11.0 Idaho Falls Power Site Tests

Idaho Falls Power is a municipal electric utility that serves the 22.4 thousand residential and 3.7 thousand commercial customers in Idaho Falls, Idaho. In 2013, 42% of its retail power was supplied to residential customers, 39% to commercial, and 13% to industrial customers. In addition to its distribution customer services, the city also operates 37 miles of transmission lines, 410 miles of distribution lines and 53.5 MW of hydroelectric, wind, and solar generation (Idaho Falls 2014). The city purchases the majority of its power from the Bonneville Power Administration (BPA) and is a slice customer of the BPA.

Idaho Falls Power elected to demonstrate a great variety of asset systems of any utility participant in the Pacific Northwest Smart Grid Demonstration project. The following asset systems will be described in this report:

- voltage management (Section 11.1)
- power factor control (Section 11.2)
- distribution automation (Section 11.3)
- water heater control (Section 11.4)
- plug-in hybrid electric vehicle (PHEV), solar, and battery storage (Section 11.5)
- thermostat control (Section 11.6)
- in-home displays (IHDs) (Section 11.7).

The layout of these tests among the Idaho Falls Power distribution circuits is shown in Figure 11.1 and Figure 11.2.

In Figure 11.1 and Figure 11.2, asset systems are labeled with asset numbers assigned by the project. For example, “IF-01” refers to the voltage management system at Idaho Falls. The two digits that are appended to the asset number indicate whether the principal objectives of the asset system were applied toward demand response (“1.x”), improved reliability (“2.x”), or conservation and efficiency (“3.x”). The series of dashes, “E,” and “C” reference the sequential numbered asset systems to which a data set is relevant as experimental data (“E”), control data (“C”), or neither (“-”).

Additionally, Table 11.1 lists the data stream names that were negotiated with Idaho Falls Power for the data listed on the layout diagram. Faced with the need to organize many data time series, the project defined shorthand for the impact metrics (“IM”) relevant to analysis of the various project assets. The asterisks represent unique text for the given asset system, device, or meter location. The table also lists the interval that each data series element represents and the interval at which the utility agreed to update the series. Not all the data streams listed in this table were, in fact, supplied by the utilities and at the requested intervals.

Table 11.1. Data Notation Shorthand used by the Project in Layout Diagram Figure 11.1 and Figure 11.2

Data Stream	Data Interval	Submit Interval	Description
IF-IM-1-*	15 minutes	1 day	Residential customer meter – power
IF-IM-3-*	1 month	1 month	Residential customer meter – monthly energy
IF-IM-13-*	1 month	1 month	System efficiency – meter operations costs
IF-IM-15-*	5 minutes	1 day	Distribution meter – voltage (end-of-line)
IF-IM-15-*	15 minutes	1 day	Residential customer meter – voltage (end-of-line)
IF-IM-20-*	1 month	1 month	System efficiency – meter operations miles driven
IF-IM-30-*	1 day	1 month	Residential customer meter – data completeness
IF-IM-40-*	1 year	1 month	Reliability events – feeder overload
IF-IM-41-*	5 minutes	1 day	Distribution meter – real power
IF-IM-42-*	5 minutes	1 day	Distribution meter – reactive power
IF-IM-48-*	1 hour	1 day	Distribution equipment – capacitor switch events
IF-IM-51-*	5 minutes	1 day	Distribution meter – power factor
IF-IM-52-*	1 month	1 month	System efficiency – truck rolls
IF-IM-61-*	1 year	1 month	System Average Interruption Duration Index
IF-IM-63-*	1 year	1 month	Reliability events – outage response time
IF-IM-66-*	1 year	1 month	Customer Average Interruption Duration Index
IF-IM-201-*	1 hour	1 day	Distribution equipment – tap changes
IF-IM-300-*	1 hour	1 day	Demand-response system – opt-out count
IF-IM-453-*	1 hour	1 day	Residential customer meter – low-voltage alarm
IF-IM-454-*	1 hour	1 day	Residential customer meter – high-voltage alarm
IF-IM-814-*	1 hour	1 day	Distribution equipment – target voltage

Two other asset systems were initially proposed—control of thermostats at commercial customer premises and a combined PHEV, solar, and battery energy storage system—but these never fully materialized. Commercial-customer–grade meters were installed and tested in February 2013, but they were found to not support the functionality that Idaho Falls Power had wanted to test at commercial premises. The project invested in the system of PHEV, solar-generation, and battery-storage assets, but this asset system ultimately failed to produce useful demonstration data for reasons that will be discussed later in this section.

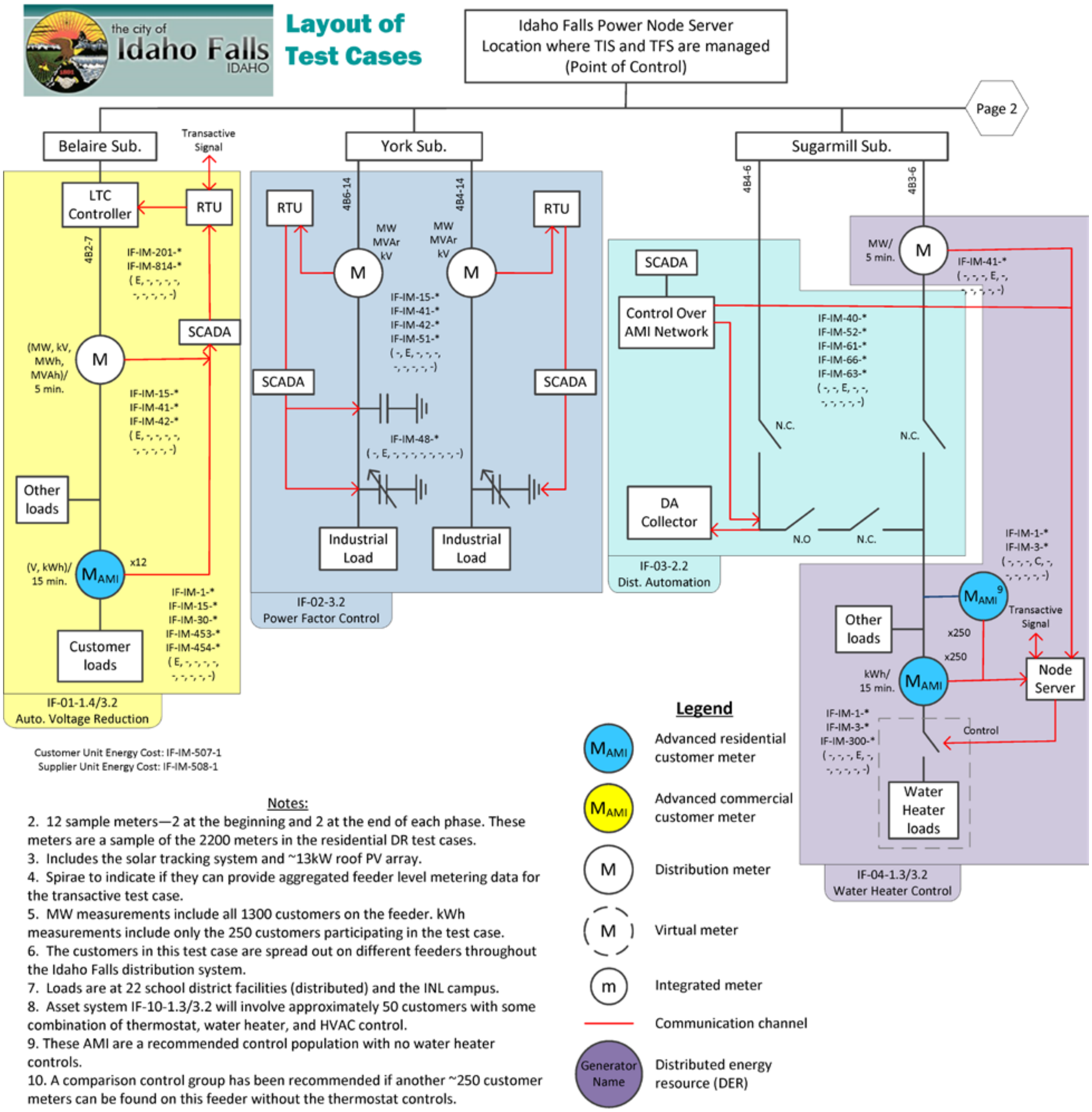


Figure 11.1. Idaho Falls Power Layout Diagram, Page 1

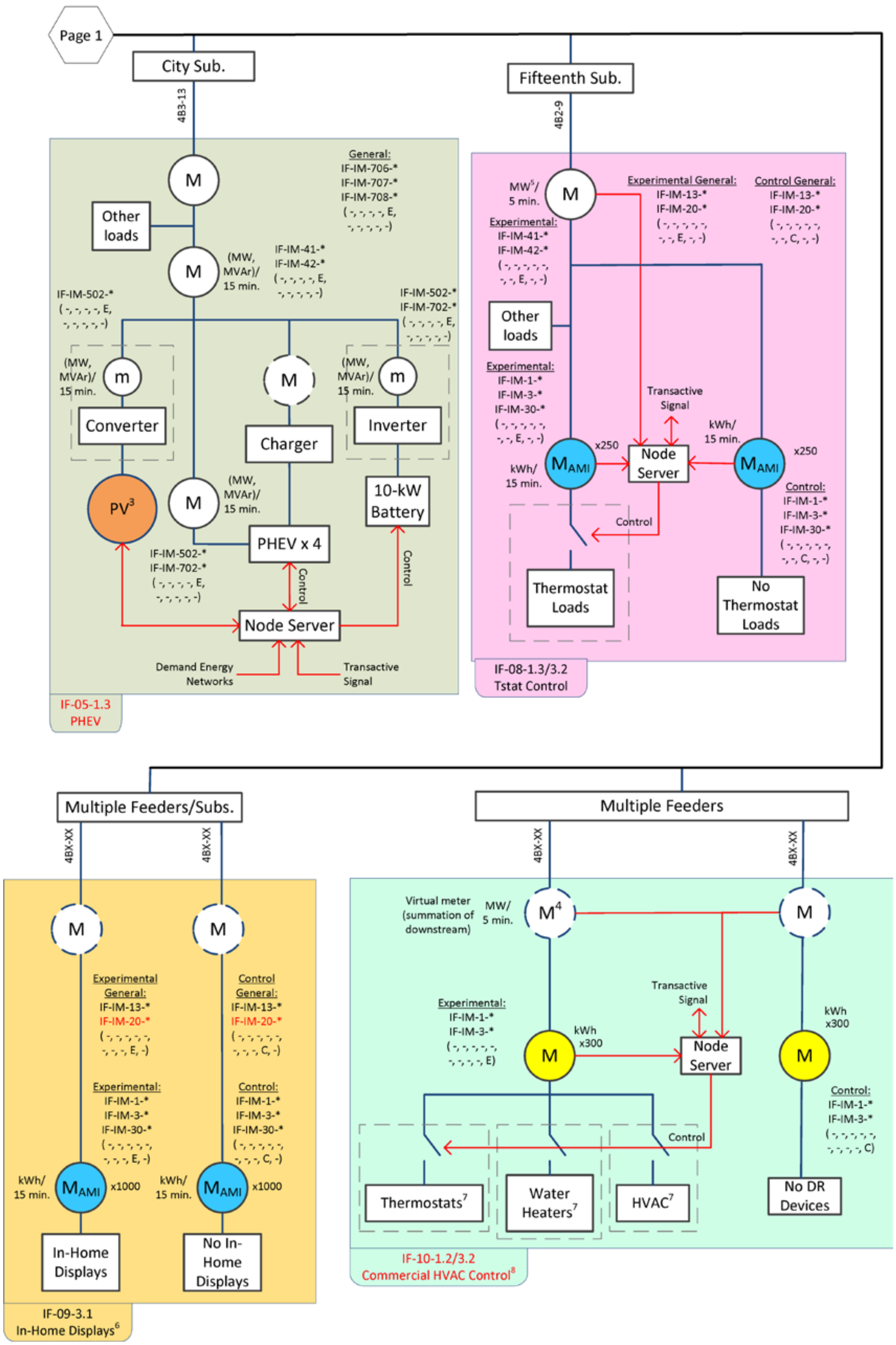


Figure 11.2. Idaho Falls Power Layout Diagram, Page 2

11.1 Conservation Voltage Regulation

Idaho Falls Power purchased and installed a load tap change controller at its Belaire substation to manage the feeder's voltage. The system was installed and useful as of June 29, 2012. One of the objectives was conservation voltage regulation, so the city expected to observe a reduction in feeder energy consumption after the system was installed and while applying a lower, managed distribution voltage to the feeder. The project monitored numbers of tap changes to address wear and tear on distribution equipment. The project also monitored high- and low-voltage alarms to address whether distribution voltage management degraded or improved the quality of delivered voltages.

The voltage control system was also configured to respond to the project's transactive system. The system was configured to conduct additional voltage reduction each day when the transactive incentive signal (TIS) was at its highest. The city asserted that it would respond to every event that was advised by the transactive system. No independent event status was made available to the project. However, this asset system allowed analysts to confirm events by observing periods when the feeder's voltage had been reduced.

The city's supervisory control and data acquisition (SCADA) system gathered 5-minute distribution power and voltage readings at the Belaire substation. Additionally, the system sampled 12 premises meters to monitor end-of-line voltages and thereby verify that customers were being supplied adequate power quality.

Table 11.2 summarizes the asset system components and estimated costs that were incurred to install and operate this system. The costs have been annualized so that they may be compared directly against annualized benefits. The project believes these annualized costs are those that would be borne by a Pacific Northwest municipality that reproduces similar voltage control capabilities. The system's total annualized cost is the sum of the individual component's annualized costs, based on the component's anticipated useful lifespan.

Table 11.2. Idaho Falls Power Costs of Voltage Management System

	Component Allocation (%)	Annualized Component Cost ($K)	Allocated Annual Component Cost ($K)	
Transactive Node	14	317.1	45.3	
Idaho Falls Power Staff Labor	100	25.3	25.3	
Administrative	11	151.5	16.8	
Network Engineering for Transactive Control and Cyber Security	13	85.4	10.7	
AMI			8.2	
• Equipment	100	0.2		0.2
• Installation and Integration	100	0.1		0.1
• Testing (new and existing meters)	100	0.0		0.0
• Communication Network System	20	3.9		0.8
• Head-End Server	20	1.2		0.2
• System Applications (includes MDM)	20	19.4		3.9
• AMI Four-Year Maintenance Warranty	17	17.9		3.0
Vulnerability and Penetration Testing for AMI Network	14	48.8	7.0	
Engineering: AMI/SCADA integration, control algorithm development, modeling, and testing	100	2.1	2.1	
Training			1.3	
• AMI	17	2.7		0.4
• SEL Device Training (1 week)	33	1.8		0.6
• SEL Year-2 Refresher Training (2 days)	33	0.8		0.3
Distribution Automation Collector/Router	100	0.6	0.6	
SEL 351 Overcurrent Relay	100	0.4	0.4	
Load Tap Change Controller	100	0.3	0.3	
Total Annualized Asset Cost			**$118.0K**	

AMI = Advanced Metering Infrastructure
MDM = meter data management
SCADA = supervisory control and data acquisition
SEL = Schweitzer Engineering Laboratories

11.1.1 Project Data and the Operation of the Voltage Management System

The independent variable for analysis of conservation voltage regulation is feeder voltage. The city provided the project 5-minute feeder voltages from March 2013 through August 2014. The voltages did not reveal any dynamic control until February 2014, when the voltage was occasionally reduced by about 1.5%. The voltage was no longer reduced after the middle of July 2014, according to this data.

Figure 11.3 shows feeder voltage data for the test period. The legend notes the times that the transactive system had advised the system to reduce its voltage ("Engaged") and not ("Not Engaged"). The project had been informed that the voltage would be reduced coincident with the advice from the transactive system.[1] As can be seen in the figure, this was not the case. The transactive function began advising the system to engage by March 2013, long before the system was first exercised. Once the voltage was truly being reduced, the advice from the transactive system imperfectly aligned with the observed voltage magnitudes. Clearly, the system's status must be inferred from observations and the project should not rely on the transactive system advice to infer its status.

The project observed that the normal voltage setting of the system was increased in July 2014. This period late in project data collection was not included in the analysis. The higher-voltage period could pollute the formulation of a regression baseline if it were included in its training set.

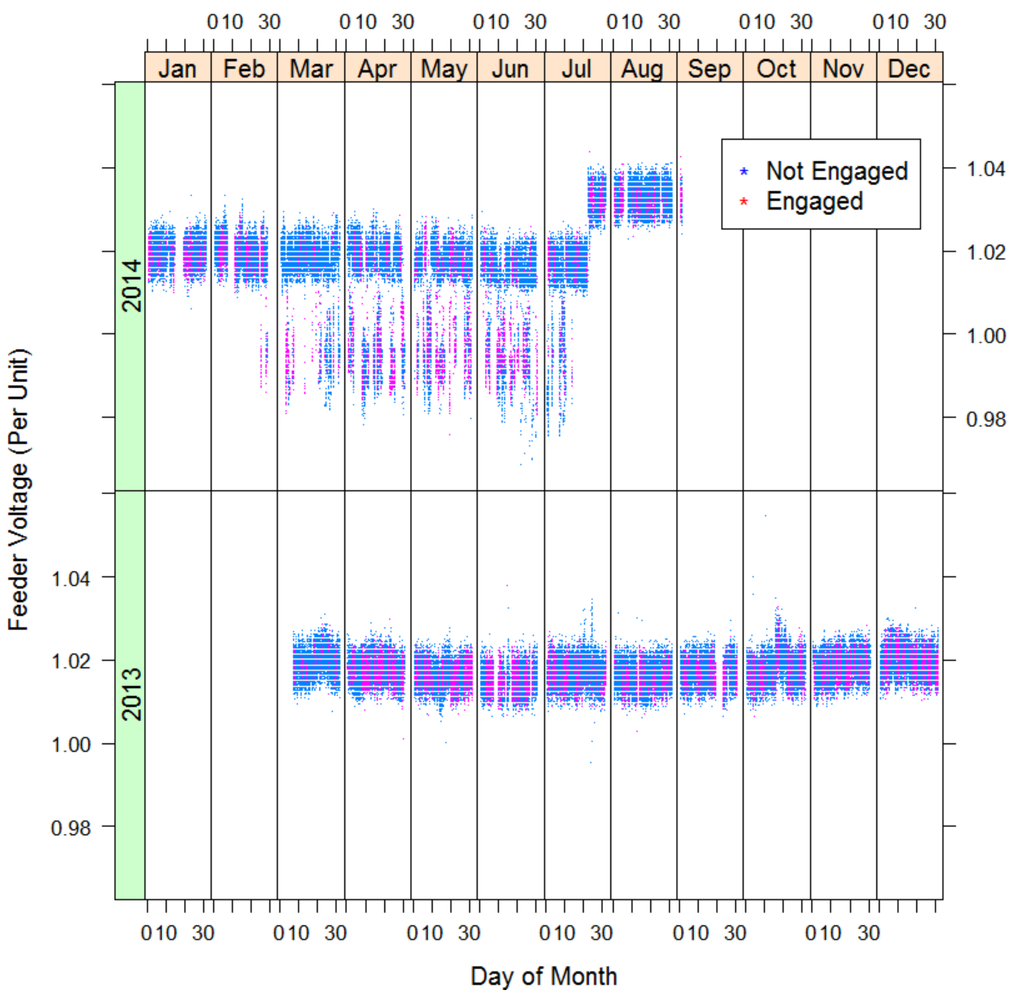


Figure 11.3. Managed Per-Unit Feeder Voltage during the Project

[1] "Advice from the transactive system" refers to the condition of the advisory control signal that was generated at the Idaho Falls utility site by its transactive load toolkit functions.

A representative sample of end-of-line feeder voltages became sporadically available in September 2013 and revealed evidence of voltage management similar to that in distribution voltage through 2014. The averages from these samplings are shown in Figure 11.4. These meters were polled sequentially, in a round-robin manner, due to limitations of the premises metering. This data confirms that voltage management was active from February to mid-July 2014. There is an unexplained inconsistency between the late July and August 2014 data in Figure 11.3 and Figure 11.4. While the distribution voltage appears to have been increased from mid-July forward, the average end-of-line voltages fell significantly after they had been initially increased.

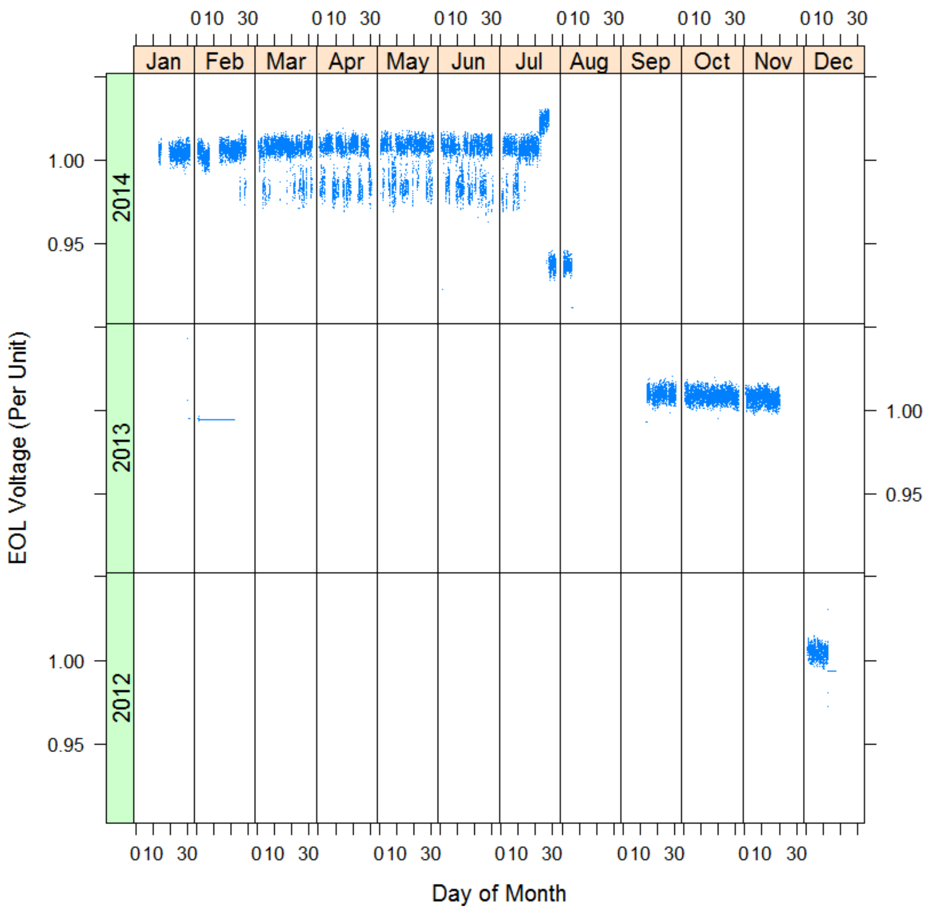


Figure 11.4. Per-Unit End-of-Line Voltage Measurements

Still further confirmation of the utility's intentions for the voltage management system may be gleaned from the target voltage settings that were provided to the project by Idaho Falls Power. The per-unit voltage settings were provided for much of 2014 and are shown in Figure 11.5. These settings appeared to closely correspond with the reported distribution voltages on the feeder.

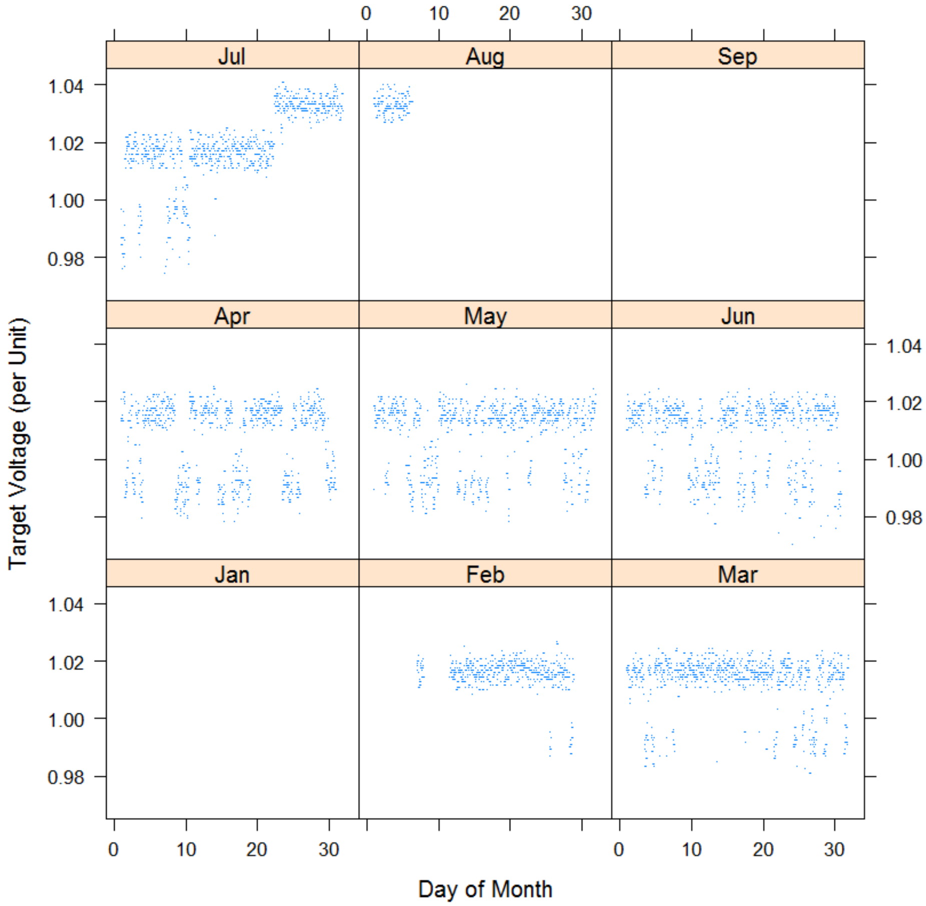


Figure 11.5. Reported Per-Unit Target Voltages in 2014

Project analysts searched 5-minute feeder real-power data for the effect of voltage reduction. The city provided this data from March 2011 until the conclusion of project at the end of August 2014. The entire set of feeder data received from Idaho Falls Power is shown in Figure 11.6. The average power of the Belaire feeder during the project, based on all the project data that is shown in Figure 11.6, was 5,593.2 ± 2.4 kW. Using the months of 2013 as an example year, the average monthly peak-hour demand on the feeder was 8.88 ± 0.37 MW.

Feeder power data quality was good. A clear weekly pattern was evident in the feeder power. The legend of Figure 11.6 distinguishes weekday periods from weekends. Feeder power was consistently lower during weekends. The yearly trends show that consumption peaks in winter but is also elevated in summer.

Residential premises power was also available to the project for about 12 residents who are supplied from the feeder, but the project spent most of its effort with feeder-level data that, unlike per-premises data, should reveal the entire impact of voltage reduction.

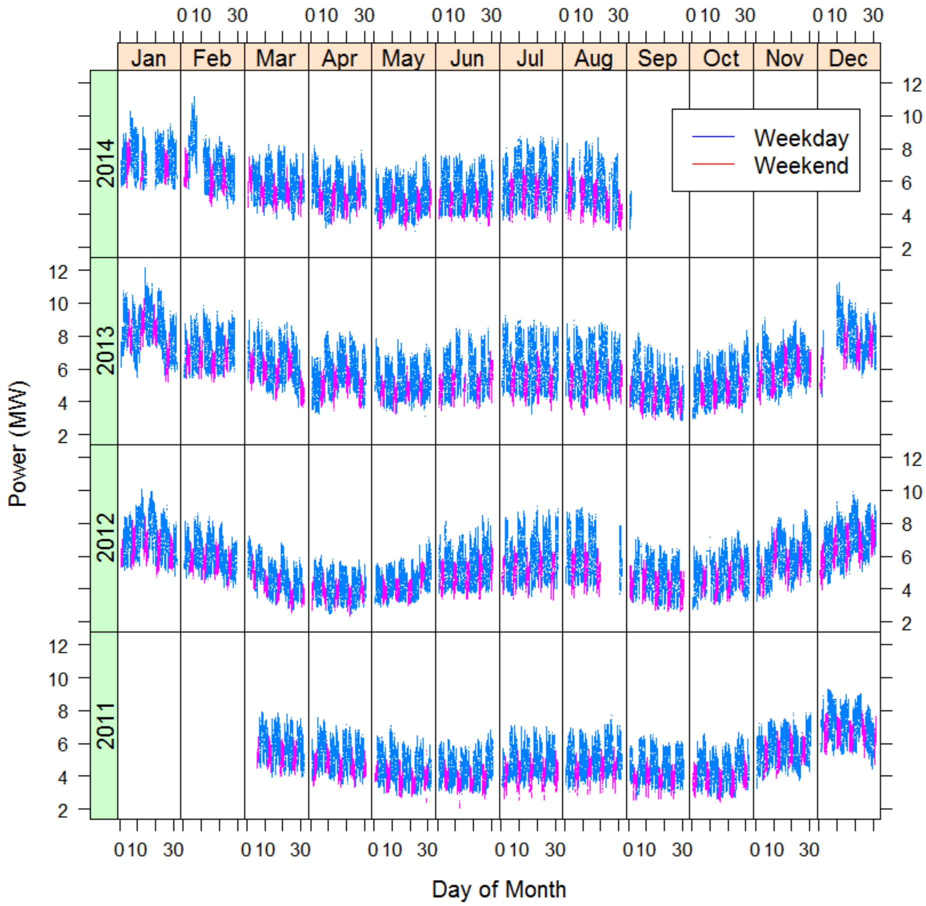


Figure 11.6. Feeder Power Data

11.1.2 Analysis of the Impact from Voltage Management

Idaho Falls Power did not provide independent confirmation of when they had and had not reduced feeder voltage. The first analysis challenge was therefore to infer engagement of the voltage management system from the available voltage data. Both the per-unit distribution voltage and reported target voltages had revealed evidence of voltage management during 2014.

Figure 11.7 compares actual feeder voltage and reported target voltage data. If the correlation between these two voltages were perfect, all the data points would have fallen on the dashed diagonal line in this figure. The correlation is not perfect, but three groupings of voltages lie on the diagonal. The three groups roughly correspond to the reduced, normal, and elevated sets of distribution voltages that were observed in both Figure 11.4 and Figure 11.5. Interestingly, the coincidence between the actual and target voltages was poorest when either the actual or target voltages were near 1.015 per unit. A hypothesis is that there was a significant delay between the times that the target voltage was changed to or from the normal and reduced voltage settings and the response of the system to actually change the voltage. Although the correlation between target and actual voltages is strong, the project elected to infer the status of voltage management from actual distribution voltage measurements.

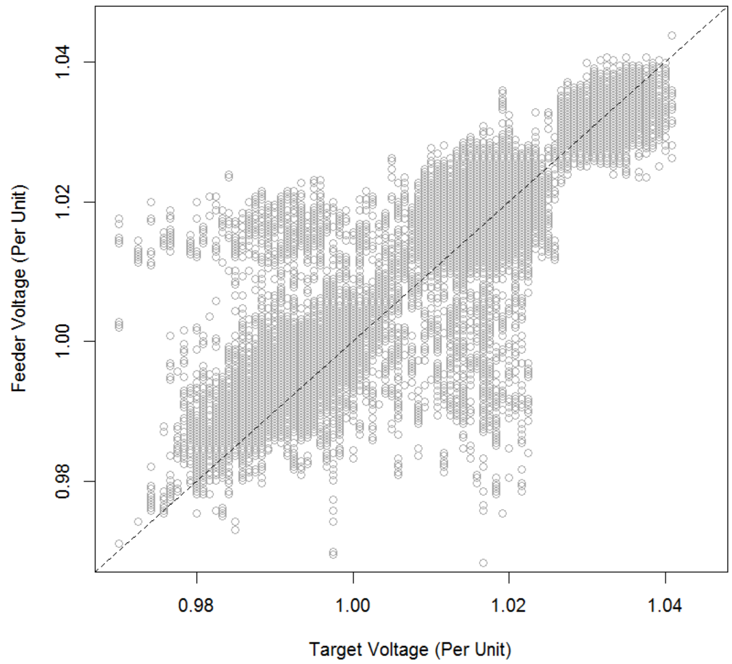


Figure 11.7. Feeder Voltage Plotted Against Target Feeder Voltage. Values on the dashed line would indicate perfect correlation between these two voltages.

Figure 11.8 is a histogram of the per-unit distribution voltages that were available to the project for 2014. The three populations of voltages—reduced, normal, and elevated—are again evident. By inspection, the value 1.0065 per unit was selected as the demarcation between the reduced and normal voltages. The voltage management system was therefore inferred to have been engaged any time that the distribution voltage was less than 1.0065 per unit.

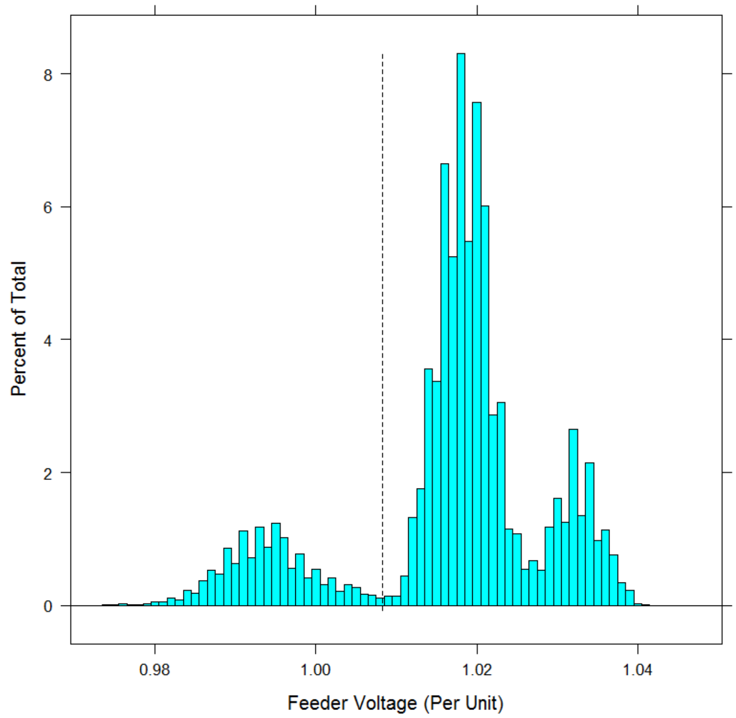


Figure 11.8. Histogram of 2014 Feeder Voltages. The separation between reduced and normal levels was assigned at 1.0065 per unit.

Several baseline control methods were considered, but the project chose to create a linear regression model of feeder power as a parametric function of temperature, cooling or heating regime, calendar month, day of week, and hour of day. The project used the R software (R Core Team 2013) environment for this analysis.

Cooling and heating regimes were determined for each calendar month. When distribution feeder power is plotted as a function of outdoor temperature, a “V” shape becomes evident. In the winter, more data lie to the left side of the “V,” representing an increase in heating power as temperature falls. In summer, feeder power rises with higher temperatures. Figure 11.9 shows, for all the month in the period August 2013 – July 2014, linear fits by hour to the cooling and heating temperatures. The “best” fit was determined at a temperature that separates the two linear regression fits such that the total sum of residuals between the modeled and actual powers is minimized. These temperatures that separate heating and cooling regimes are shown in Figure 11.9.

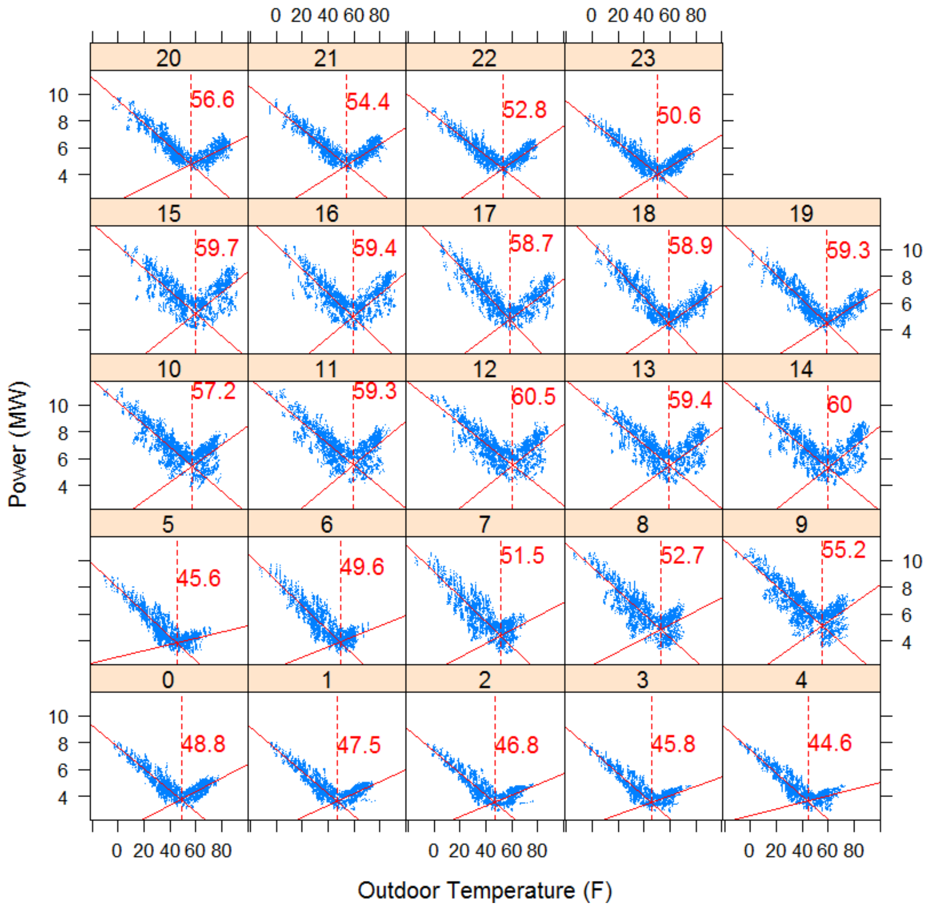


Figure 11.9. Calculated Cooling and Heating Regimes by Hour, Based on Feeder Power

A baseline was created from the regression model to emulate feeder power as if feeder voltage was unchanged. By comparing actual feeder power against this regression model baseline when the voltage was reduced and not, the impact of the reduced voltage operation could be estimated. Typically, based on all project data, the feeder's power was reduced by 137 ± 4 kW when the voltage was reduced.

Analysts also reviewed the impacts for each calendar month of the project's last year (August 2013 – July 2014), estimates of which are shown in Table 11.3. These results are based on a Student's t-test comparison of the differences between actual and baseline feeder power when the voltage had been reduced and not. Of the six months that voltage management was exercised well, data from four suggested that power had been significantly reduced. The system was not exercised much in January or during August through December, so the results from these months were probably not meaningful.

Table 11.3. Total Measured Power Impact when Voltage was Reduced

	Δ Power[b] (kW)
Jan[a]	−609
Feb	−475 ± 23
Mar	−269 ± 11
Apr	−64 ± 8
May	33 ± 11
Jun	−169 ± 8
Jul	95 ± 13
Aug[a]	−90 ± 770
Sep[a]	-
Oct[a]	−123
Nov[a]	-
Dec[a]	-
All data	−137 ± 4

(a) Few, if any, events occurred these months.
(b) The negative values in this column are costs that are avoided by the utility.

Based on the estimated change in power each month during voltage management that occurs during heavy-load hour (HLH) and light-load hour (LLH) hour types and the fraction of time that voltage was reduced during each hour type, the monthly impact on energy consumption was estimated. These results are in Table 11.4. The monthly cost impacts were then estimated by multiplying the changes in HLH and LLH energy by the unit costs of these energy usages, according to recent BPA demand rates. The impact from the two hour types was then summed for each month. The sum energy purchases avoided during the six months that the voltage management system was exercised were worth about $2,710 ± 120. If these benefits may be extrapolated to the remaining calendar months, the total annual displaced energy might be worth about twice as much, or $5,420 ± 170, to the utility.

These estimates of the value of energy purchases that may be avoided by Idaho Falls Power were based on the way that the utility practiced voltage management during six months of 2014. The project's understanding was that the utility was investigating voltage management as a dynamic resource, not a constant conservation voltage reduction resource. Results would, of course, differ if the system were exercised more or less often in the future or differently during HLHs or LLHs.

These calculations did not include the impact from lost energy sales revenues that would tend to reduce the monetary benefit. Yes, the utility does not need to purchase this energy from its supplier, but it also loses retail revenues from the sale of most of this energy to the city's electricity utility customers.

Table 11.4. Estimated Impact on HLH and LLH Energy Usage and Energy Cost Impacts, based on the period August 2013 – July 2014

	Δ HLH Energy[b] (MWh)	Δ HLH Cost[c] ($)	Δ LLH Energy[b] (MWh)	Δ LLH Cost[c] ($)	Δ Total Energy Cost[c] ($)
Jan[a]	0	0	−0.080	−2	−2
Feb	−8.80 ± 0.41	−326 ± 15	0	0	−326 ± 15
Mar	−33.6 ± 1.6	−1,017 ± 49	−8.45 ± 0.64	−212 ± 16	−1,229 ± 51
Apr	−20.0 ± 2.2	−516 ± 56	−0.7 ± 1.6	−13 ± 32	−530 ± 64
May	−4.0 ± 2.8	−84 ± 58	6.0 ± 1.2	79 ± 15	−5 ± 60
Jun	−28.2 ± 1.9	−640 ± 43	−15.2 ± 1.2	−221 ± 17	−861 ± 46
Jul	−4.2 ± 1.4	−127 ± 42	14.83 ± 0.93	363 ± 23	237 ± 48
Aug[a]	0.03	1	−0.065	−2	−1
Sep[a]	-	-	-	-	-
Oct[a]	−0.012	0	0	0	−0.012
Nov[a]	-	-	-	-	-
Dec[a]	-	-	-	-	-

(a) Voltage management was not routinely exercised these months.
(b) A negative energy value in this column refers to a reduction in electrical load.
(c) A negative cost value in this column means the utility's supply costs have decreased.

The impact of voltage management on the demand charges that are incurred by Idaho Falls Power from its energy supplier has been estimated in Table 11.5. The utility's demand charges are determined each month by its average HLH consumption and the month's peak-hour demand. The example peak hours used in these calculations were determined from the Belaire feeder data by tabulating the hours on which demand peaked each project month. This method yielded two or three hours in which peak demand was likely to occur each calendar month.

The estimated total annual impact from the demonstration of voltage management was a reduction of $3,570 ± 620 for the utility. Energy was conserved, so the utility paid less for its energy supply. This number gives no credit for months on which no events occurred and months during which the example peak hours were not among those when the system was activated, but it does give credit on a statistical basis by month, even if the precise peak hours were not those reacted to during the project.

If the voltage management had been well exercised all months of the year, the utility might have reduced its demand charges by about $6,770 ± 680 per year. This projected number presumes that peak hours are always correctly identified throughout the year, including during the six calendar months that the system was, in practice, inactive.

Table 11.5. Estimated Changes in the Peak Demand Determinant and Resulting Demand Charges, based on the period August 2013–July 2014

	Δ aHLH (kWh/h)	Typical Demand Hours	Δ Peak Demand (kW)	Δ Demand Charges ($)
Jan[(a)]	−0.2	9, 10, 10	-	2
Feb	-	10, 9, 10	−147 ± 35	−1,600 ± 380
Mar	−26 ± 2	10, 12, 10	−167 ± 21	−1,260 ± 190
Apr	−2 ± 5	10, 9, 11	155 ± 25	1,200 ± 190
May	-	14, 11, 15	−114 ± 37	−710 ± 230
Jun	-	12, 15, 14	−77 ± 24	−520 ± 160
Jul	−10 ± 3	13, 13, 14	−65 ± 32	−500 ± 290
Aug[(a)]	−0.2	15, 14, 15	-	~0
Sep[(a)]	18 ± 4	15, 13	-	−180 ± 40
Oct[(a)]	-	11, 13	-	-
Nov[(a)]	-	17, 10	-	-
Dec[(a)]	-	10, 10	-	-

(a) Little, if any, voltage management was demonstrated these months.

The management of distribution voltage could either improve or harm distribution equipment life and customer power quality. The remaining figures in this section will show metrics that were collected by the project to assess these impacts.

First, the project requested Idaho Falls Power to help it monitor the numbers of transformer tap changes. As voltage control is automated, control actions may cause distribution equipment to engage more often or differently from how it was operated prior to the automation. Idaho Falls Power submitted hourly counts of tap changes to the project, Figure 11.10, for parts of three months in 2014. Tap changers were observed to change their setting up to nine times per hour. On the hours that tap settings were changing, 79% of these intervals coincided with times that the voltage had been reduced.

The project is unable to conclude anything about changes in tap change counts that might have been caused by the project’s voltage management. No historical data about tap changes was provided from before the voltage was managed.

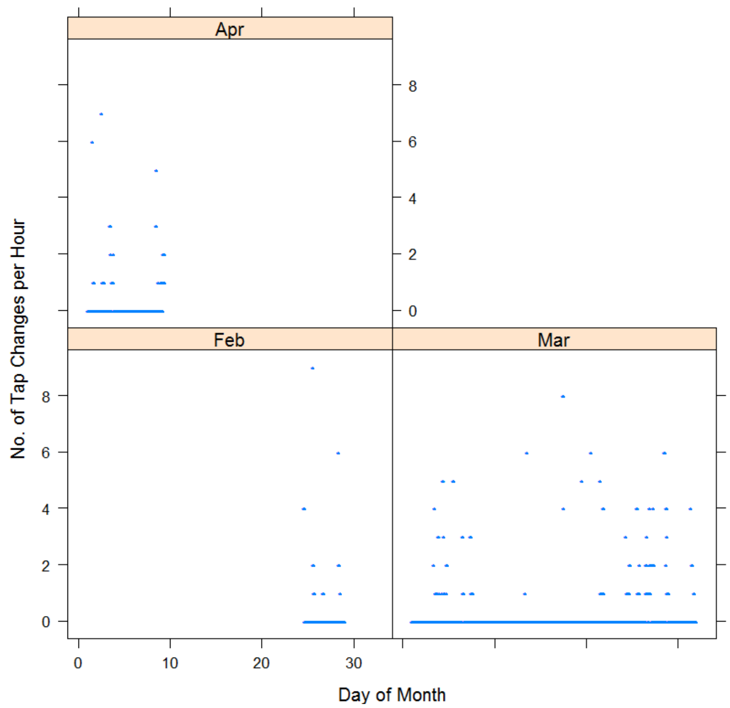


Figure 11.10. Tap Changes per Hour

The premises meters installed by Idaho Falls Power have a feature that records divergence of the delivered voltage above or below accepted thresholds. The project summed the numbers of these occurrences by hour for the premises on the Belaire feeder that were affected by voltage management. The low-voltage events are shown in Figure 11.11 and the high-voltage events in Figure 11.12. Up to three low-voltage events were received from customer premises during one hour in 2012. The high-voltage events occurred less often, and there has not been more than one in any hour.

No low- or high-voltage events were reported after the middle of February 2014 when Idaho Falls Power began exercising the voltage management system. It appears that the voltage management system has been quite effective toward improving the quality of delivered voltage for the premises on the Belaire feeder.

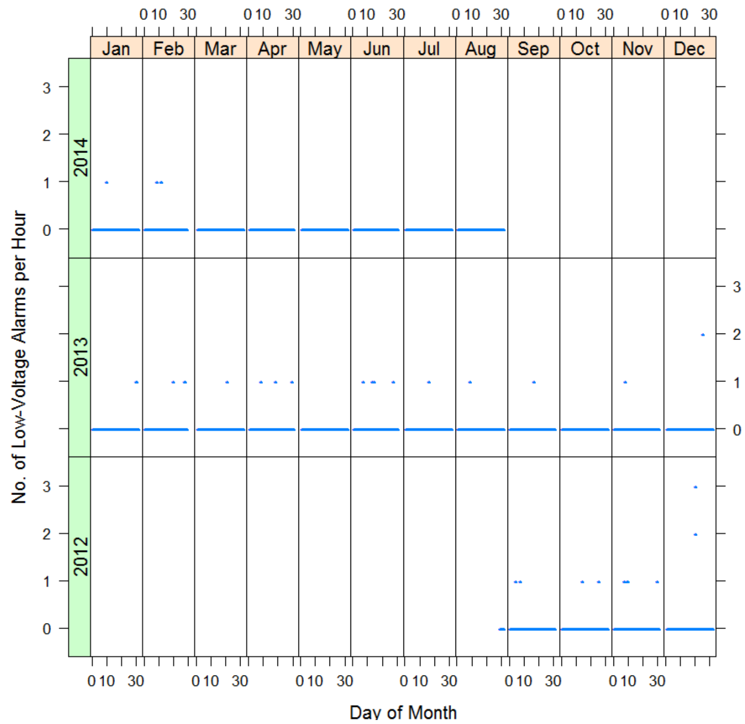


Figure 11.11. Residential Low-Voltage Alarms per Hour

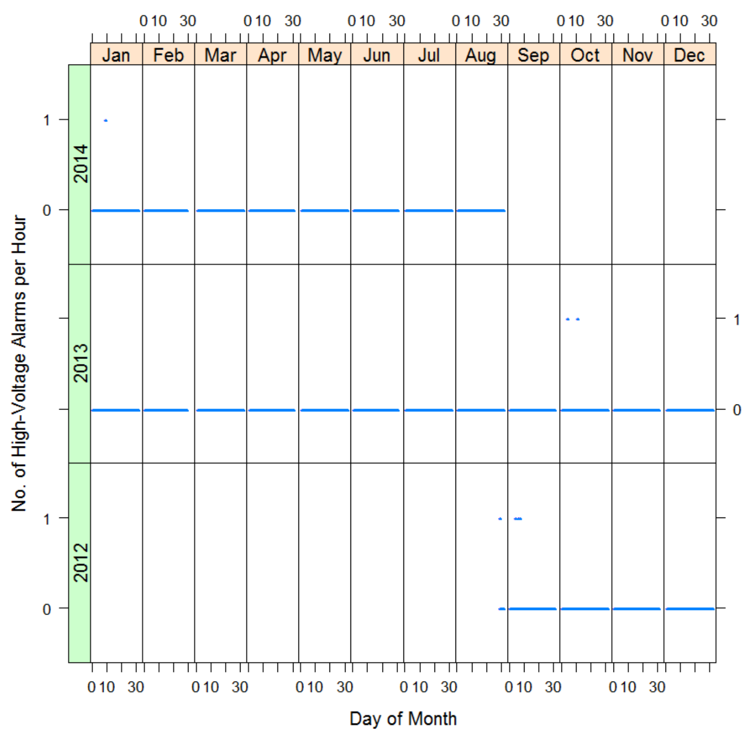


Figure 11.12. Residential High-Voltage Alarms per Hour

11.2 Automated Power Factor Control

Note. Upon its review of this section, Idaho Falls Power stated that the real power data and perhaps the reactive power data, too, are about 10 times as great as they should be. This critique, of course, calls the entire analysis in this section into question. The project was unable to confirm this possible scaling issue or rectify the inconsistency working with the utility. Regardless, the analysis text has been left in place. If the same scaling issue affected both the real and reactive power data in this section, then the calculations and conclusions may still be valid.

Idaho Falls Power automated the control of switched capacitor banks at two large breweries that are supplied from its York substation. The purposes were to reduce system losses and to improve feeder power factor. Local controllers at the industrial premises supervised the switched capacitor banks to make sure that power remained within acceptable parameters.

When preset reactive power thresholds were reached at the industrial sites, the controllers switched in or out the shunt capacitor banks. The system may be controlled remotely via the utility's SCADA system over an Ethernet network using Distributed Network Protocol version 3.0 and a fiber optic link between the substation and capacitor banks. Prior to the demonstration, Idaho Falls Power predicted that this system would conserve approximately 2% of the average feeder demand - about 140 average kilowatts - on the two affected feeders. That would have saved about 38 thousand dollars from Idaho Falls Power's annual electricity purchases. The system was declared to be installed and useful on September 30, 2011, but the data suggest that the capacitors were activated in December 2013.

Idaho Falls Power estimated annualized system costs. Refer to Table 11.6. The system components include the two capacitor banks and the communication system components that were needed to control the capacitor bank. Idaho Falls Power also applied fractions of the costs of their advanced meter system, cyber security consulting, and various training sessions.

Table 11.6. Idaho Falls Power Costs of Power Factor Control System

	Component Allocation (%)	Annualized Component Cost ($K)	Allocated Annual Component Cost ($K)
Idaho Falls Power Staff Labor	100	29.3	29.3
Administrative Costs	11	151.5	16.8
Network Engineering for Transactive Control and Cyber Security	13	85.4	10.7
Engineering: Invensys, TriAxis	100	8.0	8.0
Vulnerability and Penetration Testing for AMI Network	14	48.8	7.0
AMI Meter System			4.9
• System Applications (includes MDM)	20	19.4	3.9
• Communication Network System	20	3.9	0.8
• Head-End Server	20	1.2	0.2
Capacitor Bank	100	1.6	1.6
SEL Device Training			0.9
Communication Equipment (media converters, fiber)	100	0.6	0.6
Communication Controller	100	0.5	0.5
Total Annualized Asset Cost			**$80.2K**

11.2.1 Project Data and Operation of the Automated Power Factor Control

Idaho Falls Power submitted reactive power measurements from the two York feeders on which the power factor was controlled. The data from March 2013 into July 2014 was made available. The sum of the reactive power on the two feeders is plotted in Figure 11.13. Based on a step change reduction in the two feeders' calculated reactive power, analysts inferred that capacitors were engaged on the two feeders on the 3rd and 9th of December 2013 and stayed engaged throughout the rest of project's data collection period. The project inferred that this was the month that power factor correction must have become operational on the York feeders. Prior to then, the power was strongly reactive. After that period, the reactive power was lower and even occasionally crossed below zero to become slightly capacitive. The legend of Figure 11.13 distinguishes the data prior to and after this date.

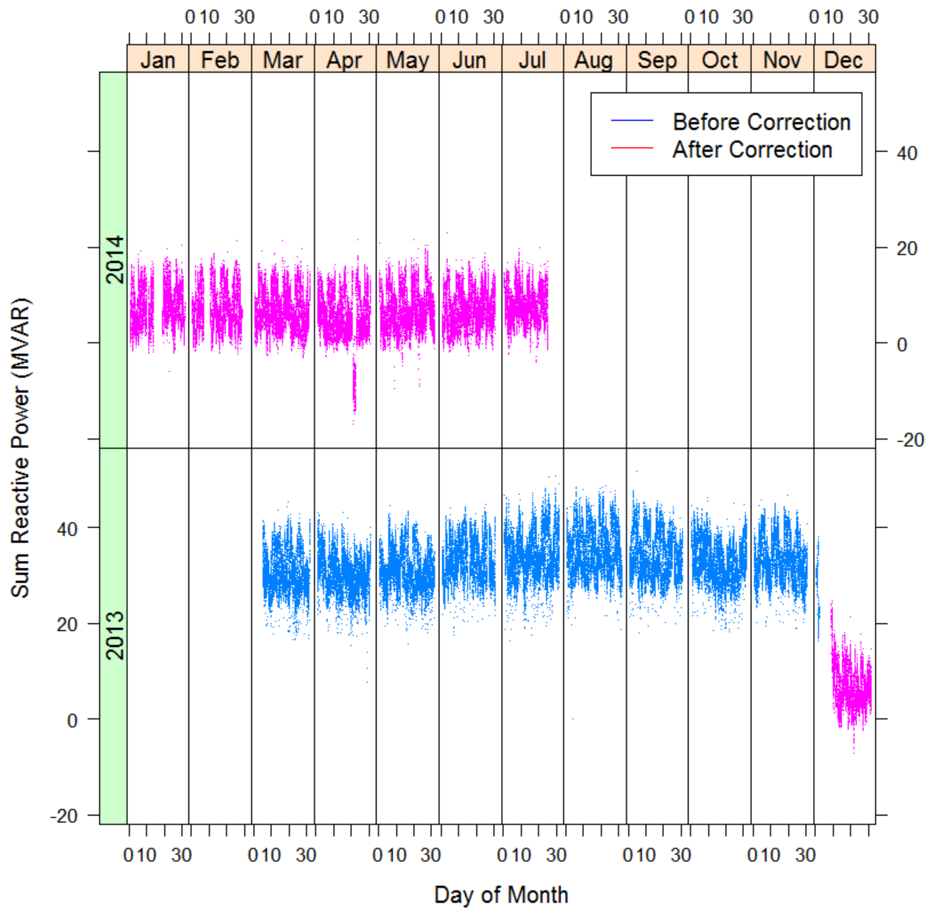


Figure 11.13. Sum Reactive Power by Month and Year for Available Data from the Two Feeders with Power Factor Control

Idaho Falls Power also submitted feeder real-power data for the two York feeders that were affected by its new power factor control. The data also covered the period from March 2013 into July 2014. The sum power from the two feeders has been plotted in Figure 11.14. The average power on these two feeders, based on the available data, was 88.86 ± 0.03 MW. When Idaho Falls Power reviewed this data, it said the magnitude is about ten times too great, but the source of the potential scaling error was not identified. The legend on this figure distinguishes the data prior to and after power factor correction had begun, according to changes that were observed in the reactive power. Total real power did not appear to change after the power factor correction began. The project did not attempt to quantify any change in the power measurement.[1]

[1] This might be an interesting extension for future analysis. Can any change in feeder power be attributed to the correction of power factor on these feeders?

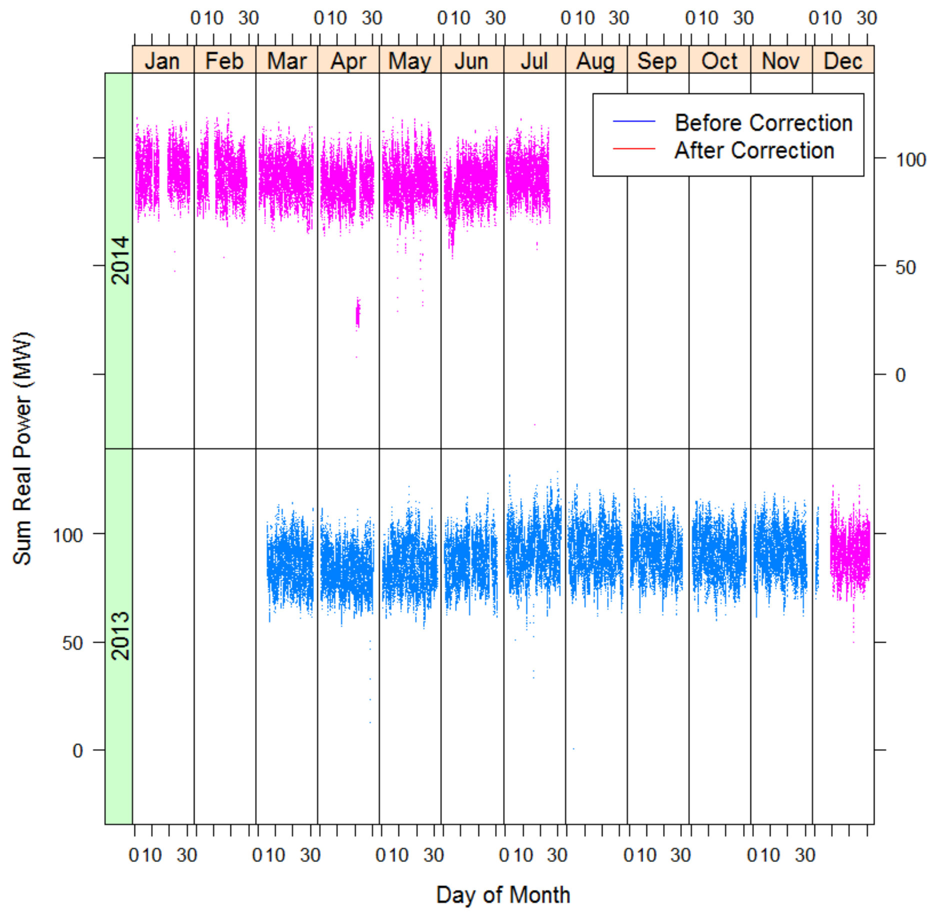
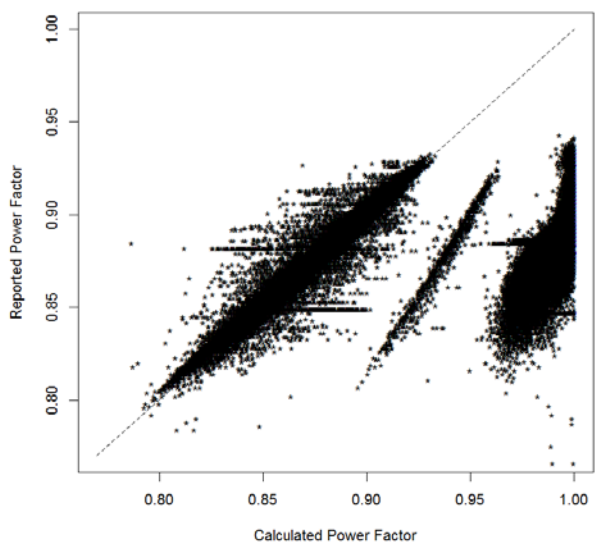


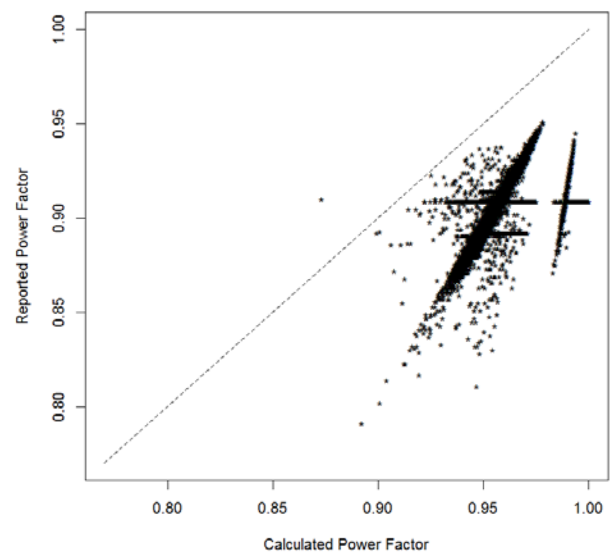
Figure 11.14. Total Real Power by Month and Year for Available Data from the Two Feeders with Power Factor Control

Idaho Falls Power submitted power factor measurements for the two York substation feeders from March 5, 2013 through August 31, 2014, but these values do not match those power factors calculated from the available feeder power data that was shown above. Figure 11.15 compares the reported power factors (vertical axis) against the calculated ones (horizontal axis). Had the reported and calculated values agreed, Figure 11.15 would have exhibited a nearly perfect linear correlation along the dashed diagonal lines that are shown in the figures. The measured and calculated values matched some months for Feeder 1, but never matched for Feeder 2. The calculated power factors were often greater than those that had been reported. Additionally, the reported power factors were found to "stick" on certain values, especially during times that capacitor bank switching events were being reported.

Upon its review, Idaho Falls Power stated that it believed its reported power factors were accurate. The project was unable to identify the source of the inconsistency. Project analysts opted to use the power factor calculated from the feeders' real and reactive powers, rather than the reported power factor data, for its analysis.



(a) Feeder 1



(b) Feeder 2

Figure 11.15. Power Factors Provided by the Utility versus Power Factors Calculated from Feeder Data for the Two York Feeders. These graphs demonstrate that the feeder data did not always match calculated values.

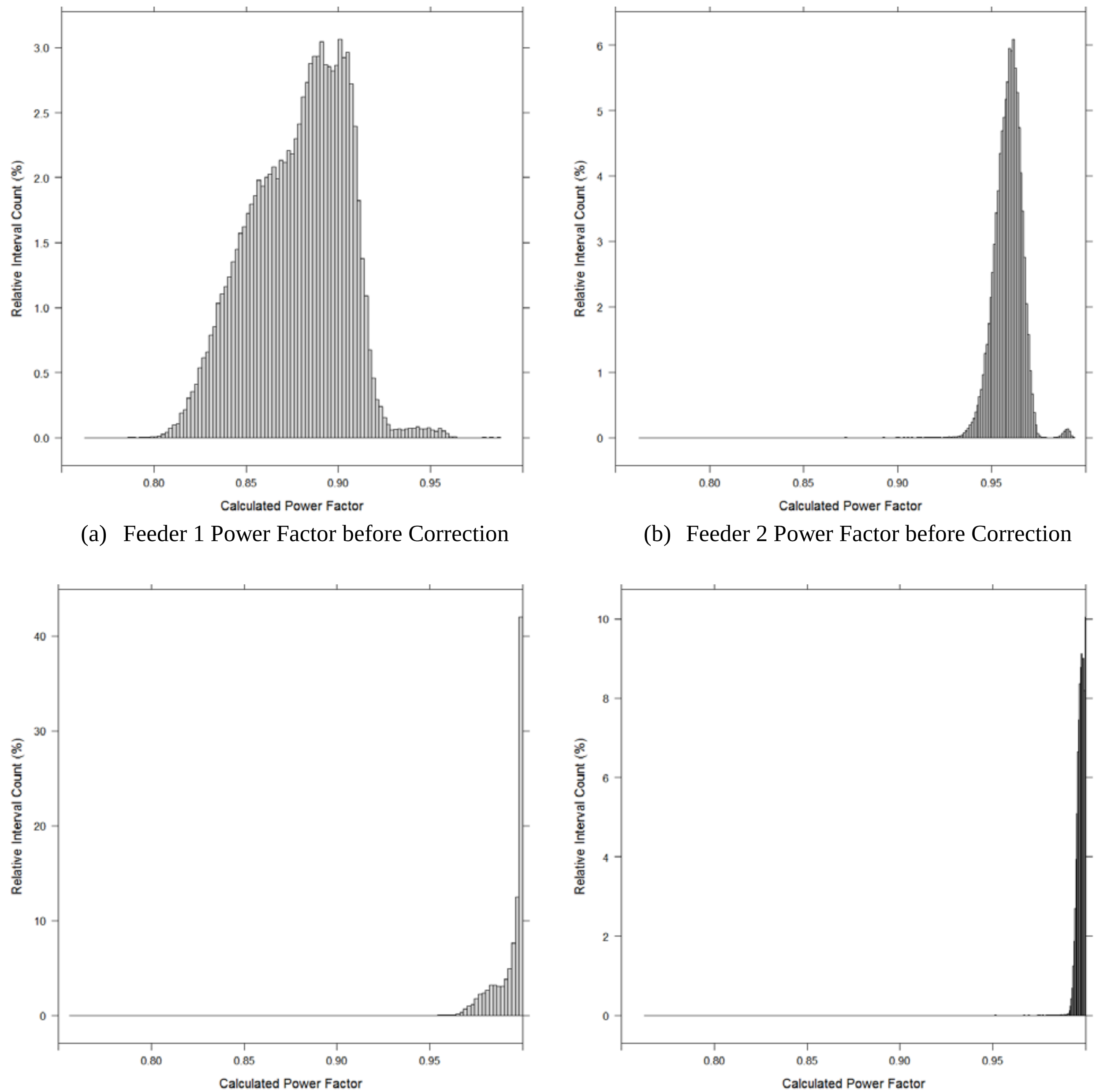
Capacitor switching events were reported to have taken place during September 2013 (2 hours), October 2013 (31 hours), and January 2014 (94 hours). The capacitors at the two industrial sites were always engaged simultaneously. These events do not appear to be meaningful amidst the significant correction that was observed in the first weeks of December 2013.

11.2.2 Analysis Results from the Automated Power Factor Correction

Comparing the power factors on the feeders before and after early December 2013, the average power factor of Feeder 1 improved from 0.878 to 0.993. The power factor of Feeder 2 improved from 0.959 to almost 0.997. The distributions of the calculated power factors on the two feeders before and after early December 2013 are shown in Figure 11.16.

This improvement means that the distribution currents now needed to supply the same electrical load on the two feeders are 88 and 96% of what was needed prior to the engagement of the capacitors. Line losses are proportional to the square of the line currents. Based conservatively on the average change in distribution line currents, the distribution losses on Feeder 1 should have been reduced by about 22%, and the distribution losses on Feeder 2 should have been reduced by about 7.5%.

The project had no independent means to measure or estimate distribution losses, but if distribution system losses on these feeders were on the order of 5% of the total power supply, then the total impact would be on the order of a 0.5 MW reduction of distribution losses on these two feeders. This is about 0.6% of the average total feeder power.



(a) Feeder 1 Power Factor before Correction
(b) Feeder 2 Power Factor before Correction
(c) Feeder 1 Power Factor after Correction
(d) Feeder 2 Power Factor after Correction

Figure 11.16. Histograms of York Feeder Power Factors Before and After Early December 2013

11.3 Distribution Automation

Using remotely controlled switch operators, its advanced metering infrastructure (AMI) system, and fault indicators, Idaho Falls Power installed a fault detection, isolation, and restoration system to quickly detect fault locations and isolate the faulted parts of two circuits that are supplied by its Sugarmill substation, thus reducing the duration of service outages. The system was installed and useful by November 9, 2012.

The annualized costs of the system and its components have been estimated in Table 11.7. The total cost of the system, as defined, is about $91.3 thousand per year. The greatest costs are for utility staff labor, administrative expenses, network engineering, and cyber security.

Table 11.7. Idaho Falls Power Costs of Distribution Automation System

	Component Allocation (%)	Annualized Component Cost ($K)	Allocated Annual Component Cost ($K)
Idaho Falls Power Staff Labor	100	52.1	52.1
Administrative	11	151.5	16.8
Network Engineering for Transactive Control and Cyber Security	13	85.4	10.7
Engineering: SCADA integration, control algorithm, modeling	100	4.9	4.9
Motorized Switch Operator	100	3.0	3.0
Fault Indication Device	100	2.0	2.0
Training			0.9
• SEL Device Training (1 week)	33	1.8	0.6
• SEL Year-2 Refresher Training (2 days)	33	0.8	0.3
Distribution Automation Collector/Router	100	0.6	0.6
SEL 351 Overcurrent Relay	100	0.4	0.4
Total Annualized Asset Cost			**$91.3K**

11.3.1 Available Reliability Metrics

Idaho Falls Power calculated and submitted yearly reliability indices and metrics for the two Sugarmill feeders for years from 2010 through the end of the project after August 2014. These indices and metrics have been compiled in Table 11.8.

Table 11.8. Yearly Reliability Indices Reported to the Project by Idaho Falls Power

Reliability Index	Units	Feeder	2010	2011	2012	2013	2014[a]
System Average Interruption Duration Index	minutes/customer/year	1	0.00	1.43	0.00	0.00	0.00
		2	1.05	1.54	0.00	1.26	0.00
Customer Average Interruption Duration Index	minutes/event	1	0.00	2.20	0.00	0.00	0.00
		2	1.50	3.35	0.00	-[b]	0.00
Outage response time	minutes/year	1	0.00	57	0.00	5,948	0.00
		2	0.00	0.00	0.00	42,975	0.00
Reliability events	count/year	1	0	0	0	0	0
		2	0	1	0	0	0

(a) Period from January 1–August 31, 2014.

(b) Values were submitted, but they were likely incorrect, given that the feeder's System Average Interruption Duration Index and outage minutes were nonzero.

11.3.2 Analysis of the Impact from Distribution Automation

The project will not report any conclusions regarding reliability based on the limited history of reliability metrics that have been collected. However, no outages had occurred during the last nine months of the project, which is very promising, providing this trend endures.

11.4 Water Heater Control

Idaho Falls Power installed 218 Tendril Networks (Tendril 2014) / Elster load control modules (LCMs) to curtail residential electric tank water heaters that are supplied energy from one of their Sugarmill substation feeders. These units were controllable by Idaho Falls Power via broadband communications. The system was declared installed and useful by December 21, 2012. Test events were conducted during 2013 and into February 2014, and the system was made automatically responsive to the project's transactive system briefly from late 2013 until early 2014.

Idaho Falls Power chose to remove all the LCMs abruptly in early 2014 due to a small number of catastrophic device failures and ensuing concerns about their customers' safety. According to the utility, the LCMs are no longer offered by the product's vendors.

Refer to Table 11.9 for a summary of annualized system and component costs. The system costs include the load controllers and all the labor and software needed to install and operate the LCMs, the cost of implementing the transactive site and its communications, a fraction (about 20%) of the cost of the AMI system that interacts with the LCM, and a fraction of the costs for reviewing and improving the utility's cyber security. One-fourth of the utility's costs for outreach and education were also included.

Table 11.9. Idaho Falls Power Costs of Water Heater Control System

	Component Allocation (%)	Annualized Component Cost ($K)	Allocated Annual Component Cost ($K)	
Transactive Node	14	317.1	45.3	
Idaho Falls Power Staff Labor	25	119.7	29.9	
Software for Demand Response	33	65.5	21.8	
Cyber Security Consulting			17.7	
• Network Engineering for Transactive Control and Cyber Security	13	85.4		10.7
• Vulnerability and Penetration Testing for AMI Network	14	48.8		7.0
Administrative	11	151.5	16.8	
Engineering	33	42.7	14.2	
AMI Meter System			7.7	
• Equipment	100	1.6		1.6
• Installation and Integration	100	1.0		1.0
• Testing (new and existing meters)	100	0.2		0.2
• Communication Network System	20	3.9		0.8
• Head-End Server	20	1.2		0.2
• System Applications (includes MDM)	20	19.4		3.9
Water Heater Controls	100	6.2	6.2	
Outreach and Education	25	24.4	6.1	
AMI Four-Year Standard Maintenance Warranty	17	17.9	3.0	
Total Annualized Asset Cost			**$168.7K**	

11.4.1 Characterization of the Water Heater Control System and Data

Idaho Falls Power gathered and delivered power data from premises that hosted responsive LCMs and water heaters. Data intervals included a mix of 1-hour and 15-minute time-series data from the individual premises. Typically 213 residential premises, mostly supplied by the Sugarmill feeder 4B3-6, were included in the test group. The project averaged these data across all the premises for analysis. Data were collected from August 2012 until the end of August 2014 from these premises. The average of this data stream was 2.2 kW. Figure 11.17 shows all the aggregated premises power data that was received by the project from Idaho Falls Power for the approximately 213 premises that received water heater load controllers.

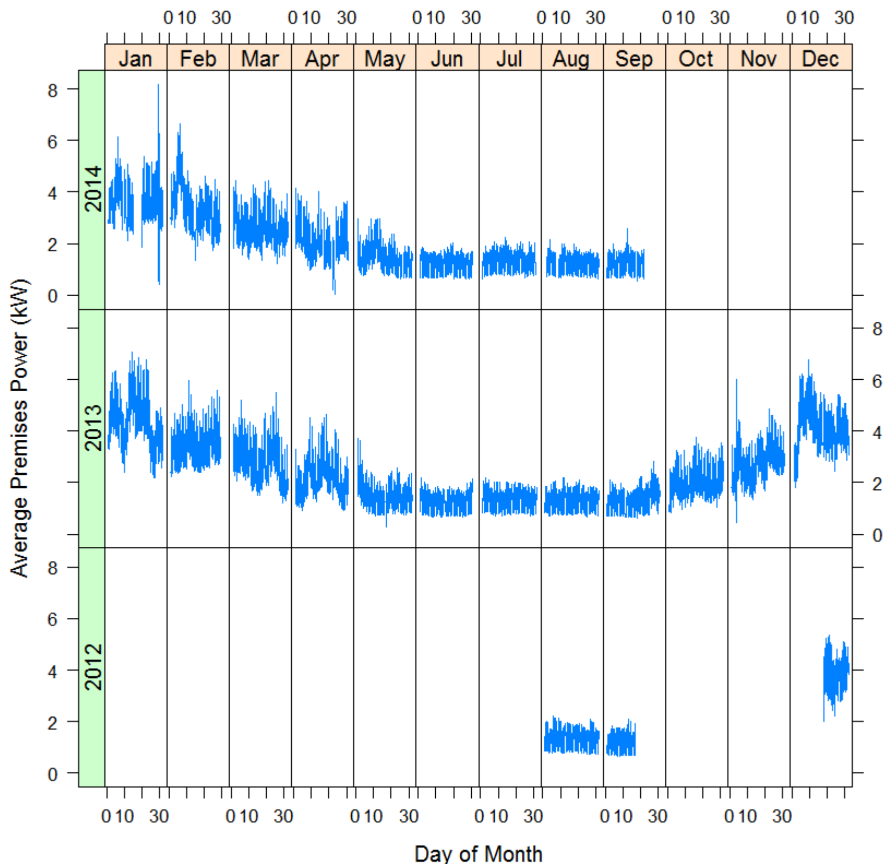


Figure 11.17. Average Premises Power for the 213 Idaho Falls Power Customers Who Received Water Heater Load Controllers

The utility also supplied real-power data from a set of similar premises that did not receive responsive LCMs or water heaters. A small set (~17) of these premises were located on the same Sugarmill substation feeder as the test group, but this data set was found to be inexplicably dissimilar to the experimental set. A set of data from a larger data set of 477 premises meters on multiple feeders—a set of premises that had received IHDs (Section 11.7) but did not receive water heater controllers—was preferred. Power data from these premises was collected from August 2012 until the end of August 2014. The averages of all the time-series data from these aggregated sets of power data were 1.25 kW for the Sugarmill comparison group and 1.53 kW for the alternative comparison group from multiple other Idaho Falls Power feeders.

Ambient temperature data was collected from Idaho Falls weather stations KIDA (airport) and IDA (central city). These temperatures were used by analysts for regression analysis. Linear interpolation was used to fill in small gaps in the temperature time series, providing that the gaps were less than 6 hours long.

Idaho Falls Power worked with the Pacific Northwest Smart Grid Demonstration project to set up and configure a toolkit function that would advise the system of water heater controllers when to curtail their loads. The function was operating and generating such advice by the beginning of 2013. Early transactive events for this asset were configured by the utility to remain almost always active. The toolkit function was revised and reconfigured in mid-2013 to advise events for no longer than a couple of hours, but events were allowed most workweek days. System installation and testing created delays, so the system was not responsive to the transactive system until at least December 2013.

Idaho Falls Power asserted to the project that the LCMs were to be engaged every time the transactive system advised[1] them to curtail their loads. However, caution had to be used. Advisory control signals had been generated by their corresponding function long before the LCMs became installed and controlled. Further, the advisory control signals continued to be generated after the LCMs had been disabled and removed from premises. An alternative set of test events was e-mailed to the project and will be described in this section.

Communications received from Idaho Falls Power led the project to believe that the system was being primarily manually controlled. A list of over 500 test event hours was sent to the project. Each hour-long event record stated the event's starting time and which of four premises subgroups was to have been engaged that hour. The utility had evenly subdivided the population of approximately 213 LCMs premises into four subpopulations. For event periods longer than 1 hour, the subpopulations were sequentially engaged and released each successive hour. Rarely was load at more than one of the subgroups curtailed the same hour.

This approach, in hindsight, was ill advised. Had all the water heaters been simultaneously curtailed, a reduction of between 0.2 and 0.8 kW per premises—a total reduction of 44 to 170 kW—might have been observed during the curtailment periods. Because only one-fourth of the total population was engaged the first hour of the curtailment period, only one-fourth of this impact may be observed among the entire population of premises that hosted controllable water heaters. After the first hour of each curtailment, the initial subpopulation was apparently released as another subpopulation became curtailed. Little or no net change in total demand should be expected between the first and subsequent hours. In fact, a rebound impact might occur after each transition as the prior subpopulation reheats its water after its hour of curtailment. The multiple, periodic energy rebounds add to the data variability.

The characteristics of the water heater test events are shown in the next several figures. The test events engaged the water heaters 559 hours between August 2013 and February 2014. After successive hours were discounted, there were 288 unique test events. The events were called regularly during this period, as is shown in Figure 11.18. On average, 41 unique test events were initiated each of the months in this period.

[1] The transactive system advised the asset systems to engage when the function that represented the asset at this transactive system site published a nonzero advisory control signal. The signal value 127 requested full curtailment by the asset.

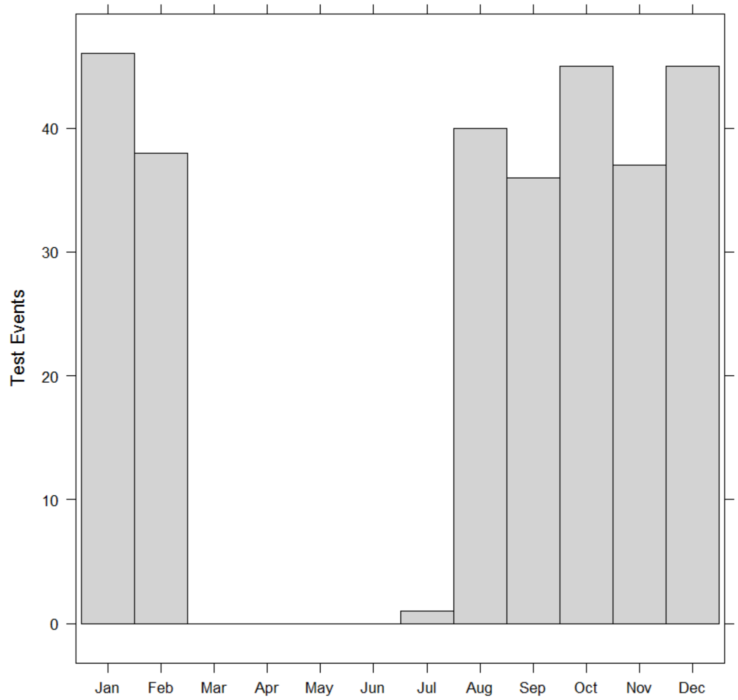


Figure 11.18. Count of Test Events According to the Events’ Calendar Month. Events started in August 2013 and ended in February 2014.

The water heater test events were also applied evenly by workweek day, as is shown in Figure 11.19. This histogram counts the test events according to the weekdays on which they began. The test events were conducted almost exclusively on weekdays.

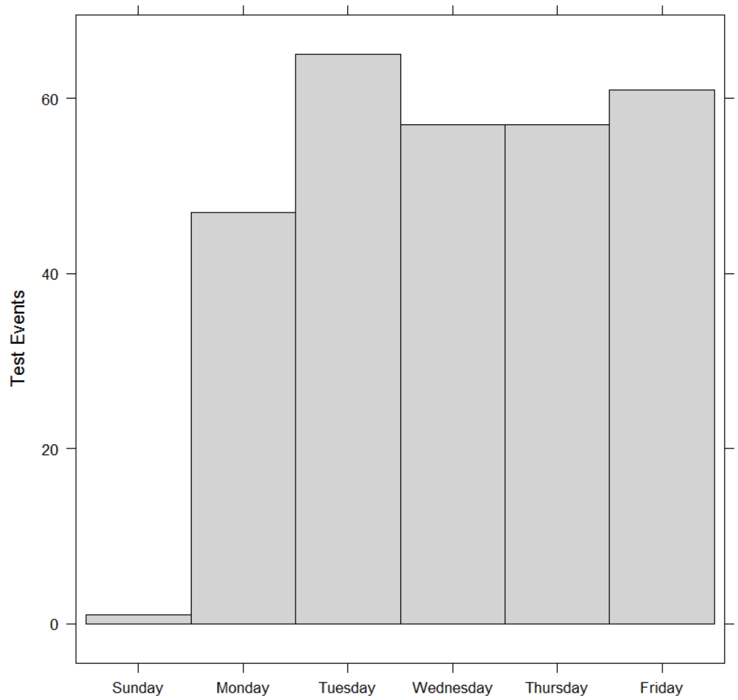


Figure 11.19. Count of Test Events According to the Day they Started

Test events were most often initiated at 07:00 and 17:00 local Mountain Time. A histogram of the hours on which the test events began is shown in Figure 11.20. Curtailment tests on a new group of LCMs that immediately followed a previous test were not counted as new events. Idaho Falls rotated through subpopulations of LCMs, each group experiencing only one hour of curtailment, in order to achieve 2-, 3- or 4-hour-long events.

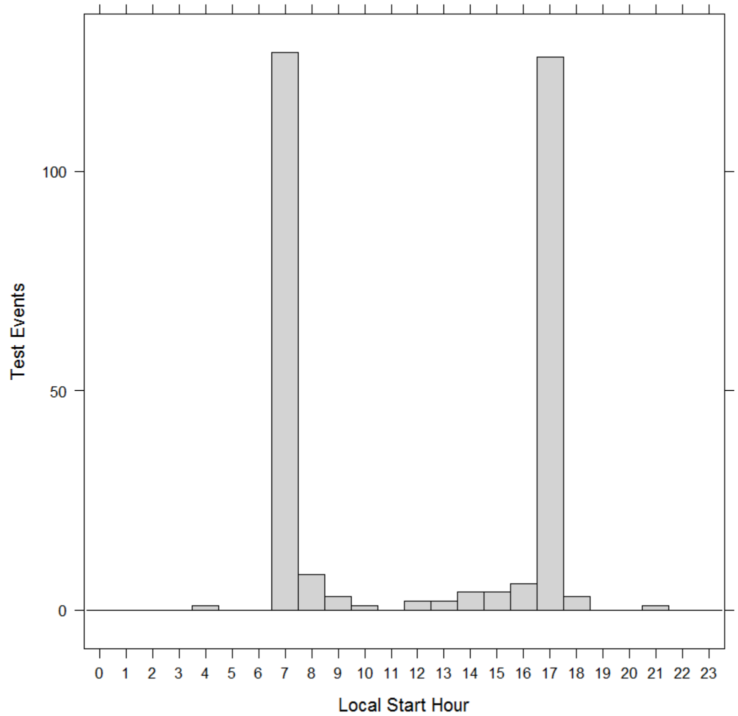


Figure 11.20. Count of Test Events According to the Local Hour they Began

The water heater load controllers permitted their homeowners to opt out of events. Data concerning occurrences of opt-outs were received for a period from December 2014 through March 2014. The controllers would ignore signals received from the utility for a period of an hour when directed to do so by an occupant. Figure 11.21 shows these opt-out occurrences per hour as a percentage of the total number of installed water heater controllers. At most, five occupants (~2.3%) opted out of an announced curtailment event.

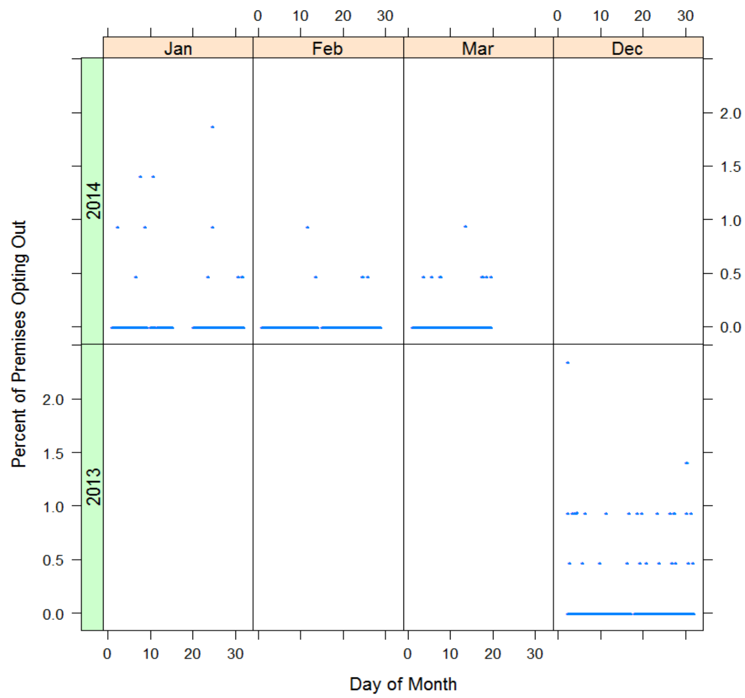


Figure 11.21. Percentage of Premises Reported to have Opted Out of Water Heater Events Each Hour

11.4.2 Water Heater Control Performance

Idaho Falls had projected to reduce yearly load by approximately 15,000 kWh and demand by 20 kW by engaging the LCMs on water heaters. The project was unable to confirm any significant change in average premises power during curtailment events. Several approaches were investigated. By observation near purported event periods, the time series never appeared to exhibit a definitive reduction “step” in load at the premises during either transactive or test event periods.

Analysts were unsuccessful at confirming any power reduction at the times the water heaters may have been commanded to curtail their loads. The utility’s anticipated performance could not be confirmed. Table 11.10 summarizes the results of eight unsuccessful baseline comparisons. All eight comparisons used the aggregated power of the approximately 213 premises that had received water heater controllers as the test group. The first column of Table 11.10 states whether analysts compared the test group against a regression model baseline or against the average power of similar groups of premises that did not receive the project’s water heater load controllers.

The second column further qualifies the regression and comparison methods. All the regression models fit the test-group power to month, heating or cooling regime, hour, day of week, and permutations of outdoor temperature with each of the previously listed variables. Because there was uncertainty in when the system was, in fact, commanded to curtail its load, the regression was first conducted without using the event period as an independent variable. Then the regression model was reconstructed to explicitly fit against the event periods. Regardless of whether regressions explicitly included the events, baseline time series were constructed to emulate what the test group’s power might have been without water heater curtailments.

The third column states which defined event periods were assumed to have been responded to. Idaho Falls Power had originally stated that the system responded to all the transactive events. Based on communication received by the project in November 2013, it was believed the automation to make the system respond to the transactive signal was not yet completed but would be completed soon. The transactive events prior to December 2013 were therefore not used by analysts. Idaho Falls Power also submitted to the project a list of hours that were described at test events. Therefore, the project also looked for the impacts of water heater curtailment during these times.

The power impacts determined for the eight baseline analyses in Table 11.10 all suggested power had *increased* during curtailment events, regardless of the baseline methods and events. Only three of the eight results may be statistically relevant. The project cannot explain this outcome.

Table 11.10. Results of Many Unfruitful Analysis Investigations that were Attempted for Water Heater Curtailments

Events	Baseline Type	Baseline Qualifier	Power Impact (kW)	Confidence[a]
Transactive events (December 2013 – August 2014)	Regression	Ignoring transactive events	0.024 ± 0.020	0.55
		Including transactive events	0.024 ± 0.20	0.55
	Comparison	Same feeder, no LCM	0.061 ± 0.046	0.91
		Similar feeder, no LCM	0.012 ± 0.023	0.71
Water heater test events (August 2013 – February 2014)	Regression	Ignoring test events	0.029 ± 0.016	0.97
		Including test events	0.072 ± 0.016	1.00
	Comparison	Same feeder, no LCM	0.104 ± 0.028	1.00
		Similar feeder, no LCM	0.012 ± 0.011	0.86

(a) This value represents the approximate fraction of the distribution's tail that is above zero. Values in this column greater than 0.95 suggest there might be 95% confidence that the power impact was an *increase* in power

The project cannot confirm from available data that any reduction in power was achieved from the curtailment of Idaho Falls Power water heaters. In fact, there is evidence that load might have *increased* during test events that were reported to the project. Based on purely hypothetical impacts, the system, as implemented, might have reduced demand by 10–40 kW during curtailment events. Analysts determined not to seek the relatively small 10–40 kW impact among the feeder's power data, which was typically 8.2 MW for this Sugarmill feeder. The expected impact would be only about 0.1–0.5% of the total feeder measurements.

No further evaluation of benefits was conducted for this asset system.

Idaho Falls Power observed that it had been difficult with their system to determine whether the load controllers had, in fact, operated at specific times. Their customers could not tell whether they were working either. As the project analysts have observed, the utility said that event timing and programming of the devices were challenging. The 1-hour events used for testing were not nearly long enough to determine real energy reduction value. When queried about their involvement, 42% of the Idaho Falls Power customers rated the water heater control program as “least obtrusive.”[1]

11.5 Battery Storage (with PHEV and Solar)

Idaho Falls Power installed a 10 kW, 40 kWh Demand Energy Networks (Demand Energy Networks, Inc. 2015) battery storage system, which was to be charged and discharged based on the TIS. The battery system was located near four PHEV charging stations and a 1.73 kW photovoltaic (PV) solar panel system at the utility’s headquarters in Idaho Falls, Idaho. The system is shown installed in Figure 11.22.

The system was declared installed and operational by January 17, 2013.

Figure 11.22. Idaho Falls Power Battery Storage and PV Array

The annualized costs of the system and its components are listed in Table 11.11. It is estimated that the system would cost $158.7 thousand per year. The greatest costs were assigned to help set up the transactive functionality, purchased the electric vehicles, engineer system integration, and administer the project. Smaller costs were anticipated for utility staff labor, cyber security services, solar panels and the batteries.

[1] Information in this paragraph was extracted or paraphrased from a presentation named “IFP - Battelle 1-22-15.pptx” that Mark Reed presented to project participants January 29, 2015.

Table 11.11. Idaho Falls Power Costs of PHEV, Solar, and Battery Storage System

	Component Allocation (%)	Annualized Component Cost ($K)	Allocated Annual Component Cost ($K)
Transactive Node	14	317.1	45.3
PHEV Cars	100	43.9	43.9
Engineering Services (integrating solar, battery, and Demand Energy Networks application with SCADA)	100	18.3	18.3
Administrative	11	151.5	16.8
Idaho Falls Power Staff Labor	100	13.5	13.5
Cyber Security Consulting	13	85.4	10.7
10 kW Battery System	100	8.1	8.1
Solar PV Panels with Solar Tracking System	100	1.9	1.9
Data Acquisition (monthly recurring cost per charger, 4 chargers)	100	0.3	0.3
Total Annualized Asset Cost			**$158.7K**

11.5.1 Data from, and Performance of, the Battery Storage System

Data was never made available from the battery storage system. The battery's vendor, Demand Energy Networks, encountered financial difficulties and stopped supporting the device soon after it had been installed. The utility was left with no way to control the battery storage module.

11.6 Thermostat Control

Idaho Falls Power installed 42 programmable, controllable thermostats at premises supplied with electricity from its Fifteenth substation. The ZigBee Smart Energy Profile devices were installed and tested October 31, 2012, and the thermostat system was declared installed and useful by December 21, 2012.

The program was offered to residents who had one thermostat and used primarily electricity to heat and cool their occupied spaces. The municipality observed that a surprising number of their customers did not know what kind of heating system they had as they responded to the recruiters.

Startup was delayed by the additional steps necessary to integrate the thermostats with the vendor's advanced metering.

The annualized costs of this system and its components are listed in Table 11.12. The greatest costs were the cost for establishing the transactive node and its connection to this system and the utility staff labor working with the project to install this system. Intermediate costs were for demand-response software, administration costs, procured engineering cyber security help, and the AMI system. The cost of the thermostats themselves was relatively small.

Table 11.12. Idaho Falls Power Costs of Thermostat Control System

	Component Allocation (%)	Annualized Component Cost ($K)	Allocated Annual Component Cost ($K)
Transactive Node	14	317.1	45.3
Idaho Falls Power Staff Labor	25	119.7	29.9
Software for Demand Response	33	65.5	21.8
Administrative	11	151.5	16.8
Engineering	33	42.7	14.2
Network Engineering for Transactive Control and Cyber Security	13	85.4	10.7
AMI Meter System			8.4
• Equipment	100	0.3	0.3
• Installation and Integration	100	0.2	0.2
• Testing (new and existing meters)	100	0.0	0.0
• Communication Network System	20	3.9	0.8
• Head-End Server	20	1.2	0.2
• System Applications (includes MDM)	20	19.4	3.9
• AMI Four-Year Standard Maintenance Warranty	17	17.9	3.0
Vulnerability and Penetration Testing for AMI Network	14	48.8	7.0
Outreach and Education	25	24.4	6.1
Load-Controlling Thermostats (~42)	100	1.0	1.0
Total Annualized Asset Cost			**$161.2K**

11.6.1 Thermostat System Operation and Project Data

Idaho Falls Power recruited 42 residents to receive and help test programmable, communicating thermostats at their premises. They recruited another 29 residents who had received AMI and also were supplied by the Fifteenth substation to help baseline this study. The baseline group did not receive controllable thermostats from the utility. Residents programmed their preferred temperature set points. The utility was able to temporarily increase or decrease the test group's set points during events. The project calculated averages of the power data from the test and baseline groups.

Idaho Falls, Idaho, is a relatively cold location, and the average premises power was found to have a strong winter morning peak. The morning peak completely disappears in the summer. The hourly weekday premises power levels for each season are shown in Figure 11.23 for the average of the premises with project thermostats. The mean premises power was 1.92 kW, including all days of the week and all project data.

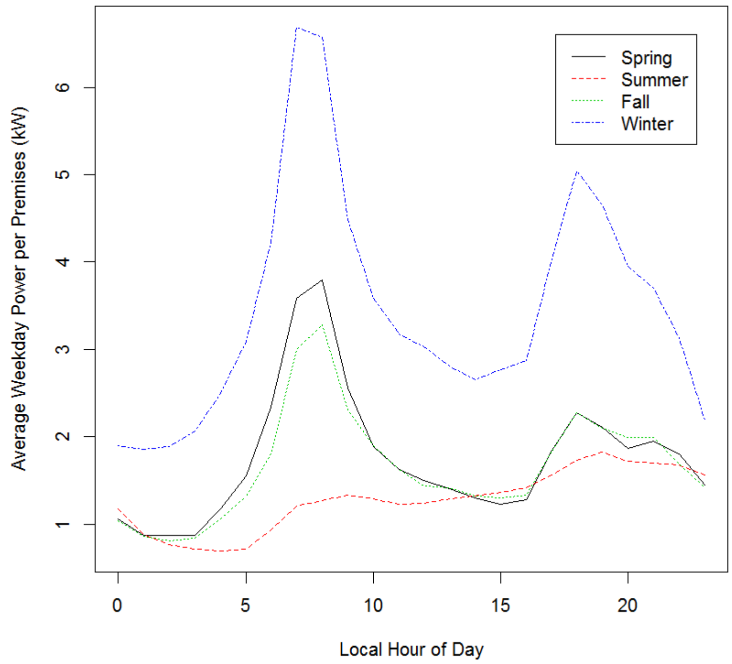


Figure 11.23. Seasonal Weekday Premises Power for the Idaho Falls Power Residents that had Project Thermostats

Some premises power data was received starting from May 2012, but several months of data were missing from fall 2012. Good premises power data was received from mid-December 2012 until the end of August 2014 when project data collection ended. The project's average premises power data series from those premises that received project thermostats is shown in Figure 11.24.

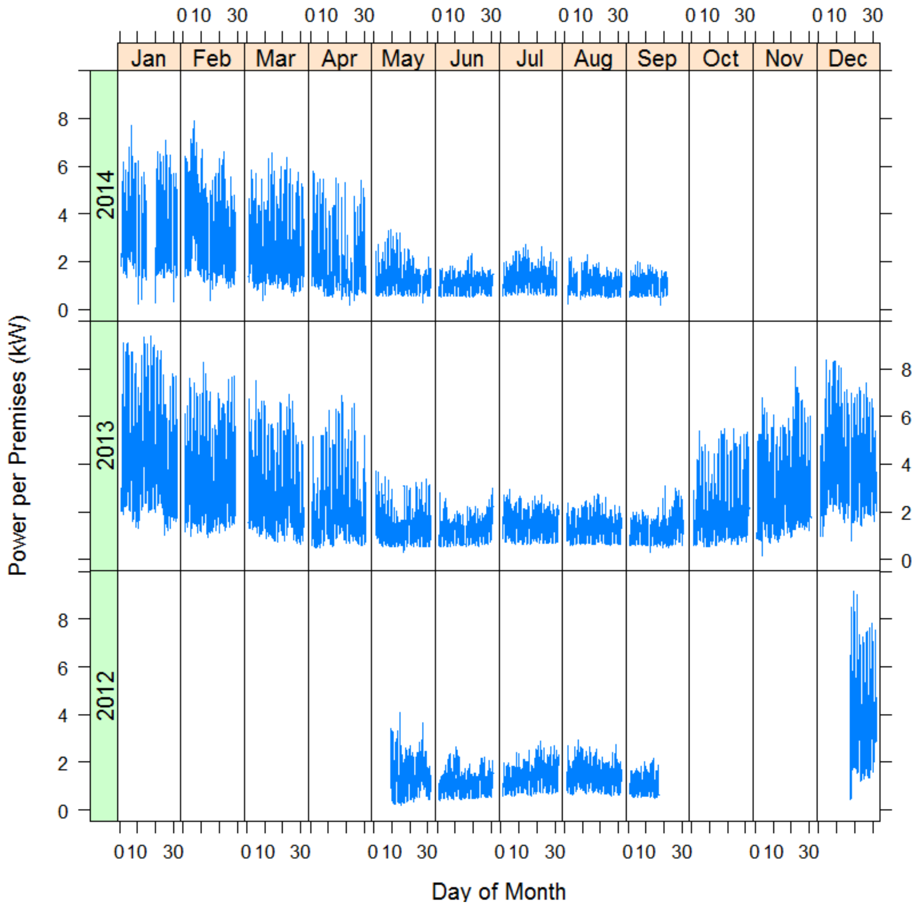


Figure 11.24. Power per Premises for Residences that Received Project Thermostats

Analysts observed that average premises loads had relatively large diurnal peaks, especially in winter. This was evident in both Figure 11.23 and Figure 11.24. The histogram of the average premises powers is shown in Figure 11.25, and this histogram confirms that a small number of premises have much higher power levels than most. Thermostatic load is clearly a driver of system peak demand in Idaho Falls.

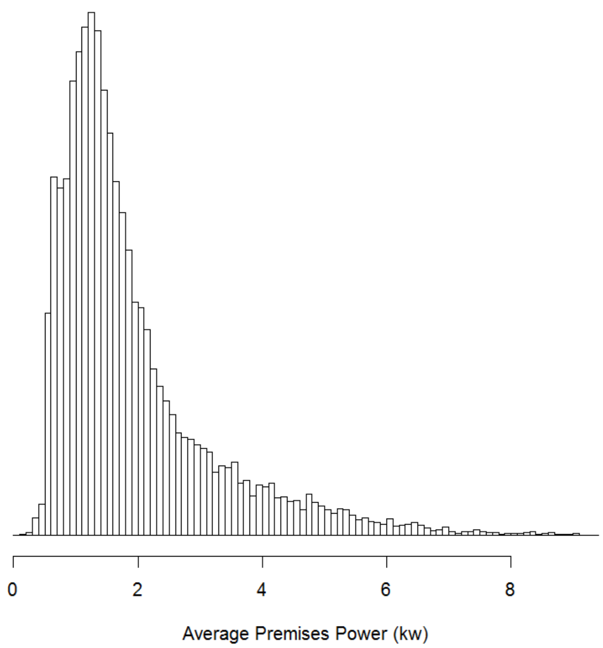


Figure 11.25. Relative Occurrences of Average Premises Power Levels for Residences that Received Project Thermostats

The transactive system began advising events for this asset in February 2013. There were altogether 410 events advised by the transactive system before the end of the project September 1, 2014. Of these, 241 occurred after September 2013, when the thermostat control began. The events were most often either exactly 1 hour long or 1 hour and 15 minutes long.

As shown in Figure 11.26, this asset was configured by the transactive system to generate events only on weekdays. Only the events following September 2013 were used in the creation of this histogram. The asset used the "daily" toolkit function that strove to place exactly one event during each weekday, coincident with the receipt of a TIS representing the highest unit cost of electricity.

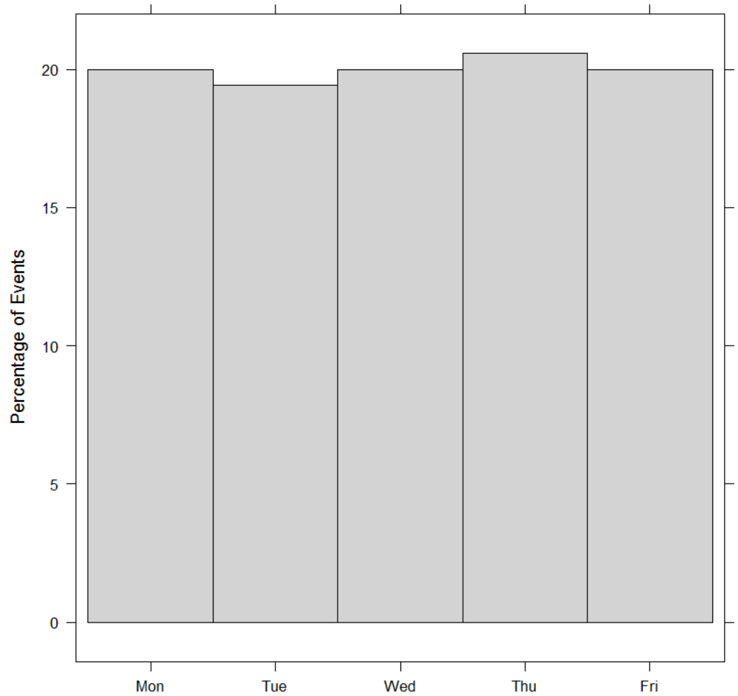


Figure 11.26. Weekdays of Events that Occurred after September 2013

Figure 11.27 uses all the transactive events that were advised to the thermostat control system by the transactive system, both before and after September 2013 when thermostat control began. Events were advised regularly throughout the year and during every calendar month.

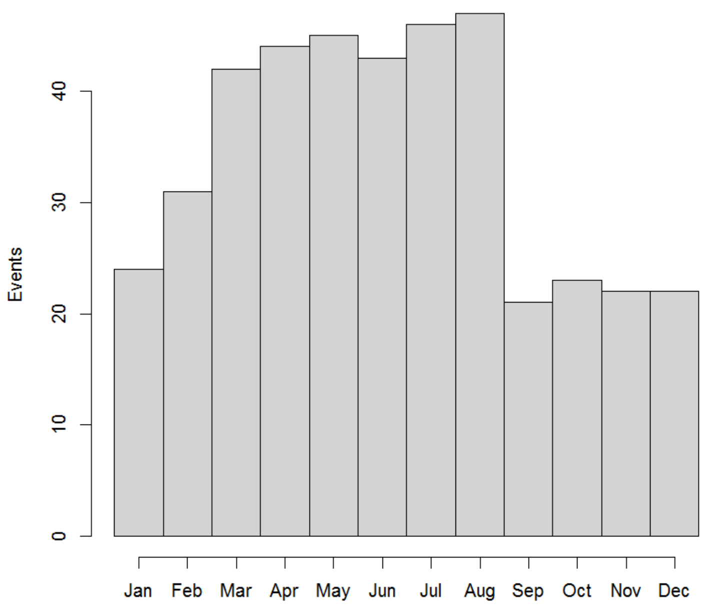


Figure 11.27. Count of All Thermostat Events by Calendar Month

Figure 11.28 is a histogram of the hours during which the thermostat control events were initiated. These events were believed to have been initiated by the project's transactive system, so the events were inferred to be coincident with the transactive system's advisory control signal for this asset. Only the events after September 2013 were used because communications from Idaho Falls Power led the project to believe that the thermostats were not controlled until then.

A startling number of transactive events began very late in the evening. The project struggled early on to make the TIS meaningful with a relevant diurnal pattern. Unfortunately, these problems persisted and may have caused assets like this one to become induced to respond at nonsensical times. The fact that events occurred far off peak hours may have reduced the magnitudes of the observed impacts as well.

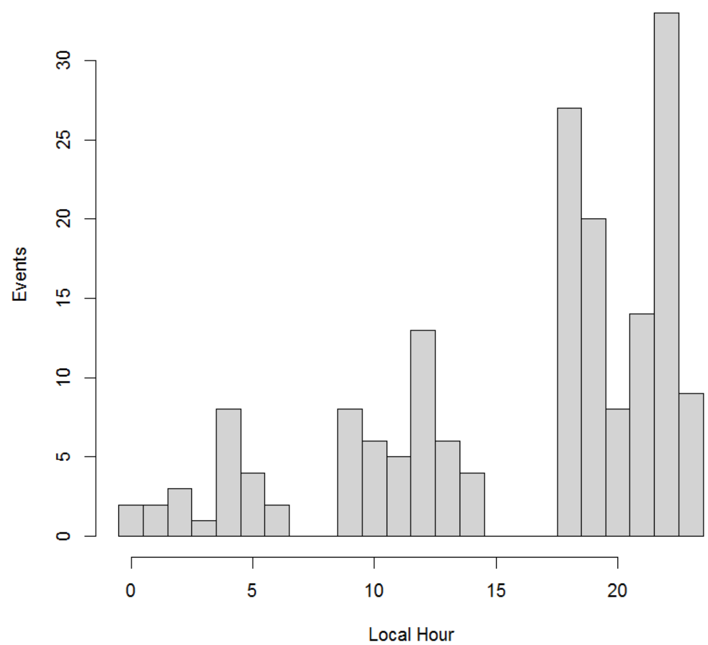


Figure 11.28. Count of Events after September 2013 by Their Local Starting Hour

11.6.2 Analysis of the System of Controllable Thermostats

Based on all the thermostat events and results of both the regression and comparison methods, the load was reduced by 0.052 ± 0.054 kW per premises during event periods. Even though the regression and comparison methods very closely agreed about the magnitude of the impact, the result has been assigned a greater uncertainty because the uncertainty in the comparison method was large. The regression model result had high confidence. Calculated results from the regression model approach are listed in Table 11.13. No results could be estimated for the months September, October, or November because the thermostats were not controlled these months.

Table 11.13. Average Change in Premises Power During Thermostat Events by Calendar Month, Based on the Period from December 2013 through August 2014

	Δ Premises Power (kW)[c]
Jan	0.11 ± 0.09
Feb	0.01 ± 0.16
Mar	−0.18 ± 0.08
Apr	−0.15 ± 0.07
May	−0.15 ± 0.07
Jun	−0.11 ± 0.05
Jul	0.02 ± 0.06
Aug	0.01 ± 0.05
…[a]	-
Dec[b]	0.02 ± 0.14

(a) The utility reported in November 2013 that the system was not yet responding to the transactive signal. Therefore, no results are being reported from September, October, and November 2013.

(b) This data was from December 2013. All other reported data were from months of 2014.

(c) A negative power in this column means that there had been a reduction in the average power consumption at the premises with the thermostats.

The value of the HLH and LLH energy that was potentially displaced by the thermostat events was small. The energy impacts and the cost impacts to the utility of the energy usages are shown in Table 11.14 for the impact of all the thermostats and the months that thermostat control was exercised. Only the results of the regression approach were used in the creation of this table. The total value of the annual avoided energy supply was only about \$6 ± 9. The project was not able to determine how much of the energy that was conserved during events was actually conserved and how much was simply shifted within the day to non-event times, so even this estimate could be higher than it should be.

Table 11.14. Total HLH and LLH Energy Impact and Value of Avoided Supply Energy, Based on the Period from December 2013 through August 2014

	HLH		LLH		Total
	(Δ kWh)[(a)]	(Δ $)[(b)]	(Δ kWh)[(a)]	(Δ $)[(b)]	(Δ $)[(b)]
Jan	70 ± 77	2.70 ± 2.90	24 ± 75	0.70 ± 2.30	3.40 ± 3.70
Feb	−96 ± 93	−3.60 ± 3.50	103 ± 54	3.20 ± 1.70	−0.40 ± 3.80
Mar	−152 ± 73	−4.60 ± 2.20	−23 ± 32	−0.60 ± 0.80	−5.20 ± 2.40
Apr	−126 ± 54	−3.30 ± 1.40	7 ± 32	0.10 ± 0.60	−3.10 ± 1.50
May	−108 ± 54	−2.30 ± 1.10	−2 ± 25	−0.00 ± 0.30	−2.30 ± 1.20
Jun	−58 ± 32	−1.30 ± 0.70	−29 ± 21	−0.40 ± 0.30	−1.80 ± 0.80
Jul	44 ± 43	1.30 ± 1.30	−26 ± 36	−0.60 ± 0.90	0.70 ± 1.60
Aug	28 ± 40	1.00 ± 1.30	8 ± 12	0.20 ± 0.30	1.20 ± 1.40
…	-	-	-	-	-
Dec	−9 ± 141	−0.30 ± 5.50	49.4 ± 32.8	1.60 ± 1.10	1.30 ± 5.60
Totals[(c)]	**−410 ± 220**	**−10.40 ± 5.50**	**110 ±120**	**4.20 ± 3.40**	**−6.20 ± 8.60**

(a) Negative energy values in this column mean that load was reduced.

(b) Negative monetary values in this column mean that the utility's supply costs were reduced by this amount. The cost magnitudes have been rounded to the nearest dime.

(c) These are actual sums from the nine months that are listed.

A similar analysis was conducted to estimate the impact of the thermostat control on the municipality's peak monthly demands and demand charges. These findings are summarized in Table 11.15. Idaho Falls Power's demand charges are determined by the average monthly load during HLH hours and by their peak-hour demand each month. The utility's peak hours were modeled using hours that distribution power was found to be greatest each month that distribution data was available. If the thermostats were not controlled during those example hours in a given calendar month, no credit was granted that month. If the thermostats had been controlled for at least one of the example peak hours in a month, then the impact was calculated from the estimated change in power for that hour, averaging among the one or more coincident hours.

This approach is generous in that it presumes that not only the peak hour, but also the day of the peak hour, can be correctly identified each month. If credit had been given only when the utility correctly selected both the peak hour and its day, the correlation and calculated benefit would have been still lower.

Based on all the utility's demonstrated control of thermostats, the utility's control of thermostats reduced their demand charges by about −$473 ± 51 per year. If the demonstrated results may be extrapolated from the nine operational months to a full calendar year, perhaps the energy impact might have been a reduction of 400 ± 251 kW in the wholesale energy that the utility must purchase that would be worth $631 ± 59 reduction, based on BPA load-shaping rates (Appendix C). If the performance in March could be replicated throughout the year, the impact might be up to −$3,516 ± 132.

Table 11.15. Estimated Demand-Charge Determinants and the Estimated Monetary Impact of Thermostat Control on Demand Charges after September 2013

	Δ aHLH (kW)	Δ aHLH ($)	Δ Peak Demand (kW)[a]	Δ Peak Demand[a] ($)	Δ Demand Charges ($)
Jan	0.17 ± 0.18	−2 ± 2	0.0	0	−2 ± 2
Feb	−0.25 ± 0.24	3 ± 3	−11.7	−128	−125
Mar	−0.36 ± 0.18	3 ± 2	−33.2 ± 4.2	−296 ± 38	−293 ± 38
Apr	−0.30 ± 0.13	2 ± 1	4.0	30	33
May	−0.26 ± 0.13	2 ± 1	0.0	0	2 ± 1
Jun	−0.15 ± 0.08	1 ± 1	0.0	0	1 ± 1
Jul	0.11 ± 0.10	−1 ± 1	0.0	0	−1 ± 1
Aug	0.06 ± 0.09	−1 ± 1	2.3	23	22
…[b]	-	-	-	-	-
Dec	−0.02 ± 0.35	0 ± 4	−9.6	−110	−110

(a) A zero in this column may mean that the month's thermostat events never coincided with example utility peak hours.

(b) Data were not reported for September through November because the thermostat system was not demonstrated responsive to the transactive signal during any of these calendar months.

The municipality recorded the numbers of participants who elected to opt out of thermostat events. The project restated these as a percentage of respondents per hour, which is shown in Figure 11.29. This data was received for the months from December 2013 through much of March 2014. As many as five of the 42 participating premises (~12%) opted out of thermostat control one hour. The project looked at the coincidence of these actions with the event periods. Of the hours that at least one premises opted out of thermostat events, 6.4% of these times were coincident with event intervals.

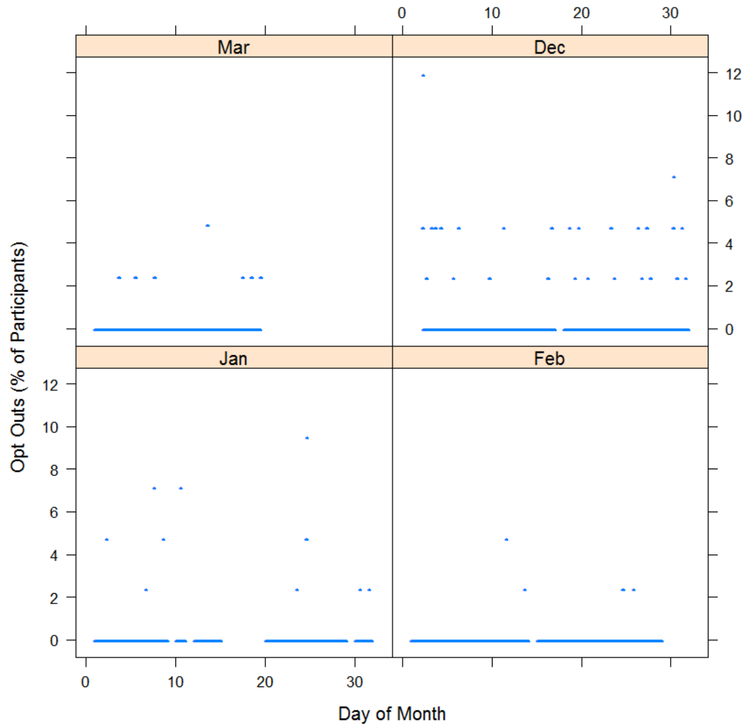


Figure 11.29. Percentage of Residents Opting Out of Thermostat Events in a Given Hour from December 2013 through much of March 2014

Upon surveying the participating residents late in the project, the utility learned that there was very little negative feedback. A few customers had inadvertently locked their thermostat's keypad during the demonstration. Also, some older heating, ventilation, and air-conditioning systems had been found to be difficult to integrate with the new digital equipment. Three-fourths of those surveyed said they would enroll in this program again going forward, but 15% said they would not. Sixty-five percent of the thermostat households indicated they had overridden an event at least once.[1]

11.7 In-Home Displays

Idaho Falls Power installed 860 IHDs, and 431 of these premises were identified in the data supplied by Idaho Falls Power as belonging to an IHD test group. Premises that had received other smart grid equipment in addition to the IHDs were excluded from the test group. The utility expected energy conservation from the installation of these devices due to behavioral changes from customers who were provided feedback on their energy consumption via the IHDs. Customers were able to view the following information when they visited the IHD:

- energy consumed in the current month
- energy consumed in the prior day
- the premises' energy consumption profile during the prior 24 hours

[1] Ibid.

- energy consumption estimated for the major appliance categories
- conservation tips
- utility service status
- weather information and forecasts
- demand-response events

The system was declared installed and tested February 22, 2013.

The annualized costs of the system and its components were estimated as shown in Table 11.16. The greatest costs were those allocated to the system for utility staff labor, for the AMI system, for administration of the project, and for the purchase and installation of the IHD hardware that includes the ZigBee smart energy profile. Smaller costs were estimated for integrating the system with the transactive system, for improving cyber security, and for outreach activities.

Table 11.16. Idaho Falls Power Costs of In-Home Display System

	Component Allocation (%)	Annualized Component Cost ($K)	Allocated Annual Component Cost ($K)
Idaho Falls Power Staff Labor	25	119.7	29.9
AMI Meter System			23.7
• Equipment	100	9.2	9.2
• Installation and Integration	100	5.7	5.7
• Testing (new and existing meters)	100	0.9	0.9
• Communication Network System	20	3.9	0.8
• Head-End Server	20	1.2	0.2
• System Applications (includes MDM)	20	19.4	3.9
• AMI Four-Year Standard Maintenance Warranty	17	17.9	3.0
Administrative	11	151.5	16.8
In-Home Display Installation (ZigBee smart energy profile)	100	11.0	11.0
Network Engineering for Transactive Control and Cyber Security	13	85.4	10.7
Vulnerability and Penetration Testing for AMI Network	14	48.8	7.0
Outreach and Education	25	24.4	6.1
Total Annualized Asset Cost			**$105.1K**

11.7.1 Data from the In-Home Display System

Idaho Falls Power recruited 431 residents to receive IHDs. The test-group premises were located on many feeders in the distribution circuit. Idaho Falls Power also recruited another 212 premises to act as a baseline for this demonstration. The baseline premises had received AMI, but they did not receive the IHD hardware and the energy information that was available to the test group via their IHDs. The IHDs were installed at nearly the same time as the AMI had been, which created some challenges for analysts to separate the influences of the AMI from those of the IHDs.

The average per-premises power for the test group and its baseline are shown in Figure 11.30. Because the project wished to understand the impact from installing IHDs, the utility provided the project historical data from years before the installation of the IHDs and AMI. Prior to the installation of AMI, utility power data was limited to monthly meter reads. Therefore, the early data from meter reads is shown to be a constant average power throughout each month. It was presumed that the meter reads had occurred precisely at the months' transitions, which, of course, cannot be strictly true. This is a source of error. Energy prior to the installation of AMI might have been shifted between prior and following months.

The consumption by the test and baseline groups rose and fell similarly. Monthly data suggests that the baseline group ("No IHDs") typically consumed more energy than the test group ("IHDs") even before the AMI had been installed. The average of the all of the project's test-group premises power data was 1.55 kW, and that of the baseline group was 1.54 kW.

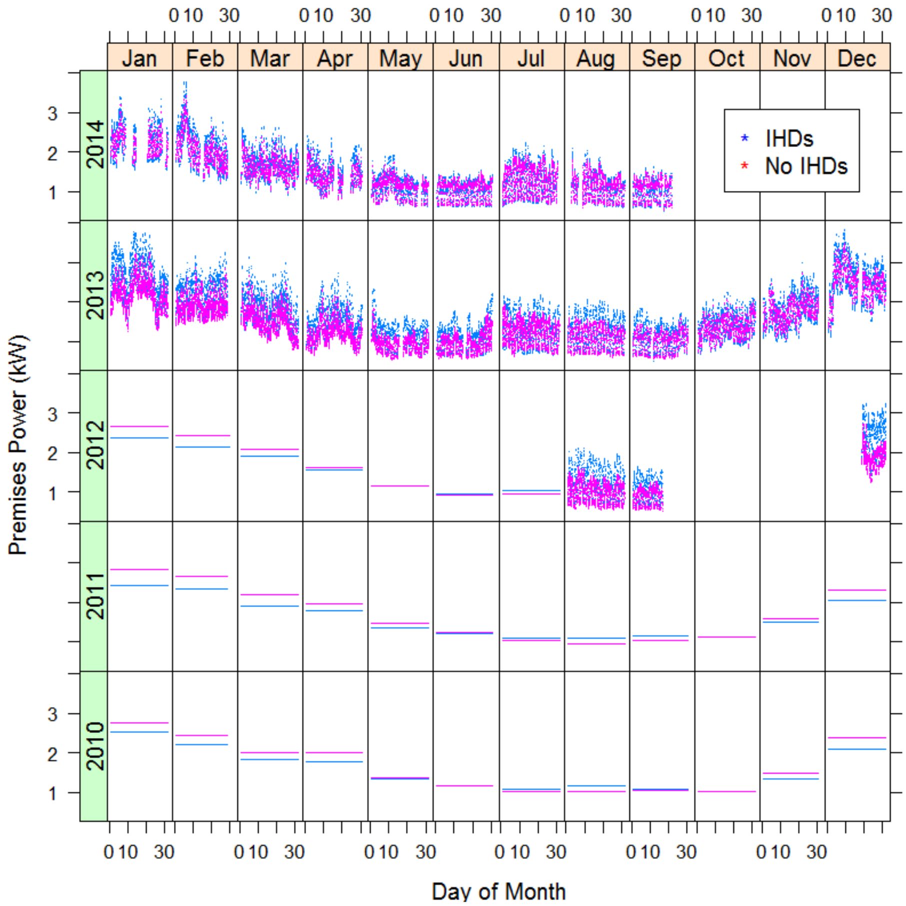


Figure 11.30. Monthly and 5-Minute Data Made Available to the Project by Idaho Falls Power

The project found complete sets of temperature data from the Idaho Falls, Idaho, regional airport and from the weather station IDA (central Idaho Falls on the west side of the Snake River). Nearly five years of these ambient temperatures are shown in Figure 11.31. While the temperature time series were found to be quite complete, temperatures were interpolated across any short data gaps less than 6 hours. It is this temperature time series that was used to generate the temperature-correction regression model and its baseline.

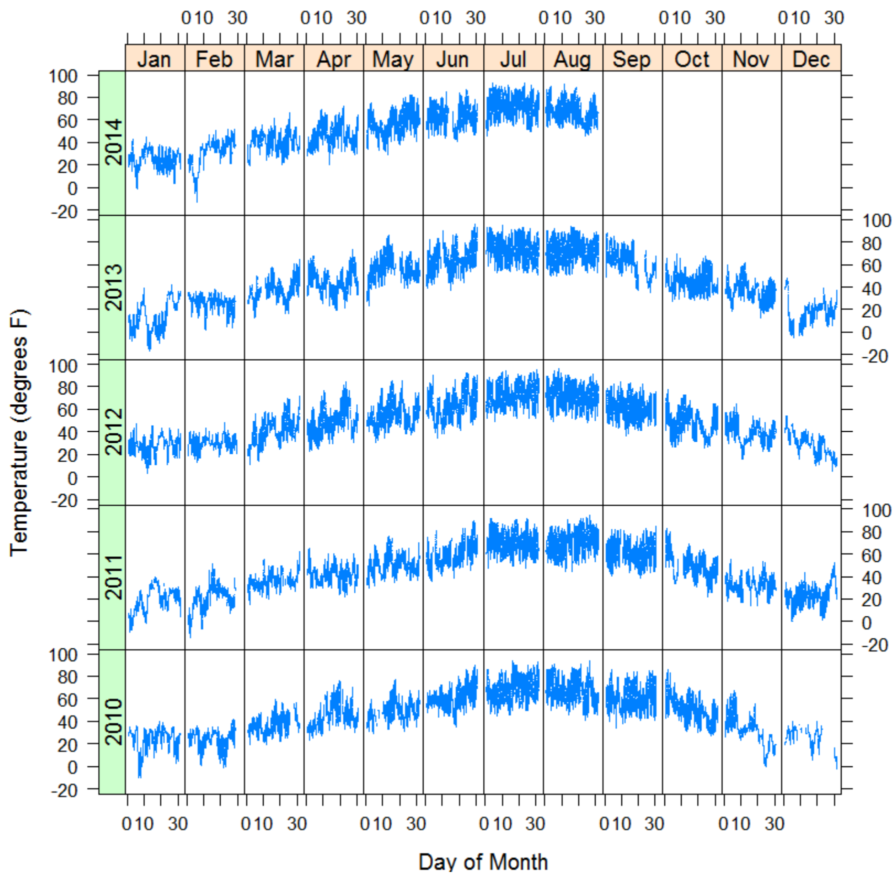


Figure 11.31. Temperature Data Available to the Project at the Idaho Falls Site

11.7.2 Analysis of the In-Home Display System

Historical data intervals were 1 month long, so regression modeling also was based on 1-month intervals. The average premises power data was converted into average monthly premises energy consumption for both the test group and the baseline group. These monthly energy usages are plotted as a function of net degree-days in Figure 11.32, where net degree-days have been defined as the sum of the product of all interval durations and their corresponding Fahrenheit temperatures for the month.

The temperature-based data representation reveals the typical curve that increases to the left—the heating curve—and to the right—the cooling curve. A separation between cooling and heating regimes was determined precisely as 57.5°F. This is the temperature at which the linear regression fits to warm temperatures (cooling regime) and cold temperatures (heating regime) intersect, giving a minimum total residual error for the two linear models.

In Figure 11.32, both the test and baseline (Control) groups are further distinguished by whether the months preceded or followed February 2013, the month when the IHDs are believed by the project to have begun informing their residences about energy consumption. Observe that the points after February 2013 appear to have a much more linear relationship—a stronger temperature correlation—than months before. The earlier months are probably affected by the uncertain dates and times of manual meter reading.

For the test group, if the information from the IHDs was, in fact, effective at reducing electricity consumption, the months after February 2013 should fall below those before February 2013. The impact for the test group includes the effects of both the IHDs and the AMI system that was installed about the same time. The baseline group received AMI, but they did not receive IHDs. If the baseline group after February 2013 falls below the values in the months before then, the difference might be attributed to the AMI alone. The differences between the test and baseline groups might inform us about the impact of IHDs alone.

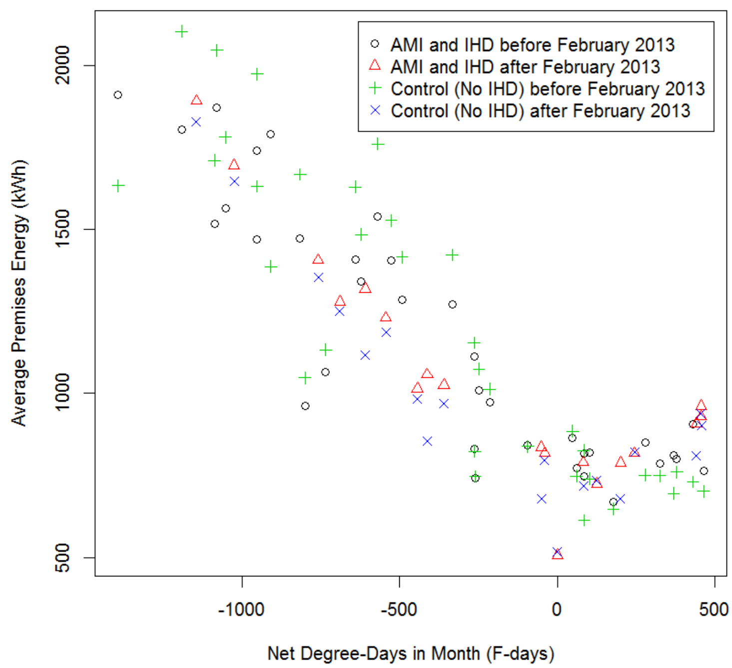


Figure 11.32. Measured Premises Energy Usage from Regression Models of the Test and Comparison Groups from Before and After February 2013 Plotted against the Net Degree-Days that Month

The data of Figure 11.32 were used for linear regression analysis. One variable in the regression fit was whether the month was before or after February 2013. The model was also fit to cooling degree-days and heating degree-days. These two variables are different from the net degree-days used in the plot of Figure 11.32. The net degree-days are the sum of cooling degree-days and heating degree-days.

Temperature data from project months was used in the regression models for the test and baseline groups before and after February 2013; the modeled per-premises energy usages are those shown in Figure 11.33. This is a check that the modeled energy usages resemble the raw data, which they do.

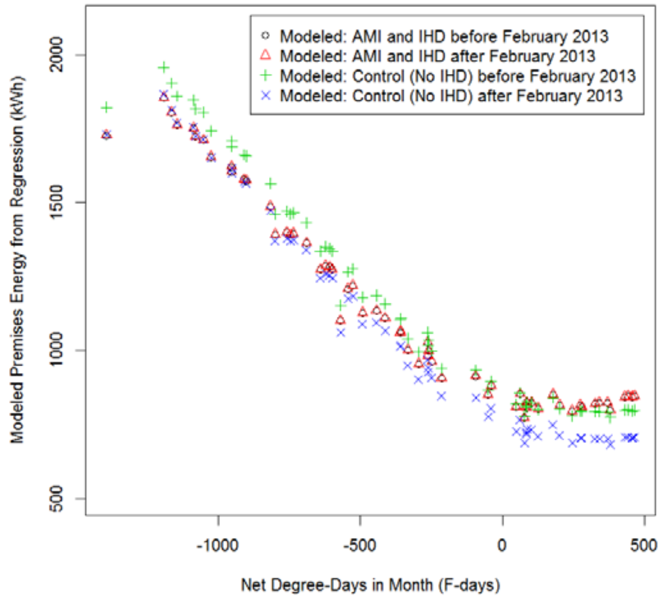


Figure 11.33. Monthly Premises Energy Use from Regression Models of the Test and Comparison Groups from Before and After February 2013 Plotted against the Net Degree-Days that Month

Based on the linear fit conducted in the R software environment (R Core Team 2013), the average monthly energy consumption of the test-group premises that received both AMI and IHDs was *increased* by 2 ± 44 kWh per month after the AMI and IHDs had been installed. The average monthly energy consumption of baseline-group premises that had received AMI and not IHDs was decreased by 92 ± 56 kWh.

The installation of AMI for the baseline group appears to have significantly reduced their metered electricity consumption. The result is not so clear for the premises that received both AMI and IHDs. While the regression fits were similar in respect to cooling and heating degree-days and intercept, the fact that the energy usages of the test and baseline groups behaved differently in warm and cool weather (review Figure 11.33) makes the project reluctant to say much about the impact of IHDs alone.

Looking back at the its experience with IHDs, Idaho Falls Power recounts obstacles including lack of vendor product integration, incomparable capabilities of pricing displays, unexplained meter outliers, and some connectivity issues.[1]

When the municipality polled the test residents after the project, it learned that 39% reported to have looked at the displays daily, 27% weekly, 16% monthly, 10% never and 5% had it unplugged. Sixty percent said their electricity usage remained unchanged throughout the program, while 35% said their usage was slightly lower, and the remaining residents said their usage was significantly lower. Thirty-five percent said they had a positive experience and would like the program to expand; 25% said they would like more information.[2]

[1] Ibid.
[2] Ibid.

11.8 Conclusions and Lessons Learned

Idaho Falls Power tested as many smart grid assets as any other participating utility. Using automated voltage regulation, they demonstrated on one feeder that they could reduce the feeder’s consumption by, on average, 137 kW. The way they operated the system during the project demonstrated they could reduce the annual cost of their energy purchases by $2,710 and could possibly reduce these purchased by $5,420 if the practices were more consistently applied through the year. The system might reduce peak demand charges by $3,570–$6,770 per year. The installation of the automated voltage management practically eliminated low- and high-voltage alarms that had occasionally been received from customer AMI concerning their supply voltages.

The utility corrected the power factor on two feeders that supply large industrial breweries. Power factors were clearly improved. By installing switched capacitors, Idaho Falls Power reduced the average distribution current by 12% on one feeder and 4% on the other. While the project was unable to quantify the impact of line losses as an absolute energy magnitude, line losses are inferred to have been reduced by about 22% and 7.5% on the two feeders.

The utility applied fault detection, isolation, and restoration distribution automation on the feeders from their Sugarmill substation. Yearly reliability indices were collected, but the project did not draw a final conclusion as to whether the circuits’ reliability had been significantly improved.

Idaho Falls Power installed over 200 water heater controllers. Possibly because these controllers were divided into and controlled in four subgroups, neither the utility nor the project was able to discern any reduction in power at the times the water heaters were reported to have been controlled. In fact, some of the statistical approaches applied by the project suggest the utility’s method of water heater control might have even increased overall power. Event periods were uncertain.

The utility installed a 10 kW modular battery energy storage system near it headquarters, which also hosts PHEV charging stations and solar PV power generation. The vendor halted its support of the module before usable data had been procured.

About 42 residents’ premises were given controllable thermostats. The project determined that the devices reduced consumption by about 52 W per premises. The total impact on energy supply and energy-supply costs was negligible. However, based on the way the utility operated the thermostats for part of a year, demand charges were reduced by about $473. Had the system been exercised similarly throughout the year the reduction might have been $631 or more.

Finally, the utility and the project installed IHDs at 431 residences that also received AMI and compared them against similar premises that that had received AMI but not IHDs. The project modeled the change in behavior between months before and after the AMI and IHDs had been installed. The homes receiving only AMI reduced their monthly energy consumption by 92 kWh, but it seems that the premises receiving both the AMI and IHD slightly increased their energy consumption.

When asked about the lessons they had learned from the project’s experiences, Idaho Falls Power said that interoperability is still very new in the smart grid industry, despite some vendors’ claims. Integration of systems was difficult, time consuming and expensive.

Idaho Falls Power polled its residents who had participated in the project. Some of the results from this poll have been inserted elsewhere in this chapter with the technologies being discussed. The entire set of results is not included in this report.

When asked for the principal reasons that participants had participated in the program,

- 44% said helping the community reduce energy use during peak times was very important
- 47% said taking advantage of the latest technologies was very important
- 55% said minimal lifestyle interference was important
- 54% convenience of participation was very important
- 53% said helping the environment by reducing energy use was very important
- 65% said lowering their bill was very important

When asked about their interest in a web portal or mobile app that would enable them to analyze their electric use in near-real time, 17% of respondents gave this the lowest ranking (least interested), while 47% of respondents gave this the top ranking (most interested).[1]

[1] Ibid.