Power System Study

for the

Lone Mountain Sewer Lift Station

Las Vegas, Nevada

Revised for Final Submission

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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RECOMMENDATIONS

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.

3. The **Arc Flash Study** resulted in PPE requirements that are reasonable values by which field personnel can comply with on a day to day basis. PPE requirements are primarily driven by breaker settings determined in the **Coordination Study**.

    - It is highly recommended that all *coordination settings* documented in this report be followed, set, and remain unchanged to maintain the listed PPE requirements for each piece of equipment during the course of operation. PQTSi assumes no liability for changes to settings by field personnel that do not follow those listed in the documented coordination settings portion of this report.

INTRODUCTORY SECTION

Study Objective

Power Quality Technical Services, Inc. was contracted to perform a short-circuit, protective device evaluation / coordination study, arc flash evaluation, and harmonic analysis power system study for the *Lone Mountain Sewer Lift Station* project located in *Las Vegas*, *Nevada*. The scope of the short-circuit study included the electrical system from the incoming 12kV, 225kVA utility transformer through a utility metering board, a main switchboard and an MCC with three VFD motor loads.

Engineering Qualifications

The Electrical Engineer performing this Power System Study has performed over 50 significantly sized Power System Studies using ESA's EasyPower software during past employment with General Electric's I&FS Engineering Services. Studies include projects ranging in size from the Oakland International Airport's Terminal 2 Expansion, Kaiser Hospital, Mesa Cap Water Treatment Plant (Mesa, AZ), City of Albuquerque Water Treatment Plant, and Nellis Air Force Base. The software used for this study is industry recognized, used by Power System Engineers including those from General Electric, Siemens Automation, and CH2MHill. A full description of the software's capabilities can be found at http://www.easypower.com.

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.

The **Arc Flash Study** work scope involves determining the appropriate PPE and incident energy levels throughout the power system analized, including flash protection boundary values, and restricted approach boundary values. Arc flash analysis is performed using IEEE-1584 standards.

The methods used in the course of these studies conform to NEC 2002, ANSI, NFPA-70E and other applicable standards and accepted industry practices.

All insulated cables within the scope of the study have been checked for protection to insure 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 1999 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 1999 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, 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 Arc Flash Analysis procedure is then outlined, followed with Arc Flash Labels and a device tabulation 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.) is 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 the generation, distribution and load buses.

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 an assumed three-phase 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 typically are 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.

The **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°C	65°C	80/110°C
55°C	65/80°C	150°C
55/65°C	80°C	150/180°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 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:

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

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 SC-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, 12.47kV 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	12.25kA
Three Phase X/R	7
Ground Fault	12.398
Ground Fault X/R	7

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 6.0 was used to calculate the three-phase fault 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 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 first printout is the *Equipment Duty Violation and Warning Report.*

The interrupting duty shown in this device evaluation report is the available fault current taken from the Short-Circuit Reports at the appropriate point in the system minus the contributions generated downstream of that point. The interrupting duty is the symmetrical rating specified by the device manufacturer. The comparison is shown as a percent under-duty (negative percentage) or a percent over-duty (positive number) e.g. (1 - 16.1 kA/37 kA) = 56.6%. Comments indicate whether the equipment is not capable of safely interrupting the available fault current i.e. "VIOLATION".

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 is the *Interrupting Breaker Duties Using Interrupting Impedance Circuit*.

The interrupting duty short-circuit program output gives the calculated 1-1/2 to 4 cycle (interrupting) short-circuit currents which are used to determine the interrupting duties for medium and high-voltage circuit breakers. Interrupting-duty currents are calculated using modified subtransient reactances for all sources of short-circuit current, as specified in the appropriate ANSI calculating procedures.[1,2,3,5] The ANSI Standard method uses a separate R network for the interrupting duty network to determine a conservative Z/R ratio. This ratio is used as the Thevenin equivalent fault point X/R ratio for determining the appropriate breaker contact parting time multipliers and NACD (No AC Decrement) ratios.

Up to six of the standard duties are given (3, 5 and 8 cycle on a Total basis and on a Symmetrical basis), along with the multiplying factors. Fault current values based listed with these interrupting times are based on circuit breaker contact parting times of 0.0333, 0.05 and 0.0667 seconds respectively (2, 3 and 4 cycles, for 60 hertz systems). "Total" refers to a circuit breaker rated on a total current basis and the calculated fault duty is based on references 2 and 4. "Symmetrical" refers to a circuit breaker rated on a symmetrical current basis and the calculated fault duty is based on references 1 and 4. The Adj. Factor times the symmetrical current gives the maximum duty level. The Adj. Factor is determined from curves in Reference 1 and 2, the fault point X/R ratio and the ratio of "Remote/Total" currents as given in Reference 4.

The contributions from adjacent buses are also listed.

The last 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 12kV, 225kVA utility transformer through a utility metering board, a main switchboard and an MCC with three VFD motor loads. 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 are 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 *Lone Mountain Sewer Lift Station* 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^{O}C or 75^{O}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^{O}C rated wire for wire sizes #14 to #1 AWG and 75^{O}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^{O}C or 75^{O}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 Breaker in MS1. 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.

System Medium Voltage Relay Settings
The medium voltage system relay settings are given in the *Relay Settings Table*.

One protection philosophy followed in this study in most cases is the avoidance of 0.5 relay time dial settings with standard non-static overcurrent relays. This is because experience has shown that nuisance tripping can be caused in this situation due to simple vibration. As much as possible, 0.75 is the lowest time dial setting used.

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 Study Analysis in conjuction with the Arc Flash Analysis determined that two breakers should be set at lower instantaneous than would normally be implemented in past field operating philosophies. Typically, in the past, the contractor (or owner) would set a breaker at its maximum instantaneous value to minimize nuisance tripping due to equipment inrush current values. Now, according to implementation and protection procedures outlined in NFPA-70E, breaker settings should be set to their lowest value that will maintain proper functionality of equipment. This will result in PPE requirements that are easier for field personnel to implement on a day to day basis.

- All Feeder Breakers should be set and tested at the recommended settings.

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

ARC FLASH STUDY INTRODUCTION

Introduction

The purpose of an arc flash hazard analysis is to determine arc flash boundary values and appropriate Personal Protective Equipment (PPE) based on coordinated circuit protective devices within an electrical distribution system. Protective device settings are selected to provide a reasonable compromise between the level of required PPE and the desired system operability, 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.

The Arc Flash Study's methods and recommendations are in conformance with the NFPA-70E-2004 and NEC-1584. A general explanation of the methods used for this portion of the study can be found in the section entitled *Procedures.*

Compliance with Codes and Standards

The results of the study will include the calculated Arc-Flash Boundary and the calculated Incident Energy (in cal/cm2) at key system points within the scope of the short circuit study. The Incident Energy will be shown with its related Protective Clothing System as found in NFPA 70E Standard for Electrical Safety Requirements for Employee Workplaces-latest edition. Arc-Flash calculations will be made using ESA's EasyPower7.0 software equations (IEEE Std 1584-2002, IEEE Guide for Performing Arc-Flash Hazard Calculations).

The following discussion addresses the study's compliance with the NFPA-70E Standards for Safety in the Workplace, and IEEE-1584's methodologies for calculating Arc Flash incident energy levels. Results of this study are in conformance with Tables 130.7(C)(9a), (10), and (11), Hazard Risk Category, the Protective Clothing and Personal Protective Equipment Matrix, and Protective Clothing Characteristics.

Procedures

The Arc Flash Hazard analysis is carried out in the *short circuit focus portion* of the analysis software, and the methodology for calculating incident energy levels is selectable between IEEE's 1584, NFPA-70E, and/or ESA's customizable calculation methods.

IEEE-1584 recommends using two scenarios when detemining the worst case scenario for incident energy levels – 100% of estimated fault current, and 85% of estimated fault current. Accurate arcing times must be determined since incident energy levels are more sensitive to arcing time than arcing current as a result of the inverse-time characteristics of the typical over-current protective device – arcing time is typically longer for smaller currents and shorter for larger currents. Therefore, both current values are evaluated, and the worst case scenario is reported.

The NFPA-70E specifies two types of flash boundaries; those were the arcing time is less than 0.1 second, the boundary is at a distance where the energy level is less than or equal to 1.5cal/cm^2, and for arcing times greater than 0.1 second, the boundary is at a distance where the energy level is less than or equal to 1.2cal/cm^2.

Arc Flash Analysis is not performed on buses at 120/208V located after secondary sides of transformers rated 125kVA or less per IEEE 1584. The reasoning behind excluding buses at 120/208V beyond transformers less than 125kVA is that it is highly unlikely for a fault to be sustained on such devices for an extended length of time, and the calculations typically result in unrealistic incident energy levels.

ARC FLASH STUDY ANALYSIS

Basis of Analysis

The Arc Flash Hazard analysis was performed in two parts. The first part was performed using Nevada Power Company's datasheet for secondary fault current for a given service transformer. In this case, the transformer was rated at 225kVA, and all fault current values were provided at the secondary bushings of the transformer. The second part was performed using a typical fault current value for NPC's 12.47kV distribution system and the maximum available fault current at the utility's substation. Fusing was selected based on the size of the service transformer.

Results of Analysis

Results of the Arc Flash Analysis are summarized in tables found in the Appendix. No panels or gear were found to require extraordinary PPE protection.

HARMONIC STUDY INTRODUCTION

Introduction

The purpose of a Harmonic Analysis is to determine the level of Harmonic Current and Voltage Distortion at the Point of Common Coupling per I.E.E.E. 519. The 1992 version of IEEE 519 set forth limits on harmonic distortion for both voltage and current in industrial distribution systems, and their overall impact on the utility's distribution system. Harmonic voltage (distortion) is caused by the flow of harmonic currents through a distribution system's impedance. Therefore, the level of Harmonic Voltage Distortion can be minimized by reducing the industrial system's contribution of current contraining harmonics (or loads that produce harmonics).

Compliance with Codes and Standards

The basis of the harmonics analysis follows the definition of several terms which are described below for clarification:

Point of Common Coupling – is identified as the point of connection (to the utility) as *defined* by the servicing utility, and is highly dependent upon whether it is determined as the high or low side of the service transformer. Location (and selection) of the PCC can adversely affect the desired results or impact of the Harmonic Distortion determination. Generally, the PCC is not considered as the point at which a variable frequency drive is connected to the commercial facility's own system (such as a Motor Control Center).

Total Demand Distortion – is defined as the Total Harmonic Current Distortion at the PCC and is based upon the maximum demand load current. TDD is the ratio of Harmonic Current to the Maximum Cumulative (linear and non-linear) Total Load.

I_{SC} – is the available Short Circuit current at the PCC, and is based upon impedance, available system capacity, and system voltage.

I_L – is the maximum demand load current (fundamental frequency component) as measured at the PCC. For new facilities, this is typically considered as the maximum anticipated load.

Harmonic Order – is described as the frequencies that are multiples of the fundamental frequency. Current magnitudes at these higher frequencies are typically expressed a percentage of the fundamental frequency and is determined through Fast Fourier Transform methods. The columns in the table illustrated on the following page indicate the maximum acceptable values for each range of harmonic order current according to I.E.E.E. 519 at the PCC.

Table 1
Maximum Harmonic Current Distortion in % of I_L

	Individual Harmonic Order (Odd only)					
I_{SC} / I_L	**< 11**	**11 ≤ h < 17**	**17 ≤ h < 23**	**23 ≤ h ≤ 35**	**35 ≤ h**	**TDD**
< 20*	4.0	2.0	1.5	0.6	0.3	**5.0**
20 < 50	7.0	3.5	2.5	1.0	0.5	**8.0**
50 < 100	10.0	4.5	4.0	1.5	0.7	**12.0**
100 < 1000	12.0	5.5	5.0	2.0	1.0	**15.0**
> 1000	15.0	7.0	6.0	2.5	1.4	**20.0**

Even harmonics are limited to 25% of the odd harmonic limits. TDD refers to Total Demand Distortion and is based on the average maximum demand current at the fundamental frequency, taken at the PCC.

*All power generation equipment is limited to these values of current distortion regardless of I_{SC} / I_L.

I_{SC} = Maximum short circuit current at the PCC
I_L = Maximum demand load current (fundamental at the PCC
h = harmonic number

Procedures

The harmonic analysis is carried out by evaluating the impact of harmonic currents produced by non-linear loads present in the customer's electrical system to the "stiffness" or "softness" of the serving utility's electrical distribution system. Several factors must be considered when evaluating this impact:

1) Level of loading by the non-linear load. For example, the harmonic spectra present for a VFD operating at 50%, 85%, or 100% motor speed varies considerably. Much of this variance is dependent on the size of the DC link filtering capacitor and its level of discharge between each cycle of incoming three phase voltage.

2) The capacity (short circuit and kW demand) of the utility's electrical system. Though these value don't often change (size of the utlity's service transformer), the utility's routing or choice of feeder circuits can affect Short Circuit current. This latter value can greatly impact the utlity's service "stiffness" and the I_{SC} / I_L ratio as used in IEEE 519.

3) The number and size of linear components in the electrical system that is under evaluation. Motors directly connected to the electrical distribution system can be

affected by negative sequence harmonics (5th, 11th, 17th, etc.) causing "cogging of those motors (creating heat and increasing load). Power Factor correction capacitors are considered low impedance "sinks" of higher frequency harmonics, and switching of these devices "into" the system can change the steady-state operating characteristics of the electrical system considerably.

The equipment supplier for this project has provided a Table of Total Harmonic Distortion Contributions based on several lines of equipment it produces. The prediction table is used since it is often impractical to model and measure operating characteristics of each drive size in the factory environment. Primarily, this is because the factory's electrical system is not representative of the customer's own system, and no guidelines have been developed to measure such characteristics (as described by varying conditions in (1), (2), and (3) above).

Table 2

THD Contribution	**GE Fuji Drives (AF300-G11 / P11)**
90%	Drives connected with no input filter
45%	Drives connected with 3% Line Reactor
35%	Drives connected with 5% Line Reactor
33%	Drives connected with 3% Line Reactor & DC Link Reactor
28%	Drives connected with 5% Line Reactor & DC Link Reactor
12%	Drives connected with 12% BBHF
8%	Drives connected with 8% BBHF
5%	Drives connected with 5% BBHF
12%	Drives connected with 12% BBHF & DC Link Reactor
8%	Drives connected with 8% BBHF & DC Link Reactor
5%	Drives connected with 5% BBHF & DC Link Reactor
15%	Drives connected, 12 pulse converter
3%	Drives connected, 18 pulse converter

HARMONIC ANALYSIS

Basis of Analysis

The Harmonic Analysis was performed using the Table of Total Harmonic Current Contributions provided by GE. Much effort was exhausted in attempts to determine the exact harmonic operating charactistics of GE's line of Fuji drives. In each effort, we were directed back to the Contribution Table illustrated in the Harmonics Analysis – Introduction portion of this report. As the Engineer performing this analysis, having performed over 500 Power Quality surveys while working for the local utility

Results of Analysis

Calculations and Results of the Harmonics Analysis are summarized in tables found on the following page. Upon review of the tables, one will see that as linear loads are added, or the introduction of installed broadband filters, the Total Harmonic Distortion at the Point of Common Coupling will progressively decrease. Use of the Matrix 8% Broad Band Harmonic Filters as supplied by GE will achieve the necessary Total Demand Distortion as required at the Point of Common Coupling.

Recommendations

As the Engineer performing this analysis, having performed over 500 Power Quality surveys while working for the local utility, this methodology and approach is reasonable. It is recommended (and in fact part of the project's specification) that actual field measurements be performed and recorded to verify the validity of this report and the conformance of the equipment to the project's operating specifications.

Evaluation of 120HP total Drive load without any linear loading (45kVA transformer)

225	Service kVA
5.71	Service Z%
12,470	Primary Voltage
480	Secondary Voltage

4740	A	I_{sc} Calculation
150	A	I_{load} Calculation (PCC Total Load)
31.6		I_{sc} / I_{load} Calculation (per IEEE 519
90	%	THD Contribution
90	%	THD Calculation
8.0	%	TDD Required

Evaluation of 120HP total Drive load + 45kVA transformer linear loading

225	Service kVA
5.71	Service Z%
12,470	Primary Voltage
480	Secondary Voltage

4740	A	I_{sc} Calculation
204	A	I_{load} Calculation (PCC Total Load)
23.2		I_{sc} / I_{load} Calculation (per IEEE 519
90	%	THD Contribution
66.2	%	THD Calculation
8.0	%	TDD Required

Evaluation of 120HP total Drive load w/ 8% Broad Band Matrix Filter (no linear load)

225	Service kVA
5.71	Service Z%
12,470	Primary Voltage
480	Secondary Voltage

4740	A	I_{sc} Calculation
150	A	I_{load} Calculation (PCC Total Load)
31.6		I_{sc} / I_{load} Calculation (per IEEE 519
8.0	%	THD Contribution
8.0	%	THD Calculation
8.0	%	TDD Required

Evaluation of 120HP total Drive load w/ 8% Broad Band Matrix Filter + 45 kVA linear load

225	Service kVA
5.71	Service Z%
12,470	Primary Voltage
480	Secondary Voltage

4740	A	I_{sc} Calculation
204	A	I_{load} Calculation (PCC Total Load)
31.6		I_{sc} / I_{load} Calculation (per IEEE 519
8.0	%	THD Contribution
5.9	%	THD Calculation
8.0	%	TDD Required

THD Calculation = Σ(THD Contribution x (Non-Linear Load Amps / PCC total Amps))
THD Contribution = value from lookup Table 2
TDD = value from lookup Table 1

APPENDIX

Database Report

Project Name: Lone Mountain Sewer Lift Station
Comment: Equipment Database Report

Summary

1	Base MVA	100
2	Frequency	60
3	Buses	15
4	MCC Schedules	0
5	Panel Schedules	0
6	Utilities	2
7	Generators	1
8	UPS	0
9	Motors	4
10	Capacitors	0
11	Loads	1
12	Shunts	0
13	Filters	0
14	2-Transformers	2
15	3-Transformers	0
16	Zigzags	0
17	Cables	11
18	Busways	0
19	Xmission Lines	0
20	CL Reactors	0
21	HV Breakers	0
22	LV Breakers	14
23	Switches	1
24	Fuses	2
25	ATS	1
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	FS PMP-1-1	On	0.48	1	1	Other	Specified	
2	GEN-5-1	On	0.48	1	1	Other	Specified	
3	LB	On	0.48	1	1	Other	Specified	
4	LP-1	On	0.208	1	1	Panelboard	Specified	
5	MCC VFD	On	0.48	1	1	MCC	Specified	
6	NPC	On	12.47	1	1	Other	Specified	
7	PMP-1-1	On	0.48	1	1	Other	Specified	
8	PMP-1-2	On	0.48	1	1	Other	Specified	
9	PMP-1-3	On	0.48	1	1	Other	Specified	
10	SB	On	0.48	1	1	Switchgear	Specified	42kA to 65kA
11	TX LP-1 H	On	0.48	1	1	Other	Specified	
12	TX LP-1 L	On	0.208	1	1	Other	Specified	
13	TX NPC H	On	12.47	1	1	Other	Specified	
14	TX NPC L	On	0.48	1	1	Other	Specified	
15	UM SWBD	On	0.48	1	1	Switchboard	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	Off	TX NPC L	0.48	0.48	kA	12.25	7	12.398	7	Swing	0	0	1	-100000	100000	0.8	1.2
2	UTIL-1	On	NPC	12.47	12.47	kA	13	8	13	8	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	TX NPC L	0.48	1.3886	9.72019	1.33887	9.37209	R-EXP	0.5	120281.	
2	UTIL-1	0	NPC	12.47	0.04417	0.35339	0.04417	0.35339	R-EXP	0.5	4629.91	

Generators

	ID Name	Status	To bus	Base kV	Gen kV	Conn	MVA	Type	Power Factor	Efficiency	RPM	X/R	Model	MW	MVAR	Ctl kV pu	MVAR Min	MVAR Max
1	GEN-5-1	On	GEN-5-1	0.48	0.48	YG	0.1875	SYN-SP	0.8	0.95	3600	12.286	PV	0	0	1	-100000	100000

Generators

	ID Name	kV pu Min	kV pu Max	Ctl Angle	Ctl Bus	Ctl Base kV	X"dv	X'dv	X0	Xlr	RG OHM	XG OHM	R1 pu	X1 pu	R0 pu	X0 pu	R Gnd pu	X Gnd pu
1	GEN-5-1	0.8	1.2	0	GEN-5-1	0.48	6.9	11.5	0.9		0	0	2.99527	36.8	0.39068	4.8	0	0

Generators

	ID Name	Hrm RC Factor	Hrm RC Value	I Hrm Rating	Comment
1	GEN-5-1	R-EXP	0.5	225.527	Typical Generator

Motors

	ID Name	Status	To Bus	Base kV	Unit	Model	Motor kV	Hp or kW	Type	Load Class	RPM	FLA	Power Factor	Eff	kVA/Hp	ANSI Code	Connected
1	M 3X	Off	MCC VFD	0.48	U.S.	Individual	0.46	120	Induction	Non-essential	1800		0.82	0.91	0.9	???	100
2	M PMP-1-1	On	PMP-1-1	0.48	U.S.	Individual	0.46	40	Induction	Non-essential	1800		0.82	0.91	0.9	???	100
3	M PMP-1-2	On	PMP-1-2	0.48	U.S.	Individual	0.46	40	Induction	Non-essential	1800		0.82	0.91	0.9	???	100
4	M PMP-1-3	On	PMP-1-3	0.48	U.S.	Individual	0.46	40	Induction	Non-essential	1800		0.82	0.91	0.9	???	100

Motors

	ID Name	X"dv or Xlr	X/R	Load Model	Motor kVA	Load Type	Load Scaling	SCADA kW	SCADA jkVar	SCADA Type	SCADA Scaling	Hrm RC Value	Hrm RC Factor	R1 pu	X1 pu	Int MF	Hrm R1 pu	Hrm X1 pu
1	M 3X	16.7	9.56534	Spec	108	kVA	100	0	0	kVA	100	0.5	R-EXP	1e+009	1e+010	10000	14.7660	141.242
2	M PMP-1-1	16.7	4.55842	Spec	36	kVA	100	0	0	kVA	100	0.5	R-EXP	1e+009	1e+010	10000	91.2906	416.141
3	M PMP-1-2	16.7	4.55842	Spec	36	kVA	100	0	0	kVA	100	0.5	R-EXP	1e+009	1e+010	10000	91.2906	416.141
4	M PMP-1-3	16.7	4.55842	Spec	36	kVA	100	0	0	kVA	100	0.5	R-EXP	1e+009	1e+010	10000	91.2906	416.141

Motors

	ID Name	I Hrm Rating	TCC Starter	Plot TCC	Service Factor	Locked Rotor Mult	Asym Offset	Reduced Inrush Mult	Accel Time	Stall Time	Stall Time To	Largest Motor HP	Comment
1	M 3X	129.903	Reduced		1	6	1.6	3	5	6	200	120	Model Only
2	M PMP-1-1	43.3012	Reduced		1	6	1.6	3	5	6	200	40	
3	M PMP-1-2	43.3012	Reduced		1	6	1.6	3	5	6	200	40	
4	M PMP-1-3	43.3012	Reduced		1	6	1.6	3	5	6	200	40	

Loads

	ID Name	Status	To Bus	Base kV	Load Model	Load Class	Const MVA MW	Const MVA MVAR	Const MVA Scaling%	Const I MW	Const I MVAR	Const I Scaling%	Const Z MW	Const Z MVAR	Const Z Scaling%	SCADA MVA MW
1	L LB	On	LB	0.48	Spec	Non-essential	0.075	0	100	0	0	100	0	0	100	0

Loads

	ID Name	SCADA MVA MVAR	SCADA MVA Scaling%	SCADA I MW	SCADA I MVAR	SCADA I Scaling%	SCADA Z MW	SCADA Z MVAR	SCADA Z Scaling%	Hrm RC Factor	Hrm RC Value	I Hrm Rating	Comment
1	L LB	0	100	0	0	100	0	0	100	R-EXP	0.5	90.2109	

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 LP-1	On	TX LP-1 H	0.48	D	TX LP-1 L	0.208	YG	Oil	OA	150	Core	0.48	0.48	0	0	0.208
2	TX NPC	On	TX NPC H	12.47	D	TX NPC L	0.48	YG	Oil	OA	65	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 LP-1	0.208	0	0	0.045	0.045	6.1	5.185	1.65901	None	0.625	0.1	1500	V (PU)	1	69.979	116.095	10000	1e+007
2	TX NPC	0.48	0	0	0.225	0.225	2.21	1.8785	3.29873	None	0.625	0.1	1500	V (PU)	1	2.84952	9.39980	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 LP-1	59.48215	98.68148	0	0	0	0	ANSI C57.109	kVA O/L	Yes	500	8	6	R-EXP	0
2	TX NPC	2.422093	7.989831	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 LP-1	15	54.1265	124.907	
2	TX NPC	15	10.4173	270.633	

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 GEN5-1 ATS	On	GEN-5-1	0.48	ATS-5-1	0.48	U.S.	1/C	1	350	42	50	THWN	310	Copper
2	C LB	On	GEN-5-1	0.48	LB	0.48	U.S.	1/C	1	2/0	11	50	THWN	175	Copper
3	C LP-1	On	TX LP-1 L	0.208	LP-1	0.208	U.S.	1/C	1	4/0	10	50	THWN	230	Copper
4	C MCC VFD	On	SB	0.48	MCC VFD	0.48	U.S.	1/C	1	4/0	16	50	THWN	230	Copper
5	C PMP-1-1	On	FS PMP-1-1	0.48	PMP-1-1	0.48	U.S.	1/C	1	4	10	50	THWN	85	Copper
6	C PMP-1-2	On	MCC VFD	0.48	PMP-1-2	0.48	U.S.	1/C	1	4	10	50	THWN	85	Copper
7	C PMP-1-3	On	MCC VFD	0.48	PMP-1-3	0.48	U.S.	1/C	1	4	10	50	THWN	85	Copper
8	C SB	On	ATS-5-1	0.48	SB	0.48	U.S.	1/C	1	350	10	50	THWN	310	Copper
9	C TX LP-1	On	SB	0.48	TX LP-1 H	0.48	U.S.	1/C	1	2	25	50	THWN	115	Copper
10	C UM SWBD	On	TX NPC L	0.48	UM SWBD	0.48	U.S.	1/C	1	350	10	50	THWN	310	Copper
11	C UM SWBD A	On	UM SWBD	0.48	ATS-5-1	0.48	U.S.	1/C	1	350	40	50	THWN	310	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 GEN5-1 ATS	Conduit	Steel	0.03565	0.03809	0.14262	0.15236	0.00446	0.00446	1	2	Copper	Separate	Yes	0	Other	10
2	C LB	Conduit	Steel	0.08883	0.03987	0.35532	0.15950	0.00588	0.00588	1	6	Copper	Separate	Yes	0	Other	10
3	C LP-1	Conduit	Steel	0.05587	0.03847	0.22349	0.15390	0.00476	0.00476	1	2	Copper	Separate	Yes	1	4/0	10
4	C MCC VFD	Conduit	Steel	0.05587	0.03847	0.22349	0.15390	0.00476	0.00476	1	4	Copper	Separate	Yes	0	Other	10
5	C PMP-1-1	Conduit	Steel	0.28320	0.04271	1.13283	0.17084	0.00814	0.00814	1	6	Copper	Separate	Yes	0	Other	10
6	C PMP-1-2	Conduit	Steel	0.28320	0.04271	1.13283	0.17084	0.00814	0.00814	1	6	Copper	Separate	Yes	0	Other	10
7	C PMP-1-3	Conduit	Steel	0.28320	0.04271	1.13283	0.17084	0.00814	0.00814	1	6	Copper	Separate	Yes	0	Other	10
8	C SB	Conduit	Steel	0.03565	0.03809	0.14262	0.15236	0.00446	0.00446	1	2	Copper	Separate	Yes	0	Other	10
9	C TX LP-1	Conduit	Steel	0.17821	0.04084	0.71283	0.16337	0.00665	0.00665	1	6	Copper	Separate	Yes	0	Other	10
10	C UM SWBD	Conduit	PVC	0.03479	0.03047	0.06959	0.06094	0.00446	0.00446	1	2	Copper	Separate	Yes	0	Other	10
11	C UM SWBD A	Conduit	Steel	0.03565	0.03809	0.14262	0.15236	0.00446	0.00446	1	2	Copper	Separate	Yes	0	Other	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 GEN5-1 ATS	Copper	Yes	Triangle	Round	0	0.64999	0.69437	2.59997	2.77750	2.16833	2.16833	R-EXP	0.5	310	
2	C LB	Copper	Yes	Triangle	Round	0	0.42410	0.19037	1.69642	0.76151	4.30629	4.30629	R-EXP	0.5	175	
3	C LP-1	Copper	Yes	Triangle	Round	0	1.29146	0.88932	5.16586	3.55732	9.07144	9.07144	R-EXP	0.5	230	
4	C MCC VFD	Copper	Yes	Triangle	Round	0	0.38801	0.26719	1.55205	1.06877	7.72951	7.72951	R-EXP	0.5	230	
5	C PMP-1-1	Copper	Yes	Triangle	Round	0	1.22919	0.18537	4.91679	0.74150	2.82819	2.82819	R-EXP	0.5	85	
6	C PMP-1-2	Copper	Yes	Triangle	Round	0	1.22919	0.18537	4.91679	0.74150	2.82819	2.82819	R-EXP	0.5	85	
7	C PMP-1-3	Copper	Yes	Triangle	Round	0	1.22919	0.18537	4.91679	0.74150	2.82819	2.82819	R-EXP	0.5	85	
8	C SB	Copper	Yes	Triangle	Round	0	0.15476	0.16532	0.61904	0.66131	5.16270	5.16270	R-EXP	0.5	310	
9	C TX LP-1	Copper	Yes	Triangle	Round	0	1.93370	0.44319	7.73478	1.77276	8.65097	8.65097	R-EXP	0.5	115	
10	C UM SWBD	Copper	Yes	Triangle	Round	0	0.15103	0.13226	0.30207	0.26452	5.16270	5.16270	R-EXP	0.5	310	
11	C UM SWBD A	Copper	Yes	Triangle	Round	0	0.61904	0.66131	2.47616	2.64524	2.06508	2.06508	R-EXP	0.5	310	

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 ATS-5-1	On	UM SWBD	0.48	Feeder	MCCB	Breaker Onl	GE	Spectra	SGL4	300	65	ANSI-SYM
2	B GEN-5-1	On	GEN-5-1	0.48	Feeder	LVPCB	Breaker Onl	<None>	<None>	<None>	0	0	ANSI-SYM
3	B LB	On	GEN-5-1	0.48	Feeder	LVPCB	Breaker Onl	<None>	<None>	<None>	0	0	ANSI-SYM
4	B LP-1 FDR-2	On	LP-1	0.208	Feeder	MCCB	Breaker Onl	GE	Q Line	THHQB	50	22	ANSI-SYM
5	B LP-1 FDR1	On	LP-1	0.208	Feeder	MCCB	Breaker Onl	GE	Q Line	THHQB	20	22	ANSI-SYM
6	B LP-1 MAIN	On	LP-1	0.208	Feeder	MCCB	Breaker Onl	GE	Q Line	THQD	225	22	ANSI-SYM
7	B MCC-VFD	On	SB	0.48	Feeder	MCCB	Breaker Onl	GE	Spectra	SFL	200	65	ANSI-SYM
8	B PMP-1-1	On	MCC VFD	0.48	Bus Tie	MCCB	Breaker Onl	GE	Spectra	SEP	80	100	ANSI-SYM
9	B PMP-1-2	On	MCC VFD	0.48	Feeder	MCCB	Breaker Onl	GE	Spectra	SEP	80	100	ANSI-SYM
10	B PMP-1-3	On	MCC VFD	0.48	Feeder	MCCB	Breaker Onl	GE	Spectra	SEP	80	100	ANSI-SYM
11	B SB-2	On	SB	0.48	Feeder	MCCB	Breaker Onl	GE	Record Plus	FCN	100	65	ANSI-SYM
12	B SB-3	On	SB	0.48	Feeder	MCCB	Breaker Onl	GE	Record Plus	FCH	25	100	ANSI-SYM
13	B SB-MAIN	On	SB	0.48	Feeder	MCCB	Breaker Onl	GE	Spectra	SGL4	300	65	ANSI-SYM
14	B TX LP-1	On	SB	0.48	Feeder	MCCB	Breaker Onl	GE	Record Plus	FCN	70	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 ATS-5-1	Closed	SST	GE	MVT-Plus	MCCB-SG/SK	400	300	1		300	3
2	B GEN-5-1	Closed	SST									
3	B LB	Closed	SST									
4	B LP-1 FDR-2	Closed	TMGN	GE	Q Line	THHQB	100A (15-50AT)	50				
5	B LP-1 FDR1	Closed	TMGN	GE	Q Line	THHQB	100A (15-50AT)	20				
6	B LP-1 MAIN	Closed	TMGN	GE	Q Line	THQD	225A(100-225AT)	225				
7	B MCC-VFD	Closed	SST	GE	Spectra RMS	MCCB SF	250	200	1		200	Fixed
8	B PMP-1-1	Closed	SST	GE	Spectra RMS	MCCB SE	100A (80AT)	80	1	1	80	Fixed
9	B PMP-1-2	Closed	SST	GE	Spectra RMS	MCCB SE	100A (80AT)	80	1	1	80	Fixed
10	B PMP-1-3	Closed	SST	GE	Spectra RMS	MCCB SE	100A (80AT)	80	1	1	80	Fixed
11	B SB-2	Closed	TMGN	GE	Record Plus	FCN	100A (100AT)	100				
12	B SB-3	Closed	TMGN	GE	Record Plus	FCH	100A (25AT)	25				
13	B SB-MAIN	Closed	SST	GE	Spectra RMS	MCCB SG	400	300	1	1	300	Fixed
14	B TX LP-1	Closed	TMGN	GE	Record Plus	FCN	100A (70AT)	70				

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 ATS-5-1	4	3	In	1200	10	Pickup	3000			Out		<None>	<None>
2	B GEN-5-1						Pickup						<None>	<None>
3	B LB						Pickup						<None>	<None>
4	B LP-1 FDR-2												<None>	<None>
5	B LP-1 FDR1												<None>	<None>
6	B LP-1 MAIN												<None>	<None>
7	B MCC-VFD	Min	Fixed	In	300	Min	Pickup	600			Out		<None>	<None>
8	B PMP-1-1	3	Fixed	In	192	3	Pickup	376			Out		<None>	<None>
9	B PMP-1-2	3	Fixed	In	192	3	Pickup	376			Out		<None>	<None>
10	B PMP-1-3	3	Fixed	In	192	3	Pickup	376			Out		<None>	<None>
11	B SB-2												<None>	<None>
12	B SB-3												<None>	<None>
13	B SB-MAIN	4	Fixed	In	900	4	Pickup	1800			Out		<None>	<None>
14	B TX LP-1												<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 ATS-5-1	<None>	<None>	<None>	<None>	<None>		1			
2	B GEN-5-1	<None>	<None>	<None>	<None>	<None>		1			
3	B LB	<None>	<None>	<None>	<None>	<None>		1			
4	B LP-1 FDR-2	<None>	<None>	<None>	<None>	<None>		1			
5	B LP-1 FDR1	<None>	<None>	<None>	<None>	<None>		1			
6	B LP-1 MAIN	<None>	<None>	<None>	<None>	<None>		1			
7	B MCC-VFD	<None>	<None>	<None>	<None>	<None>		1			
8	B PMP-1-1	<None>	<None>	GE	CR324X	Class 10 Cold	52	1			
9	B PMP-1-2	<None>	<None>	GE	CR324X	Class 10 Cold	52	1			
10	B PMP-1-3	<None>	<None>	GE	CR324X	Class 10 Cold	52	1			
11	B SB-2	<None>	<None>	<None>	<None>	<None>		1			
12	B SB-3	<None>	<None>	<None>	<None>	<None>		1			
13	B SB-MAIN	<None>	<None>	<None>	<None>	<None>		1			
14	B TX LP-1	<None>	<None>	<None>	<None>	<None>		1			

Switches

	ID Name	Status	On Bus	Base kV	Conn Type	Normal State	Manufacturer	Type	Style	Cont Current (A)	SC Mom kA	SC Test Std	PCC kVA Demand
1	ATS-5-1:Switch	On	ATS-5-1	0.48	Feeder	Closed	<None>	<None>	<None>	0	0	ANSI-SYM	

Switches

	ID Name	PCC Isc/ILoad	Comment
1	ATS-5-1:Switch		

Fuses

	ID Name	Status	On Bus	Base kV	Conn Type	Normal State	Options	Manufacturer	Type	Style	TCC Model	TCC kV
1	FS NPC	On	TX NPC H	12.47	Bus Tie	Closed	Breaker Onl	Cutler-Hammer	RBA	RBA-200	Std Speed	15.5
2	FS PMP-1-1	On	FS PMP-1-1	0.48	Feeder	Closed	Fused Brea	BUSS	(Std)	FRS-R(RK5)	<None>	0.6

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	25E	14.4	15	ANSI-SYM				<None>	<None>	<None>		1
2	FS PMP-1-1	150A~	200	4.9	ANSI-SYM				<None>	<None>	<None>		1

Fuses

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

ATSs

	ID Name	Status	Base kV	Area	Zone	AF Type	AF Option	Source Connection	Model	Comment
1	ATS-5-1	On	0.48	1	1	ATS	Specified	Source 1 Bus	Switch	

Three Phase Bolted Fault

Equipment Duty Ratings

Project Name: Lone Mountain Sewer Lift Station
Comment: Three Phase Fault - Equipment Duty Report

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

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Equipment Duty Comparison Report For Bus:
LP-1 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 LP-1 MAIN	GE	/THQD	ANSI-SYM	22.00		1.87(-91.5%)		
B LP-1 FDR1	GE	/THHQB	ANSI-SYM	22.00		1.87(-91.5%)		
B LP-1 FDR-2	GE	/THHQB	ANSI-SYM	22.00		1.87(-91.5%)		
LP-1		/	ANSI-SYM	22.00		1.87(-91.5%)		

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Equipment Duty Comparison Report For Bus:
MCC VFD 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 PMP-1-1	GE	/SEL	ANSI-SYM	65.00		10.67(-83.6%)		
B PMP-1-2	GE	/SEL	ANSI-SYM	65.00		10.67(-83.6%)		
B PMP-1-3	GE	/SEL	ANSI-SYM	65.00		10.67(-83.6%)		
MCC VFD		/	ANSI-SYM	65.00		10.67(-83.6%)		

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Equipment Duty Comparison Report For Bus:
SB 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 TX LP-1	GE	/FCN	ANSI-SYM	65.00		11.01(-83.1%)		
B SB-2	GE	/FCN	ANSI-SYM	65.00		11.01(-83.1%)		
B SB-3	GE	/FCH	ANSI-SYM	100.00		11.01(-89.0%)		
B MCC-VFD	GE	/SFL	ANSI-SYM	65.00		11.01(-83.1%)		
B SB-MAIN	GE	/SGL4	ANSI-SYM	65.00		11.01(-83.1%)		
SB		/	ANSI-SYM	42.00		11.01(-73.8%)		

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Equipment Duty Comparison Report For Bus:
UM SWBD 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 ATS-5-1	GE	/SGL4	ANSI-SYM			12.67(-80.5%)		
UM SWBD		/	ANSI-SYM			12.06(-71.3%)		

Three Phase Bolted Fault

Low Voltage Momentary Report

Project Name: Lone Mountain Sewer Lift Station

Comment: Three Phase Fault - Low Voltage Momentary Report

Momentary (First Cycle) Low Voltage Currents Using Momentary Impedance Circuit

Driving Point Voltage (P.U.) = 1.00000

___3 PHASE Fault On ___		___ Total Fault Duties ___					___ Bus Contributions ___		
Name	Bus kV	Symmetrical Amps	Bkr Duty Amps	X/R Ratio	Mult Factor	Asymmetrical Amps	Branch	Bus	Symmetrical Amps
ATS-5-1	0.480	11206.6	11206.6	4.87	1.26	14150.4			
							C SB	SB	0.0
							C UM SWBD ATS5-1	UM SWBD	11206.6
GEN-5-1	0.480	3257.7	3547.1	12.29	1.49	4847.0			
							GEN-5-1		3257.7
							C GEN5-1 ATS5-1	ATS-5-1	0.0
							C LB	LB	0.0
LB	0.480	3237.9	3475.0	10.82	1.46	4731.7			
							C LB	GEN-5-1	3237.9
LP-1	0.208	1866.5	1866.5	1.70	1.04	1940.5			
							C LP-1	TX LP-1 L	1866.5
MCC VFD	0.480	10668.2	10668.2	4.05	1.21	12953.0			
							C MCC VFD	SB	10668.2
							C PMP-1-1	PMP-1-1	0.0
							C PMP-1-2	PMP-1-2	0.0
							C PMP-1-3	PMP-1-3	0.0
PMP-1-1	0.480	10188.8	10188.8	2.83	1.13	11483.2			
							M PMP-1-1		0.0
							C PMP-1-1	MCC VFD	10188.8
PMP-1-2	0.480	10188.8	10188.8	2.83	1.13	11483.2			
							M PMP-1-2		0.0
							C PMP-1-2	MCC VFD	10188.8
PMP-1-3	0.480	10188.8	10188.8	2.83	1.13	11483.2			
							M PMP-1-3		0.0
							C PMP-1-3	MCC VFD	10188.8
SB	0.480	11007.9	11007.9	4.62	1.25	13742.7			
							C SB	ATS-5-1	11007.9
							C MCC VFD	MCC VFD	0.0
							C TX LP-1	TX LP-1 H	0.0
TX LP-1 H	0.480	10102.9	10102.9	2.62	1.11	11217.3			
							TX LP-1	TX LP-1 L	0.0
							C TX LP-1	SB	10102.9
TX LP-1 L	0.208	1884.5	1884.5	1.71	1.04	1961.5			
							TX LP-1	TX LP-1 H	1884.5
							C LP-1	LP-1	0.0

Project Name: Lone Mountain Sewer Lift Station
Comment: Three Phase Fault - Low Voltage Momentary Report

Momentary (First Cycle) Low Voltage Currents Using Momentary Impedance Circuit
Driving Point Voltage (P.U.) = 1.00000

3 PHASE Fault On		Total Fault Duties					Bus Contributions		
Name	Bus kV	Symmetrical Amps	Bkr Duty Amps	X/R Ratio	Mult Factor	Asymmetrical Amps	Branch	Bus	Symmetrical Amps
TX NPC L	0.480	12250.0	12369.4	7.00	1.36	16636.7			
							NPC		12250.0
							TX NPC	TX NPC H	0.0
							C UM SWBD	UM SWBD	0.0
UM SWBD	0.480	12061.9	12061.9	6.40	1.33	16101.9			
							C UM SWBD	TX NPC L	12061.9
							C UM SWBD ATS5-1	ATS-5-1	0.0

Three Phase Bolted Fault

Low Voltage Interrupting Report

Project Name: Lone Mountain Sewer Lift Station

Comment: Three Phase Fault - Low Voltage Interrupting Report

Interrupting Low Voltage Currents Using Interrupting Impedance Circuit

Driving Point Voltage (P.U.) = 1.00000

___3 PHASE Fault On ___		Total Fault Duties				Bus Contributions		
Name	Bus kV	Symmetrical Amps	X/R Ratio	Mult Factor	Asymmetrical Amps	Branch	Bus	Symmetrical Amps
ATS-5-1	0.480	11206.6	4.97	1.00	11206.6			
						C SB	SB	0.0
						C UM SWBD ATS5-1	UM SWBD	11206.6
GEN-5-1	0.480	3257.7	12.33	1.01	3277.6			
						GEN-5-1		3257.7
						C GEN5-1 ATS5-1	ATS-5-1	0.0
						C LB	LB	0.0
LB	0.480	3237.9	10.86	1.00	3247.8			
						C LB	GEN-5-1	3237.9
LP-1	0.208	1866.5	1.97	1.00	1866.5			
						C LP-1	TX LP-1 L	1866.5
MCC VFD	0.480	10668.2	4.17	1.00	10668.2			
						C MCC VFD	SB	10668.2
						C PMP-1-1	PMP-1-1	0.0
						C PMP-1-2	PMP-1-2	0.0
						C PMP-1-3	PMP-1-3	0.0
PMP-1-1	0.480	10188.8	3.00	1.00	10188.8			
						M PMP-1-1		0.0
						C PMP-1-1	MCC VFD	10188.8
PMP-1-2	0.480	10188.8	3.00	1.00	10188.8			
						M PMP-1-2		0.0
						C PMP-1-2	MCC VFD	10188.8
PMP-1-3	0.480	10188.8	3.00	1.00	10188.8			
						M PMP-1-3		0.0
						C PMP-1-3	MCC VFD	10188.8
SB	0.480	11007.9	4.72	1.00	11007.9			
						C SB	ATS-5-1	11007.9
						C MCC VFD	MCC VFD	0.0
						C TX LP-1	TX LP-1 H	0.0
TX LP-1 H	0.480	10102.9	2.80	1.00	10102.9			
						TX LP-1	TX LP-1 L	0.0
						C TX LP-1	SB	10102.9
TX LP-1 L	0.208	1884.5	1.98	1.00	1884.5			
						TX LP-1	TX LP-1 H	1884.5
						C LP-1	LP-1	0.0
TX NPC L	0.480	12250.0	7.07	1.00	12251.7			
						NPC		12250.0
						TX NPC	TX NPC H	0.0
						C UM SWBD	UM SWBD	0.0
UM SWBD	0.480	12061.9	6.48	1.00	12062.6			
						C UM SWBD	TX NPC L	12061.9
						C UM SWBD ATS5-1	ATS-5-1	0.0

Ground Fault

Equipment Duty Ratings

Project Name: Lone Mountain Sewer Lift Station
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:
LP-1 Area: 1 Zone: 1 Bus kV: 0.21 kV

ID	Manufacturer	/ Style	Test Standard	Ratings 1/2 Cycle (kA)	Ratings Interrupting (kA) Cyc	Duties 1/2 Cycle kA (%)	Duties Interrupting kA (%)	Comments
B LP-1 MAIN	GE	/THQD	ANSI-SYM	22.00		1.99(-91.0%)		
B LP-1 FDR1	GE	/THHQB	ANSI-SYM	22.00		1.99(-91.0%)		
B LP-1 FDR-2	GE	/THHQB	ANSI-SYM	22.00		1.99(-91.0%)		
LP-1		/	ANSI-SYM	22.00		1.99(-91.0%)		

****

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

ID	Manufacturer	/ Style	Test Standard	Ratings 1/2 Cycle (kA)	Ratings Interrupting (kA) Cyc	Duties 1/2 Cycle kA (%)	Duties Interrupting kA (%)	Comments
B PMP-1-1	GE	/SEL	ANSI-SYM	65.00		10.97(-83.1%)		
B PMP-1-2	GE	/SEL	ANSI-SYM	65.00		10.97(-83.1%)		
B PMP-1-3	GE	/SEL	ANSI-SYM	65.00		10.97(-83.1%)		
MCC VFD		/	ANSI-SYM	65.00		10.97(-83.1%)		

****

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

ID	Manufacturer	/ Style	Test Standard	Ratings 1/2 Cycle (kA)	Ratings Interrupting (kA) Cyc	Duties 1/2 Cycle kA (%)	Duties Interrupting kA (%)	Comments
B TX LP-1	GE	/FCN	ANSI-SYM	65.00		11.78(-81.9%)		
B SB-2	GE	/FCN	ANSI-SYM	65.00		11.78(-81.9%)		
B SB-3	GE	/FCH	ANSI-SYM	100.00		11.78(-88.2%)		
B MCC-VFD	GE	/SFL	ANSI-SYM	65.00		11.78(-81.9%)		
B SB-MAIN	GE	/SGL4	ANSI-SYM	65.00		11.78(-81.9%)		
SB		/	ANSI-SYM	42.00		11.78(-71.9%)		

****

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

ID	Manufacturer	/ Style	Test Standard	Ratings 1/2 Cycle (kA)	Ratings Interrupting (kA) Cyc	Duties 1/2 Cycle kA (%)	Duties Interrupting kA (%)	Comments
B ATS-5-1	GE	/SGL4	ANSI-SYM			14.97(-77.0%)		
UM SWBD		/	ANSI-SYM			14.61(-65.2%)		

Ground Fault

Low Voltage Momentary Report

(Serial #34798)
Project Name: Lone Mountain Sewer Lift Station
Comment: Ground Fault - Low Voltage Momentary Report

Momentary (First Cycle) Low Voltage Currents Using Momentary Impedance Circuit
Driving Point Voltage (P.U.) = 1.00000

S L-GND Fault On		Total Fault Duties					Bus Contributions		
Name	Bus kV	Symmetrical Amps	Bkr Duty Amps	X/R Ratio	Mult Factor	Asymmetrical Amps	Branch	Bus	Symmetrical Amps
ATS-5-1	0.480	12270.2	12270.2	3.50	1.18	14440.6			
							C SB	SB	0.0
							C UM SWBD ATS5-1	UM SWBD	12270.2
GEN-5-1	0.480	4587.4	4995.0	12.29	1.49	6825.4			
							GEN-5-1		4587.4
							C GEN5-1 ATS5-1	ATS-5-1	0.0
							C LB	LB	0.0
LB	0.480	4508.2	4719.5	8.91	1.42	6390.6			
							C LB	GEN-5-1	4508.2
LP-1	0.208	1990.5	1990.5	1.66	1.04	2064.8			
							C LP-1	TX LP-1 L	1990.5
MCC VFD	0.480	10972.2	10972.2	2.72	1.12	12272.9			
							C MCC VFD	SB	10972.2
							C PMP-1-1	PMP-1-1	0.0
							C PMP-1-2	PMP-1-2	0.0
							C PMP-1-3	PMP-1-3	0.0
PMP-1-1	0.480	9738.0	9738.0	1.71	1.04	10132.4			
							M PMP-1-1		0.0
							C PMP-1-1	MCC VFD	9738.0
PMP-1-2	0.480	9738.0	9738.0	1.71	1.04	10132.4			
							M PMP-1-2		0.0
							C PMP-1-2	MCC VFD	9738.0
PMP-1-3	0.480	9738.0	9738.0	1.71	1.04	10132.4			
							M PMP-1-3		0.0
							C PMP-1-3	MCC VFD	9738.0
SB	0.480	11783.3	11783.3	3.25	1.16	13653.8			
							C SB	ATS-5-1	11783.3
							C MCC VFD	MCC VFD	0.0
							C TX LP-1	TX LP-1 H	0.0
TX LP-1 H	0.480	9495.4	9495.4	1.55	1.03	9780.5			
							TX LP-1	TX LP-1 L	0.0
							C TX LP-1	SB	9495.4
TX LP-1 L	0.208	2032.1	2032.1	1.70	1.04	2112.8			
							TX LP-1	TX LP-1 H	2032.1
							C LP-1	LP-1	0.0

Project Name: Lone Mountain Sewer Lift Station
Comment: Ground Fault - Low Voltage Momentary Report

Momentary (First Cycle) Low Voltage Currents Using Momentary Impedance Circuit
Driving Point Voltage (P.U.) = 1.00000

___S L-GND Fault On ___		___ Total Fault Duties ___					___ Bus Contributions ___		
Name	Bus kV	Symmetrical Amps	Bkr Duty Amps	X/R Ratio	Mult Factor	Asymmetrical Amps	Branch	Bus	Symmetrical Amps
TX NPC L	0.480	14988.2	14988.2	6.32	1.33	19961.5			
							NPC		12333.9
							TX NPC	TX NPC H	2662.5
							C UM SWBD	UM SWBD	0.0
UM SWBD	0.480	14610.5	14610.5	5.57	1.30	18969.7			
							C UM SWBD	TX NPC L	14610.5
							C UM SWBD ATS5-1	ATS-5-1	0.0

Ground Fault

Low Voltage Interrupting Report

Project Name: Lone Mountain Sewer Lift Station
Comment: Ground Fault - Low Voltage Interrupting Report

Interrupting Low Voltage Currents Using Interrupting Impedance Circuit
Driving Point Voltage (P.U.) = 1.00000

S L-GND Fault On		Total Fault Duties				Bus Contributions		
Name	Bus kV	Symmetrical Amps	X/R Ratio	Mult Factor	Asymmetrical Amps	Branch	Bus	Symmetrical Amps
ATS-5-1	0.480	12270.2	3.72	1.00	12270.2			
						C SB	SB	0.0
						C UM SWBD ATS5-1	UM SWBD	12270.2
GEN-5-1	0.480	4587.4	12.33	1.01	4615.4			
						GEN-5-1		4587.4
						C GEN5-1 ATS5-1	ATS-5-1	0.0
						C LB	LB	0.0
LB	0.480	4508.2	8.99	1.00	4512.4			
						C LB	GEN-5-1	4508.2
LP-1	0.208	1990.5	1.94	1.00	1990.5			
						C LP-1	TX LP-1 L	1990.5
MCC VFD	0.480	10972.2	2.97	1.00	10972.2			
						C MCC VFD	SB	10972.2
						C PMP-1-1	PMP-1-1	0.0
						C PMP-1-2	PMP-1-2	0.0
						C PMP-1-3	PMP-1-3	0.0
PMP-1-1	0.480	9738.0	2.05	1.00	9738.0			
						M PMP-1-1		0.0
						C PMP-1-1	MCC VFD	9738.0
PMP-1-2	0.480	9738.0	2.05	1.00	9738.0			
						M PMP-1-2		0.0
						C PMP-1-2	MCC VFD	9738.0
PMP-1-3	0.480	9738.0	2.05	1.00	9738.0			
						M PMP-1-3		0.0
						C PMP-1-3	MCC VFD	9738.0
SB	0.480	11783.3	3.48	1.00	11783.3			
						C SB	ATS-5-1	11783.3
						C MCC VFD	MCC VFD	0.0
						C TX LP-1	TX LP-1 H	0.0
TX LP-1 H	0.480	9495.4	1.92	1.00	9495.4			
						TX LP-1	TX LP-1 L	0.0
						C TX LP-1	SB	9495.4
TX LP-1 L	0.208	2032.1	1.97	1.00	2032.1			
						TX LP-1	TX LP-1 H	2032.1
						C LP-1	LP-1	0.0
TX NPC L	0.480	14988.2	6.62	1.00	14989.3			
						NPC		12333.9
						TX NPC	TX NPC H	2662.5
						C UM SWBD	UM SWBD	0.0
UM SWBD	0.480	14610.5	5.83	1.00	14610.9			
						C UM SWBD	TX NPC L	14610.5
						C UM SWBD ATS5-1	ATS-5-1	0.0

Breaker Settings

Adjustable Breaker Settings
December 21, 2006

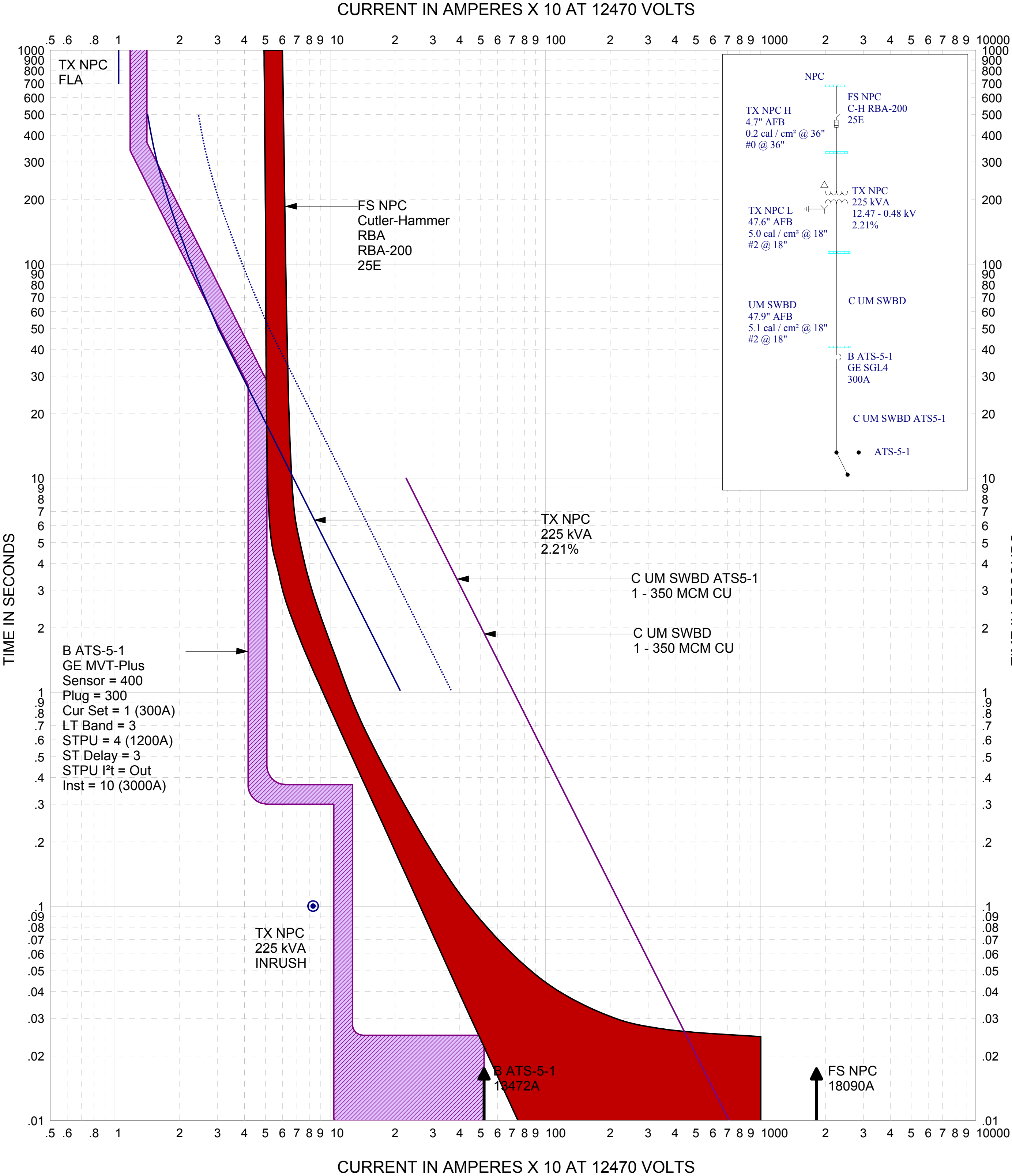
Adjustable Breaker Name	Manufacturer	Type	Style	Sensor/ Frame	Plug/ Tap	LTPU				LT Delay		STPU					Inst			Ground Trip			
						Name	Setting	Mult	Trip (A)	Name	Band	Name	Setting	Trip (A)	Band	I2t	Setting	Override	Trip (A)	Pickup	Trip (A)	Delay	I2t
B ATS-5-1	GE	MVT-Plus	MCCB-SG/SK	400	300	LT Pickup	1		300	LT Delay (s)	3	ST Pickup	4	1200	3	Out	10	Pickup	3000				Out
B SB-MAIN	GE	MVT-Plus	MCCB-SG/SK	400	300	LT Pickup	1		300	LT Delay (s)	2	ST Pickup	3	900	2	Out	8	Pickup	2400				Out
B GEN-5-1						LTPU				LT Band		STPU						Pickup					
B LB						LTPU				LT Band		STPU						Pickup					
B MCC-VFD	GE	Spectra RMS	MCCB SF	250	200	LT Pickup	1		200	LT Delay	Fixed	ST Pickup	Min	300	Fixed	In	Min	Pickup	600				Out
B PMP-1-1	GE	Spectra RMS	MCP SE	100AF(80AT)	80	LT Pickup	1		80	LT Delay	1	ST Pickup	3	236	Fixed	In	3	Pickup	368				Out
B PMP-1-2	GE	Spectra RMS	MCP SE	100AF(80AT)	80	LT Pickup	1		80	LT Delay	1	ST Pickup	3	236	Fixed	In	3	Pickup	368				Out
B PMP-1-3	GE	Spectra RMS	MCP SE	100AF(80AT)	80	LT Pickup	1		80	LT Delay	1	ST Pickup	3	236	Fixed	In	3	Pickup	368				Out

Thermal Magnetic Breakers

December 21, 2006

Thermal Magnetic Breaker	Manufacturer	Type	Style	Frame	Trip	Instantaneous	
						Setting	Trip (A)
B LP-1 FDR1	GE	Q Line	THHQB	100A (15-50AT)	20		
B LP-1 FDR-2	GE	Q Line	THHQB	100A (15-50AT)	50		
B LP-1 MAIN	GE	Q Line	THQD	225A(100-225AT)	225		
B SB-2	GE	Record Plus	FCN	100A (100AT)	100		
B SB-3	GE	Record Plus	FCH	100A (25AT)	25		
B TX LP-1	GE	Record Plus	FCN	100A (70AT)	70		

Time Current Curves

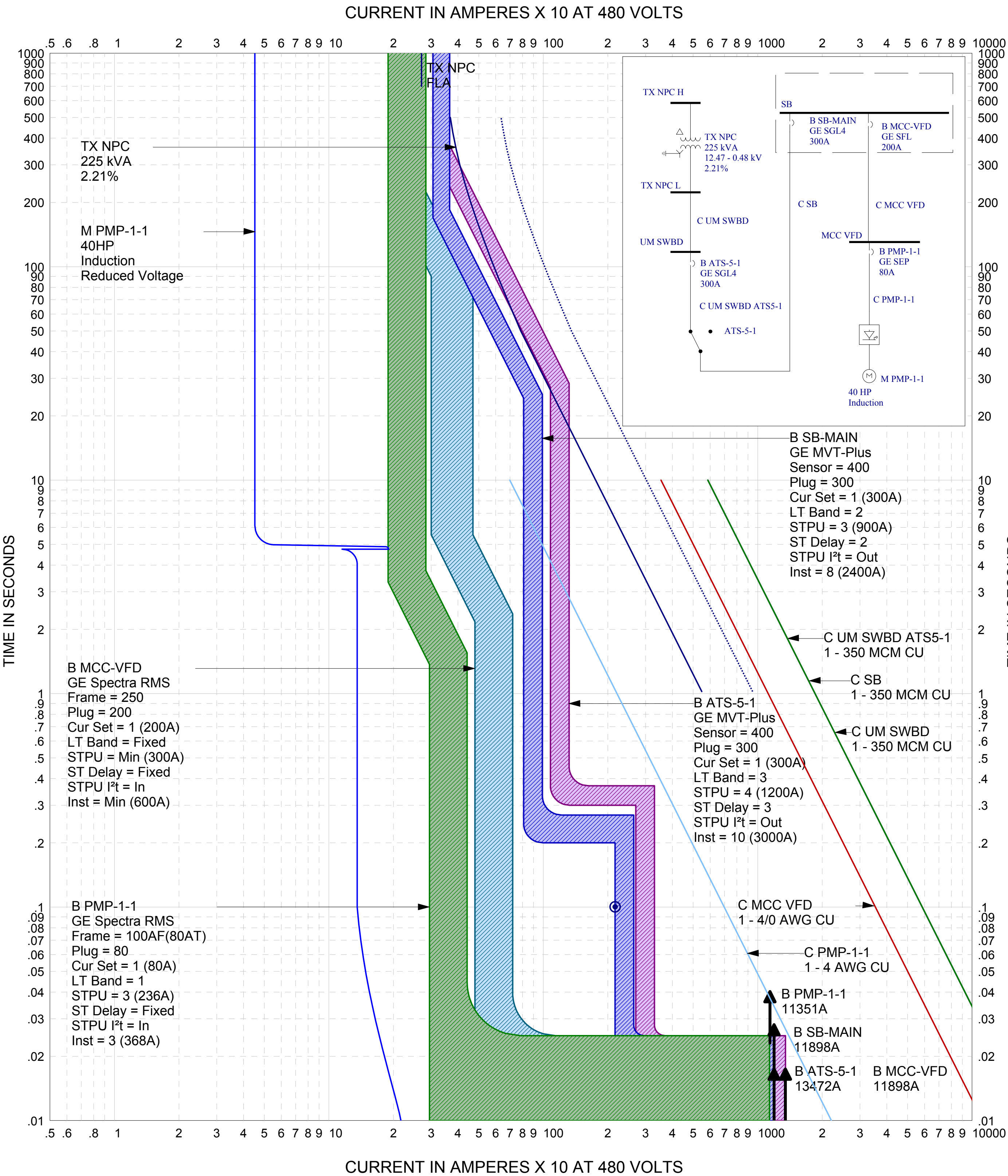


PQTSi	***EasyPower*** ® **TIME-CURRENT CURVES**	Tx NPC

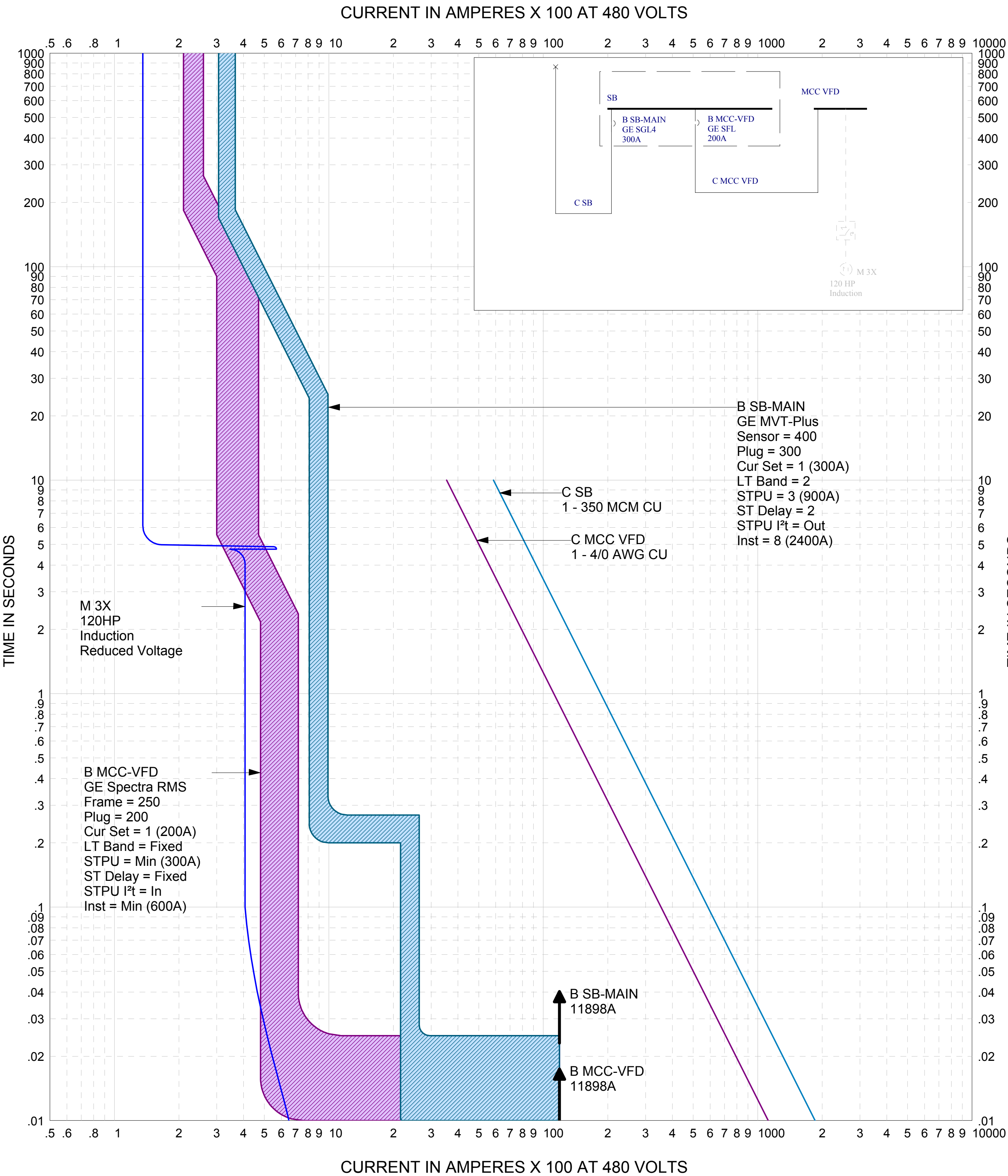
Lone Mountain Sewage Lift Station

High / Low Side protection of Utility Transformer
(MV Fuse - Typical for Utility Application)

FAULT: Phase
DATE: Dec 21, 2006
BY: Joe Dietrich
REVISION: 1



PQTSi	***EasyPower*** ® **TIME-CURRENT CURVES**	NPC to PMP-1-1
Lone Mountain Sewer Lift Station		FAULT: Phase
		DATE: Dec 21, 2006
NPC Transformer to VFD PMP-1-1		BY: Joe Dietrich
(typical for PMP-1-2 and PMP-1-3)		REVISION: 2

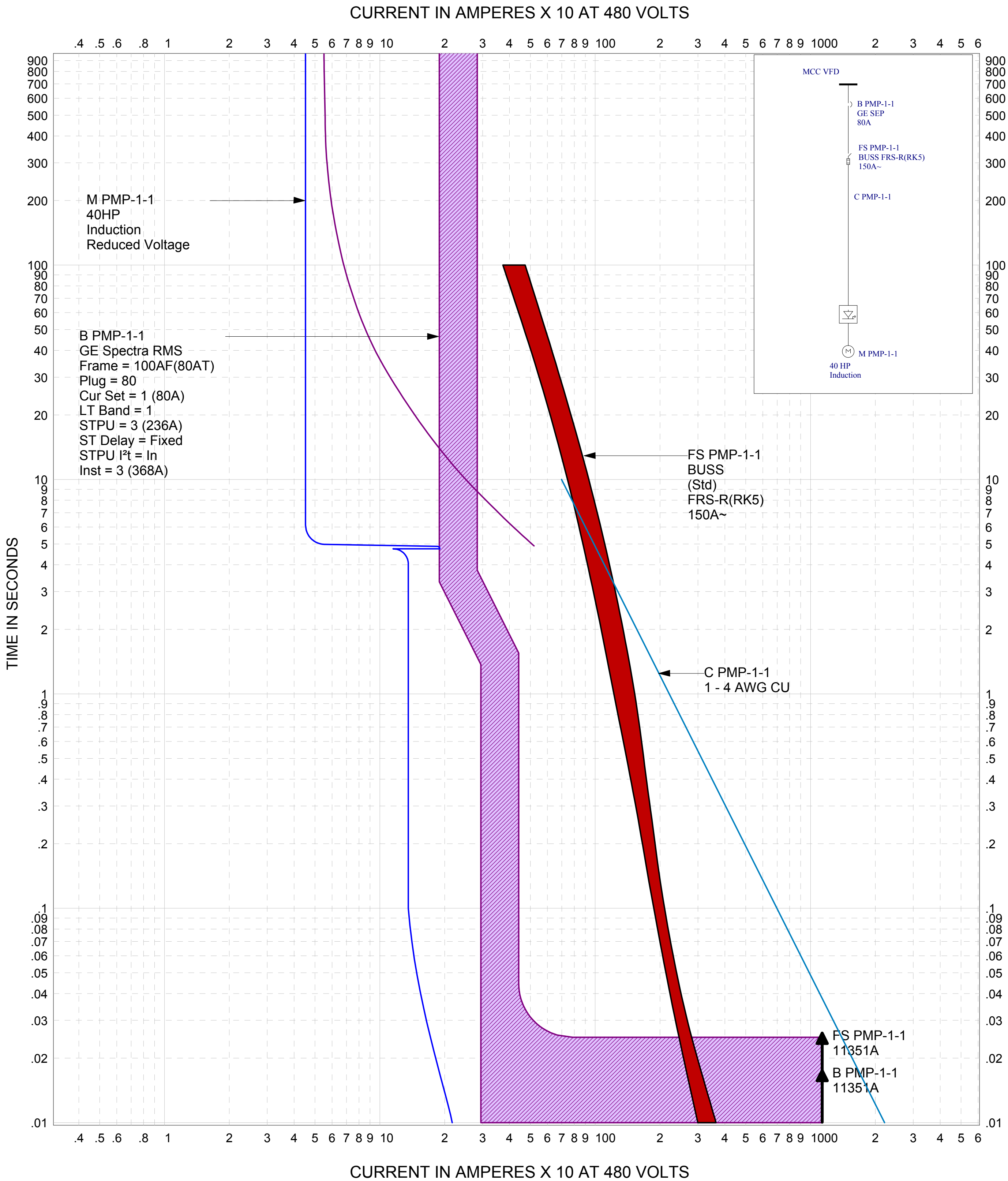


PQTSi	***EasyPower*** ® **TIME-CURRENT CURVES**	PMP-1-1, -2, -3

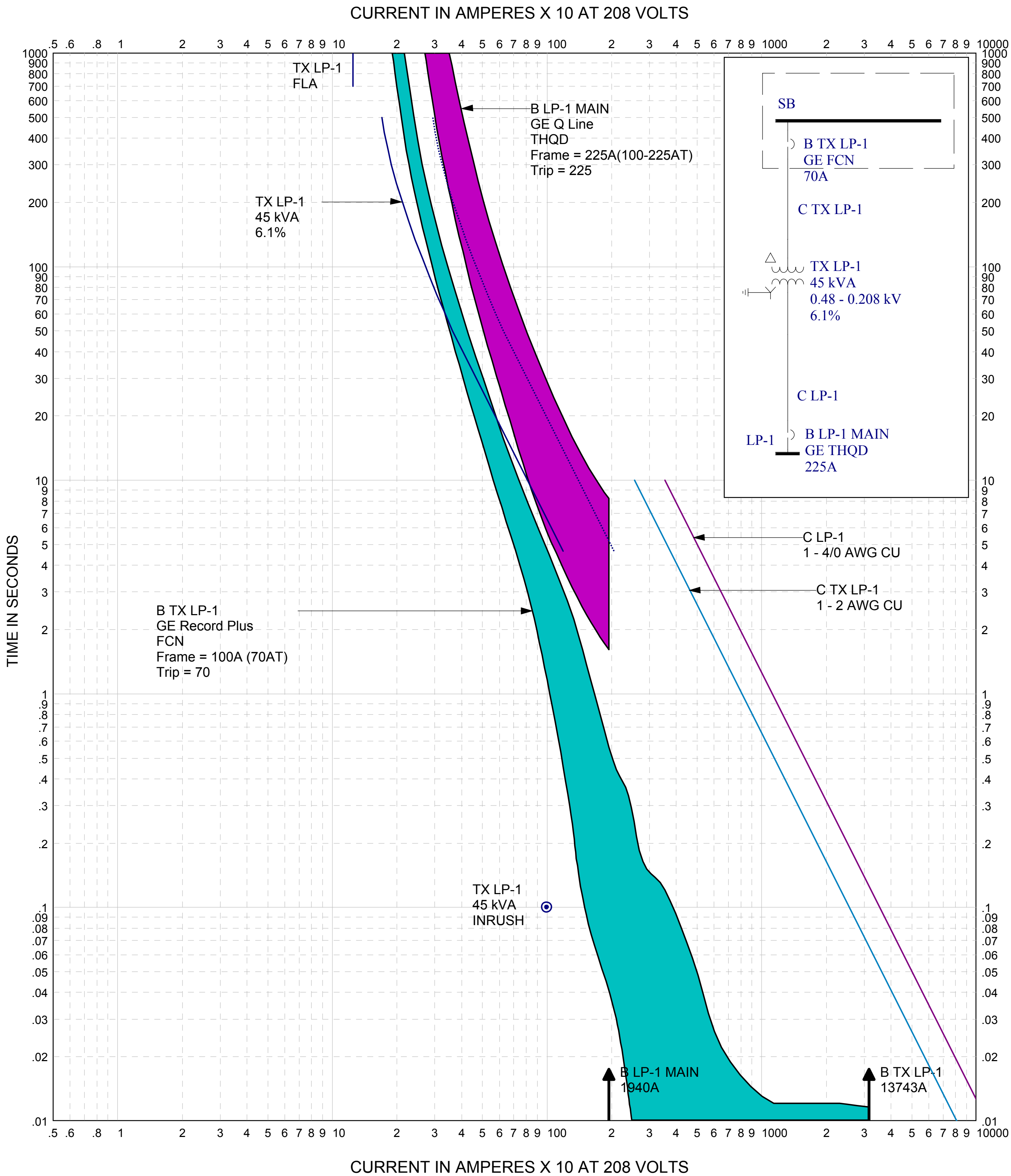
Lone Mountain Sewer Lift Station

MCC-VFD Cummulative Starting HP

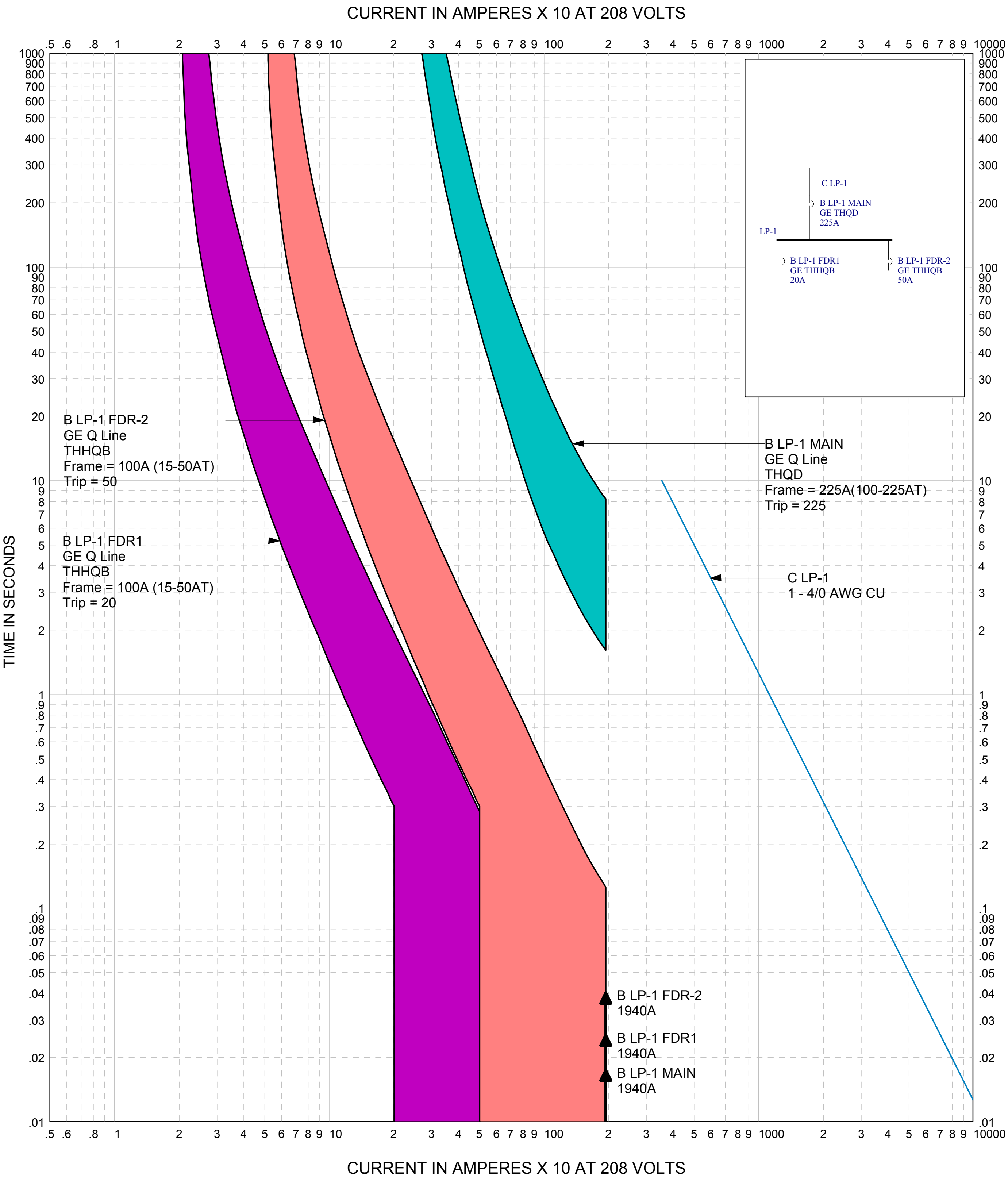
FAULT: Phase
DATE: Dec 21, 2006
BY: Joe Dietrich
REVISION: 1



PQTSi	***EasyPower*** ® **TIME-CURRENT CURVES**	PMP-1-1
Lone Mountain Sewage Lift Station		FAULT: Phase
		DATE: Dec 21, 2006
PPM-1-1 SEP breaker, Motor O/L relay, 150A fuse		BY: Joe Dietrich
		REVISION: 1



PQTSi	*EasyPower* ® TIME-CURRENT CURVES	Tx LP-1
Lone Mountain Sewer Lift Station		FAULT: Phase
		DATE: Sep 28, 2005
Transformer LP-1 High and Low Side Coordination		BY: Joe Dietrich
		REVISION: 0



PQTSi	*EasyPower* ® TIME-CURRENT CURVES	LP-1 Feeders
Lone Mountain Sewer Lift Station		FAULT: Phase
		DATE: Sep 28, 2005
Panel LP-1 Feeders 50A, 20A Vs. Main		BY: Joe Dietrich
		REVISION: 0

Arc Flash Hazard Report

Arc Flash Hazard Report

Arc Fault Bus Name	Arc Fault Bus kV	Upstream Trip Device Name	Upstream Trip Device Function	Equip Type	Arc Gap (mm)	Bolted Fault (kA)	Est Arc Fault (kA)	Trip Time (sec)	Opening Time (sec)	Arc Time (sec)	Est Arc Flash Boundary (inches)	Working Distance (inches)	Incident Energy (cal/cm2)	Required Clothing Class
FS PMP-1-1	0.48	B PMP-1-1		Other	32	10.23	6.439	0.025	0	0.025	9.9	18	0.5	#0
MCC VFD	0.48	B MCC-VFD		MCC	25	10.23	6.708	0.025	0	0.025	11.1	18	0.5	#0
PMP-1-1	0.48	FS PMP-1-1		Other	32	9.686	6.153	0.01	0	0.01	5.2	18	0.2	#0
PMP-1-2	0.48	B PMP-1-2		Other	32	9.686	6.153	0.025	0	0.025	9.6	18	0.5	#0
PMP-1-3	0.48	B PMP-1-3		Other	32	9.686	6.153	0.025	0	0.025	9.6	18	0.5	#0
SB	0.48	B ATS-5-1		Switchgear	32	10.577	6.62	0.025	0	0.025	10.1	18	0.5	#0
TX LP-1 H	0.48	B TX LP-1		Other	32	9.583	6.098	0.012	0	0.012	5.8	18	0.2	#0
TX NPC H	12.47	FS NPC		Other	153	13	12.566	0.01	0	0.01	4.7	36	0.2	#0
TX NPC L	0.48	FS NPC		Other	32	0.455	*0.238	0.263	0	0.263	47.6	18	5	#2
UM SWBD	0.48	FS NPC		Switchboard	32	0.448	*0.234	0.269	0	0.269	47.9	18	5.1	#2
ATS-5-1	0.48	B ATS-5-1		ATS	32	10.773	6.722	0.025	0	0.025	10.3	18	0.5	#0

Warning: The following Arc-Flash 'IEEE 1584' results are based on theoretical equations derived from measured test results.
The test results are a function of specific humidity, barometric pressure, temperature, arc distance, and many other variables.
These parameters will NOT be the same in your application.
These results should be applied only by experienced engineers in the application of Arc-flash hazards.
ESA makes no warranty concerning the accuracy of these results as applied to real world scenarios.

* Indicates a reduced arcing current

Arc Flash Labels

WARNING

Arc Flash and Shock Hazard
Appropriate PPE Required

0' - 10"	Flash Hazard Boundary
0.5	cal/cm2 Flash Hazard at 18 Inches
#0	PPE Level
	Non-melting, flammable materials

0.48	kV Shock Hazard when cover is removed
3' - 6"	Limited Approach
1' - 0"	Restricted Approach - Class 00 Voltage Gloves
0' - 1"	Prohibited Approach - Class 00 Voltage Gloves

Equipment Name: FS PMP-1-1

Arc Flash NPC Fusing (25E) / December 21, 2006

WARNING

Arc Flash and Shock Hazard
Appropriate PPE Required

0' - 11"	Flash Hazard Boundary
0.5	cal/cm2 Flash Hazard at 18 Inches
#0	PPE Level
	Non-melting, flammable materials

0.48	kV Shock Hazard when cover is removed
3' - 6"	Limited Approach
1' - 0"	Restricted Approach - Class 00 Voltage Gloves
0' - 1"	Prohibited Approach - Class 00 Voltage Gloves

Equipment Name: MCC VFD

Arc Flash NPC Fusing (25E) / December 21, 2006

WARNING

Arc Flash and Shock Hazard
Appropriate PPE Required

0' - 5"	Flash Hazard Boundary
0.2	cal/cm2 Flash Hazard at 18 Inches
#0	PPE Level
	Non-melting, flammable materials

0.48	kV Shock Hazard when cover is removed
3' - 6"	Limited Approach
1' - 0"	Restricted Approach - Class 00 Voltage Gloves
0' - 1"	Prohibited Approach - Class 00 Voltage Gloves

Equipment Name: PMP-1-1

Arc Flash NPC Fusing (25E) / December 21, 2006

⚠ WARNING

Arc Flash and Shock Hazard
Appropriate PPE Required

0' - 10"	Flash Hazard Boundary
0.5	cal/cm2 Flash Hazard at 18 Inches
#0	PPE Level
	Non-melting, flammable materials

0.48	kV Shock Hazard when cover is removed
3' - 6"	Limited Approach
1' - 0"	Restricted Approach - Class 00 Voltage Gloves
0' - 1"	Prohibited Approach - Class 00 Voltage Gloves

Equipment Name: PMP-1-2

Arc Flash NPC Fusing (25E) / December 21, 2006

! WARNING

Arc Flash and Shock Hazard
Appropriate PPE Required

0' - 10"	Flash Hazard Boundary
0.5	cal/cm2 Flash Hazard at 18 Inches
#0	PPE Level
	Non-melting, flammable materials

0.48	kV Shock Hazard when cover is removed
3' - 6"	Limited Approach
1' - 0"	Restricted Approach - Class 00 Voltage Gloves
0' - 1"	Prohibited Approach - Class 00 Voltage Gloves

Equipment Name: PMP-1-3

Arc Flash NPC Fusing (25E) / December 21, 2006

WARNING

Arc Flash and Shock Hazard
Appropriate PPE Required

0' - 10"	Flash Hazard Boundary
0.5	cal/cm2 Flash Hazard at 18 Inches
#0	PPE Level
	Non-melting, flammable materials

0.48	kV Shock Hazard when cover is removed
3' - 6"	Limited Approach
1' - 0"	Restricted Approach - Class 00 Voltage Gloves
0' - 1"	Prohibited Approach - Class 00 Voltage Gloves

Equipment Name: SB

Arc Flash NPC Fusing (25E) / December 21, 2006

WARNING

Arc Flash and Shock Hazard
Appropriate PPE Required

0' - 6"	Flash Hazard Boundary
0.2	cal/cm2 Flash Hazard at 18 Inches
#0	PPE Level
	Non-melting, flammable materials

0.48	kV Shock Hazard when cover is removed
3' - 6"	Limited Approach
1' - 0"	Restricted Approach - Class 00 Voltage Gloves
0' - 1"	Prohibited Approach - Class 00 Voltage Gloves

Equipment Name: TX LP-1 H

Arc Flash NPC Fusing (25E) / December 21, 2006

! WARNING

Arc Flash and Shock Hazard
Appropriate PPE Required

0' - 5"	Flash Hazard Boundary
0.2	cal/cm2 Flash Hazard at 36 Inches
#0	PPE Level
	Non-melting, flammable materials

12.47	kV Shock Hazard when cover is removed
5' - 0"	Limited Approach
2' - 2"	Restricted Approach - Class 2 Voltage Gloves
0' - 7"	Prohibited Approach - Class 2 Voltage Gloves

Equipment Name: TX NPC H

Arc Flash NPC Fusing (25E) / December 21, 2006

WARNING

Arc Flash and Shock Hazard
Appropriate PPE Required

4' - 0"	Flash Hazard Boundary
5	cal/cm2 Flash Hazard at 18 Inches
#2	PPE Level
	Cotton underwear plus FR shirt and FR pants

0.48	kV Shock Hazard when cover is removed
3' - 6"	Limited Approach
1' - 0"	Restricted Approach - Class 00 Voltage Gloves
0' - 1"	Prohibited Approach - Class 00 Voltage Gloves

Equipment Name: TX NPC L

Arc Flash NPC Fusing (25E) / December 21, 2006

WARNING

Arc Flash and Shock Hazard
Appropriate PPE Required

4' - 0"	Flash Hazard Boundary
5.1	cal/cm2 Flash Hazard at 18 Inches
#2	PPE Level
	Cotton underwear plus FR shirt and FR pants

0.48	kV Shock Hazard when cover is removed
3' - 6"	Limited Approach
1' - 0"	Restricted Approach - Class 00 Voltage Gloves
0' - 1"	Prohibited Approach - Class 00 Voltage Gloves

Equipment Name: UM SWBD

Arc Flash NPC Fusing (25E) / December 21, 2006

WARNING

Arc Flash and Shock Hazard
Appropriate PPE Required

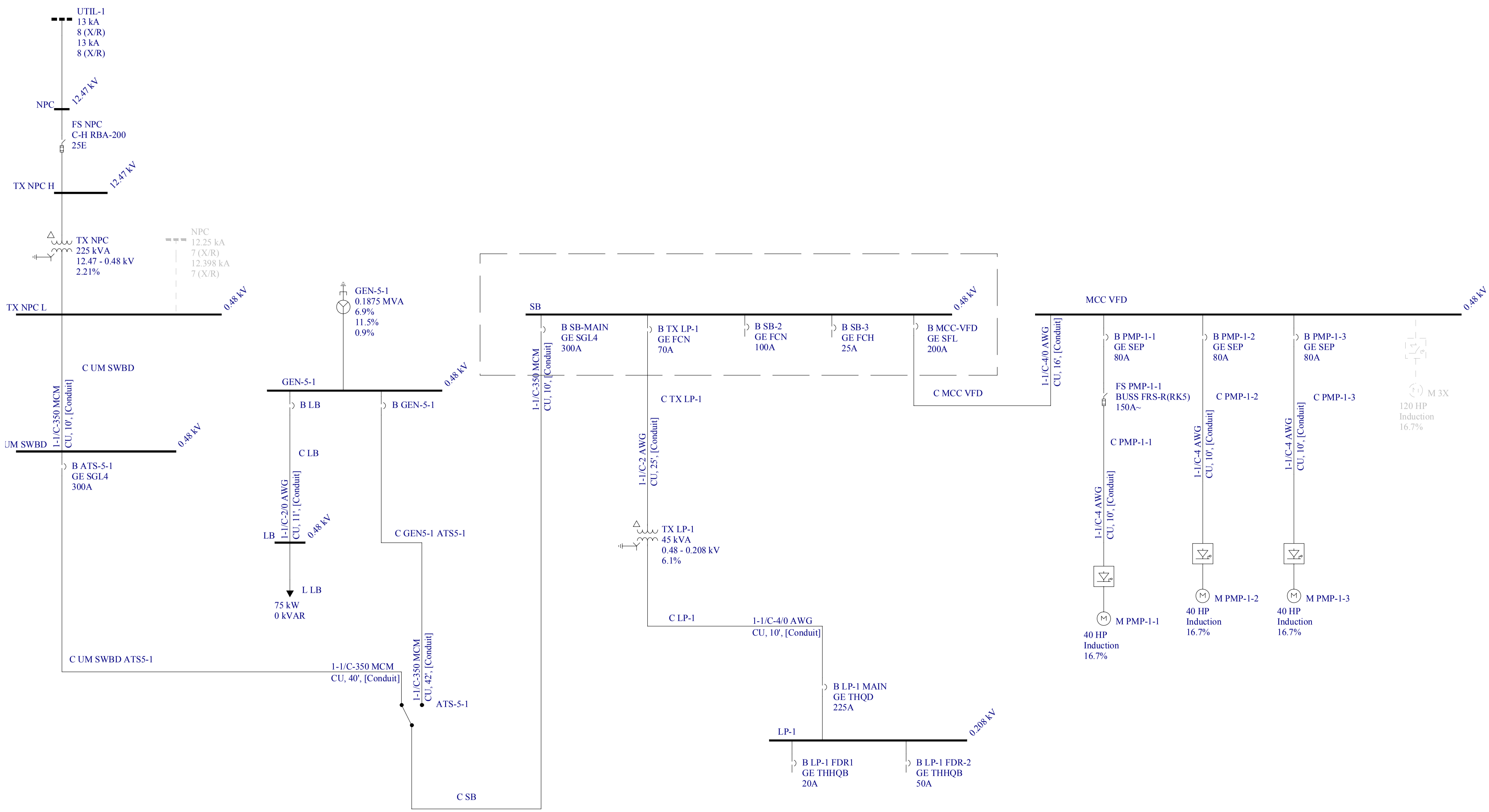
0' - 10"	**Flash Hazard Boundary**
0.5	**cal/cm2 Flash Hazard at 18 Inches**
#0	**PPE Level**
	Non-melting, flammable materials

0.48	**kV Shock Hazard when cover is removed**
3' - 6"	**Limited Approach**
1' - 0"	**Restricted Approach - Class 00 Voltage Gloves**
0' - 1"	**Prohibited Approach - Class 00 Voltage Gloves**

Equipment Name: ATS-5-1

Arc Flash NPC Fusing (25E) / December 21, 2006

Single Line Diagrams



Lone Mountain Sewer Lift Station
Single Line Model
PQTSi - Resubmittal 12-21-2006

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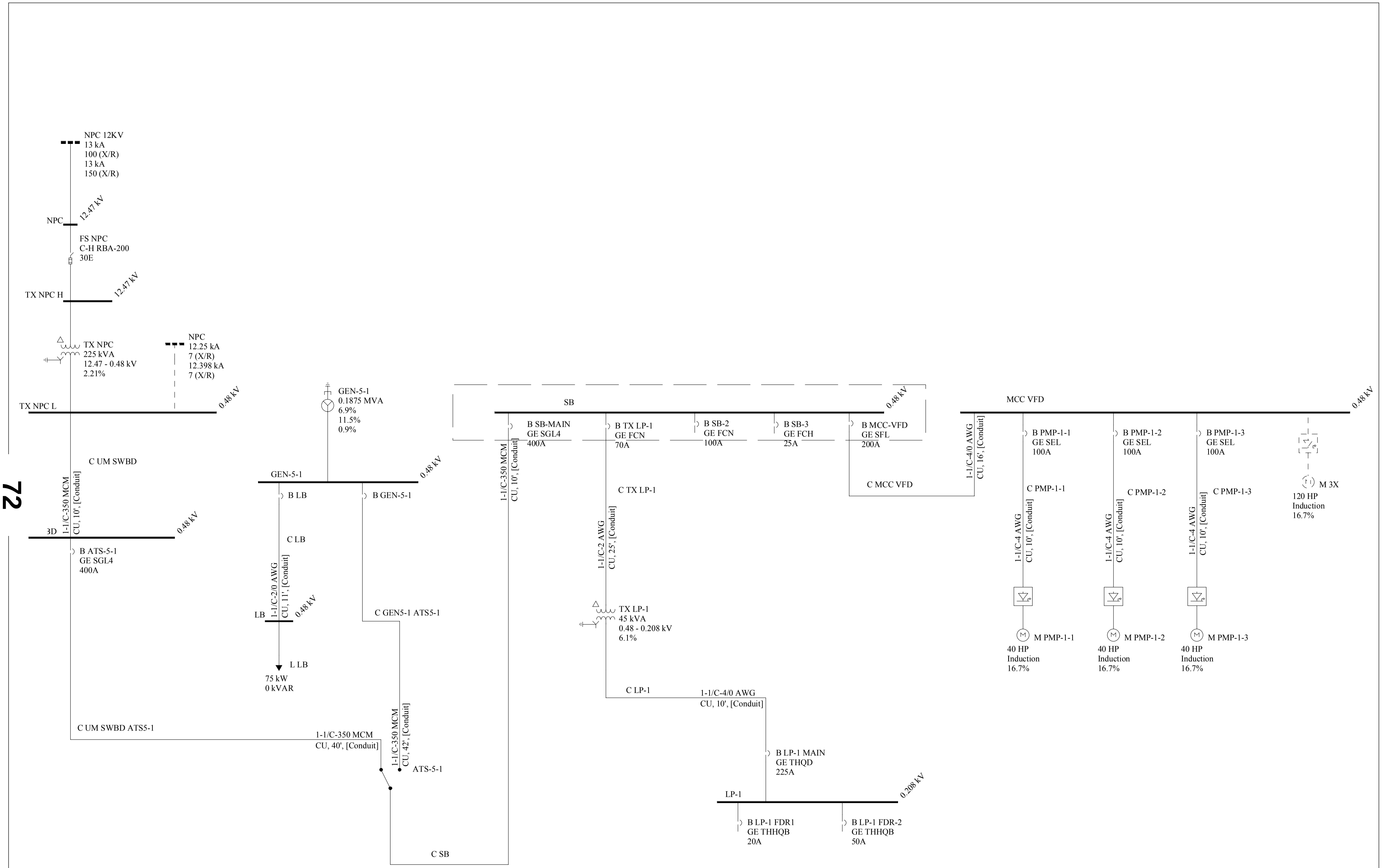

Lone Mountain Sewer Lift Station
Arc Flash Single Line Model - NPC High Side Source
PQTSi - September 28, 2005

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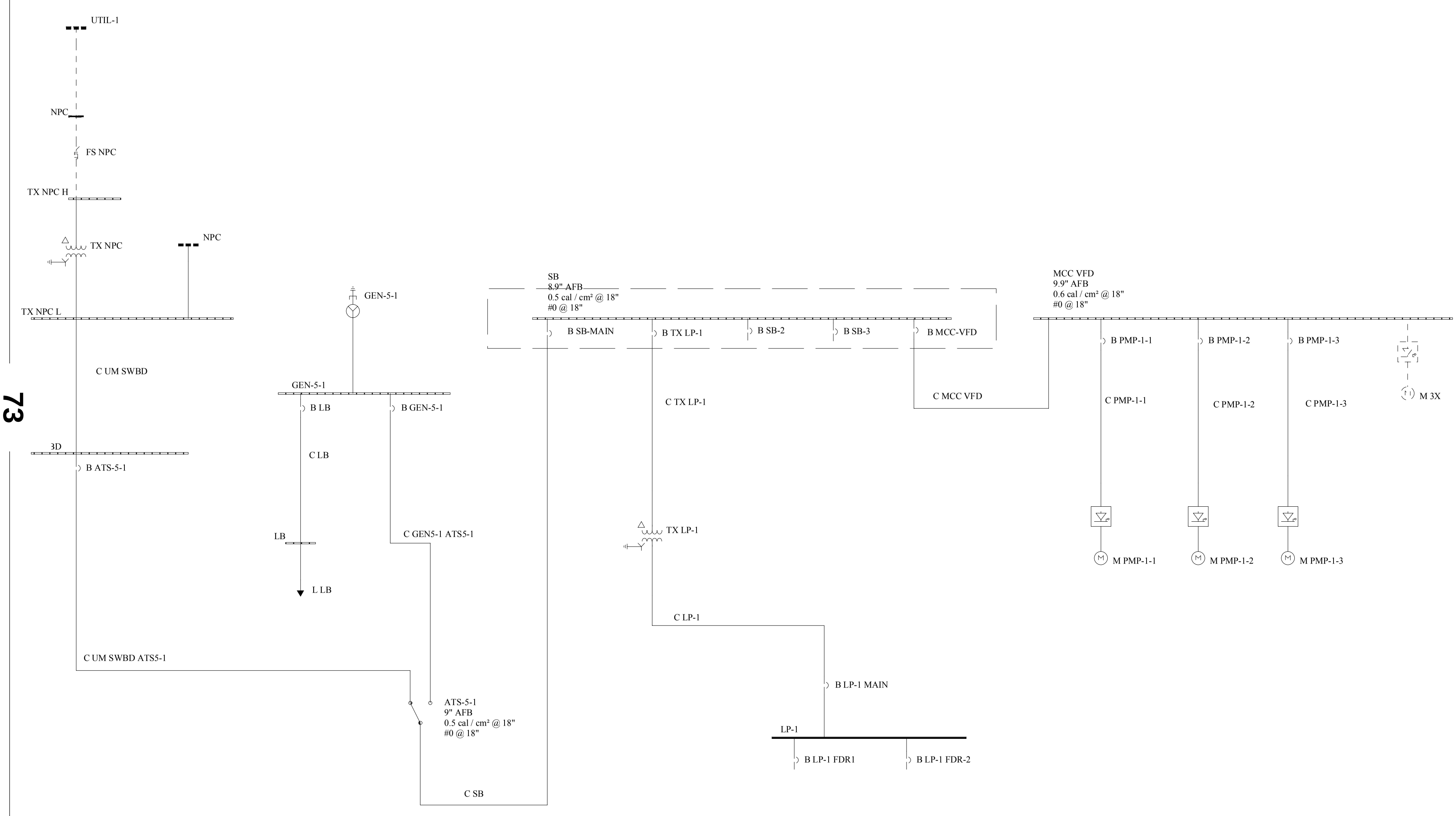

Lone Mountain Sewer Lift Station
Arc Flash Single Line Model - NPC Low Side Source
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