POWER SYSTEMS CAPACITY PLANNING GUIDELINES

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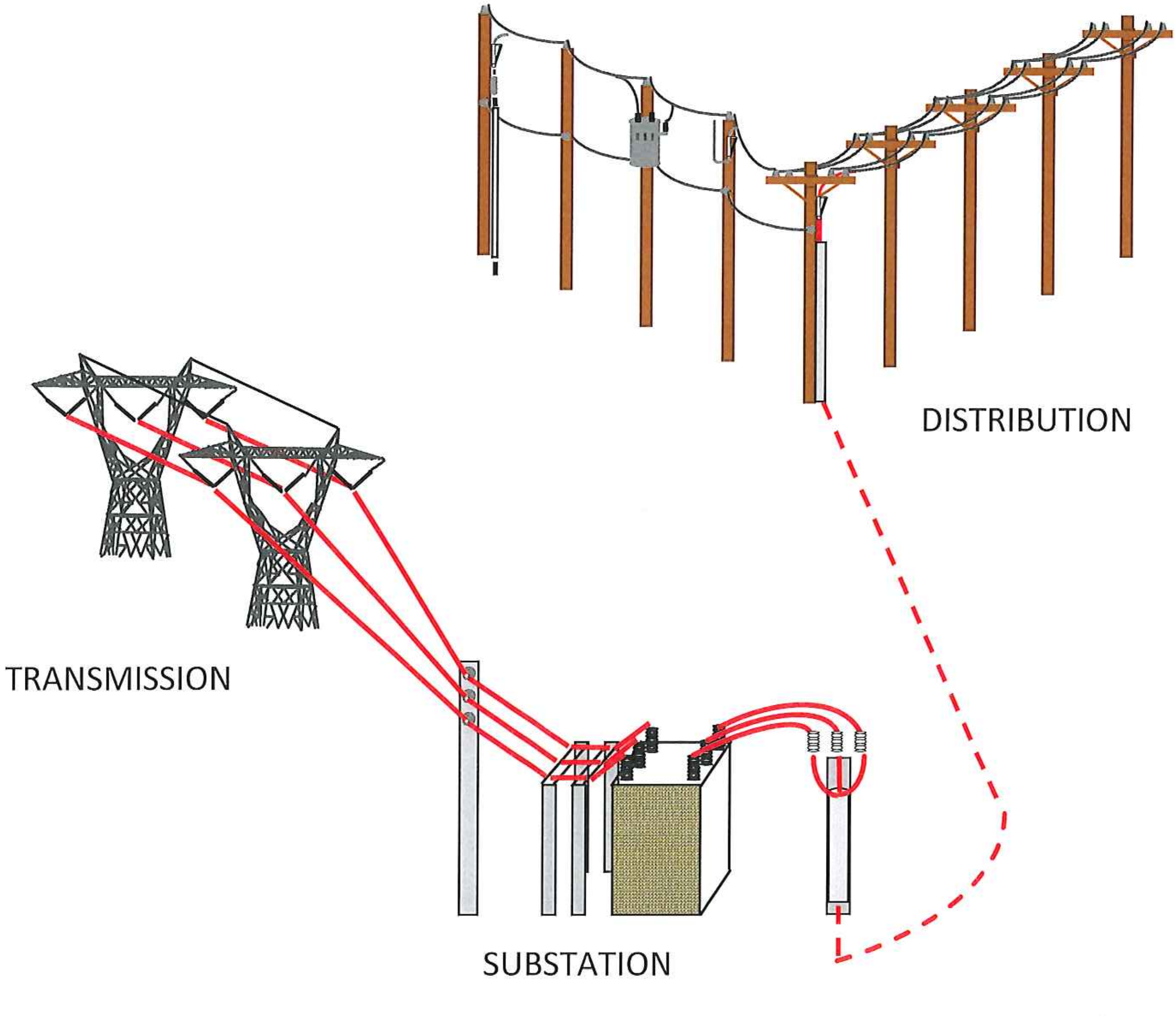

POWER SYSTEMS
CAPACITY PLANNING GUIDELINES

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REVISION HISTORY

Version	Date	Author(s)	Revision Notes
8	3/30/2016	Johnny Rivera	Added sections 3.5, 3.6, 3.7 under Distribution Planning Guidelines
9	7/29/2016	Johnny Rivera	Added revision history, section 3.8 under Distribution Planning Guidelines

DISTRIBUTION SUBSTATION CAPACITY PLANNING

1. INTRODUCTION

1.1. Objective

The objective of the revised planning criteria is to provide substation capacity at an optimal cost while maintaining the acceptable reliability and operating flexibility. This will be done by improving the utilization of existing and future substation capacity, and without imposition of undue burden on distribution facilities to back-stand substation transformer capacity for extended periods of time.

1.2. Application

These criteria/guidelines shall be used by Distribution Planning, in conjunction with Transmission & Substation Technical Services, to develop risk-ranked recommendations for budgeting of projects to relieve potential overloading of distribution substation transformers due to load growth.

As part of its annual Planning /Budgeting process, Distribution Planning reviews historical feeder loads and forecasted new loads. The team's primary interest is to identify the need for new distribution projects (new feeders, ties, etc). However, their efforts also provide the load forecast for distribution substation power transformers and helps identify any associated potential overloads by rolling up feeder loads to the transformer level. Distribution Planners have access to other relevant information for identifying and for risk-ranking of potential overloads, such as: number of customers out following a transformer outage, capability to transfer load via switching of the distribution network, number of switching operations/time to transfer load, and critical customers potentially affected.

Transmission & Substation Technical Services, on the other hand, has access to other relevant information, such as: transformer age and condition, ability to parallel transformers to alleviate overloads, and auto-restoration implications.

Therefore, both Distribution Planning and Transmission & Substation Technical Services must be deeply involved in the process of identifying and ranking potential distribution substation power transformer overloads.

1.3. General Philosophy

The revised distribution substation capacity planning criteria utilizes "Substation Firm" capacity criteria, which depends upon sufficient transformer capacity within the substation for the back-standing of any transformer outage within that substation, and "Area Firm" capacity criteria, which depends on utilizing the capability of the distribution network in an area to transfer load to adjacent substations following a transformer outage. Note that "Mobile Substation Firm" capacity criteria, which depends upon mobile transformers for the back-standing of long duration transformer outages, is a subset of "Area Firm". The actual design of the distribution substation/feeder power delivery system will use a mixture of substation firm and area firm substation firm capacity planning criteria dependent upon the actual circumstances applicable to the local load area.

1.4. Distribution Substation Power Transformer Loading Capability

Generally, distribution substation power transformers are capable of being loaded to 130% of nameplate in the summer, for up to 6 hours per day, provided that the loading does not exceed 100% of nameplate rating for the remainder of the day. In the winter, power transformers can be loaded to 150% of nameplate, for up to 3 hours per day, provided that the loading does not exceed 100% of nameplate rating for the remainder of the day. Power transformers can be loaded to these levels day after day, without accelerated loss of life, and without regard to whether all other facilities are in service (system normal condition) or, whether an adjacent transformer is out of service (single contingency or emergency condition) - the transformer doesn't know the difference. Because these loading criteria represent a significant departure from FPL's power transformer loading guidelines of the past, any forecasted loads above 100% of nameplate rating for system normal condition shall also be reported by Distribution Planning to Transmission & Substation Technical Services for in depth verification of specific transformer loading capability.

1.5. Mobile and Spare Transformer Installation Times

The typical timeframe for installation of a mobile transformer following a transformer outage is 36 hours in substations which have been outfitted with mobile hookup provisions (i.e.: bus extension, pole to tap the high-line, etc.), and 48 hours in substations which have not been outfitted with mobile hookup provisions (but which do have sufficient access and space).

The typical timeframe for installation of a spare transformer following a transformer outage is 5 to 7 days.

2. CRITERIA DEFINITIONS AND APPLICATION

2.1. Substation Firm (Multi-Transformer Stations)

This criteria requires that individual substations have sufficient installed transformer capacity for back-standing 100% of the substation seasonal peak load. Restoration of service in a substation firm load area is very simple; the transformer that is out is isolated and then either a bus-tie switch or breaker is closed to restore the interrupted distribution feeders. In an auto-restoration substation, this is done automatically; and care must be taken to insure that when load is automatically transferred from a failed transformer, the remaining transformer to which the load is transferred does not trip on overload. Although feeder switching to pick up load is not part of the Substation Firm planning philosophy, Distribution Planning shall consider, and report on, such capability as a ranking tool for Substation Firm locations.

Substations that exceed the 130% rating during transformer contingency will be reviewed for solutions. The team will verify stations between 130%-140% loading can be field switched such that after an event, the transformer loading will be reduced to below 130% percent. For substations that exceed 140% (auto-restoration disabled), the team will recommend permanent solutions which include distribution boundary changes, feeder tie, new feeder or increase capacity projects to ensure auto-restoration is enabled.

2.2. Area Firm

"Area Firm" utilizes the capability of the distribution network in an area to transfer load to adjacent substations following a transformer outage. Any unserved load would be picked up by adjacent feeders up to the usable capacity of the distribution network. Each load area is unique; and careful analysis of the local distribution network is necessary to determine the maximum useable capacity.

An Area Firm substation area is defined by the feasible switching operations that will restore load after the outage of one transformer. Some cascading beyond immediately adjacent feeders may be expected to avoid loading equipment beyond capacity. Any contingency scenarios requiring more than 6 switching steps and/or voltage/protection violations will be sent to Substation for project review and evaluation. In no case is the system normal seasonal peak load in an Area Firm Load Area to exceed the sum of the transformer capabilities in that Area.

[Note that if our philosophy is to leave feeders abnormally switched for whatever period of time it takes to bring additional transformer capacity into the Area (which, for example, would be up to a week to install a spare), then Distribution may have increased exposure for incurring additional SAIDI during this period.]

2.2.1. Mobile Firm

This criterion is a subset of Area Firm. It involves the use of mobile transformers to provide back-standing for the loss of a distribution substation power transformer. The following is an explanation of how mobile transformer firm criteria will be applied.

Single Transformer Substations

Total substation loading will be limited by the size of the largest mobile transformer designated for the site. Following is a link to a complete listing of mobile transformers

and related mobile equipment maintained by Transmission & Substation Technical Services:
http://cafe.fpl.com/sharepoint/transsub/TechSvcs/Transformers/Shared Documents/Mobile Equipment/

The loading on any mobile transformer shall never exceed 100% of its nameplate rating. That is the absolute maximum capability of a mobile.

Power Systems Distribution Dispatch Offices will restore load before the mobile transformer is installed. Customers shall not intentionally be left out of service until the mobile transformer is installed, if at all possible.

Preferably, feeders will be switched back to their normal field configurations and loading as soon as the mobile transformer is installed. This allows for back-standing other contingencies until the damaged transformer is repaired or replaced. However, as a ranking tool, Distribution Planning shall consider, and report on, the capability to serve all load following mobile installation and with extended switching.

Multiple Transformer Substations

Following the loss of a transformer, load will be transferred to the remaining transformer(s), up to 130% of nameplate in the Summer, 150% of nameplate in the Winter, and as allowed by the substation configuration; and the remaining load will be transferred to the mobile transformer when it is installed, up to its capacity. As in the case of the single transformer substation, as much of the excess (beyond capacity of remaining transformers) load as possible will be picked up in the field by switching of feeder ties, prior to installation of the mobile transformer. Feeders will be switched back to their normal field configurations and loading as soon as the mobile transformer is installed. However, as a ranking tool, Distribution Planning shall consider, and report on, the capability to serve all load following mobile installation and with extended switching. At substations with 3 or more transformers, paralleling of the remaining transformers to balance the load following a transformer outage may be an option; but this needs to be investigated on a case-by-case basis (see Section 3.4).

3. PLANNING GUIDELINES AND CONSIDERATIONS

3.1. Choosing the Appropriate Planning Criteria

The criteria for future substation capacity additions will be mobile transformer firm. However, there are many distribution substations that have design or space limitations that make the use of mobile transformers backup undesirable. The Substation Engineering Group should be contacted to determine whether or not a non moduflex substation is suitable for mobile transformer back-standing. If not, substation firm capacity criteria must be used.

The nature of load served will dictate the use of substation firm capacity, rather than mobile substation firm, particularly if an extended service interruption carries the risk of high economic or sociological impact. Examples of this include:

- Dense, urban high-rise buildings in a downtown area
- Areas containing major regional hospital complexes
- Geographical Island areas (i.e., Key Biscayne, Hutchinson Island, Palm Beach, Gasparilla Island)
- Electrical Island areas served by one or two sources only (i.e. Hallandale Substation)

There should be a concurrence between Transmission Planning, Distribution Planning, and Transmission & Substation before station firm criteria is used, based solely on load type.

3.2. Load Forecasting Methodology

Substation capacity planning shall be based on historical transformer peak loads (non-simultaneous), plus known, projected load growth. The historical transformer peaks shall be obtained via our Pi (to become EDNA in the near future) SCADA system. FPL system wide

3.3. Winter Peak Capacity Planning

Winter peak capacity planning will be allowed for all Regions. The criteria is:

- FEEDERS: No contingency (winter peak is the contingency). Load up to winter emergency ratings. Projects will be developed for feeders exceeding 684 amps. Relays will not be set higher than 720 amps (except under emergency conditions). Considerations must also be made for feeders that do not have the available fault current to raise relays to the specified value.
- SUBSTATIONS: Winter peak load not to exceed 150% of substation transformer nameplate. Transformer out contingency is NOT considered under winter peak load conditions.

3.4. Paralleling Transformers

Substations with 3 or more transformers may be subjected to overload following loss of one transformer because the load fed from that transformer can only be transferred to one of the remaining transformers. In such cases, it may be possible to plan for overload mitigation by paralleling the remaining transformers so that they share the load of the transformer that is out of service. This would be accomplished expediently by closing the bus tie-breaker via dispatcher operation following a contingency. Distribution Planning will provide Substation the stations it identified under this criteria. There are several issues that need to be investigated for each specific instance where this is considered as an alternative, including:

1. The parallel configuration increases the available fault current on the low voltage substation equipment and the associated distribution feeders. This could potentially result in fault currents in excess of equipment capability, a situation which should not be allowed to occur.
2. Transmission line relays at some voltage levels may "see through" the paralleled transformers and trip the transmission line for close-in feeder faults.
3. A bus fault will cause loss of both paralleled transformers.
4. In Scheme 10 substations, closing the bus tie-breaker to parallel transformers will lock out the entire substation if it is closed into a faulted bus.

Each case must be reviewed separately by Distribution Planning, Transmission & Substation Technical Services and Protection & Control. For planned paralleling of transformers, supervisory control of the bus-tie-breaker should be installed and telemetered transformer loading should be available.

3.5. Auto-Restoration

Auto restoration is very desirable when the load permits transferring a failed transformer's load to an adjacent transformer. This eliminates a potentially lengthy outage. However, when loads are too high, auto restoration can cause cascading transformer outages. Therefore, the following practice has been implemented regarding auto restoration.

All substations with auto-restoration are identified in the System Control Center (SCC) at the LFO; and the loadings of their transformers are continuously monitored by the SCC. When the loading reaches a level such that if auto-restoration was activated and the load is 140% or greater than the nameplate rating of the smallest transformer, auto-restoration is automatically disabled. Auto-restoration is re-enabled when the load drops to120% of the nameplate rating of the smallest transformer.

3.6. Distribution Planning Recommendations

When Distribution Planning reports potential overloads and recommends projects to mitigate such overloads to Transmission & Substation such reporting shall include not only the projected transformer loads; but also the pertinent ranking data: namely, number of Customers out following a transformer outage, capability to transfer load via switching of the distribution network, number of switching operations and average time to transfer load, number of Customers left out and for how long; and CIF Customers potentially affected.

DISTRIBUTION SUBSTATION EQUIPMENT GUIDELINES

1. DEFINITIONS

To properly apply this loading guide, it is necessary to clearly define the terms Normal Loading and Emergency Loading.

1.1. Normal Loading

Normal loading is defined as the operating condition where all substation equipment is in service and operating at or below nameplate rating. The condition of a planned equipment outage for maintenance or construction purposes is considered normal loading.

1.2. Emergency Loading

Emergency loading is defined as the operating condition where an equipment failure or unavoidable system condition has caused the necessity of loading substation equipment beyond its maximum nameplate rating.

2. DISTRIBUTION SUBSTATION POWER TRANSFORMERS

2.1. Normal & Emergency Transformer Loading

Generally, distribution substation power transformers are capable of being loaded to 130% of nameplate in the summer, for up to 6 hours per day, provided that the loading does not exceed 100% of nameplate rating for the remainder of the day. In the winter, power transformers can be loaded to 150% of nameplate, for up to 3 hours per day, provided that the loading does not exceed 100% of nameplate rating for the remainder of the day. Table 1 shows these load and temperature cycles. Power transformers can be loaded to these levels day after day, without accelerated loss of life, and without regard to whether all other facilities are in service (system normal condition) or, whether an adjacent transformer is out of service (single contingency or emergency condition) - the transformer doesn't know the difference. Because these loading criteria represent a significant departure from FPL's power transformer loading guidelines of the past, any forecasted loads above 100% of nameplate rating for system normal condition shall also be reported by Distribution Planning to Transmission & Substation Technical Services for in depth verification of specific transformer loading capability. If there is any question of a particular transformer's capability with respect to operation above nameplate rating, a project to install remote temperature and gas monitoring shall be initiated.

Table 1 - Profile to be used for Power Transformer loading when the Transformer is required to operate above Normal Nameplate load

HOUR	SUMMER LOAD P.U	WINTER LOAD P.U	SUMMER Continuous P.U	WINTER Continuous P.U	SUMMER TEMPERATURE	WINTER TEMPERATURE
12:00 AM	1.0	1.0	1.15*	1.3*	26.7 °C	5.0°C
1:00 AM	1.0	1.0	1.15*	1.3*	26.1 °C	4.4°C
2:00 AM	1.0	1.0	1.15*	1.3*	25.6 °C	3.9°C
3:00 AM	1.0	1.0	1.15*	1.3*	25.4 °C	3.9°C
4:00 AM	1.0	1.0	1.15*	1.3*	25.3 °C	3.3°C
5:00 AM	1.0	1.0	1.15*	1.3*	26.7 °C	2.8°C
6:00 AM	1.0	1.5	1.15*	1.3*	28.9 °C	5.0°C
7:00 AM	1.0	1.5	1.15*	1.3*	30.6 °C	6.7°C
8:00 AM	1.0	1.5	1.15*	1.3*	33.1 °C	8.3°C
9:00 AM	1.0	1.0	1.15*	1.3*	34.4 °C	10.0°C
10:00 AM	1.0	1.0	1.15*	1.3*	35.0 °C	11.7°C
11:00 AM	1.0	1.0	1.15*	1.3*	35.0 °C	13.9°C
12:00 PM	1.0	1.0	1.15*	1.3*	35.0 °C	13.9°C
1:00 PM	1.3	1.0	1.15*	1.3*	35.0 °C	14.4°C
2:00 PM	1.3	1.0	1.15*	1.3*	35.0 °C	15.0°C
3:00 PM	1.3	1.0	1.15*	1.3*	35.0 °C	13.9°C
4:00 PM	1.3	1.0	1.15*	1.3*	35.0 °C	12.8°C
5:00 PM	1.3	1.0	1.15*	1.3*	34.4 °C	11.7°C
6:00 PM	1.3	1.0	1.15*	1.3*	33.9 °C	11.1°C
7:00 PM	1.0	1.0	1.15*	1.3*	32.2 °C	10.0°C
8:00 PM	1.0	1.0	1.15*	1.3*	29.4 °C	9.4°C
9:00 PM	1.0	1.0	1.15*	1.3*	28.9 °C	8.9°C
10:00 PM	1.0	1.0	1.15*	1.3*	27.8 °C	8.9°C
11:00 PM	1.0	1.0	1.15*	1.3*	27.2 °C	5.6°C

*As long as Top Oil and Hot Spot Temperature does not exceed 105 and 130 Deg. C respectively

3. FEEDER VOLTAGE REGULATORS

3.1. Normal Loading

Under normal operating conditions, feeder regulators may be loaded up to the values shown on Tables 2 and 3.

The ratings shown on Table 2 are based on a continuous loading. It is important to note that in cases where a feeder has 3 single phase regulators of different ratings, the feeder loading will be limited to the lowest rated regulator loading limits.

The ratings shown on Table 3 may be used on regulators which have had their regulation range restricted to -10% through +5%. This may be achieved by pinning the operating mechanism; and may require adjustment of the substation transformer taps to raise the operating bus voltage. Use of this option requires prior review and approval, for each case, by the Substation Component Team, Distribution Planning, Power Quality, and in the cases where transformer tap adjustments are required, Power Supply.

3.2. Emergency Loading

In emergency conditions, the ratings shown in both tables shall not be exceeded. It is important that regulators be blocked from stepping to taps which would result in loading beyond the limits established in these guidelines.

4. FEEDER CIRCUIT BREAKERS & MISCELLANEOUS LOW VOLTAGE EQUIPMENT

Low voltage circuit breakers, reclosers and miscellaneous types of substation equipment may be loaded up to the values shown in Table 4. Because of the relatively small mass involved with each of these devices, they will reach their ultimate temperatures in a short period of time. For this reason, these devices have lower emergency ratings than transformers and voltage regulators. The emergency ratings in the table are 2 hour ratings.

Table 2 - Regulators - Full Regulation

Regulator Size	Voltage Application (Ph - Ph)	Nameplate Rating	Summer Normal Rating	Winter Normal Rating	Summer Emergency Rating (note 2)	Winter Emergency Rating (note 2)
100 KVA	4.16kV	400/640	400	480	496	560
167 KVA	13.8kV	219/350	219	260	272	307
250 KVA	13.8kV	328/525	328	390	407	459
333 KVA	13.8kV	418/668	418	500	518	585
416 KVA	23kV	289/462	289	345	358	405
432 KVA	23kV	300/480	300	360	372	420
500 KVA	13.8kV	627/668	627	750	777	878
576 KVA	23kV	400/640	400	480	496	560
720 KVA	23kV	500/668	500	575	575	650
500 KVA (3 ph)	23kV	209/334	209	250	259	293

1. All ratings are in amperes.
2. Emergency ratings are for **one 2 hour period** during any 24 hour period only, after which period the load **must** be returned to the Normal Rating. Emergency ratings to be used only where the capability exists to monitor the actual loading and duration.
3. Summer Ratings apply when the ambient air temperature is between 500 and 950F.
4. Winter Ratings apply when the ambient air temperature is 500F or less.

Table 3 - Regulators at +5% to -5% Regulation

Regulator Size	Application Voltage (Ph - Ph)	Nameplate Rating	Summer Normal Rating	Winter Normal Rating	Summer Emergency Rating (note 2)	Winter Emergency Rating (note 2)
100 KVA	4.16kV	400/640	640	768	792	852
167 KVA	13.8kV	219/350	350	420	433	466
250 KVA	13.8kV	328/525	525	630	649	698
333 KVA	13.8kV	418/668	668	800	827	890
416 KVA	23kV	289/462	462	555	572	615
432 KVA	23kV	300/480	480	576	594	639
500 KVA	13.8kV	627/668	668	800	828	935
576 KVA	23kV	400/640	640	765	792	852
720 KVA	23kV	500/668	668	765	765	865
500 KVA (3 ph)	23kV	209/334	334	400	413	445

1. All ratings are in amperes.
2. Emergency ratings are for **one 2 hour period** during any 24 hour period only, after which period the load **must** be returned to the Normal Rating. Emergency ratings to be used only where the capability exists to monitor the actual loading and duration.
3. Summer Ratings apply when the ambient air temperature is between 500 and 950F.
4. Winter Ratings apply when the ambient air temperature is between 500F or less.
5. To achieve these ratings substation department **MUST** physically limit the operation of the regulator so that it cannot utilize taps +9 thru +16 (i.e., >+5% thru +10%). The power transformer(s) tap(s) may have to be raised in the station in order for the customers to have adequate voltage for this option.

Table 4 - Circuit Breakers and Miscellaneous Equipment

Equipment Type	Nameplate Rating	Normal Rating	Summer Emergency Rating (note 2)	Winter Emergency Rating (note 2)
Distribution Oil Breaker	600	600	600	774
Distribution Oil Breaker	1200	1200	1320	1320
Distribution Vacuum Breaker	560	560	616	722
Distribution Vacuum Breaker	600	600	660	774
Distribution Vacuum Breaker	1200	1200	1320	1320
Metalclad Breaker, 15kV	1200	1200	1320	1320
Metalclad Breaker, 27kV	600	600	740 (note 5)	740 (note 5)
Metalclad Breaker, 27kV	1200	1200	1320	1320
Breaker Current Transformers	600	600	750	750
Breaker Current Transformers	1200	1200	1500	1500
Disconnect Switches	600	600	810	978
Disconnect Switches	1200	1200	1620	1956
Phase Reactor, 0.5 Ohm	600	600	829	908
Phase Reactor, 1.25 Ohms	600	600	727	797
Phase Reactor, 0.5 Ohm	400	400	485	530
Phase Reactor, 0.5 Ohm	450	450	545	597
Phase Reactor, 0.5 Ohm	500	500	606	664
New Metalclad Substations:				
25kV, 1MCMIL AL direct buried in duct wet soil	590	Summer 590 Winter 614	677	698
25kV, 1MCMIL AL direct buried in duct dry soil	564	Summer 564 Winter 586	642	661

1. All ratings are in amperes.
2. Emergency ratings are for **one 2 hour period** during any 24 hour period only, after which period the load **must** be returned to the Normal Rating. Emergency ratings to be used only where the capability exists to monitor the actual loading and duration.
3. Summer Ratings apply when the ambient temperature is between 500 and 950F.
4. Winter Ratings apply when the ambient air temperature is 500F or less.
5. The emergency ratings for the 600A, 27kV metalclad breaker apply for 4 hours, after which the loading must be reduced to 570A for the next 2 hours.

DISTRIBUTION CAPACITY PLANNING GUIDELINES

1. DEFINITIONS

To properly apply this loading guide, it is necessary to clearly define the terms Normal Loading and Emergency Loading.

1.1. Normal Loading

Normal loading is defined as the operating condition where all equipment is in service and operating at or below manufacturer's nameplate rating. This load can be applied to a device, day after day without any appreciable loss of life. The condition of a planned equipment outage for maintenance or construction purposes is considered normal loading.

1.2. Emergency Loading

Emergency loading is defined as the operating condition where an equipment failure or unavoidable system condition has caused the necessity of loading equipment beyond its maximum nameplate rating. This rating is based on an acceptable amount of deterioration for each emergency.

2. FEEDER EQUIPMENT

2.1 The following is a list of Feeder Devices that are evaluated for loading:

- Breakers
- Phase pick-up*
- Regulators
- Reactors
- Cable (primary pull-off)*
- Overhead conductor*
- Submarine cable*
- Auto-Transformers*
- Reclosers
- Field regulators

* Identifies devices that may be used as the "Normal Limiting Factor" or the "Emergency Limiting Factor" for a feeder inside the Planning System

2.2 Field equipment not used as the limiting factor for the feeder, i.e. reclosers, field regulators, conductor, etc. will be evaluated for loading.

2.3 Breakers, regulators, & reactors will be considered for replacement by Power Delivery using a probabilistic approach that uses loading as one of the inputs.

2.4 The phase pick-up is defined as the normal tap setting, de-rated slightly to allow for phase imbalance and relay tolerances. Table 1 expresses the ratings of the phase pick-ups in MVA for FPL's three distribution voltages.

2.5 Overhead conductors have both summer and winter ratings and have been summarized in Table 2.

2.6 Underground cable ratings including submarine cables are in the Distribution Construction Standards in Section UV-15. Table 3 is a condensed version of the most commonly used cables with values in MVA and adjusted for a 7% phase unbalance. Table 4 is the amp ratings without the adjustments. Both have been expanded to handle more fully loaded cables in a duct system than the tables in UV-15. Dry ratings are used for direct buried cables and cables in conduit. Wet ratings are used for cables installed in encased duct banks. The tables have both normal and contingency ratings.

2.7 Auto-Transformer loading should be kept below:

- 90% of Nameplate Rating during summer peak normal conditions, or below 6.75 MVA (7.5 MVA unit), 10 MVA (11.2 MVA unit), 13.5 MVA (15 MVA unit).
- 120% of Nameplate Rating during summer emergency conditions, or below 9 MVA (7.5 MVA unit), 13.4 MVA (11.2 MVA unit); 18.0 MVA (15 MVA unit) *
- 140% of Nameplate Rating during winter emergency conditions, or below 15.7 MVA (11.2 MVA units); 21.0 MVA (15 MVA units)

* Provided that: Auto-Transformer average summer load does not exceed 90% rated capacity and the peak duration does not exceed 8 hours.

The installation of 15 MVA Auto-Transformers should be limited to only feeder pull-offs in order to utilize the capacity of the feeder position as much as possible. If a 23 kV feeder dual pull-off is used to serve a 13 kV area, avoid using a15 MVA unit by installing 2 - 11.2 MVA units as step-downs from 23 kV to 13 kV whenever possible. Normally, for feeders with adequate feeder ties, 11.2 MVA Auto-Transformer units should be used for feeder ties away from the substation unless there is a special need.

2.8 Reclosers have a Normal Rating equal to 120% of their nameplate rating. An Emergency Rating is not assigned since reclosers can be by-passed during emergency conditions.

3. DISTRIBUTION PLANNING GUIDELINES

3.1. Evaluation of Normal Overloads

Whenever possible, a normal overload should be alleviated by switching even if it creates a contingency problem that needs to be addressed. If this is not possible, a project categorized as a Normal Overload should be identified. In most cases, contingency load problems are solved as well by the "Normal Overload" project because usually heavily loaded feeders above their normal ratings have insufficient capacity for emergency conditions.

Normal Overload projects should have a higher priority than projects addressing contingency overloads as described below.

3.2. Evaluation of Throwover Overloads

Throwover overloads are considered a higher priority contingency than the single contingency overloads described below, due to the risk of losing an additional feeder. As for all contingency overloads, the emergency rating is used as the limiting factor.

3.3. Evaluation of Contingency Overloads

The current guideline is to plan for a single contingency and to utilize up to 6 switching steps to restore service. This is accomplished by using the SynerGEE/Synergi Feeder-Out analysis, which systematically takes out the first line-section of each feeder. Contingency analysis has also been extended to other critical sections such as submarine cables and auto-transformers.

In addition to the Feeder-Out analysis, the critical Line-Section-Out is used to perform a risk assessment for each feeder by looking at the probability of losing a critical line-section and calculating the ability to restore.

3.4. System Expansion Project Prioritization Order

In general, the priority order for Distribution System Expansion projects is as follows:

(1) Multi-Year Projects in Construction (Carry-Over Projects)
(Note: Deferred projects that never started in construction should be re-justified again each year and if approved, should not be included under this ranking group)

(2) Projects Addressing Protection & Coordination or Low Voltage Issues

(3) Large Projects to Support Customer Growth

(a) Large Revenue Projects (LRP)
(Note: The LRP projects are not funded under the SE budget. However, they are included on the list if they require new feeders/substations for Power Delivery to budget for them)

(b) New Substation Projects
(Note: New substations require a higher ranking than new feeder projects because: Large capacity added in the area; Cost of investment in CRE substation site; Permits, etc)

(c) Special Business Needs, OH/UG Conversions, & kV Conversions
(i.e. Installation of UG ducts for future use; special reliability improvements, or other special needs, etc.)

(4) Projects Addressing Existing Issues

(a) Normal Overloads at the Feeder head level and/or Distribution Field Equipment
(b) High Customer Count Limit (HCCL) issues on Priority Feeders (HCCL < 4320 customers)
(c) Throwover Feeder Contingency overloads
(d) Winter Feeder Contingency overloads
(e) Feeder Contingency overloads
(f) AFS Feeder insufficient adjacent emergency capacity

(5) Projects Addressing Forecasted Issues

(a) Normal Overloads at the Feeder head level and/or Distribution Field Equipment
(b) High Customer Count Limit (HCCL) issues on Priority Feeders (HCCL < 4320 customers)
(c) Throwover Feeder Contingency overloads
(d) Winter Feeder Contingency overloads
(e) Feeder Contingency overloads
(f) AFS Feeder insufficient adjacent emergency capacity

(6) Projects Addressing Existing Model Feeder Violations on Priority Feeders

(a) Customer count violations

(7) Projects Addressing Forecasted Model Feeder Violations on Priority Feeders

(a) Customer count violations

3.5. Distribution Capacity Planning Analysis

Table 5 shows the different types of analyses performed on a system level.

Table 5 - Types of Planning analyses

Types of Analysis	Description
Load Flow	Checks to see if load on feeder (meter load + proposed projects) causes an overload anywhere on the feeder during normal configuration
Throw-Over	Checks to see if a throw-over operation on any throw-over device causes an overload anywhere on support feeder during loss of feeder (N-1)
Contingency - Feeder Out	Checks to see if 100% feeder load can be picked up by adjacent feeders through 6 switching operations (3 close/open switching operations) during the loss of one feeder (N-1)
Contingency - Line section	Checks to see if 100% feeder load can be picked up by adjacent feeders through 6 switching operations (3 close/open switching operations) if a critical line section is lost (N-1)
Contingency - Sub TX Bus out	Checks to see if the load on a substation transformer can be picked up by adjacent transformers in the substation without causing an overload
Contingency - Sub TX Bus out (Single TX)	Checks to see if the load on a substation transformer can be picked up by feeders on adjacent substation through field switching without causing an overload
AFS	Checks to see if an AFS transfer operation causes an overload anywhere on support feeder
Protection	Analyzes the protection tree and checks to see if any protection rules are violated
Voltage	Checks to ensure that line voltage is within limits

3.6. Distribution Capacity Planning Project Justification Criteria

Table 6 shows the criteria required to justify a capacity planning project. The analysis results must shows that the ratings from the table are exceeded by the values listed.

Table 6 - Project justification criteria

Analysis Type	Fdr Rating Constraint	Existing	Forecast
Load Flow	Phase	>100% of normal rating	>100% of normal rating
	Auto TX	>90% of normal rating	>100% of normal rating
	Cable	>100% of normal rating	>105% of normal rating
	Wire	>100% of normal rating	>100% of normal rating
	Sub TX	>100% of normal rating	>100% of normal rating
Throw-Over / AFS	Phase	>100% of normal rating	>105% of normal rating
	Auto TX	>120% of normal rating	>120% of normal rating
	Cable	>100% of **emergency** rating	>100% of **emergency** rating
	Wire	>100% of normal rating	>100% of normal rating
Contingency - Feeder/Line Section Out	Phase	>105% of normal rating	>105% of normal rating
	Auto TX	>120% of normal rating	>120% of normal rating
	Cable	>105% of **emergency** rating	>110% of **emergency** rating
	Wire	>100% of normal rating	>110% of normal rating
Sub Out	Sub TX	>130% normal rating	>140% normal rating

Note 1: normal rating is normal summer rating (e.g. phase pick-up, current carrying capacity of wire or cable, transformer nameplate)
Note 2: contingency analysis performs N-1 contingency

3.7. Distribution Capacity Planning Solutions & Descriptions

Table 7 describes the different types of solutions most commonly employed via capacity planning projects to resolve issues.

Table 7 - Common solutions to capacity planning exceptions

Solutions	Description
Switching	Execute boundary change (switching order) using existing switches to offload load area onto adjacent feeders and solve condition
Install new switches	Install new switches to execute boundary change (switching order) to offload load to adjacent feeders and solve condition
Phase Balancing	Perform phase balancing in the field to lower the loading on any high phase (solve overload condition identified)
Reconductor	Upgrade existing wire or cable to increase current carrying capacity (rating) (solve overload condition identified)
Feeder Tie	Extend existing feeder to tie with another feeder (offload area and solve overload condition identified)
New Feeder	Install new feeder (offload area and solve overload condition identified)
Upgrade Sub TX	Replace existing substation transformer with a larger capacity one (solve overload condition identified)
Add Sub TX	Install additional substation transformer (solve overload condition identified)
New substation	Install new substation (solve overload condition identified)

3.8. Boundary Change Considerations

Items to check/verify when considering a boundary change:

- **Capacity review**
  - Is normal load flow on affected feeders within our capacity guidelines after boundary change is executed?
  - Does boundary change negatively impact any contingency plans for loss of feeders or substation power transformers in the area?
  - Will boundary change result in overload conditions during automatic throw-over load transfers on affected feeders?
- **AFS Review**
  - Will boundary change result in overload conditions after an AFS team transfer?
  - Will boundary change require the configuration of an AFS team to be modified?
    - Does the SCADA one-line need to be updated?
  - Do the switch limits on normally closed AFS devices need to be updated?
  - Do the templates of any AFS device need to be updated?
- **Protection and Coordination**
  - Does boundary change result in any reach factor or arc-flash issues?
  - Does boundary change result in the miscoordination of any devices on the feeder?
- **Hardening Boundaries**
  - Does boundary change affect existing hardening boundaries (i.e. is an unhardened feeder section being added to a hardened feeder?)
- **Control Center**
  - Will the boundary change affect restoration or load management by the Control Center? (check with Switching Lead)
- **Area/Customers**
  - Will the boundary change affect any PSC customers? (check with Area Engineering Lead)
  - Will the boundary change affect any reliability or customer plans the Area has for the area? (check with Area Manager, Area Engineering Lead and Area DAL)
- **Power Quality**
  - Are any capacitor banks being moved between feeders? How will this affect the feeder power factors (VARs)?
  - Are there any large motors included in the boundary change? Will a new motor impact study need to be performed?
- **Distributed Generation**
  - Are there any distributed generation customers affected by boundary change? If so, consult with Coordination Team
  - Will the boundary change affect the configuration of any generating sites (large solar, wind, generators, etc.)? If so, consult with Coordination Team

3.9. Equipment rating

The following tables list the normal and emergency ratings of distribution equipment.

Table 8 - Phase Relay Pickup Design Ratings

Phase Pickup Setting	Phase Pickup Rating	MVA		
		4KV	13KV	23KV
240	228	1.6	5.1	8.8
300	285	2.0	6.4	11.0
320	304	2.1	6.8	11.8
360	342	2.4	7.6	13.2
400	380	2.7	8.5	14.7
420	399	2.8	8.9	15.4
480	456	3.2	10.2	17.6
500	475	3.3	10.6	18.4
560	532	3.7	11.9	20.6
600	570	4.0	12.7	22.0
640	608	4.3	13.6	23.5
720	684	4.8	15.3	26.4
800	760	5.3	17.0	29.4
840	798	5.6	17.8	30.9
900	855	6.0	19.1	33.1
960	912	6.4	20.4	35.3

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Note: Phase Pickup Rating = (Phase Pickup Setting) (Relay Tolerance Factor) (Regulation Factor) (Tolerance Diversity Factor)
MVA = 3(Phase to Ground Voltage) (Phase Pickup Rating) (Voltage factor) (Unbalance factor) / 1000

Where:			
	Phase to ground =	2.4	7.62 13.2
	Amperes =		(Appropriate ampere rating from Distribution Standards F7.0.0)
	Relay Tolerance Factor =	0.95	(From manufacturer's data)
	Regulation Factor =	0.90	(Telemetry readings on regulated side of feeder)
	Tolerance Diversity Factor =	1.11	(Reduces compounding effect of rating factors)
	Voltage Factor =	1.05	(Which comes from 126V/120V)
	Unbalance Factor =	0.93	(Assumes 7% phase unbalance)

Quick Factors:

Phase Pickup
4KV: MVA = I(amps) * (0.0067); I(amps) = (MVA) * (150.0)
13KV: MVA = I(amps) * (0.0212); I(amps) = (MVA) * (47.24)
23KV: MVA = I(amps) * (0.0367); I(amps) = (MVA) * (27.27)

Table 9 - Overhead Conductor Design Ratings

	Summer				Winter			
		MVA				MVA		
Conductor Size/Type	Amps	4KV	13KV	23KV	Amps	4KV	13KV	23KV
6 CU	118	0.8	2.6	4.6	145	1.0	3.2	5.6
4 CU	167	1.2	3.7	6.5	205	1.4	4.6	7.9
2 CU	225	1.6	5.0	8.7	277	1.9	6.2	10.7
1/0 CU	305	2.1	6.8	11.8	374	2.6	8.3	14.5
2/0 CU	354	2.5	7.9	13.7	434	3.1	9.7	16.8
4/0 CU	472	3.3	10.5	18.3	579	4.1	12.9	22.4
350 CU	659	4.6	14.7	25.5	807	5.7	18.0	31.2
500 CU	979	6.9	21.9	37.9	1199	8.4	26.8	46.4
4 ACSR	138	1.0	3.1	5.3	169	1.2	3.8	6.5
2 ACSR	177	1.2	4.0	6.8	217	1.5	4.8	8.4
1/0 ASCR	226	1.6	5.0	8.7	277	1.9	6.2	10.7
3/0 ACSR	295	2.1	6.6	11.4	362	2.5	8.1	14.0
336.4 ACSR	521	3.7	11.6	20.1	639	4.5	14.3	24.7
556.4 ACSR	718	5.0	16.0	27.8	880	6.2	19.6	34.0
4 AAAC	148	1.0	3.3	5.7	181	1.3	4.0	7.0
2 AAAC	197	1.4	4.4	7.6	241	1.7	5.4	9.3
1/0 AAAC	266	1.9	5.9	10.3	325	2.3	7.3	12.6
3/0 AAAC	354	2.5	7.9	13.7	434	3.1	9.7	16.8
						0.0	0.0	0.0
343.6 ACAR	531	3.7	11.9	20.5	651	4.6	14.5	25.2
568.3 ACAR	733	5.2	16.4	28.3	898	6.3	20.0	34.7
2 CU TW	191	1.3	4.3	7.4	234	1.6	5.2	9.0
4/0 CU TW	394	2.8	8.8	15.2	482	3.4	10.8	18.6
2 AAAC TW	152	1.1	3.4	5.9	186	1.3	4.2	7.2
568.3 ACAR TW	576	4.0	12.9	22.3	706	5.0	15.8	27.3
#4 AAC Hendrix	369	2.6	8.2	14.3	457	3.2	10.2	17.7
636 kcmil AAC Hendrix	728	5.1	16.3	28.2	905	6.4	20.2	35.0

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Note: MVA = 3(Phase to Ground Voltage) (Amperes) (Voltage factor) (Unbalance factor) / 1000
Where: Phase to ground = 2.4 7.62 13.2
Amperes = Appropriate ampere rating from Distribution Standards F7.0.0

Unbalance Factor = 0.93 (Assumes 7% phase unbalance)
Voltage Factor = 1.05 (Which comes from 126V/120V)

Quick Factors:
4KV: MVA = I(amps) * (0.00703); I(amps) = (MVA) * (142.23)
13KV: MVA = I(amps) * (0.0223); I(amps) = (MVA) * (44.797)
23KV: MVA = I(amps) * (0.0386); I(amps) = (MVA) * (25.86)

Table 10 - Summer Underground Cable Rating (MVA)

SUMMER UNDERGROUND CABLE RATING

CABLE DESCRIPTION	Code NO.	DIRECT BURIED (DRY SOIL) (A)		DIRECT BURIED DUCT (B) (DRY SOIL)		TOTAL NUMBER OF FULLY LOADED FEEDER IN DUCT BANK (C) (WET SOIL) ALL MVA listed, Include 7% ph unbalance & 1.05 Voltage Factor											
						1		2		3		4		5		6	
		NORM	EMER	NORM	EMER	NORM	EMER	NORM	EMER	NORM	EMER	NORM	EMER	NORM	EMER	NORM	EMER
3-1/C 1000 kcmil Al, 15KV - 1/12N	1	11.1	14.0	12.2	14.0	12.6	14.4	11.3	12.9	10.0	11.4	9.4	10.7	8.8	10.0	8.2	9.3
3-1/C 1000 kcmil Al, 15KV - 1/3N	2	10.3	13.0	11.4	13.0	11.8	13.4	10.7	12.2	9.6	11.0	9.0	10.4	8.4	9.7	7.9	9.0
3-1/C 1000 kcmil Al, 25KV - XPE @13kv	3A	11.3	14.0	12.6	14.3	12.6	14.4	11.3	12.9	10.0	11.4	9.4	10.7	8.8	10.0	8.2	9.3
3-1/C 1000 kcmil Al, 25KV - XPE @23kv	3B	19.5	24.2	21.8	24.8	21.9	24.9	19.6	22.4	17.4	19.8	16.4	18.5	15.3	17.3	14.3	16.1
1-3/C 750 kcmil Cu, 15KV, PL	4	11.5	14.0			12.3	13.9	11.3	12.7	10.2	11.6	9.6	10.9	9.0	10.2	8.4	9.5
1-3/C 750 kcmil Cu, 25KV, PL @13kv	5A					12.2	13.8	11.1	12.6	10.1	11.4	9.4	10.7	8.8	10.0	8.1	9.3
1-3/C 750 kcmil Cu, 25KV, PL @23kv	5B					21.2	23.9	19.3	21.8	17.4	19.8	16.3	18.5	15.2	17.3	14.1	16.0
3-1/C 750 kcmil Cu, 15KV, PL	6					12.6	14.1	11.5	12.9	10.3	11.7	9.7	10.9	9.0	10.2	8.4	9.5
3-1/C 750 kcmil Cu, 25KV, PL @13kv	7A					12.4	14.0	11.3	12.7	10.1	11.5	9.4	10.7	8.8	10.0	8.1	9.3
3-1/C 750 kcmil Cu, 25KV, PL @23kv	7B					21.5	24.2	19.5	22.0	17.5	19.8	16.4	18.6	15.2	17.3	14.1	16.0
1-3/C 500 kcmil Cu, 15KV, PL	8					10.0	11.2	9.2	10.3	8.4	9.4	7.9	8.9	7.4	8.4	6.9	7.8
1-3/C 500 kcmil Cu, 25KV, PL	9					17.2	19.4	15.8	17.8	14.3	16.2	13.5	15.2	12.6	14.3	11.7	13.3
1-3/C 750 kcmil Cu, 15KV, CLX	10	12.8	14.5			13.0	14.9	11.9	13.7	10.8	12.4	10.1	11.6	9.5	10.9	8.8	10.2
1-3/C 750 kcmil Cu, 25KV, CLX	11	22.4	25.3			22.6	26.0	20.7	23.8	18.8	21.6	17.7	20.3	16.5	19.0	15.4	17.7
1-3/C 500 kcmil Cu, 15KV, CLX/PE	12	10.5	11.8			10.6	12.1	9.7	11.1	8.8	10.1	8.2	9.5	7.7	8.8	7.2	8.2
1-3/C 500 kcmil Cu, 25KV, CLX/PE	13	18.4	20.6			18.4	21.0	16.8	19.3	15.2	17.5	14.3	16.4	13.4	15.4	12.5	14.3
1-3/C 500 kcmil Cu, 15KV, Sub	14	9.5	11.5			10.0	11.2	9.2	10.3	8.4	9.4	7.9	8.9	7.4	8.4	6.9	7.8
1-3/C 500 kcmil Cu, 25KV, Sub	15	16.3	19.6			17.2	19.4	15.8	17.8	14.3	16.2	13.5	15.2	12.6	14.3	11.7	13.3
3-1/C 1000 Cu 25KV-1/12N, @ 13KV	16A			14.8	16.9	15.2	17.5	13.7	15.7	12.1	13.8	11.4	13.0	10.6	12.1	9.9	11.3
3-1/C 1000Cu 25KV-1/12N, @25KV	16B			25.6	29.3	26.4	30.3	23.7	27.1	21.0	24.0	19.7	22.5	18.4	21.0	17.2	19.5
1-3/C 500 kcmil Cu, 25KV - XPE	17	21.4	24.1			21.3	24.3	19.5	22.2	17.7	20.1	16.6	18.9	15.5	17.7	14.5	16.5
1-3/C 350 kcmil Cu, 15KV, PL	18					8.3	9.3	7.6	8.6	6.9	7.8	6.5	7.3	6.1	6.9	5.7	6.4
3-1/C 350 kcmil Al, 25KV - XPE	19			12.0	13.6	12.6	14.3	11.4	13.0	10.3	11.6	9.7	11.0	9.1	10.3	8.5	9.6
1-3/C 500 kcmil Cu, 25KV, EPR, SUB	20	18.7	21.3			18.2	20.7	16.8	19.0	15.4	17.4	14.5	16.4	13.7	15.5	12.8	14.5
1-3/C 750 kcmil Cu, 15KV, EPR	21					12.9	14.7	11.8	13.4	10.7	12.1	10.1	11.4	9.5	10.8	8.9	10.1

NOTE: CABLE #1 WAS INSTALLED FROM 1977 TO THE PRESENT
CABLE #2 WAS INSTALLED PRIOR TO 1977

Cable Ratings2003.XLS
Rev: 3/15/2004

Table 11 - Summer Underground Cable Rating (AMPS)

SUMMER UNDERGROUND CABLE RATING

CABLE DESCRIPTION	Code NO.	DIRECT BURIED (DRY SOIL) (A)		DIRECT BURIED DUCT (B) (DRY SOIL)		TOTAL NUMBER OF FULLY LOADED FEEDER IN DUCT BANK (C) (WET SOIL) ALL amps values listed are from Distribution Standards Section UV-15											
						1		2		3		4		5		6	
		NORM	EMER	NORM	EMER	NORM	EMER	NORM	EMER	NORM	EMER	NORM	EMER	NORM	EMER	NORM	EMER
3-1/C 1000 kcmil Al, 15KV - 1/12N	1	496	625	548	625	566	645	508	578	450	511	423	480	396	448	369	417
3-1/C 1000 kcmil Al, 15KV - 1/3N	2	461	581	510	581	526	600	479	547	431	495	405	465	378	435	352	405
3-1/C 1000 kcmil Al, 25KV - XPE	3	505	626	564	642	566	645	508	578	450	511	423	480	396	448	369	417
1-3/C 750 kcmil Cu, 15KV, PL	4	515	626			553	623	506	571	458	518	431	487	403	456	376	425
1-3/C 750 kcmil Cu, 25KV, PL	5					547	617	499	564	451	511	422	479	393	447	364	415
3-1/C 750 kcmil Cu, 15KV, PL	6					563	633	513	578	463	522	434	489	404	457	375	424
3-1/C 750 kcmil Cu, 25KV, PL	7					556	627	505	570	453	513	423	480	394	448	364	415
1-3/C 500 kcmil Cu, 15KV, PL	8					446	502	411	463	376	423	354	399	331	374	309	350
1-3/C 500 kcmil Cu, 25KV, PL	9					444	501	408	460	371	419	348	394	326	369	303	344
1-3/C 750 kcmil Cu, 15KV, CLX	10	575	649			582	669	533	612	483	555	454	522	425	488	396	455
1-3/C 750 kcmil Cu, 25KV, CLX	11	580	653			585	672	536	615	486	558	457	524	427	491	398	457
1-3/C 500 kcmil Cu, 15KV, CLX/PE	12	471	530			473	540	433	496	393	451	369	424	346	396	322	369
1-3/C 500 kcmil Cu, 25KV, CLX/PE	13	476	534			475	544	435	498	394	452	370	425	347	397	323	370
1-3/C 500 kcmil Cu, 15KV, Sub	14	426	513			446	502	411	463	376	423	354	399	331	374	309	350
1-3/C 500 kcmil Cu, 25KV, Sub	15	422	508			444	501	408	460	371	419	348	394	326	369	303	344
3-1/C 1000 kcmil CU, 25KV - 1/12N	16			662	758	683	783	613	702	543	620	510	582	477	543	444	505
1-3/C 500 kcmil Cu, 25KV - XPE	17	554	622			550	628	504	575	457	521	429	490	402	458	374	427
1-3/C 350 kcmil Cu, 15KV, PL	18					371	419	341	384	310	350	291	329	272	308	253	287
3-1/C 350 kcmil Al, 25KV - XPE	19			310	352	325	369	296	335	266	301	251	284	236	266	221	249
1-3/C 500 kcmil Cu, 25KV, EPR, SUB	20	484	550			471	535	434	493	397	450	375	425	354	401	332	376
1-3/C 750 kcmil Cu, 15KV, EPR	21					578	657	528	600	478	542	452	512	426	482	400	452

NOTE: CABLE #1 WAS INSTALLED FROM 1977 TO THE PRESENT
CABLE #2 WAS INSTALLED PRIOR TO 1977

Cable Rating.XLS
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