

MODELS AND METHODOLOGY FOR SEGREGATING DISTRIBUTION SYSTEM LOSSES

1. Components of Distribution System Losses

Distribution System Losses shall be segregated into the following components as specified in Article 3.4 of the Philippine Distribution Code:

- a) Technical Loss;
- b) Non-Technical Loss; and
- c) Administrative Loss.

The Technical Loss is the component of Distribution System Losses that is inherent in the electrical equipment, devices and conductors used in the physical delivery of electric Energy. It includes the Load and No-Load (or Fixed) Losses in the following:

- a) Sub-transmission Lines;
- b) Substation Power Transformers;
- c) Primary Distribution Lines;
- d) Voltage Regulators;
- e) Capacitors;
- f) Reactors;
- g) Distribution Transformers;
- h) Secondary Distribution Lines;
- i) Service Drops; and
- j) All other electrical equipment necessary for the operation of the Distribution System.

The Non-Technical Loss is the component of Distribution System Losses that is not related to the physical characteristics and functions of the electrical System, and is caused primarily by human error, whether intentional or not. Non-Technical Loss includes the electric Energy lost due to pilferage, tampering of meters, and erroneous meter reading. For the purpose of Segregating Distribution System Losses to establish the Caps on the Rate of Recoverable Distribution System Losses, Metering burdens and inaccuracies shall be assumed included in the Non-Technical Loss.

The Administrative Loss is the component of Distribution System Losses that accounts for the electric Energy used by the Distribution Utility in the proper operation of the Distribution System and any unbilled electric Energy that is used for community-related activities. This shall include the electric Energy consumption of connected essential electrical loads in the following facilities and activities, subject to the approval by the ERC:

- a) Distribution Substations;
- b) Offices of the Distribution Utility;
- c) Warehouses and Workshops of the Distribution Utility;

- d) Community activities; and
- e) Other essential electrical loads of the Distribution Utility.

2. Calculation of Distribution System Losses

2.1. Calculation Period

Distribution System Losses shall be calculated monthly and shall coincide with the billing cycle adopted by the Distribution Utility. The Distribution Utilities shall report the total number of days, number of hours and the dates covered by the billing cycle used as the Period for calculating the Distribution System Losses.

2.2. Total Distribution System Losses

The Total Distribution System Losses shall be computed as the net of all electric Energy input (i.e., electric Energy delivered to the Distribution System by the Transmission System, Embedded Generating Plants, other Distribution Systems, and User Systems with generating facilities) and of all electric Energy output (i.e., electric Energy delivered to the Users of the Distribution System) for the billing period. In equation form, the Total Distribution System Losses shall be computed as follows:

$$\begin{aligned}
 \textit{Total Distribution System Losses} = & \\
 & \Sigma[\textit{Energy delivered by the Transmission System}] + \\
 & \Sigma[\textit{Energy delivered by Embedded Generating Plants}] + \\
 & \Sigma[\textit{Energy delivered by Other Distribution Systems}] + \\
 & \Sigma[\textit{Energy delivered by User Systems with Generating Units}] - \\
 & \Sigma[\textit{Energy delivered to the Users of the Distribution System}] \quad (1)
 \end{aligned}$$

Prior to the enactment of R.A. 9136, the electric Energy delivered by the transmission system, embedded generating plants, other Distribution Systems and User Systems with generating facilities refer to the kWh purchased and generated by the Distribution Utilities while the electric Energy delivered to the System of Distribution Users are those that are sold to customers or end-users.

2.3. Administrative Loss

Administrative Loss shall be the sum of the actual (i.e., metered) electric Energy consumption of the essential loads used by the facilities of the Distribution Utility and any unbilled electric Energy from ERC-approved community activities during the billing period. In equation form, the Administrative Loss shall be calculated as follows:

$$\begin{aligned}
 \textit{Administrative Loss} = & \\
 & \Sigma[\textit{Energy Consumed by Distribution Substations}] + \\
 & \Sigma[\textit{Energy Consumed by Offices of the Distribution Utility}] + \\
 & \Sigma[\textit{Energy Consumed by Warehouses and Workshops of the DU}] + \\
 & \Sigma[\textit{Energy Consumed by ERC-Approved Community Activities}] \quad (2)
 \end{aligned}$$

2.4. Technical Loss

The Technical Loss for the billing period shall be sum of the hourly Load and No-Load (or Fixed) Losses in all distribution equipment, devices and conductors. It shall be calculated based on Three-Phase Load Flow simulations of the Distribution System using the appropriate Distribution Network and Load Models. The Load Flow simulations must capture all technical losses from the incoming and outgoing Delivery Points of the unbalanced three-phase Distribution System (i.e., all Load and Non-Load Losses of all equipment, devices and conductors from sub-transmission lines to the service drops of the Distribution Customers). For the purpose of calculating the Technical Loss, the Delivery Points of the Distribution System shall be the Metering Points (i.e., the location of the metering equipment). In equation form, the Technical Losses shall be computed as follows:

$$\begin{aligned} \text{Technical Loss} = & \Sigma[\text{Hourly Load Losses in Sub-transmission Lines}] + \\ & \Sigma[\text{Hourly Load and No-Load Losses of Power Transformers in} \\ & \quad \text{Distribution Substations}] + \\ & \Sigma[\text{Hourly Load Losses in Primary Distribution Lines}] + \\ & \Sigma[\text{Hourly Load and No-Load Losses in Voltage Regulators}] + \\ & \Sigma[\text{Hourly Fixed Losses in Capacitors}] + \\ & \Sigma[\text{Hourly Fixed Losses in Reactors}] + \\ & \Sigma[\text{Hourly Load and No-Load Losses of Distribution Transformers}] + \\ & \Sigma[\text{Hourly Load Losses in Secondary Distribution Lines}] + \\ & \Sigma[\text{Hourly Load Losses in Service Drops}] + \\ & \Sigma[\text{Hourly Losses in other Electrical Equipment}] \end{aligned} \quad (3)$$

2.5. Non-Technical Loss

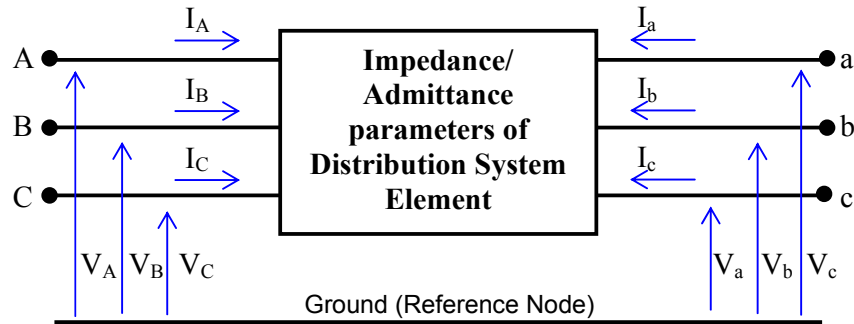
The Non-technical loss shall be the residual loss after subtracting the Administrative Loss and Technical Loss from the Total Distribution System Losses. The equivalent kWh of all Recovered Losses through anti-pilferage activities during the billing period shall also be subtracted from the Total Distribution System Losses. In equation form, the Non-technical Loss shall be computed as follows:

$$\begin{aligned} \text{Non-Technical Loss} = & \text{Total Distribution System Losses} - \\ & \text{Administrative Loss} - \\ & \text{Technical Loss} - \\ & \text{Recovered Losses} \end{aligned} \quad (4)$$

3. Distribution Network Models

For purposes of calculating the Technical Loss, the Distribution System shall be represented by Distribution Network Models that are appropriate for Three Phase Load Flow simulations. All equipment, devices and conductors of the Distribution System shall be characterized to capture the unbalances due to equipment construction, installation configurations, and connections and due to the unbalanced loading. In addition, the models must capture the Load-Losses and No-Load (or Fixed) Losses of all Distribution System equipment, devices and conductors except for metering burdens and errors which are assumed included in the Non-Technical Loss.

The Distribution System shall be modeled by an interconnected network represented by an admittance-parameter network in which a common node is used as a reference. Such model is also known as Nodal Admittance Matrix or **Ybus**. Mathematically, the each Distribution System element (e.g., line, transformer, etc.) is represented by a 6 x 6 Nodal Admittance Matrix as illustrated in Figure 1.



(a) Distribution System Element

$$\begin{bmatrix} I_A \\ I_B \\ I_C \\ I_a \\ I_b \\ I_c \end{bmatrix} = \begin{bmatrix} y_A & y_A & y_A & y_{Aa} & y_{Ab} & y_{Ac} \\ y_B & y_{BB} & y_{BC} & y_{Ba} & y_{Bb} & y_{Bc} \\ y_C & y_{CB} & y_{CC} & y_{Ca} & y_{Cb} & y_{Cc} \\ y_{aA} & y_{aB} & y_{aC} & y_{aa} & y_{ab} & y_{ac} \\ y_{bA} & y_{bB} & y_{bC} & y_{ba} & y_{bb} & y_{bc} \\ y_{cA} & y_{cB} & y_{cC} & y_{ca} & y_{cb} & y_{cc} \end{bmatrix} \begin{bmatrix} V \\ V_B \\ V_C \\ V_a \\ V_b \\ V_c \end{bmatrix}$$

(b) Nodal Admittance Matrix

Figure 1. Distribution Network Model

3.1. Line Models

Sub-transmission and Distribution Lines shall be represented by a three-phase pi (π) equivalent network with the corresponding self and mutual impedances of the phase and ground conductors as shown in Figure 2.

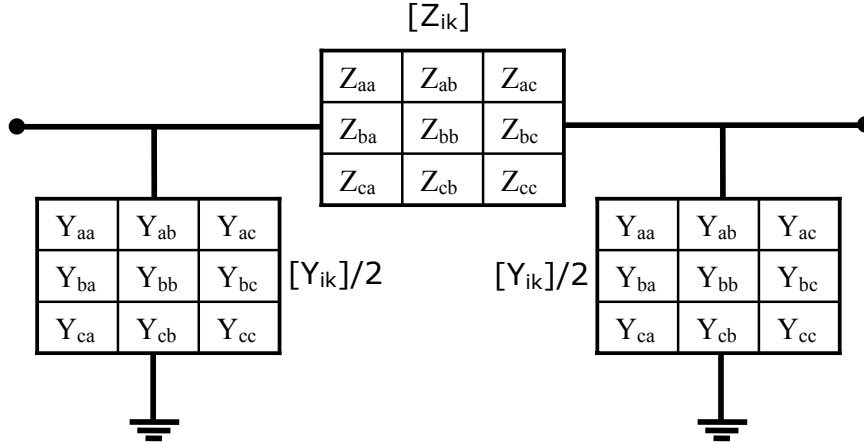


Figure 2. Equivalent π -Network of Distribution Lines

The series and shunt parameters of the three-phase pi (π) equivalent network are used according to the following equations to obtain the 6 x 6 Nodal Admittance Matrix:

$$\begin{array}{c} \begin{array}{|c|} \hline \Gamma_{1,1} \\ \hline \Gamma_{1,1} \\ \hline \end{array} \\ 6 \times 1 \end{array} = \begin{array}{c} \begin{array}{|c|c|} \hline \Gamma Z_{,1}^{-1} + \Gamma Y_{,1} / \gamma & -\Gamma Z_{,1}^{-1} \\ \hline -\Gamma Z_{,1}^{-1} & \Gamma Z_{,1}^{-1} + \Gamma Y_{,1} / \gamma \\ \hline \end{array} \\ 6 \times 6 \end{array} \begin{array}{c} \begin{array}{|c|} \hline \Gamma V_{,1} \\ \hline \Gamma V_{,1} \\ \hline \end{array} \\ 6 \times 1 \end{array} \quad (5)$$

The self- and mutual-impedances of conductors are given by the Carson equations for the series parameters:

$$z_{aa} = z_{bb} = z_{cc} = (r_a + r_d) + j\omega k \ln \frac{D_e}{D_s} \quad (6)$$

$$z_{xy} = r_d + j\omega k \ln \frac{D_e}{D_{xy}} \quad (7)$$

Where, z_{aa} = self-impedance of conductor in ohms per unit length

k = multiplying constant (2×10^{-7}) for inductance in H/m

r_a = resistance of conductor

r_d = earth resistance as a function of frequency

$D_e = 2160 \sqrt{\text{(earth resistivity/frequency)}}$

D_s = Geometric Mean Radius (GMR) of Conductor

D_{xy} = Distance between conductors x and y ($xy = ab, bc, \text{ or } ca$)

The shunt parameters consist of self- and mutual capacitive reactance of the conductors. The capacitance of an overhead conductor a of radius r at height h above ground due to its own charge and a charge on its image below the ground is

$$C_{aa} = \frac{1}{2 \ln \frac{2h}{r}} \quad (8)$$

Similarly, the capacitance of an overhead conductor a due to a charge on a neighboring conductor b and the charge on its image is

$$C_{ab} = \frac{1}{2 \ln \frac{D'}{D}} \quad (9)$$

where, D is the spacing between conductor a and b and D' is the spacing between conductor b and the image of conductor a .

The admittance parameters (\mathbf{Y}) can be obtained from the inverse of the capacitive reactance ($\mathbf{X}_c = 1/\omega C = 1/2\pi fC$) where ω and f are frequencies in radians per second and cycles per second, respectively.

Secondary Distribution Lines and Service Drops are similarly modeled except for the shunt capacitances and mutual reactances which may be neglected.

3.2. Transformer and Voltage Regulator Models

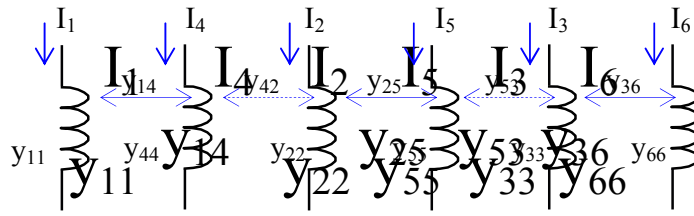
Transformer and Voltage Regulator Models shall be developed based on the structure of magnetic circuit and connections of the windings. The starting point in developing the models is the admittance parameter representation of the primitive coils that capture both self and mutual reactances of the windings. This is known as the primitive admittance matrix (\mathbf{Y}_{prim}) which will be transformed to form the complete transformer or voltage regulator model given by equation:

$$\mathbf{I}_{\text{inj}} = [\mathbf{A} \mathbf{Y}_{\text{prim}} \mathbf{A}^T] \mathbf{V}_{\text{node}} \quad (5)$$

where, $[\mathbf{A} \mathbf{Y}_{\text{prim}} \mathbf{A}^T]$ is the Nodal Admittance Matrix or \mathbf{Y}_{bus} Model. Matrix \mathbf{A} has entries \mathbf{A}_{ij} defined by:

- 1 if the current in branch i enters node j ,
- 1 if the current in branch i leaves node j , and
- 0 if the current in branch i is not incident to node j .

Figure 3 shows the primitive coils and primitive admittance matrix of a transformer with six (6) windings which shall be transformed to form the Nodal Admittance Matrix or \mathbf{Y}_{bus} model.



(a) Primitive Coils

y_{11}	y_{12}	y_{13}	y_{14}	y_{15}	y_{16}
y_{21}	y_{22}	y_{23}	y_{24}	y_{25}	y_{26}
y_{31}	y_{32}	y_{33}	y_{34}	y_{35}	y_{36}
y_{41}	y_{42}	y_{43}	y_{44}	y_{45}	y_{46}
y_{51}	y_{52}	y_{53}	y_{54}	y_{55}	y_{56}
y_{61}	y_{62}	y_{63}	y_{64}	y_{65}	y_{66}

(b) Primitive Admittance Matrix

Figure 3. Primitive Network Model for Transformer with 6 windings

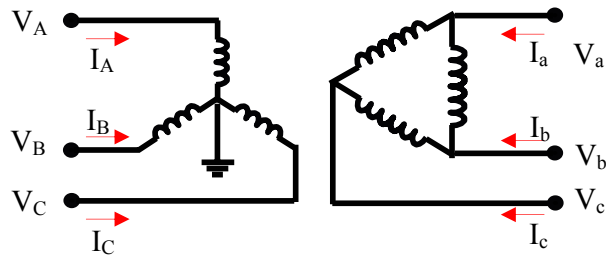
The process of building Transformer and Voltage Regulator Models is illustrated in Figure 4 for three (3) single-phase transformers connected wye grounded - delta.

3.3. Shunt Capacitors and Inductors

Shunt Capacitors shall be modeled as lumped loads that are connected to a Bus with constant real and reactive power demand as illustrated in Figure 5. The real component of the power represents the Fixed Losses in the capacitors while the reactive power are injected into the Bus that are required for power quality improvement.

Shunt Inductors shall be modeled as lumped impedance (i.e., series resistance and reactance) parameters that are connected to a Bus as shown in Figure 6. The inherent resistance of the inductor shall account for the losses which varies with the square on the current drawn by the inductor.

Series Inductors shall be modeled as series impedance like a Distribution Line without the shunt components and mutual reactances as illustrated in Figure 7. The inherent resistance of the inductor shall account for the losses which varies with the square on the current through the inductor.



(a) Connection Diagram

	1	2	3	4	5	6
1	1	0	0	0	0	0
2	0	1	0	0	0	0
3	0	0	1	0	0	0
4	0	0	0	1	-1	0
5	0	0	0	0	1	-1
6	0	0	0	-1	0	1

(b) Transformation Matrix, A

	1	2	3	4	5	6
1	y	0	0	$-y/\sqrt{3}$	$y/\sqrt{3}$	0
2	0	y	0	0	$-y/\sqrt{3}$	$y/\sqrt{3}$
3	0	0	y	$y/\sqrt{3}$	0	$-y/\sqrt{3}$
4	$-y/\sqrt{3}$	0	$y/\sqrt{3}$	$2y/3$	$-y/3$	$-y/3$
5	$y/\sqrt{3}$	$-y/\sqrt{3}$	0	$-y/3$	$2y/3$	$-y/3$
6	0	$y/\sqrt{3}$	$-y/\sqrt{3}$	$-y/3$	$-y/3$	$2y/3$

(c) Nodal Admittance Matrix, Y_{bus}

Figure 4. Network Model for a Wye Grounded – Delta Connected Three (3) Single-Phase Transformers

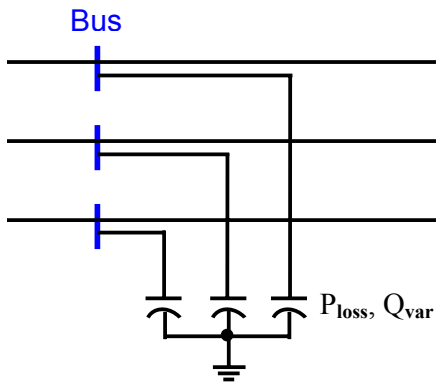


Figure 5. Shunt Capacitor Model

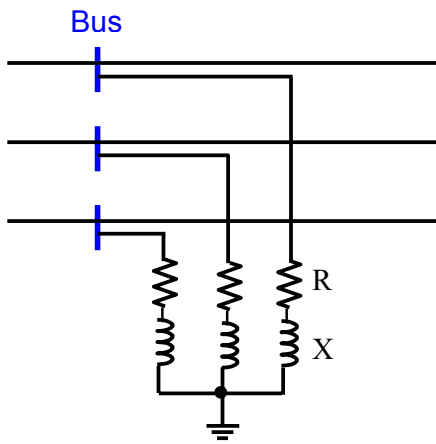


Figure 6. Shunt Inductor Model

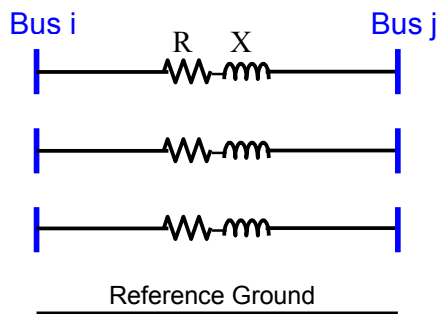


Figure 7. Series Inductor Model

4. Distribution Load Models

Typical Load Curves for different types of customers and customer monthly energy billing are the basic input to the Load Models. The total energy consumed by each customer is convolved to the normalized load curve for the type of customer to determine the hourly power demands as illustrated in Figure 8. Power factor of the load are specified based on measurements or reasonable assumptions. Figure 9 shows the step-by step procedure of converting energy consumption (kWhr in one billing cycle) to 24-hourly kW demands. The real power demand P_t for time t is obtained from the per unit (p.u.) demand p_t divided by the total area under the normalized load curve. Another set of data specifying the hourly demand is the hourly power factor (pf_t) to compute for the hourly reactive power demand (Q_t).

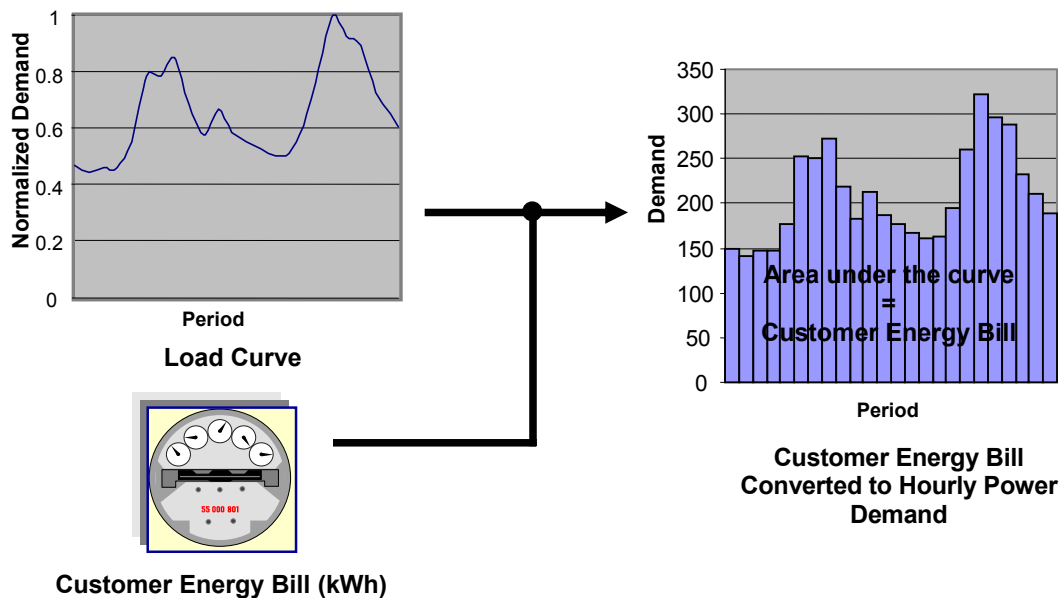


Figure 8. Conceptual Task in Developing Load Models

To illustrate this procedure, consider a typical residential customer with a monthly energy bill of 150 kWhr. Assuming that there is no significant difference between the load patterns in a residential customer between weekday and weekends, the daily average energy consumed by the customer in a 30-day month is computed as 5 kWhr/day. Assuming further a typical normalized load curve for a residential customer and discretized into hourly per unit demand as shown in Table 1.

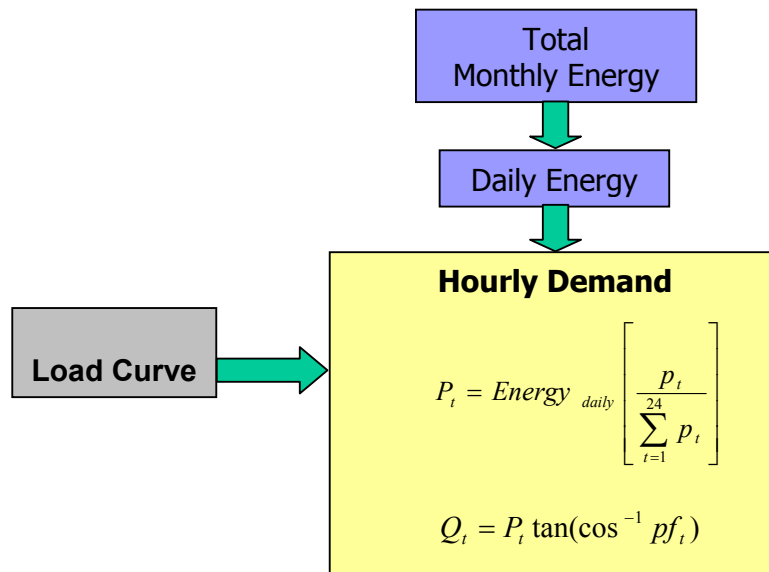


Figure 9. Conversion of Customer Energy Bill and Load Variation Curve to Hourly Power Demand

Table 1. Per Unit Demand for Residential Customer

Hour 1	0.467	Hour 13	0.549
Hour 2	0.439	Hour 14	0.521
Hour 3	0.461	Hour 15	0.502
Hour 4	0.458	Hour 16	0.505
Hour 5	0.553	Hour 17	0.606
Hour 6	0.786	Hour 18	0.808
Hour 7	0.780	Hour 19	1.000
Hour 8	0.849	Hour 20	0.921
Hour 9	0.682	Hour 21	0.895
Hour 10	0.572	Hour 22	0.726
Hour 11	0.663	Hour 23	0.654
Hour 12	0.581	Hour 24	0.587

This curve has a shape value (i.e., the area under the curve) of 15.57 units. Thus, demand for Hour 1 is equal to

$$0.467/15.57*5 = 0.15 \text{ kW or } 150 \text{ Watts}$$

Assuming 0.8 power factor, the reactive power for Hour 1 is

$$150 * \tan[\cos^{-1}(0.8)] = 112.5 \text{ Vars}$$

Figure 10 shows the complete hourly real and reactive demand for this customer.

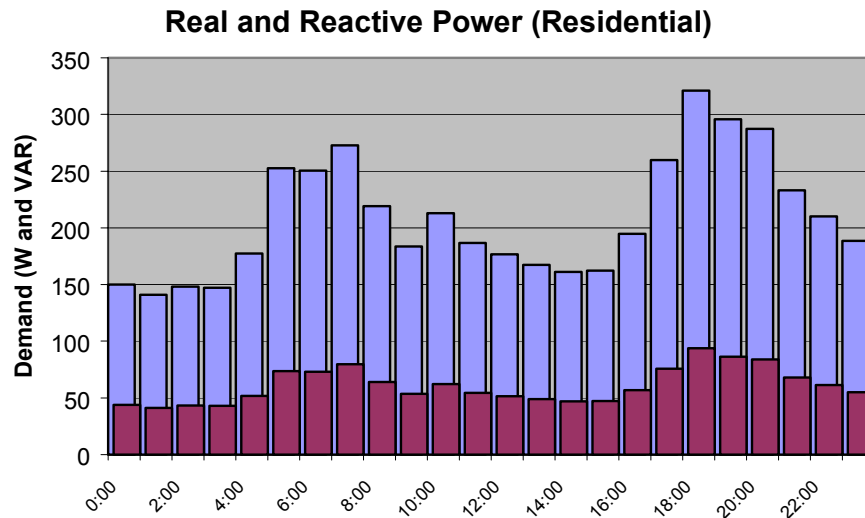


Figure 10. Hourly Power Demand of a Residential Customer

Distribution Utilities may develop more accurate load models by preparing as many load curves as possible through a load survey for each type or even sub-type of customers that can capture seasonal variations. Also, different load curves may be used for weekdays and weekends.

5. Data Requirements

This section specifies the data required to segregate Distribution System Losses into Administrative Loss, Technical Loss and Non-technical Loss and establish caps on the rate of recoverable Distribution System Losses. The data requirements detailed and described in this section correspond to the Templates of Data Requirements in Annex B.

For the Administrative Loss, the Distribution Utilities must submit to ERC for approval, the list of connected essential loads that are categorized as Administrative Load Data. These are required to establish the allowances for Administrative Loss of Distribution Utilities that can be passed on to customers.

The following are the required data for developing the Load Models to determine the hourly power demands that shall be used for the calculation of Technical Loss in a billing period:

- a) Customer Data;
- b) Meter Reading Data; and
- c) Load Curve Data.

The following Distribution System data are required for conducting Three-Phase (Unbalanced) Load Flow covering the entire Distribution System (i.e., from Sub-transmission Lines to Service Drops):

- a) Bus Data;
- b) Sub-transmission Line Data;
- c) Substation Power Transformer Data;
- d) Primary Distribution Line Data;
- e) Voltage Regulator Data;
- f) Shunt Capacitor Data;
- g) Shunt Inductor Data;
- h) Series Inductor Data;
- i) Distribution Transformer Data;
- j) Secondary Distribution Line Data; and
- k) Service Drop Data.

The following data are required to establish the caps on the recoverable Rate of Distribution System Losses to take into consideration load density, sales mix, cost of service, delivery voltage and other technical performance and characteristics as mandated by R.A. 9136:

- a) Energy Sales Data; and
- b) Other Technical Data.

5.1. Administrative Load Data

Facility/Activity

Describe the facility or community activity being applied for the approval of allowable Administrative Loss. For substations and similar facilities, include the capacity of the facility.

Location

Specify the location or address of the facility or community activity.

Purpose

Describe the purpose or the justification why the facility or community activity is being applied for Allowable Administrative Loss.

Space Area

Specify the space area of the facility in square meters (sq. m.). For buildings, specify the floor area. For substations and similar facilities, specify the land area.

Number of Occupants

Specify the number of people occupying the facilities (e.g., 5 employees).

Quantity

Specify the quantity (i.e., number of units) of connected electrical equipment or appliance.

Connected Load

Describe the connected electrical equipment or appliance (e.g., 40W Fluorescent lamp).

Use of Connected Load

Describe the usage or the services being provided by the electrical equipment or appliance.

Rating

Specify the ratings of connected electrical equipment or appliance in Watts.

Average Demand

Specify the Average Demand of the connected electrical load in kW. Note that electrical appliances do not run at rated capacity (full load) at all times.

Average Duration

Specify the average monthly duration of utilization of the connected electrical load in hours. The average duration may be estimated by adding the number of hours of usage in weekdays and in weekends in a typical 30-day month.

Average Monthly Consumption

Multiply the Average Demand by the Average Duration to obtain the Average Monthly Consumption of the connected electrical load.

Total Monthly Energy Consumption

Add the Average Monthly Consumption of all connected electrical loads to obtain the Total Monthly Energy Consumption of the Facility or Community Activity.

5.2. Customer Data

Customer ID

Specify the unique ID that will identify a customer (e.g., Customer Account Number or Meter ID). All customers must be included in the list.

Customer Type

Specify the customer type or classification code using up to 25 characters (e.g., RES1 for small residential, RES2 for large residential, etc.).

Service Voltage

Specify the nominal service voltage being supplied to the customer in Volts (e.g., 230 volts).

5.3. Meter Reading Data

Customer ID

Specify the unique ID that identifies a customer. This must be the same ID used in the Customer Data.

Billing Period Code

Specify the Billing Period according to the following coding system:

MMYYYY

Where , MM – month of the meter reading (billing) period
(e.g., 08 for August)

YYYY – Year of the meter reading (billing) period
(e.g., 2001 for year 2001)

kWhr Reading

Specify the kWhr reading of the electric meter of the customer for the billing period.

5.4. Load Curve Data

Load Curve ID

Specify the unique ID of the load curve for the Customer Type. It is possible to have different load curves for weekdays and weekend or for seasonal variations for each type or sub-type of customer.

Customer Type

Specify the customer classification code represented by the load curve. This must be the same Customer Type specified in the Customer Data and Meter Reading Data.

Description

Describe the Customer Type. For example, RES1 is small residential customer with monthly consumption of not more than 50 kWhr.

Normalized Hourly Demand

Specify the hourly demand from Hour 1 to Hour 24 of the Load Curve in per unit. This can be obtained by monitoring the 24-hour demand pattern of the Customer Type (e.g., hourly Amps, kW, kVA, etc.). To obtain the Normalized demand in per unit (p.u.), each hourly demand is divided by the peak demand. Thus, the highest value of the Normalized Hourly Demand is 1.0 which coincides with the peak hour.

5.5. Bus Data

Bus ID

Enter the unique identification (ID) of the Bus or Node in the Distribution System using up to 25 alphanumeric characters. Bus or node is created for each connection or junction point from Sub-transmission lines to Secondary Distribution Lines (e.g., connection point between transformer terminal and a line segment, connection point between two line segments, etc.).

Bus Description

Enter the Description of the Bus or Node (e.g., Transformer TX-1 primary).

Nominal Voltage

Specify the nominal voltage of the Bus or Node in kV (e.g., 13.2 kV).

5.6. Sub-transmission Line Data

Each Sub-transmission Line segment (i.e., the section of the Sub-transmission Line that can be identified by only one sending-end and only one receiving-end) must be included as one data entry. The whole length of the Sub-transmission Line may be entered as one or more line segments depending on the connection points and the construction arrangement (e.g., loop, expanded radial, etc.).

Sub-transmission Line Segment ID

Enter the unique ID of the Sub-transmission Line segment using up to 25 alphanumeric characters.

Bus Connected

Specify the Bus IDs for the connecting buses at the ends of the sub-transmission Line segment:

From Bus
To Bus

Length

Enter the length of the Sub-transmission Line segment in meters.

Conductor Type

Specify material type of the phase conductor either:

ACSR – for Aluminum Cable Steel Reinforced ; or
CU – for Copper

Size of Phase Conductors

Specify size of phase conductors in AWG, kcmil or mm²

Strands

Specify number of strands of the phase conductors. For ACSR, the number of strands of the aluminum and steel shall be specified according to the following format:

Al/St

For example, an ACSR with 7 Aluminum strands and 1 Steel should have “7/1” entry in the Strands column.

Bundled Conductors

Specify the number of bundled conductors of the phase conductors (see Figure 11):

1– for Single Conductor
2 – for Two-Conductor Bundle
3 – for Three-Conductor Bundle
4 – for Four-Conductor Bundle

Bundled Conductors Spacing

Specify the spacing S of bundled conductors in cm (see Figure 11). Enter "0.0" for Single Conductor.

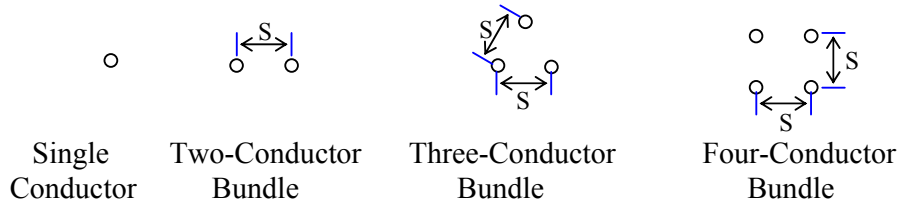


Figure 11. Bundling of Conductors

Number of Ground Wires

Specify the number of ground wires.

- 1 – for one ground wire
- 2 – for two ground wires

Size of Ground Wires

Specify size of ground wires in AWG, Circular Mils or mm²

Configuration

Specify installation configuration of conductors (see Figure 12):

- Horizontal;
- Vertical;
- Triangular; or
- Parallel

Spacing

Specify the distance between the phase conductors as sets of pairs of conductors and the ground wires in meters. For Parallel circuits, specify also the distance of nearest conductors of circuits 1 and 2 (see Figure 12).

- Dab – Distance between phase a and phase b conductors
- Dbc – Distance between phase b and phase c conductors
- Dca – Distance between phase c and phase a conductors
- D12 – Distance between nearest conductors of circuits 1 and 2
- Dgg – Distance between ground wires (for two ground wires)
- Dcg – The distance between the ground wires and a phase conductor closest to the ground wire

Enter "0.0" if not applicable.

Height

Enter the height of the Sub-transmission or distribution line from the earth in meters (see Figure 12).

Earth Resistivity

Specify the earth resistivity in ohm-meter. Use 100 ohm-meters for average damp earth if the value of resistivity is not known.

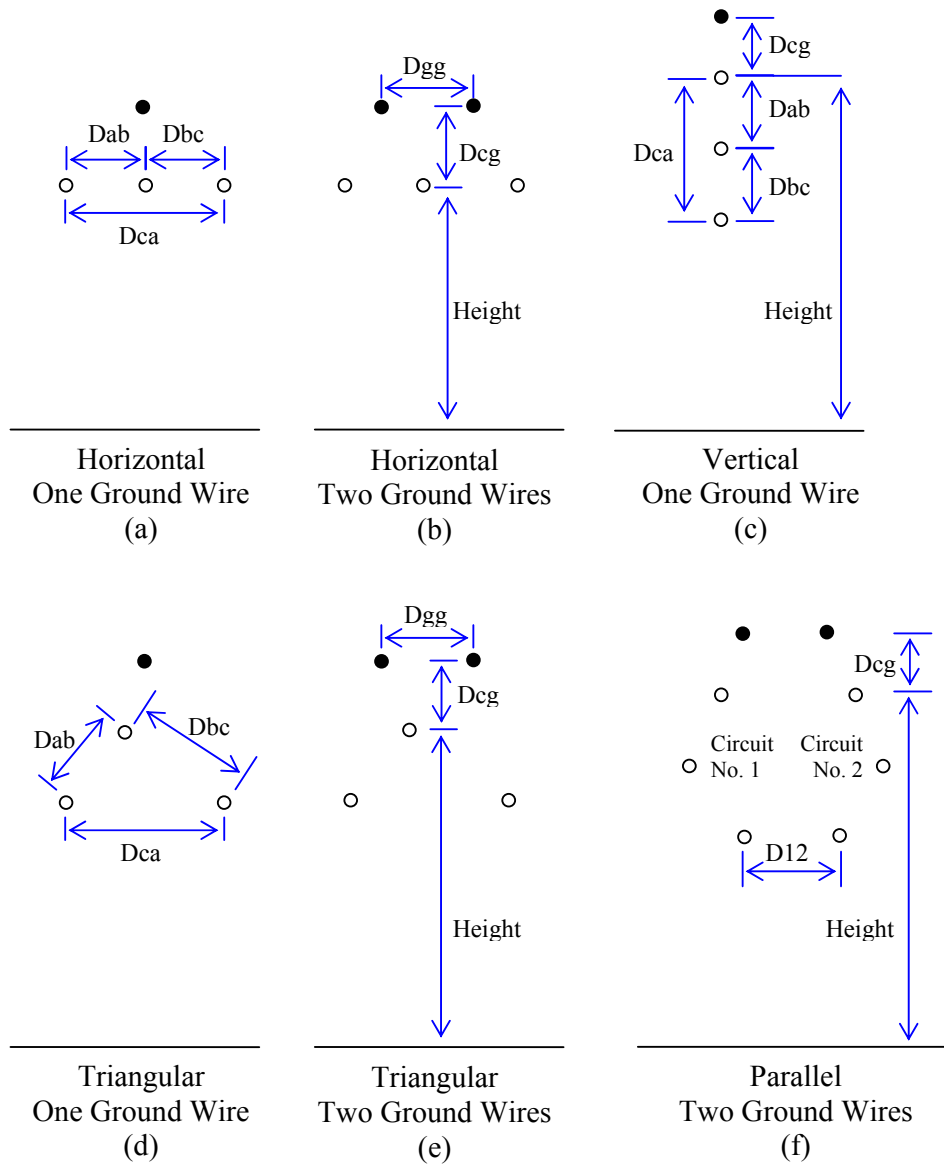


Figure 12. Line Configuration and Spacing

5.7. Substation Power Transformer Data

The following information must be filled up in the Template of Substation Power Transformer Data. In addition, Distribution utilities are required to submit all the information found in the nameplate of the power transformer in separate sheets.

Substation Power Transformer ID

Specify the unique ID for the Substation Power Transformer using up to 25 alphanumeric characters.

Winding Type

Specify transformer type according to number of windings:

- 1 – for Autotransformers
- 2 – for Two-Winding Transformers
- 3 – for Three-Winding Transformers

Bus Connected

Specify the Bus IDs for the connecting buses of the Substation Power Transformer:

- Primary Bus ID
- Secondary Bus ID
- Tertiary Bus ID for Three Winding Transformer - Enter “NA” if transformer has no tertiary winding

Core Structure

Specify the Core Structure of the Substation Power Transformer:

- 1 – if not known
- 2 – for Shell Type Transformer
- 3 – for 3-legged Core Type Transformer
- 4 – for 4-legged Core Type Transformer
- 5 – for 5-legged Core Type Transformer

Method of Cooling

Specify the method of cooling of the Substation Power Transformer:

- OA - for Oil-immersed, self-cooled
- OA/FA - Oil-immersed, self-cooled / forced-air-cooled
- OA/FA/FA - Oil-immersed, self-cooled / forced-air-cooled / forced-air-cooled

- OA/FA/FOA - Oil-immersed, self-cooled / forced-air-cooled / forced-air—forced-oil-cooled
- OA/FOA/FOA - Oil-immersed, self-cooled / forced-air—forced-oil-cooled / forced-air—forced-oil-cooled
- OW - Oil-immersed, water-cooled
- OW/A - Oil-immersed, water-cooled / self-cooled
- OTHERS - for other method cooling not included in the selection above

KVA Rating

Specify the following Substation Power Transformer capacity in kVA:

- Primary kVA – for all type of transformers
- Secondary kVA – for three-winding transformers only.
- Tertiary kVA – for three-winding transformer only.

Enter “NA” if not applicable. For example, the Secondary and Tertiary KVA of a Two-Winding Transformer should have “NA” entries.

Max KVA Rating

If the transformer has forced-cooling, specify the maximum kVA rating of the Substation Power Transformer:

- Max Primary kVA – for all type of transformers
- Max Secondary kVA – for three-winding transformers only.
- Max Tertiary kVA – for three-winding transformer only.

Max KVA is equal or greater than the KVA rating depending on the method of cooling. For oil immersed, self-cooled Power Transformers (OA), the Max kVA rating is equal to the kVA rating.

Enter “NA” if not applicable. For example, the Secondary and Tertiary Max KVA of a Two-Winding Transformer should have “NA” entries.

KV Rating

Specify the voltage rating of the Substation Power Transformer in kV:

- Primary KV – for all type of transformers
- Secondary KV – for all type of transformers.
- Tertiary KV – for three-winding transformer only.

Enter “NA” if not applicable. For example, the Tertiary KV of a Two-Winding Transformer should have “NA” entry.

Winding Connection

Specify the winding connection of the Substation Power Transformer:

Primary Connection – DELTA or WYE
Secondary Connection – DELTA or WYE
Tertiary Connection – DELTA or WYE. Enter “NA” if transformer has
no tertiary winding

Tap Changer Type

Specify the type of Tap Changer either:

Fixed - for Off-Load, Manual On-Load, and No Tap Changer
Automatic - for Automatic Load Tap Changer

Winding with Auto LTC

Specify the winding where automatic Load Tap Changing operation takes place:

PRI – for primary winding;
SEC – for secondary winding;
TER – for tertiary winding; or
NA – if not applicable.

Tap Setting

Specify the transformer Tap Voltage setting in kV:

Primary Tap kV - Tap at the primary winding
Secondary Tap kV - Tap at the secondary winding
Tertiary Tap kV - Tap at the tertiary winding

Enter “NA” if transformer has no Taps.

Percent Impedance (%Z)

Specify the Percent Impedance of the transformer taken from the nameplate of the transformer.

For Autotransformer and Two-Winding Transformer, enter the value in the %Z Column. Enter “NA” under the columns for %Zps, %Zpt and % Zst.

For Three-Winding Transformers, the following are the impedances:

Zps = Leakage impedance between the Primary and Secondary windings with the Tertiary winding open circuited.
Zpt = Leakage impedance between the Primary and Tertiary windings with the Secondary winding open circuited.

Zst = Leakage impedance between the Secondary and Tertiary windings with the Primary winding open circuited.

Enter “NA” under %Z column and the values of the impedances of the Three-Winding Transformer under the %Zps, %ZPt and %Zst Columns.

X/R Ratio

Specify the transformer impedance X/R ratios if available.

For Autotransformer and Two-Winding Transformer, enter the value in the X/R Column. Enter “NA” under the columns for X/R ps, X/R pt and X/R st.

For 3-winding transformers, three X/R values are needed, corresponding to the three winding impedances Zps, Zpt, and Zst:

$$X/R \text{ ps} = X_{ps} / R_{ps}$$

$$X/R \text{ pt} = X_{pt} / R_{pt}$$

$$X/R \text{ st} = X_{st} / R_{st}$$

Enter “NA” under X/R column and the values of the X/R ratios of the Three-Winding Transformer under the X/R ps, X/R pt and X/R st Columns.

No-Load Loss

Specify the No-load loss of the Substation Power Transformer in kW. Enter “NA” if not available.

No-Load Current

Specify the No-Load Current of the Substation Power Transformer in Amperes. Enter “NA” if not available.

5.8. Primary Distribution Line Data

Each Primary Distribution Line segment (i.e., the section of the Primary Distribution Line that can be identified by only one sending-end and only one receiving-end) must be included as one data entry. The whole length of the Distribution Line may be entered as one or more line segments depending on the connection points and the construction arrangement (e.g., loop, expanded radial, etc.). Connection point is created if an equipment (e.g., Shunt Capacitor), line, or load is connected to the Distribution Line. This connection point must be assigned a Bus ID.

The data required for the Primary Distribution Line segment is the same as in the Sub-transmission Line Data except for the Identification (ID). In addition, the Phase Connected of a 3-Phase, V-Phase and 1-Phase Lines shall be specified for the Primary Distribution Line Data.

Primary Distribution Line Segment ID

Specify the unique ID of the Primary Distribution Line segment using up to 25 alphanumeric characters.

Phasing

Specify phase(s) of the source Bus or Node (i.e., “From Bus”) where the Primary Distribution Line segment is connected (see Figure 13):

- ABC – for 3-Phase;
- AB – for V-Phase or 1-Phase Line-to-Line connected in phases AB
- BC – for V-Phase or 1-Phase Line-to-Line connected in phases BC
- CA – for V-Phase or 1-Phase Line-to-Line connected in phases CA
- A – for 1-Phase Line-to-Neutral connected in Phase A
- B – for 1-Phase Line-to-Neutral connected in Phase A
- C – for 1-Phase Line-to-Neutral connected in Phase A

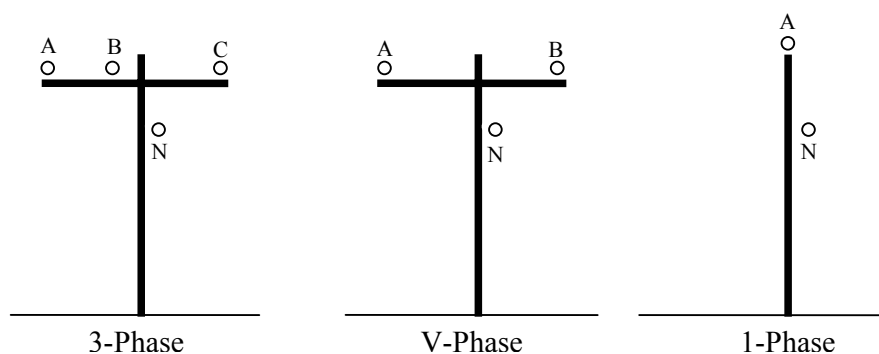


Figure 13. Phase Connected

5.9. Voltage Regulator Data

Voltage Regulator ID

Specify the unique ID for the Voltage Regulator using up to 25 alphanumeric characters.

Bus Connected

Specify the Bus IDs for the connecting buses of the Voltage Regulator:

From Bus
To Bus

Regulated Bus

Specify the Bus ID of the regulating point (Bus or Node) whose voltage is being controlled by the Voltage Regulator.

Phase Type

Specify the type of Voltage Regulator:

- 1 – Single phase
- 2 – Two single phase
- 3 – Three-phase, gang operated
- 4 – Three single phase, independently operated

Phasing

Specify phase(s) of the source Bus or Node (i.e., “From Bus”) where the Voltage Regulator is connected:

- ABC – for 3-Phase;
- AB – for V-Phase or 1-Phase Line-to-Line connected in phases AB
- BC – for V-Phase or 1-Phase Line-to-Line connected in phases BC
- CA – for V-Phase or 1-Phase Line-to-Line connected in phases CA
- A – for 1-Phase Line-to-Neutral connected in Phase A
- B – for 1-Phase Line-to-Neutral connected in Phase A
- C – for 1-Phase Line-to-Neutral connected in Phase A

kVA Rating

Specify the Rated Capacity of the Voltage Regulator in kVA.

kV Rating

Specify the voltage Rating of the Voltage Regulator in kV.

Target Voltage Level

Specify the desired voltage (on 120-volt base) to be held at the regulating point (e.g., 124 volts).

Bandwidth

Specify the voltage level tolerance on 120-volt base (e.g., 2.0 volts):

R-Setting

Specify the Compensator R-dial setting (i.e., the equivalent resistance and reactance to the regulating point calibrated in volts) of the Voltage Regulator for each phase:

R-Setting Phase A
R-Setting Phase B
R-Setting Phase C

Enter "NA" if not applicable. For example, for Two (2) Single Phase Voltage Regulator connected in Phase A and Phase B, only the Column for Phase A and B has value while the Column for Phase C has "NA".

X-Setting

Specify the Compensator X-dial setting of the Voltage Regulator for each phase:

R-Setting Phase A
R-Setting Phase B
R-Setting Phase C

Enter "NA" if not applicable. For example, for Two (2) Single Phase Voltage Regulator connected in Phase A and Phase B, only the Column for Phase A and B has value while the Column for Phase C has "NA".

CT Ratio

Specify the primary current rating of the Current Transformer used for the Voltage Regulator. The CT secondary current is assumed 1 Ampere.

PT Ratio

Specify the voltage ratio of the Potential Transformer used for the Voltage Regulator. Usually the PT secondary voltage of Voltage Regulator is 120 volts. For example, a PT rated 13,200/120 volts has a PT Ratio of 110.

No-Load Loss

Specify the No-Load (fixed) loss of the Voltage Regulator per phase in kW (if available):

No-Load Loss Phase A
No-Load Loss Phase B
No-Load Loss Phase B

Enter "NA" if not available or applicable.

5.10. Shunt Capacitor Data

Shunt Capacitor ID

Specify the unique ID for the Shunt Capacitor using up to 25 alphanumeric characters.

Bus Connected

Specify the Bus ID of the Bus or Node where the Shunt Capacitor is connected.

Phase Type

Specify the construction type of Shunt Capacitor:

- 1 – Single-phase Shunt Capacitor
- 2 – Two (2) single-phase Shunt Capacitors
- 3 – Three-phase Shunt Capacitor
- 4 – Three (3) single-phase Shunt Capacitors

Phasing

Specify phase(s) of the Bus or Node where the shunt Capacitor is connected:

- ABC – for 3-Phase;
- AB – for V-Phase or 1-Phase Line-to-Line connected in phases AB
- BC – for V-Phase or 1-Phase Line-to-Line connected in phases BC
- CA – for V-Phase or 1-Phase Line-to-Line connected in phases CA
- A – for 1-Phase Line-to-Neutral connected in Phase A
- B – for 1-Phase Line-to-Neutral connected in Phase A
- C – for 1-Phase Line-to-Neutral connected in Phase A

Voltage Rating

Specify the Voltage Rating of Shunt Capacitor in kV.

KVAR Rating

Specify reactive Power Rating of Shunt Capacitor per phase in kVars:

- Phase A KVAR
- Phase B KVAR
- Phase C KVAR

Enter “NA” if not applicable.

Fixed Loss

Specify Fixed Losses of Shunt Capacitor per phase in Watts:

Fixed Loss Phase A
Fixed Loss Phase B
Fixed Loss Phase C

Enter “NA” if not available or applicable.

5.11. Shunt Inductor Data

Shunt Inductor ID

Specify the unique ID for the Shunt Inductor using up to 25 alphanumeric characters.

Bus Connected

Specify the Bus ID of the Bus or Node where the Shunt Inductor is connected.

Phase Type

Specify the construction type of Shunt Inductor:

- 1 – Single-phase Shunt Inductor
- 2 – Two (2) single-phase Shunt Inductors
- 3 – Three-phase Shunt Inductor
- 4 – Three (3) single-phase Shunt Inductors

Phasing

Specify phase(s) of the Bus or Node where the Shunt Inductor is connected:

- ABC – for 3-Phase;
- AB – for V-Phase or 1-Phase Line-to-Line connected in phases AB
- BC – for V-Phase or 1-Phase Line-to-Line connected in phases BC
- CA – for V-Phase or 1-Phase Line-to-Line connected in phases CA
- A – for 1-Phase Line-to-Neutral connected in Phase A
- B – for 1-Phase Line-to-Neutral connected in Phase A
- C – for 1-Phase Line-to-Neutral connected in Phase A

Voltage Rating

Specify the Voltage Rating of Shunt Inductor in kV.

Reactance

Specify the Reactance of the shunt Inductor per phase in Ohms:

Phase A Reactance

Phase B Reactance

Phase C Reactance

Enter “NA” if not applicable.

Resistance

Specify the Resistance of the Shunt Inductor per phase in Ohms:

Phase A Resistance

Phase B Resistance

Phase C Resistance

Enter “NA” if not available or applicable.

5.12. Series Inductor Data

Series Inductor ID

Specify the unique ID for the Shunt Inductor using up to 25 alphanumeric characters.

Bus Connected

Specify the Bus IDs for the connecting buses of the Series Inductor:

From Bus

To Bus

Phase Type

Specify the construction type of the current-limiting Series Inductor:

1 – Single-phase Series Inductor

2 – Two (2) single-phase Series Inductors

3 – Three-phase Series Inductor

4 – Three (3) single-phase Series Inductors

Phasing

Specify phase(s) of the Bus or Node where the Series Inductor is connected:

ABC – for 3-Phase;

AB – for V-Phase or 1-Phase Line-to-Line connected in phases AB

BC – for V-Phase or 1-Phase Line-to-Line connected in phases BC

- CA – for V-Phase or 1-Phase Line-to-Line connected in phases CA
- A – for 1-Phase Line-to-Neutral connected in Phase A
- B – for 1-Phase Line-to-Neutral connected in Phase A
- C – for 1-Phase Line-to-Neutral connected in Phase A

Voltage Rating

Specify the Voltage Rating of Series Inductor in kV.

Reactance

Specify the Reactance of the Series Inductor per phase in Ohms:

- Phase A Reactance
- Phase B Reactance
- Phase C Reactance

Enter “NA” if not applicable.

Resistance

Specify the Resistance of the Series Inductor per phase in Ohms:

- Phase A Resistance
- Phase B Resistance
- Phase C Resistance

Enter “NA” if not available or applicable.

5.13. Distribution Transformer Data

Distribution Transformer ID

Specify the unique ID for the Distribution Transformer using up to 25 alphanumeric characters.

Bus Connected

Specify the Bus IDs for the connecting buses of the Distribution Transformer:

- Primary Bus ID
- Secondary Bus ID

Phase Type

Specify the construction type of Distribution Transformer:

- 1 – Single-phase Distribution Transformer
- 2 – Two (2) single-phase Distribution Transformers

- 3 – Three-phase Distribution Transformer
- 4 – Three (3) single-phase Distribution Transformers

Connection

Specify the connection of Distribution Transformer:

- 1 – Single Phase
- 2 – Delta-Delta
- 3 – Wye-Wye
- 4 – Delta-Wye
- 5 – Wye-Delta
- 6 – Open Delta-Open Delta
- 7 – Open Wye-Open Delta

Phasing

Specify phase(s) of the Bus or Node where the Primary of the Distribution Transformer is connected:

- ABC – for 3-Phase;
- AB – for V-Phase or 1-Phase Line-to-Line connected in phases AB
- BC – for V-Phase or 1-Phase Line-to-Line connected in phases BC
- CA – for V-Phase or 1-Phase Line-to-Line connected in phases CA
- A – for 1-Phase Line-to-Neutral connected in Phase A
- B – for 1-Phase Line-to-Neutral connected in Phase A
- C – for 1-Phase Line-to-Neutral connected in Phase A

kVA Rating

Specify the Rated Capacity of the Distribution Transformer in kVA. For two (2) or three (3) single-phase transformers in a bank, the rated KVA of the largest Distribution Transformer shall be used.

kV Rating

Specify the Voltage Rating of the Distribution Transformer in kV:

- Primary kV
- Secondary kV

The voltage rating should be taken from the nameplate and not the resulting line-to-line voltage of the transformer bank.

Tap Voltage

Specify the Tap Voltage of the Distribution Transformer in kV:

- Primary Tap
- Secondary Tap

Enter the Rated Voltage if the Distribution Transformer has no taps.

%Z

Specify the percent impedance (%Z) of the Distribution Transformer taken from the nameplate. Enter “NA” if not available.

X/R Ratio

Specify the X/R Ratio of the impedance of the Distribution Transformer. Enter “NA” if not available.

No-Load Loss

Specify the No-load loss of the Distribution Transformer in kW. Enter “NA” if not available.

No-Load Current

Specify the No-Load Current of the Distribution Transformer in Amperes. Enter “NA” if not available.

5.14. Secondary Distribution Line Data

Each Secondary Distribution Line segment (i.e., the section of the Secondary Distribution Line that can be identified by only one sending-end and only one receiving-end) must be included as one data entry. The whole length of the Secondary Line may be entered as one or more line segments depending on the connection points created by lateral lines or service drops.

Secondary Distribution Line Segment ID

Enter the unique ID of the Secondary Line segment using up to 25 alphanumeric characters.

Bus Connected

Specify the Bus IDs for the connecting buses at the ends of the Secondary Distribution Line segment:

From Bus
To Bus

Phasing

Specify phase(s) of the source Bus or Node where the Secondary Distribution Line is connected:

- ABC – for 3-Phase;
- AB – for V-Phase or 1-Phase Line-to-Line connected in phases AB
- BC – for V-Phase or 1-Phase Line-to-Line connected in phases BC
- CA – for V-Phase or 1-Phase Line-to-Line connected in phases CA
- A – for 1-Phase Line-to-Neutral connected in Phase A
- B – for 1-Phase Line-to-Neutral connected in Phase A
- C – for 1-Phase Line-to-Neutral connected in Phase A

Length

Enter the length of the Secondary Distribution Line segment in meters.

Conductor Type

Specify material type of the phase conductor either:

- AL – for Aluminum; or
- Cu – for Copper.

Size

Specify size of phase conductors in AWG, kcmil or mm²

Installation Type

Enter the type of installation of the secondary distribution line segment:

- 1 – Overhead, underbuilt
- 2 – Overhead, open secondary
- 3 – In Raceway, magnetic (e.g., Rigid Steel Conduit)
- 4 – In Raceway, non-magnetic (e.g., PVC)

5.15. Service Drop Data

The Service Drop is the conductor extended from the Primary or Secondary Distribution Line to the customer service entrance.

Service Drop ID

Enter the unique ID of the Service Drop using up to 25 alphanumeric characters.

Bus Connected

Specify the Bus ID of the source Bus or Node of the Service Drop. This could be any bus at the Primary Distribution Line, Secondary Distribution Line, or Distribution Transformer Secondary.

Customer Connected

Specify the Customer ID of the customer connected to the service drop. This is the same Customer ID in the Customer Data and Meter Reading Data.

Phasing

Specify phase(s) of the source Bus or Node where the Service Drop is connected:

- ABC – for 3-Phase;
- AB – for V-Phase or 1-Phase Line-to-Line connected in phases AB
- BC – for V-Phase or 1-Phase Line-to-Line connected in phases BC
- CA – for V-Phase or 1-Phase Line-to-Line connected in phases CA
- A – for 1-Phase Line-to-Neutral connected in Phase A
- B – for 1-Phase Line-to-Neutral connected in Phase A
- C – for 1-Phase Line-to-Neutral connected in Phase A

Length-1

Enter the length of the Service Drop segment from Primary or Secondary Distribution Line Connection Point to the Metering Point in meters.

Length-2

Enter the length of the Service Drop segment from the Metering Point to the Customer Service Entrance in meters.

Conductor Type

Specify material type of the phase conductor either:

- AL – for Aluminum; or
- Cu – for Copper.

Size

Specify size of phase conductors in AWG, kcmil or mm²

Installation Type

Enter the type of installation of the secondary distribution line segment:

- 1 – Overhead, underbuilt
- 2 – Overhead, open secondary
- 3 – In Raceway, magnetic (e.g., Rigid Steel Conduit)
- 4 – In Raceway, non-magnetic (e.g., PVC)

5.16. Energy Sales Data

Customer Type

Specify the customer classification code (e.g., RES1 for small residential, RES2 for large residential, etc.). This must be the same classification specified in Customer Data and Load Curve Data.

No. of Customers

Specify the number of customers for the given period (month and year) classified under the Customer Type

kWhr Sold

Specify the electric Energy sold to all customers belonging to the Customer Type in kWhr

%

Compute the percent share of the kWhr sold to customers belonging to the Customer Type over the total kWhr sold to all customers.

Average No. of Customers

Compute the average number of customers for the given year (from January to December).

Total kWhr Sold for the Year

Compute the sum of the monthly electric Energy (in kWhr) sold for the given year (from January to December).

5.17. Other Technical Data

Purchased kWhr

Enter the total electric Energy (in kWhr) purchased for the given month and year.

Generated kWhr

Enter the total electric Energy (in kWhr) generated (if the Distribution Utility has generating facilities) for the given month and year.

Total Input kWhr

Compute the total of the purchased and generated electric Energy (in kWhr) for the given month and year.

Total kWhr Sold

Enter the Total electric Energy (in kWhr) sold to all customers for the given month and year. This must be the same total kWhr sold in Energy Sales Data.

Utility Use

Enter the total energy consumed (in kWhr) by the Distribution Utility for its own use.

Recovered kWhr

Enter the equivalent energy (in kWhr) recovered through anti-pilferage activities Distribution Utility for its own use.

System Loss (kWhr)

Compute the Distribution System Loss in kWhr. This is equal to the Total Input kWhr minus the sum of the Total kWhr Sold and the Recovered kWhr.

System Loss (%)

Compute the System Loss in percent. Divide the System Loss in kWhr by the Total Input kWhr then multiply by 100.

Peak Demand

Enter the non-coincident Peak Demand of the Distribution System in MW. This is obtained by adding the Peak Demand in all delivery points from the Transmission System and Generating Plants.

Total S/S Capacity

Enter the Total Substation Capacity of the Distribution System in MVA. This is obtained by adding the MVA rating of all Substation Power Transformers.

Total Circuit Length (Primary)

Enter the Total Circuit Length of the Primary Distribution Lines in km. This is obtained by adding the following:

- a) 3-phase Primary Distribution Lines x 3
- b) V-Phase Primary Distribution Lines x 2
- c) 1-Phase Primary Distribution Lines x 1

Total Circuit Length (Secondary)

Enter the Total Circuit Length of the Secondary Distribution Lines in km. This is obtained by adding the following:

- a) 3-phase Secondary Distribution Lines x 3
- b) V-Phase Secondary Distribution Lines x 2
- c) 1-Phase Secondary Distribution Lines x 1

System Load Factor

Enter the Distribution System Load Factor. This is computed from:

$$\text{System Load Factor (\%)} = \frac{(\text{Total Input kWhr} / 8760) \times 100}{\text{Peak Demand in MW} \times 1000}$$

System Power Factor

Enter the Distribution System Power Factor. This is computed from:

$$\text{System Power Factor (\%)} = \frac{(\text{kWhr}) \times 100}{\sqrt{(\text{kWhr})^2 + \text{kVARhr}^2}}$$