Power System Study
for the
South Edge Reservoir – R36
Las Vegas, Nevada

Power Quality Technical Services, Inc.
683 Scenic Tierra Ln
Henderson, NV 89015

Engineering Services

Prepared by:
Joe Dietrich, Jr., P.E. (NV - 014436)
702- 204-5211

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EXECUTIVE SUMMARY

Each aspect of the study, its pertinent results, and recommendations are summarized below. Detailed discussions appear later in each respective section of this report.

1. The main purpose of the **Short-Circuit Study** was to determine if each protective device was rated to handle the maximum fault current that it may be subjected to during a fault condition. This was done by comparing the device's published short-circuit current rating to its calculated fault current duty.

   - The Short Circuit Study indicates that all devices and panels are appropriately rated.

2. The **Coordination Study** found that the majority of the adjustable protective devices could be set to provide the greatest selectivity and minimize overall system impact in the event of a fault. As a result, it is recommended that all adjustable low voltage (277/480V through 120/208V) breakers be set and tested at the recommended settings.

   - A complete listing of all breaker settings can be found in the *Appendix / Coordination Study - Analysis/Tables* section of this report.

INTRODUCTORY SECTION

Study Objective

Power Quality Technical Services, Inc. was contracted to perform a short-circuit, protective device evaluation / coordination analysis power system study for the *South Edge Reservoir – R36* project located in *Las Vegas*, *Nevada*. The scope of the Power System Study included the electrical system from the incoming 480V main service to a single main switchboard (MSB) and a mini-power center.

The purpose of a **Short-Circuit Study** is to determine if each protective device, within the scope of this study, is rated to handle the maximum fault current that it may be subjected to in the event of a fault. This is done by comparing each device's published short-circuit current rating to its individually calculated fault current duty. The calculated short-circuit current values are also used in selecting protective device settings in the Coordination Study. A discussion of the method of calculation is contained in the *Short-Circuit Study - Introduction* section of this report. The results are discussed in the *Short-Circuit Study – Analysis* section of this report. The report also contains documentation of the system components in the *Appendix* / *Short-Circuit Study - Analysis* section, including information on each transformer and motor, utility fault current contributions, installed feeder conductors and their respective conduits.

The **Coordination Study** work scope includes the determination of recommended settings for all adjustable protective devices down to low voltage 120/208V distribution panel main breakers. The settings recommended in this study provide a reasonable compromise between the often-conflicting goals of service continuity and equipment protection. The nature of the load and its tolerance to service interruptions must be considered as well as the consequences of delays in clearing a fault. Where possible, the minimum amount of equipment is removed from service when a system protective device operates to clear a fault or system abnormality. This is known as selectivity. The recommended settings, tabulated according to the device location, are located in the *Appendix / Coordination Study - Analysis* section of this report.

A high degree of selectivity was achieved for the majority of the studied electrical system. The section entitled *Coordination Study - Analysis* should be referenced for identifying and setting breakers to achieve the highest level of protection and selectivity. The time current curves found in the *Appendix / Coordination Study - Curve/Graphics* section of the report were generated using recognized industry software.

All insulated cables within the scope of the study have been checked for protection to ensure compliance with the National Electrical Code standard for over-current-protection.

Primary transformer protection was examined to insure avoidance of nuisance outages from inrush currents, as well as providing over-current protection as required by the 2002 National Electrical Code, and fault protection as provided by the American National Standards

Institute (ANSI). Coordination with secondary protective equipment was also an objective. This protection was examined by means of time current curves.

Compliance with the 2002 National Electric Code (NEC) sections pertaining to system protection was evaluated. Motor starting was also examined to identify the impact of starting each of the larger motors within the system (assuring breaker settings were sufficient to allow proper starting). Motor curves are found on several of the Time Current Curves located in this report.

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Description of the Electrical System

A one-line diagram was entered into EasyPower 7.0 Software to accurately model the electrical system from the utility source through the metering switchboard, the main switchboard, a single MCC, and a 120/208V sub-panel. The one-line diagram provides a complete picture of the electrical system described above, and is representative of the Single Line Diagram and Equipment Layouts provided by the design Engineer of Record.

Study Approach

When performing the power system study, the equipment Bill of Material and Engineering / Contractor supplied information was reviewed and entered into the analysis software. By using this information, it was possible to evaluate the system in its truest terms and recommend optimum engineering changes, where necessary.

Before a study of any system can begin, all system data must be collected and entered in the analysis software. All protective and impedance elements must be closely inspected to determine their true arrangement sufficient for construction of a one-line diagram model. This includes the true circuit arrangement including all breaker types and ratings, and their interrupting capacities. Additional information is required on cable sizes, types, and lengths; transformer sizes and impedances; and utility related data.

When all necessary data relating to the system has been gathered from the field, the information is entered into computer databases for short-circuit, protective device evaluation, and coordination analysis. The short-circuit program determines the maximum fault current available at each of the pre-selected fault buses as identified on the one-line diagram. The program output shows both the first cycle of fault duty (as needed for momentary evaluations, fuse and low-voltage breaker interrupting capacity), and interrupting duties for the slower, five-cycle, medium voltage breakers.

The Short-Circuit Device Evaluation Report, found in the *Appendix / Short-Circuit Study - Analysis* section of this report, compares the interrupting capacities of each device with the interrupting duty calculated from this study.

These fault levels are equally important for proper coordination, and it will be noted that each time-current coordination plot uses these values. Advantage is taken of the various line and transformer impedances to set primary instantaneous devices above the level of a secondary transformer fault. For example, it is desired that the secondary instantaneous device operate first to clear the fault without primary interruption. Also, transformer inrush current varies with circuit impedance, and is considered in the calculations to select smaller than normally required fuse or relay setting.

Coordination in practice is generally a compromise between the mutually desirable but somewhat inconsistent goals of maximum protection and maximum service continuity. For this reason, and because of factors such as established system design, there may be combinations of device settings that are classified as acceptable. The settings suggested in this study are based on an exercise of judgment as to the best balance between competing objectives.

Arrangement of the Report

This report has been divided into sections that serve to separate areas of major interest.

Immediately following this introductory section, all recommended changes have been summarized in tabular form in addition to a discussion of various problems encountered and possible solutions.

Next, a discussion of the Short Circuit Analysis procedure is outlined, and then the results are summarized in the Short Circuit Analysis Section of the report. Momentary, interrupting, and equipment duties are listed in the Appendix - Short Circuit Analysis section. The Coordination Study Introduction follows, then the Coordination Study Analysis. All the breaker settings along with time current curve graphs are located in the Appendix – Coordination TCCs, and Breaker Settings Table.

The Appendix includes each of the Single Line Diagrams used to model the electrical systems in this project.

SHORT-CIRCUIT STUDY INTRODUCTION

Introduction

A power system short-circuit study is used to check or determine:

1. The calculated fault duty against the rating of circuit interrupting devices, such as circuit breakers and fuses.
2. The selection and rating or setting of short-circuit protective devices such as direct-acting trips, fuses and relays.
3. The calculated fault duty against the short-circuit ratings of non-interrupting equipment such as busway, motor control centers, switchgear, and distribution panels.

General Discussion

The study procedure consists of representing the electrical power system in a software based modeling program. Each of the power system components (utility sources, generators, motors, transformers, cables, etc.) are represented by a resistance value and a reactance value.

The short-circuit study one-line diagram was used as a guide for "building" the database model. This model, found in the *Appendix* of this report, shows the bus IDs used in the study to identify generation, distribution and load buses within the electrical distribution system.

Bus IDs are used to assign short-circuit sources, base voltages, and per-unit impedance values to the correct locations in the modeled system. The output data is referenced to these Bus IDs. These buses, however, do not necessarily represent real buses or readily accessible connection points in the actual electrical system. They may identify hypothetical buses that are the junction points of impedance elements in the real system, such as cable and busway with transformers or reactors. A separate Bus ID facilitates data collection and organization with the operation of the software.

The software places a fault on each bus location in the system, and a set of short-circuit currents is calculated that can be compared with the published short-circuit rating of the power system equipment. Any interrupting device must be able to withstand and interrupt the most severe short-circuit current available. Generally, three-phase bolted faults and the maximum utility short-circuit duty result in the greatest required equipment duty ratings.

The calculation techniques used are in accordance with American National Standards C37.13-1981 for low-voltage breakers: C37.010-1979 and C37.5-1979 for medium and high-voltage breakers.

System Impedance Data

The one-line diagram included in this report represents the modeled electrical power distribution system. Impedance values used in this study are listed in the Database Report found in the *Appendix / Database Report* section of this report. The Database Report is a tabulation of all system components relative to the scope of this study. This includes Utility Sources, Generators, Motors, Transformers, Circuit Breakers, Switches, Fuses, Cables, and Busways.

The voltage bases used in the impedance network generally are those associated with the rated winding voltages of the main transformers and the load-centers on their "flat-tap" positions. Therefore, the system study results are typically based on 12470, 4160, 2400, 480 and 208 Volts as the "system" voltage bases.

The **utility system** is represented as an infinite bus connected to a line whose impedance equals the utility's equivalent source impedance at the facility's incoming service. The other end of this line is connected to the incoming service point. The utility impedance is typically given on the one-line diagram on a 10 or 100 MVA base.

Transformer impedances, usually given on the nameplate in per unit based on the self-cooled kVA rating of the transformer, are given in percent on the transformer's base. Normally, the X/R ratios of the transformers are derived from the "medium-typical" curves in ANSI C37.010 although specific X/R ratios may also be used for particular applications. Transformer parameters used include its type, such as oil, gas, and dry, silicone or vapor, and its class that can include various combinations of forced air, water and forced oil. Examples are shown below.

Type	Class
Oil	- OA, OA/FA, FOA, OW, OW/A, FOW, OA/FA/FA, OA/FA/FOA, OA/FOA/FOA
Gas	- VA, VA/FA
Silicon	- SA, SA/FA
VP Dry	- AA, AFA, AAFA
Cast Coil	- AA, AFA, AAFA

Other transformer parameters are its connection (delta, wye-ungrounded or wye-grounded), its ground impedance (if wye-grounded) and its ANSI temperature rating, shown below.

ANSI Temperature Ratings		
45^{o}C	65^{o}C	80/110^{o}C
55^{o}C	65/80^{o}C	150^{o}C
55/65^{o}C	80^{o}C	150/180^{o}C

A transformer's Load Tap Changer data is also used in the model. Its step size may be defined as either 5/8 or 10/8 percentage steps along with its minimum and maximum tap values. Its control type may be either voltage or MVAR controlled for load-flow analysis.

The system's **cable** and **busway** impedances are represented in per unit on the study-base impedance, using typical impedance values for such equipment available in standard references, such as the IEEE "Red Book".

Cables may be defined as one of five different types, 1/C-one conductor, 3/C-three conductor, IAA-interlocked armor aluminum, IAS-interlocked armor steel or MAC-messenger aerial cable. Other variables include material (copper or aluminum), size, length, number of conductors per phase temperature (25^{o}C to 250^{o}C) and insulation. Some common insulation abbreviations are shown below:

Low voltage Insulation (1000 volts or less):

THHN	- Heat Resistant Thermoplastic
THWN	- Moisture and Heat Resistant Thermoplastic
THW	- Moisture and Heat Resistant Thermoplastic
RHH	- Heat Resistant Rubber
RHW	- Moisture and Heat Resistant Rubber
XHHW	- Moisture and Heat Resistant Crosslinked Synthetic Polymer (480V equivalent of XLPE)

High Voltage Insulation (Over 1000 volts):

XLPE	- Crosslinked Polyethylene
XLPE-133%	- Crosslinked Polyethylene with 133% insulation
XLPE-NJ	- Non-Jacketed Crosslinked Polyethylene
XLPE-NJ-133%	- Non-Jacketed Crosslinked Polyethylene with 133% insulation
XLPES	- Shielded Crosslinked Polyethylene
XLPES-133%	- Shielded Crosslinked Polyethylene with 133% insulation
EPR	- Ethylene Propylene Rubber
EPR-133%	- Ethylene Propylene Rubber with 133% insulation
EPR -NJ	- Non-Jacketed Ethylene Propylene Rubber
EPR -NJ -133%	- Non-Jacketed Ethylene Propylene Rubber with 133% insulation
EPRS	- Shielded Ethylene Propylene Rubber
EPRS-133%	- Shielded Ethylene Propylene Rubber with 133% insulation
PILC	- Paper Insulated Lead Sheath
PILC-133%	- Paper Insulated Lead Sheath with 133% insulation

Busways are defined by manufacturer, material (copper or aluminum) and length.

The software used sometimes requires a zero-impedance branch. Cables with 10 - 500MCM conductors per phase or a 5000A Copper bus-duct with a length of ten feet is used to represent this requirement. This is used mainly with bifurcated feeder breakers where two conductors are connected to the load terminals of the breaker. A zero-impedance branch is connected through the breaker between its line-side connection to the bus and its load-side cable connections.

The **motors** in each unit substation are grouped (lumped) and a single impedance is determined based on the total connected motor kVA. Typical sub-transient reactance (X''_d) or locked rotor (X_{lr}) for each motor within the group is determined and averaged. The total equivalent kVA and impedance is based on the following assumptions when exact motor impedances are not known.

Table SCI-1

Induction motor	1 hp = 1 kVA
Synchronous motor, 0.8 PF	1 hp = 1 kVA
Synchronous motor, 1.0 PF	1 hp = 0.8 kVA
Induction motor not greater than 600V	X_{lr} = 0.25 per unit
Induction motors greater than 600V	X_{lr} = 0.17 per unit
Synchronous motors not less than 1200 rpm	X''_d = 0.15 per unit
Synchronous motors less than 1200 rpm	X''_d = 0.20 per unit

(The motor impedances are in per unit on the motor kVA rating. These reactances and motor base kVA ratings listed above were taken from data and assumptions in IEEE Publication No. 141, Fourteenth Edition, "IEEE Red Book".)

The sub-transient reactance (X''_d) values listed in the Table SCI-2 are used in first-cycle (momentary) current calculations while a modified sub-transient reactance is used for the interrupting duties for the medium and high-voltage breakers. These values are in accordance with the pertinent circuit breaker application standards.

The ANSI standards for calculating short-circuit duties require that the actual motor or generator reactances be modified under certain conditions. The modification factors are listed in the following table for both momentary (close and latch) and interrupting-duty calculations. Low-Voltage Duty is calculated per ANSI C37.13-1981 while Momentary and Interrupting Duty is calculated per ANSI C37.010-1979 and C37.5-1979.

Table SCI-2

Motor Code	Motor Type	First Cycle - Low Voltage	First Cycle - Momentary Duty for Medium & High Voltage Breakers	1.5-4 Cycles - Interrupting Duty for Medium & High Voltage Breakers
1	Synchronous	1.0 X_d''	1.0 X_d''	1.5 X_d''
2	Induction > 1000HP or > 250HP @3600 RPM	1.0 X_d''	1.0 X_d''	1.5 X_d''
3	Induction Motor Group >= 50 HP	1.2 X_d''	1.2 X_d''	3.0 X_d''
4	Induction Motor Group < 50 HP	1.67 X_d''	1.67 X_d''	Neglect
5	Lumped Induction Motor Group	1.0 X_d''	1.0 X_d'' *	3.0 X_d''

Note- X_d'' for induction motor groups are assumed equal to 0.167. This corresponds to an equivalent motor contribution of 3.6 to 4.8 times the full load current.

* = X_d'' assumed equal to 0.25.

When exact data is not known, the X/R ratios of induction motors and transformers are determined by using the "medium typical" curves from ANSI C37.010-1979. For synchronous motors less than 1000 horsepower, an X/R ratio from the curve of induction motor X/R ratios is determined.

When hand calculations are performed, the above approximations may be used along with the X/R ratios, provided in the next table, unless more accurate calculations are required. Motor code letters are usually listed on the nameplate, and correspond to kilovolt-amperes per horsepower with locked rotor in accordance with Section 430 of the National Electrical Code. The reciprocal of this kVA/horsepower value may be used as the motor impedance on its own kVA base. This is especially desirable for low-voltage motors with two pole or ratings over 250 HP.

Table SCI-3
Table of Typical Induction Motor Short-Circuit X/R Ratios

Nameplate Horsepower	X/R Ratio	Nameplate Horsepower	X/R Ratio	Nameplate Horsepower	X/R Ratio
5	2.5	50	5.7	300	15.0
7.5	2.7	60	6.3	350	16.3
10	3.2	75	7.0	400	17.4
15	3.6	100	8.2	450	18.5
20	3.9	125	9.0	500	19.4
25	4.3	150	10.0	600	20.7
30	4.5	200	11.7	700	22.1
40	5.1	250	13.4	800	23.4

Short-Circuit Calculations

There are four possibilities for a fault in a three-phase distribution system:

1. Three-phase fault - the three-phase conductors are shorted together.
2. Line-to-line fault - any two phase conductors are shorted together.
3. Double line-to-ground fault - any two phase conductors are shorted together and simultaneously to ground.
4. Line-to-ground fault - one phase conductor is shorted to ground.

For a particular location in a power system, the magnitude of fault current is generally the greatest for three-phase faults and least for phase-to-ground faults. However, ground-fault current magnitude can exceed the three-phase fault current, under certain conditions. This can occur near (1) solidly grounded synchronous machines, (2) the solidly grounded wye connection of a delta-wye transformer of the three-phase core (three leg) design, (3) grounded wye-delta "tertiary" auto-transformers, or (4) grounded wye-grounded wye-delta tertiary three-winding transformers.

The short-circuit study does not include prefault steady-state load currents. The effect of system load currents is usually negligible in short-circuit studies for industrial and commercial power distribution systems.

Bus IDs used on the one-line diagrams are assigned to establish the locations to be faulted, and typically match the system nomenclature on the Design / Construction Drawings. Contributions from sources of short-circuit current such as the electric utility system, generators, and motors are indicated on the computer printout.

Switchgear Ratings

The short-circuit rating assigned to a power circuit breaker design by the manufacturer is significant in two ways. First, the rating represents a conservative statement of the actual capability of the breaker design to close against, to withstand, and to interrupt short-circuit currents. Thus, the rating is the maximum condition under which the breaker design may be safely applied. Secondly, the rating is the maximum condition of application for which the manufacturer guarantees that the breaker will perform satisfactorily. It is essential, then, that a circuit breaker be applied within the rating assigned to its design if the installation is to be safe and if it is to be covered to the full extent of the manufacturer's warranty. One purpose of a short-circuit study is to determine the conditions under which switchgear will be applied in a specific system.

From a series of laboratory tests, the manufacturer determines the actual breaker capability. Then a rating is selected and assigned to the breaker. In the United States the procedures for testing breakers the rating structure, and the listing of preferred ratings are industry standards dictated by the Sectional Committee on Power Switchgear (C37) of the American National Standards Institute.

The short-circuit rating of a circuit breaker is its capability at the maximum voltage at which the breaker may be applied. Therefore, there is a distinction that must be made between the rating of the breaker and its capability in a specific application.

Prior to 1964, breakers were assigned a short-circuit interrupting capacity in asymmetrical MVA, and it was stated that the interrupting capacity was a constant over a defined range of voltages. An equivalent interrupting capacity in amperes could be calculated at each voltage level. This is called a total-current basis for rating breakers. Since 1964, however, breakers have been assigned an interrupting capacity in symmetrical RMS amperes at a specified maximum voltage, and the capacity is said to increase in inverse proportion to voltage up to a specified maximum current. This is the so-called symmetrical current basis of rating. Under the new rating structure, an MVA rating is still assigned to breakers for class distinction, but it is not the interrupting capability of the device in most cases.

Under the symmetrical current basis of rating switchgear, the factor k defines the permissible range of voltage and fault current. The interrupting capabilities of the breaker then fall into one of three categories:

1. Voltage is greater than the rated maximum voltage; the breaker may not be applied.
2. Voltage is between the rated maximum voltage and l/k times the rated voltage; the interrupting capacity is:

$$\frac{\textbf{(Interrupting capacity at rated voltage)} \quad \textbf{(Rated voltage)}}{\textbf{(Actual Voltage)}}$$

3. Voltage is less than l/k times the rated voltage; the interrupting capacity is k times the interrupting capacity at the rated voltage.

The momentary current capability, defined as the fully offset RMS fault current against which the breaker must be able to close and latch its contacts, is 1.5k times the symmetrical RMS interrupting capacity of the breaker at rated maximum voltage and is not a function of the actual voltage of application.

Under the total-current basis of rating switchgear, the breaker is assigned an interrupting MVA and rated voltage from which an interrupting capability in amperes at rated voltage can be calculated. The breaker is also assigned a range of voltages over which the interrupting MVA is a constant number. If the upper limit of voltage can be exceeded in application, the application is not proper. Below the lower limit, the interrupting capability is not proper. Below the lower limit, the interrupting capability in amperes is constant at a value calculated from the interrupting MVA at the lower-limit voltage. Momentary (or first-cycle) current capability is defined as the maximum fully offset

RMS current the breaker can withstand for one second and is assigned by the manufacturer.

Low-voltage breakers are tested and applied in accordance with ANSI C37.13. Low-voltage breakers of present and recent manufacture have symmetrical current interrupting ratings. For low-voltage breakers, calculated first-cycle symmetrical short-circuit currents are compared with the manufacturer's symmetrical ratings since these breakers may be operated rapidly enough to part their contacts during the first-cycle of short-circuit current. Low-voltage breakers manufactured prior to 1957 had average symmetrical short-circuit interrupting current ratings which were compared with 1.25 times calculated first-cycle symmetrical short-circuit currents.

Fuses are fast-acting protective devices that operate in the first-cycle of fault and are rated on a total symmetrical or asymmetrical fault current, depending on the fuse type and voltage rating.

Standards for Short-Circuit Duty Calculations

Electrical power system operating conditions change constantly with system loading and operating procedures. The available short-circuit current also changes with system operating conditions. For any operating condition, the short-circuit current decreases from a maximum value at the inception of a fault until the fault is removed. The rate of this short-circuit current decay depends on many factors.

The American National Standards Institute (ANSI) has developed standards to be used by the electrical industry for calculating short-circuit currents to be compared with short-circuit ratings or capabilities of electrical equipment. Industrial and commercial power system studies are made by calculating short-circuit current values in accordance with these standards.

Duty and Relay Short-Circuit Current Calculations

The following gives a brief description of the type of calculations that can be made:

1. **First-Cycle Duty per ANSI C37.13-1981 (similar to ASA C37.5-1953)**
   The momentary duty calculated by following ANSI C37.13-1981 is used to compare with the interrupting rating for low-voltage breakers and fuses since their interrupting time is within the first-cycle.

   Impedances represent the utility source, generators, motors, transformers and lines. Sub-transient impedances are used for the utility sources, generators, and synchronous motors. Locked rotor impedances are used for induction motors. For a simplified and more conservative answer only reactances need be used.

Present-day, low-voltage breaker ratings are compared to the symmetrical current obtained by an E/A calculation at the fault point, while some older low-voltage ratings are compared to an average asymmetrical current 1.25 times the symmetrical current. For symmetrically rated low-voltage circuit breakers, when the X/R ratio is greater than 6.6, the calculated duty is multiplied by a number greater than 1.00 as listed in Table 3 of ANSI C37.13-1981 for comparison with breaker rating. If the X/R ratio is not known, the multiplier should be 1.15. Fuse rating are compared to an asymmetrical current equal to 1.6 times the symmetrical currents in some cases. For low-voltage current-limiting fuses the multiplier is 1.0.

2. **First-Cycle Duty per ANSI C37.010-1979 and C37.5-1979**
Momentary duty calculated by following ANSI C37.010-1979 and C37.5-1979 is compared with the closing and latching capability of medium and high-voltage circuit breakers. Total impedances, or reactance portions of the utility source impedance, generator, motor, transformer and line impedances are used for the momentary current calculations. The reactances used for the utility source, generator, and synchronous machines are sub-transient reactances. The reactances of the induction motors are entered per Table SCI-3. The circuit E/X current at the fault point is the symmetrical momentary (short time) duty for the breakers. The close-and-latch duty is found by multiplying the symmetrical duty by 1.6 or by using the actual X/R ratio multiplier.

The superseded ASA 37.5-1953 calculating procedure or the procedure given in C37.13-1981 for low-voltage breakers is sometimes used to evaluate the medium and high-voltage breaker first-cycle duties, along with fuses and low-voltage breaker duties. Using either of the above procedures will yield a slightly higher calculated duty (usually 2%-5%) for medium and high-voltage breakers than ANSI C37.010-1979 because all induction motors are included at their locked rotor impedance.

3. **Interrupting Duty per ANSI C37.010-1979 and C37.5-1981**
The interrupting duty calculated by following ANSI C37.010-1979 for symmetrical-current-rated breakers and ANSI C37.5-1979 for total current rated circuit breakers is compared with the medium and high-voltage breaker interrupting ratings.

The interrupting current is lower than the momentary current because it takes into account the short-circuit decrement with respect to time while the power circuit breaker is opening. The interrupting duty is calculated by using the reactances given in Table SCI-3 of this introductory section.

The interrupting duty is found by calculating the short-circuit current (E/X) from the reactance network only and then finding the equivalent resistance for the circuit at the fault point, using a resistance-only network reduction. The breaker interrupting time, electrical distance away from generators (measured by the number of intervening transformers) and X/R ratio at the fault are used to determine a multiplying factor to be applied to the symmetrical current to take into account the appropriate direct-current decrements for breakers rated from two- to eight-cycles interrupting time. The multipliers are taken from curves given in ANSI Standard C37.5-1979 for total-current-rated breakers.

Frequently, interrupting current calculations are made using IEEE Transactions Paper 60TP146-IGA Sept/Oct 1969, "Interpretation of New American National Standards for Power Circuit Breaker Application" (GER-2550) as a guide. The principal extension of the ANSI standards is that a ratio of remote-generator fault current to the sum of the local-generator fault current and remote-generator fault current is used as a measure of the electrical distance from the fault to the generation. The resulting fault-current multiplier takes into account reactors and line impedances that may be equivalent to transformer impedances, as well as variations in the size of transformers.

4. **Short-Circuit Relay Currents**
   Short-circuit studies are also made to determine the branch current required to determine settings for relays and protective devices in coordination studies. The impedances of generators and motors depend on the time of interest subsequent to the fault. For long time periods after the fault, the utility source and transient impedance of the generators may be the only short-circuit sources in the network.

One-Line Diagram Discussion

It will be noted that all impedance elements consisting of motors, transformers, cables and busways are identified on this diagram in agreement with the database report. Also, all faulted buses are identified by Bus ID on the short-circuit printout. All switching devices shown on the one-line are assumed closed unless designated as "open".

All protective devices are shown with the existing type and size or setting, and may be changed after the recommended type and size or settings have been effected.

SHORT CIRCUIT ANALYSIS

Utility Short-Circuit Impedance
The Utility short-circuit contributions used in this study are shown below on a 100 MVA, 480V base. The System Protection Department of Nevada Power Company provided these values and is documented in the Appendix. The X/R values were chosen as typical values for a delivery system of this size. A sensitivity analysis was performed to verify these X/R values as reasonable by running the Short Circuit Analysis at X/R = 1 and X/R = 100. No equipment was found to fail equipment duty ratings within this range of X/R.

At the Utility Service Entrance (@480V):

	NPC
Three Phase Fault	21242A
Three Phase X/R	7
Ground Fault	21692A
Ground Fault X/R	7

Equipment Database Printout
The first computerized printout represents the database that includes all system components used in generating this report. The utility, generator and motor contributions are detailed first, then transformers, cables, and panels. The output is generally self-explanatory.

Cable sizes were determined from Single Line Diagrams and Tables submitted by the Engineer of Record. Additional information regarding cable lengths was also determined from the Single Line Diagrams. When cable lengths were not provided, a value of 10’ is used. Low-voltage motor speeds were assumed as 1800 RPM.

Short-Circuit Program Output Explanation
ESA’s EasyPower Version 7.0 was used to calculate the fault current duties using a nodal admittance network. Pre-fault steady-state load currents are omitted since the effects of system load current through a device during a fault is usually negligible in typical industrial and commercial electrical distribution systems.

This short-circuit program provides full implementation of ANSI Standards C37.010-1979, C37.5-1979 and C37.13-1981.

For **momentary duty** (1/2 cycle) fault calculations, the positive sequence impedance is assumed equal to the negative sequence impedance. X/R ratios are derived from the complex network.

For **interrupting duty** fault calculations, rotating machine subtransient impedances are modified by multipliers as outlined in ANSI Standards C37.010-1979, and C37.5-1979.

Negative sequence impedances are modeled using the rotating machine subtransient impedances with no multipliers. A separate "R" (resistance) network is formed for the calculation of the fault point X/R ratio. The X/R ratio used for the calculation of the interrupting duty multipliers is then found from the relationship Z/R. This method fully complies with the ANSI standard and has the advantage of accurate currents and voltages and increased accuracy of a separate X separate R solution technique. NACD (No AC Decrement) ratios are calculated with consideration of generator "Local" and "Remote" contributions as outlined in ANSI Standard C37.010-1979 and Reference 4. Medium and high-voltage interrupting multipliers are also derived from Reference 4.

The ***Equipment Duty Report*** for each fault type displays a comparison of each piece of equipment's listed duty rating with respect to the calculated fault current at that equipment's particular location in the distribution system. A sample section of the report is shown below:

```
EQUIPMENT DUTY VIOLATION AND WARNING DETAILED REPORTS
Driving Point Voltage (P.U.) = 1.00000


****************************************************************************************************

Equipment Duty Comparison Report For Bus:
H4              Area:    1  Zone:     1   Bus kV:  0.48 kV

____________________ Equipment _____________________   _____ Ratings ______   _________ Duties __________   Comments

  ID              Manufacturer  /  Style          Test    1/2 Cycle Interrupting       1/2 Cycle     Interrupting
                                                Standard     (kA)     (kA)   Cyc       kA   ( % )     kA   ( % )

B H4-BR         GE             /SEL            ANSI-SYM     65.00                      9.65( -85.2%)
B TX T4         GE             /SEL            ANSI-SYM     65.00                      9.65( -85.2%)
H4                             /               ANSI-SYM     65.00                      9.65( -85.2%)

****************************************************************************************************
```

The first column under Equipment, **ID,** identifies each *Breaker* in the panel or switchboard (each starting with the letter "B") and finally on the last line in the first column, the *panel* or *switchboard* itself. The second and third column under Equipment identifies the *manufacturer* and *Style* (in this case a GE Spectra series SEL breaker). The first column under **Ratings** indicates the Breaker or Panel's *kAIC rating* (in this case, 65kAIC for the SEL breaker). The first column under **Duties** indicates the ½ cycle calculated fault current at the location of the equipment within the distribution system (in this case, 9.65kAIC). The result of this comparison (between the manufacturer's listed rating and the subjected duty) indicates the required fault duty is 85% less than the listed value of the equipment. A *Warning* or *Violation* comment in the **Comments** column indicates when an evaluated piece of equipment is not capable of safely interrupting the available fault current.

Devices that are calculated as over-dutied (VIOLATION) should be replaced as indicated in the *Results - Discussion* found at the end of this section. The devices shown with a "WARNING" comment should be replaced if further motor loading or increased incoming capacity is foreseen. A "WARNING" indicates that a device's calculated fault current is within 10% of its rating. The result of a device applied in excess of its rating may be the destruction of the device as well as the load it was supposed to protect in the event of a major fault.

Molded-Case Circuit Breakers
An important consideration in the application of molded-case and insulated case circuit breakers is that often the interrupting rating given to the equipment is higher than its tested interrupting capacity. In testing circuit breakers for short circuit interrupting ratings, Underwriter's Laboratories (UL) uses an additional four feet, ten inches of cable sized to 125% of the trip setting of the breaker. Thus a 15 amp trip circuit breaker is tested with 4'10" of 14 AWG wire between it and the fault point. This added impedance can severely limit the test current actually applied to the device. The above breaker may have an interrupting rating of 14,000 amps symmetrical short-circuit current at 50% power factor but is only tested at 7,353 amps at 77% power factor at the line connections of the breaker. This discrepancy is most significant at lower trip sizes and at higher interrupting ratings. This may mean that the application of a circuit breaker whose interrupting capacity is less than the available fault current is a violation of the NEC even though the interrupting rating is sufficient. Similar testing procedures and ratings differences also exist for motor starters, enclosures, distribution panels and motor control centers.

Table SCA-1 lists some common interrupting ratings and capacities for smaller breaker sizes at 480 Volts.

Table SCA-1 [6]

Interrupting Rating	Trip Size	Tested Int. Capacity	Interrupting Rating	Trip Size	Tested Int. Capacity
10,000 A	15 A	7,353 A	14,000 A	15 A	9,772 A
10,000 A	20 A	8,203 A	14,000 A	20 A	11,226 A
10,000 A	25&30A	8,882 A	14,000 A	25&30A	12,354 A
10,000 A	40&50A	9,249 A	14,000 A	40&50A	12,926 A
25,000 A	15 A	13,530 A	42,000 A	15 A	15,714 A
25,000 A	20 A	17,037 A	42,000 A	20 A	21,526 A
25,000 A	25&30A	20,248 A	42,000 A	25&30A	28,352 A
25,000 A	40&50A	21,948 A			
25,000 A	60 A	23,104 A			

The next printout from the Short-Circuit Program is the *Low Voltage Momentary (First Cycle) Breaker Duties Using Momentary Impedance Circuit*.

Calculated first-cycle (momentary) short-circuit currents are used to evaluate interrupting duty for fast-operating interrupters such as fuses and low-voltage circuit breakers, and to calculate relay currents used in protective-device coordination studies. First-cycle duty currents are calculated using subtransient or modified subtransient reactance (X"d) for all sources of short-circuit current as specified in the appropriate ANSI calculating procedures.[1,2,3,4,5]

As indicated, this printout shows the symmetrical amps and the fault X/R ratio as well as asymmetrical amps for each faulted bus in the system. X/R ratios are derived from the complex network. Contributions from adjacent buses are also shown. The "duty" affecting a protective device is normally defined as the contribution from buses "upstream" of the device in the electrical system.

Power Circuit Breaker Duty is shown under the heading "Symmetrical Amps", while Molded-Case Breakers may be shown with multiple duties. This is because molded-case breakers have different Test Power Factors. If the actual fault PF is less than that at which the device was tested (fault X/R ratio greater than test X/R ratio), the device must be derated or a multiplier applied to its duty before comparing the duty with the device's rating for interrupting evaluation.

The Test Power Factors for the above devices are listed here at their worst-case, highest values. This means that for a fault PF less than this, a multiplier is applied to the calculated fault current before it is compared to the device's rating. Breakers with interrupting ratings 10kA or less have a Test Power Factor of 0.50. Breakers with interrupting ratings from 10kA to 20kA have a Test Power Factor of 0.30. Breakers with interrupting ratings of 20kA, or greater, have a Test Power Factor of 0.20. Power Circuit Breakers have a Test Power Factor of 0.15. Similarly, Low-Voltage Fuses have Test PF associated with them as well. There are two different Test PFs, 0.20 and 0.50.

The multiplier to increase the calculated fault current so that it may be compared to the device's nameplate interrupting rating may be calculated by equation SC-E1.

Equation SC-E1.

$$\text{Multiplier} = \frac{1 + \in^{\frac{-\Pi}{(X/R)}}}{1 + \in^{\frac{-\Pi}{K}}}$$

where X/R= Fault X/R ratio
K = tan { $\cos^{-1}$(PF)}
and PF= Test Power Factor (device dependent)

The multiplier to change the calculated symmetrical amperes to asymmetrical amperes is shown in the right half of Equation SC-E2.

Equation SC-E2.

$$\text{Asym} = \text{Sym} * \sqrt{1 + 2 \in^{\frac{-2\pi}{(X/R)}}}$$

where Sym = symmetrical amperes calculated
and Asym = asymmetrical amperes

References

1. "Application Guide for AC High-Voltage Breakers Rated on a Symmetrical Current Basis," ANSI Standard C37.010-1979.

2. "Calculation of Fault Currents for Application of Power Circuit Breakers Rated on a Total-Current Basis," ANSI Standard C37.5-1979.

3. "American National Standard for Low-Voltage AC Power Circuit Breakers Used in Enclosures," ANSI Standard C37.13-1981.

4. "Interpretation of New American National Standard for Power Circuit Breakers Applications,", W.C. Huening Jr., IEEE Transaction on Industry and General Applications, Vol. IGA-5, No. 5, Sept./Oct. 1969.

5. "Calculating Short-Circuit Currents With Contributions From Induction Motors," W.C. Huening, Jr., Conference Record Industry Applications Society, IAS-1981: 21A, 81CH1678-2, page 427-33.

6. "Short Circuit Ratings, Labels, and Fault Withstandability of Molded-case and Insulated-case Circuit Breakers and Combination Motor Starters," Arthur J. Smith, Conference Record of the 1989 IEEE Industry Applications Society Annual Meeting, 89CH2792-0.

Results - Discussion

The Equipment Duty Rating printouts indicate that all of the protective devices or panels in the scope of this study are appropriately rated (and are not within 90% of their rating).

Note: For series ratings to apply for a downstream panel to be protected by an upstream device, both the protected panel and the upstream device must be so labeled. All combinations indicated have been UL tested to the fault ratings shown. See GE Publication DET-008A

New protective devices added to the system should be checked per the short circuit levels given in the program to insure adequate interrupting ratings are provided. Any major change or addition to the power system can significantly change the short circuit levels. The program should particularly be re-examined in the event of a change in the utility service, a change of one of the principal transformers, or a significant addition of motor load to the studied electrical system.

COORDINATION STUDY INTRODUCTION

Introduction

The purpose of a coordination study is to properly select the circuit protective devices and to provide coordinated settings for adjustable protection devices in the facility that are within the scope of the study. The scope of this study includes the 480V main service to a single main switchboard (MSB) and a mini-power center. This study includes a tabulation of all appropriate feeder breaker settings.

The protective device ratings and settings were chosen to provide a reasonable compromise, based on a thorough engineering evaluation, between the often-conflicting goals of maximum protection and greatest service continuity. Judgments were made as to the best balance between these factors. When a balance is attained, the protective system is described as being "coordinated". It is not always possible to obtain the desired degree of system and equipment protection in a selective fashion. Selectivity means that for a fault at a given location, only the protective device nearest the fault will operate to isolate the fault from the circuit. Other "upstream" devices see the fault but allow the "downstream" device to operate first.

The Coordination Study's methods and recommendations are in conformance with the National Electrical Code (NEC), ANSI/IEEE Standard 242-1986 (IEEE Buff Book), and accepted industry practice. A general explanation of the methods used for this study is found under this tab in a section entitled *Procedures.*

The Coordination Study section of the report is organized as follows, *Compliance with Codes and Standards*, *Procedures*, and *General Discussion of Protective Devices.* The next section is titled *Coordination Study - Analysis* and includes the specific discussion and recommendations for the *South Edge Reservoir – R36* project. Time Current Curves used during the evaluation of this particular electrical distribution system are included in the *Appendix*.

Compliance with Codes and Standards

The following discussion addresses the study's compliance with the National Electric Code and ANSI/IEEE Standards.

Lack of selectivity normally occurs with the **use of molded-case circuit breakers and fuses** for both feeder protection and branch circuit protection. Underwriter's Laboratory standard (UL489) requires that the molded-case circuit breakers incorporate an instantaneous trip. This provides self-protection for the molded-case breaker. At high levels of fault current, the instantaneous trip sensor of both the upstream substation feeder breaker and the downstream molded-case breaker or fuse will sense the fault current. Either or both may trip. This lack of selectivity occurs under severe fault conditions when molded-case breakers or fuses are applied as feeder protective devices. It should also be noted that utilizing series rated combinations of circuit breakers would also compromise selectivity.

The electrical system is examined to find areas that do not conform to the current (2002) version of the **National Electric Code (NEC)**. The NEC is not necessarily enforced retroactively and it is not possible to determine the provisions of the NEC that were in force at the time that a particular installation was made. However, since the NEC provisions cited pertain to basic electrical system protection concepts, facility management should be cognizant of them and initiate corrective action when necessary.

Cable Ampacity - The ratings of all protective devices within the scope of this study were examined to see if they conformed to the requirements of NEC Article 240.4 which states that *"Conductors, . . ., shall be protected against overcurrent in accordance with their ampacities . . . "*

Ampacity values for wires with either a 60°C or 75°C thermal rating were used for this evaluation because these wire thermal ratings are stipulated in the UL listing instructions for the terminations of distribution equipment. The termination provisions are based on the use of 60°C rated wire for wire sizes #14 to #1 AWG and 75°C rated wire for wire sizes Nos. 1/0 and greater. Wire with a higher thermal rating may be used but this wire must have a cross-sectional area not less than that of the 60°C or 75°C rated wire in order to comply with the listing instructions. These listing instructions must be followed as required by NEC Article 110.3(B).

The next higher device rating is allowed in the code if the standard ampere rating of the fuse or circuit breaker doesn't correspond to the cable ampacity and if this rating does not exceed 800 amperes. The NEC contains tables of ampacities, which provide standard values for various cable types and voltage ranges. Adjustable trip circuit breaker settings can be considered acceptable if the minimum setting is within the limit imposed by the next largest standard device ampacity. The National Electric Code defines standard ampere ratings for fuses and inverse time circuit breakers in section 240-6 as ". . . 15, 20, 25, 30, 35, 40, 45, 50, 60, 70, 80, 90, 100, 110, 125, 150, 175, 200, 225, 250, 300, 350, 400, 450, 500, 600, 700, 800, 1000, 1200, 1600, 2000, 2500, 3000, 4000, 5000, and 6000 amperes".

The protective device that protects each of the non conforming circuits should be replaced with one having a rating not greater than that indicated as the maximum device rating <u>or</u> the wire should be replaced with a quantity and size which will provide an ampacity not less than that indicated for the minimum wire size.

The National Electric Code Table 310-16 provides the ampacity of the system's 480V cables.

SIZE	AMPACITY
1/0	150
2/0	175
3/0	200
4/0	230
250	255
300	285
350	310
400	335
500	380
600	420
700	460
750	475
800	490
900	520
1000	545
1250	590
1500	625
1750	650
2000	665

Cable Ampacity for Capacitors is addressed in NEC article 460.8, which states, *"The ampacity of capacitor circuit conductors shall not be less than 135 percent of the rated current of the capacitor."*

Ground fault protection is examined on the 480V system pursuant to NEC articles 230.95 and 215.10. Equipment ground fault protection is required on service and feeder disconnecting means rated 1,000A or more in solidly grounded wye systems with greater than 150V to ground, but not exceeding 600 volts phase-to-phase. Feeder ground fault protection is not required if ground fault protection is installed on the supply side of the feeder, for example, at a main circuit breaker.

The inability of phase overcurrent devices to protect equipment from the damage caused by arcing ground faults is well documented. The arc is resistive and can limit the fault current to levels below the pickup settings of short-time and instantaneous devices. The ground fault may only be isolated through the action of an overload device, which allows the fault to continue for an extended period of time before tripping occurs. This extended time will result in greater damage to equipment than had the ground fault been isolated rapidly. Many instances have been recorded where equipment was literally consumed by an arcing ground fault.

While ground fault protection will greatly reduce the extent of damage that a ground fault arc can cause, the ground fault device may not necessarily operate selectively with phase overcurrent devices downstream. For this reason, ground fault protection on both main and feeder circuit breakers should be contemplated in order to improve selectivity for feeder ground faults. The decision to install ground fault protection on feeder circuit breakers as well as main circuit breakers should consider the following issues:

1. Presence of critical loads on the feeders. Will critical loads experience an outage due to ground faults on other feeders?

2. Rating and type of downstream overcurrent devices. Are downstream phase overcurrent devices capable of sensing ground fault currents within their zone of protection? Is the degree of protection provided by these devices adequate to limit the extent of potential damage to a tolerable level?

3. Main ground fault protection sensitivity. Can the main ground fault device pickup and/or delay be set high enough to allow downstream overcurrent devices to isolate ground fault currents within their protective zone?

The analysis outlined above is beyond the scope of this study. A minimum recommendation would be to have ground fault protection at the main circuit breakers.

Transformer overcurrent protective devices applied at the primary and secondary of transformers were evaluated for compliance with NEC section 450.3. NEC Article 450-3(b)(2) permits the secondary protective device to be set no greater than 125 percent of the transformer rated secondary current when the primary device is not greater than 250 percent of the transformer rated primary current. Note that this article of the NEC *does not* permit the next highest rated device to be applied for the secondary protection when 125% of the rated current does not correspond to a standard rating.

Maximum Continuous Ratings of Fuses and Circuit Breakers
Permitted For Various Transformer Voltage Levels and Impedances
NEC Table 450.3(A)

Transformers with Primaries Over 600V

Location Limitations	Transformer Rated Impedance	Primary Protection		Secondary Side Protection *N2		
				Over 600V		600V or Below
		Maximum Breaker Rating	Maximum Fuse Rating	Maximum Breaker Rating *N4	Maximum Fuse Rating	Maximum Circuit Breaker or Fuse Rating
Any Location	6% & Below	600% *N1	300% *N1	300% *N1	250% *N1	125% *N1
	More than 6% & not more than 10%	400% *N1	300% *N1	250% *N1	225% *N1	125% *N1
Supervised Locations Only *N3	Any	300% *N1	250% *N1	Not Req'd	Not Req'd	Not Req'd
	6% & Below	600%	300%	300% *N5	250% *N5	250% *N5
	More than 6% & not more than 10%	400%	300%	250% *N5	225% *N5	250% *N5

*N = Notes for Table 450.3(A)

1. Where the required fuse rating or circuit breaker setting does not correspond to a standard rating or setting, a higher rating or setting that does not exceed the next higher standard rating or setting shall be permitted.
2. Where secondary overcurrent protection is required, the secondary overcurrent device shall be permitted to consist of not more than six circuit breakers or six sets of fuses grouped in one location. Where multiple overcurrent devices are utilized, the total of all the device ratings shall not exceed the allowed value of a single overcurrent device. If both circuit breakers and fuses are used as the overcurrent device, the total of the device ratings shall not exceed that allowed for fuses.
3. A supervised location is a location where conditions of maintenance and supervision ensure that only qualified persons will monitor and service the transformer installation.
4. Electronically actuated fuses that may be set to open at a specific current shall be set in accordance with settings for circuit breakers.
5. A transformer equipped with a coordinated thermal overload protection by the manufacturer shall be permitted to have separate secondary protection omitted.

NEC Table 450.3(B)

Transformers with Primaries 600V and Below

Protection Method	Primary Protection			Secondary Protection *N2	
	Currents of 9 Amperes or More	Currents Less than 9 Amperes	Currents Less than 2 Amperes	Currents of 9 Amperes or More	Currents Less than 9 Amperes
Primary Only	125% *N1	167%	300%	Not Req'd	Not Req'd
Primary & Secondary	250% *N3	250% *N3	250% *N3	125% *N3	167%

*N = Notes for Table 450.3(B)

1. Where 125 percent of this current does not correspond to a standard rating of a fuse or nonadjustable circuit breaker, a higher rating that does not exceed the next higher standard rating shall be permitted.
2. Where secondary overcurrent protection is required, the secondary overcurrent device shall be permitted to consist of not more than six circuit breakers or six sets of fuses grouped in one location. Where multiple overcurrent devices are utilized, the total of all the device ratings shall not exceed the allowed value of a single overcurrent device. If both breakers and fuses are utilized as the overcurrent device, the total of the device ratings shall not exceed that allowed for fuses.
3. A transformer equipped with coordinated thermal overload protection by the manufacturer and arranged to interrupt the primary current, shall be permitted to have primary overcurrent protection rated or set at a current value that is not more than six times the rated current of the transformer for transformers having not more than 6 percent and not more than four times the rated current of the transformer for transformers having more than 6 percent but not more than 10 percent impedance.

Conductors that supply motor loads are subject to special requirements found in Article 430 of the NEC. First, it should be noted that NEC Table 430.150 shall be utilized for the full load current values applied to cable ampacity calculations for three-phase motors as specified in Article 430.6. The table supplies full load current values for motors rated up to 200HP. Current values for motors rated greater than 200HP can be interpolated from the table data.

References to motor full load current ratings in this report, when related to conductor ampacity, pertain to the values found in the NEC tables. Motor branch conductors supplying a single motor must have an ampacity greater or equal to 125 percent of the motor full load current rating (Article 430.24). The ampacity of both branch and feeder conductors which supply several motors must have a minimum ampacity greater or equal to the sum of the full load currents of the connected motors plus 25 percent of the full load current rating of the highest rated motor. These requirements must be applied when motors are operated simultaneously and continuously. However, special consideration can be granted from the authority having jurisdiction to these requirements when it can be shown that on-duty cycle, demand factor is less than 100 percent, operational procedures, production demands or nature of the work is such that not all motors are running at the same time and reduce the conductor heating sufficiently to allow use of a smaller conductor size (Article 430.26). In this report, motors are assumed to be run on a continuous basis unless stated otherwise.

Procedures

The coordination study generally began at the Main Utility Service Disconnect in the SES switchgear. Settings were chosen with the goal of providing the best coordination that was possible with the largest downstream fixed-setting protective device (transformer breaker). The study then proceeded with coordinating each of the feeder and sub-panel breakers. Time-current curves were used to determine the settings that provided optimum coordination. This report contains those time-current curves that were deemed to contain essential information.

The following is a tested, generally accepted philosophy for selecting and setting protective devices:

1. A feeder "first-line" or "primary" protective device will remove fault current as quickly as possible.
2. If the feeder primary protection fails, a "back-up" protective device will remove the fault. An upstream device that acts as the primary device in its zone usually provides the back-up function. Therefore, time-current coordination is required between the feeder primary and back-up protective devices.

The protective device settings are individually chosen to accommodate circuit parameters. The criteria used in determining the recommended feeder protective device settings are:

1. System or feeder circuit full-load current.
2. Allowance for coordination with the largest downstream protective device set to the highest pickup and time delay including substation secondary circuit protective devices.
3. Transformer protection in compliance with American National Standards Institute (ANSI) and National Electrical Code (NEC) requirements.
4. Avoidance of nuisance tripping due to transformer magnetizing inrush currents or motor inrush currents.
5. Short circuit for faults occurring in the protected zone of the system, including faults on transformer secondaries.
6. Protection of cables per NEC requirements and published heating limits.

Included in the report are protective device one-line diagrams which functionally depict connections of protective devices to instrument transformers (current transformers, potential transformers).

Calibration and Testing of Protective Devices

The time-current relationships between protective devices as established in this report require that the individual relay operating characteristics do not depart appreciably from those shown on the published time-current curves from the manufacturer. The specified settings will provide operation of the devices essentially as shown. However, device tolerance and the difficulty in obtaining exact field settings may result in deviations from the specified operating times. Therefore, it is recommended that the device settings be calibrated by field tests to insure the desired response.

Satisfactory device coordination depends on operation of the protective devices when required, even though they may be inactive for long periods of time. To assure continued proper device action, it is essential the devices be calibrated and checked at regular intervals.

Low Voltage Cable Protection

Article 240.3 of the National Electric Code states that *"Conductors, . . . , shall be protected against overcurrent in accordance with their ampacities . . . "* The next higher standard overcurrent device rating (above the ampacity of the conductors being protected) is allowed in the code with some conditions if the standard rating of the fuse or circuit breaker doesn't correspond to the cable ampacity (below 800 amperes). NEC section 220.10(B) precludes setting an overcurrent protective device above its ampere rating in most situations.

Low Voltage Circuit Breaker Settings

The low voltage circuit breaker device settings are provided in the *Adjustable Breaker Settings Table*. The protection and coordination for many of these circuit breakers becomes highly redundant, and many settings can be derived from a single curve.

As the table may indicate, some of the long time band settings may be set higher than minimum to allow coordination with downstream circuit breakers or fuses. In most cases the long time pickup is set for cable protection. Short time trip settings are chosen for close coordination with downstream devices, while the instantaneous trip settings are set at their highest value to allow maximum selectivity with upstream coordination. Also taken into account is the fault current available at the end of a feeder. This is to assure that a breaker operates when subjected to fault current levels.

ANSI STANDARD DEVICE FUNCTION NUMBERS

Dev. No.	Function
1.	Master Element
2.	Time-delay Starting or Closing Relay
3.	Checking or Interlocking Relay
4.	Master Contactor
5.	Stopping Device
6.	Starting Circuit Breaker
7.	Anode Circuit Breaker
8.	Control-Power Disconnecting Device
9.	Reversing Device
10.	Unit Sequence Switch
11.	Reserved for Future Application
12.	Over-speed Device
13.	Synchronous-speed Device
14.	Under-speed Device
15.	Speed or Frequency-Matching Device
16.	Reserved for Future Application
17.	Shunting or Discharge Switch
18.	Accelerating or Decelerating Device
19.	Starting-to-Running Transition Contactor
20.	Electrically Operated Valve
21.	Distance Relay
22.	Equalizer Circuit Breaker
23.	Temperature Control Device
24.	Reserved for Future Application
25.	Synchronizing or Synchronism-Check Device
26.	Apparatus Thermal Device
27.	Undervoltage Relay
28.	Flame Detector
29.	Isolating Contactor
30.	Annunciator Relay
31.	Separate Excitation Device
32.	Directional Power Relay
33.	Position Switch
34.	Master Sequence Device
35.	Brush-Operating or Slip-Ring Short-Circuiting Device
36.	Polarity or Polarizing Voltage Device
37.	Undercurrent or Underpower Relay
38.	Bearing Protective Device
39.	Mechanical-Condition Monitor
40.	Field Relay
41.	Field Circuit Breaker
42.	Running Circuit Breaker
43.	Manual Transfer or Selector Device
44.	Unit Sequence Starting Relay
45.	Atmospheric Condition Monitor
46.	Reverse-Phase or Phase-Balance Current Relay
47.	Phase-Sequence Voltage Relay
48.	Incomplete Sequence Relay
49.	Machine or Transformer Thermal Relay
50.	Instantaneous Overcurrent or Rate-of-Rise Relay

Dev. No.	Function
51.	AC Time Overcurrent Relay
52.	AC Circuit Breaker
53.	Exciter of DC Generator Relay
54.	Reserved for Future Application
55.	Power Factor Relay
56.	Field-Application Relay
57.	Short-Circuiting or Grounding Device
58.	Rectification Failure Relay
59.	Overvoltage Relay
60.	Voltage or Current Balance Relay
61.	Reserved for Future Application
62.	Time-Delay Stopping or Opening Relay
63.	Pressure Switch
64.	Ground Protective Relay
65.	Governor
66.	Notching or Jogging Device
67.	AC Directional Overcurrent Relay
68.	Blocking Relay
69.	Permissive Control Device
70.	Rheostat
71.	Level Switch
72.	DC Circuit Breaker
73.	Load-Resistor Contactor
74.	Alarm Relay
75.	Position Changing Mechanism
76.	DC Overcurrent Relay
77.	Pulse Transmitter
78.	Phase Angle Measuring or Out-of-Step Protective Relay
79.	AC Reclosing Relay
80.	Flow Switch
81.	Frequency Relay
82.	DC Reclosing Relay
83.	Automatic Selective Control or Transfer Relay
84.	Operating Mechanism
85.	Carrier or Pilot-Wire Receiver Relay
86.	Locking-Out Relay
87.	Differential Protective Relay
88.	Auxiliary Motor or Motor Generator
89.	Line Switch
90.	Regulating Device
91.	Voltage Directional Relay
92.	Voltage and Power Directional Relay
93.	Field-Changing Contactor
94.	Tripping or Trip-Free Relay
95.)	
96.)	Used only for specific applications on individual
97.)	installations where none of the assigned numbered
98.)	functions from 1 to 94 are suitable.
99.)	

General Discussion of Protective Devices

The elements that make up a protected system include relays, direct-acting trip devices, and fuses. Low-voltage power circuit breakers and insulated-case circuit breakers can be adjusted within certain limits to meet protection and coordination requirements. In medium and high-voltage systems, relays are used almost exclusively in the design of a flexible and coordinated protective system.

A brief description of some common relay types used in power distribution systems follows. Appropriate instruction books should be consulted to obtain further information concerning equipment details and their application.

Time-Overcurrent Relays (Device 51) - These relays operate on the electromagnetic induction principle and are available with several time-current operating characteristics. This flexibility makes it possible to select operating characteristics in close harmony with the protective requirements of a particular system component. These relays are non-directional in their operation and are used for both phase and ground fault overcurrent protection of transformers and distribution circuits. Special types are available for motor and generator protection.

The theoretical minimum current at which the relay will operate is called the *pickup current*, which is adjustable within a specified range by changing the *ampere tap* plug. Because of extremely low torques at low-current magnitude, electromechanical relays cannot generally be expected to operate predictably for currents less than 1.5 times the ampere tap setting. This accounts for the termination of the published time operating characteristics at this current level.

Generally, the time delay can be changed by means of a continuously adjustable time dial marked 0 to 10 or 0 to 11. Time-dial markings are arbitrary reference points and are not related to the actual time delay in seconds.

On time-current plots, relay operating characteristics are extended to the maximum short-circuit current value to which a relay is expected to respond. If the overcurrent relay is equipped with an instantaneous attachment (Device 50), then the curve will be terminated at the intersection with the instantaneous relay characteristic.

Overcurrent relays intended for phase fault protection are denoted as 51. Residually connected ground fault relays carry the designation 51N while ground fault relays connected to current transformers in the neutral of a transformer or generator are designated as 51G.

Time overcurrent relays employing electronic circuitry are also available. While these relays have different operating principles from their electromechanical counterparts, the general application procedures described still apply.

Instantaneous Overcurrent Relays (Device 50) - Instantaneous relays have extremely fast operating times (about one cycle). They are essential for fast clearing of extremely high fault currents to reduce burning damage and the possibility of unstable operation of rotating machinery.

However, instantaneous relays cannot always be used when selectivity is desired. Since they cannot be made selective with other instantaneous relays, they are generally only used as the last downstream relay of a series of protective devices which respond to essentially the same magnitude of short-circuit current. This may be a branch-circuit protector, such as a motor starter, or a transformer primary protector.

Whenever there is a large impedance in the circuit (such as a current-limiting reactor or a transformer) the fault current level on the load side may differ significantly from that on the source side. In such cases, the instantaneous relay on the source side of the impedance may be able to be set above the current that would flow to a fault on the load side.

Selectivity between instantaneous relays and fuses for fault clearing times of less than 0.1 second cannot be evaluated on a time-current basis. Since sufficient data are not available to verify selectivity, extreme caution should be exercised in predicting coordination on the basis of the time current characteristics of these devices.

Instantaneous relays may be either self-contained or provided as an attachment to a time-overcurrent relay. Many instantaneous relays operate on the electromagnetic attraction principle. These relays will operate equally well on dc and ac currents and the settings determined for them must recognize the possibility of asymmetry in the fault current. Induction cup type instantaneous relays are available for special applications.

Ground instantaneous relays are given designation suffixes in the same manner as ground time overcurrent relays.

Ground Relays (Devices 50GS and 51GS) - A sensitive ground-fault relay is used to take full advantage of a resistance-grounded system. This ground-fault relay is connected to a low-ratio, window-type current transformer encompassing the three-phase conductors. A matched combination is commonly referred to as a ground sensor. Both time-overcurrent and instantaneous ground sensors can be used (Devices 51GS and 50GS, respectively) to obtain selectivity.

The low-burden capability of window-type transformers introduces a ratio error which is taken into account by the use of operating curves applicable to the ground sensor package being used; that is, the relay-CT combination. These curves may be obtained only by test and are available from the manufacturer. Note that directional ground overcurrent relays should never be connected to low ratio window-type current transformers.

The ground sensor is not responsive to positive and negative sequence load currents but is sensitive to zero sequence (ground fault) currents. Hence, the current transformer ratio is not governed by the anticipated load currents. A 50/5 current transformer ratio is generally used.

Differential Relays (Devices 87G, 87T, 87B and 87L) - Differential relays are employed to permit fast and sensitive protection for phase and ground faults in a bus (87B), a generator (87G), a transformer (87T), or a line (87L). Their use will not only reduce fault point burning damage, but will also improve the ability of rotating machines in the system to return to a stable, steady state mode of operation following a disturbance in the differential zone.

Differential relays are connected to two or more sets of current transformers located at the perimeters of the zone to be protected. Current transformers ideally should have identical characteristics so that through currents will not result in false operation of the differential relays. To allow for normal current transformer tolerances, differential relays are designed to be insensitive to small error currents.

Transformer differential relays are normally designed to provide restraint for harmonic currents predominant in transformer magnetizing inrush currents that are sensed by the transformer source-side current transformers. An adjustable percentage slope adjustment permits de-sensitizing the relay to prevent misoperation for a through fault due to current transformer ratio errors. Ratio tap adjustments are provided to match as nearly as possible the secondary currents in the primary and secondary current transformers.

COORDINATION STUDY ANALYSIS

Discussion and Recommendations

The coordination analysis is provided below.

- All main and feeder breakers should be set and tested at the recommended settings in this report.

- All low-voltage breakers should be set and tested at the recommended settings in this report for proper coordination with upstream breakers and for proper protection of equipment.

- Several 120V / 208V thermal magnetic breakers had overlapping instantaneous trip regions in upstream and downstream panels. This is not uncommon as these breakers typically do not employ adjustable instantaneous pickup capabilities. Some “racing” may occur during fault conditions that would cause an upstream feeder breaker to clear before a downstream panel main breaker on the same branch. This typically occurs on breakers of similar ampacity ratings.

APPENDIX

Nevada Power Company

Service Transformer Fault Duties

*FAULT CURRENT FOR 3-PH TRANSFORMERS (12,470 DELTA-WYE) CALCULATED FOR THE EMERGENCY SPARE TRANSFORMER

SUB IMPEDANCE (%)	SUB MVA	SYSTEM	TRANSFORMER	XFER IMPD	LINE TO LINE	LINE TO GRND	CURRENT BASE	3-PH FAULT	LINE TO GRND
2-138KV / 33MVA Banks in Parallel	BASE	IMPEDANCE	KVA - 3 PH	(%)	VOLTAGE	VOLTAGE	AMPS	AMPS	AMPS
7.05	20	0.00026	75	3.24	208	120	208	11524	11581
7.05	20	0.00040	112.5	2.67	208	120	312	11819	11878
7.05	20	0.00053	150	3.47	208	120	416	27281	27599
7.05	20	0.00079	225	2.21	208	120	625	27162	27478
7.05	20	0.00106	300	2.96	208	120	833	31659	32295
7.05	20	0.00176	500	4.18	208	120	1388	31859	32295
7.05	20	0.00264	750	5.31	208	120	2082	49019	50058
7.05	20	0.00353	1000/1200	5.31	208	120	2776	49019	50058

1500-2500/2800 KVA TRANSFORMERS NOT AVAILABLE FOR 120/208 VOLTAGE SERIES

SUB IMPEDANCE (%)	SUB MVA	SYSTEM	TRANSFORMER	XFER IMPD	LINE TO LINE	LINE TO GRND	CURRENT BASE	3-PH FAULT	LINE TO GRND
2-138KV / 33MVA Banks in Parallel	BASE	IMPEDANCE	KVA - 3 PH	(%)	VOLTAGE	VOLTAGE	AMPS	AMPS	AMPS
7.05	20	0.00026	75	3.24	480	277	90	5246	5273
7.05	20	0.00040	112.5	2.54	480	277	135	5271	5298
7.05	20	0.00053	150	3.37	480	277	180	12418	12571
7.05	20	0.00079	225	2.1	480	277	271	12250	12398
7.05	20	0.00106	300	2.84	480	277	361	14470	14677
7.05	20	0.00176	500	3.98	480	277	601	14470	14677
7.05	20	0.00264	750	5.31	480	277	902	21242	21692
7.05	20	0.00353	1000	5.31	480	277	1203	30901	31863
7.05	20	0.00529	1500	5.31	480	277	1804	39994	41620
7.05	20	0.00705	2000	5.31	480	277	2406	53484	56432
7.05	20	0.00987	2500/2800	5.31	480	277	3368	53484	56432

SEE NOTE BELOW THAT EXPLAINS THE EMERGENCY SPARE TRANSFORMER EXCEPT FOR THE 1000/1200 KVA 3-PH/208V 2500/2800 KVA 3-PH/480V AND 167 KVA 1-PH 120/240V TRANSFORMERS WHICH ARE THE LARGEST NPC CARRIES IN STOCK

*FAULT CURRENT FOR 1-PH TRANSFORMERS CALCULATED FOR THE EMERGENCY SPARE TRANSFORME
(ONLY FOR SINGLE PHASE INSTALLATIONS) CALL DISTRIBUTION PLANNING AND ANALYSIS FOR OPEN DELTA

SUB IMPEDANCE (%)	SUB MVA	SYSTEM	TRANSFORMER	XFER	XFER	XFER IZ% +	LINE TO LINE	LINE TO GRND	HALF WINDINGS	240 BOLTED	120 BOLTED
2-138KV / 33MVA Banks in Parallel	BASE	IMPEDANCE	KVA - 1 PH	IR%	IX%	SYSTEM IMPD	VOLTAGE	VOLTAGE	IMPEDANCE	AMPS	AMPS
7.05	20	0.00009	25	1.30	1.40	1.92%	240	120	0.02583	12280	18970
NO NEW TRANSFORMERS			~~37.5~~								
7.05	20	0.00018	50	0.92	1.40	1.70%	240	120	0.02196	21186	32734
7.05	20	0.00026	75	0.80	1.21	1.48%	240	120	0.01909	25816	40888
7.05	20	0.00035	100	0.72	1.40	1.61%	240	120	0.02038	43302	67717
7.05	20	0.00059	167	0.81	1.32	1.61%	240	120	0.02055	43302	67717

*FAULT CURRENT ON THE 12 kV SYSTEM (FOR CUSTOMER OWNED PRIMARY SWITCHGEAR)

3-PH FAULT	LINE TO GRND
AMPS	AMPS
12000	12000

*NOTE: THE EMERGENCY SPARE IS THE NEXT LARGEST TRANSFORMER FROM THE ACTUAL INSTALLATION AND USED IF THE SAME SIZE REPLACEMENT TRANSFORMER IS NOT IN STOCK. THE FAULT CURRENT LISTED WILL TAKE THIS INTO ACCOUNT.

Contact Distribution Planning and Analysis for more information concerning this table at (702) 252-4805.

Equipment Database

Project Name: South Edge Reservoir R-36
Comment: Equipment Database

Summary

1	Base MVA	100
2	Frequency	60
3	Buses	9
4	MCC Schedules	0
5	Panel Schedules	0
6	Utilities	1
7	Generators	0
8	UPS	0
9	Motors	0
10	Capacitors	0
11	Loads	0
12	Shunts	0
13	Filters	0
14	2-Transformers	2
15	3-Transformers	0
16	Zigzags	0
17	Cables	5
18	Busways	0
19	Xmission Lines	0
20	CL Reactors	0
21	HV Breakers	0
22	LV Breakers	7
23	Switches	0
24	Fuses	1
25	ATS	0
26	Meters	0
27	CTs	0
28	Relays	0
29	Notes	0
30	Lines	0

Buses

	ID Name	Status	Base kV	Area	Zone	AF Type	AF Option	Comment
1	DP-1	On	0.48	1	1	Switchboard	Specified	MLO
2	LP100	On	0.208	1	1	Other	Specified	
3	MCC001 FUTU	On	0.48	1	1	Other	Specified	
4	MOV100	On	0.48	1	1	Other	Specified	
5	MPC	On	0.48	1	1	Other	Specified	
6	SG001	On	0.48	1	1	Switchboard	Specified	
7	SG001-P1	On	0.48	1	1	Conductor	Specified	
8	TX MPC-SEC	On	0.208	1	1	Other	Specified	
9	XMR001-P1	On	12.47	1	1	Conductor	Specified	

Utilities

	ID Name	Status	To bus	Base kV	Util kV	Fault Unit	3Ph SC1	3Ph SC2	SLG SC1	SLG SC2	Model	MW	MVAR	CTL kV pu	MVAR Min	MVAR Max	kV pu Min	kV pu Max
1	NPC	On	XMR001-P1	12.47	12.47	kA	21.242	7	21.692	7	Swing	0	0	1	-100000	100000	0.8	1.2

Utilities

	ID Name	Ctl Angle	Ctl Bus	Ctl Base kV	R1 pu	X1 pu	R0 pu	X0 pu	Hrm RC Factor	Hrm RC Value	I Hrm Rating	Comment
1	NPC	0	XMR001-P1	12.47	0.03082	0.21576	0.02890	0.20234	R-EXP	0.5	4629.91	

2W-Xformers

	ID Name	Status	From bus	From Base kV	From Conn	To Bus	To Base kV	To Conn	Type	Class	Temp	Form	From Nom kV	From Tap kV	From Gnd R	From Gnd jX	To Nom kV
1	TX MPC	On	MPC	0.48	D	TX MPC-SEC	0.208	YG	Dry	OA	80	Core	0.48	0.48	0	0	0.24
2	TX NPC	On	XMR001-P1	12.47	D	SG001-P1	0.48	YG	Oil	OA	115	Core	12.47	12.47	0	0	0.48

2W-Xformers

	ID Name	To Tap kV	To Gnd R	To Gnd jX	MVA	MVA O/L	Z	Z0	X/R	LTC Tap	LTC Step	LTC Min Tap	LTC Max Tap	Ctl Type	Ctl Value	Zps R1 pu	Zps X1 pu	Zps R0 pu	Zps X0 pu
1	TX MPC	0.24	0	0	0.025	0.025	3	2.55	1.58333	None	0.625	0.1	1500	V (PU)	1	64.0792	101.458	10000	1e+007
2	TX NPC	0.48	0	0	0.75000	0.75000	5.31	4.5135	5.22021	None	0.625	0.1	1500	V (PU)	1	1.33204	6.95356	10000	1e+007

2W-Xformers

	ID Name	Rps0+3Rpsg	Xps0+3Xpsg	From Gnd R1 pu	From Gnd jX pu	To Gnd R1 pu	To Gnd jX pu	TCC Standard	TCC FLA Based On	Freq Fault Curve	TCC Max Plot Time	TCC Inrush FLA Mult	TCC Inrush Cycles	Hrm RC Factor	Hrm RC Value
1	TX MPC	54.46737	86.23981	0	0	0	0	ANSI C57.12.59	kVA O/L	Yes	500	8	6	R-EXP	0
2	TX NPC	1.13224	5.910529	0	0	0	0	ANSI C57.109	kVA O/L	Yes	500	8	6	R-EXP	0

2W-Xformers

	ID Name	Hrm Pec-r %	Hrm From I Rating	Hrm To I Rating	Comment
1	TX MPC	15	30.0703	60.1406	
2	TX NPC	15	34.7243	902.109	

Cables

	ID Name	Status	From Bus ID	From Base kV	To Bus ID	To Base kV	Unit	Type	No/Ph	Size	Length	Temp	Insulation	Rating (A)	Material
1	C DP100-01	On	SG001	0.48	DP-1	0.48	U.S.	1/C	6	400	10	50	THWN	2010	Copper
2	C MOV100-P1	On	DP-1	0.48	MOV100	0.48	U.S.	1/C	1	10	10	50	THWN	35	Copper
3	C SG001-P1	On	SG001-P1	0.48	SG001	0.48	U.S.	1/C	6	400	20	50	THWN	2010	Copper
4	C ULP-A	On	DP-1	0.48	MCC001 FUTU	0.48	U.S.	1/C	6	400	10	50	THWN	2010	Copper
5	C XMR100-P1	On	DP-1	0.48	MPC	0.48	U.S.	1/C	1	1	10	50	THWN	130	Copper

Cables

	ID Name	Raceway Type	Raceway Mtl	R1	X1	R0	X0	Xc	Xc0	Gnd Num	Gnd Size	Gnd Mtl	Gnd Type	Gnd Insul	Neutral Num	Neutral Size	Neutral Rating
1	C DP100-01	Conduit	EMT	0.03163	0.03775	0.06326	0.07551	0.00419	0.00419	6	4/0	Copper	Separate	Yes	0	Other	10
2	C MOV100-P1	Conduit	Steel	1.13918	0.04271	4.55673	0.17084	0.00814	0.00814	1	10	Copper	Separate	Yes	1	10	10
3	C SG001-P1	Burial	PVC	0.03070	0.02517	0.06140	0.05034	0.00419	0.00419	6	4/0	Copper	Separate	Yes	6	400	10
4	C ULP-A	Conduit	EMT	0.03163	0.03775	0.06326	0.07551	0.00419	0.00419	6	4/0	Copper	Separate	Yes	0	Other	10
5	C XMR100-P1	Conduit	Steel	0.14127	0.04157	0.56509	0.16629	0.00723	0.00723	1	6	Copper	Separate	Yes	1	1	10

Cables

	ID Name	Neutral Mtl	Neutral Insul	Conductor Lay	Conductor Form	Spacing	R1 pu	X1 pu	R0 pu	X0 pu	B1 pu	B0 pu	Hrm RC Factor	Hrm RC Value	I Hrm Rating	Comment
1	C DP100-01	Copper	Yes	Triangle	Round	0	0.02288	0.02731	0.04576	0.05462	3.29492	3.29492	R-EXP	0.5	2010	
2	C MOV100-P1	Copper	Yes	Triangle	Round	0	4.94435	0.18537	19.7774	0.74150	2.82819	2.82819	R-EXP	0.5	35	
3	C SG001-P1	Copper	Yes	Triangle	Round	0	0.04441	0.03641	0.08883	0.07283	6.58985	6.58985	R-EXP	0.5	2010	
4	C ULP-A	Copper	Yes	Triangle	Round	0	0.02288	0.02731	0.04576	0.05462	3.29492	3.29492	R-EXP	0.5	2010	
5	C XMR100-P1	Copper	Yes	Triangle	Round	0	0.61316	0.18044	2.45268	0.72176	3.18240	3.18240	R-EXP	0.5	130	

LV Breakers

	ID Name	Status	On Bus	Base kV	Conn Type	Class	Options	Breaker Mfr	Breaker Type	Breaker Style	Cont Current (A)	SC Int kA	SC Test Std
1	B LP100 BR	On	LP100	0.208	Feeder	MCCB	Breaker Onl	GE	Q Line	THQL	20	10	ANSI-SYM
2	B LP100 MAIN	On	LP100	0.208	Bus Tie	MCCB	Breaker Onl	GE	Q Line	THQL	125	10	ANSI-SYM
3	B MCC001-P1	On	DP-1	0.48	Feeder	ICCB	Breaker Onl	GE	Power Break II	SS-16	1600	65	ANSI-SYM
4	B MOV100-P1	On	DP-1	0.48	Feeder	MCCB	Breaker Onl	GE	Spectra	SEL	15	65	ANSI-SYM
5	B MPC-MAIN	On	MPC	0.48	Feeder	MCCB	Breaker Onl	GE	E150	TED (480V)	100	14	ANSI-SYM
6	B SG001-MAIN	On	SG001	0.48	Feeder	ICCB	Breaker Onl	GE	Power Break II	SS-16	1600	65	ANSI-SYM
7	B XMR100-P1	On	DP-1	0.48	Feeder	MCCB	Breaker Onl	GE	Spectra	SEL	100	65	ANSI-SYM

LV Breakers

	ID Name	Normal State	Trip	Trip Mfr	Trip Type	Trip Style	Sensor/Frame	Plug/Tap/Trip	LTPU Setting	LTPU Mult	LTPU (A)	LTD Band
1	B LP100 BR	Closed	TMGN	GE	Q Line	THQL	100(15-20AT)	20				
2	B LP100 MAIN	Closed	TMGN	GE	Q Line	THQL						
3	B MCC001-P1	Closed	SST	GE	Power+	LSI	1600	1600	1		1600	1
4	B MOV100-P1	Closed	SST	GE	Spectra RMS	MCCB SE	30A (15AT)	15	1	1	15	Fixed
5	B MPC-MAIN	Closed	TMGN	GE	E150	TED (480V)	150A(90-100AT)	100				
6	B SG001-MAIN	Closed	SST	GE	MVT-Plus	ICCB	1600	1600	1		1600	2
7	B XMR100-P1	Closed	SST	GE	Spectra RMS	MCCB SE	100A (100AT)	100	1	1	100	Fixed

LV Breakers

	ID Name	STPU Setting	STPU Band	STPU I2T	STPU (A)	Inst Setting	Inst Override	Inst (A)	Gnd Pickup	Gnd Delay	Gnd I2T	Gnd (A)	Fuse Mfr	Fuse Type
1	B LP100 BR												<None>	<None>
2	B LP100 MAIN												<None>	<None>
3	B MCC001-P1	2	Min	Out	3200	5	Pickup	8000			Out		<None>	<None>
4	B MOV100-P1	5	Fixed	In	54.75	5	Pickup	115.5			Out		<None>	<None>
5	B MPC-MAIN												<None>	<None>
6	B SG001-MAIN	3	Int	Out	4800	6.5	Pickup	10400	0.3	Max	Out	480	<None>	<None>
7	B XMR100-P1	5	Fixed	In	380	5	Pickup	770			Out		<None>	<None>

LV Breakers

	ID Name	Fuse Style	Fuse Size	Mtr O/L Mfr	Mtr O/L Type	Mtr O/L Style	Motor FLA	Service Factor	PCC kVA Demand	PCC Isc/ILoad	Comment
1	B LP100 BR	<None>	<None>	<None>	<None>	<None>		1			
2	B LP100 MAIN	<None>	<None>	<None>	<None>	<None>		1			
3	B MCC001-P1	<None>	<None>	<None>	<None>	<None>		1			
4	B MOV100-P1	<None>	<None>	<None>	<None>	<None>		1			
5	B MPC-MAIN	<None>	<None>	<None>	<None>	<None>		1			
6	B SG001-MAIN	<None>	<None>	<None>	<None>	<None>		1			
7	B XMR100-P1	<None>	<None>	<None>	<None>	<None>		1			

Fuses

	ID Name	Status	On Bus	Base kV	Conn Type	Normal State	Options	Manufacturer	Type	Style	TCC Model	TCC kV
1	FS NPC	On	XMR001-P1	12.47	Feeder	Closed	Fused Brea	S&C	SM	SM-4	Std Speed	15.5

Fuses

	ID Name	TCC Size	SC Int kA	SC Test X/R	SC Test Std	TCC Mom kA	TCC Int kA	TCC 30 cyc kA	Mtr O/L Mfr	Mtr O/L Type	Mtr O/L Style	Motor FLA	Service Factor
1	FS NPC	50E	12.5	15	ANSI-SYM				<None>	<None>	<None>		1

Fuses

	ID Name	PCC kVA Demand	PCC Isc/ILoad	Comment
1	FS NPC			

Three Phase Bolted Fault

Equipment Duty Ratings

EQUIPMENT DUTY VIOLATION AND WARNING DETAILED REPORTS
Driving Point Voltage (P.U.) = 1.00000

****

Equipment Duty Comparison Report For Bus:
DP-1 Area: 1 Zone: 1 Bus kV: 0.48 kV

Equipment ID	Manufacturer	/ Style	Test Standard	Ratings 1/2 Cycle (kA)	Ratings Interrupting (kA)	Cyc	Duties 1/2 Cycle kA (%)	Duties Interrupting kA (%)	Comments
B XMR100-P1	GE	/SEL	ANSI-SYM	65.00			16.42(-74.7%)		
B MOV100-P1	GE	/SEL	ANSI-SYM	65.00			16.42(-74.7%)		
B MCC001-P1	GE	/SS-16	ANSI-SYM	65.00			16.42(-74.7%)		
DP-1		/	ANSI-SYM	65.00			16.31(-74.9%)		

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Equipment Duty Comparison Report For Bus:
LP100 Area: 1 Zone: 1 Bus kV: 0.21 kV

Equipment ID	Manufacturer	/ Style	Test Standard	Ratings 1/2 Cycle (kA)	Ratings Interrupting (kA)	Cyc	Duties 1/2 Cycle kA (%)	Duties Interrupting kA (%)	Comments
B LP100 MAIN	GE	/THQL	ANSI-SYM	10.00			1.64(-83.6%)		
B LP100 BR	GE	/THQL	ANSI-SYM	10.00			1.64(-83.6%)		
LP100		/	ANSI-SYM	10.00			1.64(-83.6%)		

****

Equipment Duty Comparison Report For Bus:
MPC Area: 1 Zone: 1 Bus kV: 0.48 kV

Equipment ID	Manufacturer	/ Style	Test Standard	Ratings 1/2 Cycle (kA)	Ratings Interrupting (kA)	Cyc	Duties 1/2 Cycle kA (%)	Duties Interrupting kA (%)	Comments
B MPC-MAIN	GE	/TED (480V)	ANSI-SYM	14.00			16.13(15.2%)		VIOLATION

****

Equipment Duty Comparison Report For Bus:
SG001 Area: 1 Zone: 1 Bus kV: 0.48 kV

Equipment ID	Manufacturer	/ Style	Test Standard	Ratings 1/2 Cycle (kA)	Ratings Interrupting (kA)	Cyc	Duties 1/2 Cycle kA (%)	Duties Interrupting kA (%)	Comments
B SG001-MAIN SVC	GE	/SS-16	ANSI-SYM	65.00			16.53(-74.6%)		
SG001		/	ANSI-SYM	65.00			16.38(-74.8%)		

EQUIPMENT DUTY VIOLATION AND WARNING DETAILED REPORTS
Driving Point Voltage (P.U.) = 1.00000

****

Equipment Duty Comparison Report For Bus:
TX MPC-SEC Area: 1 Zone: 1 Bus kV: 0.21 kV

Equipment				Ratings			Duties		Comments
ID	Manufacturer /	Style	Test Standard	1/2 Cycle (kA)	Interrupting (kA)	Cyc	1/2 Cycle kA (%)	Interrupting kA (%)	
B LP100 MAIN	GE	/THQL	ANSI-SYM	10.00			1.64(-83.6%)		

****

Equipment Duty Comparison Report For Bus:
XMR001-P1 Area: 1 Zone: 1 Bus kV: 12.47 kV

Equipment				Ratings			Duties		Comments
ID	Manufacturer /	Style	Test Standard	1/2 Cycle (kA)	Interrupting (kA)	Cyc	1/2 Cycle kA (%)	Interrupting kA (%)	
FS NPC	S&C	/SM-4	ANSI-SYM	12.50			21.24(69.9%)		VIOLATION

Three Phase Bolted Fault

Low Voltage Momentary Report

```
Power Quality Technical Services, Inc. (Serial #34798)
Project Name: South Edge Reservoir R-36
Comment: Three Phase Fault - Low Voltage Momentary Report

Interrupting Results 3 PHASE
Driving Point Voltage (P.U.) = 1.00000


*Bus DP-1               0.480 kV, Zone     1, Area     1
      E/Z =     16.314 kA (      13.563 MVA)  At   -78.82DEG, X/R =     5.16
      Z1 =    1.430170 +j   7.233062 pu,  Z0 =   0.000000 +j   0.000000 pu

      Contributions In kA
      Bus      to       Bus                       kA     Angle  Device   Zone   Area  Branch
      SG001             DP-1                   16.31    -78.82  Branch      1      1  C DP100-01
      MCC001 FUTURE     DP-1                    0.00      0.00  Branch      1      1  C ULP-A
      MPC               DP-1                    0.00      0.00  Branch      1      1  C XMR100-P1
      MOV100            DP-1                    0.00      0.00  Branch      1      1  C MOV100-P1

*Bus LP100              0.208 kV, Zone     1, Area     1
      E/Z =      1.637 kA (       0.590 MVA)  At   -58.73DEG, X/R =     1.93
      Z1 =   88.033043 +j 144.948041 pu,  Z0 =   0.000000 +j   0.000000 pu

      Contributions In kA
      Bus      to       Bus                       kA     Angle  Device   Zone   Area  Branch
      TX MPC-SEC        LP100                   1.64    -58.73  Branch      1      1  B LP100 MAIN

*Bus MCC001 FUTURE      0.480 kV, Zone     1, Area     1
      E/Z =     16.245 kA (      13.506 MVA)  At   -78.68DEG, X/R =     5.10
      Z1 =    1.453054 +j   7.260374 pu,  Z0 =   0.000000 +j   0.000000 pu

      Contributions In kA
      Bus      to       Bus                       kA     Angle  Device   Zone   Area  Branch
      DP-1              MCC001 FUTURE          16.24    -78.68  Branch      1      1  C ULP-A

*Bus MOV100             0.480 kV, Zone     1, Area     1
      E/Z =     12.297 kA (      10.224 MVA)  At   -49.33DEG, X/R =     1.53
      Z1 =    6.374528 +j   7.418439 pu,  Z0 =   0.000000 +j   0.000000 pu

      Contributions In kA
      Bus      to       Bus                       kA     Angle  Device   Zone   Area  Branch
      DP-1              MOV100                 12.30    -49.33  Branch      1      1  C MOV100-P1

*Bus MPC                0.480 kV, Zone     1, Area     1
      E/Z =     15.641 kA (      13.004 MVA)  At   -74.59DEG, X/R =     3.76
      Z1 =    2.043339 +j   7.413504 pu,  Z0 =   0.000000 +j   0.000000 pu

      Contributions In kA
      Bus      to       Bus                       kA     Angle  Device   Zone   Area  Branch
      TX MPC-SEC        MPC                     0.00      0.00  Branch      1      1  TX MPC
      DP-1              MPC                    15.64    -74.59  Branch      1      1  C XMR100-P1

*Bus SG001              0.480 kV, Zone     1, Area     1
      E/Z =     16.383 kA (      13.620 MVA)  At   -78.95DEG, X/R =     5.22
      Z1 =    1.407287 +j   7.205749 pu,  Z0 =   0.000000 +j   0.000000 pu

      Contributions In kA
      Bus      to       Bus                       kA     Angle  Device   Zone   Area  Branch
      DP-1              SG001                   0.00      0.00  Branch      1      1  C DP100-01
      SG001-P1          SG001                  16.38    -78.95  Branch      1      1  C SG001-P1

*Bus SG001-P1           0.480 kV, Zone     1, Area     1
      E/Z =     16.482 kA (      13.703 MVA)  At   -79.24DEG, X/R =     5.35
      Z1 =    1.362871 +j   7.169333 pu,  Z0 =   0.000000 +j   0.000000 pu

      Contributions In kA
      Bus      to       Bus                       kA     Angle  Device   Zone   Area  Branch
      XMR001-P1         SG001-P1               16.48    -79.24  Branch      1      1  TX NPC
      SG001             SG001-P1                0.00      0.00  B           1      1  C SG001-P1
```

Interrupting Results 3 PHASE
Driving Point Voltage (P.U.) = 1.00000

```
*Bus TX MPC-SEC          0.208 kV, Zone     1, Area     1
      E/Z =      1.637 kA (       0.590 MVA)  At   -58.73DEG, X/R =     1.93
      Z1 =   88.033043 +j 144.948041 pu,  Z0 =   0.000000 +j   0.000000 pu

      Contributions In kA
      Bus      to       Bus                        kA     Angle  Device   Zone   Area  Branch
      MPC               TX MPC-SEC               1.64    -58.73  Branch      1      1  TX MPC
      LP100             TX MPC-SEC               0.00      0.00  Branch      1      1  B LP100 MAIN
```

Ground Fault

Equipment Duty Ratings

EQUIPMENT DUTY VIOLATION AND WARNING DETAILED REPORTS
Driving Point Voltage (P.U.) = 1.00000

****

Equipment Duty Comparison Report For Bus:
DP-1 Area: 1 Zone: 1 Bus kV: 0.48 kV

Equipment: ID	Manufacturer	/ Style	Test Standard	Ratings: 1/2 Cycle (kA)	Ratings: Interrupting (kA)	Cyc	Duties: 1/2 Cycle kA (%)	Duties: Interrupting kA (%)	Comments
B XMR100-P1	GE	/SEL	ANSI-SYM	65.00			17.30(-73.4%)		
B MOV100-P1	GE	/SEL	ANSI-SYM	65.00			17.30(-73.4%)		
B MCC001-P1	GE	/SS-16	ANSI-SYM	65.00			17.30(-73.4%)		
DP-1		/	ANSI-SYM	65.00			17.25(-73.5%)		

****

Equipment Duty Comparison Report For Bus:
LP100 Area: 1 Zone: 1 Bus kV: 0.21 kV

Equipment: ID	Manufacturer	/ Style	Test Standard	Ratings: 1/2 Cycle (kA)	Ratings: Interrupting (kA)	Cyc	Duties: 1/2 Cycle kA (%)	Duties: Interrupting kA (%)	Comments
B LP100 MAIN	GE	/THQL	ANSI-SYM	10.00			1.89(-81.1%)		
B LP100 BR	GE	/THQL	ANSI-SYM	10.00			1.89(-81.1%)		
LP100		/	ANSI-SYM	10.00			1.89(-81.1%)		

****

Equipment Duty Comparison Report For Bus:
MPC Area: 1 Zone: 1 Bus kV: 0.48 kV

Equipment: ID	Manufacturer	/ Style	Test Standard	Ratings: 1/2 Cycle (kA)	Ratings: Interrupting (kA)	Cyc	Duties: 1/2 Cycle kA (%)	Duties: Interrupting kA (%)	Comments
B MPC-MAIN	GE	/TED (480V)	ANSI-SYM	14.00			15.72(12.3%)		VIOLATION

****

Equipment Duty Comparison Report For Bus:
SG001 Area: 1 Zone: 1 Bus kV: 0.48 kV

Equipment: ID	Manufacturer	/ Style	Test Standard	Ratings: 1/2 Cycle (kA)	Ratings: Interrupting (kA)	Cyc	Duties: 1/2 Cycle kA (%)	Duties: Interrupting kA (%)	Comments
B SG001-MAIN SVC	GE	/SS-16	ANSI-SYM	65.00			17.46(-73.1%)		
SG001		/	ANSI-SYM	65.00			17.36(-73.3%)		

Power Quality Technical Services, Inc. (Serial #34798)
Project Name: South Edge Reservoir R-36
Comment: Ground Fault - Equipment Duty Report

EQUIPMENT DUTY VIOLATION AND WARNING DETAILED REPORTS
Driving Point Voltage (P.U.) = 1.00000

****

Equipment Duty Comparison Report For Bus:
TX MPC-SEC   Area: 1 Zone: 1   Bus kV: 0.21 kV

Equipment				Ratings			Duties		Comments
ID	Manufacturer	/ Style	Test Standard	1/2 Cycle (kA)	Interrupting (kA)	Cyc	1/2 Cycle kA (%)	Interrupting kA (%)	
B LP100 MAIN	GE	/THQL	ANSI-SYM	10.00			1.89(-81.1%)		

****

Equipment Duty Comparison Report For Bus:
XMR001-P1   Area: 1 Zone: 1   Bus kV: 12.47 kV

Equipment				Ratings			Duties		Comments
ID	Manufacturer	/ Style	Test Standard	1/2 Cycle (kA)	Interrupting (kA)	Cyc	1/2 Cycle kA (%)	Interrupting kA (%)	
FS NPC	S&C	/SM-4	ANSI-SYM	12.50			21.69(73.5%)		VIOLATION

Ground Fault

Low Voltage Momentary Report

Power Quality Technical Services, Inc. (Serial #34798)
Project Name: South Edge Reservoir R-36
Comment: Ground Fault - Low Voltage Momentary Report

Interrupting Results S L-GND
Driving Point Voltage (P.U.) = 1.00000

```
*Bus DP-1                 0.480 kV, Zone     1, Area     1
      E/Z =     17.253 kA (      14.344 MVA)  At   -78.62DEG, X/R =     5.07
      Z1 =    1.430170 +j   7.233062 pu,  Z0 =   1.266835 +j   6.037980 pu

      Contributions In kA
      Bus      to       Bus                        kA     Angle  Device   Zone   Area  Branch
      SG001             DP-1                    17.25    -78.62  Branch      1      1  C DP100-01
      MCC001 FUTURE     DP-1                     0.00      0.00  Branch      1      1  C ULP-A
      MPC               DP-1                     0.00      0.00  Branch      1      1  C XMR100-P1
      MOV100            DP-1                     0.00      0.00  Branch      1      1  C MOV100-P1

*Bus LP100                0.208 kV, Zone     1, Area     1
      E/Z =      1.888 kA (       0.680 MVA)  At   -58.50DEG, X/R =     1.92
      Z1 =   88.033043 +j 144.948041 pu,  Z0 =  54.466658 +j  86.239467 pu

      Contributions In kA
      Bus      to       Bus                        kA     Angle  Device   Zone   Area  Branch
      TX MPC-SEC        LP100                    1.89    -58.50  Branch      1      1  B LP100 MAIN

*Bus MCC001 FUTURE        0.480 kV, Zone     1, Area     1
      E/Z =     17.150 kA (      14.258 MVA)  At   -78.43DEG, X/R =     4.99
      Z1 =    1.453054 +j   7.260374 pu,  Z0 =   1.312602 +j   6.092604 pu

      Contributions In kA
      Bus      to       Bus                        kA     Angle  Device   Zone   Area  Branch
      DP-1              MCC001 FUTURE           17.15    -78.43  Branch      1      1  C ULP-A

*Bus MOV100               0.480 kV, Zone     1, Area     1
      E/Z =      8.995 kA (       7.478 MVA)  At   -32.61DEG, X/R =     1.23
      Z1 =    6.374528 +j   7.418439 pu,  Z0 =  21.044311 +j   6.779486 pu

      Contributions In kA
      Bus      to       Bus                        kA     Angle  Device   Zone   Area  Branch
      DP-1              MOV100                   9.00    -32.61  Branch      1      1  C MOV100-P1

*Bus MPC                  0.480 kV, Zone     1, Area     1
      E/Z =     15.720 kA (      13.069 MVA)  At   -70.12DEG, X/R =     2.96
      Z1 =    2.043339 +j   7.413504 pu,  Z0 =   3.719514 +j   6.759747 pu

      Contributions In kA
      Bus      to       Bus                        kA     Angle  Device   Zone   Area  Branch
      TX MPC-SEC        MPC                      0.00      0.00  Branch      1      1  TX MPC
      DP-1              MPC                     15.72    -70.12  Branch      1      1  C XMR100-P1

*Bus SG001                0.480 kV, Zone     1, Area     1
      E/Z =     17.356 kA (      14.430 MVA)  At   -78.81DEG, X/R =     5.15
      Z1 =    1.407287 +j   7.205749 pu,  Z0 =   1.221068 +j   5.983355 pu

      Contributions In kA
      Bus      to       Bus                        kA     Angle  Device   Zone   Area  Branch
      DP-1              SG001                    0.00      0.00  Branch      1      1  C DP100-01
      SG001-P1          SG001                   17.36    -78.81  Branch      1      1  C SG001-P1

*Bus SG001-P1             0.480 kV, Zone     1, Area     1
      E/Z =     17.505 kA (      14.554 MVA)  At   -79.21DEG, X/R =     5.34
      Z1 =    1.362871 +j   7.169333 pu,  Z0 =   1.132237 +j   5.910522 pu

      Contributions In kA
      Bus      to       Bus                        kA     Angle  Device   Zone   Area  Branch
      XMR001-P1         SG001-P1                17.51    -79.21  Branch      1      1  TX NPC
      SG001             SG001-P1                 0.00      0.00  B           1      1  C SG001-P1
```

Power Quality Technical Services, Inc. (Serial #34798)
Project Name: South Edge Reservoir R-36
Comment: Ground Fault - Low Voltage Momentary Report

Interrupting Results S L-GND
Driving Point Voltage (P.U.) = 1.00000

*Bus TX MPC-SEC 0.208 kV, Zone 1, Area 1
E/Z = 1.888 kA (0.680 MVA) At -58.50DEG, X/R = 1.92
Z1 = 88.033043 +j 144.948041 pu, Z0 = 54.466658 +j 86.239467 pu

Contributions In kA

Bus	to	Bus	kA	Angle	Device	Zone	Area	Branch
MPC		TX MPC-SEC	1.89	-58.50	Branch	1	1	TX MPC
LP100		TX MPC-SEC	0.00	0.00	Branch	1	1	B LP100 MAIN

Breaker Settings

South Edge Reservoir - R36
Adjustable Breaker Settings
6/5/2007

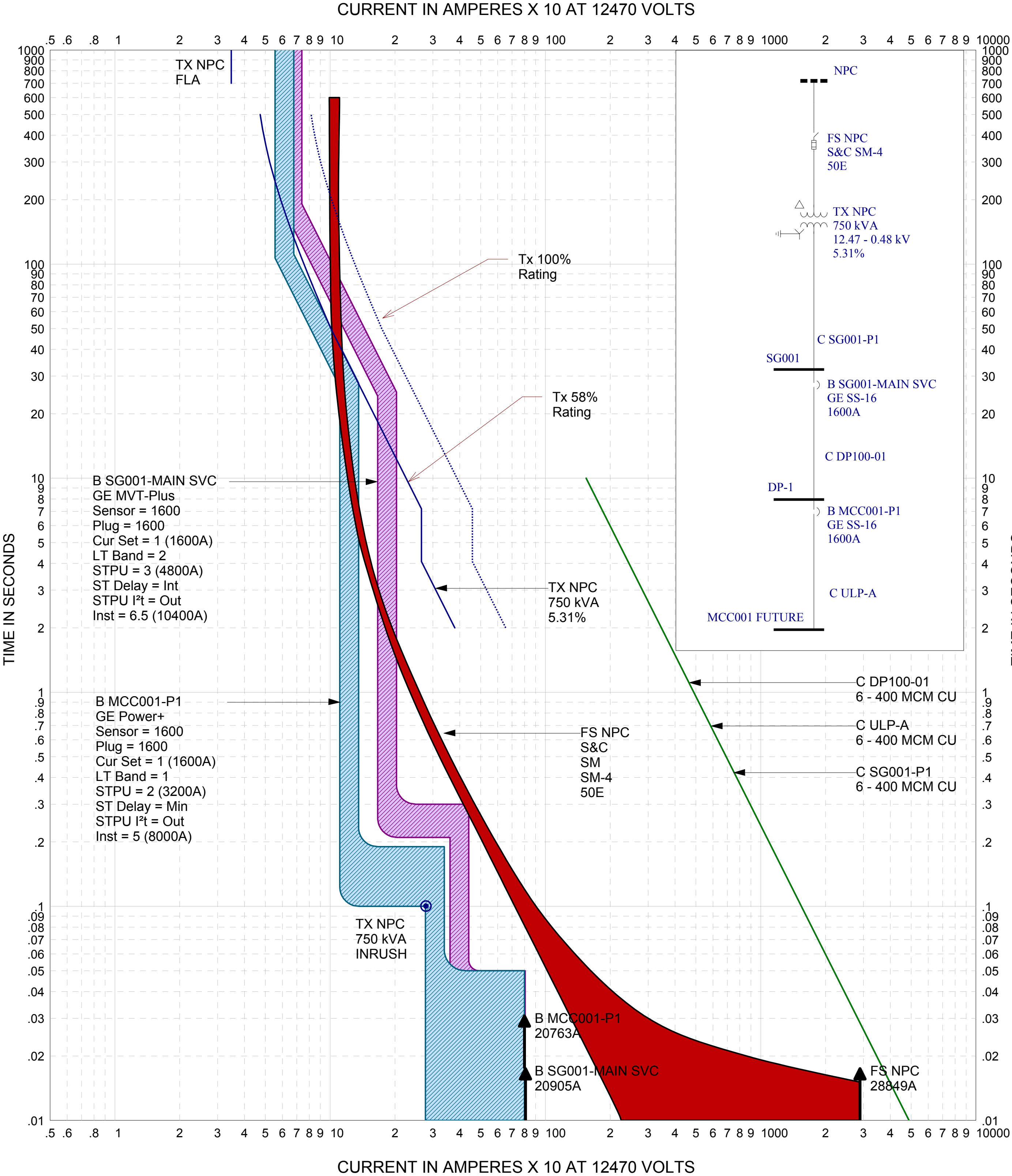
Adjustable Breaker Name	Manufacturer	Type	Style	Sensor/ Frame	Plug/ Tap	LTPU				LT Delay		STPU					Inst			Ground Trip			
						Name	Setting	Mult	Trip (A)	Name	Band	Name	Setting	Trip (A)	Band	I2t	Setting	Override	Trip (A)	Pickup	Trip (A)	Delay	I2t
B SG001-MAIN SVC	GE	MVT-Plus	ICCB	1600	1600	LT Pickup	1		1600	LT Delay (s)	2	ST Pickup	3	4800	Int	Out	6.5	Pickup	10400	0.3	480	Max	Out
B XMR100-P1	GE	Spectra RMS	MCCB SE	100A (100AT)	100	LT Pickup	1	1	100	LT Delay	Fixed	ST Pickup	5	380	Fixed	In	5	Pickup	770				Out

Verify all Rating Plugs in Breakers. Notify Engineer if rating plugs vary from this Table

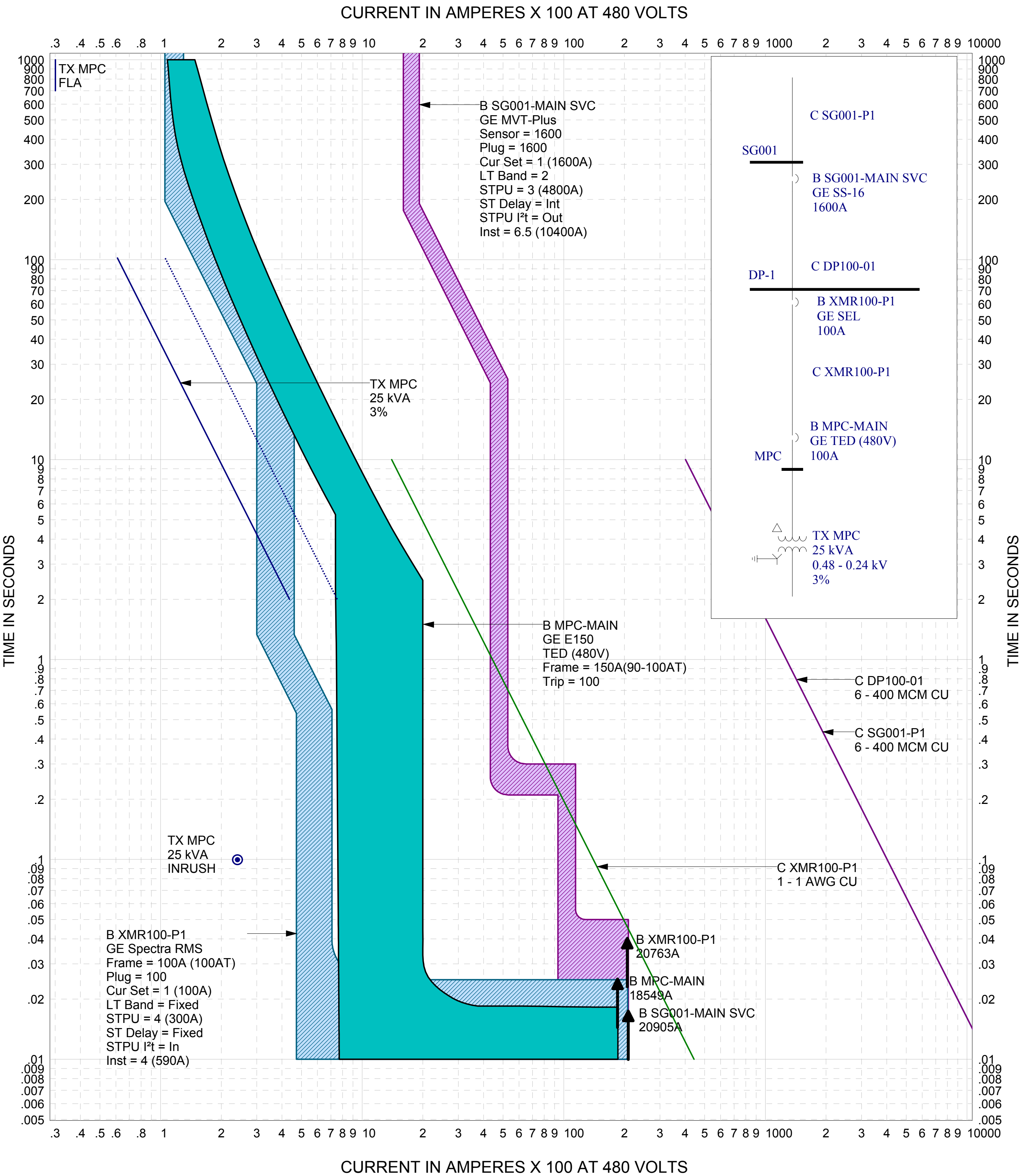
South Edge Reservoir - R36
Thermal Magnetic Breakers
6/5/2007

Thermal Magnetic Breaker	Manufacturer	Type	Style	Frame	Trip	Instantaneous	
						Setting	Trip (A)
B MPC-MAIN	GE	Q Line	THQB	100(60-100AT)	100		

Time Current Curves



PQTSi	*EasyPower* ® **TIME-CURRENT CURVES**	Main Service
South Edge Reservoir - R36 Breaker Settings: SG001-Main, Feeder MCC001-P1		FAULT: Phase DATE: Jun 05, 2007 BY: J Dietrich REVISION: 0



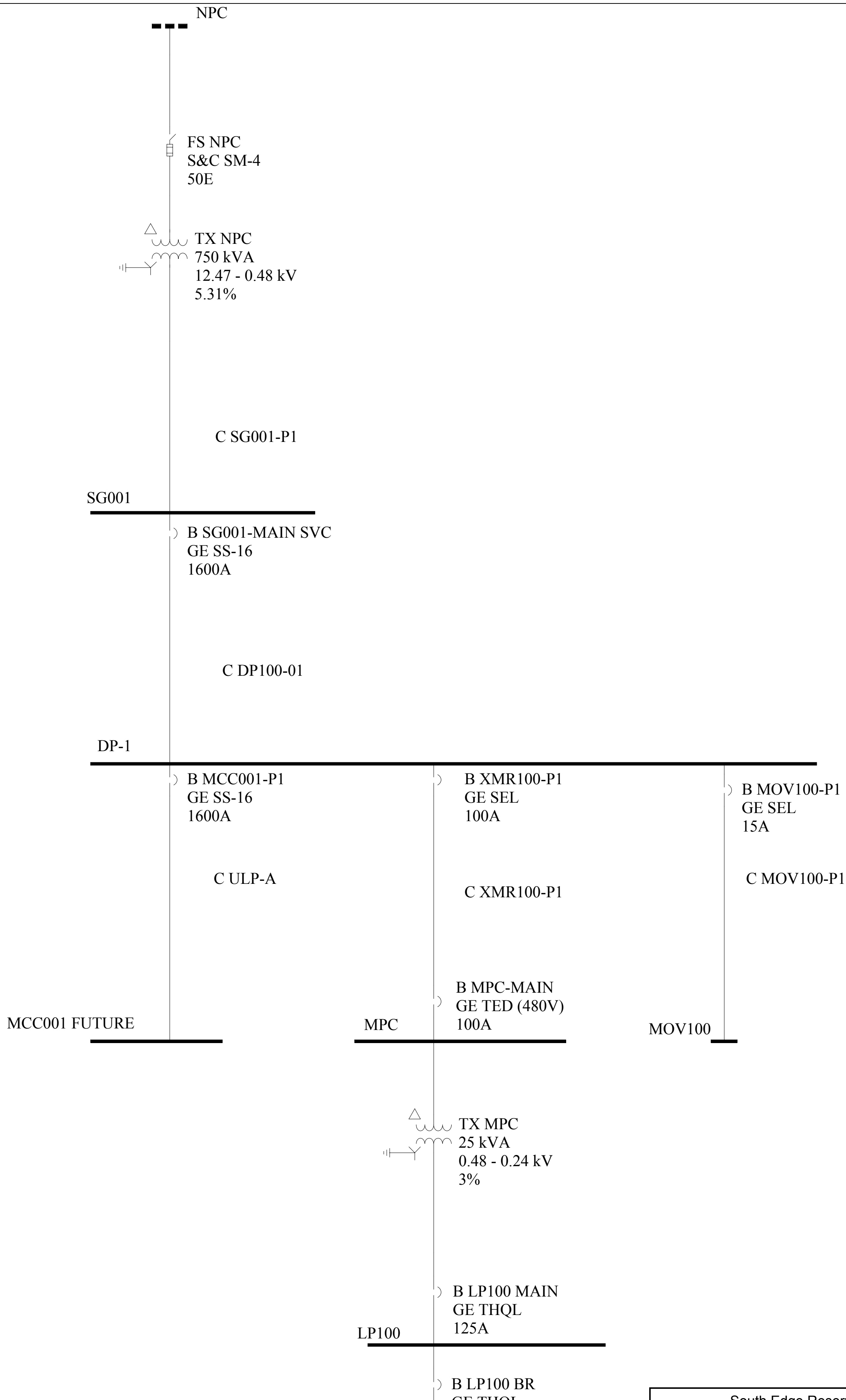
PQTSi	***EasyPower*** ® **TIME-CURRENT CURVES**	Mini Power Center

South Edge Reservoir - R36

Breaker Settings: SG001-Main, Feeder XMR100-P1, MPC-Main

FAULT: Phase
DATE: Jun 05, 2007
BY: J Dietrich
REVISION: 0

Single Line Diagrams



South Edge Reservoir R-36
Base Single Line Model
PQTSI - June 06, 2007

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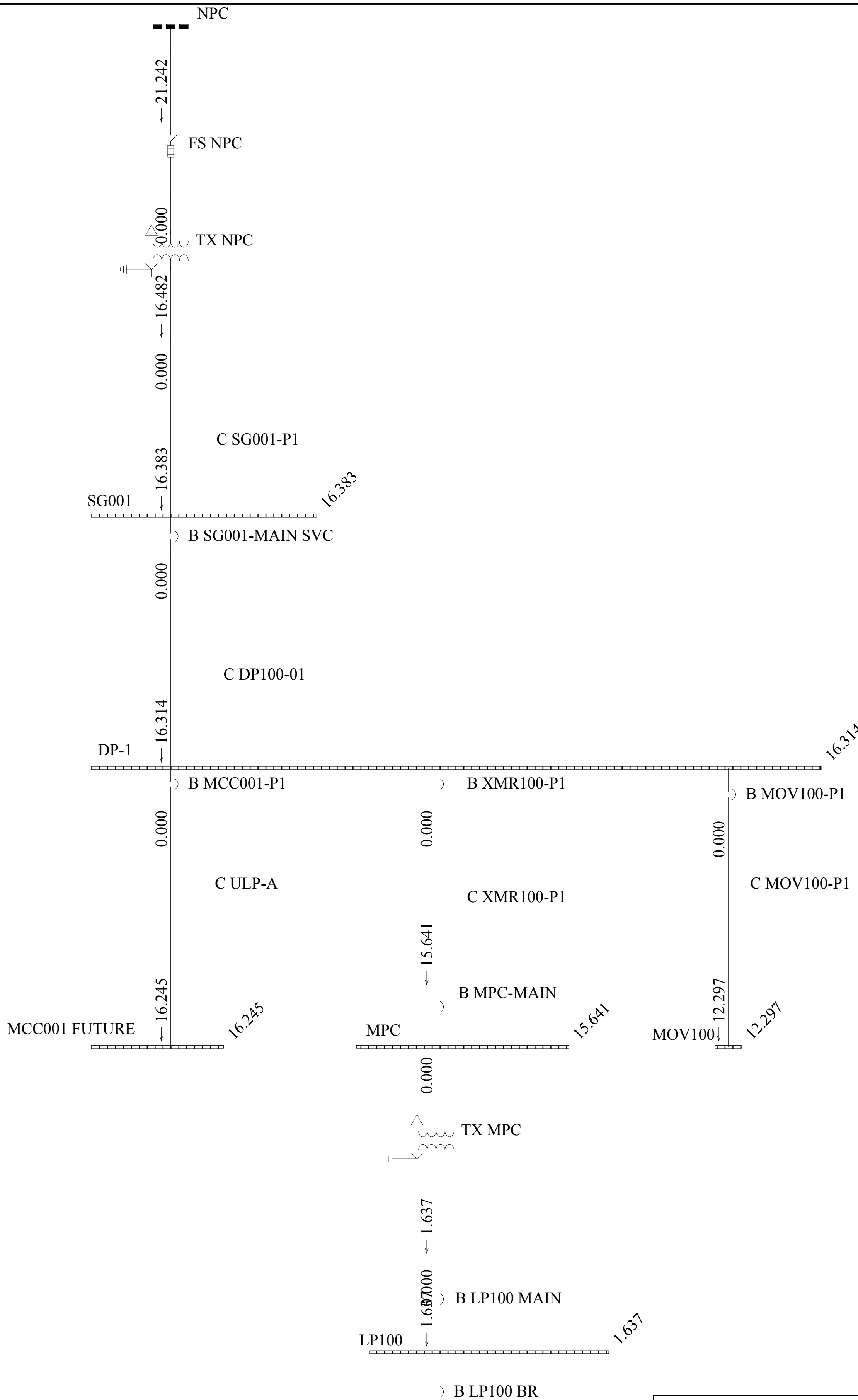
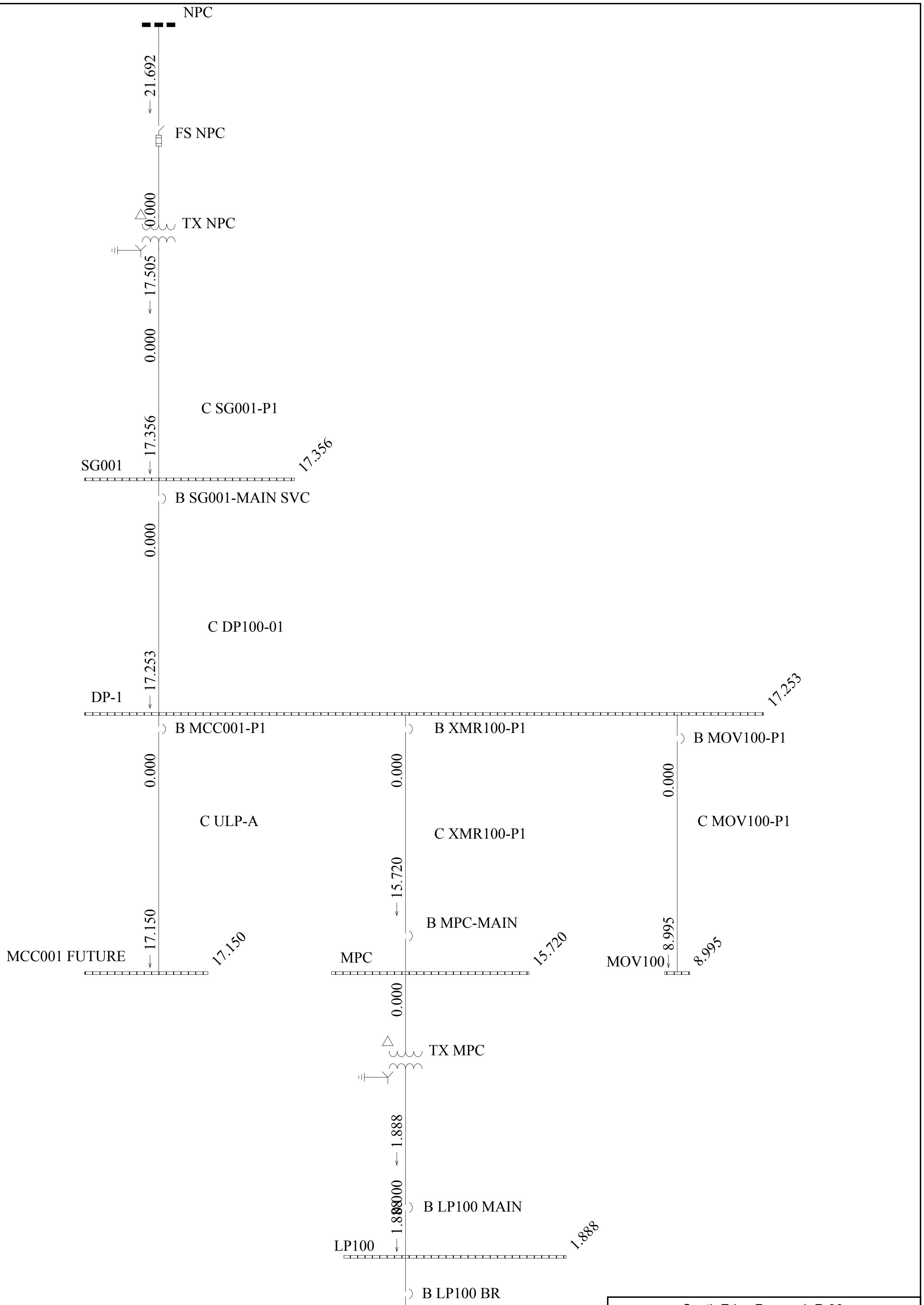


South Edge Reservoir R-36
Three Phase Fault - Short Circuit Ratings
PQTSI - June 06, 2007

Printed by EasyPower



South Edge Reservoir R-36
Ground Fault - Short Circuit Ratings
PQTSI - June 06, 2007

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