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Quantification of Risk of Unintended Islanding and Re-Assessment of Interconnection Requirements in High Penetration of Customer-Sited Distributed PV Generation

Task 2 Report: Statistical Analysis of PV Generation and Load Balance

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imagination at work

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CSI RD&D
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Executive Summary

Unintended islanding happens when a part of a utility distribution circuit that has some level of distributed generation becomes disconnected from the utility system and the distributed generation remains connected to the utility load. In this study we are primarily interested in distributed generation sources based on solar photovoltaic (PV) and interfaced to the utility system using power electronic inverters. The focus of the study are inverters that are not designed to island, which is the vast majority of PV inverters being interconnected currently. While the power supplied by the PV panels and delivered via the inverters offsets the power consumed by nearby loads, both the inverters and the load depend on the utility voltage to operate correctly. If the utility voltage is removed, as is the case during islanding conditions, the combined behavior of inverters and connected loads is not easily predicable and it depends on a large number of factors. The most dominant of the factors is the generation to load ratio, also referred to as the level of penetration.

While it is universally accepted that islanding poses low risk at low levels of penetration, there is little information about what is the safe level of penetration that can be allowed. To make an informed decision whether a given level of penetration can be allowed, it is necessary to consider the second most important factor determining the circuit behavior during islanding: the *load composition*. In the context of this project the load composition is defined in accordance to load modeling guidelines of Western Electric Coordinating Council (WECC). The WECC guidelines recommend representing utility loads using a *composite load model*, which is based on seven equipment varieties including: four types of motor loads, power electronic loads such as various power supplies used in consumer electronics, resistive loads such as those in electric water heaters, and constant current loads representative of electronically controlled fluorescent lightning. For any given level of penetration, it is the load composition that dominantly determines the electrical behavior of the island.

The main goal of our project is to improve the understanding of the combined behavior of PV inverters and connected loads in the interval of time from occurrence of islanding to its eventual cessation. The desired behavior of inverters during islanding is fast detection and disconnection, leading to an orderly outage of the connected load. There is little information available on how severe are the abnormal voltage and frequency conditions on the island before de-energization of PV inverters. As the level of penetration increases, the likelihood of a match between power output of PV inverters and power consumed by the load increases, leading to

greater probability of islanding and greater uncertainty about voltage and frequency conditions. We are seeking to find and evaluate conditions that make islanding detection difficult and to capture the resulting voltage and frequency during these conditions in laboratory measurements. In doing this, we are interested only in realistic conditions – those that can occur on real distribution circuits with realistic load varieties, with interconnected distributed generation screened and approved by a utility company. The study results will also be useful in assessing unintentional islanding conditions due to unauthorized interconnections. For completeness, we note that there may be circumstances where distributed energy resources are interfaced to the utility grid using inverters designed to island and maintain stable voltage and frequency conditions regardless of load composition and level of penetration. Such designs and the necessary requirements for their interconnection are a subject of active debate in the industry, but are not within the scope of this study.

To ensure that our study considers only realistic conditions, our project partner Pacific Gas and Electric Company (PG&E) gave us unprecedented access to the distribution system data, which provided insights into installed PV, types of served load (residential, commercial, industrial and agricultural,) and the applied reactive compensation. The distribution circuits database supplied by PG&E included the complete topological information, which we used to aggregate the PV, the loads, and the reactive compensation by line sections, that is, downstream from utility reclosers. In doing this we covered all likely islanding situations and were able to capture section-scale conditions, which provides greater diversity of conditions compared to capture of feeder-scale conditions.

We then used PG&E's *conversion factors*, which define daily load profiles based on the type of loads and energy consumption data, to convert the data from distribution system database into temporal load profiles and aggregated these profiles at circuit section-level. We compared these load profiles with the daily power profiles of installed PV determined based on the region-specific data from National Renewable Energy Laboratory (NREL). As a result, we were able to estimate temporal changes of PV penetration during hours of sunlight, which is a qualitative improvement relative to penetration test of PG&E's supplemental review that uses aggregate nameplate capacity of inverters relative to minimum load at hours of sunlight.

Next, we applied the composite load modeling guidelines, developed by WECC, to transform the types of loads recorded in the distribution database into the corresponding load compositions. Each studied circuit section provided a sample of a relative mix. We analyzed thousands of these samples to down-select the representative set to be evaluated in the laboratory experiments. The high dimensionality of the problem made it necessary to develop a clustering technique to cover the representative set of mixes with a feasible number of laboratory experiments.

All of the data analysis was automated to use the input data in the format provided by PG&E. This was done to evaluate the feasibility of defining a computer-aided methodology for interconnection studies that is based on specific properties of distribution circuits and loads. The developed tools prove that this is both possible and practical.

Revision Notes

Authors	Date	Rev	Notes
JZB	Jan. 2015	1.4	Incorporated additional comments by PG&E
JZB	Oct. 2014	1.3	Added "Selection of Load Compositions for Laboratory Evaluation", removed "Risk of Islanding" Appendix. Reorganized the document to move descriptions of processes to appendices.
JZB	Jan. 2014	1.2	Incorporated PG&E comments, expanded Ch.3
JZB	Nov. 2013	1.1	Added executive summary and Rule 21 review. Reorganized the document, moved material to appendices.
WJS	Oct. 2013	1.0	First draft

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List of Acronyms

DG distributed generation

GIS geographic information system

NREL National Renewable Energy Laboratory

PG&E Pacific Gas and Electric Company

POA Plane of Array

PV photovoltaic

WECC Western Electric Coordinating Council

Chapter 1

Introduction

The need to prevent unintentional islanding is well recognized in the industry and most photovoltaic (PV) inverters deployed in California include features to detect an island and subsequently "cease to energize" the islanded portion of a utility feeder. The governing testing standard is UL 1741 and most utilities cite inverter compliance to anti-islanding test in UL 1741 as one of the criteria for evaluation of interconnection requests. For example, our partner Pacific Gas and Electric Company (PG&E), uses *Electric Rule 21 Generating Facility Interconnections* [1] to describe the interconnection requirements for generating facilities. In it, Section L.3.b specifies inverters qualifying for "Certified Non-Islanding Designation", as "Devices that pass the Anti-Islanding test procedure described in UL 1741 Section 46.3". However, despite its widespread use and enormous utility to the industry, UL 1741 has several limitations.

To be practical, UL 1741 tests islanding detection in a synthetic condition that does not capture all possible field conditions at the actual installed location and load variations. Furthermore, it is a *type test*, so it offers no insight into possible interaction of anti-islanding schemes from different inverter manufacturers. And finally, it limits the anti-islanding assessment to a pass/fail criteria, which does not address risks of damage to utility equipment or customer connected load equipment due to transient conditions in the time interval between occurrence of the island and inverter's ultimate disconnection from the line. Utilities manage these risks by applying additional requirements to interconnection of certified inverters that in case of PG&E include the implementation of initial review and supplemental review screens and protection requirements sensitive to minimum load and to the presence of other, machine-based, distributed generation [2].

This study seeks to improve the understanding of the combined behavior of PV inverters and connected loads in the interval of time from occurrence of islanding to its eventual cessation. We are interested in exploring realistic conditions – those that can occur on distribution circuits with realistic load varieties, and with interconnected distributed generation (DG) that was screened and approved by an experienced utility company. Our partner, PG&E, is a role-model company in this context: They have a well established interconnection process, they keep detailed electronic records of their vast and diverse distribution system, and they collect and archive operating data from more than one half of their distribution substations. Best of all, they made large samples of the data available for the purpose of the study.

Getting access to the information of this quality and scale is a privilege, and we reshaped our analysis to explore the data at significantly higher level of detail than we originally planned. We undertook the analysis of unprecedented fidelity to fully understand the range of possible conditions with respect to risk of islanding and to, based on it, define the test plan for the full–scale laboratory testing.

This report documents the analysis and it is organized as follows. In Chapter 2, we review the criteria PG&E uses in evaluating the risk of islanding and explain the underlying technical concerns these criteria are based on. We also review the data sources available to PG&E and describe our approach to analyzing the data in the context of evaluating the risk of unintended islanding. In Chapter 3 we review our analysis of distribution circuit attributes of interest to islanding: load by type, installed PV, and utility-owned reactive compensation downstream from utility reclosers. The analysis was performed on three load zones, one coastal and two inland, representing major climate zones within PG&E service territory. The emphasis here is on spatial correlations between installed PV and load types and geographic locations. In Chapter 4 we review our analysis of temporal properties of PV and load. To account for all possible islanding situations, the analysis was performed on the topological level of circuit sections that can become islanded due to the operation of an upstream device. Studying section-scale conditions, in place of feeder-scale conditions, provides greater diversity of penetration levels and load mixes because the effects of averaging are reduced due to smaller scale of aggregation. The section-scale information on installed PV inverters is converted into temporal profiles of power output from PV, and the section-scale totals of *load types* converted into the corresponding temporal profiles and, subsequently, into temporal profiles of load compositions. In the context of this project load types include: residential, commercial, industrial and agricultural (recorded in the PG&E distribution database,) while load compositions include the corresponding load equipment including:

- four types of motor loads,
- power electronic loads such as various power supplies used in consumer electronics,
- resistive loads such as those in electric water heaters, and
- constant current loads representative of electronically controlled fluorescent lightning.

The transformation of load types into temporal profiles is based on PG&E's conversion factors, while the subsequent transformation into load compositions is based on WECC guidelines for composite load modeling. This analysis provides insight into how load composition changes through the day alongside changing power output from PV. Because PV peaks between 11AM and 1PM, we consider a set of load compositions from all circuit segments sampled at noon. Each sample is normalized relative to total power on the section, and this becomes a statistically representative data set from which to pull load compositions for evaluation in laboratory experiments. Chapter 5, describes the clustering technique we used to down-select the representative set of compositions to cover their highly-dimensional space with a feasible number of laboratory experiments..

The supporting processes are described in the appendices:

Appendix A describes the methodology of topological processing of circuit information that associates protective devices with downstream load and PV.

Appendix B describes the heuristic rules used to associate energy produced by behind-the-meter PV with a nearby load.

Appendix C describes the methodology used to develop the temporal power profiles of aggregate PV installation based on region-specific data from National Renewable Energy Laboratory (NREL).

Appendix D describes the components of the tool chain developed to automate the processing of distribution system information at the scale of load zones.

Chapter 2

Risk-of-Islanding in Interconnection Rules

2.1 Background

Unintended islanding of distributed generation is one of the key concerns in interconnection rules. The PG&E's Electric Rule 21 Generating Facility Interconnections [1], filed in September 2012, mentions the term *island* a total of thirty times: it is used eleven times as a part of the phrase *non-islanding* (of which three times as a part of the phrase *non-islanding protection*,) seven times as a part of the phrase *anti-islanding*, seven times as a part of the phrase *unintended island*, and five times on its own. The context for the concern can be understood from PG&E definitions:

Island; Islanding: *A condition on Distribution Provider's Distribution System in which one or more Generating Facilities deliver power to Customers using a portion of Distribution Provider's Distribution System that is electrically isolated from the remainder of Distribution Provider's Distribution System.*

Unintended Island: *The creation of an Island, usually following a loss of a portion of Distribution Provider's Distribution System, without the approval of Distribution Provider.*

In simple terms, there exists a potential operating condition where a portion of a utility-owned distribution system may be energized by distributed generation and subject existing load customers to potential abnormal voltage and frequency. At the same time, a utility has the responsibility to serve the loads by providing power with voltage and frequency within specified tolerances, yet, during islanding, it has no control over voltage and frequency because the island is disconnected from the utility system. The concern over lack of control is beyond simply declarative; it is fundamental and rooted in the typical construction of PV inverters.

Namely, all grid interactive PV inverters available on the market today depend on the utility system to define the voltage—the inverters *inject current* into a utility-provided voltage source. At the same time, the connected loads also depend on the utility system to define the voltage—the loads *draw current* from a utility-provided voltage source. The transition of inverters and loads into an island condition is discussed with reference to Figure 2.1. Part (a) of the figure illustrates a normal (non-islanded) operating condition: the utility voltage V_{GRID} is connected, via switch S_1 to the parallel combination of load, drawing current I_{LOAD}, and distributed generation, injecting current I_{DG}. In this condition, the voltage seen by both the load and the distributed generation is the utility voltage V_{GRID} and any imbalance between I_{DG} and I_{LOAD} is delivered to the utility system, shown as $I_{DG} - I_{LOAD}$ in the figure.

An islanded condition is shown in Figure 2.1 (b). The switch S_1 is now open and all of the current injected by DG is forced to flow into the load. The resulting load voltage V_{LOAD} is now an interplay between the load and DG. This is shown symbolically in the figure by $V_{LOAD} = Z_{LOAD} * I_{DG}$, where Z_{LOAD} represents load impedance. Assuming a *linear* impedance Z_{LOAD} and a surplus of generation relative to load, the load voltage can be higher than the grid voltage during the interval of time it takes the inverters to detect the islanding condition and cease to energize it. An elevated voltage presents a risk of damage to the load, so this is not a desired condition. If, alternatively, there is a deficit of generation relative to load, the resulting load voltage is expected to be lower than the grid voltage, possibly leading to erratic load behavior

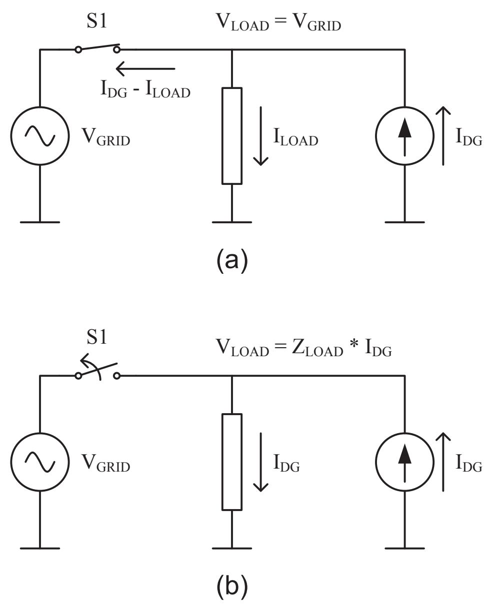


Figure 2.1: Load voltage before and after islanding

and also a risk of damage. To mitigate these potential concerns, the typical construction of PV inverters incorporates anti-islanding features that are tested and certified by nationally recognized testing laboratories.

The ability of DG to detect the islanding conditions and to disconnect is a highly desired property of DG systems. In [1, sec. C] PG&E defines non-islanding as:

Non-Islanding: *Designed to detect and disconnect from a stable Unintended Island with matched load and generation. Reliance solely on under/over voltage and frequency trip is not considered sufficient to qualify as Non-Islanding.*

Note that non-islanding is not defined as an implied feature of inverters—PG&E uses this provision to allow for alternative implementations, including monitoring of a facility power export by reverse power relays.

In the next section, we review the PG&E interconnection process and point out the parts of the process meant to reduce the risk of unintended islanding.

2.2 PG&E Interconnection Process for Distributed Generation

PG&E maintains the requirements for distributed generation interconnection in the Distribution Interconnections Handbook [3]. This content is delivered via a Web portal and includes references to new material such as Distributed Generation Protection Requirements [2], published in July 2013, alongside older material such as Sections 1–6 of the 2003 Distribution Interconnection Handbook [4]. For completeness of this report, we briefly review the available types of interconnection to explain their intended purpose. The engineering review, which is the technical part of interconnection evaluation to be informed by our study, is reviewed in more detail in the following section.

Based on [4], there are two categories of interconnection: Retail and Wholesale. This study is focused on the retail category, which stipulates generation's collocation with a load and its primary purpose of offsetting the load's energy consumption. Note the dependency of this definition on *energy* not power: retail projects can send power back to the utility system, so long as the average energy flow, (the time integral of power,) remains towards the load.

The Retail category includes the three types of interconnection: Standard E-NET (NEM), Expanded E-NET (Expanded NEM), and general retail Rule 21. The Standard and Expanded E-NET (NEM) cover *energy net metering service*. They are limited to specified energy sources, where the intent of installing DG is to offset a part or all of customer electric load. The difference between Standard and Expanded is in the DG size, Standard includes DG installations up to 30kW, while Expanded includes DG Installation greater than 30kW and up to 1MW. In comparison, Rule 21 type of interconnection may include generators of any size and any type under CPUC jurisdiction—it is not restricted to specified energy resources. The eligibility is broader than in the case of E-NET (NEM) connections, and the purpose is to allow customer-owned DG facilities to operate in parallel with the PG&E grid. The Rule 21 interconnected projects are subject to more complex contractual relationship between PG&E and the owner of the DG facility needed to establish operating and communication protocols between the two entities.

Despite the differences in contractual handling, the three types of interconnection process are subject to the same engineering review defined in PG&E's Electric Rule No 21 [1]. We discuss it in the next section.

2.3 Overview of Engineering Review of PG&E's Electric Rule No 21

The engineering review is covered by Section G of Electric Rule No 21. It consists of three parts: the initial review, the supplemental review, and the detailed studies. The initial and the supplemental reviews are relatively simple: PG&E commits to completing the initial review within 15 business days of receiving an application, and the supplemental review within another 20 business days. Detailed studies take longer and the decision to perform detailed studies generally indicates that the applying DG project has a significant impact on PG&E system and may require mitigation which has associated cost. The scope of our study is limited to screens and decision points related to risk of unintended islanding, so the following discussion will not consider any of the screens that are unrelated to islanding, regardless of how much influence they may have on the overall outcome.

The flow-chart of the overall review process is shown in Figure 2.2. Supposing that the objective of the DG project is to be allowed interconnection without triggering the need for detailed studies, we review several example traversals of the flow chart that finish in the lower left block.

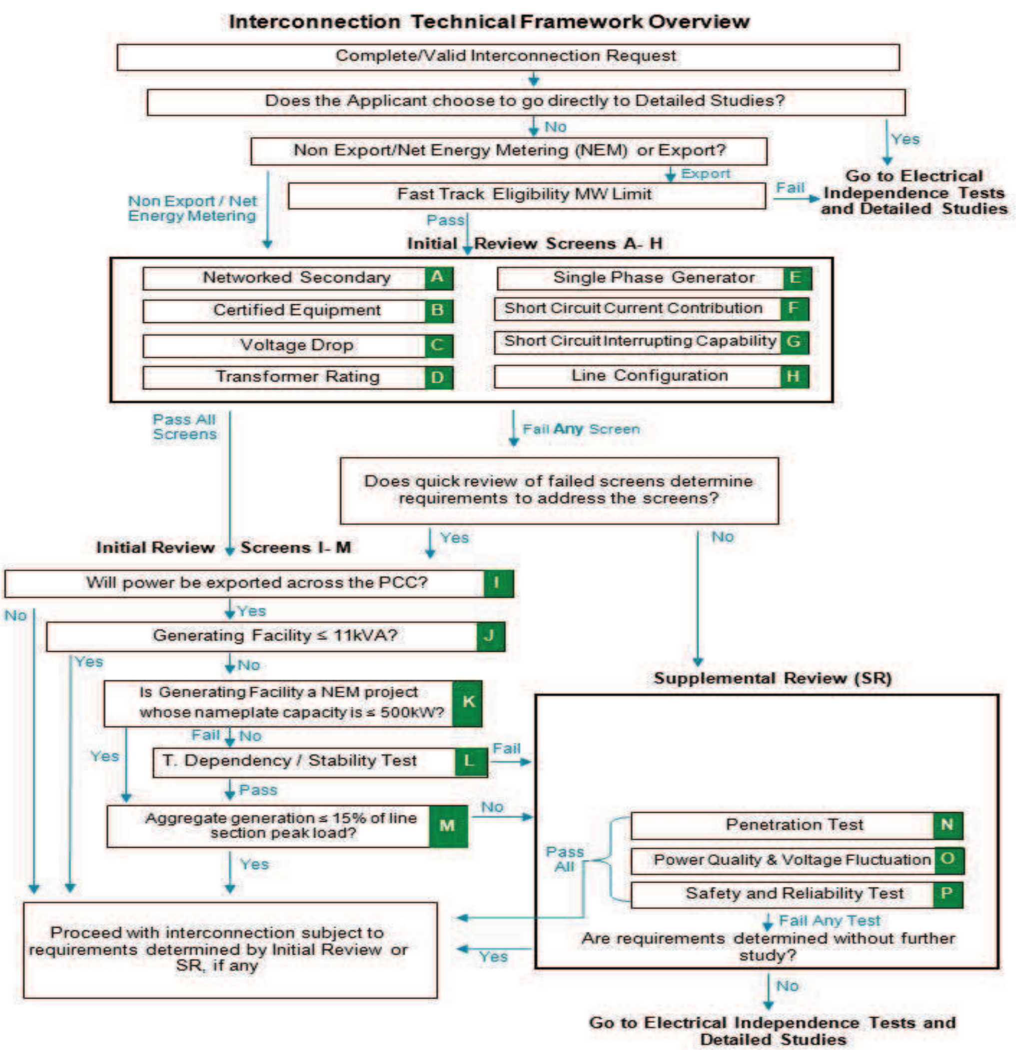


Figure 2.2: Rule 21 engineering review flowchart, image credit PG&E

2.3.1 Size Restrictions Based on the Type of Application

The simplest way to traverse the flow-chart is to apply for a non-export or net-energy metered (NEM) project. The NEM projects can export to PG&E system, but they are limited in size to 1MW. Larger sizes are allowed either as non-export without the size restriction, or as export that may be subject to much more review. For an exporting project to qualify for fast-track process, the size must be below 3MW for interconnection point voltage at 12kV or higher. The applying project now enters the *Initial Review Screens A–H* block. Screen B checks for certification which contains the anti–islanding related criteria, verifies that the protection settings are configured in accordance to project ratings, and that the stipulated adjustments points are available to configure the trip settings of voltage and frequency to match the utility practices.

2.3.2 Screen I

Assuming the positive outcome from Screens A–H, the next test is *power export* over the point of common coupling (PCC), Screen I. This is the second screen that considers the risk of islanding. This mode of operation prevents the generator from backfeeding the grid normally and during the abnormal situations for no more than 2 seconds. Screen I allows minimal review and quick interconnection to the projects willing to guarantee that their installed DG capacity is always below the served load, essentially committing the project to offsetting power, not energy, consumption of the load. There are five options to pass Screen I.

The first two are based on direct measurements using reverse power relays and they differ in the type of measured signal and the threshold. Option 1 stipulates export below 0.1% of the service transformer rating, while Option 2 requires minimum power import of at least 5% of the DG rating.

Option 3 is more interesting as it handles the export indirectly—namely if a facility has the capacity below 25% of the service equipment, and below 50% of the capacity of the service transformer, and is certified as non-islanding it is allowed interconnection. The certified non-islanding means to have passed the Anti-Islanding test procedure described in UL 1741 Section 46.3. This is the only option within Screen I that stipulates anti-islanding certification.

Option 4 allows interconnection to DG installation with capacity below the 50% of the facility's verifiable minimum load. This is functionally equivalent to the relay option, but instead of using a relay it relies on the 50% margin relative to the minimum load and thus saves the expense of relaying.

Finally, Option 5 allows for inadvertent export of up to 50% of generator rated output or 500kW, whichever is lower, not-exceeding 60 seconds in duration. This option accommodates customer facilities with controllable embedded generation designed to carry customer load and the 60 second provision covers the interval of time during which the facility control system transfers the load from the on-site generator to the grid, or vice versa. The option is designed to allow the facility to ride through load transfers with short-time reverse power flow and it uses another reverse power relay element set at $>$ 50% of peak power for 2 seconds to protect against concurrent faults during the transfer. This mode of operation prevents the generators from back feeding the grid normally and during the abnormal situations for no more than 2 seconds, unless inadvertent export with additional protection is used.

2.3.3 Screen J

Failing Screen I are the facilities that will likely export power over non-trivial time intervals. Despite this risk, projects below 11kVA are passed because of Screen J, which has a sole purpose to pass small projects. With respect to unintended islanding this is a potential risk because many small projects may carry the system load as well as one larger project, but the screen concedes to the reality that it is not practical to handle the impact of small projects individually. However, passing the small applications does not mean that they get neglected; PG&E maintains records of all installations and continuously watches the total penetration. Should the penetration level become a concern, PG&E may, at its discretion and cost, perform system upgrades to manage the system impact.

2.3.4 Screen K

Screen K has a similar purpose it expedites the interconnection of net energy metered projects with the capacity up to 500kW. However, a success on Screen K directs the applying project to Screen M, the key anti-islanding screen.

2.3.5 Screen M

Screen M is the first screen that considers the applying project in aggregate with other DG projects on the same circuit—it evaluates if the aggregate capacity of the projects downstream from an automatic sectionalizing device is less than 15% of the peak load bounded by the same sectionalizing device. This is the much misunderstood *15% rule*... The actual intent of the 15% rule is to expedite the interconnection process of smaller units at low penetration levels. It assesses if aggregate penetration of DG on a line section is sufficiently small to make the unintended islanding and misoperation of voltage regulators unlikely. The aggregate, in this context, includes: existing, queued, and the proposed generation.

The 15% measure is based on experience that the ratio of peak to minimum load is 3 to 1, leading to the expected minimum load equal to ~30% of peak load. This is combined with the additional "safety factor" of 2 to 1, similar to the safety factor of Screen I Option 4, assuming that circuits with lower than 50% penetration ratio of DG are unlikely to support the island, resulting in the threshold for the screen of 15%. The 2:1 safety factor is needed since the utilities do not control load which is dynamic and there are agricultural feeders with minimum load that is less than 15% of peak load. Failing this screen is not fatal, the worst–case outcome is the triggering of the supplemental review, within which Screen N, the penetration test, establishes eligibility based on the comparison to the best available minimum load.

2.3.6 Screen N, supplemental review

Screen N of the supplemental review establishes if the aggregate capacity of DG on a line section is less than a 100% of the actual minimum load on the line section. For DG projects based on PV, it considers the minimum load during the hours of sunlight: 10AM to 4PM for fixed panels, and 8AM to 6PM for PV with tracking panels. The screen is conservative in that it compares the minimum load with the aggregate nameplate capacity of PV installation.

In reality, the PV output will vary through the day based on sun's position in the sky and the atmospheric condition through the day. Most PV panels in use today are mounted on fixed structures resulting in a daily peak around noon (for south facing panels) and a seasonal peak when sun's altitude matches the panel tilt so that the angle of incidence of sun rays relative to the panels is 90° (occurring in one day per year.) Moreover, not all the panels in the given area will have the uniform orientation, or the ideal tilt, so some averaging is likely there too. We discuss the various factor affecting power output from PV panels in Appendix C. As a general comment, the PG&E method is practical in that it does not require significant data collection, and it errs on the side of safety, which is a prudent engineering choice.

The applicants can assess the likelihood of passing Screens M and N by requesting an optional Rule 21 Pre-Application Report, which, based on [1, sec. E.1], provides a wealth of information about the hosting circuit:

a. Total Capacity (MW) of substation/area bus or bank and circuit likely to serve proposed site.

b. Allocated Capacity (MW) of substation/area bus or bank and circuit likely to serve proposed site.

c. Queued Capacity (MW) of substation/area bus or bank and circuit likely to serve proposed site.

d. Available Capacity (MW) of substation/area bus or bank and circuit most likely to serve proposed site.

e. Substation nominal distribution voltage or transmission nominal voltage if applicable.

f. Nominal distribution circuit voltage at the proposed site.

g. Approximate circuit distance between the proposed site and the substation.

h. Relevant Line Section(s) peak load estimate, and minimum load data, when available.

i. Number of protective devices and number of voltage regulating devices between the proposed site and the substation/area.

j. Whether or not three-phase power is available at the site.

k. Limiting conductor rating from proposed Point of Interconnection to distribution substation.

l. Based on proposed Point of Interconnection, existing or known constraints such as, but not limited to, electrical dependencies at that location, short circuit interrupting capacity issues, power quality or stability issues on the circuit, capacity constraints, or secondary networks.

The easiest way to pass Screen M is to know how much of the peak is on all the protective devices available from item h. and calculate 15% of the lowest peak reported (fuses can be excluded). Failing that, the applicant may consider 30% of the lowest protective device or further upstream devices and count on passing Screen N of the supplemental review. This comes at the risk of incurring more costs, because if Screen N ultimately fails, the interconnection of the project will require some form of mitigation.

Mitigation options that directly address the penetration ratio include: downsizing the ratings of the facility, or connection of the facility to an adjacent section of the feeder or an alternate feeder. In cases where these options aren't acceptable, or feasible, the interconnection is still possible, but may require installation of additional equipment, leading to higher integration costs. Examples of mitigation options leading to additional integration costs are:

1. Installing reclose blocking at line reclosers,
2. Replacing line fuses with line reclosers
3. Installing reclose blocking at the feeder breaker
4. Installing direct transfer trip (DTT), and/or replacing a high-side fuse bank with a circuit breaker or circuit switcher.
5. Replace the feeder conductor with a larger conductor
6. Replace the voltage regulator controls
7. Reset/Replace the relays

The specific solutions are determined on a case-by-case basis within the Detailed Review and involve engineering study work by specialized staff. PG&E strives to interconnect every project at a minimum cost, but it must ensure that its distribution circuits are adequately protected. Part of the protection work is streamlined as is outlined in the, recently updated, Distributed Generation Protection Requirements. In the next section, we discuss these requirements in the context of prevention of unintended islanding.

2.4 Review of PG&E Distributed Generation Protection Requirements

The PG&E protection requirements for distributed generation are published in the Utility Bulletin TD-2306B-002 [2]. The Summary section states the following:

> The protection requirements for connecting new Distributed Generation (DG) have been modified to reduce the need for Direct Transfer Trip (DTT) schemes which are costly to employ and difficult to manage.

The flowchart of the updated protection requirements is shown in Figure 2.3. The part of the flowchart most relevant to this project is in the top box dealing with certified inverters. As was the case with the Rule 21 screens, the size of the applying units is the key driver and

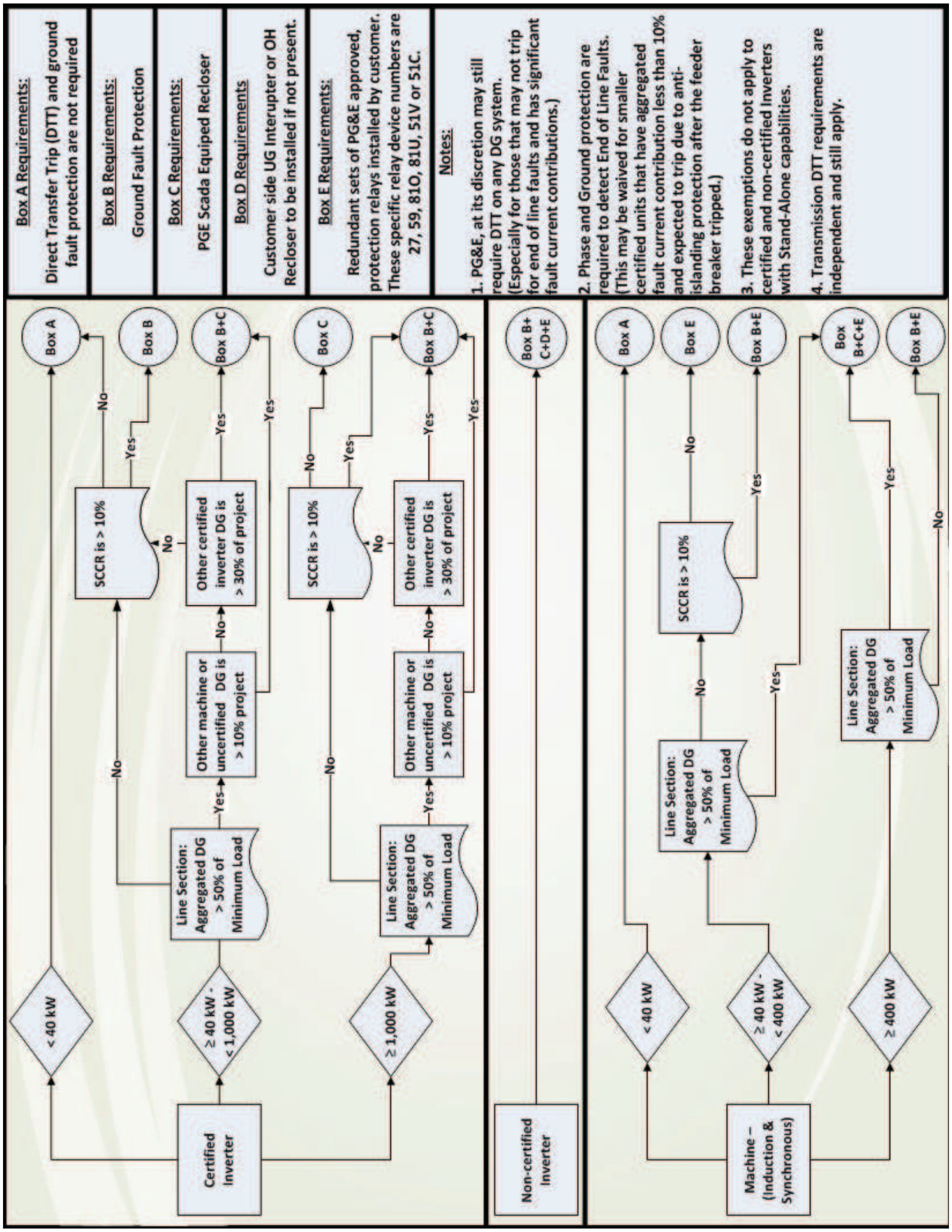


Figure 2.3: Flowchart for determining DG protection requirements, reprinted with permission from PG&E

the small units are permitted with no additional requirements. However, the requirements stipulate SCADA monitoring for units greater than 1MW, and in select cases of sections with units between 40kW and 1MW. The intent is to use SCADA monitoring in system operations to support safe energization after outages.

Apart from size, the additional drivers are:

Penetration the screen provides relief if the DG penetration is below 50% of section minimum load.

SCCR Short Circuit Contribution Ratio driving the need for ground fault detection and thus offering additional protection from voltage rise in the event of unbalanced faults on the affected section.

Presence of machine-based DG and uncertified inverters This screen expresses the concern of non-detection if other generator-based DG may become islanded alongside PV inverters. In such cases generators-based DG may provide a source of voltage to the PV inverters and contribute to the risk of non-detection. The concern of non-detection is similar relative to non-certified inverters. The thresholds of 10 and 30%, respectively, are based on engineering judgement.

With respect to protection requirements, the experimental part of our program will consider the 10% ratio as a predictor of non-detection and evaluate the likelihood of non-detection as a function of this ratio.

2.5 The Value of This Project to PG&E Interconnection Process

As the discussion in the previous two sections shows, the risk of unintended islanding is one of the key drivers for many of the decision points in the Engineering Review of Electric Rule 21 and in defining the Protection Requirements for Distributed Generation. Engineering Review focuses on the quantitative balance of load and distributed generation as the proxy for the risk of non–detection. The Protection Requirements introduce an additional proxy — the presence of machine based distributed generation. In the qualitative sense, both are prudent choices. However, the choices for the thresholds are neither confirmed nor challenged by either field data or experimental work.

The experimental part of this project will evaluate the probability of islanding as a function of both the generation to load ratio and load composition. Equally important, however, is the preparation work documented in this report because it charts the course for quantifying the composition of the loads on PG&E distribution circuits using the data already available to PG&E, but never before aggregated in this way. By choosing to perform the analysis at the scale of load zones, we made it necessary to automate the data processing and indirectly demonstrated the feasibility of large–scale analysis of higher fidelity than is presently supported by commercial distribution planning tools.

The next section explains the data management practices in PG&E, which were the key enabling factor for automating the analysis.

2.6 Distribution System Data Management in PG&E

PG&E is a modern utility company with a 150 year history. There is a strong commitment to accurate asset management, and a culture of making systematic improvements while maintaining continuity of service. The company is continuously adopting new technologies such as geographic information system (GIS) and the state-of-the-art commercial distribution planning tool CYMDIST, but these are integrated with the time-tested legacy systems that support day-to-day operation.

This commitment to extend the functionality of older systems with the new ones, offers a degree of flexibility not found in cultures where systems replacements are a norm. This was of critical importance to our study, where the new tool for distribution analysis, CYMDIST, does not support a use case to provide aggregation of components by type, downstream from a given element.

For evaluating the risk of islanding it is essential to have insight not only into the total MWs of load, but also into the composition of that load—because the probability of islanding is affected by the percentage of motor loads on the circuit section under consideration. Similarly, the total rating of power factor correction capacitors used on a given circuit section are of interest too, as it influences the transient behavior of the load and PV inverters during islanding. Extracting these circuit attributes is impractical to do in CYMDIST, but in working with the PG&E distribution planning we learned that the system data is not maintained in CYMDIST, but rather in a relational database called C-EDSA.

The comprehensive reach of C-EDSA and its interfaces are shown in Figure 2.4. Note that generating system-data for CYMDIST is only one use-case of C-EDSA, shown as a data sink labeled as "Cyme (Cymdist01)", located at the right edge of the figure, near the middle[1]. The nightly extract is generated to include all the changes to the system from C-EDSA and ORSP. The distribution planning engineers start their workday by loading the new C-EDSA extract into CYMDIST, and then proceeding as if they were in front of the file they used the day before. They study system performance and impact of system changes in CYMDIST, but ultimately prescribe the changes using other workflows with database back-ends. These changes are regularly

[1]Currently, C-EDSA is being replaced by ED-GIS to integrate the PG&E distribution data systems and allow easier data access for future uses. ED-GIS will retain the support for data export to CYMDIST.

uploaded to C-EDSA, and they become part of the CYMDIST baseline in the subsequent C-EDSA extracts.

We found the C-EDSA extract to be more useful for our project than any of the data exports available from CYMDIST. Since it is used to define the distribution system in CYMDIST, the C-EDSA extracts contain complete circuit information organized into relational databases. As will be discussed later, PG&E keeps track of their distribution system in terms of load zones, which are contiguous geographic regions with similar climatic properties. As a result, the C-EDSA extracts are prepared at a scale of load zones, so a single database file incorporates the complete information about hundreds of distribution circuits. In contrast, the scale of available CYMDIST extracts is limited to a single distribution circuit, with separate reports for different types of information: circuit data, utility equipment, loads, distributed generation... Generating each of the reports requires manual action from an operator and results in a separate computer file, which is so impractical that it would limit the extent of the analysis to the small set of example feeders, as was originally planned. Instead, by using the C-EDSA extracts we were able to study all of the feeders in a given load zone and thus analyze the properties of circuits at an unprecedented scale. In addition, we automated the analysis and were able to consider not one, but three, load zones, including a total of 557 distribution feeders.

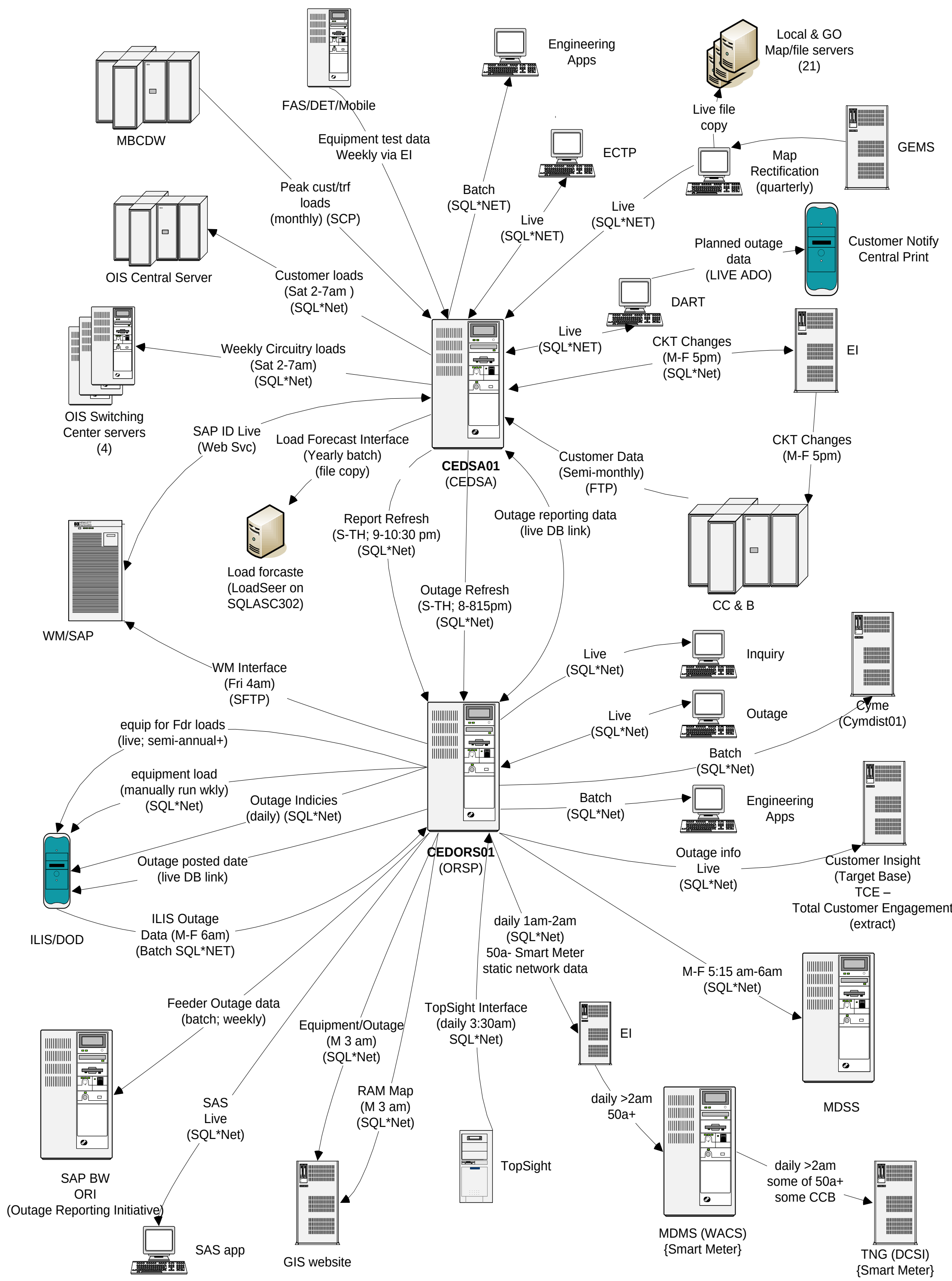


Figure 2.4: C-EDSA interfaces, reprinted with permission from PG&E

2.7 Objectives of Data Analysis

As was already mentioned, our study seeks to find system conditions that make islanding detection difficult and to then recreate such conditions in the laboratory to improve the understanding of the combined behavior of PV inverters and connected loads in the interval of time from occurrence of islanding to its eventual cessation. Despite the high degree of automation in the testing, the number of experiments is still limited and it is therefore important to focus the experimental part of our program on the areas where risk of non-detection is deemed to be high.

It is generally accepted, and confirmed by the screening process used by PG&E, that islanding is more difficult to detect when the total generation matches the total load. Screen N in the supplemental review allows interconnection of applications as long as their aggregate nameplate capacity remains below the minimum load. The apparent premise of the screen is that generation-to-load ratio equal to 1 or above will be both difficult to detect and present a risk of damage to the load due to transient voltage elevation as explained in the discussion of Figure 2.1. Therefore, the first objective of the analysis is to track the total generation-to-load ratio as one of the key factors contributing both to risk of non-detection and the risk of damage.

Another important factor contributing to risk of non-detection is the load composition. We already mentioned that both the PV inverters and the loads depend on the utility system to define the voltage, but some loads, namely large motors, have physical behavior similar to that of utility generators and may temporarily define the voltage to the island. Therefore, the second objective of our analysis is to track the composition of the load and the content of motors within it, as one of the key factors contributing to the risk of non-detection.

Finally, the presence of power factor correction capacitors can lead to electrical oscillations at frequencies other than nominal frequency and to voltage rise in tuned circuits, leading to elevated risks of damage to the loads. Therefore, the third objective of our analysis is to track the presence and the aggregate ratings of power factor correction capacitors as a likely driver of irregularity of voltage during islanding conditions.

In doing this, every circuit section that can become islanded must be considered separately. In order to accomplish this, it is necessary to perform topological processing of the circuits to discern parts of the circuit downstream from utility reclosers and calculated the ratings of the total installed PV, the composition and the ratings of the total installed loads, and the total installed power factor correction capacitance.

Our approach and the illustrative findings are presented in the following chapters.

Chapter 3

Analysis of PG&E Distribution Circuits

PG&E has their distribution system organized into load zones that are contiguous geographic areas with similar climatic conditions. In this study, we considered three load zones shown in Figure 3.1. The chosen zones represent diverse climate conditions, which correlate with load types and temporal patterns. The distribution system serving the loads is also influenced by climate in that it accommodates the load densities and types that correlate to climate. We begin this chapter by reviewing the available "raw data" within C-EDSA extracts for the load zones.

3.1 Review of Available Raw Data

Table 3.1 captures summary information about the studied load zones. Most of the data in the table is obtained by direct summation of available records within the C-EDSA database extract. From the top, the first section of the table documents the total number of substations and distribution feeders, and provides the calculated circuit miles and land area served. The total circuit miles were calculated by summing the distances spanned by the individual line

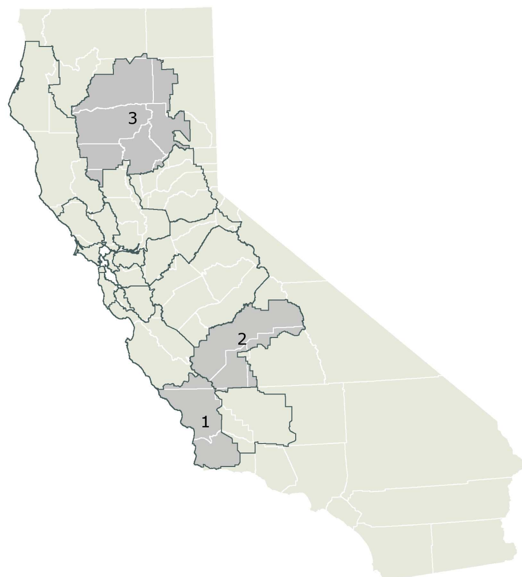


Figure 3.1: Studied load zones within PG&E service territory, map reprinted with permission from PG&E

segments. The calculations of total land area served is more complex, and we review it here to introduce the concept of *tiling* later used in calculating load densities by type. The first step in calculating the land area served is to process all line segments within the load zone to determine the most south-west and the most north-east coordinate of the zone and thus establish the rectangular reach of the zone. Next, this rectangle is tiled with squares of an arbitrary area, we chose 0.25 square mile (0.5 mile square side) as a good compromise between precision and speed of calculations. Finally, the line segments are processed again to determine if the tiles include a line segment or not. In other words, existence of any line segment within a tile "flags" the tile as a part of the land area served. The total land area served is calculated as the sum of areas of flagged tiles.

The second section of the table captures information about the loads. PG&E tracks "point loads" [1], where each point has an association with a customer, or a group of customers, served from that point on the distribution circuit.

Generally, the load points are associated with the locations of service transformers supplying the loads. The number of (individually recorded) load points gives the sense of scale of the underlying dataset; the smallest studied load zone, Zone 1, contains ˜114,000 individual load points, while the largest, Zone 2, has ˜235,000 load points. Each load point further includes the information of the total connected load (in MVA) and the energy consumption (in MWh/day,) segregated by load type: Agricultural, Commercial, Industrial, Residential, and Other. The connected MVA gives a sense of the maximum possible load demand at the load point, while the energy consumption is a measure of actual energy usage that PG&E calculates based on the metering data for the customers associated with a load point.

The third section of Table 3.1 summarizes the installed utility equipment: the number of individual power-factor correction capacitors, the total rating of those capacitors (in MVAr), and the percentage of fixed (non-switched) capacitors determined by total MVAr, not the count. This is followed by the number of reclosers (circuit elements that can separate parts of the feeder from the upstream utility system and isolate faulted sections and sometimes create electrical islands downstream with the presence of DG), and by the total number of voltage regulators. (Voltage regulators have no direct impact on risk-of-islanding, but were included for completeness, as they are sometimes affected by PV variability associated with cloud shading.)

The fourth section summarizes the available information about installed PV: the total number, the total MWs based on the nameplate AC ratings, and the PV penetration expressed as a percentage relative to connected load MVA.

[1] This is a more accurate representation relative to alternative practice of distributing loads over line segments—used by utilities that do not have accurate spatial records of their distribution loads.

Table 3.1: ***Summary information about studied load zones***

Attribute/Metric	Zone 1	Zone 2	Zone 3
Number of substations	27	66	64
Number of distribution feeders	84	325	148
Total circuit miles [mi]	1774	4101	3238
Total land area served [sqmi]	92.3	190.7	174.2
Number of load points (1000s)	114.2	235.3	189.3
Total load [connected MVA]	2647.3	7123.6	3085.1
Total load [MWh/day]	7253.7	29359.8	8372.8
Residential [%]	36.5	42.2	55.9
Commercial [%]	12.6	6.1	6.0
Industrial [%]	37.4	29.9	27.4
Agricultural [%]	13.4	21.4	10.5
Other [%]	0.1	0.4	0.2
Number of power-factor correction capacitors (including fixed and switched)	394	1465	702
Total reactive compensation [MVAr]	308.5	1457.4	491.1
Fixed [% of total] (by MVAr)	24	16	15
Number of reclosers	258	593	545
Number of voltage regulators	124	356	254
Number of PV installations	3352	7948	3521
Total PV capacity [MW] (nameplate AC)	24.8	83.8	39.2
PV/Connected MVA load [%]	0.94	1.18	1.27

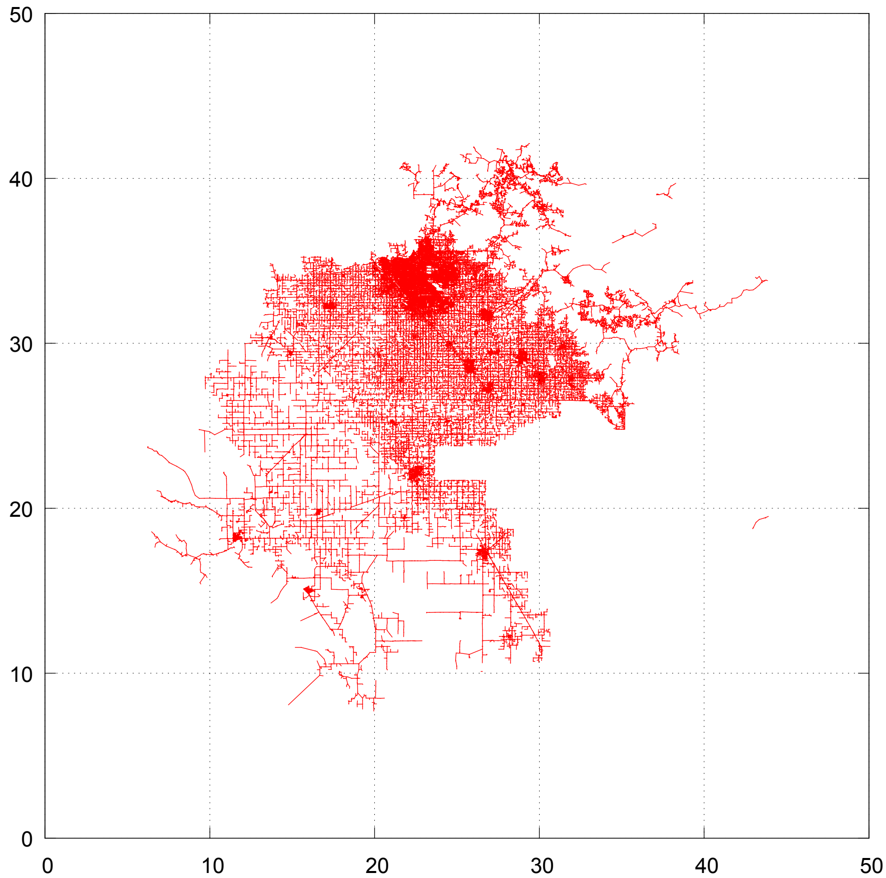


Figure 3.2: Zone 2 circuit map: line segments

3.2 Spatial Correlations of Load and PV

Example spatial views of the dataset are depicted in Figures 3.2–3.5. In Figure 3.2 all of the line segments of Zone 2 are shown in a map-view on a 10 mile grid. Figure 3.3 shows the same map, but only the part of the grid between 20 and 30 miles in the east-west axis and between 30 and 40 miles in the north-south axis. These maps illustrate the intricate level of details of over 195,000 line segments comprising the distribution system of Zone 2.

The spatial densities of various load types can be depicted as shown in Figures 3.4–3.6. The load densities were calculated using the same square grid used to calculate the land area served. Every square of the grid was assigned an array element for summation of load by

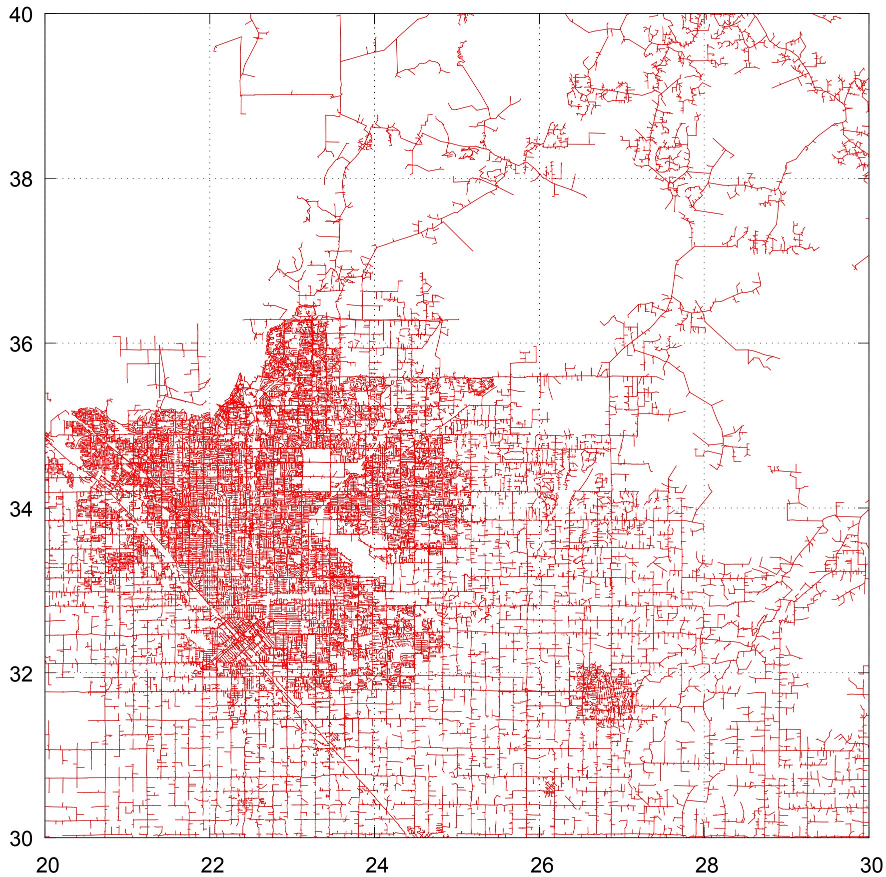
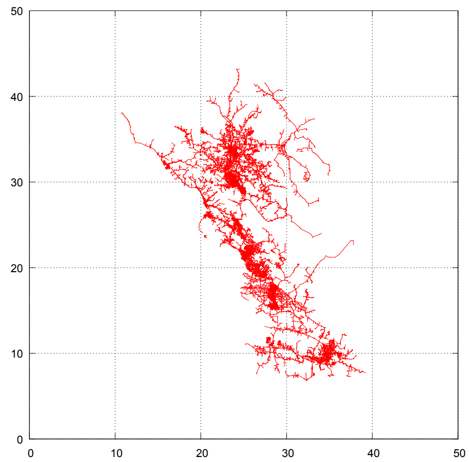
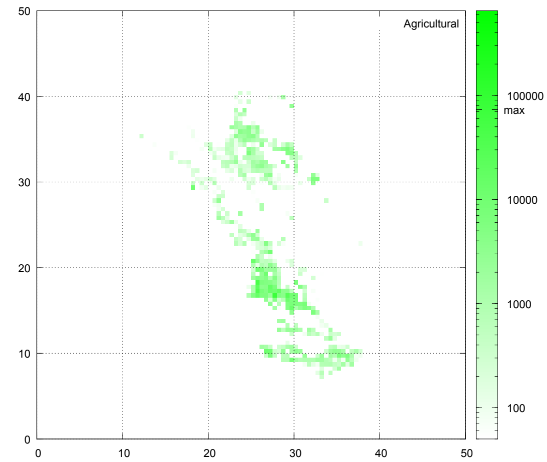


Figure 3.3: Zone 2 circuit map: line segments, zoomed view

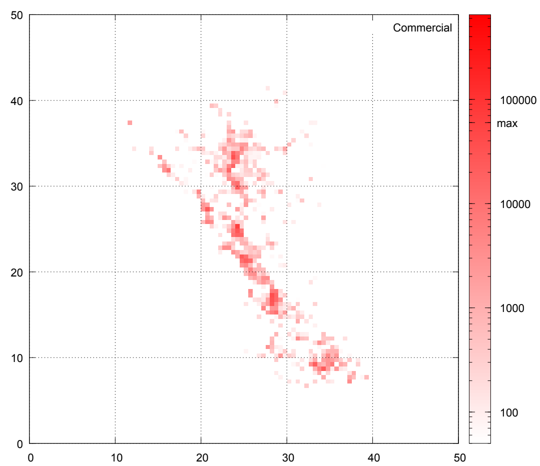
type and sums were calculated based on location of individual load types on the grid. The resulting load densities were then transcoded into colors for the individual heatmaps. Large variations in values of spatial densities made it necessary to use logarithmic scales. To enable comaprisons between the load zones, the scales on all three load zones are formatted using the same color scale ranges. For additional convenience, the maximum value for the plot is labelled on the color scale. The heatmaps show the relative spatial spreads of loads, indicating that the agricultural loads are the load type most evenly spread throughout the load zones, and that the other three types: industrial, commercial, and residential, have less uniform, but mutually correlated spatial patterns. The spatial distribution of PV installations correlates well with the latter three load types.



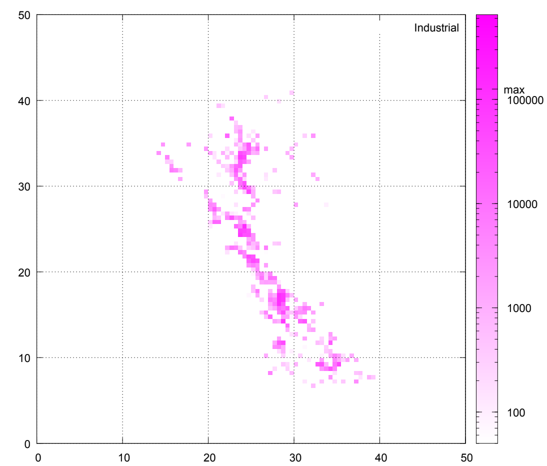
(a) Zone 1 spatial reach



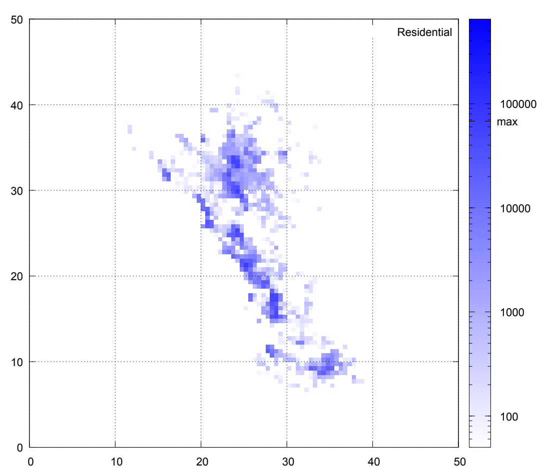
(b) Agricultural loads



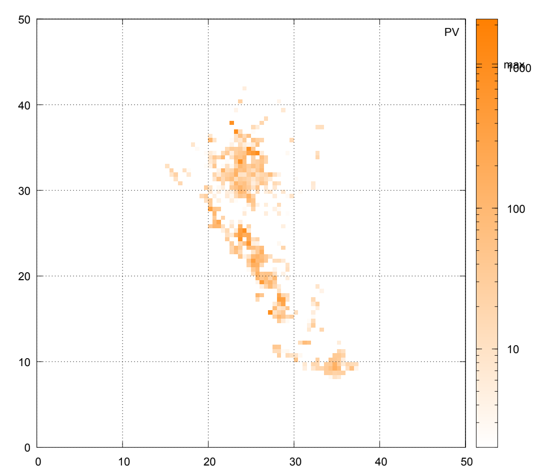
(c) Commercial loads



(d) Industrial loads

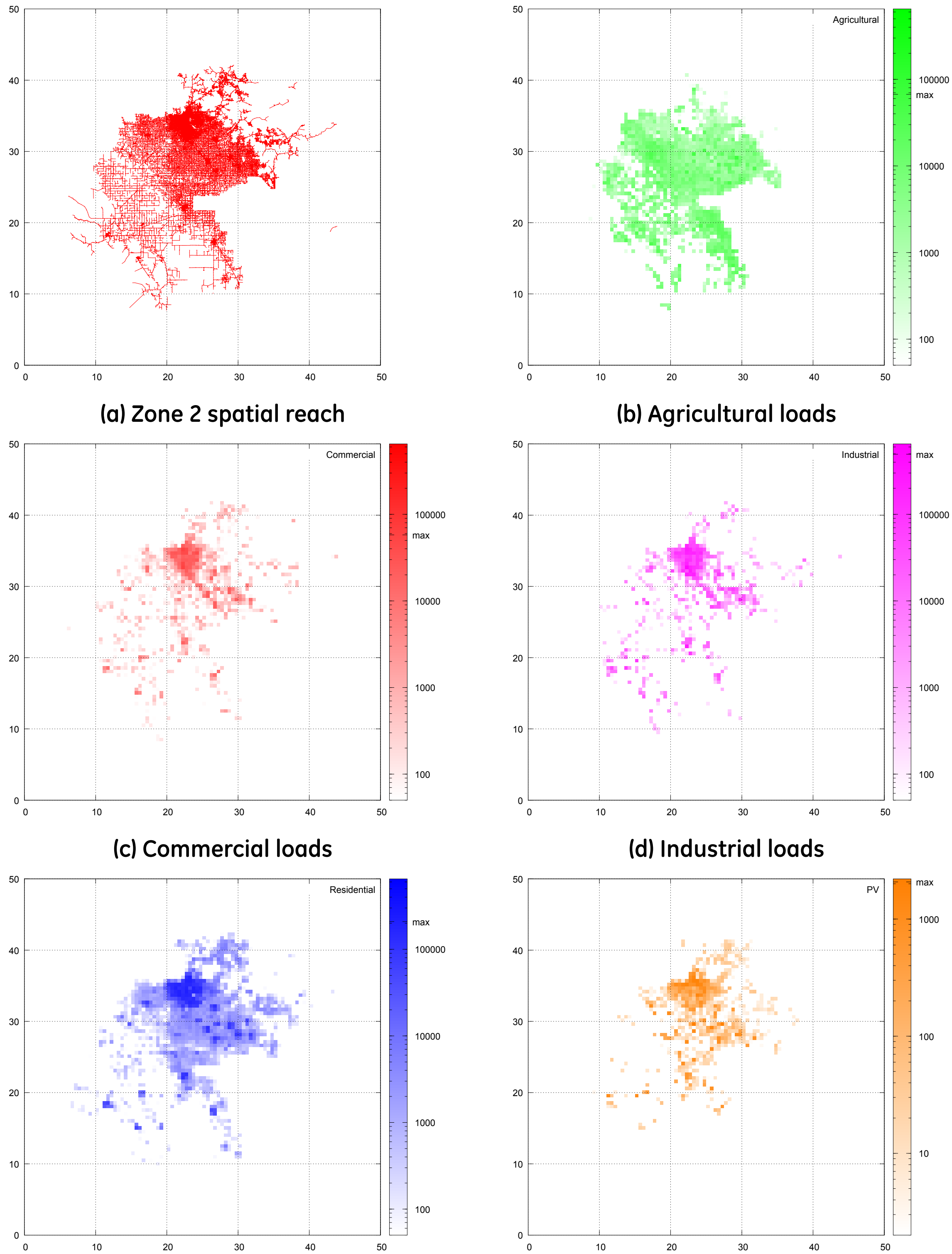


(e) Residential loads



(f) PV installations

Figure 3.4: Zone 1 spatial densities of
four load types (MWh/0.25sqmi)
alongside spatial density of PV (kW/0.25sqmi)



(a) Zone 2 spatial reach

(b) Agricultural loads

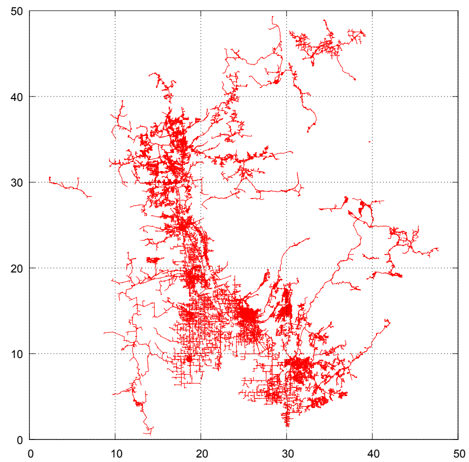
(c) Commercial loads

(d) Industrial loads

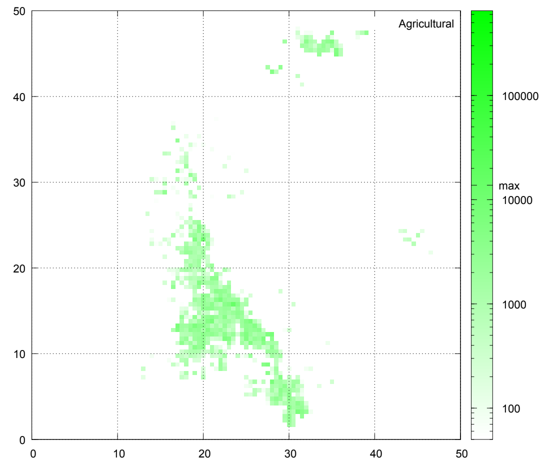
(e) Residential loads

(f) PV installations

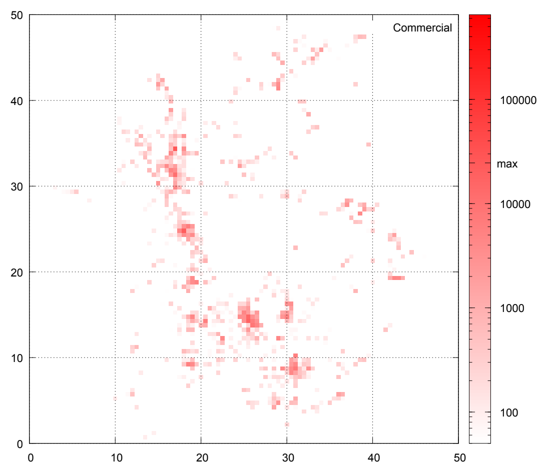
Figure 3.5: Zone 2 spatial densities of
four load types (MWh/0.25sqmi)
alongside spatial density of PV (kW/0.25sqmi)



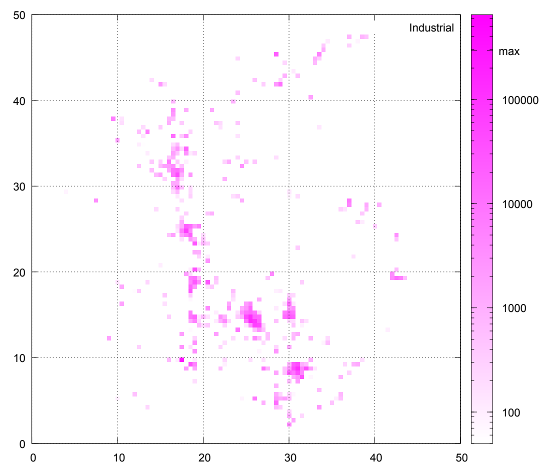
(a) Zone 3 spatial reach



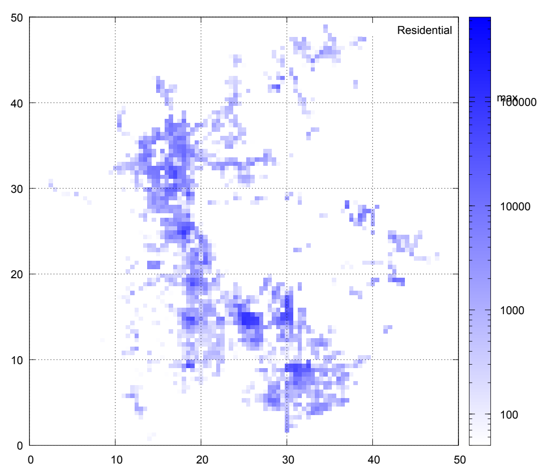
(b) Agricultural loads



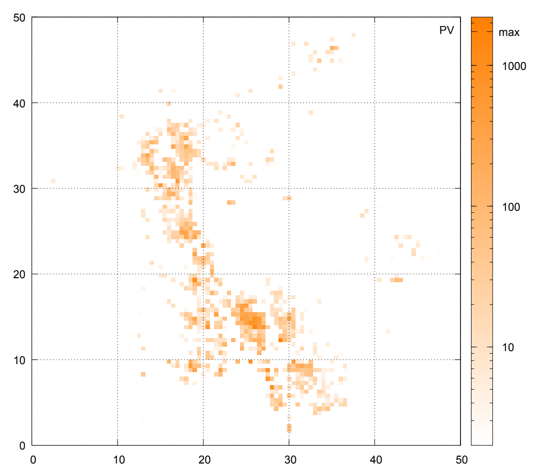
(c) Commercial loads



(d) Industrial loads



(e) Residential loads



(f) PV installations

Figure 3.6: Zone 3 spatial densities of
four load types (MWh/0.25sqmi)
alongside spatial density of PV (kW/0.25sqmi)

The spatial correlation of PV with load types gives rise to the notion of using statistics to determine load mixes by type which correspond to the areas with high penetration of PV, and to perhaps prioritize laboratory evaluation to cover the load mixes with highest probability of co-occurrence with the high penetration of PV. We discussed this at length with PG&E distribution planning and decided that it is more useful to uniformly sample all possibilities, than to downselect only the mixes that currently have high penetration. The reason for this decision is twofold:

1. The PV penetration is a localized phenomenon and one large installation can drastically change the penetration level of the associated line section.
2. It is easier to procure land at the fringes of load zones, where the load densities are not as high, so it is possible (and perhaps likely) that the future PV projects will be spreading throughout the load zones and begin to mix with dominantly agricultural loads, not continue to be correlated with the industrial-commercial-residential load types.

Essentially, we decided that it is better to run laboratory experiments so to be prepared for all options in the future, than to prioritize based on the situation at present and possibly miss a future scenario.

Referring again to summary information in Table 3.1 the load zones are similar with respect to distribution system design practices. The average number of circuit miles per recloser is consistent (between 5.9 and 6.9), the average number of circuit miles per voltage regulator is consistent (between 11.5 and 14.3) the ratio of reactive power compensation to load energy is consistent (between 0.0425 and 0.0587), the ratio of fixed to total reactive compensation is consistent (between 15 and 24%), and so on. The average penetration of PV is small (between 0.94 to 1.27%), but, as will be discussed later, this number varies greatly by individual circuits and sections of circuits.

In terms of their inherent properties Zone 2 has the highest average load density and the highest percentage of agricultural load (the two are not necessarily correlated.) Zones 1 and 3 have comparable load densities, but Zone 3 has a higher content of residential loads. The load types (residential, commercial, industrial, agricultural) are relevant as they are the proxy that determines the load mix, which affects the combined behavior of PV and load during islanding. For a complete coverage, the load mix must be assessed at any level of circuit aggregation that can become islanded. Consistent with PG&E screening practices, this means any circuit section downstream from any recloser.

3.3 Circuit- and Section-Level Analysis

3.3.1 Hierarchical Organization of PG&E Data

The C-EDSA database extract we used is conditioned for CYMDIST import and it follows the data organization used by CYMDIST. Hierarchically, CYMDIST uses "networks" as organizational units that correspond to distribution feeders. By convention, CYMDIST networks are built up from nodes and sections; the nodes are given unique identifiers and each node is associated with an (x, y) coordinate pairs. The sections connect node pairs: each section has a "from node" and a "to node" designated by node identifiers. Analogous to nodes, the sections too have unique section identifiers. The loads and all of the utility equipment are associated with the sections (not nodes,) but the actual location within the section is specified by a location identifier which places the component either at the *from* or at the *to node*. All of the underlying objects of the model: networks, nodes, sections, loads, reclosers, capacitors, voltage regulators, etc., are given unique identifiers and these identifiers are used to reference between various tables within the database.

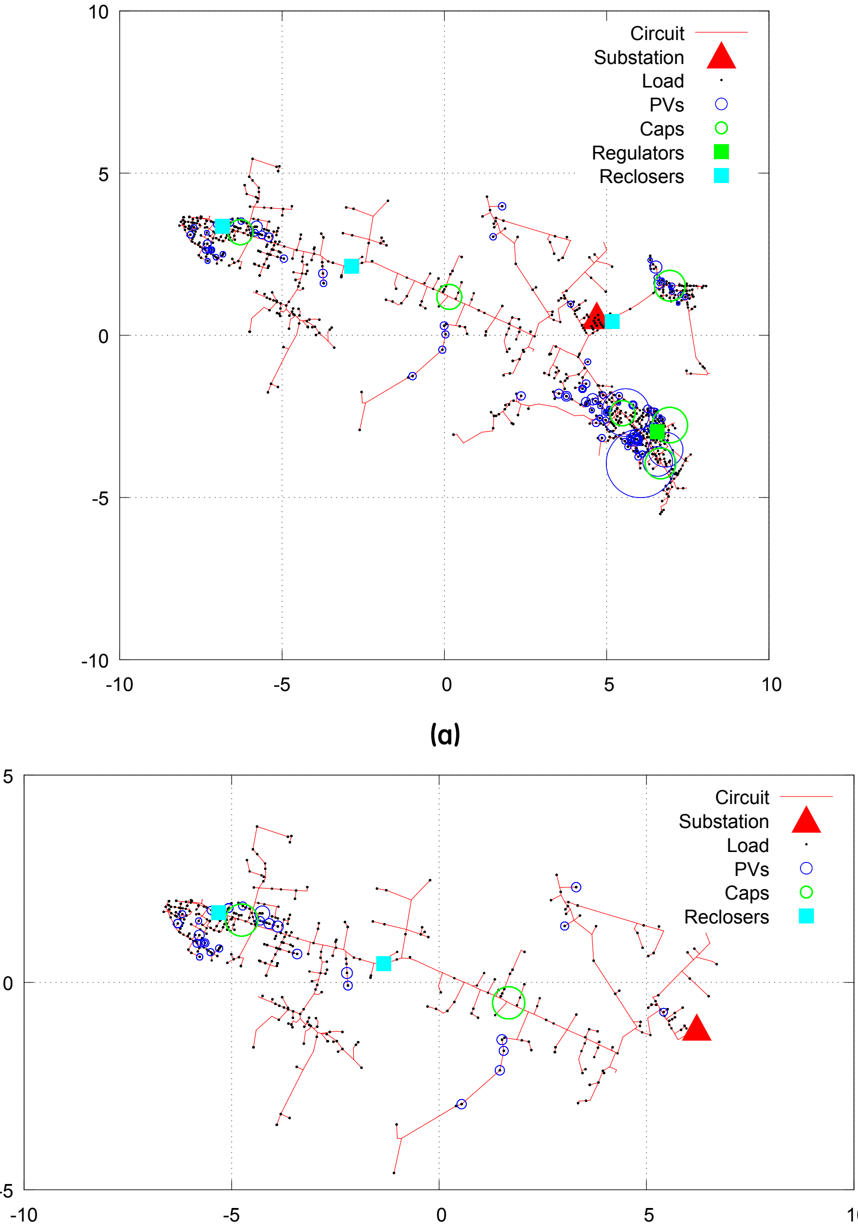
PG&E uses network identifiers to encode additional information. Each network identifier is a nine digit number, where the first two digits correspond to the PG&E load zone, the next three digits to the substation within the load zone, the next two digits to the voltage level of the distribution feeder, and the final two to the feeder number. For example, the distribution feeder represented by the network identifier 252041106, belongs in the load zone 25, is serviced from the substation number 204, has a voltage level of 12kV, and its unique identifier relative to other feeders served by the same substation is 06. [2]

The input data format of CYMDIST enhanced by the PG&E thoughtful encoding of feeder relationships to substation and load zones, facilitates building of associations (and related aggregations) at three levels of hierarchy; the load zone, the substation, and the feeder.

3.3.2 Circuit-Level View

The extent of load zones was already illustrated in Figure 3.4; while Figures 3.7 (a) and (b) illustrate the extent of a substation, and that of a feeder. Figure 3.7 (a) is a map-view of the feeders for substation 295 in load zone 1 (corresponding to the first two digits of network identifier equal to 18.) Figure 3.7 (b) is a map-view of one of those feeders. As before, the circuit sections are shown using thin red lines, but we now introduced additional elements: point loads are shown as black dots, PV installations as blue circles with areas proportional to the installed AC ratings, power factor correction capacitors are shown as green circles, and reclosers as cyan squares.

[2] This does not necessarily mean that there are five other feeders served by the same substation (with designators 01–05), it is simply a unique number assigned to the feeder.



(b)

Figure 3.7: Levels of circuit hierarchy supported by raw data: (a) substation, (b) feeder

3.3.3 Importance of Section-Level View

This hierarchy of input data allows for aggregation down to a level of a feeder, but stops short of supporting aggregation at a section level. Referring back to Figure 3.7 (b), two reclosers can be seen within the feeder, creating three possible island topologies:

1. the whole circuit, precipitated by the fault between the substation and the first recloser and cleared by the action of protection devices at the substation (feeder-head),
2. the part of the circuit downstream from the first recloser, precipitated by the fault between the first and second recloser and cleared by the action of the first recloser, and
3. the part of the circuit downstream from the second recloser, precipitated by the fault downstream from the second recloser and cleared by action of the second recloser.

It is evident from the figure that the relative density of installed PV is the highest downstream from the second recloser, illustrating our earlier observation that PV penetration is a local phenomenon that can vary significantly in different possibly-islanded regions of the same feeder. It is also evident that the location of power factor capacitors relative to location of reclosers is a matter of some chance, resulting in the similarly variable ratio of reactive compensation relative to load and PV within different feeder regions.

This makes it necessary to study the possible mixes of PV, load, and reactive power capacitor at levels of circuit hierarchy corresponding to all feasible electrical islands. To enable this, we used a technique developed in earlier work that parses the graph comprised of nodes and sections and establishes the downstream and upstream associations between nodes relative to the root node (the substation.) The description of the technique and its illustrative outputs are given in Appendix A.

Chapter 4

Analysis of Temporal Load Properties

The load aggregates collected by circuit and by section, as was explained in the previous chapter, need to be transformed into temporal profiles of load compositions in accordance with WECC load modeling guidelines [5]. There are two ways to approach this:

1. Use WECC *"light" method* for direct conversion of load energy by type to temporal profiles of load compositions, and

2. Use PG&E *conversion factors* to transform load energy by type to temporal active and reactive profiles (still associated with load types,) then transform the aggregates to temporal load compositions.

The downside of the first method is that it obscures the temporal variation of reactive power; the reactive power is a function of load composition and chosen parameters of the models representing the underlying equipment varieties. The second method offers the interim temporal profile of reactive power and thus allows the comparison to SCADA data to evaluate the effectiveness of PG&E-installed reactive power correction capacitors.

The first method has built-in transformations from load types (residential, commercial, industrial, agricultural) into end-use equipment (heating, cooling, refrigeration, lightning, etc.) and the daily temporal profiles for each equipment. However, it still depends on user-specified peak load for the circuit to seed all subsequent proportions.

The application of PG&E conversion factors provides the estimates of peak load for any level of aggregation. We discuss their application in the next section.

4.1 Load Profiles Based on PG&E Conversion Factors

The conversion factors are charts of kW/kWh and the corresponding power factor as a function of time, given at two-hour time intervals. These chart pairs are defined for summer and winter, with additional subdivision for summer into coastal and inland.

Given a season (summer, winter), a location (inland, coastal), and a circuit or circuit-section of interest (described by aggregated energy by load type), the temporal load profile becomes:

$$\begin{aligned} P(t) &= P_{agricultural}(t) + P_{commercial}(t) + \\ &\quad P_{industrial}(t) + P_{residential}(t) \qquad (4.1) \\ &= E_{agr}CF_{agr}(t) + E_{com}CF_{com}(t) + \\ &\quad E_{ind}CF_{ind}(t) + E_{res}CF_{res}(t) \qquad (4.2) \end{aligned}$$

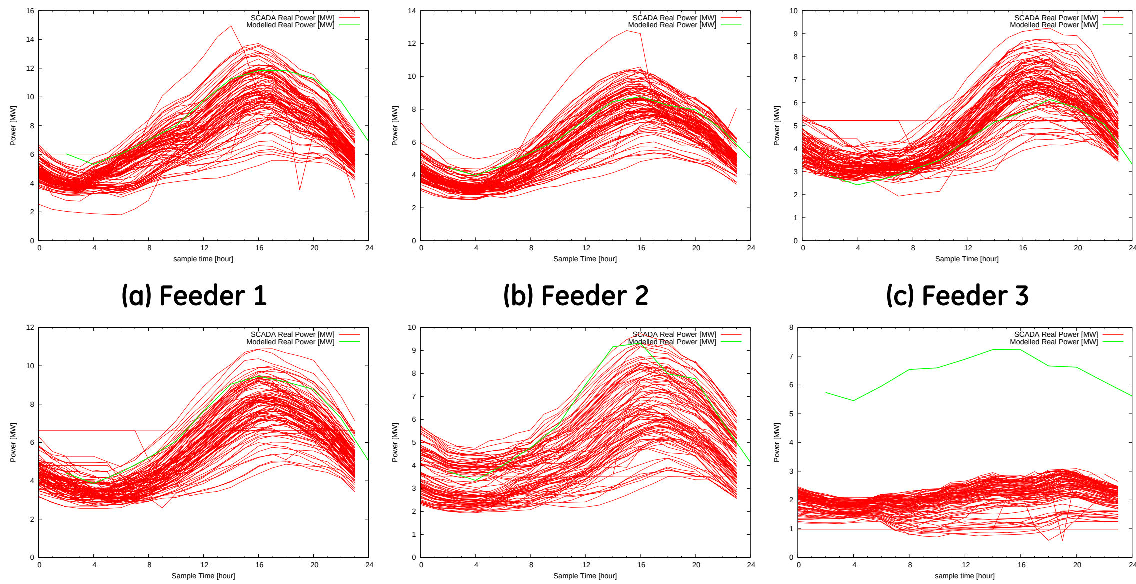
The corresponding reactive power is given by:

$$Q_{loadtype}(t) = \frac{P_{loadtype}(t)\sin(\arccos(PF_{loadtype}(t)))}{PF_{loadtype}(t)} \qquad (4.3)$$

The energy inputs for load types are maintained based on the billing data which is accurate when no PV is present behind the utility meter. If there is behind-the-meter PV, the net energy used by the load is reduced by the contribution from PV, leading to innacuracy that would propagate through all subsequent steps. The complicating factor, however, is the absence of association between the PV installation and the nearby metered load points. The C-EDSA extract tracks PV installation by location, but does not associate them to load points. This made it necessary to define a heuristic method for association of PV with nearby load based on the PV size and the particular mix of nearby load types. The heuristic method is described in Appendix B and the method used to predict temporal power production from PV in Appendix C. To achieve the best possible accuracy, the estimated PV contribution was added into the load energy before the application of conversion factors.

A subset of obtained load profiles (real and reactive) was compared against measured SCADA data to validate the work. Example results of this comparison are shown in Figure 4.1. Daily observations of load from one year of measurements are plotted as red lines, illustrating the fact that the peak load is a daily changing value. The load prediction based on the conversion factors is shown as a green trace. The results labeled Feeder 1, 2, 4, and 5 are representative of the majority of cases, where the estimated load profiles based on conversion factors match well with the measured data. This indicates that the conversion factors were selected to predict peak loading conditions, which are typically of interest to distribution planners. The remaining two examples, Feeder 3 and 6, were included for completeness, and both likely indicate measurement errors. Feeder 3 likely points out to a wrong SCADA association, where the measured data represents a higher level of aggregation (perhaps a substation) resulting in measured values being greater than estimated. Feeder 6 likely indicates use of incorrect scaling factors on SCADA instrumentation as the ratio of estimated and measured values is conspicuously close to 3. The large majority of cases with matching between measured and estimated values, validates the method of using conversion factors to accurately predict temporal load profiles.

In the next section we review how these profiles are turned into samples of load compositions.



(a) Feeder 1 (b) Feeder 2 (c) Feeder 3

(d) Feeder 4 (e) Feeder 5 (f) Feeder 6

Figure 4.1: Comparison of modeled load profile to observed SCADA data

4.2 Transformation of Temporal Profiles into Load Compositions

The remaining step is to transform the temporal profiles based on load types into load compositions according to WECC guidelines [5]. As was already discussed, WECC "light" method has built-in transformations from load types into end-use equipment represented by equipment varieties and the daily temporal profiles for each equipment. The method requires only the peak load and the type-mix, and it seeds all subsequent proportions. This has an important additional shortcoming – it is unable to consider load offset by behind-the-meter PV. To enable correct calculations, the type-mix first has to be corrected by PV energy then turned into the temporal profile using PG&E conversion factors, to finally use the peak load as the input to WECC process. We modified the process to retain the temporal load profiles determined by application of PG&E conversion factors, but transformed each hour into relevant compositions using hour-specific distributions from WECC "light" process. We then sampled the temporal profiles of load compositions at noon to create a representative set of load compositions likely to become islanded at the time of highest output from PV.

The final result is a sample of load composition for each circuit section analyzed. There are 3440 samples representing the full set of possible load compositions. In the next chapter we discuss how are these samples grouped to cover their highly dimensional space of values with a feasible number ot laboratory experiments.

Chapter 5

Selection of Load Compositions for Laboratory Evaluation

WECC load modeling guidelines [5] recommend representing distribution loads in accordance with the Figure 5.1.

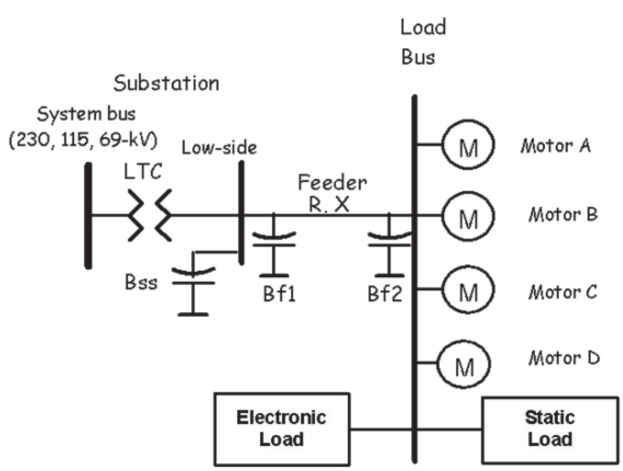


Figure 5.1: WECC composite load model in GE PSLF

From left to right, the load model includes the substations transformer with the load tap changer (LTC), the power factor correction capacitance installed at the substation (B_{ss}), the feeder model represented by the pi-equivalent circuit of the line (B_{f1}, R, X, B_{f2}) and the seven components of loads: Motor A, Motor B, Motor C, Motor D, Power Electronics, and Static comprised of constant resistance and constant current. By function, these loads represent:

Motor A Thrree-phase compressor motors (used in refrigeration)

Motor B Fans

Motor C Pumps

Motor D Single-phase air conditioners

Power Electronics Variable speed drives and electronic power supplies

Static R Incandescent lightning, electric water heaters, space heaters

Static I Ballast-controlled fluorescent lightning

Study of islanding conditions does not require this entire model. The conditions we are interested in assume opening of a protective element somewhere on the distribution feeder, effectively leaving just the equivalent load, the PV, and the power-factor correction capacitance connected together without the appreciable feeder impedance between them. With reference to Figure 5.1, we are interested in the seven components of the load, and the equivalent capacitance B_{f2} which we define to mean the equivalent power-factor correction capacitance.

5.1 Input Data

Our temporal analysis, described in Chapter 4, provides a set of 3440 samples for all circuit sections of three load divisions. One half of the samples represents summer, the other half winter loads. This data can be thought of as a table where each row represent a sample, and each column an attribute of a sample. In addition to the seven components of load compositions, we collected the following attributes:

Total P Total estimated power of the circuit section, used to normalize load components

Static X Constant reactance part of WECC Static load model

Static Iq Constant reactive current of WECC Static load model

Qtot Total estimated reactive power of the circuit section (a pair to **Total P**)

QinsFxC Reactive power contribution from fixed (non-switched) power factor correction capacitors

QinstC Total installed reactive power on the feeder section from fixed and switched power factor correction capacitors

RatedPV Rated AC output of PV installed on the section

PsmallPV Estimated total output of small PV installed on the section

PallPV Estimated total output of all PV installed on the section

To enable filtering of data, we prefaced each row with the division code, the season flag (winter or summer), and the hierarchy flag (feeder or section). We also included NetworkID, and NodeID to enable traceability back to original data and worked with PG&E distribution planning to validate table entries for several rows with high penetration of PV and, independent of that, several rows with high installed totals of power-factor correction capacitance.

To explain how all this feeds into laboratory experiments, it is helpful to first describe the end-goal, or how are the lab experiments potentially going to be used by PG&E.

5.2 Future Interconnection Process Use-Case

The ultimate objective of this project is to inform the PV interconnection studies and increase the allowable level of PV penetration by applying circuit specific evaluation criteria. Suppose that at some point in the future, a distribution engineer is considering an application for PV installation. The first step of the process, which is the same today, is to locate the proposed site in the distribution planning program and identify the upstream device that can create an islanding condition. In today's process, the total queued PV is compared to the 15% of the section peak load (Screen M), and failing that, the supplemental review is invoked. A possible future alternative is to calculate the composition of load on the section under consideration and to use this composition to query the database of experimental results. The result of the query will be the highest level of penetration that can be allowed without the risk of unintended islanding. Implementing such process would reduce the number of invocations of supplemental review and accelerate PV interconnections without posing additional risk to the utility.

To enable this use case, it is necessary to cover the complete space of possible load compositions and to run multiple experiments for each, to determine the maximum level of penetration that results in fast island-detection and orderly shut-down of PV inverters. Furthermore, each load composition and penetration level needs to also be considered for a range of possible installed reactive-power correction capacitors, because this is another variable that affects the balance within the island. If the experimental results show that the lack of reactive balance leads to less-likely islanding, this could perhaps be used as a way to accommodate more PV projects.

The database therefore needs to be populated with the variety of load compositions (seven dimensions), studied at different levels of PV penetration (adding one dimension), and studied at different levels of reactive power balance (adding another dimension). The resulting total number of dimensions is nine. Assuming that each variable is to be varied across only three values (low, medium, high), the total number of experiments that would be required to characterize the space is $3^9 = 19,683$. This is completely impractical and it makes it necessary to study mutual correlations of load compositions and down-select the parts of load compositions space with highest likelihood of occurrence. Then, structure the experimental part of the project to consider the most likely compositions first and proceed in order of descending likelihood, to cover as much space as possible. The next section reviews the correlations of the variables and describes the clustering and ranking method used to prioritize the experiments.

5.3 Analysis of Load Compositions

Starting from the table of samples described in section 5.1, the first step is to normalize load compositions to reduce all variables to the same scale. The normalization was done by dividing values of all attributes with **Total P**. This makes perfect sense for load components as it establishes percentage content of each. It also makes sense for PV components, as it describes the level of penetration, albeit at noon-time. In case of normalization of Q components, it is debatable if using a power factor would be a better metric, as the power factor is more readily known to the distribution planning engineers. For sake of consistency, we chose to normalize Q in the same way as P and to express the resulting power factor in post processing using the formula

$$pf = \cos\left(\arctan\left(\frac{Q}{P}\right)\right) \tag{5.1}$$

The normalized compositions can now be studied for correlations. This is not a trivial undertaking in the seven-dimensional space and several methods were tried to gain insights into the groupings of samples.

Figures 5.2 and 5.3 show matrices of scatter plots of variable pairs. Figure 5.2 is prepared based on summer load samples, and Figure 5.3 based on winter load samples. The axes scales are omitted to save space – each plot represents normalized value of referenced variable on the 0.1 grid.

It is apparent from the figures that load compositions are correlated, so there is an entitlement to reduce the number of experiments by identifying regions with the highest frequency of observations. It is also apparent from the figures that the correlations of summer compositions are different from winter compositions and that two independent rankings need to be used.

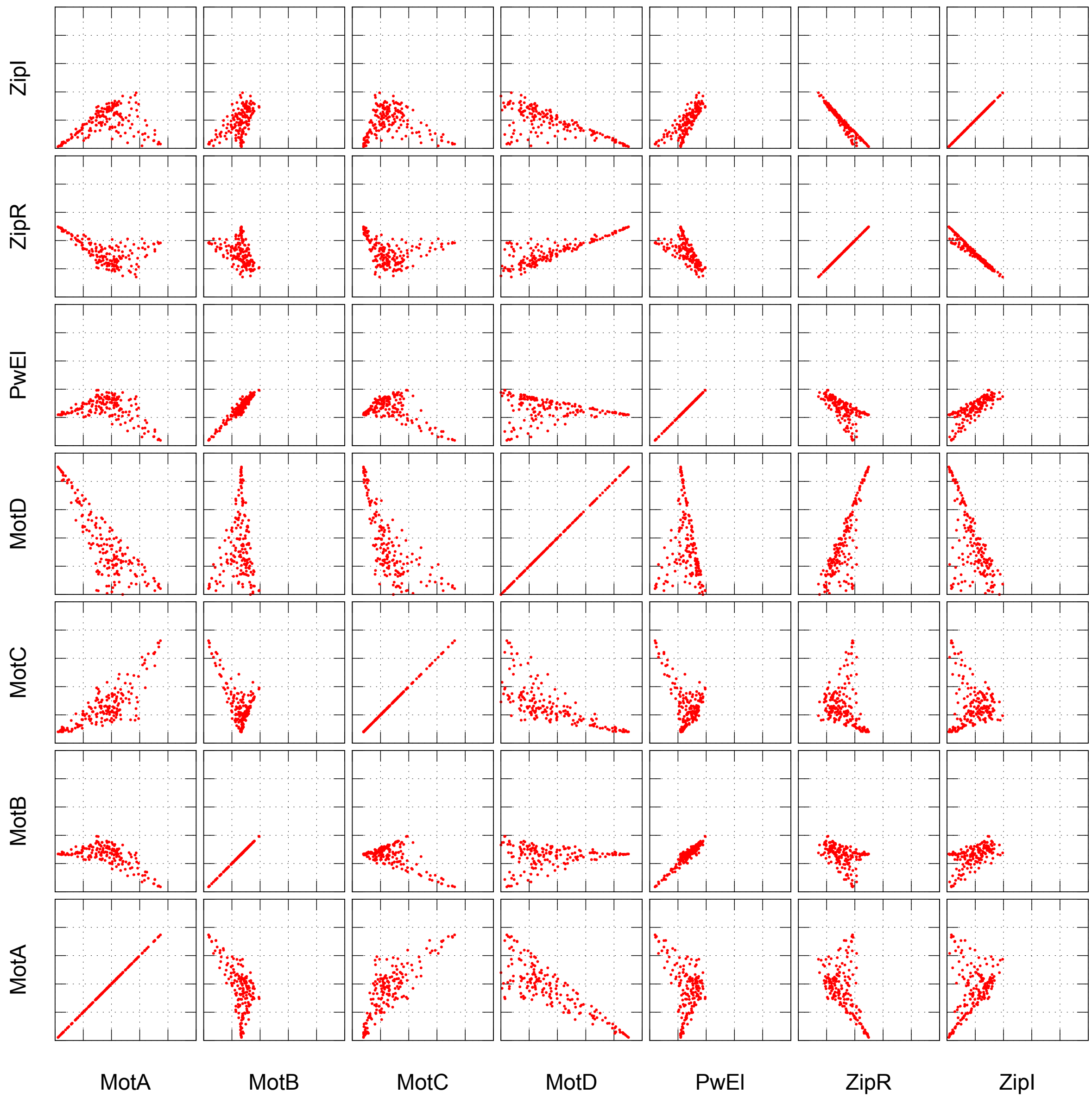


Figure 5.2: Correlations of load compositions – summer

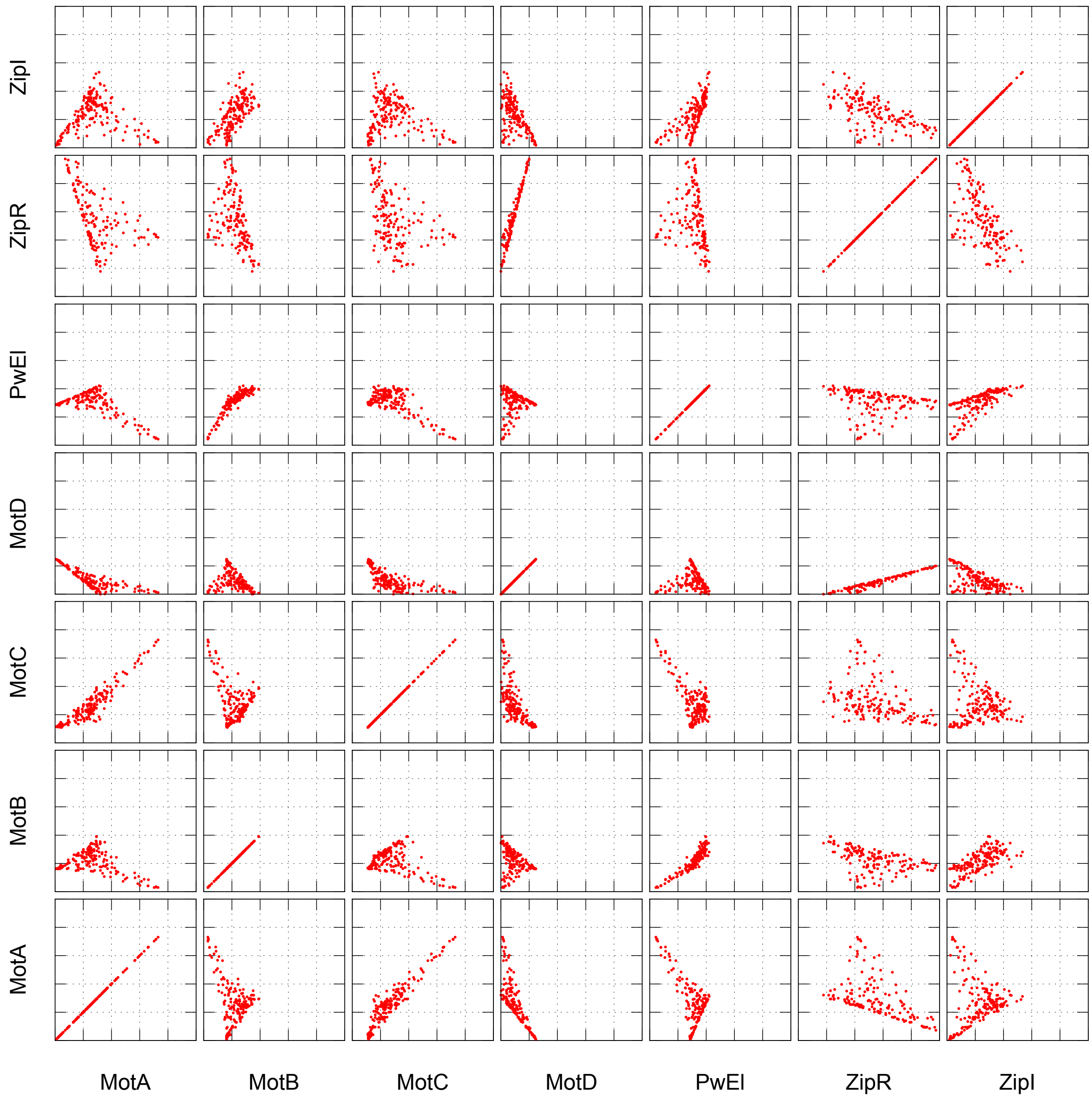
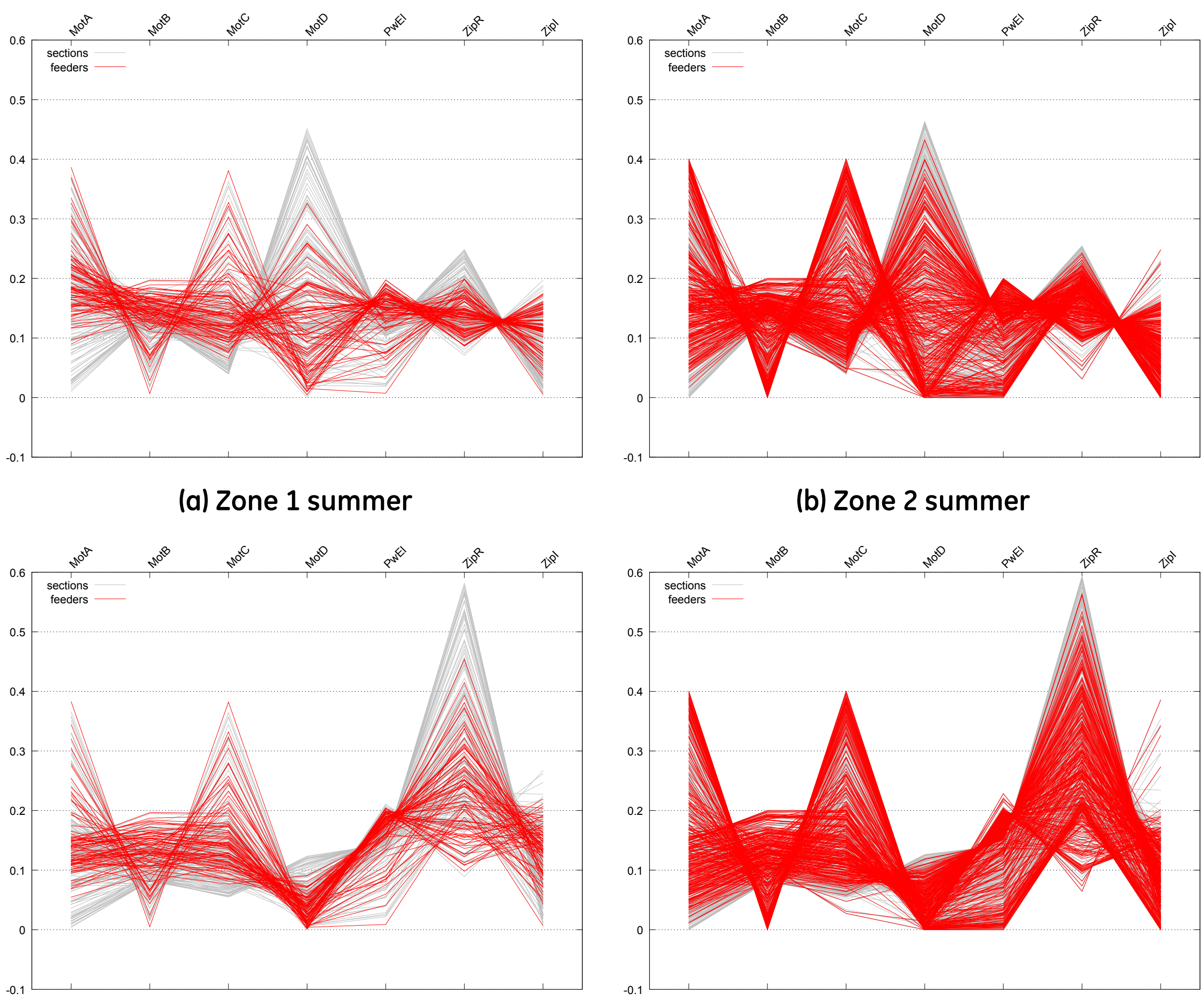


Figure 5.3: Correlations of load compositions – winter

Another way to look at load composition data is by using parallel coordinate plots as is shown in Figure 5.4. In this case, each load composition sample is a single line on the plot connecting values in each variable by straight line segments. The samples representing circuit sections are shown as gray lines and the samples representing entire feeders as red lines. This illustrates the greater diversity of load compositions when considered over sections because of the lesser scale of aggregation and therefore lesser averaging.

It is apparent from Figure 5.4 that the ranges of load compositions are consistent across load zones (Zone 3 had the same ranges and it was omitted from plots to save space.) The difference in seasonal properties is evident with the significant component of load shifting from Motor D in the summer to ZipR (static resistance) in the winter. This makes sense because Motor D represents single-phase air-conditioning units, and ZipR resistive heating.



(a) Zone 1 summer

(b) Zone 2 summer

(c) Zone 1 winter

(d) Zone 2 winter

Figure 5.4: Load compositions in parallel coordinates plot

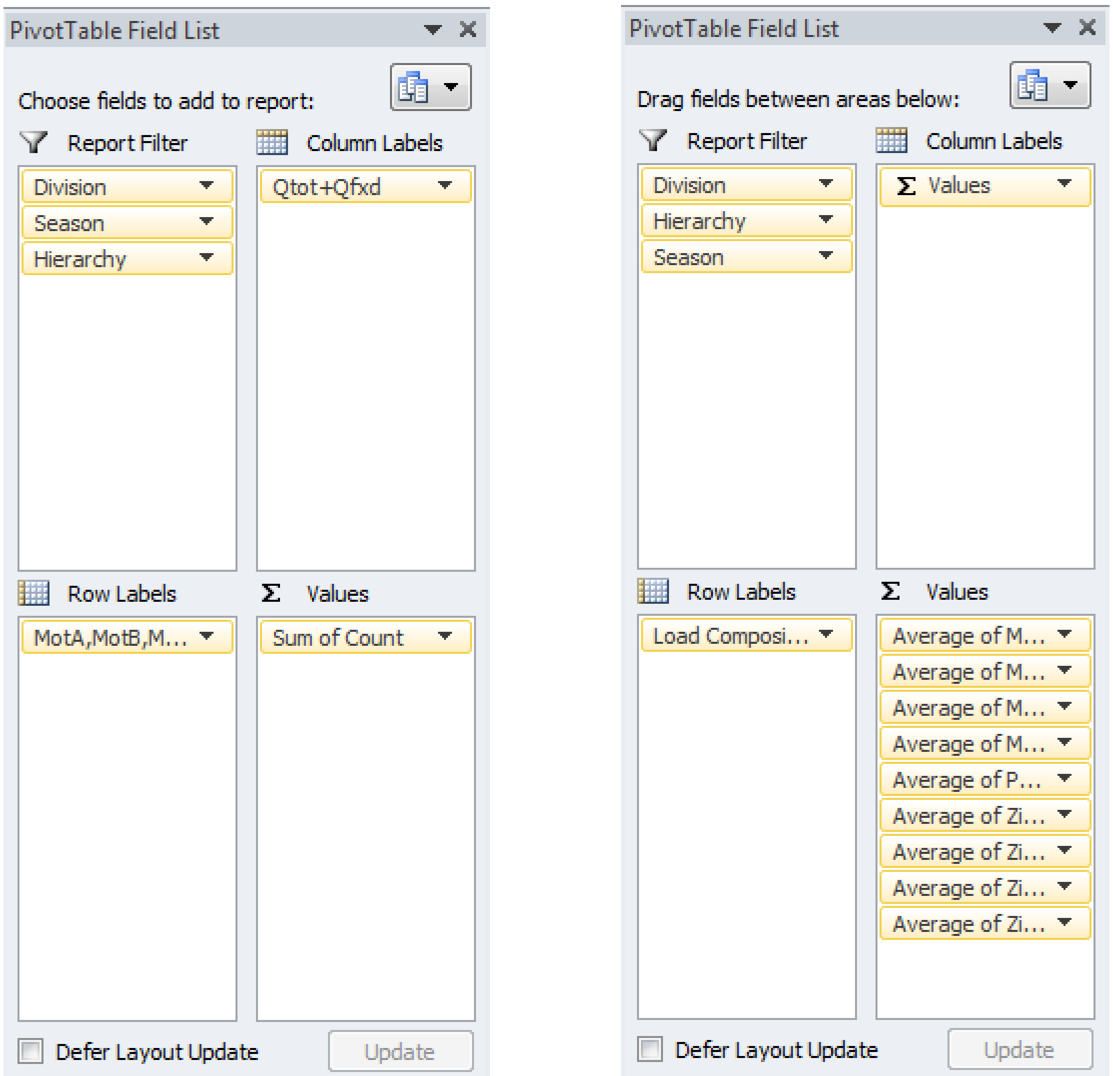
The scatter plots proved existence of significant correlations between the variables and the parallel coordinate plots provided the sense of range for each variable and uncovered the most notable difference between summer and winter. These insights provided the inspiration to group the samples of compositions into hypercubes of the seven-dimensional space. To do this, we assumed ten bins per axis (a dimension of the hypercube edge equal to 0.1) and processed all samples to associate them with the hypercubes. This is not difficult – given a vector representing the sample, each variable within the vector is associated with the bin of the corresponding hypercube-axis by integer rounding of a ratio of the variable value and the edge size. The formula is:

$$bin_n = d \cdot \mathrm{int}\left(\frac{x_n}{d}\right); \quad \text{where } d = 0.1 \text{ and } n \in \{1, \ldots, 7\} \tag{5.2}$$

For example, applying this formula associates the vector of normalized load compositions:
`(0.2112, 0.1021, 0.2235, 0.1325, 0.0971, 0.1791, 0.0545)` with the hypercube
`(0.2,    0.1,    0.2,    0.1,    0.0,    0.1,    0.0)`
This enables further analysis of the population using *Pivot Tables* in Microsoft Excel. The hypercube designations are transformed into labels and used as pivot rows. The load division, the season, and the circuit hierarchy are used as filters. There are two pivot tables:

The first one is used to count the number of load composition samples per hypercube. Subsequently, counted samples are sorted in descending order to provide the priority order for laboratory evaluation of load compositions. As an added convenience, this pivot table also includes a binned value for Qtot+Qfxd as a pivot column to count the subdivision of samples within a load composition hypercube into bins of total reactive power on those circuit sections. Because the total reactive power is of interest, we use the sum of Qtot (reactive power of the load) and Qfixed (total reactive power on non-switched power-factor correction capacitance.) The definition of this pivot table is shown in Figure 5.5(a).

The second pivot table provides the averages of the variable values within the hypercube. This is important as the association of samples with hypercubes lost information of actual variable values, so to have the representative value of samples within a hypercube, it is appropriate to use the vector average of the samples located in the hypercube. The definition of this pivot table is shown in Figure 5.5(b).



(a) Counts within hypercubes **(b) Averages within hypercubes**

Figure 5.5: Ranking of load-composition hypercubes using excel pivot tables

Table 5.1: ***Number of hypercubes containing load composition samples***

Season	Zone 1	Zone 2	Zone 3	Total
Summer	38	63	67	80
Winter	47	67	66	85
Total	85	130	133	165

The analysis of the load compositions data sets revealed that the samples are concentrated in a relatively small number of hypercubes. The results are summarized in Table 5.1. Note that the row totals are not algebraic sums of column values because many hypercubes are shared between the load zones. The column totals are algebraic sums of row values because of the differences between summer and winter data sets. These numbers are a significant reduction from the total number of hypercubes of one million[1]. Nonetheless, even with this lower number of choices, it is still sensible to rank the load compositions in the descending order of frequency of occurence and prioritize laboratory experiments based on that ranking.

5.4 Formulation of the Test Plan

As was discussed in the previous section, the laboratory tests are to be structured to cover the greatest possible space of load-compositions with the lowest number of experiments. The hypercubes of load compositions were ranked in descending order by frequency of occurrence. If the number of samples per hypercube is perceived to be proportional to the total space covered, this ranking can be transformed into a relationship between the number of compositions tested and the percentage of total space covered. This relationship is shown in Figure 5.6 for summer and winter family of load compositions.

[1] There are 10 choices per variable, over 7 variables, constrained by the sum equal to 1. This provides six independent choices with a total number of choices equal to 10^6.

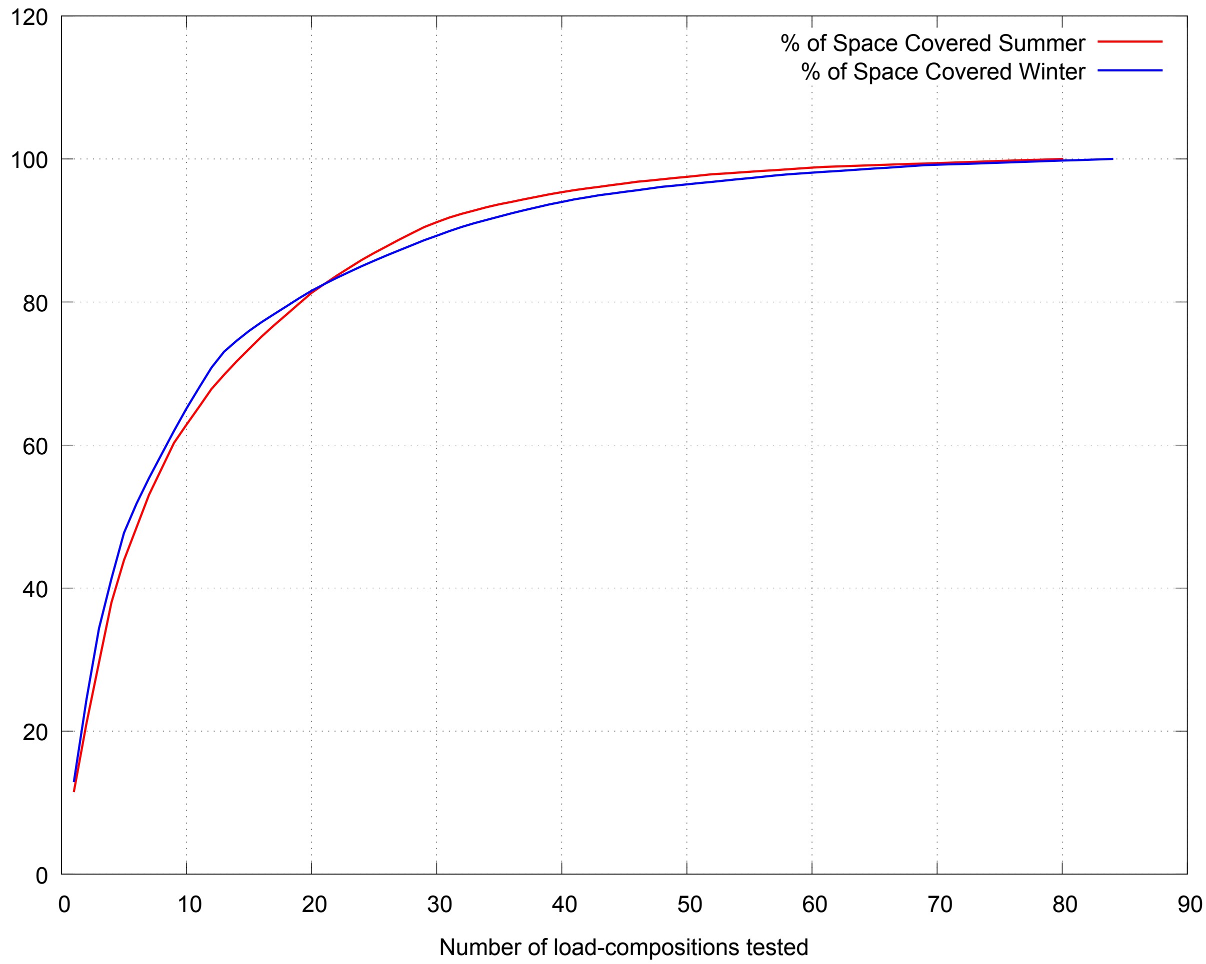


Figure 5.6: Percentage of load compositions space covered by prioritized laboratory testing of load composition samples

Furthermore, the analysis of total reactive power on circuit sections revealed that over 95% of samples have normalized Qtot+Qfxd in the range between -0.7 and +0.3. This led us to the following formulation for laboratory testing:

1. Set the priority list and the table of averages to summer
2. Chose the hypercube of load composition from the priority list
3. Set normalized Q of the experiment to -0.7 (pf = 0.82inductive)
4. Set PV penetration to 1.0
5. Run the islanding experiment and capture data
6. Repeat 4 to 5 for PV penetrations in $\{0.9, 1.1, 0.75, 0.5, 0.25\}$
7. Repeat 3 to 6 for normalized Q in $\{-0.5, -0.3, 0, +0.3\}$ (i.e. pf in $\{0.87ind, 0.95ind, 1.0, 0.95cap\}$
8. Repeat 2 to 7 for additional hypercubes following the priority sequence.
9. Repeat 1 to 8 for winter priority list

Table 5.2: ***Required number of experiments to cover desired pecentages of load compositions space***

Desired Percentage of Space	80%	90%	95%
Summer			
Required number of compositions to test	20	29	39
$\times$ Q multiplier (5 values)	100	145	195
$\times$ PV penetrations (4 avg)	400	580	780
$\times$ PV penetrations (6 max)	600	870	1170
Winter			
Required number of compositions to test	19	32	44
$\times$ Q multiplier (5 values)	95	160	220
$\times$ PV penetrations (4 avg)	380	640	880
$\times$ PV penetrations (6 max)	570	960	1320
Total assuming 4 PV penetrations	780	1220	1660
Total assuming 6 PV penetrations	1170	1850	2490

Table 5.2 provides the numerical relationships between the desired percentage of space covered, the number of load compositions tested, and the corresponding total number of tests required to cover the range of Q and the range of PV penetrations of interest. The table presents two options: one assuming a maximum number of 6 tests for PV peneterations, and another assuming assuming an average of 4 tests. The assumption here is that the tests at levels of penetration equal to 0.5 and 0.25 can be eliminated if islanding detection is succesful at 0.9 and 0.75.

Chapter 6

Summary

The analysis presented in this report is unprecedented in scale and fidelity. We studied three load zones of a major utility company to identify all possible circuit sections that can become islanded and collected relevant information for each. The analysis included 157 distribution substations, 557 distribution feeders, 1,396 reclosers, 2,561 reactive power correction capacitors, 14,821 PV installations, and 538,800 load points. The loads and PV were aggregated on 3,440 circuit sections and converted into temporal daily profiles using WECC load modeling guidelines to define equipment varieties in service during different times of day. The PV production was estimated using NREL guidelines to obtain region specific output curves. This was done for summer and winter, because both load and PV have different properties in different seasons.

The obtained load compositions were analyzed to explore their correlations in the seven-dimensional space and ultimately grouped into 165 composition clusters. The resulting clusters were then ranked by probability of occurrence to prioritize the upcoming experimental part of the program. The laboratory experiments will start with the most probable load compositions and proceed towards less probable as the schedule allows.

Several noteworthy observations can be made based on the insights gained.

1. PG&E already collects all the load and circuit data to support this level of analysis. The PG&E practices for data management should be embraced by other utilities facing high penetration of solar energy.

2. PG&E has region-specific conversion factors that transform energy consumption of load by type into temporal load profiles. These relationships were a key asset to the study and it would be most valuable if those were periodically revised to account for the changing nature of system loads.

3. PG&E has the complete data set of solar installations by location, but does not associate behind-the-meter solar with the metered load. Adding this association to the data set would improve accuracy of load modeling as it would enable accounting for load energy offset by solar within the metered net energy.

4. The tools developed for this study are computationally efficient, which allows for their periodic use to detect outliers that have passed through the interconnection process, but may present the risk to utility loads. Within the studied load zones, there are 15 circuit sections with the instantaneous noon penetration greater than 100% and 54 with the penetration greater than 50%. The maximum observed is 617%, estimated during winter on a feeder in Zone 3[1].

5. At present, PV is more correlated with residential commercial and industrial loads than with agricultural loads.

6. About 40% of PV power is contributed by installations rated less than 10kW. An additional 40% is contributed by installations greater than 200kW.[2]

7. Load compositions are similar between load zones, but dissimilar between summer and

[1] PG&E is taking actions to re-evaluate all sections with high penetration
[2] These observations are illustrated by cummulative capacity plots in C.3

winter. The greatest change in load composition between summer and winter is from single-phase airconditioning (Motor D) to resistive (space heating.) The ranges of values for other load components do not change appreciably by season.

8. All observed load compositions can be grouped into 165 clusters, 80 for summer and 85 for winter.

9. About 80% of all observed load compositions fit into 25% of composition clusters.

Appendix A

Association of Circuit Elements With Upstream Reclosers

In order to associate circuit elements with a node, we first associate downstream sections with a node. To accomplish this, sections within the feeder network are looped through to find all sections with a parent node of the recloser node. These sections are then associated with the recloser node. Next, these sections' child nodes are added to an array of associated nodes. Each of these nodes is systematically evaluated in the same manner, ultimately aggregating a comprehensive array of associated sections with any given recloser node. Effectively, the radial network dependent on a recloser is traversed radially, downstream from the recloser.

Once an array of associated sections is developed for a recloser, all of the circuit elements dependent on the associated sections are associated with the recloser. This allows for future circuit typification and modeling. Seen in Figure A.1 is a typical feeder with four reclosers. Shown is the circuit topology of the entire feeder, with each of its reclosers and only its associated circuit elements overlaid. This validates the association algorithm to be employed by other circuit analysis steps.

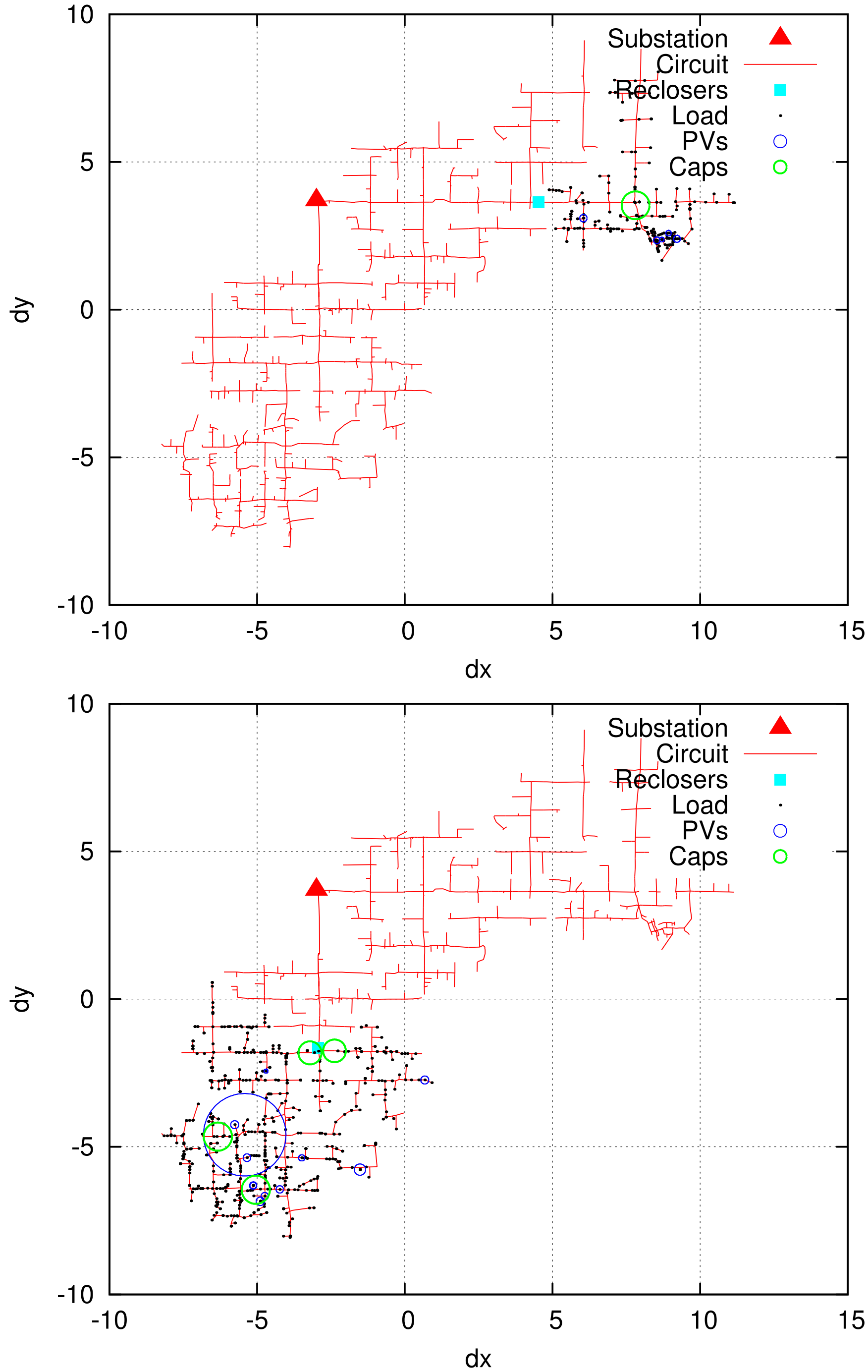


Figure A.1: Recloser topology typical example: image shows two reclosers and their associated elements on a given feeder topology

Appendix B

Accounting for Behind-the-Meter PV

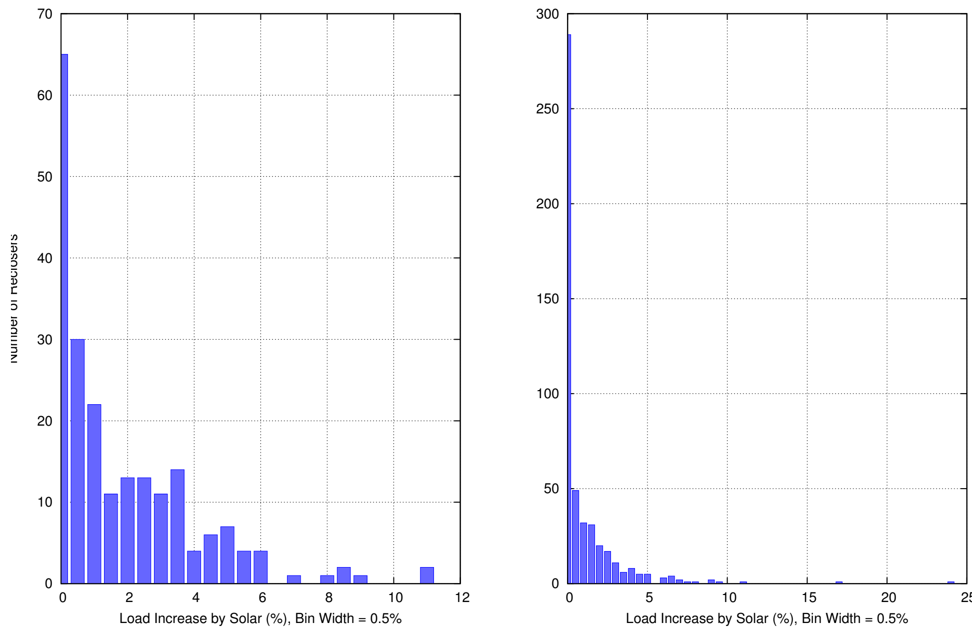
In many cases, it is assumed smaller installations will not have their own point of interconnect and will reside behind the meter. This can affect the daily kWh usage of a load, projecting a less accurate representation of the size of the load. Installed PV behind the meter will reduce a loads energy need from a utility. PV is not directly associated with a load in the provided database, however, and behind-the-meter status is not directly known, posing an inaccuracy in the load aggregation. To account for PV generation adjustments, some determinations and assumptions must be made.

First, it will be assumed solar installations greater than 300kW will not be behind-the-meter, and will subsequently be ignored for load adjustment. Next, location, nodal-based assignment is attempted. Since direct association of PV with load is not provided, the next-best approach is to indirectly associate PV with loads by location. PV installations are associated with their own section and thus must be associated nodally with loads. Each PV installation's parent node is determined, along with the associated child sections of that node. The load makeup of those child sections is aggregated by type, and the type of section is determined by load type usage percentage. If the load directly parented by the parent node of the PV is greater than 80% of one load type, the PV generation is assigned to that type of load. If there is no load type bearing a greater than 80% ownership, the PV generation is assigned on a pro-rata basis with respect to load type percentage. However, if a load type comprises of less than 20% of the total load usage, it will not be assigned any of the PV generation as it is unlikely it would be actually attributed to that load type. It is important to not simply count PV generation towards the total load usage, since each load type will comprise the aggregate load profile differently. If the PV cannot be assigned to a load type due to no loads associate with the parent node, the PV generation will be assigned to residential loads if the generation is less than 10kW.

Next, the amount of energy to credit the loads is determined by the average insolation value for the region of study and assuming a performance ratio of 73.1%. This number is obtained from typical performance ratios expected at NOCT [6]. The performance ratio can be understood as the average daily energy output, relative to the energy produced during the peak day of the year. It would not be appropriate to assume a 100% performance ratio as this would lead to an overestimate of the load and consequently an underestimate of the risk of islanding. Using the lower number from the NREL paper leads to a more conservative and appropriate estimate. Thus the energy credit will be equal to:

$$E_{credit} = PV_{rating} \times Insolation_{dailyavg} \times 73.1\% \tag{B.1}$$

For the two divisions studied, Figure B.1 shows the behind-the-meter correction effect on load values. The figure shows a histogram of how many circuits are increased a given percentage. Ninety percent of recloser total load values were increased by less than 5% (in Division 1) and 3.5% (in Division 2), indicating a still-small impact on load data.



(a) Division 1 **(b) Division 2**

Figure B.1: behind-the-meter solar load correction

Appendix C

Photovoltaic Installations and Irradiation

C.1 Insolation Data and Accounting for Panel-Tilt

C.1.1 Correcting Irradiation Data for Panel Tilt

Commonly available information about irradiation is often restricted to three solar components rather than plane-of-array data for the infinite combinations of panel-tilts and panel-orientations. Solar irradiation data is presented as the three components:

- DNI - Direct Normal Irradiation - radiation from the direct beam of the sun
- GHI - Global Horizontal Irradiation - total radiation observed as a horizontal plane; includes direct normal radiation as well as scattered diffuse radiation
- DHI - Diffuse Horizontal Irradiation - diffuse radiation observed as a horizontal plane; removed normal radiation component from GHI

For any observed radiation at a plane of array, the radiation can be described as the sum of beam radiation, diffuse radiation, and reflected radiation:

$$I_{tilt} = I_b + I_d + I_r \tag{C.1}$$

Each component can be related to the three components found in irradiance data as functions[7]:

$$\begin{aligned}
I_b &= DNI \times [\cos(\alpha)\cos(\theta - \theta_{array})\sin(\beta) + \sin(\alpha)\cos(\beta)] && \text{(C.2)} \\
I_d &= DHI \times \frac{(1 + \cos(\beta))}{2} && \text{(C.3)} \\
I_r &= \rho \times GHI \times \frac{(1 - \cos(\beta))}{2} && \text{(C.4)}
\end{aligned}$$

where α represents solar elevation relative to horizontal, θ represents solar azimuth relative to south, θ_{array} represents orientation of the array relative to south, and β represents panel tilt relative to horizontal. α and θ can be expressed in terms of time of day (hours-from-local-solar-noon) and day of year (n) as well [7]:

$$\begin{aligned}
\alpha &= \arcsin[\sin(Lat)\sin(\delta) + \cos(Lat)\cos(\delta)\cos(HA)] && \text{(C.5)} \\
\delta &= 23.45^\circ \times \sin(\frac{360}{365}(284 + n)^\circ) && \text{(C.6)} \\
HA &= 15^\circ \times \text{hours-from-local-solar-noon} && \text{(C.7)} \\
\theta &= \arcsin\left(\frac{\cos(\delta)\sin(HA)}{\cos(\alpha)}\right) && \text{(C.8)}
\end{aligned}$$

Thus, panel irradiance can be expressed as a function of time for any tilt and orientation. Given this information and the PV rating for a given circuit, a daily maximum profile can be ascertained from clear-sky irradiance data found in [7, 8].

In many cases, the optimum tilt of solar panels is assumed to be a latitude tilt. This however, is not the case. The optimum tilt for a system is actually slightly more horizontal than a latitude tilt. A latitude tilt optimizes solar output during the equinoxes, thus centering its best output there. Since there is less solar radiation incoming on the winter side of the equinox than the summer side, total overall energy output is increased by a slightly shallower panel tilt. Of course, several other factors can affect (e.g.: weather, snow cover, soiling) where the true optimal tilt is. Thus, rather than adjusting sensitivity to the peak tilt, falling subject to several other factors, the assumption is made to hold a latitude tilt for all panels to avoid adding unnecessary complication with little effect.

C.1.2 Irradiation Data

NREL's TMY files provide hourly data points of weather observations at weather stations across the United States. These files provide the key insolation values for each data point of DNI, DHI, and GHI. First, the TMY data of DNI, DHI, and GHI are combined via the methods outlined in Section C.1.1 into Plane of Array (POA) irradiation. Next, the solar data is collected by hour and season. Since the load profile data is separated by Winter/Summer, the solar data is also collected by Winter/Summer. The resulting plots of irradiance are shown in Figure C.1). Also extracted from irradiation data is a maximum irradiation observed for a given hour and season.

C.2 Orientation of Rooftop-Mounted Installations

A simplifying assumption was made that solar modules' orientations are normally distributed about due south with a standard deviation of 30° so that almost all arrays are $+/-90^\circ$ of south. This effectively leads to a peak cut in solar output around noon, and does not increase

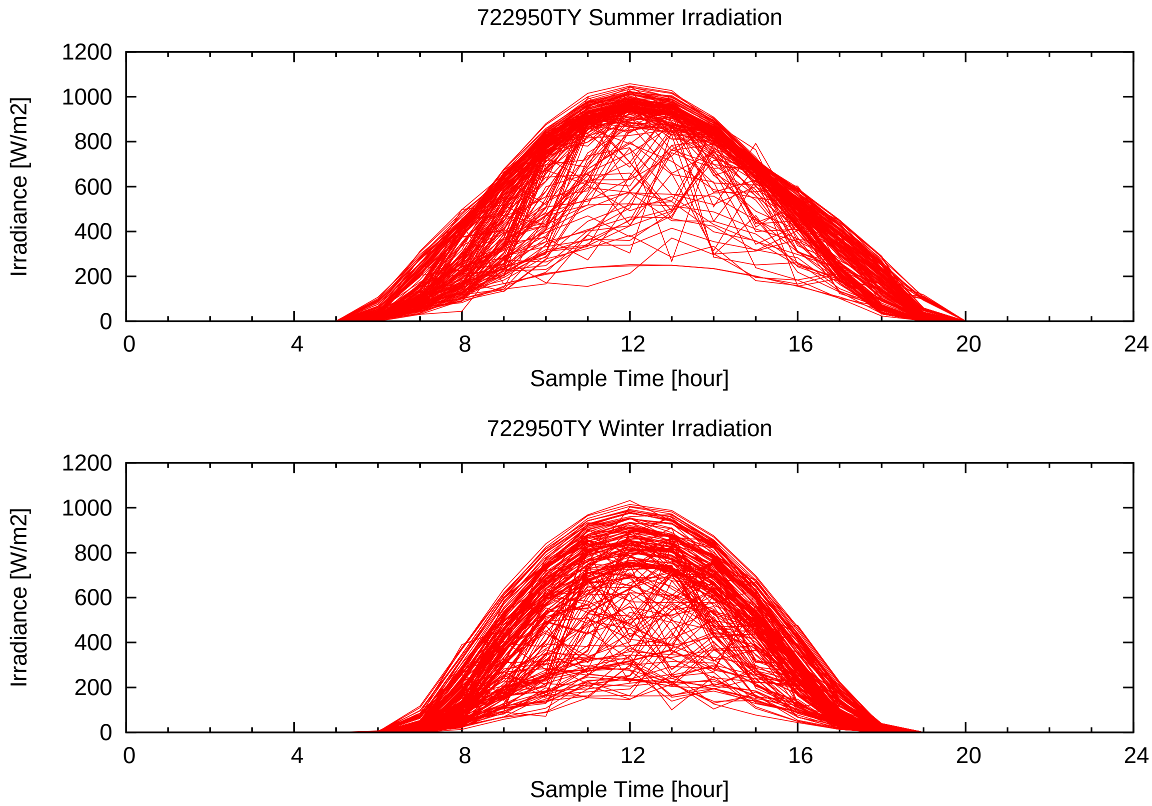


Figure C.1: POA irradiation data by season in Fresno, CA

solar output at any time of the day, despite some arrays peaking in power earlier or later in the day. The differences in irradiance between all panels facing south and panels normally distributed around due-south are shown in Figure C.2. The top two charts show comparisons of irradiance for month pairs, the bottom chart shows the ratio of the two (normally-distributed over south-facing)

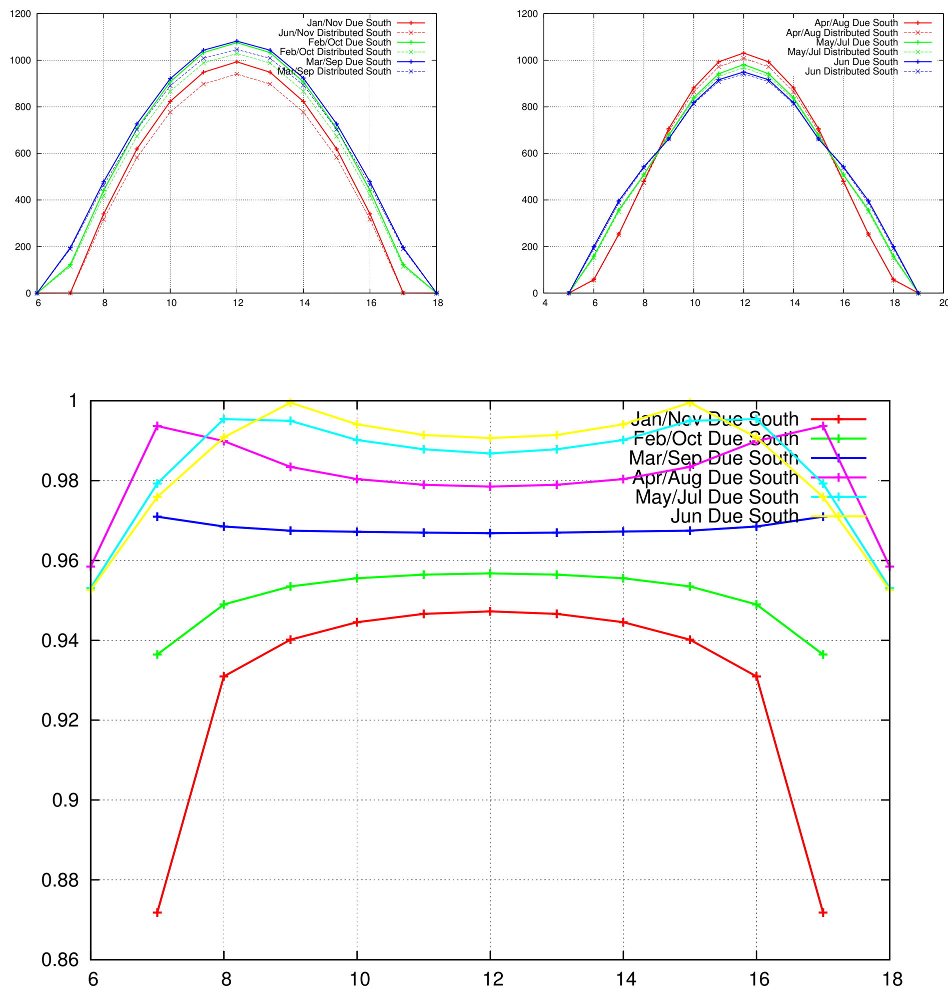
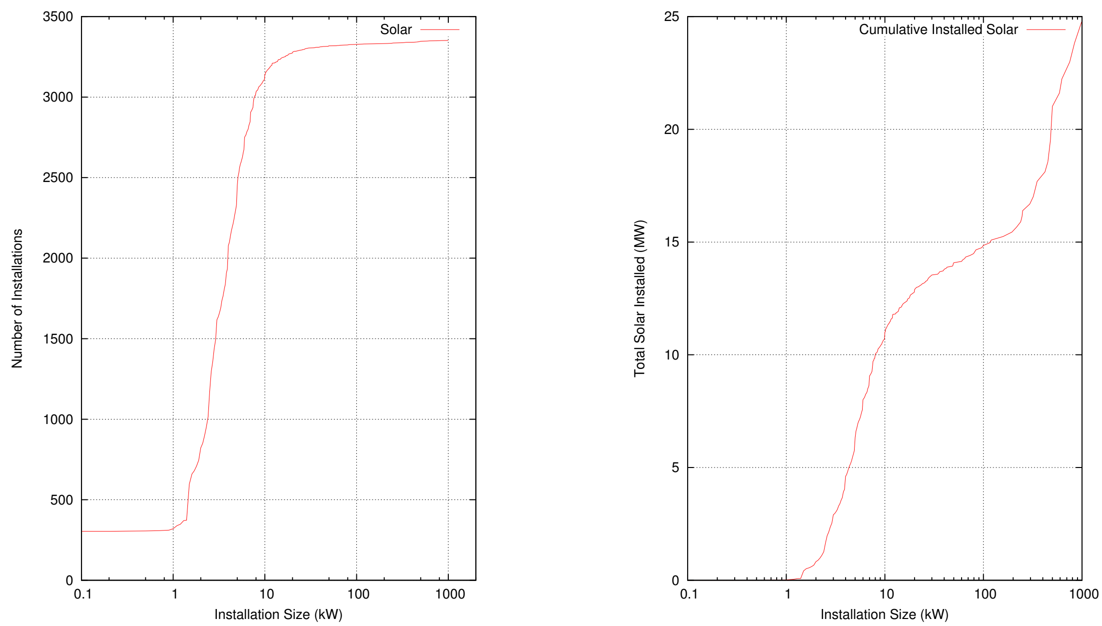


Figure C.2: Comparison between distributed south and due south panels

C.3 Solar PV Makeup

In making the determination for where residential size cutoffs might be placed, the solar makeup of the divisions in PG&E's load zones was analyzed. Seen in Figure C.3, the vast majority of installations are between 1kW and 20kW. By total installed capacity, about half of the installed solar is in the small 1-20kW range. Furthermore, another third of the installed capacity is due to installations above 100kW: likely installations not behind the meter. A small grouping of installations is located at 1MW, the observed limit of installation size on the distribution systems studied. Installations less than 1kW and between 20 and 100kW make a relatively small impact on the total installed solar base.

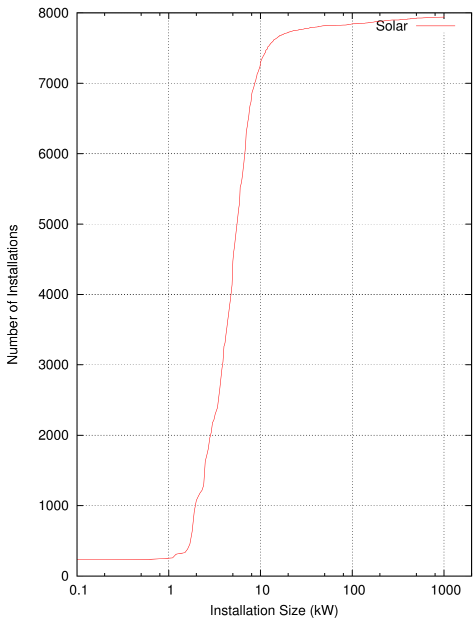
These observations led to the choice of 10kW as the threshold for associating PV installations with residential loads, discussed in Appendix B



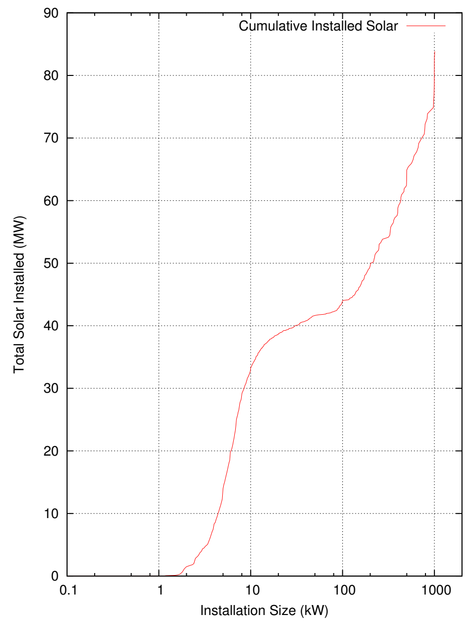
(a) By customer count **(b) By installed capacity**

Figure C.3: Division 1 solar pareto plot

These observations are consistent between divisions, with the exception of Division 2 having a slightly larger group at the 1MW range. See Division 2 in Figure C.4



(a) By customer count



(b) By installed capacity

Figure C.4: Division 2 solar pareto plot

Appendix D

Tool-chain

The data is processed through several steps aligning with the methodologies explained above. Data is extracted from an Access Database using a generalized SQL Querying VBA script. Data is extracted into CSV files, which are passed into the tool chain for manipulation.

The tool chain is run in three branches. First, the data is passed through a topological process, which arranges data by circuit of interest and plots the topology graphically to understand the layout of the system. This process is collectively under a file *runPrepCircuits.bat*. This batch file passes raw CSV files of circuit components into *PrepCircuits.awk*, which separates the components by circuit and centers them based on the relative location of other components in the circuit. The organized data is then passed to the GNUplot script *PlotCircuitMaps.gplt*, which plots the topology.

Second, the data is passed through an aggregation process, which aggregates circuit information circuit by circuit and develops models of the data over time as described in Chapters 3 and 4. The process is run collectively through *runAggregateCircuitData.bat*. This batch file passes raw CSV files of circuit components into *AggregateCircuitData.awk*, which separate the components by circuit (at the level desired) and sums all dependent load, PV, capacitance, etc., values. The resultant aggregate data is passed along with model data to *ModelAggregateCircuitData.awk*, which combines the model data in a manner consistent with Chapter 4.

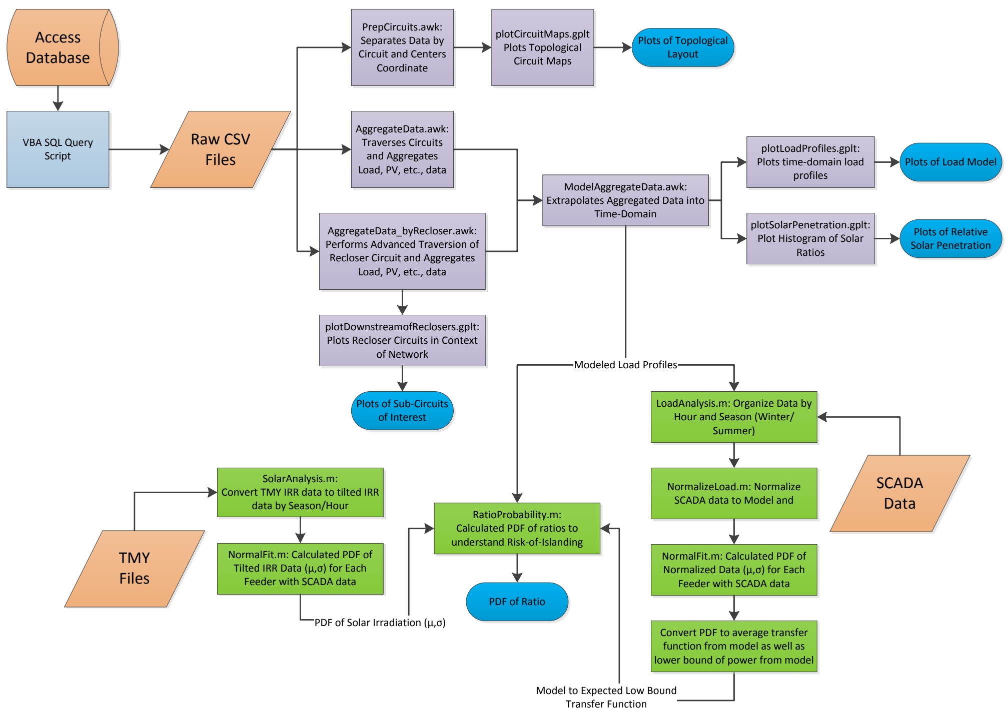


Figure D.1: Tool chain

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