High Penetration PV Project (Hi-PV) Report on Impacts to Transmission and Distribution Grids

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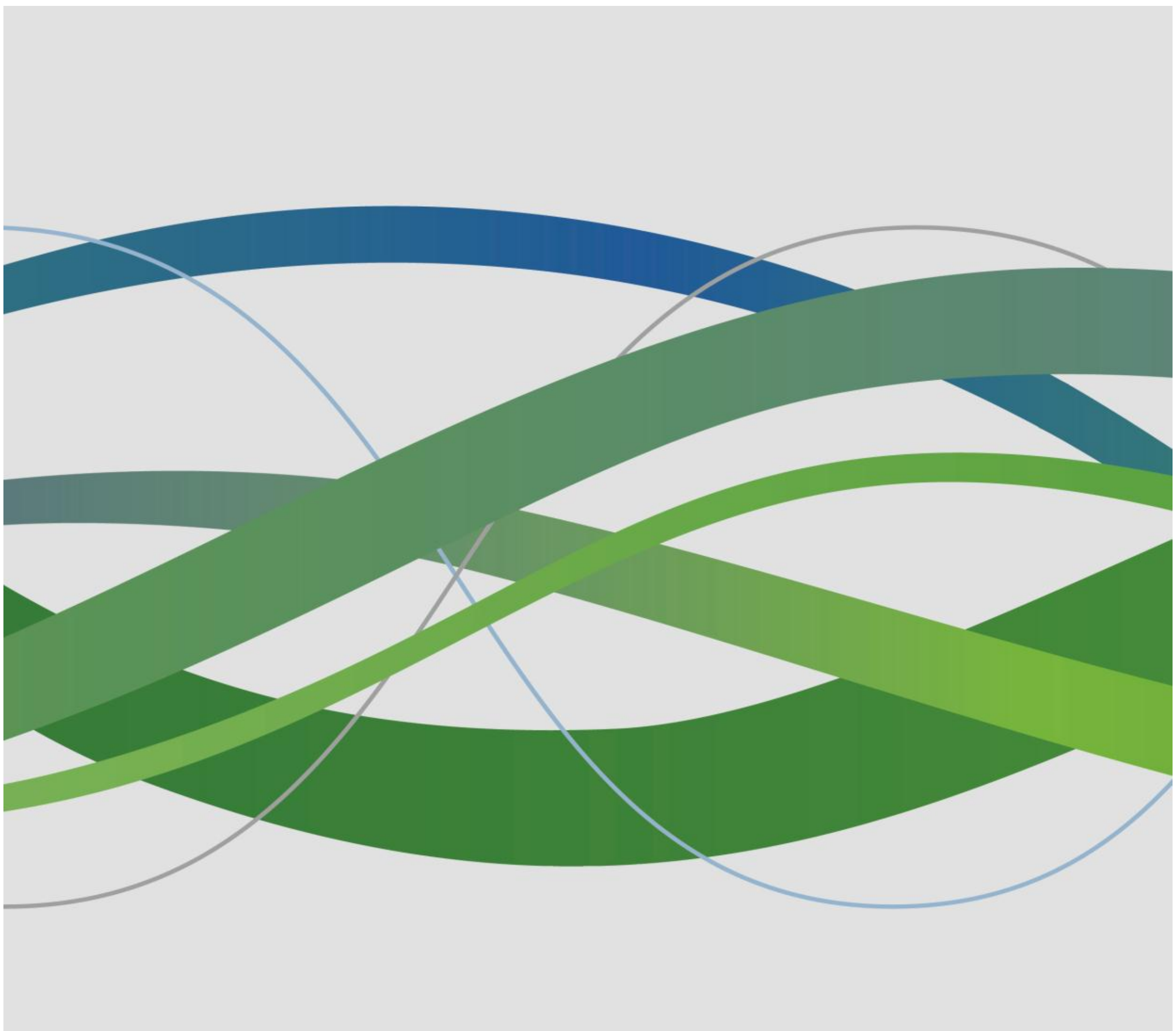
November 10, 2013



CONTENTS

Figures

Tables

EXECUTIVE SUMMARY

The Sacramento Municipal Utility District (SMUD), in partnership with the Hawaiian Electric Company (HECO), conducted a research, demonstration, and deployment project that targeted testing and development of hardware and software for high penetration photovoltaic (PV). This project, known as the High Penetration PV (HiP-PV) Initiative, is intended to address key grid integration and operational barriers that hinder larger-scale PV adoption into mainstream operations and onto the distribution grid. Both utilities are currently managing the introduction of high penetration PV into their systems. The scope of this work is divided into the following five tasks, with Tasks 2, 3 and 4 being conducted by DNV KEMA:

- Task 1: Project Management, Technology Transfer, and Outreach (SMUD)
- Task 2: Baseline Modeling of SMUD and HECO Systems (DNV KEMA)
- Task 3: Field Monitoring and Analysis (DNV KEMA, SMUD and HECO)
- Task 4: System Integration and Visualization Tools Development (SMUD, HECO and DNV KEMA)
- Task 5: Solar Resource Data Collection and Forecasting (NEO Virtus Engineering)

As part of the HiP-PV Initiative, SMUD and HECO identified case study locations in California and Hawaii, solar assessment and forecasting needs, and PV grid integration and visualization needs. This project received funding from the California Solar Initiative Research, Development, Demonstration and Deployment (CSI RD&D) Program's first grant solicitation. The CSI RD&D Program is administered by Itron, on behalf of the California Public Utilities Commission (CPUC).The HiP-PV activities addressed key integration barriers in visualizing, monitoring, and controlling high-penetration PV on the grid. Specific activities included:

- Development of a software visualization tool to enable identification of high value locations for distributed PV on the distribution system and to identify problem areas that will require reinforcement or modification to enable high penetrations. Smart siting of renewable distributed generation involves fully understanding the solar resource, its potential deployment, and interaction with the existing distribution infrastructure. Case studies include residential, commercial, and greenfield sites overlaid throughout the electrical system in order to assess interconnection benefits (cost and locational value) to the system.
- Development of a renewable generation operational tool that allows utilities to see how the renewable generation is functioning on their systems. This tool enables full use of distributed PV in displacing the need for distribution upgrades and natural gas peakers. It allows validation of forecasting software, providing three hour-ahead and day-ahead PV output forecasts.
- Deployment of a solar irradiance sensor network and coordinated advance communication for controls (i.e., dedicated cellular, advanced metering infrastructure [AMI] network, supervisory control and data acquisition [SCADA] system-enabled condition monitoring, and distribution remote terminal units [RTUs]).

This component of the CPUC CSI RDD&D Solicitation 1 research project was to study existing feeders with high penetrations of distributed solar and identify the missing distribution modeling data, determine the most typical studies conditions for evaluating solar, and highlight important factors for utilities to study with regards to high solar penetrations. Six goals are listed below:

1. Goal: Identify high penetration analysis needs (load flow, characteristics of the load, protection / coordination, voltage regulation, and islanding) for the distribution circuit being analyzed.
2. Goal: Identify additional data parameters to be collected and locations along the high penetration distribution circuit to place additional high-fidelity monitoring equipment, as necessary.
3. Goal: Record and collect at a minimum 6 to 12 months' worth of high-fidelity load data from the newly installed high-fidelity monitoring equipment.
4. Goal: Collect electrical equipment nameplate data from the distribution system being analyzed: distributed generation on the circuit, inverters, any energy storage, circuit size, circuit length, circuit loading, switchgear, and transformers to be used in the model development.
5. Goal: Investigate varying incremental levels of PV penetration at the distribution capacity level and iterate with an existing system level model to understand to what degree higher PV levels will adversely affect the grids.
6. Goal: Based on the validation results for a single circuit study, develop a methodology for extending the findings using the simulation tools to inform and expedite interconnections studies at higher penetration levels.

The report discusses methodologies for studying high solar penetrations. The simulation tools are an important consideration before starting feeder studies. Some distribution simulation tools such as SynerGEE cannot model inverters while others such as CYME can but requires additional module purchases. In order to simulate inverter impacts on an unbalanced distribution feeder, the feeder is converted to a balanced feeder and imported to a transmission model such as PSS/E or PSLF used by SMUD and HECO, respectively. This conversion eliminated the single phase issues that are important for distribution penetration studies but is adequate for screening analysis.

The table below summarizes the general findings from the study. The results are based on steady-state and first contingency analysis. The areas in red indicate feeder conditions impacted by high penetrations of distributed solar. The main conditions impacted are voltage and backfeed onto the feeder. The blue areas indicate potential areas of concern as distribution solar penetrations increase. These areas are potential line segment overloads and excessive load tap changes (LTC) operations.

Feeder	Utility	Voltage (kV)	Customer Mix	PV Penetration	Line Loading	LTC Operation	Voltage	Backfeed
A-C (3 feeders)	SMUD	12.47	Res	0% to 100%	No violations	N/A	High voltage	High backfeed
RF (1 feeder)	SMUD	12.47	Com/Ind	0% TO 88%	No violations	N/A	No violations	No violations
EB (1 feeder)	SMUD	12.47	Rur	67%	No violations	N/A	High voltage	High backfeed
CT (2 feeders)	SMUD	12.47	Res/Rur	0% to 50%	Potential for overloads	Minor operations	High voltage	No violations
EG (3 feeders)	SMUD	69	Res/Com/Rur	38% to 60%	No violations	Minor operations	No violations	No violations
L7 (1 Feeder)	SMUD	69	Ind	0% TO 150%	No violations	N/A	No violations	No violations
MI (4 feeders)	HECO	11.5	Res/Com	9% to 135%	Potential for overloads	Potential cycling	High voltage	High backfeed
ML (4 feeders)	HELCO	4.16	Com	0% to 100%	No violations	Potential cycling	High voltage	High backfeed
WA (6 feeders)	MECO	13.09	Res/Com	0% to 30%	No violations	N/A	No violations	No violations
WO (5 feeders)	HECO	11.5	Res/Com	0% to 40%	No violations	N/A	No violations	Potential for backfeed

Res is residential; Ind is Industrial; Rur is Rural, and Com is commercial

1.0 INTRODUCTION

This report documents the potential impact of high penetration of PV resources on distribution circuits on the SMUD and HECO grids. The distribution database includes details from the substation to the end-use load and includes the PV and inverter characteristics. The distribution circuit model is intended to leverage the existing distribution modeling work DNV KEMA has accomplished with HECO using a model developed with SynerGEE at the 46kV and 12kV levels. SMUD provided the distribution circuit models for DNV KEMA and both entities worked together in reviewing the modeling detail of specific circuit feeders.

HECO is the umbrella company for Maui Electric Company (MECO) and Hawaii Electric Light Company (HELCO). HECO is primarily responsible for operations on Oahu; MECO is responsible for operations on Maui, Lanai and Molokai; and HELCO is responsible for the Big Island of Hawaii.

Adequate modeling of the distribution circuits is an essential first step of the work needed to investigate impacts on grid operation with an increasing content of variable renewable energy and to help develop control and mitigation strategies. The modeling should address how to account for PV variability and what role the software distribution models should have addressing this complex issue. This is a three-year project. The goals/tasks are listed below.

- Identify high penetration analysis needs (load flow, characteristics of the load, protection / coordination, voltage regulation, and islanding) for the distribution circuit being analyzed.
- Identify additional data parameters to be collected and locations along the high penetration distribution circuit to place additional high-fidelity monitoring equipment, as necessary.
- Record and collect at a minimum 6 to 12 months of high-fidelity load data from the newly installed high-fidelity monitoring equipment.
- Collect electrical equipment nameplate data from the distribution system being analyzed: distributed generation on the circuit, inverters, any energy storage, circuit size, circuit length, circuit loading, switchgear, and transformers to be used in the model development.
- Investigate varying incremental levels of PV penetration at the distribution capacity level and iterate with an existing system level model to understand to what degree higher PV levels will adversely affect the grids.
- Based on the validation results for a single circuit study, develop a methodology for extending the findings using the simulation tools to inform and expedite interconnections studies at higher penetration levels.

The first effort is the development and validation of SynerGEE data sets for the feeders selected by SMUD and HECO. The data sets are used to simulation different aspects of SMUD's and HECO's power system including electrical characteristics of the distribution circuit and relevant characteristics of PV inverters. The tasks will provide a validation analysis of the model performance. Validation is performed over several analytical time frames. Through data collection, modeling, and analysis, the detailed single circuit study identifies barriers (data gaps, as-built infrastructure limit) and informs system-level considerations and potential strategies for accommodating higher PV penetration levels. Part of the evaluation and validation study includes: circuit voltage profiles and impacts, voltage regulation, voltage flicker, islanding, fault conditions and thermal limitation.

2.0 CPUC CSI RDD&D SOLICITATION 1: GRID INTEGRATION

The SMUD, in partnership with the HECO, proposed a research, demonstration and deployment effort which targets testing and development of hardware and software for high-penetration PV to facilitate utility integration and build a sustainable and self-supporting industry for customer-sited solar for a broad application market, including California. This effort addresses key grid integration and operational barriers that hinder larger-scale PV adoption into mainstream operations and onto the distribution grid. As two utilities managing high-penetration PV introduction onto their systems, SMUD and HECO have aligned respective case studies at specific locations in California and Hawaii, solar assessment, and PV grid integration in this coordinated effort.

This work discussed here is focused on demonstration and testing of hardware and software for high-penetration PV.

Integrating high penetrations of solar PV requires substantial changes in the way today's electricity grid is designed and operated. It requires new tools for understanding PV as a distributed generation resource, new hardware and software for communicating with and controlling thousands of generation sources, and modifications to the top-down electricity grid to enable bi-directional flow management throughout the grid. Current tools and understanding of PV are acceptable in a world where PV provides less than 1% of total capacity, but growth rates in PV technology and state renewable portfolio standard (RPS) goals indicate this paradigm will not last. Thus utilities must adopt new hardware and software and reconfigure and facilitate operational changes today to ensure a smooth transition to higher PV penetration grid scenarios. R&D activities aim at addressing key integration barriers in visualizing, monitoring and controlling high-penetration PV on the grid.

2.1 Project Goals

To attain future smart grid and clean energy targets for the respective utility operating environments, a goal for both SMUD and Hawaii utilities is the development of a sustainable portfolio of energy supply (existing generation) and energy load management capabilities, including distributed generation, customer load management and other demand-side management (DSM) programs. Advanced vision and enabling control technologies, akin to the Solar Energy Grid Integration Systems (SEGIS) concept, are therefore needed for transforming the existing, relatively small PV energy market comprised of "passively interacting" systems to a high-penetration "active partner" providing support services to the overall grid. Such a system necessarily requires a strong understanding of solar resources and potential, tools to identify optimal siting locations and problem areas, predictive output tools, and strong communications and control approaches.

SMUD and HECO expect over the next several years that the penetrations of PV will reach levels requiring significant mitigation measures on the distribution system to maintain reliability, voltage control, and fault identification capabilities. An over-arching objective of this work is to identify practical mitigation strategies for managing high penetrations of PV, which not only allows PV to reach higher penetrations, but ensure that it does so in a way that enhances grid reliability in the face of economic and environmental constraints. Meeting minute-to-minute demand with distributed intermittent resources providing a significant amount of the energy is a challenge. Doing it with a minimal amount of costly energy storage requires smart planning, much greater understanding of the solar resource, and a fundamental change in the communications and controls systems grid operators currently use to interact with generation resources. This project aims to address each of these areas and enable HECO and SMUD to demonstrate successful integration of very high penetrations of solar PV.

3.0 DISCUSSION

3.1 Baseline Modeling of Feeders for SMUD, HECO, HELCO, and MECO

Historically, electric utility distribution planners are not too concerned about installing power quality meters, solar sensors and solar monitors on the distribution feeders. There is not an urgent need to validate voltages, frequency and backfeed on the feeders since the power flows are from the distribution substation to the end of the feeder. Distribution feeders are normally radial lines, so as long as the voltages at the end of the line are within voltage tolerances, everything is fine. Sometimes, a customer may install a cogeneration plant to self-generate but not to export to the utility.

Distribution planners normally set the voltage regulation point at the distribution substation bus between 122 and 125 volts so that the end of the feeder has a voltage ranging from 115 to 122 volts. If the voltage drops too low toward the end of the feeder, then the planner installs capacitor banks or regulators, depending on the length of the feeder. If there are multiple feeders served from the same substation bus, the transformer tap changer is set to a regulation point that provides the same voltage on all the feeders.

Distributed demand side resources and new technologies have changed the distribution planning process and operational control of the transmission/distribution grids. Availability of low-cost roof-mounted solar panels, subsidies from state and local agencies, emission reduction requirements, and RPS requirements rapidly increased the penetration of distribution generation on the feeders. As these increase in magnitude, more voltage, frequency, power factor, reverse power flow, and protection issues must be addressed. Today, high PV generation and other demand-side technologies are not evenly distributed on all feeders or at the same locations on the feeder.

To study these potential barriers and limitations, 30 feeders are studied throughout the SMUD and HECO utility systems: eleven in SMUD, four in HECO, four in HELCO and six in MECO. The feeders selected for detailed analysis have distinctive characteristics that make them of particular interest as described in Table 1: Feeders selected for analysis.

Feeder	Utility	Voltage	Location	Existing PV	Other existing DG
A-C (3 feeders)	SMUD	12.47 kV	Residential	Yes - 0.6 MVA	No
RF (1 feeder)	SMUD	12.47	Commercial/Industrial	Yes- .976 MW	No
EB (1 feeder)	SMUD	12.47 kV	Rural	None (1 MW planned)	Dairy Digester
CT (2 feeders)	SMUD	12.47 kV	Residential/Rural	Yes – 3 MVA	No
EG (3 feeders)	SMUD	69 kV	Residential/Commercial/Rural	No	No
L7 (1 Feeder)	SMUD	69 kV	Industrial	Yes - 2 MVA	No
MI (4 feeders)	HECO	11.5 kV	Residential/Commercial	Yes – 8 MVA	No
WO (5 feeders)	HECO	11.5 kV	Residential/Commercial	Yes – 1 MVA	No
ML (4 feeders)	HELCO	4.16 kV	Commercial	Yes – 0.04 MVA	Yes – possibly out of service
WA (6 feeders)	MECO	13.09 kV	Residential/Commercial	Yes	No

Table 1: Feeders selected for analysis

The list of the modeling, analytical and validation steps is shown below:

- Identify high penetration analytical requirements (load flow, characteristics of the load, protection and coordination, voltage regulation, and islanding) for the distribution feeders being analyzed.
- Identify additional data parameters to be collected and locations of data collection along the high penetration distribution feeder to place additional high-fidelity monitoring equipment, if necessary.
- Record and collect a minimum of 6 to 12 months' worth of high-fidelity load data from the newly installed high-fidelity monitoring equipment.
- Collect the following electrical equipment nameplate data from the distribution system being analyzed: distributed generation on the feeder, inverters, any energy storage, feeder size, feeder length, feeder loading, switchgear, and transformers.
- Investigate varying incremental levels of PV penetration at the distribution capacity level and iterate with an existing system level model to understand to what degree higher PV levels will adversely affect the grids.
- Based on the validation results for a single circuit study, develop a methodology for extending the findings using the simulation tools to inform and expedite interconnections studies at higher penetration levels.

The typical distribution modeling and analytical processes used by developers and utilities is limited by the lack of detailed distribution modeling. Interconnection studies often use three phase models focusing on sub-transmission and substation impacts. The distribution system is often interpreted as an equivalent load, or simple impedance model. The highest level of existing detail is normally a three-phase aggregated load flow model. Most impact studies consider capacity and baseline generation. Impact of variable high PV penetrations is not generally quantified, due to a lack of accurately measured irradiance data for the PV.

An enhanced distribution modeling and analysis process is developed and compared to the simplistic process to determine the level of detail required in future studies. This project accurately quantifies the effect of high penetrations of PV on the distribution and sub-transmission systems. The modeling detail includes detailed inverter and PV modeling and performance.

The analysis determines the effect of variable resources and associated weather conditions on distribution grid as a whole. The following steps develop the feeder dataset for analysis:

- Extract (GIS) or build (when GIS not available) SynerGEE model
- Collect and apply detailed equipment information
  - Transformers, switches, fuses, capacitors, inverters, PV panels, etc.
- Collect PV data for area of interest if available
- Analyze PV performance
  - Associated weather data
- Model inverters
  - Future detailed SynerGEE model, or
  - Existing equivalent impedance model, and
  - PSSE dynamic inverter model, when applicable

Baseline modeling for the selected feeders includes data collection, evaluation, modeling and analysis of the existing system with available data. PV data and representative load profiles are monitored for SMUD and the Hawaiian utilities. As more data are collected and evaluated, more analysis on the feeders of interest is completed.

This baseline modeling report can be found at the CSI RD&D Program website at http://www.calsolarresearch.ca.gov/images/stories/documents/Sol1_funded_proj_docs/SMUD/2011_SMUD_Hi-Pen-PV-Init_Base-Line-Model-final.pdf and includes the following topics:

- Distribution modeling and analysis process
- Accounting for load displaced by existing PV
- Locating of monitors and sensors on the distribution feeder
- Inverter modeling in SynerGEE for fault current analysis
- Analysis of monitored PV data
- Analysis of representative demand profiles

3.2 Hawaii Solar Irradiance Data Analysis

HECO, in partnership with the National Renewable Energy Laboratory (NREL), installed solar monitors and power quality meters in select locations across Oahu, Maui, the Big Island, Lanai and Molokai to gather high fidelity irradiance and power monitor data. DNV KEMA obtained access to this data for solar irradiance studies. The data are analyzed and input into distribution models to study the impacts on high PV penetrations on the Hawaii distribution system. DNV KEMA is working with utility staff to gather feedback on the system conditions based on time stamped data and weather conditions and evaluating correlations between utility load, solar resources and PV generation to develop a process of quantifying impacts due to common environmental conditions (e.g., cloudy, partially cloudy, clear sky).

Clouds and environmental factors significantly impact solar sites, from the high density residential single phase installations (residential subdivisions) to large poly-phase solar installations. Data conversion techniques provide useful data to utility departments such as operations, resource planning, rates and finance. Once this analysis is complete, utility staff insight on perceived weather conditions and predicted impacts on distributed resource output at various locations on the island can be defined.

This section discusses a preliminary investigation into the value of high fidelity data. Direct comparisons are made between raw one minute irradiance data, five minute irradiance averages, and one hour irradiance averages. This aids in the determination of the acceptable time increment between data recordings for any particular type of analysis. For example, if calculating total annual irradiance, greater time increments between data points is acceptable. However, if analyzing aspects of the distribution systems, such as voltage flicker caused by PV variability, high fidelity data are necessary to inspect the immediate response in voltage data.

The one minute solar data from MECO Sub2 solar sensor are chosen for this analysis. One minute is the high level of data detail currently available through MECO. To compare the effects of average and reduced data fidelity, five minute and one hour time periods are chosen for analysis. For this test, the raw data are averaged into five minute and one hour increments by simply adding the irradiance values and dividing by the number of recordings in that time (5 or 60). A number of time increment options are possible in further studies, such as snap shot readings instead of averages at any desired time interval.

The raw one minute irradiance data, five minute averages and one hour averages are graphed in - Figure 1 for the first week of July. These data are originally recorded in UTC time, so the data actually start at 2:00 pm June 30, until 2:00 pm July 7. The first bell curve of each graph occurs on July 1, 2010, the second bell curve occurs on July 2, 2010 etc. The three graphs are stacked on top of each other in Figure 1 for direct comparison. One minute data are on top, five minute average data are in the middle, and one hour average data are the bottom graph. Due to reduced number of data points in the five minute and one hour average graphs, a two-point moving average trend line is applied to the scatterplot data.

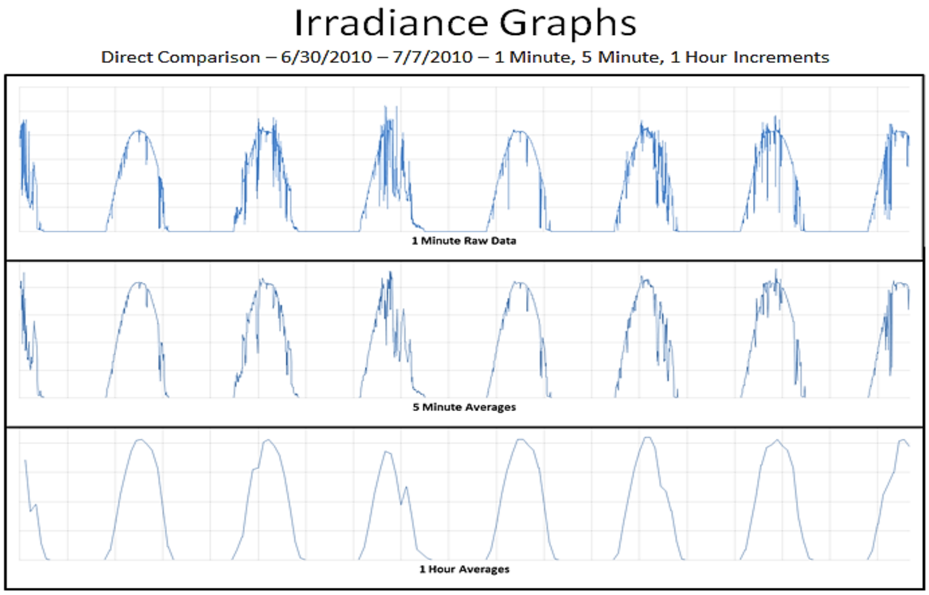


Figure 1: MECO Irradiance Full Week, Three Time Increments

Each day of sunlight hours in the one minute raw data graph contains roughly 740 data points, depending on the exact time of sunrise and sunset. Each day in the five minute averages graph contains roughly 148 data points, and each day in the one hour averages graphs contains only about 12 data points.

To demonstrate the issues with the potential averaging or mis-application of data, closer inspection of one individual day, July 1, 2010, is shown in Figure 2. This day is selected for closer analysis because it exhibits the least amount of irradiance variability in the raw data of this week.

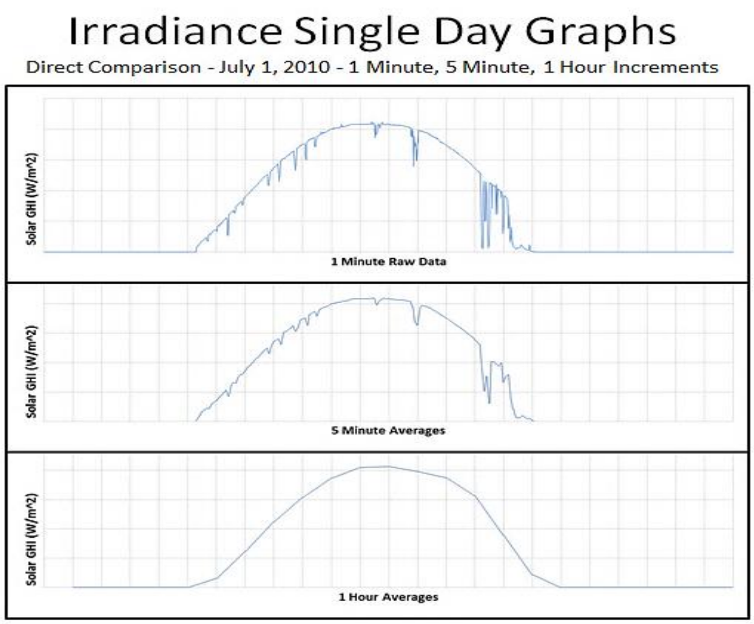


Figure 2: MECO Irradiance Select Day, Three Time Increments

Again, one minute raw irradiance data are the top graph in this figure, the five minute average data are the middle graph and the one hour average data are the bottom graph. Although the X axes do not have time labels for visual simplicity, the times quoted in the text are accurate and sourced from the data.

Even though July 1 is the least variable day of the week, there is still a drop in irradiance during the afternoon at 4:20 pm. This is clearly apparent in the one minute raw data graph and appears quite significant, with initial magnitude loss of 500 W/m^2 and continued disruptions for about one hour and 45 minutes. This irradiance drop is still visible in the five minute averages graph, but with reduced severity. The magnitude of the irradiance drop in the five minute averages graph is reduced to 400 W/m^2 with continued disruptions for only about an hour. In the final graph of one hour averages, no drastic disruption is apparent. There is a very subtle dip in the trend line in last segment of line, but all detail is lost.

This smoothing caused by averaging data into larger time increments is a problem. It is clear that data fidelity is lost when using the one hour time step. If the one hour average graph of Figure 2 is the only data available for this day, it appears to be a perfect clear sky day even though in reality this is not the case. This loss of accuracy may be acceptable for some applications such as summing total monthly or annual irradiation; however, it is unacceptable for short term applications. Very short time scales and high fidelity data are necessary to determine the exact effect of PV on the distribution system. Ramp rate analysis to define power stability, voltage fluctuations, etc., is not possible with data that have lost the necessary level of detail due to large time increments.

4.0 SUBSTATION AND FEEDER ANALYSIS FOR SMUD AND HECO

4.1 SMUD Feeders and Substations

4.1.1 EG Substation and 69 kV Line Analysis

EG Bank 1 consists of one 230/69 kV transformer with two 69 kV circuits (3 and 4). There are sixteen 69/12 kV distribution transformers connected to the circuits that have thirty-two 12 kV feeders. There are three major central PV plants connected to the 69 kV circuits with a total connected rating of 48 MW. Figure 3 below displays the layout of the two 69 kV circuits.

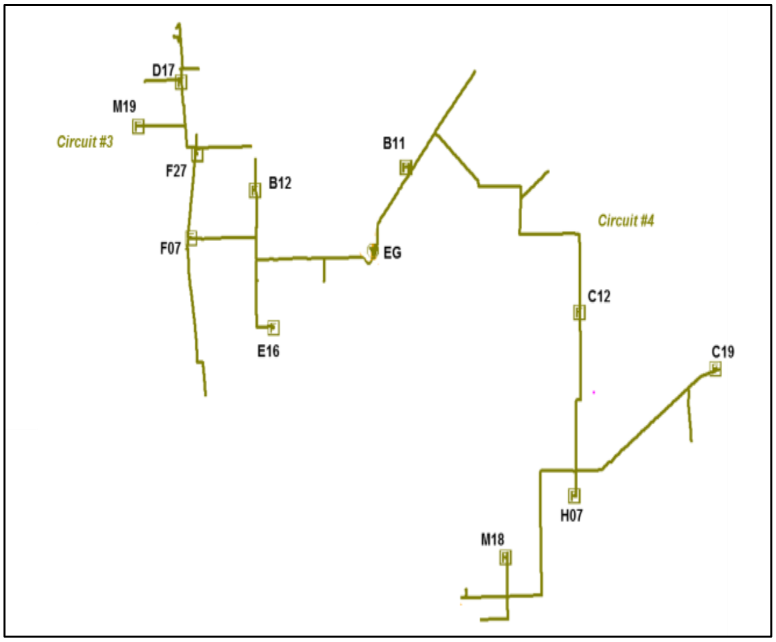


Figure 3: EG Feeder Diagram

Data are provided for July 2012 from which the peak hour is July 12, 2012 at 6 pm. Figure 4 shows the twenty-four load profile and the corresponding solar generation for the day. The recorded demand data, including the PV generation, are considered the net load and shown as the red line. The gross load or load without solar generation is the combination of the solar generation and net load as shown by the blue line. The individual solar generation profiles are shown at the bottom of the figure. One of the PV installations has a tracker system which extends the peak solar generation longer in the day.

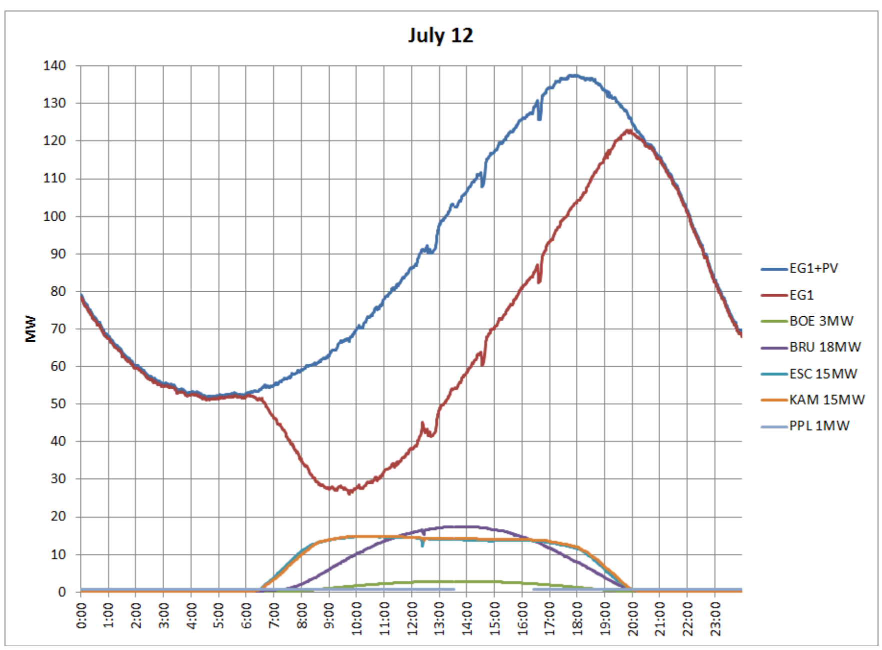


Figure 4: July 2012 Load Curve for EG

The EG Bank 1 model setup and assumptions include:

- SynerGEE model includes all 69kV and 12 kV circuits, and 3 central PV generators
- Transmission voltage set to 233.8kV
- Transformer Load Tap Changers (at 69kV and 12kV) enabled
- Capacitors switched off
- Load allocation is performed based on the assumptions made for the non-RTU feeder demand and power factor
- Simulated 2012 peak load condition for 0%, 15% and 30% PV penetration level:
  - Penetration level calculated as a percentage of the 2012 peak load
  - Calculated PV contribution assigned to the three PV generators proportionally to their MW capacity
  - Coincident MW values used for the 12kV feeder load

Table 2 lists the six scenarios selected for EG substation. The PV installed prior to the start of this portion of the project is 52 MW (38% of 137 MW peak) on the 69 kV circuits and 12 kV feeders. Since there are PV installation requests in the queue and new requests continually being added, the parties decided to increase the PV base capacity to 62 MW or 45% to reflect these changes. To further stress the system, another 42 MW of PV is added (30% increase). These values are shown in Table 2 as occurring at 2 pm. At the time of system peak (6 pm), the PV generation is lower due to the solar irradiance as shown in Figure 4 above. An installed solar generation of 62 MW at 2 pm equals 41 MW at 6 pm. As shown in Figure 4, there are tracker PV installations on the 69 kV which extends the maximum generation time that results in higher 6 pm generation in July.

Scenario	**Load (MW)**	**Time**	**PV Installed (MW)**	**PV Generation (MW)**	**% of Peak**	**% of Load**	**Comment**
1A	137	6 pm	0	0	0%	0%	
1B	137	6 pm	62	41	30%	30%	PV based on 2B
1C	137	6 pm	104	69	50%	50%	PV based on 3B
2A	108	2 pm	0	0	0%	0%	
2B	108	2 pm	62	62	45%	57%	Actual PV installed of 52 MW
2C	108	2 pm	104	104	76%	96%	Increased PV by 30% of Peak

Table 2: EG Scenarios

<u>Example of % Calculations for Scenario 1B</u>
PV installed is 62 MW but generates only 41 MW at 6pm
% of Peak = 41MW/137MW = 30%; % of Load = 41MW/137MW = 30%

Example of % Calculations for Scenario 2B
PV installed is 62 MW and generates 62 MW at 2pm
% of Peak = 62MW/137MW = 45%; % of Load = 62MW/108MW = 57%

Figure 5 below compares the gross load curve to the different solar penetrations. Normally an April day is selected to represent the minimum daytime peak period when load is load and solar is high. However, since data are only provided for the month of July, the 2 pm time period is selected to represent the impacts of high solar penetrations during a simulated lower load period.

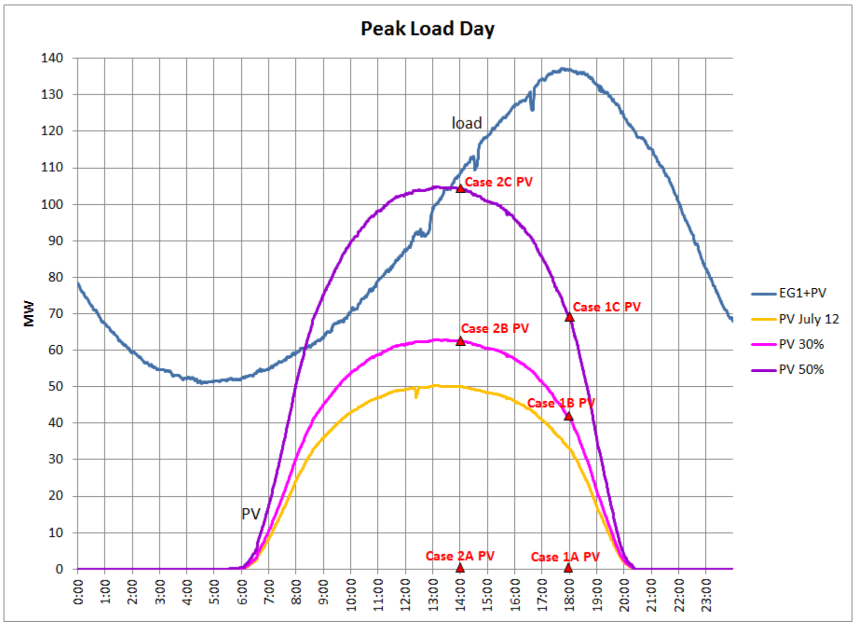


Figure 5: Comparison of PV Penetration to Load Curve

Figure 6 compares the July 12, 2012 load curve to the PV generation points. The blue line represents the 24 hour load curve for July 12 as a closed loop curve, based on the blue line in Figure above. The load is at minimum between 4 am and 6 am and increases until the peak load is reached at 6 pm (shown as the red square). The load then decreases until the minimum is reached again between 4 am and 6 am. The other red square represents the time when maximum PV generation is reached at 2 pm.

The PV generation is shown as green diamonds. Scenarios 1A and 2A represent 0% PV for comparison only. Scenario 2B represents the existing installed PV of 62 MW at 2 pm. Scenario 1B represents the PV generation at 6 pm based on the solar generation profile. Scenario 2C represents Scenario 2B with an increase of 30% PV installation as a sensitivity case. Scenario 1C is the equivalent PV generation at 6 pm based on the solar generation profile.

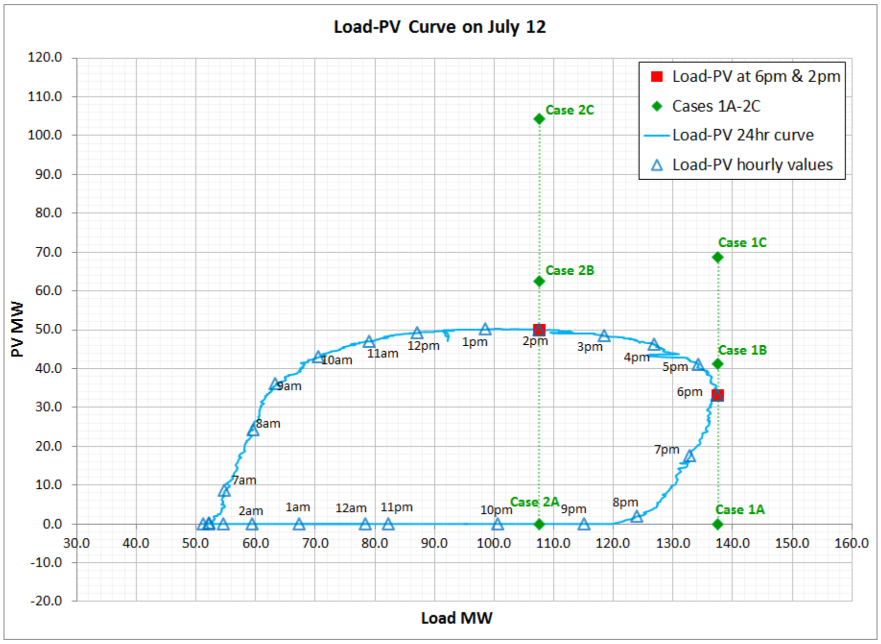
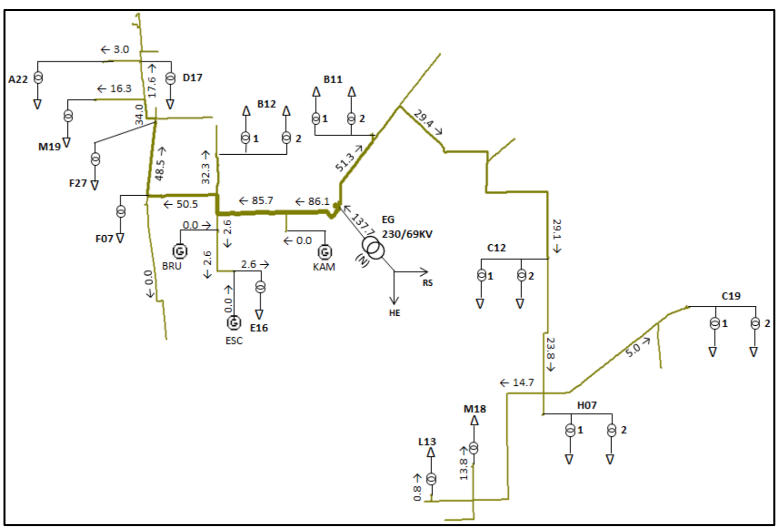


Figure 6: Comparison of Load Curve to PV Generation

The 69 kV load tap changers are enabled, the 230 kV transmission voltage is set to 233.8 kV and the 69 kV capacitor banks are switched off. Figure 7 shows the power flows on the 69 kV circuits when solar is at 0, 41 and 69 MW at 6 pm. The three 69 kV solar plants are located near the EG substation and the solar generation only impacts the first several line segments from the substation.



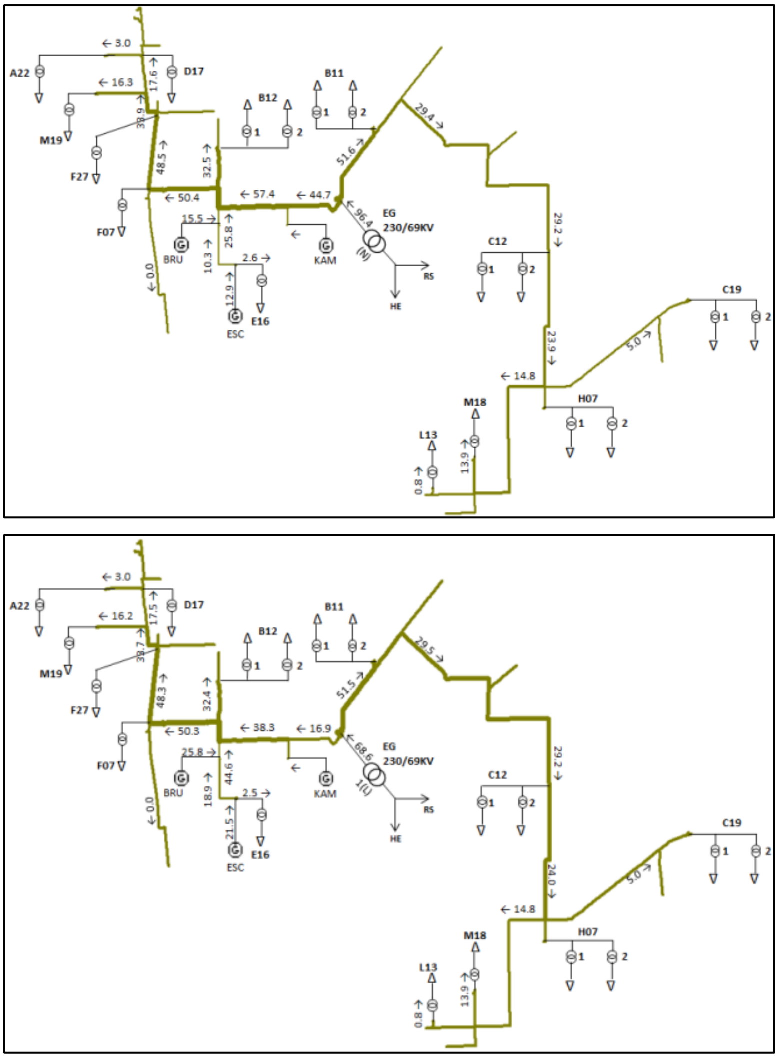


Figure 7: Power Flow Results for Scenarios 1A, 1B and 1C

Figure 8 shows the percent loading on each segment of the 69 kV circuits for Scenarios 1A, 1B and 1C. The orange colored lines indicate those line segment that are loaded between 80% and 100% whereas the yellow lines are loaded between 60% and 80%. The first several line segments from the substation are the most loaded line segments, as expected. As PV is increased, the orange lines change to yellow for the first several line segments from the substation.

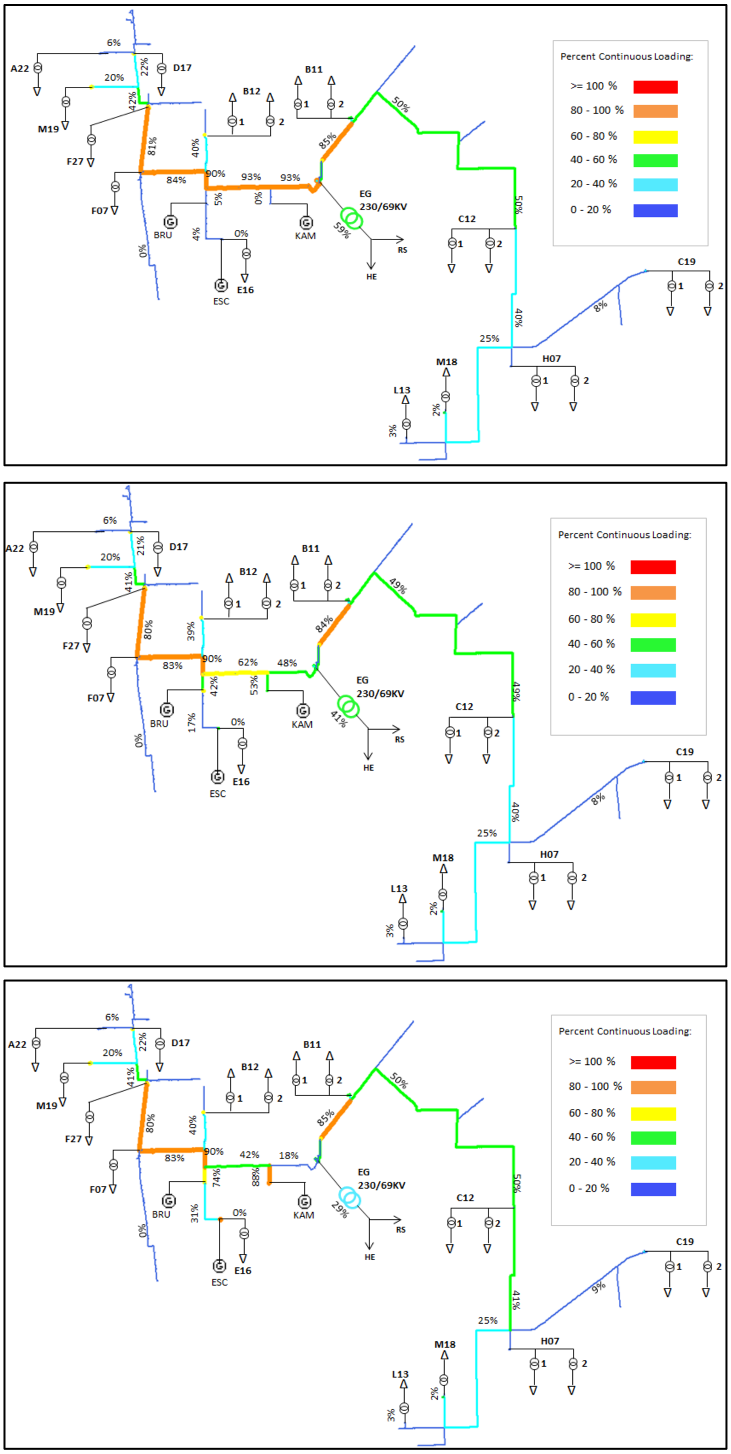


Figure 8: Percent Line Loading at Scenarios 1A, 1B and 1C

Figure 9 shows the line segment voltages for Scenarios 1A, 1B and 1C. The lowest voltage on the any line segments is 118 for Scenario 3A with the LTC is operating at the -1 position. Since the LTC is attempting to regulate to 233.8 kV at the 230 kV bus, the higher PV generation is causing the LTC to lower the taps to maintain the set voltage. This causes a lower voltage at the end of one of the 69 kV lines, but is within the voltage limits.

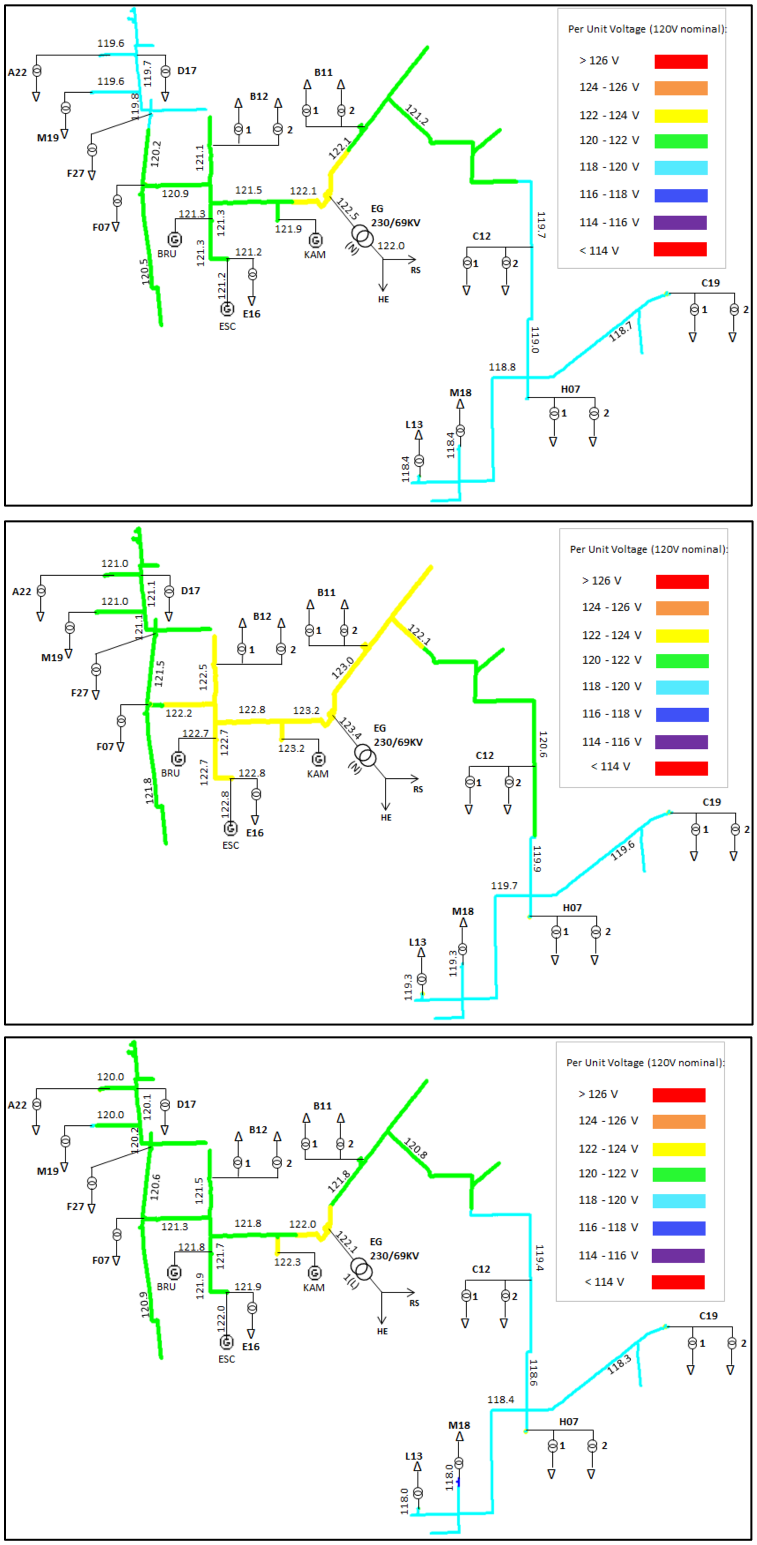
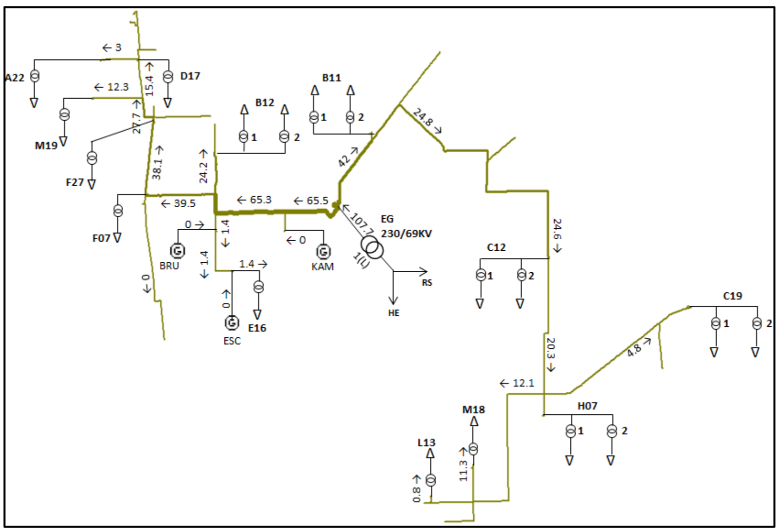
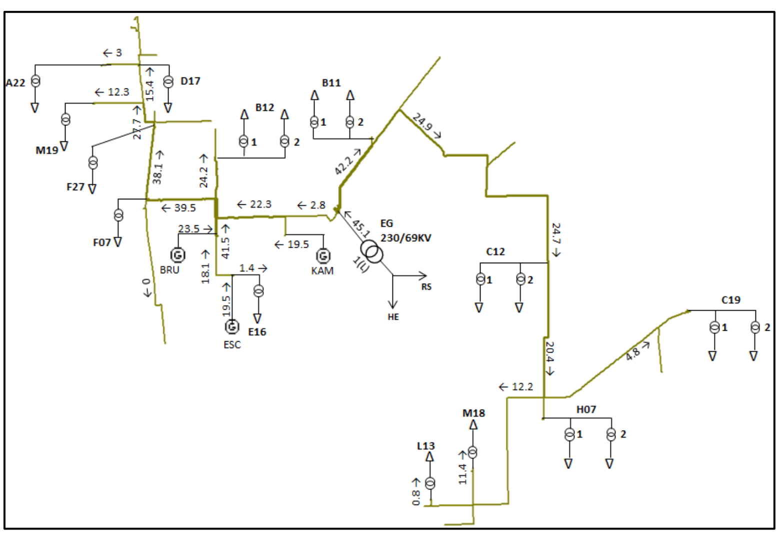


Figure 9: Voltages (120 volt base) for Scenarios 1A, 1B, and 1C

The analysis completed above focused on the peak hour of the peak day for July 12. Solar generation is lower since the peak occurs at 6 pm. The next series of figures show the impacts of high solar generation during the 2 pm time period of the same peak day. Figure 10 shows the power flows for Scenarios 2A, 2B and 2C. The load at 2 pm is 108 MW compared to 138 MW peak. However, the solar generation is generating at maximum during this time period.

For Scenario 2A when the PV is at 0 MW, the power flow is 66 MW at the substation. In Scenario 2B when the PV generation is at 61 MW, the power flow at the substation reduces to 5.6 MW. When the solar generation is at 100 MW for Scenario 2C, the power flow reverses to backflow into the substation bus. With a projected high PV penetration on the 69 kV circuits on EG substation, SMUD can still experience reverse power flow into the substation on the peak day of the year. This demonstrates that the minimum daytime peak period must be studied in detail since the load is even lower under the same solar generation.





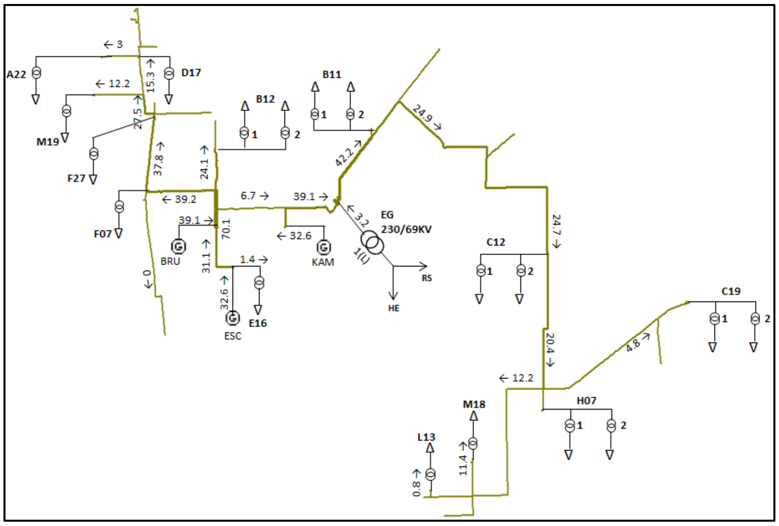


Figure 10: Power Flows for Scenarios 2A, 2B and 2C

Figure 11 shows the percent line segment loading for Scenarios 2A, 2B, 2C. When solar is at 0 MW, the line loading for the first several line segments from the substation is 71%. As the solar is increased, the line loading for Scenario 2B reduces to 6%. In Scenario 2C, the line loading is 37% in the reverse direction due to the high solar generation.

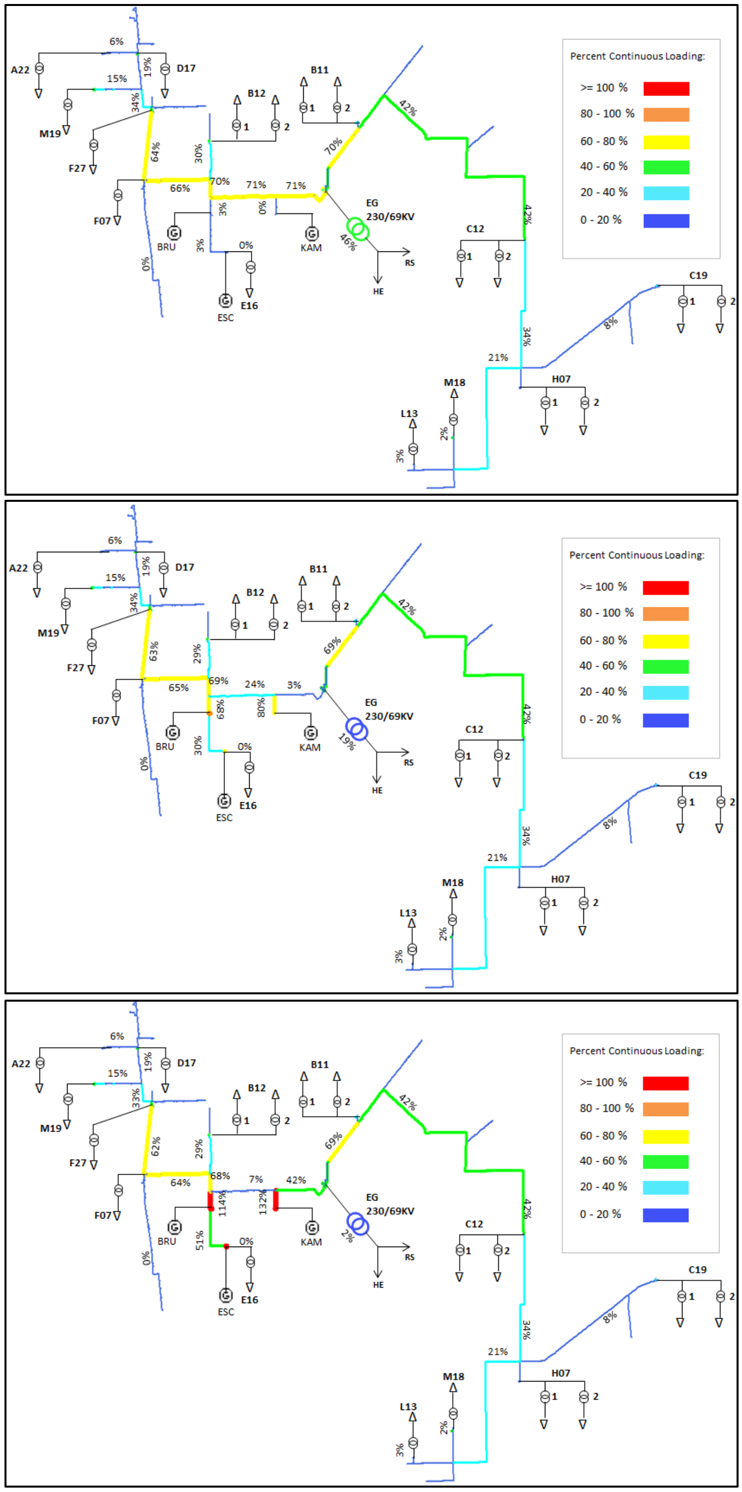


Figure 11: Line Loading for Scenarios 2A, 2B, 2C

Figure 12 shows the voltages at a 120 volt base for Scenarios 2A, 2B, and 2C. The LTC reduces from a neutral position to a -1 position which is trying to reduce the voltage at the substation. While there are no low voltages during the peak load time period, the voltage at the end of the circuits reduces to 119.5 volts.

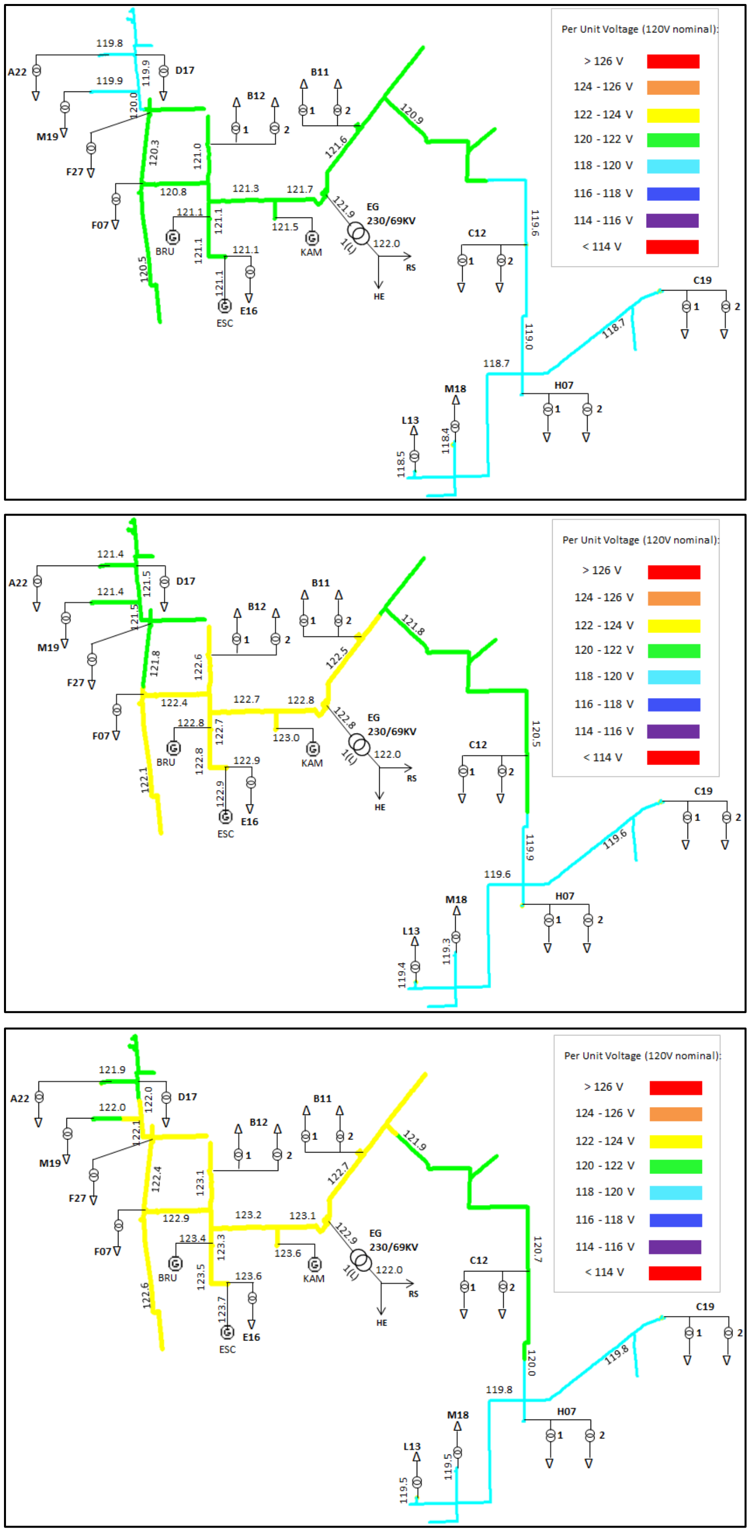


Figure 12: Line Segment Voltages (120 volt base) for Scenarios 2A, 2B, 2C

The EG area is projected to have distributed solar generation and higher penetrations of central solar plants on the 69 KV circuits. The analysis completed for the peak day with increasing PV scenarios indicate that the system can experience reverse power flow, directional power flows even on the peak day, and potential voltage violations. This analysis suggests the need to conduct studies on other non-peak load days and even time sequential power flow modeling to determine the impacts on the 69 kV circuits, the 12kV distribution circuits and even perhaps the 230 kV grid.

The conclusions of this analysis of EG Bank 1 are:

- Elk Grove Bank 1 2012 peak load ~137MW on July 12, at 6 pm
- Three load flow scenarios explored with peak load: PV penetration level of 0% (no PV), 15% (~20.5MW) and 30% (~41MW) ; PV added at the locations of existing generators
- Maximum % of a single 69kV line loading for the three cases: 89%, 86%, 86% respectively
- 0% PV: TC=N, Vmax=123.2, Vmin=120.7, Vmax-Vmin=2.5V
- 15% PV: TC=-1, Vmax=122.0, Vmin=119.5, Vmax-Vmin=2.5V
- 30% PV: TC=-1, Vmax=122.5, Vmin=119.9, Vmax-Vmin=2.6V
- Maximum voltage occurs on Circuit 3 where the three PV generators are, while minimum voltage occurs on Circuit 4; consequently the PV has small impact on voltage regulation

For the solar penetration scenarios, that range from 0% to 30%, studied for Bank 1 and the associated 69 kV lines, there are no line overloads, the transformer LTC (TC) had minor tap change positions and the minimum and maximum voltages on any line segment are within voltage limits. The maximum voltages occur on the 69 kV line with the central PV plants while the lower voltages occur on the line without PV. The analysis is limited to steady-state and contingency conditions for penetrations up to 30%. Additional studies are required to determine the upper limit of solar penetration under transient analysis.

4.1.2 EB Feeder Analysis

The study assumptions for EB include:

- Study objectives for assumed minimum feeder load:
  - Determine the maximum net generation for Co-Gen without causing a backfeed, and determine the voltage impact
  - Determine the amount and duration of generation curtailment, and determine voltage impact when Co-Gen produces 1MW
- Type of data received:
  - Total feeder kW demand and three-phase currents
  - Dairy digester kW generation and consumption
  - PV plant single-phase current
- Load calculated based on the demand, Diary Digester generation and consumption, and estimated PV generation (based on irradiance)

The initial feeder analysis for EB concentrate on the potential impacts of a variable sized central solar installation of 1 or 3 MW installed in close vicinity to the dairy digester plant. Later, the solar plant is sized as a 1 MW solar plant with a projected 1 MW customer owned cogeneration plant constructed at the customer plant that is located near the substation. The EB feeder has a T-tap located outside of the EB substation. One tap serves load west of the substation while the second tap services load east of the substation. The west tap has the dairy digester and the solar plant located at the very end of the feeder line. The east tap has the cogeneration plant located close to the substation. The feeder map shown in Figure 13 shows the east and west branches of the EB feeder.

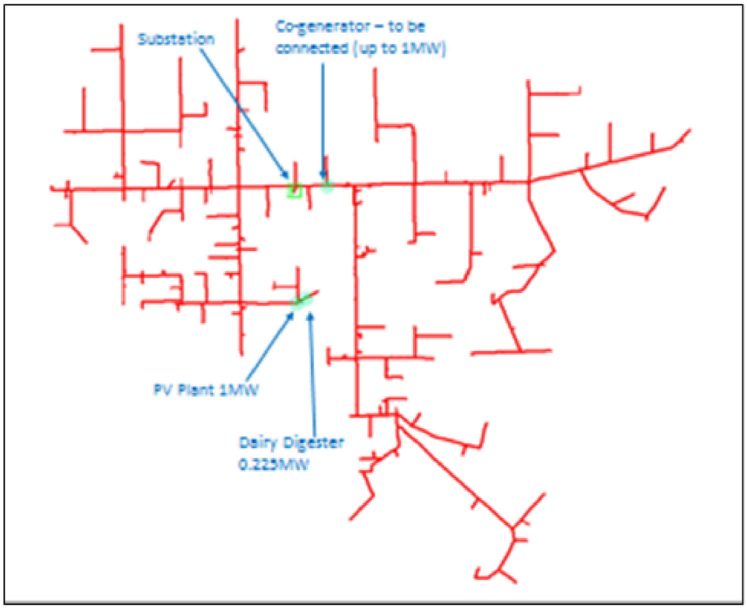


Figure 13: EB Feeder with PV Plant, Digester and Cogeneration Plant

The two graphs shown in Figure 14 are for the SMUD EB feeder for an April minimum daytime peak period. The top graph shows the megawatt power flows on the feeder for the base case without PV but with the digester only; and with 1 and 3 MWs of PV added. The base case without the PV does not have reverse power flow. The addition of 1 MW PV causes a reverse power flow on the feeder for a two hour period as compared to a seven hour reverse power flow with the addition of 3 MW of PV.

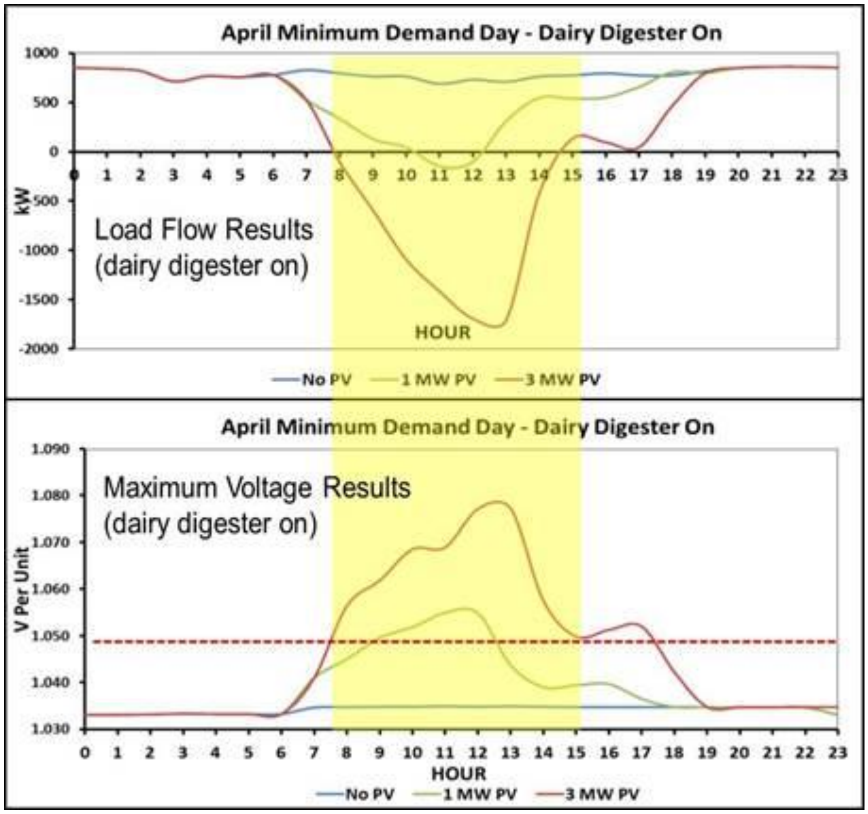


Figure 14: SMUD EB Load Profile and Voltage Profile for Minimum Daytime Peak

The bottom graph shows the voltage in PU. With only the digester, the maximum voltage on any one line segment is about 1.032 PU. With the addition of 1 MW PV, the voltage on one line segment exceeds the 1.05 PU for about three hours. With the addition of 3 MW of PV, the 1.05 PU limit is exceeded for about seven hours and reaches a maximum of 1.08 for one hour.

The EB analyses conducted is to determine if there could be high voltage and backfeed into the substation under light load and high PV generation; and determine if there could be low voltage on the east branch given that there isn't any distributed generation to support voltage or load.

When the 1 MW PV system is installed on the EB feeder, the plant data is compared to the AC average solar data to determine if the solar profiles are adequate for the analysis completed to date. As shown in the Figure 15 below, the two solar profiles are almost the same. The actual EB data has longer hours at maximum generation than the average AC solar generation.

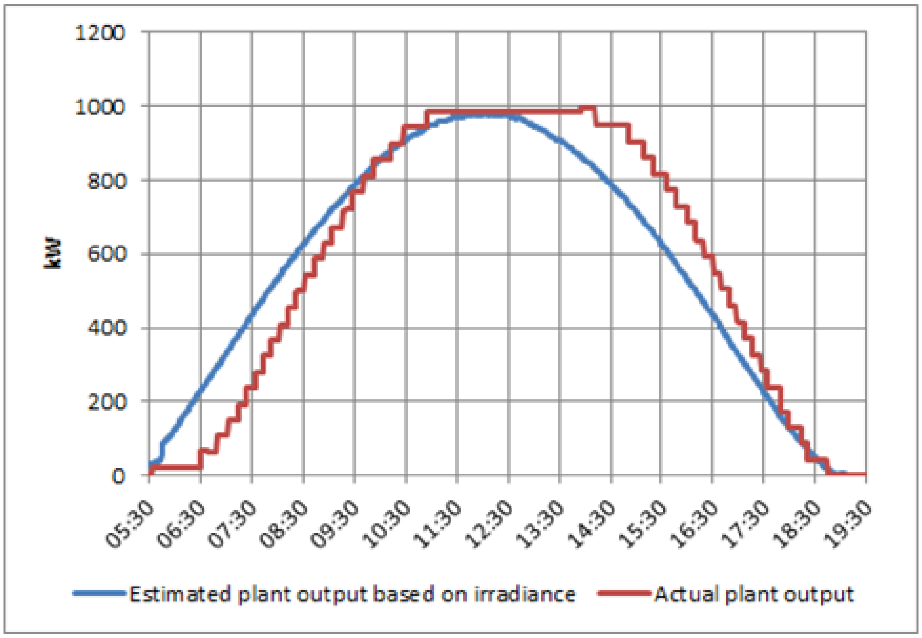


Figure 15: Comparison of an Average AC Solar Profile and EB Recorded Data

Before conducting further analysis, it is important to understand the EB load profile. In Figure 16 below, twenty-four hourly load profiles are graphed from April 1 to April 20. Although fourteen of the twenty days show consistent profiles, there are six days with high varying load profiles. Since the customer plant is on time-of-use (TOU) electric utility rate and the digester is just starting testing, the net EB load varies on some days.

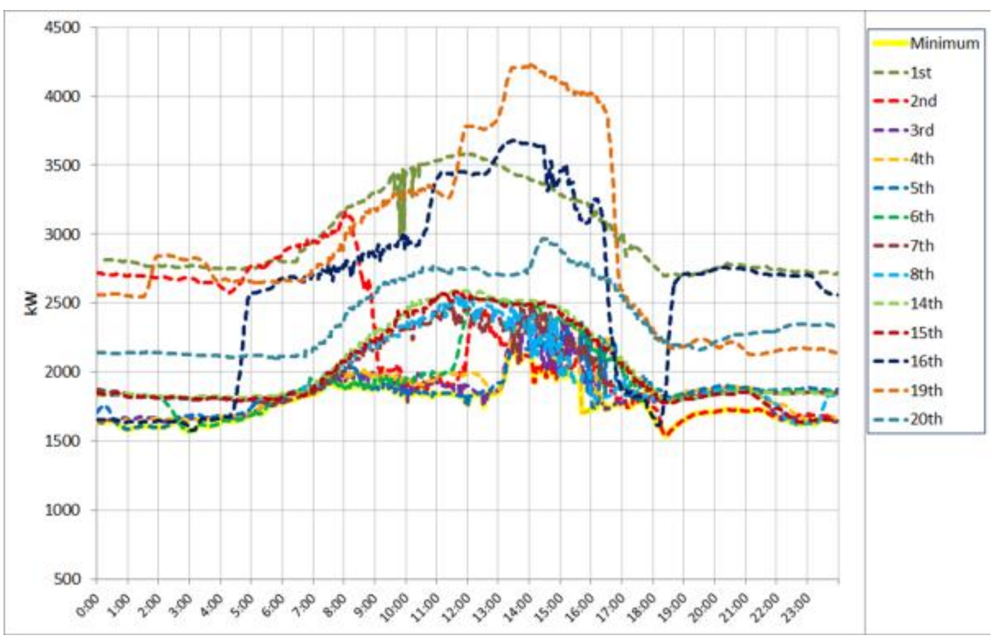


Figure 16: EB Composite Minimum Load Profiles April 1 to 20th

Figure 17 shows the EB load from April 20 to May 10. This time period is selected to observe how the feeder load changes as the TOU rates change and the ambient temperature begins to increase. As expected, the load varies widely over the twenty four hour time period and for the different days. The customer plant operates mostly at night when TOU rates are lower and reduces load during the day time hours when TOU rates are high. There are some days with high daytime peak load which may be weekend time periods when TOU rates are lower. However, there are sufficient daytime profiles to study the potential impacts of the solar plant and the customer plant with an installed cogeneration plant.

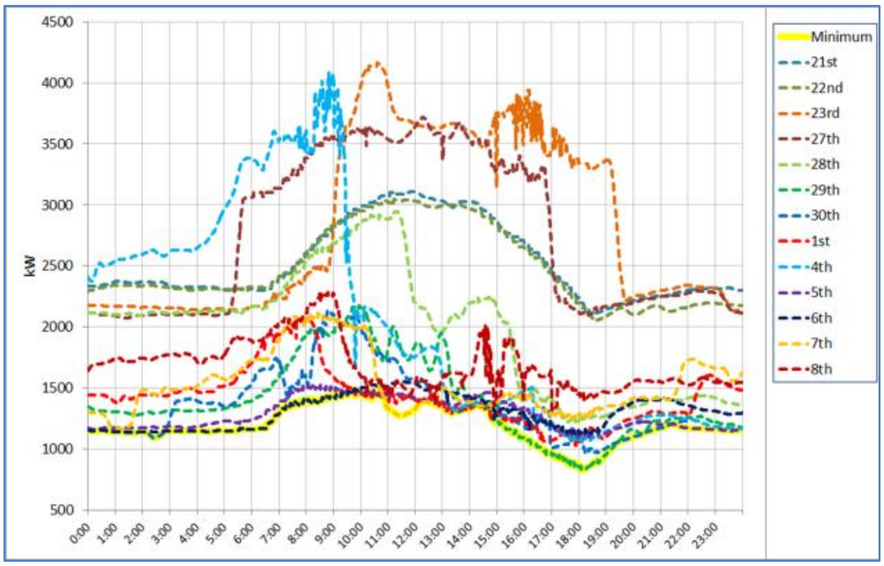


Figure 17: Composite Minimum Load Profile April 21 to May 10th

Figure 18 shows the impacts of the cogeneration plant and solar plant on the net load and the potential backfeed into the substation. The red solid and dashed lines represent the composite loads from the two figures above. The distributed EB generation is shown as the yellow line for the cogeneration plant that operates at constant generation once commercial, the green line is the solar generation profile and the purple is the digester plant generation.

Since the distributed generators are not on-line for the April and May time period, the generation is subtracted from the composite load profile. Depending on the composite profile used, there is backfeed on the west branch of EB as shown in the Figure below. Backfeed occurs anytime from the entire twenty-four hour day as shown by the solid blue line or a partial backfeed for about 8 hours during the daytime peak hours.

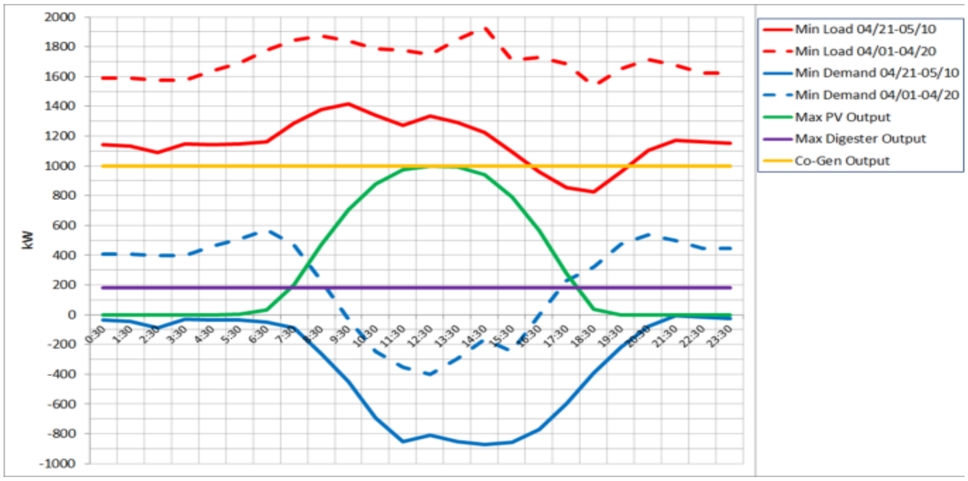


Figure 18: EB Projected Backfeed for Various Light Load Time Periods

For this analysis, the EB bus voltage is set to 123 volts. If the LTC is not operational, what is the potential impact to the voltages at any location on the EB feeder? Figure 19 shows the high and low voltage on any line segment on the feeder. The highest voltage on any line segment does slightly exceed the 126 voltage limit. The lowest voltage on any line segment is above 122 volts.

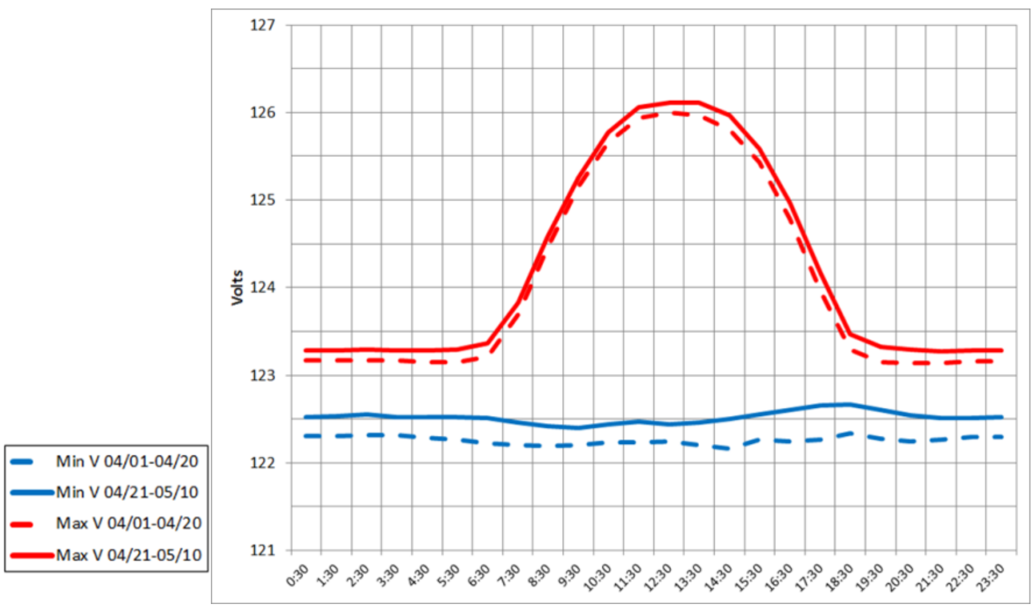


Figure 19: EB Min/Max Voltage Profiles over a 24 Hour Time period

There are 4 capacitor banks on the EB feeder. Some are fixed in the “on” position while others are either on VAr or time regulation. Figure 20 shows the potential impacts on line segment voltages as the four capacitor banks are switched on during backfeed periods. The capacitor banks increase the minimum voltage on the line segments and also slightly increase the maximum line segment voltages. Overall, the capacitors have little impact on line segment voltages.

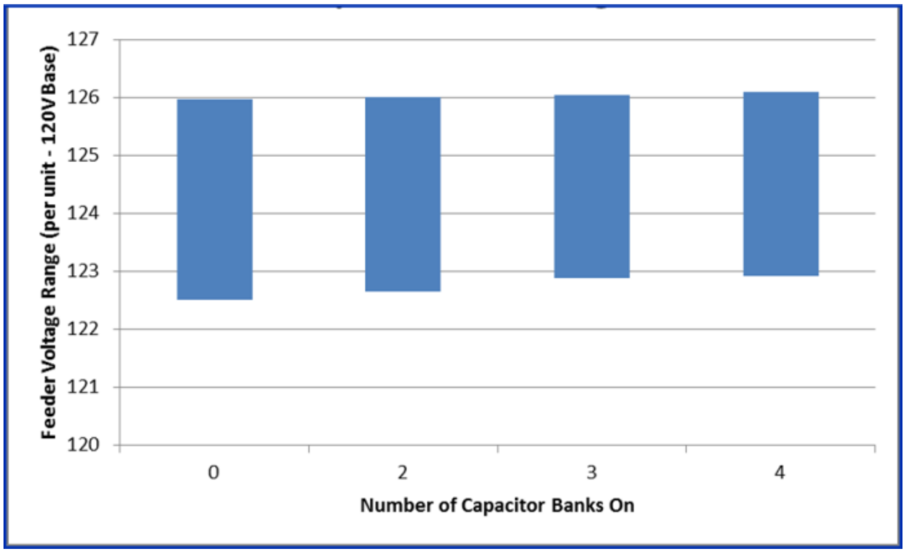


Figure 20: EB Worst Case Voltage Condition Under Backfeed from Capacitor Switching

In Figure 21, the capacitor switching impacts are evaluated during the time periods when the voltage is at the lowest minimum and at the high maximum voltage. As the capacitor banks are switched from all "off" line to all "on" line, the minimum voltage increases by about 0.5 volts. There is a slight increase in the maximum voltage that exceeds the upper limit.

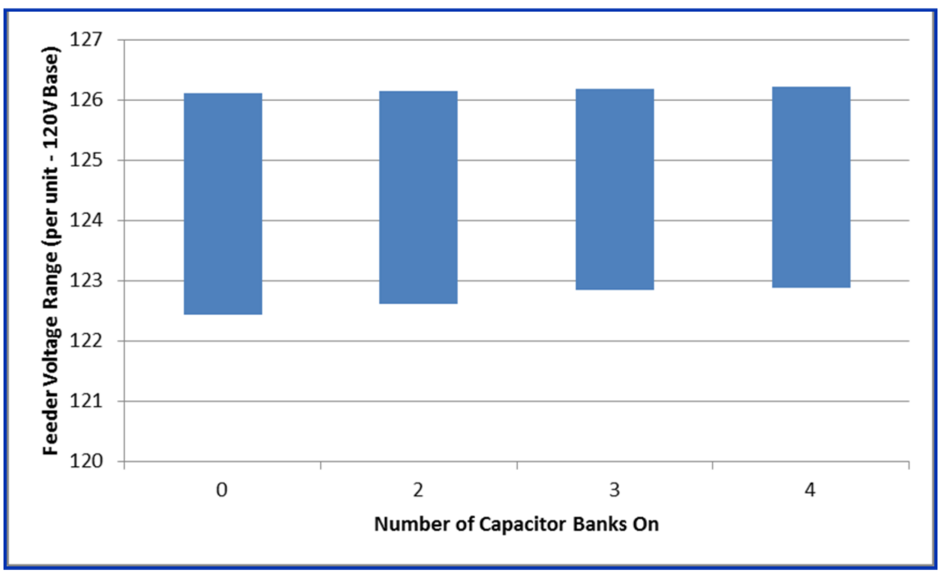


Figure 21: EB Worst Case Voltage Condition Under Capacitor Switching

The conclusions for the EB study are:

- The addition of solar during minimum daytime peak hours will create high potential for backfeed on the feeder.
- There will be periods of high voltage limit violations during the maximum daytime peak and minimum daytime periods.

- The operation of the four capacitor banks has little impact on the voltage.
- The LTC operation could reduce the voltage below the limit violation.

4.1.3 SMUD Feeder CT

Some background information used in this CT study includes:

- Single transformer supplies CT2 and CT3 feeders (CT1 no longer exists)
- One field voltage regulator and five capacitors on the feeder (6.0MVAr total)
- Existing connected PV: the RS plant on CT3 ~1.0MW max
- Considered prospective PV: at the location of RS plant
- Study objective: determine MW flow, line loading and voltages in case of peak daytime feeder load and at different PV penetration levels
- Type of data received: total feeder MW and MVAr demand, three phase currents, irradiance data; all for the month with maximum feeder load (July)
- Load calculated based on the demand and estimated PV generation (based on irradiance)
- Identified the 2012 substation peak load:
  - Daytime peak ~4.87MW at 11:46 am on July 12
  - Anytime peak ~5.20MW at 8:00 pm on July 11

Figure 22 shows the one line diagram for the CT feeder. This feeder is located in a rural area with long feeder line segments, one large existing solar site of 1 MW at a customer site, one line voltage regulator, five capacitor banks (6.0 MVAr total). The objective of the study of CT is to determine the power flows, line loadings and voltages for the minimum daytime peak period under various solar penetration levels. The 2012 substation peak loads used in this analysis are July 12 at 11:46 am for the maximum daytime peak and July 11 at 8 pm for the feeder peak. Depending on the locations of new solar installations, the line loadings and line voltages are impacted.

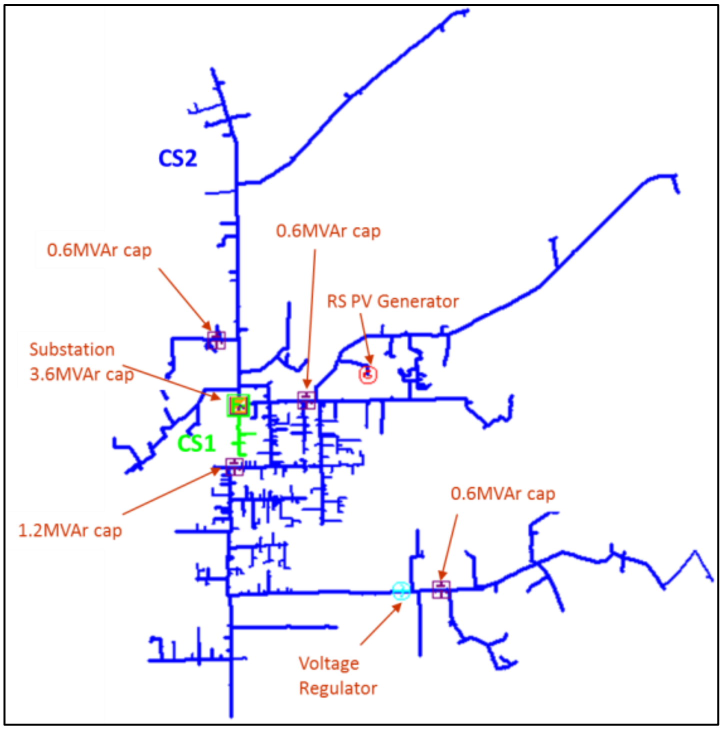


Figure 22: SynerGEE CT Feeder Diagram

Figure 23 shows the 2012 peak day load profiles. The purple line represents the gross demand for the CT feeder while the red line represents the net demand after subtracting existing solar generation. The green and blue lines show the two load readings on CT. Due to limited recorded substation data, the analysis uses the peak solar generation at 12:00 pm as a pseudo minimum daytime peak load period.

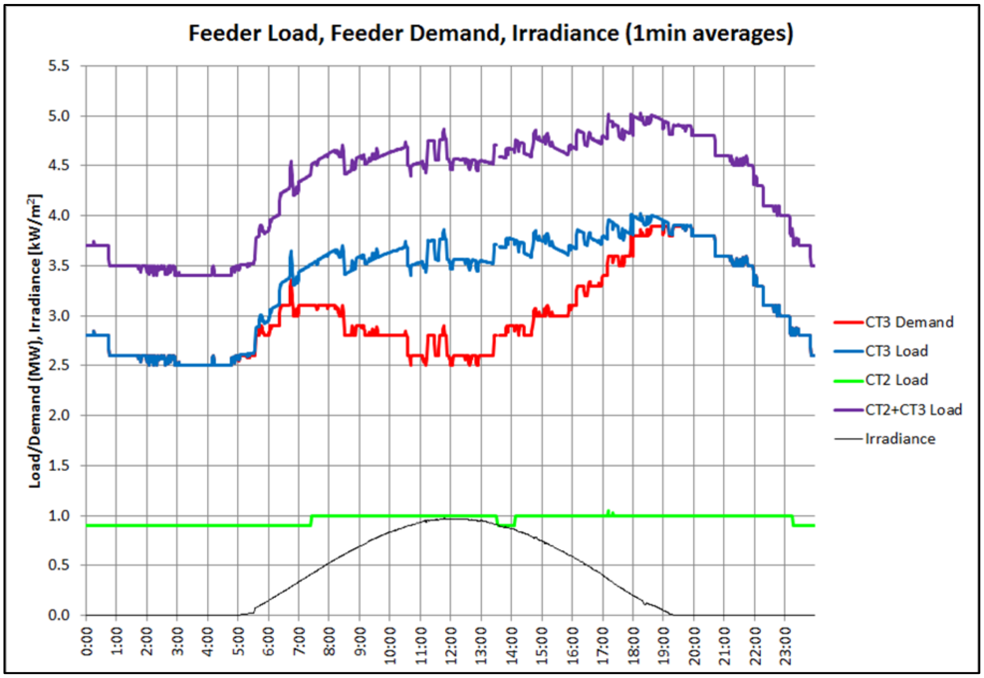


Figure 23: 2012 Daytime Peak Load Profile

To capture the potential impacts of high solar concentrations on the feeders, the following model setups and assumptions are made:

- Substation voltage on the high side of the transformer is set to 1.025 pu
- Load power factor is set to 0.95 Transformer
- Load Tap Changer setting (1.0pu~12kV): Voltage=1.025pu (12.3kV), R=3, X=0, BW=0.00625pu (75V) – independent 3-ph regulation
- Voltage Regulator setting (1.0pu~12kV): Voltage=1.025pu (12.3kV), R=0, X=0, BW=0.00625pu (75V)
- Automatic switching of capacitors disabled

There are five cases developed for substation CT, as shown in Table 3. The PV penetrations for cases 1A, 1B and 1C are 0%, 30% and 50%, respectively, of the feeder peak demand. In case 1A, there is one segment that is experiencing low voltage before the line regulator. Cases 1B and 1C simulate capacitor banks being activated to determine if the low voltage could be resolved. Cases 2A and 3A are the 30% and 50% penetrations.

Case	Load 2 MW	Load 3 MW	Load 2 + 3 MW	PV MW	Caps MVAr	Comments
1A	3.87	1.0	4.87	0.0	0.0	Load at 11:46 am; no PV
1B	3.87	1.0	4.87	0.0	1.20	
1C	3.87	1.0	4.87	0.0	1.80	
2A	3.87	1.0	4.87	1.46	0.0	
3A	3.87	1.0	4.87	2.44	0.0	

Table 3: CT Case Simulations

Figure 24, Figure 25, and Figure 26 display the power flows for Cases 1A, 2A and 3A. Since the additional solar is installed at site RS, the only power flow changes are located near location RS due to the higher solar penetrations.

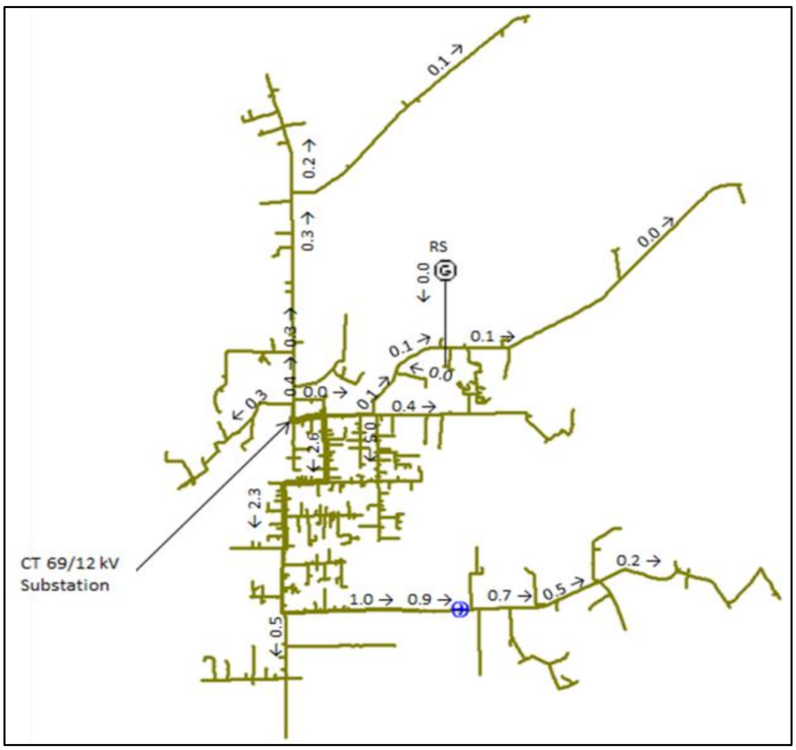


Figure 24: Case 1A Load Flow w/0 MW PV

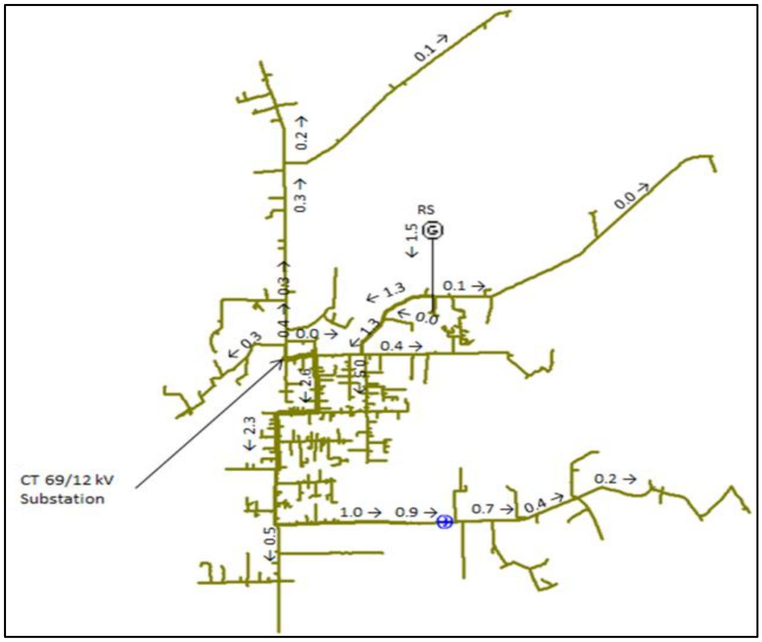


Figure 25: Case 2A Load Flow w/1.5 MW PV

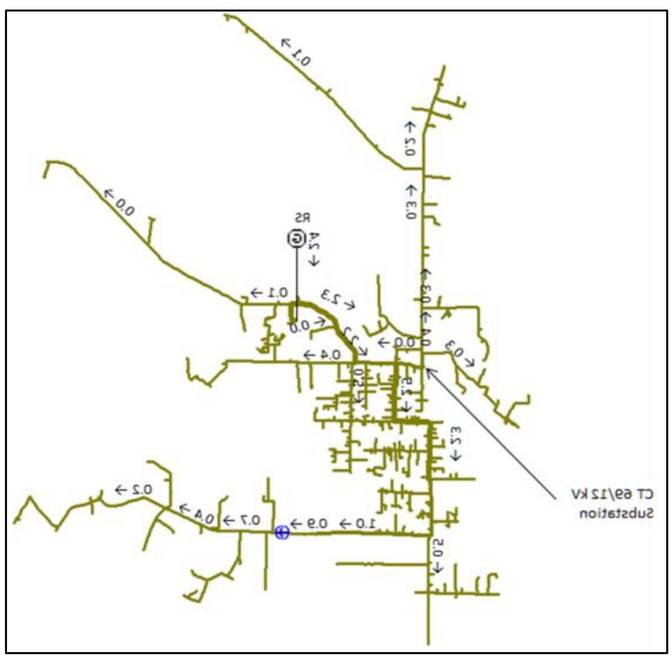


Figure 26: Case 3A Load Flow w/2.44 MW PV

Figure 27, Figure 28 and Figure 29 display the line loading of each individual line segment for Cases 1A, 2A and 3A, respectively. The line loadings are the same for all cases except for the line segments near RS. As the solar penetrations increase around RS, the percentages increase due to the exporting of solar energy but never exceed the line ratings.

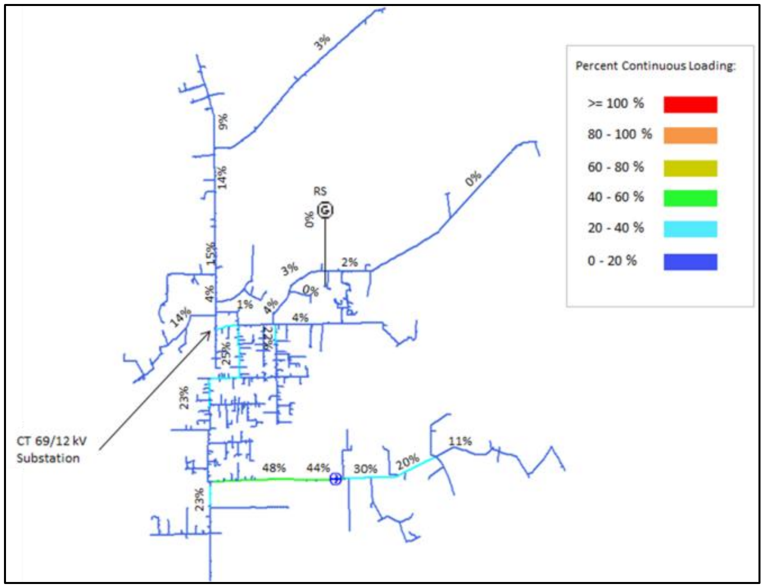


Figure 27: Case 1A Line Loading w/ 0 MW PV

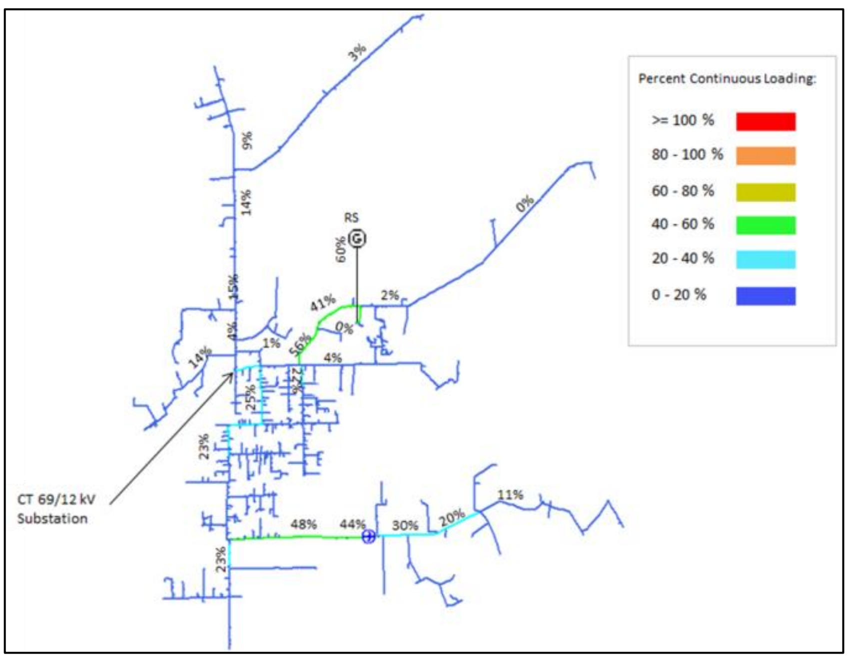


Figure 28: Case 2A Line Loading w 2.44 MW PV

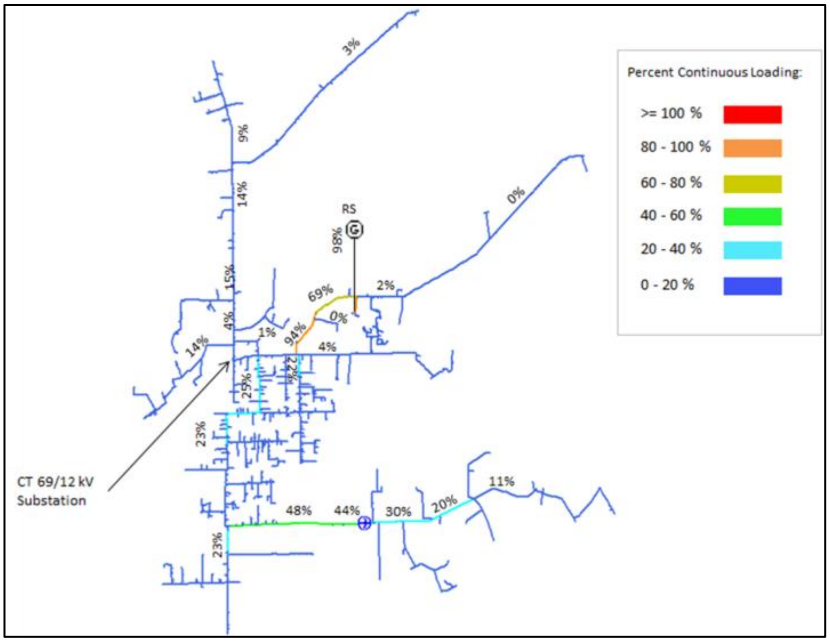


Figure 29: Case 3A Line Loading w/2.44 MW PV

Figure 30, Figure 31 and Figure 32 display the voltages at the different line segments for the same cases discussed above. Since Case 1A is the base case with 0 PV, there are no low or high voltages. Case 2A experiences high voltage on the line segments near RS. Case 3A experiences both low and high voltage. The LTC attempts to lower voltage due to higher penetrations of solar but cannot eliminate the high voltages near RS. Because the LTC is attempting to reduce the high voltages by reducing the tap changer setting, it also creates low voltage at the far end of the feeder. Case 3A demonstrates how the improper locations of solar generation can create both low and high voltages at the same time.

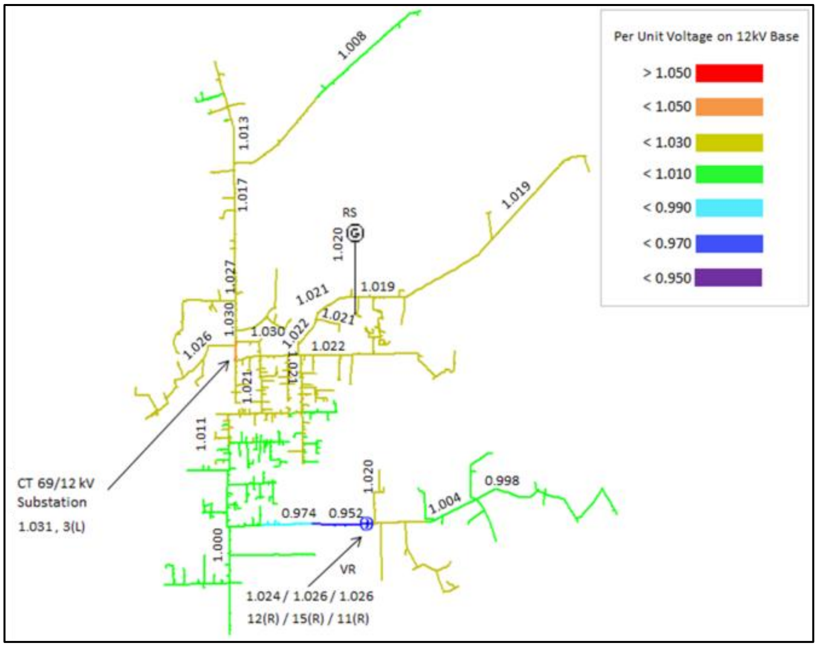


Figure 30: Case 1A Voltages (120 v Base) w0 MW

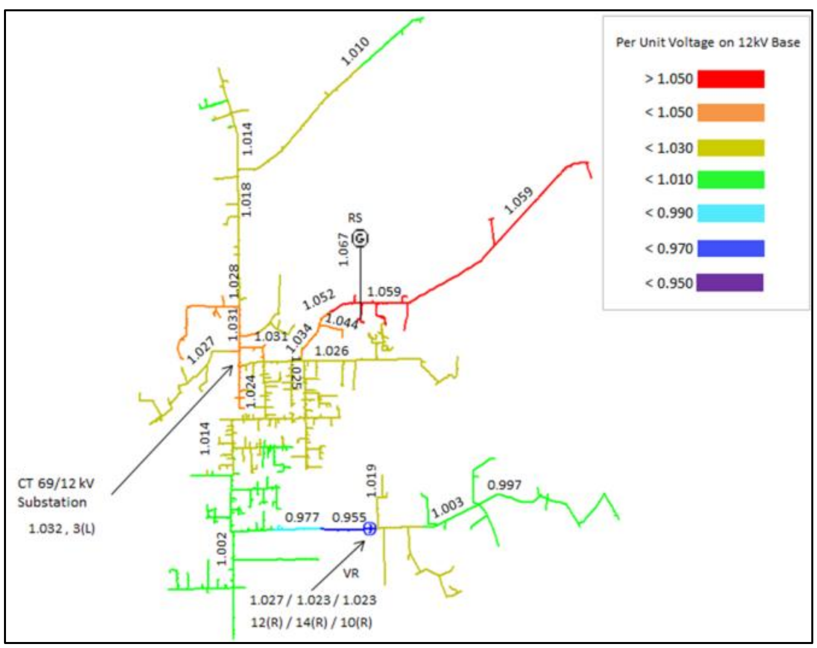


Figure 31: Case 2A Voltages with 2.44 MW w/1.5 MW PV

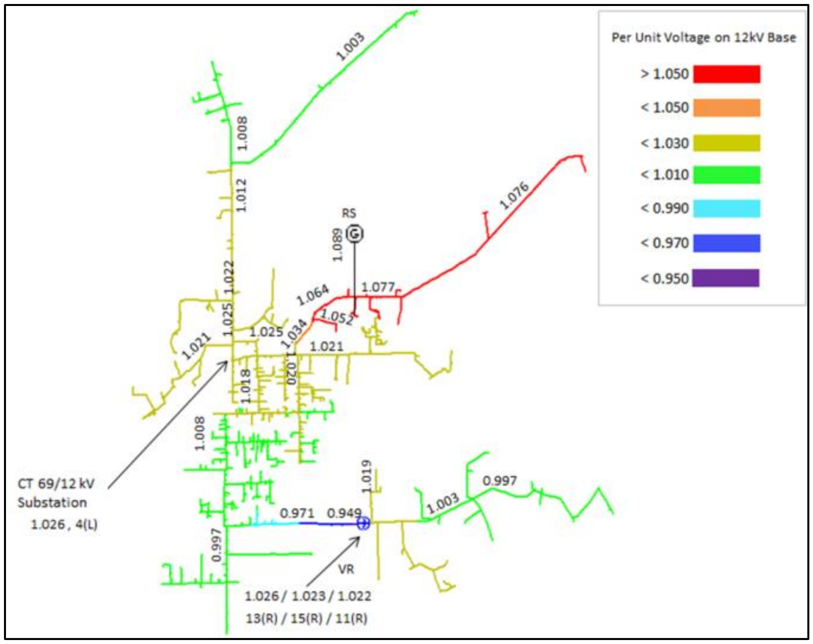


Figure 32: Case 3A Voltages (120 V Base) w/2.5 MW PV

Figure 33 and Figure 34 display the voltages for Cases 1B and 1C that have varying penetrations of capacitor banks turned on. Activating the capacitor banks eliminates the low voltage problems.

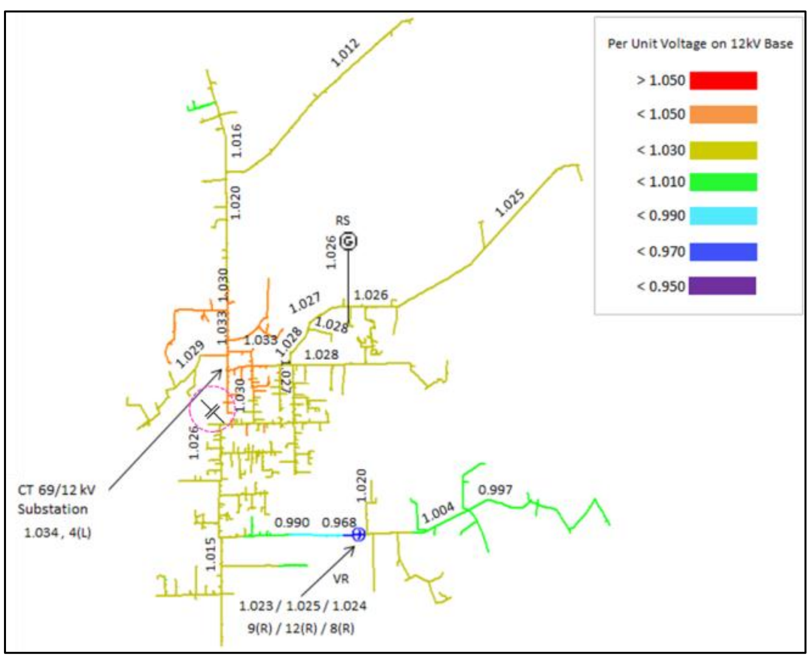


Figure 33: Case 1B Voltages w/0 MW PV & 1.2 MVAR Caps

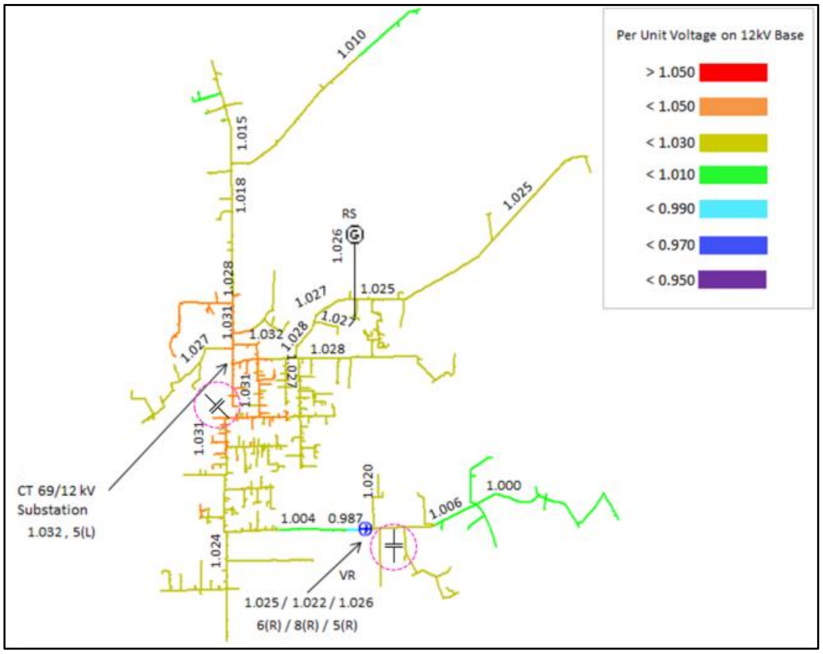


Figure 34: Case 1C w/0 MW PV & 1.8 MVAR Caps

Table 4 displays the results for Substation CT and the associated feeders. There is high voltage on one or more line segments as the solar penetration approaches 30%; and high line loading on line segments as the solar penetration approaches 60% solar penetration.

Case	**PV MW**	**Caps MVAr**	**Max line Loading**	**V max**	**V min**	**Vmax-Vmin**	**LTC**
1A	0.0	0.0	48%	1.031	0.952	0.079	-3
1B	0.0	1.2	47%	1.032	.968	0.968	-4
1C	0.0	1.8	47%	1.032	0.987	0.045	-5
2A	1.46	0.0	60%	1.067	0.955	0.112	-3
3A	2.44	0.0	98%	1.089	0.946	0.14	-4

Table 4: Summary of Results for Substation CT

4.1.4 SUBSTATION AC and FEEDER AC 1

The background information on AC1 is:

- Single transformer supplies AC 1, 2 and 3 feeders
- Existing connected PV: AC 1 ~660kW, AC 2 ~190kW
- Prospective PV: AC 1 (Solar Smart homes) ~additional 350kW, and possibly greater
- Study objective: determine feeder kW flow and voltage profiles with new PV in case of minimum feeder load
- Type of data received:

- Total feeder kW demand
- Three phase currents
- AC irradiance data

- Data origin and time frame:
  - Substation monitor data for AC 1, 2 and 3: from 09/2011 to 04/2012
  - Line monitor data for Solar Homes: from 09/2012 to 05/2012
  - Load calculated based on the demand and estimated PV generation (based on irradiance)

Substation AC has three distribution feeders (AC 1, AC 2, and AC 3). Figure 35 displays layout of the three feeders. AC 1 is shown in blue, AC 2 is shown in green and AC 3 is shown in red. AC 1 and AC 2 have large solar residential communities. AC 3 has very little load and no existing solar.

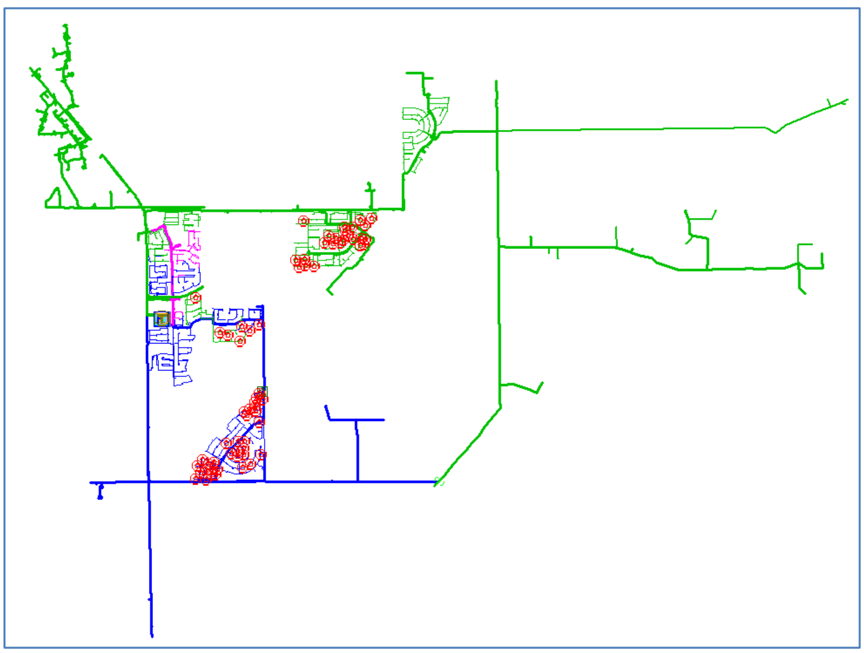


Figure 35: Map of the Feeder Layout for AC 1, AC 2 and AC 3

Since this task is only considering the solar penetrations on AC 1, the load data for April is analyzed to find the lowest minimum daytime peak. This occurred on April 29, 2012 at 12:50 pm as shown in Figure 36 below as the vertical light red line. The time period of interest is from 7:30 am to 7:30 pm.

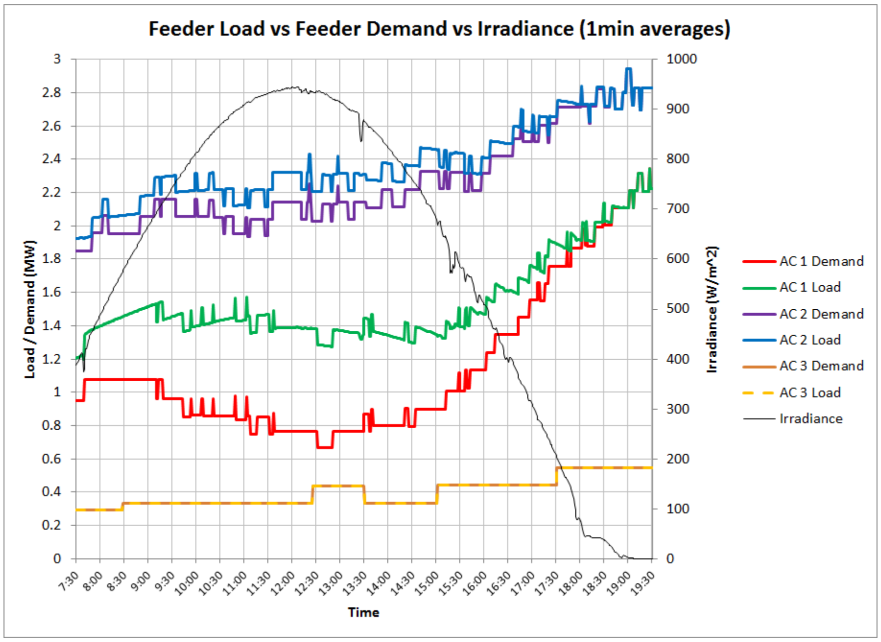


Figure 36: Comparison of Feeder load to Feeder Demand

The green line represents the AC 1 gross load if solar is not operating. The red line represents the AC 1 net load after adjustments for solar generation. The minimum daytime peak occurs when solar is only 93% of maximum generation for the day. The blue line represents the gross AC 2 load while the purple line represents the net load after adjusting for solar generation. In this case, there is very little solar generation online. AC 3 is shown in yellow with no solar generation.

Figure 37 below displays the minimum daytime peaks in a flow chart format for easier analysis. AC 1 is shown as the left feeder. The solar generation and gross load are shown separately. The AC 1 peak is 1,271 kW (330 kW of load is from a customer plant) and is served by 609 kW of solar generation and 666 kW of generation from the AC substation. AC 2 is the center feeder. The gross load is 2,295 kW that is served by 175 kW of solar and 2,130 kW of generation from the substation. AC 3 is the right feeder with no solar generation.

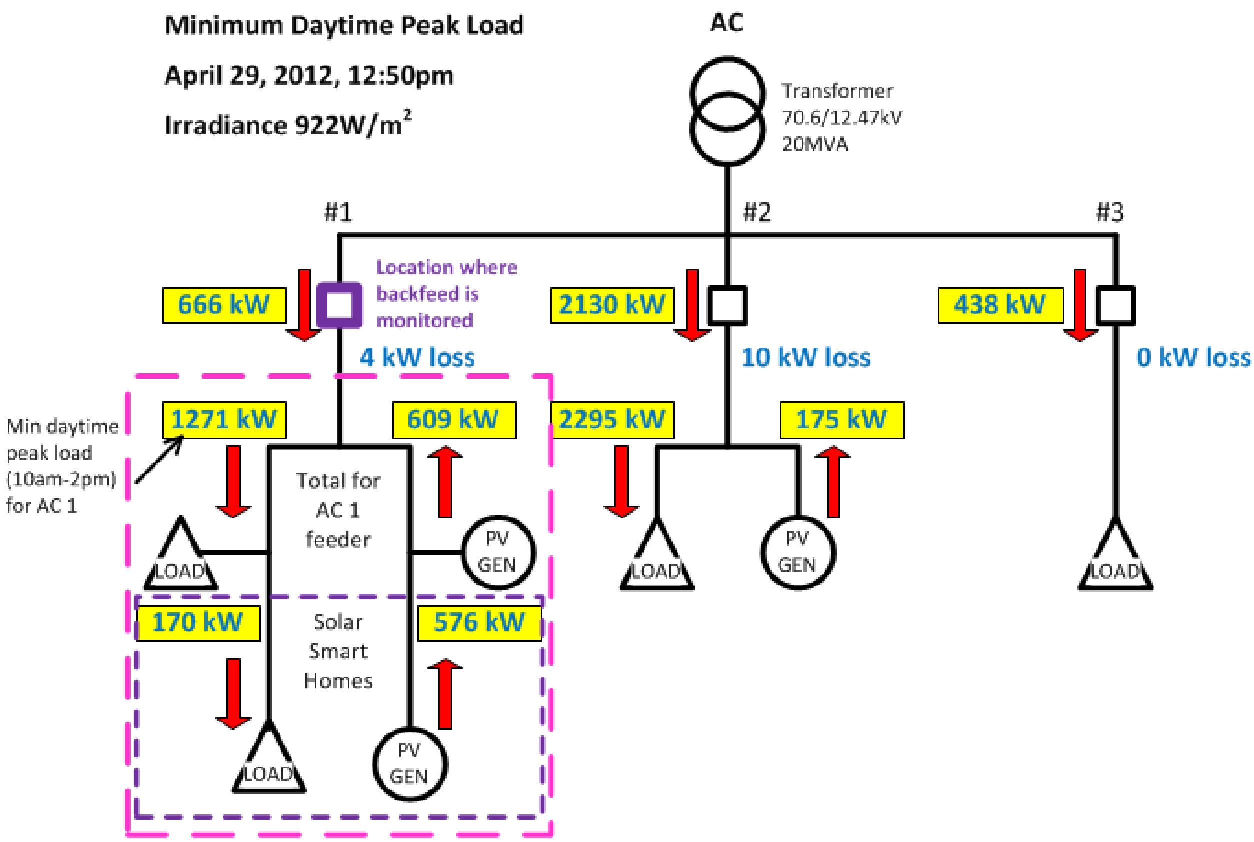


Figure 37: AC1 Power Flows for Minimum Daytime Peak Conditions

Even though the minimum daytime peak occurs when solar generation is at 93%, the analysis on the impact of high solar penetration is adjusted to 100% solar generation. The loads are adjusted down for the increased solar generation. Eight scenarios are prepared at shown in Table 5: Power Flows for Various Scenarios. Scenario 1 is the “No PV” case. Scenarios 2A and 2B show the loads changing when the solar irradiance is changed from 922 w/m^2 to 1000 w/m^2. Scenarios 3 through 6 are various changes in the magnitude of installed solar and smart home community load increases.

Scenario	Irradi-ance [W/m^2]	AC 1 Load Total [MW]	AC 1 PV Total [MW]	AC 1 Load Smart Homes [MW]	AC 1 PV Smart Homes [MW]	AC 2 Load [MW]	AC 2 PV [MW]	AC 3 Load [MW]	Minimum Daytime Peak Load (04/29/12, 12:50pm) in Scenarios 2A-6
1	1000	1257	0	170	0	2292	0	438	No PV, existing load (baseline case)
2A	922	1259	610	170	577	2292	177	438	92% Irrad (04/29/12, 12:50pm); existing PV and load
2B	1000	1259	661	170	625	2292	192	438	100% Irrad (conserv. assump.); existing PV and load
2C	922	932	610	170	577	2292	177	438	92% Irrad (04/29/12, 12:50pm); existing PV and load; rendering plant switched off
3	1000	1354	1008	264	972	2292	192	438	Smart Homes PV increase until total AC 1&2 PV is 1.2MW; Smart Homes load increase rate is 100% of PV increase rate
4	1000	1473	1445	383	1409	2292	192	438	Smart Homes PV increase until backfeed on AC 1 occurs; Smart Homes load increase rate is 100% of PV increase rate
5	1000	1307	1008	217	972	2292	192	438	Scenario 3 except load increase rate is only 50% of PV increase rate
6	1000	1350	1322	260	1286	2292	192	438	Scenario 4 except load increase rate is only 50% of PV increase rate

Table 5: Power Flows for Various Scenarios

Figure 38 shows the power flows for each of the scenarios shown in Table 5. These are the same values as in Table 5 but shown in a graphical form for easier viewing.

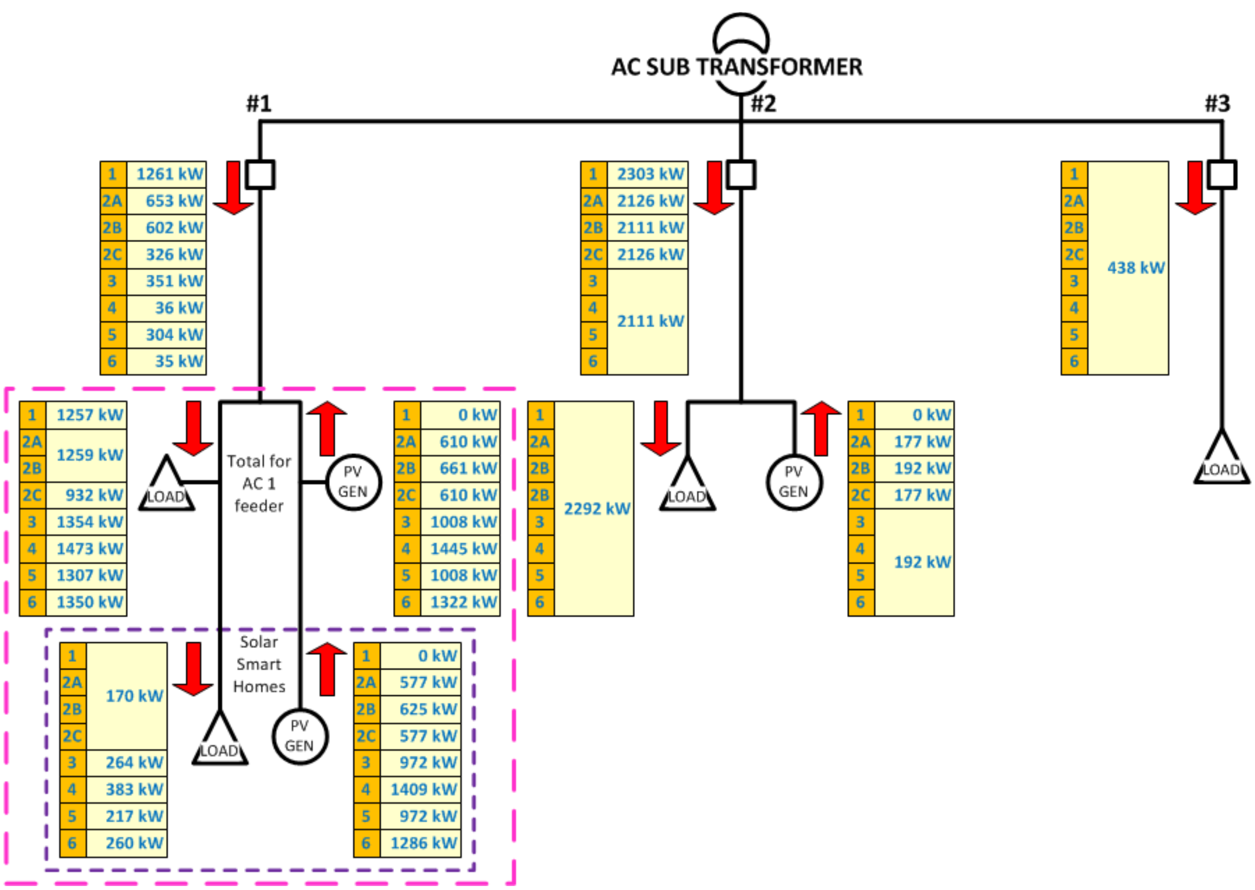


Figure 38: Power Flow Comparison for Each Scenario

Figure 39 shows the power flows from the substation to the entrance into the smart home community for Scenarios 1 through 6. The purple line shows the power flows from the substation to the end of the feeder when all solar is removed from the simulation. Since the installed solar within the smart home community is always a net backfeed into the feeder, the magnitude of the backfeed changes as the solar penetration increases. In all scenarios excluding Scenario 6, the power flows from the substation to about 0.25 mile outside of the substation. This is the location of the customer plant and other local loads are connected. In Scenario 6, the solar penetration causes backfeed into the substation.

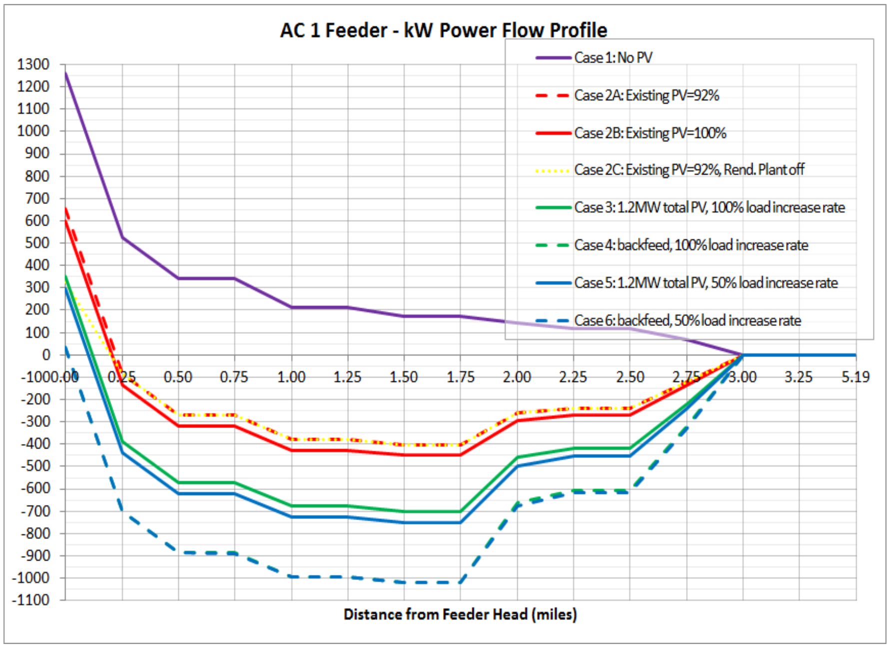
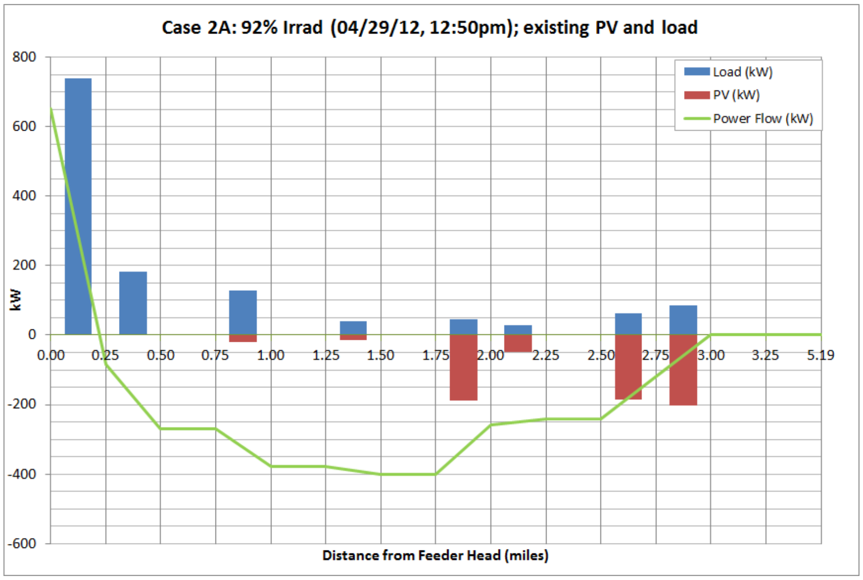


Figure 39: Load Flow Results for all Cases

Figure 40 displays the results for Scenarios 2A and 2B. This represents the actual load and solar generation that occurred on April 29 at 12:50 pm. The green lines are identical to the solid and dash red lines in the previous Figure 39. This shows the power flows from the substation to the entrance into the smart home community. The blue bars are the locations of the customer loads on the feeder. The majority of the load is located within 0.25 miles of the substation. The red bars show the locations of the solar installations. The solar installations are the end of the feeder as compared to load locations. Even though Scenario 2A represents the actual data for April 29 for verification purposes, the high solar irradiance shows more impacts on the feeder and is used as a base reference for the other scenarios. The higher irradiance produces an increase in back feed toward the substation but no back feed into the substation.



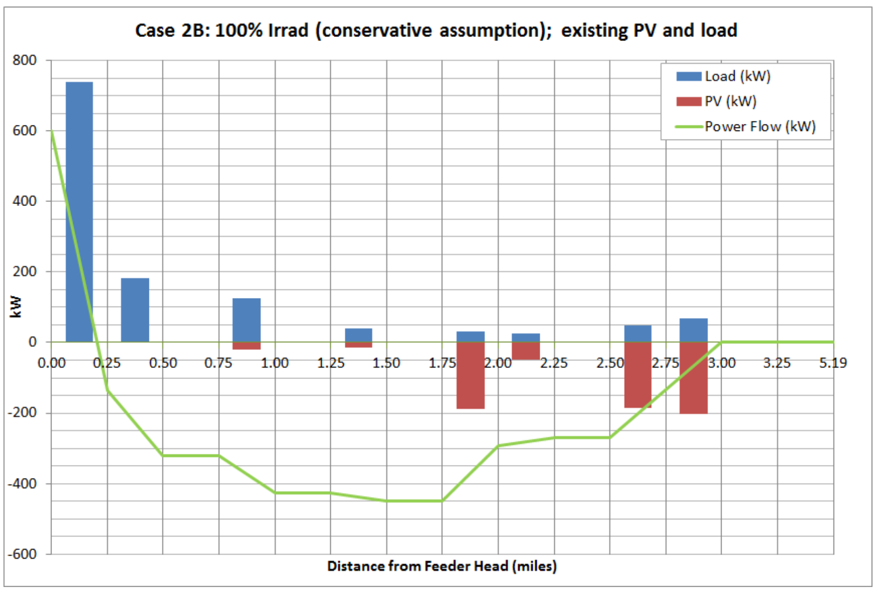


Figure 40: Scenarios 2A and 2B with Existing PV

The feeder analyses to date held the load constant based on the recorded historical load for the minimum daytime peak period with the solar penetrations varying to study the potential impacts on the feeders. Since there is new housing development in the smart home community and existing homes adding more solar, SMUD requested that the AC 1 scenarios be modified for potential increased load and increased solar penetration. Scenarios 3 to 6 evaluate the impacts for load and solar modifications.

Scenario 3 models both the increase in load and solar. The solar penetration is increased by 1.2 MW with 1 MW being installed on AC 1 and 0.2 MW installed on AC 2. The smart home community load is increased by 10% but with the increase in PV, the net smart home load is only increased to 264 kW. Figure 41 displays the Scenario 3 results. As shown by the blue and red bars, the smart home community load increases but not as much as the solar installations, respectively. The maximum power back feed occurs at the 1.75 mile marker from the substation and gradually decreases as the load increases back to the substation.

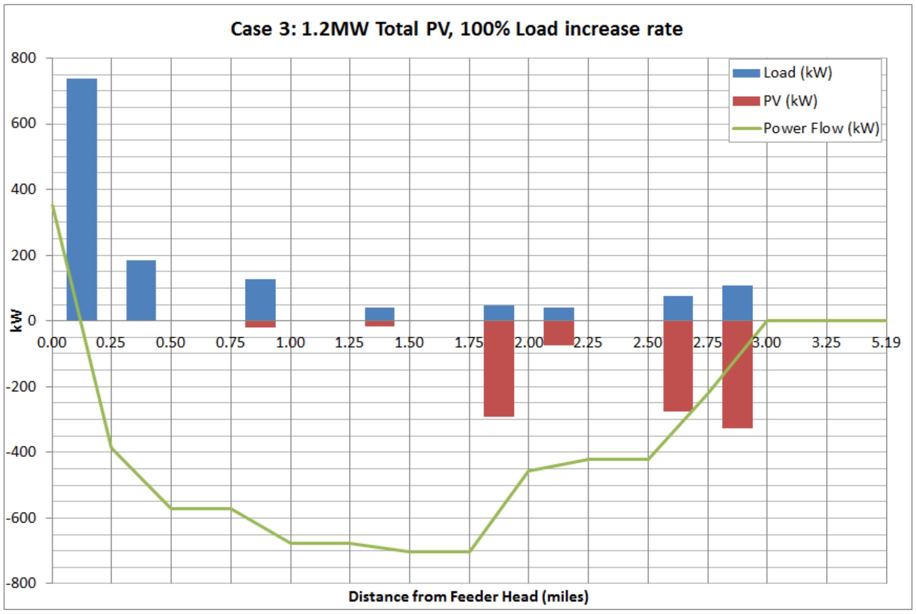


Figure 41: Scenario 3 with 1.2 MW PV increase and 100% load increase

In Figure 42, Scenario 4 represents the same 100% load increase at the smart home community but the PV increased until the net load at the substation bus is 0 MW. At the one point in time, the feeder load is served by the solar generation. On April 29 at 12:50 pm with solar generation at 1000 W/m^2 and with the smart home community load increased by 100%, the installation of 1.4 MW of solar creates a net zero generation output at the substation.

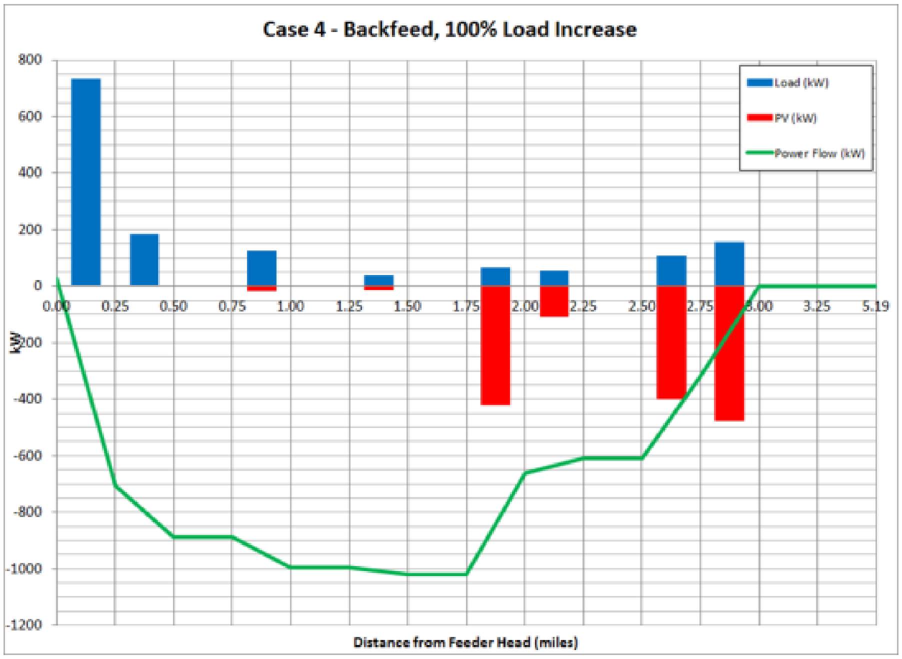


Figure 42: Scenario 4 Load and PV increased until Net zero at Substation

Summary of Analysis

The following figures and table summarize the results of the analysis and include:

- Voltages remain within limits for all scenarios studied
- There will be significant backflow into the substation as solar penetration increases
- High solar penetrations on AC1 will not impact voltages on AC2 and AC3

Figure 43 shows the voltage profile across the feeder for the various scenarios. The increase in solar irradiance and solar penetration increases the voltage at the smart home community above the "no solar" scenario but does not violate the voltage limits.

Table 6 summarizes the maximum backflow on any line segment and the maximum voltage rise at the smart home community interconnection. The backflow is not always the flow into the substation or into any other feeders connected to the same substation bus but the highest backflow on any line segment on the feeder. The backflow will vary between scenarios and solar locations on the feeder.

Two issues in the analysis of AC 1 are the impacts to the power flows and the voltage profiles on AC 2 and AC 3. When there are backflows into the substation bus resulting from high solar penetrations on AC1, will the power flows and voltages be impacted on AC 2 and AC 3? Figure 44 compares the power flows and voltage profiles. The left Figure shows the power flows on the three feeders. AC 3 is a very short line with little load. AC 2 is a long line of more than 9 miles but the majority of the load is located within 1.75 miles of the substation. AC 1 is the feeder with high solar and backfeed toward the substation. The right Figure shows the voltages across the three feeders. The feeder voltages on AC 2 and AC 3 are not impacted by the high solar penetrations on AC 1.

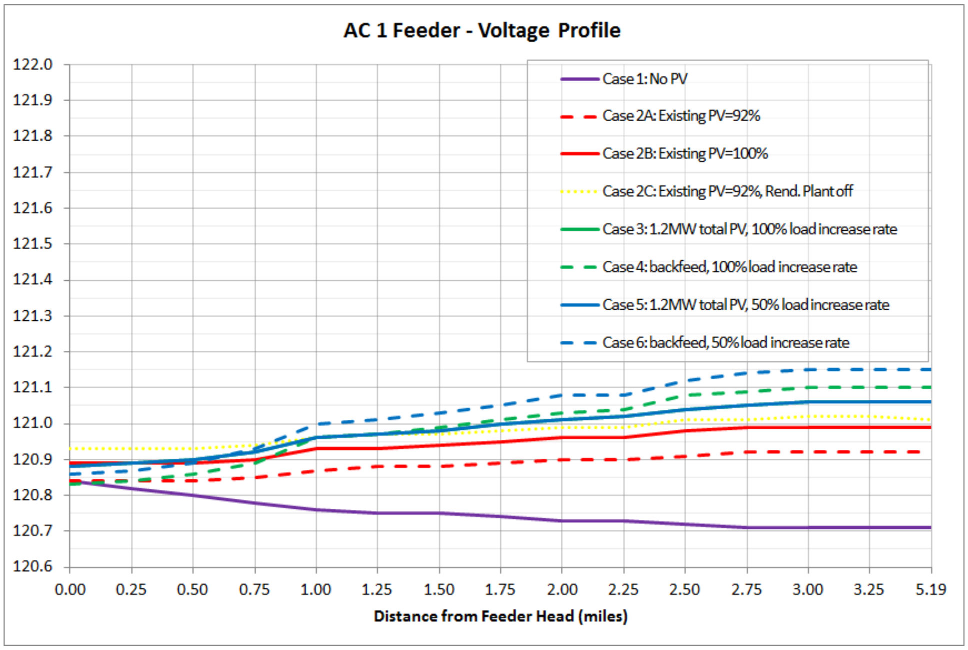
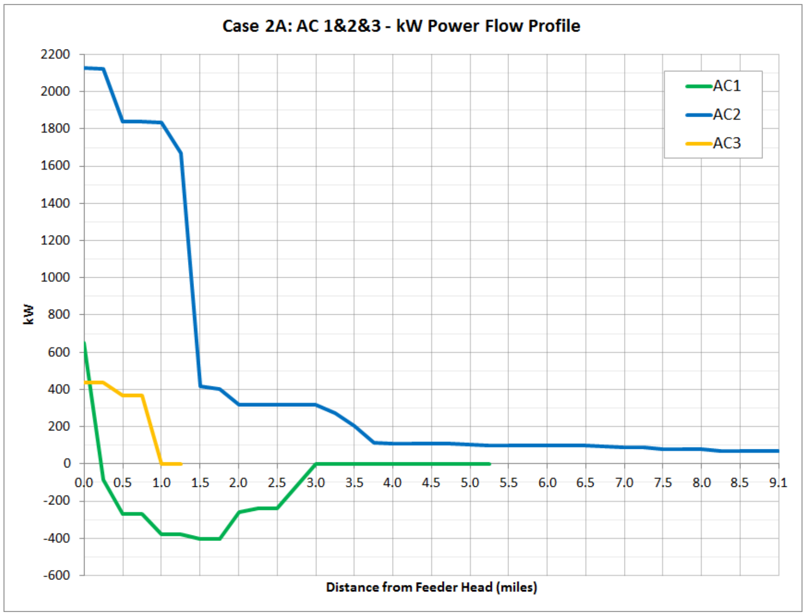


Figure 43: Voltage Profile for all Cases

Case	Reverse Flow kW	Maximum Voltage Rise	
2A	402	0.08	92% irrad. Existing PV and Load
2B	450	0.10	100% irrad. Existing PV and Load
2C	402	0.09	92% irrad. Existing PV and load; rendering plant off
3	702	0.18	1.2 MW PV; Smart home load equal to PV
4	1,020	0.27	PV increased until backfeed occurs
5	751	0.18	Scenario 3 but smart home load only 50% increase
6	1,020	0.29	Scenario 4 but smart home load increase if 50% of PV

Table 6: Summary of Reverse Power Flow and Voltage Changes



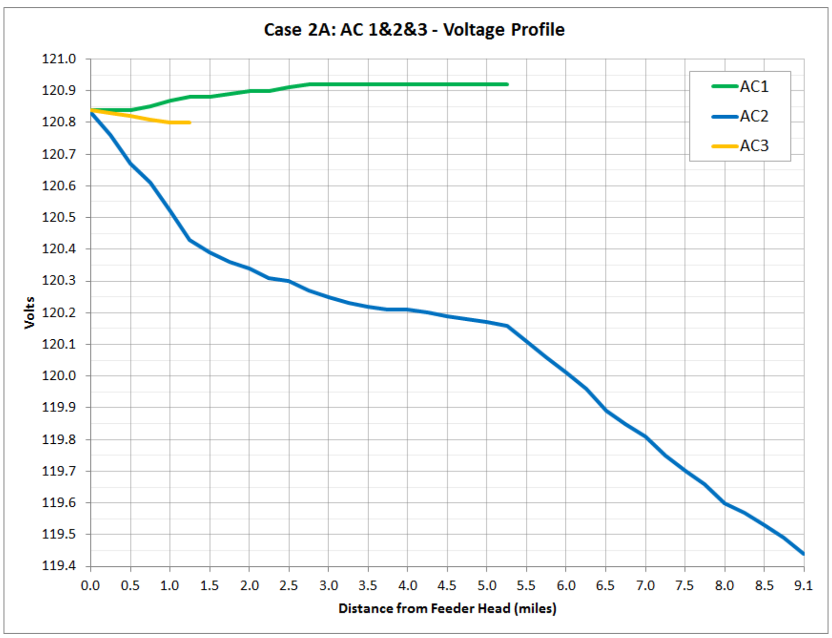


Figure 44: AC1, AC2, and AC3 Power Flow and Voltage Profiles for Scenario 2A

4.1.5 SMUD FEEDER AC 2

The model setup and assumptions are:

- Minimum estimated load at each location outside area already set in the model, therefore historical demand measurements are not used
- Assumed maximum PV generation for each home (Irrad. = 1,000 W/m^2)
- Capacitors switched off
- Tap changer disabled - Feeder head voltage set to 124.5V, irrespective of the feeder loading and PV generation (AC 1 and 3 not modelled). Since second and minute solar data are not available, the tap changer is disabled to simulate the time interval between the PV generation and the time step operation of the tap changer. This allows for a step-by-step observation on the effects of solar changes between tap changer time intervals.
- Some generators modelled as individual (wherever the 240V circuit is modelled) while the others modelled as aggregate and directly connected to 12.47kV circuit
- Conservatively assumed the total of new 853 homes (based on the drawing), each home with a generator, and all generators of the same size
- Load is not explicitly modelled – assumed for each home Pgen>Pload
- Load flow analysis performed for the following two cases:
  - 4kW net output from the generators (would be equivalent to 5kW generator and 1kW load)
  - 6kW net output from the generators (would be equivalent to 7kW generator and 1kW load)

The original AC Substation feeder selected is AC 1 with a solar smart home community located at the end of the feeder. However, as the second year of the CSI RD&D #1 work proceeded, SMUD became aware that the residential community on AC2 is being solicited to have 4 to 6 kW of solar installed on every residential home. With the final build out of this residential community set at over 800 homes, the maximum gross solar installed could be as high as 4.8 MW. During the maximum on-peak daytime hours, the projected net back feed into the feeder could be 3.2 MW, based on an average household usage of 2 kW. During the minimum on-peak daytime load periods, the back feed could be over 4 MW.

SMUD is concerned about the impacts on the feeder and the impacts to neighboring residential home solar inverters. To determine the impacts on every residential household, the entire 800 secondary service drops is modeled in SynerGEE to determine the potential impacts on voltage and determine if there is an upper limit to the amount of solar installed per household without creating voltage problems within the residential community. Figure 45 shows the one-line diagram of AC 2 as modeled in SynerGEE.

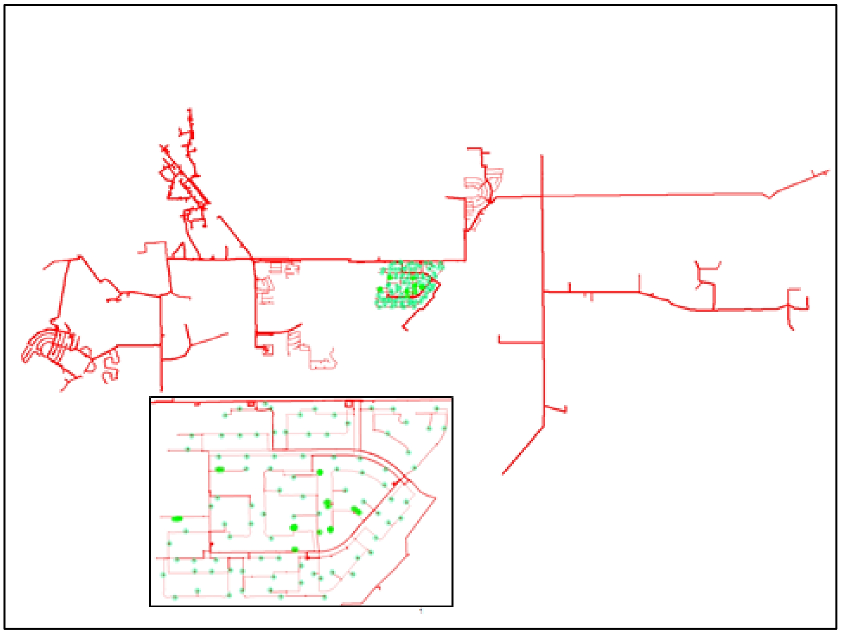


Figure 45: AC2 Feeder SynerGEE Model

Figure 46 shows the residential housing layout. It is recognized that every residential rooftop is not facing the correct direction to maximize solar generation, but the street layout and lot sizes provide valuable information on the number of rooftops that may be facing in the general direction to obtain high solar generation.

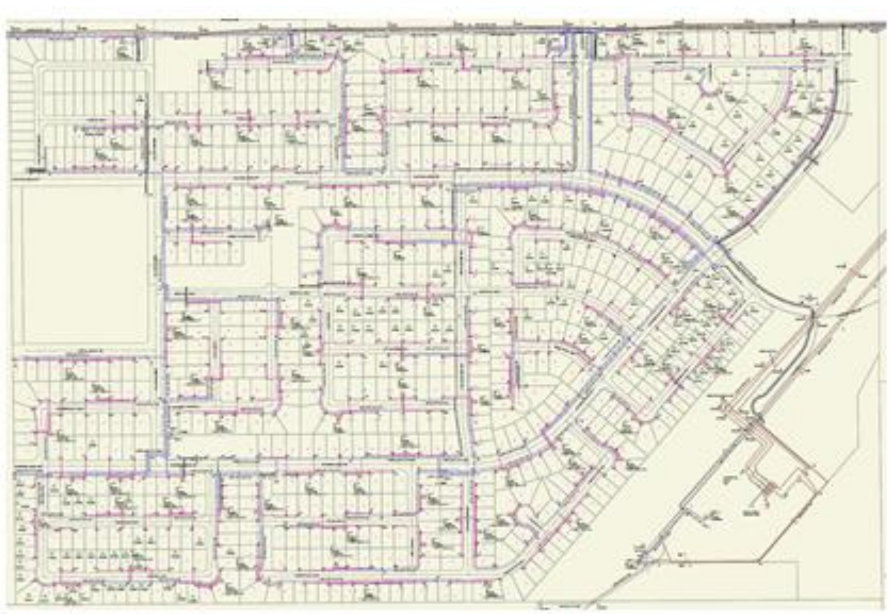


Figure 46: AC Smart Home Community Housing Layout

The modeling problem is the 800 secondary service drops into every home. The length of the service drops varies depending on the location of the ground mounted transformer and the number of homes connected to each transformer. With SMUD staff experience in designing service connections to residential housing communities, they are able to provide an average length for each service drop and the underground cable size. The next problem is modeling 800 secondary service connections in SynerGEE. The key questions are:

- Do all 800 service connection need to be modeled in SynerGEE?
- Could a combination of individual service connections and aggregated load and solar be modeled at the low side of the 12.47/0.240 kV transformer be adequate?
- How many individual service connections are needed to analyze voltage impacts?

The housing layout is divided into sections. The sections having the highest percentage of the homes facing the correct direction have the secondary service connections modeled. For those sections having a lower percentage of rooftops facing the ideal direction, the loads and solar generation are aggregated.

Figure 47 shows a sample layout of the secondary service drop connections. The green dots represent each 12kV transformer. The enlarged area on the Figure shows the secondary lines from a transformer to each of the homes connected to the transformer. Although the secondary lines are a different length but the same cable type, SMUD has provided an average cable to be used for every connection for ease of modeling and calculation of voltages and cable losses.

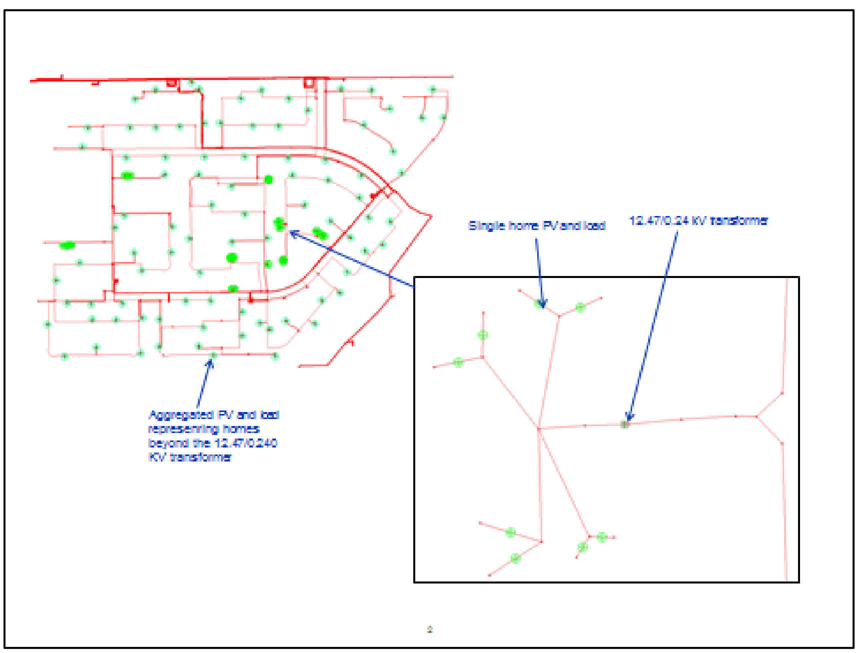


Figure 47: AC2 Smart Home Community

Figure 48 displays the voltages (120 volt base) on the 12 kV side of the transformers for a 4 kW net generation from a 5 kW solar installation on every home. The voltages on the 12 kV side exceed the maximum limit of 126 volts at several locations.

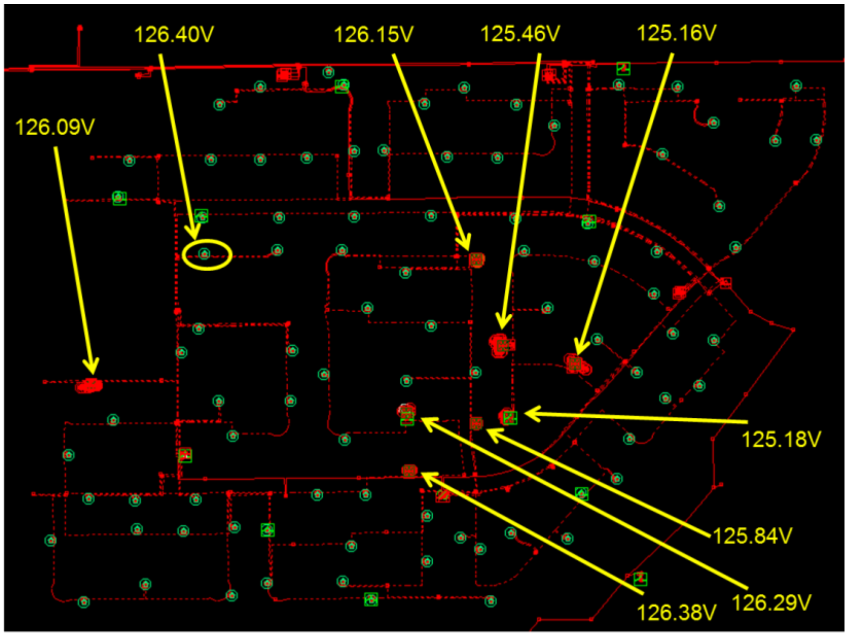


Figure 48: Voltage at the 12.47 kV bus for a net 4 kW PV Installation

Given that the voltages on the 12 kV low-side of the line transformers exceed the maximum voltage limit as shown in the Figure 47, Figure 49 shows the voltages, amps and kW flows on the secondary service drops for one of the transformers. The transformer shown on Figure 47 at the bottom right side of the Figure shows a voltage of 126.38 volts. In Figure 48, each individual residential service drop from this transformer is shown. The blue, green and yellow numbers represent the voltages, current and kW flows, respectively. The highest voltage on the secondary lines is over 127 volts.

Figure 50 shows the voltages on the secondary lines for a 7 kW solar installation on every home or a 6 kW net backflow from each home. The voltages exceed 129 volts. The yellow values show the amount of back flow onto the secondary lines and 12 kV bus for a high solar penetration.

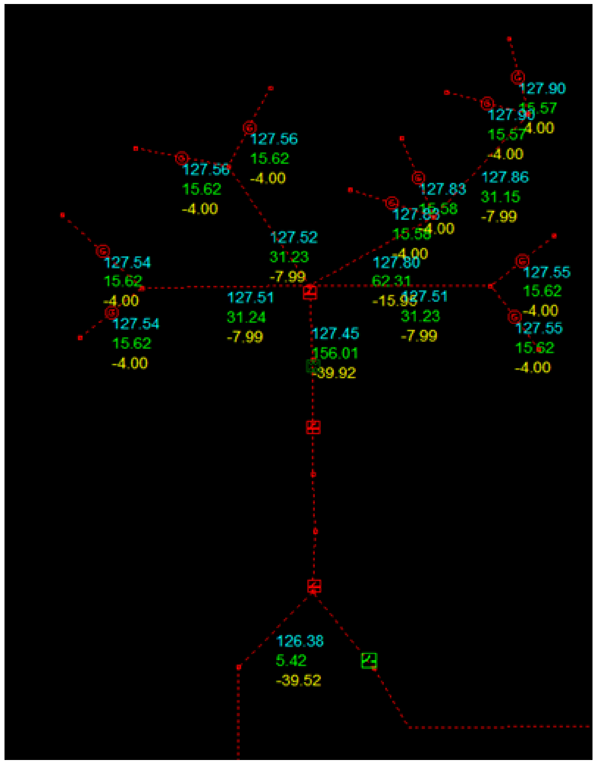


Figure 49: AC2 Voltage, Current and kW Flows for Secondary Service Drop for a net 4 kV Solar Installation

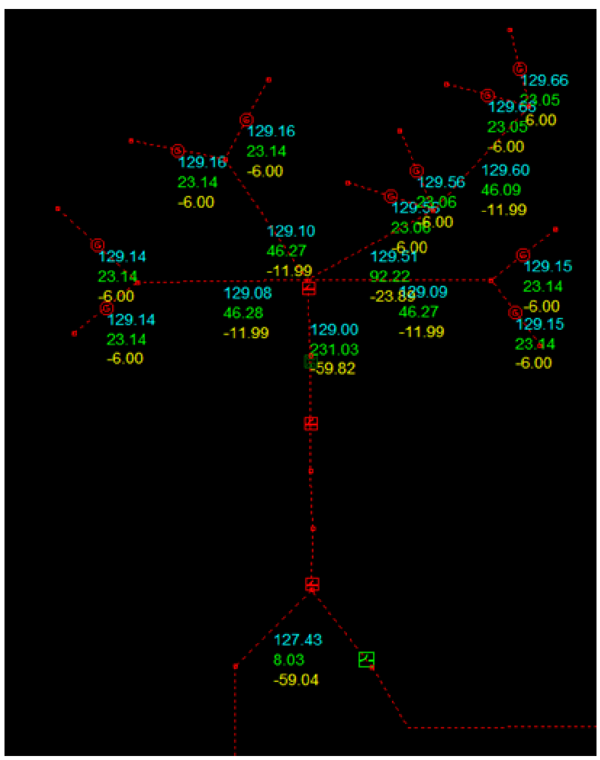


Figure 50: AC2 Voltage, Current, kW flow for a Solar 7 kW Installation

The conclusions of this study are:

- Conservatively assumed the total of 853 homes in the area, each with a generator and all generators of the same size
- With assumed net generation of 4kW the largest voltage in the 12.47kV circuit is found to be 126.40V (Transformer 6-K-3, TX 02000166)
  - Highest voltage in original set of clusters is 126.38V (Transformer 7-K-6, TX 02004517)
- Maximum voltage rise in 4kW case:
  - From feeder head to high voltage side of transformer 1.88V
  - From high voltage side of transformer to generator is 1.52V
  - Total from feeder head to generator 3.40V
  - Corresponding feeder generation exceeds feeder load by ~400kW
- Maximum voltage rise in 6kW case:
  - From feeder head to high voltage side of transformer 2.93V
  - From high voltage side of transformer to generator is 2.23V
  - Total from feeder head to generator 5.16V
  - Corresponding feeder generation exceeds feeder load by ~2000kW

Maximum voltage rise refers to the incremental increase in voltage between different points on the feeder caused by the higher solar penetrations. Voltage rise does not refer to the actual voltage but only the delta voltage.

4.1.6 SMUD L7 Feeder

The model setup and study assumptions are:

- A single 69kV line from L7 sub supplies six distribution substations each with a single 69/12kV transformer
- SynerGEE dataset received for the 69kV circuit only
- Existing connected PV: the customer plant on the 12kV side of (N08) substation transformer with two generators totaling ~5.2MW max
- Study objective: determine MW flow, line loading and voltages in case of minimum daytime load and at different PV penetration levels
- Type of data received: total MW and MVAr demand and 3-ph currents for L7 and NB feeder, total MW output and 3-ph currents for both customer PV generators, all for the month with minimum 69kV circuit load (April); maximum annual load value received for the remaining feeders without telemetry
- S29 and T13 transformers are not connected to L7 in April 2013

- Load calculated based on the demand and PV generation; identified the 2013 L7 min daytime load of 4.6MW on April 14, at 3:48 pm; coincident N08 load is 4.0MW
- Considered prospective PV: at the location of customer plant

The SMUD Substation L7 and 69 kV L7 transmission line serves several residential and commercial areas but its largest load is from the commercial customer labeled as AJ. The majority of the existing solar installations are located within the customer property and potential solar build-out is expected to be within the same area. Figure 51 shows the one line diagram of the 69 kV line.

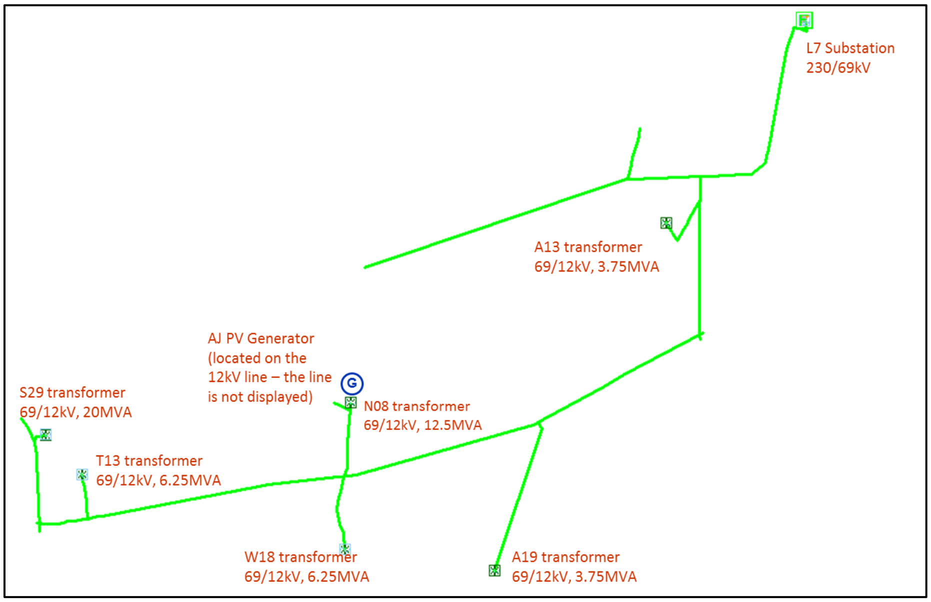


Figure 51: L7 Feeder One Line Diagram

The modeling assumptions for evaluating high solar penetration impacts are:

- SynerGEE model includes L7 69kV circuit with four 69/12kV distribution transformers and their equivalent loads representing A13, A19, W18 and N08, and one aggregate PV generator on the LV side of N08 transformer
- Two remaining distribution transformers, S29 and T13, are disconnected from the model while the 69kV circuit to their HV side is in the model; the rationale behind this configuration is to determine the voltage rise when those two substations (the most distant from the source and relatively near the PV) have minimal load
- Subtransmission voltage (transformer not modelled) set to 1.025pu (72.365kV, 1.0pu~70.6kV) irrespective of the load and PV generation
- All the distribution transformers are without a Load Tap Changer
- Feeder load power factor set based on actual MW & MVAr measurements

The L7 69 kV line serves six distribution substations. The load for April 20, 2013 is 4.6 MW with the gross N08 load at 4.0 MW. However, the substation N08 also has 5.2 MW of solar generation installed. Figure 52 shows the load profile for April 20, 2013 for the L7 line, N08 substation, and the two solar installations within the N08 property. As shown, the N08 substation has negative power flow during the on-peak period.

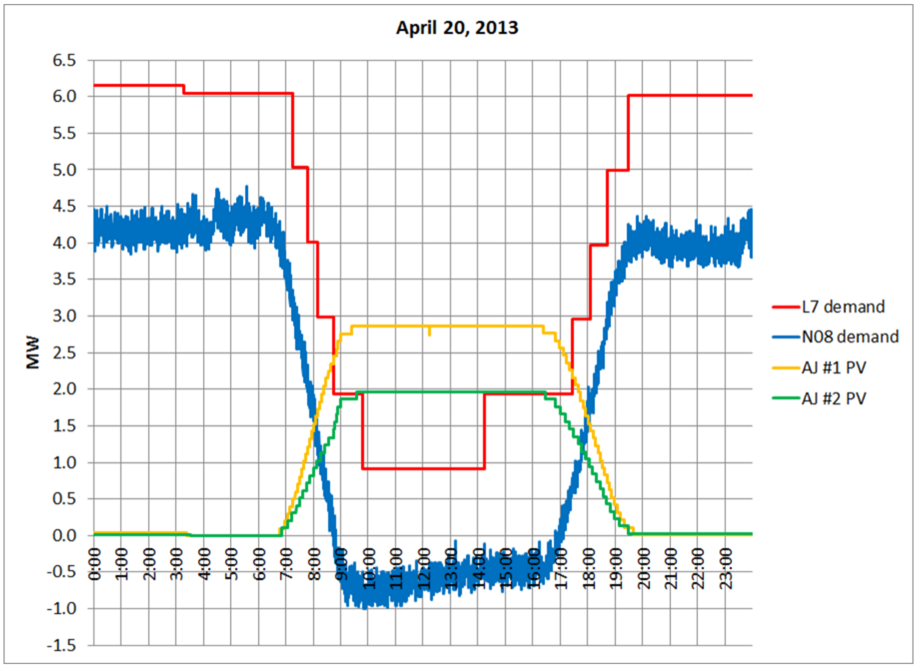


Figure 52: L7 Demand and PV MW Profiles

The power flow analysis simulates the April 13, 2013, as the minimum daytime peak demand for L7. Several cases are developed for various solar penetration levels and N08 demand levels. The four cases are:

- Case 1: N08 4.0MW, 3.7MVAr, PV 0MW
- Case 2A: N08 0MW, 0MVAr, PV 0MW
- Case 2B: N08 0MW, 0MVAr, PV 5MW
- Case 2C: N08 0MW, 0MVAr, PV 10MW

Figure 53, Figure 54, Figure 55, and Figure 56 display the power results for the four cases. The objective of evaluating these cases is to determine the potential impacts to the SMUD 69 kV line if the customer connected to N08 continues to add solar within its property area to serve its peak demand without regard to the potential impacts to the SMUD system under minimum daytime load conditions. As the solar penetration increases, there is higher excess power from N08 which results in negative power flows into the SMUD L7 substation.

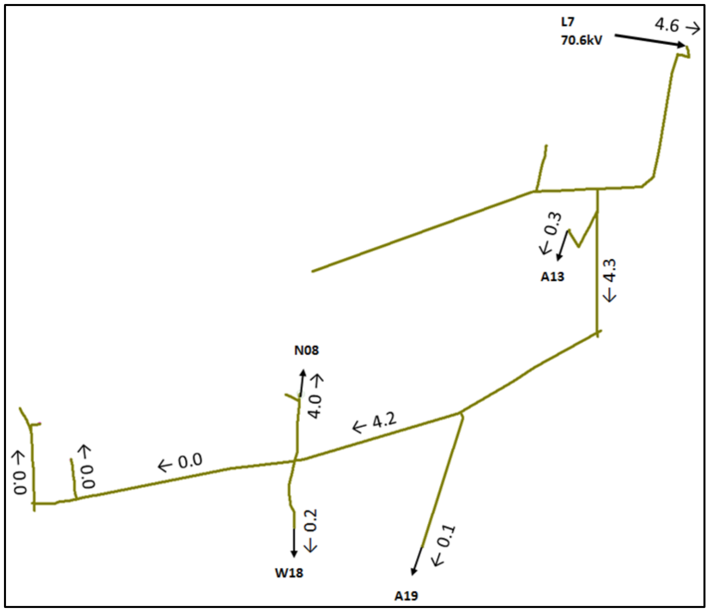


Figure 53: Case 1 Load Flow AJ w/0 MW PV & 4 MW Load

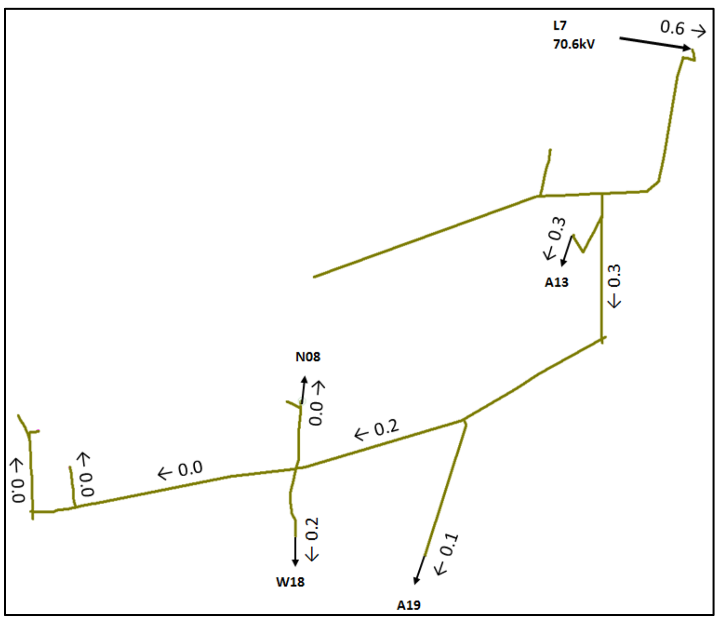


Figure 54: Case 2A Load Flow AJ w/0 MW PV & 0 MW Load

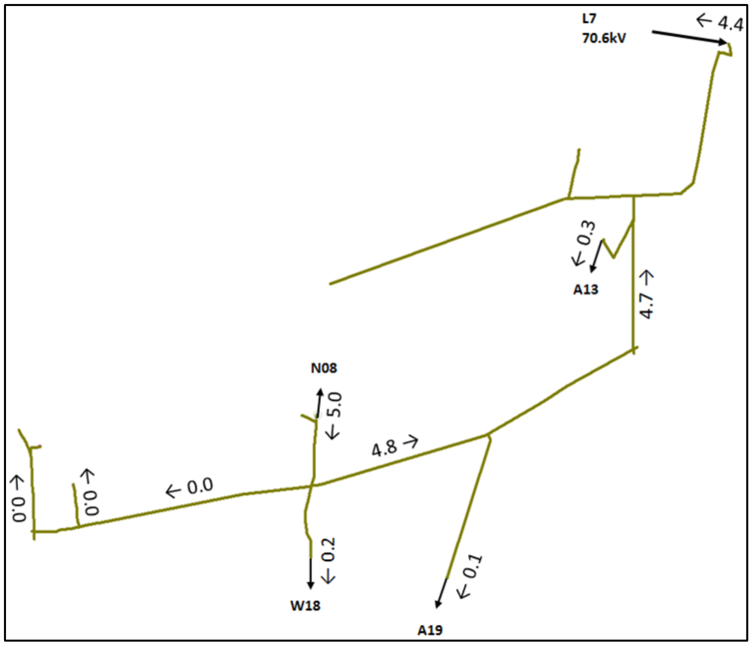


Figure 55: Case 2B AJ Load Flow w/5 MW PV & 0 MW Load

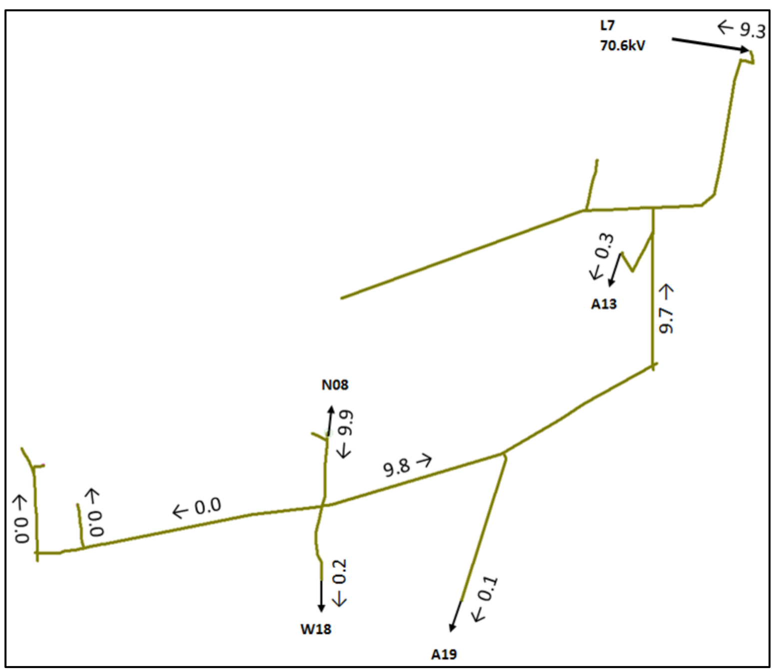


Figure 56: Case 2C AJ Load Flow w/10 MW PV & 0 MW Load

Figure 57, Figure 58, Figure 59, and Figure 60 display the line loading results for the four cases. Since L7 is a 69 kV line, it is not expected to have overloaded line segments. As expected, the heaviest loaded line segment is at the N08 line tap.

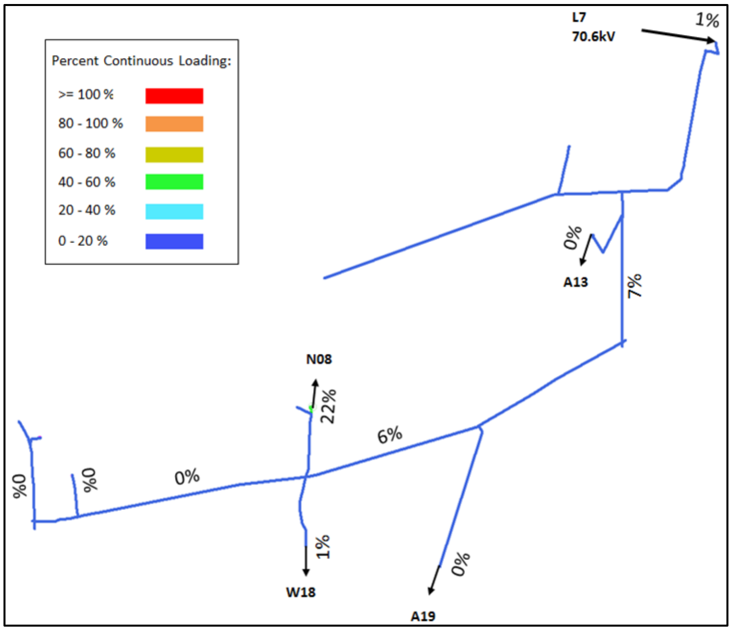


Figure 57: Case 1 Line Loading AJ w/0 PV & 4 MW load

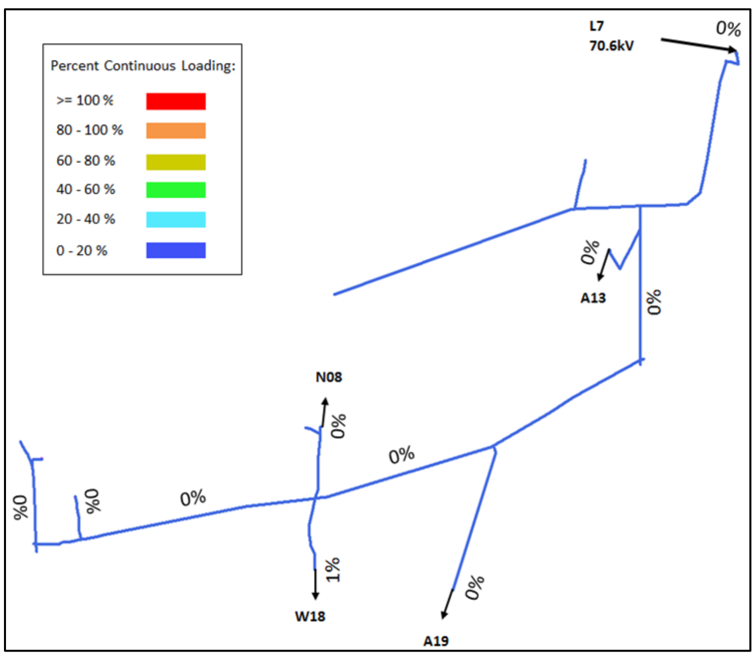


Figure 58: 2A Line Loading AJ w/0 PV & 0 MW Load

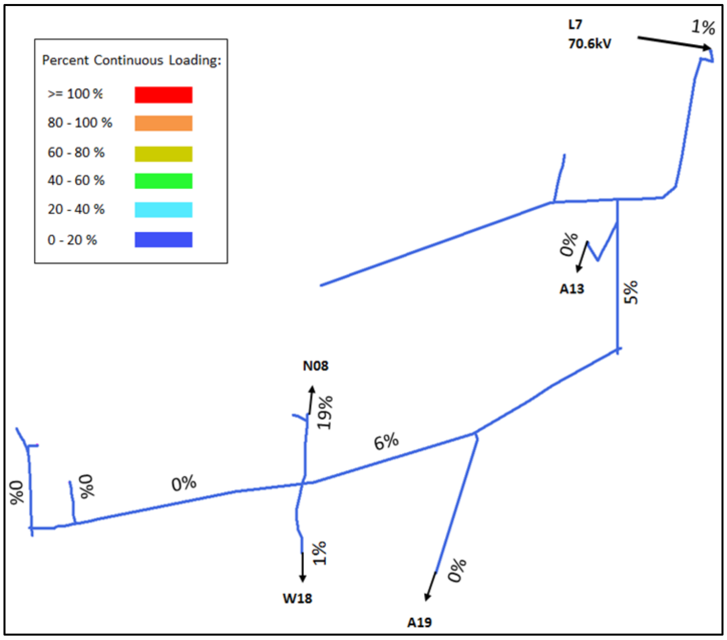


Figure 59: Line Loading AJ w/5 MW PV & 0 MW Load

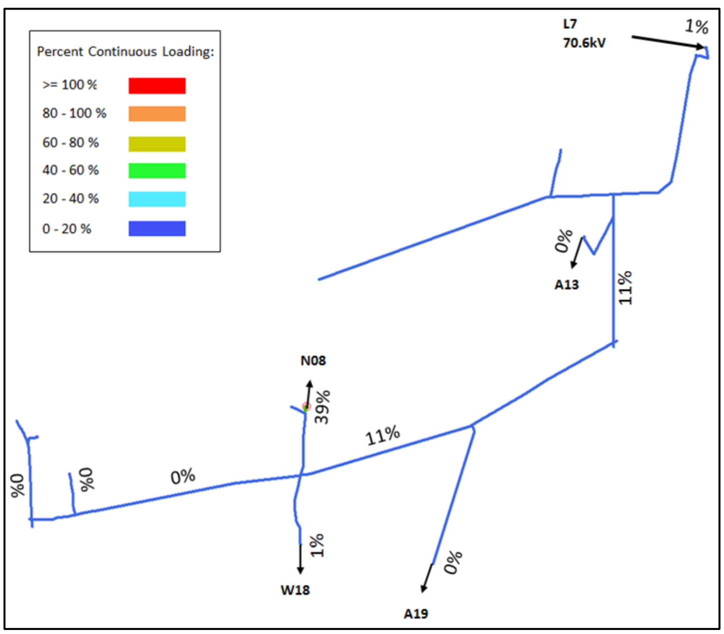


Figure 60: Line Loading AJ w/10 MW PV & 0 MW Load

Figure 61, Figure 62, Figure 63, and Figure 64 display the voltage profiles for the four cases. In all cases, the voltages range from 1.025 to 1.027 in any line segment. The voltages do not vary due to the rating of the 69 kV line and the low flows. It was initially anticipated that L7 would experience high voltages due to the back flow into L7 substation but this does not occur.

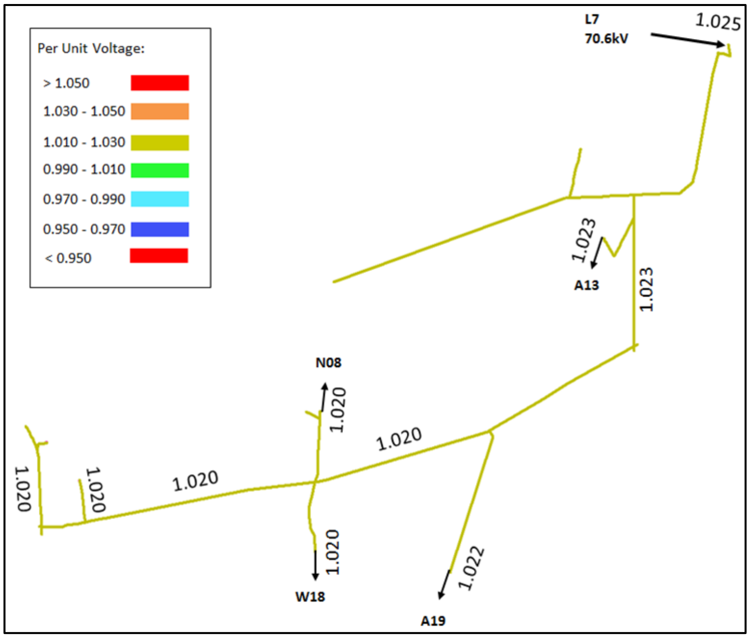


Figure 61: Case 1 Voltages AJ w/0 MW PV & 4 MW Load

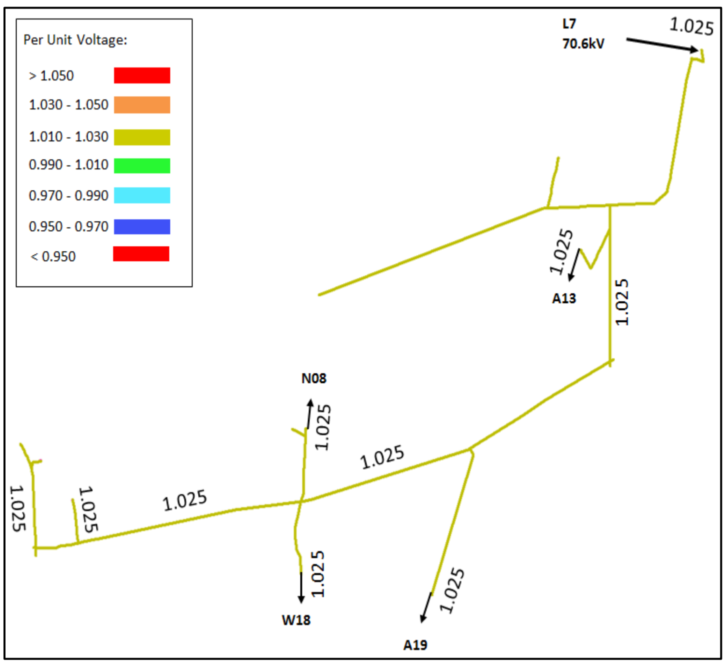


Figure 62: Case 2B Voltages AJ w/0 MW PV & 0 MW Load

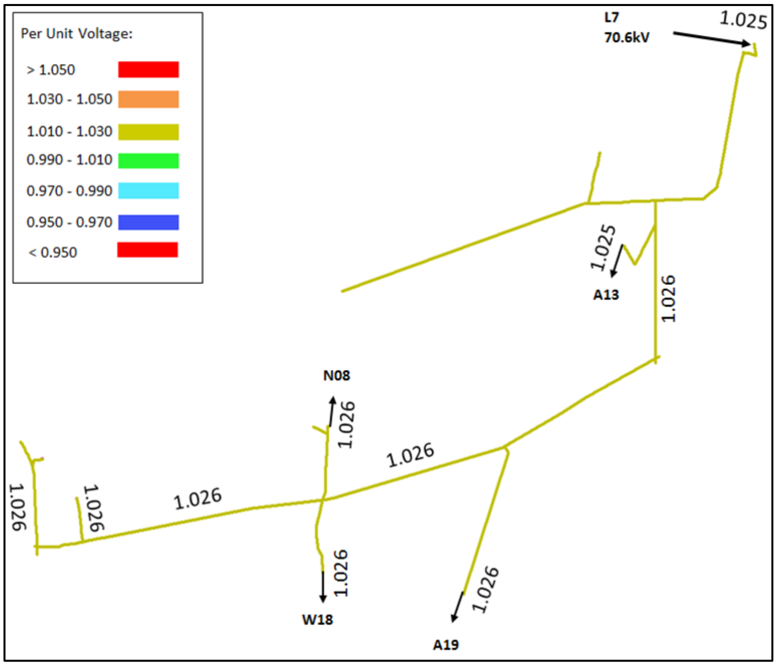


Figure 63: Case 2B AJ w/5 MW PV & 0 MW Load

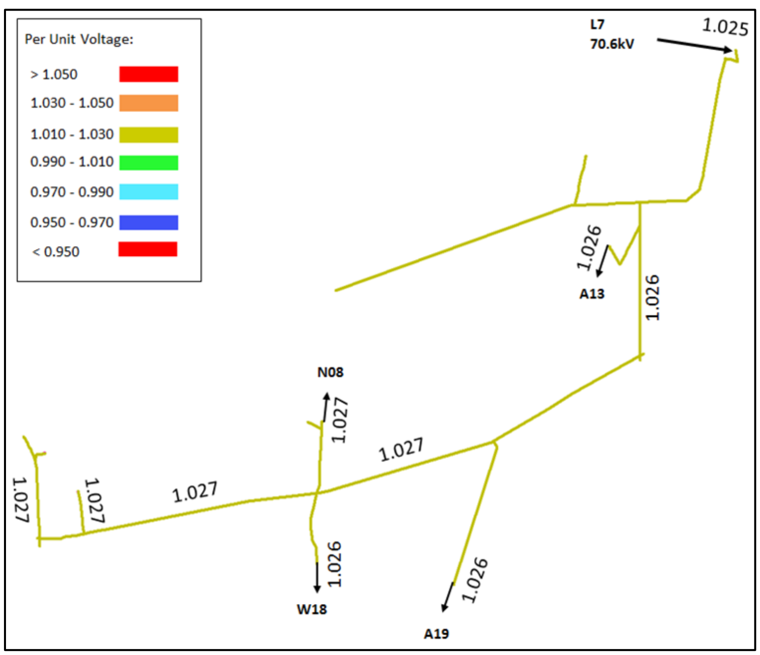


Figure 64: Case 2C AJ w/10 MW PV & 0 MW Load

The summary of the L7 study shows:

- Lake 7 2013 daytime minimum load ~4.6MW on 04/14 at 3:48 pm, corresponding N08 load ~4.0MW
- Circuit to S29 and T13 substations included but those transformers and their loads are switched off

- Simulated power flow scenarios with Lake 7/N08 load of 4.6/4.0MW and 0.6/0.0MW, and three PV generation levels: 0MW, 5MW, and 10MW
- PV added at the location of existing generator
- Practically negligible effect the existing and proposed PV on voltage regulation, and minimal effect on line loading

The solar penetration results for Substation L7. Cases 2A, 2B and 2C have the N08 loads set to 0.0 to determine the potential impacts to the SMUD L7 substation and line if the solar generation is on-line but the load at N08 is off. The results show that the loads of N08 have minimal impact to the line.

Case	L7 Load MW	L7 Load MVAr	N08 Load MW	N08 Load MVAr	N08 PV MW	Max Line Loading	Vmax	Vmin	Vmax-Vmin
1	4.6	3.7	3.7	0.0	0.0	22%	1.025	1.020	0.005
2A	0.6	0.0	0.0	0.0	0.0	1%	1.025	1.025	0.000
2B	0.6	0.0	0.0	0.0	5.0	19%	1.026	1.025	0.001
2C	0.6	0.0	0.0	0.0	10.0	39%	1.027	1.025	0.002

Table 7: Summary of L7 Simulation Results

4.1.7 SMUD RF Feeder

Figure 46 displays the one line diagram for the SMUD RF substation. The RF feeder is a 12 kV line with a large commercial customer. As in the L7 analysis, SMUD is interested in the potential impacts to the SMUD system to the large customer continuing to add solar within its property. There are four capacitor banks located on the RF3 feeder totaling 7.2 MVAr as shown in the figure.

The background information on RF include:

- Single transformer supplies RF1, RF2 and RF3 12kV feeders
- SynerGEE dataset received only for RF3 that has PV
- Four capacitors on the RF3 feeder (7.2MVAr total)
- Existing connected PV: the SM plant on RF3 with three generators totaling ~1.9MW max; Prospective PV considered to be at the same location
- Study objective: determine MW flow, line loading and voltages in case of peak daytime feeder load and at different PV penetration levels
- Type of data received: total MW and MVAr demand and 3-ph currents for each feeder, total MW output and 3-ph currents for each PV generator; all for the month with minimum feeder load (April)
- Load calculated based on the actual demand and PV generation: 2013 RF3 minimum daytime load peak of 2.3MW on April 14, at 1:00 pm (coincident values for RF1 and RF2 are 1.6MW and 1.7MW respectively)

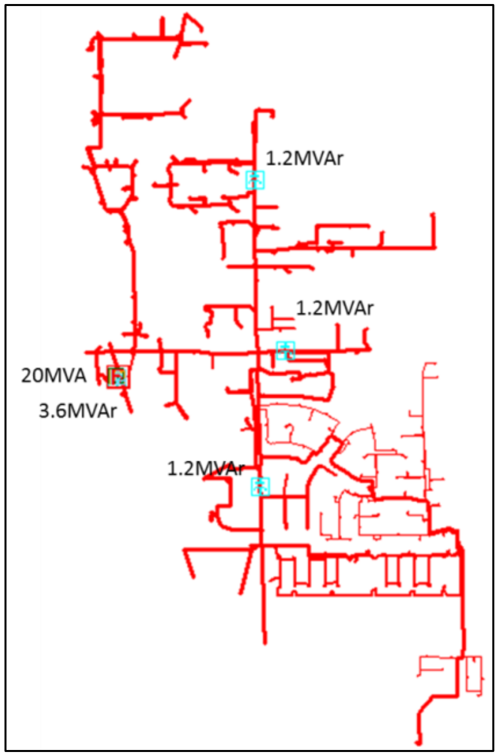


Figure 65: RF One Line Diagram

Figure 66 shows the generation for the three solar generators and the total solar generation for April 23, 2013. The three solar sites have slightly different hours when maximum solar generation occurs and the duration of the solar maximum generation also is different. Figure 65 shows the combined solar generation for the three sites. The existing solar installed at the SM location is 1.9 MW but on April 23, the maximum generation is about 1.5 MW.

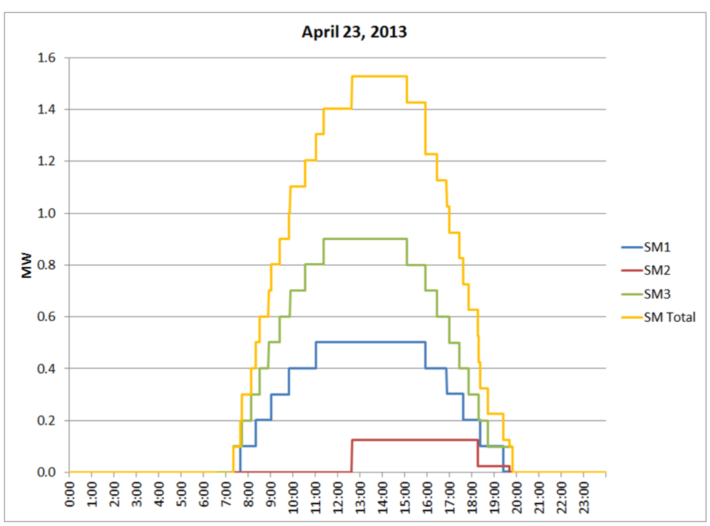


Figure 66: SM PV Generation Profiles

Although there are three 12 kV feeders connected to Substation RF, the analysis concentrates on RF 3 only. As shown on Figure 67, the gross load on RF 3 is higher than the loads on RF1 and RF2. The red line shows the impacts of the solar generation (yellow line) for April 14, 2013.

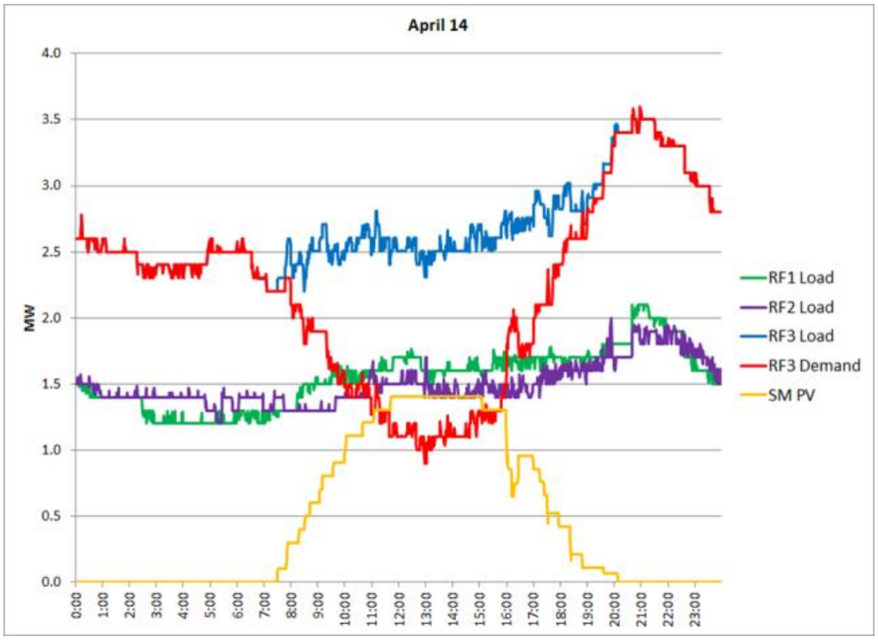


Figure 67: RF 2013 Minimum Daytime Peak Demands

The feeder modeling setup, assumptions and case studies are listed below:

- SynerGEE model includes RF3 feeder with one aggregate PV generator and four capacitors, and equivalent loads representing RF1 & RF2
- Subtransmission voltage on the high side of the transformer set to 1.025pu (72.365kV, 1.0pu~70.6kV) irrespective of the load and PV generation
- Transformer Load Tap Changer setting (1.0pu~12kV): Voltage=1.025pu (12.3kV), R=3, X=0, BW=0.025pu (300V)
- Load power factor set to 0.93
- Capacitors switched off
- Simulated the 2013 daytime minimum load condition for
  - Case 1: zero PV generation (no PV)
  - Case 2: the current peak PV generation (1.9MW)
  - Case 3: the current peak PV generation plus 1MW of additional PV (2.9MW total)

Figure 68, Figure 69, and Figure 70 display the power flow results for the three cases. The power flows are very low for the April 23, 2013, time period.

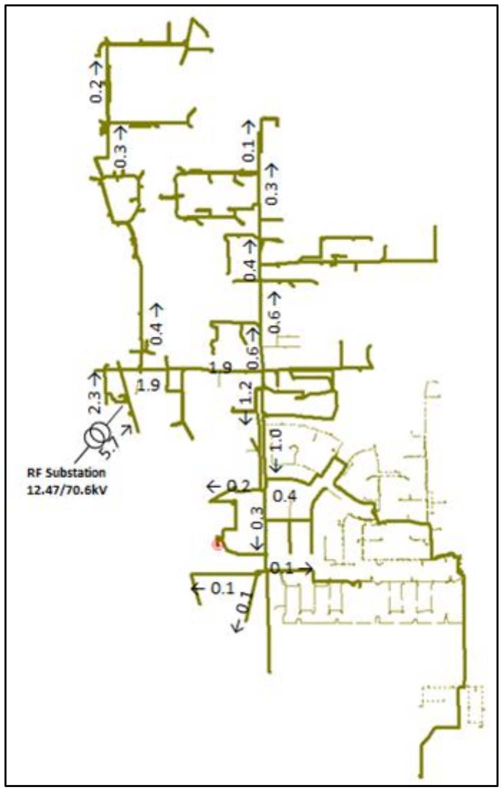


Figure 68: Case 1 RF3 Load Flow w/0 MW PV & 2.3 MW Load

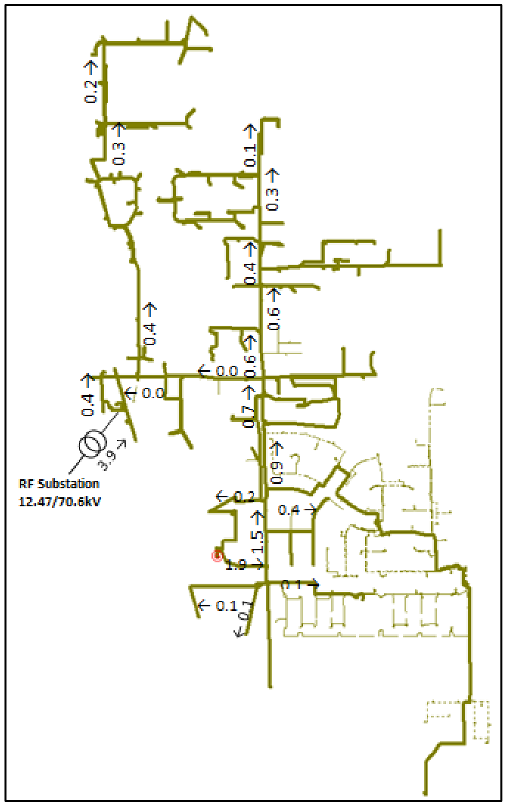


Figure 69: Case 2 RF3 Load Flow w/1.9 MW PV & 2.3 MW Load

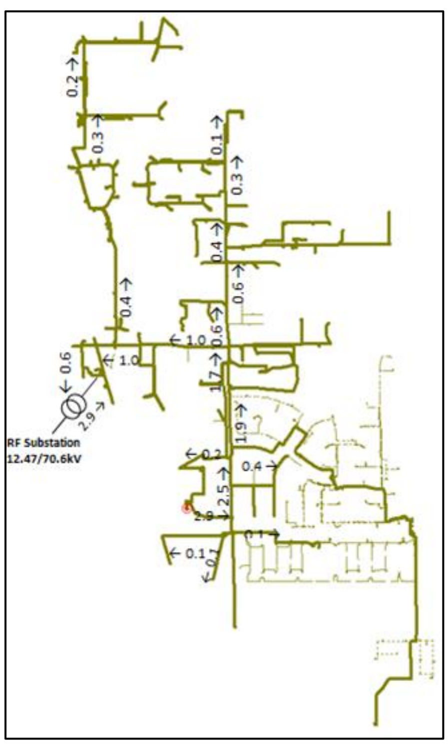


Figure 70: Case 3 Load Flow RF w/2.9 MW PV & 2.3 MW Load

Figure 71, Figure 72, and Figure 73 display the line segment loadings for the three cases. Case 3 shows a line segment loading of 112%. This occurs at the line segment that the solar is being installed. There is probably a low rated line segment at that location that causes the high percentage. Since it occurs for one line segment for one case, the line loading should be ignored for evaluating the solar penetration impacts.

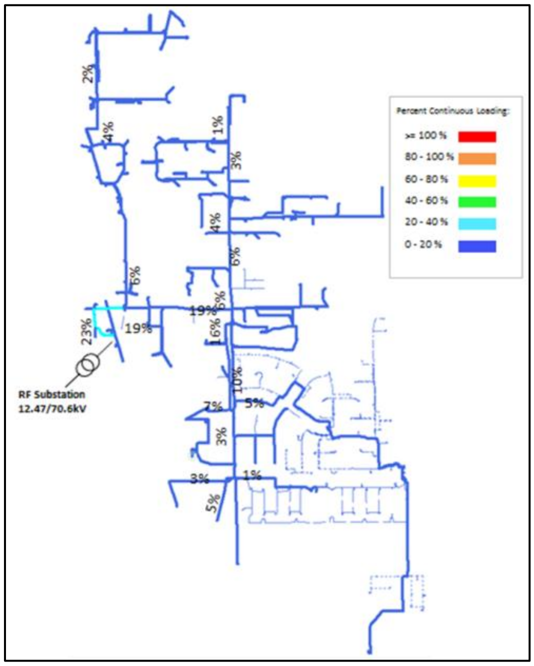


Figure 71: Case 1 Line Loading RF3 w/0 MW PV & 2.3 MW Load

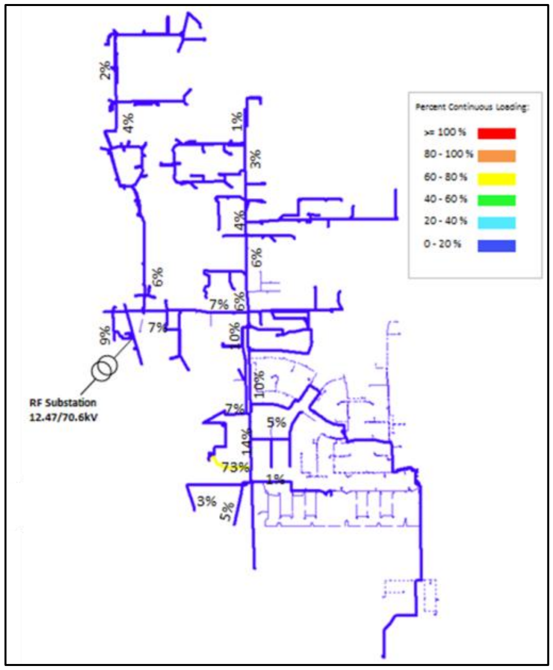


Figure 72: Case 2 Line Loading RF3 w/1.9 MW PV & 2.3 MW Load

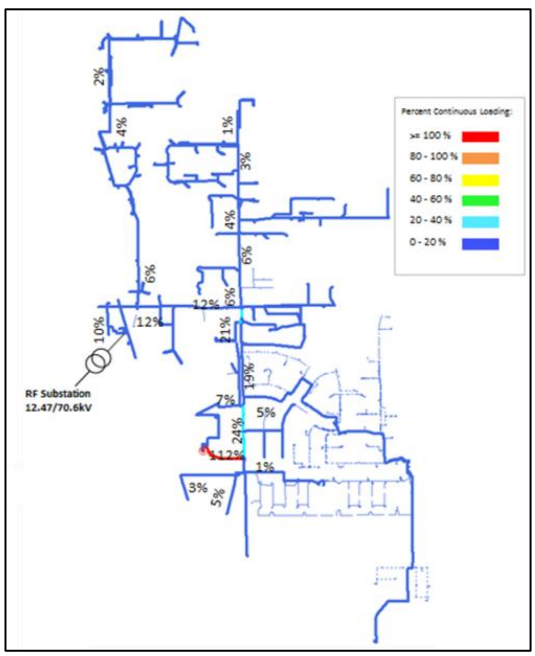


Figure 73: Case 3 Line Loading RF3 w/2.9 MW PV & 2.3 MW Load

Figure 74, Figure 75, and Figure 76 display the voltages on each line segment for the three cases. As stated previously, the substation bus voltage is set to 1.025. The highest line segment voltage occurs on Case 3 in the same line segment that has the high line loading. With 2.9 MW of solar installed on this line segment, the voltage exceeds 1.04.

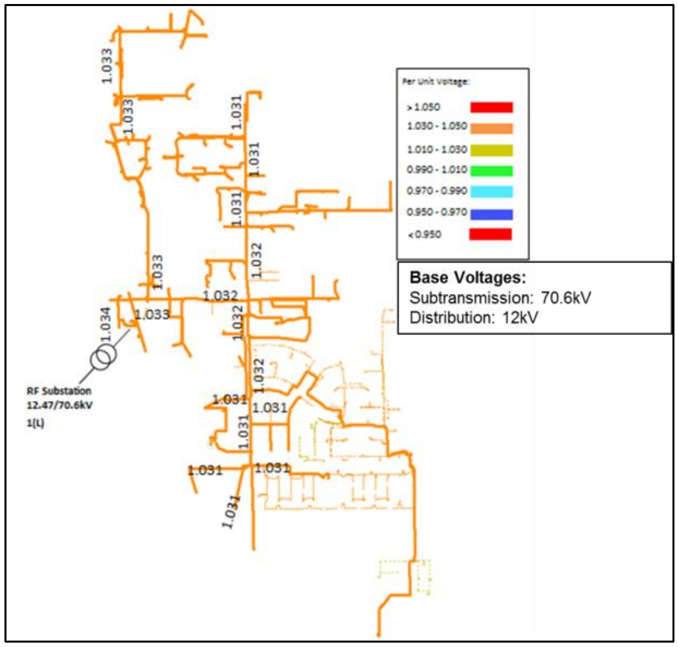


Figure 74: Case 1 Voltages RF w/0 MW PV & 2.3 MW Load

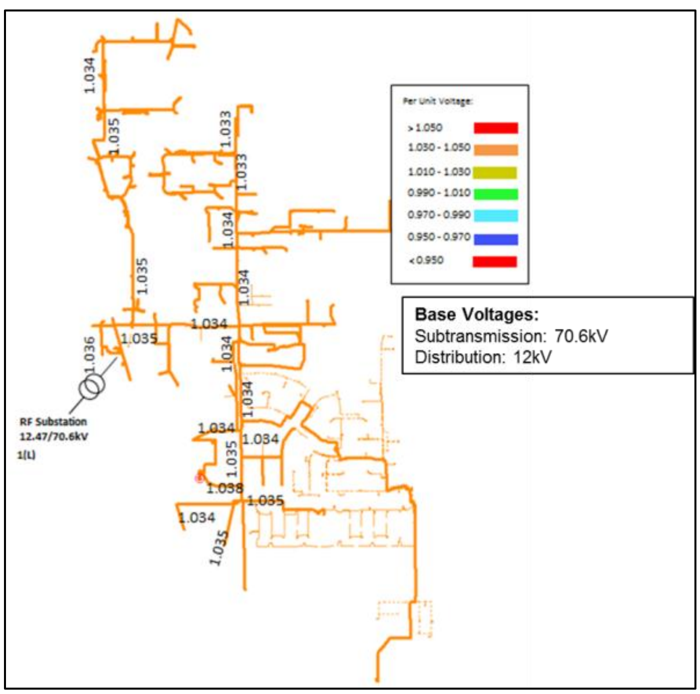


Figure 75: Case 2 Voltages RF3 w/1.9 MW PV & 2.3 MW Load

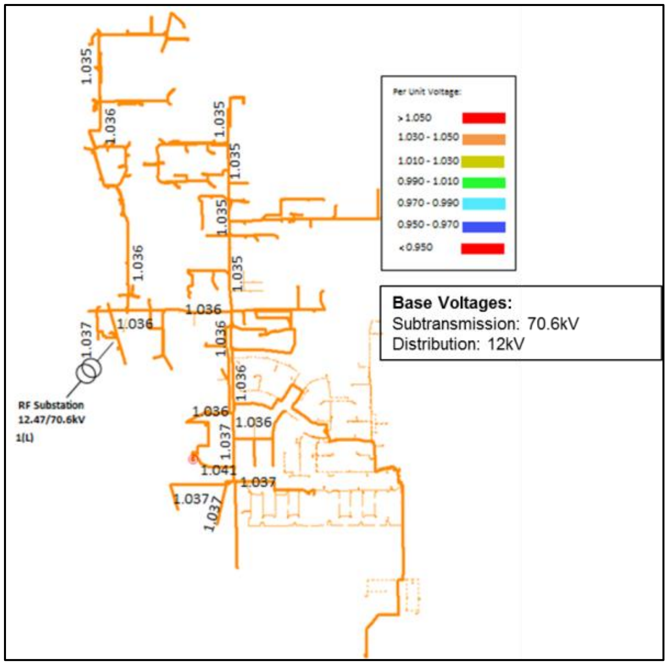


Figure 76: Case 3 Voltages RF3 w/2.9 MW PV & 2.3 MW Load

The conclusions are:

- RF Feeder #3 2013 daytime minimum load ~2.3MW on 04/14 at 1:00 pm, corresponding substation load (RF1+RF2+RF3) ~5.6MW
- Simulated power flow scenarios with substation load of 5.6MW and three PV generation levels: 0MW, 1.9MW, and 2.9MW for solar penetrations of 0%, 34% and 52%, respectively
- PV added at the location of existing generator
- Minimal impact of the existing and proposed PV on line loading and voltage regulation

4.2 HECO Substation and Feeder Analyses

4.2.1 HECO Substation/Feeder/Cluster MI

The MI cluster is defined by the distribution feeders served from MI substation and the two 46 kV lines, KP and KA-MI, that feed the substation transformers. Four feeders are served from the three MI Substation transformers, MI1, MI3, MI4 and MI5. There is another substation on the KP line, MA, and it is included in the cluster evaluation to ensure validation screens can be met. While MA is included, the focus is the MI substation. The existing and potential planned penetration on the distribution feeders is already over 100%. Data are readily available from a number of sources for MI area.

MI substation feeders are a mix of residential and commercial customers distributed along the length of the feeders, allowing investigation of a wide range of PV installation types. At the time of selection, MI1 has the highest planned penetration of PV installed of more than 100% and MI3 has a high number of available sensor locations and GIS data available. Figure 77 illustrates the SynerGEE Electric geographical and model of MI.

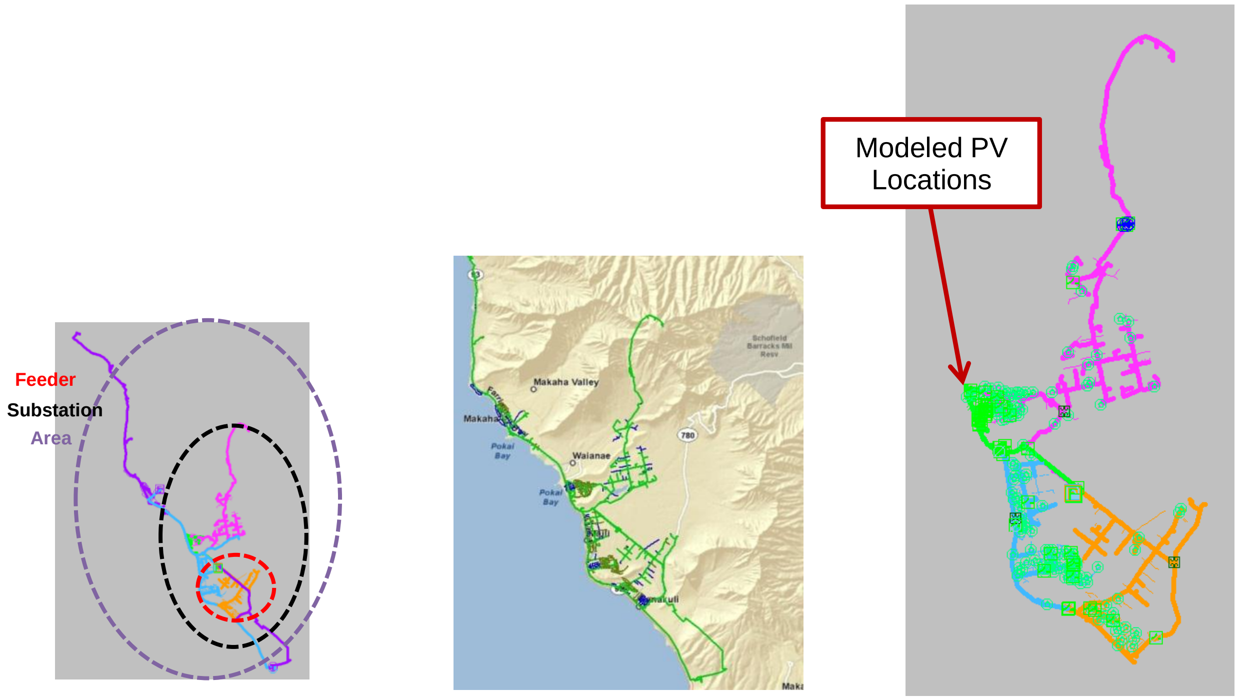


Figure 77: SynerGEE Electric Illustration of the Geographic and Electrical Focal areas for MI Cluster

PV locations are modeled as existing and queued/requested locations on the distribution feeders. Data are extracted from the Substation Load and Capacity Analysis Spreadsheet for 2012, for the non-coincident feeder peak load (KVA). SLACA KVA for each feeder is used as the basis for PV and Load Penetration percentage as shown on Table 8: MI Feeders SLACA, Existing and Planned PV Penetration by feeder and cluster.

Feeder	**SLACA non coincident peak (KVA)**	**NEM (kW)**	**FIT (All Q, kW)**	**Total PV kW (NEM + FIT)**	**NEM % Pen of SLACA**	**FIT % Pen of SLACA**	**Total PV % Pen of SLACA**
MA	5,950	161	475	636	3%	8%	11%
MI 1	3,900	46	300	346	1%	8%	9%
MI 3	3,701	100	4,900	5,000	3%	132%	135%
MI 4	3,159	165	1,650	1,815	5%	52%	57%
MI 5	5,340	265	0	265	5%	0%	5%
Cluster Total	22,050	737	7,325	8,062	3%	33%	37%

Table 8: MI Feeders SLACA, Existing and Planned PV Penetration by feeder and cluster

In Table 8: MI Feeders SLACA, Existing and Planned PV Penetration by feeder and cluster, PV Penetration is shown for both the existing case on the MI Cluster, and the potential or known cases in planning stages. These penetration levels are considered in the analysis. SCADA data are provided for the MI substation feeders, for January to April 2012. Minimum daytime load and peak daytime load are the times of interest based on input from the HECO team, normal interconnection procedures and rule 14H. Data are reviewed and the Minimum and Peak Daytime days are found to be April 25th and January 16th respectively. Figure 78 shows the demand for these times. The minimum daytime day is approximately 50% of the combined SLACA KVA of MI substation while the peak daytime demand is approximately 65% of the combined SLACA KVA demand of MI substation.

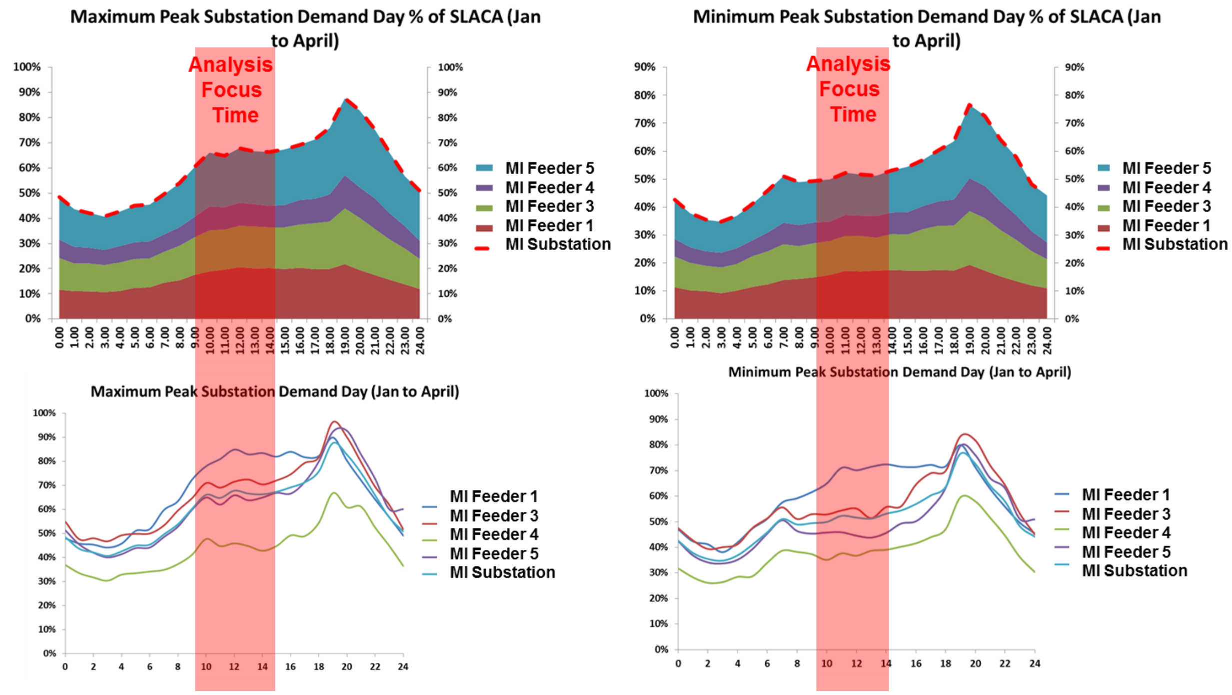


Figure 78: Peak and Minimum Demand Days for MI, extracted from SCADA data for each feeder

In Figure 78, the upper graphs illustrate the combined total demand from SCADA data on both these days while the lower graphs illustrate the individual feeder loads on these selected days. All are plotted as a percentage of SLACA from Table 8: MI Feeders SLACA, Existing and Planned PV Penetration by feeder and cluster.

Three levels of study are completed for the MI cluster; steady state using SynerGEE Electric, Pseudo Steady State or Time-Varying using SynerGEE Electric, and Dynamic using PSLF.

A number of scenarios are selected to determine a range of penetration limits for different analysis types. The analysis focuses on the 10am to 2pm time frame when PV is peaking. For steady state and pseudo steady state, the following combination of demand, PV penetration and output scenarios are selected shown in Figure 79.

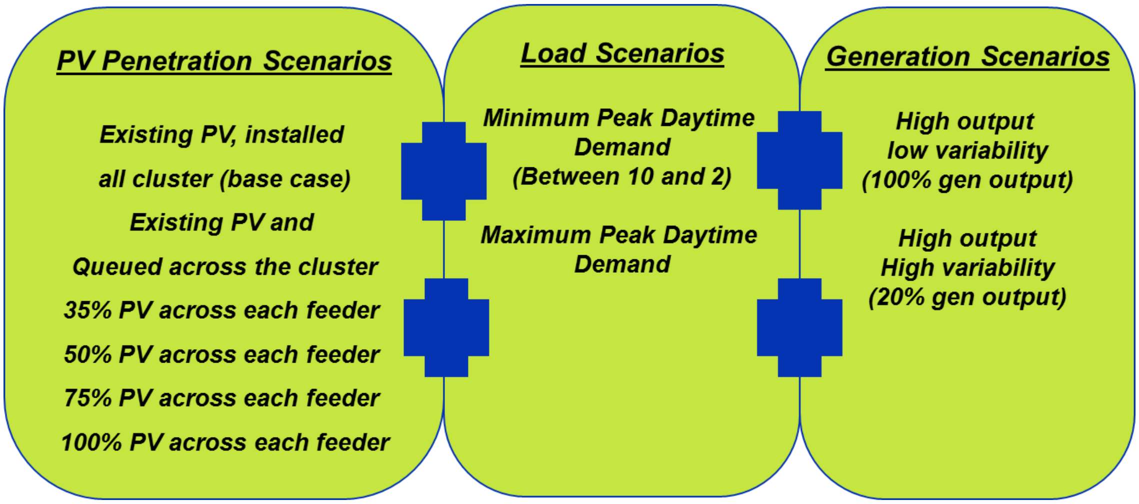


Figure 79: Scenarios for Steady State and Pseudo Steady State Analysis

For simplicity, each scenario is given a case number for steady state analysis as shown in Table 9: Scenario Case Numbers for MI.

Case Number	**PV Scenario**	**Load Scenario**	**Generation Scenario**
Case 1	Existing Confirmed	peak load	capacity gen output
Case 2	Existing Queued	peak load	capacity gen output
Case 3	50% Across the Board	peak load	capacity gen output
Case 4	100% across the board	peak load	capacity gen output
Case 5	Existing Confirmed	peak load	min gen output
Case 6	Existing Queued	peak load	min gen output
Case 7	50% Across the Board	peak load	min gen output
Case 8	100% across the board	peak load	min gen output
Case 9	Existing Confirmed	min load	capacity gen output
Case 10	Existing Queued	min load	capacity gen output
Case 11	50% Across the Board	min load	capacity gen output
Case 12	100% across the board	min load	capacity gen output
Case 13	Existing Confirmed	min load	min gen output
Case 14	Existing Queued	min load	min gen output
Case 15	50% Across the Board	min load	min gen output
Case 16	100% across the board	min load	min gen output
Case 17	35% across the board	peak load	capacity gen output
Case 18	75% across the board	peak load	capacity gen output
Case 19	35% across the board	peak load	min gen output
Case 20	75% across the board	peak load	min gen output
Case 21	35% across the board	min load	capacity gen output
Case 22	75% across the board	min load	capacity gen output
Case 23	35% across the board	min load	min gen output

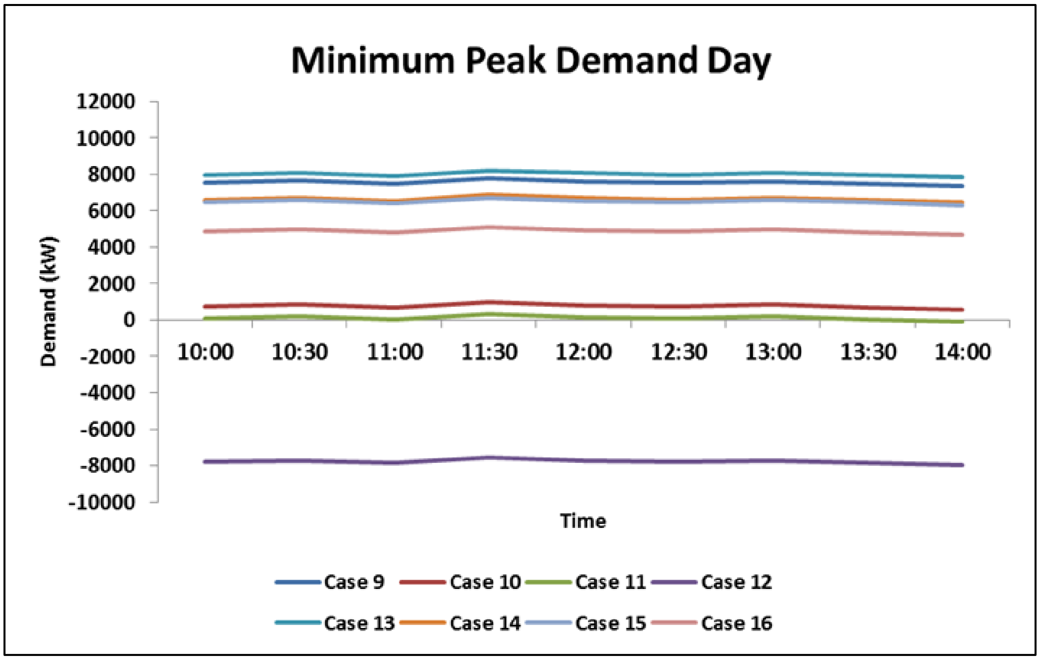
Case Number	PV Scenario	Load Scenario	Generation Scenario
Case 24	75% across the board	min load	min gen output
Case 17	35% across the board	peak load	capacity gen output
Case 18	75% across the board	peak load	capacity gen output
Case 19	35% across the board	peak load	min gen output
Case 20	75% across the board	peak load	min gen output
Case 21	35% across the board	min load	capacity gen output

Table 9: Scenario Case Numbers for MI

Demand profiles for MI Substation are evaluated to determine periods of potential back feed and at what penetrations these may occur as shown in Figure 80. Distribution feeders are traditionally not designed to carry bidirectional power flow, and therefore a number of issues can arise when distributed generation causes reverse flow through the substation transformer. Back feeding occurs when PV generation on the feeder exceeds feeder demand and feeder losses. This can occur at current levels of PV penetration during periods of high PV generation and low load. As PV penetration levels increase, there is risk of back feeding occurring more often at higher loading levels.

Most analog tap changer control systems cannot sense reverse current flow. Ideally in the event of back feed, the line drop compensation portion of the line tap changer turns off. Without the capability to sense reverse current flow, the LTC continues to regulate the 12 kV, resulting in voltage violations from incorrect measured current. Line drop compensation effectively moves the point of feeder regulation based on the setting. It is used where there is significant voltage drop along the length of a feeder so that the end of the feeder does not experience unacceptable steady state voltage under high loading conditions. The limit for back feed is therefore defined in this case on the basis that back feed is physically possible yet undesired at the substation.

Line drop compensation levels out voltages in different load conditions, but can exacerbate voltage impact when combined with other regulation equipment or high penetrations of PV. It therefore must be considered a key part of the analysis and all data on this control system should be collected in future studies.



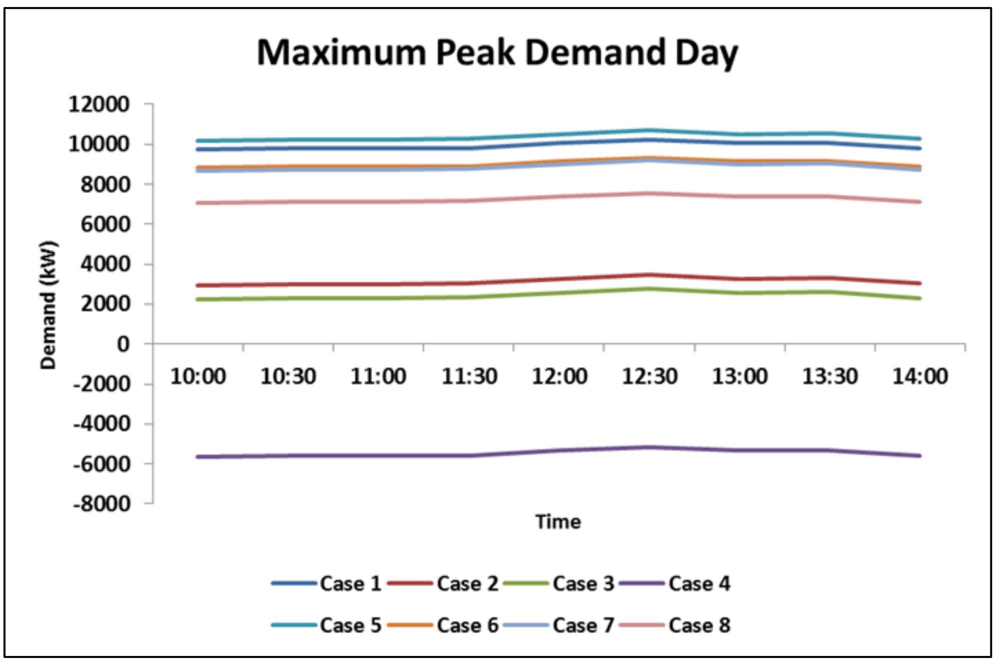


Figure 80: Demand profiles for each case on minimum and peak demand case

The cases at which back feed occurs between the hours of 10 AM and 2 PM are outlined in Table 10: Cases with Back feed conditions in steady state analysis for MI.

Case Number	Item with Back Feed
Case 2	MI XFRMR 2
Case 3	MK XFRMR
Case 4	All
Case 10	MI XFRMR 2
Case 11	MA, MI XFRMR 3
Case 12	All

Table 10: Cases with Back feed conditions in steady state analysis for MI

The load flow and data analysis indicates that back feed can be an issue at a minimum demand of 50% on these transformers.

Thermal loading of a feeder is always considered during the initial phase of standard interconnection studies, but the issue is also highly dependent on location of the PV. Voltage trends are normally considered with a single site installed. Unless this site is greater than the total load on the feeder section, or total feeder capacity, a voltage rise or drop is unlikely, but nonetheless must be considered during interconnect. Multiple PV sites on one feeder may combine to cause voltage issues. Voltage rise can cause equipment damage and protection malfunctions. Utilities consider voltage 5% above nominal a violation. There are two steady state load flow options conducted in this analysis. Losses are deemed to be a minimal impact of PV on this feeder through simulation. Load flow analysis is conducted in SynerGEE Electric and sections and feeders with high voltage conditions are noted. High voltage occurs in case 4 and case 12 on feeder MI 5. Section voltage is plotted over distance for MI 5 which showed indications of an overvoltage condition occurring in very high (100%) penetration scenarios. This is plotted below in Figure 81.

The presence of distributed PV generators in a radial distribution system causes redistribution of the fault current on the feeder circuit. Such redistribution often results in higher current magnitude on the feeder during faults. In case of higher PV penetration, the current may increase considerably, possibly exceeding the ampacity rating of conductors, fuses, breakers, and other equipment. Changes in fault current and direction may also cause a loss of protection coordination between multiple devices. Consequently, the presence of distributed PV generators requires assessments of the impacts on current magnitudes, current direction and protection coordination during faults.

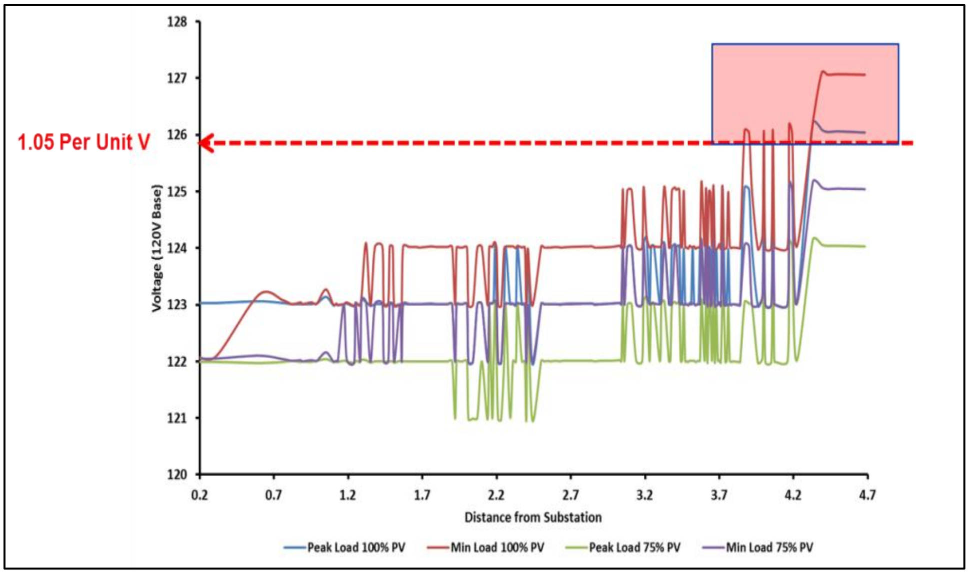


Figure 81: Voltage Rise on MI 5 from Steady State Load Flow Analysis in SynerGEE Electric

This study focuses on the changes in current magnitude along the feeder during fault, caused by PV generators. The study explores a range of penetration levels, different locations for the PV generation, different fault locations, and different limits for fault current contribution from PV inverters. Rule 21 uses a 10% fault current increase as a screening point for detailed analysis. HECO considers 5% to be this administrative screen. IEEE-1547 standard for interconnecting DGs with the utility grid, does not address the issues of fault current and protection on the distribution grid when DGs are present.

A fault is placed on feeders with PV generation (MI 1, 3 4, and 5). A fault is placed on each feeder section and the current to ground is analyzed in the fault analysis in SynerGEE Electric. PV short circuit current contribution is limited to 110% of the rated current for each PV site. The penetration scenarios considered are Existing PV Installed (NEM), Existing PV Queued (NEM + FIT), 50% and 100% PV distributed across the feeders. Peak load is considered but not minimum demand at this stage. The results are plotted and common filters indicated in Figure 82.

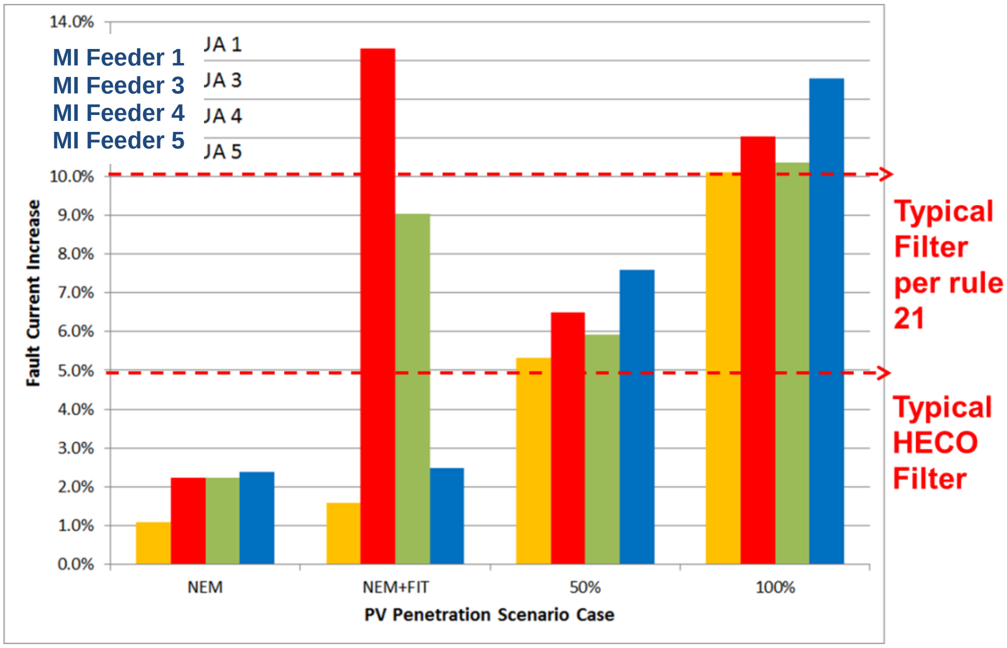
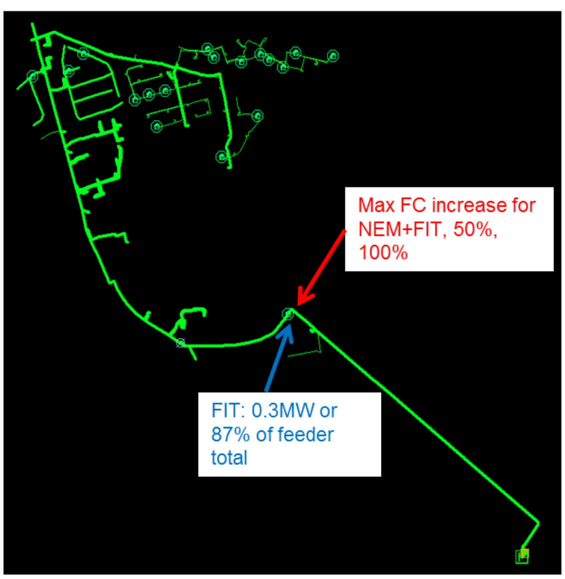


Figure 82: MI fault current analysis results

To reach the 5% increase in fault current for any of the MI feeders, a minimum of 50% PV penetration is installed. A 10% increase in fault current at the point of interconnection is found for all MI feeders, for all penetration levels at 100% of peak demand. The locations with maximum fault current increase on the feeders are plotted for illustrative purposes in Figure 83 and Figure 84.



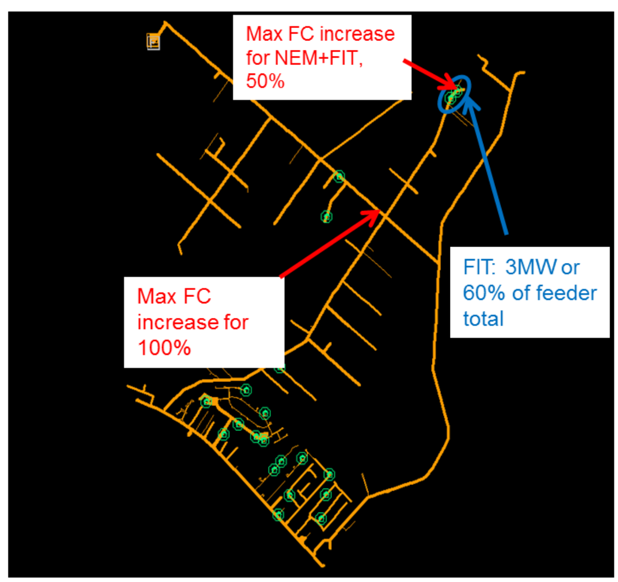


Figure 83: MI 1 and 3 Location with Maximum Fault Current Increase

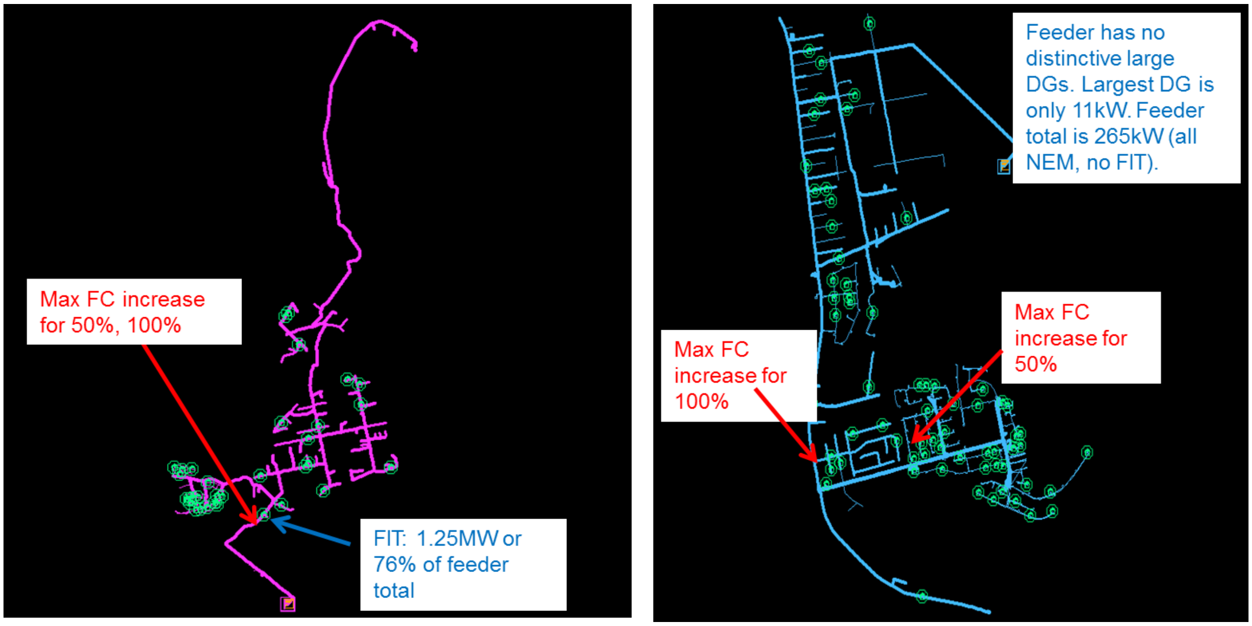


Figure 84: MI 4 and 5 Location with Maximum Fault Current Increase

In summary, with the existing PV (NEM units only), the maximum FC increase is less than 2.5%. With the existing and queued PV (NEM+FIT), the absolute maximum FC increase is around 13% (2.20kA vs. 1.95kA) for a fault that occurs near the 2MW DG on MI 3. At the substation, the current experiences a slight decrease of 0.4% for the same fault event. With the 50% PV penetration level on all four feeders, the maximum FC increase is around 5% to 7%. With the 100% PV penetration level on all four feeders, the maximum FC increase is around 10% to 12%. Typically the highest fault current increase occurs near the largest generator on the feeder.

While the scope of this report is limited to a single feeder, current limiting devices on inverters mean there is likely a very large penetration required of PV to reach 10% fault current impact. Even when 10% increase is reached, it is unlikely the 10% increase impacts co-ordination of existing protection equipment, assuming co-ordination is not impacted by anything else prior to the study. The main concern with this analysis process is how the interconnect study represents the inverter impact.

Tap changer cycling is defined as the transformer tap position increasing or decreasing a number of times, greater than the normal mean number of operations. Normal analysis considers the voltage change at point of interconnection being representative of how the tap changer operates. The full on or full off condition is not representative of normal PV operation, more a continuous variation throughout the daytime period based on irradiance fluctuations. Steady state and dynamic analysis can fully quantify if the on/off behavior is representative, or variation throughout the day should be considered. The load reduction during daytime periods and therefore increased ramp up and down of power supplied by the substation transformer is also considered.

The interaction and coordination between LTC, capacitor, and inverter operations for increased PV penetration and varying operational scenarios are a concern of many system operators, but are not normally considered part of the interconnection study. This issue is generally not a problem for single distribution sites, but when a large cluster or node of sites experiences highly variable cloud cover, there can be increased tap changer operations, and inverter tripping. The voltage and frequency impact of inverter tripping is therefore considered part of the enhanced dynamic analysis.

Tap changers alter the voltage at the substation source to the feeder depending on a measured value of voltage. Effects of tap changer cycling can result in life reduction for the transformer, localized heating and wear on the tap changer parts. Lifetime of mechanical equipment, including tap changers is defined based on number of operations and duty on the contacts. A 40% to 50% decrease in time taken to reach this limitation is therefore considered a major impact for the MI Transformers. The current duty change on contacts is not evaluated in this study. This analysis and comparison to measured data enables a greater understanding of these impacts on a steady state and dynamic level. Switching impacts are decoupled from irradiance fluctuations. Short term and long term impacts are validated using the steady state SynerGEE model of the cluster area.

The benefit of including this analysis in standard interconnects is that tap changing impacts are better quantified, and utilities can plan for an increased equipment replacement schedule or appropriate these costs to the parties responsible. High fidelity irradiance data are necessary to quantify these impacts. Data must be recorded at the fidelity of the shortest time delay of impacted equipment, in this case the LTC with a delay of 20 seconds. To determine if a change in irradiance can change the tap position, the tap position for each penetration is evaluated with the PV at 100% output and 20% output, both at steady state to account for a 20 second delay, as shown in Figure 85.

As shown in Figure 85, as PV penetration increases, the tap changer position decreases. From this basic analysis there is an indication of impact of variability at each penetration. For example at 75% penetration, varying output by one third, effectively output going from 75% penetration to 50% leads to a tap change for MI Transformer 2. This is where the limitation for PV penetration is highlighted. This does not mean the change is absolutely a negative impact, but it does indicate further study should occur of this issue at that penetration level.

Power system stability is the capability of the power system to maintain frequency and voltage. With an increase in distributed resources, there is also an increase in the variability experienced by the normally undisturbed components on a daily basis. A normally undisturbed component means a component not normally subject to dynamic studies, for example an LTC as described previously. Ramping of conventional generators is not traditionally designed for fast ramping to replace variable PV generation. The utility does not control the performance of the PV plant output therefore the operator must ramp conventional generators/utility provided power to meet these variances.

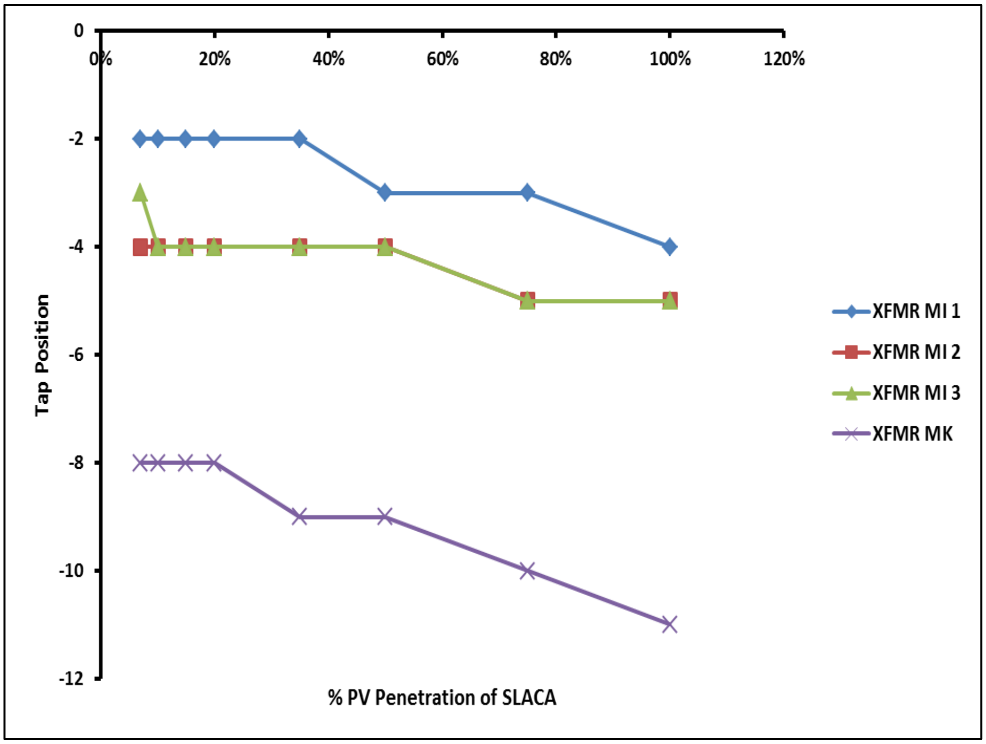


Figure 85: Tap changer position for MI Transformers with varying PV Penetration and Output

Transient and dynamic analyses are not, until recently, considered a regular part of an interconnect study for the distribution system. In an islanded system like Oahu or in a SMUD case where the site is part of a cluster, the issue is more prevalent. The necessity of doing this type of analysis and the methodology of completing this is now considered.

The three phase balanced system model, down to the 12-kV distribution line, is modeled in PSLF. Inverters are modeled at the three phase aggregate level. The inverter models include generic response characteristics and under-over frequency protection.

Assumptions and case set-up for the PSLF MI dynamic model are as follows;

- New generator and load shedding dynamic models from 2013 PSS/E model
- Includes PV as of 5/4/2012 on MI cluster only
- Each PV unit has under/over frequency/voltage trip settings and reclosing ability
- Loading is from old model because aggregated distribution already added
  - 2008 NET FORECAST DAY PK; 1315.0 MW NET/1387.4 MW GROSS
  - LOAD DIST. BASED ON 8/28/06 DAY PK (EOTP LOADS)
- UF trip is at 59.3 Hz for 0.16 seconds, OV trip is at 1.15 Per Unit
- Simulated AES (largest single conventional generator) tripping event at 5 seconds

- Spinning reserve is as specific in the case provided – enough spinning reserve to cover AES only – *no spinning reserve is added, and no generation is turned on after the simulated fault*
- Simulation continues for 10 seconds after AES trip
- PV reclosing time is delayed until after frequency & voltage recovery (system is at steady state)
  - To be updated to 5 minutes per normal IEEE, and future advanced inverter settings studies

An N-1 condition is simulated for the maximum peak demand time, for the following PV penetration scenarios, existing, existing+queued, 35, 50, 75 and 100% distributed PV penetration. Line voltage and frequency for key areas are plotted, and coordination with the existing under frequency load shedding scheme in this area is considered. These results are preliminary and no data are available for validation.

N-1 conditions are generally outside the scope of a distribution interconnection study, but this study seeks to identify analyses not normally considered in high PV scenarios. Standard HECO transmission planning contingencies are considered first i.e. N-1 Scenarios.

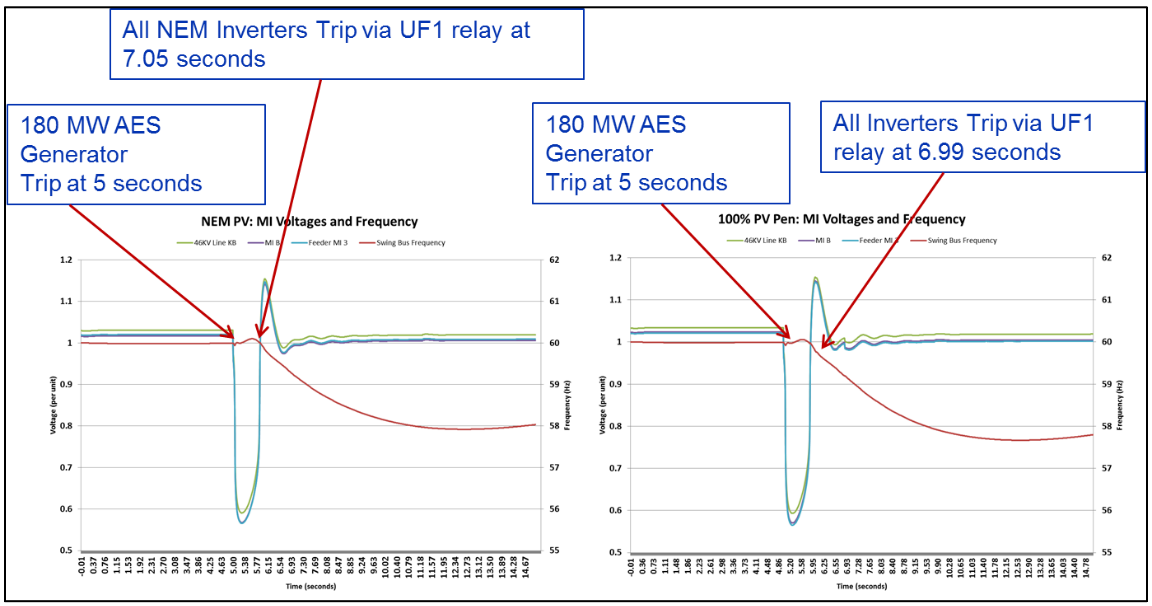


Figure 86: NEM PV and 100% PV Only Plotted

Figure 86 shows what happens at 5 seconds when the N-1 condition is simulated. With the existing PV penetration and measuring voltage on MI 3, the inverters trip in this scenario via the under frequency relays (set as defined in original assumptions). With 100% PV on MI 3 under the same N-1 condition, approximately 10% of the inverters trip via an over voltage relay, before the under frequency event trips the remaining inverters. The over voltage trip occurs 1 second earlier than the under frequency event with the increase in PV penetration. This is not expected to significantly impact the behavior of the system during N-1 conditions, but PV penetration system wide in such an event should be analyzed further, as it is expected in this N-1 condition, there could be a cascading inverter tripping impact over time. Load shedding scheme coordination is evaluated during the N-1 simulation as summarized in Table 11: UFLS load shedding coordination with varying PV Penetrations on MI 3.

PV Scenario	Event Time 1 (seconds after N-1 Event)	MW Shed Event 1	Event Time 2 (seconds after N-1 Event)	MW Shed Event 2	Total MW Shed
NEM	6.26	2.5	13.69	3.4	5.9
NEM + FIT	5.74	2.5	13.55	3.4	5.9
35% Pen	5.75	2.5	13.55	3.4	5.9
50% Pen	5.55	2.5	13.49	3.4	5.9
75% Pen	5.27	2.5	13.41	3.4	5.9
100% Pen	4.92	2.5	13.30	3.4	5.9

Table 11: UFLS load shedding coordination with varying PV Penetrations on MI 3

An increase in distributed PV penetration to 100% does not impact current load shedding schemes during and N-1 Trip in the MI Cluster Area Only. The time of load shedding event after the N-1 event is reduced as penetration increases.

Finally, the N-1 voltage response results during a dynamic analysis are summarized in Table 12: Voltage events with varying PV Penetrations on MI 3 below.

PV Scenario	Number of Inverters	Under Frequency Inverter trip %	UF Approx. Trip Time (Seconds after N-1 Event)	Over Voltage Inverter Trip %	OV Approx. Trip Time (Seconds after N-1 Event)
NEM	46	100%	7.05		
NEM + FIT	54	100%	7.04		
35% Pen	54	100%	7.04		
50% Pen	54	91%	7.02	9%	6.10
75% Pen	54	91%	7.01	9%	6.09
100% Pen	54	91%	6.97	9%	6.07

Table 12: Voltage events with varying PV Penetrations on MI 3

At existing, queued, and 35% penetration levels, there is no change to the inverter trip pattern, all inverters trip on an under frequency signal. At 50% penetration and above, there is an overvoltage condition resulting in 9% of the inverters tripping before the under frequency trip (which trips the rest of the inverters). This is indicative of a rising voltage issue being caused by the cascading inverter issues.

The results of each type and stage of analysis are summarized into combined graphs showing the penetration percentage at which either a technical criteria for HECO is violated on the feeder, transformers or cluster, or there is an indication further study is required. As exact penetrations are not considered in every case, a range of PV penetration as a percentage of SLACA is given in Figure 87 below.

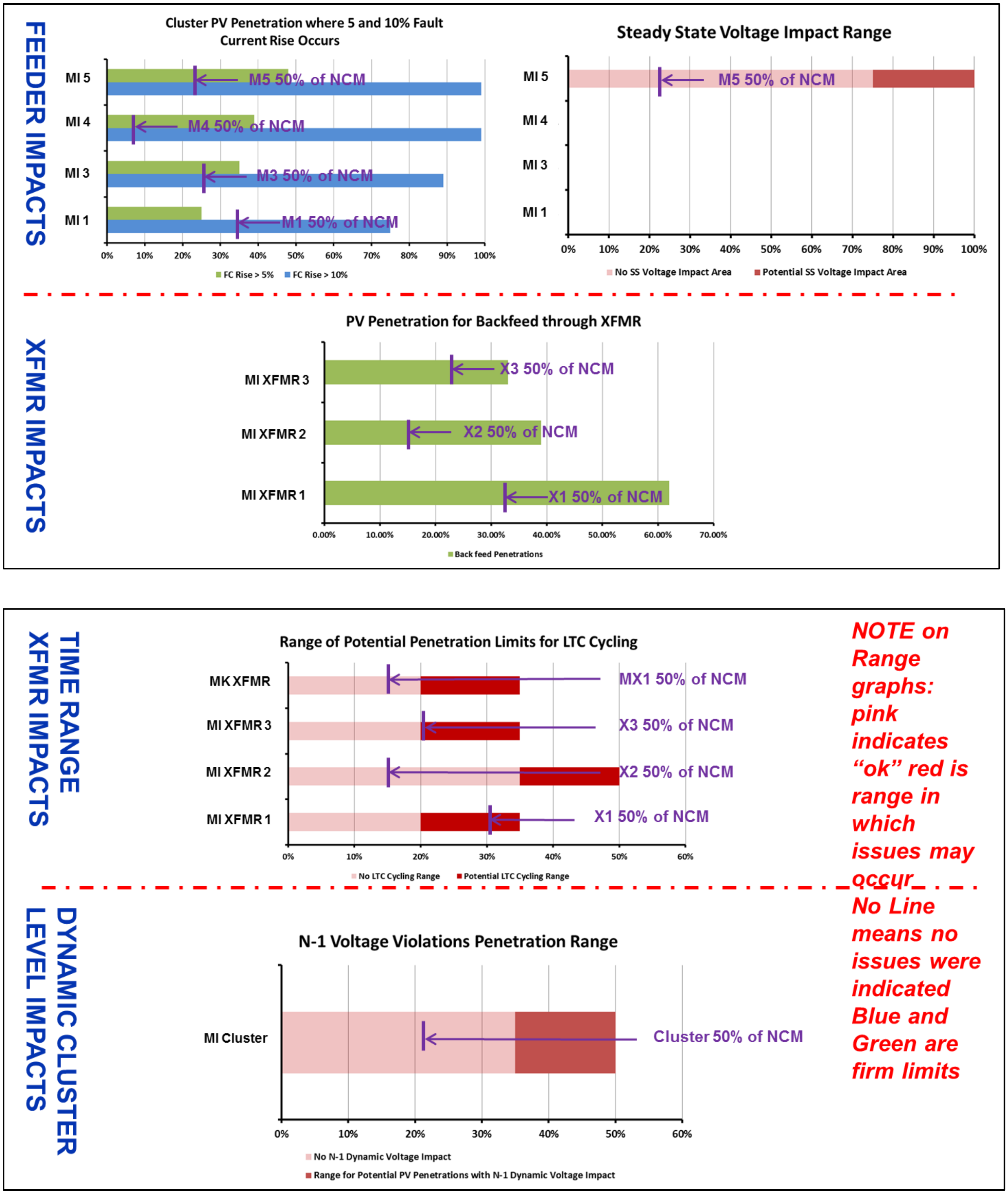


Figure 87: Penetration Percentage for Technical Criteria Violation on Feeder, Transformers or Cluster

The results are then combined and plotted in order of PV% limitation using the lowest limits from the graphs above (Figure 88).

Each bar in Figure 88 represents the lowest percent penetration at which an issue occurred or further investigation is required. Red bars are transformer issues, yellow feeder, and blue cluster level. The X-Axis is percentage penetration of SLACA.

The green line shows where 15% penetration is in comparison to the highlighted issues, the red line is showing 50% of minimum daytime load for each of the respective items, showing a comparison between the two filtering screens commonly used in both Hawaii and California. The first issues shown are potential for LTC cycling and all occurred above 15% of feeder peak load penetration but below 50% of minimum daytime load. Two different feeder loads are used to test the solar penetration impacts. The first is the 15% of feeder peak load that can occur at any time of the day. The second is the 50% of the minimum daytime load to more closely match minimum feeder load to maximum solar generation.

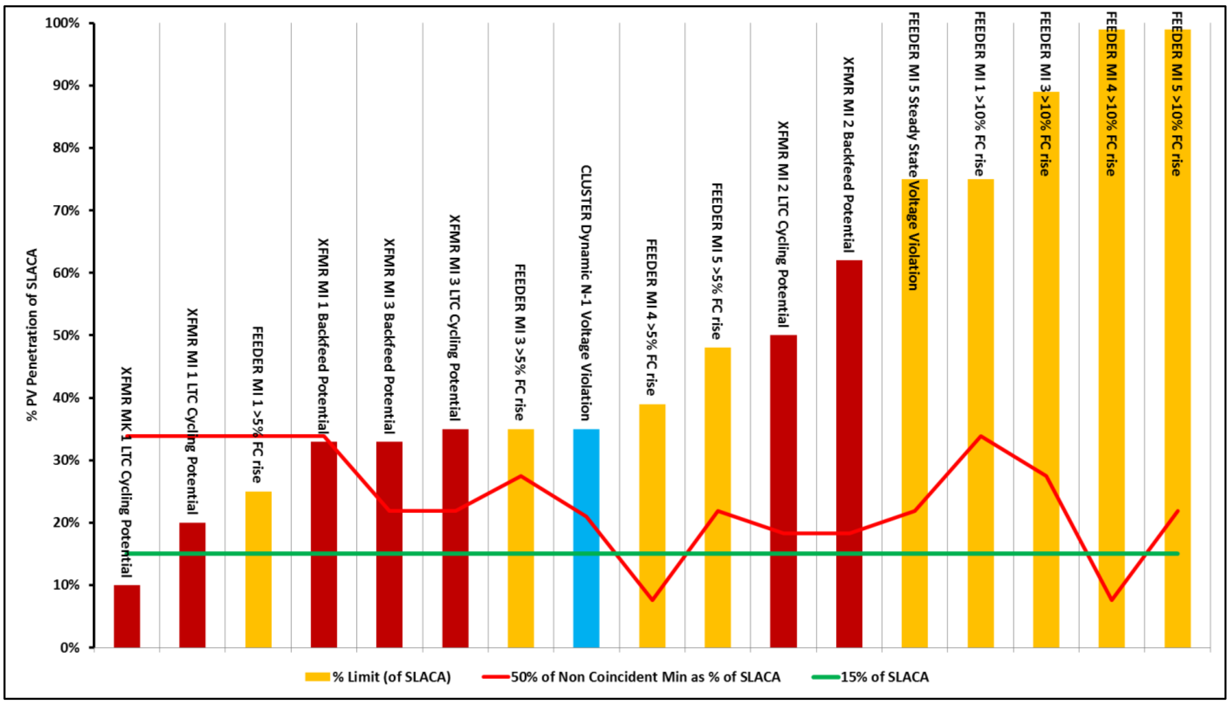


Figure 88: Combined Penetration Limits Graph for MI Feeders, Transformers, and Cluster

4.2.2 HELCO ML Substation

ML substation is selected by HELCO for detailed high PV penetration analysis and is located on the Big Island of Hawaii. ML substation supplies 4 distribution feeders, ML11, 12, 13 and 14. ML12 is a redundant feeder. The ML feeders supply mainly commercial load, hotel complexes and associated surrounding demands.

No distribution model exists for the ML substation. Data are received for the substation in hard copy switching diagram format. The hard copy is a background, and the line topology is traced to enter into SynerGEE Electric. Line construction and type is entered manually from the switching diagram. Other information is provided on PV locations, PV inverter and panel type for existing locations, switch location and type, connected distribution transformers (used for load allocation), and other protection and switchgear information. Substation transformer datasheets are also provided. The ML Feeders modeled in SynerGEE Electric is shown in Figure 89.

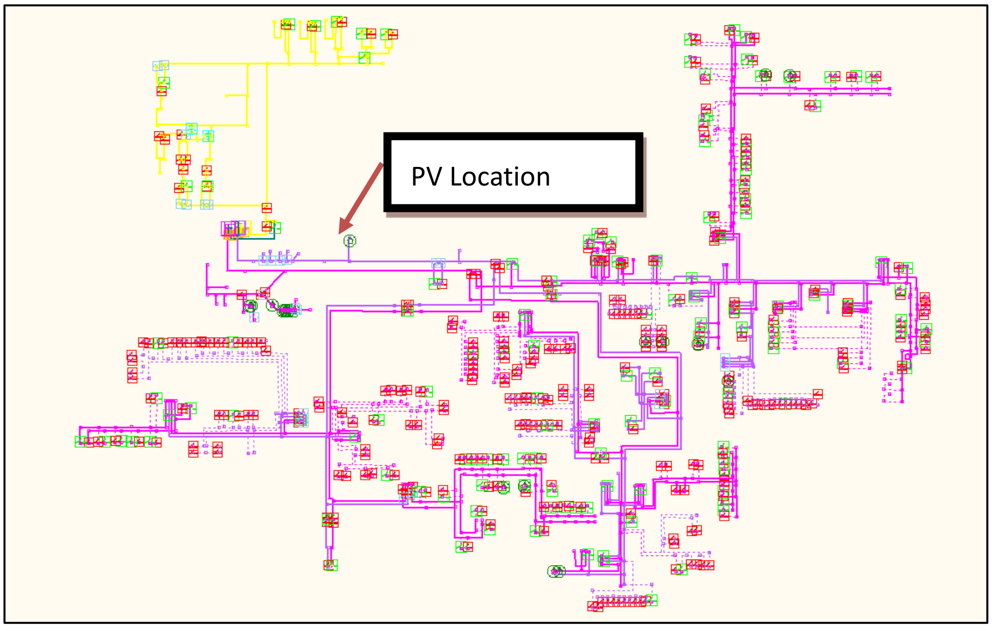


Figure 89: ML SynerGEE Model

Load information for peak and minimum day demands are provided. Load is allocated to the feeder on an hourly basis as shown in Figure 90. Load profiles are provided specifically for large hotel loads, and allocated separately to the feeder. No measured PV data are available.

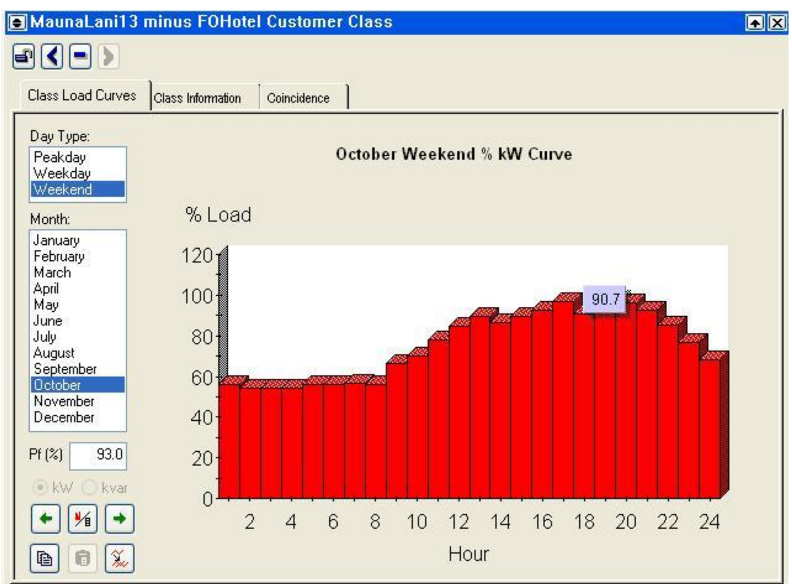


Figure 90: ML SynerGEE load profile

ML 11 peaks at approximately 8 pm with a 2,275 kVA demand. ML 12 is unloaded. ML 13 peaks at approximately 5 pm at 3,420 kVA demand. ML 14 peaks at approximately 11 am at 2,680 kVA demand. There are 16 existing PV units on ML11 with a total capacity of 272 kW. There are 5 existing PV units on ML13 with a total capacity of 390 kW. Additional PV is added at load locations along the feeder length. Due to data constraints, only steady state and pseudo steady state analysis is conducted in SynerGEE Electric.

Data are provided for an April 2011 day from SCADA for ML 11 as shown in Figure 91. PV penetration is increased on this feeder for both a low generating and high generating PV day.

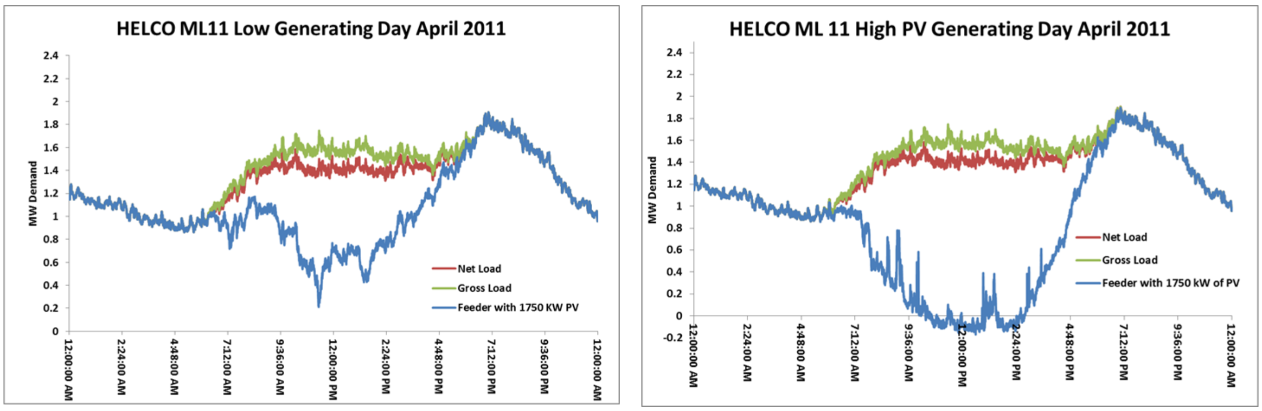


Figure 91: April 2011 Impacts for Varying PV Penetrations

Voltage and tap position are analyzed for an April load day for ML transformer 1. Existing and maximum PV levels found in the backfeed analysis for ML 11 are simulated and voltage is plotted along the length of ML 11 as shown in Figure 92. No voltage rise issues are found at either existing or maximum PV penetration conditions.

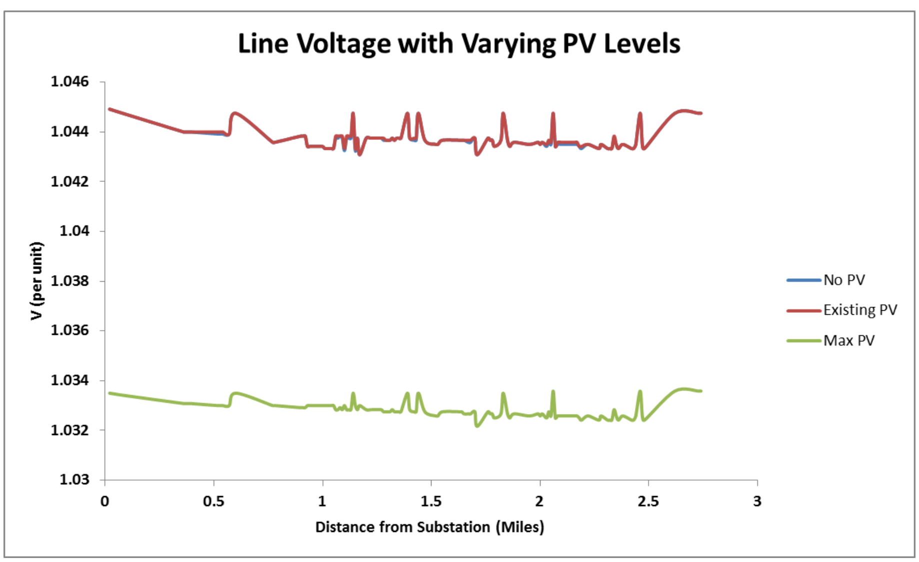
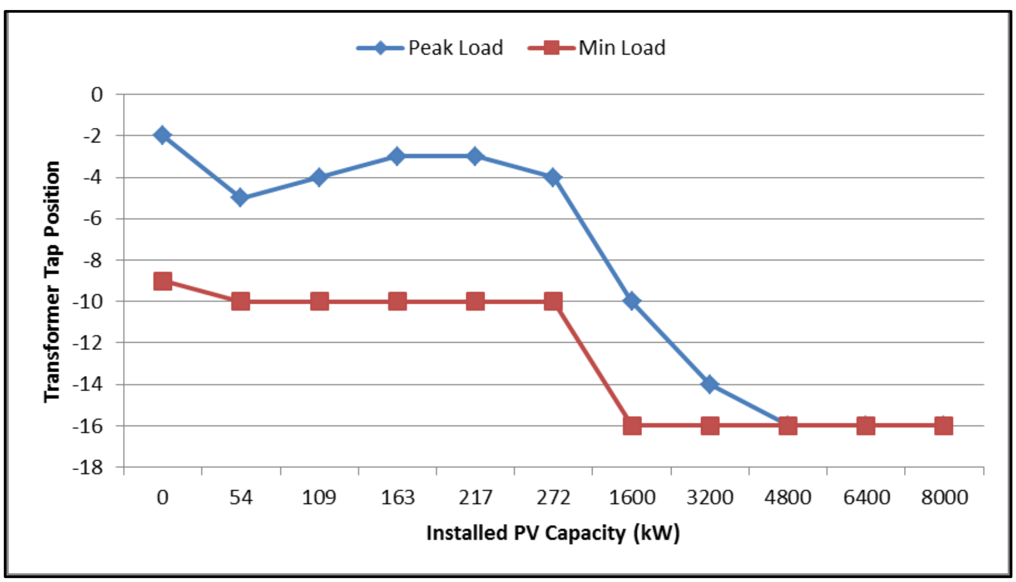


Figure 92: Voltage over distance on ML Feeder

Modeled maximum and existing PV penetration days, with high and low variability are analyzed in SynerGEE Electric to determine if LTC variability is a potential issue, as shown in Figure 92. Load is held constant as PV Penetration increases. Modeled minimum daytime load day (April) and peak load day (blue line). As shown in Figure 93, the tap changer “maxes out” when backfeed occurs on ML transformer 1 at approximately 1,700 kW PV on minimum load day.

Figure 93 shows the tap positions of the two transformers at the substation varying with increasing PV generation. Figure 92 shows the trend of tap position versus PV generation for the transformer that feeds ML 11 and 12 feeders for peak and minimum load cases. Figure 90 shows the trend of tap position versus PV generation for the transformer that feeds ML 13 and 14 feeders for peak and minimum load cases. For the entire substation, the minimum load case is assuming to be 30% of the peak load case. For both figures the first six data points represent the existing PV being swept from 0% to 100% capacity at 20% increments. The last five data points represent the potential PV being swept from 0% to 100% capacity at 20% increments. There are 16 existing PV units on ML 11 totaling a capacity of 272 kW. There are 5 existing PV units on ML 13 totaling a capacity of 390 kW. There is no existing PV on ML 12 or 14. The potential PV for all feeders is accounted for by replacing all existing PV units with 500 kW capacity units.

The overall trend for both transformers is the tap position decreasing as PV generation increases. The trend is more dramatic for the ML 11 & 12 transformers and above 2,000 kW of PV; the transformer tap position is at its lower limit of -16. The load tap changer is trying to lower high voltages caused by a very high penetration of PV generation on ML 11.



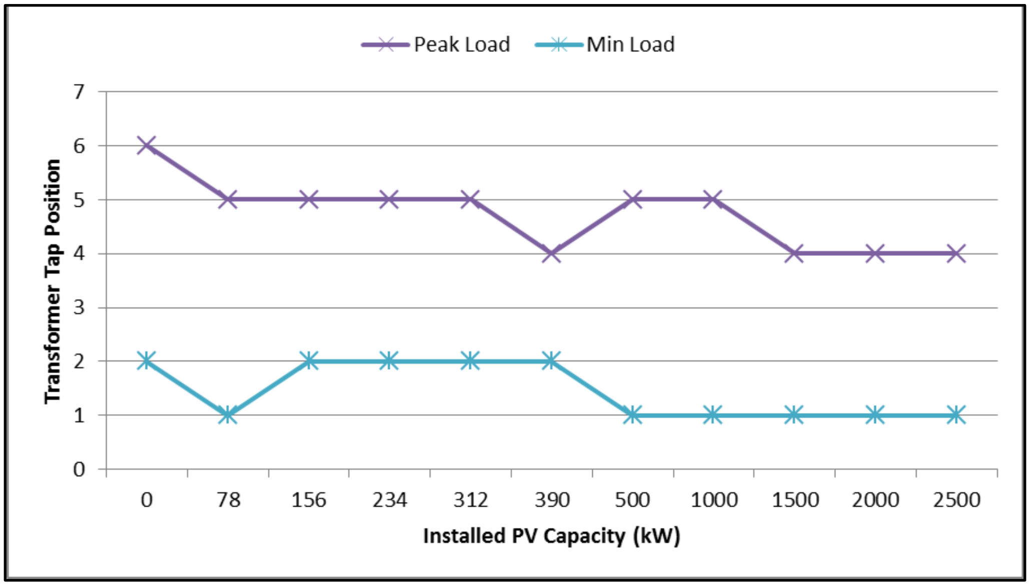


Figure 93: ML12 (top) & 14 (bottom) Transformer Tap Position vs. PV Penetration %

4.2.3 MECO WA Substation and Feeder

WA substation is selected by MECO for analysis under the high PV penetration project. The substation currently has the 5th highest PV penetration on the island of Maui and has GIS and SCADA available. WA substation currently is connected to 10 PV sites, with a 6.5% penetration level (of peak demand). The peak demand on the feeder is 2,775 kVA, and the minimum daytime demand is recorded as 1,572 kVA.

GIS data are extracted from ESRI ArcGIS and converted to SynerGEE Electric format by SynerGEE Electric software staff. There are 6 WA feeders. Figure 94 shows the SynerGEE Electric model of WA substation.

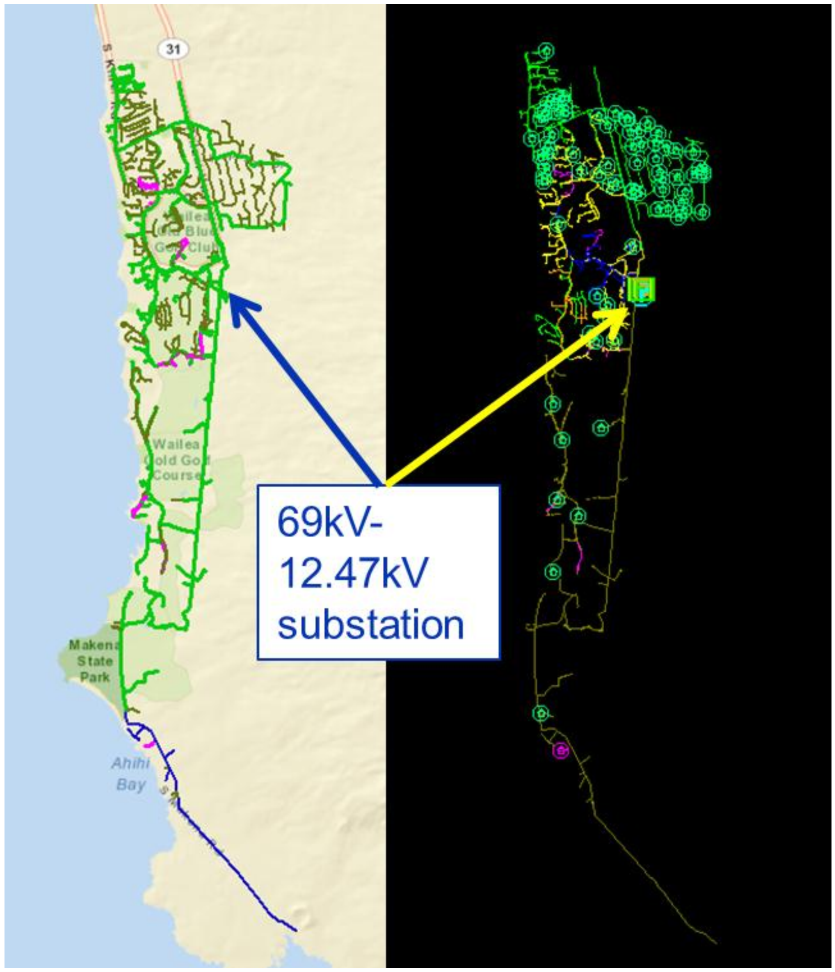


Figure 94: SynerGEE Electric model of WA substation

WA substation is fed from the MECO 69 kV system and there are three substation transformers feeding 6 distribution lines. The high side of the substation is modeled as an equivalent 69 kV source as the model for this source is not available in SynerGEE at this time. As in HELCO, ML data and validation are limited; therefore, two load scenarios are compared:

- Min load and 30% PV penetration
- Peak load and no PV

Table 13: SynerGEE Electric model of WA substation below shows load and PV totals for each feeder. The potential 30% PV scenario is based on scaling up existing PV units. Steady state results for CKT 1321 and CKT 1396 are not presented because there is no existing PV.

WA Substation Feeder	2009 Min Daytime Peak (KVA)	2009 Peak (KVA)	Existing PV (kW)	30% PV Pen Value (kW)
CKT 1280	3251	6244	439	1873
CKT 1281	933	2553	39	766
CKT 1320	2719	4598	171	1379
CKT 1321	1844	3831	0	1149
CKT 1395	1572	2775	177	833
CKT 1396	3896	6680	0	2004

Table 13: SynerGEE Electric model of WA substation

The load and PV KVA per feeder is plotted with the 2009 minimum and peak daytime load in Figure 95.

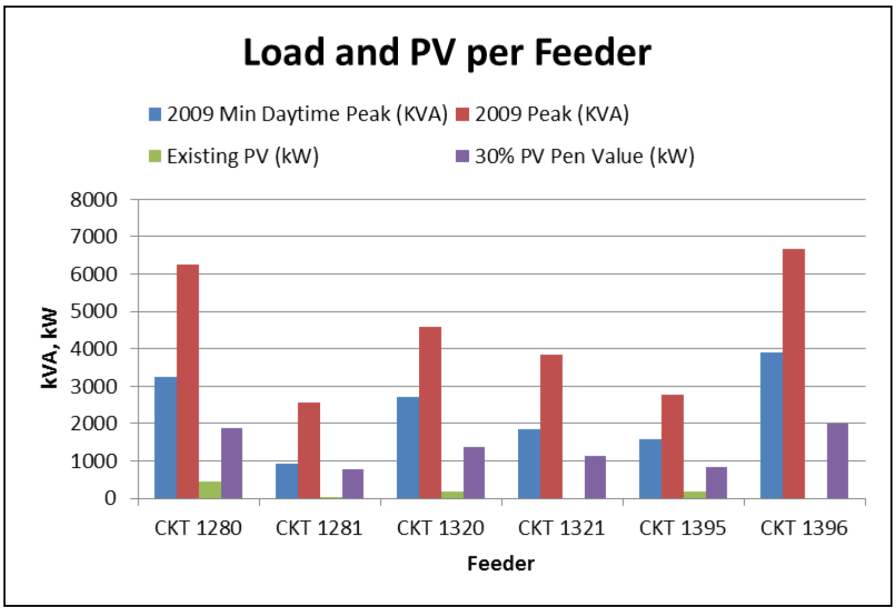


Figure 95: Load and PV KVA for Minimum, Peak load conditions and % potential PV penetration

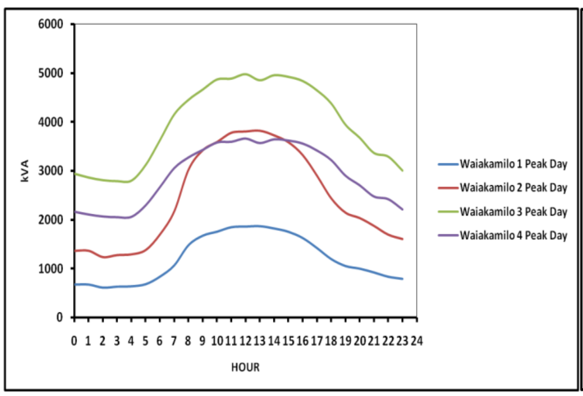
Current flow and percent loading of conductors are monitored at 13 points along the three-phase trunk of the feeder. A peak load with no PV scenario is the base case. For minimum load and 30% PV scenario, there is no back-feeding at start of any feeder. Each feeder exhibits local reverse current flow on three phase trunk line due to excess PV generation on sing-phase and two-phase lateral taps from the main trunk line. Table 14: Estimate of Portion of Feeders Trunk with Reverse Current Flow for WA analysis below shows an estimate of what portion of each feeder's main trunk exhibits reverse current flow during different time periods.

WA Substation Feeder	% of 3P Trunk with Reverse Current Flow
CKT 1280	21%
CKT 1281	24%
CKT 1320	20%
CKT 1321	-
CKT 1395	14%
CKT 1396	-

Table 14: Estimate of Portion of Feeders Trunk with Reverse Current Flow for WA analysis

4.2.4 HECO WO Substation and Feeder

WO 3 is an 11.5 kV distribution feeder connected to the WO 46 kV substation. Transformer 1 serves WO 1 and 2 feeders with power supplied by the IW 46 kV 2 line. Power to transformer 2 is supplied by the SK 46 kV line and serves the WO 3 feeder (the feeder of interest) and WO 4. Currently WO 3 has 9% PV penetration of peak feeder load, and 4.8 MVA peak demand. HECO provided 5 minute peak day (August mid-day) and minimum load day (Sunday afternoon in August) for the 2 substation transformers. The profiles are aggregated to the 11.5 kV level based on SLACA (HECO's Substation Load and Capacity Analysis system) loading information. Figure 96 shows the peak and minimum day.



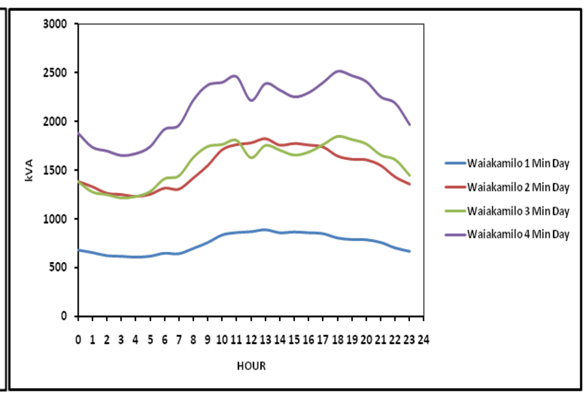


Figure 96: WO Feeders load, maximum left hand side and minimum right hand side

Street addresses are provided for each of the PV locations on the feeder. An in-house address GIS locator tool gives the SynerGEE Electric model location for each PV site. Figure 97 shows how the PV locations are mapped and transferred to the model.

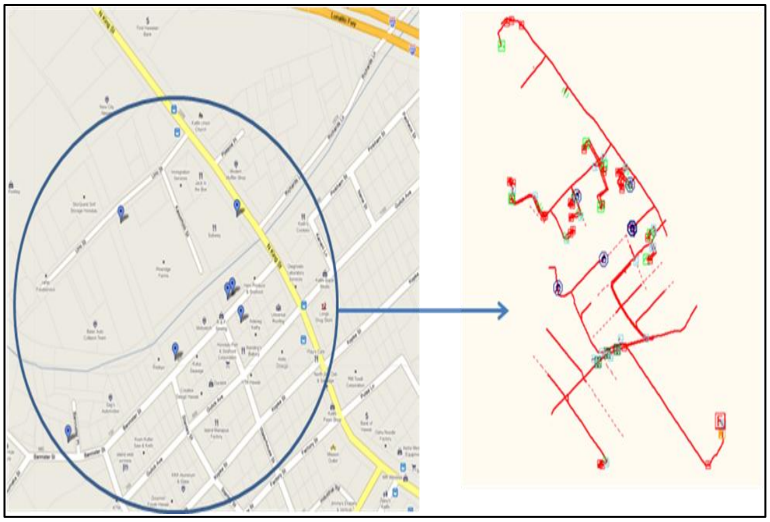


Figure 97: WO 3 Geography of PV Locations

The load displaced by PV is added to the load profile and plotted to show the actual peak time as shown in Figure 98.

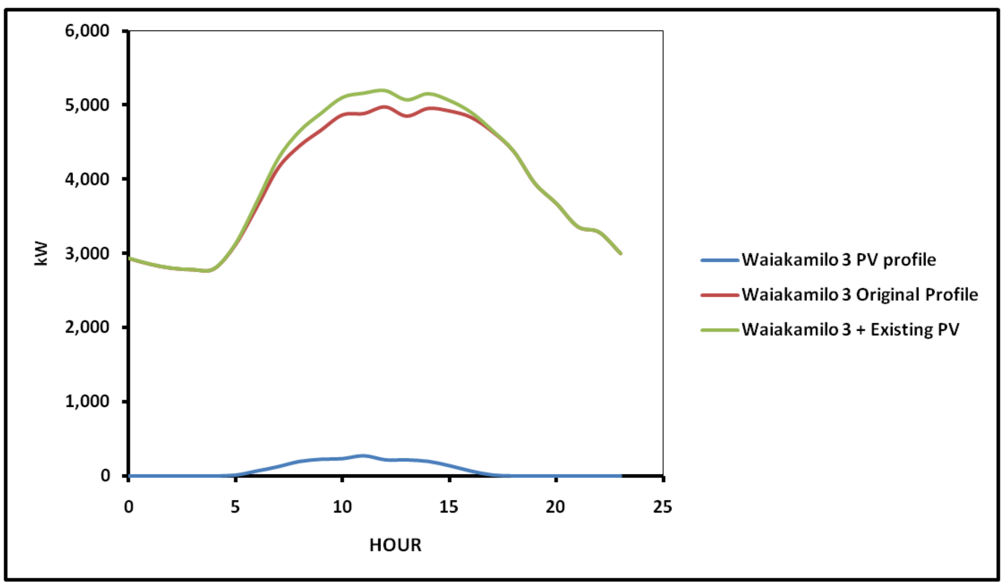


Figure 98: WO 3 PV profile added to normal load profile for replacement of displaced load

For each type of analysis (peak day) the following different potential PV levels are analyzed:

- No PV
- Existing PV
- 30% PV Capacity Penetration

Load flow is conducted for the peak load time on the August peak day. The results are plotted in Figure 99 for the peak demand time with each of the PV penetration conditions listed above. With the increasing PV penetration level, the overall demand is reduced and therefore kW losses are reduced.

In the bar graph, the first case depicts a scenario in which the existing PV is connected, but not generating. The blue section represents the demand that is met by the substation and the red section on the top represents the demand met by existing PV if it is generating. This load is added as the peak load, and is measured as net output, not as gross capacity. The blue and red sections together equate to the total demand.

The second case of the bar graph depicts a scenario in which all of the existing PV (321 kVA) is now generating at maximum output for that hour of the day. The red displaced load is replaced by the actual existing PV kW output, shown in green.

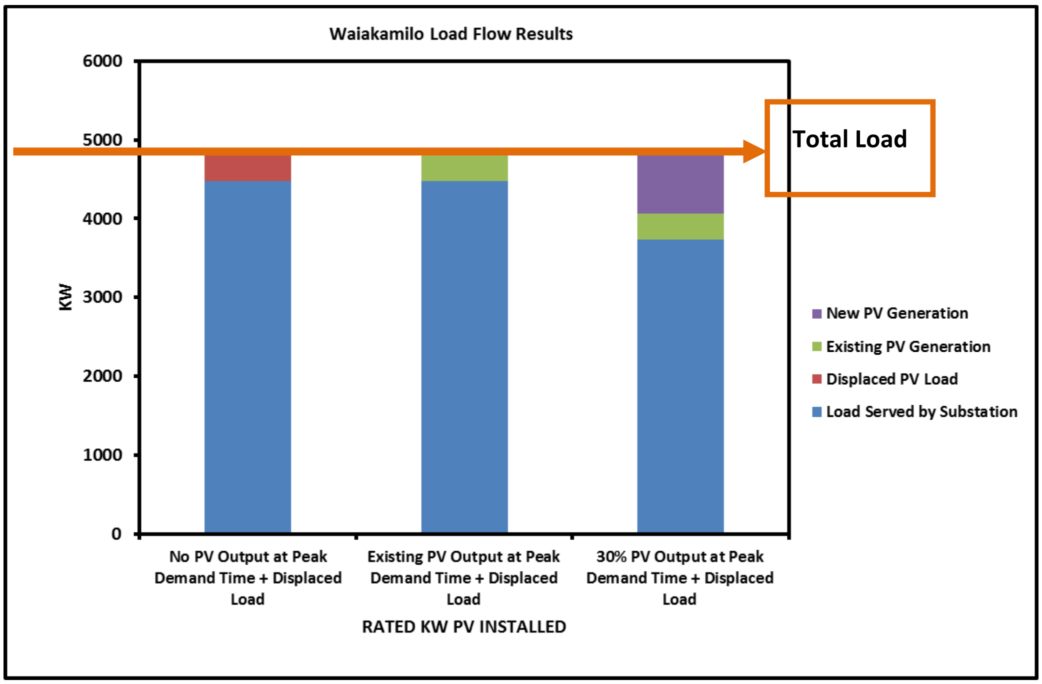


Figure 99: Bar graph for each load condition on WO 3 in the steady state load condition, and a representation of which source serves each load condition

In the third case, additional proposed PV is added to the existing PV (totaling 1,066 kVA) and load flow analysis is performed. It is possible to see the reduction in load met by the substation, due to the increase in dispersed PV output levels throughout the system.

The substation total demand reduces with the addition of PV output. With zero (0) PV output, total demand is 4,482 kW and 900 kVAR. When considering the existing PV, total demand reduces to 4,349 kW. Finally, after adding the proposed PV, the total demand lowers further to 3,554 kW.

Under the various PV installation conditions investigated, existing PV (321 kVA) and the addition of proposed PV (totaling 1,066 kVA), the PV generates roughly 41% and 87%, respectively, of total capacity at the time of load peak.

There are no individually defined spot loads. Distributed load is 4,243 kW and 890 kVAR. This substation connects to a total of 1,008 customers. The tap changer is consistently at the 14R position.

The resulting voltage levels produced by each of the four PV penetration scenarios are depicted in Figure 100. In addition to the maximum and minimum voltage at each PV penetration level, the maximum percent loading at any section is also depicted, which utilizes the right hand side Y-axis numbering. The maximum and minimum voltage level values are based on the left hand side Y-axis numbering.

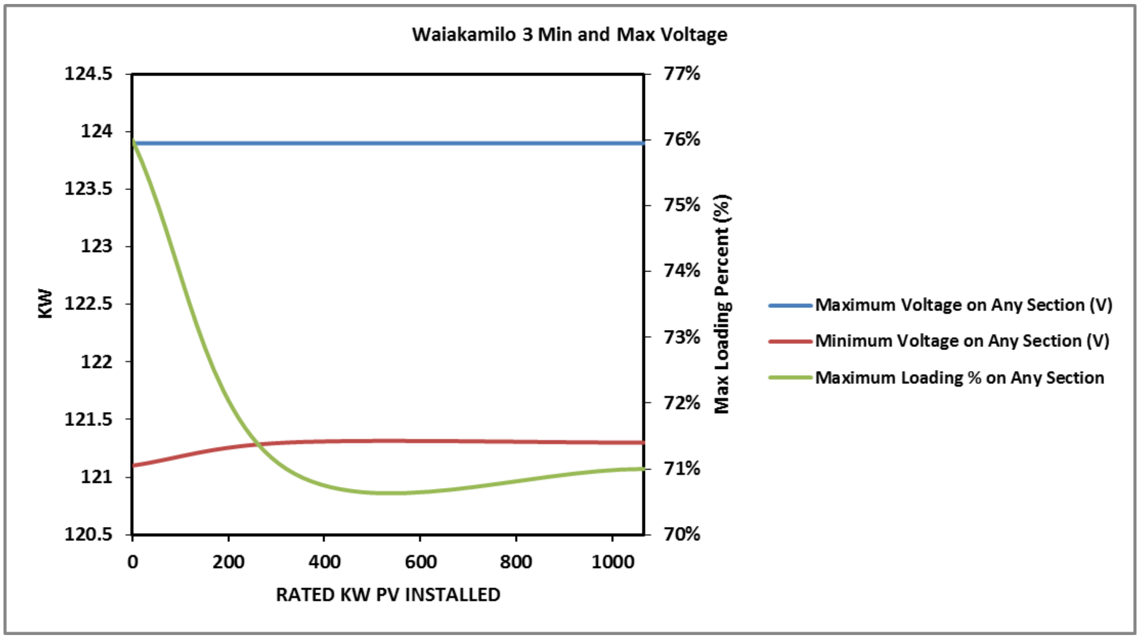


Figure 100: Minimum and Maximum voltage and maximum percentage loading on WO 3 at peak time with varying PV penetrations

The analysis is performed during the time of peak demand (6 pm) and not during the time of peak PV generation (roughly 12 pm noon), therefore there is a relatively small change in the voltage and the loading percentage as PV penetrations increase.

The maximum loading, minimum voltages, and maximum voltages are not necessarily located at the same position on the feeder in SynerGEE, but indicate the respective values. On the WO feeder, the minimum voltages increase by only 0.2%, and the maximum voltages do not change. These increases are well within the 5% limit. The maximum loading decreases 5% on the WO 3 feeder. The transformer tap changer position does not change as the PV penetration increases.

A twenty-four hour voltage analysis is completed for the WO 3 feeder under different PV penetration scenarios. Voltage is minimally improved by the additional PV. The minimum and maximum voltages can occur at any single position on the feeder over 24 hours and the average voltage is over the entire feeder length at the same hour is shown in Figure 101.

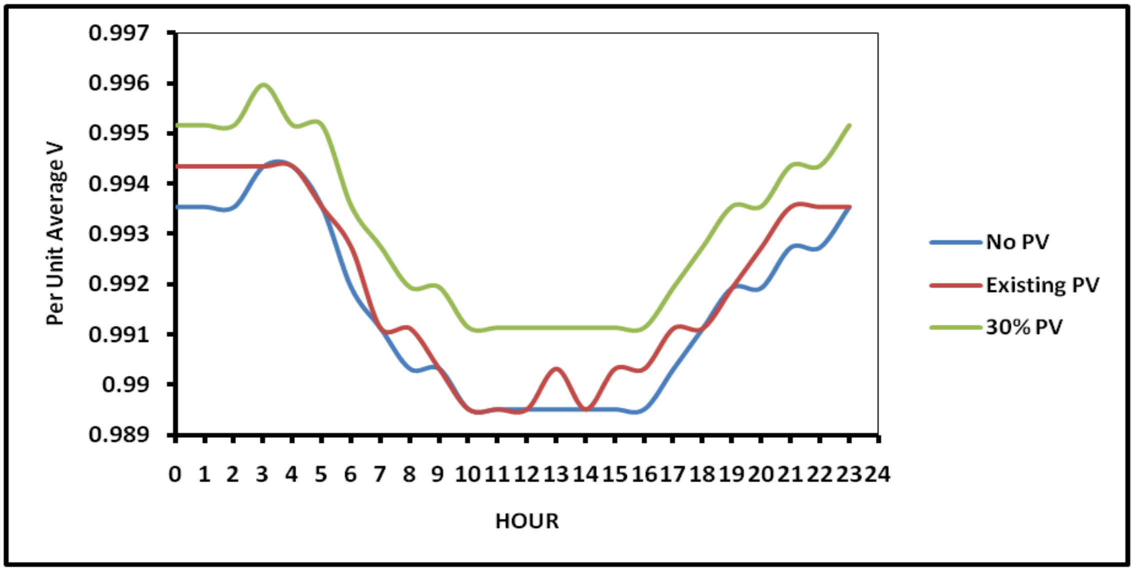


Figure 101: Average Voltage Over 24 hours peak day in varying PV penetrations, in Per Unit (124 V base)

Figure 101 shows the average voltage across the feeders is below unity throughout the entire day. It also shows an improvement of average voltage as increased amounts of installed PV increases the average voltage throughout the day.

For the backfeed analysis, PV generation capacity is increased from the existing level until the power flow at the substation becomes negative. Three scenarios are chosen for different levels of demand and PV generation. The first scenario is at the peak demand hour of the peak day (12 pm). At this time, high PV generation occurs as solar irradiance is high. The second scenario analyzes an hour of the peak day where there is daylight, but load is typically at around 50% of peak demand, 10 am. The third scenario scales the demand at peak hour to 40%.

Figure 102 shows the power flow results at the WO 3 feeder for the three scenarios. The locations for potential PV on WO 3 are selected at random.

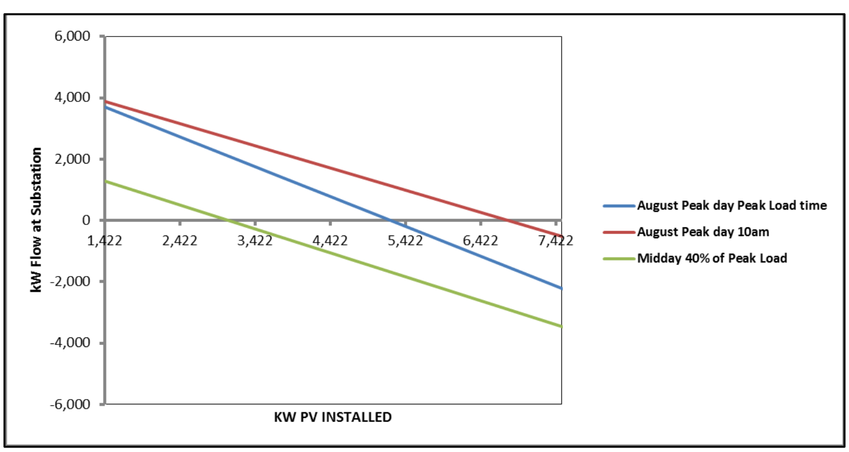


Figure 102: WO 3 Back Feed Analysis for three loading conditions

Figure 102 shows the value of kW flow at the substation for varying levels of PV penetration. Any positive kW value represents normal power flow direction, and any negative value represents backflow caused by high PV power output. The point at which the trend lines cross below zero (0) kW is the moment when back-feed first occurs and is circled in black for each loading condition. The back feed occurs at approximately 3,067 kVA for the 40% of midday peak load case, 5,244 kVA for the July peak load time, and approximately 6,789 kVA for the July day minimum load hour.

With all PV penetration levels analyzed in the back-feed scenario, the maximum voltages do not indicate potential over-voltage problems. The midday 40% of peak load results show that back feed may occur during a low load day at the 30% PV capacity penetration level.

The existing inverters and 30% penetration scenarios are used on the WO 3 feeder analysis to perform fault current contribution analyses. The existing PV sites are connected in random order and PV is increased to 30% peak penetration. The actual kVA installed is presented in Table 15: kW installed and cumulative kW installed on WO 3.

No of Installation	kVA installed
1	106
2	13
3	10
4	90
5	22
6	30
7	52

Table 15: kW installed and cumulative kW installed on WO 3

PV penetration increments are simulated on WO 3 feeder, similar to the initial load flow analyses. The results show the percent increase of the greatest symmetrical fault current on the feeder for existing and potential PV generation capacity relative to the no PV case, as shown in Figure 103.

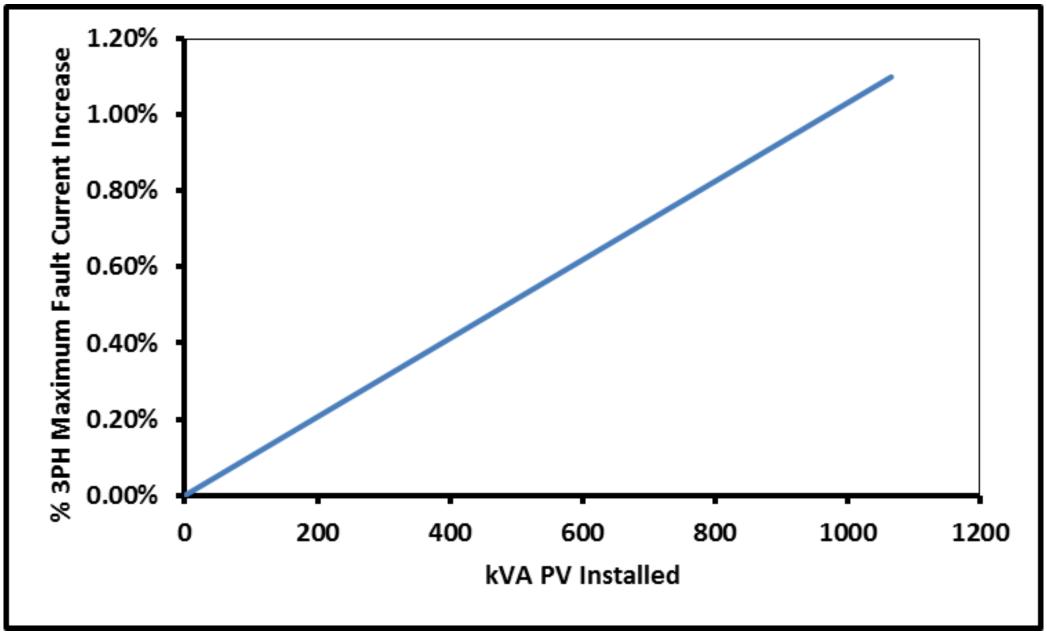


Figure 103: Maximum % Fault Current Increase for WO 3

The total fault current increases by 1.1% from the no PV case to the 30% PV penetration case. This increase is well within the 5% level.

5.0 CONCLUSIONS

This component of the CPUC CSI RDD&D Solicitation 1 research project was to study existing feeders with high penetrations of distributed solar and identify the missing distribution modeling data, determine the most typical study's conditions for evaluating solar, and highlight important factors for utilities to study high solar penetrations. The research team identified six goals for this analysis and each of these are briefly discussed below. .

1. **Goal**: Identify high penetration analysis needs (load flow, characteristics of the load, protection / coordination, voltage regulation, and islanding) for the distribution circuits being analyzed.

   Results: Following the feeder studies for SMUD, HECO, MECO, and HELCO, the major feeder circuit evaluations should consider steady-state distribution simulations, voltage regulation/impacts, and frequency impacts due to varying solar generation, islanding and backfeed into the substation. Time sequential simulations of solar variability over the on-peak periods should be considered for the minimum daytime peak and maximum daytime peak periods. These time periods have high solar generation with varying cloud densities that impact solar generation. It is determined that a single feeder should not be the only consideration when studying solar impacts. The utility planner must also consider the impacts to distribution feeders connected to the same substation bus to determine if one feeder backfeed impacts the other feeders.

Fault current, harmonics, protection and transformer load-tap-changers should be considered for further in-depth studies if there are potential or actual solar inverter impacts to the system. These specific studies are not required for screening or determining feeder potential impacts. These require more detailed data collection and modeling that is not required for high solar impact analysis.

2. **Goal**: Identify additional data parameters to be collected and locations along the high penetration distribution circuit to place additional high-fidelity monitoring equipment, as necessary.

   Results: Even though a utility planner may be using distribution planning models in daily studies, the data requirements for modeling solar inverters, gross and net loads, transformer and tap-changer, capacitor bank parameters and distributed load across the feeder are not included in the standard distribution data sets. The planner must become more aware of the distribution of the customer load along the feeder to match the solar installations to load. Many planners do not consider transformer tap changer operations since there are numerous factors that cause tap changer operations. However, during high solar variability periods, the tap changers could experience excessive tap operations that increase maintenance costs and exposure to mechanical failures.

The collection of high-fidelity solar and power data are very important and is something new to the distribution planner. The planner must study the distribution of load and solar installations to determine the optimal locations to place monitors and sensors. The baseline modeling report referenced earlier discusses selecting locations for monitors and sensors on the distribution feeder. This report can be found at the CSI RD&D Program website at:
http://calsolarresearch.ca.gov/images/stories/documents/Sol1_funded_proj_docs/SMUD/2011_SMUD_Hi-Pen-PV-Init_Base-Line-Model-final.pdf

3. **Goal**: Record and collect at a minimum 6 to 12 months' worth of high-fidelity load data from the newly installed high-fidelity monitoring equipment.

   Results: The installation of monitors and sensors is a time consuming venture. Security, safety, availability of sites, and selection of proper communication equipment create delays in beginning feeder studies. Communication equipment failures and data losses result in sporadic missing data that eliminate potential time periods of interest. The planner must take the time to preplan the selection of sensor and monitoring equipment, communication techniques and data storage.

   At HECO, a solar monitor was to be placed at the substation however, since the sensor stand was metal, it was required to be connected to the substation grounding mat and security of personnel has to be considered along with moving of equipment around the substation yard. The metal stand was replaced with a plastic container to meet safety and security concerns. At SMUD, data were being collected but not communicated back to the control room and it is discovered that animals have chewed through the communication cables.

   In collecting solar and load data, the planner must decide on the frequency of data collection. In this study, data are collected in one second, five second, fifteen minute and one hour increments. To create consistency of data for feeder analysis, data are converted into different time increments. The final data increments changed the simulation analysis. For example, if the data are in fifteen or hourly increments, the impacts to tap changers and solar variability are very limited in scope or eliminated from the analysis.

4. **Goal**: Collect electrical equipment nameplate data from the distribution system being analyzed: distributed generation on the circuit, inverters, any energy storage, circuit size, circuit length, circuit loading, switchgear, and transformers to be used in the model development.

   Results: As stated in Goal 1, there was an increase in data collection and documentation starting at the substation transformer to the last line segment on the feeder. Each feeder line length, conductor size, phase loading, single taps off the main trunk, capacitor bank operating characteristics, and fuses have to be considered in the expansion of the data sets. The planner must make a list of data requirements for field verification of equipment. Failure to understand the increase in feeder data can cause delays in starting feeder studies. Some of the additional data required to conduct a detailed high PV penetration on a distribution grid includes but not limited to:

   - Transformer LTC, and dynamic data parameters
   - Substation bus configuration, metering, relay types and capabilities,
   - Historical hourly and subhourly real and reactive power, amps, frequency, etc.
   - Customer load data in hourly and subhourly increments, feeder location and GSI
   - Existing and queued solar installations and subhourly load increments
   - Data on line transformers, capacitor banks, fuses, regulators, etc.
   - Historical incidents of outages
   - Feeder line loading profiles including voltage, amps, loads, etc.

   Even though both HECO and SMUD are actively using SynerGEE for distribution feeder studies, the additional data for monitoring and studying impacts of solar was missing. Utilities in general have not collected line loading data in increments of 1 second, 5 second, 1 minute, 5 minutes, 15 minutes and one hour. Feeder phase loads is usually not considered as a high priority item in planning. However, for PV studies, the imbalance of feeder load with high penetrations of solar can create protection issues. For the City of Roseville, California municipal utility, a phase balance was required before the solar study can be undertaken.

5. **Goal**: Investigate varying incremental levels of PV penetration at the distribution capacity level and iterate with an existing system level model to understand to what degree higher PV levels will adversely affect the grids.

   Results: In this study, the distribution feeders are studied under varying solar penetrations from no PV to 100% PV penetrations. The results indicate there is no set penetration limit for feeders, but the penetrations vary widely due to load and solar locations, feeder conductor sizes, and other factors. Some feeders experience issues at 30% penetration while others could have as high as 100% penetration. The penetrations vary by study parameters such as backfeed, voltage, frequency, etc. Each has solar penetration limits that need to be mitigated through feeder upgrades or other options.

6. **Goal**: Based on the validation results for a single circuit study, develop a methodology for extending the findings using the simulation tools to inform and expedite interconnections studies at higher penetration levels.

   Results: The report discusses methodologies for studying high solar penetrations. The simulation tools are an important consideration before starting feeder studies. Some distribution simulation tools such as SynerGEE cannot model inverters while others such as CYME can, but require, additional module purchases. In order to simulate inverter impacts on an unbalanced distribution feeder, the feeder is converted to a balanced feeder and imported to a transmission model such as PSS/E or PSLF used by SMUD and HECO, respectively. This conversion eliminates the single phase issues that are important for distribution penetration studies but is adequate for screening analysis.

   The table below summarizes the general findings from the study. The results are based on steady-state and first contingency analysis. The areas in red indicate feeder conditions impacted by high penetrations of distributed solar. The main conditions impacted are voltage and backfeed onto the feeder. The blue areas indicate potential areas of concern as distribution solar penetrations increase. These areas are potential line segment overloads and excessive LTC operations.

Feeder	Utility	Voltage (kV)	Customer Mix	PV Penetration	Line Loading	LTC Operation	Voltage	Backfeed
A-C (3 feeders)	SMUD	12.47	Res	0% to 100%	No violations	N/A	High voltage	High backfeed
RF (1 feeder)	SMUD	12.47	Com/Ind	0% TO 88%	No violations	N/A	No violations	No violations
EB (1 feeder)	SMUD	12.47	Rur	67%	No violations	N/A	High voltage	High backfeed
CT (2 feeders)	SMUD	12.47	Res/Rur	0% to 50%	Potential for overloads	Minor operations	High voltage	No violations
EG (3 feeders)	SMUD	69	Res/Com/Rur	38% to 60%	No violations	Minor operations	No violations	No violations
L7 (1 Feeder)	SMUD	69	Ind	0% TO 150%	No violations	N/A	No violations	No violations
MI (4 feeders)	HECO	11.5	Res/Com	9% to 135%	Potential for overloads	Potential cycling	High voltage	High backfeed
ML (4 feeders)	HELCO	4.16	Com	0% to 100%	No violations	Potential cycling	High voltage	High backfeed
WA (6 feeders)	MECO	13.09	Res/Com	0% to 30%	No violations	N/A	No violations	No violations
WO (5 feeders)	HECO	11.5	Res/Com	0% to 40%	No violations	N/A	No violations	Potential for backfeed

Res is residential; Ind is Industrial; Rur is Rural, and Com is commercial