Hunters Point Community Microgrid Project

Power Flow Analysis Methodology

A Distribution Grid, Dynamic Power Flow Modeling Case Study

Acknowledgements

The following organizations have provided a great deal of support through training, applications, data, and suggestions for this paper.

- CYME International T&D, a division of Eaton
- Pacific Gas and Electric Company
- Integral Analytics, Inc.

The Clean Coalition is deeply grateful to the following for their support of the Hunters Point Community Microgrid Project.

- Common Sense Fund
- Threshold Foundation, Sustainable Planet Funding Circle
- The 11th Hour Project
- The San Francisco Foundation
- Wells Fargo Foundation

Glossary/Acronyms

Some links are provided for definition and reference.

AMI	Advanced Metering Infrastructure https://en.wikipedia.org/wiki/Smart_meter#Advanced_metering_infrastructure
ANSI c84-1	American National Standard for Electric Power Systems and Equipment – Voltage Ratings (60 Hertz)
C&I	Commercial & Industrial: refers to loads and their profiles as distinct from residential
DER	Distributed Energy Resources https://en.wikipedia.org/wiki/Distributed_generation
DG	Distributed Generation https://en.wikipedia.org/wiki/Distributed_generation
ICA	Integrated Capacity Analysis http://www.cpuc.ca.gov/General.aspx?id=5071
Load Flow	https://en.wikipedia.org/wiki/Power-flow_study
LTC	Load Tap Changer
NREL	National Renewable Energy Laboratory http://www.nrel.gov/
P & Q	Real and reactive power components https://en.wikipedia.org/wiki/Power-flow_study
PF	Power Factor
SAM	System Advisor Model [from NREL] https://sam.nrel.gov/ http://en.openei.org/wiki/System_Advisor_Model_(SAM)
SCADA	Supervisory Control and Data Acquisition https://en.wikipedia.org/wiki/SCADAs

Table of Contents

List of Figures & Table

Background

The United States' power system, built on century-old technology and methods, was designed to deliver electricity from large, remote power plants across significant distances to the cities and towns where electricity is actually used. However, locally sited renewable energy generation has become economically competitive with centralized generation and offers a superior approach for a vastly improved power system.

To accelerate the deployment of high penetration distributed generation (DG), the Clean Coalition established the Community Microgrid Initiative and undertaken the Hunters Point Community Microgrid Project (HPCMP). The design criteria for the HPCMP is 1) achieving 25% of total energy consumed from local renewables, while 2) at least maintaining grid reliability and power quality. This study covers the power flow analysis modeling that was undertaken to simulate the design criteria.

The Clean Coalition collaborated with Pacific Gas & Electric (PG&E) and CYME International T&D to demonstrate that existing grid modeling software can ensure a stable, effective distribution grid containing high penetration PV. This power flow analysis case study was undertaken in coordination with the City of San Francisco and PGE&E.

Hunters Point Substation

The Bayview Hunters Point (BVHP) area of San Francisco encompasses an extensive, existing urban infrastructure, including a wastewater treatment plant, a large recycling facility, and significant commercial, industrial, and residential buildings. The area also includes the former Hunters Point Naval Shipyard that is being redeveloped with new urban, mixed use (residential and commercial) construction. PG&E Hunters Point substation provides approximately 20,000 BVHP customers with electrical power. Of those customers, 90% are residential and 10% are commercial/industrial (C&I) by customer type, but loads are mostly C&I, as is shown later in **Figure 7**.

The HPCMP had a PV penetration goal of 25% of total electric energy for BVHP from local renewables. This translates to about 30 MW for the substation boundary area, not including the part planned for redevelopment (see **Figure 1**). If the redevelopment area is included, 50 MW (60,000 MWh) of renewable generation is necessary to achieve the 25% goal. Existing and/or renewables planned for the redevelopment area total around 20 MW, leaving 30 MW of new generation to meet the 25% goal in both instances. Of critical importance is that this new power be sited such that the impact on grid reliability and power quality is neutral or enhanced.

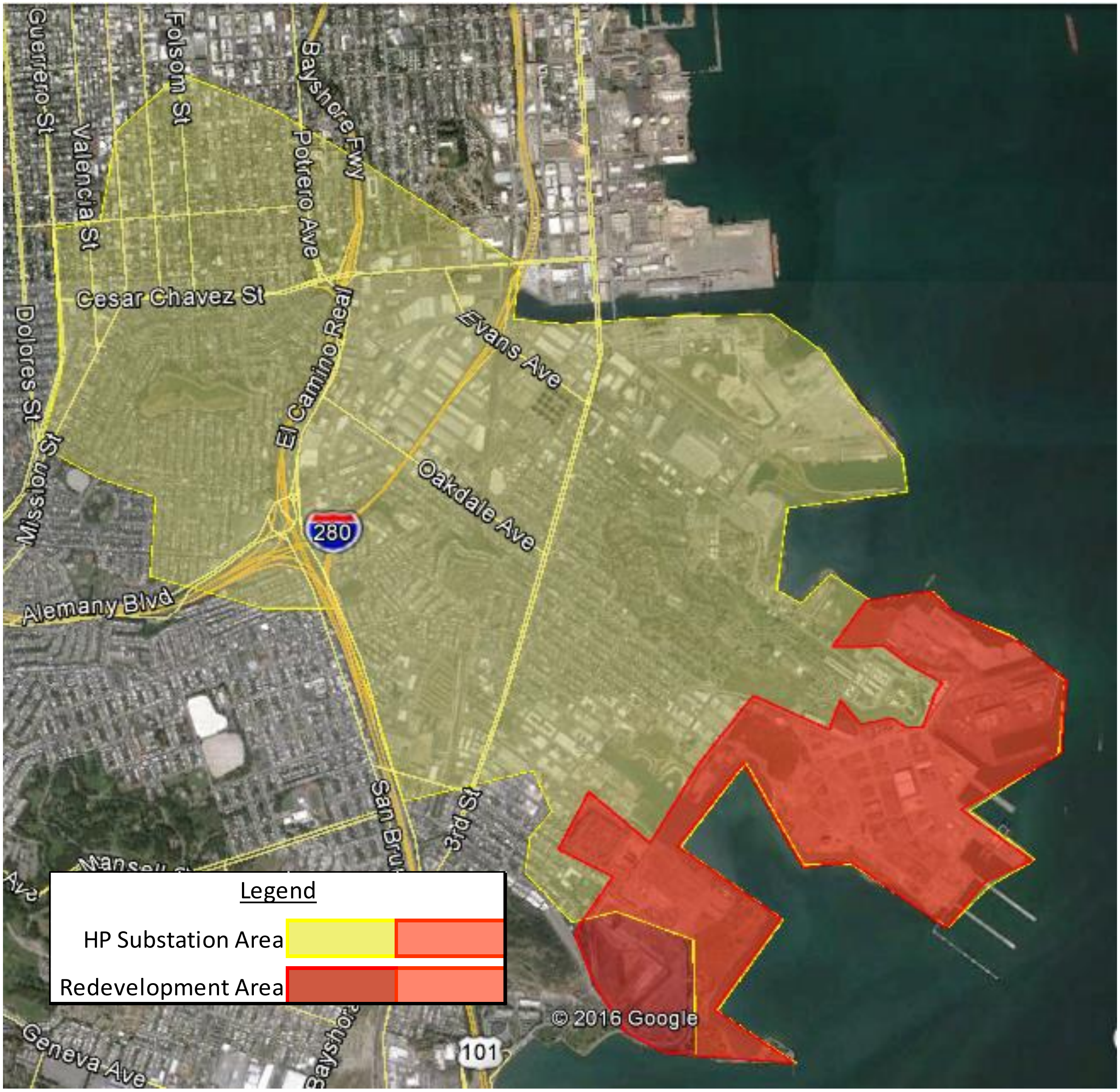


Figure 1: Hunters Point Substation Service Area and Redevelopment Zone

The plan was to establish a baseline model, add sufficient PV to reach the planned 30 MW for the non-redevelopment area, and then see what DER techniques could be employed to resolve any issues that arose from the high penetration of PV. The 30 MW was not sufficient to create backfeeding at the substation level, but the plan was to make sure that there was net export on some of the feeders in order to create a problem set for the DER solution set.

The Hunters Point Substation consists of nine 12 kV feeders grouped into two sub-banks of four and five feeders respectively. The layout of the substation and feeders is shown in **Figure 2**, with a different color representing each feeder.

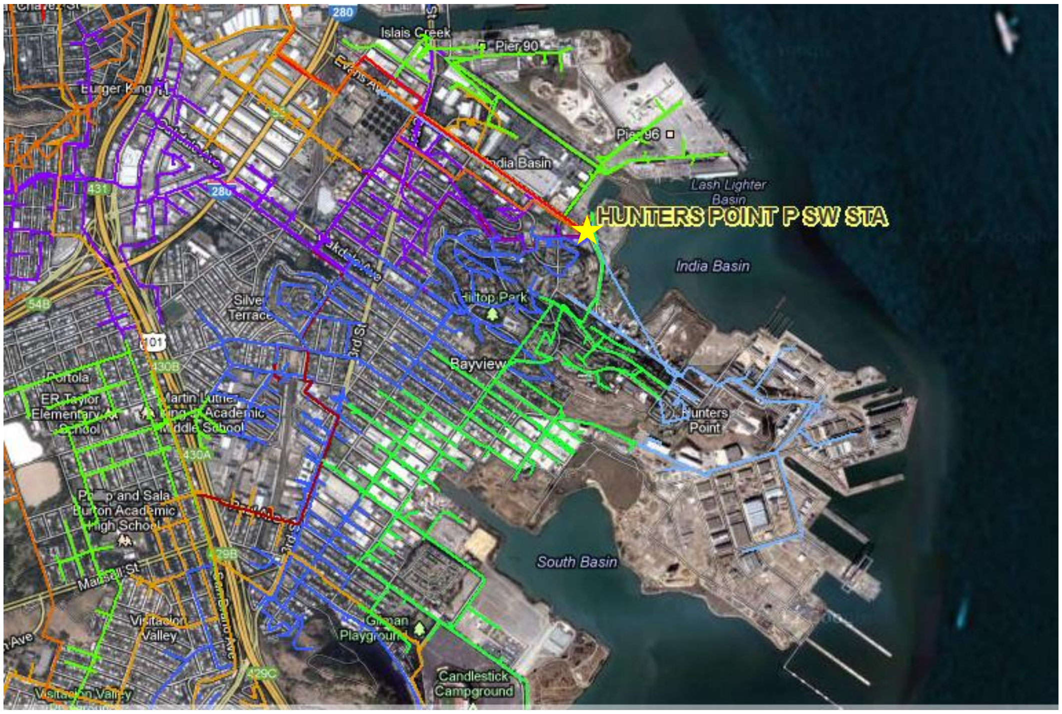


Figure 2: Feeder Lines Served by the Hunters Point Substation (the yellow star indicates the substation's location) – Source: PG&E

The distinctly colored lines represent unique feeder lines emanating from the substation.

Figure 3, below, is a simpler line representation of the substation topology, depicting the banks, feeders, and control devices. For clarity, the feeder branches have been collapsed into a single primary line. Note that feeder 1109 also has two 4 kV subfeeders designated Yosemite 401 and 402.

The green arrows represent the expected midday, September weekend load. Without any PV present, all of the power flows are in a conventional, downstream pattern, and the total noon load for the substation is 42 MW. This day was chosen because the worst case scenarios for backfeeding caused by solar occur when there is maximal sunshine and loads are at a relative minimum, which occurs around fall and spring equinoxes. Noon was chosen because this is the time of day when solar output is maximized and many C&I loads are voluntarily conserving demand due to peak time charges as shown by the Weekday C&I curve in **Figure 7**.

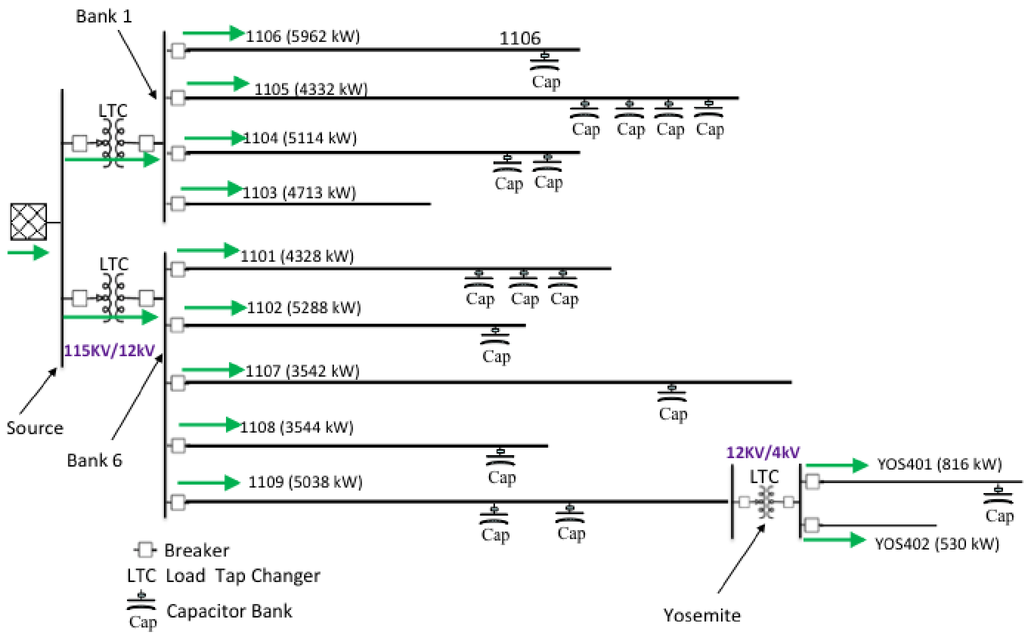


Figure 3: Bank and Feeder Layout of the Hunters Point Substation (power flows are for a September weekend day at noon without any local PV present)

This case study details the datasets, tools, methodologies, and results of conducting the power flow modeling for the 30 MW goal. The methodology for establishing a stable baseline model follows in the next section.

Methodology

Simulating the effects of adding local solar generation to the Hunters Point grid area involved numerous steps, as shown in **Figure 4**. An in-depth description of the methodology is provided in **Appendix A: Data Processing to Support Dynamic Load Flows**. A brief summary is given below.

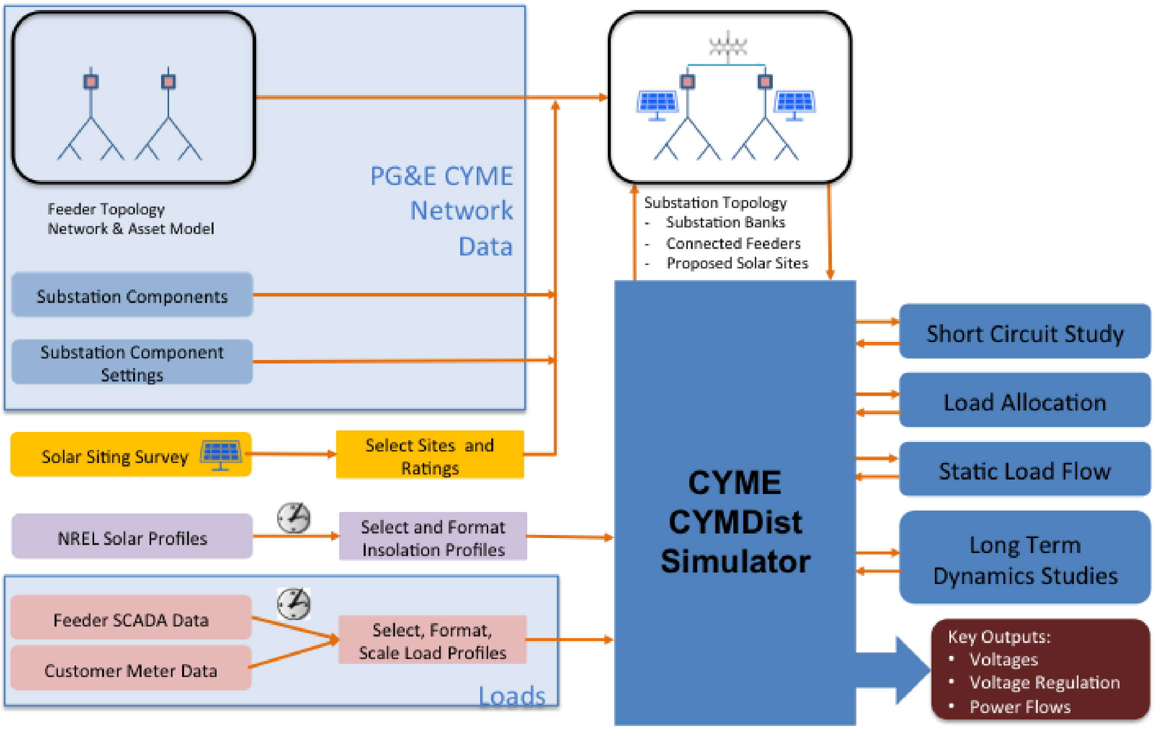


Figure 4: Process and Data Flows for Dynamic Load Flow Model

Prior to performing the simulations, numerous inputs on the detailed configuration of the feeders, voltage control devices, protection circuitry, and loads had to be assembled. Table 1 lists the specific datasets that were obtained from PG&E. As detailed in the **Problems to be Solved** section of this paper, the data sources are generally not required to work together and are usually not cross-checked for consistency. Because of this, significant effort was required to restructure the data for consistency and compatibility. Once properly formatted, the datasets were read into CYME to form the substation's baseline, topological configuration.

Dataset	Format	Description
Network Model	CYME	Data schema, lines, transformers (with ids), impedances, switches, fuses, voltage regulators (e.g. LTCs, capacitors)
Asset Database	CYME	Transformer ids / switch ids / addresses / hardware parameters that may be missing from Network Model
Network assets	Excel	Separate listings of such items as switch actions/settings, breaker trips, regulator tap movements, capacitor switches, reclosers, voltage regulators, existing distributed generation, seasonal loadings on transformers
Circuit map	CYME	Coordinate data is preferred for each element so that grid properties can be displayed on Google Earth to see the effects of changes to the models.
Substation SCADA Data	Excel	Phase loads for each feeder as granular as possible with Power Factors
Customer consumption / load data	Excel	Processed AMI data of load/consumption, monthly summary for four different load types (Residential, Commercial, Industrial, Agricultural) by weekday and weekend for 12 months

Table 1: Datasets Obtained from PG&E

The power flow simulation was performed using CYMDIST v5.04, a component of the CYME suite of power modeling tools. The simulation is a four step process as described below. At each step, stability must be achieved by correcting any issues uncovered before proceeding to the next step.

1) Short Circuit and Protection Test: The first step in the simulation is to perform a short circuit test. This test quickly identifies weak areas of protection in the circuit configuration. Any protection deficits have to be rectified before proceeding with load flow simulations. A typical finding would be the absence of series reactors in the configuration of the substation.

2) Load Allocation: Load allocation is the process of partitioning power (kW) or current (Amps) per phase load at a given point to the individual circuit elements down the line. It is a close approximation to actual loading and is something of an art form. (Jennifer Taylor, 2009).

3) Static Load Flow: Static (single set of initial conditions) load flow runs must be performed to validate the model before running dynamic load flows. The initial test is conducted with distributed generation disabled. After a stable run is completed, DG can be enabled and then gradually increased to full output to verify no new voltage or other capacity issues are caused by the DG.

4) Dynamic Load Flow: CYMEDIST's Dynamic Load Flow module runs a series of load flows with time-based profiles for load and generation. The simulation provides detailed information on the grid operating under real, dynamic conditions. Specific outputs include voltages, load flows, and voltage regulating operation. All of the simulations reported below were performed with the Dynamic Load Flow Module.

Once a stable configuration was established, we performed a baseline analysis of the grid without any DG present and then began adding DG to the grid. As with the previous steps, the overall system must be stable and any anomalous behavior must be resolved before moving forward. Comparisons were made between weekday and weekend operation. A mid-September timeframe was chosen as the time most likely to create issues with good solar power and minimal loads to create the greatest seasonal variation with high DG penetration.

Metrics and Output

The simulation reported several key outputs:

- Voltages at key monitoring points along each feeder
- Power flow magnitude, phase, and direction
- Activity for all voltage regulating equipment (LTCs & capacitor banks)

These outputs also served as the primary metrics for comparing one configuration to another. The metrics are summarized below:

Voltage: Voltage monitoring points were located at key components and some chosen nodes. Min, Max, and Average voltages were summarized. Voltages were considered in-range if they were within the ANSI c84-1 spec of ± 5% of the nominal voltage.

Power Flow: The magnitude of the power flow was monitored to ensure consistency with the load profiles. Any change in power factor, direction, cross-feeding, or backfeeding was also noted.

Voltage regulation: Tap counts were recorded for load tap changers. The tap changers were also monitored to ensure that they were not stuck at their min or max settings. Capacitor banks were also monitored to ensure proper operation of those that could sense voltage to switch on/off.

Circuit Components: In addition to the above metrics, all circuit components were monitored for normal operation and potential exceptions. Once stable runs were achieved, it was not likely that any component ratings would be exceeded, but these were monitored, nonetheless.

Establishing a Baseline

The baseline power flow for a September weekend day is shown in **Figure 3**. This case was run without any additional DG. Performing baseline runs is a critical step before assessing the impacts of local renewables. The baseline case provides the point of comparison for all subsequent simulations and must have a stable and repeatable outcome.

Effect of Adding DG

Adding DER to a grid will increase the voltage locally as shown in **Figure 5**. The amount of the voltage rise depends on the magnitude of the DER, the amount and location of loads, reactive power, other DER, and the resistance and reactance of the grid itself. A more detailed explanation is given in **Appendix B: How Adding DG Affects Local Voltage**.

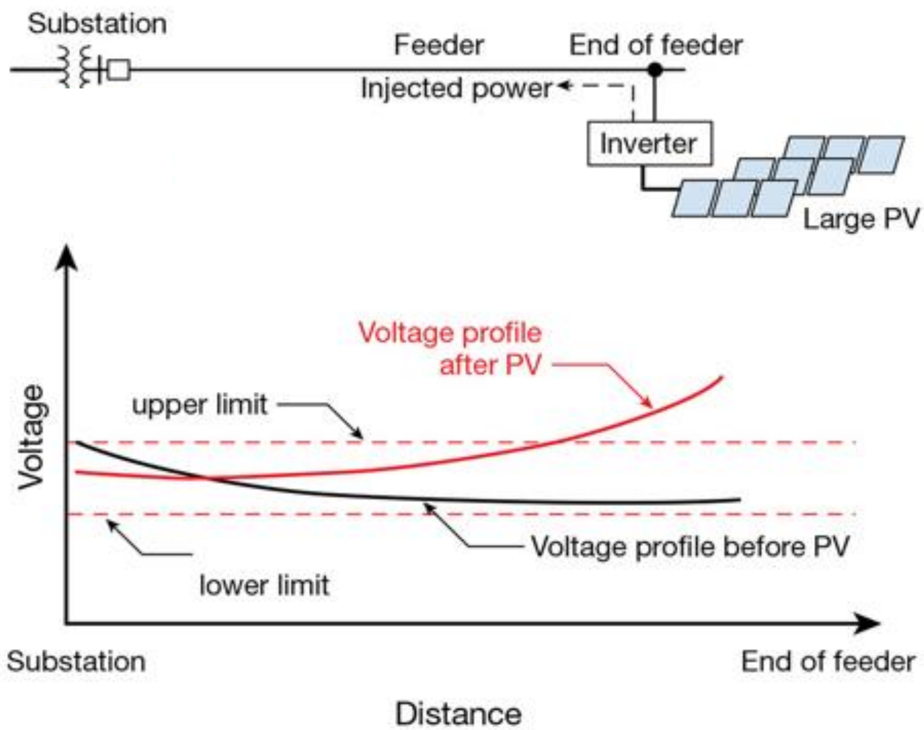


Figure 5: How Injected PV Can Pull Feeder Voltage out of Range

Siting the PV

Since the main goal in siting PV is minimizing the effect on local voltage, the discussion in **Appendix B: How Adding DG Affects Local Voltage** gives clues as to key siting criteria: low resistance between the DG and nearby loads as well as loads of sufficient magnitude to absorb most of the local DG power. This process is shown in **Figure 6**.

Each node in the feeder is plotted by its distance from the substation and its corresponding R1 Thevenin equivalent resistance. Overlayed on the nodes are symbols for the transformer loads as well as capacitor banks. When applying new PV in the model, sites were selected that had good proximity to the larger loads, which are usually C&I. Note that the presence of capacitor banks will often indicate larger industrial loads nearby.

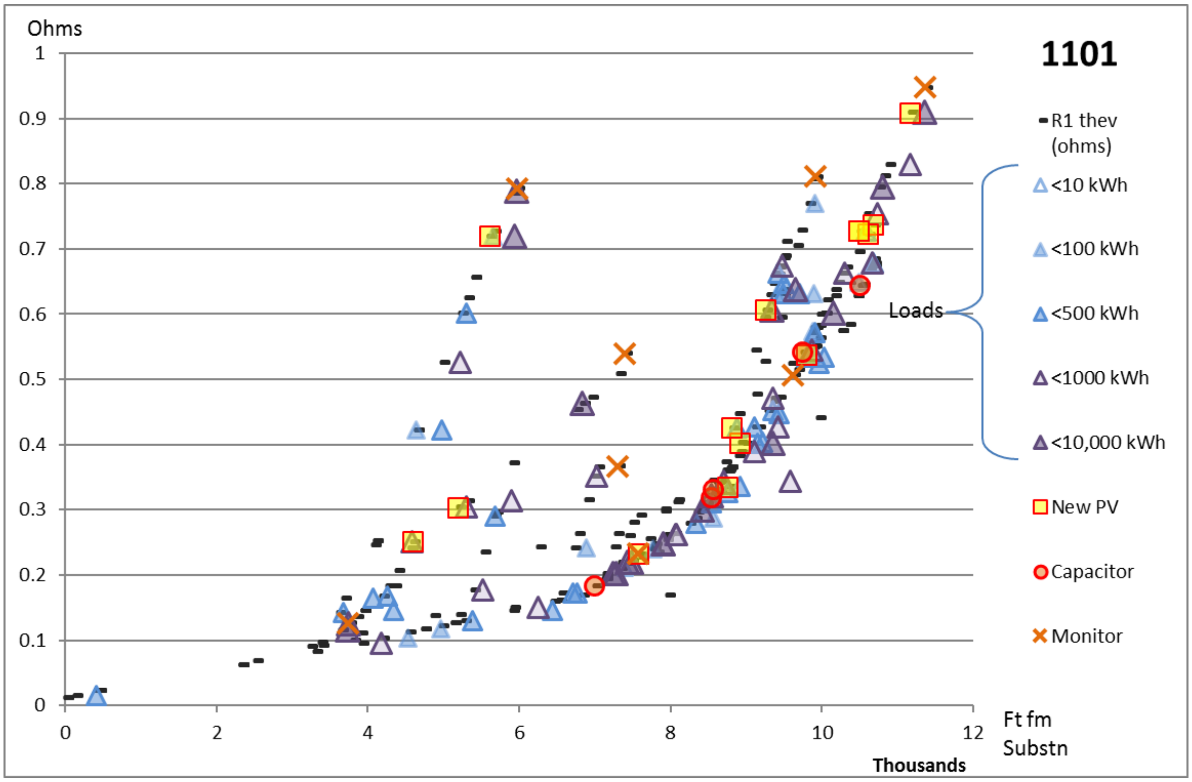


Figure 6: Short Circuit Plot Used for DG Siting on Feeder 1101

The reason that the C&I loads are so important in this substation is shown in Figure 7. The large majority of both weekday and weekend loads are C&I (red line) vs. the much smaller contribution from the Residential loads (blue line). There will typically be larger PV siting opportunities in C&I locations from large, flat roofs plus parking lots and parking structures.

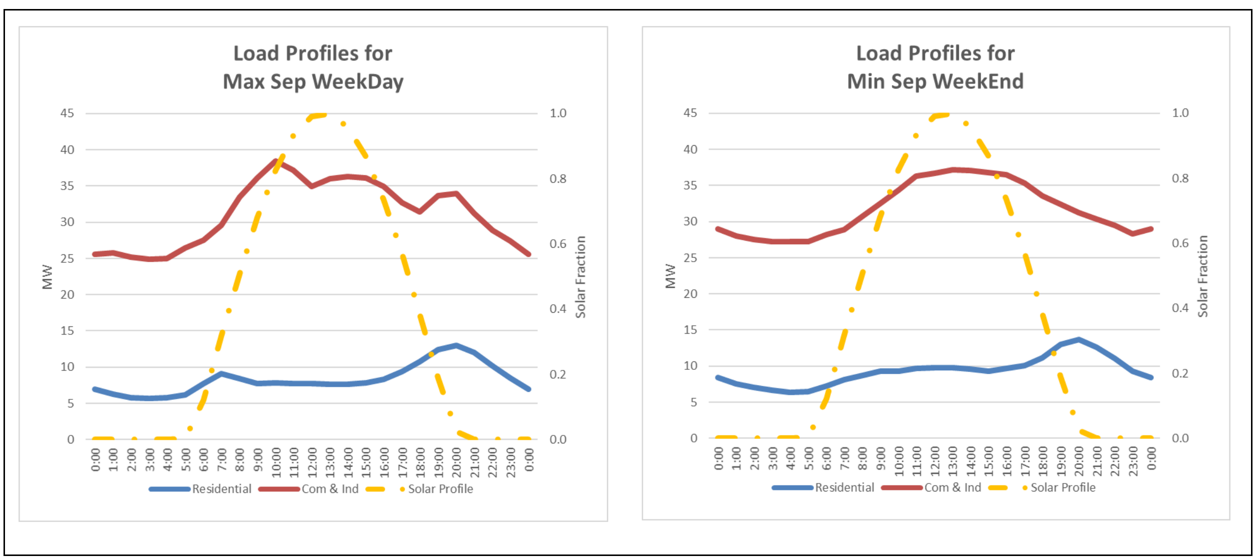


Figure 7: Maximum and Minimum Load Profiles for C&I and Residential with PV Generation Overlay throughout Hunters Point Substation Area

The correlation with load sizes and siting opportunities can be further seen with **Figure 8**. This graphic plots the transformers in the substation area. The smaller transformers are light blue. As the transformers increase in size, their color goes from white to red, and their relative symbol size increases. Along the northern edge, many large C&I rooftops can be seen where there are large transformers. Another strong cluster is seen on the western edge, past the freeways. The southern portion has many large transformers, but this area is going through redevelopment, so most of the added PV was sited among the northern opportunities.

Figure 8: Hunters Point Substation Service Transformer Sizes

Assessing Capacity to add DG to Hunters Point Grid

Assessing the capacity of the grid to incorporate DER involves grid simulations under extremes of minimum load and maximum generation. The most likely times for this situation are weekends at noon when many commercial/industrial operations have minimized their loads due to higher rates, and PV generation is at a peak. **Figure 7** shows the September weekday and weekend residential and commercial/industrial loads for the entire Hunters Point substation. The expected solar profile is overlaid for reference.

The impact of adding 30 MW of DER to the Hunters Point grid is shown in **Figure 9**. This is the same feeder as shown in **Figure 3.** The amount of solar on each feeder is shown next to the blue solar icon. On four of the feeders, the added solar at noon is greater than the noon load and the normal power flow direction is reversed as indicated by the red arrows. Power flows out of these feeders and crossfeeds to serve loads on other feeders. Because the combined net load for the entire substation is greater than the added 30 MW of PV, all of the PV is consumed within the Hunters Point substation and there is no power backfeeding from the distribution to the transmission grid.

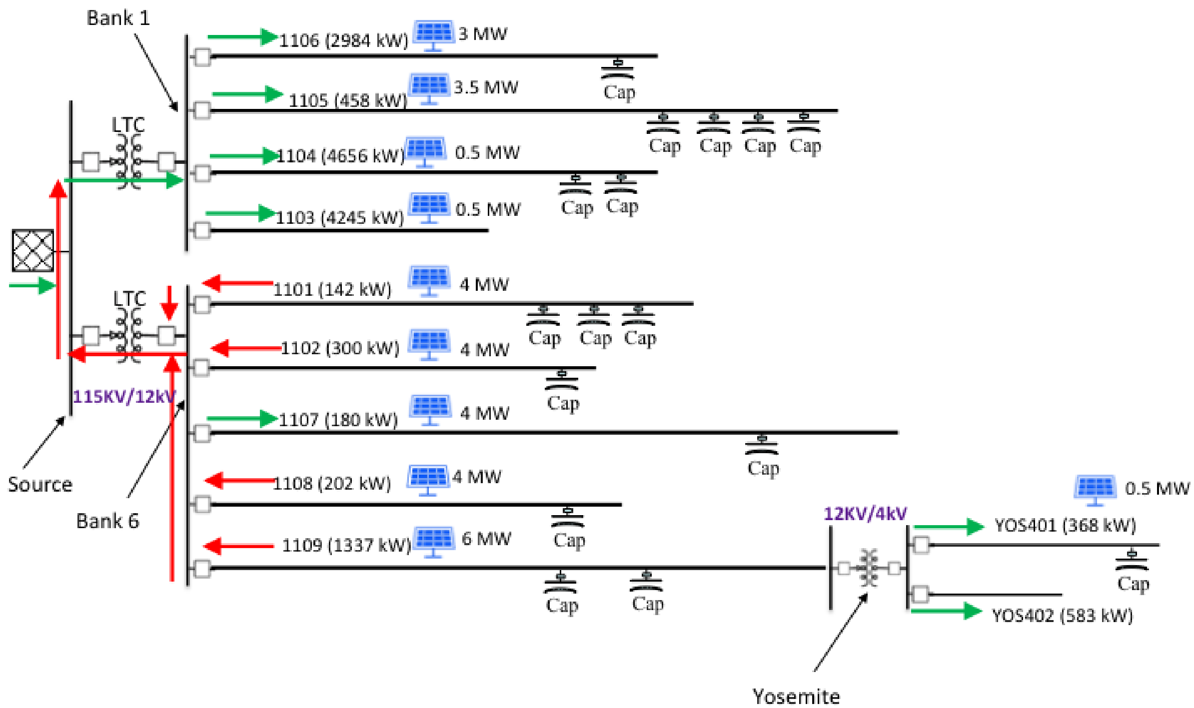


Figure 9: Feeder Map of the Hunters Point substation with 30 MW of Added Solar Distributed among the Nine Feeders at noon

Note: green arrows indicate downstream power flow; red arrows indicate upstream power flow.

The grid remains within voltage limits even with the added PV. The existing voltage control devices operate to smooth out any voltage variations, as seen in Table 2. With the added PV, the load tap changers (LTC) experienced a slight increase in activity, as seen in Table 3. The Yosemite transformer had one tap without added PV and four taps (two down, two up) with; Bank 1 had one without and one with; Bank 6 had one without and three with.

Feeder		Sep WeekEnd Min Load Profiles – No PV – V_Base, all monitored pts: Min	Avg	Max	Voltage Summary	Sep WeekEnd Min Load Profiles – 30 MW PV – V_Base, all monitored pts: Min	Avg	Max
22331106	Bank 1	121.8	122.9	124.0		121.5	123.0	124.0
22331105	Bank 1	122.0	122.9	124.0		121.7	123.0	123.9
22331104	Bank 1	122.3	123.8	124.8		122.1	123.8	124.7
22331103	Bank 1	120.0	122.6	124.0		119.4	122.5	123.9
22331101	Bank 6	122.1	122.8	123.3		121.4	122.8	123.9
22331102	Bank 6	118.9	120.6	123.2		118.3	121.0	123.6
22331107	Bank 6	116.7	119.1	123.1		115.9	119.4	123.5
22331108	Bank 6	118.1	119.7	123.1		116.9	119.7	123.5
22331109	Bank 6	119.1	121.0	123.2		118.2	121.3	123.6
22490401	Yos	119.5	121.9	124.7		117.7	122.1	125.2
22490402	Yos	122.7	123.7	124.8		119.2	123.1	125.3

Table 2: Feeder Voltages without PV (left) and with PV (right) for a Weekend Day in September

	Sep WeekEnd Min Load Profiles – No PV: Num of Tap Changes	Min Tap	Max Tap	Average Tap	Tap Change Summary	Sep WeekEnd Min Load Profiles – 30 MW PV: Num of Tap Changes	Min Tap	Max Tap	Average Tap
Bank 1	1	8	9	8		1	8	9	8
Bank 6	0	8	8	8		3	7	9	7
Yosemite	1	13	14	13		4	12	14	13

Table 3: LTC Tap Changes without PV (left) and with PV (right) for a Weekend day in September

Figure 10 shows the operation of the Bank 1, Bank 6, and Yosemite LTCs throughout the day. Without PV, the Bank 1 LTC taps up at 10 AM; with PV, the up tap is delayed until 7 PM. Without PV, the Bank 6 LTC is unchanged; with PV, there is a down tap at 10 AM as the PV generation begins to flow into the grid. Without PV, the Yosemite LTC down taps at 8 AM; with PV, the LTC down taps twice in the morning and up taps twice in the evening when the sun has set. The Yosemite sub-feeder is a higher resistance grid and thus more susceptible to voltage swings from changes in load and/or generation. Overall, the LTCs performed as expected, well within their operating ranges.

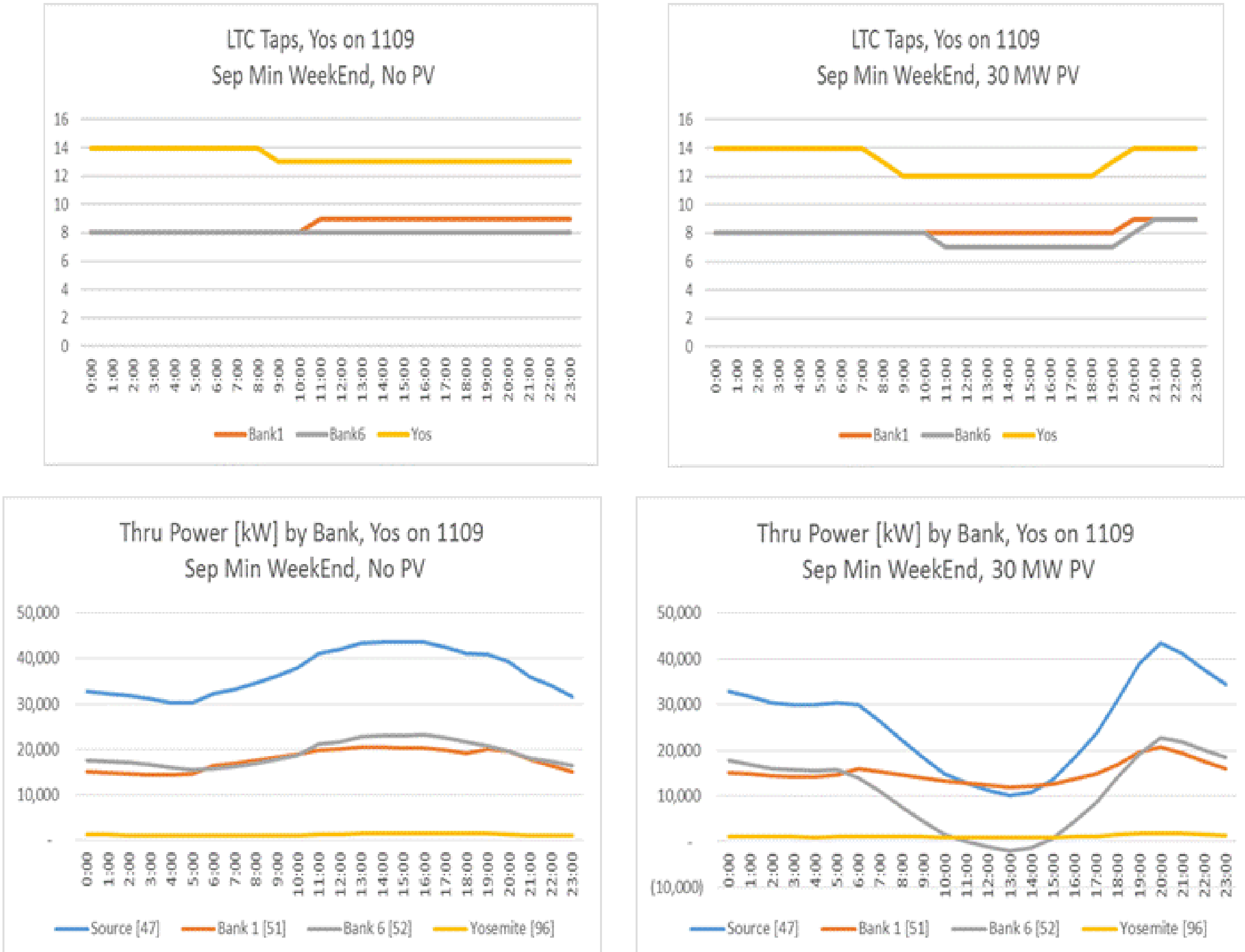


Figure 10: Hourly Substation Power Flows and Operation of the LTCs for a Weekend in September.

Also shown in **Figure 10** are plots of the time variation of the power flowing through the two banks and the Yosemite sub-feeder. Without PV, the power consumption follows a typical daily pattern — low at night, rising during the day, peaking in the afternoon, and decreasing in the evening. With PV, power consumption in Bank 6 (largest PV concentration) transforms into a "duck" shape, exhibiting negative (crossfeeding) flow when the PV output is at a maximum and rising to a sharp evening peak as the sun sets. On Bank 1, the lower concentration of PV has a similar but smaller impact. The two situations in **Figure 10** represent the well-known CAISO "duck curve" issue in that the PV helps with overall net load energy reduction from the substation, but does not help lower the evening peak. Other techniques such as Demand Response and Energy Storage must be employed to reduce evening peak.

Based on the above findings, the potential sizes and locations of solar within the community's current distribution network are estimated using the following engineering judgments:

- Lower resistance means more capacity for local generation
- Higher daytime loads mean better match to PV generation

Voltage Regulation in Action

Figure 11 is the same type of plot as Figure 6, built around a short circuit study for Feeder 1102. It illustrates the principles listed above, utilizing low resistance in combination with daytime load sizes for preferred siting of large PV sites.

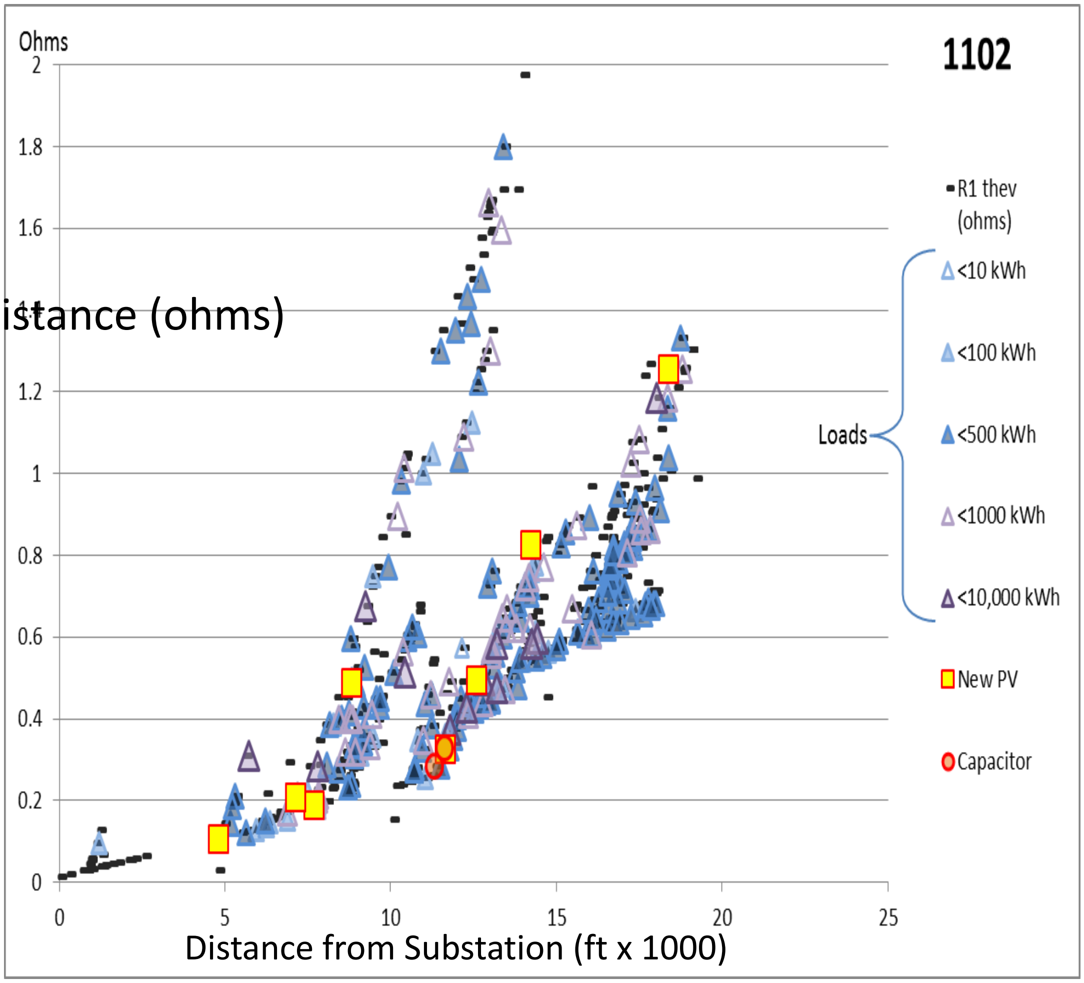


Figure 11: Feeder 1102 Resistance vs. Distance for Feeder 1102 including Load Magnitudes and PV Locations

Figure 11 visually highlights the important fact that large daytime loads are mostly located on lower resistance feeders. The optimal location for PV is as close as possible to these more "robust" feeder segments that have less resistance and high daytime load profiles. Guiding deployment to optimal locations maximizes the amount of local renewables that can be supported by a substation system with no changes or upgrades needed. This is critical information in order to design the most cost-effective solution possible because robust feeder locations and customers with large daytime loads offer the most optimal locations.

The action of the voltage regulating components can be seen in Figure 12 for two feeders that were selected because they had the largest overall variation.

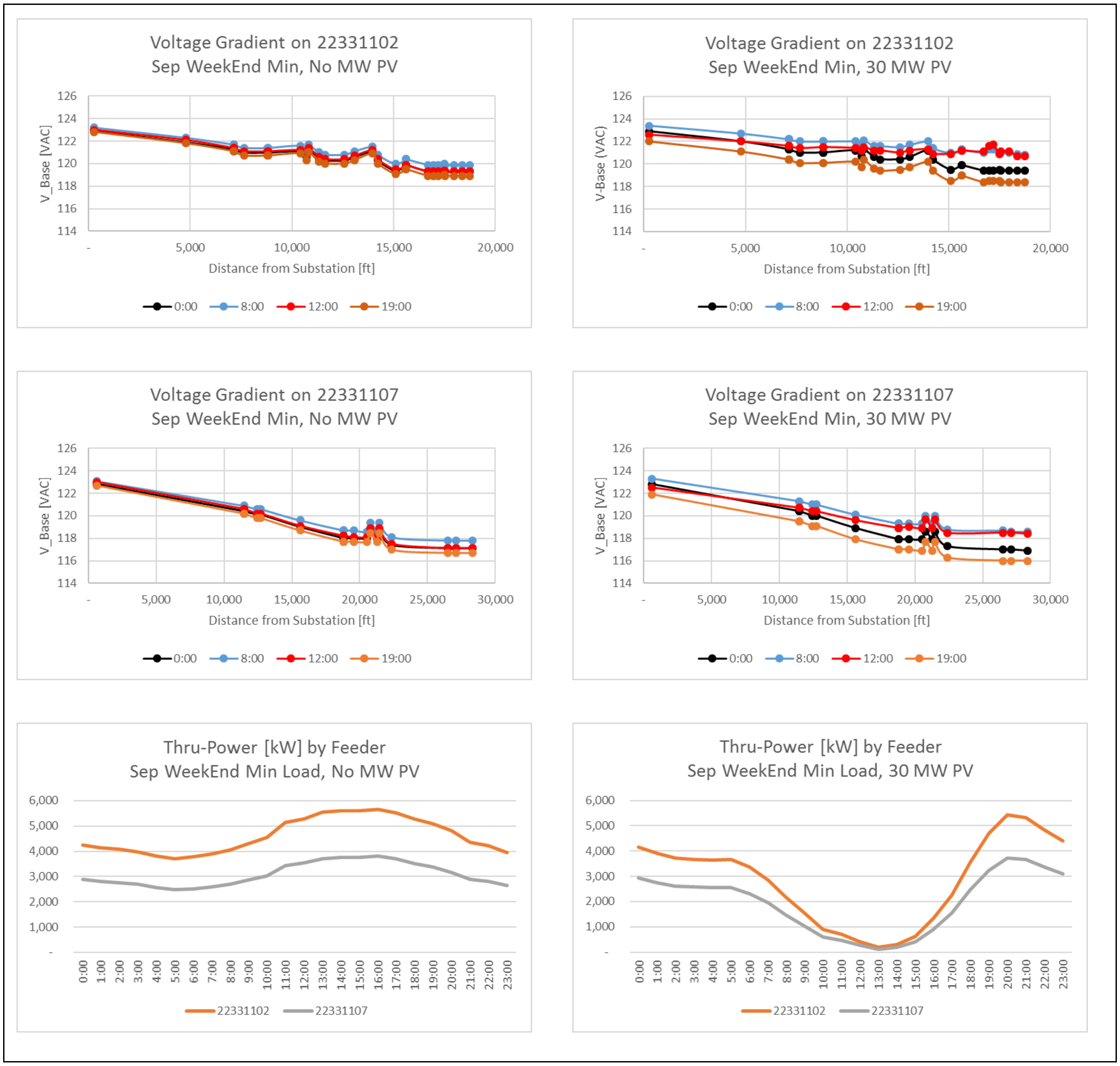


Figure 12: Voltage Regulation without (Left Column) and with (Right Column) PV

The left column shows the baseline without PV; the right with a total of 30 MW PV for the system, with 4 MW on each of these selected feeders. The top two rows are voltage gradient plots at selected points along the two feeders (1102 top most, 1107 on second row). As expected, the voltage drops from the substation (left axis) as the distance from the substation increases toward the right. The different plotted lines are for different times of day: midnight/black, 8:00 am/blue, noon/red, 7:00 pm/brown.

The impact of the large PV near the end of feeder 1102 (see the red uptick in **Figure 12**, and see the large PV at about 18 kft in **Figure 11)** is easily discerned, but the voltage does remain in compliance due to nearby loads. The plot for feeder 1107 has greater overall dispersion, but still remains compliant. The third row shows the net load as a function of time on several of the feeders, with some of them backfeeding up to the bank level (see also **Figure 9** for the noon flows). Obviously, if some of these large, nearby loads suddenly go away, control measures will have to kick in to prevent overvoltage from occurring.

Other DER Methods

It was assumed at the beginning of this project that advanced DER techniques — such as smart inverters, demand response, EV charging stations, and energy storage — would be needed to enable the planned 30 MW of PV to function without causing voltage issues. It was a surprise to discover that the combination of a network designed to service large C&I loads plus the profiles of the C&I loads were sufficient to manage the voltage for this case.

The other DER techniques were simulated successfully using fixed sets of generation and load profiles to verify they could be used to model these methods implicitly. Since this study was concluded, CYME has added explicit DER features to support advanced inverters and energy storage directly in CYMDIST.

Forcing Out-of-Range Voltages

To verify that out-of-range voltages could be created in this configuration, changes were made to force the error condition. Overvoltage was finally achieved by:

- Increasing the additional PV from 30 W to 42 MW among the feeders.
- Removing 12 MW of spot loads.
- Freezing the LTCs near the high end of their range.

This amount of perturbation needed to force an error indicates a very robust and stable grid.

Conclusion

Significant Findings

This case study emphasizes that this enormous asset — the Hunters Point Substation Distribution Grid — has significant underutilized capacity to accommodate local PV and other DER assets based on this analysis. This capacity, and capability, should be realized in order to get the most out of our distribution grid investment.

The biggest finding from the PV siting and the simulations is that existing load itself, along with low-impedance access to that load, should be considered as resources when planning DER. This resource already exists without any further effort and should be first on the list of considerations for planning.

For utility distribution planning, C&I customers can be an ideal match for DER programs, and especially PV, in these important ways:

- Maximum Generation Potential: C&I customers have larger rooftop and parking lot spaces that can generate larger amounts of energy. Although some older buildings may have problems with weight bearing of new PV systems, this issue can be addressed through newer light-weight mounting systems or adding internal reinforcement to the roof structures.
- Lower Costs: Larger PV systems at C&I locations are more cost-effective to deploy than smaller residential rooftop systems, reducing overall system costs.
- Best Locations: C&I customers typically use much larger loads and thus are connected to more robust feeder segments. These more robust feeder segments are capable of handling more DER without grid upgrades.
- Matching Loads: C&I customers typically have larger daytime loads that match solar generation profiles.
- Financial Motivation: With proper feed-in tariffs, the owner of a C&I building can create a guaranteed revenue stream that utilizes an asset, the roof, that normally does nothing more than keep the rain out.

Given these five advantages, C&I customers offer the lowest hanging fruit to achieve scalable and cost-effective DER deployments. Utilities seeking to achieve distributed generation goals quickly and cost-effectively should design DER programs to leverage the C&I opportunity. **Figure 7**, above, helps illustrate the value of a utility or community DER program focused on C&I customers. Note the load shape for the C&I customer segment, which is the red line in the diagram. As a general rule, the load requirements of the C&I customer segment reach an extended peak during the daytime, matching the generation profile of PV much more closely than the residential customer segment.

Consuming all local DER within a substation’s distribution grid is a key aspect of the Hunters Point Power Flow Analysis Methodology Case Study. These simulations demonstrate how excess power in one part of the distribution grid can meet load demands in another part of the same distribution grid. The added generation capacity can be accommodated by the existing loads and voltage control equipment. No upgrades to the grid are required.

Six Step Methodology

As a result of this and other studies, the Clean Coalition recommends the following sequence for deploying large amounts PV in small areas (substation level).

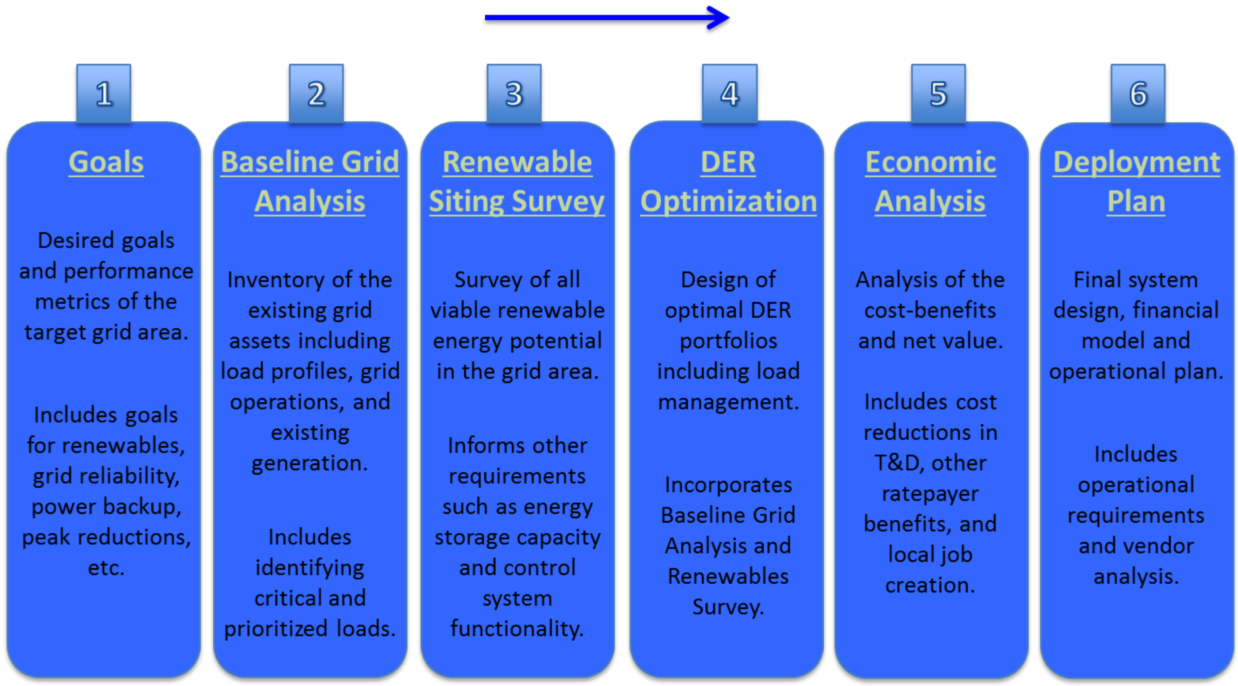


Figure 13: Steps for Deploying Large PV Systems

The steps are well defined in **Figure 13**. The goals should be aggressive, but achievable. The Clean Coalition has set a goal of achieving 25% of total annual energy (not power) from renewables in a defined area. If this is done with PV, the most easily deployed renewable, then there will be backfeeding due to the solar capacity factor. However, this case study has shown that for many urban, mixed-use areas, the distribution grid can likely handle this much, and possibly more PV, if intelligent choices are made on where to site the PV to take advantage of robust portions of the grid.

Capacity Planning Cost Effectiveness

Advanced distribution grid modeling, which includes optimization analysis for both the location and mix of distributed energy resources, allows for a quick and accurate assessment of an individual substation's potential capacity for local renewable energy. Utilities can then rapidly deploy local renewables in communities based on simplified "integration" scenarios, such as:

1. Lower Cost Capacity: the amount and location of local renewables that can be brought online, employing existing C&I loads and connectivity, utilizing existing voltage regulation and advanced inverters, with minimal investment in the distribution grid.
2. Medium Cost Capacity: the amount and location of local renewables that can be brought online with cost-effective storage and some investment in the distribution grid.
3. Higher Cost Capacity: the amount and location of local renewables that islands essential services with additional storage, local reserves, and more *substantial* investment in the distribution grid.

These scenarios will guide utilities and regulators to determine appropriate local capacity targets for renewable energy and establish pathways to meet the specified goals. This combination of advanced distribution grid modeling and cost scenario analysis creates a replicable and scalable method for deployment of local renewables.

The Hunters Point case study demonstrates that the distribution grid has the capacity to add significant amounts of local renewables when they are properly sited utilizing existing grid assets.

Impact

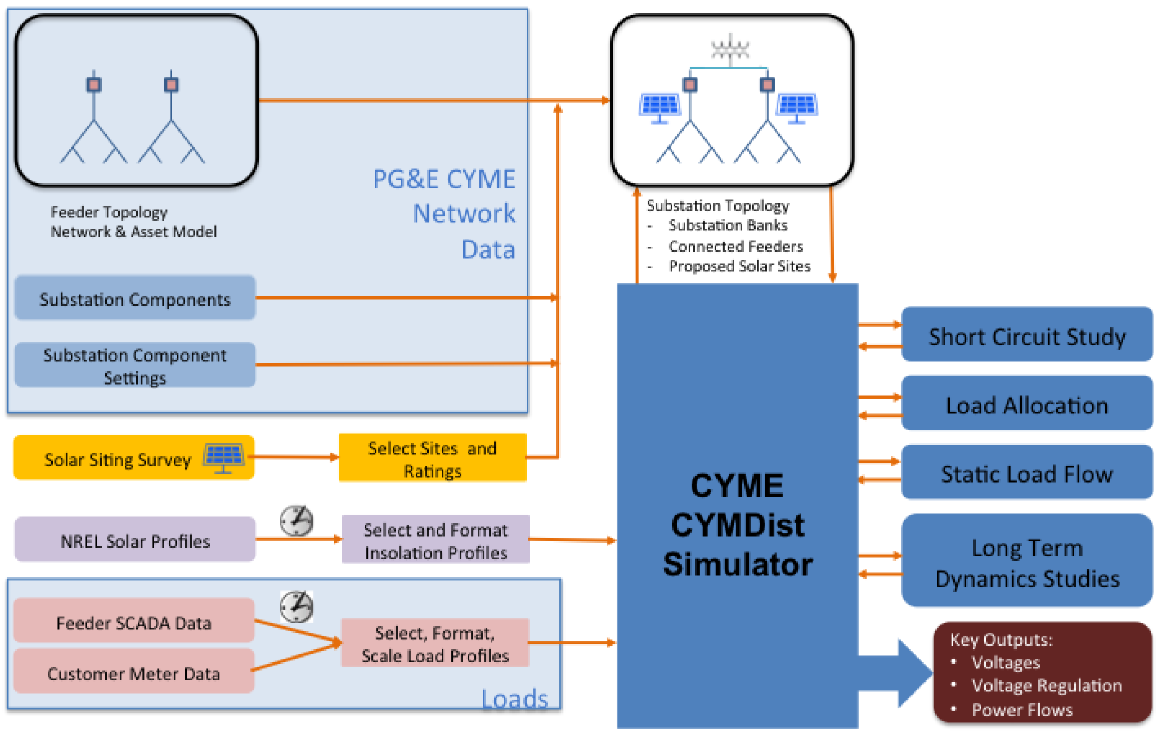
We delivered the results and recommendations from this case study to PG&E, the City of San Francisco, and the California Public Utilities Commission (CPUC). We used data from this case study to strengthen implementation of Assembly Bill (AB) 327 — first in the nation legislation requiring investor owned utilities (IOUs) in California to identify optimal locations for the deployment of DER through distribution resources plans. In November 2015, CPUC Commissioner Michael Picker issued draft guidance on AB 327 implementation through the CPUC's Distribution Resources Plan proceeding, which incorporates seven recommendations that come directly from this case study, including developing demonstration projects. This in turn has led to the Integrated Capacity Analysis (ICA) requirement for California's IOUs to develop new methods to more accurately estimate the capacity of feeders to support various types of DER and to make this information available to the public.

We also shared our case study results with officials in New York, as the State embarked on its ambitious Reforming the Energy Vision proceeding. This case study was key to the development of new requirements for New York utilities, which must now produce Distributed System Implementation Plans that are very similar to distribution resources plans.

The existing process of evaluating local renewable energy projects one at a time is painstakingly slow and introduces costly delays for these projects. By modeling large areas of the distribution grid, utilities and regulators can efficiently identify greater DG opportunities and establish streamlined deployment plans. This system-wide approach enables large amounts of local renewables to come online in months rather than years.

Appendix A: Data Processing to Support Dynamic Load Flows

At higher penetrations of distributed generation (DG), it is necessary to see the impacts of potential crossfeeding and/or backfeeding and the dynamic operation of voltage regulating elements by merging what are often discrete, non-integrated feeders into an integrated, cohesive model with all the voltage regulating elements working together dynamically. For convenience, **Figure 4** is repeated below for an overview of the data flows and the processing that are described in this appendix to create this model.



Modeling Platform

All simulations were conducted using the CYMDIST power flow modeling tool within CYME. CYME was chosen because the PG&E data was already in the CYME format, thus avoiding a data conversion step. The time series load flows and voltage regulation simulations were done using CYMDIST version 5.04 r10. This version did not include DER models (smart inverters, energy storage, EV charging, etc.). These capabilities have since been added by CYME.

Problems to be Solved

The simulation requires inputs from multiple data sources that normally are not required to work together and are rarely if ever cross-checked for consistency. The major issues are first described.

Examples

Load & Generation Profiles

Load and distributed generation (DG) profiles are provided by the utility, usually in hourly or 15 minute intervals. The sources range broadly across utilities and are normally not cross-checked for consistency.

Various types of data are used for different purposes, and their normal applications do not normally require correlation with other datasets.

Profiles by customer type

The best and most accurate load data is from Advanced Metering Infrastructure (AMI) data. Utilities collect these data from all customers of all types. With AMI data it is possible to get a detailed breakdown by customer type as long as the model is correctly configured. Integral Analytics provided anonymized AMI data of the Hunters Point substation loads. The AMI data was scaled to match known peak loads from the total substation SCADA data. Details on this methodology are discussed below in the Load Profile Scaling section.

Absent AMI data, load information is obtained from SCADA feeder level profiles which do not break loads down by customer type. The dynamic load flow can still be run successfully, but the insight from customer type on different feeders and sections will not be available. See **Load Profiles** for more details.

Solutions/limitations/work arounds/consequences

The basic goal is to find the issues with the data and decide how to correct them, correlate them, or fill in the missing components.

Data limitations

Many companies have adapted tools designed for transmission load flow studies to those targeted at the distribution grid. When used for distribution grid studies, distribution components or details may have been omitted from the models and now need to be added with newer tools that can take a more detailed look at the distribution grid. Examples include substation components like load tap changers (LTC), bank transformers, and series reactors. Without these components, the accuracy of modeling unbalanced loads and similar issues is limited.

All companies have periodic upgrades of the tools they use to conduct operations. With each major change, decisions must be made as to how much historical data will be transferred into the new formats and verified. Assumptions have to be made as to content of new fields that were not present in the old data set. As the data translations occur, data is often lost if it was not needed in the new platform or has not been added if it did not prevent studies from being run. Over time, the troublesome networks are kept up to date, but those that have not had many problems and have not much attention may be lacking in detail in the network databases. The type of data that is missing determines the approach to replacement or substitution.

Secondary Side Data

For the modeling, no secondary side data, other than load summaries by customer type at the transformer, was available. When detailed customer load information is available, it may be necessary to create a reduced dataset with the secondary information trimmed off and the net loads summed at the transformer level. Doing so will minimize the number of issues that have to be resolved in initial debug of the dataset. The section on **Static Load Flow** modeling discusses this in greater detail.

Static vs Dynamic (Time Based) Load Flow Modeling

Most utilities have focused their effort historically on static, worst-case load flows and have not yet developed the expertise in-house for dealing with high levels of DG with time-of-day dependencies. In some cases, work-arounds have been developed when varying values are needed, e.g. modeling each tap on a LTC and running separate load flows with different starting voltage conditions. Where customer types are known but time data is not available, it is sometimes possible to use curves from other studies to make reasonable estimates of the profile shapes and then make several runs to discover which ones are the best match for the overall substation SCADA profiles.

Dynamic models like CYMDIST allow load flows and voltage changes to be simulated based on the time of day, date, and time varying inputs (loads, insolation, etc.).

Network Model

Discrete Feeder Model

Utilities typically model distribution grids as distinct, disconnected feeders with no view of the banks or other substation components. These models have been adequate in the past when DG penetration was low. At higher penetrations of DG, it is necessary to see the impacts of potential crossfeeding and/or backfeeding and the dynamic operation of voltage regulating elements.

Substation Model

Simulating crossfeeding and/or backfeeding requires a model of the substation topology, potentially up to the interconnection with the transmission grid. The complexity of the model will vary depending upon how far upstream, toward the transmission grid, the simulation is required to cover. The basic level will be determined by how far backfeeding needs to be simulated. A bank level model is sufficient for simulating crossfeeding between feeders. Joining the banks into a complete substation model is usually straightforward and will cover most scenarios.

Substation Components

A reasonable representation of the substation is needed in order to see the effects of crossfeeding between feeders in the same bank. Including bank transformers will improve the accuracy of the simulations. Moving the driving point of the model upstream from the feeder headend through the transformer impedances provides more "room" for the voltages to vary in a more realistic manner. Series Reactors are needed in order to get reasonable values from short circuit studies. These can be added discretely, but some programs allow adding them as integral properties of devices such as circuit breakers.

Voltage Regulator Settings

In addition to the transformer attributes, LTC attributes and settings are crucial to getting a stable model that gives proper outputs under a wide variety of load conditions. It is important to match the control connectivity choice that is being employed in the field. The model will not be stable until the voltage regulator settings are accurate.

Capacitor Bank values and settings will also be critical. Most modeling programs allow options for fixed on/off or voltage sensing on/off. Some allow scheduled settings.

Testing the Model

Testing the complete model with all the components and their settings is found in the section on **Validation of Complete Circuit Model**.

Determining Load and Generation Profiles

Seasonal worst case loads are normally used in load flow calculations. Cases to consider are:

- Typical situations for calibration of loads, baseline (with DG off)
- Max/Min loads
- Min/Max generation

Generation

Generation profiles will come from sources associated with the type of generation. For renewables, there are sources that can provide good statistical variety.

PV Profiles

The best source of information on expected PV profiles is NREL's System Advisory Model (SAM). It includes the effects of weather (clouds). One trick that can simplify other calculations is to run SAM for a hypothetical 1 MW PV array at the location under consideration, then use the output as a scale factor for other proposed site sizes.

The weather variability inherent in the model allows simulating multiple scenarios. The choice of day(s) could include

- Clear days for max solar
- Cloudy days (minimal output)
- Consecutive minimum days (worst case total energy sum)

Ps & Qs

Modeling programs generally allow generation and load profiles to be stated as either a magnitude and phase angle or as real and reactive components. Updates to some programs are beginning to allow smart inverter functionality with variable/controllable reactive power based upon various control profiles and settings.

Siting DG

For a proposed site, the location is already determined. See **Siting DG and DER** for discussion on siting for broader capacity studies.

Loads

Spot Loads

Commercial software vendors have very detailed methods for entering load data into their models.

Fixed value given in kW or kWh (or both)

Verify what statistic the spot load in the model represents: average over a period, max in a period, etc.

Given in model

Utilities employ processes that periodically populate the spot load data based upon billing information. It is preferable to get both current and historical data to match the needs of the use cases that will be run.

Load Profiles

The approach depends upon whether metered load data is available. The load data will be used to set up corner cases with generation data, so choices should be made with this in mind.

For instance, load flows are often run with a focus on overall peak loading conditions. However, a worst case condition for dynamic modeling is minimum loads with maximum PV near the noon hour, where overvoltage is more likely. Also, the weekend and weekday profiles can be distinctly different depending upon the mix of customer types found on different feeders (see **Figure 7**).

Metered Data available

Metered data is much more useful if it can be binned by customer type. It usually consists of:

- Customer Type
- Month or season
- Weekday and Weekend
- By hour or quarter hour

Choices of Summary Statistics

Load data can be summarized in many ways with differing statistics. Utilities already are expert at extracting monthly or seasonal statistics for their own planning purposes. One very useful approach is to create separate curves which represent profile probabilities, i.e. probabilities that at a given time increment, the load value will be less than the stated value. Typical examples would be to use data for peak loads and data for minimum loads.

No metered data available

Without AMI data, SCADA data from the substation must be used to create load profiles, but there will be no independent representation by customer type.

SCADA Data

Like all other data sources, SCADA data needs to be screened and qualified. Companies may not be using SCADA data for daily operational decisions, so there may be some holes and unique situations represented in raw data.

Ps & Qs

Users of load flow modeling are already familiar with how each tool can accept complex power representation. Choices will normally be either VA magnitude plus phase angle or separate P and Q components.

Scaling

The statistical nature of the load profiles guarantees they will not sum up to any given daily load profile. Therefore, they must be scaled to match the particular case/problem being analyzed.

Scaling of the load profiles cannot be done until dynamic power flow modeling is working, as described in **Static Load Flow**.

Briefly, one must pick a reference point to scale to. Examples are peak load or total energy over some interval. Peak load is normally chosen because it represents the most likely condition in which anomalies might occur that could be triggered in the simulations. **Figure 14** shows how scaling is applied to load profiles by customer type, in this case against peak load for the substation for the given conditions.

Validation of Complete Circuit Model

The model to be used should be validated using good engineering practice. A series of steps is normally used to do this. For legacy models that have been transferred among various modeling tools over the years, this process may uncover discrepancies and missing data that may need to rectified.

Short Circuit and Protection Tests

For feeders in stable areas, these tests may not have been done for a long time, and they provide a great way to test how other components may have been dropped from the network model over the years.

Where discrete feeder models have been in use for some years, a common missing component are the series reactors at the head end. This omission will be obvious by excessive currents in the short circuit test. It may require digging through old records to find the values that need to be inserted. Any issues should be rectified before proceeding with load flow models.

The studies should first be performed with DG off. After correcting any problems, they should then be done with DG enabled to see if the new generators cause any problems.

One output of the short circuit studies that can be useful is the R1 Thevenin equivalent resistance from the substation as will be discussed in **Siting DG**. It can be used for making visualization plots for PV siting (**Figure 6**).

Running Balanced or Unbalanced

It is desirable to run the network model unbalanced to get greater detail, but very good insight can still be obtained for typical networks running only balanced. If the phase details are not available, most commercial programs will make reasonable assumptions for distributing the load on 2 and 1 phase circuits.

Load Allocation

Load allocation is the process of partitioning power (kW) or current (Amps) per phase load at a given point to the individual circuit elements down the line. It is a close approximation to actual loading and is something of an art form. (Jennifer Taylor, 2009)

There are different ways of distributing the load, and modeling programs will assist with deciding upon an allocation method based upon the type of analysis that will be done. (Milsoft)

The allocation must be done before load flow can be run.

Correct Allocation Problems

Typical problems found during allocation runs might include missing load values or locked loads that must be unlocked in order to be adjusted. Plan on several runs if the feeders have not been examined in a long time.

Inputs and Outputs.

All of the network elements for a load flow are required. In addition to the network and its components, some method of estimating the spot load on each transformer is needed. Typically billing data for power (kW) or energy (kWh) is used, but transformer ratings can be used in the absence of billing data. The modeling software will provide approaches to choose from based upon what data sources are available (Jennifer Taylor, 2009). Most utilities have standardized processes for updating the seasonal loads in their models.

The outputs will be updates to the model with properly allocated loads that are ready to run load flow simulations.

Static Load Flow

Load flow is a numerical analysis of the flow of electric power in an interconnected system. (Wikipedia)

Static (single set of initial conditions) load flow runs must be performed to validate the model before running dynamic load flows with time profiles that vary the conditions throughout a time period of interest.

Additional inputs

Voltage Regulators

Voltage regulators can destabilize the model until their settings are correct. It is simpler to start the load flow runs with the regulators disabled (set to a fixed point such as midpoint) until other issues have been resolved. Once the runs are stable, the regulators can be enabled. Most programs allow the user to adjust the initial settings of the regulators.

PV and Inverters

Solar PV usually has two main components in the model: DC power and inverter power. DG should be Off or disconnected for initial runs until the circuit model is stable. When PV is enabled, some checks must be done as to the relationship between PV DC ratings and inverter ratings.

When the DG is enabled, be sure to check how the system deals with oversized PV generation. Some modeling programs will follow the insolation curve for the PV without regard to the constraints of the inverter ratings. This can also happen when database conversion programs put in a default large value for the PV panels with the intent of adjusting later when more detailed information is available. One work-around to this problem is to drive the inverter from a generator curve rather than a PV insolation curve. It may require several test runs to determine how the modeling program handles these situations and the best way to handle it.

Voltage Check

Most commercial programs provide simple straightforward plots of voltage gradient as a function of distance on a feeder for static load flow runs. These provide an excellent quick check on stability.

Selecting Nodes to Monitor

Some programs provide outputs for every node in the model for each run. In this case, the output will be extremely large files that must be filtered for analysis.

Other programs allow the user to select the points to monitor. Where points are being selected, a chart such as **Figure 6** becomes a useful tool. More detail is provided in **Siting DG**.

Dynamic Load Flow

Dynamic load flow runs a series of load flows with time-based profiles for load and generation that allow a more detailed simulation of grid operation. It provides more detailed information about how the system, especially the voltage regulating components, will behave under varying load and generation combinations that are typical of daily operation.

Stability

It is important that the settings for regulating devices be accurate for the dynamic models to be stable under all conditions. The system must first be made stable (all voltages in range and components operating within limits) running a baseline load without DG activated. If the system is working in real life, then the settings for the regulating equipment should work in the model.

If the model is not stable (voltages out of range, LTCs pegged at limits, oscillating, etc.), it must be debugged. Settings on the voltage regulators are a typical culprit. Make sure that the monitoring points are correct and that the type of connection/operating mode are correct. On LTCs, check to see if the taps have reached their min/max limits; this could indicate errors in line drop compensation, such as R&X settings or the point being monitored.

Load Profile Scaling

The advantage of dynamic load flow modeling is that the effects on non-coincident peaks among various loads and sources can be examined. However, it does require that the profiles in use have a basis in the known reality for those circuits. When different customer types with unique profiles are employed, it is important to scale their profiles to match desired modeling conditions. As mentioned earlier, the max load of the substation with DG Off is typically the easiest statistic to target. The same scale factor can be applied to all customer type load profiles. It is an iterative process and will converge faster using a binary search algorithm where the error around the target has both positive and negative values. **Figure 14** shows an example of scaling a set of load profiles for different customer types for a given scenario.

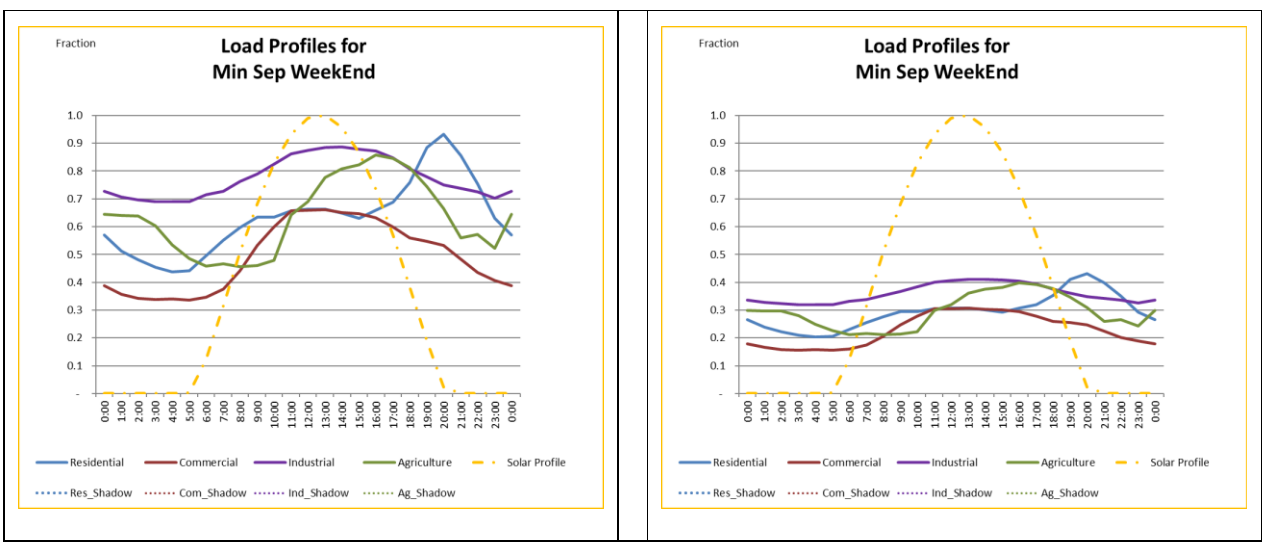


Figure 14: Load Profiles Before (left) and After (right) Scaling

Time Range

Different programs have different methods of managing time sequencing. The interval of coverage can vary from hours to unlimited. The increments may be fixed throughout the simulation run or may allow finer resolution around anticipated events. The load and generation profiles must be set up to match the intended time intervals that each simulation run will cover. CYMDIST is set up to cover 24 hours with resolution as fine as one second for observing the timings involved in voltage regulation elements.

Performing Dynamic Load Flow Runs

Siting DG and DER

For studies involving applications for specific sites, it is straightforward to add the DG to a specific transformer in the model. For more general studies of potential of a section or feeder, siting has more possibilities. Traditional fixed percentage rules of thumb for DG capacity limitations are based upon assumptions around load profile shapes and need to be replaced by analytical approaches grounded in the realities of each circuit's characteristics. New tools are evolving, e.g. California's Integrated Capacity Analysis (ICA) that is built around circuit parameters and the profiles of loads and DG (CPUC DRP).

A visual method for selecting potential locations is shown in **Figure 6**. The black dots are the R1 values from the Short Circuit Study plotted according to distance from the substation. The changes in slope represent the changes in wire gauge along the feeder. Transformer loads of various groupings have been plotted on the appropriate nodes as a reference. Existing capacitor banks are also shown and are usually good indicators of industrial loads that can absorb a lot of daytime PV.

Also shown in **Figure 6** are monitoring points that have been selected for output reports from the modeling runs. A few well-placed points can yield significant insight with smaller datasets.

Inputs

The set of inputs for each run must be logged in order to allow reproducibility of results. Most commercial programs have ways to save the entire set of inputs needed for particular studies. Notes follow on a few items.

Voltage Regulator Settings

If the initial condition for voltage regulators is critical, then these should be recorded for the different runs. Besides LTCs, settings for capacitor banks can be important.

Load & Generation Profiles

As the number of use case combinations rises it is tempting to make up many unique sets of profiles. Where programs use drop down lists for selecting profiles, it can lead to very cluttered, slow, error prone decisions each time a run is made. Some programs, e.g. CYME, only store the path name to the designated profiles in the study file. This allows setting up some standardized corner case filenames for the different cases and then changing the actual profile data to that needed for the month, season, or other appropriate condition for a set of runs. However, good record keeping and consistent methodology is required.

Time range to run

Most programs allow at least a 24-hour run duration. For those that allow longer runs, a 48-hour window allows running with the typical maximum weekday load and minimum weekend load cases in the same run, which can save time in running cases.

Outputs

All programs can output real and reactive voltages and power for the nodes being monitored. It is especially important to monitor the real power for signs of export. The negative power excursion in **Figure 15** with PV active is an example of export at the feeder level.

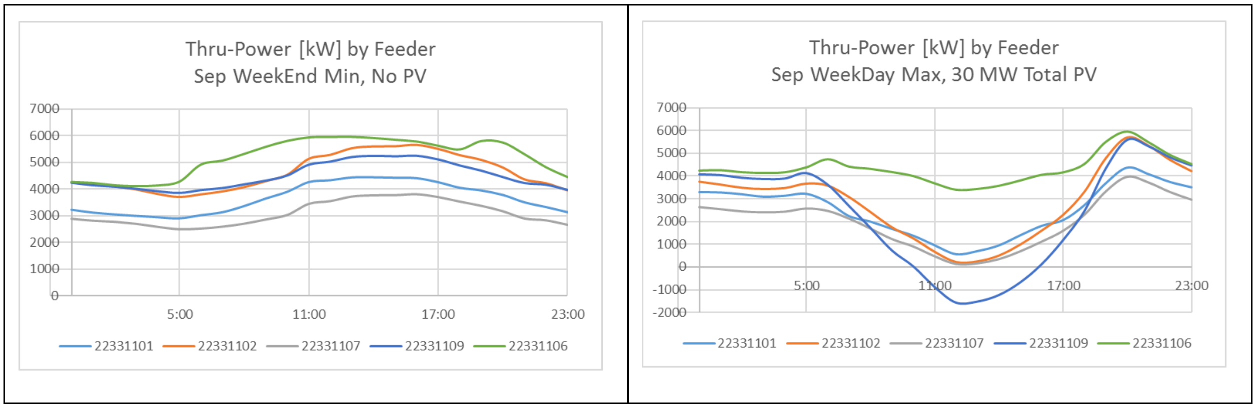


Figure 15: Examples of Feeder Power Flows without (left) and with (right) PV activated.

A set of voltage profiles for selected times can show the increased range of voltages that are caused by large amounts of PV. **Figure 16** shows the impact of PV on a feeder to increase the voltage dispersion, especially from PV near the end of the feeder.

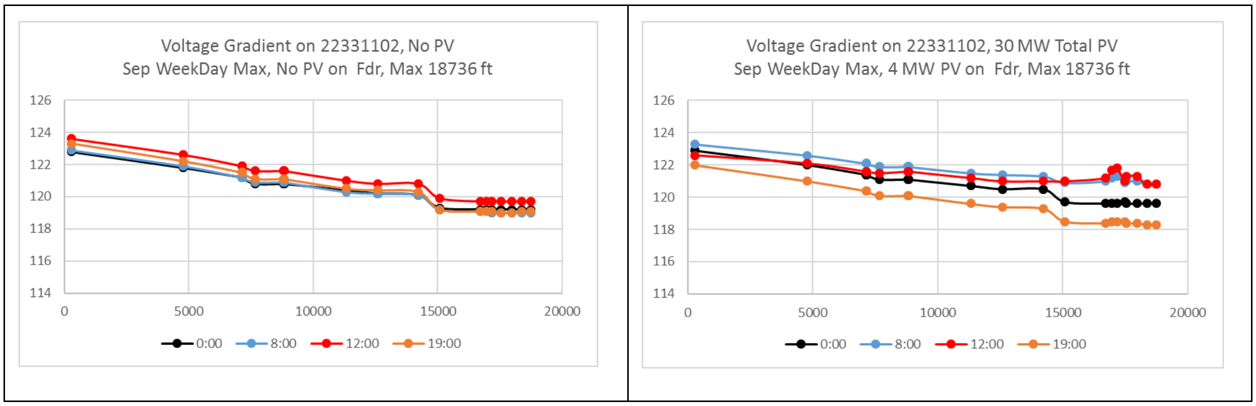


Figure 16: Voltage Gradient Plot for One Feeder at Selected Times, without (left) and with (right) PV

Voltage regulator activity is also important. The timing of state changes can provide insight into how the regulation is accomplished. **Figure 17** shows the increased activity of the LTCs in maintaining voltages in range.

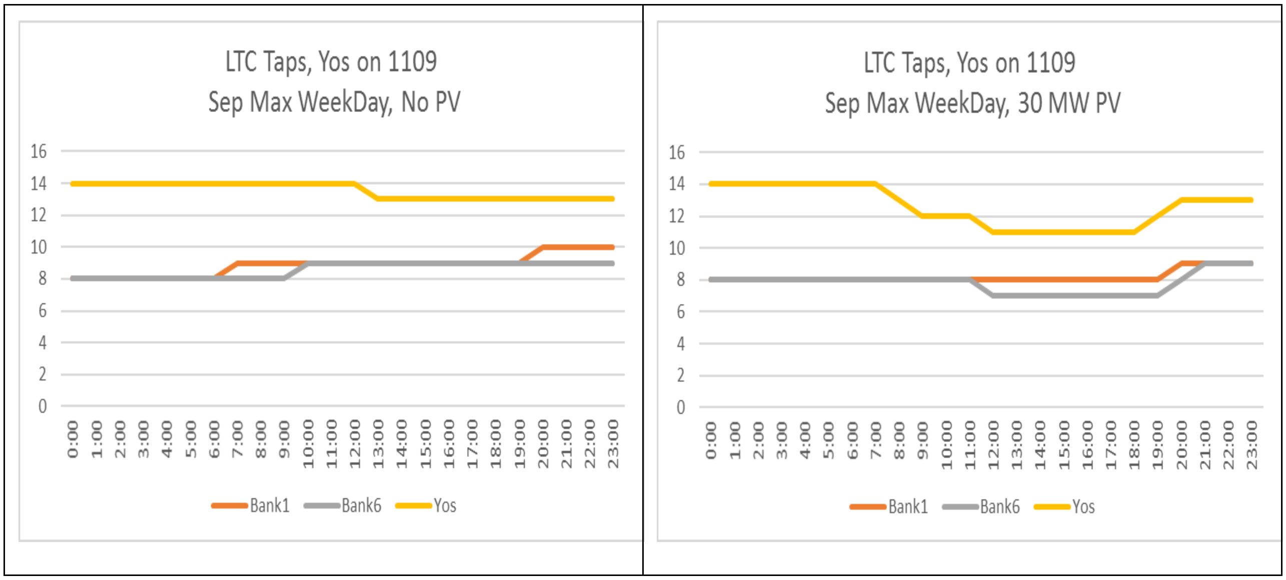


Figure 17: LTC Activity on 3 Banks, without (left) and with (right) PV

Other Assumptions, Issues

Long Term Dynamics Modeling software

Commercial power flow modeling software is rapidly evolving to add other types of DER such as energy storage and electric vehicle charging. If the tool being used does not have these capabilities, the DER can usually be mimicked as a combination of fixed load and generation profiles.

Network model conversion

Sometimes there is a need to convert data from one database format to another. This can be a tedious process, requiring the use special editing tools or writing custom translation code. If possible, check with the software vendor to see if their products can directly import the format used by the source program or if the source data can be exported into a format that the receiving software can import.

Appendix B: How Adding DG Affects Local Voltage

Adding DER to a grid will increase the voltage locally. The amount of the voltage rise depends on the magnitude of the DER; the amount and location of loads, reactive power, and other DER; and the resistance and reactance of the grid itself. The mathematical relationship between the variables is given in Equation 1 below.

$$\Delta V = \frac{R(P_L - P_{PV}) + X(Q_L)}{V} \tag{1}$$

P_L, Q_L are active and reactive power of the load, respectively, and P_{PV} is the active power of PV, respectively. $P_L - P_{PV}$ is the active power flow and Q_L the reactive power flow through the feeder.

This equation represents two important features when connecting PV to the distribution grid and illustrates PV's impact on the flow of power and voltage profile throughout the feeder. First, as the feeder becomes saturated with PV, the network will exhibit a reversal of the normal direction of power flow. Second, the voltage rise in the feeder depends on the feeder resistance (R) and reactance (X). Since R values are generally much higher than X values, the first term in the numerator, $R(P_L - P_{PV})$, usually dominates and the voltage increase is simply a function of the difference in the power consumed by the load and generated by the PV. In extreme cases, when loads are low and the resistance of the grid is high, the added PV can cause the voltage of the grid to exceed allowed limits, as illustrated in **Figure 5**. In order to prevent this from occurring, PV should be installed in as close proximity to loads as possible.

References

CPUC DRP. (n.d.). *Distribution Resources Plan (R.14-08-013).* Retrieved from http://www.cpuc.ca.gov/General.aspx?id=5071

Jennifer Taylor, C. H. (2009). *Basics of Load Allocation.* Retrieved from Slideshare.net: http://www.slideshare.net/MilsoftUtilitySolutions/basics-of-load-allocation-jennifer-taylor-and-chris-hammond

Milsoft. (n.d.). *Engineering Analysis and Load Allocation.* Retrieved from Milsoft.com: http://www.milsoft.com/sites/www.milsoft.com/files/presentation-files/2011%20-%20Engineering%20Analysis%20&%20Load%20Allocation.pdf

Wikipedia. (n.d.). *Power-flow study.* Retrieved from wikipedia.org: https://en.wikipedia.org/wiki/Power-flow_study