ω is the electrical frequency in radians per second and C_k is the capacitance at node k , and also since R_{ℓ} and X_{ℓ} are related to ϕ -elements in accordance with Table C.2, we can obtain the expressions for ϕ -elements. the results are presented in Table C.11, where

$$\begin{aligned} \sigma_{\ell}^R &= (\sigma_{\ell}^G g_{\ell}^R + \sigma_{\ell}^B b_{\ell}^R) \\ \sigma_{\ell}^X &= (\sigma_{\ell}^G g_{\ell}^X + \sigma_{\ell}^B b_{\ell}^X) \end{aligned} \quad (55)$$

for $\ell = 1, 2, \dots, 7$.

C.2.7 Solution Constraints

In a practical design study it is usual for certain limiting constraints to be superimposed such that the solution finally decided upon is not in fact the global, say, minimum cost. In other words the minimum cost is not always achievable because of practical limitations dependent upon the nature of the particular problem in hand. For example, constraints may be imposed directly on the control variables, restricting their ranges of variation to within practical limits. Implicit

TABLE C.11 FORMULAS FOR $\hat{\theta}$

$\hat{\theta}$	FORMULAS
N_p	$[\sigma_1^R R_m + \sigma_1^X X_m] N_T (N_L - 1) / 16 + (c_3^R R_p + \sigma_3^X X_p) / 2 + (\sigma_4^R R_p + \sigma_4^X X_p) (N_T - 1) / 4 + (c_6^R R_S + \sigma_6^X X_S) a^2 / 32] i_{ss} / 32$
N_T	$[(c_1^R R_m + \sigma_1^X X_m) (N_p - 1) (N_L - 1) / 4 + (c_4^R R_p + \sigma_4^X X_p) (N_p - 1)] i_{ss} / 8$
N_S	$(\sigma_2^R R_m + \sigma_2^X X_m) i_a / 4$
N_L	$(c_1^R R_m + \sigma_1^X X_m) (N_p - 1) N_T i_{ss} / 2$
R_d	$\sigma_2^R a^2 i_{sd} / 16$
X_d	$\sigma_7^X a^2 i_{sd} / 16$
R_S	$c_6^R (N_p - 1) a^2 i_{ss} / 32$
X_S	$\sigma_6^X (N_p - 1) a^2 i_{ss} / 32$
R_p	$c_4^R (N_p - 1) (N_T - 1) i_{ss} / 8$
X_p	$\sigma_4^X (N_p - 1) (N_T - 1) i_{ss} / 8$
R_m	$\sigma_1^R (N_p - 1) N_T (N_L - 1) i_{ss} / 2 + \sigma_2^R N_S i_a / 4$
X_m	$\sigma_1^X (N_p - 1) N_T (N_L - 1) i_{ss} / 2 + \sigma_2^X N_S i_a / 4$
R_t	$c_5^R / 6$
X_t	$\sigma_5^X / 8$
a	$(c_6^R R_S + \sigma_6^X X_S) (N_p - 1) a i_{ss} / 16 + (c_7^R R_d + \sigma_7^X X_d) a i_{sd} / 8$
C_1	ω_1^C
C_2	ω_2^C
C_3	ω_3^C
C_4	ω_4^C
C_5	ω_5^C

as well as explicit constraints may also be involved in that the dependent variables or indeed functions of the dependent variables may have to be constrained. Moreover, equality as well as inequality constraints may arise.

In the event that limitations are imposed directly on the control variables, it is only necessary to restrict the range of search for a minimum cost function accordingly. Typically this involves a set of inequality constraints. On the other hand, if an equality constraint is involved then the associated control variable is fixed and no perturbation is made. Thus, making reference to (46), the corresponding entry in $\Delta \underline{u}_1$ or $\Delta \phi$ would be zero. The problem is not straightforward, however, in the case of an implicit inequality. In particular, for the distribution system, it is necessary to ensure that customer voltage levels are within acceptable limits. The critical voltages, in this regard, are those corresponding to the customers most distant from the supply in-feed point. With reference to Figure C.20, these are represented by the voltage at node 8. Therefore, in general, we may write

$$0.95V_p < V_8 < 1.05V_p \quad (56)$$

by allowing for a ± 5 percent range of variation. We also have $V_1 = k_p V_p$, so that in terms of solution variables (56) becomes

$$\frac{0.95}{k_p} < \frac{V_8}{V_1} < \frac{1.05}{k_p} \quad (57)$$

The way in which (57) is handled will be dealt with shortly. First of all let us consider the implicit equality constraint represented by the fact that we are going to design a distribution system such that the current supplied from the substation into any one circuit is always 400A. In effect we may write

$$|S_1| = V_1 |I_1| \quad (58)$$

where $|I_1| = 400A$ and it is recalled that node 1 is the slack bus. In terms of real and reactive powers this yields

$$P_1^2 + Q_1^2 = 16 \times 10^4 V_1^2 \quad (59)$$

Alternatively, considering first order perturbations,

$$2P_1 \Delta P_1 + 2Q_1 \Delta Q_1 = 32 \times 10^4 V_1 \Delta V_1 \quad (60)$$

which means that the equality constraint may be deemed satisfied if we recognize the relationship between associated dependent and independent variables in accordance with (60). Specifically, (60) may be introduced in (26), rewriting $\frac{\Delta V_1}{V_1}$ in terms of ΔP_1 and ΔQ_1 . The result is such that we can redefine certain adjoint variables as follows:

$$\begin{aligned} \hat{\theta}_{1(\text{new})} &= \hat{\theta}_{1(\text{old})} - \hat{Q}_{1(\text{old})} \left(\frac{P_1}{16V_1^2} \right) 10^{-4} \\ \hat{V}_{1(\text{new})} &= \hat{V}_{1(\text{old})} - \hat{Q}_{1(\text{old})} \left(\frac{Q_1}{16V_1^2} \right) 10^{-4} \\ \hat{Q}_{1(\text{new})} &= 0 \end{aligned} \quad (61)$$

In effect, following each solution of the adjoint network, the relationships of (61) are applied.

Returning to the inequality constraint on voltage, i.e., equation (57), it is suggested that a penalty function approach be adopted whereby the cost function is modified in accordance with the additional term

$$PV = wr \frac{\left[(V_8/V_1 - \bar{k})/k_{ul} \right]^{2n}}{2n} \quad (62)$$

where

$$\bar{k} = \frac{k_u + k_l}{2} \quad ; \quad k_{ul} = k_u - k_l$$

$$k_u = \frac{1.05}{k_p} \quad ; \quad k_l = \frac{0.95}{k_p}$$

In effect, the more the voltage ratio $\frac{V_8}{V_1}$ differs from the mean ratio $\bar{k}$, the more the cost function is penalized. Therefore the tendency on this term alone is to bias a solution towards the mean. The degree of bias depends not only on n (which is typically set at 1) but also on the procedure of dividing by k_{ul} . The latter tends to offset the bias somewhat, depending on the maximum allowable variation in any particular case. Note that the factor 2 in the exponent ensures a positive cost as the voltage ratio moves in either direction from the mean. The weighting factor w is introduced because it is necessary to weight the penalty for any voltage violation against the other cost components. The degree of weighting is largely arbitrary and open to adjustment according to requirements during implementation. During the solution process to establish minimum cost, including the penalty term PV , the degree of weighting can be conveniently adjusted via the factor r . Thus r may be decreased in stages, with the voltage being forced to stay within limits during each search for a minimum at a particular r . This procedure tends to alleviate the effects of the undue bias on the mean, i.e., as long as the voltage ratio is not in violation of set limits, strictly speaking, no additional cost should be encountered. The need for a continuous penalty function term which can be differentiated does not permit this, however, and so the effect is offset as r decreases.

The penalty function term does not have to take the form suggested by (62), and so it is noted that other forms may prove more amenable to the solution process. Unfortunately it is not possible to predict the convergence characteristics yet to be encountered during actual numerical processing. Moreover, it is pointed out that the penalty function introduced is of exterior type. A quite different form could be used of interior type, but no consideration will be given to this type at present.

In general, any component of cost including the penalty function component must be considered in terms of its possible contributions to elements of $\underline{C}_x$, $\underline{C}_u$, $\underline{C}_\phi$ and ϕ . Taking the exterior penalty function of (62) then

$$PV = \frac{wr}{k_{ul}^{2n}} \left(\frac{V_8}{V_1} - \bar{k} \right)^{2n-1} \left[\left(\frac{1}{V_1} \right) \Delta V_8 - \left(\frac{V_8}{V_1^2} \right) \Delta V_1 \right] \quad (63)$$

This means that the only additional components to the partial derivative terms required are such that

$$C_x(8) = \frac{wr}{k_{ul}^{2n}} \frac{\left(\frac{V_8}{V_1} - \bar{k} \right)^{2n-1}}{V_1} + C_x(8) \quad (64)$$

$$C_u(2) = \frac{wr}{k_{ul}^{2n}} \frac{\left(\frac{V_8}{V_1} - \bar{k} \right)^{2n-1}}{V_1^2} + C_u(2) \quad (65)$$

Summary

The fundamental concepts of an automated procedure have been developed addressing the economic and energy efficient design of a distribution service area, including the determination of preferred voltage levels.

In effect the design problem is broken down into two phases. Phase I, the subject of this report, considers the evolving system in terms of an "equivalent" fixed-node system which is optimized so as to achieve minimum cost. Allowance is made for system losses, voltage drops and the conductor sizing problem. Moreover, for a given load demand, the area served is limited by fixing the service in-feed current in accordance with a circuit-breaker rating of 1,200A, corresponding to a unit substation feeding three similar circuits.

Primary interests have focused on the derivation of the "equivalent" fixed-node system, the nature of the cost function and the method by which its gradient in terms of the control variables can be computed via the adjoint-network approach. Pertinent formulas for implementing the gradient computation are provided except that the expressions for the derivations with respect to voltage magnitude have yet to be multiplied by the corresponding voltage magnitude, e.g., V_k . This reflects the form taken by the Jacobian matrix, written in terms of $\frac{\Delta V_k}{V_k}$ rather than ΔV_k .

No description is provided on how the gradient of the cost function is used during optimization because the method of steepest descent is well documented in the literature. For example, searching in the negative direction of the cost function gradient as computed by the algorithm presented herein, a single-variable search applying a Golden Section or Fibonacci algorithm is recommended, due consideration being given to any restrictions on the ranges of variation of the control variables. On the other hand the report has indicated how the inequality constraints imposed by voltage limits can be handled in terms of an exterior penalty function. Overall the procedure involves iteration to the minimum and, therefore, it is essential to reduce computational requirements as much as possible. In this regard the developed algorithm, based on adjoint variables, should prove

attractive. The only additional, major computational effort per iteration involves a direct solution of the adjoint network following each load-flow solution, noting that information already required in the Newton-Raphson load-flow method can be utilized to great advantage.

Because the "equivalent" fixed-node system used in Phase I is only an approximate representation, it is expected that the system design so obtained will be in need of further refinement, especially in regard to minimizing the cost of system losses and the cost associated with the conductor sizing problem. On the other hand Phase I should at least define the generic system configuration and provide an approximate solution to the conductor sizing problem, as well as establish the approximate levels of primary and secondary voltages to be used. From this starting point Phase II will proceed by using the system generated from Phase I in its exact form, i.e., every node will be identified and not reflected in some reduced "equivalent" system. The method of design will again be based on the adjoint approach to the cost-function gradient computation. The only real difference will be an increase in the number of nodes, but with an attendant reduction in the number of variables to be considered. At this stage an efficient evaluation of the adjoint network will be even more significant, though to some extent it is expected that this will be offset by the need for fewer iterations during the minimization process.

Finally it is pointed out that further consideration has yet to be given to the manner in which conductor reactances will be taken into account and also how the resistances and reactances of distribution transformers are to be incorporated. Conceivably the resistance and reactance of a distribution transformer could be linked to the rating of the transformer; e.g., fixed per unit reactance and resistance values could be assumed in accordance with typical values for existing

transformers, so that a fixed relationship between corresponding reactance and resistance could be used to further reduce the number of control variables. In the case of conductor reactance, it is conceivable that they could be fixed according to typical spacings for primary and secondary circuits. Strictly speaking, however, if spacings are fixed while conductor sizes are changing, reactances must also change. In addition, if conductor reactances are to be allowed to vary, then corresponding minimum allowable reactances must be established. In other words, what would prevent the reactances from going to zero, a nonphysical situation? In the other direction reactances are limited by voltage drop considerations.

APPENDIX D

Electric Distribution/Utilization System Cost
Analysis Model (EDUSCAM)
Program Listing

```

LOGICAL  ERROR, FEASBL
INTEGER  IPOINT(20)

C
REAL*8 FX, GX, PTURB(20), X(20), XMIN(20), XMAX(20), XSAVE(20),
1      VNAME

C
REAL*8 CNAME(20) / 'CSFEED  ', 'CSMAIN  ', 'CSPRIM  ', 'CSSEC  ',
1      'CSSERV  ', 'HSLOAD  ', 'VOLTHI  ', 'VOLTLO  ',
2      'VP      ', 'VS      ', 'WSLAT  ', 'WSPRIM  ',
3      'WSSEC  ', 'WSSERV  ', '      ', '      ',
4      '      ', '      ', '      ', '      ', '      ', '      '

C
COMMON / CUSPKS / CSPKSV(50)

C
COMMON / ECON  / ADJUST, C1  , C2  , C3  , C4  , CC1  ,
1      CC2  , CC3  , CC4  , CC5  , CC6  , CSFEED,
2      CSMAN, CSPRIM, CSSEC , CSSERV, FEEDRT, NUMB ,
3      OFFMIN, R  , RAT  , RATLAT, RTMAIN, SECRAT,
4      SERVRT, WSLAT , WSPRIM, WSSEC , WSSERV, CD(50),
5      FEC(50)  , VEC(50)

C
COMMON / ECONPE / AUTOFX, BMLOAD, CAPDIS, CAPRAT, CAPSIZ, CIRMAX,
1      CIRLAT, CLATR , CLATX , CRITLD, DLOT  , DTZ  ,
2      FEEDRL, FEEDWR, FEEDWX, HLAT  , HP  , HSEC ,
3      HSLOAD, IDUS  , IMAX  , MXCUST, NCAP  , NCODE ,
4      NCHNG(50) , NCUSTS, NLATPR, NPHI  , NSTART,
5      NX  , NYEAR , OBJECT, POWFAC, PRIMWR, PRIMWX,
6      RLAT , SECR , SECX , SERVWR, SERVWX, TA  ,
7      VBUFF , VOLTHI, VOLTLO, VC  , VP  , VS  ,
8      WLOT  , WRLAT , WXLAT , COMYR(20) ,
9      CUSTPK(50) , DFAC(50) , DLF(50) ,
A      F(50) , H(20) , YLF(50)

C
COMMON / PEECON / BLKLEN, BLKWID, BUSDIS, CAPNUM, CAP1  , CAP2  ,
1      CIRLEN, CIRWID, CTAREA, DEMLOS, DISCNT, DISNUM,
2      DTCL  , DTNPR , ENGYLS, FEASBL, FLAG  , FUSCUT,
3      FUSNUM, IYEAR , MXPKYR, MXSCYR, NODD  , NTRN11,
4      NTRN12, NTRN21, NTRN22, PRIMLS, REMNUM, REMOTN,
5      SOEL  , SUBLOD, TOTCEL, TOTI2R, TLATLS, TSWLOS,
6      TRANUM, YRCUST, COMNUM(20) , RNUMCP(100) ,
7      SIZCP(100)

C
C
C      LIST INPUT DATA AND READ NAMELIST INPUT

C
C      CALL INPUT

C
C      INITIALIZE CONTROL VARIABLES

C
X( 1) = CSFEED
X( 2) = CSMAN
X( 3) = CSPRIM
X( 4) = CSSEC
X( 5) = CSSERV

```

```

X( 6) = MSLOAD
X( 7) = VOLTHI
X( 8) = VOLTLO
X( 9) = VP
X(10) = VS
X(11) = MSLAT
X(12) = MSPRIM
X(13) = MSSEC
X(14) = MSSERV
X(15) = 0.0
X(16) = 0.0
X(17) = 0.0
X(18) = 0.0
X(19) = 0.0
X(20) = 0.0
C
  ERROR = .FALSE.
  DO 10 I = 1, 20
    PTURB (I) = 0.0
    XMIN  (I) = X(I)
    XMAX  (I) = X(I)
  10 CONTINUE
C
  NN = 0
C
C  READ NAMES OF CONTROL VARIABLES WHICH ARE TO BE ACTIVE
C  DURING THIS RUN, THE MINIMUM AND MAXIMUM VALUES AND THE
C  PERTURBATION FOR THE CONTROL VARIABLE.
C
  20 READ(5,30,END=60) VNAME, VMIN, VMAX, PTRB
  30 FORMAT( A6, 4X, 3F10.0 )
C
C  MAP INPUT TO CORRESPONDING LOCATIONS IN CONTROL ARRAYS.
C
  DO 40 I = 1, 20
    IF( VNAME .NE. CNAME(I) ) GO TO 40
    PTURB (I) = PTRB
    XMIN  (I) = VMIN
    XMAX  (I) = VMAX
    NN = NN + 1
    IPOINT(NN) = I
  40 CONTINUE
C
  WRITE(6,50) VNAME
  50 FORMAT( '*** ERROR ***', 5X, A6, ' IS NOT A LEGAL CONTROL ',
    1 'VARIABLE NAME.' )
  ERROR = .TRUE.
  GO TO 20
C
  60 IF( ERROR ) STOP 12
C
C  SAVE VALUES IN 'CUSTPK' ARRAY.  REQUIRED FOR REINITIALIZATION
C  AFTER FIRST CALL TO 'FOFX'..
C
  DO 80 I = 1, 50
    CSPKSV(I) = CUSTPK(I)
  80 CONTINUE

```

```

C
C   IF NO CONTROL VARIABLE HAS BEEN SPECIFIED, BYPASS OPTIMIZATION
C   ROUTINE.
C
C   IF( NN .EQ. 0 ) GO TO 120
C
C   INVOKE OPTIMIZATION ROUTINE
C
C   DO 90 I = 1, NN
C   CALL FBSRCH( X, XMIN, XMAX, PTURB, IPOINT, I )
C   90 CONTINUE
C
C   100 WRITE(6,110) OBJECT, ( X(I), I = 1, 14 )
C   110 FORMAT( '1THE MINIMUM VALUE OF THE OBJECTIVE FUNCTION FOUND IS ',
C   1      E15.8 /
C   2      '-CSFEED = ', F10.4 /
C   3      ' CSMAIN = ', F10.4 /
C   4      ' CS PRIM = ', F10.4 /
C   5      ' CSSEC = ', F10.4 /
C   6      ' CSSERV = ', F10.4 /
C   7      ' HSLOAD = ', F10.4 /
C   8      ' VOLTHI = ', F10.4 /
C   9      ' VOLTLO = ', F10.4 /
C   A      ' VP      = ', F10.4 /
C   B      ' VS      = ', F10.4 /
C   C      ' WSLAT = ', F10.4 /
C   D      ' WSPRIM = ', F10.4 /
C   E      ' WSSEC = ', F10.4 /
C   F      ' WSSERV = ', F10.4 )
C
C   120 CALL FOFX( X, .TRUE. )
C
C   STOP 0
C   END

```

```

C      FUNCTION ADAI (ITYPE )
C
C      THIS ROUTINE CALCULATES RELATIVE EFFICIENCY TO 120 VOLTS
C      GIVEN HORSEPOWER, MOTOR, AND LINE VOLTAGE.
C      HORSEPOWER AND VOLTAGE ENTER VIA COMMON BLOCK ECONPE
C      WHILE MOTOR TYPE ENTERS AS FUNCTIONAL ARGUMENT ITYPE.
C
C      ITYPE = 1    CAPACITOR
C      ITYPE = 2    SPLIT-PHASE
C      ITYPE = 3    THREE-PHASE
C
C      VOLTAGE = VC IF HP < 1 OR VS = VC
C      VOLTAGE = 2*VS IF HP > 1 AND VS = VC
C
C      INTEGER*4 M / 2/, NUMHP(3) / 7, 5, 7 /
C      REAL  CAPACR(63), COEFS(9,7,3), SPLITP(63), THREEP(63)
C      REAL*8 C(3,3), EFF(2,2), EVSTND, EVUSE, FACTOR, HPHI, HPLW,
1      HPVALS(7,3), S(2), U(2), VSTAND, VUSE, X(4), Y(4),
2      YPTS(4,7,3)
C
C      COMMON / ECONPE / AUTOFX, BMLOAD, CAPDIS, CAPRAT, CAPSIZ, CIRMAL,
1      CIRRT, CLATR, CLATX, CRITLD, DLOT, DTZ,
2      FEEDRL, FEEDWR, FEEDWX, HLAT, HP, HSEC,
3      HSLOAD, IDUS, IMAX, MXCUST, NCAP, NCODE,
4      NCHNG(50), NCUSTS, NLATPR, NPHI, NSTART,
5      NX, NYEAR, OBJECT, POWFAC, PRIMWR, PRIMWX,
6      RLAT, SECR, SECX, SERVWR, SERVWX, TA,
7      VBUFF, VOLTHI, VOLTLO, VC, VP, VS,
8      WLOT, WRLAT, WXLAT, COMYR(20),
9      CUSTPK(50), DFAC(50), DLF(50),
A      F(50), H(20), YLF(50)
C
C      DATA CAPACR /
1      0.2302D-04, 0.2148D-03, -0.1074D-02, 0.0, 0.1668D-05,
2      -0.7272D-05, 0.4835D-08, -0.1296D-07, 0.5270D-08,
3      0.1918D-04, 0.4834D-03, -0.2026D-02, 0.0, 0.4036D-05,
4      -0.1494D-04, 0.1170D-07, -0.2751D-07, 0.1083D-07,
5      -0.5620D-03, 0.8056D-04, -0.1185D-02, 0.0, 0.5588D-05,
6      -0.1109D-04, 0.1620D-07, -0.2417D-07, 0.8038D-08,
7      -0.1803D-03, 0.9974D-04, -0.8900D-03, 0.0, 0.2435D-05,
8      -0.6739D-05, 0.7059D-08, -0.1330D-07, 0.4883D-08,
9      -0.3676D-03, -0.4731D-04, -0.4156D-03, 0.0, 0.2785D-05,
A      -0.4387D-05, 0.8074D-08, -0.1039D-07, 0.3179D-08,
B      0.5857D-03, 0.3939D-03, -0.7954D-03, 0.0, -0.1668D-05,
C      -0.3503D-05, -0.4835D-08, -0.2659D-08, 0.2538D-08,
D      0.1186D-02, 0.7583D-03, -0.7916D-03, 0.0, -0.3720D-05,
E      -0.3019D-05, -0.1078D-07, 0.1015D-08, 0.2188D-08 /
C
C      DATA HPVALS / .25D0, .75D0, 1.0D, 1.5D0, 2.0D, 3.0D, 5.0D,
1      .05D0, .067D0, .25D0, .375D0, .75D0, 2*0.0D,
2      .5D0, .75D0, 1.0D, 1.5D0, 2.0D, 3.0D, 5.0D /
C
C      DATA SPLITP /

```

```

1 0.4348D-03, 0.9565D-03, -0.2174D-03, 0.0, 0.4537D-05,
2 -0.9641D-05, 0.1315D-07, -0.2055D-07, 0.6986D-08,
3 0.1822D-03, 0.6790D-03, -0.5256D-03, 0.0, 0.4320D-05,
4 -0.9557D-05, 0.1252D-07, -0.2011D-07, 0.6926D-08,
5 -0.1134D-01, -0.3414D-02, 0.4028D-02, 0.0, 0.6889D-04,
6 -0.3653D-04, 0.1997D-06, -0.1528D-06, 0.2647D-07,
7 -0.2046D-03, 0.4092D-03, -0.2046D-02, 0.0, 0.5337D-05,
8 -0.1601D-04, 0.1547D-07, -0.3094D-07, 0.1160D-07,
9 -0.1861D-03, 0.3721D-03, -0.1861D-02, 0.0, 0.4854D-05,
A -0.1456D-04, 0.1407D-07, -0.2814D-07, 0.1055D-07, 18*0.00 /

```

C

```

DATA THREEP /
1 -0.8766D-03, 0.7097D-03, -0.4592D-02, 0.0, 0.1379D-04,
2 -0.3685D-04, 0.3998D-07, -0.7339D-07, 0.2670D-07,
3 -0.1873D-03, 0.3747D-03, -0.1873D-02, 0.0, 0.4887D-05,
4 -0.1466D-04, 0.1417D-07, -0.2833D-07, 0.1062D-07,
5 -0.1419D-03, 0.2839D-03, -0.1419D-02, 0.0, 0.3703D-05,
6 -0.1111D-04, 0.1073D-07, -0.2147D-07, 0.8050D-08,
7 -0.9719D-04, 0.1944D-03, -0.9719D-03, 0.0, 0.2535D-05,
8 -0.7606D-05, 0.7349D-08, -0.1470D-07, 0.5512D-08,
9 -0.7737D-04, 0.1547D-03, -0.7737D-03, 0.0, 0.2018D-05,
A -0.6055D-05, 0.5850D-08, -0.1170D-07, 0.4387D-08,
B -0.7545D-04, 0.1509D-03, -0.7545D-03, 0.0, 0.1968D-05,
C -0.5905D-05, 0.5705D-08, -0.1141D-07, 0.4279D-08,
D 0.6228D-03, 0.3197D-03, -0.8159D-03, 0.0, -0.2635D-05,
E -0.2302D-05, -0.7639D-08, 0.4835D-09, 0.1668D-08 /

```

C

DATA U / 2*0.00 /

C

DATA X / 120.00, 240.00, 480.00, 960.00 /

C

```

DATA YPTS / 66.2800, 66.2900, 66.2700, 64.7500,
1 72.4700, 72.4900, 72.4800, 69.4400,
2 75.9100, 75.8700, 75.8900, 73.7800,
3 78.5800, 78.5700, 78.5600, 77.2000,
4 79.5100, 79.4800, 79.4900, 78.6800,
5 80.9500, 81.0100, 80.9800, 80.1200,
6 81.6500, 81.7700, 81.7600, 80.9700,
7 30.6000, 30.6700, 30.8800, 29.4200,
8 33.5700, 33.6100, 33.7500, 32.1600,
9 42.0000, 41.0000, 42.0000, 38.7000,
A 43.0000, 43.0000, 43.0000, 39.8000,
B 44.0000, 44.0000, 44.0000, 41.0900, 8*0.00,
C 65.6500, 65.6100, 65.6100, 58.3000,
D 74.7600, 74.7600, 74.7600, 71.8300,
E 78.5700, 78.5700, 78.5700, 76.3500,
F 81.9900, 81.9900, 81.9900, 80.4700,
G 83.6200, 83.6200, 83.6200, 82.4100,
H 84.2000, 84.2000, 84.2000, 83.0200,
I 86.4500, 86.5100, 86.4500, 85.7500/

```

C

```

EQUIVALENCE ( COEFFS( 1 ), CAPACR(1) ),
1 ( COEFFS( 64 ), SPLITP(1) ),
2 ( COEFFS(127), THREEP(1) )

```

C

```

MX = 4
VSTAND = 120.00
SMALL = 1.E-4

```



```

C
C   DETERMINE PROPER VOLTAGE CONVERTING KILOVOLTS TO VOLTS
C
VUSE = VC * 1000.
IF( ( ABS(VS-VC) .GT. SMALL ) .AND.
1  ( HP .GT. 1.0 .OR. ABS(HP-1.0) .LT. SMALL ) ) VUSE = VS * 2000.
U(1) = VSTAND
U(2) = VUSE

C
C   DETERMINE IF HP WITHIN ACCEPTABLE BOUNDS
C
TOOLOW = HPVALS(1,ITYPE)
TOOHI = HPVALS(NUMHP(ITYPE),ITYPE)
IF( HP .GT. TOOLOW .AND. HP .LT. TOOHI ) GO TO 20
IF( ABS( HP - TOOLOW ) .LT. SMALL .OR.
1  ABS( HP - TOOHI ) .LT. SMALL ) GOTO 20
WRITE(6,10) HP
10 FORMAT('*** ERROR *** HP OUT OF BOUNDS IN FUNCTION ADA *****' /
1  '-HP =', E15.8 )
STOP 12

C
C   CHECK IF HP IN DATA POINT LIST
C
20 ISTOP = NUMHP(ITYPE)
DO 30 ITEST = 1, ISTOP
CURHP = HPVALS(ITEST,ITYPE)
IF( ABS( HP - CURHP ) .LT. SMALL ) GO TO 40
IF( CURHP .GT. HP ) GO TO 80
30 CONTINUE

C
C   SINCE FUNCTION EXISTS FOR SPECIFIED HORSEPOWER
C   CALCULATE EFFICIENCY AT VSTAND AND VUSE
C
C   EXTRACT PROPER COEFFICIENTS
C
40 IQUIT = MX - 1
DO 60 I = 1, IQUIT
DO 50 J = 1, IQUIT
C(I,J) = COEFS((J-1)*IQUIT+I,ITEST,ITYPE)
50 CONTINUE
60 CONTINUE

C
C   GET CORRECT Y VALUES
C
DO 70 I = 1, MX
Y(I) = YPTS(I,ITEST,ITYPE)
70 CONTINUE

C
C   EVALUATE SPLINE FOR U VECTOR
C
CALL SPEVAL( X, Y, MX, C, U, S, M )
ADA = S(1) / S(2)
GO TO 140

C
C   SINCE FUNCTION DOES NOT EXIST FOR SPECIFIED HP
C   CALCULATE EFFICIENCY FOR TWO HP VALUES AND INTERPOLATE
C
80 KBEG = ITEST - 1

```

```

      IQUIT = MX - 1
      ISTORE = 0
      DO 130 K = KBEG, ITEST
C
C      GET PROPER COEFFICIENTS
C
      DO 100 I = 1, IQUIT
      DO 90 J = 1, IQUIT
      C(I,J) = COEFS((J-1)*IQUIT+I,K,ITYPE)
      90 CONTINUE
      100 CONTINUE
C
C      GET CORRECT Y VALUES
C
      DO 110 I = 1, MX
      Y(I) = YPTS(I,K,ITYPE)
      110 CONTINUE
C
C      EVALUATE SPLINE
C
      CALL SPEVAL( X, Y, MX, C, U, S, M )
C
C      STORE UNTIL INTERPOLATION CAN BE DONE
C
      ISTORE = ISTORE + 1
      DO 120 JSTORE = 1, M
      EFF(ISTORE,JSTORE) = S(JSTORE)
      120 CONTINUE
      130 CONTINUE
C
C      INTERPOLATE AND CALCULATE RELATIVE EFFICIENCIES
C
      HPHI = CURHP
      HPLOW = HPVALS(ITEST-1,ITYPE)
      FACTOR = ( HP - HPLOW ) / ( HPHI - HPLOW )
      EVSTND = EFF(1,1) + ( EFF(2,1) - EFF(1,1) ) * FACTOR
      EVUSE = EFF(1,2) + ( EFF(2,2) - EFF(1,2) ) * FACTOR
      ADA = EVSTND / EVUSE
      140 RETURN
      END

```

```

SUBROUTINE ADDCAP( ILAT )
C
COMMON / CAPDAT / LTCPBS(100) , NCAP1(50) , NCAP2(50)
C
COMMON / ECONPE / AUTOFX, BMLOAD, CAPDIS, CAPRAT, CAPSIZ, CIRMAY,
1 CIRRAT, CLATR, CLATX, CRITLD, DLOT, DTZ,
2 FEEDRL, FEEDWR, FEEDWX, HLAT, HP, HSEC,
3 MSLOAD, IDUS, IMAX, MXCUST, NCAP, NCODE,
4 NCHNG(50), NCUSTS, NLATPR, NPFI, NSTART,
5 NX, NYEAR, OBJECT, POWFAC, PRIMWR, PRIMWX,
6 RLAT, SECR, SECX, SERVWR, SERVWX, TA,
7 VBUFF, VOLTHI, VOLTLO, VC, VP, VS,
8 WLOT, WRLAT, WXLAT, COMYR(20),
9 CUSTPK(50), DFAC(50), DLF(50),
A F(50), H(20), YLF(50)
C
COMMON / PEECON / BLKLEN, BLKWID, BUSDIS, CAPNUM, CAP1, CAP2,
1 CIRLEN, CIRWID, CTAREA, DEMLOS, DISCNT, DISNUM,
2 DTCL, DTNPR, ENGYLS, FEASBL, FLAG, FUSCUT,
3 FUSNUM, IYEAR, MXPKYR, MXSCYR, NODD, NTRN11,
4 NTRN12, NTRN21, NTRN22, PRIMLS, REMNUM, REMOTH,
5 SDEL, SUBLOD, TOTCEL, TOTI2R, TLATLS, TSWLOS,
6 TRANUM, YRCUST, COMNUM(20), RNUMCP(100),
7 SIZCP(100)
C
COMMON / SYSTEM / CAPS(200), PD(200), QD(200),
1 NFRMTC(2,200), RLINE(200), XLINE(200),
2 NURBUS
C
ADD CAPACITANCE TO ALLOWABLE BUSES
C
DO 30 I = 1, NCAP
C
IF( ILAT .NE. 1 ) GO TO 10
J = NCAP1(I)
GO TO 20
C
10 J = NCAP2(I)
C
20 CAPS(J) = CAPS(J) + CAPSIZ
C
30 CONTINUE
C
STORE SIZE OF CAPACITOR ON LATERAL
C
IF( ILAT .NE. 1 ) GO TO 40
CAP1 = CAPS(NCAP1(1))
GO TO 50
40 CAP2 = CAPS(NCAP2(1))
C
50 RETURN
END

```

SUBROUTINE BUMPS
LOGICAL AFLAG, BFLAG, FEASBL

```

C
COMMON / ECONPE / AUTOFX, BMLOAD, CAPDIS, CAPRAT, CAPSIZ, CIRMAX,
1      CIRLAT, CLATR, CLATX, CRITLD, DLOT, DTZ,
2      FEEDRL, FEEDWR, FEEDWX, HLAT, HP, HSEC,
3      HSLOAD, IDUS, IMAX, MXCUST, NCAP, NCODE,
4      NCHNG(50), NCUSTS, NLATPR, NPHI, NSTART,
5      NX, NYEAR, OBJECT, POWFAC, PRIMWR, PRIMWX,
6      RLAT, SECR, SECX, SERVWR, SERVWX, TA,
7      VBUFF, VOLTHI, VOLTLO, VC, VP, VS,
8      WLOT, WRLAT, WXLAT, COMYR(20),
9      CUSTPK(50), DFAC(50), OLF(50),
A      F(50), H(20), YLF(50)

C
COMMON / PEECON / BLKLEN, BLKWID, BUSDIS, CAPNUM, CAP1, CAP2,
1      CIRLEN, CIRWID, CTAREA, DEMLOS, DISCNT, DISNUM,
2      DTCL, DTNPR, ENGYLS, FEASBL, FLAG, FUSCUT,
3      FUSNUM, IYEAR, MXPYR, MXSCYR, NODD, NTRN11,
4      NTRN12, NTRN21, NTRN22, PRIMLS, REMNUM, REMOTN,
5      SDEL, SUBLOD, TOTCEL, TOTI2R, TLATLS, TSWLOS,
6      TRANUM, YRCUST, COMNUM(20), RNUMCP(100),
7      SIZECP(100)

AFLAG = .FALSE.
BFLAG = .FALSE.

C
C
C CALL FUNCTION SUBROUTINE TO GENERATE LOCKED ROTOR CURRENT IN
C AMPS FOR TYPICAL LARGE RESIDENTIAL MOTOR CONSISTENT WITH THE
C CUSTOMER'S UTILIZATION SYSTEM SPECIFIED BY "IDUS." DIVIDE BY
C "VS" TO NORMALIZE VOLTAGE DROP TO BE CALCULATED.
C
SURGE = ROTORC( IDUS ) / ( VS * 1000. )

C
C COMPUTE VOLTAGE BUMPS BEGINNING WITH TERMINALS OF THE
C DISTRIBUTION TRANSFORMER AND PROCEED TOWARD THE CUSTOMER
C AT THE MOST DISTANT POINT ON THE SECONDARY CIRCUIT.
C
LOC = 1

C
C SINCE THERE ARE "NCUSTS" ON THE SECONDARY CIRCUIT AND EACH
C CUSTOMER HAS "NSTART" MOTOR STARTS PER HOUR, THEN THE SECONDARY
C CIRCUIT WILL SEE "ABPS" VOLTAGE BUMPS OF PER-UNIT MAGNITUDE
C "DELV."
C
ABPS = NCUSTS * NSTART
X = ( DTZ * VS**2 * 8 * ( 1 + 2*NPHI ) ) / DTNPR
R = 0.75 * X
DELV = SURGE * SQRT( R**2 + X**2 )

C
C PREPARE TO CALCULATE VOLTAGE BUMPS FOR NODES ALONG SECONDARY
C CIRCUIT.
C
TEMP = WLOT * FLOAT(NX) / 100.

```

```

RINCR = TEMP * SECR
XINCR = TEMP * SECX
NC = NCUSTS/2 + 2
TEMP = SQRT( MLOT**2 + DLOT**2 ) / 200.

C
C USE FUNCTION SUBROUTINE "FLICKR" TO SPECIFY THRESHOLD OF
C INTOLERABLE FREQUENCY OF VOLTAGE BUMPS OF PER UNIT MAGNITUDE
C "DELV."
C
10 BPSMAX = FLICKR( DELV )
   IF( ABPS .GT. BPSMAX ) AFLAG = .TRUE.

C
C AT CUSTOMER'S SERVICE ENTRANCE...
C
RR = R + SERVWR * TEMP
XX = X + SERVWX * TEMP
DELVC = SURGE * SQRT( RR**2 + XX**2 )

C
C WEIGHTED AVERAGE VOLTAGE BUMP AT CUSTOMER'S SERVICE ENTRANCE
C (MAGNITUDE WEIGHTED BY FREQUENCY)
C
DELVCA = ( NSTART * DELVC + ( ABPS-NSTART ) * DELV ) / ABPS

C
C TOLERABLE FREQUENCY
C
BPCMAX = FLICKR( DELVCA )
   IF( ABPS .GT. BPCMAX ) BFLAG = .TRUE.

C
   IF( AFLAG .OR. BFLAG ) GO TO 20

C
R = R + RINCR
X = X + XINCR
NC = NC - 2 * NX

C
   IF( NC .LE. 0 ) GO TO 40
   LOC = LOC + 1
   ABPS = NC * NSTART
   DELV = SURGE * SQRT( R**2 + X**2 )
   GO TO 10

C
20 WRITE(6,30)
30 FORMAT( ' ***** INTOLERABLE FLICKER: REDUCE NUMBER OF CUSTOMERS ',
1         ' ON THE SECONDARY CIRCUIT OR INCREASE SIZE OF THE WIRE ',
2         ' USED IN THIS CIRCUIT.' / )

C
FEASBL = .FALSE.

C
40 RETURN
   END

```

```

SUBROUTINE CARDIN
IMPLICIT INTEGER*2 ( I - N )
REAL*4 CARD(20)
REAL*8 DSAVED, TSAVED
C
C *****
C * CARDIN - READS AND LISTS INPUT CARD IMAGES AND WRITES THEM *
C * TO FT05
C *****
C
I = 0
LMAX = 60
LINCNT = LMAX
CALL DATE( DSAVED )
CALL TIME( TSAVED )
C
10 READ(15,20,END=70) CARD
20 FORMAT( 20A4 )
I = I + 1
WRITE(5,20) CARD
C
IF( LINCNT .LE. LMAX-4 ) GO TO 40
WRITE(6,30) TSAVED, DSAVED
30 FORMAT( '1', T22, 'L I S T I N G O F I N P U T ',
1 'D A T A C A R D S', 8X, 'TIME', 2X, A8, 2X,
2 'DATE ', A8 /
3 '0', T22, '0...0....', 2('1....'), 2('2....'),
4 2('3....'), 2('4....'), 2('5....'), 2('6....'),
5 2('7....'), '8' / T22, 8( '1234567890' ) /
6 T22, 80(' -' ) / )
LINCNT = 6
C
40 WRITE(6,50) CARD, I
50 FORMAT( T22, 20A4, I8 )
LINCNT = LINCNT + 1
C
IF( LINCNT .LT. LMAX-4 ) GO TO 10
WRITE(6,60)
60 FORMAT( / T22, 80(' -' ) /
1 ' ', T22, '0...0....', 2('1....'), 2('2....'),
2 2('3....'), 2('4....'), 2('5....'), 2('6....'),
3 2('7....'), '8' / T22, 8( '1234567890' ) )
LINCNT = LINCNT + 4
GO TO 10
C
70 WRITE(6,60)
REWIND 5
RETURN
END

```

SUBROUTINE CORLOS

C

```

COMMON / ECONPE / AUTOFX, BMLOAD, CAPDIS, CAPRAT, CAPSIZ, CIRMAL,
1  CIRLAT, CLATR, CLATX, CRITLD, DLOT, DTZ,
2  FEEDRL, FEEDWR, FEEDWX, HLAT, HP, MSEC,
3  HSLOAD, IDUS, IMAX, MXCUST, NCAP, NCODE,
4  MCHNG(50), NCUSTS, NLATPR, NPHI, NSTART,
5  NX, NYEAR, OBJECT, POWFAC, PRIMWR, PRIMX,
6  RLAT, SECR, SECX, SERVWR, SERVWX, TA,
7  VBUFF, VOLTHI, VOLTLO, VC, VP, VS,
8  WLOT, WRLAT, WXLAT, COMYR(20),
9  CUSTPK(50), DFAC(50), DLF(50),
A  F(50), H(20), YLF(50)

```

C

```

COMMON / PEECON / BLKLEN, BLKWID, BUSDIS, CAPNUM, CAP1, CAP2,
1  CIRLEN, CIRWID, CTAREA, DEMLOS, DISCNT, DISNUM,
2  DTCL, DTNPR, ENGYLS, FEASBL, FLAG, FUSCUT,
3  FUSNUM, IYEAR, MXPYR, MXSCYR, NODD, NTRN11,
4  NTRN12, NTRN21, NTRN22, PRIMLS, REMNUM, REMOTN,
5  SDEL, SUBLOD, TDTCEL, TDTI2R, TLATLS, TSWLOS,
6  TRANUM, YRCUST, COMNUM(20), RNUMCP(100),
7  SZCP(100)

```

C

```

PHI = NPHI
DTCL = 0.1426 + 0.111 * SQRT( VS ) - 0.3174 * PHI
1  + ( 8.544E-3 * PHI + 7.090E-6 * VP ) * DTNPR
2  + ( -3.706E-5 * PHI + 1.129E-5 ) * DTNPR**2
RETURN
END

```

SUBROUTINE COSTS(PRNTON)
 LOGICAL PRNTON
 REAL*4 COST(20), EH(100)

C

DATA	EH /	8760.,	8760.,	8760.,	8760.,	8760.,
1		8760.,	8760.,	8760.,	8760.,	8760.,
2		8760.,	8760.,	8760.,	8759.,	8756.,
3		8755.,	8754.,	8754.,	8751.,	8751.,
4		8751.,	8749.,	8749.,	8746.,	8746.,
5		8743.,	8742.,	8736.,	8724.,	8696.,
6		8657.,	8593.,	8531.,	8442.,	8320.,
7		8160.,	7960.,	7769.,	7556.,	7325.,
8		7111.,	6894.,	6592.,	6286.,	5935.,
9		5576.,	5225.,	4883.,	4532.,	4186.,
A		3827.,	3514.,	3240.,	2973.,	2719.,
B		2561.,	2327.,	2152.,	1980.,	1802.,
C		1662.,	1496.,	1370.,	1269.,	1160.,
D		1034.,	946.,	852.,	788.,	724.,
E		654.,	579.,	527.,	480.,	449.,
F		403.,	364.,	320.,	301.,	254.,
G		222.,	185.,	148.,	130.,	111.,
H		90.,	82.,	61.,	46.,	38.,
I		26.,	24.,	14.,	12.,	10.,
J		10.,	4.,	2.,	2.,	0. /

C

COMMON / ECON	/ ADJUST, C1	, C2	, C3	, C4	, CC1
1	CC2	, CC3	, CC4	, CC5	, CC6
2	CSMAIN	, CS PRIM	, CS SEC	, CSSERV	, FEEDRT
3	OFFMIN	, R	, RAT	, RATLAT	, RTMAIN
4	SERVRT	, WSLAT	, WSPRIM	, WSSEC	, WSSERV
5	FEC(50)		, VEC(50)		

C

COMMON / ECONPE	/ AUTOFX	, BMLOAD	, CAPDIS	, CAPRAT	, CAPSIZ	, CIRMAL
1	CIRRAL	, CLATR	, CLATX	, CRITLD	, DLOT	, DTZ
2	FEEDRL	, FEEDWR	, FEEDWX	, HLAT	, HP	, HSEC
3	MSLOAD	, IDUS	, IMAX	, MXCUST	, NCAP	, NCODE
4	NCHNG(50)		, NCUSTS	, NLATPR	, NPHI	, NSTART
5	NX	, NYEAR	, OBJECT	, POWFAC	, PRIMWR	, PRIMWX
6	RLAT	, SECR	, SECX	, SERVWR	, SERVWX	, TA
7	VBUFF	, VOLTHI	, VOLTLO	, VC	, VP	, VS
8	WLOT	, WRLAT	, WXLAT	, COMYR(20)		
9	CUSTPK(50)		, DFAC(50)		, DLF(50)	
A	F(50)	, H(20)	, YLF(50)			

C

COMMON / PEECON	/ BLKLEN	, BLKWID	, BUSDIS	, CAPNUM	, CAP1	, CAP2
1	CIRLEN	, CIRWID	, CTAREA	, DEMLOS	, DISCNT	, DISNUM
2	DTCL	, DTNPR	, ENGYS	, FEASBL	, FLAG	, FUSCUT
3	FUSNUM	, IYEAR	, MXPYR	, MXCYR	, NODD	, NTRN11
4	NTRN12	, NTRN21	, NTRH22	, PRIMLS	, REMNUM	, REMOTN
5	SDEL	, SUBLOD	, TOTCEL	, TOTI2R	, TLATLS	, TSWLOS
6	TRAHUM	, YRCUST	, COMNUM(20)		, RNUMCP(100)	
7	SIZCP(100)					

C


```

C      IF( IYEAR .GT. 1 ) GO TO 100
C
C      CALCULATE PER-UNIT LEVELIZED COSTS AND OTHER VALUES WHICH
C      WILL BE NEEDED FOR EACH EXECUTION OF THE COSTS SUBROUTINE.
C
C      CUSCST = 0.0
C      ENERGY = 0.0
C      CAPITL = 0.0
C
C      VP2 = VP**2
C      VPRT = SQRT( VP )
C      VSRT = SQRT( VS )
C
C      TRANSFORMER COSTS ( CAPITAL AND TEST )
C
C      STC      = CC1 * ( 532038. + 6540.3 * VP + 5840.16 * RAT )
C      STTC     = 250.0
C      COST(1) = ( STC + STTC ) / ADJUST
C
C      TRANSFORMER CORE DEMAND AND ENERGY LOSS
C
C      STCL     = 31.54 + 0.36 * RAT
C      STCEL    = STCL * 8760.0
C
C      TRANSFORMER FULL LOAD I**2*R LOSS
C
C      STFLI2   = 213.38 + 2.34 * RAT
C
C      CALCULATE THE FRACTION OF SUBSTATION COSTS ASSESSED TO ONE
C      CIRCUIT.
C
C      FRACFN = CIRRTAT / 1200.0
C
C      SUBSTATION SURGE ARRESTER COST.
C
C      SSAC     = ( 260.78 + 16.0 * VP ) * CC2
C      COST(13) = SSAC / ADJUST
C
C      SUBSTATION CIRCUIT BREAKER COST AND O AND M COST.
C
C      CBC      = CC5 * ( 57249.27 - 284.51 * VP + 8.58 * VP2 )
C      CBOMC    = 263.31 - 6.63 * VP + 0.135 * VP2
C      COST(2) = ( CBC + CBOMC ) / ADJUST
C
C      MISCELLANEOUS SUBSTATION ITEM COST AND O AND M COST.
C
C      CMISC    = CC5 * ( 138902. + 325832. * NUMB + 2233.39 * VP )
C      CMSIOM   = 11040. + 1200. * NUMB +
1      ( 144000. + 26000. * NUMB ) * FEC(IYEAR) +
2      ( 16.4 + 3. * NUMB ) * CD(IYEAR)
C      COST(3) = ( CMISC + CMSIOM ) / ADJUST
C
C      REMOTE CONTROLLED SWITCHES AND RELAY PACKAGE COST.
C
C      RSSC     = CC5 * ( 7447.83 + 49.18 * VP + 2.06 * VP2 )
C
C      SUBSTATION RELAYS AND INSTRUMENT TRANSFORMERS.
C

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IF( NUMB .EQ. 2 ) GO TO 10
CVRITC = CC5 * ( -23711.36 + 3521.29 * VP - 26.02 * VP2 )
GO TO 20
10 CVRITC = CC5 * ( -43016.40 + 6464.37 * VP - 47.88 * VP2 )
20 COST(4) = CVRITC / ADJUST
C
C UNDERGROUND CONDUIT COST PER 100 FEET.
C
CONDC = CC6 * ( 8243.09 - 145.86 * VP + 2.97 * VP2 )
COST(12) = CONDC / ADJUST
C
C STRAIGHT AND SWITCHED MANHOLE COST.
C
CMHCST = CC4 * ( 710.39 + 566.96 * VP - 2.254 * VP2 )
COST(14) = CMHCST / ADJUST
CMHCSW = CC4 * ( -12171.43 + 1655.07 * VP - 9.731 * VP2 )
COST( 7) = CMHCSW / ADJUST
C
C COST OF PRIMARY CABLE INSTALLED IN DUCT ( MAIN AND FEEDER )
C AND BURIED IN EARTH ( LATERALS ) PER 100 FEET.
C
PHI = 2 * NPHI + 1
FEEDCA = CC4 * ( 1568.39 - 86.67*VP + 1.821*VP2 + 1.116 * CSFEED )
COST(11) = FEEDCA / ADJUST
IF( NCODE .EQ. 0 ) GO TO 50
CAMAIN = FEEDCA + CC4 * 1.116 * ( CSMAIN - CSFEED )
COST(9) = CAMAIN / ADJUST
C
C CABLAT = ( 1001.75 - 46.28 * VP + 0.905 * VP2 + 0.238 * CS PRIM +
1 PHI * ( 468.76 - 21.88 * VP + 0.467 * VP2 + 0.323 * CS PRIM ) ) *
2 CC4
COST(15) = CABLAT
C
C SECONDARY CABLE COST ( BURIED ) PER 100 FEET.
C
IF( VS .GT. 0.24 ) GO TO 30
SECABL = CC4 * ( 818.37 + 0.308 * CSSEC + ( PHI - 1.0 ) *
1 ( 3.03 + 0.0505 * CSSEC ) )
SERVCA = SECABL + CC4 * ( CSSERV - CSSEC ) *
1 ( 0.2575 + 0.0505 * PHI )
GO TO 40
C
30 SECABL = ( 827.68 + 1.431 * CSSEC + ( PHI - 1.0 ) *
1 ( 4.29 + 0.239 * CSSEC ) ) * CC4
SERVCA = SECABL + CC4 * ( CSSERV - CSSEC ) *
1 ( 1.192 + 0.239 * PHI )
C
40 COST(18) = SECABL
COST(19) = SERVCA
C
50 COST( 6) = 0.0
COST(10) = 0.0
COST(16) = 0.0
COST(17) = 0.0
C
IF( NCODE .EQ. 1 ) GO TO 60
C
C AERIAL SUPPORT STRUCTURE COST PER 100 FEET AND O AND M COST.

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C
ASSC      = CC3 * ( 907.2 + 1.35 * VP + 278.0 * PHI )
ASSOMC    = 18.0
COST(10)  = ASSC + ASSOMC + ( 3.0 - PHI ) * 278. * CC3
COST(16)  = ASSC + ASSOMC
COST(17)  = 433. * CC3

C
C
C CABLE TERMINATOR COST ( THREE PHASE TERMINAL POLE )
C
CTC        = CC3 * ( 2813.77 + 69.24 * VP - 0.09 * VP2 )
COST(6)    = CTC / ADJUST

C
C AERIAL DISCONNECTING SWITCHES, FUSED CUTOUTS, AND LOAD
C INTERRUPTERS.
C---
C SUBSTATION PACKAGE COST AND O AND M COST.
C
60 COSTLI  = CC2 * ( 129474. - 2172.12 * VP + 44.91 * VP2 ) * NUMB
CLIOMC     = NUMB * ( 303.36 - 4.87 * VP + 0.133 * VP2 )
COST(5)    = ( COSTLI + CLIOMC ) / ADJUST

C
C AERIAL DISCONNECT AND FUSED CUTOUTS ON CIRCUITS.
C
ADCCOST    = PHI * ( 141.82 - 1.490 * VP + 0.086 * VP2 ) * CC2
FCCOST     = PHI * ( 124.39 + 0.158 * VP + 0.080 * VP2 ) * CC2
IF( NCODE .EQ. 1 ) GO TO 70

C
C COST OF ALUMINUM OVERHEAD WIRE PER 100 FEET FOR PRIMARY,
C SECONDARY AND SERVICE DROP PLUS SERVICE DROP INSTALLATION.
C
COST(15)   = CC2 * ( 25.3 + 0.064 * WSLAT + ( PHI - 1.0 ) *
1           ( 5.44 + 0.063 * WSLAT ) )
COST( 9)   = ( 36.18 + 0.19 * WSPRIM ) * CC2
WIRESCE    = CC2 * ( 77.12 + 0.477 * WSSEC + ( PHI - 1.0 ) *
1           ( 10.21 + 0.119 * WSSEC ) )
COST(18)   = WIRESCE
WIRESDE    = CC2 * ( 110.6 + 0.39 * WSSERV + ( PHI - 1.0 ) *
1           ( 1.7 + 0.055 * WSSERV ) )
IF( VS .GT. 0.24 ) WIRESDE = WIRESDE * 1.08
COST(19)   = WIRESDE

C
C AERIAL AND UNDERGROUND SWITCHED CAPACITOR COSTS ARE:
C
ASC = ASC1 + CC2 * 0.00052 * CAPSIZ**2
C
USC = USC1 + CC2 * 0.00065 * CAPSIZ**2
C
70 ASC1 = CC2 * ( 3611.26 - 20.42 * VP + 0.722 * VP2 )
USC1 = CC2 * ( 4487.09 - 22.81 * VP + 0.939 * VP2 )

C
C CAPACITOR LOSS PER KVAR = 0.0005 * CAPSIZ

C
C
C LOAD BREAK CABLE TERMINATORS:
C
C THREE PHASE FUSED SWITCHES ( ABOVE GROUND, PAD )
C
C THREE PHASE OIL SWITCHES ( UNDERGROUND, SUBMERSIBLE )
C
UGFSC      = CC4 * ( - 4955.15 + 958.82 * VP - 3.68 * VP2 )
UGFRSC     = UGFSC + 800.0 * CC4
UGOSC      = CC4 * ( 14557.52 + 466.43 * VP + 10.87 * VP2 )

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      IF( NCODE .EQ. 0 ) GO TO 80
      RSSC = UGFRSC
      FCCOST = UGFSC
      ADCOST = UGFSC
80  COST(8) = UGOSC / ADJUST
C
C  COMMUNICATIONS SYSTEM COST PER REMOTE CONTROLLED SWITCH.
C
      CSC = CC2 * 200.0
C
C  CUSTOMER UTILIZATION ELEMENTS
C
C  CALCULATE LEVELIZING FACTORS USED ON METERS, AUTOTRANSFORMERS,
C  BREAKER PANELS, AND BUILDING WIRE.
C
      CCM = R * ( 1.0 + R )**10 / ( ( 1.0 + R )**10 - 1.0 )
      CCA = R * ( 1.0 + R )**20 / ( ( 1.0 + R )**20 - 1.0 )
      CCBP = R * ( 1.0 + R )**30 / ( ( 1.0 + R )**30 - 1.0 )
      CCBW = R * ( 1.0 + R )**50 / ( ( 1.0 + R )**50 - 1.0 )
C
C  CALCULATE COST OF ONE METER.
C
      CMETER = 43.0 * CCM
      IF( VS .GT. 0.12 ) CMETER = ( 43. + 783. *
1      ( 1. - EXP( -9.2 * ( VS - 0.12 ) ) ) ) * CCM
      IF( NPHI .EQ. 1 ) CMETER = CMETER + CMETER
C
C  CALCULATE COST OF AUTOTRANSFORMER IF NEEDED (ONE HOUSE).
C
      AUTOC = 0.0
      IF( VS .NE. VC ) AUTOC = ( 240. * VS + 703.33 ) * CCA
      IF( NPHI .EQ. 1 ) AUTOC = AUTOC + AUTOC
C
C  CALCULATE COST OF A BREAKER PANEL ( ONE HOUSE ).
C
      BPCOST = 131.0 * CCBP
      IF( VS .GT. 0.12 ) BPCOST = ( 131. + 1477. *
1      ( 1. - EXP( -7. * ( VS - 0.12 ) ) ) ) * CCBP
      IF( NPHI .EQ. 1 ) BPCOST = BPCOST + BPCOST
C
C  BUILDING WIRE COST ( ONE HOUSE )
C
      BWCOST = ( 2000. * VS**2 - 1360. * VS + 703.29 ) * CCBW
      TCOST = BWCOST + BPCOST + AUTOC + CMETER
C
C  CALCULATE THE LOSS PER 100 CIRCUIT FEET DUE TO INSULATION ON
C  FEEDER CABLE, MAIN CABLE, AND LATERAL CABLE
C
C... FEEDER CABLE LOSS
C
      ALOSS = 552.E-8 * VP**2 / ( ALOG10( 2.9183 + 0.4386 * VP +
1      SQRT(CSFEED) ) - 0.5 * ALOG10( CSFEED ) )
      BLOSS = 0.0
      CLOSS = 0.0
      IF( NCODE .EQ. 0 ) GO TO 90
C
C... MAIN CABLE LOSS
C

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      BLOSS = 552.E-8 * VP**2 / ( ALOG10( 2.9183 + 0.4386 * VP +
1      Sqrt(CSMAIN) ) - 0.5 * ALOG10( CSMAIN ) )
C
C... LATERAL CABLE LOSS
C
      CLOSS = PHI * 184.E-8 * VP**2 / ( ALOG10( 2.9183 + 0.4386 * VP +
1      Sqrt(CSPRIM) ) - 0.5 * ALOG10( CSPRIM ) )
C
C      CALCULATE THE ANNUAL SYSTEM CAPITAL, ENERGY, DEMAND, AND
C      OPERATING AND MAINTENANCE COSTS FOR A CIRCUIT AND ACCUMULATE
C      THE PRESENT WORTH OF THESE CHARGES.
C
C      INITIALIZE PRESENT WORTH OF SYSTEM COST TO ZERO.
C
90 SYSCST = 0.0
C
C      CALCULATE PRESENT WORTH FACTOR FOR "IYEAR".
C
100 PWF = 1.0 / ( 1.0 + R )**IYEAR
C
C      DISTRIBUTION TRANSFORMER COSTS ( AERIAL, UNDERGROUND )
C
      ARTRAN = CC1 * ( 3158.87 + 4980.37 * Sqrt( NPHI * VS ) -
1      299.62 * Sqrt( NPHI * VS * DTNPR ) +
2      2.908E-5 * ( NPHI * VP * DTNPR )**2 +
3      4.116 * VP2 - 1495.67 * VPRT +
4      352.27 * Sqrt( DTNPR ) + 8.686 * VP +
5      0.8137 * ( NPHI * VP )**2 + 502.02 * NPHI -
6      17.537 * NPHI * VP )
      COST(20) = ARTRAN
      UGTRAN = CC1 * ( 5811.96 + 856.37 * NPHI +
1      2.468E-5 * ( NPHI * VP * DTNPR )**2 +
2      3.669 * VP2 - 1696.65 * VPRT + 187.6 * Sqrt( DTNPR ) +
3      1.518 * ( NPHI * VP )**2 + 5.24 * VP -
4      30.62 * NPHI * VP )
      IF( NCODE .EQ. 1 ) COST(20) = UGTRAN
C
C      TMPCST = SYSCST
C
C      ACCUMULATE THE PRESENT WORTH ANNUAL COSTS ASSOCIATED WITH
C      THE EQUIPMENT DEFINED IN SUBROUTINE "DIM".
C
      DO 110 I = 1, 20
      SYSCST = SYSCST + PWF * COST(I) * COMYR(I)
110 CONTINUE
C
C      DETERMINE IF TRANSFORMER CHANGE-OUT COSTS SHOULD BE ADDED TO
C      SYSCST. IF SO, ADD THEM.
C
      K = 1
      IF( IMAX .EQ. 0 ) GO TO 140
120 IF( IYEAR .NE. NCHNG(K) ) GO TO 130
      CHANGE = 500.0
      IF( NCODE .EQ. 1 ) CHANGE = 1500.0
      SYSCST = SYSCST + CHANGE * COMYR(20) * PWF
      GO TO 140
130 IF( K .EQ. IMAX ) GO TO 140
      K = K + 1

```

60 TO 120

```

C
C      LIST NUMBER OF EACH TYPE OF COMPONENTS AND ASSOCIATED COST.
C
140 IF( PRNTON ) WRITE(6,150) IYEAR, ( COMYR(I), COST(I), I = 1, 11 )
150 FORMAT( 'IFOR YEAR = ', I3, ' THE FOLLOWING NUMBER OF COMPONENTS',
1      ' PER CIRCUIT MUST BE IN SERVICE:' / T93, 'COST' //
2 F15.3, ' SUBSTATION TRANSFORMERS', T85, F15.2 /
3 F15.3, ' SUBSTATION CIRCUIT BREAKERS', T85, F15.2 /,
4 F15.3, ' MISCELLANEOUS SUBSTATION ITEMS', T85, F15.2 /
5 F15.3, ' SUBSTATION RELAY AND INSTRUMENT TRANSFORMER PACKAGES',
6      T85, F15.2 /
7 F15.3, ' SUBSTATION LOAD INTERRUPTER AND DISCONNECT PACKAGES',
8      T85, F15.2 /
9 F15.3, ' TERMINAL POLES', T85, F15.2 /
A F15.3, ' SWITCHED MANHOLES', T85, F15.2 /
B F15.3, ' THREE-PHASE OIL SWITCHES', T85, F15.2 /
C F15.3, ' MAIN CONDUCTORS (PER 100 CIRCUIT FEET)', T85, F15.2 /
D F15.3, ' MAIN AERIAL SUPPORT FACILITIES (PER 100 CIRCUIT FEET)',
E      T85, F15.2 /
F F15.3, ' MAIN FEEDER CABLE (PER 100 CIRCUIT FEET)', T85, F15.2 )

C
      IF( PRNTON ) WRITE(6,160) ( COMYR(I), COST(I), I = 12, 20 ),
1      REMNUM, RSSC, FUSNUM, FCCOST, DISNUM, ADCOST, RLAT
160 FORMAT(
1 F15.3, ' CONDUIT (PER 100 CIRCUIT FEET)', T85, F15.2 /
2 F15.3, ' SUBSTATION SURGE ARRESTORS', T85, F15.2 /
3 F15.3, ' STRAIGHT MANHOLES', T85, F15.2 /
4 F15.3, ' LATERAL CONDUCTOR (PER 100 CIRCUIT FEET)', T85, F15.2 /
5 F15.3, ' LATERAL AERIAL SUPPORT FACILITIES (PER 100 CIRCUIT FEET)
6', T85, F15.2 /
7 F15.3, ' SECONDARY AERIAL SUPPORT FACILITIES (PER 100 CIRCUIT FEE
8T)', T85, F15.2 /
9 F15.3, ' SECONDARY CONDUCTOR (PER 100 CIRCUIT FEET)', T85, F15.2 /
A F15.3, ' SERVICE DROP (PER 100 CIRCUIT FEET)', T85, F15.2 /
B F15.3, ' SECONDARY TRANSFORMERS', T85, F15.2 /
C F15.3, ' REMOTE CONTROLLED AERIAL OR UNDERGROUND SWITCHES',
D      T85, F15.2 /
E F15.3, ' FUSED CUTOUPS OR PAD MOUNTED SWITCHES', T85, F15.2 /
F F15.3, ' AERIAL DISCONNECTS OR PAD MOUNTED SWITCHES', T85, F15.2 /
G F15.3, ' LATERALS' / )

C
      TCUSTS = YRCUST / COMYR(20)

C
      TEMP = 2.78784E7 / CTAREA
      TEMP1 = TEMP * SDEL
      TEMP2 = TEMP * TSWLOS
      TEMP3 = TEMP * TOTI2R
      TEMP4 = TEMP * TLATLS
      TEMP5 = TEMP * PRIMLS
      TEMP6 = TEMP * ENGYLS
      TEMP7 = TEMP * TDTCEL
      TEMP8 = TEMP * DEMLOS

C
      IF( PRNTON ) WRITE(6,170) IYEAR, YRCUST, TCUSTS, TEMP1, TEMP2,
1      TEMP3, TEMP4, TEMP5, TEMP6, TEMP7,
2      TEMP8, SUBLOD
170 FORMAT(' -THE NUMBER OF CUSTOMERS ON THE CIRCUIT IN YEAR',

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1      I3, ' IS ', F11.1 /
2      ' THE NUMBER OF CUSTOMERS PER DISTRIBUTION TRANSFORMER IS'
3,      F9.1 /
4,      '-THE CIRCUIT LOSSES ON A PER SQUARE MILE BASIS ARE:/'
5      '- ', F15.1, ' KWH TOTAL SERVICE DROP ENERGY LOSS' /
6      1X, F15.1, ' KWH TOTAL SECONDARY WIRE LOSS' /
7      1X, F15.1, ' KWH DISTRIBUTION TRANSFORMER I**2 R LOSSES' /
8      1X, F15.1, ' KWH TOTAL LATERAL LOSS' /
9      1X, F15.1, ' KWH TOTAL MAIN AND FEEDER LOSS' /
A      '- ', F15.1, ' KWH ANNUAL I**2 R ENERGY LOSS' /
B      1X, F15.1, ' KWH DISTRIBUTION TRANSFORMER CORE LOSSES' /
C      '0', F14.0, ' KW PEAK DEMAND LOSS' /
D      '-THE PEAK SUBSTATION TRANSFORMER LOAD IS', F5.0, ' MVA' )

C      IF( NCODE .EQ. 1 ) GO TO 200

C      ACCUMULATE THE PRESENT WORTH ANNUAL COSTS ASSOCIATED WITH THE
C      REMOTE CONTROLLED SWITCHES, FUSED CUTOUPS, AERIAL DISCONNECTS,
C      AND CAPACITORS.

C      SYSCST = SYSCST + ( REMNUM * ( RSSC + CSC ) + FUSNUM * FCCOST +
1      DISNUM * ADCOST ) / ADJUST * PWF

C      IF( CAP1 .NE. CAP2 ) GO TO 180
ASC = ASC1 + CC2 * 0.00052 * CAP1**2
SYSCST = SYSCST + ASC * CAPNUM * PWF
GO TO 230

C      180 II = RLAT / 2.0 + 1.0

C      DO 190 I = 1, II
ASC = ASC1 + CC2 * 0.00052 * SIZCP(I)**2
SYSCST = SYSCST + ASC * RNUMCP(I) * PWF
190 CONTINUE
GO TO 230

C      ACCUMULATE PRESENT WORTH ANNUAL COSTS OF THREE-PHASE
C      FUSED SWITCHES AND CAPACITORS.

C      200 SYSCST = SYSCST + ( REMNUM * ( UGFRSC + CSC ) +
1      ( FUSNUM + DISNUM ) * UGFSC ) / ADJUST * PWF
IF( CAP1 .NE. CAP2 ) GO TO 210
USC = USC1 + CC2 * 0.00065 * CAP1**2
SYSCST = SYSCST + USC * CAPNUM * PWF
GO TO 230

C      210 II = RLAT / 2.0 + 2.0
DO 220 I = 1, II
USC = USC1 + CC2 * 0.00065 * SIZCP(I)**2
SYSCST = SYSCST + USC * RNUMCP(I) * PWF
220 CONTINUE

C      CALCULATE THE LOAD VARYING AND CONSTANT ENERGY LOSSES FOR
C      THE SUBSTATION TRANSFORMER AND THE CAPACITORS.
C      TRANSFORMER COOLING FAN DEMAND AND ENERGY REQUIREMENTS.
C
230 DELTA = 0.0

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C
IF( 0.7*RAT .LT. SUBLOO ) DELTA = 1.0
STCFD = 0.025 * ( 1.0 + DELTA ) * ( STCL + STFLI2 )
NH = 70.0 * RAT / SUBLOO + 0.5
IF( NH .GT. 100 ) NH = 100
STCFE = 0.025 * ( STCL + STFLI2 ) * ( 8760.0 + EH(NH) )

C
C
TRANSFORMER I**2*R LOSS FOR "IYEAR".
C
STI2R = STFLI2 * ( SUBLOO / RAT )**2
STVEL = STI2R * YLF(IYEAR) * 8760.0
STPDL = STI2R + STCL

C
C
CAPACITOR DEMAND AND ENERGY LOSS ASSUMES CAPACITORS OPERATE
C
50 PERCENT OF THE YEAR.
C
CAPDL = 0.0

C
IF( CAP1 .NE. CAP2 ) GO TO 240
CAPDL = 0.0005 * CAP1 * CAPNUM
GO TO 260

C
240 DO 250 I = 1, II
CAPDL = CAPDL + 0.0005 * RNUMCP(I) * SIZECP(I)
250 CONTINUE
260 CAPEL = CAPDL * 4380.0

C
C
CALCULATE THE HIGHER VOLTAGE ENERGY SAVINGS TO THE
C
CUSTOMERS IN KWH AND PRESENT WORTH COST
C
IF( IYEAR .GT. 1 ) GO TO 270
CUSSAV = 0.0
ENGSAV = 0.0
HSLOSS = 1489.2 * ( HSLOAD - CUSTPK(1) )

C
270 ENGCUS = HSLOSS * MXCUST * F(IYEAR) * CUSTPK(IYEAR) / CUSTPK(1)
ENGSAV = ENGSAV + ENGCUS
CUSSAV = CUSSAV + ENGCUS * FEC(IYEAR) * PWF

C
C
CALCULATE THE TOTAL CABLE INSULATION LOSS
C
XLOSS = ALOSS * COMYR(11) +
1 BLOSS * COMYR( 9) +
2 CLOSS * COMYR(15)

C
C
CALCULATE THE COST OF ALL ENERGY AND DEMAND LOSSES IN
C
PRESENT WORTH TERMS AND ADD TO SYSCST.
C
ECOST = ( ENGYLS + STVEL * FRACTN ) * VEC(IYEAR) +
1 ( TOTCEL + CAPEL + ( STCFE + STCEL ) * FRACTN
2 + XLOSS * 8760. ) * FEC(IYEAR)

C
DCOST = ( DEMLOS + CAPDL + ( STPDL + STCFD ) * FRACTN + XLOSS ) *
1 CD(IYEAR)

C
ENERGY = ENERGY + ( ECOST + DCOST ) * PWF
CAPITL = CAPITL + SYSCST - TMPCST
C

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      SYSCST = SYSCST + PMF * ( ECOST + DCOST )
      CUSCST = CUSCST + PMF * TCOST * YRCUST
C
C   CALCULATE THE COSTS FOR CUSTOMER UTILIZATION ELEMENTS FOR
C   ALL CUSTOMERS IN IYEAR AND SUM THE PRESENT WORTH TO SYSCST
C
      SYSCST = SYSCST + PMF * TCOST * YRCUST
      IF( PRNTON ) WRITE(6,280) IYEAR, SYSCST, ECOST,
1      DCOST, TCOST, STI2R, STCL
280 FORMAT( '----- SYSTEM COST FOR YEAR ', I3, ' IS ', F15.2
1      / ' ECOST =', F15.2,
2      / ' DCOST =', F15.2,
3      / ' TCOST =', F15.2,
4      / ' STI2R =', F15.2,
5      / ' STCL =', F15.2 / )
C
C   NORMALIZE SYSCST IN FINAL YEAR TO COST PER SQUARE MILE.
C
      IF( IYEAR .NE. NYEAR ) GO TO 300
C
      SYSCST = SYSCST - CUSSAV
      TEMP = 2.78784E7 / CTAREA
      CUSCST = CUSCST * TEMP
      ENERGY = ENERGY * TEMP
      CAPITL = CAPITL * TEMP
      CUSSAV = CUSSAV * TEMP
      ENGSAV = ENGSAV * TEMP
C
C   EVALUATE THE OBJECTIVE FUNCTION
C
      OBJECT = C1 * CAPITL + C2 * ENERGY + C3 * CUSCST - C4 * CUSSAV
C
      WRITE(6,290) OBJECT, CAPITL, CUSCST, ENERGY, CUSSAV, ENGSAV
290 FORMAT( 'THE PRESENT WORTH COST OF A CIRCUIT PER SQUARE MILE IS',
1      F16.2 //
2      ' THE CAPITAL PORTION IS ', F16.2 /
3      ' THE CUSTOMER PORTION IS ', F16.2 /
4      ' THE ENERGY PORTION IS ', F16.2 /
5      ' CUSTOMER DOLLAR SAVINGS ', F16.2 /
6      ' CUSTOMER ENERGY SAVINGS- ', F16.2, ' KWH' )
C
300 RETURN
      END

```

SUBROUTINE DIM

```

C
COMMON / ECON / ADJUST, C1 , C2 , C3 , C4 , CC1 ,
1 CC2 , CC3 , CC4 , CC5 , CC6 , CSFEED,
2 CSMAIN, CSPRIM, CSSEC , CSSERV, FEEDRT, NUMB ,
3 OFFMIN, R , RAT , RATLAT, RTHAIN, SECRAT,
4 SERVRT, WSLAT , WSPRIM, WSSEC , WSSERV, CD(50),
5 FEC(50) , VEC(50)

C
COMMON / ECONPE / AUTOFX, BMLOAD, CAPDIS, CAPRAT, CAPSIZ, CIRMAL,
1 CIRRTAT, CLATR , CLATX , CRITLD, DLOT , DTZ ,
2 FEEDRL, FEEDWR, FEEDWX, HLAT , HP , HSEC ,
3 HSLOAD, IDUS , IMAX , MXCUST, NCAP , NCODE ,
4 NCHNG(50) , NCUSTS, NLATPR, NPHI , NSTART,
5 NX , NYEAR , OBJECT, POWFAC, PRIMWR, PRIMWX,
6 RLAT , SECR , SECX , SERVWR, SERVWX, TA ,
7 VBUFF , VOLTHI, VOLTLO, VC , VP , VS ,
8 WLOT , WRLAT , WXLAT , COMYR(20) ,
9 CUSTPK(50) , DFAC(50) , DLF(50) ,
A F(50) , H(20) , YLF(50)

C
COMMON / PEECON / BLKLEN, BLKWID, BUSDIS, CAPNUM, CAP1 , CAP2 ,
1 CIRLEN, CIRWID, CTAREA, DEMLOS, DISCNT, DISNUM,
2 DTCL , DTNPR , ENGYLS, FEASBL, FLAG , FUSCUT,
3 FUSNUM, IYEAR , MXPKYR, MXSCYR, NODD , NTRN11,
4 NTRN12, NTRN21, NTRN22, PRIMLS, REMNUM, REMOTN,
5 SDEL , SUBLOD, TOTCEL, TOTI2R, TLATLS, TSWLOS,
6 TRANUM, YRCUST, COMNUM(20) , RNUMCP(100) ,
7 SIZCP(100)

C
C
C CALCULATE CIRCUIT AREA
C
CTAREA = 0.96 * ( SQRT( 3.0 ) * VP * WLOT * DLOT * CIRRTAT ) /
1 ( DFAC(MXPKYR) * F(MXPKYR) * CUSTPK(MXPKYR) )
AREA = CTAREA

C
C CALCULATE BLOCK LENGTH
C
BLKLEN = WLOT * NCUSTS / 2.0

C
C CALCULATE CIRCUIT LENGTH
C
CIRLEN = BLKLEN * NLATPR

C
C CALCULATE BLOCK WIDTH
C
BLKWID = 2.0 * DLOT

C
C CALCULATE CIRCUIT WIDTH
C
CIRWID = CTAREA / CIRLEN

C
C ROUND "CIRWID" DOWN TO A VALUE WHICH IS THE CLOSEST ODD

```

```

C      MULTIPLE OF "BLKWID".
C
      NODD = CIRWID / BLKWID
      NCHK = MOD( NODD, 2 )
      IF( NCHK .EQ. 0 ) NODD = NODD - 1
      CIRWID = NODD * BLKWID
C
C      RECALCULATE CIRCUIT AREA
C
      CTAREA = CIRWID * CIRLEN
      ADJUST = AREA / CTAREA
      FEEDRL = SQRT( AREA )
C
C      CALCULATE MAXIMUM NUMBER OF CUSTOMER PER CIRCUIT
C
      MXCUST = CTAREA / ( MLOT * DLOT )
C
C      INITIALIZE ARRAY "COMNUM" WHICH STORES THE MAXIMUM NUMBER
C      OF EACH TYPE OF COMPONENT WHICH COULD BE PLACED ON A FULLY
C      DEVELOPED CIRCUIT
C
      INDEX      COMPONENT
      -----
C      1      SUBSTATION TRANSFORMER
C      2      SUBSTATION CIRCUIT BREAKER
C      3      MISCELLANEOUS SUBSTATION ITEMS
C      4      SUBSTATION RELAY AND INSTRUMENT XFMR PACKAGE
C      5      SUBSTATION LOAD INTERRUPTER AND DISC PACKAGE
C      6      CABLE TERMINATOR
C      7      SWITCHED MANHOLE
C      8      THREE-PHASE OIL SWITCH
C      9      MAIN CONDUCTOR/CABLE
C      10     MAIN AERIAL SUPPORT FACILITIES
C      11     MAIN FEEDER CABLE
C      12     CONDUIT
C      13     SUBSTATION SURGE ARRESTERS
C      14     STRAIGHT MANHOLES
C      15     LATERAL CONDUCTOR/CABLE
C      16     LATERAL AERIAL SUPPORT FACILITIES
C      17     SECONDARY AERIAL SUPPORT FACILITIES
C      18     SECONDARY CONDUCTOR/CABLE
C      19     SERVICE DROP CONDUCTOR/CABLE
C      20     SECONDARY TRANSFORMERS
C
      TEMP = CIRLAT / 1200.0
      DO 10 I = 1, 5
      COMNUM(I) = TEMP
10 CONTINUE
C
      COMNUM(6) = 1.0
      COMNUM(7) = 1.0
      COMNUM(8) = 1.0
C
C      CALCULATE NUMBER OF 100 FEET OF MAIN WIRE AND AERIAL
C      SUPPORT FACILITIES.
C
      TEMP = CIRLEN / 100.0
      COMNUM( 9 ) = TEMP

```

```

      COMNUM(10) = TEMP
C
C   CALCULATE NUMBER OF 100 FEET OF MAIN FEEDER CONDUCTOR
C   AND CONDUIT.
C
      TEMP = FEEDRL / 100.0
      COMNUM(11) = TEMP
      COMNUM(12) = TEMP
C
C   CALCULATE NUMBER SUBSTATION SURGE ARRESTERS
C
      COMNUM(13) = CIRRTAT / 100.0
C
C   CALCULATE NUMBER STRAIGHT MANHOLES
C
      COMNUM(14) = FEEDRL / 800.0
C
C   CALCULATE NUMBER OF 100 FEET OF LATERAL AERIAL SUPPORT
C   FACILITIES AND CONDUCTOR
C
      TEMP = CIRWID * FLOAT( NLATPR ) / 100.0
      COMNUM(15) = TEMP
      COMNUM(16) = TEMP
C
C   CALCULATE THE NUMBER OF 100 FEET OF SECONDARY AERIAL
C   SUPPORT FACILITIES
C
      COMNUM(17) = CIRLEN * ( FLOAT( NODD-1 ) / 100.0 )
C
C   CALCULATE THE NUMBER OF 100 FEET OF SECONDARY CONDUCTOR
C
      COMNUM(18) = CIRLEN * ( FLOAT( NODD ) / 100.0 )
C
C   CALCULATE THE NUMBER OF 100 FEET OF SERVICE DROP WIRE
C
      COMNUM(19) = ( FLOAT( MXCUST ) / 200.0 ) *
1      SQRT( WLOT**2 + DLOT**2 )
      IF( NCODE .EQ. 1 ) COMNUM(19) = FLOAT(MXCUST) * DLOT / 200.0
C
C   CALCULATE MAXIMUM NUMBER OF SECONDARY TRANSFORMERS
C
      COMNUM(20) = CTAREA / ( BLKWID * BLKLEN )
C
C   SET HOMOGENEITY FACTORS FOR VARIOUS COMPONENTS
C
      DO 20 I = 1, 14
      H(I) = 1.0
20  CONTINUE
C
      H(15) = HLAT
      H(16) = HLAT
      H(17) = HSEC
      H(18) = HSEC
      H(19) = 0.0
      H(20) = HSEC
C
      SQMILE = CTAREA / 2.78784E7
      WRITE(6,30) SQMILE, CIRLEN, CIRWID, MXCUST

```

```
30 FORMAT( 'CIRCUIT AREA = ', F8.2, ' SQUARE MILES' /  
1         ' CIRCUIT LENGTH = ', F8.2, ' FEET' /  
2         ' CIRCUIT WIDTH = ', F8.2, ' FEET' /  
3         ' MAXIMUM NUMBER OF CUSTOMERS IN THE CIRCUIT AREA IS',  
4         I6 / )
```

C

```
RETURN  
END
```

```
FUNCTION DLFAC( X )  
DLFAC = 0.5 + 0.33 / X  
RETURN  
END
```

```

SUBROUTINE FBSRCH( V, VMIN, VMAX, VPTB, IPOINT, J )
C
  INTEGER IPOINT(20)
  REAL*4 FIBNO(25)
  REAL*8 FOFX, V(20), VMIN(20), VMAX(20), VPTB(20)
C
C-----
C  PERFORM FIBONACCI SEARCH FOR OPTIMAL PLACEMENT OF X
C-----
C
  NDX = IPOINT(J)
  PTB = VPTB(NDX)
  XLB = VMIN(NDX)
  XUB = VMAX(NDX)
C
  SPAN = XUB - XLB
  FIBNO(1) = 1.0
  FIBNO(2) = 2.0
C
  DO 10 I = 3, 18
    FIBNO(I) = FIBNO(I-1) + FIBNO(I-2)
    IF( SPAN / FIBNO(I-2) .GT. PTB ) GO TO 10
    FIB = FIBNO(I-2) / FIBNO(I)
    MAXITS = I - 2
    GO TO 20
  10 CONTINUE
C
  FIB = FIBNO(16) / FIBNO(18)
  MAXITS = 16
C
  20 X = XLB + FIB * SPAN
  V(NDX) = X
  OLDTOT = FOFX( V, .FALSE. )
  XSAV = X
  XMINF = X
  FMIN = OLDTOT
C
  I = 1
  WRITE(6,30) I, XLB, X, XUB, OLDTOT
30 FORMAT( ' FBSRCH - ITERATION', I3, ': XLB=', F12.4, 3X,
1      'X=', F12.4, 3X, 'XUB=', F12.4, 3X, 'FOFX =',
2      F12.2 )
C
  X = XLB + ( XUB - X )
C
  DO 100 I = 2, MAXITS
C
  V(NDX) = X
  TOTAL = FOFX( V, .FALSE. )
C
  WRITE(6,30) I, XLB, X, XUB, TOTAL
C
  IF( TOTAL - OLDTOT ) 40, 40, 70
C
  FUNCTION FACLOS( X )
  FACLOS = 0.14836 - 0.10958 / X
  RETURN
  END

```

```

40      OLDTOT = TOTAL
      XMINF = X
      FMIN = TOTAL
C
      IF( X - XSAV ) 50, 110, 60
C
50      XUB = XSAV
      XSAV = X
      X = XUB - ( XSAV - XLB )
      GO TO 100
C
60      XLB = XSAV
      XSAV = X
      X = XLB + ( XUB - XSAV )
      GO TO 100
C
70      IF( X - XSAV ) 80, 110, 90
C
80      XLB = X
      X = XLB + ( XUB - XSAV )
      GO TO 100
C
90      XUB = X
      X = XUB - ( XSAV - XLB )
C
100 CONTINUE
C
110 X = XMINF
      WRITE(6,120) XMINF, FMIN
120 FORMAT( '-X FOR MINIMUM =', F12.4, 5X,
1      'FOFX=', F12.2)
      V(NDX) = XMINF
      RETURN
      END

```



```

      FUNCTION FLICKR( FRACT )
C
C      THIS ROUTINE CALCULATES THE MAXIMUM TOLERABLE FREQUENCY OF
C      VOLTAGE FLUCTUATION WHOSE AVERAGE MAGNITUDE IS FRACTION "FRACTN"
C      BELOW NOMINAL USING TABLE LOOKUP AND INTERPOLATION. ( BUMPS OF
C      PER UNIT MAGNITUDE "FRACT" PER HOUR. )
C
      DIMENSION FREQ(14), FRTN(14)
C
      DATA FREQ / 0.02, 0.05, 0.10, 0.20, 0.50, 1.00, 2.00,
1          5.00, 10.00, 20.00, 50.00, 100.00, 200.00, 500.00 /,
2          FRTN / 6.50, 4.60, 3.85, 3.40, 2.93, 2.65, 2.32,
3          1.95, 1.72, 1.47, 1.20, 1.00, 0.78, 0.52 /
C
C      CONVERT FROM PER UNIT TO PERCENT.
C
      FRACTN = FRACT * 100.0
C
      IF( FRACTN .GT. FRTN(1) ) GO TO 30
      DO 10 I = 1, 13
      IF( FRACTN .LE. FRTN(I) .AND. FRACTN .GT. FRTN(I+1) ) GO TO 20
10  CONTINUE
      FLICKR = FREQ(14) * 60.0
      GO TO 40
C
C      INTERPOLATE BETWEEN FREQ(I) AND FREQ(I+1) USING LOG 10 OF FRTN
C
20  FLOG = ALOG10( FREQ(I+1) ) +
1      ( FRACTN - FRTN(I+1) ) / ( FRTN(I) - FRTN(I+1) ) *
2      ( ALOG10(FREQ(I)) - ALOG10( FREQ(I+1) ) )
C
      FLICKR = 10.0 ** FLOG * 60.0
      GO TO 40
C
30  FLICKR = FREQ(1) * 60.0
C
40  RETURN
      END

```

```

REAL FUNCTION FOFX=8( X, PRNTON )
LOGICAL FEASBL, PRNTON
REAL*8 X(20)

```

```

C
COMMON / ECON / ADJUST, C1 , C2 , C3 , C4 , CC1 ,
1 CC2 , CC3 , CC4 , CC5 , CC6 , CSFEED,
2 CSMAIN, CSPRIM, CSSEC , CSSERV, FEEDRT, NUMB ,
3 OFFMIN, R , RAT , RATLAT, RTHAIN, SECRAT,
4 SERVRT, WSLAT , WSPRIM, WSSSEC , WSSERV, CD(50),
5 FEC(50) , VEC(50)

```

```

C
COMMON / ECONPE / AUTOFX, BMLOAD, CAPDIS, CAPRAT, CAPSIZ, CIRMAL,
1 CIRLAT, CLATR , CLATX , CRITLD, DLOT , DTZ ,
2 FEEDRL, FEEDWR, FEEDWX, HLAT , HP , HSEC ,
3 MSLOAD, IDUS , IMAX , MXCUST, NCAP , NCODE ,
4 NCHNG(50) , NCUSTS, NLATPR, NPHI , NSTART,
5 NX , MYEAR , OBJECT, POWFAC, PRIMWR, PRIMWX,
6 RLAT , SECR , SECX , SERVWR, SERVWX, TA ,
7 VBUFF , VOLTHI, VOLTLO, VC , VP , VS ,
8 WLOT , WRLAT , WXLAT , COMYR(20) ,
9 CUSTPK(50) , DFAC(50) , DLF(50) ,
A F(50) , H(20) , YLF(50)

```

```

C
COMMON / PEECON / BLKLEN, BLKWID, BUSDIS, CAPNUM, CAP1 , CAP2 ,
1 CIRLEN, CIRWID, CTAREA, DEMLOS, DISCNT, DISNUM,
2 DTCL , DTNPR , ENGYLS, FEASBL, FLAG , FUSCUT,
3 FUSNUM, IYEAR , MXPYR, MXSCYR, NODD , NTRN11,
4 NTRN12, NTRN21, NTRN22, PRIMLS, REMNUM, REMOTN,
5 SDEL , SUBLOD, TDTCEL, TDTI2R, TLATLS, TSWLOS,
6 TRANUM, YRCUST, COMNUM(20) , RNUMCP(100) ,
7 SIZCP(100)

```

```

C
FEASBL = .TRUE.
CSFEED = X( 1)
CSMAIN = X( 2)
CSPRIM = X( 3)
CSSEC = X( 4)
CSSERV = X( 5)
MSLOAD = X( 6)
VOLTHI = X( 7)
VOLTLO = X( 8)
VP = X( 9)
VS = X(10)
WSLAT = X(11)
WSPRIM = X(12)
WSSSEC = X(13)
WSSERV = X(14)

```

```

C
WRITE(6,40) ( X(I), I = 1, 14 )
40 FORMAT( 'ENTERING FOFX'/
1 '-CSFEED = ', F10.4 /
2 'CSMAIN = ', F10.4 /
3 'CSPRIM = ', F10.4 /

```

```

4      ' CSSEC = ', F10.4 /
5      ' CSSERV = ', F10.4 /
6      ' HSLOAD = ', F10.4 /
7      ' VOLTHI = ', F10.4 /
8      ' VOLTLO = ', F10.4 /
9      ' VP      = ', F10.4 /
A      ' VS      = ', F10.4 /
B      ' WSLAT  = ', F10.4 /
C      ' WSPRIM = ', F10.4 /
D      ' WSSEC  = ', F10.4 /
E      ' WSSERV = ', F10.4 )

C
C      RECALCULATE RESISTANCES, ETC.
C
C      CALL RESET
C
C      SCALE RESIDENTIAL LOADS
C
C      CALL RESLD
C
C      CALL PKYR
C
C      DETERMINE CABLE RATINGS AND WHETHER SERVICE DROP CABLE
C      IS TOO SMALL
C
C      CALL RATCHK
C      IF( .NOT. FEASBL ) GO TO 60
C
C      DEVELOP SECONDARY MODEL, RUN L.F. AND CHECK VOLTAGE DROP (PECO)
C
C      CALL SECMOD
C      IF( .NOT. FEASBL ) GO TO 60
C
C      CALCULATE VOLTAGE BUMPS
C
C      CALL BUMPS
C      IF( .NOT. FEASBL ) GO TO 60
C
C      CALCULATE DIMENSIONS OF CIRCUIT, LENGTH OF MAIN AND LATERAL,
C      MAXIMUM NUMBER OF EACH TYPE OF COMPONENT FOR A SYSTEM WHICH
C      IS COMPLETELY FILLED.
C
C      CALL DIM
C      CALL RELCOM
C
C      PREPARE PEAK YEAR LOADFLOW INPUT FOR VOLTAGE DROP CHECK.
C
C
C      CALL SYSMOD
C      IF( .NOT. FEASBL ) GO TO 60
C
C      DO 50 IYEAR = 1, NYEAR
C
C      DETERMINE NUMBER OF EACH TYPE OF COMPONENT
C
C      CALL NOCOM
C
C      CALCULATE CIRCUIT DEMAND AND ENERGY LOSS

```

```
C      CALL SYSLOS
C
C      SUM AND PRESENT WORTH ALL COSTS, CAPITAL, O&M, LOSSES
C
C      CALL COSTS( PRNTON )
C
C      50 CONTINUE
C
C      GO TO 80
C
C      60 WRITE(6,70)
C      70 FORMAT( ' INFEASIBLE CONDITION.' )
C      FOFX = 1.0E60
C      GO TO 90
C
C      80 FOFX = OBJECT
C      90 RETURN
C      END
```

```

SUBROUTINE INPUT
C
LOGICAL LFDEBUG
C
COMMON / ECON / ADJUST, C1 , C2 , C3 , C4 , CC1 ,
1 CC2 , CC3 , CC4 , CC5 , CC6 , CSFEED,
2 CSMAIN, CSPRIM, CSSEC , CSSERV, FEEDRT, NUMB ,
3 OFFMIN, R , RAT , RATLAT, RTMAIN, SECRAT,
4 SERVRT, WSLAT , WSPRIM, WSSEC , WSSERV, CD(50),
5 FEC(50) , VEC(50)
C
COMMON / ECONPE / AUTOFX, BMLOAD, CAPDIS, CAPRAT, CAPSIZ, CIRMAT,
1 CIRRAT, CLATR , CLATX , CRITLD, DLOT , DTZ ,
2 FEEDRL, FEEDWR, FEEDWX, HLAT , HP , HSEC ,
3 HSLOAD, IDUS , IMAX , MXCUST, NCAP , NCODE ,
4 NCHNG(50) , NCUSTS, NLATPR, NPHI , NSTART,
5 NX , NYEAR , OBJECT, POWFAC, PRIMWR, PRIMWX,
6 RLAT , SECR , SECX , SERVWR, SERVWX, TA ,
7 VBUFF , VOLTHI, VOLTLO, VC , VP , VS ,
8 WLOT , WRLAT , WXLAT , COMYR(20) ,
9 CUSTPK(50) , DFAC(50) , DLF(50) ,
A F(50) , H(20) , YLF(50)
C
COMMON / FLODBG / LFDEBUG
C
COMMON / PEECON / BLKLEN, BLKWID, BUSDIS, CAPNUM, CAP1 , CAP2 ,
1 CIRLEN, CIRWID, CTAREA, DEMLOS, DISCNT, DISNUM,
2 DTCL , DTNPR , ENGYLS, FEASBL, FLAG , FUSCUT,
3 FUSNUM, IYEAR , MXPKYR, MXSCYR, NODD , NTRN11,
4 NTRN12, NTRN21, NTRN22, PRIMLS, REMNUM, REMOTN,
5 SDEL , SUBLOD, TOTCEL, TOTI2R, TLATLS, TSWLOS,
6 TRANUM, YRCUST, COMNUM(20) , RNUMCP(100) ,
7 SIZCP(100)
C
NAMELIST / DATAIN /
1 AUTOFX, BMLOAD, CAPRAT, CAPSIZ, C1 , C2 ,
2 C3 , C4 , CC1 , CC2 , CC3 , CC4 ,
3 CC5 , CC6 , CD , CIRRAT, CRITLD, CSFEED,
4 CSMAIN, CSPRIM, CSSEC , CSSERV, CUSTPK, DFAC ,
5 DLF , DLOT , DTZ , F , FEC , FEEDRL,
6 H , HLAT , HP , HSEC , HSLOAD, IDUS ,
7 LFDEBUG, L1 , L2 , MXCUST, NCAP , NCODE ,
8 NCUSTS, NLATPR, NPHI , NSTART, NX , NUMB ,
9 NYEAR , OFFMIN, POWFAC, R , RAT , TA ,
A VBUFF , VC , VEC , VOLTHI, VOLTLO, VP ,
B VS , WLOT , WSLAT , WSPRIM, WSSEC , WSSERV,
C YLF
C
READ AND LIST DATA CARDS
C
CALL CARDIN
C
READ INPUT DATA USING NAMELIST INPUT

```

SUBROUTINE MOCOM

```

C
COMMON / ECONPE / AUTOFX, BMLOAD, CAPDIS, CAPRAT, CAPSIZ, CIRMAT,
1 CIRRAT, CLATR, CLATX, CRITLD, DLOT, DTZ,
2 FEEDRL, FEEDWR, FEEDWX, HLAT, HP, HSEC,
3 MSLOAD, IDUS, IMAX, MXCUST, NCAP, NCODE,
4 NCHNG(50), NCUSTS, NLATPR, NPHI, NSTART,
5 NX, MYEAR, OBJECT, POWFAC, PRIMWR, PRIMWX,
6 RLAT, SECR, SECX, SERVWR, SERVWX, TA,
7 VBUFF, VOLTHI, VOLTLO, VC, VP, VS,
8 WLOT, WRLAT, WXLAT, COMYR(20),
9 CUSTPK(50), DFAC(50), DLF(50),
A F(50), H(20), YLF(50)

C
COMMON / PEECON / BLKLEN, BLKWID, BUSDIS, CAPNUM, CAP1, CAP2,
1 CIRLEN, CIRWID, CTAREA, DEMLOS, DISCNT, DISNUM,
2 DTCL, DTNPR, ENGYLS, FEASBL, FLAG, FUSCUT,
3 FUSNUM, IYEAR, MXPYR, MXSCYR, MODD, NTRN11,
4 NTRN12, NTRN21, NTRN22, PRIMLS, REMNUM, REMOTN,
5 SOEL, SUBLOD, TDTCEL, TDTI2R, TLATLS, TSWLOS,
6 TRANUM, YRCUST, COMNUM(20), RNUMCP(100),
7 SIZECP(100)

C
C CALCULATE NUMBER OF COMPONENTS OF 20 TYPES IN "COMNUM" FOR
C YEAR "IYEAR".
C
FIYEAR = F(IYEAR)
DO 10 I = 1, 20
ANUM = COMNUM(I) * ( H(I) * ( 1.0 - FIYEAR ) + FIYEAR )
IF( ANUM .GT. COMYR(I) ) COMYR(I) = ANUM
10 CONTINUE

C
C CALCULATE NUMBER OF LATERALS.
C
RNUM = 2.0 * NLATPR * ( HLAT * ( 1.0 - FIYEAR ) + FIYEAR )
IF( RNUM .GT. RLAT ) RLAT = RNUM

C
C CALCULATE NUMBER OF REMOTE SWITCHES, FUSED CUTOUTS, AND
C AERIAL DISCONNECTS.
C
REMNUM = REMOTN * RLAT
FUSNUM = FUSCUT * RLAT
DISNUM = DISCNT * RLAT

C
IF( CAP1 .EQ. 0.0 ) GO TO 40
IF( CAP1 .NE. CAP2 ) GO TO 20

C
C CALCULATE THE NUMBER OF CAPACITORS OF SIZE "CAP1".
C
CAPNUM = NCAP * RLAT
GO TO 40

C
C CALCULATE THE DELTA CAPACITANCE FOR ADJACENT LATERAL'S
C
AUTOFX = 0.01
READ(5,DATAIN)

C
RETURN
END

```

```

C     CAPACITOR SIZES.
C
20 DELCAP = ( CAP1 - CAP2 ) / ( FLOAT( NLATPR-1 ) / 2.0 )
C
C     DIVIDE THE NUMBER OF LATERALS BY 4 TO DETERMINE THE NUMBER
C     OF COMPLETE LATERAL PAIRS ON EACH HALF OF THE MAIN. THIS
C     WILL BE USED AS A COUNTER TO DETERMINE THE NUMBER OF CAPACITORS OF
C     EACH SIZE INSTALLED BY YEAR "IYEAR" FOR THESE LATERAL PAIRS.
C
NPAIRS = RLAT / 4.0
C
C     CALCULATE THE EXTRA NUMBER OF LATERALS ON THE HALF OF THE MAIN
C     WHERE LATERALS WERE ADDED NEAR TO THE CENTRAL LATERAL AND ON
C     THE HALF OF THE MAIN WHERE LATERALS ARE ADDED FAR FROM THE
C     CENTRAL LATERAL.
C
EXTRA = RLAT - FLOAT( 4 * NPAIRS )
EXTRA1 = EXTRA - 2.0
IF( EXTRA .GT. 2.0 ) EXTRA = 2.0
IF( EXTRA1 .LT. 0.0 ) EXTRA1 = 0.0
C
C     STORE SIZES AND NUMBER PER SIZE OF CAPACITORS IN ARRAYS
C     FOR LATER USE.
C
RIM1 = -1.0
CAPX2 = 2 * NCAP
DO 30 I = 1, NPAIRS
  RIM1 = RIM1 + 1.0
  RNUMCP(I) = CAPX2
  RNUMCP(NPAIRS+I) = CAPX2
  SIZCP(I) = CAP2 + RIM1 * DELCAP
  SIZCP(NPAIRS+I) = CAP1 - RIM1 * DELCAP
30 CONTINUE
C
C     STORE SIZES AND NUMBER PER SIZE OF CAPACITORS ON
C     THE EXTRA LATERALS.
C
RNUMCP(2*NPAIRS+1) = EXTRA * FLOAT( NCAP )
SIZCP(2*NPAIRS+1) = CAP2 + FLOAT(NPAIRS) * DELCAP
C
IF( EXTRA1 .EQ. 0.0 ) GO TO 40
C
RNUMCP(2*NPAIRS+2) = EXTRA1 * FLOAT( NCAP )
SIZCP(2*NPAIRS+2) = CAP1 - FLOAT( NPAIRS ) * DELCAP
C
40 RETURN
END

```

SUBROUTINE PKYR

```

C
COMMON / ECONPE / AUTOFX, BMLOAD, CAPDIS, CAPRAT, CAPSIZ, CIRMAX,
1  CIRLAT, CLATR, CLATX, CRITLD, DLOT, DTZ,
2  FEEDRL, FEEDWR, FEEDWX, MLAT, HP, HSEC,
3  MSLOAD, IDUS, IMAX, MXCUST, NCAP, NCODE,
4  NCHNG(50), NCUSTS, NLATPR, NPHI, NSTART,
5  NX, NYEAR, OBJECT, POWFAC, PRIMWR, PRIMBX,
6  RLAT, SECR, SECX, SERVWR, SERVWX, TA,
7  VBUFF, VOLTHI, VOLTLO, VC, VP, VS,
8  WLOT, WRLAT, WXLAT, COMYR(20),
9  CUSTPK(50), DFAC(50), DLF(50),
A  F(50), H(20), YLF(50)

C
COMMON / PEECON / BLKLEN, BLKWID, BUSDIS, CAPNUM, CAP1, CAP2,
1  CIRLEN, CIRWID, CTAREA, DEMLOS, DISCNT, DISNUM,
2  DTCL, DTNPR, ENGYS, FEASBL, FLAG, FUSCUT,
3  FUSNUM, IYEAR, MXPKYR, MXSCYR, NODD, NTRN11,
4  NTRN12, NTRN21, NTRN22, PRIMLS, REMNUM, REMOTN,
5  SDEL, SUBLOD, TOTCEL, TOTI2R, TLATLS, TSWLOS,
6  TRANUM, YRCUST, CONNUM(20), RNUMCP(100),
7  SZCPC(100)

C
PEAKS = 0.0
PEAKSC = 0.0
RCUSTS = NCUSTS

C
DO 20 IYEAR = 1, NYEAR
  FIYEAR = F(IYEAR)
  TEMP = FIYEAR * CUSTPK(IYEAR) * DFAC(IYEAR)
  IF( PEAKS .GT. TEMP ) GO TO 10
  PEAKS = TEMP
  MXPKYR = IYEAR

C
10 TEMP = TEMP * RCUSTS * DIVFAC( RCUSTS ) / DIVFAC( 1000. )
  TEMP = TEMP / ( (1.0 - FIYEAR) * HSEC + FIYEAR )
  IF( PEAKSC .GT. TEMP ) GO TO 20
  PEAKSC = TEMP
  MXSCYR = IYEAR
20 CONTINUE

C
C THIS SECTION CALCULATES THE NUMBER OF TIMES THAT DISTRIBUTION
C TRANSFORMERS WILL BE CHANGED OUT. IT IS ASSUMED THAT TRANSFORMERS
C WILL BE INSTALLED FOR LOADS EQUAL TO NAMEPLATE RATING AND WILL
C BE CHANGED OUT AT CAPRAT * NAMEPLATE RATING. THEREFORE, CAPRAT
C MUST BE GREATER THAN 1.0 AND IN FACT SHOULD BE GREATER THAN 1.1
C TO AVOID ANY CHANCE OF OVERWRITING THE "NCHNG" ARRAY. "IMAX" IS
C THE NUMBER OF CHANGES AND NCHNG(IMAX) STORES THE YEARS WHEN EACH
C OF THE IMAX CHANGES SHOULD OCCUR.

C
C IT IS ASSUMED THAT 25 KVA IS THE SMALLEST NAMEPLATE RATING USED.
C
K = 1

```



```

DO 40 IYEAR = 1, NYEAR
  FIYEAR = F(IYEAR)
  SECLD = FIYEAR * CUSTPK(IYEAR) * DFAC(IYEAR) * RCUSTS *
1    DIVFAC(RCUSTS) / ( DIVFAC(1000.) *
2    ( ( 1. - FIYEAR ) * HSEC + FIYEAR ) )
C
  IF( IYEAR .GT. 1 ) GO TO 30
  SECLD1 = SECLD
  IF( SECLD1 .LT. 25.0 ) SECLD1 = 25.0
  R      = PEAKSC / SECLD1
  IMAX   = ALOG10( R ) / ALOG10(CAPRAT)
C
30 X = SECLD / SECLD1
  IF( X .LT. CAPRAT**K ) GO TO 40
  NCHNG(K) = IYEAR
  K = K + 1
  IF( K .GT. IMAX ) GO TO 50
40 CONTINUE
C
50 DTNPR = SECLD1
C
  WRITE(6,60) MXPKYR, MXSCYR, DTNPR
60 FORMAT( '-THE CIRCUIT  PEAK YEAR IS ', I4 /
1    ' THE SECONDARY PEAK YEAR IS ', I4 /
2    ' THE DISTRIBUTION TRANSFORMER NAMEPLATE RATING IS ',
3    F6.1, ' KVA' )
C
  RETURN
  END

```

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Subroutine PWRFLO

The POWERFLOW package for this program can be obtained in object module form from:

Mr. Stephen T. Matrasek
Philadelphia Electric Company
2301 Market Street
S12-1
Philadelphia, PA 19101

SUBROUTINE RATCHK
LOGICAL FEASBL

```

C      COMMON / ECON / ADJUST, C1 , C2 , C3 , C4 , CC1 ,
1      CC2 , CC3 , CC4 , CC5 , CC6 , CSFEED,
2      CSMIN, CSPRIM, CSSEC , CSSERV, FEEDRT, NUMB ,
3      OFFMIN, R , RAT , RATLAT, RTHAIN, SECRAT,
4      SERVRT, WSLAT , WSPRIM, WSSEC , WSSERV, CD(50),
5      FEC(50) , VEC(50)

C      COMMON / ECONPE / AUTOFX, BMLOAD, CAPDIS, CAPRAT, CAPSIZ, CIRMAX,
1      CIRLAT, CLATR, CLATX , CRITLD, DLOT , DTZ ,
2      FEEDRL, FEEDWR, FEEDWX, HLAT , HP , HSEC ,
3      HSLOAD, IDUS , IMAX , MXCUST, NCAP , NCODE ,
4      NCHNG(50) , NCUSTS, NLATPR, NPHI , NSTART,
5      NX , NYEAR , OBJECT, POWFAC, PRIMWR, PRIMWX,
6      RLAT , SECR , SECX , SERVWR, SERVWX, TA ,
7      VBUFF , VOLTHI, VOLTLO, VC , VP , VS ,
8      WLOT , WRLAT , WXLAT , COMYR(20) ,
9      CUSTPK(50) , DFAC(50) , DLF(50) ,
A      F(50) , H(20) , YLF(50)

C      COMMON / PEECON / BLKLEN, BLKWID, BUSDIS, CAPNUM, CAP1 , CAP2 ,
1      CIRLEN, CIRWID, CTAREA, DEMLOS, DISCNT, DISNUM,
2      DTCL , DTNPR , ENGYLS, FEASBL, FLAG , FUSCUT,
3      FUSNUM, IYEAR , MXPYR, MXSCYR, NODD , NTRN11,
4      NTRN12, NTRN21, NTRN22, PRIMLS, REMNUM, REMOTN,
5      SDEL , SUBLOD, TOTCEL, TOTI2R, TLATLS, TSWLOS,
6      TRANUM, YRCUST, COMNUM(20) , RNUMCP(100) ,
7      SIZCP(100)

C      FEASBL = .TRUE.
C      IF( NCODE .EQ. 0 ) GO TO 40
C      FIND PEAK CUSTOMER LOAD YEAR.
C
C      PEAK = 0.0
C      DO 10 I = 1, NYEAR
C      IF( PEAK .GE. CUSTPK(I) ) GO TO 10
C      PEAK = CUSTPK(I)
C      MCUSYR = I
10  CONTINUE

C      CHECK SERVICE DROP RATING FOR FEASIBILITY.
C
C      RATIO = DLF(MCUSYR) / DLFAC( 1000.0 )
C      DLFAC = RATIO * DLFAC( 1.0 )
C      CN = NPHI + 2
C      CALL RATE( CN, TA, CSSERV, VS, DLFAC, SERVRT )
C      COMPAR = CUSTPK(MCUSYR) / ( CN * VS )
C      IF( COMPAR .LE. SERVRT ) GO TO 30
C      WRITE(6,20) COMPAR, SERVRT
20  FORMAT( ' THE MAXIMUM SERVICE CABLE CURRENT OF ', F5.1,

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```

1      ' AMPS IS GREATER THAN THE CABLE RATING OF ', FS.1,
2      ' AMPS.' / ' INCREASE CABLE SIZE.' )
FEASBL = .FALSE.
GO TO 50

C
C   CALCULATE SECONDARY RATING.
C
30  RATIO = DLF(MXSCYR) / DLFAC( 1000.0 )
    DLFAC = RATIO * DLFAC( NCUSTS / 2.0 )
    CALL RATE( CN, TA, CSSEC, VS, DLFAC, SECRAT )

C
C   CALCULATE LATERAL RATING.
C
    CN = 2 * NPHI + 1
    DLFAC = DLF(MXPKYR)
    CALL RATE( CN, TA, CS PRIM, VP, DLFAC, RATLAT )

C
C   CALCULATE MAIN RATING.
C
    CN = 3.0
    CALL RATE( CN, TA, CSMAIN, VP, DLFAC, RTMAIN )

C
C   CALCULATE FEEDER RATING.
C
40  CN = 3.0
    DLFAC = DLF(MXPKYR)
    CALL RATE( CN, TA, CSFEED, VP, DLFAC, FEEDRT )

C
50  RETURN
    END

```

```

C      SUBROUTINE RATE( CN, TA, CS, V, SLF, XIN )
C
C      CALCULATES THE RATING FOR CABLES BURIED IN EARTH OR BURIED IN
C      DUCT. PEAK DAY LOSS FACTOR IS CONSIDERED IN CALCULATING THIS
C      NORMAL RATING.
C
C      TA = EARTH AMBIENT TEMPERATURE FOR PEAKING SEASON.
C      CN = NUMBER OF CABLES ( 1 OR 3 )
C      CS = CABLE SIZE IN KCMIL
C      V = VOLTAGE IN KV (PHASE-TO-GROUND FOR SECONDARY)
C          (PHASE-TO-PHASE FOR PRIMARY)
C      SLF = PEAK DAY LOSS FACTOR
C      XIN = NORMAL AMPERE RATING
C
C      E = V / SQRT( 3.0 )
C      IF( V .LT. 1.0 ) E = V
C
C      DC = 0.03636 * SQRT( CS )
C      DI = 0.08611 + 0.017593 * V + DC
C
C      SIT = 0.16
C      IF( 212.0 .LE. CS .AND. CS .LT. 350.0 ) SIT = 0.19
C      IF( CS .GE. 350.0 ) SIT = 0.22
C      IF( V .LT. 1.0 ) DI = DC + SIT
C
C      DJ = DI + 0.1
C      DS = DJ
C      IF( CN .EQ. 3.0 ) DS = 2.155 * DJ
C
C      DIDC = ALOG10( DI / DC )
C      Y = 8.83067 / DS
C      RI = 5.4 * DIDC
C      RJ = 0.26 / ( DJ - 0.5 )
C      WD = 1.449E-4 * E**2 / DIDC
C      RSD = 0.0
C      RD = 0.0
C
C      IF( CN .NE. 3.0 .OR. V .LT. 1.0 ) GO TO 10
C      RSD = 12.6 / ( DS + 0.245 )
C      DE = 4.5
C      IF( V .GT. 36.0 ) DE = 8.0
C      RD = 8.58 / ( DE - 0.5 )
C      Y = 8.83067 / DE
C
10 RE = 0.96 * CN * ( ALOG10( Y ) + 1.21237 * SLF )
C      RDED = 2.072028 * CN
C      RSE = RJ + RSD + RD
C      RCA = 1.05 * ( RSE + RE ) + RI
C      RDT = 0.5 * RI + RSE + RDED
C      TD = WD * RDT
C      INEXT = 1
C      TCN = 90.0
C      RAC25 = 17747.0 / CS

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SUBROUTINE RELCOM

```

C
COMMON / ECONPE / AUTOFX, BMLOAD, CAPDIS, CAPRAT, CAPSIZ, CIRMAX,
1      CIRLAT, CLATR, CLATX, CRITLD, DLOT, DTZ,
2      FEEDRL, FEEDWR, FEEDWX, HLAT, HP, HSEC,
3      HSLOAD, IDUS, IMAX, MXCUST, NCAP, NCODE,
4      NCHNG(50), NCUSTS, NLATPR, NPHI, NSTART,
5      NX, NYEAR, OBJECT, POWFAC, PRIMWR, PRIMWX,
6      RLAT, SECR, SECX, SERVWR, SERVWX, TA,
7      VBUFF, VOLTHI, VOLTLO, VC, VP, VS,
8      WLOT, WRLAT, WXLAT, COMYR(20),
9      CUSTPK(50), DFAC(50), DLF(50),
A      F(50), H(20), YLF(50)

C
COMMON / PEECON / BLKLEN, BLKWID, BUSDIS, CAPNUM, CAP1, CAP2,
1      CIRLEN, CIRWID, CTAREA, DEMLOS, DISCNT, DISNUM,
2      DTCL, DTNPR, ENGYLS, FEASBL, FLAG, FUSCUT,
3      FUSNUM, IYEAR, MXPKYR, MXSCYR, NODD, NTRN11,
4      NTRN12, NTRN21, NTRN22, PRIMLS, REMNUM, REMOTN,
5      SOEL, SUBLOD, TOTCEL, TOTI2R, TLATLS, TSWLOS,
6      TRANUM, YRCUST, COMNUM(20), RNUMCP(100),
7      SIZECP(100)

C
C      CALCULATE MAXIMUM CIRCUIT LOAD.
C
C      CIRMAX = ( F(MXPKYR) * CUSTPK(MXPKYR) * DFAC(MXPKYR) * CTAREA ) /
1      ( WLOT * DLOT )

C
C      CALCULATE NUMBER OF LATERALS FOR MXPKYR.
C
C      RNLAT = FLOAT(2*NLATPR) * ( F(MXPKYR) + HLAT*( 1.0 - F(MXPKYR) ) )

C
C      CALCULATE THE LOAD PER LATERAL FOR "MXPKYR".
C
C      RLATLD = CIRMAX / RNLAT

C
C      CALCULATE THE NUMBER OF LATERALS HAVING A LOAD EQUAL TO
C      "CRITLD".
C
C      CRTLAT = CRITLD / RLATLD

C
C      ROUND "CRTLAT" TO NEXT LOWEST EVEN NUMBER
C
C      NTEMP = CRTLAT
C      NCHK = MOD( NTEMP, 2 )
C      IF( NCHK .EQ. 1 ) NTEMP = NTEMP - 1
C      CRTLAT = NTEMP

C
C      IF( CRTLAT .LE. 0 ) GO TO 20

C
C      CALCULATE NUMBER OF REMOTE CONTROLLED AERIAL SWITCHES
C      OR REMOTE CONTROLLED THREE-PHASE FUSED SWITCHES PER LATERAL
C
C
20  RACN = RAC25 * ( 1.0 + 0.003951 * ( TCN - 25. ) )
    XIN = SQRT( ( TCN - TA - TD ) / ( RACN * RCA ) ) * 1000.0
    TPC = TA + ( XIN / 1000.0 )**2 * RACN * RE + WD * RE
    INEXT = INEXT + 1
    IF( INEXT .GT. 150 ) GO TO 30
    IF( ( TPC - 55.0 ) .LE. 0.1 ) GO TO 30
    TCN = TCN - 0.5
    GO TO 20

C
30  RETURN
    END

```

```

      REMOTN = 1.0 / CRTLAT
C
C   SET NUMBER OF FUSED CUTOUPS OR STANDARD THREE-PHASE
C   PER LATERAL FUSED SWITCHES
C
      FUSCUT = 1.0
C
C   SET NUMBER OF DISCONNECTS OR STANDARD THREE-PHASE
C   FUSED SWITCHES PER LATERAL
C
      IF( CRTLAT .LE. 2.0 ) GO TO 10
      DISCNT = 0.5
      GO TO 40
10  DISCNT = 1.5
      GO TO 40
C
20  IF( RLATLD .GE. CRITLD ) GO TO 30
C
C   SET NUMBER OF REMOTE CONTROLLED AERIAL SWITCHES OR
C   REMOTE CONTROLLED THREE-PHASE FUSED SWITCHES PER LATERAL
C
      REMOTN = 2.0
C
C   SET NUMBER OF FUSED CUTOUPS PER LATERAL
C
      FUSCUT = 0.0
C
C   SET NUMBER OF DISCONNECTS OR STANDARD THREE-PHASE
C   FUSED SWITCHES PER LATERAL
C
      DISCNT = 3.0
      GO TO 40
C
C   CALCULATE THE NUMBER OF LOADS EQUAL TO CRITLD ON A LATERAL AND
C   ROUND UP TO THE NEXT HIGHER INTEGER.
C
30  SECT = RLATLD / CRITLD
      NSECT = SECT
      TEST = SECT - NSECT
      IF( TEST .GT. 0.0 ) NSECT = NSECT + 1
C
C   SET NUMBER OF REMOTE CONTROLLED AERIAL SWITCHES OR
C   REMOTE CONTROLLED THREE-PHASE FUSED SWITCHES PER LATERAL
C
      REMOTN = NSECT + 1
C
C   SET NUMBER OF FUSED CUTOUPS PER LATERAL
C
      FUSCUT = 0.0
C
C   SET NUMBER OF DISCONNECTS OR STANDARD THREE-PHASE
C   FUSED SWITCHES PER LATERAL
C
      DISCNT = 3 * NSECT
C
40  RETURN
      END

```

```

SUBROUTINE RESET
C
COMMON / CUSPKS / CSPKSV(50)
C
COMMON / ECON / ADJUST, C1 , C2 , C3 , C4 , CC1 ,
1 CC2 , CC3 , CC4 , CC5 , CC6 , CSFEED,
2 CSMAIN, CSPRIM, CSSEC , CSSERV, FEEDRT, NUMB ,
3 OFFMIN, R , RAT , RATLAT, RTMAIN, SECRAT,
4 SERVRT, WSLAT , WSPRIM, WSEC , WSSERV, CD(50),
5 FEC(50) , VEC(50)
C
COMMON / ECONPE / AUTOFX, BMLOAD, CAPDIS, CAPRAT, CAPSIZ, CIRMAL,
1 CIRRT, CLATR, CLATX , CRITLD, DLOT , DTZ ,
2 FEEDRL, FEEDWR, FEEDWX, HLAT , HP , HSEC ,
3 HSLOAD, IDUS , IMAX , MXCUST, NCAP , NCODE ,
4 NCHNG(50) , NCUSTS, NLATPR, NPHI , NSTART,
5 NX , NYEAR , OBJECT, POWFAC, PRIMWR, PRIMWX,
6 RLAT , SECR , SECX , SERVWR, SERVWX, TA ,
7 VBUFF , VOLTHI, VOLTLO, VC , VP , VS ,
8 WLOT , WRLAT , WXLAT , COMYR(20) ,
9 CUSTPK(50) , DFAC(50) , DLF(50) ,
A F(50) , H(20) , YLF(50)
C
COMMON / PEECON / BLKLEN, BLKWID, BUSDIS, CAPNUM, CAPI , CAP2 ,
1 CIRLEN, CIRWID, CTAREA, DEMLOS, DISCNT, DISNUM,
2 DTCL , DTNPR , ENGYLS, FEASBL, FLAG , FUSCUT,
3 FUSNUM, IYEAR , MXPYR, MXSCYR, NODD , NTRN11,
4 NTRN12, NTRN21, NTRN22, PRIMLS, REMNUM, REMOTN,
5 SOEL , SUBLOD, TOTCEL, TOTI2R, TLTLS, TSWLOS,
6 TRANUM, YRCUST, COMNUM(20) , RNUMCP(100) ,
7 SZCP(100)
C
IF( NCODE .EQ. 1 ) GO TO 10
C
SERVWR = 1.9234 / WSSERV
SERVWX = .0022
C
SECR = 1.9234 / WSEC
SECX = .0022
C
WRLAT = 1.9234 / WSLAT
WXLAT = 5.29E-3 * ( ALOG10( 10258. + 154.5 * VP - VP**2 ) -
1 0.5 * ALOG10(WSLAT) - 0.2723 )
C
PRIMWR = 1.9234 / WSPRIM
PRIMWX = ( .005715 * ( ALOG10( 3.25+.001106*VP+.0007955*VP**2 )
1 -0.5 * ALOG10(WSPRIM) ) + .01677 )
C
10 FEEDWR = 1.9234 / CSFEED
C = 1.0 / SQRT( CSFEED )
FEEDWX = ( .00635 * ALOG10( 2.6109 + 6.1834*C + 1.2633*VP*C ) )
C
IF( NCODE .EQ. 0 ) GO TO 20

```



```

      SECR = 1.9234 / CSSEC
      SECX = 0.0023
C
      SERVWR = 1.9234 / CSSERV
      SERVWX = 0.0023
C
      PRIMWR = 1.9234 / CSMAIN
      PRIMWX = 0.01448 - 0.00265 * ALOG10( CSMAIN )
C
      CLATR = 1.9234 / CSPRIM
      CLATX = 0.01448 - 0.00265 * ALOG10( CSPRIM )
C
      IF( NPHI .EQ. 1 ) GO TO 20
      C = SQRT( CSPRIM )
      GMDGMR = 0.635 + 1.5459/C + 0.3158 * VP/C +
1          SQRT( 0.852 + 2.02/C + 2.39/CSPRIM + 0.4126 * VP/C +
2          0.977 * VP/CSPRIM + 0.0998 * VP**2 / CSPRIM )
      CLATX = 0.00529 * ALOG10( GMDGMR )
C
20  RLAT = 0.0
C
      CAP1 = 0.0
      CAP2 = 0.0
      CAPNUM = 0.0
C
      DO 30 I = 1, 100
      RNUNCP(I) = 0.0
      SIZCP(I) = 0.0
30  CONTINUE
C
      DO 40 I = 1, 20
      COMYR(I) = 0.0
40  CONTINUE
C
      RAT = ( 75.0 * VP * NUMB / 36.0 )
C
      DO 50 I = 1, 50
      CUSTPK(I) = CSPKSV(I)
50  CONTINUE
C
      RETURN
      END

```

SUBROUTINE RESLD

```

C      COMMON / ECONPE / AUTOFX, BMLOAD, CAPDIS, CAPRAT, CAPSIZ, CIRMAX,
1      CIRLAT, CLATR, CLATX, CRITLD, DLOT, DTZ,
2      FEEDRL, FEEDWR, FEEDWX, HLAT, HP, HSEC,
3      MSLOAD, IDUS, IMAX, MXCUST, NCAP, NCODE,
4      NCHNG(50), NCUSTS, NLATPR, NPHI, NSTART,
5      NX, NYEAR, OBJECT, POWFAC, PRIMWR, PRIMWX,
6      RLAT, SECR, SECX, SERVWR, SERVWX, TA,
7      VBUFF, VOLTHI, VOLTLO, VC, VP, VS,
8      WLOT, WRLAT, WXLAT, COMYR(20),
9      CUSTPK(50), DFAC(50), DLF(50),
A      F(50), H(20), YLF(50)

C      COMMON / PEECON / BLKLEN, BLKWID, BUSDIS, CAPNUM, CAP1, CAP2,
1      CIRLEN, CIRWID, CTAREA, DEMLOS, DISCNT, DISNUM,
2      DTCL, DTNPR, ENGYLS, FEASBL, FLAG, FUSCUT,
3      FUSNUM, IYEAR, MXPYR, MXSCYR, NODD, NTRN11,
4      NTRN12, NTRN21, NTRN22, PRIMLS, REMNUM, REMOTN,
5      SDEL, SUBLOD, TDTCEL, TDT12R, TLTLS, TSWLOS,
6      TRANUM, YRCUST, COMNUM(20), RNUMCP(100),
7      SZCPI(100)

C      HPSAV = HP
C
C      REMOVE BIG MOTOR PART
C
C      BMLOAD = HP * 0.77
C      HLD = MSLOAD - BMLOAD
C
C      GET RESISTIVE PART
C
C      RESIS = HLD * .579
C
C      SCALE ROOM AIRCONDITIONER
C
C      HP = 0.75
C      AIRR = HLD * .043 * ADA(2)
C
C      SCALE CENTRAL AIR-CONDITIONER
C
C      HP = 3.0
C      AIRC = HLD * .112 * ADA(1)
C
C      SCALE WASHERS
C
C      HP = .33
C      WASH = HLD * .023 * ADA(2)
C
C      SCALE DRYERS
C
C      HP = .33
C      DRY = HLD * .043 * ADA(2)

```

```

C
C   SCALE FREEZER
C
  HP = .33
  FREZ = HLD * .058 * ADA(2)
C
C   SCALE REFRIGERATOR
C
  HP = .33
  REFR = HLD * .142 * ADA(2)
C
C   SCALE POSSIBLE AUTOTRANSFORMER
C
  IF( VS .EQ. VC ) AUTOFX = 0.0
  AUTO = AUTOFX * ( AIRR + WASH + DRY + FREZ + REFR + RESIS )
C
C   SCALE BIG MOTOR
C
  HP = HPSAV
  BIGM = BMLOAD * ADA(1+2*NPHI)
C
C   RECOMBINE PARTS
C
  CUST = RESIS + AIRR + AIRC + WASH + DRY + FREZ + REFR
  CUST = CUST + AUTO + BIGM
C
  CUSTPK(1) = CUST
  IF( NYEAR .EQ. 1 ) GO TO 20
  DO 10 I = 2, NYEAR
    CUSTPK(I) = CUSTPK(I) * CUSTPK(I-1)
  10 CONTINUE
C
  20 RETURN
  END

```

SUBROUTINE RESLD

```

C      COMMON / ECONPE / AUTOFX, BMLOAD, CAPDIS, CAPRAT, CAPSIZ, CIRMAL,
1      CIRLAT, CLATR, CLATX, CRITLD, DLOT, DTZ,
2      FEEDRL, FEEDWR, FEEDWX, HLAT, HP, HSEC,
3      HSLOAD, IDUS, IMAX, MXCUST, NCAP, NCOOE,
4      NCHNG(50), NCUSTS, NLATPR, NPHI, NSTART,
5      NX, NYEAR, OBJECT, POWFAC, PRIMWR, PRIMWX,
6      RLAT, SECR, SECX, SERVWR, SERVWX, TA,
7      VBUFF, VOLTHI, VOLTLO, VC, VP, VS,
8      WLOT, WRLAT, WXLAT, COMYR(20),
9      CUSTPK(50), DFAC(50), DLF(50),
A      F(50), H(20), YLF(50)

C      COMMON / PEECON / BLKLEN, BLKWID, BUSDIS, CAPNUM, CAP1, CAP2,
1      CIRLEN, CIRWID, CTAREA, DEMLOS, DISCNT, DISNUM,
2      DTCL, OTNPR, ENGYS, FEASBL, FLAG, FUSCUT,
3      FUSNUM, IYEAR, MXPYR, MXSCYR, NODD, NTRN11,
4      NTRN12, NTRN21, NTRN22, PRIMLS, REMNUM, REMOTN,
5      SDEL, SUBLOD, TDTCEL, TDTI2R, TLATLS, TSWLOS,
6      TRANUM, YRCUST, COMNUM(20), RNUMCP(100),
7      SIZCP(100)

C      HPSAV = HP

C      REMOVE BIG MOTOR PART
C
C      BMLOAD = HP * 0.77
C      HLD = HSLOAD - BMLOAD

C      GET RESISTIVE PART
C
C      RESIS = HLD * .579

C      SCALE ROOM AIRCONDITIONER
C
C      HP = 0.75
C      AIRR = HLD * .043 * ADA(2)

C      SCALE CENTRAL AIR-CONDITIONER
C
C      HP = 3.0
C      AIRC = HLD * .112 * ADA(1)

C      SCALE WASHERS
C
C      HP = .33
C      WASH = HLD * .023 * ADA(2)

C      SCALE DRYERS
C
C      HP = .33
C      DRY = HLD * .043 * ADA(2)

```

```

C
C   SCALE FREEZER
C
C   HP = .33
C   FREZ = HLD * .058 * ADA(2)
C
C   SCALE REFRIGERATOR
C
C   HP = .33
C   REFR = HLD * .142 * ADA(2)
C
C   SCALE POSSIBLE AUTOTRANSFORMER
C
C   IF( VS .EQ. VC ) AUTOFX = 0.0
C   AUTO = AUTOFX * ( AIRR + WASH + DRY + FREZ + REFR + RESIS )
C
C   SCALE BIG MOTOR
C
C   HP = HPSAV
C   BIGM = BMLOAD * ADA(1+2*NPHI)
C
C   RECOMBINE PARTS
C
C   CUST = RESIS + AIRR + AIRC + WASH + DRY + FREZ + REFR
C   CUST = CUST + AUTO + BIGM
C
C   CUSTPK(1) = CUST
C   IF( NYEAR .EQ. 1 ) GO TO 20
C   DO 10 I = 2, NYEAR
C   CUSTPK(I) = CUSTPK(I) * CUSTPK(I-1)
10  CONTINUE
C
C   20 RETURN
C   END

```

FUNCTION ROTOR(IDUPMY)

THIS ROUTINE RETURNS FIXED LOCK ROTOR CURRENT GIVEN
MOTOR TYPE, HORSEPOWER AND LINE VOLTAGE.

VOLTAGE AND HORSEPOWER ENTER THRU COMMON BLOCKS AND
MOTOR TYPE IS INDICATED AS FOLLOWS:

CAPACITOR IDUS = 1
SPLIT PHASE IDUS = 2
THREE-PHASE IDUS = 3

THE FUNCTIONS ARE ASSUMED TO BE HYPERBOLIC OF THE FORM
 $IV = C$ WHERE I = CURRENT V = VOLTAGE AND C IS CONSTANT.

COMMON / ECONPE / AUTOFX, BMLOAD, CAPDIS, CAPRAT, CAPSIZ, CIRMAL,
1 CIRRAT, CLATR, CLATX, CRITLD, DLOT, DTZ,
2 FEEDRL, FEEDWR, FEEDWX, HLAT, HP, HSEC,
3 MSLOAD, IDUS, IMAX, MXCUST, NCAP, NCOOE,
4 MCHNG(50), NCUSTS, NLATPR, NPHI, NSTART,
5 NX, NYEAR, OBJECT, POWFAC, PRIMWR, PRIMWX,
6 RLAT, SECR, SECX, SERVWR, SERVWX, TA,
7 VBUFF, VOLTHI, VOLTLO, VC, VP, VS,
8 WLOT, WRLAT, WXLAT, COMYR(20),
9 CUSTPK(50), DFAC(50), DLF(50),
A F(50), H(20), YLF(50)

REAL*8 CONS(7,3), HPVALS(7,3), DHP, C1, C2, CURHP
REAL*8 SMALL / 1.0-4 /
INTEGER*4 NUMHP(3)

DATA HPVALS / .25D0, .75D0, 1.0D, 1.5D0, 2.0D, 3.0D, 5.0D,
1 .05D0, .067D0, .25D0, .375D0, .75D0, 2*0.0D,
2 .50D0, .75D0, 1.0D, 1.5D0, 2.0D, 3.0D, 5.0D /

DATA CONS / 1883.9875D0, 3798.7375D0, 6061.3625D0, 11284.087 D0,
1 16952.437 D0, 29315.8 D0, 55275.325 D0, 348.7375D0,
2 553.15 D0, 2752.525 D0, 5141.9375D0, 13565.4 D0,
3 2*0. D0, 1034.7125D0, 1995.25 D0, 3056.4125D0,
4 5294.025 D0, 7585.4 D0, 11697.512 D0, 22013.3 D0 /

DATA NUMHP / 7, 5, 7 /

DHP = HP

CONVERT LINE VOLTAGE TO VOLTS

VSC = 2 * VS * 1000.

CHECK IF HORSEPOWER ACCEPTABLE

IF(DHP .GE. HPVALS(1,IDUS) .AND.
1 DHP .LE. HPVALS(NUMHP(IDUS),IDUS)) GO TO 20

```

C      IF( DABS( DHP - HPVALS(1,IDUS) ) .LT. SMALL) GO TO 20
C
C      IF( DABS( DHP - HPVALS(NUMHP(IDUS),IDUS) ) .LT. SMALL ) GO TO 20
C
C      WRITE(6,10)
10  FORMAT('*** ERROR *** HORSEPOWER OUT OF BOUNDS IN ROTORC')
      GO TO 60
C
C      CHECK IF HP IS IN LIST
C
C      20  ISTOP = NUMHP(IDUS)
          DO 30 ITEST = 1, ISTOP
              CURHP = HPVALS(ITEST,IDUS)
              IF( DABS( DHP - CURHP ) .LT. SMALL ) GO TO 40
              IF( CURHP .GT. DHP ) GO TO 50
          30  CONTINUE
C
C      IF HP MATCHES A DATA POINT RETURN FUNCTION VALUE OF CURRENT
C
C      40  ROTORC = CONS(ITEST,IDUS) / VSC
          GO TO 60
C
C      CALCULATE VALUES ON EITHER SIDE OF HP AND INTERPOLATE
C
C      50  C1 = CONS(ITEST,IDUS) / VSC
          C2 = CONS(ITEST-1,IDUS) / VSC
          ROTORC = C2 + ( C1 - C2 ) * ( DHP - HPVALS(ITEST-1,IDUS) )
              1 / ( CURHP - HPVALS(ITEST-1,IDUS) )
60  RETURN
      END

```

SUBROUTINE SECH00
LOGICAL FEASBL

```

C
COMMON / ECON / ADJUST, C1 , C2 , C3 , C4 , CC1 ,
1 CC2 , CC3 , CC4 , CC5 , CC6 , CSFEED,
2 CSMAIN, CSPRIM, CSSEC , CSSERV, FEEDRT, NUMB ,
3 OFFMIN, R , RAT , RATLAT, RTHAIN, SECRAT,
4 SERVRT, WSLAT , MSPRIM, WSSEC , WSSERV, CO(50),
5 FEC(50) , VEC(50)

C
COMMON / ECONPE / AUTOFX, BMLOAD, CAPDIS, CAPRAT, CAPSIZ, CIRMAL,
1 CIRRTAT, CLATR , CLATX , CRITLD, DLOT , DTZ ,
2 FEEDRL, FEEDWR, FEEDWX, HLAT , HP , HSEC ,
3 MSLOAD, IDUS , IMAX , MXCUST, NCAP , NCODE ,
4 NCHNG(50) , NCUSTS, NLATPR, NPHI , NSTART,
5 NX , NYEAR , OBJECT, POWFAC, PRIMWR, PRIMWX,
6 RLAT , SECR , SECX , SERVWR, SERVWX, TA ,
7 VBUFF , VOLTHI, VOLTLO, VC , VP , VS ,
8 WLOT , WRLAT , MXLAT , COMYR(20) ,
9 CUSTPK(50) , DFAC(50) , DLF(50) ,
A F(50) , H(20) , YLF(50)

C
LOGICAL LFDBUG

C
COMMON / FLODBG / LFDBUG

C
COMMON / LDFLOW / PFLOW(2,200) , QFLOW(2,200) , VANGLE(200) ,
1 VMAG(200)

C
COMMON / PEECON / BLKLEN, BLKWID, BUSDIS, CAPNUM, CAP1 , CAP2 ,
1 CIRLEN, CIRWID, CTAREA, DEMLOS, DISCNT, DISNUM,
2 DTCL , DTNPR , ENGYLS, FEASBL, FLAG , FUSCUT,
3 FUSNUM, IYEAR , MXPKYR, MXSCYR, NODD , NTRN11,
4 NTRN12, NTRN21, NTRN22, PRIMLS, REMNUM, REMOTN,
5 SDEL , SUBLOD, TDTCEL, TDTI2R, TLATLS, TSWLOS,
6 TRANUM, YRCUST, COMNUM(20) , RNUNCP(100) ,
7 SIZCP(100)

C
COMMON / SECNDY / CAPSEC(200) , PDSEC(200) , QDSEC(200) ,
1 NSECFT(2,200) , RLNSEC(200) , XLNSEC(200) ,
2 NSECBS

C
FOR UNDERGROUND SYSTEM "NX" IS ALWAYS ONE

C
IF( NCODE .EQ. 1 ) NX = 1

C
COMPUTE NUMBER OF BUSES TO BE USED IN LOAD FLOW NETWORK

C
NSECBS = ( ( NCUSTS + 4 ) / ( 4 * NX ) ) + 1

C
COMPUTE SINGLE CUSTOMER LOAD IN PEAK SECONDARY
C YEAR "MXSCYR".
C

```



```

POSEC(1) = ( CUSTPK(MXSCYR) * POWFAC ) / FLOAT( 2 - NPHI )
QDSEC(1) = SQRT((CUSTPK(MXSCYR)/FLOAT(2-NPHI))**2 - POSEC(1)**2 )

C
C ADD TO SINGLE CUSTOMER, THE REAL LOSSES OF THE SERVICE
C CONNECTION.
C
SERVL = SQRT( WLOT**2 + DLOT**2 )
IF( NCODE .EQ. 1 ) SERVL = DLOT

C
TEMP = ( CUSTPK(MXSCYR) / ( VS * FLOAT( 2+NPHI ) ) )**2 *
1 ( SERVL / 2.0E5 ) * FLOAT(2*NPHI+1)
PDL = POSEC(1) + SERVWR * TEMP
QDL = QDSEC(1) + SERVWX * TEMP

C
C SPECIFY REAL AND REACTIVE LOADS ON BUSES 2 THROUGH NSECBS -1.
C
DIVERS = DIVFAC( FLOAT( NCUSTS/2 - 2*(NX-1) ) ) * DFAC(MXSCYR) /
1 DIVFAC( 1000.0 )
TWOX = 2.0 * NX
PDVAL = TWOX * ( POSEC(1) * DIVERS + DIVERS**2 * SERVWR * TEMP )
QDVAL = TWOX * ( QDSEC(1) * DIVERS + DIVERS**2 * SERVWX * TEMP )

C
POSEC(2) = PDVAL - PDL
QDSEC(2) = QDVAL - QDL

C
NSM1 = NSECBS - 1
DO 10 NBUS = 3, NSM1
CAPSEC(NBUS) = 0.0
POSEC (NBUS) = PDVAL
QDSEC (NBUS) = QDVAL
10 CONTINUE

C
CAPSEC( 1) = 0.0
CAPSEC( 2) = 0.0
CAPSEC(NSECBS) = 0.0
POSEC (NSECBS) = 0.0
QDSEC (NSECBS) = 0.0

C
C SPECIFY LINE CONNECTIONS, RESISTANCE AND REACTANCE, FOR
C SERVICE CONNECTIONS.
C
NSECFT(1,1) = 1
NSECFT(2,1) = 2

C
PCTPU = ( 3.0 * VS**2 ) / ( 10.0 * ( 3 - 2 * NPHI ) )
TEMP = SERVL / 200.0
RLNSEC(1) = TEMP * SERVWR / PCTPU
XLNSEC(1) = TEMP * SERVWX / PCTPU

C
TEMP = FLOAT( NX ) / 100.0
RPU = TEMP * WLOT * SECR / PCTPU
XPU = TEMP * WLOT * SECX / PCTPU

C
DO 20 I = 2, NSM1
NSECFT(1,I) = I
NSECFT(2,I) = I + 1
RLNSEC(I) = RPU
XLNSEC(I) = XPU

```

```

20 CONTINUE
   NSECFT(1,NSECBS) = 9999
C
   IF( LFDBUG ) WRITE(6,30)
30 FORMAT( '-THE FOLLOWING LOAD FLOW WAS GENERATED BY "SECH00"' )
C
   RUN THE LOAD FLOW WITH SECONDARY MODEL INPUTS
C
   CALL PWRFLOW( NSECBS , PDSEC , QDSEC , CAPSEC ,
1      NSECFT , RLNSEC , XLNSEC ,
2      VMAG , VANGLE , PGSEC , QGSEC ,
3      PFLOW , QFLOW , PLSSEC , QLSSEC ,
4      100.0 , 100.0 , 0.0001 , 0.0001 )
C
   IF( NCODE .EQ. 0 ) GO TO 50
C
   CHECK SECONDARY CABLE RATING FOR FEASIBILITY
C
   COMPAR = SQRT( PGSEC**2 + QGSEC**2 ) / ( ( 2 * NPHI + 1 ) * VS )
   IF( COMPAR .LE. SECRAT ) GO TO 50
   FEASBL = .FALSE.
C
   WRITE(6,40) COMPAR, SECRAT
40 FORMAT( 'OTHE MAXIMUM SECONDARY CABLE CURRENT OF', F6.1,
1      ' AMPS IS GREATER THAN THE CABLE RATING OF', F6.1,
2      ' AMPS.' / ' INCREASE CABLE SIZE.' )
   GO TO 70
C
   CHECK MAXIMUM VOLTAGE DROP.
C
50 FEASBL = VMAG(NSECBS)-VMAG(1) .LT. (VOLTTHI-VOLTLO)/VS - VBUFF
   IF( FEASBL ) GO TO 70
C
   WRITE(6,60)
60 FORMAT( ' EXCESSIVE VOLTAGE DROP IN SECONDARY CIRCUIT.' )
C
70 RETURN
   END

```

```

SUBROUTINE SPEVAL( X, Y, MX, C, U, S, M )
IMPLICIT REAL*8 ( A - H, O - Z )

```

```

C      THIS ROUTINE EVALUATES THE CUBIC SPLINE FUNCTION AT ALL
C      POINTS OF VECTOR U USING COEFFICIENTS IN 3 BY 3 MATRIX C
C      VECTORS X AND Y CONTAINING THE DATA POINTS FROM WHICH THE
C      SPLINE HAS BEEN CALCULATED.

```

```

C      INPUTS ARE:

```

```

C      X  ABSCISSAE
C      Y  ORDINATES
C      MX NUMBER OF DATA POINTS
C      C  MATRIX OF COEFFICIENTS
C      U  VECTOR OF POINTS TO BE EVALUATED
C      M  NUMBER OF POINTS TO BE EVALUATED

```

```

C      OUTPUTS ARE:

```

```

C      S  VECTOR OF SPLINE EVALUATIONS

```

```

REAL*8 C(3,3), S(1), U(1), X(1), Y(1)

```

```

SMALL = 1.0-4
DO 50 IPT = 1, M

```

```

C      CHECK IF EVALUATION POINT SAME AS GREATEST DATA POINT

```

```

C      IF( DABS( U(IPT) - X(MX) ) .GT. SMALL ) GO TO 10
C      S(IPT) = Y(MX)
C      GO TO 50

```

```

C      LOCATE INTERVAL OF POINT TO BE EVALUATED

```

```

10 ISTOP = MX - 1
DO 20 IPART = 1, ISTOP
IF( DABS( U(IPT) - X(IPART) ) .LT. SMALL ) GO TO 40
IF( U(IPT) .GT. X(IPART) .AND.
1   U(IPT) .LT. X(IPART+1) ) GO TO 40
20 CONTINUE

```

```

C      WRITE(6,30) U(IPT)
30 FORMAT( ' *** ERROR *** VOLTAGE VALUE',F10.5,' NOT IN ANY PARTITION
1      ' )
STOP 12

```

```

C      CALCULATE DISTANCE TO LEFT ENDOPOINT OF PARTITION

```

```

40 D = U(IPT) - X(IPART)

```

```

C      EVALUATE SPLINE

```

```

C      S(IPT) = ( ( C(IPART,3) * D + C(IPART,2) ) * D
1      + C(IPART,1) ) * D + Y(IPART)
50 CONTINUE

```

SUBROUTINE SYSLOS

```

C      COMMON / CAPDAT / LTCPBS(100) , NCAP1(50) , NCAP2(50)
C
C      COMMON / ECONPE / AUTOFX, BMLOAD, CAPDIS, CAPRAT, CAPSIZ, CIRMAL,
1      CIRLAT, CLATR , CLATX , CRITLD, DLOT , DTZ ,
2      FEEDRL, FEEDWR, FEEDWX, HLAT , HP , HSEC ,
3      HSLOAD, IDUS , IMAX , MXCUST, NCAP , NCODE ,
4      NCHNG(50) , NCUSTS, NLATPR, NPHI , NSTART,
5      NX , NYEAR , OBJECT, POWFAC, PRIMWR, PRIMAX,
6      RLAT , SECR , SECX , SERVWR, SERVWX, TA ,
7      VBUFF , VOLTHI, VOLTLO, VC , VP , VS ,
8      WLOT , WRLAT , WXLAT , COMYR(20) ,
9      CUSTPK(50) , DFAC(50) , DLF(50) ,
A      F(50) , HI(20) , YLF(50)
C
C      LOGICAL LFDBUG
C
C      COMMON / FLODBG / LFDBUG
C
C      COMMON / LATRAL / CAPLAT(200) , POLAT(200) , QOLAT(200) ,
1      NLATFT(2,200) , RLNLAT(200) , XLNLAT(200) ,
2      LATBUS
C
C      COMMON / LDFLOW / PFLOW(2,200) , QFLOW(2,200) , VANGLE(200) ,
1      VMAG(200)
C
C      COMMON / PEECON / BLKLEN, BLKWID, BUSDIS, CAPNUM, CAP1 , CAP2 ,
1      CIRLEN, CIRWID, CTAREA, DEMLOS, DISCNT, DISNUM,
2      DTCL , DTNPR , ENGYLS, FEASBL, FLAG , FUSCUT,
3      FUSNUM, IYEAR , MXPBYR, MXSCYR, NODD , NTRN11,
4      NTRN12, NTRN21, NTRN22, PRIMLS, REMNUM, REMOTN,
5      SDEL , SUBLOD, TDTCEL, TDTI2R, TLATLS, TSWLOS,
6      TRANUM, YRCUST, COMNUM(20) , RNUMCP(100) ,
7      SIZCP(100)
C
C      COMMON / PRIMRY / CPMALN(200) , PDMALN(200) , QDMALN(200) ,
1      MAINFT(2,200) , RLMAIN(200) , XLMAIN(200) ,
2      NPRIME
C
C      COMMON / SECNDY / CAPSEC(200) , PDSEC(200) , QDSEC(200) ,
1      NSECFT(2,200) , RLNSEC(200) , XLNSEC(200) ,
2      NSECBS
C
C      CALCULATE THE NUMBER OF CUSTOMERS IN THE YEAR "IYEAR".
C
C      YRCUST = F(IYEAR) * FLOAT( MXCUST )
C
C      CALCULATE THE NUMBER OF SECONDARY CUSTOMERS PER SECONDARY
C      TRANSFORMER.
C
C      TCUSTS = YRCUST / COMYR(20)
C
C
C      RETURN
C      END

```

```

C      CALCULATE SERVICE DROP I**2*R LOSS FOR A SINGLE LINE
C      SERVICE WIRE FOR CUSTOMER PEAK LOAD IN KW.
C
      SERVL = SQRT( DLOT**2 + WLOT**2 )
      IF( NCODE .EQ. 1 ) SERVL = DLOT
      PSDL = ( CUSTPK(IYEAR) / ( FLOAT( 2+NPHI ) * VS ) )**2 *
1      SERVL / 2.0 * SERVWR * 1.0 E-5
C
C      CALCULATE TOTAL ANNUAL SERVICE DROP ENERGY LOSS.
C
      SDEL = YRCUST * FLOAT( 2+NPHI ) * PSDL * 8760.0 * FACLOS( 1.0 ) *
1      YLF(IYEAR) / FACLOS( 1000.0 )
C
C      CALCULATE THE SINGLE CUSTOMER COINCIDENT PEAK LOAD FOR THE
C      NUMBER OF CUSTOMERS ON ONE-HALF OF A SECONDARY TRANSFORMER.
C
      SCUSTS = TCUSTS / 2.0
      SDMAND = CUSTPK(IYEAR) * DIVFAC(SCUSTS) * DFAC(IYEAR) /
1      DIVFAC( 1000.0 )
C
C      CALCULATE SERVICE DROP I**2*R AND I**2*X LOSS FOR A SINGLE
C      LIVE SERVICE WIRE.
C
      PSDPL1 = ( SDMAND / ( FLOAT( 2+NPHI ) * VS ) )**2 *
1      SERVL / 2.0 * SERVWR * 1.0 E-5
      PSDQL1 = PSDPL1 * SERVWX / SERVWR
C
C      CALCULATE THE FRACTION OF PRESENT SECONDARY CUSTOMERS PER
C      SECONDARY BANK DIVIDED BY MAXIMUM NUMBER OF SECONDARY
C      CUSTOMERS PER SECONDARY BANK.
C
      SECF = TCUSTS / FLOAT( NCUSTS )
C
C      CALCULATE THE BUS LOADS TO BE PLACED ON THE SECONDARY MODEL
C      BUSES FOR THE LOAD FLOW.
C
      RNXM1 = NX - 1
      TWONX = 2 * NX
      SECP = SECF * TWONX * ( SDMAND * POWFAC / FLOAT( 2-NPHI ) +
1      FLOAT( 2*NPHI + 1 ) * PSDPL1 )
      SECQ = SECF * TWONX * ( PSDQL1 * FLOAT( 2*NPHI + 1 ) +
1      SDMAND * SQRT( 1.0 - POWFAC**2 ) / FLOAT( 2-NPHI ) )
C
C      PLACE LOADS ON SECONDARY BUSES FOR LOADFLOW
C
      DO 10 I = 1, NSECBS
      PDSEC(I) = SECP
      QDSEC(I) = SECQ
10 CONTINUE
C
C      IF( LFDEBUG ) WRITE(6,20)
20 FORMAT( '-*** SYSLOS --- THIS LOAD FLOW IS USED TO CALCULATE THE '
1, 'SECONDARY WIRE LOSS.' )
C
C      RUN THE LOAD FLOW WITH SECONDARY MODEL INPUTS
C
      CALL PMRFLO( NSECBS+1, PDSEC , QDSEC , CAPSEC,
1      NSECFT , RLNSEC , XLNSEC ,

```

```

2          VMAG      , VANGLE , PGSEC , QGSEC ,
3          PFLOW     , QFLOW  , PLSSEC , QLSSEC ,
4          100.0     , 100.0  , 0.0001 , 0.0001 )

C          IF( NPHI .NE. 0 ) GO TO 30

C          CALCULATE LOSS ON BOTH LIVE WIRES OF THE SINGLE PHASE
C          SECONDARY

C          SWLOSS = 2.0 * PLSSEC
C          GO TO 40

C          CALCULATE LOSS ON ALL THREE PHASES OF SECONDARY.
C
30 SWLOSS = PLSSEC

C          CALCULATE THE TOTAL SECONDARY WIRE LOSS FOR THE YEAR "IYEAR".
C
40 TSWLOS = SWLOSS * COMYR(20) * 17520.0 * FACLOS( SCUSTS ) *
1          YLF(IYEAR) / FACLOS( 1000.0 )

C          CALCULATE THE COINCIDENT PEAK LOAD FOR ONE CUSTOMER BASED ON
C          THE NUMBER OF CUSTOMERS ON A SECONDARY TRANSFORMER.
C
SDMAND = CUSTPK(IYEAR) * DIVFAC(TCUSTS) * DFAC(IYEAR) /
1      DIVFAC( 1000.0 )

C          CALCULATE SERVICE DROP I**2*R AND I**2*X LOSS FOR A SINGLE
C          LIVE SERVICE WIRE.
C
PSDPL2 = ( SDMAND / ( FLOAT( 2*NPHI ) * VS ) )**2 *
1      SERVL / 2.0 * SERVWR * 1.0 E-5
PSDQL2 = PSDPL2 * SERVWX / SERVWR

C          CALCULATE THE BUS LOADS TO BE PLACED ON THE SECONDARY MODEL
C          BUSES FOR THE LOAD FLOW.
C
SECP = SECF * THONX * ( FLOAT( 2*NPHI + 1 ) * PSDPL2 +
1      ( SDMAND * POWFAC ) / FLOAT( 2-NPHI ) )
SECQ = SECF * THONX * ( FLOAT( 2*NPHI + 1 ) * PSDQL2 +
1      ( SDMAND * SQRT( 1.0 - POWFAC**2 ) ) / FLOAT( 2-NPHI ) )

C          REPLACE LOADS ON SECONDARY BUSSES FOR LOADFLOW
C
DO 50 I = 1, NSECBS
PDSEC(I) = SECP
QDSEC(I) = SECQ
50 CONTINUE

C          IF( LFOBUG ) WRITE(6,60)
60 FORMAT( '--- SYSLOS --- THIS LOAD FLOW IS USED TO CALCULATE THE '
1,      'PEAK LOAD ON A DISTRIBUTION TRANSFORMER' )

C          RUN THE LOAD FLOW WITH SECONDARY MODEL INPUTS
C
CALL PMRFLOW( NSECBS+1, PDSEC , QDSEC , CAPSEC ,
1          NSECFT , RLNSEC , XLNSEC ,
2          VMAG      , VANGLE , PGSEC , QGSEC ,

```

```

3          PFLOW , QFLOW , PLSSEC , QLSSEC ,
4          100.0 , 100.0 , 0.0001 , 0.0001 )
C
C      CALCULATE THE SECONDARY TRANSFORMER LOW SIDE LOAD.
C
      IF( NPHI .EQ. 0 ) GO TO 70
      TRNPLD = 2.0 * PGSEC + SECP * RNXM1
      TRNQLD = 2.0 * QGSEC + SECQ * RNXM1
      GO TO 90
C
70 TRNPLD = 4.0 * PGSEC + 2.0 * SECP * RNXM1
   TRNQLD = 4.0 * QGSEC + 2.0 * SECQ * RNXM1
C
C      DETERMINE THE DISTRIBUTION TRANSFORMER RATING AND CORE LOSS
C      FOR THE CURRENT YEAR.
C
      DO 80 I = 1, IMAX
      IF( IYEAR .EQ. NCHNG(I) ) DTNPR = DTNPR * CAPRAT
80 CONTINUE
      CALL CORLOS
C
C      CALCULATE THE SECONDARY TRANSFORMER KVA LOAD
C
90 TRNKVA = SQRT( TRNPLD**2 + TRNQLD**2 )
C
C      CALCULATE TRANSFORMER I**2*R LOSS IN KW
C
      DTI2R = ( TRNKVA / DTNPR )**2 * DTNPR * DTZ * 0.006
C
C      CALCULATE TOTAL SYSTEM I**2*R LOSS FOR DISTRIBUTION TRANSFORMER
C
      TDTI2R = DTI2R * COMYR(20) * FACLOS( TCUSTS ) * 8760.0 *
1      YLF(IYEAR) / FACLOS( 1000.0 )
C
C      CALCULATE TOTAL SYSTEM DISTRIBUTION TRANSFORMER CORE LOSS
C
      TDTCEL = DTCL * COMYR(20) * 8760.0
C
C      CALCULATE THE COINCIDENT PEAK FOR ONE CUSTOMER AT THE
C      CIRCUIT PEAK.
C
      SDMAND = CUSTPK(IYEAR) * DFAC(IYEAR)
C
C      CALCULATE SERVICE DROP I**2*R AND I**2*X LOSS FOR A SINGLE
C      LIVE SERVICE WIRE.
C
      PSDPL3 = ( SDMAND / ( FLOAT( 2+NPHI ) * VS ) )**2 *
1      SERVL / 2.0 * SERVWR * 1.0 E-5
      PSDQL3 = PSDPL3 * SERVWX / SERVWR
C
C      CALCULATE THE BUS LOADS TO BE PLACED ON THE SECONDARY MODEL
C      BUSES FOR THE LOAD FLOW.
C
      SECP = SECF * TWONX * ( FLOAT( 2*NPHI + 1 ) * PSDPL3 +
1      ( SDMAND * POWFAC ) / FLOAT( 2-NPHI ) )
      SECQ = SECF * TWONX * ( FLOAT( 2*NPHI + 1 ) * PSDQL3 +
1      ( SDMAND * SQRT( 1.0 - POWFAC**2 ) ) / FLOAT( 2-NPHI ) )
C

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```

C   REPLACE LOADS ON SECONDARY BUSES FOR LOAD FLOW
C
DO 100 I = 1, NSECBS
  PSEC(I) = SECP
  QDSEC(I) = SECQ
100 CONTINUE
C
  IF( LFDBUG ) WRITE(6,110)
110 FORMAT( '--- SYSLOS --- THIS LOAD FLOW IS USED TO CALCULATE THE '
1, 'LOAD ON A DISTRIBUTION TRANSFORMER AT CIRCUIT PEAK' )
C
C   RUN THE LOAD FLOW WITH SECONDARY MODEL INPUTS
C
CALL PLRFLO( NSECBS+1, PSEC , QDSEC , CAPSEC ,
1          NSECFT , RLNSEC , XLNSEC ,
2          VMAG , VANGLE , PGSEC , QGSEC ,
3          PFLOW , QFLOW , PLSSEC , QLSSEC ,
4          100.0 , 100.0 , 0.0001 , 0.0001 )
C
C   CALCULATE THE SECONDARY TRANSFORMER LOW SIDE LOAD.
C
  IF( NPHI .EQ. 0 ) GO TO 120
  TRNPLD = 2.0 * PGSEC + SECP * RNXM1
  TRNQLD = 2.0 * QGSEC + SECQ * RNXM1
  GO TO 130
C
120 TRNPLD = 4.0 * PGSEC + 2.0 * SECP * RNXM1
  TRNQLD = 4.0 * QGSEC + 2.0 * SECQ * RNXM1
C
C   CALCULATE THE SECONDARY TRANSFORMER KVA LOAD
C
130 TRNKVA = SQRT( TRNPLD**2 + TRNQLD**2 )
C
C   CALCULATE TRANSFORMER I**2*R LOSS IN KW AND I**2*X LOSS IN KVAR.
C
  TEMP = ( TRNKVA / DTNPR )**2 * DTNPR * DTZ
  DTI2R = TEMP * 0.006
  DTI2X = TEMP * 0.008
C
C   CALCULATE DISTRIBUTION TRANSFORMER HIGH-SIDE LOAD.
C
  TRNPLD = TRNPLD + DTI2R + DTCL
  TRNQLD = TRNQLD + DTI2X
C
C   DETERMINE THE RATIO OF SECONDARY TRANSFORMERS PER LATER FOR
C   "IYEAR" DIVIDED BY THE MAXIMUM NUMBER OF SECONDARY TRANSFORMERS
C   PER LATERAL.
C
  FTRAN = ( 2.0 * COMYR(20) ) / ( RLAT * FLOAT( NODD ) )
C
C   REPLACE LOADS ON LATERAL MODEL BUSES.
C   LOSSES ON THE LATERALS ARE NOT CALCULATED WITH THE LOAD FLOW
C   BECAUSE THE LOSSES BEING SOLVED FOR ARE TOO SMALL TO ITERATE TO.
C   CALCULATE LATERAL LOSS IN KW, KVAR.
C
  POVAL = TRNPLD * FTRAN
  QOVAL = TRNQLD * FTRAN
  PUKVA = SQRT( POVAL**2 + QOVAL**2 ) / 100.0

```



```

      PKVASQ = PUKVA**2
      TEMP1 = PKVASQ * RLNLAT(1)
      TEMP2 = PKVASQ * XLNLAT(1)
C
      SUM = 0
      DO 140 I = 1, LATBUS
      SUM = SUM + I**2
140 CONTINUE
C
      PLOSLT = TEMP1 * SUM
      QLOSLT = TEMP2 * SUM
C
C
C      CALCULATE THE TOTAL LATERAL WIRE LOSS FOR THE YEAR "IYEAR"
C
      TLATLS = PLOSLT * RLAT * YLF(IYEAR) * 8760.0
C
      CALCULATE THE FRACTION OF POSSIBLE LATERALS INSTALLED BY "IYEAR"
C
      FLAT = RLAT / FLOAT( 2*NLATPR )
C
      REPLACE LOADS ON PRIMARY MODEL FOR LOAD FLOW
C
      PDVAL = ( ( 2 * LATBUS + 1 ) * PDVAL + 2.0 * PLOSLT ) * FLAT
      QDVAL = ( ( 2 * LATBUS + 1 ) * QDVAL + 2.0 * QLOSLT ) * FLAT
C
      DO 150 I = 1, NLATPR
      PDMAIN(I) = PDVAL
      QDMAIN(I) = QDVAL
150 CONTINUE
C
      IF( LFDBUG ) WRITE(6,160)
160 FORMAT( '-*** SYSLOS --- THIS LOAD FLOW IS USED TO CALCULATE THE '
1,      'MAIN/FEEDER LOSS' )
C
      RUN THE LOAD FLOW WITH MAIN/FEEDER MODEL AS INPUT.
C
      PTOLER = PDVAL / 1.0E8
      QTOLER = QDVAL / 1.0E8
      CALL PWRFLOW( NLATPR+1, PDMAIN, QDMAIN, CPMAIN,
1          MAINFT, RLMAIN, XLMAIN,
2          VMAG, VANGLE, PGMAIN, QGMAIN,
3          PFLOW, QFLOW, PLOSPR, QLOSPR,
4          100000., 100.0, PTOLER, QTOLER )
C
      CALCULATE THE TOTAL PRIMARY MAIN AND FEEDER WIRE LOSS FOR
      THE YEAR "IYEAR".
C
      PRIMLS = PLOSPR * YLF(IYEAR) * 8760.0
C
      CALCULATE THE TOTAL CIRCUIT ENERGY LOSS BY SUMMING THE
      ENERGY LOSSES CALCULATED FOR SERVICE DROPS, SECONDARIES,
      SECONDARY TRANSFORMERS, ETC.
C
      ENGYLS = SDEL + TSWLOS + TDTI2R + TLATLS + PRIMLS
C
      CALCULATE THE PEAK DEMAND LOSS FOR THE ENTIRE CIRCUIT BY
      CALCULATING THE COINCIDENT DEMAND OF ALL CUSTOMERS ON THE

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C   CIRCUIT AND SUBTRACTING THIS FROM THE INPUT TO THE SWINGBS.
C
  DEMLOS = PGMAIN - YRCUST * CUSTPK(IYEAR) *
1      DFAC(IYEAR) * POWFAC
C
C   CALCULATE SUBSTATION LOAD IN MVA TO BE USED IN COSTS
C   ROUTINE WHEN COMPUTING TRANSFORMER LOSSES.
C
  TEMP = 1200.0 / CIRRTAT
  SUBLOD = SQRT( ( TEMP * PGMAIN )**2 + ( TEMP * QGMAIN )**2 ) /
1      1000.0
C
  RETURN
  END

```

SUBROUTINE SYSMOD
LOGICAL FEASBL, FLAG

```

C      COMMON / CAPDAT / LTCPBS(100) , NCAP1(50) , NCAP2(50)
C
C      COMMON / ECON / ADJUST, C1 , C2 , C3 , C4 , CC1 ,
1      CC2 , CC3 , CC4 , CC5 , CC6 , CSFEED,
2      CSMAN, CS PRIM, CSSEC , CSSERV, FEEDRT, NUMB ,
3      OFFMIN, R , RAT , RATLAT, RTMAIN, SECRAT,
4      SERVRT, WSLAT , WSPRIM, WSSEC , WSSERV, CD(50),
5      FEC(50) , VEC(50)
C
C      COMMON / ECONPE / AUTOFX, BMLOAD, CAPDIS, CAPRAT, CAPSIZ, CIRMAL,
1      CIRRTAT, CLATR , CLATX , CRITLD, DLOT , DTZ ,
2      FEEDRL, FEEDWR, FEEDWX, HLAT , HP , HSEC ,
3      HSLOAD, IDUS , IMAX , MXCUST, NCAP , NCODE ,
4      NCHNG(50) , NCUSTS, NLATPR, NPHI , NSTART,
5      NX , NYEAR , OBJECT, POWFAC, PRIMWR, PRIMWX,
6      RLAT , SECR , SECX , SERVWR, SERVWX, TA ,
7      VBUFF , VOLTHI, VOLTLO, VC , VP , VS ,
8      WLOT , WRLAT , WXLAT , COMYR(20) ,
9      CUSTPK(50) , DFAC(50) , DLF(50) ,
A      F(50) , H(20) , YLF(50)
C
C      LOGICAL LFDBUG
C
C      COMMON / FLODBG / LFDBUG
C
C      COMMON / LATRAL / CAPLAT(200) , PDLAT(200) , QDLAT(200) ,
1      NLATFT(2,200) , RLNLAT(200) , XLNLAT(200) ,
2      LATBUS
C
C      COMMON / LDFLOW / PFLOW(2,200) , QFLOW(2,200) , VANGLE(200) ,
1      VMAG(200)
C
C      COMMON / PEECON / BLKLEN, BLKWID, BUSDIS, CAPNUM, CAP1 , CAP2 ,
1      CIRLEN, CIRWID, CTAREA, DEMLOS, DISCNT, DISNUM,
2      DTCL , DTNPR , ENGYLS, FEASBL, FLAG , FUSCUT,
3      FUSNUM, IYEAR , MXPYR, MXSCYR, NOOD , NTRN11,
4      NTRN12, NTRN21, NTRN22, PRIMLS, REMNUM, REMOTN,
5      SDEL , SUBLOD, TDTCEL, TDTI2R, TLATLS, TSWLOS,
6      TRANUM, YRCUST, COMNUM(20) , RNUMCP(100) ,
7      SIZCP(100)
C
C      COMMON / PRIMRY / CPMAIN(200) , PDMAIN(200) , QDMAIN(200) ,
1      MAINFT(2,200) , RLMAIN(200) , XLMAIN(200) ,
2      NPRIME
C
C      COMMON / SECNDY / CAPSEC(200) , PDSEC(200) , QDSEC(200) ,
1      NSECFT(2,200) , RLNSEC(200) , XLNSEC(200) ,
2      NSECBS
C
C      COMMON / SYSTEM / CAPS(200) , PD(200) , QD(200) ,

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1          NFRMT0(2,200) , RLINE(200) , XLINE(200) ,
2          NUMBUS
C
C      FEASBL = .TRUE.
C
C-----
C      CREATE SECONDARY MODEL INPUT EXCEPT FOR BUS LOADS
C-----
C
C      CALCULATE THE NUMBER OF SECONDARY BUSES EXCLUDING THE SWING BUS.
C      NSECBS = ( NCUSTS / ( 2*NX ) - NX + 1 ) / 2
C
C      CALCULATE THE NUMBER OF 100 FEET BETWEEN SECONDARY BUSES.
C      BUSDIS = ( FLOAT( NX ) * WLOT ) / 100.0
C
C      CALCULATE PERCENT PER UNIT R AND X BETWEEN BUSES
C
C      SPUR = ( SECR * BUSDIS * 10.0 * FLOAT( 3 - 2*NPHI ) ) /
1      ( 3.0 * VS**2 )
C      SPUX = SPUR * SECX / SECR
C
C      DO 10 I = 1, NSECBS
C
C      FILL IN THE LINE TERMINAL BUS NUMBERS
C
C      NSECFT(1,I) = I
C      NSECFT(2,I) = I + 1
C
C      FILL IN RESISTANCE AND REACTANCE ARRAYS
C
C      RLNSEC(I) = SPUR
C      XLNSEC(I) = SPUX
C
C      FILL CAPACITOR ARRAY
C
C      CAPSEC(I) = 0.0
10 CONTINUE
C
C      FILL IN CAPACITOR ARRAY ELEMENT FOR THE SWING BUS
C
C      CAPSEC(NSECBS+1) = 0.0
C      NSECFT(1,NSECBS+1) = 9999
C
C-----
C      CREATE LATERAL MODEL INPUT EXCEPT FOR BUS LOADS.  CREATE ARRAY
C      DENOTING LATERAL BUSES ON WHICH CAPACITORS MAY BE PLACED.
C-----
C
C      CALCULATE THE NUMBER OF LATERAL BUSES EXCLUDING THE SWING BUS.
C
C      LATBUS = ( NODD - 1 ) / 2
C
C      CALCULATE THE NUMBER OF 100 FEET BETWEEN LATERAL BUSES.
C
C      BUSDIS = BLKWID / 100.0

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C      IF( NCODE .EQ. 1 ) GO TO 20
C
C      CALCULATE THE PERCENT PER UNIT R AND X BETWEEN BUSES (AERIAL).
C      FOR SINGLE PHASE ASSUME 40 PERCENT OF RETURN CURRENT PASSES
C      THROUGH NEUTRAL.
C
      PURLAT = ( WRLAT * ( 1.4 - 0.4 * NPHI ) * BUSDIS * 10.0 *
1          FLOAT( 3 - 2*NPHI ) ) / VP**2
      PUXLAT = PURLAT * WXLAT / WRLAT
      GO TO 30
C
C
C      CALCULATE PERCENT R AND X BETWEEN BUSES (UNDERGROUND).
C
20  PURLAT = ( CLATR * ( 2 - NPHI ) * BUSDIS * 10.0 *
1      ( 3 - 2 * NPHI ) ) / VP**2
      PUXLAT = PURLAT * CLATX / CLATR
C
30  DO 40 I = 1, LATBUS
C
C      FILL IN THE LINE TERMINAL BUS NUMBERS
C
      NLATFT(1,I) = I
      NLATFT(2,I) = I + 1
C
C      FILL IN RESISTANCE AND REACTANCE ARRAYS
C
      RLNLAT(I) = PURLAT
      XLNLAT(I) = PUXLAT
C
C      FILL CAPACITOR ARRAY
C
      CAPLAT(I) = 0.0
C
40  CONTINUE
C
C      FILL IN THE ARRAY ELEMENTS FOR THE SWING BUS
C
      CAPLAT(LATBUS+1) = 0.0
      NLATFT(1,LATBUS+1) = 9999
C
C      CREATE AN ARRAY WHICH WILL STORE THE BUS NUMBERS OF THE LATERAL
C      BUSES WHICH CAN HAVE CAPACITORS ADDED TO THEM.
C
      IF( NCAP .GT. 1 ) GO TO 50
      LTCPBS(1) = FLOAT( LATBUS ) / 3.0 + 1.5
      GO TO 70
C
50  TEMP = NCAP + 1
      DO 60 I = 1, NCAP
          LTCPBS(I) = FLOAT( LATBUS*I ) / TEMP + 1.5
      60  CONTINUE
C
C      CALCULATE THE NUMBER OF 100 FEET BETWEEN MAIN BUSES.
C
70  BUSDIS = BLKLEN / 100.0
C

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C      CALCULATE PERCENT PER-UNIT R AND X BETWEEN BUSES.
C
C      RMAIN = PRIMWR * BUSDIS * 10.0 / VP**2
C      XMAIN = RMAIN * PRIMWX / PRIMWR
C
C      NB = NLATPR - 1
C      DO 80 I = 1, NB
C
C      FILL IN TERMINAL BUS NUMBERS.
C
C      MAINFT(1,I) = I
C      MAINFT(2,I) = I + 1
C
C      FILL IN RESISTANCE AND REACTANCE ARRAYS.
C
C      RLMAIN(I) = RMAIN
C      XLMAIN(I) = XMAIN
C
C      FILL CAPACITOR ARRAY.
C
C      CPMAIN(I) = 0.0
C
C      80 CONTINUE
C
C      FILL REMAINING ARRAY ELEMENTS.
C
C      N = ( NLATPR + 1 ) / 2
C
C      MAINFT(1,NLATPR) = N
C      MAINFT(2,NLATPR) = NLATPR + 1
C
C      RLMAIN(NLATPR) = ( FEEDWR * FEEDRL * 0.1 ) / VP**2
C      XLMAIN(NLATPR) = RLMAIN(NLATPR) * FEEDWX / FEEDWR
C
C      CPMAIN(NLATPR) = 0.0
C      CPMAIN(NLATPR+1) = 0.0
C      MAINFT(1,NLATPR+1) = 9999
C
C-----
C      CREATE MODEL USED IN VSCHK TO DETERMINE CAPACITOR SIZES.
C-----
C
C      CALCULATE THE LOAD ON THE MODELED CUSTOMER BUS.
C
C      PLOAD1 = ( CUSTPK(MXPKYR) * POWFAC ) / FLOAT( 2 - NPHI )
C      QLOAD1 = PLOAD1 * SQRT( 1.0 / POWFAC**2 - 1.0 )
C
C      DETERMINE THE NUMBER OF TRANSFORMERS INSTALLED BY "MXPKYR"
C      AS WELL AS THE NUMBER OF LATERALS.
C
C      TRANUM = 0.0
C      RLATNM = 0.0
C
C      C20 = COMNUM(20)
C      H20 = H(20)
C      CONST = 2 * NLATPR
C
C      DO 90 I = 1, MXPKYR

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      FI = F(I)
      TEMP = 1.0 - FI
      ANUM = C20 * ( H20 * TEMP + FI )
      IF( ANUM .GT. TRANUM ) TRANUM = ANUM
      BNUM = CONST * ( HLAT * TEMP + FI )
      IF( BNUM .GT. RLATNM ) RLATNM = BNUM
90 CONTINUE
C
      IF( LFDBUG ) WRITE(6,100)
100 FORMAT( '--- SYSMOD --- THE NEXT TWO LOAD FLOWS ARE USED TO ',
1          'CALCULATE THE LOAD PLACED ON THE TRANSFORMER LOW-SIDE ',
2          'BUS' )
C
C      CALCULATE THE NUMBER OF SECONDARY CUSTOMERS PER TRANSFORMER
C      DIVIDED BY "NCUSTS" THE MAXIMUM NUMBER OF CUSTOMERS PER
C      TRANSFORMER.
C
      SECF = ( F(MXPKYR) * FLOAT(MXCUST) ) /
1          ( TRANUM * FLOAT( NCUSTS ) )
C
C      CALCULATE THE NUMBER OF CUSTOMERS ON A SECONDARY RUN AND ON A
C      SECONDARY TRANSFORMER.
C
      TCUSTS = SECF * FLOAT( NCUSTS )
      SCUSTS = TCUSTS / 2.0
C
C      CALCULATE THE COINCIDENT LOAD OF A CUSTOMER FOR A COINCIDENCE
C      FACTOR BASED ON "SCUSTS".
C
      D = DFAC(MXPKYR) / DIVFAC( 1000.0 )
      PLOAD2 = ( SECF * CUSTPK(MXPKYR) * DIVFAC(SCUSTS) * D * POWFAC ) /
1          FLOAT( 2 - NPHI )
      QLOAD2 = PLOAD2 * SQRT( 1.0 / POWFAC**2 - 1.0 )
C
C      CALCULATE THE LOSS ON THE SERVICE DROP TO A CUSTOMER BASED
C      ON A COINCIDENCE FACTOR FOR "SCUSTS".
C
      SERVL = SQRT( DLOT**2 + WLOT**2 )
      IF( NCODE .EQ. 1 ) SERVL = DLOT
      PLOAD3 = SECF * SERVL * SERVWR * FLOAT( 2*NPHI - 1 ) *
1          ( ( CUSTPK(MXPKYR) * DIVFAC( SCUSTS ) * D ) /
2          ( FLOAT( 2 + NPHI ) * VS ) )**2 / 2.0 E5
      QLOAD3 = PLOAD3 * SERVWX / SERVWR
C
C      CALCULATE COINCIDENT CUSTOMER LOAD BASED ON "TCUSTS".
C
      TEMP = DIVFAC(TCUSTS) / DIVFAC(SCUSTS)
      PLOAD4 = PLOAD2 * TEMP
      QLOAD4 = QLOAD2 * TEMP
C
C      CALCULATE LOSS ON SERVICE DROP BASED ON "TCUSTS".
C
      PLOAD5 = PLOAD3 * TEMP**2
      QLOAD5 = PLOAD5 * SERVWX / SERVWR
C
C      CALCULATE COINCIDENT CUSTOMER LOAD FOR A CUSTOMER BASED ON
C      1000 CUSTOMERS.
C

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TEMP = DIVFAC( 1000.0 ) / DIVFAC( SCUSTS )
PLOAD6 = PLOAD2 * TEMP
QLOAD6 = QLOAD2 * TEMP
C
C   CALCULATE LOSS OF SERVICE DROP BASED ON 1000 CUSTOMERS.
C
PLOAD7 = PLOAD3 * TEMP**2
QLOAD7 = PLOAD7 * SERVWX / SERVWR
C
C   CALCULATE LOAD TO BE PLACED ON THE BUS CONNECTED TO THE
C   CUSTOMER BUS.
C
  TWONX = 2 * NX
  TEMP = TWONX - 1.0
  PLOAD8 = TWONX * PLOAD2 + TEMP * PLOAD3 - CUSTPK(MXPKYR) *
1    POWFAC / FLOAT( 2 - NPHI )
  QLOAD8 = TWONX * QLOAD2 + TEMP * QLOAD3 - CUSTPK(MXPKYR) *
1    SQR( 1.0 - POWFAC**2 ) / FLOAT( 2 - NPHI )
C
C   CALCULATE LOAD TO BE PLACED ON THE OTHER SECONDARY BUSES.
C
PLOAD9 = TWONX * ( PLOAD2 + PLOAD3 )
QLOAD9 = TWONX * ( QLOAD2 + QLOAD3 )
C
C-----
C   CALCULATE THE LOAD TO BE PLACED ON THE TRANSFORMER LOW SIDE BUS.
C-----
C
  PVAL = TWONX * ( PLOAD4 + PLOAD5 )
  QVAL = TWONX * ( QLOAD4 + QLOAD5 )
C
C   PLACE LOADS FOR "TCUSTS" ON SECONDARY BUSES
C
DO 110 I = 1, NSECBS
  PDSEC(I) = PVAL
  QDSEC(I) = QVAL
110 CONTINUE
C
  PDSEC(NSECBS+1) = 0.0
  QDSEC(NSECBS+1) = 0.0
C
C   RUN THE LOAD FLOW WITH SECONDARY MODEL INPUTS
C
  CALL PWRFLOW( NSECBS+1, PDSEC , QDSEC , CAPSEC ,
1    NSECFT , RLNSEC , XLNSEC ,
2    VMAG , VANGLE , PGSEC , QGSEC ,
3    PFLOW , QFLOW , PLSSEC , QLSSEC ,
4    100.0 , 100.0 , 0.0001 , 0.0001 )
C
C   CALCULATE TOTAL TRANSFORMER LOW SIDE LOAD
C
  TEMP = 2 - NPHI
  TEMP2 = NX - 1
  PLOAD10 = TEMP * ( 2.0 * PGSEC + TEMP2 * PVAL )
  QLOAD10 = TEMP * ( 2.0 * QGSEC + TEMP2 * QVAL )
C
C   PLACE LOADS ON SECONDARY BUSES WITH COINCIDENCE BASED ON
C   "SCUSTS".

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C
PVAL = TWONX * ( PLOAD2 + PLOAD3 )
QVAL = TWONX * ( QLOAD2 + QLOAD3 )
DO 120 I = 1, NSECBS
PDSEC(I) = PVAL
QDSEC(I) = QVAL
120 CONTINUE
C
IF( LFOBUG ) WRITE(6,130)
130 FORMAT( '*** SYSMOD --- THIS LOAD FLOW IS USED TO CALCULATE ',
1 'THE LOAD PLACED ON THE TRANSFORMER HIGH-SIDE BUS' )
C
C RUN LOAD FLOW WITH SECONDARY MODEL INPUTS
C
CALL PWRFLOW( NSECBS+1, PDSEC , QDSEC , CAPSEC ,
1 NSECFT , RLNSEC , XLNSEC ,
2 VMAG , VANGLE , PGSEC , QGSEC ,
3 PFLOW , QFLOW , PLSSEC , QLSSEC ,
4 100.0 , 100.0 , 0.0001 , 0.0001 )
C
C CALCULATE BUS LOAD FOR SECONDARY TRANSFORMER LOW SIDE BUS.
C
PLOAD11 = PLOAD10 - PGSEC
QLOAD11 = QLOAD10 - QGSEC
C
C-----
C CALCULATE BUS LOAD TO BE PLACED ON THE TRANSFORMER HIGH SIDE
C BUSES.
C-----
C
PVAL = TWONX * ( PLOAD6 + PLOAD7 )
QVAL = TWONX * ( QLOAD6 + QLOAD7 )
DO 140 I = 1, NSECBS
PDSEC(I) = PVAL
QDSEC(I) = QVAL
140 CONTINUE
C
C RUN LOAD FLOW WITH SECONDARY MODEL INPUTS
C
CALL PWRFLOW( NSECBS+1, PDSEC , QDSEC , CAPSEC ,
1 NSECFT , RLNSEC , XLNSEC ,
2 VMAG , VANGLE , PGSEC , QGSEC ,
3 PFLOW , QFLOW , PLSSEC , QLSSEC ,
4 100.0 , 100.0 , 0.0001 , 0.0001 )
C
C CALCULATE TRANSFORMER LOW SIDE LOAD.
C
PLOAD12 = FLOAT( 2 - NPHI ) * ( 2.0 * PGSEC +
1 TWONX * FLOAT( NX - 1 ) * ( PLOAD6 + PLOAD7 ) )
QLOAD12 = FLOAT( 2 - NPHI ) * ( 2.0 * QGSEC +
1 TWONX * FLOAT( NX - 1 ) * ( QLOAD6 + QLOAD7 ) )
C
C CALCULATE TRANSFORMER LOW SIDE KVA.
C
TKVA = SQRT( PLOAD12**2 + QLOAD12**2 )
C
C DETERMINE THE TRANSFORMER RATING DURING THE PEAK YEAR.
C

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      I = 0
150  I = I + 1
      IF( MXPKYR .LT. NCHNG(I) ) DRATE = DTNPR * CAPRAT**(I-1)
      IF( MXPKYR .LT. NCHNG(I) ) GO TO 160
      IF( I .LT. IMAX ) GO TO 150
      DRATE = DTNPR * CAPRAT**IMAX
C
C      CALCULATE PERCENT Z, R, AND X ON 100 KVA BASE.
C
160  PCTZ = DTZ * 100.0 / DRATE
      PCTR = PCTZ * 0.6
      PCTX = PCTZ * 0.8
C
C      CALCULATE LOSS ON THE TRANSFORMER
C
      TEMP = TKVA**2 / 10000.0
      DTI2R = PCTR * TEMP
      DTI2X = PCTX * TEMP
C
C      CALCULATE DISTRIBUTION TRANSFORMER CORE LOSS AS A FUNCTION OF
C      DTNPR, VP, VS, AND NPHI
C
      CALL CORLOS
C
      WRITE(6,170) DTCL
170  FORMAT( '-THE DISTRIBUTION TRANSFORMER CORE LOSS IS', F8.2,
1      ' KW' )
C
C      CALCULATE TRANSFORMER HIGH SIDE LOAD.
C
      PLOD13 = PLOD12 + DTI2R + DTCL
      QLOD13 = QLOD12 + DTI2X
C
C      CALCULATE THE NUMBER OF SECONDARY TRANSFORMERS PER LATERAL
C      DIVIDED BY THE MAXIMUM NUMBER OF SECONDARY TRANSFORMERS PER
C      LATERAL.
C
      FTRAN = ( 2.0 * TRANUM ) / ( FLOAT( MODD ) * RLATNM )
C
C      CALCULATE THE TRANSFORMER HIGH SIDE LOAD TO BE PLACED ON
C      LATERAL BUSES.
C
      PLOD14 = PLOD13 * FTRAN
      QLOD14 = QLOD13 * FTRAN
C
C      CALCULATE THE TRANSFORMER LOW SIDE LOAD FOR A COINCIDENCE
C      FACTOR BASED ON "TCUSTS".
C
      TKVA = SQRT( PLOD10**2 + QLOD10**2 )
C
C      CALCULATE LOSS ON TRANSFORMER.
C
      TEMP = TKVA**2 / 10000.0
      DTI2R = PCTR * TEMP
      DTI2X = PCTX * TEMP
C
C      CALCULATE TRANSFORMER HIGH SIDE LOAD FOR A COINCIDENCE FACTOR
C      BASED ON "TCUSTS".

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C      PLOD15 = PLOD14 + DTI2R + DTCL
C      QLOD15 = QLOD14 + DTI2X
C
C      ADJUST THE LATERAL BUS LOADS SO THAT THE SUM OF PLOD15 +
C      ( LATBUS - 1 ) * TRANSFORMER HIGH SIDE LOAD IS EQUAL TO
C      LATBUS * PLOD14.
C
C      PLOD16 = ( FLOAT( LATBUS ) * PLOD14 - PLOD15 ) /
1      FLOAT( LATBUS - 1 )
C      QLOD16 = ( FLOAT( LATBUS ) * QLOD14 - QLOD15 ) /
1      FLOAT( LATBUS - 1 )
C
C      PLACE LOAD ON FIRST TRANSFORMER BUS ON LATERAL MODEL WHICH
C      WILL BE RUN SO THAT SWING BUS GENERATION CAN BE USED TO
C      CALCULATE THE EQUIVALENT LOADS PLACED ON THE MAIN BUSES.
C
C      PDLAT(1) = PLOD15
C      QDLAT(1) = QLOD15
C
C      PLACE REMAINING LOADS ON LATERAL BUSES.
C
C      DO 180 I = 2, LATBUS
C      PDLAT(I) = PLOD16
C      QDLAT(I) = QLOD16
180 CONTINUE
C
C      PDLAT(LATBUS+1) = 0.0
C      QDLAT(LATBUS+1) = 0.0
C
C      IF( LFDBUG ) WRITE(6,190)
190 FORMAT( '---SYSMOD --- THIS LOAD FLOW IS USED TO CALCULATE ',
1      'THE LOADS TO BE PLACED ON THE MAIN BUSES.' )
C
C      RUN LOAD FLOW WITH LATERAL MODEL INPUTS.
C
C      PTOLER = PLOD16 / 1.0E8
C      QTOLER = QLOD16 / 1.0E8
C      CALL PWRFLOW( LATBUS+1, PDLAT , QDLAT , CAPLAT ,
1      NLATFT , RLNLAT , XLNLAT ,
2      VMAG , VANGLE , PGLAT , QGLAT ,
3      PFLOW , QFLOW , PLSLAT , QLSLAT ,
4      100000. , 100.0 , PTOLER , QTOLER )
C
C      CALCULATE EQUIVALENT LATERAL LOAD AND TRANSFORMER LOAD TO
C      BE PLACED ON BUS CONNECTING LATERAL TO MAIN.
C
C      PLOD17 = PLOD14 + PGLAT
C      QLOD17 = QLOD14 + QGLAT
C
C      CALCULATE THE EQUIVALENT LOAD TO PLACE ON THE MAIN BUSES.
C
C      PLOD18 = PLOD17 + PGLAT
C      QLOD18 = QLOD17 + QGLAT
C
C      CALCULATE RATIO OF LATERALS INSTALLED DIVIDED BY THE
C      MAXIMUM NUMBER OF POSSIBLE LATERALS.
C

```

```

      FLAT = RLATNM / FLOAT( 2*NLATPR )
C
C   PLACE LOADS ON THE BUSES IN THE MAIN/FEEDER MODEL TO CALCULATE
C   A PORTION OF THE LOAD ON THE SWING BUS CONNECTED TO THE SWING
C   FOR THE MODEL USED TO DETERMINE CAPACITOR REQUIREMENTS.
C
      PVAL = PLOAD18 * FLAT
      QVAL = QLOAD18 * FLAT
      DO 200 I = 1, NLATPR
        PDMAIN(I) = PVAL
        QDMAIN(I) = QVAL
      200 CONTINUE
C
      PDMAIN(NLATPR+1) = 0.0
      QDMAIN(NLATPR+1) = 0.0
C
      IF( LFDBUG ) WRITE(6,210)
      210 FORMAT( '---SYSMOD --- THIS LOAD FLOW IS USED TO CALCULATE ',
        1      'THE LOAD TO BE PLACED ON THE BUS CONNECTED TO THE ',
        2      'SWING BUS' )
C
C   RUN THE LOAD FLOW WITH MAIN/FEEDER MODEL AS INPUT.
C
      PTOLER = PVAL / 1.0E8
      QTOLER = QVAL / 1.0E8
      CALL PWRFLOW( NLATPR+1, PDMAIN, QDMAIN, CPMAIN,
        1      MAINFT, RLMAIN, XLMAIN,
        2      VMAG, VANGLE, PGMAIN, QGMAIN,
        3      PFLOW, QFLOW, PLMAIN, QLMAIN,
        4      100000., 100.0, PTOLER, QTOLER )
C
C   CALCULATE THE BUS LOAD FOR THE BUS CONNECTED TO THE SWING BUS.
C
      PLOAD19 = PLOAD17 + PFLOW(2,N-1)
      QLOAD19 = QLOAD17 + QFLOW(2,N-1)
C
C   CALCULATE THE BUS NUMBERS USED IN DO LOOPS AND IN "VSCHK".
C
      NTRN11 = NSECBS + 3
      NTRN12 = NTRN11 + LATBUS
      NTRN21 = NTRN12 + ( NLATPR - 1 ) / 2
      NTRN22 = NTRN21 + LATBUS
C
C   SET POWERFLOW INPUT ARRAY VALUES WHICH CANNOT BE SET IN
C   DO LOOPS.
C
      PD (1) = PLOAD1
      QD (1) = QLOAD1
      CAPS (1) = 0.0
      NFRMTO(1,1) = 1
      NFRMTO(2,1) = 2
      RLINE(1) = SERVWR * SERVL * FLOAT( 3-2*NPHI ) / ( 60.0 * VS**2 )
      XLINE(1) = RLINE(1) * SERVWX / SERVWR
      NSP2 = NSECBS + 2
      PD (NSP2) = PLOAD11
      QD (NSP2) = QLOAD11
      CAPS (NSP2) = 0.0
      NFRMTO(1,NSP2) = NSP2

```

```

NFRMTO(2,NSP2) = NTRN11
RLINE(NSP2) = PCTR
XLINE(NSP2) = PCTX
PD (NTRN22) = PLOD15
QD (NTRN22) = QLOD15
CAPS (NTRN22) = 0.0
NFRMTO(1,NTRN22) = NTRN21
NFRMTO(2,NTRN22) = NTRN22 + 1
RLINE(NTRN22) = RLMAIN(NLATPR)
XLINE(NTRN22) = XLMAIN(NLATPR)
NTP1 = NTRN22 + 1
PD (NTP1) = 0.0
QD (NTP1) = 0.0
CAPS (NTP1) = 0.0

```

```

C
C   FILL ARRAYS WITH SECONDARY LOOP VALUES.
C

```

```

NSP1 = NSECBS + 1
DO 220 I = 2, NSP1
PD (I) = PLOAD9
QD (I) = QLOAD9
CAPS (I) = 0.0
NFRMTO(1,I) = I
NFRMTO(2,I) = I + 1
RLINE(I) = SPUR
XLINE(I) = SPUX

```

```

220 CONTINUE

```

```

C
C   RESET LOAD ON THE BUS CONNECTED TO THE LAST CUSTOMER.
C

```

```

PD(2) = PLOAD8
QD(2) = QLOAD8

```

```

C
NTH1 = NTRN12 -1
DO 230 I = NTRN11, NTH1
PD (I) = PLOD16
QD (I) = QLOD16
CAPS (I) = 0.0
NFRMTO(1,I) = I
NFRMTO(2,I) = I + 1
RLINE(I) = PURLAT
XLINE(I) = PUXLAT

```

```

230 CONTINUE

```

```

C
C   RESET LOAD ON HIGH SIDE TRANSFORMER BUS.
C

```

```

PD(NTRN11) = 0.0
QD(NTRN11) = 0.0

```

```

C
NTH1 = NTRN21 -1
DO 240 I = NTRN12, NTH1
PD (I) = PLOD18
QD (I) = QLOD18
CAPS (I) = 0.0
NFRMTO(1,I) = I
NFRMTO(2,I) = I + 1
RLINE(I) = RMAIN
XLINE(I) = XMAIN

```

```

      FEASBL = .FALSE.
C
      WRITE(6,290) COMPAR, FEEDRT
290 FORMAT( '0THE MAXIMUM FEEDER CABLE CURRENT OF', F6.1,
1          ' AMPS IS GREATER THAN THE CABLE RATING OF', F6.1,
2          ' AMPS.' / ' INCREASE CABLE SIZE.' )
C
300 IF( NCODE .EQ. 0 ) GO TO 340
C
      MAIN CABLE...
C
      COMPAR = SQRT( PFLOW(2,NTRN21-1)**2 + QFLOW(2,NTRN21-1)**2 ) /
1          ( SQRT( 3.0 ) * VP )
C
      IF( COMPAR .LE. RTMAIN ) GO TO 320
      FEASBL = .FALSE.
C
      WRITE(6,310) COMPAR, RTMAIN
310 FORMAT( '0THE MAXIMUM MAIN CABLE CURRENT OF', F6.1,
1          ' AMPS IS GREATER THAN THE CABLE RATING OF', F6.1,
2          ' AMPS.' / ' INCREASE CABLE SIZE.' )
C
      LATERAL...
C
320 COMPAR = SQRT( PFLOW(2,NTRN12-1)**2 + QFLOW(2,NTRN12-1)**2 ) *
1          ( 3 - 2 * NPHI ) / ( SQRT( 3.0 ) * VP )
C
      IF( COMPAR .LE. RATLAT ) GO TO 340
      FEASBL = .FALSE.
C
      WRITE(6,330) COMPAR, RATLAT
330 FORMAT( '0THE MAXIMUM LATERAL CABLE CURRENT OF', F6.1,
1          ' AMPS IS GREATER THAN THE CABLE RATING OF', F6.1,
2          ' AMPS.' / ' INCREASE CABLE SIZE.' )
C
340 IF( .NOT. FEASBL ) GO TO 360
C
      DETERMINE LARGEST VOLTAGE DROP TO A SECONDARY CUSTOMER.
      ADD CAPS AS NECESSARY.
C
350 CALL VSCHK
      IF( FLAG ) GO TO 280
C
360 RETURN
      END

```

SUBROUTINE VSCHK
LOGICAL FLAG

```

C      COMMON / ECONPE / AUTOFX, BMLOAD, CAPDIS, CAPRAT, CAPSIZ, CIRMAX,
1      CIRLAT, CLATR, CLATX, CRITLD, DLOT, DTZ,
2      FEEDRL, FEEDWR, FEEDWX, HLAT, HP, HSEC,
3      HSLOAD, IDUS, IMAX, MXCUST, NCAP, NCODE,
4      NCHNG(50), NCUSTS, NLATPR, NPHI, NSTART,
5      NX, NYEAR, OBJECT, POWFAC, PRIMWR, PRIMWX,
6      RLAT, SECR, SECX, SERVWR, SERVWX, TA,
7      VBUFF, VOLTHI, VOLTLO, VC, VP, VS,
8      WLOT, WRLAT, WXLAT, COMYR(20),
9      CUSTPK(50), DFAC(50), DLF(50),
A      F(50), H(20), YLF(50)

C      COMMON / LDFLOW / PFLOW(2,200), QFLOW(2,200), VANGLE(200),
1      VMAG(200)

C      COMMON / PEECON / BLKLEN, BLKWID, BUSDIS, CAPNUM, CAP1, CAP2,
1      CIRLEN, CIRWID, CTAREA, DEMLOS, DISCNT, DISNUM,
2      DTCL, DTNPR, ENGYS, FEASBL, FLAG, FUSCUT,
3      FUSNUM, IYEAR, MXPYR, MXSCYR, NODD, NTRN11,
4      NTRN12, NTRN21, NTRN22, PRIMLS, REMNUM, REMOTN,
5      SDEL, SUBLOD, TDTCEL, TDTI2R, TLATLS, TSWLOS,
6      TRANUM, YRCUST, COMNUM(20), RNUMCP(100),
7      SIZCP(100)

C      COMMON / SYSTEM / CAPS(200), PD(200), QD(200),
1      NFRMTO(2,200), RLINE(200), XLINE(200),
2      NUMBUS

C      FLAG = .FALSE.

C      DETERMINE PER UNIT VOLTAGE DROP BETWEEN CUSTOMER BUS AND
C      TRANSFORMER HIGH-SIDE BUS.
C
C      SECDRP = VMAG(NTRN11) - VMAG(1)
C      VTRAN = VMAG(NTRN11) - VMAG(NTRN11-1)

C      DO 20 ILAT = 1, 2

C      DETERMINE LOWEST TRANSFORMER HIGH SIDE BUS VOLTAGE
C      FOR LATERAL "ILAT".
C
C      ICHK1 = NTRN11 + 1
C      IF( ILAT .EQ. 2 ) ICHK1 = NTRN21 + 1
C      ICHK2 = NTRN12
C      IF( ILAT .EQ. 2 ) ICHK2 = NTRN22
C      VLTMIN = VMAG(ICHK1-1)

C      DO 10 I = ICHK1, ICHK2
C      IF( VMAG(I) .GE. VLTMIN ) GO TO 10
C      VLTMIN = VMAG(I)

```

```

10 CONTINUE
C
C   CALCULATE MINIMUM CUSTOMER VOLTAGE.
C
C    $VLTHIN = VLTHIN - SECDRP$ 
C
C   CALCULATE THE LOWEST ACCEPTABLE VOLTAGE TO COMPARE
C   AGAINST "VLTHIN."
C
C    $VOLTS = VMAG(NTRN21) - ( ( VOLTHI - VOLTLO ) / VS ) - VTRAN$ 
C
C   IF( VLTHIN .GE. VOLTS ) GO TO 20
C
C   FLAG = .TRUE.
C   CALL ADDCAP( ILAT )
C
20 CONTINUE
C   IF( .NOT. FLAG ) GO TO 40
C
C   ADJUST THE CAPS ON THE MAIN BUSES
C
C    $CAPS(NTRN12) = NCAP * CAP1$ 
C    $DELTA = ( CAP1 - CAP2 ) / ( NTRN21 - NTRN12 )$ 
C    $SETCAP = CAP1 - DELTA$ 
C    $I1 = NTRN12 + 1$ 
C    $I2 = NTRN21 - 1$ 
C
C   DO 30 I = I1, I2
C   CAPS(I) = SETCAP * 2. * NCAP
C   SETCAP = SETCAP - DELTA
30 CONTINUE
C
C    $SWNGCP = NCAP * ( CAP2 + ( NTRN21 - NTRN12 ) * ( CAP1 + CAP2 + DELTA ) )$ 
C    $CAPS(NTRN21) = SWNGCP$ 
C
40 RETURN
END

```