14.0 NorthWestern Energy Site Tests

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NorthWestern Energy serves over 400,000 electric customers in a service territory that covers much of Montana, South Dakota, and Nebraska. The service territory covers approximately 123,000 square miles and manages 27,600 miles of electric transmission and distribution lines. In the Pacific Northwest Smart Grid Demonstration (PNWSGD), they think of their participation as having two distinct sets of activities that address utility and customer activities.

The utility-side activities included

- a form of distribution automation (DA) known as fault detection, isolation, and restoration (FDIR) (Section 14.2)
- integrated volt/VAr control (IVVC) , also known as volt/VAr integration and optimization (VVO) (Section 14.1 and Section 14.4).

On the customer side, the utility provided a set of residential and commercial customers the means to control their electricity usage, respond to time-of-use pricing, and participate in demand-response (DR) load control (Section 14.3).

The utility offered the PNWSGD two field sites. The first involved eight distribution circuits from three of the seven utility substations in Helena, Montana. This site is relatively urban for Montana and engaged approximately 200 residential customer homes and two Montana State government buildings. The second site was a much more rural region and electric circuit near Philipsburg, Montana. This site included only one substation and circuit; the circuit extends 40 miles from the substation and consists of approximately 240 line miles.

Figure 14.1 is Northwestern Energy’s layout diagram that shows the relative placement of the utility’s test equipment and test groups among the distribution circuits that it operates in Helena and Philipsburg, Montana.

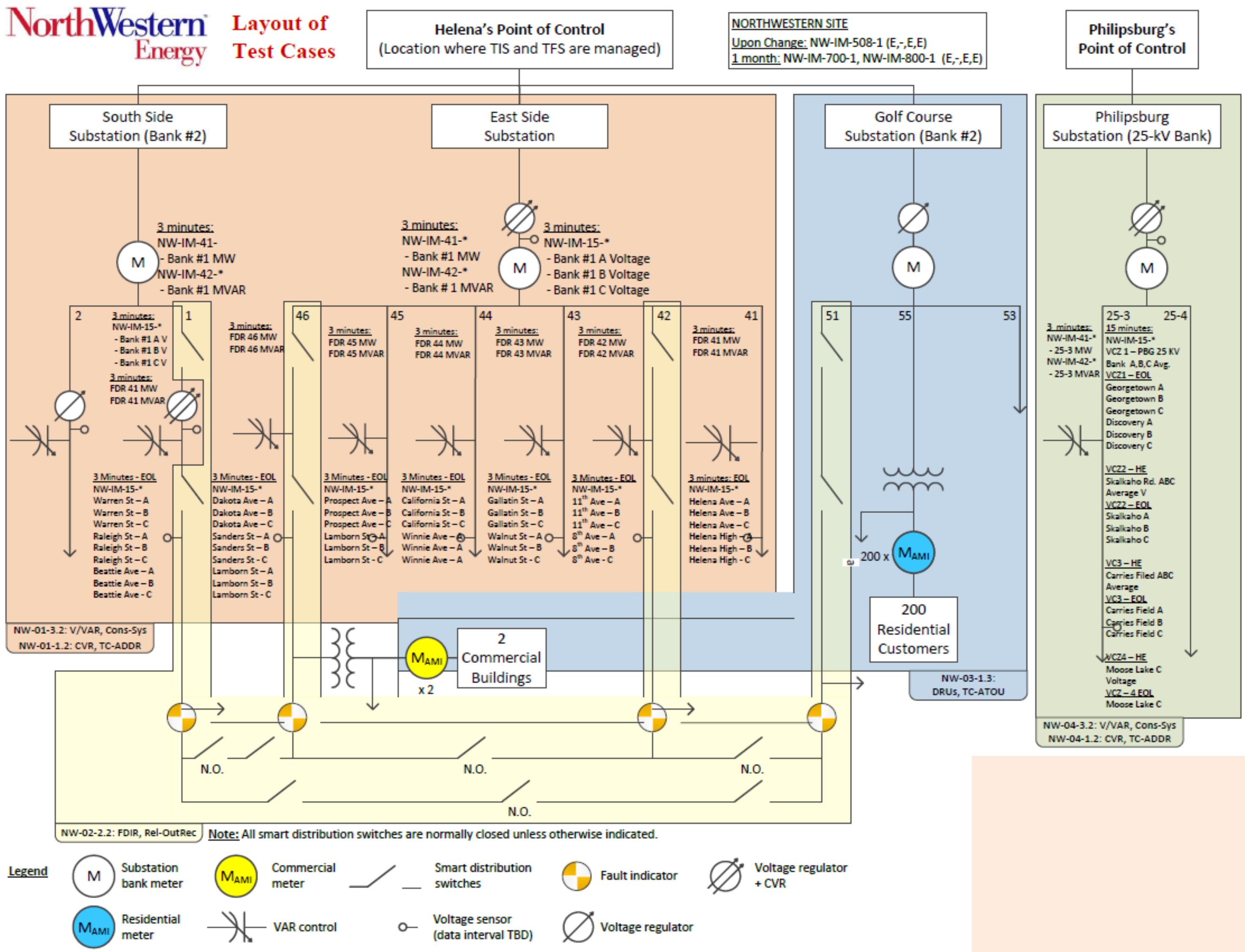


Figure 14.1. NorthWestern Energy Tests Overlaid on the Helena, Montana and Philipsburg, Montana Distribution Circuits

14.1 Automated Voltage and Reactive Power Control – Helena

Automated voltage regulator controls, automated capacitor banks, distribution voltage sensors, and distribution system software were used to automate voltage and reactive power control (IVVC) on several feeders in NorthWestern Energy's Helena, Montana service territory. In Helena, voltage and reactive power control affected 6,100 customers on seven circuits supplied by two substations. The Helena IVVC system was deployed on South Side Feeders 1 and 2 and East Side Feeders 41 through 46.

The utility also installed an IVVC system on a more rural feeder at Philipsburg, Montana, and that system is described later in Section 14.4.

The utility's objective with this system is to demonstrate that voltage and reactive power control automation produces benefits without customer complaints, and to measure its benefits. The system regulates reactive power (VArs) by switching strategically placed capacitors controlled via an algorithm from S&C Electric Company. The algorithm flattens the feeder voltage profile and reduces line losses by increasing power factors in the distribution system.

Helena devices included two Beckwith load tap changer (LTC) controllers, seven Beckwith capacitor controllers, and 48 distribution voltage sensors for end-of-line voltage sensing. The annualized costs of the Helena IVVC system and its components are shown in Table 14.1 and sum to about $181.5 thousand per year.

Table 14.1. Annualized Costs of the Helena IVVC System and its Components

	Component Allocation (%)	Annualized Component Cost ($K)	Allocated Annual Component Cost ($K)
CVR/Volt-VAr and DA System Software	50	154.9	77.5
Helena Capacitor Bank (new banks with controller)	100	33.7	33.7
Helena Communications (radio and tower)	33	72.1	24.0
Helena Distribution Voltage Sensors	100	17.2	17.2
Helena Substation Communications	50	29.7	14.9
Helena Substation RTUs and Relaying	50	21.4	10.7
Helena Substation Regulator/LTC Controls	100	3.6	3.6
Total Annualized Cost			**$181.5K**

CVR = conservation voltage reduction
RTU = remote terminal unit
VAr = volt-amperes reactive

14.1.1 Data and System Operation Concerning the Helena IVVC System

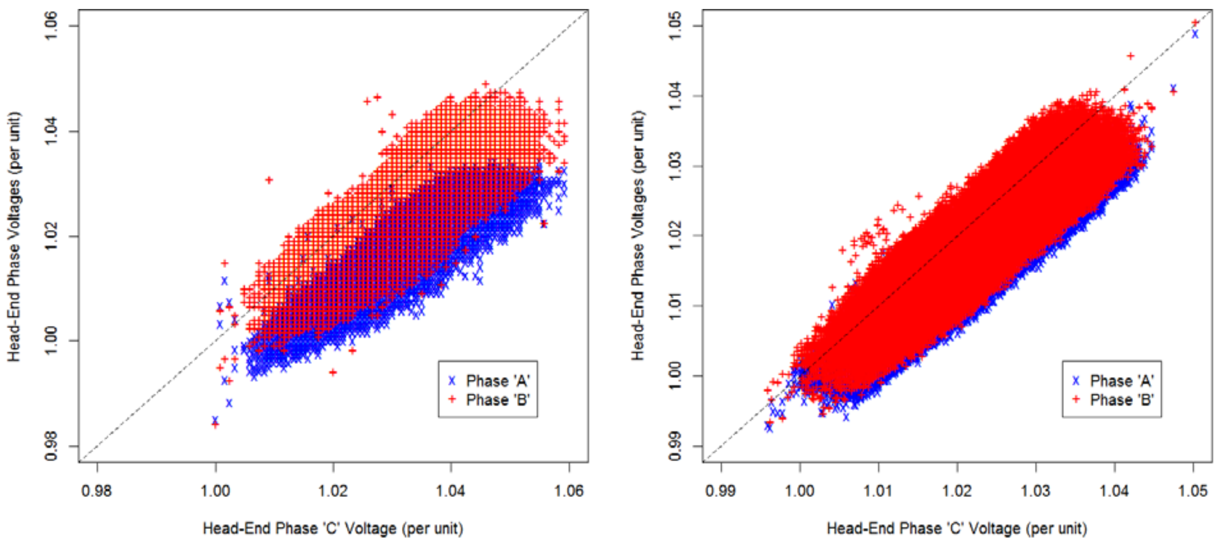
The IVVC voltage status of the South Side and East Side circuits were reported to the PNWSGD by NorthWestern Energy using the many enumerations listed here. The same enumerations were used for both the voltage control and reactive power control components of their IVVC systems:

- "Engaged"
- "Engaged – Comm Restored" (East Side only)
- "Engaged – Scada Restored"
- "Engaged – Via Schedule" (East Side only)
- "Not Engaged"
- "Not Engaged – By Scada (YFA[1])"
- "Not Engaged – Comm Loss"
- "Not Engaged – Comm Restored"
- "Not Engaged – Missing Data" (South Side only)
- "Disabled" (South Side only)
- "Early Unknown"

This is an example of an enumeration that attempts to capture multiple statuses. This set not only states whether the IVVC system is engaged, it also tries to address the status of communications, the source of the control directive, the status of the supervisory control and data acquisition (SCADA) system, and whether the system has been disabled. From the project analysts' perspectives, only the engagement status verification is needed, which should be indicated by the distinction between the enumerations listed in the left-hand column and those listed in the right-hand one.

[1] YFA = Yukon Feeder Automation

NorthWestern Energy provided the PNWSGD with head-end distribution phase voltages for the South Side and East Side circuits. The data for both circuits began in mid-March 2013 and continued to the end of the PNWSGD data collection period at the end of August 2014. The phase voltages for both circuits were observed to be similar and to track one another closely, as shown in Figure 14.2. There exists an offset between the voltages of Phase “a” and Phase “b” in the South Side circuit, as shown in Figure 14.2a, but the sets have similar slopes, meaning that changes in one phase’s voltage are also seen similarly in the other phases. The dashed line represents perfect correlation. If the circuit were perfectly balanced and had similar loads on all phases, the correlation between phase voltages would be close to this line. Because the phases are seen to track one another well, analysts had confidence that they might calculate and use the average of each circuit’s phase voltages to simplify analysis.



(a) South Side Circuit (b) East Side Circuit

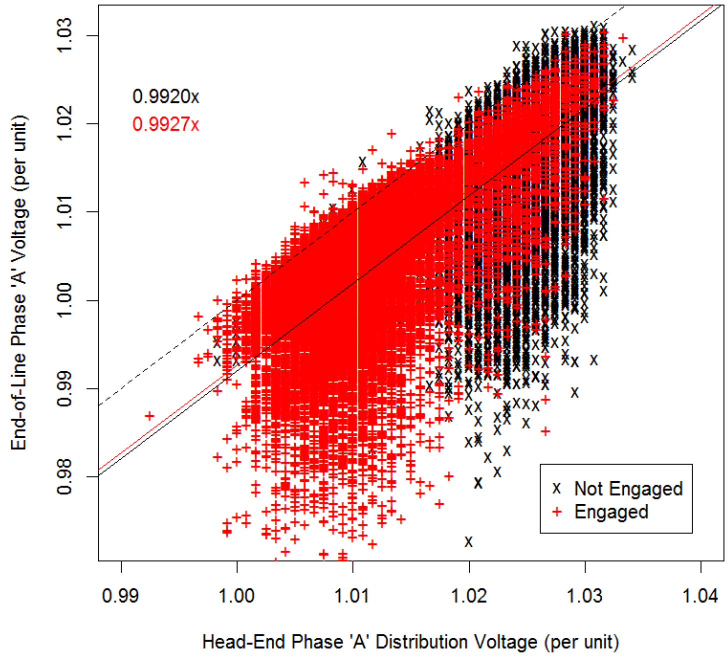
Figure 14.2. Head-End Phase “A” and Phase “B” Voltages Plotted Against the Phase “C” Voltage for the (a) South Side and (b) East Side Circuits. The argument is made that the phase voltages are similar and change together, so analysis may proceed using an averaged phase voltage.

It is also worthwhile to check the relationship between the end-of-line service voltages and the head-end distribution voltages on a phase-by-phase basis. The impact of voltage reduction is often reported in terms of end-of-line voltages and changes in end-of-line voltages. Additionally, IVVC systems monitor the end-of-line service voltage to make sure that electricity is always delivered at or above an accepted minimum voltage level. This comparison is done in Figure 14.3, using the phases of the South Side circuit to demonstrate the comparison.

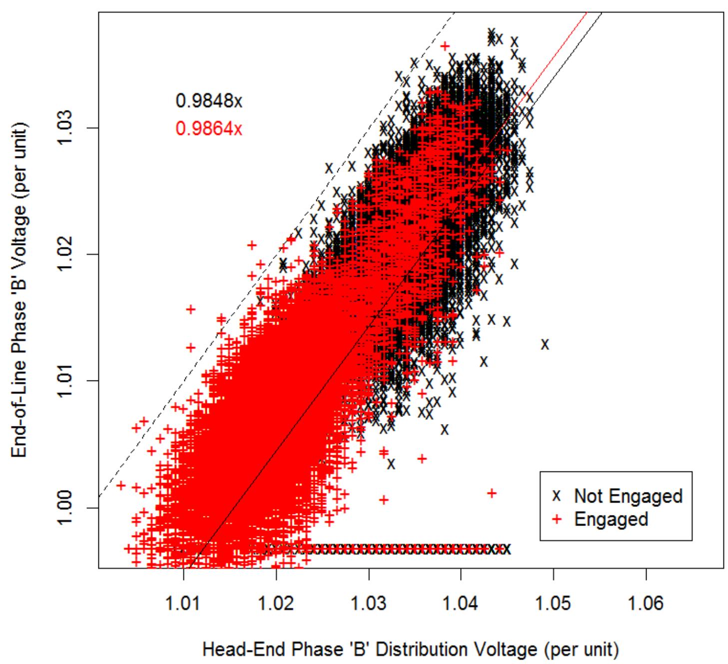
The vertical axis is the per-unit end-of-line service voltage. The utility will strive to keep the customer delivery voltage at or above 114 V. This is 0.95 p.u., based on a 120 V service voltage (which is the case here). The reduction in voltage indeed reduces the average service voltages, but there remains a safety cushion above the 0.95 p.u. criterion.

The horizontal axis is the head-end per-unit phase voltage. This is the voltage at or near the substation transformer. If there were no voltage drop (or increase) during distribution of electricity on this circuit, the data points would lie along the dashed black line, which would mean that the head-end and end-of-line voltages are the same. Both the “Engaged” and “Not Engaged” data sets lie below the dashed black line, meaning that all phases experience voltage drops during distribution. For some reason, the voltage drop is greater on Phase “c” than on Phases “a” and “b.” Since the LTCs control all three phases together, it is Phase “c” that will ultimately limit the magnitude of the reduction that may be achieved. Best-fit lines and their slopes have been provided in Figure 14.3. These presume the line must go through the origin. The x-coefficients (slopes) inform us of the characteristic line drop on the corresponding phase. These coefficients may be used to depreciate the change in voltage that is observed in the head-end voltages, to thereby estimate the corresponding changes in end-of-line phase voltages. However, it is the worst-case data points, those that potentially fall below acceptable service voltages, that determine the acceptability of the IVVC algorithms.

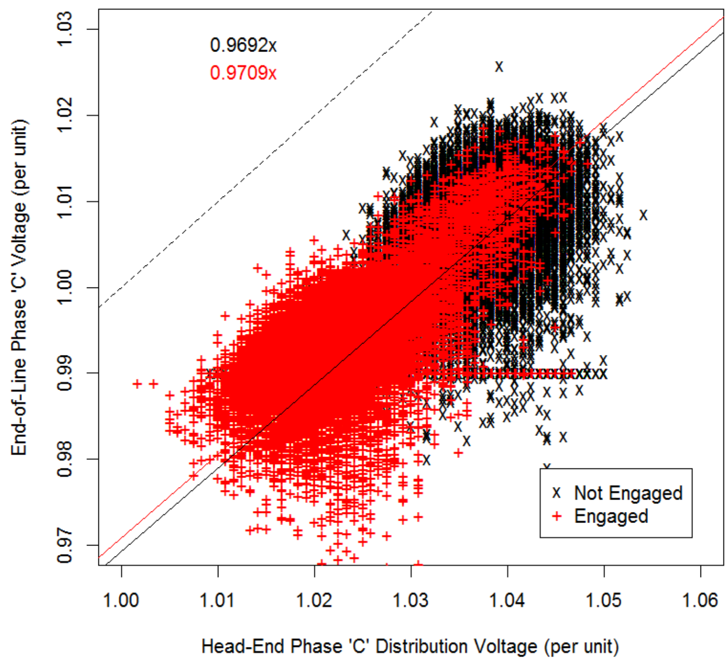
The relationship between end-of-line and head-end voltage on the East Side circuit is acceptable but will not be shown here.



(a) South Side Phase “A”



(b) South Side Phase “B”



(c) South Side Phase “C”

Figure 14.3. End-of-Line Per-Unit Phase Voltages as a Function of the Corresponding Head-End Per-Unit Phase Voltages on the South Side Circuit. The dashed black line represents perfect correlation. The solid red and black lines are the linear best fits for the “Not Engaged” (black) and “Engaged” (red) data sets.

All the distribution voltage data received from NorthWestern Energy is represented in Figure 14.4. This figure shows the results of some of the simplifications that were justified in the discussion leading up to this point. First, the per-unit voltage being plotted is the average of the head-end phase voltages reported for the South Side circuit. Second, the color coding has used a simplification of the IVVC voltage status indicator, where all the enumerations of type “Engaged” were combined, and all the enumerations of type “Not Engaged” were also combined. The status “Disabled” was assigned to the “Not Engaged” group and “Early Unknown” status was treated as unavailable.

A fairly complete time series exists for the South Side head-end voltages. The first data became available in mid-March 2013 and data collection ended at the end of August 2014. The data “stuck” on a constant value through parts of June 2013 and February 2014.

There exists evidence of day-on, day-off voltage reduction experimentation in Figure 14.4. This experimentation appears at this scale to be the simultaneous assignment of “Engaged” and “Not Engaged” statuses, but is, in fact, successive alternate assignments being made on short (daily) intervals. Candidate evaluation time periods like those shown with yellow shading on the figure should both show evidence of alternating voltage treatment and have been assigned meaningful, accurate status indicators during the period. The second criterion helps make sure that the changes in voltage are intentional and being applied for the purposes being studied.

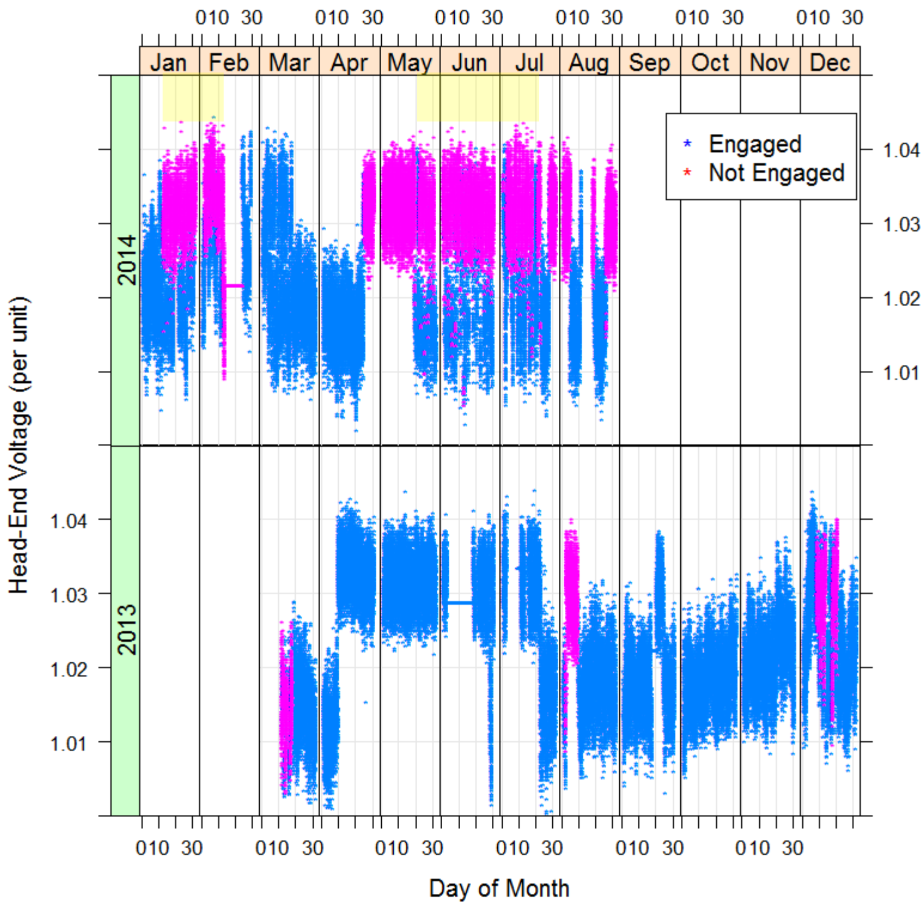


Figure 14.4. Average Head-End Phase Voltages for the South Side Circuit, Including the Simplified IVVC Status for that Circuit. Candidate evaluation periods have been marked by yellow shading.

Similar data and similar data treatments are shown in Figure 14.5 for the East Side circuit. Head-end phase data became available from the last weeks of July 2014, and this data was collected until the end of the PNWSGD data collection period at the end of August 2014. As in the South Side figure, candidate evaluation periods have been marked with yellow shading.

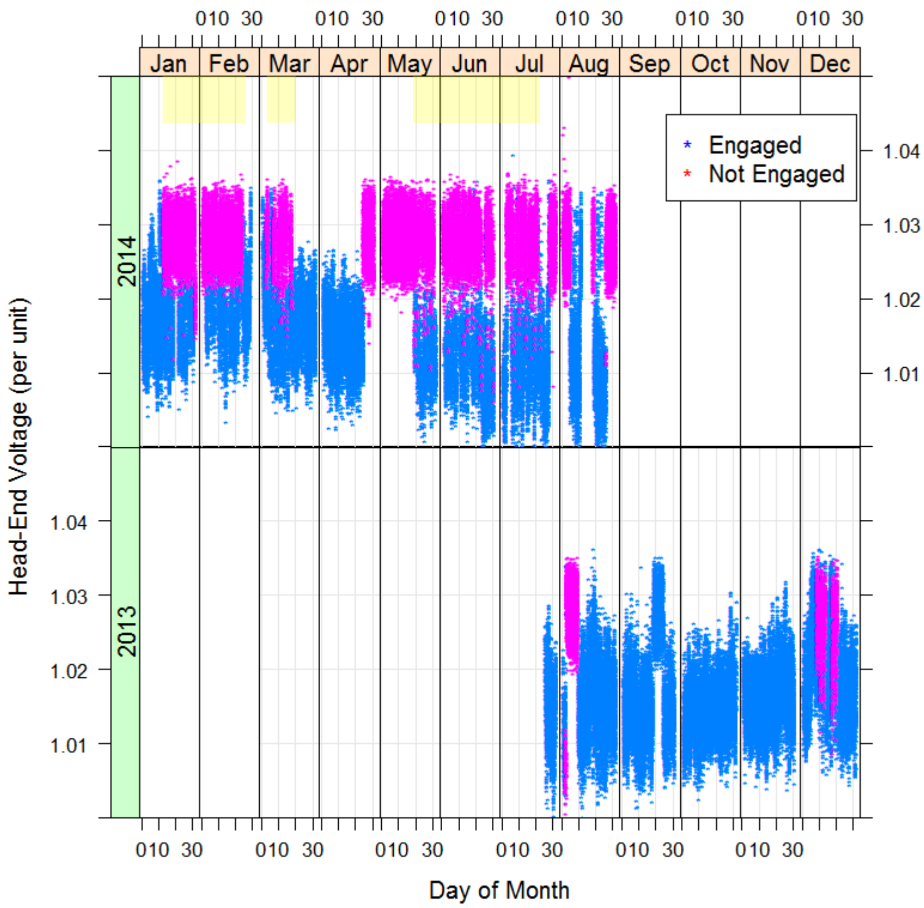


Figure 14.5. Average Head-End Phase Voltages for the East Side Circuit, Including the Simplified IVVC Status for that Circuit. Candidate evaluation periods have been marked by yellow shading.

The corresponding real and reactive power loads on the South Side and East Side circuits are now shown in Figure 14.6 and Figure 14.7, respectively. These data have fine resolution at 5-minute intervals. The South Side circuit is winter peaking, but the East Side circuit exhibits an unusual peak during July and August each year. Some step changes occur in the reactive power of both plots, but these do not appear to be correlated with the patterns of or times that day-on, day-off voltage experimentation had occurred. This power data should support analysis.

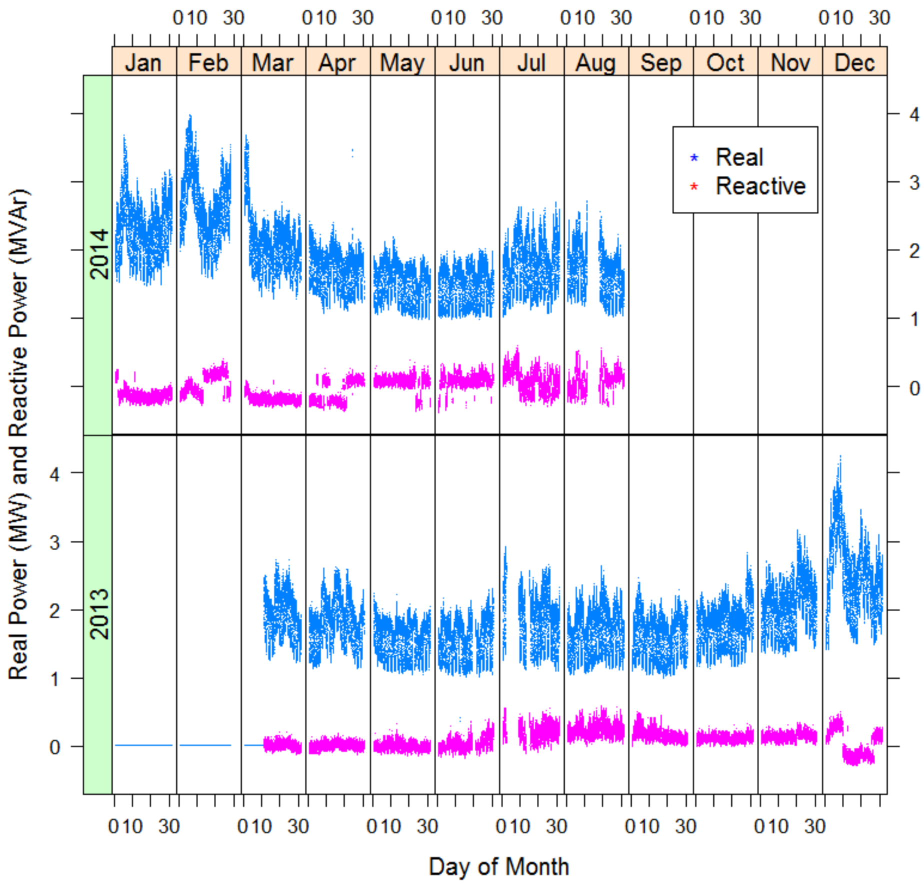


Figure 14.6. Total Real and Reactive Loads on the South Side Circuit

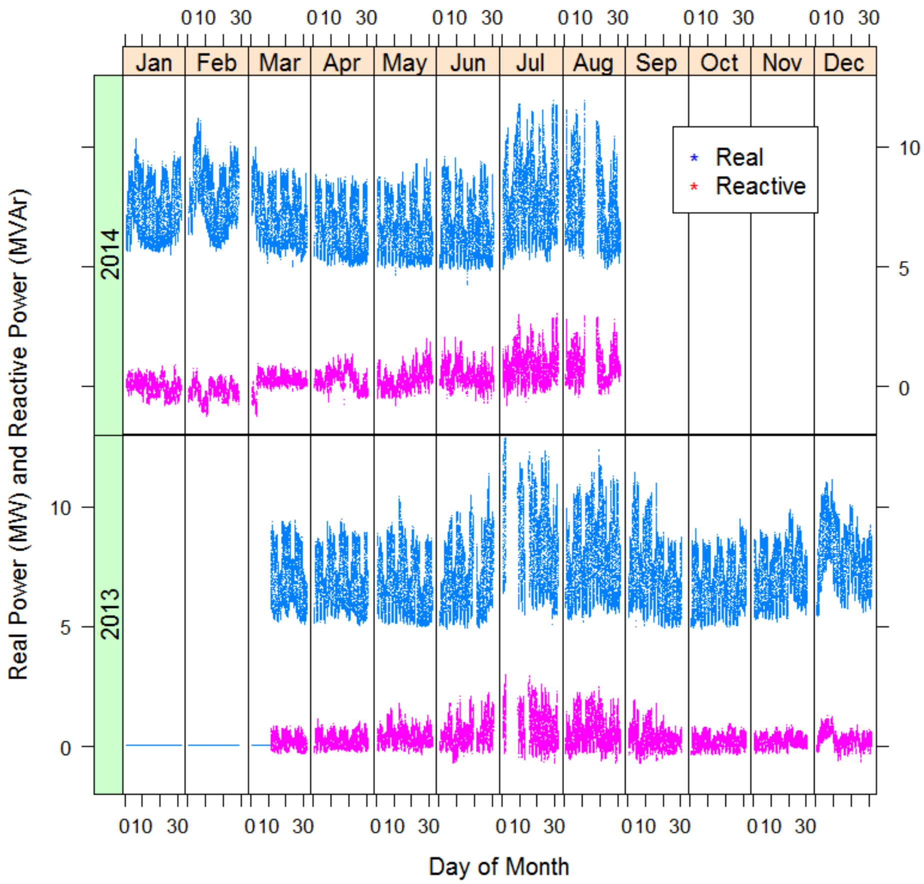


Figure 14.7. Total Real and Reactive Loads on the East Side Circuit

14.1.2 Analysis of the Helena IVVC Systems

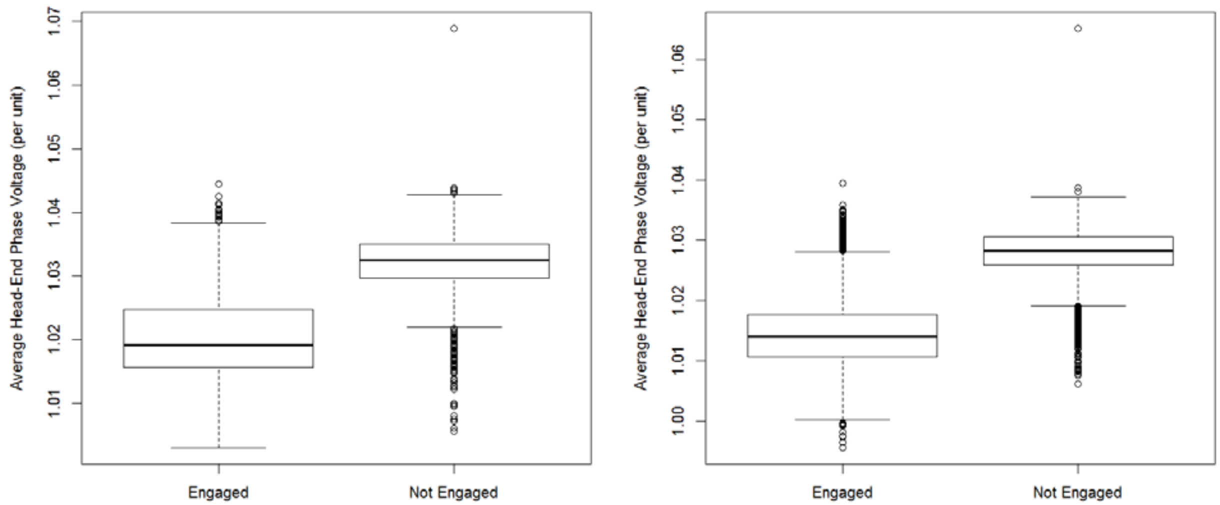
Analysts reviewed and refined the evaluation periods to make sure that they included only times that voltage changes occurred and had been accurately marked. This was done by inspection on a month-by-month basis.

South Side IVVC voltage evaluation periods were January 12–February 12 and May 19–July 22, 2014, excluding July 1, 2014.

East Side IVVC voltage evaluation periods were January 12–February 23, March 6–March 19, and May 19–July 20, 2014.

Figure 14.8 shows the quartile distributions of the head-end distribution voltages according to the engagement statuses at the South Side (Figure 14.8a) and East Side (Figure 14.8b) circuits. These are being reported for the narrowed evaluation periods that were defined for each of the circuits. The South Side voltage is seen to be reduced by 0.013 p.u., based on the calculated difference between the medians of the head-end voltages under the two control statuses. This is a reduction of 1.3%. The East Side head-end voltage was reduced by 0.014 p.u., or 1.4%, based on the change in the median voltages between the two voltage levels. Given that the end-of-line voltages were determined to be 97–99% of the head-end voltages (on a per-unit basis) the changes in voltage would be the same if it were measured at an end of the line (within a couple of significant digits).

NorthWestern Energy had reported that when they first exercised their Helena IVVC system in December of 2013, they observed an average change of 1.21% in the voltage.



(a) South Side Circuit (b) East Side Circuit

Figure 14.8. Quartile Plots of the Average Per-Unit Head-End Phase Voltages at the (a) South Side and (b) East Side Circuits during their Respective Evaluation Periods

Analysts created linear regressions of the circuits' real power as functions of ambient temperature and separately calculated by month, weekday type, and hour of day. The temperature from station HVMT in Helena, Montana was used. The records of temperature were found to be quite complete, but the data was further interpolated to fill in all the missing 5-minute intervals and thereby use more power measurements in the regression models. Only data in the evaluation periods was used. R software (R Core Team 2012) was used to facilitate the linear regression modeling.

The linear model at the South Side site had an impressive R^2 value of 0.9599. Based on this regression model, the circuit consumed 16.6 ± 1.5 kW less power when the IVVC system was "Engaged" than it did while it was "Not Engaged." That is about 0.9% of the average power on the circuit during 2014 and about 0.4% of the peak power during 2014. In a 24-hour period that would be almost 400 kWh energy savings, on average.

For the East Side circuit, the R^2 of the fit was 0.944. Unfortunately, the change in power determined by the approach using the East Side circuit was inconclusive.

14.2 Fault Detection, Isolation, and Restoration

NorthWestern Energy installed FDIR technology at their Helena and Philipsburg Montana sites. This is a form of DA that automatically reconfigures circuits after outages to restore service to as many customers as possible. They wanted to quantify the benefits they would realize from its use, including the improvement of service and reliability.

Circuits in Helena with FDIR affected 4,800 customers on four circuits that are served by three substations—Eastside (42 and 46), Golf Course (51), and Southside (1). The four circuits are tied together by reclosers that are programmed as sectionalizing switches. The feeder can be further sectionalized by its in-line reclosers that are also programed as sectionalizing switches. A communication system between all the smart devices allows Cooper Power Systems' Yukon Feeder Automation (YFA) software to isolate the fault, sectionalize the fault, and restore as many customers as possible without overloading any field devices or conductor line segments. The YFA software also communicates with Schweitzer Electric Laboratory relays to retrieve loading information.

Table 14.2. Annualized Costs of the FDIR System and its Components over the Four-Year Term

	Component Allocation (%)	Annualized Component Cost ($K)	Allocated Annual Component Cost ($K)
Smart Distribution Switches	100	123.7	123.7
CVR/Volt-VAr and DA System Software	50	154.9	77.45
Helena Communications (radio and tower)	33	72.1	24.0
Helena Substation Communications	50	29.1	14.55
Fault Indicators	100	11.5	11.5
Helena Substation RTUs and Relaying	50	21.4	10.7
Total Annualized Cost			**$261.9K**

14.2.1 Reliability Metrics for the FDIR Circuits

The PNWSGD collected several metrics from NorthWestern Energy, hoping that these metrics might confirm reliability improvements that would be possibly attributable to the FDIR systems. These metrics include the utility's yearly distribution restoration costs, Customer Average Interruption Duration Index (CAIDI), and System Average Interruption Duration Index (SAIDI).

NorthWestern Energy submitted their yearly distribution restoration costs to the PNWSGD for the years from 2010 into 2014. The logic was that these restoration costs might have been reduced if the utility were able to recover from its outages more efficiently. These costs were rounded to the nearest $100 and are listed in Table 14.3. The costs for year 2014 are incomplete because PNWSGD data collection stopped at the end of August that year. The costs for the complete years 2010 through 2013 appear to have remained fairly constant. We cannot conclude that distribution restoration costs were reduced from this reporting.

Table 14.3. Yearly Distribution Restoration Costs that were Reported to the PNWSGD by NorthWestern Energy ($K)[a]

2010	2011	2012	2013	2014
28.7	25.2	20.3	25.4	8.5[b]

(a) Yearly restoration costs have been rounded to the nearest $100.
(b) This is the sum of 2014 costs through September that year.

The yearly calculated CAIDI values for 2010 through 2013 and part of 2014 are listed in Table 14.4 for each of the four circuits on which FDIR was exercised in Helena, Montana. These are the average number of minutes that a customer experiences an outage on each of these circuits. These minutes should become reduced if outages can be responded to and mitigated more quickly. No clear trends are evident from the yearly CAIDI values.

Table 14.4. Yearly CAIDI Values Reported to the PNWSGD by NorthWestern Energy for the Four Helena Circuits in which FDIR was Used (minutes per customer outage)[a]

Circuit	2010	2011	2012	2013	2014[b]
South Side #1	102	50	62	180	118[b]
East Side #42	82	207	89	120	0[b]
East Side #46	26	41	136	61	63[b]
Golf Course #51	43	110	65	128	51[b]

(a) CAIDI values have been rounded to the nearest minute.
(b) 2014 CAIDI was calculated for the period January – September 2014, not the entire year.

The calculated yearly SAIDI values for these same four feeders are listed in Table 14.5. These are the average total outage durations that each customer experienced on the given feeder in the given year. As with CAIDI, total duration outages might be reduced and reflected in SAIDI if outage durations have been reduced. Again, the 2014 data is incomplete, but it appears that the circuits were having a remarkably reliable year from the beginning of 2014 to the time that data collection ceased at the end of August 2014. None of the recent years has exceeded the 2010 SAIDI values on three of the four circuits.

Table 14.5. Yearly SAIDI Values Reported to the PNWSGD by NorthWestern Energy for the Four Helena Circuits in which FDIR was Used (outage minutes per customer)[a]

Circuit	2010	2011	2012	2013	2014[b]
South Side #1	278	57	90	46	10[b]
East Side #42	4	31	3	2	0[b]
East Side #46	94	50	18	23	11[b]
Golf Course #51	91	78	3	30	~0[b]

(a) SAIDI values have been rounded to the nearest minute.
(b) 2014 SAIDI was calculated for the period January – September 2014, not the entire year.

FDIR may not be effective on all types of outages. We will consider some anecdotal observations in the next section that might point to improved responses to outages.

14.2.2 Anecdotal Results

NorthWestern Energy reported two outage events to the PNWSGD in great detail because these two point to advantageous use of the new FDIR system.

Event #1, June 12, 2013. This was a tree fall incident on one of the Helena South Side feeders. The Cooper YFA system operated as programmed. The circuit breaker locked out, and the majority of the circuit load was transferred to a Helena Golf Course feeder by the FDIR system within 51 seconds. Because of its actions, 1,250 of the circuit's 1,506 customers experienced the 51-second outage instead of the 119-minute outage that was experienced by the remainder of customers for whom power could not be as quickly restored. NorthWestern attributes the avoidance of 148,000 customer outage minutes to the FDIR system during this event. The consensus of the utility investigators was that, for this event, the FDIR system did not necessarily change the expenditure in lineperson and response efforts because the experienced staff believed they would have similarly found and remedied the source of the outage. A similar outage had occurred near that same circuit location not long before then.

Event #2, September 5, 2013. At about 07:50, a squirrel caused Helena Eastside Feeders 44 and 46 to lock out. Circuit 46, which is under FDIR control, was able to automatically restore power to 780 of the circuit's 1,007 customers within 30 seconds by activating one of its recloser switches. Feeder 44 is not equipped with FDIR. Its 492 customers, and about 220 customers on Feeder 46, whose power could not so quickly be restored experienced 30 minutes without electricity. These two feeders also serve many businesses, and even a hospital.

NorthWestern Energy reports that it has seen its new FDIR system operate three times in Helena so far, all successfully. They also had one event in Philipsburg, although a communications issue prevented one of the Philipsburg reclosers from performing correctly for that event. By the utility's calculations, the two Helena events described above represent a savings of approximately 0.2 SAIDI minutes within its Montana system calculations. Approximately 20 man-hours were also avoided (6–8 man-hours per event) restoring the power after those events.

14.3 Residential and Commercial Building Demand Response

NorthWestern Energy supplied groups of its residential- and commercial-scale customers sets of tools with which they could learn about and better manage their electricity consumption. The suite of tools included demand-responsive, controllable loads that the utility could engage to reduce its peak energy consumption.

About 208 residential customers received these devices:

- smart meter—serves as the basis for 15-minute interval premise energy measurements and facilitates remote reading of meters
- energy portal, or home area network (HAN)—facilitates communication of energy information and energy price information with which the customers may modify their electricity consumption
- plug-load switch—load controller that may be configured by the customer to respond at different energy price levels
- in-home display—source of energy information in the home, including price signals
- Web-based services—source of energy use profiles and metrics that may be displayed via in-home displays or the internet
- programmable thermostat—about 22.6% of the 208 residential customers received controllable thermostats that could respond to pricing levels

The utility hopes to evaluate the performance of the types of tools and the ways they were used by their customers. The utility took a small step toward exploring variable pricing and was able to observe and learn from its customers' responses to the price signals. The utility surveyed the residential customers at the conclusion of the PNWSGD to learn from their experiences.

On the commercial side, Helena is the capitol of Montana and hosts Montana State buildings. The utility outfitted the Lee Metcalf building with lighting control, installed automated dimming on overhead lights that were near outside windows, and installed dimming control in other building areas.

At the Lee Metcalf building, the heating, ventilating, and air conditioning system was upgraded with additional air conditioning controls and improved ventilation. The utility planned to also make state buildings demand responsive by integrating controllable loads using the Lockheed Martin SEELoad™ DR application, but this plan did not come to completion due to the Lockheed Martin software's inability to interface with the building's automation management system. At the Walt Sullivan building, HVAC systems were not incorporated into the control network due to the building automation system's legacy software.

All the residential customers who accepted the suite of tools were also placed on a time-of-use pricing schedule. They could reduce their energy bills if they modified the times that they consumed electricity according to this schedule of prices. For example, they could schedule their controllable plug loads to respond to any of the three price levels in the time-of-use schedule. However, there were no losers; any customer whose time-of-use-calculated bill was greater than it would have been under the normal flat rates paid the lower amount.

Critical peak pricing, or DR, responses were also facilitated through residential pricing. This is how the project understands the DR to have worked: First, a pricing signal was sent to the building automation control system. The buildings respond according to predetermined load curtailment schedules to reduce load based on price. Building energy measurements were then fed back to the Lockheed Martin SEELoad DR application. In near-real time, communications were then sent to building occupants through graphical displays on computer screens. The occupants, having been informed of the changes being made to temperature or lighting levels, recognize the changes as intentional efforts to modify the building's energy consumption.

The annualized costs of the commercial and residential DR system are summarized in Table 14.6. The total annualized cost of the system was estimated to be about $668.0 thousand per year.

Table 14.6. Annualized Costs of the Helena Residential and Commercial DR System and its Components

	Component Allocation (%)	Annualized Component Cost ($K)	Allocated Annual Component Cost ($K)
DR - Energy Management Software (Lockheed Martin)	100	248.9	248.9
HAN Management Software and Services (Tendril®)	100	211.5	211.5
Helena DR Devices - Lighting Control Modules[(a)]	100	69.0	69.0
Helena DR Devices - Smart Plug-Load Outlet	100	33.2	33.2
Helena Meter Data Collectors	100	27.3	27.3
Helena Communications (radio and tower)	33	72.1	24.0
Advanced Metering Software and Services	100	12.8	12.8
Helena DR Devices - Home Energy Displays	100	10.3	10.3
Helena Advanced Residential Electric Meters	100	10.0	10.0
Helena DR Devices - Programmable Thermostats	100	8.7	8.7
Helena HAN (bridge/communication)	33	23.2	7.7
Helena DR Devices - Load Control Switches	100	3.8	3.8
Helena Advanced Commercial Electric Meters	100	0.8	0.8
Total Annualized Cost			**$668.0K**

(a) For two commercial buildings

To boost interest in their time-of-use pilot, NorthWestern Energy conducted quarterly contests and rewarded those participating customers who had conserved the most energy in the quarter compared with their consumption in that quarter the prior year. The results from the first quarter's competition (April–June 2013) and its prize awards are listed in Table 14.7.

Table 14.7. Outcome of the First Quarterly (April–June 2013) Customer Conservation Contest and its Top Three Customer Awards

Place	Energy Conserved (kWh)	Customer Cost Savings ($)	Prize ($)
1st	2,176	132	100
2nd	1,459	136	50
3rd	1,440	193	25

14.3.1 Characterization of Asset System Responses

Of the 208 premises that were reported to participate in the DR program, all received automatic meter reading, a plug-load control switch, an energy portal, and an in-home display. Of these participants, 22.6% also received programmable thermostats.

Three DR events occurred and are listed in Table 14.8 as they were reported to the project by NorthWestern Energy.

Table 14.8. DR Events Reported to the Project by NorthWestern Energy. All events were reported to have occurred August 28, 2014.

Event Number	Reported Hour	Scheduled Participants	Scheduled Devices	Program Scale (%)	Predicted Load Reduction (kW)	Actual Load Reduction (kW)
1	14	26	102	100	306	5
	15	26	102	100	357	4
2	13	26	102	100	408	6
3	14	41	120	70	770	3
	15	41	120	70	855	2

Figure 14.9 shows the available sets of averaged premises power data for the approximately 101 residential test premises that are supplied from the Golf Course substation, and another approximately 87 that are supplied from the West Side substation. The horizontal axis in each of the panels depicts the time of day. The change in consumption patterns by month should be evident. However, the plots also reveal discrepancies from year to year that are likely attributable to persistent time-shift problems that the project was unable to trace down and fix as it worked with the utility.

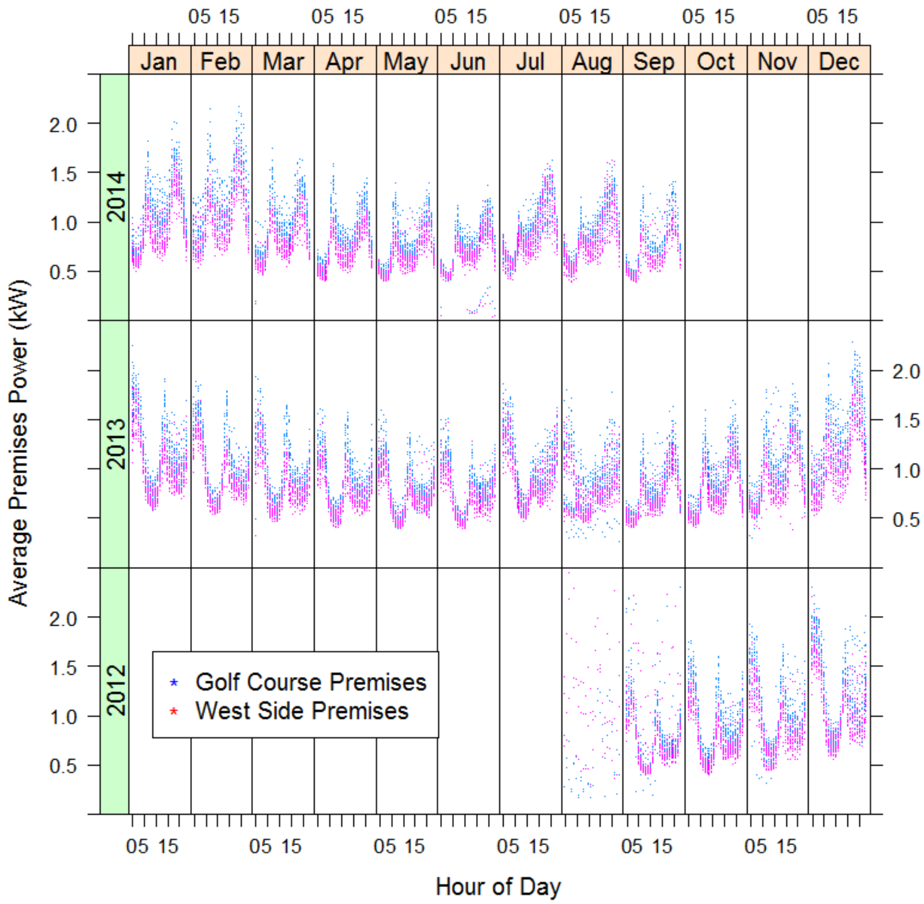


Figure 14.9. Average Premises Power of the DR Golf Course and West Side Test Groups as Functions of Hour of Day. We believe the data still exhibits time-shift issues based on the differences seen in the data from year to year.

The utility's time-of-use pricing program was initiated at all the DR test premises soon after the suite of DR devices had been installed in September 2012. There is no interval metering available from these premises from before the time-of-use program began. These were the only residences whose energy was monitored by the project using premises interval metering.

NorthWestern Energy designated three price levels—off-peak, mid-peak, and on-peak—to influence when plug loads at participating residential locations would be switched on and off. The designations of this schedule and its assigned unit price levels are shown in Table 14.9. The light-load hours have been consistently assigned the off-peak price level, regardless of the season. The position of the on-peak period is seen to vary some through the year as the utility's load shifts from peaking in the mornings during cold weather months to peaking in the afternoon during the hottest months.

Customers had the option of assigning each of their plug loads to one of the price levels. Customers were able to view their energy consumption via the web portals and could view how they compared to other customers. They could adjust the assignments of their plug loads under the different price levels to modify their energy consumption.

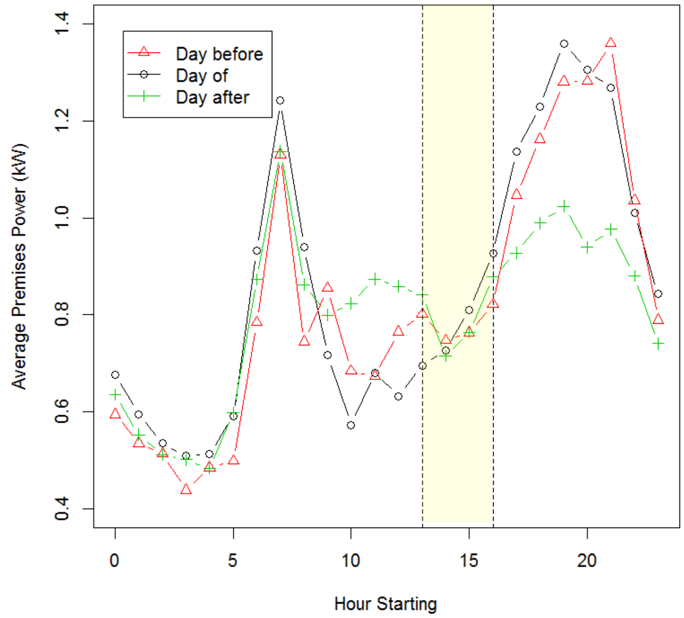
Table 14.9. Time-of-Use Pricing for Selected Participants Showing On-Peak (red, \$0.08/kWh), Mid-Peak (yellow, \$0.05/kWh), and Off-Peak (green, \$0.03/kWh) Price Levels

	Mountain Time - Hour Ending																							
	1 AM	2 AM	3 AM	4 AM	5 AM	6 AM	7 AM	8 AM	9 AM	10 AM	11 AM	NOON	1 PM	2 PM	3 PM	4 PM	5 PM	6 PM	7 PM	8 PM	9 PM	10 PM	11 PM	12 AM
Jan	0.03	0.03	0.03	0.03	0.03	0.03	0.05	0.08	0.08	0.08	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.08	0.08	0.08	0.08	0.08	0.05	0.03
Feb	0.03	0.03	0.03	0.03	0.03	0.03	0.05	0.08	0.08	0.08	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.08	0.08	0.08	0.08	0.08	0.05	0.03
Mar	0.03	0.03	0.03	0.03	0.03	0.03	0.05	0.08	0.08	0.08	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.08	0.08	0.08	0.08	0.08	0.05	0.03
Apr	0.03	0.03	0.03	0.03	0.03	0.03	0.05	0.05	0.05	0.05	0.05	0.05	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.05	0.05	0.05	0.05	0.03
May	0.03	0.03	0.03	0.03	0.03	0.03	0.05	0.05	0.05	0.05	0.05	0.05	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.05	0.05	0.05	0.05	0.03
Jun	0.03	0.03	0.03	0.03	0.03	0.03	0.05	0.05	0.05	0.05	0.05	0.05	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.05	0.05	0.05	0.05	0.03
Jul	0.03	0.03	0.03	0.03	0.03	0.03	0.05	0.05	0.05	0.05	0.05	0.05	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.05	0.05	0.05	0.05	0.03
Aug	0.03	0.03	0.03	0.03	0.03	0.03	0.05	0.05	0.05	0.05	0.05	0.05	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.05	0.05	0.05	0.05	0.03
Sep	0.03	0.03	0.03	0.03	0.03	0.03	0.05	0.05	0.05	0.05	0.05	0.05	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.05	0.05	0.05	0.05	0.03
Oct	0.03	0.03	0.03	0.03	0.03	0.03	0.05	0.08	0.08	0.08	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.08	0.08	0.08	0.08	0.08	0.05	0.03
Nov	0.03	0.03	0.03	0.03	0.03	0.03	0.05	0.08	0.08	0.08	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.08	0.08	0.08	0.08	0.08	0.05	0.03
Dec	0.03	0.03	0.03	0.03	0.03	0.03	0.05	0.08	0.08	0.08	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.08	0.08	0.08	0.08	0.08	0.05	0.03

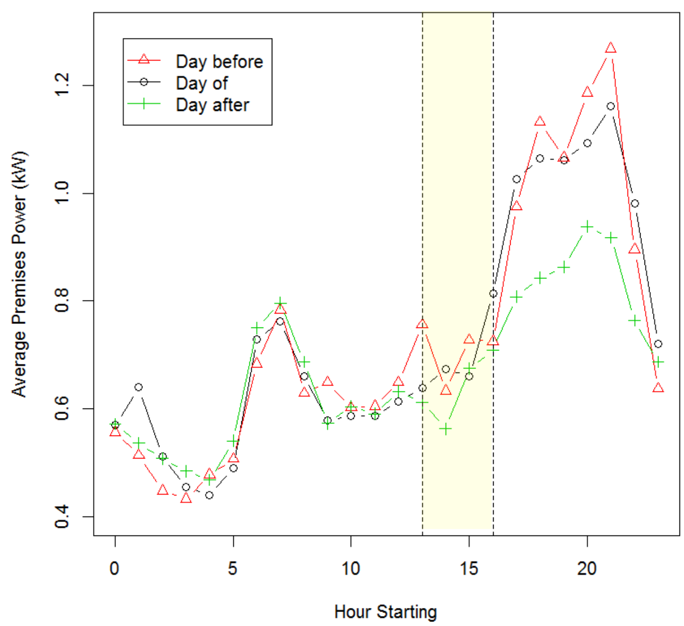
14.3.2 Analysis of NorthWestern Energy's DR Experience

Project analysts attempted to observe a reduction in average premises loads for those premises on the West Side and Golf Course circuits that had received the suite of DR equipment. The project was not provided comparable power consumption for premises that did not receive the suite of DR equipment, so there is no control population available for comparison.

There are only three relevant hours to review according to Table 14.8—hours 13:00–16:00 Mountain Time, August 28, 2014. Figure 14.10 plots the average premises consumption for the test premises on the (a) Golf Course and (b) West Side circuits during August 28, 2014, a Thursday, when the DR tests were reported to have happened. The hours of the tests have been bordered by dashed vertical lines at 13:00 and 16:00. The plots also include the average premises data for these test groups on the days before and after the test events.



(a) Golf Course DR Premises



(b) West Side DR Premises

Figure 14.10. Average Premises Power Consumption of (a) Golf Couse DR Premises and (b) West Side DR Premises for the Days before, on, and after August 28, 2014, when NorthWestern Conducted DR Tests. The tests were reported by the utility to have occurred between 13:00 and 16:00, which are shown in the figure by dashed vertical lines.

No characteristic curtailment notches are evident in the power data during the hours that testing was reported to have occurred. The data from the day before, a Wednesday, is similar to that from the test day, a Thursday. The Friday power consumption patterns are somewhat different from those of the test day. Regardless, the average power consumption during the event hours does not appear to differ significantly among the days.

Next the project reviewed the data to see whether any impacts might be attributable to the time-of-use price differences that were applied to premises in the DR group. This was deemed impossible with the present data. No historical premises-power data was available from prior to the initiation of time-of-use pricing. No control group data was collected from similar control premises that were not subjected to time-of-use pricing. No meaningful data analysis was possible with the existing data sets for this asset system.

The utility reported that its residential participants had, in fact, lowered their electricity bills in the program by shifting electric load to times having lower electricity prices. The program began with 195 participants and ended with 190. There was some flux with customers entering and leaving the program over its duration. The maximum bill credit earned by a customer was $31.15, in January 2013. The highest average savings occurred that month, too, when the average customer earned $8.88. The lowest average savings were earned in October 2013, when the average participant earned $1.33.

There was no penalty if the bill according to the price levels exceeded the bill that would have been incurred under the flat rate. In that case, the customer simply paid the lower of the two calculated bills. Therefore, some customers had no bill savings.

14.4 Philipsburg/Georgetown IVVC

Automated voltage regulator controls, automated capacitor banks, distribution voltage sensors, and distribution system software were used for voltage and reactive power control on Feeder 25-3 in NorthWestern Energy's Philipsburg/Georgetown service territory. The community is rural. It includes approximately 240 line miles of distribution service and stretches 40 miles to the most extreme line end. This region is in mountainous terrain that presented challenges for the wireless communications. Its power supply includes the 2 MW Flint Creek hydroelectric generation site.

NorthWestern Energy also installed an IVVC system in Helena, and that system was described in Section 14.1.

The Philipsburg/Georgetown IVVC system includes five voltage control zones, four of which were controlled by IVVC. Equipment includes seven Beckwith voltage regulator controllers, three Cooper voltage regulator controllers, one Beckwith capacitor bank controller, and 13 distribution voltage sensors for sensing end-of-line voltages.

The annualized costs of the Philipsburg IVVC system and its components are shown in Table 14.10. The total annualized cost of the system over the four-year term was estimated at about $202.7 thousand per year.

Table 14.10. Annualized Costs of the Philipsburg IVVC System and its Components

	Component Allocation (%)	Annualized Component Cost ($K)	Allocated Annual Component Cost ($K)
CVR/Volt-VAr and DA System Software	50	154.9	77.5
Philipsburg Line Regulator Controls	100	51.6	51.6
Philipsburg Substation Communications	100	25.2	25.2
Philipsburg Substation Regulator / LTC Controls	100	19.9	19.9
Philipsburg Distribution Voltage Sensors	100	8.7	8.7
Philipsburg Communications (radio and cell phone)	100	7.3	7.3
Philipsburg Substation RTUs and Relaying	100	6.8	6.8
Philipsburg Capacitor Banks (new banks with controller)	100	5.7	5.7
Total Annualized Cost			**$202.7K**

14.4.1 Data and Operations Concerning the Philipsburg IVVC System

NorthWestern Energy reported to the project that the Philipsburg IVVC system was installed and active by February 2014. The reactive power control IVVC component was reported never to have become engaged due to technical challenges, but the voltage control component was reported to have been engaged on an on/off testing basis from late February through the remainder of the PNWSGD. The combination of long distribution line lengths, multiple voltage control zones (multiple sets of voltage regulators controlling their downstream area), and excessive voltage drop in certain line segments limited the ability to achieve voltage reductions in two of the four voltage control zones.

The utility provided head-end phase voltages for this feeder covering a period from the end of April 2013 until the end of the PNWSGD data collection period at the conclusion of August 2014. Analysts confirmed that the individual head-end phase voltages tracked one another well and behaved similarly during at least the months March through July 2014, when the feeder's voltage will be shown to have been actively managed. This fact is demonstrated by Figure 14.11, in which two of the head-end phase voltages have been plotted against the third. This similarity gave analysts confidence that the individual phase voltages could be averaged for the remainder of analysis.

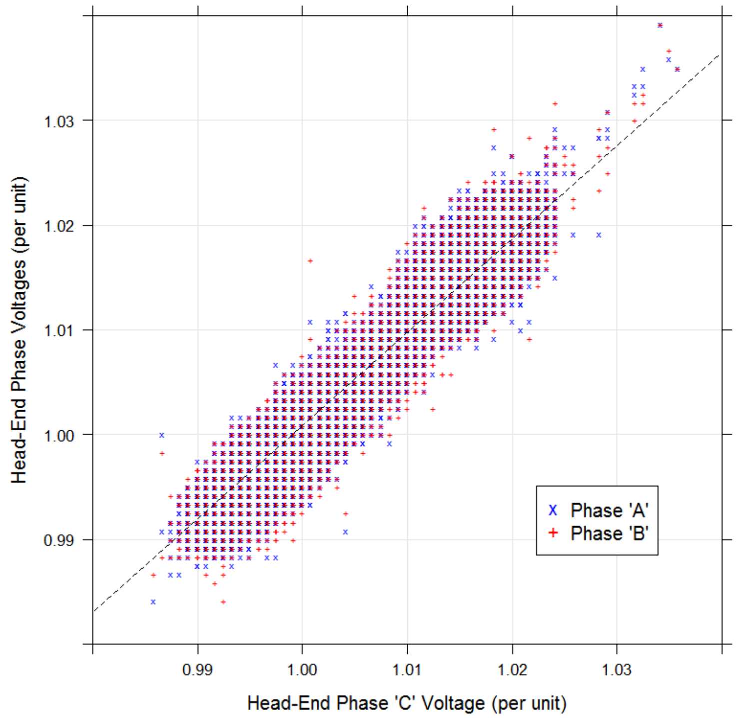


Figure 14.11. Head-End Distribution Voltages from Phases "A" and "B" Plotted against the Corresponding Voltage of Phase "C". Upon this confirmation that phase voltages behave similarly, the average phase voltage was calculated and used for further analysis.

Figure 14.12 shows the resulting average per-unit phase voltage at the Philipsburg feeder. The months from March through much of July 2014 exhibit evidence of active control. A pattern of approximately daily changes between reduced and normal voltage levels is evident these months, even though the system had been reported to be continuously under reactive power control throughout the period.

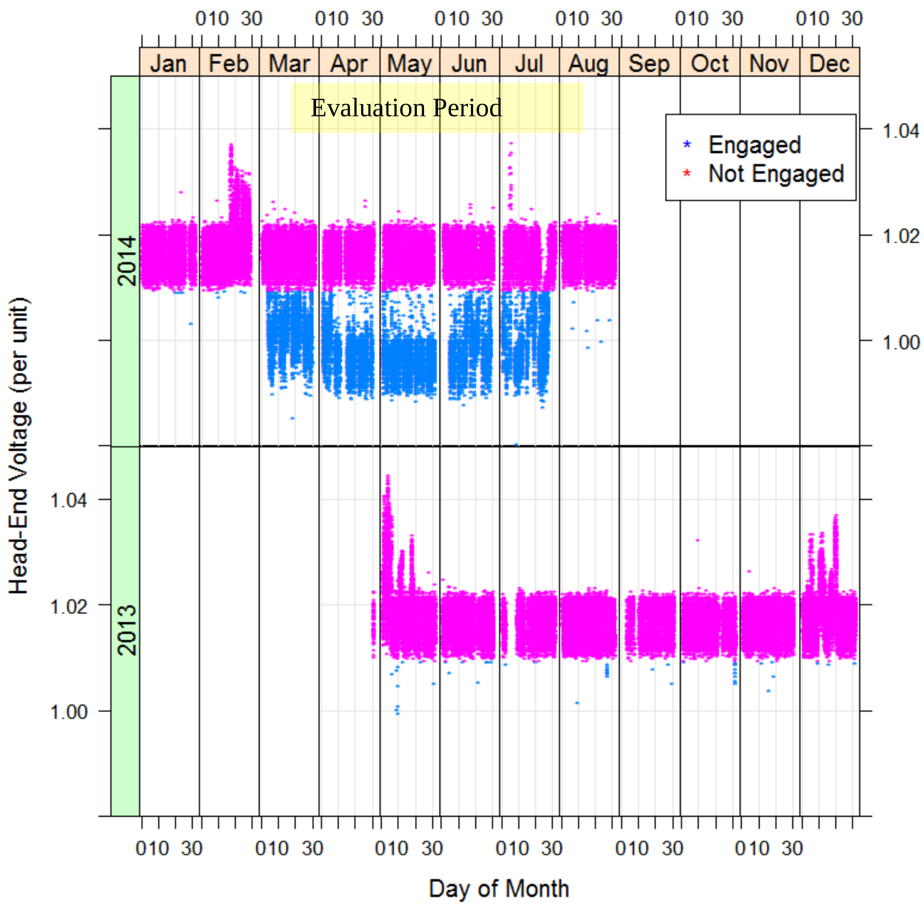


Figure 14.12. Average Head-End Per-Unit Phase Voltage for the Philipsburg Feeder that was Under IVVC Control. The shaded yellow box represents the period that analysts inferred IVVC control had been active.

The project selected the months March through July 2014 as its evaluation period based on Figure 14.12, and the analysis period is shown in the figure by yellow shading. The figure's legend also distinguishes the color of voltage measurements that are normal, when the IVVC system was inferred to not be engaged (blue). The reduced voltages, when the IVVC system was inferred to have been engaged, are shown by red data markers.

Figure 14.13 provides the basis for the inferred distinction between normal and reduced voltages during the analysis period. This is a distribution of the average head-end phase voltages during that evaluation period. It is clear from this distribution that the system was operated under two distinct modes—one having normal voltages and the other having reduced voltages. By inspection, the separation between the populations was determined to be about 1.0095 p.u. The two populations are shown to overlap some, so the inference cannot perfectly recreate the precise timing of the controls that are being inferred. Since voltage is managed fairly smoothly over time, minor incorrect assignments of voltages near the separation are unlikely to greatly change the analysis results. Based on Figure 14.12, the inferred assignments of the data values between the groups “Engaged” and “Not Engaged” seem to be reasonable.

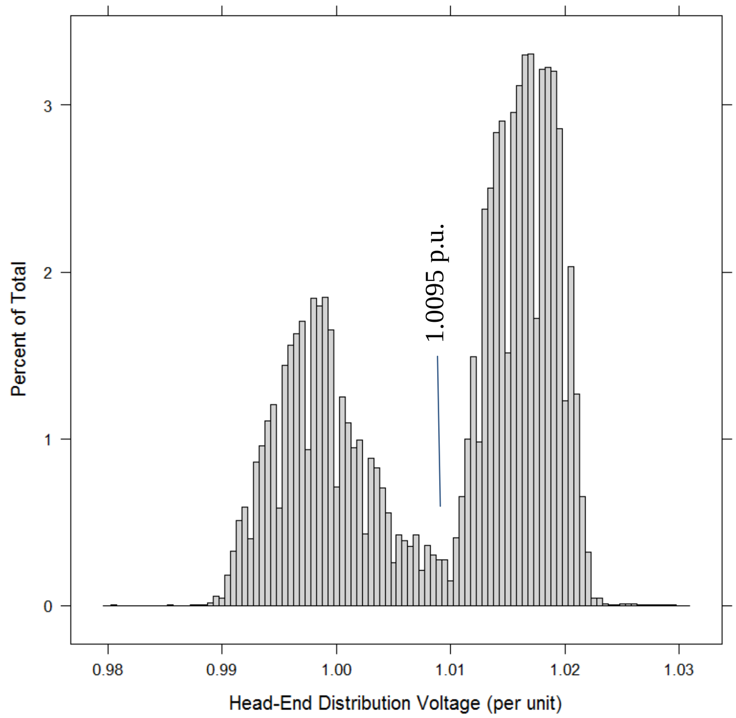


Figure 14.13. Distribution of the Average Head-End Per-Unit Voltages on the Philipsburg Feeder from March through July 2014 while Voltage Appeared to Have Been Managed. Based on this distribution, the separation between normal and reduced voltages was assigned the value 1.0095 p.u.

Figure 14.14 shows the real and reactive powers of the Philipsburg feeder where IVVC was being exercised. This is all the Philipsburg distribution power data that was delivered to the PNWSGD by NorthWestern Energy. The power is observed to become negative at times in the months March through September each year, which is presumed to be caused by power generation from Flint Creek hydroelectric generation on this circuit. The circuit becomes a net exporter of power those months. The intermittent periods when the net power again became strongly positive these months are probably attributable to periodic maintenance on the hydroelectric generators.

No clear changes in real or reactive power are evident in the period March–July 2014, when the IVVC is inferred to have changed status approximately daily. Interestingly, periodic changes in reactive power are observed late September through mid-December 2013. Distribution voltages had been steady that period. The utility reports that the system is capacitive (reactive power is negative) due to the significant amount of underground 25 kV primary conductor near the ends of that circuit.

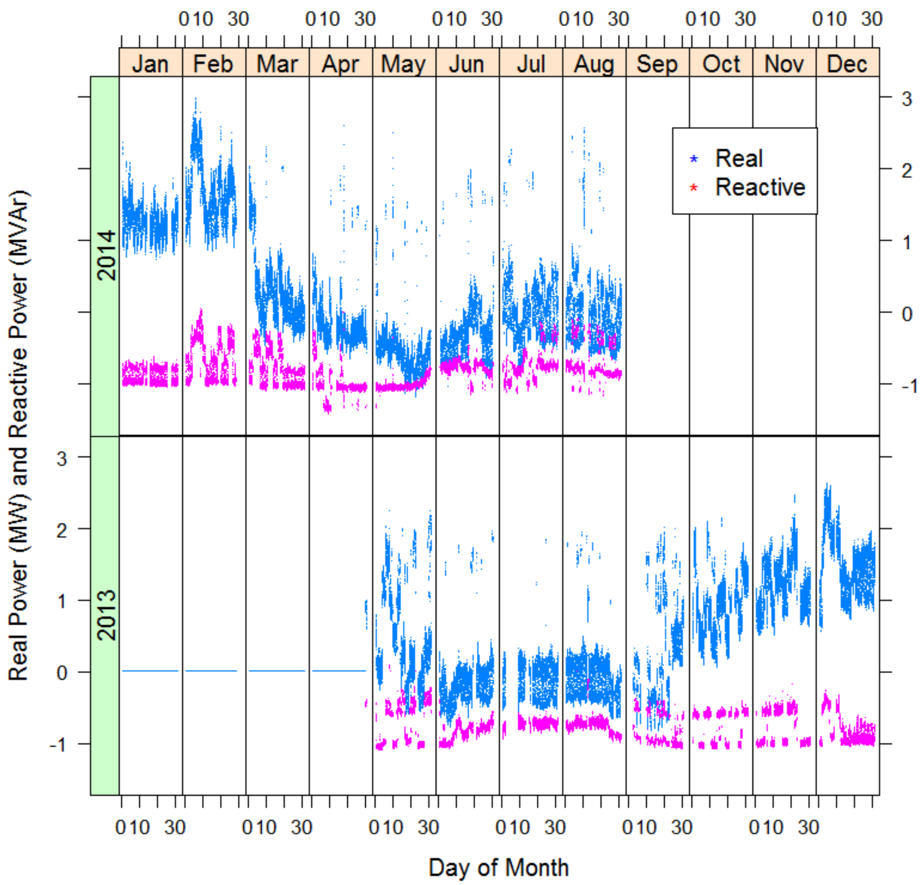


Figure 14.14. Real and Reactive Power on the Philipsburg Feeder

14.4.2 Analysis of the Philipsburg IVVC System

Based on the inference of IVVC status, the project compared the head-end distribution voltages at the times that system was inferred to be engaged and not. A quartile plot is presented in Figure 14.15 to compare the voltages during the two inferred statuses during the evaluation period. During the evaluation period, the median of the voltages was reduced by 0.018 p.u., or 1.8%, on average, during voltage reduction periods.

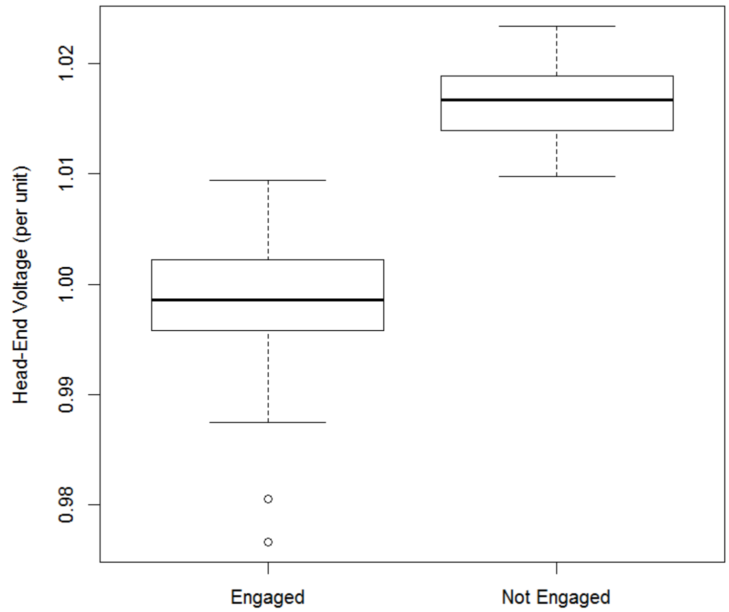


Figure 14.15. Quartile Plot of the Philipsburg Average Head-End Phase Voltages when the IVVC System was Inferred to be Engaged and Not Engaged

Analysis of the Philipsburg IVVC system was confounded by the generated power levels and the intermittent starting and stopping of generation at the Flint Creek hydroelectric plant. The resulting step discontinuities prevent the meaningful application of regression methods on the days that the discontinuities occurred. Ideally, the generated power would be removed from the load power before completing the analysis.

In the absence of power generation data from the Flint Creek generator, the project attempted to mitigate its influences. A filtered data set was prepared to include only the evaluation period from March 2014 through July 2014, inclusive. Any day on which the load power jumped to an elevated power consumption level was eliminated from the filtered data set. These jumps were assumed to be short periods when generation at the Flint Creek generator had been halted. The thresholds above which the day was eliminated from analysis varied by month, as were determined by inspection of the months' data. The specific thresholds were 1.0, 1.0, 0.0, 0.5, and 1.0 MW for the five contiguous months in the evaluation period. The resulting filtered load is shown in Figure 14.16.

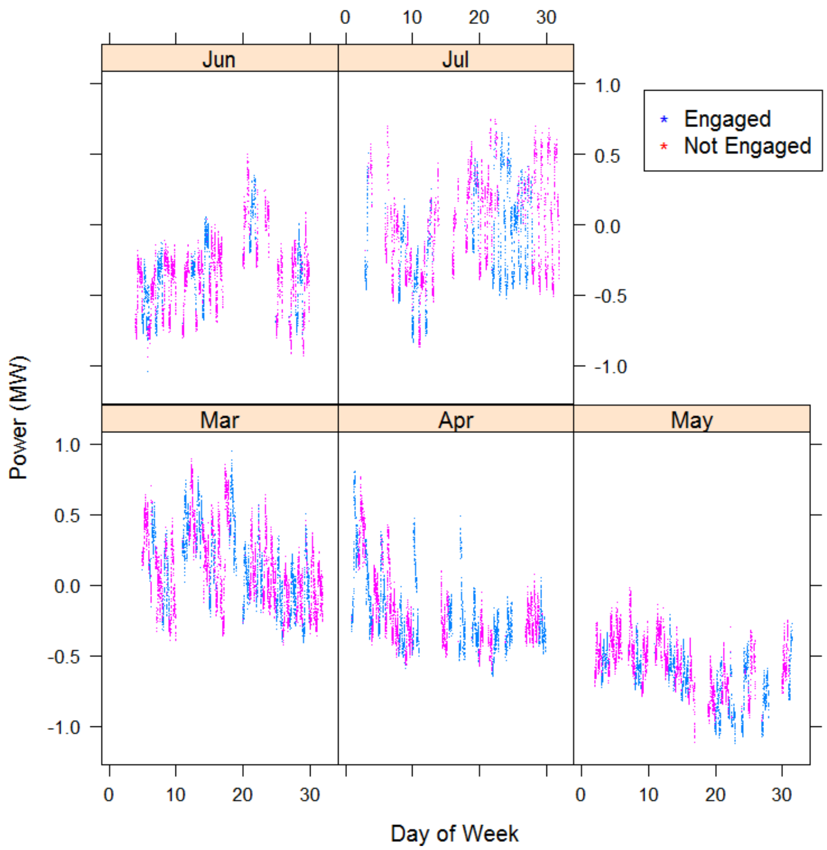


Figure 14.16. Filtered Load Power for the Philipsburg Circuit during the Evaluation Period. Days have been removed from analysis if positive spikes were observed in the load, which are assumed to be periods when Flint Creek generator stopped generating. The circuit is a net exporter of power at times during these months.

Linear regression analysis was then conducted using the software tool R (R Core Team 2013). Implicit assumptions are that the generation at Flint Creek (a) is slowly varying from day to day, (b) is random over time (which seems unlikely based on the consistent magnitudes of the spikes in Figure 14.14), or (c) that generation conforms to a consistent diurnal pattern for months at a time. Any of these conditions could allow a meaningful analysis; however, these assumptions have not been fully tested or confirmed.

The regression was fit to ambient temperature in Philipsburg, Montana (weather station PHGM8), separately calculated by month, weekday type, and hour of day. The temperature data was found to be very complete, but it was further interpolated across short missing data periods (spans less than 6 hours) so that more data points would be used in the regression analysis. The final fit had an R^2 value of 0.733. A single coefficient was determined for the inferred voltage status for all included months, weekday types, and hours. It was determined that the circuit used 27.6 ± 2.5 kW more power, on average, when the voltage was at its normal level than it did when the voltage was reduced. This magnitude is approximately 1% of the peak Philipsburg load on this circuit during times of the year that the generator is not operating. This corresponds to about 660 kWh reduction in energy consumption for any 24-hour period that the voltage is reduced.

14.5 Conclusions and Lessons Learned

NorthWestern Energy implemented IVVC at two locations to optimize real and reactive power control. The implementations were successful both in the somewhat urban Helena circuits and at the more rural Philipsburg circuit. Analysts were able to detect carefully conducted day-on, day-off voltage control at both sites. The voltages had been reduced by approximately 1.5%. Using regression analysis, project analysts were able to confirm that power levels of the Philipsburg circuit and one of the Helena circuits are reduced by about 1% of average load while the voltage is reduced. The analysis on the other Helena circuit was inconclusive. Also, the presence of the Flint Creek hydroelectric generator in Philipsburg created new challenges for the analysis and somewhat reduces our confidence in the findings from regression there.

The utility also implemented FDIR to improve service reliability on four Helena circuits. No improvements could be detected from the yearly reliability indices that had been calculated by the utility, including annual restoration costs, CAIDI, and SAIDI. However, the utility had three outage events in Helena and another in Philipsburg that had tested the FDIR systems at these two sites. Two of the Helena outages in particular convinced the utility that the FDIR system had significantly reduced customer outage minutes and had, to a lesser degree, reduced its response man hours. A communication problem at the Philipsburg site prevented the FDIR system from fully responding to the one outage that was encountered there.

NorthWestern Energy gave a suite of DR equipment to about 200 of its residential customers. Further, the customers were placed under a time-of-use pricing plan for the remainder of the PNWSGD to see how they would respond and configure their equipment to automatically respond to the various pricing levels. Customer acceptance in the pricing program was strong. DR requests could also be initiated by the utility through the price levels, but this option was rarely exercised, and its results are uncertain. The project's efforts to quantify the changes in customer behavior were unsuccessful. No prior baseline 15-minute interval meter data exists for these customers, and no control population was defined. Regardless, the utility believes that conservation was achieved. Many, but not all, customers lowered their electricity bills. Some even won a clever quarterly completion award and monetary prize for lowering their consumption more than the other participants had.

Looking to the future, NorthWestern Energy continues its work to determine the actual costs and cost savings to the smart grid activities that it conducted. As a company, it must keep its focus on cost recovery. The influences to watch include load growth, both in Montana and through the larger region, peak demand, renewable energy integration, and the evolving state of smart grid technologies. The utility intends to implement smart grid technology as the values of such technologies become proven, and is moving ahead with the wireless communication deployment across its Montana service territory to prepare its systems for future smart grid deployments as these begin to make business sense to perform.

The following sections contain responses that were received from NorthWestern Energy when they were asked to list their lessons learned from the PNWSGD.

14.5.1 Lesson Learned #1: Vendors (Good Experiences and Challenges)

NorthWestern Energy used many vendors and their products to implement the various technologies used to set up the smart grid transactive systems. These vendors included Lockheed Martin, Spirae, Inc., S&C Electric, Cooper Power Systems, Tendril, and Itron. The technologies ranged from software and hardware for FDIR, for volt-VAr control, for residential home area management, and for commercial building automation.

Since the inception of this PNWSGD, we have observed that many vendors have left the smart grid business and are no longer involved in smart grid technology. It is important to choose a vendor that has a solid financial history and has a proven track record with their technology. For example, NorthWestern Energy faced increased pressure on schedule and cost due to one manufacturer having been bought out by another prior to producing an agreed-upon FDIR software package. Additionally, another vendor downsized staff numbers in order to stay in business, which meant decreased technical support time and constant changes in project management and sales. When implementing a new product for our customers, it is imperative that they see a consistent brand and also have consistent and timely technical support when required.

At the beginning of a project, it is important to develop a backup plan that includes both estimated costs and schedule changes in the event that one of your primary vendors exits the field.

Keep in mind that some of your vendors are in competition with other vendors, and they will attempt to slow or derail another vendor’s product. This can be as subtle as not approving design documents in a timely manner or not responding to software code updates.

First-time integration of systems and products from various manufacturers and vendors will generally never go as planned. Budget a large contingency in time and funds at the beginning of the project to make sure that integration issues can be overcome. NorthWestern Energy found that setting up a demonstration lab prior to customer installation helped to alleviate some integration issues and helped to keep this aspect of the project on schedule and budget.

On a positive note, we have had several vendors stay very committed to the project even though other factors outside of their, and our, control caused delays. These were vendors with a proven track records and solid financial bases. They seemed to recognize that they were part of a demonstration project, their name and their technology were on the line to a degree, and hence they became committed to the success of the project.

14.5.2 Lesson Learned #2: Experimental Nature of the Project

The concept of smart grid and transactive control is relatively new to the utility industry and to NorthWestern Energy as well. Therefore, NorthWestern was pleased to be able to investigate and test a pilot-scale smart grid project prior to undertaking a larger-scale deployment. Additionally, having multiple project participants from many types of energy users, producers, and distributors was a bonus, since we are all able to learn from each other as we apply different smart grid technologies.

The smart grid pilot project touched almost every department of the utility. This included distribution engineering, distribution operations, business technology, regulatory affairs, legal, contracting, customer care, billing, corporate communications, safety, health, environmental, and construction. Many personnel, from all of these disciplines, worked to complete the design, installation, and testing of the project.

We found that most of our customers were not familiar with smart grid technology; hence recruitment of participants in our target area was difficult. We deemed it important to hire a third-party installation company that knew the customer base and was willing to take extra time with each customer installation, in order to teach the customers about the equipment and explain the benefits of a smart electrical system. The installer explained what smart grid is about from a customer perspective, a utility perspective, and a regional perspective. This installer had performed many home visits while conducting energy audits for NorthWestern Energy customers over the last 20 years and had a good sense of how much time and effort would be required for each installation. An allowance for this time was added to the budget at the start of the project and proved to be money well spent.

System maintenance was also added to all vendor contracts associated with customers prior to the contracts being issued. This forethought helped in many situations where the customer had issues and new equipment was required.

It proved difficult to recruit the small number of test customers for the HAN portion of the project. The footprint of this part of the project was enlarged so that the required number of participants could be secured. Enlarging the geographic area caused an increase in project cost and schedule. Additionally, up to 10% of these customers moved or dropped out of the project during the testing period. This required additional recruitment of new participants, thereby increasing costs and lengthening the schedule. Anticipate at least a 10% dropout rate from the beginning of a project and budget both time and resources for new participants.

NorthWestern Energy found that involving all departments in our organization, from the beginning of the project, helped to alleviate concerns and motivate each to help make the project a success. All areas within the organization worked to solve problems that developed and helped to integrate this unique project into NorthWestern Energy's distribution system. Many managers in different functional areas identified leads and backup personnel so that a smooth flow of information and work could be completed regardless of the problems encountered.

Over the course of integrating hardware, software, and systems from various vendors, the utility found that, as a general rule, it takes much more effort and time to integrate devices into a smart grid system than originally anticipated. Interoperability is an item that needs to be addressed in this industry. In the world of personal computers and home electronics, for example, the computer system components of today do generally "plug and play," even though that was not the case many years ago. The smart grid systems of today are like the early stages of the personal computer industry, where standards were in their infancy or did not exist at all. Similar standards work needs to be done in the smart grid industry today.

One of the software vendors sold the utility their product at the beginning of the project. Software was installed and parts of its functions were not used until the last year of the project. By this time, other software superseded the hardware and software in the field and could no longer communicate with the existing software. The cost and time to upgrade the existing software was never considered in the original design. This meant these functions were never used, because the project did not have the additional time or budget.

14.5.3 Lesson Learned #3: System Integration (FDIR System)

NorthWestern Energy completed DA by using Cooper Power YFA software, automated reclosers and radio communications. The DA was completed in rural and urban settings. Data was collected at a central server in another location that was running Open Platform Communications-compliant software. S&C Electric IntelliTeam® volt/VAr control software was used to automatically modify LTC settings at the substations and end-of-line voltage sensors for feedback values. Additionally, automated capacitor controllers were used in locations along the feeders and were also controlled by S&C Electric IntelliTeam software. Communication in the urban setting was done using Redline radios, and in the rural setting using both SpeedNet™ and FullMAX™ radios.

NorthWestern Energy found that these types of equipment deployments and systems do not "plug and play out of the box." They require several iterations of fine tuning to get all of the components to work together efficiently. Additional equipment may be required for different systems to interface. For example, an Open Platform Communications server was added to the server node to translate data to a protocol that was common between systems.

For NorthWestern Energy, YFA factory testing was exceptional to prove interoperability. Cooper Power simulated integration for the utility in their lab prior to field deployment, proving interoperability. As a result, the utility had minimal issues during field commissioning. S&C Electric (originally Current Group) had verified the interoperability of their system with certain Beckwith LTC and capacitor controllers. The utility purchased these controllers and had minimal interoperability issues.

A robust communication network is paramount for the system to operate properly. In the rural location, testing and deployment was delayed on several occasions because of communication failure issues. Devices consistently went into communication loss; however, a firmware upgrade to the FullMAX radios in late December 2013 appears to have improved their spotty connections. Several radio failures occurred with extreme temperatures (below −20F) and high winds.

SpeedNet radios deployed in Philipsburg did not allow Dynamic Host Configuration Protocol, so the utility had to manually set Internet Protocol addresses at each site.

E-mail notifications are being used to notify personnel when an event occurs on the system. It is difficult to use auto-generated e-mails; the event must be described well enough that it can be understood by the recipient without viewing the on-line system in real time.

In summary, allow additional time, resources and funds for integration of systems, especially communications. Verify interoperability with devices, communications, software, etc., on the bench before deploying devices in the field. Allow event notification recipients access to on-line systems in real time so that they can respond to events.

14.5.4 Lesson Learned #4: IVVC System Observations

NorthWestern Energy enabled IVVC on both the urban and rural locations. S&C Electric IntelliTeam volt/VAr control software was used to automatically modify LTC settings at the substations and end-of-line voltage sensors for feedback values. Additionally, automated capacitor controllers were used in locations along the feeders, and were also controlled by S&C Electric IntelliTeam software.

The utility saw that IVVC has enabled a more efficient operation of the distribution system; however, additional testing needs to be completed to determine the predictability of the CVR control strategy to achieve the calculated savings. For example, the utility found that a limited number of end-of-line sensors had lower than normal voltage; therefore, these low end-of-line voltage points controlled the savings for the entire circuit. Also, the low voltage points may occur in the middle of the feeder due to other factors such as overloaded secondary transformers, low secondary power factor, and long secondary feeders. Going forward, the utility believes the secondary circuit should be more closely analyzed to determine sensor placement. It may be advantageous to perform secondary upgrades to achieve a greater overall voltage reduction.

Furthermore, the utility found that operating in the lower portion of the American National Standards Institute standard caused an increase in tap changes. This was especially true in the five voltage control zones in the rural area. When the software adjusted the voltage in the first voltage zone, it caused all downstream voltages regulators to readjust to maintain their current voltages based on their end-of-line sensors. In the future, the utility hopes to implement a control logic that would attempt to keep the number of tap changes the same or reduce them.

In the rural area, two of the five voltage control zones were unable to achieve any savings. The utility saw a large voltage drop along these, which limited their ability to further reduce the circuit's voltage. Therefore, circuit improvements should be more closely investigated before implementing VVO.

Two urban substations used LTCs to adjust the bus voltage, and software capabilities limited individual control of single-phase regulators located in the rural substation. The utility believes additional savings could be achieved if single-phase voltage regulators could be individually controlled. This would not only help balance the voltages on all phases, it would allow all phases to be lowered to the minimum allowed voltages for the greatest savings.

Without standardized measurement and verification processes, the utility found verifying actual savings difficult. Going forward, they hope to outline a second measurement and verification process, such as sister feeder comparison with base-case testing or CVR Protocol Number 1 alongside S&C's power flow model. This would allow more confidence in the results they observed.

In summary, IVVC has enabled a more efficient operation of the distribution system, but additional testing needs to be completed to determine the predictability of the CVR control strategy to achieve calculated savings. Circuit improvements should be more closely investigated before VVO is implemented to achieve the greatest savings.