12.0 Lower Valley Energy Site Tests

Additional chapter coauthors: R Knori and W Jones – Lower Valley Energy

Lower Valley Energy is a rural electric cooperative located in Northwest Wyoming and Eastern Idaho. It serves 27,000 electric customers. Their service territory is expansive, featuring towns, very remote rural substations, and even a mountain ski resort. Terrain is mountainous at the feet of the impressive Teton Mountains. The backbone of their distribution electric system is the Teton-Palisades power interconnect—a loop that includes lengths of Lower Valley Energy 115 kV lines and connects to the regional Bonneville Power Administration (BPA) transmission system at the Teton and Palisades stations.

The cooperative offered altogether four demonstration sites where it planned to test its asset systems. The sites are listed here with the types and quantities of newly installed equipment at each of the sites:

- East Jackson Substation, East Jackson, Wyoming
  - 2,665 Aclara and Landis+Gyr advanced premises meters
  - substation Two-Way Automatic Communication System (TWACS) infrastructure, including a modulation transformer unit, a control and receiving unit, and an outbound modulation unit
  - in-home displays (IHDs)
- Afton substation, Afton, Wyoming
  - 1,530 Aclara and Landis+Gyr advanced premises meters
  - substation TWACS infrastructure, including a modulation transformer unit, a control and receiving unit, and an outbound modulation unit
  - IHDs
- Hoback substation, Bondurant, Wyoming
  - 300 kVAr static volt-amperes reactive (VAr) compensator (SVC)
  - 20 kW solar photovoltaic (PV) array
  - four 2.5 kW wind turbines
  - 125 kW, 250 kWh battery bank.[1]

Lower Valley Energy originally had intended to engage distributed generation at the Jackson Hole Mountain Resort as one of their project sites, but these plans fell through. The remaining three sites are shown by blue stars on the Lower Valley Energy service territory map in Figure 12.1.

[1] The demonstrated power and energy capacities of this battery system, as reported to the project by Lower Valley Energy, fell considerably short of these nameplate values, as will be discussed later in this chapter.

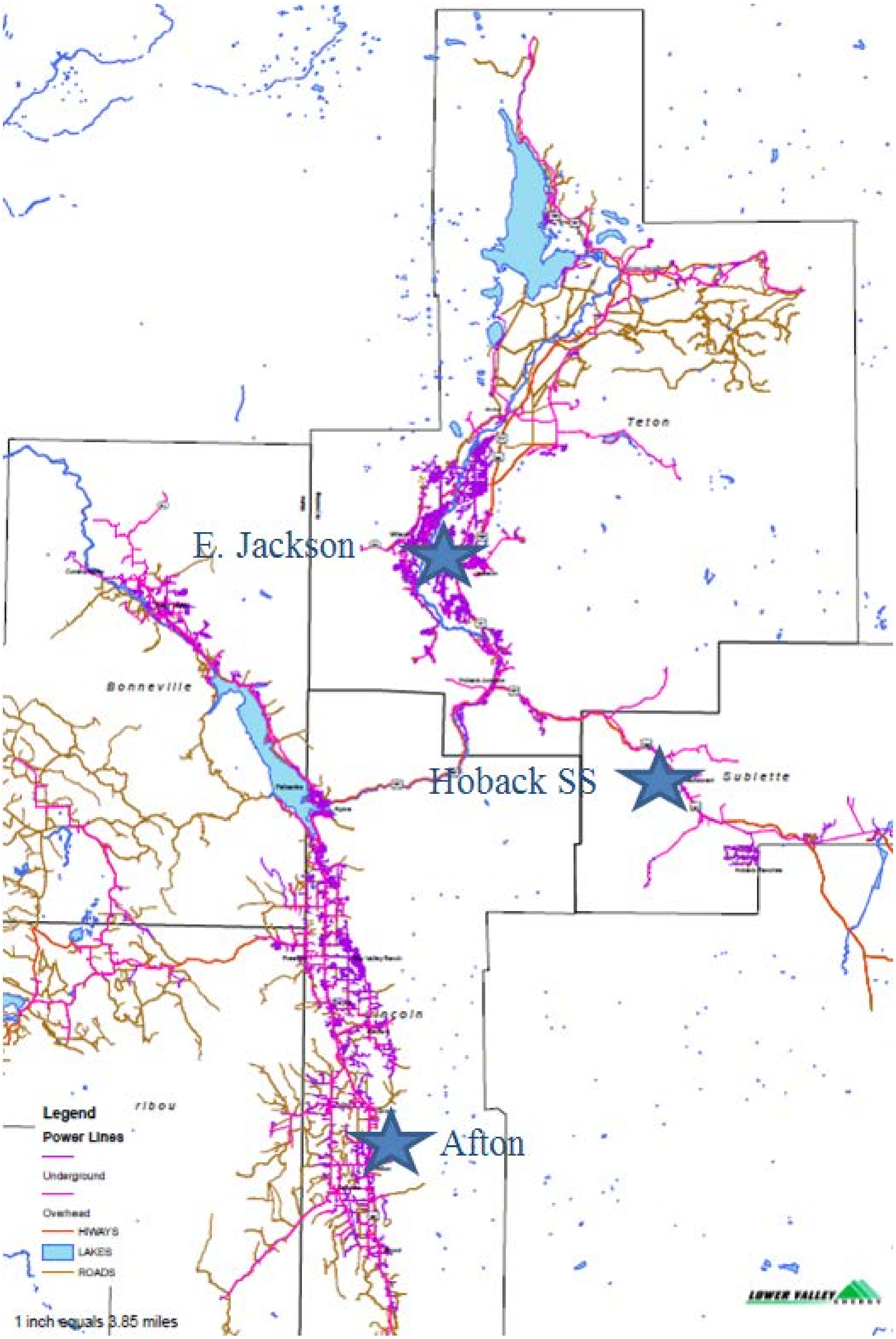


Figure 12.1. Lower Valley Energy Sites. The corridors highlighted in red are important Eastern Idaho transmission lines that supply Lower Valley Electric. (Lower Valley Energy 2015)

The East Jackson and Afton sites are moderately populated. These two sites were primarily used to test member interaction with advanced metering and IHDs. In contrast, the Bondurant, Wyoming site is rural and is at the remote end of a long distribution line. While some premises on this feeder also received advanced metering and IHDs, the cooperative hoped to strengthen the electrical supply to the Hoback substation, which serves Bondurant, and to defer upgrades using a diverse set of SVCs, renewable energy resources, and battery energy storage. The existing C3-ILEX SCADA (supervisory control and data acquisition) system and remote terminal units were used to control and monitor these assets during the project.

The project organized the Lower Valley Energy asset systems into eight tests. These are the eight asset systems that were demonstrated, including their site locations and the chapter sections where each is discussed:

- advanced metering infrastructure (AMI) and IHDs (all sites) (Section 12.2)
- demand-response units (DRUs) (all sites) (Section 12.3)
- DRUs and AMI for reliability (all sites) (Section 12.4)
- adaptive voltage management (East Jackson site) (Section 12.5)
- 300 kVAr static VAr compensator (Hoback site) (Section 12.6)
- 125 kW battery storage system (Hoback site) (Section 12.7)
- 20 kW solar PV system (Hoback site) (Section 12.8)
- four 2.5 kW wind turbines (Hoback site) (Section 12.9).

The layout diagram in Figure 12.2 shows how these asset systems and their test groups lie among the cooperative’s distribution feeders.

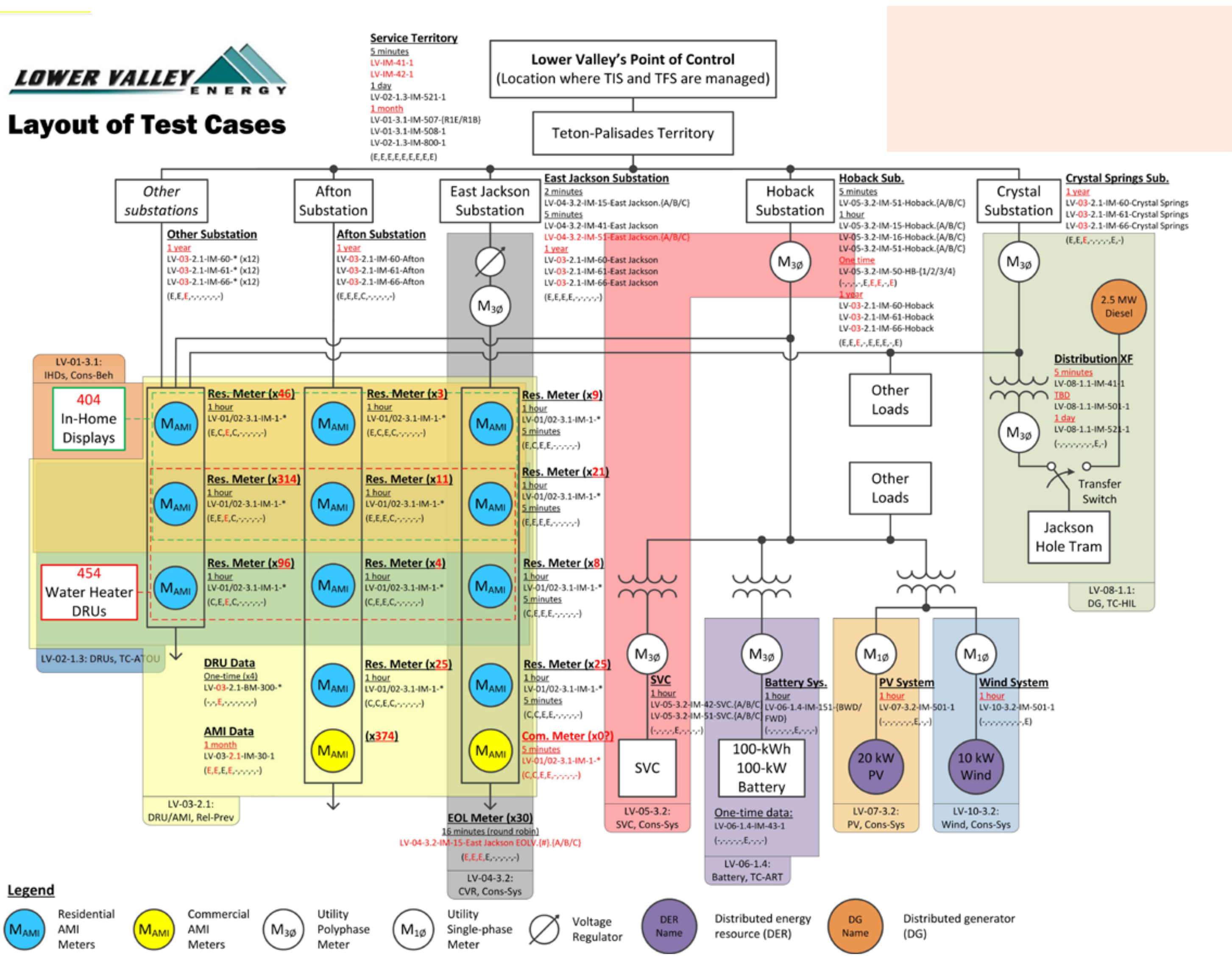


Figure 12.2. Layout of Lower Valley Energy Test Groups and Asset Systems on their Distribution System

Figure 12.3 is a picture of several of the assets that were installed at the Bondurant, Wyoming (Hoback substation) site. The Lower Valley Energy asset systems will be discussed in greater detail in the sections below.

Figure 12.3. Bondurant Site where SVC, Solar PV, Wind, and Battery Systems Resided

The cooperative's service territory is in a relatively cold part of the country and is strongly winter peaking. Figure 12.4 shows the average premises power of the cooperative's members whose data was collected during the project. Strong morning peaks are evident during winter and spring seasons.

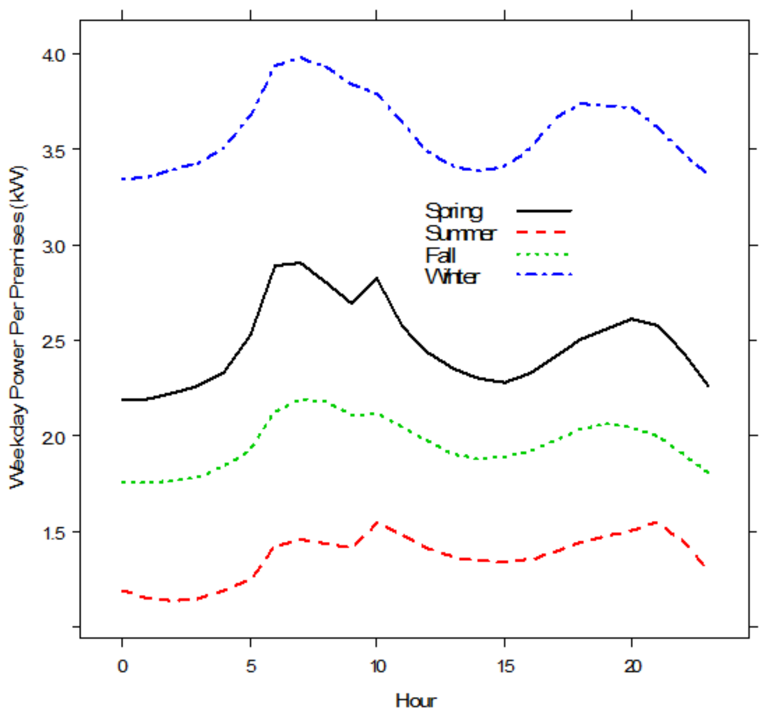


Figure 12.4. Representative Average Per-Premises Power by Season for Lower Valley Energy Cooperative Members. The time scale shows local Mountain Time hour.

12.1 Lower Valley Energy's Transactive Demand-Charges Function

A transactive system function was created to help the cooperative anticipate monthly peak demand and to augment the transactive system's incentive signal such that the battery system and other system assets might help mitigate the cooperative's peak demand. Lower Valley Energy chose to create and operate only one transactive site for the entire Lower Valley Energy service territory, so the demand-charges function attempted to respond to total utility demand. Preferably, if the Hoback site had been defined as another transactive site, the function might have helped the battery system respond to the specific load on the long Hoback distribution lines. As it was, the cooperative already had an application that monitored the distribution line and predicted peak, so they did not especially need the transactive function that attempted to predict and mitigate their demand charges.

The demand-charges function began to successfully identify the timing of new peaks by fall 2013, but its impact on the site's transactive signal was never correctly assessed or calibrated.

12.2 AMI and In-Home Energy Displays

Lower Valley Energy wished to induce energy conservation by providing IHDs and information to its members. They targeted the installation of 500 IHDs, primarily at their Afton, Wyoming site. Landis+Gyr meters equipped with Aclara TWACS modules were also installed, and these meters were used to communicate with and monitor the performance of the system of premises having IHDs. The IHDs were managed from the cooperative's Afton, Wyoming control center.

The cooperative wished to engage its members via the IHDs to reduce its needs for future BPA TIER-2 power, which is the more expensive power that must be used after the utility's allocation of TIER-1 power has been consumed. The IHDs were initially to respond to the project's transactive system, but early during the project the cooperative opted not to use transactive technology at this site. Instead, they asked the project to help them assess the conservation impact. The cooperative originally targeted 8–15% conservation using the IHDs.

Members were able to view their real-time power demand and energy that they had consumed during the current month (for some members) when they visited their IHD.

Participating members were not charged for the IHDs and were not given any monetary incentives by Lower Valley Energy for their participation in the project.

As shown in Table 12.1, the annualized costs of the Lower Valley Electric in-home display system included premises metering, the IHDs, operations and maintenance (O&M) costs, administrative costs, and the costs of educating members concerning how they may interact with their IHDs. The annualized costs were calculated for each component according to that component's estimated useful lifespan.

Table 12.1. Lower Valley Electric Costs of In-Home Display System

	Shared Component Allocation (%)	Annualized Component Cost ($K)	Allocated Annual Component Cost ($K)
Advanced Metering			57.1
• AMI System (backbone)	25	129.8	32.4
• AMI Meters (premises with IHD)	50	26.5	13.3
• AMI Meters (premises with IHD and DRU)	33	29.8	9.9
• AMI Meters (premises with IHD and affected by CVR)	33	2.5	0.8
• AMI Meters (with IHD, DRU, and affected by CVR)	25	2.6	0.7
In-Home Energy Displays	100	8.7	8.7
Ongoing O&M Costs	100	6.1	6.1
Administrative	100	3.7	3.7
Outreach and Education	100	2.9	2.9
Total Annualized Asset Cost			**$78.4K**
CVR = conservation voltage reduction			

12.2.1 Characterization of the In-Home Display System

Working with the project, Lower Valley Energy established premises test groups based on the assets that were installed at those premises. The test groups overlap one another, meaning that some of the groups were affected by multiple asset systems. Some of the premises hosted a DRU, (Section 12.3). Some of the premises resided on the East Jackson feeder where voltage regulation (Section 12.5) was being exercised and others did not. The counts of the various test populations are summarized in Table 12.2.

Table 12.2. Counts of Premises in Each Test Population According to Assets at the Premises

Assets at the Premises	No CVR	CVR	**Totals**
AMI only	24	24	**48**
AMI and IHD	15	3	**18**
AMI, IHD, and DRU	324	27	**351**
AMI and DRU	103	5	**108**
Totals	**466**	**59**	**525**

The challenge, then, is to isolate a conservation impact that is attributable to the installation of IHDs. Ideally, the 15 premises having IHDs should be compared against the 24 premises where no assets other than advanced meters were installed. An alternative exists if we can compare the 234 premises that have both a DRU and an IHD against those 103 that receive only the DRU.

Lower Valley Energy informed the project that the IHDs were installed over a three-month period, January through March 2012. They supplied historical data from monthly meter reads for these test sets starting from September 2009. The early historical data let the project establish a baseline prior to the installation of the IHDs.

It was found that data quality changed the same months that the IHDs were being installed. The IHDs were installed near the same time that premises meters were upgraded, which added variability to the data. This data's variability might be attributable to the inexact timing of dates and times that premises meters were read. In the months of early 2012, hourly interval measurements became available to the project as the advanced premises meters were activated. Because the installations of advanced metering and IHDs were concurrent, the impacts from the new metering and assets might not be fully separable.

Figure 12.5 shows a sample of the averaged premises power for the test group that received IHDs (red) and the control group that did not (blue). The figure shows data for all of 2012, during which both IHDs and AMI were actively being installed. The data markers that remain constant for an entire month at a time represent the historical data that was available from monthly manual meter reads prior to the installation of AMI.

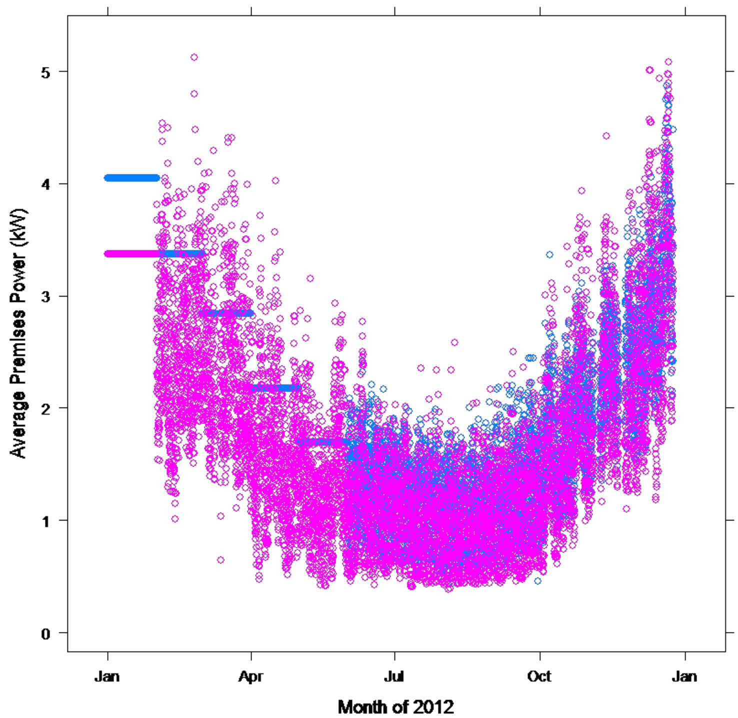


Figure 12.5. Average Premises Power of the Test Group that Received In-Home Displays (red) and the Control Group (blue) during Early 2012, when Both the Advanced Meters and In-Home Displays were Being Installed

The aggregate premises power data was reviewed. If the power for the test groups and/or their baseline groups were found to be uncharacteristic during any time period, then the data from both test groups was removed for that period. If either the test group or baseline was unavailable, then the other was made unavailable. Inexplicable low measurements below about 0.3 kW per premises were removed because these values were remote from other measurements and were not characteristic of normal premises behavior.

As for the historical monthly power data, these were believed to derive from monthly meter reads. Total monthly premises energy was divided by the hours in the month to create an average per-premises power. The project believes the historical data should not have been subject to the same types of errors from missing data as were the recent measurements.

All premises data were averaged across the test groups shown in Table 12.2, stating average power per premises. The data was also averaged by calendar month to make data from the recent and historical periods comparable. Figure 12.6 shows the monthly average premises power for one of the pairs of comparable test and control groups. The arrow on this figure points to the center of the installation period. The data from February 2014 was entirely removed because visual inspection revealed stepwise reductions in one of the time series and not the other that month. Except for the winter of 2012, the yearly profiles appear similar to each other.

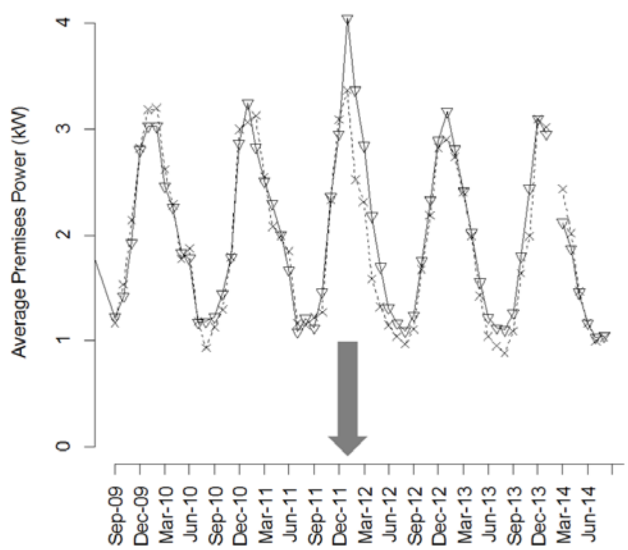


Figure 12.6. Monthly Average Premises Power for Premises that have Both Advanced Meters and In-Home Displays (dashed line with cross markers) and Those Receiving only Advanced Meters but Not IHDs (solid line with triangle markers)

The aggregated monthly data for the alternative pairing of premises that also have DRUs is shown in Figure 12.7. As for the comparison in Figure 12.6, the two data series differ only in that one of each pair had IHDs installed and the other did not. The data sets graphed in Figure 12.7, for premises that also had DRUs, are much larger and might be expected to have better statistical outcomes than for the comparison using premises that did not receive DRUs (Figure 12.6). Some interesting anomalous patterns are observed, however, in the control set that did not receive IHDs. The peak 2013 and 2014 winter average power consumption exhibits uncharacteristic dips or flattening of peaks. Furthermore, a relatively constant reduction in energy consumption appears over the project's duration that was not as evident in Figure 12.6.

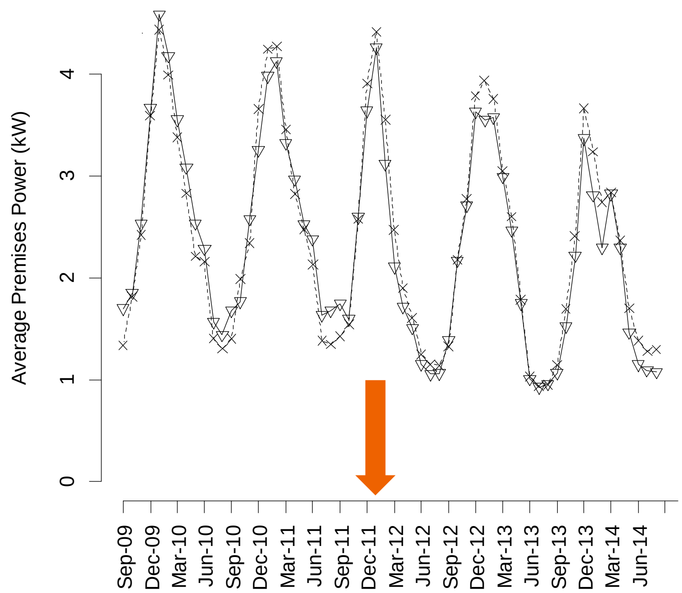


Figure 12.7. Monthly Average Premises Power for Premises that have Advanced Meters, DRUs, and In-Home Displays (dashed line with cross markers) and those receiving only Advanced Meters and DRUs but Not IHDs (solid line with triangle markers)

Analysis also used ambient temperature in the formulation of modeled data sets. Temperatures were accessed primarily from weather station D1489 in Wilson, Wyoming. Wherever these measurements were found to be missing, replacement data was generated from a linear model that was informed additionally from weather station KJAC, Jackson Hole Airport, Jackson Hole, Wyoming.

12.2.2 Performance of the Advanced Metering and In-Home Display System

The project first attempted to directly compare the raw data sets that were shown in Figure 12.6 and Figure 12.7. That is, presuming the test groups are comparable, did the installation of IHDs change the relationship between the two test groups? This method generated results that, at first, seemed compelling, but the results turned out to be contradictory between the datasets in Figure 12.6 and those in Figure 12.7. The effect apparent from the simple comparison also dissolved away after temperature-based modeling approaches were applied.

Because advanced metering had been installed concurrently with the IHDs, the project first tried to isolate any impact from the smart meters alone. Using the average monthly per-premises power of the 24 members who received only advanced metering, the project created a linear parametric model using R software (R Core Team 2014). Because the project wished to estimate and eliminate the impact from any consistent change in affluence for the population over time, the model was fit to an affine fractional year counter. The model also used average ambient temperatures and a Boolean indicator for the months that advanced meters had been activated. The date of advanced meter installation was inferred from when interval measurements changed from monthly to hourly.

Northwestern Wyoming is a cool climate. The highest average monthly temperature was about 65°F (~18°C). Little air conditioning is needed or used by these premises. The load was quite (inversely) linearly proportional to the temperature, so separation of cooling and heating regimes was deemed unnecessary for the month-interval data.

The linear fit suggested that average load is increasing about 93 W per premises per year in this population. The average monthly premises load decreased by about 43 W for every 1°F increase in average ambient temperature. (78 W/°C). Finally, the installation of advanced metering seems to have reduced average premises power consumption by 266 W.

The model was then used to generate predictions of what the average per-premises consumption would be if advanced meters were never installed. This prediction was useful for the project to understand the statistical confidence that should accompany the reduction. Based on a Student's t-test comparison between modeled and actual average monthly premises power, the project reports that the installation of advanced metering reduced average premises power by 270 ± 70 W in this test group. The results were further assessed by month in Figure 12.8, in which the heavy error bars represent standard error and the longer bars estimate a 95% confidence interval.

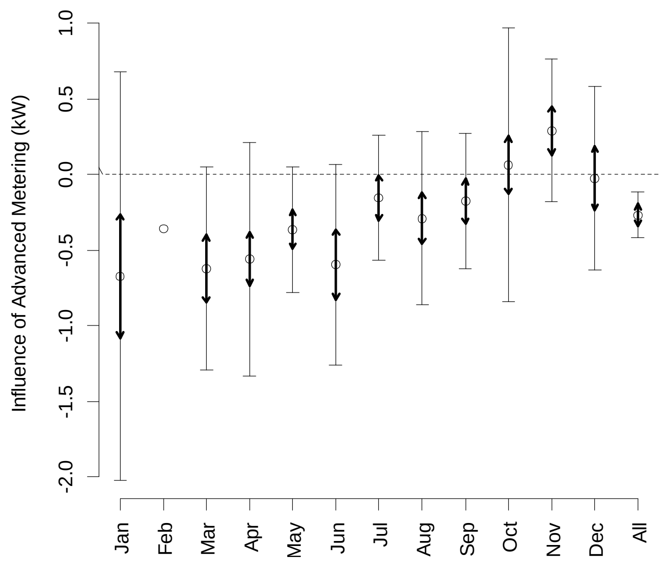


Figure 12.8. Impact of Installing Advanced Premises Metering on Average Premises Power by Calendar Month

For confirmation, the analysis was repeated using the alternative test group that received DRUs but never received IHDs. Formally, this result should be described as the long-term conservation impact from installing both advanced metering and DRUs. The installation of advanced meters and DRUs reduced average premises power consumption by 400 ± 110 W. For this test group, premises power consumption also decreased at a rate of 22 W per year throughout the 5 years.

The project then created similar models for the test group that had received both advanced meters and IHDs to see whether the addition of the IHDs changed the outcome. The same parametric variables were used for the linear fit as for the modeled control group that received only advanced meters. In this case, a reduction of 210 ± 70 W was found. This result is a little less than, but otherwise very similar to, that found for advanced meters alone. It probably confirms that outcome for the impact of advanced metering, but nothing can be said about the incremental impact of the IHDs.

The results from this last analysis are shown broken out by calendar month in Figure 12.9. This figure may be compared against Figure 12.8 that was for premises that received only advanced meters. Again, the results are similar. Even the monthly patterns share similarities.

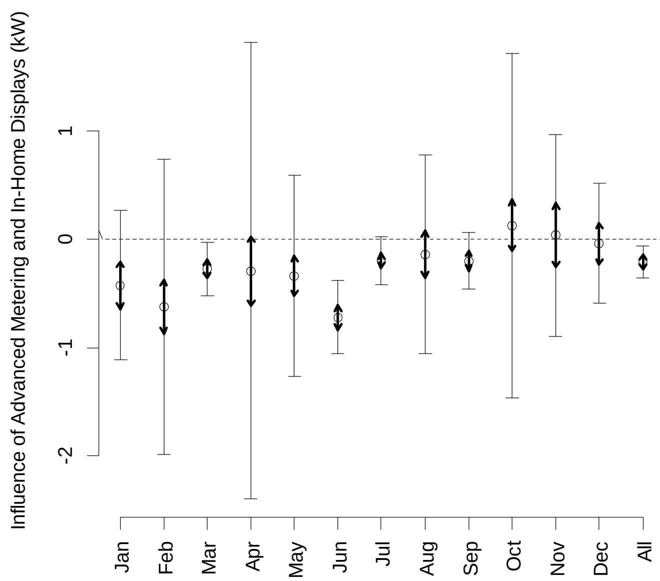


Figure 12.9. Change in Premises Power from Installation of Both Advanced Metering and IHDs by Calendar Month

The project made further attempts to distinguish the impacts of installing IHDs from that evident from installing advanced metering. Any results that were found were small in comparison to the impacts from installing advanced metering, and the project could not confidently state that any effects were significant.

The project was not able to differentiate any diurnal impacts of the conservation with the available data. The impact on peak premises load must be presumed to be identical to the global finding.

In conclusion, the project was not able to confidently attribute any reduction in power consumption to the installation of IHDs, but the project found compelling evidence that the installation of advanced metering reduced premises power consumption. One hypothesis is that an actual power reduction follows the installation of advanced metering because the information and education received by the affected members induces them to truly conserve energy. Another hypothesis is that the newer meters are calibrated differently from the older meters and in the cooperative members' favor.

12.3 DRUs

Lower Valley Energy reported installing 530 Aclara DRUs on premises controlling 566 water heaters at the Afton, Wyoming site. Electric water heater load was to be curtailed when advised to do so by the project's transactive control system. The system of DRUs was managed from the Afton control center. The cooperative's main purpose for the DRUs was reduction of monthly system peak and reduction of the corresponding demand charges that it pays for peak demand.

The utility had already installed about 50 DRUs prior to their participating in the project. Curtailments of varying durations were being conducted on subgroups of this population to determine members' tolerance for the curtailments.

Lower Valley Energy waived a $15 monthly service facility charge for participating members who allowed the utility to install a DRU to control their electric tank water heater. This monthly credit was later reduced to $10. Briefly stated, the utility justifies this expense based on peak demand charges that will be avoided. The total incentives to be paid for this responsive asset by the utility were predicted by the utility to be about $87 thousand per year.

Lower Valley Energy offered to make the DRUs responsive to the project's transactive system. In fact, only several of the DRUs—those at utility offices and under close utility supervision—were made automatically responsive to the project's transactive system. Lower Valley Energy had a second objective that was automated through their SCADA system to automatically respond at preset demand thresholds.

The vendor provided additional features. The DRUs were configured to automatically respond to under-frequency and under-voltage events that they detected in the distribution system. Furthermore, the DRUs were programmed to delay the reconnection after distribution outages to provide cold-load pickup for the utility. These responses were thought by the utility to be useful, especially when the DRUs were positioned on long, rural distribution feeders.

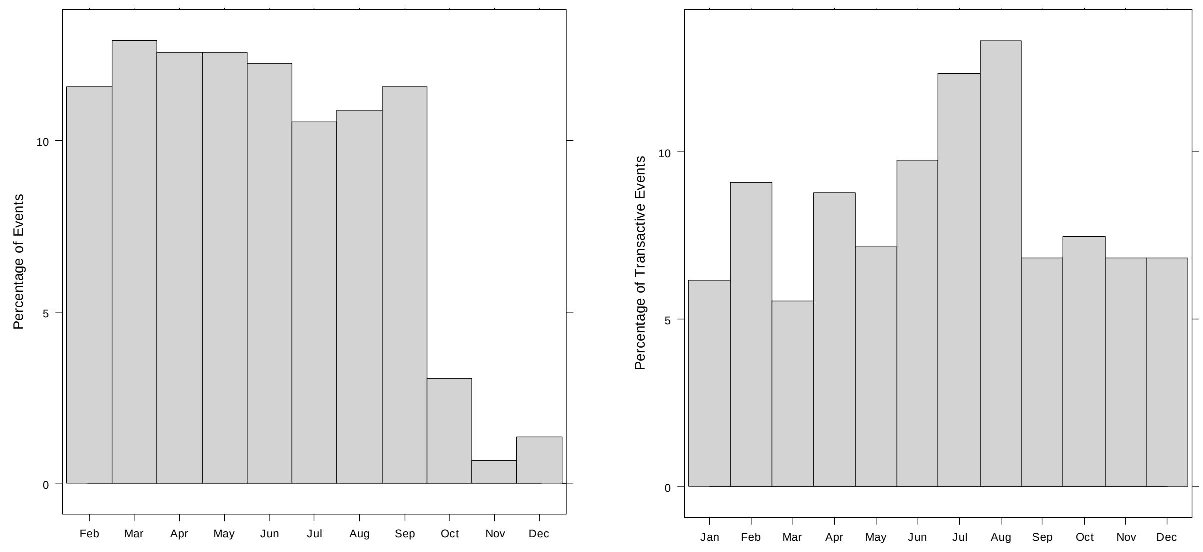
The annualized costs of the Lower Valley Energy DRU system and its components are summarized in Table 12.3. The greatest annual cost is for member incentives. The costs of the members' advanced metering were included because these meters were essential for monitoring and controlling the DRUs. Other costs to the utility include the purchase and installation of the DRUs, system upkeep, connecting control of the DRUs to the transactive system, and administrative costs.

Table 12.3. Lower Valley Electric Costs of DRU System

	Shared Component Allocation (%)	Annualized Component Cost ($K)	Allocated Annual Component Cost ($K)
Member Incentives	100	72.0	72.0
Advanced Metering			57.4
• AMI System (backbone)	25	129.8	32.4
• AMI Meters (premises with DRU)	50	27.1	13.6
• AMI Meters (premises with IHD and DRU)	33	29.8	9.9
• AMI Meters (with DRUs and affected by CVR)	33	2.5	0.8
• AMI Meters (with IHD and DRU and affected CVR)	25	2.6	0.7
Water Heater DRUs	50	17.1	8.5
Ongoing O&M Costs	100	6.1	6.1
Transactive Signal	50	8.4	4.2
Administrative	100	3.7	3.7
Outreach and Education	100	2.9	2.9
Total Annualized Asset Cost			**$154.9K**

12.3.1 Characterization of Asset System Responses

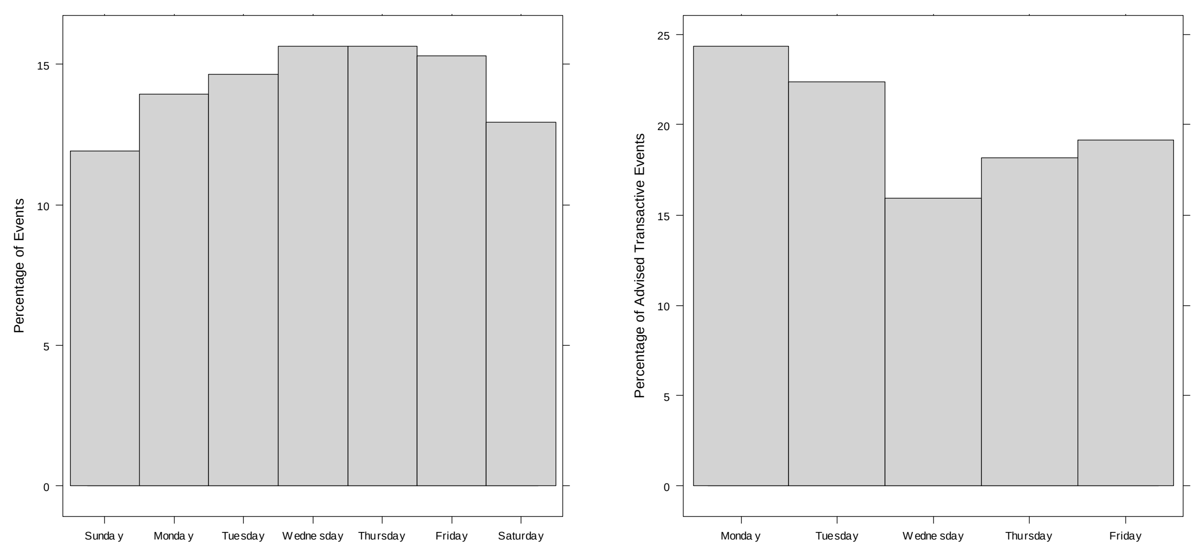
Figure 12.10 shows the relative numbers of times per calendar month that the DRUs were reported to have been engaged (left) and had been advised to respond by the transactive system (right). The utility did not engage the DRUs much during the calendar months October, November, and December.



(a) (b)

Figure 12.10. Distributions of the Months that (a) DRUs were Truly Engaged and (b) Transactive System DRU Engagements were Advised

Histograms of the reported and advised events are shown in Figure 12.11. Analysts were somewhat surprised that the DRUs had been engaged all days of the week, including weekend days. The toolkit function that was established to advise event periods for the system of DRUs was apparently configured to disallow weekend events.



(a) (b)

Figure 12.11. Distributions of Weekdays that (a) the Lower Valley Energy DRUs were Reported to Have Been Engaged and (b) the Transactive System Advised the DRU System to Become Engaged

When analysts reviewed the durations of events that had been initiated by the utility, over 80% of the DRU events had been precisely 3 hours long. Figure 12.12 shows the distribution of the event durations with the most predominant duration being 36 5-minute intervals, which is 3 hours. An extremely long event was omitted from this figure and must have been an outlier.

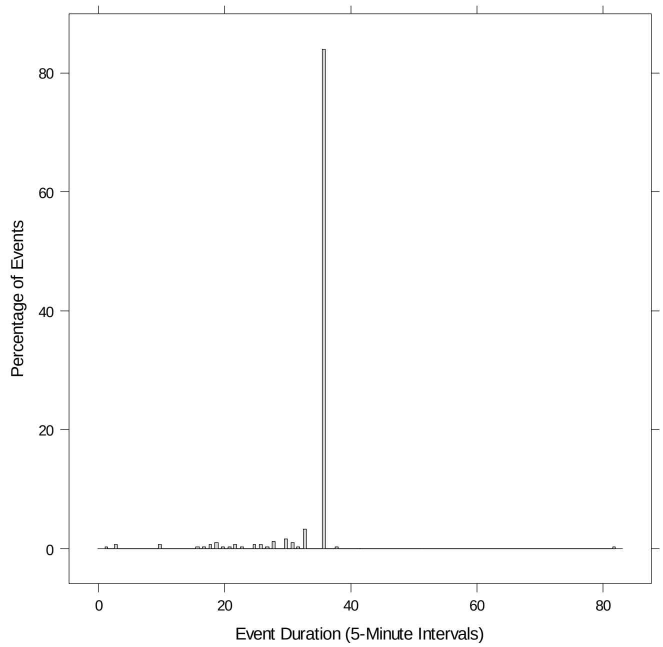
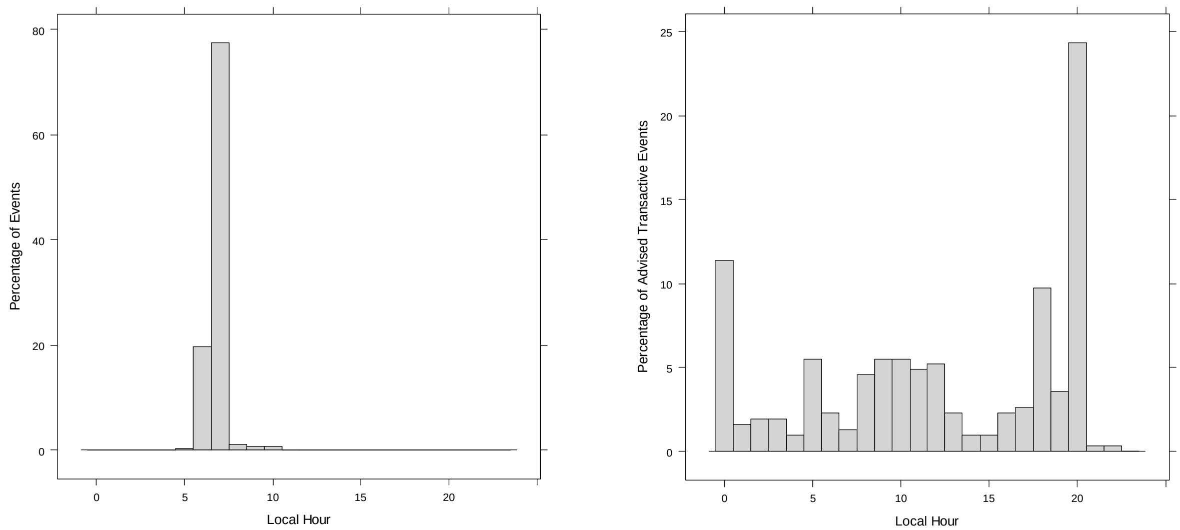


Figure 12.12. Histogram of Event Durations for Lower Valley Energy DRU Engagements. Very long event #253 was deleted prior to this and most other analyses in this section.

Figure 12.13 shows the local hour when the events were engaged by Lower Valley Energy (left) and the starting hours that events were advised by the transactive system (right). The utility engaged the DRUs during a narrow window of morning hours between 05:00 and 10:00. The transactive system advised events all hours of the day, including too many midnight and late evening hours (e.g., 20:00), which might be attributable to the challenges the PNWSGD encountered as it calibrated the transactive signals and the asset's toolkit function.



(a) (b)

Figure 12.13. Local Hours that DRU Engagements (a) Actually Began and (b) Were Advised to Begin by the Transactive System

12.3.2 Performance of the Lower Valley Energy DRUs

The project analyzed the change in power during the times that the loads on the DRUs were reported to have been curtailed. Both comparison and modeled baselines were established for this analysis. The comparison baseline was created from the approximately 24 premises that had neither DRUs nor IHDs (Section 12.2). The average power consumption data series from these comparison premises were normalized to have the same monthly mean and standard deviation as for the approximately 104 premises that had only DRUs. The DRU-event time periods were excluded from the normalization. A further global correction was then performed to make the global means the same each hour of the day. Neither the test nor comparison premises groups resided on the East Jackson feeder to avoid any potentially confounding interactions with the adaptive voltage management being practiced there (Section 12.5).

The averaged premises power consumption of the 104 premises that had DRUs was modeled using R software to create a modeled baseline. The linear model incorporated the parameters month, hour, weekday, temperature, and any permutation of the first three factors with the ambient temperature. The DRU-event time periods were excluded during the training of the linear model.

As stated before, temperatures were accessed primarily from weather station D1489 in Wilson, Wyoming. Wherever these measurements were found to be missing, replacement data was generated from a linear model that was informed additionally from weather station KJAC, Jackson Hole airport, Jackson Hole, Wyoming.

The two baselines (“comparison” and “modeled”) predicted what the premises power time series would have been had there been no DRUs. The comparison baseline was derived from the behaviors of a set of control premises that did not receive DRUs. The modeled baseline was formulated by linear regression using the average power of the test group that had received DRUs. The project compared the differences between the test and baseline time series both during event periods and during non-event periods to help mitigate any biases in the baselines.

The project reports a reduction of 370 ± 80 W per premises during DRU events after combining the results from both baseline approaches. Using the modeled baseline only, the project observed a reduction of 420 ± 20 W per premises. The project observed a reduction of 310 ± 20 W per premises using the comparison baseline approach.

The results are reported for each project month in Figure 12.14. As expected, the monthly results show large confidence intervals. Most of the months' results show power reduction, but there are some months that show increases in power consumption instead. Note the consistent power reduction in early 2012 when the DRUs were being exercised almost daily. The consistent results from those four months heavily influenced the final results being reported by the project. This influence may be clearer below when we look at cumulative results.

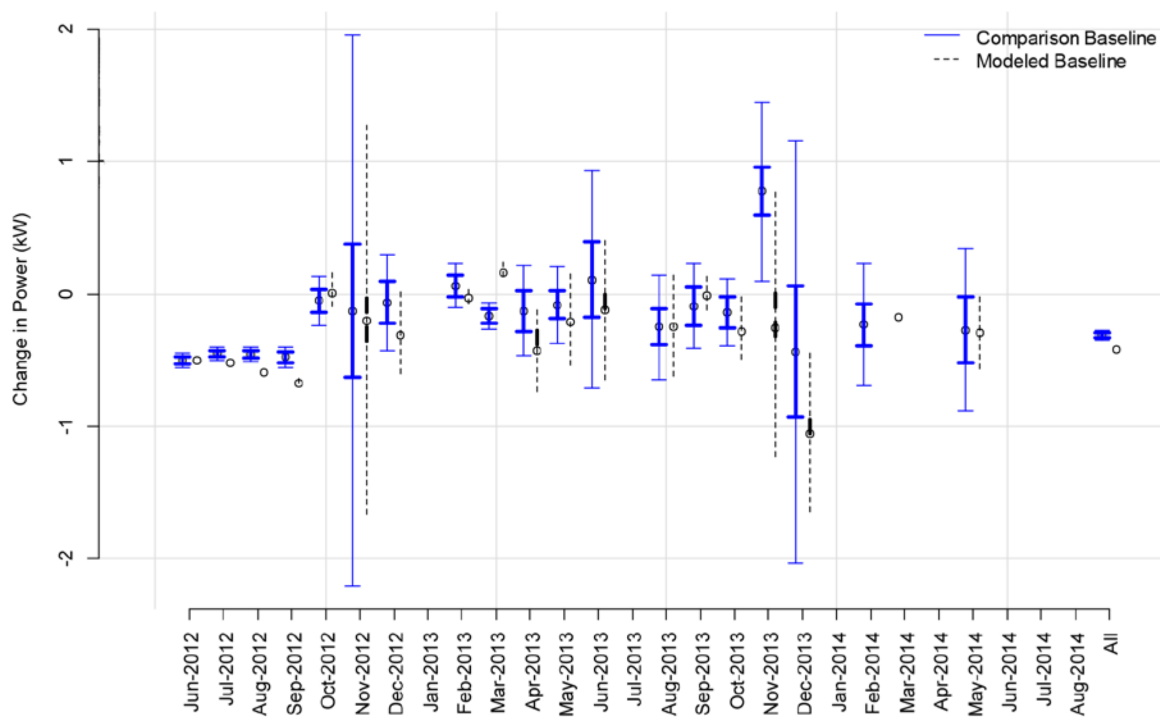


Figure 12.14. Average Impact on Premises Power Observed during DRU Curtailment Events Each Project Month According to the Comparison (blue) and Modeled (black dashed) Baselines

The project next looked at the impact on premises power during the hours immediately following the ends of events. During these hours, the thermostatically controlled devices that had been curtailed by the DRUs attempt to consume the energy that had been denied to them during the event.

The project reports that a 150 ± 150 W increase in power consumption per premises occurred during the rebound hour following DRU events. This result combines both the comparison and modeled baseline approaches. Actually, the comparison baseline itself yielded a convincing increase of 260 ± 70 W per premises by itself, but the results from the modeled baseline were smaller and inconclusive. When the same evaluation was conducted on East Jackson premises, a consistent increase of 440 ± 50 W was found, but this result is potentially confounded by voltage management on the East Jackson feeder. The project elected to use only the results that were not on the East Jackson feeder. The results again appear more consistent during the time the DRUs were being consistently exercised in early 2012.

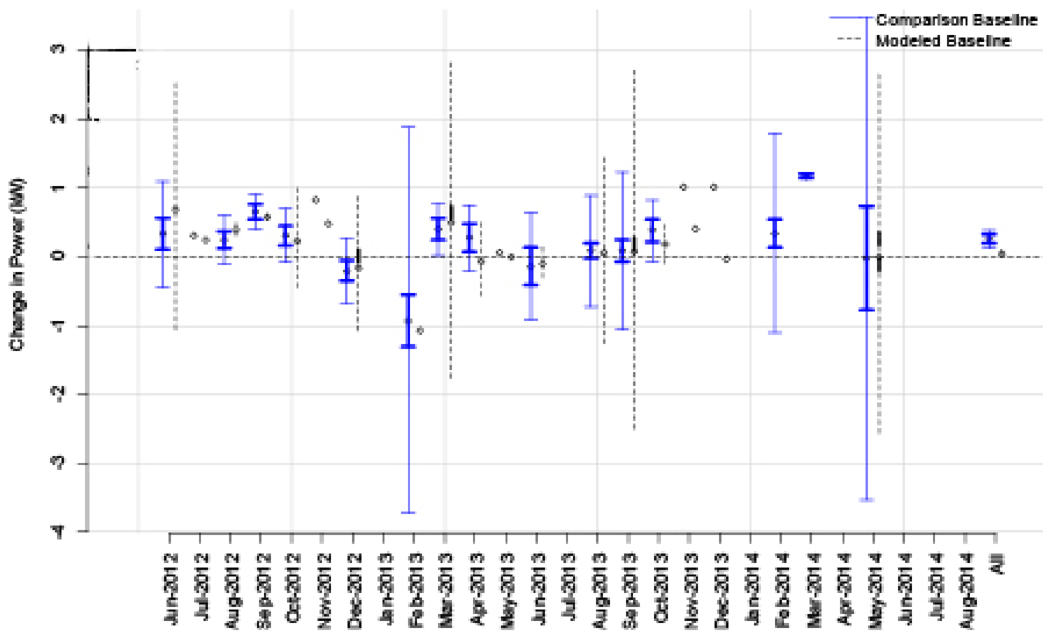


Figure 12.15. Average Impact during Rebound Hours each Project Month using the Comparison (blue) and Modeled (black dashed) Baselines

Throughout event days, the project observed that average premises consumption was reduced by 60 ± 70 W. Both baseline methods indicated that a significant reduction had occurred. However, the results from the two baseline approaches—105 ± 7 W per premises using the modeled baseline and 10 ± 7 W per premises using the comparison baseline—differed. Therefore, the project is reporting the variability as the standard deviation of the two results, which is much greater than the standard errors from either of the two baseline approaches. The broadened uncertainty is further justified by the monthly results in Figure 12.16, from which these final results are not obvious.

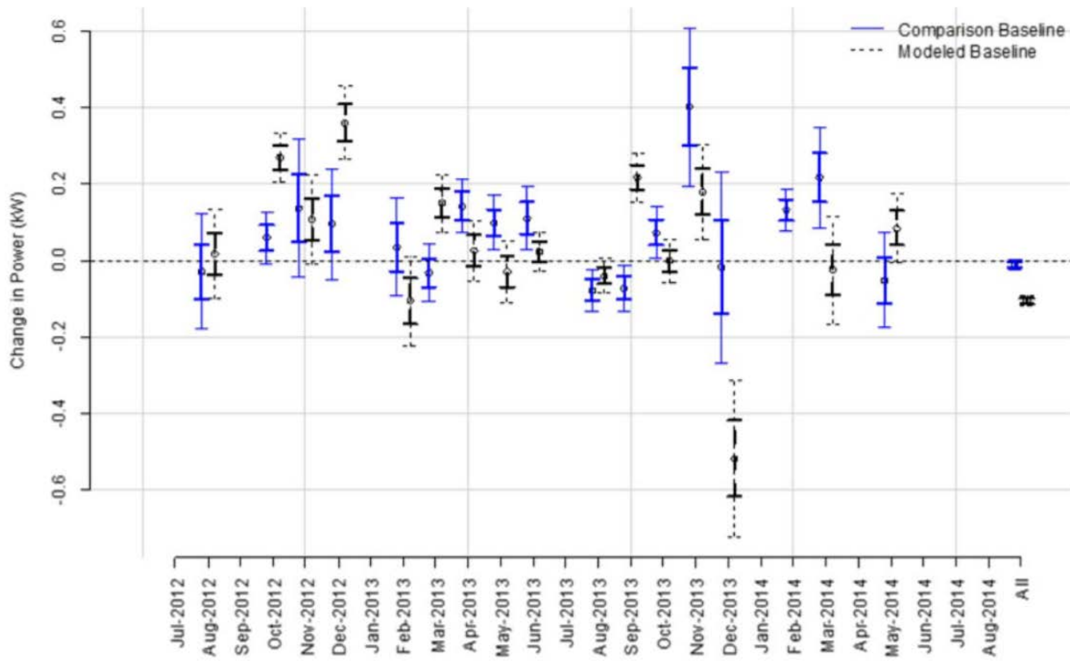


Figure 12.16. Average Impact throughout Days that DRU Events Occurred Using the Comparison (blue) and Modeled (black dashed) Baselines

The DRUs were not exercised in the same fashion throughout the project's duration. Therefore, the monthly representations in the above figures might overstate the variability and understate the potentially verifiable impacts during events, rebound hours, and event days. In the next section, the cumulative results are presented, which better show the consistency with which the system was operated in early 2012.

One of the curtailment events (number 12) has been ignored in this analysis because it lasted 11 days—much longer than the cooperative would actually permit a DRU to remain curtailed.

The following analysis uses only the comparison baseline approach to state cumulative impacts. The modeled approach could have been selected instead. Either baseline approach would support the discussion, but minor differences might be observable in the resulting figures and exemplar values.

Figure 12.17 shows the cumulative system energy impact (black solid line) on its left-hand axis. This is the cumulative sum of the change in energy per premises during curtailment events, multiplied by the numbers of premises that have the DRUs. This test group hosted about 104 of the total 459 controlled water heaters installed by Lower Valley Energy for this project. The figure also shows the cumulative product of the number of impacted premises and the hours that their DRUs were reported to be curtailed over time. The long, almost linear parts of these two lines show that the system was frequently and regularly engaged during early 2012. The energy impact accumulated accordingly.

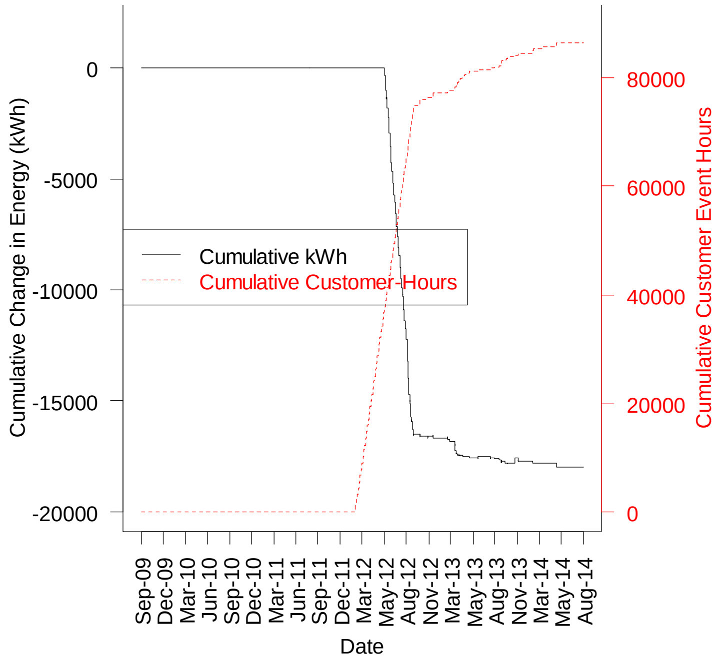


Figure 12.17. Cumulative System Energy Impact and Cumulative Customer Event Hours throughout the Project. Lower Valley Energy exercised the system frequently in the early months of the 2012 calendar year.

When the cumulative energy impact is plotted against the cumulative customer curtailment hours (Figure 12.18), the impact is demonstrated to be consistent throughout the project. The downward slope of the line represents the energy reduction per customer curtailment hour. That is, because this figure was based on the comparison baseline approach, the slope will be −470 Wh per customer-hour. This happens to be precisely the impact observed from June through September 2012 in Figure 12.14. If the modeled baseline approach had been used, the result would be similar, but the slope would be a little steeper.

The slope of the line in Figure 12.18 diminishes during the latest customer hours. This might indicate that the system impact and the quality of system processes diminished late in the project. This might be attributable to the system itself, but it could also be attributable to poorer data collection late in the project.

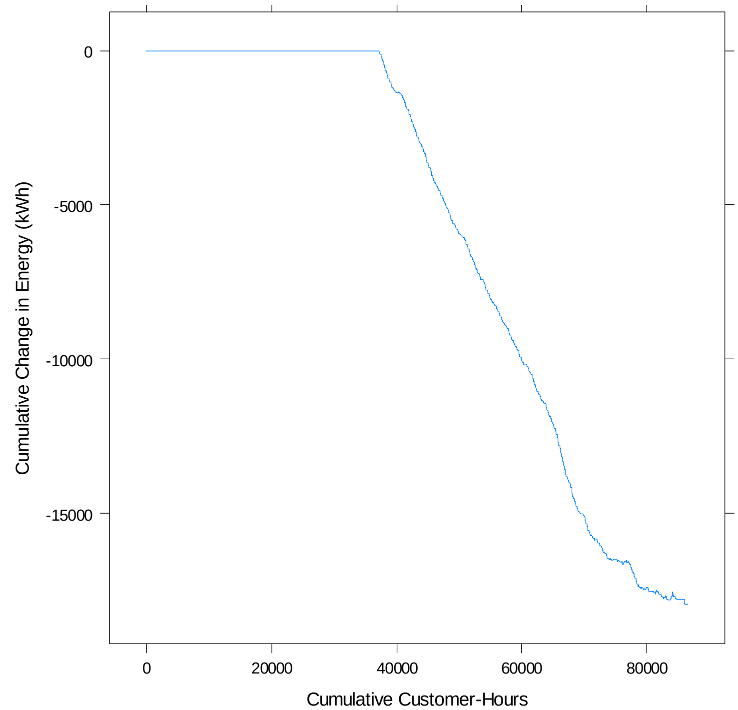


Figure 12.18. Cumulative Impact on System Energy Plotted against Cumulative Customer Hours. The slope of this curve represents the average premises power impact.

12.4 DRUs/AMI for Improved System Reliability

Lower Valley expected to improve the reliability indices at all its feeders by employing advanced metering and other smart grid assets. The improved metering provided them better overall visibility of the Lower Valley Energy distribution system. Additionally, autonomous tripping of water heater DRUs (Section 12.3) during under-frequency and under-voltage events can shed load and perhaps avoid some outages. The water heater DRUs also may be commanded to remain off during cold-load pickups, thus helping the utility recover from outages.

Lower Valley Energy therefore supplied to the project all three major reliability indices— System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI), and Customer Average Interruption Duration Index (CAIDI)—at yearly intervals for each of its feeders. The project worked with them to determine whether any measureable improvement in these indices accompanied the installations of their smart grid assets.

The installation of new, smart assets is just one of many things that may affect reliability indices. The quality of utility O&M processes is all important. Outages may certainly be caused or mitigated by equipment, but they may also be caused and mitigated by personnel. The analysis conducted in this section is a correlation study. If a correlation can be found, it cannot be definitively attributed to the smart equipment or any other factor.

The annualized costs of the system are listed in Table 12.4. A significant fraction of the costs of advanced meters is allocated to this system and toward the improvement of distribution system reliability. A fraction of the cost of the DRU system is also included because these assets contribute autonomous responses and cold-load pickup capabilities. A fraction of the cost of substation TWACS communication system components was included because such communication is critical to mitigating and preventing outages. The remaining annualized costs include labor, outreach, and data activities and equipment. The total annualized cost of the system was estimated as $156.5 thousand per year.

Table 12.4. Annualized Costs of the DRU and AMI System and its Components

	Shared Component Allocation (%)	Annualized Component Cost ($K)	Allocated Annual Component Cost ($K)
Advanced Metering			122.4
• AMI System (backbone)	25	129.8	32.4
• AMI Meters (with no devices, unaffected by CVR)	100	28.4	28.4
• AMI Meters (with no devices, but affected by CVR)	50	44.9	22.5
• AMI Meters (premises with DRU)	50	27.1	13.6
• AMI Meters (premises with IHD)	50	26.5	13.3
• AMI Meters (premises with IHD and DRU)	33	29.8	9.9
• AMI Meters (with IHD and affected by CVR)	33	2.5	0.8
• AMI Meters (premises with DRU and affected by CVR)	33	2.5	0.8
• AMI Meters (with IHD and DRU and affected by CVR)	25	2.6	0.7
Water Heater DRUs	50	17.1	8.5
Substation TWACS Components			6.8
• Outbound Modulation Unit	50	6.2	3.1
• Control and Receiving Unit	50	3.8	1.9
• Modulation Transformer Unit	50	3.6	1.8
Ongoing O&M Costs	100	6.1	6.1
Administrative	100	3.7	3.7
Operations Labor[(a)]	50	6.7	3.4
Outreach and Education	100	2.9	2.9
Backroom Data	50	3.2	1.6
Control Network - Power Line Carrier	50	1.3	0.7
Substation Network Multiplexer	50	0.9	0.5
Total Annualized Asset Cost			**$156.5K**

(a) Operations labor was shared between this asset system and adaptive voltage regulation (Section 12.5).

12.4.1 Available Data

Lower Valley Energy reported to the project that this system that was to improve distribution system reliability was installed and useful by early 2011. The meters and other components were used as soon as they became installed. The installation proceeded over months.

As stated earlier, the utility submitted yearly SAIDI, SAIFI, and CAIDI data for each distribution feeder and an overall assessment of the percentage of meters that were read by 02:00. These meter reading assessments were found to be yearly summaries, and the assessments for 2013 and 2014, the only years for which data was received, were identical at 95%.

Table 12.5 lists the calculated SAIFI index for each of 16 Lower Valley Energy distribution feeders for the years 2010 through 2014. The utility calculated and delivered these values to the project. These numbers represent the average number of sustained outages incurred by a cooperative member in the given year. The largest index is about 8.4 and the smallest is 0.03. It is difficult to see a clear trend.

Table 12.5. Calculated SAIFI for 16 Lower Valley Energy Distribution Feeders by Year (Outages per Year)

	2010	2011	2012	2013	2014
Afton	0.67	0.03	0.63	0.43	0.32
Bedford	1.10	1.18	1.15	0.27	1.08
Crystal	0.60	1.01	0.37	0.74	0.13
Drycreek	0.07	0.76	0.82	1.46	0.17
E Jackson	0.10	0.16	0.19	0.56	0.19
Freedom	1.67	0.81	0.82	0.58	3.73
Grover	2.44	0.33	1.28	1.22	5.18
Hoback	1.82	1.03	1.05	9.48	2.10
Jackson	0.09	0.35	0.83	0.37	0.05
Kelly	1.95	0.23	2.25	1.20	1.61
Lanescreek	0.09	2.04	1.73	8.37	0.15
Moran	3.11	1.98	2.72	2.97	4.63
Pinecreek	1.64	2.19	1.06	1.99	1.93
Rafterj	0.22	1.38	0.24	0.80	0.05
Snake	0.55	1.30	1.17	1.50	1.24
Wilson	1.11	0.20	0.74	0.96	1.10

The sets of feeder indices in a given year were grouped in the quartile plots of Figure 12.19. In this plot, each box represents the range from 25–75% of the year’s feeder indices, and the extended bars represent the remaining two quartiles. The median appears to be creeping upward gradually throughout the 5-year data period. The range of calculated SAIFI indices in 2012 narrowed compared to those in earlier and later years.

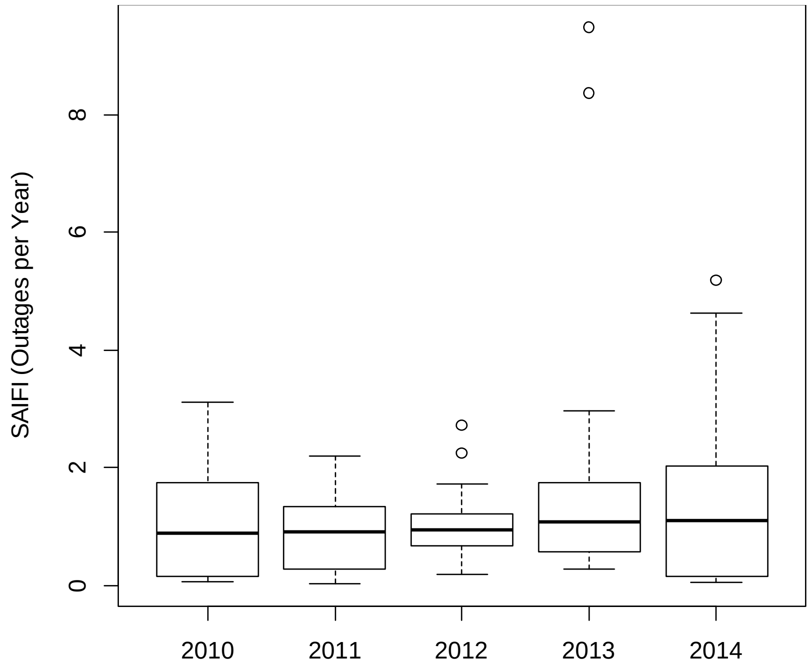


Figure 12.19. Quartile Plots of Calculated SAIFI for 16 Lower Valley Energy Distribution Feeders by Year

A similar set of SAIDI indices were gathered and are reported in Table 12.6 and Figure 12.20. These values represent the average number of total sustained outage minutes experienced by a cooperative member in the given year. These indices were calculated by the cooperative.

Table 12.6. Calculated SAIDI for 16 Lower Valley Energy Distribution Feeders by Year (Minutes per Year)

	2010	2011	2012	2013	2014
Afton	39.6	4.8	31.7	29.7	25.3
Bedford	37.2	96.1	57.5	13.0	69.3
Crystal	82.9	59.4	41.3	29.2	12.1
Drycreek	3.6	46.2	133.5	43.2	9.3
E Jackson	12.6	19.2	28.7	16.9	15.4
Freedom	138.7	72.1	59.9	25.0	261.1
Grover	285.2	18.0	170.7	25.5	150.8
Hoback	284.6	135.1	204.8	155.6	259.5
Jackson	13.2	22.8	58.1	14.6	3.3
Kelly	488.7	27.6	365.3	45.4	726.6
Lanescreek	9.6	559.0	390.4	101.7	10.8
Moran	637.6	684.5	1,195.7	42.4	966.2
Pinecreek	190.9	190.9	219.8	36.8	358.0
Rafterj	15.6	72.1	30.5	25.0	7.0
Snake	85.3	180.1	137.1	39.0	165.7
Wilson	145.9	64.2	43.7	27.7	92.8

No sustained trend is evident in Figure 12.20, but 2013 was a remarkable year. The cooperative members experienced, on average, shorter outage durations, and the index was consistently reduced across almost all the distribution feeders.

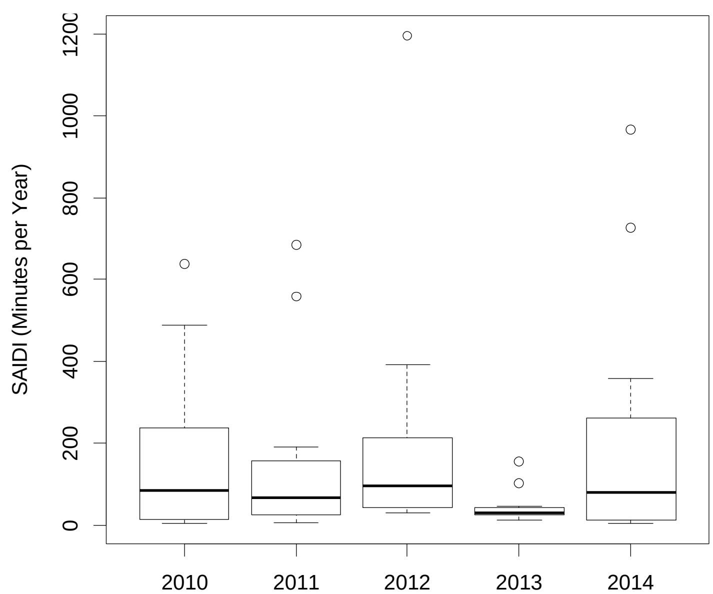


Figure 12.20. Quartile Plots of Calculated SAIDI for 16 Lower Valley Energy Distribution Feeders by Year

CAIDI is not an independent index. It may be calculated from SAIDI and SAIFI. Nonetheless, CAIDI was received by the project from Lower Valley Energy, and the received data is displayed in Table 12.7 and Figure 12.21.

Table 12.7. Calculated CAIDI for 16 Lower Valley Energy Distribution Feeders by Year (Minutes per Outage)

	2010	2011	2012	2013	2014
Afton	59.4	142.2	49.8	52.1	77.6
Bedford	33.6	81.6	49.8	76.0	64.0
Crystal	138.6	59.4	110.4	91.1	90.8
Drycreek	51.0	60.6	169.8	121.8	55.4
E. Jackson	126.6	9.6	147.6	120.5	82.5
Freedom	82.8	48.6	73.2	83.7	70.0
Grover	117.0	19.8	133.8	173.2	29.2
Hoback	156.6	132.0	195.0	219.2	123.8
Jackson	153.0	64.2	70.2	91.8	62.8
Kelly	250.8	123.6	162.6	95.5	451.7
Lanescreek	112.8	273.6	226.2	296.2	69.8
Moran	205.2	345.0	439.2	252.5	208.6
Pinecreek	116.4	87.0	207.0	195.0	185.0
Rafterj	72.0	52.2	125.4	114.7	133.4
Snake	155.4	138.6	117.0	138.8	133.4
Wilson	131.4	316.2	58.8	124.9	84.0

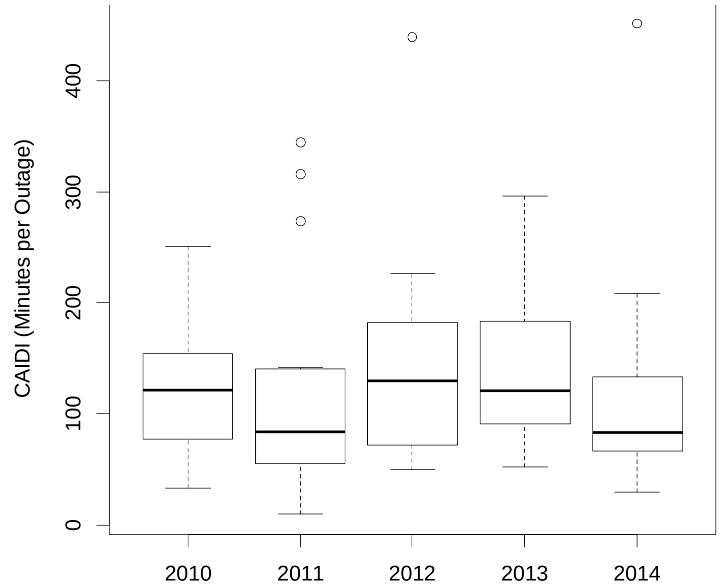


Figure 12.21. Quartile Plots of Calculated CAIDI for 16 Lower Valley Energy Distribution Feeders by Year

12.4.2 Analysis of Trends in the Reliability Indices

Further analysis was conducted to determine whether subtle, significant differences could be detected between the years. The cooperative had reported that the system became useful beginning in 2011. The project looked at this separation, but the separation between other successive years was also tried. The populations of feeder indices before and after the separation were treated as independent populations and were tested using the Student's t-test in the R software environment. The null hypothesis was that the index remained unchanged or had increased across the separation.

The null hypothesis could not be confidently rejected for any of the four possible separations of years or for any of the three tested reliability indices. In fact, the null hypothesis might be accepted when testing SAIFI indices for two of the possible partitions. With better than 95% confidence, SAIFI was found to have *increased* either after year 2011 or 2012. This finding should not be too surprising, given that a consistent increase was observable in Figure 12.19. The increase was about 0.6 outages per year, on average, beginning in 2013.

The project could find no evidence that reliability indices had been reduced during the project term. Of course, it is possible that an impact occurred and was overwhelmed by other natural and induced influences.

12.5 Adaptive Voltage Regulation

With the help of voltage data from its AMI system, Lower Valley used adaptive voltage control and CVR to reduce its peak demand. The voltage was reduced on four feeders and affected about 2,340 premises. The Lower Valley Electric costs of the adaptive voltage regulation system are displayed in Table 12.8.

The annualized costs of the voltage regulation system and its components are listed in Table 12.8. The utility elected to include the costs of the existing load tap changers that are critical to this system and are the system's greatest cost component. The AMI system is next most expensive and is required to verify that end-of-line voltages remain acceptable.

Table 12.8. Lower Valley Electric Costs of Adaptive Voltage Regulation System

	Shared Component Allocation (%)	Annualized Component Cost ($K)	Allocated Annual Component Cost ($K)	
Existing Load Tap Changers	100	201.5	201.5	
Advanced Metering			91.4	
• AMI System (backbone)	25	129.8		32.4
• AMI Meters (with no assets, but affected by CVR)	50	44.9		22.5
• AMI Meters (premises with IHD and affected by CVR)	33	2.5		0.8
• AMI Meters (premises with DRU and affected by CVR)	33	2.5		0.8
• AMI Meters (with IHD and DRU, and affected by CVR)	25	2.6		0.7
Existing SCADA System	100	32.9	32.9	
Ongoing O&M Costs	100	30.5	30.5	
Integration Between Aclara and Ilex	100	10.4	10.4	
Administrative	100	3.7	3.7	
Operations Labor[(a)]	50	6.7	3.4	
Outbound Modulation Unit	50	6.2	3.1	
Outreach and Education	100	2.9	2.9	
Control and Receiving Unit	50	3.8	1.9	
Modulation Transformer Unit	50	3.6	1.8	
Backroom Data	50	3.2	1.6	
Control Network – Power Line Carrier	50	1.3	0.7	
Digital Channel Bank Network Multiplexer	50	0.9	0.5	
Existing Regulators	100	0.0	0.0	
Total Annualized Asset Cost			**$351.9K**	

(a) The cost of Operations labor was shared between this asset and the DRU/AMI system (Section 12.4).

12.5.1 Characterization of Asset System Responses

The impact of the dynamic voltage management was to be observed on the East Jackson feeder. The diurnal, seasonal, weekday load shapes for this feeder are shown in Figure 12.22. Northwest Wyoming is a relatively cold location. The feeder is winter-peaking, showing two clear peak hours during winters. Only a single afternoon peak is evident on weekdays in summer, the season that has least load. It supplies East Jackson, Wyoming, which is relatively urban for Wyoming. The feeder phase voltage is 7.2 kV, and average load during the project was measured as 8.7 MW.

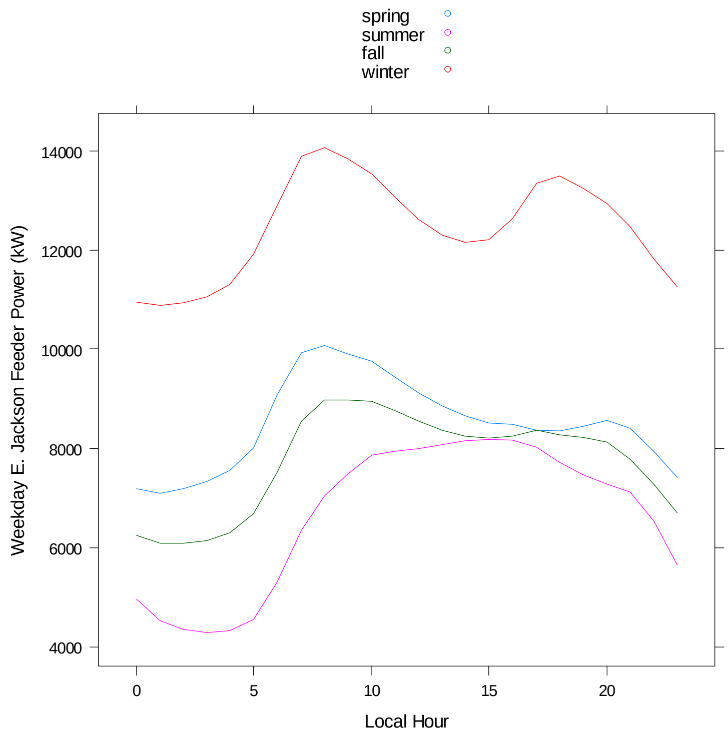


Figure 12.22. East Jackson Diurnal Distribution Feeder Weekday Load by Season

Lower Valley Energy reported the system status to the project, stating when the voltage was being actively reduced on the feeder and when the voltage was normal, unaffected by the voltage-management system. The cooperative told the project the system was in place and active at the end of summer 2012. The status “Early Unknown” was applied to the status of the voltage-management system prior to this date.

Figure 12.23 shows the average per-unit voltage on the East Jackson feeder throughout the data collection period. The base feeder voltage is 7.2 kV. The cooperative separately supplied the three individual phase voltages. The average of the three phases is shown. Values below 0.96 were ignored to better show the intentional voltage reductions.

Lower Valley Energy appears to have practiced voltage reduction for months prior to the date on which the system was declared installed and useful. These events were not analyzed. Thereafter, the voltage was reduced periodically. The correlation between the reported events (blue markers) and reduced average voltage levels is strong, but it is not perfect. There are unreported voltage reductions (red markers at reduced voltages) and reported events while the voltage is in its normal range.

A large range of voltages were measured while the system was active and the voltage reduced. A string of voltage measurements is often observed from about 0.98 to 1.02 pu. Some of this variability might follow from active voltage-management control that is more complex than a simple changing of transformer tap settings. The voltage is managed to carefully move into and out of the reduced-voltage range. Thirty premises meters had been identified at feeder locations that typically had the lowest voltages. These meters were subdivided into eight smaller groups that were sequentially polled at 2-minute intervals. All the meters were polled in 16 minutes.

Data was removed at times that status was undefined and during periods that the feeder power was anomalous. This explains the data gaps in Figure 12.23. The project also eliminated one of the events (event 12) that was reported to the project to have lasted for 11 days but did not coincide with any voltage reduction.

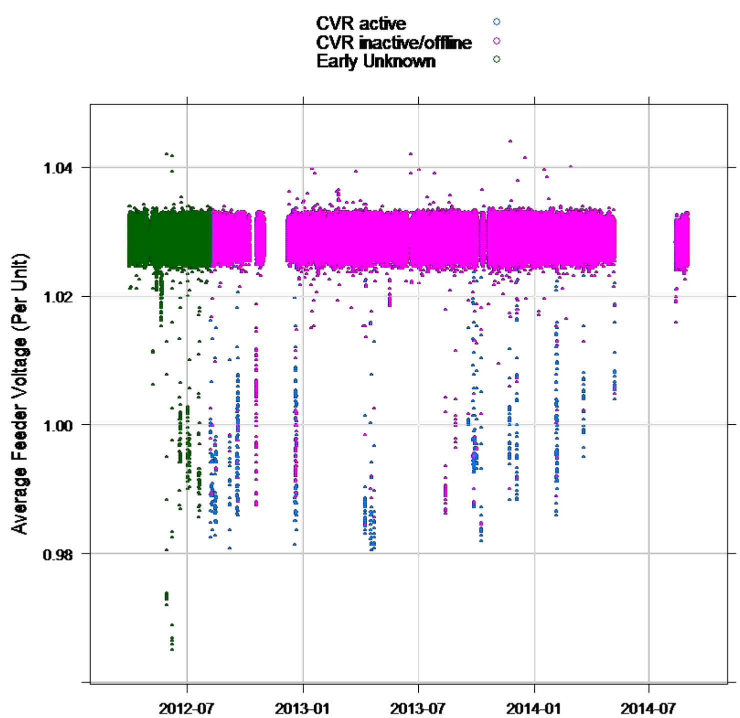


Figure 12.23. Per-Unit Feeder Voltages and their Reported Statuses

Figure 12.24 shows the distribution of per-unit feeder voltages, including a group of reduced voltages centered at about 0.995 per unit. The distribution was necessarily magnified to better show the infrequent reduced voltages. Voltages below about 0.96 were deemed to be predominantly anomalous readings not important to show.

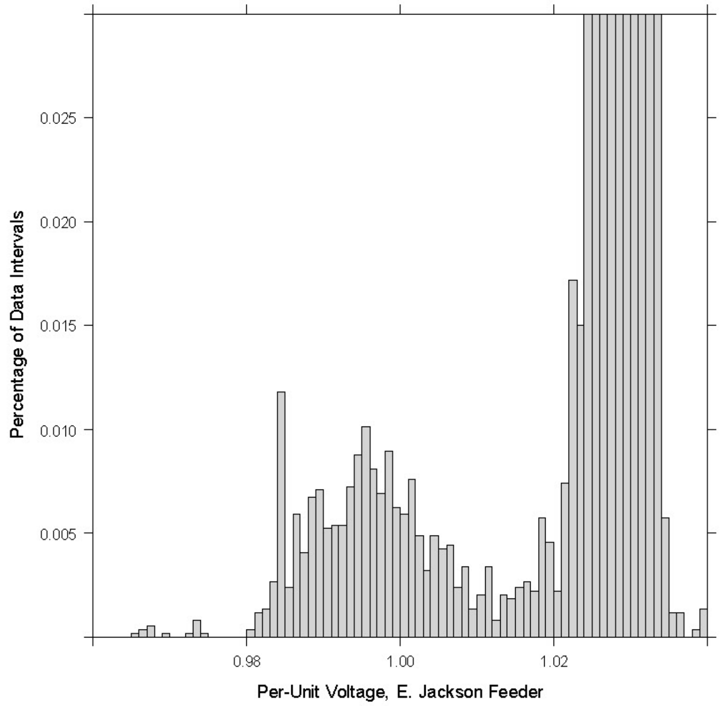


Figure 12.24. Magnified Part of Per-Unit Voltage Distribution that Shows Reduced-Voltage Occurrences

Review Table 12.9 that shows how the reduced voltages were managed over the project months. The reported voltage-management event periods were used to separate monthly voltage measurements into groups—measurements while the voltage was managed, and not. For months when events were reported, this table shows the average percent voltage reduction during the reported events. Voltage was not managed every month. In months that voltage management was exercised, the relative reduction in voltage varied greatly from an insignificant reduction during October 2012 to an average 3.4-% reduction April 2013.

Table 12.9. Average Percent Change in Feeder Voltage for Months in which the Voltage was Modified

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2012	-	-	-	-	-	-	-	−2.7	−1.4	−0.0	-	−1.8
2013	-	-	-	−3.4	-	-	-	-	−1.7	−2.4	−2.5	−2.4
2014	-	−1.9	−2.2	-	−1.9	-	-	-	-	-	-	-

In aggregate, the difference between managed voltages and unmanaged voltages during the project is summarized by Figure 12.25. In this figure, the narrow range of normal per-unit voltages is shown at the left. The box contains 50% of the measurements, and the bars most of the remaining ones. A string of outlier measurements is also shown. The box to the right similarly shows the reduced-voltage measurements. The groupings are fully determined in this plot by the reported status of the voltage-management system.

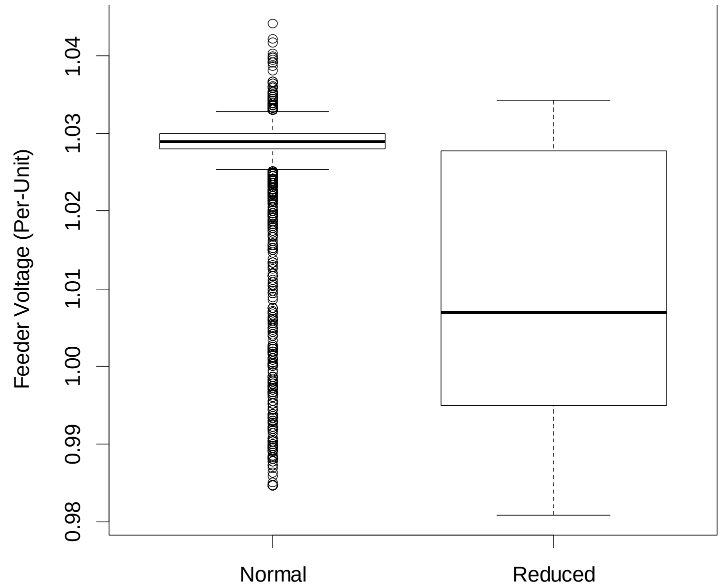


Figure 12.25. Quartile Plots of all the Measured Per-Unit Feeder Voltages at the Normal and Reduced-Voltage Settings

The cooperative reported 38 events from August 2012 through May 2014. The dates, times, and durations of these events are listed in Table 12.10.

Table 12.10. List of Events when Lower Valley Energy Reduced the East Jackson Feeder Voltage

Event	Year	Month	Day	Weekday	Local Hour	Minute	Duration (d h:m)
1	2012	Aug	9	Thursday	9	0	1:00
2	2012	Aug	10	Friday	8	0	2:00
3	2012	Aug	15	Wednesday	8	0	2:00
4	2012	Aug	16	Thursday	8	0	2:00
5	2012	Sep	7	Friday	8	5	1:55
6	2012	Sep	12	Wednesday	7	30	2:30
7	2012	Sep	13	Thursday	7	0	3:00
8	2012	Sep	14	Friday	7	0	3:00
9	2012	Sep	18	Tuesday	7	10	2:50
10	2012	Sep	19	Wednesday	7	0	3:00
11	2012	Sep	20	Thursday	7	15	2:45
12[a]	2012	Oct	8	Monday	8	0	11 1:20
13	2012	Oct	24	Wednesday	7	10	2:20
14	2012	Oct	25	Thursday	7	0	3:00
15	2012	Oct	26	Friday	7	0	3:00
16	2012	Nov	27	Tuesday	7	5	2:35
17	2012	Dec	19	Wednesday	6	0	3:00
18	2012	Dec	20	Thursday	6	0	3:00
19	2012	Dec	21	Friday	6	0	2:35
20	2013	Apr	8	Monday	7	25	2:05
21	2013	Apr	17	Wednesday	6	55	1:20
22	2013	Apr	18	Thursday	6	45	1:35
23	2013	Apr	23	Tuesday	8	0	1:30
24	2013	Sep	19	Thursday	7	0	2:30
25	2013	Sep	26	Thursday	7	15	2:15
26	2013	Sep	27	Friday	7	0	2:30
27	2013	Sep	28	Saturday	7	35	1:55
28	2013	Oct	1	Tuesday	7	50	1:40
29	2013	Oct	9	Wednesday	7	35	1:35
30	2013	Nov	22	Friday	6	45	2:45
31	2013	Dec	4	Wednesday	10	55	3:10
32	2014	Feb	4	Tuesday	7	0	2:30
33	2014	Feb	5	Wednesday	6	45	2:45
34	2014	Feb	6	Thursday	6	45	2:45
35	2014	Feb	27	Thursday	8	15	0:05
36	2014	Mar	19	Wednesday	7	0	2:10
37	2014	May	7	Wednesday	7	5	2:20
38	2014	May	12	Monday	6	45	2:05

(a) Event number 12 was very long, and the voltage did not appear to have been reduced during this event. It was excluded from most analysis.

Lower Valley Energy initiated voltage-management events at times that might reduce their system peak demand. The next figures demonstrate the months, days, and hours that the events were begun.

The reported events were quite evenly distributed among calendar months, as is shown by Figure 12.26. The exception is September, in which the cooperative initiated almost three times as many events as in other calendar months.

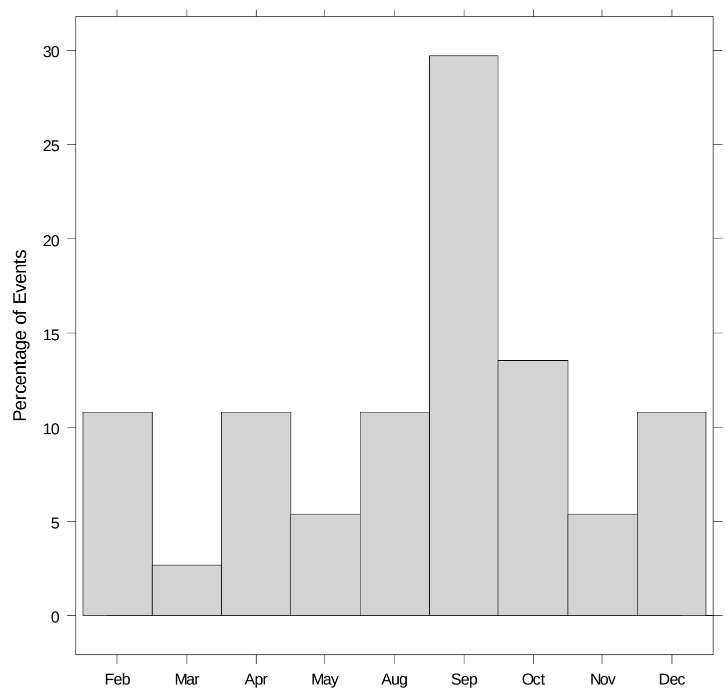


Figure 12.26. Distribution of the 37 Event Months that Lower Valley Energy Reduced the Voltage on the East Jackson Feeder

Lower Valley Energy tended to exercise the voltage-management system in the middle of the work weeks as shown in Figure 12.27. Wednesdays and Thursdays were preferred days for conducting voltage management. The system was activated only once during a weekend day. This distribution ignored 11-day-long event 12.

Because the system was exercised predominantly during weekdays, the results of project analysis can only be stated for weekdays. Results will not necessarily help predict performance of the system on weekends. The shape of the weekday distribution weights the results, but there are typically small differences in load behavior from one weekday to another.

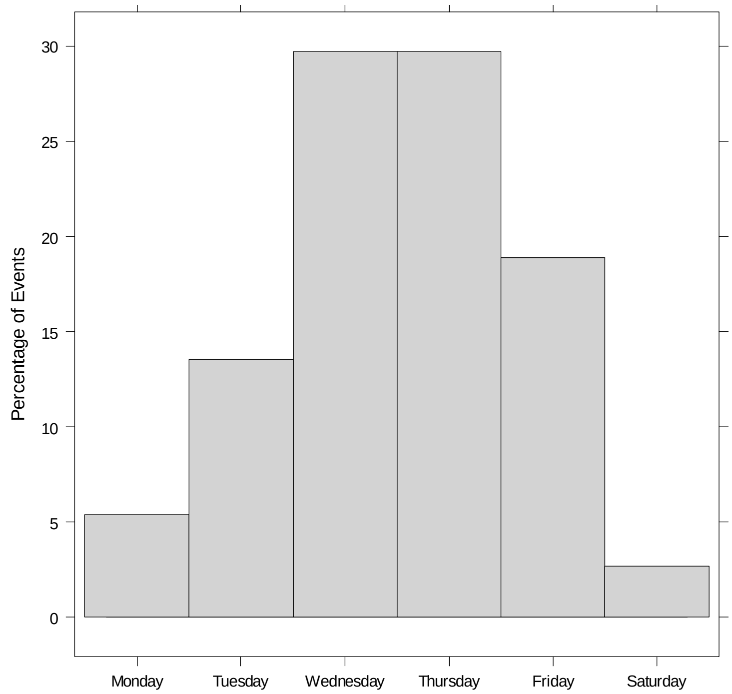


Figure 12.27. Distribution of Weekdays that Lower Valley Energy Reduced East Jackson Feeder Voltage

Lower Valley Energy initiated the events tightly clustered around 07:00 local Mountain Time, as shown in Figure 12.28. All of the events were initiated between 06:00 and 10:00 local Mountain Time. Again, Lower Valley Energy exercised the system only during these limited morning hours. Analysis results do not necessarily extend to afternoon and other times of the day.

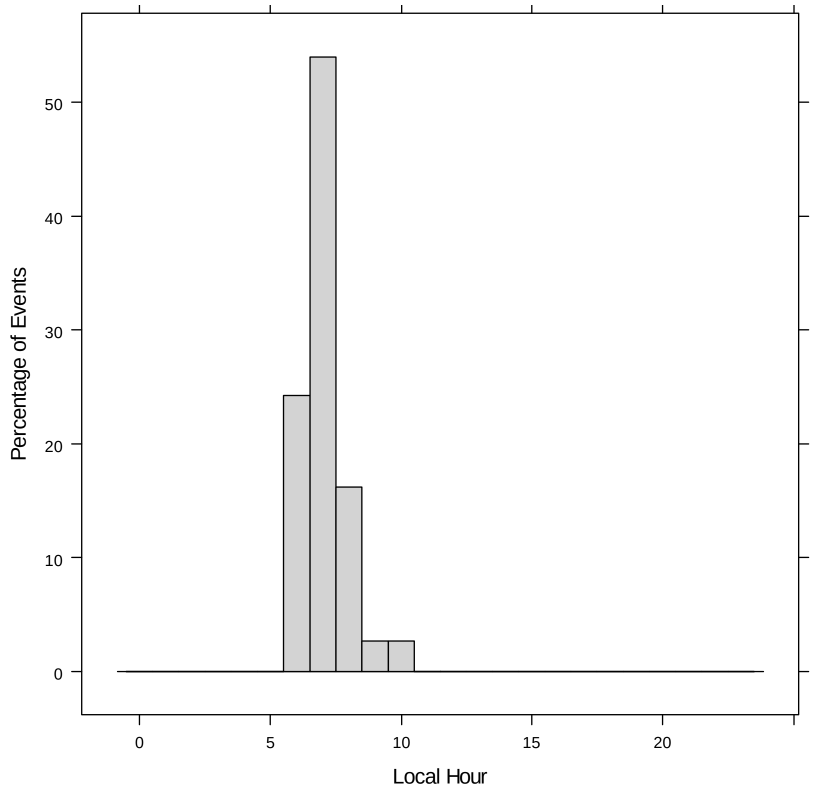


Figure 12.28. Distribution of Hours (Mountain Time) that Voltage-Reduction Events Began

12.5.2 Performance of the Dynamic Voltage-Management System

A parametric linear model of the East Jackson feeder load was created to model power as a function of month, day of week, hour, and ambient temperature. The event periods reported for both DRU engagements (Section 12.3) and voltage reduction were not used during the training of the model. The East Jackson distribution load was then predicted from this parametric model as a comparison baseline. This comparison baseline should have predicted what the load might have been had DRU curtailments and voltage reductions not occurred.

Unless otherwise stated, analysts removed eleven-day-long event number 12 prior to the calculations in this section. Voltage was never actually reduced during that event period. The analysis did not include any impacts from voltage reductions that were evident in Figure 12.23, but had been reported by Lower Valley Energy with the status "Early Unknown."

The average change in power that may be attributed to the dynamic reduction of voltage on the East Jackson feeder was a reduction of 300 ± 100 kW. This is about 3.4% of the average load on the East Jackson feeder during the project (8.7 MW).

While DRUs (Section 12.3) were colocated on the East Jackson feeder, were engaged at similar event times, and admittedly confounded these results, only about 32 premises on this feeder possessed DRUs. The total impact from the DRUs should therefore be less than about 15 kW during events, presuming that each premises might experience a reduction of about 0.5 kW. The rebound impact might be twice as great, adding perhaps 30 kW where the DRU rebound hour happened to fall within a voltage-reduction event on the East Jackson feeder. These impacts are smaller than the uncertainty of the distribution impact.

No significant rebound impact could be observed in the hours after feeder voltage had been returned to normal levels. None was expected. The analysis might have been polluted by rebound impacts from the 32 DRUs that were colocated on the East Jackson feeder.

An average power reduction was observed at the feeder level throughout the days on which voltage-reduction events had occurred. A reduction of 50 ± 30 kW was observed throughout event days. This is probably evidence that the reduction in power during events was truly conservation and not a shift of energy consumption from event hours to other hours. That is, this magnitude is very close to the 300 kW reduction through a 3-hour event (i.e., 900 kWh), averaged though an entire event day. That calculation would yield an expected reduction of about 38 kW, virtually indistinguishable from the analysis result.

Analysts also looked at the impact at the premises level. The aggregate average hourly load of a set of premises supplied by the East Jackson feeder was compared against that of premises that were supplied by other feeders. The comparison group members were selected to possess neither IHDs (Section 12.2) nor DRUs (Section 12.3). Each test group had about 24 premises. The per-premises power measurements from the comparison group were scaled to have the same averages and standard deviations as the test group each project month. The measurements were further scaled globally to have the same average power on an hour-by-hour basis. This diurnal correction was conducted because the test and comparison populations differed somewhat in their diurnal consumption patterns.

The short-term reductions, however, appeared to have *increased*, not decreased, consumption at premises. Per-premises power consumption was found to have increased 120 ± 60 W during events. Consumption increased even more during the hours following the voltage reductions—200 ± 100 W. This rebound impact might have been confounded somewhat by coincident rebounds among the East Jackson test-group premises that also had DRUs. This method also indicated a strong increase in consumption by premises throughout event days.

The cumulative distribution energy impact and the cumulative event hours are shown in Figure 12.29 for the period from 2012 until the end of data collection in August 2014. A consistent reduction in energy is evident through 2012, but the trend disappeared for the remainder of the project through 2013 and 2014. No seasonal trend can be claimed because the reduction evident in late 2012 became an increase in late 2013 during the same months.

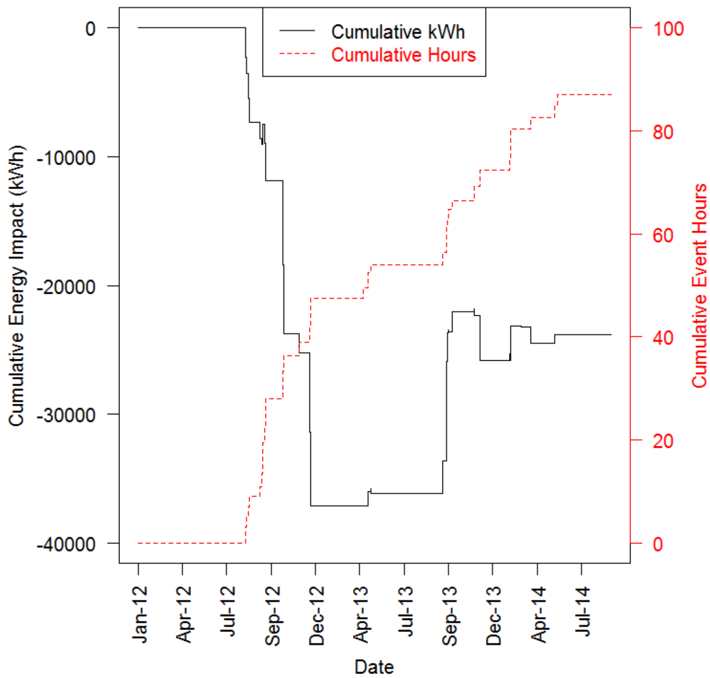


Figure 12.29. Cumulative Energy Impact and Cumulative Event Hours when Distribution Voltage was Reported to have been Reduced

The cumulative distribution energy impact was plotted against cumulative event hours in Figure 12.30. The slope of this curve is the power reduction during voltage-reduction events on the East Jackson feeder. Again, the trend toward power reduction reversed itself and disappeared after about 45 event hours. It is tempting to report the slope of only the downward trend, but the project reports instead the average slope from the top left to the last event hour. A fair demonstration evaluation must report the long-term benefit, which may be affected not only by performance of the system itself, but also by fatigue and by the quality of measurement and validation processes.

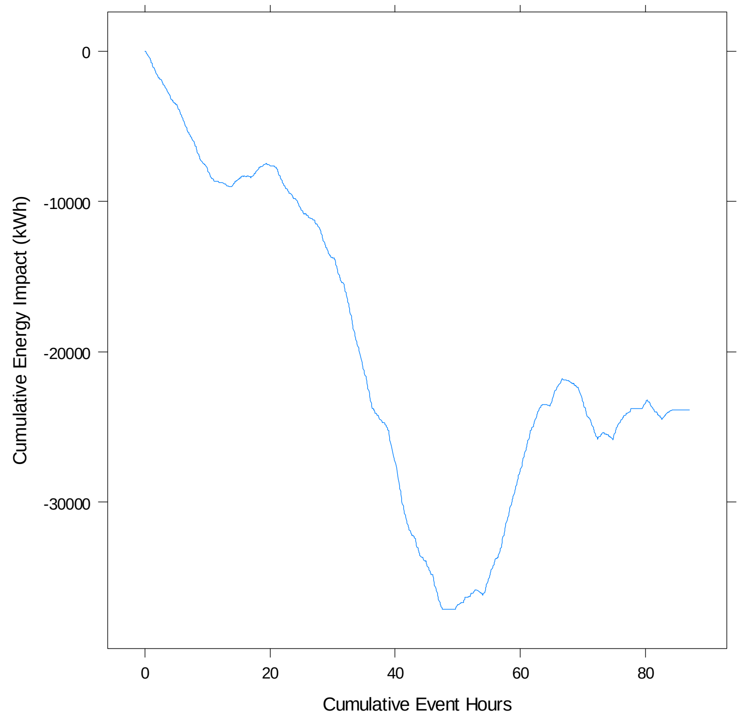


Figure 12.30. Cumulative Energy Impact as a Function of Cumulative Event Hours

The majority of the impacts of CVR are often attributed to end uses and less to distribution efficiency (Schwartz 2010). A contrary result was observed by the project when it evaluated consumption by residential premises. Figure 12.31 shows both a cumulative energy impact per residential premises and a cumulative sum of customer event hours. The cumulative energy curve rarely decreases throughout the project duration as customer event hours are accumulated. This trend may be seen more clearly in Figure 12.32, where the cumulative energy impact per residential premises has been plotted against accumulated customer hours. This cumulative premises impact was based on a set of about 24 premises that were on the affected feeders but did not possess other devices that might confound the results. The average per-premises consumption of this test group was compared against that of a normalized control group, also having 24 premises, that was unaffected by the voltage reductions.

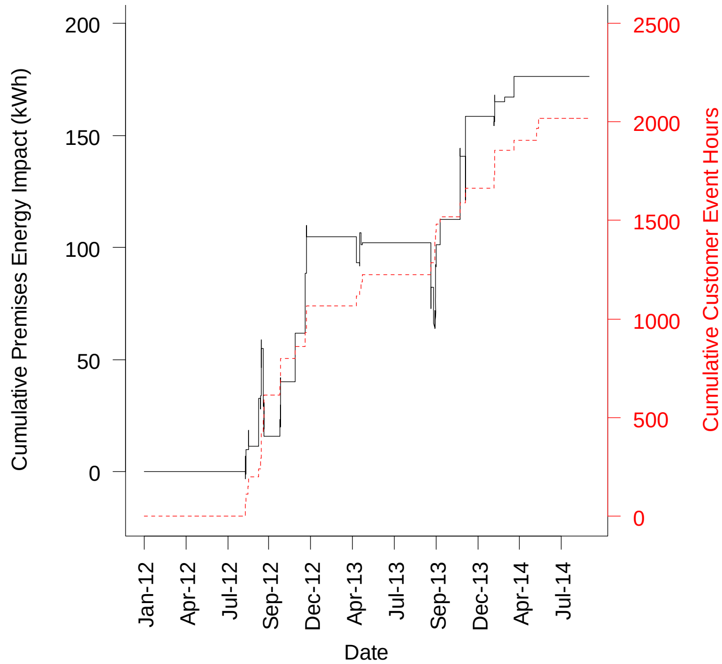


Figure 12.31. Cumulative Energy Impact and Customer Hours at Premises that were Affected by Dynamic Voltage Reductions

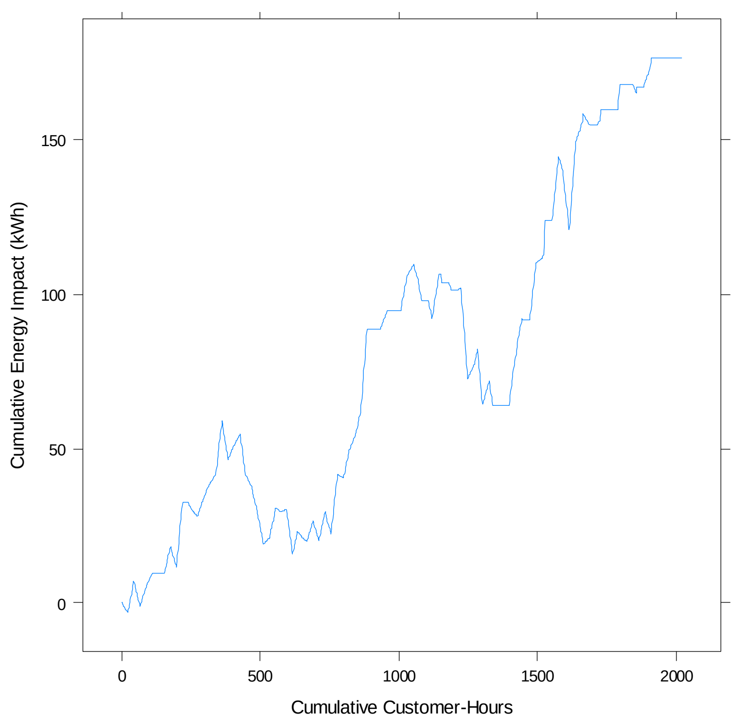


Figure 12.32. Cumulative Premises Energy Impact as a Function of Cumulative Customer Event Hours

The average trend is consistent at premises. A seasonal influence might exist at premises; perhaps consumption increased at premises in late fall and early winter, but was flat or even decreased in other seasons.

The results of Figure 12.31 and Figure 12.32 used a comparison baseline, in which consumption at residential premises on the East Jackson feeder was compared against a normalized comparison group that was composed from consumption at residential premises on other feeders. The project repeated this analysis at the premises level using a linear model baseline having parameters for month, day of week, hour of day, and temperature. Similar results and trends were observed, giving the project additional confidence in this finding.

In conclusion, a strong reduction in feeder distribution power was observed for the typically 3-hour-long voltage-reduction events on the East Jackson feeder, but the impact diminished after a strong showing in 2012. However, the project found evidence that consumption at residential premises actually increased during these events. Test groups would need to be better controlled for the potentially confounding impacts from DRUs (Section 12.3) and repeated to confirm the contrary result at the premises level.

12.6 SVC for Power Factor Improvement

Lower Valley Energy procured and installed a 600 kVAr Asea Brown Boveri SVC, at the Bondurant, Wyoming, site, supplied from the Hoback substation. The device is shown installed in Figure 12.33. When its SVC was engaged, Lower Valley expected to decrease about 300 kVAr for power factor and voltage support. The device was installed to be remotely controllable via a remote terminal unit and existing SCADA at the substation. Automation was installed to make the SVC responsive to reactive-power readings from the distribution lines that supply the substation.

This site is at the remote end of a long, lightly loaded distribution line. The power factor on this line was heavily leading, and the SVC somewhat improved the power factor. The power factor lagged only during cold-load-pickup periods immediately following power outages. By improving power factor, the cooperative hoped to reduce line losses and to improve voltage management on the feeder.

Figure 12.33. 300 kVAr SVC at the Bondurant, Wyoming, Site

The annualized costs of the system and its component parts are listed in Table 12.11. The largest cost is that of the SVC, followed by upgrades to the existing SCADA communications, upgrades to the site, O&M, outreach, and administrative costs. Many component costs were shared between this and other asset systems that Lower Valley Energy installed at the Bondurant site or at the Hoback substation, Wyoming. The total annualized cost is estimated to be $43.8K.

Table 12.11. Lower Valley Electric Costs of Power Factor Improvement System

	Shared Component Allocation (%)	Annualized Component Cost ($K)	Allocated Annual Component Cost ($K)
SVC	100	34.1	34.1
Existing SCADA System[a]	25	25.7	6.4
Operations Labor[a]	25	5.5	1.4
Building	25	3.9	1.0
Building Site	25	2.1	0.5
Ongoing O&M Costs[a]	25	0.6	0.2
Outreach and Education[a]	25	0.6	0.2
Administrative[a]	25	0.4	0.1
Quest[b]-to-SCADA Comm. Fees	25	0.2	0.1
AMI Meter	100	0.0	0.0
Total Annualized Asset Cost			**$44.0K**

(a) These components were shared among the SVC system (Section 12.6), battery storage system (Section 12.7), PV array (Section 12.8), and wind turbine (Section 12.9).
(b) Quest is a well-known communications provider.

12.6.1 Project Data and Operation of the SVC

The SVC was installed and operational by mid-2012. The cooperative submitted data stating when the SVC system became active and inactive. This list is believed accurate because its transitions were found to coincide well with observed changes in power factor and reactive power near the site and at the Hoback substation. The transitions were infrequent and irregular.

The cooperative supplied the following data for the evaluation of the SVC system performance: They supplied 5-minute reactive-power data from a point on the source side of the SVC site, which is quite remote from the Hoback substation. They also submitted data from the Hoback substation for this feeder, including phase currents, phase voltages, and power factor.

These data were all found to have “stuck” at certain magnitudes many of the project months. These data periods were removed from analysis. Hoback feeder data was not available after March 2014.

The project also observed that the test feeder’s phase-c voltage had been periodically modified several months during the project. The project elected to remove these periods from analysis because the impact of voltage management on the feeder could confound observations of the SVC system’s performance.

In the figures shown in this and following sections, the data has been filtered to remove time periods that had “stuck” values and potentially confounding voltage management.

Other variables were necessarily calculated from the data that was received. For example, the real and reactive-power totals for the Hoback feeder were calculated from the phase voltages, phase currents, and phase power factors. Because the power factors were crudely discretized, the calculated power levels were also discretized and were of limited value for quantitative analysis.

Figure 12.34 shows another interesting observation about voltage management on this feeder. Starting November 2013, Lower Valley Energy raised the voltage on this feeder. This is different from the previously described voltage management that affected only one of the feeder phases. The figure shows the magnitudes of a phase-averaged feeder phase voltage. Because the phases of this feeder are relatively poorly balanced, care was taken in the calculation of the average feeder voltage, weighing the contribution of each phase by its current magnitude. A step is clearly evident in the resulting voltage. Note also the key of this figure that helps demonstrate the infrequent and irregular pattern of SVC system engagement. The change in feeder voltage may confound observation of SVC system performance. The discussion that follows may refer to “early” and “late” voltage-management periods for the data before and after November 1, 2013.

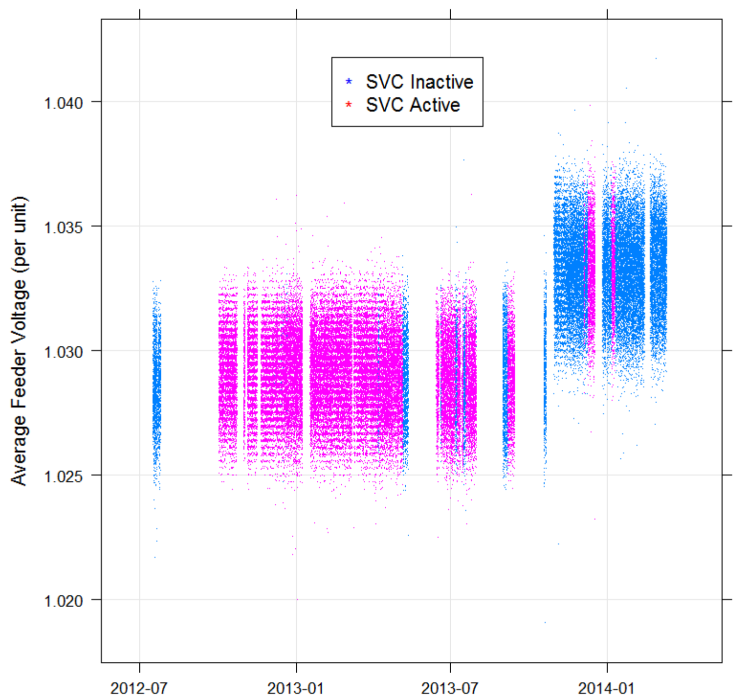


Figure 12.34. Averaged Per-Unit Feeder Voltage for the Hoback Feeder that was Affected by the Project’s SVC

Figure 12.35 shows the reactive-power data series for each of the three feeder phases at the Hoback substation. The phases are not well balanced, as often occurs for long, rural feeders. Jumps may be seen in the reactive power of each phase. These jumps are attributable to changes in the engagement of the SVC system. The jumps are greatest for the phase that has the greatest reactive-power magnitude (the pink markers). The project did not further investigate differences between the performance on each phase, but it seems that the SVC also contributes to balancing the three phases.

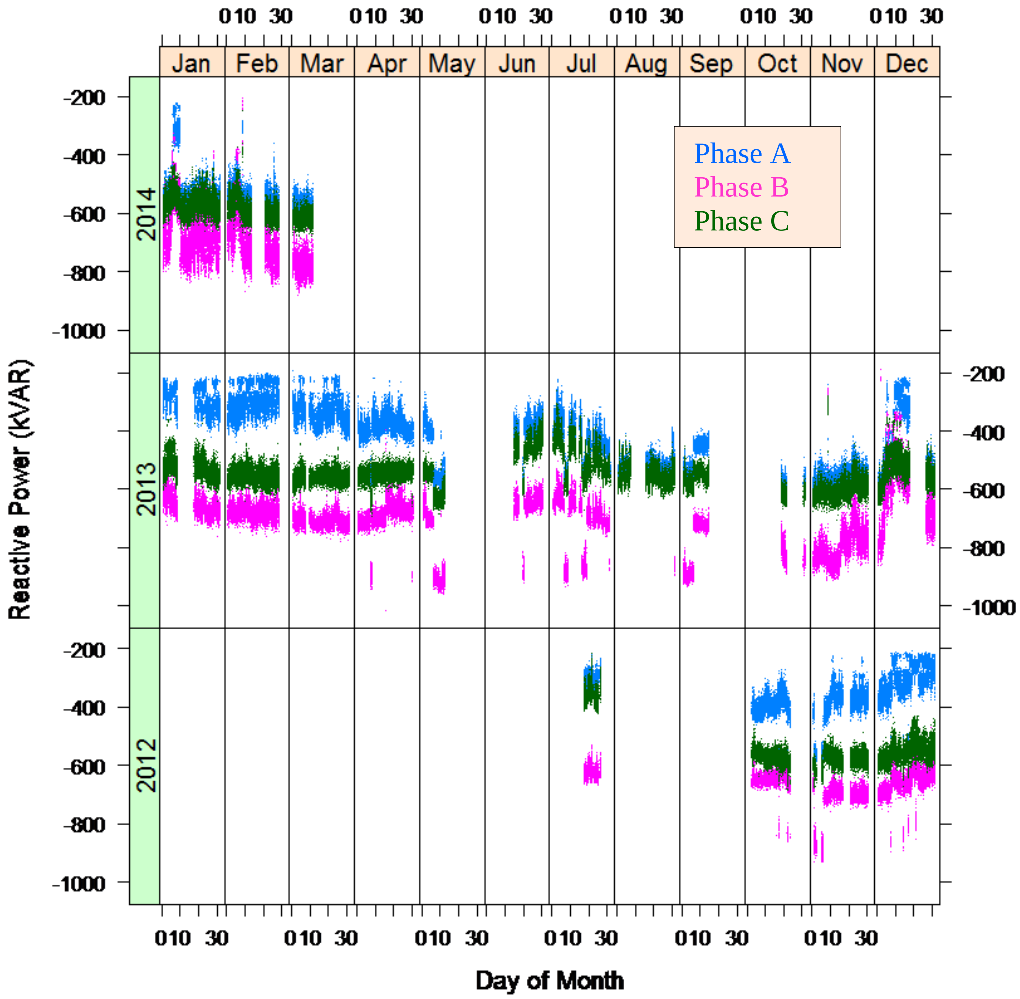


Figure 12.35. Reactive Power Levels of the Three Hoback Feeder Phases that were Affected by the Project's SVC

Figure 12.36 similarly shows the individual power factors for each feeder phase at the Hoback substation. Again, it is evident that the phases are imbalanced and do not possess comparable power factors. The phases' capacitive power factors improve during the cold months when demand is greater. The worst phase consistently has power factors as low as 0.5. Such a low power factor means it is taking approximately twice as much distribution current to serve the load as would be needed if the power factor were unity.

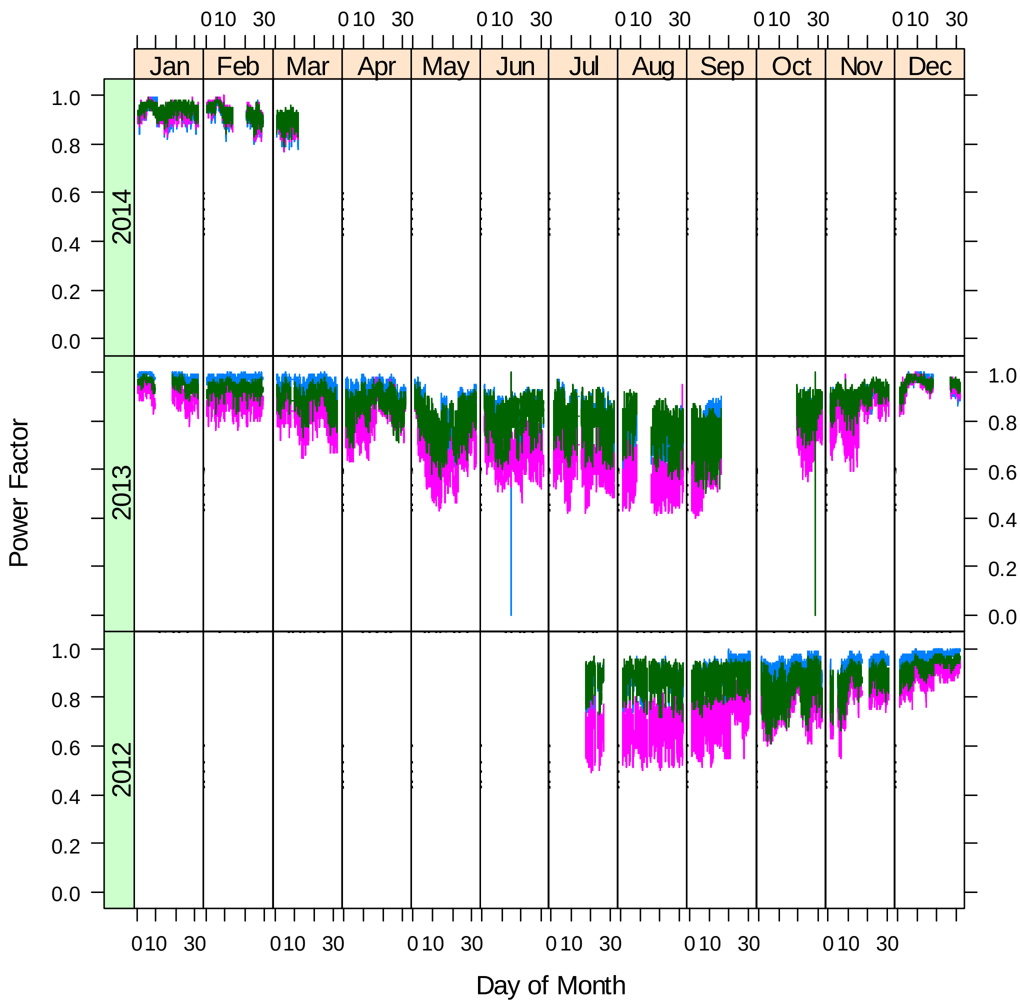


Figure 12.36. Three-Phase Power Factors at Hoback Substation that were Affected by the Project's SVC

12.6.2 Performance of the SVC

The impact of SVC system operation is more clearly seen in Figure 12.37, which displays the calculated total feeder reactance (note that the vertical axis is negative). The circuit is capacitive regardless of the status of the SVC system. The magnitude of reactive power is usually diminished (less negative) when the SVC system is active (pink markers). The exceptions early in the project may have resulted from misstatements of the SVC system engagement periods.

By inspection, the differences in total reactive power when the SVC system is engaged are about 500 kVAr. Analysts presumed that the entire difference was attributable to the SVC system, but it is possible that other non-project assets were also being engaged by the utility on this feeder.

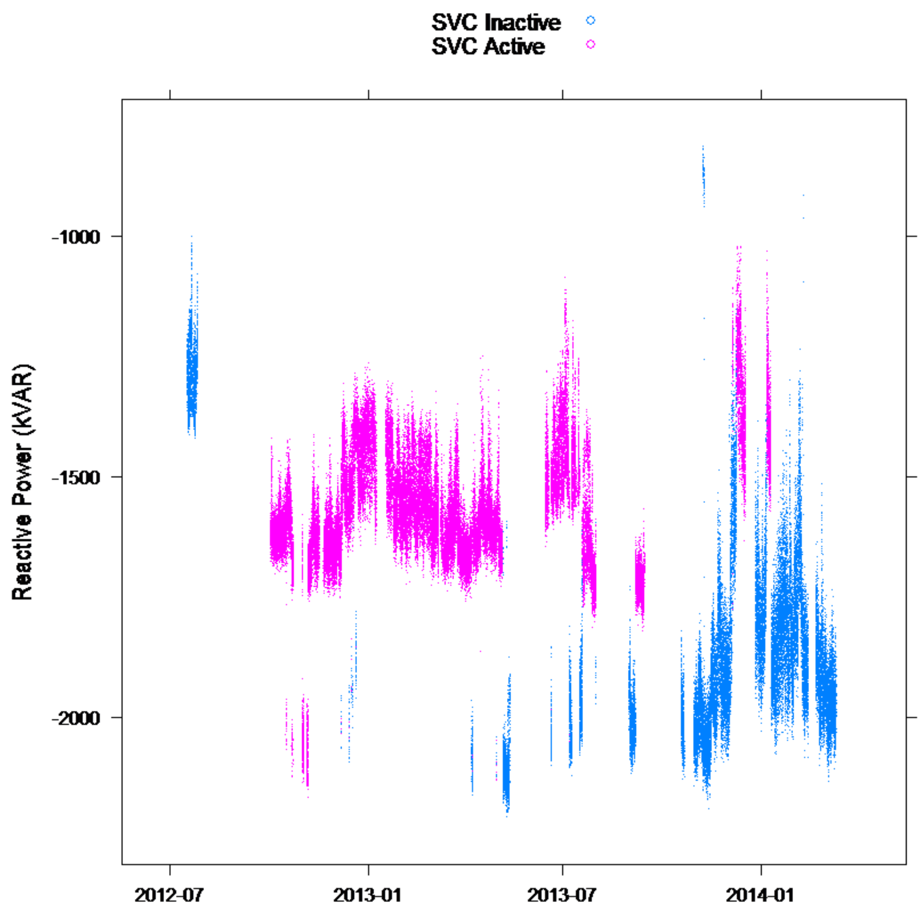


Figure 12.37. Feeder Reactive Power for the Hoback Feeder that was Affected by the Project's SVC

The project also calculated and reviewed feeder real power. See Figure 12.38. If the operation of the SVC system affected real power on the feeder, it is not evident by inspection. Lower Valley Energy activated the SVC system throughout most of the winter peak months of 2012–2013, but they activated the system less frequently during the winter of 2013–2014. The demand was greater during the second winter than it had been during the first. This pattern challenged the project as it attempted to quantify an energy impact from the raw data. Differences in the power demand over time may be caused by weather, affluence, load growth, or other influences.

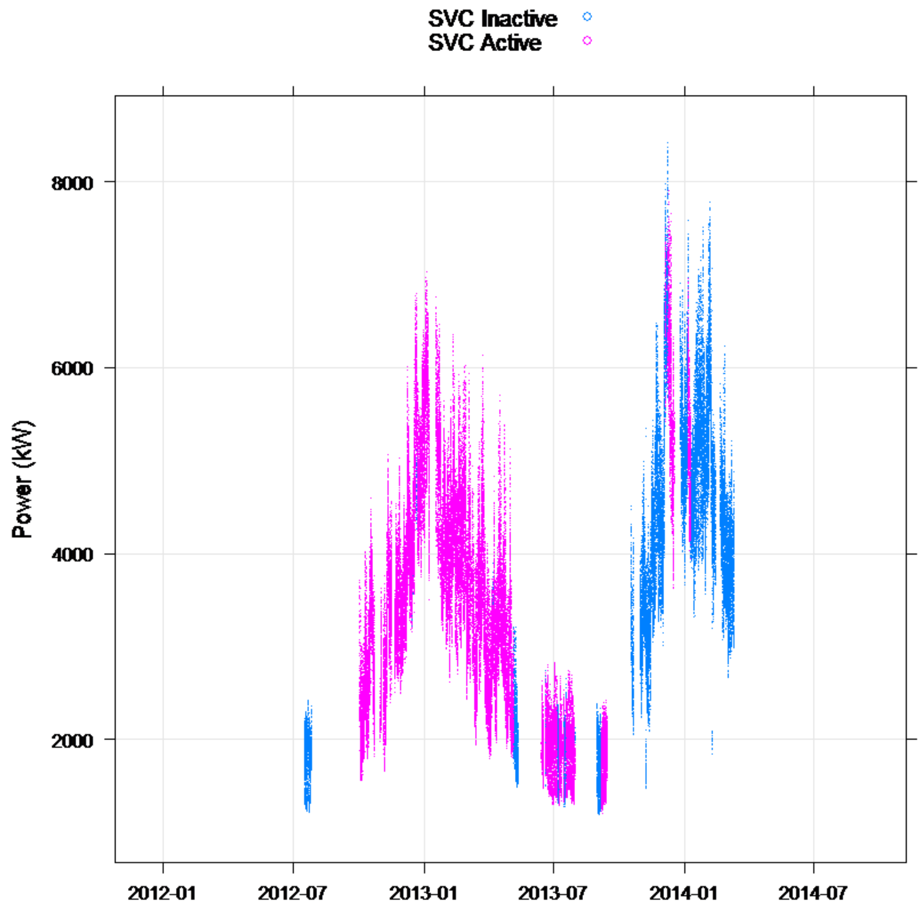


Figure 12.38. Feeder Power for the Hoback Feeder that was Affected by the Project's SVC

The influence of the SVC operation on feeder reactive power at the Hoback substation is more easily observed and quantified than its impact on real power. Figure 12.39 displays the quartile populations of the reactive power that has been calculated for the feeder. The magnitudes of the reactive power are significantly less (i.e., less negative) when the SVC system was active. The left two boxes represent the measurements prior to April 2013 when the feeder was being managed to a lower voltage than thereafter. The right two boxes are from the latter period when feeder voltage was higher. The impact is similar for both feeder voltages.

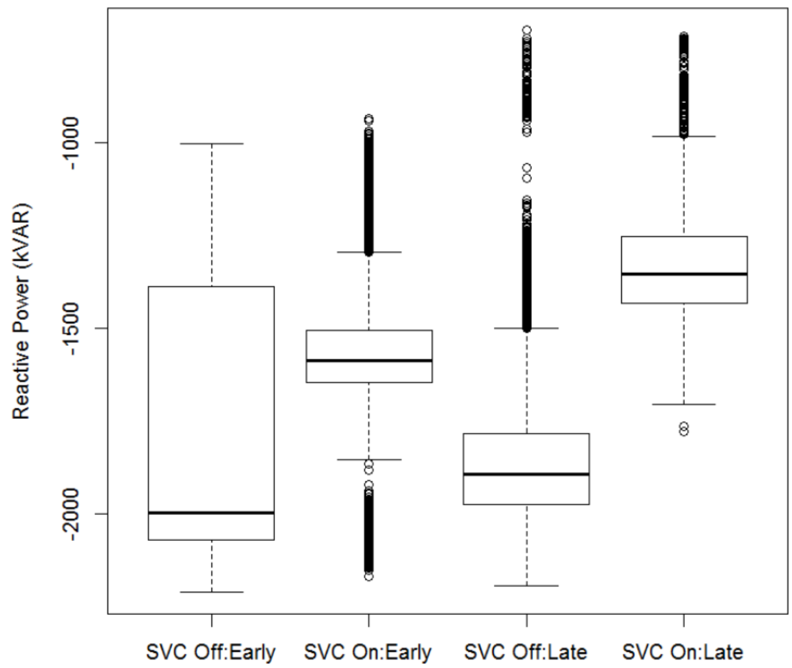


Figure 12.39. Averaged Feeder Reactive Power with the SVC Inactive and Active under the Lower ("Early") and Higher ("Late") Voltage Strategies

A similar quartile representation, this time displaying feeder power factor, is shown in Figure 12.40. The improvement in median power factor when the SVC system becomes engaged prior to April 2013 is remarkable. The power factors were improved after April 2013 when the voltage was managed at a greater magnitude, but the SVC system still appears to further improve the power factor when it becomes activated. Analysts did not discern whether the improvement after April 2013 could be attributed to the change in voltage management. It is possible that other utility circuit improvements also came into play at that time. Upon its review, Lower Valley Energy staff thought this improvement might be attributable to an additional set of reactors that were activated on the circuit on July 8, 2013.

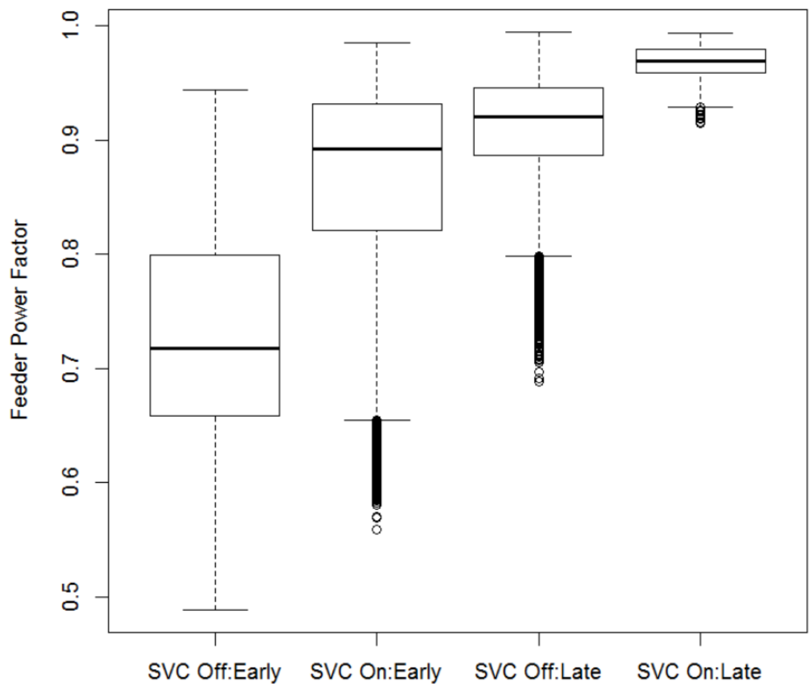


Figure 12.40. Feeder Power Factor with the SVC Inactive and Active Under the Lower (“Early”) and Higher (“Late”) Voltage Strategies

The project attempted to quantify power savings directly from feeder power calculations and a modeled baseline, but this effort was not successful. No significant real-power difference could be determined. A carefully designed experimental procedure would need to be devised and followed to observe the change in power, which might be estimated to be on the order of 1.3% of the supplied feeder load.[1] Perhaps the SVC system should be engaged and disengaged alternating days during the trial to mitigate the many other influences that potentially confounded the project’s efforts to measure this small change in feeder load.

A relative impact may be stated. The averaged feeder power factors are summarized in Table 12.12 according to the reported status of the SVC system and whether the measurements were taken at the new, higher feeder voltage level after April 2013, or not. Based on these ratios of power factor, the project concludes that distribution currents were reduced 11% prior to April 2013 and 6.2% after that date. The reduction of distribution line losses when the SVC was active was therefore approximately 30% prior to April 2013 and 13% thereafter.

[1] This estimate presumes 5% of feeder load is lost in the distribution feeder and that the SVC operation reduces those losses by 25%.

Table 12.12. Feeder Power Factors as affected by SVC Status and Voltage-Management Status

	Before April 2013	After April 2013
SVC Inactive	0.753	0.912
SVC Active	0.861	0.968

The project has reservations claiming these impacts on power factor. As was described earlier in this section, the SVC was engaged dissimilarly in the two project years. Power factor is a function of total real power, and load is greatest in winter for the Lower Valley Energy service territory. Because the asset was not applied similarly by year and by season, seasonal variations might well confound the project's measurements of impacts of the SVC.

12.7 Battery Storage System

Lower Valley Energy installed a 125 kW, 250 kWh battery storage system. Ideally, for the demonstration, this battery storage system was to be controlled automatically according to advice received from the project's transactive system. Except for a week in January 2014, Lower Valley Energy primarily controlled this system by direct demand-response commands and restricted the engagements to limited time periods.

The battery system was controlled and monitored via a remote terminal unit and the existing SCADA system at the Hoback substation. When a control signal was received by the asset system, it either supplied energy to or stored energy from the feeder line. Lower Valley Energy sought to reduce its peak demand, reduce distribution line losses, and defer distribution capacity investments on the distribution supply to the Hoback substation.

A transactive system function was created by the project to advise the battery system when to generate or store energy. This function advised the battery system when to charge and discharge at optimal times using the predicted transactive incentive signals (TISs). The function could be configured with the system's energy storage capacity, charge and discharge power ratings, minimum and maximum states of battery charge, and a parameter with which the system's owner could modify the aggressiveness of their battery management strategy. An aggressive strategy permits many rapid changes between charging and discharging, whereas a conservative strategy might limit the system to few charge cycles per month. It will be shown in this section that Lower Valley Energy was unable to capitalize on this function and automate the control of the battery system. The function remained configured more aggressively than the utility could allow based on the very limited number of lifetime duty cycles promised by the battery system.

The annualized costs of the system and its components are listed in Table 12.13. The largest cost was the battery system itself with the requisite power inverter. Other costs included upgrades to SCADA communications at the substation, working with the project to implement an instantiation of the transactive system at the site, labor, site upgrades, outreach, and O&M costs. The total annualized cost was estimated to be about $55.8K.

Table 12.13. Lower Valley Electric Costs of Battery Storage System

	Shared Component Allocation (%)	Annualized Component Cost ($K)	Allocated Annual Component Cost ($K)
100 kW Battery/Inverter Package	100	41.8	41.8
Existing SCADA System[a]	25	25.7	6.4
Transactive Signal	50	8.4	4.2
Operations Labor[a]	25	5.5	1.4
Building	25	3.9	1.0
Building Site	25	2.1	0.5
Outreach and Education[a]	25	0.6	0.2
Ongoing O&M Costs[a]	25	0.6	0.2
Administrative[a]	25	0.4	0.1
Quest-to-SCADA Communication Fees	25	0.2	0.1
AMI Meter	100	0.0	0.0
Total Annualized Asset Cost			**$55.8K**

(a) These components were shared among the SVC system (Section 12.6), battery storage system (Section 12.7), PV array (Section 12.8), and wind turbine (Section 12.9).

12.7.1 Characterization of the Battery System and Data

The function that generated advice for the battery system concerning when it should charge or discharge its stored energy operated continuously from November 2013 through the end of data collection at the end of August 2014. The function's outputs are shown in Figure 12.41. The outputs are intentionally scaled from −127 to 127 (i.e., 1 signed byte) so that a designed function, once designed, could be applied to other similar asset systems. Ideally, only configuration changes are needed to move the function from one battery system to another. The full range of advisory signal outputs represents the entire range from fully charge (negative advisory signal) to fully discharge (positive advisory signal).

The function scheduled the battery's state of charge based on the transactive incentive signal at the Lower Valley Energy site. The advice would induce the battery system owners to discharge energy at relatively high incentive costs and to recharge at low ones. If properly configured, the function takes into account the battery system's capabilities and the owners' preferences for the frequency of charge and discharge cycles. The function did not optimize the value of the battery system as had been hoped for these reasons:

- The TIS was not used for billing. The region's and Lower Valley Energy's benefits were not correctly represented in the transactive signals at this site.
- Lower Valley Energy did not configure the function and heed the advice the function gave. The system offered far fewer lifetime charge and discharge cycles than had been anticipated.
- Persistent issues with the forecast within the transactive signals caused the function to advise nonsensical outcomes. Lower Valley Energy lost confidence as these issues remained unresolved.

Figure 12.41 also shows the statuses that were reported to the project by Lower Valley Energy concerning whether the system was charging (blue markers), discharging (red), or idle (green). These indicators changed character in late March 2014 when the transactive function became updated and improved and was reinstalled at the utility site. The system was exercised regularly after March 2014, so the project limited its analysis to the months March through July 2014.

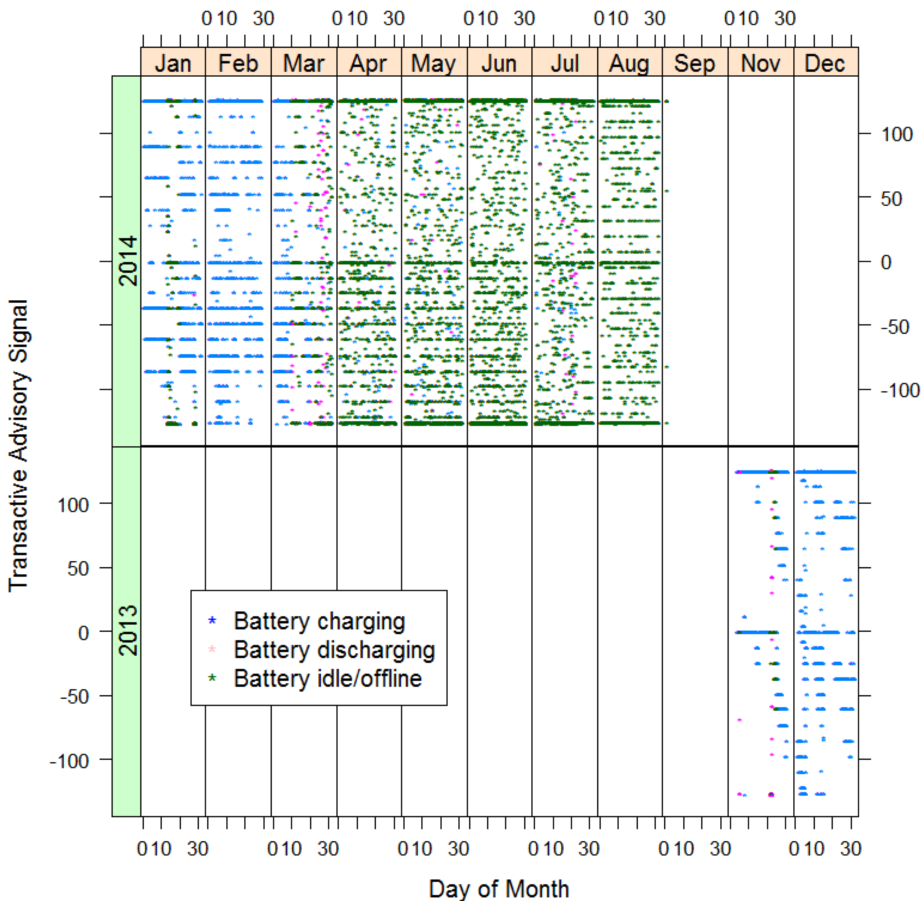


Figure 12.41. Output of the Transactive Function that advised the Battery System when to Charge (negative) and Discharge (positive)

The actual battery power data from this period is in shown in Figure 12.42. Again, this figure includes color coding for the data according to the system status reported by the utility to the project. The reported statuses are meaningful. The periods of maximum charging and discharging are pretty accurately assigned to the data near positive and negative 20 kW, respectively. The status “idle/offline” was applied over a large range of intermediate charging and discharging rates.

Analysts were not able to resolve with Lower Valley Energy staff the discrepancy between the power levels that were received in the utility’s data and the claim that this was a 125 kW, 250 kWh storage system. The project’s power data seems to be about one-fifth the magnitudes that should be expected from this battery system. Utility staff reported that metering was poor, and utility staff had even regenerated electronic data manually from paper results at one time. This question remains unresolved. The impacts may be up to 5 times greater than those reported in this section.

The project has low confidence in the data prior to March 20, 2014. No useful data was received after July 2014. Data from June 2014 was unavailable.

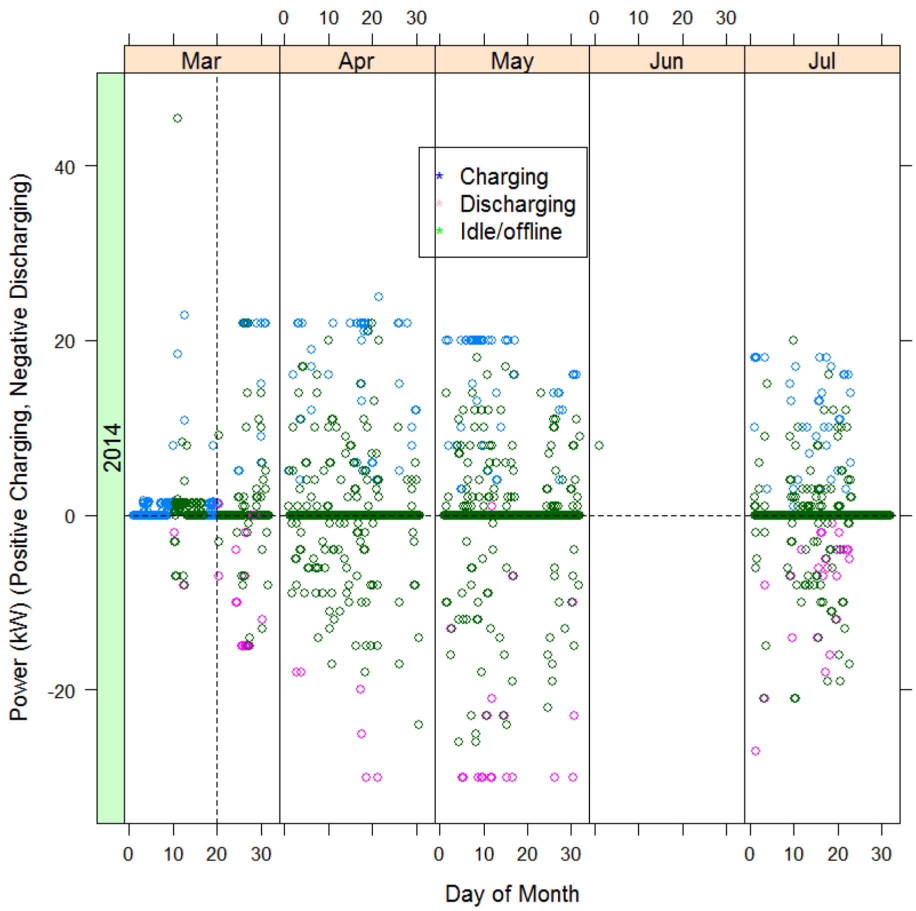


Figure 12.42. Power Data as the Battery System is Charged (Positive) and Discharged (Negative) During Spring and Early Summer 2014

The next figure, Figure 12.43, drives home the point that battery system operations and the advice from the transactive system were not well correlated. This figure uses data from March–May and July 2014. The quartiles of battery power are plotted for each transactive advisory level. If the advice from transactive function were followed, there would be a strong negative correlation. The battery was requested to discharge its stored energy (negative power) when the advisory signal was positive.

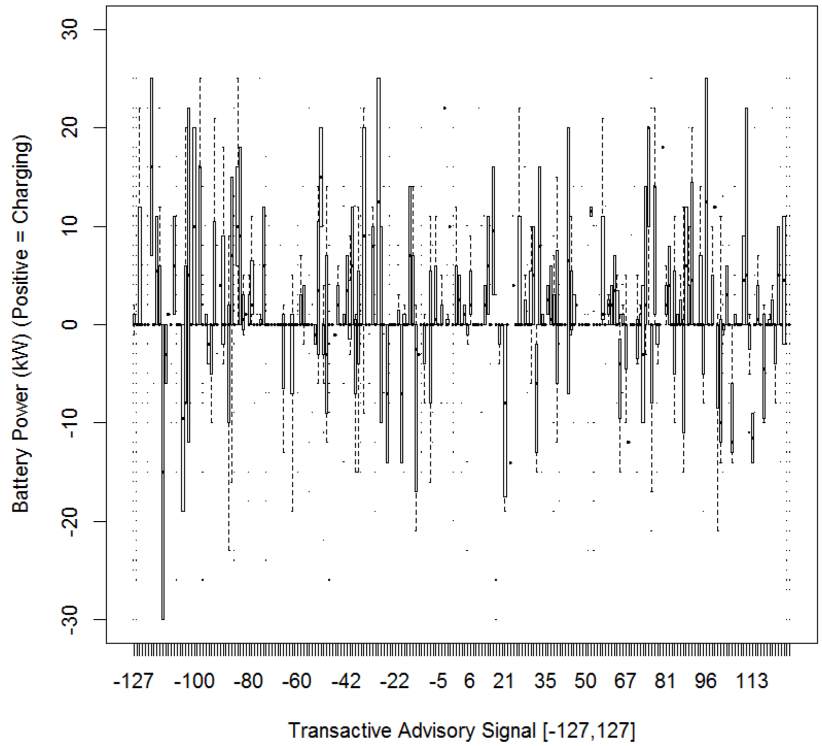


Figure 12.43. Correlation of Battery System Charging and Discharging to the Output of the Transactive System Function that Advised the System when to Charge (transactive signal is negative) and Discharge (transactive signal is positive)

12.7.2 Performance of the Battery System

Lower Valley Energy conducted tests January 13–17, 2014 in which they cautiously had the battery system track advice from the transactive system. According to Lower Valley Energy's test report,[1] only 700–800 discharge and charge cycles are anticipated for the life span of the battery system. This would allow perhaps eight cycles per month. The transactive function was configured to allow multiple daily cycles at the time of this testing.

To ease the potential stress on the battery system during this testing, the utility narrowly limited its operating hours and the system status. Discharging was permitted 07:15–09:30 and 16:30–19:00 Mountain Time when it coincided with a load-shedding level calculated by the utility's engineers. Similarly, charging was permitted from 22:00–03:00 Mountain Time. The system was commanded to charge if it had not reached 118 kWh by 03:00.[2]

[1] Dory, H. January 20, 2014. *Lower Valley Energy Battery Controller Test*. Lower Valley Energy report concerning battery system tests that were conducted January 13–17, 2014. Lower Valley Energy, Jackson, Wyoming 83001. (unpublished).

[2] The transactive function preferably receives updates from the system concerning its state of charge. This feedback was not implemented in this instantiation.

The utility observed unacceptable fast changes in the advisory signal. For example, the signal was observed to have changed from advising full charging (−126) to idle (0) in five minutes. This behavior might have been mitigated by eventual improvements in the function that allowed the system to perform fewer charge and discharge cycles. The utility also observed a pronounced dip in the TIS each day at 07:00. They hypothesized that this dip might have corresponded to regional operations in the Pacific Time Zone that were conveyed to the site through the transactive system. Peak incentive signals rarely occurred during the utility's peak during the testing.

The capabilities of the battery system were observed to change during testing. The testing was halted after less than a week.

Thereafter, Lower Valley Energy controlled the system to more directly address system peak. The daily pattern is evident in the quartile graph of Figure 12.44. Battery power levels are displayed for each local Mountain Time hour. The median battery power each hour is usually zero, as is indicated by the diamond-shaped markers in this figure. The battery system is frequently idle. This figure includes data from March 20 through July 2014 when data quality was good and the system was being routinely exercised. While there is much diversity in day-to-day operations, the system primarily discharges (negative power) near the daily peak hours and recharges elsewhere during the day. The power capacity of the system is being cautiously employed.

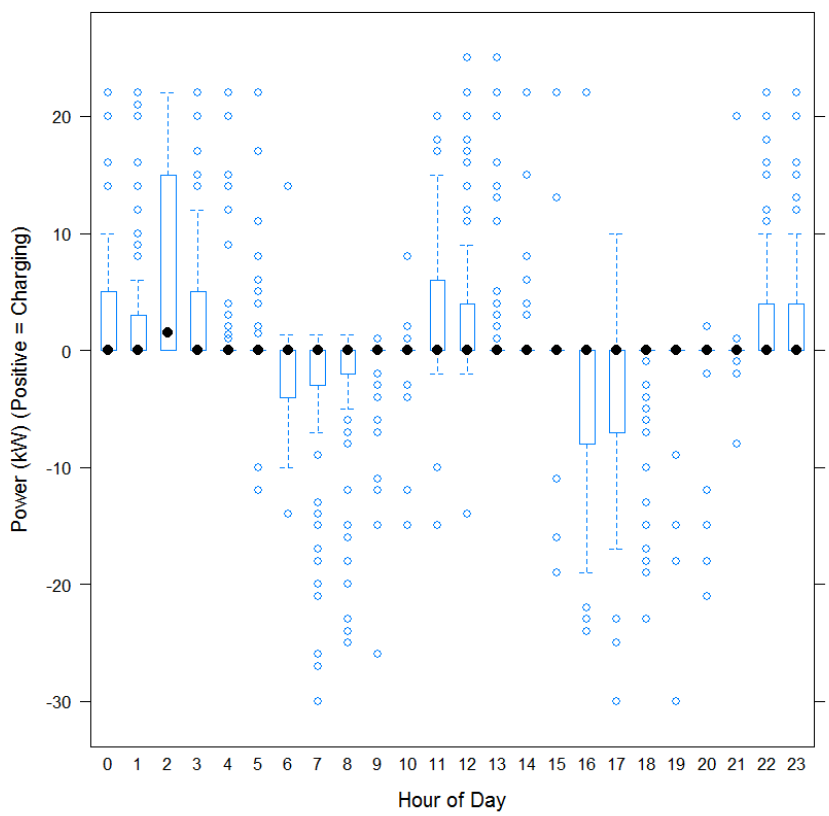


Figure 12.44. Quartile Battery Power each Hour of the Day (Mountain Time) from March 20 through July 2014. The diamond markers are median values for each hour. The boxes and whiskers represent approximately one-fourth of the data each hour.

The observance of this daily charging and discharging pattern is clearer in Figure 12.45 that shows the hourly average charge and discharge rates during the same time period. On average, the utility displaced a little more than 4 kW during peak morning and afternoon hours. The system was charged at almost 7 kW in the hour between 02:00 and 03:00.

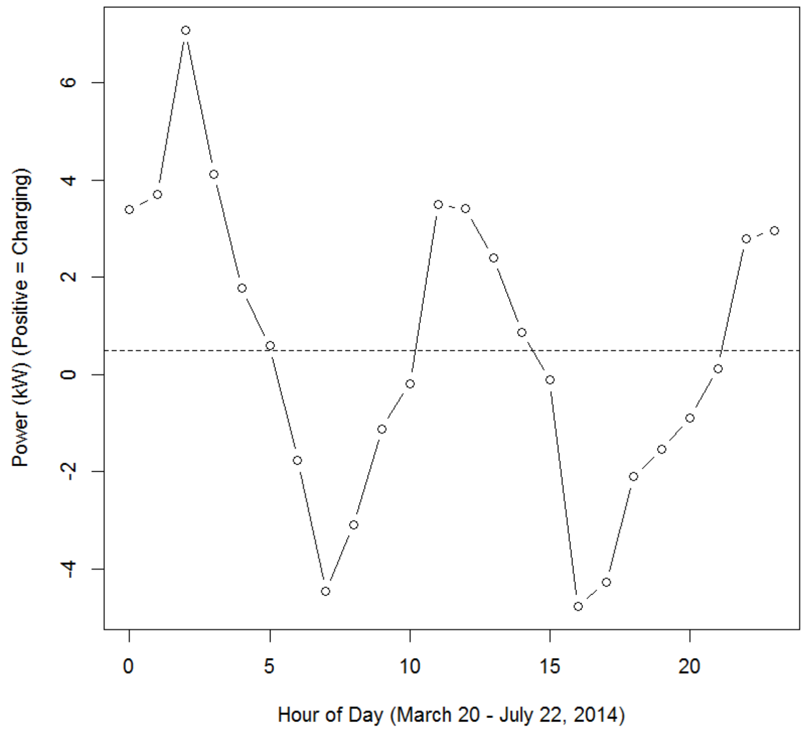


Figure 12.45. Average Battery Charge or Discharge Rates each Hour for the Period from March 20 through July 2014

It had appeared in Figure 12.44 that the battery system might charge more than discharge. This conjecture was tested by summing cumulative energy exchange during the period from March 20–May 31, 2014 (see Figure 12.46). This figure shows cumulative energy—both charging and discharging—plotted against the hours that the system was available or active. The cumulative energy rises steadily over the hours. The system consumes energy over time. This might be an indicator of the inefficiency of the system. Not all the energy stored by the system is available to be reinjected back into the distribution system later. A line was fit to the data. The slope of the line is 0.64 kWh/h. While small, these losses reduce the monetary benefits available to the system, regardless of how cleverly the battery system is operated.

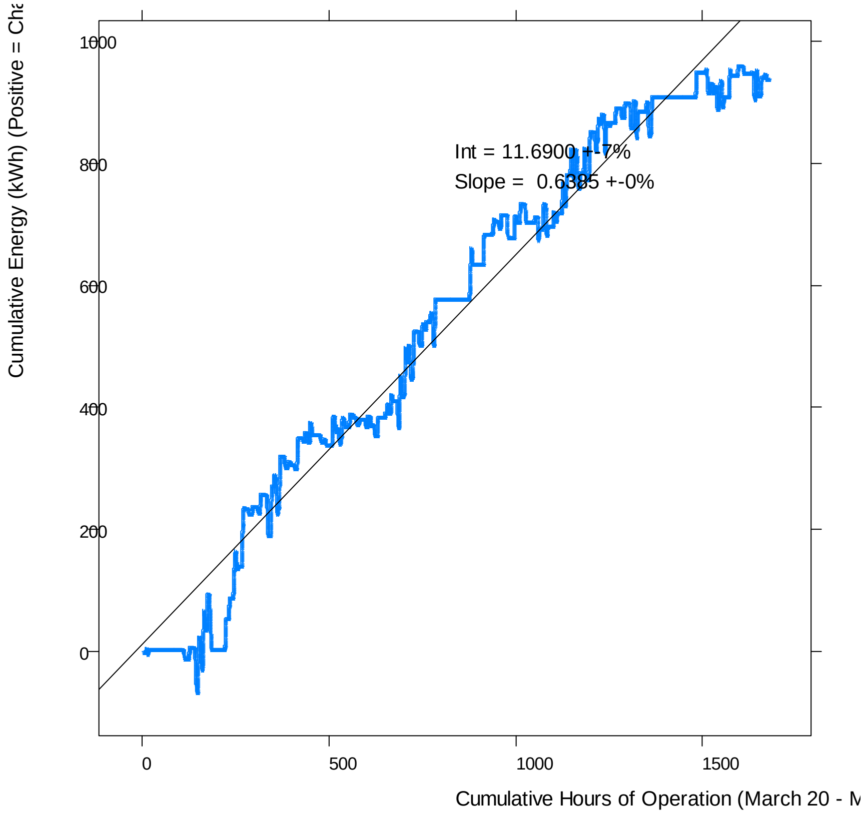


Figure 12.46. Battery System Cumulative Energy Intake over its Operating Hours. The graph shows that the system lost 640 W, on average, from March 20 through May 31, 2014.

The project has summarized the monthly and total energy and demand impacts based on the way that Lower Valley Energy operated its battery system during four months of 2014. This performance is summarized in Table 12.14. The average monthly charging and discharging rates were determined for heavy-load hours (HLHs) and light-load hours (LLHs), as defined for BPA customers (Appendix C), and these power levels were then used to extrapolate the total energy that would have been generated or consumed that month during those hour types. The standard deviations of the months' measurements were determined and used to estimate the standard error range of the monthly energy consumption values. Using BPA's most recent load-shaping rates (Appendix C), these monthly energy totals were then used to estimate the value of the net BPA energy supply that was consumed or generated during the BPA HLH and LLH hours.

A strong pattern was evident. For each month that was evaluated, the batteries performed net discharge of energy during HLH hours and net charging of energy during LLH hours. However, there was more net charging energy consumed each month during LLH hours than net discharged energy during the HLHs. Even though LLH energy supply is less expensive than HLH supply, there was a small net loss in the supply energy that was consumed and later displaced each month.

In order to predict the total yearly energy cost impact, analysts had to presume that the system would be operated for the unavailable eight months as it had been operated for the four months that good data was available. If the system were to be similarly operated through a year, the project predicts that the utility would *lose* about $69 ± 19 through the arbitrage of energy supply.

The project also evaluated the impact of operations on demand charges. Lower Valley Energy incurs demand charges most months from its energy supplier BPA. They supplied the project a list of the peak HLH hours that triggered these charges, and these example hours are listed in Table 12.14. Observe the same peak hour might be listed multiple times for any given calendar month. The project evaluated the battery power produced and consumed each HLH each month. Data was available from four months of early 2014. Presuming that battery operation during these four months was representative of the way that Lower Valley Energy would continue to exercise the system, the project estimated the monthly demand impacts. The monthly demand charges are primarily impacted by the month's BPA demand rate (Appendix C) and the difference between the peak-hour demand and the average HLH demand. This approach allows for a statistical treatment, including an estimation of the corresponding variability for the demand impacts and costs.

The monthly monetary impacts on the utility's demand charges are shown in Table 12.14. The system was operated in ways that reduced the monthly demand charges three of the four months for which data were available. The pattern of charging and discharging did not work well in July, when the exemplary peak hour was in the evening.

Presuming that the costs from the four months with data are similar to those of the remaining eight, the project estimated the yearly impact of battery operations on demand charges. The system would net charge 4.56 ± 0.73 MWh throughout the year if it were to be operated all year in the same way it had been demonstrated. The cost of the supplied energy would be a net loss of $72 ± 18 per year for the utility, based on the costs that it pays its wholesale supplier for this lost energy. The system would reduce lower Valley's demand charges by about $120 ± 40 per year.

Table 12.14. Summary of Monthly Energy and Demand Impacts from the Demonstrated Operation of the Battery System

		Energy[a] (MWh)	Energy Cost ($)	Historical Peak Hours[c]	Demand Cost[d] ($)
Jan		-	-	08:00, 07:00	-
Feb		-	-	07:00, 07:00	-
Mar	HLH	−0.37 ± 0.20	−11 ± 6	07:00, 07:00	−12 ± 14
	LLH	0.95 ± 0.21	24 ± 5		
Apr	HLH	−0.40 ± 0.12	−10 ± 3	07:00, 07:00	−24 ± 12
	LLH	0.91 ± 0.12	18 ± 2		
May	HLH	−0.36 ± 0.14	−7 ± 3	07:00, 08:00	−21 ± 9
	LLH	0.66 ± 0.13	9 ± 2		
Jun		-	-	09:00, 08:00	-
Jul	HLH	−0.29 ± 0.14	−9 ± 4	21:00	17 ± 11
	LLH	0.42 ± 0.09	10 ± 2		
Aug		-	-	21:00	-
Sep		-	-	08:00	-
Oct		-	-	07:00	-
Nov		-	-	07:00, 07:00	-
Dec		-	-	07:00, 07:00	-
Year		**4.56 ± 0.73[f]**	**72 ± 18[b]**		**−120 ± 40[e]**

(a) The total month’s energy impact is extrapolated using available power measurements and the numbers of HLH and LLH each month. Numbers are rounded to the nearest 0.01 MWh.

(b) The total year energy supply cost impact is estimated by presuming the values for the eight unmeasured months are similar to the four that were available. Numbers are rounded to the nearest whole dollar. Positive values represent increased supply cost for the utility. Positive values are utility supply costs and negative values are displaced supply costs.

(c) These are the starting hours (Mountain Time) of peak demand hours reported to the project for these months. If more than one hour is listed, the multiple hours were from multiple historical years for the given calendar month.

(d) The monthly impact on BPA demand charges uses the average impact on HLHs and the average impact on the listed exemplary peak hours. Other secondary billing impacts may come into play and were not considered here.

(e) The total yearly demand-charges impact is estimated by presuming that the eight unavailable months are similar to the four that had data available. The negative value indicates that supply costs have been displaced by the asset.

(f) This sum has been projected as if the battery system were used as it was demonstrated, but throughout the year.

12.8 20 kW Solar PV System

Lower Valley Energy installed a 20 kW solar PV generator system at its Hoback substation, Bondurant, Wyoming. The cooperative hoped to displace energy supply and learn the cost-benefit of investing in PV systems. The panels are shown during their assembly in Figure 12.47.

Figure 12.47. Lower Valley Electric Cooperative Solar and Wind Site near their Bondurant Substation

The cooperative worked with the project to estimate the PV system's annualized costs, which are listed in Table 12.15. The greatest annualized cost is that of the PV system hardware, but the utility also elected to include significant costs incurred for upgrading the substation's SCADA system to monitor the PV system. Other smaller cost components include the costs of operations, the building and building site, maintenance, outreach, administrative costs, and a cellular wireless connection to the SCADA system. The overall annualized costs are $18.8K.

Table 12.15. Lower Valley Electric Costs of 20 kW Solar Photovoltaic System

	Shared Component Allocation (%)	Annualized Component Cost ($K)	Allocated Annual Component Cost ($K)
20 kW Solar PV System	100	9.0	9.0
Existing SCADA System[(a)]	25	25.7	6.4
Operations Labor[(a)]	25	5.5	1.4
Building	25	3.9	1.0
Building Site	25	2.1	0.5
Ongoing O&M Costs[(a)]	25	0.6	0.2
Outreach and Education[(a)]	25	0.6	0.2
Administrative[(a)]	25	0.4	0.1
Quest-to-SCADA Communication Fees	25	0.2	0.1
AMI Meter	100	0.0	0.0
Total Annualized Asset Cost			**$18.8K**

(a) These components were shared among the SVC system (Section 12.6), battery storage system (Section 12.7), PV array (Section 12.8), and wind turbine (Section 12.9).

12.8.1 Characterization of the Data

The PV system was reported to be installed and useful by the end of October 2012. Lower Valley Energy submitted hourly power generation data to the project from that time through August 2014. The entire data set is shown in Figure 12.48. The data quality faltered and did not recover after mid-April 2014. The project elected to ignore the data after March 2014 and prior to November 2012. The project determined that there were 17 meaningful months having usable power data.

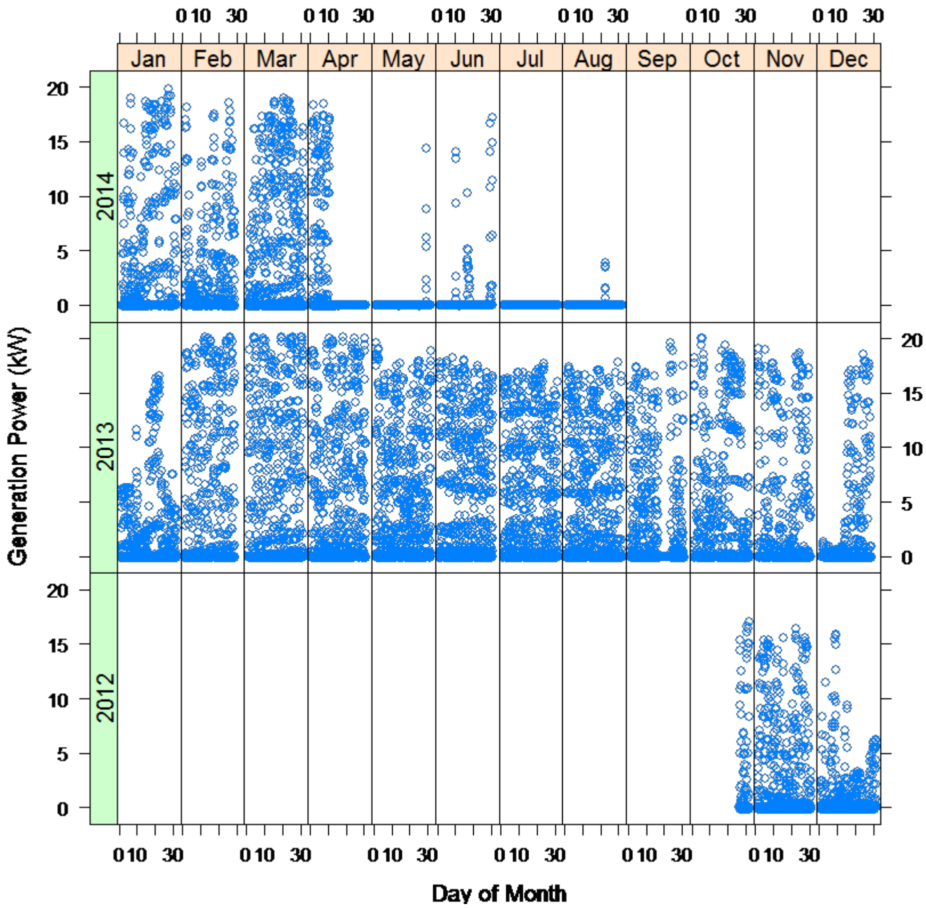


Figure 12.48. Complete Series of Solar Generation Power Data Received by the Project from Lower Valley Energy

Analysts then plotted the hourly generation pattern for each project month (Figure 12.49). The patterns are acceptable and rule out data time shifts that have plagued the project. Months that demonstrated many zero values throughout days invited further review. Closer inspection of these months showed that the system was offline the week September 16–23, 2013. Occassional system outages for maintenance or other purposes are probably characteristic of this system's operation. The project therefore chose not to remove this or any other apparent outages from analysis.

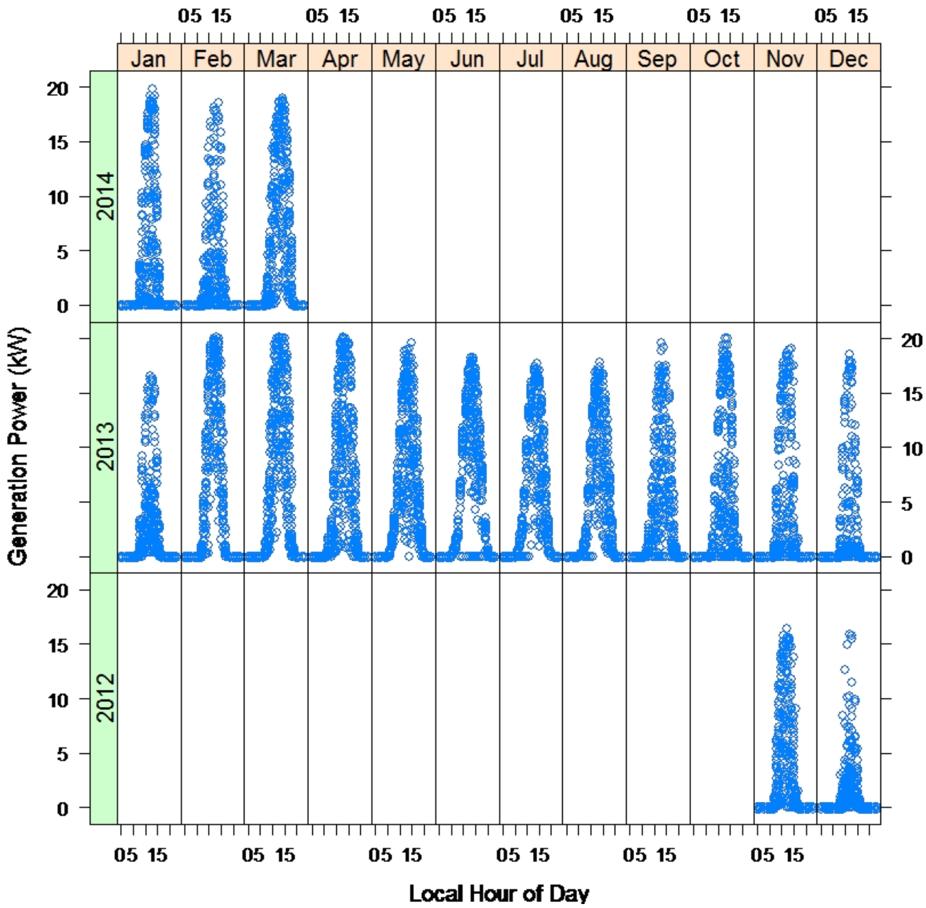


Figure 12.49. Solar Power by Local Hour and by Project Month after Filtering Out Early 2012 and Later 2014 Data

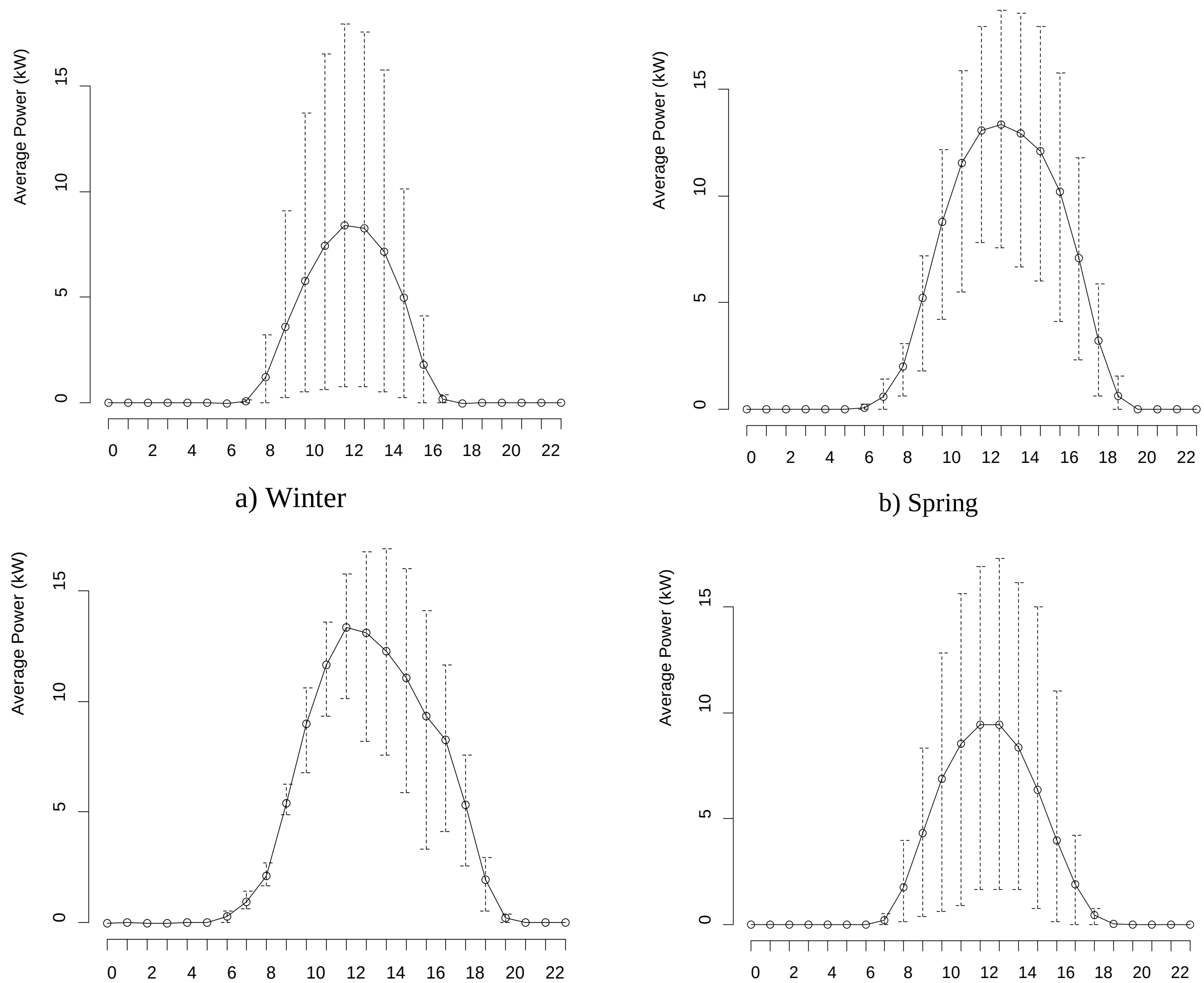
The project located two weather stations that reported solar insolation, but these data were not close enough to the site being analyzed to yield strong correlation.

12.8.2 Performance of the PV System

The project characterized the solar power generation by season and according to the beginning of the given hour. These results are summarized in Figure 12.50. The markers are the average power generation for these hours, local Mountain Time. The error bars represent the standard deviations of the measurements received for the hour. More precisely, the error bars span from the bottom of the 16th percentile to the top of the 84th percentile and are not necessarily symmetrical about the average values.

Average generation in the winter is 8.4 kW and the array generates power from about 07:00 until 18:00 local time. The maximum average summer and spring generation is almost identical at 13.3 kW, but the spring peak hour begins at 13:00 rather than noon. Generation lasts from 05:00 until 21:00 during the summer months.

The tops of the 84th percentile bars are remarkably similar each month—17.9 kW in winter, 18.7 kW in spring, 16.9 kW in summer, and 17.3 kW in fall. However, the generation is more variable in the fall and winter than in the spring and summer. The variability is also greater in the afternoon than in the morning hours.



a) Winter b) Spring c) Summer d) Fall

Figure 12.50. Hourly Solar Power Generation by Seasons (a) Winter, (b) Spring, (c) Summer, and (d) Fall. The vertical dashed lines represent standard deviations of the hourly measurements.

The project estimated the annual generation from the solar generation system by calendar month and by BPA hour type, which is critical for the way that displaced energy supply must be valued. These results are summarized in Table 12.16. The average generation during HLH and LLH hours was determined using all available data for the given months. The variability was estimated by separating the population of 2013 measurements from those of other years. Comparison months were available for five of the 12 months. A Student's t-test was used to estimate the variability of the calculated averages. The magnitudes of the uncertainties justified reporting no more than about two significant digits for most of the analysis results.

Table 12.16. Summary of Generation and the Value of Its Displaced Supply

		Average Generation[(b)] (kW)	Energy[(b)] (MWh)	Displaced Supply Value[(b,c)] ($)	Historical Peak Hours[(d)]	Change in Demand Charge[(e)] ($)
Jan	HLH	3.0 ± 0.3	1.30 ± 0.14	48 ± 5	8:00, 7:00	27 ± 4
	LLH	0.8 ± 0.2	0.26 ± 0.08	8 ± 2		
Feb	HLH	4.5 ± 0.4	1.70 ± 0.16	63 ± 6	7:00, 7:00	46 ± 3
	LLH	1.0 ± 0.3	0.28 ± 0.08	9 ± 3		
Mar	HLH	6.2 ± 0.5	2.60 ± 0.19	78 ± 6	7:00, 7:00	53 ± 4
	LLH	1.5 ± 0.3	0.50 ± 0.11	13 ± 3		
Apr[(a)]	HLH	6.5	2.70	70	7:00, 7:00	47
	LLH	1.2	0.36	7		
May[(a)]	HLH	6.3	2.60	55	7:00, 8:00	26
	LLH	1.6	0.52	7		
Jun[(a)]	HLH	6.8	2.70	62	9:00, 8:00	19
	LLH	1.9	0.60	9		
Jul[(a)]	HLH	6.6	2.80	84	21:00	60
	LLH	1.5	0.50	12		
Aug[(a)]	HLH	5.9	2.60	87	21:00	59
	LLH	1.4	0.43	12		
Sep[(a)]	HLH	3.9	1.50	65	8:00	29
	LLH	0.8	0.27	9		
Oct[(a)]	HLH	4.5	1.90	61	7:00	41
	LLH	1.1	0.36	10		
Nov	HLH	3.5 ± 0.37	1.40 ± 0.15	50 ± 5	7:00, 7:00	34 ± 4
	LLH	0.9 ± 0.25	0.28 ± 0.08	9 ± 3		
Dec	HLH	1.6 ± 0.26	0.66 ± 0.11	25 ± 4	7:00, 7:00	19 ± 3
	LLH	0.5 ± 0.17	0.16 ± 0.06	5 ± 2		
Year			**28.98 ± 0.60[(f)]**	**858 ± 20[(f)]**		**460 ± 12[(f)]**

(a) The variability could not be stated this month because only one calendar month of this type was demonstrated during the project.

(b) The uncertainty in these columns is estimated by comparing 2013 hours against hours from other years using a Student's t-test on the populations.

(c) This is the value of the energy that need not be purchased by the utility from BPA in the given month.

(d) These are the starting hours (Mountain Time) of monthly peak demand reported to the project for these months. There are two hours listed for calendar months for which two historical years' peak hours were available.

(e) The impact on BPA demand charges is estimated as the average generation during HLHs, minus the average generation during peak demand hours in the given month. The sign reversal results from the fact that generated power is displacing power that would otherwise be purchased from BPA. Positive results in this column mean that demand charges are being increased in the given month by the diurnal pattern of solar generation.

(f) The standard error of this yearly estimate has been projected from the five months for which standard error could be estimated.

(g) The variability in the other months is presumed to be similar in magnitude.

The average power was used to estimate the total monthly and annual energy generation. The total energy values are listed in Table 12.16 by calendar month and are grouped according to HLH and LLH hours. The project reports that based on this systems' installation, location, and the way it was operated by Lower Valley Energy, its annual generation should be expected to be 28.98 ± 0.60 MWh. Of this generated energy, 24.4 ± 0.52 MWh occurs during HLH hours, and 4.5 ± 0.29 MWh occurs during LLH hours.

One of the benefits of this system is its ability to displace energy that would otherwise need to be supplied from BPA. These results were tabulated for the asset based on the most recent set of BPA load-shaping rates (Appendix C). Again, these are shown in Table 12.16 by calendar month and are grouped according to HLH and LLH hours. The project reports that the value of annual displaced supply energy for Lower Valley Energy is $858 ± 20. Of this, about $748 ± 18 is during HLH hours, and $108 ± 8 is during LLH hours.

The project also estimated the monthly and annual impacts from BPA demand charges and the load-shaping rate determinant that is used to calculate the utility's monthly demand charges. The cooperative reported their monthly peak hours to the project. These are listed in Table 12.16. The BPA determinant for demand charges is based primarily on the difference between demand during the peak hour each month and the average heavy-load hour demand. Lower Valley Energy typically exceeds its determinant every month. The solar generation changes the determinant according to its average generation during HLH hours and the generation that occurs during the single peak hour each month. The impact on the peak hour is estimated from typical generation during the exemplary peak hours. Refer to Figure 12.50 to see the approximate magnitudes at the given exemplary peak hours.

An ideal resource would displace supply energy during the peak HLH hours more than during other HLHs. That is not the case for solar energy in the Northwest. The peak HLH hours lie predominantly in early morning and late afternoon hours when solar power is weak. However, much of the solar energy is generated during off-peak HLHs, further decreasing the billing determinant.[1] The resource appears to *increase* the annual demand charges by $460 ± 12.

For the five months that Lower Valley Energy supplied more than one month's data, the variability in the demand charges was calculated. This was done by comparing 2013 hours against other hours using a Student's t-test to estimate the natural variability from cloud cover and other environmental variables that affect the generation from one year to the next. The uncertainty in the average HLH component was already discussed. The variability of the peak-hour impacts was derived from the hourly statistics of the hours that match those in the historic peak hours column each month. Monthly results were rounded to the nearest whole dollar.

[1] The BPA supply bill includes some secondary effects and corrections that could come into play, but these were not considered here.

12.9 Four 2.5 kW WindTronics Wind Turbines

Lower Valley intended to displace energy supply and better understand the costs and benefits of investing in wind turbines. Lower Valley installed 10 kW WindTronics wind generators at the Hoback substation, Bondurant, Wyoming. These turbines had an innovative design with the generator surrounding the turbine blades (Popular Science 2014). Regrettably, Lower Valley Energy was not able to achieve acceptable performance from these turbines. They reported to the project that the company is no longer in business, which is supported by a statement from the company (WindTronics 2013).

The project assessed the annualized costs of the system and its components as shown in Table 12.17. Components include upgrades to the existing SCADA system, the wind generators, building site improvements, outreach, operations costs, administrative overhead, and fees for cellular communication with the SCADA at this remote site. The annualized cost of the system was estimated as $15 thousand.

Table 12.17. Lower Valley Electric Costs of a 10 kW Wind Turbine System

	Shared Component Allocation (%)	Annualized Component Cost ($K)	Allocated Annual Component Cost ($K)
Existing SCADA System[a]	25	25.7	6.4
10 kW WindTronics Generators (four)	100	5.2	5.2
Operations Labor[a]	25	5.5	1.4
Building	25	3.9	1.0
Building Site	25	2.1	0.5
Outreach and Education[a]	25	0.6	0.2
O&M[a]	25	0.6	0.2
Administrative[a]	25	0.4	0.1
Quest-to-SCADA Communication Fees	25	0.2	0.1
AMI Meter	100	0.0	0.0
Total Annualized Asset Cost			**$15.0K**

(a) These components were shared among the SVC system (Section 12.6), battery storage system (Section 12.7), PV array (Section 12.8), and wind turbine (Section 12.9).

According to Lower Valley Energy staff, the wind turbine at times consumed more energy than it generated, resulting in energy consumption instead of generation. Data were collected from late October 2012 through August 2014. All of the generation supplied to the project is shown in Figure 12.51. The reported generation is less than 1 kW, and the generation is negative as often as it is positive. Furthermore, the data is badly discretized.

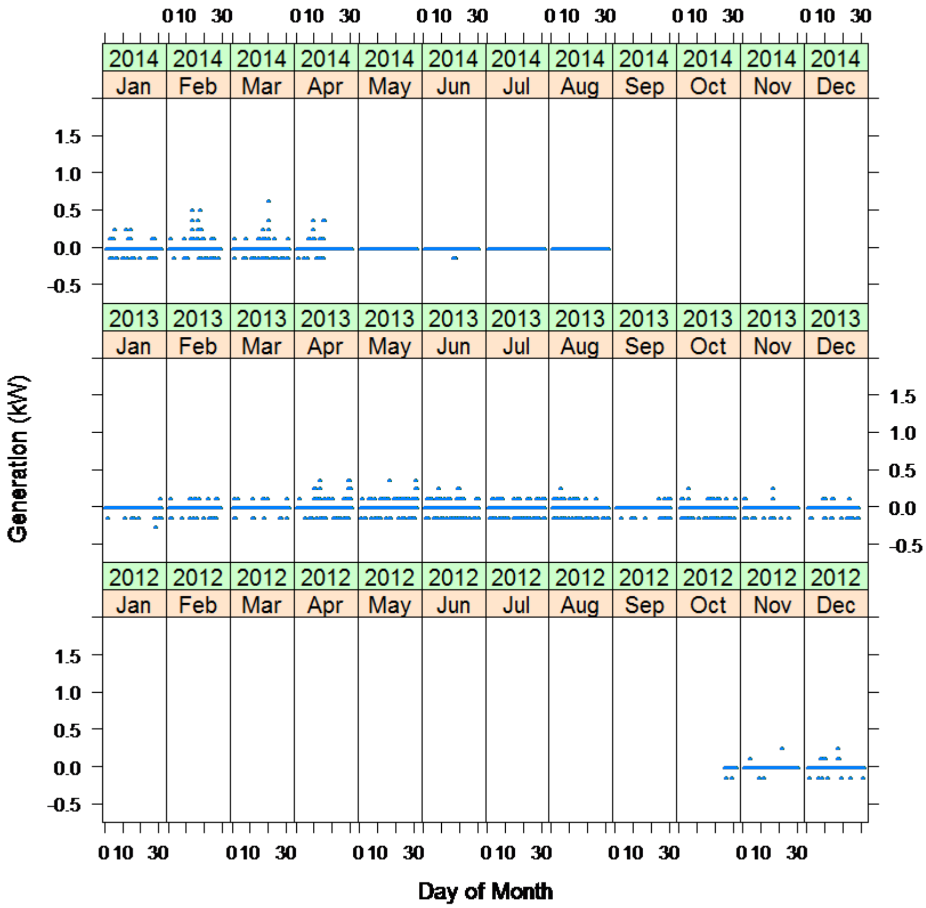


Figure 12.51. Wind Generation Reported to the Project by Lower Valley Energy

The project, of course, mistrusts this data, but the cooperative, when asked, insisted that this data is correct and is all that is available from the monitoring of this asset. The project cannot proceed any further with analysis using this data. No significant generation can be reported. No meaningful correlation to wind speed could be determined. The utility appears to have achieved no monetary benefits from this asset system.

12.10 Conclusions and Lessons Learned

Lower Valley Energy tested eight technologies during the PNWSGD. The project looked at historical and recent energy usage at premises that received various smart grid devices, including AMI, IHDs, and DRUs. A gradual, long-term reduction in average premises energy consumption appeared for many of the groups that were tested. The installation of AMI appears to have reduced energy consumption by about 0.2 kW at premises, but the impact from additional IHDs was probably negligible. Premises that had received both AMI and DRUs reduced their consumption a little more than those that received only the AMI.

The cooperative installed DRUs and controlled about 566 electric water heaters. The performance of this system was inconsistent over the PNWSGD, according to the project's analysis. Based on all the curtailment events that the cooperative had reported that they controlled these DRUs, the project concluded that, on average, each DRU had conserved just over 0.1 kW during the events. Upon looking at the cumulative impacts over time, the project identified several months of peak performance, when each DRU curtailed about 0.47 kW. The reason for the inconsistent performance was not fully determined.

The cooperative compiled yearly reliability indices for each of 16 feeders and submitted these to the project. Analysis was conducted by the project to determine whether the features of the recently installed AMI and DRU systems helped the cooperative improve its service reliability. Advanced meters quickly alert the cooperative to outages. And the DRUs included under-frequency responses and cold load pickup capabilities that were hypothesized to help the cooperative avoid and recover from outages. The project could not determine a global improvement in system reliability had occurred. In fact, the last two project years may have exhibited elevated SAIFI metrics. The project recommends that the metrics should be calculated and compared monthly with prior months' performance.

Lower Valley Electric periodically reduced the voltage on its East Jackson feeders by what was measured to be about 2%. This was normally done for up to three hours during the morning peak hours. By analyzing distribution power data, the project calculated that the events had reduced the distribution load by about 300 kW, or about 3.4% of the feeder's average load. When the project analyzed the impact of the short voltage reductions at a sample of 24 premises, an *increase* in premises load was found. A similar result was found by the project at Milton-Freewater (Chapter 13) that had also conducted short-term voltage reductions on its feeders. Researchers hope to revisit this analysis to determine if the counterintuitive result is real and meaningful.

The cooperative installed a 600 kVAr SVC at its remote Hoback substation to mitigate power factor issues on this long, rural feeder line. Power factors were improved over time, and the installation is estimated by the project to have reduced feeder line losses by 13 to 30%.

The cooperative installed a 125 kW, 250 kWh battery energy storage system at its remote Bondurant, Wyoming site. A discrepancy was found between the system's reported capacity and the power data received from the utility by the project. The utility successfully moved electric load from HLH hours to LLH hours. However, the battery system is a net consumer of energy, and the monetary value of system energy losses overcame any benefit the utility might have gleaned from arbitrage of HLH and LLH energies.

Lower Valley Energy also installed and demonstrated a 20 kW PV solar generation system. The system performed well and would be expected to generate about 29 MWh each year. However, solar generation at this location was found to impact average heavy-load hour while infrequently coinciding with the utility's actual monthly peak demand hour. The system helps the utility reduce its purchases of wholesale energy, but it does not help toward reducing its demand charges.

The cooperative installed four 2.5 kW WindTronics wind turbines, but these failed to ever generate significant amounts of energy. The product's vendor experienced financial difficulties during the PNWSGD and their assistance was discontinued.

Among its lessons learned, Lower Valley Energy reported that they should have budgeted more money for integration and project reporting expenses. Generally, their vendors had had difficulty meeting production time deliveries. Some equipment had been damaged during shipment, resulting in unexpected delays. Device integration was particularly challenging between existing systems that used MultiSpeak® (MultiSpeak 2015) and new devices that did not. While the new technologies had made compelling business cases to the utility, one of the vendors had gone into bankruptcy before the product warranty could be exercised.