15.0 Peninsula Light Company Site Tests

Additional chapter coauthors: M Simpson and R Grinberg − Peninsula Light Company

Peninsula Light Company is the second-largest rural electric cooperative in Washington, serving over 65 thousand people with over 31 thousand electric meters. Roughly 88% of its members are residential—73% of the electric load. Their service territory includes peninsulas and islands that surround Gig Harbor. The temperatures on the island are moderate, meaning that the island's residents require some energy for winter heating but little energy for summer cooling.

The cooperative chose to focus its project resources on Fox Island (lower left in Figure 15.1). The island was served from the Gig Harbor Peninsula by only two distribution circuits. With load growth preceding the project start, either of these circuits' capacity limits could be exceeded if the other circuit were to fail. The Fox Island feeders were among their 10 least reliable feeders. Load factor was poor because virtually all the island load was residential. As an island with rugged terrain, capacity improvements were anticipated to be expensive.[1]

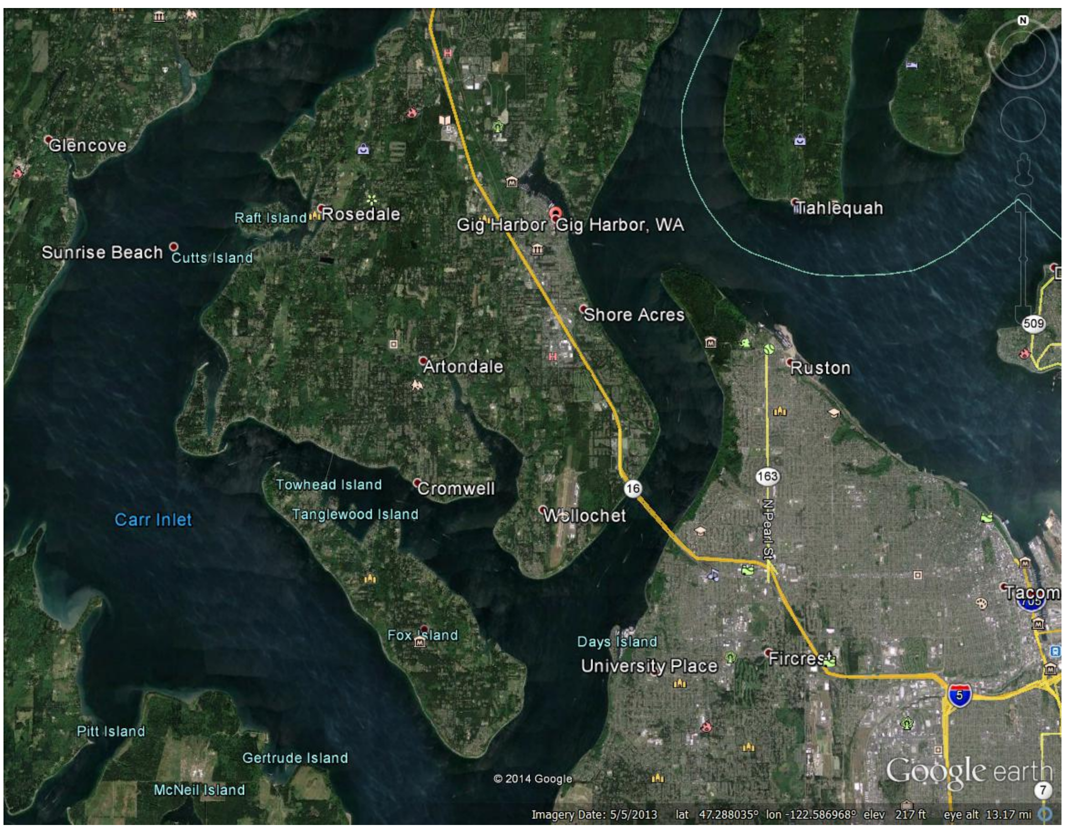

Figure 15.1. Aerial View of Fox Island, Gig Harbor, and Vicinity

[1] The facts in these introductory paragraphs were gleaned primarily from unpublished project presentation slides titled "Peninsula Light's Smart Grid Project." These presentation slides were found among July 15, 2010 Pacific Northwest Smart Grid Demonstration weekly project participant meeting slides.

Peninsula Light Company resolved to work with the project to

- install and evaluate demand-side management on the island using load-control modules (LCMs) (Section 15.1)
- apply distribution management on the island, including model-based dynamic conservation voltage reduction (CVR) that monitored end-of-line voltages (Section 15.2)
- improve member service quality on the island using dynamic distribution automation, including fault detection, isolation, and restoration (FDIR) (Section 15.3).

These three efforts were divided into three asset systems by the project. Details about the three asset systems will be discussed in subsections of this chapter. Figure 15.2 depicts the three asset systems and their components overlaid on the Fox Island distribution circuit. In Figure 15.2, text that begins "PL-IM-" represents data collection points defined in Table 15.1.

Table 15.1. Definitions of Data Collection Points that Were Shown in Figure 15.2

Data Label	Description
PL-IM-1-*	Daily Electricity Usage from One of 2,650 Customers
PL-IM-15-2	Hourly Feeder Voltage at Head-End of Feeder 2
PL-IM-15-6	Hourly Feeder Voltage at Head-End of Feeder 6
PL-IM-41-2	Hourly Distribution Feeder (Average) Power Loading on Feeder 2
PL-IM-41-6	Hourly Distribution Feeder (Average) Power Loading on Feeder 6
PL-IM-42-2	Hourly Distribution Feeder (Average) Reactive Power Loading on Feeder 2
PL-IM-42-6	Hourly Distribution Feeder (Average) Reactive Power Loading on Feeder 6

In Figure 15.2, text such as "(C, E, E)" is a nominal description of whether the data is a member of the Control or Experimental set for each of the three assets.

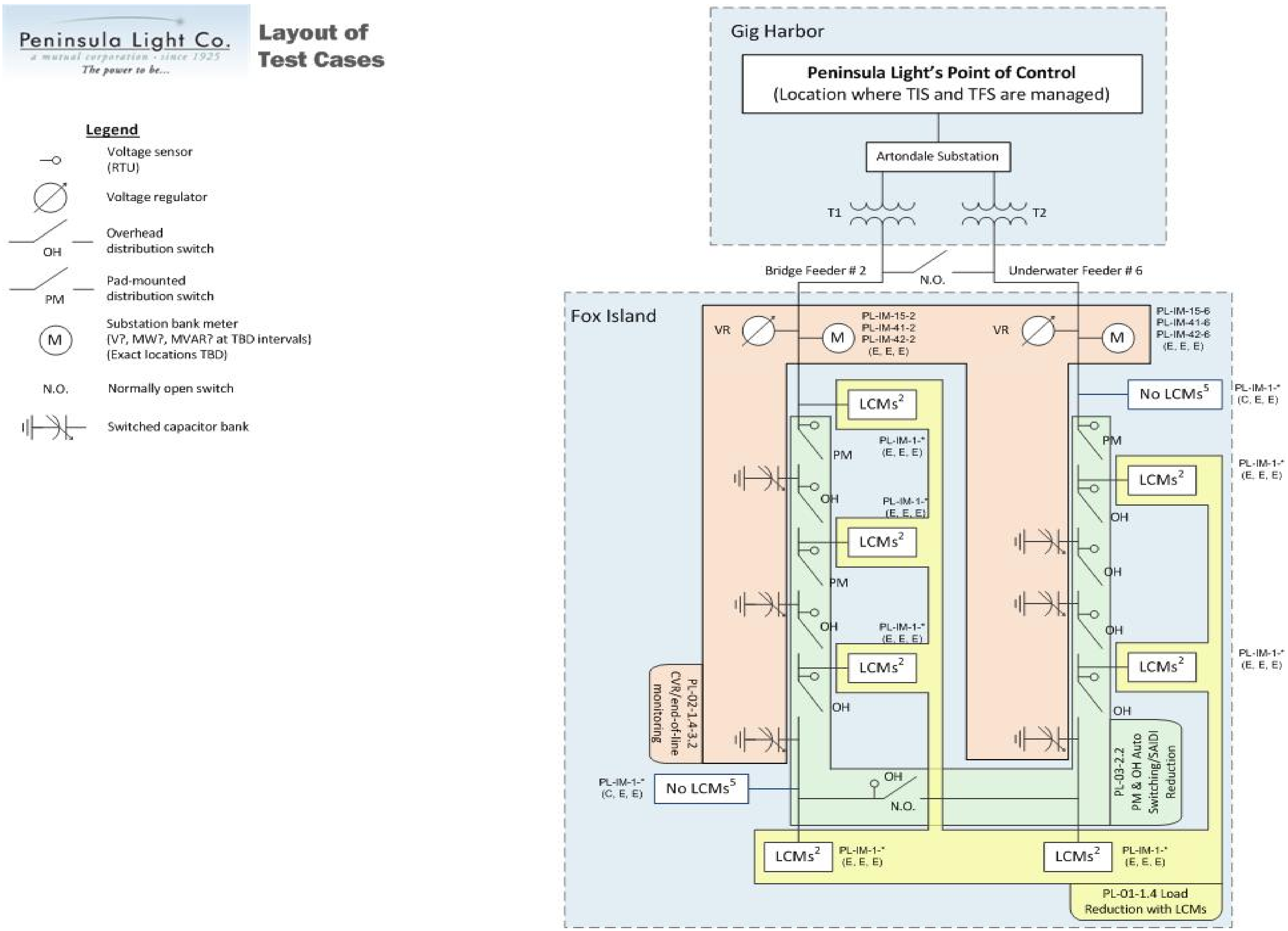

Figure 15.2. Layout of the Test Groups and Assets on the Fox Island, Washington, Distribution Circuit

15.1 Load Reduction with Load-Control Modules

Peninsula Light Company installed and engaged approximately 500 Landis+Gyr residential LCMs during the project. These devices were to disconnect hot water heaters and other household resistive loads in order to achieve demand reduction. They were controlled using the utility's existing power line carrier (PLC) network.

Members who allowed the LCMs to be installed were given a $5 monthly bill credit.

The original plan had been to fully automate the curtailments of the LCMs according to advice that was being received from the project's transactive system. This transactive system implementation proved challenging for the cooperative, but it eventually aligned control of the system of LCMs with the transactive system. In the end, the system of LCMs was engaged about 61% of the time that advice was received from the transactive system, and 87% of the time periods that load was curtailed had been advised by the transactive.

The capabilities of the PLC premises metering system limited the observations available to the cooperative and project. Installed PLC equipment was unable to carry the bandwidth that was needed for hourly or finer premises data intervals. Therefore, the project had to do its best with daily premises energy consumption measurements. The utility's efforts to resolve this lack of resolution during the project were unsuccessful. The lack of resolution especially limited the project's ability to observe the behaviors of premises equipment, such as the system of LCMs, that was typically engaged for hours, not days, at a time.

The annualized costs of the LCM system and its components are listed in Table 15.2. As a reminder, each component's cost was annualized over the expected useful lifetime of that component. The only subsystem component that was shared with other asset systems by this one was the implementation and integration of the transactive node—the local software that interacted with the larger transactive system. Most of the annualized cost is for the LCMs. Other smaller costs were for member incentives, transactive system integration, outreach, upgrades to the PLC system, and training. The total system's annualized cost was estimated at $450.1K.

Table 15.2. Annualized Cost of the Load-Control Module System and Its Components

	Shared Usage of Component (%)	Annualized Component Cost ($K)	Allocated Annual Component Cost ($K)
LCMs	100	410.7	410.7
Incentives	100	30.0	30.0
Transactive Node (integration)	50	8.9	4.4
Outreach and Education	100	3.4	3.4
PLC Communication Infrastructure	100	1.0	1.0
Training	100	0.6	0.6
Total Annualized Asset Cost			**$450.1K**

15.1.1 Characterization of Asset System Responses and Data

Peninsula Light Company submitted premises power data from August 2012 through August 2014, when the project data collection ceased. The project aggregated this data into various test and baseline comparison groups. As already stated, averaged premises power data was available only for one-day intervals. All of the daily average premises power measurements for the test group of premises that eventually possessed project LCMs are shown in Figure 15.3. Peninsula Light Company began allowing the LCMs to be curtailed gradually beginning in June 2013.

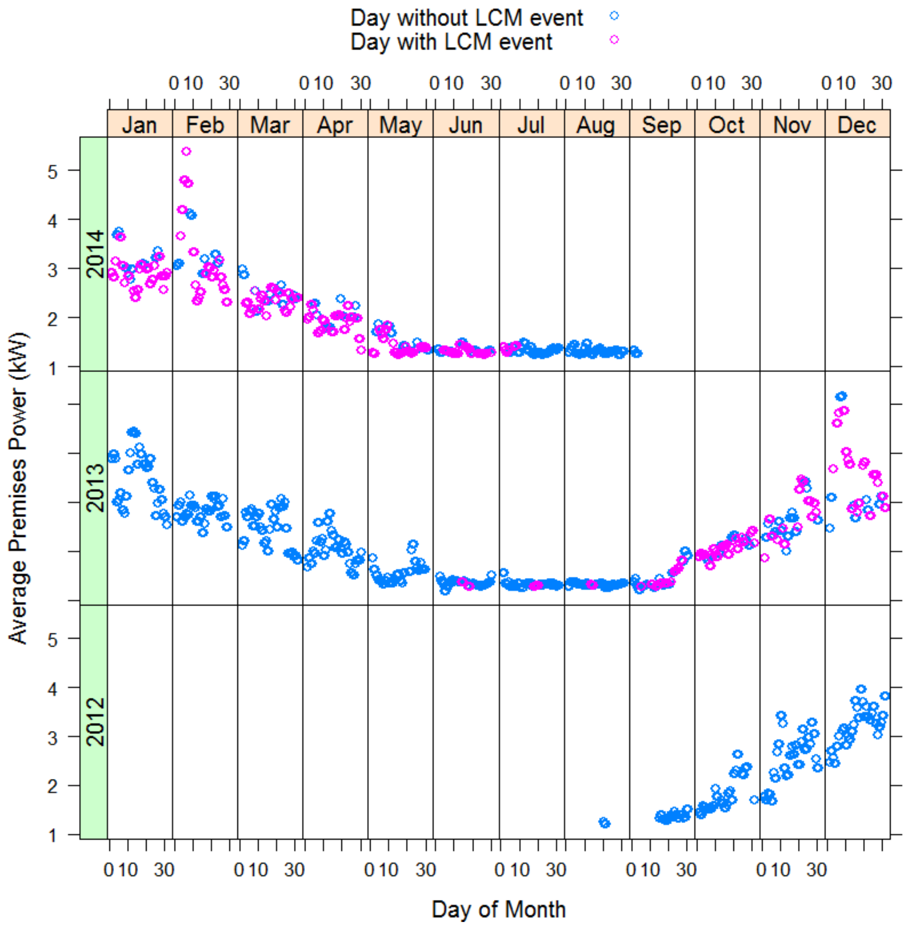

Figure 15.3. Time Series of Daily Mean Power for Premises Test Group that Received Load-Control Modules

The sum distribution power for Fox Island, Washington, was available to the project at hourly data intervals (Figure 15.4). This data was collected at the Artondale substation, which supplies all of Fox Island as well as additional mainland loads. The distribution data was available from August 2012 forward, but the LCM system was not declared installed and operational until summer 2013. Once operational, the system was engaged routinely until August of 2014. The quality of the distribution data appears good. A strong diurnal pattern was evident (not shown in Figure 15.4). There were only infrequent zero values—possibly low outliers—observed.

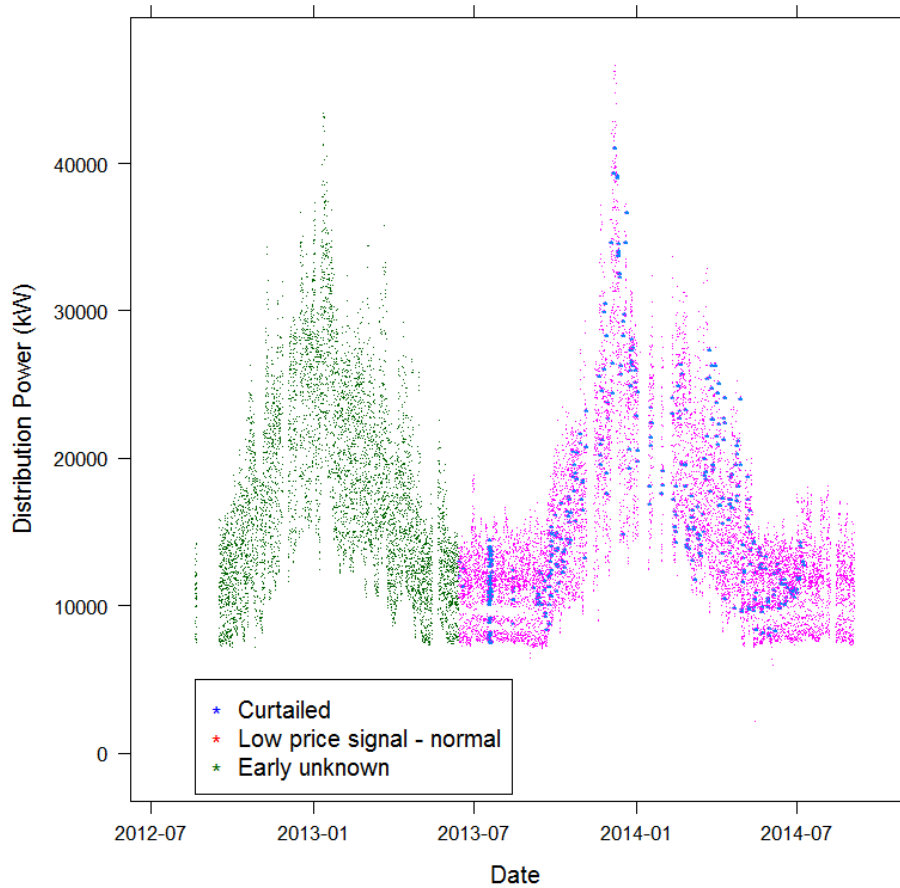

Figure 15.4. Total Hourly Distribution Power Measurements and Reported LCM System Status

Ambient temperature data was collected from weather station KTIW at the Tacoma Narrows Airport. The data intervals of weather data vary over time. Available measurements were treated as instantaneous measurements and were mapped to the corresponding 5-minute interval. These temperature measurements were averaged within the corresponding hours and days, according to the shortest data intervals that were available for premises and distribution circuit data.

There were altogether 217 curtailments called for by the LCMs during the project. The third event, in July 2013, was reported to have remained engaged for over 65 hours. That is unlikely, and Event 3 was therefore excluded from the analyses that the project conducted, except as noted. Figure 15.5 shows the percentage of curtailment events by calendar month.

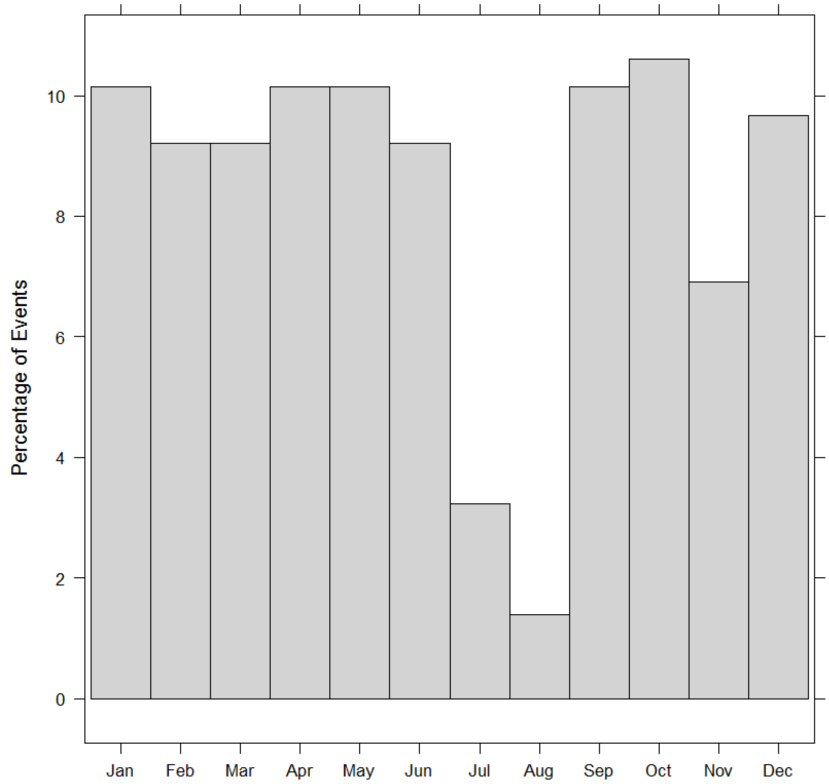

Figure 15.5. Percentage of Calendar Months that LCM Events were Conducted

As shown in Figure 15.6, most of the events were called on weekdays. For this reason, analysis carefully excluded or separately handled weekday and weekend days to avoid confounding impacts from differences between weekday and weekend loads and load patterns. The events were fairly equally distributed across the five week days.

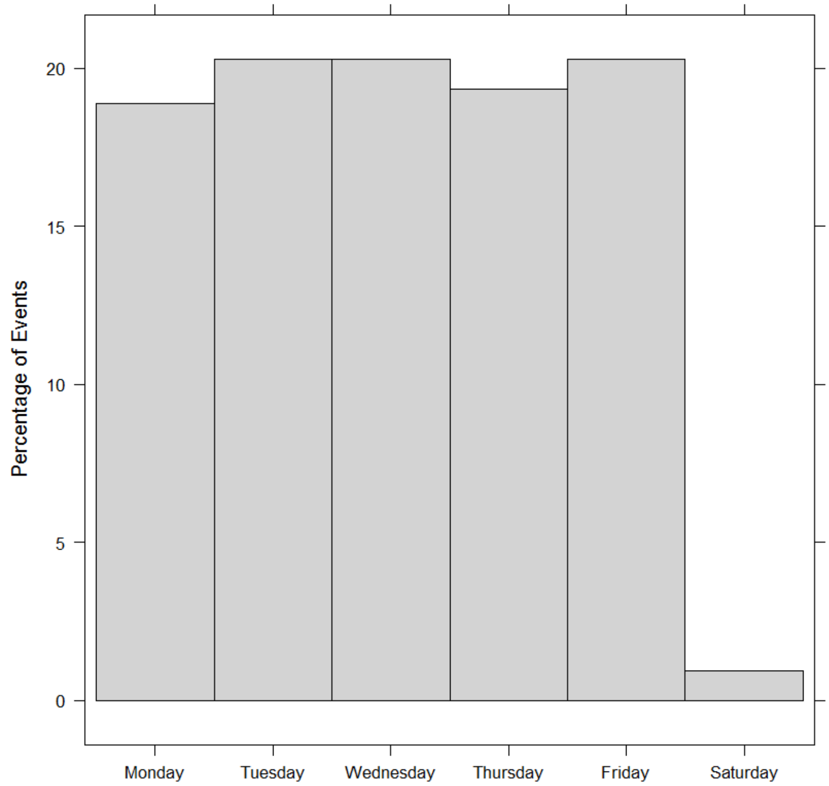

Figure 15.6. Days of the Week that LCM Events were Conducted

The project next looked at the hours during which these events began; see Figure 15.7. The events were most often initiated between 11:00 and noon local Pacific Time. The starting hours are less likely to be before or after those times. The midnight and very late evening events were probably attributable to a startup period while the project was teaching the transactive system how to select and configure meaningful event periods.

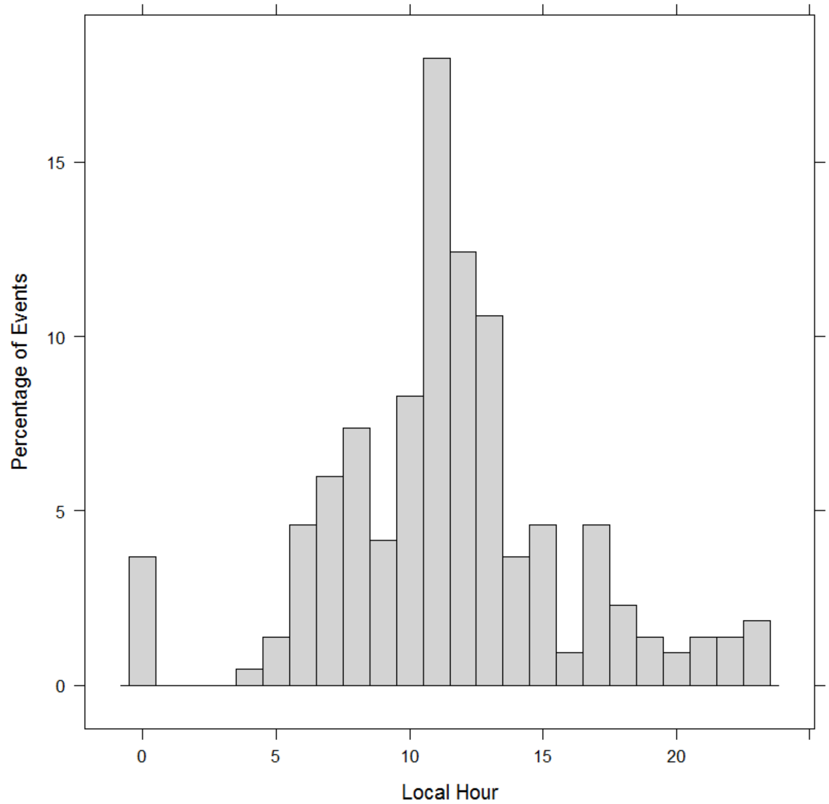

Figure 15.7. Local Pacific Time Hour that LCM Events Started

15.1.2 Performance of the Load-Control Module System

Having observed that the system of LCMs had been exercised only during the second year of data collection, analysts compared data from the two years to make sure that load growth and changes in customer affluence over the years would not confound the results. The 2013 and 2014 data sets' temperature dependence is compared in Figure 15.8. The data from the two years appears to be similar, although there might be small differences in the data at and above 60°F.

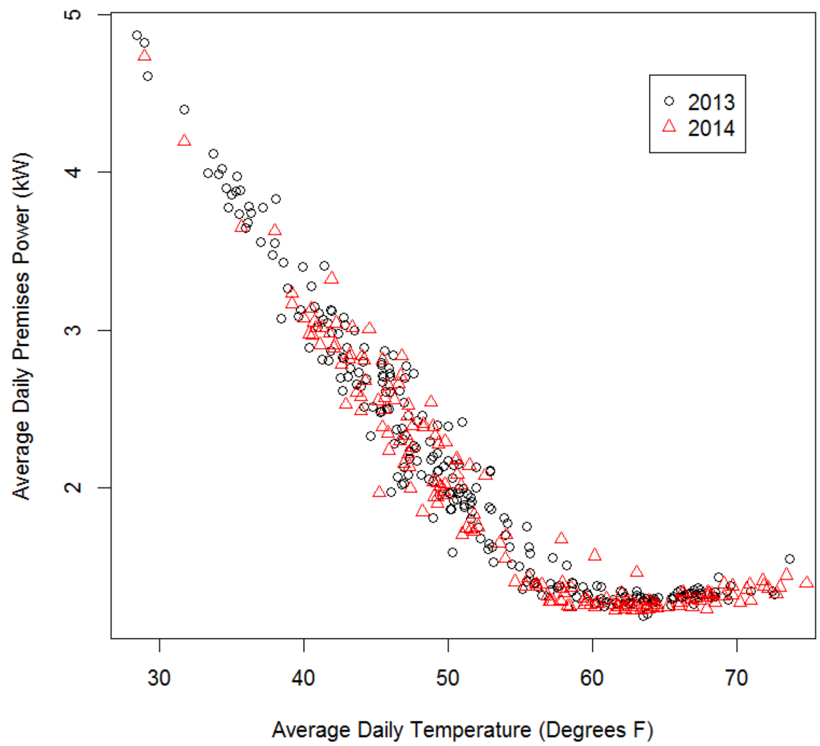

Figure 15.8. 2013 and 2014 Test-Group Average Daily Premises Power as a Function of the Average Daily Outdoor Temperature. The LCM system operated from summer 2013 to summer 2014.

Peninsula Light Company supplied daily premises power data from a group of Fox Island premises that did not participate in the LCM system. Figure 15.9 compares the power data from the LCM test group and this baseline group as functions of temperature. By inspection, these groups are dissimilar. The LCM test-group premises, on average, consume more power than the baseline group during cold days. They may also consume more during hot days, but the warm weather trend is not so evident. The project chose to not use this control group. The two groups might have different size homes or homes that were built using different insulation practices, for example.

Both Figure 15.8 and Figure 15.9 include the long Event 3 from July 2013, but its inclusion does not appreciably influence the conclusions that will be based on the observations. Each point in these figures represents the average premises power over an entire day from local Pacific midnight until the following midnight.

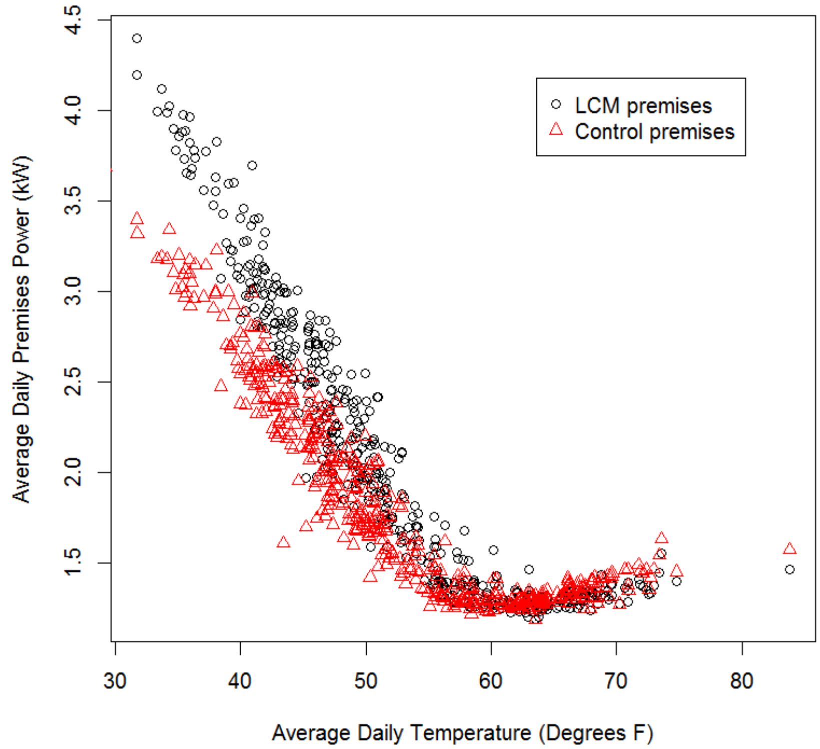

Figure 15.9. Average Daily Power of Test-Group Premises, which Received LCMs, and a Candidate Control Group, both as Functions of Outdoor Temperature

Figure 15.10 addresses only the test group that had LCMs installed, comparing days when LCMs were engaged to days when they were not. Only measurements from weekdays were used. Using the data from days that the LCMs were not engaged, linear regression was conducted to determine a line for a heating regime and another for a cooling regime. Similar regression lines are shown for event days. The analysis is based on average daily temperature to correspond to the daily average premises power interval. The dashed vertical line is the temperature that minimizes the modeling errors for the linear fits to the temperatures above (cooling regime) and below (heating regime) this temperature—about 56.7 degrees Fahrenheit in this case.

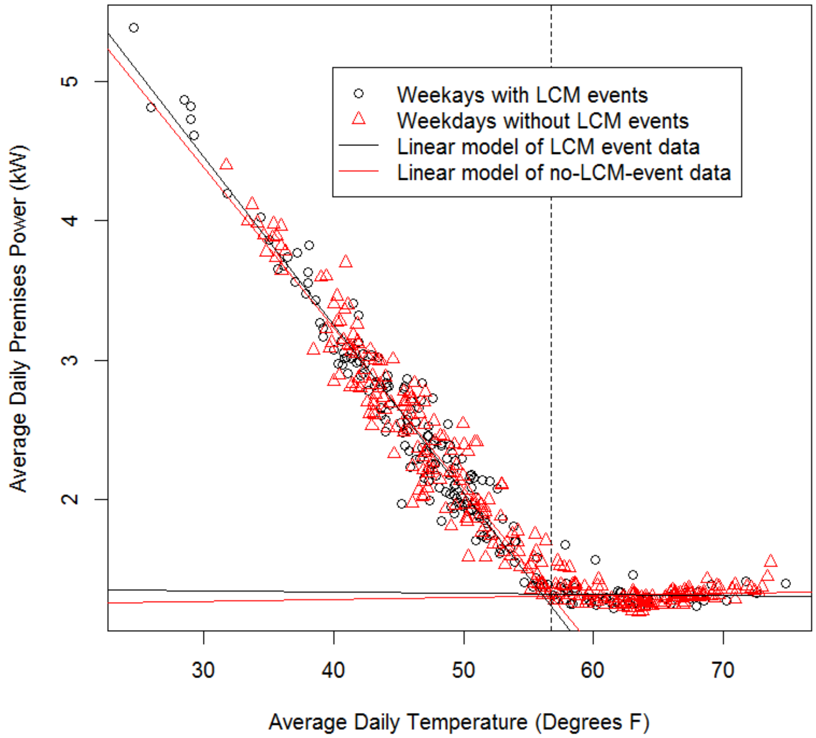

Figure 15.10. Average Premises Power on LCM Event and Non-Event Days as Function of Temperature. The lines show regression fits of cooling and non-cooling regimes based on days that no events occurred.

The equations for the linear models are listed in Table 15.3, but they have been referenced not to 0°F but to the temperature T_{cp} that separates the heating and cooling regimes. The intercepts are the average daily premises power consumptions that would be expected on days that the average temperature is 56.7°F. Upon taking the difference between the linear models during event days and non-event days, the impact of events is represented as an offset and temperature coefficient for the heating and cooling regimes. On average, premises consumed 67 W less power during event days than during days that had no events, but the impact was reduced by about 5 watts for every average Fahrenheit degree below T_{cp}. The two lines cross in the heating regime. The lines in the cooling regime also cross one another.

Table 15.3. Linear Models of the Average Daily Premises Power Consumption for Cooling and Heating Regimes during Event Days and Non-Event Days. The temperatures have been referenced to temperature T_{cp}=56.7°F that separates the cooling and heating regimes.

	Heating Regime (average kW)	Cooling Regime (average kW)
Event Days	$1.244 - 0.120\ (T - T_{cp})$	$1.325 - 0.000931\ (T - T_{cp})$
Nonevent Days	$1.311 - 0.115\ (T - T_{cp})$	$1.311 + 0.00137\ (T - T_{cp})$
Difference	$\mathbf{-0.067 + 0.005\ (T - T_{cp})}$	$\mathbf{0.014 - 0.00230\ (T - T_{cp})}$

The residual differences between the event-day data and the linear model baseline for nonevent days are plotted in Figure 15.11 as a function of outdoor temperature. In this figure, the negative differences represent reductions in average premises power for the daylong intervals.

There is a very small reduction in average premises power on the days that events occur, based on the simple temperature model that has been described in this section. The magnitude is about 7 W. However, the project's confidence is low (~72%) that any reduction occurred for premises on event days. The project cannot state with satisfactory confidence that any reduction occurred with the actuation of the LCMs. This was as good as analysts could do with daily premises data.

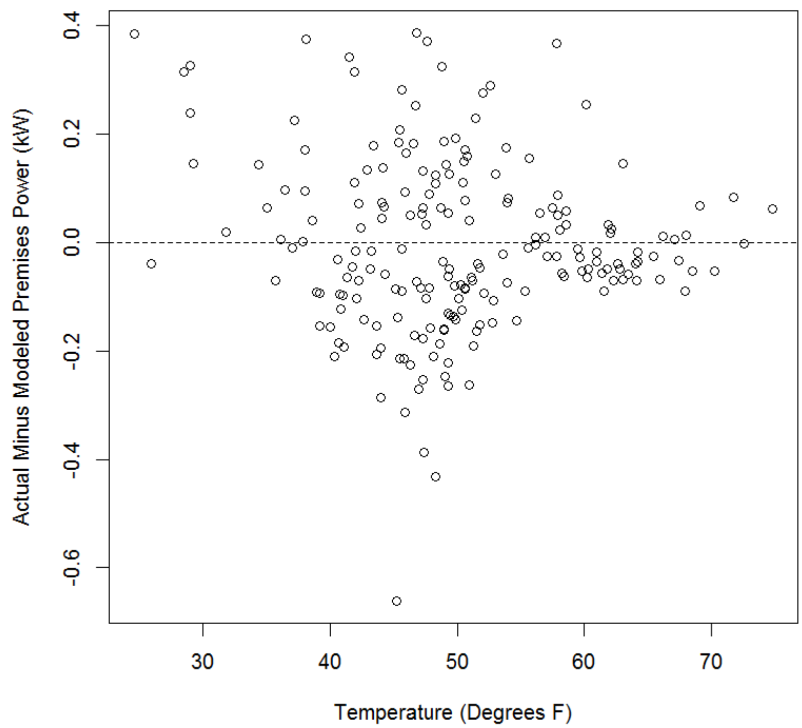

Figure 15.11. Power Difference: Premises Power During Event Days Less the Temperature-Modeled Power from Non-Event Days

Because analysis at the premises level was inconclusive, the project proceeded to analyze distribution power data from the Artondale substation. This data is available at hourly intervals, but it includes a larger distribution circuit, not all of which participated in the LCM system tests. Figure 15.12 shows distribution system power data as a function of temperature. Different markers were used for the hours that the LCMs were engaged and not. It appears that the data points from hours that the LCMs were engaged are toward the top of the cluster of measurements, meaning that the power load is higher when the LCMs are engaged. That observation simply means that the cooperative wisely engaged the asset when load was high.

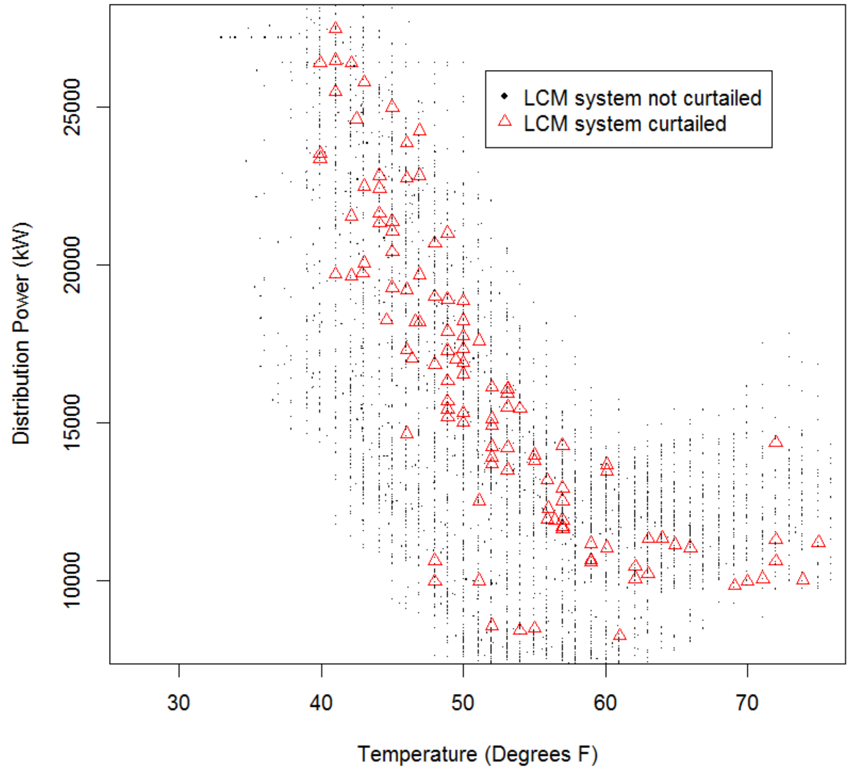

Figure 15.12. Average Hourly Distribution Power from Artondale Substation as a Function of Temperature and LCM System Status. This plot excludes the prolonged Event 3.

A regression model was created to better analyze whether any reduction may be observed from the distribution data. The model was fit to the status of the LCM system, calendar month, whether the days were weekdays or weekend days, hour, temperature, and the permutations of temperature with the hour. The analysis excluded all data from the time period that prolonged Event 3 had been reported to have been engaged. A baseline was generated from the regression model to emulate what the distribution power might have been had the LCMs never been engaged.

When a Student's t-test was run on the difference between distribution power levels during LCM event periods and otherwise, a small reduction was calculated. However, the result was reported with very low confidence. The project can report no impact evident from the distribution data.

15.2 Conservation Voltage Reduction with End-of-Line Monitoring

Peninsula Light Company procured and installed two voltage regulator banks and controlled six existing capacitor banks to facilitate CVR on Fox Island, Washington. The system was intended to reduce electricity demand, especially at times that the system was heavily loaded.

The cooperative offered to have the CVR system become dynamically responsive to advice from the project's transactive system. A function was established to determine when the CVR system should be engaged and for how long it should remain engaged based on the predicted magnitudes of the transactive incentive signal. The cooperative was unable to fully automate the responses, but some coincidence was achieved through a combination of automation and manual responses. The CVR system was reported to have been engaged about 24% of the hours that it had been advised to engage by the transactive system. The transactive system advised the system to respond about 59% of the total hours that the system was reported to have, in fact, responded.

The asset's transactive function modeled the expected change in system load that should have accompanied each event and its controlled change in system voltage. However, the predicted change in load remained poorly configured throughout the project, and the model failed to predict reasonable power magnitudes for the CVR system.

It will be shown in this section that the project could not detect that any change in voltage, in fact, took place when the CVR system was reported to have been activated. Given this lack of evidence, the project elected not to compile and present detailed information about the actual and advised transactive system events in this subsection.

The annualized cost of the CVR system and its components are listed in Table 15.4. The cost of implementing and integrating the transactive system was shared with that of the system of Fox Island LCMs (Section 15.1). The costs of all the other listed system components were fully borne by the CVR system. The greatest costs were for six capacitor banks, supervisory control and data acquisition (SCADA) upgrades, and utility engineering staff. Other less costly components included radio equipment, integration of the transactive system, two voltage regulators, and maintenance and administrative costs. The total annualized cost of the CVR system was estimated to be $226.9K.

Table 15.4. Annualized Cost of the CVR System and its Components

	Shared Usage of Component (%)	Annualized Component Cost ($K)	Allocated Annual Component Cost ($K)
Distribution – Six Capacitor Banks	100	101.1	101.1
SCADA Control Module	100	52.9	52.9
Peninsula Light Line and Engineering Personnel to Design and Install Equipment	100	31.5	31.5
SCADA Software Module	100	21.9	21.9
Communication (radio) Equipment	100	8.4	8.4
Transactive Node (integration)	50	8.9	4.4
Distribution – Two Voltage Regulator Banks	100	4.1	4.1
Administrative	100	2.2	2.2
Hardware SCADA Maintenance	100	0.4	0.4
Total Annualized Asset Cost			**$226.9K**

15.2.1 Conservation Voltage Reduction Data

Two feeders (Numbers 2 and 6) supply electricity to Fox Island from the Artondale substation. Peninsula Light Company supplied averaged hourly phase voltage for each of these feeders, normalized to 120 V. The project averaged the data from the two feeders and restated them as per-unit quantities. The average per-unit voltage data is shown in Figure 15.13. The voltage appears to have been managed within a very narrow range throughout the project. The first data was made available from late July 2010 through the remainder of the project. Data was unavailable for July and much of August and September 2012.

The figure’s markers have been colored to represent the status of the CVR system. Prior to 2014, the system was not yet installed and was inactive. In January 2014, the utility declared the system installed and useful. They reported that the system became engaged periodically throughout the remainder of the project for several hours at a time. It is not evident in Figure 15.13 that the voltage, in fact, changed at all during these reported events. Even during June and July 2014 the “on” voltages, which might have been reduced, are not abnormally low compared with normal (“off”) operations.

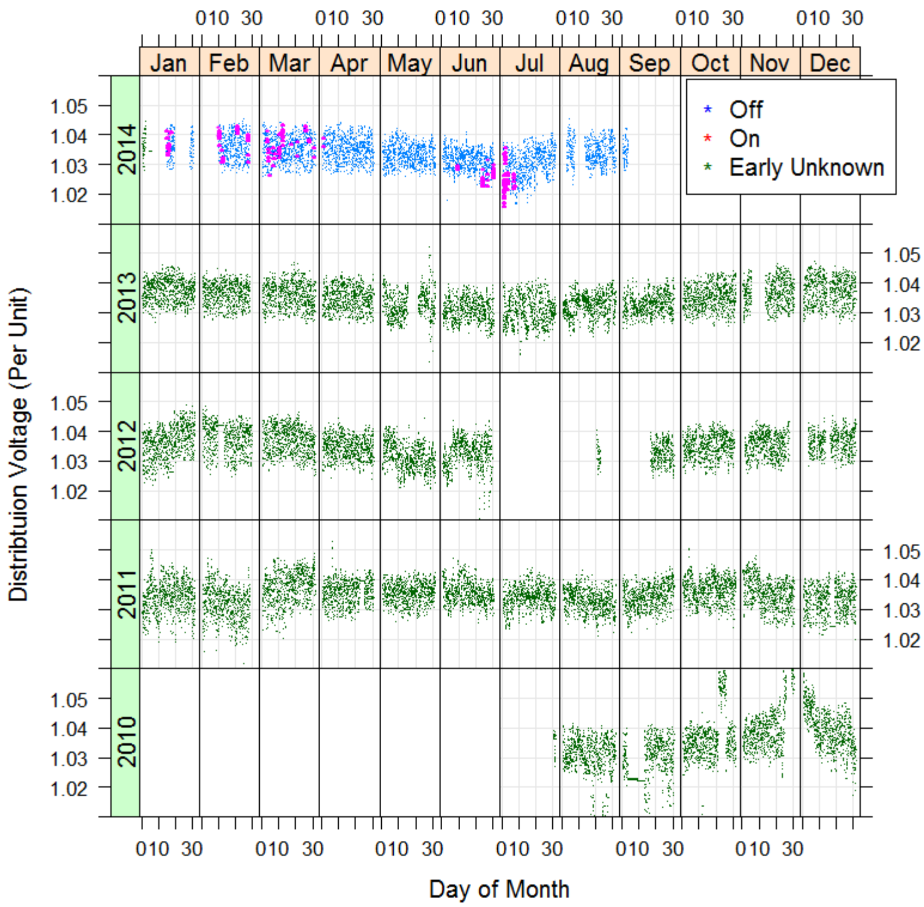

Figure 15.13. Average Distribution Feeder Per-Unit Phase Voltage. Marker colors indicate the status of the CVR system.

The project also collected total power for the two Artondale substation feeders over the same period. The availability of this data was similar to that of the voltage data; see Figure 15.14. The median total power over all project data for these two feeders was 14.6 MW. The average was 16.4 MW. The maximum approached 47 MW.

No reduction in the feeders' power during reported event periods was evident by inspection at this or any other scale.

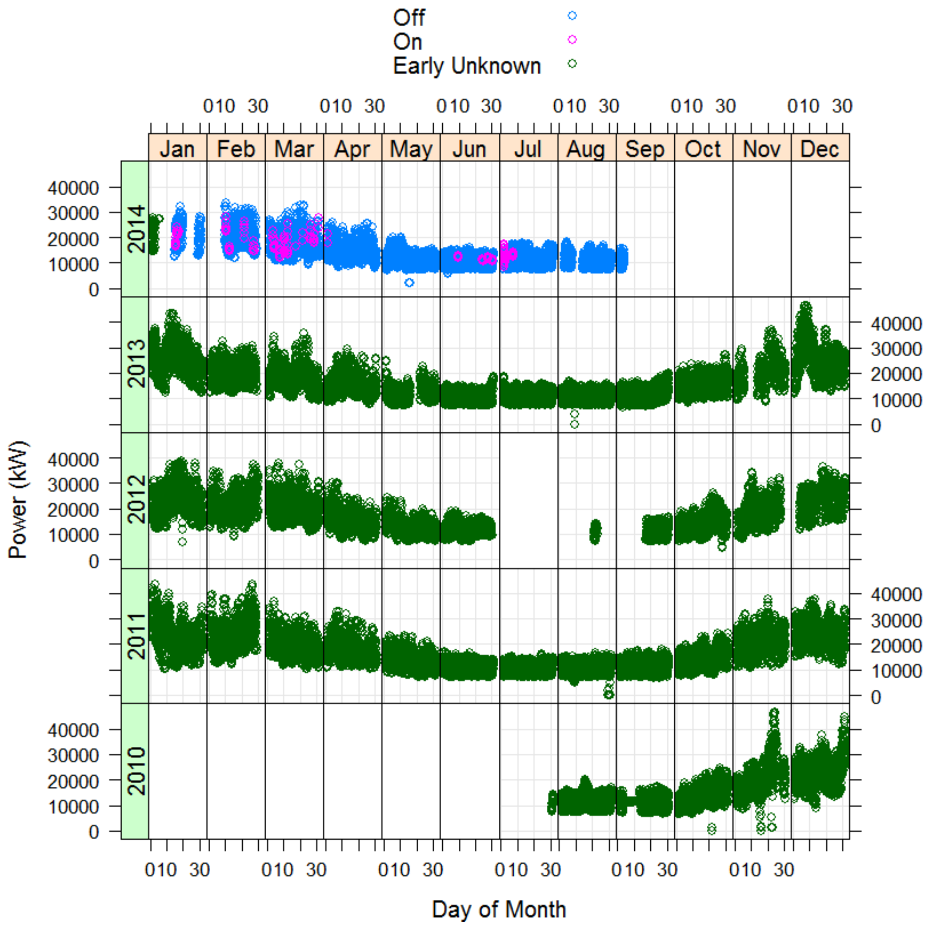

Figure 15.14. Average Hourly Distribution Feeder Power. Marker colors indicate status of the CVR system.

The feeders' sum reactive power was similarly plotted in Figure 15.15. Either the reactive power or the quality of the reactive power data changed March 5, 2013. Prior to that date, the reactive power data was dynamic. The load was inductive, but it occasionally changed sign to become slightly capacitive. After that date, the system data is less dynamically variable. The system load appears to have become strongly capacitive.

Neither the project's data staff nor Peninsula Light Company personnel have yet been able to confirm this change in behavior or to confirm and correct any data problems. Candidate causes include the activation of a new submarine cable from the mainland to Fox Island, activation of a new bank of distribution capacitors, or simply miscommunication of data.

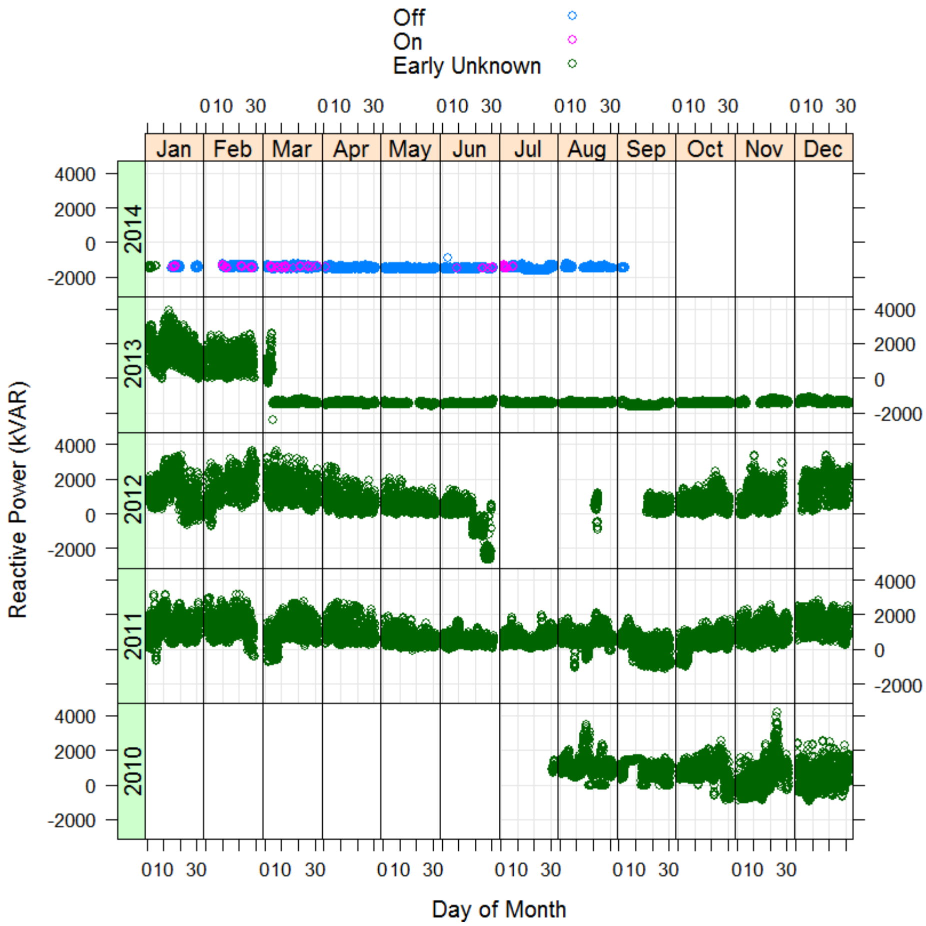

Figure 15.15. Average Hourly Distribution Feeder Reactive Power. Marker colors indicate the status of the CVR system.

15.2.2 Performance of the Conservation Voltage Reduction System

Quartile plots of distribution voltage as a function of CVR system status are shown in Figure 15.16. The CVR system is active when the status is “On.” The median and many of the values are somewhat smaller when the CVR system is engaged than when it is not. A Student’s t-test was run on the “on” and “off” populations. The difference is significant, but the average difference in voltage is a reduction of only about 0.12%. No measureable impact should be expected for such a small voltage difference. No further analysis was conducted.

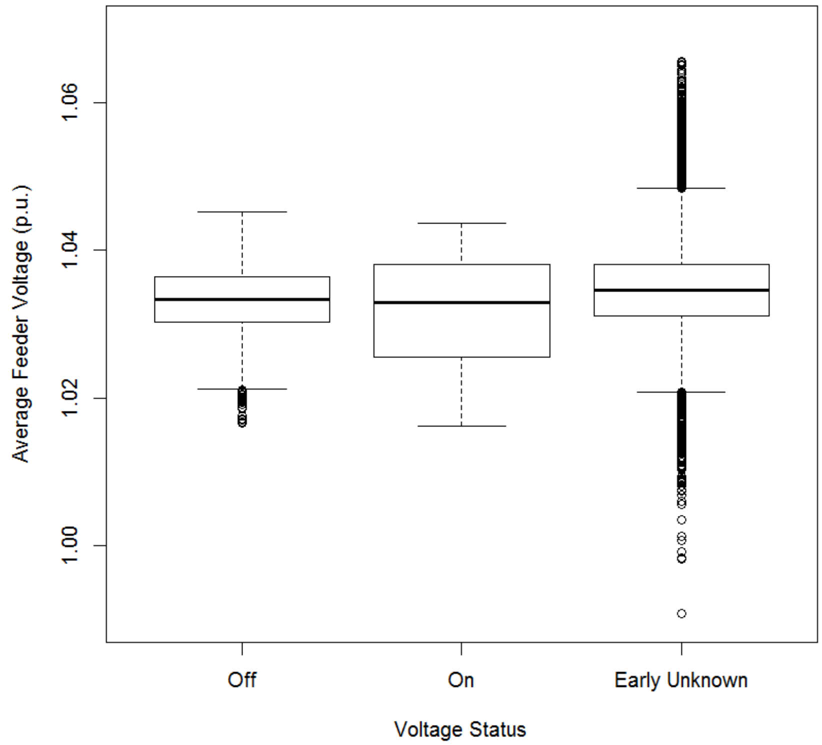

Figure 15.16. Quartile Plots of Average Per-Unit Distribution Feeder Voltage According to the CVR System Status

In summary, the project has found no evidence that the system behaviors were significantly changed at the times that the system was reported to have differently managed distribution voltages. The actions taken by the utility on event days were similar to actions that were taken on nonevent days anyway.

15.3 Pad-Mounted and Overhead Automated Switching

Peninsula Light Company applied FDIR with SCADA-controlled distribution switches to monitor and more quickly recover from distribution system faults on Fox Island. The SCADA system maintained a real-time state of the connected network with load flow and circuit ratings, and calculated an optimal network configuration in the event of a faulted section of network. The objective was to reduce the System Average Interruption Duration Index (SAIDI) and perform cold-load pickup by quickly restoring as much healthy network as practical, without exceeding circuit capacity. Peninsula Light Company declared the FDIR system installed and useful beginning September 2012.

The annualized costs of this system and its components are listed in Table 15.5. The greatest costs were for the FDIR module, SCADA system upgrades, and the pad-mounted and overhead distribution switches. Smaller costs were for administration, upgrades to radio communication, and utility staff labor. Total annualized cost of the system was estimated to be $187.4K.

Table 15.5. Annualized Costs of the Automated Switching System and its Components

	Shared Usage of Component (%)	Annualized Component Cost ($K)	Allocated Annual Component Cost ($K)
FDIR Module	100	47.7	47.7
SCADA Hardware Resources	100	46.5	46.5
Backroom Server	100	36.5	36.5
Distribution Pad-Mounted Switchgear	100	28.8	28.8
Distribution Overhead Switches, 600 A	100	13.8	13.8
Administrative	100	6.2	6.2
Communication (radio) Equipment (remote)	100	3.8	3.8
SCADA Components and Software Integration	100	3.5	3.5
Staff	100	0.5	0.5
SCADA-Mate® Switching System Overhead	100	0.0	0.0
Total Annualized Asset Cost			**$187.4K**

15.3.1 Switching System Data

Peninsula Light Company submitted monthly SAIDI values for the project footprint that was affected by this FDIR system on Fox Island. These calculations were performed by the utility, and the project performed no review of their calculation. The values were made available for the months from June 2012 through August 2014. The SAIDI values are listed by month and year in Table 15.6 to two significant digits.

Table 15.6. SAIDI Values[(a)] by Month (Average Minutes per Member

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2012	-	-	-	-	-	0.0	4.3	90	3	2.9	24	0.0
2013	0.00093	0.62	0.0	13	6.7	2.8	0.0	0.0	430	0.0	260	58
2014	79	660	0.27	0.0	4.6	0.28	0.93	2.2	-	-	-	-

(a) Reported values have been rounded to two significant digits.

It was the project's practice to normalize duration indices like this based on the data time interval. Therefore these are stored in the project database as the typical outage minutes each 5 minutes—a very small number. The advantage of this practice is that the index may be restated for longer intervals—a month, for example—by simply summing the individual records from the included data intervals. The practice allowed the project to address data with diverse measurement intervals in the same database. The practice is not normally needed when utilities calculate SAIDI at monthly, or longer, intervals.

The SAIDI values have been plotted by project month in Figure 15.17. It is clear from this figure that members experienced relatively long outages during the months of fall 2013 and the winter that followed. The dashed horizontal line is the average of the SAIDI value for all project months—60.4 minutes per member per month.

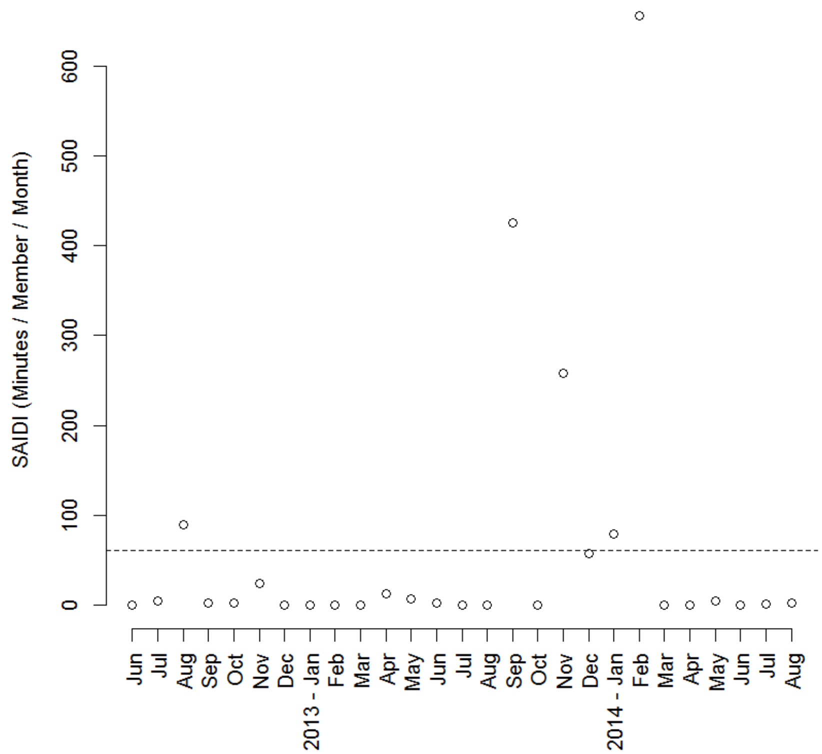

Figure 15.17. Monthly SAIDI Values

Peninsula Light Company also tracked outage response minutes, another indicator of the speed with which the utility recognized and responded to outages. The cooperative calculated these durations and submitted their calculations to the project for months from June 2012 through August 2014. The index is listed in Table 15.7.

Table 15.7. Average Outage Response Times[a] (Minutes per Outage)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2012	-	-	-	-	-	0.00	97.2	356	305	182	191	0.00
2013	0.00	318	0.00	265	136	256	0.00	0.00	148	0.00	148	76.2
2014	274	144	69	0.00	296	145	239	278	-	-	-	-

(a) Reported outage response times have been rounded to three significant digits.

Because the outage response times are normalized by outages, the monthly calculations were simply duplicated in the project's database throughout the project month to which the index referred.

The outage response times from Table 15.7 are plotted in Figure 15.18. No clear pattern is evident in this figure. The dashed horizontal line is the average of all the monthly outage response times collected by the project and displayed in this figure—145 minutes per outage per month.

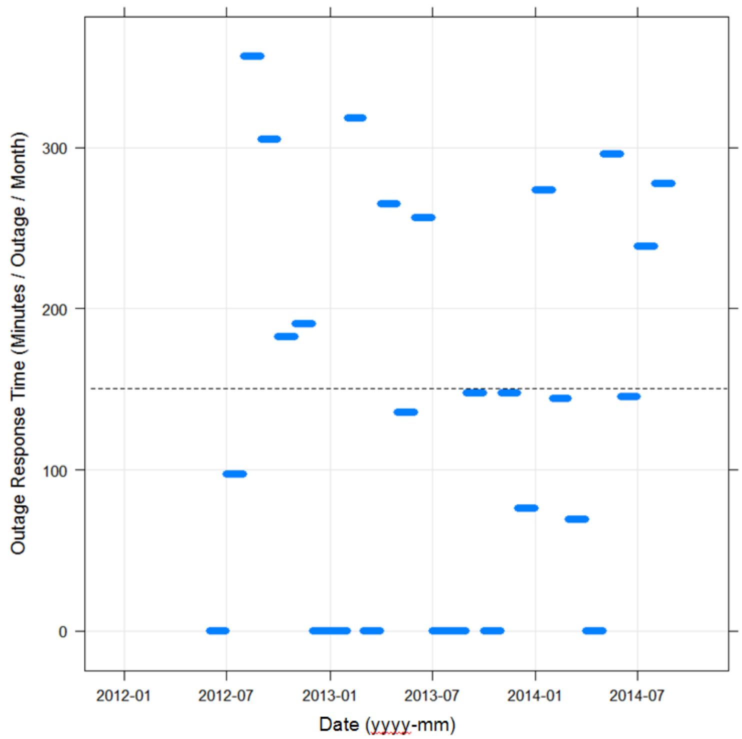

Figure 15.18. Outage Response Times by Month

The utility submitted its monthly service restoration costs for Fox Island, which have been plotted in Figure 15.19. Some of their worst restoration costs were incurred during the last project months of 2014.

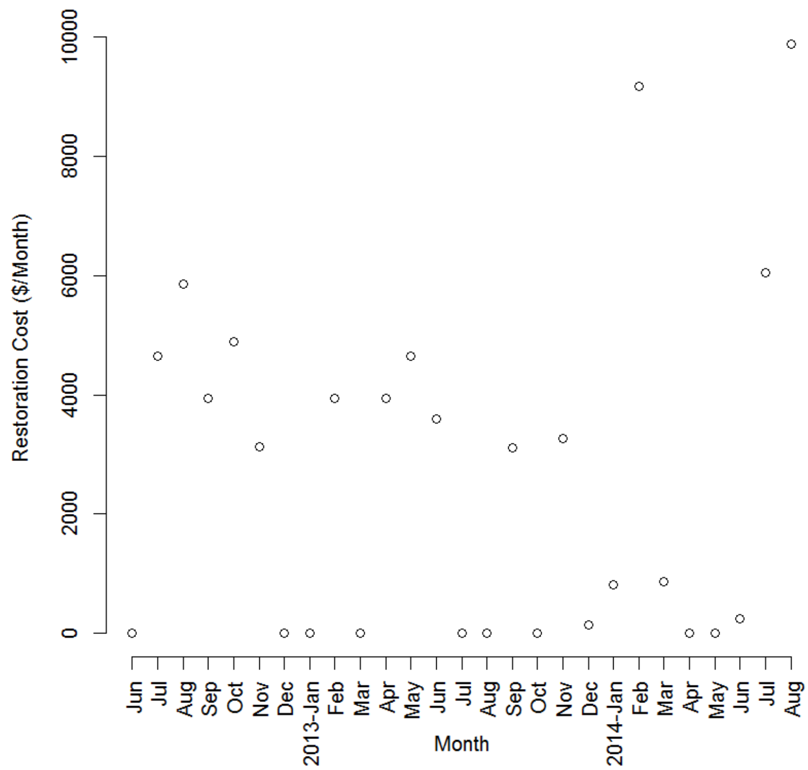

Figure 15.19. Peninsula Light Company's Monthly Restoration Costs during the Project

15.3.2 Switching System Performance

The utility supplied the project very little historical data concerning reliability indices before about September 2012 when the system was reported to be installed and useful. Regardless, the project conducted analysis on the series of monthly reliability indices to determine whether any significant change in the distribution system's reliability could be identified. This approach might be novel.

The approach was as follows. The indices from the successive months were separated according to whether they occurred before or after the beginning of a given project month. The resulting two groups of monthly indices were treated as independent populations of indices. A Student's t-test was run to determine whether the two groups differed significantly. The resulting probability value from the test states the probability with which the null hypothesis should be rejected. Both of the reliability indices in this section should have decreased if the utility's efforts to improve system reliability had been successful. Therefore, the null hypothesis was that the indices instead *increased* after the start of the given month. Analysts would normally reject the null hypothesis if the probability exceeded 95%.

The described analysis was duplicated for each project month. That is, the beginning of each project month was used to separate the reliability indices into two sets for comparison. The first months' and last months' results must be used cautiously. The Student's t-test naturally accounts for variability and the size of data sets, but the results should be questioned if either comparison set has only one or a small number of samples.

Because the project conducted an observational study, any improvement detected by this method can only be said to be correlated to the asset system's engagement or another utility practice. It was hoped that the installation of the FDIR system would correspond to the timing of a significant improvement in one or both reliability indices.

Figure 15.20 shows the result of this analysis for the reliability index SAIDI. Recall that the worst indices occurred in late fall 2013 and into the following winter. The indices were very favorable from March 2014 until the end of data collection. This pattern might indicate that a change in members' electric reliability indeed occurred beginning March 2014. The difference between SAIDI values before and after March 2014 is significant according to the Student's t-test method that has been described. The null hypothesis should be discarded with better than 95% certainty (the upper dashed horizontal line).

Then again, the result might be caused by chance and favorable weather patterns.

Regardless, the project cannot state that SAIDI improved with the installation of the FDIR system in September 2012.

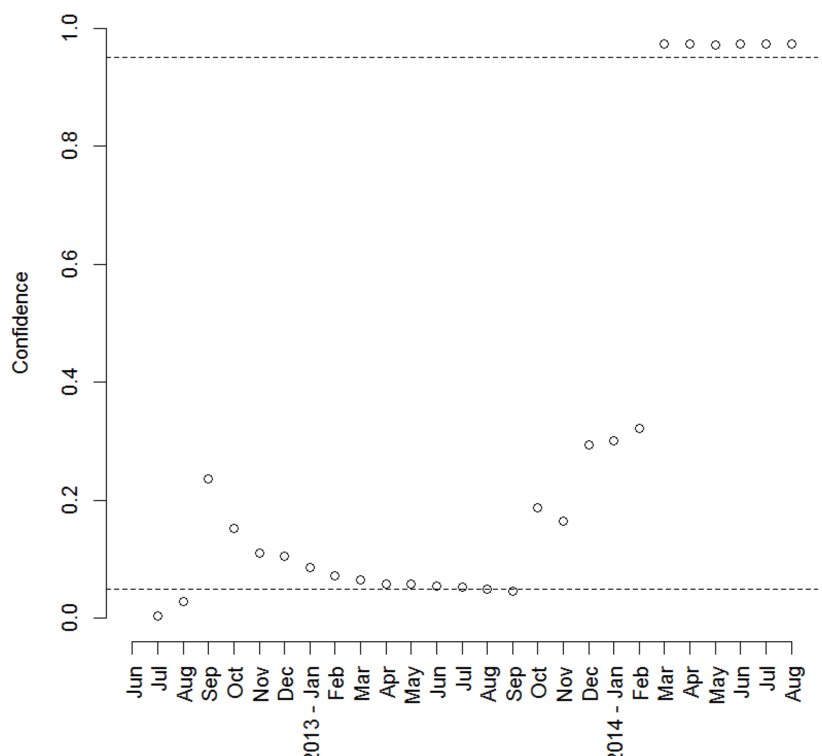

Figure 15.20. Student's T-Test Confidence that SAIDI in the Following Months is Smaller than in Prior Months

A similar analysis was conducted on outage response time; see Figure 15.21. While no clear trend was evident in the raw data, the method used in this section seems to show a long-term worsening of outage response time. In fact, the last months' values might be interpreted to indicate we should be confident in declaring this worsening. However, the last months might have simply exhibited higher indices within the normal variability of the index over time.

Regardless, the project cannot state that the utility's outage response times improved significantly with the installation of the FDIR system in September 2012.

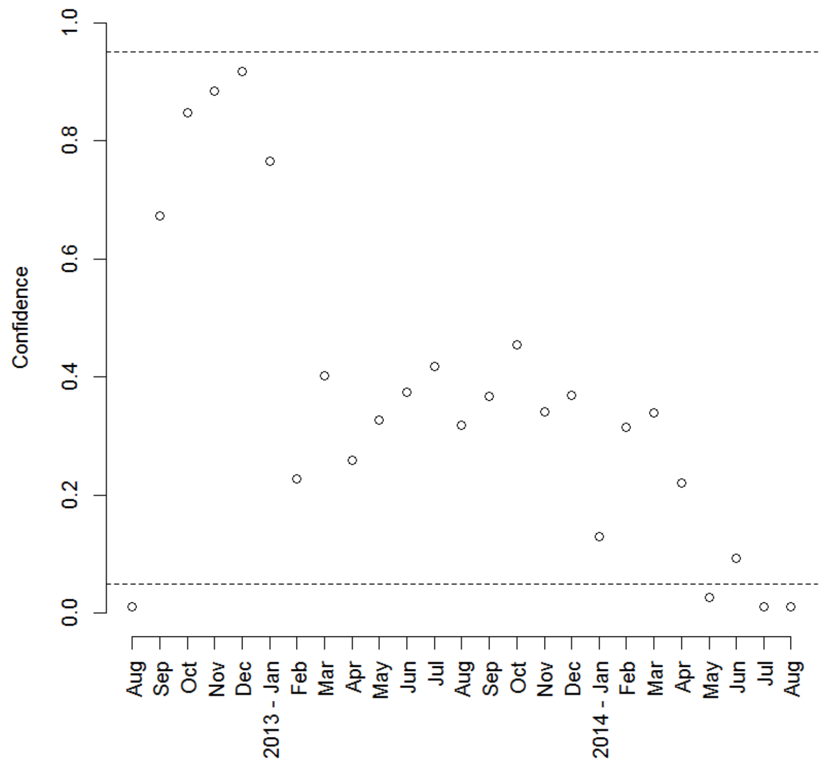

Figure 15.21. Student's T-Test Confidence over Time that the Following Month's Response Times Were Shorter than in Prior Months

The analysis was repeated using the monthly restoration costs that had been reported to the project by Peninsula Light Company. The confidence that restoration costs had decreased after a given month when compared with prior months is shown in Figure 15.22. Because the last project months had incurred some of the greatest restoration costs, the trend shown in this figure is generally downward, meaning that restoration costs appear to be getting worse, not better.

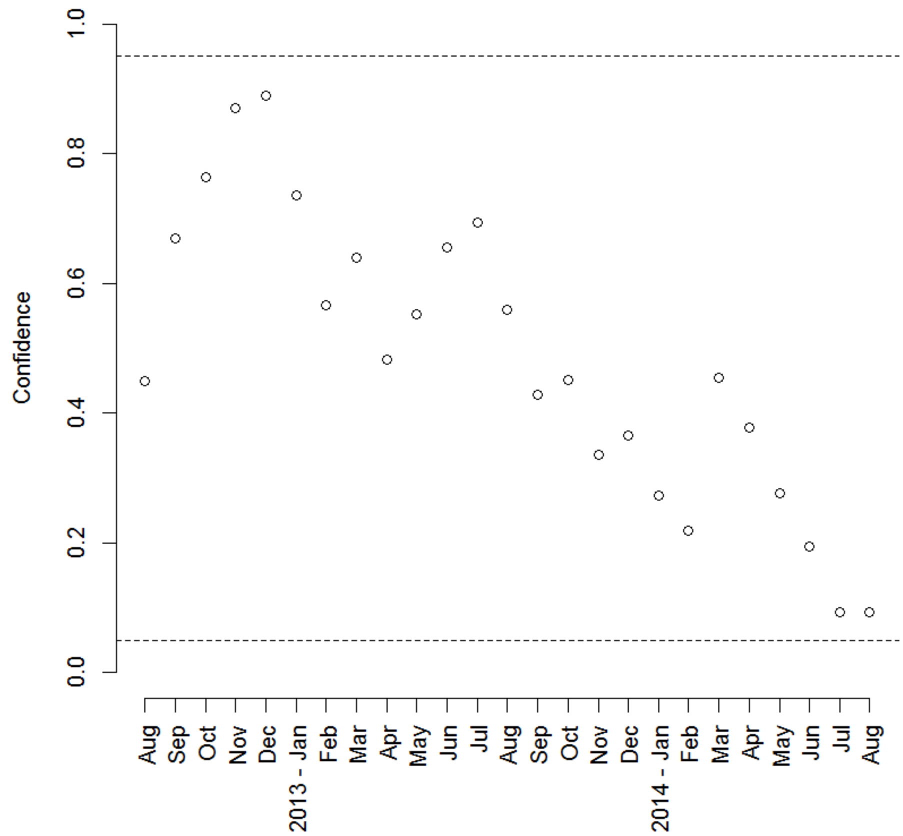

Figure 15.22. Confidence Levels when Comparing Restoration Costs before and After Each Project Month. Confidence should approach unity if following months have a significantly reduced restoration cost compared to preceding months.

15.4 Conclusions and Lessons Learned

Fox Island proved to be a challenging test site because of its natural isolation, the growing demand, and the predominantly residential member population. Peninsula Light Company tested three technologies during the Pacific Northwest Smart Grid Demonstration.

The utility engaged about 500 LCMs for the curtailment of electric tank water heater load on the island. These modules were engaged soon after they became deployed to help the Peninsula Light Company manage the failure of one of the lines that supplied the island from the mainland. The project analyzed data from the premises of members that had received the LCMs. The utility's existing PLC meter technology was found to not support premises metering for intervals shorter than 24 hours. The project was not able to confidently confirm that any power reduction had occurred at the premises from the 1-day interval data. The project also reviewed feeder data. Again, no power reduction could be confirmed from this data that had much shorter hourly intervals. The curtailment impact was perhaps too small a fraction of the overall feeder power for its signal to be identified.

The second technology to be demonstrated was active voltage management with end-of-line voltage monitoring. Peninsula Light Company encountered delays in the implementation of this asset because the existing infrastructure could not provide rapid, accurate voltage measurements that were necessary.

Transformer monitors were eventually installed to satisfy this requirement. Regardless, the project was unable to confirm significant changes in feeder voltage at the times that the system was reported to have been engaged. No change in system power could be determined during the engagements.

The utility also installed overhead and pad-mount switches throughout Fox Island to practice FDIR and improve its member's service reliability there. Two of the biggest challenges in implementing this system were the improvement and management of the site's circuit model and obtaining accurate voltage measurements back from circuit locations. A more detailed discussion of these challenges by the cooperative is included later in this section. The project analyzed reliability indices to determine whether an improvement could be confirmed. While the project cannot definitively attribute improvements to the FDIR system, the values of SAIDI at the site have been small since spring 2014. An outage response time metric did not mirror this improvement. The method applied by the project in this analysis might be generally useful to utilities as they monitor monthly changes in their reliability indices.

The following lessons were authored by Peninsula Light Company staff for the project.

There have been many challenges in the implementation of the Peninsula Light Company demonstration tests. The challenges primarily fell into two camps: technology and integration. An additional factor that added to the challenge was changes to the cooperative's engineering staff after the tests had been defined and equipment and software had been selected and purchased. The collective shortcomings of the hardware, software and existing system capabilities that emerged as the project progressed would have been a challenge even without changes in utility personnel.

Following is a summary of the lessons learned by Peninsula Light Company while implementing its demonstration component in the Pacific Northwest Smart Grid Demonstration project.

15.4.1 Accuracy of the System Model is Critical

The utility is currently using an Environmental Systems Research Institute geospatial database (Esri 2015) model. The Environmental Systems Research Institute model was built from a very difficult import of a legacy called 4th Dimension Database Log File (4DL) system. Many compromises had to be made to get the model to import and display correctly. The need for integration with a new design tool further exacerbated the problems.

The system model is the underpinning of the FDIR and integrated volt/VAr control (IVVC) functionality. The model is used by a prediction engine to determine the most likely location of a fault, calculate the impact of switching loads, or estimate voltage drop. Depending on the vendor and how the modules are configured, any errors in the mapping system may cause the system to crash (to varying degrees) or if addressed, can be processed through rules or manually overcome.

If a map-dependent application is being considered and an existing mapping system is in place, extract at least a portion of the system for vendors to evaluate before a vendor product selection is made.

15.4.2 Know Integration Dependencies of Software

When vendors were being considered for the IVVC and FDIR systems, there were two viable choices: select the vendor of the utility's current SCADA system or select a vendor whose solution could bolt on to the utility's existing SCADA system.

Although the utility's existing SCADA vendor had not deployed either module elsewhere, a decision was made to select them because of the inherent integration that would result from using the existing vendor. The same model and analysis tools used by the utility's existing outage management system (OMS) would be shared. Ultimately, this turned out to be a liability because problems in one area would affect other areas.

Furthermore, the chosen system relied on a single instance of a database runtime engine. This engine was also shared between the test system and the production system. An additional instance could have been added, but at very high cost.

The alternative vendor that was considered had several systems deployed and operational. They offered a stand-alone product that was configured with a simplified version of the system model, and obtained status and sent controls via industry standard master/slave protocols. The strength of this solution was that if a problem emerged in the OMS module, the OMS could have been down, but the SCADA system would then likely remain functional and could continue to interface with the bolt-on solution.

Accurately assess the system model and fully understand the impact of any errors on the software that is being considered. Some programs are written to effectively work around connectivity errors. Do not purchase software that does not allow direct editing of any database that supports that software. Regardless how attractive a single vendor solution looks, seriously consider a best-of-breed approach if the players are well established in their fields and have a track record of successful deployments.

15.4.3 Automated Meter Reading Power Line Carrier Technology is Slow but Reliable

The asset systems chosen by Peninsula Light required voltage measurements (IVVC) and energy measurements (load control). The existing automated meter reading (AMR) system was purported to be able to provide both. When the asset systems were being considered, discussions with Landis+Gyr indicated that the AMR system was capable of measuring voltage, and the voltage measurements would be returned with data packets. Furthermore, the energy measurements needed for measurement of the efficacy of the load-control tests could be returned on an hourly basis.

In order to get hourly data measurements (with a two-hour lag), the units needed to be configured to use 11 carrier channels per meter over the power line versus one channel for its normal one-read-per-day configuration. Equipment currently installed in the site's substations did not have the channel capacity to provide for all of the meters on the test circuits. Upgrades necessary to support this would have been

$100,000–$200,000 for the system, and would have used all of the channels that were available for the whole system on a single substation. This could have been repeated at all of the substations; however, it would have precluded switching feeders between substations because the channel numbers would not be unique to each substation.

The accuracy of the voltage measurements turned out to be inadequate for the IVVC application. In addition, the IVVC vendor required voltage measurements every five minutes, at a minimum.

Understand the capabilities and limits of any supporting system or infrastructure, regardless of the technology used. Each has its own peculiarities. Get vendor commitments on data accuracy and data flow rates to make sure all performance needs are met.

15.4.4 Secondary Data Sources are Expensive (Additional Transformers / Sensors)

The IVVC system required highly accurate voltage measurements and the ability to collect those data measurements at five-minute intervals. The need for accuracy was known early on, but the requirement for the short intervals was not revealed by the vendor until we were close to software deployment.

As Peninsula Light Company explored other ways to collect accurate voltage measurements, it found that pole-mounted transformers and other sensors were expensive and came in a difficult form factor. As the need for five-minute intervals emerged, the issues were compounded by the location of the sensors and the additional equipment that would need to be installed for communication.

Ultimately, cellular-based private network communications proved to be the most effective way to provide the necessary polling rates and in the locations that were needed. The project was delayed somewhat while the utility waited for vendors to get their equipment certified on Verizon's 4G LTE network. Interestingly, vendors/devices certified in one area of the country do not necessary get immediate certification in other parts.

To obviate the need for additional equipment at each location, use equipment that could be used elsewhere in the system and keep the costs in check. Seek solutions that provide other functionality in addition to supporting cellular communications. For example, switches were augmented or replaced with reclosers and controllers capable of using Distributed Network Protocol. Transformer monitors allowed precise energy measurements, 0.05%-accuracy voltage, and expandability with daughter cards and power quality measurements. Both solutions were widely deployed and had proven track records.

To every degree possible, develop taxonomy for every functionality being considered and evaluate all vendors/solutions against it.

15.4.5 Load Controllers Leveraged the Existing AMR System but with Limited Performance

To support the load-control demonstration, switches controlled by the Landis+Gyr PLC system were installed in member homes. There was no real-time feedback on whether an "open" or "close" command had been executed. The use of the PLC load controllers seemed ideal for the load-control tests, but in retrospect, a more robust system would have been preferable. Wireless/modem technologies or ping-capable PLC products would have enabled immediate feedback. Regardless of the organic capabilities of any existing systems, consideration should be given to all solutions.

15.4.6 Involve Operations Personnel in the Selection of Field Devices

Switching devices were necessary to support the FDIR demonstration. The overhead switches were selected based on lowest cost, and the pad-mount switch controllers were chosen for the same reason. Siemens switches were selected for the overhead switching functionality, and when delivered, the switch configuration and provisions for manual operation were contrary to preferences of the utility's operations department. The switches contained a remote terminal unit that, though adequate for the basic functionality of the switch, was inadequate for additional functionality that was necessary. The voltage and current measuring capability of the switches did not meet expectations or requirements of the operations staff.

For the pad-mounted switches, the lack of voltage and current sensors on different switch configurations detracted from the functionality. The sensors were not selected because the cost of the controller that supported the sensors was higher. Retrofitting the switches was impractical.

All equipment selections should be carefully reviewed from every aspect of use. The short-term and long-term needs of the system should be considered. If possible, arrange for the vendor to bring units on site for evaluation. Talk to other customers who have purchased the product. Purchase based on value.

15.4.7 Reclosers are the New Overhead Switch

Switching devices were necessary to support the FDIR demonstration. The overhead switches were selected based on lowest cost. The shortcomings of the overhead switches discussed above were further highlighted when the utility was looking for voltage sources for the IVVC functionality. The remote terminal units in the switches were inadequate for the task and the sensors were incomplete.

Reclosers were chosen to augment the system because they served the needs of more than one asset system and were deemed to add high value to the systems. Reclosers have built-in high accuracy sensors and a microprocessor-based controller that can be polled via industry standard protocols for voltage and current data. In addition, the inclusion of reclosers at key locations in the system yielded additional protective functions to circuits when reconfigured on the fly.

Recloser costs are about the same as those for switches when all aspects are considered, i.e., speed, sensors, control, status, etc., and they are inherently more flexible in their applications.

15.4.8 When a Historian is not a Historian

Reporting requirements for Peninsula Light Company's demonstration components required SCADA data to be sent to the project. The SCADA system stores data in flat files, so a tool was necessary to convert and present the data in a friendlier format. The software package sold by the vendor was represented as a historian.

For speed and efficiency, event status, control action and analog points are stored by the SCADA system in binary, flat files for speed and efficiency. These files are generally not reader friendly and are sometimes written in manner similar to encryption. To review the data, present it in a usable format, or otherwise manipulate it, another software package was required. The package our vendor offered was their "historian." Peninsula Light Company's existing SCADA system did not have one, so it was purchased.

The tool was an extraction and reporting tool, not a true historian. Furthermore, the configuration of the software was incomplete, and status and control points were not included. Only the analog data necessary for the demonstrations was included. For reasons outside the scope of the demonstration, this was a fatal flaw and for all intents and purposes, the utility still does not have a historian. Although a true historian was not necessary for the project, it would have been of great value to the rest of the enterprise.

Carefully review software functionality before making a purchase decision. Make sure that the capabilities of the packages are evaluated by personnel with the experience necessary to note the subtle differences that may exist. When software is purchased and deployed, make sure that the personnel with the right experience are driving the configuration and participate in any evaluations concerning the performance of the delivered product. If the knowledge and experience does not exist in-house, consider hiring a third party to provide the oversight and deployment management.

15.4.9 Manage Change

Technology deployment and integration inherently heralds change, and all aspects of the change must be addressed. The changes associated with the newly deployed technologies included new hardware, software, processes, operational ownership, etc. It is common knowledge that change must be managed, but when the changes are subtle, occur in unexpected areas, or emerge too quickly, silos form and progress is slowed. Ownership of a function or area of responsibility may need to change in the midst of the change. The end user is the true measure of how well the change is being managed.

Carefully assess the impacts of the technologies and integration, including a comparison between the landscape at the start and what it might look like at the end. Discuss the changes openly so everyone has a good idea of what to expect going forward. Define terms and concepts so everyone is clear on expected roles and responsibilities. Ask very specific questions.