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November 7, 2011

Mr. Ranie K. Wohnhas
Kentucky Power Company
101-A Enterprise Drive
P.O. Box 5190
Frankfort, KY 40602-5190

RE: Case No. 2011-00295
Kentucky Power Company

Mr. Wohnhas:

The enclosed documents, which represent Accion Group's initial data request to Kentucky Power, the onsite interview summaries, including additional data request items, Kentucky Power's responses to both data requests and the final report, have been filed into the record of the above referenced case.

Sincerely,

Jeff Derouen
Executive Director

Enclosures

cc: Parties of Record

ACCION GROUP

FINAL REPORT
To
THE KENTUCKY PUBLIC SERVICE COMMISSION

Focused Review of Documentation Filed by Kentucky Power Company for a Proposed 138kV Transmission Line from Soft Shell Substation to Bonnyman Substation
Case No. 2011-00295

October 31, 2011

Submitted by:

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I. INTRODUCTION AND CONCLUSION SUMMARY

A. PURPOSE AND SCOPE OF THIS REPORT

1. Background

Pursuant to KRS 278.255, the Kentucky Public Service Commission ("Commission" or "KSPC"), retained Accion Group, Inc. ("Accion") to perform a focused need review of documentation associated with a 138 kiloVolt ("kV") transmission line proposed for construction by Kentucky Power Company ("KPC" or "Company") between the Soft Shell Substation in Knott County, Kentucky and the Bonnyman Substation in Perry County, Kentucky.

Accion Group's transmission and distribution professionals have an average of thirty years of individual experience constructing and operating transmission and distribution systems in the United States and overseas. Accion Group's consultants are well-versed in siting matters, interconnection requirements and responsibilities, bulk power system planning, and transmission system design, and are also experienced in investigations of safety and reliability, implementation of public policy in the electric and gas industries, and in investigations of unit outage and system outage causes.

Interconnection requirements and responsibilities are important considerations in the review of available options. We are experienced in the complexities of both the regulatory and data review processes, with significant experience in the siting of electric and gas energy facilities.

Over the years, Accion personnel have conducted comprehensive siting reviews, comprehensive and focused transmission and distribution management and operational audits, generator outage prudence reviews, reliability assessments, asset sales, mergers, and other consulting engagements for regulatory clients either for Accion or previous employers. In addition, Accion personnel has conducted comprehensive and focused transmission and distribution audits, reliability assessments, rate case analysis, due diligence assessments, and generator outage prudence reviews for private industry clients.

With more than thirty years of in-depth experience in electric, gas, water, and renewable utilities, Accion Group's diverse consortium of consultants provides insightful, candid, and practical advice to the utility industry and their associated government regulatory bodies. Headquartered in Concord, New Hampshire, with a branch office in suburban Washington, D.C. and consulting affiliates nationwide, Accion's specialties range from transmission and distribution and utility management to nuclear decommissioning and construction monitoring.

Since its incorporation in 2001, Accion Group has been routinely involved in high-profile consulting engagements, thus securing a reputation as one of the premier firms providing review and advice of transmission and distribution-related activities. Accion Group has served as a consultant to utilities on transmission and distribution projects in markets from our primary base in New Hampshire to Maine, D.C., Kentucky, Illinois, and Canada. The breadth of our consultants' personal experience, ranging from federal prosecutor, state's counsel, and counsel for utilities and energy markets to Chairman of the Board, Chief Executive Officer, senior management of nuclear power plants, and managing engineer with state public service commissions, ensures that Accion provides advice with a full appreciation of the needs of regulators and shareholders.

Adding to our experience in transmission and distribution systems, Accion Group has served as Independent Evaluator, Independent Monitor, or Independent Observer to state commissions on competitive solicitations covering more than 130,000 MW across the nation, and has assisted utilities in the preparation for, and the conduct of, power supply solicitations.

This Final Report presents the results of Accion's review of KPC's application for a Certificate of Public Convenience and Necessity ("Certificate") to construct a 138kV transmission line between the Soft Shell and Bonnyman substations and all supporting documentation provided by KPC in Case No. 2011-00295.

2. *Project Scope and Objectives*

The overall objective of this project was to review KPC's analyses regarding the need for KPC's evaluation of alternatives to, and the engineering aspects of, the proposed 138kV transmission line. The proposed transmission line would be located in Perry and Knott Counties, Kentucky, and is approximately 20.0 miles in length. Substation construction and ancillary facilities for the project would be located in Perry, Knott, and Breathitt Counties, Kentucky. Included in this report is an independent evaluation of

a. KPC's analyses and conclusions in support of the reasonableness of the need for the proposed transmission line;

b. KPC's analyses and conclusions in support that the proposed transmission line is the best overall alternative including wheeling of power through neighboring systems; and that

c. The routing proposed by KPC is reasonable in that proper social, environmental, and economic factors were fairly and reasonably considered.

The project was a focused review. While Accion reviewed KPC's work processes and methods, Accion did not perform an independent analysis of the need for the proposed facilities; as such work is beyond the stated work scope of this engagement. An evaluation of the overall cost of, and the engineering design aspects of the proposed line were also beyond the stated work scope of this engagement. However, Accion did review the economic analyses and line design for reasonableness and adherence to good utility practice based on its experience.

Accion's work focused on the following aspects of the review:

a. KPC's analysis of the ability of existing facilities to reliably serve existing and expected load. The review included power flow, transient stability and short circuit analyses, and a review of the load forecast and methodology as required.

b. KPC's analyses that support the need for additional facilities. The evaluation included whether adequate consideration was given to

    - The upgrade of existing facilities to alleviate either thermal overloads or low voltage conditions, including a review of KPC's methodology to determine system component ratings.
    - Other alternatives including other transmission alternatives, the addition of generation, and improvement of load power factor.
    - Whether wheeling of power through neighboring systems or interconnections presented a viable alternative to construction of the proposed facilities.
    - Whether the routing proposed by KPC for the proposed transmission line is reasonable in that proper social, environmental, and economic factors were reasonably considered, and whether adequate consideration was given to co-locating the new transmission line with existing facilities.

B. PROJECT OVERVIEW

1. *Project Description*

KPC, an electric utility organized as a corporation under the laws of the Commonwealth of Kentucky in 1919, is a wholly owned subsidiary of American power Company, Inc. ("AEP"). The AEP system is a multi-state public utility holding company system that provides electric service in parts of eleven states – Arkansas, Indiana, Kentucky, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia, and West Virginia. KPC is engaged in the generation, purchase, transmission, distribution, and sale of electric power. KPC serves approximately 173,400 customers in the following 20 counties of eastern Kentucky: Boyd, Breathitt, Carter, Clay, Elliot, Floyd, Greenup, Johnson, Knott, Lawrence, Leslie, Letcher, Lewis, Magoffin, Martin, Morgan, Owsley, Perry, Pike, and Rowan. KPC also supplies electric power at the wholesale level to other utilities and municipalities in Kentucky for resale.[1]

KPC owns and operates 1,233 miles of transmission lines, 11,242 miles of distribution lines and 1,060 MW of generation with assets totaling $1.22 billion.[2]

On September 29, 2011, KPC filed an application with the Commission to construct a 138kV line that is more than one mile in length plus ancillary facilities ("Application"). According to Kentucky law, such facilities require a Certificate prior to construction. The Commission assigned the Application Case No. 2011-00295.

The proposed 20.0 mile 138kV transmission line would begin at KPC's Soft Shell Substation in Knott County and terminate at the KPC Bonnyman Substation in Perry County.[3] The routing of the proposed transmission line would generally parallel Interstate Highway 80.[4] Ancillary equipment includes substation and circuit breaker additions at the Soft Shell and Bonnyman Substations to connect the new line and capacitor additions at the Beckham Substation in Knot County, and the Haddix Substation in Breathitt County.[5]

The proposed transmission line would be constructed with two construction configurations. A section of the line approximately 19.0 miles long, would be in a new 100-foot right-of-way and would be of single circuit construction configuration; constructed in the center of said right-of-way with steel pole H-frame and 3 pole steel construction. This section of the line would average 85 feet in height, utilize 1,590 kcmil[6] Aluminum Conductor Steel Reinforced ("ACSR") conductors for the phase conductors, and in addition, one 7#8 Alumoweld wire and one fiber optic overhead ground wire for lightning protection. The fiber optic ground wire would also be used for communications between stations.[7]

The remaining approximately one mile section of the line would be constructed in an existing 100-foot right-of-way with the existing Hazard to Bonnyman 69kV circuit. The existing 69kV circuit would be removed and rebuilt with the new 138kV line constructed on double circuit steel lattice towers to be located in the center of the right-of-way. The new double circuit tower configuration

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[1] September 29, 2011 application of KPC, paragraphs 1 and 2.

[2] https://www.kentuckypower.com/info/facts.aspx

[3] September 29, 2011 application, paragraph 3.

[4] September 29, 2011 application, Exhibit 1.

[5] September 29, 2011 application.

[6] Kcmil is wire gauge size that is an area of 1,000 circular mils or 0.5067 square millimeters.

[7] September 29, 2011 application, paragraph 7, Exhibit 4, and Exhibit 5.

would average 100' in height.[8] Conductors and static wires for this section of the line would be the same as the remainder of the line as described directly above.

2. *Summary of Accion's Focused Review*

Accion performed its independent need review by organizing its work into two main Task Areas. This report addresses these Task Areas as follows:

Task Area One – Chapter Two, Technical Need Review

To determine if the proposed facilities are required from a technical viewpoint, Accion reviewed KPC's technical analyses, including its power flow analysis, load forecast driving the needed facilities and economic evaluation compared to other alternatives. Accion further reviewed the capability of KPC's existing facilities to determine if the proposed facilities were required in order for KPC to serve its current and projected load in a manner that most economically meets KPC and regional reliability criterion.

Task Area Two – Chapter Three, Project Alternatives

To determine if KPC's analyses considered appropriate engineering alternatives to meet its needs, Accion's evaluation and review considered whether KPC gave adequate consideration to

a. Upgrading existing lines and facilities to increase their thermal capacity or eliminate low voltage conditions, including a review of KPC's transmission component rating methodology;

b. Other alternatives including other transmission alternatives, the addition of generation, and improvement of load power factor;

c. Wheeling of power through neighboring systems or interconnections; and

d. Whether routing would be reasonable considering social, environmental and economic factors and co-location of the proposed transmission line with other existing facilities.

Review Process

Accion reviewed KPC's Application filed on September 29, 2011 as Case No. 2011-00295. Based on that filing, Accion formulated an Initial Set of Data Requests and Interview Requests to KPC on October 2, 2011. KPC quickly responded with comprehensive written responses to those requests on

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[8] September 29, 2011 application, paragraph 8 and Exhibit 6.

October 7, 2011. Accion reviewed the KPC responses to the Data Requests prior to interviews scheduled with the Company on October 12. 2011.

On October 12, 2011, Accion conducted extensive on-site interviews with KPC management and subject matter experts at the KPC Transmission Training Center located in Pataskala, Ohio with Commission Staff participating. Interview participants are as listed below:

Petitioner

Ranie Wohnhas	Managing Director-Regulatory & Finance
George Reese	Senior Environmental Manager – GAI Consultants, Inc.
Mark R. Overstreet	Outside Counsel – Sties & Harbison
Lila Munsey	Manager Regulatory Services
Michael Lasslo	Customer & Distribution Manager
David Wright	AEP Project Manager
Ali Kamran, Manager	Transmission Planning
Randy Holliday	Staff Economist
Ned Merrifield	Supervisor-Transmission Right-of-Way
Timothy Earhart	Supervisor-Transmission Line Engineering
Joseph Meisner	Engineer
Michael Russ	Engineer
Victoria Stone	Senior Right-of-Way Agent

Regulatory (KPSC Staff)

John Rogness	Director of Financial Analysis
Kimra Cole	Director of Engineering
Daryl Newby	Manager Gas & Electric Rate Design
Jeffrey Johnson	Engineer
Michael D. Cannata, Jr.	Senior Consultant – Accion Group

On October 14, 2011, Accion generated follow-up information requests resulting from issues that were not answered at the interviews. KPC provided written responses to those requests on October 14, 2011.

C. CONCLUSION SUMMARY

Based on the information filed in its Application, responses received to written information requests, and interviews conducted, Accion makes the following conclusions relative to the need for the 138kV transmission line from the Soft Shell Substation to the Bonnyman Substation as proposed by KPC in its Application:

1. KPC has provided sufficient documentation in support of the need to construct the Soft Shell to Bonnyman 138kV transmission line and the ancillary facilities, as presented in its September 29, 2011 Application, in order to supply reliable service to its customers in the Hazard load area at current and expected load levels.
2. KPC performed appropriate system studies and analyses, applied its reliability criterion correctly, and made sound conclusions to justify the need for the proposed facilities.
3. KPC has previously made appropriate system additions in order to defer the large expenditure associated with the proposed facilities to the extent practical.
4. KPC has considered all reasonable alternatives to the proposed project and has made adequate economic evaluation of those alternatives.
5. KPC considered proper social, environmental, and economic factors, including co-location of new facilities with existing facilities, in the selection of its preferred route for the new transmission line.

II. TECHNICAL NEED REVIEW

A. BACKGROUND

On September 29, 2011, KPC applied to the Commission for a Certificate to construct approximately 20.0 miles of new 138kV transmission facilities between KPC's Soft Shell and Bonnyman Substations. In addition, ancillary facilities would be constructed at those substations and the Beckman and Haddix Substations in support of the project.[9] KPC states that the proposed project is a second 138kV source into the Hazard load area and is vital to strengthen the current electrical network which has reached its capacity for reliable operation. The need for the project is further described in the Hazard Area Improvement Plan contained in Exhibit 12 of the Application.[10]

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[9] September 29, 2011 application, paragraphs 3 and 5.

[10] September 29, 2011 application, paragraph 17.

B. RELIABILITY CRITERIA

1. *Definition*

Accion reviewed the reliability criteria used by KPC to design its transmission and sub-transmission systems. Those criteria consist of both steady state[11] and transient stability[12] requirements. The review consisted of system thermal performance, dynamic system performance, and system voltages under the types of contingencies specified in the various reliability criteria. The review also considered whether KPC selected appropriate contingencies for its analysis, whether KPC correctly interpreted the results of its analyses, and whether generation bias[13] was adequate to ensure conservative results.

2. *Discussion*

The source documents for all transmission design above 100kV in North America are the mandatory North American Electric Reliability Corporation ("NERC") standards contained in its Transmission Planning Standards ("TPL"). Since 2007, NERC defines the term "Bulk Electric System" as the non-radial electrical equipment operated at 100kV or higher. NERC reliability standards are considered to be the minimum requirement and regional or local entities responsible for system design may require more stringent standards.[14]

NERC's TPLs set forth standards of performance that the system must meet regarding transient stability, thermal, voltage, loss of demand or curtailed firm transfers, and cascading under different types of system events. Those events are no contingencies or system normal, specifically stated single element contingencies, and two or more element contingencies. In addition, the TPL standards also require evaluation for risks and consequences resulting from extreme contingency events[15] that are more severe than those previously stated. Typically outage conditions are referred to as no

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[11] Steady state criteria are the outage conditions under which the transmission system must maintain power flows within the capability of the equipment and voltages to customers that are adequate for proper operation of their equipment.

[12] Transient stability criteria are the outage conditions that the power system must withstand without interfering with the synchronous dynamic operation of the power system.

[13] Generation bias is used in system studies to generate more conservative results in a system analysis. For example, a power exporting area might assume more generation on line (larger exports) during contingency conditions to stress the system harder, while conversely, an importing area may assume less generation in service to accomplish the same goal.

[14] www.NERC.com, Glossary of Terms, page 9.

[15] An extreme contingency event would be loss of all transmission lines on a right-of-way, loss of all units at a generating station, total loss of a substation, etc.

contingencies (N-0), single element contingencies (N-1), and contingencies involving two elements (N-1-1[16]).[17]

KPC is a member of the Reliability First Corporation ("RPC"). RPC is the regional entity responsible for administering NERC's reliability standards. RPC administers the NERC standards through Regional Transmission Operators (RTO), one of which is the Pennsylvania-New Jersey-Maryland Interconnection (PJM). The PJM RTO performs design studies for the power system using NERC standards, or those of the individual Transmission Operators (TO) if they are more stringent. AEP is a TO within PJM and adheres to AEP's transmission reliability standards in the design of its transmission system.[18]

KPC's most recent revision to its planning criteria is the document entitled "The American Electric Power System Transmission Planning Criteria and Assessment Practices – Eastern AEP," dated March 2011 ("Planning Criteria").[19] The AEP Planning Criteria is used in the planning and design of the sub-transmission system (below 100kV), the High Voltage transmission system (also part of the Bulk Electric System rated 100kV through 230kV), and the Extra High Voltage transmission system (also part of the Bulk Electric System above 230kV through 765kV). The AEP Planning Criteria is compatible with NERC reliability standards, RFC standards, and PJM planning and operating manuals.[20]

The AEP Planning Criteria sets performance standards for thermal limits,[21] voltage limits, transient stability limits, and short circuit limits under steady state testing for its three transmission classes as set forth in the table below.

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[16] N-2 events are not equivalent to N-1-1 events. An N-2 event would be two simultaneously occurring single element events while an N-1-1 event is a single element contingency followed by operator action to adjust system generation, transfers, etc. prior to the next single contingency event occurring.

[17] www.NERC.com, all TPL standards.

[18] www.pjm.com/planning/planning-criteria.aspx.

[19] AEP uses both a west and east planning criteria. KPC is part of the eastern AEP transmission system.

[20] Response to Accion Data Request DR-7, pages 7 and 8.

[21] Accion notes that the AEP Planning Criteria assumes that power flow equally splits though the terminal equipment when in a full breaker and one half configuration. Although terminal equipment is oversized in this configuration, the basic premise is not true and equipment overload may result depending on configuration after a contingency event and depending on power flow direction.

Table 1

AEP Planning Criteria Steady State performance Requirements[22]

NERC Contingency Category	EHV Facilities	HV Facilities	Sub-T Facilities
No Contingencies - System Normal – N-0	May not exceed normal ratings Voltages within 0.95 and 1.05 per unit	May not exceed normal ratings Voltages within 0.95 and 1.05 per unit	May not exceed normal ratings Voltages within 0.95 and 1.05 per unit
Single Element Contingency **N-1**	May not exceed normal ratings Voltages within 0.92 and 1.05 per unit Less than 8% voltage change from normal	May not exceed emergency ratings Voltages within 0.92 and 1.05 per unit Less than 8% voltage change from normal	May not exceed emergency ratings Voltages within 0.92 and 1.05 per unit Less than 8% voltage change from normal
Multiple Element Contingencies with One Event **N-2**	May not exceed emergency ratings Voltages within 0.92 and 1.05 per unit Less than 8% voltage change from normal	May not exceed emergency ratings Voltages within 0.92 and 1.05 per unit Less than 8% voltage change from normal	Not planned for
Two Single Element Contingencies with Two Events **N-1-1**	May not exceed emergency ratings Voltages within 0.92 and 1.05 per unit Less than 8% voltage change from normal Manual system adjustment after first contingency except for supply to major load centers	May not exceed emergency ratings Voltages within 0.92 and 1.05 per unit Less than 8% voltage change from normal Manual system adjustment after first contingency except for supply to major load centers	Not planned for
Extreme Contingencies	Evaluate risks and consequences	Evaluate risks and consequences	Not planned for

The AEP Planning Criteria also specifies specific modeling assumptions that must be followed in system design studies. The AEP Planning Criteria requires that[23]

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[22] Response to Accion Data Request DR-7, page 17.

a. The sub-transmission system be modeled in detail in order to capture the effects of generation and voltage changing equipment connected to the sub-transmission system; and

b. The load power factor[24] must be represented for the load power factor of the load area and that the current load power factor will be maintained as load increases.

c. Power transfers modeled not only include the firm transfers identified in the Multi-Regional Model Working Group model but regionally experienced transfers as modified by RFC and PJM.

d. Generation dispatch is one that simulates economic system operation.

3. Analysis

Accion reviewed the planning criteria of AEP and found that it is consistent with NERC and RFC reliability standards and has reasonable performance standards.

C. THERMAL RATINGS

1. Definition

Accion reviewed the thermal ratings of the limiting transmission line components, including equipment in the substation, to ensure that KPC not only develops ratings that efficiently utilizes its equipment, but also appropriately applies those ratings. Accion performed its review both for ratings that are used under no contingency conditions (normal ratings) and those used under contingency conditions (emergency ratings).

2. Discussion

The Company documents the methods by which it rates its transmission facilities in documents entitled 1) *Transmission & Station Facility Rating Guidelines* 2) *AEP Procedure for Determining Circuit*

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[23] Response to Accion Data Request DR-7, pages 6 and 7.

[24] Voltage and current alternate their magnitude 60 times per second in accordance with their sinusoidal waveforms. When the angular difference between the two is equal to zero, all power flow is called "real power" and it can be measured in Watts. When the voltage waveform is angularly ahead of the current waveform, power other than Watts is required to satisfy the power relationship. This power is called "reactive or imaginary" power. When the voltage waveform leads the current waveform, it is inductive reactive power that is required and this reactive power is said to be lagging and tends to lower system voltage. Conversely, when the current waveform angularly leads the voltage waveform, capacitive reactive power that is required and this reactive power is said to be leading and tends to raise system voltage. All reactive power is measured in Volt Amperes reactive. When speaking of load, the load power factor is the cosine of the angle between the voltage and current waveforms. For example, an inductive load would have a load power factor of 0.97, and a capacitive load would have a load power factor of -0.97, and a purely resistive load would have a power factor of 1.00.

ratings, and 3) *A Guide for Maximum Temperature and Ampacity of Bare Overheard Conductors*. These documents consider specific methodology for rating every piece of equipment contained in the transmission or sub-transmission line.[25] The overall circuit rating is based on the most limiting component in the line. KPC considers ambient temperature, ampacity and trip settings of relays, overload capabilities based on time duration, sag limitations to remain within National Electrical Safety Code clearance requirements and wind velocity.[26] Additionally, KPC develops both normal and emergency ratings for summer and winter conditions. Conductor ratings are developed for 35°F and 95°F for average weather conditions and 0°F and 122°F for extreme weather conditions.[27]

Accion notes that KPC conductor ratings are very conservative with respect to assumed ambient temperature conditions. The minimum ambient temperature under load forecast conditions is approximately 2°F minimum in the winter and 93°F maximum in the summer. Under extreme load forecast ambient weather conditions, the minimum temperature is -21°F in the winter and 101°F in the summer.[28] Using temperatures for conductor ratings that are higher in the winter and lower in the summer, results in conductor ratings that are conservative in both cases. This is an important factor, as the Soft Shell to Bonnyman project justification is based on winter conductor ratings limits being exceeded. Accion will discuss this topic later in detail.

3. *Analysis*

For system power flow studies, KPC uses the composite component ratings developed for a transmission or sub-transmission line as the rating of the line. In this manner, opportunities for upgrading line components rather than rebuilding the line can be identified.

Accion found that KPC rates its equipment in accordance with what is considered good utility practice and is conservative in the calculation of its conductor ratings. Accion also found that KPC consistently applies equipment ratings across the system.

D. FAULT ANALYSIS (SHORT CIRCUIT AND TRANSIENT STABILITY)

1. *Definition*

Short circuit analysis is performed by simulating various types of system faults throughout the system to determine if the interrupting current capabilities of equipment (mainly circuit breakers and automatic switches) are sufficient. Studies are performed periodically to ensure that generation

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[25] Transformers are similarly rated.

[26] Industry practice is to use 2'/second for wind speed to represent natural convection surrounding a heated conductor. KPC also develops a 1 '/second rating for use when facilities are in a restricted location.

[27] Response to Accion Data Request DR-11.

[28] Response to Accion Data Request DR-F1.

additions and line additions do not increase the available short circuit current above the interrupting current capability of the equipment. Generally speaking, the more lines into a substation and the greater the generation level at or near the substation, the higher the short circuit current will be. When installing interrupting equipment, a margin is used to allow for system growth that would take place over the life of the equipment.[29]

Transient stability analysis is also performed by representing faults on the system. Transient stability analysis is performed to determine if faults on the system are able to be cleared in sufficient time in order not to disturb the synchronism[30] of the system. Studies are performed periodically to ensure that generation additions and line additions do not decrease the impedance between generators where system synchronism is lost due to faults. Generally speaking, the more lines into a substation and the greater the generation level at or near the substation, the lower the impedance between the generators will be.

2. *Discussion*

The interrupting current capability of equipment is part of the nameplate information of the equipment. Although some utility companies factor in overload capability into the interrupting capability of the equipment, the general industry practice is to use nameplate interrupting capability.

The nearest generation to the Soft Shell to Bonnyman project is at the Big Sandy generating station with 1078 MW in two units located 75 miles to the northeast and 600 MW at the Clinch River generating station located 60 miles to the southeast. These two generating stations located at these long distances and connected at 138kV would have little impact on the short circuit current available in the project area or the impedance between those remote generators. KPC stated that they performed no short circuit or transient stability analysis for the proposed project as there is no generation in proximity to the project or within the KPC study area. KPC also stated that any equipment installed would be installed with the appropriate short circuit duty.[31]

3. *Analysis*

Generation is not located in or near the proposed project and changes in the level of generation at those remote generators would not therefore impact the short circuit duty of interrupting equipment in the project area. Likewise, the small change in impedance due to the addition of the Soft Shell to Bonnyman transmission line would have little to no effect to the impedance between those

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[29] Response to Accion Data Request DR-7, Attachment 1, page 16.

[30] A power system is said to be in synchronism when the angular difference between generators remains relatively constant.

[31] Accion October 12. 2011 Interview Notes, page 3.

remote generators. In addition, all equipment would be installed with appropriate interrupting current capability.

Accion found that KPC's analysis of short circuit duty and transient stability for the Soft Shell to Bonnyman project was both adequate and reasonable. Transient stability and short circuit performance requirements are not further enumerated in this report as they are not pertinent to the need for the proposed Soft Shell to Bonnyman 138kV transmission line.

E. LOAD FORECASTING

1. Definition

Accion reviewed the KPC load forecasting methods on both total system and sub-area basis to assess whether they represented the future in a reasonable manner. Items reviewed included the use of weather-based forecasting and the weather inputs to the forecast. Accion also reviewed the econometric model assumptions used in load forecasting.

2. Discussion

KPC develops its total company energy load forecast by customer class separately. Energy and revenue data are taken from internal sources, and regional economic drivers are taken from external sources such as Moody's Analytics, National Oceanic and Atmospheric Administration (NOAA), and the U. S. Energy Information Administration. Short-term models are developed for the one to two-year near term period and long-term models for the time period beyond.[32] The KPC forecasting model considers factors such as energy prices, real personal income within the service area, weather, service area population changes, and appliance and housing efficiency. Demand side management and energy efficiency adjustments are made in the post-model results.[33]

KPC obtains a peak company load forecast by combining the revenue class sales with class level and end-use level load shapes. Actual and forecasted temperatures are modeled to provide hourly load shapes by revenue class and end-use. The end-use load shapes are aggregated to form an overall system load shape which may be modified when evaluated against historic peak loads and load factors.[34]

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[32] Short-term models take current economic factors into consideration and may produce a sharply changing forecast direction. The short-term forecast blends into the long-term forecast which is usually represented as a smooth forecast over the longer term

[33] Response to Accion Data Request DR-10.

[34] Response to Accion Data Request DR-10.

KPC employs peak and energy normalization to its historical data to mitigate impacts due to severe weather or load curtailment. A Monte Carlo probabilistic model is used to normalize peak data, and a heating/cooling degree-day adjustment is applied to all classes of energy data by class. KPC prepares load forecasts for four load areas; Ashland, Pikeville, Hazard, and South Williamson. The 2009 Total System Load Forecast used for the Hazard Load Area Study was based on a 50/50 probability[35] of occurrence.[36]

3. *Analysis*

In terms of winter peak forecasted load, KPC projected the 2014/2015 winter peak to be 1,745 MW in 2006, 1,653 MW in 2007, 1,700 MW in 2009, and 1,564 MW in 2011. KPC also projected winter peak loads for the Hazard load area. KPC forecasted a Hazard load area 2014/2015 winter peak of 495 MW in 2006, 437 MW in 2007, and 459 MW in 2010.[37] KPC used the 2009 Total System Load Forecast and the 2007 Hazard Load Area Forecast[38] for its analysis of the Hazard load area, as they were the most recent forecasts available in 2009 when the analysis was performed.[39]

Accion found that KPC's load forecasting methods, economic inputs, adjustments, and inclusion of demand side management and energy efficiency are both reasonable and adequate for forecasting both Company-wide and load area loads for use in transmission and sub-transmission reinforcement studies, and that reasonable study results would be produced. Accion suggests that KPC use load area load forecasts and company-wide load forecasts of the same vintage in future transmission analyses.

F. TECHNICAL ANALYSIS

1. *Definition*

Accion reviewed the power flow,[40] transient stability,[41] and other technical analyses used to justify the Soft Shell to Bonnyman 138kV line project. These other technical analysis could include

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[35] A 50/50 probability load forecast is one whose forecasted load would be expected to be exceeded once in two years.

[36] Response to Accion Data Request DR-10 and Accion October 12. 2011 Interview Notes, page 2.

[37] KPC attributed the drop in the load forecast in 2007 and subsequent increase due to operating assumptions regarding a single customer which in fact did not materialize.

[38] Accion notes that use of the 2007 Load Area Load Forecast would underestimate the need for facilities when compared to more recent vintage forecasts.

[39] Response to Accion Data Request DR-9.

[40] Power flows analysis is done with a mathematical impedance model of the power system. Final or steady state (when angular change between generators has ceased) voltages are calculated at nodes and power flows are calculated on the various pieces of equipment. Contingencies are simulated to ensure that voltages and equipment loadings stay within prescribed limits.

[41] Transient stability analysis is done with a mathematical impedance model of the power system but also includes time in the calculations. Usually the time increment is 0.01 seconds and the analysis is carried out to approximately 2.0 seconds.

reactive requirements, economic evaluations, or short circuit analysis. Accion reviewed the size of the system modeled for the analysis to determine if it was of sufficient detail and size to produce valid study results. Accion also reviewed the application of the reliability criteria to assure proper simulations and the results themselves to ascertain if KPC drew proper conclusions from its analysis.[42]

2. Discussion

The System planning Department has the responsibility to perform the technical analyses required to justify projects such as the Soft Shell to Bonnyman 138kV transmission line. Accion presents the history of KPC's efforts to maintain reliability in the Hazard load area below.

Prior to the early 1980's - The Hazard load area was served by a 69kV sub-transmission system from western Virginia and West Virginia to the east, and from a 161kV line to Hazard from the TVA system to the west.

Mid 1980's - KPC built a 138kV line from its Beaver Creek Substation westward to its Hazard Substation, and installed 138kV/69kV transformer at Hazard.

Mid 1990's - KPC established the normally open Lee City to Jackson 69kV tie with East Kentucky Power Cooperative (EKPC) on the northern end of the Hazard load area.

1998 – Installed a 24.3 MVAR capacitor bank at the Hazard 69kV Substation.

2005 - KPC established a hard tie (no circuit breakers) on the Kentucky Utilities (KU) 161kV line between Delvinta and Arnold Substations at Hyden with KU, established a new 161kV substation at Wooton, and constructed the Hyden to Wooton 161kV line on the western side of the Hazard load area. KPC also ties the exiting 161kV tie to Stinnett into Wooton Substation.

2009 – KPC required that the 69kV tie at Lee City with EKPC be closed. Its capability was approximately 50 MW.

2010 – Installed a 14.4 MVAR capacitor bank at the Leslie 69kV Substation.

2011 – Filed for Certificate of Convenience and Necessity for the construction of the Soft Shell to Bonnyman 138kV transmission line.[43]

Various faults and associated equipment outages are modeled on the system along with the associated clearing times of the protective equipment which takes the faulted equipment out of service. A power flow analysis is calculated at each time increment and voltages, power flows, and angular differences between generators are calculated. These time changing power flows, voltages, and angular differences produce a speed change (frequency) at the generators. If a generator cannot remain within certain speed limits, it becomes unstable and is automatically tripped off line.

[42] As stated above, and for those reasons, short circuit analysis and transient stability analysis are not relevant to this review.

[43] Accion October 12, 2011 Interview Notes, page2.

KPC's base case power flow analysis assumed load conditions at the peak winter hour in the Hazard load area and heavy load conditions elsewhere; an expected economic dispatch of generation for typical conditions; typically expected transfers between dispatch areas; and no additional generation was taken out of service for a more conservative bias.[44] The transmission representation was that of the PJM 2014 Regional Transmission Expansion Plan (RTEP).[45]

The study was performed in 2009 and used peak hour loads developed in the 2009 load forecast for KPC and the peak hour 2007 Hazard load area forecast. Both load forecasts were based on an expected 50/50 probability of occurrence. KPC stated that the 2007 load forecast projected a downturn in load which did not occur. The 2009 forecast then produced loads that looked like 2013/2014 loads in the 2007 load forecast. This shift forward in load growth prompted the need for the proposed facilities.[46]

The 2009 study was the first time KPC had studied the Hazard load area using the new NERC N-1-1 requirements for 100kV and above transmission systems.[47] The study model conformed to the AEP Planning Criteria.[48]

3. *Analysis*

The study area modeled by KPC was identical to the area PJM modeled for its transmission reinforcement 2014 RTEP analysis, which was based on heavy load, and economic dispatch, and firm and expected regional transfers. Such a transmission representation is more than sufficient for the study of the Hazard load area.[49] KPC followed the AEP planning criteria and represented the entire 69kV sub-transmission system to capture the effect of voltage changing equipment in its representation. Additionally, it used actual load power factors of between .984 and .998 in the Hazard loop load representation.[50]

KPC uses the Power Technologies Inc. ("PTI") Power System Simulator/Engineering ("PSS/E") power flow program (version 30) for its power flow analysis. This software enables assessment of system performance under normal and emergency conditions and has the capability to flexibly present

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[44] There is no local generation within the study area.

[45] Accion October 12, 2011 Interview Notes, page2.

[46] Accion October 12, 2011 Interview Notes, page2.

[47] Accion October 12, 2011 Interview Notes, page2.

[48] Response to Accion Data Request DR-7, pages 6 and 7.

[49] Accion October 12, 2011 Interview Notes, page 2.

[50] Except where capacitors were to be added as part of the proposed project.

output results for the planner.[51] The PTI PSS/E power flow program is widely used throughout the industry for power system analyses.

Accion concluded that the system studies conducted were appropriate, and that system representation was adequate to obtain valid study results.

The Hazard 69kV loop consists of a 69kV line starting at the Hazard Substation and includes the Bulan Shamrock Bonnyman Combs Blue Grass Substations and terminates back at the Hazard Substation. In addition a radial 69kV line runs from the Bonnyman Substation to the Chavies Haddix and Jackson Substations and continues to Lee City, a tie point with EKPC. KPC simulated an outage of the Hazard to Bulan end of the 69kV loop, and the Blue Grass to Hazard section of the loop loaded to the 107% of its normal rating. Similarly, when the Bluegrass to Hazard line was outaged, the Hazard to Bulan line loaded to 116% of its normal rating. These limiting 69kV lines may not be operated above the normal conductor temperature of 95°C due to sag limitations.[52] The only operating procedure available to KPC to alleviate these overloads is closure of the normally open Lee City 69kV tie. KPC simulated closing the Lee City tie and found that the Blue Grass to Hazard line contingency still loaded the Hazard to Bulan 69kV line to 110% of its normal rating. These same contingencies resulted in voltages at all busses on the Bonnyman to Jackson 69kV line (to Lee City) below KPC's required minimum 0.92 per unit voltage single contingency value.[53] Modeling the Lee City tie as closed resulted in voltages that were higher, but still generally below required values in almost every contingency.[54]

PJM also identified an N-1-1 contingency that the system had not been previously tested to withstand. That outage was the loss of the Stinnett to Pineville 161kV circuit followed by the loss of the Wooton to Hyden 161kV circuit. The N-1-1 contingency represented the loss of both transmission feeds to the western side of the Hazard load area. Previous system design only required the loss of one of the circuits to be considered. The loss of the two circuits overloaded the Beaver Creek to Topmost 138kV transmission line, to 130% of its normal rating[55] prior to closure of the Lee City tie.[56]

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[51] Response to Accion Data Request DR-6.

[52] Response to Accion Data Request DR-18.

[53] KPC assumes that by maintaining 0.92 per unit voltage at the 69kV level, that adequate voltage will be maintained at the distribution bus. Accion notes that many times, distribution planners assume a 1.05 per unit voltage at their source bus. A 0.92 per unit voltage at the sub-transmission voltage level may not result in adequate voltage at the distribution source bus that can maintain required voltage at the end of the distribution circuits.

[54] September 29, 2011 Application, Exhibit 12, Pages 4 through 6.

[55] This line is also limited to 95°C conductor temperature due to sag limitations. (See DR-18)

[56] September 29, 2011 Application, Exhibit 12, page 6.

Accion found that KPC applied its planning criterion properly and consistently and also identified the correct outages to simulate in its analysis. In addition, KPC drew proper conclusions from its study results and used appropriate software for its analysis.

G. SUMMARY

With regard to reliability criteria, Accion reviewed the planning criteria of AEP and found that it is consistent with NERC and RFC reliability standards and has reasonable performance standards.

Concerning thermal ratings of equipment, Accion found that the KPC transmission equipment thermal rating methods include all system elements, have sufficient coordination so they are consistently applied, and are appropriately conservative. Accion does suggest that KPC re-evaluate the ambient temperatures when rating conductors to be more consistent with the temperatures used in the construction of the 50/50 (normal) and extreme weather load forecasts.

Accion found that due to the remote nature of the study area from system generators, there was no need to perform short circuit or transient stability analyses.

Accion found that KPC's load forecasting methods, economic inputs, adjustments, and inclusion of demand side management and energy efficiency are both reasonable and adequate for forecasting Company-wide and load area loads for use in transmission and sub-transmission reinforcement studies, and that reasonable study results would be produced. Accion suggests KPC use load area load forecasts and company-wide load forecasts of the same vintage in future transmission analyses.

Accion found that KPC applied its planning criterion properly and consistently and also identified the correct outages to simulate in its analysis. In addition, KPC drew proper conclusions from its study results and used appropriate software for its analysis. Accion suggests KPC revisit its practice of maintaining 0.92 per unit voltage at the sub-transmission voltage level, as that value may not ensure adequate distribution source voltage for the distribution planner.

III. ALTERNATIVE SOLUTIONS AND ROUTING

This chapter presents the results of Accion's review of the alternatives that KPC considered and their associated analyses that support the KPC choice of the proposed Soft Shell to Bonnyman transmission line as the most reasonable alternative and that the route selected is reasonable. The chapter addresses

a. The upgrade of existing transmission lines or facilities;

b. Other alternatives, including the use of generation and power factor improvement;

c. Whether wheeling power through neighboring systems or through interconnections with neighboring systems would be a viable alternative to the construction of the proposed transmission line; and

d. Whether the routing selected for the best alternative is reasonable in that proper social, environmental, and economic factors were reasonably considered, and whether adequate consideration was given to co-location of the new transmission line with new facilities.

A. EXISTING FACILITY UPGRADES

1. *Definition*

Accion evaluated whether KPC gave adequate consideration to upgrades of existing transmission facilities. Accion included a review of the cost analysis of the alternatives considered and a review of the application of new technology or system automation as, or as a part of, the solution.

2. *Discussion*

KPC has remedial action available to alleviate overloads when an outage is simulated at either end of the Hazard 69kV loop. KPC can close the Lee City 69kV tie with EKPC. When KPC modeled the closure of the Lee City tie, the Blue Grass to Bulan line remained overloaded at 110% of its normal rating for loss of the Blue Grass to Hazard line. In addition, the Beaver Creek to Topmost 138kV transmission line overloaded for the loss of the Stinnett to Pineville 161kV and the Hyden to Wooton 161kV transmission lines.[57]

KPC identified three alternatives to the proposed facility. The first alternative (Alternative #1) was to establish a second 1.2 mile 161kV tie with KU from Wooton to Hyden Substations, add a 300 MVA 161/138kV transformer at Wooton, construct a 138kV line from Wooton to Bonnyman, and add a 138/69kV transformer at Bonnyman. A second alternative (Alternative #2) contemplated the rebuilding of the approximately 17.0 mile 69kV Hazard sub-transmission loop and the replacement of the Hazard 138/69kV transformer with a transformer of larger size. The third alternative conceptually considered (Alternative #3) was the construction of a second transmission line from the Tennessee Valley Authority ("TVA") Pineville Substation to the KPC system.

3. Analysis

Alternative #1 appeared to be the most economical alternative which would resolve the 69kV overloads and voltage problems and the 138kV transmission overload due to the N-1-1 161kV

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[57] September 29, 2011 application, Exhibit 12, pages 5 through 7.

contingency. KPC stated that KU only allows hard ties[58] to its system. When KPC built the first 161kV tie to KU at Hyden, a hard tap was required and that connection required the construction of the Wooton Substation where protective equipment was installed. If KPC were to construct the second tie at Hyden as a hard tap, both feeds into the KPC system would be lost under single contingency conditions. Under these conditions, the overload of the Beaver Creek to Topmost 138kV line would not be alleviated. KPC discarded Alternative #1 as a viable alternative to the proposed project and no construction estimate was made for this alternative.[59] To rectify the deficiencies of this alternative, the new interconnection would have to be at a location where no existing ties currently exist.[60] (See Alternative #3 below)

By rebuilding the Hazard sub-transmission 69kV loop, Alternative #2 would resolve the 69kV overload and voltage issues, but would not resolve the overload of the Beaver Creek to Topmost 138kV transmission line, due to the N-1-1 161kV contingency. KPC discarded Alternative #2 as a viable alternative to the proposed project. KPC performed no construction estimate for this project.[61] To rectify the deficiencies of this alternative, the construction of a new transmission tie to the east or west of the KPC system would also be required to alleviate the 138kV transmission line overload.

Alternative #3 considered the construction of a 161kV line from Wooton to the TVA Pineville Substation.[62] The construction of this long line would be required to correct the deficiencies in Alternative #1 so that both 161kV lines would not be lost for a single contingency. This alternative would not address the 69kV loop thermal overloads and voltage problems. KPC performed no construction estimates for this project.[63] To rectify the deficiencies of this alternative, Accion believes that the transformer additions and 138kV construction depicted for Alternative #1 would also be required.

KPC performed an initial construction estimate for the proposed project in 2009 and updated that estimate in September, 2011. The current estimate for the proposed project, including ancillary equipment at the 138kV line terminals and other substations, is $47.8 million plus $14.7 million in labor cost for a total of $62.5 million".[64] KPC confirms that the new estimate is in 2014 dollars,

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[58] A hard tie is where the tie line is physically connected with no protective devices. Conversely, a soft tie would have protection equipment installed at the tie location.

[59] Accion October 12, 2011 Interview Notes, page 5.

[60] Accion notes that both 161kV transmission lines in the western area of the KPC system have existing hard taps to KPC.

[61] Accion October 12, 2011 Interview Notes, page 5.

[62] Pineville Substation is approximately 35 miles west of Wooton Substation (DR-1).

[63] Accion October 12, 2011 Interview Notes, page 5.

[64] September 29, 2011 application, Exhibit 12, page 14.

includes Allowance for Funds Used During Construction,[65] and has included a full scope detailed review of substation construction issues.[66]

With regard to new technology, KPC could replace the existing conductor on the 138kV Beaver Creek to Topmost line with a composite conductor[67] (Aluminum Conductor Composite Reinforced or ACCR). If KPC made this conductor replacement, and assuming that the additional thermal capacity was able to alleviate the thermal overload, 69kV sub-transmission loop overloads and low voltages would still remain for the 69kV loop contingencies.

Accion concluded that KPC considered all reasonable alternatives to the proposed project and has made adequate economic evaluation of those alternatives.

B. WHEELING OF POWER

1. Definition

Accion reviewed whether KPC gave adequate consideration to wheeling power from/through adjoining systems via existing or new interconnections with other systems.

2. Discussion

The Hazard load area is an area of the KPC system that encompasses approximately 300 MW of load[68] that is served by a single 138kV transmission line from the east, and two 161kV transmission interconnections from the west. A 69kV sub-transmission system delivers the power to the distribution load centers in the Hazard load area.

3. Analysis

All transmission lines into the Hazard load area have power flows that are into the Hazard load area. It is the contingency loss of the transmission and sub-transmission facilities into the Hazard load area that causes violations of KPC's reliability criteria to occur on the remaining facilities. The wheeling of additional power over these facilities is therefore not feasible to alleviate reliability violations.

Accion found that additional wheeling of power from/through adjoining systems was not feasible as an alternative to the proposed project.

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[65] Response to Accion Data Request DR-27.

[66] Response to Accion Data Request DR-F2.

[67] A composite conductor is an aluminum stranded conductor that has its steel core replaced with an aluminum embedded fiber core. The fiber core is much lighter than steel and has a much higher conductivity than steel. The result is that a composite conductor weighs less than and can carry more current at similar sags than a similarly sized ACSR conductor.

[68] September 29, 2011 application, Exhibit 12, page 2.

C. ADDITION OF GENERATION AND POWER FACTOR IMPROVEMENT

1. *Definition*

Accion evaluated whether KPC gave adequate consideration to the installation of local generation and power factor improvement as viable alternatives.

2. *Discussion*

In addition to system upgrades or wheeling of power, there are other alternatives that may provide a solution to reliability criteria violations. In cases where a utility encounters thermal restrictions, it may consider the installation of local generation. If voltage constraints are encountered, the use of either fixed or variable[69] shunt capacitors can be considered. In either reliability criteria violation scenario, the use of series capacitors or inductors[70] may also provide potential solutions.

3. *Analysis*

In the case of the Hazard load area, any generation addition would have to be placed such that thermal overloads could be mitigated. That location would most likely be at the Bonnyman Substation. In addition, capacitors would be required to mitigate voltage violations. When generation is placed in load areas, generally fast start generation such as combustion turbines is used to eliminate the need for a cooling medium. The Beaver Creek to Topmost 138kV line is overloaded to 130% of its normal rating under contingency conditions[71] which is approximately 260 MVA,[72] with the remaining 50 MW of Hazard area load carried by the remaining 69kV facilities. Bonnyman Substation is approximately equidistant between the 138kV and 69kV feeds into the Hazard load area under N-1-1 contingency conditions. The size of the generation required to alleviate the overload would be in accordance with the power split between the two feeds or approximately 70 MW at the time of installation. The generator size would have to be incrementally increased through time as the Hazard load area load increased. Even if it was economic to do so, generation of that size is unreasonable for the 69kV sub-transmission system, and it is also unreasonable to rely on incrementally increasing generation as a solution to reliability criteria violations. Accion discounted additional generation as a viable alternative to the project.

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[69] Solid state new technology that varies reactive output in accordance with need.

[70] A transmission line is composed of both resistive and inductive reactance components in its impedance. The installation of series capacitors in a transmission line negates a portion of the inductive reactance of the line, thus lowering its impedance which allows more power to be carried by that network component. Similarly, a series inductor acts to increase the transmission line impedance allowing for less power to be carried by that network component.

[71] September 29, 2011 application, Exhibit 12, page 7.

[72] Response to Accion Data Request DR-17, Attachment 1.

Load power factor can be improved by the addition of shunt capacitors. With the addition of the two shunt capacitor banks proposed by the project, the power factor of the Hazard 69kV load area approaches 1.00. Further improvement of voltages cannot be expected by increasing the load power factor in the Hazard 69kV loop with either fixed or variable capacitors.

The limiting contingency for the 138kV Beaver Creek to Topmost transmission line is the N-1-1 contingency of the two 161kV feeds into the Hazard load area. The 138kV transmission line is the only bulk source into the area under the N-1-1 contingency. Increasing the power flow over the overloaded 138kV line by use of series capacitors does not resolve the thermal violation. Decreasing the power flow over the 138kV line to remain within its rating would have to be such that an additional approximate 60 MW would have to be force fed though the remaining 69kV facilities to the Hazard load area. Those facilities do not have that thermal capability.

Accion concluded that the addition of generation, improved power factor correction and the deployment of newer conductor and reactive supply technologies were not viable alternatives to the proposed project.

D. USE OF EXISTING RIGHTS-OF-WAY (CO-LOCATION)

1. Definition

Accion reviewed the final alternate chosen to determine if existing rights-of-ways were used to the extent practical.

2. Discussion

The terminals of the proposed transmission line would be the Soft Shell Substation to the east and the Bonnyman Substation to the west. The area between these two substations is practically void of existing sub-transmission and transmission lines except from the Bulan Substation to the west. At Bulan Substation, one 69kV sub-transmission line heads generally westerly for approximately 4.5 miles to the Bonnyman Substation, and a second 69kV sub-transmission line heads generally southerly for approximately 4.0 miles to the Hazard Substation. The Hazard Substation is approximately 6.0 miles to the southeast of the Bonnyman Substation.[73]

Once KPC had selected the Soft Shell to Bonnyman line as the preferred alternate, GAI Consultants, Inc. ("GAI") identified 25 potential line segments for the proposed transmission line. The number of line segments increased to 35 after discussions during the public review process. The

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[73] September 29, 2011 application, Exhibit 13, Figure 4.

potential line segments included the entire 4.5 miles of the exiting 69kV corridor between the Bulan and Bonnyman Substations.[74]

Initial screening eliminated 12 line segments from further consideration. KPC developed five routes from the remaining 23 line segments.[75] Each potential route used the following amount of the 4.5 mile Bonnyman to Bulan 69kV right-of-way:[76]

Route #1 – 2.6 miles
Route #2 – 0.0 miles
Route #3 – 0.9 miles (preferred alternative)
Route #4 – 0.9 miles
Route #5 – 0.9 miles

Route #1 was disqualified later in the routing selection process due to the fact that 30% of the line along this route would be subject to potential rebuilding due to future coal mining operations.[77] Using the cost of the line as estimated in the Application at Exhibit 12 and at page 14 on a linear basis, 6.0 miles of line rebuild would cost approximately $12 million in 2014 dollars.

Accion concluded that KPC gave adequate consideration to co-location of new facilities with those of existing facilities when selecting Route #3 as the preferred alternative.

E. ROUTE SELECTION PROCESS

1. *Definition*

Accion reviewed whether the routing selected for the best alternative is reasonable in that proper social, environmental, and economic factors were reasonably considered.

2. *Discussion*

The terminals of the proposed transmission line are the Soft Shell Substation to the east and the Bonnyman Substation to the west. KPC retained GAI to develop and evaluate alternative line route locations for overall environmental suitability and feasibility.[78] Once KPC had selected the Soft Shell to Bonnyman line as the preferred alternate, GAI identified the route study area that comprised 277

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[74] September 29, 2011 application, Exhibit 13, Figure 2.

[75] See the discussion in Route Selection Process below.

[76] September 29, 2011 application, Exhibit 13, Table 4.

[77] September 29, 2011 application, Exhibit 13, Table 4.

[78] September 29, 2011 application, Exhibit 13, page 1.

square miles between the two terminals.[79] Within the study area, GAI identified potential line segments for the proposed transmission line.[80]

KPC employed the following siting criteria in the selection of route alternatives:

a. Avoid or minimize conflicts with existing and future land uses (e.g. future coal mining extraction activities);

b. Avoid or minimize impacts upon human, natural, visual and cultural resources;

c. Avoid or minimize visibility from populated areas or visually sensitive and designated areas;

d. Minimize impacts of construction and maintenance costs by selecting shorter, more direct routes;

e. Locate routes through terrain where economical construction and mitigation techniques could be employed, where line operation and maintenance would be feasible, and where access road length would be minimized;

f. Would be consistent with KPC transmission needs, project schedules, regulatory agency oversight requirements, and environmental regulations; and

g. Would have stakeholder support including property owners, coal/gas companies, and local officials.

These siting criteria formed the basis of the impact/resource conflict avoidance methodology used to identify the alternative routes.[81]

The following list summarizes GAI efforts to develop environmental constraint data used to develop and evaluate potential line segments. Data was collected from: 1) Literature Review and Data Collection; 2) Ground Reconnaissance; 3) Agency Coordination; 4) Mining Company Coordination; 5) Gas Company Coordination; 6) Landowner Coordination; and 7) Public Coordination.[82]

Environmental constraints evaluated with the data collected included: 1) Topology and Geology; 2) Hydrocarbon Resources; 3) Existing Utilities; 4) Groundwater; 5) Soils; 6) Existing Land Use; 7) Future Land Use; 8) Wetlands; 9) Steams; Rivers; and Reservoirs; 10) Public Drinking Water Sources; 11) Solid and Hazardous Waste Sites; 12) Natural Heritage; Threatened and Endangered Species; 13) Federal; State; or Local Natural Area Preserves and Conservation Lands; 14) Archaeological and

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[79] September 29, 2011 application, Exhibit 13, page 1.

[80] September 29, 2011 application, Exhibit 13, Figure 4.

[81] September 29, 2011 application, Exhibit 13, pages 1 and 2.

[82] September 29, 2011 application, Exhibit 13, pages 2 through 3.

Historic Resources; 15) Scenic Resources; 16) National Wild and Scenic Rivers; Parkways; and National Landmarks; 17) Floodplains; 18) Recreation; and 19) Transportation/ Aviation.[83]

Within the constraint process, GAI developed 25 potential line segments for evaluation. The number of line segments was increased to 35 after discussions during the public review process. The evaluation process reduced the number of line segments to 23; these line segments formed the basis for the development of five alternate routes.[84] Routes 1 and 2 follow a generally northern route through the study area, Route 3 (the preferred route) follows a central route through the study area, and Routes 4 and 5 follow a generally southerly route through the study area.[85]

GAI's two main objectives were to minimize impacts on people (proximity) and to minimize line relocation due to future mining operations. Acceptance by landowners was also an important factor in the final route selection process.[86] Routes 4 and 5, the two most southerly routes, had significant future mining concerns and also had visual impacts.[87]

With regard to Electric and Magnetic Fields[88] ("Collectively referred to as EMF), KPC stated that the issue had not been raised by any landowner.[89] Each transmission construction configuration results in different EMF levels that relate to the line voltage and line current. The proposed alternative has three construction configurations.

KPC calculated Electric and Magnetic Field strengths for each configuration based on the current expected to flow at normal peak load levels and operating voltage level. KPC calculations show that the maximum Electric Field at the edge of the right-of-way and one meter off the ground is 0.8kV/meter, and that the maximum Magnetic field is 7.3 milli Gauss under the same conditions. Both values are far below the values stated in the Institute of Electrical and Electronics Engineers ("IEEE") Standard C95.6-2002, IEEE Standard for Safety Levels With Respect to Human Exposure to

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[83] September 29, 2011 application, Exhibit 13, pages 3 through 9.

[84] September 29, 2011 application, Exhibit 13, pages 10 and 11.

[85] September 29, 2011 application, Exhibit 13, Figure 3.

[86] KPC stated in the October 12, 2011 interview, that only 4 landowners had expressed concerns and that KPC was working with those landowners to address them. (Interview Notes, page 4)

[87] Accion October 12, 2011 Interview Notes, page 4.

[88] Electric Fields are related to the operating voltage of the facility and are of constant value. The higher the facility operating voltage, the higher the Electrical Field. Electrical Fields are measured in kilo Volts per meter. Magnetic Fields are related to the current in the facility (irrespective of voltage). The higher the current, the higher the Magnetic Field. Magnetic Fields are measured in milli Gauss.

[89] Accion October 12, 2001 Interview Notes, page 4.

Electromagnetic Fields, 0-3 kHz.[90] The IEEE limits for Electrical and Magnetic Fields are 5.0 kV/meter and 9040 milli Gauss respectively.[91]

3. *Analysis*

Table 4 of Exhibit 13 in the KPC September 29, 2011 application shows the relative impact of the 5 potential routes on socioeconomic features and natural resources and serves as an excellent visual summary of the final route selection process. From the table, it can be seen that:

a. Route 1 has the most impact with regard to proximity to people. Three structures were within the proposed right-of-way and 34 structures were within 250 feet of the proposed right-of way. Routes 4 and 5 have lesser proximity impact and Routes 2 and 3 have the least proximity impact;

b. Route 1 is the longest route, but all routes are approximately the same length;

c. Routes 1 and 2 have a 30% potential transmission line relocation risk ($12 million on a linear line cost basis[92]); and

d. Routes 4 and 5 have a 50% potential transmission line relocation risk ($20 million on a linear line cost basis[93]) and as noted above, also had visual impacts.

From these observations, KPC selected the center route, Route 3 as its preferred alternative for the Soft Shell to Bonnyman 138kV transmission line.

Accion concluded that KPC selected the best reasonable alternative route and that proper social, environmental, and economic factors were reasonably considered.

F. SUMMARY

Accion concluded that KPC considered all reasonable alternatives to the proposed project and has made adequate economic evaluation of those alternatives.

Accion found that additional wheeling of power from/through adjoining systems was not feasible as an alternative to the proposed project.

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[90] Kilo Hertz, a measure of frequency in thousands of times per second.

[91] Response to Accion Data Request DR-33.

[92] Based on September 29, 2011 application, Exhibit 12, page 14.

[93] Based on September 29, 2011 application, Exhibit 12, page 14.

Accion concluded that the addition of generation, improved power factor correction and the deployment of newer conductor and reactive supply technologies were not viable alternatives to the proposed project.

Accion concluded that KPC gave adequate consideration to co-location of new facilities with those of existing facilities when selecting Route #3 as the preferred alternative.

Accion concluded that KPC selected the best reasonable alternative route and that proper social, environmental, and economic factors were reasonably considered.

ACCION GROUP

MEMO

TO: FILE
DATE: October 19, 2011
RE: KPSC INTERVIEW NOTES October 12, 2011

INTERVIEW NOTES

Study Area of Interest

The study area of interest for this facility addition is the most eastern part of Kentucky. The majority of the foundation of the transmission system that feeds eastern Kentucky resides in Virginia and West Virginia. (DR-1)

Base Case Study Modeling

The base case power flow analysis assumed load conditions at the peak winter hour in the Hazard load area and heavy load conditions elsewhere, an expected economic dispatch of generation for typical conditions, typically expected transfers between dispatch areas, and no additional generation out of service for conservative bias.

The study was performed in 2009 and used loads developed in the 2009 load forecast for the Hazard area. The transmission representation was that of the PJM 2014 Regional Transmission Expansion Plan (RTEP). KPC stated that the 2007 load forecast forecasted a projected downturn in load which did not occur. The 2009 forecast then produced loads that looked like 2013/2014 loads in the 2007 load forecast. This shift forward in load growth prompted the need for the proposed facilities.

The 2009 study was the first time that KPC had studied the Hazard load area using the new NERC N-1-1 requirements for 100kV and above transmission systems.

Load Forecast

The 2009 load forecast was based on an expected 50/50 probability of occurrence (expects to be exceeded once in 10 years). (KPC also develops an 80/20 load forecast which would expect to be exceeded once in 5 years)

Tried to correlate the temperatures used in the load forecast to those used in conductor ratings and could not. KPC was going to follow up (DR-F1)

History of Hazard Area Construction Projects to Serve Load Reliably

Prior to the early 1980's - The Hazard load area was served by a 69kV sub-transmission system from western Virginia and West Virginia to the east and from a 161kV line to Hazard from the TVA system to the west.

Mid 1980's - KPC built a 138kV line from its Beaver Creek Substation westward to its Hazard Substation and installed 138kV/69kV transformer at Hazard.

Mid 1990's - KPC established the normally open Lee City to Jackson 69kV tie with EKPC on the northern end of the Hazard load area.

2005 - KPC established a hard tie (no circuit breakers) on the KU 161kV line between Delvinta and Arnold Substations at Hyden with KU, established a new 161kV substation at Wooton, and constructed the Hyden to Wooton 161kV line on the western side of the Hazard load area.

1998 – Installed a 24.3 MVAR capacitor bank at the Hazard 69kV Substation.

2009 – KPC required that the 69kV tie at Lee City with EKPC be closed. Its capability is approximately 50MW.

2010 – Installed a 14.4 MVAR capacitor bank at the Leslie 69kV Substation.

2011 – Filed for Certificate of Convenience and Necessity for the construction of the Softshell to Bonnyman 138kV transmission line.

Reliability Criterion

KPC requires that there be no manual switching performed for contingencies impacting major load centers.

Future transmission expansion plans must satisfy both KPC transmission planning criteria and the new NERC double contingency requirements.

At Hazard, KPC states that the N-1-1 and stuck breaker contingencies are equivalent.

Analysis of Hazard Load Area

Only power flow analysis was performed.

No transient stability testing was performed as there is no generation, including small hydros, within the study area. The nearest generation is at Big Sandy with 2 units totaling 1078 MW 75 miles to the NE, Clinch River with 600 MW of generation 60 miles to the SE, and Pineville, 50 miles to the SW. (KPC was to check on generation at Pineville in DR-F3)

No short circuit analysis was performed as there is no generation, including small hydros, within the study area. KPC stated that any equipment installed will have the appropriate short circuit duty.

Line Route Selection (DR-21)

Proximity to residences and avoidance of relocation due to future mining operations were the two main factors in route selection.

Regulatory requirements and acceptance by landowners were also important factors. (only 4 landowners have raised concerns and KPC is working with those landowners)

Alternatives 4 and 5 had visual and future mining concerns compared to the other 3 alternatives.

Project Estimate

The current $62.5 million estimate for the project contains a 5% contingency for the line, 15% for materials, and 5% for labor. The total contingency is $1.5 million.

The Phase 1 estimate in Exhibit 12 of the filing was a planning grade estimate (+/- 25%), the phase 2 estimate was a budget grade estimate (usually +/- 10%), and the phase three costs include labor.

The current estimate was updated in September 2011.

KPC could not explain the increase in cost for the Softshell Substation while the cost for the Bonnyman Substation remained flat. KPC was to follow-up. (DR-F2)

Miscellaneous

The radial line from Softshell Substation to the Spicewood Substation carries the load of 2 coal customers totaling about 10 to 15 MW.

The per unit voltages stated in Exhibit 12 of the filing are at the 69kV bus.

The power factors supplied in DR-15 are at the 12kV bus.

In DR-17, a C equates to a conductor thermal limit and an R equates to a riser thermal limit.

KPC has talked to all parties impacted by the construction of the line and no EMF concerns were raised.

PJM operationally controls and performs design studies on the 100kV and above transmission system.

Economic analysis is done in the Planning Department. Only a first cost analysis was done for this project. (no NPV analysis was performed)

Alternatives to the Project

The most promising economic alternative to the project that resolved both 69kV and N-1-1 issues was the establishment of a second 161kV tie to KU at Hyden via the Wooton Substation. However; KU would not allow ties to be established to their system with breakers. In this manner, additional facilities will not be required on their system to serve load as the tie flow is eliminated with the contingency of the line feeding the tie. KPC stated that under this requirement, both 161kV ties to Hyden would be lost and the N-1-1 contingency overloads would remain as they exist today.

None of the three alternatives considered had estimates developed as no alternative either solved all the issues or was on the face less expensive to the proposed project.

Follow-Up Data Requests

Temperatures used in load forecasts – KPC was to supply S & W normal and S & W extreme daily average and peak hour temperatures. (DR-F1)

Explain why the cost of the Softshell Substation work increased while the cost of the Bonnyman Substation remained flat from the initial 2009/2010 estimate to the current estimate. (DR-F2)

Generation at Pineville - KPC found that there is no generation at Pineville. (DR-F3)

ATTENDEES:

Petitioner

Ranie Wohnhas, Managing Director-Regulatory & Finance - Kentucky Power Company
George Reese, Senior Environmental manager – GAI Consultants, Inc. (for Kentucky Power Company)
Mark R. Overstreet, Outside Counsel – Sties & Harbison (for Kentucky Power Company)
Lila Munsey, Manager Regulatory Services – Kentucky power Company
Mike Lasslo, Customer & Distribution manager – Kentucky Power Company
David Wright, AEP Project Manager – American Electric Power Company
Ali Kamran, Manager-Transmission planning - American Electric Power Company
Randy Holliday, Staff Economist - American Electric Power Company
Ned Merrifield, Supervisor-Transmission Right-of-Way - American Electric Power Company
Tim Earhart, Supervisor-Transmission Line Engineering - American Electric Power Company
Joe Meisner, Engineer - American Electric Power Company
Michael Russ, Engineer - American Electric Power Company
Vickie Stone, Senior Right-of-Way Agent - American Electric Power Company

Regulatory

John Rogness, Director of Financial Analysis – Kentucky Public Service Commission
Kimra Cole, Director of Engineering - Kentucky Public Service Commission
Daryl Newby, Manager Gas & Electric Rate Design - Kentucky Public Service Commission
Jeff Johnson, Engineer - Kentucky Public Service Commission
Mike Cannata, Senior Consultant -- Accion Group (for the Kentucky Public Service Commission)

AEP
KENTUCKY POWER
A unit of American Electric Power

Kentucky Power
101A Enterprise Drive
P O Box 5190
Frankfort, KY 40602-5190
KentuckyPower.com

RECEIVED
OCT 17 2011
FINANCIAL ANA

October 14, 2011

RECEIVED
OCT 17 2011
PUBLIC SERVICE
COMMISSION

Mr. Michael D. Cannata, Jr.
65A Ridge Road
Deerfield, NH 03037

RE: Kentucky Power Company's Responses to the Accion Group Follow-Up Questions During the October 12, 2011 Meeting for the Construction of the Bonnyman to Soft Shell 138kV Transmission Line in KPSC Case No. 2011-00295

Dear Mr. Cannata:

We received your Follow-Up Questions dated October 14, 2011, concerning the subject case and have prepared the enclosed responses to those inquiries. The responses are being sent by email.

Should you have any questions on this subject, please feel free to contact me at 502-696-7010.

Sincerely,

Lila P. Munsey

Lila P. Munsey
Manager, Regulatory Services

cc: Harold T. Judd, President Accion Group, Inc.
George T. Reese, GAI Consultants

Kentucky Power Company

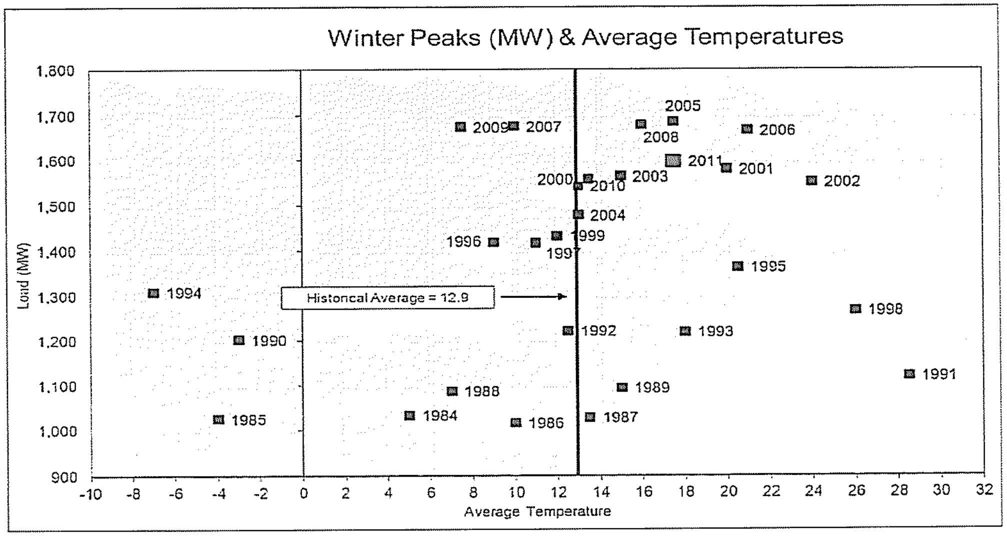
REQUEST

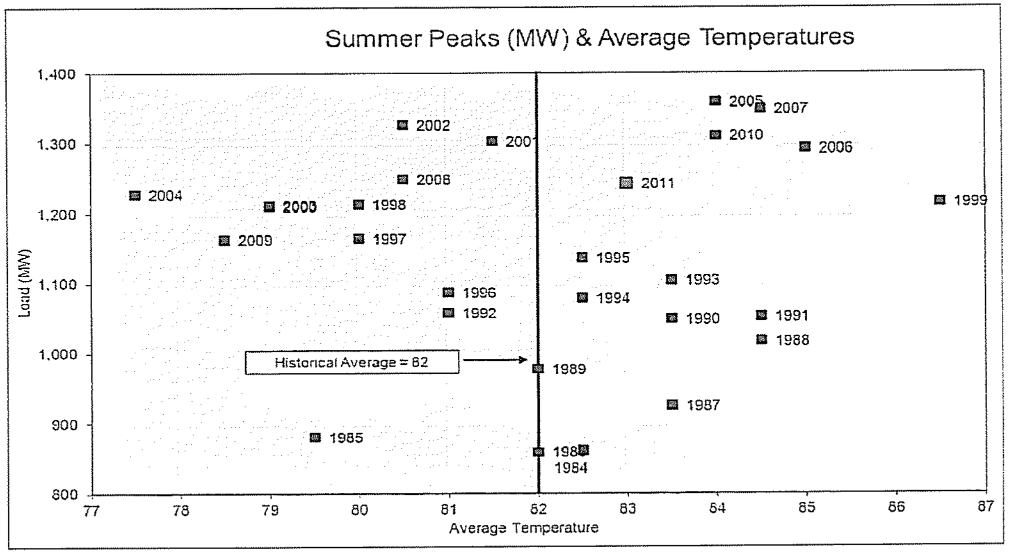
For the load forecasts that were supplied as the response to Initial Data Request #11, please supply the summer and winter normal and the summer and winter extreme peak daily average and peak hour design temperatures.

RESPONSE

Please refer to page 2 of the response. The "Forecast" section is summer and winter normal daily average peak hour temperatures used in our forecasts. The next section illustrates a historical 28 year average of summer and winter normal daily average peak hour temperatures. The last section illustrates the historical 28 extreme summer and winter daily average peak hour temperatures which were also used in our forecast.

		Winter	Summer
Forecast			
	Peak Day	2/15/2012	7/18/2012
	Average Temperature	15.0	81.0
	Min	1.9	69.0
	Max	28.1	93.0
Typical Peak Temperatures Over the Last 28 Years			
	Average Temperature	12.9	82.0
	Min	2.4	70.8
	Max	23.4	93.3
Record Extreme Peak Day Temperatures Over the Last 28 Years			
	Peak Day	1/19/1994	7/30/1999
	Average Temperature	-7.0	86.5
	Min	-21.0	72.0
	Max	7.0	101.0





Kentucky Power Company

REQUEST

Reference the detailed preliminary and final project estimates in Exhibit #12, and on page 13. Please explain why the final estimate for the Soft Shell Substation construction cost increased approximately 45% from the preliminary to final estimate while the Bonnyman substation construction cost increased a negligible amount from the preliminary estimate to the final estimate.

RESPONSE

The preliminary estimate for the Soft Shell Substation was a conceptual estimate (high level, non-detailed). The preliminary estimate for the Bonnyman Substation was a full scope estimate including an on-site visit to the substation. The planning team determined early in the process that due to the amount of work necessary at the station a full scope estimate would be more prudent. The estimates shown for September 2011 are both full scope estimates. As is not uncommon when full scope estimates are performed following conceptual estimates there were substantial differences (increases) between the conceptual and full scope estimates for the Soft Shell Station as a result of more precise calculations of the material, labor and overheads required. Conversely, the changes between the two full scope estimates for the Bonnyman Station were not material.

Kentucky Power Company

REQUEST

Please supply the size of the generators that exist at the Pineville generating station in the TVA system.

RESPONSE

After further review, Kentucky Power confirmed there is no TVA or other generating station in the Pineville area.

The Accion Group

For the Kentucky Public Service Commission

Focused Need Analysis

Of the

Application of Kentucky Power Company

For the Construction of the Bonnyman to Soft Shell 138kV Transmission Line

Case No. 2011-00295

Initial Data Requests*

October 2, 2011

1. Please supply a transmission map of the Kentucky Power (KP) and surrounding power systems that depicts transmission system and generation system facilities by voltage level.
2. Please supply a transmission map of the KP power sub-transmission power system that depicts sub-transmission system and generation system facilities by voltage level.
3. Please supply one-line system diagrams for the KP transmission and sub-transmission power systems. These diagrams should show substation breaker configurations.
4. Please supply a transmission map of the Reliability First Corp. and the SERC Reliability Corp. systems.
5. Please supply one-line breaker diagrams for the Bonnyman and Soft shell substations and any substations involved in the limiting contingency or contingencies.
6. Please supply a short description of the power analysis software used by KP in the study for the need for the proposed facilities. (I.e. power flow, transient stability, short circuit, and others as appropriate)
7. Please supply a copy of the KP voltage, thermal, stability, load power factor, and short circuit reliability design criterion that are applicable to the proposed facilities.
8. Please supply a copy of the PJM transmission reliability criterion.
9. Please supply a copy of the 10-year KP summer and winter coincident peak load projections used for the analysis of the need of the proposed facilities for the system as a whole and for subareas. As part of your response, please supply the date they were prepared. In addition, if there are newer vintage load forecasts, please supply them also.
10. Please supply a succinct description of the KP load forecasting methodology including inputs, econometric data requirements, load ratioing, and weather normalization.
11. Please supply the input parameters for the ratings programs used to rate KP transmission and sub-transmission line and substation components.
12. Please supply a copy of the final report justifying the proposed facilities if different from filing Exhibit 12.
13. If the limiting condition is voltage driven, please supply the transmission to sub-transmission transformer no load tap settings, no load tap capabilities, hold voltages, and tap changer ranges. Please also supply the same information for the sub-transmission/lower voltage transformers.

14. If the limiting condition is voltage driven, please supply the generator minimum VAR capability, maximum VAR capacity, MW size, hold voltages, and power factor for generators within the Hazard load area or within 25 miles of the Soft Shell and Hazard 138kV substations that are on the 138kV or lower voltage power system. As part of your response, please locate these facilities on a geographical transmission and sub-transmission map
15. If the limiting condition is voltage driven, please supply the location and size of capacitors on the 138kV and sub-transmission system. In addition, please also supply the load power factor at the low side of the sub-transmission to lower voltage transformers in the Hazard load area.
16. Please supply the estimated cost of installing distribution voltage rated capacitors on a $/KVAR basis.
17. If the limiting condition is thermally driven, please supply the component by component ratings of the limiting system line element(s). If a transformer is part of the limit, please supply the transformer nameplate ratings, overload ratings, and the transformer rating calculations.
18. If the limiting condition is thermally driven and a line, please supply the line conductor size, temperature to which the line was designed to operate, tension, and design clearances.
19. Please supply a description on how KP conducts economic evaluations between competing alternative projects. (Not alternative routes of the proposed line, but other transmission alternatives, generation alternatives, rebuild with composite conductors, etc.)
20. Please supply a list of alternative projects to the Bonnyman to Soft Shell 138kV line evaluated by KP and a copy of the economic evaluations.
21. Please supply a short description on how KP selects the final route of the proposed line versus alternative routes for the same facilities if different than Reese testimony, page 11.
22. Reference, Filing, page 5. Please identify the 4 property owners to date, by parcel referenced in Exhibit 9, that have expressed objections to the preferred alternate. Your response should also include a short description of each owner objection.
23. Reference Filing, Section 18, and page 8. Please supply the benefits and costs of the three alternatives stated compared to the preferred Bonnyman to Soft Shell 138kV alternative.
24. Reference Filing, Section 18, and page 8. Was a second Hyden to Wooten 161kV line considered as an alternative? If not, why not?
25. Reference Filing, Section 18, and page 8. Please describe any and all alternatives considered to defer the preferred project where the carrying cost of the deferral project(s) are less than the first year carrying costs of the preferred project.
26. Accion understands that the $62.5 million cost of the proposed project is in 2009 dollars. Please confirm or identify the year dollars the estimate is stated in. As part of your response, please also supply the impact of rising commodity prices on the projected cost of the project since the estimate was made.
27. Please supply the cost of the project in 2014 completion date dollars for the project segments as listed in Exhibit 12, page 13. Please identify the IDC portion of the estimate in each project segment as part of your response.
28. Reference Lasslo testimony, page 4, lines 11-19. Is the first contingency event described a design issue or a vegetation management issue. Please explain.
29. Reference Lasslo testimony, page 4, and line 24 through page 5, line12. The second event described here was a single contingency. If KY performs system adequacy analysis annually, as stated at the bottom of page 12 of the Lasslo testimony, and the system is designed to withstand the first contingency, please explain why customer load was required to be curtailed.
30. Reference Lasslo testimony, page 5, lines 7-13. Please supply the analysis performed to evaluate the factors generally listed here and specifically listed in Exhibit 13, Table 4 for each of the alternatives. As part of your

response, please indicate what weights were given to the factors (and their subsets) as described in the Kentucky Transmission Line Siting Model, Project Report dated July 31, 2006.

31. Reference Lasslo testimony, page 5, lines 19-22. Please explain the status of the NERC requirement regarding transmission design down to the 100kV level. In your response, please indicate the ability to obtain waivers to said design and the KY effort to attain such waivers.
32. Reference Reese testimony, page 9, and lines 17-26. Please explain how the two tier corridor selection process described relates to the process described in the Kentucky Transmission Line Siting Model, Project Report dated July 231, 2006.
33. Reference Exhibits 4, 5, and 6. Please supply edge of right-of-way EMF levels (magnetic and electric) for each of the three configurations.
34. Reference Exhibit 8. Please supply before and after one line breaker diagrams of the Bonnyman substation.
35. Reference Exhibit 12, page1. Why wasn't a looped alternative considered where the terminus of the new line would be the Hazard 138kV substation instead of the preferred radial alternative terminating at Bonnyman substation?
36. Reference Exhibit 12, page 3. In what year do KY system studies show that the completion of the 138kV loop from Bonnyman to Hazard substation is required to meet reliability criterion?
37. Reference Exhibit 12, page 6. Please relate the significance of closing the Lee City tie to the system diagram on Exhibit 12, page 2.

*Accion understands that some of these data requests may be voluminous. It is acceptable to supply or have a limited number of the responses available for inspection at the time of the interviews.

The Accion Group

For the Kentucky Public Service Commission

Focused Need Analysis

Of the

Application of Kentucky Power Company

For the Construction of the Bonnyman to Soft Shell 138kV Transmission Line

Case No. 2011-00295

Interview Requests for October 12, 2011 Interviews*

October 2, 2011

Please make the following subject matter experts available on October 12, 2011.

- T and Sub-T system design analysis including that required by PJM and the FERC.
- T, Sub-T & D system analysis models and study modeling.
- T, Sub-T & D system configurations.
- Siting and route selection.
- Load forecasting and modeling performed.
- T and Sub-T Component ratings and rating programs.
- Economic analysis of alternatives of different lives and net present value.
- Others as deemed necessary by KU.

*Not all experts will be required for the entire day. Accion will work with KU on October 12, 2011 to minimize KU time to the extent practical.

Kentucky Power Company

REQUEST

Reference Exhibits 4, 5, and 6. Please supply edge of right-of-way EMF levels (magnetic and electric) for each of the three configurations.

RESPONSE

EMF effects are computed at the ROW edges (50 feet in each direction from centerline) for three configurations planned in the project (shown as Exhibits 4, 5, and 6 of the Application). The double-circuit design is a typical lattice structure that will support segments of the new 138 kV line and the existing Shamrock-Bulan 69 kV line for approximately one mile of the 20 mile line. The 138 kV single-circuit designs -- an H-frame structure and a three-pole structure -- will be used in the remaining parts of the project. Note that the three-pole structure has horizontal insulator posts, resulting in asymmetrical placement of phase conductors with respect to the right-of-way (ROW) edges of the line.

Normal maximum loading levels, representing peak load conditions, are assumed in the analysis to maximize the calculated EMF effects. No trees, shrubs, buildings or other objects that can block EMF are assumed in proximity to the proposed lines. Nominal voltages and balanced conditions are assumed, with currents flowing in the directions expected during normal system operation. Since the aforesaid 138 kV and 69 kV lines normally will carry power in the same direction, a phase configuration known as "low reactance" (A-B-C/C-B-A, top-to-bottom) is planned for the double-circuit segment, resulting in lower EMF. All calculations are obtained at the height of 3.28 feet (one meter) above ground using the Electric Power Research Institute (EPRI) EMF Workstation "Enviro" computer program. The results are summarized in the table, below.

Line Design and Loading Data and EMF Calculations

Line	Phase Conductor	Ground Clear. (Feet)	Line Load (A)	Electric Field (kV/m)*	Magnetic Field (mG)*
MODEL 1**					
Bonnyman-Soft Shell 138 kV	1590 kCM ACSS (Falcon)	30	96	0.2/ - - -	2.4/ - - -
Shamrock-Bulan 69 kV	336 kCM ACSR (Oriole)	30	155	- - - /0.1	- - - /6.1
MODEL 2 ***					
Bonnyman-Soft Shell 138 kV	1590 kCM ACSS (Falcon)	30	96	0.8/0.8	7.0/7.3
MODEL 3 ****					
Bonnyman-Soft Shell 138 kV	1590 kCM ACSS (Falcon)	30	96	0.5/0.8	4.6/6.6
IEEE Std C95.6-2002 Limits*****				5.0/5.0	9040/9040

* EMF levels (left ROW edge/right ROW edge) calculated one meter above ground at the point of minimum ground clearance, assuming nominal voltages and balanced phase voltages and currents. ROW width is 100 feet.

** Two circuits sharing common towers (double-circuit design) modeled together using "low reactance" phase configuration. Application Exhibit 6.

*** H-frame structure (single-circuit design). Application Exhibit 4.

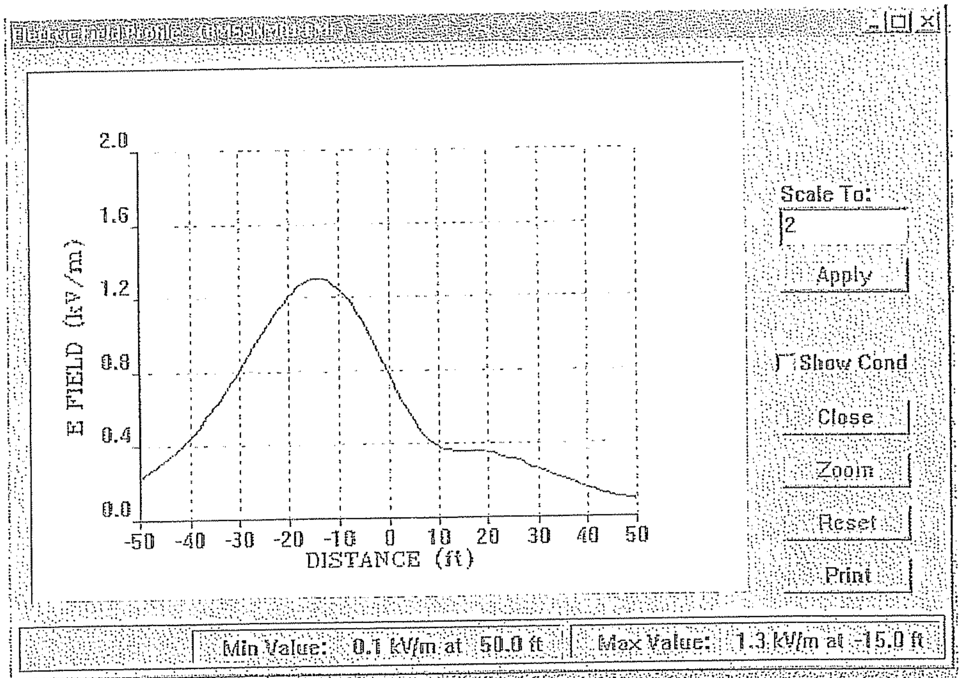
**** Three-pole structure (single-circuit design). Application Exhibit 5.

***** The limits specified in IEEE Standard C95.6^{TM}-2002.

Our results show that electric and magnetic fields associated with the Bonnyman-Soft Shell 138 kV line (and the Shamrock-Bulan 69 kV line strung on common structures) decline rapidly with distance from the line, and will be well within the limits specified in IEEE Standard C95.6^{TM}-2002. The IEEE EMF limits, an industry benchmark, have been established to "prevent harmful effects in human beings exposed to electromagnetic fields in the frequency range of 0-3 kHz."

Bonnyman-Soft Shell 138 kV and Shamrock-Bulan 69 kV*
Combined EMF Profile

Normal Maximum Loading



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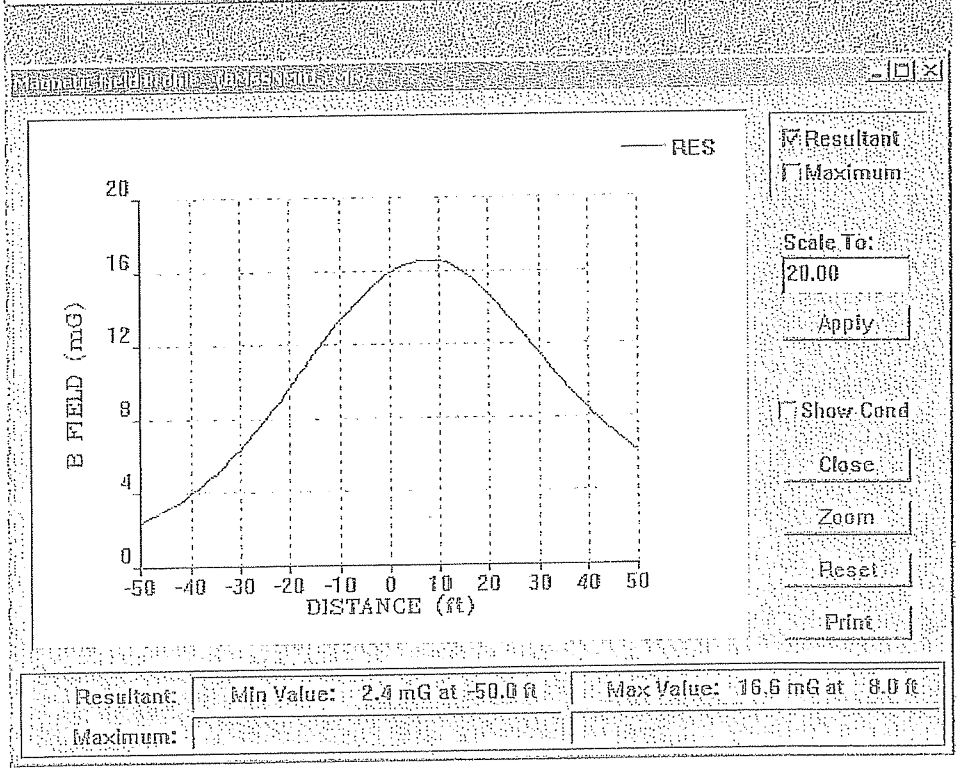
Min Value: 0.1 kV/m at 50.0 ft

Max Value: 1.3 kV/m at -15.0 ft



Scale To: 20.00

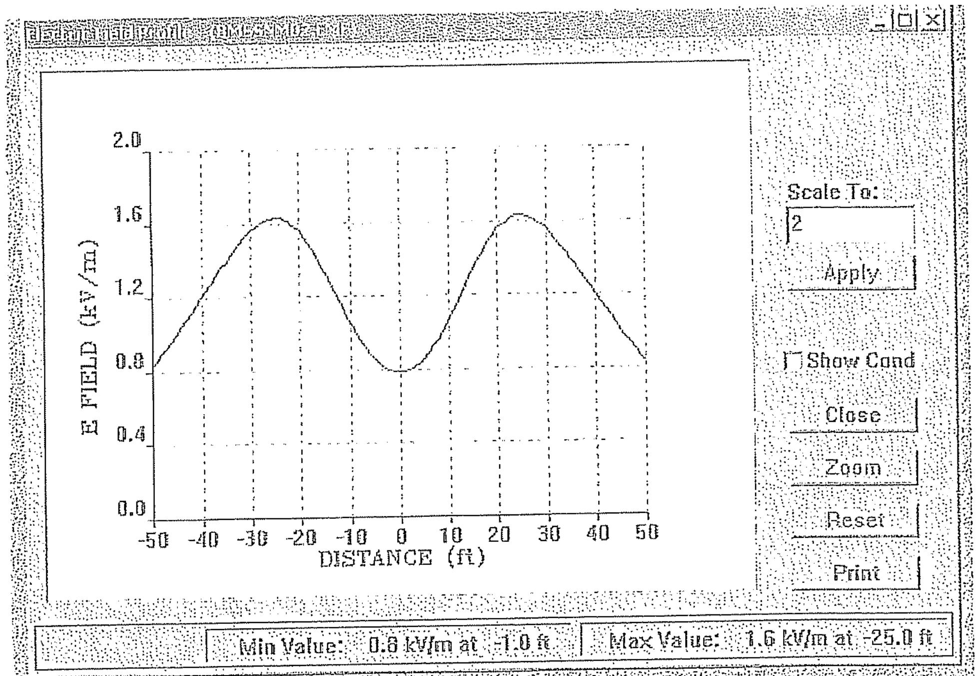
Resultant: Min Value: 2.4 mG at -50.0 ft | Max Value: 16.6 mG at 8.0 ft

Maximum:

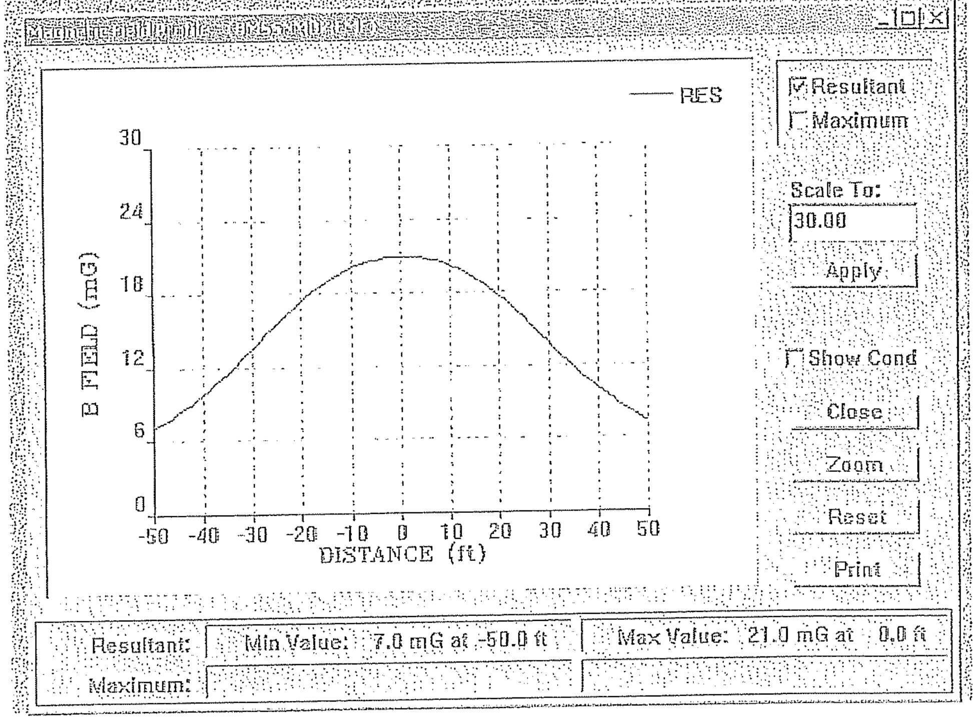
*Double-Circuit "Low Reactance" Phase Configuration

Bonnyman-Soft Shell 138 kV EMF Profile*

Normal Maximum Loading



Min Value: 0.8 kV/m at -1.0 ft
Max Value: 1.6 kV/m at -25.0 ft

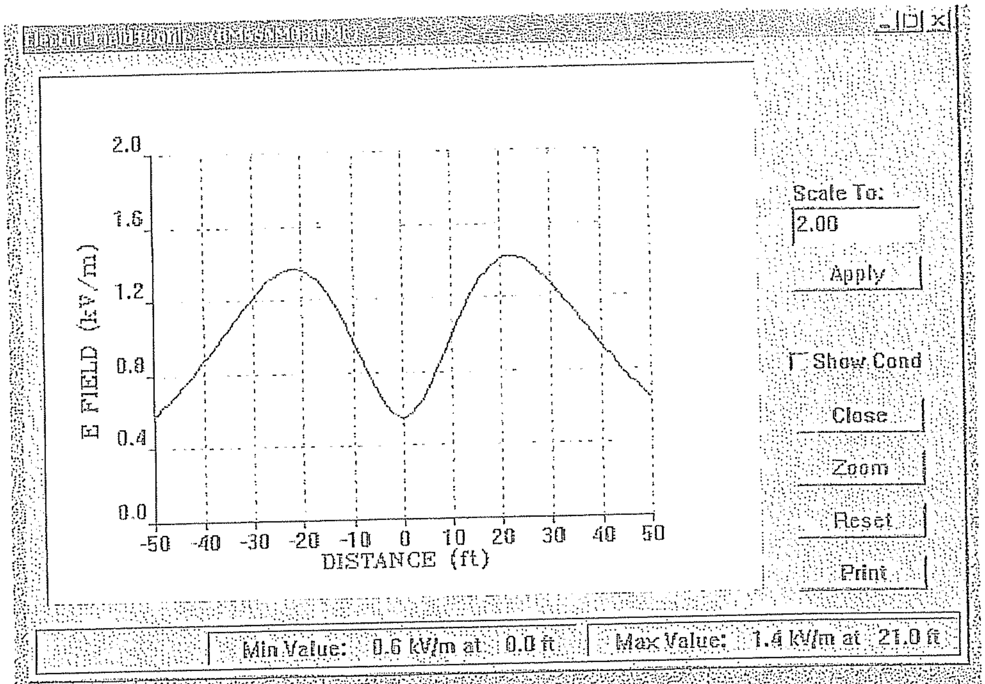


Resultant: Min Value: 7.0 mG at -50.0 ft
Max Value: 21.0 mG at 0.0 ft
Maximum:

*Single-Circuit H-Frame Structure.

Bonnyman-Soft Shell 138 kV EMF Profile*

Normal Maximum Loading



Scale To: 2.00

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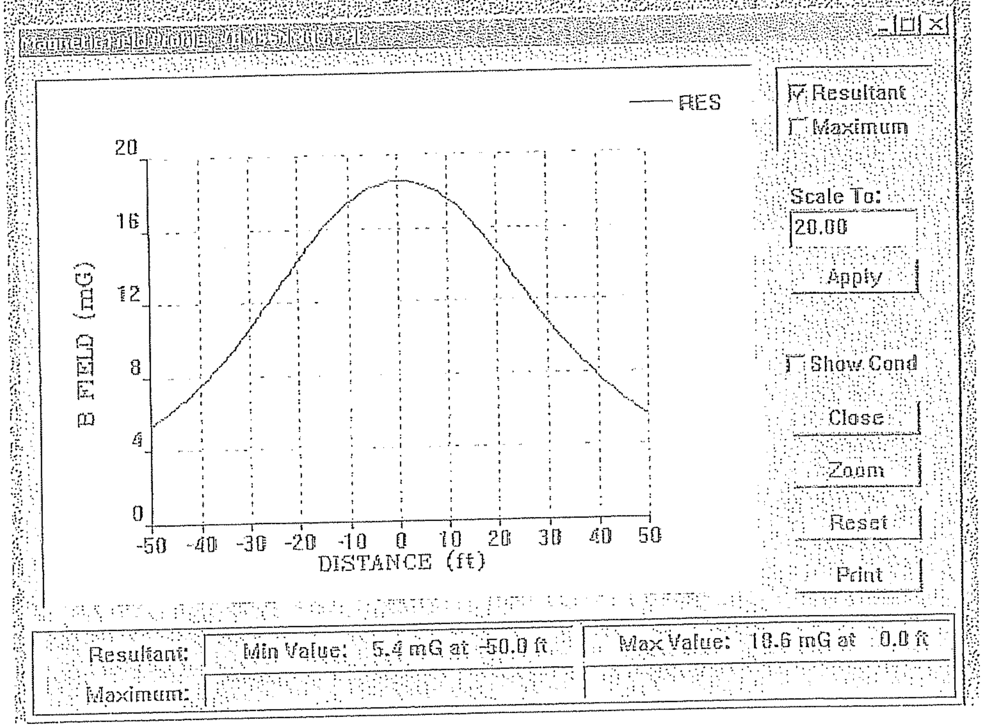
Min Value: 0.6 kV/m at 0.0 ft

Max Value: 1.4 kV/m at 21.0 ft



☑ Resultant
☐ Maximum

Scale To: 20.00

☐ Show Cond

Resultant: Min Value: 5.4 mG at -50.0 ft Max Value: 18.6 mG at 0.0 ft

Maximum:

*Single-Circuit Three-Pole Structure.

CASE NO: 2011-00295

CONTAINS

LARGE OR OVERSIZED

MAP(S)

FILED INTO THE RECORD
ON: 11/07/2011

AEP KENTUCKY POWER®
A unit of American Electric Power

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101A Enterprise Drive
Frankfort KY, 40601
(502) 696-7010
lpmunsey@aep com

Mr. Michael D. Cannata, Jr.
65A Ridge Road
Deerfield, NH 03037

October 7, 2011

RE: Kentucky Power Company's Responses to the Staff Consultant's First Set of Questions for the Construction of the Bonnyman to Soft Shell 138kV Transmission Line in KPSC Case No. 2011-00295

Dear Mr. Cannata:

We received your Initial Data Requests dated October 2, 2011, concerning the subject case and have prepared the enclosed responses to those inquiries. The responses are being sent by overnight mail.

Should you have any questions on this subject, please feel free to contact me at 502-696-7010.

Sincerely,

Lila P. Munsey

Lila P. Munsey
Manager, Regulatory Services
Kentucky Power Company

RECEIVED
OCT 10 2011
FINANCIAL ANA

cc: Harold T. Judd, President Accion Group, Inc.
George T. Reese, GAI Consultants

Kentucky Power Company

REQUEST

Please supply a transmission map of the Kentucky Power (KP) and surrounding power systems that depicts transmission system and generation system facilities by voltage level.

RESPONSE

Two maps will be provided on Wednesday, October 12, 2011, at the face-to-face meeting with the consultant and the PSC Staff. The first map shows the Roanoke Region of the AEP transmission and subtransmission systems including Kentucky Power (KP) and neighboring systems. The second map shows the generation facilities connected to the transmission and subtransmission systems within the PJM footprint which includes KP.

Kentucky Power Company

REQUEST

Please supply a transmission map of the KP power sub-transmission power system that depicts sub-transmission system and generation system facilities by voltage level.

RESPONSE

Please refer to the maps included as part of the answer to Question No. 1.

Kentucky Power Company

REQUEST

Please supply one-line system diagrams for the KP transmission and sub-transmission power systems. These diagrams should show substation breaker configurations.

RESPONSE

A map will be provided on Wednesday, October 12, 2011, at the face-to-face meeting with the consultant and the PSC Staff, showing KP transmission and subtransmission systems one-line diagrams including circuit breaker configurations.

Kentucky Power Company

REQUEST

Please supply a transmission map of the Reliability First Corp. and the SERC Reliability Corp. systems.

RESPONSE

Two maps will be provided on Wednesday, October 12, 2011, at the face-to-face meeting with the consultant and the PSC Staff. The first map shows the Reliability*First* Corporation transmission system. The second map shows the SERC Reliability Corporation transmission system.

Kentucky Power Company

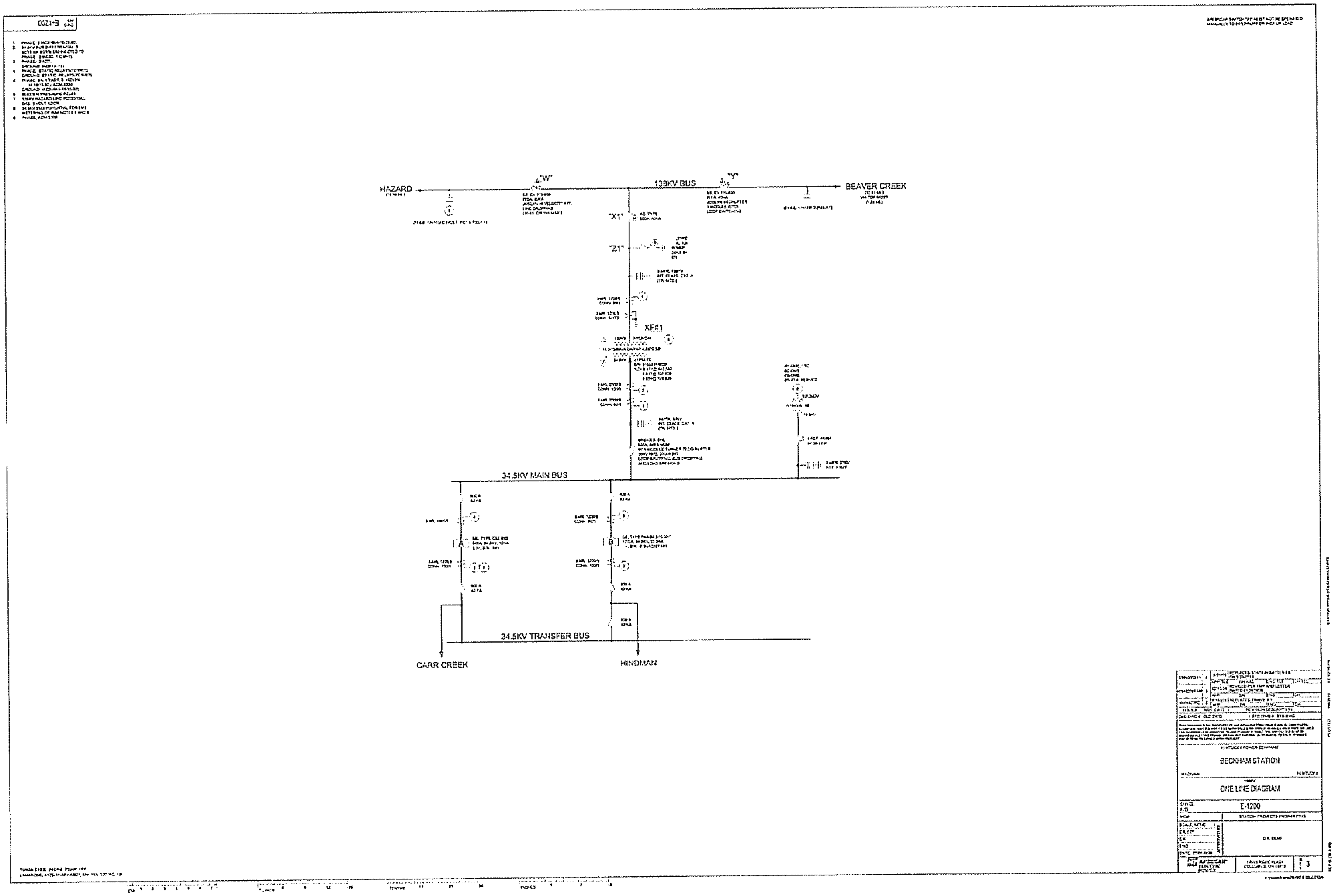
REQUEST

Please supply one-line breaker diagrams for the Bonnyman and Softshell substations and any substations involved in the limiting contingency or contingencies.

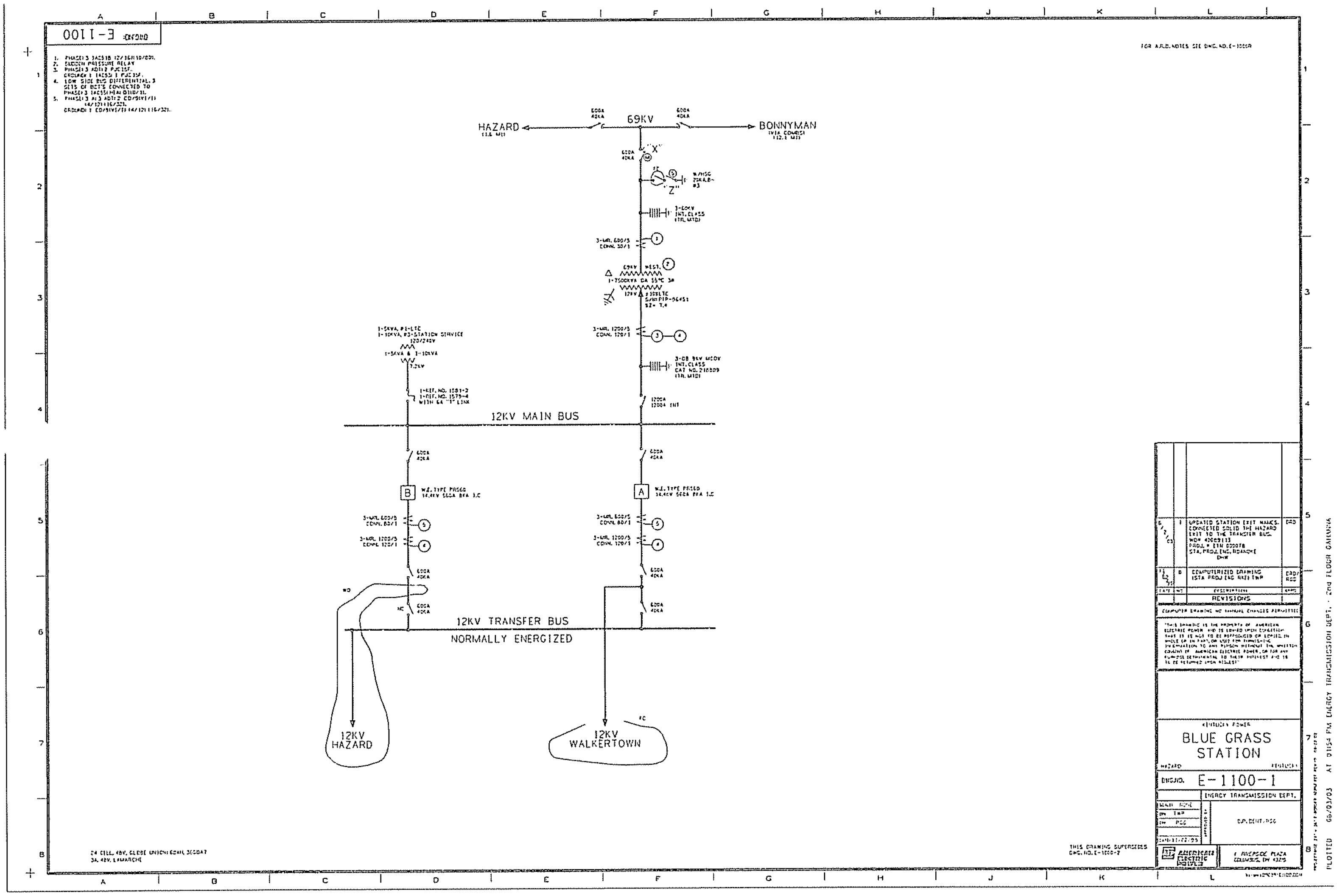
RESPONSE

The one-line diagrams of KP stations involved in the limiting contingency(ies) are attached below.

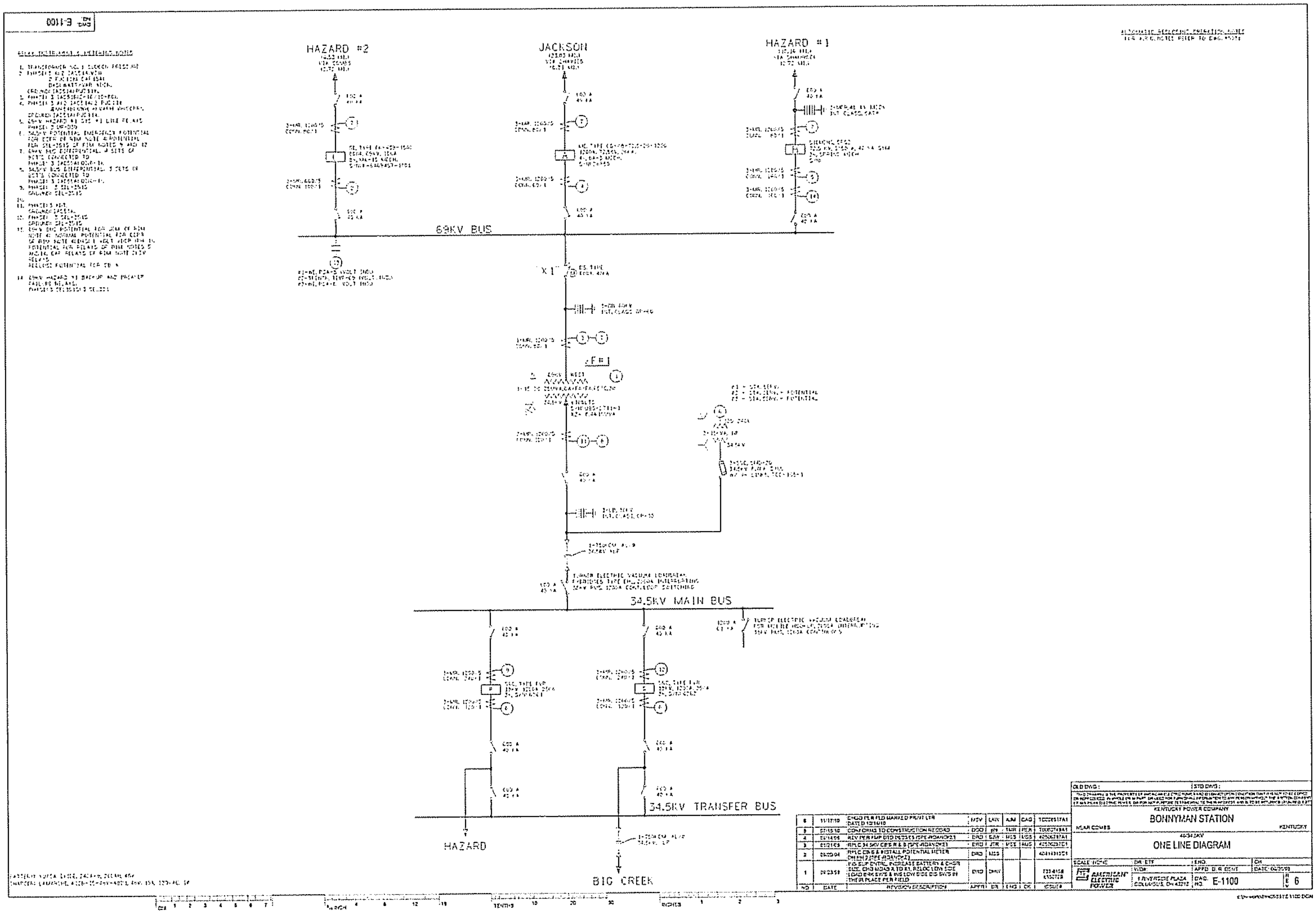
KPSC Case No. 2011-00295
1st Set of Questions of Accion Consultant
Dated October 2, 2011
Item No. 5
Attachment 1
Page 1 of 1



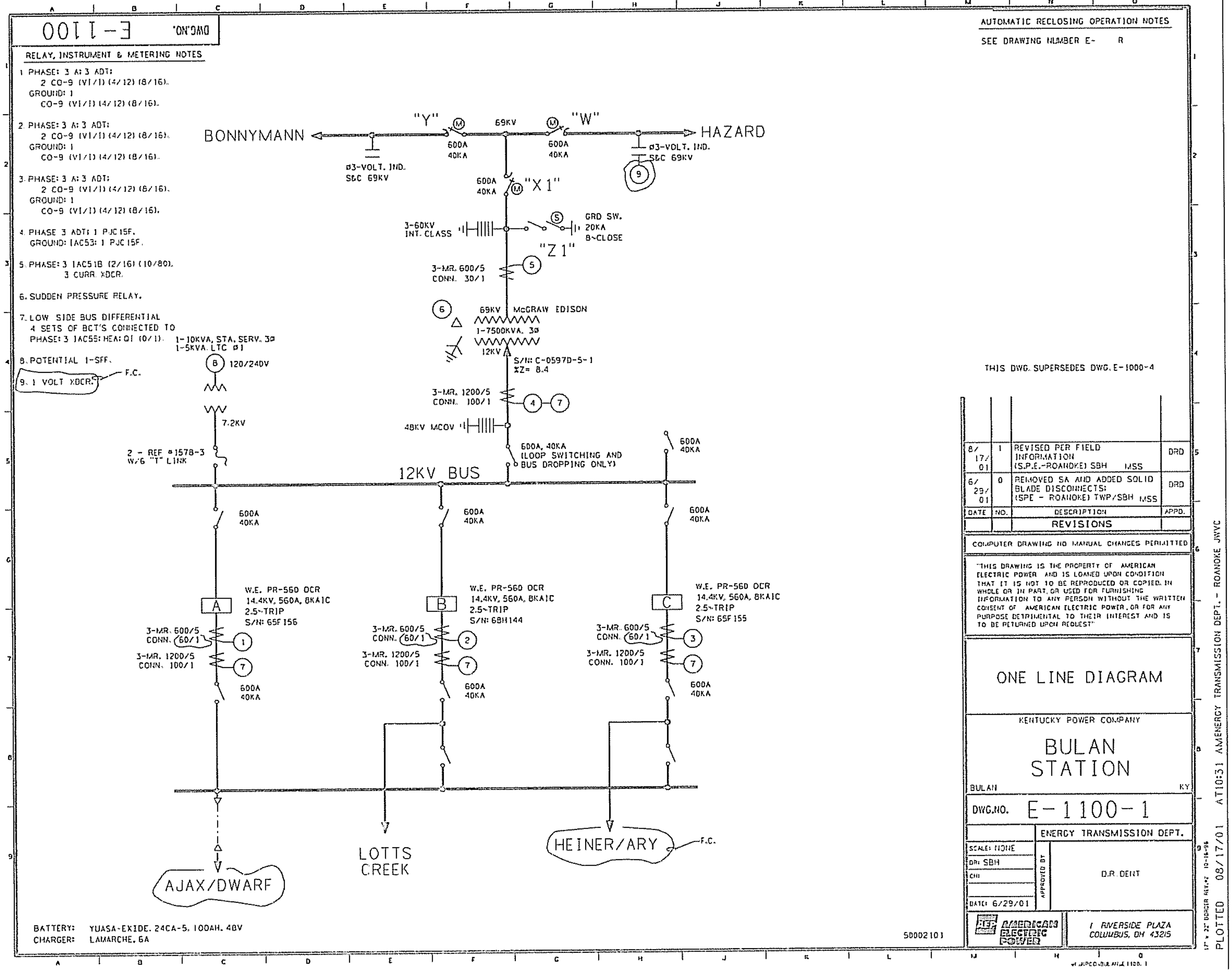
KPSC Case No. 2011-00295
1st Set of Questions of Accion Consultant
Dated October 2, 2011
Item No. 5
Attachment 2
Page 1 of 1



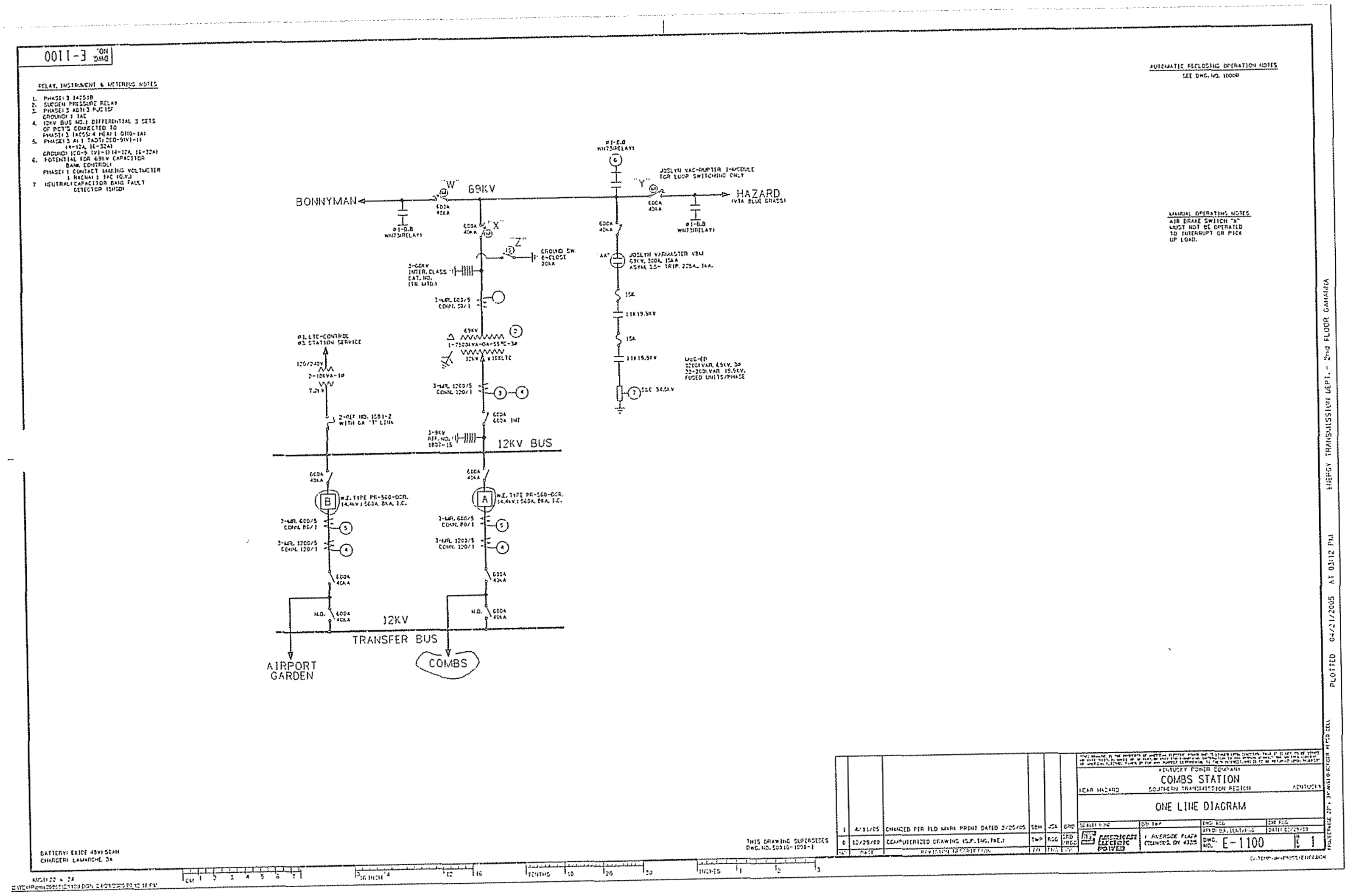
KPSC Case No. 2011-00295
1st Set of Questions of Accion Consultant
Dated October 2, 2011
Item No. 5
Attachment 3
Page 1 of 1



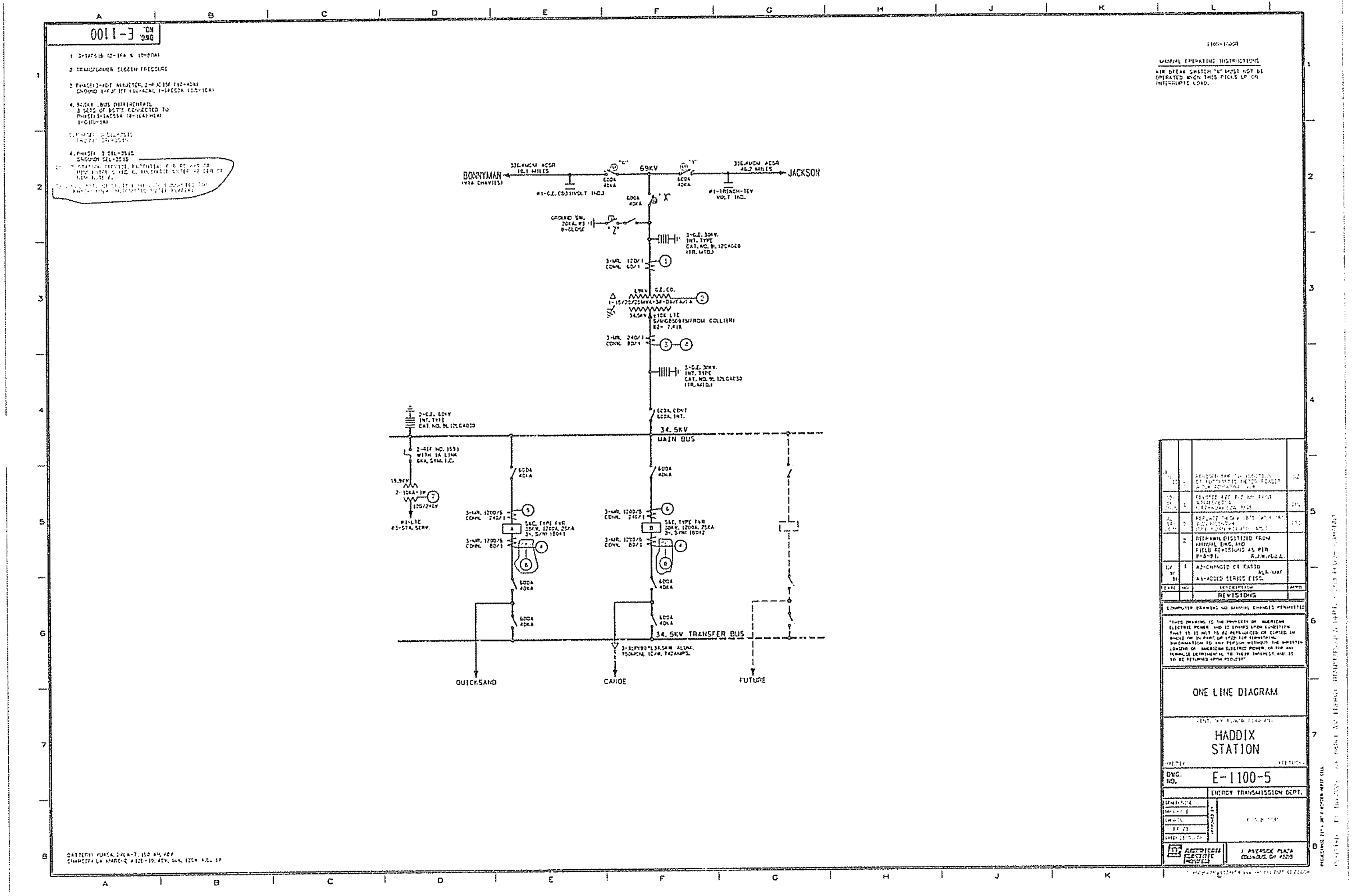
KPSC Case No. 2011-00295
1st Set of Questions of Accion Consultant
Dated October 2, 2011
Item No. 5
Attachment 4
Page 1 of 1



KPSC Case No. 2011-00295
1st Set of Questions of Accion Consultant
Dated October 2, 2011
Item No. 5
Attachment 5
Page 1 of 1



KPSC Case No. 2011-00295
1st Set of Questions of Accion Consultant
Dated October 2, 2011
Item No. 5
Attachment 6
Page 1 of 1



KPSC Case No. 2011-00295
1st Set of Questions of Accion Consultant
Dated October 2, 2011
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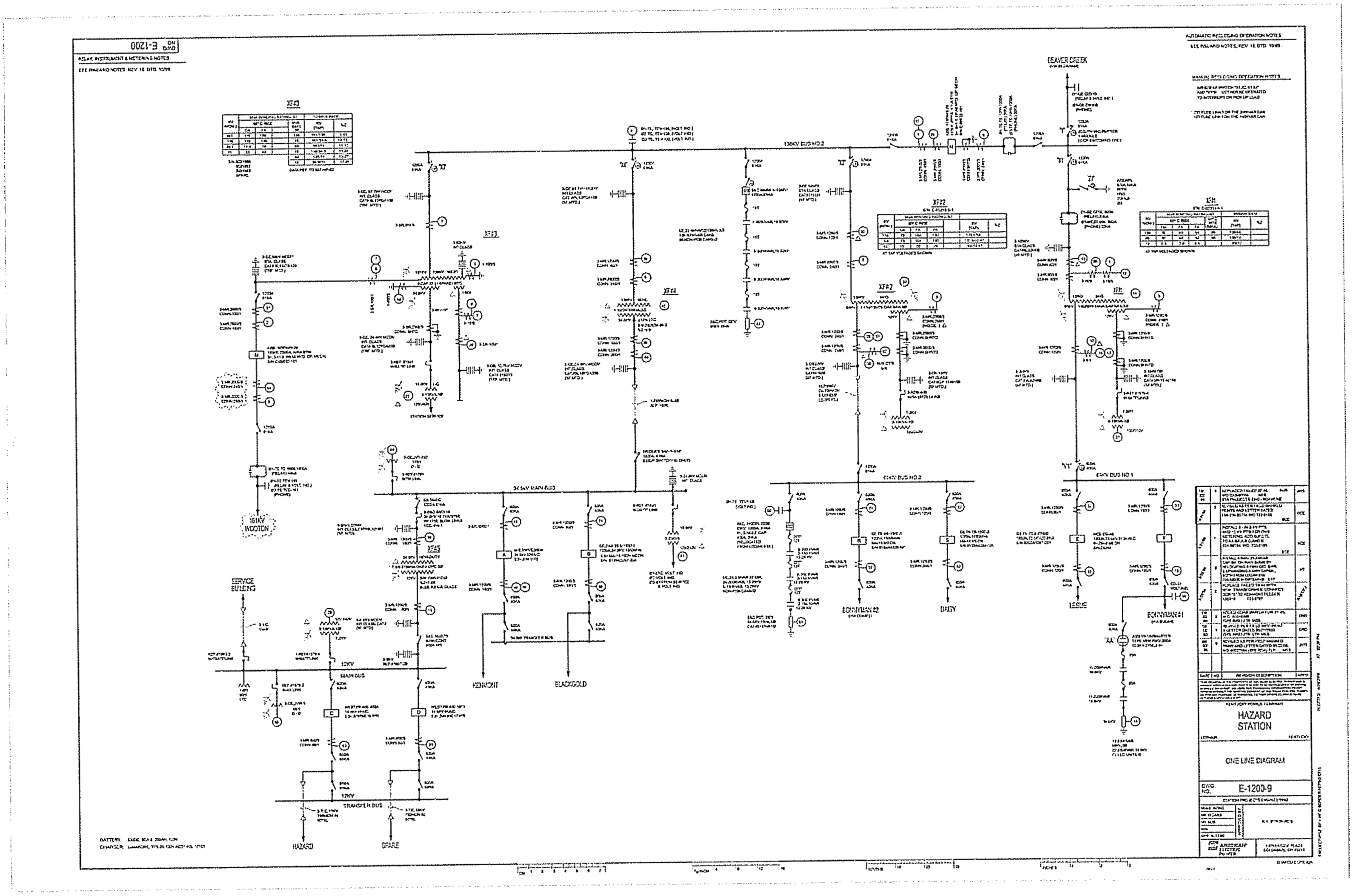

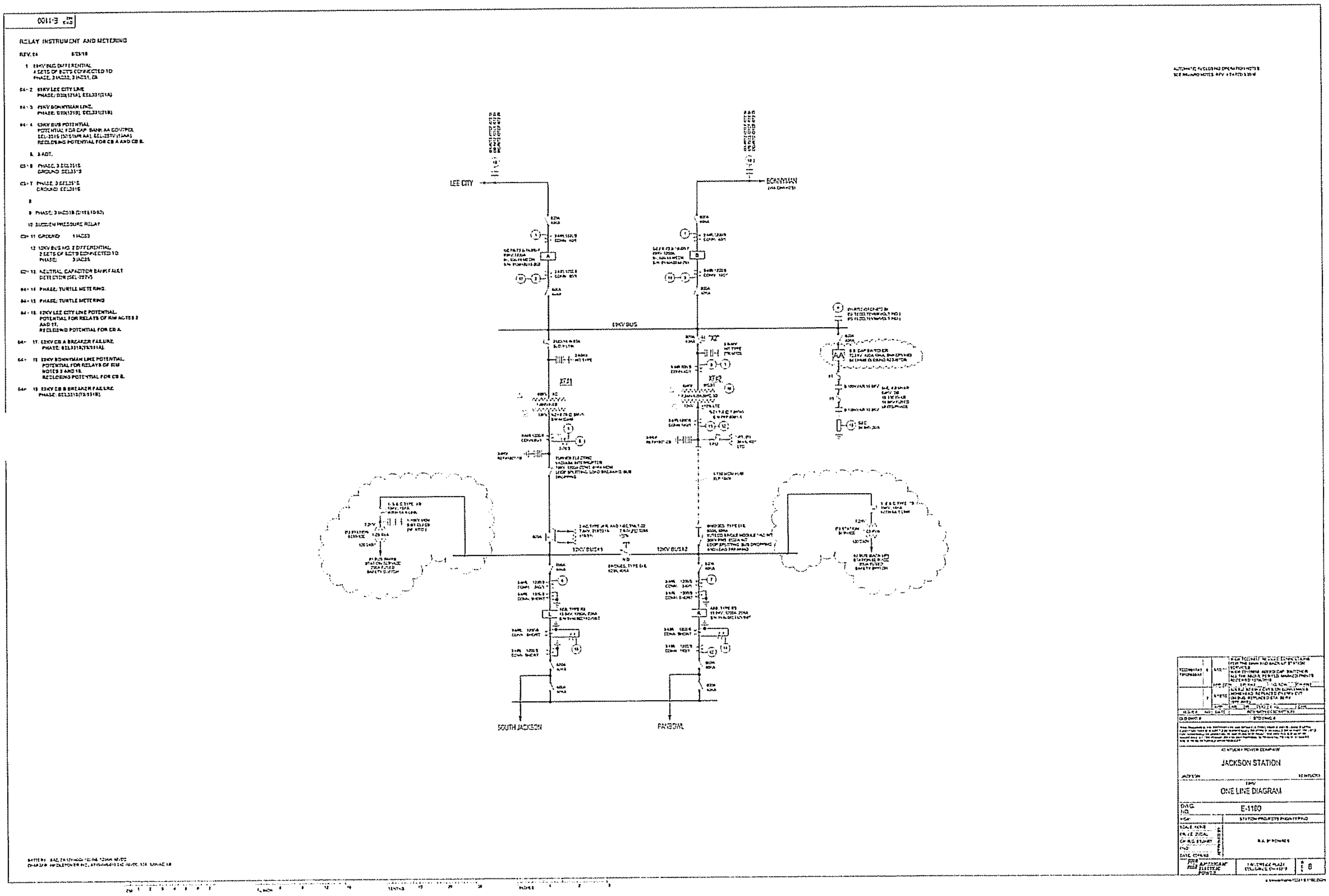
E-1100
RELAY INSTRUMENT AND METERING
LEE CITY
BONNYMAN
69KV BUS
A
B
XF#1
XF#2
AA
12KV BUS #1
12KV BUS #2
SOUTH JACKSON
PANBOWL
JACKSON STATION
ONE LINE DIAGRAM
DWG. NO.
E-1100
8

KPSC Case No. 2011-00295
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Dated October 2, 2011
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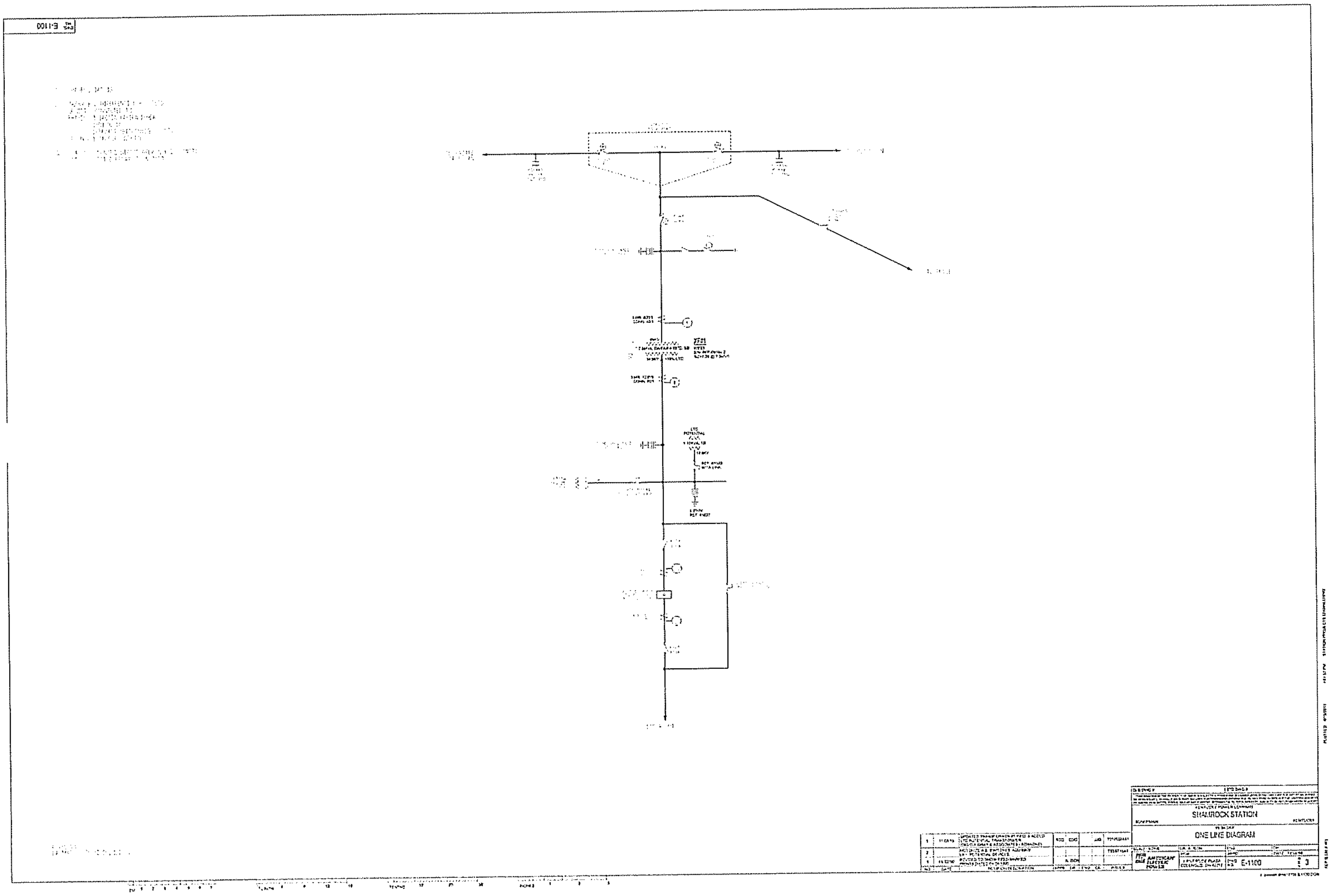

KPSC Case No. 2011-00295
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Item No. 5
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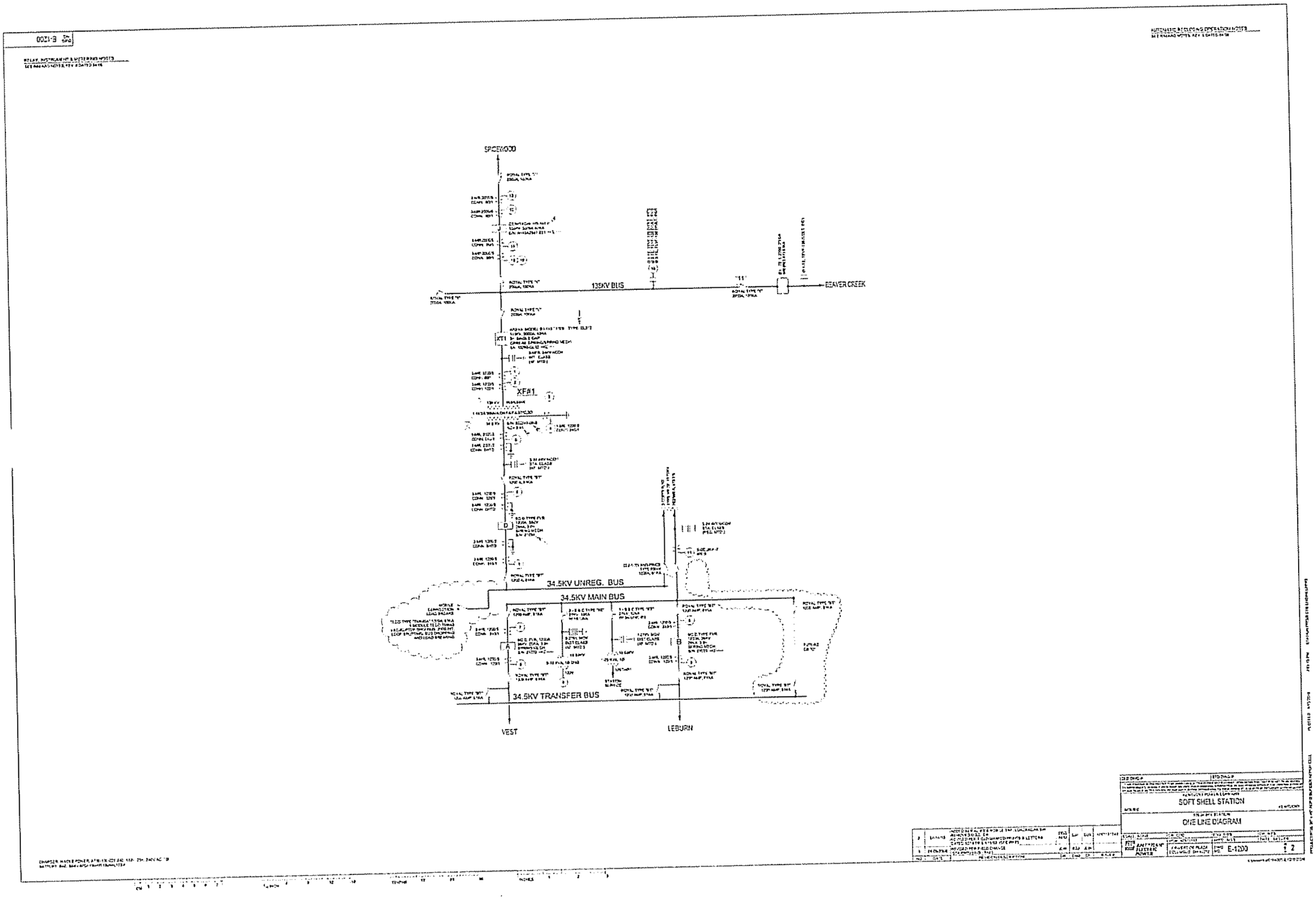

KPSC Case No. 2011-00295
1st Set of Questions of Accion Consultant
Dated October 2, 2011
Item No. 5
Attachment 11
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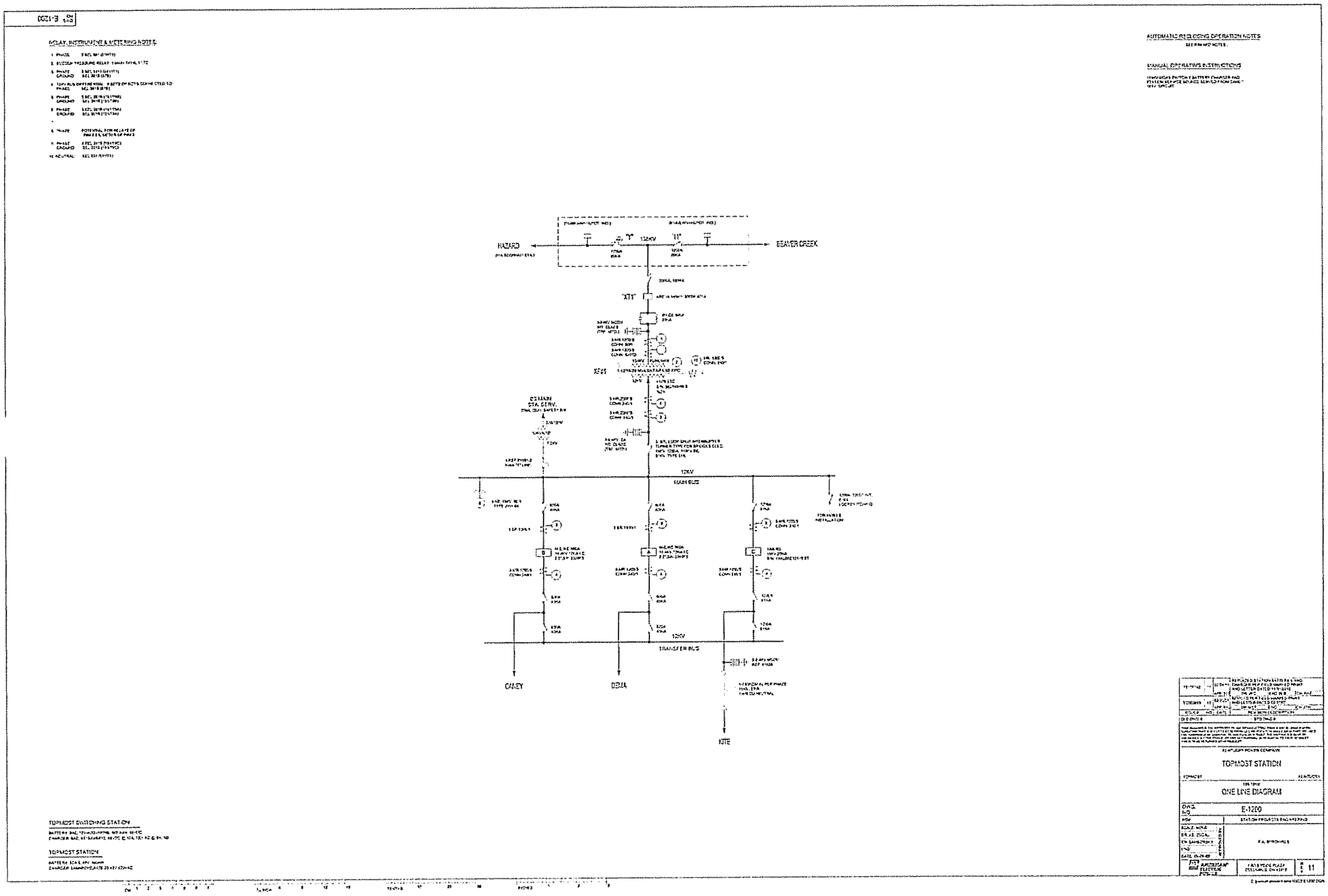

KPSC Case No. 2011-00295
1st Set of Questions of Accion Consultant
Dated October 2, 2011
Item No. 5
Attachment 12
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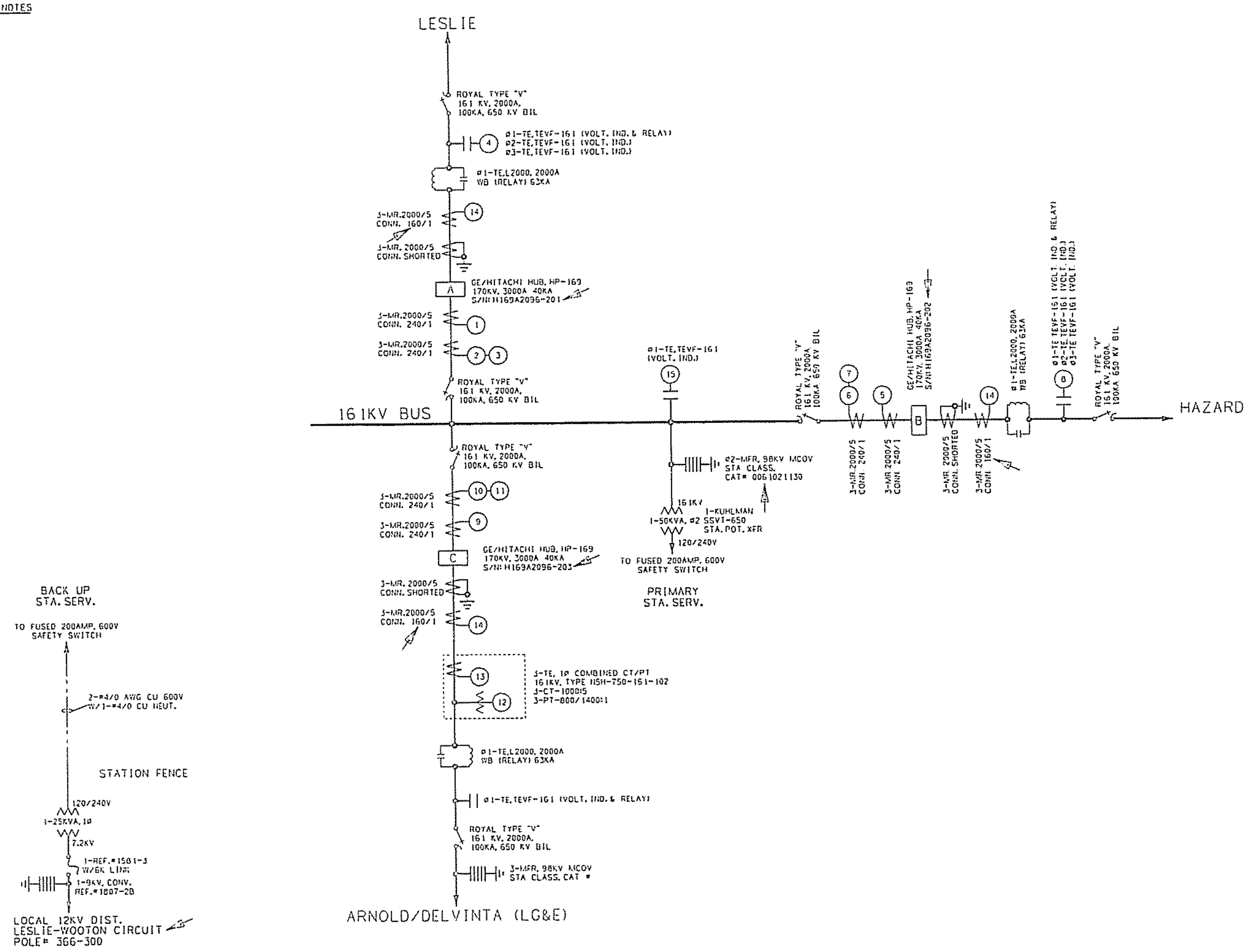
PLOTTED 08/12/11 AT 03:22 PM ENERGY TRANSMISSION DEPT. - 2nd FLOOR GAHANNA

DWG. NO. E-1200

RELAY, INSTRUMENT & METERING NOTES
SEE RIMARD NOTES, REV. 0

AUTOMATIC RECLOSING OPERATION NOTES
SEE RIMARD NOTES, REV. 0



CHARGER: YUASA-EXIDE, 3CA-9, 200AH, 125V
BATTERY: LAMARCHE, TPS-20-130V-ABD1, 130VDC, 20ADC, 120VAC, 1ø

ANSI: 22 x 34

NO.	DATE	REVISION DESCRIPTION	DR.	ENG.	CK.
1	5/24/2007	REVISED PER FIELD MARKED PRINT DATED (7/11/06) (STA PROJ ENG-RKE)	LTO	MSS	LTO

Standard Drawing No. 20LL001U sh. A | Revision: 0

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KENTUCKY POWER COMPANY
WOOTON STATION
LESLIE COUNTY KENTUCKY
161KV
ONE LINE DIAGRAM

SCALE: NONE | DR: | ENG: MJS/MSS | CH: MSS
AMERICAN ELECTRIC POWER | 1 RIVERSIDE PLAZA COLUMBUS, OH 43215 | APPD: D.R. CENT | DATE: 01/23/2006
DWG. NO. E-1200 | REV 1

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PROJECTWISE 22" x 34" ANSI D-BORDER AEPSD CELL

Kentucky Power Company

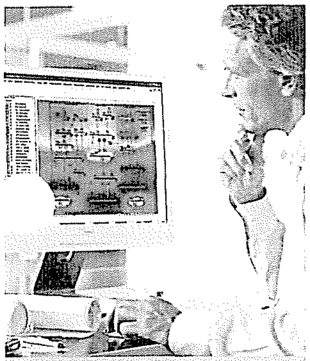
REQUEST

Please supply a short description of the power analysis software used by KP in the study for the need for the proposed facilities. (i.e. power flow, transient stability, short circuit, and others as appropriate)

RESPONSE

The PSSE power flow program was used to conduct system studies for this proposal. PSSE version 30 was used for this specific study. The PSSE program allows the planning engineer to model the Kentucky Power system including reactive devices (like capacitors, etc.) along with surrounding power systems to conduct power flow studies that analyze the performance of the system. This program enables assessment of the system performance under normal and contingency conditions. PSSE has the capability to output specific information such as bus voltages on a per unit basis, line loading as a percent of its rated value, transformer loading as a percent of its rated value, and the status of reactive sources. The planning engineer will analyze different critical contingencies for a given area and can run a report for a specified area to indicate any thermal or voltage problems.

See the attachment for further details on the PSSE software.



PSS®E

Power Flow

At a glance

The PSS®E Power Flow module is widely recognized as one of the most fully featured, time-tested and best performing commercial programs available for power systems analysis. Over 30 years of commercial use and user-suggested enhancements have made the PSS®E Power Flow base package comprehensively superior in analytical depth, modeling, and user convenience and flexibility. Rich graphical tools allow the user to easily edit models and present results.

Analysis

- User-switchable choice of five solution methods including Newton-Raphson (full, decoupled, fast decoupled), Gauss-Seidel, and modified Gauss-Seidel
- Inertial and governor power flow redistributes generation after major load or supply changes
- Standard and complex contingency analysis and transfer limit calculations
- Automatic corrective actions for improving system responses
- System reliability calculations
- Simulated generator economic dispatch or participation factors
- Generator reactive capability curves
- Extensive load modeling capabilities

Modeling

The PSS®E power flow base package includes a full range of standard models as well as flexible models that allow users to include groundbreaking technologies in their analysis. Models include:

- Local or remote control switched shunts and transformers (continuous range or discrete step control available)
- Extensive transformer models include tap impedance correction
- Two and multi-terminal HVDC transmission lines
- Extensive and flexible modeling of FACTS devices
- Extensive vendor-provided and generic wind models
- Multi-section lines
- True zero impedance branches
- Network equivalent construction (optional)
- Transmission line constants calculation

The challenge

The challenges in power systems planning and analysis are directed toward the same objectives as other business environments – do more with less.

To meet these needs, a power systems engineer needs an analytical tool that is accurate, efficient and flexible. To gain maximum benefit, the user must have access to techniques, technologies and processes developed by a large cross-section of power systems engineers and experts in their fields, and must be able to adapt the software to localized processes and procedures.

Our solution

The PSS®E Power Flow incorporates the experience of a world-wide user base to allow today's and tomorrow's power systems engineers to perform thorough steady state analyses of network plans or events. PSS®E has been used and tested against most, if not all, major power systems disturbances since the 1970s. This use has demonstrated the accuracies of PSS®E, justifying it as a world leader in power systems analysis. PSS®E has also been used to study all new network equipment and control technologies introduced in power

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Answers for energy.

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systems over this same time period. The result is a software package that is accurate and versatile in modeling power systems.

But, of equal importance to the PSS®E accuracy and modeling flexibility is the improvement of the engineer's efficiency through using PSS®E. The user interface in PSS®E is based on a full-graphical representation of the network and rich Microsoft Excel®-like data spreadsheets used to manipulate the data and present the results. In combination, these two presentations, and others, allow the engineer to clearly understand the data and analyses.

Additionally, what differentiates PSS®E is its open data structure and user controllability. World-wide experience has shown that any analytical tool must be prepared to perform major studies "out of the box" as well as allow for user differences in standards and practices worldwide. PSS®E exceeds these needs through its fully open data structure and integration with the Python scripting language. These characteristics provide user control of the PSS®E execution and preparation of customized results presentation.

The PSS®E Power Flow offers outstanding accuracy, user efficiency, and flexibility.

Application example

PSS®E offers tools for both deterministic and probabilistic reliability assessment.

The PSS®E Automatic AC Contingency Computation and Multi-Level AC Contingency Computation (ACCC/MACCC) features can be used to perform deterministic reliability assessment, while the PSS®E probabilistic methods provide another dimension to system planning.

The automatic contingency analysis processes user-specified and automatically-selected single and multiple contingencies within one run. User specified and automatically generated contingencies can be tested individually or combined with each other as overlapping outages of up to three levels (N-3). The contingency enumeration process is based on the use of several built-in contingency ranking schemes which provide tremendous savings in computation effort by avoiding the explicit evaluation of contingencies that are not likely to affect system reliability.

Automatic contingency analysis also features generation dispatch, a non-divergent power flow solution algorithm, tripping simulation and corrective action. Figure 1 outlines the computational procedures in performing a deterministic reliability assessment.

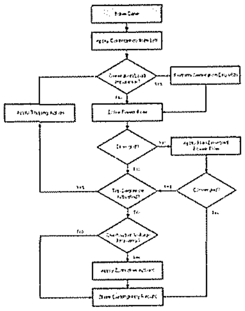

Figure 1 - Computational procedures in a contingency analysis

Within the automatic contingency analysis process, a new load flow solution is developed whenever trip sequences are triggered. The tripping option can be applied to model special protection schemes (SPS), to simulate cascading outages in severely overloaded conditions, and many other complex events.

Corrective action functions can be applied to simulate operator responses, such as the re-dispatch of generation, curtailment of load and adjustment of phase-shifting transformers. This translates system-based reliability measures, such as the location and magnitude of branch overloads and bus voltage violations, to customer-impact indices in terms of the potential amount of service interruptions.

PSS®E provides several functions to post process results for reporting. The Single ACCC report function provides seven types of reports and Multiple ACCC runs compare up to nine contingency runs. Python programs allow users to extract data stored in contingency result files for use when creating their own reports.

Probabilistic transmission reliability incorporates the impact of frequency and average duration of equipment outages on system reliability assessment. Bulk reliability measures are obtained relative to various system problems, including branch overloads, load interruptions, voltage limit violations, and voltage collapse conditions. These indices provide a better indication of power system reliability by taking into consideration the relative likelihood of different contingencies that may occur (see Figure 2).

The basic contingency analysis process can be extended to assess the steady state power transfer capabilities in a power system. The capability of transmission system to support power transfers is a measure of interconnected transmission system reliability. The PSS®E functions for transfer capability study include the transmission interchange limits calculation (TLTG) and interchange limits with two opposing systems (POLY).

The PSS®E reliability functions allow for deterministic reliability to evaluate certainty of service, and for probabilistic analysis to evaluate consequences that can be expressed in terms of cost.

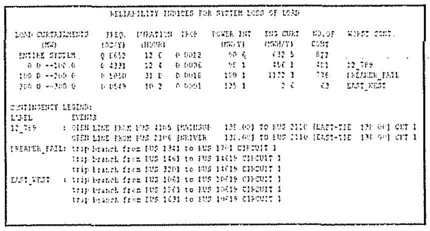

Figure 2 - Probabilistic reliability assessment results

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Kentucky Power Company

REQUEST

Please supply a copy of the KP voltage, thermal, stability, load power factor, and short circuit reliability design criterion that are applicable to the proposed facilities.

RESPONSE

The KP system is planned based on the following attachments:

- Attachment 1, AEP's planning criteria (included in the FERC 715 filing).
- Attachment 2, PJM's Reliability Planning Criteria, per Manual 14B.

AMERICAN ELECTRIC POWER – 2011 FILING

FERC FORM 715 – ANNUAL TRANSMISSION PLANNING AND EVALUATION REPORT

PART 4 – TRANSMISSION PLANNING RELIABILITY CRITERIA
EASTERN AEP

Attached is a document entitled "The American Electric Power System Transmission Planning Criteria and Assessment Practices Eastern AEP". This document provides the criteria to test and assess the strength of AEP's transmission system to meet its load responsibility, including power transfers with other systems (including activity within PJM) as well as to move bulk power between and among other electric systems. This document, in conjunction with the documents submitted under Part 5, provides a description of transmission planning criteria and assessment practices for the AEP System.

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THE AMERICAN ELECTRIC POWER SYSTEM

TRANSMISSION PLANNING CRITERIA AND ASSESSMENT PRACTICES

EASTERN AEP

East Transmission Planning
Transmission Asset Strategy & Planning

American Electric Power Service Corporation

March 2011

INDEX (Part 4)

INDEX (Part 4)

(Continued)

Introduction

Electric utilities, such as AEP, meet their obligation to supply electricity demanded by their customers with a high degree of reliability through the carefully planned development of electric generating sources, transmission, and distribution systems. The reliable supply of electricity involves two elements – adequacy and security. "Adequacy" relates to the production and delivery of electric power and energy in the quantity and quality that the customer requires. For example, sufficient power must be provided at acceptable voltage levels and frequency to match the customers' equipment specifications. "Security" relates to the ability to produce and deliver power whenever the customer needs it. Credible contingencies, such as the sudden outage of transmission facilities, should not result in uncontrollable power interruptions over a wide area. Planning a reliable transmission system requires the application of fundamental principles and the establishment of criteria, which balance adequacy and security against the cost to provide them.

The eastern AEP transmission system was developed over many decades. In the early days of the utility industry, power plants were small and located near load centers. Consequently, transmission distances between the generation resources and the ultimate consumer were comparatively short and the amounts of power delivered were small. As the demand for electricity increased, larger power plants were designed and built further from the load centers to exploit economies of scale, and greater amounts of power had to be transmitted over longer distances. This led to the development of higher voltage, higher capacity transmission facilities.

As utilities developed in their respective geographic areas, the establishment of interconnecting transmission facilities between adjacent systems became attractive as a means to provide mutual support during emergencies and to avoid constructing duplicate facilities. The high transmission voltages have enabled power systems to interconnect on a broad scale. Interconnections allow utilities to support each other during forced or scheduled generation and transmission outages, to buy and sell power for reasons of economy and thereby enhance reliable and economic operation. On the other hand, each interconnected system is unavoidably impacted by events on neighboring systems, requiring coordinated planning and operating practices among neighboring systems and regions. Facility outages and variations in generation dispatch within one system will affect power flow patterns in neighboring systems. Consequently, cascading outages that affect widespread areas are possible. The highly interconnected nature of electric utilities has made it necessary that system planning criteria evolve to recognize these interrelated consequences of interconnected operation.

This document describes the criteria that AEP uses for planning a reliable transmission system to meet its customers' needs at the lowest cost. The first section describes the principles underlying the planning criteria and discusses the planning process. The following three sections provide details of modeling assumptions, performance expectations, and testing criteria, respectively, for AEP's bulk transmission system and area transmission system.

AEP's eastern bulk transmission system, which consists of an extensive network of extra high voltage (EHV) facilities generally operating at 345 kV and above, delivers power from generating plants to major load centers and connects load centers together to form an integrated network. The area transmission system, which consists of high voltage (HV) facilities operating at 230 kV, 161 kV, 138 kV and 115 kV and lower voltage sub-transmission (Sub-T) facilities (from 23 kV to 88 kV), moves power within the major load centers and delivers it to distribution centers and major customers. The EHV and HV facilities connect the AEP System to neighboring companies. Even though AEP's eastern bulk and area transmission systems are planned and operated on a totally integrated basis, the planning criteria of each differ because of separate and distinct functions that each of these systems are intended to serve.

The AEP transmission facilities are divided into the following three performance categories:

- EHV Facilities:
  Transmission lines rated 765 kV, 500 kV, and 345 kV, and transformers with secondary voltages at or above 345 kV, are considered Extra High Voltage (EHV) facilities, and are referred to as "EHV facilities" in this document. These facilities are also part of the Bulk Electric System (BES).

- HV Facilities:
  Transmission lines rated 230 kV, 161 kV, and 138 kV, and transformers with secondary voltages above 100 kV but below 345 kV, are considered High Voltage (HV) facilities, and are referred to as "HV facilities" in this document. These facilities are also part of the BES.

- Sub-T Facilities:
  Transmission lines rated below 100 kV, and transformers with secondary voltages below 100 kV are considered sub-transmission (Sub-T) facilities, and are referred to as "Sub-T facilities" in this document. These facilities are not part of the BES.

1. UNDERLYING PRINCIPLES AND PLANNING PROCESS

1.1 Underlying Principles

Although planning is essential in any industry, it is critical for electric utilities due to the characteristics of an electric power system: the inherent need to respond instantaneously to the electric power demand of customers (load); the heavy financial investment and long service lives of its facilities; the long lead and construction times to add facilities; and the social and economic importance of a reliable power supply. AEP has adopted fundamental planning principles as the basis for specific reliability criteria. Briefly, these principles state that a properly designed transmission system should provide a good distribution of power flows by avoiding excessive geographic concentrations of generating sources or transmission paths. A transmission system should have ample margin to allow for contingencies so as to avoid uncontrolled, area-wide power interruptions and also provide flexibility to deal with the uncertainties inherent in making long range forecasts. Interconnection capabilities between systems should be maintained commensurate with the amount of system load and the size of the individual generating units connected to the transmission system. Station switching arrangements, relay protection, and system controls should be adequate to maximize the use of the transmission system and minimize interruptions; and to provide flexibility for scheduling required maintenance as well as facilitating the restoration of outaged facilities while always, and most importantly, insuring the safety of the general public and our employees.

It is impossible to anticipate or test all possible contingencies that could adversely affect the eastern AEP transmission system because of the large number of individual elements that comprise the system and the fact that power flows, and load levels are continually changing. Therefore, the planning criteria and related contingency tests outlined in this report do not represent an exhaustive set of system operating conditions, transfer levels, and specific contingencies; instead, they constitute an effective and practical means to stress the eastern AEP transmission system, testing its ability to survive the entire spectrum of possible contingencies and identifying potential weaknesses and problems.

The AEP criteria described herein are compatible with: 1) the North American Electric Reliability Corporation (NERC) Reliability Standards; 2) the Reliability*First* Corporation (RFC) Standards, 3) PJM Planning and Operating Manuals, and 4) other external documents. A listing of those external documents is provided in Appendix A. The application of the NERC and RFC criteria to any particular utility system, including AEP, must be adapted to the specific characteristics of that utility. Each utility's transmission system is configured in a way that is specific to the geographic region it serves as well as the electrical facilities that are installed to meet these requirements. There are also various ways of achieving reliability objectives. Therefore, differences can exist among the specific planning criteria employed by various systems. Compatibility among different systems' criteria and guidelines are achieved, however, by adopting fundamentally sound planning principles and practices.

This report presents an overview of AEP's eastern transmission planning criteria and assessment practices. Specific application of these criteria and practices on a case-by-case basis must employ sound engineering judgment. The transmission planner conducting each study should always evaluate these criteria and apply them in such a manner to account for special considerations applicable to the area under study.

Due to inherent uncertainties associated with forecasts of loads, new technological developments, equipment costs, and changing social, economic, and political conditions, it is prudent to develop long range plans of transmission system expansion/modification based on a range of assumed scenarios. Sensitivity analysis is also useful in making these judgments. By their very nature, long-range plans must be reevaluated and modified periodically to reflect the persistent changes in the variety of factors that influence future system performance. While current planning criteria are inherently deterministic, qualitative distinctions about the likelihood of various scenarios and contingencies are recognized.

More likely events require higher levels of system performance; lower system performance standards (greater negative impacts) are acceptable for events that are less likely to happen. Deterministic reliability criteria that are sufficiently stringent to ferret out potential system problems may also result in specific design consequences, which are impractical or too expensive in relation to the benefits realized or the risks mitigated. In these cases, prudent exceptions to the criteria can be made, or other less expensive control schemes employed.

1.2 Planning Process

The planning process, as carried out in the eastern AEP area, provides the focus for establishing an appropriate level of system reliability. The planning process includes seasonal assessments of system performance; near-term facility addition studies; and long-term strategic planning. The planning process typically begins with a deterministic appraisal of transmission system performance. When such appraisals identify potential problems, detailed studies are conducted to evaluate the severity of the problem and to develop an optimal plan to remove or mitigate the deficiency.

Seasonal assessments, also referred to as operational planning assessments, have a horizon of up to one year. These appraisals verify that the transmission system, as planned and built based on long term predictions and assumptions, is adequate to meet the actual requirements that emerge for the approaching peak load periods. Delays in transmission reinforcements, and changing power flow patterns or performance expectations, also influence the need for short-term appraisals. These appraisals also provide an early warning of future system reinforcement needs. Operational planning appraisals are conducted in a manner similar to facility planning appraisals. The major difference is that problems identified in these assessments typically cannot be corrected by transmission reinforcements due to insufficient lead time. Therefore, problems identified by these studies are addressed by deriving indices for system operators to monitor system performance and establishing operating procedures to mitigate any transmission problems detected by the operators during real time operation.

Near-term (1 to 5 years) and long-term (more than 5 years) facility planning appraisals analyze anticipated system conditions within the specified time periods. Near-term and long-term planning of the transmission system allows adequate time to identify emerging trends and anticipated system deficiencies and then to plan and build needed transmission reinforcements, including time for potentially lengthy regulatory approval processes.

Near and long term facility planning studies are conducted for both the bulk transmission system and the area transmission system in accordance with their respective testing criteria and performance expectations. These studies are conducted externally by PJM transmission planners from a regional perspective and internally by AEP transmission planners from a local perspective, and are supplemented by information generally available from neighboring electric utilities. In addition, joint planning studies involving one or more neighboring systems and/or the appropriate Regional Transmission Organization(s) are carried out to assess and enhance the transmission interfaces between AEP and its neighbors through the coordination of operating procedures, development of new interconnection facilities, and/or coordinated transmission enhancements within each system.

AEP's eastern Transmission Planning organization continues to receive requests through PJM from merchant generation and transmission developers for interconnection of new facilities to the eastern AEP transmission system. PJM assesses the impact of these requests on the AEP bulk transmission system. The PJM studies are supplemented by studies conducted by AEP transmission planners. The integration of new merchant projects into the AEP transmission system is conducted based on the same planning principles as for any other transmission facilities.

In addition, seasonal, near-term and long-term appraisal studies, limited to assessing regional and inter-regional transmission system performance, are conducted jointly with neighboring utilities as part of PJM, RFC and Eastern Interconnection Reliability Assessment Group (ERAG) agreements. These joint appraisals focus on measuring the strength of the interconnected network and on assuring coordination of facility planning and operational planning efforts. Where such assessments uncover deficiencies, the specific findings are referred to the appropriate company or companies to develop solutions as part of their normal planning processes.

This document does not directly address regional and interregional appraisal criteria except to note that AEP's criteria comply with those in the NERC and RFC Reliability Standards. Also, AEP uses regional and interregional transfer capability measures that are consistent with the NERC and RFC definitions, to assess the strength of its transmission system. AEP is an active participant in many regional and interregional study groups and has made significant contributions to the development of regional and interregional criteria, including the NERC and RFC Reliability Standards.

2. KEY MODELING ASSUMPTIONS

The computer models used in transmission planning studies necessarily differ widely in dimensions and details to suit the scope of each study. Power flow models are developed to represent system operation during highly stressed periods such as peak load conditions and heavy power transfers that simulate emergency and opportunity power transactions. System dynamics and short circuit computer models are also used, depending on the specific analysis, to complement the power flow models. Using these computer models, transmission system performance is assessed by simulating disturbances to identify system strengths and weaknesses. In general, the following assumptions are used in conducting various types of transmission planning studies.

System active power (MW) loads are often represented at extreme weather, peak, off-peak, and/or light load levels depending upon the type of analysis being conducted. The load levels for studies of the EHV and HV systems are based on the forecasts of diversified peak demand (developed for transmission analysis purposes) provided by AEP's Fundamental Analysis and Economic Forecasting function. These forecasts include both the loads of full requirements customers and customers taking transmission service within the AEP Transmission Zone of PJM. For studies of the sub-transmission system, load levels are based on peak demands of individual load areas.

Facility planning studies usually simulate performance during peak load periods because this is the condition that produces the most heavily loaded transmission conditions. There are exceptions due to: 1) pumped storage hydro characteristics, and 2) the fact that the heaviest power transactions often occur at load levels 80-90% of peak. Sensitivity analyses are conducted to investigate the impact of load growth forecasts on the expansion/modification plans being considered. For most internal and some external studies of the eastern AEP transmission system, sub-transmission facilities are modeled in detail, in order to capture the effects of shunt capacitors, LTC transformers, and the hydro-electric generators that are connected to the sub-transmission system. Broader regional and interregional studies and assessments, such as those conducted by RFC, ERAG, and NERC, generally include detailed models only at the 138 kV and higher voltage levels, with the sub-transmission facilities represented through appropriate equivalents.

Reactive power (MVAr) loads are based on the measured power factor for each load area. It is assumed that reactive correction will be provided as load increases in the future to maintain that power factor. Where future system assessments indicate a need for additional power factor correction, appropriate reinforcements are proposed to meet AEP's design goal that each voltage level is not a reactive burden to its source system. When the impacts of extreme weather forecasts are assessed on the transmission system, the power factor of the incremental load (above the base forecast load) is modeled at 80% because it is assumed that power factor correction is not provided for load that exceeds the forecast.

Power transfer levels modeled in base cases for analysis of the AEP transmission system vary from one study to another depending on the particular focus of the study. The ERAG Multi-Regional Modeling Working Group (MMWG) power flow base cases generally model only committed firm energy commitments. The Reliability*First* base cases, which are derivatives of the ERAG base cases, are modified to include additional recently experienced power transfer biases. AEP's base cases, which are derived from these regional models and those developed by PJM, may require further updates and detail. Often high levels of transfers are simulated to reflect parallel flow conditions reflecting recent experience and in order to assure that probable system bottlenecks are identified.

Generators are normally dispatched to simulate economic operation (lower cost generation 'loaded' first followed by higher cost units) to meet the load demand for system conditions being studied. Most generators will be modeled at or near full output for peak load conditions while some units may be at minimum levels for light load conditions depending upon generation market assumptions. In addition, for operational planning studies, the generation dispatch reflects scheduled generation maintenance related outages. In some cases, the generation dispatch may be adjusted to more accurately reflect other constraints or typical dispatch levels of the units. Pumped storage units are dispatched in the pumping, generating, or condensing mode, depending on modeled system load level and other typical operating constraints such as generating unit minimum output levels appropriate for the modeled conditions. Emergency dispatch models may also be used to simulate actions taken to relieve transmission constraints or to simulate a response to an extreme condition. In the absence of specific information, non-utility generators are modeled in the same manner as utility generation for transmission study purposes.

Base cases model all transmission facilities in service except for known scheduled maintenance, long term construction outages, or long-term forced outages. These known outages are normally only reflected in operational planning studies. Because it is impractical and unnecessary to represent all interconnected systems in detail, the type of planning study dictates the extent of the interconnected network representation. Thus, an interconnection study involving the bulk transfer of power between two power systems not only would require sufficient detail of the bulk transmission in each participating system but also would include sufficient detail and/or equivalent representation of other interconnected systems to assure proper analysis of critical elements.

Sufficient modeling of neighboring systems is essential in any study of the AEP bulk transmission system. Neighboring company information is obtained from the latest regional or interregional study group models, the RFC base cases, the ERAG MMWG power flow library, the PJM base cases, or the neighboring company itself. In general, sufficient detail is retained to adequately assess all outages and changes in generation dispatch, which are contemplated in the particular study. Other areas are usually reduced to a mathematical equivalent.

With the power flow base cases described above, the study engineer develops scenarios that are surrogates for a wide range of possible conditions. Numerous facility outages and power transfers occur daily in the interconnected network. It would be impractical to simulate all such possible conditions in planning studies. In order to establish a manageable set of base case scenarios, historical data and experience are employed. Although history is not a perfect indicator of the future, it provides valuable information to benchmark the base case models. For future power flow base cases, further adjustments are made to reflect forecasted load levels, expected facility changes, and projected power transfers, as well as emerging trends that will affect historical power flow patterns.

Power flow models described above are the most frequently used models for transmission planning studies. Transient stability and short circuit studies are also used to evaluate the system performance during and immediately following fault conditions on the transmission system. The network configurations used in the power flow models also provide a starting point for transient stability and short circuit studies. In addition, for transient stability studies, additional impedance and electromechanical detail of generators and their controls are included. Three-phase models of the power system are employed to study single-phase switching and other unbalanced operating configurations.

3. PERFORMANCE STANDARDS

Performance standards provide the basis for determining whether system response to contingency analysis is acceptable. Depending on the nature of the study, one or more of the following five types of performance standards will be applied: thermal, voltage, relay, stability, and short circuit.

In general, system response to contingencies evolves over a period of several seconds or more. Steady state conditions can be simulated using a power flow computer program. A short circuit program can provide an estimate of the large magnitude currents, due to a disturbance, that must be detected by protective relays and interrupted by devices such as circuit breakers. A stability program simulates the power and voltage swings that occur as a result of a disturbance, which could lead to undesirable generator/relay tripping or cascading outages. Finally, a post contingency power flow study can be used to determine the voltages and line loading conditions following the removal of faulted facilities and any other facilities that trip as a result of the initial disturbance.

3.1 Thermal Limits

Thermal ratings define transmission facility loading limits. Normal ratings are generally based upon no abnormal loss of facility life or equipment damage. Emergency ratings accept some loss of life or strength, over a defined time limit for operation at the rated loading level. The thermal rating for a transmission line is defined by the most limiting element, be it a conductor capability, sag clearance, or terminal equipment rating. When a line is terminated with multiple circuit breakers, as in a ring bus or "breaker and a half" configuration, it is assumed that the line flow splits equally through the terminal equipment unless one breaker is open. Ratings in power flow simulations normally assume all breakers are in service.

Most thermal ratings are defined in amperes. However, transmission planning studies use ratings expressed in MVA, based on the ampere rating at nominal voltage. When voltages during testing deviate considerably from nominal, the MVA loading is adjusted for the voltage deviation from nominal to permit an appropriate comparison to the MVA rating.

3.2 Voltage Limits

Voltages at transmission stations should be within the values listed in Table 1 in subsection 4.1 to reduce the risk of system collapse and/or equipment problems. In addition, voltages at generating stations below minimum acceptable levels established for each station must be avoided to prevent tripping of the generating units. High voltage limits are specific for particular pieces of equipment, but are typically 105% of nominal.

3.3 Relay Trip Limits

Relay trip settings, selected primarily for fault conditions, could be reached in some cases during contingency loading conditions or transient power swings. These relay trip settings are evaluated in operational planning studies, as well as longer term studies, to determine whether adjustments are needed. If it is not practical to revise the setting, subsequent planning studies must recognize that the line could trip due to the resultant contingency loading condition. Facilities that must comply with NERC Reliability Standard PRC-023 requirements have relay limits set at least 150% above the highest seasonal (emergency) Facility Ratings, for the available defined loading duration nearest 4 hours.

3.4 Stability Limits

Stability limits can be of several types and are characteristic of any power system. These include steady-state, transient, and oscillatory stability limits. More than one type of limit may impact power system operation, but often only one type of limit is most constraining.

The steady-state stability limit (P_{MAX} in Figure 3.1) is the point at which no more power can flow through a system without precipitating a voltage collapse. This limit is often related to heavily loaded systems where even small perturbations, such as the normal adjustment of generator output to match load, could cause system collapse. Steady-state stability limits are typically evaluated using power vs. voltage (PV) curves or power vs. angle curves, for individual lines or transmission interfaces. In planning studies, a loadability limit is defined, which includes a safety margin of 5-10% below the theoretical maximum power flow.

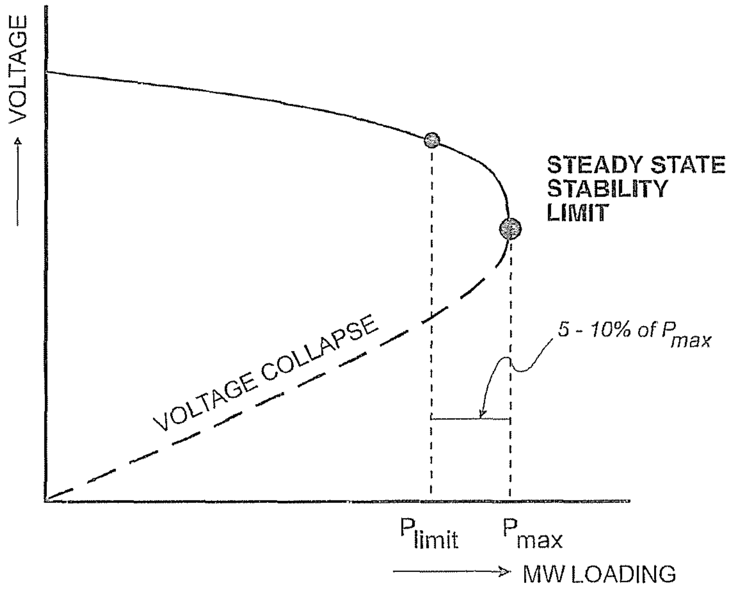

Figure 3.1

Transient stability refers to the ability of a power system to remain in synchronism following a disturbance, such as a short circuit. Facilities must be planned and operated so that all generating units remain stable through the transient period regardless of the plant's output level prior to the disturbance. Also, transient voltage dips at generating stations below established minimum acceptable levels, and for significant durations, must be avoided to prevent tripping of the auxiliary loads, which in turn, could trip generating units.

Oscillatory stability refers to the ability of a power system to damp out electromechanical oscillations (or power swings) in the 0.1-3.0 Hz range. Oscillatory modes within this range inherently exist on any power system. Oscillatory instability is manifested in terms of sustained or growing oscillations in various electrical quantities observable at power plants and on the transmission system, following a disturbance, or a routine network operation such as load ramping. These oscillations must be suppressed within seconds to prevent potential equipment tripping and damage. The oscillatory instability limit is defined as the power level beyond which one or more generators or groups of generators continue to exhibit one or more sustained modes of oscillation beyond a reasonable time limit. Generally, this limit is not dependent on the size of the disturbance or the period of the mode. Any sustained or growing oscillation that persists beyond a reasonable time period indicates that the stability limit has been exceeded and represents unacceptable performance.

3.5 Short Circuit Limits

Short circuit limits are also an important aspect of system performance, since the extremely high, short duration currents that accompany system faults will impose considerable stresses on network elements. Circuit breakers must be capable of interrupting the anticipated fault currents in the shortest possible time. Failure to interrupt these currents may lead to catastrophic equipment damage and endanger human life. Short circuit levels increase as network reinforcements are implemented or new generating units are added to the system. Therefore, short circuit levels must be reviewed periodically so that inadequate equipment can be replaced or upgraded, or a mitigation procedure developed.

AEP steady state planning criteria requires that no bus voltage on AEP system shall exceed 1.05 per unit under system normal or contingency conditions. This voltage limit takes into consideration the equipment capabilities on AEP system. Short circuit assessment is performed assuming 1.05 per unit voltage at all the AEP system buses. This is a conservative approach but accounts for a wide range of system conditions. Circuit breakers at or near a generator plant shall be analyzed differently based on the scheduled voltage at the generator bus. This exception only applies to generator plants already in operation with established scheduled voltages.

4. TRANSMISSION TESTING AND PERFORMANCE CRITERIA

4.1 Steady State Testing Criteria

The planning process for AEP's transmission network embraces two major sets of contingency tests to ensure reliability. The first set, which applies to both bulk and local area transmission assessment and planning, includes all significant single contingencies. The second set, which is applicable only to the BES, includes multiple and more extreme contingencies. For the eastern AEP transmission system, thermal and voltage performance standards are usually the most constraining measures of reliable system performance. Each type of performance requirement is described in the following discussion. Table 1 below documents the performance criteria for all transmission facilities under normal and contingency conditions.

Table 1

NERC Contingency Category	**Transmission Facilities**		
	EHV Facilities	**HV Facilities**	**Sub-T Facilities**
A – System Normal	**Thermal:** No facility may exceed its normal rating. **Voltage:** All station voltages must stay between 1.05 per unit and 0.95 per unit.		
B1 – Single Generator B2 – Single Line B3 – Single Transformer	**Thermal:** No facility may exceed its normal rating.	**Thermal:** No facility may exceed its emergency rating.	
	Voltage: All station voltages must stay between 1.05 per unit and 0.92 per unit. A voltage change from system normal of 8% or greater is not acceptable at any station.		
C1 – Bus C2 – Breaker Failure C5 – Double Circuit Tower	**Thermal:** No facility may exceed its emergency rating. **Voltage:** All station voltages must stay between 1.05 per unit and 0.92 per unit. A voltage change from system normal of 8% or greater is not acceptable at any station.		**Note:** Not planned for this Category of contingencies.

C3 – Two Category B Contingencies (one Category B contingency followed by another Category B contingency)	**Thermal:** No facility may exceed its emergency rating. **Voltage:** All station voltages must stay between 1.05 per unit and 0.92 per unit. A voltage change from system normal of 8% or greater is not acceptable at any station. **Manual System Adjustments After First Contingency:** Not acceptable for transmission facilities supplying major load centers (as defined below).	**Note:** Not planned for this Category of contingencies.
D6 – Loss of Tower Line with 3 or More Circuits D7 – Loss of All Transmission Lines on Same Right of Way D8 – Loss of Substation D9 – Loss of Switching Station D10 – Loss of All Generating Units at a Station	**Note:** Performance is evaluated for risks and consequences. Issues identified may not be mitigated, but may be used to screen viable solutions to resolve violations from Category B and C contingencies.	**Note:** Not planned for this Category of contingencies.

Major Load Centers: Considering the location and strength of the eastern AEP transmission system, it is subjected to a wide variety of power flow patterns. In some instances, these conditions result from economic power transfers between neighboring systems which are outside the control of AEP or PJM system operators. It is not possible to ensure that effective system readjustments will be available to address all of the credible outages that are identified in the planning study. This is of particular concern for major load centers where the impact of a blackout is too severe to allow reliance on manual system adjustments. Therefore, AEP does not allow the use of manual system adjustments after the first contingency in anticipation of the next contingency as a viable mitigation tool for planning the transmission system supporting major load centers. A major load center is defined as an area with significant demand that is dependent on the bulk transmission system. In the eastern AEP footprint, the following areas are considered major load centers:

- Columbus Metropolitan Area
- Fort Wayne Metropolitan Area
- Eastern Appalachian Power Company Service Territory
- Central Appalachian Power Company Service Territory

Special Protection Schemes (SPS): An SPS may be implemented as an interim measure to prevent propagation of cascading outages across the transmission network and thus mitigate the possibility of a large scale blackout. Interim use of an SPS is intended to provide sufficient time for implementation of a permanent solution.

4.1.1 Singe and Double Contingencies

Single contingencies include the forced outage of generating units, transmission circuits, transformers, and/or other equipment. In general, a single contingency is defined as the outage of any one of these facilities. Due to the interconnected nature of power systems, testing includes outages of facilities in neighboring systems. A single facility is defined by the arrangement of automatic protective devices. Generally, double circuit tower outages, breaker failures, station outages, common right-of-way outages, and other common mode failures have substantially lower probabilities of occurrence than the outage of a single transmission facility and are, therefore, not considered single contingencies.

Double contingencies, being a more severe test of system performance, are used as a surrogate for the significant uncertainties that are inherent in the planning process. A double contingency can be defined as an outage of any two facilities.

For facility planning purposes, contingencies result from scheduled maintenance and/or forced outages. Double outages are generally viewed as separate events that overlap in time. Each contingency is tested with the system load level, generation dispatch, generating unit outages, and transfer conditions, which would be most severe, but still credible, for that particular contingency.

Single and double contingencies are tested with firm import and export transactions, third party transfers, and the expected level of opportunity transfers (or expected generation market activity) as a base condition. The import scenarios assessed assume planned imports plus an additional level of imports necessary to assure that the load expectation for the eastern AEP transmission system will be no greater than one day in ten years. Furthermore, since the availability of off system resources is uncertain, the transmission system must be capable of importing these resources across a limited number of interfaces when these resources are not available from one or more directions. Sensitivity studies are also normally conducted for a range of opportunity transfers and generation dispatches as well as extreme weather conditions. The various types of sensitivity analyses performed are discussed in subsection 4.3.

Operational planning studies consider up to two key outages in effect prior to the next (third) contingency. It is assumed that all operator adjustments required for the prior outages have been implemented. Uncertainties such as generation availability and dispatch, load forecast error and load diversity are also considered. The number of prior outages depends on the strength of the transmission system and the number of variables to be considered in developing effective operating guidelines. Clearly, as the number of concurrent contingencies increases, it will become increasingly difficult to meet the required performance limits (see Section 3), even with special operating procedures.

The number of outages actually occurring on the system can exceed the number assumed for study purposes. Operational planning engineers evaluate those conditions, as needed.

4.1.2 Extreme Contingencies

The more severe reliability assessment criteria required in the NERC Reliability Standards (Category D contingencies) are primarily intended to assess the risks for uncontrolled area-wide cascading outages under adverse but credible conditions. AEP, as a member of Reliability*First*, plans and operates its bulk transmission system to meet the criteria. However, new facilities would not be committed on the basis of local overloads or voltage depressions following the more severe multiple contingencies unless those resultant conditions were expected to lead to widespread, uncontrolled outages.

In operational planning studies, the purpose of studying multiple contingencies and/or high levels of power transfers is to evaluate the strength of the system. Where conditions are identified that could result in significant equipment damage, uncontrolled area-wide power interruptions, or danger to human life, IROL operating procedures will be developed, if possible, to mitigate the adverse effects. It is accepted that the defined performance limits could be exceeded on a localized basis during the more severe multiple contingencies, and that there could be equipment damage, increased loss of equipment life, or limited loss of customer load. Normally, operating procedures to mitigate uncontrolled area-wide power interruptions are only used on an interim basis until facility additions can be put in place to restore acceptable reliability levels.

In carrying out operational or facility planning studies, it is recognized that there are many protective and special controls on the system that must operate properly when an event occurs. These controls include but are not limited to: protective relays, circuit breakers, breaker failure schemes, quick reactor or capacitor switching, rapid generating unit runback, automatic motor operated disconnects, and emergency generator tripping. The misoperation of any of these controls may result in equipment damage, but should not result in widespread power interruptions or danger to human life.

4.2 Stability Testing Criteria

Stability testing covers the entire range of power system dynamics from "first swing" transient stability to longer term oscillatory and steady-state stability. This testing is an essential complement to the steady-state analysis embodied in the power flow testing described above.

Maintaining power plant transient stability is essential because loss of synchronism (or instability) of a generating unit or an entire generating plant can lead to equipment damage and severe power system transient swings. Instability may further compound a disturbance by causing the tripping of the unstable generators and possibly other equipment. When simulating system contingencies affecting power plant stability, various types of fault and network conditions are analyzed in accordance with the transient stability disturbance testing criteria outlined in Appendix B.

The Appendix B transient stability disturbance testing criteria specifies the disturbance events for which stable operation is required of all transmission and EHV connected generation. The stability testing criteria appropriate for sub-transmission and distribution connected generation is determined on a case-by-case basis and may be less stringent as long as instability may be shown not to adversely affect the bulk transmission system. In cases where the bulk system is not adversely affected and the speed of sub-transmission or distribution system protection is inadequate to prevent instability for normally cleared faults, out-of-step tripping would be required to prevent adverse affects on the sub-transmission or distribution systems.

Steady state and oscillatory stability performance problems may be initiated by a wide variety of contingencies or operating conditions on the transmission network. Appendix B network disturbances are similarly applied when testing for steady state and oscillatory instability and these criteria are sufficient for detecting these types of instability. The measures of acceptable performance for each type of stability performance problem are discussed in Section 3.4.

AEP generally carries out simulations corresponding to the A through E set of criteria in Appendix B for facility planning studies. For operational planning studies, the F and G criteria, in addition to the A-E set, are applied, especially when a long-term facility outage is anticipated. Testing of more severe disturbances than those of Appendix B may be performed to evaluate the strength of the transmission system and to assess potential for cascading outages. Examples of such testing include common-failure mode disturbances such as double circuit tower faults or bus faults that result in the outage of multiple facilities at a location.

The disconnection of generation due to a disturbance is distinct from instability. Instability refers to loss of synchronism or pole slipping when the generation remains physically connected. Disconnection results in generator overspeed followed by turbine shutdown in response to protective relay action. Systems are planned such that disconnection does not occur for single contingencies. Disconnection may occur during Appendix B disturbance scenarios involving the outage of more than one transmission element, or common-failure mode disturbances such as bus outages, as a consequence of isolating faulted facilities or other system design considerations. Disconnection under these circumstances is considered to be acceptable whereas instability is not.

4.3 Sensitivity Scenarios Testing Criteria

In addition to testing base case conditions, as described in the preceding sections, uncertainty inherent in the system planning process warrants that variations from the assumptions underlying the base case models also be evaluated. The particular sensitivities examined may vary from area to area, depending on the characteristics of both the portion of the AEP transmission system which is the focus of study, and its (AEP or non-AEP) neighbors. In this regard, the individual study area considered may be one or more of the AEP Transmission Regions (Fort Wayne, Columbus, or Roanoke). The thermal rating and voltage limits defined in Table 1 must be adhered to for the sensitivity assessments of AEP transmission system performance as well. In addition to the particular sensitivity scenarios described below, sensitivity of other system conditions are also considered, including but not limited to changes in system load such as shoulder peak load, light load, extreme (e.g., one in ten years) load, or local area load conditions, different generation dispatch scenarios, and system conditions reflecting historical operating experience.

4.3.1 Power Transfers

Power transfers of at least 4000 MW across the AEP transmission system, both with and against the normal flow bias, are simulated to assess the performance of the BES. The geographic span of the eastern AEP transmission facilities results in connection points between areas that may experience conditions substantially different from those projected for the peak load period. Past events that have produced different patterns of sustained (weeks or months) flows have included drought, flood, fuel supply disruptions, and regulatory restrictions affecting similar generating units.

4.3.2 Potential Generation Retirements or Unavailability of Generation

A significant portion of the generation fleet in the U.S. entered service 30 years ago or more, and even newer units may be exposed to early retirement if changing regulations, such as environmental regulations, render their continued operation uneconomical. Robust transmission requires years to study and develop. On the other hand, the PJM tariff requires that retiring generators only provide 90-days notice before they retire. Therefore, the potential retirement of generating units in or adjacent to the study area based on credible information available in the public domain is analyzed to determine the potential impact on AEP transmission system performance.

4.3.3 Potential Generation Development

In areas with significant intermittent generation (wind, solar) connected to the BES or requesting interconnection, sensitivity analyses include simulations with high generation output (100% of seasonal installed nameplate) in or near the study area, concurrent with 85% of the projected peak load. The following generation dispatch scenarios are considered:

a) All the intermittent generation connected to the BES or requesting interconnection is dispatched to neighboring areas. The neighboring areas are chosen so as to reflect a stressed condition on the AEP transmission system.

b) 20% of all intermittent generation connected to the BES or requesting interconnection is dispatched to replace existing generation in the AEP footprint while the remainder is dispatched to neighboring areas. At no time are any base load units dispatched to less than their minimum generating capabilities. The neighboring areas are chosen so as to reflect a stressed condition on the AEP transmission system.

c) 50% of all intermittent generation connected to the BES or requesting interconnection is dispatched to replace existing generation in the AEP footprint while the remainder is dispatched to neighboring areas. At no time are any base load units dispatched to less than their minimum generating capabilities. The neighboring areas are chosen so as to reflect a stressed condition on the AEP transmission system.

4.3.4 Energy Storage Facilities

Several portions of the eastern AEP transmission system are affected by large storage facilities. To properly plan the transmission system, operation of BES connected Energy Storage facilities in the charging mode, at 85% of projected peak load and during light load conditions, is assessed.

APPENDIX A

External Documents that Relate to AEP's Transmission Planning Criteria and Assessment Practices

1. NERC Reliability Standards *

2. NERC "Transfer Capability – A Reference Document" *

* NERC website: www.nerc.com

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APPENDIX B

AEP TRANSIENT STABILITY DISTURBANCE TESTING CRITERIA

PREFAULT CONDITION	765 KV PLANTS	345 KV PLANTS	138 KV PLANTS
All Transmission Facilities in Service	1A Permanent single line-to-ground (SLG) fault with 1φ breaker failure. Fault cleared by backup breakers.	2A Permanent SLG fault with 1φ breaker failure. Fault cleared by backup breakers.	3A Permanent SLG fault with 3φ breaker failure. Fault cleared by backup breakers.
	1B Permanent SLG fault cleared by primary breakers. 3φ fault developed following HSR. Fault cleared by primary breakers.	2B Permanent 3φ fault with unsuccessful HSR, if applicable. Fault cleared by primary breakers.	3B Permanent 3φ fault with unsuccessful HSR, if applicable. Fault cleared by primary breakers.
	1C 3φ line opening without fault.	2C 3φ line opening without fault.	3C 3φ line opening without fault.
One Transmission Facility Out o Service	1D Permanent SLG fault with unsuccessful HSR, if applicable. Fault cleared by primary breakers.	2D Permanent 3φ fault with unsuccessful HSR, if applicable. Fault cleared by primary breakers.	3D Permanent 3φ fault with unsuccessful HSR, if applicable. Fault cleared by primary breakers.
	1E 3φ line opening without fault.	2E 3φ line opening without fault.	3E 3φ line opening without fault.
Two Transmission Facilities Out of Service	1F Temporary SLG fault with successful HSR, if applicable.	2F Temporary 3φ fault with successful HSR, if applicable.	3F Temporary 3φ fault with successful HSR, if applicable.
	1G 3φ line opening without fault.	2G 3φ line opening without fault.	3G 3φ line opening without fault.

Working to Perfect the Flow of Energy

PJM Manual 14B:

PJM Region Transmission Planning Process

Revision: 19
Effective Date: September 15, 2011

Prepared by
Planning Division
Transmission Planning Department

PJM Manual 14B:

PJM Region Transmission Planning Process

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Approval

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Paul McGlynn, General Manager

System Planning

Current Revision

Revision 19 (09/15/2011):

- Added Attachment H Power System Modeling Data

Introduction

Welcome to the **PJM Region Transmission Planning Process** Manual. In this Introductory Section you will find information about PJM manuals in general, an overview of this PJM Manual in particular and information on how to use this manual.

About PJM Manuals

The PJM Manuals are the instructions, rules, procedures, and guidelines established by PJM for the operation, planning, and accounting requirements of the PJM RTO and the PJM Energy Market. The manuals are grouped under the following categories:

- Transmission
- PJM Energy Market
- PJM Regional Transmission Expansion
- Reserve
- Accounting and billing
- PJM administrative services

For a complete list of all PJM manuals, go to www.pjm.com and select "Manuals" under the "Documents" pull-down menu.

About This Manual

The **PJM Region Transmission Planning Process Manual** is one of the PJM manuals in the PJM Regional Transmission Expansion group. This manual focuses on the process for planning baseline expansion facilities under the PJM Region Transmission Planning Process. Capitalized terms not defined as they are used have the meaning defined in the PJM's Open Access Transmission Tariff (OATT) and in the Operating Agreement (OA.)

This **PJM Region Transmission Planning Process Manual** consists of two sections and related attachments. All sections and attachments are listed in the Table of Contents.

> **NOTE:** While the PJM Manuals provide instructions and summaries of the various rules, procedures and guidelines for all phases of PJM's planning process, the PJM Operating Agreement and the PJM Open Access Transmission Tariff (OATT) contain the authoritative provisions.

Intended Audience

The intended audiences for this PJM Region Transmission Planning Process Manual include:

- Generation and Transmission Interconnection Customers and their engineering staff

> **NOTE**: The term "**Transmission Interconnection Customer**", as defined in the PJM Open Access Transmission Tariff, refers to those separate and independent entities proposing to install new or upgrade existing transmission facilities rather than an existing Transmission Owner on the PJM System that installs Regional Transmission Expansion Plan "baseline," "economic," "system performance" or "Supplemental projects".

- Transmission Customers

> **NOTE:** The term **"Transmission Customer"** refers to any entity requesting or utilizing transmission service on the PJM Transmission System, as defined in the PJM Open Access Transmission Tariff.

- Transmission Owners and their respective engineering staff
- Federal and state regulatory bodies
- PJM Members
- PJM staff

References

There are other PJM documents that provide both background and detail on specific topics that may be related to topics in this manual. References with related information include:

- PJM Manual 1: *Control Center Requirements*
- PJM Manual 2: *Transmission Service Request*
- PJM Manual 3: *Transmission Operations*
- PJM Manual 14: Introduction to PJM Manual 14 Series
- PJM Manual 14A: *Generation and Transmission Interconnection Process*
- PJM Manual 14C: *Generation and Transmission Interconnection Facility Construction*
- PJM Manual 14D: *Generator Operational Requirements*
- PJM Manual 14E: *Merchant Transmission Specific Requirements*
- PJM Manual 21: *Rules and Procedures for Determination of Generating Capability*

Using This Manual

We believe that explaining concepts is just as important as presenting procedures. This philosophy is reflected in the way we organize the material in this manual. We start each section with an overview. Then we present details, procedures or references to procedures found in other PJM manuals. The following provides an orientation to the manuals' structure.

What You Will Find In This Manual

- A table of contents.
- An approval page that lists the required approvals and a brief outline of the current revision.
- This Introduction and sections containing the specific transmission planning process details including assumptions, criteria, procedures and stakeholder interactions.
- Attachments that include additional supporting documents, forms, or tables.
- A section at the end detailing all previous revisions of this PJM Manual.

About Critical Energy Infrastructure Information (CEII)

PJM Critical Energy Infrastructure Information Release Guidelines

Background

The Federal Energy Regulatory Commission ("FERC" or "Commission") considers the information filed in the FERC-715, Part 2, Part 3, and Part 6 (http://www.ferc.gov/legal/ceii-foia/ceii.asp) to be Critical Energy Infrastructure Information (CEII). This information contains electrical models, detailed one-line diagrams and analysis of the filer's actual transmission system including potential weaknesses of the filer's transmission system. PJM treats all such power flow and associated system modeling data as CEII. This includes all power flow models that are developed using or including filed data and related information used in transmission analysis such as contingency and monitored element files. Power flows specifically configured for short circuit analysis that do not contain load and typical generation dispatch are not considered CEII. Regarding all types of PJM information, however, additional consideration must be given to whether or not PJM received or originated the information as Confidential Information prior to decisions regarding its release. Confidential information is discussed in PJM documents including the Operating Agreement §18.17 and the Open Access Transmission Tariff §§222 – 223. Power flows may but generally do not contain Confidential information. Confidential information of individual members, if any, will be redacted prior to release. Some PJM power flows are special cases that contain both confidential information and CEII. For example PJM power flows originating from system operations and used for near-term operational studies often contain confidential information in addition to CEII. These cases can only be obtained with authorization through the CEII process and authorization from the responsible Operating Committee and/ or working group.

The events of 2001 prompted the Commission to reconsider its previous policy of making the FERC form 715 report publicly available. Subsequent to September 11, 2001, the Commission removed from public files all documents likely to contain detailed specifications of facilities licensed or certified by the Commission. This restriction was later expanded to include information about proposed facilities as well as those already licensed or certificated by the Commission, excluding information that simply identified the location of the infrastructure. After the events of September 11, 2001, FERC Form 715 information became subject to CEII review prior to its release. In its October 2007 Order, the Commission issued revisions to the treatment of CEII and reclassified FERC Form No. 715, Parts 1, 4, and 5 as public. The remaining portions of the report are CEII. In the FERC Order Nos. 890 and 890A the Commission directed Transmission Providers to develop a process for handling CEII while implementing the Orders' requirements for open, transparent and participatory planning.

The PJM power flow information is a combination of CEII information filed or provided by a number of "owners" and additional information introduced by PJM, PJM Members, and non-members.

The Commission's treatment of CEII has evolved over a progression of Orders that must be read together to understand the procedures applicable to the determination and handling of CEII. In consideration of the multiple-owner nature, the sensitivity of the information, and the essential role of this information in PJM's Tariff procedures and participatory planning, PJM has implemented a process for handling and documenting such material. PJM's intent is to provide a process for eligible recipients to access CEII consistent with the Commission's standards for handling CEII material.

Procedure to Request Access to PJM CEII

PJM will act as the first point of contact to process CEII requests from Members, Interconnection Customers (as defined in the PJM OATT) or active participants in PJM's eFTR or eRPM markets. In addition, employees of other RTO's, similar independent transmission organizations recognized by FERC, and NERC Planning Coordinators (interregional planning entity) may also come to PJM as a first point of contact for access to PJM CEII. PJM accommodates other RTO's and Planning Coordinators in order to carry out interregional planning responsibilities pursuant to applicable FERC orders and interregional planning agreements between and among the parties. These interregional planning entities, similar to PJM, are those that have primary responsibility for creating and protecting CEII and have their own FERC compliant processes for handling CEII in their possession. Interregional transmission planning creates the need for unique interregional business processes that accommodate Interconnection-wide exchange and sharing of CEII among eligible persons while enforcing the standards for non-disclosure of such information. When necessary, PJM establishes interregional CEII procedures that uphold the essential underlying tenants of PJM's process.

All CEII requests must be from individuals. Each individual who may view or discuss the requested CEII must complete the PJM process. To request CEII in PJM's possession, a requestor must complete a PJM CEII Request Form identifying the requestor and the need for and planned use of the requested information. The request must also be accompanied by an executed CEII Non-disclosure Agreement (NDA). These two PJM CEII documents are available from your PJM Planning contacts, the PJM CEII Contact in the NERC and Regional Coordination department or the Planning area of the PJM website. If a PJM Member or PJM Interconnection Customer desires to coordinate a consultant's access to CEII on behalf of the organization, the organization's authorized representative must submit an Authorization Form (in addition to the authorized representative's Request and CEII NDA) that identifies each individual consultant who may make individual requests for CEII on the organization's behalf. The consultant additionally must submit a Request Form and CEII NDA requesting access to the same information specified on the form of the organization's authorized representative. Entities who are not PJM members, Interconnection Customers, registered PJM auction participants, or employees of another RTO are encouraged to first seek authorization from FERC by following the procedures outlined at www.ferc.gov/legal/ceii-foia.asp.

The field on the PJM Request Form for the FERC CEII Identification Number must be completed by individuals who have first received authorization from the Commission. This field is not applicable for any requestor who uses PJM as the first point of contact for a request. The FERC link is also useful to review the definition of CEII and the Commission's process for handling CEII and useful in understanding the PJM process.

Requirements to become an Authorized Recipient of CEII

PJM's process provides for release of CEII information to authorized individuals of organizations engaged in business with PJM, as detailed above. The information provided on the required documents should be sufficiently detailed to enable PJM's CEII Contact to identify the individual, the specific information requested, the need for the information, and the proposed use of the information. The requester's explanations will be used by PJM staff (i) to establish whether a requester has presented a legitimate need for the information and (ii) to weigh the need for the information against the potential harmful effects of its release. PJM reserves the right to revise its process from time-to-time, to limit access to CEII as may be appropriate in any specific instance, and to require any requestor to first seek authorization for CEII access from the Commission.

Section 1: Process Overview

In this section you will find an overview of PJM's transmission planning process that culminates in the Regional Transmission Expansion Plan (RTEP). This process (referred to in this Manual interchangeably as the RTEP process or more generically as the PJM Region transmission planning process) is one of the primary functions of Regional Transmission Organizations (RTOs.) As such, PJM implements this function in accordance with the Regional Transmission Expansion Planning Protocol set forth in Schedule 6 of the PJM Operating Agreement.

As further described in following portions of this manual, the PJM RTEP process consists of baseline reliability reviews as well as analysis to identify the transmission needs associated with generation interconnection and merchant transmission interconnection. PJM implements the planning of interconnections as part of the broader RTEP process pursuant to the PJM Open Access Transmission Tariff (OATT.) The relationship between Interconnection planning and the RTEP is discussed in later sections of this manual and in related manuals.

1.1 Planning Process Work Flow

The Manual 14 series provides information regarding PJM's Planning Process to complement Schedule 6 of the PJM Operating Agreement and the planning provisions of the PJM Open Access Transmission Tariff (OATT.) These agreements can be found on-line at http://www.pjm.com/documents/agreements.aspx.

The PJM planning process activities, culminating in PJM's annual Regional Transmission Expansion Plan, constitute PJM's single, Order No. 890 compliant, transmission planning process. All PJM Open Access Transmission Tariff (OATT) facilities are planned through and included in this open, fully participatory, and transparent process.

PJM planning is implemented through an annual cycle centered on activities of PJM's Planning and Market Simulation functions and their interactions with members, regulatory bodies, and other interested parties primarily through the PJM Transmission Expansion Advisory Committee (TEAC), the Subregional RTEP Committee, and the PJM Planning Committee (PC) forums. This ongoing process has continued to evolve since 1997, when PJM's Regional Transmission Expansion Planning (RTEP) Protocol (codified in Schedule 6 of PJM's Operating Agreement) was approved by the Federal Energy Regulatory Commission. Since that time, the process has been expanded and enhanced in response to member and regulatory input as documented in the revisions to the OATT, PJM Manual 14 series, and the Operating Agreement Schedule 6. The current PJM Region transmission planning process includes ample opportunity for Stakeholder input through frequent oral and written exchange of information and reviews via the TEAC organizational structure. The process culminates in PJM's presentation of the RTEP for approval by the PJM Board of Managers.

There are four planning paths that ultimately culminate in the PJM RTEP. Facilities in each path allow the opportunity for early, full and transparent participation by interested PJM stakeholders. The four paths are reliability planning, economic planning, interconnection planning, and local planning.

Reliability and economic planning facilities are produced from PJM's annual planning cycle activities described in this manual, Operating Agreement Schedule 6, and portrayed in Exhibit 1. PJM leads this analysis and development of upgrades related to reliability and market efficiency planning for all facilities 100 kV and above. These facilities are designated as Bulk Electric System (BES) facilities and are subject to the NERC requirements and criteria for such facilities. The PJM analyses ensure compliance with NERC, PJM and regional criteria. In addition, the PJM led analyses also include analysis and upgrade of transmission facilities with nominal voltages below 100kV to the extent they are under PJM's operational control (see http://www.pjm.com/markets-and-operations/transmission-service/transmission-facilities.aspx). The TEAC, Subregional RTEP Committee, and stakeholder opportunities to engage the process are described in this manual.
The analysis of OATT transmission facilities below 100kV and not under PJM operational control is led by the Transmission Owner (TO.) This is appropriate since local Transmission Owner operations, maintenance and planning personnel oversee these local systems. These facilities typically provide only local transmission function of interest to the customers in the nearby electrical vicinity. The TO analysis ensures local facilities meet NERC and local reliability criteria. In addition, the local Transmission Owner personnel may also develop recommended modifications to transmission facilities that are not required by PJM reliability, market efficiency or operational performance criteria (the non-criteria based upgrades are called Supplemental RTEP Projects.) The Transmission Owner will initiate all reliability-based and supplemental upgrade requests for facilities not under PJM's control. All such projects will be introduced to the PJM Regional planning process through PJM's TEAC and Subregional RTEP Committees. In this way these TO initiated projects will be subject to the same open, transparent and participatory PJM committee activities as PJM initiated projects (see discussion of TEAC and Subregional RTEP Committee.)

Interconnection planning encompasses generator and merchant transmission requests for Interconnections and rerates as well as requests for long-term firm transmission service. Studies of these transmission requests and any resulting transmission modifications are posted to PJM's website in the project queue area (http://www.pjm.com/planning/generation-interconnection.aspx). In addition, any necessary facility modifications are brought to the TEAC for presentation and stakeholder participation. Interconnection planning is discussed in more detail in Manual 14A.

1.2 TEAC and Subregional RTEP Committee and Related Activities

The PJM TEAC functions in accordance with its established charter and provisions of Schedule 6 of the Operating Agreement. Additionally, in 2008 PJM began to facilitate more localized planning functions through the Subregional RTEP Committee. The Subregional RTEP Committee, including any local reviews that may be initiated, will follow TEAC procedures and other applicable PJM committee procedures. All PJM stakeholders will be provided with the opportunity for participation in the TEAC and Subregional RTEP Committees and related activities.

The subregional and any related meetings allow more focused and meaningful stakeholder participation and attention to subregional and local transmission issues. RTEP projects are labeled as Regional RTEP Projects and Subregional RTEP Projects, as defined in the Operating Agreement, to make an initial categorization and posting of violations and upgrades that will enable stakeholders to more easily sort through and review issues of interest. Regional RTEP Projects are those transmission expansions or enhancements rated at voltages 230 kV and above. Subregional RTEP Projects are those rated below 230 kV. This differentiation by voltage between Regional RTEP Projects and Subregional RTEP Projects is made only for administrative convenience.

The Subregional RTEP Committee is responsible for the initial review of Subregional RTEP Projects. PJM will facilitate meetings as necessary for TEAC and Subregional RTEP Committee review and evaluation of reliability and market efficiency reinforcements. The Subregional RTEP Committee will forward all Subregional RTEP Projects to the TEAC. TEAC or the Subregional RTEP Committee, as appropriate will also have the opportunity to provide advice and recommendations regarding the study scope, assumptions and procedures at an initial assumptions setting meeting. This meeting will cover both reliability and market efficiency assumptions, as appropriate. Initially, a minimum of three PJM RTEP subregions will be established: one each for the Mid Atlantic, South, and West subregions of PJM. When a Subregional RTEP Committee meeting is scheduled it is understood that this generally will be implemented as a separate meeting for each subregion. In this way, the TEAC and Subregional RTEP Committees provide a transparent and participatory planning process throughout the RTEP development, from early assumptions-setting stages, through discussion of criteria violations, review of recommendations for alternative solutions, and review and comment on the final RTEP facilities.

All RTO stakeholders can participate in any or all subregional activities on a voluntary basis, with one exception. The Transmission Owners that comprise each of the various subregions must participate in the subregional meeting that includes their area. PJM, with stakeholder input, may initiate additional subregional or local review as may be necessary or beneficial. Local meetings or more localized review occurs in the event that PJM, taking into account stakeholder input, decides that it is appropriate to address issues in a forum other than or in addition to the context of one of the initial subregions. In addition to their participation in the TEAC and Subregional RTEP Committee meetings, stakeholders can also provide written comments on the development of the RTEP. Written comments can be forwarded to RTEP@pjm.com.

There are various categories of facilities that enter the PJM plan through distinct paths, however, each path is transparent and open to all interested stakeholder participation through TEAC and Subregional RTEP Committee processes. All four planning paths to the PJM RTEP; reliability planning, economic planning, interconnection planning, and local Transmission Owner Planning; flow through the TEAC and Subregional RTEP Committee planning process.

PJM Committee review of all RTEP projects, regardless of the path of origin of the project, will occur during the February through August RTEP Stakeholder analysis and review periods (see Exhibit 1.) Stakeholders will be provided all the information necessary for full participation in the discussions and evaluations, including: (1) the criteria and assumptions used as the basis for projects, (2) the procedure to access the study information necessary to participate in the project's evaluation and discussion, (3) a detailed description of the timing, need and justification of the project, (4) a description of the cost and construction responsibility for the project, and (5) a detailed description of the proposed modifications to facilities.

In addition, projects that originate through local Transmission Owner planning will be posted on the PJM web site. This site will include all currently planned transmission owner RTEP projects (including both newly planned Supplemental RTEP projects and Transmission Owner Initiated projects from past RTEP cycles that are yet to be placed in-service.) This website will provide tracking information about the status of listed projects and planned in-service dates. It will also include information regarding criteria, assumptions and availability of study cases related to local planning.

1.3 Planning Assumptions and Model Development

1.3.1 Reliability Planning

PJM's planning analyses are based on a consistent set of fundamental assumptions regarding load, generation and transmission built into power flow models. Load assumptions are based on the annual PJM entity load forecast independently developed by PJM (found at http://www.pjm.com/planning/resource-adequacy-planning/load-forecast-dev-process.aspx.) This forecast includes the basis for all load level assumptions for planning analyses throughout the 15 year planning horizon. Generation and transmission planning assumptions are embodied in the base case power flow models developed annually by PJM and derived from the Eastern Reliability Assessment Group processes and procedures pursuant to NERC standards MOD-010-0, -011-0, and -012-0. As necessary, PJM updates those models with the most recent data available for its own regional studies. All PJM base power flow and related information are available pursuant to applicable Critical Energy Infrastructure Information, Non-Disclosure and OATT-related requirements (accessible via http://www.pjm.com/planning/rtep-development/powerflow-cases.aspx or by contacting the PJM Planning Committee contacts.) Each type of RTEP analysis (e.g., load deliverability, generator deliverability etc.) encompasses its own methodological assumptions as further described throughout the rest of this Manual. Additional details regarding the reliability planning criteria, assumptions, and methods can be found in following sections and this manual's Attachments.

1.3.2 Market Efficiency Planning

PJM will perform a market efficiency analysis each year, following the completion of the near-term reliability plan for the region. PJM's market efficiency planning analyses are based on the same starting assumptions applicable to the reliability planning phase of the RTEP development. In addition, key market efficiency input assumptions, used in the projection of future market inefficiencies; include load and energy forecasts for each PJM zone, fuel costs and emissions costs, expected levels of potential new generation and generation retirements and expected levels of demand response. PJM will input its study assumptions into a commercially available market simulation data model that is available to all stakeholders. The data model contains a detailed representation of the Eastern Interconnection power system generation, transmission and load. In addition, the market efficiency analysis of the cost/benefit of potential market efficiency upgrades will also include the discount rate and annual revenue requirement rate. The discount rate is used to determine the present value of the enhancements' annual benefits and annual cost. The annual revenue requirement rate is used to determine the enhancements' annual cost. PJM will finalize the market efficiency analysis input assumptions soon after the development of the PJM load forecast that is generally available approximately in late January. Prior to finalizing, PJM will review the proposed assumptions at the same PJM Subregional RTEP Committee assumptions meetings that address the reliability analysis assumptions, expected to occur in December preceding the year of the annual RTEP cycle. This review will provide the opportunity for stakeholder review of and input to all of the key assumptions that form the basis of the market efficiency analysis. In this way, PJM will facilitate a comprehensive stakeholder review and input regarding RTEP study assumptions. All final assumptions and analysis parameters will be presented to the TEAC for discussion and review and to the PJM Board for approval.

1.4 RTEP Process Key Components

PJM's goal is to ensure electric supply adequacy and to enhance the robustness of energy and capacity markets. Achieving these objectives requires the successful completion of PJM's planning, facility construction and operational and market infrastructure requirements.

Key components of PJM's 15-year transmission planning process discussed in this Manual include:

1. Baseline reliability analyses:

   The PJM Transmission System ("PJM System") provides the means for delivering the output of interconnected generators to the load centers in the PJM energy and capacity markets. Baseline reliability analyses ensure the security and adequacy of the Transmission System to serve all existing and projected long term firm transmission use including existing and projected native load growth as well as long term firm transmission service. RTEP baseline analyses include system voltage and thermal analysis, and stability, load deliverability, and generation deliverability testing. These tests variously entail single and multiple contingency testing for violations of established NERC reliability criteria regarding stability, thermal line loadings and voltage limits. Baseline reliability analyses are discussed in more detail in Section 2 and Attachment C.

2. Generation and transmission interconnection analyses:

   All entities requesting interconnection of a generating facility (including increases to the capacity of an existing generating unit) or requesting interconnection of a merchant transmission facility within the PJM RTO must do so within PJM's defined interconnection process. In addition to the baseline analyses discussed above, as resources or merchant transmission requests interconnection, deliverability in the local area of the request is restudied and updated. The generation and transmission interconnection process and deliverability testing procedures are discussed in Attachment C and Manual 14A. The evaluation of generation and merchant transmission interconnection requests is codified in the PJM Open Access Transmission Tariff (available on the PJM Web site at www.pjm.com).

3. Market efficiency analyses:

   In addition to reliability based analyses PJM also evaluates the economic merit of proposed transmission enhancements. These analyses focus on the economic impacts of security constraints on production cost, congestion charges to load and other econometric measures of market impacts. PJM's market efficiency analyses are discussed in Section 2 of this Manual and Attachment E. PJM development of economic transmission enhancements is also codified under Schedule 6 of the PJM Operating Agreement.

4. Operational performance issue reviews and accompanying analyses:

   Maintaining a safe and reliable Transmission System also requires keeping the transmission system equipment in safe, reliable operating condition as well as addressing actual operational needs. On an ongoing basis, PJM operating and planning personnel assess the PJM transmission development needs based on recent actual operations. This may lead to special studies or programs to address actual system conditions that may not be evident through projections and system modeling.

To ensure that system facilities are maintained and operated to acceptable reliability performance levels, PJM has implemented an Aging Infrastructure Initiative to evaluate appropriate spare transformer levels and optimum equipment replacement or upgrade requirements. This initiative, based on a Probability Risk Assessment (PRA) process, is intended to result in a proactive, PJM-wide approach to assess the risk of facility failures and to mitigate operational and market impacts. Section 2 of this manual provides further discussion of the PRA process.

5. The final RTEP Plan:

Based on all of the requirements for firm transmission service on the PJM System, PJM annually develops a Regional Transmission Expansion Plan to meet those requirements on a reliable, economic system development and environmentally acceptable basis. Furthermore, by virtue of its regional scope, the RTEP process assures coordination of expansion plans across multiple transmission owners' systems, permitting the identification of the most effective and efficient expansion plan for the region. The RTEP plan developed through this process is reviewed by PJM's independent Board of Managers who has the final authority for plan's approval and implementation. The following Section 2 describes the PJM RTEP Process analysis.

1.5 Planning Criteria

1.5.1 Reliability Planning

Stakeholders have the opportunity at a national level through the participatory standards development process of the North American Electric Reliability Corporation (NERC) to influence the industry planning criteria that form the basis of PJM's planning process (found at http://www.nerc.com/page.php?cid=2.) NERC regional criteria development, applicable to PJM, is also open to stakeholder input through the open and participatory process of ReliabilityFirst Corporation (found at https://www.rfirst.org/standards/Pages/StandardsDocuments.aspx.)

Additionally, regional and local criteria that go beyond and complement the NERC obligations can be created and incorporated into PJM planning through participation in PJM's Planning Committee and other related stakeholder processes (please refer to http://www.pjm.com/committees/pjm.html.) In this manner, PJM, as the independent planning authority, avails stakeholders full opportunity to participate in the planning process from assumptions setting to the final plan. The PJM annual regional plan is based on the effective criteria in place at the time of the analyses, including applicable standards and criteria of the NERC and the applicable regional reliability council[1], the various Nuclear Plant Licensees' Final Safety Analysis Report grid requirements and the PJM and local Reliability

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[1] The Reliability*First* Regional Reliability Corporation (RRC) for the PJM Mid-Atlantic and Western Regions (which replaced the former ECAR, MAAC and MAIN RRCs on January 1, 2006) and the Virginia-Carolinas (VACAR) Area Reliability subregion of the SERC Reliability Corporation for PJM Southern Region.

Planning Criteria (Attachment D.) Section 2 details the specific criteria applicable to each transmission planning process study phase. Criteria are comparably applicable to all similarly situated Native Load Customers and other Transmission Customers.

1.5.2 Market Efficiency Planning

Market efficiency planning is an evaluation process that results in facilities planned to achieve economic efficiencies rather than an analysis that produces violations measured against criteria. This process compares alternative plans' cost effectiveness in improving transmission efficiency and produces RTEP recommendations from this process. The metrics of economic inefficiency include historic and projected congestion. The measures of historic congestion are gross congestion, unhedgeable congestion, and pro-ration of auction revenue rights. The measure of projected congestion is based on a market analysis of future system conditions performed with a commercially available security constrained, economic dispatch market analysis tool. This market analysis results in future projections of the congestion and its binding constraint drivers. These congestion measures are posted and available to stakeholders by binding constraint and form the basis for PJM and stakeholder development of remedies. Transmission plans from the reliability analysis or a new plan presented that economically relieves historical or projected congestion are candidates for market efficiency solutions. The successful candidates will be those facilities that pass PJM's threshold test and bright line economic efficiency test. This test specifies that a proposed solution's savings in the sum of the weighted production cost of energy and capacity plus the weighted load cost of energy and capacity (weighted 70%, 30% respectively) must exceed its projected revenue requirements, on a 15 year present worth basis, by at least 25% (the threshold cost/benefit test.) Each of this process' elements, its underlying assumptions and its methods is described in more detail in the accompanying sections of this manual 14B and in Attachment E.

Section 2: Regional Transmission Expansion Plan Process

In this section you will find an overview of the PJM Region transmission planning process, covering the following areas:

- Components of PJM's 15-Year planning
- The need and drivers for a regional transmission expansion plan
- Reliability planning overview
- Specific components of reliability planning and the Stakeholder process
- Interconnection request drivers of RTEP
- Cost responsibility for reliability related upgrades
- Market efficiency planning review
- Specific components of market efficiency planning and the Stakeholder process.
- Operational performance driven planning
- Specific components of operational performance driven planning

2.1 Transmission Planning = Reliability Planning + Market Efficiency

Effective with the 2006 RTEP, PJM, after stakeholder review and input, expanded its RTEP Process to extend the horizon for consideration of expansion or enhancement projects to fifteen years. This enables planning to anticipate longer lead time transmission needs on a timelier basis.

Fundamentally, the Baseline reliability analysis underlies all planning analysis and recommendations. On this foundation, PJM's annual 15-year planning review now yields a regional plan that encompasses the following:

1. Baseline reliability upgrades, discussed in this Section 2;
2. Generation and transmission interconnection upgrades, discussed in Attachment C and Manual 14A.
3. Market efficiency driven upgrades, discussed in this Section 2.
4. Operational performance issue driven upgrades, discussed in this Section 2.

Exhibit 1 shows the annual cycle of the 15-year RTEP process. This cycle integrates reliability and market efficiency analysis with information transparency, stakeholder input and review and PJM Board of Manager approvals. This Cycle is discussed in detail in this and related manuals and attachments. Activities shown on this diagram and their timing are an idealized view that will be responsive to the RTEP and Stakeholder needs and thus may vary accordingly.

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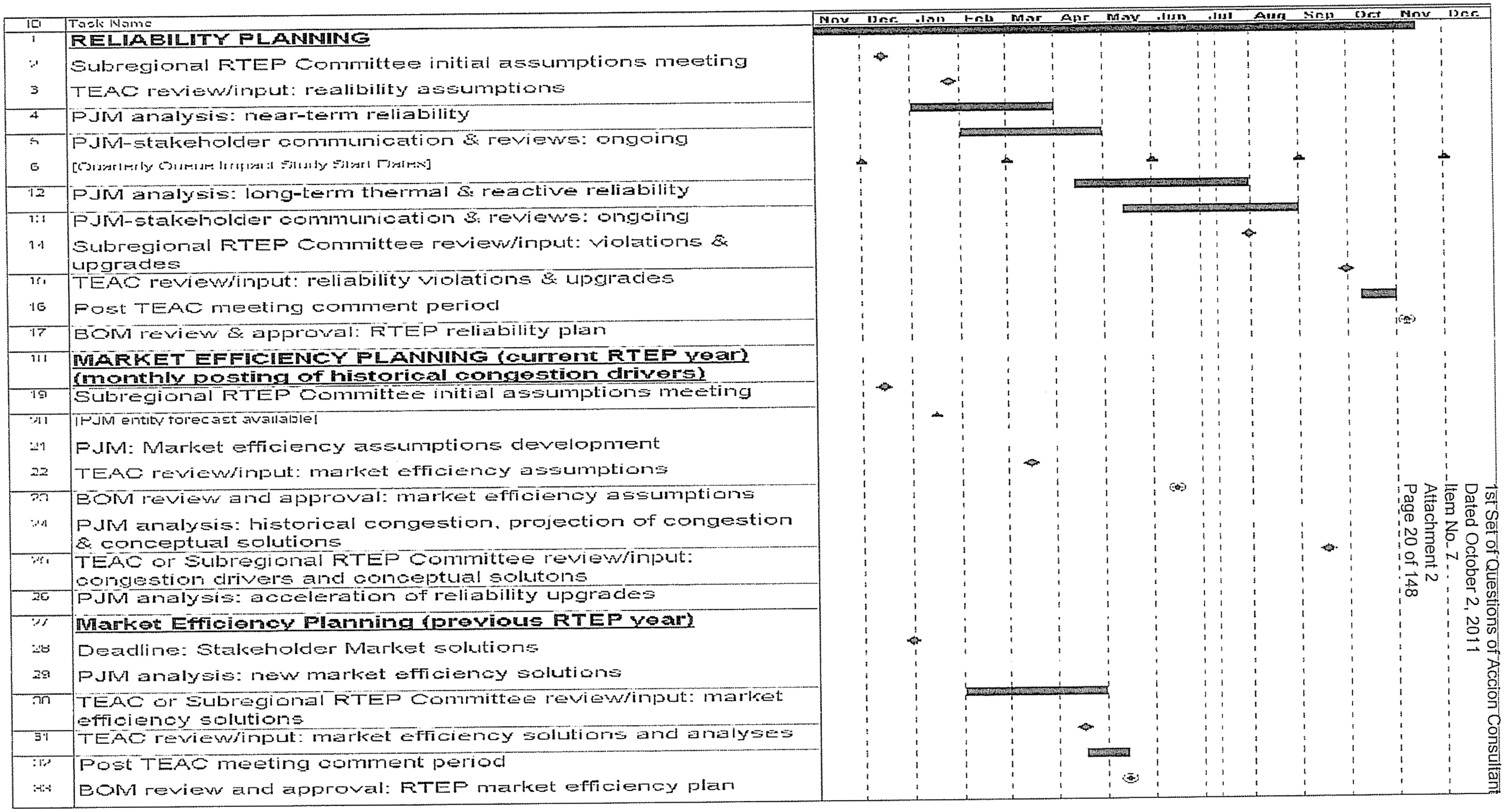
Exhibit 1: PJM Annual RTEP Planning Cycle for 15-Year Plan

This timeline represents the idealized RTEP process. At the beginning of each RTEP cycle, PJM will provide specific timeline information for the upcoming study cycle.



ID	Task Name
1	**RELIABILITY PLANNING**
2	Subregional RTEP Committee initial assumptions meeting
3	TEAC review/input: realibility assumptions
4	PJM analysis: near-term reliability
5	PJM-stakeholder communication & reviews: ongoing
6	[Quarterly Queue Impact Study Start Dates]
12	PJM analysis: long-term thermal & reactive reliability
13	PJM-stakeholder communication & reviews: ongoing
14	Subregional RTEP Committee review/input: violations & upgrades
15	TEAC review/input: reliability violations & upgrades
16	Post TEAC meeting comment period
17	BOM review & approval: RTEP reliability plan
18	**MARKET EFFICIENCY PLANNING (current RTEP year) (monthly posting of historical congestion drivers)**
19	Subregional RTEP Committee initial assumptions meeting
20	[PJM entity forecast available]
21	PJM: Market efficiency assumptions development
22	TEAC review/input: market efficiency assumptions
23	BOM review and approval: market efficiency assumptions
24	PJM analysis: historical congestion, projection of congestion & conceptual solutions
25	TEAC or Subregional RTEP Committee review/input: congestion drivers and conceptual solutons
26	PJM analysis: acceleration of reliability upgrades
27	**Market Efficiency Planning (previous RTEP year)**
28	Deadline: Stakeholder Market solutions
29	PJM analysis: new market efficiency solutions
30	TEAC or Subregional RTEP Committee review/input: market efficiency solutions
31	TEAC review/input: market efficiency solutions and analyses
32	Post TEAC meeting comment period
33	BOM review and approval: RTEP market efficiency plan

2.2 The RTEP Process Drivers

The continuing evolution and growth of PJM's robust and competitive regional markets rests on a foundation of bulk power system reliability, ensuring PJM's ongoing ability to meet control area load-serving obligations. It also includes a commitment to enhance the robustness and competitiveness of Energy and Capacity markets by incorporating analysis and development of market efficiency projects. Schedule 6 of the PJM Operating Agreement describes the PJM RTEP process, governing the means by which PJM coordinates the preparation of a plan for the enhancement and expansion of the Transmission Facilities – on a reliable and environmentally sensitive basis and in full consideration of available economic and market efficiency factors and alternatives - in order to meet the demands for firm transmission service in the PJM region. PJM's FERC-approved RTEP process preserves this foundation through independent analysis and recommendation, supported by broad stakeholder input and approval by an independent RTO Board in order to produce a single RTEP.

The PJM Region transmission planning process is driven by a number of planning perspectives and inputs, including the following:

- ReliabilityFirst Regional Reliability Corporation[2] (RFC) Reliability Assessment – forward-looking assessments performed to assure compliance with NERC and applicable regional reliability corporation (ReliabilityFirst or SERC Reliability Corporation) reliability standards, as appropriate.
- SERC Reliability Corporation (SERC) Reliability Assessment
- PJM Annual Report on Operations – an assessment of the previous year's operational performance to assure that any bulk power system operational conditions which have emerged, e.g., congestion, are adequately considered going forward.
- PJM Load Serving Entity (LSE) capacity plans
- Generator and Transmission Interconnection Requests – submitted by the developers of new generating sources and new Merchant Transmission Facilities, these requests seek interconnection in the PJM Region (or seek needed enhancements as the result of increases in existing generating resources.)
- Transmission Owner and other stakeholder transmission development plans
- Interregional transmission development plans – the transmission expansion plans of those power systems adjoining PJM, and in some cases, beyond.
- Long-term Firm Transmission Service Requests
- Activities under the PJM committee structure especially, the Planning Committee (PC), the Transmission Expansion Advisory Committee

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[2] Reliability*First*, a new regional reliability corporation under the North American Electric Reliability Corporation (NERC), replaced three existing PJM-related reliability councils (ECAR, MAAC and MAIN) on January 1, 2006.

(TEAC), the Subregional RTEP Committee, and local groups facilitated by PJM within the TEAC established processes (see section 1 "TEAC, Subregional RTEP Committee, and related planning activities".)

- PJM Development of Economic Transmission Enhancements based on Economic and Market Efficiency factors
- Operational performance assessments and reviews such as the aging Infrastructure Initiative – a Probabilistic Risk Assessment of equipment that poses significant risk to the Transmission System.

The cumulative effect of these drivers is analyzed through the PJM Region transmission planning process to develop a single RTEP which recommends specific transmission facility enhancements and expansion on a reliable and environmentally sensitive basis and in full consideration of economic and market efficiency analyses. See Attachment B for details of the RTEP – Scope and Procedure.

NOTE: The most recent version of the PJM RTEP is available PJM Web site at http://www.pjm.com/planning/rtep-upgrades-status.aspx.

These analyses are conducted on a continual basis, reflecting specific new customer needs as they are introduced, but also readjusting as the needs of Transmission Customers and Developers change. One such RTEP baseline regional plan will be developed and approved each year.

NOTE: Generation withdrawals have the potential to impact study results for any generation or merchant transmission project that doesn't have an executed ISA.

Generation retirements will not affect the study results for any generation or merchant transmission project that has received an Impact Study Report (i.e., No Retool – the generator retirements are applied at the next baseline update.)

Generation retirements included in interconnection project studies will be those announced as of the date a project enters the interconnection queue.

In this way, the plan continually represents a reliable means to meet the power system requirements of the various Transmission Customers and Interconnection Customers in a fully integrated fashion, at the same time preserving the rights of all parties with respect to the Transmission System. The assurance of a reliable Transmission System and the protection of the Transmission Customer/Developer rights with respect to that system coupled with the timely provision of information to stakeholders are the foundation principles of the PJM transmission planning process.

The PJM Region transmission planning process also establishes the cost responsibility for the following types of facility enhancements as defined in the PJM Tariff:

- Attachment Facilities
- Direct Assignment Facilities
- Network Upgrades (Direct and Non-direct)
- Local Upgrades

- Merchant Network Upgrades

Each RTEP encompasses a range of proposed power system enhancements: circuit breaker replacements to accommodate increased current interrupting duty cycles; new capacitors to increase reactive power support; new lines, line reconductoring and new transformers to accommodate increased power flows; and, other circuit reconfigurations to accommodate power system changes as revealed by the drivers discussed above.

Requests for interconnection of new generators or transmission facilities, while not the sole drivers of the PJM Region transmission planning process, are a key component of the RTEP. Analyzing these requests has required adoption of an approach that establishes baseline system improvements driven by known inputs, followed by separate queue-defined, cluster-based impact study analyses. Overall, PJM's RTEP process – under a FERC-approved RTO model – encompasses independent analysis, recommendation and approval to ensure that facility enhancements and cost responsibilities can be identified in a fair and non-discriminatory manner, free of any market sector's influence. All PJM market participants can be assured that the proposed RTEP was created on a level playing field.

2.3 RTEP Reliability Planning

2.3.1 Establishing a Baseline

In order to establish a reference point for the annual development of the RTEP reliability analyses a 'baseline' analysis of system adequacy and security is necessary. The purpose of this analysis is threefold:

- To identify areas where the system, as planned, is not in compliance with applicable NERC and the applicable regional reliability council (ReliabilityFirst or SERC) standards, Nuclear Plant Licensee requirements and PJM reliability standards including equipment replacement and/or upgrade requirements under PJM's Aging Infrastructure Initiative. The baseline system is analyzed using the same criteria and analysis methods that are used for assessing the impact of proposed new interconnection projects. This ensures that the need for system enhancements due to baseline system requirements and those enhancements due to new projects are determined in a consistent and equitable manner.
- To develop and recommend facility enhancement plans, including cost estimates and estimated in-service dates, to bring those areas into compliance.
- To establish the baseline facilities and costs for system reliability. This forms the baseline for determining facilities and expansion costs for interconnections to the Transmission System that cause the need for facilities beyond those required for system reliability.

The system as planned to accommodate forecast demand, committed resources, and commitments for firm transmission service for a specified time frame is tested for compliance with NERC and the applicable regional reliability council (ReliabilityFirst or SERC) standards, Nuclear Plant Licensee requirements, PJM Reliability Standards and PJM design standards. Areas not in compliance with the standards are identified and enhancement plans to achieve compliance are developed.

The 'baseline' analysis and the resulting expansion plans serve as the base system for conducting Feasibility Studies for all proposed generation and/or merchant transmission facility interconnection projects and subsequent System Impact Studies.

2.3.2 Baseline Reliability Analysis

PJM's most fundamental responsibility is to plan and operate a safe and reliable Transmission System that serves all long term firm transmission uses on a comparable and not unduly discriminatory basis. This responsibility is addressed by PJM RTEP reliability planning. Reliability planning is a series of detailed analyses that ensure reliability under the most stringent of the applicable NERC, PJM or local criteria. To accomplish this each year, the RTEP cycle extends and updates the transmission expansion plan with a 15 year review. This cycle entails several steps. The following sections describe each step's assumptions, process and criteria. Attachments A through F of this manual add essential details of various aspects of the reliability planning process.

Reliability planning involves a near-term and a longer term review. The near term analysis is applicable for the current year through the current year plus 5. The longer term view is applicable for the current year plus 6 through plus 15. Each review entails multiple analysis steps subject to the specific criteria that depend on the specific facilities and the type of analysis being performed.

The analysis is initiated in December prior to each annual cycle and concludes with review by the TEAC and approval by the PJM Board about October (TEAC and the PJM Board are appraised regularly throughout the process and partial reviews and approvals of the plan may occur throughout the year.) The TEAC, Subregional RTEP and PJM Planning Committee roles in the development of the reliability portion of the RTEP are described in Schedule 6 of the PJM Operating Agreement.

2.3.3 Near-Term Reliability Review

The near-term reliability review (current year plus 5) provides reinforcement for criteria violations that are revealed by applicable contingency analysis. Limits used in the analysis are established consistent with the requirements of NERC standards FAC-010 and FAC-014. The methodology used to determine system operating limits is included in Attachment-F of this manual. System conditions revealed as near violations will be monitored and remedied as needed in the following year near-term analysis. Violations that occur in many deliverability areas or severe violations in any one area will be referred to the long term analysis for added study of possible more robust system enhancement. PJM annually conducts this detailed review of the current year plus 5. Each year of the period through the current year plus 4 ("in-close" years) has been the subject of previous years' detailed analyses. In addition, for each of these "in-close" years, PJM updates and issues addendum to address changes as necessary throughout the year. For example planned generation modifications or changes in transmission topology can trigger restudy and the issuance of a baseline addendum. This is referred to as a "retool" study. (For example generators that drop from the Q's cause restudy and an addendum to be issued for affected baseline analyses.) Also each year during the establishment of the assumptions for the new annual baseline analysis, current updated views of load, transmission topology, installed generation, and generation and transmission maintenance are assessed for the "in-close" range of years to validate the continued applicability of each of the "in-close" baseline analyses and resulting upgrades (including any addendum.) Adjustments in the "in-close" analyses are performed as deemed necessary by PJM. PJM, therefore, annually verifies the continued need for or modification of past recommended upgrades through its retool studies, reassessment of current conditions and any needed adjustments to analyses. All criteria thermal and voltage violations resulting from the near term analyses are produced using solved AC power flow solutions. Initial massive contingency screening may use DC power flow solution techniques.

There are seven steps in an annual near-term reliability review. They are:

- Develop a Reference System Power Flow Case
- Baseline Thermal
- Baseline Voltage
- Load Deliverability - Thermal
- Load Deliverability - Voltage
- Generation Deliverability - Thermal
- Baseline Stability

These reliability related steps are followed by a scenario analysis that ensures the robustness of the plan by looking at impacts of variations in key parameters selected by PJM. Each of these steps are described in more detail in the following material.

2.3.4 Reference System Power Flow Case

The reference power flow case and the analysis techniques comprise the full set of analysis assumptions and parameters for reliability analysis. Each case is developed from the most recent set of Eastern Reliability Assessment Group system models. PJM transmission planning revises this model as needed to incorporate all of the current system parameters and assumptions. These assumptions include current loads, installed generating capacity, transmission and generation maintenance, system topology, and firm transactions. These assumptions will be provided to and reviewed by the Subregional RTEP Committee. The subregional modeling review and modeling assumptions meeting provides the opportunity for stakeholders to review and provide input to the development of the reference power system models used to perform the reliability analyses.

The results of any locational capacity market auction(s) will be used to help determine the amount and location of generation or demand side resources to be included in the reliability modeling. Generation or demand side resources that are cleared in any locational capacity market auction will be included in the reliability modeling, and generation or demand side resources that either do not bid or do not clear in any locational capacity market auction will not be included in the reliability modeling. All such modeling described here will comport with the capacity construct provisions approved by the FERC.

Subsequent to the subregional stakeholder modeling reviews facilitated by PJM, PJM will develop the final set of reliability assumptions to be presented to TEAC for review and comment, after which PJM will finalize the reliability review reference power flow. This model is expected to be available in early January of each year to interested stakeholders, subject to applicable confidentiality and CEII requirements, to facilitate their review of the results of the reliability modeling analyses.

2.3.5 Contingency Definitions

Contingency definitions used in RTEP analysis are the same as applicable NERC TPL contingency definitions. Where the physical design of connections or breaker arrangements results in the outage of more than the faulted equipment when a fault is cleared, the additional facilities are also taken out of service in the contingency definition. For example, if a transformer is tapped off a line without a breaker, both the line and transformer are removed from service as a single contingency event.

Contingency definitions for double circuit tower line outages shall include any two adjacent (vertically or horizontally) circuits on a common structure, but shall exclude circuits that share a common structure for one mile or less. The loss of more than two circuits on a common structure constitutes a NERC extreme event.

2.3.6 Baseline Thermal Analysis

Baseline thermal analysis is a thorough analysis of the reference power flow to ensure thermal adequacy based on normal (applicable to system normal conditions prior to contingencies) and emergency (applicable after the occurrence of a contingency) ratings specific to the Transmission Owner facilities being examined. It is based on a 50/50 load forecast from the latest available PJM Load Forecast Report (50% probability that the actual load is higher or lower than the projected load.) It encompasses an exhaustive analysis of all NERC category A, B and C events and the most critical common mode outages. Final results are supported with AC power flow solutions.

For normal conditions, all facilities shall be loaded within their normal ratings. After each single contingency, all control equipment is allowed to adjust. After the first contingency of a multiple-contingency event (NERC category C.3, also referred to as an "N-1-1" event,) all system adjustments are made to achieve a new steady state power flow, including redispatch in preparation for the next contingency. Subsequent to redispatch all facilities must be within normal ratings. After the second contingency of the pair the technique for single contingencies is followed except that phase shifters are locked and do not adjust to hold flow. All violations of emergency ratings are recorded and reported and tentative solutions will be developed. These study results will be presented to and reviewed with stakeholders.

2.3.7 Baseline Voltage Analysis

Baseline voltage analysis parallels the thermal analysis. It uses the same power flow and examines all the same NERC category A, B, and C events. Also, voltage criteria are examined for compliance. PJM examines system performance for both a voltage drop criteria and an absolute voltage criteria. The voltage drop is calculated as the decrease in bus voltage from the initial steady state power flow to the post-contingency power flow. The post-contingency power flow is solved with generators holding a local generator bus voltage to a pre-contingency level consistent with specific Transmission Owner specifications. In most instances this is the pre-contingency generator bus voltage. Additionally, all phase shifters, transformer taps, switched shunts, and DC lines are locked for the post-contingency solution. SVC's are allowed to regulate.

The absolute voltage criteria is examined for the same contingency set by allowing transformer taps, switched shunts and SVC's to regulate, locking phase shifters and allowing generators to hold steady state voltage criteria (generally an agreed upon voltage on the high voltage bus at the generator location.)

In all instances, specific Transmission Owner voltage criteria are observed. All violations are recorded and reported and tentative solutions will be developed. These study results will be presented to and reviewed with stakeholders.

2.3.8 Load Deliverability Analysis

The load deliverability tests are a unique set of analyses designed to ensure that the Transmission System provides a comparable transmission function throughout the system. These tests ensure that the Transmission System is adequate to deliver each load area's requirements from the aggregate of system generation. The tests develop an "expected value" of loading after testing an extensive array of probabilistic dispatches to determine thermal limits. A deterministic dispatch method is used to create imports for the voltage criteria test. The Transmission System reliability criterion used is 1 event of failure in 25 years. This is intended to design transmission so that it is not more limiting than the generation system which is planned to a reliability criterion of 1 failure event in 10 years.

Each load areas' deliverability target transfer level to achieve the transmission reliability criterion is separately developed using a probabilistic modeling of the load and generation system. The load deliverability tests described here measure the design transfer level supported by the Transmission System for comparison to the target transfer level. Transmission upgrades are specified by PJM to achieve the target transfer level as necessary. Details of the load deliverability procedure can be found in Attachment C.

Thermal

This test examines the deliverability under the stressed conditions of a 90/10 summer load forecast. That is, a forecast that only has a 10% chance of being exceeded. The transfer limit to the load is determined for system normal and all single contingencies (NERC category A and B criteria) under ten thousand load study area dispatches with calculated probabilities of occurrence. The dispatches are developed randomly based on the availability data for each generating unit. This results in an expected value of system transfer capability that is compared to the target level to determine system adequacy. As with all thermal transmission tests applied by PJM the applicable Transmission Owner normal and emergency ratings are applied. The steady state and single contingency power flows are solved consistent with the similar solutions described for the baseline thermal analyses.

Voltage

This testing procedure is similar to the thermal load deliverability test except that voltage criteria are evaluated and that a deterministic dispatch procedure is used to increase study area imports. The voltage tests and criteria are the same as those performed for the baseline voltage analyses.

2.3.9 Generation Deliverability Analysis

The generator deliverability test for the reliability analysis ensures that, consistent with the load deliverability single contingency testing procedure, the Transmission System is capable of delivering the aggregate system generating capacity at peak load with all firm transmission service modeled. The procedure ensures sufficient transmission capability in all areas of the system to export an amount of generation capacity at least equal to the amount of certified capacity resources in each "area". Areas, as referred to in the generation deliverability test, are unique to each study and depend on the electrical system characteristics that may limit transfer of capacity resources. For generator deliverability areas are defined with respect to each transmission element that may limit transfer of the aggregate of certified installed generating capacity. The cluster of generators with significant impacts on the potentially limiting element is the "area" for that element. The starting point power flow is the same power flow case set up for the baseline analysis. Thus the same baseline load and ratings criteria apply. The flowgates ultimately used in the light load reliability analysis are determined by running all contingencies maintained by PJM planning and monitoring all PJM market monitored facilities and all BES facilities. As already mentioned the same contingencies used for load deliverability apply and the same single contingency power flow solution techniques also apply. Details of the generation deliverability procedure can be found in Attachment C.

One additional step is applied after generation deliverability is ensured consistent with the load deliverability tests. The additional step is required by system reliability criteria that call for adequate and secure transmission during certain NERC category C common mode outages. The procedure mirrors the generator deliverability procedure with somewhat lower deliverability requirements consistent with the increased severity of the contingencies.

The details of the generator deliverability procedure including methods of creating the study dispatch can be found in Attachment C.

2.3.10 Light Load Reliability Analysis

The light load reliability analysis ensures that the Transmission System is capable of delivering the system generating capacity at light load. The 50% of 50/50 summer peak demand level was chosen as being representative of an average light load condition. The system generating capability modeling assumption for this analysis is that the generation modeled reflects generation by fuel class that historically operates during the light load demand level.

The starting point power flow is the same power flow case set up for the baseline analysis, with adjustment to the model for the light load demand level, interchange, and accompanying generation dispatch. The PJM portion of the model is adjusted as well as areas surrounding PJM that impact loadings on facilities in PJM. Interchange levels for the various PJM zones will reflect a statistical average of typical previous years interchange values for off-peak hours. Load level, interchange, and generation dispatch for non-PJM areas impacting PJM facilities are based on statistical averages for previous off-peak periods. Thus the same baseline network model and criteria apply. The flowgates ultimately used in the light load reliability analysis are determined by running all contingencies maintained by PJM planning and monitoring all PJM market monitored facilities and all BES facilities. The contingencies used for light load reliability analysis will include NERC TPL category B and category C, with the exception of the C3 "N-1-1" criteria. NERC TPL Category A, normal system conditions will also be studied. All BES facilities and all non-BES facilities in the PJM real-time congestion management control facility list are monitored. The same single contingency power flow solution techniques also apply. Details of the light load reliability analysis procedure, including methods of creating the study dispatch, can be found in Attachment D.1.

2.3.11 Baseline Stability Analysis

PJM ensures generator and system stability during its interconnection studies for each new generator. In addition, PJM annually performs stability analysis for approximately one third of the existing generators on the system. Analysis is performed on the RTEP baseline power flow. These analyses ensure the system is transiently stable and that all system oscillations display positive damping. Generator stability is performed for critical system conditions, which includes light load and three phase faults with normal clearing plus single line to ground faults with delayed clearing. Also, specific Transmission owner designated faults are examined for plants on their respective systems.

{PJM IS CURRENTLY EVALUATING STABILITY ANALYSIS NEEDS RELATED TO RFC CRITERIA. ANY REVISIONS OR ADDITIONS TO RTEP STABILITY ASSESSMENTS WILL BE INCLUDED HERE AS THAT REVIEW PROGRESSES AND WILL BE PRESENTED THROUGH THE APPROPRIATE PJM MANUAL REVIEW PROCESS.}

Finally, PJM will initiate special stability studies as the need arises. The impetus for such special studies commonly includes but is not limited to conditions arising from operational performance reviews or major equipment outages.

2.3.12 Long Term Reliability Review

The PJM RTEP reliability review process examines the longer term planning horizon using a current year plus 15 power flow model and a current year plus 10 power flow model. Assumptions and model development regarding this longer term view will be presented and reviewed and stakeholder input will be considered in the same process used for the near-term review. The longer term view of system reliability is subject to increased uncertainty due to the increased likelihood of changes in the analysis as time progresses. The purpose of the long term review is to anticipate system trends which may require longer lead time solutions. This enables PJM to take appropriate action when system issues may require initiation during the near term horizon in anticipation of potential violations in the longer term. System issues uncovered that are amenable to shorter lead time remedies will be addressed as they enter into the near-term horizon.

Current Year Plus 15 Analysis

The Longer term reliability review involving single and multiple contingency analyses is conducted to detect system conditions which may need a solution with a lead-time to operation exceeding five years. Two processes will be used as indicators to determine the need for contingency analysis in the longer term horizon. The first is a review of the near-term results to detect violations that occur for multiple deliverability areas or multiple or severe violations clustered in a one area of the system. This review may suggest larger projects to collectively address groups of violations. The second is a thermal analysis including double circuit towerline outages at voltages exceeding 100 kV performed on the current year plus fifteen system. All of the current year plus fifteen results produced will be reviewed to determine if any issues may require longer lead time solutions. If so such solutions will be determined and considered for inclusion in RTEP.

This evaluation of the need for longer lead time solutions considers that the NERC category C results may employ load shedding and/or curtailment of firm transactions to ease potential violations. Also this review considers that the current year plus fifteen planning horizon exceeds the required NERC planning horizon. The main effect of this extension to 15 years is to examine a load level that is significantly higher than the base forecast year-ten planning load level. This year fifteen analysis, therefore, captures the equivalent (in a 10-year horizon) of a higher load forecast plus weather sensitivity. To the extent that this long term reliability thermal review indicates marginal system conditions that may require a longer lead time solution, PJM will undertake additional longer term analyses as may be needed.

The long term deliverability analyses follow a similar pattern to the near-term load and generation deliverability analyses. The long term, however, relies solely on linear DC analysis whereas all near term violations result from analysis solutions that rely on the full AC power flow. The load deliverability case is set up for a 90/10 load level and the generation deliverability case is set up for a 50/50 load level. Generation dispatches are determined consistent with the methods for the near term analyses. The analysis for the longer term horizon evaluates all NERC category A and B single contingencies against the same normal and emergency thermal ratings criteria used for the near term (subject to any upgrades that may be applicable for the longer term.)

Reactive Analysis

In addition, the longer term review includes a current year plus 10 reactive analysis. This focuses on contingencies involving facilities above 200 kV in areas where the preceding year-15 analysis uncovered thermal violations. Areas experiencing thermal violations that also show earlier reactive deficiencies will be reviewed for possible acceleration of any longer lead time thermal solutions that were suggested by the year-15 analysis. This analysis, as necessary from year to year, will also consider long-term upgrade sensitivity to key variables such as load power factor delivered from the Transmission System or heavy transfers. If uncovered violations are insufficient to justify acceleration of upgrades and are all amenable to shorter lead-time upgrades, then the violations will continue to be monitored in future RTEP analyses.

2.3.13 Stakeholder review of and input to Reliability Planning

RTEP reliability planning, through the operation of the TEAC and Subregional RTEP Committees, provides interested parties with the opportunity to review and provide meaningful and timely input to all phases of the reliability planning analyses. This section extends the Section 1 discussion of the TEAC and Subregional RTEP Committee process specifically as it relates to reliability planning. Exhibit 1 shows the workflow and timing for the reliability planning process steps. PJM anticipates at least two Subregional RTEP Committee reliability reviews. The initial subregional meeting will present and address reliability study assumptions and parameters. The second meeting will provide the opportunity for stakeholder comment and input on criteria violations and presentations of alternative remedies to identified violations. Between the two meetings PJM will provide feedback on interim study progress sufficient to enable stakeholder preparation for the second set of subregional meetings. Additional subregional meetings will be facilitated as PJM determines is necessary for adequate input and review. The relative timing of the TEAC and subregional activities are illustrated in Exhibit 1.

Subregional RTEP Committee initial assumptions meeting

This meeting is expected to occur in ***December*** of each year in preparation for the upcoming annual RTEP review. Prior to the meeting PJM will post its anticipated inputs and assumptions to enable stakeholder review and preparation for the meeting. At the meeting PJM will present the assumptions for discussion and input by all interested parties. Subsequent to this meeting stakeholders will have additional opportunity to provide input to PJM in preparation for the next TEAC meeting, at which PJM will present the final reliability assumptions for TEAC review. Although the initial Subregional assumptions meeting will discuss anticipated assumptions for both the reliability and market efficiency phase of the RTEP, The final TEAC review of each will likely occur at separate TEAC meetings (see also the market efficiency discussion following.) The TEAC endorsement of final RTEP reliability assumptions is expected to occur in early ***January***.

PJM development of criteria violations and stakeholder participation

After the TEAC endorsement of PJM's RTEP analysis assumptions, PJM will finalize its reference system power flow which is the starting point of its series of reliability analyses. This power flow is available to stakeholders subject to applicable confidentiality and CEII requirements. PJM will perform its series of detailed RTEP reliability analyses encompassing the 15-year planning horizon. Details of the methods and procedures for the reliability analyses can be found elsewhere in this Manual 14B and its attachments. The five-year and longer time-frame criteria violations will be posted for review, evaluation and development of remedy alternatives by all interested parties. The PJM production of the reliability analysis raw results is expected to occur about ***January through July*** of each year. Posting of the results and stakeholder review and consideration of alternative remedies is expected to occur about ***February through August*** of each year. PJM will post TO and other stakeholder alternative upgrade remedies made available throughout this process. Throughout this time frame, TEAC typically has monthly or more frequent regularly scheduled meetings. PJM will periodically apprise TEAC of the progress of the violations identification and production of upgrade alternatives. Stakeholders may use these meetings to raise and discuss issues found in their reviews. Depending on the issues raised and input from stakeholders PJM may facilitate Subregional RTEP Committee meetings instead of or in addition to a scheduled TEAC meeting. These subregional meetings are intended for more focused review of subregional violations and alternative solutions.

Subregional RTEP Committee criteria violations and upgrade alternative meeting

This meeting is expected to occur, as may be necessary in various subregions, in the ***July / August*** timeframe each year. If a subregional meeting is unnecessary, the regularly scheduled TEAC meetings will provide the opportunity for that subregion's participants open discussion of violations and upgrades. In any event, all regional and subregional projects will be appropriately presented and reviewed at a TEAC meeting. Prior to a subregional violations and upgrade meeting, PJM will post the upgrade solutions that it proposes to remedy the identified criteria violations. At this subregional meeting PJM will present the reliability upgrades of specific violations and alternative upgrades as may be appropriate. By this Subregional RTEP Committee meeting, interested parties will have had the opportunity for ongoing participation in the ***February through August*** process of violation review and solution identification along with PJM and Transmission Owners. This subregional criteria violations and upgrade meeting is the forum for a final open discussion of the subregional reviews which have been occurring, prior to presentation to TEAC.

PJM TEAC Committee RTEP review

PJM expects that about ***August*** of each year, the final RTEP upgrade facilities will be available for presentation, review and endorsement at a scheduled TEAC meeting. PJM will post its recommendations of RTEP upgrades for identified violations as early as possible in the month prior to the TEAC meeting at which the final RTEP facilities will be reviewed (see RTEP@pjm.com). This posting will distinguish facilities that are deemed Supplemental RTEP Projects. After the TEAC RTEP review meeting, there will be about a month of additional time for final written comments on the proposed RTEP facilities, after which the PJM Board will consider the final RTEP plan excluding Supplemental Projects for approval.

2.4 RTEP integrates Baseline Assumptions, Reliability Upgrades and Request Evaluations

PJM's robust energy market has attracted numerous requests from generator and transmission developers for interconnections with the Transmission System. These generator and transmission Interconnection Requests constitute a significant driver of regional transmission expansion needs. This subsection discusses this driver in the context of the RTEP preparation. Details of this process are contained in Manual 14A.

Requests for Long Term Firm Transmission Service and generator deactivations are other types of request that are evaluated and incorporated into RTEP.

Demand Response (DR) can be a load response solution to the need for transmission upgrades. DR solutions enter the PJM process in the Reliability Pricing Model (RPM) through the associated base residual and incremental auctions. The DR cleared in the auction is included in the assumptions for RTEP development and physically modeled in the baseline power flows. In this manner, load can mitigate or delay the need for RTEP upgrades.

The RTEP process baseline analyses include previously processed generators and transmission modifications as starting point assumptions. The current year RTEP evaluations performed on this baseline case are incremental to the baseline and establish a "revised" baseline for the year of the annual RTEP analysis. This revised baseline forms the starting case for the reviews of new interconnection requests. The new interconnection request analyses result in system modifications beyond RTEP upgrades that are caused by each interconnection request. New interconnection request evaluations also include a review of their effects on newly approved RTEP upgrades that are not yet committed to construction. If previously identified RTEP upgrades can be delayed because of a new interconnection request, the projects responsible for the upgrade deferrals will be credited for the benefits of the delayed need for the upgrades.

The RTEP integrates reliability upgrades, interconnection request upgrades and plan modifications and DR effects into a single process that accounts for the mutual interaction of the various market forces. In this way, transmission upgrades, interconnection requests and DR receive comparable treatment with respect to their opportunity to relieve transmission constraints.

Timing of Long-Term Firm Transmission Service Requests, and Generation and Transmission Interconnection Requests are based on the business needs of the party requesting the service. Such Requests, therefore, enter the RTEP planning process throughout the RTEP planning year. Expansion plans that result from these individual project evaluations are incorporated into the RTEP after the system impact study stage. In addition, if needed to satisfy assumed planning reserve requirements for future planning year analyses, queue generators in earlier stages of the queue process may also be included. Only the queue generators with completed signed Interconnection Service Agreements, however, are allowed to be used to alleviate constraints.

This manual contains the details regarding the RTEP reliability planning process procedures. Refer to the introductory Manual 14 for references to the details associated with other elements of RTEP including the request and RPM processes.

2.5 RTEP Cost Responsibility for Required Enhancements

The RTEP encompasses two types of enhancements: Network Reinforcements and Direct Connection Attachment Facilities. Network Reinforcements can be required in order to accommodate the interconnection of a merchant project (generation or transmission) or to eliminate a Baseline problem as a result of system changes such as load growth, known transmission owner facility additions, etc. Merchant project driven upgrades are addressed in Manual 14A. The cost responsibility for each baseline-revealed Network Reinforcement is borne by transmission owners based on the contribution to the need for the network reinforcement. Such costs are recoverable by each transmission owner through FERC-filed transmission service rates. Network reinforcements may also be proposed by PJM to mitigate unhedgeable congestion. Allocation procedures for Baseline and Market Efficiency upgrades are discussed in Attachment A.

Overall, the RTEP is best understood from the perspective of the studies that revealed the recommended Plan enhancements. To that end, the Baseline Analysis and Impact Studies identify the enhancements required to meet defined NERC and applicable regional reliability council (Reliability First or VACAR/SERC) standards, Nuclear Plant Licensee requirements and PJM reliability standards.

2.6 RTEP Market Efficiency Planning

Market efficiency analysis is performed as part of the overall PJM Regional Transmission Expansion Planning (RTEP) process to accomplish the following two objectives:

1. Determine which reliability upgrades, if any, have an economic benefit if accelerated.
2. Identify new transmission upgrades that may result in economic benefits.

PJM will perform a market efficiency analysis each year, following the availability of the appropriate updated RTEP power flow resulting from the reliability analysis process. As a result, there is a mechanism in place for regularly identifying transmission enhancements or expansions that will relieve transmission reliability violations that also have an economic impact. Constraints that have an economic impact include, but are not limited to, constraints that cause: (1) significant historical gross congestion; (2) significant historical unhedgeable congestion; (3) pro-ration of Stage 1B ARR; or (4) significant future congestion as forecast in the market efficiency analysis.

In the market efficiency analysis, PJM will compare the costs and benefits of the economic-based transmission improvements. To calculate the benefits of these potential economic-based enhancements, PJM will perform and compare market simulations with and without the proposed accelerated reliability-based enhancements or the newly proposed economic-based enhancements for selected future years within the planning horizon of the RTEP. The relative benefits and costs of the economic-based enhancement or expansion must meet the benefit/cost ratio threshold test to be included in the RTEP recommended to the PJM Board of Managers for approval (This test and its implementation is described in detail in Attachment E.) PJM will also consider potential individual plans meeting objectives 1 or 2 resulting from the analyses of the posted congestion data by all stakeholders. PJM will present all the RTEP market efficiency enhancements to the TEAC Committee for review, comment and endorsement. Subsequent to TEAC review, PJM will address the TEAC review and present the final RTEP market efficiency plan to the PJM Board, along with the advice, comments, and recommendations of the TEAC Committee, for Board approval.

2.6.1 Market Efficiency Analysis and Stakeholder Process

PJM's market efficiency analysis involves several phases. The process begins with the determination of the congestion drivers that may signal market inefficiencies. PJM will collect and publicly post relevant drivers. These metrics will be reviewed by PJM and all stakeholders to assess the system areas that are most likely candidates for market efficiency upgrades. In addition, PJM will perform market simulations to determine projections of future market congestion based on the anticipated RTEP upgraded system. This process facilitates concurrent PJM and stakeholder review of the same information considered by PJM in preparation for PJM's solicitation of stakeholder input for upgrades that may economically alleviate market inefficiencies. This solicitation of input will be to the appropriate TEAC or Subregional RTEP Committee. Following the evaluation of congestion drivers and solicitation of remedies, PJM will initiate an analysis phase which first examines the potential economic costs and benefits that may be associated with any upgrades specified during the reliability analysis. After this assessment, PJM will evaluate the economic costs and benefits of any identified new potential upgrades target specifically at economic efficiency. The following information looks at each of these phases in more detail.

2.6.2 Determination and evaluation of historical congestion drivers

All PJM metrics of historical congestion drivers will be posted monthly throughout the year, except that AAR information will be posted as specified by the AAR auction process. This information can be found at:

http://www.pjm.com/planning/rtep-development/market-efficiency.aspx

http://www.pjm.com/markets-and-operations/ftr.aspx

PJM will calculate and post gross congestion costs by constraint for each constraint causing real-time off-cost operations. Gross congestion will be calculated as the product of the constraint shadow price times the load MWs at each load bus in the affected area times the load bus dfax where the affected area is defined as any bus with a dfax of 3% or greater.

PJM will calculate and post the Unhedgeable congestion cost statistics and associated constraints. Unhedgeable congestion costs will be calculated by taking the sum of load MWs at each load bus in the affected area times the relevant load bus dfax minus the sum of economic generation MWs at each generator bus in the affected area times the relevant generator bus dfax minus the sum of FTR MWs, and multiplying the resulting MW by the constraint shadow price. Economic generation is generation which is available and on-line and which, at its current level of output, has a bid price no greater than the PJM system marginal price. Self-scheduled generation is assigned a bid price of zero in the determination of economic generation MW.

Congestion causing a pro-ration of Stage 1A ARR requests will be determined and recommended for inclusion in the RTEP with a recommended in-service date based on the 10-year Stage 1A simultaneous feasibility analysis results. This recommendation will also include a high-level analysis of the cost and economic benefits of the upgrade as additional information but such upgrades will not be subject to market efficiency cost/benefit analysis. More information on the ARR allocation auction process can be found in Manual 6 titled PJM Capacity Market.

Congestion causing pro-ration of Stage 1B ARR requests will be addressed using the "with and without" analysis and the benefit/cost ratio threshold described previously in this market efficiency material.

2.6.3 Determination of projected congestion drivers and potential remedies

PJM will provide all stakeholders with estimates of the projected congestion by performing annual hourly market simulations of future years using a commercially available market analysis software modeling tool (see assumptions and criteria material in Section 1.) This simulation will produce and PJM will post projected binding constraints, binding hours, average economic impact of binding constraints, and cumulative economic impact of binding constraints for the four RTEP market efficiency analyses (current year plus 1, current year plus 4, current year plus 7 and current year plus 12).

This analysis is expected to be completed about the ***third quarter*** of the RTEP cycle year. At this time PJM will also facilitate a TEAC or Subregional RTEP Committee meeting, as appropriate, to review congestion and solicit feedback from the stakeholders' review of the projected congestion data as well as the historical congestion data. All stakeholders can provide input to PJM's consideration of the congestion data and potential upgrades to be considered for market efficiency solutions to identified economic issues.

The timing of this meeting will depend, to some extent, on the complexity of the analysis, however, it is anticipated that this meeting will occur during the ***third quarter*** of each year. At this meeting, PJM will provide a summary of the analysis results and a description of any congested areas that will be analyzed using Market Efficiency analysis. PJM will also provide a high-level estimate of the transmission upgrades then being considered. At the completion of this stakeholder review, any member of the TEAC can provide additional written comments within sixty (60) days of this meeting.

Stakeholder Written Comments

These written comments will consist of three (3) sections:

- Introduction, which will describe the party submitting the comments and their reason for submitting these comments
- Summary, which will consist of no more than 3 pages summarizing the positions described in the written comments
- Discussion, which will consist of no more than 20 pages describing in detail the positions taken by the party

Parties wishing formally to submit alternative proposals of their own are encouraged to do so separately, as described further, below.

The Office of the Interconnection will have the responsibility of compiling comments from TEAC participants. All written comments will be posted to the PJM web site and provided to the PJM Board of Managers together with a PJM staff summary that will focus on conveying the following: (1) the issues; (2) the parties raising the issues; and, (3) as may be appropriate, PJM's discussion of ramifications of the issues. Communication to the Board of Managers will not include results of any voting.

2.6.4 Evaluation of cost / benefit of advancing reliability projects

PJM will perform annual market simulations and produce cost / benefit analysis of advancing reliability projects. An initial set of simulations will be conducted for each of the four years (current year plus 1, current year plus 4, current year plus 7 and current year plus 10) using the "as is" transmission network topology without modeling future RTEP upgrades. A second set of simulations will be conducted for each of the four years using the as planned RTEP upgrades. A comparison of the "as is" and "as planned" simulations will identify constraints which have caused significant historical or simulated congestion costs but for which an as-planned upgrade will eliminate or relieve the congestion costs to the point that the constraint is no longer an economic concern. A comparison of these simulations will also reveal if a particular RTEP upgrade is a candidate for acceleration or expansion. For example, if a constraint causes significant congestion in year 7 but not in year 10 then the upgrade which eliminates this congestion in the year 10 simulation may be a candidate for acceleration. The benefit of accelerating this upgrade would then be compared to the cost of acceleration as described below before recommendation for acceleration is made.

When the reliability project economic acceleration analyses have been completed, PJM will schedule a TEAC or Subregional Committee meeting, as appropriate, to review the results. The timing of this meeting will depend, to some extent, on the amount and complexity of analysis that must be performed. However, it is anticipated that this meeting will take place during the ***fourth quarter*** of each year. At this meeting PJM will provide a summary of the analysis results, including an update of the Market Efficiency analysis and a description of any recommendations for accelerating reliability projects based on economic considerations.

2.6.5 Determination and evaluation of cost / benefit of potential RTEP projects specifically targeted for economic efficiency

PJM will perform annual market simulations and produce cost / benefit analysis of projects specifically targeted for economic efficiency. The net present value of annual benefits will be calculated for the first 15 years of upgrade life and compared to the net present value of the upgrade revenue requirement for the same 15 year period.

An initial set of simulations will be conducted for each of four years (current year plus 1, current year plus 4, current year plus 7 and current year plus 10) using the as planned transmission network topology as defined by the most recent RTEP. A second set of simulations will be conducted for each of the four years using the as planned transmission network topology plus the upgrade being studied. The upgrade will be included in each of the four simulation years regardless of the actual anticipated in-service date of the upgrade. A comparison of these simulations will identify the benefit of the upgrade in each of the four years analyzed. Annual benefits within the 10-year time frame for years which were not simulated would be interpolated using these simulation results. A forecast of annual benefits for years beyond the 10-year simulation time frame would be based on an extrapolation of the market simulation results from the studied years. A higher-level annual market simulation will be made for future year 15 to validate the extrapolation results and the extrapolation of annual benefits for years beyond the 10-year simulation time frame may be adjusted accordingly. This high level simulation of future year 15 may require a less detailed model of the transmission system below the 500 kV level.

An extrapolation of the simulation results will provide a forecast of annual upgrade benefits for each of the anticipated first 15 years of upgrade life, beginning from the projects anticipated in-service date. The present value of annual benefits projected for the first 15 years of upgrade life will be compared to the present value of the upgrade revenue requirement for the same 15 year period to determine if the upgrade is cost beneficial and recommended for inclusion in the PJM RTEP. If the ratio of the present value of benefits to the present value of costs exceeds 1.25 then the upgrade is recommended for inclusion in the RTEP.

For each upgrade which is recommended for inclusion in the RTEP, PJM will provide the level of new generation or DSM per region that would eliminate the need for the transmission upgrade.

When the economic efficiency project evaluations have been completed, PJM will schedule a TEAC or Subregional Committee meeting, as appropriate, to review the results. The timing of this meeting may depend on the amount and complexity of analysis that must be performed. It is, however, anticipated that this meeting will take place ***by April*** of the calendar year that begins the subsequent RTEP planning cycle. At this meeting PJM will provide a summary of the analysis results, including an update of the Market Efficiency analysis, and a description of any recommendations for economic efficiency projects.

2.6.6 Determination of final RTEP market efficiency upgrades

PJM will perform a combined review of the accelerated reliability projects and new market efficiency projects that passed the economic screening tests to determine if there are potential upgrades with electrical similarities. This may result in new projects to replace the original projects to form a more efficient overall market solution. Stakeholders may also suggest such potential synergies. PJM will evaluate the cost / benefits of any such resulting "hybrid" projects[3]. The final list of reliability projects and market efficiency projects, including any "hybrid" projects will be presented and discussed at a ***second quarter (April)*** TEAC meeting. At this TEAC meeting PJM will review all the Market efficiency plans resulting from this cycle of market efficiency studies. Recommended projects will be taken to the PJM Board for endorsement, and will either be included in subsequent RTEP analysis if there is a "volunteer" to build the project, or a report will be filed with FERC in accordance with Schedule 6 of the PJM Operating Agreement. As part of this request for endorsement, PJM will provide the written comments submitted by the parties, and will discuss these written comments with the PJM Board.

Within the limits of confidential, market sensitive, trade secret, and proprietary information, PJM will make all of the information used to develop the Market Efficiency recommendations available to market participants to use in their own, independent analyses.

For each enhancement which is analyzed, PJM will calculate and post on its website changes in the following metrics on a zonal and system-wide basis: (i) total energy

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[3] Hybrid transmission upgrades include proposed solutions which encompass modification to reliability-based enhancements already included in RTEP that when modified would relieve one or more economic constraints. Such hybrid upgrades resolve reliability issues but are intentionally designed in a more robust manner to provide economic benefits in addition to resolving those reliability issues.

production costs (fuel costs, variable O&M costs and emissions costs); (ii) total load energy payments (zonal load MW times zonal load Locational Marginal Price); (iii) total generator revenue from energy production (generator MW times generator Locational Marginal Price); (iv) Financial Transmission Right credits (as measured using currently allocated Auction Revenue Rights plus additional Auction Revenue Rights made available by the proposed acceleration or modification of a planned reliability-based enhancement or expansion or new economic-based enhancement or expansion); (v) marginal loss surplus credit; and (vi) total capacity costs and load capacity payments under the Reliability Pricing Model construct.

For each market efficiency project proposed for RTEP, PJM will also post, as soon as practical, the following:

a. Anticipated high-level project schedule and milestone dates
b. Final commitment date after which any change to input factors or drivers will not result in transmission project deferral or cancellation.

After this TEAC meeting, any member of the TEAC can provide written comments within sixty (60) days of this meeting. These written comments will consist of three (3) sections:

- Introduction, which will describe the party submitting the comments and their reason for submitting these comments
- Summary, which will consist of no more than 3 pages summarizing the positions described in the written comments
- Discussion, which will consist of no more than 20 pages describing in detail the positions taken by the party

2.6.7 Submitting Alternative Proposals

Any TEAC member or other entity (consistent with PJM Operating Agreement Schedule 6 provisions), may formally submit alternative proposals for evaluation under the Market Efficiency analysis at any time, but no later than **December 31st** of each year RTEP cycle year in order to be considered in the then-current planning cycle (the RTEP market efficiency planning analysis carries over from the RTEP cycle year into the first quarter of the following RTEP planning cycle year.) These alternatives will be posted on the PJM Website. PJM will consider these alternatives, and establish the final set of proposals to be included in market efficiency analysis. The process of formally submitting proposals is not limited to transmission solutions but may also include generation solutions via PJM's established interconnection queue process; or, demand side management and load management proposals as well. Alternatively, market projects to relieve congestion can be submitted by market participants through the queue process at any time. PJM will evaluate these projects under the then current business rules contained in the PJM Tariff and Operating Agreement.

Regardless of all proposals considered -- whether proposed by PJM or other parties - PJM will establish a "go/no-go" decision-point deadline (or final commitment date) after which existing RTEP transmission components will not be deferred or cancelled. This will provide certainty to developers, owners and investors.

2.6.8 Ongoing Review of Project Costs

To assure that projects selected by the PJM Board for Market Efficiency continue to be economically beneficial, both the costs and benefits of these projects will periodically be reviewed, nominally on an annual basis. Substantive changes in the costs and/or benefits of these projects will be reviewed with the TEAC at a subsequent meeting to determine if these projects continue to provide measurable economic benefit and should remain in the RTEP.

For projects with a total cost exceeding $50 million, an independent review of project costs and benefits will be performed to assure both consistency of estimating practices across PJM and that the scope of the project is consistent with the project as proposed in the Market Efficiency analysis.

2.7 Evaluation of Operational Performance Issues

As per Schedule 6, section 1.5 of the PJM Operating Agreement, PJM is required to address operational performance issues and include system enhancements, as may be appropriate, to adequately address identified problems. To fulfill this obligation, PJM Transmission Planning staff and Operations Planning staff annually review actual operating results to assess the need for transmission upgrades that would address identified issues. Typical operating areas of interest in these reviews include Transmission Loading Relief (TLR) and Post Contingency Local Load Relief Warning (PCLLRW) events.

The first operational performance issue to be addressed through the RTEP was an upgrade of the Wylie Ridge 500/345 kV transformation. The metric applied to designate Wylie Ridge an operational performance issue was the TLR metric. This same metric is applied consistently across the PJM footprint.

In addition, PJM has also developed and initiated use of a tool for Probabilistic Risk Assessment (PRA) of transmission infrastructure. PJM's 500/230 kV transformer infrastructure has been identified as particularly suited for assessment using this tool. PRA is further discussed in following sections.

2.7.1 Operational Performance Metrics

Events and metrics considered in the annual operational performance reviews are not limited to a specifically defined list and will be responsive to events and conditions that may arise. In addition, PJM stakeholders may raise operational issues to PJM's attention for consideration during the RTEP process through interactions with the Planning, TEAC or Subregional RTEP Committees.

The PJM TLR metric identifies facilities that result in over 1,000 hours or 100 occurrences of TLR level 3 or higher on an annual basis. These facilities will be evaluated through the RTEP process for system enhancement.

For PCLLRW events, PJM will review all such events after the conclusion of the peak season. The initiating facilities will be determined and the expected impacts of planned RTEP upgrades will be reviewed and the need for additional planned upgrades will be evaluated.

PRA evaluation uses an economic analysis of the cost of the investment that mitigates a risk and the dollar value of the avoided risk. The mitigation strategy cost, prime rate and payback period are used to determine if the strategy cost is less than the value of risk. Projects with lower cost than risk are candidates for the RTEP.

2.7.2 Probabilistic Risk Assessment of PJM 500/230 kV Transformers

One significant element of PJM's operational performance reviews involves a risk evaluation aimed at anticipating significant transmission loss events. PJM integrates aging infrastructure decisions into the ongoing RTEP process: analysis, plan development, stakeholder review, PJM Board approval, and implementation, over PJM's entire footprint. Thus, the aging infrastructure initiative implements a proactive, PJM-wide approach to assess the risk of transmission facility loss and to mitigate operational and market impacts of such losses.

PRA's initial implementation at PJM is a risk management tool employed to reduce the potential economic and reliability consequences of transmission system equipment losses. In collaboration with academia, vendors and member TOs, PJM integrated various input drivers into a transformer PRA initiative to manage 500/230 kV transformer risk. In the case of the 500/230 kV transformers, risk is the product of the probability of incurring a loss and the economic consequence of the loss. Probability of loss is determined based on the individual transformer unit's condition assessments and vintage history. Economic loss impact is based upon the duration of the loss and the accumulation of unhedgeable congestion costs, or the increased cost of running out of merit generation to meet load requirements after a transformer loss. If lead times for 500/.230 kV transformer units are as great as eighteen months, then outage durations can be long if adequate loss mitigation is not in place. The PRA outputs the annual risk to the PJM system of each transformer unit in terms of dollars. The annual risk dollars are then used to justify mitigating solutions such as redundant bank deployment, proactive replacement or adding spares. The deployment strategy chosen will depend on the level of risk mitigation and reliability benefit.

While initially developed for aging 500/230 kV transformers, the PRA tool is capable of assessing other equipment types and other transformer voltage classes. The PRA tool is commercially available software.

Attachment A: PJM Baseline Cost Allocation Procedures

A.1 Purpose

One of the responsibilities of PJM as an RTO is to allocate the cost responsibility for all system reinforcement projects including projects required for Customer interconnection requests, baseline transmission reliability upgrades and market efficiency upgrades. The cost allocation procedures used by PJM for baseline upgrades are described below. Manual 14A addresses request-driven upgrade cost allocation procedures.

A.2 Scope

The PJM Cost Allocation Procedures are presented in two parts: "PJM Generation and Transmission Interconnection Cost Allocation Methodologies" discusses the cost allocation methodology for projects required for generator and transmission interconnections in Manual 14A and: "Schedule 12 Cost Allocation Process for Baseline Transmission Reliability and Market Efficiency Upgrades" describes the cost allocation process for baseline transmission reliability and market efficiency upgrade project requirements.

A.3 Schedule 12 Cost Allocation Process for Baseline Transmission Reliability and Market Efficiency Upgrades

In addition to allocating the costs of interconnection projects (described above), PJM is responsible, under Schedule 6 of the Operating Agreement and Schedule 12 of the Tariff, for determining the cost allocation of all RTEP upgrades and submitting them to the PJM Board for approval. Allocation of transmission upgrades for reliability is cost-causation based. With respect to reliability, the determination of benefit is based on the elimination of a reliability criteria violation. The parties causing the violation are the parties that benefit through the elimination of the violation and the quantification of the benefit is based on the relative contribution to the violation being eliminated. Accordingly, each cost allocation calculation is based on the particular assumptions used to determine whether or not a violation exists of a particular criterion.

A.3.1 RTEP Baseline Cost Allocation

PJM's allocation of cost responsibility for RTEP reliability baseline upgrades in accordance with these provisions is based on cost causation. The market participants (typically load) that create the circumstances that would constitute a violation of reliability criteria are those that will benefit from elimination of that violation. Therefore, the quantification of the relative benefits of eliminating the violation, and thus the quantification of relative responsibility for the cost of the system upgrade(s) needed to remove the violation, is based on the relevant market participants' relative contribution to the violation to be eliminated.

The planning (modeling) assumptions associated with each reliability criterion in PJM are highly prescriptive, such that discretion cannot be applied to manipulate the determination that a violation does or does not exist. The reliability criteria and the associated modeling rules were established in this way specifically to ensure consistency of application and ability to replicate results. In this way, once it is determined that an applicable criterion has been violated, it is a simple matter to determine the extent to which load within each transmission zone contributes to that violation. That relative contribution then establishes the appropriate, proportional allocation to each zone of the costs required to remove the violation.

To the extent that a criteria violation is based on the thermal limits of a transmission facility, the cost allocation is based directly on the relative contribution of the load in each zone to the flow on that facility. For criteria violations based on voltage criteria, thermal surrogates are determined, such that the flow on a transmission facility or group of facilities best correlates to the reactive performance of the system at the point of the criteria violation. The same approach described above is then utilized to simulate incremental flows on the limiting facilities, i.e., the thermal surrogate that best correlates to the violation. Accordingly, the cost allocation for the solution to the voltage criteria violation is, again, based on the relative contribution of load in each zone to flow on the limiting facility, in these cases, the thermal surrogates.

Under this approach to cost allocation, it is entirely possible, and certainly consistent with the philosophy of assessing relative cost-causation, that the costs of upgrades that are required to mitigate criteria violations in one transmission zone may be allocated in significant part to load in other transmission zones. While many required transmission upgrades are allocated entirely to load within the same zone where the criteria violation and the related upgrade are located, the nature of large, integrated transmission systems like the PJM system is such that the needs of one area can cause or contribute to problems in other areas. The planning process identifies the most effective solutions to criteria violations without regard to the location of the load that causes such violations. Therefore, responsibility for the costs of baseline upgrades likewise must be allocated to those who cause such costs to be incurred, regardless of their physical location relative to the location of the baseline upgrade required to ensure the reliability of their service.

The basic steps for calculating the cost allocations for baseline upgrades can be summarized as follows:

Generator Deliverability and NERC Category C Load Flow Violations

Calculate the Distribution Factor (DFAX), where DFAX represents a measure of the effect of each zone's load on the transmission constraint that requires the mitigating upgrade, as determined by power flow analysis. The source used for the DFAX calculation is the aggregate of all PJM generation and the sink is each Transmission Owners peak zonal load.

Multiply each DFAX by each zonal load to determine the zone's MW impact on the facility that requires upgrading.

Divide MW impact for each zone by sum of all MW impacts to yield baseline cost allocation factors.

Load Deliverability Violations

Calculate the Distribution Factor (DFAX), where DFAX represents a measure of the effect of each zone's load on the transmission constraint that requires the mitigating upgrade, as determined by power flow analysis. The source used for the DFAX calculation is the aggregate of all generation external to the study area and the sink is the peak zonal load for each Transmission Owner within the study area.

Multiply each DFAX by each zonal load to determine the zone's MW impact on the facility that requires upgrading.

Divide MW impact for each zone by sum of all MW impacts to yield baseline cost allocation factors.

Market Efficiency Allocation

[As of the effective date of this Revision 12 of Manual 14B, the cost allocation method for transmission upgrades is currently being debated at the FERC and is yet to be determined. Neither the RPPWG nor Planning Committee are recommending or endorsing any cost allocation method, pending the outcome of the proceedings at the FERC.]

The dollar benefit in all zones with affected load is summed and the final allocation is the zonal dollar benefit divided by the total dollar benefit.

RTEP Baseline Cost Allocation Representative Example

In order to explain the derivation of baseline cost allocation factors, PJM offers the following representative example based on Upgrade # b0174, an upgrade to the Portland – Greystone 230 kV circuit.

Cost Allocation Procedure	AE	JCPL	Neptune	PSE&G	RECo
1. Calculation of Distribution Factors (DFAX), representing a measure of the impact of each zone's load on the constraint requiring the mitigating upgrade in the first place, as determined by power flow analysis.	0.27%	2.42%	3.57%	2.76%	3.02%
2. Transmission Owner Load (MW)	2995	6713	685	10760	445
3. Calculate MW Impact (MW) of each TO zone by multiplying DFAX by TO Load.	8.09	162.45	24.45	296.98	13.44
4. Total MW Impacts (MW) across zones	505.41				
5. Calculate cost allocation factors by dividing each zone's MW Impact by the Total MW Impact across all zones. (Values rounded)	1.00%	32.00%	5.00%	59.00%	3.00%

Attachment B: Regional Transmission Expansion Plan—Scope and Procedure

B.1 Purpose

The purpose of the Regional Transmission Expansion Plan (RTEP) is to develop plans which will assure reliability and meet the demands for firm transmission service in the PJM Region as described in Schedule 6 of the Operating Agreement.

B.2 Scope

As part of its ongoing responsibility, PJM Interconnection, LLC (PJM) will prepare a Regional Transmission Expansion Plan (RTEP) which shall consolidate the transmission needs of the region into a single plan. The RTEP shall reflect transmission enhancements and expansions, load and capacity forecasts, and generation additions and retirements for the ensuing five years. The RTEP shall also reflect new transmission construction and right-of-way acquisition required to support load growth in years 6 through 15.

The RTEP will:

A. Provide a 5-year plan ("near term plan") to address needs for which a commitment to expand or enhance the transmission system must be made in the near term in order to meet scheduled in service dates.

B. PJM will develop the necessary documentation of previous year's RTEP analyses and updates to demonstrate compliance with applicable criteria. Such documentation may include the most recent Baseline study for each year in the near-term planning horizon (current year through current year plus 5,) annual changes to each year's baseline study assumptions for generation, transmission and load compared to the current year's assumptions for each respective study year, and retool studies to evaluate and ensure compliance with applicable standards and criteria for significant changes proposed to the system (Interconnection and New Service Requests.) The need for additional baseline retools will be considered and any needed restudy will be performed and reported.

C. Provide a 15-year plan ("long term plan") to address new transmission construction and right-of-way acquisition. System evaluations will be performed to:

   - Identify overloads 230 kV and above due to load growth for years 6 through 15. This will be completed using DC analysis only.
   - Include in the RTEP any new 230 kV or 345 kV circuits identified as required to support load growth in years 6 through 8.
   - Include in the RTEP any right-of-way acquisition required for any new 230 kV or 345 kV circuits identified as required to support load growth in years 9 and 10.
   - Include in the RTEP any new circuits 500 kV or greater identified as required to support load growth in years 6 through 12.

- Include in the RTEP any right-of-way acquisition required for any new circuits 500 kV or greater identified as required to support load growth in years 13 through 15.

D. Include reactive planning to determine if any new transmission identified in the 15-year plan should be accelerated to mitigate identified voltage criteria violations. Additional details for the reactive planning follow:

- Development of a 10-year RTEP base case that will include Transmission Owner reactive plans.
- The long term plan voltage analysis will be performed using contingencies 345 kV and greater and monitoring substation voltages 345 kV and greater. Analysis of lower voltage systems will be completed on an exception basis only.
- Voltage analysis will be performed for areas where PJM identified thermal problems in years 6 through 15 or other areas as identified by PJM.
- Based on the results of the voltage analysis, PJM will recommend appropriate modifications to the RTEP through the Transmission Expansion Advisory Committee.

E. Provide an assessment based on maintaining the PJM region's reliability in an economic manner.

F. Avoid any unnecessary duplication of facilities.

G. Avoid the imposition of unreasonable costs on any Interconnected Transmission Owner (ITO) or any user of transmission facilities.

H. Take into account the legal and contractual rights and obligations of the Interconnected Transmission Owners.

I. Provide, if appropriate, alternative means for meeting transmission needs in the PJM Region.

J. Provide for coordination with existing transmission systems and with appropriate interregional and local expansion plans.

K. Include a designation of the Interconnected Transmission Owner or Owners or other entity that will own a transmission facility and how all reasonably incurred costs are to be recovered.

L. Identify local system limitations discovered in analyzing the Transmission System.

M. Include Scenario Planning evaluations beginning in mid-2006. Scenario Planning examines the long-term impacts on the reliability of the PJM system from uncertainty with respect to certain assumptions implicit in the development of the RTEP. PJM will examine the effects of uncertainty with respect to selected variables such as economic growth effect on the Load Forecast, Circulating transmission flow effects on system deliverability and generation scaling sensitivities.

N. Include Probabilistic Risk Assessment (PRA) of Aging Transmission System Infrastructure beginning in 4Q, 2006. PRA is employed to mitigate transformer risk on the bulk power system. The consequences of a failure, both reliability and economic impacts, are then considered to implement, when appropriate, a proactive, PJM-wide approach to mitigate operational and market impacts to such failures.

The RTEP will not:

A. Include an evaluation of Transmission Owner transmission expansion or enhancement plans for local area load supply, which are not needed for reliability, market efficiency or operational effectiveness of the Transmission System and do not otherwise negatively impact the Transmission System. These Transmission Owner projects (Supplemental Projects) will be identified in the RTEP for information purposes and tracked for possible future impact implications.

B. Include any upgrades based solely on scaling up of generation to solve load flow studies for years 6 through 15.

B.3 Procedure

I. Solicit input and coordinate with Transmission Expansion Advisory Committee (TEAC) and, as appropriate, TEAC's Subregional RTEP Committee.

   A. Present the preliminary results of the most recent, applicable NERC regional reliability council (Reliability*First* and SERC) Reliability Assessments and the most recent PJM Regional Transmission Expansion Plan (RTEP).

   B. Present a summary of the transmission expansion or enhancement needs that will be addressed in the RTEP.

   C. Provide periodic updates to the TEAC on status of the RTEP.

   D. Solicit input on future transmission needs and requirements from those who will not be contacted directly as listed below.

   E. Schedule and facilitate Subregional RTEP committee reviews as may be needed to foster the goal of a transparent and participatory planning process.

II. Identify known Transmission System expansion or enhancement needs from the following plans and analysis results:

   A. Most recent, applicable Reliability Assessments (Reliability*First* and SERC) -- (on PJM website)

   B. Most recent PJM Annual Report on Operations -- (on PJM website)

   C. PJM Load Serving Entity (LSE) capacity plans

   D. Generator and Transmission Interconnection requests

   E. Transmission Owner transmission plans

   F. Interregional transmission plans.

   G. Firm Transmission Service Requests

   H. PJM Transmission Expansion Advisory Committee (TEAC) and Subregional RTEP Committee input

   I. PJM Development of Economic Transmission Enhancements

III. PJM will consider the RTEP impacts of each Generation Interconnection Customer ("GIC") and/or Transmission Interconnection Customer that is currently engaged in discussion with PJM concerning plans for siting generating and/or transmission facilities.

Typical items to be included are as follows:

A. GIC and/or Merchant Transmission Facilities developer project status, schedule, and milestones.

B. PJM will review the status of studies currently being performed or scheduled to be performed by PJM for the GIC and/or Merchant Transmission Facilities developer.

IV. GIC and/or Merchant Transmission Facilities developer plans will be included in the RTEP based on the following criteria:

A. Developer must be presently engaged in discussion with PJM concerning their plans for siting generating and/or transmission facilities and actively pursuing those plans. Interconnection Studies in response to requests for Generator and/or Transmission Interconnections will be conducted in accordance with the following scope:

- Identify transmission enhancements required to meet reliability requirements over the next 5 years.
- No studies will be conducted beyond 5 years for interconnection projects.
- "But-for" costs will be applicable toward all system upgrades identified in the RTEP Baseline.

B. GIC and/or Merchant Transmission Facilities developer plans will be treated equal to LSE plans submitted via EIA 411 in that they will be explicitly modeled and explicitly included in the RTEP report.

C. GIC and/or Merchant Transmission Facilities developer plans, which have not been released publicly, will be masked to the greatest extent possible to preserve the confidentiality of the developer's identity and specific site location(s).

D. GIC and/or Merchant Transmission Facilities developer plans, which were developed as a result of a PJM feasibility study or are being developed in conjunction with a PJM feasibility study being performed concurrent with the RTEP process, will be evaluated explicitly during the RTEP.

E. GIC and/or Merchant Transmission Facilities developer plans which have not undergone a PJM feasibility study or are not actively being developed as a result of an agreement executed with PJM to perform a feasibility study concurrent with the RTEP process, will only be considered to the extent that the GIC generator installation or Merchant Transmission Facilities developer facility may affect the sensitivity of transmission enhancement or expansion alternatives which are being evaluated.

V. PJM will exchange information and data with each Transmission Owner (TO) for the purpose of developing RTEP assumptions in preparation for the Subregional RTEP Committee assumptions meeting. Typical items to be included are as follows:

A. TOs will verify their transmission and capacity plans.

B. TOs and PJM will discuss the status, impact, and schedule of relevant studies in which they are mutually engaged in performing.

C. TOs will provide information concerning the contractual rights and obligations which PJM must consider per the RTEP protocol as listed in Schedule 6 of the PJM Operating Agreement.

D. TOs will provide PJM with any information related to concerns, operating procedures, or special conditions for each of the TO's systems that PJM should consider related to the analysis to be performed for the RTEP.

E. TOs will discuss the accuracy of PJM's load flow representation for each of the TO's systems including the impact of using the present representation for each of the TO's underlying systems.

F. TOs will identify system needs which are currently not identified by published transmission plans but could be included for consideration during the RTEP analysis.

G. TOs will provide the names, addresses, telephone numbers, FAX number, and email address for personnel identified to interact with PJM on matters dealing with the RTEP process.

H. TOs will provide a confidentiality statement regarding all information released to the TO by PJM during the course of the RTEP process.

I. TOs will provide information on new loads or changing loads that will impact the transmission plan.

VI. PJM will include available information from neighboring TOs / Regional Transmission Operators, gained in the course of interregional planning activities, related to plans in other regions which may impact the PJM RTEP.

VII. RTEP Analysis General Assumptions:

A. PJM System Models will be drawn from the PJM and applicable regional reliability council (Reliability*First* and SERC) central planning database which includes transmission plans consistent with the most recent FERC 715 Report and most recent Regional EIA-411 Reports.

B. LSE capacity models are to be based on the most recent Regional EIA-411 Reports.

C. GIC capacity plans will be modeled as described in Procedures III and IV.

D. When the PJM load in the RTEP model exceeds the sum of the available in-service generation plus generation with an executed ISA, PJM will model new generation to accommodate additional load growth by including queued generation that has received an Impact Study.

E. PJM Load Forecasts are to be based on the most recent LAS Report.

F. Power Flow models for world load, capacity, and topology will be based on the most recent Eastern Reliability Assessment Group (ERAG) power flow base cases.

G. Generation outage rates will be based on the most recent generator unavailability data available to PJM. Estimates, based on historical outage rates for similar in-service units, will be used for all generating units in the neighboring regions and for all future PJM units.

H. Firm sales to, and firm purchases from, regions external to PJM will be modeled consistent with the ERAG base interchange schedule.

I. Only PJM's share of generation will be modeled to serve PJM load. Generation located within PJM, but not committed to PJM, will be accounted for in the interchange schedule.

J. The Reliability Principles and Standards as shown on Attachment D to this Manual 14B, "PJM Reliability Planning Criteria."

K. Stability analysis and short circuit studies will also be performed.

L. All PJM Transmission System facilities 100 kV and greater, and all tie lines to neighboring systems will be monitored.

M. Contingency analysis will include all facilities operated by PJM.

N. The published line and transformer thermal ratings at ambient temperatures of 50°F (10°C) winter and 95°F (35°C) summer will be used for all facilities.

O. The voltage limits applied for planning purposes will be the same as applied in PJM Operations.

P. PS/ConEd PAR Flows: Model a 1000MW import at Waldwick and 1000MW Export at Goethals and Farragut with Ramapo PARS controlling 920 MW to NYPP. Except, for load deliverability testing, the export to ConEd at Goethals and Farragut may be decreased to 600 MW to represent a 400 MW emergency PJM purchase from NY for the capacity deficiency conditions being modeled. Likewise, the Ramapo setting is changed to 1000 MW into New Jersey.

Q. Assumptions used for the economic analysis and comparison of alternatives will be included in the report.

R. Planning and Markets will, annually based on historical data, develop a circulation model to be applied to the 5 year RTEP base case. This assumption will be reviewed with the PJM Planning Committee prior to implementation.

VIII. Evaluate Transmission enhancement and expansion alternatives and develop a coordinated Regional Transmission Expansion Plan.

A. Develop solution alternatives for regional and subregional transmission needs.

B. Evaluate solutions on a regional basis and optimize solutions to address needs on a coordinated regional basis in a single plan.

C. Test the single regional plan for reliability, economy, flexibility, and operational performance based on forecasts for future years.

IX. RTEP Deliverables

A. A 5-year plan, which includes recommended regional transmission enhancements, including alternatives if applicable, that address the transmission needs for which commitments need to be made in the near term in order to meet scheduled in-service dates.

B. The 5-year plan will include planning level cost estimates and construction schedules.

C. The 5-year plan will specify the level of budget commitments which must be made in order to meet scheduled in-service dates. The commitment may include facility engineering and design, siting and permitting of facilities, or arrangements to construct transmission enhancements or expansions.

D. The 15-year plan will identify new transmission construction and right-of-way acquisition requirements to support load growth.

B.4 Scenario Planning Procedure

Beginning in mid-2006, PJM will include scenario planning evaluations as part of the RTEP process. Scenario planning examines the long-term impacts on the reliability of the PJM system due to uncertainty with respect to certain assumptions implicit in the development of the RTEP. PJM will examine the effects of uncertainty with respect to selected variables such as economic growth effect on the load forecast, circulating transmission flow effects on system deliverability and generation sensitivities. In the course of the RTEP planning cycle scenario planning will evaluate Transmission System requirements, as may be necessary to ensure the robustness of the RTEP. The following sensitivities will be considered:

I. Load forecast for economic growth

The current 90/10 load values only account for weather uncertainty and do not consider economic growth deviations. An economic growth sensitivity may consider the effects of high economic growth factors and higher than forecast loads to determine the impact on RTEP baseline upgrades identified for years 6 through 10 for:

- Eastern PJM Mid-Atlantic Region (PSE&G, JCP&L, PECO, Delmarva, AE and RECO).
- Southwestern PJM Mid-Atlantic Region (PEPCO and BG&E).
- Western PJM Mid-Atlantic Region (MetEd, PPL, UGI and Penelec).
- PJM Western Region (ComEd, AEP, Dayton, Duquesne and AP).
- PJM Southern Region (Dominion).

System upgrades identified as required in years 6 through 10 may be advanced if the initiating overload occurs in an earlier year due to the high economic growth factor scenario.

II. Circulation

Circulation assumptions included in the RTEP baseline analysis will be reviewed for appropriate sensitivities.

III. Generation sensitivities

When the PJM load in the RTEP model exceeds the sum of the available in-service generation plus generation with an executed ISA, PJM will model new generation to accommodate additional load growth by including queued generation that has received an Impact Study. This newly added generation could affect the load deliverability results either by advancing or mitigating limits. Generation sensitivities may be examined as appropriate to add information regarding the impacts of any such generators with less certain in-service dates. In addition, in areas that are experiencing load deliverability issues, sensitivities to the mitigating effects of new local generation may also be quantified.

PJM will analyze the results of any generation sensitivities for consideration of adjustments to any new transmission or ROW acquisition previously identified in the RTEP for years 6 through 15.

IV. Additional Information

For any overloads that resulted in transmission or ROW acquisition in years 6 through 15, PJM will provide the level of new generation or DSM per region that would eliminate the need for the transmission or ROW acquisition.

Attachment C: PJM Deliverability Testing Methods

C.1 Introduction

Schedule 10 of the PJM Reliability Assurance Agreement states that Capacity Resources must be deliverable, consistent with a loss of load expectation as specified by the Reliability Principles and Standards, to the total system load, including portion(s) of the system in the PJM Control Area that may have a capacity deficiency at any time. Certification of deliverability means that the physical capability of the transmission network has been tested by the Office of the Interconnection and found to provide service consistent with the assessment of transfer capability internal to PJM as set forth in the PJM Tariff and, for Capacity Resources owned or contracted for by a Load Serving Entity, that the Load Serving Entity has obtained Network Transmission Service or Firm Point-to-Point Transmission Service to have capacity delivered on a firm basis under specified terms and conditions .

PJM determines the Capacity Requirement for the entire PJM footprint to achieve this reliability objective assuming sufficient network transfer capability will exist. The energy from generating facilities that are ultimately committed to meet this capacity requirement must be deliverable to wherever they are needed within PJM in a capacity emergency. Therefore, there must be sufficient transmission network transfer capability within PJM. PJM determines sufficiency of network transfer capability through a series of Deliverability tests.

It is important to point out that deliverability ensures that the PJM Transmission System is adequate for delivery of energy from the aggregate of capacity resources to the aggregate of PJM load. Additionally, the generator deliverability test determines whether a generator qualifies for the status of a "certified" capacity resource with respect to the installed capacity obligations imposed under the Reliability Assurance Agreement. It does not guarantee any rights to specific generators to deliver energy to specific loads within PJM. Nor does it guarantee any rights to generators to produce energy during any particular set of operational circumstances. Deliverability ensures that the Transmission System within PJM can be operated within applicable Reliability Criteria and, ensures within those criteria that regional load will receive energy, with no guarantee as to price, from the aggregate of capacity resources available to PJM.

Failure of the deliverability test for a new capacity resource will result in denial of full capacity rights for the generator until such generator deliverability deficiencies are corrected. Failure of load deliverability tests will result in the initiation of appropriate mitigation actions including securing additional capacity resources, reduction of peak load and/or an enhancement to the Transmission System to increase the load area's ability to import power.

C.2 Deliverability Methodologies

To maintain reliability in a competitive capacity market, capacity resources must contribute to the deliverability of energy within PJM in two ways. First, within an area experiencing a localized capacity emergency, or deficiency, energy must be deliverable from the aggregate of the available capacity resources to load. Second, capacity resources within a given electrical area must, in aggregate, be able to be exported to other areas of PJM. PJM has developed testing methodologies to verify compliance with each of these deliverability requirements.

C.3 Overview of Deliverability to Load

The first of these tests, the delivery of energy from the aggregate of available capacity resources in one PJM electrical area and adjacent non-PJM areas (support from external areas may be considered to meet deliverability to the extent such support may be reasonably expected) to another PJM electrical area experiencing a capacity deficiency, is the more common deliverability test that has been utilized within PJM for some time. It is often discussed in the context of demonstrating the "deliverability to the load" as opposed to the "deliverability of individual generation resources". This ensures that, within accepted probabilities, energy can be delivered to each PJM load area from the aggregate of capacity resources available to PJM (regardless of ownership). These tests address reliability only and do not address the economic performance of the system.

For the adequacy of generating capacity of the entire PJM footprint, the acceptable loss of load expectation (LOLE) is based on load exceeding available capacity, on average, during only one occurrence in ten years (1/10). This concept of deliverability coincides with the assumptions inherent in the determination of the PJM Installed Reserve Margin (IRM), i.e. the total amount of installed capacity necessary to be at the disposal of the PJM operator to ensure delivery of energy to load consistent with an LOLE of 1/10. The determination of the IRM is based on the assumption that the delivery of energy from the aggregate of available capacity resources to load within the PJM footprint will not be limited by transmission capability. This assumption depends on the existence of a balance between the distribution of generation throughout PJM and the strength of the Transmission System to deliver energy to portions of PJM experiencing capacity deficiencies.

The specific procedures utilized to test deliverability from the load perspective involve the calculation of Capacity Emergency Transfer Objectives (CETO) and Capacity Emergency Transfer Limits (CETL) for the various electrical areas of PJM. A CETO value represents the amount of energy that a given area must be able to import in order to remain within an LOLE of 1 event in 25 years (1/25) when that area is experiencing a localized capacity emergency. The LOLE calculation takes into account all generation within the study area including that which may not be a PJM capacity resource. The CETL represents the actual ability of the Transmission System to support deliveries of energy to an electrical area experiencing such a capacity emergency. Providing that the CETL for a given area exceeds the CETO for that area, the test is passed and, on a probabilistic level, the area will be able to import sufficient energy during emergencies. The Transmission System is tested at a LOLE of 1/25 so that the transmission risk does not appreciably diminish the overall target of a 1/10 LOLE for PJM.

To test the assumptions used in the development of the PJM Installed Reserve Margin, electrically cohesive load areas must first be defined. The historical implementation of this test based these areas on Transmission Owner service territories and larger geographical zones comprised of a number of those service territories. Current study areas include the definition of smaller areas, within service territory boundaries. These areas, known as Locationial deliverability Areas (LDSs) were defined based on the impact of generators, potentially within the area and on the contingencies known to limit operations in the area. Similar techniques may be used to form future new areas to establish incentives for infrastructure that promotes reliability.

PJM will analyze the need for the addition of an LDA if either of the following criteria is met:

- RTEP Market Efficiency Analysis

Constrained facilities will be identified utilizing the market efficiency analysis. Facility constraints that are not resolved by an existing approved RTEP upgrade are identified for further consideration. PJM may propose a new LDA when annual market efficiency analysis identifies persistent congestion on a 500 kV or above facility or interface for multiple years beyond the next BRA.

- RTEP Long Term Planning

Future constrained facilities or clusters of facilities are identified utilizing the long term planning analysis. Potential facilities are screened using thresholds that are utilized in the RTEP long-term planning studies. This analysis is updated annually based on approved RTEP upgrades. 500 kV and above facilities that advance more than three years between RTEP cycles are identified for further consideration. If the driver for a 500 kV facility advancing more than three years is linked to a specific event (e.g. significant generation retirement), it may require further analysis.

Once a facility has been identified utilizing the above methods, distribution factor analysis is utilized to determine the specific busses included in the analyzed LDA. The model used to determine the load bus distribution factors would include all approved RTEP upgrades. A distribution factor cutoff is established based on one of the existing LDA's, and is dependent upon an analysis of the specific system topology and the identified constrained facilitiy(s).

These procedures are consistent with the changing nature of load responsibility under wholesale and retail access and provide a wider range of information about the performance of the Transmission System as electrical areas of different sizes are evaluated. The sequence of evaluating areas of differing size involves nesting small sub-areas into larger areas and finally areas into larger geographical areas of PJM to help identify the interrelationships between local and large geographical area deliverability problems.

After an area is defined, two generation patterns must be established. The first represents the capacity resource deficiency within the area. Based on the calculated CETO for the area, sufficient resources must be removed from service to create a need to import energy into the area. As the magnitude of the deficiency is adjusted, single contingency analysis is used to establish the CETL value. The second generation pattern required represents the dispatch of the remainder of PJM and surrounding non-PJM areas, comprised of a much larger number of generators not experiencing any emergency conditions. The larger area in PJM is modeled as experiencing only normal levels of unit outages simulated through a uniform reduction of all on-line generation. The reduction is based on an average Equivalent Forced Outage Rate (EFORd) as that term is defined by NERC standards (http://www.nerc.com/page.php?cid=4|43|47) for PJM capacity resources.

Thermal studies to determine potential overload conditions are evaluated using a probabilistic approach whereby up to 10,000 different generation outage scenarios within the study area are simulated to determine an expected value for the various facility loading levels under test at the CETO. Voltage analysis uses a combination of discrete generator outages and scaled generator output under test at the CETO.

C.4 PJM Load Deliverability Procedure—Capacity Emergency Transfer Objective (CETO)

The Capacity Emergency Transfer Objective (CETO) analysis determines a target MW import value for a test area that ensures sufficient transmission capability to access available external capacity reserves. The import value determined is a measure of the transmission capability required by the test area so that the area does not experience a modeled, transmission induced loss of load event more frequently, on average, than 1 in 25 years. This test ensures comparability of transmission service to all areas within the PJM Region.

The CETO for each sub-area in PJM is determined separately using PJM's reliability software to perform a single area reliability study for each load area. The system models are based on the latest RTEP load and capacity data available at the time of the study. Only the load and capacity within the study area are modeled while the capacity supply from outside the study area is assumed unlimited. The transmission system is not modeled. The CETO is the import capability value that is necessary for the study area to achieve the CETO reliability standard. The CETO reliability standard is one event in 25 years.

More detail is available by referring to PJM Manual 20 – Resource Adequacy Analysis at http://www.pjm.com/documents/manuals.aspx

C.5 PJM Load Deliverability Procedure—Capacity Emergency Transfer Limit (CETL)

1.0 Introduction

PJM specifies a reliability objective regarding each study area's ability to import needed and available capacity assistance. The purpose of performing a Capacity Emergency Transfer Objective/Limit Study (CETO/CETL) also known as a Load Deliverability study is to verify that this objective is met. Load Deliverability analysis is therefore one of the tests applied to validate the deliverability of PJM capacity resources to PJM load. Load Deliverability analysis is performed for a study area. At present, load deliverability study areas consist of individual zones, sub-zones and the geographical combinations of zones. Eighteen zones and sub-zones have thus far been identified. The zones correspond to the present power flow areas of the PJM operating companies. Five global study areas which are geographical combinations of power flow zones have thus far been identified.

2.0 Study Objectives

The goal of a PJM Load Deliverability study is to establish the amount of emergency power that can be reliably transferred to the study area from the remainder of PJM and the areas adjacent to PJM in the event of a generation deficiency within the study area (the study area's CETL). This transfer limit, in combination with its corresponding CETO, is then used to determine if the import capability required to meet the reliability objective is sufficient. An indicator of the amount of reserve transfer capacity (if any) available is also provided.

3.0 General Procedures and Assumptions

3.1 Independent Study Area Generation Capacity Deficiency

For the purposes of analysis, each tested study area within the PJM control area is assumed to be experiencing a generation deficiency independently. Thus, the remainder of PJM and adjacent non-PJM areas are operating normally and are assumed to be able to supply the study area with emergency power up to the limit of their available reserves. Load in all other areas beyond the area under test will be modeled at 50/50 load level reduced by forecast energy efficiency. The amount of reserves considered available from any adjacent non-PJM area may be changed to reflect historical data. Generally the procedure first tests the limit based on PJM reserves. The resource supply is opened to areas external to PJM as necessary, based on a reasonable expectation of such external support.

3.2 Consistency with PJM Emergency Operations Procedures

In all cases, the study area CETL analysis should reflect actual PJM emergency operations procedures designed to make as much power available to the deficient study area as possible under the prevailing system conditions. This should include (but is not limited to):

- The operation of any available PJM generation regardless of system economics.
- The activation of any PJM Load Management (LM) schemes that may serve to unload limiting facilities to the extent that it does not reduce the load in the area under test below expected 50/50 load reduced by forecast energy efficiency levels.
- The modification of any transfers modeled in the base case.
- The adjustment of any Phase Angle Regulators (PARs) which PJM or PJM member companies control (within existing agreements for emergency operation).
- The activation of any approved PJM or PJM member company operating procedure (procedure descriptions are available in Manual 3.)
- Re-dispatch of capacity resources in PJM are allowed internal to the study area to relieve an overload provided that the CETO is increased by the amount of generation re-dispatch required to eliminate the internal overload.

3.3 Study Area Definitions—Zonal and Global

A study area may consist of a single PJM transmission owner's transmission system (230 kV and below for the Mid-Atlantic system) with its connected load and generation. In this case, the study area is referred to as a **Zonal** study area. A study area may also consist of a geographical combination of various transmission systems (with all connected load and generation) sharing common bulk facilities for importing power. For this combination type of study area, a **Global** CETL analysis will be performed in which all load and generation in the area will be modeled internal to the study area. Assessment of both Global and Zonal Load Deliverability analyses will identify the most restrictive emergency import margins with respect to reliability criteria and deliverability of capacity resources.

PJM Global CETL Study Areas

Eastern Mid-Atlantic Area – Comprises all load and generation connected 500 kV and lower in PECO, PSE&G, JCP&L, Delmarva, AE, and RECO.

Southern Mid-Atlantic Area – Comprises all load and generation connected 500 kV and lower in BG&E and PEPCO.

Western Mid-Atlantic Area -- Comprises all load and generation connected 500 kV and lower in Penelec, Met-Ed and PP&L.

Mid-Atlantic Region – Comprises all load and generation connected 500 kV and lower in Penelec, Met-Ed, PP&L, BG&E, PEPCO, PECO, PSE&G, JCP&L, Delmarva, AE and RECO.

Western Region – Comprises all load and generation connected 765 kV and lower in ComEd, ATSI, AEP, Dayton, Duquesne and AP. Note that CPP is within the ATSI transmission Zone.

PJM Zonal CETL Study Areas

Penelec – All load and generation connected at 230 kV and below.

AP – All load and generation connected at 500 kV and below.

ATSI – All load and generation connected at 345kV and below.

Met-Ed - All load and generation connected at 230 kV and below.

PP&L - All load and generation connected at 230 kV and below.

BG&E - All load and generation connected at 230 kV and below.

PEPCO - All load and generation connected at 230 kV and below.

JCP&L - All load and generation connected at 230 kV and below.

PECO - All load and generation connected at 230 kV and below.

AE - All load and generation connected at 230 kV and below.

PSE&G - All load and generation connected at 230 kV and below.

Delmarva - All load and generation connected at 230 kV and below.

ComEd - All load and generation connected at 765 kV and below.

AEP - All load and generation connected at 765 kV and below.

Dayton - All load and generation connected at 345 kV and below.

Duquesne - All load and generation connected at 345 kV and below.

Dominion – All load and generation connected at 500 kV and below.

Delmarva South - All load and generation connected at 230 kV and below as defined in Figure E-1.

PSE&G North - All load and generation connected at 230 kV and below as defined in Figure E-2.

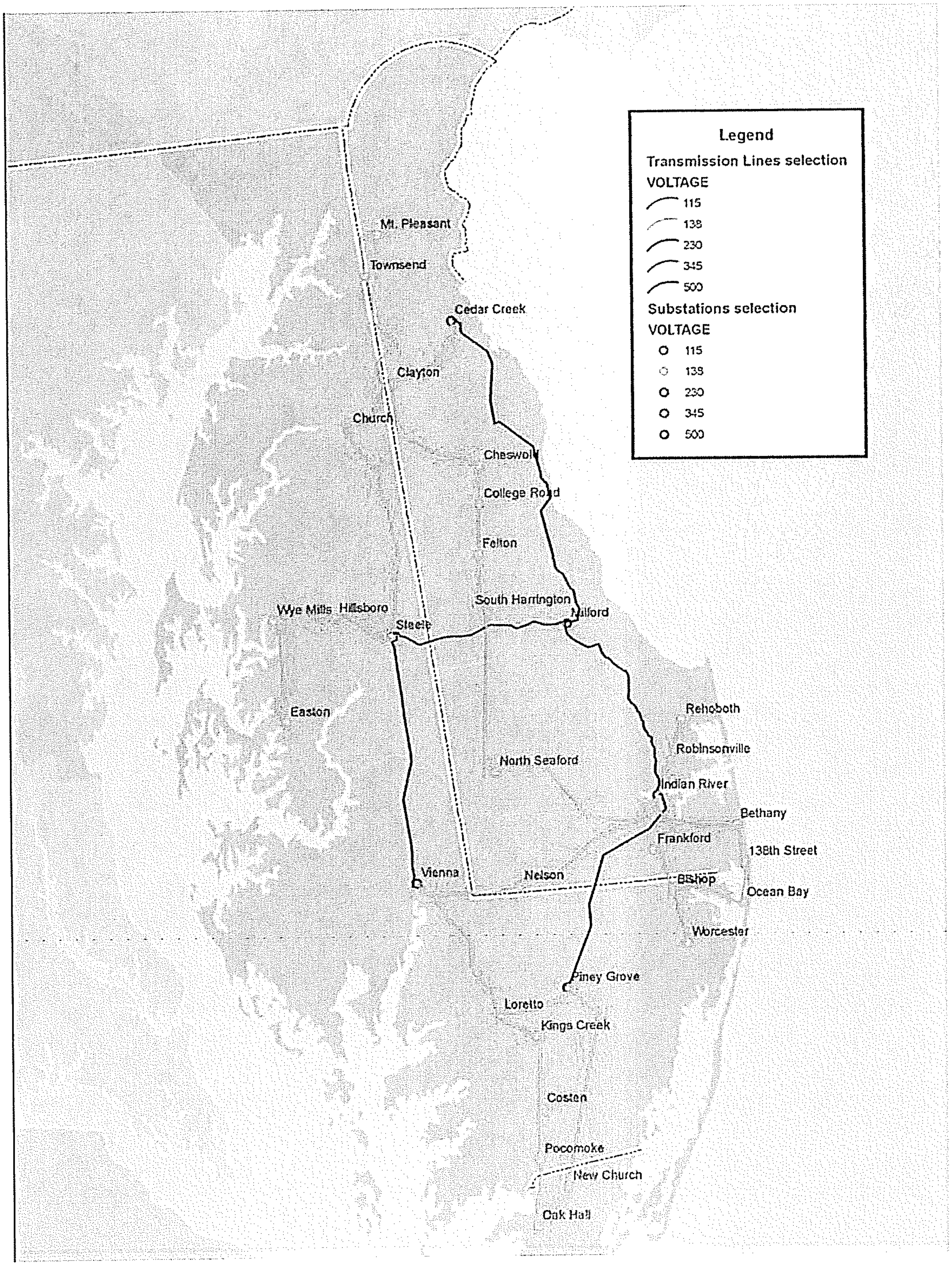

Figure E-1 (Delmarva South)

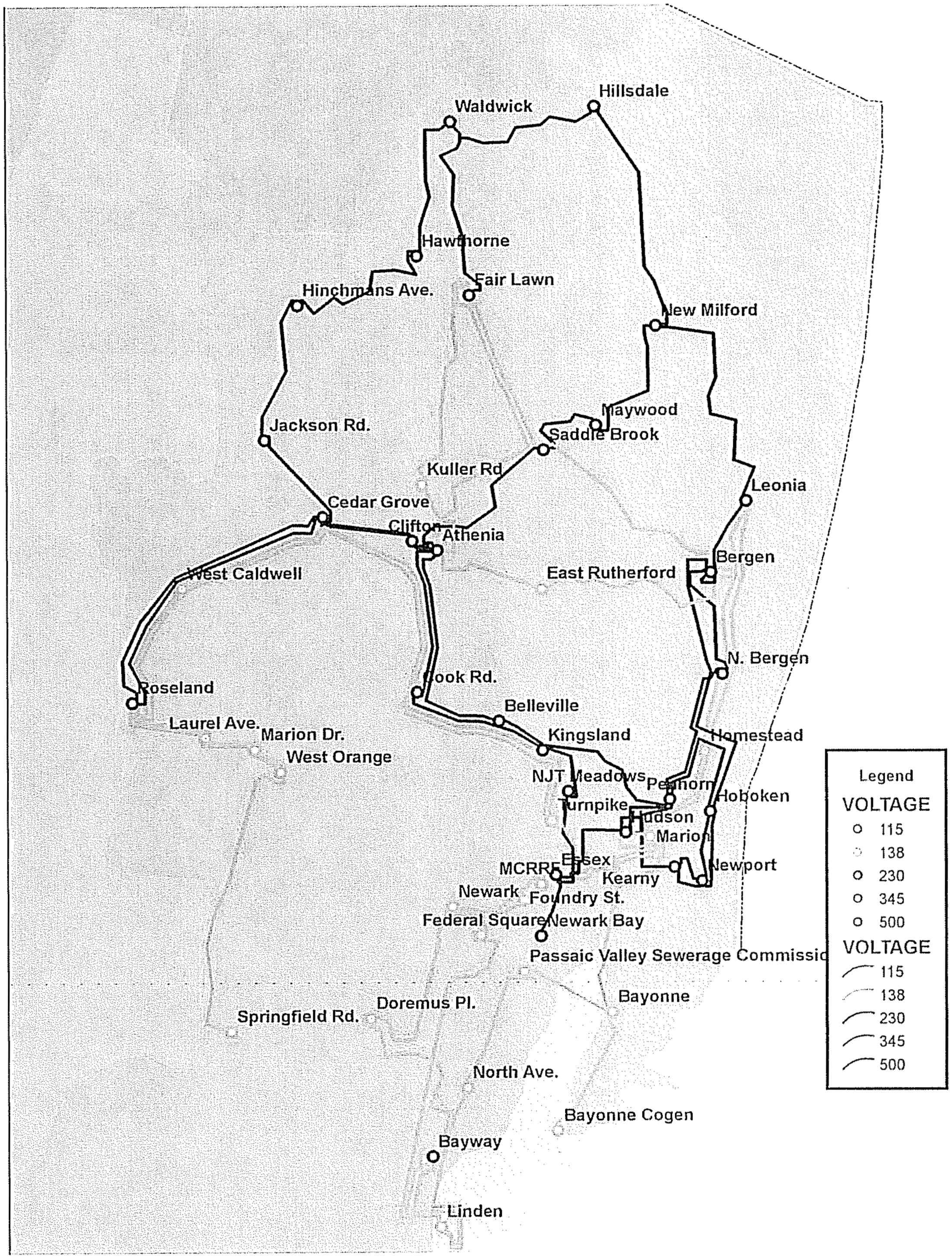

Figure E-2 (PSE&G North)

4.0 Base Case Development

Two separate base case models are developed as may be necessary; a PJM summer peak case to study summer-peaking study areas and a PJM winter peak case to study winter-peaking study areas (The need for a winter case is assessed annually. Currently the only PJM winter peaking area has summer and winter peaks sufficiently close to enable the analysis on only a summer peak case). The RTEP load flow case nearest to the study time period should be selected and modified as required (modeling the projected load, generation, and transmission system configuration for the target study period).

To calculate plausible generator outage scenarios, a file containing the installed MW capacity and the Generator Unavailability Subcommittee (GUS) five-year planning equivalent forced outage rate demand (EFORd) for every PJM capacity resource will be developed. Related data is available at http://www.nerc.com/page.php?cid=4|43|47.

4.1 Study Area Capacity Deficiency Assumptions

The study area being evaluated is assumed to be experiencing the generation deficiency due to a combination of higher-than-expected load demand (a 90/10 load forecast) and greater-than-expected generator unavailability. The 90/10 load forecast level is modeled by using the value of the 90/10load contained in the latest LAS report along with generator outage scenario(s) that would lead to a generation deficiency which cause a transmission limitation.

4.2 Study Area CETL Base Case Modeling Summary

- Behind the Meter and energy only generation should be modeled at the average historic MW output during the previous year's 10 highest load hours for the study area each hour being selected from a different day.
- No study areas will be defined less than a peak load of 1500 MW.
- Generator reactive output will be reduced in proportion to the MW scaling reduction for any generation that is modeled below the rated capability.
- The 90/10 load adder is assumed to be at 0.8 power factor.
- Normal and emergency ratings included in the power flow will be those applied in Operations (at 35°C).
- PAR setting should be 1000 MW to NJ at Ramapo, 1000 MW to NJ at Waldwick, and 1000 MW into ConEd at Goethals and Farragut. PARs located within PJM may be operated as needed subject to the appropriate agreements (if any) and PJM Operating Company practices. Except as follows.
- PAR settings during subsequent contingency analysis can decrease the 1000 MW delivery to ConEd at Goethals and Farragut to as low as 600 MW delivery as required to enhance deliverability to the eastern study areas.
- The forecast 90/10 MW load for the area under test will be reduced by the available energy efficiency and DR (both in MW).The greater of the 90/10 MW load in the area under test reduced by the total amount of energy

efficiency and DR or the 50/50 load reduced by forecast energy efficiency, will be used as the MW load in the area being tested.

- If the 50/50 load reduced by energy efficiency is used to model the load in the test area, the forecast 90/10 MW load reduced by the amount of energy efficiency and DR needs to be adjusted by a MW adder to reach the level of 50/50 MW load minus the energy efficiency. The MVAR load associated with the 50/50 load minus the energy efficiency also needs to be increased by an amount equal to the difference between the MVAR associated with the 90/10 load adder at an 80% power factor and at the power factor in the 50/50 load forecast. The MVAR adder is to account for the assumption that the incremental MW (90/10 load adder) between the 90/10 and 50/50 load forecast is at an 80% power factor.

  Note that the above assumes that the 90/10 forecast contains only a MW value. If the 90/10 forecast contains both a MW and a MVAR value, the power factor of this forecast 90/10 load needs to be used for the adjustment instead of the 80% power factor.

4.3 Procedure for Determining Load Deliverability Facility List

The following procedures outline the process for determining which facilities will be monitored for the PJM Load Deliverability test. The first procedure provides the details for internal PJM facilities and the second procedure concentrates on external PJM facilities.

Internal PJM Load Deliverability Facility List

1. PJM monitors all transmission facilities for its load deliverability test and screens criteria violations for upgrades that pass a transfer distribution factor (TDF) cutoff test and are on PJM's monitored facility list (Lists of PJM monitored lines and substations are available at http://www.pjm.com/markets-and-operations/transmission-service/transmission-facilities.aspx.) PJM performs load deliverability for its entire region by individually studying each study area listed in § 3.3. A different subset of the Transmission Facilities is the focus for each study area.
2. The following defines the TDF cutoff for PJM facilities that will be included in the separate Load Deliverability test for each study area. If a 100 kV and up facility is excluded from all load deliverability analyses based on its unresponsiveness to load supply, that facility may be addressed in generator deliverability or it becomes subject to reliability screening under the standard NERC TPL 001-004 criteria[4].
   a. All non-radial facilities 345 kV or greater will be included regardless of OTDF.

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[4] Any 100 kV and above facility that is not subject to upgrade screening in the load deliverability analysis will be evaluated in a subsequent screening that evaluates the NERC TPL-001 through 004 criteria in the 50/50 peak load scenario. All facilities failing these standard NERC criteria will be identified for upgrade.

   b. All facilities with an external OTDF (an "external OTDF" is based on a source point external to the study area and a sink point internal to the study area) greater than 10% will be included regardless of voltage class.
   c. All facilities with an external OTDF between 5% and 10% will be included unless both PJM and the TO agree that the facility should not be subject to the load deliverability test.
   d. All facilities with an external OTDF less than 5% will not be included unless the PJM and TO agree that the facility should be subject to the load deliverability test.
3. The Load Deliverability Facility List can be modified prior to each baseline analysis but cannot be changed between baseline studies.
4. All PJM monitored facilities will be included when determining any generation re-dispatch or PAR movements required for the base case development. However, only the facilities on the Load Deliverability Facility List will require system upgrade if overloaded for this load deliverability test.
5. The substations to be included for voltage analysis will be developed based on the Load Deliverability Facility List.
6. Additional substations to be included for voltage analysis as agreed to by PJM and the TO.

External PJM Load Deliverability Facility List

For study areas electrically close to PJM, PJM conducts joint coordinated interregional studies on a periodic basis that examines and addresses deliverability issues between PJM and adjacent external systems.

4.4 Dispatch for PJM Areas Not in Capacity Emergency

PJM generators should be dispatched as per existing RTEP base case procedures (see also "Deliverability of Generation"). To simulate the average forced outage rate for generation in PJM, a uniform de-rate of all generation is done.

4.4.1 Dispatch for non-PJM Areas Not in Capacity Emergency

One of the base principles for the load deliverability test is that the study area is the only area that is in a capacity emergency. All adjacent external areas to PJM are assumed to be at a peak load but in a non-emergency condition. Increasing available generation (respecting Pmax) simulates exports from these areas to the study area.

The locations of generation increases and corresponding MW import level to the study area is typically optimized to provide the highest available imports to any given study area. The import amounts from each external area can be based on strength of ties or historical imports when the study area was capacity deficient. The amount of reserves considered available from any external system may be changed from the optimized scenario to reflect historical import data or to minimize constraints at the discretion of the engineer conducting the study.

4.5 Dispatch for Load Deliverability Study Area

4.5.1 Procedure to Determine Dispatch for Voltage Analysis

1. Derate all generators in the zone by their EFORd.
2. Rank generators by EFORd^(1/PMAX).
3. To model discrete generator outages, select generators in rank order until the next selected generator would exceed 105% of the target generator outage value.
4. Multiple generators at the same substation may be outaged unless the outaged MW to installed MW ratio is greater than 60%. (For example, if a station had 3-100 MW units, 1 unit would be outaged since 100 MW/300 MW = 33% but two units would not be outaged since 200 MW/300 MW = 66%)
5. Any remaining MW outages required to meet the target generator outage value will be obtained through a uniform scale of all on-line generation's MWs and MVARs in the study area.
6. The Transmission Owner(s) may request analysis of a different outage pattern. If this outage pattern results in more severe reliability problems it will be used in place of the original outage pattern only if both the Transmission Owner and PJM accept the new outage pattern.

4.5.2 Procedure to Determine Dispatch for The Mean Dispatch Case

1. All generators in the study area are sampled until 10,000 generation outage scenarios are found where the amount of generation selected is within +/- 2% of the amount needed to meet the target generator outage value required to model the import objective.
2. The 10,000 generation outage scenarios are determined by using a Monte Carlo simulation and randomly assigning a value between 1 and 0 to each generator in the study area. If the value is greater than the generator forced outage rate, then that generator is turned on. If the value is less than the generator forced outage rate, then that generator is turned off. There is no limit to the number of units that can be simultaneously outaged at a station.
3. Determine the average MW output of each generator in the study area by using its dispatched values in the 10,000 generator outage scenarios. These average MW output values for each generator are referred to as the Mean Dispatch.
4. The reactive capability of each unit is reduced by the ratio of each unit's average MW output from the preceding step to the unit's maximum MW output.
5. Create a base case modeling the average MW output of each generator determined in step 5 above. This case is referred to as the mean dispatch case. It models a generation outage scenario based on the average MW for each unit from the 10,000 generation outage scenarios determined in step 5 above. This case is used by the entities to study potential

reinforcements required to resolve any overloaded flowgates. In addition, since the case models an average generation outage scenario and therefore average losses for those outage scenarios, it is the best case to use when determining the impact on flowgates of the various discrete generation outage scenarios applied for the median loading.

6. Perform an AC contingency analysis on the mean dispatch case to obtain the percent loading for each flowgate. This percent loading is referred to as the reference loading.
7. Flowgates that have a reference loading greater than or equal to 90% of the appropriate (i.e., normal or emergency) rating (at 35°C) in the mean dispatch case are tested further as defined below.
8. To determine the discrete generation outage scenarios, all generators in the study area are sampled until 10,000 generation outage scenarios are found where the amount of generation selected is within +/- 2% of the amount needed to meet the target generator outage value required to model the import objective. (This process is described in steps 7 and 8 above).
9. The flowgate loading for each discrete generation outage scenario is determined as follows:
    a. For each generator in the study area, a distribution factor is established for each flowgate using the generator in the study area as the sink point and all generators external to the study area, being used to model the transfer as the source points.
    b. The impact on the flowgate due to the change in generation is determined for each generator by determining the change in MW output in the generation outage scenario from the output modeled in the mean dispatch case. The change in MW value is then multiplied by the distribution factor of each flowgate to determine the +/- impact on the flowgate.
    c. The AC MVA loading from the mean dispatch case is incremented or decremented by this MW result.
    d. This results in 10,000 percentage loadings being established for each flowgate (i.e., one flowgate percent loading for each of the generation outage scenarios studied).
10. If any overloads exist, any of the system adjustments noted in section 3.2 can be implemented and the procedure in section 4.5.2 is repeated.
11. Any overloads that still remain will require mitigation in order for the study area CETL to exceed the CETO.

4.6 Study Results

1 Five % points are selected (30-70% in 10% increments) to quantify the probability of a given % loading for each flowgate.

2 For example, a 90% flowgate loading in the column of the first point, 30%, means that in 3,000 of the 10,000 discrete generation outage scenarios the

line loading was below 90%. Likewise, a 90% flowgate loading in the column of the third point, 50%, means that in 5,000 of the 10,000 discrete generation outage scenarios the line loading was below 90%. This third point is the median flowgate loading.

3. Select 50% probability point such that any circuits with loadings exceeding their applicable rating for more than 50% of the dispatch scenarios will require upgrade.

4.7 CETL Determination

After steps 4.5.1 and 4.5.2 are completed and any required system upgrades are identified to eliminate any voltage problems or overloads, the study area CETL can be determined.

CETL for Voltage Problems

To determine the CETL for voltage problems, the imports into the study area will be increased in 50 MW increments starting from the dispatched base case identified in section 4.5.1. The import change will be modeled by increasing external generation and uniformly decreasing internal study area generation.

CETL for Thermal Problems

To determine the CETL for thermal problems, the transfer distribution factor on each of the flowgates will be calculated by using a source of generation external to the study area and a sink of generation internal to the study area. The transfer distribution factor multiplied by the increased imports will indicate which overload will limit the study area imports from a thermal perspective.

CETL for Study Area

The lower of the CETL identified for the voltage problems and the thermal problems will be used as the study area CETL.

5.0 Transitional Rules

This Load Deliverability Procedure will be applied for all future load deliverability analysis for planning years 2008 and beyond. Any existing projects identified through the RTEP for installation prior to June 2008 and approved by the PJM Board will remain requirements as identified in previous analysis.

C.6 Deliverability of Generation

The second deliverability test, the ability of an electrical area to export capacity resources to the remainder of PJM has historically been applied in situations where problems were expected to occur. Consistent with the move from IOU service territories to electrical areas, this test is applied to ensure that capacity is not "bottled" from a reliability perspective. This would require that each electrical area be able to export its capacity, at a minimum, during periods of peak load. Export capabilities at lower load levels would be based more on economic decisions and would not reflect on deliverability criteria and therefore the "certification" of resources as deliverable capacity.

Deliverability, from the perspective of individual generator resources, ensures that, under normal system conditions, if capacity resources are available and called on, their ability to provide energy to the system at peak load will not be limited by the dispatch of other certified capacity resources. This test does not guarantee that a given resource will be chosen to produce energy at any given system load condition. Rather, its purpose is to demonstrate that the installed capacity in any electrical area can be run simultaneously, at peak load, and that the excess energy above load in that electrical area can be exported to the remainder of PJM, subject to the same single contingency testing used when examining deliverability from the load perspective. In short, the test ensures that bottled capacity conditions will not exist at peak load, limiting the availability and usefulness of certified capacity resources to system operators. In actual operating conditions, energy-only resources may displace capacity resources in the economic dispatch that serves load. This test would demonstrate that a magnitude of resources equal to or greater than the installed capacity in any given electrical area could simultaneously deliver energy to the remainder of PJM. Therefore, these tests do not require the calculation of the equivalent of export CETO and CETL values.

The electrical Regions from which generation must be deliverable, range from individual buses to the entire regional generation under study. The premise of the test is that all capacity within the Region is required; hence the remainder of the system is experiencing a significant reduction in available capacity. However, since localized capacity deficiencies reductions are tested when evaluating deliverability from the load perspective, the dispatch pattern in the remainder of the system is modeled based on a uniformly distributed outage pattern.

C.7 Generator Deliverability Procedure

1.0 Introduction

To maintain reliability in a competitive capacity market, resources must contribute to the deliverability of the Control Area in two ways. First, energy must be deliverable, from the aggregate of resources available to the Control Area, to load in portions of the applicable PJM region experiencing a localized capacity emergency, or deficiency. PJM utilizes the CETO / CETL procedure to study this "deliverability of load". Second, capacity resources within a given electrical area must, in aggregate, be able to be exported to other areas of PJM that are experiencing a capacity emergency. PJM utilizes a Generator Deliverability procedure to study the "deliverability of individual generation resources". This document provides the procedure for Generator Deliverability.

2.0 Study Objectives

The goal of the PJM Generator Deliverability study is to determine if the aggregate of generators in a given area can be reliably transferred to the remainder of PJM. Any generators requesting interconnection to PJM must be "deliverable" in order to be a PJM installed capacity resource.

3.0 General Procedures and Assumptions

Step 1: Develop Base case

The RTEP base case is developed for a reference year 5 years in the future. All RTEP identified system upgrades and Supplemental RTEP Projects are included in the system model. Load is modeled at a non-diversified forecasted 50/50 summer peak load level reduced by energy efficiency as per the latest load forecast. All approved firm interchange is included with roll-over rights. Generation and Merchant Transmission projects that have proceeded at least through the execution of the Facility Study Agreement stage of the interconnection process are considered in the model along with any associated network upgrades. The starting point dispatch is developed as explained in the next step. PJM uses a uniform reduction of generation in place of discrete forced outages for this test due to the significant bias any one specific outage pattern can have on the final overload results.

Step 2: Establish initial RTEP dispatch for unit under study

Place all in-service capacity resources (those that have procured capacity delivery rights) on-line at a generation value equal to their installed capacity x (1 – PJM average EEFORd). Wind units with capacity delivery rights are derated to their granted capacity rights (either 13% beginning with the "U" queue or 20% for prior queues) representing the combined effects of wind variation and outage characteristics. The target generation value is the projected load + losses + firm interchange. (See addendum 1 for treatment of transmission withdrawal and injection rights). If all in-service capacity resources de-rated by the PJM EEFORd are greater than the target generation value, then all in-service capacity resources should be uniformly reduced to meet the target generation value. If all in-service capacity resources de-rated by the PJM EEFORd is less than the target generation value, then place all capacity resources with an executed Interconnection Service Agreement (ISA) on-line at a generation value equal to the installed capacity x (1 – PJM average EEFORd). If all in-service and ISA capacity resources de-rated by the PJM EEFORd are greater than the target generation value, then all these resources should be uniformly reduced to meet the target generation value. If all in-service and ISA capacity resources de-rated by the PJM EEFORd is less than the target generation value, then place all capacity resources with an executed Facility Study Agreement on-line at a generation value equal to the installed capacity x (1 – PJM average EEFORd). If all in-service, ISA and Facility Study capacity resources de-rated by the PJM EEFORd are greater than the target generation value, then all these resources should be uniformly reduced to meet the target generation value.

All resource requests in the study queue ahead of the unit under study are set at 0 MW but available to be turned on. The resource request under study is also set at 0 MW but available to be turned on. Resource requests queued after the unit under study are not modeled. The loading on each transmission line that results from this dispatch and the application of a contingency is the base loading of the facility. (See Addendum 2 for treatment of Common Mode Outage Procedures).

Step 3: Determine potential overloads

PJM uses a linear (DC) power flow program to analyze each facility for which PJM is responsible to determine whether any contingencies can overload the facility (including comprehensive analysis of single, towerline, bus, and stuck breaker contingencies). These results are utilized to determine which flowgates will be used in the generator deliverability analysis,i.e., the program examines each PJM flowgate (contingency / monitored element pair) on the entire PJM footprint. The procedure below explains conceptually how the program works; following the procedure below would yield the same results as the program. The procedure uses a load flow set up according to step 2.

Determine the distribution factor for each generator on each flowgate. The distribution factor for a particular generator is referenced to the PJM online generation. For each flowgate, multiply the distribution factor of each generator by the offline portion of the generator to obtain the MW impact the generator would have on a particular flowgate if it were ramped from its output in the initial load flow to its full output. This result will be referred to the ramping impact of a particular generator on a particular flowgate. For all flowgates determine the cumulative ramping impact of generators with greater than a 1% distribution factor. The total amount of ramped generation is capped to limit the number of potential overloads to a reasonable number of the worst impacts. A typical cap for the total ramping is 10,000 MW but the actual value can vary to establish a reasonable scope for the potential overloads. For each flowgate, add the cumulative ramping impact to the initial DC loading. If the resulting DC loading is greater than the flowgate rating, then this flowgate is a potential overload.

Step 4: Determine 80/20 DC loading

The number of generators having greater than a 1% distribution factor in Step 2 is often large enough that having them all simultaneously outputting their full installed capacity would be extremely improbable. As a result, in this step the number of generators contributing to the cumulative ramping impact on a flowgate is further restricted in the following manner.

Units modeled in the power flow with greater than a 5% distribution factor (or 10% distribution factor for flowgates whose monitored element's highest terminal voltage level is equal to or greater than 500 kV) that contribute to the cumulative ramping impact are ranked according to their distribution factor on a potentially overloaded flowgate. The availability (1 – EEFORd) of the unit with the highest distribution factor is then multiplied by the availability of the unit with the second highest distribution factor and so on until the expected availability of the selected units is as close to but not less than 20%. This resulting "80/20" cumulative ramping impact is then added to the initial DC loading on the flowgate. This resulting loading is the 80/20 DC loading and the generators chosen to contribute to the cumulative ramping impact are the 80/20 generators.

Step 5: Determine Facility Loading Adder

This Step 5 addresses off-line generators which are not included in the 80/20 list. Existing generators that do not have capacity delivery rights and active queued generators that are not yet in commercial operation (or do not yet have a signed ISA) are offline but available to be turned on. The ramping impact of this set of generators determines the Facility Loading Adder. First, for their ramping impact to be considered, off-line generators must pass the impact threshold of at least a 5% DFAX (10% for flowgates with monitored elements having the highest terminal voltage 500 kV and above) on a flowgate or with an impact (DFAX times a generator's full energy output rating) greater than 5% of the flowgate's rating.

The ramping impact of offline generators is determined according to their classification as: (1) existing generators that do not have capacity delivery rights and active queued generators with signed ISA's, or (2) active queued generators without signed ISA's. Category (1) generators are allowed to aggravate or backoff overloaded flowgates. Category (2) generators are considered only if they aggravate overloaded flowgates (active queued generators without signed ISAs are not allowed to backoff overloads.)

The amount of generation change from the initial load flow due to changes in 80/20 and Facility Loading Adder generation shall not be any more than the online installed capacity exclusive of the 80/20 generators x PJM average EEFORd. Ramping ipacts for lower DFAX offline generators that do not influence the 80/20 cumulative ramping impact are not considered when this threshold is exceeded.

The ramping impact of active queued generators without signed ISA's considers the commercial probability of queued generators at the feasibility and impact study stage of the interconnection process. For generators at the feasibility study stage of the interconnection process, the output of the generator is multiplied by the historic commercial probability of a generator at the feasibility study stage of the interconnection process. For generators at the impact study stage of the interconnection process, the output of the generator is multiplied by the historic commercial probability of a generator at the impact study stage of the interconnection process. To be conservative, these values are then multiplied by 150% to determine the ramping impact of generation at the feasibility study and impact study stage of the interconnection process. The entire requested capacity of queued generation is used to determine the ramping impact of generation that has signed a facility study agreement.

The summation of 85% (100% for a Merchant Transmission project) of the ramping impact on a flowgate of each off-line resource that meets the above conditions is calculated. The resulting impact defines the Facility Loading Adder. The Facility Loading Adder is added to the base loading and the 80/20 DC loading to obtain the final DC loading on the facility.

Step 6: Determine Final Flowgate Loading

If a flowgate has a final DC loading less than 90% of its rating, it is not considered to be overloaded and is not tested further. If a flowgate has a final DC loading greater than or equal to 90% of its rating, the 80/20 generators are ramped up to their installed capacity in the load flow from step 2 and all remaining PJM generators are uniformly ramped down such that the PJM firm interchange is maintained. The resulting flowgate loading is the 80/20 AC loading.

The Facility Loading Adder can sometimes have a significant impact on the results of a deliverability study. However, ramping up the units associated with the adder in the load flow will typically create too much localized generation and a localized capacity emergency condition elsewhere when the rest of PJM is proportionally displaced to maintain the firm interchange. Therefore, to account for the effect of these units on the facility in question, the Facility Loading Adder, as determined in Step 5, is added to the 80/20 AC loading to result in the Final Flowgate Loading. This Facility Loading Adder accounts for the ramping impact of those offline resource requests that are both electrically close to a flowgate and did not participate as an 80/20 generator without actually turning them on. If the cumulative ramping impact of these offline resource requests has a beneficial effect on the flowgate, then the loading of the flowgate will be decreased to account for this beneficial effect. Similarly, the flowgate loading will be increased if these offline resource requests will further add to the overload.

In summary, the 80/20 generators will define the study area *for a particular flowgate* by determining which units to ramp up. All remaining online units are proportionally displaced to some level below their installed capacity x (1 – PJM average EEFORd) to maintain the firm PJM interchange.

Addendum 1: Modeling Transmission Withdrawal Rights (TWRs) and Transmission Injection Rights (TIRs)

Firm TWRs and TIRs may be associated with a controllable merchant transmission request, i.e. HVDC, which interconnects PJM to another system. If the transmission request has an executed ISA associated with it, the firm rights are modeled at their full amount. When the firm rights are modeled, the initial dispatch in step 2 will need to be modified to support these rights. If the transmission request does not have an executed ISA and is queued ahead of the project under study or is the project under study the following rules apply; for TWRs the sign of the distribution factor is changed for the purpose of deciding whether to model the right. The right is modeled at its full amount if a generator with its distribution factor would be in the 80/20 list. The right is treated as a Facility Loading Adder using the rules of Step 5.

Addendum 2: Common Mode Outage Procedure

In addition to single contingencies, PJM planning criteria requires that the PJM system withstand certain common mode outages. These outages include line faults coupled with a stuck breaker, double circuit towerline outages, faulted circuit breakers and bus faults. PJM uses a procedure very similar to the generator deliverability procedure to study common mode outages. The list below highlights the other details of the common mode outage procedure that differ from the generator deliverability procedure.

In addition to the modeling of capacity resource requests, all existing energy resources and energy resource requests queued ahead of the unit under study are set at 0 MW but available to be turned on. The energy resource request under study is also set at 0 MW but available to be turned on. Energy resource requests queued after the unit under study are not modeled.

A 50/50 DC loading is used instead of an 80/20 DC loading, i.e., the expected availability of the selected units is close to but not less than 50%.

For all voltage levels, a 10% distribution factor is used instead of a 5% distribution factor to select the 50/50 generators.

Attachment D: PJM Reliability Planning Criteria

The PJM Reliability Planning Criteria consist of multiple standards and applicable planning principles that include PJM planning procedures, NERC Planning Standards, NERC Regional Council planning criteria, and the individual Transmission Owner FERC filed planning criteria. PJM applies all applicable planning criteria when identifying reliability problems and determining the need for system upgrades on the PJM system. Details of specific criteria applicable to the various stages of reliability planning are discussed along with the corresponding discussion of each procedure found elsewhere in this manual.

I. The PJM Transmission Owners are required to follow NERC and Regional Planning Standards and criteria as well as the Transmission Owner FERC filed criteria. References to the various planning standards and criteria can be found at: PJM - NERC and Regional Compliance and http://www.pjm.com/planning/planning-criteria.aspx.

- Reliability*First* Approved Standards will be applied for all Reliability*First* *Bulk Electric System facilities.*
- SERC Reliability Criteria will be applied to all SERC networked transmission systems rated 100 kV and higher.
- Transmission Owner standards filed in their FERC 715 filings will be applied to all facilities included in the PJM Open Access Transmission Tariff facility list. Also, interconnections to Transmission Owner facilities are subject to owner standards found at: http://www.pjm.com/planning/design-engineering.aspx (these are technical interconnection requirements and do not factor into near-term and long-term planning analyses.

PJM maintains a list (http://www.pjm.com/markets-and-operations/transmission-service/transmission-facilities.aspx) of all PJM Open Access Transmission Tariff facilities along with which facilities are included in the PJM real-time congestion management control facility list. Both facility lists are referenced in the PJM Reliability Planning Criteria.

II. The PJM Generator Deliverability Procedure and Load Deliverability Procedure will be applied to all facilities in the PJM real-time congestion management control facility list.

III. Facilities included in the PJM real-time congestion management control facility list but not included in the applicable regional council planning criteria as defined in section I above will be evaluated against the following criteria. For all tests, PJM will not accept a planned loss of load of more than 300 MW. Attachment D-1 contains a description of the various load loss types referred to in this document. This criterion is in addition to, not in place of, each Transmission Owners Planning Criteria as reported in the FERC 715 filing.

1. The loss of any single transmission line, cable, generator, or transformer may not result in any monitored facility exceeding the applicable emergency rating or applicable voltage limit. (The applicable emergency rating and voltage limits will be as defined in PJM Operations.) The single contingency test will be applied as per the RTEP Generator Deliverability Procedure. (See Attachment C of this PJM Manual 14B.)

- The RTEP base case which includes a 5-year horizon system representation and non-diversified forecasted 50/50 summer peak load will be used for this analysis.
- System load will be represented at an area or zone wide minimum power factor of 0.97 lagging as measured at the transmission / distribution interface point.
- The 300 MW load limit referenced above does not include load that is immediately restored via automatic switching to adjacent substations.
- Automatic or supervisory switching as proposed by the Transmission Owner to sectionalize the system for single contingency events must receive acceptance by PJM Operations.
- During normal conditions with all facilities initially in-service, no uncontrolled load loss or load loss due to automatic schemes is allowed for a single contingency event. Consequential load loss is allowed.

2. After the occurrence of the transmission line, cable, generator or transformer outage, the system must be capable of re-adjustment such that no facility exceeds the maximum continuous rating or voltage limits as defined in PJM Operations.
3. During maintenance of any single transmission line, cable, generator, transformer, bus or circuit breaker, the loss of a transmission line, cable, generator, or transformer may not result in any monitored facility exceeding the applicable emergency rating or voltage limit (The applicable emergency rating and voltage limits will be as defined in PJM Operations.) However, for practical purposes, PJM Planning will only include a specific bus or circuit breaker maintenance condition in all future analysis if PJM Operations experiences operational problems as a result of the bus or circuit breaker maintenance condition.
    - Pre-contingency generation redispatch will be considered acceptable for mitigation of a potential overload or voltage limit.
    - This test will be applied at 70% of the diversified forecasted 50/50 summer peak load, as modeled in the RTEP base case, unless the Transmission Owner provides information to PJM Operations demonstrating sufficient maintenance windows at a lower load level.
    - No cascading or uncontrolled load loss is allowed under any circumstance.
    - Consequential load loss is allowed.
4. After occurrence of the maintenance outage and the subsequent facility outage as defined in the previous test #3, the system must be capable of re-adjustment such that no facility exceeds the maximum continuous rating or voltage limits as defined in PJM Operations.

IV. The PJM Light Load Reliability Analysis Procedure will be applied to all facilities in the PJM real-time congestion management control facility list.

Attachment D-1: Load Loss Definitions

Uncontrolled Load Loss – Uncontrolled load loss would require operator interaction to prevent system cascading or to return the system to applicable ratings or voltage limits. Manual load dump as defined in PJM Operations would be included in this category. The PJM Reliability Planning Criteria does not allow for the system design to permit Uncontrolled Load Loss for any contingencies that are studied.

Examples:

- Voltage collapse
- A facility overload without automatic schemes to drop load and with no available generation to re-dispatch pre-contingency.

Consequential Load Loss – Consequential load loss occurs due to the design of the system but does not include automatic schemes designed to drop load under various conditions.

Examples:

- A transformer serving radial load that taps a networked circuit.
- Load that is served from a radial circuit.

Controlled Load Loss due to Automatic Schemes – Controlled load loss occurs due to the operation of automatic schemes that are designed to drop load under specific maintenance conditions.

Planned Load Loss = Consequential load loss + Controlled load loss due to automatic schemes.

The 300 MW total load loss limit is based, in part, on a Federal reporting requirement for major system incidents on electric power systems (refer to Electric Power System Emergency Report - Form EIA-417R).

Attachment D-2: PJM Reliability Planning Criteria Methods

D-2.1 Light Load Reliability Analysis

The light load reliability analysis tests the ability of an electrical area to export generation resources to the remainder of PJM during light load conditions. The export generation is selected by using the historical mix of generation that operates at the light load level. This test is applied to ensure that generation capability, including renewable generation capability that typically operates at light load such as wind, pumped hydro, or other emerging storage technologies are not "bottled" from a reliability perspective.

The light load reliability analysis, from the perspective of individual generator resources, ensures that, under light load system conditions, their ability to provide energy to the system has a probability of not being limited by the typical dispatch of other generation resources that operate at that demand level, including resources in neighboring systems. The Generator Deliverability Test and Common Mode Outage procedure have a similar objective at the summer peak forecast load. While deliverability under all possible system conditions is not in the purview of the RTEP, analyzing the system performance under this wide range of forecasted demand levels improves overall deliverability of generating resources. Consideration will be given to the capacity factor by fuel class during this period, as described in Table 1. This test does not guarantee that a given resource will be able to deliver energy at the light load condition. Rather, the purpose is to demonstrate that typical light load generating capabilities in any electrical area can be run simultaneously, at light load, and that the excess energy above demand in that electrical area can be exported to the remainder of PJM. In short, the test ensures that bottled capability conditions will not exist at light load, limiting the availability and usefulness of a range of resources available to system operators, including renewable resources. In actual non-emergency operating conditions, the economic dispatch serves load.

D-2.2 Light Load Reliability Analysis Procedure

1.0 Introduction

To maintain reliability and operational flexibility during the light load period, resources within a given electrical area must, in aggregate, be able to be exported to other areas of PJM. PJM utilizes a Light Load Reliability Analysis procedure to study the system performance during typical light load conditions. This document provides the procedure for Light Load Reliability Analysis.

2.0 Study Objectives

The goal of the PJM Light Load Reliability Analysis study is to determine if the aggregate of generators in a given area can be reliably transferred to the remainder of PJM during light load conditions. Generators requesting interconnection to PJM must pass this test in order to become a PJM capacity or energy resource.

3.0 General Procedures and Assumptions

Step 1: Develop Base case

The RTEP base case is developed for a reference year 5 years in the future. All RTEP identified system upgrades and Supplemental RTEP Projects are included in the system model. PJM load is modeled at 50% of a non-diversified forecasted 50/50 summer peak load level reduced by energy efficiency as per the latest load forecast. System Interchanges will be determined by PJM through the use of data, including statistical averages based on historical data for off-peak load periods for typical previous years. Generation and Merchant Transmission projects that have proceeded at least through the execution of the Facility Study Agreement stage of the interconnection process are considered in the model along with any associated network upgrades. The starting point dispatch is developed as explained in the next step. PJM uses a combination of uniform reduction of coal powered generation and discrete outages for this test.

Step 2: Establish initial RTEP dispatch for unit under study

Existing PJM Resources: Place all in-service nuclear resources on-line at a generation value equal to their installed capacity. Wind units are derated in the initial dispatch to 40% of their nameplate capability. Coal units are initially derated consistent with Table 1. Queued Units in the PJM queue that have an ISA will be placed on-line consistent with Table 1. The target generation value for each Transmission Owner (TO) zone in the model is the projected load + losses + historical interchange for the light load period, as calculated by PJM. If necessary, coal resources in each TO zone are then uniformly de-rated or increased from the initial dispatch until the target generation value is met.

Existing MISO Resources: Model all existing wind generation in the MISO area online at a 100% capacity factor. Sink all MISO generation uniformly to maintain the target interchange. MISO generation dispatch utilized to serve MISO load will reflect a typical yearly statistical average for off-peak periods for interchange between MISO West, Central, and East.

Queued Resources in PJM and neighboring systems: Model all non-ISA queued generation offline. Model all ISA queued generation online. If selected by the test procedure, queued MISO wind resources will have the potential to be dispatched to 100% capacity factor. Similarly, if selected by the test procedure, queued PJM wind resources will have the potential to be dispatched to 80%.

For queued interconnection studies, all queued resources in the study queue ahead of the unit under study are set at 0 MW but available to be turned on per the Generator Deliverability procedure and Common Mode Outage test procedure. The resource request under study is also set at 0 MW but available to be turned on. Resource requests queued after the unit under study are not modeled. The loading on each transmission line that results from this dispatch and the application of a contingency is the base loading of the facility. (See Addendum 2 for treatment of Common Mode Outage Procedures).

Table 1 – Light Load Base Case

Network Model	Current year + 5 base case
Load Model	Light Load (50% of 50/50 summer peak)
Capacity Factor for Base Generation Dispatch for PJM Resources (Online in Base Case)	Nuclear – 100% Coal >= 500 MW – 60% Coal < 500 MW – 45%

	Oil – 0% Natural Gas – 0% Wind – 40% All other resources – 0% Pumped Storage – full pump
Capacity Factor for Base Generation Dispatch for MISO Resources (Online in Base Case)	Wind – 100%
Interchange Values	Historical values
Contingencies	NERC Category A, B, C (except C3)
Monitored Facilities	All PJM market monitored facilities

Step 3: Determine potential overloads

The method to determine potential overloads is similar to the methods used for the generator deliverability test. Also, the Common Mode Outage procedure is applied to include the effects NERC Category C events such as bus faults, faulted breakers, and double circuit towerline outages.

Step 4: Determine 80/20 DC loading

This portion of the test is the generator deliverability procedure except only wind generation is considered with a maximum ramping from the base dispatch of 40% to 80% of nameplate capability.

Step 5: Determine Facility Loading Adder

This portion of the test is the generator deliverability procedure except only wind generation is considered with a maximum ramping from the base dispatch of 40% to 80% of nameplate capability.

Step 6: Determine Final Flowgate Loading

This portion of the test is the generator deliverability procedure except only wind generation is considered with a maximum ramping from the base dispatch of 40% to 80% of nameplate capability.

Attachment E: Market Efficiency Analysis Economic Benefit / Cost Ratio Threshold Test

PJM uses a Benefit/Cost Ratio test to determine whether an economic-based enhancement or expansion will be included in the RTEP. Specifically, to be included in the RTEP recommended to the PJM Board of Managers for approval, the relative benefits and costs of the economic-based enhancement or expansion must meet a Benefit/Cost Ratio Threshold of at least 1.25:1. The Benefit/Cost Ratio is calculated by dividing the present value of the total annual benefit for each of the first fifteen years of the life of the enhancement or expansion by the present value of the total annual cost for each of the first fifteen years of the life of the enhancement or expansion. Assumptions for determining the present value of the benefits and costs (e.g. discount rate and annual revenue requirement) will be among the assumptions that are approved by the PJM Board each year to be used in the economic planning process.

The Benefit/Cost Ratio is expressed as follows:

Benefit/Cost Ratio = [Present value of the Total Annual Enhancement Benefit for each of the first 15 years of the life of the enhancement or expansion] ÷ [Present value of the Total Enhancement Cost for each of the first 15 years of the life of the enhancement or expansion]

The purpose of a Benefit/Cost Ratio Threshold is to hedge against the uncertainty of estimating benefits in the future and to provide a degree of assurance that a project with a 15-year net benefit near zero will not be approved. At the same time the threshold is not so restrictive as to unreasonably limit the economic-based enhancements or expansions that would be eligible for inclusion in the RTEP.

E.1 Total Annual Enhancement Benefit

The benefit component of the Benefit/Cost Ratio (Total Annual Enhancement Benefit) is the sum of two metrics: the "Energy Market Benefit" and the "Reliability Pricing Model (RPM) Benefit." By including these two metrics, the benefits to customers from reductions in both energy prices and capacity prices as a result of an economic-based enhancement or expansion will be taken into account in the formulaic analysis. These two metrics in turn each consist of two elements -- the change in production cost and the change in load payment, which are weighted seventy percent and thirty percent respectively. This comprehensive test captures customers' benefits in the energy markets and the capacity markets that may correspond to responsibilities related to obtaining reasonably priced energy as well adequate capacity.

a. Energy Market Benefit

The energy-market benefit analysis is conducted using an energy market simulation tool that models the hourly least-cost, security-constrained commitment and dispatch of generation over a future annual period. A detailed generation, load, and transmission system model is used as input into the simulation tool in order to mimic the hourly commitment and dispatch of generation to meet load, while recognizing constraints imposed on the economic commitment and dispatch of generation by the physical limitations of the transmission system. Benefits of potential economic-based enhancements, PJM will perform and compare market simulations with and without the proposed enhancement for selected future years within the planning horizon of the RTEP. A comparison of these simulations will identify the annual economic impact of the enhancement for each of the future study years. An extrapolation of these results provides a projection of annual benefits for each of the first fifteen years of the life of the enhancement.

The Energy Market Benefit component of the Benefit/Cost Ratio is expressed as:

Energy Market Benefit = [.70] * [Change in Total Energy Production Cost] + [.30] * [Change in Load Energy Payment]

The Change in Total Energy Production Cost is the difference in estimated total annual fuel costs, variable O&M costs, and emissions costs of the dispatched resources in the PJM Region without and with the enhancement or expansion.

The Change in Load Energy Payment is the difference between the annual sum of the hourly estimated zonal load megawatts for each PJM transmission zone multiplied by the hourly estimated zonal Locational Marginal Price for each PJM transmission zone without and with the economic-based enhancement or expansion. In determining the Change in Load Energy Payments for projects, the costs of which will be assigned cost responsibility on a regional basis (e.g. above 500 kV facilities), the Load Energy Payment in all PJM transmission zone will be considered whether there is an increase or decrease in the Load Energy Payment in the transmission zone. However, for projects, the cost of which will be allocated using a flow-based or distribution factor methodology (e.g. below 500 kV facilities), only the Load Energy Payment in the PJM transmission zones that show a decrease will be considered in determining the Change in Load Energy Payments.

b. Reliability Pricing Model Benefit

Reliability pricing benefit analysis is conducted using the Reliability Pricing Model software. The Reliability Pricing Model Benefit component of the Benefit/Cost Ratio evaluates the benefits of a proposed economic-based enhancement or expansion that will be realized in the capacity market and is expressed as:

Reliability Pricing Benefit = [.70] * [Change in Total System Capacity Cost] + [.30] * [Change in Load Capacity Payment]

The Change in Total System Capacity Cost is the difference between the sum of the megawatts that are estimated to be cleared in the Base Residual Auction under PJM's Reliability Pricing Model capacity construct times the prices that are estimated to be contained in the offers for each such cleared megawatt (times the number of days in the study year) without and with the economic-based enhancement or expansion.

The Change in Load Capacity Payment is the sum of the estimated zonal load megawatts in each PJM transmission zone times the estimated Final Zonal Capacity Prices (payments paid by load in each transmission zone) for capacity under the Reliability Pricing Model construct (times the number of days in the study year) without and with the economic-based enhancement or expansion. The Change in Load Capacity Payment will be evaluated in the same manner as the Change in Energy Load Payment. Like for the Change in Energy Load Payment, in determining the Change in Load Capacity Payment for projects the costs of which will be assigned cost responsibility on a regional basis (e.g. above 500 kV facilities), the Load Capacity Payment in each and every PJM transmission zone will be considered; for projects, the cost of which will be allocated using a flow-based or distribution factor methodology (e.g. below 500 kV facilities), only the Load Capacity Payments in the PJM transmission zones that show a decrease will be considered in determining the Change in Load Capacity Payment.

E.2 Total Annual Enhancement Cost

The annual cost of the enhancement is the revenue requirement of the enhancement. The enhancement's annual revenue requirement is an assumption that is developed by PJM and presented to the TEAC for discussion and review. As stated earlier, the benefits and costs will be considered over the same time period (for each of the first fifteen years of the life of the expansion).

Attachment F: Determination of System Operating Limits used for planning the Bulk Electric System

This document describes the process and measures used by PJM to develop System Operating Limits (SOLs) used for the planning horizon. The method described in this attachment is applicable to all Bulk Electric System (BES) facilities.

Definitions:

A System Operating Limit (SOL) is defined as:

The value (such as MW, MVAr, Amperes, Frequency or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within applicable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to:

- Facility Thermal Ratings (Applicable pre- and post-Contingency equipment or facility ratings)
- Transient Stability Ratings or Limits (Applicable pre- and post-Contingency Stability Limits)
- Voltage Stability Ratings or Limits (Applicable pre- and post-Contingency Voltage Stability)
- System Voltage Ratings or Limits (Applicable pre- and post-Contingency Voltage Limits)

PJM's Planning analyses are designed to ensure all applicable PJM, NERC, regional and Transmission Owner criteria are enforced. This is accomplished through exhaustive application of established PJM facility ratings in the on-going system power flow and short circuit analysis. PJM ensures that its exhaustive application of facility ratings are also within system dynamic limits through system dynamic testing. This dynamic testing confirms that PJM system operating limits are not more limiting than the limits established using facility ratings.

Facility Ratings are defined by NERC as:

> The maximum or minimum voltage, current, frequency, or real or reactive power flow through a facility that does not violate the applicable equipment rating of any equipment comprising the facility.

Facility ratings determine the fundamental limits of transmission system equipment. SOLs shall not exceed the facility ratings. The facility rating is based on which ever device or component is the limiting element of the facility such as a conductor, current transformer, disconnect switch, circuit breaker, wave trap or protective relay. PJM plans its system such that no facility exceeds the limit/rating consistent with NERC Standard TPL 001 – 004. Additional information concerning SOL can be found in the Transmission Operations Manual (M-03), and Reliability Coordination Manual (M-37) located on the PJM web page at the following link:

(http://www.pjm.com/documents/manuals.aspx)

Interconnected Reliability Operating Limits are defined as:
An Interconnected Reliability Operating Limit (IROL) is defined as System Operating Limits that, if violated, could lead to instability, uncontrolled separation or Cascading Outages that adversely impact the reliability of the Bulk Electric System. In the planning horizon PJM analyses examine and reveal the violations of applicable criteria. This includes violations affecting PJM monitored facilities at all voltage levels as well as violations that may have widespread impacts affecting the Bulk Electric System, which may be eligible for designation as IROLs. PJM plans system upgrades for violations of applicable criteria, thus IROL designations are not typically required for the upgraded system in the planning horizon. PJM closely tracks the project status and milestones of all planned upgrades on a frequent and recurring basis. For baseline reliability upgrades, the project tracking is coordinated with the entity that has been designated the construction responsibility, typically the Transmission Owner. If the schedule for implementation for a planned upgrade does not meet in-service date required for system reliability in the planning or operating horizon, PJM will perform additional analysis to determine any alternative plans that need to be taken to ensure system reliability, including the establishment of an IROL. For additional information on IROLs for the operating horizon see the PJM Transmission Operation Manual (M03) and the PJM Reliability Coordination Manual (M37).

PJM's Planning methodology to determine IROL facilities simulates transfers across a facility or interface (combination of facilities), comparing thermal and voltage violations associated with a facility. The transfer scenarios used by PJM Planning are established through the application of PJM's deliverability criteria. Additional information on PJM's deliverability criteria is included in Attachment C of this manual. PJM classifies a facility as an IROL facility on the network if wide-area voltage violations occur at transfer levels that are near the Load Dump thermal limit.

As part of the development of the PJM Regional Transmission Expansion plan, SOLs which could result in system instability or uncontrolled cascading outages are identified and system reinforcements are developed. All BES facilities in PJM's footprint and ties to external systems are monitored for violation. In addition, certain selected 69kV and below facilities may also be monitored consistent with the procedures defined in the PJM Transmission Operation Manual (M-03).

SOL and IROL use in Planning

PJM plans its system based on the most restrictive System Operating Limits (such as MW, MVAr, Amperes, Frequency or Volts) of its facilities for the system configurations and contingency conditions that represent the most stringent of the applicable PJM, NERC, regional or Transmission Owner criteria over the planning horizon. The System Operating Limits used to plan the system are consistent with the limits used in Operations. Voltage limits and any exception to those limits are identified in the PJM Transmission Operation Manual (M-03).

An Interconnection Reliability Operating Limit is the value (such as MW, MVAr, Amperes, Frequency or Volts) that is derived from or is a subset of the System Operating Limits, which if exceeded, could expose a widespread area of the Bulk Electric System to instability, uncontrolled separation(s) or cascading outages. PJM Reliability Coordination Manual (M37) defines PJM's methodology for determining, monitoring, and controlling IROL facilities.

Nuclear Power Plant Generator Operators are required to transmit Nuclear Plant Interface Requirement (NPIR) to transmission entities. The transmission entities are required to include those parameters into planning and operational analysis, operate to meet those parameters, and inform the nuclear licensees when those parameters cannot be met for any reason. For details please refer to Manual M03 Section 3: http://www.pjm.com/~/media/documents/manuals/m03.ashx

PJM Planning SOL Methodology

Consistent with the requirements of NERC Standard TPL-001, in the pre-contingency state and with all facilities in service, all facilities shall be within their facility ratings and within voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect expected system conditions and shall reflect changes to system topology such as facility outages.

Following single contingencies as defined in NERC Standard TPL-002 all facilities should be within their applicable facility ratings and the system shall be transient, dynamic and voltage stable. Cascading outages or uncontrolled separation shall not occur.

Starting with all Facilities in service, the response to a single contingency as defined in NERC Reliability Standard TPL 002, may include any of the following:

Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the faulted facility. This is often referred to as consequential load loss.

System reconfiguration through manual or automatic control or protection actions.

To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and changes to the transmission system topology.

Starting with all facilities in service and following any of the multiple contingencies identified in NERC Reliability Standard TPL-003 the system shall be transient, dynamic and voltage stable and all facilities shall be within their applicable facility ratings and within applicable thermal, voltage and stability limits. Cascading Outages or uncontrolled separation shall not occur. In general, stability is not a limiting constraint in the PJM RTO. Stability limits that have been identified for certain system configurations or following multiple contingencies are identified in the PJM Transmission Operation Manual (M-03). New stability limits identified in Planning are communicated to PJM Operations and included in the Transmission Operation Manual (M-03).

In determining the response to any of the multiple contingencies, identified in NERC Reliability Standard TPL-003, in addition to the actions identified above following single contingencies, the following shall be acceptable:

For all tests, as described in Attachment D-1, consequential load loss of up to 300 MW may occur.

PJM's Reliability Planning methodology for determining SOLs utilizes multiple standards and applicable planning procedures including the PJM Reliability Planning Criteria, NERC Planning Standards (TPL 001 – TPL 004), Regional Reliability Organization criteria, and individual Transmission Owner FERC filed criteria. In all cases, PJM applies the most conservative of all applicable planning criteria when identifying reliability problems. PJM tests these criteria on a regional basis including all facilities within its footprint. All BES network elements in PJM's footprint and all transmission tie lines within PJM and to external systems are monitored for thermal, voltage and stability violations. Remediation plans are developed to mitigate the violations that exceed the established SOL limits.

PJM's develops models for specific planning horizons using the latest Eastern Reliability Assessment Group (ERAG formerly MMWG) modeling information available for the applicable planning period. A detailed model is utilized for PJM's internal system (transmission owner under PJM's footprint) while the latest ERAG model for that planning period is used for facilities outside of PJM to incorporate critical modeling details of other control areas. Additional information about PJM's base case development procedures can be found in section 2 of this manual.

PJM reliability planning criteria requires that the system be tested for all BES single contingency outages and all common mode outages. Common mode outages consist of line faults coupled with a stuck breakers that result in multiple facility outages, double circuit towerline outages and bus faults in the PJM system. PJM's planning procedures require all NERC category A, B, and C conditions be tested.

When appropriate PJM will identify and implement Special Protection Schemes. If the scheme is required for reliability purposes, operational performance, or to restore the system to a reliable state following a significant transmission facility event, operation of the scheme will be tested in the on-going planning analysis. See the Transmission Operations Manual (M-03) (http://www.pjm.com/documents/~/media/documents/manuals/m03.ashx) for additional information concerning special protection schemes.

The PJM planning process includes a series of detailed analyses to ensure reliability under the most stringent of applicable NERC, PJM or local criteria. Through this process, violations of system operating limits are identified. System reinforcements required to mitigate the violations are developed and included in the Regional Transmission Expansion Plan for implementation. As a result PJM's application of its System Operating Limits for the planning horizon ensures system operation within Interconnection Reliability Operating Limits.

PJM Planning will communicate to PJM Operations any potential IROL facilities resulting from PJM deliverability criteria analysis. PJM Planning and Operations work to develop new IROL Reactive Interfaces and associated operating procedures as required.

Attachment G: PJM Stability, Short Circuit and Special RTEP Practices and Procedures

G.1 Stability

PJM Planning conducts stability studies to ensure that the planned system can withstand NERC criteria disturbances and maintain stable operation throughout the PJM planning horizon.

NERC criteria disturbances are those required by the NERC planning criteria applicable to system normal, single element outage and common-mode multiple element outage conditions. These conditions are specified in the NERC approved Transmission Planning (TPL) Reliability Standards that can be found on the NERC website (www.NERC.com). Because these standards change from time to time they are included here by reference. In addition, PJM's analyses also satisfy the Transmission Owner specific stability practices and procedures as may be applicable when these are more demanding tests than the standard NERC criteria tests applied by PJM. All Transmission Owner specific information and criteria that exceed *standard testing of NERC criteria* and are applicable to PJM reliability based RTEP stability analyses are included or referenced in the Appendix to this Attachment. Transmission Owner stability criteria filed as FERC Form No. 715 and posted on PJM's website and not included in the Appendix may be used to support Transmission Owner funded upgrades. The currently approved version of this Appendix at the commencement of the annual RTEP process will be the basis for that baseline RTEP and related generator queue assessments. PJM's stability analyses verify satisfactory projected system performance over the range of anticipated load levels and identify any need for upgrades, operating guides, or special protection systems that may be indicated based on stability or short circuit testing as a primary driver. In general, the most appropriate remedy to NERC criteria violations is a system upgrade. In circumstances involving criteria that go beyond PJM's standard testing of NERC criteria, operating guides or special protection system remedies may also be considered as discussed further in this Attachment and its Appendix. New Special Protection Systems, however are generally avoided and, if considered, require case-by-case review and justification. Also certain specific areas of PJM have been identified through PJM or Transmission Owner analysis as stability limited areas of the system. In such areas of the system, stability operating guides may apply. For related information see PJM Manual 03 at http://www.pjm.com/documents/manuals.aspx.

System conditions most critical for stability analysis on the PJM system are generally characterized by light load. Peak load analysis is added for stability reviews that involve new connections of wind turbines and performance of low voltage ride through testing. In exceptional cases, PJM may add heavy load testing for other types of units when PJM determines that heavy load may be the critical load level for system stability for the limitation under review.

PJM's stability analyses ensure the dual objectives of stability of new interconnection projects and system-wide stability. PJM, each year conducts dozens of interconnection queue project stability studies. These analyses ensure newly-connecting projects and nearby changes to the system configuration maintain the stability of the project and the system. Study of these projects located throughout PJM provides a thorough, ongoing review of PJM both at the project level and system-wide. In addition, each year, PJM conducts a re-study of one third of existing PJM generation stations. This results in a three-year cycle of on-going re-study of the entire PJM system. PJM also performs additional system-wide stability analyses during the annual RTEP review. In addition, as may be required from time to time, PJM conducts stability analyses to evaluate the dynamic performance of actual or possible major future system developments. For example a proposed new backbone transmission project or prolonged unexpected backbone transmission outage in a stability sensitive area would be cause for a specifically targeted system study. Another cause could be the need to evaluate system performance resulting from major developments affecting power and energy policy.

G.2 Dynamics Procedures

This section provides a high level review of the process of setting up and performing dynamics analyses.

G.2.1 Dynamics Reference Cases

Reference power flow cases for stability analysis are created in a similar manner to that of the power flow reference cases. Additional information, however, is necessary for stability studies to simulate the combined dynamic responses of various power system components. Included in this additional information are dynamics models for generators, excitation systems, power system stabilizers, governors, loads and various other equipments. The required dynamic and other modeling information that must be supplied by generators interconnected to the PJM system is detailed in Manual 14A. A dynamic simulation links the system model or power flow information with the dynamic data or models to determine if the system and generators will remain stable for steady-state and various disturbances. The current RTEP summer peak case is used as a starting point to create new dynamics cases (light load and peak load.) For example the RTEP analysis is performed for the current year plus five (available early in each calendar year and updated for the five-year-out RTEP analyses in early fall of each calendar year). The stability case setup is for the same study year using the updated RTEP case. This updated RTEP power flow case and the associated stability case become the baseline cases for the impact study analyses (that begin in the fall of each year) that begin with the first interconnection queue of each calendar year and continue through each of the 3 subsequent annual queues.

G.2.2 Dynamics Analysis

The two dynamics cases Originate from the RTEP Power Flow Case that is created for the annual RTEP Plan analyses. The annual RTEP cycle is depicted in Manual 14B, Exhibit 1. The earliest availability for this annual RTEP reference power flow case is for the impact studies associated with the interconnection request queue that closes on January 31. For subsequent project queues that close later in the year, this reference RTEP case is updated to the most current data. The reference power flow case is reviewed and modified as necessary to correspond to the dynamics database (which includes external world dynamics data from the NERC System Dynamics Data Working Group as well as PJM data.) In addition, the case is modified to include generator step-up transformers and explicit modeling of generator station service power use along with gross generator rating. Also, because of the demands of dynamics analyses, power flow static load representations are replaced with their dynamic load model representations. PJM currently represents loads as 100% constant current real power and 100% constant impedance reactive power. In light load representations, pumped storage resources are in pumping mode.

This process is followed to develop stability setups for analysis of all PJM interconnection requests. In addition PJM's system stability analyses will use the most current available setup from this continuous development process.

Testing

After the dynamics model setup, an unperturbed dynamic simulation is run for 20 seconds. After case verification, the final, initialized set of power flows and the associated snap-shots, along with the associated dynamic run files are available to Interconnection Customers and others who have a legitimate need for the information, subject to applicable Confidentiality and Critical Energy Infrastructure Information processes (see PJM Operating Agreement §18.17 and http://www.pjm.com/documents/ferc-manuals/ceii.aspx.

Dispatch

The assumptions used for generation dispatch can be critical to the results. It is generally accepted that units operating at their highest possible power output and generating as little reactive power as necessary to maintain voltages are likely to be less stable. Normally, the units in the vicinity of the project under study will be turned on to their maximum real power output with unity power factor at the high side of the GSU's, or units' VAR output will be adjusted to hold scheduled voltages, depending on specific Transmission Owner criteria. Wind turbines are tested at light load for stability and peak load for low voltage ride through at 100% of their maximum energy value. In addition, stability test scenarios necessitated by any applicable Transmission Owner operating guides will also factor into each analysis.

Simulations to determine required upgrades (also see the Appendix to this Attachment)

Fault Criteria:

a. Fault Types: For interconnection and system stability analyses, three phase faults, single line to ground faults with stuck breaker and single line to ground faults with the communications failure cleared within zone 2 time will be examined. Each analysis will include a determination of the most critical faults to apply.

b. Clearing Times: Dynamic simulation issues are identified using estimates of actual (nominal) clearing times, including relay trip times, breaker interrupting time, fault extinguishing time, intentional delay time, and a margin for error.

c. Reclosing: Only high speed reclosing is modeled if present.

d. Fault locations: For interconnection analysis, criteria faults at power flow busses including one bus removed from the interconnection point will be examined. When clusters of generating busses are studied, the most critical faults one bus removed from new generators in the cluster will be examined. In addition, other fault locations judged critical to cluster response will be added to the scope. For system analyses, the scope will determine the most critical locations to apply criteria faults.

e. Maintenance outages: Interconnection analyses of planned line maintenance outage conditions prior to fault application are system conditions that can be anticipated and that are generally of limited duration. The least cost remedy to issues during such system conditions is to require generation to curtail output. Such analyses are, therefore, of primary interest in the operating horizon and are not generally considered to determine upgrade facilities required prior to interconnection. Nevertheless, prior to commercial operation, or prior to completion of the facilities study at the request of the Interconnection Customer, Planning will screen critical faults for issues during line maintenance. The results of the line maintenance study will be conveyed to PJM Operations, the Interconnection Customer, and affected Transmission Owners.

PJM addresses Power System Stabilizer (PSS) outages in a similar fashion. If there are existing PSS installations nearby a new interconnection or if PSS is required on the new interconnection, critical faults for the outage of these devices will be studied prior to commercial operation and the results will be conveyed to PJM Operations, the Interconnection Customer, and affected Transmission Owners.

Margins:
The margins applied by PJM are intended to be applied in impact study stability analysis that uses a project's final stability study data as further discussed below. As such, these margins account primarily for uncertainty in actual clearing times, and the final data represents the "as built" performance. With the machine modeled at net unity power factor at the high-side of the GSU (or unity power factor at the generator terminals for wind turbine installations), transient stability must be maintained for tested faults when the following margins are included:

a. Add 0.25 cycles to the nominal primary clearing time for 3 phase, normally cleared faults.
b. Add 0.25 cycles to the nominal primary clearing time for single-line-to-ground faults, plus an additional 0.5 cycles added to the nominal backup clearing time for stuck breaker (.75 cycle total clearing time margin).
c. Add 0.25 cycles to the nominal primary clearing time for single-line-to-ground faults, plus an additional 1.25 cycles to the nominal Zone 2 clearing time for failure of primary relaying (1.5 cycle total clearing time margin).

Monitoring requirements:
Rotor angle, Real power output, EFD, speed and terminal voltage of units under study are monitored. Bus Voltages in the same area are also monitored.

Acceptable Voltage Drop:
Following the disturbance, the voltages of the monitored buses maintain voltages within ±5% of the precontingency voltages

Acceptable Damping:
Following the disturbance, the oscillations of the monitored parameters display positive damping. The positive damping is determined with a damping coefficient calculation algorithm. This characterizes the degree of positive (damped) or negative (undamped) damping based on the damping trend, over the duration of the stability run, of the envelope of machine angle oscillation peaks. This trend can be observed

by drawing an envelope connecting each succeeding peak or valley of the oscillation of the monitored element. An acceptable oscillation envelope will demonstrate a positive decay within the appropriate test period (normally 10 to 15 seconds). A sustained oscillatory system response, even if slightly damped, will cause the system to be in a vulnerable state and exposed to adverse impacts for subsequent changes to the system over some prolonged time. To limit this system exposure PJM uses a 3% damping margin. Such positive damping demonstrates an acceptable response by the system, and no further analysis is required. Failure to meet the damping standard will require application of some combination of power system stabilizers, excitation system upgrade and tuning, and system upgrade.

G.3 System Impact Study and Initial Study Stability Procedures

Generating unit stability analysis is performed by PJM as a part of the System Impact Study for proposed generation interconnection to the PJM system. PJM also conducts annual system stability analysis of the PJM system in compliance with applicable NERC transmission planning criteria. PJM's standards for stability analyses satisfy NERC criteria and are the generally applicable criteria for all PJM stability analyses. In addition, Transmission Owner stability criteria may apply. Certain specific areas of PJM have been identified by PJM or Transmission Owner analysis as stability limited areas of the system. In such areas of the system, stability operating guides may apply. See PJM Manual 03 at http://www.pjm.com/documents/manuals.aspx for more information on PJM stability operating guides.

G.3.1 Stability Data Requirements

a. Submission of Project Stability Study Data

Stability study data is included in the data required for the series of studies generally required for a System Impact Study. A System Impact Study typically includes a short circuit study, power flow study and stability study. As required by the PJM Tariff, and detailed in PJM Manual 14A, all data for the System Impact Study, including stability analysis data, must be submitted by the Interconnection Customer as part of a completed System Impact Study Agreement. System Impact Study Agreements are not complete until the required agreement is fully executed and all associated data for the complete series of studies is received. Upon PJM's acceptance of a completed System Impact Study Agreement, all associated data becomes the Interconnection Customer's final data for the System Impact Study and any subsequently necessary Facilities Study.

b. Final Stability Study Data

Prior to beginning any of the studies generally required for a System Impact Study, PJM will accommodate modifications to submitted data unless, in PJM's judgment, such modification would adversely impact subsequently queued projects. It is the Interconnection Customer's responsibility to establish and maintain communication with the assigned PJM Project Manager to determine the latest date that specific data changes can be accommodated. Interconnection Customers are encouraged to work closely with their Project Managers to determine if any anticipated project changes can be accommodated without adversely affecting subsequent projects. After acceptance of the System Impact Study Agreement, PJM is under no obligation to accept any changes in data and may proceed through the System Impact Study, Facilities Study and the Interconnection Service Agreement processes on the basis of the final data. This final data is considered consistent with the "as built" representation of the system. As such, it should represent the actual equipment that will be installed and commissioning settings that can be achieved.

c. Changes to Stability Data After Commencement of Stability Study

This section addresses project changes that affect the stability study and often the short circuit study. Such changes typically involve the electrical, configuration and physical parameters of the generator and associated electrical equipment between the connection to the networked power system and the generator. While some configuration changes could necessitate power flow re-study, the changes that are discussed here only cause stability and possibly short circuit re-study.

After the start of the stability study PJM will complete the stability study, issue the System Impact Study report, complete any necessary Facilities Study and issue the Interconnection Service Agreement. After the start of the stability study, changes to electrical parameters that will require stability re-study, will be accommodated by PJM as resources are available and in a manner that does not negatively impact later queued projects. In addition, certain parameter changes may also require new short circuit studies. Necessary re-study caused by parameter changes may be performed by contractors. The re-study will be performed on the system model that includes all project studies completed at the time of the re-study. The scope of the re-study will determine all necessary incremental system facilities necessitated by the parameter changes.

d. Cost of Incremental Facilities Caused by Re-study

The Interconnection Customer that makes the parameter changes that cause re-study will be responsible for the costs of re-study and the cost of the incremental facilities that are specified by the re-study, including facilities that are revealed by the short circuit re-study.

G.3.2 System Impact Study Stability Scope and Process

These procedures apply to stability studies required as part of System Impact or Initial Studies. These stability studies determine the project's cost responsibility for upgrades due to interconnection stability issues. These upgrade responsibilities become part of a project's Interconnection Service Agreement (ISA.)

Stability study start dates, generally, are at least six months after the close of a queue. This allows time to complete feasibility studies and the power flow and short circuit phases of the impact study. This section outlines the process of coordination and execution of the stability study among the representatives of PJM, the Interconnection Customers and Transmission Owners.

1. PJM will develop a study scope at the beginning of each project stability analysis. This scope will include but not be limited to the following items:
    1.1. The MW Size of the project. Developers may reduce the project maximum output, based on tariff terms, from the feasibility request. Stability will study projects at their maximum outputs regardless of the project's value for capacity markets.

    1.2. The electrical Point of Interconnection (POI) of the project. For projects that tap an existing transmission line, the feasibility power flow generally assumes a line POI is at the line midpoint. Stability analysis will require the actual location information to determine the tap point.

    1.3. A detailed fault list testing all applicable NERC and Transmission Owner criteria faults. Fault specification will include fault:
        1.3.1. location
        1.3.2. phase involvement
        1.3.3. impedance
        1.3.4. actual timing for clearing and reclosing
        1.3.5. explicit timing or other margins to be added
        1.3.6. justification of any procedures that exceed PJM standard methods

    1.4. Dispatch in the vicinity of the study location.

    1.5. Selection of the appropriate base case, light load or peak load, for study of the interconnection request.

2. Study scope will be supplied to the affected Transmission Owner. Affected parties have one week to provide input to the study scope after which time PJM will issue the final scope and a date that the study will begin. All special study conditions, scenarios or simulations, if any, required by guides or sensitive areas and accurate clearing times must be included in this final scope. The study will progress to completion based on the final scope document.
    2.1. The study scope for interconnection studies will consider *standard NERC criteria* faults and Transmission Owner criteria faults, as a general rule, including the POI bus and one bus away from that bus. In other words if a new POI is cut-in at the midpoint of an existing line, faults will be examined at the POI, and up to and including faults at the adjacent existing system substations and lines. If a project interconnects to an existing system bus location, then faults at that location and including adjacent substations and lines will be examined. When new interconnection requests are considered, in PJM's judgment, in a cluster study, they will consider intervening bus location faults (further than one bus from any new interconnection) at PJM's discretion when the electrical configuration indicates that the added locations could pose a more severe test and that a contributing cause of the stability concern is the new interconnection. In a similar fashion, PJM may use its judgment in any stability analysis to expand the fault locations outside the general "one bus removed" criteria when system electrical configurations dictate and the interconnecting project poses the concern.

    2.2. The stability scope for interconnections in areas affected by established operating guides or Special Protection Systems (SPS) (for example see Manual 03) may include scenarios designed to test the proper operation of the existing guides or SPS. In such cases, the scope may be augmented to examine and specify modified procedures or facilities that ensure the integrity of the system operation.

3. After completion of the study scope, PJM will transmit results and supporting information to the Transmission Owner. A review conference call between the Transmission Owner and PJM will be scheduled within a week of providing the results.
4. The transmission Owner will provide an estimated date for completion of its determination of system remedies for any issues identified in the stability results. Such remedies will include system impact cost estimates and the earliest feasible date to complete system modifications that accommodate the new interconnection.
5. Upon completion of the Transmission Owner review and estimates PJM will issue the final impact study report to the project developer.
6. In situations when the required system modifications or upgrades cannot be accomplished by the projected in-service date of the project, PJM will develop a scope and schedule to determine interim solutions and dates along with provided interim capability.

G.4 System Stability Studies

In addition to the system impact stability analyses of new generating interconnections, the three year cycle testing of all existing generating units interconnected to the PJM system, and certain "ad hoc" stability testing required by special circumstances that occur from time to time, PJM also conducts system stability testing of its most critical stressed system conditions during the annual Regional Transmission Expansion Plan study cycle. The RTEP stability testing examines and ensures system performance within criteria for heavy system transfer conditions. Power flow criteria are ensured on a local and system-wide basis for heavy transfers during the application of PJM's load deliverability testing (see Manual 14B Attachment C.) These test scenarios examine emergency conditions involving extreme generating outages and loads coupled with single transmission element outages. Such circumstances are critical when the system is stressed at heavy load, rather than light load.

Based on the results of each annual RTEP cycle and previously completed stability analyses, PJM determines the load delivery limits for the case that represents the most critical conditions for PJM system stability testing. The transfers into the selected Region emanate from external PJM and non-PJM generation. Imports from external areas are based on historical levels for heavy load. An example of the type of PJM scenario that could represent the critical study condition may have local load of 65,000 MW with a transfer into the area caused by the simultaneous outage about 10,000 MW of internal area generation. This may cause a thermal limit to transfers well in excess of 6000 MW.

The transmission outage that sets the limit for transfers during the Mid-Atlantic load delivery testing is modeled for stability to ensure that the region is not stability limited. PJM also determines several more critical three-phase and single-line-to-ground fault tests to apply from a stability perspective to ensure robust, stable and adequately damped system performance. Fault testing for system stability includes the most critical Bulk Electric System lines.

G.5 Impact Study Procedures Applicable to Wind Turbine Analyses

PJM follows a process of procedures and studies when handling requests to interconnect to the transmission system. These procedures are outlined in PJM Manuals and agreements, particularly PJM's Manuals 14A and 14B and the PJM Open Access Transmission tariff (OATT.) In recognition of some of the unique characteristics and challenges posed by wind projects, however, the PJM OATT procedures include certain special provisions applicable to wind farm interconnection requests. Interconnection Customers should familiarize themselves with all applicable PJM procedures and requirements, in consultation with their assigned PJM project manager. Some provisions of particular interest to wind interconnection requests can be found in OATT PART IV, Subpart A, PART VI, Subpart A, and OATT Attachment O Schedule H.

G.5.1 Wind Project Final Impact Study Data

Upon entering the interconnection queue, wind generators may submit approximate data for the feasibility study that represents the wind farm as a single equivalent unit. Prior to commencement of the wind farm impact study the approximate data must be replaced with detailed design data including the detailed electrical layout of the wind farm. This data is required for wind farm projects, by tariff provisions, no later than six months after the filing of the interconnection request. As described in the general discussion of System Impact and Initial Study procedures, final impact study data is generally required at the beginning of the system impact study process which often will happen to be about six months after the close of the queue. In the case of wind projects, tariff requirements ensure that the data may be supplied up to six months from the initiation of the queue request. In practice the wind farm developer, as well as all project developers, should maintain good communications with the assigned project manager to determine when PJM is scheduled to begin a specific project's stability analysis.

G.5.2 Wind Project LVRT Requirements

In addition to all facets of the standard stability study scope previously discussed, wind generators will be studied during their impact study stability analysis for compliance with the Low Voltage Ride Through Criteria (LVRT.) The LVRT criteria tests the ability to the wind farm generator to maintain operation and interconnection with the system during events that cause extremely low voltage transients as measured at the high side of the transformer that steps up the Wind Farm's voltage to the transmission system (high side of the wind farm GSU.) Peak load conditions are the most stressful for maintaining system voltage so this analysis will be conducted on a peak load power flow model (in contrast to the standard stability analysis that is conducted on an off-peak model.) Based on the results of the standard stability analysis, PJM will determine the most critical three phase faults with normal clearing and phase to ground faults with delayed clearing. The wind generator will be required to maintain its power output to the system following three phase faults cleared in up through 9 cycles (9 cycles includes any applicable margins) and that produce a voltage as low as zero at the high side of the GSU. Actual clearing times plus applicable margins will be used, which may be less than 9 cycles and high side GSU voltages may be somewhat greater than zero. Also the wind farm must maintain output to the system following the most critical phase to ground faults with delayed clearing, using actual clearing times. Applicable clearing time margins will apply to the LVRT test.

G.5.3 Wind Project Reactive Power Modeling

Stability tests will be conducted on a system model with the GSU modeled and zero generator reactive power output (unity power factor.) When power flow analysis does not model the generator step up transformer, the zero generator reactive power output is applied at the collector bus. This base case and the stability analysis will establish power factor or reactive power delivery requirements only if impact study analysis is conducted that demonstrates that the safety or reliability of the system is impacted by the lack of the requirement. System transient, oscillatory, or voltage instability during any phase of the impact study is evidence of system safety or reliability impact. For such results, the least cost remedy that considers system protection, transmission upgrades, or reactive requirements will be determined and specified.

In the event that the transient or voltage instability only affects the wind project (for example when long radial interconnection facilities cause the inability of the wind facility to remain stably interconnected), the wind project will be notified and be requested to provide project design remedies. PJM's analysis of possible remedies will be limited to specifying the size of dynamic reactive device or increased transmission interconnection capacity if such a remedies are sufficient.

G.6 Stability Analyses of Stability Sensitive Local Areas in PJM

The PJM system generally operates to limits determined by thermal and reactive criteria. In some specific instances local areas of PJM or individual plants operate to stability limitations. The PJM transmission system conditions and procedures due to localized thermal, reactive and stability considerations are outlined in PJM Manual 03.

The PJM Transmission Owners are often owners of the facilities that are subject to these procedures and carry out PJM's operating instructions ensuring safe and reliable operation consistent with these guidelines and procedures. PJM, therefore, closely coordinates review of the stability guides and procedures with the Transmission Owners and, when appropriate, Transmission Owners may conduct analysis, subject to PJM's review.

Stability guides applicable to specific plants are reviewed as part of PJM's three year cycle of generator stability analysis that ensures continued compliance with NERC criteria. Local stability guides and procedures are reviewed as necessary when interconnections or transmission changes cause the need for review. Each review is specific to the area or plants operating procedures and guides and confirms or develops modifications to the guide and system upgrades, as appropriate, to maintain reliable operation within applicable criteria.

G.7 Short Circuit

PJM performs short circuit analysis as part of the annual Regional Transmission Expansion Plan (RTEP) baseline assessment. This analysis includes a study of the entire PJM system based on its current configuration and equipment. In addition, PJM also performs the analysis on the planned system configuration using a 5-year out case. The generation and merchant transmission interconnection process (see Manual 14A) also includes short circuit analysis for each requested new interconnection project. The addition of new sources drives most breaker replacements. PJM Planning conducts short circuit analysis to ensure the high-voltage circuit breakers on the transmission system are sufficiently rated to safely interrupt fault currents. These short circuit studies are also referred to as breaker interrupting studies. Since new sources only become committed with relative assurance a few years before scheduled commercial operation and since breaker replacement lead times are only a few years, these analysis are only conducted within the 5-year planning horizon.

The short circuit analysis is performed in accordance with the following industry standards:

- ANSI/IEEE 551-2006 "IEEE Recommended Practice for Calculating Short-Circuit Currents in Industrial and Commercial Power Systems"
- ANSI/IEEE C37.04-1999 "IEEE Standard Rating Structure for AC High-Voltage Circuit Breakers"
- ANSI/IEEE C37.010-1999 "IEEE Application Guide for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis"
- ANSI/IEEE C37.5-1979 "IEEE Guide for Calculation of Fault Currents for Applications of AC High-Voltage Circuit Breakers Rated on a Total Current Basis"

The system condition most critical for short circuit analysis on the PJM system is all available generation in-service. This condition is modeled in short circuit reference cases that are specially configured for short circuit analysis. The PJM Transmission Planning Department maintains the following short circuit base case representations and associated data:

- 1 year planning representation consisting of the current system plus all facilities planned to be in-service within the next year.
- Current year plus 5 planning representation using the 1 year planning representation as the base model and including all system upgrades, generation projects, and merchant transmission projects planned to be in-service from years 1 through 5. This 5 year planning representation is consistent with the PJM RTEP 5 year load flow base case.
- Data file containing current circuit breaker interrupting ratings and other relevant circuit breaker nameplate data for all BES circuit breakers.

The short circuit base cases are maintained using Aspen One Liner and short circuit analysis is performed using the Aspen Breaker Rating Module. The PJM short circuit 1 year planning representation is developed annually with the assistance of the designated transmission owner short circuit contacts and maintained by the PJM Transmission Planning Department.

G.8 Nuclear Plant Specific Impact Study Procedures

Stability analysis of nuclear facilities is conducted during PJM's three-year cycle of stability review of all existing generating units. Also, interconnections or transmission modifications in the vicinity of existing generating stations, including nuclear stations, may necessitate additional reviews. PJM conducts these reviews consistent with the NERC criteria and certain added criteria specified by the Transmission Owner or plant operator or owner. PJM stability studies take into account coordination with any applicable Special Protection Schemes. Results of PJM Planning analyses can be found under the "planning" tab material and "committees & groups" tab material on PJM.com particularly:

http://www.pjm.com/planning/planning-criteria.aspx

http://www.pjm.com/planning/rtep-development.aspx

http://www.pjm.com/planning/generation-interconnection.aspx http://www.pjm.com/committees-and-groups/committees/teac.aspx

PJM will notify PJM System Operations and the affected Transmission Owner in the event that PJM's planning analyses indicate planning study results that violate PJM planning criteria or nuclear specific planning criteria. In addition, results of PJM Impact Studies affecting nuclear facilities are communicated to the affected Nuclear owner and operator.

PJM applies some nuclear plant study procedures that exceed *standard NERC criteria* to be consistent with certain regulatory and safety requirements specific to these facilities. Material contained in the Appendix to this Attachment G provides Nuclear Plant Interface Requirements (NPIR) regarding the nuclear specific testing procedures applied by PJM and Transmission Owner Planning.

G.9 Appendix to Manual 14B Attachment G

This appendix contains Transmission Owner specific criteria applicable to RTEP stability study analyses that may go beyond the NERC system stability performance tests routinely applied by PJM. PJM normal stability testing enforces the NERC criteria that are based on single contingencies and common-mode multiple contingencies. PJM does not permit planned load loss or interruption of firm transmission service for these events, even when such service curtailment may be permitted by the NERC standards. These contingencies are also referred to in this Attachment and Appendix as the "standard" NERC criteria and include the following events:

- System normal,
- Single phase and/or three phase fault (N-1),
- Single phase fault stuck breaker (N-2),
- Three phase fault tower (N-2), and
- Single Phase fault and communication failure (N-2).

More stringent NERC criteria that involve multi phase faults, non-common mode multiple contingencies, and higher order contingencies (also referred to as "beyond" *standard NERC criteria*) do not routinely form the basis for required PJM RTEP upgrades. Some Transmission Owner criteria, however, as detailed in this Appendix, go beyond the *standard* PJM stability screening criteria and do require remedies. These procedures, as applicable, are applied during PJM RTEP (including interconnection related) stability analyses in addition to PJM thorough testing of *standard NERC criteria* tests and system performance is verified to be stable and within criteria. The Transmission Owner specific criteria are limited to interconnections with the transmission facilities of the respective Transmission Owners.

All PJM testing applies the clearing margins and damping criteria discussed in Attachment G and more stringent criteria when the specific Transmission Owner criteria exceed these standard margins. In all cases PJM applies the criteria in a comparable and not unduly discriminatory fashion to new interconnection projects and existing generators. Violations based on *standard NERC criteria* and standard margins must be remedied by upgrade modifications to the system. Operating curtailments will generally be an available remedy for issues found for line maintenance outage tests.

G.9.1 Testing of Transmission Owner Criteria

For interconnection queue studies that pass the *standard* NERC and PJM criteria but produce localized violations based on criteria that are beyond the *standard NERC criteria* and/or margins that exceed standard PJM margins, PJM, in consultation with the affected Transmission Owners, will determine lower cost remedies. For these Transmission Owner tests, planned load loss or interruption of firm transmission service is not allowed when lower cost remedies are available. An available lower cost remedy will be required to address such violations. For example, lower cost remedies that may be considered include:

- Relaying modifications
- Sectionalizing schemes
- breaker upgrades

- Independent pole tripping
- High speed breaker failure schemes
- High speed reclosing
- Fast closing of steam intercept valves
- Braking resistors.

If the search for lower cost upgrades produces none, or in the case of wide-spread system violations such as may be encountered during RTEP baseline stability analysis, then PJM, in consultation with the affected Transmission Owners, will make a more detailed assessment of the violation(s) including factors such as the extent of violations, the events' likelihood, system impact and cost to remedy. Based on the gathered information, PJM will specify a remedy including possible consideration of operating guides, special protection systems, and more extensive high voltage upgrade options.

G.9.2 Nuclear Station Testing

With regard to nuclear station related planning stability analysis, in addition to the *standard NERC criteria* and specific Transmission Owner criteria testing, PJM reviews and enforces criteria testing that can be found under the Planning section of the Nuclear Plant Interface Requirement (NPIR) documents. In some cases the Transmission Owner also performs special nuclear unit stability testing as described in PJM Manual 39 and the NPIR. Together, the analyses that may be performed by the Transmission Owner and PJM's testing incorporate the voltage and stability requirements of the station. PJM ensures Transmission System performance to the specified criteria that enables the station equipment and systems to perform as designed. Nuclear voltage criteria at the Transmission System level, including any voltage drop criteria, are enforced on a system normal and post-contingency basis as described in the NPIR planning requirements. Observed criteria violations during planning assessments affecting nuclear stations will be evaluated jointly by PJM Planning and PJM Operations consistent with procedures outlined in PJM Manual 39. Appropriate remedies, consistent with this Attachment and the PJM Manuals and Agreements, will be specified to ensure applicable criteria are met. The nuclear owner will be responsible for reinforcements necessary to comply with criteria that are specific to the Nuclear Plant and that are more stringent than the standard PJM and Transmission Owner tests.

The specific nuclear unit planning criteria contained in the NPIR documents are included in the Appendix to this Attachment G when the nuclear plant owner has consented to these excerpts being included here for convenient planning reference. In any instances of a nuclear plant owner preference to maintain confidentiality of this information, it is not reproduced in this manual but is still evaluated and enforced during planning studies.

G.9.3 BG&E Specific Criteria

Additional stability testing applicable to interconnections with BG&E transmission facilities includes tests of three-phase faults at a point 80% of the circuit impedance away from the station under study with delayed (zone two) clearing.

G.9.4 ComEd Specific Criteria

Additional stability testing applicable to interconnections with ComEd transmission facilities includes:

- Three-phase fault on any transmission or generation element with delayed clearing due to a stuck breaker or other protective equipment failure. For situations involving independent pole operated breakers, it is assumed that only one phase of the breaker fails to open and the delayed clearing time is used for the remaining single-phase fault.
- Three-phase fault on any transmission or generation element with delayed clearing due to failure of a special protection system.
- Three-phase fault on all transmission lines on a multiple circuit tower with normal clearing.
- Three-phase fault on any transmission or generation element during the scheduled outage of any other transmission or generation element.

It should be noted that a one-cycle margin is included in all primary-clearing times for faults on the ComEd system, instead of the PJM margins. For more severe, lower probability events such as faults occurring during maintenance outages or faults cleared in delayed time, if lower cost remedies are not available, PJM will retest with the PJM's standard margins as a possible remedy.

G.9.5 PPL Specific Criteria

Additional stability testing applicable to interconnections with PPL transmission facilities includes:

- permanent three-phase faults at a point 80% of the line impedance away from the PPL zone generating facility under consideration with delayed (Zone 2) clearing times, including reclosing, if applicable.
- Permanent three phase fault with stuck breaker or other cause of delayed clearing.
- Permanent three phase fault on one line in the substations one substation removed from the interconnection point with an over-trip of another unfaulted line in the same station. Both the over-trip and clearing of the faulted line occur in normal primary clearing time. Reclosing sequences, if applicable, will be included.
- PPL EU applies a transient synchronous stability safety margin of 7% in the export limited Northern PPL area (see PJM Manual 03 at http://www.pjm.com/documents/manuals.aspx). This implies that the net export limit based on stability will be reduced by 7% to account for a margin of error in the specified net export limit from the area.

G.9.6 Implementation of the NPIR for Planning Analysis

PJM is required to incorporate the Nuclear Plant Interface Requirements (NPIRs) into its planning processes according to the applicable NERC standards. PJM performs these planning analyses consistent with the NPIR planning requirements and its Regional Transmission

Planning requirements. PJM Manuals 14B and 39 are the two principal sources that document these requirements, among various other planning and operating process business rules. It the responsibility of the Planning engineer to monitor changes to the planning requirements contained in the NPIR source documents (kept in confidence by PJM System Operating) and Manual 39 and to update this manual to reflect changes as appropriate per the protocols of Manual 39 section 3.1.

The following material are the excerpted planning requirements and criteria contained in the NPIR's that must be incorporated into PJM Planning analyses. This material must only be changed to be consistent with the source documents.

Braidwood Station, Units 1 and 2 Planning Requirements

Nuclear Plant Voltage Adequacy Studies: Periodic analysis of the expected Braidwood switchyard voltages following a unit trip (Unit 1 or 2) shall be performed for various transmission system load levels and contingencies based on the study template provided by Exelon Nuclear. Exelon Nuclear will periodically request these studies from the ComEd transmission entity on a periodic basis to support compliance with GDC 17. The results of the studies are to be provided to Exelon Nuclear by the ComEd Transmission Entity.

PJM Planning and Operations transmission studies shall incorporate the Braidwood voltage and stability requirements that follow. Exelon Nuclear shall be notified by the Planning Authority if planning study results identify that the Braidwood requirements are not met by current or future system configurations, load levels, and contingencies. Transmission study violations based on standard PJM criteria testing will be handled by the procedures described in the PJM agreements and manuals. Study violations based on criteria that are specified specifically for Braidwood and are beyond standard PJM criteria testing will require remedies that will be the plant owner's responsibility. The following Braidwood requirements shall be utilized for the planning studies:

Voltage and Offsite Source Load Capacity Requirements:

The Braidwood Voltage Operating Limits, which are based upon internal plant limitations reflected at the transmission system voltage limit level, are as follows:

345kV: Normal Low (actual voltage evaluations) – 349.2kV (1.0122)

Emergency Low (contingency voltage evaluations) – 349.2kV (1.0122)

Note:

The limits above are applicable for Braidwood Units 1 and 2. It is acceptable that the Normal Low limit be conservatively adjusted upward by1kV to allow for design limitations of the transmission entity state estimators. Some state estimator designs do not allow a Normal Low limit and an Emergency Low limit to be the same value.

For the purposes of the planning studies only the Braidwood unit trip contingency voltage limit requires evaluation. Other transmission system contingencies do not require evaluation.

Stability:

Braidwood generating units 1 and 2 are to be stable for the following conditions (the following are included in PJM standard stability testing):

- A three-phase line fault with normal clearing of the line protective systems.
- A phase-to-ground fault with abnormal (delayed) clearing involving the failure of a relay or circuit breaker.
- A double line tower fault.

Exelon Nuclear shall be notified by the Planning Authority if the results of system stability studies identify that any of the stability requirements discussed above are not met. In addition, Exelon Nuclear shall be notified if the system stability studies pertinent to the Braidwood generators, the Braidwood switchyard, or the lines connecting the Braidwood switchyard to the transmission system indicate that stability requirements contained in the PJM, NERC or ComEd Transmission Entity standards are not met.

Byron Station, Units 1 and 2 Planning Requirements

Nuclear Plant Voltage Adequacy Studies: Periodic analysis of the expected Byron switchyard voltages following a unit trip (Unit 1 or 2) shall be performed for various transmission system load levels and contingencies based on the study template provided by Exelon Nuclear. Exelon Nuclear will periodically request these studies from the ComEd transmission entity on a periodic basis to support compliance with GDC 17. The results of the studies are to be provided to Exelon Nuclear by the ComEd Transmission Entity.

PJM Planning and Operations transmission studies shall incorporate the Byron voltage and stability requirements that follow. Exelon Nuclear shall be notified by the Planning Authority if planning study results identify that the Byron requirements are not met by current or future system configurations, load levels, and contingencies. Transmission study violations based on standard PJM criteria testing will be handled by the procedures described in the PJM agreements and manuals. Study violations based on criteria that are specified specifically for Byron and are beyond standard PJM criteria testing will require remedies that will be the plant owner's responsibility. The following Byron requirements shall be utilized for the planning studies:

Voltage and Offsite Source Load Capacity Requirements:
The Byron Voltage Operating Limits, which are based upon internal plant limitations reflected at the transmission system voltage limit level, are as follows:

345kV: Normal Low (actual voltage evaluations) – 341.0kV (.9885 pu)

Emergency Low (contingency voltage evaluations) – 341.0kV (.9885 pu)

Notes:

The limits above are applicable for Byron Units 1 and 2. It is acceptable that the Normal Low limit be conservatively adjusted upward by .1kV to allow for design limitations of the transmission entity state estimators. Some state estimator designs do not allow a Normal Low limit and an Emergency Low limit to be the same value.

For the purposes of the planning studies only the Byron unit trip contingency voltage limit requires evaluation. Other transmission system contingencies do not require evaluation.

Stability:

Byron generating units 1 and 2 are to be stable for the following conditions (the following are included in PJM standard stability testing):

- A three-phase line fault with normal clearing of the line protective systems.
- A phase-to-ground fault with abnormal (delayed) clearing involving the failure of a relay or circuit breaker.
- A double line tower fault.

Exelon Nuclear shall be notified by the Planning Authority if the results of system stability studies identify that any of the stability requirements discussed above are not met. In addition, Exelon Nuclear shall be notified if the system stability studies pertinent to the Byron generators, the Byron switchyard, or the lines connecting the Byron switchyard to the transmission system indicate that stability requirements contained in the PJM, NERC or ComEd Transmission Entity standards are not met.

LaSalle Station, Units 1 and 2 Planning Requirements

Nuclear Plant Voltage Adequacy Studies: Periodic analysis of the expected LaSalle Station switchyard voltages following a unit trip (Unit 1 or 2) shall be performed for various transmission system load levels and contingencies based on a study template provided by Exelon Nuclear. Exelon Nuclear will periodically request these studies from the ComEd Transmission Entity on a periodic basis to support compliance with GDC 17. The results of the studies are to be provided to Exelon Nuclear by the ComEd Transmission Entity.

PJM Planning and Operations transmission studies shall incorporate the LaSalle voltage and stability requirements that follow. Exelon Nuclear shall be notified by the Planning Authority if planning study results identify that the LaSalle requirements are not met by current or future system configurations, load levels, and contingencies. Transmission study violations based on standard PJM criteria testing will be handled by the procedures described in the PJM agreements and manuals. Study violations based on criteria that are specified specifically for LaSalle and are beyond standard PJM criteria testing will require remedies that will be the plant owner's responsibility. The following LaSalle requirements shall be utilized for the planning studies:

Voltage and Offsite Source Load Capacity Requirements:

The LaSalle Voltage Operating Limits, which are based upon internal plant limitations reflected at the transmission system voltage limit level, are as follows:

345 kV: Normal low (actual voltage evaluations) – 353.0 kV (1.0232 pu)

Emergency Low (contingency voltage evaluations) – 353.0 kV (1.0232 pu)

Note:

The limits above are applicable for LaSalle Units 1 and 2. It is acceptable that the Normal Low limit be conservatively adjusted upward by .1kV to allow for design limitations of the transmission entity state estimators. Some state estimator designs do not allow a Normal Low limit and an Emergency Low limit to be the same value.

For the purposes of the planning studies only the LaSalle unit trip contingency voltage limit requires evaluation. Other transmission system contingencies do not require evaluation.

Stability:

LaSalle generating units 1 and 2 are to be stable for the following conditions (the following are included in PJM standard stability testing):

- A three-phase line fault with normal clearing of the line protective systems.
- A phase-to-ground fault with normal clearing and with abnormal (delayed) clearing involving the failure of a relay or circuit breaker.
- A double line tower fault.
- A phase-to-ground fault during planned transmission line maintenance outages

Exelon Nuclear shall be notified by the Planning Authority if the results of system stability studies identify that any of the stability requirements discussed above are not met. In addition, Exelon Nuclear shall be notified if the system stability studies pertinent to the LaSalle generators, the LaSalle switchyard, or the lines connecting the LaSalle switchyard to the transmission system indicate that stability requirements contained in the PJM, NERC or ComEd Transmission Entity standards are not met.

Quad Cities Nuclear Power Station Units 1 and 2 Planning Requirements

Nuclear Plant Voltage Adequacy Studies: Periodic analysis of the expected Quad Cities switchyard voltages following a unit trip (Unit 1 or 2) shall be performed for various transmission system load levels and contingencies based on the study template provided by Exelon Nuclear. Exelon Nuclear will periodically request these studies from the ComEd Transmission Entity to support compliance with GDC 17. The results of the studies are to be provided to Exelon Nuclear by the ComEd Transmission Entity.

PJM Planning and Operations transmission studies shall incorporate the Quad Cities voltage and stability requirements that follow. Exelon Nuclear shall be notified by the Planning Authority if planning study results identify that the Quad Cities requirements are not met by current or future system configurations, load levels, and contingencies. Transmission study violations based on standard PJM criteria testing will be handled by the procedures described in the PJM agreements and manuals. Study violations based on criteria that are specified specifically for Quad Cities and are beyond standard PJM criteria testing will require remedies that will be the plant owner's responsibility. The following Quad Cities requirements shall be utilized for the planning studies.

Voltage and Offsite Source Load Capacity Requirements:

The Quad Cities Voltage Operating Limits, which are based upon internal plant limitations reflected at the transmission system voltage limit level, are as follows:

345kV: Normal Low (actual voltage evaluations) – 348.2 kV (1.0093 pu)
Emergency Low (contingency voltage evaluations) – 348.2 kV (1.0093 pu)

Note:

The limits above are applicable for Quad Cities Units 1 and 2.

For the purposes of the planning studies only the Quad Cities unit trip contingency voltage limit requires evaluation. Other transmission system contingencies do not require evaluation.

Power flow and Stability Testing:

The following design requirements of the Quad Cities UFSAR are to be annually verified through the battery of transmission tests performed by PJM and ComEd. All of the Quad Cities requirements are embodied in the standard NERC, PJM and ComEd transmission criteria applied during PJM and ComEd studies related to the Regional Transmission Expansion Plan and generation interconnections. These tests ensure the Quad Cities and ComEd system are in compliance with the applicable criteria.

The transmission system is designed to withstand the sudden outage of large amounts of generating capacity. The system shall be designed to compensate for the simultaneous loss of any two generating units and maintain all transmission network flows within short term emergency limits, and all 345kV and 138kV voltages within steady state limits. This is required at all load levels up to the 50/50 load forecast. PJM testing examines the non-simultaneous outage of any two units. ComEd testing examines the most critical combination of simultaneous outages of two units.

Quad Cities Station and the transmission system is designed for stability and circuit isolation that will prevent the sudden loss of one unit at Quad Cities from causing the second unit to trip. This is confirmed by power flow and stability studies. The system shall be stable for situations involving a three phase fault on the most critical generating element with normal clearing, or a three phase fault on the most critical generating element with delayed clearing, or the loss of the most critical single facility with no fault.

Assuming one or both of the Quad Cities units are tripped when carrying full load, the high voltage lines at the station will continue to be energized from the transmission system. The transmission system shall be designed to withstand the outage of any one generator and maintain all network flows within emergency ratings (up to 50/50 load) or short term emergency ratings (up to 90/10 load).

Exelon Nuclear shall be notified by the Planning Authority (PJM) if the results of system stability studies identify that any of the stability requirements discussed above are not met. In addition, Exelon Nuclear shall be notified if the system stability studies pertinent to the Quad Cities generators, the Quad Cities switchyard, or the lines connecting the Quad Cities switchyard to the transmission system indicate that stability requirements contained in the PJM, NERC or ComEd Transmission Entity standards are not met.

Dresden Units 2 and 3 Planning Requirements

Nuclear Plant Voltage Adequacy Studies: Periodic analysis of the expected Dresden Station switchyard voltages following a unit trip (Unit 2 or 3) shall be performed for various transmission system load levels and contingencies based on a study template provided by Exelon Nuclear. Exelon Nuclear will periodically request these studies from the ComEd Transmission Entity on a periodic basis to support compliance with GDC 17. The results of the studies are to be provided to Exelon Nuclear by the ComEd Transmission Entity.

PJM Planning and Operations transmission studies shall incorporate the Dresden voltage and stability requirements that follow. Exelon Nuclear shall be notified by the Planning Authority if planning study results identify that the Dresden requirements are not met by current or future system configurations, load levels, and contingencies. Transmission study violations based on standard PJM criteria testing will be handled by the procedures described in the PJM agreements and manuals. Study violations based on criteria that are specified specifically for Dresden and are beyond standard PJM criteria testing will require remedies that will be the plant owner's responsibility. The following Dresden requirements shall be utilized for the planning studies:

Voltage and Offsite Source Load Capacity Requirements:
The Dresden Voltage Operating Limits, which are based upon internal plant limitations reflected at the transmission system voltage limit level, are as follows:

345 kV: Dresden Unit 2 (Blue Bus);

Normal low (actual voltage evaluations) – 332.9 kV (0.9650 pu) with Tr 86 LTC in auto, 346.2 kV (1.0035 pu) with Tr 86 LTC in manual

Emergency Low (contingency voltage evaluations) – 332.9 kV (0.9650 pu) with Tr 86 LTC in auto, 346.2 kV (1.0035 pu) with Tr 86 LTC in manual

345 kV: Dresden Unit 3 (Red Bus);

Normal low (actual voltage evaluations) – 338.8 kV (0.9821 pu) with RAT 32 LTC in auto, 345.3 kV (1.0009 pu) with RAT 32 LTC in manual

Emergency Low (contingency voltage evaluations) – 338.8 kV (0.9821 pu) with RAT 32 LTC in auto, 345.3 kV (1.0009 pu) with RAT 32 LTC in manual

Note: For the purposes of the planning studies only the Dresden unit trip contingency voltage limit requires evaluation. Other transmission system contingencies do not require evaluation.

Stability:

Dresden generating units 2 and 3 are to be stable for the following conditions (the following are included in PJM standard stability testing):

A three-phase fault on any transmission or generation element with normal clearing of the protective systems.

a. A three-phase fault on any transmission or generation element with abnormal (delayed) clearing involving the failure of a relay or circuit breaker. The fault is cleared in delayed time by back-up equipment. If the protective device which fails to operate is an independent pole operated (IPO) breaker, only one phase will be assumed to fail to clear in the primary clearing attempt which will leave only a single phase fault during the delayed clearing time. Mitigation for unstable scenarios may include generator tripping.

b. A three phase fault on any transmission or generation element accompanied by the failure of a special protection scheme to detect, clear, or properly respond to the fault. The fault is cleared in delayed time by back-up equipment, or the special protection scheme may fail to operate as designed. Mitigation for unstable scenarios may include generator tripping.

c. A three phase fault on all transmission lines installed on a multiple circuit tower. No relay or circuit breaker failure is assumed for this contingency.

d. A three phase fault on any transmission or generation element during the scheduled outage of any other transmission or generation element. No relay, circuit breaker, or special protection scheme failure is assumed for this contingency. Mitigation for unstable scenarios may include generator tripping.

Exelon Nuclear shall be notified by the Planning Authority if the results of system stability studies identify that any of the stability requirements discussed above are not met. In addition, Exelon Nuclear shall be notified if the system stability studies pertinent to the Dresden generators, the Dresden switchyard, or the lines connecting the Dresden switchyard to the transmission system indicate that stability requirements contained in the PJM, NERC or ComEd Transmission Entity standards are not met.

Oyster Creek Unit 01 Planning Requirements

Nuclear Plant Voltage Adequacy Studies: (FirstEnergy responsibility) Periodic analysis of the expected station switchyard voltages following a unit trip shall be performed for various transmission system load levels and contingencies to support station compliance with GDC 17. The bulk transmission system must be examined for performance during system disturbances; using normal case load flows, transient stability studies, and post-transient load flow studies. The studies are to confirm that the system performs adequately for the predicted worst case single contingency (one line or other failure) on the bulk transmission system with normal system adjustments, followed by the loss of the Oyster Creek generator. For these conditions, the studies must confirm that there was no loss of load in the system, the Oyster Creek 230kV substation is not interrupted, and a predicted minimum grid (substation) voltage is determined . Once per year any changes made to the transmission system that would affect voltage stability at Oyster Creek must be reviewed and if necessary, a new value for the minimum expected/predicted grid voltage is to be provided to Exelon Nuclear. Results of the studies are to be provided to Exelon Nuclear.

Transmission Planning studies (PJM responsibility) shall incorporate the voltage and stability requirements of the station. These studies shall include those performed for Operations and for future transmission and generation interconnection. Exelon Nuclear shall be notified if planning study results identify that the station requirements are not met by current or future system configurations, load levels, and contingencies. The following station requirements shall be utilized for the planning studies:

Voltage and Offsite Source Load Capacity Requirements:

The Oyster Creek voltage limits, which are based upon internal plant limitations reflected at the transmission system voltage limit level, are as follows:

	230kV Oyster Creek Switchyard Voltage
Normal Low (actual voltage evaluations)	227kV (0.9869 p.u.)
Emergency Low (contingency voltage evaluations)	223.7kV (0.9726 p.u)

Note: For the purposes of the planning studies only the Oyster Creek unit trip contingency voltage limit requires evaluation. Other transmission system contingencies do not require evaluation.

Planning assessments enforce nuclear voltage criteria at the Transmission System level, including any voltage drop criteria. Criteria are enforced on a post-contingency basis without system adjustments but allowing generation reactive supply within normal reactive limits, except as may be explicitly noted below.

Oyster Creek system normal (reference case conditions) 230 kV low voltage limit is 227 kV (.987 pu) and, under contingency conditions it is 223.7 kV (.973 pu). In addition, frequency will be monitored for all studied contingencies and verified to be maintained above 57.5 Hz.

Stability Requirements:

The system shall remain stable and perform within voltage and other applicable criteria following:

1. A 3 phase fault with primary clearing on the most critical of the 230 kV lines emanating from Oyster Creek. (standard PJM test)
2. A 3 phase fault with primary clearing on the most critical of the 34.5 kV lines emanating from Oyster Creek. (standard PJM test applied to lower voltage than PJM's standard testing)
3. A 1 phase fault on the most critical of the two 230 kV lines emanating from Oyster Creek, followed by a stuck breaker and clearing in backup clearing time. (standard PJM test)
4. The simultaneous loss of the Oyster Creek generating unit and the largest generating unit in New Jersey (Salem Unit 2) with no faults. (not part of standard testing)
5. 3 phase close-in fault on the most critical 230 kV and above lines from the station (double circuit tower outage, specifically both Manitou-Oyster Creek lines) and loss of the Oyster Creek generator (verify Oyster Creek unit trips based on out-of-step relay protection), (standard PJM test)

Exelon Nuclear shall be notified by the Planning Authority if the results of system stability studies identify that any of the stability requirements discussed above are not met.

Three Mile Island Unit 1 Planning Requirements

Nuclear Plant Voltage Adequacy Studies: (FirstEnergy responsibility) Periodic analysis of the expected Station switchyard voltages following a unit trip shall be performed for various transmission system load levels and contingencies to support Station compliance with GDC 17. The bulk transmission system must be examined for performance during system disturbances; using normal case load flows, transient stability studies, and post-transient load flow studies. The studies are to confirm that the system performs adequately for the predicted worst case single contingency (one line or other failure) on the bulk transmission system with normal system adjustments, followed by the loss of the TMI generator. For these conditions, the studies must confirm that there was no loss of load in the system, the TMI 230kV substation is not interrupted, and a predicted minimum grid (substation) voltage is determined. Once per year any changes made to the transmission system that would affect voltage stability at TMI must be reviewed and if necessary, a new value for the minimum expected/predicted grid voltage is to be provided to Exelon Nuclear. Results of the studies are to be provided to Exelon Nuclear.

Transmission Planning studies (PJM responsibility) shall incorporate the voltage and stability requirements of the Station. These studies shall include those performed for Operations and for future transmission and generation interconnection. Exelon Nuclear shall be notified if planning study results identify that the Station requirements are not met by current or future system configurations, load levels, and contingencies. The following Station requirements shall be utilized for the planning studies:

Voltage:

The TMI Station voltage limits, which are based upon internal plant limitations reflected at the transmission system voltage limit level, are as follows:

	2 Auxiliary Transformer Operation	Single Auxiliary Transformer Operation	Manual Load Tap Changer Operation
Normal Low	223 (0.9710 pu)	223 (0.9710 pu)	223 (0.9710 pu)
Emergency Low	223 (0.9710 pu)	223 (0.9710 pu)	223 (0.9710 pu)

Planning assessments enforce nuclear voltage criteria at the Transmission System level, including any voltage drop criteria. Criteria are enforced on a system normal and post-contingency basis after allowance for full system adjustments that can be available within 30 minutes following a disturbance.

Stability:

Three Mile Island generating unit stability is to be analyzed according to the applicable NERC, Regional Entities of NERC, and PJM criteria for transient stability.

Exelon Nuclear shall be notified if the results of system stability studies identify that any of the stability requirements discussed above are not met. In addition, Exelon Nuclear shall be notified if the system stability studies pertinent to the TMI generator, the TMI switchyard, or the lines connecting the TMI switchyard to the transmission system indicate that any of the stability requirements are not met.

Limerick Generating Station Units 1 and 2 Planning Requirements

Nuclear Plant Voltage Adequacy Studies: Periodic analysis of the expected Limerick switchyard voltages following a unit trip (Unit 1 or 2) shall be performed for various transmission system load levels and contingencies based on the study template provided by Exelon Nuclear. Exelon Nuclear will periodically request these studies from the PECO Transmission Entity to support compliance with NRC licensing commitments for Limerick. The results of the studies are to be provided to Exelon Nuclear by the PECO Transmission Entity.

PJM Planning and Operations transmission studies shall incorporate the Limerick voltage and stability requirements that follow. Exelon Nuclear shall be notified by the Planning Authority if planning study results identify that the Limerick requirements are not met by current or future system configurations, load levels, and contingencies. Transmission study violations based on standard PJM criteria testing will be handled by the procedures described in the PJM agreements and manuals. Study violations based on criteria that are specified specifically for Limerick and are beyond standard PJM criteria testing will require remedies that will be the plant owner's responsibility. The following Limerick requirements shall be utilized for the planning studies:

Voltage and Offsite Source Load Capacity Requirements:

The Limerick Voltage Operating Limits, which are based upon internal plant limitations reflected at the transmission system voltage limit level are as follows:

230kV: Normal Low (actual voltage evaluations) – 225kV (.9783 p.u.)

Emergency Low (contingency voltage evaluations) – 225kV (.9783 p.u.)

Voltage drop: 2.5% (Post contingency voltage drop limit to be applied for a contingency trip of Limerick Unit 1 or Unit 2).

500kV: Normal Low (actual voltage evaluations) – 500kV (1.0 p.u.)

Emergency Low (contingency voltage evaluations) – 500kV (1.0 p.u.)

Voltage drop: 2.5% (Post contingency voltage drop limit to be applied for a contingency trip of Limerick Unit 1 or Unit 2).

69kV: Normal Low (actual voltage evaluations) – 67.5kV (.9783 p.u.)

Voltage drop: 3.4% (Post contingency voltage drop limit to be applied for a contingency trip of Limerick Unit 1 or Unit 2).

Note: The 69kV voltage limits are to be activated when notification is received from Exelon Nuclear that the Limerick 69kV source is in operation.

Note: For the purposes of the planning studies only the Limerick unit trip contingency voltage limit requires evaluation. Other transmission system contingencies do not require evaluation.

Stability Requirements:

Limerick Generating Station (LGS) Units 1 and 2 are to be stable for the following conditions:

a. A three-phase fault on any single 500 kV or 230 kV circuit terminating in the Limerick 500kV or 230kV switchyards that is cleared by primary protective equipment (standard PJM test.)

b. A three-phase fault on any single 500 kV or 230 kV circuit terminating in the Limerick 500kV or 230kV switchyards, where the most critical LGS circuit breaker fails to open and the fault is cleared at LGS by backup protective equipment. (beyond standard PJM testing.)

c. A three-phase fault on the transformer connecting the LGS 500 kV and 230 kV buses that is cleared by primary protective equipment (standard PJM test.)

d. A three-phase fault on the transformer connecting the LGS 500 kV and 230 kV buses, where the most critical circuit breaker fails to open and the fault is cleared at LGS by backup protective equipment. (beyond standard PJM testing.)

e. Simultaneous three-phase faults on both LGS to Whitpain 500 kV circuits that are cleared by primary protective equipment (beyond standard PJM testing.)

In addition, the transmission system shall remain stable for the following three cases with either one or both LGS units in service. (All the following are beyond standard PJM testing):

a. Loss of the largest generating station (i.e., loss of Peach Bottom Atomic Power Station (PBAPS) Units 2 and 3) (No faults applied).

b. Loss of the largest load (No faults applied).

c. Loss of the most critical right-of-way (i.e., four simultaneous three-phase faults on the four transmission lines on the 130-30 right-of-way):

   1. Cromby-Perkiomen (130-30) 138 kV Line
   2. Cromby-Upper Providence (220-62) 230 kV Line
   3. Limerick-Whitpain (5030) 500kV Line
   4. Limerick-Whitpain (5031) 500kV Line

Exelon Nuclear shall be notified by the Planning Authority if the results of system stability studies identify that any of the stability requirements discussed above are not met. In addition, Exelon Nuclear shall be notified if PJM system stability studies pertinent to the Limerick generators, the Limerick switchyards, or the lines connecting the Limerick switchyards to the transmission system indicate that any of the stability requirements contained in the PJM, NERC or PECO Transmission Entity standards are not met.

Peach Bottom Station Units 2 and 3 Planning Requirements

Nuclear Plant Voltage Adequacy Studies:

Periodic analysis of the expected Peach Bottom offsite power source voltages following a unit trip (Unit 2 or 3) shall be performed for various transmission system load levels and contingencies based on a study template provided by Exelon Nuclear. Exelon Nuclear will periodically request these studies from the PECO Transmission Entity to support compliance with NRC licensing commitments for Peach Bottom. The results of the studies are to be provided to Exelon Nuclear by the PECO Transmission Entity.

PJM Planning and Operations transmission studies shall incorporate the Peach Bottom voltage and stability requirements that follow. Exelon Nuclear shall be notified by the Planning Authority if planning study results identify that the Peach Bottom requirements are not met by current or future system configurations, load levels, and contingencies. Transmission study violations based on standard PJM criteria testing will be handled by the procedures described in the PJM agreements and manuals. Study violations based on criteria that are specified specifically for Peach Bottom and are beyond standard PJM criteria testing will require remedies that will be the plant owner's responsibility. The following Peach Bottom requirements shall be utilized for the planning studies:

Voltage and Offsite Source Load Capacity Requirements:

The Peach Bottom Station Voltage Operating Limits, which are based upon internal plant limitations reflected at the transmission system voltage limit level are as follows:

2SU: (Peach Bottom Tap on 220-08 line)

Normal Low (actual voltage conditions)- 225kV (.9783 p.u.)

Emergency Low (contingency voltage conditions)- 225kV (.9783 p.u.)

Voltage Drop: 1.8% (Post contingency voltage drop limit to be applied for a contingency trip of Peach Bottom Unit 2 or 3).

Maximum - 242kV (1.05 p.u.)

343SU: (Peach Bottom 230kV; Peach Bottom terminal of 220-34 line)

Normal Low (actual voltage conditions)- 225kV (.9783 p.u.)

Emergency Low (contingency voltage conditions)- 225kV (.9783 p.u.)

Voltage Drop - 2.6% (Post contingency voltage drop limit to be applied for a contingency trip of Peach Bottom Unit 2 or 3).

Maximum - 242kV (1.05 p.u.)

3SU: (13kV tertiary of Peach Bottom #1 transformer)

Normal Low (actual voltage conditions)- 13.5kV

Emergency Low (contingency voltage conditions)- 13.5kV

Voltage Drop - 2.5% (Post contingency voltage drop limit to be applied for a contingency trip of Peach Bottom Unit 2 or 3).

Maximum – 538kV (1.0760 p.u.)(on 500kV side of Peach Bottom #1 Autotransformer)

Note: The limits above are applicable for Peach Bottom Units 2 and 3.

Stability Requirements:

Stability studies shall have simulated 500 kV and 230 kV transmission line faults, the loss of each of the Peach Bottom generators, and the loss of the largest generator on the 500 kV grid. The studies must show that the transmission system is stable and there will be no cascading transmission outages for the simulated transmission line faults. The studies must show that continuous offsite power is assured for the simulated transmission system contingencies. This requirement is demonstrated by showing that offsite power sources 2SU, 343SU, and 3SU are maintained in service unless the simulated transmission system contingency is the direct supply to the offsite power source.

Exelon Nuclear shall be notified by the Planning Authority if the results of system stability studies identify that any of the stability requirements discussed above are not met. In addition, Exelon Nuclear shall be notified if PJM system stability studies pertinent to the Peach Bottom generators, the Peach Bottom switchyards, the lines connecting the Peach Bottom switchyards to the transmission system, or the 220-08 line indicate that any of the stability requirements contained in the PJM, NERC or PECO Transmission Entity standards are not met.

Susquehanna Station units 1 & 2 Planning Requirements

Nuclear Plant Voltage Adequacy Studies: Periodic analysis of the expected Susquehanna switchyard voltages following a unit trip (Unit 1 or 2) shall be performed considering peak transmission system load levels with the system normal or altered by contingencies. Results of the studies are to be provided to PPL Susquehanna. To satisfy this requirement, the PJM normal course of planning studies fulfills this requirement.

Transmission Planning Studies shall incorporate the voltage and stability requirements of Susquehanna. These studies shall include those performed to evaluate future transmission and generation interconnection. PPL Susquehanna shall be notified if planning study results identify that the Susquehanna requirements are not met by current or future system configurations, load levels, and contingencies.

The Transmission Planner or Transmission Owner will perform voltage analysis using a "current year + 5" planning horizon 50-50 peak summer load flow case considering N-1, stuck breaker and tower outage contingencies on 230 kV facilities and above and a stability study (following transmission normal stability criteria along with the special stability cases identified in the FSAR (Section 8.2)). These studies are to be completed on a three year cycle by the Transmission Planner and on a two year cycle by the Transmission Owner, or sooner, if system changes dictate. The Transmission Planner or Transmission Owner will communicate the results of these studies to PPL SSES. These studies may include load flow, voltage and/or stability related work analyses.

The following Susquehanna requirements shall be utilized for the planning studies:

SSES Transformer Loading

	T-10	T-20	T-11	T-12
Normal Plant Loading	5 + J3	5 + J3	42 + J24	42 + J24
Post Unit 1 Trip Loading both Start-up transformers in-service	27.1 +J14.65	27.1 +J14.65		42 + J24
Post Unit 2 Trip Loading both Start-up transformers in-service	27.1 +J14.65	27.1 +J14.65	42 + J24	
Post Unit 1 Trip Loading T-10 Start-up transformer in-service	54.2 +J 29.3			42 + J24
Post Unit 2 Trip Loading T-10 Start-up transformer in-service	54.2 +J 29.3		42 + J24	
Post unit 1 Trip Loading T-20 Start-up transformer in-service		54.2 +J 29.3		42 + J24
Post Unit 2 Trip Loading T-20 Start-up transformer in-service		54.2 +J 29.3	42 + J24	

Monitor offsite circuits with/without one S/U transformer in service.

With **both** Start-up Transformers (T-10 & T-20) in-service

Minimum Voltage	Allowable Voltage Drop*
212kV (0.9217)	5%

With **one** Start-up Transformer (T-10 or T-20) in-service

Minimum Voltage	Allowable Voltage Drop*
216.7kV (0.9421)	2%

*Post contingency voltage drop limit to be applied for a contingency trip of Susquehanna unit 1 or unit 2.

NOTE: Voltage excursions below the Susquehanna voltage limits with durations expected to be greater than 9 seconds will result in the affected unit or units transferring from offsite power to the onsite power distribution system. Therefore, the transmission Entities shall take into consideration actions that will mitigate voltage excursions below the Susquehanna minimum voltage limits with durations greater than 9 seconds and provide notification when proposed actions cannot mitigate the voltage excursion.

Stability:

Susquehanna generating units 1 and 2 are to be stable for the following conditions:

In general, the stability requirements are that the system shall be maintained without loss of non-consequential load during and after the following types of contingencies based on the latest light load forecast prepared annually by the PJM Load Analysis Subcommittee.

Standard NERC criteria contingencies (identified as R-* cases of FSAR Table 8.2-1):

- Single contingency outage conditions
- Double circuit tower line outage or single stuck circuit breaker conditions Three phase faults with normal clearing time
- Single line to ground faults with a stuck breaker or other cause for delayed clearing

The NERC TPL Standard reliability criteria also requires an evaluation of the ability of the bulk electric system to withstand abnormal or extreme system disturbances (identified as the N-* cases of FSAR Table 8.2-1). The NERC TPL Standard reliability criteria does not require that the bulk electric system be planned and constructed to withstand these abnormal or extreme disturbances due to their low probability of occurrence. However, it is PPL SSES position to maintain stability for these FSAR Table 8.2-1 cases as well. These abnormal system disturbances are analyzed not on the basis of their likelihood of occurrence but rather as a practical means to study the system for its ability to withstand disturbances beyond those that can be reasonably expected.

A total of six (6) contingencies identified in the FSAR Table 8.2-1 are required by NERC standards. Seventeen (17) other contingencies are not required by NERC standards but analyzed to assure a high level of transmission system reliability. FSAR table 8.2-1 is attached with the list of stability cases performed for PPL Susquehanna LLC. PPL Susquehanna shall be notified if the results of system stability studies identify that any of the stability requirements discussed above are not met. In addition, PPL Susquehanna shall be notified if the system stability studies indicate that any of the stability requirements contained within the attached stability summary tables is not met.

CASE	DESCRIPTION
R-1	3 phase fault at Susquehanna 500 kV on the Sunbury 500 kV line. Fault cleared in primary clearing time.
R-5	Phase-ground fault at Susquehanna 500 kV on Sunbury 500 kV line with Sunbury South 500 kV circuit breaker stuck. Clear remote terminal in primary time. Delayed clearing of Susquehanna.
R-6	3 phase fault at Susquehanna 230 kV on the Susquehanna 500/230 kV transformer. Fault cleared in primary clearing time.
R-7	3 phase fault at Montour 230 kV on Susquehanna 230 kV line. Fault cleared in normal primary clearing time.
R-13	Phase-ground fault at Susquehanna 500 kV on Susquehanna-Wescosville-Alburtis 500 kV line with Wescosville South 500 kV circuit breaker stuck. Clear remote terminal in primary time. Delayed clearing at Susquehanna.
R-18	3 phase fault at Susquehanna 230 kV on Harwood #1 & #2 Double Circuit. Fault cleared in primary clearing time.
N-2	3 phase fault at Susquehanna 500 kV on the Sunburn 500 kV line with one breaker pole stuck at Sunbury. Clear Susquehanna in primary time. Delayed clearing at remote terminal.
N-3	3 phase fault at Susquehanna 500 kV on the Susquehanna-Wescosville-Alburtis 500 kV line with one Susquehanna 500/230 kV transformer breaker pole stuck. Clear remote terminal in primary time. Delayed clearing of Susquehanna.
N-4	3 phase fault at Susquehanna 500 kV on the Sunbury 500 kV line with one Susquehanna 500/230 kV transformer breaker pole stuck. Clear remote terminal in primary time. Delayed clearing of Susquehanna.

N-8	3 phase fault at Susquehanna 230 kV on Montour line with stuck west bus breaker. Clear remote terminal in primary time, clear Susquehanna with delay (lose Stanton-Susquehanna #2 230 kV line).
N-9	3 phase fault at Susquehanna 230 kV on Jenkins line with stuck east bus breaker. Primary clearing at remote terminal. Delayed clearing at Susquehanna.
N-10	3 phase fault at Susquehanna 230 kV on the 500/230 kV transformer with stuck west bus breaker pole. Clear two poles in primary time. Primary clearing at remote terminal (Susquehanna 500 kV Switchyard). Clear stuck pole in delayed clearing time (lose Stanton-Susquehanna #2 230 kV line).
N-11	3 phase fault at Susquehanna 230 kV on Harwood #1 line with stuck tie breaker pole. Clear two poles in primary time. Clear stuck pole in delayed clearing time (lose Sunbury-Susquehanna 230 kV line).
N-12	3 phase fault at Susquehanna 230 kV on Harwood #2 line with one pole stuck on west bus breaker. Clear two poles in primary time. Clear stuck pole in delayed clearing time (lose Stanton-Susquehanna #2 230 kV line).
N-14	Susquehanna-Wescosville-Alburtis 500 kV and Susquehanna-Harwood #1 & #2 Double Circuit 230 kV crossing failure (3 phase fault on all circuits). Automatically trip Susquehanna Unit #1. Clear Susquehanna-Wescosville-Alburtis 500 kV line in primary time. Clear Susquehanna- Harwood #1 & #2 230 kV lines in primary time.
N-15	3 phase fault near E. Palmerton on all lines in E. Palmerton-Harwood R/W corridor. Clear Susquehanna-Wescosville-Alburtis 500 kV line in primary time. Primary clearing of E. Palmerton-Harwood and Harwood-Siegfried 230 kV lines.
N-16	3 phase fault near Susquehanna on both lines in Sunbury-Susquehanna R/W corridor. Clear Sunbury-Susquehanna #2 500 kV line in primary time. Primary clearing of Sunbury-Susquehanna #1 230 kV line.

N-17	3 phase fault near Susquehanna 500 kV at Sunbury 230 kV line crossing. Trip Susquehanna – Wescosville-Alburtis 500 kV, Sunbury-Susquehanna #2 500 kV, and Unit #2 in primary time. Trip Sunbury-Susquehanna #1 230 kV in primary clearing time.
N-19	3 phase fault at Columbia-Frackville 230 kV line crossing. Trip Sunbury-Susquehanna #2 500 kV line in primary time. Trip Columbia-Frackville and Sunbury-Susquehanna #1 230 kV lines in primary time.
N-20	3 phase fault on 230 kV side of Unit #1 main transformer. Trip Unit #1 main transformer. Trip Unit #1 and overtrip Unit #2 in primary time.
N-21	3 phase fault at Susquehanna 230 kV on Unit #1 generator leads with a stuck west bus breaker. Trip Unit #1 and Stanton #2 line.
N-23	Sudden loss of all lines from Susquehanna 230 kV Switchyard
N-24	3 Phase fault on Susquehanna-Jenkins 230 kV line 80% towards Jenkins with pilot relaying out. Fault cleared in Zone 2 (backup) time at Susquehanna and Zone 1 time at Jenkins.

FSAR table 8.2-1

Calvert Cliffs Units 1 and 2 (CCNPP) Planning Requirements

Nuclear Plant Voltage Adequacy Studies

At the request of CCNPP, BGE shall perform periodic analysis of expected Calvert Cliffs 500 kV Switchyard post Unit trip voltages. These studies are typically performed on an annual frequency, but could be needed on a more frequent basis. The results of these studies shall be provided to CCNPP by BGE.

Planning and Operations Transmission Studies

PJM planning and operations transmission studies shall incorporate the Calvert Cliffs 500 kV Switchyard voltage, frequency and capacity requirements in switchyard voltage section below. CCNPP shall be notified by the Planning Coordinator (PJM) if planning study results identify that the Calvert Cliffs 500 kV Switchyard requirements are not met by current or future system configurations, load levels, or contingencies. Transmission study violations based on standard PJM criteria testing will be dispositioned in accordance with the applicable PJM agreements and manuals. Resolution of study violations based on criteria that are specific to CCNPP and are beyond standard PJM criteria testing will be CCNPP responsibility. The following Calvert Cliffs 500 kV Switchyard requirements shall be utilized for the planning studies:

Voltage and Offsite Source Load Capacity Requirements: Refer to Section 1 for the voltage and load capacity requirements.

Stability Requirements: Stability studies shall have simulated transmission line faults, the loss of each of the CCNPP main generators, and the loss of the largest generator on the 500 kV system. The studies must show that the transmission system is stable and there will be no cascading transmission outages for the simulated transmission line faults. They must also show continuity of offsite power at the Calvert Cliffs 500 kV Switchyard for the simulated transmission system contingencies by ensuring voltage limits defined in section 1.3 are not violated. CCNPP shall be notified by the Planning Authority (PJM) if the results of system stability studies identify if any of the stability requirements are not met.

Calvert Cliffs 500 kV Switchyard Voltage and CCNPP Frequency Requirements

Operating Voltage Limits for the Calvert Cliffs 500 kV Switchyard

Calvert Cliff Voltage Limits		
Plant Service Transformers (P-13000-2 & P-13000-2)	**Pre-Contingency**	**Post-Contingency**
Both xfmrs in service	500kV – 550kV	475kV – 550kV
Only one xfmr in service	520kV – 550kV	510kV – 550kV

Note: See maximum post-trip voltage drop below for loss of a CCNPP unit.

Calvert Cliffs 500 kV Switchyard Voltage Drop Limit

Maximum post-trip voltage drop (Post-contingency for a single CCNPP unit): Voltage drop of 5% of the pre-trip bus voltage with either one or both P-13000 transformers in service. The 5% post contingency voltage drop limit is to be applied at the Calvert Cliffs 500 kV Switchyard for a contingency trip of CCNPP Unit 1 or Unit 2.

Short Circuit Calculations

BGE and SMECO shall provide to CCNPP available short circuit current data at the points of interconnection, when requested for use in the CCNPP distribution system short circuit calculations.

Beaver Valley Units 1 and 2 Planning Requirements

Nuclear Station Voltage Adequacy studies: Per Service Agreement No. 1668, Schedule F, paragraph 12: "ATSI (American Transmission Systems Incorporated) will perform a probability study, at FENOC's (FirstEnergy Nuclear Operating Company) expense, by June 1 of each year to determine the frequency of grid voltage outside of values identified in this schedule. This study will include expected power flow transfers through the region that would influence grid voltages." Results of the studies are to be provided to FENOC.

Transmission Planning studies: The Transmission Planner shall incorporate the voltage and stability requirements of BVPS. These studies shall include those performed to evaluate future transmission and generation interconnection in accordance with applicable NERC and Regional Entities of NERC standards. Both FENOC (Akron) and the BVPS Design Engineering staff shall be notified if planning study results identify that the BVPS requirements are not met by current or future system configurations, load levels, and contingencies by the Transmission Planner performing the studies. Transmission study violations based on standard PJM criteria testing will be handled by the procedures described in the PJM agreements and manuals. Study violations based on criteria that are specified specifically for BVPS and are beyond standard PJM criteria testing will require remedies that will be the plant owner's responsibility. The following BVPS requirements shall be utilized for the planning studies:

Voltages:

The voltage limit requirements are as stated below.

The Station voltage limits are as follows:

Beaver Valley Switchyard 345kV Voltage Limits

EL (Emergency Low) 341 kV (0.9850 p.u.)

NL (Normal Low) 343 kV (0.9942 p.u.)

NH (Normal High) 355 kV (1.0290 p.u.)

Beaver Valley Switchyard 138kV Voltage Limits

EL (Emergency Low) 131 kV (0.9493 p.u.)

NL (Normal Low) 136 kV (0.9855 p.u.)

NH (Normal High) 142 kV (1.0289 p.u.)

Planning assessments enforce nuclear voltage criteria at the Transmission System level, including any voltage drop criteria. Criteria are enforced on a system normal and post-contingency basis after allowance for full system adjustments that can be available within 30 minutes following a disturbance.

Frequency:

Both BVPS-1 and BVPS-2 require a stable grid frequency of 59.9 to 60.1 Hz.

Stability:

BVPS generating unit stability is to be analyzed according to the applicable NERC, and Regional Entities of NERC, criteria for transient stability. The analyzed contingencies that are evaluated against Beaver Valley's voltage requirements include:

- Loss of a significant generating unit (standard PJM testing)
- Loss of a significant transmission line (standard PJM test), or
- Loss of a Beaver Valley unit (standard PJM test)

BVPS and FENOC (Akron) shall be notified by the Transmission Planner performing the studies if the results of system stability studies identify that any of the stability requirements discussed above are not met.

Cook Unit 1 and 2 Planning Requirements

The following requirements are derived from Cook Plant Design Information Transmittal DIT-B-03036-00. The information in this DIT is to be used to perform transmission studies that support Cook Plant Operation.

This DIT looks at case reports for Mode 1 and LOCA. The purpose is to allow a comparison between plant data and the model (Mode 1) and make adjustments to the model if appropriate. These values will be transmitted to Transmission planning as input for their studies.

Depending on the preferred power line up (split = Transformer #4 and Transformer #5; Transformer #4 only; or Transformer #5 only) different values for transfer must be considered. The "split" lineup will transfer the IA & I B or 2A & 2B busses to Transformer #5 and the IC & ID or 2C & 2D busses to Transformer #4. The transfer includes the associated T-busses. These groups of loads (load groups) are called Division AB and Division CD for each unit. When the preferred power lineup is Transformer #4 only or Transformer #5 only; then both divisions (AB and CD) will transfer to the applicable single transformer. The single transformer load group is called "Entire Plant" and consists of the Division AB and Division CD for a single unit. This DIT also looks at 69kv power requirements.

3. Design Value Determination

3.1. The values determined above are increased to allow increased use of power within the plant and for margin. The amount of the increase was determined by engineering judgement considering weld receptacles and desired margins. All power magnitudes are assumed to be at 0.8 power factor. This is reasonable since the current plant model shows power factor slightly above 0.8.

	Accident Megawatt Load		
	AB Division	**CD Division**	**Entire Plant**
Unit 1	22	22	42
Unit 2	20	24	42.5

3.2. The division power levels should be used for the normal split lineup of the switchyard when the AB division will be powered via transformer 5 and the CD division will be powered via transformer 4. The division power levels cannot be added together to represent the entire plant because the division power values are representative of different plant lineups where depending on which pumps are in service power can be shifted from one division to another. The total power levels should be used when the switchyard is lined up in either the Transformer4 only or transformer 5 only lineups.

4. 69kv System Determination

4.1. Power for the 69kv system is procedurally limited to 600 amperes at the 4kv level for each unit (Ref 4). This power would be in addition to the normal load seen on 69kv. The normal load consists of power to other buildings at the site such as the Training Center and the Visitors Center. Actual power factor is expected to be between 0.8 and 0.9. The value which results in the lowest voltage should be selected for conservatism.

4.2. Since the primary result from determining these values is the evaluation of voltage adequacy and the limitation is an absolute value for current; available power will reduce with available voltage.

4.3. The bounding case of determining minimum adequate voltage will be when system conditions are such that the minimum acceptable voltage results from applying the power allowed at that voltage via the EP (69kv source).

4.4. The lowest allowable voltage is cited in the TRM as 91%.

4.5. The power for the bounding case is 1200*0.91*4160*1.73*pf=7.86*pf (MW)

5. Conclusions for Transmission Planning Studies

5.1. The power transferred to our 34kv system will depend on the lineup of the system. The normal lineup is split so that the AB division will transfer to TR5 and the CD division will transfer to TR4. If either transformer is out of service then the entire unit will transfer to the remaining transformer (TR5 and TR4 only lineups). The following table prescribes the value to be used for transmission studies. The power factor associated with these loads is 0.80.

	Megawatt Load Transferred at Unit Trip		
	AB Division (TR5 split)	CD Division (TR4 split)	Entire Plant (TR5 or TR4 only)
Unit 1	22	22	42
Unit 2	20	24	42.5

5.2. The power that can be transferred to the 69kv system is 7.86* power factor (MW). The power factor between 0.80 and 0.90 which provides the lowest voltages should be selected.

Using the input data described above, periodic planning studies are conducted of the transmission and subtransmission networks surrounding the D. C. Cook Plant to determine worst-case offsite power voltage conditions that could credibly exist during a plant shutdown scenario, as well as minimum and maximum voltage and short circuit levels that may be experienced. These studies determine the impact of the most significant factors including transmission and subtransmission network contingencies, Cook Plant generating unit configurations, status of other generation near Cook Plant, 765 kV switched shunt reactor status, and transmission network power flows and take into account the various possible reserve auxiliary switchyard lineups. Available historic data for EHV flows and voltages is utilized in preparation of power flow models used in the studies and for independent validation of study results.

Typically, planning studies will be requested by Cook Plant personnel and performed by AEP Transmission with results provided to Cook Plant and to PJM Planning.

Voltage Requirement

TABLE 1

Maximum switchyard voltage swing requirements to reset the degraded voltage relays with the Main Generator Synchronized to the Transmission Network and the buse(s) are powered from the Unit Auxiliary Transformer(s) source:

Cook Offsite Power Source	34 kV Switchyard Source Breaker position	345 kV System Swyd Swing Limit (Value @ DGR reset.) % of 345kV				TR4 Tertiary 34.5 kV System Swyd Swing Limit (Value @ DGR reset) % of 34.5kV			
		Unit 1		Unit 2		Unit 1		Unit 2	
		Limit Note 1	**Alarm** Setpoint	**Limit** Note 1	**Alarm** Setpoint	**Limit** Note 1	**Alarm** Setpoint	**Limit** Note 1	**Alarm** Setpoint
TR5 & TR4	BD – Open BE & BC – Closed	**5.0%** Note 3	**4.5%** Note 2	**3.7%** Note 3	**3.2%** Note 2	**5.3%** Note 3	**4.8%** Note 2	**3.6%** Note 3	**3.1%** Note 2
TR5	BD & BE - Closed BC – Open	**1.1%**	**0.6%** Note 2	**0.0%**	**-0.5%** Note 2	N/A	N/A	N/A	N/A
TR4	BD & BC – Closed BE – open	N/A	N/A	N/A	N/A	**4.3%**	**3.8%** Note 2	**2.5%**	**2.0%** Note 2

The BOLDED values indicate the limits and alarm values.

TABLE 2

Maximum switchyard voltage swing requirements to reset the degraded voltage relays with the Main Generator Synchronized to the Transmission Network and the buse(s) are powered from the Reserve Auxiliary Transformer(s) source:

Cook Offsite Power Source	34 kV Switchyard Source Breaker position	345 kV System Swyd Swing Limit (Value @ DGR reset.) % of 345kV				TR4 Tertiary 34.5 kV System Swyd Swing Limit (Value @ DGR reset) % of 34.5kV			
		Unit 1		Unit 2		Unit 1		Unit 2	
		Limit Note 1	**Alarm** Setpoint	**Limit** Note 1	**Alarm** Setpoint	**Limit** Note 1	**Alarm** Setpoint	**Limit** Note 1	**Alarm** Setpoint
TR5 & TR4	BD – Open BE & BC – Closed	**1.6%**	**1.1%** Note 2	**1.1%**	**0.6%** Note 2	**2.4%**	**1.9%** Note 2	**2.0%**	**1.5%** Note 2
TR5	BD & BE - Closed BC – Open	**1.0%**	**0.5%** Note 2	**0.7%**	**0.2%** Note 2	N/A	N/A	N/A	N/A
TR4	BD & BC – Closed BE – open	N/A	N/A	N/A	N/A	**1.5%**	**1.0%** Note 2	**1.1%**	**0.6%** Note 2

The BOLDED values indicate the limits and alarm values.

North Anna Units 1 and 2 Planning Requirements

The Dominion System Operator must notify the station in a timely manner if any of the GDC-17 limits stated in item 1 above may potentially be impacted by the results of Operations Planning studies.

It is the responsibility of Transmission Planning to develop a long-range transmission plan which provides for orderly and timely modifications to the transmission system in order to insure an adequate, economical and reliable supply of electric power. The system must be planned, designed, and constructed to operate reliably within thermal, voltage, and stability limits. Dominion's Transmission Planning performs a wide variety of specific studies to ensure the GDC-17 requirements are met.

These include:

- Power Flow Studies
- Stability Studies

PJM and Dominion Electric Transmission Planning will design the system to meet the GDC-17 requirements. Steady state voltage limits will use the "Emergency Limit Low" and "Emergency Limit High" voltage limits of section 1. Only the following contingency scenarios will be evaluated:

Transmission Condition	Unit 1	Unit 2
All lines in	On	On
All lines in	Trip	On
All lines in	On	Trip
All lines in	Trip	Trip
Worst case N-1 contingency	On	On
Worst case N-1 contingency	Trip	On
Worst case N-1 contingency	On	Trip

PJM/Dominion Electric Transmission Planning will notify Dominion Nuclear of any NPIR criteria violations. Transmission study violations based on standard PJM/Dominion planning criteria will be handled through the normal planning processes described in the PJM agreements and manuals. Upgrades for study violations based on the more stringent Dominion Nuclear NPIR criteria will be the responsibility of the plant owner.

Voltage Limits:

The NAPS 500 kV switchyard voltage must be maintained between 505kV and 535 kV to ensure compliance with GDC-17 voltage analysis. The Dominion System Operator must notify the station in a timely manner (within 15 minutes) when one of the following conditions occurs:

- The 500 kV or 230 kV voltage or frequency limits are exceeded, and the steps taken or being taken to mitigate the exceeded limit.

Bus Name	Normal Limit Low	Emergency Limit Low
500 kV	510.0 kV (1.02 pu)	505.0 kV (1.01 pu)
230 kV	226.3 kV (0.984 pu)	224.0 kV (0.974 pu)

Bus Name	Normal Limit High	Emergency Limit High
500 kV	530.0 kV (1.06 pu)	535.0 kV (1.07 pu)
230 kV	239.2 kV (1.04 pu)	242.0 kV (1.052 pu)

Bus Name	Normal Voltage Drop	Emergency Voltage Drop
500 kV	3.5 %	3.5 %
230 kV	3.5 %	3.5 %

Bus Name	Frequency Limit Low	Frequency Limit High
500 kV	59.5 Hz	60.5 Hz
230 kV	59.5 Hz	60.5 Hz

- A contingency analysis study indicates the normal or emergency limit for the station will be exceeded if a single contingency occurs and the Transmission Operator cannot effectively mitigate the condition to avoid the violation.
- Both the Dominion and the PJM Real Time Contingency Analysis (RTCA) are not available.
- The real time telemetry between Dominion System Operator and the station is known to be out of service.
- The system conditions return to normal.

Surry Units 1 and 2 Planning Requirements

The Dominion System Operator must notify the station in a timely manner if any of the GDC-17 limits stated in item 1 above may potentially be impacted by the results of Operations Planning studies.

It is the responsibility of Transmission Planning to develop a long-range transmission plan which provides for orderly and timely modifications to the transmission system in order to insure an adequate, economical and reliable supply of electric power. The system must be planned, designed, and constructed to operate reliably within thermal, voltage, and stability limits. Dominion's Transmission Planning performs a wide variety of specific studies to ensure the GDC-17 requirements are met. These include:

- Power Flow Studies
- Stability Studies

PJM and Dominion Electric Transmission Planning will design the system to meet the GDC-17 requirements. Steady state voltage limits will use the "Emergency Limit Low" and "Emergency Limit High" voltage limits of section 1. Only the following contingency scenarios will be evaluated:

Transmission Condition	Unit 1	Unit 2
All lines in	On	On
All lines in	Trip	On
All lines in	On	Trip
All lines in	Trip	Trip
Worst case N-1 contingency	On	On
Worst case N-1 contingency	Trip	On
Worst case N-1 contingency	On	Trip

PJM/Dominion Electric Transmission Planning will notify Dominion Nuclear of any NPIR criteria violations. Transmission study violations based on standard PJM/Dominion planning criteria will be handled through the normal planning processes described in the PJM agreements and manuals. Upgrades for study violations based on the more stringent Dominion Nuclear NPIR criteria will be the responsibility of the plant owner.

Voltage Limits:

The SPS 500 kV switchyard voltage must be maintained between 505 kV and 535 kV to ensure compliance with GDC-17 voltage analysis. Similarly, the 230 kV switchyard voltage must be maintained between 220 kV and 245 kV. The Dominion System Operator must notify the station in a timely manner (within 15 minutes) when one of the following conditions occurs:

- The 500 kV or 230 kV voltage or frequency limits are exceeded, and the steps taken or being taken to mitigate the exceeded limit.

Bus Name	Normal Limit Low	Emergency Limit Low
500 kV	510.0 kV (1.02 pu)	505.0 kV (1.01 pu)
230 kV	222.3 kV (0.967 pu)	220.0 kV (0.957 pu)

Bus Name	Normal Limit High	Emergency Limit High
500 kV	530.0 kV (1.06 pu)	535.0 kV (1.07 pu)
230 kV	239.2 kV (1.04 pu)	245.0 kV (1.065 pu)

Bus Name	Normal Voltage Drop	Emergency Voltage Drop
500 kV	4.5 %	4.5 %
230 kV	6.0 %	6.0 %

Bus Name	Frequency Limit Low	Frequency Limit High
500 kV	59.67 Hz	60.33 Hz
230 kV	59.67 Hz	60.33 Hz

- A contingency analysis study indicates that the normal or emergency limit for the station will be exceeded if a single contingency occurs and the Transmission Operator cannot effectively mitigate the condition to avoid the exceeded limit.
- Both the Dominion and the PJM Real Time Contingency Analysis (RTCA) are not available.
- The real time telemetry between Dominion System Operator and the station is known to be out of service.
- The system conditions return to normal.

Hope Creek Unit Planning Requirements

Transmission Planning (PJM)

Hope Creek Generating Station, operating in the PJM controlled bulk electric system requires periodic transmission planning studies to be performed to ensure onsite power systems remain connected to the offsite power sources during grid transients or a unit trip of Hope Creek or the adjacent Salem generating units.

Periodic analysis of the expected Hope Creek switchyard voltage and voltage drop following a unit trip shall be performed for various transmission system load levels and contingencies.

Studies shall also be performed, as needed, to evaluate the effect that future proposed modifications or changes to the transmission system may have on Hope Creek offsite power source limits.

PSEG Nuclear shall be notified if any of the above planning studies identify that the Hope Creek requirements stated in Section 1 are not met by current or future configurations, load levels, and /or contingencies.

Transmission Planner organization shall provide the 500kV System Equivalent Impedances (min and max) at the Hope Creek switchyard whenever transmission planning studies are performed or as requested by the generating station.

Voltage Limits

Hope Creek Generating Station is analyzed to operate within the following voltage limits:

Emergency Low: 493 KV (0.986 p.u.)

Normal Low: 500 KV (1.000 p.u.)

High Limit: 550 KV (1.100 p.u.)

Voltage Drop Requirements

Hope Creek Generating station has been analyzed for a maximum allowable offsite voltage drop at the station following a unit trip and the worst case post trip accident loading.

2.5% Voltage Drop

Stability Requirements

Hope Creek Generating Station is operated in close proximity with the PSEG Nuclear Salem Units 1 and 2 generating stations and has been analyzed for stability for the following faults provided the station is operated per the Artificial Island Operating Guide (AIOG) A-5-500-EEE-1686:

1. Loss of Hope Creek Generator.
2. Loss of most critical Generating Unit on the Grid
3. Loss of the Most Critical Transmission Line

The Transmission Operator, Transmission Planner and PSE&G Transmission Owner are required to incorporate the requirements of the latest revision of the Artificial Island Operating Guide A-5-500-EEE-1686, into all future stability studies, and provide PSEG Nuclear with at least 24 months notice of any violations to the guide due to future system modifications which could impact generation output at Artificial Island.

Salem Units 1 & 2 Planning Requirements

Transmission Planning (PJM)

Salem Generating Station, operating in the PJM controlled bulk electric system requires periodic transmission planning studies to be performed to ensure onsite power systems remain connected to the offsite power sources during grid transients or a unit trip of Salem or the adjacent Hope Creek generating units.

Periodic analysis of the expected Salem switchyard voltage and voltage drop following a unit trip shall be performed for various transmission system load levels and contingencies.

Studies shall also be performed, as needed, to evaluate the effect that future proposed modifications or changes to the transmission system may have on Salem offsite power source limits.

PSEG Nuclear shall be notified if any of the above planning studies identify that the Salem requirements stated in Section 1 are not met by current or future configurations, load levels, and /or contingencies.

Transmission Planner organization shall provide the 500kV System Equivalent Impedances (min and max) at the Salem switchyard whenever transmission planning studies are performed or as requested by the generating station.

Voltage Limits

Salem Generating Station is analyzed to operate within the following voltage limits:
Emergency Low: 493 KV (0.986 p.u.)
Normal Low: 500 KV (1.000 p.u.)
High Limit: 550 KV (1.100 p.u.)

Voltage Drop Requirements

Salem Generating station has been analyzed for a maximum allowable offsite voltage drop at the station following a unit trip and the worst case post trip accident loading.

2.0% Voltage Drop

Stability Requirements

Salem Units 1 and 2 are located in close proximity with the PSEG Nuclear Hope Creek generating station and have been analyzed for stability for the following faults provided the station is operated per the Artificial Island Operating Guide (AIOG) A-5-500-EEE-1686:

1. Loss of One Salem Nuclear Unit
2. Loss of Largest Generating Unit on the Grid
3. Loss of the Most Critical Transmission Line

The Transmission Operator, Transmission Planner and PSE&G Transmission Owner are required to incorporate the requirements of the latest revision of the Artificial Island Operating Guide A-5-500-EEE-1686, into all future stability studies, and provide PSEG Nuclear with at least 24 months notice of any violations to the guide due to future system modifications which could impact generation output at Artificial Island

G.10 NERC Standard PRC-023 – Transmission Relay Loadability

Background

The purpose of the standard is to ensure that protective relay settings shall not limit transmission loadability; not interfere with system operators' ability to take remedial action to protect system reliability and; be set to reliably detect all fault conditions and protect the electrical network from these faults. There are a number of requirements that specify how protective relays should be set so that they will not limit loadability of a circuit. One of the requirements of the Standard (R3) is for the Planning Coordinator to identify the 100 kV to 200 kV facilities that must meet Requirement 1of the standard to prevent potential cascade tripping that may occur when protective relay settings limit transmission loadability. The Planning Coordinator shall have a process to determine the facilities that are critical to the reliability of the Bulk Electric System, maintain a current list of facilities determined according to the process, and provide the list of facilities to its Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within 30 days of establishment of the initial list and within 30 days of any changes to the list.

As part of the development of the RTEP each year PJM staff will perform analysis to determine what facilities may be susceptible to cascading. The test will determine if the simultaneous loss of two independent[5] BES elements (without intermediate system adjustments) results in a 100 kV – 200 kV facility being loaded in excess of 115% of its emergency rating and the loss of that overloaded facility results in additional overloaded BES facilities. If there are additional overloaded BES facilities loaded in excess of their emergency rating, the 100 kV – 200 kV element that was overloaded after the initial N-1-1 will be identified as needing to meet the requirements of the standard.

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[5] Note that this test methodology is beyond the current requirements of NERC Standard TPL-003 given the standard evaluates common mode failures (i.e. loss of a double circuit tower line, bus, or circuit breaker failure) that result in the loss of two or more facilities. Category C3 in Table 1 of the standard evaluates the loss of independent BES elements however system adjustments can be made following the loss of the first facility.

Attachment H: Power System Modeling Data

H.1 Power System Modeling Data

Accurate power system modeling data is a key component of quality power system analysis. PJM System Planning uses a variety of models and analytical techniques to create and maintain the simulation models used for the RTEP studies. The intended use of this Attachment is to supplement existing documentation by PJM and other entities that specify accurate modeling data requirements. PJM will continue to follow the data guidelines and standards set forth by NERC as part of the MOD standards and the Eastern Interconnection Reliability Assessment Group (ERAG) Multiregional Modeling Working Group (MMWG) Procedural Manual.

H.1.1 Load Flow Analysis Models

Base case creation is a collaborative process between PJM and its members. From a technical standpoint PJM follows the guidelines set forth in the ERAG MMWG Procedural Manual. In the following sections, the logistics and transfer of information between PJM and its members are detailed.

Annual Updates

In the fourth quarter of each year, PJM will distribute to the Transmission Owners a current year +5 summer peak network model based on the most up to date MMWG case combined with the previous year's RTEP case. This draft case will contain all upgrades identified during the previous year's RTEP cycle. Within 4 weeks of receiving the initial draft network model, Transmission Owners will provide:

- Network updates to the model that will advance the case to represent a current year + 5 base case with respect to the 1st Quarter of the following year. This update should be reviewed for correctness and compatibility with the final version of the base case under development
- Complete NERC category B and C contingency file updates that correspond to the updated network model (Include any contingencies which may not change the poweflow model, but change contingency definitions)
- Maximum credible disturbance (NERC Category D) contingencies
- Any other significant changes such as new load or block load additions
- Support, if necessary, for the development of network models for additional years and demand levels for both near term (years 1 through 5) and longer term (beyond 5 years) analyses.
- Verification that all baseline, network and supplemental upgrades are included in the updated case along with a written description of any case modifications.
- Notification of any changes to tie lines whether they are ties internal to PJM or to external companies.

Generation Owner Requirements:

- Specific information regarding generator capability per MOD 10 and MOD 12

H.1.2 Load Flow Modeling Requirements

In addition to the guidelines set forth by NERC and the ERAG MMWG procedural manual, PJM uses several specific procedures in establishing the base case so that it represents the best starting point for the annual RTEP analysis.

Generator step-up transformers

Generator models should represent the physical plant lay-out to the extent possible, explicitly modeling generator step-up transformers (GSUs) and Station Service loads (aka Auxiliary loads). This applies to units above 20 MW and connected to the BES system, consistent with BES requirements. Plants consisting of multiple units aggregating to 75 MW or more also require explicit representation of GSUs and station service loads.

Interchange

The PJM net interchange in the summer peak case is determined by the firm interchanges that are represented in the PJM OASIS system. The interchange in light load cases follows the light load criteria as defined in the Light Load Reliability Analysis in section 2.3.10 of this manual.

Generator Reactive Capability

Annually, PJM updates the model for the generator reactive capability (GCAP) of each generator based on data used by PJM Operations, which includes default limits obtained from the most up to date d-curves as well as data provided by the Generator Owners.

Interconnection Projects With Interconnection Service Agreements (ISAs)

PJM includes queue projects with a signed ISA into the base case as well as verifying the accuracy of queue projects that have not yet signed an ISA. PJM also includes the interconnection, ratings and associated upgrades for each of these projects. Transmission Owners will verify the accuracy of the points of interconnection and the associated upgrades in their zones.

Real and Reactive Load

Each TO is responsible for modeling the active (real) and reactive load profile in its zone. PJM will scale the load in each zone to the targeted values reported in the latest annual PJM load forecast report.

Real loads will be scaled uniformly in each zone to meet the PJM 50/50 load forecast less any Demand Response (DR), Energy Efficiency (EE), or Behind the Meter (BTM) generation as necessary. Real loads will also be scaled uniformly within each zone for off-peak analysis. Reactive load in each area will be scaled at a constant power factor along with the real load for peak load analysis. For off-peak analysis including light-load, PJM will provide a case to the Transmission Owners, at their discretion, for updating their zonal reactive load profile.

Any deviation from the above method of load modeling method, associated with specific test procedures such as the PJM Load Deliverability Procedure or the PJM Light Load Reliability Test Procedure will be defined specifically in other sections of this manual.

PJM will coordinate with TOs on an individual basis to ensure that non-conforming loads are properly modeled and not uniformly scaled.

Voltage Schedules

The setting of voltage schedules is crucial to the robustness of cases. PJM allows Transmission Owners to supply generator voltage schedule data. If the data is not provided PJM will use the default voltage schedules as defined in PJM Manual 03.

H.1.3 Submittal of Load Flow Data

Acceptable Data Formats

- For PSS/E users, cases should be submitted to PJM in a ".SAV" format in a PSS/E version that is readable by the current version of PSS/E that MMWG is using.
- For users of PSLF or other modeling software, cases shall be submitted to PJM in a ".RAW" format that is PSS/E compatible and is readable by the current version of PSS/E that MMWG is using.
- PJM's migration of PSS/E versions may slightly lag MMWG, in that case it is acceptable to provide updates formatted for the current version that PJM is using.
- TO's can submit data in an agreed to version if they are unable to export to the latest MMWG compatible version.

Timing

Transmission Owners must comply with the schedule dictating the timeliness of the case creation process which will be included in the initial email sent to kick off the process. This schedule will include a minimum of 4 weeks to provide updates to the case and corresponding files for the first iteration, and 2 weeks for the second iteration.

Load Flow Data Quality

- In the event that data provided by Transmission Owners does not pass all of the testing included in the MMWG data checker, PJM may request updated data.
- Transmission Owners must provide unique bus names or circuit ID's for each winding of all transformers.
- Bus numbers must be within the allocated bus number range for each company.
- Conventions used for the naming of Machine ID's vary for different TO zones. PJM will coordinate with each TO individually to align with their preferred convention.

- Certain specific modeling and naming conventions which must be followed by all TO's include:
  - High/Low Pressure units should be modeled on the same bus and designated with the corresponding machine ID "H" and "L".
  - No other machine ID should be named "H" or "L".
  - With the exception of High/Low Pressure units, multiple machines modeled on the same bus must have the same status. Offline machines should not be modeled on the same bus as machines which have a status of online.
  - Machines at the same plant with different statuses should be modeled on separate busses connected by a very low impedance line (X=.002) as defined in the MMWG manual.

H.1.4 Short Circuit Analysis Models

Short Circuit data procedures are documented in the Attachment G.7 of this manual, which references ANSI/IEEE 551. The intended use of this attachment is to supplement these procedures and outline the data requirements which PJM follows in creating the short circuit cases used for analysis.

- Short circuit models should be provided in Aspen ".olr" format, if possible.
- Each TO provided Aspen ".OLR" case should model only the TO area and its tie lines. No outside areas should be included in the submission.
- All area numbers in the TO provided cases should be consistent with MMWG designated area numbering convention. Area numbers such as 1, 2, 3, etc. are not acceptable.
- Generation owners must submit to PJM all their breaker data for breakers rated above 100 kV.
- Transmission Owners must submit an excel sheet containing explanations for outaged and out-of-service equipment that is normally in-service.

Timing

In the 1st quarter of each year, PJM will send the Transmission Owners an initial current year +5 impedance network model. This case is based on the most up to date PJM short circuit case combined with the previous year's RTEP case containing all upgrades, MTX projects, and generation queue projects in the Facility Studies Phase that have been identified during that RTEP cycle.

In the 4th quarter of each year, PJM will send the Transmission Owners an initial current year +1 impedance network model. This case is based on the most up to date PJM short circuit case combined with the previous year's RTEP case containing all upgrades, MTX projects, and generation queue projects in the Facility Studies Phase that have been identified during that RTEP cycle.

Transmission Owners must comply with the time schedule of the case creation process which will be included in the initial email sent to kick off the process. This schedule will include a minimum of 4 weeks to provide updates to the case and corresponding files. Once all cases and corresponding files have been submitted to PJM, a +1 case is created and analysis performed to determine overdutied breakers. TOs are then given another 4 weeks to confirm any new overdutied breakers. After the +1 year short circuit case is finalized, the +1 year case is then used to create the+5 year short circuit case for performing the short circuit studies and identifying the new system issues. The identified issues will be sent out to the Transmission Owners who will have 4 weeks to provide solutions to address these issues.

H.1.5 Stability Analysis Models

The case used for stability and dynamic studies is developed by PJM based on information from the Regional Transmission Expansion Plan (RTEP) case prepared by PJM Interconnection and the MMWG case prepared by Powertech Labs for the Eastern Interconnection Reliability Assessment Group (ERAG).

When preparing the base case for stability and dynamics, the ERAG case provides the information for the areas outside PJM while the RTEP case provides the PJM information (e.g. load forecast, network configuration). When combining the ERAG and the RTEP cases, care should be taken to preserve the ties between the PJM areas and the rest of the Eastern Interconnection.

All generator projects active in the PJM queue process that have been studied must be included in the base case for stability and dynamics. In some instances, the RTEP model for the queue project may not be detailed enough for use in stability studies. In this situation, the case must be updated to make sure that all detailed components associated with this project are included in the stability and dynamics power flow model (e.g. generator step-up transformer, loads).

In addition to updating the power flow case with the latest network information, the dynamic models must also be updated to reflect the changes introduced by the RTEP case and the stability and dynamic studies performed by PJM. In this regard, the dynamic data file from the ERAG MMWG case is updated so that the dynamic models for the generators in the PJM areas are matched against the new power flow information from the RTEP. The dynamic model for each queue generator must also be added to the dynamic data file.

The resulting power flow case, the dynamic data file and supporting files required for a complete stability and dynamics base case need also to be correlated and reviewed to determine inconsistencies as well as missing or questionable data. A base case is considered to be finished when, after the review, it compiles, links the models to the PSS/E main structure and initializes correctly. An acceptable condition for a finished base case is when simulated system dynamics, using this case, do not deviate from the initial conditions for any simulation setup with no disturbances applied to the system.

Timing

In the first quarter of each year, PJM will build stability cases based on the latest RTEP power flow model and the latest ERAG dynamic cases. In this period, PJM will request the Transmission Owners for load models for dynamic studies, and for other supporting data if necessary. Transmission Owners must comply with the time schedule of the stability case creation process which will be included in the initial email sent to kick off the process.

Stability and dynamics base cases:

Stability is assessed using a summer peak load and a light load condition. The summer peak stability case has the load profile of the RTEP summer peak case and corresponds to the demand expected to be served in the specific planning year. The light load stability case represents 50% of the summer peak load and is developed by scaling down the summer peak load case at the same power factor.

For simplicity, it is recommended to first build the summer peak case and then update that case to reflect the second load condition (light load). This approach provides two cases that are common in bus numbers and network information. Updates to both cases, such as addition or removal of proposed lines or queue projects would be easy to handle due to the uniformity.

After the power flow case has been finalized and revised, the dynamic data file from the dynamic data file will be updated to reflect the changes that were introduced by the addition of the PJM areas from the RTEP case and generation interconnection studies. It is important to note that the RTEP case and the ERAG case complement each other. RTEP case information is used for future generation queue projects and transmission upgrades which don't exist in the ERAG case and ERAG case consists of information of existing units.

The light load case (50% peak) is derived from the summer peak case. This approach ensures consistent bus numbers and network information in both cases, making addition or removal of proposed lines or queue projects easy to handle. After the summer peak case is completed, the PJM load is scaled down to a load representing 50% of the 50/50 load. The areas outside PJM are updated with the light load case from the corresponding ERAG MMWG case. Note that generation and shunt capacitors may be turned off or disabled in order to achieve convergence of the power flow. In addition, all pumped storage hydro units are modeled in the pumping mode with their governors and power systems stabilizers deactivated or adjusted to reflect the appropriate operating condition.

Generation/Transmission Owner Responsibilities:

- Provide necessary supporting data for stability case build upon PJM's request including but not limited to: topology information and dynamic modeling and station loads
- Provide station loads, including power factors and load representation data (CONL file) if the load representation is different from the one in the ERAG MMWG series
- Verify upgrades and generator modeling (MVA base & Topology)

If there is any discrepancy between the RTEP case and the ERAG MMWG case for existing units, PJM will follow up with the Generation owner with assistance from the TO to insure that the most current data is used.

A complete base case (summer peak or light load) must include at least:

- A power flow file: This file contains the network information and provides the initial conditions for the dynamic models.
- A dynamic data file: This file contains all the information necessary to simulate the dynamic response of the various system components.

- A gnet file: This file contains the information of those generators that do not have a dynamic model. Any generator listed in this file is considered as a negative MVA load.
- A conl file: This file indicates how loads will be modeled based on a combination of constant MVA, constant current and constant admittance. It is strongly recommended that each TO develop more accurate load representation for stability and dynamics studies

Dynamics Data Submittal Requirements and Guidelines:

The Multiregional Modeling Working Group (MMWG) provides the following topics pertaining to dynamics data submittal requirements and guidelines. This information is accessible in Appendix II of the MMWG Procedure Manual V5. A hyperlink to the manual is located at the bottom of this section.

- Power Flow Modeling Requirements
  - Bus name identifiers for synchronous condensers, Static VAr Compensators (SVCs) modeled as generators, switched shunts, relays, and HVDC terminals.
  - Step-up transformer representation requirements for both MMWG power flow cases and non-MMWG power flow cases.
  - Resistance and reactance data placements for step-up transformers represented in the power flow generator data records.
  - Xsource value representations in the power flow generator data record.
  - SVC representation requirements in power flows.
- Dynamic Modeling Requirements
  - Synchronous generator and condenser modeling / associated data requirements and exceptions.
  - Additional representation requirements and exceptions for synchronous generators and condensers modeled as described in Requirement II.1.
  - PSS/E modeling requirements for any other types of generating units and dynamic devices.
  - Exceptions to the use of standard PSS/E dynamic models.
  - Required written documentation and its submittal procedures for user-defined modeling in MMWG cases.
  - Generating unit, synchronous condenser, and other dynamic device requirements for netting.
  - Lumping conditions of similar or identical generating units at a plant.
  - Location requirements for per unit data.
  - Exception procedure for any requirements listed.

- Dynamics Data Validation Requirements
    - Dynamics data screening requirements
    - Preliminary procedures to undergo before regional data submittal to the MMWG coordinator.
    - Material required by each region to validate the dynamics model.
- Guidelines
    - Additional documentation that should be submitted with dynamics data.
    - Information pertaining to parameters for representing loads via the PTI PSS/E CONL activity that the regions should provide to the MMWG.

Location of MMWG Procedural Manual:

https://rfirst.org/reliability/easterninterconnectionreliabilityassessmentgroup/mmwg/Documents/

Revision History

Revision 18 (7/20/2011):

- Added Light Load Reliability Analysis criteria and created a new attachment D-2 to contain the criteria.
- Added description of reactive load modeling in CETL base cases.

Revision 17 (4/13/2011):

- Added references where appropriate to reflect the inclusion of the American Transmission Systems, Inc. (ATSI) and Cleveland Public Power (CPP).
- Clarified the methodology to establish an IROL in the Planning Horizon.
- Updated the short circuit methodology to include the existing process to study all BES breakers.

Revision 16 (11/18/2010):

- Added a Contingency Definitions section (10/20/2010 MRC approval)
- Added Appendix G.10 NERC Standard PRC-023 – Transmission Relay Loadability (10/20/2010 MRC approval)
- Modified PJM Critical Energy Infrastructure Information Release Guidelines (08/05/2010 MRC approval)
- Added clarifying language to Baseline Voltage Analysis test methodology (08/05/2010 MRC approval)Updated the IROL definition to align with the latest NERC IROL definition (08/05/2010 MRC approval)

Revision 15 (04/21/2010):

- Added new Attachment F describing PJM stability, short circuit and special RTEP practices and procedures. This Attachment includes the special requirements for coordination of planning for nuclear interfaces

Revision 14 (02/01/2010):

- Attachment C: Added language to specify how energy efficiency is incorporated into deliverability tests. Added additional language to specify the load level modeled in the load deliverability test for the area being tested. (1/22/10 MRC Approval)

Revision 13 (11/16/2009):

- Inserted Commercial Probability technique in Attachment C, Generator Deliverability Procedure Step 5 (10/2/08 MRC approval)
- Added Attachment F: Determination of System Operating Limits for Planning the Bulk Electric System (06/17/09 MRC approval)

- Attachment C: Cap on generation delivery adders (12/21/09 MRC approval)
- Attachment C: Added language to Overview of Deliverability to Load to clarify criteria that may trigger analysis of potential new LDAs (11/11/09 MRC approval)
- Updated hyperlinks throughout the manual
- Temperature correction and clarification to Attachment B Section VII.N.

Revision 12 (08/08/2008)

The following revisions primarily consist of additions, clarifications and reorganization to address FERC Order No. 890 requirements:

- Additions to Section 1 to update, clarify, and expand the RTEP overview.
- Combine old Sections 6 and 2 into an expanded Section 2.
- Move wind, power factor and behind the meter generation material to a reconstituted Section 6
- Include additional reliability planning process and criteria information
- Market Efficiency Process revisions (section 2 and Attachment E) plus additional editorial and consistency changes throughout including Attachments D, E, and G.
- Added Exhibit 1 edits to Intro, Sections 1, 2, related attachments
- Multiple passes of CEII revisions.
- Generation Delivery clarifications in Attachment C.
- Removed the final material in Section 2 that is related to Interconnections to Manual 14A and revised the remaining material appropriately for Manual 14B.
- Exhibit 1 update for quarterly queues
- Attachment D criteria clarifications
- Added final RPPWG comments of Nov 30, 2007 meeting, added minor clarifications, and cut material to move to the appropriate generation or transmission interconnection related portions of revised 14A and 14E as to be determined. Sections deleted from here and moved to either 14A or 14E are: (the following attachment designations are according to the previous version Manual 14B lettering)
- Moved Section 3: Generator and Transmission Interconnection Planning Process
- Generation and Transmission Interconnection Feasibility Study
- System Impact study
- Generation and Transmission Interconnection Facilities Study

- Moved Section 4: Small Resource Interconnection Process
- Moved Section 5: Interconnection Service, Construction & Other Service Agreements
- Moved Section 6: Additional Generator Requirements
- Behind The Meter Generation Projects
- Generator Power Factor Requirements
- Wind-Powered Generation Projects
- Moved Attachment A: PJM Generation and Transmission Interconnection Planning Process Flow
- Attachment B: PJM Cost Allocation Procedures
- Moved PART 1: PJM GENERATION AND TRANSMISSION INTERCONNECTION COST ALLOCATION
- Moved Attachment C : PJM Generation and Transmission Interconnection Planning Team Role Diagram
- Moved Attachment F: General Description of Facilities Study Procedure
- Moved Attachment H: Small Generator (10 MW and Below) Technical Requirements and Standard
- Moved Attachment H-1: Small Generator (above 10 MW to 20 MW) Technical Requirements and Standards
- Moved Annex 1: SCADA Requirements by Transmission Owner Region

Revision 11 (10/05/2007)

The Manual Title has been changed. The RTEP process has evolved over the past 5+ years and so has the scope of Manual 14B. The title of the manual has been changed from "Generation and Transmission Interconnection Planning" to "PJM Regional Planning Process"

Section 6 and Attachment I have been revised to reflect the implementation of the 15-year horizon component of PJM's Regional Planning Process cycle, including that for market efficiency. These changes are made in accordance with the mmm, dd 2006 FERC approval of PJM's subject Operating Agreement and Open Access Transmission Tariff (OATT) revisions.

Conforming editorial revisions have been made throughout the remainder of the document.

Revision 10 (03/01/2007)

- Attachment B: Regional Transmission Expansion Plan revised to include steps for reactive planning in the RTEP.
- Revised hyperlinks in Attachment D: PJM Reliability Planning Criteria.

- Attachment H: Small Generator (10 MW and Below) Technical Requirements and Standards replaces former attachment on Small Generators of 2 MW and less.
- Attachment H-1: Small Generator (above 10 MW to 20 MW) Technical Requirements and Standards added.
- References to PJM OATT provisions in Sections 2 and 5 are revised to indicate that they are now in the new Part VI of the OATT (along with their former Part IV locations)
- Wording in Section 2 under "Summary of RTEPProcess" and again in Attachment E is revised to reflect that generation retirements included in project studies will be those announced as of the date a project enters the project queue.
- Introduction trimmed to eliminate redundant information.
- List of PJM Manuals exhibit removed, with directions given to PJM Web site where all the manuals can be found.
- Revision History permanently moved to the end of the manual.

Revision 09 (06/07/06)

Manual sections 1 and 2 and Attachment B (Regional Transmission Expansion Plan – Scope and Procedure) are revised to include Probability Risk Analysis (PRA) of Aging Infrastructure as an input to the PJM Region transmission planning process. The timeline in Section 5 is revised to require the Transmission Owner to submit a final invoice to PJM within 120 days after project completion. Attachment B (Regional Transmission Expansion Plan – Scope and Procedure) is also revised to add guidelines for Scenario Planning. Replaced references throughout to "ECAR, MAAC and MAIN" with ReliabilityFirst, the new replacement regional reliability council as of January 1, 2006.

Revisions were made on the following pages: 8, 10, 12 through 16, 23, 24, 41, 56, 62, 63, 65, 67, 68 and 98.

Revision 08 (01/16/06)

Section 1 is revised to state that all analyses of Transmission System adequacy are conducted using the load forecast produced annually by PJM. Attachments E and G are revised to state that load is modeled in the RTEP base case used for the Generator Deliverability procedure at a "non-diversified" 50/50 summer peak load level as per the latest load forecast.

Revision 07 (01/04/06)

Section 2 is revised to add process for "Evaluation of Operational Performance Issues." Attachment A is revised to clarify the Load Flow Cost Allocation Method and to add the Schedule 12 Cost Allocation process. Attachment C is revised to include references to Dominion and to add Addendum 2 "Common Mode Outage Procedure" to the Generator Deliverability Procedure. Attachment D is revised to include a minimum power factor for system "load".

Revision 06 (11/21/05)

Section 2 is revised to indicate that "One RTEP baseline regional plan will be developed and approved each year" and that "Generation retirements will not affect the study results" for any project that has received an Impact Study Report. Attachment B is revised to clarify and expand the scope and procedure of the Regional Transmission Expansion Planning Process.

Revision 05 (06/23/05)

Revision includes a change in Section 6 to include reference to new Attachment E, re-writes of Attachment C (**PJM Deliverability Testing Methods**) and Attachment D (**PJM Reliability Planning Criteria**) and the addition of new Attachment E (**Economic Planning Process, Congestion Relief Evaluation**).

Revision 04 (12/17/04)

Revision includes the changes in Sections 2 and 4 necessitated for compliance with FERC Order 2003 for standardized Generator Interconnection Agreements and Procedures, re-write of Attachment F: Facilities Study Guidelines, re-write of Attachment D: PJM Reliability Planning Criteria, and the addition of Attachment H: Small Generator (2MW or less) Technical Requirements and Standards.

Revision 03 (06/08/04)

Revision includes the addition of rules for Generator Power Factor Requirements and Behind the Meter Generation in Section 2, the designation of small resources as 20 MW or less in Section 4, the addition of the Economic Planning Process in Section 6 and general updates.

Revision 02 (10/31/03)

Revision includes the addition of Wind-Powered Generator Specific Requirements to Section 2, a placeholder for the addition of the Economic Planning Process in new Section 6 (currently under development) and the addition of Attachments D (**Regional Transmission Expansion Plan – Scope and Procedure**), E (**PJM Deliverability Testing Methods**), F (**General Description of Facilities Study Procedure**) and G (**PJM Reliability Planning Criteria**); also, text changes throughout to conform with Nuclear Plant Licensee Final Safety Analysis Report grid requirements and with new Manual M-14E (**Merchant Transmission Specific Requirements** – also currently under development).

Revision 01 (02/26/03)

Revision includes a manual title change from PJM Manual for **Generation Interconnection Transmission Planning (M-14B)** to PJM Manual for **Generation and Transmission Interconnection Planning (M-14B)**; also, text changes throughout to conform to new Manuals M-14C and M-14D.

Revision 00 (12/18/02)

This document is the initial release of the PJM Manual for **Generation Interconnection Transmission Planning (M-14B)**.

Manual M-14, Revision 01 (03/03/01) has been restructured to create five new manuals:

M-14A: "Generation Interconnection Process Overview"

M-14B: "Generation Interconnection Transmission Planning"

M-14C: "Generation Interconnection Facility Construction"

M-14D: "Generation Operational Requirements"

M-14E: "Merchant Transmission Specific Requirements"

Kentucky Power Company

REQUEST

Please supply a copy of the PJM transmission reliability criterion.

RESPONSE

Please refer to Section 1.5 in Attachment 2 (PJM Manual 14B) included in the answer to Question No. 7.

Kentucky Power Company

REQUEST

Please supply a copy of the 10-year KP summer and winter coincident peak load projections used for the analysis of the need of the proposed facilities for the system as a whole and for subareas. As part of your response, please supply the date they were prepared. In addition, if there are newer vintage load forecasts, please supply them also.

RESPONSE

Page 1 of the attachment provides 2006, 2008, 2009 and 2011 Load Forecasts for the Company's seasonal peak demands. The 2006 Load Forecast was completed in the summer of 2005. The 2008 Load Forecast was completed in the fall of 2007. The 2009 Load forecast was finalized in the spring of 2009. The 2011 Load Forecast was completed in the winter of 2010/11.

The area load forecasts are completed on as needed basis. Page 2 of the attachment provides 2006, 2007 and 2010 area load forecasts of seasonal coincident peak demands. The 2006 area forecast was complete in the fall of 2006. The 2007 area forecast was finalized in the spring of 2007. The 2010 area forecast was completed in the spring of 2010.

Kentucky Power Company
Seasonal Peak Demand (MW)
Forecast Comparisons

Year	2006 Load Forecast		2008 Load Forecast		2009 Load Forecast		2011 Load Forecast	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
2008	1,351	1,640	1,257	1,610				
2009	1,363	1,665	1,272	1,626				
2010	1,373	1,686	1,277	1,646	1,338	1,639		
2011	1,382	1,703	1,280	1,648	1,357	1,668	1,267	1,551
2012	1,392	1,715	1,286	1,647	1,364	1,672	1,271	1,550
2013	1,403	1,727	1,291	1,647	1,379	1,689	1,285	1,563
2014	1,413	1,745	1,297	1,653	1,389	1,700	1,288	1,564
2015	1,424	1,768	1,305	1,662	1,400	1,711	1,291	1,563
2016	1,435	1,791	1,320	1,679	1,408	1,717	1,290	1,557
2017	1,447	1,805	1,338	1,695	1,420	1,728	1,292	1,554
2018	1,459	1,820	1,355	1,714	1,431	1,739	1,297	1,556
2019					1,441	1,750	1,303	1,560
2020					1,448	1,754	1,308	1,561
2021							1,321	1,575
Average Annual Ten-Year Growth Rate	0.8%	1.0%	0.8%	0.6%	0.8%	0.7%	0.4%	0.1%

Kentucky Power Company
Hazard Area
2006, 2007 and 2010 Area Forecasts (MW)

	2006 Area Forecast		2007 Area Forecast		2010 Area Forecast	
Year	Summer	Winter	Summer	Winter	Summer	Winter
2008	344	453				
2009	349	461	287	433		
2010	354	469	288	439	325	464
2011	359	477	289	439	326	471
2012	363	482	289	437	321	465
2013	369	487	290	436	318	460
2014	374	495	291	437	320	459
2015	380	504	292	438	323	461
2016	385	513	295	442	325	464
2017	390	519	299	445	329	467
2018	395	525	302	449	331	470
2019			304	453	335	474
2020					338	476
Ten-Year Average Annual Growth Rate	1.4%	1.5%	0.6%	0.5%	0.4%	0.3%

Kentucky Power Company

REQUEST

Please supply a succinct description of the KP load forecasting methodology including inputs, econometric data requirements, load ratioing, and weather normalization.

RESPONSE

Kentucky Power Company develops its load forecast by customer class to derive total load for the Company. Energy and revenue data are from internal sources. Economic drivers are from external sources such as Moody's Analytics, NOAA and Energy Information Administration.

Residential, commercial, industrial and other retail classes are modeled separately, which reflects the individual characteristics of each class. In addition, wholesale customers load are modeled separately.

The Company uses national and regional forecasts developed by Moody's Analytics in its energy forecasts. The regional forecasts reflect a sum of county level data for each state jurisdiction of the Company.

Short-term models are developed using ARIMA processes. The short-term models are used for the first 12 to 24 months of the forecast period. The long-term models are estimated using econometric models. The long-term models project out up to 30 years.

Long-term customers are modeled by retail customer class. These models relate customers to regional economic variables specific for each class.

Long-term residential energy usage is modeled using a statistically adjusted end-use model (SAE) developed by Itron. This model reflects factors such as energy prices (electricity and natural gas), service area real personal income, service area weather and service area population. The effects of Federal legislation related to appliance and housing efficiency on household usage are captured in this model. Residential energy sales are derived by multiplying residential usage times residential customers. DSM/EE effects are reflected in post-model adjustments.

Long-term commercial energy sales are modeled using SAE models. The model reflects factors such as electricity price, weather and service area commercial output. The effects of Federal legislation on energy consumption are captured in the modeling process. DSM/EE effects are reflected in post-model adjustments.

Short-term industrial sales are modeled as large and small manufacturing and mining customers. For KPCo, there are models for eight large manufacturing customers and three large mining customers. There are also 'small customer' models for the remainder of the manufacturing and industrial sales. Long-term manufacturing energy sales are modeled as a function of electricity price, natural gas price and FRB industrial production indexes for petroleum and primary metals. Long-term mining energy sales are modeled as a function of service area coal production and electricity price. DSM/EE effects are reflected in post-model adjustments.

The other retail sales are modeled by relating sales to service area commercial employment.

The wholesale models reflect regional economic activity, weather and electric prices. And where appropriate, changes in contracts are reflected.

To forecast peak, revenue class sales is combined with class level and end-use level load shapes. These shapes are modeled and simulated with actual and forecast temperatures to provide hourly load shapes by revenue class and end-use. Each of the end-use shapes is aggregated to form an overall system shape. The system shape is evaluated against historic peaks and load factors and adjusted if necessary.

Peak normalization is a fundamental process of evaluating annual or monthly peaks over time, without the impact of "abnormal" weather events and load curtailment events. The limited number of true annual or monthly peaks over time makes it difficult to use traditional regression analysis. So, a regression model is used to determine statistical relationships among a set of daily observations that are similar to annual/monthly peaks and weather conditions. Any load curtailment or significant outage events are added back to the daily observations. The peak normalization demand model is replicated numerous times in a Monte Carlo (stochastic) simulation model. This approach derives probability distributions for both the dependent variable (peak) and independent variables (weather). Multiple estimates for peak are obtained over time, that ultimately produce a weather normalized peak.

Similarly, the weather-normalized internal energy requirements is determined by applying, to each month of the year, an adjustment related to heating or cooling degree-days, as appropriate, to each class of the recorded internal energy requirements. The adjustment for each class is obtained as the product of (1) the difference between the service area's expected (or "normal") heating or cooling-degree-days for the month and the actual heating or cooling degree-days for that month and (2) a weather-sensitivity factor (in MWh per heating or cooling degree-day), which is estimated by regressing over the past years monthly class energy requirements against heating or cooling degree-days for the month. The normalized monthly energy requirements thus determined for each class are then added for all classes across all twelve months to obtain the net total weather-normalized energy requirements for the year.

On an as needed basis, four sub-areas are forecast for the Company, i.e., Ashland, Pikeville, Hazard and South Williamson. These forecasts are for seasonal coincident peak demands. Each area is modeled separately and adjustments are made to assure that the forecasts sum to the Company total.

Kentucky Power Company

REQUEST

Please supply the input parameters for the ratings programs used to rate KP transmission and sub-transmission line and substation components.

RESPONSE

The attached documents provide the methodologies used in determining the substation facilities ratings, transmission/sub-transmission circuit ratings, and line ratings:
Attachment 1: Transmission & Station Facility Rating Guidelines

Attachment 2: AEP Procedure for Determining Transmission Circuit Ratings

Attachment 3: A Guide for Maximum Temperature and Ampacity of Bare Overhead Conductors.

Transmission & Station Facility Rating Guidelines

1. Table of Contents

2. Purpose (or Foreword)

This document is intended to satisfy regulatory documentation requirements, to establish transmission line, station, and equipment ratings, and to serve as a listing of those existing guidelines that also establish these ratings to be used throughout AEP. It has previously existed as a book titled by the same name as this document's title but is being published in this format with the initial release of this document.

3. Scope

All ratings or ratings methodology set forth in this document shall be effective upon its release and shall be applicable throughout the AEP system.

4. References

1. FAC-008-1 AEP Transmission, as a Transmission Owner, shall document its current methodology used for developing Facility Ratings (Facility Ratings Methodology) of its solely and jointly owned Facilities in ERCOT, PJM and SPP.
2. TP-000003 AEP Procedure for Determining Transmission Circuit Ratings Applicable to AEP East and AEP West Facilities)
   Transmission Asset Management website under TP Guidelines
3. All documents listed in this compendium are referenced as they occur.

5. Information Requests and technical review of Ratings Methodology

This document and any or all referenced documents shall be provided within fifteen (15) days of the receipt of request from Reliability Coordinators, Transmission Operators, Transmission Planners, and Planning Authorities that have responsibility for the area in which the associated facilities are located.

If a Reliability Coordinator, Transmission Operator, Transmission Planner, or Planning Authority provides written comments on its technical review of these referenced guides, AEP Transmission shall provide a written response to that commenting entity within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the referenced guides and if no change will be made, the reason why.

6. Facility Ratings Basis and Limits

Equipment nameplate ratings, manufacturers' recommendations and Industry Standards have been routinely considered in the process of arriving at the ratings per the referenced guides if and as appropriate. In limited cases, the age and lineage of some equipment that is in service precludes obtaining or documenting rating information consistent with present equipment nameplate ratings, manufacturers' recommendations and Industry Standards. That is to say, in some limited cases, equipment was installed prior to the development of the equipment nameplate ratings, manufacturers' recommendations and Industry Standards that are presently commonly found. In these limited cases, AEP has historically employed Good Utility Practices in the application of the equipment. In these limited cases, the equipment can be rated using equipment nameplate ratings, manufacturers' recommendations and Industry Standards for modern equipment of similar construction. AEP is not aware of any instance in its history where the application of the above mention practice has resulted in the failure of any piece of equipment, or misoperation of any equipment or systems.

Kremlin is a chronological database where power flow modeling data, including system topology, facilities rating and impedance data are stored. The equipment as discussed in TP-000003 is considered when populating Kremlin with data. The data in Kremlin, in some cases contains the most limiting series element which was previously developed using Good Utility Practices. In cases where AEP Station Standards are created or revised to reflect modern Industry Standards, AEP will perform due diligence and implement these changes in Kremlin and downstream operational databases within 6 months from effective date of the Station Standard.

7. Maximum Temperature and Ampacity of Bare Overhead Conductors

Refer to Report No. TP-000786, which is available at the following intranet URL:

\\oh0co013\nerc\Trans\2008 FAC\FAC-008-1\TP-000786_Guide_for_Maximum_T_Ampacity_Bare_Overhead_Conductors_Rev3_20080722.pdf

8. Underground Pipe-Type & Solid Dielectric Transmission Cable Ampacity Methodology

Refer to the document stored at the following path and name:

\\oh0gh007\etgah\Standards_Sta\Cable_Power\SS-090020_Underground Cable Ampacity Methodology_R4. pdf

9. Bushing Loadability

Refer to SS-070002, "Bushing Loadability Guide" at the following path and name:

\\oh0gh007\etgah:\Standards_Sta\Transformers_Power\Bushing_Loadability\SS-070002_Bushing_Loadability_Guide_R2.pdf.

10. Power Transformer Loading Capability

Refer to SS-780001, "Guide for Calculation of Power Transformer Loading Capability at the following path and name:

\\oh0gh007\etgah\Standards_Sta\Transformer_Data\SS_780001_PwrTransLoadCpbltyCalcGuide_R3.pdf

11. Power Transformer Loading Limitations

Refer to SS-780002, "Power Transformer Loading Limitations" at the following path and name:

\\oh0gh007\etgah\Standards_Sta\Transformer_Data\SS_780002_PwrTransLoadLimits_R3.pdf

12. Current EHV Transformer Capability Report

A current listing of EHV transformer capabilities can be obtained at any time by running the ISIS Canned Query, "Transformer Capability Report - EHV".

13. Bus Ampacity Ratings

Refer to SS-060000, "Bus Ampacity Ratings and Design Guidelines for Substations and Switching Stations" at the following path and name:

\\oh0gh007\etgah\Standards_Sta\Bus_Design\Ampacity Ratings\SS-060000_R4 Bus Ampacity Ratings and Design Guidelines for Substations and Switching Stations. pdf

14. Circuit Breaker Rating Methodology

Refer to SS-030002, "Current Overload Capabilities of AC High-Voltage Circuit Breakers" at the following path and name:

\\oh0gh007\etgah\Standards_Sta\Breakers|SS-030002_Current_Overload_Cap_AC_HV_CB_R3.pdf

15. Substation Bus Switch Rating Methodology

Refer to SS-763010 "Air Switches Current Carrying Capability" at the following path and name:

\\oh0gh007\etgah\Standards_Sta\Switches\Application_Guide\SS-763010_Air_Switch_Current_Carrying_Capability_R2.pdf

16. Wave Trap Thermal Rating

Refer to SS-478601 "Line Trap Equipment Rating Guideline" at the following path and name:

\\oh0gh007\etgah\Standards_Sta\Protection_&_Control\Distr_Sta_General\SS-478601_Line_Trap_Equipment_Rating_Guideline_R2.pdf

17. Protection & Control Rating Methodology

Refer to SS-451015 "Protection and Control Equipment Rating Guideline" at the following path and name:\\oh0gh007\etgah\Standards_Sta\Protection_&_Control\Distr_Sta_General\SS-451015_Protection_Control_Eqipment_Rating_Guideline_R4.pdf

18. Revenue Metering Rating Methodology

Refer to SS-490004 "Energy Metering Equipment Rating Guideline at the following path: and name: \\oh0gh007\etgah\Standards_Sta|Mearsurements|General\SS-490004_Energy_Metering_Equipment_Rating_Guideline_R4.pdf

19. Rating Methodology for Other Series Elements

Refer to SS-660300, "AEP Technology Fleet Equipment Thermal Overload Capabilities" at the following path and name:

\\oh0gh007\etgah\Standards_Sta\PJM\SS-660300_TechFleetOloadCapabilities_R3.pdf

20. Standard for Establishing the Maximum Operating Temperature of AEP Transmission Lines

Refer to TLES -25 "Standard for Establishing the Maximum Operating Temperature of AEP Transmission Lines (23 kV to 765 kV Inclusive)

21. Revision History

Rev.	Description of Change(s)	By	Date	Approved
0	This document has been prepared and is being released to formalize a previous compendium of information published in a book known as "Transmission and Station Equipment Rating Guidelines".	SF Wilson	3/21/2007	TAH
1	Added sections for "Information Requests" and "Facility Ratings Basis and Limits"	SF Wilson	4/2/2007	TAH
2	Added Relay Setting Guide SS-451010 to correct its inadvertent omission and added outline numbering to document.	SF Wilson	4/3/2007	TAH
3	Revision during annual review	A K McCabe	9/18/2008	TAH
4	Revision to Remove Protection & Control Rating Methodology into referenced SS-451015 and Revenue Metering rating Methodology into referenced SS-490004	A K McCabe	12/22/08	TAH
5	Revision to add reference to Kremlin in Section 6 Facility Ratings Basis and Limits	A K McCabe	1/20/09	TAH
6	Annual review. Updated Substation Bus Switch Rating Methodology and Wave Trap Thermal Rating from SEP to Station Standards	A K McCabe	6/10/09	TAH
7	Added requirement regarding response to technical review of ratings guides, clarified statements in Facility Ratings Basis and Limits	A K McCabe	7/24/09	TAH
8	Added time requirement for ratings to be implemented from new or revised Station Standards into Kremlin and downstream databases.	A K McCabe	8/18/09	TAH
9	Annual Review – No Changes	A K McCabe	6/10/10	TAH
10	Added TLES-25 to document	A K McCabe	12/31/10	SKG
11	Annual Review – Updated Preparation List, Distribution List, and Effective Date, Confirmed Supporting Documents are Updated with Associated links	M L Skidmore	6/13/11	SKG

22. Document Control

Preparation

Action	Name(s)	Title	Approved	Date of Approval
Prepared by:	M. L. Skidmore	Senior Engineer	MLS	6-13-11
Reviewed by:	K. R. Posey	Supervisor Station Equipment Standards	KRP	6-14-2011
Reviewed by:	S. K. Guinty	Manager Station Standards		6-14-11
Approved by:	K. S. Robinson	Director, Station Engineering		6-14-11

Review Cycle

Quarterly	Semi-annual	Annual	As Needed
		X	

Distribution List

Name	Department	Title
ETP,SWTP,TTP	T-Planning,	Group
SE	Station Engineering	
TOPS Ratings Changes T-Operations TRELCOMP	T-Operations, T-Reliability Compliance	

Retention Period

Six months	One Year	Two Years	Three Years
			X

Effective Date

6/13/11

AEP AMERICAN ELECTRIC POWER

AEP Procedure for Determining Transmission Circuit Ratings

(Applicable to AEP East and AEP West Facilities)

December 2010

TRANSMISSION PLANNING GUIDELINE
TITLE: AEP Procedure for Determining Transmission Circuit Ratings

AEP AMERICAN ELECTRIC POWER	Responsible Engineer: Meredith Gafford	Updated Issue Rev. 1.2	TP-000003 Page 1 of 6

Preparation

ACTION	NAME	TITLE	SIGNATURE & DATE
Prepared by:	Meredith L. Gafford	Engineer I, ETP	Meredith Gafford 12/28/2010
Reviewed by:	Mohammed Ahmed	Manager, ETP	Ahmed 12/29/2010
Reviewed by:	James H. Treece	Supervisor Planning & Engineering II, WTP	JHT 12/28/2010
Approved by:	Evan R. Wilcox	Director, ETP	Evan R. Wil 12/29/2010
Approved by:	Joseph P. Hassink	Director, WTP	JPH 12/28/2010

Review Cycle

Quarterly:	Semi-annual:	Annual: X	As Needed:

Release

VERSION	DATE RELEASED	FILE NAME	CHANGE NOTICE	REMARKS
Rev. 0	October 29, 2004	TP-000003 -- Transmission Circuit Ratings -- Rev 0 -- 2004-10-29.doc	Original Issue	
Rev. 1	September 18, 2008	TP-000003 -- Transmission Circuit Ratings -- Rev 1 -- 2008-09-18.doc	Updated Issue	
Rev. 1.1	December 23, 2009	TP-000003 -- Transmission Circuit Ratings -- Rev 1.1 -- 2009-12-23.doc	Annual Review	
Rev. 1.2	December 28, 2010	TP-000003 -- Transmission Circuit Ratings -- Rev 1.2 -- 2010-12-28.doc	Annual Review	

Retention Period

Six months:	One Year:	Two Years:	Three Years: X

Distribution List

NAME / GROUP	DEPARTMENT / DESCRIPTION	TITLE / GROUP
ETP	East Transmission Planning	Lotus Notes E-mail Group
TPW	West Transmission Planning	Lotus Notes E-mail Group
Evan R Wilcox	East Transmission Planning	Director
Joseph P Hassink	West Transmission Planning	Director
Jeffrey A Fleeman	Advanced Transmission Studies & Technology	Director
ATST	Advanced Transmission Studies & Technology	Lotus Notes E-mail Group
Jeffrey E Momme	Transmission Line Projects Engineering	Director
T David Parrish	Transmission Line Engineering Design Standards	Manager
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Steven K Guinty	Station Design Standards	Manager
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TRELCOMP	Transmission Reliability Compliance	Lotus Notes E-mail Group

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1. Introduction

NERC Reliability Standard FAC-008-1 (Facility Ratings Methodology), effective August 7, 2006, requires Transmission Owner facilities be rated in compliance with the applicable Regional requirements. The three Measures that are used to audit compliance to this standard require that:

M1. Transmission Owners shall have a documented Facility Ratings Methodology that includes all of the items identified in FAC-008 Requirement 1.1 through FAC-008 Requirement 1.3.5.

M2. The Transmission Owner shall have evidence it made its Facility Ratings Methodology available for inspection within 15 business days of a request as follows:

- **M2.1** The Reliability Coordinator shall have access to the Facility Ratings Methodologies used for Rating Facilities in its Reliability Coordinator Area.
- **M2.2** The Transmission Operator shall have access to the Facility Ratings Methodologies used for Rating Facilities in its portion of the Reliability Coordinator Area.
- **M2.3** The Transmission Planner shall have access to the Facility Ratings Methodologies used for Rating Facilities in its Transmission Planning Area.
- **M2.4** The Planning Authority shall have access to the Facility Ratings Methodologies used for Rating Facilities in its Planning Authority Area.

M3. If the Reliability Coordinator, Transmission Operator, Transmission Planner, or Planning Authority provides documented comments on its technical review of a Transmission Owner's Facility Ratings Methodology, the Transmission Owner shall have evidence that it provided a written response to that commenting entity within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the Facility Ratings Methodology and, if no change will be made to that Facility Ratings Methodology, the reason why.

Within AEP, the responsibility for documenting the various equipment rating methodologies and determining the Relay Compliance Trip Limits rests with Transmission Asset Engineering. The responsibility for applying these equipment rating methodologies and Relay Compliance Trip Limits to determine the applicable seasonal normal and emergency facility ratings for all AEP transmission circuits rests with the three Transmission Planning groups. This determination of facility ratings is made in accordance with the requirements outlined in NERC Reliability Standard FAC-009-1 (Establish and Communicate Facility Ratings).

During emergency conditions, Transmission Operations may apply temporary ratings of equipment. The temporary ratings are determined in coordination with Transmission Asset Engineering. These ratings frequently reflect equipment capabilities of a shorter duration than typically applied by AEP. The application of any temporary ratings is documented in operating procedures or operator logs.

2. Procedure

The application of the equipment rating methodologies to determine the overall seasonal normal and emergency facility ratings shall consider the following individual equipment associated with transmission circuits, as appropriate:

1. Buses and Risers (Thermal Limits)
2. Line Conductors (Thermal Limits)
3. Circuit Breakers (Thermal Limits)
4. Switches (Thermal Limits)
5. Wave Traps (Thermal Limits)
6. Current Transformers (Thermal Limits)
7. Relays (Thermal Limits)
8. Relays (Trip Limits)
9. Meters (Thermal Limits)
10. Transformers (Thermal Limits)
11. Series Reactive Devices (Thermal Limits)
12. Loadability Limits (Surrogate MW Limits for Voltage or Steady-State Stability Limits)
13. Other Series Elements (That May Limit the Capability of the Transmission Circuit)
14. Business Rules Imposed by Regional Transmission Organizations and Reliability Coordinators (For Example: PJM requires that emergency ratings be 3% below load drop ratings. This may result in the implementation of emergency ratings that are lower than those specified in the AEP Facility Ratings Methodology.)

The seasonal normal and emergency ratings assigned to any transmission circuit shall not exceed the most limiting applicable equipment ratings of the individual pieces of equipment that comprise that transmission circuit. In the absence of an applicable rating methodology for specific equipment, the nameplate or recommendation from the manufacturer shall be used in determining the transmission circuit ratings. In addition, and unless otherwise documented, emergency ratings shall reflect 24-hour equipment ratings.

In the case of line conductors, ratings shall be determined in accordance with AEP guideline TP-000786 (A Guide for Maximum Temperature and Ampacity of Bare Overhead Conductors). This guideline also includes directions on how sag limits shall be considered when determining the line conductor ratings.

In the case of current transformers, ratings shall be determined based on the connected ratios and not on the nameplate ratings.

In the case of relays (trip limits), ratings shall be determined based on the Relay Compliance Trip Limits, as outlined in the separate PRC-023-1 process flow document. Documented facility ratings shall explicitly note instances where Relay Compliance Trip Limits are not applicable.

In the case of transformers, ratings shall not exceed instantaneous capabilities that are limited to 150% of their respective nameplate ratings.

In the case of loadability limits, ratings shall take into consideration any limitations determined by the Planning Authority in accordance with NERC Reliability Standard FAC-010-2, and by the Reliability Coordinator in accordance with NERC Reliability Standard FAC-011-2.

Ratings assigned to transmission circuits that terminate in either a ring or breaker-and-a-half arrangement shall be based on the assumption that both circuit breakers associated with such a transmission circuit are normally in service (system normal condition), and that power flow will split 50/50 across both of these circuit breakers. For relays that sum the secondary flows from two relaying current transformers (each associated with one circuit breaker in a breaker-and-a-half arrangement), their thermal ratings are based on the assumption that such relays see 100% of the power flow. As a supplement to these system normal ratings (for the benefit of users such as Transmission Operations), one-breaker-open ratings may also be determined. In such instances, the one-breaker-open ratings shall be clearly labeled in order to avoid any confusion with the system normal (all circuit breakers in service) ratings.

Rating deviations from the standard equipment rating methodologies, such as providing a consistent basis for rating jointly-owned/jointly-operated facilities and other unique applications, shall be documented. Ratings of jointly-owned/jointly-operated facilities (including interconnection ratings) shall be coordinated with the counter-parties to the jointly-owned/jointly-operated facility agreements.

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A GUIDE FOR
MAXIMUM TEMPERATURE AND AMPACITY
OF
BARE OVERHEAD CONDUCTORS

Report No. TP-000786 (Revision #3)
July 2008

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Always check for the latest revision prior to use.

Document Control

Preparation

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Review Cycle

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REVISION HISTORY

Rev.	Description of Change(s)	Prepared or Revised By	Date	Approved
0	Original Issue	R. J. Gursky P. Krugh M. Ea. Rahman	June 1982	R. A. Byron R. M. Maliszewski W. E. Mekolites
1	Revision 1 – Write-up modified and conductor list expanded	R. J. Gursky B Freimark	January 1994	R. A. Byron B. M. Pasternack
2	Revision 2 – Assumption for wind direction revised and Ampacity values calculated for AEP West	M. Ea. Rahman J. W. Graham	December 2004	M. D. Higgins B. M. Pasternack

3	Revision 3 – Modified the application of conductor emergency ratings.	R. W. Reinaker J. W. Graham	July 2008	A. W. Smith
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I. SUMMARY

This guide for maximum temperature and ampacity of bare overhead conductors includes maximum conductor temperature and ampacity values for normal and emergency conditions during summer and winter seasons. These values indicate the capabilities of conductors to carry current with a calculated loss of strength over their lifetime.

This report replaces in its entirety Ampacity Report TP-000786 (Rev 2) issued December 2004. The changes, however, are limited to the application of conductor emergency ratings as described in the "text boxes" below. The ampacity values revised in "Ampacity Report TP-000786 (Rev 2) issued December 2004" are unchanged and reflect modified assumptions, namely the wind direction. In particular, the wind direction was initially presumed "at right angles" to all lines and has been changed to "60 degrees" for all lines. The report also incorporates the basis for establishing ampacity values applicable to AEP West.

Copper and aluminum conductors react differently to thermal loading conditions. For copper conductors, continuous thermal loading at the normal value results in some loss of strength. Both the normal and continuous emergency capabilities are based on the stated loss of strength. Aluminum conductors lose very little, if any, strength below and at normal ratings. For aluminum conductors, the continuous emergency capabilities are based on a stated loss of strength resulting from emergency loading.

Conductor thermal loadings in excess of continuous emergency ratings will greatly accelerate strength loss and, in most cases, will result in excessive sag. Planned operations at ampacities or conductor temperature levels above those established as emergency values are not recommended.

AEP East

IT SHOULD BE NOTED THAT the ampacities in this report are based on mechanical considerations (i.e., conductor breaking strength), assuming that adequate clearance can be maintained. However, for AEP East transmission line facilities (138 kV – 345 kV) designed prior to 1982, circuit ampacities might be limited by sag (i.e., clearance). For those lines expected to exceed their conductor normal ratings, as determined by planning or operational studies, limits due to sag should be determined by specific investigations (coordinated by Transmission Line Projects Engineering). Until those investigations are concluded, the planning study and operational models representing the emergency capabilities of these lines must assume the conductor normal ratings as defined in this report as the circuit rating (assuming no other line or station limiting elements). Sag investigations may indicate maximum operating temperatures different from the values in this report.

All new AEP overhead transmission lines are to be designed assuming the conductor temperatures as indicated in this report (Table 1).

AEP West

IT SHOULD BE NOTED THAT the ampacities in this report are based on mechanical considerations (i.e., conductor breaking strength), assuming that adequate clearance can be maintained. However, for AEP West transmission lines designed prior to 2003, circuit ampacities might be limited by sag (i.e., clearance). For those lines expected to exceed their conductor normal ratings, as determined by planning or operational studies, limits due to sag should be determined by specific investigations (coordinated by Transmission Line Projects Engineering). Until those investigations are concluded, the planning study and operational models representing the emergency capabilities of these lines must assume the conductor normal ratings as defined in this report as the circuit rating (assuming no other line or station limiting elements). Sag investigations may indicate maximum operating temperatures different from the values in this report.

All new AEP overhead transmission lines are to be designed assuming the conductor temperatures as indicated in this report (Table 1).

Currently, there are two primary standards relating to transmission lines:

a) TLES-10:	System Standards for AEP Transmission and Sub-transmission Lines (New Construction)
b) TLES-25:	Guideline for Reviewing Transmission Lines Designed Prior to July 1978 for Maximum Operating Temperatures Above 120°F

The values given in this report are appropriate for a conductor for which there is no knowledge of loading history, etc. If such knowledge is available, it may be used to determine applicable ampacities. The design for new transmission (below 765 kV) and sub-transmission (below 138 kV) lines should be based on the maximum operating temperatures as defined in this guide. **New 765 kV lines are to be designed on the basis of a 203°F maximum operating temperature without including the effects of elevated temperature creep.**

II. STRENGTH LOSS CRITERIA

Permanent strength loss of aluminum or copper strands results from cumulative annealing. In contrast, the steel core wire in ACSR and SSAC type conductors neither anneals nor loses strength (at the temperatures at which AEP operate its lines). As a result, ACSR conductors with higher steel-to-aluminum ratios (as well as aluminum wire diameter) can be operated at substantially higher temperatures than other aluminum conductors.

For the determination of conductor ampacity values, a 50-year conductor life is assumed. Different design bases are used for copper and aluminum. The design basis for copper conductors is that the combined operation at 100°C (for a cumulative duration of 600 hours) plus operation at 75°C over its remaining life results in a strength loss of not more than 17%. For aluminum conductors, combined operation at the specified emergency temperature (for a cumulative duration of 1000 hours) plus operation at 95°C for its remaining life results in not more than 10% strength loss. In both cases, remaining strengths are adequate to meet mechanical design loadings (e.g., maximum ice loading assumptions). For ACSS conductors, which do not exhibit any strength loss up to 401°F, the normal and emergency ratings are the same.

The reasons for different design bases for copper and aluminum relate to the differences in the strength loss characteristics of the two materials and differences in their application. Aluminum based conductors (e.g., ACSR) are subject to strength loss at temperatures exceeding about 94°C. In comparison, copper conductors are subject to strength loss when conductor temperatures exceed approximately 50°C. Accordingly, for copper conductors, the use of a "normal operation" design temperature, based on no loss of strength, would mean a significant limitation in load capability. Rather than accept this capability limitation, it is more desirable to accept the risk of strength loss by using a normal operating design temperature of 75°C. This statement also assumes that future new lines or line re-conductoring will not include any copper conductors.

For emergency operation a common basis of a 10% strength loss was used. For copper conductors, operation at 100°C for 600 hours results in 10% loss of strength. For aluminum based conductors, operation at the temperatures noted in Table 1 (dependent on stranding) for 1000 hours results in 10% loss of strength. After the allowable strength losses, the specified remaining strengths of copper (installed many years ago and not used today in new construction) and aluminum conductors (used today) are compatible with the strengths of their supporting structures, as designed by different past and present criteria. Without strength loss, the structures are the mechanical limiting elements. With strength loss beyond the specified 17% and 10% values, the conductor becomes the mechanical weak link.

The loss of strength of conductors has a non-linear relationship to temperature and time. At the conductor temperatures on which the emergency ratings are based, most of the strength loss occurs in the early hours of operation. For example, for 795 kcmil 45/7 ACSR, 1000 hours of operation at 140°C leads to 10% strength loss, half of that strength loss occurs in the first 70 hours of operation. Because of the non-linear relationship, operation at higher temperatures has a significant impact. If 795 kcmil 45/7 ACSR is operated at 160°C (i.e., 20°C above its emergency operating temperature) a strength loss of 10% occurs in less than fifty (50) hours. So for this example, a small increase in capability (approximately 6.5%) has been obtained at the expense of a very large decrease in emergency loading hours. Accordingly, it is recommended that conductor emergency operating temperatures not be exceeded. The emergency loading design durations (600 hours for copper and 1000 hours for aluminum) should provide a sufficient margin such that system operators do not have to monitor cumulative hours of elevated temperature operation.

III. FACTORS AFFECTING AMPACITY CAPABILITIES OF CONDUCTORS

Two groups of factors govern the ampacity of conductors. One relates to conductor heating and the other relates to the physical consequences of excessive temperature.

Factors in the first group, which cover heat generation in the conductor, the loss of heat to the atmosphere, and the resulting conductor temperature, are:

- Current and its distribution over the cross-sectional area of the conductor;
- Conductor diameter;
- Resistance and its variation with conductor temperature;
- Emissivity of the conductor surface;
- Solar absorption and the angle of the sun's rays;
- Ambient temperature;
- Wind velocity and its direction;
- Connectors and their contact resistance;
- Ferrous hardware in direct contact with the conductor's surface (i.e., without armor rods) causes a localized temperature increase of about 10°C and accelerates annealing of the conductor.

The factors in the second group cover the physical consequences of heating the conductor beyond allowable limits. Specific items in this category are:

- Annealing of aluminum and copper strands causing a significant reduction in fatigue endurance limits, yield, and tensile strengths. This can result in non-recoverable elongation or mechanical failure of conductors at significantly reduced tension stress values.
- Additive creep (a form of non-recoverable elongation).
- Excessive thermal elongation (a form of temporary recoverable elongation).
- Significant increases in conductor sag, due to elongation (i.e., the cumulative effects of the above three items), which can result in operational and safety related problems due to reduced clearances.
- Deterioration of galvanizing on ACSR and ACSS steel core wires at temperatures above 401°F, thus, exposing the steel and resulting in corrosion of the steel core wires.

The above five factors most directly affect the integrity, life, and operation of the conductor and, therefore, exert a major influence on its current rating.

IV. METHOD AND CRITERIA OF ESTABLISHING AMPACITY GUIDELINES

To determine the current rating for a conductor, first its allowable temperature is established according to criteria for annealing and reflecting acceptable operating practices. Then, a heat balance based on conductor I2R, solar absorption, radiated and converted heat loss, all as influenced by the nine items in the first group in Section III, establishes the specific magnitude of current for that conductor temperature.

The values of factors used to calculate the conductor heat balance and temperature, and thus, its normal and continuous emergency ratings are as follows:

AMBIENT TEMPERATURES

AEP East

Winter	35 °F (approximately 2 °C)
Summer	95 °F (35 °C)

AEP West

Winter	68 °F (20 °C)
Summer	104 °F (40 °C)

WIND VELOCITY

Transmission lines (138 kV and above)	2 MPH (2.933 fps)
Sub-Transmission lines (below 138 kV)	1 MPH (1.467 fps)

WIND DIRECTION

At 60 degrees angle to all line conductors

RADIATION

Emissivity Factor	0.8

SOLAR ABSORPTION

Absorption Factor	0.8

ANGLE OF SUN'S RAYS

At right angles to all line conductors

ELEVATION ABOVE SEA LEVEL

1000 feet

CONDUCTOR TEMPERATURES

Conductor temperature varies and depends on conductor type and stranding. These temperatures are listed in Table 1 below.

TABLE 1

Normal and Emergency Allowable Temperatures of Bare Overhead Conductors

Conductor Type	Normal Rating	Continuous Emergency Rating [1]
ACSS (SSAC)		
All Sizes	205°C (401°F) [2]	205°C (401°F)
ACSR		
Sizes with 36/1, 18/1 and 6/1 (#1 and smaller) strandings	95°C (203°F) [3]	130°C (266°F) [3]
Sizes with 45/7, 72/7 and 84/19 strandings		140°C (284°F) [3]
Sizes with 26/7 and 54/7 strandings		150°C (302°F) [3]
Sizes with 6/1 (1/0 and larger) strandings		160°C (320°F) [3]
Sizes with 24/7 and 30/7 strandings		165°C (329°F) [3]
Sizes with 30/19 strandings		185°C (365°F) [3]
Paper expanded with 54/19, 62/19 and 66/19 strandings		155°C (311°F)
Sizes with 12/7, 8/7, 9/7 and 16/19 strandings		205°C (401°F)
ACAR		
All Sizes	95°C (203°F)	125°C (257°F)
SAC (also called AAC)		
All Sizes	95°C (203°F)	120°C (248°F)
AAAC		
All Sizes	75°C (167°F)	75°C (167°F)
HD Copper & Copper Pipe		
All Sizes	75°C (167°F)	100°C (212°F)

(1) The emergency rating should only be used for higher voltage transmission lines (138 kV and above).

(2) For ACSS (SSAC) conductors, it is assumed that aluminum strands are fully annealed, so that no loss of strength occurs at temperatures below 401°F.

(3) For both transmission and subtransmission lines with ferrous clamps and without armor rods, the allowable temperatures are 10°C (18°F) less than the stated value.

NOTE: The values given in this report are appropriate for a conductor for which there is no knowledge of loading history, etc. If such knowledge is available, it may be used to determine applicable ampacities. The design for new 345 kV, 138 kV and sub-t

V. RECOMMENDED OVERHEAD CONDUCTOR AMPACITY RATINGS

Recommended ratings for overhead transmission and sub-transmission line conductors are attached as Tables 2 through 5. Tables 2 (AEP East) and 3 (AEP West) list both normal and continuous emergency ratings for selected transmission line conductors, at an assumed wind speed of 2 MPH (2.933 fps).

Tables 4 (AEP East) and 5 (AEP West) list normal ratings for selected sub-transmission line conductors for assumed wind speeds of 1 MPH and 2 MPH. The 1 MPH wind speed values should be used for urban lines and the 2 MPH values should be used for rural lines. Emergency ratings for sub-transmission lines are not indicated because the AEP planning criteria is based on not exceeding normal ratings. This is because of the greater likelihood that there will be structures or facilities passing under the conductors (distribution line and other under-builds). By utilizing only normal capabilities, the likelihood of conductors sagging into these facilities is minimized.

In certain areas where a sub-transmission line is designed for higher voltage operation and the likelihood of under-built facilities is small, Table 2 or 3 values can be used for conductor ampacity (including emergency values) of sub-transmission lines, **as long as there are no sag limitations**.

The tabulated data was calculated based on a paper entitled "Current Carrying Capacity of ACSR" by H. E. House and P. D. Tuttle, IEEE Transactions, Power Apparatus and Systems, Volume 40, page 1169. Reference has also been made to "738-1993 IEEE Standard for Calculating the Current-Temperature of Bare Overhead Conductors 1993".

AEP has developed a spreadsheet based computer data file that includes an extensive collection of conductor data and the ampacity calculation algorithm. Additional spreadsheet files have been developed to include a large assortment of conductors that are or can be used for overhead transmission or sub-transmission lines. These files include an extensive array of graphical plots, which will be available at the Transmission Planning Share Point site.

In order to expand on the material in Tables 2 through 5, graphical plots were made and these are presented in the Appendices. "Appendices A and B" include plots of ACSR conductor temperature as a function of conductor loading for AEP East and AEP West, respectively. Plots of ACSR conductor normal and contingency capabilities as a function of ambient temperature are included in "Appendix C". The first set of curves will help determine allowable conductor ampere loading on any specific circuit if it is limited to a particular conductor temperature by sag or other constraints. The second set of curves will assist system operators to determine circuit capabilities with changing ambient temperatures. "Appendices D and E" plots show curves for ACAR and AAC conductors as in "Appendices A and B," and "Appendix F" provides similar information for copper conductors.

To determine MVA ratings for specific transmission/sub-transmission voltages the following multipliers should be used (based on ampacities specified in Table 2 through Table 5) or as shown in various plots in the appendices:

Voltage Class (kV)	To get MVA Capability Multiply Ampacity by:
23	0.0398
34.5	0.0598
40	0.0693
46	0.0797
69	0.120
88	0.152
138	0.239
161	0.279
230	0.398
345	0.598
500	0.866
765	1.33

TABLE 2

Allowable Current Carrying Capacity of Bare Overhead Conductors*
Transmission Lines – 138 kV and Above -- AEP East

Conductor Type, Size, Stranding (cm) and Name				Extreme Winter		Conductor Ratings				Extreme Summer	
				Ambient (0°F or -18°C)		Winter (35°F)		Summer (95°F)		Ambient (122°F or 50°C)	
Type	Size	Stranding	Name	Normal	Emerg.**	Normal	Emerg.**	Normal	Emerg.**	Normal	Emerg.**
ACSS	336,400	(26/7)	Linnet/ACSS	1,153	1,153	1,111	1,111	1,032	1,032	992	992
	397,500	(26/7)	Ibis/ACSS	1,288	1,288	1,242	1,242	1,153	1,153	1,109	1,109
	477,000	(26/7)	Hawk/ACSS	1,454	1,454	1,402	1,402	1,303	1,303	1,253	1,253
	556,500	(26/7)	Dove/ACSS	1,611	1,611	1,554	1,554	1,445	1,445	1,390	1,390
	636,000	(26/7)	Grosbeak /ACSS	1,760	1.760	1,699	1,699	1,580	1,580	1,520	1,520
	795,000	(26/7)	Drake/ACSS	2,044	2,044	1,974	1,974	1,836	1,836	1,767	1,767
	954,000	(54/7)	Cardinal /ACSS	2,211	2.211	2,134	2,134	1,987	1,987	1.912	1,912
	1,033,500	(54/7)	Curlew /ACSS	2,336	2,336	2,257	2,257	2,101	2,101	2,023	2,023
	1,590,000	(54/19)	Falcon/ACSS	3,106	3,106	3,000	3,000	2,797	2,797	2,694	2,694
ACSR-Standard	4/0	(6/1)	Penguin	583	734	530	698	421	626	259	590
	176,900	(12/7)	Dotterel	539	724	490	698	389	647	332	622
	266,800	(26/7)	Patridge	740	873	673	826	534	734	455	687
	266,800	(26/7)+	Patridge	710	851	639	802	484	704	392	652
	336,400	(18/1)	Merlin	841	943	765	883	607	765	517	701
	336,400	(18/1)+	Merlin	808	916	726	852	550	725	445	656
	336,400	(30/7)	Oriole	869	1,066	790	1,016	627	917	533	866
	336,400	(30/7)+	Oriole	834	1,041	749	988	567	882	458	829
	397,500	(18/1)	Chickadee	936	1,051	852	984	676	853	575	782
	397,500	(18/1)+	Chickadee	899	1,020	808	949	612	808	494	731
	397,500	(30/7)	Lark	968	1,190	880	1,134	698	1,024	593	968
	397,500	(30/7)+	Lark	928	1,162	834	1,103	631	985	509	926
	477,000	(26/7)	Hawk	1,075	1,277	978	1,209	775	1,075	659	1,007
	477,000	(26/7)+	Hawk	1,031	1,243	927	1,172	701	1,030	564	955
	556,500	(18/1)	Osprey	1,162	1,308	1,057	1,225	838	1,062	712	974
	556,500	(18/1)+	Osprey	1,114	1,268	1,001	1,180	757	1,005	609	909
	556,500	(26/7)	Dove	1,187	1,412	1,080	1,338	856	1,190	727	1,115
	556,500	(26/7)+	Dove	1,138	1,375	1,023	1,296	773	1,140	622	1,056
	605,000	(26/7)	Squab	1,253	1,491	1,140	1,413	903	1,257	766	1,178
	605,000	(30/19)	Teal	1,268	1,642	1,154	1,574	914	1,447	775	1,382
	605,000	(30/19)+	Teal	1,215	1,607	1,092	1,536	824	1,401	662	1,332
	636,000	(26/7)	Grosbeak	1,294	1,541	1,177	1,460	932	1,299	791	1,217
	636,000	(26/7)+	Grosbeak	1,240	1,500	1,114	1,414	841	1,244	676	1153
	795,000	(26/7)	Drake	1,494	1,785	1,359	1,692	1,076	1,506	912	1,412
	795,000	(54/7)	Condor	1,456	1,722	1,325	1,632	1,049	1,453	889	1,361

*	This table shows the capability to load overhead conductors during various conditions of ambient temperature. The "ratings" are used for planning studies and other forward looking analyses. The "extreme ambient" capabilities can be used for operating the system on a real-time basis; the extreme temperatures are close to extremes experienced on the AEP System. "Normal" capabilities imply no loss-of-strength. "Emergency" capabilities imply a loss-of-strength; e.g., for ACSR conductors there is a 10% loss-of-strength for 1000 hours of operation at the specified loading.
**	The emergency capabilities should be applied as described on page 5 of this report.
+	Ferrous clamps without armor rods.
NOTE:	FOR CIRCUITS DESIGNED PRIOR TO 1982, EXCESSIVE SAG MAY OCCUR AT LOADINGS ABOVE THE NORMAL RATING. See TLES-25 Standards. The emergency capabilities should be applied as described on page 5 of this report.
	The design for new 345 kV, 138 kV and sub-transmission lines should be based on the maximum operating temperatures as defined in this guide. New 765 kV lines are to be designed on the basis of a 203°F maximum operating temperature.
	Transmission line specific ratings can be calculated when information from field surveys or as built documentation is available.

TABLE 2 (Continued)

Allowable Current Carrying Capacity of Bare Overhead Conductors* Transmission Lines – 138 kV and Above -- AEP East

Conductor Type, Size, Stranding (cm) and Name				Extreme Winter		Conductor Ratings				Extreme Summer	
				Ambient (0°F or -18°C)		Winter (35°F)		Summer (95°F)		Ambient (122°F or 50°C)	
Type	Size	Stranding	Name	Normal	Emerg.**	Normal	Emerg.**	Normal	Emerg.**	Normal	Emerg.**
ACSR-Standard	954,000	(45/7)	Rail	1,637	1,902	1,490	1,794	1,179	1,579	999	1,464
	954,000	(54/7)	Cardinal	1,637	1,942	1,490	1,841	1,179	1,639	998	1,536
	1,033,500	(45/7)	Ortolan	1,723	2,003	1,568	1,890	1,240	1,664	1,050	1,542
	1,033,500	(54/7)	Curlew	1,723	2,047	1,568	1,940	1,240	1,728	1,050	1,620
	1,192,500	(45/7)	Bunting	1,887	2,199	1,717	2,076	1,358	1,827	1,149	1,694
	1,272,000	(45/7)	Bittem	1,965	2,294	1,788	2,165	1,414	1,906	1,196	1,767
	1,351,000	(45/7)	Dipper	2,041	2,385	1,857	2,251	1,468	1,982	1,242	1,838
	1,590,000	(45/7)	Lapwing	2,266	2,647	2,058	2,499	1,625	2,201	1,373	2,041
	1,780,000	(84/19)	Chukar	2,446	2,865	2,222	2,703	1,750	2,381	1,478	2,208
	2,156,000	(84/19)	Bluebird	2,755	3,240	2,503	3,055	1,970	2,687	1,660	2,492
ACSR-Expanded											
Paper	1,275,000	(54/19)		2,097	2,556	1,905	2,430	1,501	2,177	1,267	2,050
Paper	1,414,000	(62/19)		2,273	2,792	2,065	2,652	1,625	2,374	1,370	2,235
Air	1,563,000	(66/19)		2,407	2,956	2,186	2,807	1,721	2,514	1,450	2,366
ACSR-TW	966,200	(Type 13) (54/7)	Columbia /TW	1.645	1,962	1,497	1,859	1,185	1,655	1,004	1,550
AAC	336,400	(19)	Tulip	831	905	756	841	600	716	511	648
	556,500	(19)	Dahlia	1,148	1,252	1,044	1,165	827	992	703	898
	795,000	(37)	Arbutus	1,443	1,578	1,313	1,469	1,039	1,251	882	1,132
ACAR	2,049,000	(42/19)		2,561	2,873	2,327	2,682	1,832	2,305	1,545	2,100
	2,303,500	(54/37)		2,729	3,069	2,479	2,865	1,952	2,460	1,645	2,240
COPPER	2/0	(7)		531	588	470	537	336	435	251	377
	3/0	(7)		615	681	544	623	389	504	289	437
	4/0	(7) or (19)		715	793	633	725	451	586	333	508
	200,000	(7)		585	616	518	564	369	456	273	395
	250,000	(19)		795	883	703	807	501	653	369	566
	300,000	(19)		893	993	790	908	561	733	412	635
	350,000	(19)		984	1,095	870	1,002	618	809	452	701
	500,000	(37)		1,233	1,376	1,090	1,258	771	1,016	560	879
	750,000	(37)		1,586	1,776	1,401	1,624	987	1,311	711	1,133
	1,000,000	(37)		1,885	2,118	1,665	1,937	1,169	1,563	836	1,349

* This table shows the capability to load overhead conductors during various conditions of ambient temperature. The "ratings" are used for planning studies and other forward looking analyses. The "extreme ambient" capabilities can be used for operating the system on a real-time basis; *the extreme temperatures are close to extremes experienced* on the AEP System. "Normal" capabilities imply no loss-of-strength. "Emergency" capabilities imply a loss-of-strength; e.g., for ACSR conductors there is a 10% loss-of-strength for 1000 hours of operation at the specified loading.

** The emergency capabilities should be applied as described on page 5 of this report.

+ Ferrous clamps without armor rods.

NOTE: FOR CIRCUITS DESIGNED PRIOR TO 1982, EXCESSIVE SAG MAY OCCUR AT LOADINGS ABOVE THE NORMAL RATING. See TLES-25 Standards. The emergency capabilities should be applied as described on page 5 of this report.

The design for new 345 kV, 138 kV and sub-transmission lines should be based on the maximum operating temperatures as defined in this guide. New 765 kV lines are to be designed on the basis of a 203°F maximum operating temperature.

Transmission line specific ratings can be calculated when information from field surveys or as built documentation is available.

TABLE 3

Allowable Current Carrying Capacity of Bare Overhead Conductors* Transmission Lines -- 138 kV and Above -- AEP West

Conductor Type, Size, Stranding (cm) and Name				Extreme Winter Ambient (0°F or -18°C)		Conductor Ratings Winter (68°F)		Conductor Ratings Summer (104°F)		Extreme Summer Ambient (122°F or 50°C)	
Type	Size	Stranding	Name	Normal	Emerg.**	Normal	Emerg.**	Normal	Emerg.**	Normal	Emerg.**
ACSS	336,400	(26/7)	Linnet/ACSS	1,153	1,153	1,069	1,069	1,019	1,019	992	992
	397,500	(26/7)	Ibis/ACSS	1,288	1,288	1,195	1,195	1,139	1,139	1,109	1,109
	477,000	(26/7)	Hawk/ACSS	1,454	1,454	1,350	1,350	1,287	1,287	1,253	1,253
	556,500	(26/7)	Dove/ACSS	1,611	1,611	1,496	1,496	1,427	1,427	1,390	1,390
	636,000	(26/7)	Grosbeak /ACSS	1,760	1,760	1,635	1,635	1,560	1,560	1,520	1,520
	795,000	(26/7)	Drake/ACSS	2,044	2,044	1,900	1,900	1,814	1,814	1,767	1,767
	954,000	(54/7)	Cardinal /ACSS	2,211	2,211	2,056	2,056	1,963	1,963	1,912	1,912
	1,033,500	(54/7)	Curlew /ACSS	2,336	2,336	2,173	2,173	2,075	2,075	2.023	2,023
	1,590,000	(54/19)	Falcon /ACSS	3,106	3,106	2,893	2,893	2,764	2,764	2,694	2,694
ACSR-Standard	1/0	(6/1)	Raven	389	486	316	436	268	406	240	390
	2/0	(6/1)	Quail	446	562	363	505	308	470	275	451
	3/0	(6/1)	Pigeon	500	647	417	581	353	540	316	519
	4/0	(6/1)	Penguin	583	734	474	660	402	614	359	590
	203,200	(16/19)	Brahma	521	570	423	529	358	504	320	490
	211,300	(12/7)	Cochin	523	579	425	537	360	512	321	498
	266,800	(26/7)	Patridge	740	873	601	778	509	718	455	687
	266,800	(26/7)+	Patridge	710	851	560	751	456	688	392	652
	336,400	(18/1)	Merlin	841	943	684	821	579	745	517	702
	336,400	(18/1)+	Merlin	808	916	637	786	518	703	445	656
	336,400	(26/7)	Linnet	858	1,015	698	905	591	836	527	800
	336,400	(26/7)+	Linnet	824	989	649	873	528	800	453	759
	397,500	(26/7)	Ibis	956	1,133	777	1,010	657	933	586	893
	397,500	(26/7)+	Ibis	917	1,103	723	974	587	893	503	847
	477,000	(18/1)	Pelican	1,053	1,183	856	1,030	724	935	645	881
	477,000	(18/1)+	Pelican	1,010	1,148	796	985	646	882	554	823
	477,000	(26/7)	Hawk	1,075	1,277	874	1,139	739	1,052	659	1,007
	477,000	(26/7)+	Hawk	1,031	1,243	812	1,098	659	1,006	564	955
	477,000	(30/7)	Hen	1,088	1,341	885	1,212	748	1,135	666	1,092
	477,000	(30/7)+	Hen	1,044	1,309	822	1,174	667	1,090	571	1,044
	556,500	(26/7)	Dove	1,187	1,412	965	1,260	816	1,165	727	1,115
	556,500	(26/7)+	Dove	1,138	1,375	896	1,215	727	1,114	622	1,056
	636,000	(26/7)	Grosbeak	1,294	1,541	1,051	1,376	888	1,272	791	1,217
	636,000	(26/7)+	Grosbeak	1,240	1,500	976	1,326	790	1,215	676	1153
	666,600	(24/7)	Flamingo	1,325	1,639	1,077	1,482	910	1,387	810	1,336
	666,600	(24/7)+	Flamingo	1,269	1,599	999	1,434	809	1,332	692	1,277

* This table shows the capability to load overhead conductors during various conditions of ambient temperature. The "ratings" are used for planning studies and other forward looking analyses. The "extreme ambient" capabilities can be used for operating the system on a real-time basis; the extreme temperatures are close to extremes experienced on the AEP System. "Normal" capabilities imply no loss-of-strength. "Emergency" capabilities imply a loss-of-strength; e.g., for ACSR conductors there is a 10% loss-of-strength for 1000 hours of operation at the specified loading.

** The emergency capabilities should be applied as described on page 5 of this report.

\+ Ferrous clamps without armor rods.

NOTE: FOR CIRCUITS DESIGNED PRIOR TO 2003, EXCESSIVE SAG MAY OCCUR AT LOADINGS ABOVE THE NORMAL RATING. See TLES-25 Standards. The emergency capabilities should be applied as described on page 5 of this report.

The design for new 345 kV, 138 kV and sub-transmission lines should be based on the maximum operating temperatures as defined in this guide. New 765 kV lines are to be designed on the basis of a 203°F maximum operating temperature.

Transmission line specific ratings can be calculated when information from field surveys or as built documentation is available.

TABLE 3 (Continued)

Allowable Current Carrying Capacity of Bare Overhead Conductors*
Transmission Lines – 138 kV and Above -- AEP West

Conductor Type, Size, Stranding (cm) and Name				Extreme Winter		Conductor Ratings				Extreme Summer	
				Ambient (0°F or -18°C)		Winter (68°F)		Summer (104°F)		Ambient (122°F or 50°C)	
Type	*Size*	*Stranding*	*Name*	Normal	Emerg.**	Normal	Emerg.**	Normal	Emerg.**	Normal	Emerg.**
ACSR-Standard	795,000	(36/1)	Coot	1,452	1,639	1,180	1,429	997	1,297	887	1,223
	795,000	(26/7)	Drake	1,494	1,785	1,214	1,595	1,025	1,474	912	1,412
	795,000	(45/7)	Tern	1,458	1,690	1,184	1,494	1,000	1,370	890	1299
	954,000	(54/7)	Cardinal	1,637	1,942	1,330	1,735	1,123	1,605	998	1,536
	954,000	(20/7)	Corncrake	1,644	1,968	1,336	1,758	1,128	1,626	1,003	1,556
	1,033,500	(45/7)	Ortolan	1,723	2,003	1,400	1,772	1,181	1,625	1,050	1,542
	1,033,500	(54/7)	Curlew	1,723	2,047	1,400	1,830	1,181	1,692	1,050	1,620
	1,272,000	(45/7)	Bittern	1,965	2,294	1,597	2,031	1,347	1,863	1,196	1,767
	1,272,000	(54/19)	Pheasant								
	1,351,000	(45/7)	Dipper	2,041	2,385	1,658	2,111	1,398	1,937	1,242	1,838
	1,590,000	(45/7)	Lapwing	2,266	2,647	1,835	2,345	1,547	2,151	1,373	2,041
	1,780,000	(84/19)	Chukar	2,446	2,865	1,980	2,536	1,665	2,327	1,478	2,208
	2,156,000	(84/19)	Bluebird	2,755	3,240	2,230	2,864	1,874	2,625	1,660	2,492
ACSR-AW	336,000	(26/7)	Linnet/AW	610	682	496	608	420	561	375	537
	477,000	(26/7)	Hawk/AW	1,093	1,298	888	1,158	751	1,070	669	1,024
	795,000	(26/7)	Drake/AW	1,518	1,814	1,233	1,620	1,042	1,498	927	1.432
	795,000	(45/7)	Tern/AW	1,467	1,701	1,192	1,504	1,007	1,379	896	1,308
	1,590,000	(45/7)	Lapwing/AW	2,280	2.663	1,846	2,358	1,556	2,164	1.381	2,053
ACSR-Expanded											
Paper	1,275,000	(54/19)		2,097	2,556	1,695	2,298	1,428	2,137	1,267	2,050
Paper	1,414,000	(62/19)		2,273	2,792	1,839	2,506	1,546	2,330	1,370	2,235
Air	1,563,000	(66/19)		2,407	2,956	1,948	2,653	1,637	2,467	1,450	2,366
ACSR-TW	966,200	(Type 13) (54/7)	Columbia /TW	1,645	1,962	1,337	1,752	1,129	1,620	1,004	1,550
AAC	336,400	(19)	Tulip	831	905	676	776	572	695	511	648
	477,000	(37)	Syringa	1041	1135	846	974	716	872	638	813
	556,500	(19)	Dahlia	1,148	1,252	933	1,075	789	962	703	898
	795,000	(37)	Arbutus	1,443	1,578	1,172	1,355	990	1,213	882	1,132
	1,272,000	(61)	Narcissus	1938	2128	1575	1829	1328	1637	1180	1527
ACAR	755,000	(24/13)		1,368	1,522	1,112	1,317	940	1,168	836	1,114
	1,024,000	(24/13)		1,668	1,863	1,355	1,613	1,144	1,454	1,017	1,364
	1,703,000	(54/7)		2,324	2,604	1,882	2,256	1,586	2,035	1,408	1,909
	2,049,000	(42/19)		2,561	2,873	2,073	2,483	1,743	2,239	1,545	2,100
	2,168,000	(42/19)									
	2,267,000	(42/19)		2,726	3,060	2,206	2,645	1,855	2,382	1,643	2,234
	2,303,500	(54/37)		2,729	3,069	2,209	2,653	1,857	2,389	1,645	2,240

* This table shows the capability to load overhead conductors during various conditions of ambient temperature. The "ratings" are used for planning studies and other forward looking analyses. The "extreme ambient" capabilities can be used for operating the system on a real-time basis; the extreme temperatures are close to extremes experienced on the AEP System. "Normal" capabilities imply no loss-of-strength. "Emergency" capabilities imply a loss-of-strength; e.g., for ACSR conductors there is a 10% loss-of-strength for 1000 hours of operation at the specified loading.

** The emergency capabilities should be applied as described on page 5 of this report.

† Ferrous clamps without armor rods.

NOTE: FOR CIRCUITS DESIGNED PRIOR TO 2003, *EXCESSIVE SAG MAY OCCUR AT LOADINGS ABOVE THE NORMAL RATING. See TLES-25* Standards. The emergency capabilities should be applied as described on page 5 of this report.

The design for new 345 kV, 138 kV and sub-transmission lines should be based on the maximum operating temperatures as defined in this guide. New 765 kV lines are to be designed on the basis of a 203°F maximum operating temperature.

Transmission line specific ratings can be calculated when information from field surveys or as built documentation is available.

TABLE 3 (Continued)

Allowable Current Carrying Capacity of Bare Overhead Conductors* Transmission Lines – 138 kV and Above -- AEP West

Conductor Type, Size, Stranding (cm) and Name				Extreme Winter Ambient (0°F or -18°C)		Conductor Ratings Winter (68°F)		Conductor Ratings Summer (104°F)		Extreme Summer Ambient (122°F or 50°C)	
Type	Size	Stranding	Name	Normal	Emerg.**	Normal	Emerg.**	Normal	Emerg.**	Normal	Emerg.**
AAAC6201	559,600	(19)	Darien (477)	990	990	746	746	568	568	448	448
	740,800	(37)	Flint (636)	1184	1184	892	892	676	676	531	531
COPPER	2/0	(7)		531	588	403	484	310	417	251	377
	3/0	(7)		615	681	466	561	359	483	289	437
	4/0	(7) or (19)		715	793	541	653	416	562	333	508
	200,000	(7)		585	616	443	508	340	437	273	395
	250,000	(19)		795	883	602	727	461	625	369	566
	300,000	(19)		893	993	675	817	517	703	412	635
	350,000	(19)		984	1,095	744	902	568	775	452	701
	500,000	(37)		1,233	1,376	930	1,133	708	973	560	879
	750,000	(37)		1,586	1,776	1,194	1,462	905	1,255	711	1,133
	1,000,000	(37)		1,885	2,118	1,418	1,744	1,070	1,496	836	1,349

*	This table shows the capability to load overhead conductors during various conditions of ambient temperature. The "ratings" are used for planning studies and other forward looking analyses. The "extreme ambient" capabilities can be used for operating the system on a real-time basis; the extreme temperatures are close to extremes experienced on the AEP System. "Normal" capabilities imply no loss-of-strength. "Emergency" capabilities imply a loss-of-strength; e.g., for ACSR conductors there is a 10% loss-of-strength for 1000 hours of operation at the specified loading.
**	The emergency capabilities should be applied as described on page 5 of this report.
+	Ferrous clamps without armor rods.
NOTE:	FOR CIRCUITS DESIGNED PRIOR TO 2003, EXCESSIVE SAG MAY OCCUR AT LOADINGS ABOVE THE NORMAL RATING. See TLES-25 *Standards. The* emergency capabilities should be applied as described on page 5 of this report.
	The design for new 345 kV, 138 kV and sub-transmission lines should be based on the maximum operating temperatures as defined in this guide. New 765 kV lines are to be designed on the basis of a 203°F maximum operating temperature.
	Transmission line specific ratings can be calculated when information from field surveys or as built documentation is available.

TABLE 4

Allowable Current Carrying Capacity of Bare Overhead Conductors* Subtransmission Lines – Below 138 kV -- AEP East

Conductor Type, Size, Stranding (cm) and Name				Extreme Winter		Conductor Ratings				Extreme Summer	
				Ambient (0°F or -17.8°C)		Winter (35°F)		Summer (95°F)		Ambient (122°F or 50°C)	
Type	Size	Stranding	Name	1 MPH Wind	2 MPH Wind	1 MPH Wind	2 MPH Wind	1 MPH Wind	2 MPH Wind	1 MPH Wind	2 MPH Wind
				Amps	Amps	Amps	Amps	Amps	Amps	Amps	Amps
ACSR-Standard	4	(6/1)	Swan	189	221	172	201	137	160	117	137
	2	(6/1)	Sparrow	252	294	230	267	182	213	155	182
	1/0	(6/1)	Raven	334	389	304	354	241	281	205	240
	2/0	(6/1)	Quail	384	446	349	406	277	323	235	275
	3/0	(6/1)	Pigeon	441	512	402	466	318	370	270	316
	4/0	(6/1)	Penguin	503	583	458	530	362	421	307	359
	4/0	(6/1)+	Penguin	482	565	435	503	322	378	270	315
	266,800	(26/7)	Partridge	639	740	581	673	460	534	389	455
	266,800	(26/7)+	Partridge	611	710	549	639	413	484	330	392
	336,400	(18/1)	Merlin	727	841	661	765	523	607	442	517
	336,400	(18/1)+	Merlin	695	808	626	726	470	550	375	445
	336,400	(30/7)	Oriole	751	869	684	790	540	627	457	533
	336,400	(30/7)+	Oriole	718	834	646	749	485	567	386	458
	397,500	(30/7)	Lark	837	968	762	880	602	698	508	593
	397,500	(30/7)+	Lark	800	928	719	834	540	631	429	509
	477,000	(26/7)	Hawk	931	1,075	847	978	669	775	565	659
	477,000	(26/7)+	Hawk	890	1,031	799	927	600	701	476	564
	556,500	(18/1)	Osprey	1,007	1,162	916	1,057	724	838	610	712
	556,500	(18/1)+	Osprey	961	1,114	864	1,001	648	757	514	609
	556,500	(26/7)	Dove	1,029	1,187	937	1,080	740	856	623	727
	556,500	(26/7)+	Dove	983	1,023	883	1,023	662	773	524	622
	636,000	(26/7)	Grosbeak	1,122	1,294	1,021	1,177	806	932	679	791
	636,000	(26/7)+	Grosbeak	1,071	1,240	962	1,114	720	841	570	676
	795,000	(26/7)	Drake	1,298	1,494	1,181	1,359	932	1,076	784	912
	795,000	(45/7)	Tern	1,265	1,458	1,152	1,326	909	1,050	765	890
	954,000	(45/7)	Rail	1,423	1,637	1,295	1,490	1,021	1,179	859	999
	954,000	(54/7)	Cardinal	1,423	1,637	1,295	1,490	1,021	1,179	859	999
	1,033,500	(45/7)	Ortolan	1,498	1,723	1,364	1,567	1,076	1,240	903	1,050
	1,192,500	(45/7)	Bunting	1,642	1,887	1,495	1,717	1,178	1,358	989	1,149
	1,272,000	(45/7)	Bittern	1,711	1,965	1,558	1,788	1,227	1,414	1,030	1,196
AAC	336,400	(19)	Tulip	718	831	653	756	517	600	437	511
	556,500	(19)	Dahlia	994	1,148	904	1,044	714	827	603	703
	795,000	(37)	Arbutus	1,252	1,443	1,139	1,313	899	1,039	757	882

* This table shows the capability to load overhead conductors during various conditions of ambient temperature. The "ratings" are used for planning studies and other forward looking analyses. The "extreme ambient" capabilities can be used for operating the

\+ Ferrous clamps without armor rods.

TABLE 4 (Continued)

Allowable Current Carrying Capacity of Bare Overhead Conductors*
Subtransmission Lines – Below 138 kV – AEP East

Conductor Type, Size, Stranding (cm) and Name				Extreme Winter		Conductor Ratings				Extreme Summer	
				Ambient (0°F or -17.8°C)		Winter (35°F)		Summer (95°F)		Ambient (122°F or 50°C)	
Type	Size	Stranding	Name	1 MPH Wind	2 MPH Wind	1 MPH Wind	2 MPH Wind	1 MPH Wind	2 MPH Wind	1 MPH Wind	2 MPH Wind
				Amps	Amps	Amps	Amps	Amps	Amps	Amps	Amps
COPPER	2	(3)		300	351	266	311	189	223	138	168
	1	(3)		348	407	308	361	218	259	159	193
	1/0	(7)		391	458	346	405	245	291	179	217
	2/0	(7)		454	531	401	470	284	336	206	251
	3/0	(7)		526	615	465	544	328	389	237	289
	4/0	(7) or (19)		612	715	541	633	380	451	273	333
	200,000	(7)		501	585	442	518	311	369	224	273
	250,000	(19)		681	795	602	703	422	501	302	369
	300,000	(19)		765	893	676	790	473	561	337	412
	350,000	(19)		844	984	745	870	521	618	369	452
	500,000	(37)		1.059	1,233	934	1,090	650	771	455	560
	750.000	(37)		1,364	1,586	1,203	1,401	833	987	575	711
	1,000,000	(37)		1,623	1,885	1,431	1,666	986	1,169	673	836

* This table shows the capability to load overhead conductors during various conditions of ambient temperature. The "ratings" are used for planning studies and other forward looking analyses. The "extreme ambient" capabilities can be used for operating the

\+ Ferrous clamps without armor rods.

TABLE 5

Allowable Current Carrying Capacity of Bare Overhead Conductors*
Subtransmission Lines – Below 138 kV -- AEP West

Conductor Type, Size, Stranding (cm) and Name				Extreme Winter		Conductor Ratings				Extreme Summer	
				Ambient (0°F or -18°C)		Winter (68°F)		Summer (104°F)		Ambient (122°F or 50°C)	
Type	Size	Stranding	Name	1 MPH Wind	2 MPH Wind	1 MPH Wind	2 MPH Wind	1 MPH Wind	2 MPH Wind	1 MPH Wind	2 MPH Wind
				Amps	Amps	Amps	Amps	Amps	Amps	Amps	Amps
ACSR-Standard	2	(6/1)	Sparrow	252	294	205	239	174	203	155	182
	1/0	(6/1)	Raven	334	389	272	316	230	268	205	240
	2/0	(6/1)	Quail	384	446	312	363	264	308	235	275
	3/0	(6/1)	Pigeon	441	512	359	417	303	353	270	316
	4/0	*(6/1)*	*Penguin*	*503*	*583*	409	474	345	402	307	359
	4/0	(6/1)+	Penguin	485	565	382	446	308	363	264	313
	266,800	(26/7)	Partridge	639	740	519	601	438	509	389	455
	266,800	(26/7)+	Partridge	611	710	481	560	388	456	330	392
	300,000	(26/7)	Ostrich	689	798	560	648	472	549	419	490
	300,000	(26/7)+	Ostrich	660	766	518	603	418	491	355	422
	336,400	(18/1)	Merlin	727	841	591	684	498	579	442	517
	336,400	(18/1)+	Merlin	695	808	547	637	441	518	375	445
	336,400	(26/7)	Linnet	742	858	603	698	508	591	451	527
	336,400	(26/7)+	Linnet	710	824	558	649	450	528	382	453
	397,000	(26/7)	Ibis	827	956	672	777	566	657	502	586
	397,000	(26/7)+	Ibis	790	917	621	723	500	587	424	503
	477,000	(18/1)	Pelican	911	1,053	740	856	624	724	553	645
	477,000	(18/1)+	Pelican	871	101	684	796	551	646	467	554
	477,000	(26/7)	Haw k	931	1,075	756	874	637	739	565	659
	477,000	(26/7)+	Haw k	890	1,031	699	812	562	659	476	564
	556,500	(26/7)	Dove	1,029	1,187	836	965	704	816	623	727
	556,500	(26/7)+	Dove	983	1,138	772	896	620	727	524	622
	636,000	(26/7)	Grosbeak	1,122	1,294	912	1,051	767	888	679	791
	636,000	(26/7)+	Grosbeak	1,071	1,240	841	976	675	790	570	676
	666,000	(24/7)	Flamingo	1,149	1,325	933	1,077	785	910	695	810
	666,001	(24/7)+	Flamingo	1,097	1,269	861	999	691	809	583	692
	795,000	(26/7)	Drake	1,298	1,494	1,054	1,214	886	1,025	784	912
	795,000	(45/7)	Tern	1,265	1,458	1,028	1,184	864	1,000	765	890
	1,272,000	(45/7)	Bittern	1,711	1,965	1,390	1,597	1,166	1,347	1,030	1,196
	1,272,000	(54/19)	Pheasant	1,709	1,963	1,388	1,595	1,165	1,345	1,028	1,194
	1,590,000	(45/7)	Lapw ing	1,970	2,266	1,599	1,835	1,341	1,547	1,183	1,373
ACSR/AW	336,400	(26/7)	Linnet/AW	755	873	613	709	517	600	459	536
	477,000	(26/7)	Haw k/AW	947	1,094	769	888	647	751	574	669
	795,000	(26/7)	Drake/AW	1,320	1,519	1,071	1,233	900	1,042	796	927
	795,000	(45/7)	Tern/AW	1,275	1,469	1,035	1,192	870	1,007	770	896
	1,590,000	(45/7)	Lapw ing/AW	1,984	2,282	1,609	1,846	1,349	1,556	1,190	1,381
ACSR/EHS	203,200	(16/19)	Brahma	440	510	358	414	302	350	268	313
	211,300	*(12/7)*	*Cochin*	440	509	357	413	301	350	267	312

* This table shows the capability to load overhead conductors during various conditions of ambient temperature. The "ratings" are used for planning studies and other forward looking analyses. The "extreme ambient" capabilities can be used for operating the

\+ *Ferrous clamps without armor rods.*

TABLE 5 (Continued)

Allowable Current Carrying Capacity of Bare Overhead Conductors* Subtransmission Lines – Below 138 kV -- AEP West

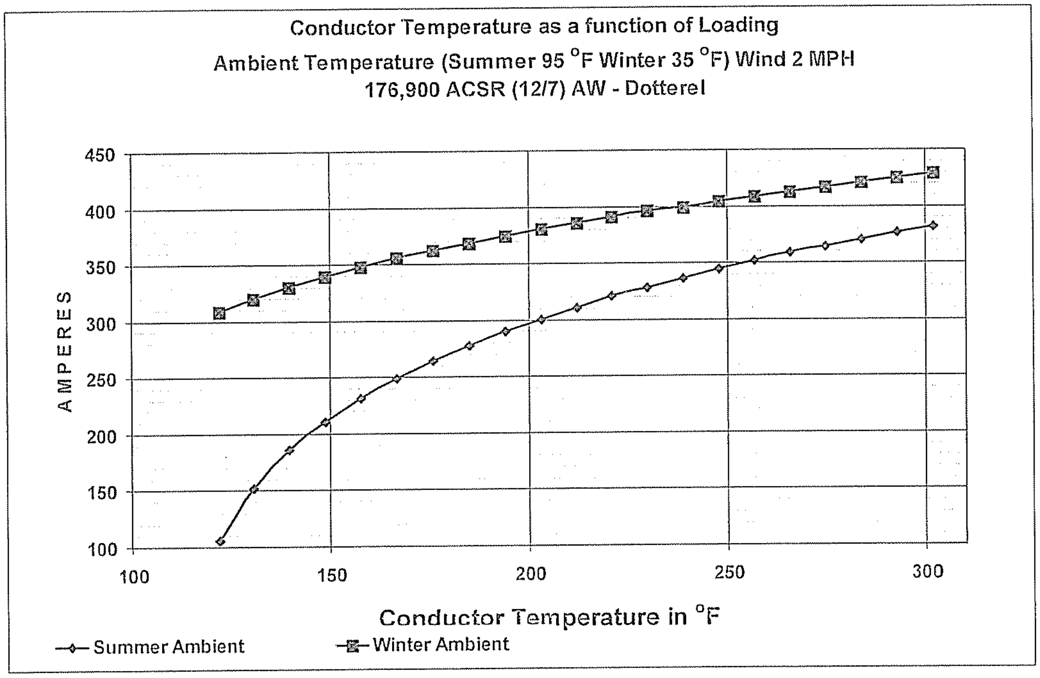
Conductor Type, Size, Stranding (cm) and Name				Extreme Winter		Conductor Ratings				Extreme Summer	
				Ambient (0°F or -18°C)		Winter (68°F)		Summer (104°F)		Ambient (122°F or 50°C)	
Type	Size	Stranding	Name	1 MPH Wind	2 MPH Wind	1 MPH Wind	2 MPH Wind	1 MPH Wind	2 MPH Wind	1 MPH Wind	2 MPH Wind
				Amps	Amps	Amps	Amps	Amps	Amps	Amps	Amps
ACAR	755,000	(24/13)		1,187	1,368	964	1,112	811	940	718	836
	1,024,000	(24/13)		1,449	1,668	1,177	1,355	989	1,144	875	1,017
AAC	477,000	(37)	Syringa	901	1,041	732	846	617	716	547	638
	795,000	(37)	Arbutus	1,252	1,443	1,017	1,172	855	990	757	881
	1,272,000	(61)	Narcissus	1,686	1,938	1,370	1,575	1,150	1,328	1,016	1,180
AAAC6201	559,600	(19)	Darien (477)	850	990	637	746	475	568	364	448
	740,800	(37)	Flint (636)	1028	1184	762	892	566	676	429	531
COPPER	2	(7)		300	351	227	267	174	207	138	168
	2/0	(7)		454	531	342	403	261	310	206	251
	4/0	(19)		612	715	461	541	349	416	273	333
	250,000	(19)		681	795	512	602	387	461	302	369
	500,000	(37)		1059	1233	794	930	593	708	455	560
	750,000	(37)		1364	1586	1020	1194	757	905	575	711
	1,000,000	(37)		1623	1885	1212	1418	895	1070	673	836

* This table shows the capability to load overhead conductors during various conditions of ambient temperature. The "ratings" are used for planning studies and other forward looking analyses. The "extreme ambient" capabilities can be used for operating the

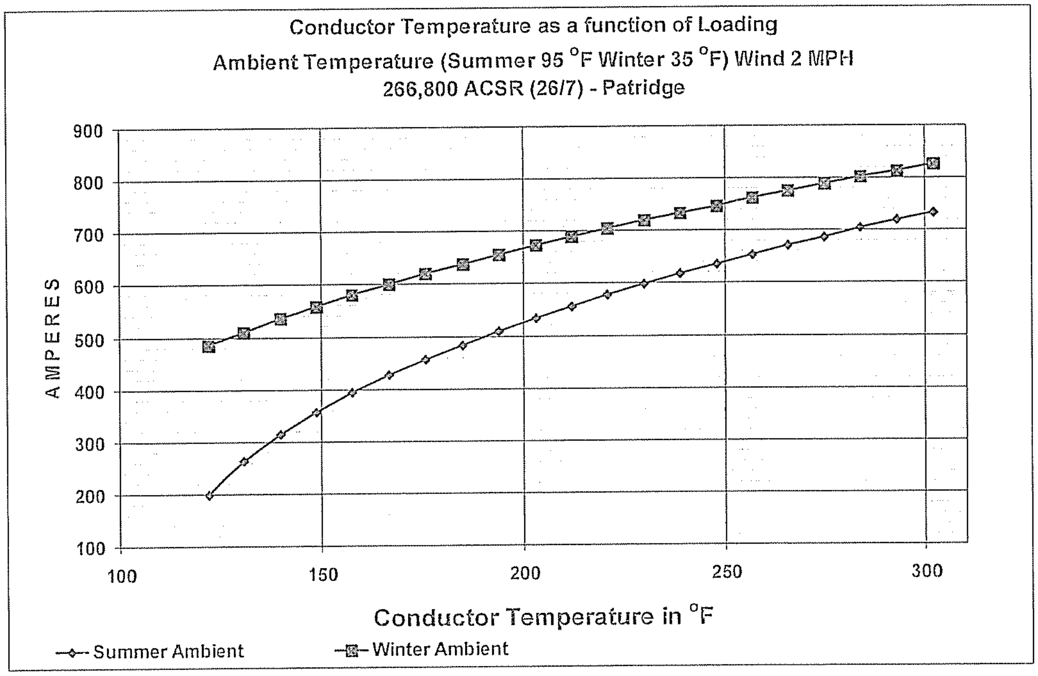
\+ Ferrous clamps without armor rods.

Appendix A	Plots of Conductor Temperature as a function of Conductor Loading ACSR Conductors – AEP East
Appendix B	Plots of Conductor Temperature as a function of Conductor Loading ACSR Conductors – AEP West
Appendix C	Plots of Normal and Emergency Capabilities as a function of Ambient Temperature ACSR Conductors
Appendix D	Plots of Conductor Temperature as a function of Conductor Loading ACAR and AAC – AEP East
Appendix E	Plots of Conductor Temperature as a function of Conductor Loading ACAR and AAC Conductors – AEP West
Appendix F	Plots of Normal and Emergency Capability as a function of Ambient Temperature ACAR and AAC Conductors
Appendix G	Plots of Conductor Temperature as a function of Conductor Loading Copper Conductors – AEP East
Appendix H	Plots of Conductor Temperature as a function of Conductor Loading Copper Conductors – AEP West
Appendix I	Plots of Normal and Emergency Capability as a function of Ambient Temperature Copper Conductors

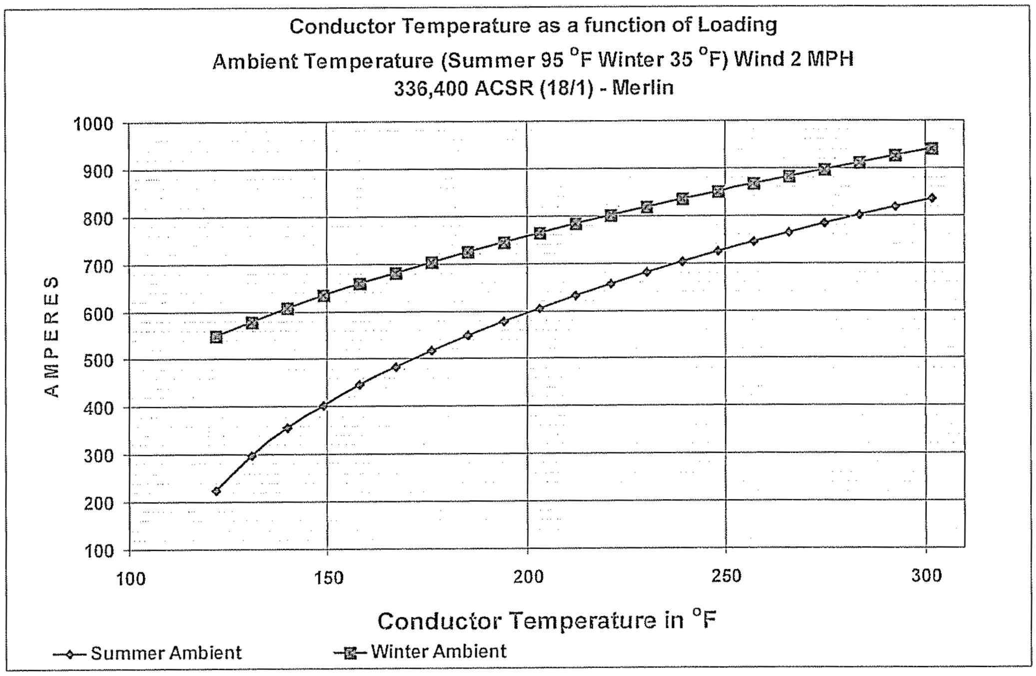
Appendix A	Plots of Conductor Temperature as a function of Conductor Loading **ACSR Conductors – AEP East**

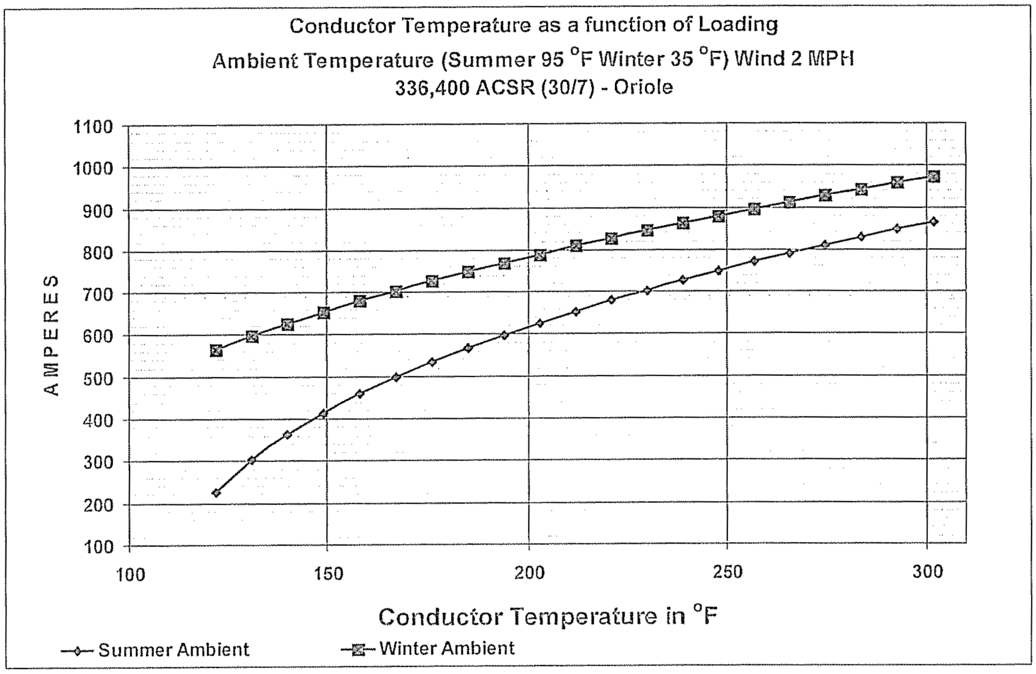


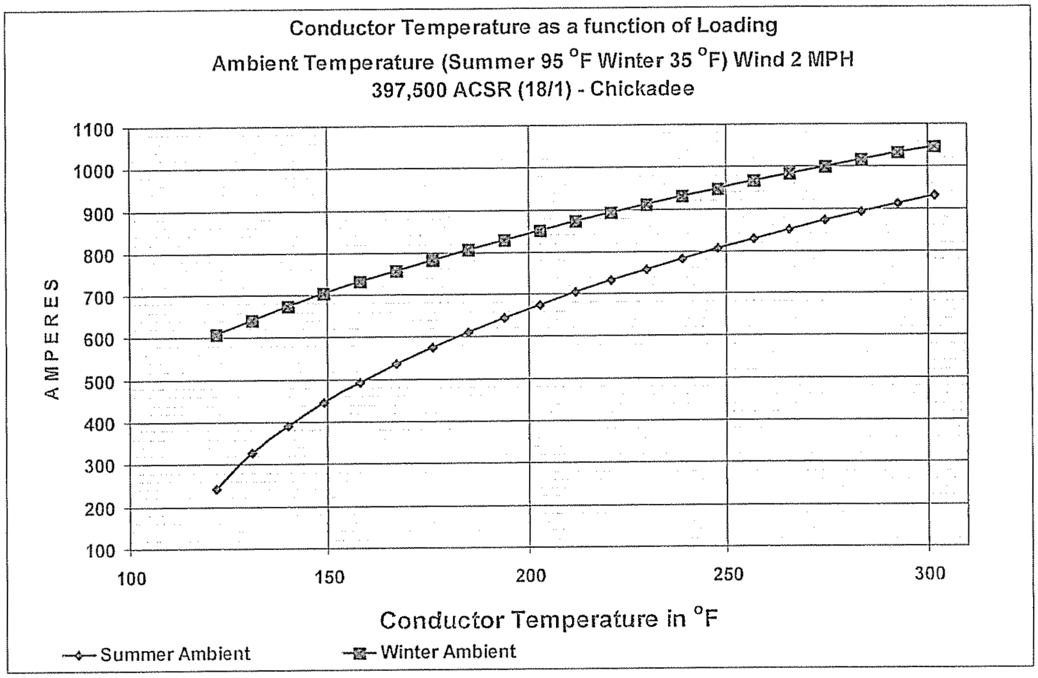
Conductor Temperature as a function of Loading
Ambient Temperature (Summer 95 °F Winter 35 °F) Wind 2 MPH
176,900 ACSR (12/7) AW - Dotterel

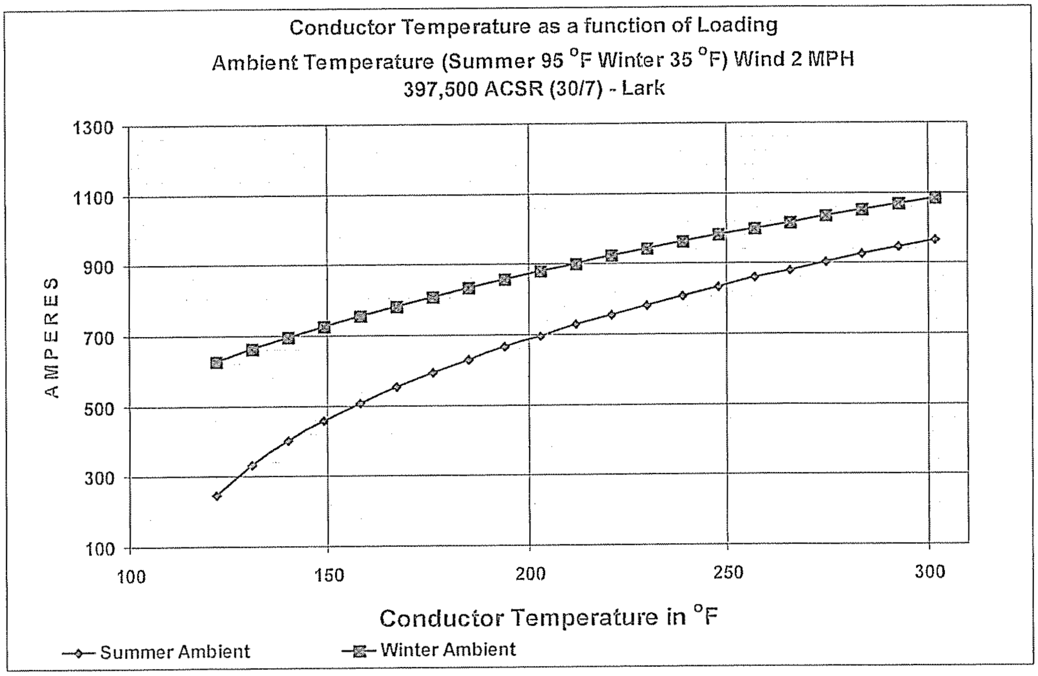


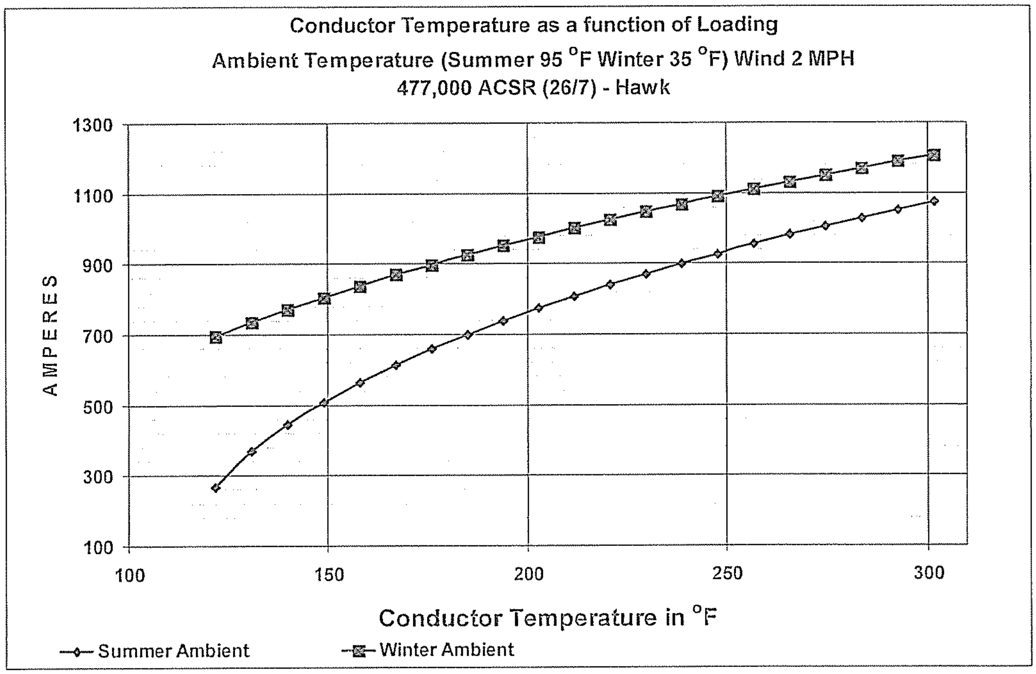
Conductor Temperature as a function of Loading
Ambient Temperature (Summer 95 °F Winter 35 °F) Wind 2 MPH
266,800 ACSR (26/7) - Patridge

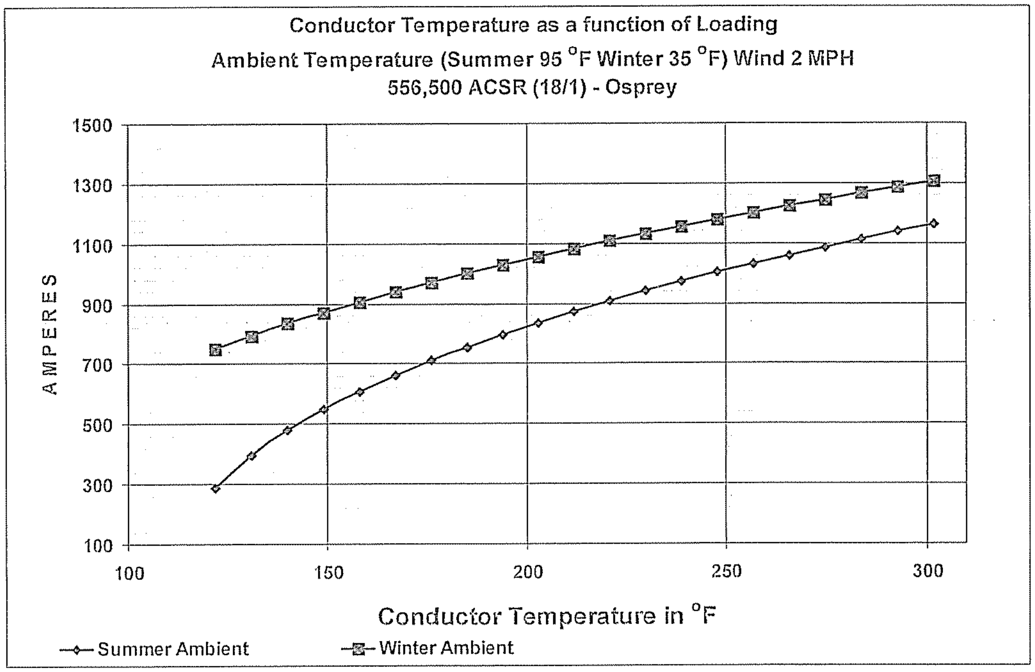

Conductor Temperature as a function of Loading
Ambient Temperature (Summer 95 °F Winter 35 °F) Wind 2 MPH
336,400 ACSR (18/1) - Merlin
AMPERES
1000
900
800
700
600
500
400
300
200
100
100
150
200
250
300
Conductor Temperature in °F
Summer Ambient
Winter Ambient

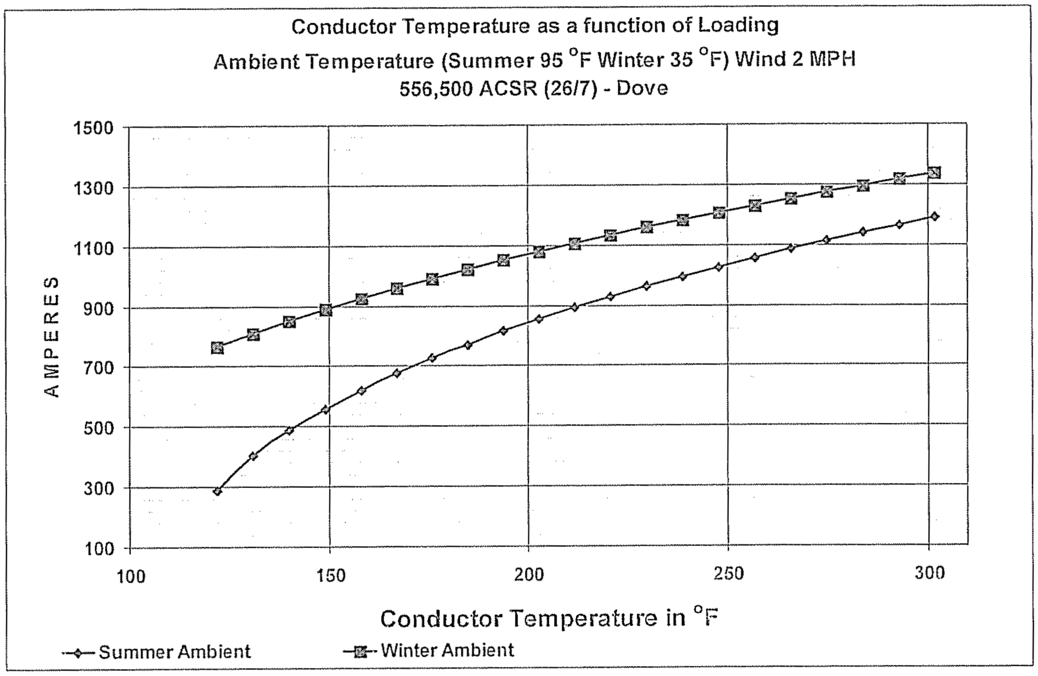

Conductor Temperature as a function of Loading
Ambient Temperature (Summer 95 °F Winter 35 °F) Wind 2 MPH
336,400 ACSR (30/7) - Oriole
AMPERES
1100
1000
900
800
700
600
500
400
300
200
100
100
150
200
250
300
Conductor Temperature in °F
Summer Ambient
Winter Ambient

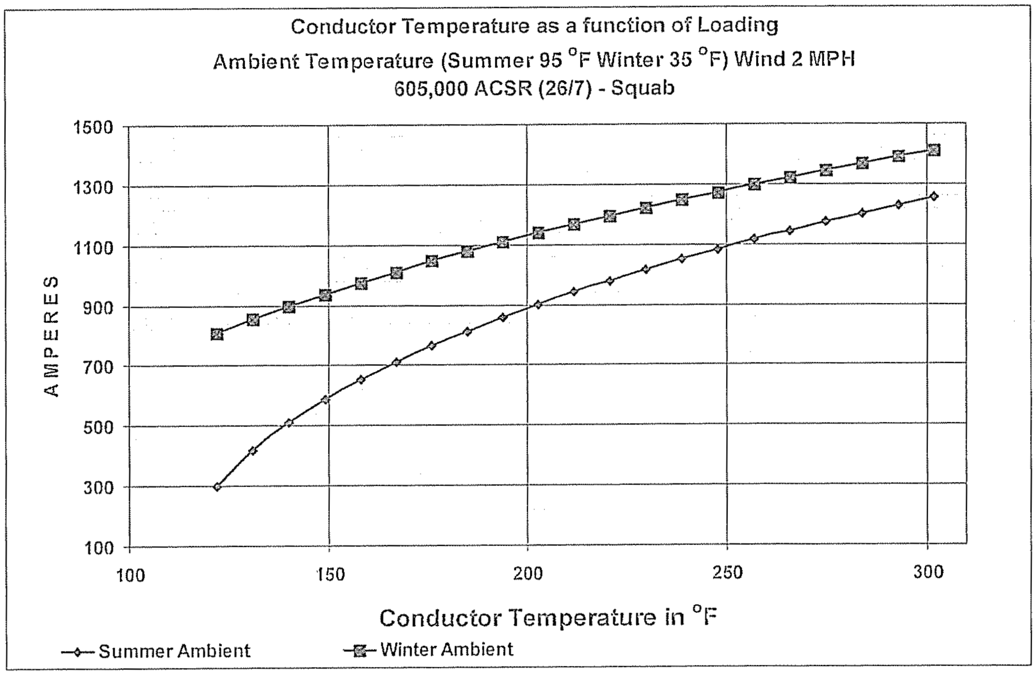

Conductor Temperature as a function of Loading
Ambient Temperature (Summer 95 °F Winter 35 °F) Wind 2 MPH
397,500 ACSR (18/1) - Chickadee
AMPERES
1100
1000
900
800
700
600
500
400
300
200
100
100
150
200
250
300
Conductor Temperature in °F
Summer Ambient
Winter Ambient

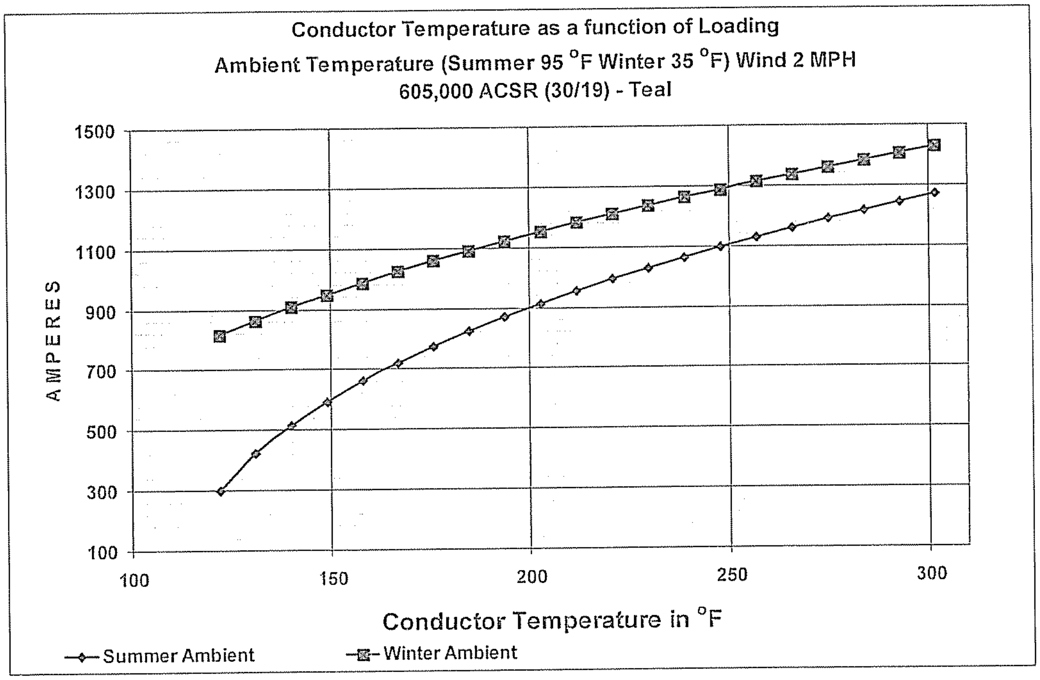

Conductor Temperature as a function of Loading
Ambient Temperature (Summer 95 °F Winter 35 °F) Wind 2 MPH
397,500 ACSR (30/7) - Lark
AMPERES
1300
1100
900
700
500
300
100
100
150
200
250
300
Conductor Temperature in °F
Summer Ambient
Winter Ambient

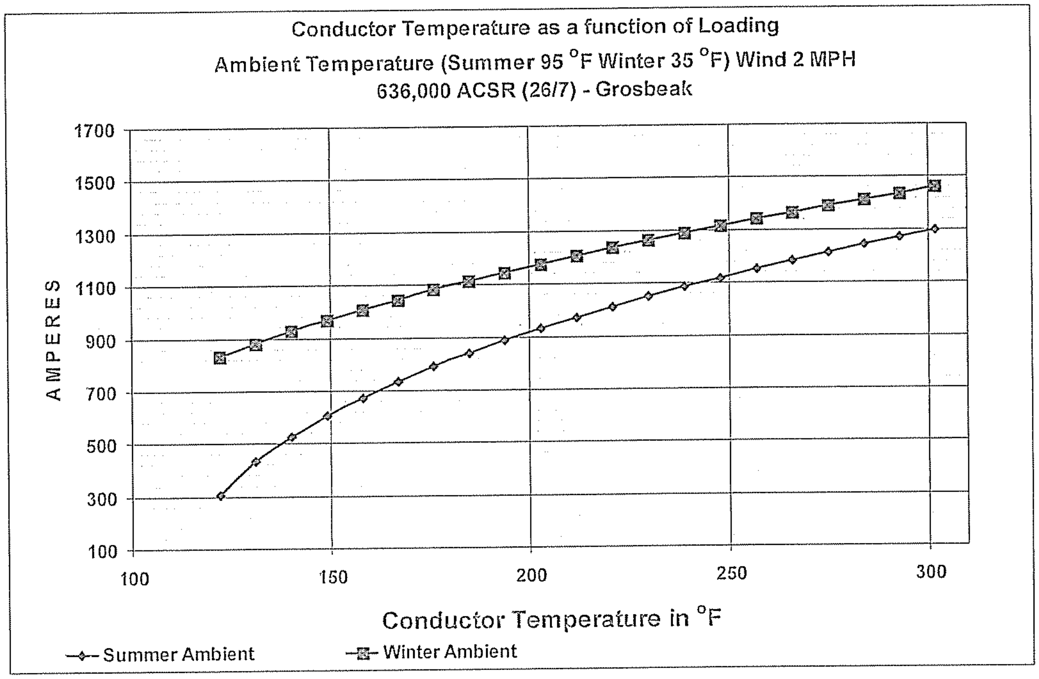

Conductor Temperature as a function of Loading
Ambient Temperature (Summer 95 °F Winter 35 °F) Wind 2 MPH
477,000 ACSR (26/7) - Hawk
AMPERES
1300
1100
900
700
500
300
100
100
150
200
250
300
Conductor Temperature in °F
Summer Ambient
Winter Ambient

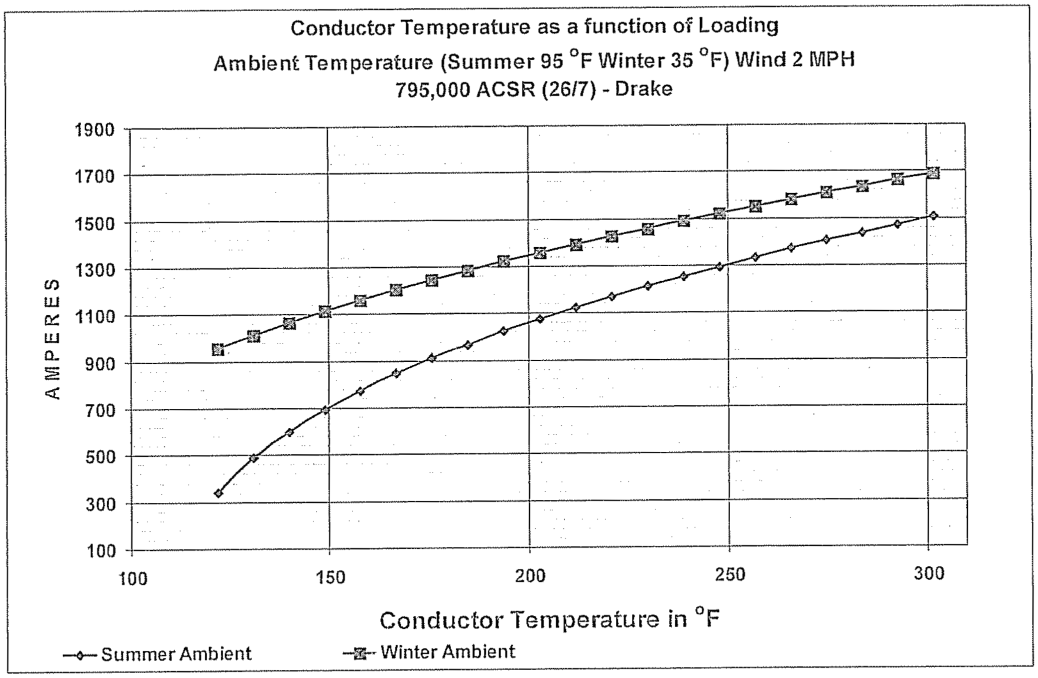

Conductor Temperature as a function of Loading
Ambient Temperature (Summer 95 °F Winter 35 °F) Wind 2 MPH
556,500 ACSR (18/1) - Osprey
AMPERES
1500
1300
1100
900
700
500
300
100
100
150
200
250
300
Conductor Temperature in °F
Summer Ambient
Winter Ambient

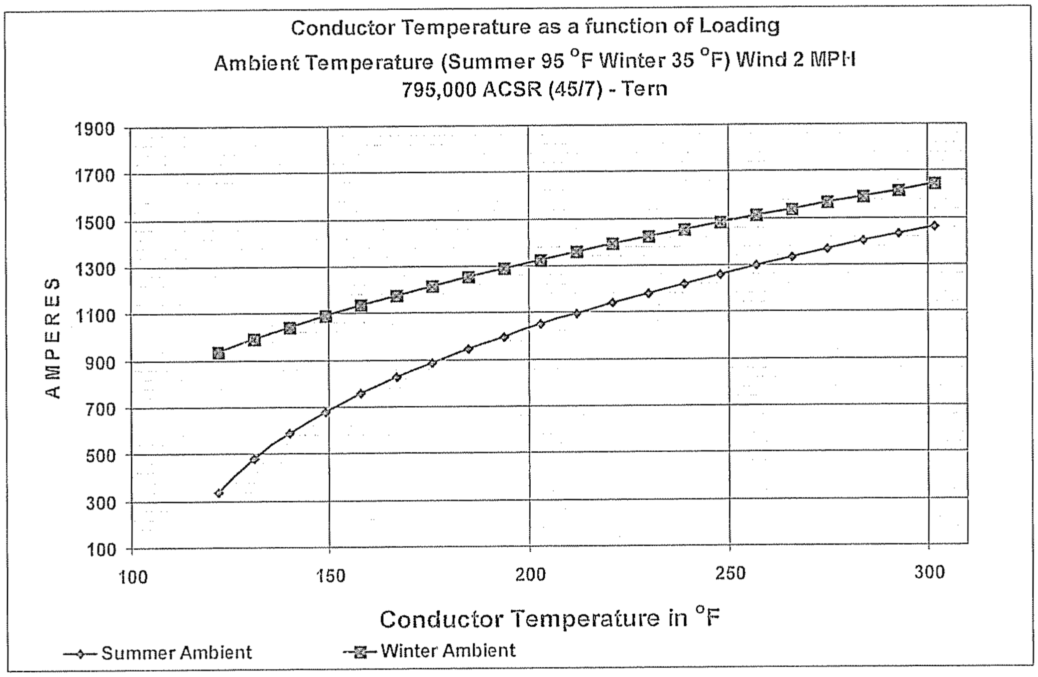

Conductor Temperature as a function of Loading
Ambient Temperature (Summer 95 °F Winter 35 °F) Wind 2 MPH
556,500 ACSR (26/7) - Dove
AMPERES
1500
1300
1100
900
700
500
300
100
100
150
200
250
300
Conductor Temperature in °F
Summer Ambient
Winter Ambient

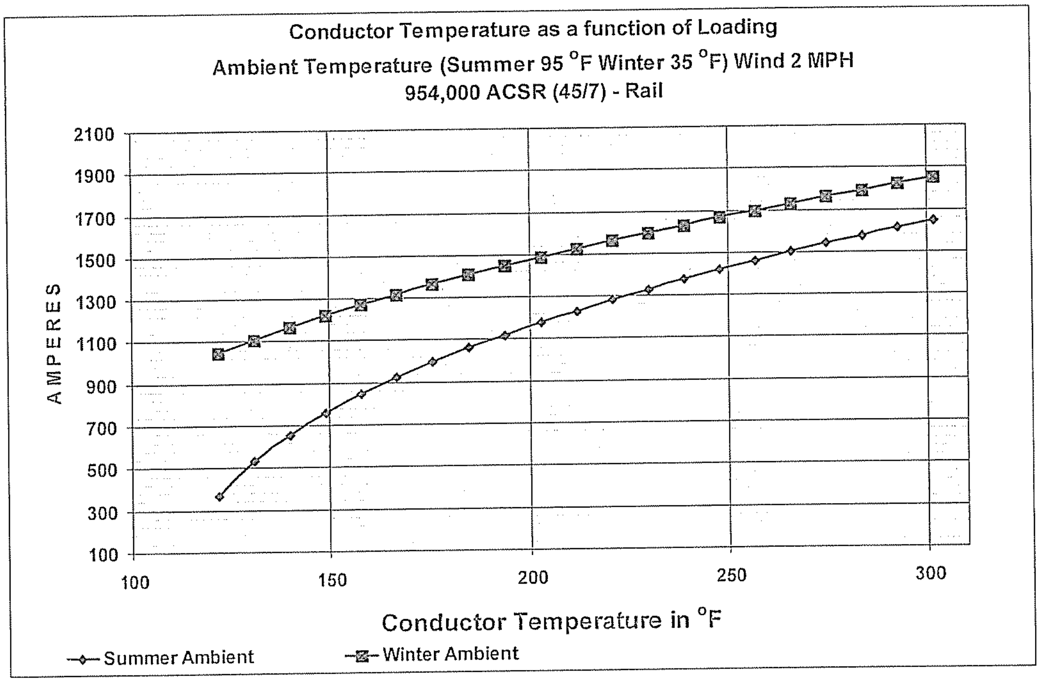

Conductor Temperature as a function of Loading
Ambient Temperature (Summer 95 °F Winter 35 °F) Wind 2 MPH
605,000 ACSR (26/7) - Squab
AMPERES
1500
1300
1100
900
700
500
300
100
100
150
200
250
300
Conductor Temperature in °F
Summer Ambient
Winter Ambient


Conductor Temperature as a function of Loading
Ambient Temperature (Summer 95 °F Winter 35 °F) Wind 2 MPH
605,000 ACSR (30/19) - Teal
AMPERES
1500
1300
1100
900
700
500
300
100
100
150
200
250
300
Conductor Temperature in °F
Summer Ambient
Winter Ambient

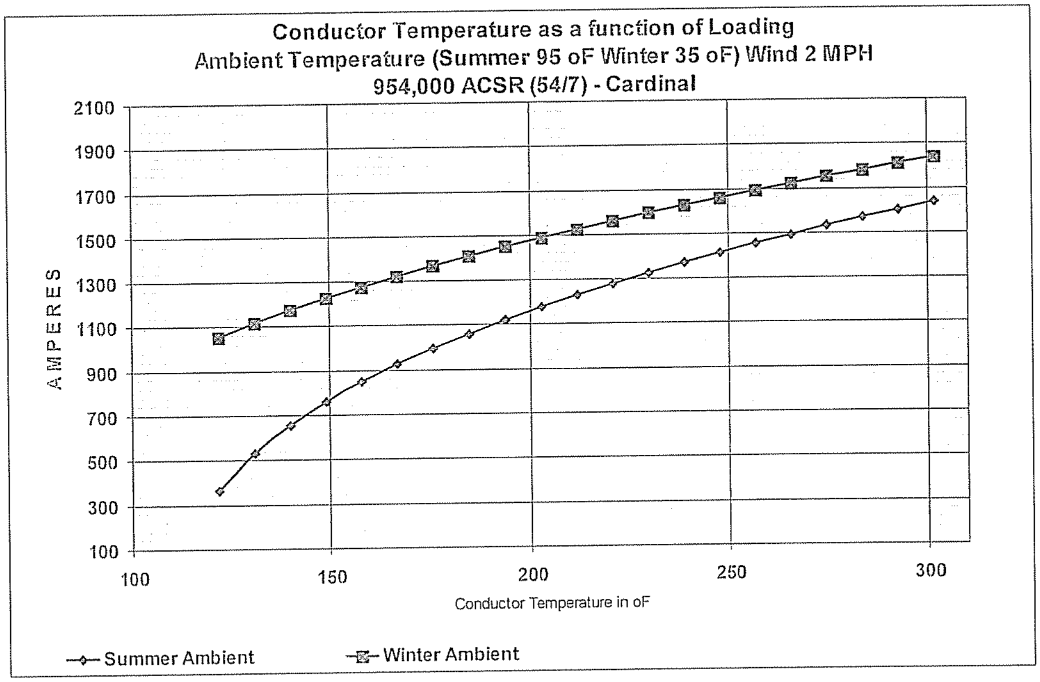

Conductor Temperature as a function of Loading
Ambient Temperature (Summer 95 °F Winter 35 °F) Wind 2 MPH
636,000 ACSR (26/7) - Grosbeak
AMPERES
1700
1500
1300
1100
900
700
500
300
100
100
150
200
250
300
Conductor Temperature in °F
Summer Ambient
Winter Ambient


Conductor Temperature as a function of Loading
Ambient Temperature (Summer 95 °F Winter 35 °F) Wind 2 MPH
795,000 ACSR (26/7) - Drake
AMPERES
1900
1700
1500
1300
1100
900
700
500
300
100
100
150
200
250
300
Conductor Temperature in °F
Summer Ambient
Winter Ambient

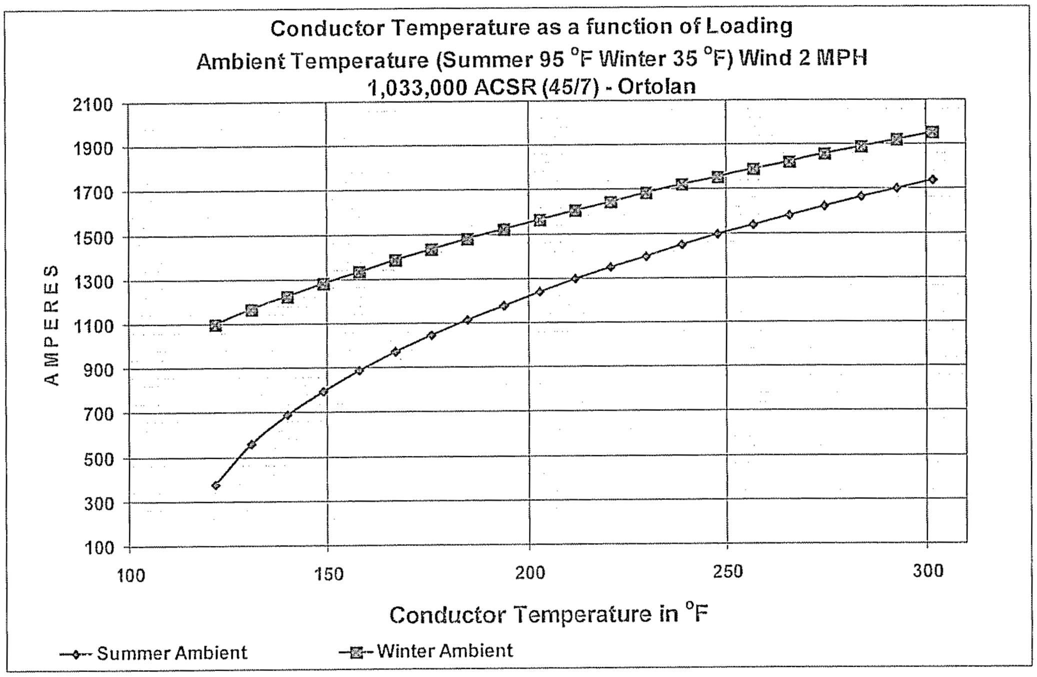

Conductor Temperature as a function of Loading
Ambient Temperature (Summer 95 °F Winter 35 °F) Wind 2 MPH
795,000 ACSR (45/7) - Tern
AMPERES
1900
1700
1500
1300
1100
900
700
500
300
100
100
150
200
250
300
Conductor Temperature in °F
Summer Ambient
Winter Ambient

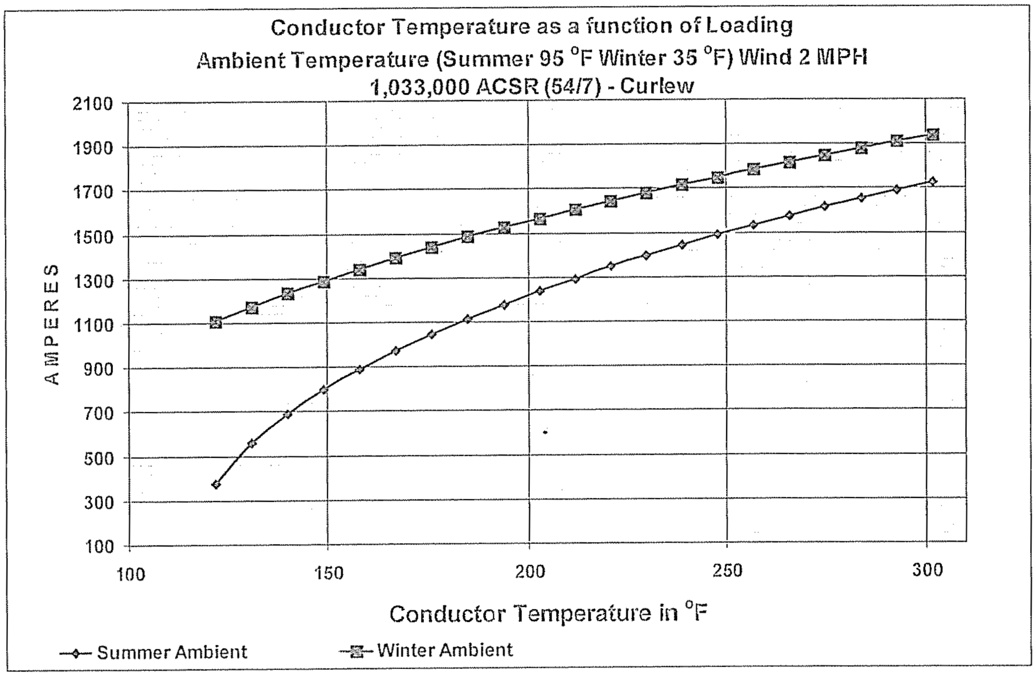


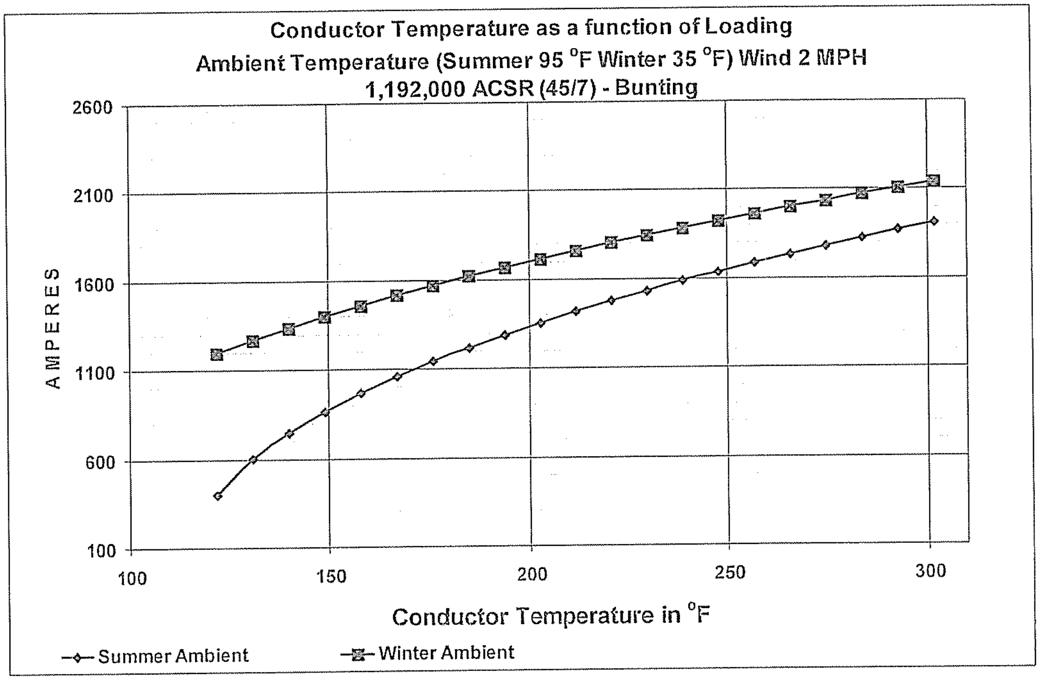
Conductor Temperature as a function of Loading
Ambient Temperature (Summer 95 °F Winter 35 °F) Wind 2 MPH
954,000 ACSR (45/7) - Rail

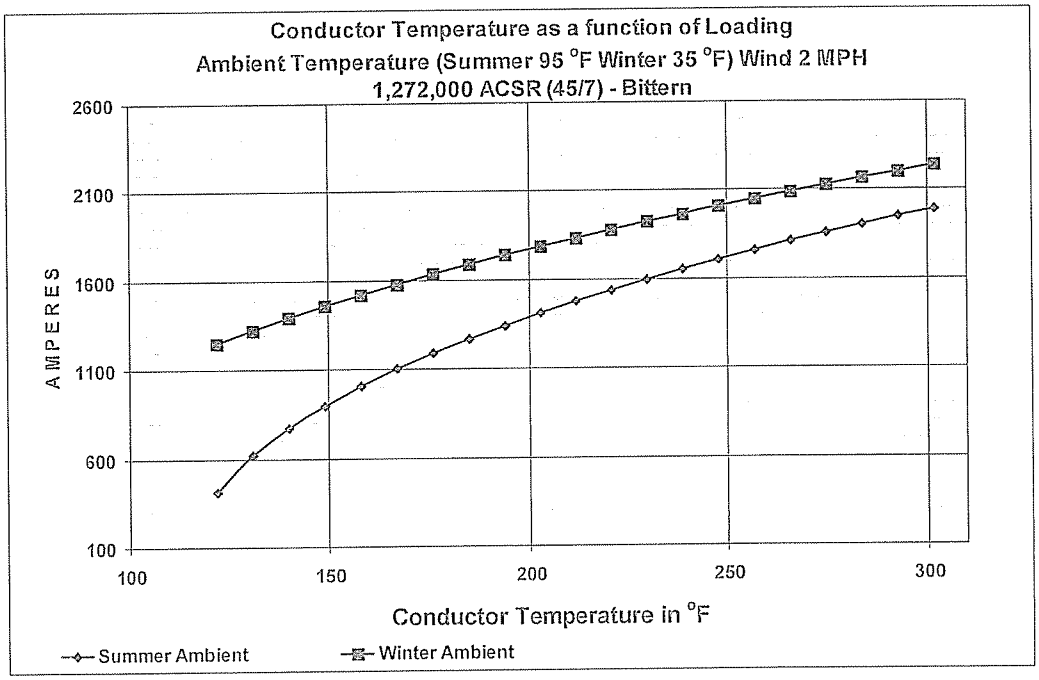


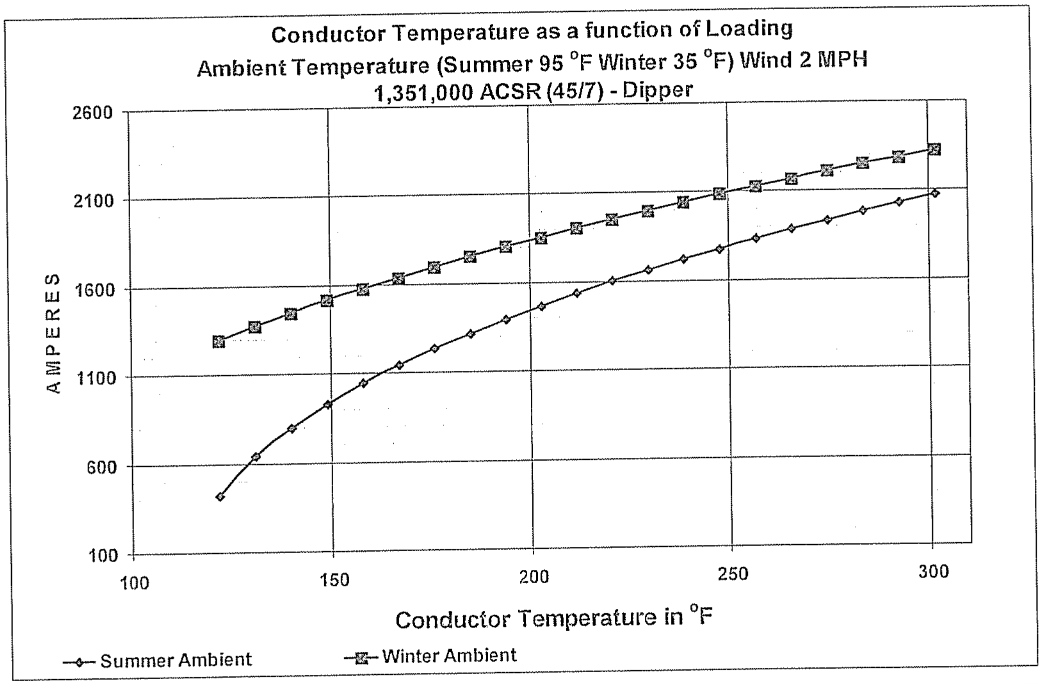
Conductor Temperature as a function of Loading
Ambient Temperature (Summer 95 oF Winter 35 oF) Wind 2 MPH
954,000 ACSR (54/7) - Cardinal


Conductor Temperature as a function of Loading
Ambient Temperature (Summer 95 °F Winter 35 °F) Wind 2 MPH
1,033,000 ACSR (45/7) - Ortolan
AMPERES
2100
1900
1700
1500
1300
1100
900
700
500
300
100
100
150
200
250
300
Conductor Temperature in °F
Summer Ambient
Winter Ambient

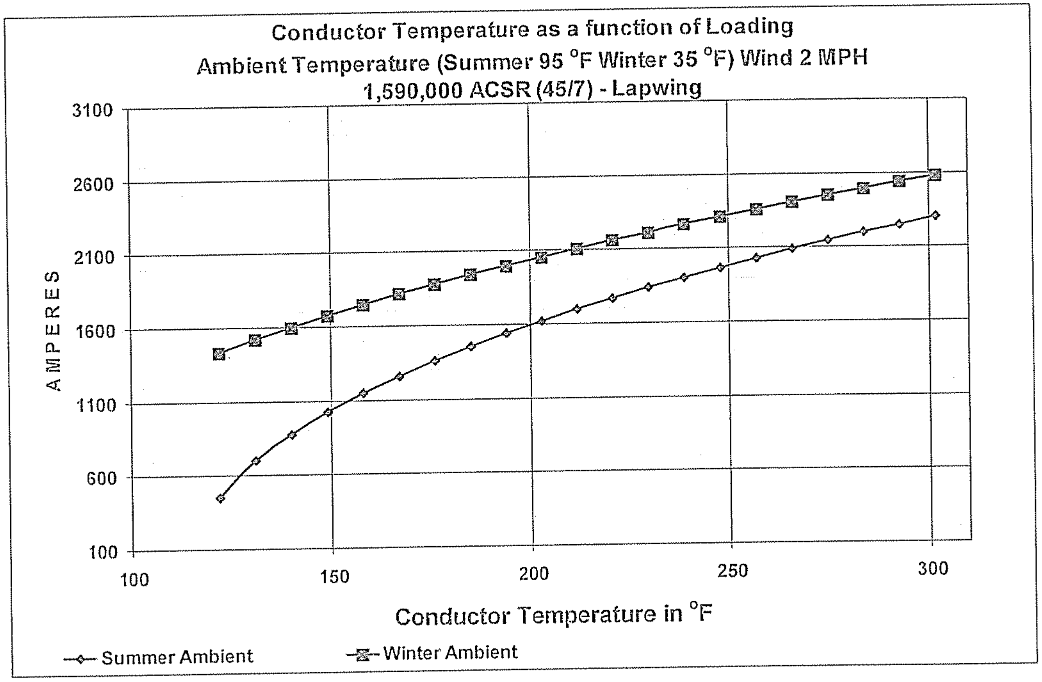

Conductor Temperature as a function of Loading
Ambient Temperature (Summer 95 °F Winter 35 °F) Wind 2 MPH
1,033,000 ACSR (54/7) - Curlew
AMPERES
2100
1900
1700
1500
1300
1100
900
700
500
300
100
100
150
200
250
300
Conductor Temperature in °F
Summer Ambient
Winter Ambient


Conductor Temperature as a function of Loading
Ambient Temperature (Summer 95 °F Winter 35 °F) Wind 2 MPH
1,192,000 ACSR (45/7) - Bunting


Conductor Temperature as a function of Loading
Ambient Temperature (Summer 95 °F Winter 35 °F) Wind 2 MPH
1,272,000 ACSR (45/7) - Bittern



Conductor Temperature as a function of Loading
Ambient Temperature (Summer 95 °F Winter 35 °F) Wind 2 MPH
1,351,000 ACSR (45/7) - Dipper



Conductor Temperature as a function of Loading
Ambient Temperature (Summer 95 °F Winter 35 °F) Wind 2 MPH
1,590,000 ACSR (45/7) - Lapwing

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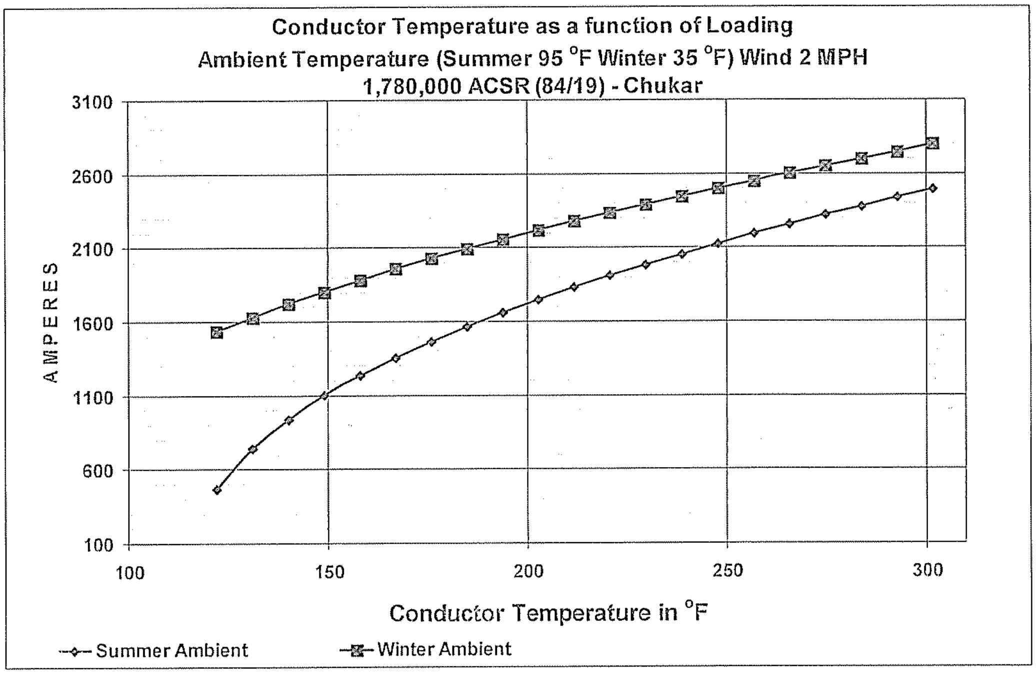
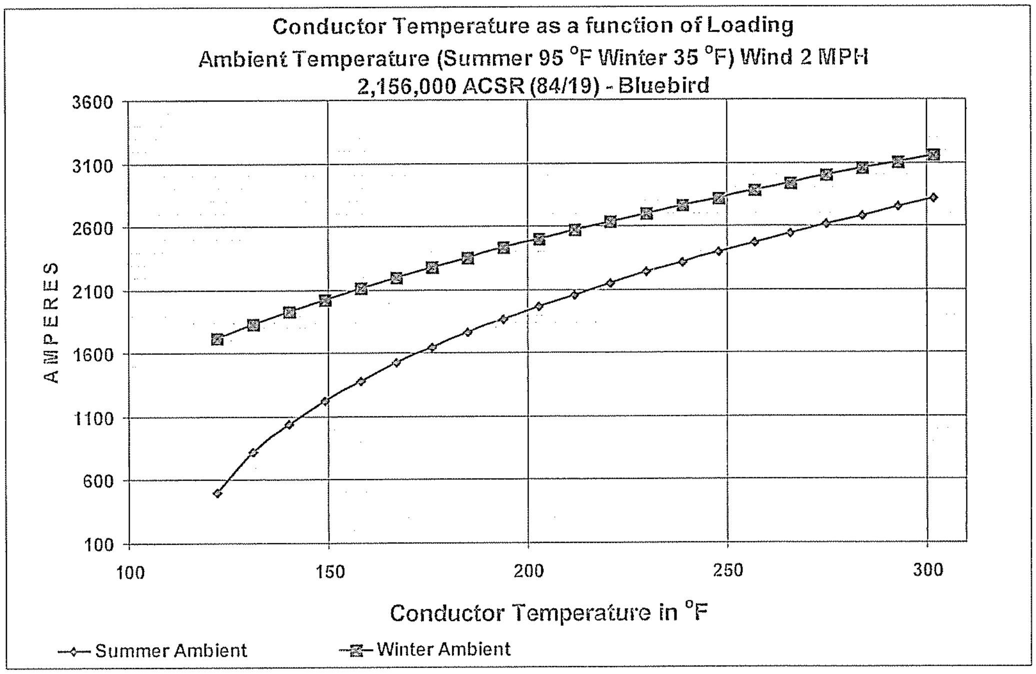
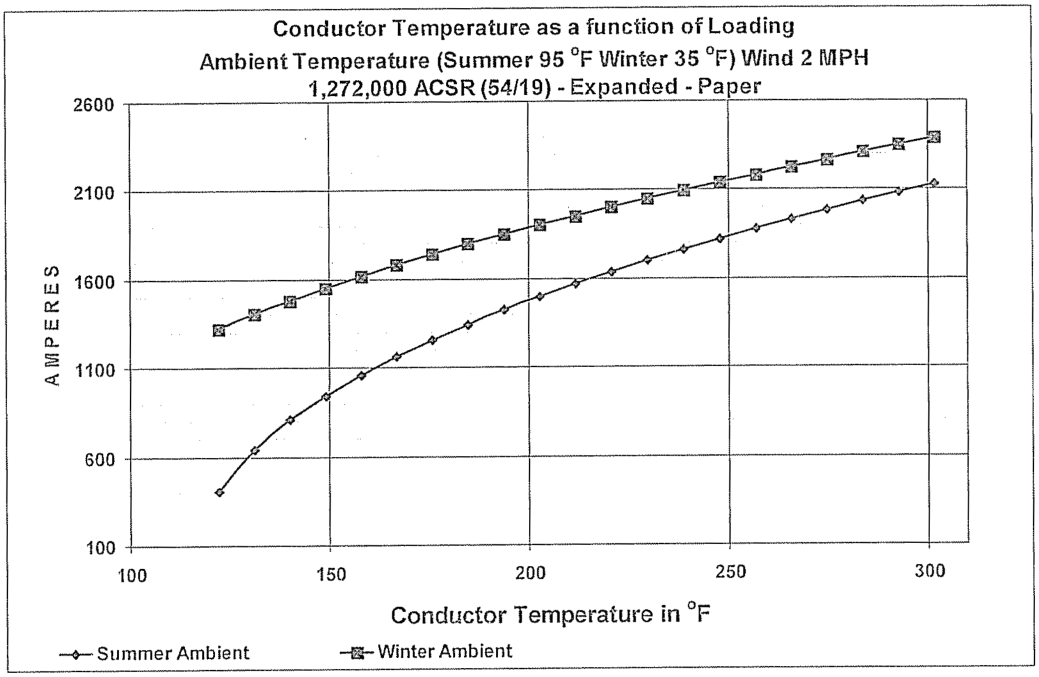
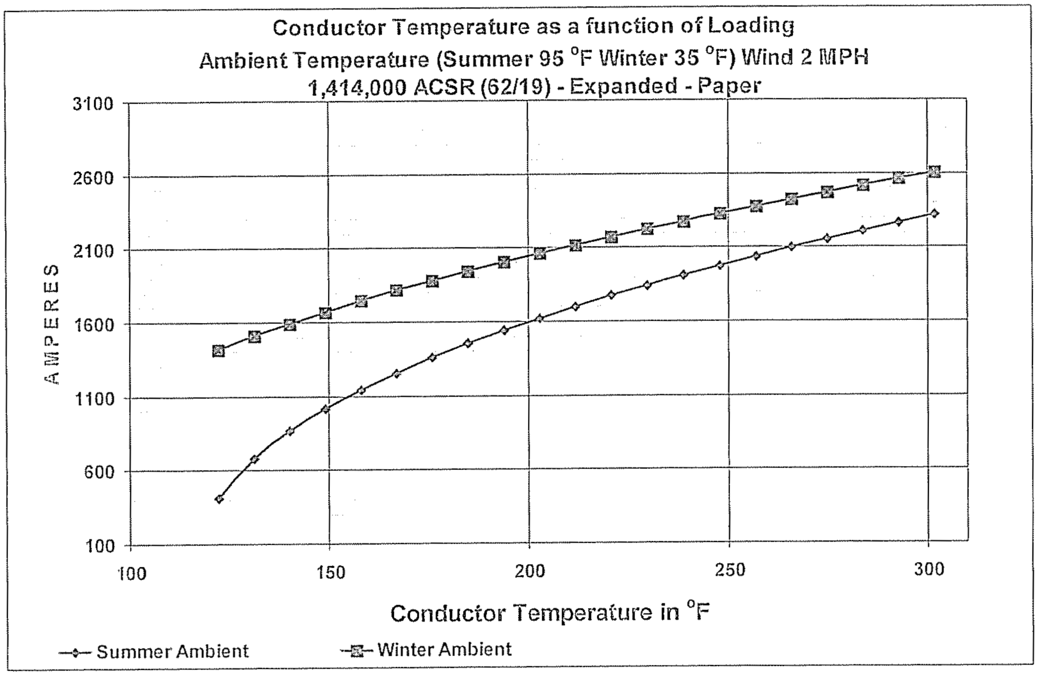
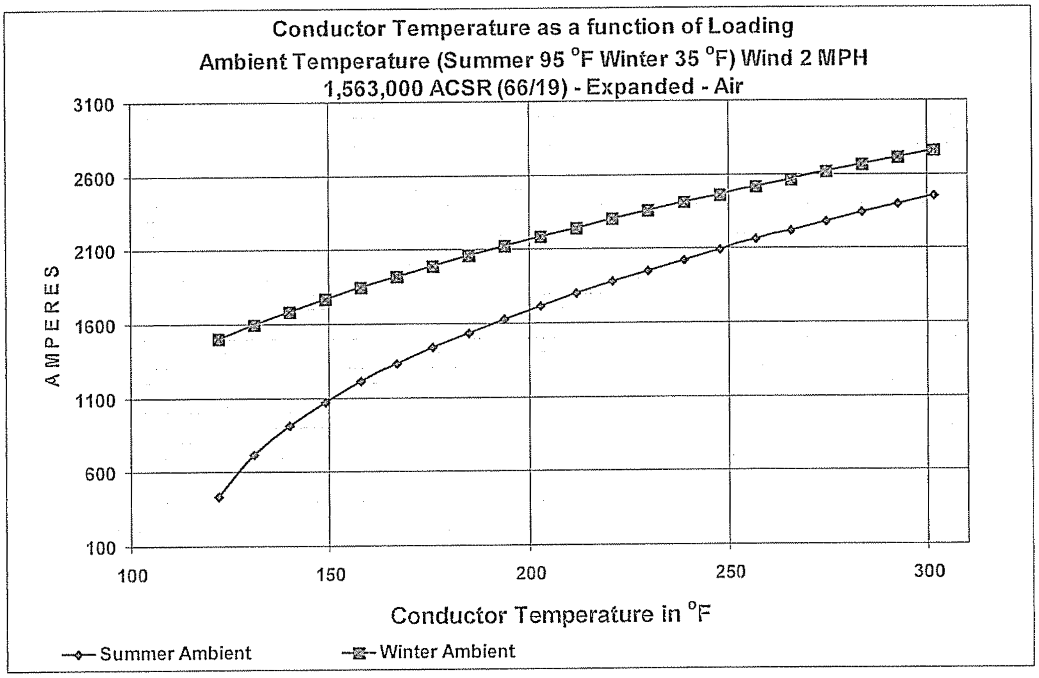
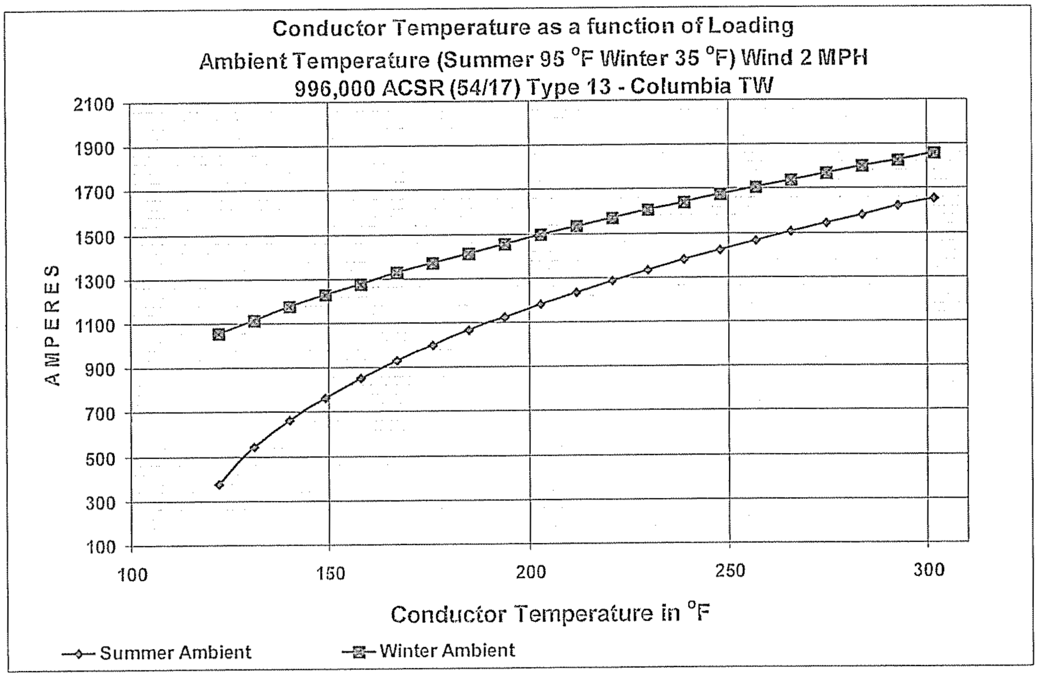




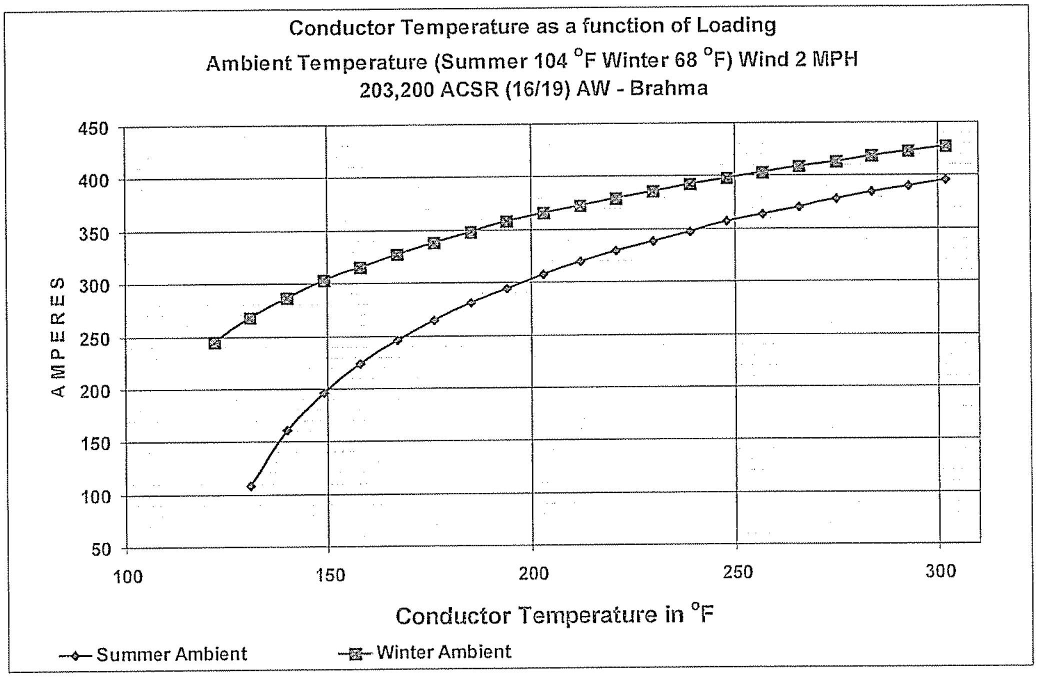

Conductor Temperature as a function of Loading
Ambient Temperature (Summer 95 °F Winter 35 °F) Wind 2 MPH
1,272,000 ACSR (54/19) - Expanded - Paper
AMPERES
2600
2100
1600
1100
600
100
100
150
200
250
300
Conductor Temperature in °F
Summer Ambient
Winter Ambient

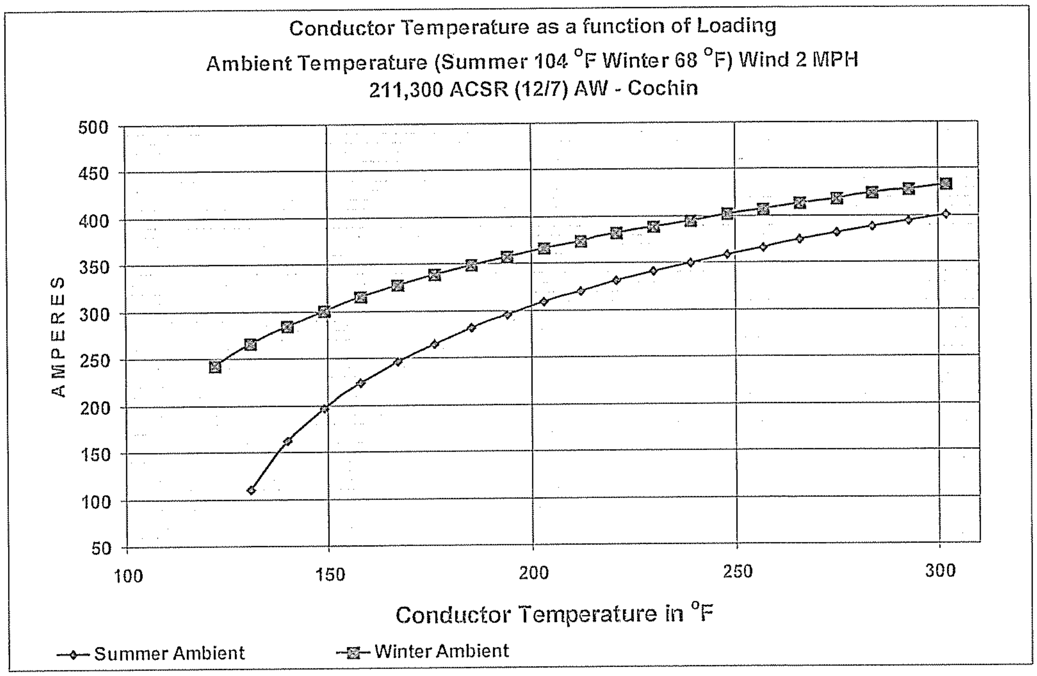

Conductor Temperature as a function of Loading
Ambient Temperature (Summer 95 °F Winter 35 °F) Wind 2 MPH
1,414,000 ACSR (62/19) - Expanded - Paper
AMPERES
3100
2600
2100
1600
1100
600
100
100
150
200
250
300
Conductor Temperature in °F
Summer Ambient
Winter Ambient

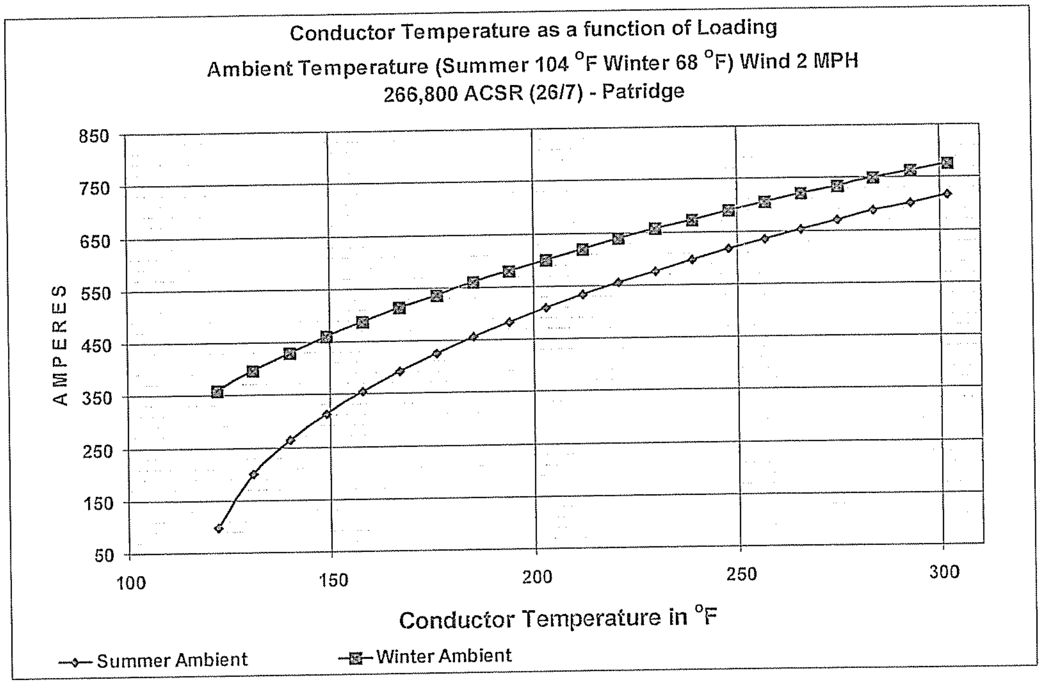

Conductor Temperature as a function of Loading
Ambient Temperature (Summer 95 °F Winter 35 °F) Wind 2 MPH
1,563,000 ACSR (66/19) - Expanded - Air
AMPERES
3100
2600
2100
1600
1100
600
100
100
150
200
250
300
Conductor Temperature in °F
Summer Ambient
Winter Ambient

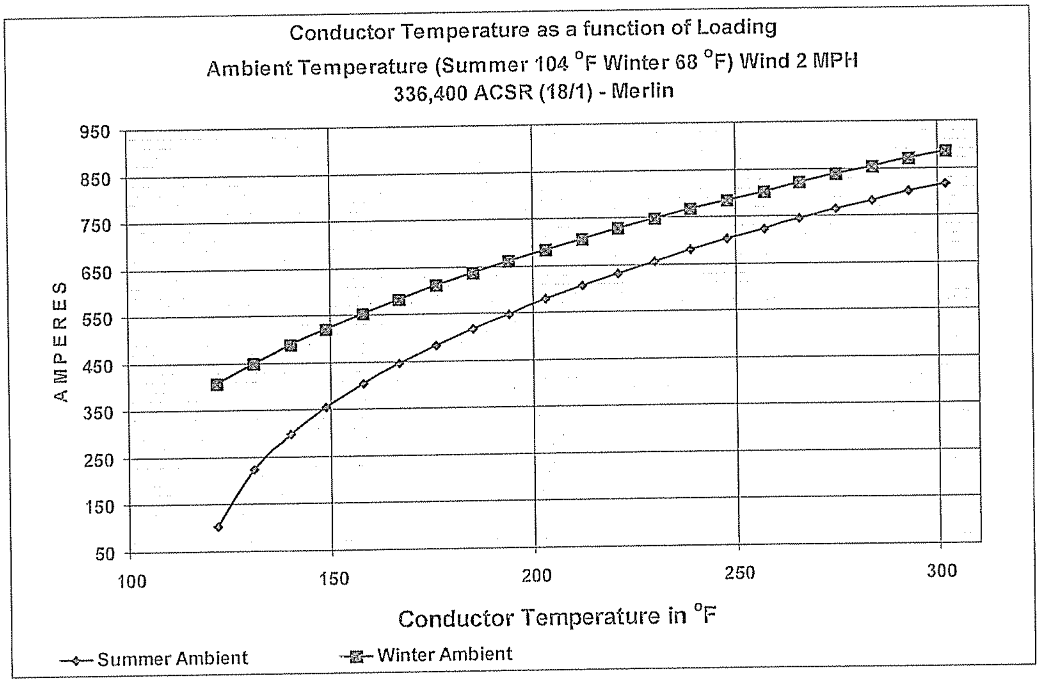

Conductor Temperature as a function of Loading
Ambient Temperature (Summer 95 °F Winter 35 °F) Wind 2 MPH
996,000 ACSR (54/17) Type 13 - Columbia TW
AMPERES
2100
1900
1700
1500
1300
1100
900
700
500
300
100
100
150
200
250
300
Conductor Temperature in °F
Summer Ambient
Winter Ambient

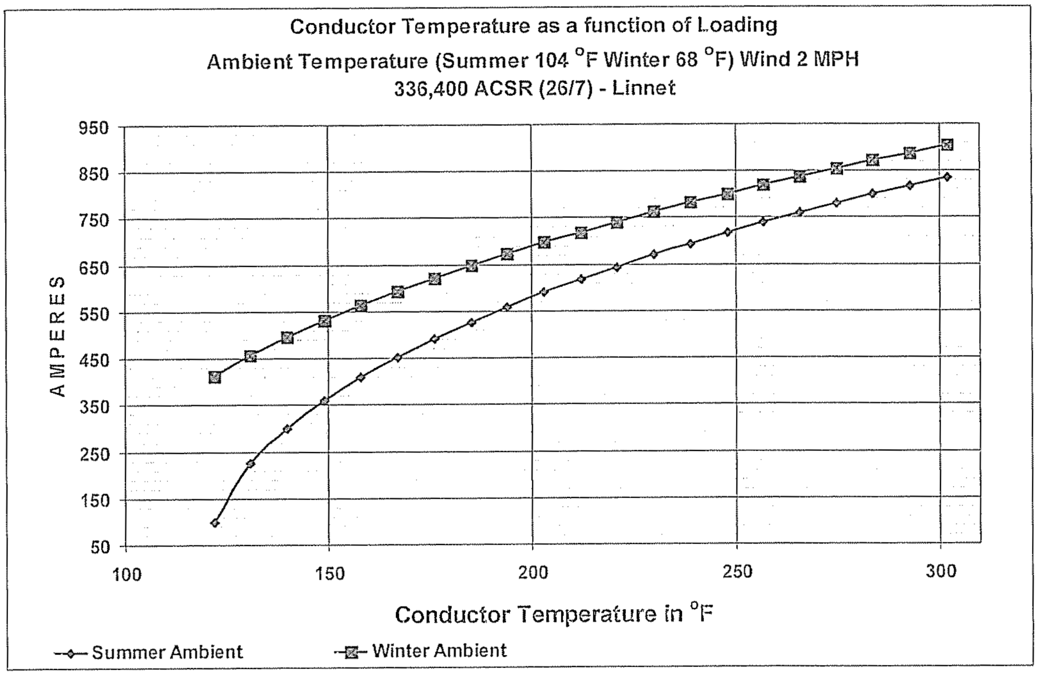
Appendix B	Plots of Conductor Temperature as a function of Conductor Loading **ACSR Conductors – AEP West**

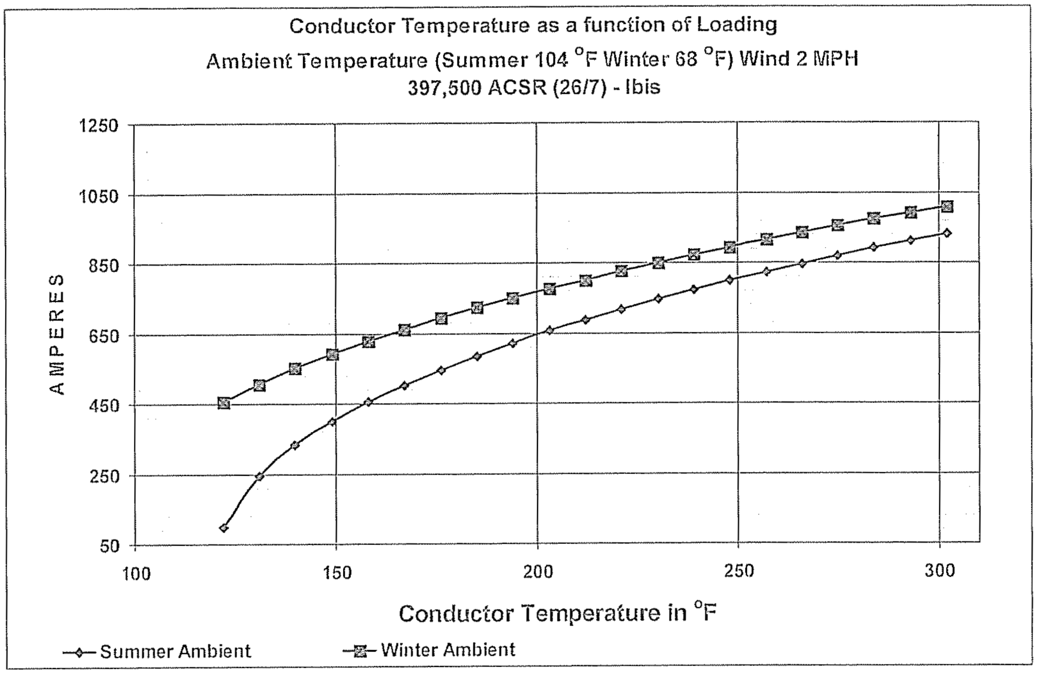

Conductor Temperature as a function of Loading
Ambient Temperature (Summer 104 °F Winter 68 °F) Wind 2 MPH
203,200 ACSR (16/19) AW - Brahma
AMPERES
450
400
350
300
250
200
150
100
50
100
150
200
250
300
Conductor Temperature in °F
Summer Ambient
Winter Ambient

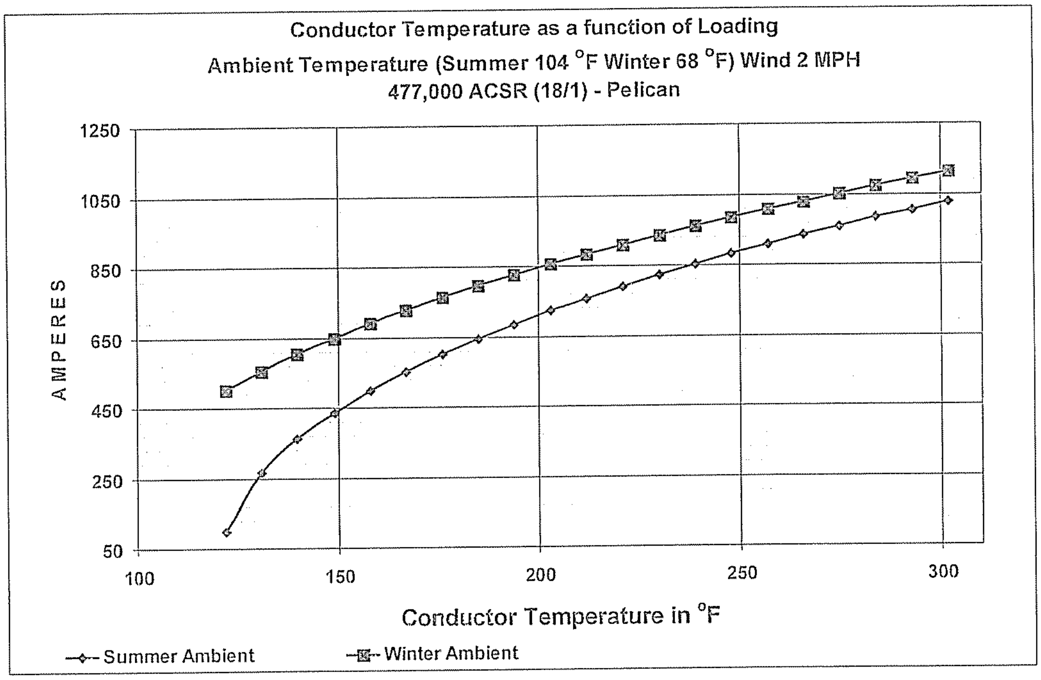

Conductor Temperature as a function of Loading
Ambient Temperature (Summer 104 °F Winter 68 °F) Wind 2 MPH
211,300 ACSR (12/7) AW - Cochin
AMPERES
500
450
400
350
300
250
200
150
100
50
100
150
200
250
300
Conductor Temperature in °F
Summer Ambient
Winter Ambient


Conductor Temperature as a function of Loading
Ambient Temperature (Summer 104 °F Winter 68 °F) Wind 2 MPH
266,800 ACSR (26/7) - Patridge

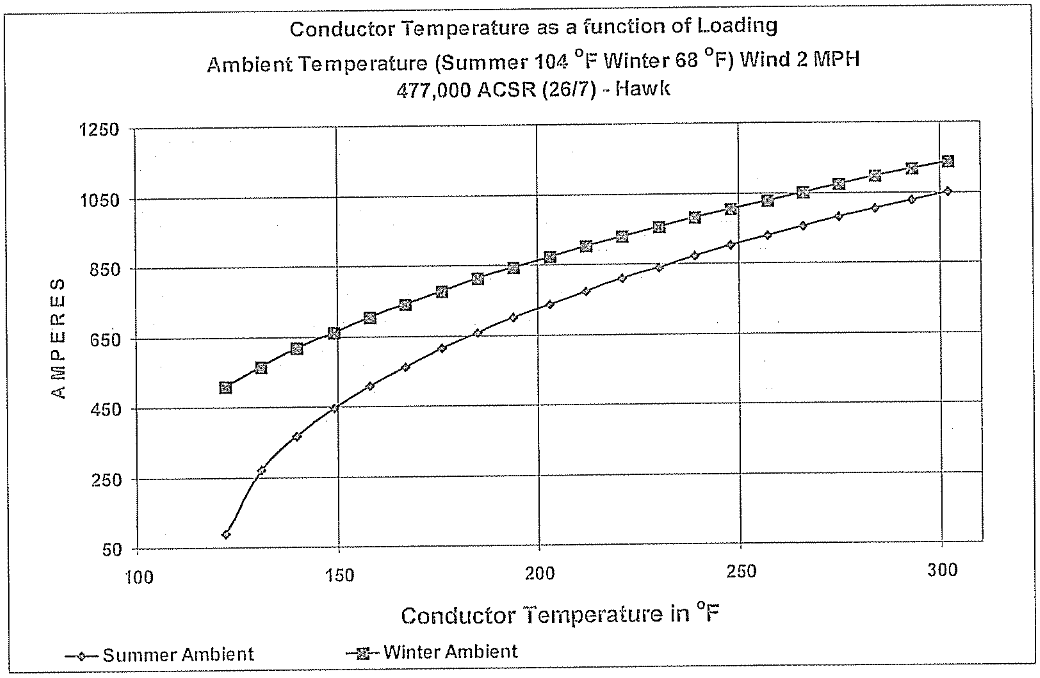

Conductor Temperature as a function of Loading
Ambient Temperature (Summer 104 °F Winter 68 °F) Wind 2 MPH
336,400 ACSR (18/1) - Merlin


Conductor Temperature as a function of Loading
Ambient Temperature (Summer 104 °F Winter 68 °F) Wind 2 MPH
336,400 ACSR (26/7) - Linnet

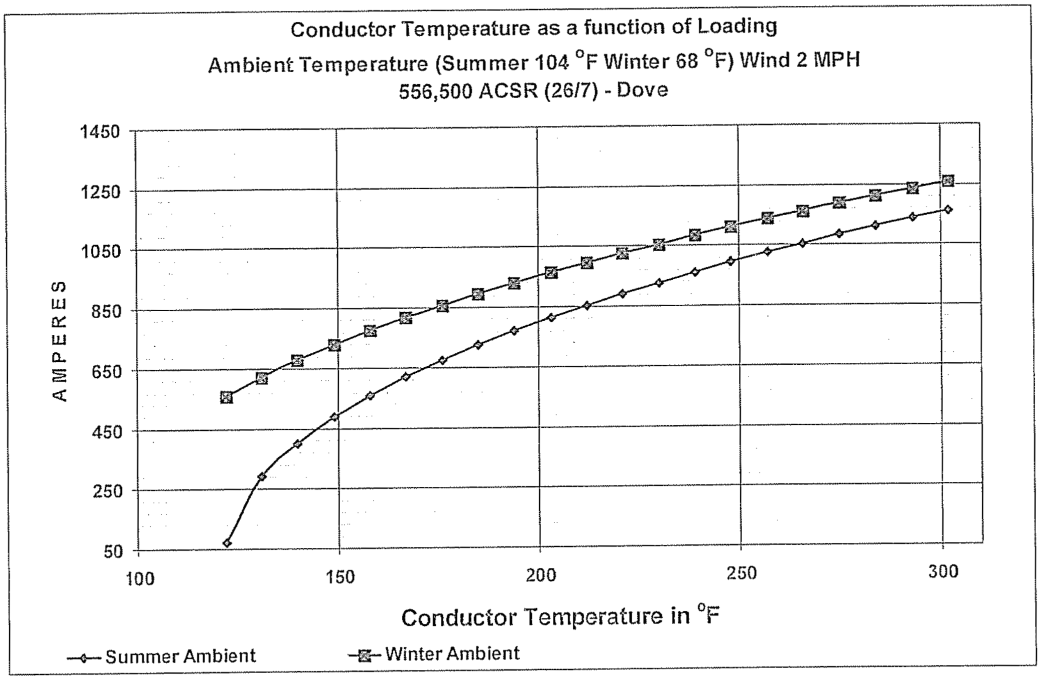

Conductor Temperature as a function of Loading
Ambient Temperature (Summer 104 °F Winter 68 °F) Wind 2 MPH
397,500 ACSR (26/7) - Ibis



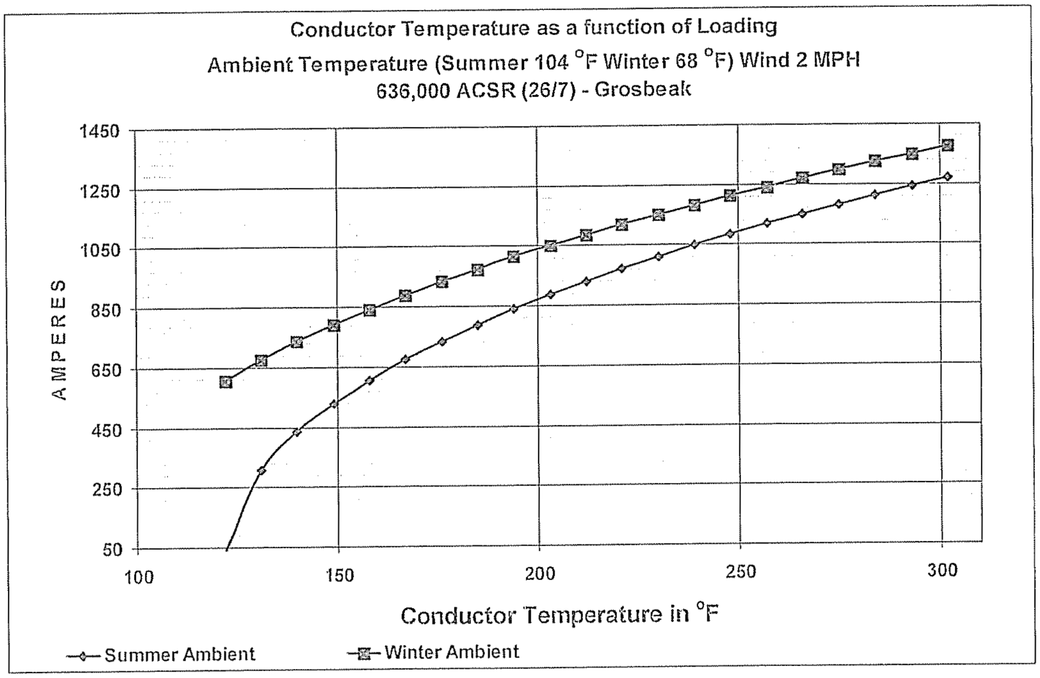
Conductor Temperature as a function of Loading
Ambient Temperature (Summer 104 °F Winter 68 °F) Wind 2 MPH
477,000 ACSR (18/1) - Pelican



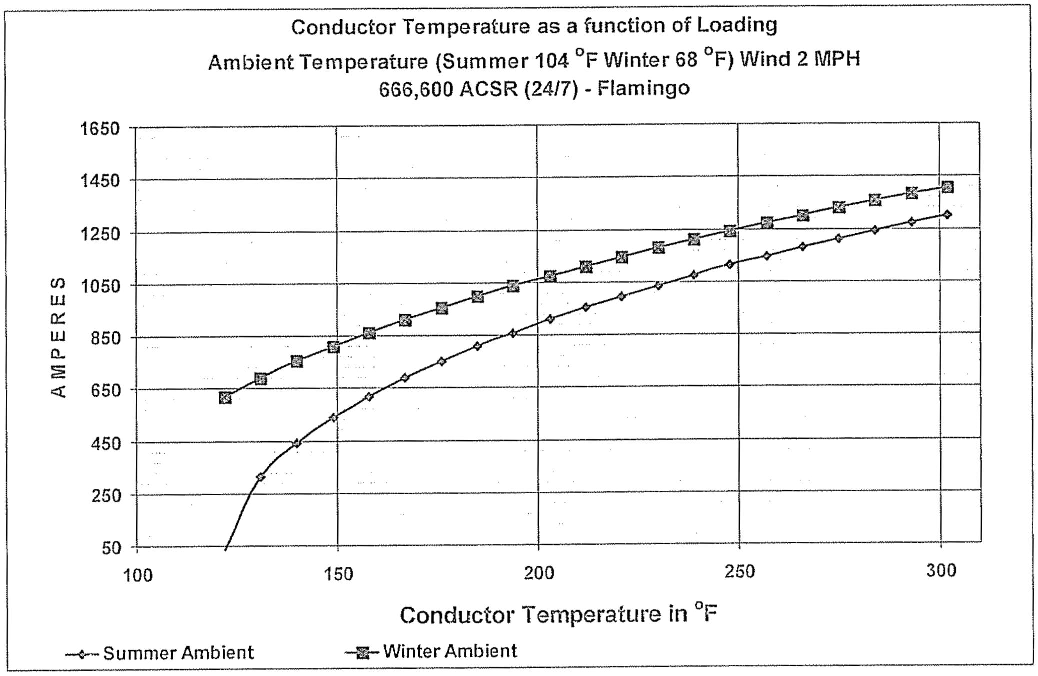
Conductor Temperature as a function of Loading
Ambient Temperature (Summer 104 °F Winter 68 °F) Wind 2 MPH
477,000 ACSR (26/7) - Hawk

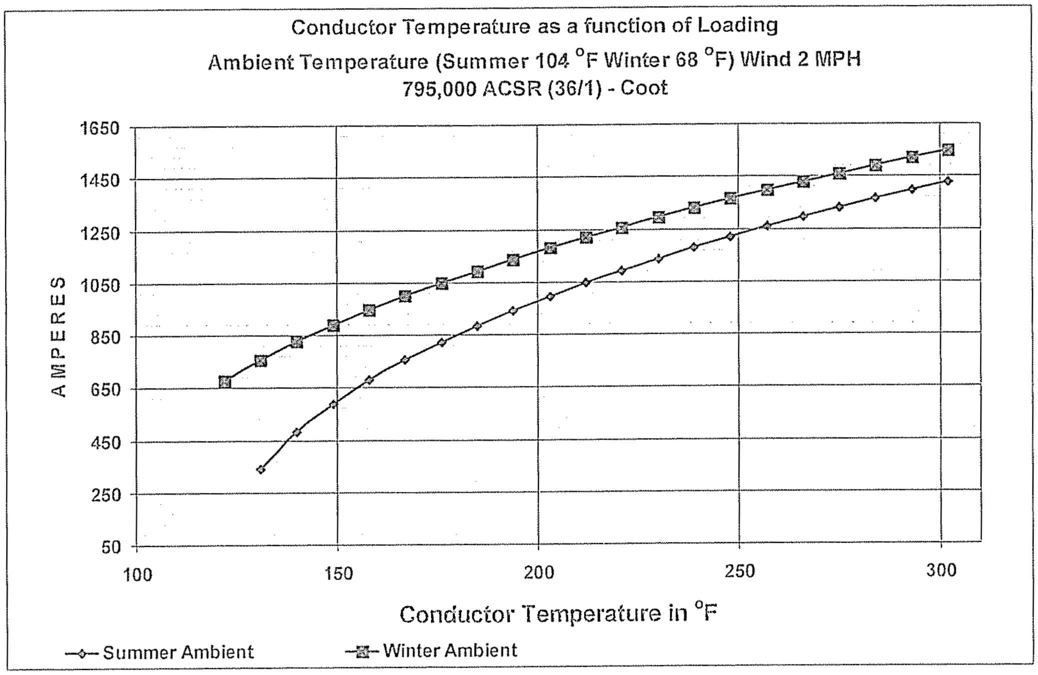


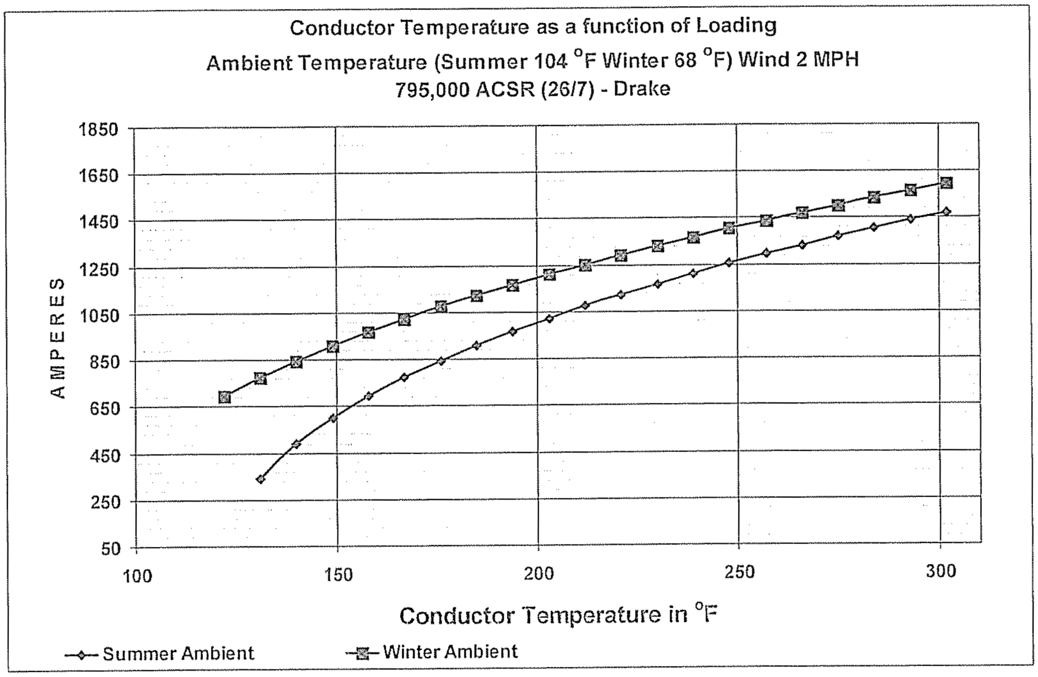
Conductor Temperature as a function of Loading
Ambient Temperature (Summer 104 °F Winter 68 °F) Wind 2 MPH
556,500 ACSR (26/7) - Dove

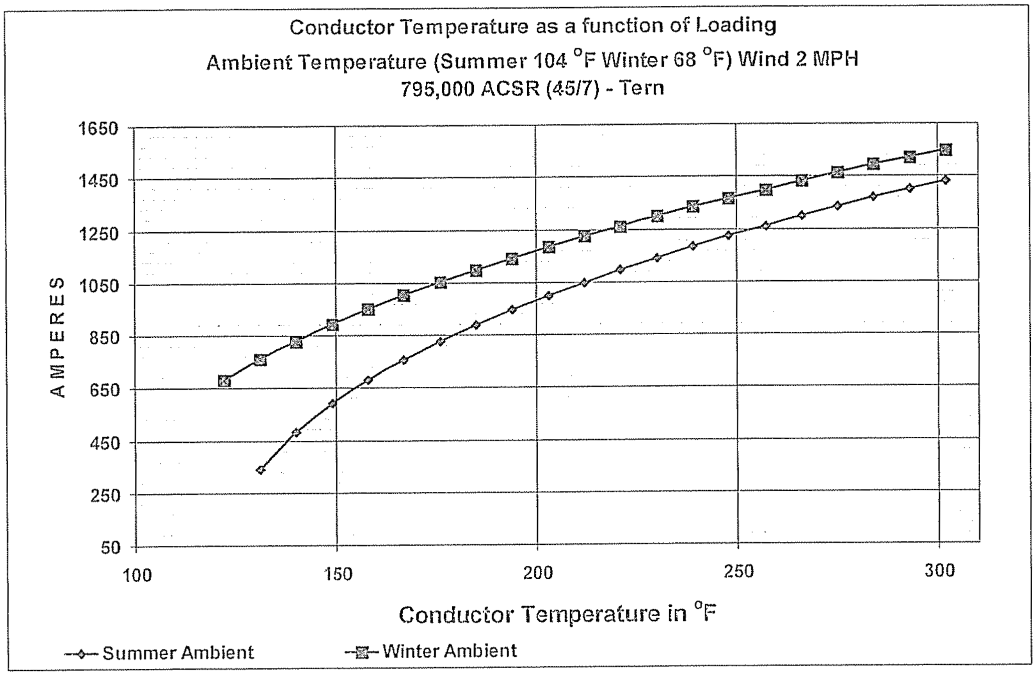


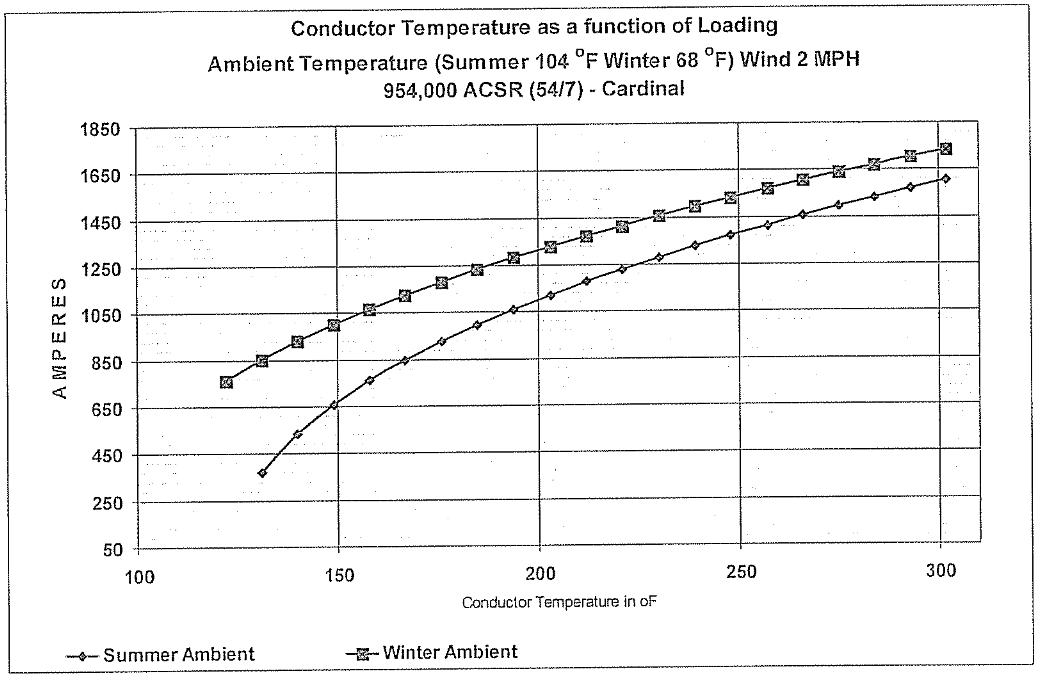
Conductor Temperature as a function of Loading
Ambient Temperature (Summer 104 °F Winter 68 °F) Wind 2 MPH
636,000 ACSR (26/7) - Grosbeak

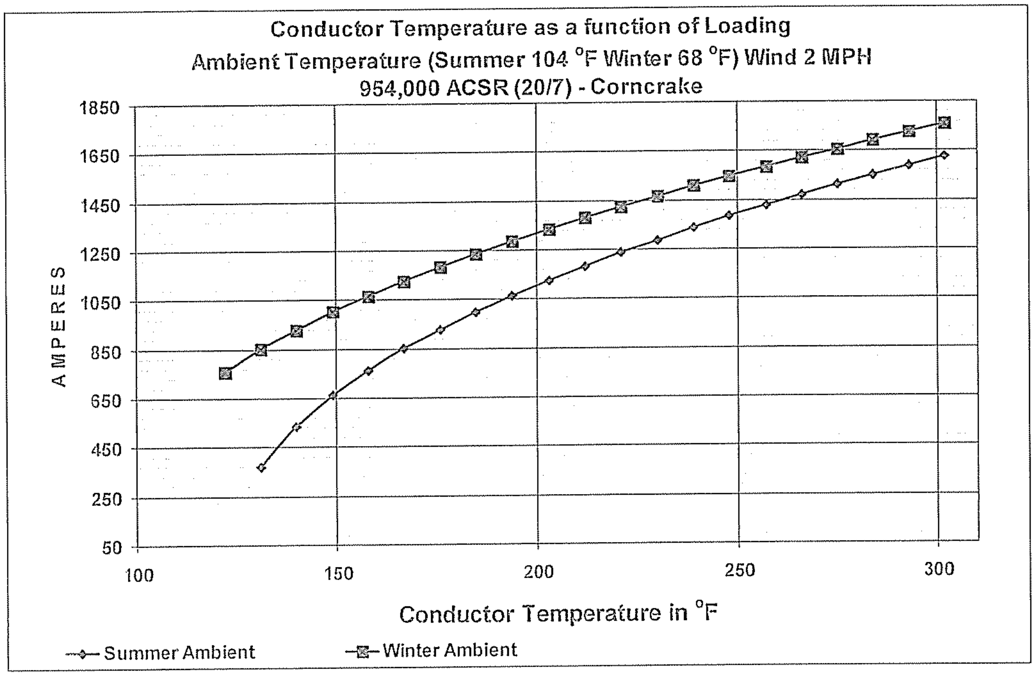

Conductor Temperature as a function of Loading
Ambient Temperature (Summer 104 °F Winter 68 °F) Wind 2 MPH
666,600 ACSR (24/7) - Flamingo
AMPERES
1650
1450
1250
1050
850
650
450
250
50
100
150
200
250
300
Conductor Temperature in °F
Summer Ambient
Winter Ambient

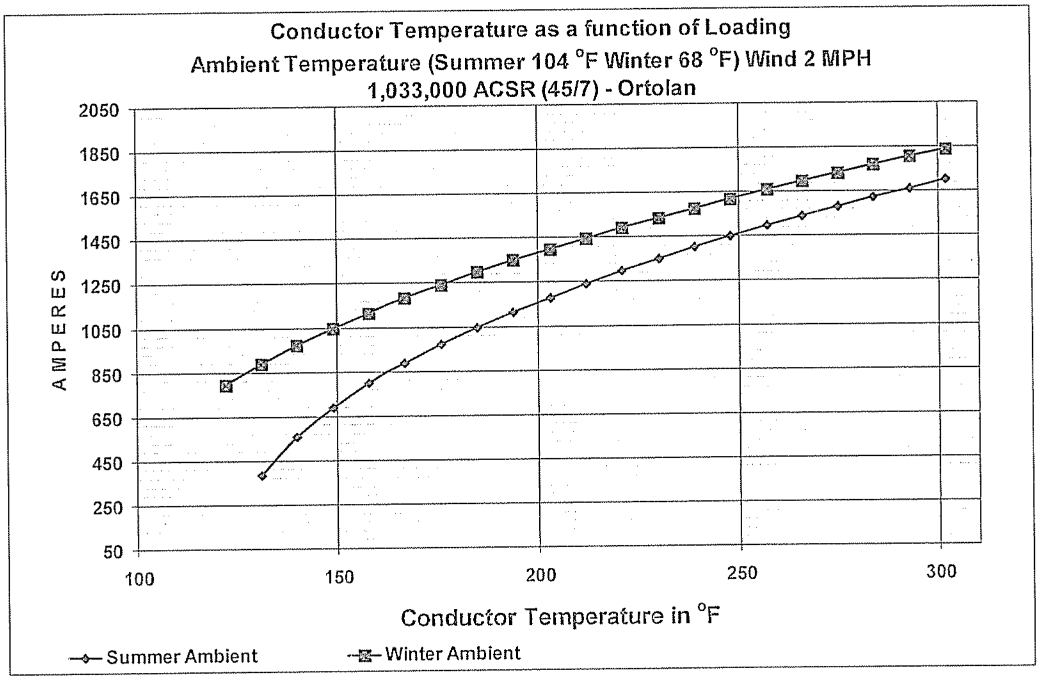

Conductor Temperature as a function of Loading
Ambient Temperature (Summer 104 °F Winter 68 °F) Wind 2 MPH
795,000 ACSR (36/1) - Coot
AMPERES
1650
1450
1250
1050
850
650
450
250
50
100
150
200
250
300
Conductor Temperature in °F
Summer Ambient
Winter Ambient

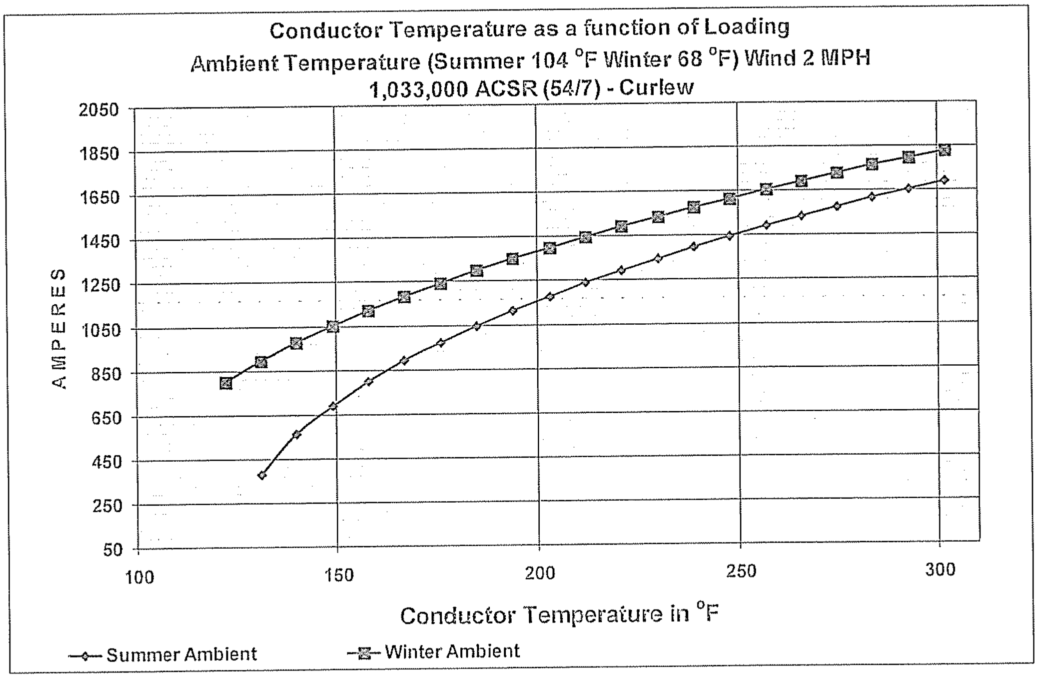

Conductor Temperature as a function of Loading
Ambient Temperature (Summer 104 °F Winter 68 °F) Wind 2 MPH
795,000 ACSR (26/7) - Drake
AMPERES
1850
1650
1450
1250
1050
850
650
450
250
50
100
150
200
250
300
Conductor Temperature in °F
Summer Ambient
Winter Ambient

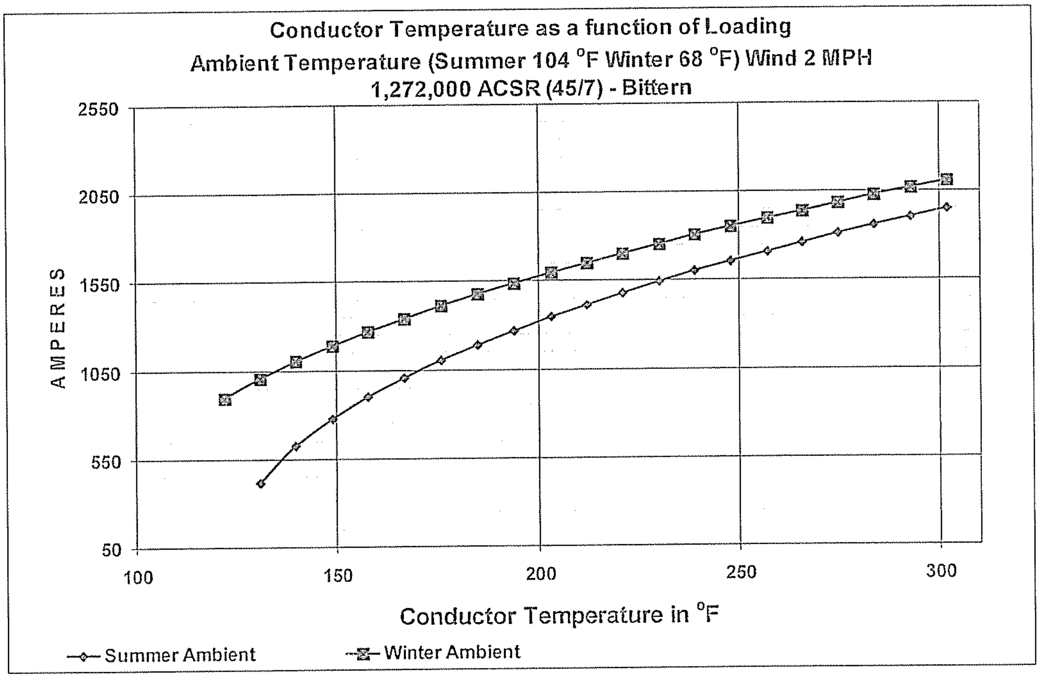

Conductor Temperature as a function of Loading
Ambient Temperature (Summer 104 °F Winter 68 °F) Wind 2 MPH
795,000 ACSR (45/7) - Tern
AMPERES
1650
1450
1250
1050
850
650
450
250
50
100
150
200
250
300
Conductor Temperature in °F
Summer Ambient
Winter Ambient

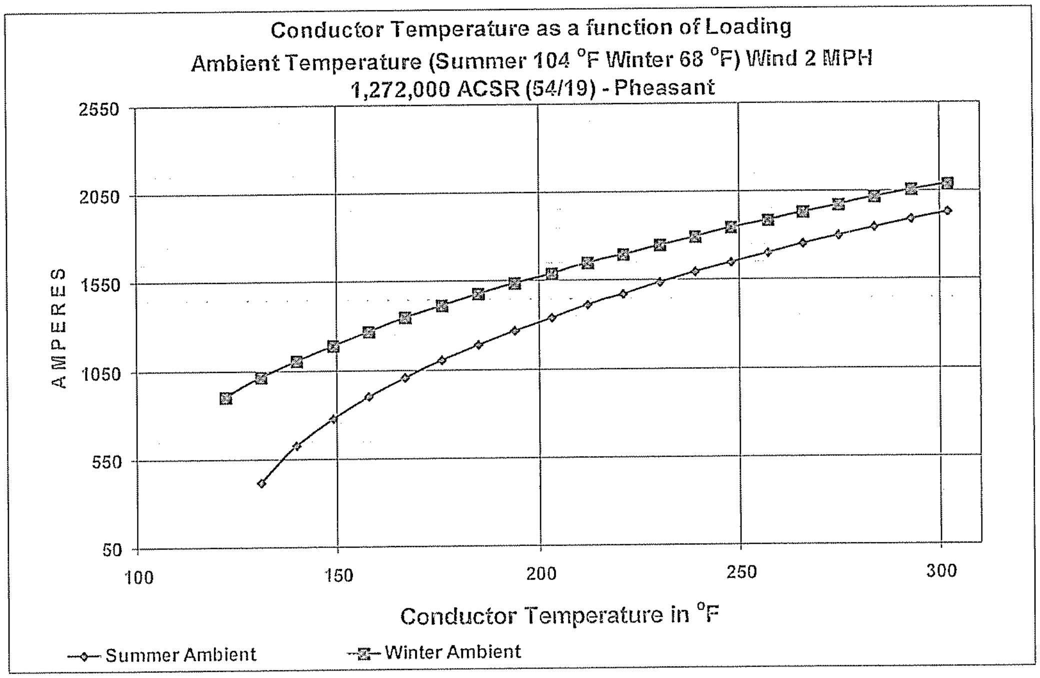

Conductor Temperature as a function of Loading
Ambient Temperature (Summer 104 °F Winter 68 °F) Wind 2 MPH
954,000 ACSR (54/7) - Cardinal
AMPERES
1850
1650
1450
1250
1050
850
650
450
250
50
100
150
200
250
300
Conductor Temperature in oF
Summer Ambient
Winter Ambient

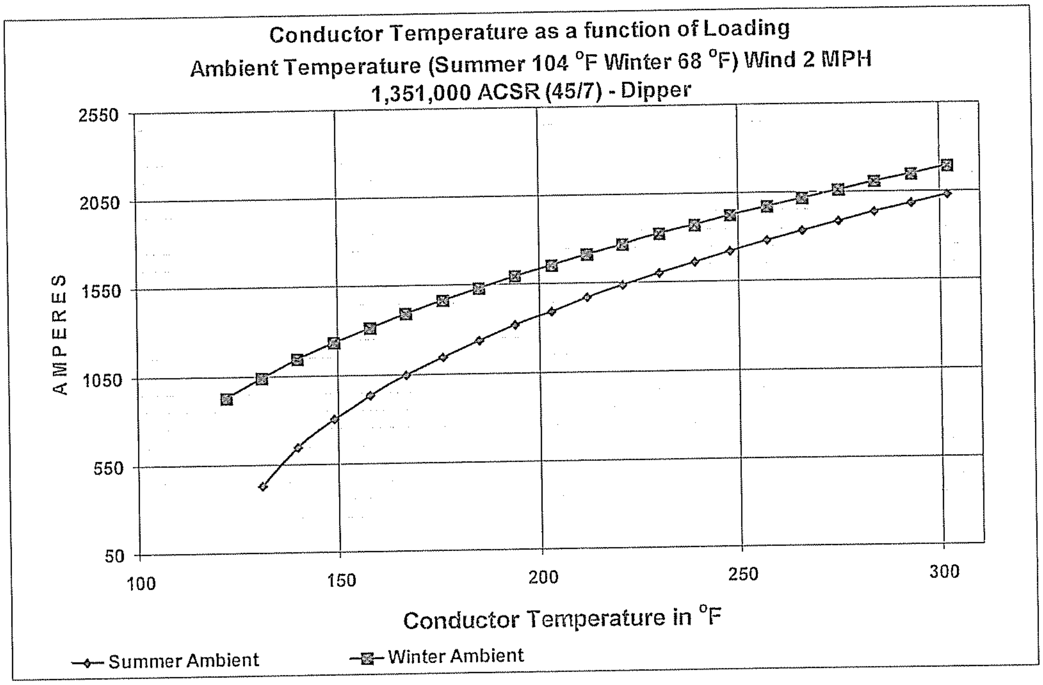

Conductor Temperature as a function of Loading
Ambient Temperature (Summer 104 °F Winter 68 °F) Wind 2 MPH
954,000 ACSR (20/7) - Corncrake
AMPERES
1850
1650
1450
1250
1050
850
650
450
250
50
100
150
200
250
300
Conductor Temperature in °F
Summer Ambient
Winter Ambient

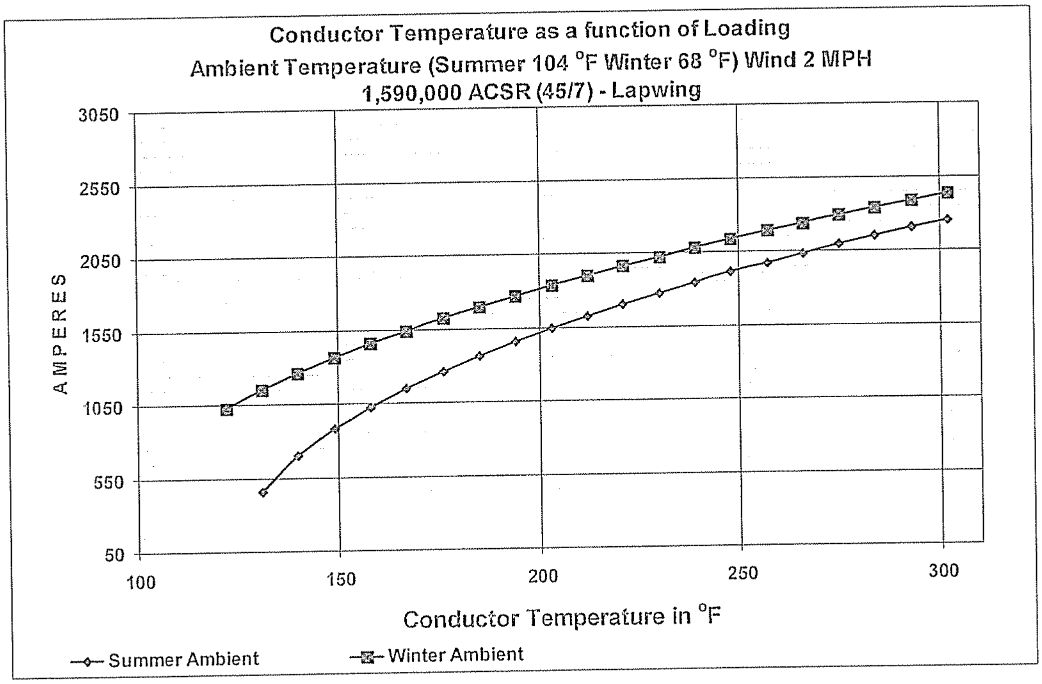

Conductor Temperature as a function of Loading
Ambient Temperature (Summer 104 °F Winter 68 °F) Wind 2 MPH
1,033,000 ACSR (45/7) - Ortolan
AMPERES
2050
1850
1650
1450
1250
1050
850
650
450
250
50
100
150
200
250
300
Conductor Temperature in °F
Summer Ambient
Winter Ambient

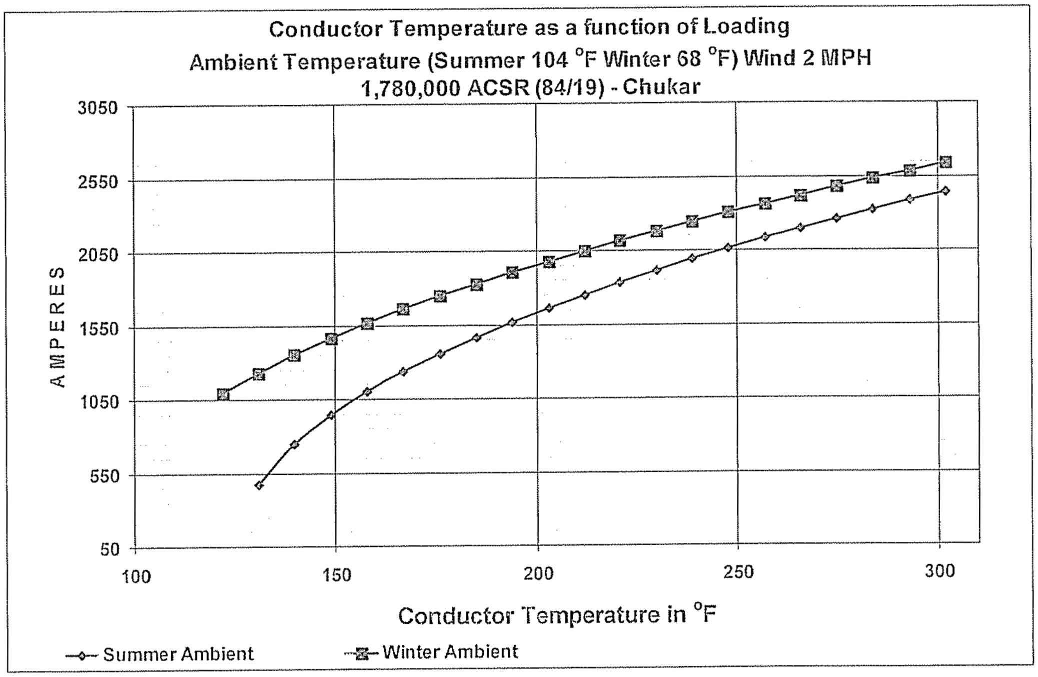

Conductor Temperature as a function of Loading
Ambient Temperature (Summer 104 °F Winter 68 °F) Wind 2 MPH
1,033,000 ACSR (54/7) - Curlew
AMPERES
2050
1850
1650
1450
1250
1050
850
650
450
250
50
100
150
200
250
300
Conductor Temperature in °F
Summer Ambient
Winter Ambient

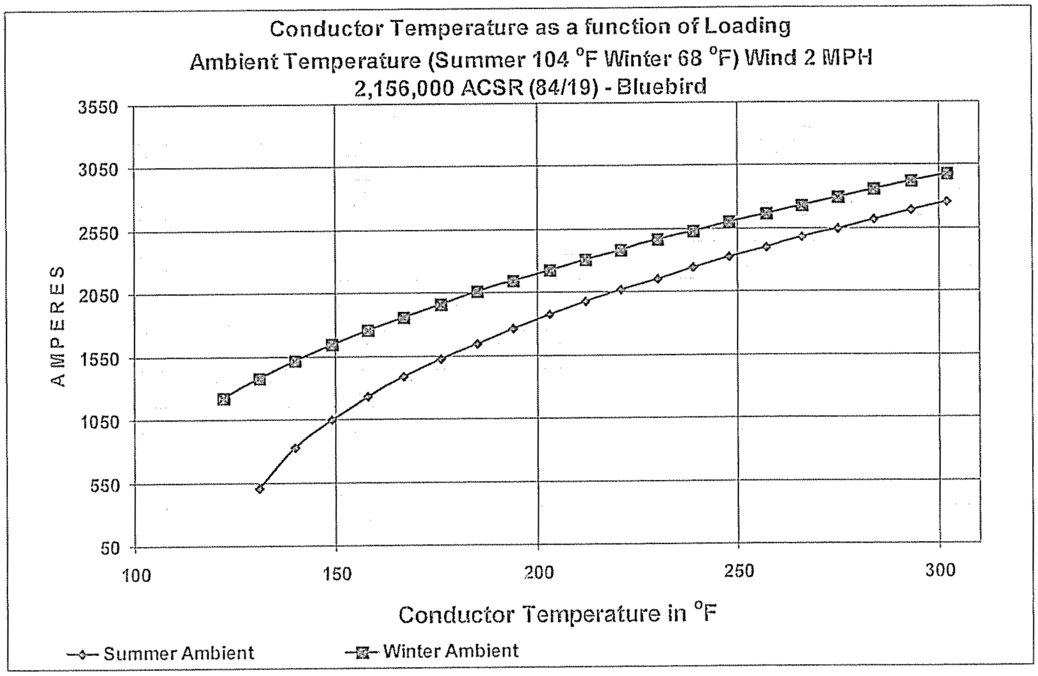

Conductor Temperature as a function of Loading
Ambient Temperature (Summer 104 °F Winter 68 °F) Wind 2 MPH
1,272,000 ACSR (45/7) - Bittern

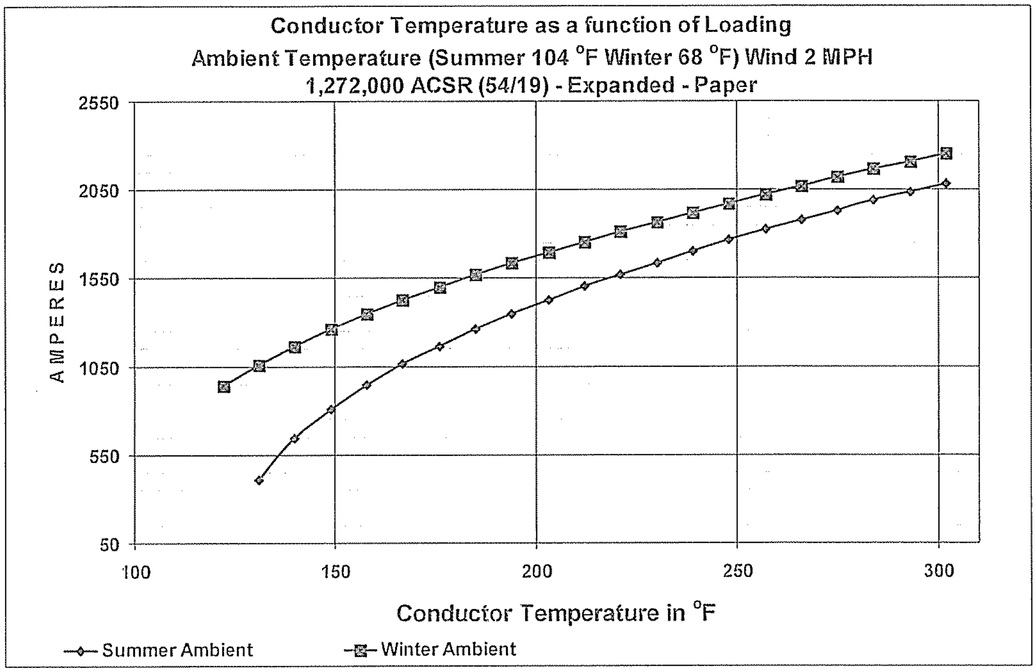

Conductor Temperature as a function of Loading
Ambient Temperature (Summer 104 °F Winter 68 °F) Wind 2 MPH
1,272,000 ACSR (54/19) - Pheasant

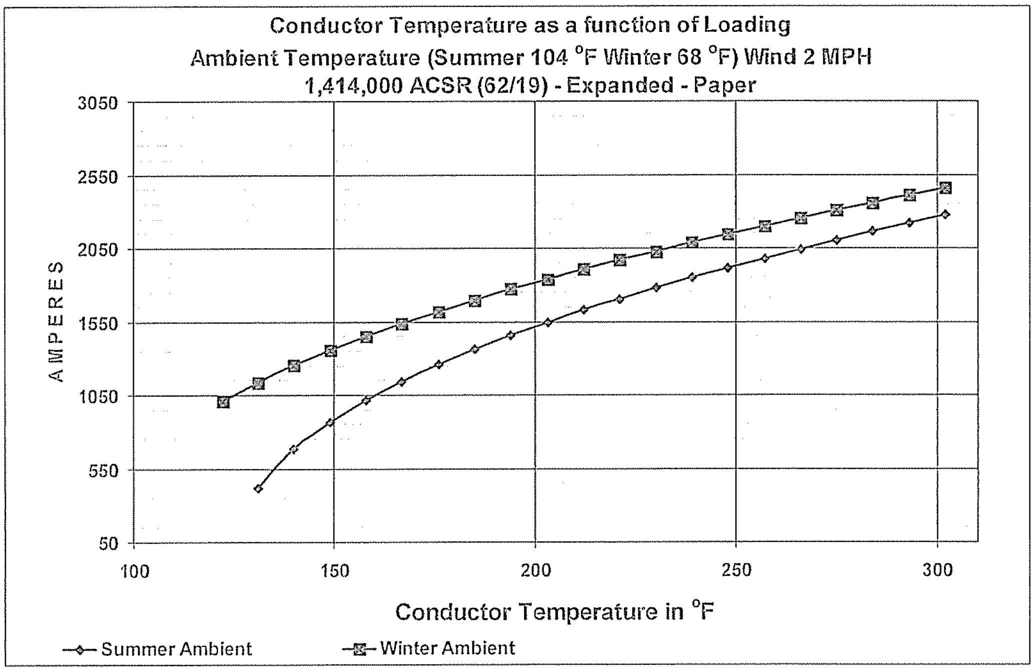

Conductor Temperature as a function of Loading
Ambient Temperature (Summer 104 °F Winter 68 °F) Wind 2 MPH
1,351,000 ACSR (45/7) - Dipper
AMPERES
2550
2050
1550
1050
550
50
100
150
200
250
300
Conductor Temperature in °F
Summer Ambient
Winter Ambient

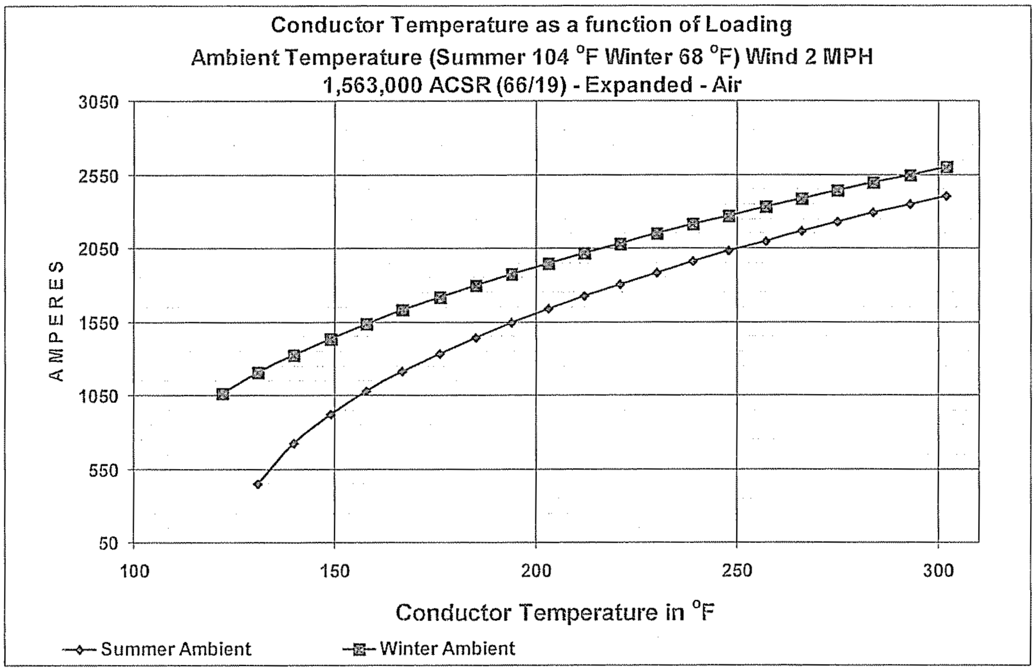

Conductor Temperature as a function of Loading
Ambient Temperature (Summer 104 °F Winter 68 °F) Wind 2 MPH
1,590,000 ACSR (45/7) - Lapwing
AMPERES
3050
2550
2050
1550
1050
550
50
100
150
200
250
300
Conductor Temperature in °F
Summer Ambient
Winter Ambient

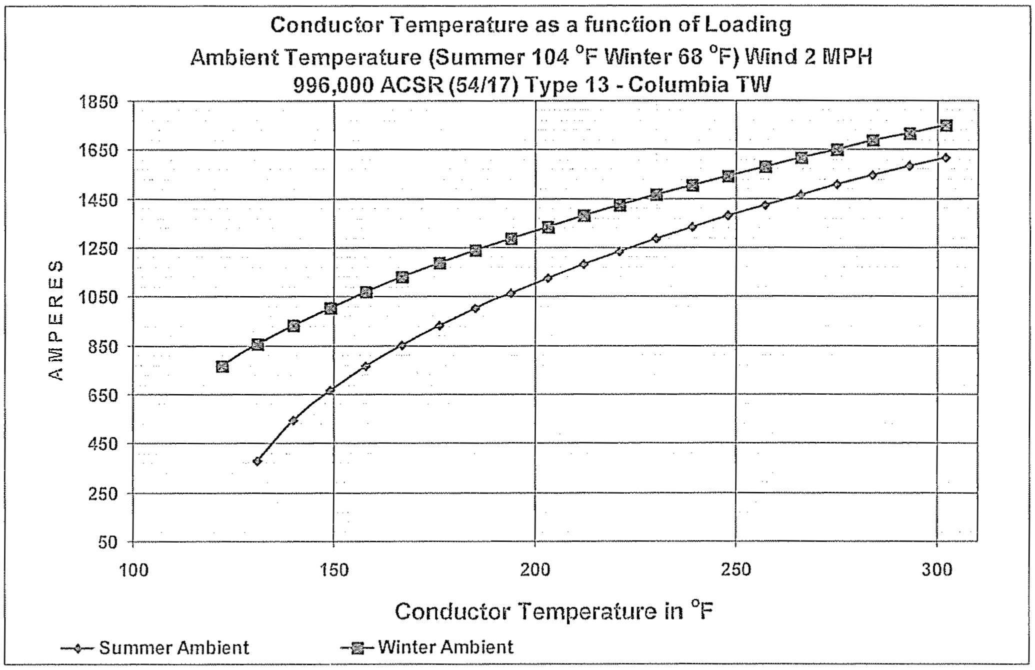

Conductor Temperature as a function of Loading
Ambient Temperature (Summer 104 °F Winter 68 °F) Wind 2 MPH
1,780,000 ACSR (84/19) - Chukar
AMPERES
3050
2550
2050
1550
1050
550
50
100
150
200
250
300
Conductor Temperature in °F
Summer Ambient
Winter Ambient


Conductor Temperature as a function of Loading
Ambient Temperature (Summer 104 °F Winter 68 °F) Wind 2 MPH
2,156,000 ACSR (84/19) - Bluebird
AMPERES
3550
3050
2550
2050
1550
1050
550
50
100
150
200
250
300
Conductor Temperature in °F
Summer Ambient
Winter Ambient

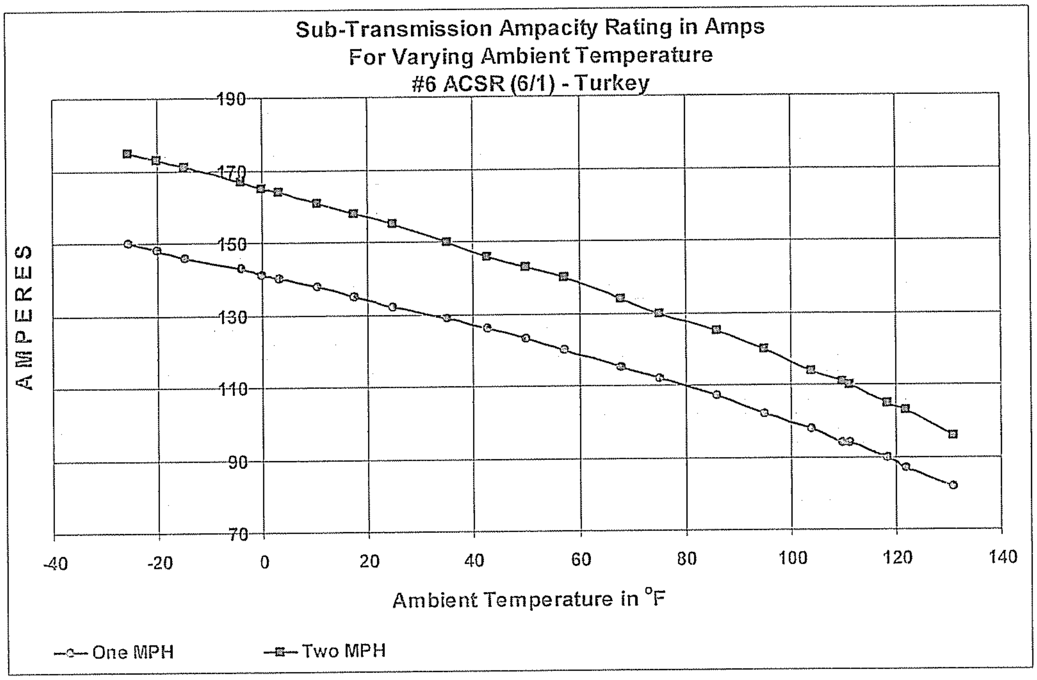

Conductor Temperature as a function of Loading
Ambient Temperature (Summer 104 °F Winter 68 °F) Wind 2 MPH
1,272,000 ACSR (54/19) - Expanded - Paper
AMPERES
2550
2050
1550
1050
550
50
100
150
200
250
300
Conductor Temperature in °F
Summer Ambient
Winter Ambient

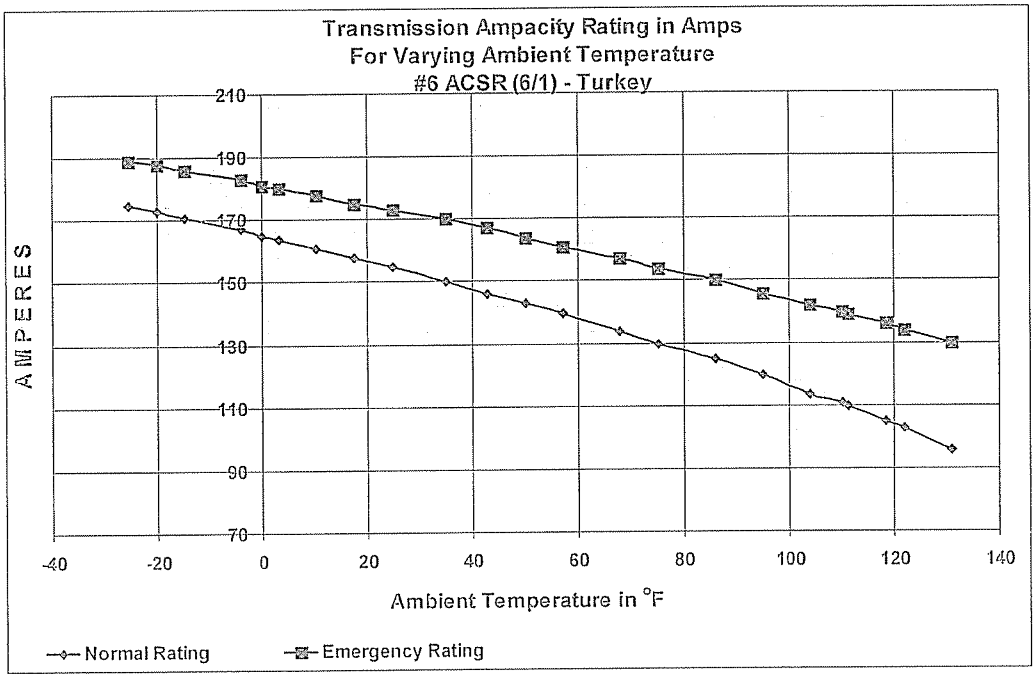

Conductor Temperature as a function of Loading
Ambient Temperature (Summer 104 °F Winter 68 °F) Wind 2 MPH
1,414,000 ACSR (62/19) - Expanded - Paper
AMPERES
3050
2550
2050
1550
1050
550
50
100
150
200
250
300
Conductor Temperature in °F
Summer Ambient
Winter Ambient

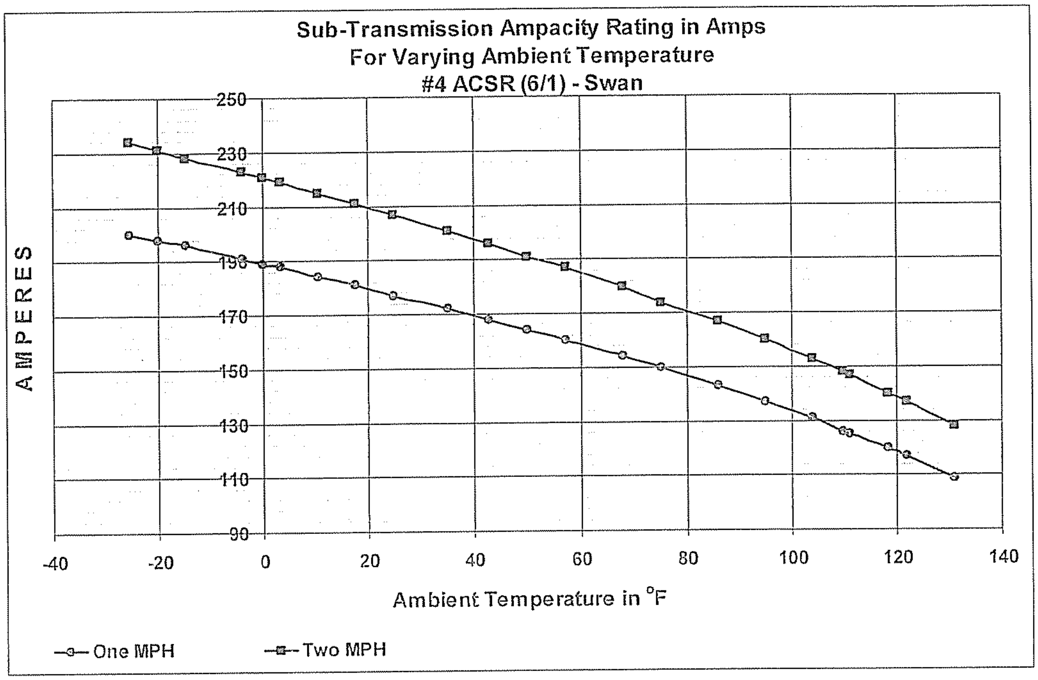

Conductor Temperature as a function of Loading
Ambient Temperature (Summer 104 °F Winter 68 °F) Wind 2 MPH
1,563,000 ACSR (66/19) - Expanded - Air
AMPERES
3050
2550
2050
1550
1050
550
50
100
150
200
250
300
Conductor Temperature in °F
Summer Ambient
Winter Ambient

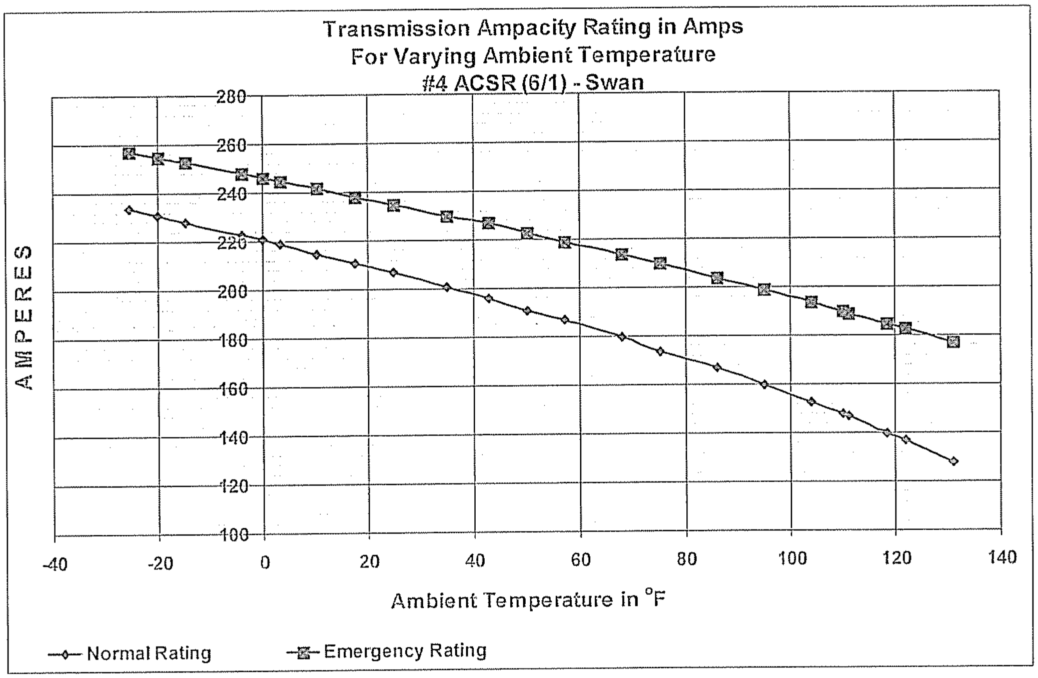

Conductor Temperature as a function of Loading
Ambient Temperature (Summer 104 °F Winter 68 °F) Wind 2 MPH
996,000 ACSR (54/17) Type 13 - Columbia TW
AMPERES
1850
1650
1450
1250
1050
850
650
450
250
50
100
150
200
250
300
Conductor Temperature in °F
Summer Ambient
Winter Ambient

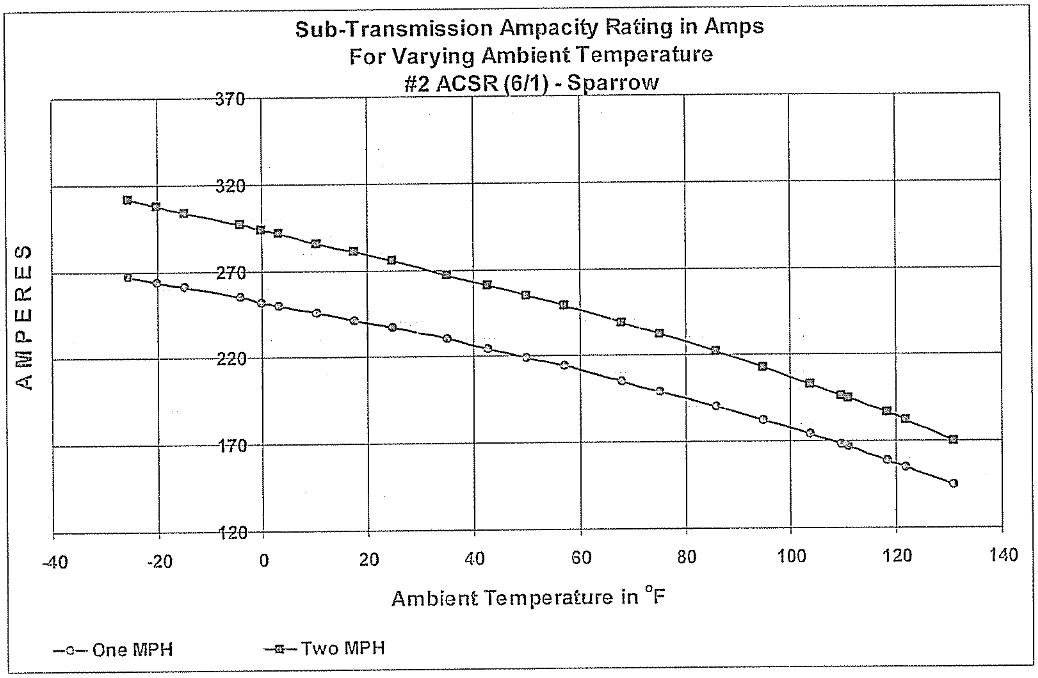
Appendix C	Plots of Normal and Emergency Capabilities as a function of Ambient Temperature **ACSR Conductors**

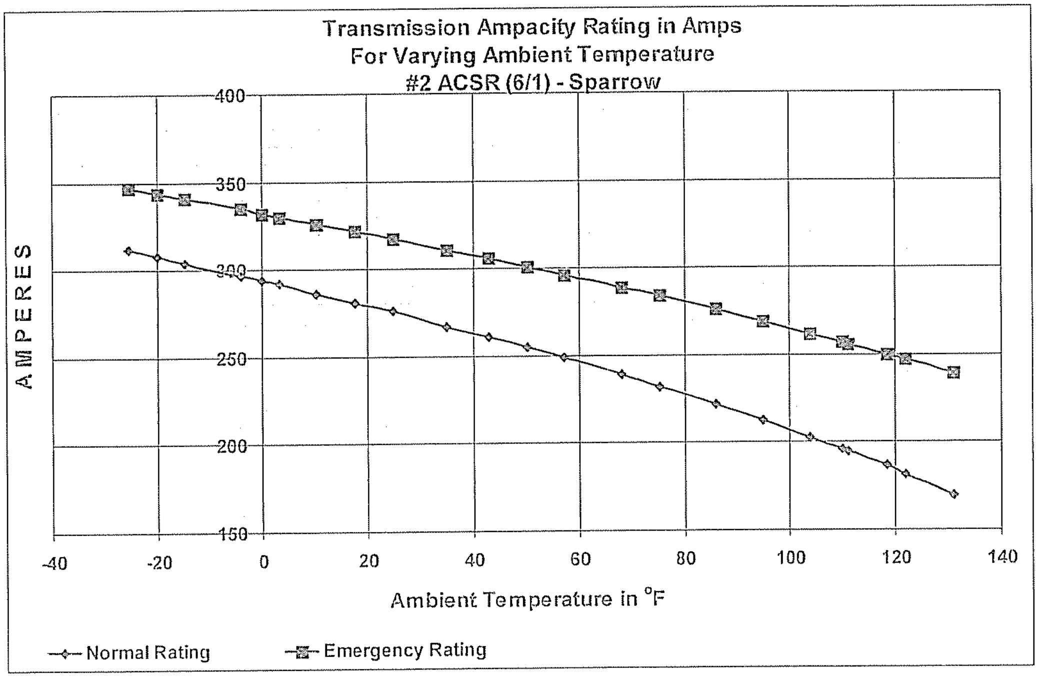

Sub-Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
#6 ACSR (6/1) - Turkey
AMPERES
190
170
150
130
110
90
70
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
One MPH
Two MPH

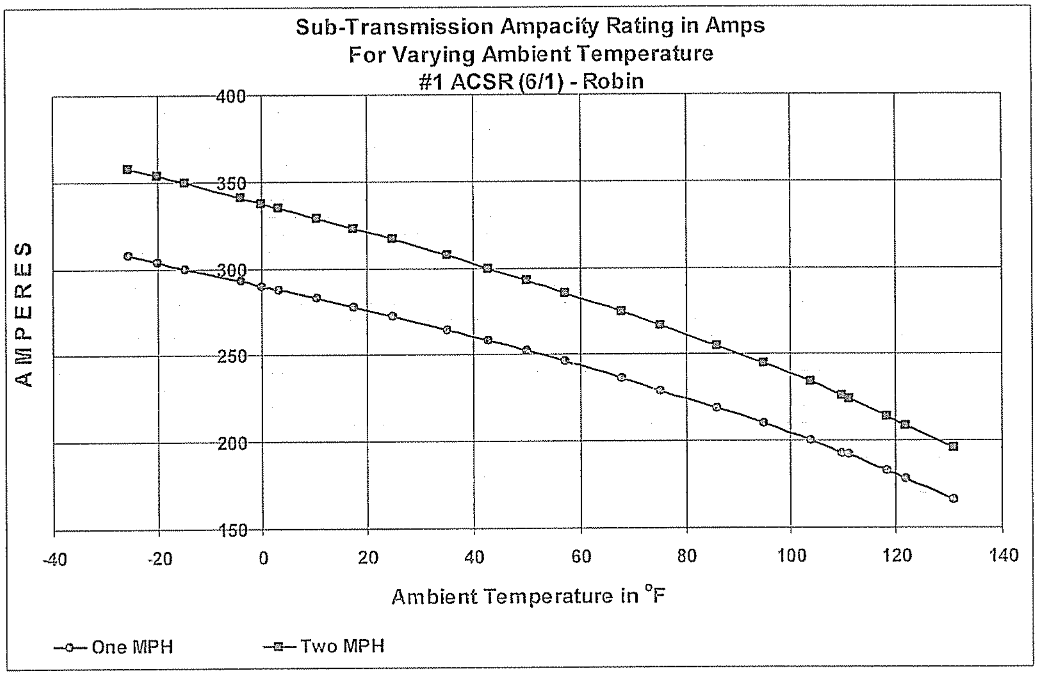

Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
#6 ACSR (6/1) - Turkey
AMPERES
210
190
170
150
130
110
90
70
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
Normal Rating
Emergency Rating

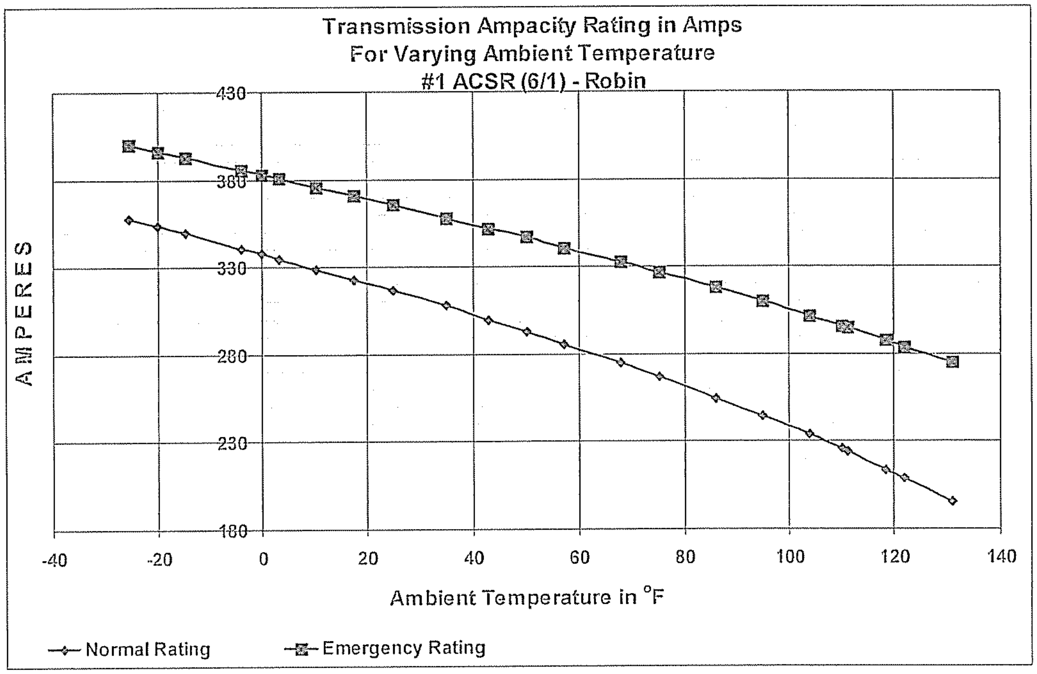

Sub-Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
#4 ACSR (6/1) - Swan
AMPERES
250
230
210
190
170
150
130
110
90
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
One MPH
Two MPH

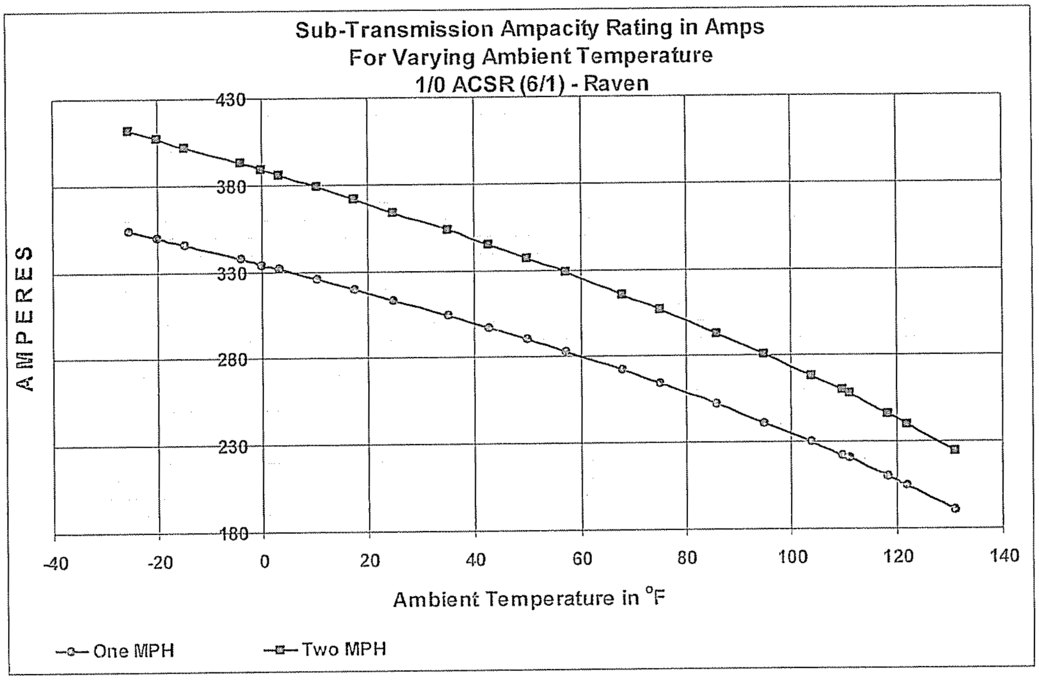

Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
#4 ACSR (6/1) - Swan
AMPERES
280
260
240
220
200
180
160
140
120
100
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
Normal Rating
Emergency Rating

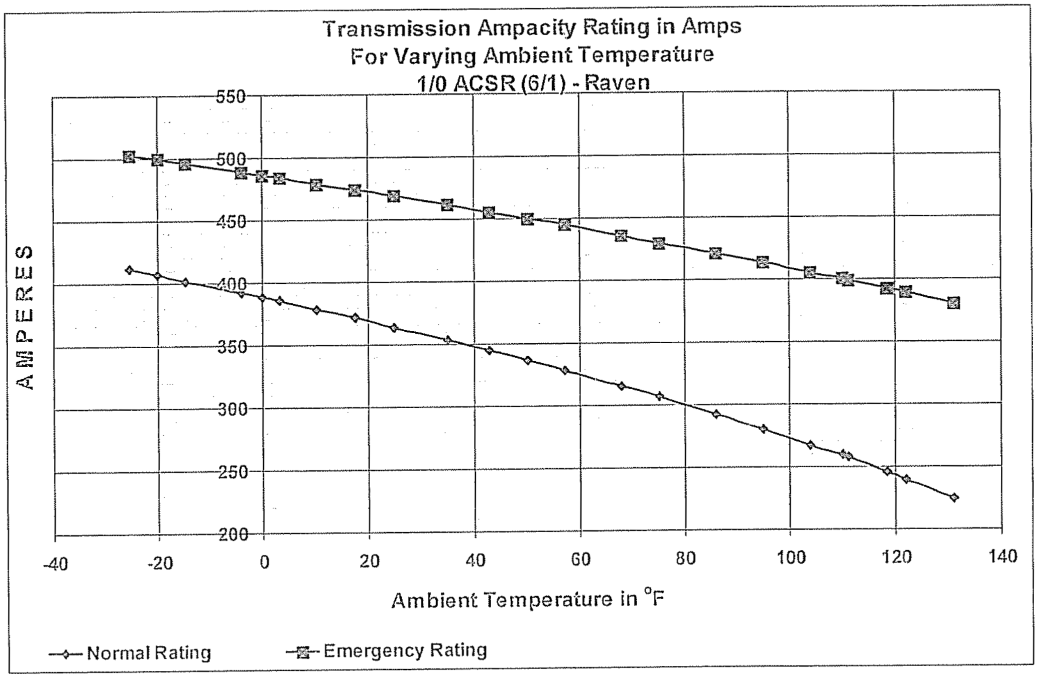

Sub-Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
#2 ACSR (6/1) - Sparrow
AMPERES
370
320
270
220
170
120
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
One MPH
Two MPH

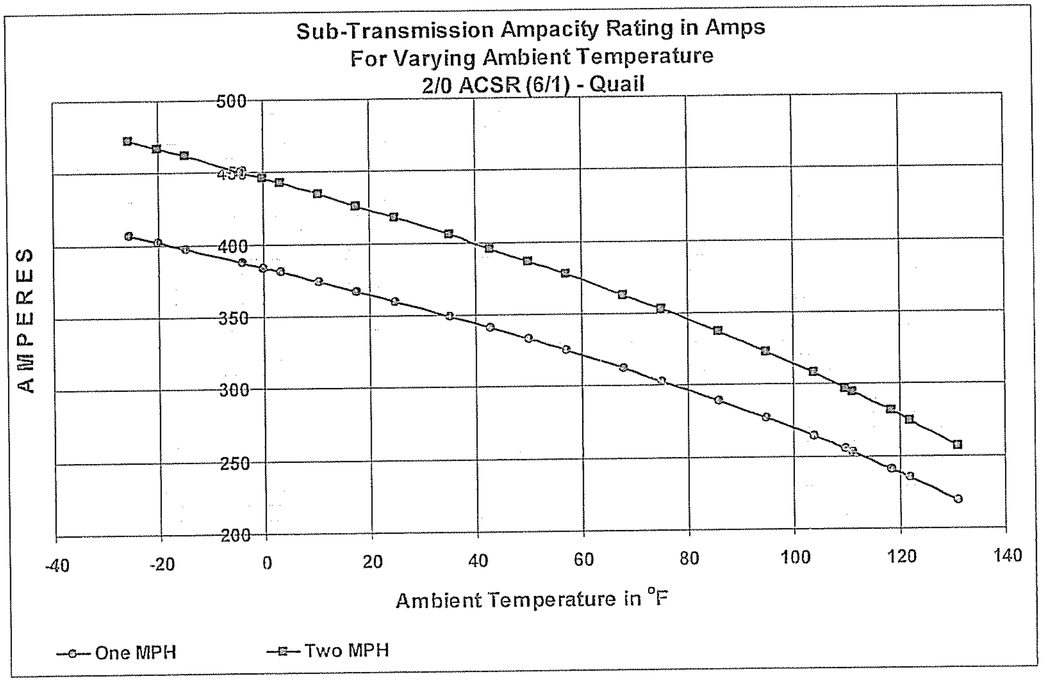

Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
#2 ACSR (6/1) - Sparrow
AMPERES
400
350
300
250
200
150
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
Normal Rating
Emergency Rating

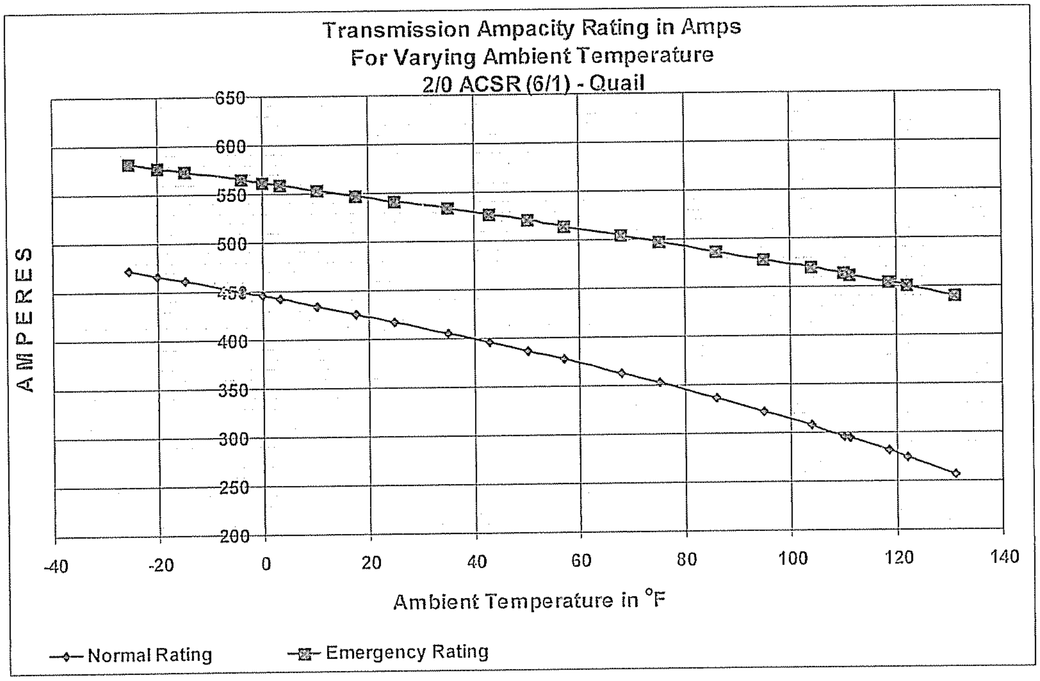

Sub-Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
#1 ACSR (6/1) - Robin
AMPERES
400
350
300
250
200
150
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
One MPH
Two MPH


Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
#1 ACSR (6/1) - Robin
AMPERES
430
380
330
280
230
180
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
Normal Rating
Emergency Rating

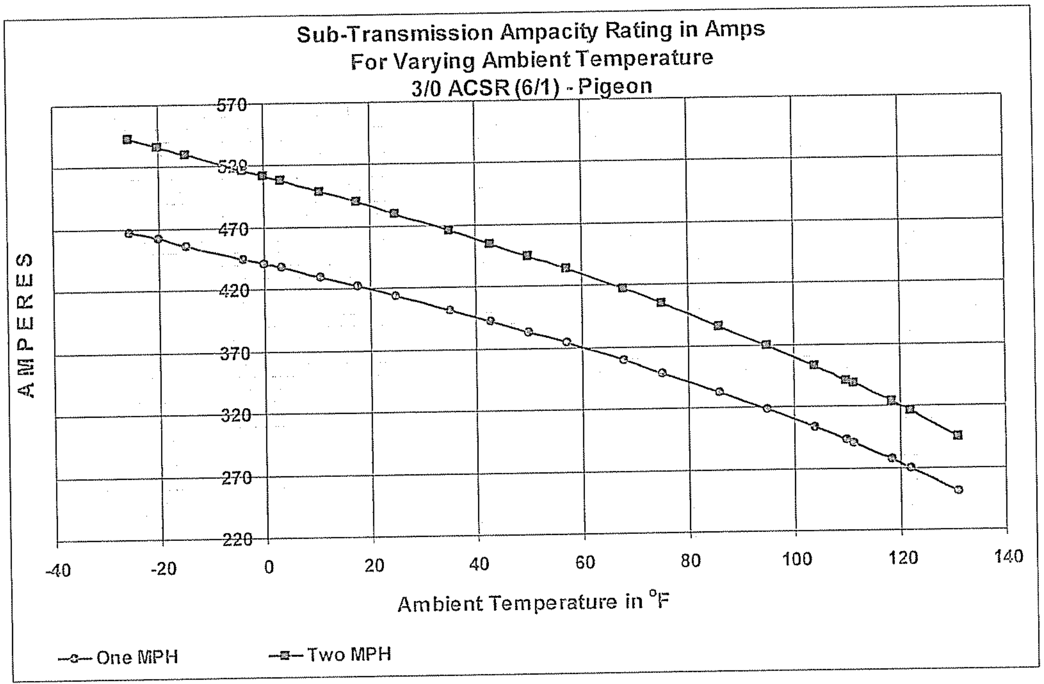

Sub-Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
1/0 ACSR (6/1) - Raven

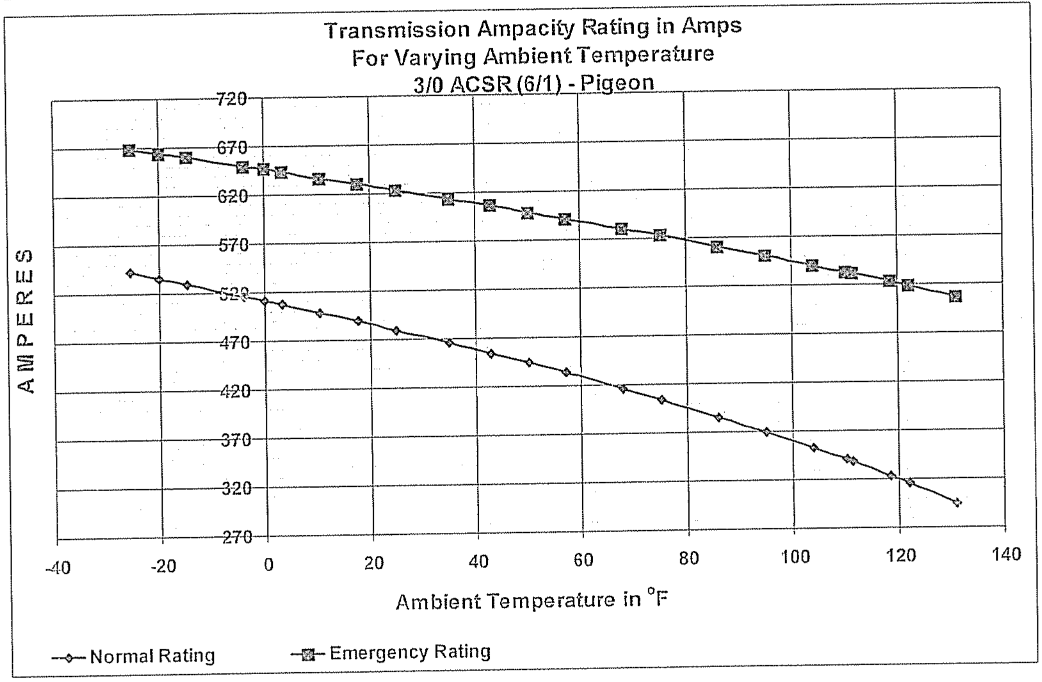

Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
1/0 ACSR (6/1) - Raven

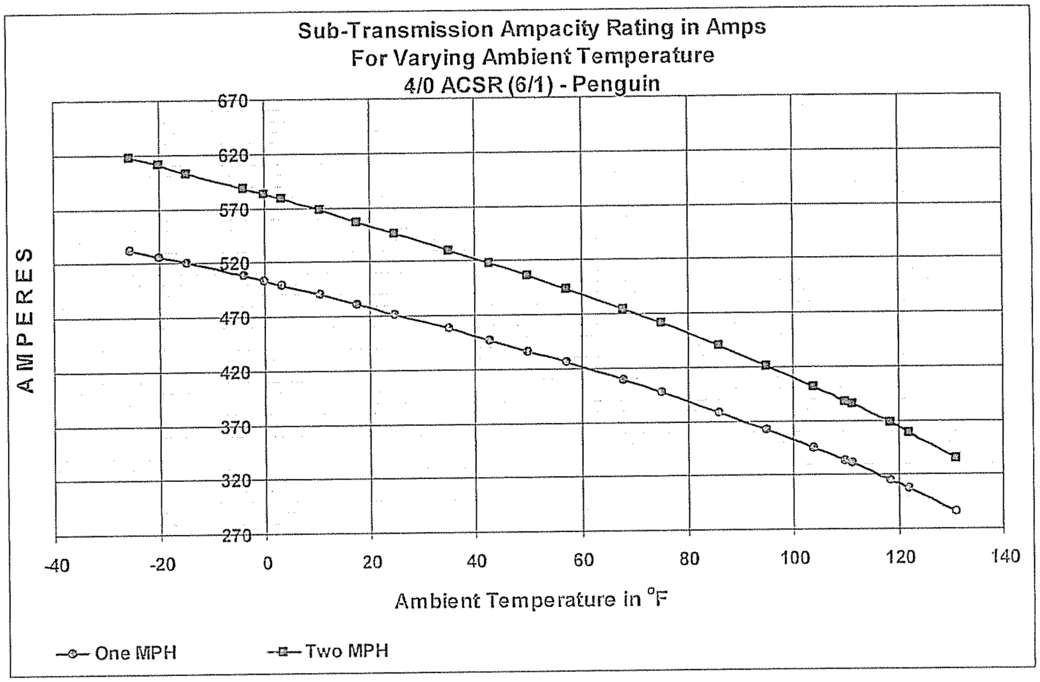

Sub-Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
2/0 ACSR (6/1) - Quail
AMPERES
500
450
400
350
300
250
200
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
One MPH
Two MPH

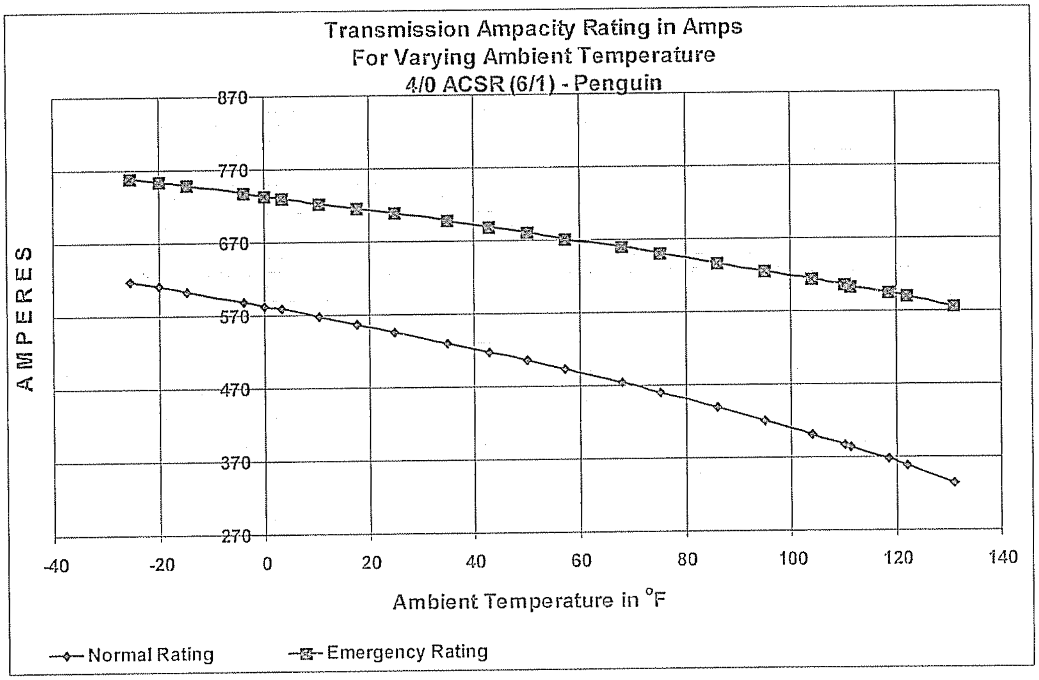

Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
2/0 ACSR (6/1) - Quail
AMPERES
650
600
550
500
450
400
350
300
250
200
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
Normal Rating
Emergency Rating

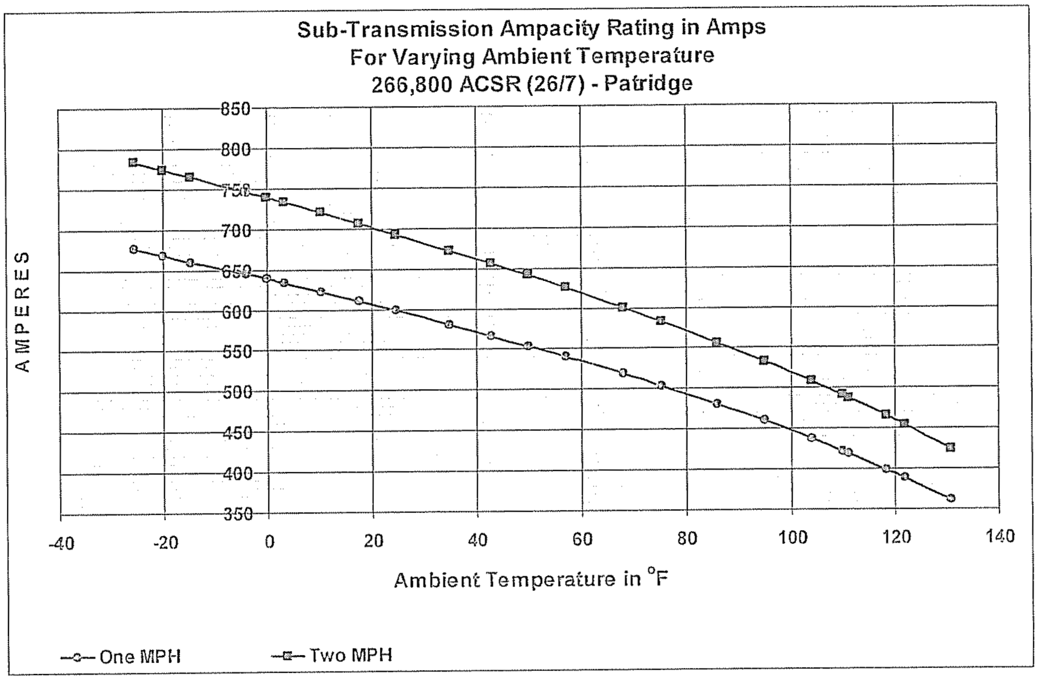
CAUTION: Printed copies of this document are uncontrolled and may be obsolete.
Always check for the latest revision prior to use.

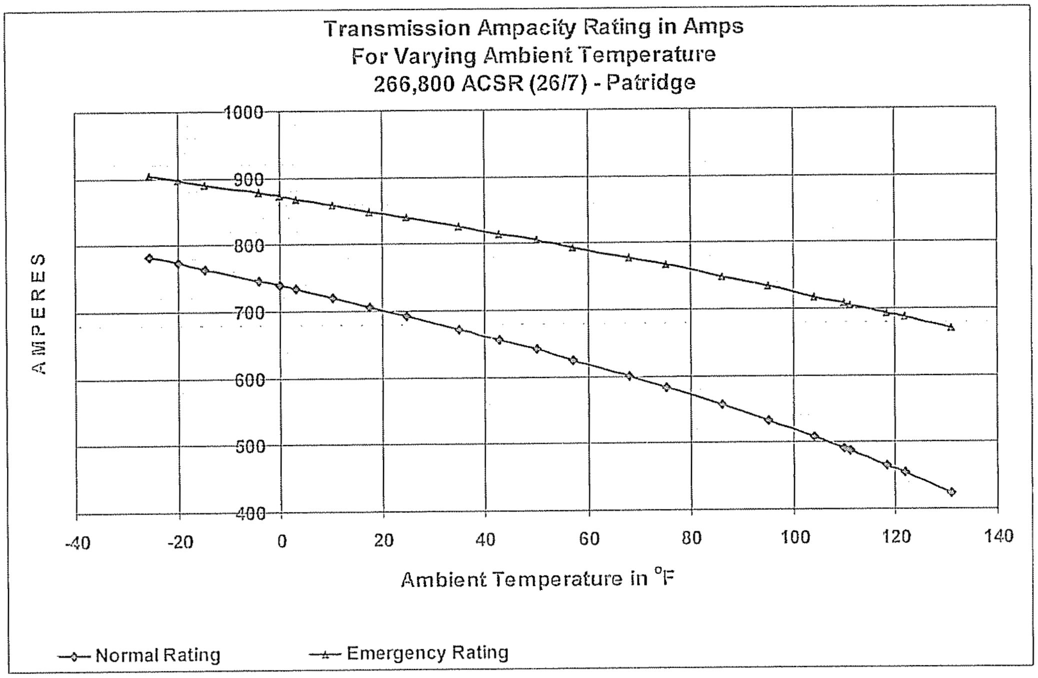

Sub-Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
3/0 ACSR (6/1) - Pigeon

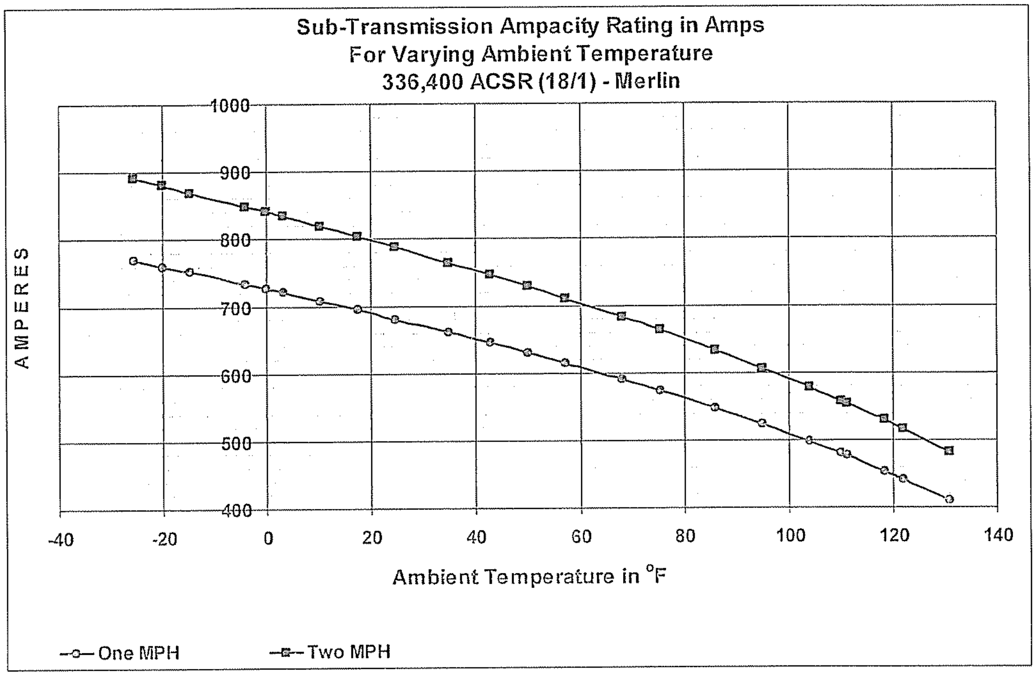

Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
3/0 ACSR (6/1) - Pigeon


Sub-Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
4/0 ACSR (6/1) - Penguin
AMPERES
670
620
570
520
470
420
370
320
270
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
One MPH
Two MPH

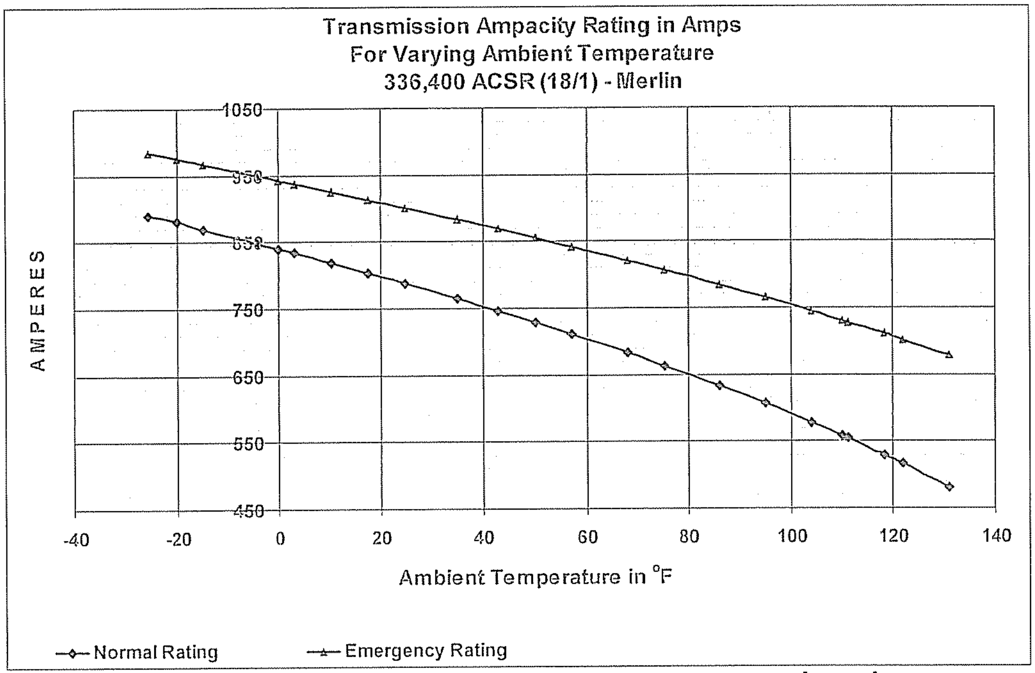

Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
4/0 ACSR (6/1) - Penguin
AMPERES
870
770
670
570
470
370
270
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
Normal Rating
Emergency Rating


Sub-Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
266,800 ACSR (26/7) - Patridge

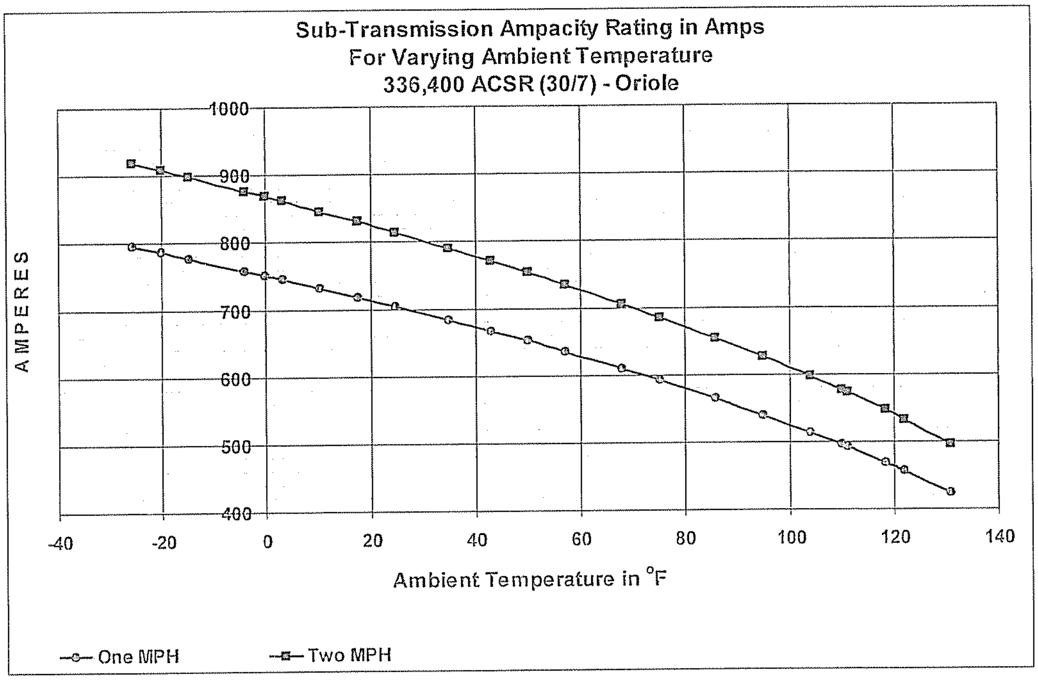

Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
266,800 ACSR (26/7) - Patridge

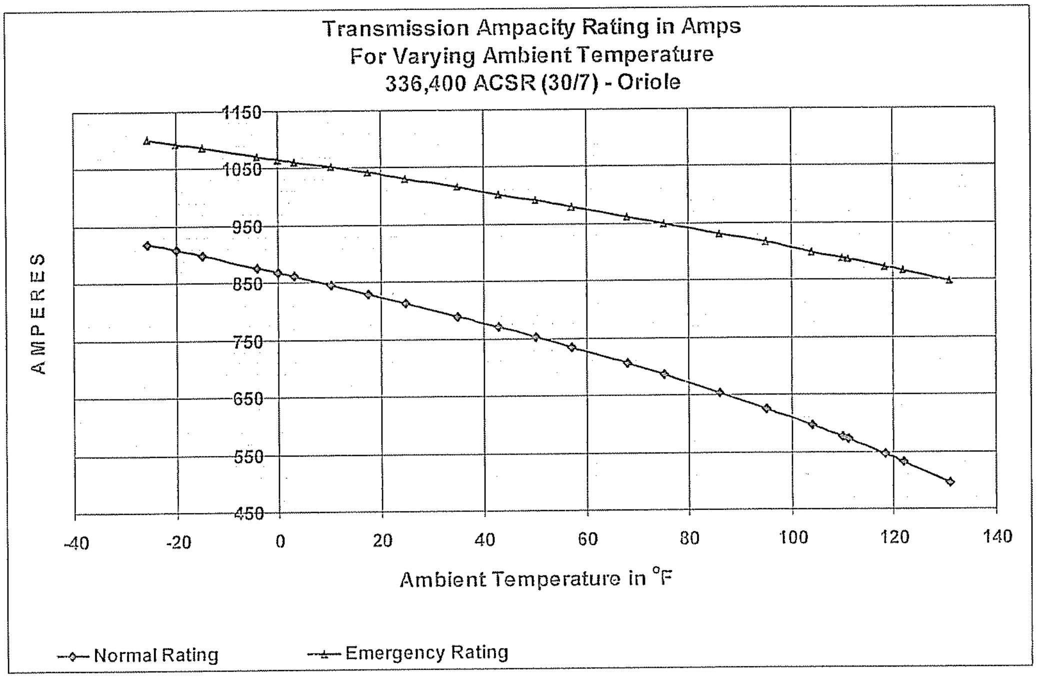


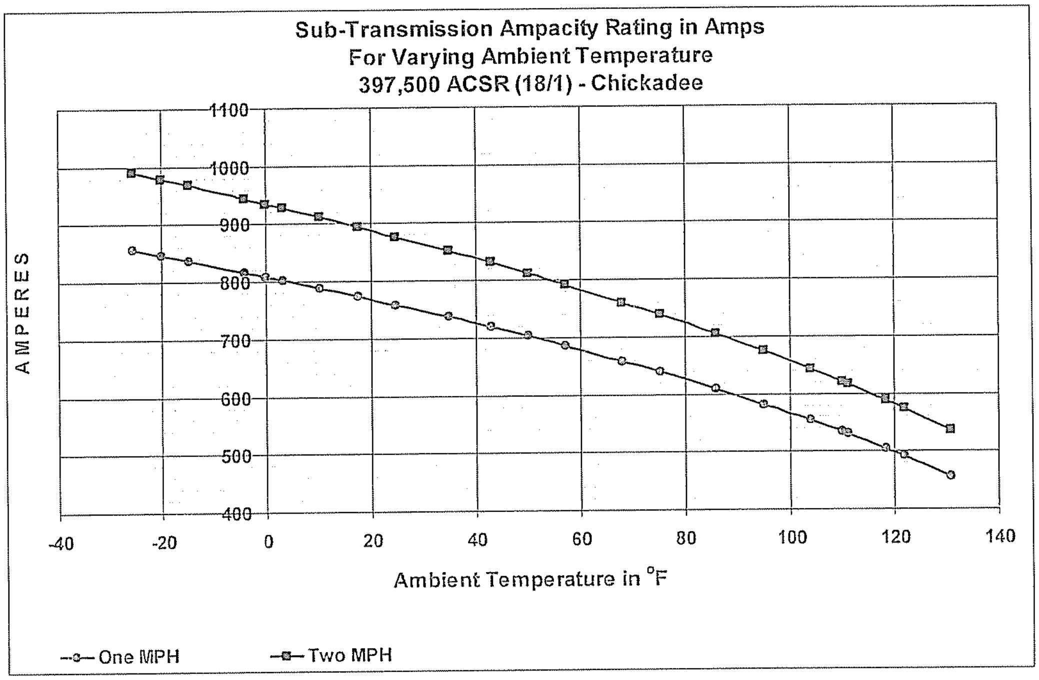
Sub-Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
336,400 ACSR (18/1) - Merlin

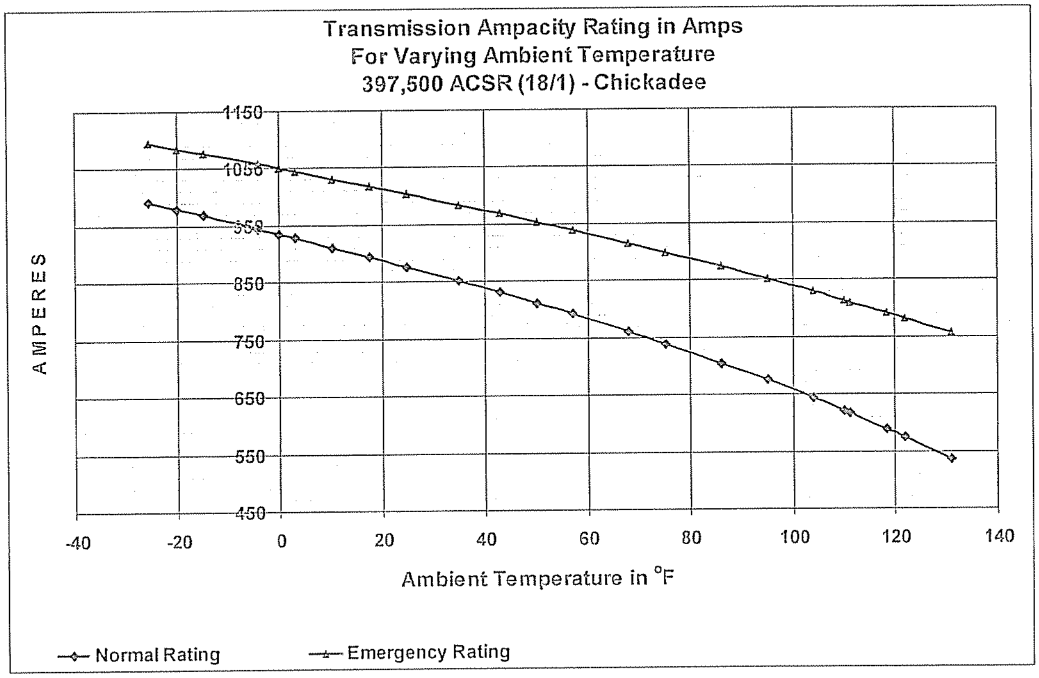


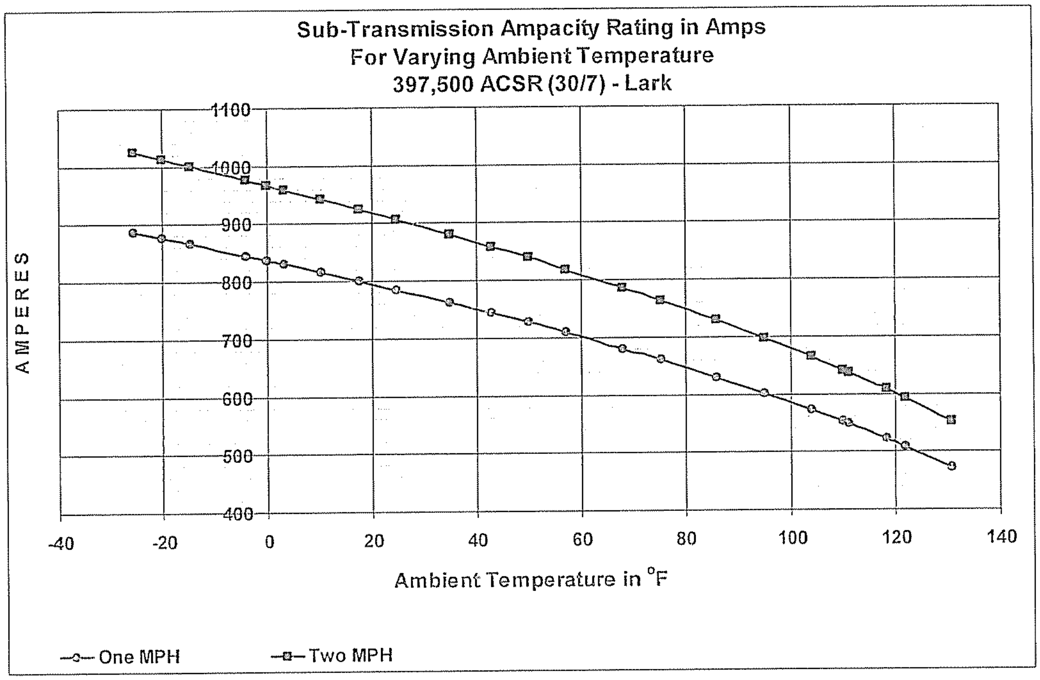
Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
336,400 ACSR (18/1) - Merlin

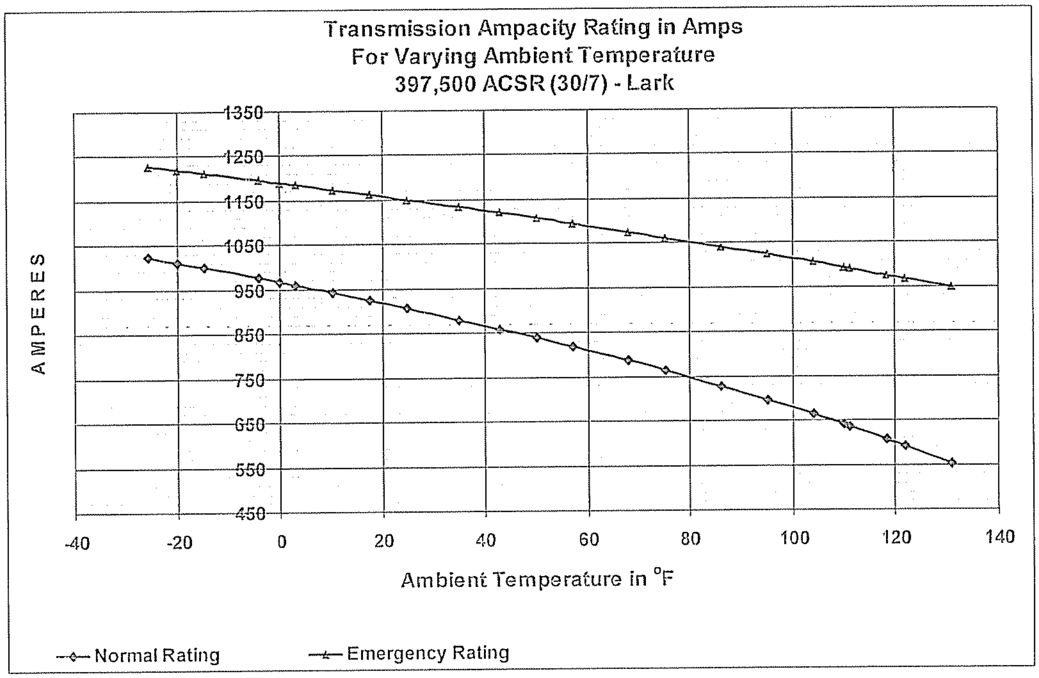

Sub-Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
336,400 ACSR (30/7) - Oriole
AMPERES
1000
900
800
700
600
500
400
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
One MPH
Two MPH

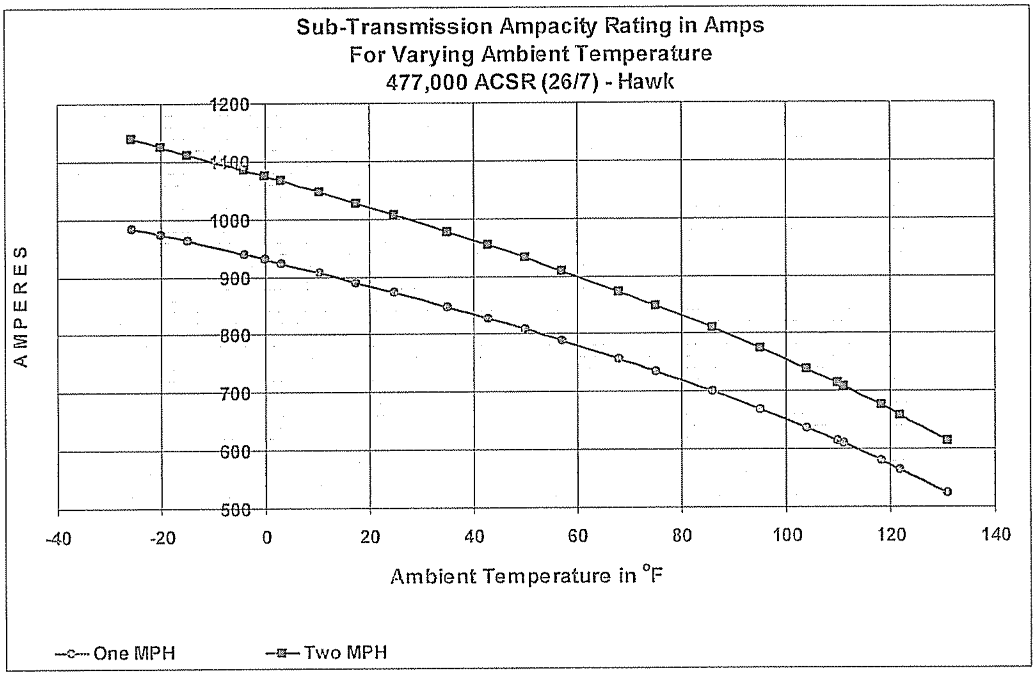

Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
336,400 ACSR (30/7) - Oriole
AMPERES
1150
1050
950
850
750
650
550
450
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
Normal Rating
Emergency Rating

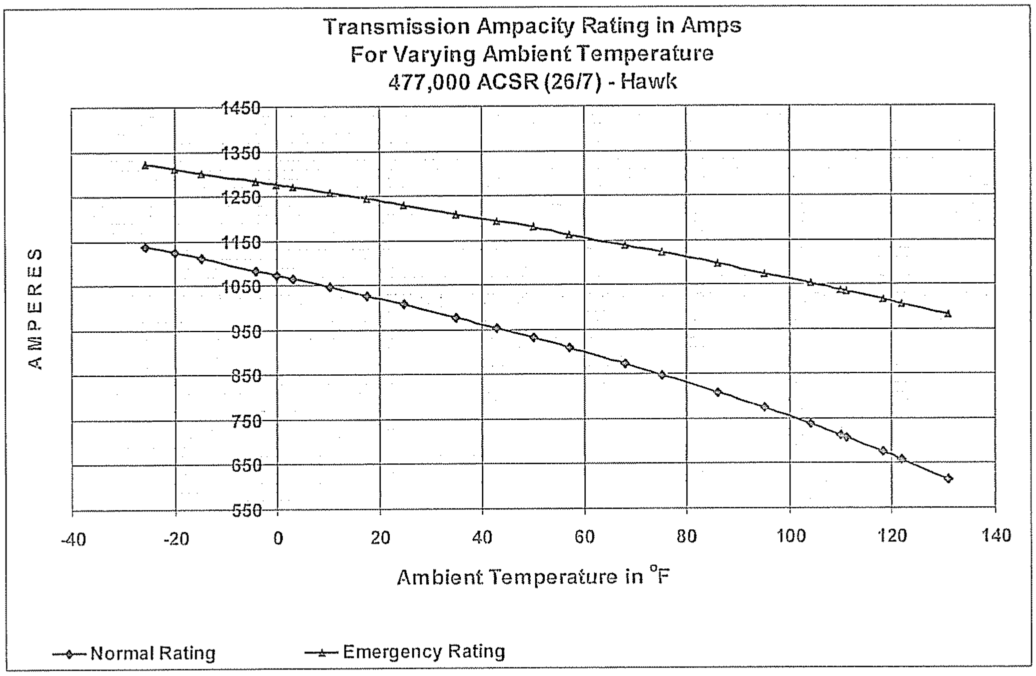

Sub-Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
397,500 ACSR (18/1) - Chickadee
AMPERES
1100
1000
900
800
700
600
500
400
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
One MPH
Two MPH

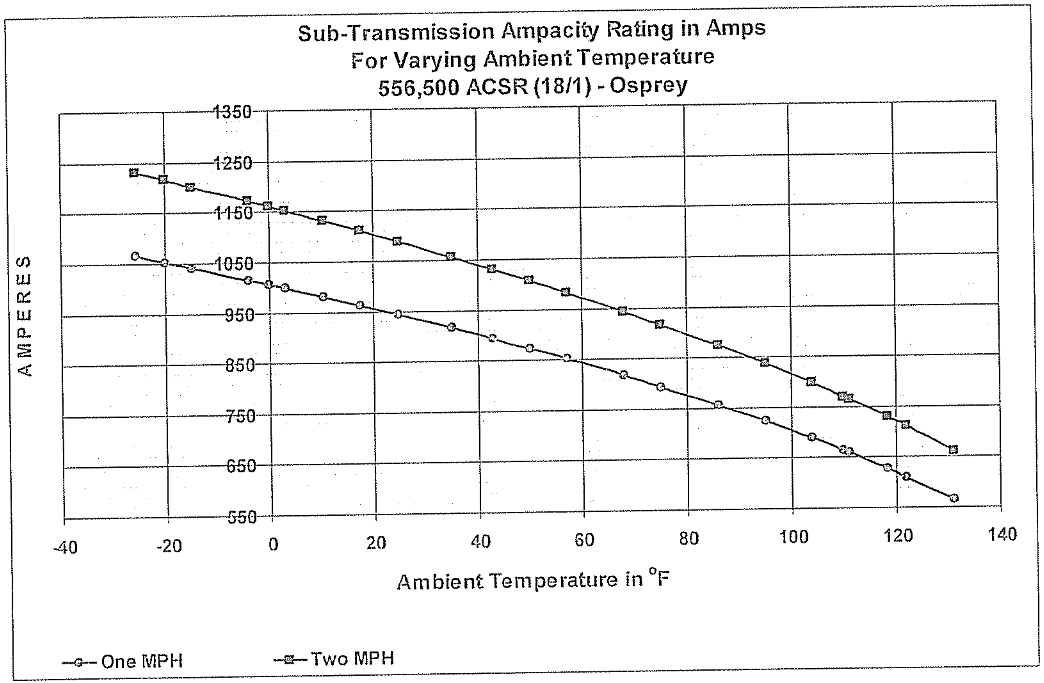

Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
397,500 ACSR (18/1) - Chickadee
AMPERES
1150
1050
950
850
750
650
550
450
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
Normal Rating
Emergency Rating

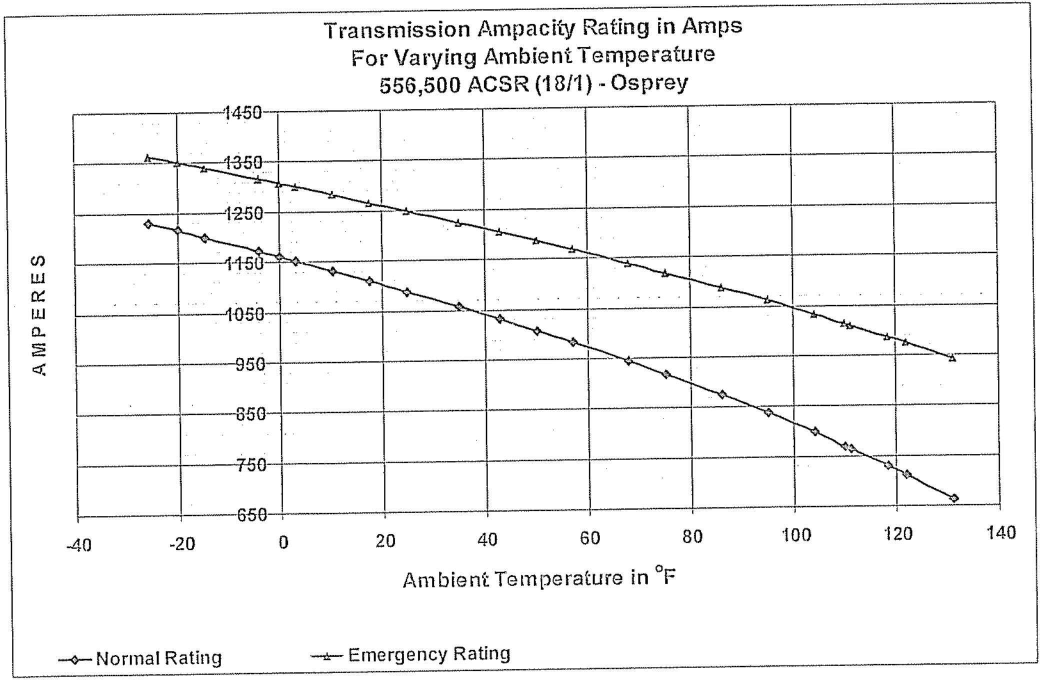

Sub-Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
397,500 ACSR (30/7) - Lark
AMPERES
1100
1000
900
800
700
600
500
400
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
One MPH
Two MPH

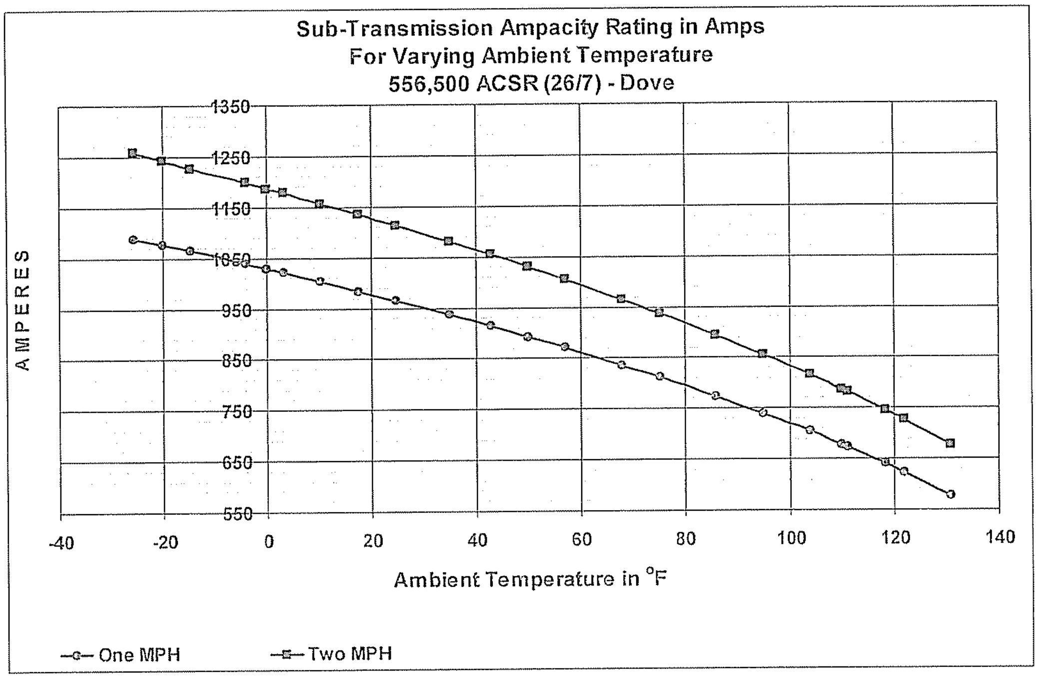

Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
397,500 ACSR (30/7) - Lark
AMPERES
1350
1250
1150
1050
950
850
750
650
550
450
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
Normal Rating
Emergency Rating

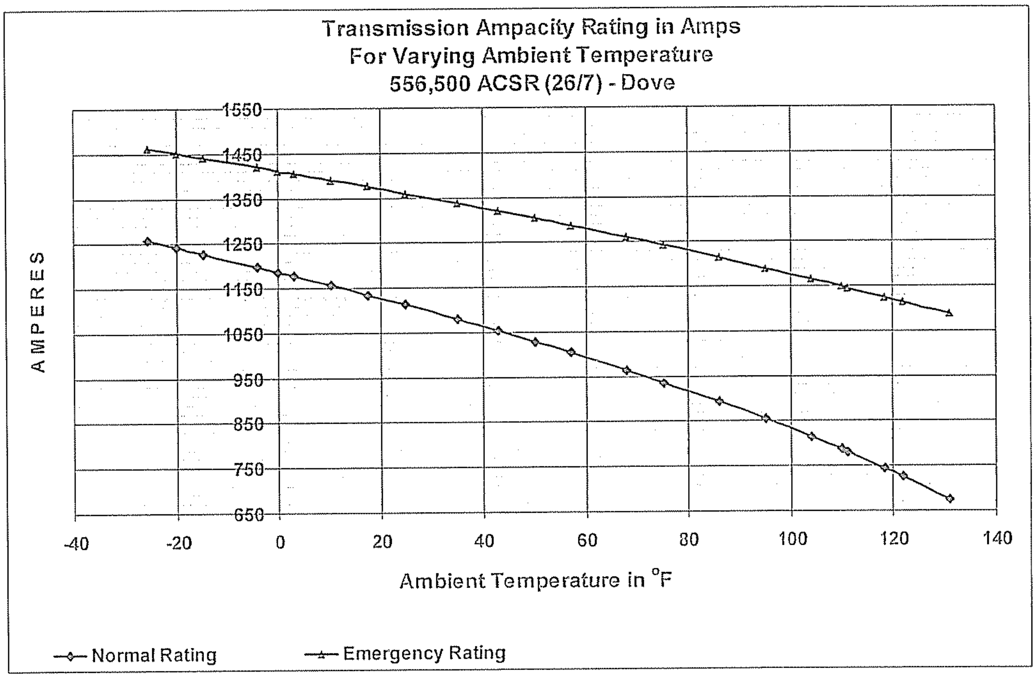

Sub-Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
477,000 ACSR (26/7) - Hawk
AMPERES
1200
1100
1000
900
800
700
600
500
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
One MPH
Two MPH

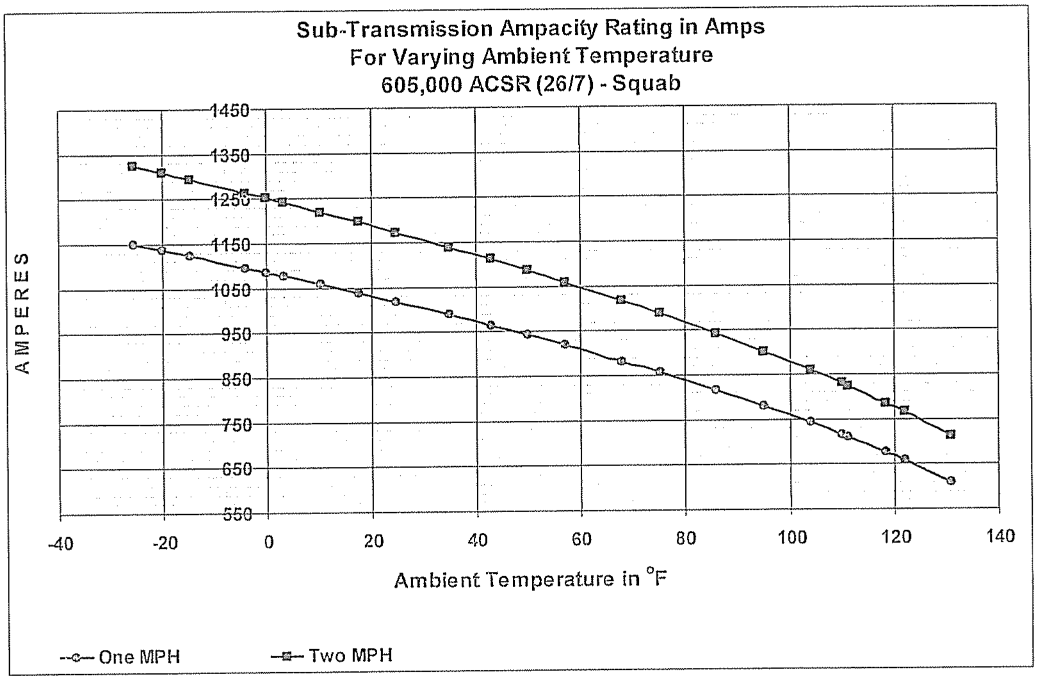

Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
477,000 ACSR (26/7) - Hawk
AMPERES
1450
1350
1250
1150
1050
950
850
750
650
550
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
Normal Rating
Emergency Rating


Sub-Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
556,500 ACSR (18/1) - Osprey
AMPERES
1350
1250
1150
1050
950
850
750
650
550
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
One MPH
Two MPH

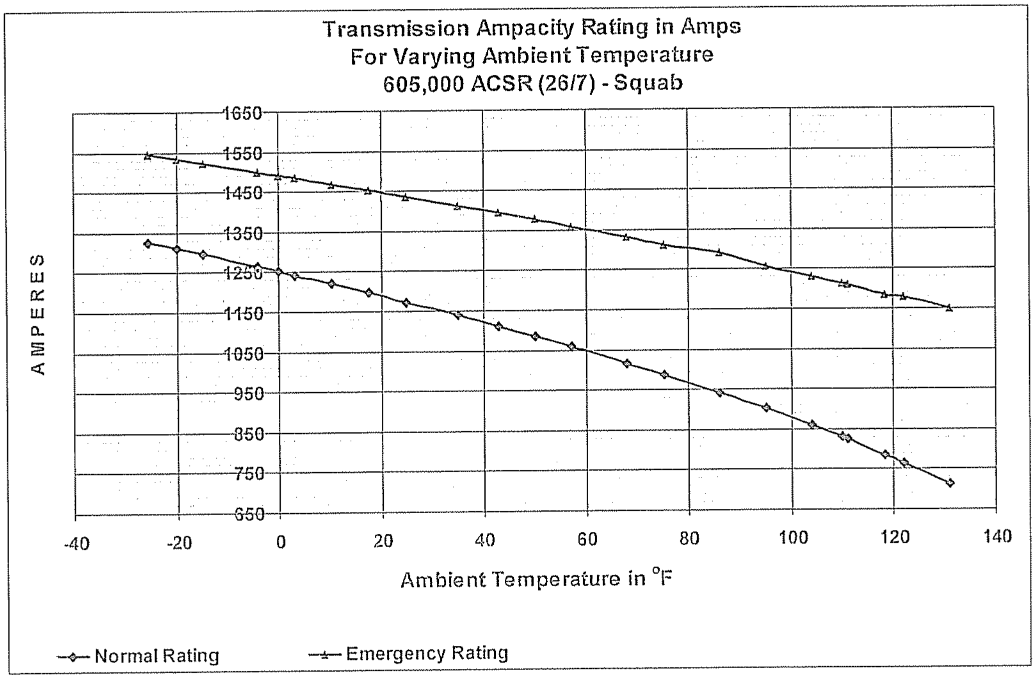

Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
556,500 ACSR (18/1) - Osprey
AMPERES
1450
1350
1250
1150
1050
950
850
750
650
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
Normal Rating
Emergency Rating


Sub-Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
556,500 ACSR (26/7) - Dove
AMPERES
1350
1250
1150
1050
950
850
750
650
550
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
One MPH
Two MPH

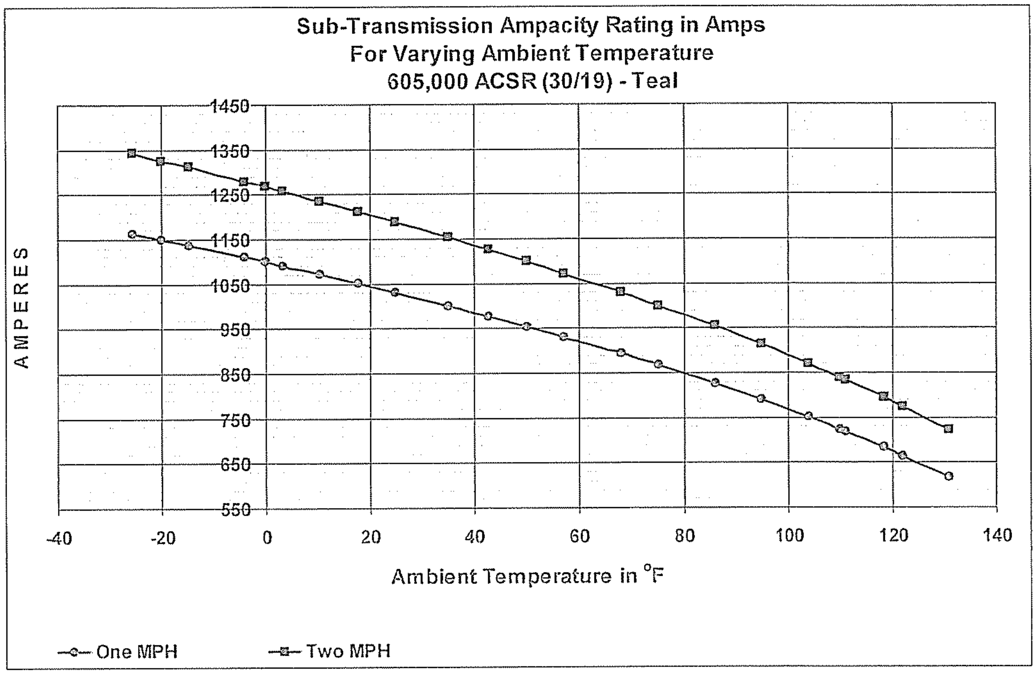

Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
556,500 ACSR (26/7) - Dove
AMPERES
1550
1450
1350
1250
1150
1050
950
850
750
650
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
Normal Rating
Emergency Rating

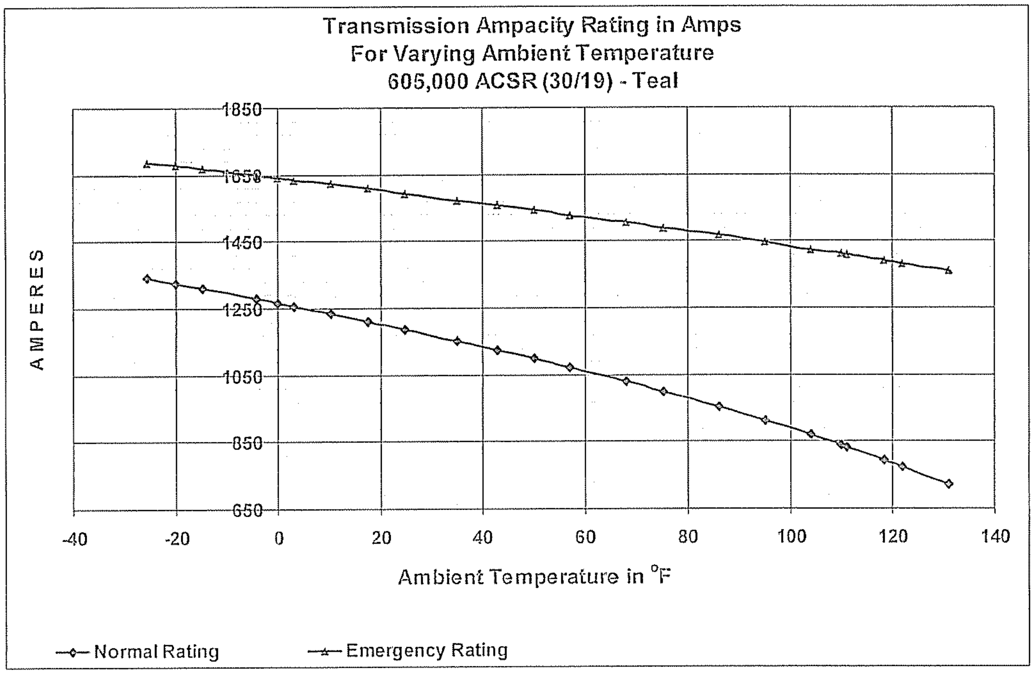


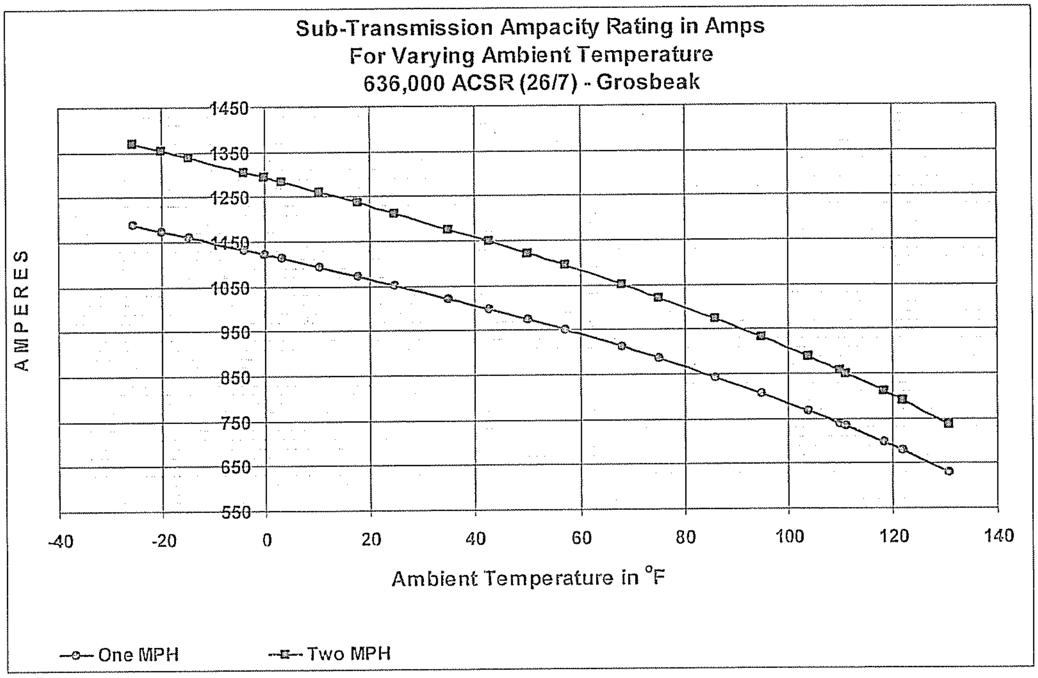
Sub-Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
605,000 ACSR (26/7) - Squab

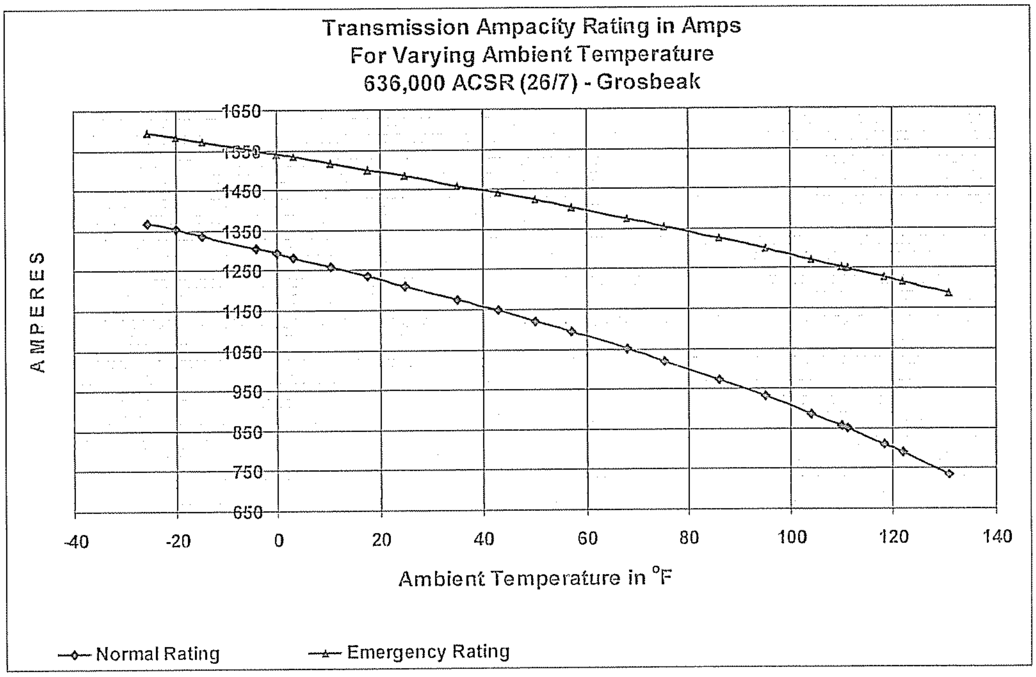


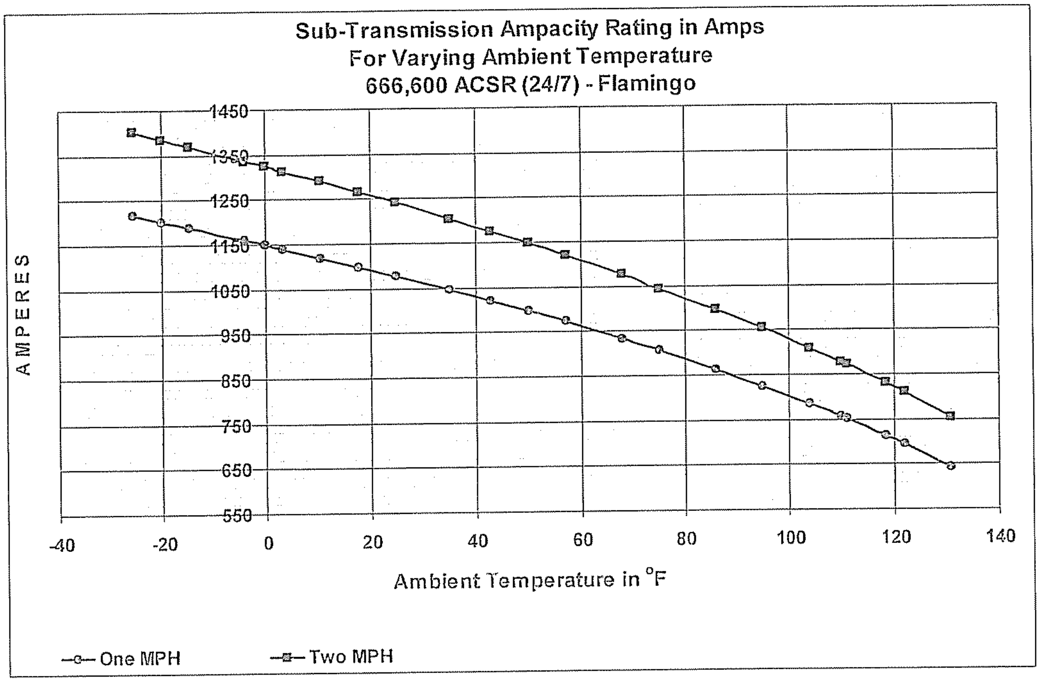
Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
605,000 ACSR (26/7) - Squab

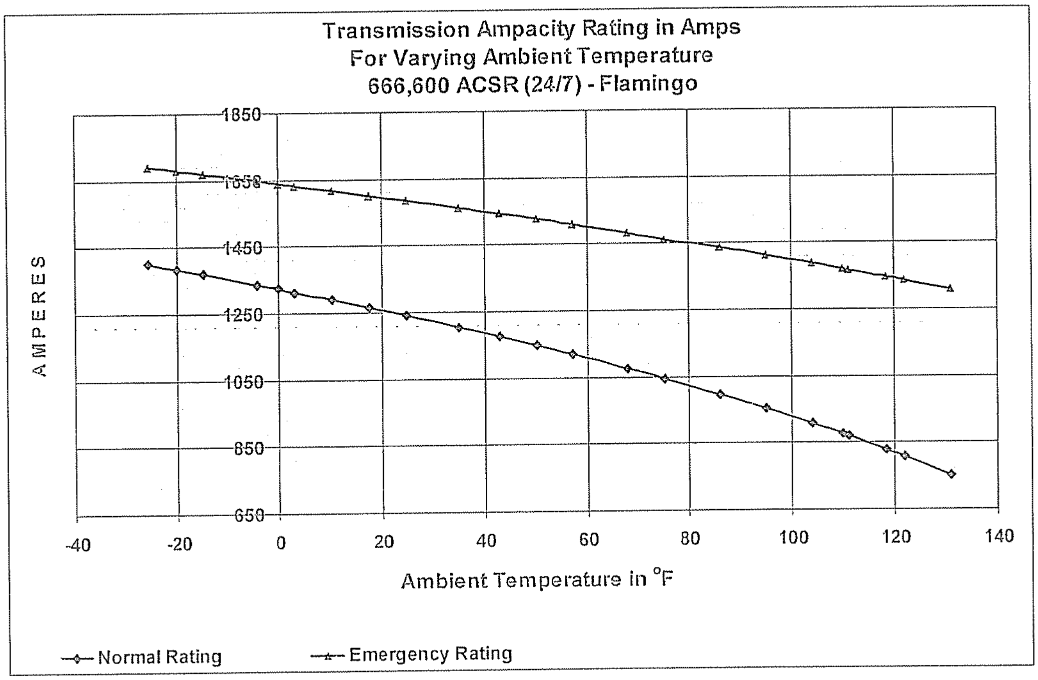

Sub-Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
605,000 ACSR (30/19) - Teal
AMPERES
1450
1350
1250
1150
1050
950
850
750
650
550
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
One MPH
Two MPH

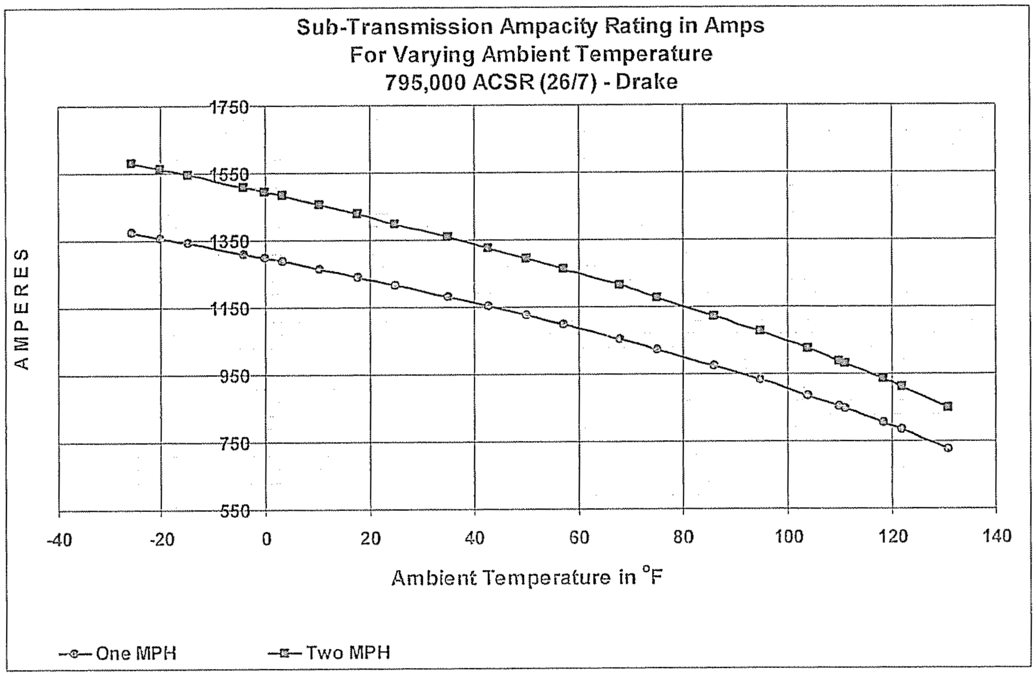

Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
605,000 ACSR (30/19) - Teal
AMPERES
1850
1650
1450
1250
1050
850
650
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
Normal Rating
Emergency Rating

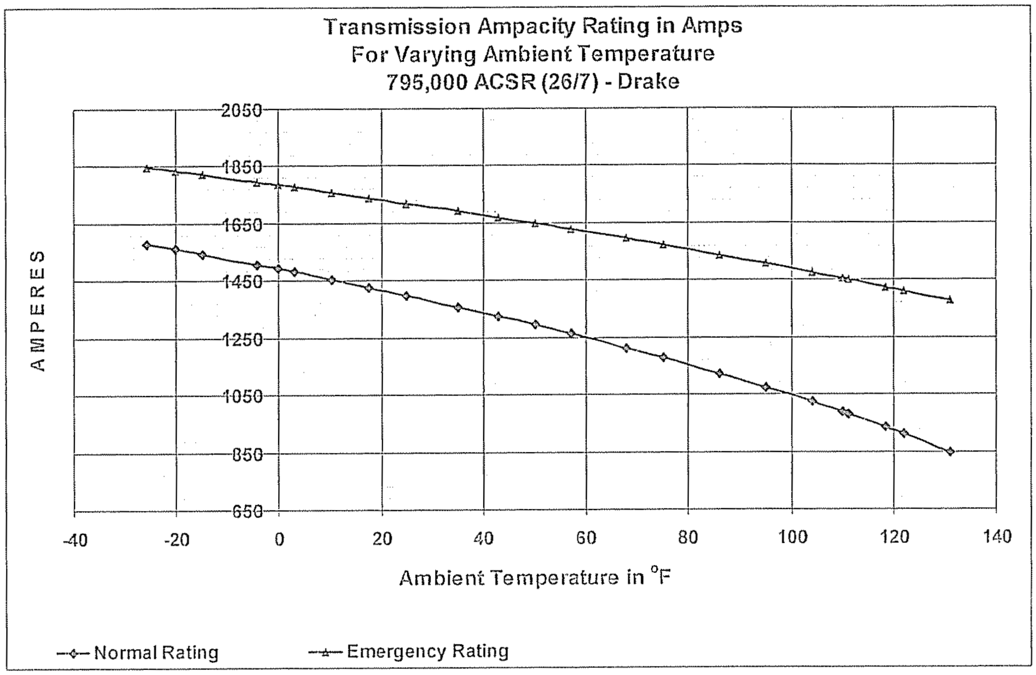

Sub-Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
636,000 ACSR (26/7) - Grosbeak

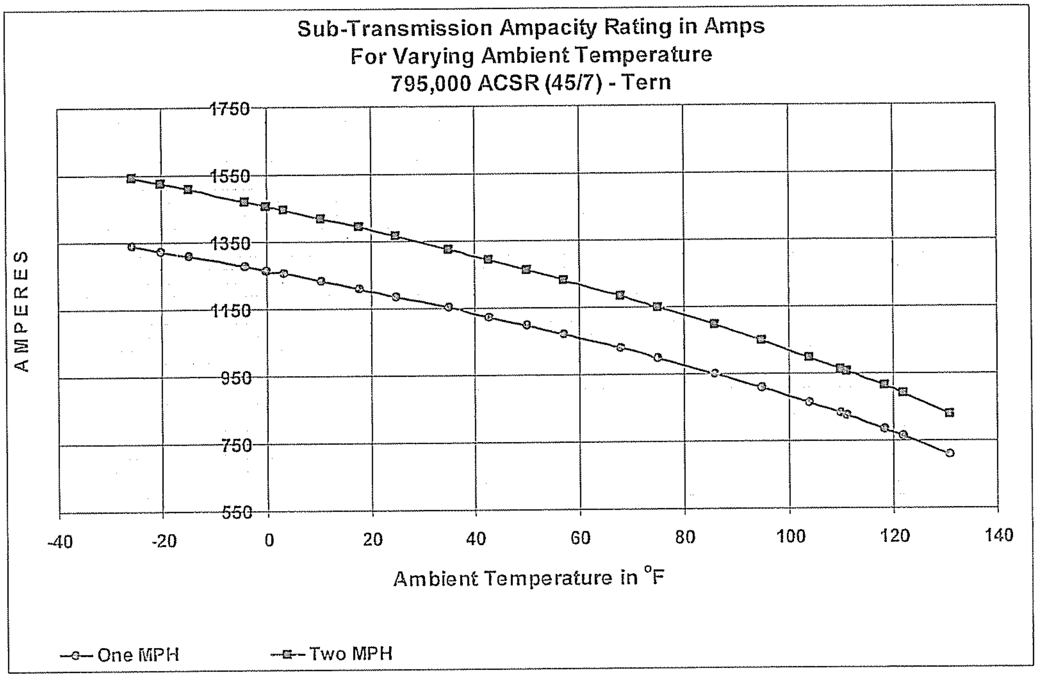

Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
636,000 ACSR (26/7) - Grosbeak

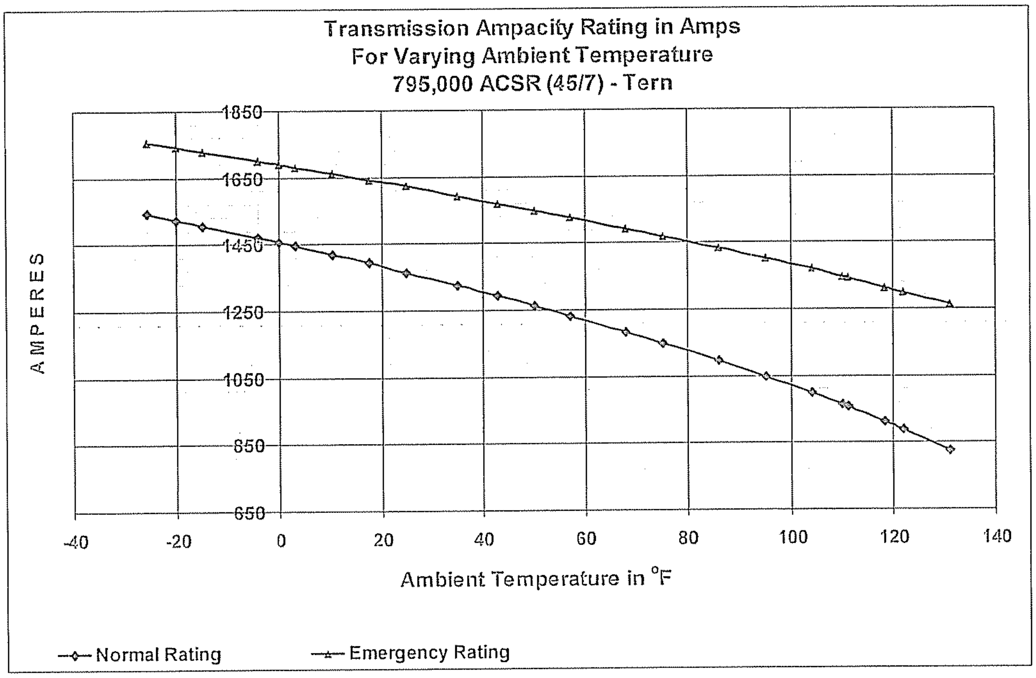

Sub-Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
666,600 ACSR (24/7) - Flamingo
AMPERES
1450
1350
1250
1150
1050
950
850
750
650
550
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
One MPH
Two MPH

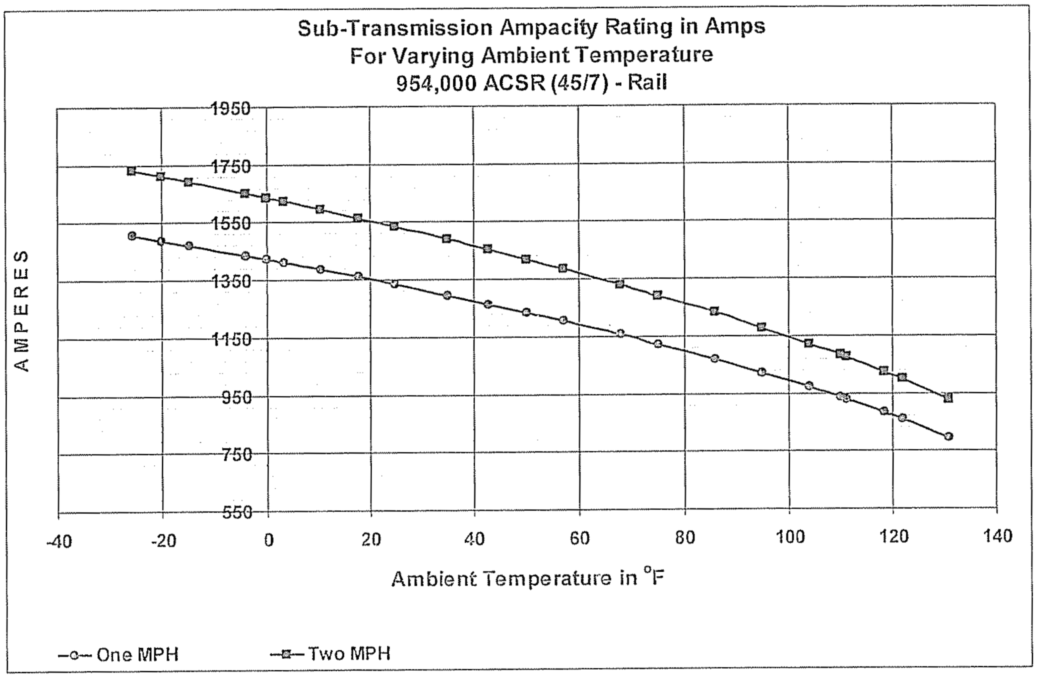

Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
666,600 ACSR (24/7) - Flamingo
AMPERES
1850
1650
1450
1250
1050
850
650
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
Normal Rating
Emergency Rating

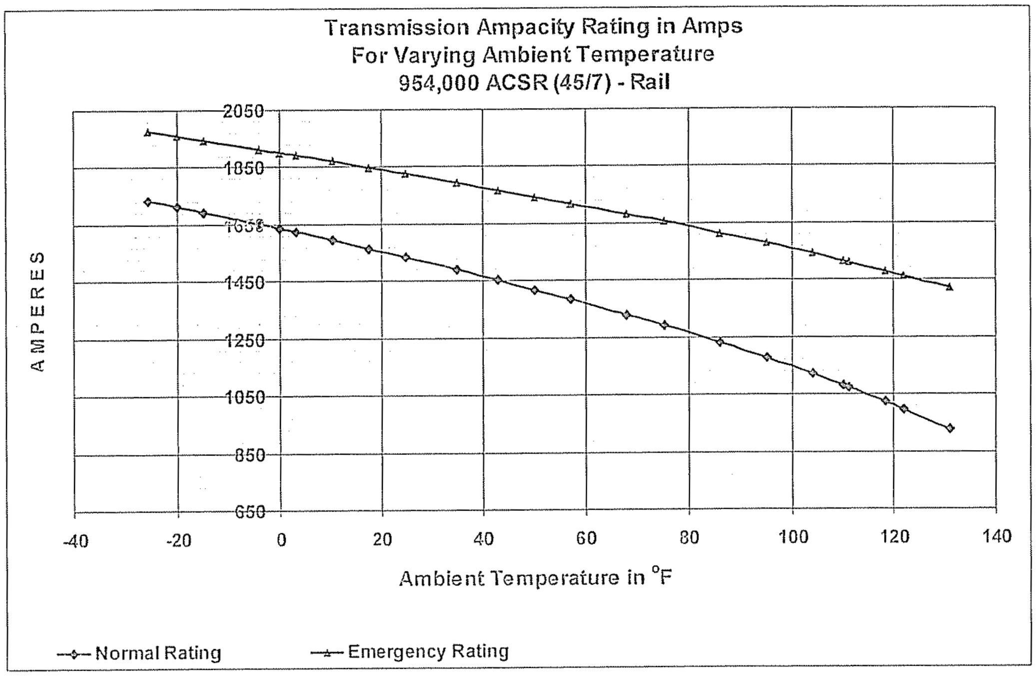

Sub-Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
795,000 ACSR (26/7) - Drake
AMPERES
1750
1550
1350
1150
950
750
550
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
One MPH
Two MPH

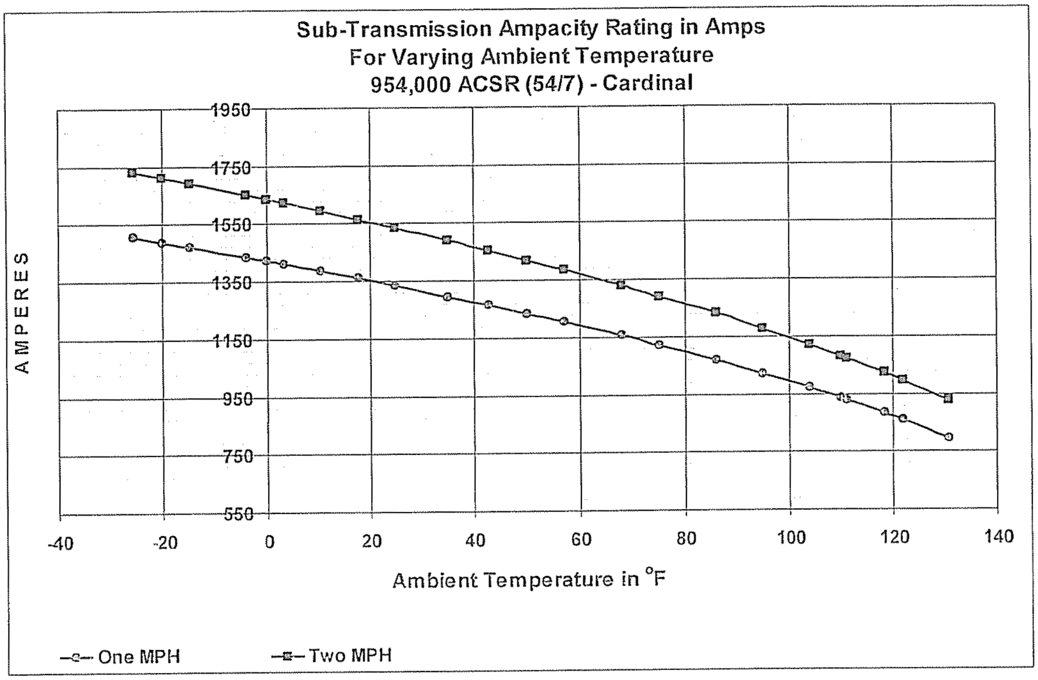

Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
795,000 ACSR (26/7) - Drake
AMPERES
2050
1850
1650
1450
1250
1050
850
650
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
Normal Rating
Emergency Rating

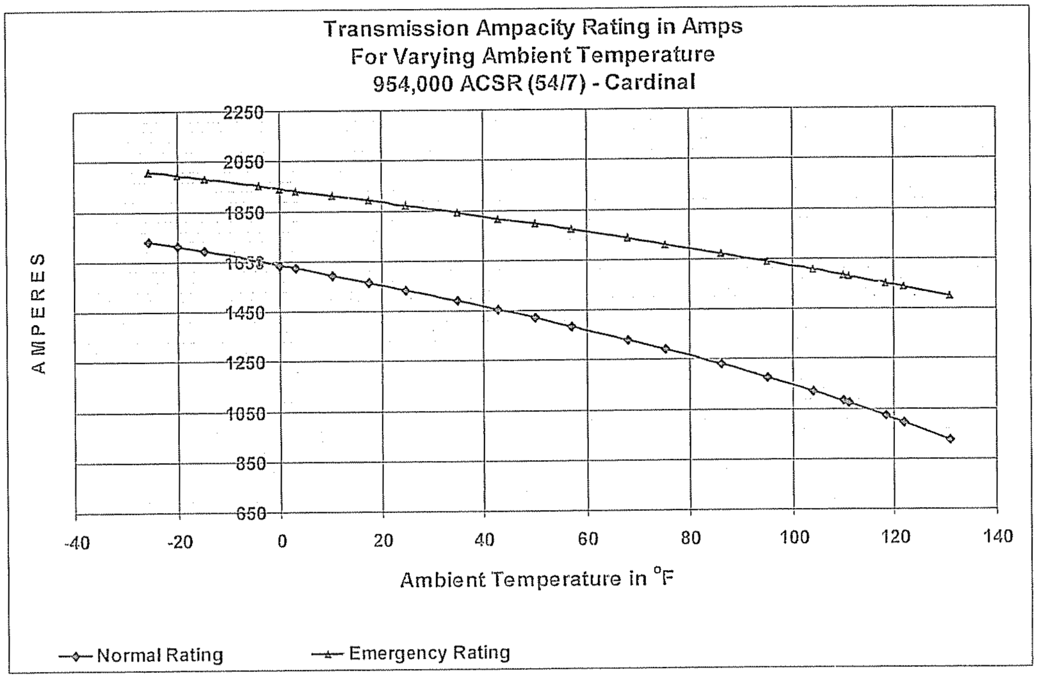

Sub-Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
795,000 ACSR (45/7) - Tern
AMPERES
1750
1550
1350
1150
950
750
550
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
One MPH
Two MPH

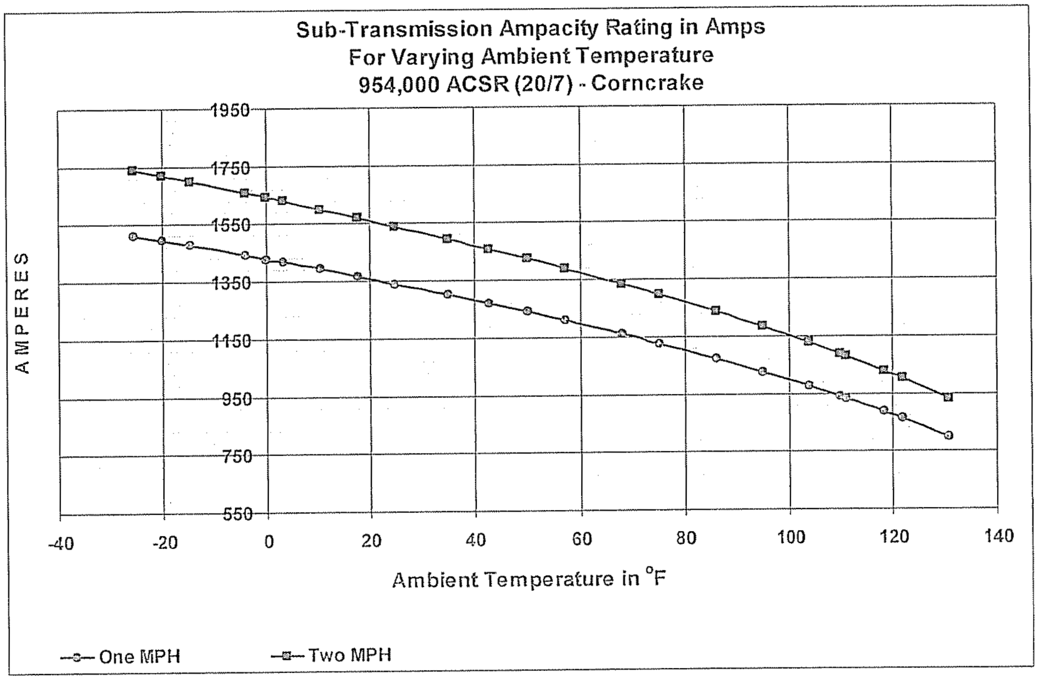

Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
795,000 ACSR (45/7) - Tern
AMPERES
1850
1650
1450
1250
1050
850
650
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
Normal Rating
Emergency Rating

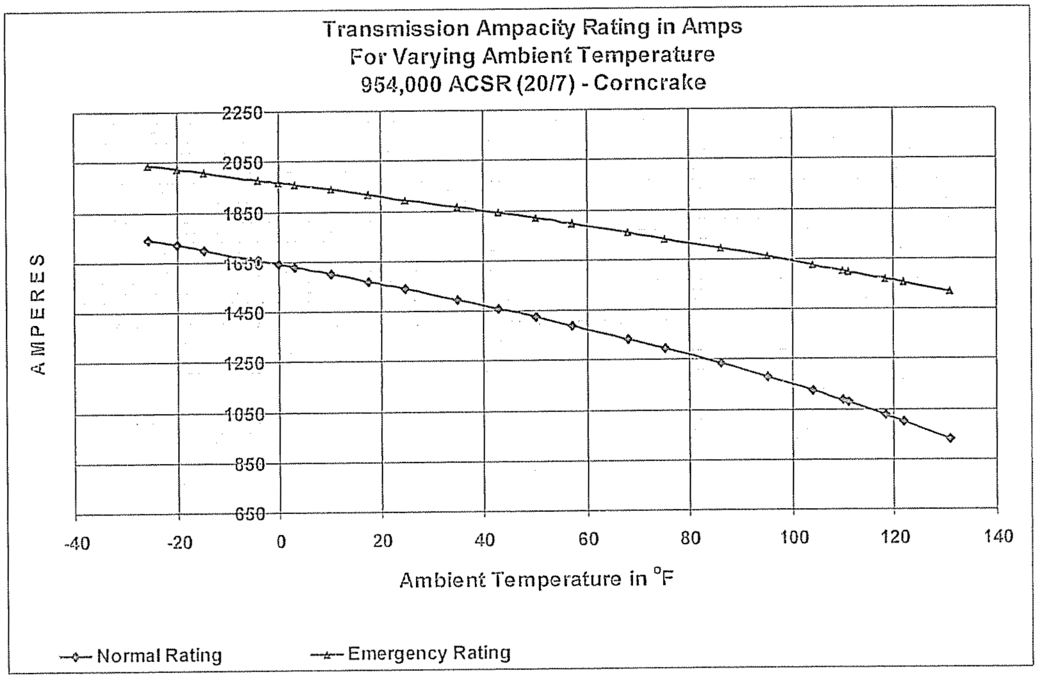

Sub-Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
954,000 ACSR (45/7) - Rail
AMPERES
1950
1750
1550
1350
1150
950
750
550
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
One MPH
Two MPH

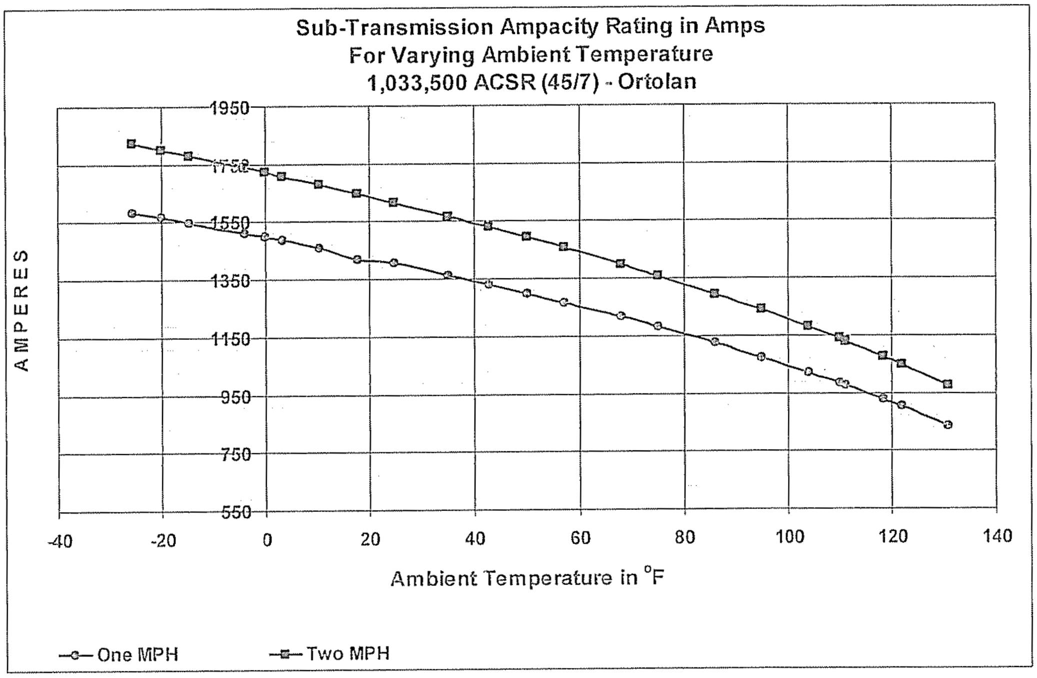

Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
954,000 ACSR (45/7) - Rail
AMPERES
2050
1850
1650
1450
1250
1050
850
650
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
Normal Rating
Emergency Rating

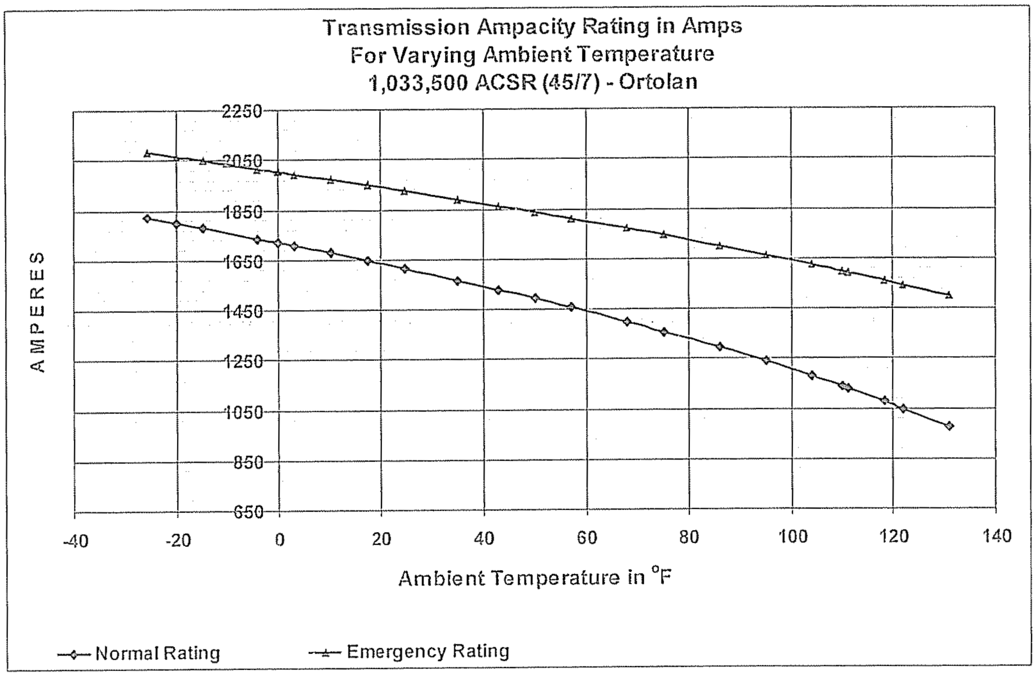

Sub-Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
954,000 ACSR (54/7) - Cardinal
AMPERES
1950
1750
1550
1350
1150
950
750
550
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
One MPH
Two MPH


Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
954,000 ACSR (54/7) - Cardinal
AMPERES
2250
2050
1850
1650
1450
1250
1050
850
650
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
Normal Rating
Emergency Rating


Sub-Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
954,000 ACSR (20/7) - Corncrake
AMPERES
1950
1750
1550
1350
1150
950
750
550
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
One MPH
Two MPH


Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
954,000 ACSR (20/7) - Corncrake
AMPERES
2250
2050
1850
1650
1450
1250
1050
850
650
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
Normal Rating
Emergency Rating


Sub-Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
1,033,500 ACSR (45/7) - Ortolan
AMPERES
1950
1750
1550
1350
1150
950
750
550
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
One MPH
Two MPH


Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
1,033,500 ACSR (45/7) - Ortolan
AMPERES
2250
2050
1850
1650
1450
1250
1050
850
650
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
Normal Rating
Emergency Rating

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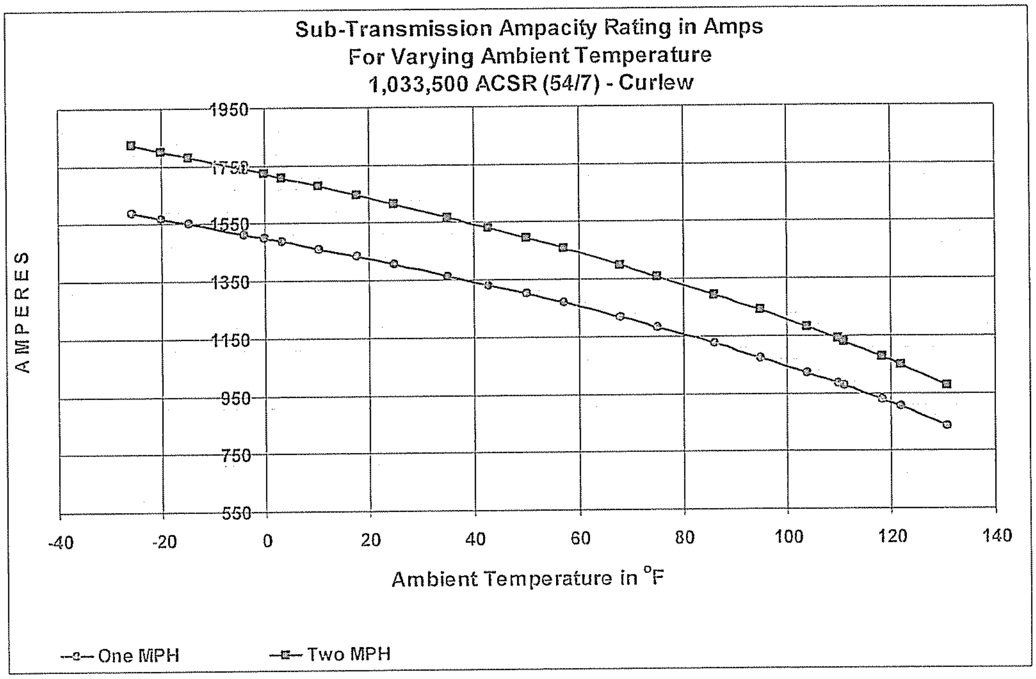
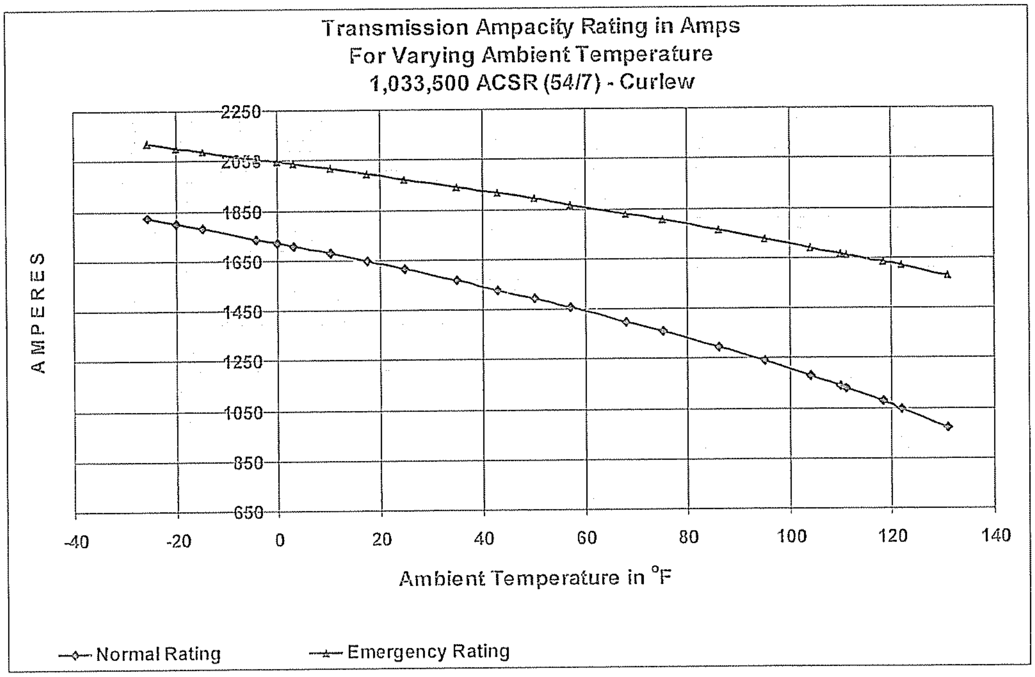
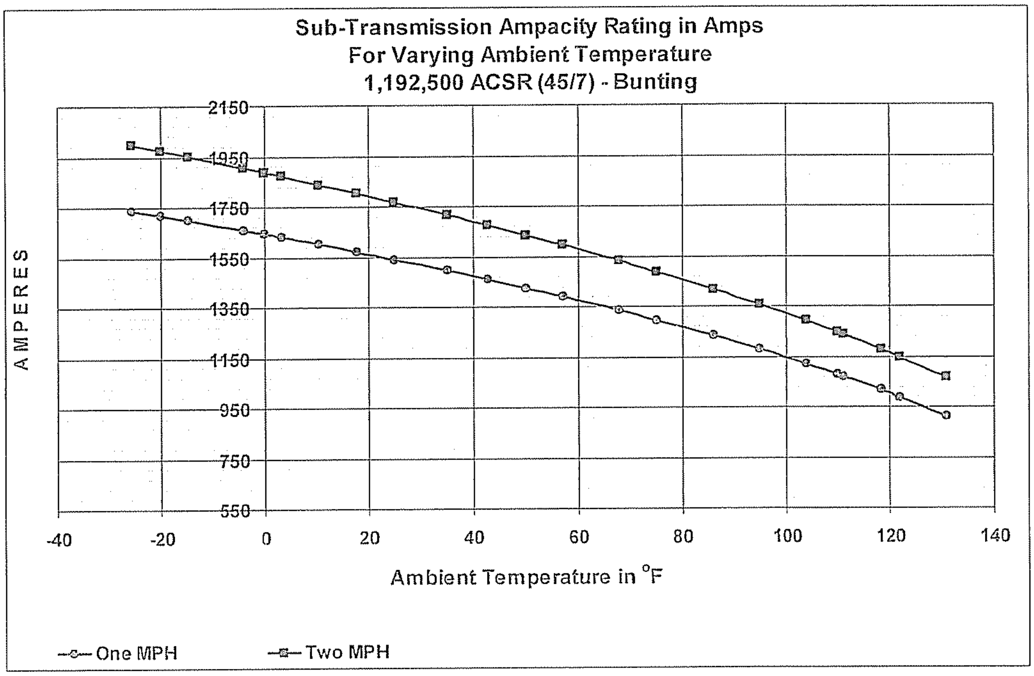
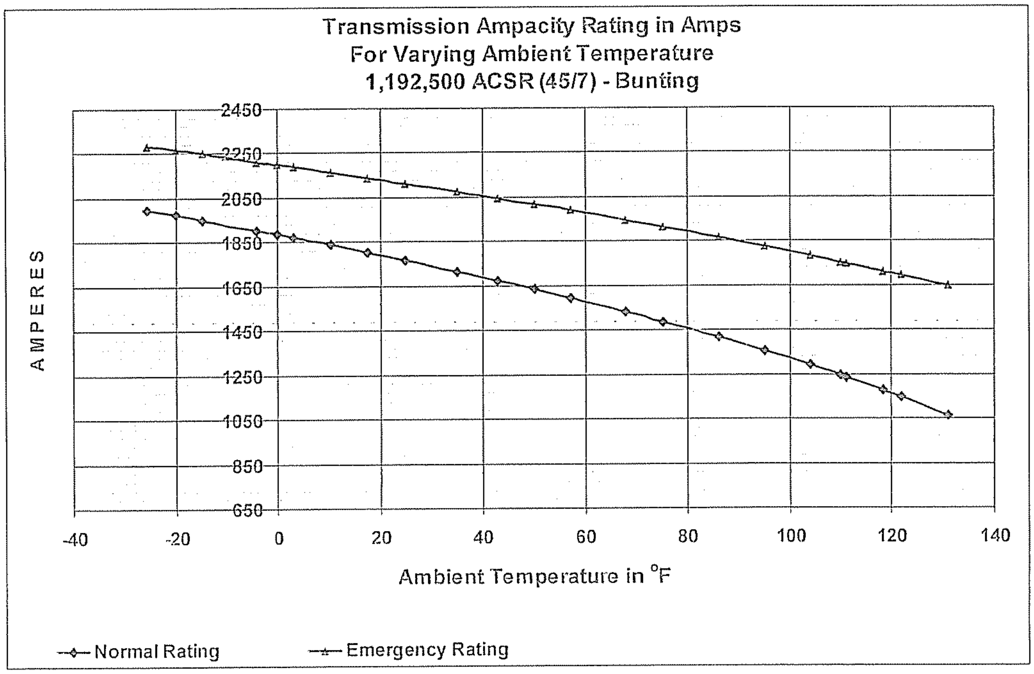


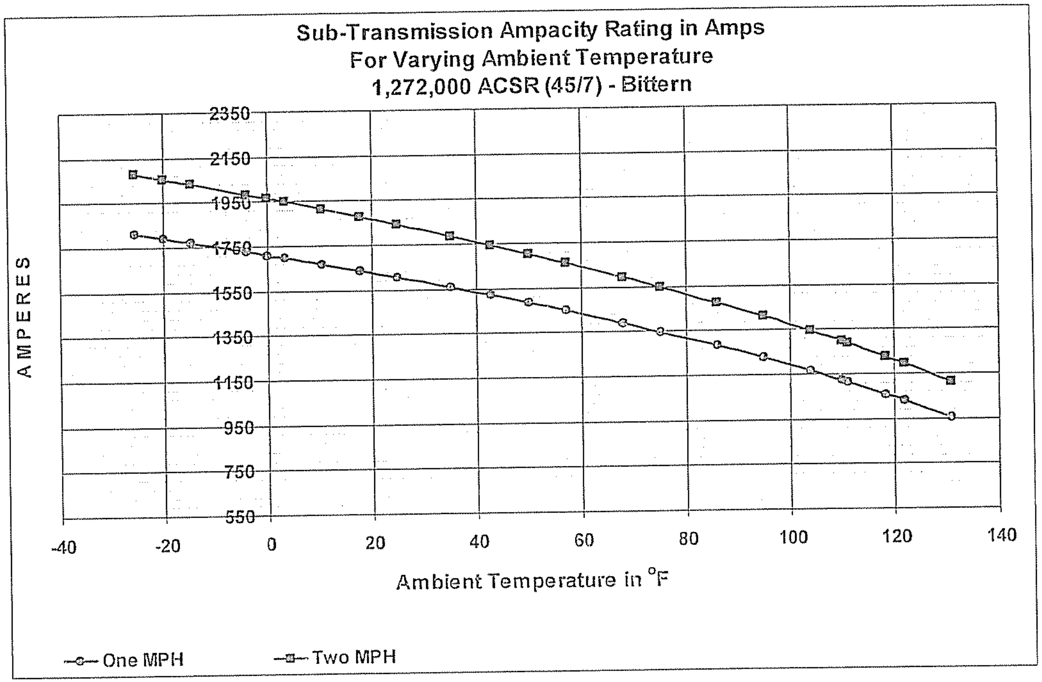
Sub-Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
1,033,500 ACSR (54/7) - Curlew

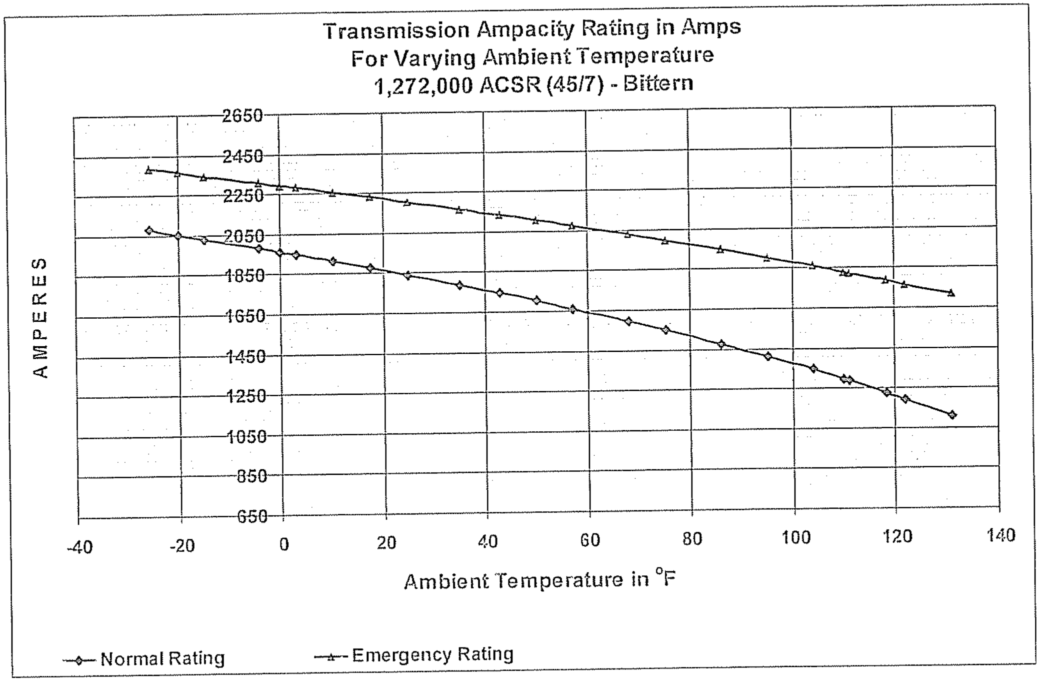


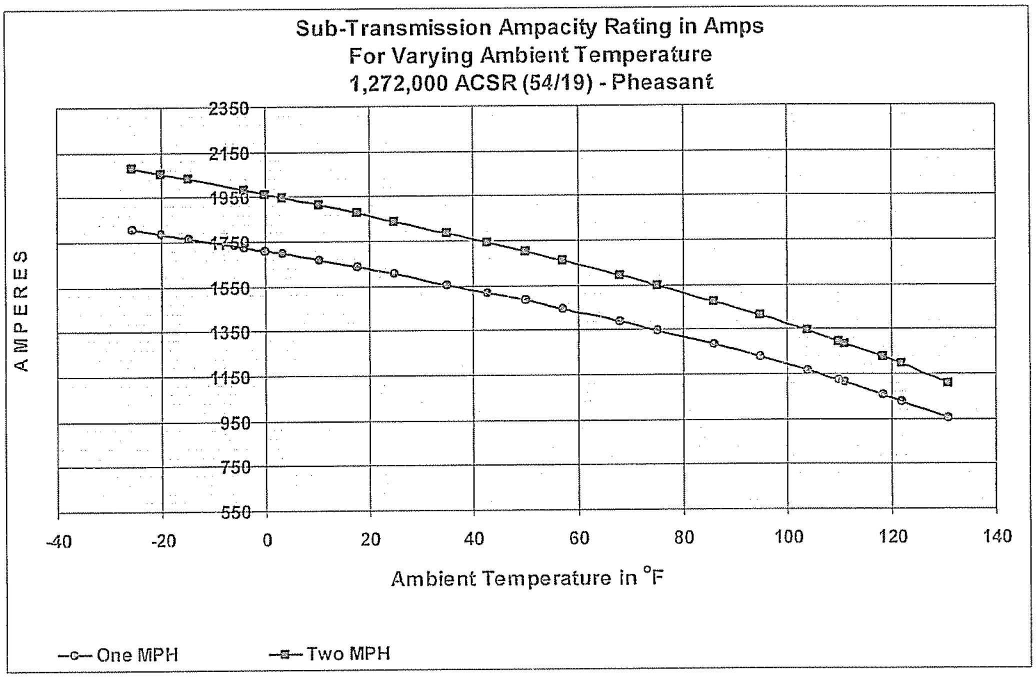
Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
1,033,500 ACSR (54/7) - Curlew

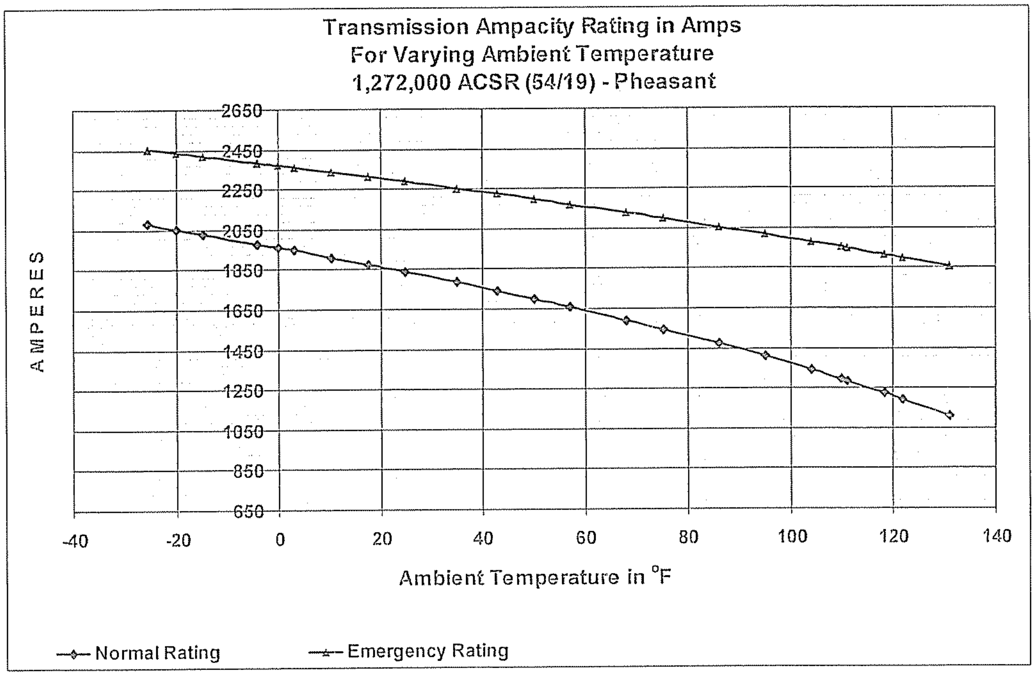

Sub-Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
1,192,500 ACSR (45/7) - Bunting
AMPERES
2150
1950
1750
1550
1350
1150
950
750
550
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
One MPH
Two MPH

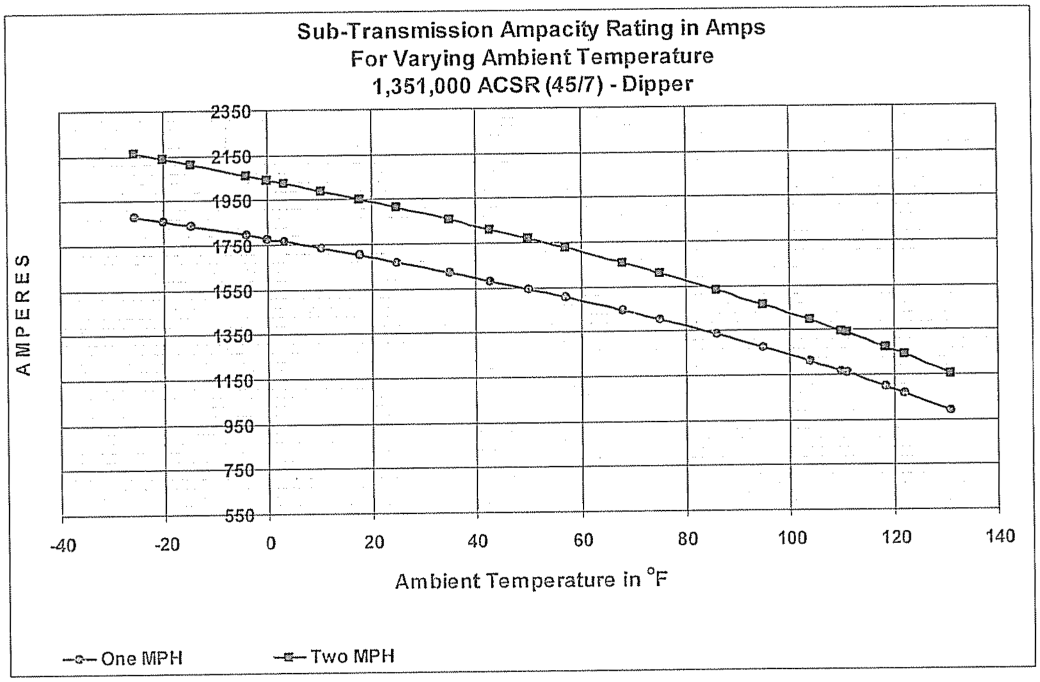

Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
1,192,500 ACSR (45/7) - Bunting
AMPERES
2450
2250
2050
1850
1650
1450
1250
1050
850
650
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
Normal Rating
Emergency Rating

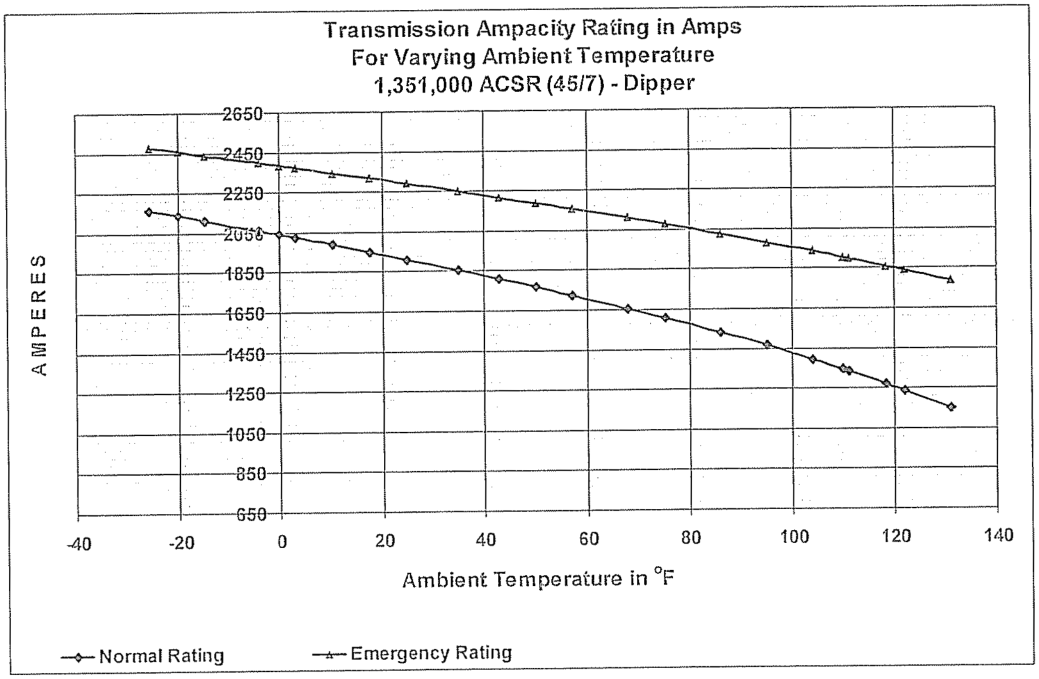

Sub-Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
1,272,000 ACSR (45/7) - Bittern
AMPERES
2350
2150
1950
1750
1550
1350
1150
950
750
550
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
One MPH
Two MPH

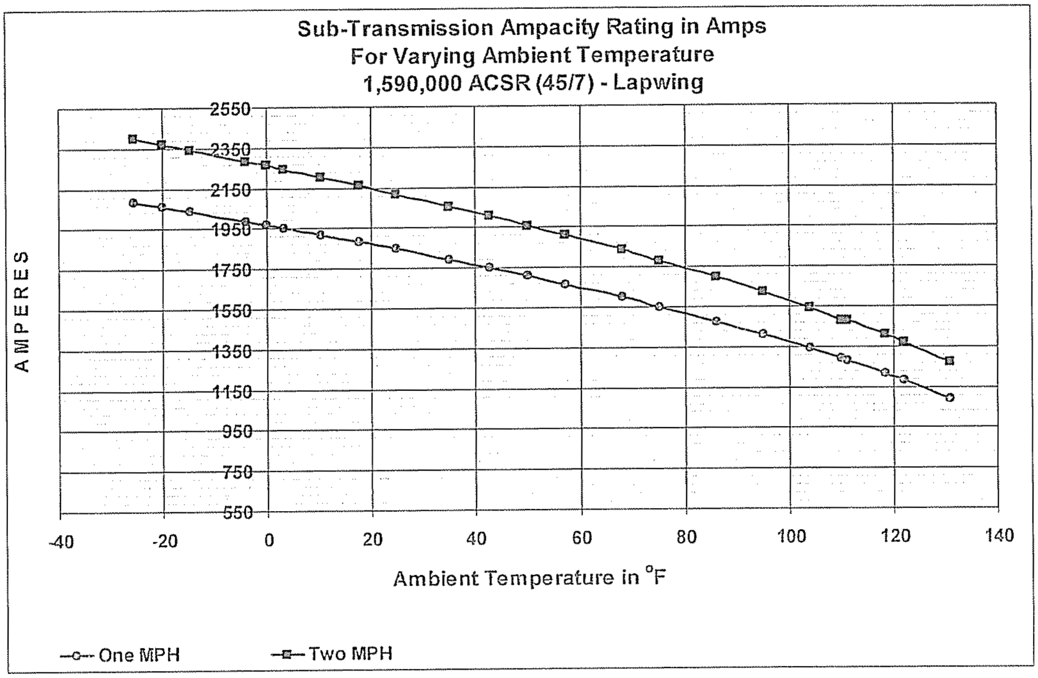

Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
1,272,000 ACSR (45/7) - Bittern
AMPERES
2650
2450
2250
2050
1850
1650
1450
1250
1050
850
650
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
Normal Rating
Emergency Rating

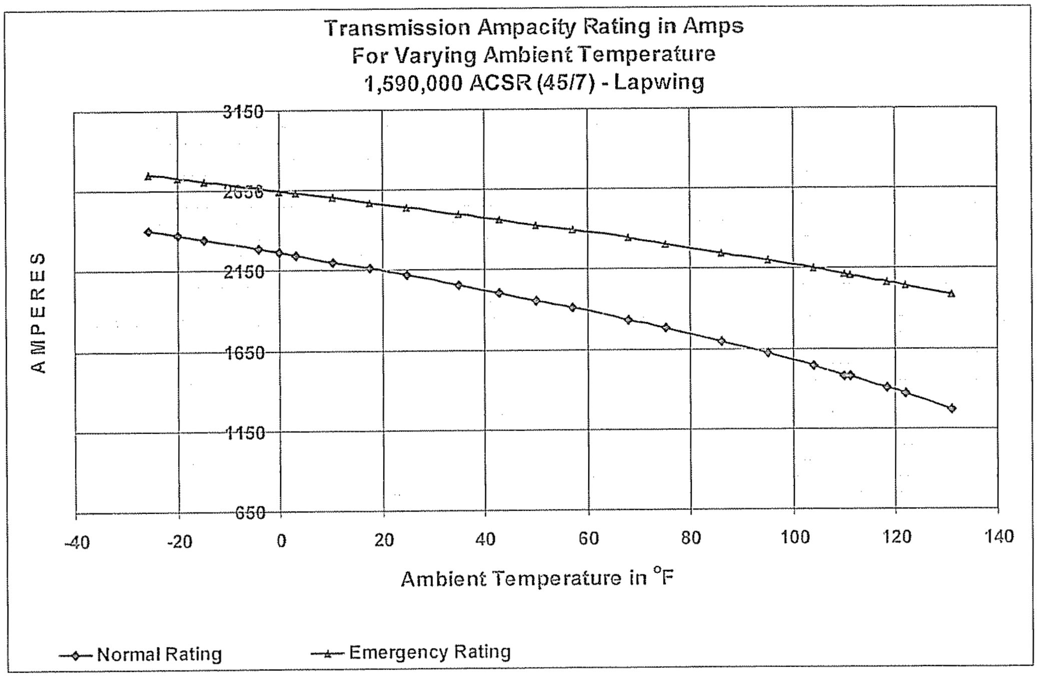

Sub-Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
1,272,000 ACSR (54/19) - Pheasant
AMPERES
2350
2150
1950
1750
1550
1350
1150
950
750
550
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
One MPH
Two MPH

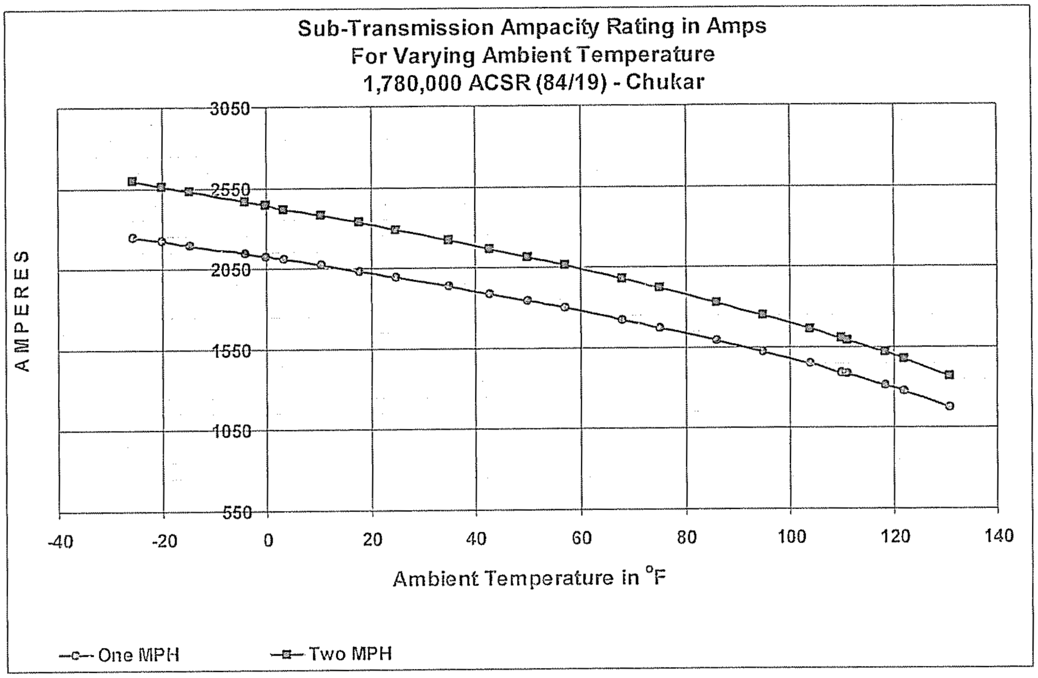

Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
1,272,000 ACSR (54/19) - Pheasant
AMPERES
2650
2450
2250
2050
1850
1650
1450
1250
1050
850
650
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
Normal Rating
Emergency Rating

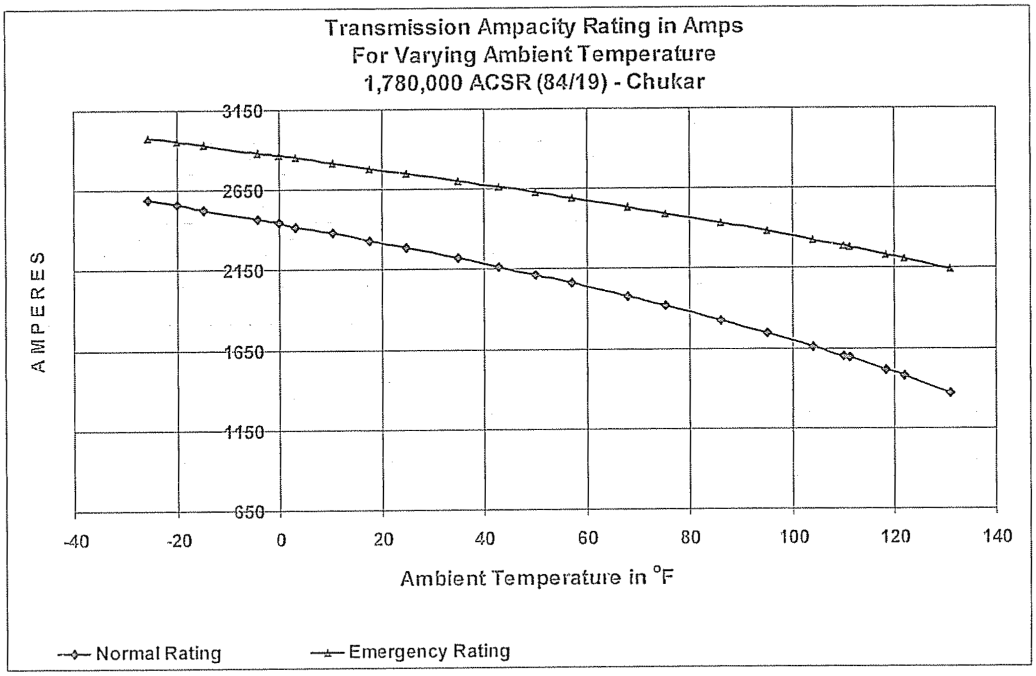

Sub-Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
1,351,000 ACSR (45/7) - Dipper

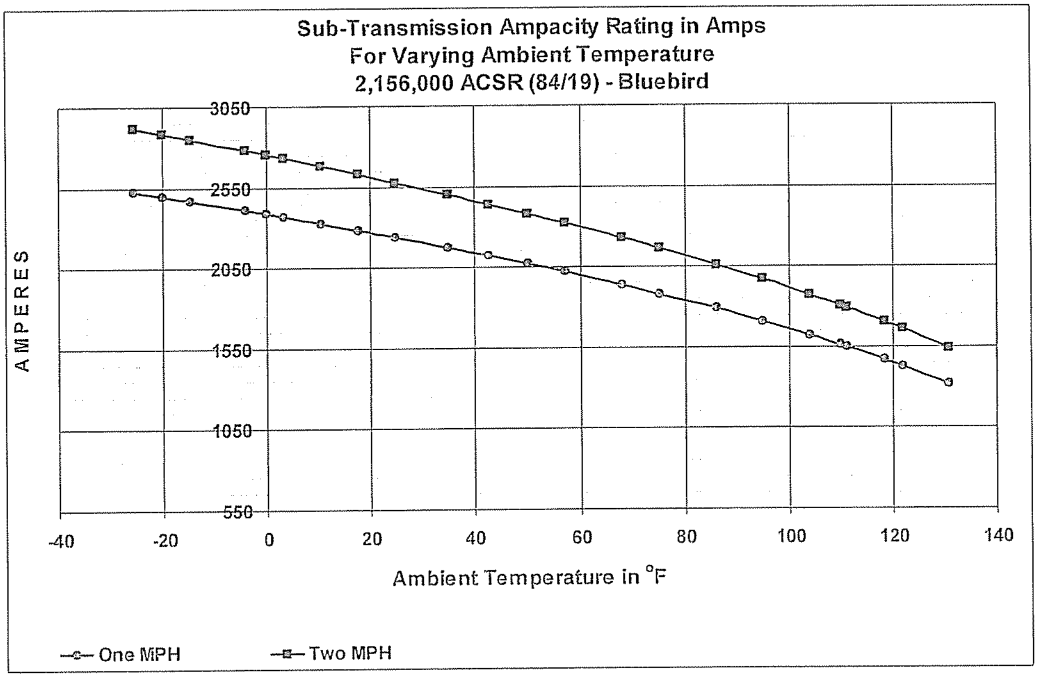

Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
1,351,000 ACSR (45/7) - Dipper

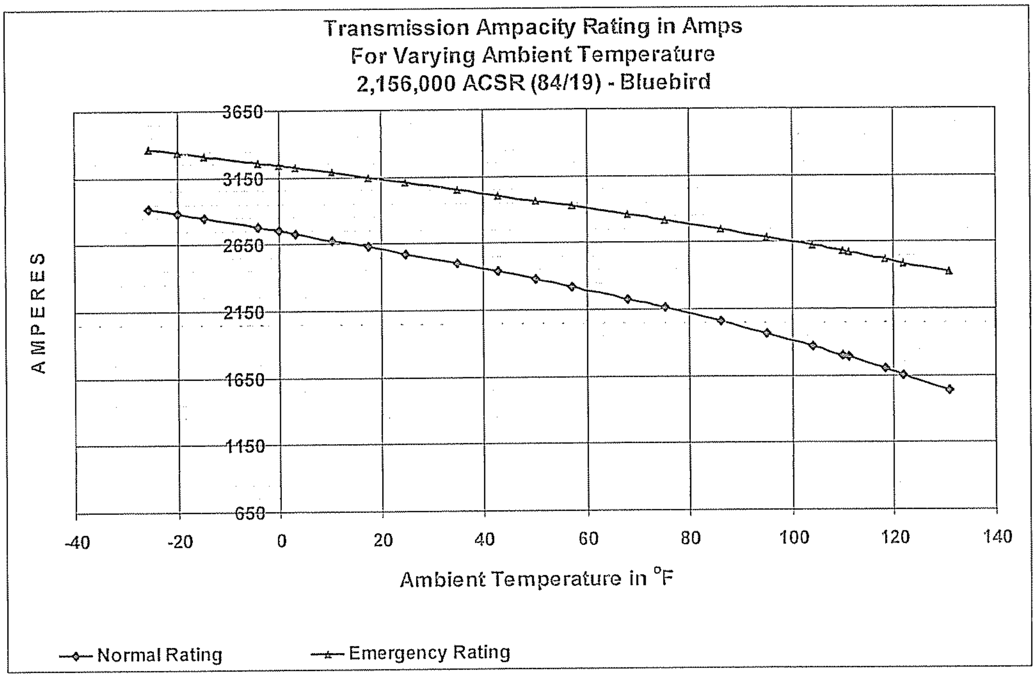

Sub-Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
1,590,000 ACSR (45/7) - Lapwing
AMPERES
2550
2350
2150
1950
1750
1550
1350
1150
950
750
550
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
One MPH
Two MPH

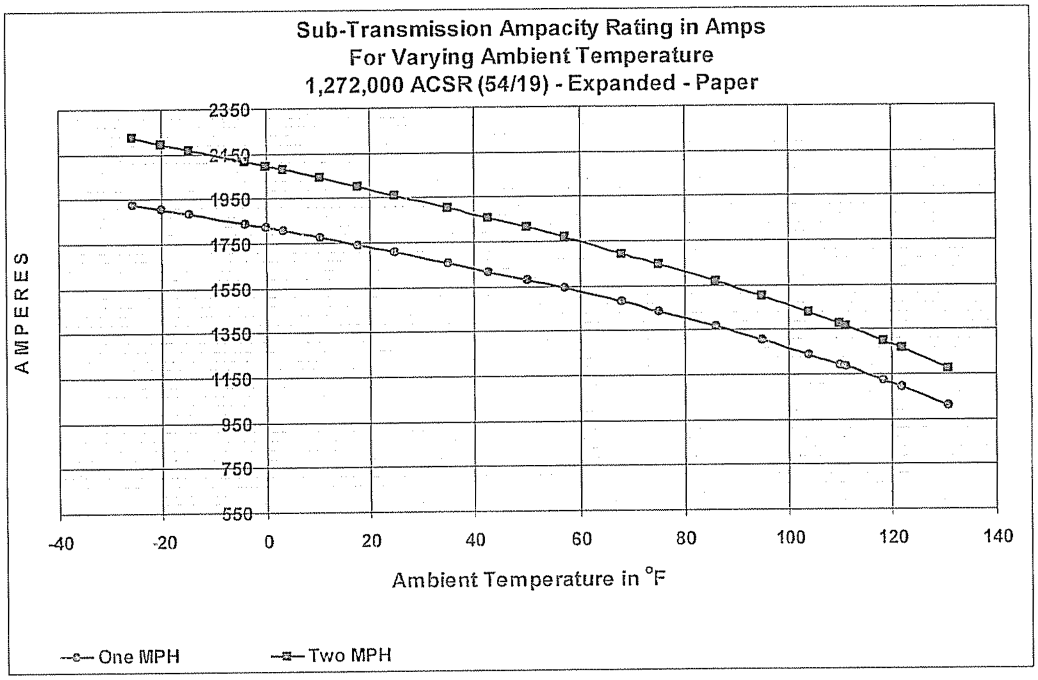

Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
1,590,000 ACSR (45/7) - Lapwing
AMPERES
3150
2650
2150
1650
1150
650
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
Normal Rating
Emergency Rating

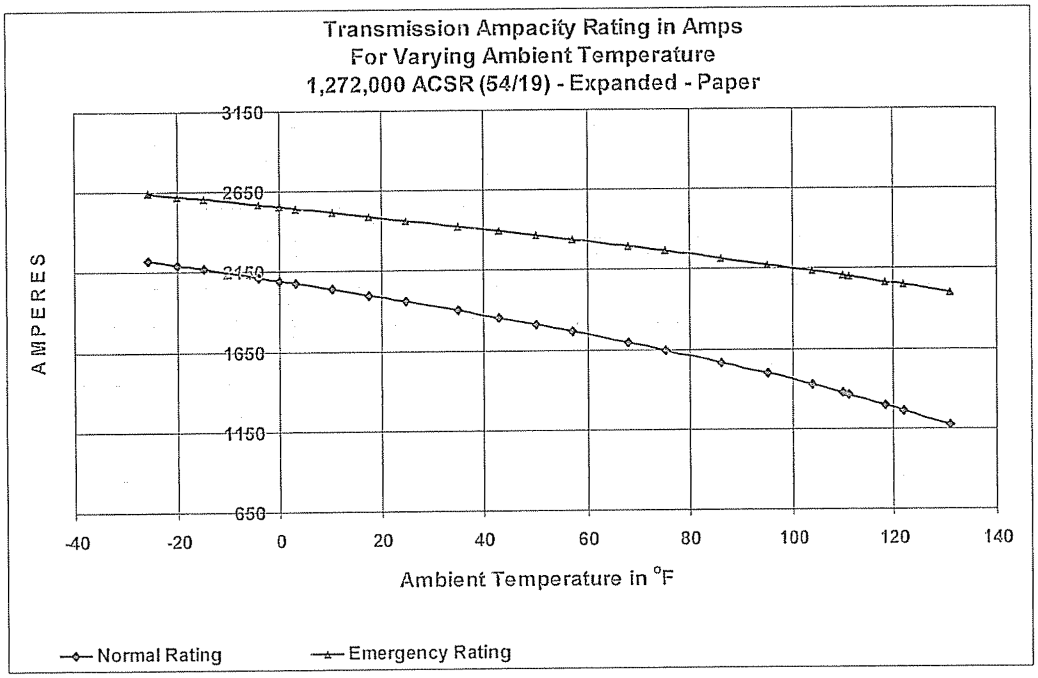

Sub-Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
1,780,000 ACSR (84/19) - Chukar


Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
1,780,000 ACSR (84/19) - Chukar


Sub-Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
2,156,000 ACSR (84/19) - Bluebird
AMPERES
3050
2550
2050
1550
1050
550
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
One MPH
Two MPH


Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
2,156,000 ACSR (84/19) - Bluebird
AMPERES
3650
3150
2650
2150
1650
1150
650
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
Normal Rating
Emergency Rating


Sub-Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
1,272,000 ACSR (54/19) - Expanded - Paper
AMPERES
2350
2150
1950
1750
1550
1350
1150
950
750
550
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
One MPH
Two MPH


Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
1,272,000 ACSR (54/19) - Expanded - Paper
AMPERES
3150
2650
2150
1650
1150
650
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
Normal Rating
Emergency Rating

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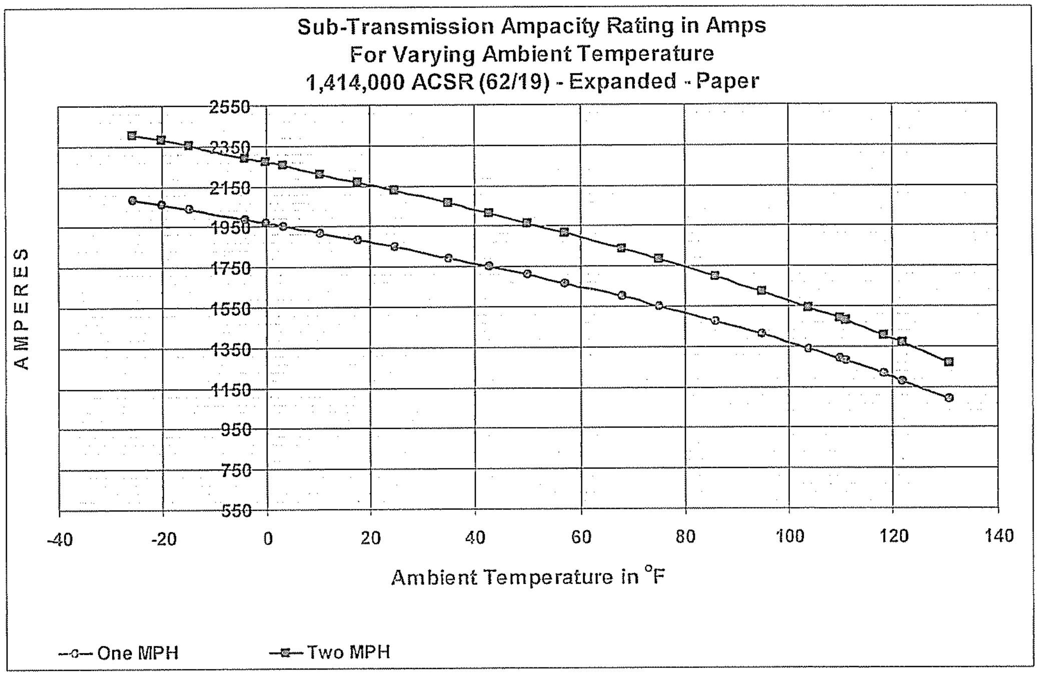
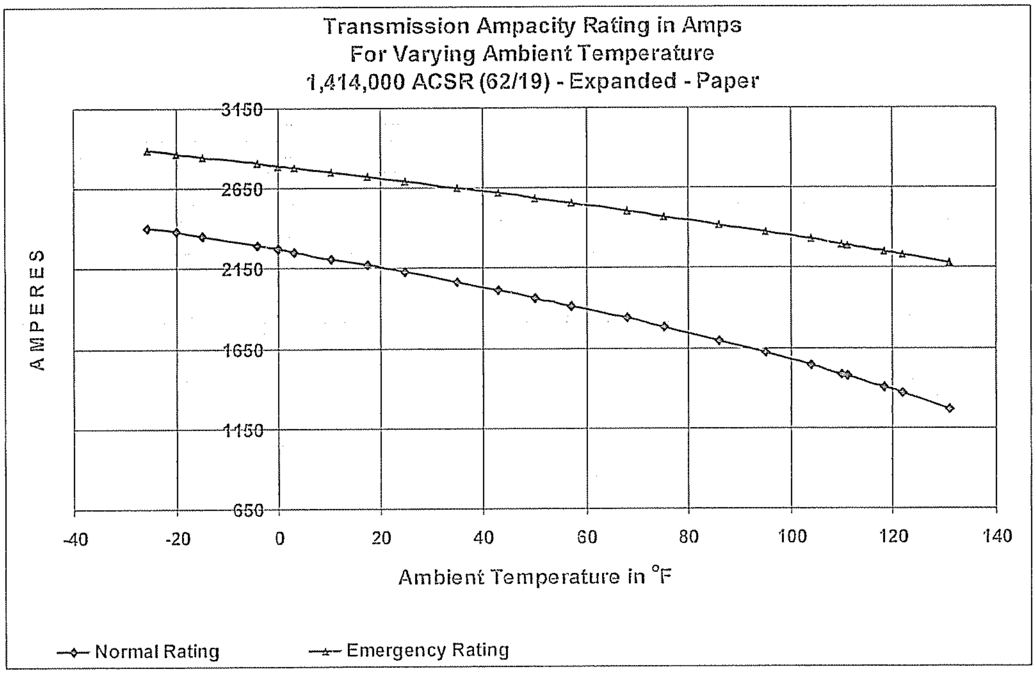
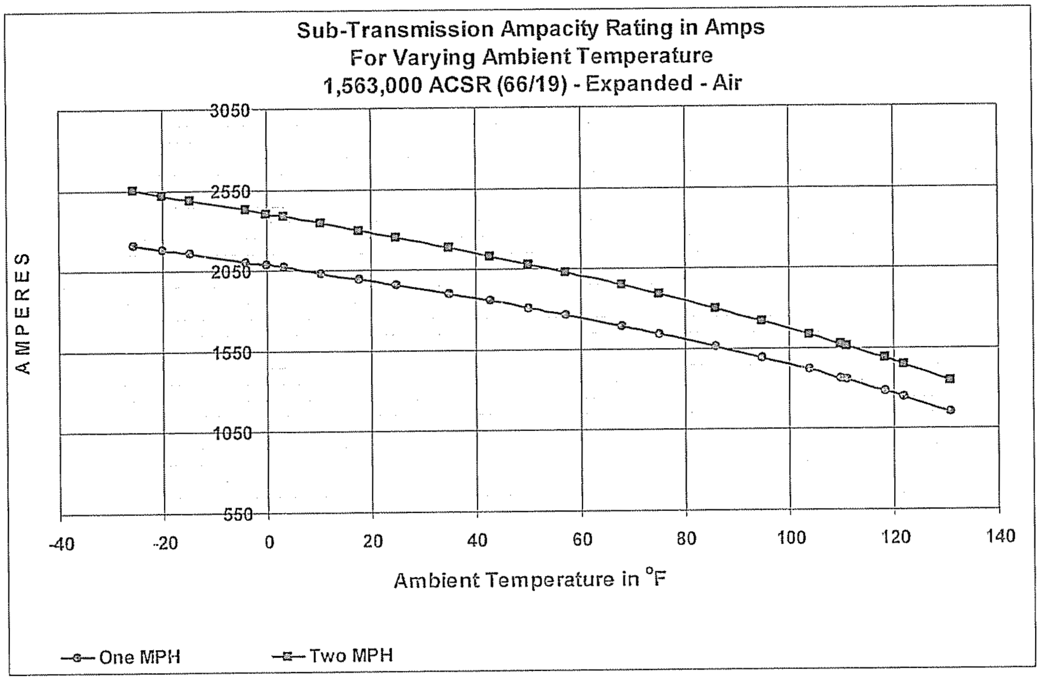
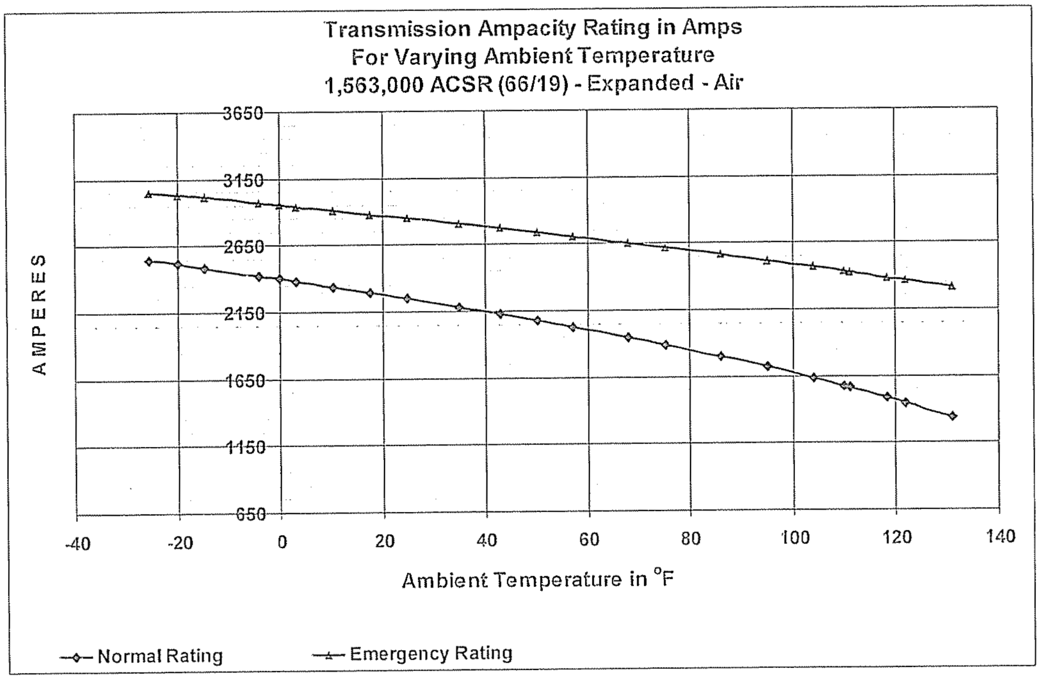
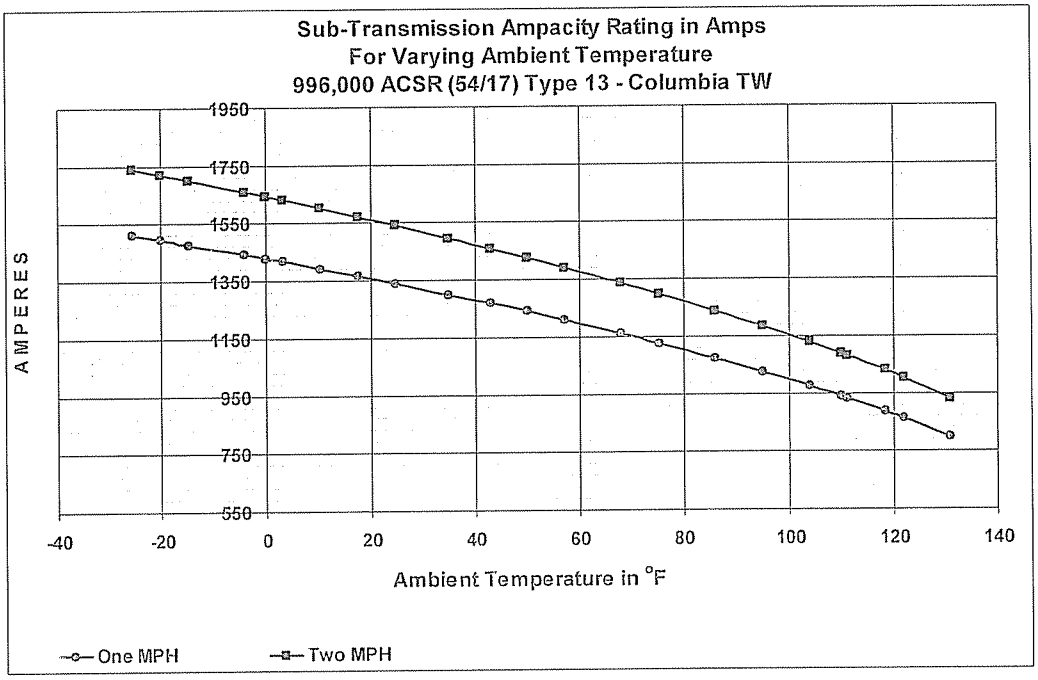
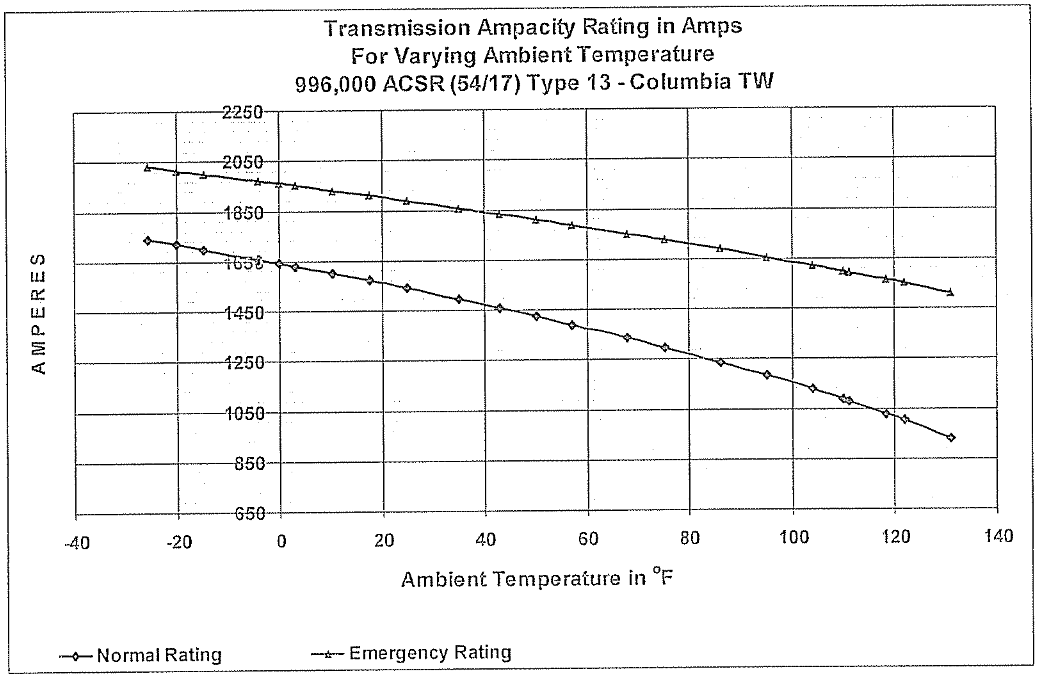

Sub-Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
1,414,000 ACSR (62/19) - Expanded - Paper

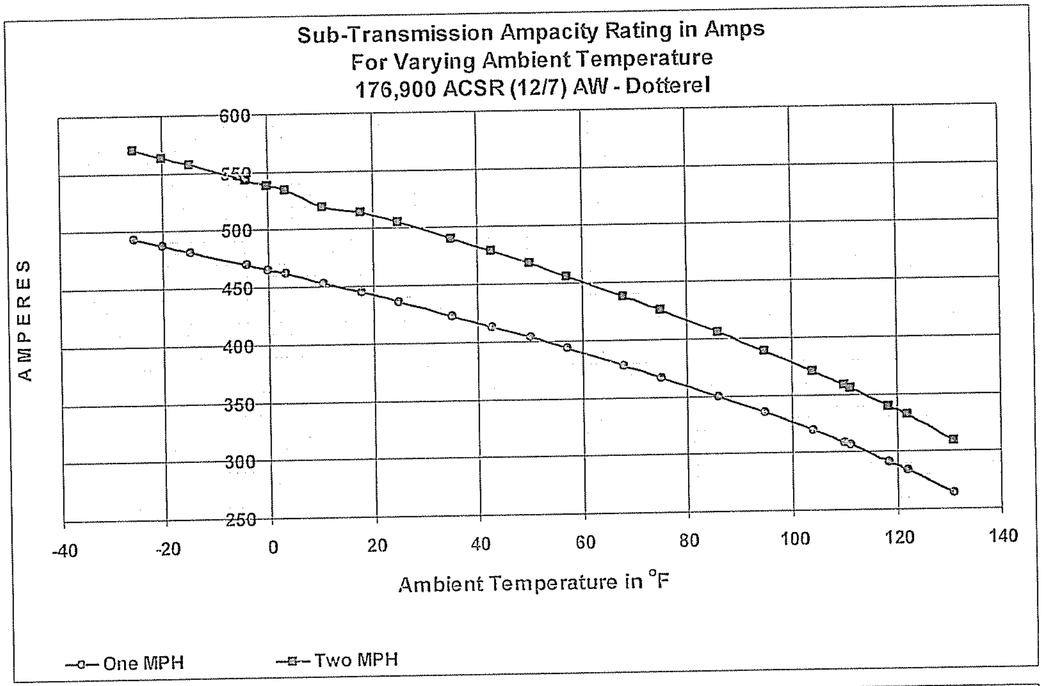

Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
1,414,000 ACSR (62/19) - Expanded - Paper


Sub-Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
1,563,000 ACSR (66/19) - Expanded - Air
AMPERES
3050
2550
2050
1550
1050
550
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
One MPH
Two MPH

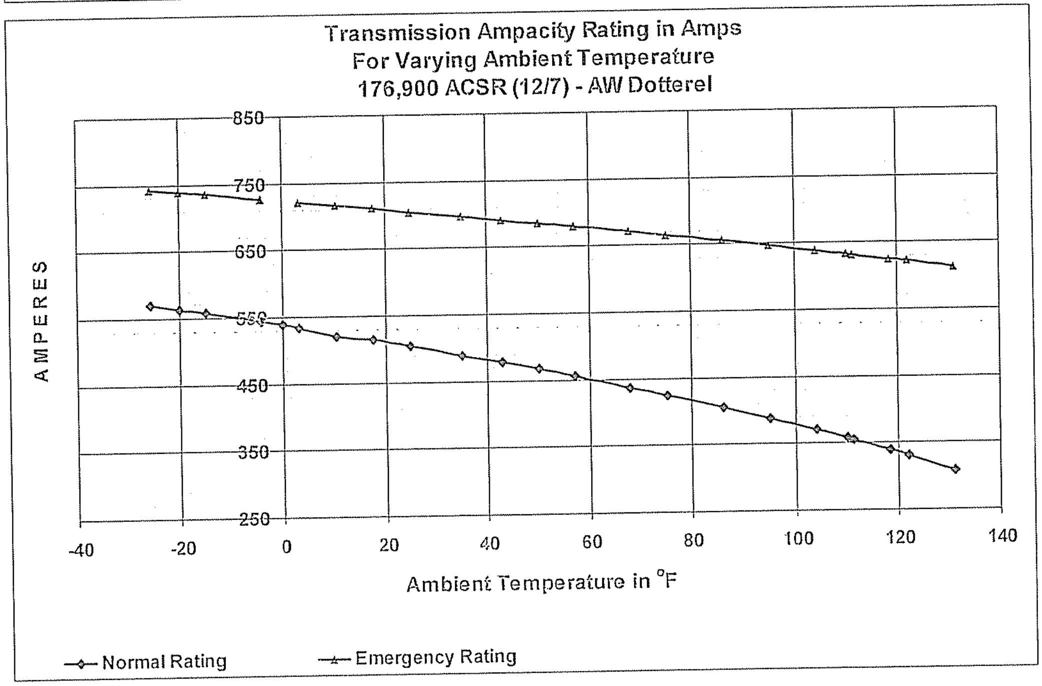

Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
1,563,000 ACSR (66/19) - Expanded - Air
AMPERES
3650
3150
2650
2150
1650
1150
650
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
Normal Rating
Emergency Rating


Sub-Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
996,000 ACSR (54/17) Type 13 - Columbia TW

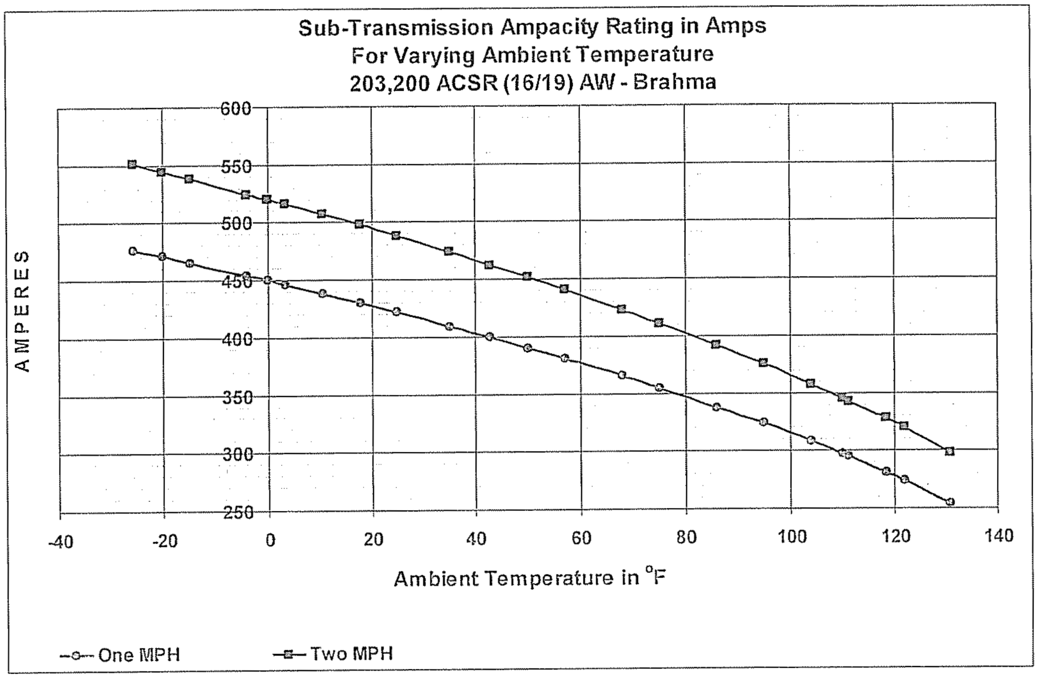

Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
996,000 ACSR (54/17) Type 13 - Columbia TW

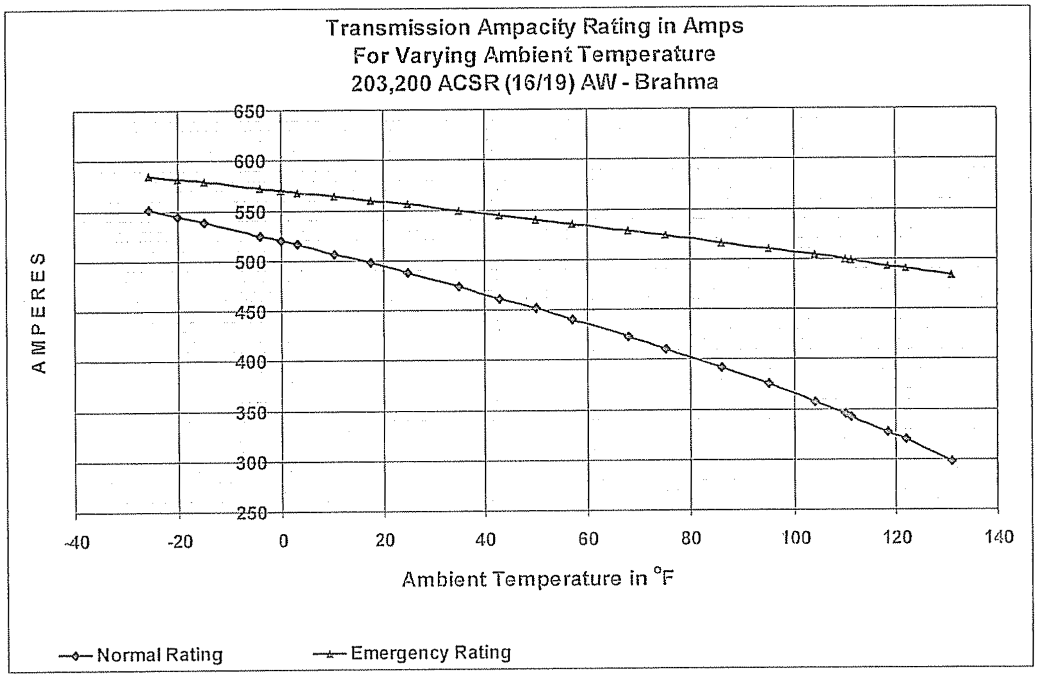


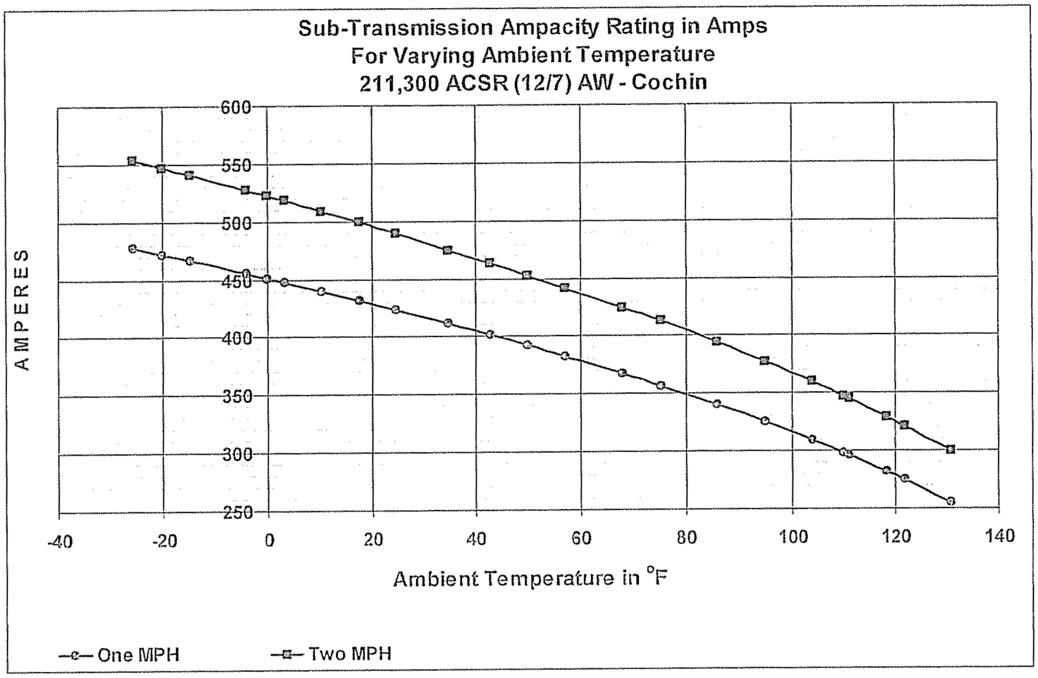
Sub-Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
176,900 ACSR (12/7) AW - Dotterel

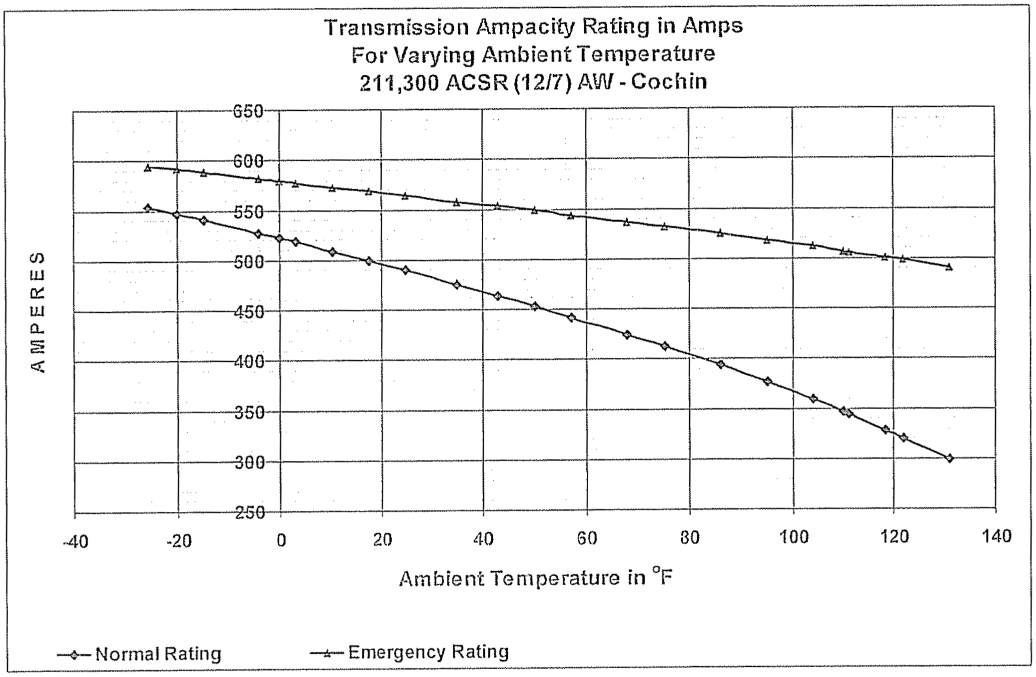


Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
176,900 ACSR (12/7) - AW Dotterel

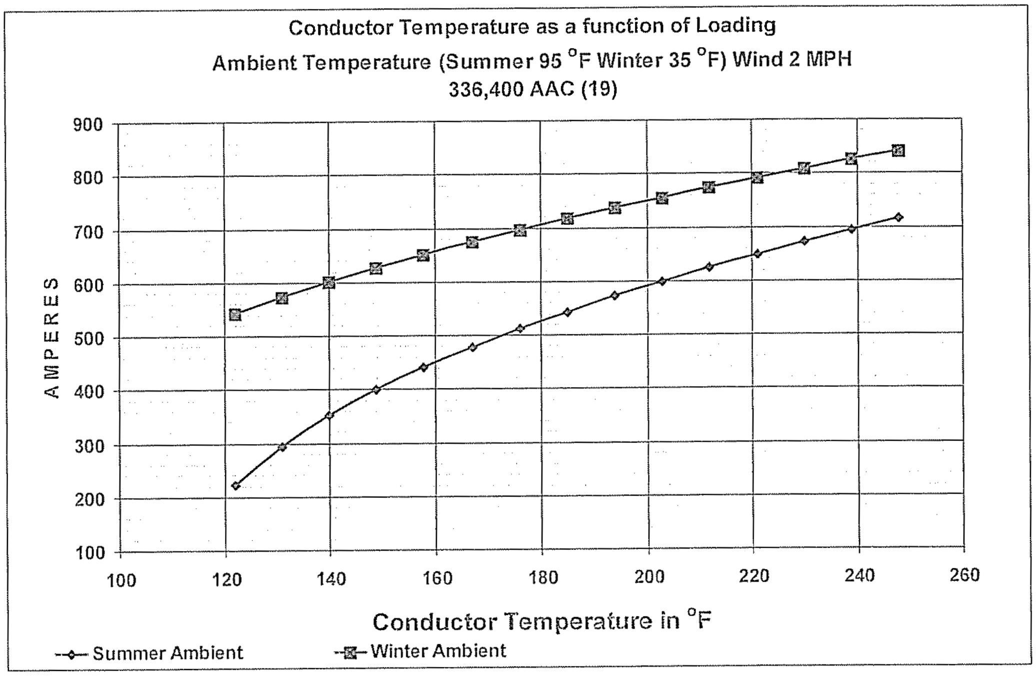

Sub-Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
203,200 ACSR (16/19) AW - Brahma
AMPERES
600
550
500
450
400
350
300
250
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
One MPH
Two MPH

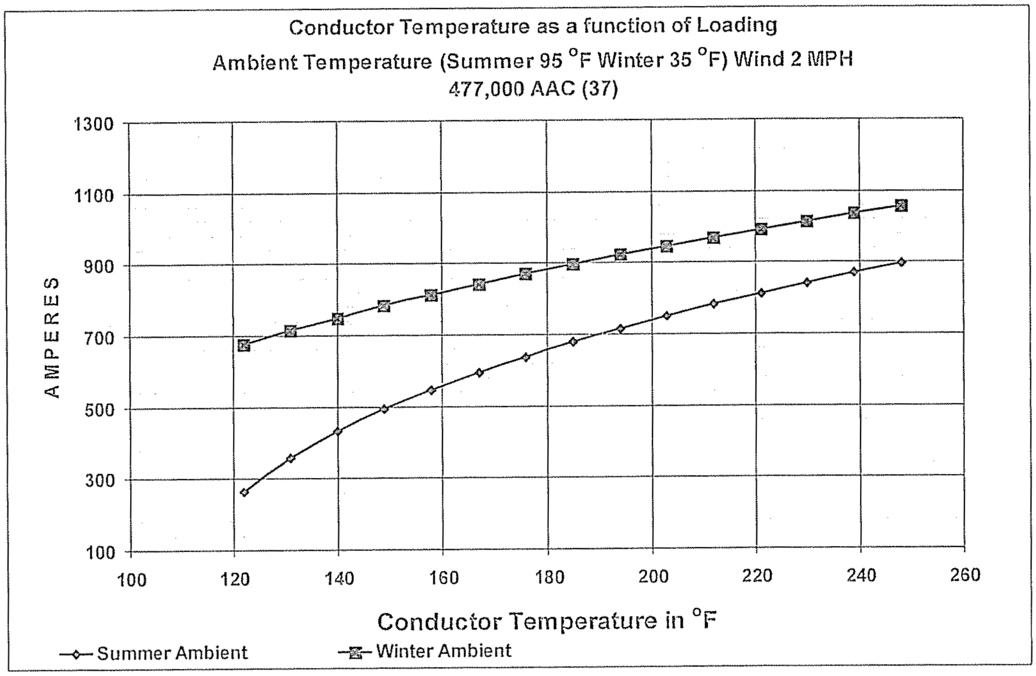

Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
203,200 ACSR (16/19) AW - Brahma
AMPERES
650
600
550
500
450
400
350
300
250
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
Normal Rating
Emergency Rating

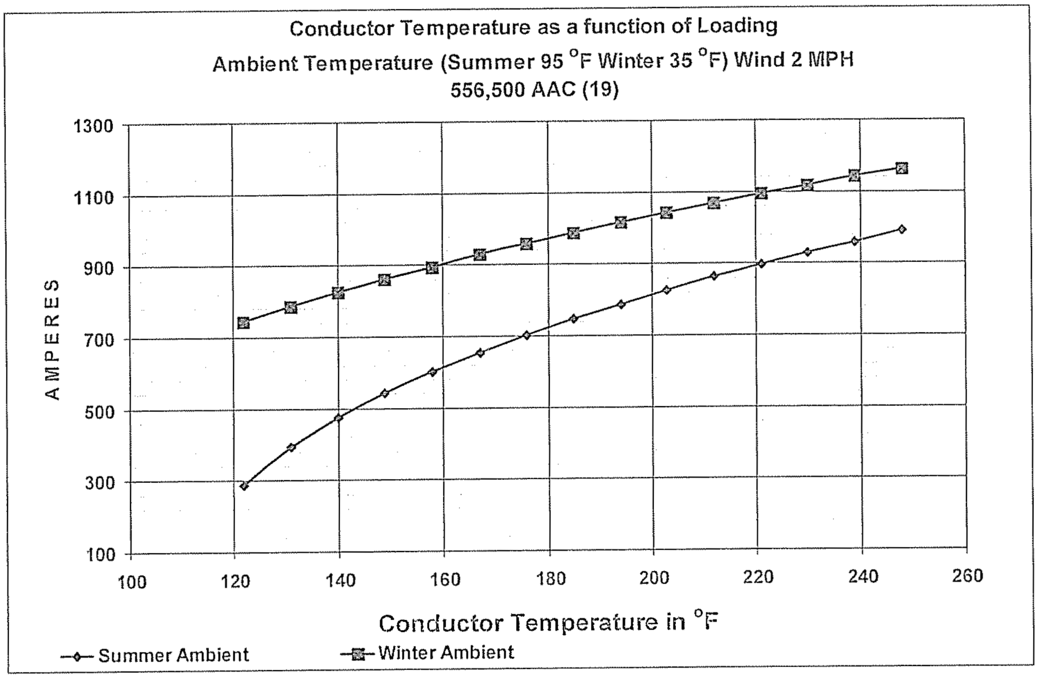

Sub-Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
211,300 ACSR (12/7) AW - Cochin
AMPERES
600
550
500
450
400
350
300
250
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
One MPH
Two MPH

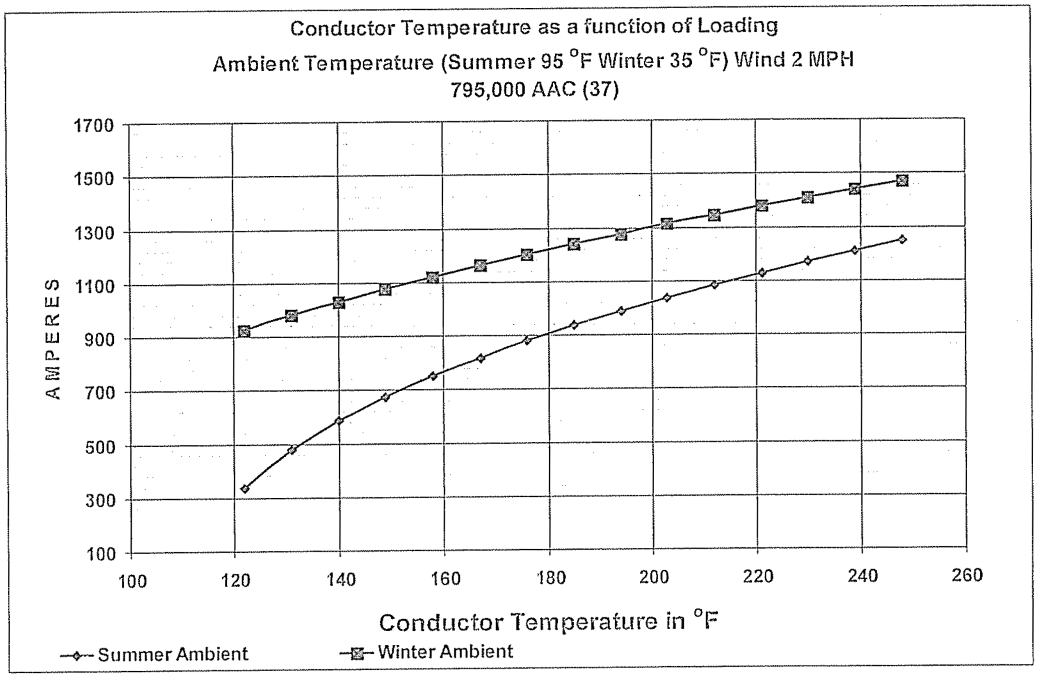

Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
211,300 ACSR (12/7) AW - Cochin
AMPERES
650
600
550
500
450
400
350
300
250
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
Normal Rating
Emergency Rating

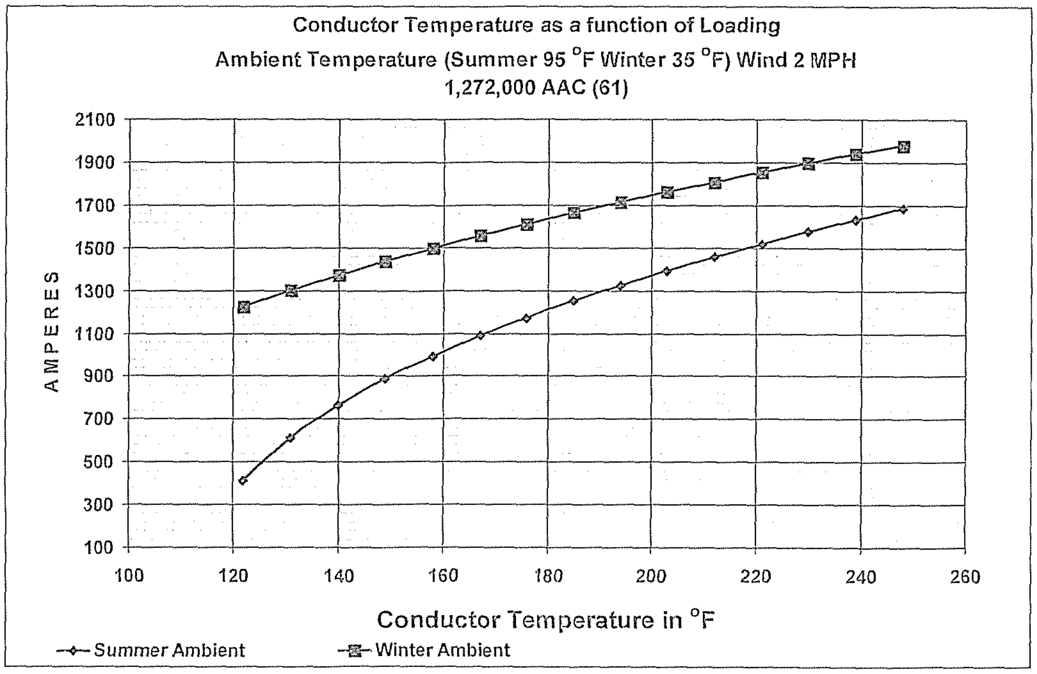
Appendix D	Plots of Conductor Temperature as a function of Conductor Loading **ACAR and AAC – AEP East**

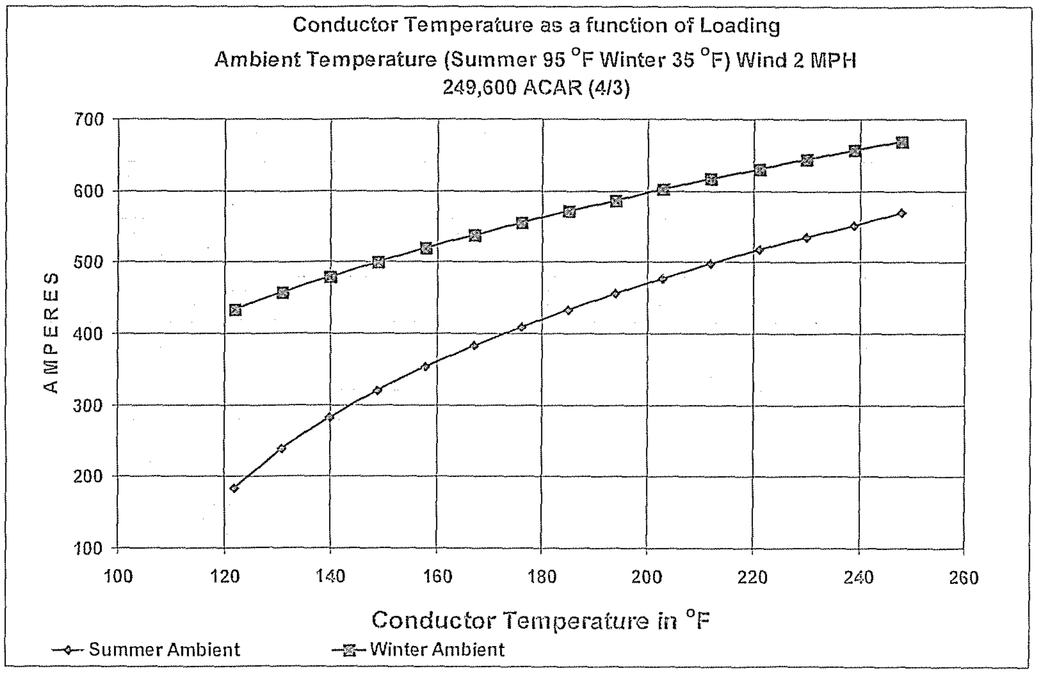

Conductor Temperature as a function of Loading
Ambient Temperature (Summer 95 °F Winter 35 °F) Wind 2 MPH
336,400 AAC (19)
AMPERES
900
800
700
600
500
400
300
200
100
100
120
140
160
180
200
220
240
260
Conductor Temperature in °F
Summer Ambient
Winter Ambient

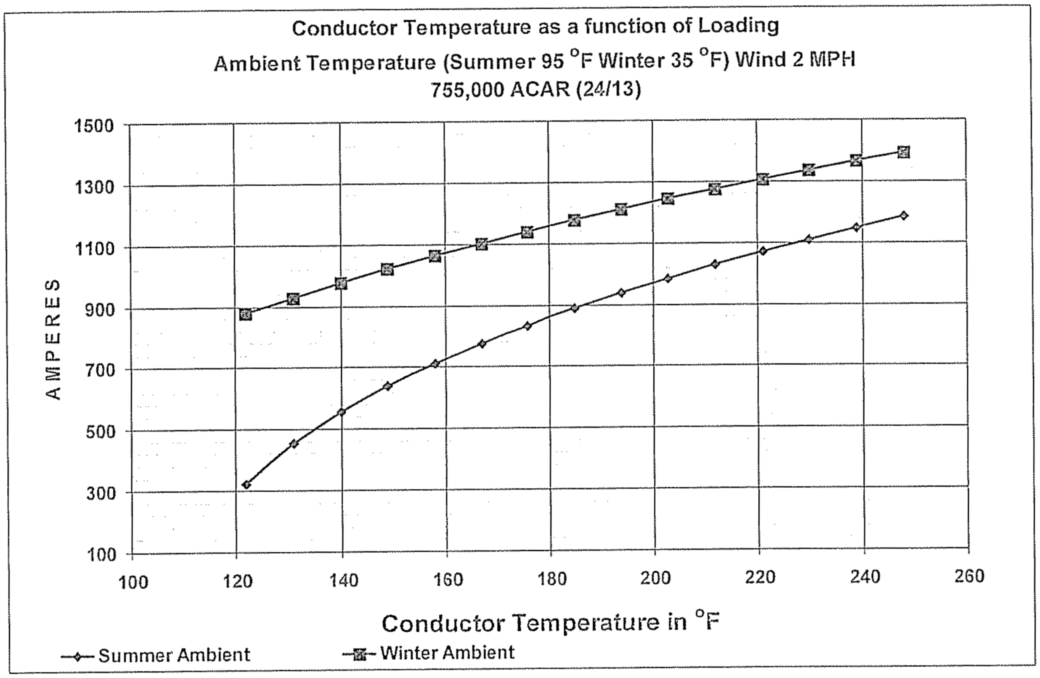

Conductor Temperature as a function of Loading
Ambient Temperature (Summer 95 °F Winter 35 °F) Wind 2 MPH
477,000 AAC (37)
AMPERES
1300
1100
900
700
500
300
100
100
120
140
160
180
200
220
240
260
Conductor Temperature in °F
Summer Ambient
Winter Ambient

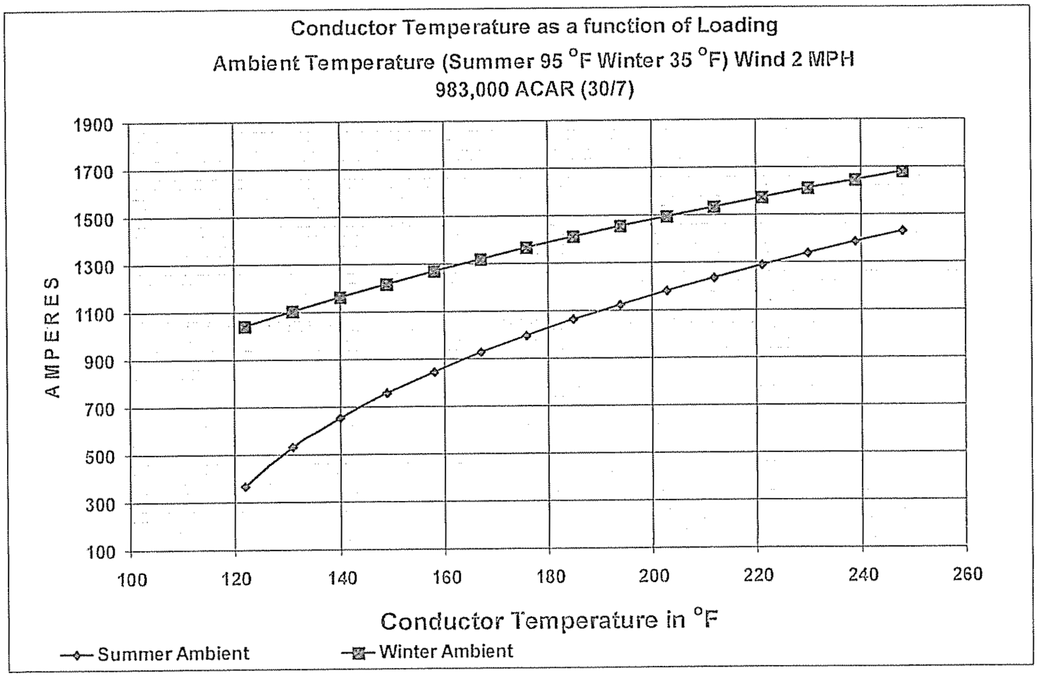

Conductor Temperature as a function of Loading
Ambient Temperature (Summer 95 °F Winter 35 °F) Wind 2 MPH
556,500 AAC (19)
AMPERES
1300
1100
900
700
500
300
100
100
120
140
160
180
200
220
240
260
Conductor Temperature in °F
Summer Ambient
Winter Ambient

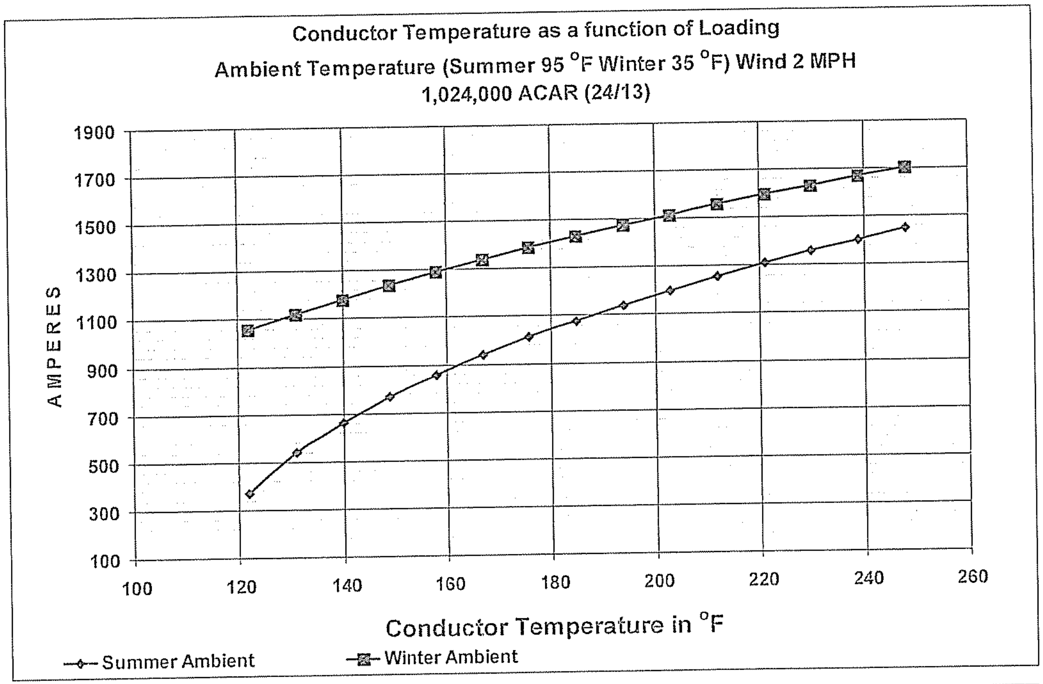

Conductor Temperature as a function of Loading
Ambient Temperature (Summer 95 °F Winter 35 °F) Wind 2 MPH
795,000 AAC (37)
AMPERES
1700
1500
1300
1100
900
700
500
300
100
100
120
140
160
180
200
220
240
260
Conductor Temperature in °F
Summer Ambient
Winter Ambient


Conductor Temperature as a function of Loading
Ambient Temperature (Summer 95 °F Winter 35 °F) Wind 2 MPH
1,272,000 AAC (61)
AMPERES
2100
1900
1700
1500
1300
1100
900
700
500
300
100
100
120
140
160
180
200
220
240
260
Conductor Temperature in °F
Summer Ambient
Winter Ambient

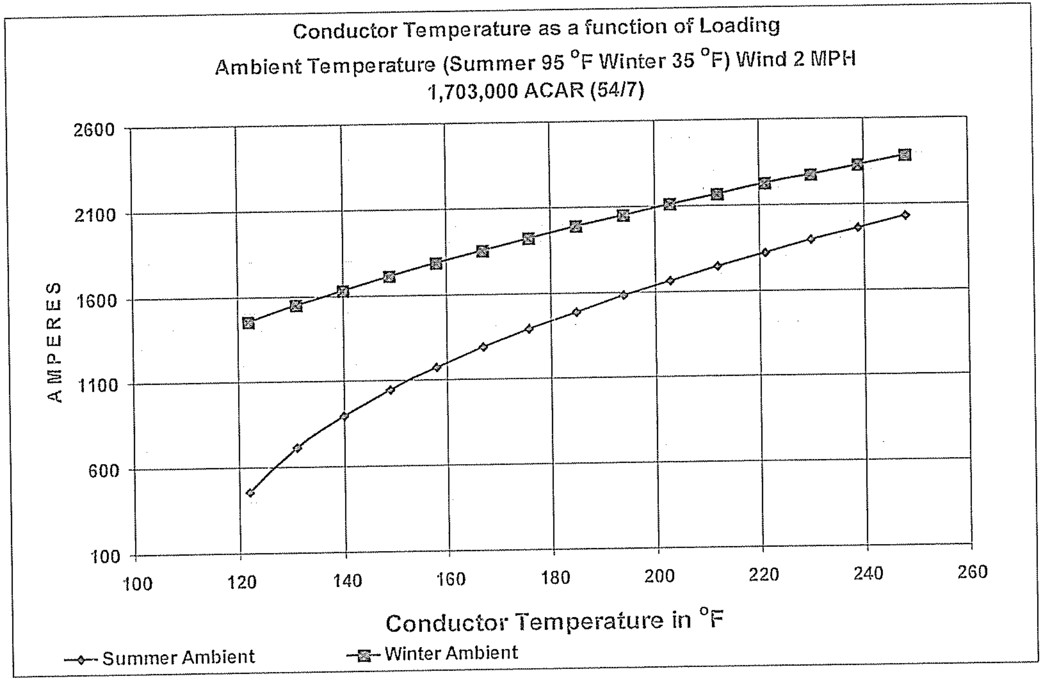

Conductor Temperature as a function of Loading
Ambient Temperature (Summer 95 °F Winter 35 °F) Wind 2 MPH
249,600 ACAR (4/3)
AMPERES
700
600
500
400
300
200
100
100
120
140
160
180
200
220
240
260
Conductor Temperature in °F
Summer Ambient
Winter Ambient


Conductor Temperature as a function of Loading
Ambient Temperature (Summer 95 °F Winter 35 °F) Wind 2 MPH
755,000 ACAR (24/13)
AMPERES
1500
1300
1100
900
700
500
300
100
100
120
140
160
180
200
220
240
260
Conductor Temperature in °F
Summer Ambient
Winter Ambient

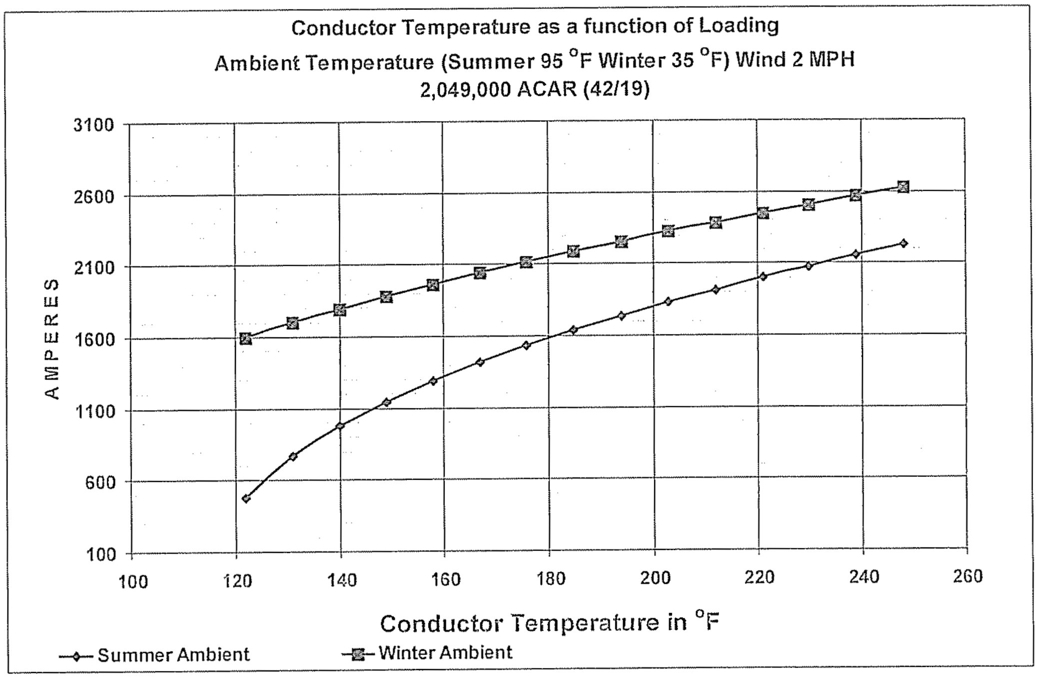

Conductor Temperature as a function of Loading
Ambient Temperature (Summer 95 °F Winter 35 °F) Wind 2 MPH
983,000 ACAR (30/7)
AMPERES
1900
1700
1500
1300
1100
900
700
500
300
100
100
120
140
160
180
200
220
240
260
Conductor Temperature in °F
Summer Ambient
Winter Ambient

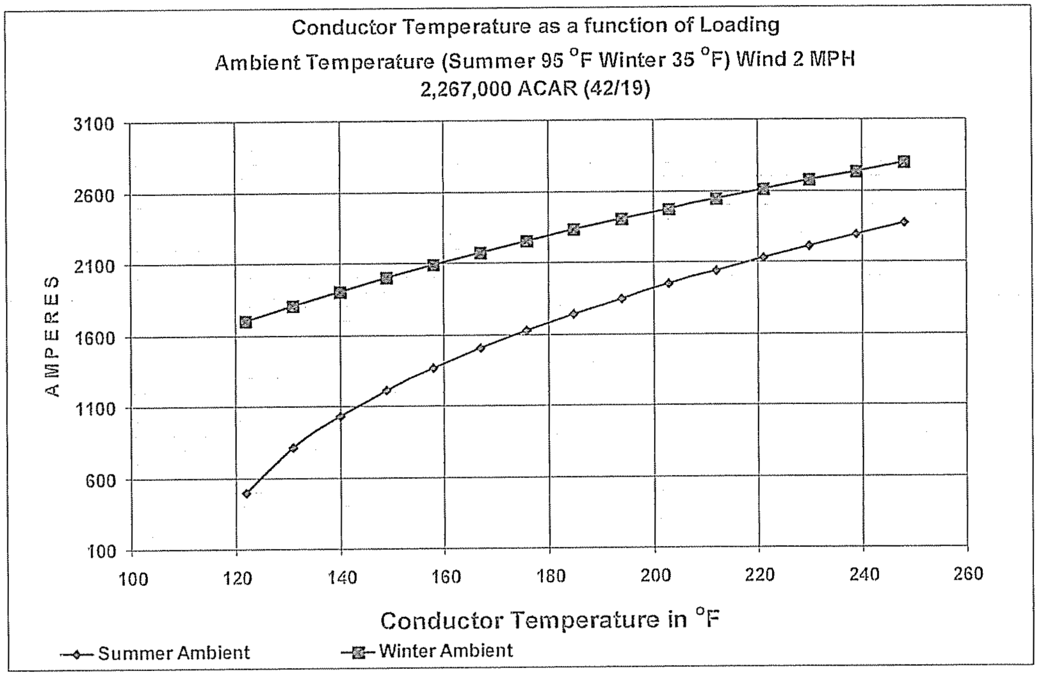


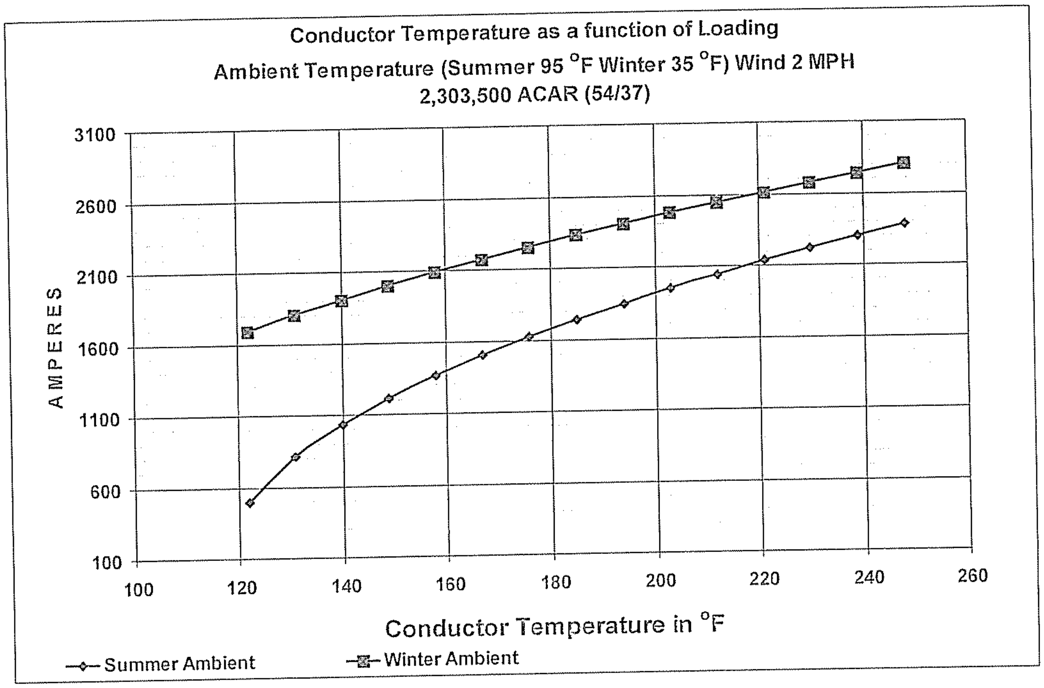
Conductor Temperature as a function of Loading
Ambient Temperature (Summer 95 °F Winter 35 °F) Wind 2 MPH
1,024,000 ACAR (24/13)

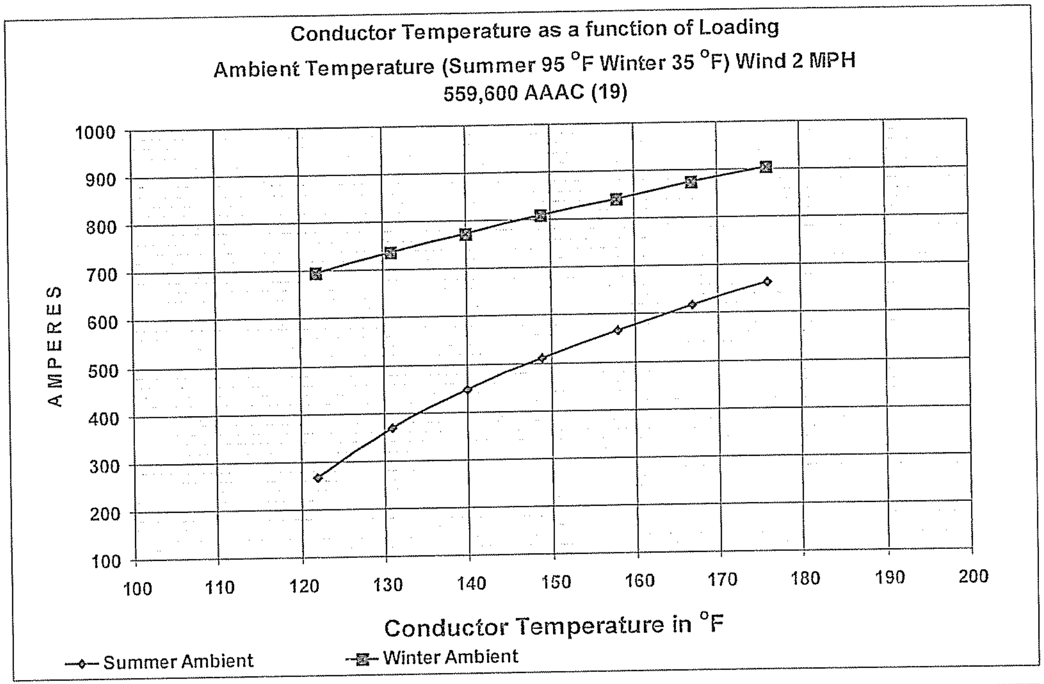


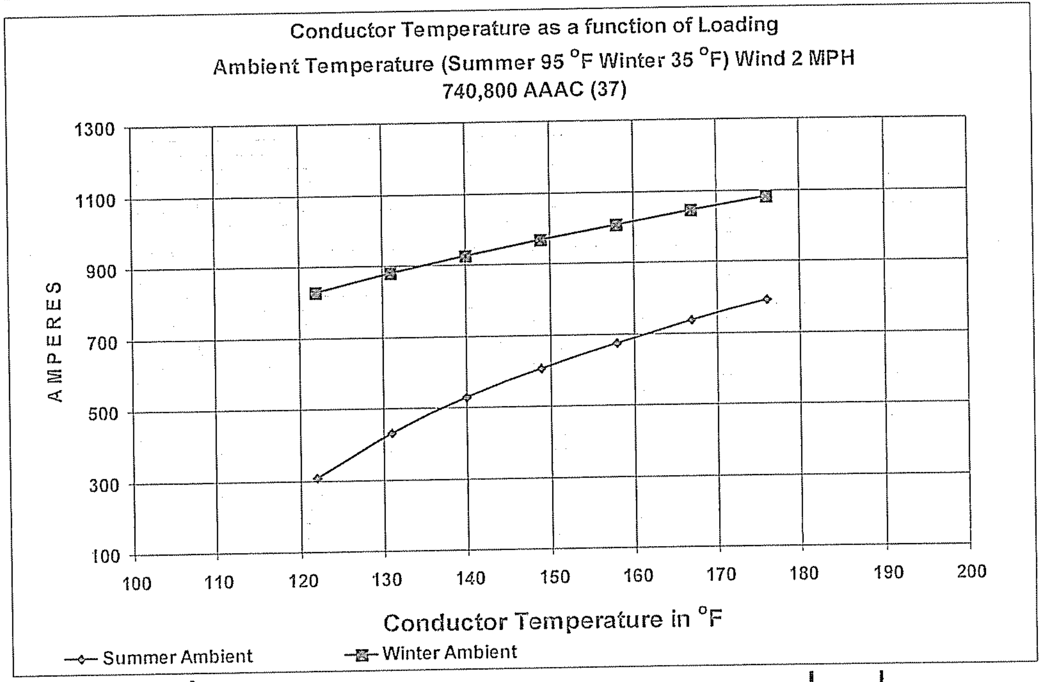
Conductor Temperature as a function of Loading
Ambient Temperature (Summer 95 °F Winter 35 °F) Wind 2 MPH
1,703,000 ACAR (54/7)


Conductor Temperature as a function of Loading
Ambient Temperature (Summer 95 °F Winter 35 °F) Wind 2 MPH
2,049,000 ACAR (42/19)
3100
2600
2100
1600
1100
600
100
AMPERES
100
120
140
160
180
200
220
240
260
Conductor Temperature in °F
Summer Ambient
Winter Ambient

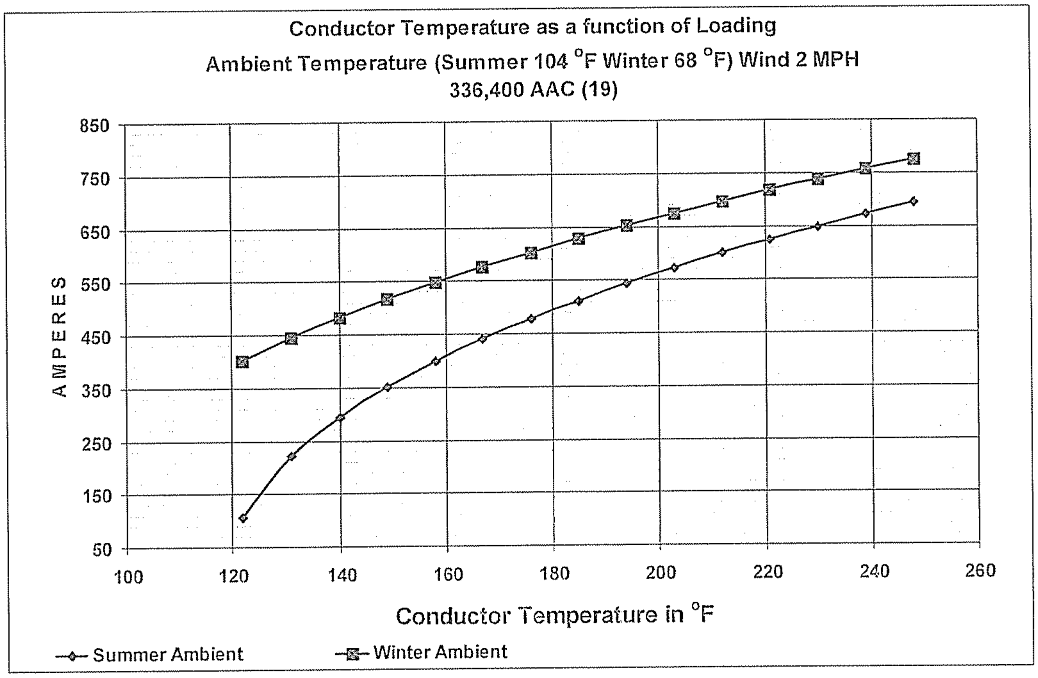

Conductor Temperature as a function of Loading
Ambient Temperature (Summer 95 °F Winter 35 °F) Wind 2 MPH
2,267,000 ACAR (42/19)
3100
2600
2100
1600
1100
600
100
AMPERES
100
120
140
160
180
200
220
240
260
Conductor Temperature in °F
Summer Ambient
Winter Ambient

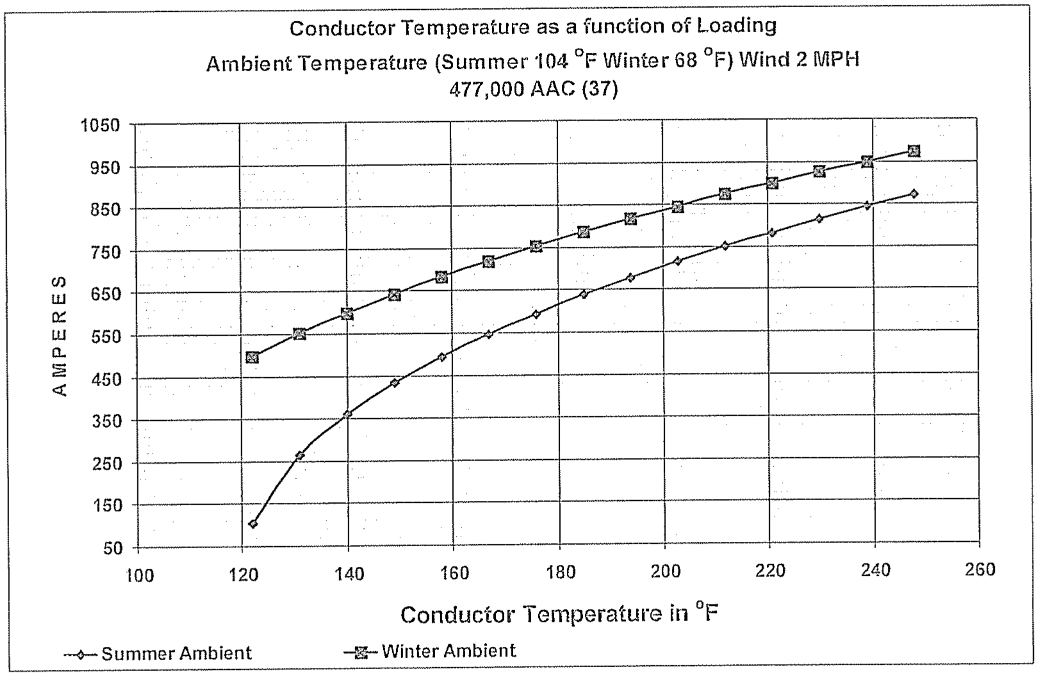

Conductor Temperature as a function of Loading
Ambient Temperature (Summer 95 °F Winter 35 °F) Wind 2 MPH
2,303,500 ACAR (54/37)
AMPERES
3100
2600
2100
1600
1100
600
100
100
120
140
160
180
200
220
240
260
Conductor Temperature in °F
Summer Ambient
Winter Ambient

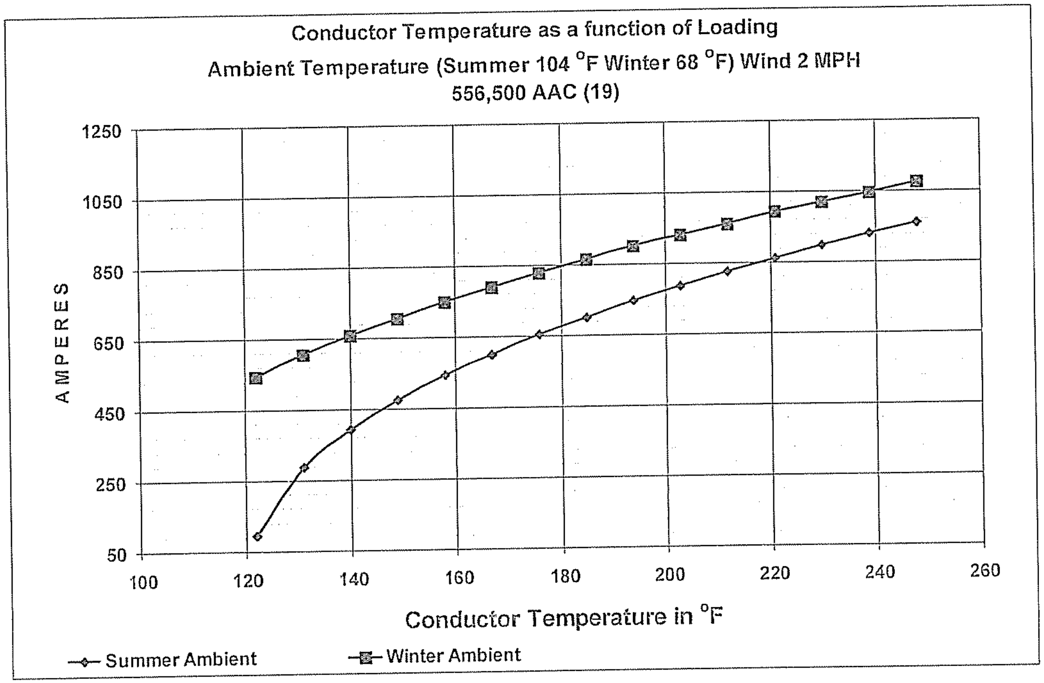

Conductor Temperature as a function of Loading
Ambient Temperature (Summer 95 °F Winter 35 °F) Wind 2 MPH
559,600 AAAC (19)
AMPERES
1000
900
800
700
600
500
400
300
200
100
100
110
120
130
140
150
160
170
180
190
200
Conductor Temperature in °F
Summer Ambient
Winter Ambient

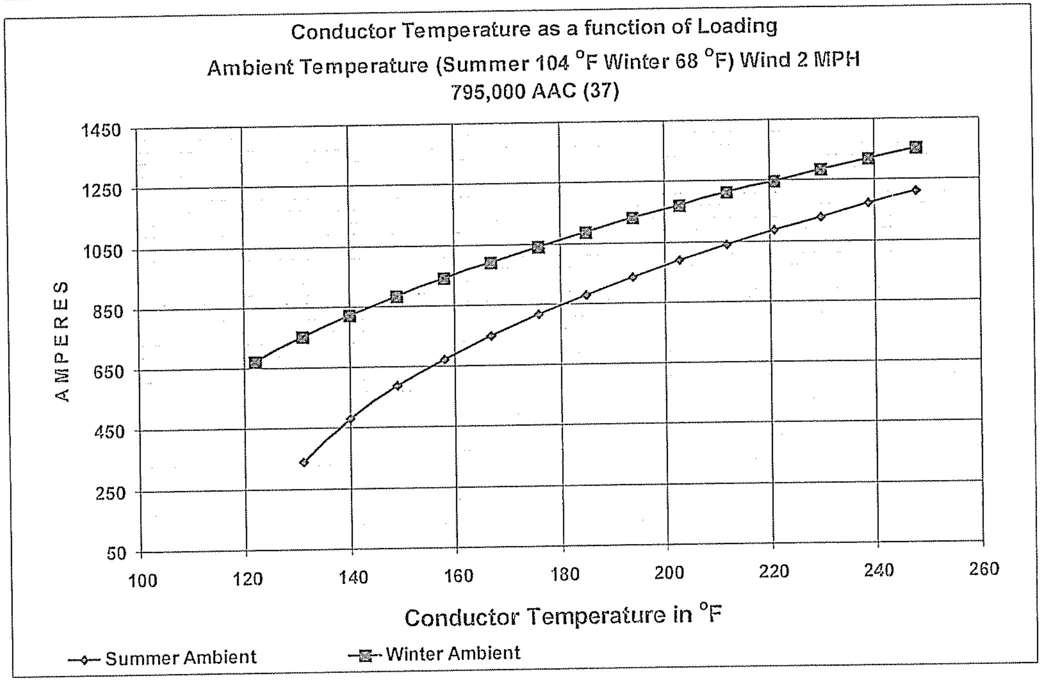

Conductor Temperature as a function of Loading
Ambient Temperature (Summer 95 °F Winter 35 °F) Wind 2 MPH
740,800 AAAC (37)
AMPERES
1300
1100
900
700
500
300
100
100
110
120
130
140
150
160
170
180
190
200
Conductor Temperature in °F
Summer Ambient
Winter Ambient

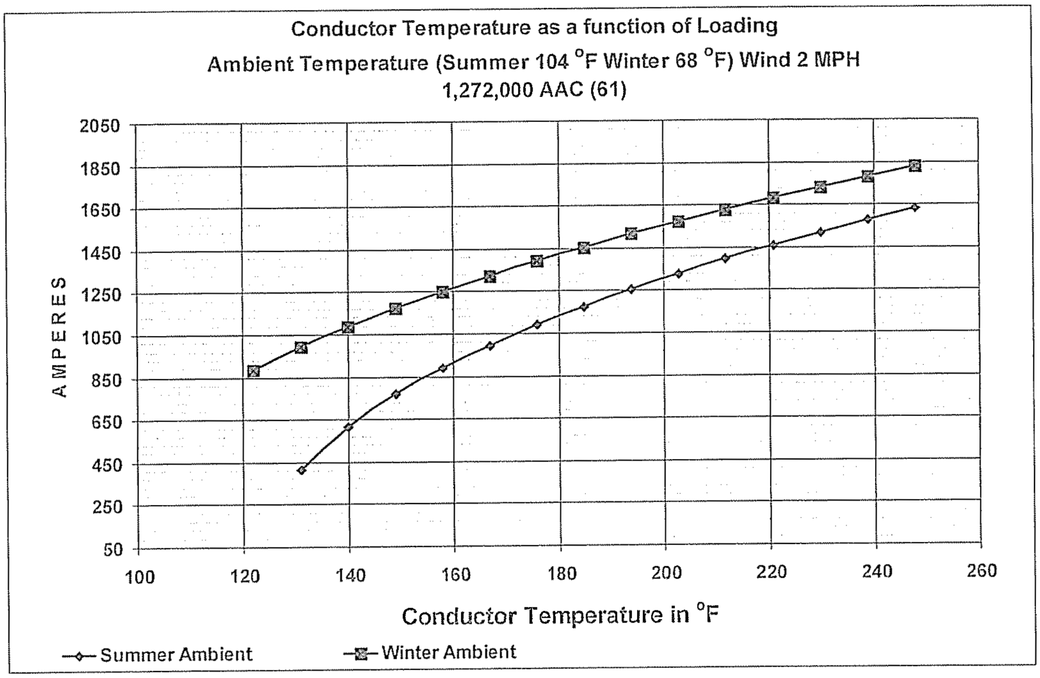
Appendix E	Plots of Conductor Temperature as a function of Conductor Loading **ACAR and AAC Conductors – AEP West**

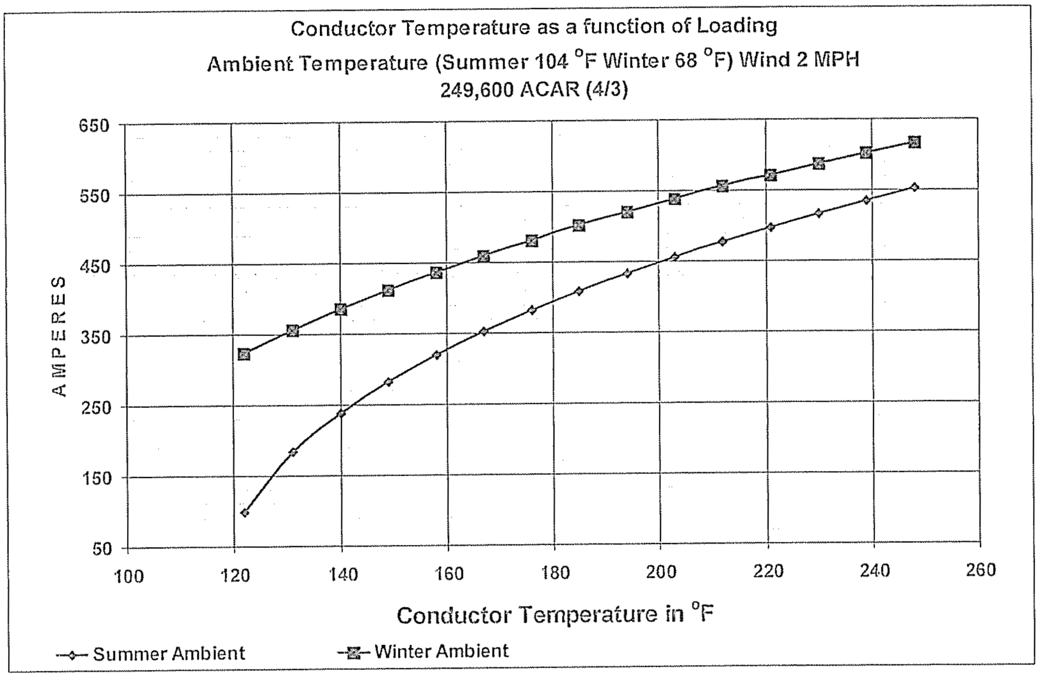

Conductor Temperature as a function of Loading
Ambient Temperature (Summer 104 °F Winter 68 °F) Wind 2 MPH
336,400 AAC (19)

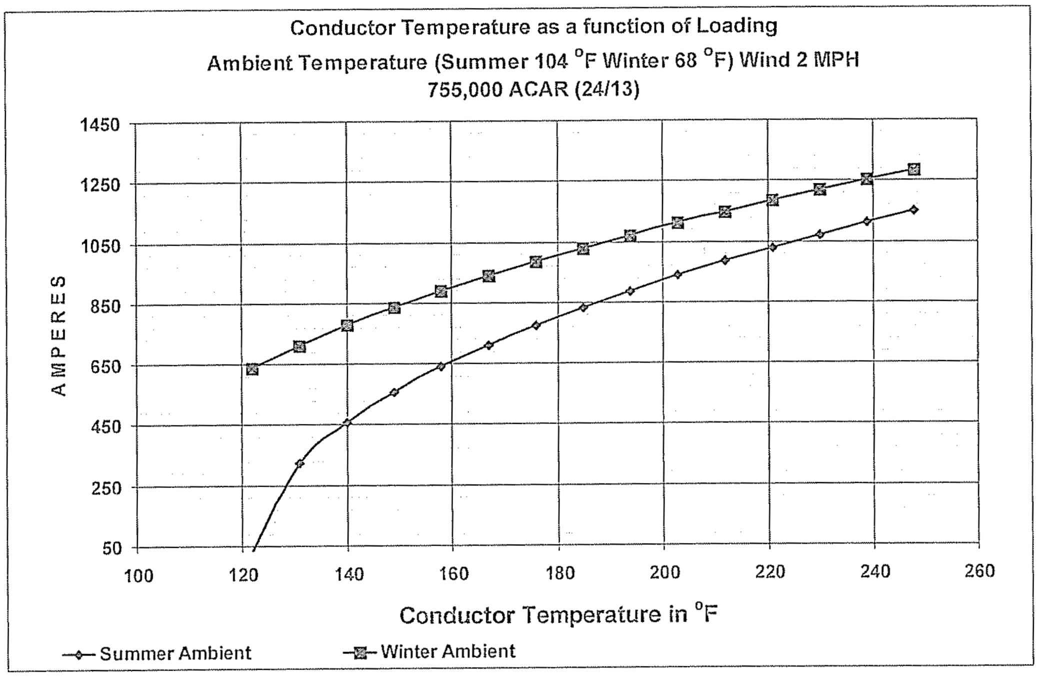

Conductor Temperature as a function of Loading
Ambient Temperature (Summer 104 °F Winter 68 °F) Wind 2 MPH
477,000 AAC (37)

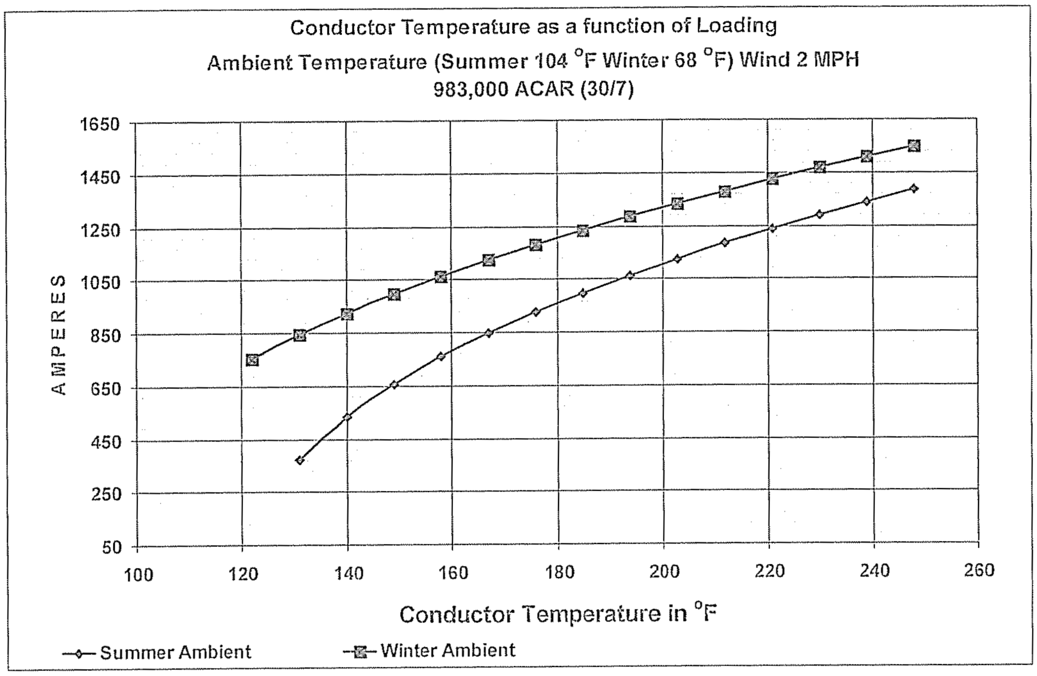

Conductor Temperature as a function of Loading
Ambient Temperature (Summer 104 °F Winter 68 °F) Wind 2 MPH
556,500 AAC (19)
1250
1050
850
650
450
250
50
AMPERES
100
120
140
160
180
200
220
240
260
Conductor Temperature in °F
Summer Ambient
Winter Ambient

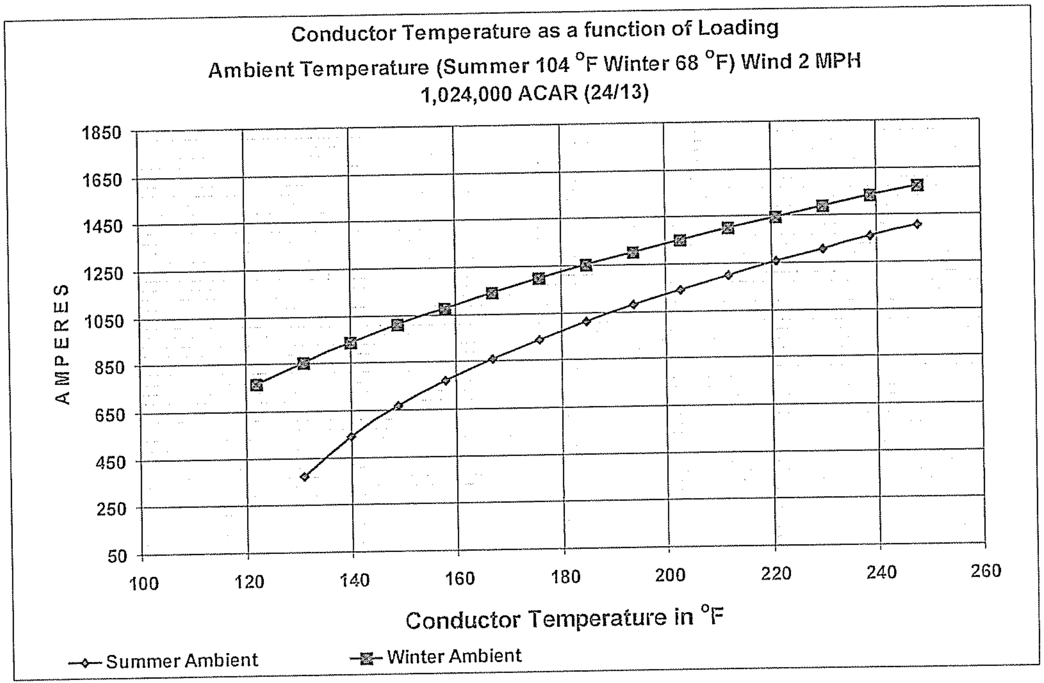

Conductor Temperature as a function of Loading
Ambient Temperature (Summer 104 °F Winter 68 °F) Wind 2 MPH
795,000 AAC (37)
1450
1250
1050
850
650
450
250
50
AMPERES
100
120
140
160
180
200
220
240
260
Conductor Temperature in °F
Summer Ambient
Winter Ambient

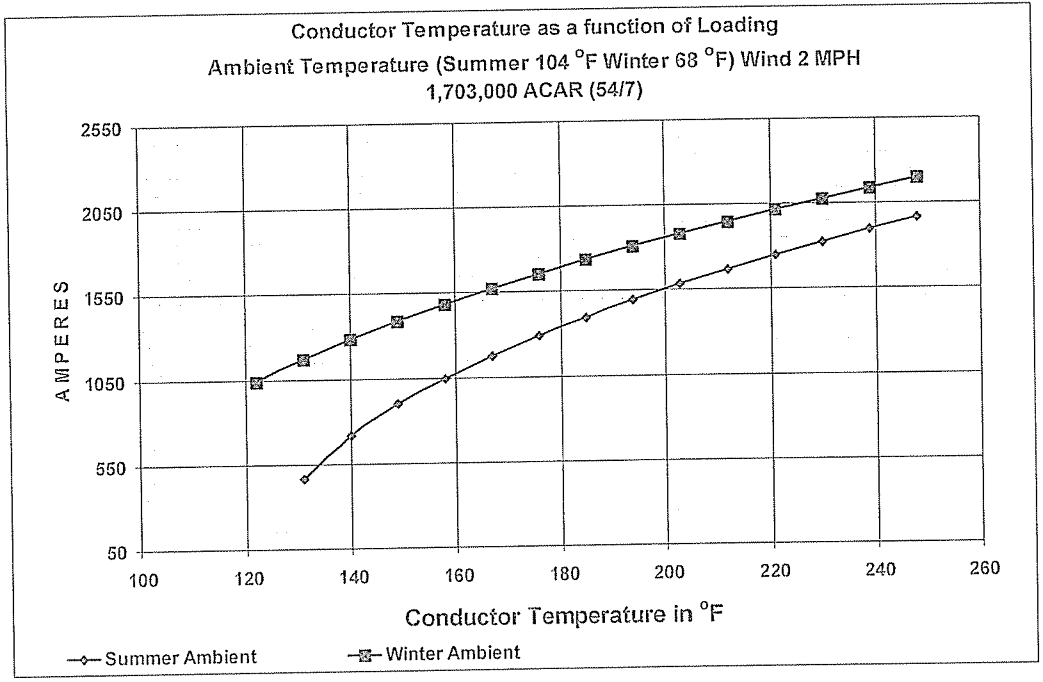

Conductor Temperature as a function of Loading
Ambient Temperature (Summer 104 °F Winter 68 °F) Wind 2 MPH
1,272,000 AAC (61)

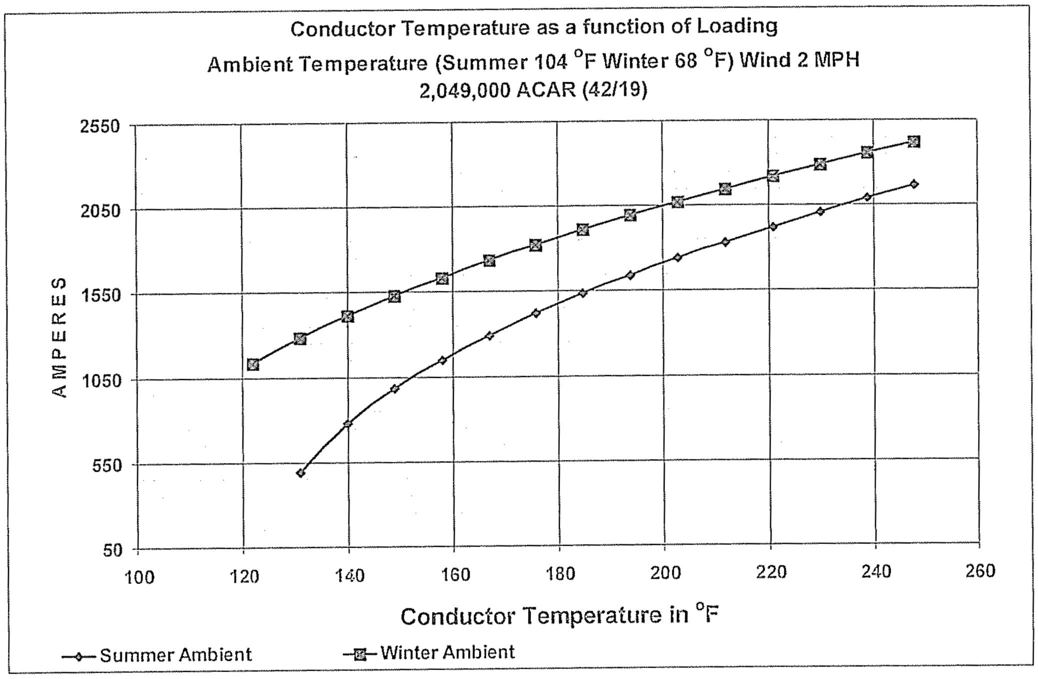

Conductor Temperature as a function of Loading
Ambient Temperature (Summer 104 °F Winter 68 °F) Wind 2 MPH
249,600 ACAR (4/3)

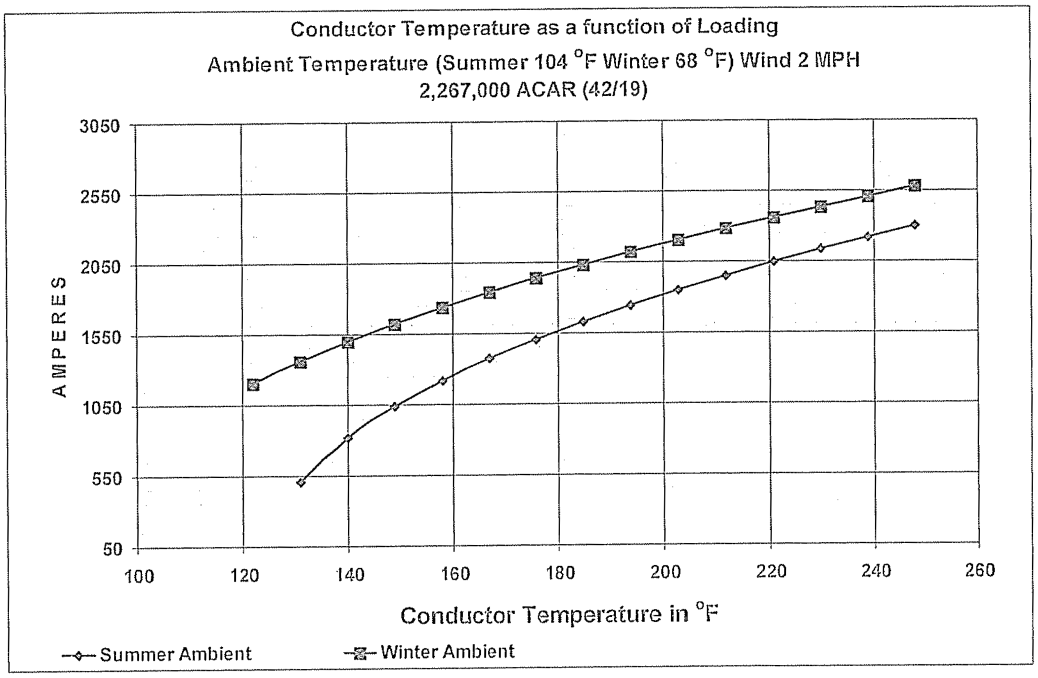

Conductor Temperature as a function of Loading
Ambient Temperature (Summer 104 °F Winter 68 °F) Wind 2 MPH
755,000 ACAR (24/13)
AMPERES
1450
1250
1050
850
650
450
250
50
100
120
140
160
180
200
220
240
260
Conductor Temperature in °F
Summer Ambient
Winter Ambient

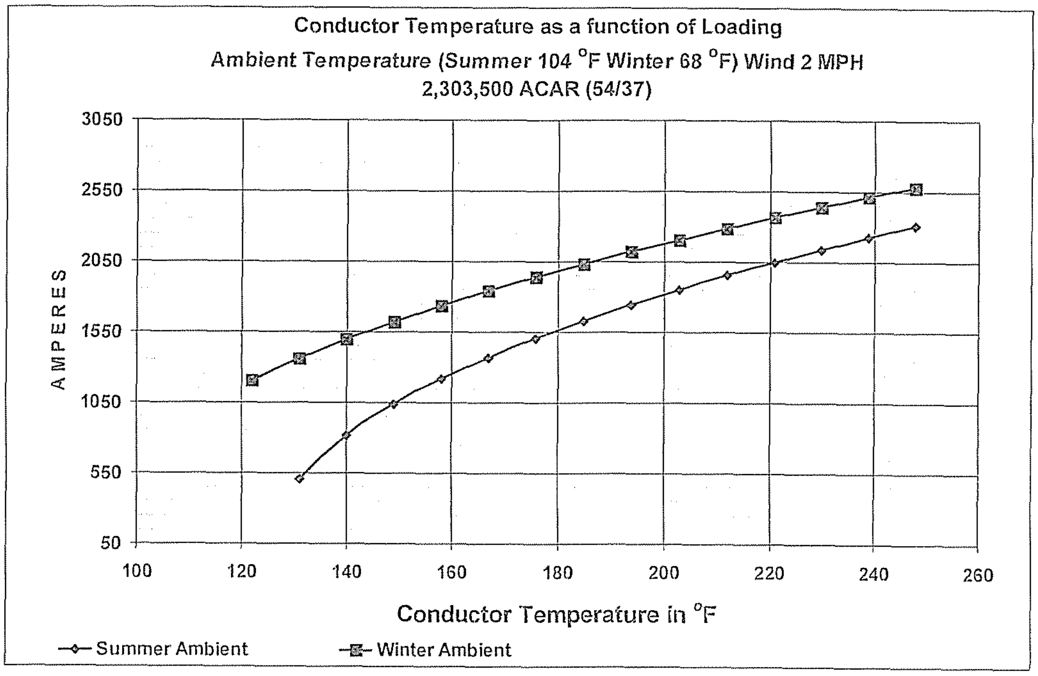

Conductor Temperature as a function of Loading
Ambient Temperature (Summer 104 °F Winter 68 °F) Wind 2 MPH
983,000 ACAR (30/7)
AMPERES
1650
1450
1250
1050
850
650
450
250
50
100
120
140
160
180
200
220
240
260
Conductor Temperature in °F
Summer Ambient
Winter Ambient


Conductor Temperature as a function of Loading
Ambient Temperature (Summer 104 °F Winter 68 °F) Wind 2 MPH
1,024,000 ACAR (24/13)
AMPERES
1850
1650
1450
1250
1050
850
650
450
250
50
100
120
140
160
180
200
220
240
260
Conductor Temperature in °F
Summer Ambient
Winter Ambient

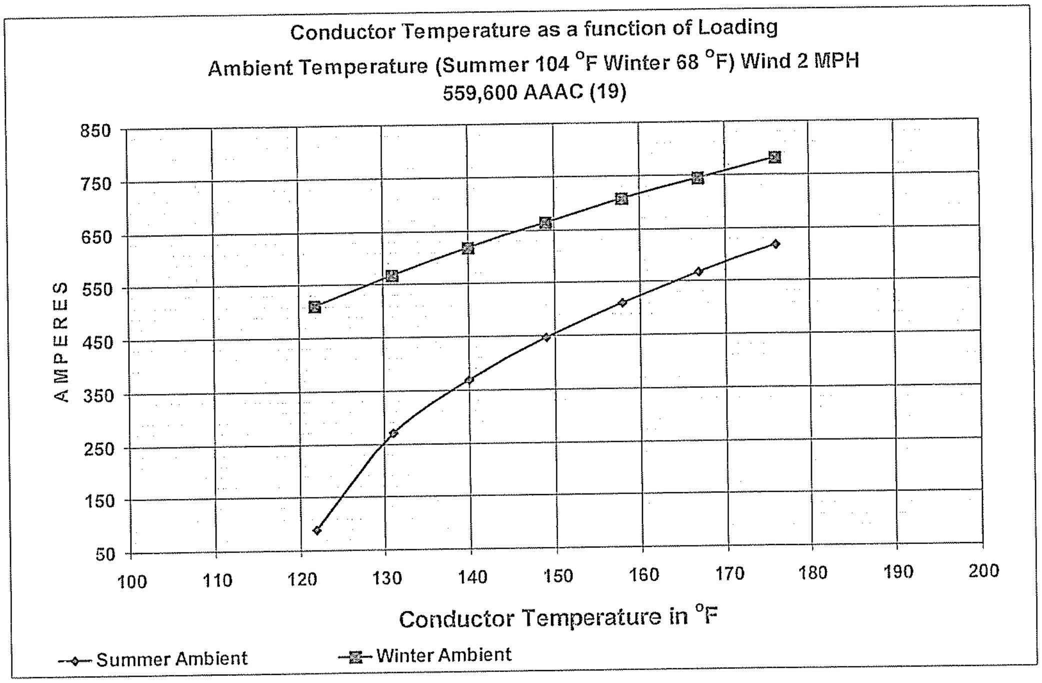

Conductor Temperature as a function of Loading
Ambient Temperature (Summer 104 °F Winter 68 °F) Wind 2 MPH
1,703,000 ACAR (54/7)
AMPERES
2550
2050
1550
1050
550
50
100
120
140
160
180
200
220
240
260
Conductor Temperature in °F
Summer Ambient
Winter Ambient

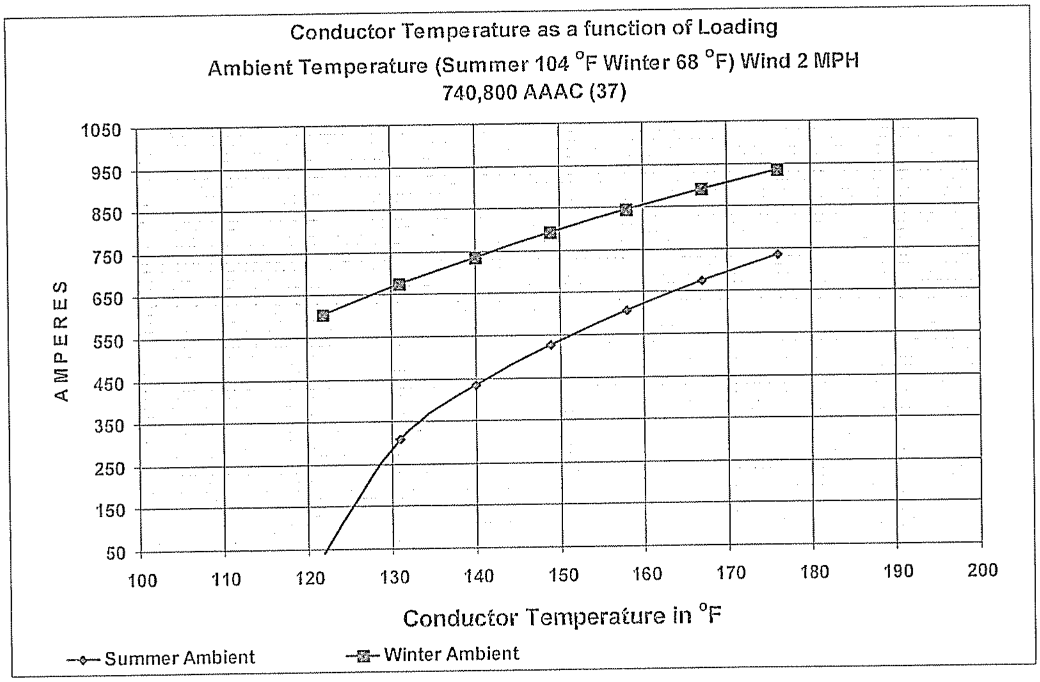

Conductor Temperature as a function of Loading
Ambient Temperature (Summer 104 °F Winter 68 °F) Wind 2 MPH
2,049,000 ACAR (42/19)


Conductor Temperature as a function of Loading
Ambient Temperature (Summer 104 °F Winter 68 °F) Wind 2 MPH
2,267,000 ACAR (42/19)

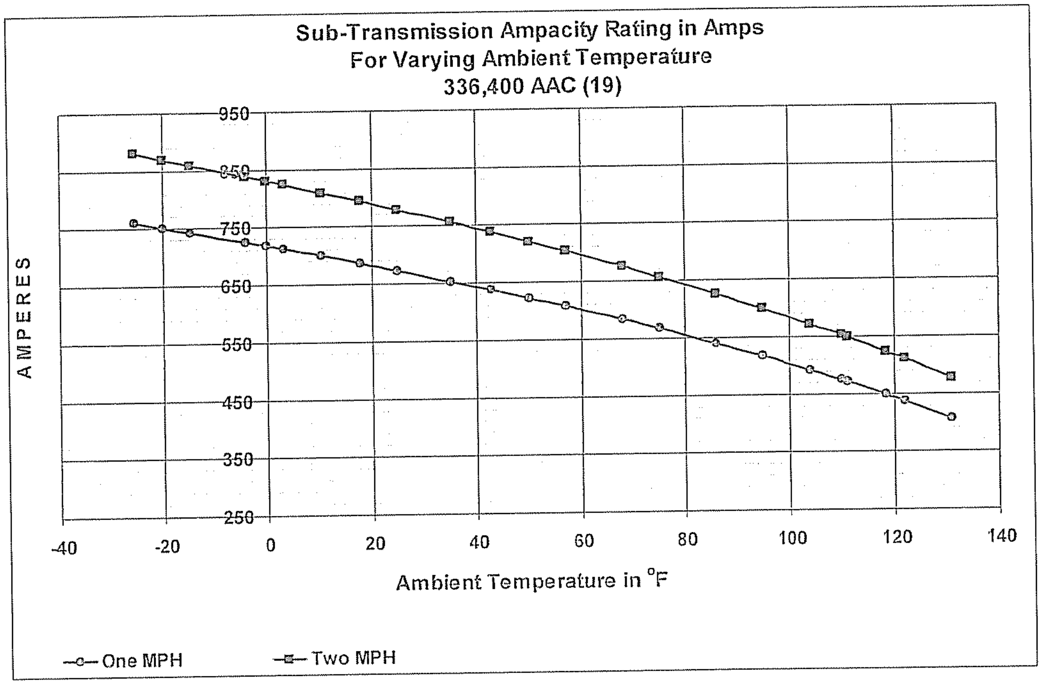


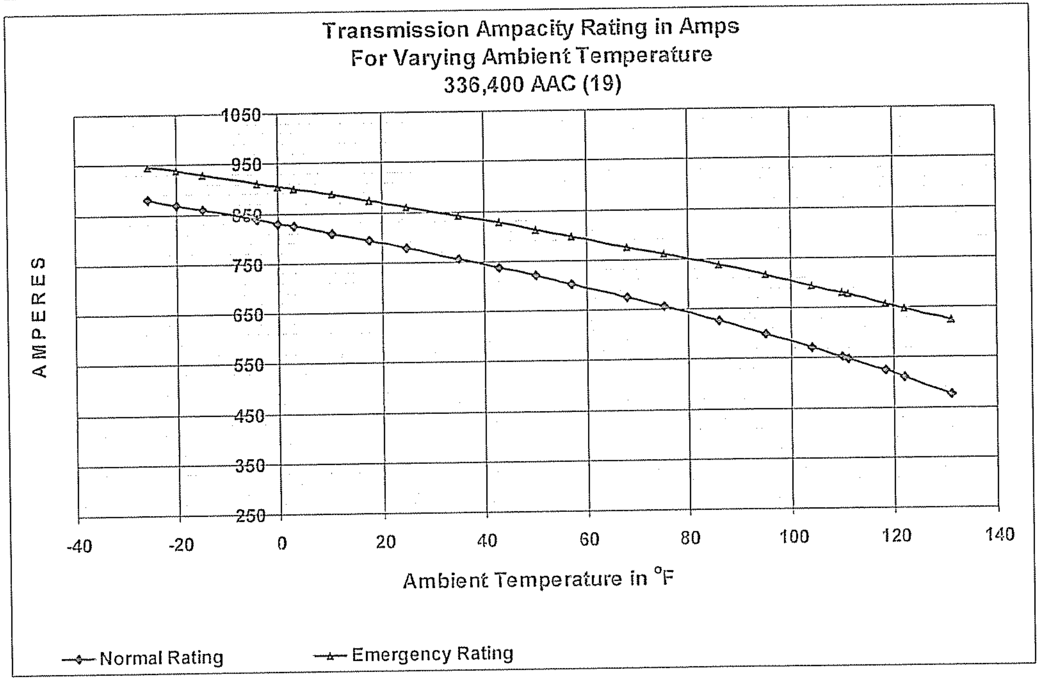
Conductor Temperature as a function of Loading
Ambient Temperature (Summer 104 °F Winter 68 °F) Wind 2 MPH
2,303,500 ACAR (54/37)

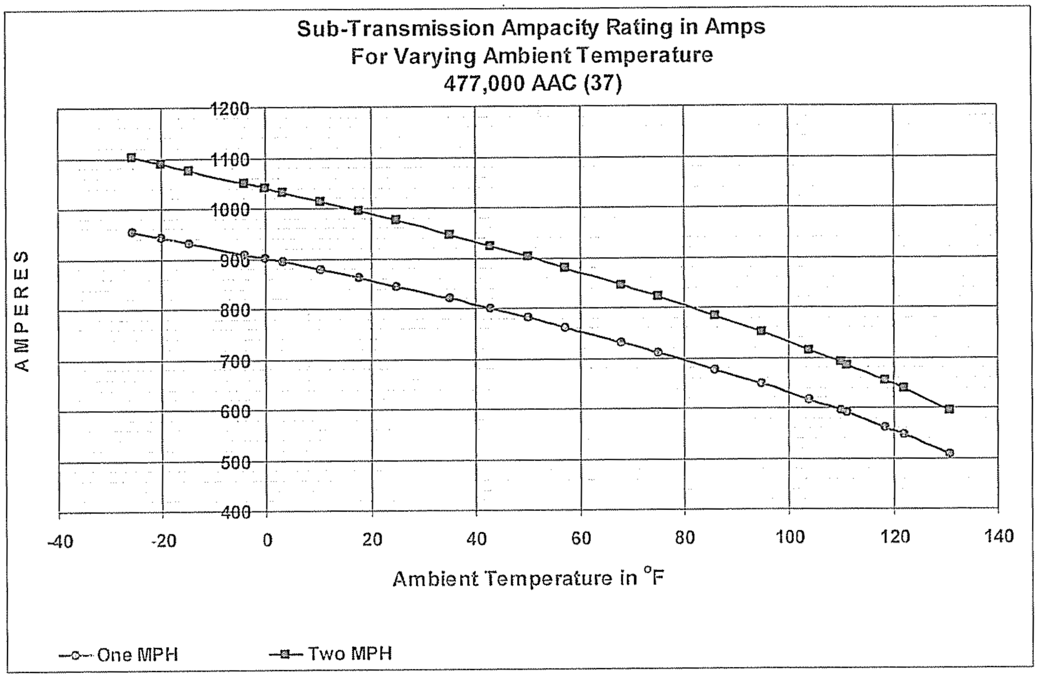

Conductor Temperature as a function of Loading
Ambient Temperature (Summer 104 °F Winter 68 °F) Wind 2 MPH
559,600 AAAC (19)
AMPERES
850
750
650
550
450
350
250
150
50
100
110
120
130
140
150
160
170
180
190
200
Conductor Temperature in °F
Summer Ambient
Winter Ambient

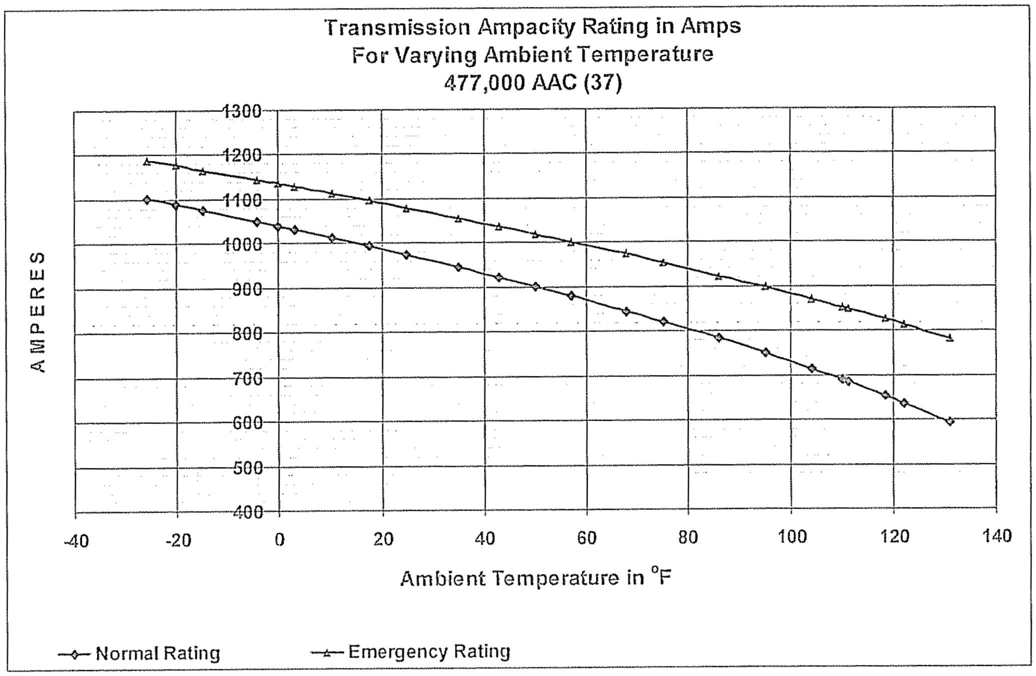

Conductor Temperature as a function of Loading
Ambient Temperature (Summer 104 °F Winter 68 °F) Wind 2 MPH
740,800 AAAC (37)
AMPERES
1050
950
850
750
650
550
450
350
250
150
50
100
110
120
130
140
150
160
170
180
190
200
Conductor Temperature in °F
Summer Ambient
Winter Ambient

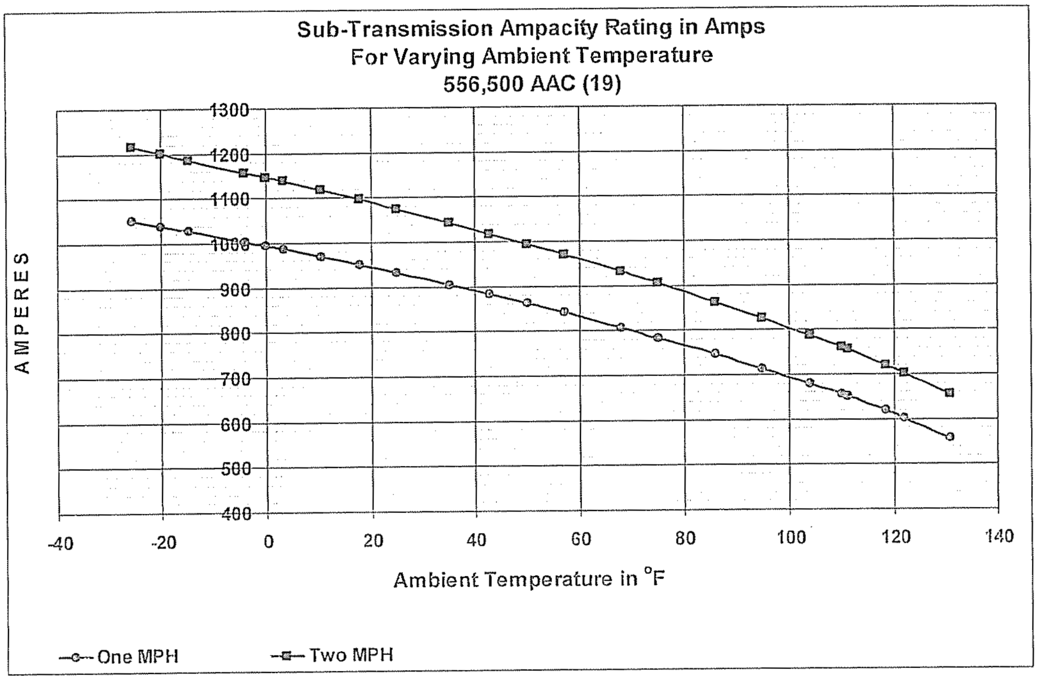
Appendix F	Plots of Normal and Emergency Capability as a function of Ambient Temperature **ACAR and AAC Conductors**

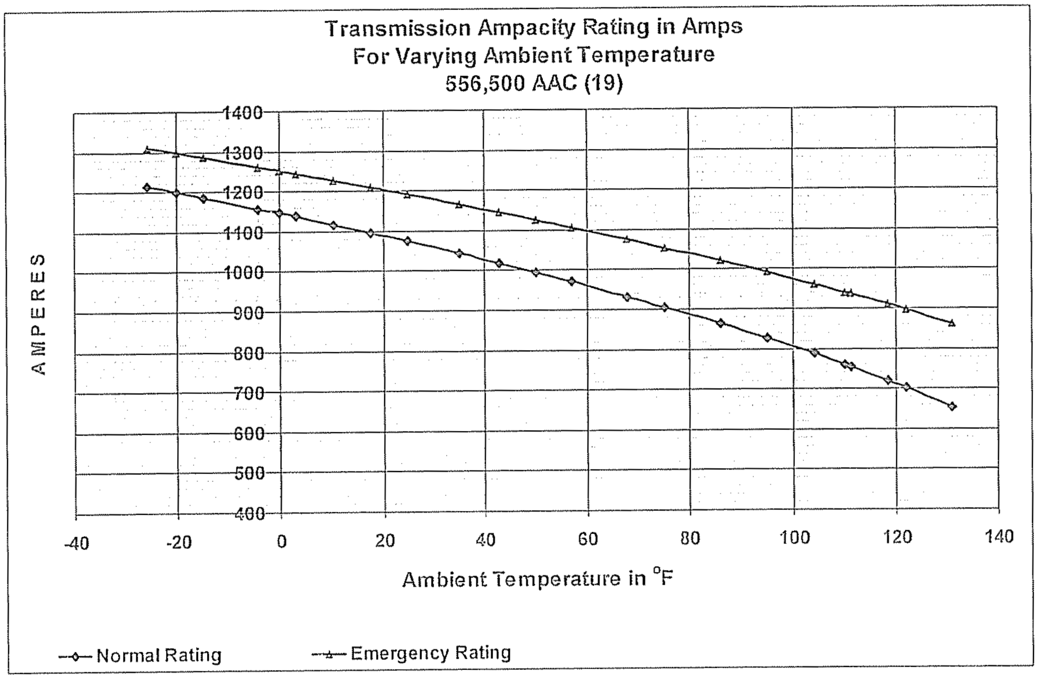

Sub-Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
336,400 AAC (19)
AMPERES
950
850
750
650
550
450
350
250
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
One MPH
Two MPH

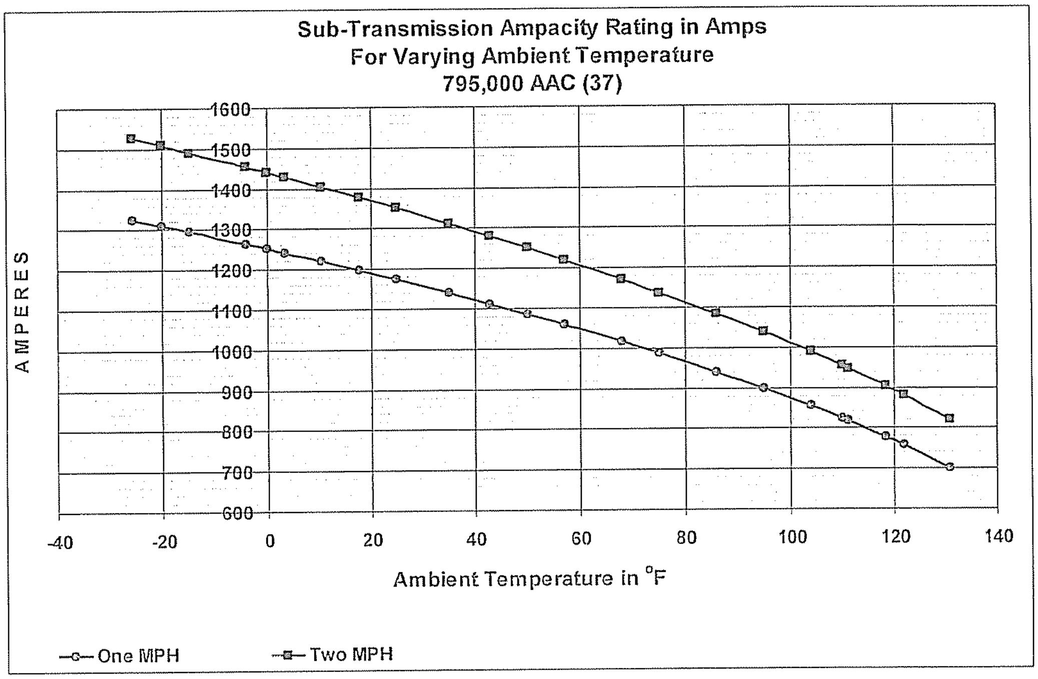

Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
336,400 AAC (19)
AMPERES
1050
950
850
750
650
550
450
350
250
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
Normal Rating
Emergency Rating


Sub-Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
477,000 AAC (37)
AMPERES
1200
1100
1000
900
800
700
600
500
400
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
One MPH
Two MPH

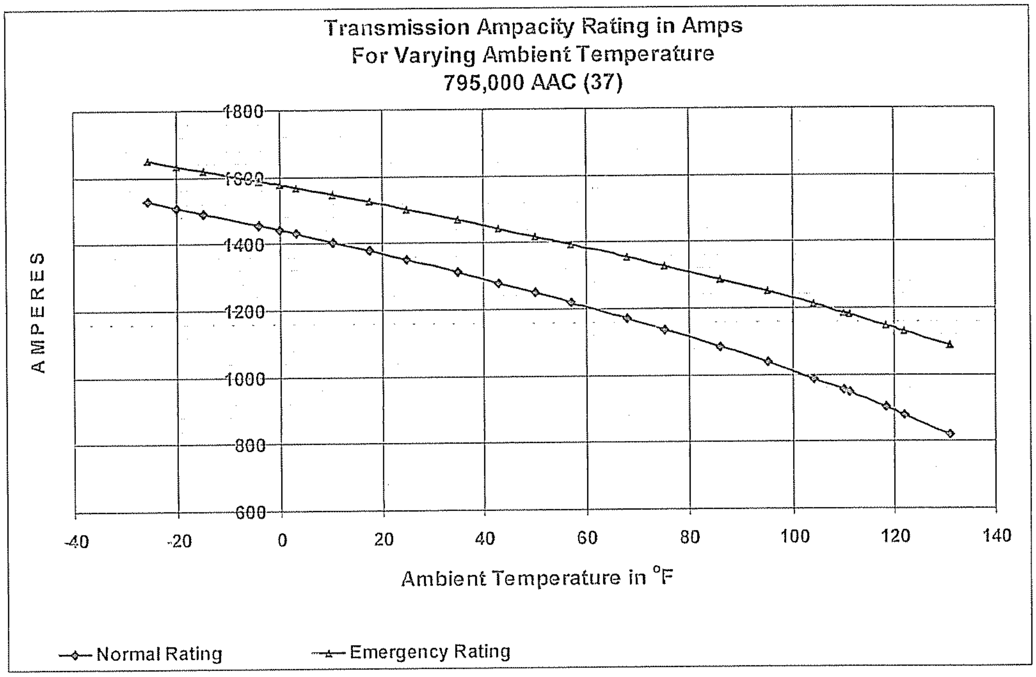

Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
477,000 AAC (37)
AMPERES
1300
1200
1100
1000
900
800
700
600
500
400
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
Normal Rating
Emergency Rating


Sub-Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
556,500 AAC (19)
AMPERES
1300
1200
1100
1000
900
800
700
600
500
400
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
One MPH
Two MPH


Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
556,500 AAC (19)
AMPERES
1400
1300
1200
1100
1000
900
800
700
600
500
400
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
Normal Rating
Emergency Rating



Sub-Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
795,000 AAC (37)



Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
795,000 AAC (37)

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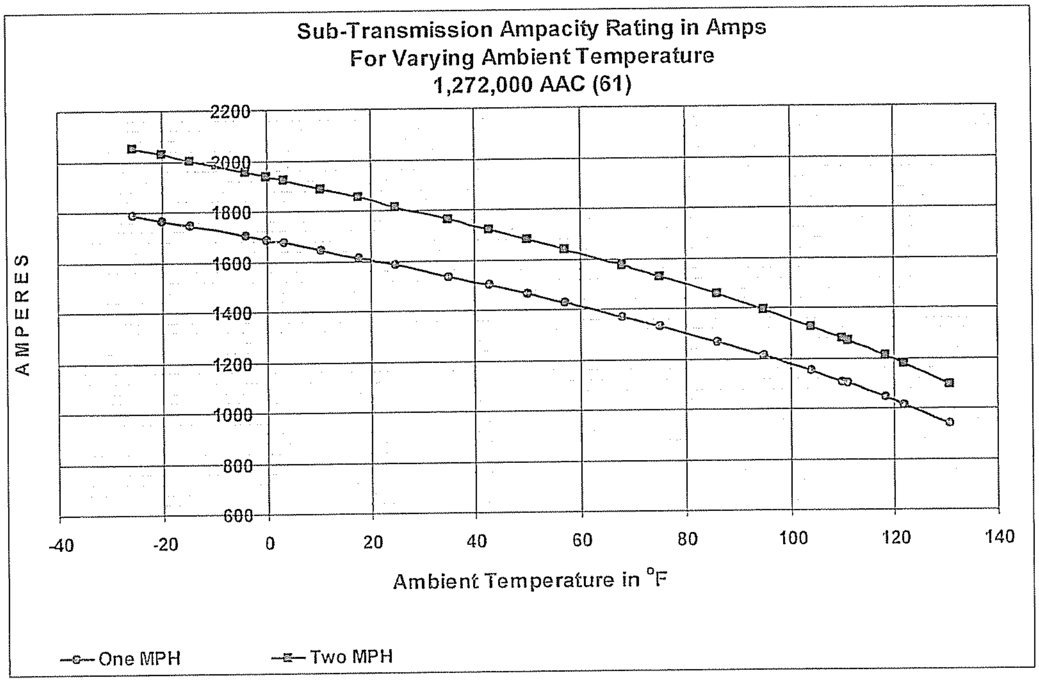
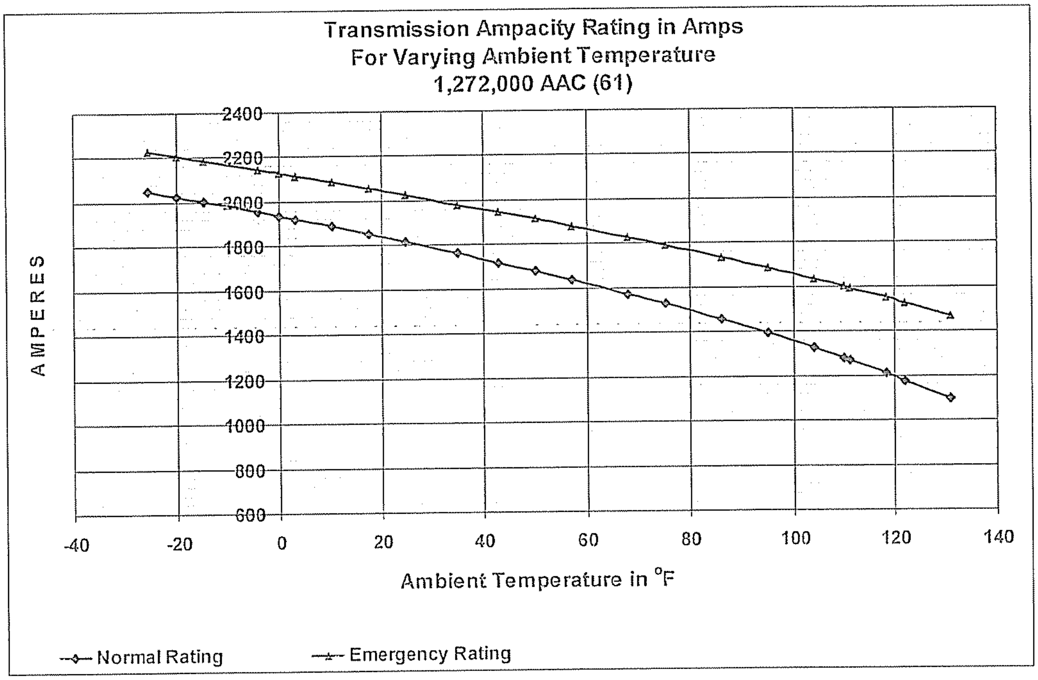
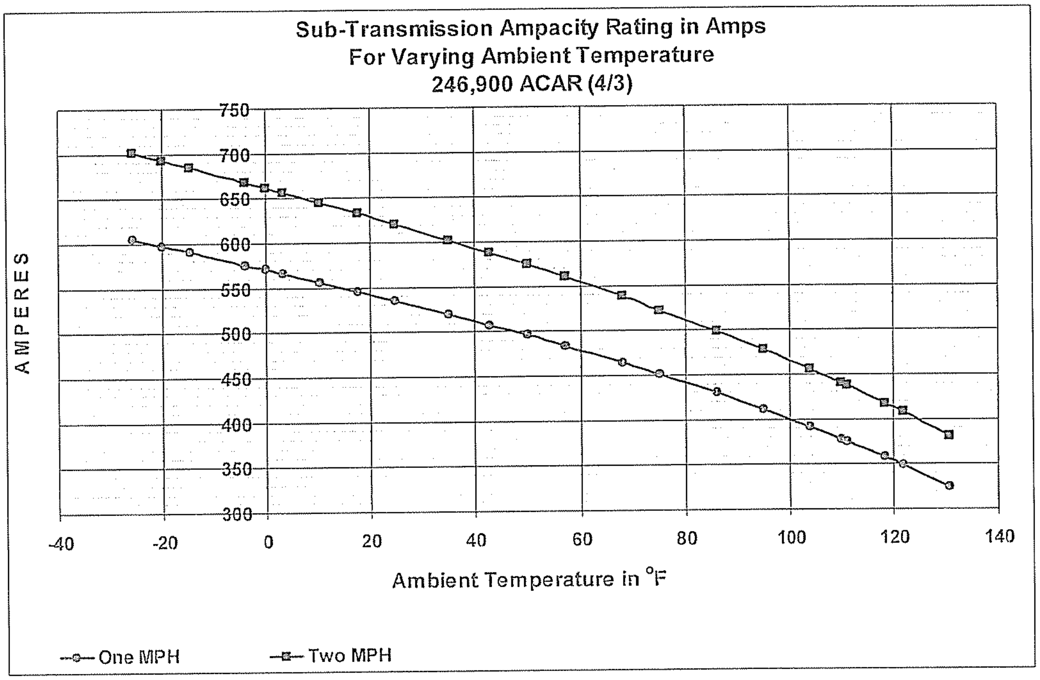
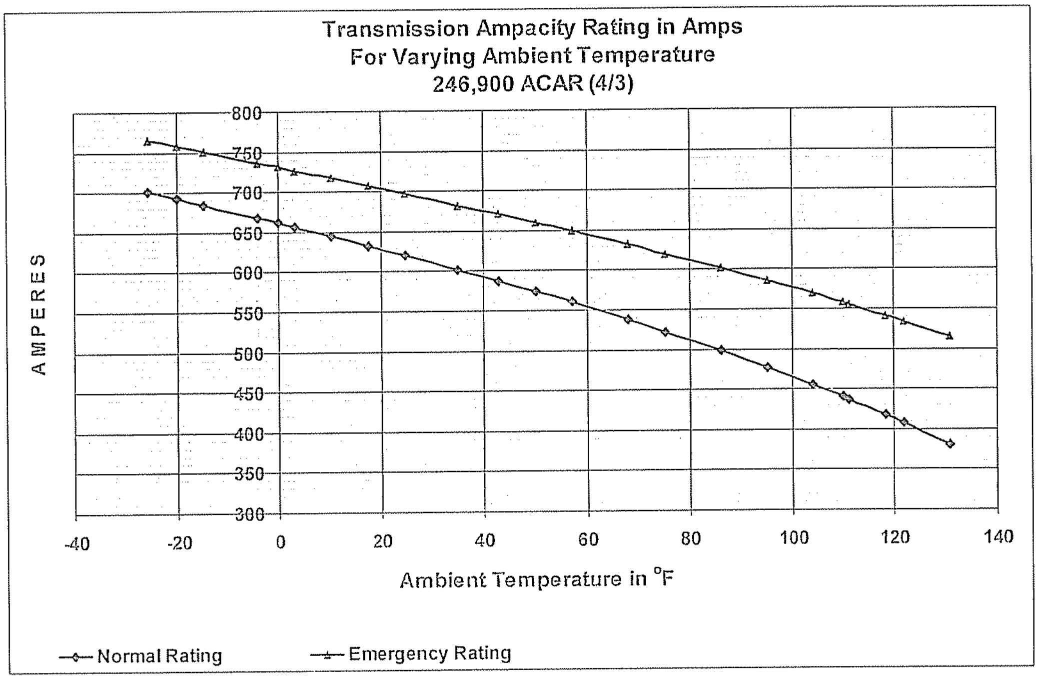
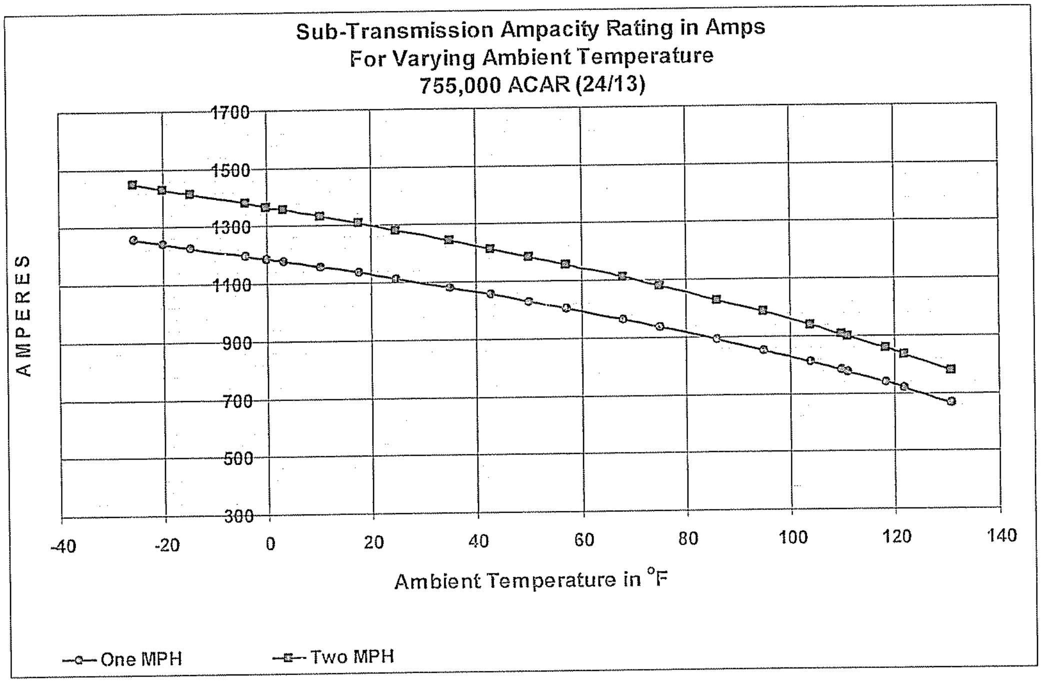
Always check for the latest revision prior to use.

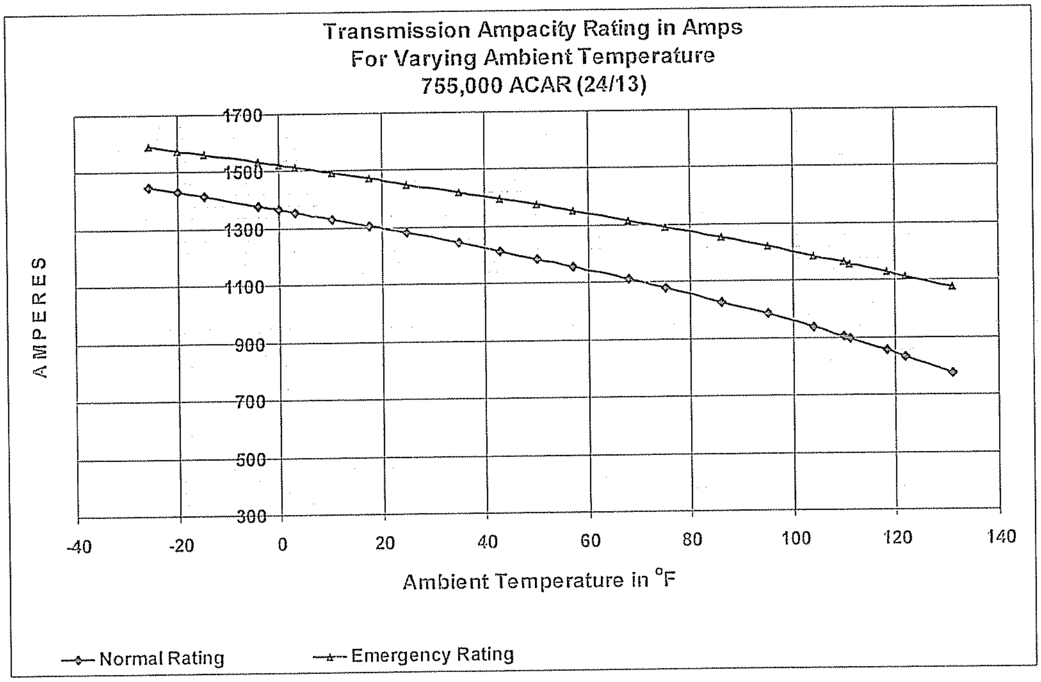


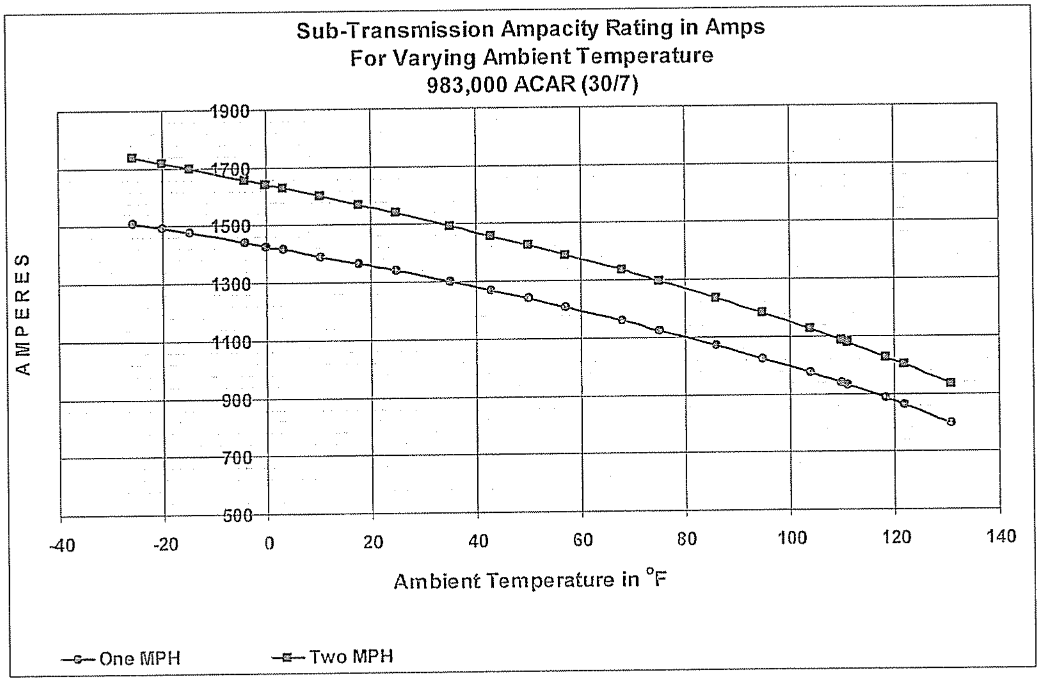


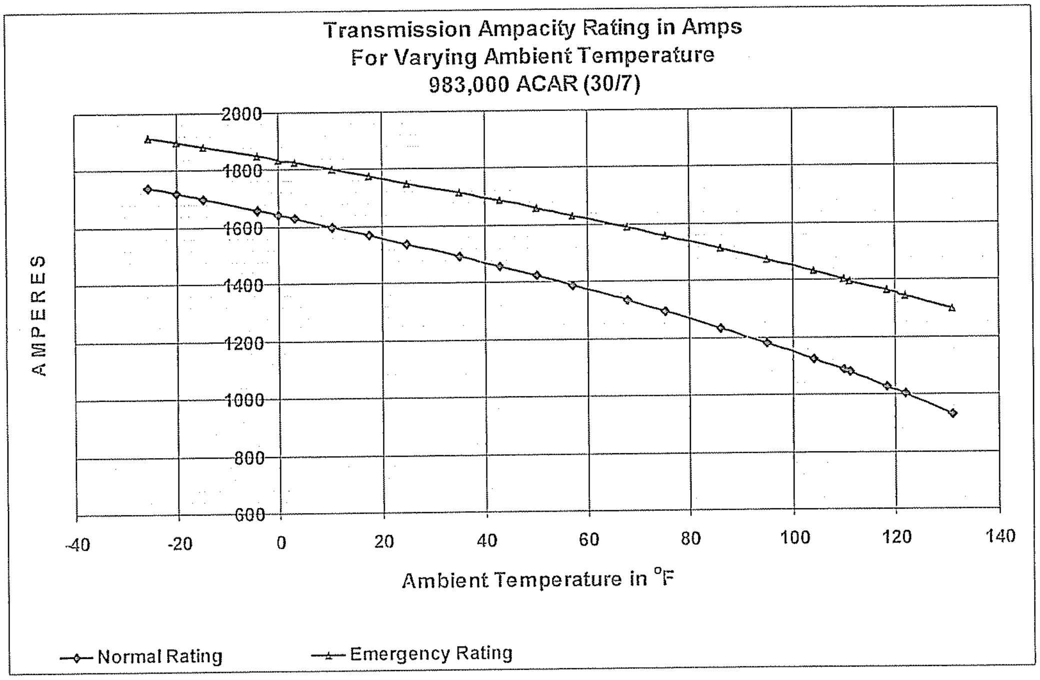

Sub-Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
246,900 ACAR (4/3)
AMPERES
750
700
650
600
550
500
450
400
350
300
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
One MPH
Two MPH

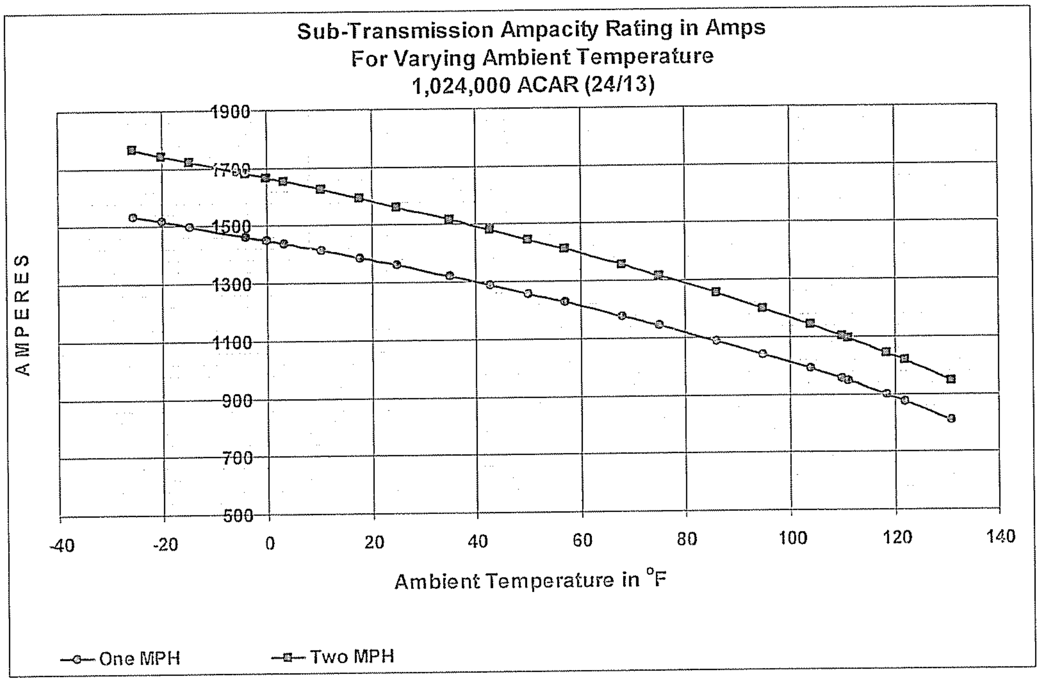

Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
246,900 ACAR (4/3)
AMPERES
800
750
700
650
600
550
500
450
400
350
300
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
Normal Rating
Emergency Rating

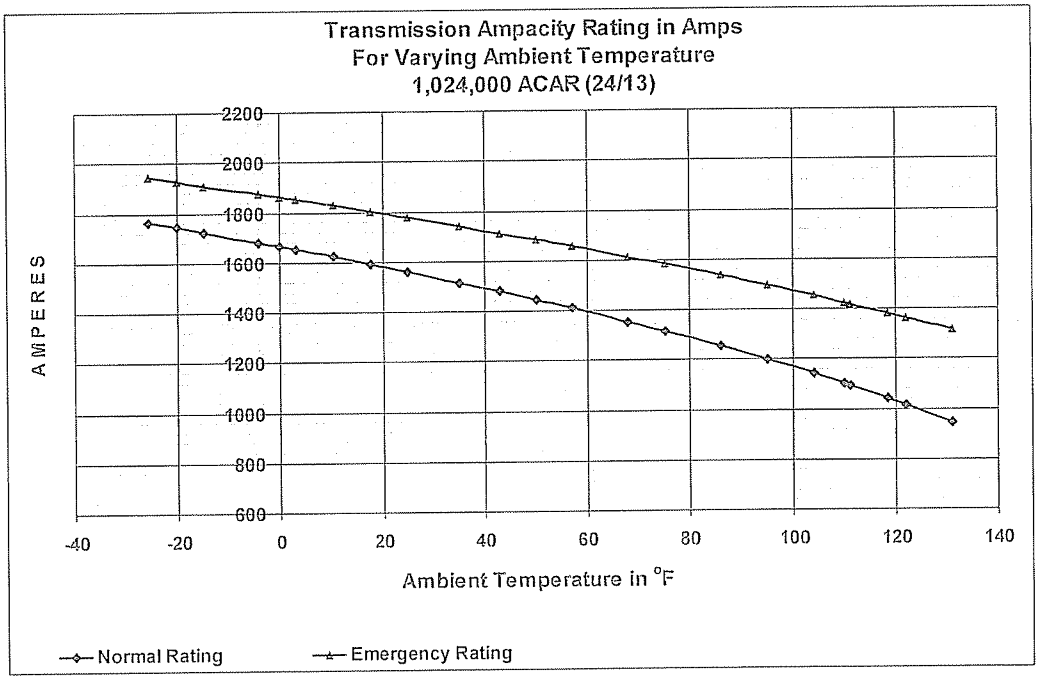

Sub-Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
755,000 ACAR (24/13)
AMPERES
1700
1500
1300
1100
900
700
500
300
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
One MPH
Two MPH

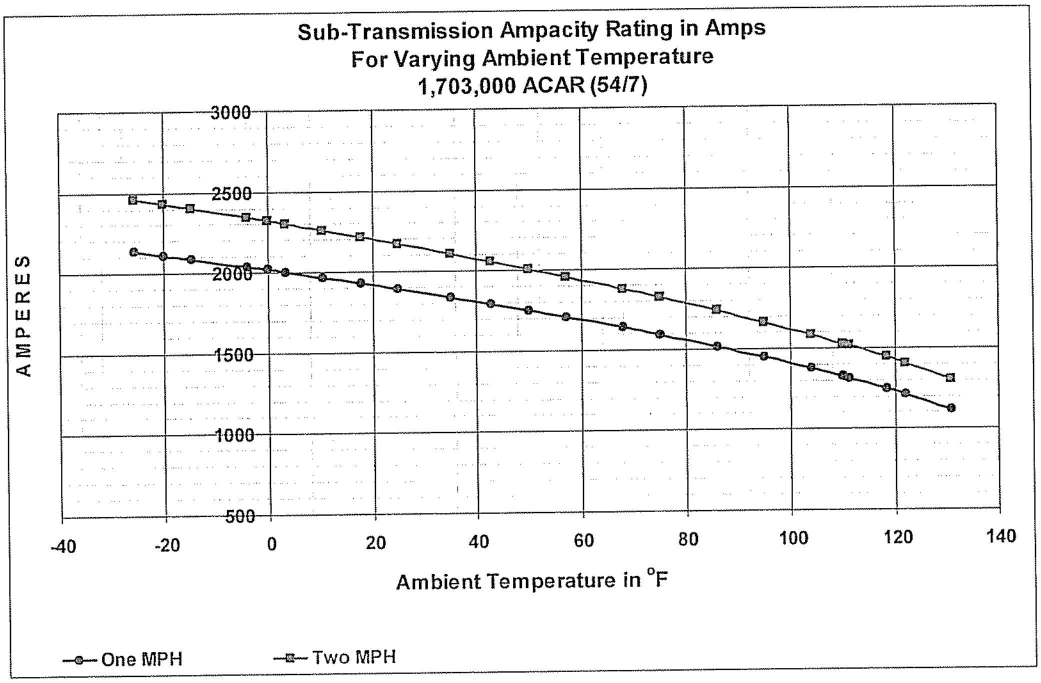

Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
755,000 ACAR (24/13)
AMPERES
1700
1500
1300
1100
900
700
500
300
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
Normal Rating
Emergency Rating

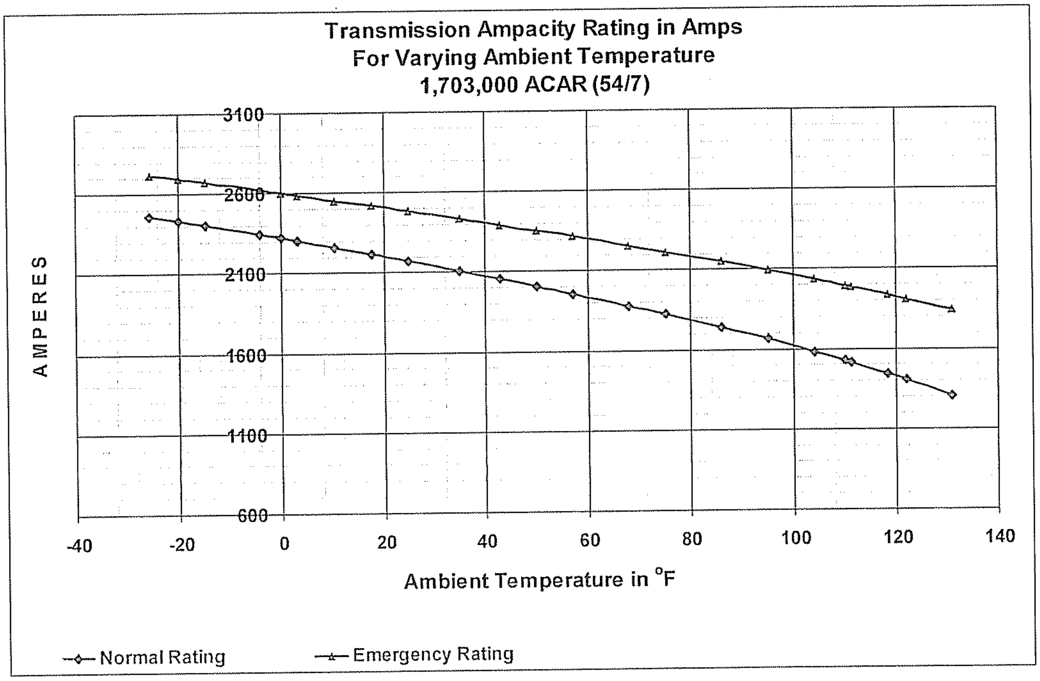

Sub-Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
983,000 ACAR (30/7)
AMPERES
1900
1700
1500
1300
1100
900
700
500
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
One MPH
Two MPH

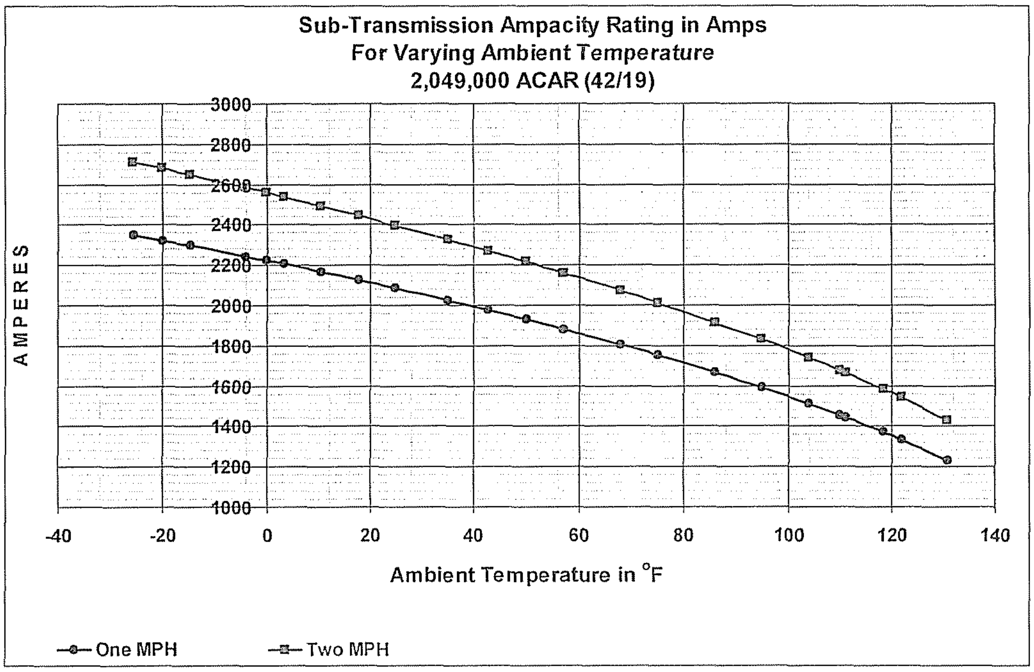

Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
983,000 ACAR (30/7)
AMPERES
2000
1800
1600
1400
1200
1000
800
600
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
Normal Rating
Emergency Rating

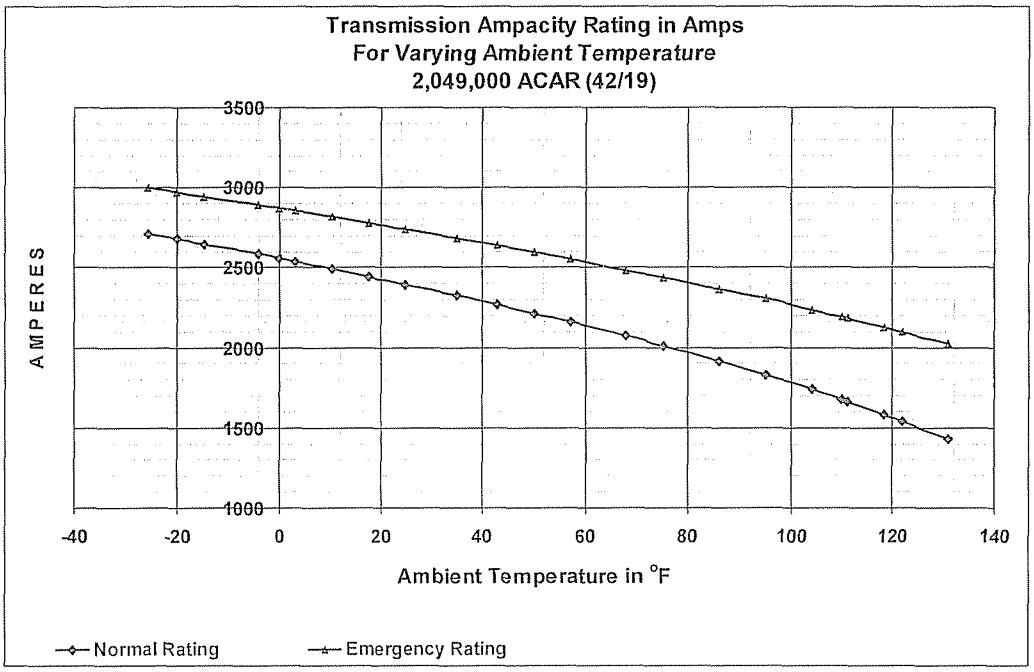

Sub-Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
1,024,000 ACAR (24/13)
AMPERES
1900
1700
1500
1300
1100
900
700
500
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
One MPH
Two MPH

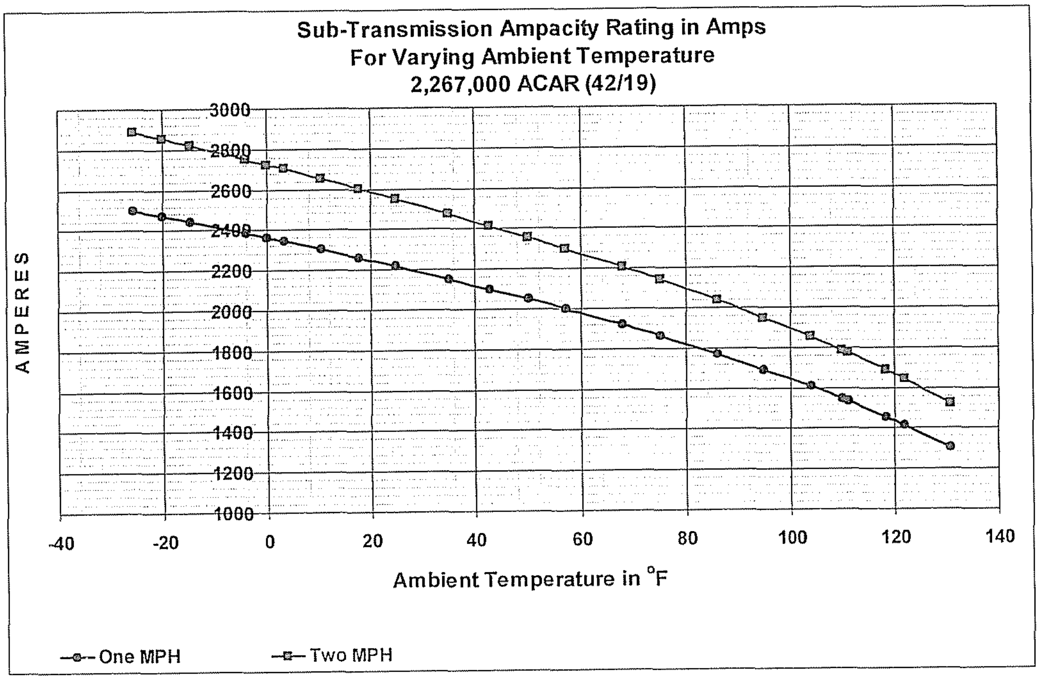

Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
1,024,000 ACAR (24/13)
AMPERES
2200
2000
1800
1600
1400
1200
1000
800
600
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
Normal Rating
Emergency Rating

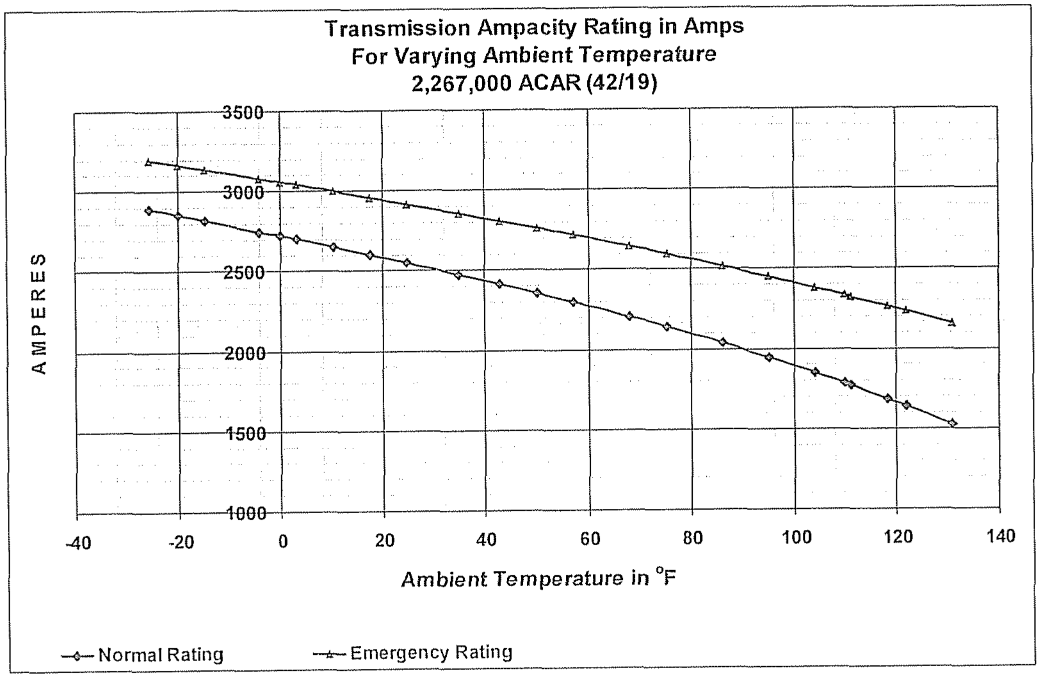

Sub-Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
1,703,000 ACAR (54/7)
AMPERES
3000
2500
2000
1500
1000
500
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
One MPH
Two MPH

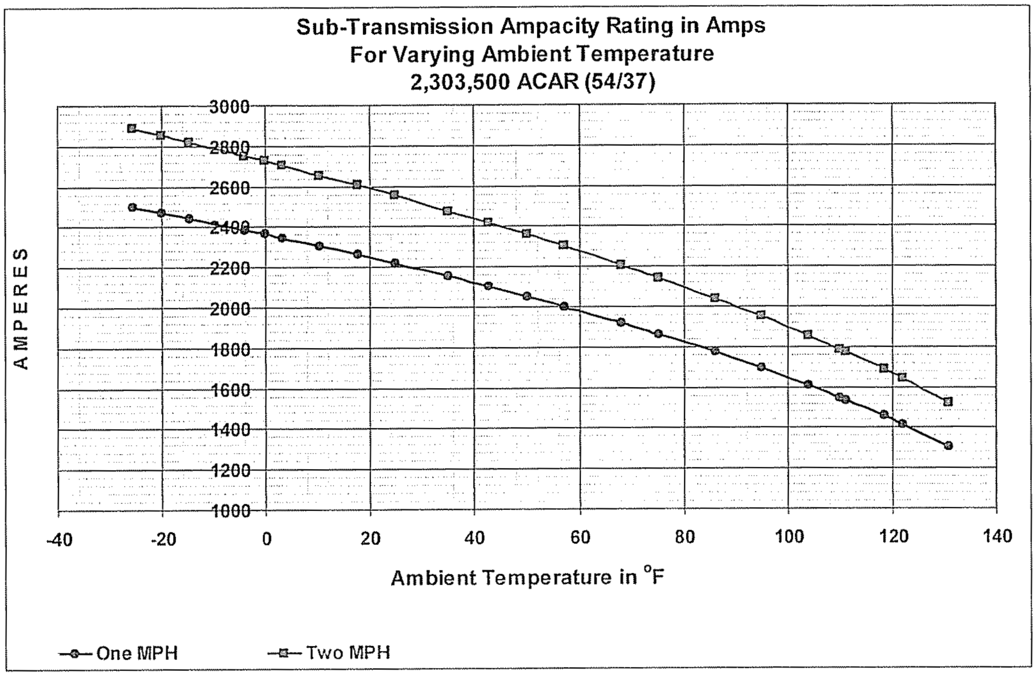

Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
1,703,000 ACAR (54/7)
AMPERES
3100
2600
2100
1600
1100
600
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
Normal Rating
Emergency Rating

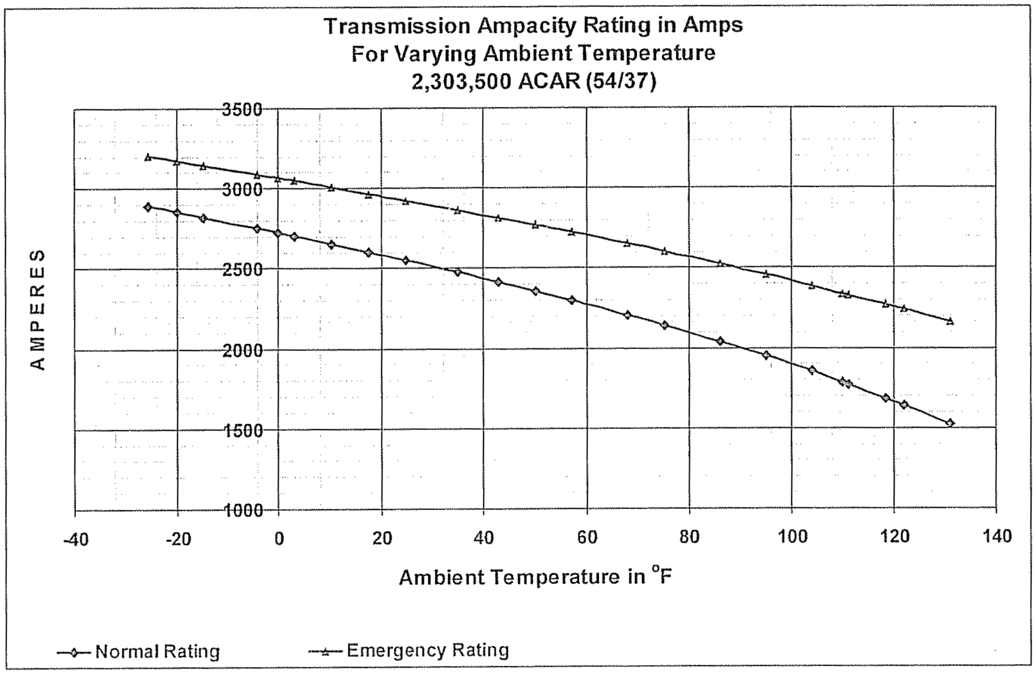

Sub-Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
2,049,000 ACAR (42/19)
AMPERES
3000
2800
2600
2400
2200
2000
1800
1600
1400
1200
1000
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
One MPH
Two MPH


Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
2,049,000 ACAR (42/19)
AMPERES
3500
3000
2500
2000
1500
1000
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
Normal Rating
Emergency Rating


Sub-Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
2,267,000 ACAR (42/19)
AMPERES
3000
2800
2600
2400
2200
2000
1800
1600
1400
1200
1000
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
One MPH
Two MPH


Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
2,267,000 ACAR (42/19)
AMPERES
3500
3000
2500
2000
1500
1000
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
Normal Rating
Emergency Rating


Sub-Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
2,303,500 ACAR (54/37)
AMPERES
3000
2800
2600
2400
2200
2000
1800
1600
1400
1200
1000
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
One MPH
Two MPH


Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
2,303,500 ACAR (54/37)
AMPERES
3500
3000
2500
2000
1500
1000
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
Normal Rating
Emergency Rating

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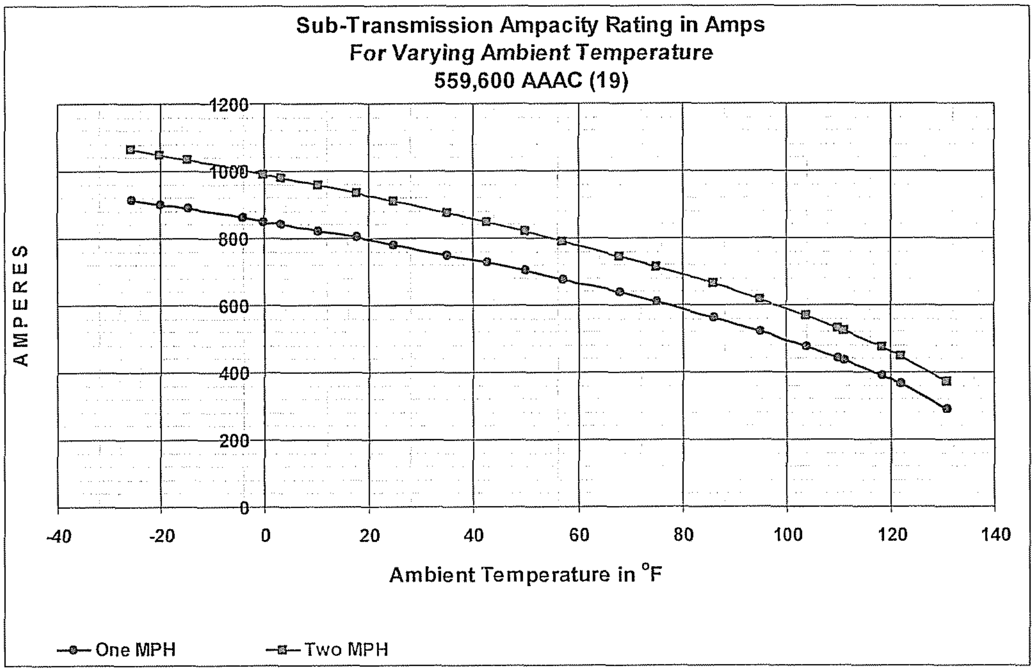
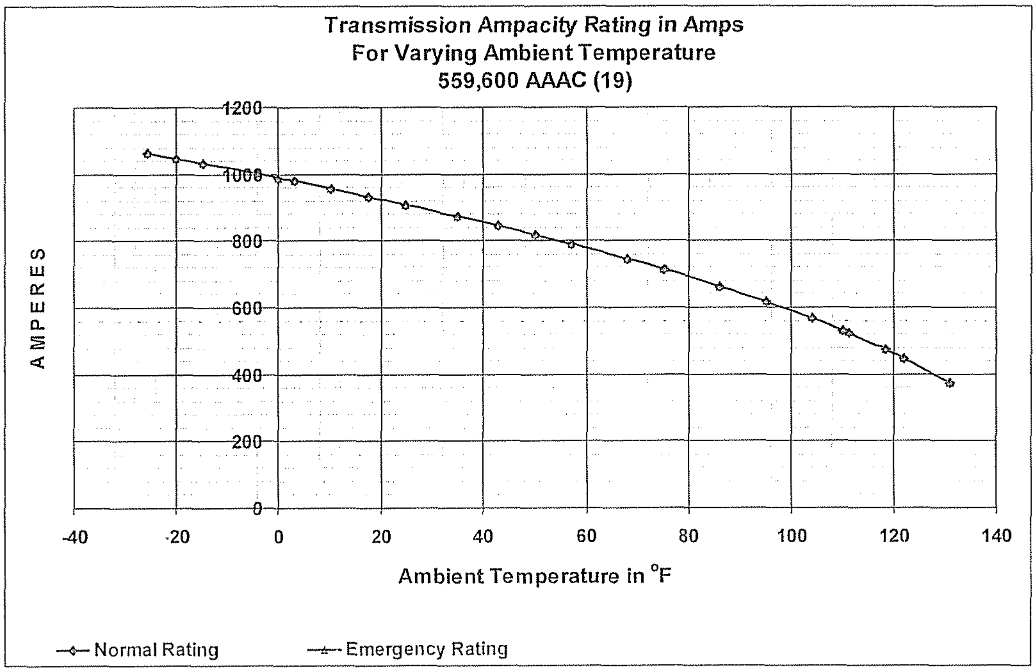
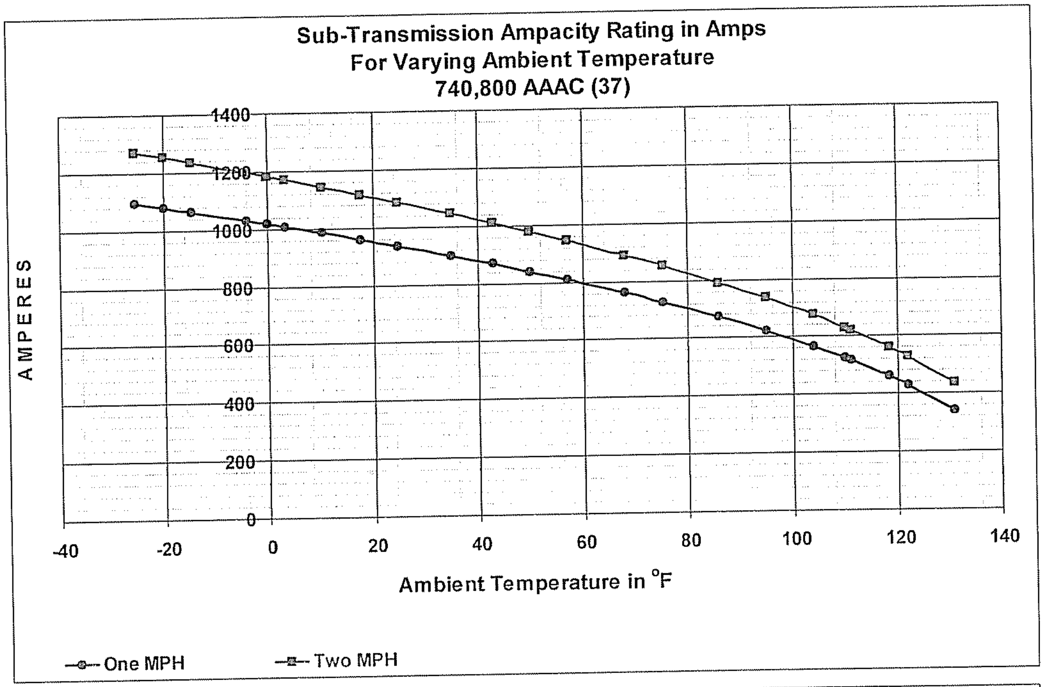
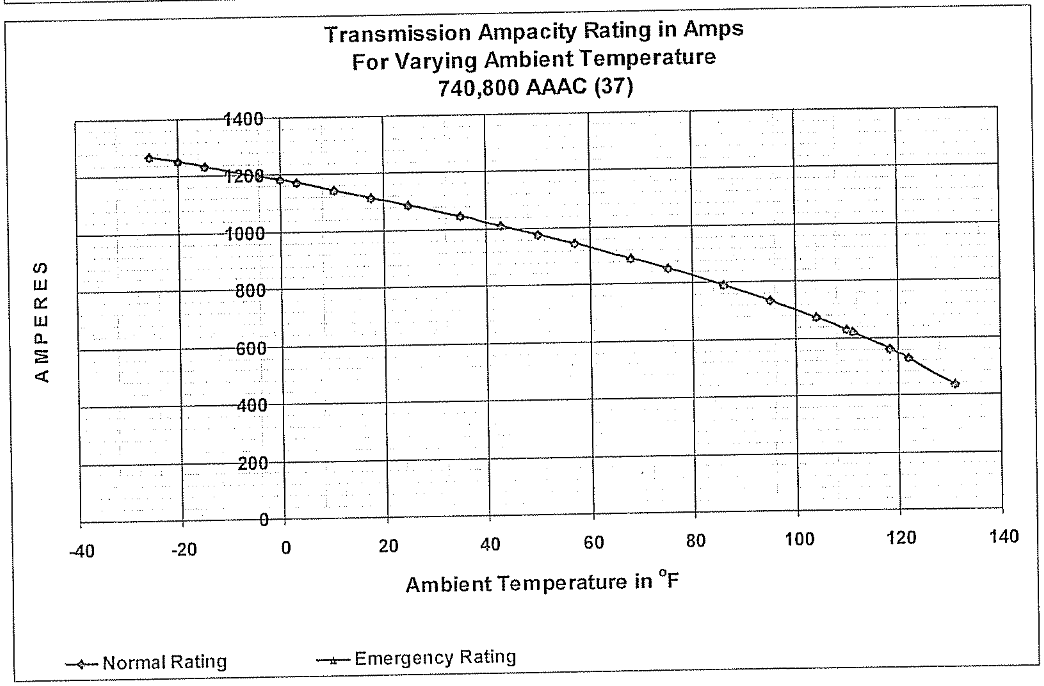
Always check for the latest revision prior to use.

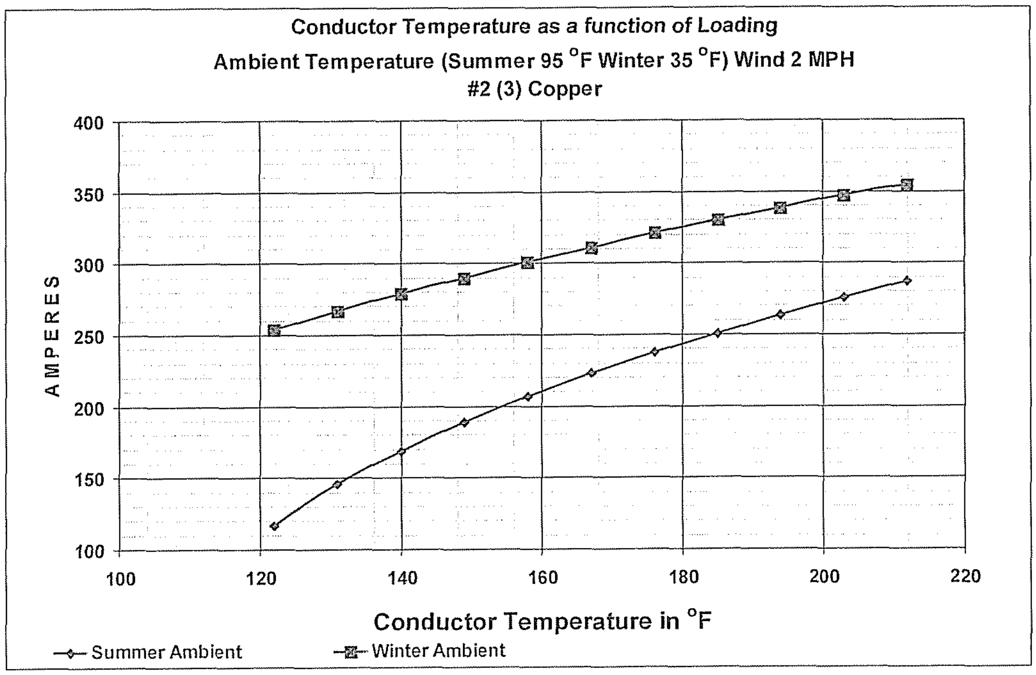


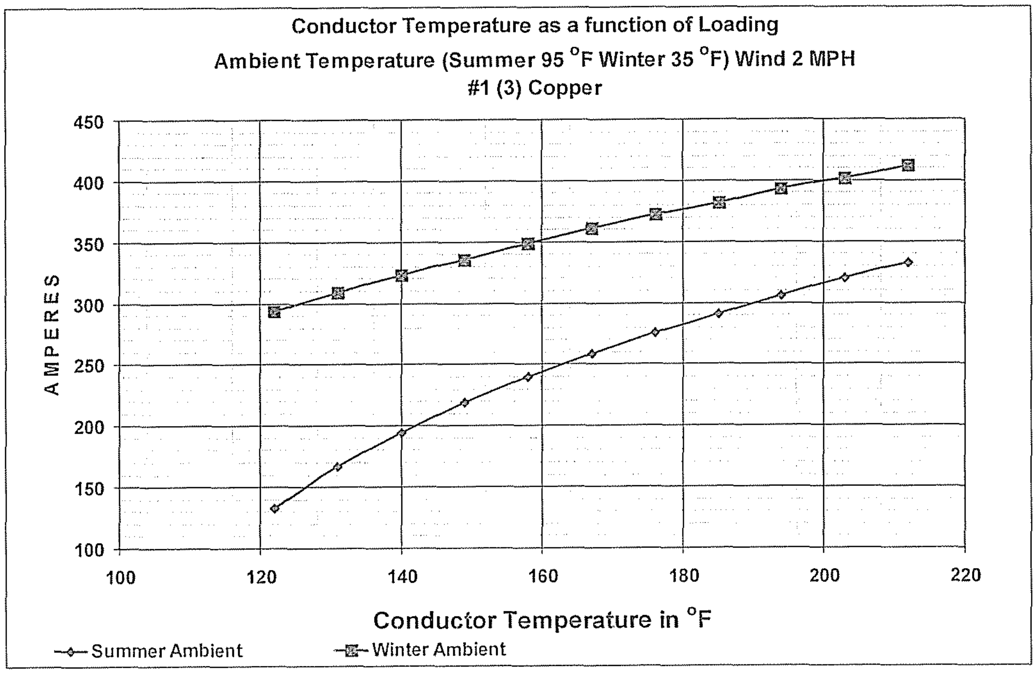


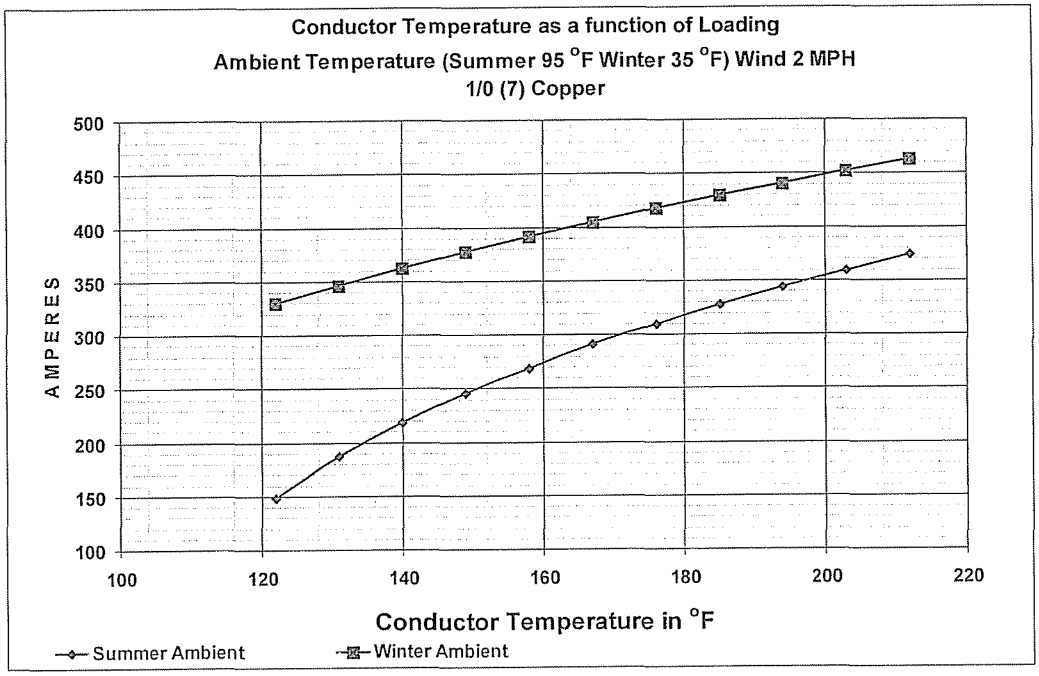

Sub-Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
740,800 AAAC (37)
AMPERES
1400
1200
1000
800
600
400
200
0
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
One MPH
Two MPH

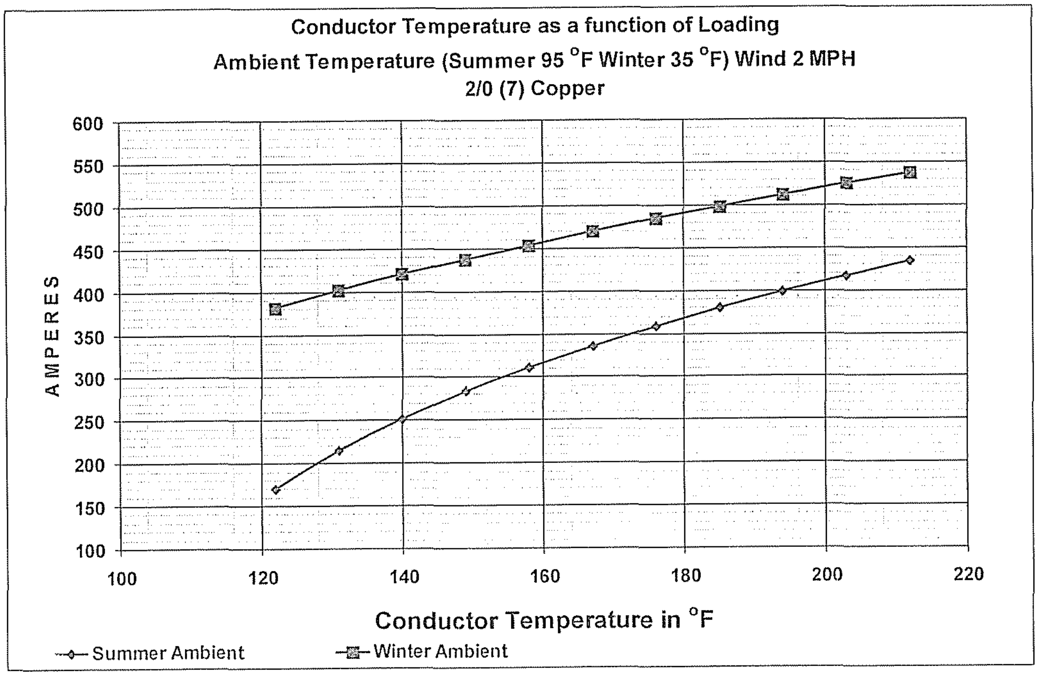

Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
740,800 AAAC (37)
AMPERES
1400
1200
1000
800
600
400
200
0
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
Normal Rating
Emergency Rating

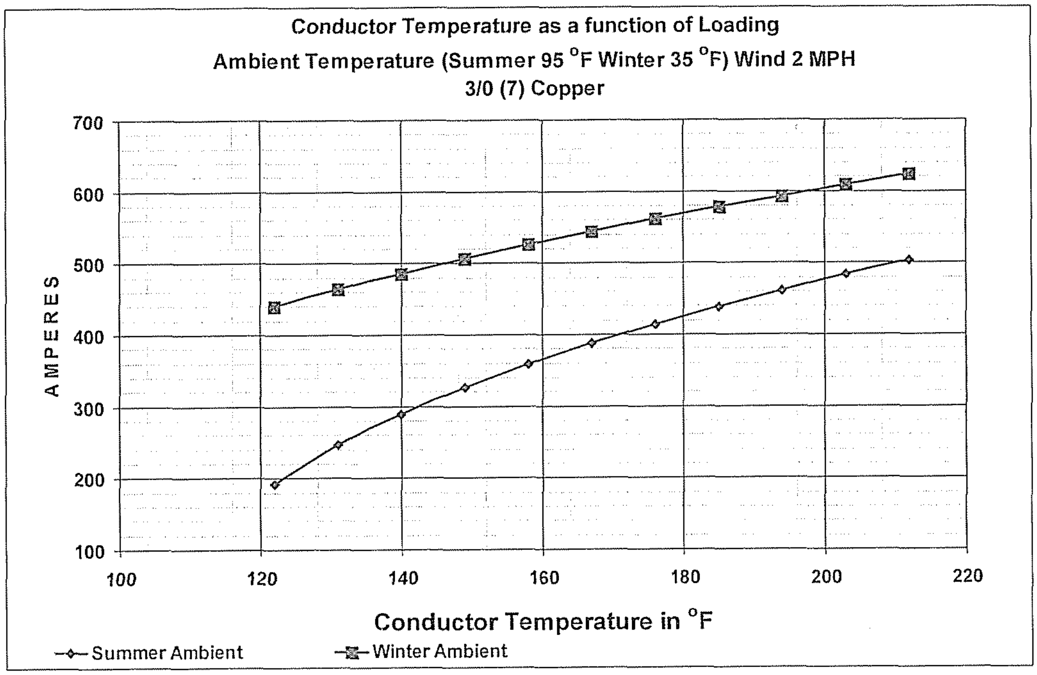
Appendix G	Plots of Conductor Temperature as a function of Conductor Loading **Copper Conductors – AEP East**

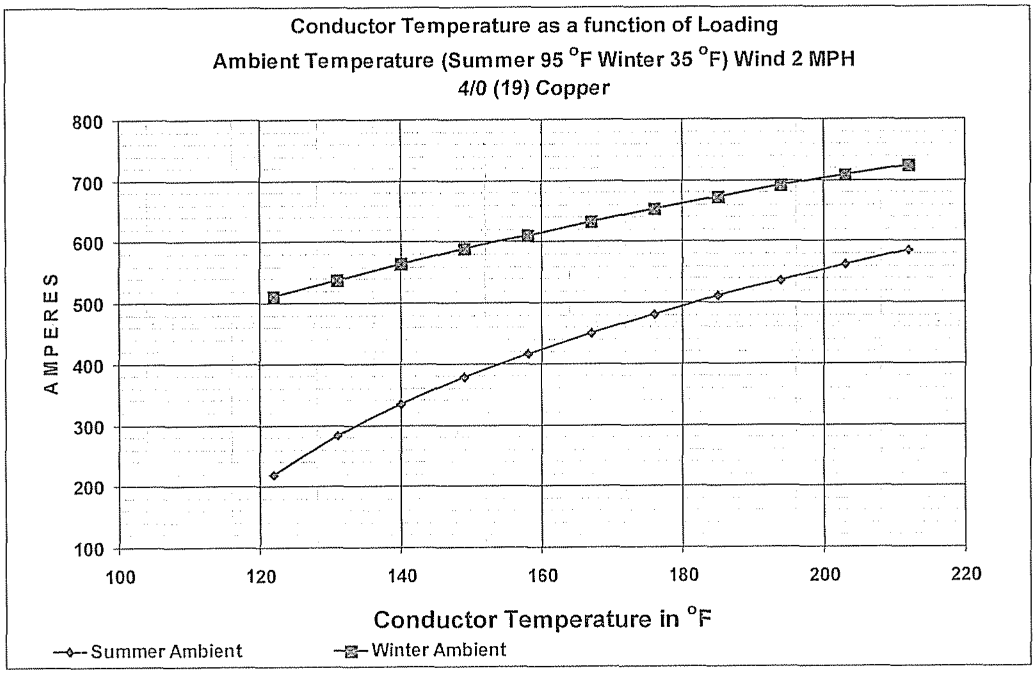

Conductor Temperature as a function of Loading
Ambient Temperature (Summer 95 °F Winter 35 °F) Wind 2 MPH
#2 (3) Copper
AMPERES
400
350
300
250
200
150
100
100
120
140
160
180
200
220
Conductor Temperature in °F
Summer Ambient
Winter Ambient

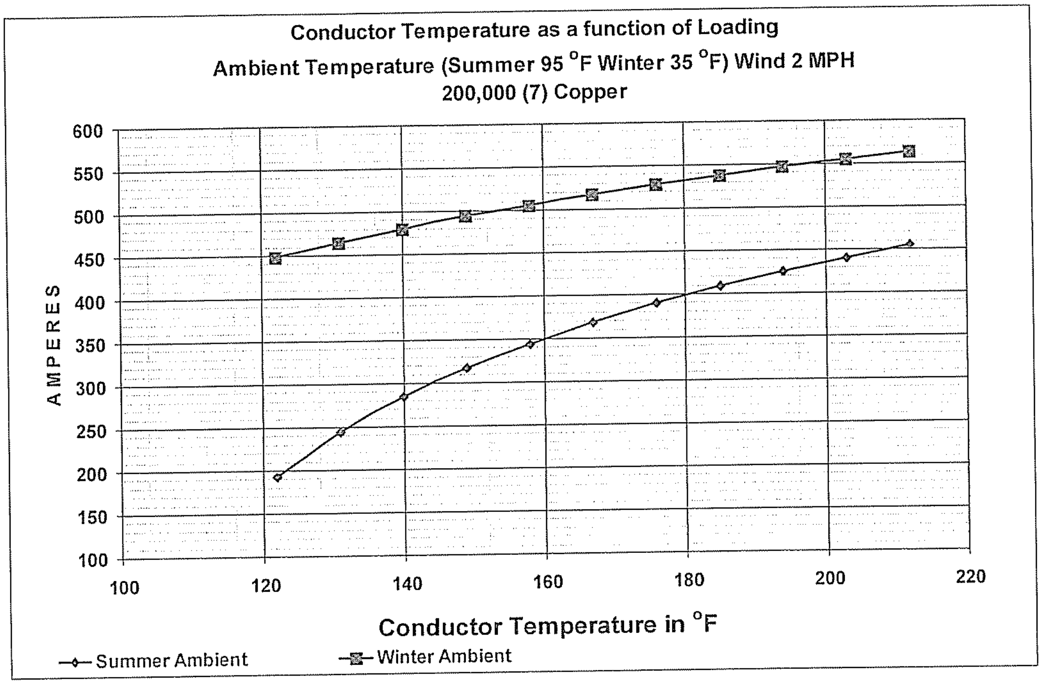

Conductor Temperature as a function of Loading
Ambient Temperature (Summer 95 °F Winter 35 °F) Wind 2 MPH
#1 (3) Copper
AMPERES
450
400
350
300
250
200
150
100
100
120
140
160
180
200
220
Conductor Temperature in °F
Summer Ambient
Winter Ambient

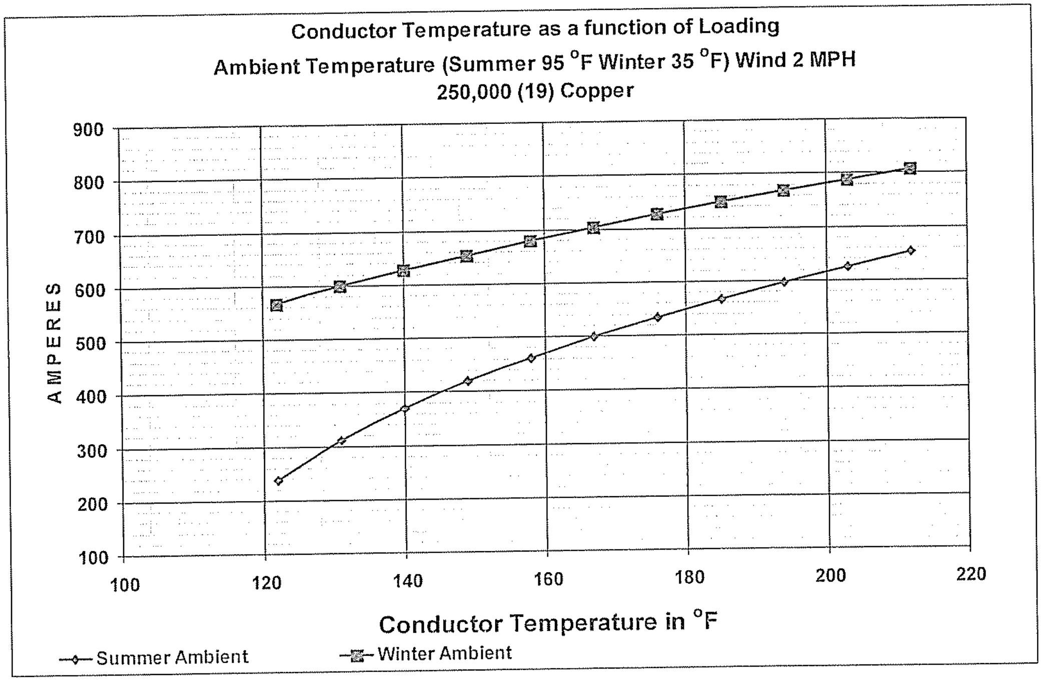

Conductor Temperature as a function of Loading
Ambient Temperature (Summer 95 °F Winter 35 °F) Wind 2 MPH
1/0 (7) Copper
AMPERES
500
450
400
350
300
250
200
150
100
100
120
140
160
180
200
220
Conductor Temperature in °F
Summer Ambient
Winter Ambient

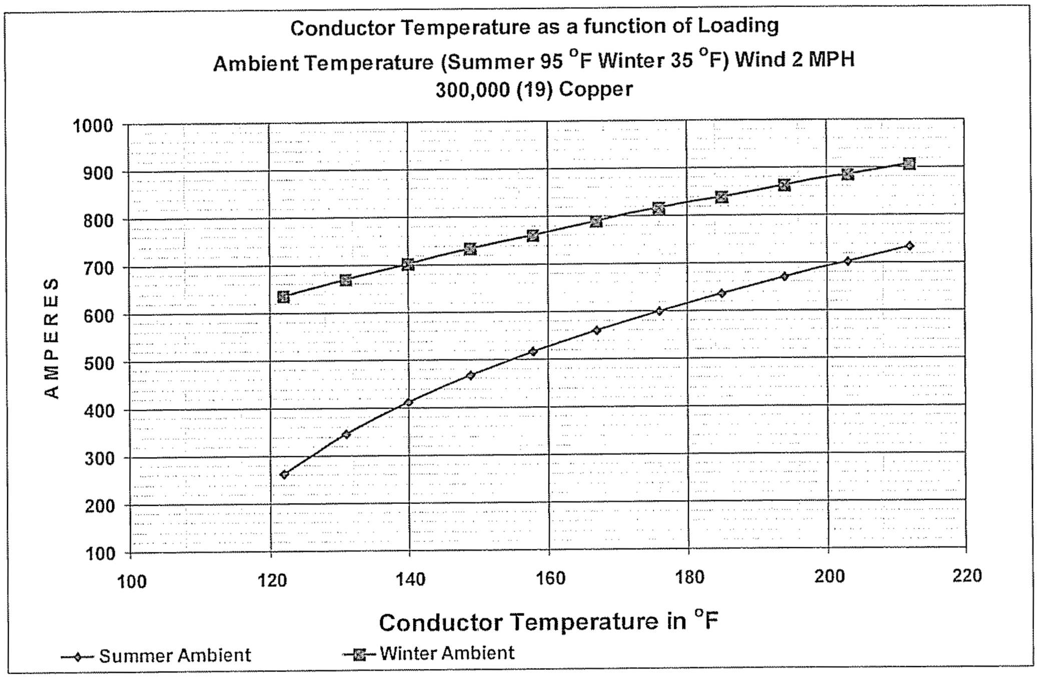

Conductor Temperature as a function of Loading
Ambient Temperature (Summer 95 °F Winter 35 °F) Wind 2 MPH
2/0 (7) Copper
AMPERES
600
550
500
450
400
350
300
250
200
150
100
100
120
140
160
180
200
220
Conductor Temperature in °F
Summer Ambient
Winter Ambient

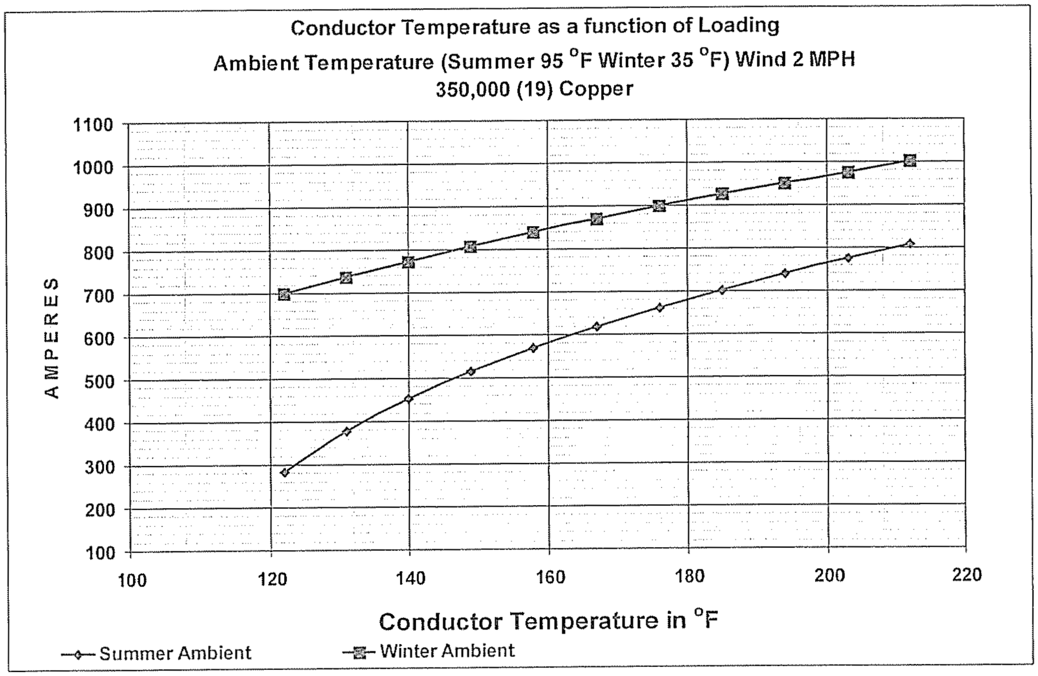

Conductor Temperature as a function of Loading
Ambient Temperature (Summer 95 °F Winter 35 °F) Wind 2 MPH
3/0 (7) Copper
AMPERES
700
600
500
400
300
200
100
100
120
140
160
180
200
220
Conductor Temperature in °F
Summer Ambient
Winter Ambient

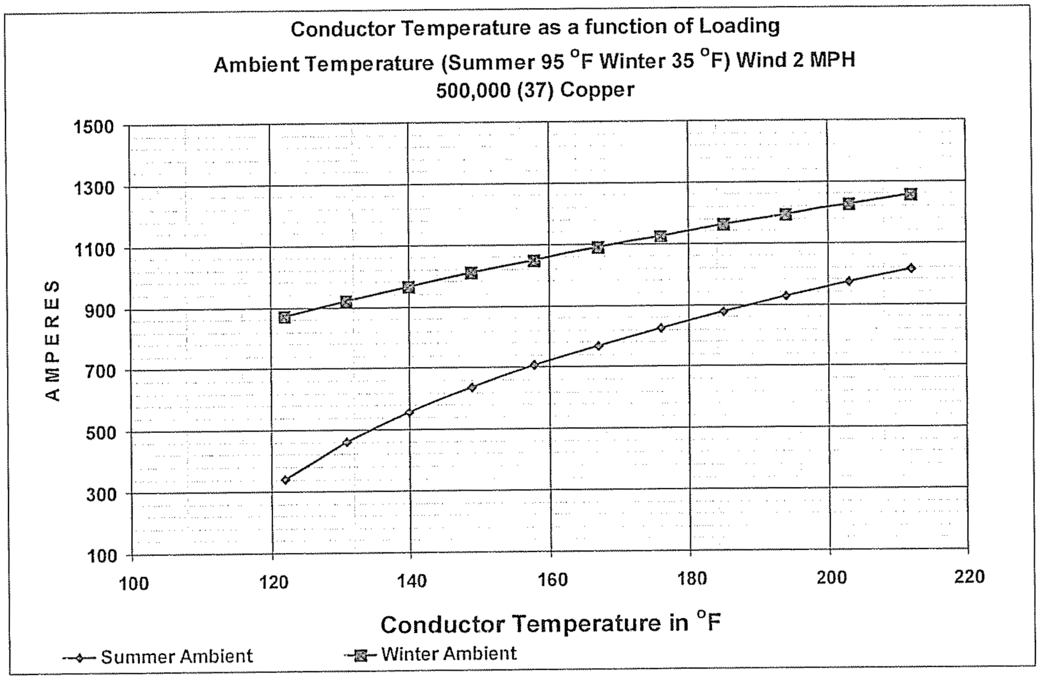

Conductor Temperature as a function of Loading
Ambient Temperature (Summer 95 °F Winter 35 °F) Wind 2 MPH
4/0 (19) Copper
AMPERES
800
700
600
500
400
300
200
100
100
120
140
160
180
200
220
Conductor Temperature in °F
Summer Ambient
Winter Ambient


Conductor Temperature as a function of Loading
Ambient Temperature (Summer 95 °F Winter 35 °F) Wind 2 MPH
200,000 (7) Copper
AMPERES
600
550
500
450
400
350
300
250
200
150
100
100
120
140
160
180
200
220
Conductor Temperature in °F
Summer Ambient
Winter Ambient

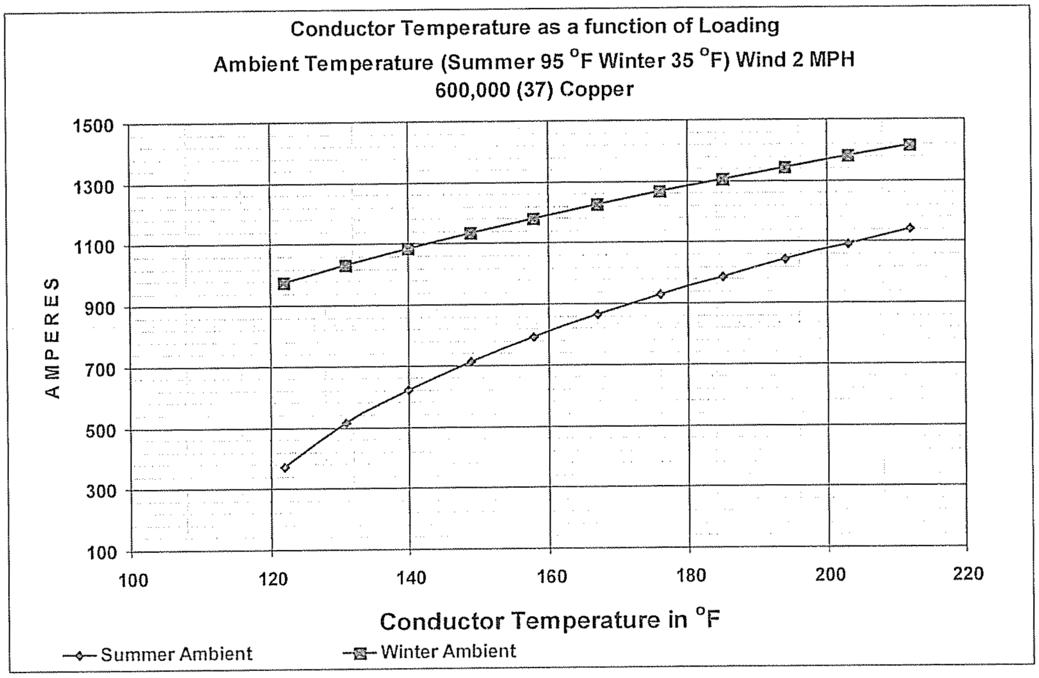

Conductor Temperature as a function of Loading
Ambient Temperature (Summer 95 °F Winter 35 °F) Wind 2 MPH
250,000 (19) Copper
AMPERES
900
800
700
600
500
400
300
200
100
100
120
140
160
180
200
220
Conductor Temperature in °F
Summer Ambient
Winter Ambient


Conductor Temperature as a function of Loading
Ambient Temperature (Summer 95 °F Winter 35 °F) Wind 2 MPH
300,000 (19) Copper
AMPERES
1000
900
800
700
600
500
400
300
200
100
100
120
140
160
180
200
220
Conductor Temperature in °F
Summer Ambient
Winter Ambient

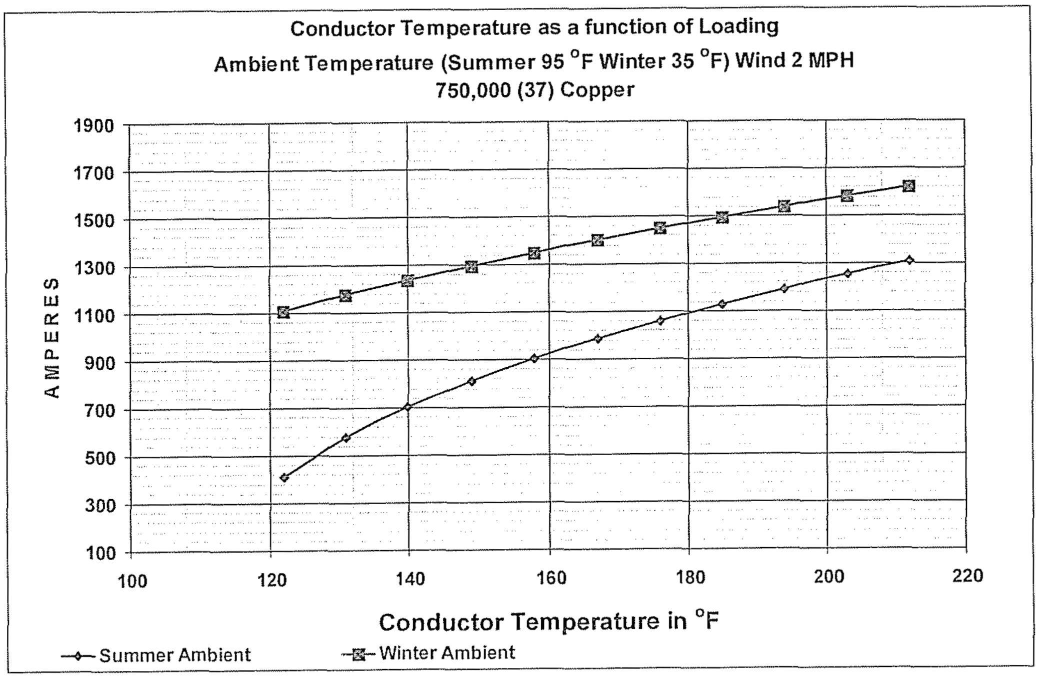

Conductor Temperature as a function of Loading
Ambient Temperature (Summer 95 °F Winter 35 °F) Wind 2 MPH
350,000 (19) Copper
AMPERES
1100
1000
900
800
700
600
500
400
300
200
100
100
120
140
160
180
200
220
Conductor Temperature in °F
Summer Ambient
Winter Ambient



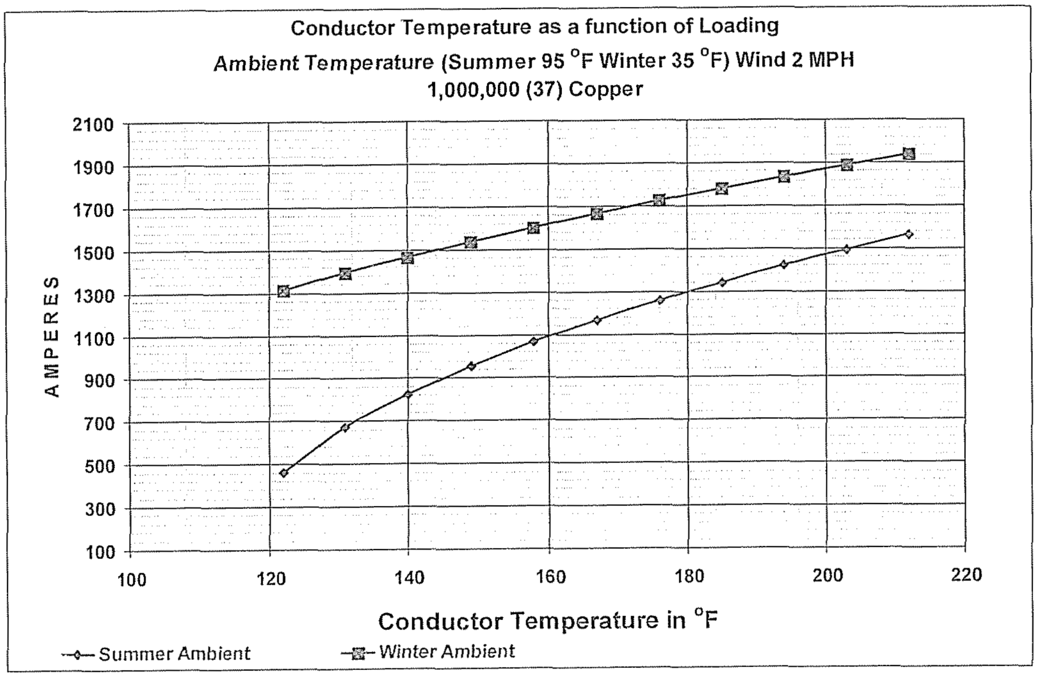
Conductor Temperature as a function of Loading
Ambient Temperature (Summer 95 °F Winter 35 °F) Wind 2 MPH
500,000 (37) Copper



Conductor Temperature as a function of Loading
Ambient Temperature (Summer 95 °F Winter 35 °F) Wind 2 MPH
600,000 (37) Copper

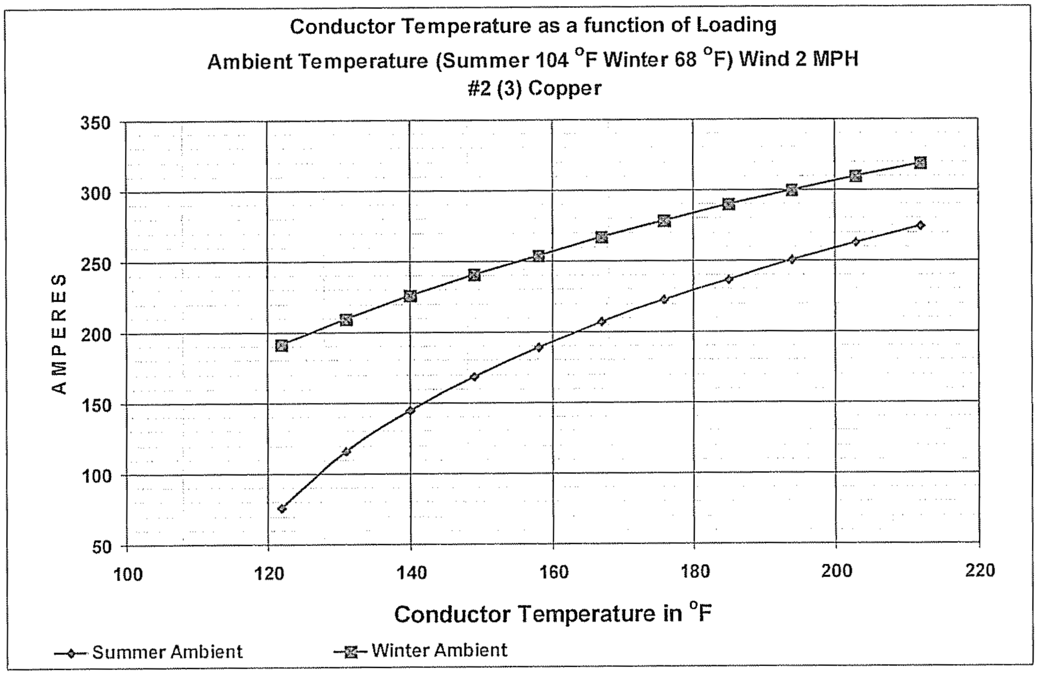


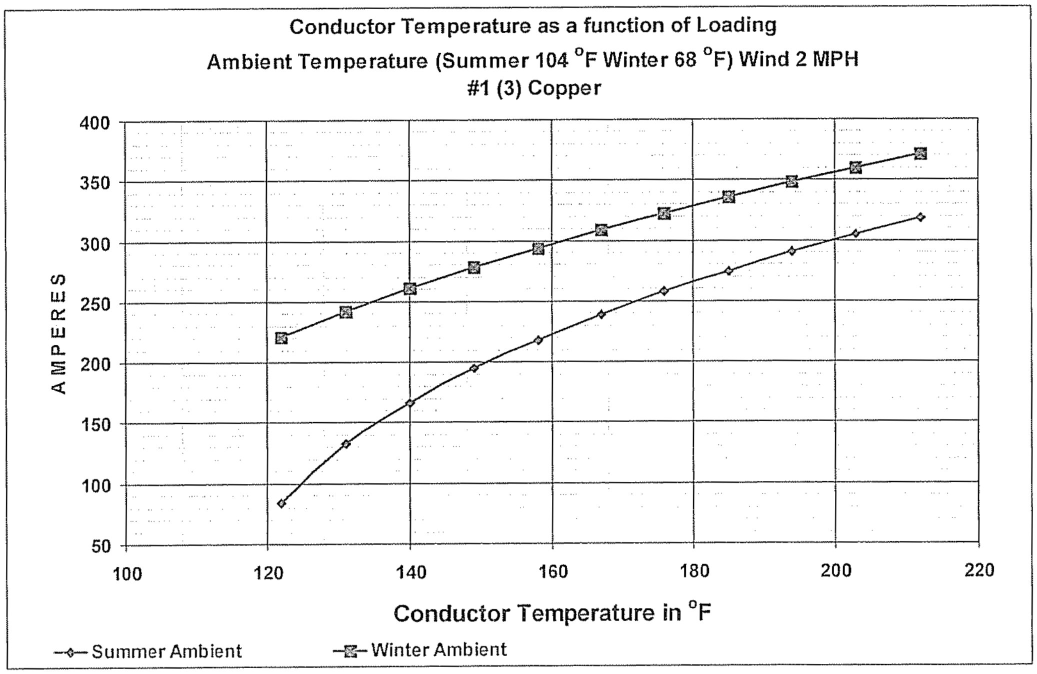
Conductor Temperature as a function of Loading
Ambient Temperature (Summer 95 °F Winter 35 °F) Wind 2 MPH
750,000 (37) Copper



Conductor Temperature as a function of Loading
Ambient Temperature (Summer 95 °F Winter 35 °F) Wind 2 MPH
1,000,000 (37) Copper

Appendix H	Plots of Conductor Temperature as a function of Conductor Loading **Copper Conductors – AEP West**


Conductor Temperature as a function of Loading
Ambient Temperature (Summer 104 °F Winter 68 °F) Wind 2 MPH
#2 (3) Copper
AMPERES
350
300
250
200
150
100
50
100
120
140
160
180
200
220
Conductor Temperature in °F
Summer Ambient
Winter Ambient


Conductor Temperature as a function of Loading
Ambient Temperature (Summer 104 °F Winter 68 °F) Wind 2 MPH
#1 (3) Copper
AMPERES
400
350
300
250
200
150
100
50
100
120
140
160
180
200
220
Conductor Temperature in °F
Summer Ambient
Winter Ambient

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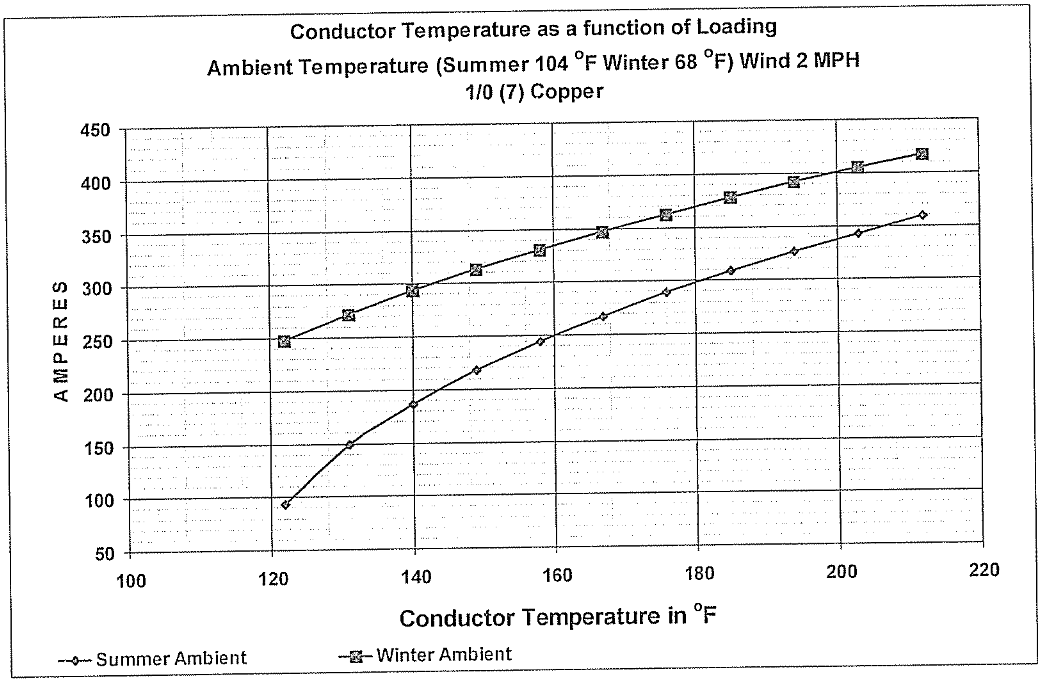
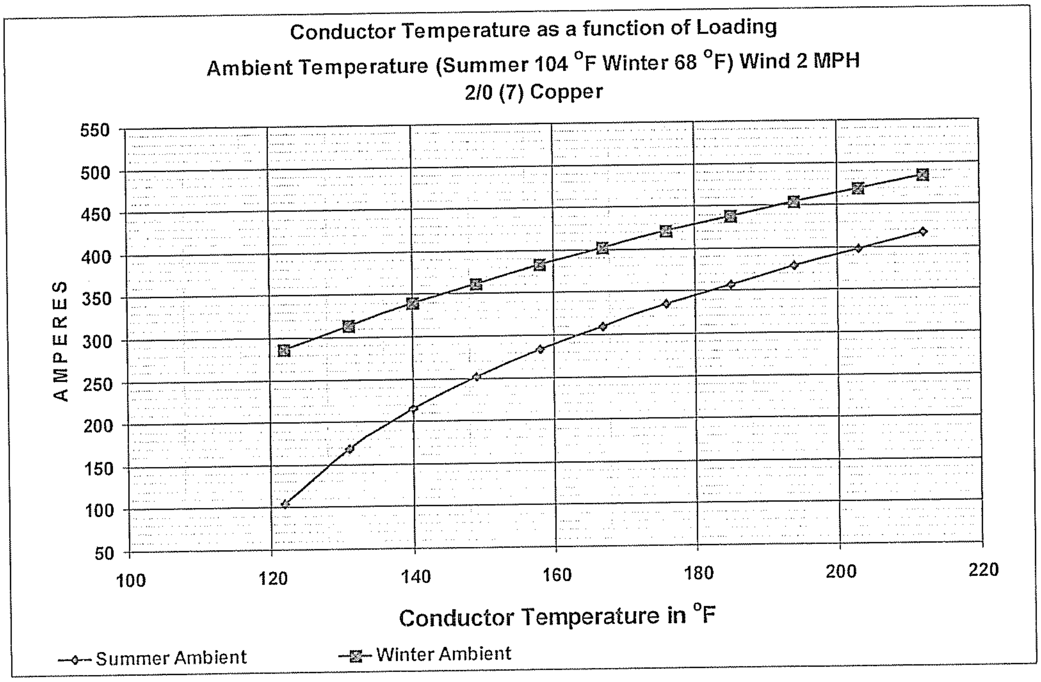
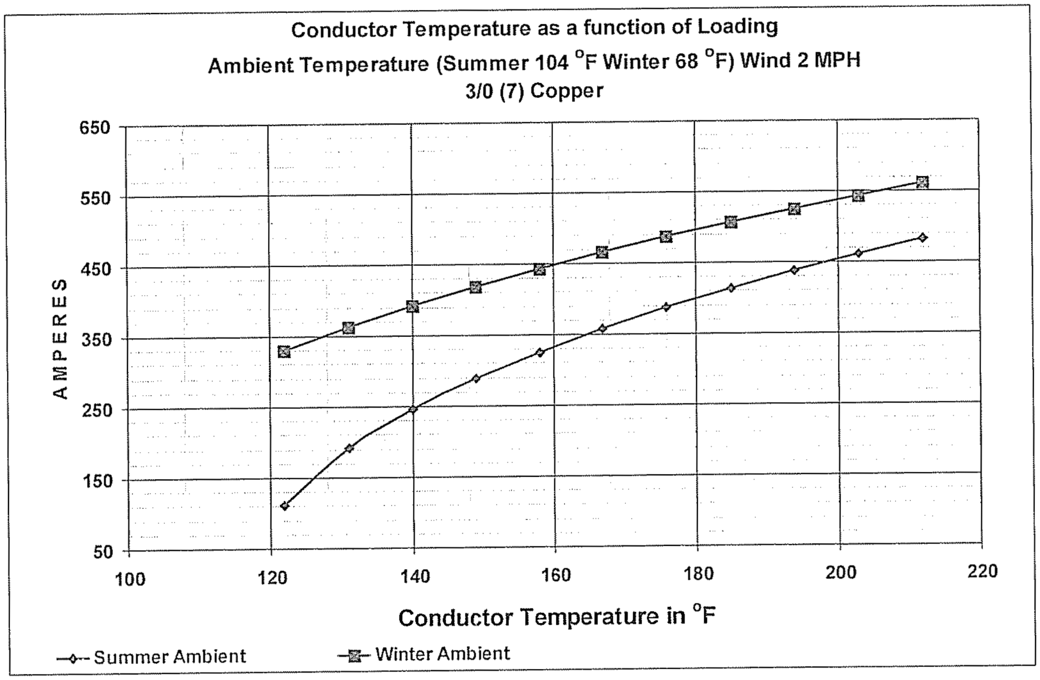
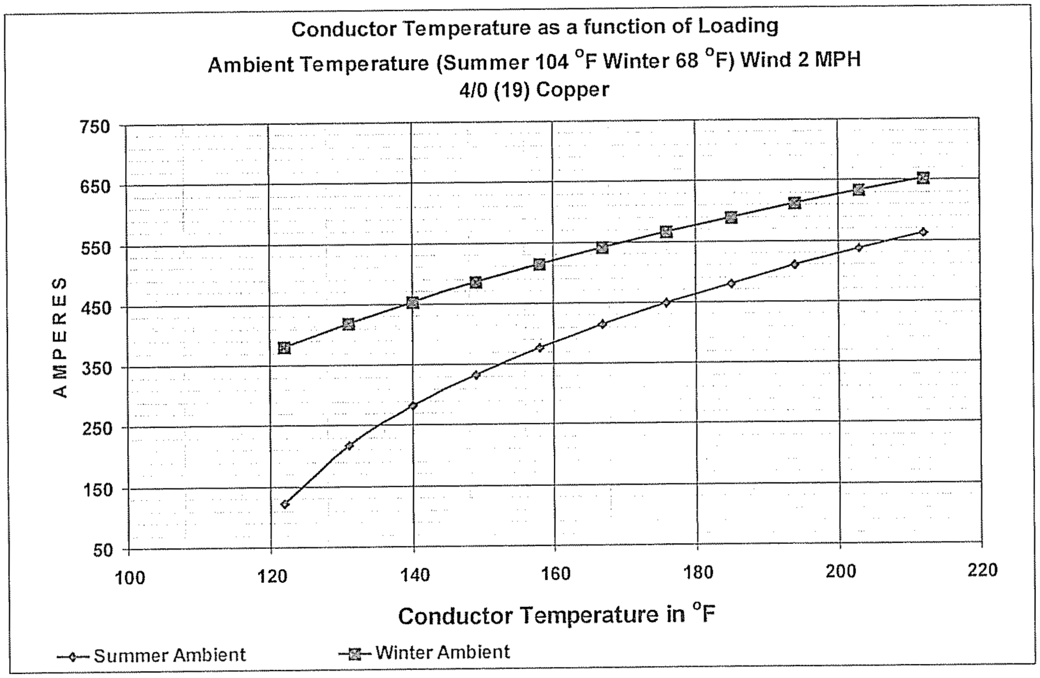
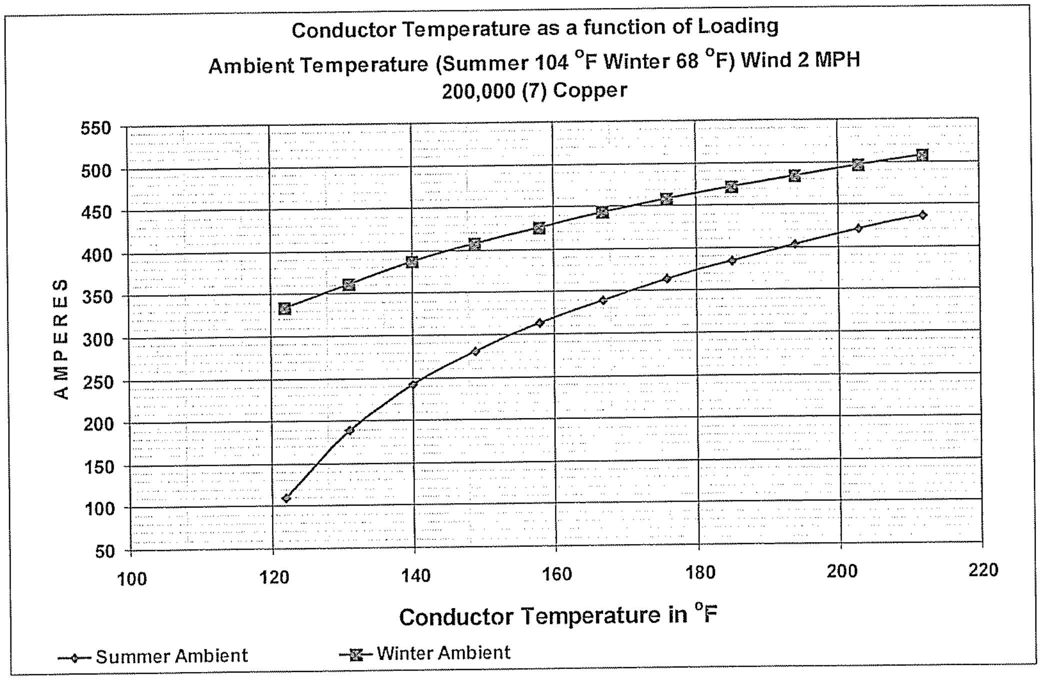
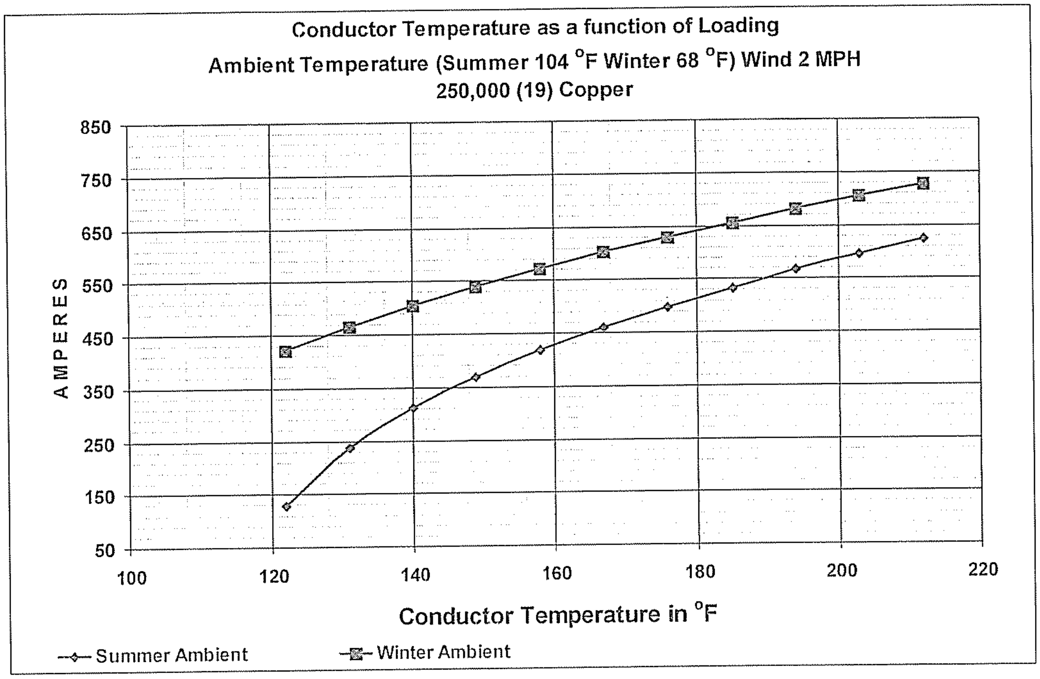


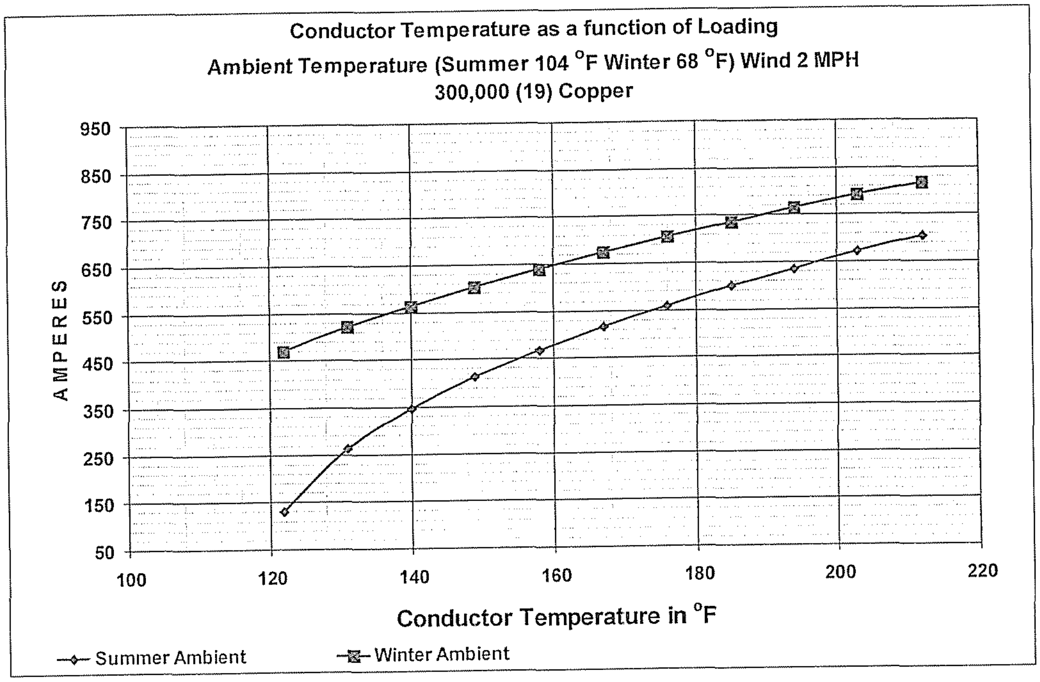



Conductor Temperature as a function of Loading
Ambient Temperature (Summer 104 °F Winter 68 °F) Wind 2 MPH
3/0 (7) Copper

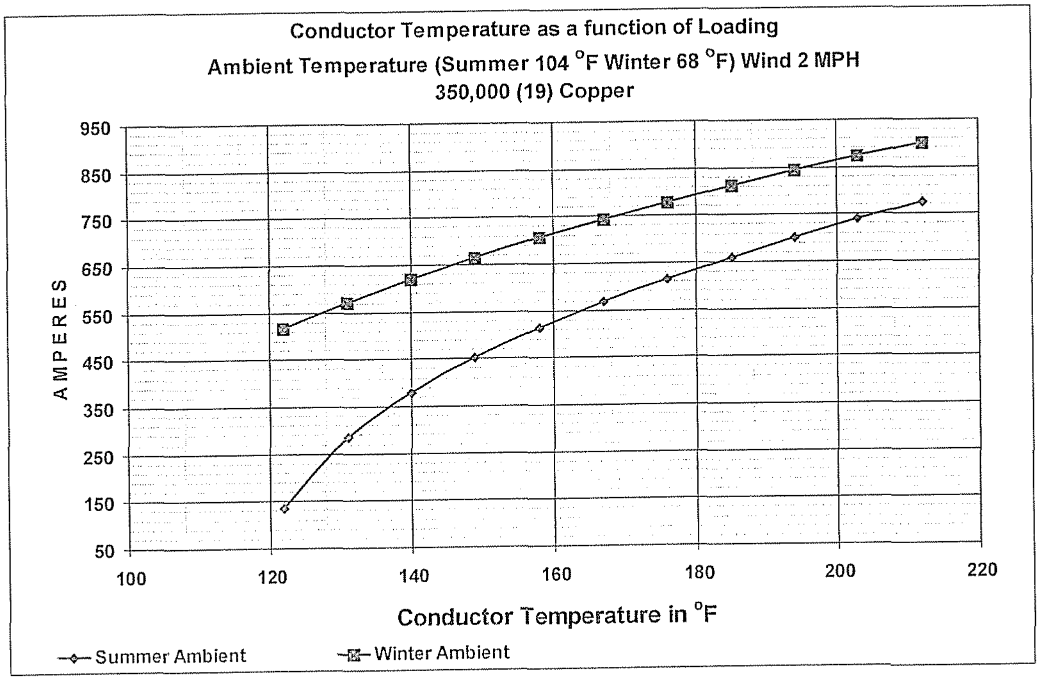

Conductor Temperature as a function of Loading
Ambient Temperature (Summer 104 °F Winter 68 °F) Wind 2 MPH
4/0 (19) Copper


Conductor Temperature as a function of Loading
Ambient Temperature (Summer 104 °F Winter 68 °F) Wind 2 MPH
200,000 (7) Copper

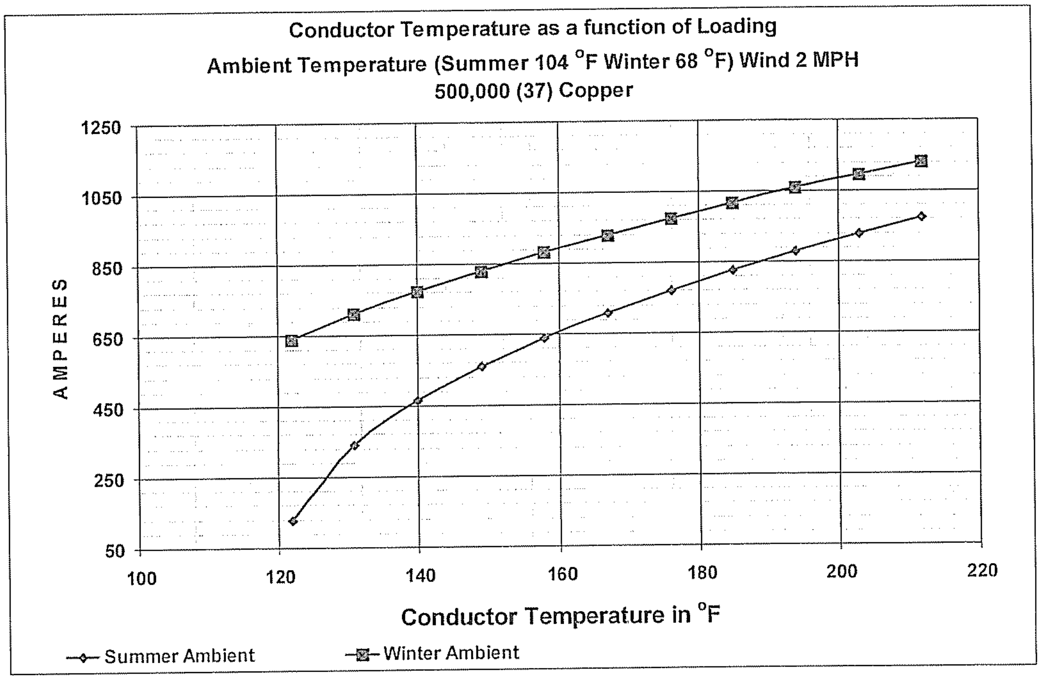

Conductor Temperature as a function of Loading
Ambient Temperature (Summer 104 °F Winter 68 °F) Wind 2 MPH
250,000 (19) Copper

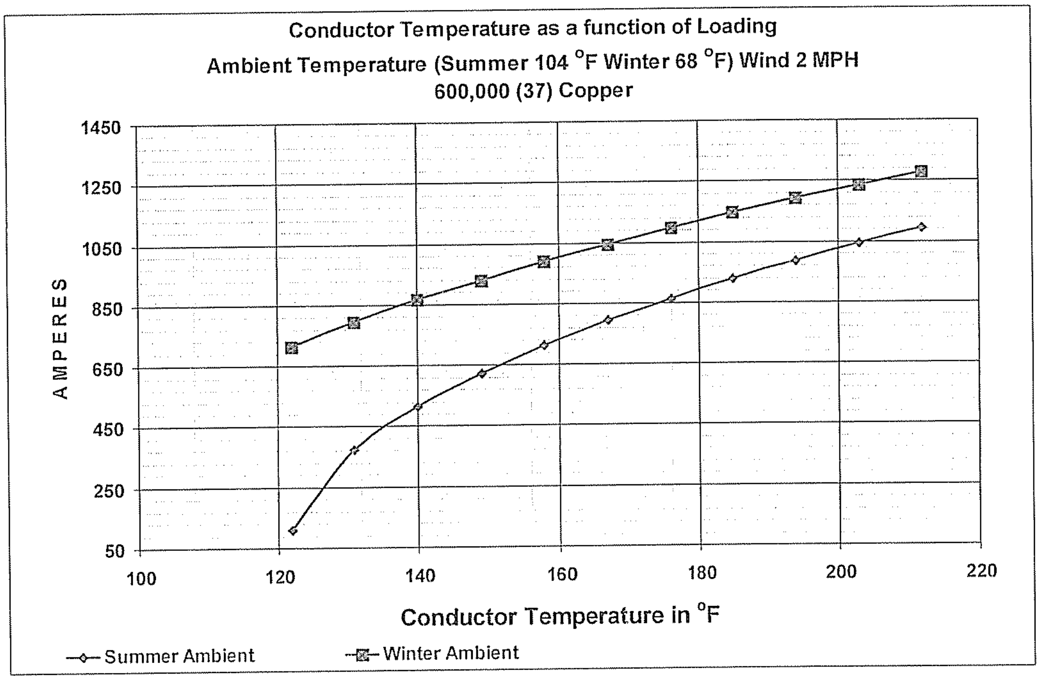


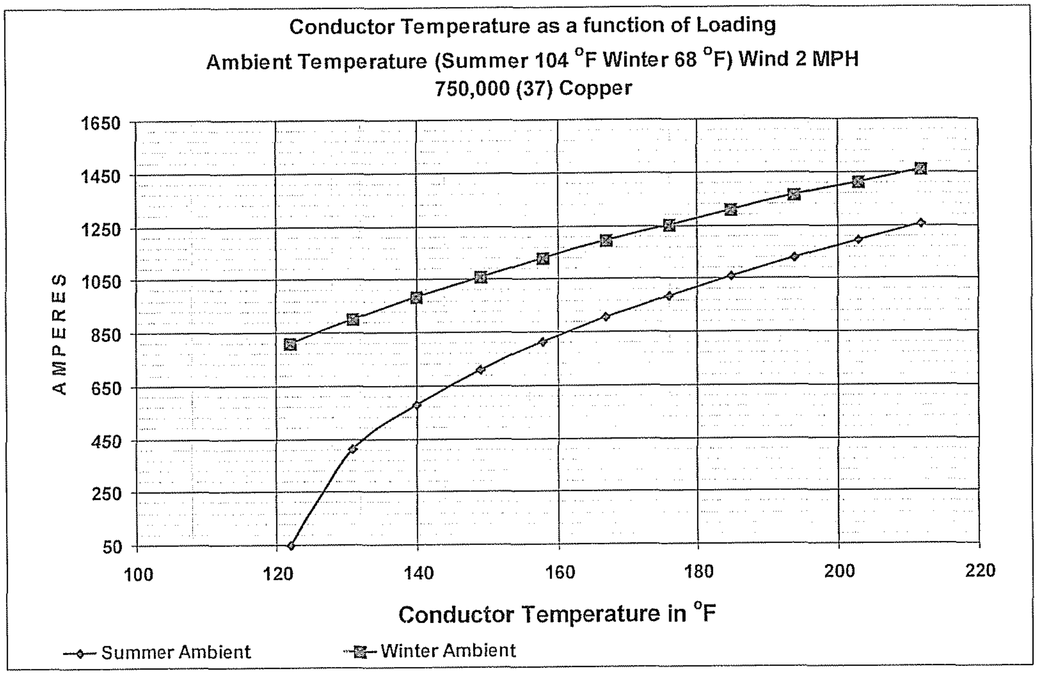
Conductor Temperature as a function of Loading
Ambient Temperature (Summer 104 °F Winter 68 °F) Wind 2 MPH
300,000 (19) Copper



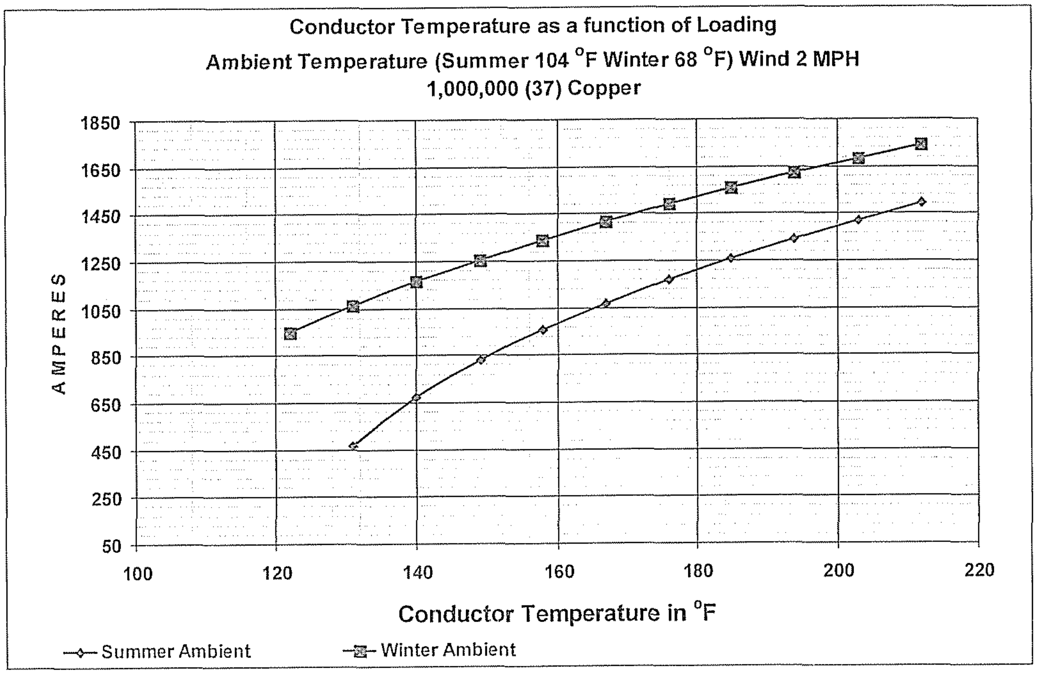
Conductor Temperature as a function of Loading
Ambient Temperature (Summer 104 °F Winter 68 °F) Wind 2 MPH
350,000 (19) Copper


Conductor Temperature as a function of Loading
Ambient Temperature (Summer 104 °F Winter 68 °F) Wind 2 MPH
500,000 (37) Copper


Conductor Temperature as a function of Loading
Ambient Temperature (Summer 104 °F Winter 68 °F) Wind 2 MPH
600,000 (37) Copper

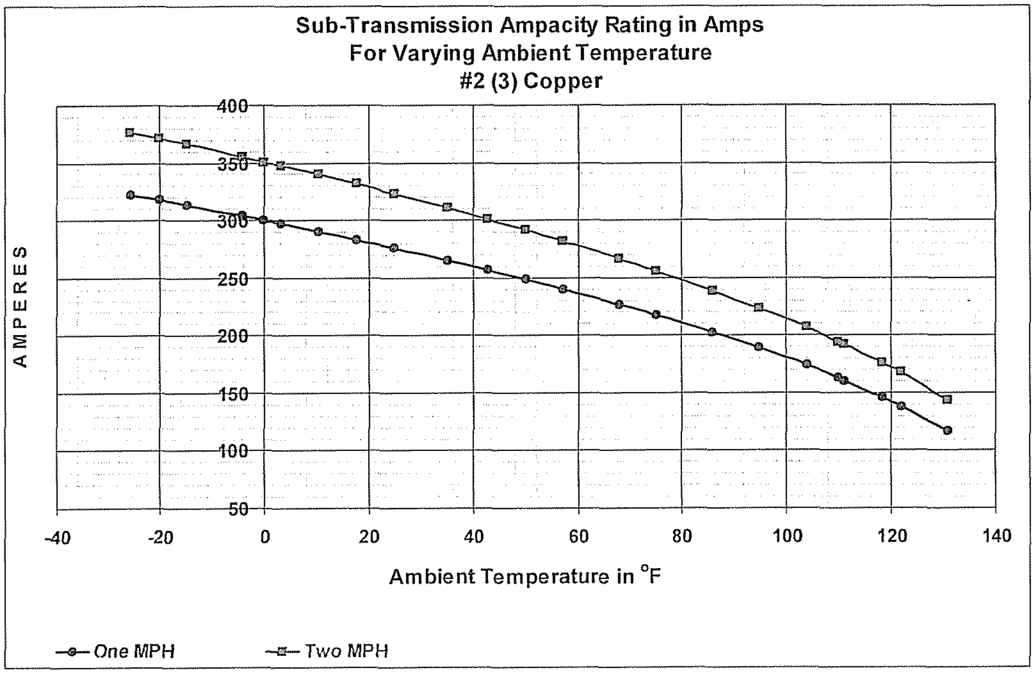


Conductor Temperature as a function of Loading
Ambient Temperature (Summer 104 °F Winter 68 °F) Wind 2 MPH
750,000 (37) Copper

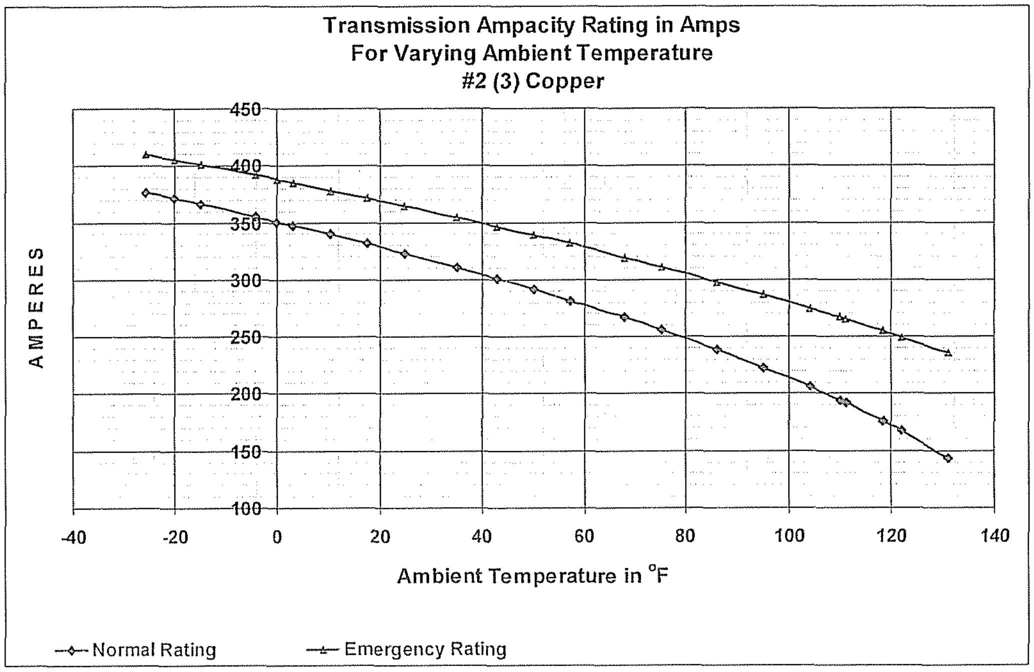


Conductor Temperature as a function of Loading
Ambient Temperature (Summer 104 °F Winter 68 °F) Wind 2 MPH
1,000,000 (37) Copper

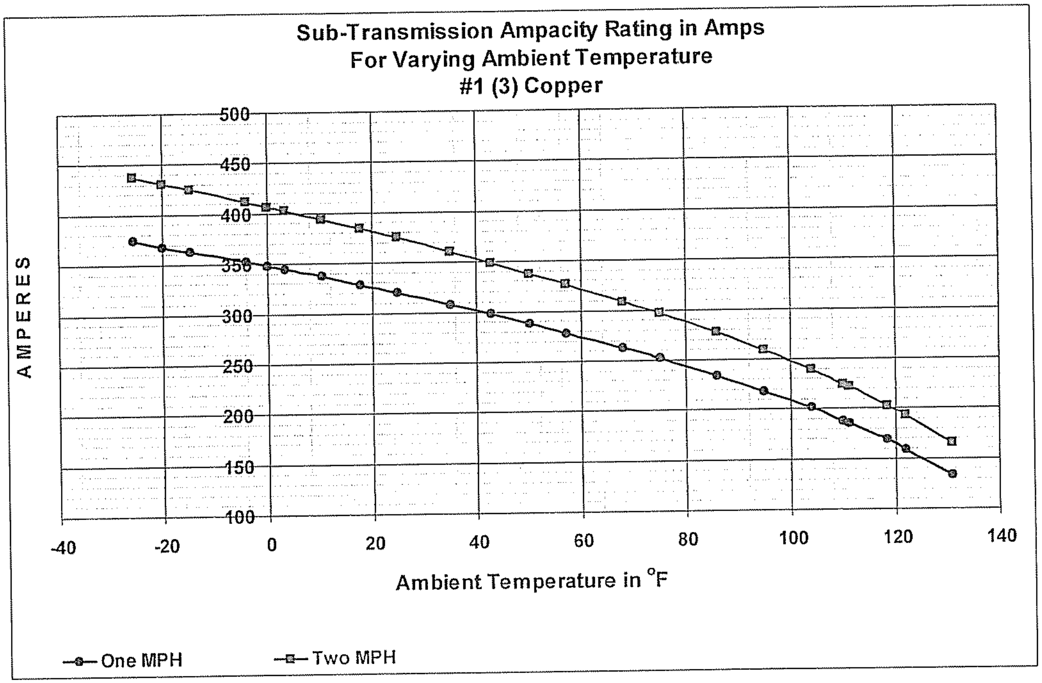
Appendix I	Plots of Normal and Emergency Capability as a function of Ambient Temperature **Copper Conductors**

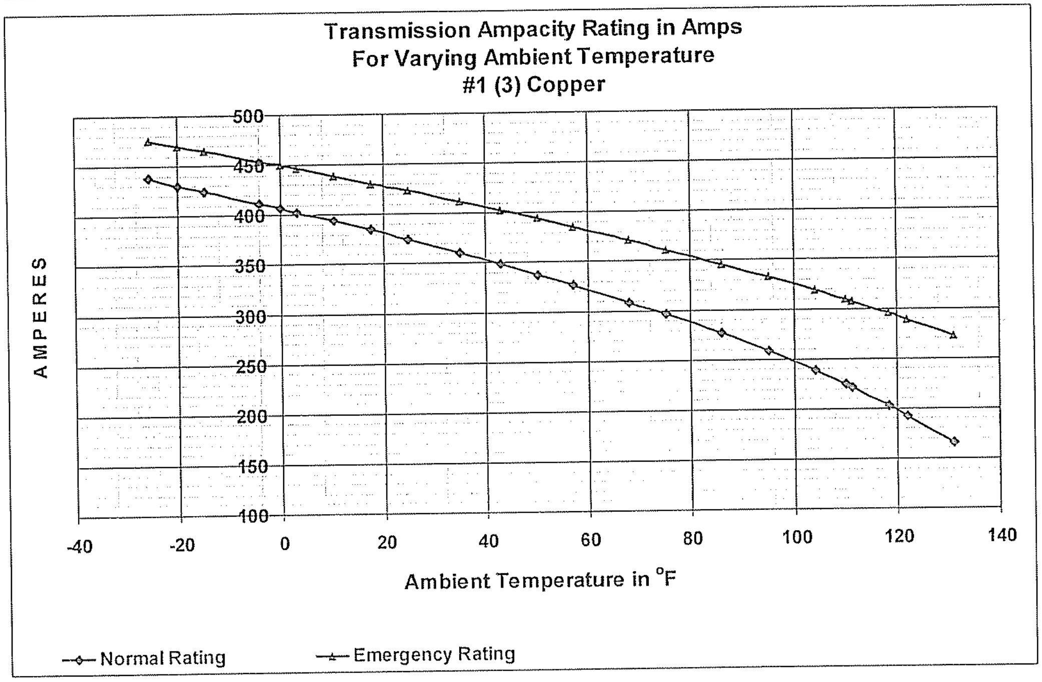


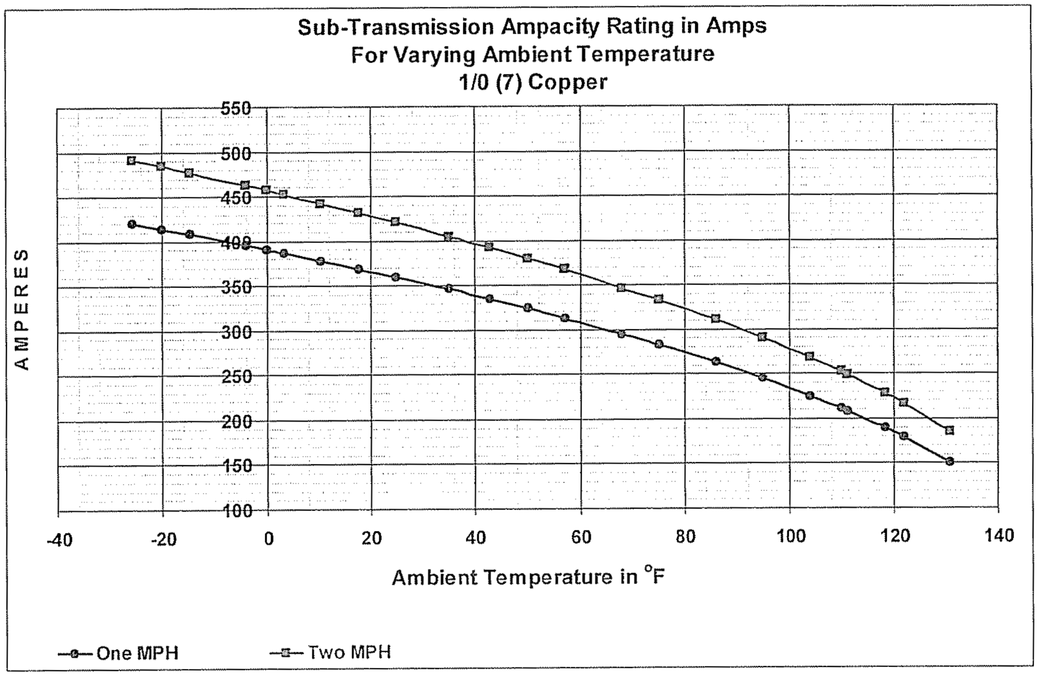
Sub-Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
#2 (3) Copper

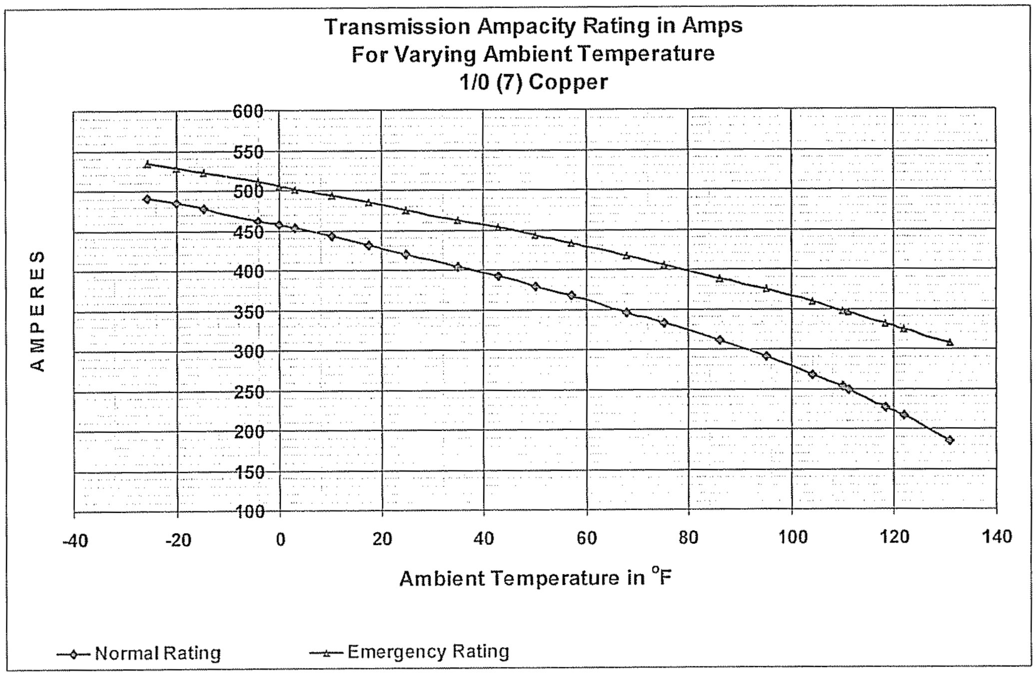


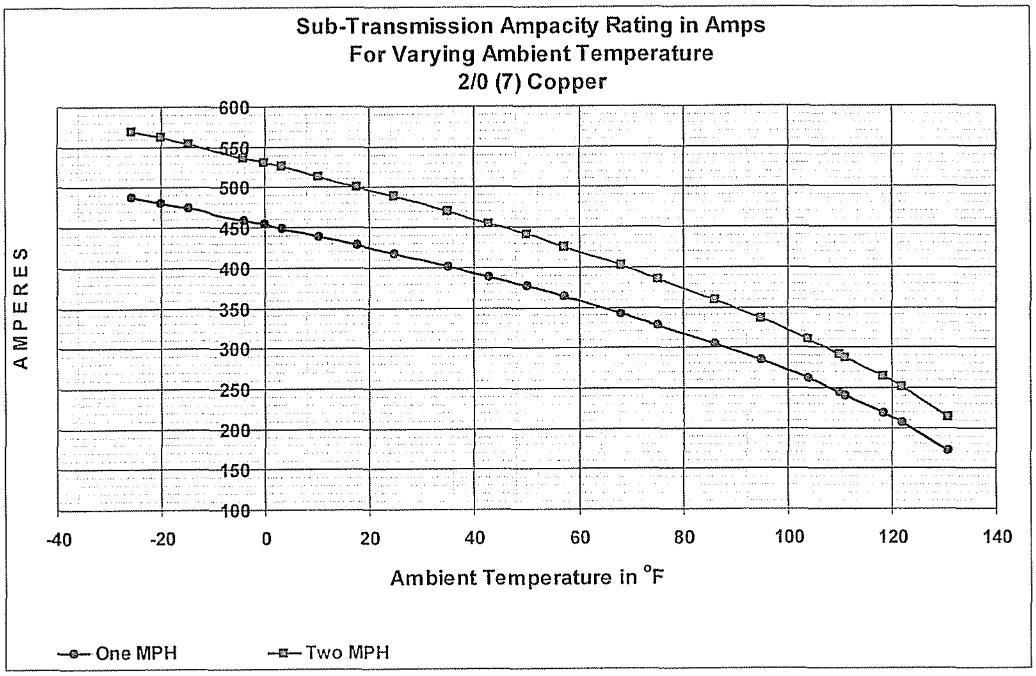
Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
#2 (3) Copper

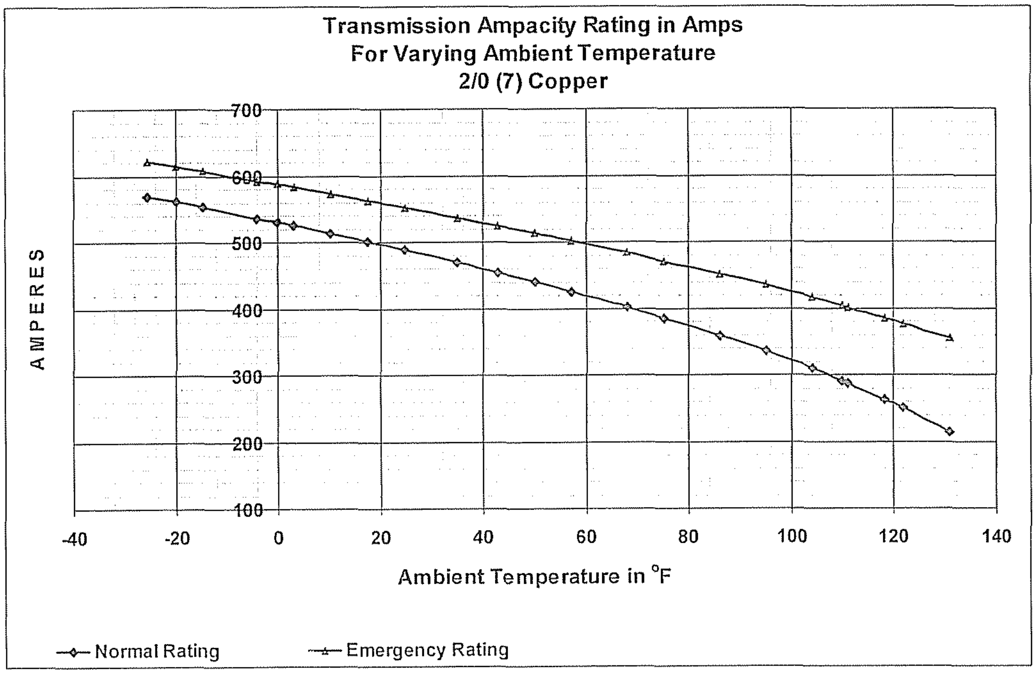

Sub-Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
#1 (3) Copper
AMPERES
500
450
400
350
300
250
200
150
100
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
One MPH
Two MPH


Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
#1 (3) Copper
AMPERES
500
450
400
350
300
250
200
150
100
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
Normal Rating
Emergency Rating

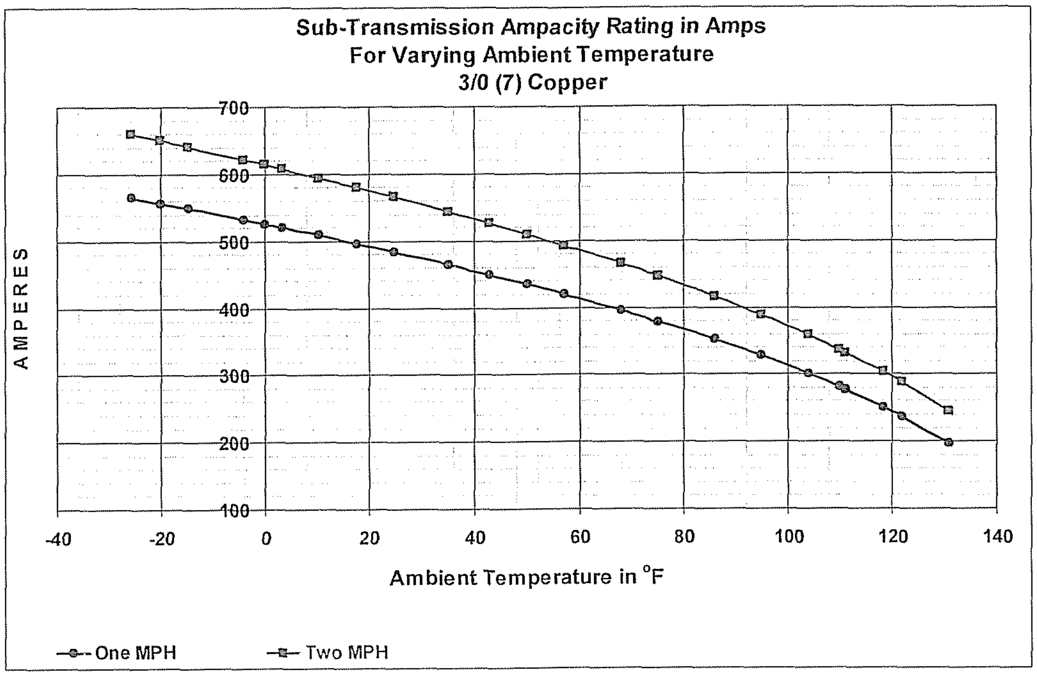

Sub-Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
1/0 (7) Copper
AMPERES
550
500
450
400
350
300
250
200
150
100
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
One MPH
Two MPH

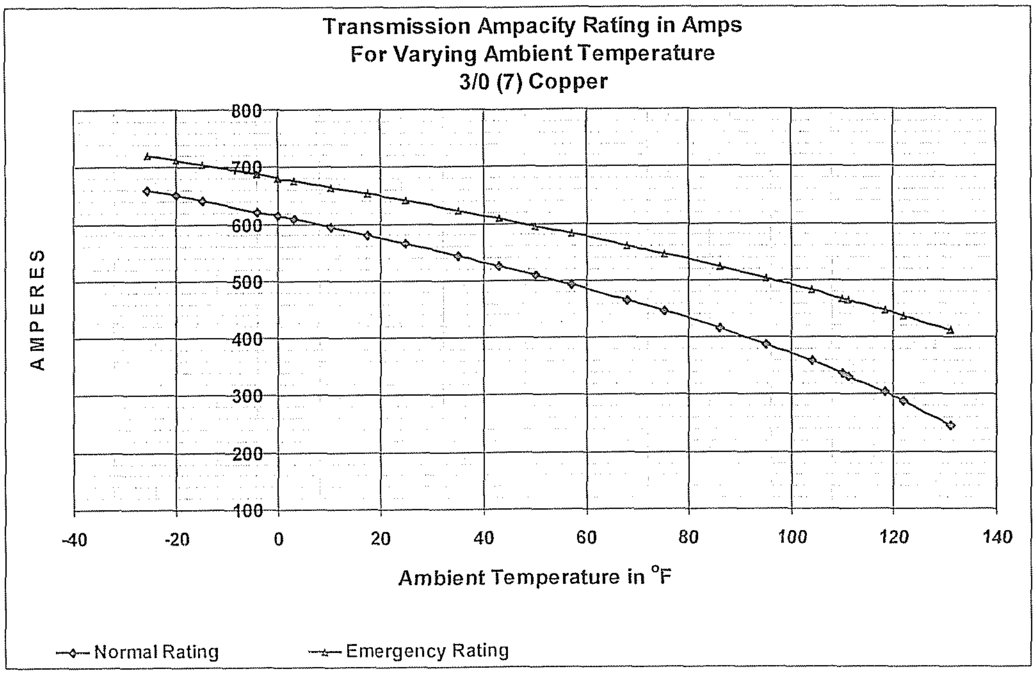

Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
1/0 (7) Copper
AMPERES
600
550
500
450
400
350
300
250
200
150
100
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
Normal Rating
Emergency Rating

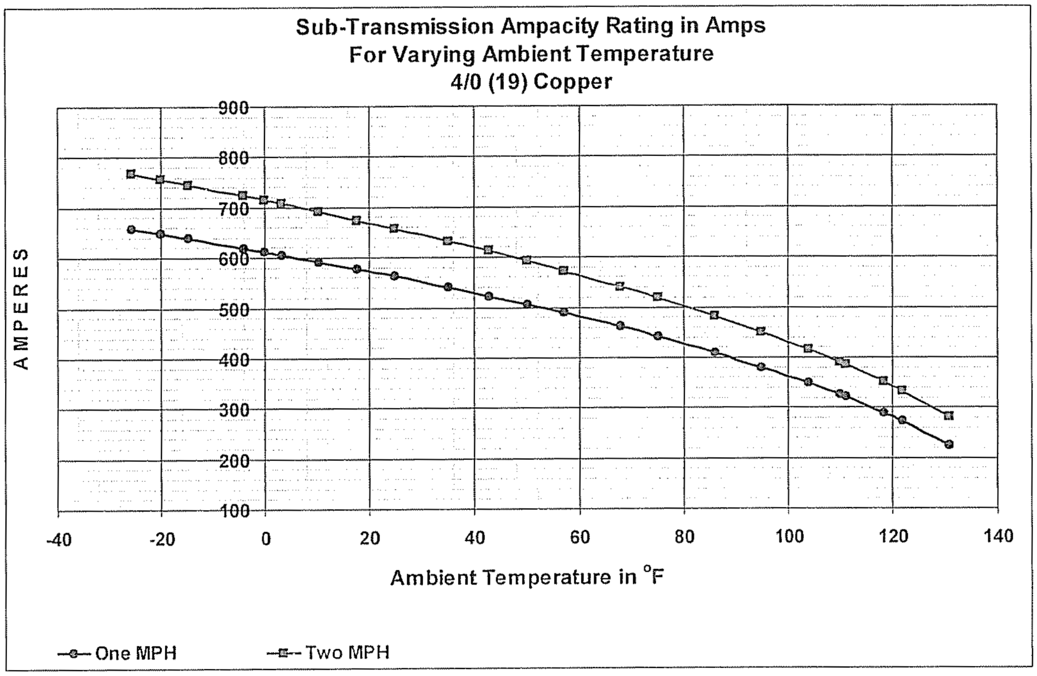

Sub-Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
2/0 (7) Copper
AMPERES
600
550
500
450
400
350
300
250
200
150
100
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
One MPH
Two MPH

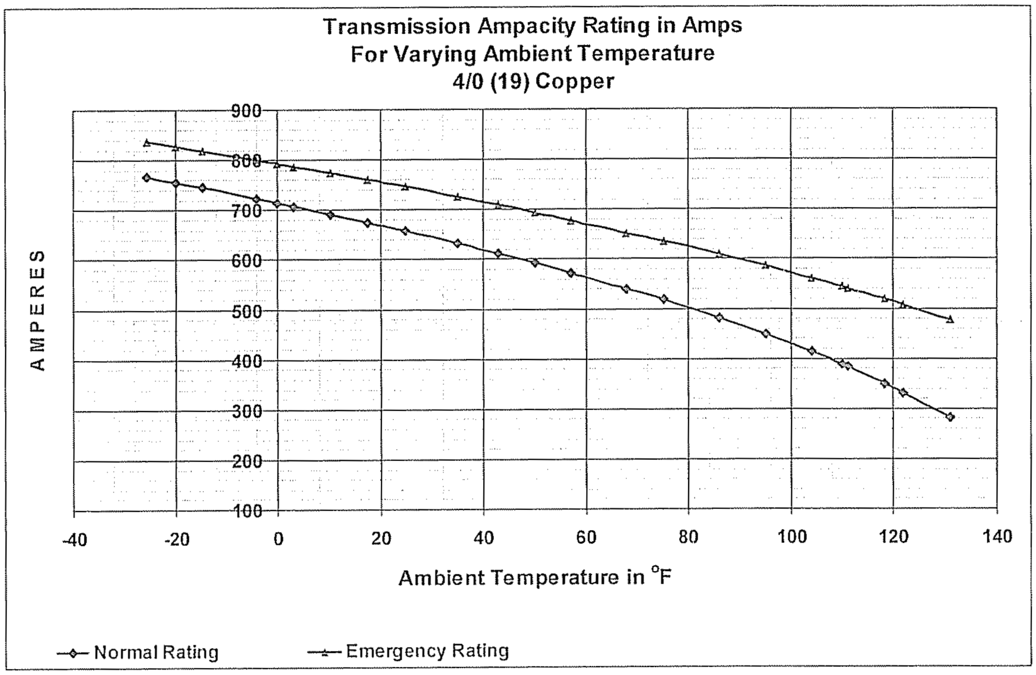

Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
2/0 (7) Copper
AMPERES
700
600
500
400
300
200
100
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
Normal Rating
Emergency Rating

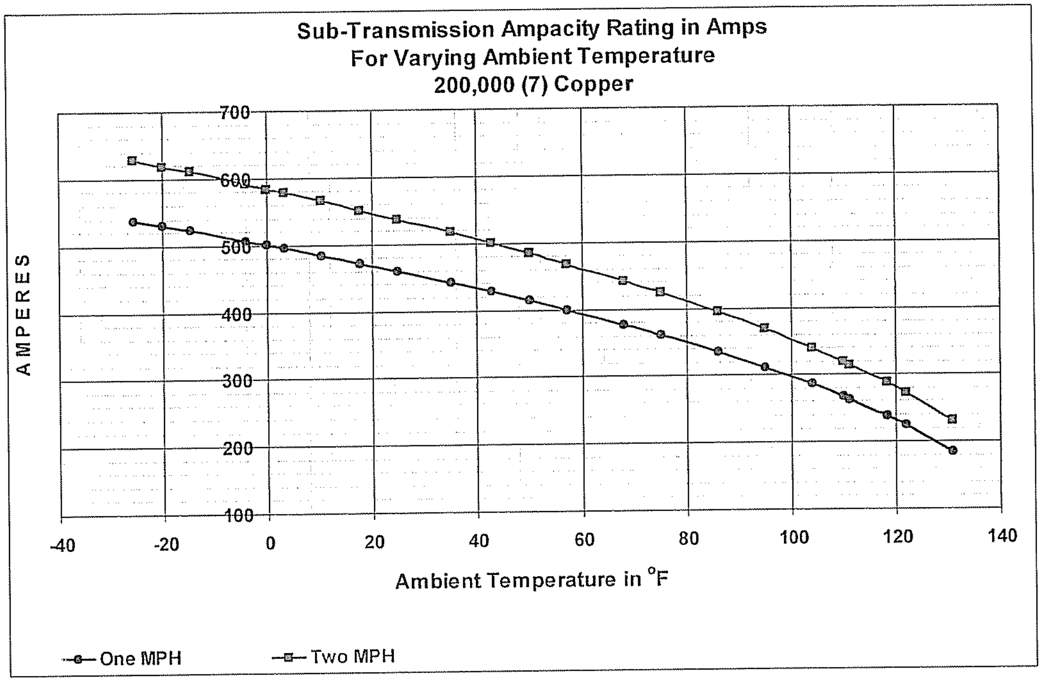
CAUTION: Printed copies of this document are uncontrolled and may be obsolete.
Always check for the latest revision prior to use.

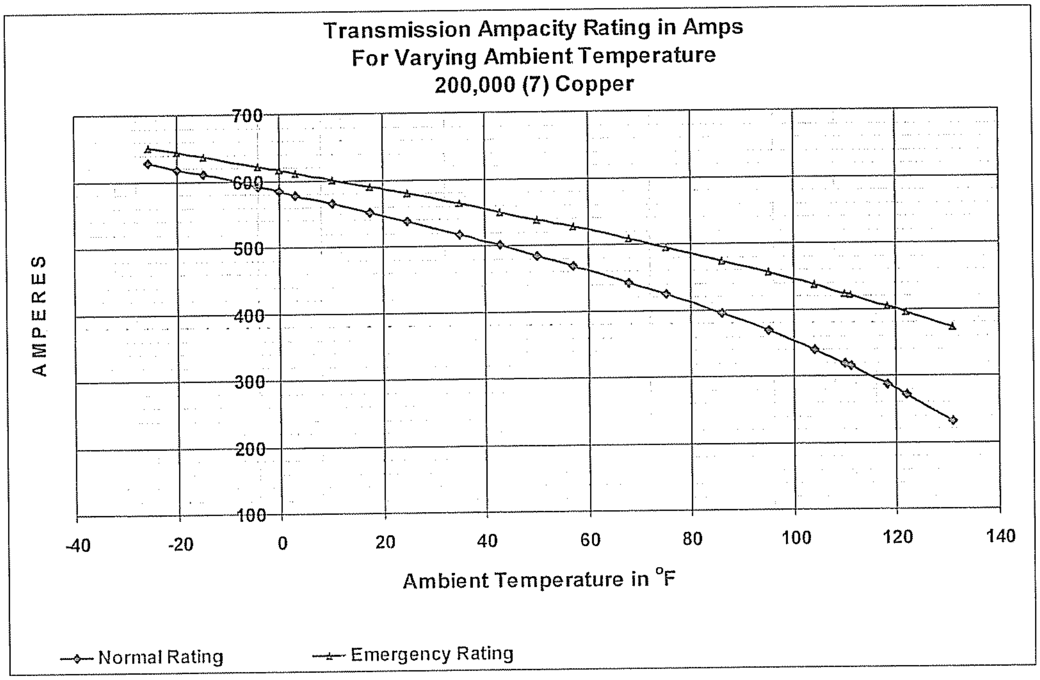





Sub-Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
4/0 (19) Copper
AMPERES
900
800
700
600
500
400
300
200
100
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
One MPH
Two MPH


Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
4/0 (19) Copper
AMPERES
900
800
700
600
500
400
300
200
100
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
Normal Rating
Emergency Rating


Sub-Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
200,000 (7) Copper
AMPERES
700
600
500
400
300
200
100
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
One MPH
Two MPH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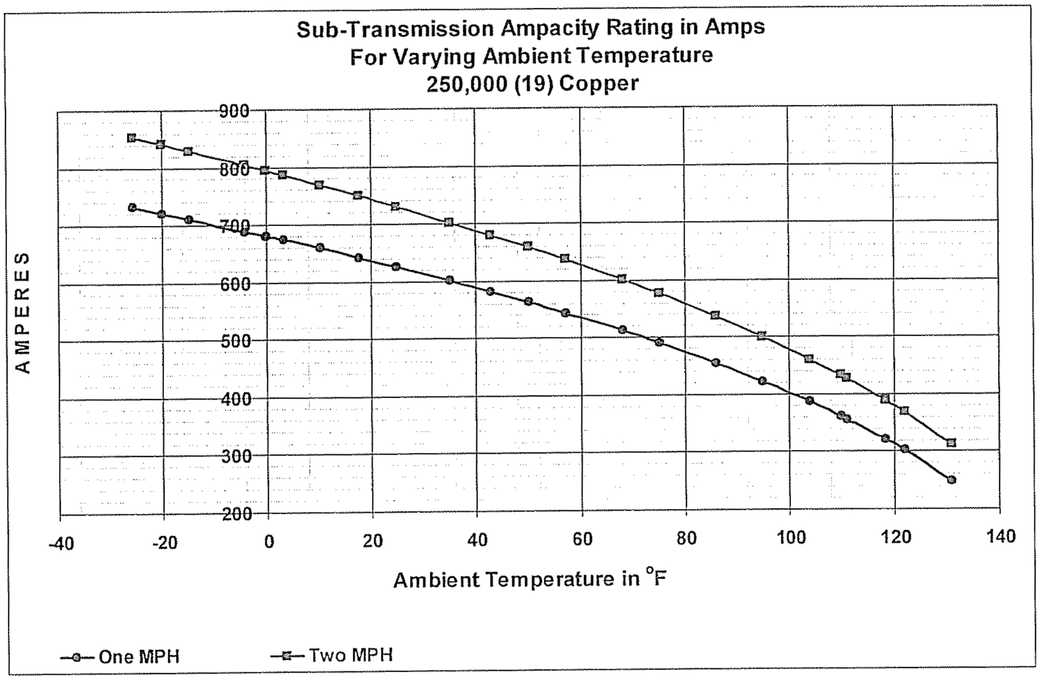
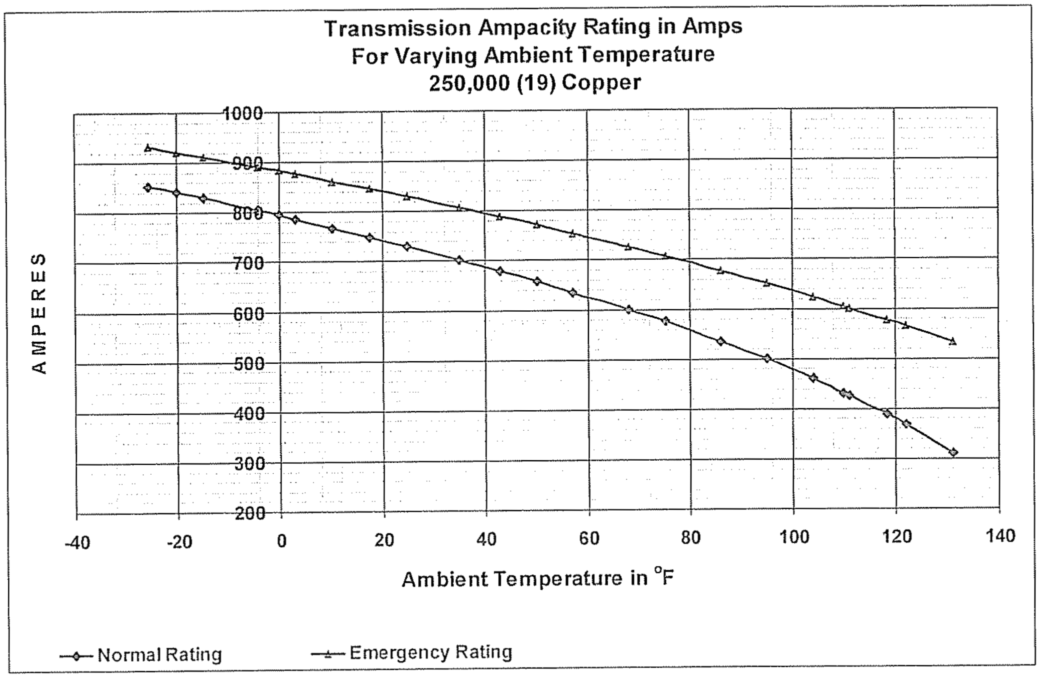
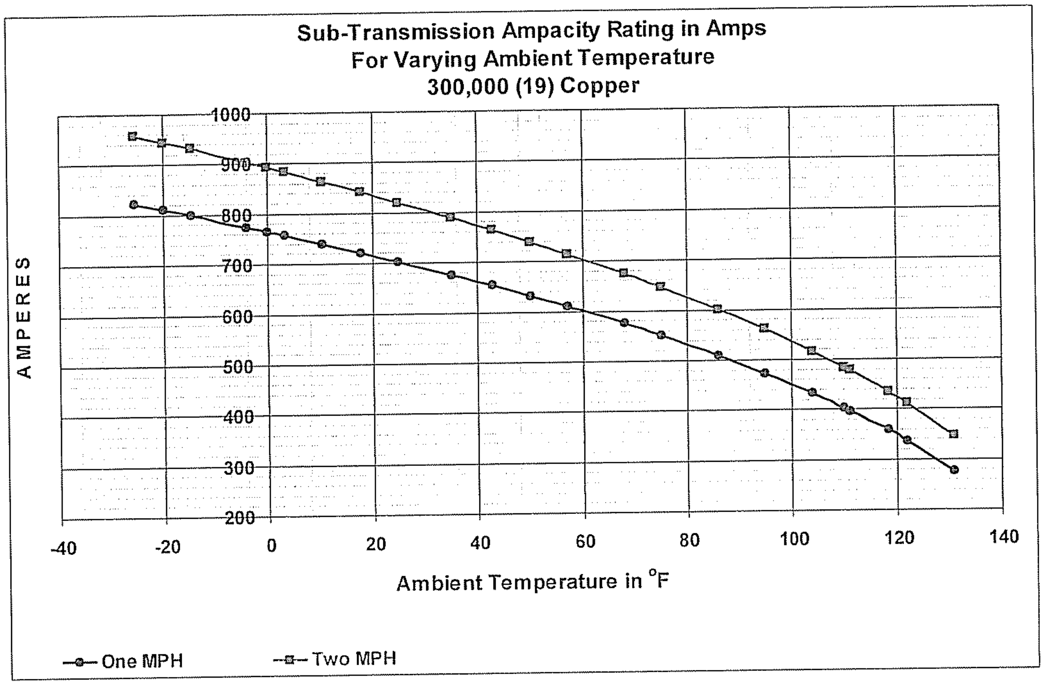
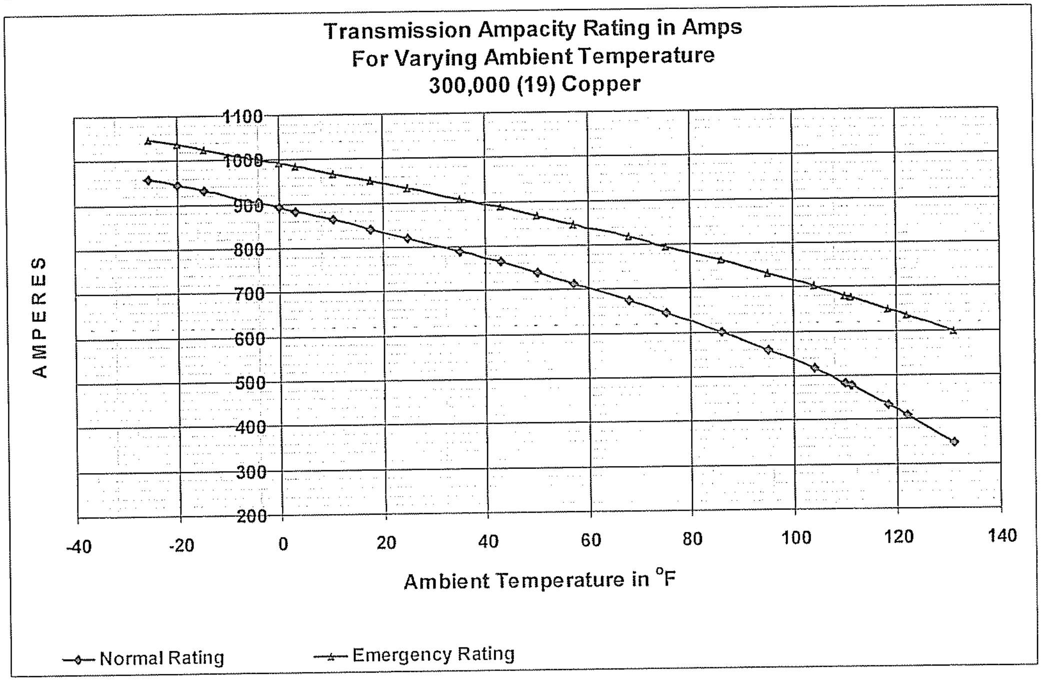
For Varying Ambient Temperature
200,000 (7) Copper
AMPERES
700
600
500
400
300
200
100
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
Normal Rating
Emergency Rating


Sub-Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
250,000 (19) Copper
AMPERES
900
800
700
600
500
400
300
200
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
One MPH
Two MPH


Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
250,000 (19) Copper
AMPERES
1000
900
800
700
600
500
400
300
200
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
Normal Rating
Emergency Rating


Sub-Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
300,000 (19) Copper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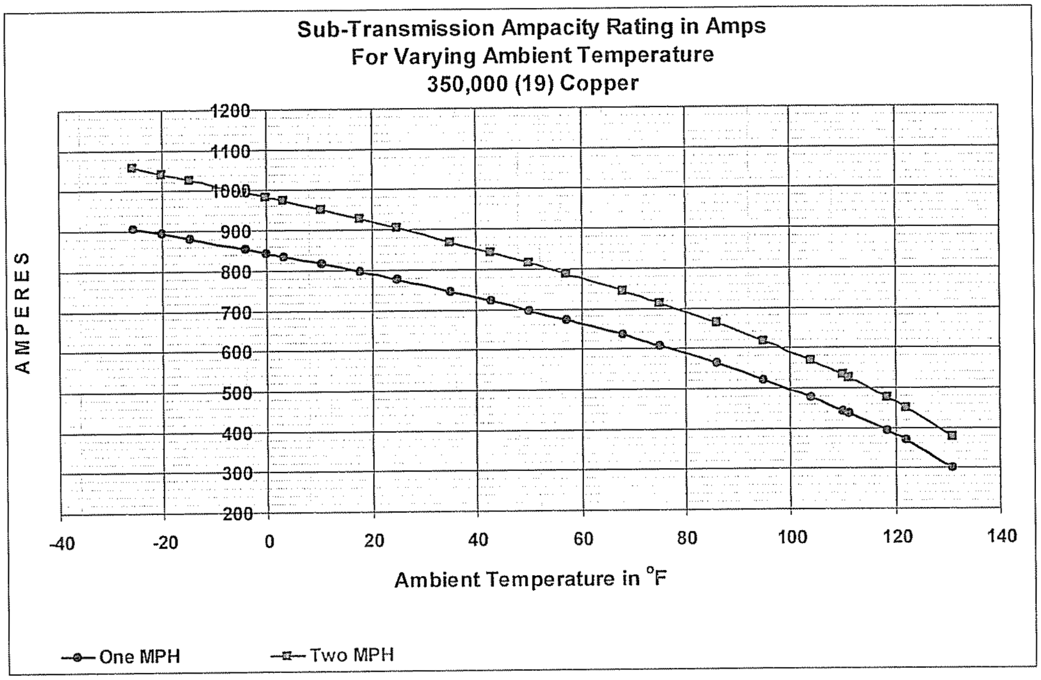
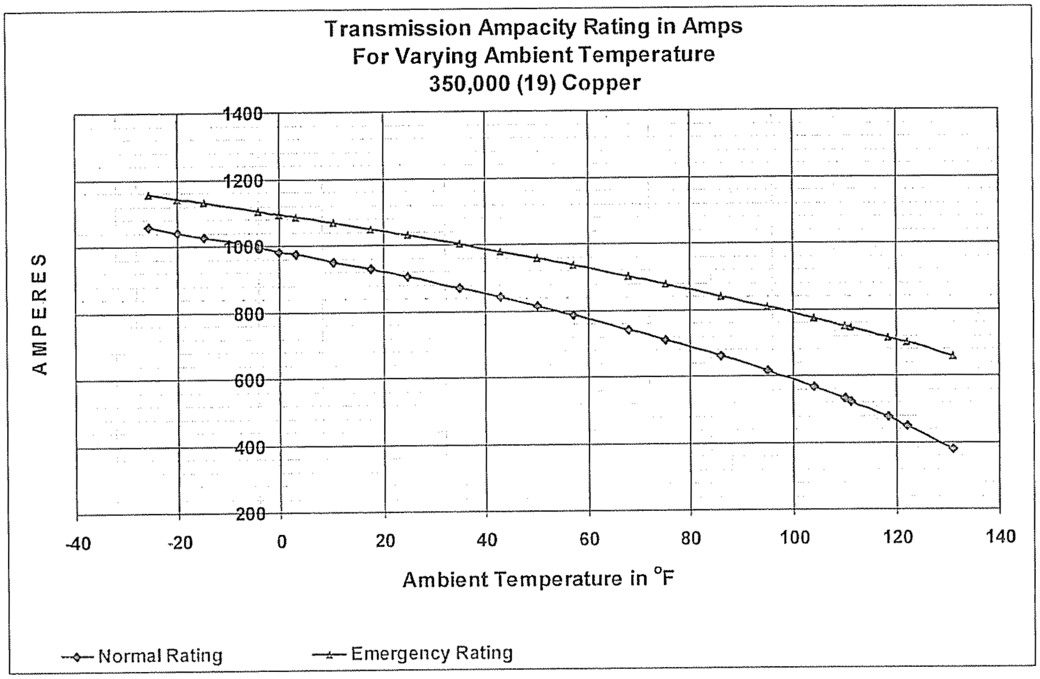
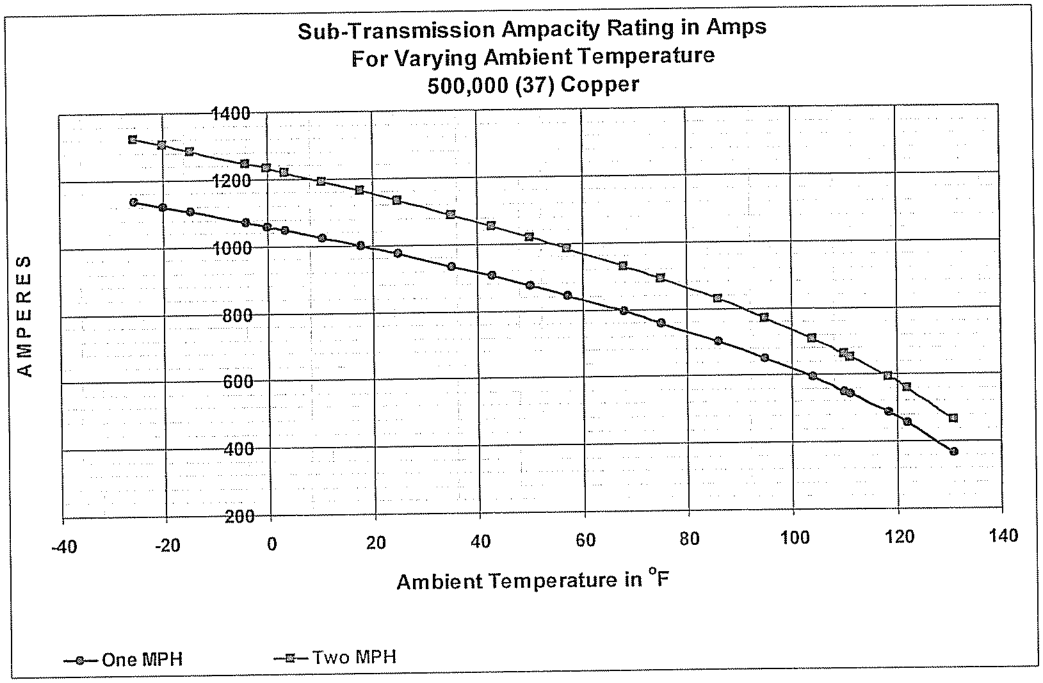
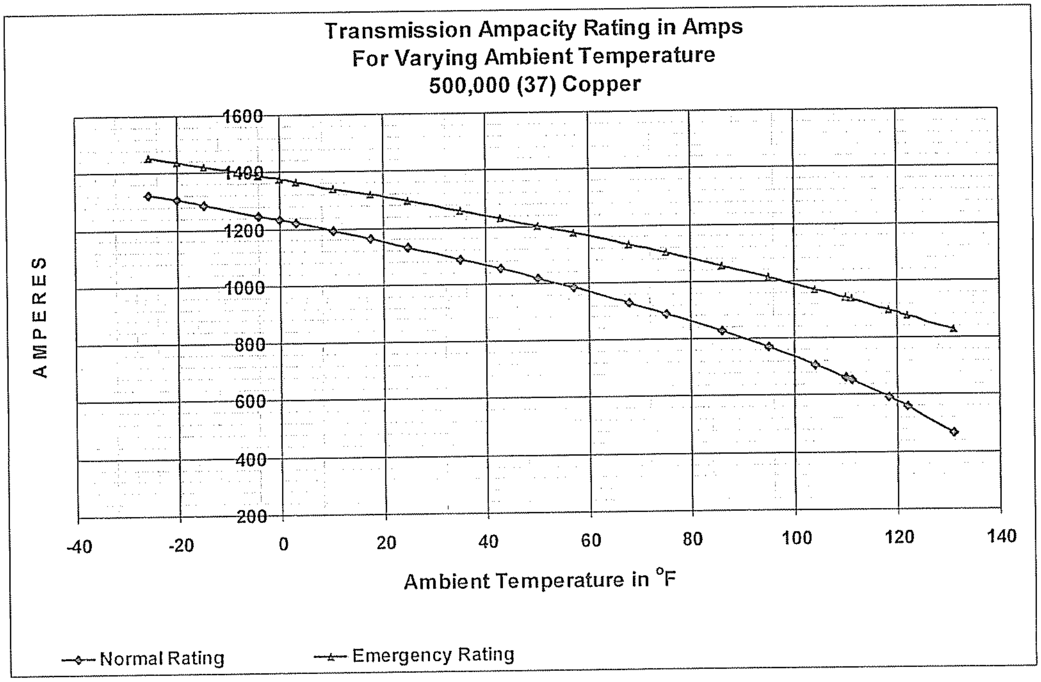
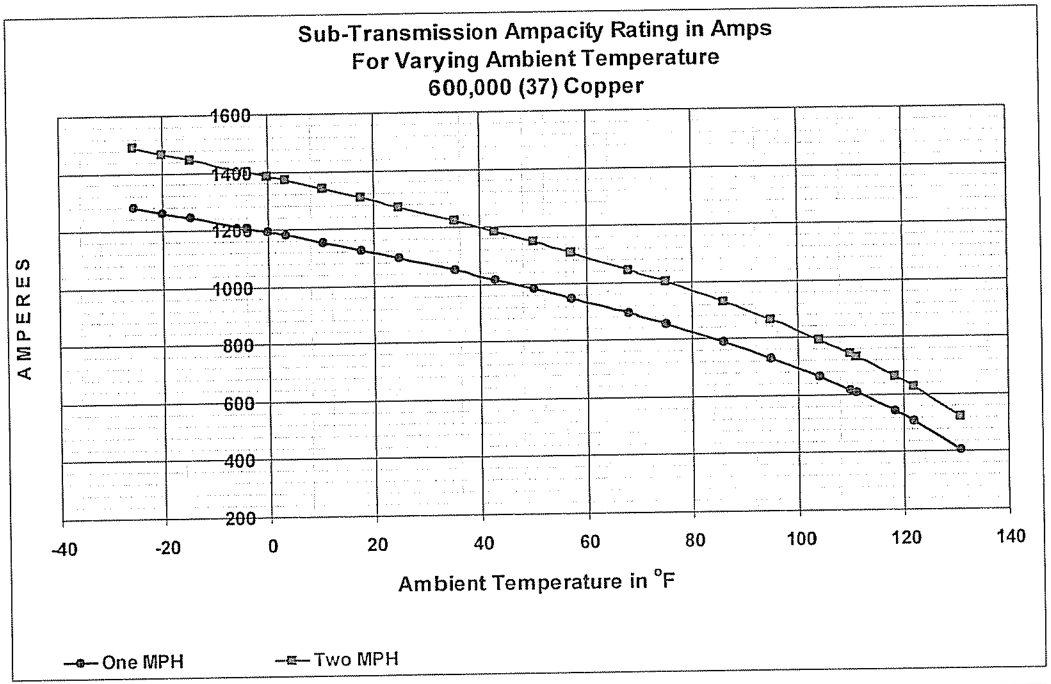
For Varying Ambient Temperature
300,000 (19) Copper

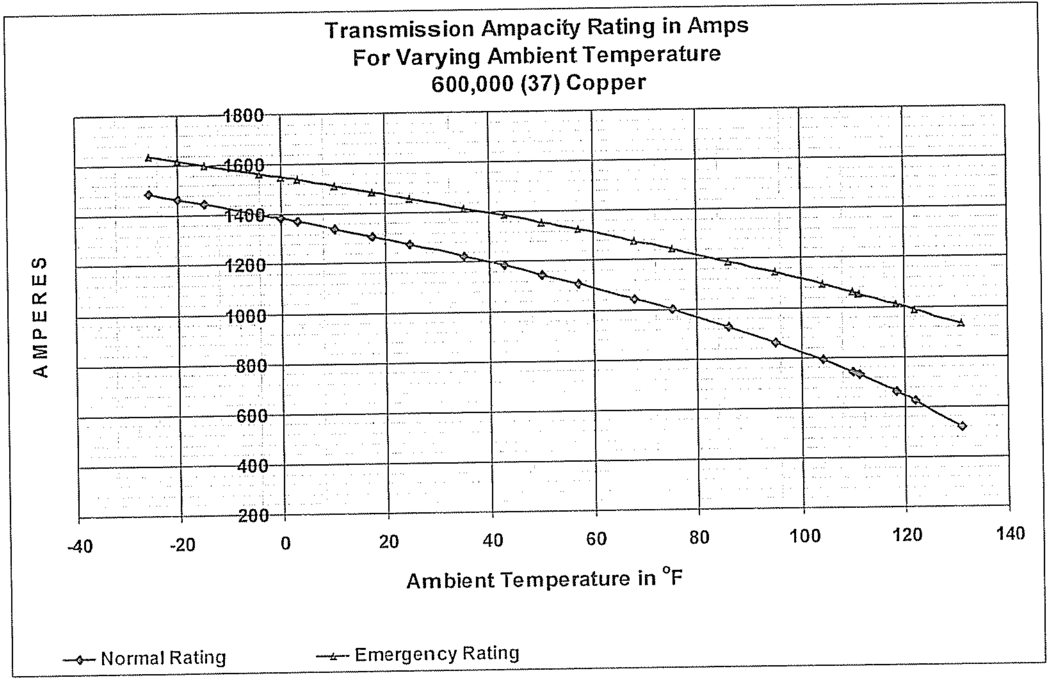

Sub-Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
350,000 (19) Copper
AMPERES
1200
1100
1000
900
800
700
600
500
400
300
200
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
One MPH
Two MPH

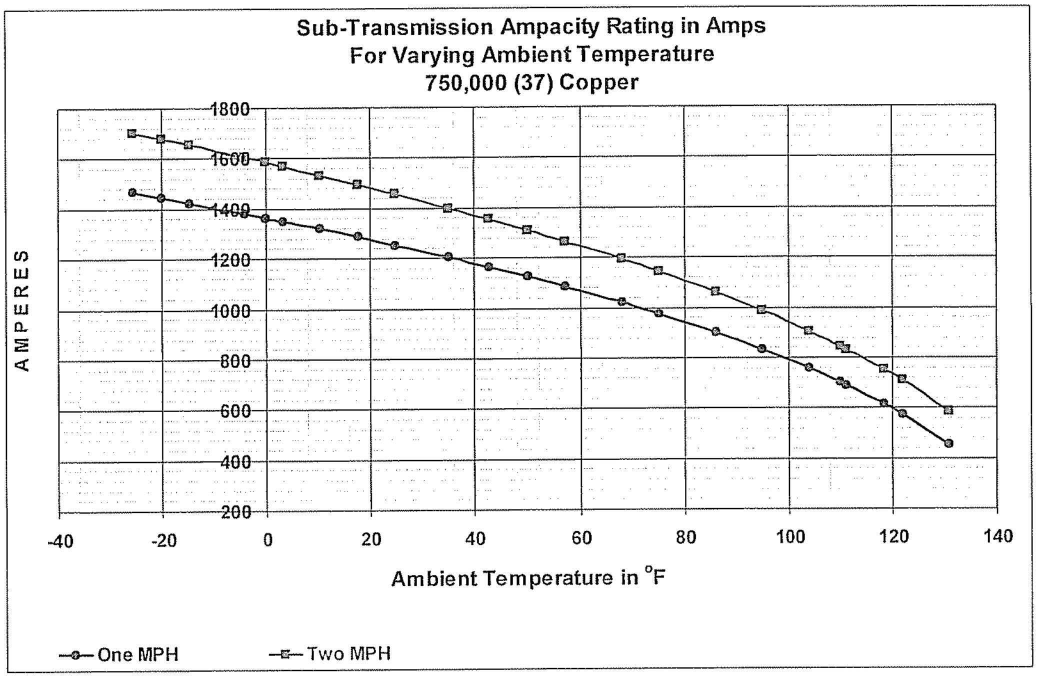

Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
350,000 (19) Copper
AMPERES
1400
1200
1000
800
600
400
200
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
Normal Rating
Emergency Rating

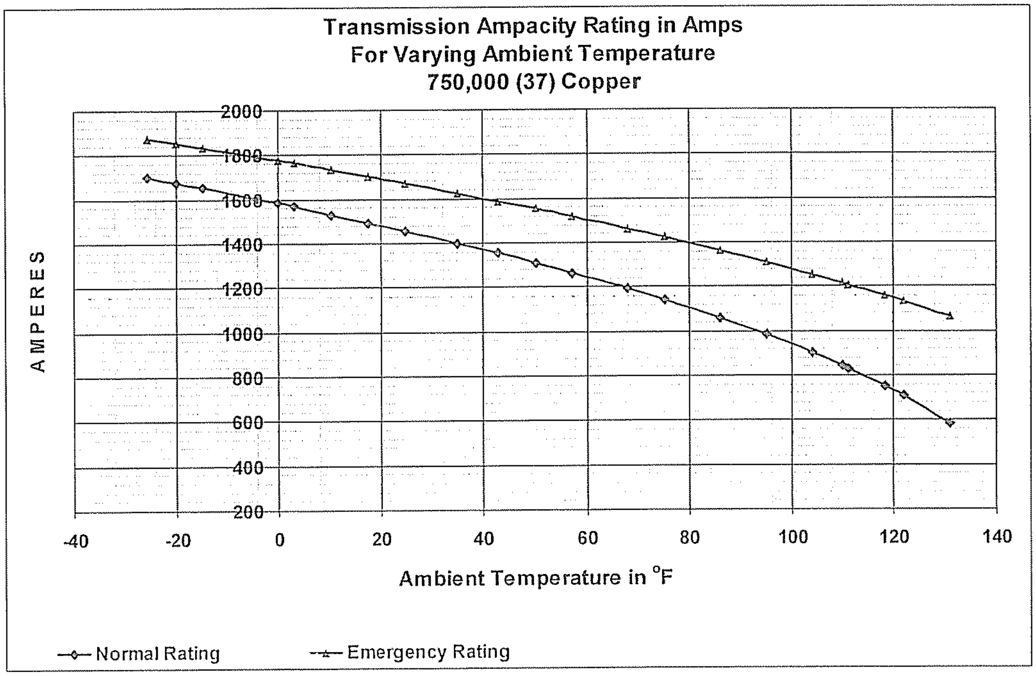

Sub-Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
500,000 (37) Copper
AMPERES
1400
1200
1000
800
600
400
200
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
One MPH
Two MPH

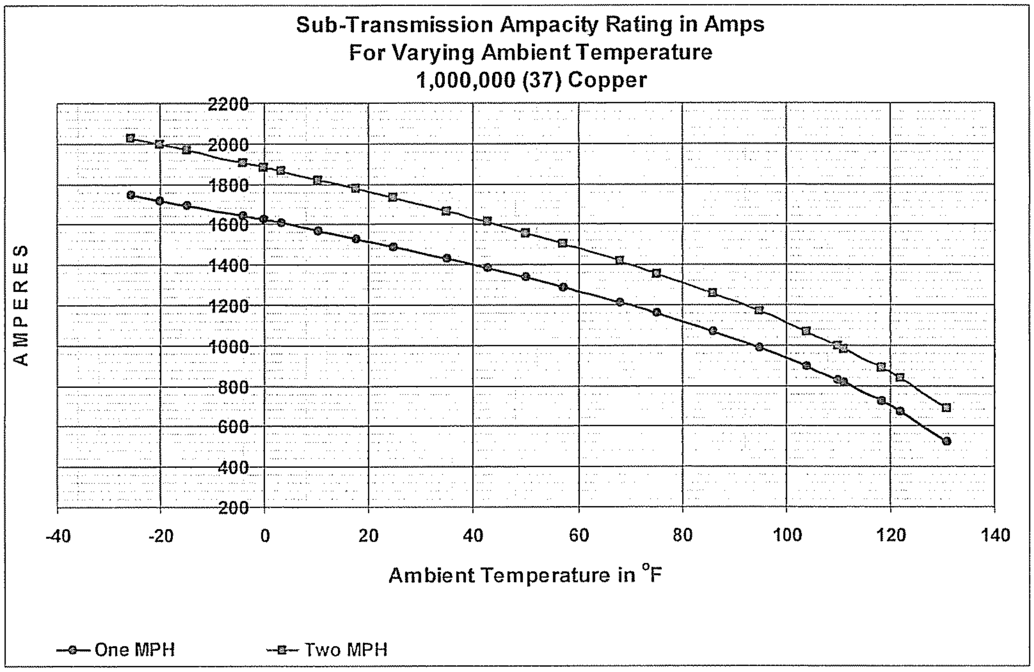

Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
500,000 (37) Copper
AMPERES
1600
1400
1200
1000
800
600
400
200
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
Normal Rating
Emergency Rating

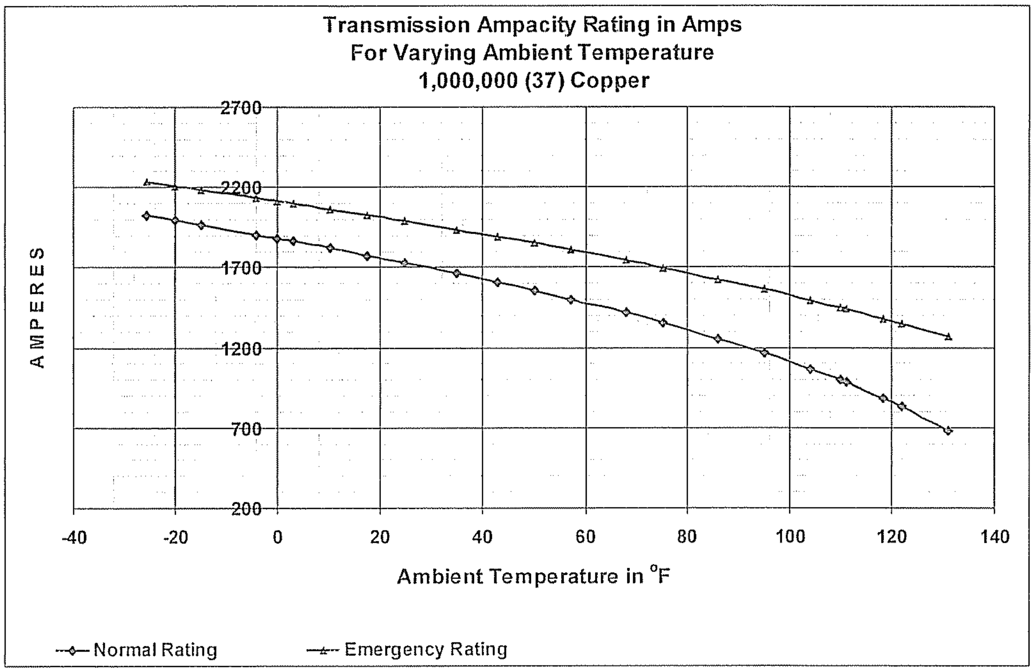

Sub-Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
600,000 (37) Copper
AMPERES
1600
1400
1200
1000
800
600
400
200
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
One MPH
Two MPH


Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
600,000 (37) Copper
AMPERES
1800
1600
1400
1200
1000
800
600
400
200
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
Normal Rating
Emergency Rating


Sub-Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
750,000 (37) Copper
AMPERES
1800
1600
1400
1200
1000
800
600
400
200
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
One MPH
Two MPH


Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
750,000 (37) Copper
AMPERES
2000
1800
1600
1400
1200
1000
800
600
400
200
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
Normal Rating
Emergency Rating


Sub-Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
1,000,000 (37) Copper
AMPERES
2200
2000
1800
1600
1400
1200
1000
800
600
400
200
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
One MPH
Two MPH


Transmission Ampacity Rating in Amps
For Varying Ambient Temperature
1,000,000 (37) Copper
AMPERES
2700
2200
1700
1200
700
200
-40
-20
0
20
40
60
80
100
120
140
Ambient Temperature in °F
Normal Rating
Emergency Rating

Kentucky Power Company

REQUEST

Please supply a copy of the final report justifying the proposed facilities if different from filng Exhibit 12.

RESPONSE

The final report was included as Exhibit 12 in the Application filing.

Kentucky Power Company

REQUEST

If the limiting condition is voltage driven, please supply the transmission to sub-transmission transformer no load tap settings, no load tap capabilities, hold voltages, and tap changer ranges. Please also supply the same information for the sub-transmission/lower voltage transformers.

RESPONSE

The attachment provides the transmission and subtransmission transformer tap settings and the tap ranges.

Station Name	Transformer Manufacturer	Primary Voltage	Secondary Voltage	Tertiary Voltage	MVA Rating	Transformer Tap Setting	HV Taps Available	LV Taps Available	TV Taps Available
BECKHAM	ME	138	34		25	C - 135600-36200	1-142380 2-138990 3-135600 4-132210 5-128820	plus/minus 10% LTC	
BLUE GRASS	WE	69	12		7.5	3 - 68800-13090	1-72400 2-70600 3-68800 4-67000 5-65200	plus/minus 10% LTC	
BONNYMAN	WE	69	34		25	3 - 68800-36200	1-72240 2-70520 3-68800 4-67080 5-65360	plus/minus 10% LTC	
BULAN	ME	69	12		7.5	C - 68800-13090	1-72240 2-70520 3-68800 4-67080 5-65360	plus/minus 10% LTC	
COLLIER	ME	69	34		25	C - 68800-36200	1-72240 2-70520 3-68800 4-67080 5-65360	plus/minus 10% LTC	
COMBS	WE	69	12		7.5	3 - 68800-13090	1-72400 2-70600 3-68800 4-67000 5-65200	plus/minus 10% LTC	
DAISY	AC	69	12		3.75	A - 70600-13090	A-70600 B-68800 C-67000 D-65200 E-63400	None	ISIS shows tap B
ENGLE	HD	69	34.5		20	4 - 67080-36200	1-72240 2-70520 3-68800 4-67080 5-65360	None	
HADDIX	GE	69	34		25	C - 68800-36200	1-72400 2-70600 3-68800 4-67000 5-65200	plus/minus 10% LTC	
HAZARD	PT	138	69	12	50	C - 135400/69500-13090	1-142200 2-138800 3-135400 4-132000 5-128600	None	None
HAZARD	ME	138	69	12	130	C - 135400/69500-13090	1-142200 2-138800 3-135400 4-132000 5-128600	None	None
HAZARD	WE	161	138	34	135	34650	1-161800 2-157900 3-154000	1-139850 2-135950 3-132000	1-34650 2-33800 3-33000 4-32800
HAZARD	KE	138	34		30	D - 132210-36200	1-142360 2-138990 3-135600 4-132210 5-128820	plus/minus 10% LTC	
HAZARD	HDE	34	12		7.5	1 - 36120-13090	1-3612 2-35260 3-34400 4-33540 5-32680	None	
INDEX	ME	69	12		7.5	D - 67000-13090	1-72400 2-70600 3-68800 4-67000 5-65200	plus/minus 10% LTC	
JACKSON	AC	69	12		5	C - 67000-13090	1-70600 2-68800 3-67000 4-65200 5-63400	None	
JACKSON	WE	69	12		7.5	D - 67000-13090	1-72400 2-70600 3-68800 4-67000 5-65200	plus/minus 10% LTC	
JEFF	GE	69	12		5	3 - 67000-12470	1-70600 2-68800 3-67000 4-65200 5-63400	None	
LESLIE	FP	161	69	12	90	2 - 160925/69500-13090	1-164850 2-160925 3-157000 4-153075 5-149150	None	
LESLIE	KUHL	69	34		24	5 - 65360 - 36200	1-72240 2-70520 3-68800 4-67080 5-65360	None	
MAYKING	WAU	69	12		20	B - 70520-13090	1-72240 2-70520 3-68800 4-67080 5-65360	None	
SHAMROCK	WE	69	34		10.5	2 -72,600-37600	1-72400 2-70600 3-68800 4-67000 5-65200	plus/minus 10% LTC	bank upgraded
SLEMP	ME	69	34		10.5	C - 70725 - 36200	1-72450 2-70725 3-69000 4-67275 5-65550	plus/minus 10% LTC	
SLEMP	KE	69	34		20	C - 68800-36200	1-72240 2-70520 3-68800 4-67080 5-65360	None	
STINNETT	GE	161	34	12	22.4	3 - 156975/34500-7200	1-169050 2-165025 3-161000 4-156975 5-152950	None	Vendor changed to GE
STINNETT	MEI	161	34	7.2	14.9	3 - 154000/34000-7200	1-162400 2-158200 3-154000 4-149800 5-145600	None	
TOPMOST	WE	138	12		8.4	3 - 135600-13090	A-142380 B-138990 C-135600 D-132210 E-128820	plus/minus 10% LTC	Vendor changed to Kuhlman
VICCO	HD	138	34		30	3 - 135600 - 36200	1-142375 2-139000 3-135600 4-132200 5-128825	plus/minus 10% LTC	
WHITESBURG	ME	69	12		9.375	C - 68800-13090	1-72400 2-70600 3-68800 4-67000 5-65200	plus/minus 10% LTC	
WHITESBURG	KE	69	12		9.375	C - 68800-13090	1-72240 2-70520 3-68800 4-67080 5-65360		vendor changed to Kuhlman
Transmission									

Kentucky Power Company

REQUEST

If the limiting condition is voltage driven, please supply the generator minimum VAR capability, maximum VAR capacity, MW size, hold voltages, and power factor for generators within the Hazard load area or within 25 miles of the Soft Shell and Hazard 138kV substations that are on the 138kV or lower voltage power system. As part of your response, please locate these facilities on a geographical transmission and sub-transmission map

RESPONSE

There are no generators in the study area. Generator information and location can be found in the PJM map attached as a reference in Question No.1.

Kentucky Power Company

REQUEST

If the limiting condition is voltage driven, please supply the location and size of capacitors on the 138kV and sub-transmission system. In addition, please also supply the load power factor at the low side of the sub-transmission to lower voltage transformers in the Hazard load area.

RESPONSE

Attachment 1 lists the location and size of capacitors on the 138 kV and the sub-transmission systems in the study area. The exhibit attached as a response to Question 3 also shows the location and size of capacitors. Attachment 2 provides the load power factors on the low-side of transformers where metering data is available.

Attachment 1: Hazard Area Capacitors

Attachment 2: Hazard Area Power Factor Information

Area 138kV Capacitors

Hazard: 32.4 MVAR

Area 69kV Capacitors

Hazard 2: 24.3 MVAR
Hazard 1: 13.2 MVAR
Combs: 13.2 MVAR
Chavies: 9.6 MVAR
Leslie: 14.4 MVAR
Daisy: 13.2 MVAR
Fleming: 14.4 MVAR
Collier: 9.6 MVAR
Jackson: 4.8 MVAR
Whitesburg: 13.2 MVAR

Planner: MCMILLION, BRENT
Forecast Year: 2010-2011
Operating Unit: All
Forecast Season: Winter
District: All

Name	Source Voltage (kV)	Nominal Voltage (kV)	Max Nm Plate Rt	Limit Cap (MVA)	Power Factor (%)	Unbal. Factor (%)	Peak Winter Load	Metering Data Available
BECKHAM (#3084) 1X	138.0	34.50	30.00	48.33	-100.00	3.46	23.77	DMS
BEEFHIDE (#4512) 1X	138.0	34.50	20.00	19.57	70.21	0.00	5.86	ISIS, But MV90 data is available from May 2002 to Jan 2010, SCADA information is also available on the low side of transformer only (3 phase KW, 3 Phase KVA, 3 phase MVAR data available). (Mining Load)
BLUEGRASS (#3006) 1X	69.0	12.47	10.50	17.00		17.05	11.88	ISIS
BONNYMAN (#3085) 1X	69.0	34.50	25.00	31.50	98.36**	14.12	28.37	ISIS, But SCADA data is available
BULAN (#3073) 1X	69.0	12.47	9.38	16.36		22.61	10.35	ISIS, SCADA information is also available on the high side of transformer only (Only AMP data per phase is available).
CHAVIES (#3011) 1X	69.0	12.47	5.25	8.40		17.68	4.07	ISIS
COLLIER (#3086) 1X	69.0	34.50	25.00	36.19	99.39	7.57	23.23	DMS
COMBS (#3014) 1X	69.0	12.47	10.50	17.00		7.87	12.02	ISIS
DAISY (#3017) 1X	69.0	12.47	5.25	8.62	99.92	2.15	6.56	DMS
ENGLE (#3122) 1X	69.0	34.50	20.00	29.60	-99.82	17.82	11.26	DMS
FLEMING (#4013) 3X	69.0	12.47	20.00	30.40	99.87	18.38	12.79	DMS
HADDIX (#3105) 1X	69.0	34.50	25.00	36.50		4.46	18.59	ISIS
HAZARD (#3027) 4X	138.0	34.50	30.00	47.23	94.67	4.80	34.50	DMS
HAZARD (#3027) 5X	34.5	12.47	9.40	13.33	-99.65	5.19	5.21	DMS
JACKSON (#3080) 1X	69.0	12.47	6.25	8.16		7.25	8.79	ISIS, But SCADA data is available (amps and voltage data only)
JACKSON (#3080) 2X	69.0	12.47	10.50	15.45		15.37	9.62	ISIS, But SCADA data is available (amps and voltage data only)
JEFF (#3090) 1X	69.0	12.47	6.25	7.89		15.39	5.38	ISIS
JENKINS (#3129) 1X	69.0	12.47	10.50	16.50	98.03	11.86	9.85	DMS
LESLIE (#3039) 2X	69.0	34.50	22.40	34.10	98.96	12.04	31.40	DMS
MAYKING (#3144) 1X	69.0	12.47	20.00	31.80	99.67	9.85	12.93	DMS
REEDY (#3114) 1X	69.0	34.50	20.00	32.00		2.85	16.77	DMS data from APR 97 to Feb 2009
SHAMROCK (#3117) 1X	69.0	34.50	5.00	6.79			0.00	ISIS
SLEMP (#3099) 1X	69.0	34.50	10.50	16.00		22.45	6.10	ISIS
SLEMP (#3099) 2X	69.0	34.50	20.00	32.20		3.96	16.77	ISIS
SOFT SHELL (#4200) 1X	138.0	34.50	30.00	45.00	96.94	5.86	8.73	DMS
STINNETT (#3111) 1X	161.0	34.50	14.10	19.16			10.47	ISIS, But SCADA data is available (amps and voltage data only)
STINNETT (#3111) 1BX	161.0	34.50	14.10	19.16			10.47	ISIS, But SCADA data is available (amps and voltage data only)
STINNETT (#3111) 1X 1BX	161.0	34.50	28.20	38.32	98.19	12.50	20.93	ISIS, But SCADA data is available (amps and voltage data only)
VICCO (#3093) 1X	138.0	34.50	25.00	47.28	97.83	2.66	25.46	DMS
WHITESBUR (#3091) 1X	69.0	12.47	10.50	16.80	97.82	37.54	11.68	DMS
WHITESBUR (#3091) 2X	69.0	12.47	25.00	30.00	95.64	17.11	11.74	DMS

**Value derived from SCADA info on 12/15/10 and also assuming that the metering is on the correct side of the trasformer per the SCADA information

Kentucky Power Company

REQUEST

Please supply the estimated cost of installing distribution voltage rated capacitors on a $/KVAR basis.

RESPONSE

The estimated installed cost for distribution voltage rated capacitors is $20/kVAR.

Kentucky Power Company

REQUEST

If the limiting condition is thermally driven, please supply the component by component ratings of the limiting system line element(s). If a transformer is part of the limit, please supply the transformer nameplate ratings, overload ratings, and the transformer rating calculations.

RESPONSE

The attachments provide the ratings of the limiting elements including the transformer.

- Attachment 1: Limiting Line Component Spreadsheet
- Attachment 2: Hazard Transformer #1 Rating Report

		Ratings (MVA)			
Limiting Component	MLSE	SN	SE	WN	WE
Beaver Creek-Topmost 138kV Line	Riser/Conductor	159 (R)	167 (C)	200 (R)	210 (C)
Hazard 1-Bulan 69kV Line	Conductor	76 (C)	76 (C)	96 (C)	96 (C)
Bulan-Shamrock 69kV Line	Conductor	76 (C)	76 (C)	96 (C)	96 (C)
Blue Grass- Hazard 2 69kV Line	Conductor	76 (C)	76 (C)	96 (C)	96 (C)

		Ratings (MVA)			
Limiting Component		SN	SE	WN	WE
Hazard Transformer #1		69	75	69	75

KPSC Case No. 2011-00295
1st Set of Questions of Accion Consultant
Dated October 2, 2011
Item No. 17
Attachment 2
Page 1 of 4

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HAZARD STA  S/N:C-02333-5-1,138/69/12-KV, 50/50/9.8-MVA

INPUT DATA                    CASE  5
                         TRANSFORMER LOSSES

WINDING     BASE   WINDING    BASE    WINDING     BASE    NO.LOAD LOSS
HV TO LV    MVA    HV TO TV   MVA     LV TO TV    MVA

 63.520    30.000    8.660    5.900     9.600     5.900      27.260

                         TEMPERATURE RISE

  WINDING (H.V.)         WINDING (L.V.)         WINDING (T.V.)      TOP OIL   TOTAL HEAT
TEMP.  TEST LOAD MVA   TEMP.  TEST LOAD MVA   TEMP.  TEST LOAD MVA   RISE     RUN LOSSES

49.60      50.00       53.50      50.00       42.20       9.83       41.10      214.80

  NAME PLATE  RATINGS (MVA)       TF      TEMP.COND (C)      AUTO TRANSFORMER DATA
WINDING 1   WINDING 2  WINDING 3  TYPE   WINDING AMBIENT     MAX.      MIN.    TEST
                                          RISE              H.V.TAP  L.V.TAP  H.V.TAP

 50.000      50.000     9.830      6     133.00   10.00     142.20    69.50   142.20

L.V. WINDING      PF =0.97      LG          T.V. WINDING      PF =0.97      LG
---------------------------------------------------------------------------------
  HOT SPOT WINDING RISE    HIGH VOLTAGE    LOW VOLTAGE   TERTIARY VOLTAGE
  H.V.     L.V.    T.V.        MVA            MVA             MVA           PF(H)    ANGLE    TOP OIL TEMP.

 1 122.8   131.6   81.2       75.00          75.00            0.0           0.97      LAG      91.2
 2 129.0   132.0   84.7       77.96          75.50            2.46          0.97      LAG      94.0
 3 132.7   129.7   88.2       79.91          75.00            4.91          0.97      LAG      95.4
 4 132.1   123.2   90.5       80.37          73.00            7.37          0.97      LAG      94.3
 5 132.1   117.7   94.8       80.83          71.00            9.83          0.97      LAG      93.7
 6 132.7   113.1  101.1       81.29          69.00           12.29          0.97      LAG      93.8
 7  48.4    49.0  132.6       28.02           0.0            28.02          0.97      LAG      52.6
 8  57.8    47.7  132.3       39.93          12.50           27.43          0.97      LAG      56.0
 9  72.0    52.5  132.7       51.44          25.00           26.44          0.97      LAG      62.5
10  90.2    63.1  132.4       62.37          37.50           24.87          0.97      LAG      71.4
11 112.5    80.4  132.9       72.81          50.00           22.81          0.97      LAG      83.2
12 132.7   102.0  123.7       81.08          62.50           18.58          0.97      LAG      94.1
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HAZARD STA  S/N:C-02333-5-1,138/69/12-KV, 50/50/9.8-MVA

 INPUT DATA                    CASE  6

                          TRANSFORMER LOSSES

  WINDING     BASE    WINDING    BASE    WINDING     BASE    NO.LOAD LOSS
  HV TO LV    MVA     HV TO TV   MVA     LV TO TV    MVA

   63.520    30.000    8.660    5.900     9.600     5.900      27.260

                          TEMPERATURE RISE

   WINDING (H.V.)          WINDING (L.V.)          WINDING (T.V.)       TOP OIL   TOTAL HEAT
  TEMP.  TEST LOAD MVA   TEMP.  TEST LOAD MVA   TEMP.  TEST LOAD MVA    RISE     RUN LOSSES

  49.60      50.00       53.50      50.00       42.20      9.83         41.10     214.80

    NAME PLATE  RATINGS (MVA)          TF     TEMP.COND (C)       AUTO TRANSFORMER DATA
  WINDING 1   WINDING 2  WINDING 3    TYPE   WINDING AMBIENT      MAX.      MIN.     TEST
                                              RISE              H.V.TAP  L.V.TAP  H.V.TAP

   50.000      50.000     9.830        6     110.00   10.00      142.20    69.50   142.20

  L.V. WINDING        PF =0.97     LG         T.V. WINDING       PF =0.97      LG
  ----------------------------------------------------------------------------------
    HOT SPOT WINDING RISE    HIGH VOLTAGE   LOW VOLTAGE   TERTIARY VOLTAGE
     H.V.     L.V.    T.V.       MVA           MVA            MVA           PF(H)    ANGLE   TOP OIL TEMP.

  1 101.9   109.1    67.7       68.00         68.00           0.0            0.97     LAG      77.7
  2 107.5   109.5    71.0       70.96         68.50           2.46           0.97     LAG      80.3
  3 109.5   106.0    73.4       72.41         67.50           4.91           0.97     LAG      80.7
  4 109.1   100.4    76.0       72.87         65.50           7.37           0.97     LAG      79.8
  5 109.3    95.7    80.6       73.33         63.50           9.83           0.97     LAG      79.5
  6 108.6    90.6    86.2       73.29         61.00          12.29           0.97     LAG      78.9
  7  40.6    41.1   109.6       25.36          0.0           25.36           0.97     LAG      45.8
  8  49.4    40.2   109.5       37.27         12.50          24.77           0.97     LAG      49.1
  9  62.9    45.4   109.7       48.69         25.00          23.69           0.97     LAG      55.3
 10  80.4    56.6   109.8       59.52         37.50          22.02           0.97     LAG      64.2
 11 101.5    74.3   109.9       69.66         50.00          19.66           0.97     LAG      75.6
 12 110.0    93.8    84.2       73.71         62.50          11.21           0.97     LAG      79.8
```

HA 533-5-1,138/69/12-KV, 50/50/9.8-MVA

INPUT DATA CASE 7

TRANSFORMER LOSSES

WINDING HV TO LV	BASE MVA	WINDING HV TO TV	BASE MVA	WINDING LV TO TV	BASE MVA	NO.LOAD LOSS
63.520	30.000	8.660	5.900	9.600	5.900	27.260

TEMPERATURE RISE

WINDING (H.V.) TEMP.	WINDING (H.V.) TEST LOAD MVA	WINDING (L.V.) TEMP.	WINDING (L.V.) TEST LOAD MVA	WINDING (T.V.) TEMP.	WINDING (T.V.) TEST LOAD MVA	TOP OIL RISE	TOTAL HEAT RUN LOSSES
49.60	50.00	53.50	50.00	42.20	9.83	41.10	214.80

NAME PLATE RATINGS (MVA) WINDING 1	WINDING 2	WINDING 3	TF TYPE	TEMP.COND (C) WINDING RISE	AMBIENT	AUTO TRANSFORMER DATA MAX. H.V.TAP	MIN. L.V.TAP	TEST H.V.TAP
50.000	50.000	9.830	6	113.00	30.00	142.20	69.50	142.20

L.V. WINDING PF =0.97 LG T.V. WINDING PF =0.97 LG

	HOT SPOT WINDING RISE H.V.	L.V.	T.V.	HIGH VOLTAGE MVA	LOW VOLTAGE MVA	TERTIARY VOLTAGE MVA	PF(H)	ANGLE	TOP OIL TEMP.
1	104.7	112.2	69.5	69.00	69.00	0.0	0.97	LAG	99.5
2	106.1	108.0	70.0	70.46	68.00	2.46	0.97	LAG	99.3
3	108.0	104.5	72.5	71.91	67.00	4.91	0.97	LAG	99.7
4	109.1	100.4	76.0	72.87	65.50	7.37	0.97	LAG	99.8
5	109.3	95.7	80.6	73.33	63.50	9.83	0.97	LAG	99.5
6	110.1	92.0	87.1	73.79	61.50	12.29	0.97	LAG	99.8
7	41.7	42.2	112.9	25.75	0.0	25.75	0.97	LAG	66.8
8	50.6	41.3	112.8	37.66	12.50	25.16	0.97	LAG	70.1
9	64.1	46.3	112.8	49.08	25.00	24.08	0.97	LAG	76.3
10	81.7	57.4	112.8	59.91	37.50	22.41	0.97	LAG	85.1
11	102.8	75.0	112.6	70.05	50.00	20.05	0.97	LAG	96.5
12	110.2	93.9	84.6	73.80	62.50	11.30	0.97	LAG	99.9

HAZARD STA S/N:C-02333-5-1,138/69/12-KV, 50/50/9.8-HVA

INPUT DATA CASE 8

TRANSFORMER LOSSES

WINDING HV TO LV	BASE MVA	WINDING HV TO TV	BASE MVA	WINDING LV TO TV	BASE MVA	NO.LOAD LOSS
63.520	30.000	8.660	5.900	9.600	5.900	27.260

TEMPERATURE RISE

WINDING (H.V.)		WINDING (L.V.)		WINDING (T.V.)		TOP OIL	TOTAL HEAT
TEMP.	TEST LOAD MVA	TEMP.	TEST LOAD MVA	TEMP.	TEST LOAD MVA	RISE	RUN LOSSES
49.60	50.00	53.50	50.00	42.20	9.83	41.10	214.80

NAME PLATE RATINGS (MVA)			TF	TEMP.COND (C)		AUTO TRANSFORMER DATA		
WINDING 1	WINDING 2	WINDING 3	TYPE	WINDING RISE	AMBIENT	MAX. H.V.TAP	MIN. L.V.TAP	TEST H.V.TAP
50.000	50.000	9.830	6	90.00	30.00	142.20	69.50	142.20

L.V. WINDING PF =0.97 LG T.V. WINDING PF =0.97 LG

	HOT SPOT WINDING RISE			HIGH VOLTAGE	LOW VOLTAGE	TERTIARY VOLTAGE			
	H.V.	L.V.	T.V.	MVA	MVA	MVA	PF(H)	ANGLE	TOP OIL TEMP.
1	83.0	88.8	55.5	61.00	61.00	0.0	0.97	LAG	85.5
2	88.1	89.2	58.5	63.96	61.50	2.46	0.97	LAG	87.8
3	89.9	86.2	61.0	65.41	60.50	4.91	0.97	LAG	88.3
4	89.7	81.3	63.9	65.87	58.50	7.37	0.97	LAG	87.6
5	88.8	76.2	67.8	65.83	56.00	9.83	0.97	LAG	86.8
6	89.8	73.3	74.6	66.29	54.00	12.29	0.97	LAG	87.3
7	33.8	34.2	89.7	22.81	0.0	22.81	0.97	LAG	60.0
8	42.1	33.8	89.8	34.72	12.50	22.22	0.97	LAG	63.1
9	54.8	39.3	89.9	46.04	25.00	21.04	0.97	LAG	69.1
10	71.5	51.0	89.9	56.67	37.50	19.17	0.97	LAG	77.7
11	89.8	68.5	86.8	65.92	50.00	15.92	0.97	LAG	87.7

NO ADDITIONAL SIGNIFICANT VALUE FOR T.V. AT 1.25 PU OF L.V.'S NAMEPLATE

Kentucky Power Company

REQUEST

If the limiting condition is thermally driven and a line, please supply the line conductor size, temperature to which the line was designed to operate, tension, and design clearances.

RESPONSE

The attached document provides the requested information.

Attachment 1: Thermally Limited Line Details

Thermally Limited Line	Voltage	Conductor Size	Maximum Operating Temperature (Normal Rating)	Tension	Design Clearance*
Blue Grass-Hazard 2	69 kV	336.4 (30/7) ACSR	95°C	6400 lbs NESC Heavy	17.0'
Bulan-Shamrock	69 kV	336.4 (30/7) ACSR	95°C	6400 lbs NESC Heavy	17.0'
Hazard 1-Bulan	69 kV	336.4 (30/7) ACSR	95°C	6400 lbs NESC Heavy	17.0'
Beaver Creek-Topmost **	138 kV	397.5 (30/7) ACSR	95°C	7300 lbs NESC Heavy	18.6'

* The lines were designed to exceed minimum clearances outlined in TLES-25 (an AEP Standard). The clearances provided in the table above are general clearances to ground.

** The Beaver Creek - Topmost 138 kV line is designed to be operated at a Maximum Operating Temperature (MOT) of 165°C to allow for Winter Emergency Rating if there are no sag limitations.
For this particular line, there are sag limitations and thus, corrective measures need to be taken before operating the line at the maximum operating temperature (emergeny rating).
Based on the studies, double-contingency loading on the circuit (130% of its current winter rating), will exceed the rating based on MOT of 165°C.

Kentucky Power Company

REQUEST

Please supply a description on how KP conducts economic evaluations between competing alternative projects. (Not alternative routes of the proposed line, but other transmission alternatives, generation alternatives, rebuild with composite conductors, etc.)

RESPONSE

AEP and PJM on behalf of KP conduct annual planning studies to ensure the adequacy of the transmission and the sub-transmission systems in maintaining reliable service against mandatory reliability standards and planning criteria. After the studies are performed and problems identified, both thermal and voltage, transmission system upgrades are identified and studied to make sure that the reliability and any operational problems are addressed. PJM and AEP develop transmission plans in collaboration to resolve violations that could otherwise lead to overloads, low voltages, and black-outs. The process seeks to develop plans that address the reliability criteria violations, are feasible and physically viable, can be implemented by the need date, and are cost affective. This process culminates in one recommended plan.

The recommended plan developed is shared with all the stakeholders through the PJM's Regional Transmission Expansion Plan (RTEP) process to seek input and determine that the plan recommended is the most cost effective in addressing the mandatory reliability standards and planning criteria.

Kentucky Power Company

REQUEST

Please supply a list of alternative projects to the Bonnyman to Soft Shell 138kV line evaluated by KP and a copy of the economic evaluations.

RESPONSE

KP investigated three alternatives to the proposed plan.

Alternative #1: This alternative was to establish a second 161 kV interconnection with Kentucky Utilities Company (KU) at Hyden Station via Wooten Station. The key elements of the plan involved: construction of approximately 1.2 miles of new 161 kV line from Hyden (KU) to Wooten; Installing 161/138 kV, 300 MVA transformer at Wooten; 138 kV line kV line from Wooten to Bonnyman; 138/69 kV transformer at Bonnyman; and miscellaneous additions.

The plan would have solved both thermal and voltage problems associated with the BES and the 69 kV system. However, the plan was not selected because of the potential upgrades on the KU System and the associated costs in implementing the plan, uncertainty of timely completion of the plan; and the overall operational concerns due to reliance on the 161 kV infrastructure which is not a standard transmission voltage utilized on the AEP System.

No detailed cost estimates or an economic evaluation was performed since coordinated planning studies with KU were not performed.

Alternative #2: This alternative entailed rebuilding the Hazard 69 kV loop (approximately 17 miles in length) and replacement of Hazard #1 138/69 kV, 50 MVA transformer in addition to miscellaneous additions.

The economic evaluation of this plan was not pursued since it did not address the PJM BES violation on the 138 kV system under contingency condition.

Alternative #3: The interconnection with TVA at Pineville Station, although conceptually viable, was not pursued because of the cost of a longer line and more importantly the need to address thermal and voltage issues within the Hazard 69kV loop.

Kentucky Power Company

REQUEST

Please supply a short description on how KP selects the final route of the proposed line versus alternative routes for the same facilities if different than Reese testimony, page 11.

RESPONSE

Kentucky Power selected the final route of the proposed line based upon the recommendation by GAI in conjunction with Kentucky Power's independent analysis of the information contained in the GAI report, the work of Kentucky Power's right-of-way agents, public comments made at the public forums hosted by Kentucky Power that were conducted in December 2010, discussions with public officials, and Kentucky Power's evaluation of the cost and "constructability" of the line along the proposed route.

Kentucky Power generally follows the guidance contained within the Federal Power Commission (1970) *Guidelines for the Protection of Natural, Historic, Scenic, and Recreational Values in the Design and Location of Rights-of-Way and Transmission Facilities* in the siting and planning of its facilities. In this specific instance, the methodology described in the Reese testimony is generally consistent with the Federal Power Commission Guidelines. In addition, prior to Kentucky Power making its decision, Kentucky Power/AEP planning personnel flew the proposed route, consulted with field personnel, and Hazard District management.

Kentucky Power Company

REQUEST

Reference, Filing, page 5. Please identify the 4 property owners to date, by parcel referenced in Exhibit 9, that have expressed objections to the preferred alternate. Your response should also include a short description of each owner objection

RESPONSE

Attached is a list of the four (4) property owners to date that have expressed objections to the preferred alternate. Further discussions continue with each of the four property owners.

Owners that have expressed objections to the proposed project

Tax Map No.	Parcel Ref for Map	Name & Address	County	Affected Acreage	Description of Objection
074-00-00-081.00	7	Hershell and Margaret Dixon P.O. Box 91 Bonnyman, KY 41719	Perry	0.06	Allowed surveying, however prefers we not affect her property and plans to put a mobile home on part of the property.
037-00-00-081.00 071-00-00-001.00	74, 70A	Daniel Gayheart P.O. Box 619 Hindman, KY 41822	Knott	5.91	Allowed surveying, however he prefers we use a alternate route because of concerns he has on the impact of potential mining of his coal.
015-00-00-050.05	63	Jon Amburgey 224 Bearville Road Emmalena, KY 41740	Knott	1.75	Allowed surveying, however they prefer an alternate route becaue they plan future development and does not want to split-up the property
115-00-00-033.00	38	James Jones and Mable Jones 2823 N. Woodard Chicago, IL 60618	Perry	1.3	Allowed surveying, however they prefer an alternate route becaue they plan future development and does not want to split-up the property

Kentucky Power Company

REQUEST

Reference Filing, Section 18, and page 8. Please supply the benefits and costs of the three alternatives stated compared to the preferred Bonnyman to Soft Shell 138kV alternative.

RESPONSE

Please refer to the company's response to Question No. 20.

Kentucky Power Company

REQUEST

Reference Filing, Section 18, and page 8. Was a second Hyden to Wooten 161kV line considered as an alternative? If not, why not?

RESPONSE

Yes, please see Alternative #1 in the Company's response to Question No. 20.

Kentucky Power Company

REQUEST

Reference Filing, Section 18, and page 8. Please describe any and all alternatives considered to defer the preferred project where the carrying cost of the deferral project(s) are less than the first year carrying costs of the preferred project.

RESPONSE

Over the years, interim plans were developed and implemented to defer the cost of a large scale project, which entails bringing another source into the area. To illustrate, we established a 161kV interconnection with KU at Hyden Station, installed facilities to close the normally open 69kV interconnection at Lee City with EKPC, and added a capacitor bank in the Hazard Area. We have reached a point today that we need an additional 138kV source that will address the local area 69kV thermal and voltage problems in addition to the thermal overload on a BES facility.

Kentucky Power Company

REQUEST

Accion understands that the $62.5 million cost of the proposed project is in 2009 dollars. Please confirm or identify the year dollars the estimate is stated in. As part of your response, please also supply the impact of rising commodity prices on the projected cost of the project since the estimate was made.

RESPONSE

The Company's current estimate of $62.5 million is in 2014 dollars. Rising commodity prices are addressed with contingencies included within the estimate.

Kentucky Power Company

REQUEST

Please supply the cost of the project in 2014 completion date dollars for the project segments as listed in Exhibit 12, page 13. Please identify the IDC portion of the estimate in each project segment as part of your response.

RESPONSE

As stated in response to Question No. 26, the $62.5 million is in 2014 dollars. Listed below is a breakdown of that estimated cost between direct, indirect and AFUDC. All figures are in millions.

Component	Direct Cost	Indirect Cost	AFUDC	Total
Line	$28.0	$ 9.4	$1.6	$39.0
Station	$ 9.4	$ 3.1	$0.5	$13.0
R/W	$10.3	$ 0.2	$0.0	$10.5
Total	$47.7	$12.7	$2.1	$62.5

Kentucky Power Company

REQUEST

Reference Lasslo testimony, page 4, lines 11-19. Is the first contingency event described a design issue or a vegetation management issue. Please explain.

RESPONSE

Although the first contingency event was primarily a vegetation management issue, it did demonstrate the reliability risks for the large portion of the Hazard District customers that are served from the Hazard 69kV loop.

The conductor sagged into a tree that was located in the buffer zone under the conductors. The buffer zone is where the right of way transitions from the clear cut area to the forest.

Kentucky Power Company

REQUEST

Reference Lasslo testimony, page 4, and line 24 through page 5, line12. The second event described here was a single contingency. If KY performs system adequacy analysis annually, as stated at the bottom of page 12 of the Lasslo testimony, and the system is designed to withstand the first contingency, please explain why customer load was required to be curtailed.

RESPONSE

The Kentucky Power subtransmission system that includes the 69kV system was designed to meet thermal and voltage requirements under single contingency conditions. As the system grows and the customer loads increase, system improvements are developed and implemented based on the annual studies performed to meet the reliability criteria.

Load flow studies have indicated that a single contingency on the Hazard 69kV loop would violate thermal and voltage planning criteria under peak loading conditions and would jeopardize service to customers. Over the past several years, Kentucky Power has implemented interim improvement plans to address these issues. As an example, a normally-closed 69kV tie at the Lee City Station was established. However, the system has now reached a point that a permanent long term solution needs to be implemented to meet the reliability standards.

The referenced event in the testimony demonstrated the real consequences of a single contingency on the Hazard 69kV loop during winter loading conditions and provided a validation of the results of the load flow studies.

A wide spread outage was narrowly avoided due to voluntary load curtailments. If the voluntary load curtailments had failed to stabilize the conditions on the Hazard 69kV loop, additional load shedding would have been required to maintain the integrity of the remaining sections of the Hazard 69kV loop.

Kentucky Power Company

REQUEST

Reference Lasslo[sic] testimony, page 5, lines 7-13. Please supply the analysis performed to evaluate the factors generally listed here and specifically listed in Exhibit 13, Table 4 for each of the alternatives. As part of your response, please indicate what weights were given to the factors (and their subsets) as described in the Kentucky Transmission Line Siting Model, Project Report dated July 31, 2006.

RESPONSE

The raw data presented in Tables 2 and 4 of Exhibit 13, along with input received through the public and agency review process, were used to evaluate each of the alternatives. An iterative review based on these data was used that employed the siting criteria identified in Section 2 of Exhibit 13. These criteria were selected to avoid or minimize land use conflicts; impacts on human, natural, visual, and cultural resources; regulatory conflicts; construction, operation and maintenance problems; and project schedule delays. Each alternative was reviewed with respect to these siting issues, and the relative suitability of each was assessed. This analysis is provided in Section 4.3 of Exhibit 13.

A quantitative weighted ranking protocol as described in the Kentucky Model was not employed as a part of this analysis. The methodology utilized was selected to enable maximal flexibility in siting the line to incorporate on-going landowner preference and stakeholder input. Compatibility with future mining and land use plans and the needs of landowners are of high priority in the study area where resource extraction activities are significant components of the local and regional economy.

For further information please see the company's response to Question No. 32.

Kentucky Power Company

REQUEST

Reference Lasslo testimony, page 5, lines 19-22. Please explain the status of the NERC requirement regarding transmission design down to the 100kV level. In your response, please indicate the ability to obtain waivers to said design and the KY effort to attain such waivers.

RESPONSE

NERC is the minimum standard that transmission providers and planners must utilize in assessment of the transmission system. NERC planning standards evolve around system assessment under various types of contingencies and developing plans to address identified violations. The contingencies that are planned for are very descriptive and involve single or multiple events on the system. AEP is not aware of any instance where a waiver has been granted by NERC.

Kentucky Power Company

REQUEST

Reference Reese testimony, page 9, and lines 17-26. Please explain how the two tier corridor selection process described relates to the process described in the Kentucky Transmission Line Siting Model, Project Report dated July 231, 2006.

RESPONSE

The two-tier process describes a process that is similar to that shown in Figure 2-2 of the Kentucky Transmission Line Siting Model (Kentucky Model). The three potential corridors referenced in Line 18 generally correspond to macro-corridors as discussed in the Kentucky Model. These were identified based upon review of high-level data incorporated into a GIS constraints database. This database included information from aerial photography, USGS topographic mapping, published GIS data layers, and preliminary input from area stakeholders. Within these macro-corridors, preliminary transmission line segment locations and alternative routes were subsequently identified using a process that combines the alternative corridors and alternative routes development phases of the Kentucky Model. This phase incorporated increasingly refined data based upon field views, additional interpretation of remote sensor data, landowner and stakeholder input, agency coordination, and a helicopter survey of the preferred route. A quantitative weighted ranking protocol as described in the Kentucky Model is not employed in the two-tier analysis. Rather, as discussed in Exhibit 13, the two-tier process utilized a GIS-based comparison of raw data for resources within a 100-foot wide ROW and/or within approximately 250 feet of the centerline reviewed in consideration to siting criteria (Section 2.0 of Exhibit 13) and input from stakeholders and landowners.

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Kentucky Power Company

REQUEST

Reference Exhibits 4, 5, and 6. Please supply edge of right-of-way EMF levels (magnetic and electric) for each of the three configurations.

RESPONSE

The requested information will be made available upon completion of the study.

Kentucky Power Company

REQUEST

Reference Exhibit 8. Please supply before and after one line breaker diagrams of the Bonnyman substation.

RESPONSE

The attached document contains a before and after one-line breaker diagram of the Bonnyman Substation.

Figure 1: Station One-Line: Bonnyman 138kV (Before)

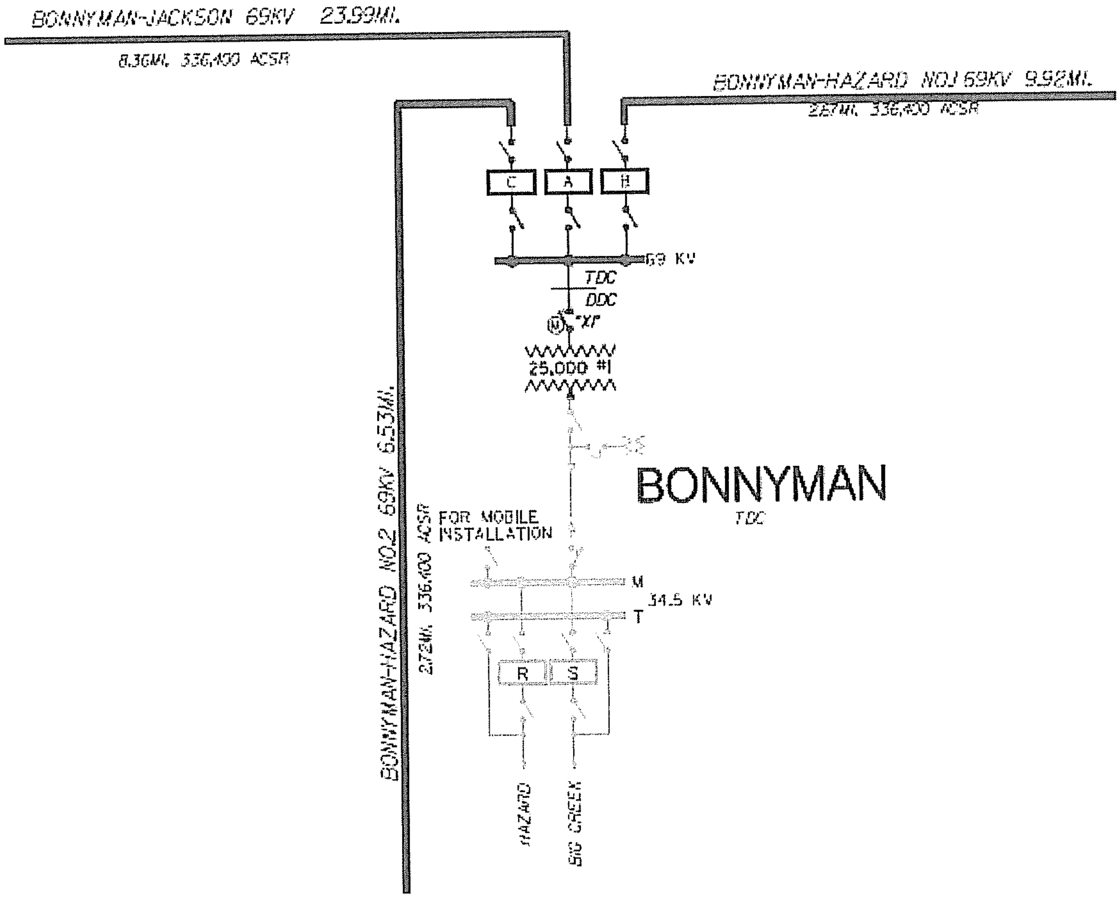
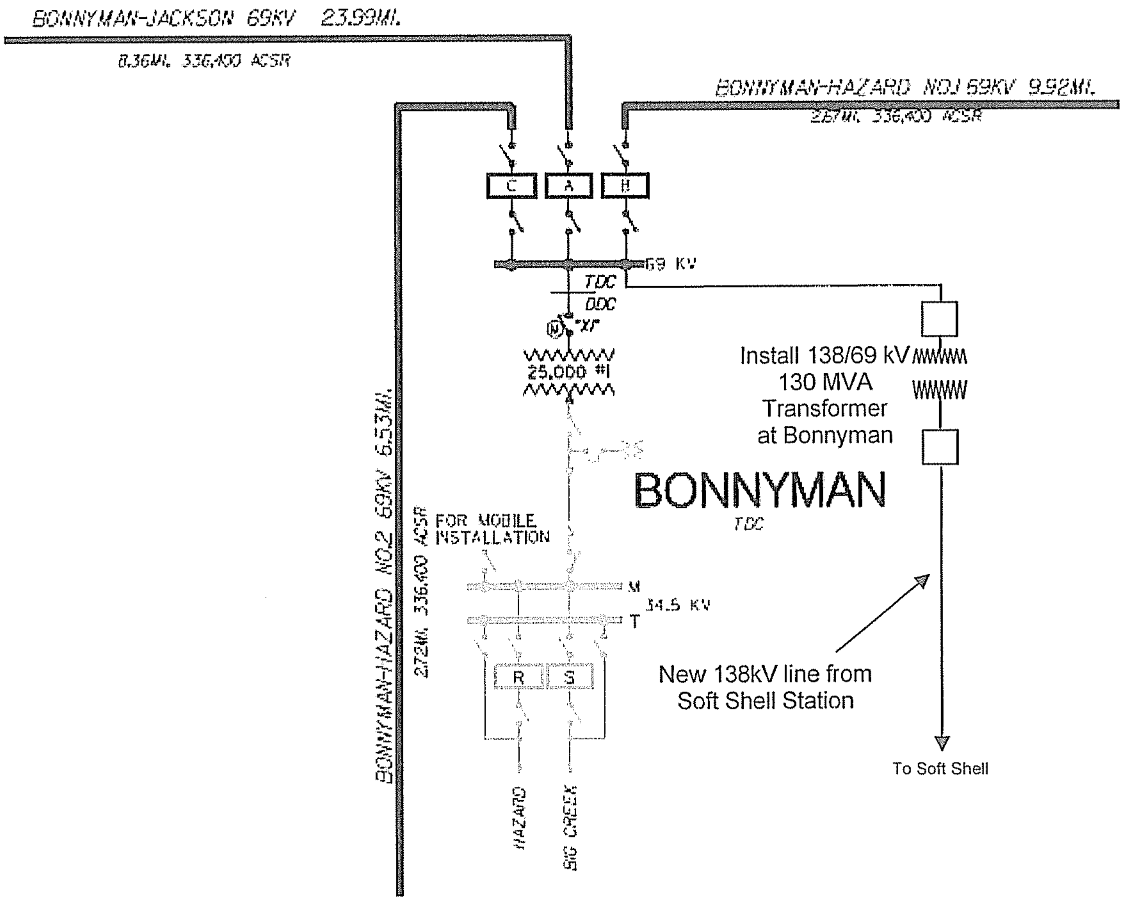


Figure 2: Station One-Line: Bonnyman 138kV (After)



Install 138/69 kV 130 MVA Transformer at Bonnyman

New 138kV line from Soft Shell Station

Kentucky Power Company

REQUEST

Reference Exhibit 12, page1. Why wasn't a looped alternative considered where the terminus of the new line would be the Hazard 138kV substation instead of the preferred radial alternative terminating at Bonnyman substation?

RESPONSE

Bringing a new 138kV source into Bonnyman Station allows KP to introduce a new source in the northern part of the Hazard Area system which will help reduce the bias of the south to north power flow in the Hazard Area. Under contingency conditions, the south to north bias increases in an effort to compensate for outages and establishing an additional source at Hazard Station instead of Bonnyman Station would increase the south to north bias, thus causing thermal issues on the 69kV system. For an outage of the Blue Grass-Hazard 2 69kV line, the Hazard-Bulan 69kV line overloads as noted in Exhibit 12 Figure 4. Bringing an additional source into Hazard Station and not Bonnyman Station would increase the severity of this overload. If the new 138kV line was constructed into Hazard 138kV Station instead of Bonnyman Station low voltage issues would still exist on the 69kV Hazard loop under single contingency conditions. If the line was constructed to Hazard Station low voltages would exist for the single contingency loss of Bonnyman-Combs 69kV line or Blue Grass-Hazard 69kV line because the principal source to the 69kV loop would still be the 69kV line from Hazard towards Bulan. The only way to effectively correct the low voltage and thermal issues on the 69kV loop is to construct an additional source in the northern part of the 69kV loop.

Kentucky Power Company

REQUEST

Reference Exhibit 12, page 3. In what year do KY system studies show that the completion of the 138kV loop from Bonnyman to Hazard substation is required to meet reliability criterion?

RESPONSE

PJM and AEP on behalf of KP have not established a firm date for the need of closing the 138kV loop from Bonnyman Station to Hazard Station. Completing the 138kV loop from Bonnyman Station to Hazard Station will depend on the area load including distribution and mining loads, any large industrial load locating in the area, or any significant changes in the support from neighboring systems tie lines. On-going transmission system studies by PJM and AEP on behalf of KP will continue to ensure reliability criterion is being met in the Hazard Area. If a reliability criterion violation were to arise in the area consideration will be given to completing the 138kV loop.

Kentucky Power Company

REQUEST

Reference Exhibit 12, page 6. Please relate the significance of closing the Lee City tie to the system diagram on Exhibit 12, page 2.

RESPONSE

Closing the Lee City tie line will help the KP 69kV system, specifically the Hazard 69kV loop. Although closing the Lee City tie helps our system, it is limited to a maximum of 51 MVA support from the EKPC system. Previously the stations from Bonnyman to Jackson were supplied radially from Bonnyman Station and had severe low voltage issues under contingency. The closed tie at Lee City allows the stations from Bonnyman to Jackson to receive a looped feed that helps during contingency conditions.

Closing the normally open Lee City 69kV switch will help the KP system under contingency conditions, but does not effectively solve the thermal and voltage issues in the area. The voltages under single contingency conditions in the local Hazard Area will improve as a result of this interconnection, but not to the extent that is needed to meet voltage reliability criterion. Exhibit 12, Figures 4 & 5 contain voltage and thermal performance for the Hazard Area with the Lee City tie closed. Closing the Lee City line does not help KP solve the BES thermal overload concern because it is not a strong enough source to carry the additional load in the event of losing the two principal sources into the area. This interconnection with EKPC lacks the strength to fully support our system under contingency conditions.