

Transmission System Construction and Analysis

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Abstract:

In this project we designed and analyzed a simple power system from scratch using Positive Sequence Load Flow (PSLF) and Computer Aided Protection Engineering (CAPE). PSLF is used to solve the balance transmission system. The simulation results from PSLF prove the proposed methodology numerical accuracy. Short circuit duty is simulated using CAPE to find the fault current each bus can have on the system, so engineers can protect the system with the appropriate protection scheme. This project totals two major loads with a combine MW intake of 450 MW. In order to supply multiple loads with constant power, the system would need multiple generators and transformers.

Introduction:

The modern electric power system is perhaps one of the largest and complex network of machines ever built by man. These electric power systems are made up of essentially four elements: generation, transmission, distribution, and load. The generator is the source of electrical power to the system. The generator converts different types of energy resources to electrical power. The transmission system is tasked to deliver the electrical power, created at the generation site, to the distribution centers located more commonly near the loads. Since generators are practically limited to a medium voltage level due to AC machine theory, the voltage must be stepped up very high to prevent losses over the long transmission lines. Finally, the transmission lines terminate into distribution substations which then bring the voltage back down and deliver the electricity at utilization voltages. To create a basic system as described above, we need to make the proper assumptions and then analyze the system accounting for contingences that might occur on the system during normal operation. We then can mitigate the problems (i.e. faults) using different methods and tools.

Background:

The requirements of the modern electric power system are to maintain a safe and continuous flow of power to customers. One role of the electrical protection system is to detect abnormal conditions and initiate actions to isolate and mitigate the abnormal conditions. For this project, the abnormal conditions that are implemented are short circuit faults on the power system. However, there are other conditions such as high/low voltage, over/under frequency or equipment failures. Not only will faults cost the power company money due to customer complaints, but it may also cause damage to properties and may lead to death. It is imperative for a utility company to supply safe and reliable power.

Safety and reliability in an electrical system means few or no black outs and a dependable source of power continuously being delivered to the loads. But what does it take to keep the lights on? It takes more than building generators, transformers or putting up power lines. Safety and reliability are needed along with careful calculation, planning and lots of questions, such as: What if a tree hits your power line and shorts the line? What if wind blows one line into another? What if a generator shuts down? Can other generators supply enough power to handle the load? To account for these problems, engineers today use programs and hand calculations to help them quickly calculate every problem that can happen to the system. When new generators or substations are added to the system, new studies like short circuit faults results need to be re-calculated to assure reliability.

Requirements:

Positive Sequence Load Flow (PSLF) and Computer Aided Protection Engineering (CAPE) are essential for this project. PSLF is used to run load flow simulations and CAPE is used to run short circuit duty simulations.

The results of the Power Flow analysis will be used to ensure that the proper paths of power flow exists and that the loads are receiving their specified power at rated voltage and current. Power Flow analysis will also give you the power angle for each bus in the system (view Appendix G) when the initial information, like the ones shown in Appendix F, are exported into PSLF. The larger the power angle differences between two buses, the more power will flow between the buses. The short circuit analysis will aid in the design of the protection system by calculating the contribution of fault current from each generator. The short circuit duty values can help engineers determine the types of relays or breakers they will need to install in case of a fault.

Project layout:

of buses: 19

of loads: 2

of transformers: 15

of transmission lines: 8

of generators: 8

Design and Construction:

When designing the project, the bus names and numbers are chosen at random but with consistence and no overlap. However, the type of bus is chosen based on the purpose of the bus. In PSLF, swing bus (type 0) would have a fixed voltage magnitude and phase. Therefore, allowing the generation connected to mitigate itself due to any power loss or gain to the system. A load bus (type 1) or unconstrained bus is used to connect transmission line and to serve loads. A generator bus (type 2) is used to help supply generation to the system. Table I shows the bus type and bus characteristics mentioned above.

Table I – BUS TYPE AND CHARACTERISTICS

| Bus Type | Bus Characteristics |
|----------|---|
| 0 | swing bus; fixed voltage magnitude and phase |
| 1 | unconstrained bus; magnitude and phase angle of voltage may vary |
| 2 | Generator bus; a synchronous or induction machine may be connected to the bus to control either its own voltage or the voltage of another |

All of the generators in the system shown in Appendix A and B go through two different voltage levels before reaching the transmission voltage level of 115 kV. The mid-voltage levels like Bus 8004, 8005, 8006 and 8007 are needed because most power plants require a small amount of power to operate its facilities. The mid-voltage level bus gives them the desired voltage level to supply themselves with the

necessary load even though most facility loads are small enough to neglect. When the power reaches the transmission voltage level, the generator's dispatch is then delivered to a common substation modeled as TAPBus1 or Bus 9006. The power is then distributed from Bus 9006 to a distribution level voltage of 66 kV to serve the distribution load. TAPBus3 or Bus 9008 is different from all the other buses on the system because it loops the SubBus4 (9004) to TapBus1 (9006) line so more generation or load can be added later on in that area. Southern California Edison Transmission Planning Criteria 4.4.3.2 dictates that only one tap shall be connected to a transmission line. Therefore, if TAPBus3 is not available, only one future power plant or load can be connected to that line, instead of two. Due to the amount of renewable energy and proposed projects in that area, TAPBus3 was added.

When designing components in a transmission system, future cost of upgrade is a necessary factor to consider. It is often better discretion to buy a higher rated line or transformer at the time of new work installation then to buy a lightly rated line or transformer and have to perform major rework to the substation to install another transformer in the future. Three scenarios were applied to the system. For the renewable solar and wind generation on Bus 8004, scenario one is practiced. Since renewable generators such as solar and wind cannot supply VARs to the system, they are normally supported by shunt capacitors like the one shown in Appendix B. In scenario one, the transformers and the lines are rated similar to each other. The advantage of this configuration is that either components would not have to be upgraded for a long period of time. However, the disadvantage is that when the

components do need to be upgraded, everything would have to be upgraded. We used this configuration for generators on Bus 8004 because by California law, 20% of all utilities' total power consumption needs to come from renewable energy by the end of 2010 and 33% by the end of 2020. Therefore, we expect a greater contribution of generation from the 8004 bus generators in the future. The last two scenarios are highly dependent on the size of the substation and the length of the line. It is easier, cheaper, and faster to add/upgrade a 10 mile line than it is for a 15 or 20 mile line. If the substation is small, it is then wise to have a higher rated transformer because of its future value to the entire system. However, if the substation is large and has space to expand, you would not need to invest in a highly rated transformer. For the generator on Bus 8002, scenario 2 is practiced and for the generator on Bus 8001, scenario 3 is practiced (see Table II).

Table II – SCENARIO APPLIED TO THE SYSTEM

| | Transformer Rating (MVA) | Transmission Line Rating (MVA) | Transmission Line Length (Miles) |
|------------|-----------------------------|-----------------------------------|-------------------------------------|
| Scenario 1 | 100 | ≈100 | 10 |
| Scenario 2 | 250 | 120 | 10 |
| Scenario 3 | 250 | 394 | 15 |

There are a total of six generators supplying the transmission system. Appendix E shows a typical generator data form provided by the power plant. Appendix A shows two of the six generators are on the swing bus (8003), meaning those two generators will supply more generation if there is any power loss to the other generators. The generators on the swing bus will also generate less power if it

decides to increase the generation on the other generators in the future. All transformers data adjacent to the generator are given by the customer. An example of transformer data given to Southern California Edison by a customer is shown in Appendix D. The four transformers attached to the swing bus 8003 have two transformers stepping up from 6kV to 34kV and another two stepping it up from 34kV to 115kV. All four transformers are rated at 380MVA, but only energized at 25%, as shown in the load flow results on page 20. At first look, it may seem like the transformers are not used efficiently because we are only using one fourth of their capacity. However, the swing bus' generators do not have a set output; it might have to generate 100 MW one moment and 300 MW the next depending on the characteristics of the system. The same applies to the 230 kV 1590 ACSR line; it needs to have enough reserve capability to deliver the power supplied by the swing bus. Due to the 20 mile difference between bus 9003 and 9007, the 230 kV line was chosen instead of the 115 kV line to supply this generation. A 115 kV line in this situation would give us more losses due to its larger impedance in comparison to the 230 kV line.

Even with the ratings set on the transformers, there are still many types of transformer configurations to choose from; each transformer has its own advantages and disadvantages. The four most popular types of configuration are: Wye-Wye, Delta-Delta, Wye-Delta and Delta-Wye. For Wye-Wye connection, the neutral connections provide grounding and ground fault relay protection. They also need less insulation at the neutral ends of the coil because of reduced voltages. However, a

disadvantage is that it does not trap third harmonics or block zero sequence currents. For Delta-Delta connections, it traps the third harmonics but there is no common grounding point. In this project we used only Wye-Delta and Delta-Wye connections due to the high voltage level of our system. Wye-Delta connections are usually used for high voltage transmissions as a Wye-Delta step down transformer. Delta-Wye connections are also best for high voltage transmissions as a Delta –Wye step up transformer. This is due to the inherent $\sqrt{3}$ voltage gain factor associated with the configuration .

Picking the type of conductor is also very important. You have to always take into account how each line is going to affect your circuit. The lines that are most critical to the system should have a higher rating in order to handle any increase of power to that line. There are hundreds of different types of transmission lines which ensure the proper choice for the desired application. The type of transmission line picked by the engineers is based on the importance of the line and the cost that comes with it. Consider the line that is supplying power to a Nuclear Power Plant and the Transmission line going to your home. If the line that is supplying the nuclear power plant fails, critical plant systems and safety related equipment will be in danger, as opposed to the inability to watch TV if the transmission line near your house goes down.

In a transmission system, the transmission line has a capacitance between the line and the ground. Due to this, the transmission line in a system will give your system a constant VAR. The surge impedance loading or SIL is simply the MW

loading at which the line's MVAR usage is equal to the line's MVAR production. Different conductors will have a different SIL and different length conductors with the same conductor will also have a different SIL. When operating under the SIL, where the VAR support (B or B/2) on the conductor can no longer give enough VAR, shunt capacitors are switched online to supply more VAR to counteract the inductive lines and whatever lagging load is applied. However, when operating above the SIL (too much VAR), shunt capacitors are turned off and if needed a reactor such as the tertiary winding in a transformer comes online to counter the leading VAR supplied by the transmission line.

On the south side of the system shown in Figure 1, the 12 mile 115 kV line from bus 9006 to 9010 is supplying the 250 MW load. The 2156 ACSR line was chosen because the other available 115 kV transmission lines were either rated too high > 80% and not future planning friendly, or rated too low < 40% and not economically friendly (see Table III). The 2156 ACSR has a normal line rating of 1975A and it is currently energized at 66% (see Figure 1 & 2). Usually when a big load such as this is presented to us, an additional line to help supply the load would be added to avoid overloads and faults. In this case, the reliability you gain from adding an additional 12 mile line would be minimal in comparison to the substantial cost. Other lines and generators can be added when the 66% load increases due to the growth of cities and residential communities. Once the 115 kV reaches the bus 9010, the voltage steps down from 115 kV to 66 kV with a 400 MVA transformer. The transformer was chosen based on the 2156 ACSR line rating for reliability demand to

the load. When the 12 mile line reaches the load, it steps down to a distribution voltage level.

Table III – LOAD CONDUCTOR RATINGS

| Conductor | p.u./mi | | | ampacity | rating |
|--------------------|----------|----------|----------|----------|-----------|
| | R | X | B | N-0 (A) | N-0 (MVA) |
| 1/0 CU (115 kV) | 0.004600 | 0.006500 | 0.000660 | 350.0 | 69.7 |
| 4/0 CU (115 kV) | 0.002300 | 0.006000 | 0.000700 | 540.0 | 102.0 |
| 336 ACSR (115 kV) | 0.002300 | 0.005700 | 0.000740 | 605.0 | 120.5 |
| 1250 UG (115 kV) | 0.000410 | 0.002220 | 0.015420 | 670.0 | 133.5 |
| 1750 UG (115 kV) | 0.000550 | 0.002390 | 0.017360 | 800.0 | 159.3 |
| 653 ACSR (115 kV) | 0.001200 | 0.005400 | 0.000780 | 920.0 | 183.3 |
| 954 SAC (115 kV) | 0.000900 | 0.005400 | 0.000800 | 1090.0 | 217.1 |
| 1033 ACSR (115 kV) | 0.000800 | 0.005200 | 0.000820 | 1240.0 | 247.0 |
| 2156 ACSR (115 kV) | 0.000400 | 0.004700 | 0.000860 | 1975.0 | 393.4 |
| 2B-2156 (115 kV) | 0.000011 | 0.000238 | 0.017520 | 3950.0 | 3421.0 |

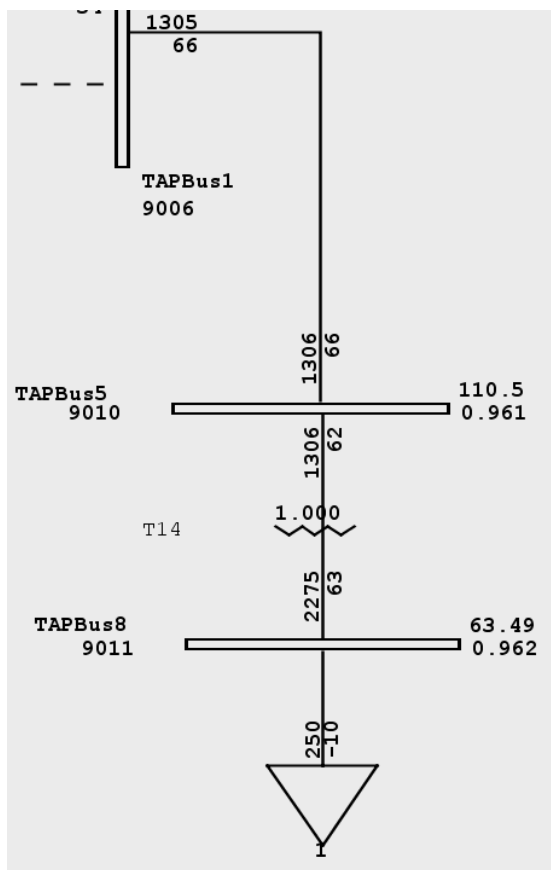


Figure 1 – south side line/load in Amp/% rated

| | | |
|------------|-------|------------|
| R pu | | 0.004800 |
| * X pu | | 0.056400 |
| B pu | | 0.010320 |
| Rating MVA | [1] | 393.399994 |

Figure 2 – 9006 to 9010 line data from Transmission Criteria

On the north side of the system, shown in Figure 3, there is a smaller load with the same line and transformer used on the south side. Therefore, the line and transformer is only energized around 50% each due to the 1975A rating (see Figure 3

& 4). We keep the same line due to forecast load increase on the north side. Right now the north side load is absorbing 200 MWs and giving 10 MVARs. View pages 20 - 21 for complete load flow results.

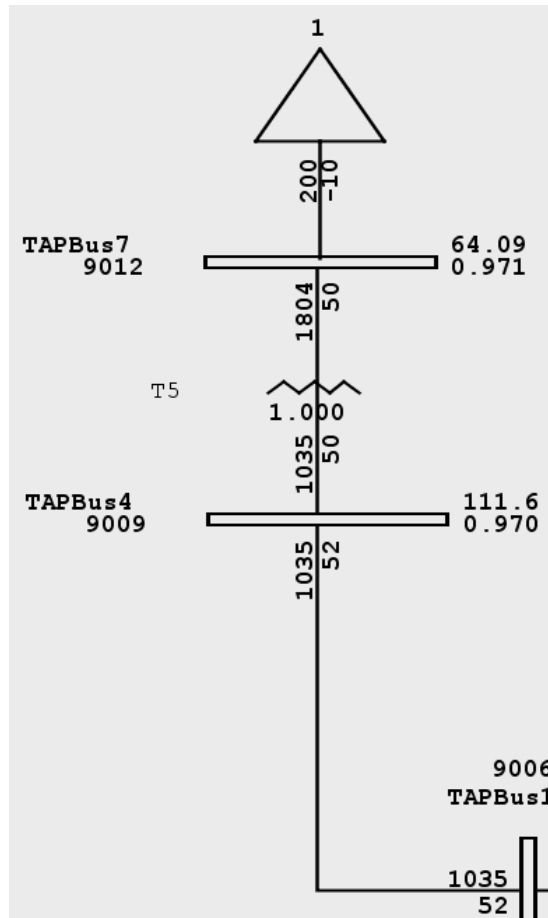


Figure 3 – North side line/load in Amp/% rated

| | |
|------------|------------------|
| R pu | 0.004800 |
| * X pu | 0.056400 |
| B pu | 0.010320 |
| Rating MVA | [1] 393.399994 |

Figure 4 – 9006 to 9009 line data from Transmission Criteria

SCD Test Results:

In this project we looked at: three-phase faults and phase-to-ground faults. Three-phase faults are the worst case scenario that involves a fault across all three phases, as shown in Figure 5. Phase-to-ground faults are results of an energized conductor contacting the ground, as shown in Figure 6. To ensure the short circuit current is accurate, we used hand calculations to validate the results of the simulation. Once we see one or two of the hand calculation(s) match the value of the short circuit duty program, we can be sure the circuit we built was being simulated correctly. View pages 22 – 33 for fault calculations and simulations.

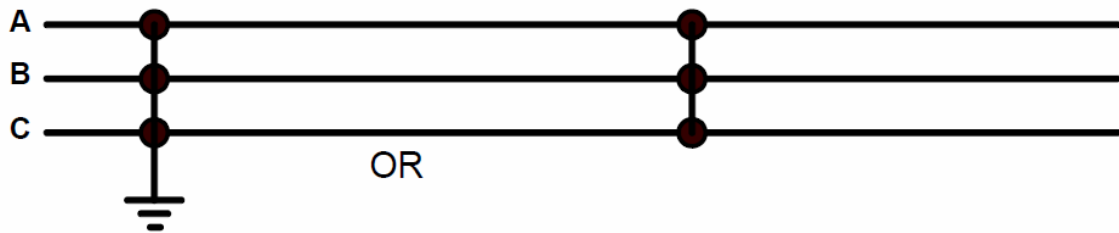


Figure 5: three-phase fault to ground or three-phase fault

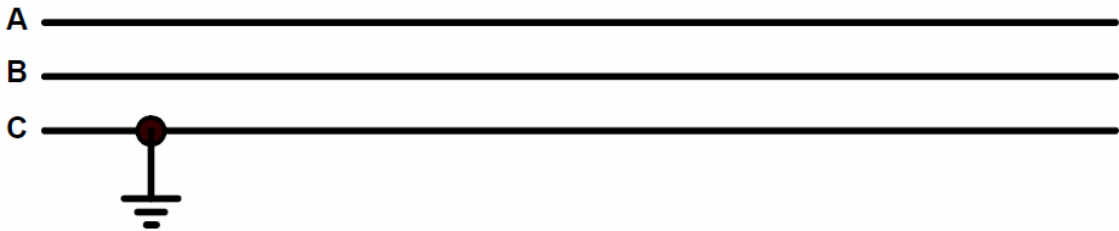


Figure 6: phase-to-ground fault

Protection Development:

The loss of major loads in the system will lead to excessive generator production of MW and MVAR, which will cause both over-voltage on our buses and over-speed problems for the generators. The loss of load may be due to the loss of transmission line or due to a load shedding scheme set up to maintain system stability. In order to keep the system balanced, generation plants that are supplying the power to the load will be turned off by the operator. The loss of VAR sources other than generators, such as shunt capacitor banks, also can change the voltage.

Transmission engineers work closely with substation and protection engineers when creating or changing a transmission system. However in this design, we assume all protection devices will be taken care of by the substation and protection engineers. To ensure safety and reliability, reclosing relays, disconnects, fuses, circuit breakers (CB), current transformers (CT), and many other devices are used. These devices are there to ensure a local fault or power loss does not affect neighboring circuits. To accomplish this, protective devices isolate the problems by isolating the problem area. Different relays are designed to detect different types of faults. It is not unusual to find two relays installed together because neither relay is able to respond adequately to every type of fault. Also, a backup relay is always used on any feeder with significant safety and reliability concern. Fuses are designed pieces of wire which vaporize when a fault or overload condition occurs. The size and type of the metal determines how much current is required to melt. The cost for fuses is minimal when compared to CBs and relay systems, and are very easy to maintain. However, every

time they are blown, linemen must travel to the location to replace it. It also creates operational problems for switching and maintenance since they are not remotely controlled. Replacing fuses with remotely controlled CBs being supervised by protective relays can eliminate the disadvantages associated with the use of fuses.

One example of where breakers will be put into service is the transformers near our two major loads. The Mitsubishi 200-SFMT-40SE breaker shown in table IV is used for the protection of these two lines and transformers. Because of the rated 2000A continuous current (amount of current the breakers are able to handle without faulting) was chosen for the 9006 to 9010 line due to the 1300A continuous current loaded on the South line (Figure 1), the 1200A would be too small and the 3000A continuous would be too expensive. Because the 1200A continuous current rating was chosen for the 9006 to 9009 line due to the 1050A continuous current loaded on the North line (Figure 3), both the 2000A and the 3000A continuous rating would be too expensive. The interrupting current in Table IV shows the amount of current this breaker can handle in the given amount of interrupting time. The interrupting time on a breaker is usually given in cycles (60 cycles = 1 seconds). If either the interrupting current or interrupting time exceeds the rated amount, the breaker will open itself to protect the system until the problem is resolved. The breakers will be placed between the transformer and the buses adjacent to the transformer. This configuration will protect the system as well as the customer and prevent the damage of expensive equipment.

Table IV. MITSUBISHI 200 SFMT-40SE BREAKER RATING

| | |
|---------------------------|----------------|
| Type | 200-SFMT-40SE |
| Voltage (max kV) | 245 |
| Continuous Current (A) | 1200/2000/3000 |
| Interrupting Current (KA) | 40 |
| Interrupting Time | 3 |

Conclusion:

Every element in the transmission system helps one another to ensure safe and reliable electricity for us to use. To construct such a system requires continuous re-simulations and calculations. The objective of this project was to first construct a safe, balanced and reliable system using PSLF. Second, to expose the system to some conceivable faults and calculate the fault current's effect on the transmission system. Third, to investigate in any protection schemes the system may need now or in the future.

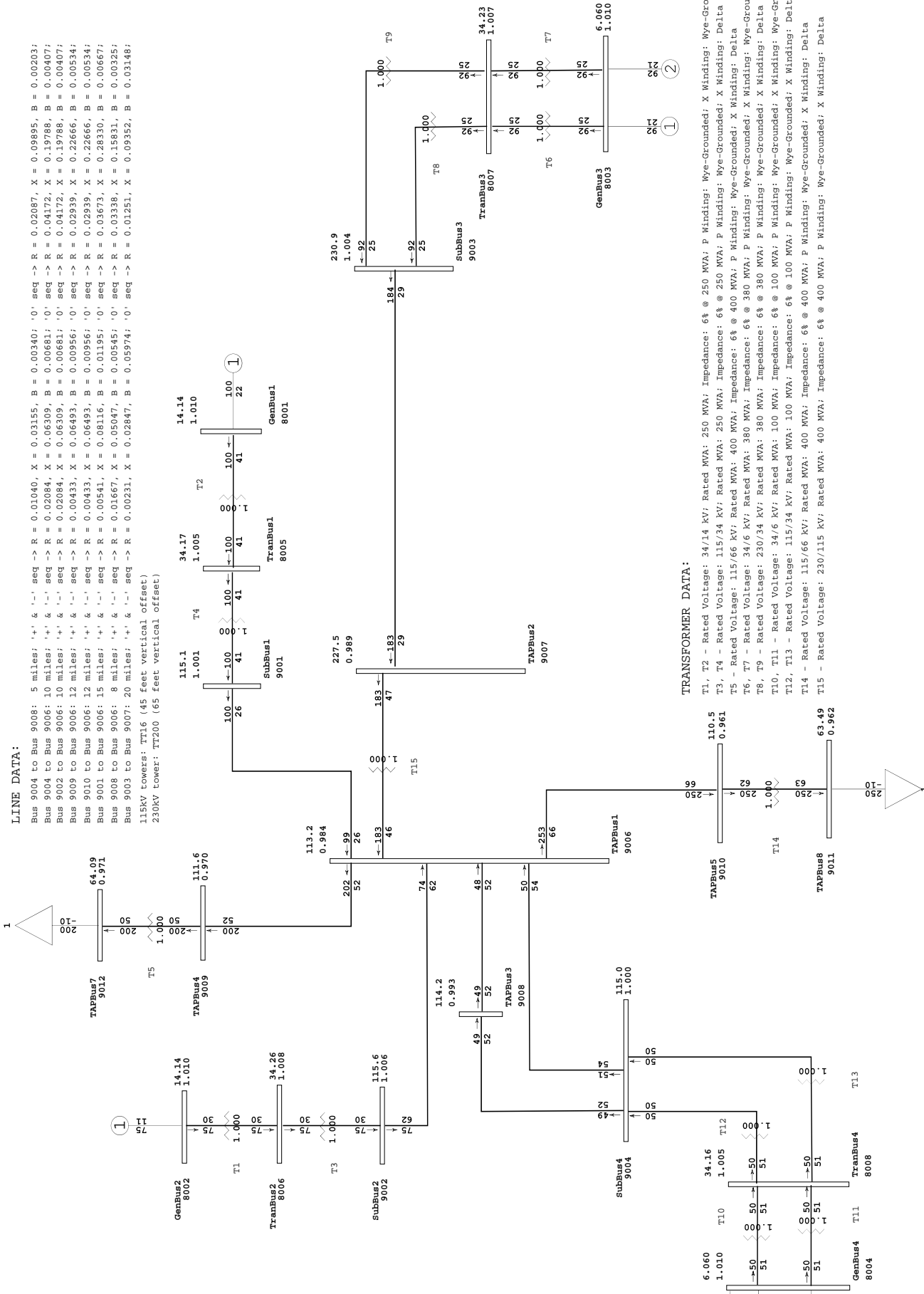
Future Work:

In the future, we can add more load to the system. We can also adjust the system to the amount of load added, by adjusting MW and MVAR output. Replacing small generators with bigger generators is another option to clean up the system if needed. The protection system can be expanded and developed in future projects to provide a comprehensive analysis and solution to faults in order to improve the stability criterion as well as the general reliability and safety of the entire system.

Bibliography:

- Southern California Edison. Transmission Planning Criteria and Guidelines. 8/2004.
- “Mitsubishi Electric Power Products, INC.”
<<http://www.meppi.com/Products/PowerCircuitBreakers/HVGCB/Synchronous%20Breaker%20Brochures/3page200SFMT50SE.pdf>>.

Appendix A



LINE DATA:
 Bus 9004 to Bus 9008: 5 miles; '+', '-' seq -> R = 0.01040, X = 0.03155, B = 0.00340; '0' seq -> R = 0.02087, X = 0.09895, B = 0.00203;
 Bus 9004 to Bus 9006: 10 miles; '+', '-' seq -> R = 0.02084, X = 0.06309, B = 0.00681; '0' seq -> R = 0.04172, X = 0.19788, B = 0.00407;
 Bus 9002 to Bus 9006: 10 miles; '+', '-' seq -> R = 0.02084, X = 0.06309, B = 0.00681; '0' seq -> R = 0.04172, X = 0.19788, B = 0.00407;
 Bus 9009 to Bus 9006: 12 miles; '+', '-' seq -> R = 0.00433, X = 0.06493, B = 0.00956; '0' seq -> R = 0.02939, X = 0.22666, B = 0.00534;
 Bus 9010 to Bus 9006: 12 miles; '+', '-' seq -> R = 0.00433, X = 0.06493, B = 0.00956; '0' seq -> R = 0.02939, X = 0.22666, B = 0.00534;
 Bus 9001 to Bus 9006: 15 miles; '+', '-' seq -> R = 0.00541, X = 0.08116, B = 0.01195; '0' seq -> R = 0.03673, X = 0.28330, B = 0.00667;
 Bus 9008 to Bus 9006: 8 miles; '+', '-' seq -> R = 0.01667, X = 0.05047, B = 0.00545; '0' seq -> R = 0.03338, X = 0.15831, B = 0.00325;
 Bus 9003 to Bus 9007: 20 miles; '+', '-' seq -> R = 0.00231, X = 0.02847, B = 0.05974; '0' seq -> R = 0.01251, X = 0.09352, B = 0.03148;

115KV towers: TT16 (45 feet vertical offset)
 230KV tower: TT200 (65 feet vertical offset)

TRANSFORMER DATA:

- T1, T2 - Rated Voltage: 34/14 kV; Rated MVA: 250 MVA; Impedance: 6% @ 250 MVA; P Winding: Wye-Grounded; X Winding: Wye-Grounded
- T3, T4 - Rated Voltage: 115/34 kV; Rated MVA: 250 MVA; Impedance: 6% @ 250 MVA; P Winding: Wye-Grounded; X Winding: Delta
- T5 - Rated Voltage: 115/66 kV; Rated MVA: 400 MVA; Impedance: 6% @ 400 MVA; P Winding: Wye-Grounded; X Winding: Delta
- T6, T7 - Rated Voltage: 34/6 kV; Rated MVA: 380 MVA; Impedance: 6% @ 380 MVA; P Winding: Wye-Grounded; X Winding: Wye-Grounded
- T8, T9 - Rated Voltage: 230/34 kV; Rated MVA: 100 MVA; Impedance: 6% @ 100 MVA; P Winding: Wye-Grounded; X Winding: Delta
- T10, T11 - Rated Voltage: 34/6 kV; Rated MVA: 100 MVA; Impedance: 6% @ 100 MVA; P Winding: Wye-Grounded; X Winding: Wye-Grounded
- T12, T13 - Rated Voltage: 115/34 kV; Rated MVA: 100 MVA; Impedance: 6% @ 100 MVA; P Winding: Wye-Grounded; X Winding: Delta
- T14 - Rated Voltage: 115/66 kV; Rated MVA: 400 MVA; Impedance: 6% @ 400 MVA; P Winding: Wye-Grounded; X Winding: Delta
- T15 - Rated Voltage: 230/115 kV; Rated MVA: 400 MVA; Impedance: 6% @ 400 MVA; P Winding: Wye-Grounded; X Winding: Delta



| | | |
|---|-------------------------------------|--------------------|
| Engineer: Shawn Wang | [OMW][OMW][OMW][OMW] | MW/% rate |
| CASE NAME:c:\documents and settings\wangsl\Desktop\shawn's system\final7(withup | [SYLMAR 0][VIC-LOGO 0][0][0][0] | final(project).drv |
| SCE [LOAD 450 XCHGE 0 GEN 0][AA 0V 0M 0D 0VA]MW | | Rating = 1 |

Appendix C

Bus 9001/9002 SCD (three phase to ground)

TRANSFORMER DATA:

Impedance: 6% at 250 MVA

GENERATOR DATA:

Impedance: 6% at 200 MVA

$$\text{Transformer 2: } 6\% \times \frac{100MVA}{250MVA} = 0.024$$

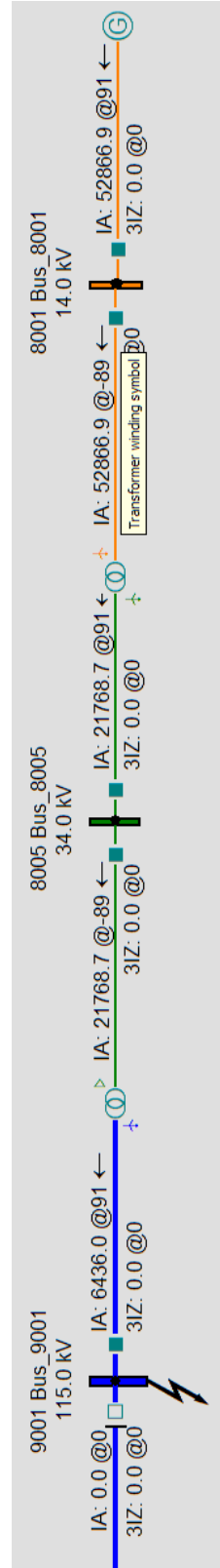
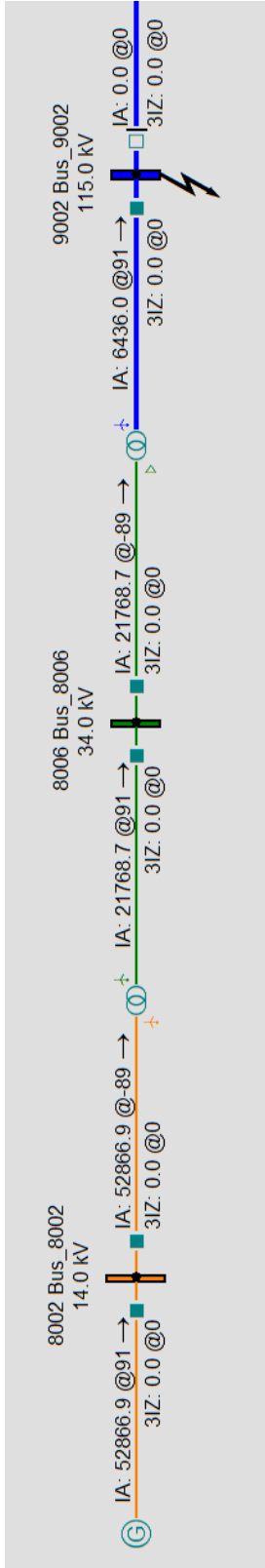
$$\text{Transformer 4: } 6\% \times \frac{100MVA}{250MVA} = 0.024$$

$$\text{Generator 1: } 6\% \times \frac{100MVA}{200MVA} = 0.03$$

$$\text{SCD}_{(MVA)}: \frac{100MVA}{0.024 + 0.024 + 0.03} = 1282.05MVA$$

$$\text{Fault Current: } \frac{1282.05MVA}{\sqrt{3}(115kV)} = 6436A$$

* All generator & transformer data are provide by the customer (see Appendix D&E)



Bus 9003 SCD (three phase to ground)

TRANSFORMER DATA:

Impedance: 6% at 380 MVA

GENERATOR DATA:

Impedance: 6% at 300 MVA

$$\text{Transformer 6: } 6\% \times \frac{100MVA}{380MVA} = 0.01579$$

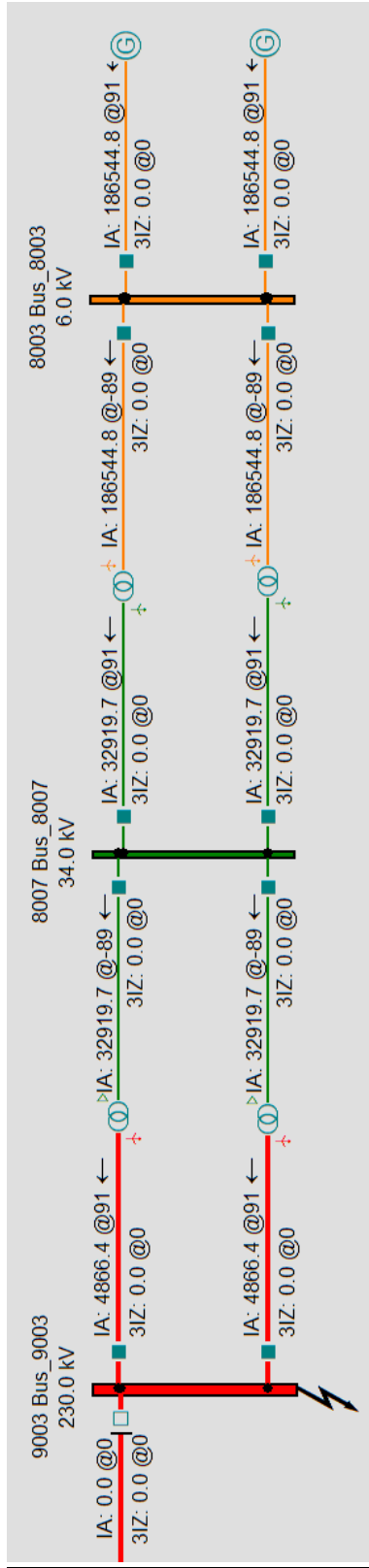
$$\text{Transformer 8: } 6\% \times \frac{100MVA}{380MVA} = 0.01579$$

$$\text{Generators: } 6\% \times \frac{100MVA}{300MVA} = 0.02$$

$$\text{SCD}_{(MVA)}: \frac{100MVA}{0.01579 + 0.01579 + 0.02} = 1938.74MVA$$

$$\text{Fault Current: } \frac{1938.74MVA}{\sqrt{3}(230kV)} = 4866.66A$$

* All generator & transformer data are provide by the customer (see Appendix D&E)



Bus 9004 SCD (three phase to ground)

TRANSFORMER DATA:

Impedance: 6% at 100 MVA

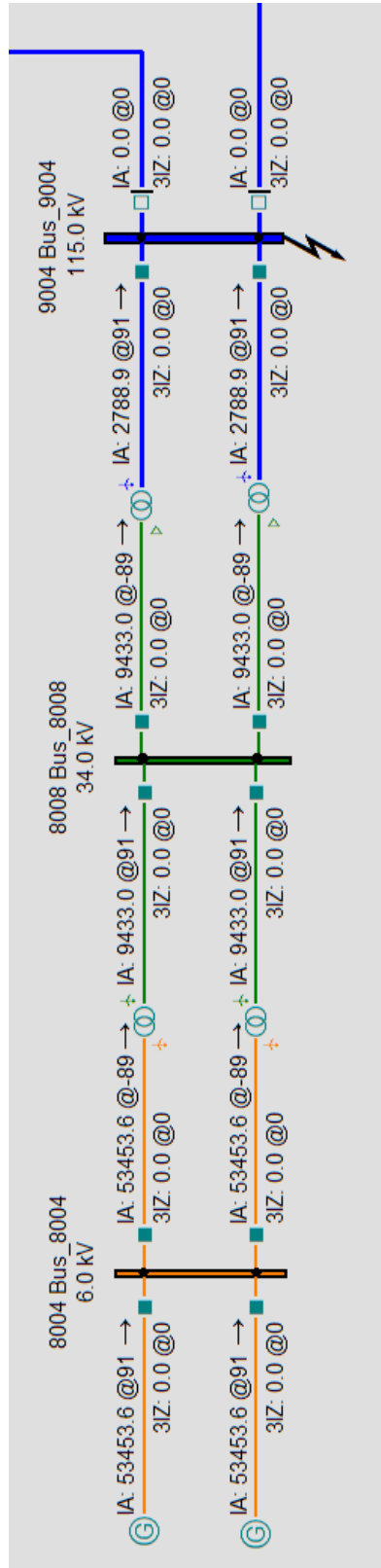
GENERATOR DATA:

Impedance: 6% at 100 MVA

$$SCD_{(MVA)}: \frac{100MVA}{0.06 + 0.06 + 0.06} = 555.555MVA$$

$$\text{Fault Current: } \frac{555.555MVA}{\sqrt{3}(115kV)} = 2788.9A$$

* All generator & transformer data are provide by the customer (see Appendix D&E)



Bus 9001/9002 SCD (single line to ground)

TRANSFORMER DATA:

Impedance: 6% at 250 MVA

GENERATOR DATA:

Impedance: 6% at 200 MVA

$$\text{Transformer 2: } 6\% \times \frac{100MVA}{250MVA} = 0.024$$

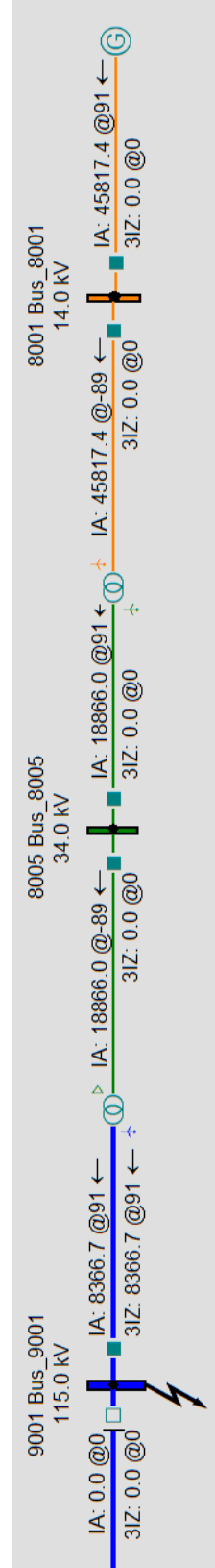
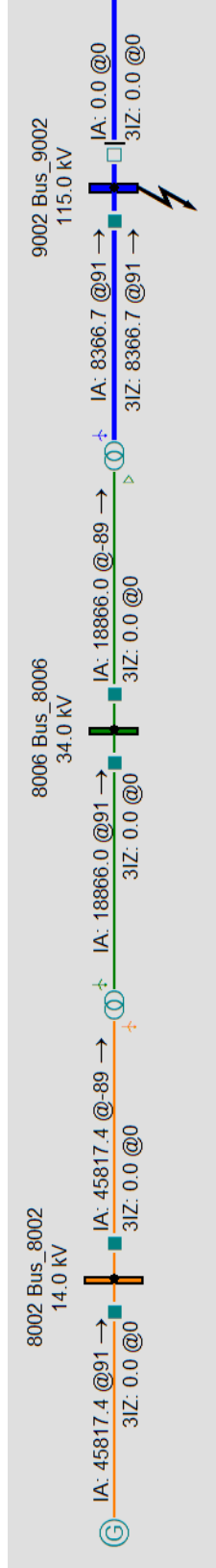
$$\text{Transformer 4: } 6\% \times \frac{100MVA}{250MVA} = 0.024$$

$$\text{Generator 1: } 6\% \times \frac{100MVA}{200MVA} = 0.03$$

$$\text{SCD}_{(MVA)}: \frac{300MVA}{2(0.024 + 0.024 + 0.03) + 0.24} = 1666.67MVA$$

$$\text{Fault Current: } \frac{1666.67MVA}{\sqrt{3}(115kV)} = 8367.4A$$

* All generator & transformer data are provide by the customer (see Appendix D&E)



Bus 9003 SCD (single line to ground)

TRANSFORMER DATA:

Impedance: 6% at 380 MVA

GENERATOR DATA:

Impedance: 6% at 300 MVA

$$\text{Transformer 6: } 6\% \times \frac{100MVA}{380MVA} = 0.01579$$

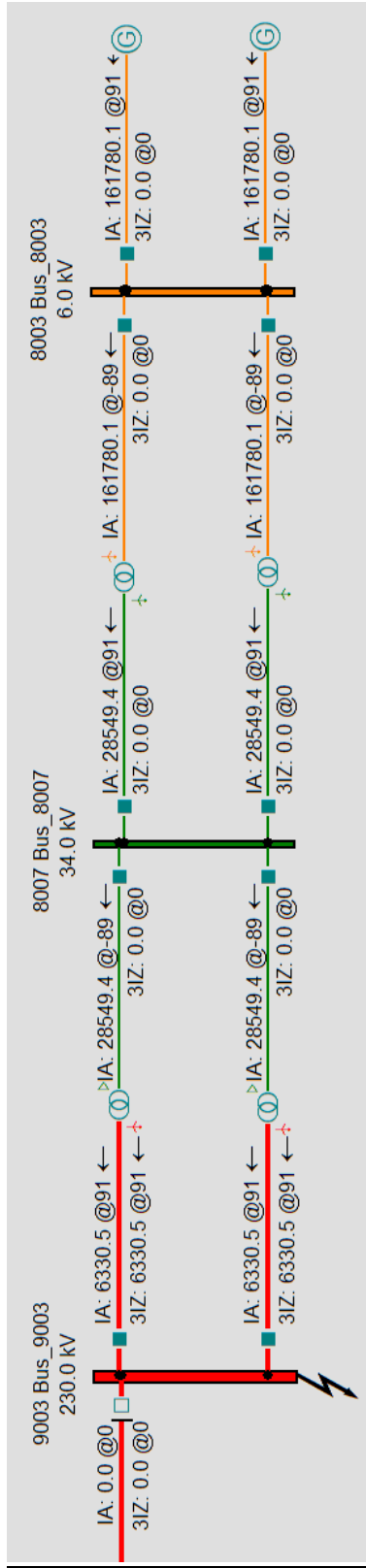
$$\text{Transformer 8: } 6\% \times \frac{100MVA}{380MVA} = 0.01579$$

$$\text{Generators: } 6\% \times \frac{100MVA}{300MVA} = 0.02$$

$$\text{SCD}_{(MVA)}: \frac{300MVA}{2(0.01579 + 0.01579 + 0.02) + 0.01579} = 2522.07MVA$$

$$\text{Fault Current: } \frac{2522.07MVA}{\sqrt{3}(230kV)} = 6330.9A$$

* All generator & transformer data are provide by the customer (see Appendix D&E)



Bus 9004 SCD (single line to ground)

TRANSFORMER DATA:

Impedance: 6% at 100 MVA

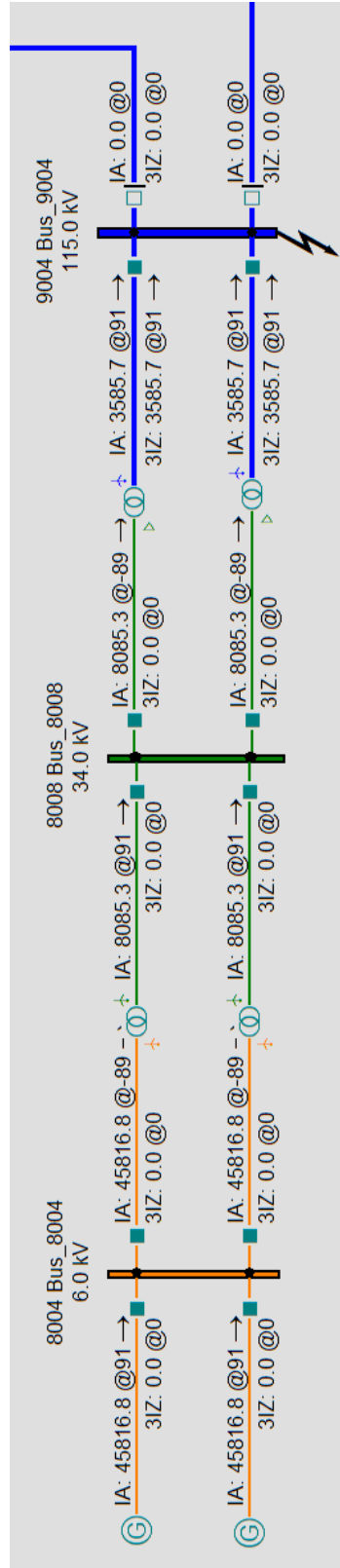
GENERATOR DATA:

Impedance: 6% at 100 MVA

$$SCD_{(MVA)}: \frac{300MVA}{2(0.06 + 0.06 + 0.06) + 0.06} = 714.286MVA$$

$$\text{Fault Current: } \frac{714.286MVA}{\sqrt{3}(115kV)} = 3586.03A$$

* All generator & transformer data are provide by the customer (see Appendix D&E)



Appendix D

SAMPLE TRANSFORMER DATA

Step-up Transformers

| | NUMBER OF TRANSFORMERS <u>2</u> (1 for each unit) | | PHASE <u>3-phase</u> |
|---|---|-----------------------------|-----------------------------|
| RATED KVA | H Winding | X Winding | Y Winding |
| Connection (Delta, Wye, Gnd.) | <u>Wye-Gnd</u> | <u>Wye-Gnd</u> | <u> </u> |
| 55 C Rise | <u> </u> | <u> </u> | <u> </u> |
| 65 C Rise | <u> </u> | <u> </u> | <u> </u> |
| RATED VOLTAGE | <u>34kV</u> | <u>14kV</u> | <u> </u> |
| BIL | <u> </u> | <u> </u> | <u> </u> |
| AVAILABLE TAPS (planned or existing) | <u>None</u> | <u>None</u> | <u>None</u> |
| LOAD TAP CHANGER? | <u> </u> | <u> </u> | <u> </u> |
| TAP SETTINGS | <u> </u> | <u> </u> | <u> </u> |
| COOLING TYPE : | OA <u> </u> | OA/FA <u>X</u> | OA/FA/FA <u> </u> |
| | | | OA/FOA <u> </u> |
| IMPEDANCE | H-X | H-Y | X-Y |
| Percent | <u>6 %</u> | <u>N/A</u> | <u>N/A</u> |
| MVA Base | <u>100</u> | <u>N/A</u> | <u>N/A</u> |
| Tested Taps | <u> </u> | <u> </u> | <u> </u> |

Appendix E

Sample Generating Facility Information

- A. Total Generating Facility rated output (kW): 75000kW
- B. Generating Facility auxiliary Load (kW): N/A
- C. Project net capacity (kW): 75000kW
- D. Standby Load when Generating Facility is off-line (kW): N/A
- E. Number of Generating Units: 1
- F. Individual generator rated output (kW for each unit): 75000kW
- G. Manufacturer: Siemens
- H. Year Manufactured: 2008
- I. Nominal Terminal Voltage: N/A kV
- J. Type (Induction, Synchronous, D.C. with Inverter): Synchronous
- K. Phase (3 phase or single phase): 3 ph

Sample Generator Short Circuit Data

For each generator, provide the following reactances expressed in p.u. on the generator base:

- X"1 – positive sequence subtransient reactance: 6.0 %
- X"2 – negative sequence subtransient reactance: 6.0 %
- X"0 – zero sequence subtransient reactance: 10.0 %

Appendix F

Initial Bus data from user:

| Bus Data | | | Type | V-sched | volt | angle | vmax | vmin |
|----------|----------|--------|------|---------|------|-------|------|------|
| 8001 | GenBus1 | 14.00 | 2 | 1.01 | 1.01 | 0.00 | 0.00 | 0.00 |
| 8002 | GenBus2 | 14.00 | 2 | 1.01 | 1.01 | 0.00 | 0.00 | 0.00 |
| 8003 | GenBus3 | 6.00 | 0 | 1.01 | 1.01 | 0.00 | 0.00 | 0.00 |
| 8004 | GenBus4 | 6.00 | 2 | 1.01 | 1.01 | 0.00 | 0.00 | 0.00 |
| 8005 | TranBus1 | 34.00 | 1 | 1.01 | 1.01 | 0.00 | 0.00 | 0.00 |
| 8006 | TranBus2 | 34.00 | 1 | 1.01 | 1.01 | 0.00 | 0.00 | 0.00 |
| 8007 | TranBus3 | 34.00 | 1 | 1.01 | 1.01 | 0.00 | 0.00 | 0.00 |
| 8008 | TranBus4 | 34.00 | 1 | 1.01 | 1.01 | 0.00 | 0.00 | 0.00 |
| 9001 | SubBus1 | 115.00 | 1 | 1.01 | 1.01 | 0.00 | 0.00 | 0.00 |
| 9002 | SubBus2 | 115.00 | 1 | 1.01 | 1.01 | 0.00 | 0.00 | 0.00 |
| 9003 | SubBus3 | 230.00 | 1 | 1.01 | 1.01 | 0.00 | 0.00 | 0.00 |
| 9004 | SubBus4 | 115.00 | 1 | 1.01 | 1.01 | 0.00 | 0.00 | 0.00 |
| 9006 | TAPBus1 | 115.00 | 1 | 1.01 | 1.01 | 0.00 | 0.00 | 0.00 |
| 9007 | TAPBus2 | 230.00 | 1 | 1.01 | 1.01 | 0.00 | 0.00 | 0.00 |
| 9008 | TAPBus3 | 115.00 | 1 | 1.01 | 1.01 | 0.00 | 0.00 | 0.00 |
| 9009 | TAPBus4 | 115.00 | 1 | 1.01 | 1.01 | 0.00 | 0.00 | 0.00 |
| 9010 | TAPBus5 | 115.00 | 1 | 1.01 | 1.01 | 0.00 | 0.00 | 0.00 |
| 9011 | TAPBus6 | 66.00 | 1 | 1.01 | 1.01 | 0.00 | 0.00 | 0.00 |
| 9012 | TAPBus7 | 66.00 | 1 | 1.01 | 1.01 | 0.00 | 0.00 | 0.00 |

Appendix G

Output Bus data from PSLF:

| BUS-NO | NAME | Bus KV | VOLT SCHED | VOLT-PU | DEG |
|--------|----------|--------|------------|---------|--------|
| 8001 | GenBus1 | 14.00 | 1.01 | 1.01 | 0.56 |
| 8002 | GenBus2 | 14.00 | 1.01 | 1.01 | -1.81 |
| 8003 | GenBus3 | 6.00 | 1.01 | 1.01 | 0.00 |
| 8004 | GenBus4 | 6.00 | 1.01 | 1.01 | -1.21 |
| 8005 | TranBus1 | 34.00 | 1.01 | 1.01 | -0.80 |
| 8006 | TranBus2 | 34.00 | 1.01 | 1.01 | -2.82 |
| 8007 | TranBus3 | 34.00 | 1.01 | 1.01 | -0.82 |
| 8008 | TranBus4 | 34.00 | 1.01 | 1.00 | -2.90 |
| 9001 | SubBus1 | 115.00 | 1.01 | 1.00 | -2.16 |
| 9002 | SubBus2 | 115.00 | 1.01 | 1.01 | -3.84 |
| 9003 | SubBus3 | 230.00 | 1.01 | 1.00 | -1.64 |
| 9004 | SubBus4 | 115.00 | 1.01 | 1.00 | -4.61 |
| 9006 | TAPBus1 | 115.00 | 1.01 | 0.98 | -6.21 |
| 9007 | TAPBus2 | 230.00 | 1.01 | 0.99 | -4.59 |
| 9008 | TAPBus3 | 115.00 | 1.01 | 0.99 | -5.36 |
| 9009 | TAPBus4 | 115.00 | 1.01 | 0.97 | -13.00 |
| 9010 | TAPBus5 | 115.00 | 1.01 | 0.96 | -14.78 |
| 9011 | TAPBus8 | 66.00 | 1.01 | 0.96 | -17.10 |
| 9012 | TAPBus7 | 66.00 | 1.01 | 0.97 | -14.83 |