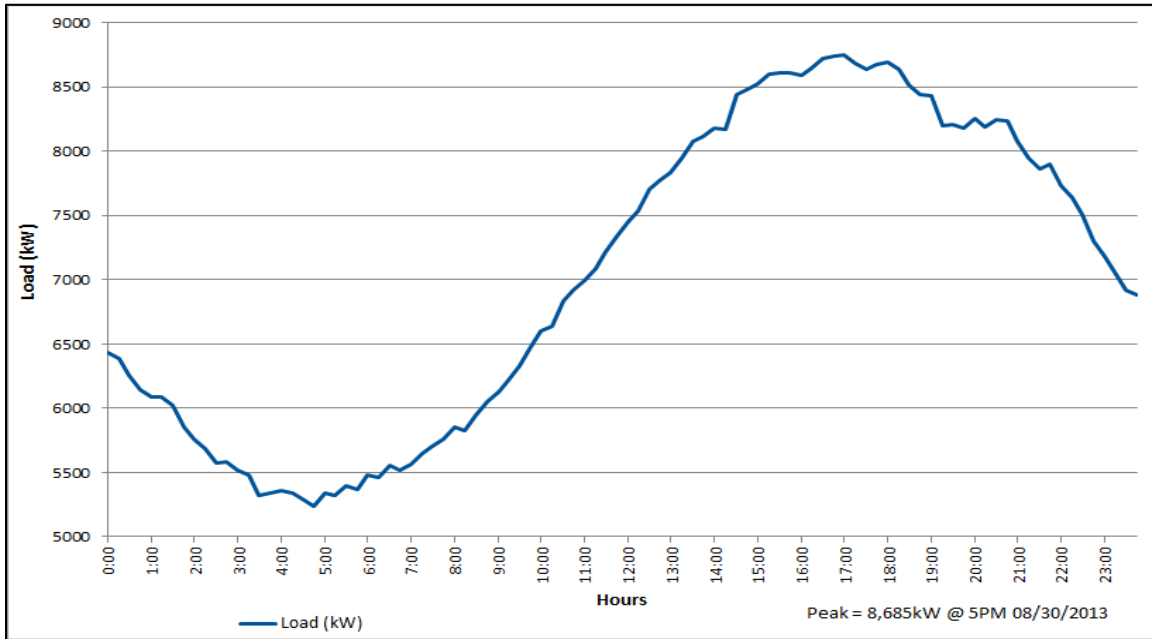


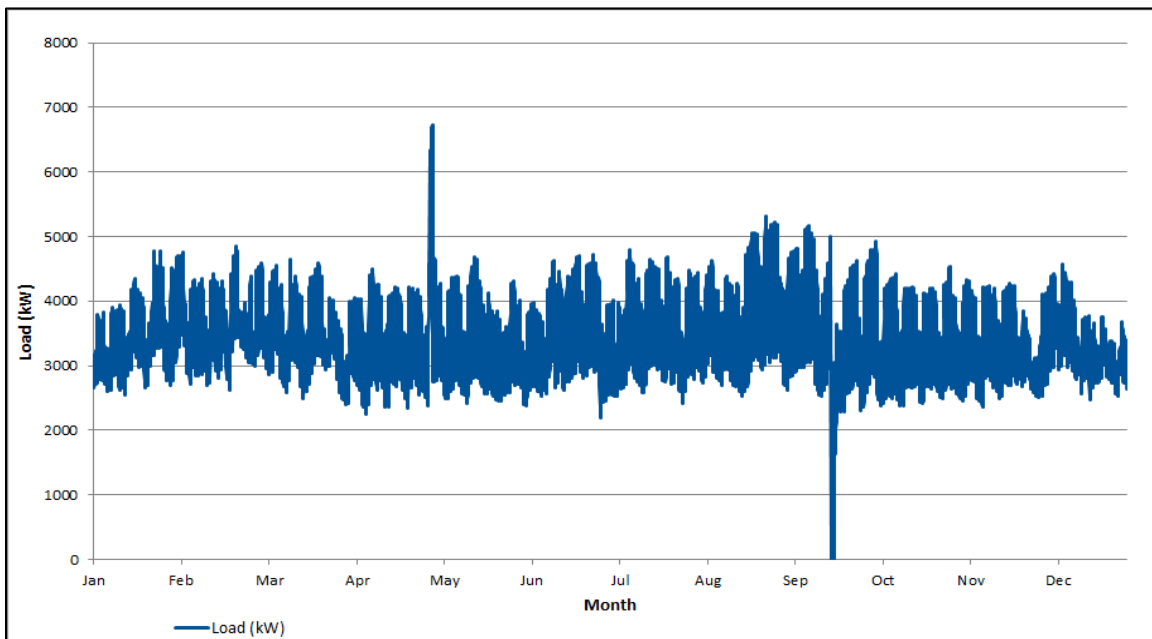
For circuit 7571 the circuit peak under normal load conditions was 8,685 kW and occurred at 5:00 PM on August 30, 2013. Figure 3-176 below shows the 15-minute load profile for the circuit for this day. This daily load curve was further analyzed for this function.

Figure 3-176: 2013 Peak Normal Day Load Profile Circuit 7571



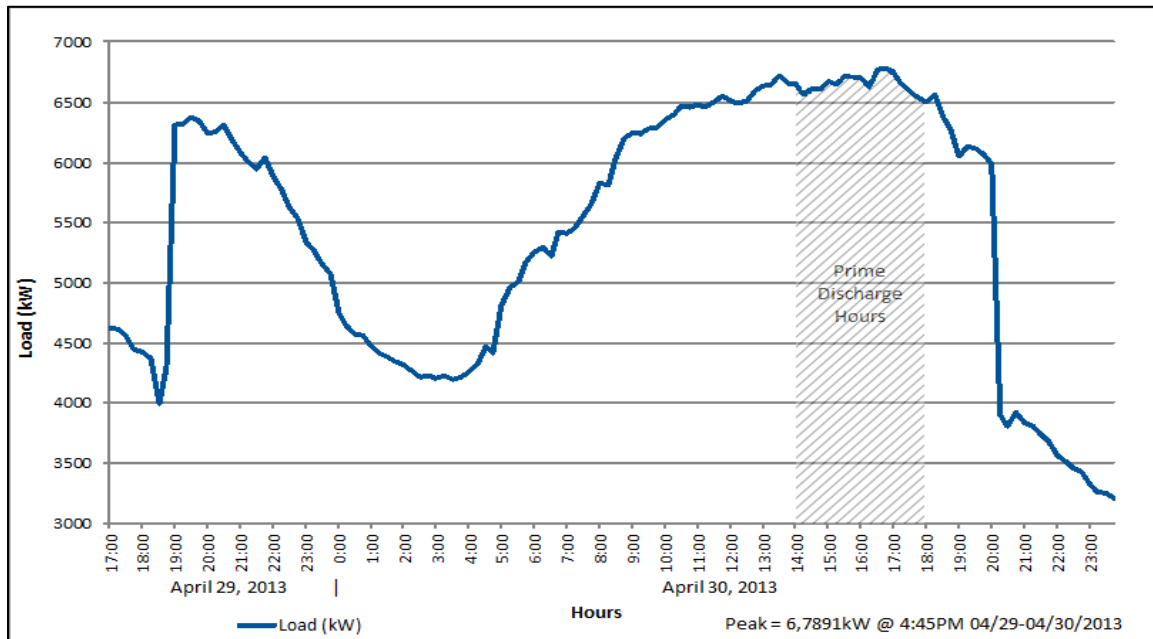
Similarly, hourly data for a SmartGrid commercial feeder was captured and recorded in the DMAT. Figure 3-177 below shows the hourly annual load profile for the year 2013 for SmartGrid Circuit 7514, a predominately commercial feeder.

Figure 3-177: Annual Load Profile Circuit 7514



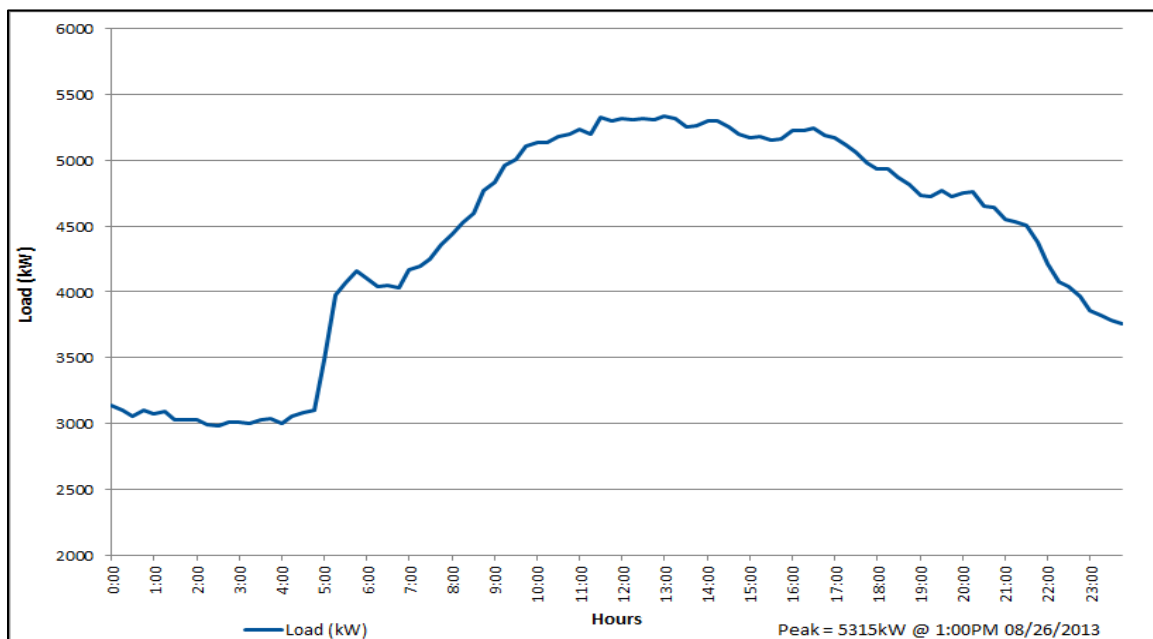
For circuit 7514 the peak load of 6.789 kW occurred at 4:45 PM on April 30, 2013 due to a contingency switching condition. Figure 3-178 below shows the 15-minute load profile for the day of the circuit peak. This daily load curve was further analyzed for this function.

Figure 3-178: 2013 Peak Day Load Profile Circuit 7514



For circuit 7514 the circuit peak under normal load conditions was 5,315 kW and occurred at 1:00 PM on August 26, 2013. Figure 3-179 below shows the 15-minute load profile of the circuit for this day. This daily load curve was further analyzed for this function.

Figure 3-179: 2013 Peak Normal Day Load Profile Circuit 7514



3.4.9.3.2.3 Potential Feeder Peak Load Reduction

The project team performed an analysis to identify the potential transformer and circuit peak load reduction that may be realistically achievable with battery energy storage systems. For this analysis, hourly load data, presented in the previous section, was analyzed. Figure 3-180 below shows the hourly annual load profile for the two circuits under normal and contingency switching conditions.

Figure 3-180: Feeder Load Duration Curve

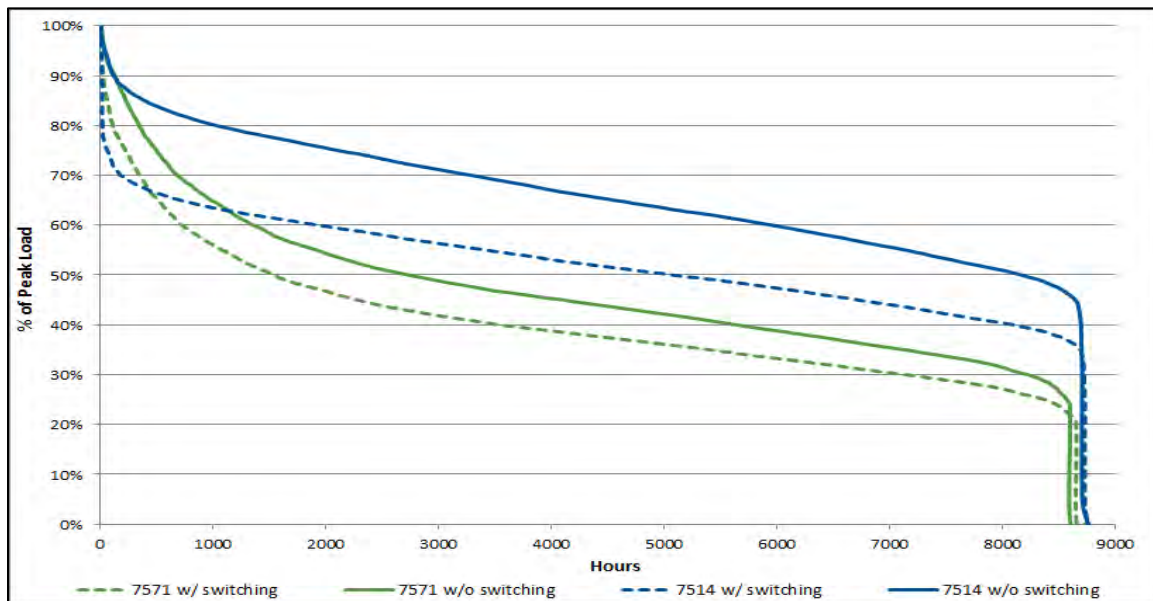
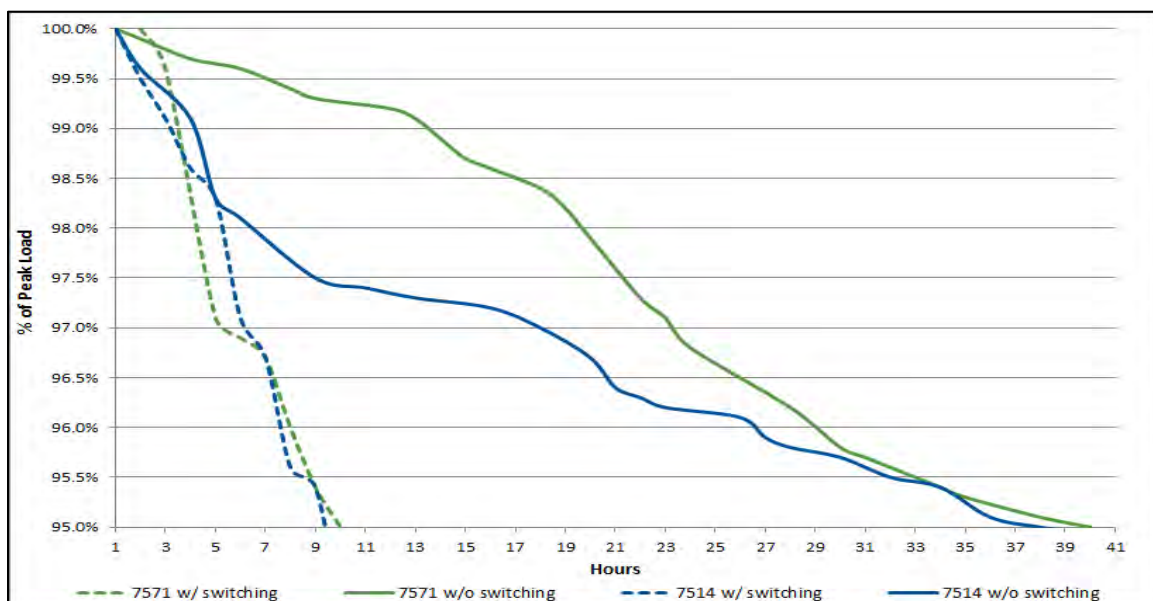


Figure 3-181 plots the number of hours when the load was 95% of peak load or higher. This chart shows that to achieve a capacity reduction of 5% under normal load condition, DR or energy storage resources would be required 40 hours annually. But, since most circuit peak loads occur during contingency switching conditions, a capacity reduction of 5% would only require the use of DR and energy storage resources 10 hours annually.

Figure 3-181: Hours with Load Higher than 95% of Peak Load



The project team performed an analysis to determine the number of hours and days a BESS would be required in order to achieve various levels of load reduction on the substation transformer and circuits being studied. Each table shows Peak Day Hours the BESS would be operated along with the Days and Total Hours of Operation that the BESS would be needed to maintain the reduced system load level. The Prime Hours of Operation column shows the number of total hours that fall within the 4-hour, prime-operation windows illustrated in the peak day load profile figures.

Table 3-121 below show the results of the analysis for substation transformer. This analysis shows that a BESS with a 1.5-MW discharge capacity could achieve a peak load reduction of approximately 5% and would have needed to operate on two days and would have discharged for 6 hours on the peak day.

Table 3-121: Transformer Peak Load Reduction Potential – Transformer 5-6

Peak Day Time	Peak Load (kW)	Max. LF. Discharge (kW)	Peak Reduction (%)	Peak Day Hours of Operation	Days of Battery Operation	Total Hours of Operation	Prime Hours of Operation	Prime Operations (%)
8/25 5:00 PM	29,928	250	0.84%	1	1	1	1	100.0%
		500	1.67%	3	1	3	3	100.0%
		750	2.51%	4	1	4	4	100.0%
		1,000	3.34%	4	1	4	4	100.0%
		1,250	4.18%	6	1	6	4	66.7%
		1,500	5.01%	6	2	7	5	71.4%
		1,750	5.85%	6	2	9	7	77.8%
		2,000	6.68%	6	2	9	7	77.8%
		3,000	10.02%	9	6	26	20	76.9%
		4,000	13.37%	11	11	57	39	68.4%

Table 3-122 below shows the results of the analysis of the residential circuit under contingency switching conditions. This analysis shows that a BESS with 500-kW discharge capacity could achieve approximately a 5% peak load reduction and would have needed to operate on two days and would have discharged for 5 hours on the peak day. Similarity, a BESS with a 1.0-MW discharge capacity could have achieved approximately a 10% peak load reduction, but it would have been required to discharge over 8 hours on the peak day.

Table 3-122: Feeder Peak Load Reduction Potential – Circuit 7571

Peak Day Time	Peak Load (kW)	Max. LF. Discharge (kW)	Peak Reduction (%)	Peak Day Hours of Operation	Days of Battery Operation	Total Hours of Operation	Prime Hours of Operation	Prime Operations (%)
7/9 5:00 PM	10,185	125	1.23%	3	1	3	3	100.0%
		250	2.45%	3	1	3	3	100.0%
		500	4.91%	5	2	9	8	88.9%
		750	7.36%	7	4	16	12	75.0%
		1,000	9.82%	8	4	23	16	69.6%
		1,250	12.27%	9	7	35	22	62.9%
		1,500	14.73%	9	11	57	36	63.2%
		1,750	17.18%	11	11	78	41	52.6%
		2,000	19.64%	11	16	103	55	53.4%

Table 3-123 below shows the results of the analysis of the commercial circuit under contingency switching conditions. This analysis shows that a BESS with 500-kW discharge capacity could achieve approximately a peak load reduction of 7.5% and would have needed to operate on two days and would have discharged for 10 hours on the peak day. Similarity, a BESS with a 1.0-MW discharge capacity could have achieved peak load reduction of approximately 15%, but it would have been required to discharge over 12 hours on the peak day.

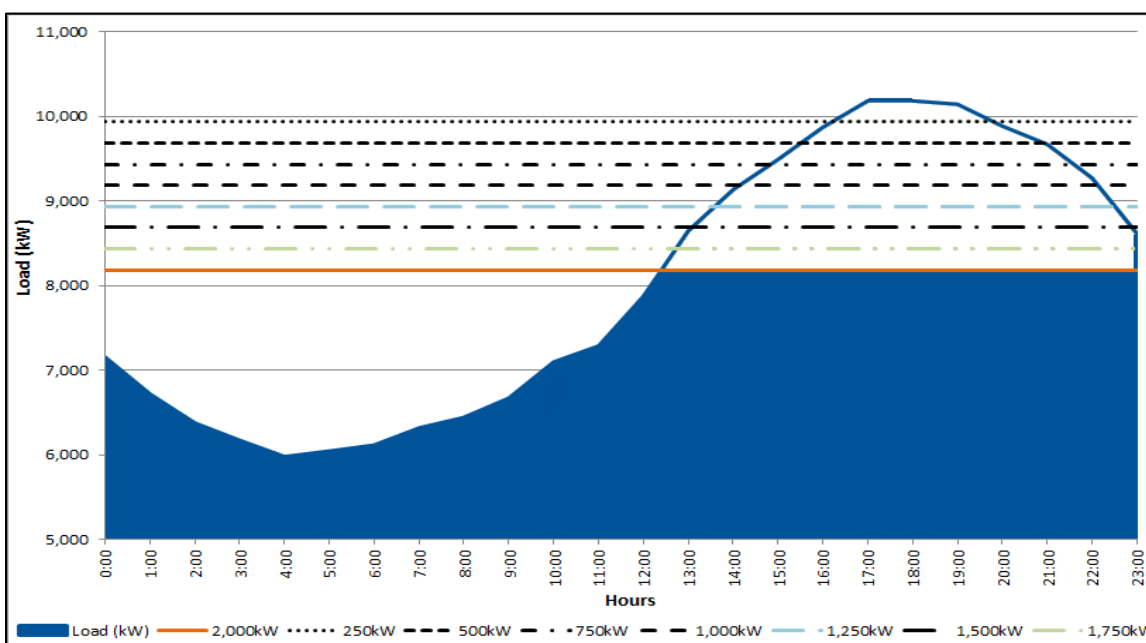
Table 3-123: Feeder Peak Load Reduction Potential – Circuit 7514

Peak Day Time	Peak Load (kW)	Max. LF Discharge (kW)	Peak Reduction (%)	Peak Day Hours of Operation	Days of Battery Operation	Total Hours of Operation	Prime Hours of Operation	Prime Operations (%)
4/30 4:00 PM	6,725	125	1.86%	5	1	5	4	80.0%
		250	3.72%	7	1	7	4	57.1%
		500	7.43%	10	2	12	4	33.3%
		750	11.15%	11	2	14	4	28.6%
		1,000	14.87%	12	2	15	4	26.7%
		1,250	18.59%	13	2	17	4	23.5%
		1,500	22.30%	14	3	22	5	22.7%
		1,750	26.02%	15	14	82	31	37.8%
		2,000	29.74%	15	27	169	67	39.6%

3.4.9.3.2.4 Battery Storage Requirements to Achieve Load Following

The KCP&L project team performed an analysis to identify the energy storage requirements needed to achieve the potential transformer and circuit peak load reductions presented in the previous section. An iterative analysis, illustrated in Figure 3-182, of the hourly load data for the respective peak days was performed to determine the BESS-stored energy requirement to achieve various levels of load reduction. The results of this analysis are presented in the following tables.

Figure 3-182: BESS kWh Required to Achieve Peak Reduction



Each table shows the Peak Day Energy required to limit the system peak load for various levels of load following discharge. Each table also lists the number of Peak Day Hours the BESS would be operated, and the Days of Operation that the BESS would be needed to maintain the reduced system load level. The Battery Capacity column factors in the 80% manufacturer derating and provides the battery capacity required to deliver the Peak Day Energy (MWh) required. The Ratio column shows the optimum MWh/MW ratio for the fleet of BESS resources to achieve the indicated peak load reduction.

Table 3-124 below show the results of the analysis for substation transformer. This analysis shows that a BESS with a 1.5-MW inverter would require a 6.7-MWh battery to achieve the 5% peak load reduction. The table also shows that for this transformer's load profile, a BESS optimally configured between 1 MW and 2MW would have a MWh/MW ratio between 3.25 and 5.25, which would be consistent with the optimal ratios identified in the BESS Electric Supply Capacity analysis.

Table 3-124: BESS kWh to Reduce Transformer Peak

Peak Day Time	Peak Load (kW)	Max. LF. Discharge (kW)	Peak Reduction (%)	Peak Day Hours of Operation	Days of Battery Operation	Total Hours of Operation	Peak Day Energy (kWh)	Battery Capacity kWh	Ratio
8/25 5:00 PM	29,928	250	0.84%	1	1	1	250	313	1.25
		500	1.67%	3	1	3	784	980	1.96
		750	2.51%	4	1	4	1,630	2,038	2.72
		1,000	3.34%	4	1	4	2,630	3,288	3.29
		1,250	4.18%	6	1	6	3,857	4,821	3.86
		1,500	5.01%	6	2	7	5,357	6,696	4.46
		1,750	5.85%	6	2	9	6,857	8,571	4.90
		2,000	6.68%	6	2	9	8,357	10,446	5.22
		3,000	10.02%	9	6	26	16,218	20,273	6.76
		4,000	13.37%	11	11	57	26,539	33,174	8.29

Table 3-125 below show the results of the analysis for the residential circuit. This analysis shows that a BESS with a 0.5-MW inverter would require a 2.5-MWh battery to achieve the 5% peak load reduction. The table also shows that for this circuits load profile, an optimally configured BESS larger than 0.5 MW would need to be configured with considerable storage with MWh/MW ratios significantly above 5.0, which could be an uneconomical deployment configuration.

Table 3-125: BESS kWh to Reduce Residential Peak

Peak Day Time	Peak Load (kW)	Max. LF. Discharge (kW)	Peak Reduction (%)	Peak Day Hours of Operation	Days of Battery Operation	Total Hours of Operation	Peak Day Energy (kWh)	Battery Capacity kWh	Ratio
7/9 5:00 PM	10,185	125	1.23%	3	1	3	335	419	3.35
		250	2.45%	3	1	3	710	888	3.55
		500	4.91%	5	2	9	1,850	2,313	4.63
		750	7.36%	7	4	16	3,393	4,241	5.66
		1,000	9.82%	8	4	23	5,230	6,538	6.54
		1,250	12.27%	9	7	35	7,431	9,289	7.43
		1,500	14.73%	9	11	57	9,681	12,101	8.07
		1,750	17.18%	11	11	78	12,324	15,405	8.80
		2,000	19.64%	11	16	103	15,074	18,843	9.42

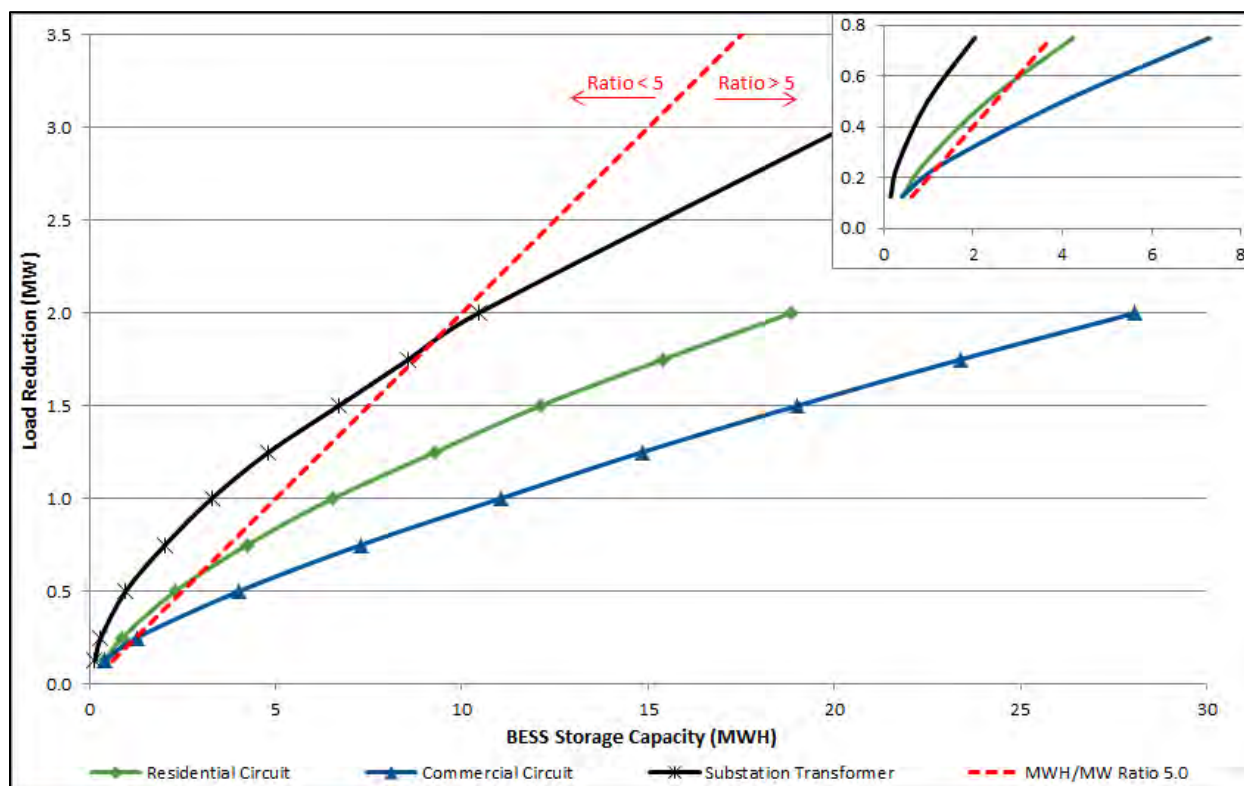
Table 3-126 below show the results of the analysis for the commercial circuit. This analysis shows that a BESS with a 0.5-MW inverter would require a 4.0-MWh battery to achieve a 7.5% peak load reduction. This BESS configuration to achieve this minimal load reduction would have a MWh/MW ratio of 8.0, which could lack economic viability.

Table 3-126: BESS kWh to Reduce Commercial Peak

Peak Day Time	Peak Load (kW)	Max. LF Discharge (kW)	Peak Reduction (%)	Peak Day Hours of Operation	Days of Battery Operation	Total Hours of Operation	Peak Day Energy (kWh)	Battery Capacity (kWh)	Ratio
4/30 4:00 PM	6,725	125	1.86%	5	1	5	324	405.0	3.24
		250	3.72%	7	1	7	1,026	1,283	5.13
		500	7.43%	10	2	12	3,218	4,023	8.03
		750	11.15%	11	2	14	5,836	7,295	9.73
		1,000	14.87%	12	2	15	8,827	11,034	11.03
		1,250	18.59%	13	2	17	11,877	14,846	11.88
		1,500	22.30%	14	3	22	15,197	18,996	12.66
		1,750	26.02%	15	14	82	18,712	23,390	13.37
		2,000	29.74%	15	27	169	22,462	28,078	14.04

Figure 3-183 is a graph of data from the previous tables and shows the BESS storage capacity required to achieve various levels of peak load reduction. The figure generally shows that a BESS with a MWh/MW ratio of 5.0 can achieve its MW rating in peak load reduction for substations, and that to achieve rated KW reduction for individual circuits may typically require the BESS to be configured with MWh/MW ratios significantly greater than 5.0.

Figure 3-183: Peak Load Reduction vs. Storage Capacity



3.4.9.3.2.5 Impact of Distributed Solar PV Generation

The previous analysis showed that to achieve significant levels of peak curtailment on residential and commercial circuits with load profiles similar to those studied, a BESS would be required to discharge in load a significant amount of stored energy over an extended period, often 4 to 12 hours. Configuring a BESS to deliver this amount of energy likely would be cost prohibitive. The project team performed an additional analysis to determine if a modest level of distributed solar PV generation would alter the capability of a BESS to provide T&D peak load reduction. The solar PV generation profile developed in the Distributed Rooftop Solar Generation operational test was used for this analysis.

Figure 3-184 and Table 3-127 summarize the results of this analysis for the substation transformer. This analysis shows that a 15% solar penetration (4.5 MW) would result in a 5% reduction in transformer loading at peak, shifting the peak hour from 4 PM to 7 PM. The analysis also shows that for the solar-adjusted transformer's load profile, an optimally configured 1.5-MW/6.0-MWh BESS, operating in load following mode over 6 hours, could achieve a 5% reduction in transformer peak load. Combined, the solar and BESS could achieve a 10% reduction in the transformer peak load.

Figure 3-184: Solar Adjusted Transformer Peak

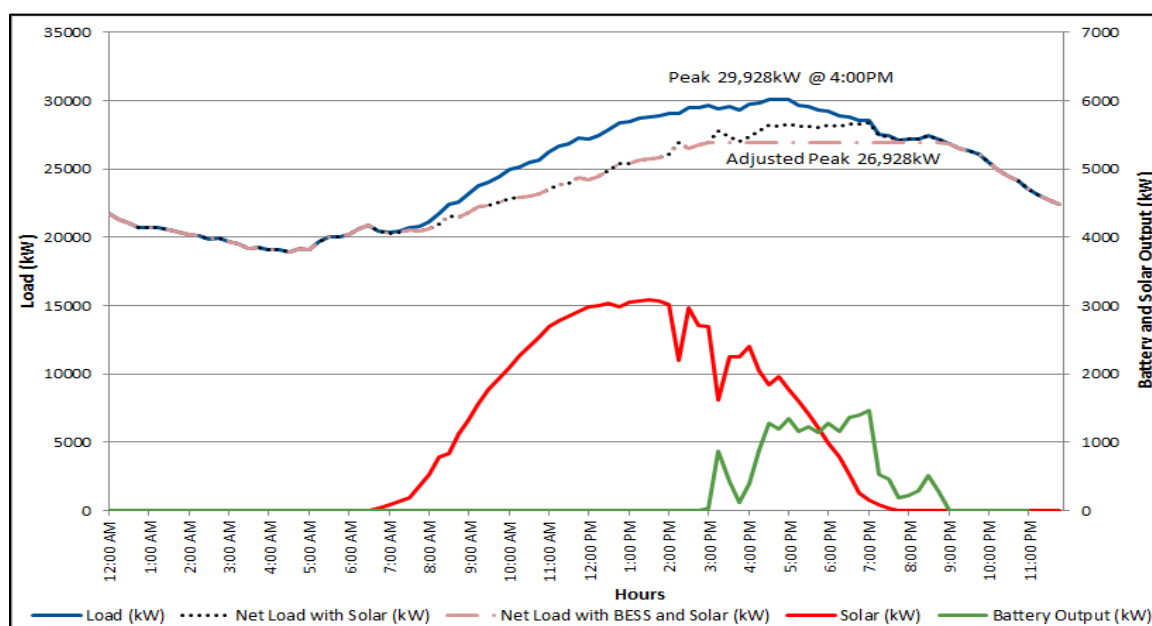


Table 3-127: Solar Adjusted Transformer Peak Analysis

Metric	Value
Original Transformer Peak	29,928 kW @ 4:00PM
Solar Capacity (15% peak)	4,489 kW
Solar Peak	3,077 kW @ 1:30 PM
Solar Adjusted Transformer Peak	28,391 kW @ 7:00 PM
Battery Discharge Duration	6 Hrs; 3:00–9:00 PM
Max. Battery Discharge	1,463 kW @ 7:00 PM
Battery Adjusted Transformer Peak	26,928 kW
% Peak Reduction with Battery	5.12 %
% Peak Reduction with Solar and Battery	10.0%
Total Battery Discharge	4,800 kWh
Total Battery Capacity Required	6,000

Figure 3-185 and Table 3-128 summarize the results of this analysis for the residential circuit. This analysis shows that a 15% solar penetration (1.5 MW) would result in less than a 1% reduction in circuit loading at peak but shifts the peak hour from 5 PM to 7 PM. The analysis also shows that for the solar adjusted residential circuit load profile, an optimally configured 1.0-MW/4.0-MWh BESS, operating in load following mode over 7 hours, could achieve a 9% reduction in circuit peak load. Combined, the solar and BESS could achieve a 9.8% reduction in the circuit peak load. This BESS with a MWh/MW ratio of 4.0 is consistent with the optimal ratios identified in the BESS Electric Supply Capacity analysis.

Figure 3-185: Solar Adjusted Residential Circuit Peak Day

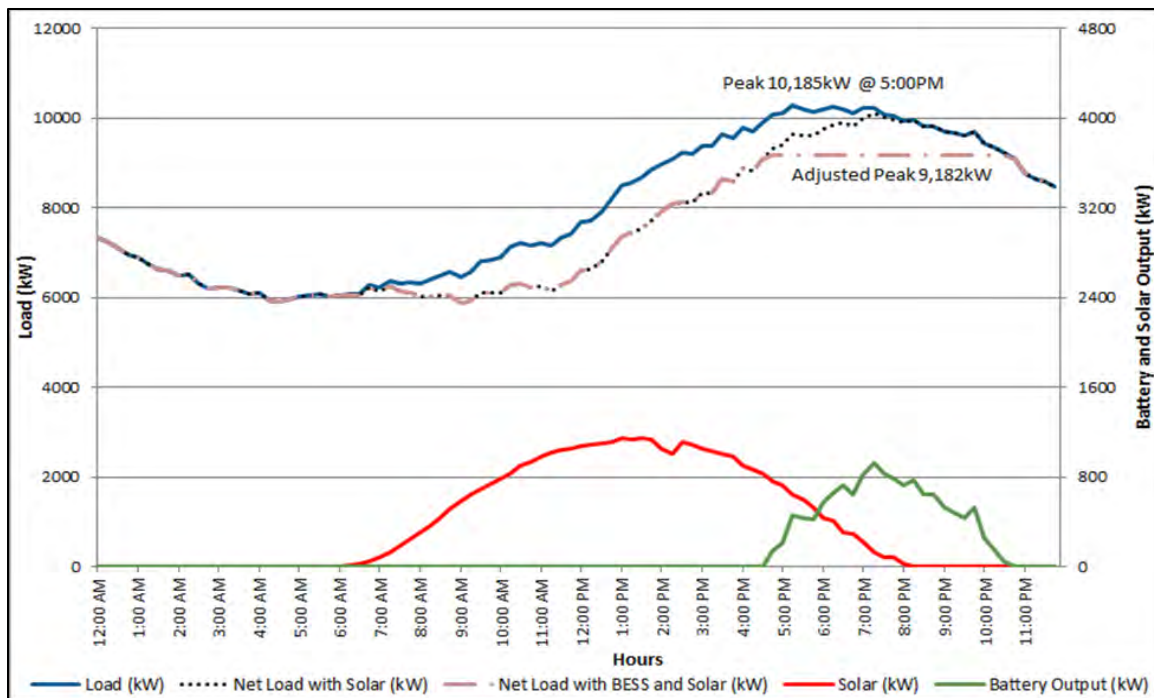


Table 3-128: Solar Adjusted Residential Circuit Peak Analysis

Metric	Value
Original Circuit Peak	10,185 kW @ 5:00 PM
Solar Capacity (15% peak)	1,528 kW
Solar Peak	1,140 kW @ 1:30 PM
Solar Adjusted Circuit Peak	10,105 kW @ 7:15 PM
Battery Discharge Duration	7 hours; 4:00 PM-11:00 PM
Max. Battery Discharge	923 kW @ 7:15PM
Battery Adjusted Circuit Peak	9,182 kW
% Peak Reduction with Battery	9.1 %
% Peak Reduction with Solar and Battery	9.8 %
Total Battery Discharge	3,200 kWh
Total Battery Capacity Required	4,000 kWh

Figure 3-186 and Table 3-129 summarize the results of this analysis for the commercial circuit. This analysis shows that a 15% solar penetration (0.85 MW) would result in a modest 1.3% reduction in circuit loading, with only a slight shift in the timing of the peak load. The analysis also shows that for the solar adjusted commercial circuit load profile, a 1.0-MW/4.0-MWh BESS, operating in load following mode over 12 hours, could achieve a 10% reduction in circuit peak load. Combined, the solar and BESS could achieve an 11.5% reduction in the circuit peak load. This BESS, with a MWh/MW ratio of 4.0, is consistent with the optimal ratios identified in the BESS Electric Supply Capacity analysis.

Figure 3-186: Solar Adjusted Commercial Circuit Peak Day

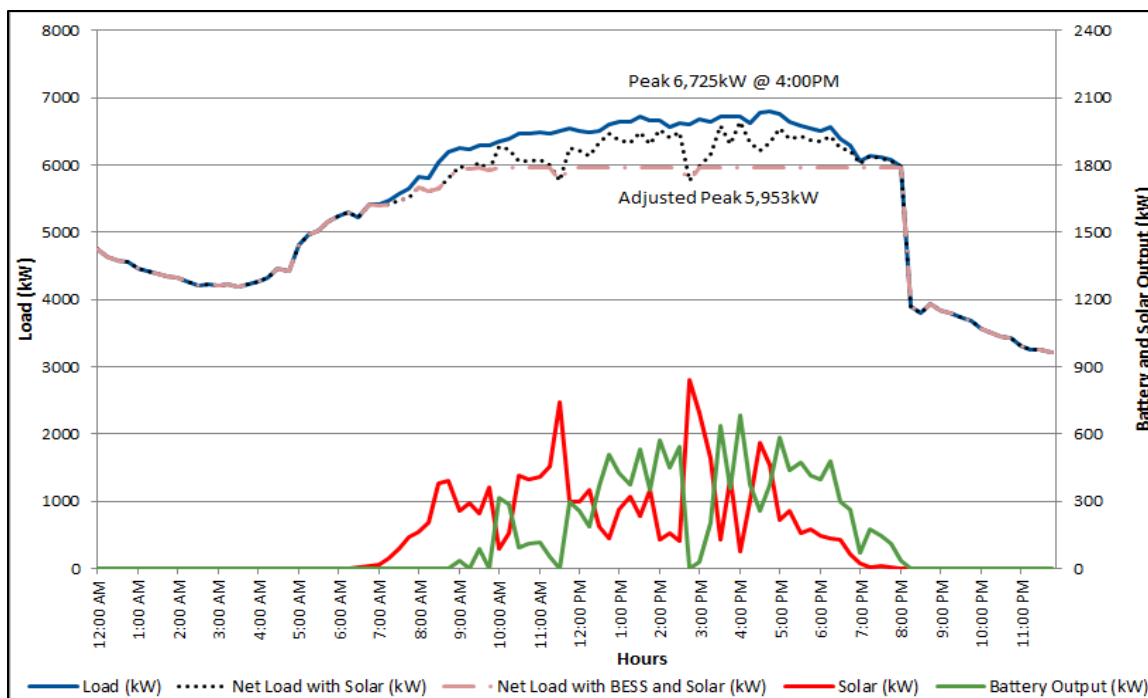


Table 3-129: Solar Adjusted Commercial Circuit Peak Analysis

Metric	Value
Original Circuit Peak	6,725 kW @ 4:00 PM
Solar Capacity (15% peak)	1,009 kW
Solar Peak	843 kW @ 2:45 PM
Solar Adjusted Circuit Peak	6,636 kW @ 4:45 PM
Battery Discharge Duration	12 hours; 9:00 AM-9:00 PM
Max. Battery Discharge	683 kW @ 4:00PM
Battery Adjusted Circuit Peak	5,953 kW
% Peak Reduction with Battery	9.8 %
% Peak Reduction with Solar and Battery	11.5 %
Total Battery Discharge	3,200 kWh
Total Battery Capacity Required	4,000 kWh

3.4.9.3.2.6 Issues and Corrective Actions

The following issues and corrective actions were encountered during the performance of the T&D Upgrade Deferral operational testing and analysis.

Table 3-130: Issues and Corrective Actions

Issue	Corrective Action
Per manufacturer recommendation, battery should not be routinely discharged below 20% of rating.	- Limited scheduled BESS discharge to 800 kW. - Set minimum threshold to 15% of capacity for discharge events.
BESS SMS did not provide a load-following function, but did provide a DNP point to externally control SMS output.	Team implemented a rudimentary load, following an algorithm in a local controller to manage the SMS output.
Other operational demonstrations, testing, and analyses precluded dispatching BESS during T&D peak times.	Performed the BESS T&D load following demonstration as scheduling allowed, but analyzed the impact of event as if it had occurred at peak.
Circuit to which the BESS was connected was not a good representation of either residential or commercial circuits.	Performed the BESS T&D Upgrade deferral following analysis on SGDP transformer and circuits that were more representative than typical urban circuits.
Residential and commercial circuits required the BESS to be configured with a high MWh/MW ratio for MW reduction.	Performed additional analysis to evaluate the impact of distributed Solar PV generation on MWh/MW ratios for T&D Upgrade Deferral.

3.4.9.3.3 Findings

The results obtained in the execution and analysis phase of the T&D Upgrade Deferral operational testing are summarized in the sections below.

3.4.9.3.3.1 Discussion

The 1.0-MW/1.0-MWh grid-connected BESS is only capable of discharging 80% of its rated storage capacity. Therefore the BESS—by discharging 800 kWh in Load Following Mode—is only capable of reducing the respective T&D component peak loads as follows:

- Substation Transformer 505 kW with LF discharge over 3 hours
- Residential Circuit 7571 280 kW with LF discharge over 3 hours
- Commercial Circuit 7514 217 kW with LF discharge over 5 hours

The BESS Storage Management System (SMS) did not provide a load following function, so to demonstrate this function the project team implemented a rudimentary load-following algorithm in a local controller. Although not as tight as expected, the AMI 15-minute interval data showed that the load following algorithm generally maintained the circuit load at the desired level. While the local controller could rapidly alter the SMS outputs, the wide fluctuations in local load—in conjunction with the relay deadband settings—made it virtually impossible for the local controller to precisely maintain the circuit loading at the desired load following threshold setting.

To determine of the potential of a BESS to provide T&D capacity reductions, the project team selected a representative substation transformer, residential circuit, and commercial circuit on which to perform the analysis. The annual hourly load profile data for these circuits was collected evaluated under normal and contingency switching conditions. Most distribution circuit capacity constraints occur during

contingency switching operation. Therefore, the majority of the capacity reduction analysis was performed during the circuit peaks created during contingency switching operations.

The analysis, summarized in Table 3-131, shows the BESS configuration that could provide an approximate 5% reduction in peak load. To achieve peak reduction greater than 5% would require the BESS to be discharged over a significant portion of the day (8+ hours) and be configured with an MWh/MW ratio greater than 5.0, which could be economically unviable.

Table 3-131: BESS kWh to Reduce Peak by 5%

Distribution Component	Peak Load (kW)	Max. LF. Discharge (kW)	Peak Reduction (%)	Peak Day Hours of Operation	Days of Battery Operation	Total Hours of Operation	Battery Capacity kWh	Ratio
Sub. Transformer	29,928	1,500	5.01%	6	2	7	6,696	4.46
Residential Ckt.	10,185	500	4.91%	5	2	9	2,313	4.63
Commercial Ckt.	6,725	500	7.43%	10	2	12	4,022	8.03

While each distribution constraint had different characteristics, the analysis showed that to achieve significant levels of peak curtailment on residential and commercial circuits with load profiles similar to those studied would require a BESS to discharge in load a significant amount of stored energy over an extended period, often 4 to 12 hours. Configuring a BESS to deliver this amount of energy is likely cost prohibitive.

The project team performed an additional analysis to determine if a modest level (15%) of distributed solar PV generation would alter the capability of a BESS to provide T&D peak load reduction. Generally the addition of the solar reduced the mid-day loads, reducing the peak load somewhat, and created a new peak hour later in the day—7 PM for the transformer and residential circuit. The analysis, summarized in Table 3-132, shows that BESS configurations with 4.0 MWh/MW ratios when combined with the solar PV could provide a 10% reduction in peak loads.

Table 3-132: BESS kWh to Reduce Peak by 10%

Distribution Component	Peak Load (kW)	Peak w/PV (kW)	Inverter Capacity (MW)	Battery Capacity (MWh)	Peak Day Hours of Operation	Peak Reduction (kW)	ES Peak Reduction	PV & ES Peak Reduction
Sub. Transformer	29,928	28,391	1.5	6.0	6	1,463	5.1 %	10.0 %
Residential Ckt.	10,185	10,105	1.0	4.0	7	923	9.1 %	9.8 %
Commercial Ckt.	6,725	6,636	1.0	4.0	12	683	9.8 %	11.5 %

As mentioned previously, the ability of a BESS to defer T&D capacity investments is very site specific and varies greatly based on the load profile of the loads at the point of congestion. These examples show that commercial circuits, with much flatter load profiles, will require a BESS to be configured with significantly more battery storage to achieve a significant amount of congestion relief. For these situations a BESS alone may not be economical, but when combined with other demand-response and distributed generation, an optimally sized BESS could become a part of an economical T&D capacity deferral solution.

Figure 3-186 also illustrates additional challenge that the intermittency of distributed PV generation introduces to managing circuit loading. In this example, the commercial circuit was experiencing a peak loading condition following contingency switching the previous day. In this case the solar PV intermittency increased the fluctuation of the circuit load but did not significantly shift the daily load

pattern and peak load time. However, even with the intermittency the solar generation that was produced allowed the BESS to provide a slightly larger peak reduction with fewer energy-storage requirements.

3.4.9.3.3.2 Expectations vs. Actuals

The following table provides a comparison of the Expected Results and the Actual Outcomes for the T&D Upgrade Deferral operational test.

Table 3-133: Expected Results vs. Actual Outcome

Expected Results	Actual Outcome
Demonstrate load following discharge of battery based on real-time transformer, bus, and circuit loadings.	- The BESS was used to demonstrate load-following operation based on real-time transformer, bus, and circuit loadings. - Load-following precision of the BESS was limited by the relay deadband settings and variability of local loads.
Using several representative company distribution circuit load profiles, determination of a representative distribution circuit peak reduction (kW) that could be achieved for a 1-MWh battery.	- Determined T&D upgrade deferral potential for the project's 1.0MWh battery. - Also calculated the T&D upgrade deferral potential for the BESS with various MW/MWh configurations.

3.4.9.3.3.3 Computational Tool Factors

The following table lists the values derived from the T&D Upgrade Deferral operational test analysis that will be used as inputs to the SmartGrid Computational Tool and the Energy Storage Computational Tool.

Table 3-134: Computational Tool Values

Name	Description	Value
Distribution Capacity Deferred (kVA)	The size of the distribution investment deferred as a result of installing energy storage.	500 kVA
Capital Carrying Charge of Distribution Upgrade	The total capital cost of distribution system investments that can be deferred as a direct result of the project.	\$ 159,634
Distribution Investment Time Deferred	The time in years that the distribution investment will be deferred.	5 yr
Capital Cost of Deferred Distribution Capacity (\$/KVA) (ESCT)	The base overnight capital cost of the deferred transmission investment.	\$ 319.26

- Capital Carrying Charge of Distribution Upgrades (\$) – Using an incremental distribution deferral method this value is calculated as follows:

$$\text{Dist. Capacity Deferred (kVA)} \times \text{Typical Cost of Dist. Capacity (\$/kVA)} \times \text{Life Cycle Value Multiplier} =$$

$$500 \text{ kVA} \times \$23.94/\text{kW} \times 13.3362 = \$159,634$$
- Distribution Investment Time Deferred (Yr.) – The distribution investment deferral is assumed to be 5 years due to the fact that the team is using an incremental calculation and aggregating all incremental distribution deferral components into a single SGCT value.

- Capital Cost of Deferred Distribution Capacity (ESCT) (\$) – Using an incremental distribution deferral method this value is calculated as follows:

$$\begin{aligned} & \text{Typical Cost of Dist. Capacity (\$/kVA)} \times \text{Life Cycle Value Multiplier} = \\ & \$23.94/\text{kW} \times 13.3362 = \$319.26 \end{aligned}$$

3.4.9.3.4 Lessons Learned

Throughout the conduct of the operational testing and analysis of the BESS for Transmission and Distribution Upgrade Deferral function, numerous considerations were realized and should be noted for future implementations. These Lessons Learned are as follows:

- Confirmed that manufacturer's recommendation that the battery should not be routinely discharged below a 20% charge level to protect the battery and maintain its life. This limitation must be factored in when sizing the battery storage component for any BESS.
- The ability of a BESS to defer T&D capacity investments is very site specific and will vary greatly based on the load profile at the point of congestion. This analysis shows that a BESS alone may produce a 5% reduction in distribution transformer and circuit peak loading.
- In many cases, using a BESS alone for T&D Upgrade Deferral may not be economical, but when combined with other demand-response and distributed-generation programs, an optimally sized BESS could become a part of an economical T&D Upgrade Deferral solution.
- Based on the demonstration's analysis it appears that a BESS optimally sized for T&D Upgrade Deferral would have a 0.5-MW to 2.0-MW inverter paired with four to five times the inverter rating in MWh battery storage.

3.4.9.4 Time-of-Use Energy Cost Management

For the Time-of-Use (TOU) Energy Cost Management application, energy end users (utility customers) could use a Premise Energy Storage System (PESS) to reduce their overall costs for electricity. They would accomplish this by charging the storage during Off-Peak periods, when the electric energy price is low, then discharge the energy during times when On-Peak TOU energy prices apply. This application is similar to Electric Energy Time Shift application, although electric energy savings are based on the customer's retail tariff, whereas the benefit for Electric Energy Time Shift is based on the prevailing wholesale price.

3.4.9.4.1 Overview

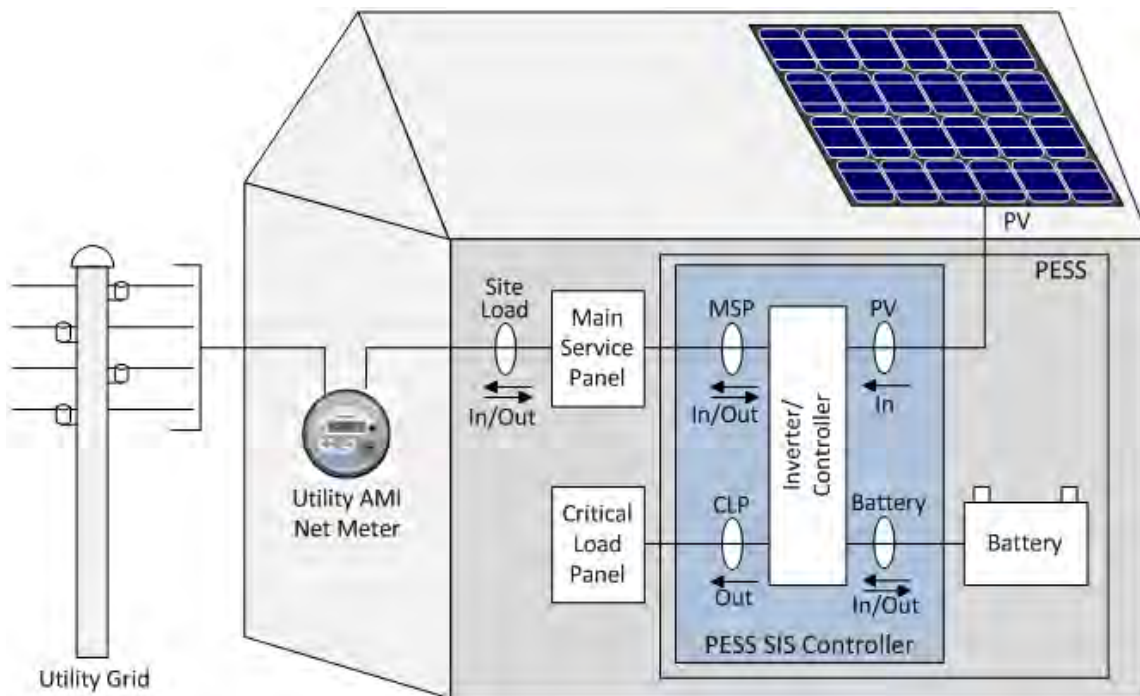
The following sections provide an overview of the operational, demonstration, testing, and evaluation methodology used for the Time-of Use Energy Cost Management operational test.

3.4.9.4.1.1 Description

A consumer PESS was installed at the SmartGrid Demonstration House in conjunction with the 2.82-kW solar PV array. The PESS consists of an 11.7-kWh lithium-ion battery with a unique hybrid inverter/converter rated for 6.0-kW discharge.

The PESS was configured as illustrated in Figure 3-187 and was used to demonstrate how the consumer could use the PESS in conjunction with multitier TOU rates to reduce the consumer's overall cost for electricity. This was accomplished by charging the PESS battery during Off-Peak periods, when the electric energy price is low, and then discharging the battery during times when On-Peak TOU energy prices apply.

Figure 3-187: PESS Installation at SmartGrid Demonstration House



3.4.9.4.1.2 Expected Results

This technical demonstration was expected to yield the following:

- Typical daily charge/discharge load cycles for TOU Energy Cost Management would be developed and demonstrated at the Demonstration House.
- The Round Trip Efficiency factor of the PESS factor for TOU Energy Cost Management would be determined. The system would be expected to operate at greater than 70% efficiency with respect to net energy output versus input.
- The Total Energy Discharged for TOU Energy factor for the PESS would be determined. The system would be expected to have approximately 10 kWh available daily for TOU discharge.
- The charge/discharge load cycles developed would be mathematically applied to a load profile for a typical residential customer to illustrate how a PESS system could be used with TOU rates to lower the customer's energy cost.

3.4.9.4.1.3 Benefit Analysis Method/Factors

The DOE SGCT was used to perform the SGDP benefit analysis. For this application the following Smart Grid Function benefits were quantified.

- Deferred Generation Capacity Investments
- Deferred Distribution Capacity Investments
- Reduced Electricity Costs

Benefits were calculated using SGCT formulas. The following factors were measured, projected or calculated during the application operation and/or demonstration.

Deferred Generation Capacity Investments (Utility)

- Energy Storage Use at Annual Peak Time (MW)

Deferred Distribution Capacity Investments (Utility)

- Distribution Feeder Load Reduction (MW)
- Capital Carrying Charge of Distribution Upgrade (\$)

Reduced Electricity Costs (Customer)

- Reduced Total Residential Electricity Cost (\$)

Additionally, the DOE ESCT was used to perform the benefit analysis for a customer owned PESS system. The following Stationary Energy Storage applications were combined in this analysis.

- Primary Application – Time-of-Use Energy Cost Management
- Secondary Application – Renewable Energy Time Shift
- Secondary Application – Electric Service Reliability

Primary Benefit for TOU Energy Cost Management:

- Reduced Electricity Cost (Consumer)

3.4.9.4.1.4 Testing Methodology

The following points provide an overview of how the operational demonstration and testing for this application was accomplished:

- Energy delivered to and received from the PESS was measured by the PESS Solar Integration System (SIS). All PESS data collected was stored in the SIS data archive.

- Energy delivered to and received from the customer's electrical system by the utility distribution grid was measured by the AMI net meter installed at the customer service entrance. All AMI data collected was stored in KCP&L's MDM and DMAT systems.
- A daily charge/discharge program was implemented to demonstrate and evaluate the operational benefit of using the PESS. Charging occurred daily from 9:00 PM to 12:00 AM and discharge occurred from 1:00 AM to 5:00 AM. This nighttime daily/charge discharge cycle was used so that data collection for this operational test could be conducted in parallel with data collection for Renewable Energy Shift Time Shift analysis.
- The PESS was operated in this mode at least two weeks to determine the Round Trip Efficiency of the battery storage system factor.

3.4.9.4.1.5 Analytical Methodology

The following points provide an overview of the analytical methods that were used to evaluate the impact and benefits of this application:

- 1-minute interval energy (AC watts) delivered to and received from the customer's electrical system (MSP) by the PESS was recorded by the PESS SIS.
- 1-minute interval energy (AC watts) delivered to the customer's emergency critical load panel (CLP) by the PESS was recorded by the PESS SIS.
- The functionality of the PESS SIS was used to aggregate the 1-minute interval data to 15-minute interval data and was exported to Excel for analysis.
- The daily charge/discharge cycles were analyzed to determine the potential maximum energy that could be discharged and stored, and the round trip efficiency of the battery charge/discharge cycle.
- The Daily Round Trip Efficiency of PESS was calculated as the Daily Energy Delivered to the utility and customer load/Daily Energy Received from the utility.
- The SmartGrid Demonstration House is not a typical residential customer. Therefore a typical residential customer was selected to analyze the PESS charge and discharge cycle.
- The Reduced Electricity Cost for the consumer was calculated for inclusion in the Smart Grid Computational Tool and Energy Storage Computational Tools.

3.4.9.4.2 Plan Execution and Analysis

The following sections provide details regarding the functional tests performed, data collected, and analysis performed for the Time-of-Use Energy Cost Management operational test.

3.4.9.4.2.1 Daily Block Charge and Discharge Operation

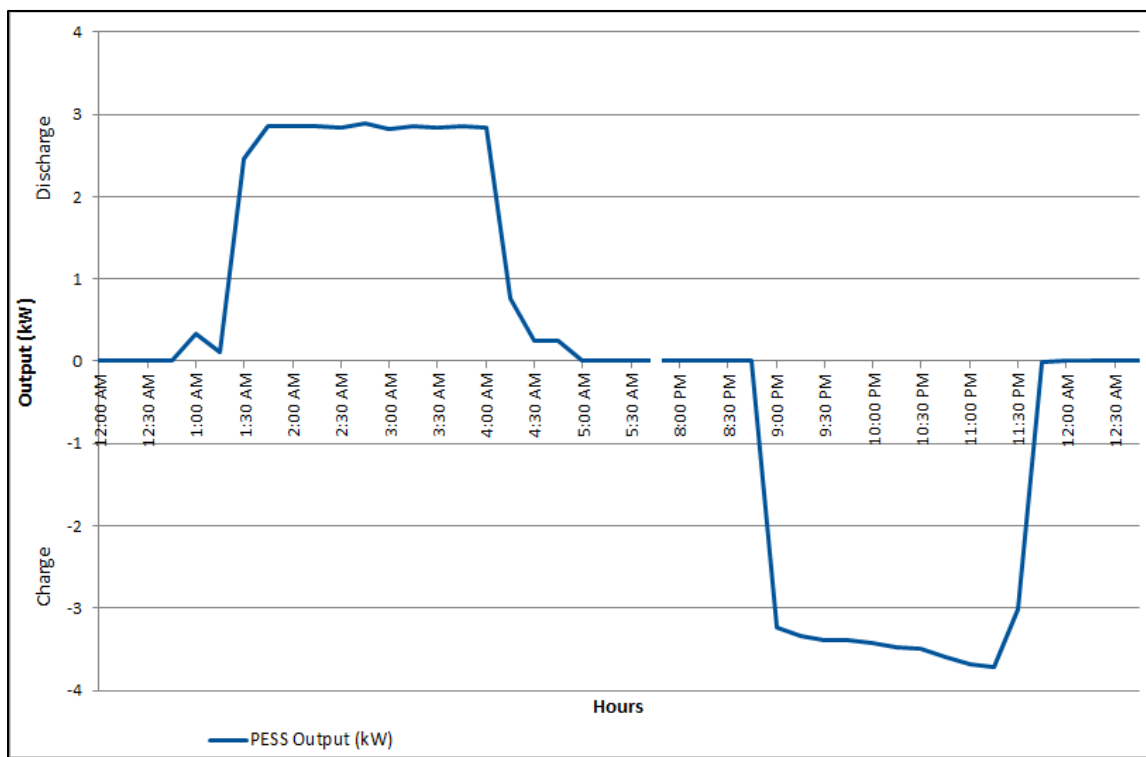
A review of the manufacturer's operation manual identified a recommendation that the battery should not be routinely charged above 95%, and should not be discharged below 10% charge level, to protect the battery and maintain its useful life. The manual also included a recommendation for reserving 10% battery capacity for UPS mode. These operational constraints limit the operational output of the 11.7-kWh Lithium polymer battery for routine application use to 8.75 kWh.

The PESS was set to charge daily from 9 PM to 12 AM and discharge from 1 AM to 5 AM local time. To achieve a full charge and discharge, the following settings were configured in the SMS:

- The SIS discharge rate was set at 45% of inverter capacity, or 2.7 kW, to deliver approximately 9 kWh during the 4-hour discharge period.
- The SIS charge rate was set at 66% of inverter capacity, or 3.96 kW, to provide a full charge, up to 11.7 kWh, during the 3-hour charge period.

Figure 3-188 shows the 15-minute interval daily block charge and discharge cycles under these settings. During idle hours, the utility grid supplies load to the house for the critical load and main load.

Figure 3-188: PESS Daily Block Charge and Discharge Profile



As illustrated in the figure above, the battery starts to charge and slowly increases the charge rate over a period of 3 hours. The SIS calculates the state of charge for the battery, and increases the charge rate if the battery is not close to its full state of charge.

3.4.9.4.2.2 Daily Round Trip Efficiency of the PESS

At the beginning of the project, it was expected that the PESS would operate at efficiency greater than 70% with respect to net energy output versus input. The SIS records the energy delivered to the grid, energy received from the grid, and energy delivered to the critical load at the site. The purpose of this analysis is to verify the round trip efficiency of PESS.

Based on the daily charge and discharge cycle, the round trip efficiency of the PESS is calculated as:

$$RTE \text{ of PESS} = \frac{\text{Energy discharged from PESS}}{\text{Energy required to charge PESS} + \text{Energy received during idle hours}} \times 100\%$$

The energy discharged from PESS is calculated as the sum of energy delivered to the grid and the critical load panel at the site. The energy required to charge PESS is calculated as the difference of energy from the grid and energy delivered to the critical load panel on site. Energy received during idle hours is the difference of energy from the grid and energy delivered to the critical load panel on site when the PESS is non-operational.

Table 3-135 shows the energy delivered by the grid to charge PESS, energy discharged by the PESS, energy received during idle hours, and round trip efficiency of PESS. These values were measured over several days. The daily round trip efficiency varied from 80.9% to a maximum of 96.1%, with average efficiency of 86.4%.

Table 3-135: Daily Round Trip Efficiency of the PESS

Date	Discharge (kWh)	Charge (kWh)	Idle hours (kWh)	Efficiency
Sept. 04	9.09	9.36	0.087	96.16%
Sept. 07	8.16	9.44	0.056	85.97%
Sept. 13	8.38	9.23	0.045	90.38%
Sept. 16	8.10	9.38	0.052	85.88%
Sept. 21	7.92	9.31	0.060	84.56%
Sept. 25	7.84	9.63	0.059	80.97%
Sept. 29	7.97	9.57	0.062	82.74%
Oct. 02	8.00	8.70	0.067	91.32%
Oct. 08	7.98	9.13	0.051	86.92%
Oct. 16	7.80	9.21	0.044	84.34%
Oct. 23	7.86	8.90	0.059	87.69%
Oct. 28	7.91	9.13	0.117	85.53%
Average	7.98	9.17	0.062	86.45%

3.4.9.4.2.3 Potential Utility System and Distribution Peak Reduction

The PESS can be operated in multiple ways that would affect the utility capacity requirements. First, the customer could participate in a utility Demand Response program or allow the utility to dispatch the PESS for Demand Response. For Demand Response the PESS could potentially supply 6 kW (inverter capacity) for a 1-hour duration event; 4.3 kW for a 2- hour duration event; or 2.15 kW for a 4-hour duration event.

Secondly, if KCP&L assumed that the utility's system and distribution peaks occur during the On-Peak TOU billing period, the utility would experience a demand reduction when the customer discharged the battery for TOU Energy Cost Management. For this operational test KCP&L assumed a 4-hour On-Peak billing period, corresponding to the experimental SmartGrid TOU rate implemented for the project.

During the daily charge/discharge cycle, the PESS discharged at a rate of 2.7 kW but did not discharge for a full 4 hours. Table 3-135 shows that the average discharge was 7.98 kWh which, if the settings were tuned further, could deliver 2 kW of customer and utility load reduction for a 4-hour duration.

3.4.9.4.2.4 Customer Energy Usage with PESS Used for On-Peak TOU Cost Management

The SmartGrid Demonstration house electrical usage is not representative of a typical residential customer. Therefore a "typical" residential customer—with an annual usage of 10,319 kWh, approximately 15% more than the average Demonstration Area residential customer (~8,800 kWh)—was selected to analyze customer benefits of the PESS when used for energy cost management.

The daily load profile for such a typical residential customer from the SmartGrid Demonstration area is shown in Figure 3-189. While no two customers have identical usage patterns, this customer displays a typical daily pattern; minimal usage during the late night, sharp rise to moderate usage in the early morning hours, followed by a mid-morning drop in usage that begins to increase throughout the day, significant peak usage during the On-Peak period, followed by a slightly reduced but sustained moderate usage until midnight.

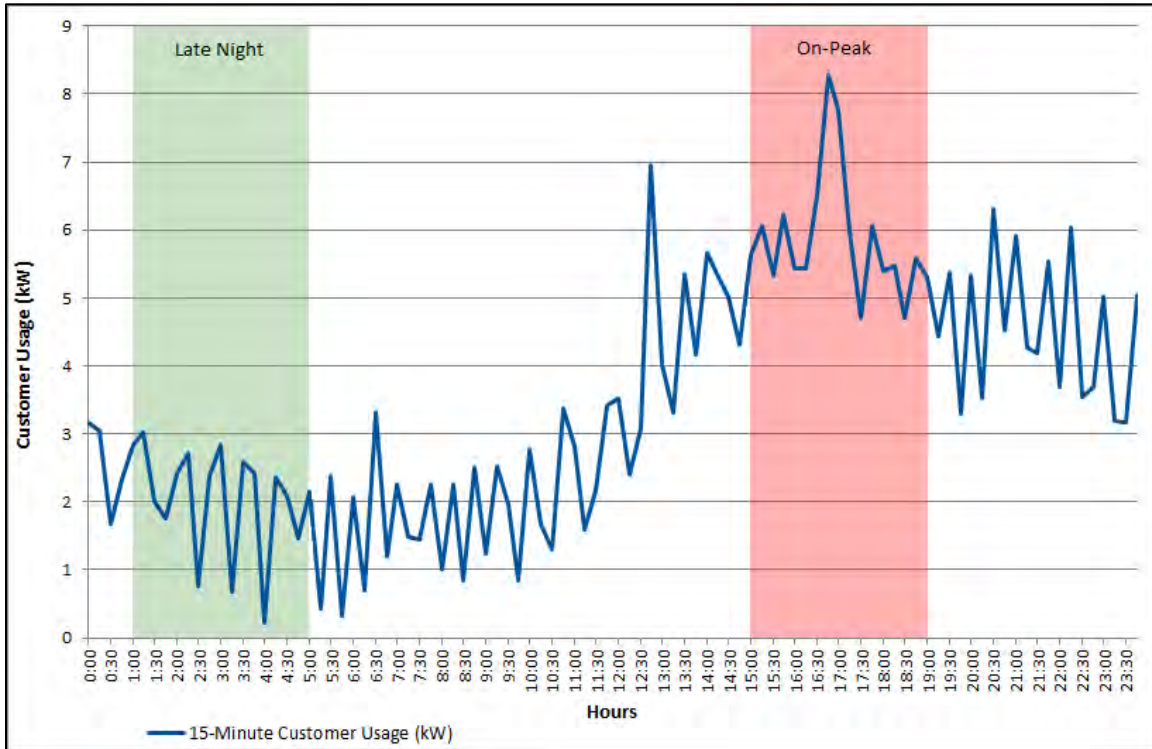
Figure 3-189: Summer Typical Residential Customer Daily Load Profile

Figure 3-190 shows the weekly kWh usage of this residential customer throughout the year in three usage groupings: Late Night Usage (when the battery would charge), Normal Usage, and On-Peak Usage (when the battery would be discharged).

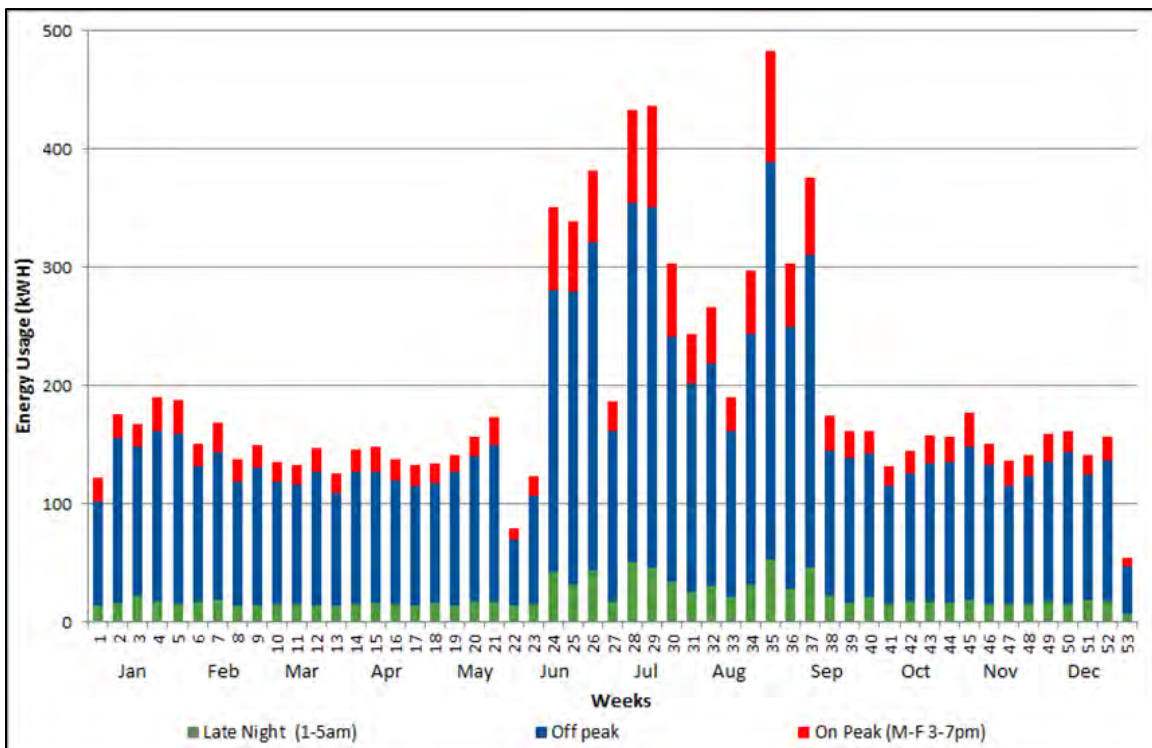
Figure 3-190: Weekly Typical Residential Customer Usage

Figure 3-191 shows the shift in daily energy use this residential customer with the maximum PESS block charge/discharge operation applied. The PESS is charged from 1:00 AM to 5:00 AM and discharged from 3:00 PM to 7:00 PM, thus boosting energy usage in the late night and reducing usage during On-Peak hours.

Figure 3-191: Daily Load Profile with PESS Daily Block Operation

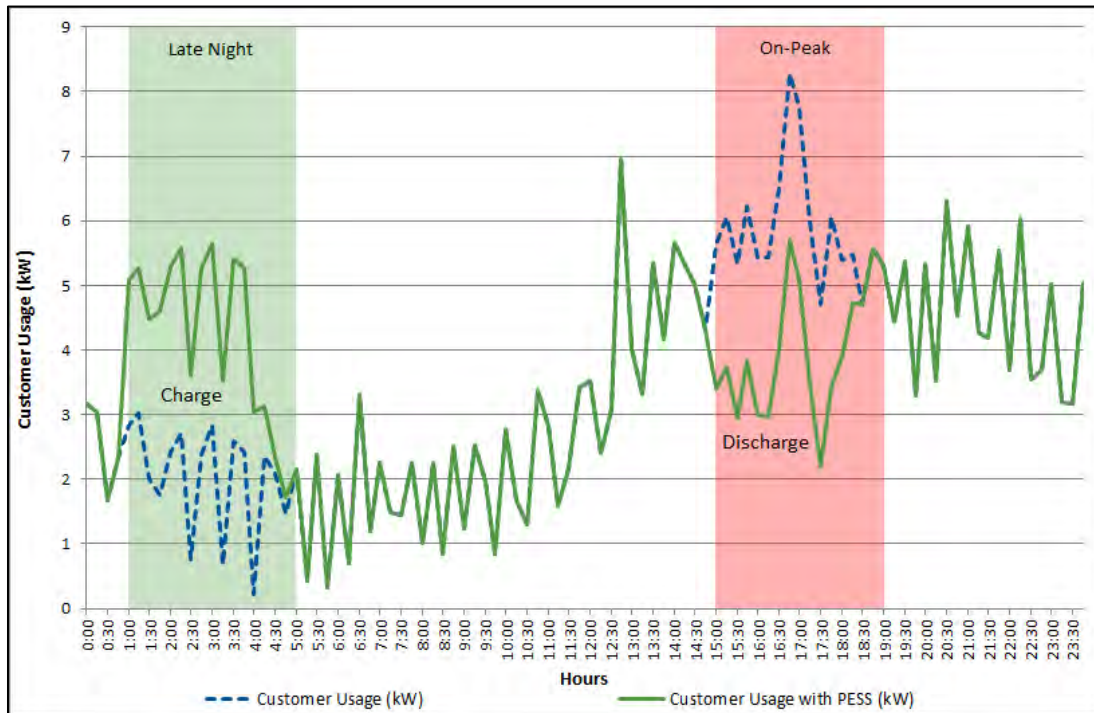


Figure 3-192: Weekly Typical Residential Usage with PESS Block Operation

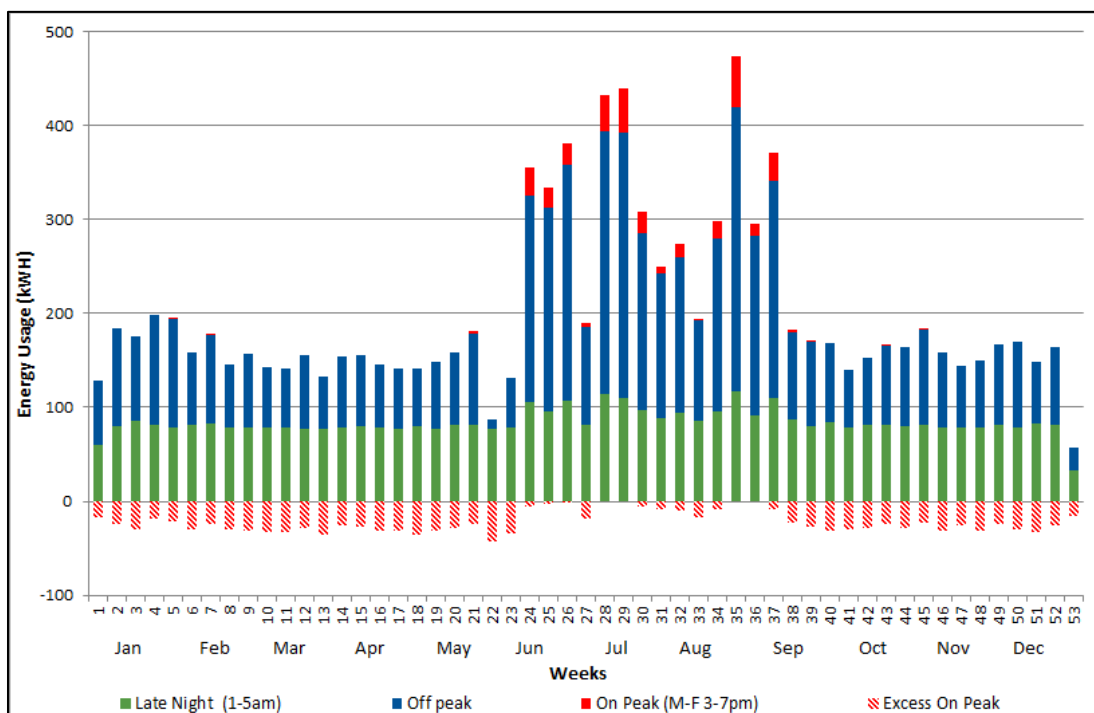


Figure 3-192 above shows the shift in weekly residential customer usage with the PESS block operation. The PESS block discharge during peak hours results in zero to negative consumption (supply to grid) of energy during On-Peak hours. The energy consumption significantly increases during Off-Peak hours when PESS is scheduled to charge to its full potential.

Figure 3-193 shows the shift in daily energy use this residential customer with the maximum PESS load-leveling operation applied. The PESS is charged at a variable rate from 1:00 AM to 5:00 AM and discharged at a variable rate from 3:00 PM to 7:00 PM. With the load-leveling application the variability the customer's load on the grid during the charge and discharge cycles will be minimized and the ability of the customer to fully discharge the PESS without feeding energy back to the grid will be improved.

Figure 3-193: Daily Load Profile with PESS Daily On-Peak Load Leveling Operation

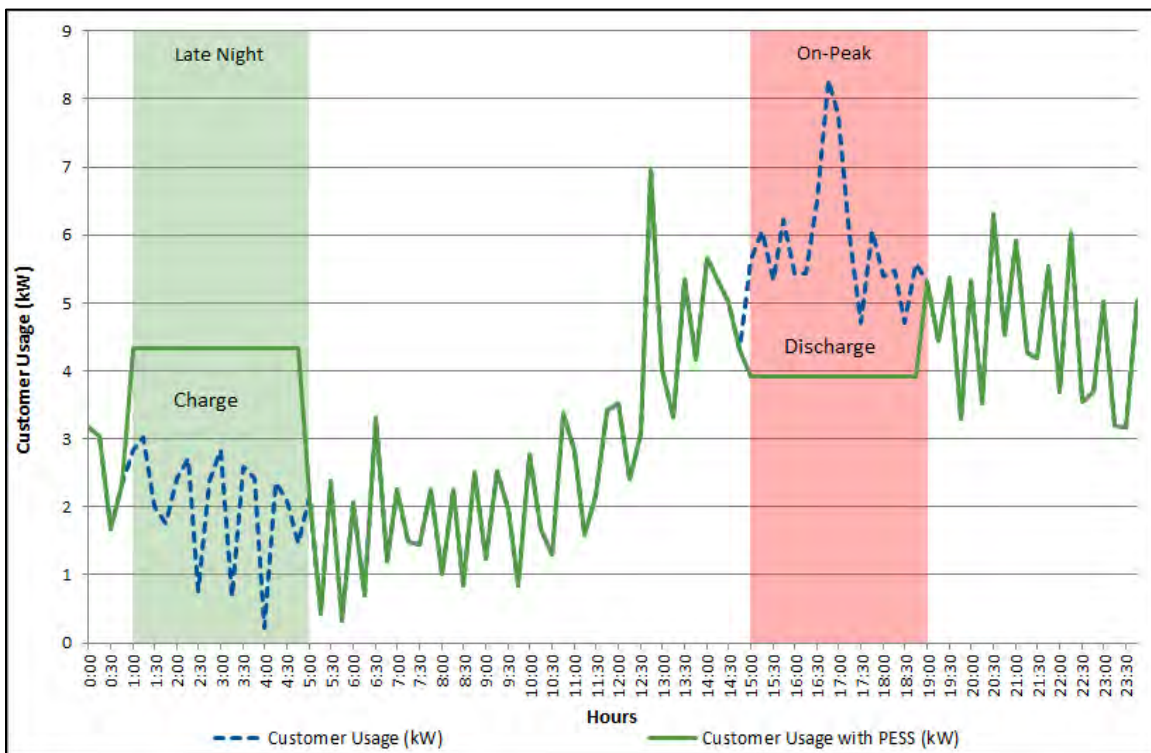


Figure 3-194 shows the shift in weekly residential customer usage with the PESS load-leveling operation. The PESS load-leveling discharge during peak hours results in no negative consumption (supply to grid) and only a few occurrences where the customer's On-Peak usage was low enough that the entire capacity of the PESS could not be fully discharged during the On-Peak period.

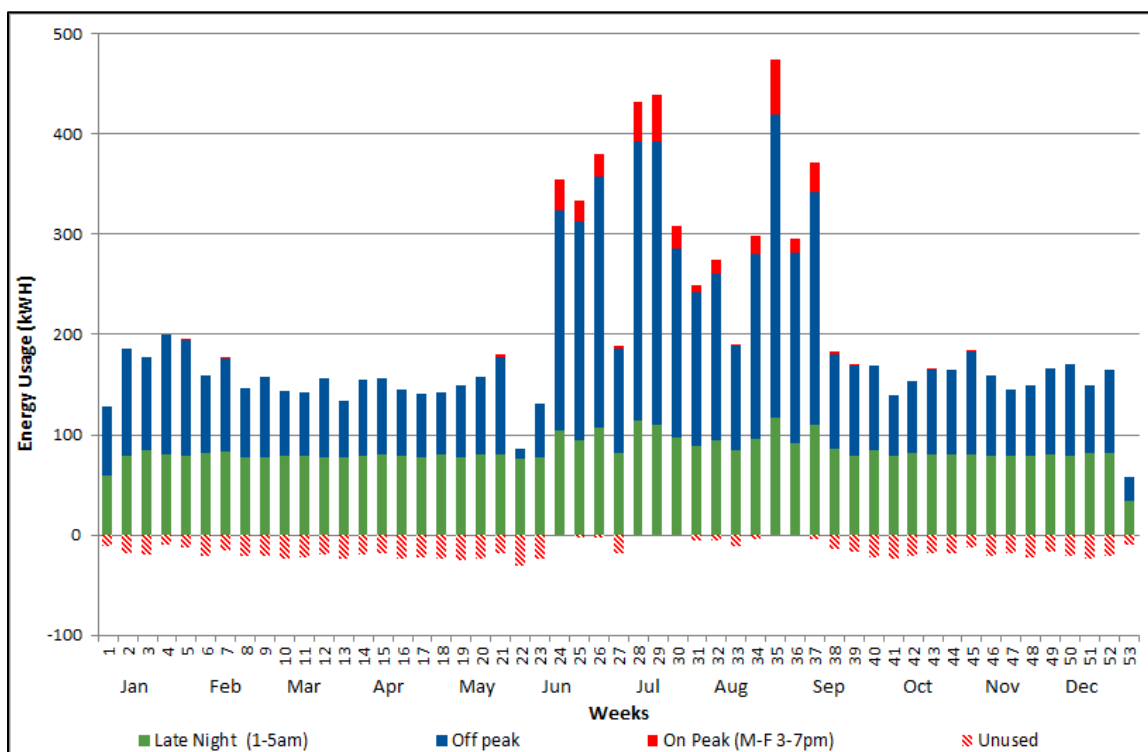
Figure 3-194: Weekly Typical Residential Usage with PESS Load-Leveling Operation

Table 3-136 below summarizes the impact of the PESS on the Late Night and On-Peak energy usage for this residential customer by season. In this table the PESS has been operated in load-leveling mode to maximize the offset of the customer's On-Peak usage and minimize unused PESS energy or energy delivered to the utility.

Table 3-136: Residential Customer Energy Usage per Session with On-Peak Reduction

	Customer Energy Usage Metrics (kWh)	Summer (Jun 16 - Sep 15)	Fall (Sep 16 - Dec 15)	Winter (Dec 16 - Mar 15)	Spring (Mar 16 - Jun 15)	Annual Total
Usage Before PESS	On-Peak Energy (3-7 PM M-F)	757	282	275	280	1,594
	Off-Peak Energy	3,040	1,514	1,541	1,510	7,606
	Late Night Energy (1-5 AM)	459	220	217	223	1,119
	Total Energy	4,256	2,016	2,033	2,013	10,319
With PESS (Load Leveling)	PESS Charge Energy	481	157	177	138	953
	PESS Discharged Energy	416	135	153	120	824
	PESS Unused Energy	88	351	343	379	1,161
Usage with PESS	On-Peak Energy (3-7 PM M-F)	342	147	122	160	771
	Off-Peak Energy	3,040	1,514	1,541	1,510	7,606
	Late Night Energy (1-5 AM)	941	376	394	361	2,072
	Total Energy	4,323	2,037	2,057	2,031	10,448

3.4.9.4.2.5 Customer Cost Savings Potential from PESS with SmartGrid TOU Rate

The TOU rate implemented for the SGDP incorporated a rate differential during the period the KCP&L Summer Rates were in effect. The SmartGrid TOU rate was based on the following parameters:

- Effective Dates – May 15th–Sept. 15th
- On-Peak Times – 3-7 PM, Monday-Friday Excluding Holidays
- On-Peak Rate – \$0.3784 (approximately 3X the standard summer rate)
- Off-Peak Rate – \$0.0631 (approximately half of the standard summer rate)

Based on these TOU program parameters a customer could implement 77 charge/discharge cycles during the period in which the summer On-Peak rates are in effect. Assuming the customer's load was such that the customer could consume the full PESS discharge of 7.98kWh during the On-Peak time, a total of 614.5 kWh could be discharged annually for TOU cost savings. The annual Customer Energy Cost savings would be \$187.73 calculated by the following formula:

$$\text{Reduced Customer Energy Cost (\$)} = \text{Total Energy Discharged for TOU Energy (kWh)} \times \\ [\text{Avg. On-Peak Retail Price of Electricity (\$/kWh)} - \text{Avg. Off-Peak Retail Price of Electricity (\$/kWh)} / \\ \text{Storage System Round-trip Efficiency (\%)}]$$

$$\text{Reduced Customer Energy Cost (\$)} = 614.5\text{kWh} \times [0.3784 \text{ \$/kWh} - (0.0631 \text{ \$/kWh}/0.8645)] = \$ 187.73$$

3.4.9.4.2.6 Customer Cost Savings Potential from PESS with 3 Tier TOU Rate and Net Metering

Analysis in previous sections has covered customer usage and the cost savings impact of operating the PESS to reduce On-Peak energy consumption from the utility. When a PESS is operated in conjunction with solar generation the savings potential between the Time-of-Use Energy Cost Management and the Renewable Energy Time Shift functions can conflict. To achieve maximum TOU Cost Managing savings in conjunction with solar renewable generation, the operation of the PESS for TOU Cost Management must be adjusted to offset On-Peak usage with Late Night usage, which requires a 3-tier TOU rate.

KCP&L could not implement a 3-tier TOU rate for the SGDP due to limitation in the utility's CIS billing system. But to support this analysis, the project team developed a hypothetical year-round 3-tier TOU structure that was revenue neutral with the 2-tier TOU rate outlined in the previous section. The hypothetical TOU rate used for this analysis was based on the following parameters:

- Summer Effective Dates – June 15th–Sept. 15th
- On-Peak Times – 3-7 PM, Monday-Friday Excluding Holidays
- Late Night Times – Midnight -5 AM
- Off-Peak Times – All other time
- Summer On-Peak Rate – \$0.336
- Summer Off-Peak Rate – \$0.09
- Summer Late Night Rate – \$0.03
- Winter On-Peak Rate – \$0.225
- Winter Off-Peak Rate – \$0.075
- Winter Late Night Rate – \$0.025

Table 3-137 below summarizes the impact of the PESS on the Late Night and On-Peak energy usage for this residential customer, by season. Results in this table come from the PESS being operated in block discharge mode to offset of the customer's On-Peak usage and deliver any excess stored energy to the utility.

Table 3-137: Residential Customer Energy Usage with 3 Tier TOU and Net Metering

	Customer Energy Usage Metrics (kWh)	Summer (Jun 16 - Sep 15)	Fall (Sep 16 - Dec 15)	Winter (Dec 16 - Mar 15)	Spring (Mar 16 - Jun 15)	Annual Total
Usage Before PESS	On-Peak Energy (3-7 PM M-F)	757	282	275	280	1,594
	Off-Peak Energy	3,040	1,514	1,541	1,510	7,605
	Late Night Energy (1-5 AM)	459	220	217	223	1,119
	Total Energy	4,256	2,016	2,033	2,013	10,318
PESS	PESS Charge Energy	844	834	825	844	3,347
	PESS Discharged Energy	734	726	718	734	2,913
Usage with PESS	On-Peak Energy (3-7 PM M-F)	246	-229	-220	-239	-441
	Off-Peak Energy	2,817	1,299	1,318	1,295	6,727
	Late Night Energy (1-5 AM)	1,303	1,054	1,042	1,067	4,466
	Total Energy	4,365	2,124	2,140	2,122	10,752

Based on these TOU program parameters a customer could implement 92 charge/discharge cycles (64 On-Peak and 28 Off-Peak) during the summer period and 273 charge/discharge cycles (190 On-Peak and 82 Off-Peak) during the rest of the year. Assuming the PESS performs a full discharge of 7.98 kWh daily, a total of 2,913 kWh could be discharged annually for TOU cost savings. Based on the following calculations, the annual Customer Energy Cost savings would be \$ 495.26 if the net metering tariff credits the customer with the full retail rate for any energy delivered back to the utility.

$$\text{Reduced Customer Energy Cost (\$)} = \text{Total Energy Discharged for TOU Energy (kWh)} \times [\text{On/Off-Peak Retail Price of Electricity (\$/kWh)} - \text{Avg. Late Night Retail Price of Electricity (\$/kWh)} / \text{Storage System Round-trip Efficiency (\%)}]$$

$$\begin{aligned} \text{Reduced On-Peak Energy Cost-Summer (\$)} &= 511 \text{ kWh} \times [0.336 \text{ \$/kWh} - (0.03 \text{ \$/kWh}/0.8645)] = \$ 153.96 \\ \text{Reduced Off-Peak Energy Cost-Summer (\$)} &= 223 \text{ kWh} \times [0.09 \text{ \$/kWh} - (0.03 \text{ \$/kWh}/0.8645)] = \$ 12.33 \\ \text{Reduced On-Peak Energy Cost-Winter (\$)} &= 1,524 \text{ kWh} \times [0.225 \text{ \$/kWh} - (0.025 \text{ \$/kWh}/0.8645)] = \$ 298.83 \\ \text{Reduced Off-Peak Energy Cost-Winter (\$)} &= 654 \text{ kWh} \times [0.075 \text{ \$/kWh} - (0.025 \text{ \$/kWh}/0.8645)] = \$ 30.14 \\ \text{Reduced Customer Energy Cost} &= \$153.96 + \$12.33 + \$298.83 + \$30.14 = \$495.26 \end{aligned}$$

3.4.9.4.2.7 Issues and Corrective Actions

The following issues and corrective action were encountered during the performance of the Time-of-Use Energy Cost Management operational testing and analysis.

Table 3-138: Issues and Corrective Actions

Issue	Corrective Action
The SmartGrid Demonstration House electrical usage is not representative of a typical residential customer	The annual load profile of a “typical” residential customer was used for this analysis
Due to technical issues and conflicting demonstrations at the Demonstration House, KCP&L was not able to achieve annual data collection for this test.	Daily PESS charge/discharge patterns were modeled and applied to the “typical” residential customer load profile
KCP&L did not have a 3-tier TOU rate to evaluate Off-Peak reduction scenarios	Developed a hypothetical 3-tier TOU rate that was revenue neutral for this analysis.

3.4.9.4.3 Findings

The results obtained in the execution and analysis of the Time-of-Use Energy Cost Management operational test are summarized in the sections below.

3.4.9.4.3.1 Discussion

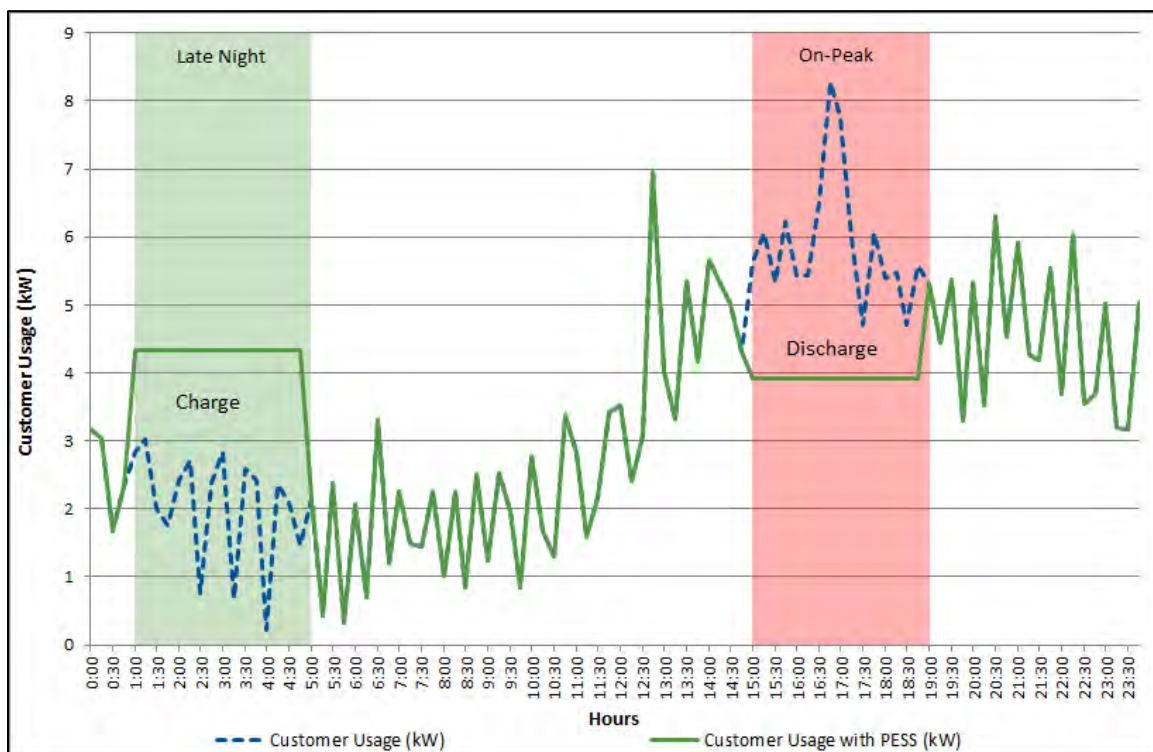
The PESS installed at the Demonstration House is a 11.7-kWh lithium-ion battery with a unique hybrid 6.0 kW inverter/converter, a battery set to charge and discharge daily from the grid. Due to project constraints the daily operation of the PESS for this analysis was performed at night so that the Renewable Energy Time Shift function test could be performed concurrently. The PESS was charged from the grid for 3 hours, from 9 PM to 12 AM local time, and discharged to the grid for 4 hours, from 1 AM to 5 AM local time.

The Round Trip Efficiency (RTE) of the PESS was measured and calculated. The average PESS efficiency was calculated to be 86.4%, higher than the expected efficiency of 70%.

The SmartGrid Demonstration House electrical usage is not representative of a typical residential customer. Therefore a “typical” residential customer, with annual usage of 10,319 kWh, was selected to analyze customer benefits of the PESS when used for energy cost management. The PESS energy charge/discharge cycles were then mathematically applied to this customer’s usage in both block and load-leveling dispatch modes and analyzed for On-Peak grid load reduction. Figure 3-195 illustrates the impact of the PESS when charged from 1 AM to 5 AM during the late night and discharged from 3 PM to 7 PM to offset On-Peak grid load.

Operating in the On-Peak reduction method in conjunction with the parameters of KCP&L’s SmartGrid Demonstration Rate as illustrated in Figure 3-195, the customers annual Late Night energy consumption increased 953 kWh and the On-Peak energy consumption decreased 824 kWh, which would yield the customer annual savings of \$188.

Figure 3-195: On-Peak Energy Shift Impact on Typical Residential Load Profile



In the previous analysis the customer usage and cost savings were derived by operating the PESS to reduce On-Peak energy received from the utility. When a PESS is operated in conjunction with solar generation the savings potential between the Time-of-Use Energy Cost Management and the Renewable Energy Time Shift functions can conflict. To achieve maximum TOU Cost Managing savings in conjunction with solar renewable generation, the operation of the PESS for TOU Cost Management must be adjusted to offset On-Peak usage with Late Night usage, which requires a 3-tier TOU rate.

To determine potential PESS TOU Cost Management savings that could be combined with the solar generation and net metering, a hypothetical year round 3-tier TOU structure that was revenue neutral with the 2-tier TOU rate was developed. This hypothetical TOU rate had a 30-cent differential between Late Night and On-Peak rates during a 3 month summer period and a 20-cent differential the rest of the year.

Table 3-137 summarizes the impact of the PESS on the Late Night and On-Peak energy usage for this residential customer, by season. Results in this table come from the PESS being operated in block discharge mode to offset of the customer's On-Peak usage and deliver any excess stored energy to the utility.

Operating in the Off-Peak reduction method in conjunction with the parameters of hypothetical 3-tier TOU rate, the typical customer's annual Late Night energy consumption increased 3,347 kWh and the On-Peak energy consumption decreased 2913 kWh, which would yield the customer annual savings of \$495 if the net metering tariff credits the customer with the full retail rate for any energy delivered back to the utility

3.4.9.4.3.2 Expectations vs. Actuals

The following table provides a comparison of the Expected Results and the Actual Outcomes for the Time-of-Use Energy Cost Management operational test.

Table 3-139: Expected Results vs. Actual Outcome

Expected Results	Actual Outcome
Typical daily charge/discharge load cycles for TOU Energy Cost Management will be developed and demonstrated.	Daily charge/discharge operations for TOU Energy Cost Management were developed and demonstrated.
The Round Trip Efficiency factor of the PESS factor will be determined, with it expected to be greater than 70%.	The RTE factor for the PESS was determined to be 86.45%.
The system is expected to have approximately 10 kWh available daily for TOU discharge.	With vendor operating guidelines and a 10% reservation for UPS mode (Electric Service Reliability) the 11.7-kWh PESS had 8.75 kWh available for routine application use.
The charge/discharge cycles developed will be mathematically applied to a "typical" residential customer load profile to illustrate how a PESS system could be used with TOU rates to reduce the customer's energy cost.	The charge/discharge cycles were applied to a typical customer load profile and analyzed to show the potential for cost savings with TOU rates.

3.4.9.4.3.3 Computational Tool Factors

The following table lists the values derived from the Time-of-Use Cost Management operational test analysis that will be used as inputs to the Smart Grid Computational Tool and the Energy Storage Computational Tool.

Table 3-140: Computational Tool Values

Name	Description	Calculated Value
Energy Storage Use at Annual Peak Time	The amount of energy storage power available to meet annual peak demand	.002 MW
Capital Carrying Charge of Distribution Upgrade	The total capital cost of distribution system investments that can be deferred as a direct result of the project.	\$638
Distribution Investment Time Deferred (years)	The time in years that the distribution investment will be deferred.	5 yrs.
Total Residential Electricity Cost (\$) (Avoided)	Total amount of money spent on electricity by residential customers annually.	\$495.26
Total Energy Discharged for TOU Energy Cost Management (MWh) (ESCT)	Total amount of energy discharged by the PESS to provide energy during peak-time so as to avoid paying peak prices.	2.913 MWh
Average On-Peak Retail Price of Electricity (\$/MWh) (ESCT)	Average On-Peak retail price of electricity. This would be the price that was avoided as a result of the energy storage device.	\$200.45 /MWh
Average Off-Peak Retail Price of Electricity (\$/MWh) (ESCT)	Average On-Peak retail price of electricity. This would be the price that was avoided as a result of the energy storage device.	\$26.26 /MWh

- Capital Carrying Charge of Distribution Upgrades (\$) – Using an incremental distribution deferral method this value is calculated as follows:

$$\text{Dist. Capacity Deferred (kVA)} \times \text{Typical Cost of Dist. Capacity (\$/kVA)} \times \text{Life Cycle Value Multiplier} =$$

$$2 \text{ kVA} \times \$23.94/\text{kW} \times 13.3362 = \$638$$
- Distribution Investment Time Deferred (Yr.) – The distribution investment deferral is assumed to be 5 years due to the fact that the project team is using an incremental calculation and aggregating all incremental distribution deferral components into a single SGCT value.
- Total Energy Discharged for TOU Energy Cost Management (MWh) – This value was extracted from the data presented in Table 3-137:
- Average On-Peak Retail Price of Electricity (\$/MWh) – This value has been calculated based on a weighted average of the On-Peak and Off-Peak rates and discharge values presented in in Table 3-137.
- Average Off-Peak Retail Price of Electricity (\$/MWh) – This value has been calculated based on a weighted average of the Late Night rates and discharge values presented in Table 3-137.

3.4.9.4.4 Lessons Learned

Throughout the conduct of the operational testing and analysis of the PESS for the Time-of-Use Energy Cost Management function, numerous considerations were realized and should be noted for future implementations. These Lessons Learned are as follows:

- The manufacturer's recommendations for protecting the battery and maintaining its useful life—that the battery should not be routinely charged above 95%, and should not be discharged below 10% charge—must be factored in when sizing the battery storage component for any PESS.
- Differential in TOU rates needs to be at least 16% for the customer to receive any monetary savings. KCP&L's SmartGrid TOU rate was a 2-tier rate structure limited to four summer months. A PESS could achieve greater savings for the customer with year round 3-tier rates. The PESS benefits could be further maximized when operated in conjunction Renewable Energy Time Shift.
- The PESS demonstrated that it has considerable flexibility in how it can be applied to provide maximum customer benefits, but it must be tailored to the specific customer load profile and rate structure.

3.4.9.5 Renewable Energy Time Shift

The Renewables Energy Time Shift application involves storing electricity from renewable sources when the price of electricity is low and using (or selling) that stored energy when the price of electricity is higher. Because solar typically produces its maximum energy midday when electricity prices are typically lower, the price differential between the electricity used to charge the battery and the electricity sold at peak can be significant. The energy that is discharged from the storage could be sold via the wholesale market, sold under terms of an energy purchase contract, or used by an integrated utility to reduce the overall cost of providing generation during peak times.

3.4.9.5.1 Overview

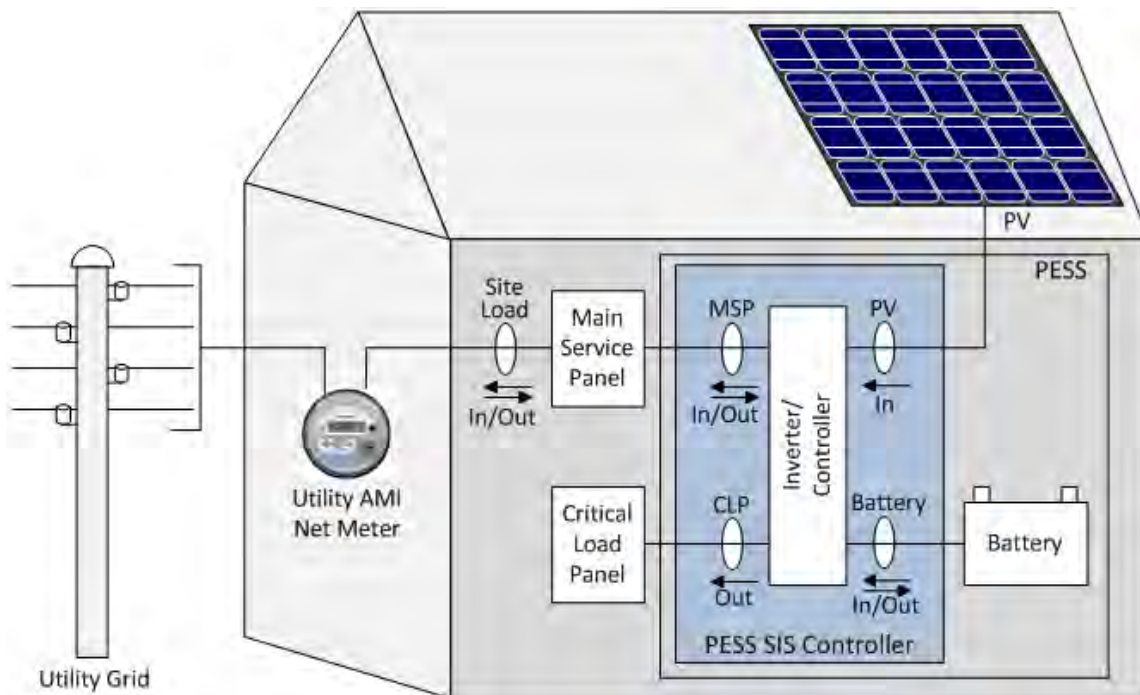
The following sections provide an overview of the operational, demonstration, testing, and evaluation methodology used for the Renewable Energy Time Shift operational test.

3.4.9.5.1.1 Description

A consumer PESS was installed at the SmartGrid Demonstration House in conjunction with the 2.82-kW solar PV array. The PESS consists of an 11.7-kWh lithium-ion battery with a unique hybrid inverter/converter rated for 6.0-kW discharge.

The PESS was configured as illustrated in Figure 3-196 and was used to demonstrate how consumers can use the PESS in conjunction with renewable solar generation and tiered TOU rates to reduce their overall electricity costs. This was accomplished by configuring the BESS to store solar electric energy generated during off peak times (typically 8 AM to 4 PM) and then discharge the stored renewable energy during times of peak usage and rates (typically 4 to 8 PM).

Figure 3-196: PESS Installation at SmartGrid Demonstration House



3.4.9.5.1.2 Expected Results

This technical demonstration was expected to yield the following:

- Typical daily charge/discharge load cycles for Renewable Energy Time Shift would be developed and demonstrated at the Demonstration House.
- The DC-DC Efficiency factor of the PESS for Renewable Time Shift would be determined. The system would be expected to operate at greater than 90% efficiency with respect to stored DC energy output versus solar DC energy input.
- The Energy Discharged for Renewable Energy Time-Shift factor for the PESS would be determined. The system would be expected to have approximately 10 kWh available daily for discharge.
- The charge/discharge load cycles developed would be mathematically applied to several typical load profiles to illustrate how a PESS system could be used with solar generation and TOU rates to lower the customer's energy cost.

3.4.9.5.1.3 Benefit Analysis Method/Factors

The DOE SGCT was used to perform the SGDP benefit analysis. For this application the following Smart Grid Function benefits were quantified.

- Deferred Generation Capacity Investments
- Deferred Distribution Capacity Investments
- Reduced Electricity Costs
- Reduced CO₂ Emissions

Benefits were calculated using SGCT formulas. The following factors were measured, projected, or calculated during the application operation and/or demonstration.

Deferred Generation Capacity Investments

- Distributed Generation Use at Annual Peak Time (MW)
(This benefit was included in the Distributed Production of Energy analysis.)
- Energy Storage Use at Annual Peak Time (MW)

Deferred Distribution Capacity Investments (Utility)

- Distribution Feeder Load Reduction (MW)
- Capital Carrying Charge of Distribution Upgrade (\$)

Reduced Electricity Costs (Utility)

- Reduced Total Residential Electricity Cost (\$)

Reduced CO₂ Emissions

- Annual Distributed Generation Production (MWh)
(This benefit was included in the Distributed Production of Energy analysis.)

Additionally, the DOE ESCT was used to perform the benefit analysis for a customer owned PESS system. The following Stationary Energy Storage applications were combined in this analysis.

- Primary Application – Time-of-Use Energy Cost Management
- Secondary Application – Renewable Energy Time Shift
- Secondary Application – Electric Service Reliability

Primary Benefit for Renewable Energy Time Shift:

- Reduced Electricity Costs (Consumer)

3.4.9.5.1.4 Testing Methodology

The following points provide an overview of how the operational demonstration and testing for this application was accomplished:

- Customer solar photovoltaic panels were installed and connected to the PESS.
- Energy delivered to and received from the PESS was measured by the PESS Management System (PMS). All PESS data collected was stored in the PMS data archive.
- Energy delivered to and received from the customer's electrical system by the utility distribution grid was measured by the AMI net meter installed at the customer service entrance. All of the collected AMI data was stored in KCP&L's MDM and DMAT systems.
- A daily charge/discharge program was implemented to demonstrate and evaluate the benefit of using the PESS for solar generation time shift in conjunction with TOU rates. Charging occurred daily during Off-Peak rate times from available solar generation, and the energy was discharged during On-Peak rate times from 4 to 8 PM
- The PESS was operated with this as its standard mode over several months.

3.4.9.5.1.5 Analytical Methodology

The following points provide an overview of the analytical methods that were used to evaluate the impact and benefits of this application:

- Energy (DC watts) generated by the customer's solar photovoltaic panels system was measured and recorded in 1-minute intervals by the PESS SIS.
- Energy (DC watts) delivered to and received from the PESS battery was measured and recorded in 1-minute intervals by the by the PESS SIS.
- Energy (AC watts) delivered to and received from the customer's electrical system by the PESS was measured and recorded in 1-minute intervals by the by the PESS SIS.
- Energy (AC watts) delivered to the customer's emergency load panel by the PESS was measured and recorded in 1-minute intervals by the PESS SIS.
- The functionality of the PESS SIS was used to aggregate the 1-minute interval data to 15-minute interval data and was exported to Excel for analysis.
- AMI 15-minute interval solar generation data from the project's grid-connected solar installations was extracted from the MDM System through KCP&L's DMAT and used as a solar generation baseline.
- An annual solar generation profile for the PESS was constructed using the solar generation baseline data to fill in any missing data caused by Demonstration House activities and other project operational testing.
- Multiple energy shift cycles were analyzed to determine the potential maximum solar energy that could be stored and the efficiency of the battery charge/discharge cycle.
- The Daily Round Trip Efficiency of the PESS battery was calculated as [Daily Energy (DC watts) Delivered by the battery to the PESS inverter] / [Daily Energy (DC watts) Received from the Solar Panels].
- An annual daily Shifted Renewable Energy profile for the PESS was constructed using the using the solar generation profile and daily Round Trip Efficiency of the PESS battery.
- The Daily Unshifted Renewable Energy was calculated as [Daily Shifted Energy]/[Daily Round Trip Efficiency of the PESS battery]. The Unshifted Renewable Energy is the renewable energy that would have been delivered to the customer electric system if it had not been diverted to the battery.

- The Annual PESS Shifted and Unshifted Renewable Energy (kWh) was calculated from the daily energy profiles.
- The Annual Reduced Customer Electricity Cost was calculated by the Smart Grid Computational Tool and Energy Storage Computational Tool, and expressed in subsequent sections.

3.4.9.5.2 Plan Execution and Analysis

The following sections provide details regarding the functional tests performed, data collection, and analysis performed for the Renewable Energy Time Shift operational test.

3.4.9.5.2.1 Baseline Solar Generation Profile for PESS Analysis

To aid in determining the potential of a PESS to provide Renewable Energy Time Shift reductions, the project team constructed the solar generation profile for the Demonstration House using the composite per-unit solar generation load profile developed as part of the Distributed Rooftop Solar Generation function analysis.

Figure 3-197: Demonstration House Monthly Solar Energy Production

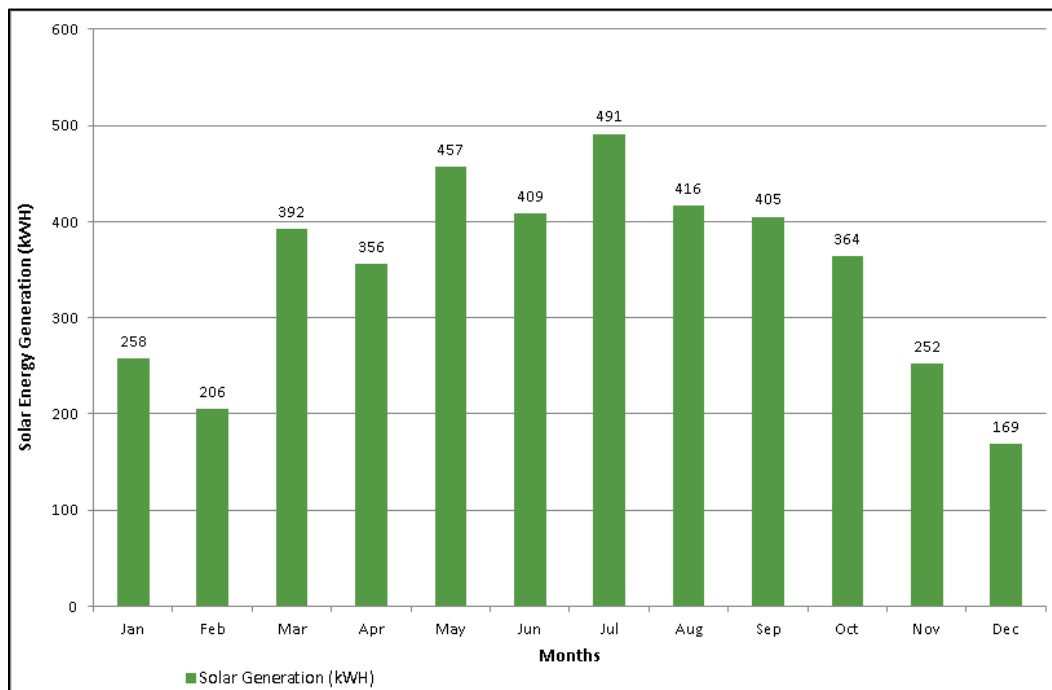
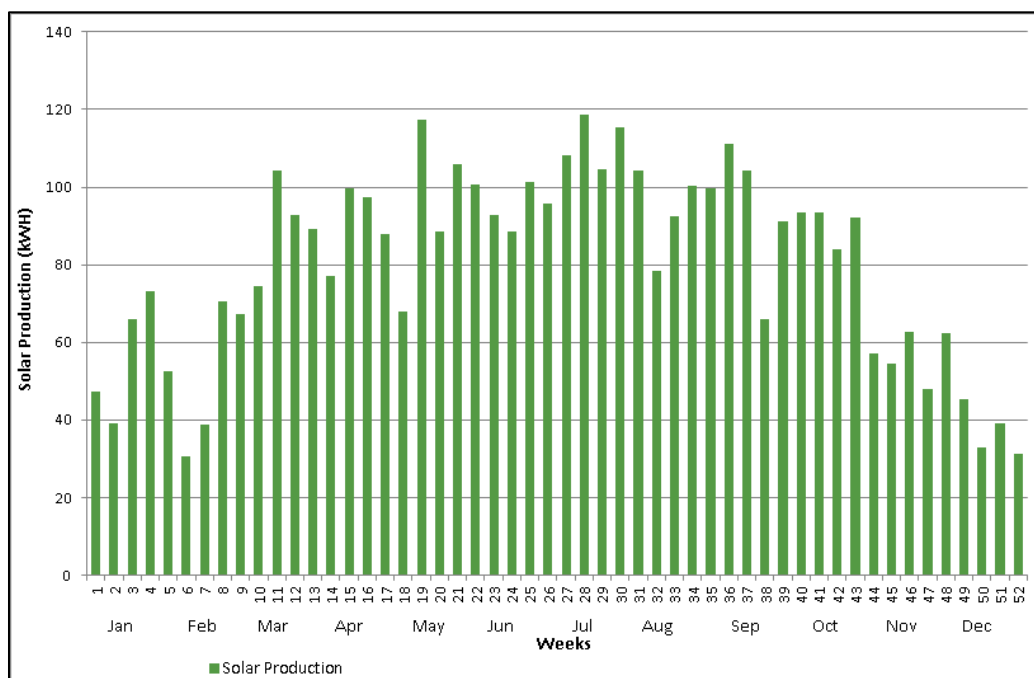
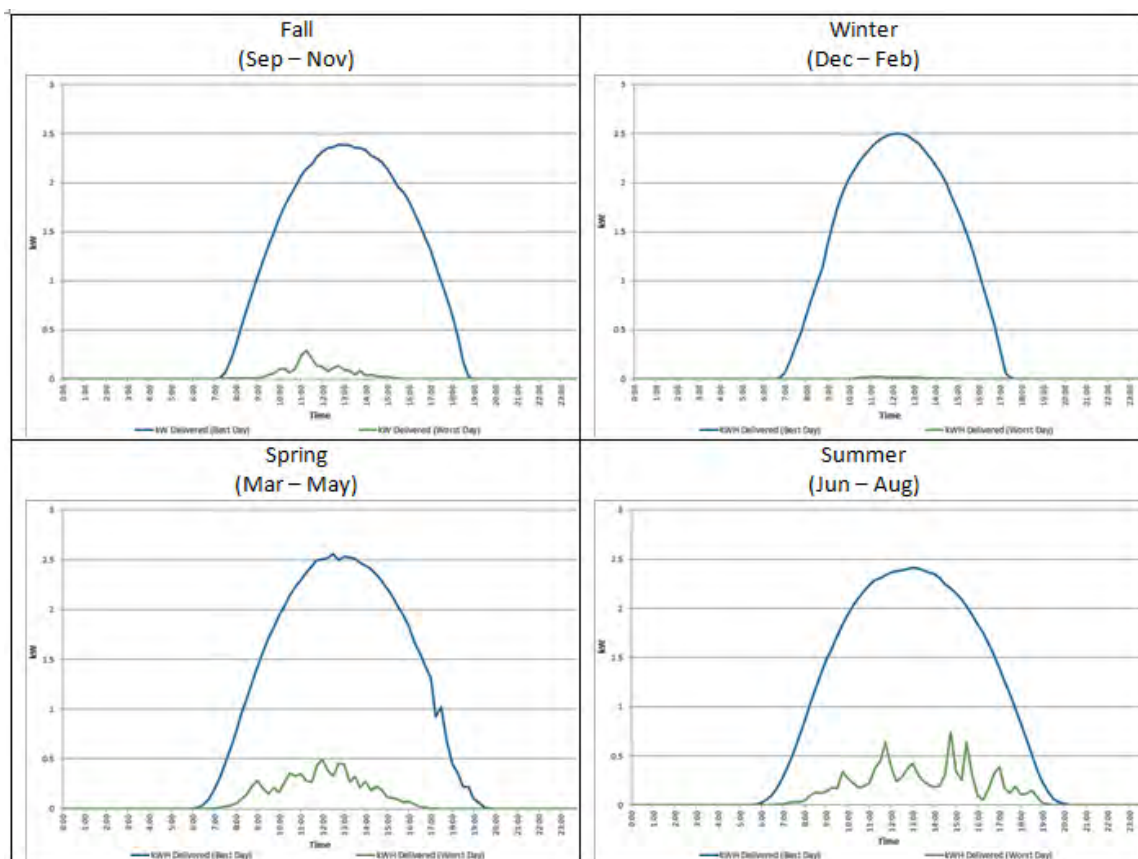


Figure 3-198: Demonstration House Weekly Solar Energy Production

The following figure provides illustrations of the composite PV production load profiles for the best and worst solar production days by season.

Figure 3-199: Demonstration House Solar kW – Typical Day

3.4.9.5.2.2 Daily Charge and Discharge Operation

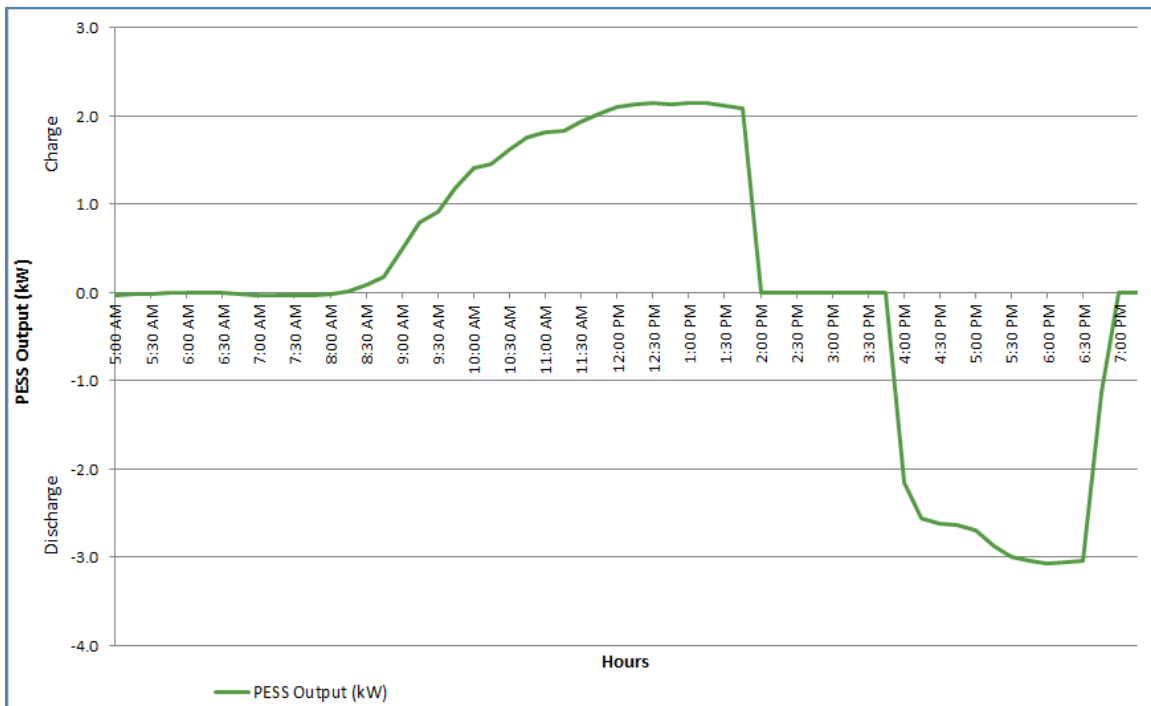
The manufacturer's operation manual recommends that the battery should not be routinely charged above 95% or discharged below 10% charge level to protect the battery and maintain its useful life. It also recommends reserving 10% battery capacity for UPS mode. These operational constraints limit the operational output of the 11.7-kWh lithium polymer battery for routine application use to 8.75 kWh.

The PESS was set to charge daily from the solar generation from 6 AM to 4 PM and discharge from 4 PM to 8 PM local time. Due to solar panel and roof replacement constraints, the daily operation for the demonstration could not be conducted until late July. To increase the likelihood that the solar generation could fully charge the battery, the project team set the 4 hour On-Peak period as 4-8 PM for this analysis. For the demonstration the PESS SMS was configured with the following settings:

- The SIS charge rate was set at 66% of inverter capacity, or 3.96 kW, to provide a full charge, up to 11.7 kWh, during the 3-hour charge period.
- The SIS discharge (or deliver to main service panel) rate was set at 45% of inverter capacity, or 2.7 kW, to deliver approximately 9 kWh during the 4-hour discharge period.

Figure 3-200 shows a representative 15-minute interval daily charge and discharge cycles for renewable Energy Time Shift under these settings. Note that the battery discharge rate is not constant over the discharge time as part of the PESS discharge energy is supplied by the solar generation.

Figure 3-200: PESS Daily Renewable Time Shift Charge and Discharge Profile



3.4.9.5.2.3 Efficiency of PESS Battery for Renewable Energy Time Shift

At the beginning of the project, it was expected that the PESS would operate for Renewable Energy Time Shift with efficiency greater than 90% with respect to DC energy output versus solar DC energy input. The SIS records the DC energy received from the solar panels and DC energy discharged from the battery modules. The purpose of this analysis is to verify the DC-DC efficiency of PESS for Renewable Energy Time Shift analysis.

Based on the daily charge and discharge cycle, the DC-DC Efficiency of the PESS is calculated as:

$$DC - DC \text{ Efficiency of PESS} = \frac{DC \text{ energy discharged from PESS battery}}{DC \text{ energy received by PESS battery from solar panels}} \times 100\%$$

Table 3-141 shows the DC energy delivered by the solar panels to charge the PESS battery, the DC energy discharged from the PESS battery, and DC-DC Efficiency of PESS battery. These values were measured over many days. The daily DC-DC efficiency varied from 89.9% to 98.7%, with average efficiency of 93.6%.

Table 3-141: Daily DC-DC Efficiency of the PESS

Date	PV-Battery In (kWh-DC)	Battery Out (kWh-DC)	DC-DC Efficiency
09/04/2014	8.41	7.91	94.0%
09/07/2014	8.81	7.98	90.6%
09/25/2014	8.36	8.26	98.7%
09/27/2014	9.02	8.11	89.9%
09/29/2014	8.69	8.44	97.1%
09/30/2014	8.78	8.50	96.8%
10/08/2014	8.59	7.94	92.4%
10/18/2014	8.34	7.85	94.2%
10/24/2014	8.81	8.18	92.9%
10/29/2014	8.94	8.09	90.6%
11/05/2014	8.29	7.80	94.1%
11/08/2014	8.52	7.92	92.9%
11/09/2014	8.25	8.02	97.2%
11/10/2014	8.51	7.98	93.9%
11/12/2014	8.18	7.51	91.8%
11/25/2014	8.23	7.68	93.3%
11/29/2014	8.03	7.43	92.6%
Average All Samples	8.49	7.98	93.6%

3.4.9.5.2.4 Potential Utility System and Distribution Peak Reduction

The PESS can be operated in multiple ways to effect utility capacity requirements. First, the customer could participate in a utility Demand Response program or allow the utility to dispatch the PESS for Demand Response. For Demand Response the PESS could potentially supply 6 kW (inverter capacity) for an event lasting 1 hour, 4.3 kW for an event lasting 2 hours, or 2.15 kW for an event lasting 4 hours.

Secondly, under the assumption that the utility's system and distribution peaks occur during the On-Peak TOU billing period, the utility would experience a demand reduction when the customer discharged the battery for Renewable Energy Time Shift. For this operational test an On-Peak billing period of 4 hours was assumed, corresponding with the experimental SmartGrid TOU rate implemented for the project.

During the daily charge/discharge cycle, the PESS battery discharged at a rate of varying from 2 kW to 3 kW, and did not discharge for a full 4 hours. Upon further investigation it became clear that the discharge rate (or deliver to the grid) was net of the critical load panel loads, solar generation, and battery discharge. Table 3-141 shows that the average discharge was 7.98 kWh, which, if the settings were tuned further, could deliver 2 kW of customer and utility load reduction for a 4-hour duration.

3.4.9.5.2.5 Customer Energy Usage with PESS Used for Renewable Energy Time Shift

The SmartGrid Demonstration house electrical usage is not representative of a typical residential customer. Therefore, a typical residential customer was selected to analyze customer benefits of the PESS when used for Renewable Energy Time Shift. The customer selected has an annual usage of 10,319 KW, approximately 15% more than the average Demonstration Area residential customer (~8,800 kWh).

A daily load profile of the selected representative residential customer from the SmartGrid Demonstration area is shown in Figure 3-201. While no two customers have identical usage patterns, this customer displays a typical daily pattern: minimal usage during the late night, a sharp rise to moderate usage in the early morning hours, then by a midmorning drop in usage that begins to increase throughout the day, with significant peak usage during the On-Peak period, and then slightly reduced but sustained moderate usage until midnight.

Figure 3-201 also shows the impact a solar PV system similar to the one installed at the Demonstration House would have on this customers' daily load profile.

Figure 3-202 shows the weekly kWh usage of this residential customer throughout the year in four usage groupings: Late Night, Off-Peak (Day), Off-Peak (Evening), and On-Peak.

Figure 3-203 shows the impact on this customers' daily load profile with the PESS operated for Renewable Energy Time Shift.

Figure 3-204 shows the weekly kWh usage of this residential customer throughout the year in four usage groupings: Late Night, Off-Peak (Day), Off-Peak (Evening), and On-Peak.

Figure 3-201: Summer Typical Residential Customer Daily Load Profile with PV

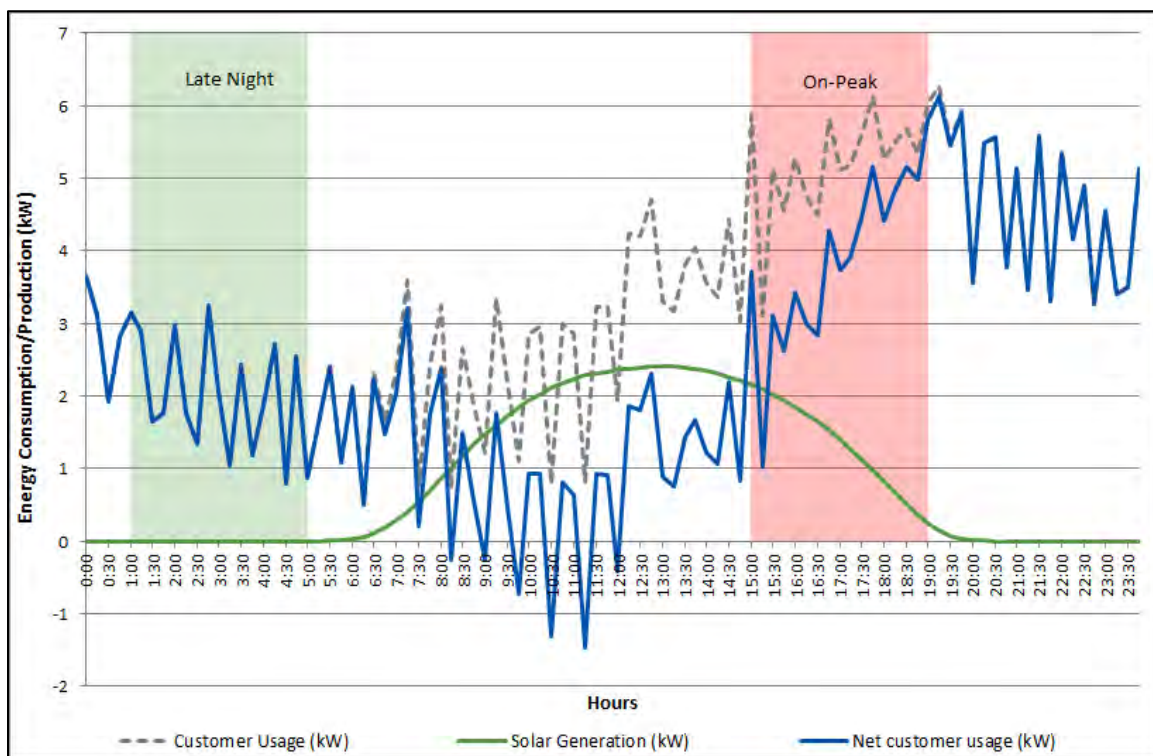


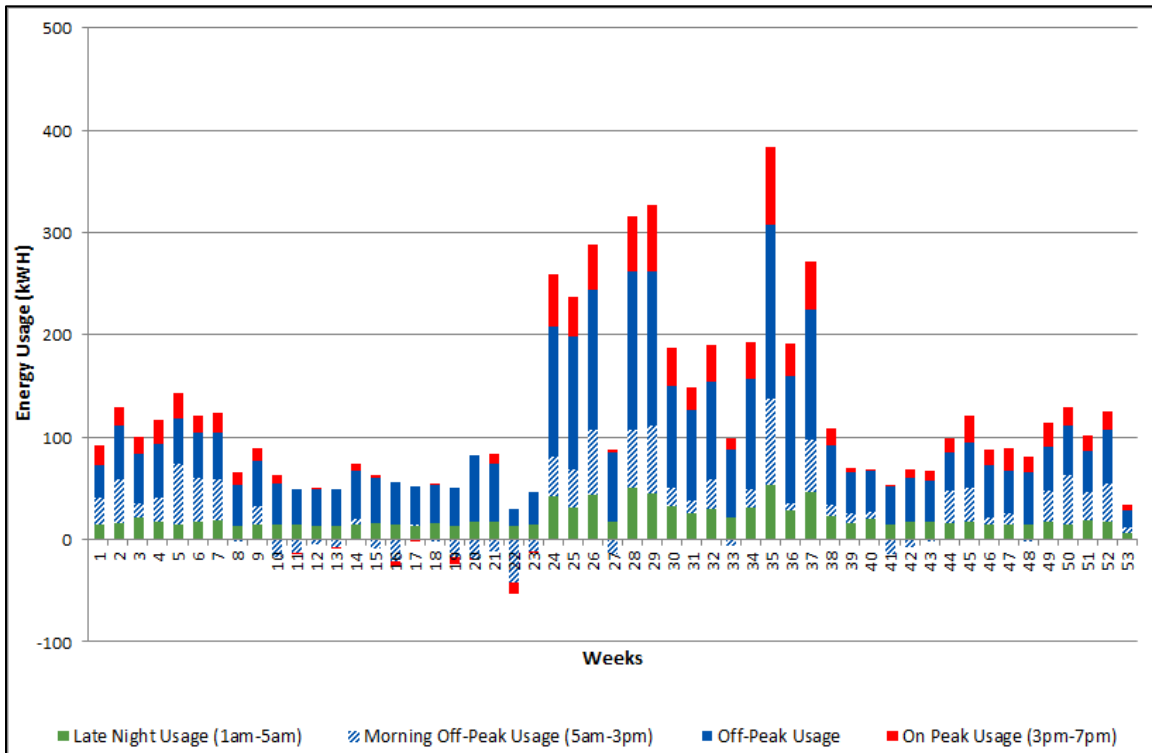
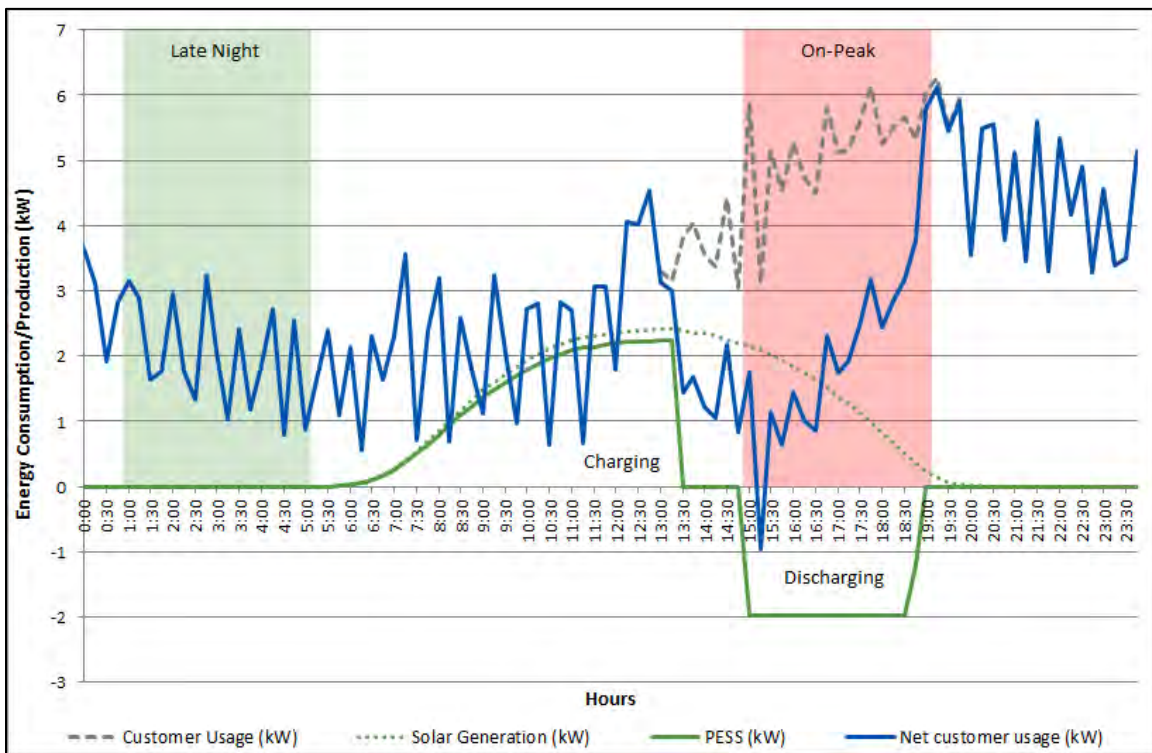
Figure 3-202: Weekly Typical Residential Customer Usage with PV**Figure 3-203: Summer Typical Customer Daily Load Profile with PV & PESS**

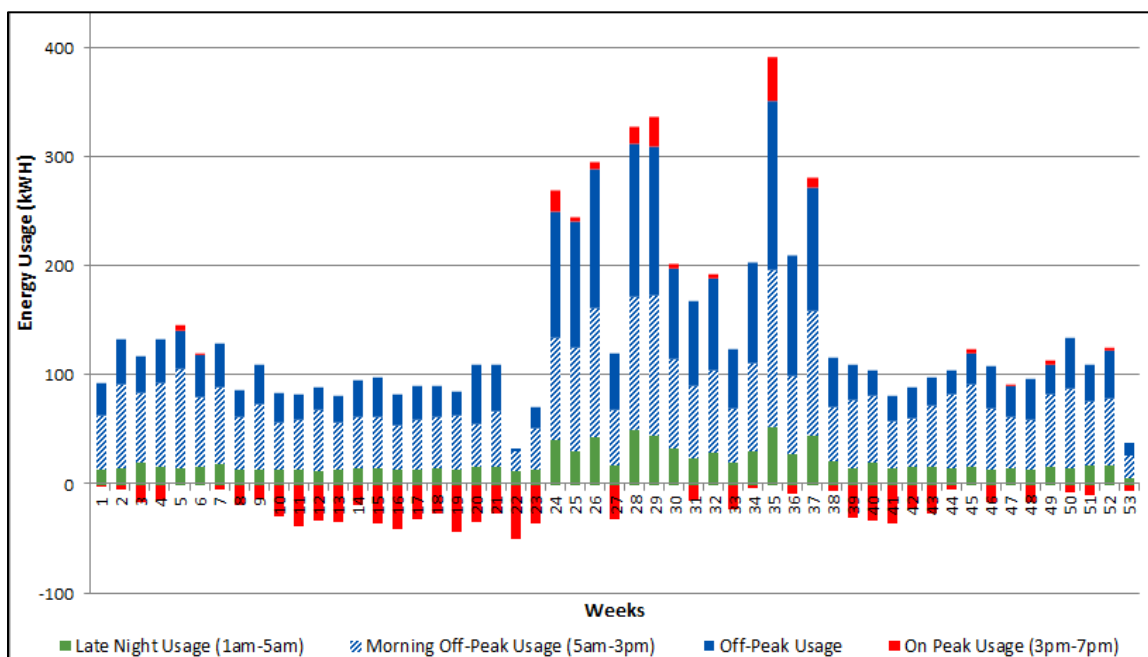
Figure 3-204: Weekly Typical Residential Customer Usage with PV & PESS

Table 3-142 below summarizes the impact of PV and the PESS on the On-Peak, Off-Peak (Day), Off-Peak (Evening), and Late Night energy usage for this residential customer by season. In this table the PESS has been operated in Renewable Energy Time Shift mode to maximize the offset of the customer's On-Peak usage by discharging all stored renewable energy during the On-Peak period.

Table 3-142: Residential Customer Usage per Season with PESS Renewable Time Shift

	Customer Energy Usage Metrics (kWh)	Summer (Jun 16 - Sep 15)	Fall (Sep 16 - Dec 15)	Winter (Dec 16 - Mar 15)	Spring (Mar 16 - Jun 15)	Annual Total
Usage Before PV	On Peak Grid Energy (3-7 PM M-F)	757	282	275	280	1,594
	Off Peak Grid Energy (5 AM-3 PM)	1,396	888	942	799	4,025
	Off Peak Grid Energy (7 PM-1 AM)	1,644	626	599	712	3,581
	Late Night Energy (1-5 AM)	459	219	217	223	1,117
	Total Energy	4,257	2,015	2,033	2,013	10,318
Usage with PV	On Peak Grid Energy (3-7 PM M-F)	501	172	208	45	926
	Off Peak Grid Energy (5 AM-3 PM)	428	166	305	-96	803
	Off Peak Grid Energy (7 PM-1 AM)	1,525	575	577	620	3,297
	Late Night Energy (1-5 AM)	459	219	217	223	1,117
	Total Energy	2,914	1,132	1,306	791	6,143
Usage with PV & PESS	On Peak Grid Energy (3-7 PM M-F)	35	-181	-139	-378	-662
	Off Peak Grid Energy (5 AM-3 PM)	1,203	743	814	620	3,380
	Off Peak Grid Energy (7 PM-1 AM)	1,337	408	455	456	2,657
	Late Night Energy (1-5 AM)	459	219	217	223	1,117
	Total Energy	3,034	1,189	1,347	921	6,492

3.4.9.5.2.6 Customer Cost Savings Potential with PESS Used for Renewable Energy Time Shift

As was discussed in the Time-of-Use Energy Cost Management analysis, to combine cost of electricity savings from both the Time-of-Use Energy Cost Management and Renewable Energy Time Shift requires a three-tier TOU rate. KCP&L could not implement a three-tier TOU rate for the SGDP due to limitation in the utility's CIS billing system. But to support this analysis, the project team developed a hypothetical year-round three-tier TOU structure that would be revenue neutral with the two-tier TOU rate implemented by the project. The hypothetical TOU rate used for this analysis was based on the following parameters:

- Summer Effective Dates – June 15–Sept. 15
- On-Peak Times – 3-7 PM, Monday-Friday (excluding holidays)
- Late Night Times – 1-5 AM
- Off-Peak Times – All other times
- On-Peak Rate: \$0.336 (summer); \$0.225 (winter)
- Off-Peak Rate: \$0.09 (summer); \$0.075 (winter)
- Late Night Rate: \$0.03 (summer); \$0.025 (winter)

This hypothetical rate was used to illustrate the potential customer savings for installing solar generation and a PESS used for Renewable Energy Time shift.

Annual Energy Cost without PV or PESS

Based on these TOU program parameters and the usage presented in Table 3-142 this customer's annual cost of electricity without PV or PESS would be \$1,076.95, calculated as follows:

$$\begin{aligned}
 \text{Summer On-Peak Cost (\$)} &= \$0.336/\text{kWh} \times 757 \text{ kWh} = \$242.352 \\
 \text{Summer Off-Peak Cost (\$)} &= \$0.09/\text{kWh} \times [1,396 \text{ kWh} + 1,644 \text{ kWh}] = \$273.600 \\
 \text{Summer Late Night Cost (\$)} &= \$0.03/\text{kWh} \times 459 \text{ kWh} = \$13.77 \\
 \text{Winter On-Peak Cost (\$)} &= \$0.225/\text{kWh} \times [1,594 \text{ kWh} - 757 \text{ kWh}] = \$188.325 \\
 \text{Winter Off-Peak Cost (\$)} &= \$0.075/\text{kWh} \times [4,025 \text{ kWh} + 3,581 \text{ kWh} - 1,396 \text{ kWh} - 1,644 \text{ kWh}] = \$342.45 \\
 \text{Winter Late Night Cost (\$)} &= \$0.025/\text{kWh} \times [1,117 \text{ kWh} - 459 \text{ kWh}] = \$16.45 \\
 \text{Total Annual Residential Cost of Electricity (\$)} &= \$1,076.95
 \end{aligned}$$

Annual Energy Cost with PV but without PESS

Based on these TOU program parameters and the usage presented in Table 3-142 this customer's annual cost of electricity without PV or PESS would be \$1,076.95, calculated as follows:

$$\begin{aligned}
 \text{Summer On-Peak Cost (\$)} &= \$0.336/\text{kWh} \times 501 \text{ kWh} = \$168.336 \\
 \text{Summer Off-Peak Cost (\$)} &= \$0.09/\text{kWh} \times [428 \text{ kWh} + 1,525 \text{ kWh}] = \$175.77 \\
 \text{Summer Late Night Cost (\$)} &= \$0.03/\text{kWh} \times 459 \text{ kWh} = \$13.77 \\
 \text{Winter On-Peak Cost (\$)} &= \$0.225/\text{kWh} \times [926 \text{ kWh} - 501 \text{ kWh}] = \$95.625 \\
 \text{Winter Off-Peak Cost (\$)} &= \$0.075/\text{kWh} \times [803 \text{ kWh} + 3,297 \text{ kWh} - 428 \text{ kWh} - 1,525 \text{ kWh}] = \$161.025 \\
 \text{Winter Late Night Cost (\$)} &= \$0.025/\text{kWh} \times [1,117 \text{ kWh} - 459 \text{ kWh}] = \$16.45 \\
 \text{Total Annual Residential Cost of Electricity (\$)} &= \$630.98
 \end{aligned}$$

Annual Energy Cost with PV and PESS

Based on these TOU program parameters and the usage presented in Table 3-142 this customer's annual cost of electricity with PV and PESS would be \$376.03, calculated as follows:

$$\begin{aligned}
 \text{Summer On-Peak Cost (\$)} &= \$0.336/\text{kWh} \times 35 \text{ kWh} = \$11.76 \\
 \text{Summer Off-Peak Cost (\$)} &= \$0.09/\text{kWh} \times [1,203 \text{ kWh} + 1,337 \text{ kWh}] = \$228.60 \\
 \text{Summer Late Night Cost (\$)} &= \$0.03/\text{kWh} \times 459 \text{ kWh} = \$13.77 \\
 \text{Winter On-Peak Cost (\$)} &= \$0.225/\text{kWh} \times [-662 \text{ kWh} - 35 \text{ kWh}] = \$-156.825 \\
 \text{Winter Off-Peak Cost (\$)} &= \$0.075/\text{kWh} \times [3,380 \text{ kWh} + 2,657 \text{ kWh} - 1,203 \text{ kWh} - 1,337 \text{ kWh}] = \$262.275 \\
 \text{Winter Late Night Cost (\$)} &= \$0.025/\text{kWh} \times [1,117 \text{ kWh} - 459 \text{ kWh}] = \$16.45 \\
 \text{Total Annual Residential Cost of Electricity (\$)} &= \$376.03
 \end{aligned}$$

Based on this hypothetical rate, customer could potentially save \$446 (41% savings) annually by installing the 2.82 kW of solar PV generation and save an additional \$255 (40% additional savings) annually by investing in a PESS and implementing the Renewable Energy Time Shift function.

These calculations are theoretical and are provided solely to illustrate the potential order of magnitude for electricity cost savings that these functions might provide. Cost savings a customer could actually achieve would be dependent on the specific TOU and net metering tariffs under which it was implemented.

3.4.9.5.2.7 Customer Energy Usage with PESS Used with Renewable Energy and TOU

Analysis in previous sections has covered the customer usage and the cost savings impact of operating the PESS in conjunction with solar generation and the Renewable Energy Time Shift. In this section the analysis covers the customer usage and cost savings impact of operating the PESS in conjunction with solar generation using the Time-of-Use Energy Cost Function. Under this scenario the PESS would be configured to operate as follows during each of the TOU rate time periods:

- Off-Peak (Day) – Solar PV would offset any customer consumption.
- On-Peak – Solar PV would offset any customer consumption.
- On-Peak – PESS would be fully discharge the battery to offset consumption.
- Off-Peak (Evening) – Solar PV would offset any customer consumption.
- Late Night – The PESS would fully charge the battery.

For this analysis, no load-leveling operation that the PESS could perform was depicted; as such operation would slightly increase the customer's kWh consumption due to PESS efficiency losses and not provide any additional cost savings. If the TOU tariff included a demand component, the PESS could operate in load-leveling mode to lower the kW demand and achieve additional cost savings.

Figure 3-205 shows the impact on this customer's daily load profile with the PESS operated for Renewable Energy Time Shift and Time-of-Use Energy Cost Management.

Figure 3-205: Summer Typical Daily Load Profile with TOU & RETS

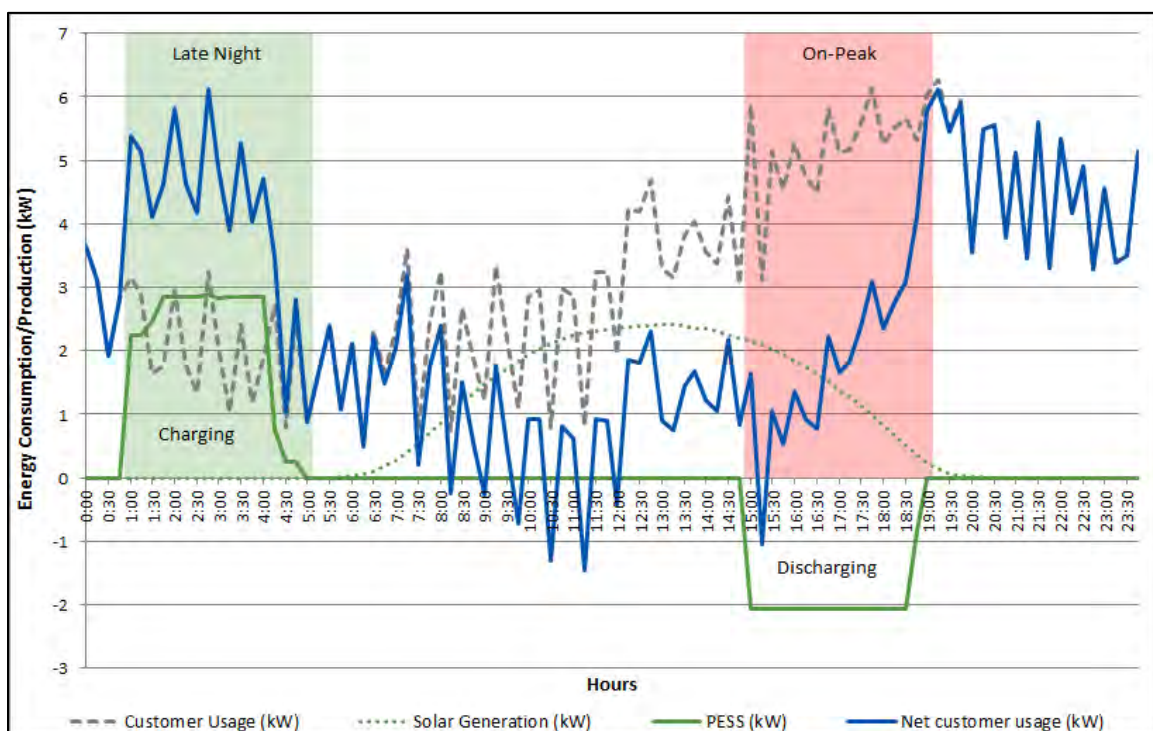


Figure 3-206 shows the weekly kWh usage of this residential customer throughout the year in four usage groupings; Late Night, Off-Peak (Day), Off-Peak (Evening), and On-Peak.

Figure 3-206: Weekly Typical Customer Usage with TOU & RETS

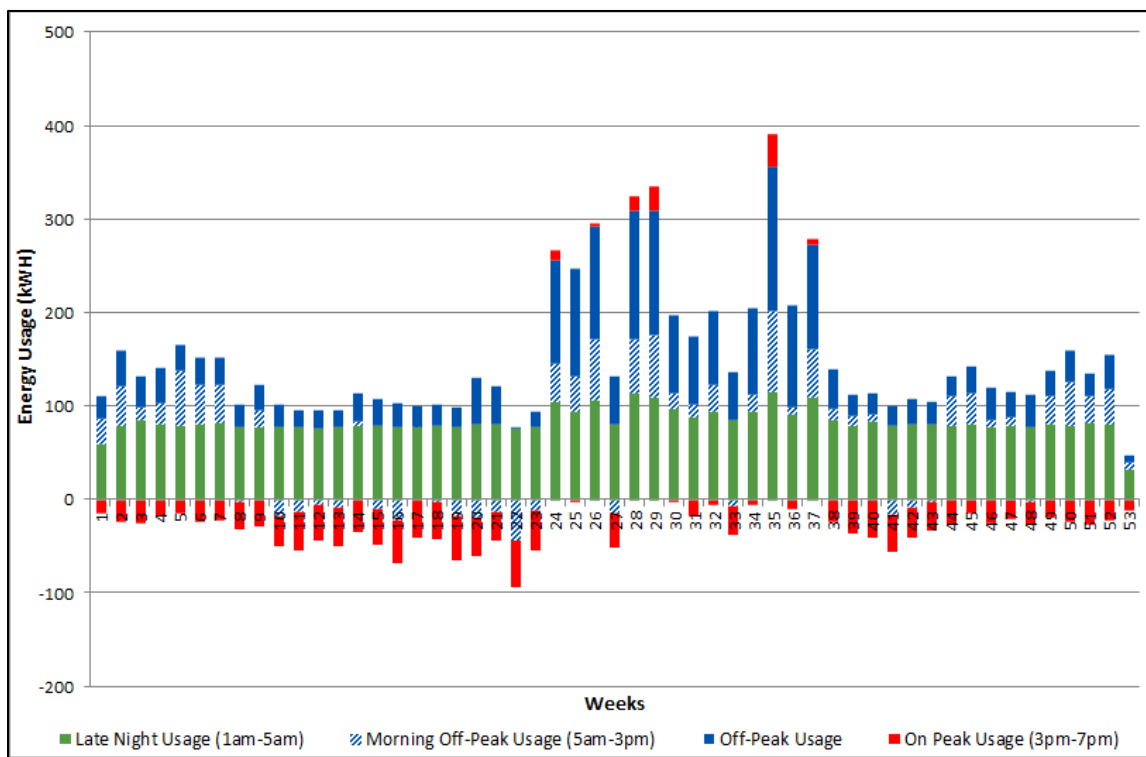


Table 3-143 summarizes the impact of both PESS functions on the On-Peak, Off-Peak (Day), Off-Peak (Evening), and Late Night energy usage for this residential customer by season. In this table the PESS has been operated to maximize the offset of the customer's on-peak usage by discharging all stored renewable energy during the On-Peak period.

This hypothetical rate presented earlier was used to illustrate the potential customer savings for installing solar generation and a PESS used for Renewable Energy Time shift and Time-of-Use Energy Cost Management.

Annual Electric Cost Under Three-Tier TOU with PV and PESS

Based on these TOU program parameters and the usage presented in Table 3-143 this customer's annual cost of electricity with PV and PESS used with the Time-of-Use Energy Cost Management function would be calculated as follows:

Summer On-Peak Cost (\$) = $\$0.336/\text{kWh} \times -233 \text{ kWh} = \$ - 78.29$
 Summer Off-Peak Cost (\$) = $\$0.09/\text{kWh} \times 1,953 \text{ kWh} = \$ 175.77$
 Summer Late Night Cost (\$) = $\$0.03/\text{kWh} \times 1,303 \text{ kWh} = \$ 39.09$
 Winter On-Peak Cost (\$) = $\$0.225/\text{kWh} \times -1,753 \text{ kWh} = \$ - 394.43$
 Winter Off-Peak Cost (\$) = $\$0.075/\text{kWh} \times 2,147 \text{ kWh} = \$ 161.03$
 Winter Late Night = Cost (\$) $\$0.025/\text{kWh} \times 3,162 \text{ kWh} = \$ 79.05$
 Total Annual Residential Cost of Electricity (\$) = $\$ - 17.78$

Annually the customer would generate net bill credit of \$ 17.78 with the utility if the net metering tariff credits the customer with the full retail rate for any energy delivered back to the utility.

Table 3-143: Residential Customer Usage per Season with TOU & RETS

	Customer Energy Usage Metrics (kWh)	Summer (Jun 16 - Sep 15)	Fall (Sep 16 - Dec 15)	Winter (Dec 16 - Mar 15)	Spring (Mar 16 - Jun 15)	Annual Total
Usage Before PV	On Peak Grid Energy (3-7 PM M-F)	757	282	275	280	1,594
	Off Peak Grid Energy (5 AM-3 PM)	1,396	888	942	799	4,025
	Off Peak Grid Energy (7 PM-1 AM)	1,644	626	599	712	3,581
	Late Night Energy (1-5 AM)	459	219	217	223	1,117
	Total Energy	4,257	2,015	2,033	2,013	10,318
Usage with PV	On Peak Grid Energy (3-7 PM M-F)	501	172	208	45	926
	Off Peak Grid Energy (5 AM-3 PM)	428	166	305	-96	803
	Off Peak Grid Energy (7 PM-1 AM)	1,525	575	577	620	3,297
	Late Night Energy (1-5 AM)	459	219	217	223	1,117
	Total Energy	2,914	1,132	1,306	791	6,143
	PESS Charge Energy	844	834	825	844	3,347
	PESS Discharged Energy	734	726	718	734	2,913
Usage with PV & PESS	On Peak Grid Energy (3-7 PM M-F)	-233	-554	-510	-689	-1,986
	Off Peak Grid Energy (5 AM-3 PM)	428	166	305	-96	803
	Off Peak Grid Energy (7 PM-1 AM)	1,525	575	577	620	3,297
	Late Night Energy (1-5 AM)	1,303	1,053	1,042	1,067	4,465
	Total Energy	3,023	1,240	1,414	902	6,579

3.4.9.5.2.8 Issues and Corrective Actions

The following issues and corrective action were encountered during the performance of the Renewable Energy Time Shift operational testing and analysis.

Table 3-144: Issues and Corrective Actions

Issue	Corrective Action
Original solar panels were not compatible with the Sunverge PESS.	Replaced the solar panels with compatible panels.
The SmartGrid Demonstration House electrical usage is not representative of a typical residential customer	The annual load profile of a “typical” residential customer was used for this analysis.
Due to technical solar integration issues, roof replacement and conflicting demonstrations at the Demonstration House, annual data collection for this test was not able to be collected.	- Used the per-unit solar generation profile developed in the Distributed Rooftop Solar Generation operational test. - Modeled daily PESS charge/discharge patterns and applied them to the load profile of the typical residential customer.
KCP&L did not have a three-tier TOU rate to evaluate Off-Peak reduction scenarios	Developed a hypothetical three-tier TOU rate that was revenue neutral for this analysis.

3.4.9.5.3 Findings

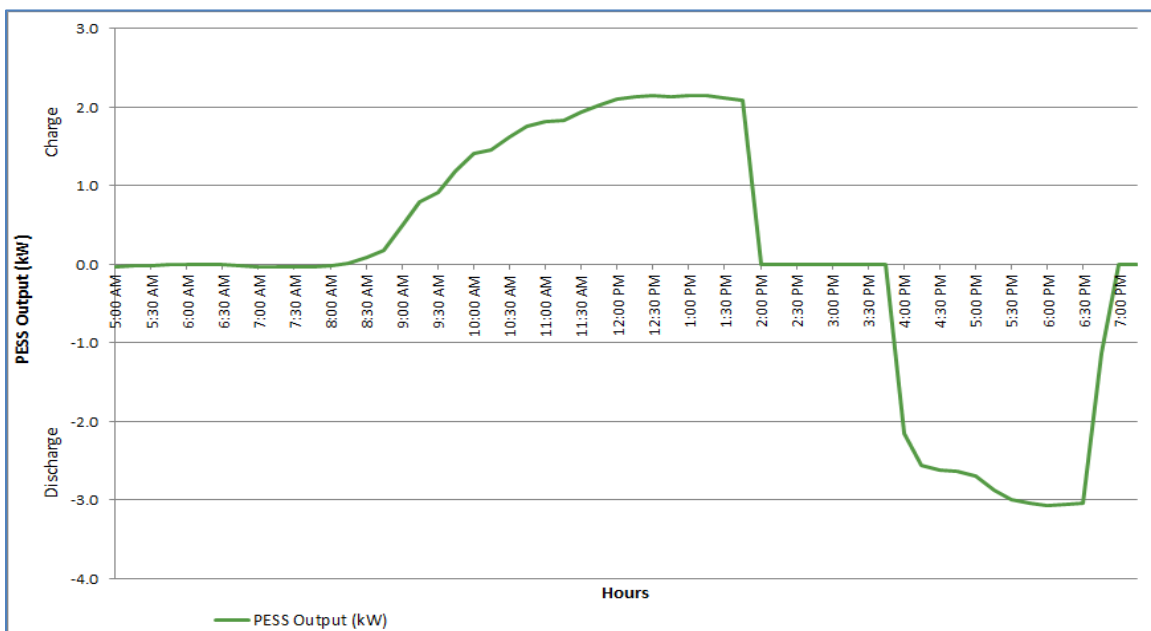
The results obtained in the execution and analyses of Renewable Energy Time Shift operational testing are summarized in the sections below.

3.4.9.5.3.1 Discussion

The PESS installed at the Demonstration House is a 11.7-kWh lithium-ion battery with a unique hybrid 6.0-kW inverter/converter, a battery set to charge and discharge daily from the grid. Due to limitations of the Demonstration House and other project constraints, the majority of this operational demonstration analysis was conducted using constructed data models constructed from project data.

The DC-DC efficiency of the PESS was measured and calculated over many days of operation. Figure 3-207 illustrates a typical PESS charge/discharge cycle used for renewable energy time shift. The average DC-DC efficiency was calculated to be 93.6%, higher than the expected efficiency of 90%.

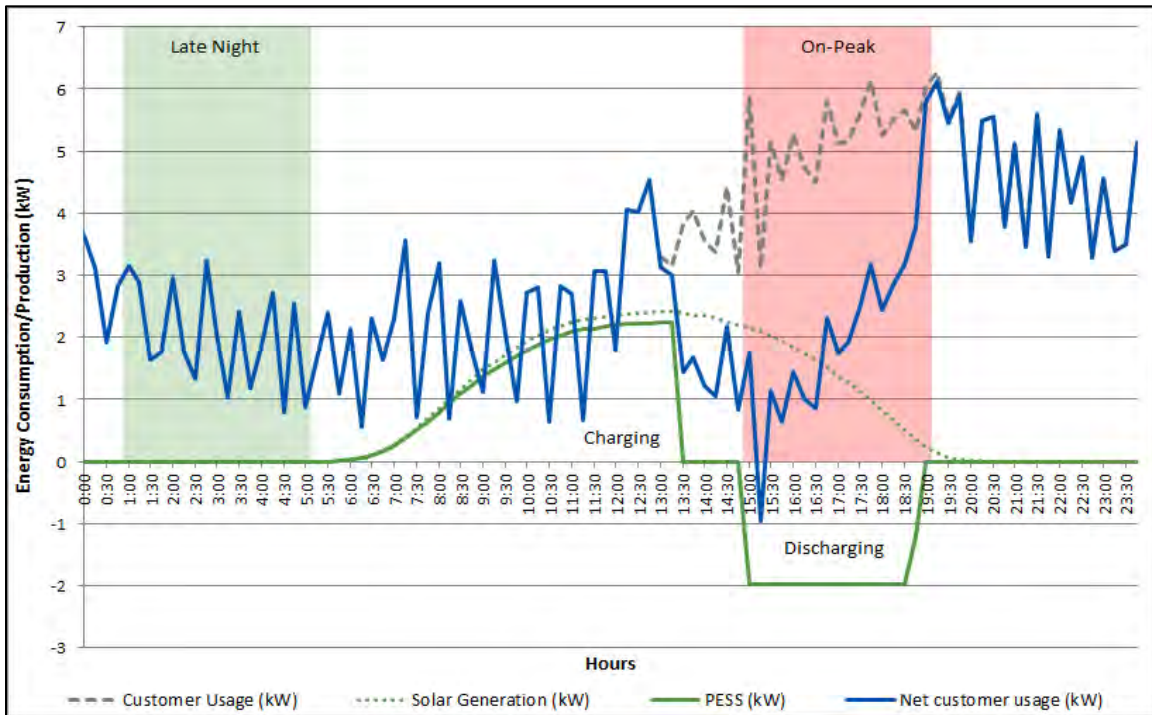
Figure 3-207: PESS Daily Renewable Time Shift Charge and Discharge Profile



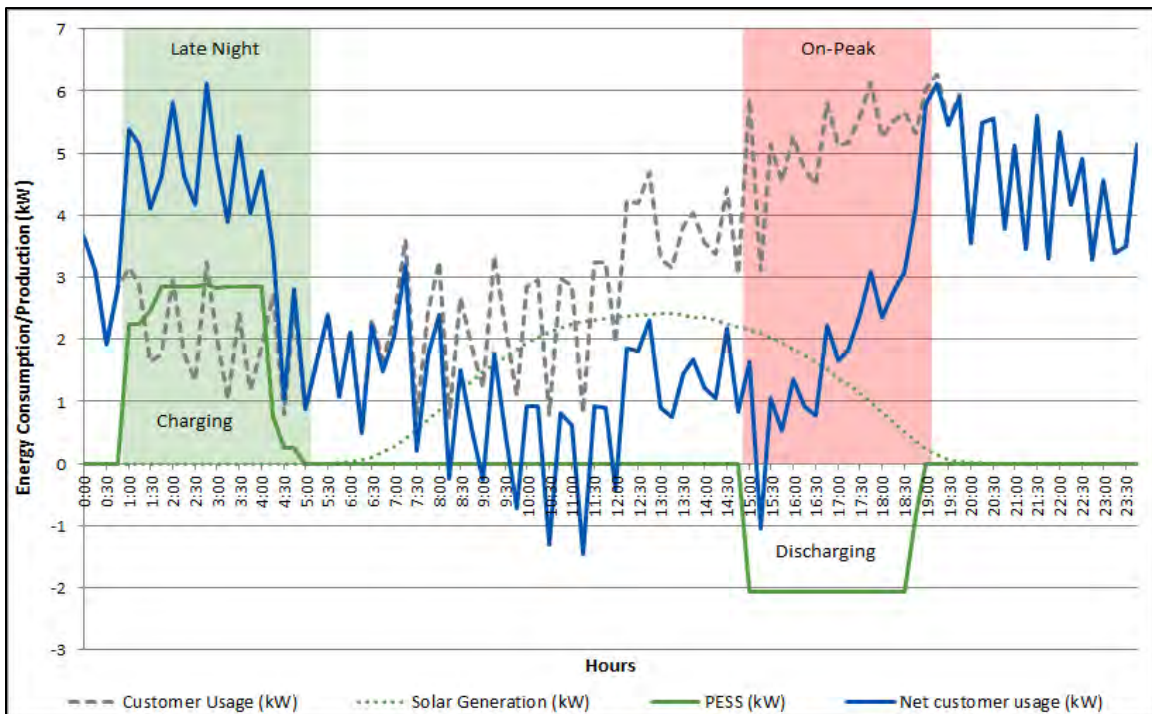
The SmartGrid Demonstration House electrical usage is not representative of a typical residential customer. Therefore, a typical residential customer, with annual usage of 10,319 kWh, was selected for analysis of customer benefits of the PESS when used for renewable energy time shift. The 2.82-kW solar PV system produced 4,175 kWh of renewable energy, of which only 668 kWh was produced during the 3-7 PM On-Peak time period.

The PESS energy charge/discharge cycles were then mathematically applied to this customer's usage and analyzed for cost savings. Figure 3-208 illustrates the effect on the customer's load profile when the PESS was charged from 6 AM to 3 PM from the solar generation and discharged from 3 PM to 7 PM to offset On-Peak usage. The analysis showed that the PESS shifted 1,588 kWh of solar energy produced Off-Peak to the On-Peak time period, creating an On-Peak negative consumption of 662 kWh annually.

When analyzed in conjunction with the parameters of hypothetical three-tier TOU rate, this customer's annual cost of electricity before adding the solar generation or PESS would have been \$1,077. By installing the 2.82 kW of solar PV generation, the customer's annual cost of electricity dropped to \$631, a savings of \$446 or 41%. Investing in a PESS and implementing the Renewable Energy Time Shift function would create an additional \$255 in savings, reducing the annual cost of electricity to \$376.

Figure 3-208: Summer Typical Customer Daily Load Profile with PV & PESS

Further analysis was performed to quantify the customer usage and cost savings effect of operating the PESS in conjunction with solar generation the Time-of-Use Energy Cost Function as illustrated in Figure 3-209 below.

Figure 3-209: Summer Typical Daily Load Profile with TOU & RETS

Based on the hypothetical three-tier TOU program, this customer's annual cost of electricity—with PV and PESS used with the Time-of-Use Energy Cost Management function—would be reduced by \$1,095 and would generate an annual net bill credit of nearly \$18 with the utility if the net metering tariff credits the customer with the full retail rate for any energy delivered back to the utility.

3.4.9.5.3.2 Expectations vs. Actuals

The following table provides a comparison of the Expected Results and the Actual Outcomes for the Renewable Energy Time Shift operational test.

Table 3-145: Expected Results vs. Actual Outcome

Expected Results	Actual Outcome
Typical daily charge/discharge load cycles Renewable Energy Time Shift will be developed and demonstrated	Daily charge/discharge operations for Renewable Energy Time Shift were developed and demonstrated.
The DC-DC Efficiency factor of the PESS will be determined. Expected to be greater than 90%.	The DC-DC Efficiency factor for the PESS was determined to be 93.6%.
The dischargeable Energy for Renewable Energy Time-Shift for the PESS will be determined. The system will be expected to have approximately 10 kWh available daily for discharge.	With vendor operating guidelines and a 10% reservation for UPS mode (Electric Service Reliability) the 11.7-kWh PESS had 8.75 kWh available for routine application use.
The charge/discharge cycles developed will be mathematically applied to a typical residential customer load profile to illustrate how a PESS system could be used with TOU rates to lower the customers energy cost.	The Renewable Energy Time Shift charge/discharge cycles were applied to a typical customer load profile and analyzed to show the potential for cost savings with TOU rates.

3.4.9.5.3.3 Computational Tool Factors

The following table lists the values derived from the Renewable Energy Time Shift operational test analysis for use as inputs to the Energy Storage Computational Tool.

Table 3-146: Computational Tool Value

Name	Description	Calculated Value
Total Renewable Energy Discharged for Energy Time Shift	Total amount of renewable energy discharged for the purpose of shifting energy from an Off-Peak time to an On-Peak time	0 MWh

- Total Renewable Energy Discharged for Energy Time Shift (MWh) – For the SGCT analysis greater economic benefits can be achieved with the TOU Energy Cost Management function in conjunction with a 3-tier tariff. Therefore, there will be no renewable energy discharged for energy time shift.

3.4.9.5.4 Lessons Learned

Throughout the conduct of the operational testing and analysis of the PESS for the Renewable Energy Time Shift function, numerous considerations were realized and should be noted for future implementations. These Lessons Learned are as follows:

- Learned that manufacturer's recommendation that the battery should not be routinely charged above 95% and discharged below 10% charge level to protect the battery and maintain its useful life. This limitation must be factored in when sizing the battery storage component for any PESS.
- Differential in TOU rates needs to be at least 16% for there to be any savings to be experienced by the customer. KCP&L's SmartGrid TOU rate was a two-tier rate structure limited to four summer months. A PESS could achieve greater savings from Renewable Energy Time Shift for the customer with year-round TOU rates. The PESS benefits could be further maximized when operated in conjunction with Time-of-Use Energy Cost Management function in conjunction with year-round three-tier TOU Rates.
- The PESS demonstrated it has considerable flexibility in how it can be applied to provide maximum customer benefits, but it must be tailored to the specific customer load profile and rate structure.

3.4.9.6 Electric Service Reliability

The Electric Service Reliability application involves using electric energy storage to ensure highly reliable electric service. In the event of a complete power outage lasting more than a few seconds, the energy storage system provides enough energy to ride through outages of extended duration; complete an orderly shutdown of processes; and/or transition to on-site generation resources.

3.4.9.6.1 Overview

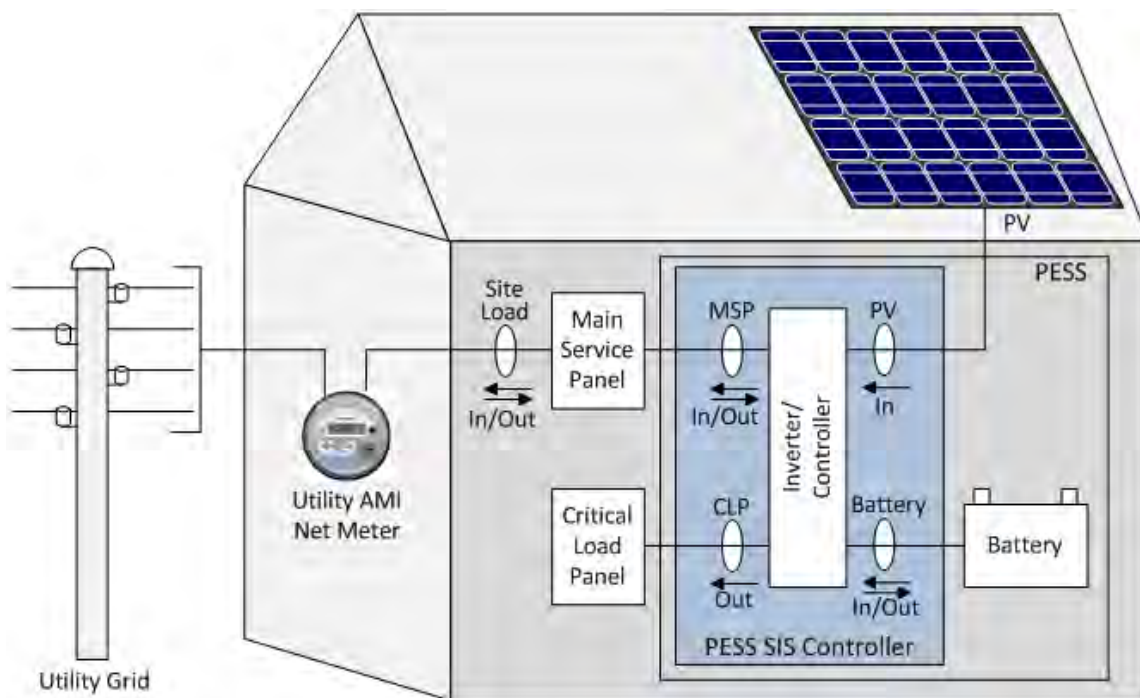
The following sections provide an overview of the operational, demonstration, testing, and evaluation methodology used for the Electric Service Reliability operational demonstration.

3.4.9.6.1.1 Description

A consumer PESS was installed at the SmartGrid Demonstration House in conjunction with the 2.82 kW solar PV array. The PESS consists of an 11.7 kWh lithium-ion battery with a unique hybrid inverter/converter rated for 6.0 kW discharge.

The PESS was configured as illustrated in Figure 3-210 to demonstrate how the consumer can benefit by using the PESS during extended power outages. This was accomplished by configuring the PESS to provide emergency stand-by power to critical loads during extended power outages.

Figure 3-210: PESS Installation at SmartGrid Demonstration House



3.4.9.6.1.2 Expected Results

This technical demonstration was expected to yield the following:

- Emergency stand-by power functionality would be demonstrated at the Demonstration House.
- An understanding would be developed for how much critical load the PESS could maintain indefinitely at the Demonstration House with the installed solar panels.

3.4.9.6.1.3 Benefit Analysis Method/Factors

The DOE SGCT was used to perform the SGDP benefit analysis. For this application the following Smart Grid Function benefits were quantified.

- Reduced Sustained Outages
- Reduced Major Outages

Benefits were calculated using SGCT formulas. The following factors were measured, projected or calculated during the application operation and/or demonstration.

Reduced Sustained Outages

- SAIDI
- Total Residential Customers Impacted by Feeders or Lines (or PESS)
- Value of Service – Residential (\$/kWh)
- Average Hourly Load Not Service During Outage per Customer – Residential (kWh)

Reduced Major Outages

- Outage Time of Major Outage – Residential
- Number of Customer affected by the Outage – Residential (or PESS)
- Value of Service – Residential (\$/kWh)
- Average Hourly Load Not Service During Outage per Customer – Residential (kWh)

Additionally, the DOE ESCT was used to perform a benefit analysis for a customer-owned PESS system. The following Stationary Energy Storage applications were combined in this analysis.

- Primary Application – Time-of-Use Energy Cost Management
- Secondary Application – Renewable Energy Time Shift
- Secondary Application –Electric Service Reliability

Primary Benefit for Electric Service Reliability

- Reduced Outages (Consumer)

3.4.9.6.1.4 Testing Methodology

The following points provide an overview of how the operational demonstration and testing for this application was accomplished:

- A customer critical load panel and solar photovoltaic panels were installed and connected to the PESS.
- All energy delivered to and received from the PESS was measured by the PESS Solar Integration System (SIS). All PESS data collected was stored in the SIS data archive.
- Load served by the customer critical load panel was measured by the PESS SIS.
- Customer's main breaker was opened, simulating a power outage, and the PESS used its internal battery storage to maintain service to the critical loads panel.

3.4.9.6.1.5 Analytical Methodology

The following points provide an overview of the analytical methods that were used to evaluate the impact and benefits of this application:

- An annual solar generation profile previously developed for the Demonstration House was used to project the daily energy solar production that would be available to support emergency loads.

- The DC-DC efficiency factor previously calculated for solar energy shift was used to determine solar DC energy available after being stored by the battery.
- Typical daily energy usage of the customer loads that could be served from the emergency load panel were compiled from a search of industry literature.
- An analysis was performed to determine the length of time the PESS could sustain power to the customer critical load panel.
- The Reduced Outage Benefits to the consumer were calculated for inclusion in the Smart Grid Computational Tool and Energy Storage Computational Tools.

3.4.9.6.2 Plan Execution and Analysis

The following sections provide details regarding the functional tests performed, data collected, and analysis performed for the Electric Service Reliability operational test.

3.4.9.6.2.1 PESS UPS Configuration and Operation

Implementation of the PESS to support the Electric Service Reliability function required the installation of an electrical subpanel that would sustain the customer's critical loads during power grid outages. The following loads were determined to be essential and their electrical feed was reconfigured to be sourced from the critical load panel.

- Furnace fan
- Refrigerator
- Freezer
- Microwave
- Critical Lighting
- ISP Access , Home Network, and Security
- Sump Pump
- Outlet for charging for mobile phones, laptops, etc.

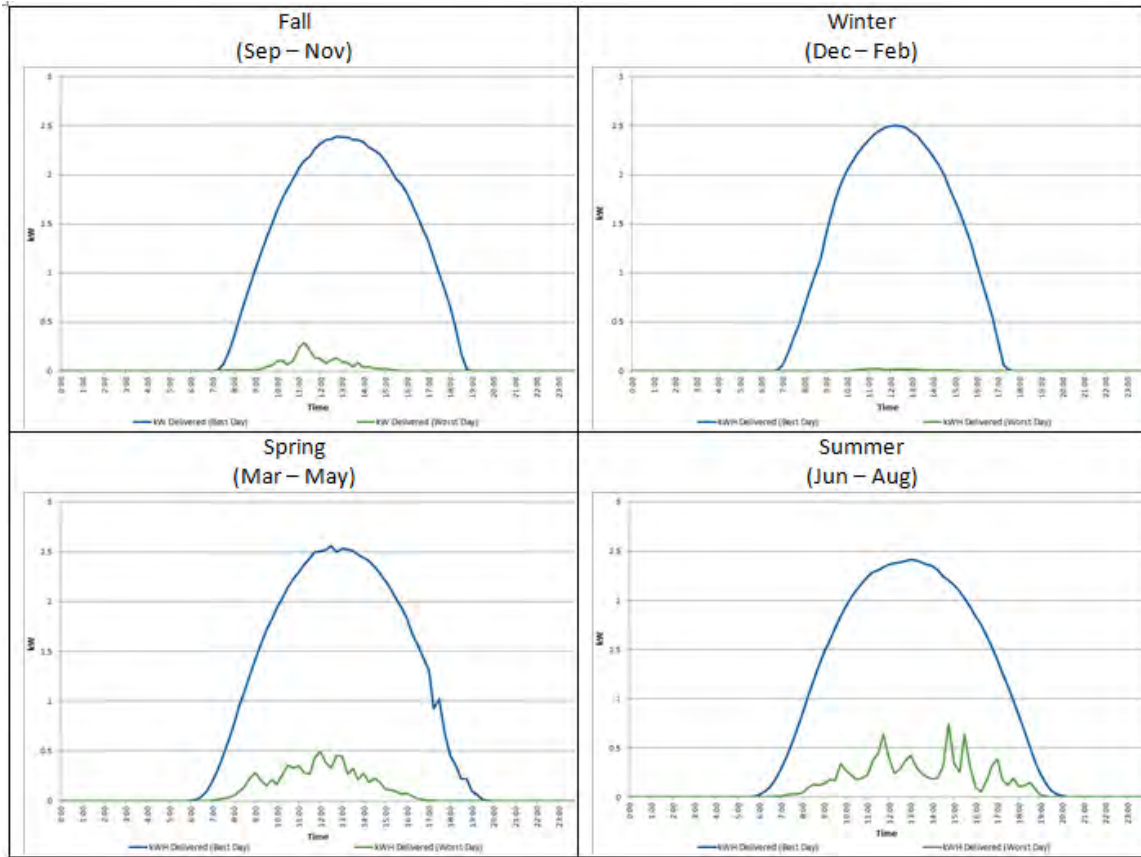
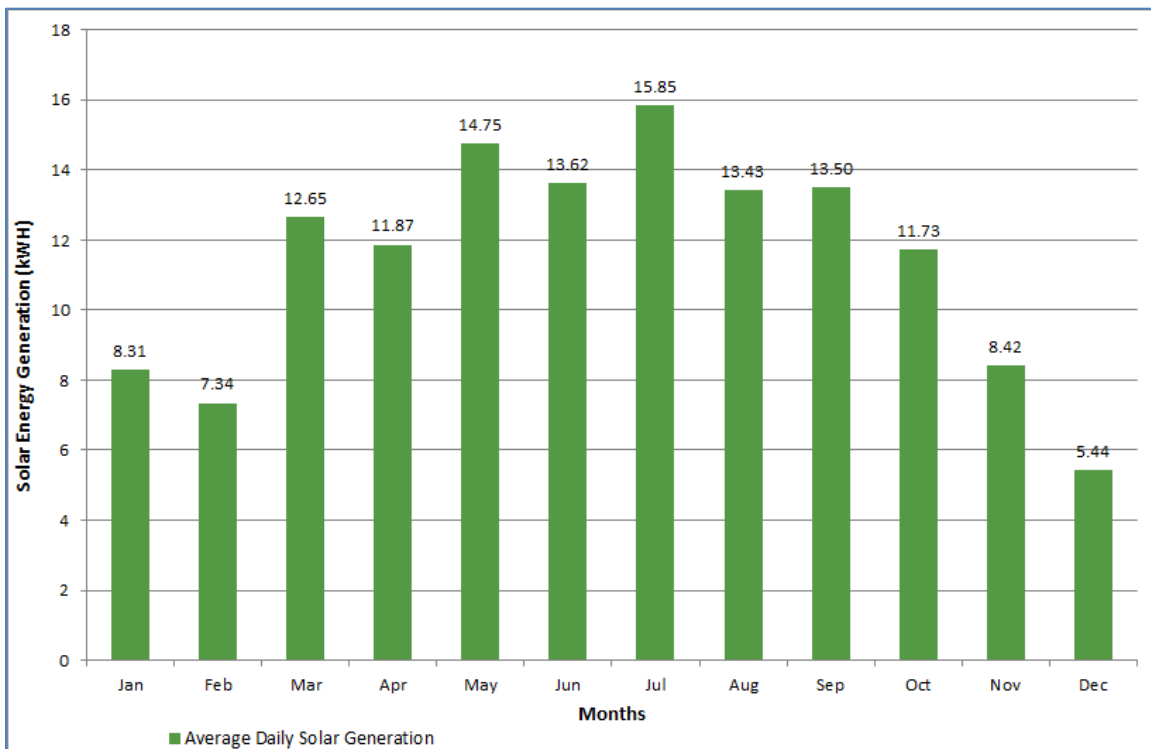
The manufacturer's operation manual recommends that the battery should not be routinely charged above 95% and discharged below 10% charge level to protect the battery and maintain its useful life. It also recommends reserving 10% battery capacity for UPS mode. These standard settings limit the output of the 11.7-kWh Lithium polymer battery to 1.17 kWh for unexpected outages of short duration. Under these settings the PESS could supply its maximum output, 6 kW, continuously to sustain emergency loads for approximately 10-12 minutes. Under these standard settings the PESS could sustain CLP loads of 6 kW through momentary and longer grid outages that are restored by automated switching.

When there is a higher probability of extended outages occurring, from either utility planned outages or weather predictions of snow/ice storms or severe thunderstorms, it is expected that the customer will suspend the normal operational settings of the PESS and reserve 90% of the battery for UPS mode. Under these revised settings the fully charged 11.7-kWh battery could supply 10.5 kWh for outages of longer duration. Under these settings the PESS could supply its maximum output, 6 kW, continuously to sustain critical load panel loads for approximately 1 ¾ hours.

3.4.9.6.2.2 Baseline Solar Generation Profile for PESS Analysis

To aid in determining the potential of a PESS to leverage solar generation further expand its ability to provide Electric Service Reliability, the project team constructed the solar generation profile for the Demonstration House using the composite per-unit solar generation load profile developed as part of the Distributed Rooftop Solar Generation function analysis.

Figure 3-211 shows the best and worst solar production days by season, and illustrates how variable the solar production is on a daily basis. Figure 3-212 shows the average daily solar production by month.

Figure 3-211: Demonstration House Solar kW – Typical Days**Figure 3-212: Demonstration House Average Daily Solar Energy Production**

3.4.9.6.2.3 Baseline Critical Load Panel Daily Usage Profile

The SmartGrid Demonstration House electrical usage is not representative of a typical residential customer and could not be used to determine the typical energy delivered to a critical load panel for this analysis. The project team performed a literature search to ascertain typical daily usage characteristics for appliances and other customer loads that should be served by the critical load panel.

Most extended outages for the KCP&L service territory typically last only a few hours, but, on rare occasions, severe winter ice storms have caused widespread outages affecting large portions of KCP&L's service territory, taking 10-12 days to restore power to all customers. Therefore, the project team focused on appliances and other end-use loads that would be required during an extended winter storm restoration period. The results of this analysis are shown in Table 3-147 and show that these loads would typically require approximately 8 kWh of electricity daily if additional energy conservation measures were not initiated by the consumer.

It is important to note that the actual usage from individual customers' appliances may differ significantly from the values presented. Most of the values in the table are for newer appliances with Energy Star ratings. Older appliances may consume more; smaller or hyper-efficient models may use less energy. The analysis of critical loads to be powered assumes the following parameters, which are representative of the majority of customers in KCP&L's service territory:

- Heating is nonelectric; electricity powers the circulation fan.
- Water heating is gas-fired or, if electric, it is not powered during an outage.
- Electric cooking is limited to a microwave oven.
- Lighting is limited to a single lighting circuit.
- ISP modem/router and computer are powered by UPS to manage PESS.
- Sump pump, while fed from CLP, typically would not operate during winter storms.

Table 3-147: Critical Load Panel Winter Daily Energy Consumption by Use

Critical Loads	Rating (Watts)	Daily Use Assumptions	Annual Use (kWh)	Daily Use (kWh)
Gas Furnace Fan – 650 W 25% duty cycle	650	25 %		3.90
Refrigerator – 26CF, side-by-side, New, E Star			519	1.42
Freezer – 20cu Upright new, Energy Star			512	1.40
Microwave – 1200 w	1,200	30 min.		0.60
Critical Lighting 4 – 60w LED @9w	36	5 Hrs.		0.18
ISP Access , Home Network, Security	12	24 Hrs.		0.29
Sump Pump – ¾ HP	1,200	0 min.		0.00
Laptop – 41wh battery	65	3 charges		0.12
Total Daily Use				7.92

The development of the estimated energy required to operate the load connected to the critical load panel shows that the furnace fan represents half of the CLP energy consumption. To increase the ability of the PESS to sustain CLP loads for a longer period, the PESS customer should consider installing the most efficient furnace fan available and aggressively manage thermostat settings during non-solar-producing periods to further reduce furnace operation. Other energy-conserving measures the customer could adopt to extend storage capacity of the PESS would include minimizing the number of times the refrigerator/freezer doors are opened, and limiting the running of the freezer to periods of significant solar production.

3.4.9.6.2.4 Critical Load Sustainability Analysis

Using the manufacturer's recommendation that 10% of the battery capacity (1.17 kWh) be reserved for UPS mode, the PESS can supply its full 6 kW of output for 10-12 minutes, thus sustaining any CLP loads through momentary and short duration sustained grid outages that are restored by automated switching. But can the PESS sustain critical loads for outages longer than 10-12 minutes? Yes, based on the estimated average daily CLP consumption of 8.0 kWh, the default 1.17 kW of reserved storage could sustain the average CLP consumption for 3.5 hours and longer if the additional battery capacity was not previously discharged by other PESS functions and remained available. With an average sustained outage duration for customers in the SmartGrid Demonstration Area being just under 1.75 hours (CAIDI-101 min.), the default-reserved PESS storage could sustain the average CLP consumption for outages of durations twice the average.

Now, the remainder of the analysis focuses on the ability of the PESS to sustain the CLP requirements through extended outages. Most extended outages for the KCP&L service territory typically last only a few hours, but, on rare occasions, severe winter ice storms have caused widespread outages to large portions of KCP&L's service territory, taking up to 10-12 days to restore power to all customers. Since the standard UPS reserve can only supply the CLP requirements for approximately 3.5 hours, it is important that the customer change the operational setting and fully charge the PESS before periods of predicted snow/ice storms or severe thunderstorms, and prior to any scheduled outages.

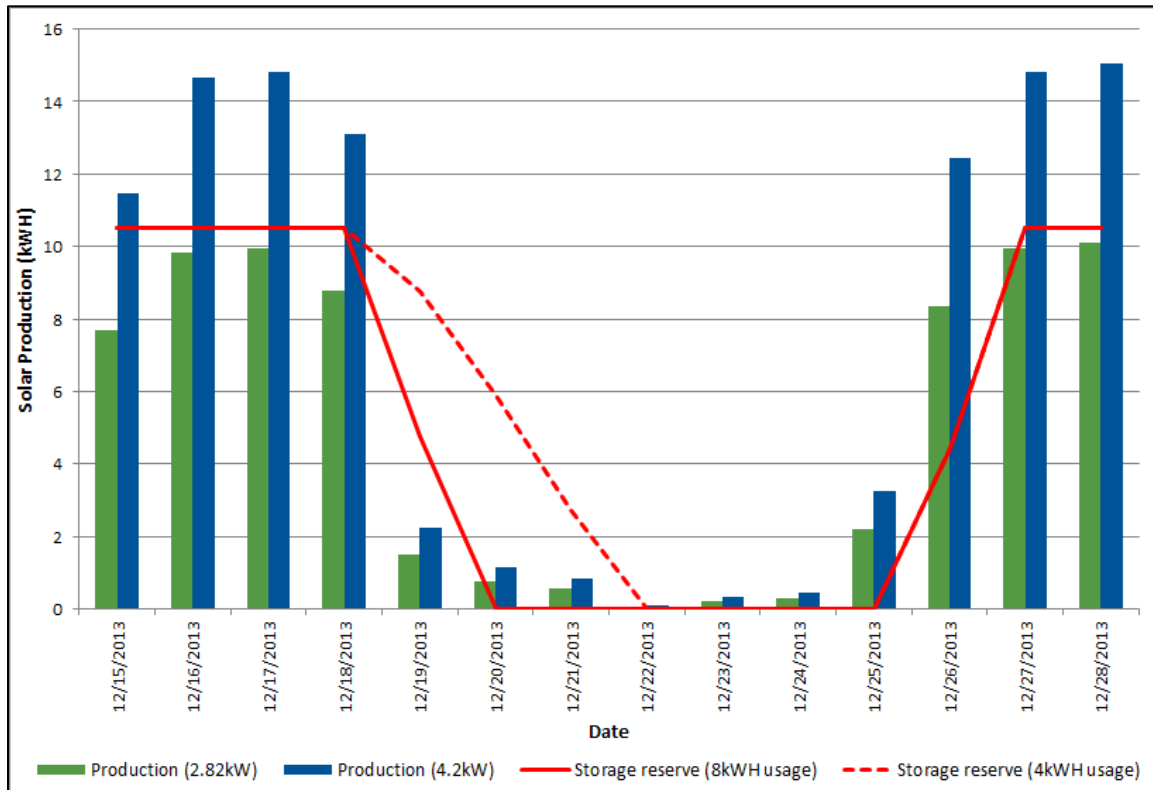
In these circumstances, it is expected that the customer would suspend the normal operational settings of the PESS and reserve 90% of the battery capacity for UPS mode. Under these revised settings, the fully charged 11.7-kWh battery could supply 10.5 kWh during outages of longer duration. Under these settings the PESS could sustain the estimated average daily CLP consumption of 8.0 kWh for approximately 31 hours, and longer if solar generation were available. If the local solar PV system produced at least 8 kWh per day, the PESS could sustain the CLP consumption through extended outages indefinitely.

Table 3-148 shows the number of days per month that solar production falls below 8 kWh per day. Analysis of two PV systems are represented, one representing the 2.83-kW system installed at the Demonstration House, and the second a 4.2-kW system. The 4.2-kW system was picked for comparative analysis, as it would provide a minimum monthly daily average PV production of 8 kWh. As this table illustrates, there were a significant number of winter days during which the daily production fell below the consumption of the CLP, and the PESS capacity would be needed to sustain the CLP usage over several days. In many of these instances it may be possible for the customer to implement additional energy savings measures to maintain the CLP usage for the duration of the outage.

Table 3-148: Days with PV Production Less than CLP Consumption

PV	Jan	Feb	Mar	April	May	June	July	Aug	Sept	Oct	Nov	Dec	Yearly
2.82 kW	13	17	4	7	3	4	1	2	4	6	12	18	91
4.2 kW	6	10	3	6	1	1	0	0	3	4	9	13	56

However, on at least two occasions, as illustrated in Figure 3-213, the modeled PV generation was so low for an extended period that it would be unlikely that the PESS could have sustained the CLP usage if there had been a prolonged grid outage during this period of time. While the PESS may not have been able to sustain the CLP through the entirety of an extended outage under these conditions, the ability to sustain the critical load for 2 days could substantially minimize the customer impact. Figure 3-213 also shows that the PESS could potentially sustain the CLP loads for 4 days if the CLP usage was reduced by 50% with aggressive critical load management

Figure 3-213: Example Winter Period of Minimum Solar Production

3.4.9.6.2.5 Issues and Corrective Actions

The following issues and corrective action were encountered during the performance of the Electric Service Reliability operational testing and analysis.

Table 3-149: Issues and Corrective Actions

Issue	Corrective Action
Due to technical issues and conflicting demonstrations at the Demonstration House, annual solar generation data was unable to be collected for this test.	Used the per-unit solar generation profile developed in the Distributed Rooftop Solar Generation operational test.
Demonstration House occupancy and CLP usage was not representative of a typical residential customer	Team performed a literature search to ascertain typical daily usage characteristics for CLP loads.
The SIS lost Internet connection to PESS during power outages.	Cable Modem/Router power was transferred to the critical load panel.

3.4.9.6.3 Findings

The results obtained in the execution and analyses of the Electric Service Reliability operational testing are summarized in the sections below.

3.4.9.6.3.1 Discussion

The PESS installed at the Demonstration House is a 11.7-kWh lithium-ion battery with a unique hybrid 6.0-kW inverter/converter; normal operations of the PESS reserve 10% battery capacity (1.17 kWh) for UPS mode. Under these standard settings the PESS could sustain 6 kW of load through momentary and longer grid outages that are restored by automated switching. If the customer suspends the normal PESS operational settings and reserves 90% (10.5 kWh) of the battery for UPS mode, the PESS could supply 6 kW of loads continuously to sustain critical load panel loads for approximately 1 ¾ hours.

The project team performed a literature search to ascertain typical daily usage characteristics for appliances and other customer loads that should be served by the critical load panel. The results of this analysis show that these loads would typically require approximately 8 kWh of electricity daily if additional energy conservation measures were not initiated by the consumer.

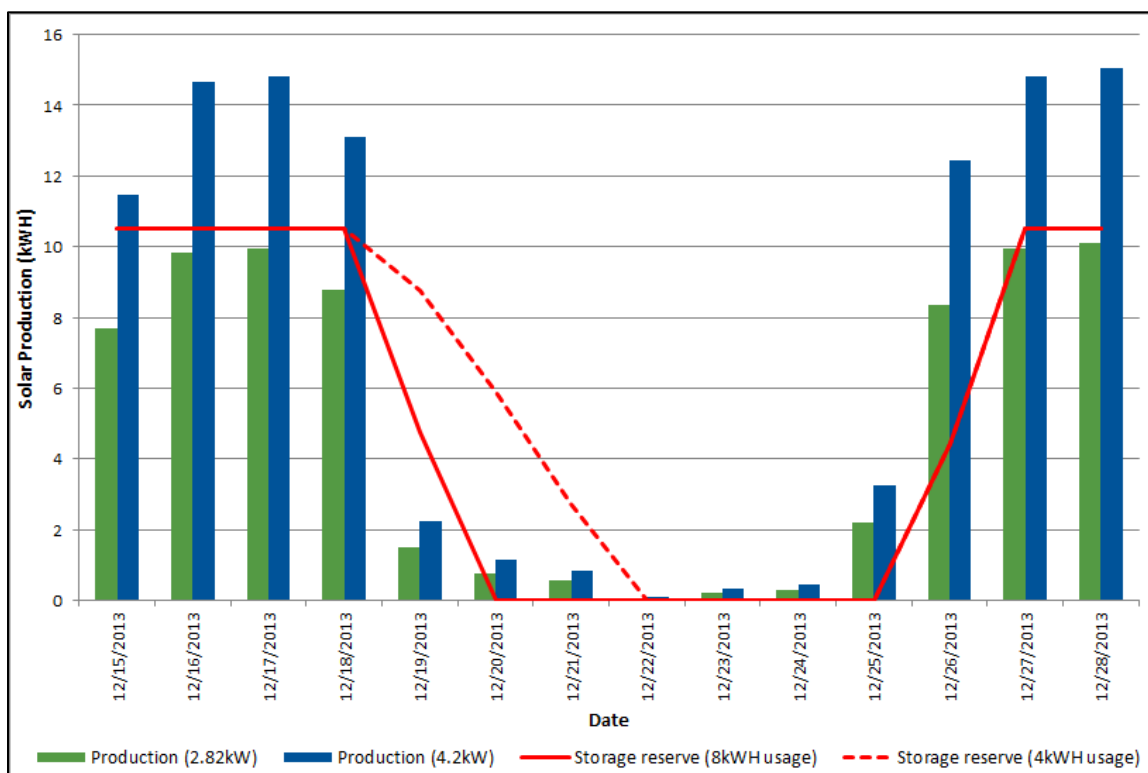
Based on the estimated average daily CLP consumption of 8.0 kWh, the default operational settings of 1.17 kW of reserved storage could sustain the average CLP consumption for 3.5 hours, or longer if there were additional battery capacity not previously discharged by other PESS functions and remained available. With an average sustained outage duration for customers in the SmartGrid Demonstration Area being just under 1.75 hours (CAIDI-101 min.), the default-reserved PESS storage could sustain the average CLP consumption for outages of durations twice the average.

Most extended outages for the KCP&L service territory typically last only a few hours, but, on rare occasions, severe winter ice storms have caused widespread outages to large portions of KCP&L's service territory, taking up to 10-12 days to restore power to all customers. In these circumstances, it is expected that the customer would suspend the normal operational settings of the PESS and reserve 90% of the battery capacity for UPS mode. Under these revised settings the fully charged 11.7-kWh battery could supply 10.5 kWh for outages of longer duration. The PESS could then sustain the estimated average daily CLP consumption of 8.0 kWh for approximately 31 hours, or longer with solar generation available. If the local solar PV system produced at least 8 kWh per day, the PESS could sustain the CLP consumption through extended outages indefinitely.

The project team constructed solar generation profiles for two solar systems: one representing the 2.82-kW system installed at the Demonstration House, and the second, a 4.2-kW system that would provide a minimum monthly daily average PV production of 8 kWh. Detailed analyses of these solar generation profiles show that, in both cases, there are a significant number of winter days during which the daily production fell below the consumption of the CLP, and the PESS storage energy capacity would be used to sustain the CLP usage during extended outages lasting multiple days.

PV	Jan	Feb	Mar	April	May	June	July	Aug	Sept	Oct	Nov	Dec	Yearly
2.82 kW	13	17	4	7	3	4	1	2	4	6	12	18	91
4.2 kW	6	10	3	6	1	1	0	0	3	4	9	13	56

However, on at least two occasions, as illustrated in Figure 3-214, the modeled PV generation was so low for an extended period that it was unlikely that the PESS could have sustained the CLP usage if there had been a prolonged grid outage during this period of time. While the PESS may not have been able to sustain the CLP through the entirety of an extended outage under these conditions, the ability to sustain the critical load for 2 days could substantially minimize the customer impact. Figure 3-214 also shows that the PESS could potentially sustain the CLP loads for 4 days if the CLP usage was reduced by 50% with aggressive critical load management.

Figure 3-214: Example Winter Period of Minimum Solar Production

3.4.9.6.3.2 Expectations vs. Actuals

The following table provides a comparison of the Expected Results and the Actual Outcomes for the Electric Service Reliability operational test.

Table 3-150: Expected Results vs. Actual Outcomes

Expected Results	Actual Outcome
Emergency standby power functionality will be demonstrated at the Demonstration House.	A critical load panel was installed and the PESS was configured for emergency standby power operation, and the functionality was demonstrated.
Develop an understanding of how much critical load the PESS can maintain indefinitely at the Demonstration House with the installed solar panels.	- PESS as normally configured (10% UPS) can sustain CLP through momentary and short-duration outages. - When reconfigured for UPS operations, the PESS storage alone can sustain CLP loads for more than a day. - Combined with the Demonstration House solar array (2.82 kW), the PESS could sustain CLP load for multiday restorations throughout most of the non-winter months. - Combined with a slightly larger array (4.2 kW) and/or very active CLP energy usage management, PESS could sustain CLP loads for multiday restorations throughout most of the year. - The PESS may be unable to sustain CLP loads for multiday restorations during extended periods (3+ days) of minimal solar production without CLP load reductions.

3.4.9.6.3.3 Computational Tool Factors

The following table lists the values derived from the Electric Service Reliability operational test analysis that will be used as inputs to the Energy Storage Computational Tool.

Table 3-151: Computational Tool Values

Name	Description	Calculated Value
SAIDI	System Average Interruption Duration Index is defined as: Total Customer Hours Interrupted/Total Customers Served.	181.48 min. 3.025 Hr.
Outage Time of Major Outage – Residential	Total outage time experienced by residential customers from an interruption of electric service that is categorized as a major event by IEEE Std. 1366-2003	294.43 Min 4.91 Hr.
Outage Minutes Avoided by Residential Customers	The total outage minutes avoided by residential customers as a result of energy storage devices being used to provide power during system interruptions.	475.91 Min
Average Hourly Load Not Service During Outage per Customer – Residential (kWh)	These inputs represent the average hourly load (kW) of a typical residential, commercial, or industrial customer within the project scope. This average hourly load will be used to calculate the unserved electricity during an outage event.	1.178 kWh
Value of Service – Residential (\$)/kWh	Represents the true value of the electricity service to the specified customer without regard to the actual cost of providing the service. This input captures the value of service reliability quantified by the willingness of customers to pay for service reliability, taking into account the resources (e.g., income) of the residential customer or by a firm's expected net revenues associated with the added reliability.	\$2.27 /kWh

- **SAIDI:** The analysis will use the 3 year average of the reported project level Impact Metrics values.
- **Outage Time of Major Outage – Residential:** This value has been calculated based on a 15-year average of outages classified as major events by IEEE and excluded from the standard indices calculations. This value is calculated as follows:

$$15\text{yr Average SAIDI for major events} - 294.43 \text{ Min/Cust}$$

$$3.025 \text{ Hr} + 294.43 \text{ min/cust} \div 60 \text{ min/hr} = 4.91 \text{ hr}$$
- **Outage Minutes Avoided by Residential Customers (Min):** Based on the project level indices, this value is calculated as follows:

$$\text{SAIDI (Min)} + \text{Outage Time of Major Outages-Residential (Min)} =$$

$$181.48 \text{ min} + 294.43 \text{ min} = 475.91 \text{ min}$$

- Average Hourly Load Not Service During Outage per Customer – Residential (kWh): Based on the energy consumption of the “typical” residential customer used for all PESS analysis this value is calculated as follows:

$$10,319 \text{ kWh/year} \div 8760 \text{ hours/year} = 1.178 \text{ kWh/hr}$$

- Value of Service – Residential (\$/kWh): The DOE/LBNL ICECalculator^[31] (Interruption Cost Estimate Calculator) was used to calculate the value with the following input parameters.

Modified default values for the report’s “typical” residential customer, with a detached single family house using 10,319 kWh/year yielded \$2.10 /kWh (2011 \$)

Applied 2% annual escalation to yield \$2.27 /kWh (2015 \$)

3.4.9.6.4 Lessons Learned

Throughout the conduct of the operational testing and analysis of the PESS for the Electric Service Reliability function, numerous considerations were realized and should be noted for future implementations. These Lessons Learned are as follows:

- The manufacturer’s recommendation for protecting the battery and maintaining its useful life is that the battery should not be routinely charged above 95% nor discharged below 10% charge level. This limitation must be factored in when sizing the battery storage component for any PESS.
- The PESS ratings, 6.0 kW/11.7 kWh, appear to be appropriately sized to serve the critical loads of most residential homes in the KCP&L service area. Combining the PESS with a
- 4.2-kW solar array would allow the CLP loads to be sustained through multiday restorations for the majority of the year.
- In the Kansas City region during the winter months, occasionally there are periods extending several days with minimal solar production. The PESS may be unable to sustain CLP loads for multiday restorations during these extended periods of minimal solar production without reductions in the CLP loads.
- It is important for the customer to understand the energy consumption characteristics of the loads connected to the CLP. Approximately half of the daily energy consumption may be attributed to the furnace fan. To extend the ability of the PESS to sustain loads during outages, the customer should consider installing the most efficient furnace fan available and to manage thermostat settings to further reduce furnace operation.
- To further extend the ability of the PESS to improve its ability to sustain loads during outages, the customer should implement additional energy management measures, which would include only running certain appliances (freezer, computer while charging, etc.) during times of significant solar production.
- It is critical that the customer’s home network and ISP connection remain operational during power outages. Without the ISP connection, the customer’s ability to monitor and manage the PESS is lost. It may be necessary for the customer to have a backup cellular Internet connection for the PESS if the customer’s normal home ISP supplier loses service due to widespread power outages.

3.4.9.7 PEV Charging

The batteries in plug-in electric vehicles (PEVs) can be portrayed as nonstationary energy storage devices. As such, they are similar to stationary energy storage devices and support economic, reliability and environmental benefits. By increasing vehicle fuel efficiency, they also support Reduced Oil Usage, an Energy Security Benefit.

3.4.9.7.1 Overview

The following sections provide an overview of the operational, demonstration, testing, and evaluation methodology used for the PEV Charging operational test.

3.4.9.7.1.1 Description

The ChargePoint VCMS and a total of 10 Electric Vehicle Charging Stations (EVCSs) will be deployed within the SGDP area. Each EVCS consists of a dual port, level 2 (240V) Coulomb Charging Station capable of charging two PEVs simultaneously. The EVCSs was installed on the EVCS sponsor's side of the meter, with charging free to the public. The VCMS was integrated with the DERM and serves as the "control authority" for each EVCS during demand response events.

3.4.9.7.1.2 Expected Results

This technical demonstration was expected to yield the following:

- Technical demonstration of 10 EVCSs, accessible to the public and providing PEV owners the convenience of public charging.
- The DERM would dispatch DR events to the EVCS, demonstrating how PEVs can participate in DR events.
- KCP&L would be able to monitor, record, and summarize the charging patterns at each EVCS site.

3.4.9.7.1.3 Benefit Analysis Method/Factors

The DOE SGCT was used to perform the SGDP benefit analysis. For this application the following Smart Grid Function benefits were quantified.

- Reduced CO₂ Emissions

Benefits were calculated using SGCT formulas. The following factors were measured, projected, or calculated during the application operation and/or demonstration.

Reduced CO₂ Emissions

- Annual Electricity Consumed by PEVs (kWh)

3.4.9.7.1.4 Demonstration Methodology

The following points provide an overview of how the operational demonstration of this application was accomplished:

- Energy use at each PEV charging station was measured through PEV Charge Management System and the AMI system deployed as part of the Project. All data collected by the AMI system was stored in KCP&L's MDM system.

3.4.9.7.1.5 Analytical Methodology

The Technical Demonstration of this application does not require any analytical calculations.

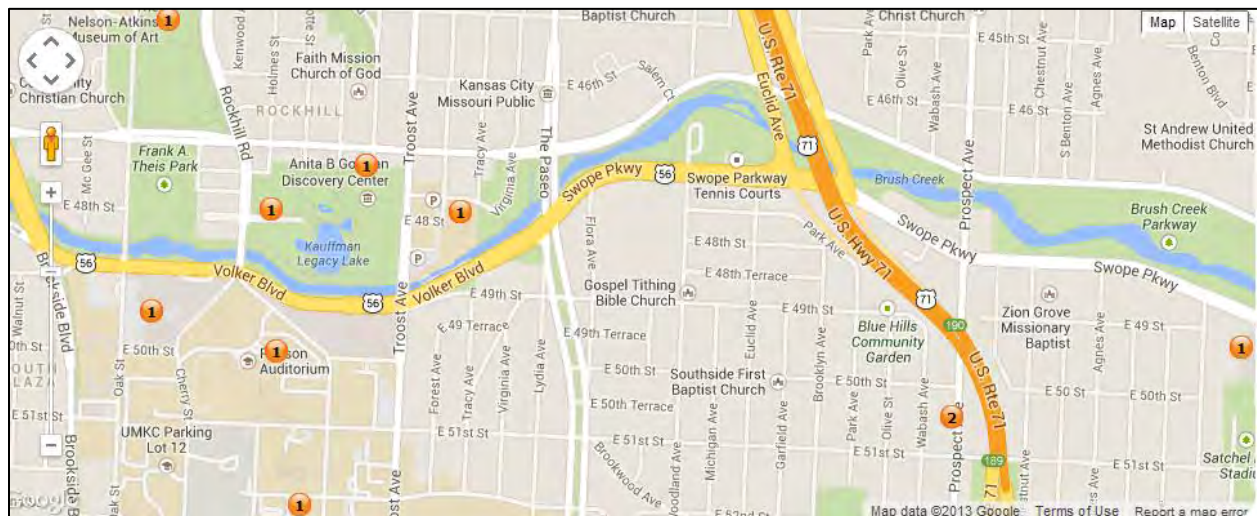
3.4.9.7.2 *Plan Execution and Analysis*

The following sections provide details regarding the functions, data collection, and evaluation performed for the PEV Charging demonstration.

3.4.9.7.2.1 PEV Charging Station Installations

As part of this SGDP, KCP&L installed 10 EVCSs at locations illustrated in Figure 3-215. Each EVCS consists of a dual port, level 2 (L2) (240V) Coulomb CT2021 Charging Station with SAE J1772 standard connectors. Each EVCS is equipped with a cellular modem that enables two-way communications with the ChargePoint web platform. This allows electric vehicle owners to locate and reserve individual EVCSs by using web mapping applications. These charging stations are free for electric vehicle owners to use.

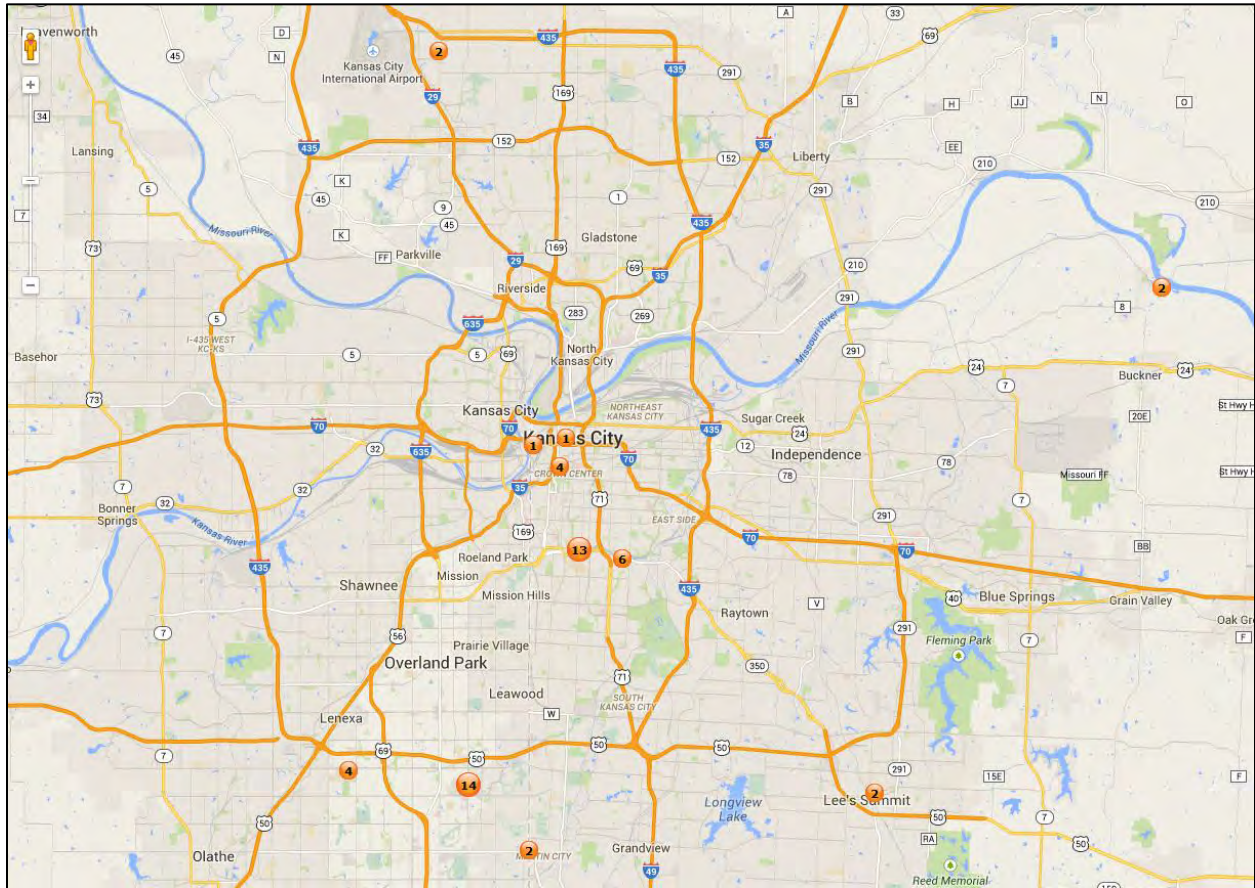
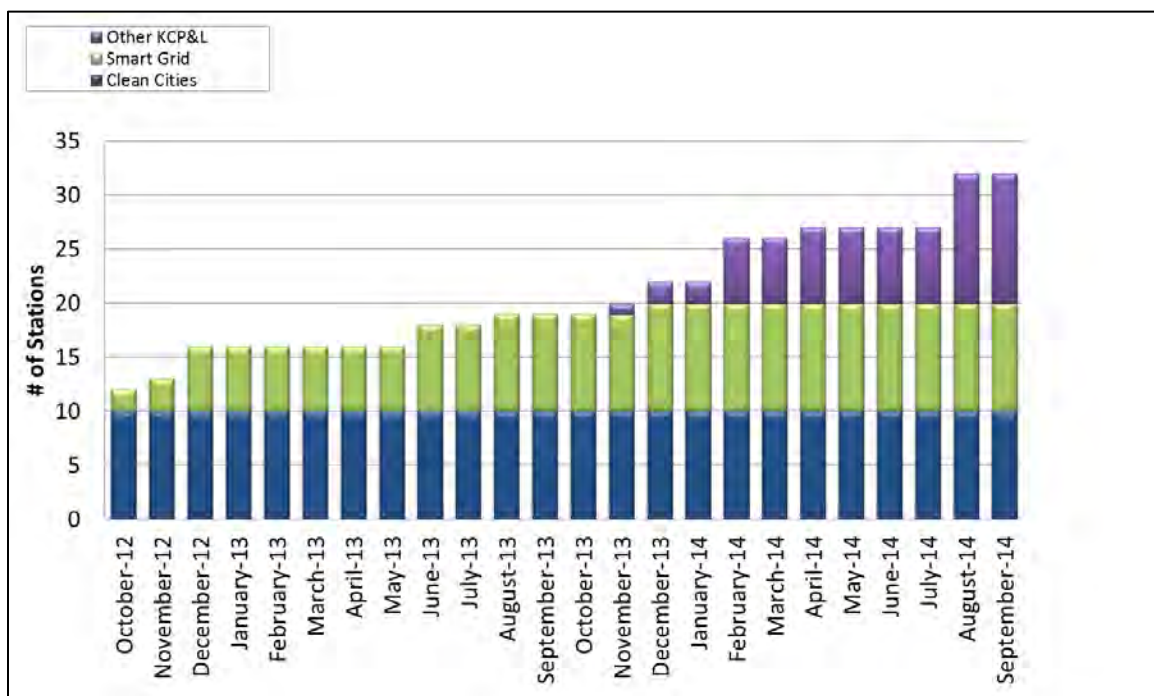
Figure 3-215: ChargePoint Map of SmartGrid EVCS Locations



KCP&L has installed an additional 22 EVCSs throughout the Kansas City Metropolitan Area, at locations illustrated in Figure 3-216. Ten (10) of these additional EVCSs are combination L1/L2 stations installed as part of a Clean Cities project, which also received federal funding. The remaining 12 EVCSs are Level 2 stations installed as part of an internal KCP&L test marketing program.

Figure 3-217 shows the deployment schedule of all stations during the SGDP's Operational Test period.

KCP&L monitors and manages all of these EVCSs via the ChargePoint web platform. Station summaries—including usage and inventory reports, reservation schedules, and audit reports—are readily available through the platform and were used in the analysis presented in the following section.

Figure 3-216: ChargePoint Map of All KCP&L EVCS Locations**Figure 3-217: EV Charging Station Deployment by Month**

3.4.9.7.2.2 Electric Vehicle Charge Station Utilization

Figure 3-218 illustrates the total charging session per month for all EVCSs, and Figure 3-219 illustrates the average number of charging session per EVCS by program (SmartGrid, Clean Cities, and other KCP&L).

Figure 3-218: Total EVCS Charging Sessions by Month

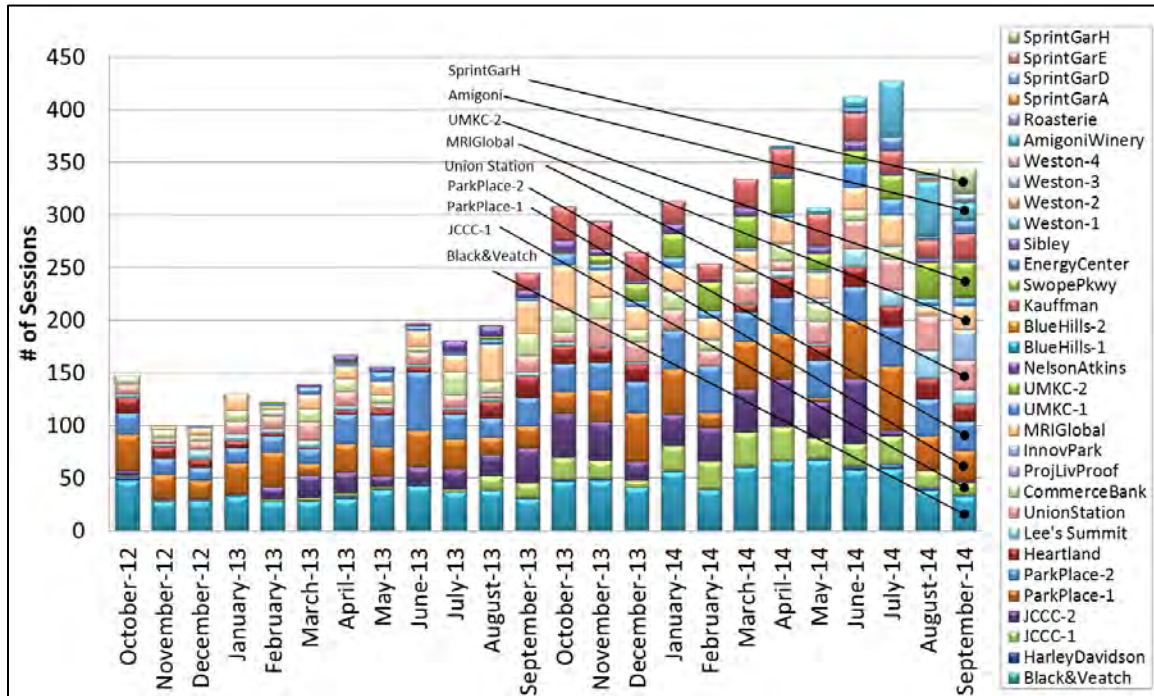


Figure 3-219: Average EVCS Charging Sessions by Month (by Program)

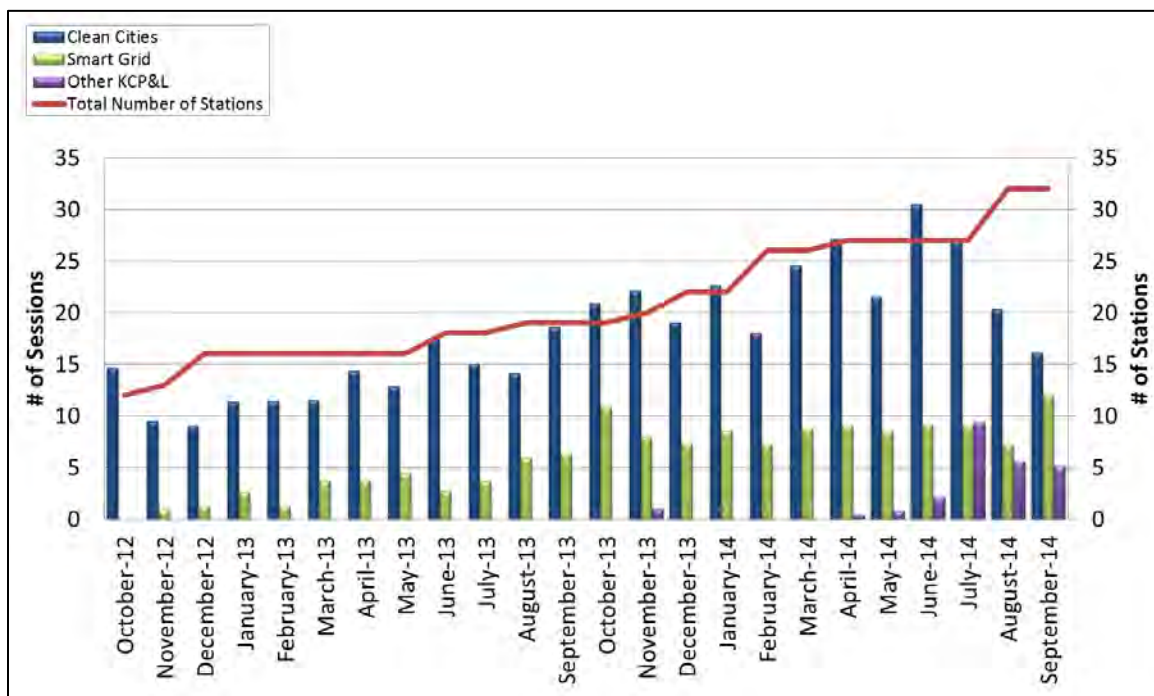


Figure 3-220 depicts the total kWh consumption per month for all EVCSs, and Figure 3-221 depicts the average kWh consumption per EVCS by program (SmartGrid, Clean Cities, and other KCP&L).

Figure 3-220: Total EVCS kWh Consumption by Month

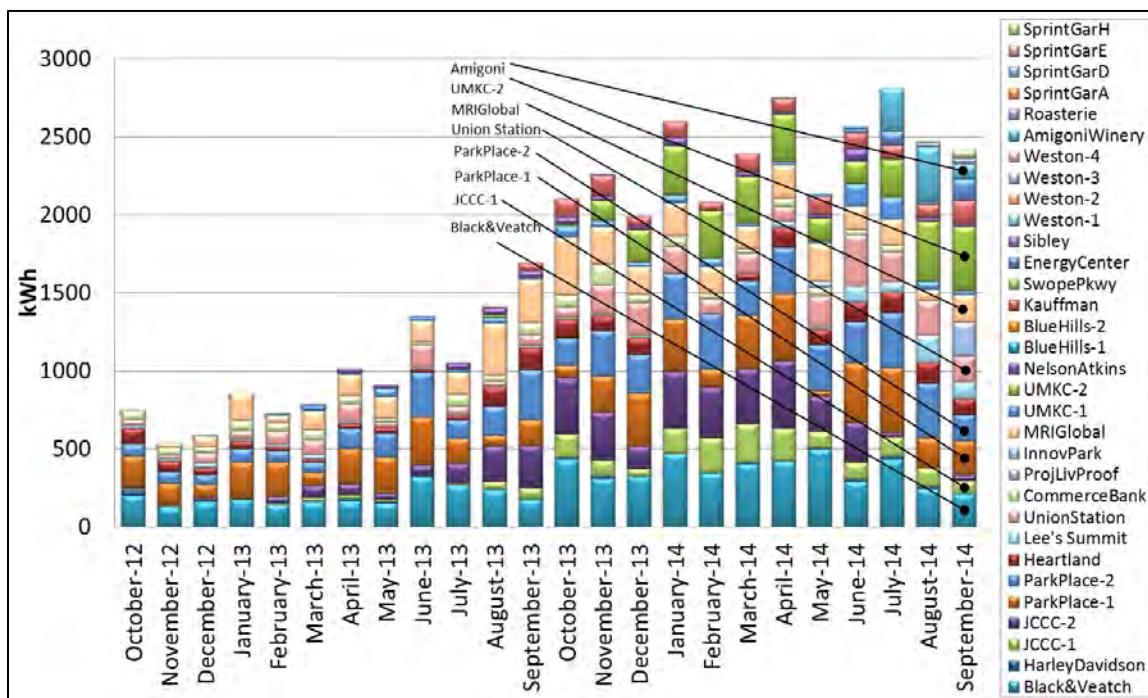
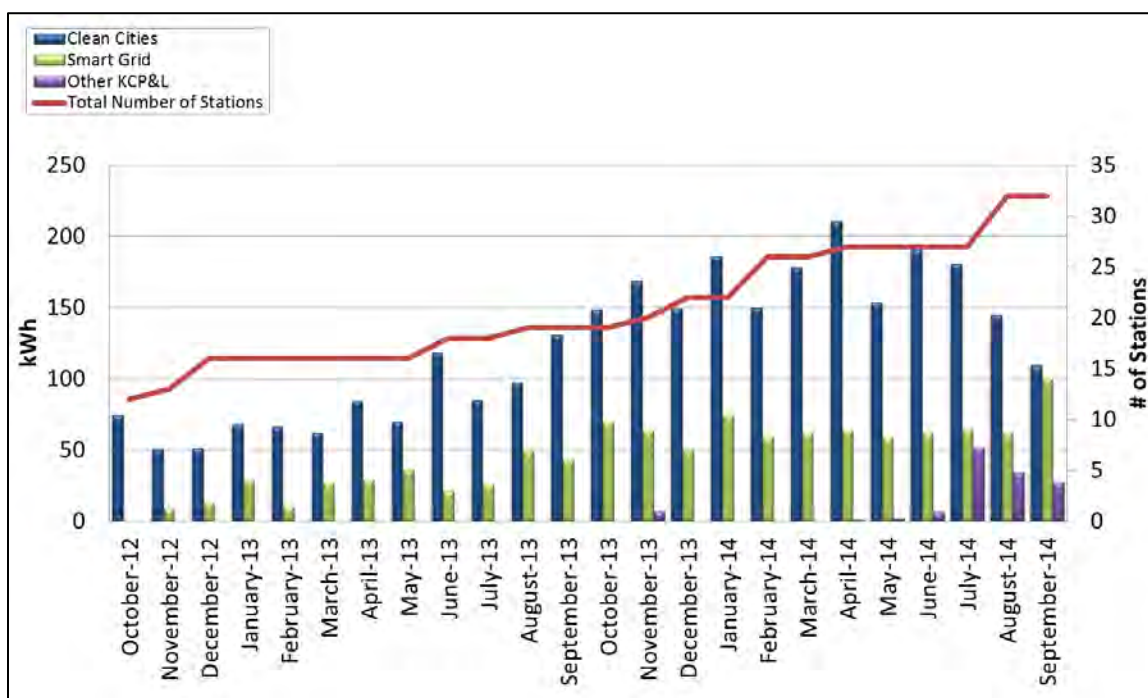


Figure 3-221: Average EVCS kWh Consumption by Month (by Program)



3.4.9.7.2.3 PEV Charging Results

Figure 3-222 depicts the average EVCS Session Connect Time over time and Figure 3-223 depicts the average EVCS Session Charge Time over time for all EVCSs (SmartGrid, Clean Cities, and other KCP&L).

Figure 3-222: Average EVCS Charge Session – Connect Time



Figure 3-223: Average EVCS Charge Session – Charge Time

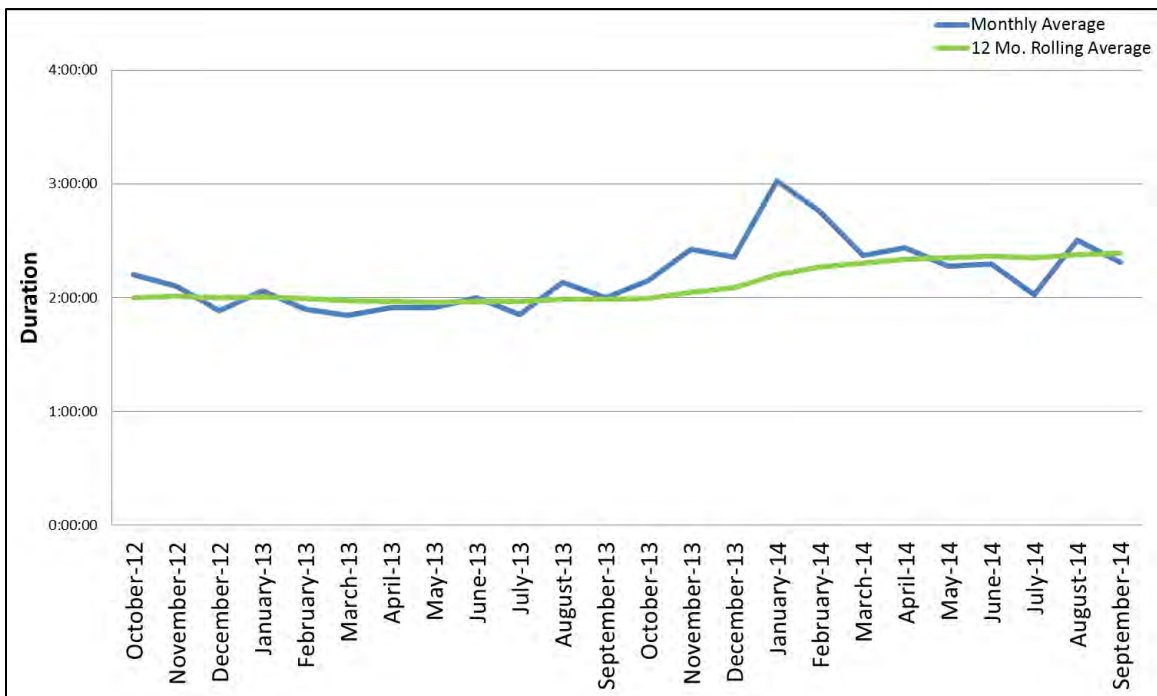


Figure 3-224 depicts the average EVCS Session kWh consumption over time for all EVCSs and Figure 3-225—a scatter plot of all charging sessions for the August 2014—illustrates the two most common charge rates used by the Kansas City PEV population.

Figure 3-224: Average EVCS Charge Session – kWh

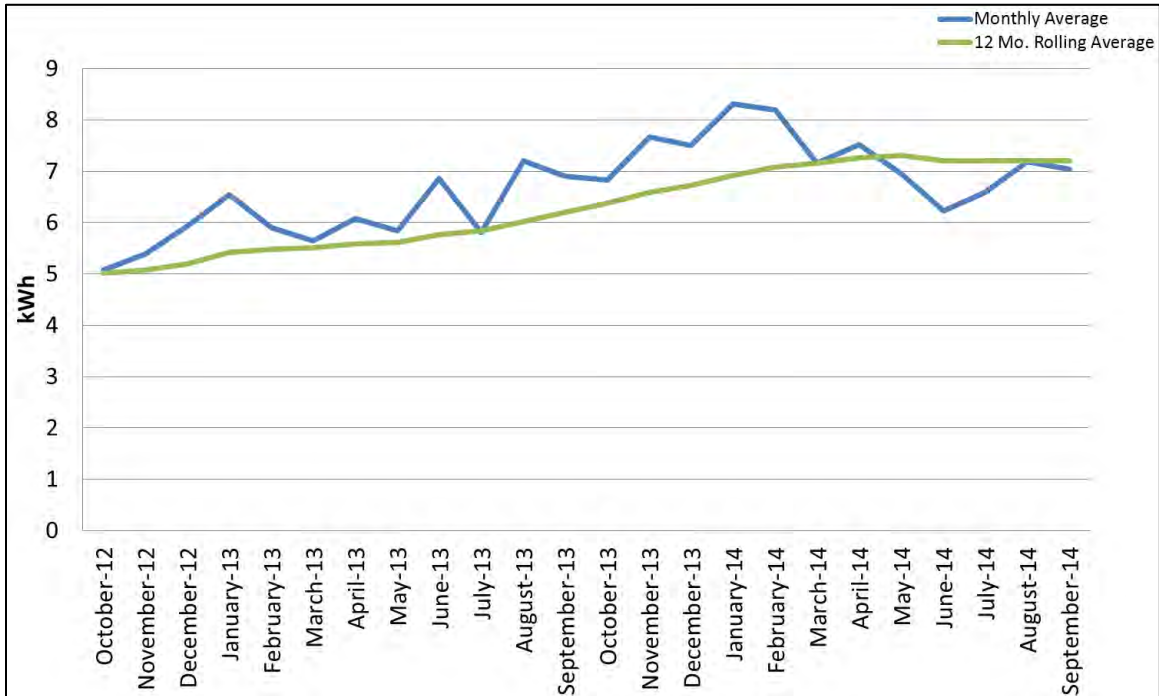
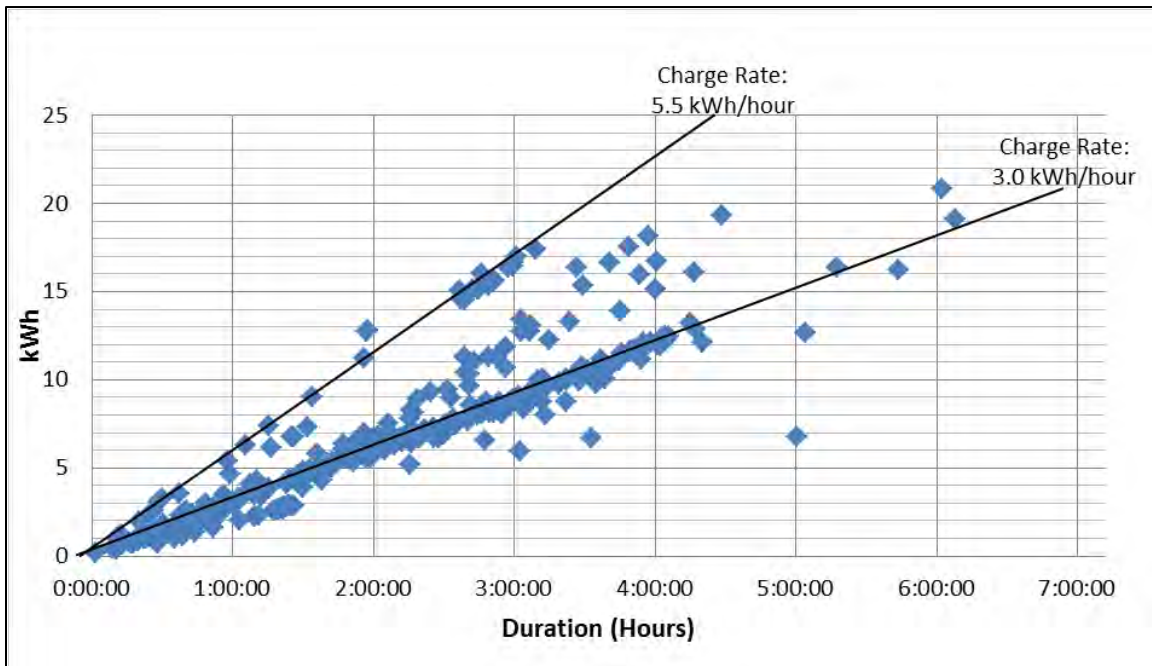


Figure 3-225: EVCS Session Charge Rates



3.4.9.7.2.4 PEV Charging Station Participation in DR Event

As part of the demand response demonstration, KCP&L worked with OATI and ChargePoint to build an interface between the DERM and the VCMS. Unlike most of the vendor-to-vendor interfaces, this one was not routed through the ESB; rather, it was a point-to-point interface between the two vendors. ChargePoint's existing API was utilized to communicate the necessary information between the two systems.

To demonstrate the charging station participation in DR events, KCP&L triggered several events specifically targeted to the Innovation Park charging station. KCP&L also completed one event with a PEV actually plugged into the charging station. Several pictures and screenshots are shown below, but the complete screenshots from this event demonstration are contained in Appendix K.

Figure 3-226 below shows the ChargePoint charge station management dashboard (specifically, the Innovation Park station) during the event. As indicated below, the load shed level was at 100% during the event.

Figure 3-226: ChargePoint Dashboard During PEV DR Event

The screenshot displays the ChargePoint web interface. At the top, the ChargePoint logo is on the left, and a user greeting 'Welcome Meghan Lyons' with a 'Logout' link is on the right. Below this is a navigation bar with tabs: Dashboard, Manage Stations, Reports, Manage Energy, Organizations, and Find Stations. The 'Manage Stations' tab is active, showing a 'Stations Overview' section. Under this, there's a 'KCP&L / SUBSTATION Info' section with details: Org KCP&L, Make / Model Coulomb CT2020-HD-GPRS1-CCR, MAC Address 000D:6F00:015B:7703, Serial number 114410010668, and Station Network Type Gateway. Below this is another set of tabs: General, Status / Actions, Configuration, Sessions, and Contacts. The 'Status / Actions' tab is selected, showing a 'Station Status' summary. The status is 'AVAILABLE' as of 2014-08-29 10:05:28 (CDT). Below this, 'Port Status' is shown for two ports: Port 1 is 'INUSE' and Port 2 is 'AVAILABLE', both as of the same timestamp. The 'Load Shed' status is 'Yes 100 %'. Other details include 'Network Status' as 'REACHABLE', 'OTA Updates' as '-', and 'Software Version' as '3.3.0.31 Build 29471 nandflash'.

Section	Item	Value
KCP&L / SUBSTATION Info	Org	KCP&L
	Make / Model	Coulomb CT2020-HD-GPRS1-CCR
	Station Network Type	Gateway
MAC Address	000D:6F00:015B:7703	Serial number 114410010668
Station Status	Station Status	AVAILABLE
	as of 2014-08-29 10:05:28 (CDT)	
	Port Status	as of 2014-08-29 10:05:28 (CDT)
	Port 1:	INUSE
	Port 2:	AVAILABLE
Load Shed	Yes 100 %	
Network Status	REACHABLE	
OTA Updates	-	
Software Version	3.3.0.31 Build 29471 nandflash	

Figure 3-227 below shows the DERM event summary screen during the event. As shown in the last line, the ChargePoint program was Active during the demand response event.

Figure 3-227: DERM Event Summary During PEV DR Event

Schedule Event	Program	Date	Status	Strategy	Enm	Notification Date	Start Hour	Start Min	End Hour	End Min	Response	Relax	Audit Trail
Battery (01/09/2014)	Battery	01/09/2014	Completed	LCS	Yes	01/09/2014 13:30	14	00	15	00	No	No	No
ChargePoint Resource (01/09/2014)	ChargePoint	01/09/2014	Completed	CYCLING	Yes	01/09/2014 13:50	13	50	14	00	No	No	No
801 LCS resource (01/09/2014)	801 load control devices	01/09/2014	Aborted	LCS	Yes	01/09/2014 14:05	14	10	14	12	No	No	No
801 LCS resource (01/09/2014)	801 load control devices	01/09/2014	Aborted	LCS	Yes	01/09/2014 16:35	16	40	16	40	No	No	No
ChargePoint Resource (01/09/2014)	ChargePoint	01/09/2014	Aborted	CYCLING	Yes	01/09/2014 16:34	16	36	16	50	No	No	No
801 total resource - test(01/09/2014)	801 thermostats	01/09/2014	Cancelled	PCT	Yes	01/09/2014 16:50	17	00	17	10	No	No	No
801 LCS resource - test(01/09/2014)	801 load control devices	01/09/2014	Aborted	LCS	Yes	01/09/2014 16:59	17	04	17	04	No	No	No
801 LCS resource - test(01/09/2014)	801 load control devices	01/09/2014	Aborted	LCS	Yes	01/09/2014 17:27	17	29	17	29	No	No	No
GridViolation RT test(01/09/2014) 98	801 thermostats	01/09/2014	Completed	PCT	Yes	01/09/2014 15:10	15	20	15	00	0	0	Yes
GridViolation RT test(01/09/2014) 99	801 load control devices	01/09/2014	Completed	LCS	Yes	01/09/2014 15:18	15	20	16	00	0	0	Yes
GridViolation RT test(01/10/2014) 99	801 thermostats	01/10/2014	Completed	PCT	Yes	01/10/2014 11:59	12	09	13	00	0	0	Yes
801 total resource - manual test(01/10/2014)	801 load control devices	01/10/2014	Completed	LCS	Yes	01/10/2014 12:07	12	09	13	00	0	0	Yes
GridViolation RT test(01/10/2014) 92	801 thermostats	01/10/2014	Completed	PCT	Yes	01/10/2014 16:53	16	53	16	55	No	No	No
GridViolation RT test(01/10/2014) 93	801 thermostats	01/10/2014	Completed	PCT	Yes	01/10/2014 17:02	17	05	17	15	0	0	Yes
GridViolation RT test(01/10/2014) 94	801 load control devices	01/10/2014	Completed	LCS	Yes	01/10/2014 17:05	17	05	17	15	0	0	Yes
GridViolation RT test(01/10/2014) 94	801 thermostats	01/10/2014	Completed	PCT	Yes	01/10/2014 17:34	17	38	17	45	0	0	Yes
GridViolation RT test(01/10/2014) 95	801 load control devices	01/10/2014	Completed	LCS	Yes	01/10/2014 17:34	17	36	17	45	0	0	Yes
GridViolation RT test(01/10/2014) 96	801 thermostats	01/10/2014	Completed	PCT	Yes	01/10/2014 17:56	18	00	18	05	0	0	Yes
GridViolation RT test(01/10/2014) 97	801 load control devices	01/10/2014	Completed	LCS	Yes	01/10/2014 17:59	18	00	18	05	0	0	Yes
GridViolation RT test(01/10/2014) 98	801 thermostats	01/10/2014	Completed	PCT	Yes	01/10/2014 18:00	18	00	18	05	0	0	Yes
GridViolation RT test(01/10/2014) 99	801 load control devices	01/10/2014	Completed	LCS	Yes	01/10/2014 18:00	18	00	18	05	0	0	Yes
801 total resource - sync test(01/12/2014)	801 thermostats	01/12/2014	Aborted	PCT	Yes	01/12/2014 14:42	14	44	14	44	0	0	Yes
801 LCS resource - sync test(01/12/2014)	801 load control devices	01/12/2014	Completed	LCS	Yes	01/12/2014 14:58	15	00	15	15	No	No	No
801 total resource - sync test(01/12/2014)	801 thermostats	01/12/2014	Completed	PCT	Yes	01/12/2014 14:59	15	01	15	15	No	No	No
GridViolation RT test(01/13/2014) 99	801 load control devices	01/13/2014	Completed	LCS	Yes	01/13/2014 15:04	15	06	15	08	0	0	Yes
GridViolation RT test(01/13/2014) 100	801 thermostats	01/13/2014	Completed	PCT	Yes	01/13/2014 15:04	15	06	15	08	0	0	Yes
GridViolation RT test(01/13/2014) 101	801 load control devices	01/13/2014	Completed	LCS	Yes	01/13/2014 15:04	15	06	15	08	0	0	Yes
GridViolation RT test(01/13/2014) 102	801 thermostats	01/13/2014	Completed	PCT	Yes	01/13/2014 16:08	16	10	16	15	0	0	Yes
GridViolation RT test(01/13/2014) 103	801 load control devices	01/13/2014	Completed	LCS	Yes	01/13/2014 17:05	17	07	17	10	0	0	Yes
801 LCS resource (03/06/2014)	801 thermostats	03/06/2014	Cancelled	LCS	Yes	03/06/2014 09:20	09	22	09	30	No	No	No
801 total resource - comparison test(05/14/2014)	801 load control devices	05/14/2014	Completed	PCT	Yes	05/14/2014 10:24	10	26	10	35	No	No	No
801 LCS resource - comparison test(05/14/2014)	801 thermostats	05/14/2014	Completed	LCS	Yes	05/14/2014 10:30	10	32	10	35	No	No	No
801 total resource - temp test(05/15/2014)	801 load control devices	05/15/2014	Cancelled	PCT	Yes	05/15/2014 13:26	13	28	13	35	No	No	No
801 total resource - temp test(05/15/2014)	801 thermostats	05/15/2014	Completed	PCT	Yes	05/15/2014 13:32	13	34	13	40	No	No	No
801 total resource - cooling test(05/23/2014)	801 thermostats	05/23/2014	Completed	PCT	Yes	05/23/2014 15:58	16	00	16	05	No	No	No
ChargePoint Resource - event(06/15/2014)	ChargePoint	06/15/2014	Completed	CYCLING	Yes	06/15/2014 08:25	08	25	08	30	No	No	No
ChargePoint Resource - event(08/29/2014)	ChargePoint	08/29/2014	Active	CYCLING	Yes	08/29/2014 10:05	10	05	10	15	No	No	No

Figure 3-228 below shows the text message that was received by the PEV owner during the event, notifying her that her vehicle was no longer receiving charge.

Figure 3-228: Text Message Sent to PEV Owner During PEV DR Event

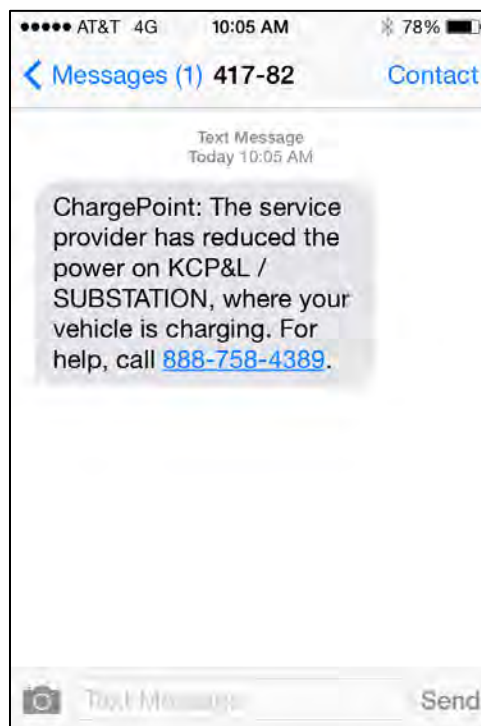


Figure 3-229 below shows the message displayed on the charging station during the DR event. The text scrolling across the display read: “#1: SUSPENDED” on the top line and “LOAD SHED IN PROGRESS/TAP CARD TO END” on the bottom line.

Figure 3-229: Charge Station Message During PEV DR Event



Figure 3-230 below shows the PEV dashboard during the DR event. It displayed “Not Able to Charge”.

Figure 3-230: PEV Dashboard During PEV DR Event



3.4.9.7.2.5 Issues and Corrective Actions

No issues requiring corrective action were encountered during the performance of the PEV Charging operational demonstration.

3.4.9.7.3 Findings

The results obtained in the execution and analyses of PEV Charging operational demonstration are summarized in the sections below.

3.4.9.7.3.1 Discussion

KCP&L has installed 32 EVCSs throughout the Kansas City Metropolitan Area. Ten of the EVCSs were directly funded by this SGDP. An additional 10 are combination L1/L2 stations installed as part of a Clean Cities project, which also received federal funding. The remaining 12 EVCSs are Level 2 stations installed as part of an internal KCP&L test marketing program. The operational performance of all 32 stations was tracked and analyzed for this analysis.

Site selection has proven key to early utilization of the EVCSs. The EVCSs deployed under the Clean Cities program have experienced higher utilization, as they were placed at locations with high EV usage potential. In contrast, the SmartGrid demonstration EVCSs were limited to placement within the SGDP boundary, an area with a relatively low potential EV population. Even so, utilization for all charging stations has increased over time as the EV population increases and as EV owners become aware of the EVCS locations.

Through 2014, total EVCS kWh consumption leveled out at approximately 2.5 MWh per month. During this period of flat consumption, KCP&L deployed additional EVCSs, causing average station consumption to drop.

Based on monitoring of all EVCSs, the following characteristics were uncovered regarding charge sessions.

- Annual Electricity Consumed by PEVs is 28.586 MWh
- Average Connect Time is 4.5 hours
- Average Charge Duration is 2 hours, 20 minutes
- Average Charge is approx. 7 kWh
- Most common Charge Rate is 3 kWh/hour
- Less common Charge Rate is 5.5 kWh/hour

KCP&L also demonstrated the EVCS and EV participation in DR events. While KCP&L did not call any DR events in 2014 due to abnormally cool weather, an analysis was conducted upon the potential EVCS contribution to an event if one would have been called on the utility's 2014 peak hour, which occurred from 4 PM to 5 PM on August 25, 2014. During this hour, two (2) charging sessions were active but only one EV was actually charging. If a DR event had been called, a single 3.2-kW charge session would have been interrupted.

3.4.9.7.3.2 Expectations vs. Actuals

The following table provides a comparison of the Expected Results and the Actual Outcomes for the PEV Charging operational demonstration.

Table 3-152: Expected Results vs. Actual Outcome

Expected Results	Actual Outcome
Technical demonstration of 10 EVCSs, accessible to the public	Successfully deployed 10 SGDP EVCSs and applied the knowledge learned to additional KCP&L test market installations.
The DERM will dispatch DR events to the EVCS, demonstrating how PEVs can participate in DR events.	The DERM dispatched DR events to the EVCS demonstrating how PEVs can participate in DR events.
KCP&L will be able to monitor, record, and summarize the charging patterns at each of the EVCS sites.	KCP&L developed an understanding of typical PEV charging session characteristics, including charge session connection duration, charge duration, charge rate, and kWh consumption.

3.4.9.7.3.3 Computational Tool Factors

The following table lists the values derived from the PEV Charging operational demonstration that will be used as inputs to the Smart Grid Computational Tool and the Energy Storage Computational Tool.

Table 3-153: Computational Tool Values

Name	Description	Calculated Value
Annual Electricity Consumed by PEVs	The total electricity consumed by PEVs in the service territory	28,586 kWh

3.4.9.7.4 Lessons Learned

Throughout the conduct of the operational demonstration, testing, and evaluation of the PEV Charging function, numerous considerations were realized and should be noted for future implementations. These Lessons Learned are as follows:

- Site selection is key to the early utilization of a public EVCS. The best sites are locations where potential PEV owners work, or are businesses where PEV owners frequent, usually an hour or so at a time. Having moderate wait times provides enough time for a user to charge a vehicle, while also generating enough vehicle turnover to make the charging station available to multiple users. With increased exposure comes increased acceptance and, it follows, use.
- Monitoring of all EVCS locations generated the following generalizations regarding usage of charging stations.
 - Annual Electricity Consumed by PEVs is 28.586 MWh
 - Average Connect Time is 4.5 hours
 - Average Charge Duration is 2 hours, 20 minutes
 - Average Charge is approx. 7 kWh
 - Most common Charge Rate is 3 kWh/hour
 - Less common Charge Rate is 5.5 kWh/hour
- While considerable DR potential exists for use of EVCSs, the potential for reducing KCP&L's system peak (typically 4 PM to 5 PM) in the foreseeable future is very limited.

3.5 METRICS AND BENEFITS REPORTING

The SGDP operational demonstrations and testing, outlined in the previous section, were performed to not only demonstrate the SmartGrid Functions achievable through end-to-end interoperability, but to also capture and quantify the operational benefits achievable by each of the SmartGrid applications. EPRI and the DOE have developed specific, quantifiable methodologies to translate benefit metrics into potential monetary value. KCP&L used the DOE-developed metrics reporting and computational tools to evaluate the overall costs and benefits of the demonstrated SmartGrid technologies and functions. The results of this reporting and analysis are summarized in the following subsections.

3.5.1 Build Metrics

Build Metrics were reported on a quarterly basis as outlined in the MBRP. The list of reported metrics was approved by the DOE and is listed in Appendix A. The final cumulative build metrics were submitted on October, 31, 2014 for the quarter ending September 30, 2014. All submitted build metrics, including baselines, can be found in Appendix S.

3.5.1.1 Build Metrics Calculations

The following tables list the calculated values for each of the reported build metrics along with the method used to calculate them.

Table 3-154: Build Metrics for KCP&L's AMI Assets

Metric	Units	Final Reported Value		Calculation
		Project	System	
End-Points (meters)	# endpoints	13,483	231,571	Count of Normal meters from AMI Head-End
Portion of Customers with AMI: residential	# endpoints	12,259	207,674	Count of Normal meters in residential rate classes from AMI Head-End
Portion of Customers with AMI: commercial	# endpoints	1,224	23,399	Count of Normal meters in commercial rate classes from AMI Head-End
Portion of Customers with AMI: industrial	# endpoints	0	498	Count of Normal meters in industrial rate classes from AMI Head-End
Reading interval for meters	minutes	15	15	N/A
Remote Connect/Disconnect	Yes/No # endpoints	Yes 13,003	Yes 26,904	Count of Normal meters from AMI Head-End that have this capability, based on meter model
Outage Reporting	Yes/No # endpoints	Yes 13,483	Yes 231,571	Count of Normal meters from AMI Head-End – All of the KCP&L installed AMI meters have this capability
Power Quality Measurement	Yes/No # endpoints	No	No	N/A
Tamper Detection	Yes/No # endpoints	Yes 13,483	Yes 231,571	Count of Normal meters from AMI Head-End – All of the KCP&L installed AMI meters have this capability

Metric	Units	Final Reported Value		Calculation
		Project	System	
Integration with Billing System	Yes/No Description	Yes AMI is integrated with enterprise Oracle CIS.	Yes AMI is integrated with enterprise Oracle CIS.	N/A
Integration with Customer Information System	Yes/No Description	Yes AMI is integrated with KCP&L enterprise Oracle CIS. The project AMI was incorporated into the existing AMR – CIS interfaces. CIS daily account/meter synchronization. AMI provides CIS daily register meter reads for direct billing. CIS daily billing cycle-to-date usage info and bill prediction pushed to IHDs via AMI Network.	Yes AMI is integrated with KCP&L enterprise Oracle CIS. The project AMI was incorporated into the existing AMR – CIS interfaces. CIS daily account/meter synchronization. AMI provides CIS daily register meter reads for direct billing. CIS daily billing cycle-to-date usage info and bill prediction pushed to IHDs via AMI Network.	N/A
Integration with Outage Management System	Yes/No Description	Yes AMI is integrated with enterprise OMS. An additional project OMS (redundant) will also be implemented in conjunction with a DMS. The project AMI was incorporated into the existing AMR to enterprise OMS interfaces including meter outage alerts and meter “ping” functionality to verify power restoration.	Yes AMI is integrated with enterprise OMS. An additional project OMS (redundant) will also be implemented in conjunction with a DMS. The project AMI was incorporated into the existing AMR to enterprise OMS interfaces including meter outage alerts and meter “ping” functionality to verify power restoration.	N/A

Metric	Units	Final Reported Value		Calculation
		Project	System	
Integration with Distribution Management System	Yes/No Description	Yes DMS is integrated with multiple project and legacy systems including AMI, DERM, OMS, and energy storage.	Yes DMS is integrated with multiple project and legacy systems including AMI, DERM, OMS, and energy storage.	N/A
Integration with Other Enterprise System	Yes/No Description	Yes Data Mining and Analysis Tool covered by the MDA	Yes Data Mining and Analysis Tool covered by the MDA	N/A
Backhaul Network	Description	Hybrid of Fiber and Wireless Raven radio with network carrier	Hybrid of Fiber and Wireless Raven radio with network carrier	N/A
Meter Communication Network	Description	Landis+Gyr Gridstream RF 900MHz - Collectors and Routers	Landis+Gyr Gridstream RF 900MHz - Collectors and Routers	N/A
Head-end System	Description	Landis+Gyr Command Center	Landis+Gyr Command Center	N/A
Meter Data Management System	Description	eMeter/Siemens	eMeter/Siemens	N/A
Meter Data Analysis System	Description	The project AMI was incorporated into the existing AMR – MDA interfaces. AMI daily register reads and 15-min interval reads are loaded into MDA on a daily basis.	The project AMI was incorporated into the existing AMR – MDA interfaces. AMI daily register reads and 15-min interval reads are loaded into MDA on a daily basis.	N/A
		Project Funded	Cost Share	
Back Office Systems Cost	\$	\$2,337,739	\$2,157,913	Costs associated with installation of the AMI meter software and MDM system
Communications Equipment Cost	\$	\$119,308	\$110,130	Costs associated with installation of the AMI network
AMI Smart Meters Cost	\$	\$2,252,704	\$2,076,390	Costs associated with purchase of the AMI meters

Table 3-155: Build Metrics for KCP&L's Customer System Assets

Metric	Units	Final Reported Value		Calculation
		Project	System	
In-Home Displays	# devices Description	616 Tendril InSight	616 Tendril InSight	Count of Normal devices from AMI Head-End
Direct Load Control Devices	# devices Description	131 Tendril Volt	131 Tendril Volt	Count of Normal devices from AMI Head-End
Programmable Communicating Thermostats	# devices Description	112 Tendril Setpoint	53,824 Tendril Setpoint and Honeywell PCTs	Count of Normal devices from AMI Head-End for project. System includes KCP&L thermostat program.
Smart Appliances	# devices Description	0	0	N/A
Energy Management Devices/Systems	# devices Description	0	0	N/A
Home Area Network Gateways	# devices Description	61 Tendril Transport Gateway	61 Tendril Transport Gateway	Count of Normal devices from AMI Head-End
Home Area Network	Description	ZigBee SEP 1.0	ZigBee SEP 1.0	N/A
Web Portal	# w/access # active acct Description	12,036 2,109 Tendril Energize Web Portal	12,036 2,109 Tendril Energize Web Portal	Count of customers with access and active accounts from enrollment tracking.
		Project Funded	Cost Share	
Back Office Systems Cost	\$	\$441,625	\$406,255	Costs associated with installation of the back office systems
Web Portals Cost	\$	\$940,730	\$868,293	Costs associated with installation and maintenance of the web portal
In-Home Displays Cost	\$	\$155,669	\$143,694	Costs associated with purchase and installation of the IHDs
Direct Load Control Devices Cost	\$	\$90,344	\$83,395	Costs associated with purchase and installation of the DLC devices
Smart Appliances Cost	\$	\$0	\$0	N/A
Programmable Communicating Thermostats Cost	\$	\$378,345	\$335,076	Costs associated with purchase and installation of the PCTs
Home Area Network Gateways Cost	\$	\$228,510	\$204,484	Costs associated with purchase and installation of the HAN Gateways
Other Costs	\$	\$390,761	\$357,473	Program delivery costs including KCP&L labor for program administration, analysis, and customer engagement as well as vendor travel expenses.

Table 3-156: Build Metrics for KCP&L's Pricing Programs

Metric	Units	Final Reported Value		Calculation
		Project	System	
Flat Rate	Yes/No # with access # enrolled Description	No N/A N/A	Yes N/A 162,409 KCP&L has multiple residential and C&I Flat Rates that occur during both summer and winter.	Not able to calculate how many customers have access. Count of customers with Flat Rate codes from system query.
Flat Rate with Critical Peak Pricing	Yes/No	No	No	N/A
Flat Rate with Peak-Time Rebate	Yes/No	No	No	N/A
Tiered Rate	Yes/No # with access # enrolled Description	No	Yes N/A 694,691 KCP&L has multiple existing residential and C&I Tiered Rates. A majority of those are declining block rates.	Not able to calculate how many customers have access. Count of customers with Tiered Rate codes from system query.
Tiered Rate with Critical Peak Pricing	Yes/No	No	No	N/A
Tiered Rate with Peak-Time Rebate	Yes/No	No	No	N/A
Time-of-Use Rate	Yes/No # with access # enrolled Description	Yes 12,259 102 A new residential TOU rate is being piloted as part of this project to augment the evaluation of customer information systems and control devices.	Yes N/A 341 KCP&L has multiple existing residential and C&I TOU Rates.	For project, all residential AMI customers have access. Not able to calculate how many customers have access for system. Count of customers with TOU Rate codes from system query.
Time-of-Use Rate with Critical Peak Pricing	Yes/No	No	No	N/A
Time-of-Use Rate with Peak-Time Rebate	Yes/No	No	No	N/A

Metric	Units	Final Reported Value		Calculation
		Project	System	
Real-Time Pricing	Yes/No # with access # enrolled Description	No	Yes N/A 9 KCP&L has multiple existing RTP rates for commercial and industrial customers.	Not able to calculate how many customers have access. Count of customers with RTP Rate codes from system query.
Real-Time Pricing with Critical Peak Pricing	Yes/No	No	No	N/A
Real-Time Pricing with Peak Time Rebate	Yes/No	No	No	N/A
Variable Peak Pricing	Yes/No	No	No	N/A
Pre-Pay Pricing	Yes/No	No	No	N/A
Net Metering	Yes/No # with access # enrolled Description	No	Yes N/A 2,336 KCP&L has multiple existing residential and C&I Net Metering Rates.	Not able to calculate how many customers have access. Count of customers with Net Metering Rate codes from system query.
Rate Decoupling	Yes/No	No	No	N/A

Table 3-157: Build Metrics for KCP&L's Distributed Energy Resources

Metric	Units	Final Reported Value		Calculation
		Project	System	
Distributed Gen.: Number of Units Distributed Gen.: Installed Capacity Distributed Gen.: Total Energy Delivered	# MW MWh	9 176.11 28,310.57	2,361 46,055.126 N/A	Project numbers are for project solar PV systems. System numbers include solar PV and wind systems throughout the KCP&L and KCP&L-GMO region.
Energy Storage: Number of Units Energy Storage.: Installed Capacity Energy Storage: Total Energy Delivered	# MW MWh	1 1,000 45,645.32	1 1,000 45,645.32	Calculations for the 1 battery system installed as part of this project. No additional systems have been installed.
PEV Charging: Number of Units PEV Charging: Installed Capacity PEV Charging: Total Energy Delivered	# points MW MWh	19 133.2 3,738	57 370.8 10,049	Project numbers include the 10 EV charging stations in the Green Impact Zone. System numbers also include all KCP&L-owned charging stations throughout the KC metro area.

Metric	Units	Final Reported Value		Calculation
		Project	System	
DG (DER) Interconnection equipment	# of units	0	0	N/A
Distributed Gen. Interface	Description	All DG installed is non-dispatchable utility-owned PV that is being metered separately. All project EV chargers are installed behind customer meters. Most interfaces currently limited to measuring data. EV chargers may be remotely deactivated to curtail load.	Non-dispatchable utility-owned DG and EV Chargers. All EV chargers are installed behind customer meters. Most interfaces currently limited to measuring data. EV chargers may be remotely deactivated to curtail load.	N/A
		Project Funded	Cost Share	
DER Interface Control Systems Cost	\$	\$2,585,472	\$2,183,009	Costs associated with installation of the DERM.
Communications Equipment Cost	\$	\$0	\$0	N/A
DER/DG Interconnection Equipment Cost	\$	\$0	\$0	N/A
Renewable DER Cost	\$	\$668,165	\$541,403	Costs associated with installation of the solar PV systems.
Distributed Gen. Equipment Cost	\$	\$0	\$0	N/A
Stationary Electric Storage Equipment Cost	\$	\$4,017,795	\$3,708,112	Costs associated with installation of the battery energy storage system.
PEVs and Charging Stations Cost	\$	\$71,089	\$60,207	Costs associated with installation of the EV charging stations.
Other Costs		\$0	\$0	N/A

Table 3-158: Build Metrics for KCP&L's Distribution System Assets

Metric	Units	Final Reported Value		Calculation
		Project	System	
Portion of System with SCADA	% Description	100% Distribution SCADA has been deployed to all field devices in the project area.	10.5% The ABB Network Manager (EMS) communicates with 70% of feeder breakers, but only 15% of those have communications capable of supporting Smart Grid functionality.	N/A
Portion of System with Distribution Automation (DA)	% Description	100% DA capabilities are installed on all project circuits.	85% KCP&L has locally automated devices such as capacitors, voltage monitors, faulted circuit indicators, and reclosers across the distribution system. 85% represents an estimate of coverage based on number of circuits with one or more of these devices.	N/A
Automated Feeder Switches	# devices	20	117	Count of installed devices.
Automated Capacitors	# devices	29	2,342	Count of installed devices.
Automated Regulators	# devices	0	3	Count of installed devices.
Feeder Monitors	# devices	0	0	N/A
Remote Fault Indicators	# devices	96	325	Count of installed devices.
Transformer Monitors (line)	# devices	0	0	N/A
Smart Relays	# devices	63	2,277	Count of installed devices.
Fault Current Limiter	# devices	0	0	N/A

Metric	Units	Final Reported Value		Calculation
		Project	System	
SCADA	Description	Distribution SCADA in conjunction with project DMS/OMS, includes a Tropos wireless network to reach devices outside the substation.	ABB Network Manager (EMS) across system plus project Distribution SCADA.	N/A
DA Devices	Description	There is a mix of communicating and automated capacitors, faulted circuit indicators, and reclosers across the project area.	There is a mix of locally automated capacitors, voltage monitors, faulted circuit indicators, and reclosers across distribution system.	N/A
DA Communications Network	Description	Tropos GridCom wireless IP mesh network	Landis+Gyr AMR system and Telemetric/Sensu s cellular-based system.	N/A
Fault Location, Isolation and Service Restoration (FLISR)	Yes/No Description	No As part of the project, the DMS enables FLISR across project circuits. This will reduce outages and outage response time, and improve overall system performance.	No As part of the project, the DMS enables FLISR across project circuits. This will reduce outages and outage response time, and improve overall system performance.	N/A

Metric	Units	Final Reported Value		Calculation
		Project	System	
Voltage Optimization	Yes/No Description	Yes As part of the project, the DMS enables voltage optimization across project circuits. This will improve power factor as well as enable voltage conservation.	Yes A Dynamic Voltage Control (DVC) system exists on 203 buses within metropolitan Kansas City. This system is able to dynamically reduce voltage through load tap changers to achieve voltage changes in coordination with locally controlled cap banks.	N/A
Feeder Peak Load Management	Yes/No Description	No As part of the project, the DMS enables dynamic feeder load transfer across project circuits. This will reduce outages on project feeders, reduce stress on critical assets, and improve maintenance.	No System peak loads are curtailed through utilization of the DVC system and existing PCT program operated by Honeywell.	N/A
Microgrids	Yes/No Description	No	No	N/A
Integration with AMI	Yes/No Description	Yes DMS is integrated with project AMI.	Yes DMS is integrated with project AMI.	N/A
Integration with Outage Management System	Yes/No Description	Yes DMS is integrated with project OMS.	Yes DMS is integrated with project OMS.	N/A
Integration with Transmission Management System	Yes/No Description	No	No	N/A
Integration with Distributed Energy Resources	Yes/No Description	No DMS is integrated with project DERM.	No DMS is integrated with project DERM.	N/A

Metric	Units	Final Reported Value		Calculation
		Project	System	
Distribution Management System	Description	DMS consisting of D-SCADA and DNA provided by Siemens and OMS and user interface provided by Intergraph.	DMS consisting of D-SCADA and DNA provided by Siemens and OMS and user interface provided by Intergraph.	N/A
		Project Funded	Cost Share	
Back Office Systems Cost	\$	\$372,159	\$343,106	Costs associated with installation of the back office systems.
Distribution Management System Cost	\$	\$4,338,858	\$3,436,891	Costs associated with installation of the DMS.
Communications Equipment and SCADA Cost	\$	\$959,422	\$885,621	Costs associated with the installation of the communications equipment and SCADA.
Feeder Monitor/Indicator Cost	\$	\$26,079	\$23,876	Costs associated with the installation of the feeder monitors/indicators.
Substation Monitors Cost	\$	\$1,244,388	\$1,141,646	Costs associated with the installation of the substation monitors.
Automated Feeder Switches Cost	\$	\$690,574	\$632,255	Costs associated with the installation of the automated feeder switches.
Capacitor Automation Equipment Cost	\$	\$72,896	\$66,740	Costs associated with the installation of the capacitor automation equipment.
Regulator Automation Equipment Cost	\$	\$0	\$0	N/A
Fault Current Limiter Equipment Cost	\$	\$0	\$0	N/A
Other Costs	\$	\$377,579	\$339,818	KCP&L labor charges across various devices types.

3.5.2 Impact Metrics

Impact Metrics were reported on a semiannual basis as outlined in the MBRP. The list of reported metrics was approved by the DOE and is listed in Appendix A. The final semiannual impact metrics were submitted on October, 31, 2014 for the 6-month period ending September 30, 2014. All submitted impact metrics can be found in Appendix T.

3.5.2.1 Impact Metrics/Benefits Calculations

The following tables list the calculated values for each of the reported impact metrics along with the method used to calculate them.

Table 3-159: Impact Metrics for KCP&L's AMI and Customer Systems

Metric	Units	Final Reported Value		Calculation
		Project	System	
Hourly Customer Electricity Usage: Residential	kWh \$/kWh	Reported in a separate file	N/A	Hourly average residential customer load data were calculated by aggregating all Normal AMI meters in residential rate classes in the project area
Hourly Customer Electricity Usage: Commercial	kWh \$/kWh	Reported in a separate file	N/A	Hourly average commercial customer load data were calculated by aggregating all Normal AMI meters in commercial rate classes in the project area
Monthly Customer Electricity Usage: Residential	kWh \$/kWh	Reported in a separate file	N/A	Total monthly residential customer load data were calculated by aggregating all Normal AMI meters in residential rate classes in the project area
Monthly Customer Electricity Usage: Commercial	kWh \$/kWh	Reported in a separate file	N/A	Total monthly residential customer load data were calculated by aggregating all Normal AMI meters in residential rate classes in the project area
Peak Load: Total Amount	MW	49.4753562	N/A	Total maximum hourly MW load for the 6 month period, as determined from hourly aggregation of load data
Peak Load: Residential	MW	26.9865111	N/A	Residential component of total MW load at peak date and time
Peak Load: Commercial	MW	22.4888451	N/A	Commercial component of total MW load at peak date and time
Peak Load: Date and Time	Date/Time	8/25/2014 5:00:00 PM	N/A	Date and time at which the maximum hourly MW load occurred
Peak Load Mix: Direct Load Control Available	MW	N/A	N/A	N/A
Number of Meter Tamper Detections	# identified # confirmed	N/A	N/A	N/A
Meter Operations Cost	\$	167,090.10	N/A	AMI operations costs for the 6 month period, including software licenses and hosting services
Truck Rolls Avoided	#	4,043	N/A	Count of avoided truck rolls for on-demand reads, remote disconnects, and remote reconnects as tracked by the RSO.

Metric	Units	Final Reported Value		Calculation
		Project	System	
Meter Operations Vehicle Miles	miles	64,688	N/A	Assuming an average of 16 miles round trip per truck roll based on distance from Dotson service center. (4,043 truck rolls x 16 miles/truck roll = 64,688 miles)
SAIFI	Index	2.331273	N/A	Total number of customer interruptions divided by the total number of customers served in the project area
SAIDI	Index	235.4554	N/A	Total sum of customer interruption durations (in minutes) divided by the total number of customers served in the project area
CAIDI	Index	100.9986	N/A	Total sum of customer interruption durations (in minutes) divided by the total number of customer interruptions
SAIDI and SAIFI: Number of customers	#	13,427	N/A	Count of Normal AMI meters in the project area
Avoided CO ₂ Emissions	tons	38.46779733	N/A	8.92 × 10 ⁻³ metric tons CO ₂ /gallon of gasoline (http://www.epa.gov/cleanenergy/energy-resources/refs.html) Assuming 15 miles/gallon ((64,688 miles/15 miles/gallon) * 0.00892 tons CO ₂ /gallon = 38.46779733 tons)
Avoided Pollutant Emissions (SO _x , NO _x , PM-2.5)	tons	N/A	N/A	N/A
Meter Data Completeness	%	99.27	N/A	Calculated by taking the number of meters in Normal status divided by the number of meters deployed, according to the AHE
Meters Reporting Daily	%	99.22	N/A	Calculated by taking the number of meters with good reads on final reporting day divided by the number of meters deployed, according to the AHE

Table 3-160: Impact Metrics for KCP&L's Distribution Systems

Metric	Units	Final Reported Value		Calculation
		Project	System	
Distribution Feeder or Equipment Overload Incidents: Feeder Line	# incidents Average duration (minutes)	0 0	N/A	No incidents were reported in the project area during the 6 month period, based on a query of the OMS system
Distribution Feeder or Equipment Overload Incidents: Substation Transformer	# incidents Average duration (minutes)	0 0	N/A	No incidents were reported in the project area during the 6 month period, based on a query of the OMS system
Distribution Feeder Load: Aggregated Average Load	MW MVAR	N/A	N/A	N/A
Distribution Feeder Load: Hourly Load Curves	MW MVAR	Reported in a separate file	N/A	Hourly MW data was extracted from the DMAT for each feeder
Deferred Distribution Capacity Investments	\$ years	N/A	N/A	N/A
Equipment Failure Incidents: Transformers	# incidents Reasons for failures	0 N/A	N/A	No incidents were reported in the project area during the 6 month period, based on a query of the OMS system
Equipment Failure Incidents: Feeders	# incidents Reasons for failures	3 Failure Wear	N/A	3 incidents of Failure Wear were reported in the project area during the 6 month period, based on a query of the OMS system
Equipment Failure Incidents: Other Distribution Equipment	# incidents Reasons for failures	N/A	N/A	No incidents were reported in the project area during the 6 month period, based on a query of the OMS system N/A
Truck Rolls Avoided	# truck rolls	N/A	N/A	N/A
SAIFI	Index	2.331273	N/A	Total number of customer interruptions divided by the total number of customers served in the project area
SAIDI	Index	235.4554	N/A	Total sum of customer interruption durations (in minutes) divided by the total number of customers served in the project area
CAIDI	Index	100.9986	N/A	Total sum of customer interruption durations (in minutes) divided by the total number of customer interruptions
SAIDI and SAIFI: Number of customers	#	13,427	N/A	Count of Normal AMI meters in the project area

Metric	Units	Final Reported Value		Calculation
		Project	System	
Major Event Information	Event Statistics	N/A	N/A	No major events were reported in the project area during the 6 month period, based on a query of the OMS system
Avoided Distribution Operations Vehicle Miles	miles	N/A	N/A	N/A
Avoided CO ₂ Emissions	tons	N/A	N/A	N/A

Table 3-161: Impact Metrics for KCP&L's Storage Systems

Metric	Units	Final Reported Value		Calculation
		Project	System	
Annual Storage Dispatch	kWh	95,864	N/A	Total electricity discharged from the storage system for the 6 month period ending 9/30/14, based on summation of 15-minute interval reads from DMAT.
Average Energy Storage Efficiency	%	69.34	N/A	Roundtrip efficiency for the storage system for the 6 month period ending 9/30/14, based on summation of 15-minute interval reads from DMAT.

3.6 BENEFITS ANALYSIS

The SGDP operational demonstrations and testing, outlined in the previous section, were performed to not only demonstrate the SmartGrid Functions achievable through end-to-end interoperability, but to also capture and quantify the operational benefits achievable by each of the SmartGrid applications. The KCP&L Demonstration used the DOE-developed Smart Grid Computational Tool (SGCT) and Energy Storage Computational Tool (ESCT) to evaluate the overall costs and benefits of the demonstrated SmartGrid technologies and functions. The results of this benefits analysis are summarized in the following subsections.

3.6.1 Smart Grid Computational Tool Analysis

Using the SGCT, the SGDP team: 1) identified the Smart Grid Assets deployed; 2) identified the Smart Grid Functions that the demonstration would enable; and 3) for each Function, identified the applicable benefit mechanisms. Based on these inputs, the SGCT identified the expected benefits the project could achieve. The SGDP team identified several additional function benefits not identified by the SGCT that it was able to quantify. Table 3-162 identifies the project benefits by Smart Grid Function used in the SGCT analysis. The benefit areas quantified by the project and included in the benefit analysis are highlighted in green. All entry and output screens for the SGCT analysis were captured and can be found in Appendix U.

Table 3-162: SGCT Function Benefit Chart for KCP&L SmartGrid Demonstration Project

Benefits			Smart Grid Functions								
			Delivery						Use	Other	
			Automated Feeder and Line Switching	Automated Islanding and Reconnection	Automated Voltage and VAR Control	Diagnosis & Notification of Equipment Condition	Real-Time Load Measurement & Management	Real-time Load Transfer	Customer Electricity Use Optimization	Storing Electricity for Later Use	Distributed Production of Electricity
Economic	Improved Asset Utilization	Optimized Generator Operation			YES					YES	YES
		Deferred Generation Capacity Investments			YES				YES	YES	YES
		Reduced Ancillary Service Cost									
		Reduced Congestion Cost									
	T&D Capital Savings	Deferred Transmission Capacity Investments									
		Deferred Distribution Capacity Investments			YES		YES			YES	YES
		Reduced Equipment Failures				YES					
	T&D O&M Savings	Reduced T&D Equipment Maintenance Cost									
		Reduced T&D Operations Cost	YES								
		Reduced Meter Reading Cost					YES				
	Theft Reduction	Reduced Electricity Theft					YES				
Reliability	Power Interruptions	Reduced Sustained Outages	YES	YES		YES	YES			YES	YES
		Reduced Major Outages		YES			YES	YES			
		Reduced Restoration Cost	YES			YES	YES				
	Power Quality	Reduced Momentary Outages									
		Reduced Sags and Swells									
	Air Emissions	Reduced CO2 Emissions	YES				YES	YES	YES	YES	YES
		Reduced SOx, NOx, and PM-2.5 Emissions	YES				YES	YES	YES	YES	YES
	Energy Security	Reduced Oil Usage (not monetized)	YES				YES				
		Reduced Wide-scale Blackouts									

3.6.1.1 Input Parameters

The SGCT uses two different types of data to calculate benefits, baseline data and project data. All benefit assumptions rely on the calculated difference between baseline and project data at a given point in time. Due to the nature of the SGDP, the benefits analysis for most operational demonstrations quantified most benefits as avoided costs. Using the Mirror inputs capability of the SGCT, the avoided costs were entered into the tool as negative values. Table 3-163 lists the calculated values for each of the SGCT inputs along with the operational tests used to calculate them.

2013 was selected as the Project Start Year as it correlated closely to the project's operational Go-Live date of October 1, 2012. The majority of the benefits quantified by each of the operational demonstration analyses were based on the 2014 data. These computed values are listed in Table 3-163 and were entered as benefits for the years 2014-2017. For 2013, benefits were assumed to be 50% of the 2014 values.

Table 3-163: SGCT Input Parameters

Benefit	Input Name	Operational Test	Op. Test Value	Input Value 2014	Unit
PCM Main Data	Organization Name			KCP&L	-
	Project Name			Smart Grid Demo	-
	NERC Region			SPP	-
	Project Start Year			2013	-
DIM Step 1 Population and Tariff Data	Average Energy Rate-Res	Project Metric		0.10837	\$/kWh
	Average Demand Charge-Res	Project Metric		0	\$/kW
	Customers Served-Res	Project Impact Metric		12,204	
	Average Energy Rate-Com	Project Metric		.05692	\$/kWh
	Average Demand Charge-Com	Project Metric		2.65	\$/kW
	Customers Served-Com	Project Impact Metric		1,223	
	Average Energy Rate-Ind	n/a		.05692	\$/kWh
	Average Demand Charge-Ind	n/a		2.65	\$/kW
DIM Step 2 Escalation Factors	Customers Served-Ind	n/a		0	#
	Population Growth Factor	SGCT SPP Default		0.40	%
	Load Growth Factor	SGCT SPP Default		1.80	%
	Economic Inflation Factor	SGCT SPP Default		2.10	%
	Energy Price Factor	SGCT SPP Default		1.40	%
DIM Step 3 Cost Data Entry	Final year of benefits	SGCT SPP Default		2038	%
	Discount Rate	KCP&L Metric		6.584	%
	Use Custom Cost Schedule	n/a		YES	
	Capital Proj. Total	Project Metric	24,278,592	n/a	\$
	Levelized Fixed Charge Rate	Project Metric	14.112	n/a	%
	Annual Capital Fixed Charge	Project Metric	3,426,186	4,111,423	\$
Optimized Generator Operation	Annual Generation Cost (Avoided)	Annual Capital O&M @20%	685,237		
		Integrated Volt/VAR	(112,126)	(124,488)	\$
		Electric Energy Time Shift (BESS)	(2,963)		
		Distributed Rooftop PV	(9,399)		

Benefit	Input Name	Operational Test	Op. Test Value	Input Value 2014	Unit
Deferred Generation Capacity Investments	Energy Storage Use at Annual Peak Time	Electric Supply Capacity (BESS)	0.8	0.802	MW
		TOU Energy Cost Management (PESS)	.002		
	Distributed Generation Use at Annual Peak Time	Distributed Rooftop PV	.0745	0.0745	MW
	Total Customer Peak Demand (Avoided)	Integrated Volt/VAR	(0.559)	(0.583)	MW
		Home Area Network	0		
		Time of Use Rates	(.024)		
	Price of Capacity at Annual Peak	SGCT Default Value	95,700	95,700	\$/MW
Deferred Distribution Capacity Investments	Capital Carrying Charge of Distribution Upgrade	Integrated Volt/VAR	178,471	338,743	\$
		T&D Upgrade (BESS)	159,634		
		TOU Energy Cost Management (PESS)	638		
		Real Time Load Transfer	0		
	Distribution Investment Time Deferred	Integrated Volt/VAR	5	5	yrs
		T&D Upgrade (BESS)	5		
		TOU Energy Cost Management (PESS)	5		
		Real Time Load Transfer	0		
Reduced Equipment Failures	Capital Replacement of Failed Equipment	Asset Condition Monitoring	1,250,000	1,250,000	\$
	Portion Caused by Lack of Condition Diagnosis	Asset Condition Monitoring	100	100	%
Reduced T&D Operations Cost	Distribution Feeder Switching Operations (Avoided)	Real Time Load Transfer	0	0	\$
	Distribution Capacitor Switching Operations (Avoided)	Integrated Volt/VAR	n/a	0	\$
	Other Distribution Operations Costs (Avoided)	Auto. Feeder Switching	(901.25)	(901.25)	\$
Reduced Meter Reading Cost	Meter Operations Cost (Avoided)	Automated Meter Reading	(63,380)	(167,500)	\$
		Remote Connect Disconnect	(104,120)		
Reduced Electricity Theft	Number of Meter Tamper Detections – Residential	Automated Meter Reading	10	10	#
	Number of Meter Tamper Detections – Commercial	n/a	0	0	#
	Number of Meter Tamper Detections – Industrial	n/a	0	0	#
	Average Annual Customer Electricity Usage – Residential	Project Impact Metric	7,982	7,982	kWh
	Average Annual Customer Electricity Usage – Commercial	Project Impact Metric	89,715	89,715	kWh
	Average Annual Customer Electricity Usage – Industrial	Project Impact Metric	0	0	kWh

Benefit	Input Name	Operational Test	Op. Test Value	Input Value 2014	Unit
Reduced Electricity Losses	Distribution Feeder Load	Integrated Volt/VAR	0	0	MVA
	Distribution Losses	Integrated Volt/VAR	0	0	%
		Real Time Load Transfer	0		
	Average Price of Wholesale Energy	2014 SPP DAH Market	.03321	.03321	\$/kWh
Reduced Electricity Cost	Total Residential Electricity Cost (Avoided)	Integrated Volt/VAR	(172,072)	(180,073)	\$
		TOU Energy Cost Management (PESS)	(495)		
		Historical Interval Usage	0		
		In Home Display	0		
		Home Area Network	0		
		Time of Use Rates	(7,506)		
	Total Comm. Electricity Cost	Integrated Volt/VAR	(101,799)	(101,799)	\$
	Total Industrial Electricity Cost	n/a	0	0	\$
Reduced Sustained Outages	SAIDI (Baseline)	Auto. Feeder Switching	3.025	3.025	Hrs
	SAIDI (Project)	Auto. Feeder Switching	1.966	1.966	
	Total Residential Customers Served by Impacted Feeders or Lines	Project Impact Metric	12,204	12,204	#
	Total Commercial Cust. Served by Impacted Feeders or Lines	Project Impact Metric	1,223	1,223	#
	Total Industrial Customers Served by Impacted Feeders or Lines	Project Impact Metric	0	0	#
	Outage Time of Major Outage – Commercial	n/a	0	0	hr
	Number of Customers Affected by Major Outage – Commercial	n/a	0	0	#
	Outage Time of Major Outage – Industrial	n/a	0	0	hr
	Number of Customers Affected by Major Outage – Industrial	n/a	0	0	#
Reduced Sustained Outages & Reduced Major Outages	Value of Service – Residential	KCP&L Metric	2.27	2.27	\$/kWh
	Value of Service – Commercial	KCP&L Metric	97.30	97.30	\$/kWh
	Value of Service – Industrial	SGCT Default Value	17.33	17.33	\$/kWh
	Average Hourly Load Not Served During Outage per Customer – Residential	Project Impact Metric	0.91119	0.91112	kW
	Average Hourly Load Not Served During Outage per Customer – Commercial	Project Impact Metric	10.24124	10.24124	kW
	Average Hourly Load Not Served During Outage per Customer – Industrial	Project Impact Metric	0	0	kW
Reduced Restoration Cost	Number of Outage Events (Avoided)	Auto. Feeder Switching	(77)	(77)	# of events
	Restoration Cost per Event	KCP&L Metric	260	260	\$/event

Benefit	Input Name	Operational Test	Op. Test Value	Input Value 2014	Unit
Reduced CO ₂ Emissions, Reduced SO _x , NO _x , and PM-2.5 Emissions, & Reduced Oil Usage (not monetized)	Number of Feeder Switching or Maintenance Operations Completed (Avoided)	Auto. Feeder Switching	(77)	(77)	# of events
	Average Miles Traveled per Switching or Maintenance Operation	KCP&L Metric	20	20	miles/event
	Average Fuel Efficiency for Feeder Service Vehicle	KCP&L Metric	6.33	6.33	miles/gallon
	Number of Meter Reading Operations (Avoided)	Automated Meter Reading	(3,169)	(8,375)	# of events
		Remote Connect Disconnect	(5,206)		
	Average Miles Traveled per Meter Read	KCP&L Metric	2.2	2.2	miles/event
	Average Fuel Efficiency for Real-Time Load Measurement/ Management Service Vehicle	KCP&L Metric	11.83	11.83	miles/gallon
	kWh of Electricity Consumed by PEVs	PEV Charging	28,586	28,586	kWh
Reduced CO ₂ Emissions	Electricity to Fuel Conversion Factor	SGCT Default Value	.13	.13	gallons/kWh
	CO ₂ Emissions per Gallon of Fuel	SGCT Default Value	.0097	.0097	tons/gallon
	CO ₂ Emissions (Avoided)	Distributed Rooftop PV	(221.8)	(3,259.5)	tons
		Integrated Volt/VAR	(3,037.7)		
Reduced SO _x , NO _x , and PM-2.5 Emissions	Value of CO ₂	SGCT Default Value	20	20	\$/ton
	SO _x Emissions per Gallon of Gas	SGCT Default Value	0.000000 2237691 9593	0.000000 2237691 9593	tons/gallon
	NO _x Emissions per Gallon of Gas	SGCT Default Value	0.00017	0.00017	tons/gallon
	PM-2.5 per Gallon of Gas	SGCT Default Value	0	0	tons/gallon
	SO _x Emissions (Avoided)	Distributed Rooftop PV	(0.314)	(4.621)	tons
		Integrated Volt/VAR	(4.307)		
	NO _x Emissions (Avoided)	Distributed Rooftop PV	(0.236)	(3.475)	tons
		Integrated Volt/VAR	(3.239)		
	PM-2.5 Emissions (Avoided)	Distributed Rooftop PV	(0.00252)	(0.03703)	tons
		Integrated Volt/VAR	(0.03451)		
	Value of SO _x	SGCT Default Value	520	520	\$/ton
	Value of NO _x	SGCT Default Value	3,000	3,000	\$/ton
	Value of PM-2.5	SGCT Default Value	36,000	36,000	\$/ton

3.6.1.2 Results/Tool Output

The following tables and figures provide a summary of the SGCT benefits analysis for the SGDP. Additional analysis results can be found in Appendix U. Table 3-164 and Figure 3-231 present a summary of the cumulative gross benefits of the SGCT benefits analysis.

Table 3-164: SGCT Cumulative Gross Benefits Summary

Cumulative Gross Benefits 2013 - 2040		
Economic	\$	24,629,720
Reliability	\$	53,452,464
Environmental	\$	2,552,834
Security	\$	-
Total	\$	80,635,019

Figure 3-231: SGCT Cumulative Gross Benefits Summary

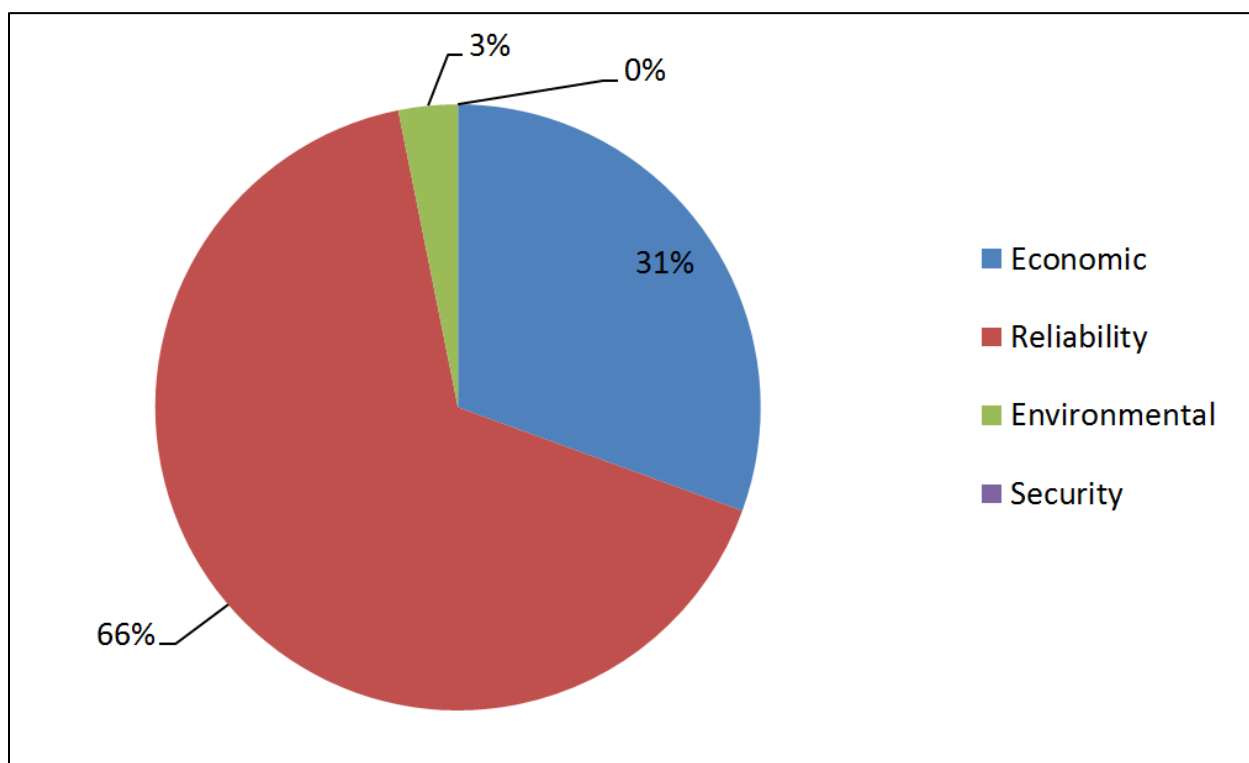


Table 3-164 and Figure 3-232 present a summary of the cumulative economic benefits of the SGCT benefits analysis.

Table 3-165: SGCT Cumulative Economics Benefits Summary

Cumulative Economic Benefits 2013 - 2040		
Improved Asset Utilization	\$	9,271,353
T&D Capital Savings	\$	1,347,714
T&D O&M Savings	\$	5,395,439
Reduced Electricity Theft	\$	101,966
Reduced Electricity Losses	\$	-
Reduced Electricity Costs	\$	8,513,248
Total	\$	24,629,720

Figure 3-232: SGCT Cumulative Economic Benefits Summary

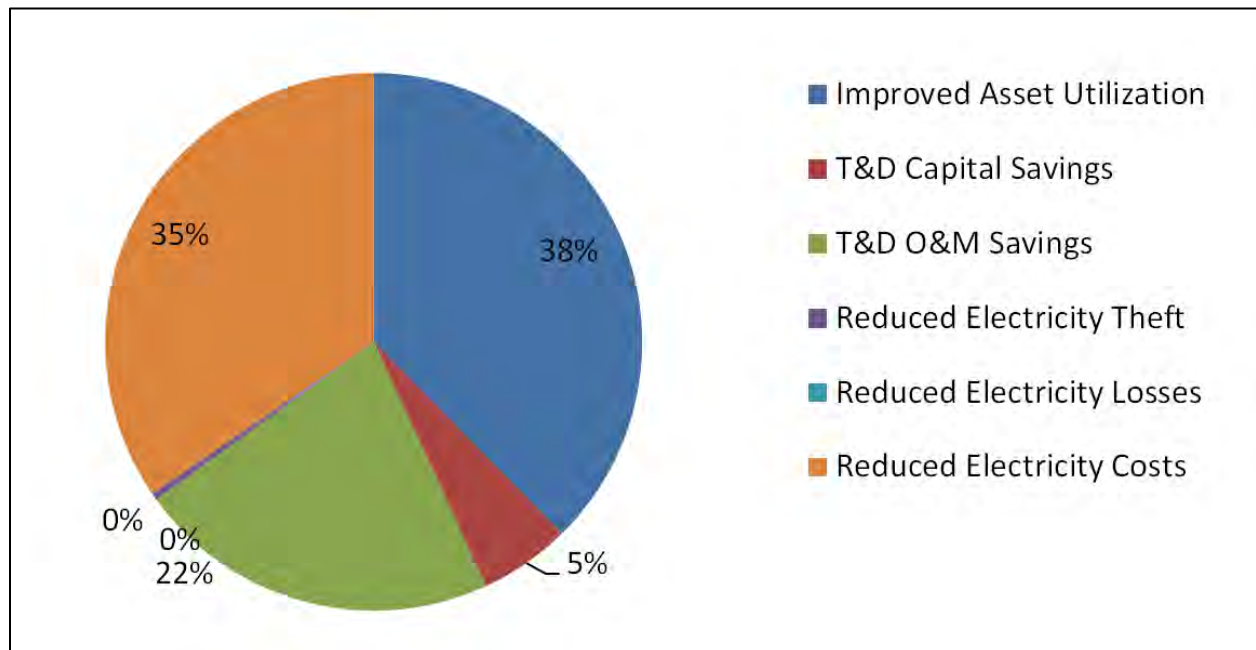


Figure 3-233 illustrates the annual PV benefits, costs, and net benefits results for the SGCT analysis.

Figure 3-233: SGCT Annual PV Benefits, Costs, and Net Benefits

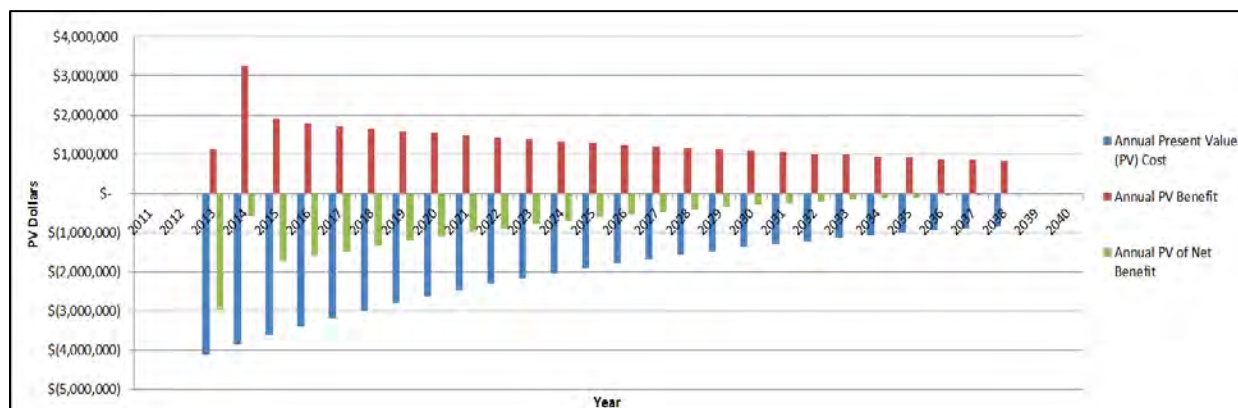
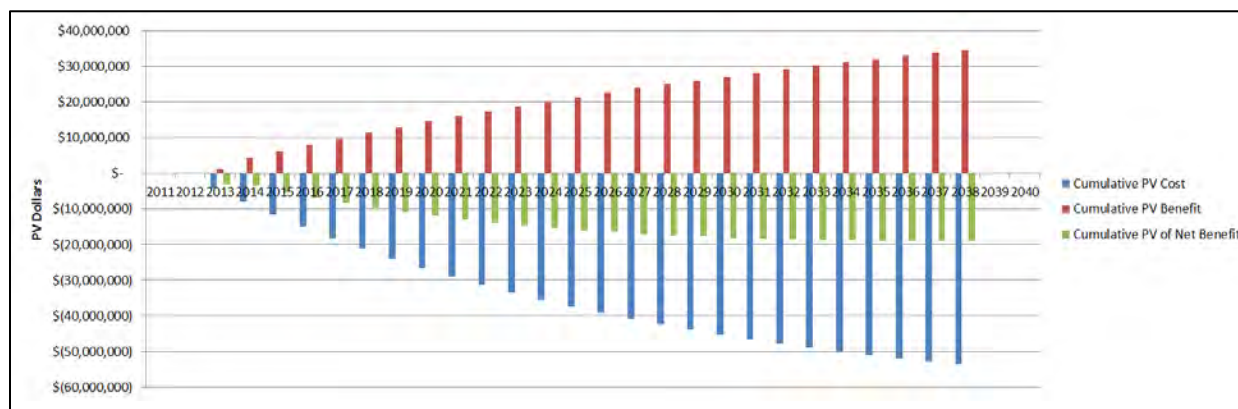


Figure 3-234 illustrates the cumulative PV benefits, costs, and net benefits results for the SGCT analysis.

Figure 3-234: SGCT Cumulative PV Benefits, Costs, and Net Benefits



3.6.1.3 Benefits Summary

The SGCT benefits analysis was performed from the holistic perspective including utility, customer, and societal benefits. Present value benefits of \$1.14 million were quantified in economic (31%), reliability (66%), and environmental (3%) benefits. But, the overall net present value of the project remained a net cost to the utility of nearly \$3 million. However, it must be noted that several of the SGDP systems (AMI, MDM, and some SmartDistribution components) were capable of supporting much larger smart grid deployments with minimal incremental cost. For these systems, a larger deployment would result in a lower cost per field unit deployed result in a more favorable analysis.

3.6.2 BESS Energy Storage Computational Tool Analysis

Using the ESCT, the project team input the energy storage asset information, grid location, market, and ownership for the BESS. Based on these inputs, the ESCT identified the expected benefits the BESS could achieve. Table 3-166 identifies the expected benefits by Energy Storage Application. The benefit areas quantified by the project and included in the benefit analysis are highlighted in green. To achieve the desired ESCT Application/Benefit combination for this specific BESS configuration required the following ESCT data entry adjustments.

- Location was set to Generation & Transmission instead of Distribution
- Deferred Distribution Investments were entered as Deferred Transmission Investments

All entry and output screens for this ESCT analysis were captured and can be found in Appendix V.

Table 3-166: ESCT Application-Benefit Matrix for KCP&L BESS Analysis

Location	Market	Owner	Application	Optimized Generator Operation	Deferred Generation Capacity Investments	Deferred Transmission Investments	Deferred Distribution Investments	Reduced Electricity Losses	Reduced Electricity Cost	Reduced CO2 Emissions	Reduced SOx Emissions	Reduced NOx Emissions	Reduced PM Emissions
Distribution	Regulated	Utility	Electric Energy Time-shift	0	0		0	0					
Distribution	Regulated	Utility	Electric Supply Capacity										
Distribution	Regulated	Utility	Transmission & Distribution (T&D) Upgrade Deferral	0	0			0		0	0	0	0

3.6.2.1 Input Parameters

Table 3-167 lists the data values for each of the ESCT inputs along with the operational tests used to calculate them.

Table 3-167: BESS – ESCT Input Parameters

Benefit	Input Name	Operational Test	Project Value	Unit
Energy Storage Location	Location	ESCT Setup	Gen & Trans	-
	Market	ESCT Setup	Regulated	-
	Owner	ESCT Setup	Utility	-
	Storage Technology	ESCT Setup	Battery-Li Ion	-
Energy Storage System Parameters	Nameplate Power Output	Project Metric	1,000	kW
	Nameplate ES Capacity	Project Metric	2,000	kWh
	ES Response Time	ESCT Default Value	0.001	seconds
	ES Round Trip Efficiency	Project Metric	75.06	%
	Nameplate Life Cycles	ESCT Default Value	4,500	cycles
	Yr. over Yr. Demand Growth	SGCT Default Value	1.8	%
	ES Reactive Power Capability	Project Metric	Yes	-
	NERC Region	Project Metric	SPP North	-

Benefit	Input Name	Operational Test	Project Value	Unit
Energy Storage Cost Parameters	Expected Lifetime	Project Metric	10	yrs
	Inflation Rate	SGCT Default Value	2.1	%
	Discount Rate	KCP&L Metric	6.584	%
	Installed Cost	ESCT Default Value	2,950,000	\$
	Fixed Charge Rate	KCP&L Metric	17.441	%
	Operating & Maintenance	ESCT Default Value	21,000	\$/yr
	Expected Decommissioning	ESCT Default Value	147,500	\$
	Initial Year of Analysis	Project Metric	2013	year
Reduced Electricity Cost	Total Energy Discharged for Energy Time-Shift	Energy Time Shift	266.68	MWh
	Average Variable Peak Generation Costs	Energy Time Shift	41.46	\$/MWh
	Average Variable Off-Peak Generation Costs	Energy Time Shift	22.78	\$/MWh
	CO2 Emissions Factor for Generation on the Margin	ESCT Default Value	1,151	lbs/MWh
	CO2 Emissions Factor for Base Generation	ESCT Default Value	2,251	lbs/MWh
	SOx Emissions Factor for Generation on the Margin	ESCT Default Value	0.012	lbs/MWh
	SOx Emissions Factor for Base Generation	ESCT Default Value	6.67	lbs/MWh
	NOx Emissions Factor for Generation on the Margin	ESCT Default Value	1.41	lbs/MWh
	NOx Emissions Factor for Base Generation	ESCT Default Value	3.73	lbs/MWh
	PM Emissions Factor for Generation on the Margin	ESCT Default Value	0.040	lbs/MWh
	PM Emissions Factor for Base Generation	ESCT Default Value	0.200	lbs/MWh
	Value of CO2	ESCT Default Value	20	\$/ton
	Value of SOx	ESCT Default Value	520	\$/ton
	Value of NOx	ESCT Default Value	3,000	\$/ton
	Value of PM	ESCT Default Value	36,000	\$/ton
Deferred Generation Capacity Investment	Generation Capacity Deferred	Electricity Supply Capacity	0.8	MW
	Capital Cost of Deferred Generation Capacity	ESCT Default Value	1,227,000	\$/MW
	Yearly O&M Costs of Deferred Generation Capacity	ESCT Default Value	14,000	\$/MW-year
	Annual Fixed Charge Rate for Generation Capital Investment	KCP&L Metric	10.470	%
	Initial Year of Generation Deferral	Electricity Supply Capacity	2014	year
	Final year of Generation Deferral	Electricity Supply Capacity	2022	year
Transmission and Distribution Upgrade Deferral	Distribution Capacity Deferred	T&D Upgrade Deferral	500	kVA
	Annual Fixed Charge Rate for Distribution Capital Investment	KCP&L Metric	10.470	%
	Capital Cost of Deferred Distribution Capacity	T&D Upgrade Deferral	319.26	\$/kVA
	Yearly O&M Costs of Deferred Distribution Capacity	KCP&L Metric	0	\$/year
	Initial Year of Distribution Deferral	T&D Upgrade Deferral	2014	year
	Final year of Distribution Deferral	T&D Upgrade Deferral	2022	year

3.6.2.2 Results/Tool Output

The following tables and figures provide a summary of the ESCT benefits analysis for the BESS. Additional analysis results can be found in Appendix V. Table 3-168 contains a summary of the ESCT benefits analysis for the BESS.

Table 3-168: BESS – ESCT Benefits Summary

Cumulative Gross Benefits over the Deployment Period		Lifetime Benefit per kW of Energy Storage Installed
Arbitrage Revenue	\$ -	\$ -
Capacity Market Revenue	\$ -	\$ -
Ancillary Services Revenue	\$ -	\$ -
Optimized Generator Operation (Non-Utility Merchant)	\$ -	\$ -
Optimized Generator Operation (Utility/Ratepayer)	\$ -	\$ -
Deferred Generation Capacity Investments	\$ 106,500	\$ 107
Reduced Congestion Costs (Non-Utility Merchant)	\$ -	\$ -
Reduced Congestion Costs (Utility/Ratepayer)	\$ -	\$ -
Deferred Transmission Investments	\$ 15,600	\$ 16
Deferred Distribution Investments	\$ -	\$ -
Reduced Electricity Losses	\$ -	\$ -
Reduced Electricity Cost (Consumer)	\$ -	\$ -
Reduced Electricity Cost (Utility/Ratepayer)	\$ 38,400	\$ 38
Reduced Outages (Consumer)	\$ -	\$ -
Reduced Outages (Utility/Ratepayer)	\$ -	\$ -
Improved Power Quality	\$ -	\$ -
Reduced Emissions	\$ -	\$ -
Total Gross Benefit	\$ 160,500	\$ 161

Figure 3-235 summarizes the cumulative BESS benefits by benefit area.

Figure 3-235: BESS–ESCT Benefit Contribution Summary

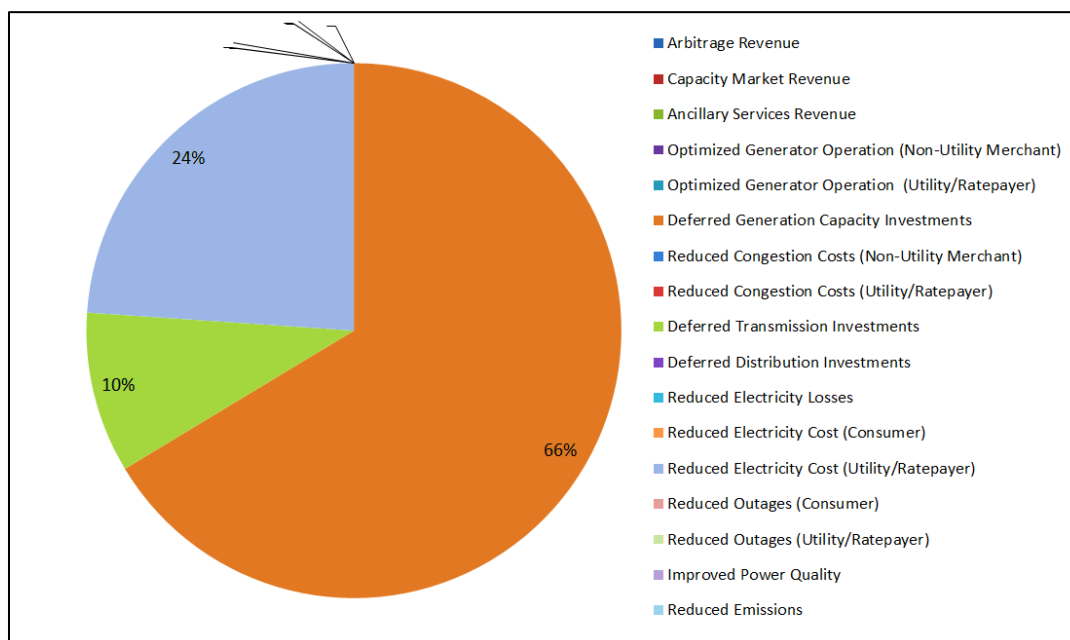


Figure 3-236 illustrates the annual benefits, costs, and net benefits results for the BESS analysis.

Figure 3-236: BESS Annual Benefits, Costs, and Net Benefits

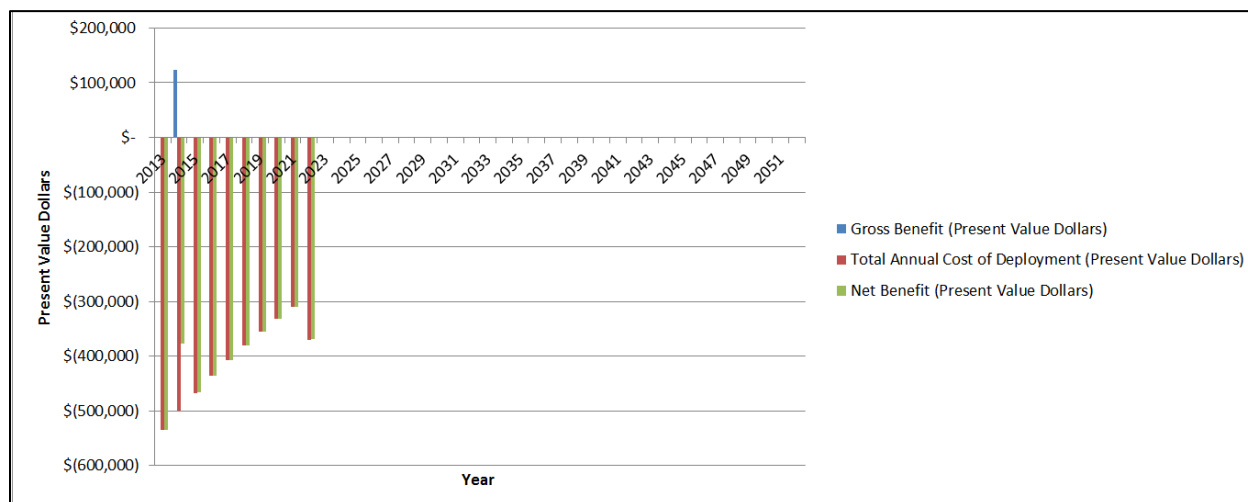
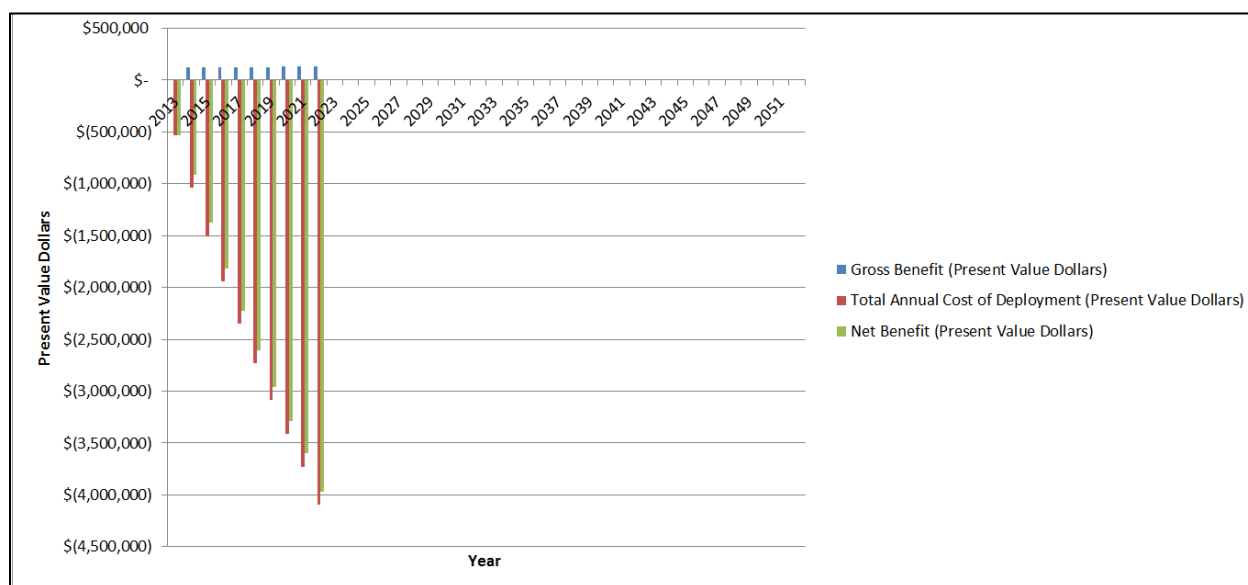


Figure 3-237 illustrates the cumulative benefits, costs, and net benefits results for the BESS analysis.

Figure 3-237: BESS Cumulative Benefits, Costs, and Net Benefits



3.6.2.3 Benefits Summary

The BESS ESCT benefits analysis was performed from the utility perspective. Utility present value benefits of \$160,500 were quantified from deferred generation capacity investments (66%), deferred distribution investments (10%), and reduced electricity costs (14%). But, the overall net present value of the BESS remained a net cost to the utility of nearly \$4 million. While it may be possible for the utility to achieve increased benefits through T&D efficiencies, the most significant components in determining the economic viability of a BESS for the utility are the upfront installed cost of the unit and the ability to derive additional benefit streams from wholesale ancillary service markets.

3.6.3 PESS Energy Storage Computational Tool Analysis

Using the ESCT, the SGDP team input the energy storage asset information, grid location, market, and ownership for the PESS. Based on these inputs, the ESCT identified the expected benefits the PESS could achieve. Table 3-169 identifies the expected benefits by Energy Storage Application. The benefit areas quantified by the project and included in the benefit analysis are highlighted in green. All entry and output screens for this ESCT analysis were captured and can be found in Appendix W.

Table 3-169: ESCT Application-Benefit Matrix for KCP&L PESS Analysis

Location	Market	Owner	Application	Optimized Generator Operation	Deferred Generation Capacity Investments	Deferred Transmission Investments	Deferred Distribution Investments	Reduced Electricity Losses	Reduced Electricity Cost (Consumer)	Reduced Outages (Consumer)	Reduced CO2 Emissions	Reduced SOx Emissions	Reduced NOx Emissions	Reduced PM Emissions
End-User	Regulated	End-User	Time-of-use (TOU) Energy Cost Management											
End-User	Regulated	End-User	Electric Service Reliability											
End-User	Regulated	End-User	Renewable Energy Time Shift											

3.6.3.1 Input Parameters

Table 3-170 lists the data values for each of the ESCT inputs along with the operational tests used to calculate them.

Table 3-170: PESS – ESCT Input Parameters

Benefit	Input Name	Operational Test	Project Value	Unit
Energy Storage Location	Location	ESCT Setup	End User	-
	Market	ESCT Setup	Regulated	-
	Owner	ESCT Setup	End User	-
	Storage Technology	ESCT Setup	Battery-Li Ion	-
Energy Storage System Parameters	Nameplate Power Output	Project Metric	6	kW
	Nameplate ES Capacity	Project Metric	11.7	kWh
	ES Response Time	ESCT Default Value	0.005	seconds
	ES Round Trip Efficiency	Project Metric	86.45	%
	Nameplate Life Cycles	ESCT Default Value	5000	cycles
	Yr. over Yr. Demand Growth	SGCT Default Value	1.8	%
	ES Reactive Power Capability	Project Metric	No	-
	NERC Region	Project Metric	SPP North	-
Energy Storage Cost Parameters	Expected Lifetime	Project Metric	10	yrs
	Inflation Rate	SGCT Default Value	2.1	%
	Discount Rate	ESCT Default Value	5.0	%
	Installed Cost	ESCT Default Value	24,000	\$
	Fixed Charge Rate	ESCT Default Value	15.0	%
	Operating & Maintenance	ESCT Default Value	126	\$/yr
	Expected Decommissioning	ESCT Default Value	885	\$
	Initial Year of Analysis	Project Metric	2014	year

Benefit	Input Name	Operational Test	Project Value	Unit
TOU Energy Cost Management	Average On-Peak Price of Electricity	KCP&L Metric	41.46	\$/MWh
	CO2 Emissions Factor for Generation on the Margin	ESCT Default Value	1,151	lbs/MWh
	SOx Emissions Factor for Generation on the Margin	ESCT Default Value	0.012	lbs/MWh
	NOx Emissions Factor for Generation on the Margin	ESCT Default Value	1.41	lbs/MWh
	PM Emissions Factor for Generation on the Margin	ESCT Default Value	0.040	lbs/MWh
	Value of CO2	ESCT Default Value	20	\$/ton
	Value of SOx	ESCT Default Value	520	\$/ton
	Value of NOx	ESCT Default Value	3,000	\$/ton
	Value of PM	ESCT Default Value	36,000	\$/ton
	Total Energy Discharged for TOU Energy Cost Management	TOU Energy Cost Management	2.913	MWh
	Average On-Peak Retail Price of Electricity	TOU Energy Cost Management	200.45	\$/MWh
	Average Off-Peak Retail Price of Electricity	TOU Energy Cost Management	26.26	\$/MWh
Electric Service Reliability	Outage Minutes Avoided by Residential Customers	Elec. Service Reliability	475.91	minutes
	Outage Minutes Avoided by Commercial Customers	n/a	0	minutes
	Outage Minutes Avoided by Industrial Customers	n/a	0	minutes
	Average Hourly Residential Load Not Served During Outage	Elec. Service Reliability	1.178	kW
	Average Hourly Commercial Load Not Served During Outage	n/a	0	kW
	Average Hourly Industrial Load Not Served During Outage	n/a	0	kW
	Residential VOS	Elec. Service Reliability	2.27	\$/kWh
	Commercial VOS	n/a	0	\$/kWh
	Industrial VOS	n/a	0	\$/kWh
Renewable Energy Time Shift	Total Renewable Energy Discharged for Energy Time-Shift	Renewable Energy Time Shift	0	MWh

3.6.3.2 Results/Tool Output

The following tables and figures provide a summary of the ESCT benefits analysis for the PESS. Additional analysis results can be found in Appendix W. Table 3-171 contains a summary of the ESCT benefits analysis for the PESS.

Table 3-171: PESS – ESCT Benefits Summary

Cumulative Gross Benefits over the Deployment Period (Present Value)		Lifetime Benefit per kW of Energy Storage Installed
Arbitrage Revenue	\$ -	\$ -
Capacity Market Revenue	\$ -	\$ -
Ancillary Services Revenue	\$ -	\$ -
Optimized Generator Operation (Non-Utility Merchant)	\$ -	\$ -
Optimized Generator Operation (Utility/Ratepayer)	\$ -	\$ -
Deferred Generation Capacity Investments	\$ -	\$ -
Reduced Congestion Costs (Non-Utility Merchant)	\$ -	\$ -
Reduced Congestion Costs (Utility/Ratepayer)	\$ -	\$ -
Deferred Transmission Investments	\$ -	\$ -
Deferred Distribution Investments	\$ -	\$ -
Reduced Electricity Losses	\$ -	\$ -
Reduced Electricity Cost (Consumer)	\$ 4,200	\$ 700
Reduced Electricity Cost (Utility/Ratepayer)	\$ -	\$ -
Reduced Outages (Consumer)	\$ 200	\$ 33
Reduced Outages (Utility/Ratepayer)	\$ -	\$ -
Improved Power Quality	\$ -	\$ -
Reduced Emissions	\$ -	\$ -
Total Gross Benefit	\$ 4,400	\$ 733

Figure 3-238 summarizes the cumulative PESS benefits by benefit area.

Figure 3-238: PESS–ESCT Benefit Contribution Summary

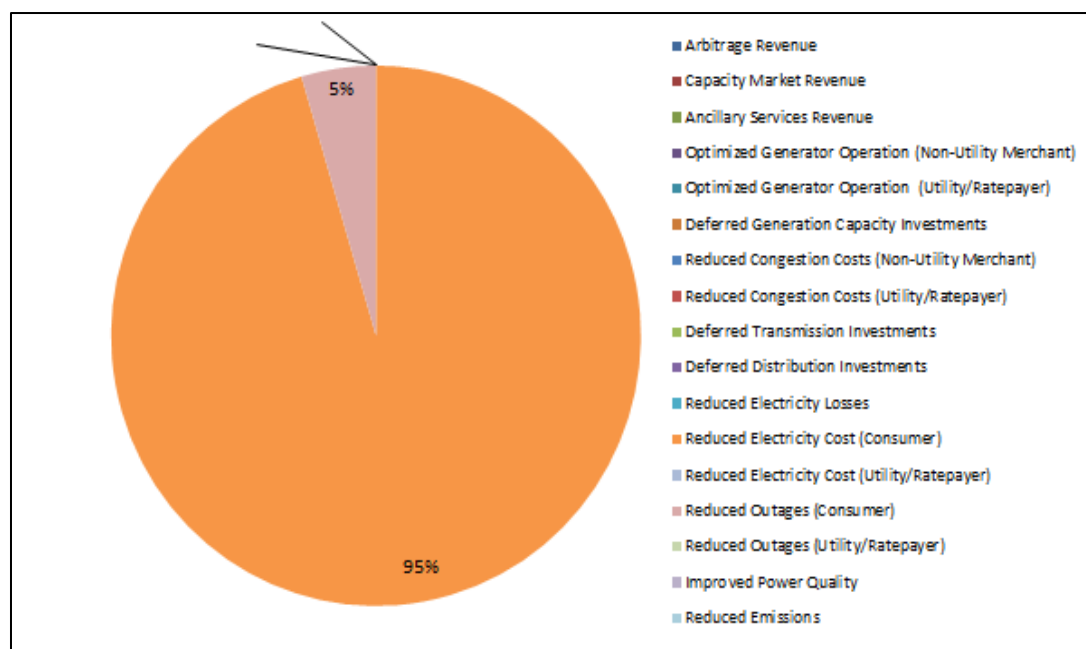


Figure 3-239 illustrates the annual benefits, costs, and net benefits results for the PESS analysis.

Figure 3-239: PESS Annual Benefits, Costs, and Net Benefits

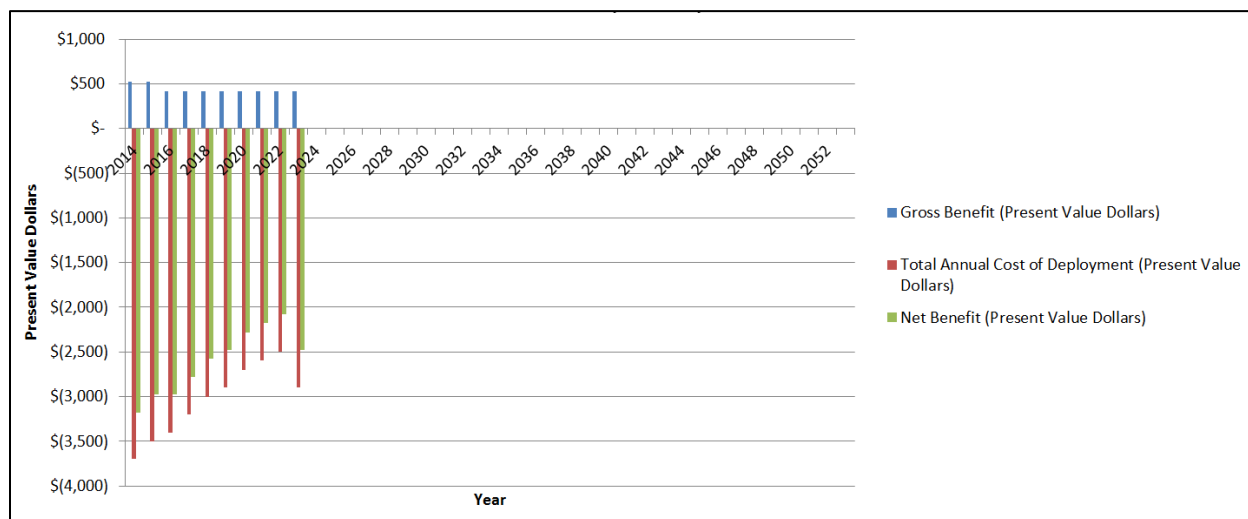
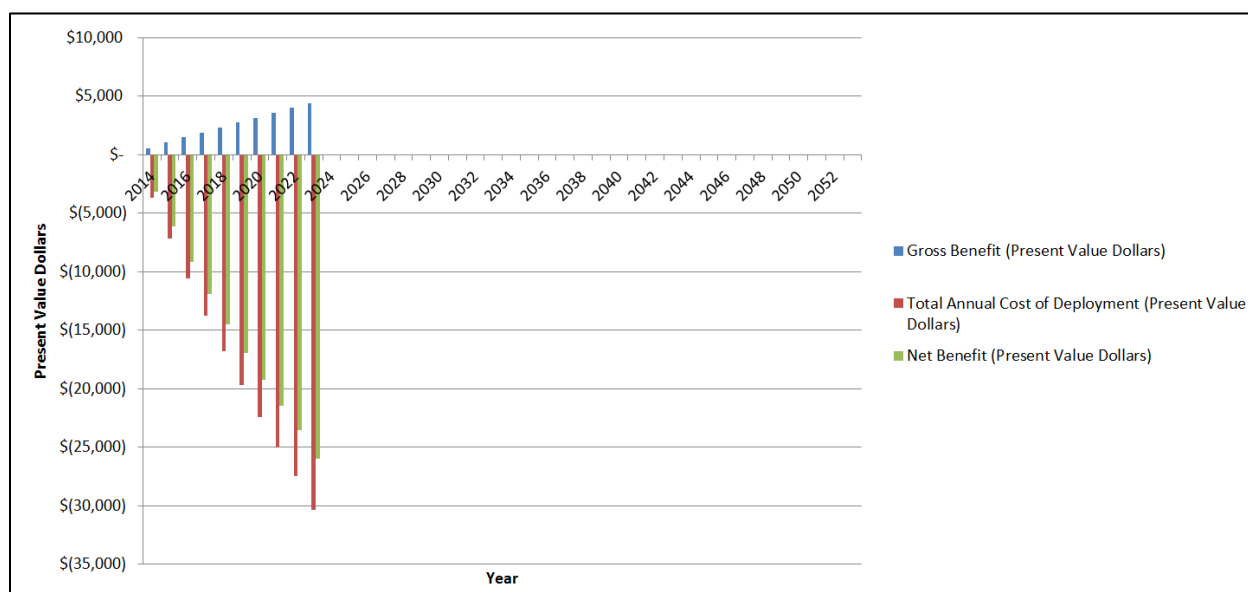


Figure 3-240 illustrates the cumulative benefits, costs, and net benefits results for the PESS analysis.

Figure 3-240: PESS Cumulative Benefits, Costs, and Net Benefits



3.6.3.3 Benefits Summary

The PESS ESCT benefits analysis was performed from the consumer perspective. Consumer benefits were quantified for reduced electricity costs (\$4,200) and reduced outages (\$200) but, the overall net present value of the PESS remained a net cost to the consumer of \$26,000. While it may be possible for the consumer to achieve increased benefits through participation in utility cost sharing or DR programs, the most significant components in determining the economic viability of a PESS for the customer are the upfront installed cost of the unit and the value of outage avoidance perceived by the customer.

4 CONCLUSIONS

The primary objectives of the KCP&L SmartGrid Demonstration Project (SGDP) were twofold: (a) to demonstrate, test, and report on the feasibility of combining, integrating, and applying existing and emerging smart grid technologies and solutions to build innovative smart grid solutions, and (b) to demonstrate, measure, and report on the costs, benefits, and business model viability of the demonstrated solutions. KCP&L has gained valuable knowledge and experience in the implementation and performance of these technologies and systems, as well as insights into the operational, consumer, environmental, and societal benefits that can be achieved. This section summarizes the project's major findings, key takeaways, and implications for future implementation of smart grid technologies at KCP&L and beyond.

4.1 SMART GRID DEMONSTRATION BENEFITS SUMMARY

Throughout the Operational Demonstrations KCP&L identified and quantified, where possible, benefits resulting from deployments of smart grid technologies and implementations of specific smart grid functions. The benefits identified will be instrumental in justifying future enterprise deployments of such smart grid technologies and functions.

4.1.1 SmartMetering Benefits

SmartMetering benefits identified during the conduct of the SGDP include:

- The AMI system established a daily register read performance rate of 99% and provided a more consistent performance throughout the year as compared to the legacy AMR system. On average, AMI performed 2 percentage points better than the AMR system, requiring fewer manual billing reads.
- The AMI infrastructure significantly outperformed the legacy AMR system for completeness of interval data, delivering 99.96% of interval usage data.
- The AMI system significantly outperformed the legacy AMR system by delivering "Power Outage" alerts from 90% of the outaged meters and "Power Restore" alerts from 95% of restored meters, typically within 15 minutes.
- SmartMeters with remote disconnect/reconnect capability significantly reduced the number of truck rolls and labor required for these functions.
- SmartMeter can be programmed to provide a vast number of event notifications, alerts, and alarms. Alerts like "Fatal Error" and "Tamper Detected" were used to generate service orders, speeding up problem detection and resolution.
- Alerts like "Under/Over Voltage" and functions like on-demand voltage reading can be used to support grid operations.
- While not quantified, the MDM demonstrated significant integration benefits by establishing a central meter data repository and acting as the integration point for communications with AMI meters.

4.1.2 SmartEnd-Use Benefits

SmartEnd-Use benefits identified during the conduct of the SGDP include:

- 53% of survey respondents said the Home Energy Management Portal (HEMP) helped them understand more about their electricity usage, how to reduce usage, and how to save money.

- 45% of survey respondents agreed that the HEMP influenced their decisions to take steps to save energy at home over the previous 12 months.
- 85% of survey respondents reported that the daily Estimated Bill feature provided by the HEMP and In-Home Display (IHD) was useful. Many said that this was the feature that provided the most value.
- TOU participants, on average, reduced their On-Peak energy consumption by approximately 18% and saved annually an average of \$68 over the 4 month summer rate period.

4.1.3 SmartDistribution Benefits

SmartDistribution benefits identified during the conduct of the SGDP include:

- While not quantified, the DMS and D-SCADA provided grid operators with improved visibility and operational control of the distribution grid.
- While not all benefits were quantified, the DMS and OMS functions provided grid operators with improved capabilities for outage and restoration detection.
- The CVR voltage regulation function was implemented with an average voltage reduction of 2%, resulting in a 1.6% reduction in delivered energy.
- The DVC voltage reduction function was implemented during peak periods and led to an average voltage reduction of 1.6%, resulting in a 1.13% reduction in kW demand.
- The VVC function provided a more stable voltage profile compared to that of the individual, locally controlled capacitor banks.
- Mid-circuit reclosers with fast-trip protection reduced the number of transformer level outages by an estimated 33%, which is enough to prevent 77 truck rolls and 571,600 customer outage minutes.
- FISR and automated switching reduced the number of customers affected by feeder-level outages by an estimated 73.5%, enough to reduce the resulting customer outage minutes by 74% for a savings of over 767,000 customer interruption minutes.
- The combination of FISR and recloser fast-trips provided a 35% reduction in SAIDI for the customers in the study area.
- Asset condition monitoring detected an internal arc in a newly installed substation power transformer, avoiding the loss of a \$1.25 million dollar asset.
- While not quantified, the substation HMI provided operations personnel with improved visibility and insight to substation conditions when working within the substation.

4.1.4 SmartGeneration Benefits

SmartGeneration benefits identified during the conduct of the SGDP include:

- While not quantified, the DMS/DERM system integration provided grid operators with the ability to call geographically constrained load reduction events.
- While not quantified, the DERM system provided significant operational benefits in its ability to manage all DR and DER assets and load reduction events.
- Each 1.0 kW of grid-connected rooftop solar generation produced 1,396 kWh annually and reduced the KCP&L 2014 system peak load in August by 0.42 kW.

- The 1.0 MWh BESS could discharge 266 MWh of stored energy annually for energy time shifting. Based on the 2014 SPP Day Ahead Energy Market, this produced approximately \$3,000 savings.
- The 1.0 MWh BESS could discharge 0.8 MWh during the system peak hour, thus contributing a 0.8 MW reduction to system peak.
- The 1.0 MWh BESS could discharge 0.8 MWh during the distribution peak load periods, thus providing load reduction of 200 kW to 500 kW at the distribution substation or circuit level. Analysis showed that to provide effective generation or distribution capacity deferral, a BESS should be configured with 4 MWh to 5 MWh of storage for each MW of capacity.
- While not quantified, it was demonstrated that the BESS could island a portion of a distribution circuit and sustain power to customers during an outage to the grid supply.
- The 11.7 kW PESS, when operated for TOU Energy Cost Savings, could discharge 2,900 kWh of stored energy annually during On-Peak periods, potentially saving the customer \$638.
- The On-Peak discharge of the PESS resulted in reduction of at least 2 kW in customer peak load, providing the utility the equivalent potential generation and distribution capacity deferral benefits.
- The PESS, when operated for Renewable Energy Time Shift, could store solar energy that was generated Off-Peak and release 2,900 kWh of stored energy annually during On-Peak periods, potentially saving the customer \$255.
- The PESS provides the customer with significant benefits from improved electric service reliability by providing power to critical loads and sustaining the solar power generation operation during all but the most extensive power outage events.
- Public EV charging provided increased kWh energy sales of approximately 7 kW per charge. Even more significant, each charge avoided the consumption of approximately 1 gallon of gasoline.

4.2 LESSONS LEARNED AND BEST PRACTICES

This section describes Lessons Learned for all demonstrated technologies. Others may find benefit from issues and solutions that KCP&L encountered, mitigated, or resolved. Lessons Learned are provided for General Project Execution, Interoperability, Cybersecurity, Education & Outreach, and the SGDP technology components. More detailed explanations of these Lessons Learned are included in Section 2 and Section 3. The most significant highlights are listed below.

4.2.1 General Project Execution Lessons Learned

General Project Execution Lessons Learned during the conduct of the SGDP include:

- When staffing for a project, consider dedicating resources specifically toward the project rather than using a number of employees in part-time capacities. Enterprisewide issues will typically take precedence, so it can be difficult to get the focused attention necessary to complete a project.
- When projects utilize third-party system integrators or contract resources, it is imperative that an effective knowledge transfer and plan for system training be put into place to ensure that the permanent utility team members will be able to fully support the system once the external resources have rolled off the project.
- Upon implementation of a project, business users of new systems need to be encouraged to actively use the new systems, even if their enterprisewide, legacy systems remain operational.
- The SGDP lab and testing environments were beneficial and should be incorporated into any future smart grid technology deployments.

4.2.2 Interoperability Lessons Learned

Interoperability Lessons Learned during the conduct of the SGDP include:

- The standards creation process is slow and tedious. If a standard isn't complete and approved, it may not be feasible to use, as vendors will have to make assumptions, perform custom development, and create extensions. One potential solution is to have all project vendors develop to a common working version of the standard.
- Standards creation isn't sufficient to ensure interoperability; rather, specific application profiles are necessary to minimize some of the ambiguity associated with a standard.
- Even with standard application profiles, there is room for interpretation to facilitate interoperability; there is a need to establish industry testing bodies to ensure consistency in the certification process across vendors.
- Since standards and application profiles don't typically provide complete plug-and-play interoperability between vendors, an ESB can greatly assist in message transformations.
- Careful attention should be devoted to the process for model migration. While only one back office system should be the system of record for the utility data model, the information contained within the back office system ultimately is shared among multiple other systems. Because of such informational complexity, the migration process itself should be as efficient, effective, timely, and accurate as possible. A streamlined migration process can enable the model to be updated frequently.

- Manufacturers of field devices can be slow to adopt new communication technologies. Even if a standard is fully vetted, the time to develop, test, and bring the devices to market is quite long. Utilities need to push vendors to expedite adoption of new communications technologies, especially Internet Protocol (IP).
- Time synchronization between systems and devices is imperative for smart grid deployments to function as desired. Regardless of how a utility chooses to source time (satellite clocks, network time, devices, etc.), it is critical that all time is stored and exchanged in Coordinated Universal Time (UTC) format.
- To ensure stability for all back office systems that facilitate smart grid applications, a holistic monitoring system is necessary. This system should alarm when a critical event on a particular server, device, interface, or communication path occurs. Although no single utility department is capable of responding to all the various alarms that might result from this system, the messages could be relayed to the appropriate group for troubleshooting and resolution.

4.2.3 Cyber Security Lessons Learned

Cyber Security Lessons Learned during the conduct of the SGDP include:

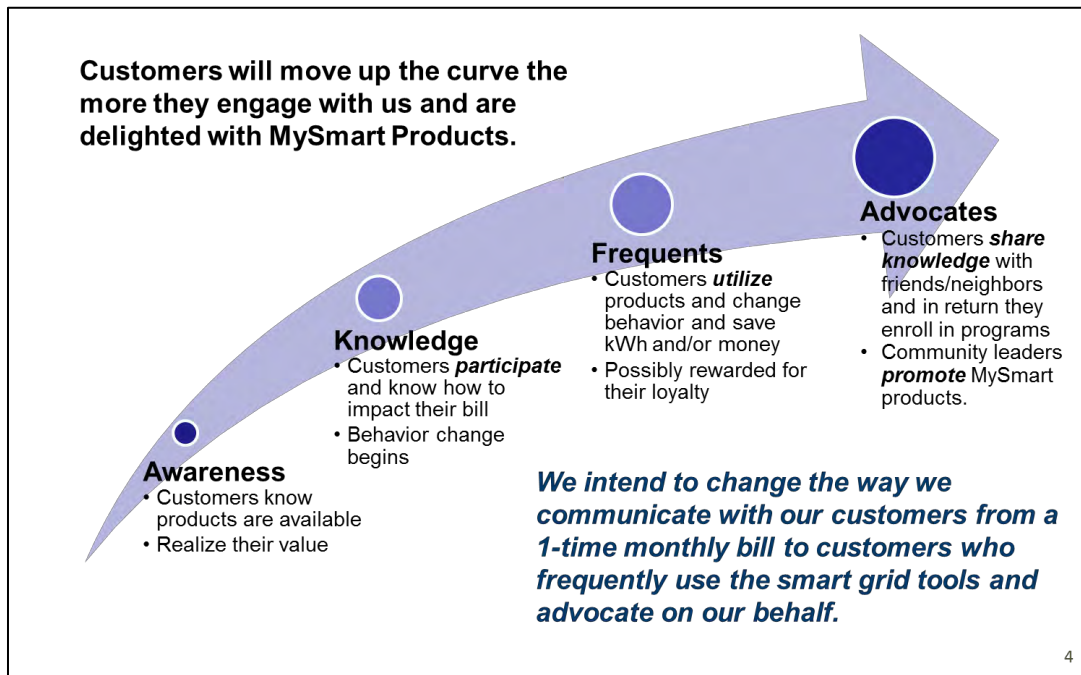
- The convergence and cooperation of IT and operations is paramount when deploying IP-based communications in the substation and beyond. If responsibility is shared between these groups, then management needs to clearly define roles and responsibilities and encourage open dialogue and cross-training. Alternatively, management could create a new, cross-functional support group that has the expertise to bridge the gap for installing, maintaining, and troubleshooting both the networking hardware as well as the end devices that utilize IP-based communications.
- Cyber security requirements should be incorporated into processes for vendor selection and for procurement. Internally hosted systems should consider access control, configuration management, system/communication protection, and system/information integrity. Systems hosted by a third party should also consider continuity of operations, incident response, media protection, and physical security assessments.
- Physical access control and key management should be done via a centralized, electronic platform. Such a platform allows for regular, inexpensive key refreshes; the capability to quickly modify user access permissions; and the capability to provide logging information to security.
- Cyber security zones and robust network segmentation should be established to comply with current and future industry standards pertaining to IP-based communications.
- Strict isolation should be implemented between distribution- and transmission-level assets in the substation, especially if both utilize IP-based communication. This isolation is also necessary for distribution- and transmission-level backhaul data. This isolation could be implemented logically via logical segmentation on shared network hardware, or physical via completely separate cabling and network hardware.
- Firmware, settings files, and Configured IED Description (CID) files for meter, field and substation devices should be maintained in a system for managing device configuration and versioning. Device firmware and settings should be verified on a routine, scheduled basis.

4.2.4 Education & Outreach Lessons Learned

Education & Outreach Lessons Learned during the conduct of the SGDP include:

- Based on the customer focus group, interest forms, and surveys, there is no silver bullet for customer communication channel preference.
- Reaching out to customers at existing community events was more effective than creating new, utility-sponsored events specifically for the SGDP effort.
- Consumers are looking for ways to manage energy, but don't know how to go about it. Most consumers weren't able to identify the energy hogs in their home, and they had a hard time translating the notion of efficiency into actionable steps; rather, they were seeking direction on the biggest bang for their buck.
- Utilizing a local labor force led to goodwill, but the Green Impact Zone ambassadors lacked product knowledge and their customer training skills were weak. Future programs should focus on sufficient training for the workforce.
- When deploying devices in customers' homes, capitalize on installer visits to offer a superior on-boarding experience and educate customers about general project initiatives and specific product offerings.
- Customer enrollment does not equal customer engagement. To remain engaged, customers need ongoing communication and education. As shown below in Figure 4-1, KCP&L created a customer experience timeline showing the ideal customer's progression over time.

Figure 4-1: The Customer Experience



4.2.5 SmartMetering Lessons Learned

SmartMetering Lessons Learned during the conduct of the SGDP include:

Advanced Metering Infrastructure

- Prior to the AMI rollout, KCP&L conducted a meter inventory/audit to identify safety, theft, and nonstandard situations. This preparation work made the AMI rollout more efficient and helped keep the AMI meters from getting blamed for other unrelated issues.
- KCP&L had a very successful deployment in terms of customer reaction and satisfaction due to strong and deliberate education efforts through numerous grassroots communication paths. KCP&L also met face-to-face with concerned and objecting AMI customers to discuss their concerns. This helped ensure a full deployment of AMI meters to all service points within the project area.
- Plans should be made for at least two AMI system software upgrades per year. These upgrades to the head end system and to the meters themselves are executed to provide additional functionality, performance, and scalability improvements, along with security enhancements. The upgrades need to be scheduled carefully to reduce impacts on AMI performance and system-to-system interfaces. All upgrades should first be thoroughly tested in a development environment.
- The daily performance of the AMI infrastructure significantly outperformed the legacy AMR system by establishing a consistent 99% daily read performance metric. With more than 30 days of reads and interval usage data stored on the meter and the gap-filling data retrieval functions of the AMI head-end, actual data capture was significantly improved, providing nearly 99.96% of meter interval data from functioning meters.
- KCP&L's AMI implementation has resulted in good outage and restoration message receipt rates. KCP&L's OMS received about 90% of outage/restoration messages via the AMI system, as compared to about 30% via the legacy AMR system.

Meter Data Management

- Loading historical AMI data into the MDM proved difficult. The MDM solution should be deployed at the beginning of an AMI rollout or its implementation planning should avoid the need for loading historical interval data.
- The MDM should be used as the system of record for all interval and register meter read data, as well as for all meter asset and configuration information. As the system of record for meter read data within a utility, the MDM needs to have robust capabilities to export meter read data to external systems through a variety of mechanisms, frequencies, and formats.
- The ability for a new MDM system to enable new rate types might be hampered by a utility's legacy customer information system or billing system. Many older systems aren't able to ingest billing determinants from the MDM. Utilities should understand the limitations of their legacy customer information and billing systems prior to MDM deployment.

4.2.6 SmartEnd-Use Lessons Learned

SmartEnd-Use Lessons Learned during the conduct of the SGDP include:

- Saving money on their bill was the primary reason that customers signed up for a SmartEnd-Use program. Customers expected a 23% average savings on their energy bill with the new tools. Secondary motivations were control over energy use and concern for the environment.

- Several SmartEnd-Use products allowed customers receive a daily estimate of their monthly bill. Many said that this was the program feature that gave them the most value.
- Wait to deploy customer thermostats, in-home displays, and HAN devices until after the customer's AMI meter has been installed and stabilized for a few weeks. Premature deployment of devices only frustrated customers, because unstable AMI meter communications prevented the devices from working properly.
- KCP&L's separate, dedicated support staff for SmartEnd-Use programs and tools was very beneficial—the traditional customer support staff fielded billing and lights-out calls, so they were not well-versed in the specific SGDP products.
- Two-thirds of customers in the SGDP service territory were renters. Because of this highly transient population, additional engagement was required, especially to transfer devices and program enrollment to new places of residence.
- Meter exchanges were problematic with the SmartEnd-Use devices. The devices maintained their associations with the old meter, and required manual provisioning to the new meter. An automatic provisioning process would alleviate this issue.

Home Energy Management Portal

- The HEMP functionality didn't evolve as originally envisioned throughout the duration of the project. A robust portal would have allowed customers to easily control DR participation, set their preferences for priced-based programs, and remotely control their devices.
- Customer usage of the portal waned over time. The HEMP should have ongoing, proactive marketing and be deployed in conjunction with other customer self-service functions to encourage ongoing portal usage.
- Close communication with the portal vendor is important to ensure that upgrade strategies and timelines align with the utility's goals. Portal upgrades should be used as an opportunity to engage with customers and promote use of the portal.

In-Home Display

- Based on customer surveys, the IHD was an underutilized device. Customers don't need a highly interactive device on a wall or counter; rather, they would prefer a single, mobile device (like their smartphone) with an application for home energy management.
- An IHD needs to be immediately useful upon installation in order for the customer to have any long-term engagement potential. The customers that received the IHD in parallel with their AMI meter were not able to do anything with the device for several days, until the AMI network communications stabilized. As a result, many of these customers failed to use the IHDs at all, even when the devices became functional.
- Customers that did use the IHDs really liked the estimated bill feature, especially because KCP&L considered the added taxes and fees in the number presented on the IHD.
- Of customers that used the IHD, 89% also took other energy-saving actions based on their IHD use. This shows that the IHDs heightened awareness of energy usage.
- IHD connectivity was only verified during IHD provisioning to the AMI meter. KCP&L could not "ping" IHDs to verify connectivity. The ability to remotely verify IHD connectivity could trigger communications to enhance engagement with customers where an IHD is not functioning properly.

Home Area Network

- A successful HAN installation requires a carefully planned set of coordinated steps between the device installer and the customer service representatives performing the device provisioning to the SmartMeter. When the process was not followed properly, issues would arise with devices joining improperly or not joining the network at all.
- Customer broadband connectivity issues prevented many HAN thermostats from participation in DR events. If the utility DR program is going to rely on the customer broadband and Wi-Fi network, the utility needs to implement proactive HAN monitoring and initiate customer contact to restore HAN communications so that devices are available to participate in DR events.
- Utilities should manage the provisioning of the meter to a single HAN gateway. All other customer HAN devices should be provisioned by the customer to the HAN gateway. It doesn't make sense for all HAN devices to be provisioned through the AMI meter, as was required by the SGDP vendor's implementation of ZigBee SEP 1.x.
- Industry trends now appear to favor HAN devices that communicate over Wi-Fi rather than ZigBee networks. Since many customers already have a Wi-Fi network in their home, they don't have to maintain an additional network.

Time-of-Use Rates

- Overall, enrollment in the TOU program was higher than anticipated. TOU enrollment peaked in 2013, with approximately 1% of the SmartGrid Demonstration customers enrolled.
- Program design and communication are crucial to customer acceptance. Customers were receptive to an aggressive TOU pricing program (6x rate differential) if the program was simple to understand and the customer's risk exposure (On-Peak hours) was limited.
- KCP&L further reduced customer risk by allowing customers to exit the program at any time and, upon request, customers could be credited for increased costs incurred by the pilot TOU rate for the current and previous billing cycles only. While very few customers exited the program, customers viewed this as a positive aspect of the program.
- Overall, customers were satisfied with the TOU program, and on average participants reduced their On-Peak electricity usage by 15-20% and saved money, an average of \$68, on their electricity bills.

4.2.7 SmartSubstation Lessons Learned

SmartSubstation Lessons Learned during the conduct of the SGDP include:

- Utilizing a phased deployment for the SmartSubstation components was imperative for project success. This approach gave each relevant work group time to get accustomed to the new technology and gain trust before adding additional layers of complexity.
- Selecting substation relays that could provide parallel communications to both the legacy EMS (via serial) and the new substation data concentrator (via IEC 61850) was key. The dual communications allowed the legacy transmission SCADA and new DMS to monitor all elements of the substation while allowing control to be effectively switched between systems as the SmartSubstation functions were deployed, tested, and operated.
- Many of the SmartSubstation components are more easily deployed when procured from a single vendor. When additional vendors are introduced, the complexity of integrating these technologies increases dramatically.

- The span of control between transmission operators and distribution dispatchers needs to be evaluated to fully utilize the SmartSubstation components. Currently, KCP&L's transmission operator is responsible for distribution bus voltage and operation of transformer load tap changers, plus the operation of substation bus tie breakers for internal substation load transfers. Distribution system operators currently only operate distribution feeder breakers inside the substation. Since the First Responder applications were designed to operate all of these devices, the distribution system operators need to have control of these distribution assets.
- The convergence of IT/OT staff within the SmartSubstation can be problematic unless careful planning and coordination is performed between the various work groups at the project initiation.

Substation Protection Network

- It is feasible to design, construct, and run a multivendor substation protection network, but there are certainly drawbacks to this approach. The hybrid approach yields uncertainty in regards to functionality and failover time. Testing out the proposed network architecture in a lab environment was critical prior to deployment of the networking equipment in the production environment.
- Utility department ownership of the substation protection network isn't clear cut. Some utilities give ownership to the Network Services team, while others add this to the responsibilities of the Substation or Relay System Protection teams. Meanwhile, other utilities are creating a third, hybrid group that specifically addresses this mix of skill sets. A clear ownership structure is essential to ensuring that the network is operational and maintained.

Distribution Data Concentrator

- If using report by exception rather than traditional SCADA polling, careful attention must be given when determining the analog deadbands to avoid excessive analog reporting from each device (and potentially overloading the data concentrator). Utilities should consider setting a deadband on only one type of analog in the 61850 report dataset. For example, they might set deadbands on all of the current values, so that only changes to the system current would trigger data transfer.
- As the points list is created, it is important to understand the logic and arithmetic capabilities of the data concentrator. Utilizing these functionalities could limit the number of data points brought back from each device, as the data concentrator could calculate certain values rather than sending everything from each device. For example, instead of bringing back all the points associated with voltage, current, and power, the device could just send the voltage and current data and the data concentrator could calculate the power values.
- CID file versioning and proper device configuration management is critical to managing a 61850 substation implementation. If the CID file on the device doesn't exactly match the CID file on the data concentrator, then the device becomes unreachable.

Human Machine Interface

- The HMI was useful for both the SGDP team as well as the system end user—the relay technicians. By using the HMI at Midtown Substation, the technicians were able to see the status of all substation devices in one place, rather than walking around to each relay to troubleshoot or test. While this is obviously a convenience to the technicians, it can also enhance the safety practices for all operations personnel.
- The HMI provided visibility to the status of the substation protection and control network, which was a major benefit to the project team. When a communications issue with a particular device was discovered via the data concentrator, the team could easily determine whether the root issue was related to the device itself or to network equipment.

GOOSE Messaging

- Deploying GOOSE schemes in a slow, incremental process was necessary for protection and control engineers and relay technicians to gain trust.
- Although the cross triggering GOOSE scheme didn't result in any actions taken by substation relays, it was very beneficial for KCP&L engineers. They were able to see the status of all substation devices any time an event occurred in the substation, and this was useful for post-event analysis.
- Understanding the impact of communications failures on the outcome of various substation events with and without the GOOSE schemes is beneficial. GOOSE schemes should be designed in such a manner that if communications fail and the devices operate based on their local protection settings, then the result is no worse than the pre-GOOSE scheme.

Substation DCADA

- By design, the substation DCADA (local substation automation controller) is supposed to operate in closed loop in the substation without any user intervention. The user has the authority to enable and disable DCADA closed loop at the substation, but the user does not have the flexibility to authorize individual decisions made by DCADA. This proved to be a major change-management issue as the operations group was uncomfortable in relinquishing complete control from the onset. Though incongruent with the DCADA philosophy, additional flexibility in terms of user intervention—at least during the implementation or testing phases—would help gain the trust of the operations group and transition into full-fledged closed loop mode.

4.2.8 SmartDistribution Lessons Learned

SmartDistribution Lessons Learned during the conduct of the SGDP include:

- Careful scheduling was required to accommodate all of the necessary field crews required for field device deployment. The recloser deployments, for example, typically took five different field crews: engineering, construction, distribution field operations, radio, and relay technicians. In order to deploy a field device network enterprisewide, a utility should look at its field crew responsibilities and consider modifying roles to make the process more efficient.

- The need for adequate change management for operational personnel cannot be overemphasized when deploying automation to the distribution system. In addition to addressing work practices dealing with individual device construction and operating practices, grid operations practices must also be addressed. Some specific examples of decisions for discussion include: Will Volt/VAR be allowed to run in closed loop? Can the system be allowed to switch itself, both to isolate and restore? Can the system be allowed to optimize away from its typical steady state?

Outage Management System

- The outage and restoration events delivered by the L+G AMI were much more reliable than what KCP&L has experienced with the traditional AMR “last gasp” outage alerts.
- When power was lost, the AMI meter waited approximately 30 seconds before broadcasting a power outage event. This eliminated “last gasp” alert broadcasts caused by momentary interruptions; the meters continued communicating for an additional 60 seconds to ensure that the event messages were transported through the mesh network. For this project, KCP&L found that the AMI Head End receives over 90% of power outage events, far superior to the 25% experienced with the legacy AMR system.
- When power was restored, the meter set an internal timer that was used to calculate the restore time once the network was re-established and network time was reset in the meter. The meter sent a first power restoration event message when network communications were re-established. A second power restoration event message was sent 5 minutes after network communications were restored as a precaution in case the network backhaul was not fully established when the first message was sent. The majority of power restoration messages were typically received by the AMI Head End within 5 minutes of the actual power restoration, and 95% of the power restoration events were typically received within 15 minutes.

Distribution SCADA

- Current distribution SCADA technologies do not provide all of the capabilities that will be required to support the future requirements of the smart grid.
- Maintaining the distribution SCADA database is very labor intensive and prone to error. For each field device deployed, great attention and user involvement was required with loading/verification at every step of the communication path. Care was needed to ensure proper naming conventions and appropriate cross mapping between DNP and 61850 naming. These efforts to enable substation and field device communications were a notable contrast to the deployment of incremental AMI meters in the field. In the same way that meters would self-identify and propagate communication point capabilities, other distribution devices would benefit from these same capabilities through to all systems with which they communicate.
- Since data from the field devices is sent upstream periodically or reported by exception, all systems using this data need to receive, display to the operator, and act on the data quality (good, bad, telemetered, non-telemetered, entered, etc.) and the time stamp (staleness) of the data.
- When it comes to field devices, the industry is far from achieving device interchangeability. Interpretations of industry standards vary greatly from vendor to vendor. The majority of field devices on the market today are still based on serial communications.

Distribution Management System

- Deploying a complex system like a DMS should be done in phases. KCP&L successfully separated the deployment into the following phases where possible: substation device point-to-point checkout, field device point-to-point checkout, First Responder open loop testing, and finally, First Responder closed loop testing.
- A detailed network model is critical for the success of an intelligent distribution system. All of the proper network elements and their connectivity are necessary for state estimation. Additionally, precision is required for accurate load flows (power flow) and stability-type analysis.
- Any time a new device was added to the GIS, it required the redeployment of the entire network model throughout the various distribution systems. This resulted in significant system downtime to update and re-stabilize the system. An incremental network model migration capability from the GIS to the DMS and other systems requiring network topology is critical for future enterprise deployments.
- For most Distribution Management Systems there are several modes of control, such as complete user control, open loop control, and closed loop control. With an anticipated future in which multiple systems would integrate together forming a single DMS, there is a need for a single hierarchical control system that interacts with all systems yet still gives complete authority to the operator at needed times.
- Having a lab environment for testing the First Responder applications was not very beneficial, because the First Responder applications require a significant quantity of frequently updated data from devices in the field. In a production environment, legitimate devices continually provide this data. However, in the lab environment, it is challenging to simulate or compile enough data to truly simulate an entire distribution footprint.

ADA Field Area Network

- A mesh network for Advanced Distribution Automation functions best when its size allows for multiple paths to any node. Unfortunately, KCP&L's mesh network was too small (in geographic span) to realize the benefits of multiple paths. Thus, when one node went down, multiple backup paths were not always available.
- In order for the mesh network to perform as well as possible, it is critical to have as many takeout points as possible. This would decrease the hop count and decrease the burden on any single set of gateways.
- The use of wireless network technology for ADA means that the data concentrator needs to support less-than-ideal communication quality. Although many data concentrators claim to handle wireless communications, most on the market today were built to work with wired communications.

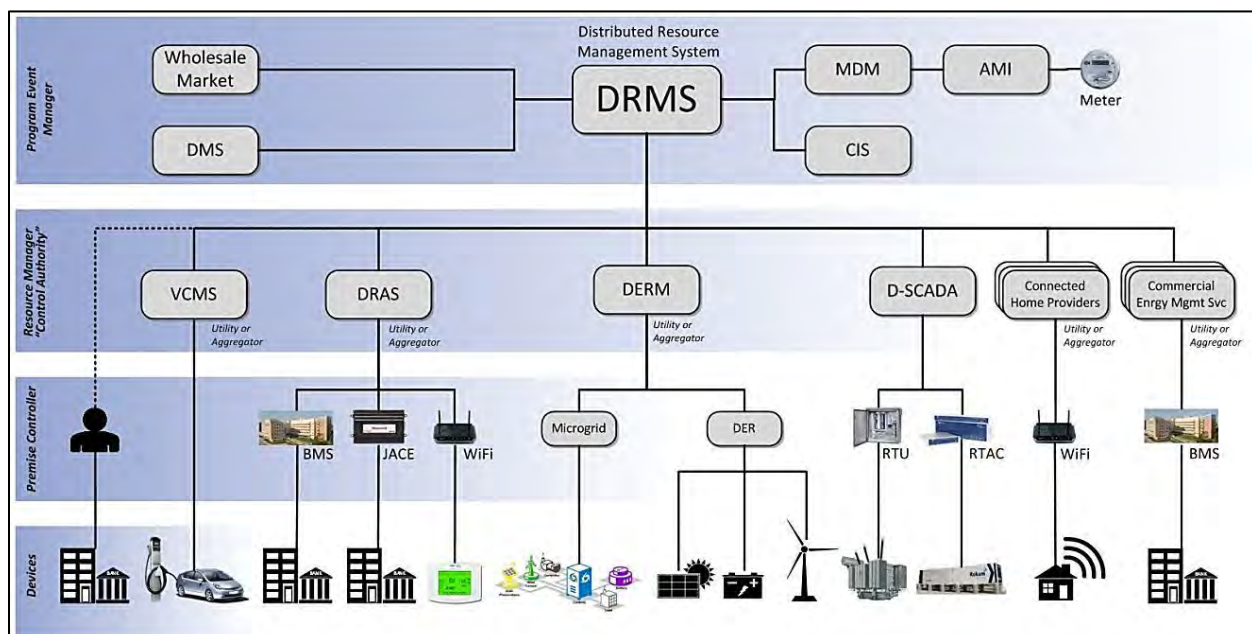
4.2.9 SmartGeneration Lessons Learned

SmartGeneration Lessons Learned during the conduct of the SGDP include:

Distributed Energy Resource Management System

- Current standards are not sufficient for DMS/DERM interactions. For the SGDP, the vendors created a custom DMS/DERM interface. They utilized IEC 61968 for dynamic message exchanges, but they had to create numerous extensions to the standard to pass the necessary information between systems. A significant amount of industry work needs to happen in this standard for it to be sufficient for the exchange of power flow and state estimation messages.
- To perform geographic load reduction, the DERM required a network topology model. Since the DERM isn't typically the system of record for this model, careful consideration must be given for how to keep network topology models synchronized across back office systems.
- Originally, KCP&L thought that direct load control DR events needed to be done with utility infrastructure. Because of the development of the OpenADR messaging standards with availability assessment and post-event analysis messaging, however, this might not be as critical going forward. If utilized properly, OpenADR messages could notify the event scheduler (utility) if assets are offline or already being utilized.
- Unlike many other back office utility systems, the DERM system isn't fully defined yet; rather, it's an evolving technology, and its functions still need to be defined and vetted across the industry. Various vendors have approached their product offerings with different strategies, yielding various "classes" of systems (DRAS, DERM, etc.), with each managing a specific type of distributed resource asset. Through this project, KCP&L defined the DERM as a higher level critical component for optimal scheduling (both geographical and economical) of demand response and distributed energy resources. KCP&L's hierarchical architecture for the distributed resources management moving forward is as shown below in Figure 4-2. In this diagram, the DRMS represents the SGDP component referred to as the DERM.

Figure 4-2: DRMS Proposed Architecture



Battery Energy Storage System

- The BESS is a complicated system with very complex internal control systems. It is not a set-and-forget system like most other distribution technologies. Rather, it requires a significant amount of ongoing operational monitoring and support.
- While it may be possible for a utility to achieve economic benefits from Energy Time Shift, Peak Shaving, and T&D efficiencies, the most significant components in determining the economic viability of a BESS for a utility are still the upfront installed cost of the unit and the ability to derive additional benefit streams from wholesale ancillary service markets.
- The annual average daily round trip efficiency of the BESS was determined to be 75%, but it varied significantly with the daily average temperature. To improve operational performance of future BESS specifications should focus on improving the efficiency of auxiliary loads and installing improved insulation and more efficient HVAC units on the SMS and battery enclosures.
- Manufacturer's recommended discharge thresholds need to be followed to protect the battery and maintain its life. These thresholds and the efficiency of the inverter need to be factored in when sizing the battery storage component. For example, KCP&L's 1.0-MWh battery could only deliver a net impact of 780 kWh to the grid.
- For BESS resources operated for Electric Supply Capacity and T&D Upgrade Deferral functions, KCP&L's analysis shows the optimal economic configuration of BESS assets is to install between 4.0 MWh and 5.0 MWh of storage capacity for each MW of inverter capacity.

Premise Energy Storage System

- A PESS is a good potential business opportunity for the utility to collaborate with customers. It provides an edge-of-grid platform for improved customer resilience, allows the customer's PV to continue generation during outages, provides the customer additional savings potential with TOU rates, and provides a resource for the utility to call upon for DR.
- The PESS avoids the major neighborhood storage issue: Who gets to use the power when islanding occurs? If the storage is done at the premise, then the individual customer completely controls what the storage is used for and how long the storage lasts.
- The SGDP PESS ratings, 6.0 kW/11.7 kWh, appear appropriately sized to serve the critical loads of most residential homes in the KCP&L service area. Combining the PESS with a 4.2 kW or larger solar array would allow the critical load panel (CLP) loads to be sustained through multiday restorations for the majority of the year.
- The customer's home Wi-Fi network and Internet connection remain operational during power outages. Without the Internet connection, the customer's ability to monitor and manage the PESS is lost. It may be necessary for the customer to have a backup cellular Internet connection for the PESS if the customer's normal home Internet supplier loses service due to widespread power outages.
- It is important for the customer to understand the energy consumption characteristics of the loads connected to the CLP. Approximately half of the daily energy consumption may be attributed to the furnace fan. To further extend the PESS's capabilities, the customer should consider implementing additional energy management controls for loads connected to the CLP.

Solar PV Generation

- Any agreements for siting utility-owned solar generation on a customer's property should be structured in a manner that does not create unmanageable property encumbrances for current and future owners.
- KCP&L determined that NREL's New PVWatts Calculator, released in the fall of 2014, provides very credible estimates for sites in and around Kansas City. It estimates that a rooftop solar installation in Kansas City would produce 1,389 W-AC per kW-DC annually for an annual solar production load factor of 15.85%.
- KCP&L's analysis determined that the coincidence of solar generation with the utility's system peak could range from 40% to 55%, depending on when in July or August the peak condition occurs. If a system peak event occurs in early July, solar coincidence as high as 55% may be expected. But as peak events occur later in the year, the coincidence reduces—to 40% by late August.

Vehicle Charge Management System

- The charging station program deployed for this project was developed within current legislative and commission constraints: 1) No tariff exists for KCP&L to sell (or give away) electricity at public charging stations, and 2) Missouri and Kansas do not allow resale of electricity by third parties. As a result, businesses were recruited to host the charging station, meaning that the business would provide the parking space and pay for the electrical consumption. The EV charging was provided at no cost to the EV owner. This model is not desirable long-term, so new legislation and/or tariffs will be key in the development of public EV charging programs.
- Site selection is key to the early utilization of the public charging stations. The best sites are highly visible locations where current and potential PEV owners work or frequent. Overall charging station usage increased throughout the duration of the project as current and prospective PV owners became aware of their existence and the adoption of electric vehicles increased.
- Location is also a critical factor in determining EVCS utilization. Locations that generate multiple, moderate duration (1-2 hours) visits can have multiple charging sessions daily, providing the best overall EVCS utilization. Employee parking locations, while used daily, tend to only generate 1 or 2 charge sessions per day.
- Monitoring of all EVCS locations generated the following generalizations regarding usage of charging stations.
 - annual electricity consumed by PEVs is 28.586 MWh
 - average connect time is 4.5 hours
 - average charge duration is 2 hours, 20 minutes
 - average charge is approximately 7 kWh
 - most common charge rate is 3 kWh/hour
 - less common charge rate is 5.5 kWh/hour

4.3 TECHNOLOGY GAPS

This section describes the Technology Gaps identified for all demonstrated technologies. These gaps outline some of the areas where the industry needs to advance. Other utilities may find benefit in understanding where they could run into issues in similar implementations. Vendors could benefit by addressing some of these issues and advancing the available technologies on the market. Technology Gaps are provided for SmartMetering, SmartEnd-Use, SmartDistribution, SmartGeneration, and Interoperability. More detailed explanations of these Technology Gaps are included in Section 2 and Section 3. The most significant highlights are listed below.

4.3.1 SmartMetering Technology Gaps

The SmartMetering technologies used in the SGDP proved to be relatively mature technologies. Very few industrywide technology gaps were identified.

Advanced Metering Infrastructure

- AMI systems need to automatically re-establish the ZigBee HAN connections when meters are changed out. The manual reprovisioning process currently used will become too cumbersome and labor intensive as users and utility programs rely more heavily on data and messages received from the meter.

Meter Data Management

- The functionality of MDM systems needs to be expanded, or developed in a companion system, to manage all characteristics of the meter. The MDM needs to provide centralized configuration management and firmware version tracking across all meter platforms.
- The MDM system is expected to be the system of record for meter read data and, therefore, needs to have robust capabilities to export meter read data to other back office systems that have traditionally received such data either from the CIS or directly from the meter reading systems. The MDM system should be capable of:
 - Exporting the meter read data in multiple formats: Green Button, IEC 61968-9, CSV, and others.
 - Pushing meter data on a predetermined schedule, and responding to real-time requests for data based on a list of customers and a time period.
- Other back office systems should have the ability to consume raw, uncorrected meter data, VEEed data, and subsequent corrected versions of data provided by the MDM.

4.3.2 SmartEnd-Use Technology Gaps

Although KCP&L encountered a number of issues in the SmartEnd-Use project component, the industry is already working to resolve many of these. This part of the grid has seen a multitude of newcomers over the past decade, and each of these entrants is bringing new ideas and devices to leverage and build upon the foundation laid by early pioneers in the home energy automation space.

Home Energy Management Portal

HEMP technology hasn't advanced as quickly as anticipated. Most portals today are limited to display of customers' energy usage information along with energy efficiency tips and programs, with limited end-use device management and control.

- In the future, HEMPs should support:
 - Opportunities for customers to manage their usage from a pricing perspective, so that price-based demand response programs are feasible
 - Distributed resources
 - Solar
 - Smart appliances
- As HEMPs evolve there will likely be a separation between customer and utility portals.
 - Utility customer portals will likely be focused on energy presentment, energy efficiency alternatives, energy products, and pricing options.
 - Customer home energy management systems will likely focus on the "connected home." Such systems would register devices, provide security and home automation, integrate with the utility to receive pricing signals, and manage solar, PEV, and smart appliances.

Home Area Network

KCP&L utilized the ZigBee SEP 1.x for the project. It didn't have all the functionality needed for KCP&L's project, so both the ZigBee SEP and the Home Automation profiles were utilized in order to get as much of the desired functionality as possible. In addition to the lacking functionality, all HAN devices were required to register to the meter. This approach would be impractical moving forward, as it would force the utility to provision all the smart devices and appliances in the customer's home.

- Many of the technical issues with ZigBee and SEP 1.x are being addressed by current efforts via SEP 2.0 and other home automation protocols, but here are some of the necessary requirements moving forward:
 - Need ability to differentiate between different types of load control switches for demand-response events.
 - Air conditioning cycling with fan control is needed as a thermostat DR event mechanism.
- HAN implementations should evolve such that devices are provisioned to a customer gateway, allowing the customer to install any end-use devices desired within the home. With this design, the utility would be responsible only for provisioning the gateway and any utility managed direct load control devices to the meter.
- The customer home energy/automation space needs to continue to evolve and provide capabilities required for increased customer participation. Most likely this will be better handled in the near term by "connected home" providers, rather than the traditional electric distribution utility.

4.3.3 SmartDistribution Technology Gaps

Throughout KCP&L's SGDP, it became clear that the SmartDistribution project component was the area with the most technology gaps. Currently there are many changes occurring within the distribution grid, and vendors are scrambling to get products to market. Vendors rarely consider the scalability of their solutions, and rarely do their designs accommodate multivendor solutions. The following items describe some of the major technology gaps that KCP&L discovered in SmartDistribution.

Device Control Functionalities

To add intelligence and automation to the distribution grid, many IEDs will need to be added to the distribution lines. Vendors should do a better job of preparing their controllers for the proliferation of these devices. The current industry approach for controllers outside the substation walls is similar to the approach for controllers attached to substation devices: Each vendor utilizes proprietary software for developing configurations, and many controllers are accessible only via local interrogation. This approach won't be sufficient for field devices, due to the sheer quantity of devices and the geographic reach of their deployment.

- In the future, IEDs need to do the following:
 - Support a predefined mode of operation in the event of communications loss from the data concentrator.
 - Be capable of simultaneous reporting of multiple points from a single deadband instead of multiple unsynchronized deadbands.
 - Provide native IP support instead of relying on communications radios to translate from serial to IP.
- Third-party software developers need to create a common software package that utilities could use to develop configuration and settings files applicable to all device manufacturers.

Application Profiles

Even when vendors develop products using specific industry standards, there is ample room for interpretation and manufacturer-specific implementation. This is problematic when utilities are trying to achieve interoperability and multivendor interchangeability.

- Device application profiles should be created, defining the following:
 - A common set of analog, digital, and control points for a particular type of device.
 - A common set of device behaviors, with prescribed methods for performing those behaviors.
- Devices should be certified to an application profile via an external agency instead of utilizing self-certification.

Remote Device Configuration and Management

In contrast to legacy devices, current IEDs require frequent changes to firmware, settings files, and other configurations. Although local updates to devices may be feasible with substation devices, this approach is not scalable for field devices across a utility's entire service territory.

- IEDs need to support the following:
 - Remote monitoring of firmware, settings files, and configurations.
 - Remote updates of firmware, settings files, and configurations via over-the-air pushes.
 - Remote detection of changes made in the field.
 - Remote password management and versioning control.
 - Automatic configuration with the SCADA server when connected to the network.

SCADA Systems

As the volume of smart devices proliferates, discrete polling of devices will become impractical. Radio frequency communications have introduced challenges for many legacy RTUs and communications controllers, and legacy SCADA provides operators with nominal real-time data. Legacy SCADA technologies must adapt to new communications technologies and paradigms to support the emerging smart grid with high volumes of low-cost sensors and controls.

- In the future, SCADA systems and RTUs should:
 - Accommodate high volumes of devices reporting by exception rather than utilizing traditional polling methods.
 - Accommodate “sleepy” sensors that “wake up” to report.
 - Present operators data with increased degrees of variability, to accommodate intermittent renewable generation.
- SCADA communications need to adapt to handle significantly more points per device than in the past, to facilitate new smart grid applications.

SCADA Control Authority Management

Current distribution SCADA systems have an all-or-nothing approach to control authority. Future distribution systems will require control to be established at various network levels (substation/transformer/bus/line/device), in multiple modes (centralized/decentralized), and by multivendor systems controlling different grid components.

- Control management messaging between systems should be developed as a standard protocol so that the control authority management can be extracted and placed into a separate system, controlled independently. This would allow for authority communications between systems from divergent vendors.
- SCADA systems need to utilize an independent control authority manager, which should do the following:
 - Allow an application to have control authority only over the subset of devices that it requires for operation, doing whatever optimization is possible with the devices that it has been given designated control authority.
 - Define the appropriate designation of control between different systems that can control the same assets.
 - Define the appropriate designation of control priority and data management in the case of two separate localized areas (substations) that share common assets.
 - Control competing priorities between different applications. For example, they need to be able to operate different applications in closed-loop versus open-loop modes.
 - Operate different applications locally and centrally in open-loop or closed-loop modes. For example, the operator might want FISIR to be run locally in closed-loop mode, but VVC to be run centrally in open-loop mode.
 - Facilitate the concept of “control reservation,” where control authority would be granted for a specified length of time and then released automatically, relinquished to default or previous device mastership.
- An operator should be able to intercede and make a tactical choice to implement a change without having to go through the full process of taking back control.
- SCADA data can’t all be handled at the control center moving forward. The DMS solution of the future needs to have multiple levels of control hierarchy, to accommodate the increasingly large amounts of information on the distribution system.

SCADA Model Management

Legacy SCADA models are typically manually constructed and, thus, very labor intensive. In the future, they must adopt new technologies for constructing, managing, and maintaining their data models.

- Vendors should work toward GIS-supplied device configurations, since most utilities use GIS as an asset repository.
- Devices should have configuration templates to define standard point mapping. This would help to streamline the process for adding new devices.
- Industry standards (ICCP, IEC 61850, and DNP) must adopt compatible naming conventions for SCADA points to minimize point name transformations between systems.
- Devices should be plug-and-play and have the ability to automatically configure themselves with the SCADA server when connected to the network.

Advanced Distribution Management Systems

Distribution Management Systems available today vary greatly in terms of capabilities and base functionalities. Some DMSs are simply distribution SCADA systems with OMS capabilities. Others have various applications to locate and isolate faults and to reconfigure circuits. Such systems claiming to be “advanced” should have some similar functionalities, as described below.

- Many DMS vendors today claim that their systems have advanced applications, when in reality they are far from advanced. DMS applications have a lot of growth potential. Some key improvements that are needed for future DMS applications include:
 - Analysis areas must be highly configurable and granular. They should be broken down by system, area, substation, transformer, bus, feeder, and device.
 - Additional flexibility for application parameters is needed to allow different settings or algorithms for different areas of analysis.
 - DMS applications must be able to run in different modes for different areas of analysis. For example, a user might want to run applications in a closed loop for the majority of the system but, for a subset, the closed-loop mode might need to be deactivated due to planned work to be carried out in that area. An option to select closed-loop versus open-loop operation then would be needed, based on injection point or even down to the circuit level.
 - The load-flow solution has been a required element of many DMS applications, but is often difficult to achieve due to the data quality of distribution models. As more sensors proliferate in the distribution network, it may be possible to base most DMS applications on the results of state estimation. A good state estimation will go a long way—it just won’t disclose system losses.
- Current DMS models are bulky and difficult to update. Instead of approaching distribution modeling as they have approached transmission modeling, vendors need to take a completely different approach to make the form meet desired functionality.
 - Where possible, a single, standards-based network model for the distribution system should be utilized.
 - Network model updates should be driven by the frequency and volume of real-time changes to the distribution network. Model updates should be streamlined so as not to require human intervention unless data discrepancies arise.

- The granularity of the modeling system of record, typically the GIS for the distribution network, needs to be carefully considered for ingestion by the DMS. Often the GIS models pole-to-pole spans, which are too granular for many load flow/state estimation algorithms currently available.
- Lightly loaded areas of the distribution network do not have a high level of interconnectivity, so they could be optimized and analyzed based on a simplified model. Network applications should be simplified to use a heuristic or logic-based approach rather than a running power flow solution.
- Heavily loaded areas of the distribution network that are highly interconnected should use a model-based approach. These areas require advanced algorithms to make recommendations based on the real-time state of the network and optionally carry out the remedial actions to alleviate power flow violations or isolate and restore power to as many customers as possible.
- The DMS needs to adapt to accommodate distributed generation and other edge-of-grid device requirements. Currently, distributed energy resources are often modeled as negative loads, but this isn't sufficient or accurate. To accommodate the growth of distributed generation in the future, the following changes should occur with the DMS:
 - The DMS must model distributed generation appropriately and include these assets in the advanced DMS applications.
 - The advanced DMS applications should have the ability to control distributed generation.
 - The DMS needs the capability to request geographically constrained load reduction from the Distributed Resources Management System and analyze available DR/DER potential.
- As the DMS grows to incorporate more SCADA data and functionality, it will be critical to consider data presentment and how the growing quantities of data are prioritized for the appropriate users. Without careful consideration, the DMS could contain an overwhelming amount of information, and the user wouldn't be able to focus on the relevant content.
 - The DMS user interface needs to be selective at various levels so as to only present truly important information to each system in the hierarchical level. This will prevent operators from drowning in lots of irrelevant data.
 - The various components of the user environment need to be reachable from within the same environment. They don't all have to share the same user interface, but the user should be able to seamlessly navigate from one to the next.

4.3.4 SmartGeneration Technology Gaps

This is rapidly emerging area, so it is difficult to identify technology gaps. As vendors work quickly to move new products to market, such rapid development is bound to lead to oversights and subpar integrations.

Distributed Resource Management System

Most of the industry currently utilizes separate systems for managing demand response and distributed energy resource assets. The industry commonly refers to these as Demand Response Automation Servers (DRAS) and Distributed Energy Resource Management (DERM) systems. To maximize effectiveness, there should be one higher-level umbrella system capable of considering and dispatching both DR and DER. The DERM system KCP&L implemented as part of the SGDP combined these functionalities, but this certainly isn't common across the industry. As noted in the previous Lessons Learned section, the concept of a DRMS was introduced to distinguish the function of the SGDP's DERM component from the more common DERM system functionality that has evolved over the duration of the project.

- Future Distributed Resource Management Systems (DRMS) should be capable of the following:
 - Knowing all demand response assets and their capabilities.
 - Knowing all distributed energy resources and their capabilities.
 - Receiving requests for load reduction from other systems, like DMS.
 - Selecting the best resources to utilize to minimize cost.
 - Selecting the best resources to utilize to solve a geographic problem.
 - Dispatching demand response event commands.
 - Dispatching commands to distributed energy resources.
 - Receiving availability information from the assets to keep real-time expectations aligned.
- The IEC 61968 standard for dynamic exchanges does not contain sufficient messages to pass the necessary information between the DMS and the DRMS, so extensions are currently required. A significant amount of industry work needs to happen in this standard for it to be sufficient for the exchange of power flow and state estimation messages. EPRI is currently working on a set of messages that would assist with some of the new back office administration—registration of assets in the DRMS, for example.

Battery Energy Storage Systems

- Regardless of the type of battery technology used, one common shortfall is that a function-specific controller is required to send the required inverter control signals to the BESS. In the future, vendors should create standard controllers that are capable of supporting a number of BESS functions.

4.3.5 Interoperability Technology Gaps

KCP&L encountered numerous project challenges in establishing the desired level of systems integration and interoperability with the current technologies. Many of the technology gaps impacting integration and interoperability have been outlined above. Several additional points are outlined below.

Standards Development Efforts

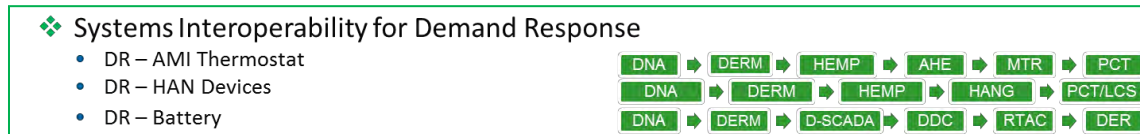
As KCP&L discovered throughout the SGDP, industry interoperability efforts have focused on standardization of the utility data model through CIM, back office systems communications via IEC 61968 and MultiSpeak, and communications to field devices via IEC 61850 and DNP. While these efforts have been important, they are not sufficient to achieve multivendor smart grid implementations.

- The CIM standard defines an informational model and not an implementation model. To achieve interchangeable, multivendor interoperability, the industry needs to focus on the development of application profiles. The application profiles would provide further functional definition, requirements, and constraints to the underlying standards. Each profile would be a collection of classes, attributes, references and behaviors, along with additional constraints that would be made by making attributes mandatory or restricting the cardinalities on associations. To enable a true plug-and-play multivendor smart grid, application profiles should have implementations configurations in:
 - IEC 61968 and MultiSpeak for back office systems integration.
 - IEC 61850 and DNP for communications to and between field devices.
- Naming conventions and point mapping need to advance to accommodate the transmission of data between systems and vendors. KCP&L utilized ICCP messaging for transmitting control and monitoring data between the user interface and the D-SCADA system, but IEC 61850 was used to transmit control and monitoring data to substation and field devices from the D-SCADA. These protocols had different naming conventions and the data points from the same device had to be assigned different names when moving from one system to another, which made data migrations and points list modifications complex.
- To promote IEC 61850 device interoperability between vendors, industry should develop standardized ANSI ICD and CID files on an application profile basis. This would provide utility engineers with a good starting point for developing their own specific standards. For example, all capacitor bank vendors could be plugged into any manufacturer's data concentrator and work interchangeably using one standardized ANSI capacitor bank CID file. Alternatively, all capacitor banks could be installed with a standardized CID file and the data concentrator would recognize it as a certain manufacturer's profile with a known behavior.

System Situational Awareness

With increased system-to-system integration, intermittent process and communication failures can have greater impacts to operations and raise the importance of proactive monitoring of systems and communication networks. A single process flow might travel through six or more different systems with stops at the ESB along the way. Figure 4-3 below shows several examples—three DR flows from KCP&L's SGDP.

Figure 4-3: Message Flows for Demand Response



- A solution is needed to provide a bird's-eye view of all of process components and their communications linkages that make up an integrated smart grid solution. This process dashboard approach should be tailored with content suitable for IT support staff, operations support staff, and grid operators. This process dashboard should accommodate the following:
 - An IT Network Operations Center to actively monitor the state of all system and intersystem processes and communications.
 - Relevant information flow to operations personnel.
 - Systems messaging for alerts, status, and exception handling.
 - Insight to communications failures several systems away.
 - Self-awareness of data quality to assist with the transition to more automated grid operations.

4.4 COMMERCIALIZATION

Although not a primary objective of KCP&L's SGDP, commercialization of smart grid technologies and products was certainly a secondary goal. For some project partners, this project experience reinforced existing assumptions about smart grid design and implementation. For others, this project modified their product road map, or even changed their over-arching smart grid strategy.

This section addresses the insights gained by project partners. The specific examples below are illustrative of the types of commercialization benefits that KCP&L's partners gained through this project. These examples are not all-inclusive, but do represent some of the most insightful feedback that KCP&L received from the project partners.

4.4.1 Technology Partners

SmartMetering

The commercialization aspects of SmartMetering focused on the AMI and MDM systems. While L+G's AMI solution was fairly well established at the time of deployment, there were some significant new challenges associated with KCP&L's project. Most of the commercialization benefit for L+G consisted of troubleshooting and bug-fixing efforts associated with ZigBee SEP 1.x. Together with KCP&L, L+G conducted extensive device interoperability testing between L+G and other vendors' devices. These efforts strengthened implementations for all devices that were using ZigBee SEP 1.x, a developing technology standard. According to L+G, "The result was a more seamless and valuable experience for customers who selected devices from two or more vendors."

In addition to assisting with the ZigBee SEP 1.x implementation, L+G's integration with Tendril on the Home Area Network helped to clarify L+G's understanding of the limitations of the first generation HAN application standard. This experience led to the proposal of additional functionality for standard adoption that was incorporated into subsequent generations of the SEP application standard.

Since L+G manages KCP&L's AMI network, this project provided L+G with experience in technology deployment that could be helpful for future enterprisewide deployment. This wasn't necessarily product commercialization, but rather service commercialization. The project helped L+G to improve functionalities and tools required to support various device installation scenarios (i.e., IHDs and thermostats) and support troubleshooting with limited customer interaction.

This project gave eMeter/Siemens the opportunity to demonstrate implementation of a hosted MDM that enables the complete meter-to-cash functions using an off-premise service. The project solution demonstrated a successful proof-of-concept in the hosted MDM market space.

Lastly, this project produced experience in IEC 61968 implementation. At the onset of the project, vendors were hesitant to utilize this standard for metering data, but KCP&L pushed them to implement it where possible. Through team work and cooperation, KCP&L, eMeter/Siemens and L+G advanced the standard to a new level of detail and operational capability. This feat enabled Siemens to differentiate between other MDM vendors that have not achieved such a high level of interoperational capability.

SmartEnd-Use

In the SmartEnd-Use project component, much commercialization was achieved through the deployment of the residential products. Many of these in-home products are very new, so experiences from each project deployment are critical for the product road maps and feature sets. KCP&L's SGDP helped L+G and Tendril identify shortcomings in the integration standards and push industry working groups to make necessary modifications. According to L+G, "While the road to commercialization of the standards-based Home Area Network is still a journey in the making, the KCP&L demonstration mobilized a key set of technologies and enabled vendors to drive this evolution toward a standards-based, interoperable, and consumer-engaging energy management solution."

In addition, Tendril's work with KCP&L led to growth of the vendor's own product. Tendril understood that customer engagement was important prior to the project, but its experiences on this project solidified the vendor's belief that segmentation is critical to improving engagement. According to Tendril, "Quite simply, each individual is unique and has different needs. Those in low-income environments interact with energy differently and require different types of messaging and incentives. With this learning in mind, coupled with experiences from working with other utilities, Tendril continually enhances its segmentation and micro-targeting functionality. These capabilities enable the delivery of targeted messaging that improves a customer's propensity to act."

SmartDistribution

The SmartDistribution component of KCP&L's project pushed some high-level distribution system philosophies. When KCP&L first drafted the proposal for this project, most vendors were adamant about centralized control of the distribution system. Very few believed that hierarchical control was a feasible strategy; Siemens was one of the few vendors that had the capabilities and the desire to pursue this approach. Although the legacy Siemens DMS that was deployed had a number of shortcomings, Siemens leveraged the learning from this project to drive its new DMS platform.

In addition to commercialization improvements to the DMS, the project also resulted in several improvements to the Tropos (ABB) mesh network, which was utilized for distribution automation. As a result of feedback from KCP&L, Tropos is planning several enhancements to its graphical user interface to allow for easy customization based on each utility's needs. Additionally, Tropos plans to provide functionality that will support encrypted communication to serial based device controllers. This wasn't feasible during KCP&L's project but, based on KCP&L's requests, Tropos prioritized this capability in its product road map.

SmartGeneration

In this rapidly changing area of KCP&L's SGDP, vendors were able to immediately apply project experience to their product road maps. The battery vendor, Exergonix, only had two Lithium Ion storage systems deployed worldwide at the beginning of the project, so the company certainly wanted to learn as much as possible from KCP&L's project. Exergonix used KCP&L's operational testing to help develop its product objectives moving forward. According to Exergonix, "What we learned about the future of energy through the SGDP was a more efficient way to deliver electricity with a high reliability level. As we look to improve performance and life of the overall system, our Next Generation distributed energy storage system will have the flexibility to integrate a higher energy density battery and will enhance reliability through advanced electronic controls, improving efficiency of the system and humanizing the life expectancy of a grid-tied unit." As a result of the SGDP, in 2015 Exergonix will be unveiling an advanced, turnkey solution that can help stabilize the grid of the future.

Another aspect of the SmartGeneration component that received commercialization throughout the project was the Distributed Energy Resources Management system provided by OATI. In order to fulfill the interoperability requirements of the project, OATI created several new interfaces: an OpenADR interface to communicate demand response events to the residential devices and the battery; an OpenCharge interface to communicate demand response events to the charging stations; and IEC 61968 messaging to exchange information with the DMS. In addition to the new interfaces, participation in KCP&L's SGDP reinforced OATI's stance on the role of webDistribute, one of its products. The product provides the functionality to manage individual DR and DER assets—both customer-side and utility-connected—to address various system, economic, and grid-reliability objectives while analyzing their impacts on the distribution grid and connected equipment. Other vendors have split up this architecture and required separate systems for DR and DER. This project confirmed that a higher-level system is needed that can call upon both types of assets.

4.4.2 Implementation Partners

In addition to the technology commercialization benefits, KCP&L's project partners also gained implementation experience. Several consulting firms assisted with the design, deployment, and operational testing for the project. All bolstered their services résumés with this comprehensive project. According to Burns & McDonnell, "Involvement with this project provided Burns & McDonnell engineers and consultants with broad, end-to-end utility systems implementation experience. Both the unique architectural design and strict interoperability standards approach have resulted in additional and valuable base experience as Burns & McDonnell assists other utilities with front-end smart grid and advanced technology feasibility studies and analyses." The Structure Group described how the project advanced its domain knowledge of a variety of smart grid technologies, in addition to improving its project delivery methods. The Structure Group was able to gain experience in vendor selection, requirements definition, system integration, testing, standards adoption, data analytics, and training/change management.

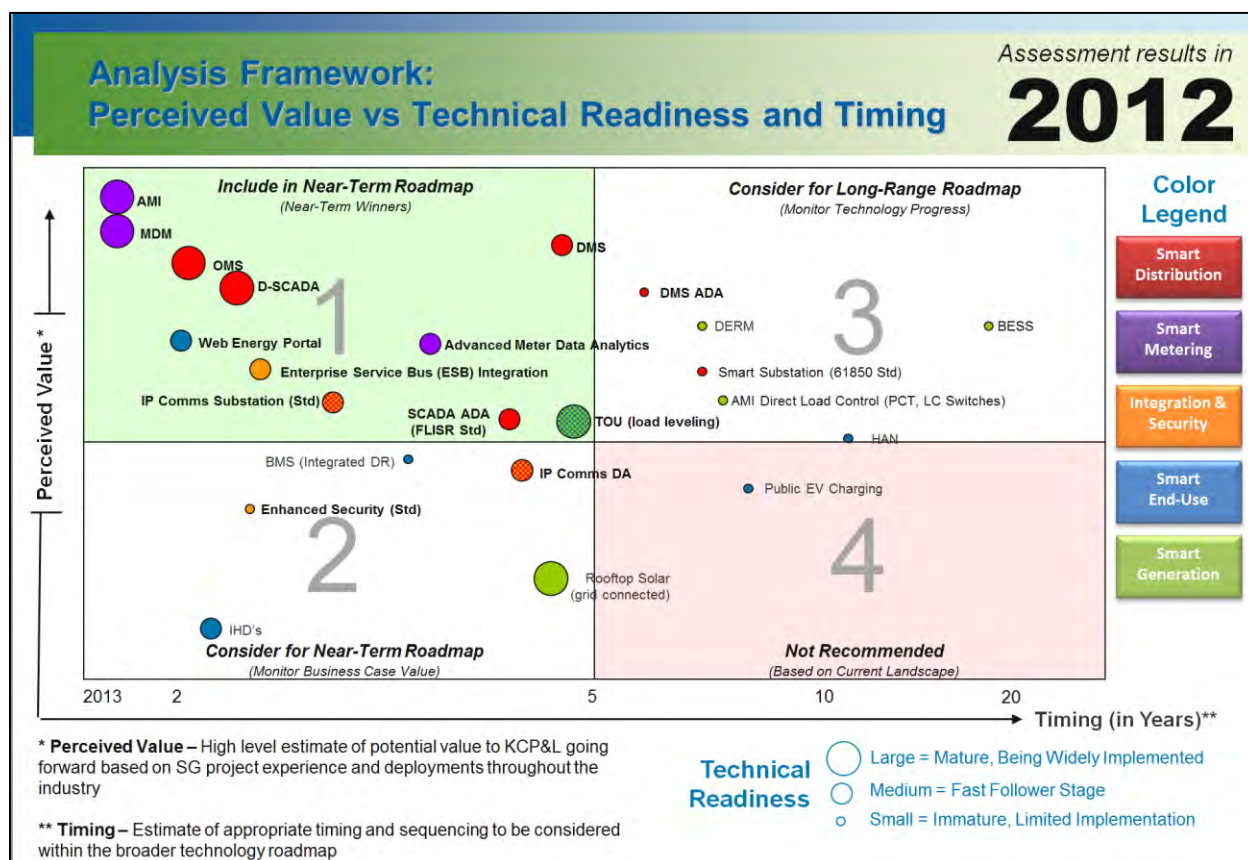
4.5 PROJECT IMPACT ON KCP&L'S FUTURE PLANS FOR SMART GRID DEPLOYMENT

The KCP&L SGDP successfully implemented and demonstrated an end-to-end smart grid that included renewable generation, premise and grid energy storage resources, leading edge substation and distribution automation and controls, energy management interfaces, and innovative customer programs and rate structures. These products were selected in 2009 and 2010. KCP&L believes that many of the smart grid technologies and functions demonstrated will be key components of the future KCP&L grid, providing more reliable service, reducing operational costs, and enhancing opportunities for consumers to manage their energy costs. KCP&L is using the findings of the project to guide planning for enterprisewide deployments of smart grid technologies.

4.5.1 Mid-Project Go-Forward Assessment

In early 2012 KCP&L began development of a near-term, multiyear (5+) corporate IT Roadmap, and the project team was asked to identify candidate smart grid systems or technologies that should be considered in this planning effort. The team evaluated each technology component to assess perceived value, technical readiness, and potential timing at which enterprise deployment would be viable. This proved particularly challenging, as many of the project components were still under development and had not yet entered the project's operational phase. Figure 4-4 illustrates the findings of the Mid-Project Technology Assessment with the following recommendations.

Figure 4-4: Mid-Project Technology Assessment



SmartMetering – This includes AMI, MDM, and Meter Data Analytics (MDA). All three of these technologies were identified as winners and it was recommended that they be evaluated for incorporation and proper sequencing (along with the planned CIS upgrade) into KCP&L’s IT Roadmap.

SmartDistribution – This includes integrated OMS/DMS/D-SCADA/ADA. The SmartDistribution technologies were designated as winners and were recommended for incorporation in the broader KCP&L IT Roadmap. OMS had already been identified as an item for replacement by the organization and there were enough benefits to move forward with these technologies in keeping with the general industry direction. Detailed requirements and vendor selections were to be incorporated early in the corporate strategy effort.

Integration and Cyber Security – The SGDP has shown the importance of proper integration between systems, and just how difficult multisystem integrations can be. Enhanced security, while not required today, is likely on the horizon to be driven by state or federal mandates. As technology continues to advance, KCP&L should seek to apply advanced and standard integration technologies (such as an ESB) wherever and whenever possible, and proactively incorporate additional physical and cyber security measures as part of the broader technology road map.

SmartEnd-Use – This includes HEMP, IHDs, HANs, and public charging stations. While some of these technologies are viable (and others may be viable at some point) the team’s recommendation was to discontinue demonstration programs at the end of 2014 (with a web portal solution as a possible exception) and to continue to evaluate select program components for future implementation as technology advances.

SmartGeneration – This includes BESS, DERM, AMI DR PCTs, and Rooftop Solar. While some of these technologies may ultimately be considered winners, it was deemed too early to tell if/when the demonstrated technologies should be considered for implementation.

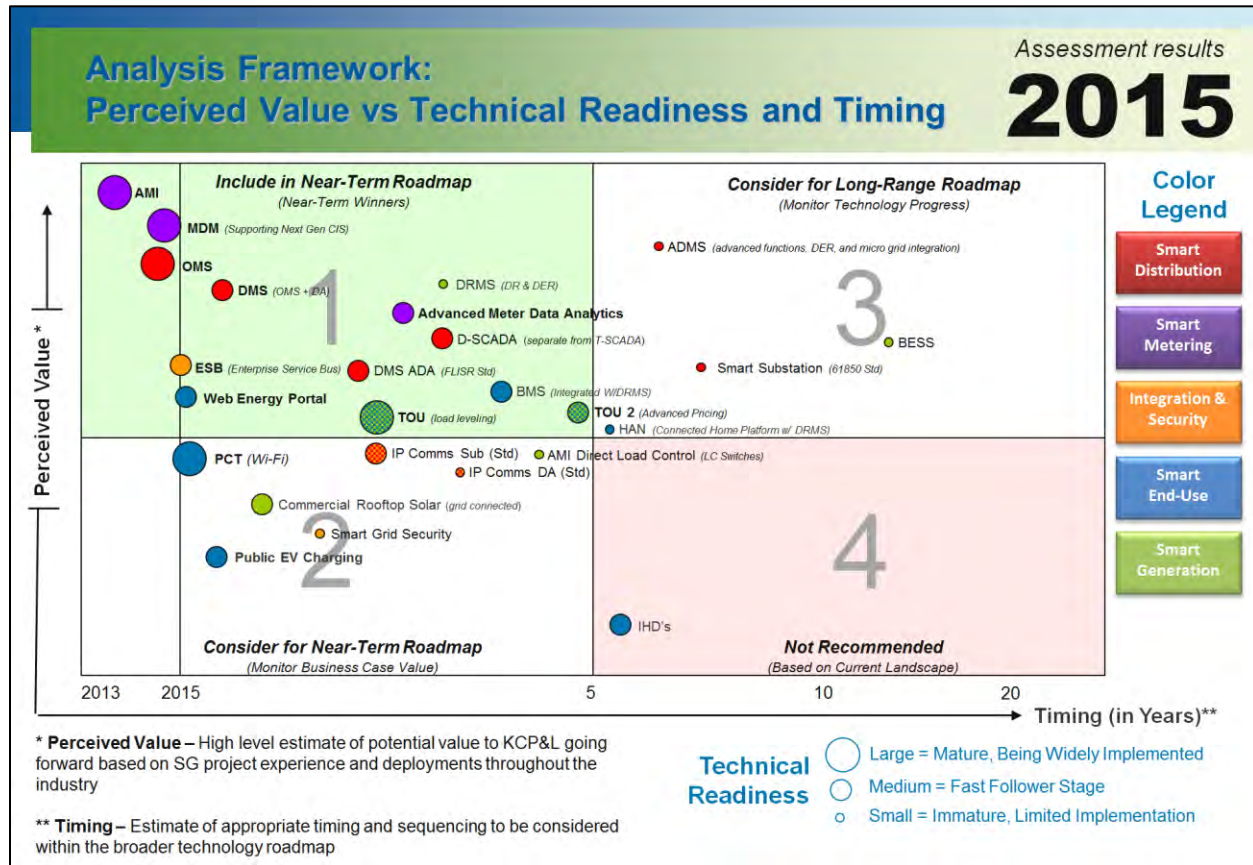
With this input, along with other analysis and considerations, the resulting IT Roadmap incorporated the implementation of a new enterprise integration architecture platform, the upgrade of the OMS, and enterprise deployments of AMI and MDM as prerequisite projects ahead of the planned next generation CIS implementation. Because most of the SGDP systems selections were made in 2009—prior to the DOE application—KCP&L determined that it would be prudent to re-evaluate all system selections prior to enterprise deployments. Therefore some of the enterprise deployments are going forward with different vendors than were used for the SGDP.

4.5.2 Current Go-Forward Strategies

Over the course of the project operational period and throughout subsequent operational demonstration testing and analysis, the project team accumulated additional insights and knowledge that have been incorporated into subsequent technology assessments and project planning that resulted from the Mid-Project Technology Assessment and IT Roadmap development discussed in the previous section.

With all of this additional learning, the team performed an end-of-project evaluation to reflect current smart grid technology initiatives and again evaluate remaining technologies to assess their perceived value and technical readiness to develop Go-Forward Strategies for each of the components of the KCP&L SGDP. Figure 4-5 illustrates the findings of the End-of-Project Technology Assessment, including go-forward recommendations.

Figure 4-5: End-of-Project Technology Assessment



4.5.2.1 Near Term Initiatives

Several of the SGDP components have been evaluated and approved for enterprisewide expansion. The following smart grid technology deployments are currently underway or planned for the immediate future.

4.5.2.1.1 SmartMetering

AMI (KC Metro) – In 2014, KCP&L began upgrading its legacy AMR system to L+G Gridstream AMI technology for approximately 500,000 customers in the metropolitan Kansas City area. This upgrade will be complete in 2015, and in 2016 an additional 185,000 manually read metro area meters will be added.

MDM – In 2015, KCP&L will be implementing an enterprisewide MDM system as the system of record for all meter information and meter read data. In addition to AMI meters, the MDM will receive meter reads from the MV-90 and hand-held meter reading systems. The MDM is being deployed ahead of, and will provide billing determinants to, the planned next-generation CIS.

4.5.2.1.2 SmartEnd-Use

Web Energy Portal – Leveraging the project knowledge in the SmartEnd-Use area, KCP&L began an energy efficiency paper reports program in 2014. In 2015, this energy efficiency program is being expanded to include a Web Energy Portal for all residential customers.

4.5.2.1.3 SmartDistribution

OMS – In the fall of 2014, KCP&L upgraded its legacy OMS to a state-of-the-art OMS, one incorporating many of the capabilities and functions demonstrated during the SGDP.

DMS – Beyond the SGDP, KCP&L has a fairly extensive DA platform for managing field devices via a public communications network. The second phase of the OMS upgrade will occur when the OMS is integrated with the existing DA platform in 2015, effectively creating a first-generation DMS.

4.5.2.1.4 SmartGeneration

PCT (Wi-Fi) – In 2014, the KCP&L DR PCT program was upgraded from a pager-based technology to a system that uses customer Wi-Fi for communication, providing customers with thermostat control capabilities from a computer or cellphone.

Public EV Charging – In late 2014, KCP&L began construction of the KCP&L Clean Charge Network, which will include more than 1,000 Level 2 and Level 3 public charging stations. The network, along with future EV charging products and services, will allow KCP&L to manage increased EV penetrations and minimize grid impacts. The network should reduce anxiety regarding EV range by providing a charging infrastructure that is both robust and public.

Rooftop Solar – In 2015, KCP&L plans to begin an expanded rooftop solar pilot program with an additional 3-5 MW of utility-owned, grid-connected, rooftop commercial solar installations.

4.5.2.2 Longer Term Strategies

While some of the SGDP technologies are viable today (and others may be viable at some point), they may be dependent on some pre-requisite technology deployments or different economic conditions to become cost beneficial. KCP&L will continue to evaluate these project components for future implementation. The following points outline the SGDP team's current recommendations for the key remaining SGDP technology components demonstrated.

4.5.2.2.1 SmartMetering

AMI (non Metro) – After implementation of the next-generation CIS, KCP&L plans to deploy AMI technology to KCP&L's remaining 160,000 customers outside of the Kansas City metropolitan area, assuming the business case remains favorable.

4.5.2.2.2 SmartEnd-Use

TOU – The SGDP validated the challenges of implementing TOU rates with KCP&L's legacy CIS. The recommendation is that multitier TOU rates be developed and planned for implementation after the next-generation CIS is implemented and a majority of the AMI rollout is complete.

TOU2 – This would include several advanced pricing programs, such as critical peak pricing and real-time pricing. The team projects that these types of pricing programs may have merit at some point; however, they must be carefully constructed and should be considered for implementation after basic TOU rates. AMI, MDM, and next-generation CIS implementations form the foundation for these advanced pricing programs.

HAN – The area of customer home energy automation has been slow to progress, and platform technologies have been rapidly changing. In the near term it appears that providers of connected homes are better positioned to provide such services than a traditional electric distribution utility would be. The project team’s current recommendation is that KCP&L use the AMI’s capabilities to provide real-time customer meter information to a customer’s HAN Gateway, but that KCP&L not be the provider of the home energy automation platform. At some future point, it may become desirable, from a strategic standpoint, for the utility to offer some form of home energy automation/management platform.

4.5.2.2.3 SmartDistribution

DMS-ADA – This proposed Advanced DA initiative would deploy additional automated reclosers, switches, and localized automation schemes targeted at the worst-performing circuits, along with localized areas of lower reliability. The project team believes that by leveraging the existing DA network and first-generation DMS, many issues regarding customer reliability could be addressed—and reliability improved—at a relatively low cost.

D-SCADA – While the project team believes that a dedicated distribution SCADA system is a foundational smart grid technology and that it will eventually be required at KCP&L, the SGDP identified several significant technology gaps in the current SCADA technology relative to the future smart grid needs. The team recommends that KCP&L continue to monitor the progress of the industry in addressing these gaps and consider deployment of a D-SCADA system once significant progress has been made or when the existing DA platform no longer meets the company’s automation needs.

ADMS – The project team believes that an Advanced DMS is a foundational smart grid technology and will eventually be required at KCP&L. However, the SGDP identified several technology gaps in current DMS technology relative to future smart grid needs or managing distributed energy resources and other emerging edge-of-grid technologies. The team recommends that KCP&L continue to monitor the progress of the industry in addressing these gaps and consider deployment of an ADMS system after the deployment of a D-SCADA system and when significant progress has been made or when the existing first-generation DMS no longer meets the company’s needs.

4.5.2.2.4 SmartGeneration

DRMS – The project team believes that a Distributed Resource Management System is an integral smart grid technology that will eventually be required at KCP&L for managing DR and DER resources across a growing number of technologies and platform providers. DRMS systems are continuing to expand their capabilities, and the team recommends that KCP&L evaluate inclusion of a DRMS as a platform component in the next round of DR program planning.

Grid Battery – The project team believes that a grid BESS will at some point be cost effective and become a key element of the future distribution grid. The team recommends that KCP&L continue to monitor the economics of BESS and consider BESS application when costs come down and additional benefit streams can be obtained from the wholesale market.

Premise Battery – The project team believes that a Premise Energy Storage System will at some point be cost effective and become a key energy support element for both the customer and the distribution utility. The team recommends that KCP&L continue to monitor the economics of PESS and consider designing DR programs that incorporate them.

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7 ABBREVIATIONS AND ACRONYMS

ACM – Asset Characterization Module
ADA – Advanced Distribution Automation
AHE – AMI Head-End
AMI – Advanced Metering Infrastructure
AMR – Automated Meter Reading
AOS – Alexander Open Systems
BAC – Battery Automation Controller
BESS – Battery Energy Storage System
BMS – Building (Energy) Management System
CAD – Computer-Aided Dispatch
CID – Configured IED Description
CIM – Common Information Model
CIP – Critical Infrastructure Protection (NERC)
CIS – Customer Information System
CLP – Critical Load Panel
CM – Computational Module
CMEP – California Metering Exchange Protocol
CPHE – Customer Pilot Hosting Environment
CSWG – SGIP Cyber Security Working Group
CT – Current Transformer
CVR – Conservation Voltage Reduction
DA – Distribution Automation
DAC – Distribution Automation Controller
DCADA – Distributed Control and Data Acquisition
DDC – Distribution Data Concentrator
DER – Distributed Energy Resource
DERM – Distributed Energy Resource Management
DG – Distributed Generation
DIM – Data Input Module
DLC – Direct Load Control
DM – Distribution Management
DMAT – Data Mining and Analysis Tool
DMS – Distribution Management System
DNA – Distribution Network Analysis
DNP – Distributed Network Protocol
DOE – Department of Energy
DR – Demand Response
DRAS – Demand Response Automation Server
DRMS – Distributed Resource Management System
D-SCADA – Distribution Supervisory Control and Data Acquisition
DSE – Data Synchronization Engine
DSPF – Distribution System Power Flow
DSSE – Distribution System State Estimator
DVC – Dynamic Voltage Control
EISA – Energy Independence and Security Act
EMS – Energy Management System
EPRI – Electric Power Research Institute
eRSTP – Enhanced Rapid Spanning Tree Protocol
ESB – Enterprise Service Bus
ESCSWG – Energy Sector Control Systems Working Group
ESCT – Energy Storage Computational Tool

EV – Electric Vehicle
EVCS – Electric Vehicle Charge Station
EVSE – Electric Vehicle Supply Equipment
FAN – Field Area Network
FAT – Factory Acceptance Testing
FCI – Fault Current Indicator
FDIR – Fault Detection, Isolation and Restoration
FDP – Fiber Distribution Panels
FERC – Federal Energy Regulatory Commission
FISR – Fault Isolation and Service Restoration
FLOC – Fault Location
FLT – Feeder Load Transfer
FTE – Full Time Equivalent
GIS – Geographic Information System
GOOSE – Generic Object-Oriented Substation Event
GPE – Great Plains Energy
GUI – Graphical User Interface
GWAC – GridWise Architecture Council
HAN – Home Area Network
HAND – Home Area Network Device
HANG – Home Area Network Gateway
HEMP – Home Energy Management Portal
HIS – Historical Information System
HMI – Human Machine Interface
IBEW – International Brotherhood of Electrical Workers
ICCP – Inter-Control Communications Protocol
IEC – International Electrotechnical Commission
IED – Intelligent Electronic Device
IEEE – Institute of Electrical and Electronics Engineers
IETF – Internet Engineering Task Force
IHD – In-Home Display
IMM – Information Model Management
IP – Internet Protocol
IRP – Integrated Resource Planning
ISO – Independent System Operator
IT – Information Technology
IVR – Integrated Voice Response
JMS – JAVA Messaging Service
KCC – Kansas Corporation Commission
KCP&L – Kansas City Power & Light
KCP&L-GMO – KCP&L Greater Missouri Operations Company
L+G – Landis + Gyr
LCS – Load Control Switch
LTC – Load Tap Changer
MARC – Mid-American Regional Council
MDM – Meter Data Management
MEC – Metropolitan Energy Center
MMS – Manufacturing Messaging Specification
MPLS – Multi-Protocol Label Switching
MPSC – Missouri Public Service Commission
MQ – Message Queues
MUDR – Metered Data Usage Repository
NERC – North American Electric Reliability Corporation
NETL – National Energy Technology Laboratory
NIPP – U.S. National Infrastructure Protection Plan

NIST – National Institute of Standards and Technology
NISTIR – NIST Interagency or Internal Reports
NRC – Nuclear Regulatory Commission
NREL – National Renewable Energy Laboratory
NSPE – National Society of Professional Engineers
OASIS – Advancing Open Standards for the Information Society
OATI – Open Access Technology International
ODR – On-Demand Read
OEM – Original Equipment Manufacturer
OMS – Outage Management System
OMSM – Outage Management Support Module
OpenADR – Open Automated Demand Response
OT – Operational Technology
PAS – Power Automation System
PCM – Project Characterization Module
PCS – Power Conditioning System
PCT – Programmable Communicating Thermostat
PESS – Premise Energy Storage System (battery)
PEV – Plug-in Electric Vehicle
PFP – Pay for Participation
PLC – Programmable Logic Controller
PLP – Project Living Proof
POA – Power Outage Analysis
PoE – Power over Ethernet
PSV – Power Status Verification
PT – Potential Transformer
PV – Photo Voltaic (Solar)
RDBMS – Relational Data Base Management System
RDF – Resource Description Framework
REP – Resilient Ethernet Protocol
REST – Representational State Transfer
RSO – Remote Service Order
RSTP – Rapid Spanning Tree Protocol
RTAC – Real Time Automation Controller
RTO – Regional Transmission Organization
RTU – Remote Terminal Unit
RVA – Restoration Verification Analysis
SAAS – Software-As-A-Service
SAML – Security Assertion Markup Language
SAT – Site Acceptance Testing
SEL – Schweitzer Engineering Laboratory
SEP – Smart Energy Profile
SGAC – Smart Grid Architecture Committee
SGCT – Smart Grid Computational Tool
SGDG – Smart Grid Demonstration Grant
SGDP – SmartGrid Demonstration Project
SGIG – Smart Grid Investment Grant
SGIP – Smart Grid Interoperability Panel
SICAM – Siemens Integrated Control and Monitoring
SIS – Solar Integration System
SLPB – Superior Lithium Polymer Battery
SME – Subject Matter Expert
SMS – Storage Management System
SOA – Service-Oriented Architecture
SOAP – Simple Object Access Protocol

SPID – Service Point Identifier
SPM – Switching Procedure Management
SPN – Substation Protection Network
SPP – Southwest Power Pool
SSO – Single Sign-On
T&D – Transmission and Distribution
TOU – Time of Use
TPR – Technology Performance Report
TTM – Tunnel Text Message
UCAIug – UCA International Users Group
UI – User Interface
USABC – U.S. Advanced Battery Consortium
VAR – Volt-ampere reactive
VCMS – Electric Vehicle Charge Management System
VEE – Validation, Estimation and Editing
VVC – Volt/VAR Control
W3C – World Wide Web Consortium
WAN – Wide Area Network
WASA – Wide Area Situational Awareness
WS-I – OASIS Web Service Interoperability
XML – Extensible Markup Language

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Appendices were published in separate document entitled

KCP&L Green Impact Zone SmartGrid Demonstration Final Technical Report Appendices.

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RECOVERY ACT – SMARTGRID REGIONAL DEMONSTRATION
TRANSMISSION AND DISTRIBUTION (T&D) INFRASTRUCTURE

KCP&L GREEN IMPACT ZONE SMARTGRID DEMONSTRATION

FINAL TECHNICAL REPORT APPENDICES

DOE-KCP&L-0000221



WORK PERFORMED UNDER AGREEMENT

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SUBMITTED BY

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A.1 Build Metrics

“Project Only” pertains to assets deployed only within this project scope DOE/Cost Share funding. “System-Wide” pertains to the total assets deployed on the KCP&L system, including those deployed within this project.

A.1.1 Build Metrics for KCP&L’s AMI Assets

BUILD METRICS: Advanced Metering Infrastructure Assets				
Metric	Value Units	Project-Only	System-Wide	Notes
End-Points (meters)	# endpoints	-	-	~14,000 planned
Portion of Customers with AMI				
Residential	# endpoints	-	-	~13,000 planned
Commercial	# endpoints	-	-	~1,000 planned
Industrial	# endpoints	-	-	None planned
Metering Features				
Interval Reads of 1 Hour or Less	minutes	-	-	15-min interval through all AMI endpoints
Remote Connection/Disconnection	Yes/No # endpoints	- -	- -	Not necessarily on all AMI endpoints
Outage Detection/Reporting	Yes/No # endpoints	- -	- -	All AMI endpoints but on system, not all AMR?
Power Quality Monitoring	Yes/No # endpoints	- -	- -	AMI will report voltage violations
Tamper Detection	Yes/No # endpoints	- -	- -	All AMI endpoints
Backhaul Communications Network	Description	Private Fiber	Private Fiber	KCP&L will use existing private fiber at the project substation for backhaul comm.
Meter Communications Network	Description	L+G Gridstream AMI Mesh (900 MHz)	L+G Gridstream AMI Mesh (900 MHz)	L+G AMI Mesh installed with this project and no other AMI is on the system
Head-end System	Description	L+G Gridstream	L+G Gridstream	L+G hosted head-end
Meter Data Management System	Description	eMeter	eMeter	New AMI MDM
Meter Data Analysis Systems	Description	MDM, DataRaker	MDM, DataRaker	Will use existing DMAT (DataRaker) and MDM for data analysis
Enterprise Systems Integration				
Billing	Yes/No Description	-	-	New AMI will be integrated with existing Billing system
Customer Information System	Yes/No Description	-	-	New AMI will be integrated with existing CIS
Outage Management System	Yes/No Description	-	-	New AMI will be integrated with existing OMS
Distribution Management System	Yes/No Description	-	-	New AMI will be integrated with New DMS

A.1.2 Build Metrics for KCP&L's Customer System Assets

BUILD METRICS: Customer System Assets				
Metric	Value Units	Project-Only	System-Wide	Notes
Home Area Network	# devices Description	-	-	400 Tendril HAN gateways to be deployed in conjunction with PCT and some plug load monitor/switches
In-Home Displays	# devices Description	-	-	1600 project IHDs to be deployed
Web Portal	# with access # active acct.	-	-	All AMI endpoints will have access
Energy Management Devices/Systems	# devices Description	-	-	3 commercial SmartGrid enabled BEMSs
Direct Load Control Devices	# devices Description	-	-	None system-wide, to be deployed thru HAN and maybe others
Programmable Controllable Thermostat	# devices Description	-	-	Up to 1600 expected to be deployed (50,000 in Energy Optimizer Program)
Smart Appliances	# devices Description	-	-	No deployment on Project beyond appliances installed at Demonstration House

A.1.3 Build Metrics for KCP&L's Electrical Distribution Assets

BUILD METRICS: Electric Distribution System Assets				
Metric	Value Units	Project-Only	System-Wide	Notes
Portion of System with SCADA	%	N/A	N/A	SCADA already present in Demonstration Area.
Portion of System with Distribution Automation (DA)	%	-%	-%	Number of distribution feeders that have fully integrated DA equipment installed as a result of this project divided by total distribution feeders.
DA Devices				
Automated Feeder Switches	# devices	-	-	TBD switches/reclosers to be added on DA circuits
Automated Capacitors	# devices	-	-	Upgrading all cap controls and comm.
Automated Regulators	# devices	-	-	Incl. LTCs at substation
Feeder Monitors	# devices	-	-	End of line voltage monitors 3+ circuits
Remote Fault Indicators	# devices	-	-	On DA circuits
Transformer Monitors (line)	# devices	-	-	None planned
Smart Relays	# devices	-	-	All Midtown circuits
Fault Current Limiter	# devices	-	-	None planned
DA Communications Network	Yes/No Description	AMI Mesh	AMI Mesh	DA devices will use AMI Mesh network
Substation Transformer Monitor & Dynamic Ratings	# devices	-	-	All 161/13kV transformers will have temp & DGA monitoring installed. (4 transformers in total)
Distribution Feeder Cable Monitor & Dynamic Ratings	# devices	-	-	Deployment potential being investigated.
DA System Features/Applications				
Fault Location, Isolation and Service Restoration (FLISR)	Yes/No	-	-	
Voltage Optimization	Yes/No	-	-	Including DVC and CVR, Urban circuits already have DVC
Feeder Peak Load Management	Yes/No	-	-	Batt, DR will be added and enhanced.
Microgrids	Yes/No	-	-	None planned
Distribution Management System				
Integration with AMI	Yes/No	-	-	New DMS will integrate with AMI
Integration with Outage Management System	Yes/No	-	-	New DMS will integrate with OMS
Integration with Transmission Management System	Yes/No	N/A	N/A	None planned
Integration with Distributed Energy Resources	Yes/No	-	-	New DMS will integrate with DERM

A.1.4 Build Metrics for KCP&L's Distributed Energy Resources

BUILD METRICS: Distributed Energy Resources				
Metric	Value Units	Project-Only	System-Wide	Notes
Distributed Gen.: Number of Units	#	-	-	~180 kW distributed solar to be installed by the project. This metric only considers KCP&L-owned DG.
Distributed Gen.: Installed Capacity	MW	-	-	
Distributed Gen.: Energy Delivered	MWh	-	-	
Energy Storage: Number of Units	#	-	-	1x1.0MW grid battery and 1x8kW at demo home
Energy Storage: Installed Capacity	MW	-	-	
Energy Storage: Energy Delivered	MWh	-	-	
PEV Charging: Number of Units	# points	-	-	10 charging points planned for project.
PEV Charging: Installed Capacity	kW	-	-	
PEV Charging: Energy Delivered	kWh	-	-	
DG (DER) Interconnection equipment	# of units	-	-	Grid batt, parallel gens, and DR devices

A.1.5 Build Metrics for KCP&L's Pricing Programs

BUILD METRICS: Pricing Programs				
Metric	Value Units	Project-Only	System-Wide	Notes
Retail Rate Design and Rate Level				
Flat	Yes/No # with access # enrolled Description	-	-	None planned
Flat with Critical Peak Pricing				None planned
Flat with Peak-Time Rebate				None planned
Tier				KCP&L has seasonal w/ declining block
Tier with Critical Peak Pricing				None planned
Tier with Peak-Time Rebate				None planned
Time-of-Use				Existing plus new piloted rates
Variable Peak Pricing				None planned
Time-of-Use with Critical Peak Pricing				Maybe
Time-of-Use with Peak-Time Rebate				Maybe
Real-Time Pricing				None planned
Real-Time Pricing with Critical Peak Pricing				None planned
Real-Time Pricing with Peak Time Rebate				None planned
Pre-Pay Pricing				Maybe
Net Metering				Yes
Rate Decoupling				None planned

A.2 Impact Metrics

A.2.1 Impact Metrics for KCP&L's AMI and Customer Systems

IMPACT METRICS: AMI and Customer Systems				
Metric	Value Units	Project-Level	System-Level	Notes
Metrics Related Primarily to Economic Benefits				
Hourly Customer Electricity Usage	kWh \$/kWh	- -	N/A N/A	Pilot project affects a small portion of KCP&L load and will have no discernable affect on these metrics.
Monthly Customer Electricity Usage	kWh \$/kWh	- -	N/A N/A	
Peak Generation and Mix	MW Mix	N/A	N/A	
Peak Load and Mix	MW Mix	N/A	N/A	
Annual Generation Cost	\$	N/A	N/A	
Hourly Generation Cost	\$/MWh	N/A	N/A	
Annual Electricity Production	MWh	N/A	N/A	
Ancillary Services Cost	\$	N/A	N/A	
Meter Operations Cost	\$	-	N/A	
Truck Rolls Avoided	#	-	N/A	
Metrics Related Primarily to Environmental Benefits				
Meter Operations Vehicle Miles	miles	-	N/A	Estimate based on average miles/roll
CO2 Emissions	tons	-	N/A	Prorated plant emissions and fleet emission associated with reduced vehicle miles
Pollutant Emissions (SO _x , NO _x , PM-2.5)	tons	-	N/A	
Metrics Related Primarily to AMI System Performance				
Meter Data Completeness	%	-	N/A	Considers only project AMI meters, no AMR metrics
Meters Reporting Daily by 2AM	%	-	N/A	

A.2.2 Impact Metrics for KCP&L's Electric Distribution Systems

IMPACT METRICS: Electric Distribution Systems				
Metric	Value Units	Project-Level	System-Level	Notes
Metrics Related Primarily to Economic Benefits				
Distribution Feeder or Equipment Overload Incidents	# incidents	-	N/A	
Distribution Feeder Load	MW MVAR	-	N/A	
Deferred Distribution Capacity Investments	\$	-	N/A	Only if an upgraded is deemed avoided through load mgmt.
Equipment Failure Incidents	# incidents	-	N/A	Failed project dist. equipment
Distribution Equipment Maintenance Cost	\$/semi-annum	-	N/A	Maintenance Cost as defined by KCP&L
Distribution Operations Cost	\$/semi-annum	-	N/A	Operations Cost as defined by KCP&L
Distribution Feeder Switching Operations	# manual switchings	-	N/A	Tally of manual switching events
Distribution Capacitor Switching Operations	# manual switchings	N/A	N/A	All capacitors have local/remote switching capabilities installed already.
Distribution Restoration Cost	\$/semi-annum	-	N/A	Estimated based on restoration activities tracked in MWMS
Distribution Losses (%)	%	-	N/A	Cum. of kWh lost b/w sub. and meters
Distribution Power Factor	project PF	-	N/A	PF for project circuits
Truck Rolls Avoided	# truck rolls	-	N/A	Activities that previously required a truck roll
Metrics Related Primarily to Reliability Benefits				
SAIFI	Index	-	N/A	
SAIDI/CAIDI	Index	-	N/A	
MAIFI	Index	-	N/A	
Outage Response Time	Minutes	-	N/A	If no events, will consider simulation
Major Event Information	Event Statistics	-	N/A	Describe each event that qualifies (#, etc.)
Number of High Impedance Faults Cleared	# faults cleared	-	N/A	Logged by DMS/DCADA?
Metrics Related Primarily to Environmental Benefits				
Distribution Operations Vehicle Miles	miles	-	N/A	Base on average system miles/roll
CO ₂ Emissions	tons	-	N/A	Prorated plant emissions and fleet emission associated with reduced vehicle miles
Pollutant Emissions (SO _x , NO _x , PM-2.5)	tons	-	N/A	

A.2.3 Impact Metrics for Battery Energy Storage System (BESS)

IMPACT METRICS: Battery Energy Storage System (BESS)				
Metric	Value Units	Project-Level	System-Level	Notes
Metrics Related Primarily to Economic Benefits				
Annual Storage Dispatch	kWh	-	N/A	
Average Energy Storage Efficiency	%	-	N/A	
Monthly Demand Charges	\$/kW-month	N/A	N/A	
Capacity Market Value	\$/MW	N/A	N/A	
Ancillary Services Revenue, A	\$	N/A	N/A	
Average Ancillary Service Price, A	\$/MWh	N/A	N/A	
Ancillary Services Revenue, B	\$	N/A	N/A	
Average Ancillary Service Price, B	\$/MWh	N/A	N/A	
Ancillary Services Revenue, C	\$	N/A	N/A	
Average Ancillary Service Price, C	\$/MWh	N/A	N/A	

A.3 Baseline Build Metrics

Baseline Estimates are limited to the Project area, system, and assets.

A.3.1 Baseline Build Metrics for KCP&L's AMI Assets

BASELINE ESTIMATES FOR BUILD METRICS: AMI Assets				
Metric	Baseline Remarks	Baseline Estimate	Quarterly Forecast	Baseline Estimation Method
End-Points (smart meters):				
Residential	No AMI metering would be planned for installation in the KCP&L service territory without this project	0	-	
Commercial		0	-	
Industrial		0	-	
Metering Features:				
Interval reads of 1 hour or less	Some load research meters are read on 15 min. intervals thru the AMR for regulatory	0	-	No AMI without project
Remote Connection/Disconnection	No remote connect/disconnect meters would be installed without this project	0	-	
Outage Detection/Reporting	AMR has Outage Reporting	0	-	
Power quality monitoring	No PQ monitoring meters would be installed at residential without project	0	-	
Tamper detection	No tamper detection meters would be installed without this project	0	-	
Backhaul Communications Network	KCP&L has an existing fiber backhaul comm. network that will be utilized by project	0	-	
Meter Communications Network	KCP&L has AMR but would not implement 2-way meter comm. without this project	0	-	
Head End system	KCP&L has AMR head-end but would not implement AMI head-end without this project	0	-	
Meter Data Management System	KCP&L would not implement MDMS without this project	0	-	
Enterprise systems integration:				
Billing	No AMI without project	0	-	Integrated w/ AMI
Customer information system	No AMI without project	0	-	Integrated w/ AMI
Outage management system	No AMI without project	0	-	Integrated w/ AMI
Distribution Management System	No AMI without project	0	-	Integrated w/ AMI

A.3.2 Baseline Build Metrics for KCP&L's Customer System Assets

BASELINE ESTIMATES FOR BUILD METRICS: Customer System Assets				
Metric	Baseline Remarks	Baseline Estimate	Quarterly Forecast	Baseline Estimation Method
Home Area Network	KCP&L would not implement HANs without this project	0	-	Number of HANs
In-Home Displays	KCP&L would not implement IHDs without this project	0	-	Number of IHDs
AMI Web Portal	KCP&L offers AccountLink (daily read data online access to all AMR customers)	0	-	This is a baseline of AMI Portal participants
Energy Management Devices/Systems	KCP&L would not interface with BEMSs without this project	0	-	Number of communicating BEMSs
Direct Load Control Devices	KCP&L would not implement DLCs without the project	0	-	Number of DLCs
Programmable Controllable Thermostat	KCP&L currently operates a successful PCT program, Energy Optimizer, which utilizes a paging system.	-		Number of EO participants (~50,000)

A.3.3 Baseline Build Metrics for KCP&L's Electric Distribution System Assets

BASELINE ESTIMATES FOR BUILD METRICS: Electric Distribution System Assets				
Metric	Baseline Remarks	Baseline Estimate	Quarterly Forecast	Baseline Estimation Method
Portion of System with SCADA	SCADA is already installed on project substation feeders and most of KCP&L system	N/A	N/A	Existing SCADA will remain in place on project substation. This project will install a distributed substation controller and new substation network that will operate in parallel with SCADA
Portion of project system with Distribution Automation (DA)	Some automated equipment exists within the project area but no circuits have comprehensive DA	0%	-	Portion of feeders with distributed automated control and monitoring
DA Devices				
Automated Feeder Switches	No Automated Feeder Switches would be installed on the project system	0	-	Number of automated feeder switches installed on project system
Automated Capacitors	Unknown how many additional Capacitors would be installed without this project.	0	-	Unknown how many additional Capacitors would be installed without this project.
Automated Regulators	KCP&L would not install automated regulators without this project	0	-	Number of automated regulators installed on project system
Feeder Monitors (voltage or current)	KCP&L would not install feeder voltage or current monitors without project	0	-	Number of feeder voltage monitors installed on project system
Remote Fault Indicators	KCP&L would not install RFIs without this project	0	-	Number of remote fault indicators installed on project system
Transformer Monitors(line)	Line transformer monitors would not be installed without this project	0	-	Number of line xfmr monitors installed on project system
Smart Relays	KCP&L would not install smart relays without this project	0	-	Number of smart relays installed on project system
DA Communications Network	KCP&L currently has segregated device communications (telemetry and cellnet). Advanced DA in this project will primarily utilize the AMI Mesh network.			
Substation Transformer Monitors & Dynamic Ratings	Transformer monitors and DGA would not be installed without this project	0	-	Number of xfmr monitors installed on project system

BASELINE ESTIMATES FOR BUILD METRICS: Electric Distribution System Assets				
Metric	Baseline Remarks	Baseline Estimate	Quarterly Forecast	Baseline Estimation Method
Distribution Feeder Cable Monitor & Dynamic Ratings	KCP&L would not install cable monitors without project	0	-	Number of devices
DA System Features/Applications				
Fault Location, Isolation and Service Restoration (FLISR)	KCP&L would not install FLISR without this project	No	-	
Voltage Optimization	KCP&L has no circuits with true voltage optimization but does have many circuits with voltage reduction capabilities through LTCs at the sub in conjunction with cap banks on the lines	No	-	Select circuits will get true voltage optimization through decentralized control
Feeder Peak Load Management	Project circuits currently have DVC and some DR devices which are controlled on a system-wide execution	No	-	System enabled and functional
Microgrids	KCP&L is not pursuing Microgrids in this project	No	-	N/A
Distribution Management System				
Integration with AMI	AMI would not be installed without this project	No	-	
Integration with Outage Management System	No DMS without this project	No	-	
Integration with Trans. Mgmt System (EMS)	No DMS without this project	No	-	
Integration with DER	No DMS without this project	No	-	
Fault Current Limiter	No DMS without this project	No	-	

A.3.4 Baseline Build Metrics for KCP&L's Distributed Energy Resource Assets

BASELINE ESTIMATES FOR BUILD METRICS: Distributed Energy Resource Assets				
Metric	Baseline Remarks	Baseline Estimate	Quarterly Forecast	Baseline Estimation Method
Distributed Gen.: Number of Units Distributed Gen.: Installed Capacity Distributed Gen.: Energy Delivered	No KCP&L owned DG would be implemented in the project area without project	0 0 0	- - -	Only refers to KCP&L-owned DG in project area
Energy Storage: Number of Units Energy Storage.: Installed Capacity Energy Storage: Energy Delivered	Would not implement storage without project	0 0 0	-	Project area
DER Integration	There would be no DERM without project	0	-	# of interfaces
PEV Charging: Number of Units PEV Charging: Installed Capacity PEV Charging: Energy Delivered	It is not likely that charging stations would have been installed in the project area without the project funding	0 0 0	-	

A.4 Baseline Impact Metrics

A.4.1 Baseline Impact Metrics for KPC&L's AMI and Customer System

BASELINE ESTIMATES FOR IMPACT METRICS: AMI and Customer Systems				
Metric	Baseline Remarks	Baseline Estimate	Quarterly Forecast	Baseline Estimation Method
Hourly Customer Electricity Usage	kWh \$/kWh	TBD		Baseline 8760 data for each group of smart grid customers
Monthly Customer Electricity Usage	kWh \$/kWh	TBD		Historical monthly consumption data
Peak Generation and Mix	MW Mix	N/A		N/A
Peak Load and Mix	MW Mix	N/A		N/A
Annual Generation Cost	\$	N/A		N/A
Hourly Generation Cost	\$/MWh	N/A		N/A
Annual Electricity Production	MWh	N/A		N/A
Ancillary Services Cost	\$	N/A		N/A
Meter Operations Cost	\$	TBD		Extracted from accounting systems
Truck Rolls Avoided	#	TBD		Based on automated or remote actions that previously manual
Meter Operations Vehicle Miles	Miles	TBD		Avg. travel distance times number of rolls avoided.
CO ₂ Emissions	tons	TBD		Prorated plant emissions and fleet emission associated with reduced vehicle miles
Pollutant Emissions (SO _x , NO _x , PM-2.5)	tons	TBD		
Meter Data Completeness	%	TBD		Portion of attempted reads missing or corrupt
Meters Reporting Daily by 2AM	%	TBD		Portion of meters successfully reporting by 2AM

A.4.2 Baseline Impact Metrics for KPC&L's Electric Distribution Systems

BASELINE ESTIMATES FOR IMPACT METRICS: Electric Distribution Systems				
Metric	Baseline Remarks	Baseline Estimate	Quarterly Forecast	Baseline Estimation Method
Distribution Feeder or Equipment Overload Incidents	#	TBD		Derived from historical records
Distribution Feeder Load	MW MVAR	TBD		Derived from historical records
Deferred Distribution Capacity Investments	\$	TBD		Derived from historical records
Equipment Failure Incidents	#	TBD		Derived from historical records
Distribution Equipment Maintenance Cost	\$	TBD		Derived from historical records
Distribution Operations Cost	\$	TBD		Derived from historical records
Distribution Feeder Switching Operations	#	TBD		Derived from historical records
Distribution Capacitor Switching Operations	#	TBD		Derived from historical records
Distribution Restoration Cost	\$	TBD		Derived from historical records
Distribution Losses (%)	%	TBD		Derived from historical records
Distribution Power Factor	pf	TBD		Derived from historical records
Truck Rolls Avoided	#	TBD		Derived from historical records
SAIFI	Index	TBD		Derived from historical records. Baseline estimates are calculated very differently from project observation
SAIDI/CAIDI	Index	TBD		
MAIFI	Index	TBD		
Outage Response Time	Minutes	TBD		Derived from historical records
Major Event Information	Event Statistics	TBD		Derived from historical records
Number of High Impedance Faults Cleared	#	TBD		Derived from historical records
Distribution Operations Vehicle Miles	Miles	TBD		Derived from historical records
CO ₂ Emissions	tons	TBD		Derived from historical records
Pollutant Emissions (SO _x , NO _x , PM-2.5)	tons	TBD		Derived from historical records

Appendix B KCP&L SmartGrid Use Cases

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The KCP&L Project Team would like to acknowledge the prior works of many individuals that form the basis of the Use Cases developed specifically for our project. Prior works by EPRI, the following organizations, and others provided the foundation for a significant portion of this work.

- American Electric Power
- California ISO
- New Energy and industrial Technology Development Organization
- OpenHAN Organization
- Public Service New Mexico
- Smart Grid Interoperability Panel
- Southern California Edison

This Appendix contains summary descriptions of each Use Case. Where appropriate, references to the prior works are included in the detailed Use Case documentation developed by the Project Team.

B.1 Automated Metering Infrastructure (AMI)

B.1.1 Customer Initiated Remote Service Order Completion

This Use Case describes the steps in a customer requested remote service order completion. The remote service order request could be made due to customer move-in/out or other customer initiated action. Traditionally, utilities send a field technician to the Customer premise to (dis)connect service to the meter. With an Automated Metering Infrastructure, the (dis)connect can be performed remotely by initiating a remote service order request. The customer move-in/out and reinstatement for payment received allow for the use of remote service order completion directly.

This Use Case addresses four service types that can be completed using an automated procedure.

- Customer move out with landlord revert
- Customer move out without landlord revert
- Customer move in
- Reconnect for reinstatement of service upon payment (not implemented)

The customer requested move in/out operations are batched for daily processing by CIS. The reconnects for reinstatement of service are processed in quasi real-time by CIS.

B.1.2 Utility Initiated Remote Service Order Completion

This Use Case describes the steps in a remote service order completion initiated by the utility for non-payment or other revenue protection action. Traditionally, utilities send a field technician to the Customer premise to (dis)connect service to the meter. With an Automated Metering Infrastructure, the (dis)connect can be performed remotely by initiating a remote service order request. However, for connects for non-payment and other utility initiated service orders, Missouri commission rules require a technician to be deployed to the premise for proper notification prior to the remote disconnect request being issued to the SmartMeter.

This Use Case addresses the following utility initiated service types that can be completed using the combined manual and automated procedure:

- Disconnect for non-payment
- Vacant with Usage
- Service Investigation Order

The meter disconnect associated with these order completions is performed in near real-time after the technician provides the local notification. The reconnects upon payment will be processed in quasi real-time according to the customer initiated remote service order completion Use Case.

Implementation of this Use Case is outside the scope of the DOE demonstration project.

B.1.3 On-Demand Meter Read

This Use Case describes the process of the Customer Information System (or other system) requesting and receiving an on-demand meter read from a SmartMeter. An on-demand meter read may be requested by multiple systems for a number of reasons. The process is carried out by transferring a meter read request message from the requesting system to the desired SmartMeter. In order to obtain a real-time meter read, the meter read request will travel to the SmartMeter via the Meter Data Management (MDM) and AMI Head End (AHE) systems and the Field Automation Network (FAN). The SmartMeter then sends the requested meter read data back to the requesting system via the FAN, AHE, and MDM. The meter read data can then be analyzed and processed as needed upon receipt by the requesting system.

B.1.4 On-Demand Meter Status Check

This Use Case describes the process of the Distribution Management Information (or other system) requesting and receiving the current status of a SmartMeter. An on-demand meter status check may be requested by multiple persons, systems, or organizations for a number of reasons including service status verification, SmartMeter health/functionality, power restoration, and service (dis)connect status. The process is carried out by transferring a meter read request message from the requesting system to the desired SmartMeter via the MDM, AHE, and Field Automation Network. The SmartMeter then sends the requested meter read data back to the requesting system via the Field Automation Network, AHE and MDM systems.

With the Distribution Management System software integrated with the Meter Data Management System and AMI Head End, the DMS and grid operations personnel can automatically check the status of the SmartMeter. This functionality has the potential to limit field visits to verify service status by service technicians. It can also be used to verify that service has been restored in the event of an outage.

B.1.5 Automated Daily Meter Read

This Use Case describes the automated meter reading process. The SmartMeter records interval usage readings every fifteen minutes and pushes the data to the AMI Head-End every four hours throughout the day. Each SmartMeter uses a random offset to level traffic across the AMI network. Daily register readings (total daily usage) are taken at midnight and pushed to the AMI Head-End at a random offset after midnight. The random offsets are used to level traffic across the AMI network with the goal of having all daily register readings to the AMI Head-End by 4:00 AM.

While each SmartMeter is pushing data to the AMI Head-End every four hours, the AMI Head-End is sending data to the Meter Data Management System on a different schedule. The AMI Head-End aggregates data from multiple SmartMeters and pushes a batch file to the Meter Data Management System on an hourly basis. This batch file can contain both interval and register data.

In addition to pushing data to the Meter Data Management System, the AMI Head-End contains the intelligence to recognize when meter reading data is missing and make specific requests to SmartMeters for the missing data to be resent. Once the data is retrieved, it is sent to the Meter Data Management System with the next hourly data push.

B.1.6 SmartMeter Alarm Events

The Advanced Metering Infrastructure system provides each SmartMeter with event capabilities to inform the Utility that the status of the SmartMeter has changed. Events are enabled within the SmartMeter to proactively identify possible tampering and/or diversion conditions, power quality conditions, and device status conditions. Each SmartMeter Event can be configured to one of the four following statuses: Log Only, Advisory, Alarm, or Disabled. These configurations can vary from SmartMeter to SmartMeter depending on the application. Events enabled on the SmartMeter may represent, but are not limited to, the following categories:

- Power Quality
- Meter Health
- Revenue Protection

This Use Case details the process of a SmartMeter sending an Event with an Alarm status after a status change within the SmartMeter. The SmartMeter sends any Alarm Events to the AMI Head-End in real-time. From there, the Alarm Event may be sent on to the Meter Data Management System.

B.1.7 SmartMeter Advisory Events

The Advanced Metering Infrastructure system provides each SmartMeter with event capabilities to inform the Utility that the status of the SmartMeter has changed. Events are enabled within the SmartMeter to proactively identify possible tampering and/or diversion conditions, power quality conditions, and device status conditions. Each SmartMeter Event can be configured to one of the four following statuses: Log Only, Advisory, Alarm, or Disabled. These configurations can vary from SmartMeter to SmartMeter depending on the application. Events enabled on the SmartMeter may represent, but are not limited to, the following categories:

- Power Quality
- Meter Health
- Revenue Protection

This Use Case details the process of a SmartMeter sending an Event with an Advisory status after a status change within the SmartMeter. The SmartMeter sends any Advisory Events to the AMI Head-End every four hours, with the next SmartMeter data push. From there, the Advisory Event may be sent on to the Meter Data Management System.

B.1.8 SmartMeter Log Only Events

The Advanced Metering Infrastructure system provides each SmartMeter with event capabilities to inform the Utility that the status of the SmartMeter has changed. Events are enabled within the SmartMeter to proactively identify possible tampering and/or diversion conditions, power quality conditions, and device status conditions. Each SmartMeter Event can be configured to one of the four following statuses: Log Only, Advisory, Alarm, or Disabled. These configurations can vary from SmartMeter to SmartMeter depending on the application. Events enabled on the SmartMeter may represent, but are not limited to, the following categories:

- Power Quality
- Meter Health
- Revenue Protection

This Use Case details the process of a SmartMeter sub-device sending an Event with a Log Only status after a status change within the SmartMeter. The SmartMeter sub-device sends any Log Only Events to the Meter FAN Radio, where they are logged and maintained for diagnostics and troubleshooting purposes. Log Only Events can be retrieved by sending a command to the SmartMeter via the AMI Head End or other system.

B.1.9 SmartMeter Source Power Events

This Use Case details a specific type of Alarm Event – those dealing with SmartMeter source power. The outage event serves as a surrogate for the Customer's call, often allowing the problem to be fixed before the Customer even becomes aware of the outage. AMI systems also help the Outage Management System (OMS) and dispatcher understand and efficiently respond to widespread outage conditions. The restoration event will follow a similar path and will notify the Utility when power has been restored to a SmartMeter.

This Use Case is detailed in two sequences that describe outage events and restoration events. When a power outage is detected at a SmartMeter, an outage event message is sent from that SmartMeter to the Meter Data Management System. The Meter Data Management System determines whether or not the outage information needs to be sent to the Distribution Management System for processing. Once power is restored to a SmartMeter, a restoration event message is sent from that SmartMeter to the Meter Data Management System. The Meter Data Management System then sends the restoration information to the Distribution Management System for processing.

B.1.10 AMI FAN Device Alarm Events

The Field Automation Network (FAN) within the Advanced Metering Infrastructure system provides each device with event capabilities to inform the Utility that the status of the FAN device has changed. Events are enabled within the devices to proactively identify possible tampering and/or diversion conditions, source power quality conditions, and FAN device status conditions. Each FAN device event can be configured to one of the four following statuses: Log Only, Advisory, Alarm, or Disabled. These configurations can vary from FAN device to FAN device depending on the application. Events enabled on a FAN device may represent, but are not limited to, the following categories:

- Source Power
- Device Health

This Use Case details the process of a FAN device sending an Event with an Alarm status after a status change within the FAN device. The FAN device sends any Alarm Events to the AMI Head-End in real-time.

B.1.11 AMI FAN Device Advisory Events

The Field Automation Network (FAN) within the Advanced Metering Infrastructure system provides each device with event capabilities to inform the Utility that the status of the FAN device has changed. Events are enabled within the devices to proactively identify possible tampering and/or diversion conditions, source power quality conditions, and FAN device status conditions. Each FAN device event can be configured to one of the four following statuses: Log Only, Advisory, Alarm, or Disabled. These configurations can vary from FAN device to FAN device depending on the application. Events enabled on a FAN device may represent, but are not limited to, the following categories:

- Source Power
- Device Health

This Use Case details the process of a FAN device sending an Event with an Advisory status after a status change within the FAN device. The FAN device sends any Advisory Events to the AMI Head-End every four hours, with the next FAN device data push. From there, the Advisory Event may be sent on to the Meter Data Management System.

B.1.12 AMI FAN Device Log Only Events

The Field Automation Network (FAN) within the Advanced Metering Infrastructure system provides each device with event capabilities to inform the Utility that the status of the FAN device has changed. Events are enabled within the devices to proactively identify possible tampering and/or diversion conditions, source power quality conditions, and FAN device status conditions. Each FAN device event can be configured to one of the four following statuses: Log Only, Advisory, Alarm, or Disabled. These configurations can vary from FAN device to FAN device depending on the application. Events enabled on a FAN device may represent, but are not limited to, the following categories:

- Source Power
- Device Health

This Use Case details the process of a FAN device logging an Event with a Log Only status after a status change within the FAN device. The FAN device logs any Log Only Events to internal memory, where they are logged and maintained for diagnostics and troubleshooting purposes. Log Only Events can be retrieved by sending a command to the FAN device via the AMI Head End.

B.1.13 Remote SmartMeter Update

The SmartMeter is adaptive to the Utility's changing environment, and it has the capacity to be remotely modified via the AMI Field Automation Network. The SmartMeter program, which defines the functionality of the SmartMeter, can be modified from one rate structure to another. For example, the SmartMeters can be modified from flat rate meters to time-of-use meters. The SmartMeter configuration, which determines the program settings, can be modified to incorporate specific settings of the current meter program. For example, if the SmartMeter program is defined as a time-of-use meter, then the Utility could update the configuration to modify the time-of-use bucket definitions. Both the program and the configuration can be updated remotely.

In addition to updating the SmartMeter program and configuration remotely, the SmartMeter firmware can be updated remotely via the Field Automation Network. The SmartMeter consists of three independent sub-devices which all have their own firmware. These sub-devices are the Meter FAN Radio, Meter Metrology Board and Energy Services Interface Radio. The SmartMeter vendor can issue a firmware update for any or all of these sub-devices for various reasons (bug fixes, feature enhancements, manufacturing changes, etc.). These updates can be completed remotely.

This Use Case describes how SmartMeter program updates, configuration updates, and firmware updates are implemented remotely via the Field Automation Network.

B.1.14 Field SmartMeter Update

The SmartMeter is adaptive to the Utility's changing environment, and it has the capacity to be modified by a field technician. Each SmartMeter has an Opticom port allowing the meter program, configuration, and firmware to be updated by field technicians. Using a laptop equipped with an Opticom probe and the SmartMeter vendor programming software, the technician can update the SmartMeter program file, configuration file, or the firmware to any of the sub-devices within the SmartMeter.

The SmartMeter program, which defines the functionality of the SmartMeter, can be modified from one rate structure to another. For example, the SmartMeters can be modified from flat rate meters to time-of-use meters. The SmartMeter configuration, which determines the program settings, can be modified to incorporate specific settings of the current meter program. For example, if the SmartMeter program is defined as a time-of-use meter, then the Utility could update the configuration to modify the time-of-use bucket definitions. Both the program and the configuration can be updated in the field.

In addition to updating the SmartMeter program and configuration, the SmartMeter firmware can also be updated in the field. The SmartMeter consists of three independent sub-devices which all have their own firmware. These sub-devices are the Meter FAN Radio, Meter Metrology Board and Energy Services Interface Radio. The SmartMeter vendor can issue a firmware update for any or all of these sub-devices for various reasons (bug fixes, feature enhancements, manufacturing changes, etc.).

This Use Case describes how SmartMeter program, configuration, and firmware updates are implemented in the field by a field technician.

B.1.15 Remote AMI FAN Device Update

The AMI Field Automation Network (FAN) devices are adaptive to the Utility's changing environment, and they have the capacity to be remotely modified via the FAN. The FAN devices include FAN Endpoint Nodes, FAN Routers, and FAN Collectors. The FAN device configuration, which defines how frequently data is pushed from the devices, can be updated remotely. The FAN Device firmware can also be updated remotely.

This Use Case describes how FAN device configuration and firmware updates are implemented remotely via the Field Automation Network.

B.1.16 Field AMI FAN Device Update

The Field Automation Network (FAN) devices are adaptive to the Utility's changing environment, and they have the capacity to be modified by a field technician. The FAN devices include FAN Endpoint Nodes, FAN Routers, and FAN Collectors. Each FAN device has an Opticom port allowing the FAN device configuration (defining how frequently data is pushed from the device) and firmware to be updated by field technicians. Using a laptop equipped with an Opticom probe and the vendor programming software, the technician can update the FAN device configuration file or firmware to any of the FAN devices.

This Use Case describes how FAN device configuration and firmware updates are implemented in the field by a field technician.

B.1.17 SmartMeter Replaced by Field Crew (Future)

This Use Case describes the processes involved when a meter is exchanged for any purpose. It will involve updating customer-meter relationships in numerous back office systems (CIS, MDM, AMI, etc.). Additionally, any In-Premise Devices (IPD) registered to the meter will be reregistered to the new meter. This Use Case is divided into two scenarios to address these implications as follows:

- Update customer-meter relationships in multiple back-office systems.
- Re-establish the Utility Home Area Network by registering existing IPDs to the new SmartMeter.

Implementation of this Use Case is outside the scope of the DOE demonstration project.

B.2 Meter Data Management (MDM)

B.2.1 MDM Distributes Daily Service Delivery Point Updates

This Use Case describes the process where Meter Data Management System (MDM) distributes updated service delivery point (SDP) information to any system that uses the meter read data. The MDM, AMI Head End, and other systems maintain certain SDP information to perform their functions. The SDP information in MDM is updated as meters are changed out and customer account change. The MDM will distribute these updates to other systems that consume or generate meter data.

The MDM creates a Daily SDP Update Data file containing the updated service delivery point data and according to the IEC 61968-9 specification. The MDM distributes the Daily SDP Update Data file to the AMI Head End (AHE), Data Mining and Analysis Tool (DMAT), the Distributed Energy Resource Management System (DERM), the Home Energy Management Platform (HEMP) via the enterprise service bus. The AHE, DMAT, DERM and the HEMP then apply the Daily SDP Update Data to their local data repositories.

The SDP Updates could be processed transactionally, but, the systems deployed for the demonstration project are architected to process these updates daily.

Implementation of this Use Case is outside the scope of the DOE demonstration project.

For the project, SDP updates were generated from CIS

B.2.2 MDM Distributes Daily Meter Data

This Use Case describes the process where Meter Data Management System (MDM) distributes the register read and 15 minute interval data of all meters to any system that requires the meter read data. MDM performs VEE (validation, estimation, and editing) and distributes the daily batch of the meter data.

The MDM creates the Daily Meter Data file containing VEE'd register and interval readings according to the IEC 61968-9 specification. The MDM distributes the Daily Meter Data file to the Data Mining and Analysis Tool (DMAT), the Distributed Energy Resource Management System (DERM), the Home Energy Management Platform (HEMP) via the enterprise service bus. The DMAT, DERM and the HEMP then apply the Daily Meter Data to their local data repositories.

This Use Case will be partially implemented within the scope of the DOE demonstration project.

B.2.3 MDM Creates Billing Determinants

This Use Case describes the process by which the Meter Data Management System (MDM) responds to CIS requests for billing determinates. On each billing cycle, the MDM will summarize the register, interval, and demand data for each period over the requested billing span and deliver these billing determinants to the billing system. By performing the billing determinant summations on a daily basis, the MDM platform can support end-user presentation of “month-to-date” information.

This Use Case describes the following information flows:

- CIS sends billing profile to MDM for new accounts and account billing tariff changes
- CIS sends daily “billing determinate request” for accounts in current bill cycle.
- MDM calculates billing determinates and sends “billing determinate response” to CIS
- MDM sends “billing determinate update” to CIS when VEE'd data changes previous determinate
- CIS sends “off cycle billing determinate request” for an account
- MDM calculates billing determinate and sends “off cycle billing determinate response” to CIS

This Use Case will be partially implemented within the scope of the DOE demonstration project.

B.2.4 SmartMeter Inventory Management

This Use Case describes the management of Utility owned SmartMeters. Throughout the lifecycle of the SmartMeter it will be received at the Utility from the vendor, installed at a Customer premise, tested for return to inventory and periodically retrieved for statistical sampling purposes.

At each step along the way the Meter Data Management System (MDM) must be able to account for the whereabouts of the SmartMeter and communicate this status to other systems within the Advanced Metering Infrastructure (AMI). This collaboration minimizes required human intervention in the meter reading process and maximizes the Utility's return on the metering assets.

Implementation of this Use Case is outside the scope of the DOE demonstration project.

B.3 SmartSubstation (SUB)

B.3.1 DCADA Monitors and Controls Substation Devices

This Use Case describes the Distributed Control and Data Acquisition System (DCADA) monitoring and control of substation devices. The DCADA system monitoring process works in two ways: 1) DCADA polling a substation device for status and 2) a substation device reporting status (or status change) to DCADA due to an exception. When the Distribution Automation Device (DAD) in the substation needs to be operated, DCADA sends a control signal to the device. DCADA makes use of the Substation Distribution Protection Network to communicate with substation devices. The Distribution Data Concentrator is a sub-system of DCADA that is utilized to communicate with Distribution Automation Devices (DADs). The substation devices include various DADs such as transformer tap changer controls, bus, tie, and feeder breaker relays, capacitor bank controls, and automated switches.

B.3.2 DCADA Monitors and Controls Field Devices

This Use Case describes the Distributed Control and Data Acquisition System (DCADA) monitoring and control of field devices. The DCADA system monitoring process works in two ways: DCADA polling a field device for status and a field device reporting status (or status change) to DCADA due to an exception. When the configuration settings of a Distribution Automation Device in the field need to be updated, DCADA sends a control signal to the device. DCADA makes use of the Field Automation Network to communicate with field devices. The Distribution Data Concentrator is a sub-system of DCADA that is utilized to communicate with Distribution Automation Devices. The field devices include various Distribution Automation Devices such as voltage monitors, automated reclosers, capacitor bank controls, voltage regulators, automated switches and fault indicators.

B.3.3 DCADA Monitors Equipment for Condition-Based Maintenance Programs

This Use Case describes how the use of remote sensor devices could enable utility staff to proactively monitor equipment in the field to make maintenance decisions based on the current conditions of those assets. This is referred to as condition-based maintenance, and stands in contrast to “reactive” or traditional “preventive” maintenance strategies that prescribe maintenance based on when assets fail or on the calendar, respectively. Under a condition-based maintenance (CBM) approach remote sensors provide operational and non-operational data to back office systems both periodically (e.g. every 10 minutes or every hour, depending on the asset or data), and upon an event occurring. Analyses are automatically performed on sensor data using rules and algorithms that identify assets potentially in need of repair or replacement. This approach to monitoring and maintaining assets would enable operators to identify equipment needing repair or replacement prior to failure. It would also allow the utility to optimize asset utilization over their useful lives. The business value of condition-based monitoring includes improved system reliability, reduced costs, and increased customer benefits.

B.3.4 Substation IEC 61850 GOOSE Protection Schemes

This Use Case describes the IEC 61850 GOOSE protection schemes that will be implemented to enhance the protection of the substation devices. The DCADA system monitoring process works in two ways:

- Automatic load transfer upon transformer lockout
- Faster clearing of the bus upon feeder breaker failure
- Backup overcurrent protection in the bus differential relay
- Cross triggering of all devices for distribution system events

These functions involve the substation Distribution Automation Devices (DADs) communicating peer-to-peer in a coordinated manner via the Substation Distribution Protection Network (SDPN). The substation devices include various DADs such as transformer differential, bus, tie, and feeder breaker relays.

B.3.5 Substation Transformer DGA & Thermal Monitoring

This Use Case describes how the deployment of online Dissolved Gas Analysis (DGA) devices could improve the monitoring, maintenance, and operation of substation transformers. Monitoring devices and probes are installed on Substation transformers that are capable of sampling and evaluating dissolved gasses and recording oil-temperature. The probes will continuously monitor oil temperature and will send Dissolved Gas Analysis (DGA) data to DCADA system as often as once per hour. DCADA will contain a rule engine with preconfigured asset-specific parameters that trigger alarms, alerting D-SCADA when transformers are in condition that requires additional analysis.

Implementation of this Use Case is outside the scope of the DOE demonstration project.

B.3.6 Substation Transformer Dynamic Ratings

This Use Case describes the process of calculating dynamic ratings for substation transformers to maximize energy throughput. Dynamic transformer ratings are calculated by a DCADA Dynamic Transformer Rating (DTR) module using a series of algorithms. These algorithms utilize asset and condition data obtained from Dissolved Gas Analysis (DGA) devices, transformer sensors, substation sensors, and the EAMS. DGA devices provide dissolved gas levels, moisture, and partial discharge information. Transformer sensors provide information about other transformer components beyond the tank and windings, such as Load Tap Changers and Cooling System Status. Weather data can be incorporated from local Substation sensors or National Weather Service. DGA device data and substation sensor data are both delivered to DTRS via a Data Concentrator. EAMS information includes the transformer's static rating and other information, which might include heat run test data and historical loading data.

The dynamic transformer ratings consist of a normal rating and a series of 3 emergency ratings (15 minute, 30 minute, and one hour). After calculating this series of dynamic ratings, the DTR module updates the dynamic transformer rating values in the local DCADA data base.

Implementation of this Use Case is outside the scope of the DOE demonstration project.

B.3.7 Feeder Cable Dynamic Ratings

This Use Case describes the process of calculating dynamic Feeder Cable ratings to maximize energy throughput. Dynamic transformer ratings are calculated by a DCADA Dynamic Cable Rating (DCR) module using a series of algorithms. These algorithms utilize asset condition data obtained from duct temperature sensors, substation sensors, and the EAMS. Weather data can be incorporated from local substation sensors or National Weather Service. EAMS information includes the cable's static rating and other information, which might include historical loading data.

The dynamic cable ratings consist of a normal rating and a series of 3 emergency ratings (15 minute, 30 minute, and one hour). After calculating this series of dynamic ratings, the DCR module updates the dynamic transformer rating values in the local DCADA database.

Implementation of this Use Case is outside the scope of the DOE demonstration project.

B.4 First Responder (1ST)

B.4.1 DCADA Performs Fault Detection, Location, Isolation, and Restoration

Many types of faults can occur on a line section of a distribution system. Transient faults can be cleared after power has been disconnected for a short period of time. Transient faults are cleared by distribution automation devices, such as reclosers. Persistent faults can only be cleared by removing power from the line section where the fault has occurred and dispatching a field crew. Fault management applications are used to locate distribution network faults and provide fault isolation and service restoration. The fault location capabilities determine the location of permanent faults, whereas fault isolation and service restoration capabilities isolate the faulty section or area of distribution network and provide possible switching procedure to restore service.

This Use Case describes how the Distributed Control and Data Acquisition System (DCADA) responds to a persistent fault on a line section by approximately locating the fault, isolating the faulted line segment, and restoring service to customers through automated switching. Ultimately, the DCADA passes control authority to the Distribution Management System to dispatch field crews, correct the fault, and complete service restoration to Customers.

This function involves the DCADA communicating in a coordinated manner with the various Distribution Automation Devices (DADs) in both the field and the substation via the Substation Distribution Data Concentrator (DDC), the Substation Distribution Protection Network (SDPN) and the Distribution Automation Network (DAN).

B.4.2 DCADA Performs Volt/VAR Management

This Use Case describes the Volt/VAR Control (VVC) functionality is executed in a distributed architecture by the substation Distributed Control and Data Acquisition System (DCADA). The primary objective of VVC functionality is to satisfy voltage and loading constraints. VVC functionality can be executed to satisfy any of the following 4 objective functions.

- Minimize subsystem power losses
- Minimize power demand
- Maximize generated reactive power
- Maximize voltage

Under normal operating conditions, the distributed VVC manages voltage along all distribution circuits within its area of control to achieve a voltage profile based upon KCP&L design parameters.

This function involves the DCADA communicating in a coordinated manner with the various Distribution Automation Devices (DADs) in both the field and the substation via the Substation Distribution Data Concentrator (DDC), the Substation Distribution Protection Network (SDPN) and the Distribution Automation Network (DAN).

B.4.3 DCADA Performs Dynamic Voltage Control

This Use Case describes the Dynamic Voltage Control (DVC) functionality for load reduction is executed in a distributed architecture. For load reduction scenarios, the Volt/var Control (VVC) functionality of the substation Distributed Control and Data Acquisition System (DCADA) can lower the line voltage, within its area of control, through a technique known as Dynamic Voltage Control. Under typical peak load conditions DVC can achieve approximately 1% load reduction for each 1% of voltage reduction on the system.

This function involves the DCADA communicating in a coordinated manner with the various Distribution Automation Devices (DADs) in both the field and the substation via the Substation Distribution Data Concentrator (DDC), the Substation Distribution Protection Network (SDPN) and the Distribution Automation Network (DAN).

Implementation of this Use Case is outside the scope of the DOE demonstration project.

B.4.4 DCADA Performs Localized Feeder Load Transfer

This Use Case describes the dynamic Feeder Load Transfer executed in a distributed architecture by the substation Distributed Control and Data Acquisition System (DCADA). The primary objective of the DCADA Feeder Load Transfer (FLT) function is to identify and respond to a feeder overload condition within its area of control.

Circuit and/or transformer overloads at the distribution level can occur when higher than anticipated customer loads are placed on a circuit or when operator or automat switching actions are implemented and change the network configuration. Localized FLT can be a key tool to temporarily transfer load from a specific area to reduce the impact on specific equipment.

This function involves the DCADA communicating in a coordinated manner with the various Distribution Automation Devices (DADs) in both the field and the substation via the Substation Distribution Data Concentrator (DDC), the Substation Distribution Protection Network (SDPN) and the Distribution Automation Network (DAN).

B.4.5 DCADA Initiates Relay Protection Re-coordination

This application adjusts the relay protection settings to real-time conditions based on the preset rules. This is accomplished through analysis of relay protection settings and operational mode of switching devices (i.e., whether the switching device is in switch or recloser mode), while considering the real-time connectivity, tagging, and severe weather conditions. The application is called to perform after feeder reconfiguration and in the case when conditions are changed and fuse saving is required. The updates needed to meet the Smart Grid requirements include coordinating feeder protection and re-synchronization with Distributed Energy Resources and with Microgrids.

Implementation of this Use Case is outside the scope of the DOE demonstration project.

B.5 Distribution Management System (DMS)

B.5.1 DMS Network Model Maintenance

The existing GIS is the system of record for all distribution grid asset information and maintains the as-built geographical location and connectivity model for all distribution facilities. Map technicians update the electrical equipment information and connectivity model as they receive notifications of construction activities.

This Use Case describes the processes involved in periodically updating the DMS network model from the GIS. The Use Case contains three sequences required to the DMS Network Model Maintenance function.

- DMS (InService) Network Model Build from GIS
- DMS (PowerCC) Network Mode Build from InService
- DMS (PowerCC) Network Model Sync with DCADA

B.5.2 DMS Monitors and Controls Substation Devices

This Use Case describes the DMS Distribution Supervisory Control and Data Acquisition System (D-SCADA) function for monitoring and control of substation devices. The D-SCADA system monitoring process works in two ways: the D-SCADA can poll a substation device for status, or a substation device can report the status (or status change) to D-SCADA due to an exception. When the configuration settings of a Distribution Automation Device in the substation need to be updated, D-SCADA sends a control signal to the device. D-SCADA makes use of the Distribution Management System Virtual Private Network, the Distribution Data Concentrator, and the Substation Distribution Protection Network to communicate with substation devices. The Distribution Data Concentrator is a sub-system of the Distributed Control and Data Acquisition System (DCADA) that is utilized to communicate with Distribution Automation Devices. The substation devices include various Distribution Automation Devices such as relays, voltage monitors, transformer tap changer controls, breaker relays, capacitor bank controls, voltage regulators, and automated switches.

B.5.3 DMS Monitors and Controls Field Devices

This Use Case describes the DMS Distribution Supervisory Control and Data Acquisition System (D-SCADA) function for monitoring and control of field devices. The D-SCADA system monitoring process works in two ways: the D-SCADA can poll a field device for status, or a field device can report the status (or status change) to D-SCADA due to an exception. When the configuration settings of a Distribution Automation Device in the field need to be updated, D-SCADA sends a control signal to the device. D-SCADA makes use of the Distribution Management System Virtual Private Network, the Distribution Data Concentrator, and the DA Field Automation Network to communicate with field devices. The Distribution Data Concentrator is a sub-system of the Distributed Control and Data Acquisition System (DCADA) that is utilized to communicate with Distribution Automation Devices. The field devices include various Distribution Automation Devices such as automated reclosers, capacitor bank controls, fault indicators, and battery energy storage systems.

B.5.4 DMS Monitors and Controls Grid Battery Energy Storage System

This Use Case describes the DMS Distribution Supervisory Control and Data Acquisition System (D-SCADA) function for monitoring and control of grid Battery Energy Storage System (BESS). The D-SCADA system monitoring process works in two ways: the D-SCADA can poll a field device for status, or a field device can report the status (or status change) to D-SCADA due to an exception. When the configuration settings of a Distribution Automation Device in the field need to be updated, D-SCADA sends a control signal to the device. D-SCADA makes use of the Distribution Management System Virtual Private

Network, the Distribution Data Concentrator, and the DA Field Automation Network to communicate with the BESS.

In addition to standard monitoring and control function, the DMS also uses the D-SCADA function to allow the operator to change the BESS Mode of Operation. From the DMS the operator can put the BESS into any one of the following operating modes and set the control parameters required for each mode of operation:

- Idle
- Block Dispatch (kw and kvar)
- Load Following-circuit (kw and kvar)
- Load Following-bus (kw and kvar)
- Load Following-station (kw and kvar)
- DERM (awaiting DR event dispatch)
- Islanding

B.5.5 DMS Coordinates Control Authority Responsibility with DCADA

This Use Case describes the describes a hierarchical control scheme in which a DMS and Distributed Control and Data Acquisition System (DCADA) can cooperatively monitor and control substation and field devices and coordinate the execution of 1st Responder functions the DMS or DCADA systems.

This Use Case describes how a DMS and DCADA can cooperatively monitor and control substation and field devices along with grid connected DER to improve grid economics and reliability and minimize potential violations. This Use Case describes the following hierarchical control schemes:

- DMS –Manual : Only Operator can control all devices and run applications manually from the centralized DMS.
- DMS – Open Loop: DMS runs applications in Open loop but only operator can execute application results and can control all the devices
- DMS – Closed Loop: DMS runs applications in closed loop and executes results (controls devices) but operator can still control all devices
- DCADA – Closed Loop: Local DCADA runs applications in closed loop and controls all substation and field devices attributed to that substation but operator can still control all devices

B.5.6 DMS Processes Protective Device Alarms for Outage Analysis

Utilities are constrained in their response to outages by the sensors and the information currently available to them. SCADA systems typically extend only to the substation. Typically, AMI is the only system that extends to the edges of a utility network, sensing every line segment and transformer on the system. This AMI capability is used in conjunction with OMS functions to predict outage locations and to verify power restoration, enabling utilities to proactively identify customers whose power has yet to be restored.

When outages reported by other systems such as SCADA, DCADA (Distributed Control and Data Acquisition) System, or protective devices themselves, these outages can be immediately recorded as confirmed and bypass or discontinue the OMS prediction process. This Use Case will outline the systems interaction anticipated when the D-SCADA processes protective device alarms and send the appropriate messages to OMS and MDM systems.

- The OMS, upon notification that a protective device has operated will create a confirmed outage for that device and discontinue any downstream outage prediction processing.
- The MDM, upon notification that a protective device has operated will mark all downstream customers as out of service. It will continue to process meter grid alerts, but will discontinue sending any meter out notifications to OMS.

B.5.7 DMS Performs Emergency Load Transfer

The Distribution Management System (DMS) can trigger emergency load reduction for several reasons. At the substation level, the Distributed Control and Data Acquisition System (DCADA) might detect an immediate overload or other grid violation (or approaching violation; within the next hour) within its area of control that it cannot resolve even after utilizing the “first responder” Feeder Load Transfer (FLT) application. As a result, the DCADA notifies and passes control to the DMS Operator for load reduction. The DMS Operator then initiates the DMS Feeder Load Transfer (FLT) for broader, system wide analysis.

Emergency load reduction can also be initiated as a result of monitoring conducted at the DMS level, either through the Distribution System State Estimator (DSSE) application or the Distribution Supervisory Control and Data Acquisition (D-SCADA) sub-system. During DMS-initiated emergency load reduction, the DMS Operator calls upon one or multiple grid reconfiguration strategies in order to solve the grid violation.

B.5.8 DMS Schedules Required Load Transfer

The Distribution Management System Operator (DMSOP) can initiate a Studycase in the Distribution Management System (DMS) at any time. The DMS operator might choose to run a Studycase each morning, or he could run a Studycase when he thinks the system load might be problematic due to weather, system maintenance, or some other issue. The Studycase will show the DMSOP the predicted condition of the distribution system during a certain time period in the future. The DMSOP will have 168 hourly values for all loads at his disposal. These values can be modified by using the correction coefficient to represent the expected future network conditions.

Upon creation of a Studycase, the DMS runs Distribution System Power Flow (DSPF) to determine whether any overloads are predicted during the Studycase time period. If so, the DMSOP uses a Feeder Load Transfer (FLT) program to determine the iterative switching required to achieve the optimal solution to eliminate (or reduce) the predicted overload or other violation. Once the DMSOP is satisfied with the outcome, he can save the proposed schedule to be applied at the appropriate time. This solution will be verified before executing it in order to see if any changes have occurred between the study and execution time affecting the validity of the original solution.

B.5.9 DMS Initiates Load Reduction with DERM

The Distribution Management System (DMS) can initiate Load Reduction with DERM in two scenarios; emergency and scheduled. This Use Case augments the previous Emergency and Scheduled Load Transfer Use Cases when switching alone will not solve the grid violation. If the grid overload or violation condition still exists, then the DMS Operator requests emergency/scheduled DR from the DERM.

This Use Case describes how the DMS and DERM interact to initiate geographically constrained load reduction in response to grid overloads or other violations:

- DMS requests load reduction from DERM specifying the desired load reduction by grid element.
- DERM analyzes all DR or DER programs and assets (DR, DER, DVC, BESS, DG, etc) available and creates pending DR event with most economic resources to meet the required load reduction.
- If emergency reduction, DERM creates DR event
- If scheduled reduction, DERM send available load reduction by grid element to DMS for further analysis
- DMS analyzes impact of pending DR event load reduction
- DMS sends DERM approval to schedule pending DR event

For a scheduled load reduction, the DMS Operator would monitor grid conditions as the time of the scheduled DR event approaches to see if any changes in condition have occurred that would affect the validity of the original solution. If changes have occurred, the DMS Operator could initiate a cancel event or request additional load reduction events be scheduled

B.5.10 DMS Performs Fault Detection, Location, Isolation, and Restoration

Many types of faults can occur on a line section of a distribution system. Transient faults can be cleared after power has been disconnected for a short period of time. Transient faults are cleared by distribution automation devices, such as reclosers. Persistent faults can only be cleared by removing power from the line section where the fault has occurred and dispatching a field crew. Fault management is a Distribution Network Analysis (DNA) application to locate distribution network faults and providing fault isolation and service restoration. Fault location function defines the location of permanent faults whereas fault isolation and service restoration function isolates the faulty section or area of distribution network and provides possible switching procedure to restore service.

This Use Case describes how the Distribution Management System responds to a persistent fault on a line section by approximately locating the fault, isolating the faulted line segment, and restoring service to customers through automated switching.

This function involves the DMS DNA and D-SCADA systems communicating in a coordinated manner with the various Distribution Automation Devices (DADs) in both the field and the substation via the Substation Distribution Data Concentrator (DDC), the Substation Distribution Protection Network (SDPN) and the Distribution Automation Network (DAN).

B.5.11 DMS Operator Returns Grid to NORMAL Configuration

This Use Case describes what activities are performed by the DMS Operator in the control center when the grid must be returned to its normal operating conditions after completion of service restoration, maintenance, or repair to a portion of the grid. The DMS Operator sends the appropriate switching commands to the field devices needed to restore each feeder to NORMAL Configuration.

B.5.12 DMS Performs Volt/VAR Management

This Use Case describes the Volt/VAR Control (VVC) functionality is executed in a centralized architecture by the Distribution Management System (DMS). The primary objective of VVC functionality is to satisfy voltage and loading constraints. VVC functionality can be executed to satisfy any of the following 4 objective functions.

- Minimize subsystem power losses
- Minimize power demand
- Maximize generated reactive power
- Maximize voltage

Under normal operating conditions, the VVC manages voltage along all distribution circuits to achieve a voltage profile based upon KCP&L design parameters.

This function involves the DMS DNA and D-SCADA systems communicating in a coordinated manner with the various Distribution Automation Devices (DADs) in both the field and the substation via the Substation Distribution Data Concentrator (DDC), the Substation Distribution Protection Network (SDPN) and the Distribution Automation Network (DAN).

B.5.13 DMS Performs Dynamic Voltage Reduction

This Use Case describes the Dynamic Voltage Control (DVC) functionality for load reduction is executed in a centralized architecture. For load reduction scenarios, the Volt/var Control (VVC) functionality of the Distribution Network Analysis within the Distribution Management System (DMS) can lower the line voltage through a technique known as Dynamic Voltage Control. Under typical peak load conditions DVC can achieve approximately 1% load reduction for each 1% of voltage reduction on the system.

This function involves the DMS DNA and D-SCADA systems communicating in a coordinated manner with the various Distribution Automation Devices (DADs) in both the field and the substation via the Substation Distribution Data Concentrator (DDC), the Substation Distribution Protection Network (SDPN) and the Distribution Automation Network (DAN).

B.5.14 DMS Initiates Relay Protection Re-coordination

This application adjusts the relay protection settings to real-time conditions based on the preset rules. This is accomplished through analysis of relay protection settings and operational mode of switching devices (i.e., whether the switching device is in switch or recloser mode), while considering the real-time connectivity, tagging, and severe weather conditions. The application is called to perform after feeder reconfiguration and in the case when conditions are changed and fuse saving is required. The updates needed to meet the Smart Grid requirements include coordinating feeder protection and re-synchronization with Distributed Energy Resources and with Microgrids.

Implementation of this Use Case is outside the scope of the DOE demonstration project.

B.6 Distributed Energy Resources Management (DERM)

Distributed Energy Resources Management (DERM), includes multiple forms of distributed resources that can be called upon to affect grid load reduction including Distributed Generation (DG), Battery Energy Storage System (BESS) and Demand Response (DR) resources.

B.6.1 DERM Network Model Maintenance

This Use Case describes what activities required to communicate real-time changes in the DMS network device hierarchy to the DERM. The Use Case contains two sequences required to the DERM Network Model Maintenance function.

- DERM Network Model Build/Update from DERM (PowerCC)
- DERM initiates network devices state synchronization with DMS
- DERM receives network device state changes from DMS

The Network Model Build/update is a periodic scheduled process but can be manually initiated as well. The DMS (PowerCC module) runs a process that extracts the current production network model and generates a CIM/XML file per the RDF specification with project defined extensions. DERM receives the RDF file and processes it applying any additions, deletions, or modifications to the DERM representation of the network.

The network device state changes and synchronization sequences occur in real-time using CIM IEC-61968 messages.

B.6.2 DR/DER Resource/Asset is Registered in DERM

This Use Case will describe the process to enroll a Customer (or utility) DR or DER program asset in DERM. A customer wants to sign up for the Demand Reduction (DR) or a Distributed Energy Resource (DER) program offered by the utility which would give either: 1) give the utility permission to control specific customer loads; or 2) the customer would control their loads in response to utility event signals, during peak load periods in return for incentives. The utility representative enrolls the customer, handles installation of demand control devices along with a new SmartMeter for gathering Measurement and Verification data, and registers the customer's participation in the program with the DERM.

B.6.3 DERM Manages DR/DER Resource Potential and Availability

This Use Case describes the processes by which the DERM maintains the current availability of DR/DER resources to participate in events and predicts the DR/DER potential for resources based on current and forecasted conditions. The Use Case will detail several scenarios that the DERM may utilize to forecast DR/DER asset participation in and response to DR events. These scenarios include:

- DR/DER Asset reports planned viability schedule to DERM daily
- DERM monitors utility DER assets via utility D-SCADA system
- DERM monitors customer DER assets via customer internet or private telemetry
- DERM monitors customer DR assets via customer internet or private telemetry
- HEMP reports planned customer HAN DR/DER availability to DERM daily
- HEMP monitors and reports customer HAN DR/DER potential to DERM
- DERM tracks historical DR response for all assets.
- DERM forecasts DR asset potential based on historical response and temperature

This Use Case will be partially implemented within the scope of the DOE demonstration project.

B.6.4 DERM Creates DR/DER Event for DMS Load Reduction

This Use Case proposes that a computer system known as the Distributed Energy Resource Manager (DERM), which would serve as a clearinghouse for all load reduction requests. This Use Case deals specifically with load reduction request initiated by the DMS. This Use Case augments the “DMS Initiates Load Reduction with DERM” Use Case for emergency and scheduled load reductions.

This Use Case describes how the DERM creates and processes DR/DER requests that have been initiated by the DMS for geographically constrained load reduction in response to a grid overload or other violation:

- If emergency reduction, DERM creates event upon initial DMS request
- If scheduled reduction, DERM receives approval to schedule pending DR event from DERM
- DERM approval workflow processes and completes any additional approval requirements
- DERM creates Scheduled DR event and updates DR/DER asset availability
- DERM initiates Scheduled DR event workflow and process event notifications and messages according to program requirements.
- DERM monitors DR/DER asset availability leading up to the event and adds DR/DER resources to the event if needed to achieve planned load reduction.

This Use Case will be partially implemented within the scope of the DOE demonstration project.

B.6.5 DERM Creates DR/DER Event for Power Market Operations

Market Operations prepares and submits bids and offers into the market. Bids and offers are evaluated against needs, offsetting bids and offers, and then accepted, matched, or rejected. The evaluated bids will lead to load curtailment when it is economically feasible, the matched bid and offer curtail load, instead of accepting the offers from supply side resources within the ancillary services market.

This Use Case proposes that a computer system known as the Distributed Energy Resource Manager (DERM), which would serve as a clearinghouse for all load reduction requests. Some of these requests may originate from Market Operations for economic dispatch purposes, and some may originate from the DMS for grid operations reliability purposes. This Use Case deals specifically with Market Operations economic dispatch requests.

Implementation of this Use Case is outside the scope of the DOE demonstration project.

B.6.6 DERM Distributes Demand Response Information Messages

This Use Case describes the process for notifying customers of DR events. Some customers participating in DR programs do not have an automated communication and control infrastructure in place. For these customers, when the Distributed Energy Resource Management System schedules a Demand Response (DR) event, the event details are communicated to the customer via telephone, e-mail, text messages, or other agreed upon communications. The customer acknowledges receipt of event communications and manually implements DR mechanisms within their premise or enterprise.

Some DR programs require the utility to provide the customer advance notification for scheduled DR events. This Use Case also describes the process by which the DRAS DR event workflow provides these notifications via telephone, e-mail, text messages, or other agreed upon communications.

- Scenario #1 – Scheduled Direct Load Curtailment (Opt-out possible)
- Scenario #2 – Emergency Direct Load Curtailment (Immediate, no opt-out option)
- Scenario #3 – Advance Notification of DR Events

Implementation of this Use Case is outside the scope of the DOE demonstration project.

B.6.7 DERM Distributes DR/DER Event Schedule to Resource/Asset to Control Authority

The Utility will make use of various Distributed Energy Resources (DER) and Demand Response (DR) as needed to temporarily reduce or shift load on the distribution system. DER may include in-home devices, building management systems, and distributed generation and storage devices. The Utility may dispatch the DER for grid-reliability and/or economic reasons.

The Utility will implement a Distributed Energy Resource Management System (DERM) to determine the availability of the various DER for Utility use and schedule them when needed for a DR/DER event. The DERM will communicate with the above three categories of DER through the following systems:

- Distribution Management System (DMS), which acts as the control authority for the BESS and other grid-connected DER
- Home Energy Management Portal (HEMP), which acts as the control authority for Residential DR (located at the Residential Customer premise)
- Demand Response Application Server (DRAS), which acts as the control authority for AMI connected DR resources
- Commercial Building Management System (CBMS), which acts as the control authority for Commercial and Industrial DR/DER (located at the Commercial and Industrial Customer premise)
- Vehicle Charge Management System (VCMS), which acts as the control authority for public and customer owned Electric Vehicle Charging Stations (EVCS).

This Use Case describes the process by which the DERM sends DR/DER event schedules to one or multiple residential, commercial and industrial, and grid-connected DER control authorities after DER have been committed and a DR/DER Event has been scheduled.

B.6.8 HEMP Manages DR Event Messages for HAN Connected Resources

When the Distributed Energy Resource Management System schedules a Demand Response (DR) event, the event details are pushed to the Home Energy Management Platform (HEMP). The HEMP is then responsible for delivering the DR event message to Home Area Network (HAN) devices via the customer's Internet Service Provider (ISP) and the HAN Gateway (HANG). This Use Case describes how create, modify, and cancel DR event messages are pushed from the HEMP to HAN connected devices.

HAN connected devices deployed include Programmable Communicating Thermostat (PCT), 240v load control switch (LCS) and 120 volt load control switches (VOLT). Considerations are made for future deployment of PEV charging stations, premise energy storage systems (PESS), and smart appliances. This solution will also provide interactions with customers to convey direct load control information via in-home display (IHD) and through the customer portal.

- Scenario #1 – Scheduled Direct Load Curtailment (Opt-out possible)
- Scenario #2 – Emergency Direct Load Curtailment (Immediate, no opt-out option)
- Scenario #3 – Price Incented Customer Load Curtailment

B.6.9 DRAS Manages DR Events for AMI Connected Resources

When the Distributed Energy Resource Management System schedules a Demand Response (DR) event, the event details are pushed to the Demand Response Application Server (DRAS). The DRAS is then responsible for delivering the DR event message to AMI connected devices via AMI communication infrastructure and SmartMeter. This Use Case describes how create, modify, and cancel DR event messages are pushed from the DRAS to AMI connected devices.

AMI connected devices deployed included Programmable Communicating Thermostat (PCT) but considerations were made for future deployment of 240 volt load control switches (LCS) for water heaters, pool pumps, and other larger customer loads.

- Scenario #1 – Scheduled Direct Load Curtailment (Opt-out possible)
- Scenario #2 – Emergency Direct Load Curtailment (Immediate, no opt-out option)
- Scenario #3 – Price Incented Customer Load Curtailment

DRAS was implemented as a function of HEMP for the DOE demonstration project.

B.6.10 DRAS Manages DR Events for Commercial Building Resources

When the Distributed Energy Resource Management System schedules a Demand Response (DR) event, the event details are pushed to the Demand Response Application Server (DRAS).). The HEMP is then responsible for delivering the DR event message to Commercial Building via the customer's Internet Service Provider (ISP) and a local premise (utility or customer provided) Demand Response Controller (DRC). This Use Case describes how create, modify, and cancel DR event messages are pushed from the DRAS to DRC connected devices.

DRC connected devices may include HVAC equipment, lighting, variable speed motors, and other controllable commercial customer loads.

- Scenario #1 – Scheduled Direct Load Curtailment (Opt-out possible)
- Scenario #2 – Emergency Direct Load Curtailment (Immediate, no opt-out option)
- Scenario #3 – Price Incented Customer Load Curtailment

Implementation of this Use Case is outside the scope of the DOE demonstration project.

B.6.11 CBMS Manages DR Events for Commercial Buildings

When the Distributed Energy Resource Management System schedules a Demand Response (DR) event, the event details are pushed to the customer's Commercial Building Management System (CBMS). The CBMS is then responsible for delivering the DR event message to BMS connected devices via BMC communication infrastructure. This Use Case describes how create, modify, and cancel DR event messages are pushed from the CBMS to CBMS connected devices.

CBMS connected devices may include HVAC equipment, lighting, variable speed motors, and other controllable commercial customer loads.

- Scenario #1 – Scheduled Direct Load Curtailment (Opt-out possible)
- Scenario #2 – Emergency Direct Load Curtailment (Immediate, no opt-out option)
- Scenario #3 – Price Incented Customer Load Curtailment

Implementation of this Use Case is outside the scope of the DOE demonstration project.

B.6.12 VCMS Manages DR Events for EV Charging Stations

When the Distributed Energy Resource Management System schedules a Demand Response (DR) event, the event details are pushed to the Vehicle Charge Management System (VCMS). The VCMS is then responsible for delivering the DR event message to EV Charging Stations (EVCS) and controlling the vehicle charging via the connected devices via VCN communication infrastructure. This Use Case describes how create, modify, and cancel DR event messages are pushed from the VCMS to EVCS and to the Plug-in Electric Vehicle (PEV).

EVCSs include the physical electrical cord and connectors that provide transfer of electric energy from the charging point to the PEV.

- Scenario #1 – Scheduled Direct Load Curtailment (Opt-out possible)
- Scenario #2 – Emergency Direct Load Curtailment (Immediate, no opt-out option)
- Scenario #3 – Price Incented Customer Load Curtailment

B.6.13 DMS Manages DR Events for DVC and Grid Connected DER

The Distribution Management System (DMS) is the control authority for the grid-connected Distributed Energy Resources (DER) and the Distribution Voltage Control (DVC) load reduction program. Distributed Energy Resources include small-scale generation or energy storage of any kind. DER can exist in a number of forms, including photovoltaic panels, batteries, or wind generators. The location of proposed and future DER could be either inside or outside of a substation.

When the Distributed Energy Resource Management System schedules a Demand Response (DR) event, the event details are pushed to the Distribution Management System (DMS). The DMS is then responsible for delivering the DR event message or device control signals to the DER and substation transformer tap changer controls. This Use Case describes how create, modify, and cancel DR event messages are pushed from the DMS to the DER and transformer tap changer controls.

- Scenario #1 – Scheduled Direct Load Curtailment via Distribution Field Area Network(DAN)
- Scenario #2 – Scheduled Direct Load Curtailment via Substation Automation Network (SAN)
- Scenario #3 – Emergency Direct Load Curtailment via Distribution Field Area Network(DAN)
- Scenario #4 – Emergency Direct Load Curtailment via Substation Automation Network (SAN)

This Use Case will be partially implemented within the scope of the DOE demonstration project.

B.6.14 Verification of DR/DER Event Participation

Upon completion of a Demand Response (DR)/Distributed Energy Resources (DER) event, the Utility needs to know which customers participated in the event and which customers did not. In some cases, the Utility uses this information to determine customer compensation. In all cases, the Distributed Energy Resource Management System (DERM) uses this information to modify its forecasting algorithms to better predict load reduction for the next DR/DER event.

This Use Case describes the process by which the DERM receives participation verification from the following systems:

- Distribution Management System for DVC, BESS and other grid-connected DER
- Home Energy Management Portal for customer HAN connected devices
- Demand Response Application Server for AMI and DRC connected DR devices
- Commercial Building Management System for BMS managed DR/DER
- Vehicle Charge Management System for PEV charging stations

This Use Case will be partially implemented within the scope of the DOE demonstration project.

B.6.15 DERM Generates Retail Pricing Signals

To support real-time pricing system, a pricing signal is produced every hour (or shorter interval) and communicated to the customer and customer's demand response devices for appropriate consumption behavior. The computation of the hourly pricing signal is the function of the DERM system. This Use Case describes how the Utility will produce an hourly pricing signal and how it is communicated through the required enterprise and SmartGrid systems.

Implementation of this Use Case is outside the scope of the DOE demonstration project.

B.7 Distributed Energy Resources (DER)

B.7.1 Utility Operates Grid Storage for Capacity and Economic Benefits

This Use Case describes how the utility operates the Battery Energy Storage System (BESS) and other distributed grid storage systems for system capacity and economic benefits. The scenarios described in this Use Case typically involve operation of the storage systems in block charge/discharge cycles.

Storage devices can be utilized as a tool to provide energy shifting and peak shaping capability across the grid. In the case of energy shifting, energy storage will be set to charge during off-peak hours when the electricity supply is cheap and abundant and when ample wind and solar generation is available, the stored energy is converted back to electricity during peak hours and during load pickup intervals. Also because energy storage devices act as load, these can be used to flatten the load curve making the troughs and peaks less pronounced. This will intern decrease the need to rely on extra expensive generation to supply the extra load in the system above the base load.

At any given time, the BESS and other distributed storage systems would be operating under the scenario, outlined in this or other grid storage Use Cases, that would provide the maximum benefit.

- Scenario #1 - BESS operates on a daily charge/discharge cycle economic benefit
- Scenario #2 –BESS is operated for system capacity benefits
- Scenario #3 - BESS operates in response to DR events for load reduction

B.7.2 Utility Operates Grid Storage for T&D Asset Deferral and Power Quality

This Use Case describes how the utility operates the Battery Energy Storage System (BESS) and other distributed grid storage systems for T&D asset deferral and power quality. The scenarios described in this Use Case typically involve operation of the storage systems in dynamic or load following charge/discharge cycles.

Storage devices can be utilized as a tool to extend the life of the equipment comprising the T&D grid and minimize the power quality impact of variable intermittent renewable generation sources on the grid. . This is where using energy storage devices comes into play where such devices located in critical areas across the network respond to real-time signals from local controllers and/or the D-SCADA system to mitigate negative impacts on critical grid assets.

At any given time, the BESS and other distributed storage systems would be operating under the scenario, outlined in this or other grid storage Use Cases, that would provide the maximum benefit.

- Scenario #1 - BESS operates in feeder/bus/substation load following mode
- Scenario #2 –BESS operates in feeder/bus/substation load smoothing mode
- Scenario #3 - BESS operates in feeder/bus/substation voltage support mode

B.7.3 Utility Operates Grid Storage for Service Continuity

This Use Case describes how the utility operates the Battery Energy Storage System (BESS) and other distributed grid storage systems to maintain electric service to customers during outage conditions. It is sometimes referred to as Islanding.

Islanding refers to the isolation of the compact network. This is done by opening the network protectors upon recognition of a system fault (or the network operator decides to isolate the switch) Once this happens, the BESS provides ride-through capability during the islanding event depending on the economics and timing requirements to re-establish network power flows.

- Scenario #1 – Distribution Operator puts BESS in islanding mode after isolating grid.
- Scenario #2 - BESS operates in Islanding mode adjusting output to server local loads
- Scenario #3 - BESS re-synchronizes with gird and restores normal grid power flow.

B.7.4 Customer Installs Premise Solar PV Distributed Generation

Of all the Distributed Generation technology options solar PV has the greatest potential for residential applications and is expected to dominate due to its lower cost, lower projected cost, high local and regional insolation, lower installation cost, lack of emissions, abundance of open space and ease of integration.

This Use Case will describe the process for a Customer to provide a PV based generation source on the customer's premise and enrolls in the utility NetMetering program. The customer typically connects the PV inverter to the customer's local home area network and monitors the PV performance using the inverter manufacturers Internet based monitoring system.

B.7.5 Customer Installs Premise Energy Storage System in Conjunction with Solar PV

This Use Case will describe the process for a Customer to provide a Premise Energy Storage System (PESS) in conjunction with solar PV. This Use Case augments the previous Use Case where the customer provided premise solar PV distributed generation.

This Use Case will describe the process for a Customer to provide a PESS on the customers premise and enrolls in the utility NetMetering, TOU, and/or Demand Response programs. The customer typically connects the PESS unit to the customer's local home area network and monitors the PESS performance using the manufacturers Internet based monitoring system.

B.7.6 Customer Operates Premise Energy Storage System for Economic Benefits

This Use Case will describe how the Customer can use the Premise Energy Storage System (PESS) in conjunction with a variety of utility programs for economic benefits. The Use Case describes four potential scenarios by which the customer can gain economic benefits:

- Renewable energy shift from off-peak to on-peak periods
- Benefit from TOU charging off-peak and discharging on-peak
- Discharge battery during utility DR events
- Serve critical loads during extended power outages

In the first scenario the customer uses the PESS to store solar generation during off/shoulder peak times and discharge it during on-peak pricing period or at time of high consumption to minimize peak demand charges. In the second scenario the PESS is used daily to store energy during off-peak times and discharged the energy during peak pricing times. In the third scenario the BESS is discharged in response to utility DR events maximizing the DR participation credits. And in the fourth scenario the PESS is used to feed critical loads and provide service continuity during extended power outages.

B.7.7 Utility Installs Grid Connected Rooftop Solar Distributed Generation

Of all the Distributed Generation technology options available; solar PV has the greatest potential and is expected to dominate due to its lower cost, lower projected, high local and regional insolation, lower installation cost, lack of emissions, abundance of open space and ease of integration. Other Distributed Generation technologies may play a part but are expected contribute near the extent that PV will.

This Use Case will describe the process for a utility install utility owned; grid connected solar PV on customer premises. These installations on may be on leased rooftops or open space provided by residential, commercial, or industrial customers. As the solar PV is grid connected, the only direct customer benefits from the compensation provided by the utility for the use of space occupied by the PV. The utility will typically install private communications to monitor the PV performance using the utility DERM but, could also use the customer's internet connection if available.

B.7.8 Utility Operates Premise Storage for Grid Benefits

This Use Case will describe how the utility can use the Premise Energy Storage System (PESS) for economic and grid operation benefits. The PESS can utility owned and operated or they can be owned by either party with some form of joint operating arrangement. In either case, the utility would be able to manage their portion of the PESS for economic and grid benefits. The Use Case describes the following operational scenarios by which the utility can gain economic and grid benefits:

- PESS provides VARs in response to grid requirements
- PESS provides local smoothing for variable PV and customer loads
- PESS provides system peak shaving for bulk generation capacity
- PESS provides local peak shaving T&D capacity deferrals
- PESS provides voltage regulation support

B.8 SmartEnd-Use (SEU)

B.8.1 Customer Views Historical Energy Information via HEMP

This Use Case describes the steps by which a Customer can access, view and analyze their historical energy usage via the Internet using the Home Energy Management Platform (HEMP). The Meter Data Management System pushes updated meter usage data to the Home Energy Management Platform on a daily basis, and this information is stored internally. Upon Customer request, the Home Energy Management Platform displays the Customer's historical usage data.

B.8.2 Customer In-Home Display – Basic Functions

The IHD is an information-only device that provides one-way reception of information such as a customer's present energy usage, charges and payments, energy rates, and total energy costs at the premise for a selected period of time or billing interval. This Use Case describes the basic functions of the In-Home Display. As defined here, the basic functions include the display of real-time energy usage, current energy prices, and Utility-generated text messages.

B.8.3 Customer In-Home Display – Daily Bill True-Up

This Use Case describes the process of sending a Daily Bill True-Up to the In-Home Display within a Customer premise. The In-Home Display calculates the daily and monthly usage based on regular readings received from the SmartMeter. These values are only estimates and the Daily Bill True-Up process allows the Utility to send validated billing data to the In-Home Display for display to the Customer. The Daily Bill True-Up message is sent as a special text message through the Field Automation Network to the SmartMeter and to the In-Home Display using the Home Area Network.

B.8.4 Customer In-Home Display – Prepayment

AMI systems consist of the hardware, software, and associated system and data management applications that create a communications network between end systems at customer premises (including meters, gateways, and other equipment) and diverse business and operational systems of utilities and third parties. AMI systems provide the technology to allow the exchange of information between customer end systems and those other utility and third-party systems. In order to protect this critical infrastructure, end-to-end security must be provided across the AMI systems, encompassing the customer end systems, as well as the utility and third-party systems that are interfaced to the AMI systems.

AMI systems can also trigger notifications when the prepayment limits are close to being reached and/or have been exceeded.

Implementation of this Use Case is outside the scope of the DOE demonstration project.

B.8.5 Customer Uses HEMP to Register HAN Gateway

This Use Case describes the process by which a Customer can register a Home Area Network (HAN) Gateway to the Home Energy Management Platform. The Utility limits the scope and number of devices that can be connected directly to the Energy Services Interface within the SmartMeter and also closely manages the communications across the Field Automation Network. Once provisioned to the SmartMeter and registered to the Home Energy Management Platform, the HAN Gateway creates the Customer HAN allowing the Customer to introduce more functionality into their HAN. The HAN Gateway includes an IP Interface for connection to the Internet allowing for third-party developed products to interact with the HAN Devices in the Customer premise.

B.8.6 Customer Uses HEMP to Provision HAN Device to HAN Gateway

This Use Case describes the steps by which a Customer can provision Home Area Network (HAN) devices to an existing HAN Gateway. The HAN Gateway communicates with the SmartMeter and allows the Customer to expand the size and scope of their HAN. Devices are authenticated on the Customer HAN through the Home Energy Management Platform, ensuring that only desired devices are allowed to communicate with the HAN infrastructure.

B.8.7 Customer Uses HEMP to Monitor Real-Time Energy Usage via HAN

As customers become more knowledgeable about how much energy they are using and how their energy consumption habits affect their monthly power bills, they tend to become more likely to desire real-time energy usage information and capabilities to control their energy usage and costs. When coupled with SmartGrid HAN, the HEMP becomes a sophisticated environment with the capability providing the customer real-time energy usage and cost information. The SmartGrid Home Area Network (HAN) provides the remote transmission of energy usage data directly from SmartMeters and in premise HAN devices.

This Use Case covers the communication of energy usage information from the SmartMeter and HAN Devices to the HEMP.

B.8.8 Customer Uses HEMP for Programmable Communicating Thermostat Management

This Use Case examines the management, by the Customer, of the Programmable Communicating Thermostat (PCT). Using the Programmable Communicating Thermostat and the Home Energy Management Platform (HEMP), the Customer has the option of controlling their thermostat directly or remotely. The Home Energy Management Platform is synchronized with the Programmable Communicating Thermostat such that both serve as a source of accurate, real-time information regarding the thermostat settings. The Home Energy Management Platform can communicate with the Thermostat via the Internet/Home Area Network Gateway (HANG) or through the Utility's Field Automation Network (FAN).

This Use Case covers the Customer management of the Programmable Communicating Thermostat in four sequences.

- Customer changes settings of PCT on UHAN and information is pushed to HEMP via FAN
- Customer changes settings of PCT on CHAN and information is pushed to HEMP via Internet
- Customer changes HEMP Settings and information is pushed to PCT on UHAN via FAN
- Customer changes HEMP Settings and information is pushed to PCT on CHAN via Internet

B.8.9 Customer Uses HEMP for Load Control Switch Management

This Use Case examines the management, by the Customer, of the Load Control Switch (LCS). Using the Load Control Switch and the Home Energy Management Platform (HEMP), the Customer has the option of controlling large energy consuming devices remotely. The Home Energy Management Platform can communicate with the Load Control Switch via the Utility's Field Automation Network (FAN) or via the Internet.

B.8.10 Customer Uses HEMP to Opt Out of DR Events

When the Distributed Energy Resource Management System (DERM) schedules a Demand Response (DR) event, the event details are pushed to Home Area Network (HAN) devices, as described in Use Case DRM-08. In some cases, the Customer may choose to not participate in the DR Event. This may occur either before or after the DR Event has started. The Customer may use either the HAN device or the Home Energy Management Platform as a portal to opt out of a scheduled event. This Use Case describes how the customer opts out of scheduled DR Events.

B.8.11 Customer Initiates De-Provisioning of Customer HAN Device

This Use Case describes the process by which a Customer can initiate the de-provisioning of a Home Area Network device. This Use Case applies to Home Area Network devices that are Customer owned and have been provisioned to the Home Area Network Gateway. This request could be made for a variety of reasons, such as replacing a device, moving, etc.

B.8.12 Customer Enrolls in Time Based Pricing Program

Time based pricing is a general capability that could be implemented in many different ways. The primary focus is to provide the customer with pricing information for current or future time periods so they may respond by modifying their usage. This may entail just decreasing load or may involve shifting load by increasing demand during lower priced time periods so that they can decrease usage during higher priced time periods. The pricing periods may be real-time based (RTP) or may be tariff based (TOU), while the prices may also be operationally based or fixed or some combination. Real-time pricing inherently requires computer-based responses, while the fixed TOU pricing may be manually handled once the customer is aware of the time periods and the pricing.

B.8.13 Customer Configures HEMP with Energy Usage Preferences

The HEMP Gateway establishes HAN communication with the Utility ESI through the Commissioning and subsequent Registration processes. HEMP gains access to three types of data: usage data from the electric meter, private Consumer data (e.g. energy program and rate data) that the utility may transmit to the HEMP through the Utility ESI, and public information which the utility may choose to transmit to all Consumer HAN devices and Smart Appliances via the Utility ESI. It is not necessary for the HAN devices to be enrolled in a Utility program to access this information.

Consumer interacts with the HEMP using a web browser, mobile phone, or other display device to define preferences for energy use and automation. Preferences may be based on a single factor, such as a time or price for energy, or a combination of factors such as occupancy, type of activity, DER production, and current price.

Once configured with the customer's Energy Usage Preferences, the HEMP continuously provides information and control services utilizing its rules and internal algorithms. HEMP makes decisions affecting total energy usage of the premises, optimizing the load of various devices under its control.

Implementation of this Use Case is outside the scope of the DOE demonstration project.

B.8.14 Customer Uses HEMP to Respond to Energy Signals

The HEMP provides the customer with a central system to manage their premise energy usage. It can be programmed to take action based on price signals, demand response, and other event messages from the utility and actual changes to customer's load. It can make setting adjustments or turn loads on or off in response to changing market and power system conditions and provides feedback to the utility's SmartGrid system.

The utility is able to send customers messages such as energy usage, current energy tariff and pricing level, demand response events, planned outages, conservation alerts or tips, and other energy related information. Customers equipped with a HAN Gateway (HANG) are able to receive this information via the HEMP and the AMI meter.

This Use Case describes the process by which the HEMP uses the customer's energy management usage preferences to manage and adjust energy use by accessing their most recent usage and pricing data to determine how much energy they are using and the associated costs at their premise.

- Scenario #1 – HEMP adjusts usage for Time of Use Rate Plan
- Scenario #2 – HEMP adjusts usage in response to Real-Time Pricing Signals
- Scenario #3 – HEMP curtails load in response to Direct Load Control DR events
- Scenario #4 – HEMP curtails load in response to Price Incented DR events

Implementation of this Use Case is outside the scope of the DOE demonstration project.

B.8.15 Customer Uses HEMP to Manage PV and PESS

This Use Case describes the process by which the HEMP uses the customer's energy management preferences to manage and adjust energy performance characteristics of the Solar PV and Premise Energy Storage Units (PESS). This Use Case augments the DER Use Cases where the Customer Provides Solar PV and PESS.

The HEMP provides the customer with a central system to manage their premise distributed Solar PV and/or Premise Energy Storage System (PESS). It can be programmed to take action based on price signals, demand response, and other event messages from the utility. It can make setting adjustments to the units or turn DER on or off in response to changing market and power system conditions and provides feedback to the utility's SmartGrid system.

The utility is able to send customers messages such as energy usage, current energy tariff and pricing level, demand response events, planned outages, and other energy related information. Customers equipped with a HAN Gateway (HANG) are able to receive this information via the HEMP and the AMI meter.

- Scenario #1 – HEMP manages PV and PESS for Time of Use Rate Plan
- Scenario #2 – HEMP adjusts PV and PESS in response to Real-Time Pricing Signals
- Scenario #3 – HEMP discharges PESS in response to Direct Load Control DR events
- Scenario #4 – HEMP discharges PESS in response to Price Incented DR events
- Scenario #5 – HEMP manages PV and PESS for service continuity during outages

Implementation of this Use Case is outside the scope of the DOE demonstration project.

B.8.16 Customer Uses HEMP to Manage PEV Charging

This Use Case describes the process by which the HEMP uses the customer's energy management preferences to manage and adjust operating characteristics of the premise EV Charging Station (EVCS). This Use Case augments the numerous other PEV Use Cases. In this Use Case the EVCS is registered to the HAN Gateway (HANG) and communicates to the HEMP via the HANG.

The HEMP provides the customer with a central system to manage their premise EVCS. It can be programmed to take action based on price signals, demand response, and other event messages from the utility. It can make setting adjustments and control PEV charging in response to changing market and power system conditions and provides feedback to the utility's SmartGrid system.

- Scenario #1 – HEMP controls PEV charging for Time of Use Rate Plan
- Scenario #2 – HEMP controls PEV charging in response to Real-Time Pricing Signals
- Scenario #3 – HEMP curtails PEV charging in response to Direct Load Control DR events
- Scenario #4 – HEMP controls PEV charging in response to Price Incented DR events

Implementation of this Use Case is outside the scope of the DOE demonstration project.

B.9 Home Area Network (HAN)

B.9.1 Utility Commissions Home Area Network

This Use Case describes the commissioning of the Home Area Network (HAN) by the Utility. Specifically, the Utility commissions the Utility HAN using the Energy Services Interface radio in the SmartMeter. In addition to the Energy Services Interface radio, the Utility HAN contains other ZigBee enabled devices approved by the Utility for presence on the Utility Home Area Network. The most common devices that will be added to the Utility HAN will be Programmable Communicating Thermostats, Load Control Switches, In-Home Displays and HAN Gateway devices.

B.9.2 Utility Provisions HAN Device to SmartMeter

This Use Case describes the steps, initiated by the Customer, to provision a Home Area Network (HAN) Device to the SmartMeter. The Customer provides the unique identifying information for the HAN Device to the Utility, and then the Utility enters a provisioning request into its back-office systems. The Utility limits and controls the devices that can be provisioned to the SmartMeter, and the Customer has little involvement in the process beyond providing the identifying information for the HAN Device. The HAN Devices that can be provisioned to the SmartMeter include Programmable Communicating Thermostats, Load Controls Switches, In-Home Displays and HAN Gateway Devices.

B.9.3 Utility Sends Text Message to HAN Device

This Use Case describes how the Utility sends text messages to devices on the Home Area Network (HAN). This Use Case occurs when the Utility needs to communicate information with the customer. The messages could include marketing related correspondence or advisory messages regarding upcoming pricing changes. The text messages can reach the HAN devices via two distinct paths.

- Utility sends text message to Utility HAN Devices via Field Automation Network
- Utility sends text message to Customer HAN Devices via HAN Gateway

As a general rule, text messages intended for HAN devices on the Utility HAN (provisioned to the SmartMeter) will travel through the Field Automation Network. Text messages intended for HAN devices on the Customer HAN (provisioned to the HAN Gateway) will travel through the Internet. All text message confirmations will follow the same delivery path as the original text message.

B.9.4 Utility Cancels Text Message

This Use Case describes how the Utility cancels previously sent text messages to devices on the Home Area Network (HAN). When text messages are sent to Home Area Network (HAN) devices, both a start time and duration are included in the message. The HAN devices store the incoming text messages, and, at the indicated start time, they display the text messages to the Customer for the specified duration. The Utility can cancel a text message that is scheduled for display at a future start time. Upon cancellation it will be removed from the HAN device message queue. The Utility can also cancel the currently displayed message to have it removed from the HAN device display prior to its scheduled expiration time. The Utility has the option to request a confirmation that the text message was successfully cancelled.

- Utility cancels text message to Utility HAN Devices via Field Automation Network
- Utility cancels text message to Customer HAN Devices via HAN Gateway

As a general rule, text message cancellation messages for HAN devices on the Utility HAN (provisioned to the SmartMeter) will travel through the Field Automation Network. Text message cancellation messages intended for HAN devices on the Customer HAN (provisioned to the HAN Gateway) will travel through the Internet. All text message confirmations will follow the same delivery path as the original text message.

B.9.5 Utility Sends Pricing Signals to SmartMeter and HAN Devices

This Use Case describes how the Utility sends pricing signals to the SmartMeter and devices on the Utility Home Area Network (UHAN). This Use Case occurs when the Utility needs to communicate pricing information with the customer. This pricing information could be in the form of flat rate, time-of-use (TOU) or critical peak (CP) pricing. Pricing information is communicated to the SmartMeter using the Field Automation Network (FAN). When requested by the Pricing Signals, responses to Pricing Signals are passed from the Home Area Network devices to the Utility back-office systems via the FAN.

B.9.6 Utility Home Area Network Device Information

This Use Case describes the process by which a Utility back-office system queries the Advanced Metering Infrastructure (AMI) Head-End for information on a specific Home Area Network (HAN) device. This information returned includes device MAC Address, Installation Code, Device Type, Installation Date and Pair ID. Under specific situations, the AMI Head-End may also query the HAN device for a subset of this information.

B.9.7 Utility De-Provisions HAN Device on Utility Home Area Network

This Use Case describes the steps taken by the Utility to de-provision a Home Area Network (HAN) device from the SmartMeter. This might be done if there are issues with the HAN device or if the HAN device is to be replaced. Upon completion of this Use Case the HAN device could be re-provisioned to the Utility HAN if desired.

B.9.8 Utility De-Commissions Utility Home Area Network

This Use Case describes the process to decommission a Utility Home Area Network (HAN). This might be done if a customer moves or if problems with a HAN device necessitate resetting the Utility HAN. This process would also be completed prior to a planned SmartMeter exchange. To properly decommission the Utility HAN, the HAN devices must first be de-provisioned from the HAN. Upon completion of this Use Case, the Customer Home Area Network (if it exists) can still function, but it can't communicate with the Utility. Pricing information and Utility status messages can no longer be sent to the Home Area Network Devices via the Field Automation Network.

B.9.9 HAN Device Vendor Change Control

This Use Case describes the process followed by the Utility to approve Home Area Network (HAN) devices for inclusion in the HAN by communicating directly with the SmartMeter. This process is not intended to apply to HAN devices purchased by the Customer for inclusion in the HAN by communicating directly with a gateway device. This process should be followed when evaluating product enhancements from existing HAN device vendors, evaluating new HAN device vendors or evaluating HAN devices not currently allowed to communicate with the SmartMeter.

Implementation of this Use Case is outside the scope of the DOE demonstration project.

B.9.10 HAN Device Status Check

This Use Case describes the steps taken to remotely check the status of a Home Area Network (HAN) device operating at the Customer premise and communicating to the SmartMeter. This function could be used by Customer Service Representatives to assist in troubleshooting Customer complaints about their HAN devices. It could also be used by the Utility to gather information about which HAN devices are being used and how. We need to determine, technically, what information needs to be returned from the HAN. This will determine which ZigBee command is used.

Implementation of this Use Case is outside the scope of the DOE demonstration project.

B.10 Plug-In Electric Vehicle (PEV)

B.10.1 PEV Charging at a Public Charge Station

The Vehicle Charge Management System (VCMS) is the control authority for the Public Electric Vehicle Charging Stations (EVCS). EVCSs include the physical electrical cord and connectors that provide transfer of electric energy from the charging point to the Plug-In Electric Vehicle (PEV).

This Use Case describes how the VCMS manages the schedules of the EVCS and what happens at the EVCS when a PEV plugs into a utility owned public charging station. This Use Case details the establishment of communications between the PEV and EVCS; identification of the PEV and program enrollment; and manages the transfer of energy to the PEV. There are several possible scenarios based on the program/registration parameters the owner of the PEV has selected.

- Immediate payment via credit/debit card
- IF PEV registered with utility, energy charge billed to EVCS sponsor account
- IF PEV registered with utility, energy charge billed to PEV owner's home account
- IF PEV registered with a clearinghouse, energy charge billed to PEV owner via clearinghouse

This Use Case will be partially implemented within the scope of the DOE demonstration project.

B.10.2 Customer Participates in Utility PEV Charging Program

The utility offers special programs specifically for customers with plug-in electric vehicles (PEV). Participants in selected PEV charging programs respond to Time-of-Use (TOU) pricing programs and demand response (DR) requests by the utility by reducing PEV load or shifting the time of day that the PEV is being charged.

Enrolling in a PEV charging program allows the customer to respond in different ways to the utility pricing and demand signals. Whenever a DR request or pricing change is initiated, the utility notifies PEV customers enrolled in applicable utility PEV demand-side management programs to encourage action. This Use Case describes desired customer responses for three types of PEV charging programs:

- Customer is enrolled in a PEV Time-of-Use (TOU) pricing demand-side management program
- Customer is enrolled in a PEV Periodic/Hourly Pricing Price Response program
- Customer is enrolled in a PEV Discrete Event demand-side management program

This Use Case will be partially implemented within the scope of the DOE demonstration project.

B.10.3 Customer Registers PEV to Home Premise

This scenario involves the registration of the PEV(s) that may be charged at the premise Electric Vehicle Service Interface (EVS). Several available options may include:

- Any PEV may charge and will be billed to the premise account
- Registered PEVs may charge and will be billed to the premise account
- Un-registered PEVs may NOT be charged, or
- Un-registered PEVs may charge if they are billed to another premise account or clearinghouse

Implementation of this Use Case is outside the scope of the DOE demonstration project.

B.10.4 Customer PEV Charging at Home Premise EVSI

Customer connects PEV at Home (premise) and expects energy charge billed to home account. The customer is charging a PEV under a selected PEV rate tariff that may provide an incentive to charge during off peak periods. This Use Case details the Connection Location (VIN Authentication, Basic Charging per enrolled program) for the customer to transfer energy.

Implementation of this Use Case is outside the scope of the DOE demonstration project.

B.10.5 Unregistered PEV Charging at Premise EVSI

An unregistered PEV connects to a customer's home charging station and expects to receive a charge. This Use Case details the Connection Location (VIN Authentication, Basic Charging per enrolled program) for the customer to transfer energy. There are several possible scenarios based on the program/registration parameters the customer has selected.

- Un-registered PEV may charge and will be billed to the premise account
- Un-registered PEV may charge and will be billed to the PEV owner's home account and program.
- Un-registered PEVs may charge if they are billed through a PEV charging clearinghouse
- Un-registered PEVs may NOT be charged

Implementation of this Use Case is outside the scope of the DOE demonstration project.

B.10.6 Charge Validation and Settlement via Clearinghouse

This Use Case describes the processes involved when a PEV/PHEV registered to another utility (or other entity) charge program is verified through a PEV charge clearinghouse and settlement transactions are processed between the clearinghouse and the two utilities.

Implementation of this Use Case is outside the scope of the DOE demonstration project.

B.10.7 Utility Controls PEV Charging at Public Charge Station

The utility offers special programs specifically for owner (sponsors) of Public EV Charging Stations that allows the utility to dynamically control PEV charging. More specifically these programs allow the utility to actively manage the PEV charging load by either reducing or interrupting it based on grid conditions. In either case, the active management will support turn off those who have higher state of charge while only reducing the charge rate of those that have lower state of charge. This Use Case describes the following scenarios:

- Public EV Charge Station reports state of charge and charge rate to utility VCMS
- Utility VCMS sends charging instructions to Public EV Charge Station

This Use Case will be partially implemented within the scope of the DOE demonstration project.

B.10.8 Utility Controls Customer On-Premise PEV Charging

The utility offers special programs specifically for customers with plug-in electric vehicles (PEV) that allows the utility to dynamically control PEV charging. More specifically these programs allow the utility to actively manage the PEV charging load by either reducing or interrupting it based on grid conditions. In either case, the active management will support turn off those who have higher state of charge while only reducing the charge rate of those that have lower state of charge. Usually, the utility offers an array of options with programs varying in the quantity of events and length of reduction or interruption periods. This Use Case describes the following scenarios:

- Customer EVSE reports state of charge and charge rate to utility VCMS
- Utility VCMS sends charging instructions to customer EVSE

Implementation of this Use Case is outside the scope of the DOE demonstration project.

B.11 Communication Networks (NWK)

B.11.1 AMI Field Automation Network (FAN)

The Advanced Metering Infrastructure (AMI) provides flexible, two-way communications between the SmartMeter and the AMI Head-End. This is accomplished through the implementation of a hierarchical, RF mesh network of devices known as the Field Automation Network (FAN). The FAN can be used for many applications including meter reading, smart end-use, and demand response.

FAN systems promise to provide advanced energy monitoring and recording, sophisticated tariff/rate program data collection, and load management command and control capabilities. Additionally, these powerful mechanisms will enable consumers to better manage their energy usage and allow the grid to run more efficiently from both a cost and energy delivery perspective. These advanced capabilities will also allow utilities to provision and configure the advanced SmartMeters in the field, thus offering new rate programs and energy monitoring and control.

This Use Case describes the processes of data traveling via the FAN from the AMI Head-End to the SmartMeter and from the SmartMeter to the AMI Head-End.

B.11.2 DA Field Automation Network (DAN)

The Field Automation Network for Distribution Automation provides flexible, two-way communications for Distribution Automation (DA) and Distributed Energy Resource (DER) functionality between a Distribution Automation Device Controller (DADC) or a Distributed Energy Resource Controller (DERC) and the Distribution Data Concentrator (DDC). This is accomplished through the implementation of an RF mesh network of devices known as the Distribution Automation Network (DAN). The DAN can be used for many applications including DA, DER, Volt/VAR Management, and Fault Detection, Location, Isolation, and Restoration (FDLIR).

This Use Case describes the following processes:

- DA messages sent from the DDC to a DADC via the DAN
- DA Messages sent from a DADC to the DDC via the DAN
- DER messages sent from the DDC to a DERC via the DAN
- DER Messages sent from a DERC to the DDC via the DAN

B.11.3 Utility Home Area Network (UHAN)

This Use Case describes the functionality of, and devices that comprise, the Utility Home Area Network. The Utility Home Area Network is formed by the ZigBee radio in the SmartMeter and exists as a conduit to get Utility information (energy prices, Utility text messages, etc.) into the Customer premise, as well as to provide control of energy consuming devices for demand response purposes. The Utility owns and manages all Home Area Network devices that are included in the Utility Home Area Network. Together, the Utility Home Area Network and Customer Home Area Network comprise the Home Area Network.

B.11.4 Customer Home Area Network (CHAN)

This Use Case describes the functionality of, and devices that comprise, the Customer Home Area Network. The Customer Home Area Network is formed by one of the ZigBee radios in the Home Area Network Gateway and exists to allow the Customer to expand the number of devices on their Home Area Network. The Home Area Network Gateway also contains an IP Interface, allowing for Internet access to Home Area Network devices. The Customer owns and manages all Home Area Network devices that are included in the Customer Home Area Network. Together, the Utility Home Area Network and Customer Home Area Network comprise the Home Area Network.

B.11.5 Public EV Charge Network (VCN)

This Use Case details the Public EV Charge Network (VCN) for the customer to use a public EV charge station. The vehicle connects to the public EV charge station using a cord that is included with the public charge station. The public EV charge station will be capable of Level 1 or Level 2 charging and could have more than one cord allowing it to be connected to more than one vehicle at a location. The EV Charge Station is connected via public wireless network to a cloud based charge station access and charge management system. This Use Case describes how data will travel through the VCN Network.

The ChargePoint Charge Station Network was implemented for the DOE Demonstration Project

B.11.6 Substation Distribution Automation Network (SAN)

The deployment of Smart Grid technologies presents various new challenges to the Utility industry. For instance, the implementation of IEC 61850 and the reliance on communication networks instead of direct wiring represents a fundamental change in protection and control system design and operation.

Substation automation and control networks are deployed in harsh environments and transport critical data, which results in demanding requirements of the network and its components. The network must have high availability and low latency, providing fast, reliable communication between networked devices. Networking equipment deployed in these networks must be environmentally hardened, as it may be deployed in enclosures with limited climate control, requiring the equipment to operate across extreme humidity and temperature ranges. Therefore, a reliable physical architecture for the network is needed along with ruggedized, highly reliable network components.

This Use Case describes the data flow of high-priority automation and control functions, including IEC 61850 Manufacturing Message Specification (MMS) between substation devices and the Distribution Data Concentrator (DDC) and Distributed Control and Data Acquisition (DCADA) system controllers within the substation via a high-speed, Ethernet communication network.

B.11.7 Substation Distribution Protection Network (PAN)

The deployment of Smart Grid technologies presents various new challenges to the Utility industry. For instance, the implementation of IEC 61850 and the reliance on communication networks instead of direct wiring represents a fundamental change in protection and control system design and operation.

Substation protection networks are deployed in harsh environments and transport critical data, which results in demanding requirements of the network and its components. The network must have high availability and low latency, providing fast, reliable communication between networked devices. Networking equipment deployed in these networks must be environmentally hardened, as it may be deployed in enclosures with limited climate control, requiring the equipment to operate across extreme humidity and temperature ranges. Therefore, a reliable physical architecture for the network is needed along with ruggedized, highly reliable network components.

This Use Case describes the data flow of high-priority protection and control functions, including IEC 61850 Generic Object-Oriented Substation Event (GOOSE) messages between protective relays and Manufacturing Message Specification (MMS) between substation devices and the Distribution Data Concentrator (DDC) within the substation via a high-speed, Ethernet communication network.

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Appendix C KCP&L SmartGrid Master Interface List

Msg ID	Name of Process/Transaction	Description of Process/Transaction	Producer (Actor 1)	Receiver (Actor 2)	Transport Network	Network Protocols	Information Object Name	Information Object Description	Interface Standard	Standard Msg Name	Standard Msg Code	Use Case
1.a.1	Daily Bill TrueUp Msg Transfer	CIS sends Daily Bill TrueUp Msg to AHE	CIS	AHE			Daily Bill TrueUp Msg	Tunnel Text Msg from CIS to AHE that contains Daily Bill TrueUp data.	IEC 61968-9	CREATE(HANDeviceControl s)	12.19.6.290	SEU-03
1.b.1	Remote Service Order Completion Msg Transfer	AHE sends Remote Service Order Completion Msg to CIS	AHE	CIS			Remote Service Order Completion Msg	Response from MFR indicating that the Remote Service Order Request was received and implemented.	IEC 61968-9	CREATED(EndDeviceControl s)	3.31.6.68	AMI-08
2.a.1	Outage Event Msg Transfer	AHE sends Outage Event Msg to OMS via Legacy MQ.	AHE	OMS		TCP/IP	Outage Event Msg	Msg generated by a MTR and sent from the MFR to the AHE when the MFR detects a sustained voltage loss lasting at least 30 seconds.	MultiSpeak	ODEventNotification		
2.b.1	On-Demand Meter Status Request Transfer	OMS issues On-Demand Meter Status Request to AHE via Legacy MQ. This process is also considered the Restoration Verification Application flow (RVA) internally.	OMS	AHE		TCP/IP	On-Demand Meter Status Request	Request from OMS to AHE for current meter status, which is accomplished through a meter reading.	MultiSpeak	GetOutagedODDevices		
3.a.1	Control Signals		DAD	EMS								
4.a.1	Customer usage data (post VEE)		MDM	DERM								
4.b.1			DERM	MDM								
5.a.1	On-Demand Meter Read Request Transfer	AHE sends On-Demand Meter Read Request to MFR via FAN	AHE	MFR	FAN	L+G Proprietary	On-Demand Meter Read Request	Request from AHE to MMB's internal reading table for current meter usage data.	L+G Proprietary	Command(OnDemandRead)		AMI-02
5.a.2	On-Demand Meter Status Request Transfer	AHE sends On-Demand Meter Status Request to MFR via FAN	AHE	MFR	FAN	L+G Proprietary	On-Demand Meter Status Request	Request from AHE to MMB's internal reading table for current meter reading data. This data is used to determine meter status.	L+G Proprietary	Command(OnDemandRead)		AMI-03
5.a.3	Remote Service Order Request Transfer	AHE sends Remote Service Order Request to MFR	AHE	MFR	FAN	L+G Proprietary	Remote Service Order Request	Remote request entered into AHE by AMIOP or external system.	IEC 61968-9	CREATE(EndDeviceControl s) CREATE(MeterReadings)	3.31.6.68	AMI-08
5.a.4	Commission HAN Command Transfer	AHE sends Commission HAN Command to MFR via FAN	AHE	MFR	FAN	L+G Proprietary	Commission HAN Command	Command from the AHE to the MTR to turn on the ESI and enable the UHAN.	L+G Proprietary	Command(CommissionHAN)		HAN-01
5.a.5	Provision HAND Command Transfer	AHE sends Provision HAND Command to MFR via FAN	AHE	MFR	FAN	L+G Proprietary	Provision HAND Command	Request from AHE to MTR for HAND provisioning. Contains Meter ID, HAND MAC Address and HAND Install Code, and Allow Joining duration.	L+G - Aligns with SEP 1.0	Command(ProvisionHANDDev ice)		HAN-02
5.a.6	Text Msg Transfer	AHE sends Text Msg to MFR via FAN	AHE	MFR	FAN	L+G Proprietary	Text Msg	Request from AHE to ESI to send a text Msg to HAND. Contains text Msg, start time, duration and confirmation flag.	L+G - Aligns with SEP 1.0	Command(HANMsg)		HAN-03
5.a.7	Cancel Text Msg Request Transfer	AHE sends Cancel Text Msg Request to MFR via FAN	AHE	MFR	FAN	L+G Proprietary	Cancel Text Msg Request	Request from AHE to ESI to cancel a previously sent text Msg. Includes ID of previously sent Msg and, optionally, requests an acknowledgement of receipt.	L+G - Aligns with SEP 1.0	Command(CancelTextMsg)		HAN-04
5.a.8	Pricing Signals Transfer	AHE sends Pricing Signals to MFR via FAN	AHE	MFR	FAN	L+G Proprietary	Pricing Signals	Pricing information sent from AHE to ESI. Contains flat, time-of-use, or critical peak pricing.	L+G - Aligns with SEP 1.0	Command(HANPricing)		HAN-05
5.a.9	HAND Pairing Info Request Transfer	AHE sends HAND Pairing Info Request to MFR via FAN	AHE	MFR	FAN	L+G Proprietary	HAND Pairing Info Request	Request from AHE to ESI for HAND pairing information.	L+G - Aligns with SEP 1.0	Command(GetPairingDetails)		HAN-06
5.a.10	HAND De-Provision Request Transfer	AHE sends HAND De-Provision Request to MFR via FAN	AHE	MFR	FAN	L+G Proprietary	HAND De-Provision Request	Request sent from AHE to ESI for the de-provisioning of a HAND.	L+G - Aligns with SEP 1.0	Command(DeProvisionHANDev ice)		HAN-07
5.a.11	UHAN De-Commission Request Transfer	AHE sends UHAN De-Commission Request to MFR via FAN	AHE	MFR	FAN	L+G Proprietary	UHAN De-Commission Request	Request from AHE to ESI for de-commissioning of the UHAN.	L+G Proprietary	Command(DecommissionHAN)		HAN-08
5.a.12	DR Event Msg Transfer	AHE sends DR Event Msg to MFR via FAN	AHE	MFR	FAN	L+G Proprietary	DR Event Msg	Msg from AHE to ESI, through MFR, that contains the load curtailment details for a specific MTR. Details are based upon the type of DR event and user defined preferences in the HEMP.	L+G - Aligns with SEP 1.0	Command(LoadControl)	TBD	UDR-02
5.a.13	Gap-Filling Meter Read Request Transfer	AHE sends Gap-Filling Meter Read Request to MFR via FAN	AHE	MFR	FAN	L+G Proprietary	Gap-Filling Meter Read Request	Request from AHE to MMB for a specific set of interval and/or register MTR data.	L+G Proprietary	GET(MeterReadings)	TBD	AMI-04
5.a.14	MTR Program Update Transfer	AHE sends MTR Program Update to MFR of target MTR via FAN	AHE	MFR	FAN	L+G Proprietary	MTR Program Update		TBD	TBD	TBD	AMI-12

Msg ID	Name of Process/Transaction	Description of Process/Transaction	Producer (Actor 1)	Receiver (Actor 2)	Transport Network	Network Protocols	Information Object Name	Information Object Description	Interface Standard	Standard Msg Name	Standard Msg Code	Use Case
5.a.15	MTR Configuration Update Transfer	AHE sends MTR Configuration Update to MFR of target MTR via FAN	AHE	MFR	FAN	L+G Proprietary	MTR Configuration Update	TBD	TBD	TBD	TBD	AMI-12
5.a.16	MFR Firmware Update Transfer	AHE sends MFR Firmware Update to MFR of target MTR via FAN	AHE	MFR	FAN	L+G Proprietary	MFR Firmware Update	TBD	TBD	TBD	TBD	AMI-12
5.a.17	MMB Firmware Update Transfer	AHE sends MMB Firmware Update to MFR of target MTR via FAN	AHE	MFR	FAN	L+G Proprietary	MMB Firmware Update	TBD	TBD	TBD	TBD	AMI-12
5.a.18	ESI Firmware Update Transfer	AHE sends ESI Firmware Update to MFR of target MTR via FAN	AHE	MFR	FAN	L+G Proprietary	ESI Firmware Update	TBD	TBD	TBD	TBD	AMI-12
5.a.19	Daily Bill TrueUp Msg Transfer	AHE sends Daily Bill TrueUp Msg to MFR via FAN	AHE	MFR	FAN	L+G Proprietary	Daily Bill TrueUp Msg	Tunnel Text Msg from AHE to ESI that contains Daily Bill TrueUp data.	L+G - Aligns with SEP 1.0	Command(HANMsg)		SEU-03
5.a.20	HEMP Settings Update Transfer	AHE sends HEMP Settings Update to MFR via FAN	AHE	MFR	FAN	L+G Proprietary	HEMP Settings Update	Msg from AHE to ESI containing changes to the HEMP settings including set point, fan operation and daily/weekly schedule.	Aligns with SEP 1.0	Demand Resonse and Load Control Cluster	ZigBee SEP 1.0 § D.2	SEU-06
5.a.21	HEMP Settings Update Transfer	AHE sends HEMP Settings Update to MFR via FAN	AHE	MFR	FAN	L+G Proprietary	HEMP Settings Update	Msg from AHE to ESI containing changes to the HEMP settings. Includes schedule and on/off state.	Aligns with SEP 1.0	Demand Resonse and Load Control Cluster	ZigBee SEP 1.0 § D.2	SEU-07
5.b.1	On-Demand Meter Read Data Transfer	MFR sends On-Demand Meter Read Data to AHE via FAN	MFR	AHE	FAN	L+G Proprietary	On-Demand Meter Read Data	Current meter usage data retrieved from MMB's internal reading table and sent to AHE.	L+G Proprietary	Response(Readings)		AMI-02
5.b.2	On-Demand Meter Status Response Transfer	MFR sends On-Demand Meter Status Response to AHE via FAN	MFR	AHE	FAN	L+G Proprietary	On-Demand Meter Status Response	Current meter reading data retrieved from MMB's internal reading table and sent to AHE. This data is used to determine meter status.	L+G Proprietary	Response(Readings)		AMI-03
5.b.3	Aggregated Meter Read Data Transfer	MFR pulls Interval and Register Meter Read Data stored since its last data push and sends it to the AHE via FAN	MFR	AHE	FAN	L+G Proprietary	Aggregated Meter Read Data	Aggregated data (could include Interval Meter Read Data and Register Meter Read Data) from a single MTR compiled at the MFR and sent to the AHE.	L+G Proprietary	TBD		AMI-04
5.b.4	Outage Event Msg Transfer	MFR sends Outage Event Msg to AHE via FAN	MFR	AHE	FAN	L+G Proprietary	Outage Event Msg	Msg generated by a MTR and sent from the MFR to the AHE when the MFR detects a sustained voltage loss lasting at least 30 seconds.	L+G Proprietary	Event (Endpoint Power Outage)		AMI-08
5.b.5	Restoration Event Msg Transfer	MFR sends Restoration Event Msg to AHE via FAN	MFR	AHE	FAN	L+G Proprietary	Restoration Event Msg	Msg generated by a MTR and sent from the MFR to the AHE when the MFR detects a voltage following an outage.	L+G Proprietary	Event (Endpoint Power Restore)		AMI-08
5.b.6	Advisory Event Msg Transfer	MFR sends Advisory Event Msg to AHE via FAN	MFR	AHE	FAN	L+G Proprietary	Advisory Event Msg	Msg generated in MTR and sent from the MFR to the AHE. Contains any MTR events defined as "advisory" that were created since the last data push.	L+G Proprietary	Various. See AMI-06 for details.	Various. See AMI-06 for details.	AMI-06
5.b.7	Alarm Event Msg Transfer	MFR sends Alarm Event Msg to AHE via FAN	MFR	AHE	FAN	L+G Proprietary	Alarm Event Msg	Msg generated in MTR and sent from the MFR to the AHE. Contains any MTR events defined as "alarm".	L+G Proprietary	Various. See AMI-05 for details.	Various. See AMI-05 for details.	AMI-05
5.b.8	Remote Service Order Completion Msg Transfer	MFR issues Remote Service Order Completion Msg to the AHE via FAN	MFR	AHE	FAN	L+G Proprietary	Remote Service Order Completion Msg	Response from MFR indicating that the Remote Service Order Request was received and implemented.	IEC 61968-9	CREATED(EndDeviceControl) CREATED(MeterReading)		AMI-08
5.b.9	HAN Commissioned Response Transfer	MFR sends HAN Commissioned Response to AHE via FAN	MFR	AHE	FAN	L+G Proprietary	HAN Commissioned Response Transfer	Response from the ESI to the AHE indicating that the ESI has been enabled and the UHAN has been established. Contains Meter ID and HAN Network ID.	L+G Proprietary	Response(HANCommissioned)		HAN-01
5.b.10	Ready-to-Pair Response Transfer	MFR sends Ready-to-Pair Response to AHE via FAN	MFR	AHE	FAN	L+G Proprietary	Ready-to-Pair Response	Response from MTR to AHE indicating UHAN is commissioned and ESI is ready to begin the pairing process.	L+G - Aligns with SEP 1.0	Response(Ready-to-Pair)		HAN-02
5.b.11	Provision Complete Response Transfer	MFR sends Provision Complete Response to AHE via FAN	MFR	AHE	FAN	L+G Proprietary	Provision Complete Response	Response from MTR to AHE indicating that HAN has been provisioned to ESI.	L+G - Aligns with SEP 1.0	Response(PairingComplete)		HAN-02
5.b.12	Text Msg Response Transfer	MFR sends Text Msg Response to AHE via FAN	MFR	AHE	FAN	L+G Proprietary	Text Msg Response	Confirmation from ESI to AHE that CUST acknowledged receipt of text Msg. Requirement for this Msg is controlled by the Text Msg.	L+G - Aligns with SEP 1.0	Response(TextMsgCreated)		HAN-03
5.b.13	Cancel Text Msg Confirmation Transfer	MFR sends Cancel Text Msg Confirmation to AHE via FAN	MFR	AHE	FAN	L+G Proprietary	Cancel Text Msg Confirmation	Optional Msg from ESI to AHE indicating successful cancellation of a previously sent text Msg. Requirement for this Msg is controlled by the Cancel Text Msg Request.	L+G - Aligns with SEP 1.0	Response(TextMsgCancelled)		HAN-04
5.b.14	Pricing Signals Acknowledgement Transfer	MFR sends Pricing Signals Acknowledgement to AHE via FAN	MFR	AHE	FAN	L+G Proprietary	Pricing Signals Acknowledgement	Acknowledgement from ESI to AHE that Pricing Signals were received. Requirement for this Msg is controlled by the Pricing Signals.	L+G - Aligns with SEP 1.0	Response(HANPricing)		HAN-05

Msg ID	Name of Process/Transaction	Description of Process/Transaction	Producer (Actor 1)	Receiver (Actor 2)	Transport Network	Network Protocols	Information Object Name	Information Object Description	Interface Standard	Standard Msg Name	Standard Msg Code	Use Case
5.b.15	HAND Pairing Info Response Transfer	MFR sends HAND Pairing Info Response to AHE via FAN	MFR	AHE	FAN	L+G Proprietary	HAND Pairing Info Response	Response from ESI to AHE containing HAND pairing information. Response includes MAC Address, Device Type and Pair ID.	L+G - Aligns with SEP 1.0	Response(PairingDetails)		HAN-06
5.b.16	HAND De-Provision Confirmation Transfer	MFR sends HAND De-Provision Confirmation to AHE via FAN	MFR	AHE	FAN	L+G Proprietary	HAND De-Provision Confirmation	Confirmation from ESI to AHE that the HAND has been de-provisioned.	L+G - Aligns with SEP 1.0	Response(HANDDeviceDeprovisioned)		HAN-07
5.b.17	UHAN De-Commission Confirmation Transfer	MFR sends UHAN De-Commission Confirmation to AHE via FAN	MFR	AHE	FAN	L+G Proprietary	UHAN De-Commission Confirmation	Response from ESI to AHE confirming that the UHAN has been de-commissioned.	L+G Proprietary	Response(HANDeCommissioned)		HAN-08
5.b.18	DR Event Received Acknowledgement Transfer	MFR sends DR Event Received Acknowledgement to AHE via FAN	MFR	AHE	FAN	L+G Proprietary	DR Event Received Acknowledgement	Response Msg from ESI to AHE, through MFR, indicating that the demand response event has been scheduled at the PCT.	L+G - Aligns with SEP 1.0	Response(LoadControl)	TBD	UDR-02
5.b.19	Gap-Filling Meter Read Data Transfer	MFR sends Gap-Filling Meter Read Data to AHE via FAN	MFR	AHE	FAN	L+G Proprietary	Gap-Filling Meter Read Data	Interval and/or register MTR data for a specific period of time that is retrieved from MMB and sent to AHE.	L+G Proprietary	REPLY(MeterReadings)	TBD	AMI-04
5.b.20	MTR Program Update Confirmation Transfer	MFR sends MTR Program Update Confirmation to AHE via FAN	MFR	AHE	FAN	L+G Proprietary	MTR Program Update Confirmation	TBD	TBD	TBD	TBD	AMI-12
5.b.21	MTR Configuration Update Confirmation Transfer	MFR sends MTR Configuration Update Confirmation to AHE via FAN	MFR	AHE	FAN	L+G Proprietary	MTR Configuration Update Confirmation	TBD	TBD	TBD	TBD	AMI-12
5.b.22	MFR Firmware Update Confirmation Transfer	MFR sends MFR Firmware Update Confirmation to AHE via FAN	MFR	AHE	FAN	L+G Proprietary	MFR Firmware Update Confirmation	TBD	TBD	TBD	TBD	AMI-12
5.b.23	MMB Firmware Update Confirmation Transfer	MFR sends MMB Firmware Update Confirmation to AHE via FAN	MFR	AHE	FAN	L+G Proprietary	MMB Firmware Update Confirmation	TBD	TBD	TBD	TBD	AMI-12
5.b.24	ESI Firmware Update Confirmation Transfer	MFR sends ESI Firmware Update Confirmation to AHE via FAN	MFR	AHE	FAN	L+G Proprietary	ESI Firmware Update Confirmation	TBD	TBD	TBD	TBD	AMI-12
5.b.25	PCT Settings Update Transfer	MFR sends PCT Settings Update to AHE via FAN	MFR	AHE	FAN	L+G Proprietary	PCT Settings Update	Msg from ESI to AHE containing changes to the PCT settings including set point, fan operation and daily/weekly schedule.	ZigBee SEP 1.0	Thermostat Settings Attribute Set	ZCL 1.0 § 6.3.2.2.2	SEU-06
5.b.26	DR Event Started Msg Transfer	MFR sends DR Event Started Msg to AHE via FAN	MFR	AHE	FAN	L+G Proprietary	DR Event Started Msg	Msg from ESI to AHE, through MFR, indicating that the demand response event has started.	L+G - Aligns with SEP 1.0	Response(LoadControl)		UDR-02
5.b.27	DR Event Completed Msg Transfer	MFR sends DR Event Completed Msg to AHE via FAN	MFR	AHE	FAN	L+G Proprietary	DR Event Completed Msg	Msg from ESI to AHE, through MFR, indicating that the demand response event has ended.	L+G - Aligns with SEP 1.0	Response(LoadControl)		UDR-02
6.a.1	On-Demand Meter Read Request Transfer	MDM sends On-Demand Meter Read Request to appropriate AHE via ESB	MDM	AHE	ESB		On-Demand Meter Read Request	Request from MDM to AHE for current meter usage data.	IEC 61968-9	REPLY(MeterReading)		AMI-02
6.a.2	On-Demand Meter Status Request Transfer	MDM sends On-Demand Meter Status Request to appropriate AHE via ESB	MDM	AHE	ESB		On-Demand Meter Status Request	Request from DMS (or other system) to AHE for current meter status, which is accomplished through a meter reading.	IEC 61968-9	GET(MeterReading)	TBD	AMI-03
6.a.3	Remote Service Order Completion Msg Transfer											
6.b.1	On-Demand Meter Read Data Transfer	AHE sends On-Demand Meter Read Data to MDM via ESB	AHE	MDM	ESB		On-Demand Meter Read Data	Current meter usage data retrieved from MMB's internal reading table and sent from AHE to CIS (or other system).	IEC 61968-9	REPLY(MeterReading)		AMI-02
6.b.2	On-Demand Meter Status Response Transfer	AHE sends On-Demand Meter Status Response to MDM via ESB	AHE	MDM	ESB		On-Demand Meter Status Response	Current meter reading data retrieved from MMB's internal reading table and sent from AHE to DMS (or other system). This data is used to determine meter status.	IEC 61968-9	REPLY(MeterReading)	TBD	AMI-03
6.b.3	Aggregated Multi-Meter Data Transfer	AHE pulls Aggregated Meter Read Data from multiple MTRs stored since its last data push and sends it to the MDM via ESB	AHE	MDM	ESB		Aggregated Multi-Meter Data	Aggregated data from multiple MTRs compiled at the AHE and sent as a batch file to the MDM.	IEC 61968-9	TBD		AMI-04
6.b.4	Outage Event Msg Transfer	AHE sends Outage Event Msg to MDM via ESB	AHE	MDM	ESB		Outage Event Msg	Msg generated by a MTR and sent from the AHE to the MDM when the MFR detects a sustained voltage loss lasting at least 30 seconds.	IEC 61968-9	CREATED(EndDeviceEvents)	3.26.9.185	AMI-08
6.b.5	Restoration Event Msg Transfer	AHE sends Restoration Event Msg to MDM via ESB	AHE	MDM	ESB		Restoration Event Msg	Msg generated by a MTR and sent from the AHE to the MDM when the MFR detects a voltage following an outage.	IEC 61968-9	CREATED(EndDeviceEvents)	3.26.9.216	AMI-08
6.b.6	Advisory Alert Msg Transfer	AHE sends Advisory Event Msg to MDM via ESB	AHE	MDM	ESB		Advisory Event Msg	Msg sent from the AHE to the MDM. Contains any MTR events defined as "advisory" that were created since the last data push.	IEC 61968-9	CREATED(EndDeviceEvents)	Various. See AMI-06 for details.	AMI-06

Msg ID	Name of Process/Transaction	Description of Process/Transaction	Producer (Actor 1)	Receiver (Actor 2)	Transport Network	Network Protocols	Information Object Name	Information Object Description	Interface Standard	Standard Msg Name	Standard Msg Code	Use Case
6.b.7	Alarm Event Msg Transfer	AHE sends Alarm Event Msg to MDM via ESB	AHE	MDM	ESB		Alarm Event Msg	Msg sent from the AHE to the MDM. Contains any MTR events defined as "alarm".	IEC 61968-9	CREATED(EndDeviceEvents) Various. See AMI-05 for details.	Various. See AMI-05 for details.	AMI-05
6.b.8	Remote Service Order Completion Msg Transfer	AHE forwards Remote Service Order Completion Msg to MDM	AHE	MDM	ESB		Remote Service Order Completion Msg	Response from MFR indicating that the Remote Service Order Request was received and implemented.	IEC 61968-9	CREATED(EndDeviceEvents)	3.31.6.68	
6.b.9	HAN Commissioned Response Transfer	AHE sends HAN Commissioned Response to MDM via ESB	AHE	MDM	ESB		HAN Commissioned Response	Response from AHE to MDM and external system that initiated HAN Commissioning, if applicable, that ESI has been enabled and the UHAN has been established. Contains Meter ID and HAN Network ID.	IEC 61968-9	CREATED(HANDeviceEvents)	12.23.17.42	HAN-01
6.b.10	Provision Complete Response Transfer	AHE sends Provision Complete Response to MDM via ESB	AHE	MDM	ESB		Provision Complete Response	Response from AHE to MDM and HEMP indicating that HAND has been provisioned to ESI.	IEC 61968-9	CREATED(EndDeviceEvents)	12.7.16.242	HAN-02
6.b.11	Text Msg Response Transfer	AHE sends Text Msg Response to MDM via ESB	AHE	MDM	ESB		Text Msg Response	Confirmation from AHE to HEMP (or other originating system) that CUST acknowledged receipt of text Msg. Requirement for this Msg is controlled by the Text Msg. For FAN-delivered Text Msgs, AHE also sends this response to MDM.	IEC 61968-9	CREATED(HANDeviceEvents)	12.19.17.290	HAN-03
6.b.12	Cancel Text Msg Confirmation Transfer	AHE sends Cancel Text Msg Confirmation to MDM via ESB	AHE	MDM	ESB		Cancel Text Msg Confirmation	Optional Msg from AHE to HEMP (or other originating system) and MDM indicating successful cancellation of a previously sent text Msg. Requirement for this Msg is controlled by the Cancel Text Msg Request.	IEC 61968-9	CREATED(HANDeviceEvents)	12.19.17.24	HAN-04
6.b.13	Pricing Signals Acknowledgement Transfer	AHE sends Pricing Signals Acknowledgement to MDM via ESB	AHE	MDM	ESB		Pricing Signals Acknowledgement	Acknowledgement from AHE to DERM and MDM that Pricing Signals were received. Requirement for this Msg is controlled by the Pricing Signals.	IEC 61968-9	CREATED(HANDeviceEvents)	12.23.17.291	HAN-05
6.b.14	HAND De-Provision Confirmation Transfer	AHE sends HAND De-Provision Confirmation to MDM via ESB	AHE	MDM	ESB		HAND De-Provision Confirmation	Confirmation from AHE to HEMP and MDM that the HAND has been de-provisioned.	IEC 61968-9	CREATED(EndDeviceEvents)	12.39.17.212 12.40.17.212 12.41.17.212 12.42.17.212 12.43.17.212 12.44.17.212 12.45.17.212 12.46.17.212 12.47.17.212	HAN-07
6.b.15	UHAN De-Commission Confirmation Transfer	AHE sends UHAN De-Commission Confirmation to MDM via ESB	AHE	MDM	ESB		UHAN De-Commission Confirmation	Response from AHE to HEMP and MDM confirming that the UHAN has been de-commissioned.	IEC 61968-9	CREATED(HANDeviceEvents)	12.23.17.68	HAN-08
6.b.16			AHE	MDM	ESB							
6.b.17			AHE	MDM	ESB							
6.b.18			AHE	MDM	ESB							
6.b.19	MTR Program Update Confirmation Transfer	AHE sends MTR Program Update Confirmation to MDM via ESB	AHE	MDM	ESB		MTR Program Update Confirmation	TBD	TBD	TBD	TBD	AMI-12
6.b.20	MTR Configuration Update Confirmation Transfer	AHE sends MTR Configuration Update Confirmation to MDM via ESB	AHE	MDM	ESB		MTR Configuration Update Confirmation	TBD	TBD	TBD	TBD	AMI-12
6.b.21	MFR Firmware Update Confirmation Transfer	AHE sends MFR Firmware Update Confirmation to MDM via ESB	AHE	MDM	ESB		MFR Firmware Update Confirmation	TBD	TBD	TBD	TBD	AMI-12
6.b.22	MMB Firmware Update Confirmation Transfer	AHE sends MMB Firmware Update Confirmation to MDM via ESB	AHE	MDM	ESB		MMB Firmware Update Confirmation	TBD	TBD	TBD	TBD	AMI-12
6.b.23	ESI Firmware Update Confirmation Transfer	AHE sends ESI Firmware Update Confirmation to MDM via ESB	AHE	MDM	ESB		ESI Firmware Update Confirmation	TBD	TBD	TBD	TBD	AMI-12
7.a.1	Analog and Status Data, alerts											
7.b.1	Fault Detected Msg Transfer	DMS sends Fault Detected Msg to internal sub-systems (D-SCADA and OMS)	DMS	D-SCADA			Fault Detected Msg	A signal sent from the DAC to the DMS & other internal systems indicating the DAD has detected a fault.	IEC 61850	TBD		1st-01
7.b.2	Recloser Open and Fault Detected Msg Transfer	DMS sends Recloser Open and Fault Detected Msg to internal sub-systems (D-SCADA and OMS)	DMS	D-SCADA			Recloser Open & Fault Detected Msg	A signal sent from the DAC to the DMS & other internal systems indicating the Recloser is open due to a fault.	IEC 61850 or DNP3	TBD		1st-01
7.b.3	DAD Status Update Transfer	DMS sends DAD Status Update to internal sub-systems	DMS	D-SCADA			DAD Status Update	A Msg sent from the DAC to the DMS & other internal systems containing the configuration settings of the DAD.	IEC 61850 or DNP3	TBD		1st-01

Msg ID	Name of Process/Transaction	Description of Process/Transaction	Producer (Actor 1)	Receiver (Actor 2)	Transport Network	Network Protocols	Information Object Name	Information Object Description	Interface Standard	Standard Msg Name	Standard Msg Code	Use Case
7.b.4	Lock-Out Signal Transfer	DMS sends Lock-Out Signal to internal sub-systems (D-SCADA and OMS)	DMS	D-SCADA			Lock-Out Signal	A signal sent from the DAC to the DMS & other internal systems indicating the CBR is locked due to the fault.	IEC 61850 or DNP3	TBD		1st-01
7.c.1												
7.d.1												
7.e.1	Restoration requests											
7.f.1	Work order completion notifications											
7.g.1												
8.a.1	On-Demand Meter Read Request	CIS issues On-Demand Meter Read Request to MDM via ESB	CIS	MDM	ESB		On-Demand Meter Read Request	Request from CIS (or other system) to MDM for current meter usage data.	IEC 61968-9	GET(MeterReading)		AMI-02
8.a.2	Remote Service Order Request Transfer	CIS issues Remote Service Order Request to MDM via ESB	CIS	MDM	ESB		Remote Service Order Request	Remote request entered into CIS by a CSR in the call center.	IEC 61968-9	CREATE(MeterServiceRequest)		
8.b.1	On-Demand Meter Read Data Transfer	MDM sends On-Demand meter Read Data to CIS via the ESB	MDM	CIS	ESB		On-Demand Meter Read Data	Current meter usage data retrieved from MMB's internal reading table and sent from AHE to CIS (or other system).	IEC 61968-9	REPLY(MeterReading)		AMI-02
8.b.2	Remote Service Order Completion Msg Transfer	MDM forwards Remote Service Order Completion Msg to CIS via ESB.	MDM	CIS	ESB		Remote Service Order Completion Msg	Response from MFR indicating that the Remote Service Order Request was received and implemented.	IEC 61968-9	UPDATED(MeterServiceRequest)		
9.a.1	Historical Usage Transfer	MDM sends Historical Usage to HEMP via ESB	MDM	HEMP	ESB		Historical Usage	Response from MDM to HEMP containing historical energy usage for a specific CUST over a specified time range.	IEC 61968-9	REPLY(MeterReadings)	TBD	SEU-01
9.b.1	Historical Usage Request Transfer	HEMP sends Historical Usage Request to MDM via ESB	HEMP	MDM	ESB		Historical Usage Request	Request from HEMP to MDM for historical energy usage for a specific CUST for a specified time range.	IEC 61968-9	GET(MeterReadings)	TBD	SEU-01
10.a.1	On-Demand Meter Status Request	DMS issues On-Demand Meter Status Request to MDM via ESB	DMS	MDM	ESB		On-Demand Meter Status Request	Request from DMS (or other system) to AHE for current meter status, which is accomplished through a meter reading.	IEC 61968-9	GET(MeterReading)	TBD	AMI-03
10.a.2	Lock-Out Signal Transfer	DMS sends Lock-Out Signal to MDM via ESB	DMS	MDM	ESB		Lock-Out Signal	A signal sent from the DMS to the MDM indicating the CBR is locked due to the fault via the ESB.	IEC 61850	TBD		1st-01
10.b.1	On-Demand Meter Status Response Transfer	MDM sends On-Demand Meter Status Response to DMS via ESB	MDM	DMS	ESB		On-Demand Meter Status Response	Current meter reading data retrieved from MMB's internal reading table and sent from AHE to DMS (or other system). This data is used to determine meter status.	IEC 61968-9	REPLY(MeterReading)	TBD	AMI-03
10.b.2	Outage Event Msg Transfer	MDM sends Outage Event Msg to DMS via ESB, if necessary	MDM	DMS	ESB		Outage Event Msg	Msg generated by a MTR and sent from the MDM to the DMS when the MFR detects a sustained voltage loss lasting at least 30 seconds.	IEC 61968-9	CREATED(EndDeviceEvents)	3.26.9.185	AMI-08
10.b.3	Restoration Event Msg Transfer	MDM sends Restoration Event Msg to DMS via ESB	MDM	DMS	ESB		Restoration Event Msg	Msg generated by a MTR and sent from the MDM to the DMS when the MFR detects a voltage following an outage.	IEC 61968-9	CREATED(EndDeviceEvents)	3.26.9.216	AMI-08
11.a.1	DAD Status Request Transfer	DDC sends DAD Status Request to DAD via SDPN/DAN	DDC	DAD	DAN		DAD Status Request	A Msg sent from the DAC to the DDC & DAD containing a request for the configuration settings of the DAD.	DNP3	TBD		1st-01
11.a.2	Circuit Reconfiguration Transfer	DDC sends Circuit Reconfiguration to DAD via SDPN/DAN	DDC	DAD	DAN		Circuit Reconfiguration	A command sent from a DAC to the DAD containing the configuration settings of the DAD.	IEC 61850 or DNP3	TBD		1st-01
11.a.3	DAD Status Request Transfer	DDC sends DAD Status Request to all DADs within the area of control via the SDPN/DAN	DDC	DAD	DAN		DAD Status Request	Monitor request sent by DCADA to DAD to determine optimal system parameters.	IEC 61850 or DNP3	TBD		1st-02
11.a.4	DAD Control Signal Transfer	DDC sends DAD Control Signal to all relevant DADs via SDPN/DAN	DDC	DAD	DAN		DAD Control Signal	Updated configuration settings for a Substation or Field DAD as determined by VVC.	IEC 61850 or DNP3	TBD		1st-02
11.a.5	DAD Control Signal Transfer	DDC sends DAD Control Signal to DAD via DAN to initiate load reduction	DDC	DAD	DAN		Field DAD Control Signal	Configuration settings for a Field DAD sent from the DCADA to a Field DAD.	DNP3	TBD		1st-04
11.b.1	DAD Status Response Transfer	DAD sends DAD Status Response to DDC via SDPN/DAN	DAD	DDC	DAN		DAD Status Response	A Msg sent from a DAD to the DDC containing the configuration settings of the DAD.	DNP3	TBD		1st-01
11.b.2	DAD Status Update Transfer	DAD sends DAD Status Update to DDC via SDPN/DAN	DAD	DDC	DAN		DAD Status Update	A Msg sent from a DAD to the DAC containing the configuration settings of the DAD.	IEC 61850 or DNP3	TBD		1st-01
11.b.3	DAD Status Response Transfer	DAD sends DAD Status Response to DDC via SDPN/DAN	DAD	DDC	DAN		DAD Status Response	Response from DAD to DCADA that DAD Status has been sent.	IEC 61850 or DNP3	TBD		1st-02

Msg ID	Name of Process/Transaction	Description of Process/Transaction	Producer (Actor 1)	Receiver (Actor 2)	Transport Network	Network Protocols	Information Object Name	Information Object Description	Interface Standard	Standard Msg Name	Standard Msg Code	Use Case
11.b.4	DAD Alarm Report	Field DAD sends DAD Alarm to DDC via DAN	DAD	DDC	DAN		Field DAD Alarm	An alarm Msg sent from a Field DAD to the DCADA to report an alert condition that has occurred at the DAD.	DNP3	TBD		1st-04
11.b.5	DAD Status Report	DAD sends DAD Status Update to DDC via DAN	DAD	DDC	DAN		Field DAD Status	A Msg containing DAD status sent from a Field DAD to the DCADA.	DNP3	TBD		1st-04
12.a.1	Model Updates Transfer	D-SCADA sends Model Updates to DAC via the Backhaul WAN.	DMS	DAC	Backhaul WAN		Model Updates	The message will contain any new Tags or Manual Updates. The message is triggered anytime DAC sends a request and after a new Tag or Manual Update is applied to the model via the OMS GUI otherwise.				
12.b.1	Fault Detected Msg Transfer	DAC sends Fault Detected Msg to DMS	DAC	DMS			Fault Detected Msg	A signal sent from the DAC to the DMS & other internal systems indicating the DAD has detected a fault.	IEC 61850	TBD		1st-01
12.b.2	Estimated Fault Isolation Msg Transfer	DAC sends Estimated Fault Isolation Msg to DMS	DAC	DMS			Estimated Fault Isolation Msg	A command sent by the DAC to a DAD to isolate a fault that has occurred.	IEC 61850	TBD		1st-01
12.b.3	Recloser Open and Fault Detected Msg Transfer	DCADA sends Recloser Open and Fault Detected Msg to DMS	DAC	DMS			Recloser Open & Fault Detected Msg	A signal sent from the DAC to the DMS & other internal systems indicating the Recloser is open due to a fault.	IEC 61850 or DNP3	TBD		1st-01
12.b.4	DAD Status Update Transfer	DAC sends DAD Status Update to DMS	DAC	DMS			DAD Status Update	A Msg sent from the DAC to the DMS & other internal systems containing the configuration settings of the DAD.	IEC 61850 or DNP3	TBD		1st-01
12.b.5	Lock-Out Signal Transfer	DCADA sends Lock-Out Signal to DMS	DAC	DMS			Lock-Out Signal	A signal sent to the DAC from a DAD indicating the CBR is locked due to the fault.	IEC 61850 or DNP3	TBD		1st-01
12.b.6	Network Configuration Update Transfer	DCADA sends a distribution system Network Configuration Update to the DMS	DAC	DMS			Network Configuration Update	Updated configuration settings for relevant DADs is sent to DMS.	IEC 61850 or DNP3	TBD		1st-02
12.c.1	Model Updates Transfer	DNA sends Model Updates to DAC via the Back Office Network.	DNA	DAC	Backhaul WAN		Model Updates	The message will contain any new JCGs (Jumper Cuts and Grounds). The message is triggered anytime DAC sends a request and after a new JCG is applied to the model via the OMS GUI otherwise.				
13.a.1	Map Migration	GIS sends current Map Data to the OMS (DMS sub-system) via the Back Office Network. This process mostly consists of manual steps.	GIS	OMS (DMS)	Back Office Network	TCP/IP	Map Data	Current geographical data needed to build the OMS map is retrieved from GIS on an ad hoc basis and sent to OMS.				
14.a.1	Network Model Sync Response Transfer	D-SCADA sends Network Model Sync Response to DERM via ESB.	D-SCADA	DERM	ESB	HTTP(S) & JMS MQ	Network Model Sync Response	The message contains a list of all the switches that currently in an abnormal state. It is a response to the GetDiscreteMeasurements message sent from DERM to D-SCADA.	IEC 61968-3 with extensions	ReplyDiscreteMeasurements (KCP&L Msg Name)		
14.a.2	DPF Results Response Transfer	D-SCADA sends DPF Results Response to DERM via ESB.	D-SCADA	DERM	ESB	HTTP(S) & JMS MQ	DPF Results Response	The message contains the requested set of DPF (Distribution Power Flow) results. It is a response to the GetDistributionPowerFlowLimitViolation message sent from DERM to D-SCADA.	IEC 61968-3 with extensions	ReplyDistributionPowerFlowLimitViolation (KCP&L Msg Name)		
14.a.3	DPF Limit Violations Modification Notification Transfer	D-SCADA sends DPF Limit Violations Modification Notification to DERM via ESB.	D-SCADA	DERM	ESB	HTTP(S) & JMS MQ	DPF Limit Violations Modification Notification	The message contains one or more existing DPF (Distribution Power Flow) limit violations that have been modified.	IEC 61968-3 with extensions	ChangedDistributionPowerFlowLimitViolation (KCP&L Msg Name)		
14.a.4	DPF Limit Violations Creation Notification Transfer	D-SCADA sends DPF Limit Violations Creation Notification to DERM via ESB.	D-SCADA	DERM	ESB	HTTP(S) & JMS MQ	DPF Limit Violations Creation Notification	The message contains the DPF (Distribution Power Flow) limit violations that have been created.	IEC 61968-3 with extensions	CreatedDistributionPowerFlowLimitViolation (KCP&L Msg Name)		
14.a.5	DPF Limit Violations Deletion Notification Transfer	D-SCADA sends DPF Limit Violations Deletion Notification to DERM via ESB.	D-SCADA	DERM	ESB	HTTP(S) & JMS MQ	DPF Limit Violations Deletion Notification	The message contains the DPF (Distribution Power Flow) limit violations that have been deleted.	IEC 61968-3 with extensions	DeletedDistributionPowerFlowLimitViolation (KCP&L Msg Name)		
14.a.6	DR Event List Request Transfer	DERM sends DR Event List Request to D-SCADA via ESB.	D-SCADA	DERM	ESB	HTTP(S) & JMS MQ	DR Event List Request	This message contains a request for the list of the currently scheduled DR (Demand Response) events.	IEC 61968-3 with extensions	GetDemandResourceControls (KCP&L Msg Name)		
14.a.7	Network Model Status Change Notification Transfer	D-SCADA sends Network Model Status Change Notification to DERM via ESB.	D-SCADA	DERM	ESB	HTTP(S) & JMS MQ	Network Model Status Change Notification	The message contains a list of all the spontaneous switch status changes.	IEC 61968-3 with extensions	ChangedDiscreteMeasurements (KCP&L Msg Name)		

Msg ID	Name of Process/Transaction	Description of Process/Transaction	Producer (Actor 1)	Receiver (Actor 2)	Transport Network	Network Protocols	Information Object Name	Information Object Description	Interface Standard	Standard Msg Name	Standard Msg Code	Use Case
14.a.8	DR Event Msg Response Transfer	D-SCADA sends DR Event Msg Response to DERM via ESB.	D-SCADA	DERM	ESB	HTTP(S) & JMS MQ	DR Event Msg Response	Msg from D-SCADA to DERM to acknowledge opt-in or opt-out disposition for a previously created DR (Demand Response) event for the Grid-Connected DER. It is a response to the oadrDistributeEvent message sent from DERM to D-SCADA.	OpenADR	oadrCreatedEvent		
14.a.9	Network Static Model Transfer	D-SCADA sends Network Static Model to DERM.	D-SCADA	DERM	Internet	TCP/IP	Network Static Model	The file contains the current Network Static Model from D-SCADA. It is manually extracted and transferred after a new model is built in D-SCADA.	IEC 61970-552	N/A		
14.b.1	Network Model Sync Request Transfer	DERM sends Network Model Sync Request to D-SCADA via ESB.	DERM	D-SCADA	ESB	HTTP(S) & JMS MQ	Network Model Sync Request	The message contains a request for DERM to synchronize its dynamic network model with the DMS. The message can be sent in real-time, after DERM re-starts following the creation of a new Study Case in DMS, or after a different set of dynamic data has been loaded into the DMS.	IEC 61968-3 with extensions	GetDiscreteMeasurements (KCP&L Msg Name)		
14.b.2	DPF Results Request Transfer	DERM sends DPF Results Request to D-SCADA via ESB.	DERM	D-SCADA	ESB	HTTP(S) & JMS MQ	DPF Results Request	The message enables DERM to query DMS for a specific set of DPF (Distribution Power Flow) results.	IEC 61968-3 with extensions	GetDistributionPowerFlowLimitViolation (KCP&L Msg Name)		
14.b.3	DR Event Creation Notification Transfer	DERM sends DR Event Creation Notification to D-SCADA via ESB.	DERM	D-SCADA	ESB	HTTP(S) & JMS MQ	DR Event Creation Notification	This message is a notification to D-SCADA that DERM has created a DR (Demand Response) event.	IEC 61968-3 with extensions	CreatedDemandResourceControls (KCP&L Msg Name)		
14.b.4	DR Event Modification Notification Transfer	DERM sends DR Event Modification Notification to D-SCADA via ESB.	DERM	D-SCADA	ESB	HTTP(S) & JMS MQ	DR Event Modification Notification	This message is a notification to D-SCADA that DERM has modified an existing DR (Demand Response) event.	IEC 61968-3 with extensions	ChangedDemandResourceControls (KCP&L Msg Name)		
14.b.5	DR Event Deletion Notification Transfer	DERM sends DR Event Deletion Notification to D-SCADA via ESB.	DERM	D-SCADA	ESB	HTTP(S) & JMS MQ	DR Event Deletion Notification	This message is a notification to D-SCADA that DERM has deleted an existing DR (Demand Response) event.	IEC 61968-3 with extensions	DeletedDemandResourceControls (KCP&L Msg Name)		
14.b.6	DR Event List Response Transfer	DERM sends DR Event List Response to D-SCADA via ESB.	DERM	D-SCADA	ESB	HTTP(S) & JMS MQ	DR Event List Response	This message includes a list of the currently scheduled DR (Demand Response) events. It is a response to the GetDemandResourceControls message sent from D-SCADA to DERM.	IEC 61968-3 with extensions	ReplyDemandResourceControls (KCP&L Msg Name)		
14.b.8	DR Event Msg Transfer	DERM sends DR Event Msg to D-SCADA via ESB.	DERM	D-SCADA	ESB	HTTP(S) & JMS MQ	DR Event Msg	Msg from DERM to D-SCADA to schedule a utility-managed DR (Demand Response) event for the Grid-Connected DER.	OpenADR	oadrDistributeEvent		
15.a.1	Schedule DR Event Msg Transfer	DERM sends Schedule DR Event Msg to HEMP	DERM	HEMP	ESB	HTTP(S)	Schedule DR Event Msg	Msg from DERM to HEMP to schedule, modify, or cancel a utility-managed DR (Demand Response) event.	OpenADR	oadrDistributeEvent		UDR-02
15.b.1	DR Event Msg Response Transfer	HEMP sends DR Event Msg Response to DERM via ESB, if required.	HEMP	DERM	ESB	HTTP(S)	DR Event Msg Response	Msg from HEMP to DERM to acknowledge opt-in or opt-out disposition for a previously created DR (Demand Response) event. This Msg is only sent if the corresponding DR Event Msg required a response from HEMP.	OpenADR	oadrCreatedEvent		
16.a.1	Text Msg Transfer	HEMP sends Text Msg to IPI	HEMP	IPI	Internet	IP	Text Msg	Request from HEMP to CHR to send a text Msg to HAND. Contains text Msg, start time, duration and confirmation flag.	Tendrill - Aligns with SEP 1.0			HAN-03
16.a.2	Provision HAND Command Transfer	HEMP sends Provision HAND Command to IPI	HEMP	IPI	Internet	IP	Provision HAND Command	Command from HEMP to CHR to open the provision window and allow HANDs to join the HAN.	Tendrill - Aligns with SEP 1.0	Proprietary		SEU-05
16.a.3	HEMP Settings Update Transfer	HEMP sends HEMP Settings Update to IPI	HEMP	IPI	Internet	IP	HEMP Settings Update	Msg from HEMP to CHR containing changes to the HEMP settings including set point, fan operation and daily/weekly schedule.	Tendrill - Aligns with SEP 1.0			SEU-06
16.a.4	HEMP Settings Update Transfer	HEMP sends HEMP Settings Update to IPI	HEMP	IPI	Internet	IP	HEMP Settings Update	Msg from HEMP to CHR containing changes to the HEMP settings. Includes schedule and on/off state.	Tendrill - Aligns with SEP 1.0			SEU-07
16.a.5	HAND De-Provision Request Transfer	HEMP sends HAND De-Provision Request to IPI	HEMP	IPI	Internet	IP	HAND De-Provision Request	Request from HEMP to CHR to de-provision a HAND from the HAN.	Aligns with ZigBee SEP 1.0			SEU-08
16.a.6	Cancel Text Msg Request Transfer	HEMP sends Cancel Text Msg Request to IPI	HEMP	IPI	Internet	IP	Cancel Text Msg Request	Request from HEMP to CHR to cancel a previously sent text Msg. Includes ID of previously sent Msg and, optionally, requests and acknowledgement of receipt.	Tendrill - Aligns with SEP 1.0			HAN-04

Msg ID	Name of Process/Transaction	Description of Process/Transaction	Producer (Actor 1)	Receiver (Actor 2)	Transport Network	Network Protocols	Information Object Name	Information Object Description	Interface Standard	Standard Msg Name	Standard Msg Code	Use Case
16.b.1	Text Msg Response Transfer	IPI sends Text Msg Response to HEMP	IPI	HEMP	Internet	IP	Text Msg Response	Confirmation from CHR to HEMP that CUST acknowledged receipt of text Msg. Requirement for this Msg is controlled by the Text Msg.	Tendrill - Aligns with SEP 1.0			HAN-03
16.b.2	HANG Information Transfer	HANG sends HANG Information to HEMP	HANG	HEMP	Internet	IP	HANG Information	MAC Address and Install Code for the HANG. Provided by the HANG manufacturer and typically printed on a sticker applied to the device.	Tendrill - Aligns with SEP 1.0	MAC Address Install Code		SEU-04
16.b.3	Read-to-Pair Response Transfer	IPI sends Ready-to-Pair Response to HEMP	IPI	HEMP	Internet	IP	Ready-to-Pair Response	Response from CHR to HEMP acknowledging that the provision window is open and the CHR is ready to join new HANDs to the HAN.	Tendrill - Aligns with SEP 1.0	Proprietary		SEU-05
16.b.4	Provision Complete Response Transfer	IPI sends Provision Complete Response to HEMP	IPI	HEMP	Internet	IP	Provision Complete Response	Response from CHR to HEMP indicating that the HAND has been provisioned to the CHR and joined the CHAN.	Tendrill - Aligns with SEP 1.0	Proprietary		SEU-05
16.b.5	PCT Settings Update Transfer	IPI sends PCT Settings Update to HEMP	IPI	HEMP	Internet	IP	PCT Settings Update	Msg from CHR to HEMP containing changes to the PCT settings including set point, fan operation and daily/weekly schedule.	Tendrill - Aligns with SEP 1.0			SEU-06
16.b.6	HAND De-Provision Confirmation Transfer	IPI sends HAND De-Provision Confirmation to HEMP	IPI	HEMP	Internet	IP	HAND De-Provision Confirmation	Confirmation from CHR to HEMP that HAND has been de-provisioned from HANG.	Aligns with ZigBee SEP 1.0			SEU-08
16.b.7	Cancel Text Msg Response Transfer	IPI sends Cancel Text Msg Response to HEMP	IPI	HEMP	Internet	IP	Cancel Text Msg Confirmation	Confirmation from CHR to HEMP indicating successful cancellation of a previously sent text Msg.	Tendrill - Aligns with SEP 1.0			HAN-04
17.a.1	Modify DR event, delete DR event, availability request, pricing information		DERM	BMS								
17.b.1	Confirmation/acknowledgement of DR event create, modify, delete, opt out information, availability info		BMS	DERM								
18.a.1	Shed Load Command Transfer	DERM sends Shed Load Command to VCMS.	DERM	VCMS	Internet	HTTP(S)	Shed Load Command	This command is used to shed load for one or more EVCSs. The message can specify that either a certain percentage of an EVCS's current power output or the absolute maximum allowable load be shed.				
18.a.2	Clear Shed State Command Transfer	DERM sends Clear Shed State Command to VCMS.	DERM	VCMS	Internet	HTTP(S)	Clear Shed State Command	This command is used to clear the shed state from one or more EVCSs.				
19.a.1	Shed Load Command Transfer	VCMS sends Shed Load Command to EVCS.	VCMS	EVSE	Hosted Cellular Network	OCPP	Shed Load Command	This command is used to shed load for a specific EVCS. The message can specify that either a certain percentage of the EVCS's current power output or the absolute maximum allowable load be shed.	N/A	N/A		
19.a.2	Clear Shed State Command Transfer	VCMS sends Clear Shed State Command to EVCS.	VCMS	EVSE	Hosted Cellular Network	OCPP	Clear Shed State Command	This command is used to clear the shed state from a specific EVCS.	N/A	N/A		
20.a.1	Current (projected schedules) DR available		DERM	RTO								
20.b.1	Potentially query for available DR		RTO	DERM								
21.a.1	DAD Status Request Transfer	DDC sends DAD Status Request to DAD via DAN/SDPN	DDC	DAD	SDPN		DAD Status Request	A Msg sent from the DAC to the DDC & DAD containing a request for the configuration settings of the DAD.	IEC 61850	TBD		1st-01
21.a.2	Circuit Reconfiguration Transfer	DDC sends Circuit Reconfiguration to DAD via DAN/SDPN	DDC	DAD	SDPN		Circuit Reconfiguration	A command sent from a DAC to the DAD containing the configuration settings of the DAD.	IEC 61850 or DNP3	TBD		1st-01
21.a.3	DAD Status Request Transfer	DDC sends DAD Status Request to all DADs within the area of control via DAN/SDPN	DDC	DAD	SDPN		DAD Status Request	Monitor request sent by DCADA to DAD to determine optimal system parameters.	IEC 61850 or DNP3	TBD		1st-02
21.a.4	DAD Control Signal Transfer	DDC sends DAD Control Signal to all relevant DADs via DAN/SDPN	DDC	DAD	SDPN		DAD Control Signal	Updated configuration settings for a Substation or Field DAD as determined by VVC.	IEC 61850 or DNP3	TBD		1st-02
21.a.5	DAD Control Signal Transfer	DDC sends DAD Control Signal to DAD via SDPN to initiate load reduction	DDC	DAD	SDPN		Substation DAD Control Signal	Configuration settings for a Substation DAD sent from the DCADA to a Substation DAD.	IEC 61850	TBD		1st-04

Msg ID	Name of Process/Transaction	Description of Process/Transaction	Producer (Actor 1)	Receiver (Actor 2)	Transport Network	Network Protocols	Information Object Name	Information Object Description	Interface Standard	Standard Msg Name	Standard Msg Code	Use Case
21.b.1	Fault Detected Msg Transfer	RELAY sends Fault Detected Msg to DDC via SDPN	DAD	DDC	SDPN		Fault Detected Msg	A signal sent to the DAC from a DAD indicating the DAD has detected a fault.	IEC 61850	TBD		1st-01
21.b.2	DAD Status Response Transfer	DAD sends DAD Status Response to DDC via DAN/SDPN	DAD	DDC	SDPN		DAD Status Response	A Msg sent from a DAD to the DDC containing the configuration settings of the DAD.	IEC 61850	TBD		1st-01
21.b.3	Recloser Open and Fault Detected Msg Transfer	RECL sends Recloser Open and Fault Detected Msg to DDC via SDPN	DAD	DDC	SDPN		Recloser Open & Fault Detected Msg	A signal sent to the DAC from a DAD indicating the Recloser is open due to a fault that has occurred.	IEC 61850	TBD		1st-01
21.b.4	DAD Status Update Transfer	DAD sends DAD Status Update to DDC via DAN/SDPN	DAD	DDC	SDPN		DAD Status Update	A Msg sent from a DAD to the DAC containing the configuration settings of the DAD.	IEC 61850 or DNP3	TBD		1st-01
21.b.5	Lock-Out Signal Transfer	RELAY sends Lock-Out Signal to DDC via SDPN	DAD	DDC	SDPN		Lock-Out Signal	A signal sent to the DAC from a DAD indicating the CBR is locked due to the fault.	IEC 61850 or DNP3	TBD		1st-01
21.b.6	DAD Status Response Transfer	DAD sends DAD Status Response to DDC via DAN/SDPN	DAD	DDC	SDPN		DAD Status Response	Response from DAD to DCADA that DAD Status has been sent.	IEC 61850 or DNP3	TBD		1st-02
21.b.7	DAD Alarm Report	Substation DAD sends DAD Alarm to DDC via SDPN	DAD	DDC	SDPN		Substation DAD Alarm	An alarm Msg sent from a Substation DAD to the DCADA to report an alert condition that has occurred at the DAD.	IEC 61850	TBD		1st-04
21.b.8	DAD Status Report	DAD sends DAD Status Update to DDC via SDPN	DAD	DDC	SDPN		Substation DAD Status	A Msg containing DAD status sent from a Substation DAD to the DCADA.	IEC 61850	TBD		1st-04
22.a.1	DAD Status Request Transfer	D-SCADA begins Fault Isolation Calculation by sending DAD Status Request to DDC	D-SCADA	DDC	Backhaul WAN	MMS	DAD Status Request	A Msg sent from D-SCADA to DDC & a DAD containing a request for the configuration settings of a DAD.	IEC 61850	Various		
22.a.2	Circuit Reconfiguration Transfer	D-SCADA sends Circuit Reconfiguration Command to DDC	D-SCADA	DDC	Backhaul WAN	MMS	Circuit Reconfiguration	A command sent from D-SCADA to DDC containing the configuration settings of a DAD.	IEC 61850	Various		
22.a.3	DAD Status Request Transfer	D-SCADA sends a DAD Status Request to DDC	D-SCADA	DDC	Backhaul WAN	MMS	DAD Status Request	Monitor request sent by D-SCADA to DDC to determine optimal system parameters.	IEC 61850	Various		
22.a.4	DAD Control Signal Transfer	D-SCADA creates and sends a DAD Control Signal to DDC	D-SCADA	DDC	Backhaul WAN	MMS	DAD Control Signal	Updated configuration settings for a Substation or Field DAD as determined by VVC.	IEC 61850	Various		
22.a.5	DAD Control Signal Transfer	D-SCADA sends DAD Control Signal to DDC	D-SCADA	DDC	Backhaul WAN	MMS	DAD Control Signal	Configuration settings for a Substation or Field DAD sent from D-SCADA to DDC.	IEC 61850	Various		
22.a.6	DAD Control Signal Transfer	D-SCADA sends DAD Control Signal to DDC	D-SCADA	DDC	Backhaul WAN	MMS	Field DAD Control Signal	Configuration settings for a Field DAD sent from D-SCADA to DDC.	IEC 61850	Various		
22.b.1	Fault Detected Msg Transfer	DDC sends Fault Detected Msg to D-SCADA	DDC	D-SCADA	Backhaul WAN	MMS	Fault Detected Msg	A signal sent to D-SCADA from DDC indicating a DAD has detected a fault.	IEC 61850	Various		
22.b.2	DAD Status Response Transfer	DDC sends DAD Status Response to D-SCADA	DDC	D-SCADA	Backhaul WAN	MMS	DAD Status Response	A Msg sent from DDC to D-SCADA containing the configuration settings of a DAD.	IEC 61850	Various		
22.b.3	Recloser Open and Fault Detected Msg Transfer	DDC sends Recloser Open and Fault Detected Msg to D-SCADA	DDC	D-SCADA	Backhaul WAN	MMS	Recloser Open & Fault Detected Msg	A signal sent to D-SCADA from DDC indicating a Recloser is open due to a fault that has occurred.	IEC 61850	Various		
22.b.4	DAD Status Update Transfer	DDC sends DAD Status Update to D-SCADA	DDC	D-SCADA	Backhaul WAN	MMS	DAD Status Update	A Msg sent from DDC to D-SCADA containing the configuration settings of a DAD.	IEC 61850	Various		
22.b.5	Lock-Out Signal Transfer	DDC sends Lock-Out Signal to D-SCADA	DDC	D-SCADA	Backhaul WAN	MMS	Lock-Out Signal	A signal sent to D-SCADA from DDC indicating a CBR is locked due to the fault.	IEC 61850	Various		
22.b.6	DAD Status Response Transfer	DDC sends DAD Status Response to D-SCADA	DDC	D-SCADA	Backhaul WAN	MMS	DAD Status Response	Response from DDC to D-SCADA that a DAD Status has been sent.	IEC 61850	Various		
22.b.7	DAD Alarm Transfer	DDC sends DAD Alarm to D-SCADA	DDC	D-SCADA	Backhaul WAN	MMS	Substation DAD Alarm	An alarm Msg sent from DDC to D-SCADA to report an alert condition that has occurred at a Substation DAD.	IEC 61850	Various		
22.b.8	DAD Alarm Transfer	DDC sends DAD Alarm to D-SCADA	DDC	D-SCADA	Backhaul WAN	MMS	Field DAD Alarm	An alarm Msg sent from DDC to D-SCADA to report an alert condition that has occurred at a Field DAD.	IEC 61850	Various		
22.b.9	DAD Status Transfer	DDC sends DAD Status Update to D-SCADA	DDC	D-SCADA	Backhaul WAN	MMS	Substation DAD Status	A Msg containing a Substation DAD status sent from DDC to D-SCADA.	IEC 61850	Various		
22.b.10	DAD Status Transfer	DDC sends DAD Status Update to D-SCADA	DDC	D-SCADA	Backhaul WAN	MMS	Field DAD Status	A Msg containing a Field DAD status sent from DDC to D-SCADA.	IEC 61850	Various		
23.a.1	Pricing Signals Transfer	DERM sends Pricing Signals to AHE via ESB	DERM	AHE	ESB		Pricing Signals	Pricing information sent from DERM to AHE. Contains flat, time-of-use, or critical peak pricing.	IEC 61968-9	CREATE(HANDeviceControl s)	12.23.6.291	HAN-05

Msg ID	Name of Process/Transaction	Description of Process/Transaction	Producer (Actor 1)	Receiver (Actor 2)	Transport Network	Network Protocols	Information Object Name	Information Object Description	Interface Standard	Standard Msg Name	Standard Msg Code	Use Case
23.b.1	Pricing Signals Acknowledgement Transfer	AHE sends Pricing Signals Acknowledgement to DERM via ESB	AHE	DERM	ESB		Pricing Signal Acknowledgement	Acknowledgement from AHE to MDM and DERM that Pricing Signals were received. Requirement for this Msg is controlled by the Pricing Signals.	IEC 61968-9	CREATED(HANDDeviceEvents)	12.23.17.291	HAN-05
24.a.1	DAD Status Request Transfer	DAC begins Fault Isolation Calculation by sending DAD Status Request to DDC	DAC	DDC			DAD Status Request	A Msg sent from the DAC to the DDC & DAD containing a request for the configuration settings of the DAD.	IEC 61850 or DNP3	TBD		1st-01
24.a.2	Circuit Reconfiguration Transfer	DAC sends Circuit Reconfiguration Command to DDC	DAC	DDC			Circuit Reconfiguration	A command sent from a DAC to the DAD containing the configuration settings of the DAD.	IEC 61850 or DNP3	TBD		1st-01
24.a.3	DAD Status Request Transfer	DCADA sends a DAD Status Request to DDC	DAC	DDC			DAD Status Request	Monitor request sent by DCADA to DAD to determine optimal system parameters.	IEC 61850 or DNP3	TBD		1st-02
24.a.4	DAD Control Signal Transfer	DAC creates and sends a DAD Control Signal to DDC	DAC	DDC			DAD Control Signal	Updated configuration settings for a Substation or Field DAD as determined by VVC.	IEC 61850 or DNP3	TBD		1st-02
24.a.5	DAD Control Signal Transfer	DAC sends DAD Control Signal to DDC	DAC	DDC			DAD Control Signal	Configuration settings for a Substation/Field DAD sent from the DCADA to a Substation DAD.	IEC 61850	TBD		1st-04
24.a.6	DAD Control Signal Transfer	DAC sends DAD Control Signal to DDC	DAC	DDC			Field DAD Control Signal	Configuration settings for a Field DAD sent from the DCADA to a Field DAD.	DNP3	TBD		1st-04
24.b.1	Fault Detected Msg Transfer	DDC sends Fault Detected Msg to DAC	DDC	DAC			Fault Detected Msg	A signal sent to the DAC from a DAD indicating the DAD has detected a fault.	IEC 61850	TBD		1st-01
24.b.2	DAD Status Response Transfer	DDC sends DAD Status Response to DAC	DDC	DAC			DAD Status Response	A Msg sent from a DAD to the DDC containing the configuration settings of the DAD.	IEC 61850	TBD		1st-01
24.b.3	Recloser Open and Fault Detected Msg Transfer	DDC sends Recloser Open and Fault Detected Msg to DAC	DDC	DAC			Recloser Open & Fault Detected Msg	A signal sent to the DAC from a DAD indicating the Recloser is open due to a fault that has occurred.	IEC 61850	TBD		1st-01
24.b.4	DAD Status Update Transfer	DDC sends DAD Status Update to DAC	DDC	DAC			DAD Status Update	A Msg sent from a DAD to the DAC containing the configuration settings of the DAD.	IEC 61850 or DNP3	TBD		1st-01
24.b.5	Lock-Out Signal Transfer	DDC sends Lock-Out Signal to DAC	DDC	DAC			Lock-Out Signal	A signal sent to the DAC from a DAD indicating the CBR is locked due to the fault.	IEC 61850 or DNP3	TBD		1st-01
24.b.6	DAD Status Response Transfer	DDC sends DAD Status Response to DCADA	DDC	DAC			DAD Status Response	Response from DAD to DCADA that DAD Status has been sent.	IEC 61850 or DNP3	TBD		1st-02
24.b.7	DAD Alarm Transfer	DDC sends DAD Alarm to DAC	DDC	DAC			Substation DAD Alarm	An alarm Msg sent from a Substation DAD to the DCADA to report an alert condition that has occurred at the DAD.	IEC 61850	TBD		1st-04
24.b.8	DAD Alarm Transfer	DDC sends DAD Alarm to DAC	DDC	DAC			Field DAD Alarm	An alarm Msg sent from a Field DAD to the DCADA to report an alert condition that has occurred at the DAD.	DNP3	TBD		1st-04
24.b.9	DAD Status Transfer	DDC sends DAD Status Update to DAC	DDC	DAC			Substation DAD Status	A Msg containing DAD status sent from a Substation DAD to the DCADA.	IEC 61850	TBD		1st-04
24.b.10	DAD Status Transfer	DDC sends DAD Status Update to DAC	DDC	DAC			Field DAD Status	A Msg containing DAD status sent from a Field DAD to the DCADA.	DNP3	TBD		1st-04
25.a.1	Provision HAND Command Transfer	HEMP sends Provision HAND Command to AHE via ESB	HEMP	AHE	ESB		Provision HAND Command	Request from administrative portion of HEMP to AHE for HAND provisioning. Contains Meter ID, HAND MAC Address and HAND Install Code, and Allow Joining duration.	IEC 61968-9	CREATE(HANDDeviceAssets)		HAN-02
25.a.2	Text Msg Transfer	HEMP sends Text Msg to AHE via ESB	HEMP	AHE	ESB		Text Msg	Request from HEMP (or other external system) to AHE to send a text Msg to HAND. Contains text Msg, start time, duration and confirmation flag.	IEC 61968-9	CREATE(HANDDeviceControls)	12.19.6.290	HAN-03
25.a.3	Cancel Text Msg Request Transfer	HEMP sends Cancel Text Msg Request to AHE via ESB	HEMP	AHE	ESB		Cancel Text Msg Request	Request from HEMP (or other Utility back-office system) to AHE to cancel a previously sent text Msg. Includes ID of previously sent Msg and, optionally, requests an acknowledgement of receipt.	IEC 61968-9	CREATE(HANDDeviceControls)	12.19.6.24	HAN-04
25.a.4	HAND Info Request Transfer	HEMP sends HAND Info Request to AHE via ESB	HEMP	AHE	ESB		HAND Info Request	Request from HEMP (or other Utility back-office system) to AHE for HAND information.	IEC 61968-9	GET(HANDDeviceAssets)		HAN-06
25.a.5	HAND Pairing Info Request Transfer	HEMP sends HAND Pairing Info Request to AHE via ESB	HEMP	AHE	ESB		HAND Pairing Info Request	Request from HEMP (or other Utility back-office system) to AHE for HAND pairing information.	IEC 61968-9	GET(HANDDeviceAssets)		HAN-06
25.a.6	HAND De-Provision Request Transfer	HEMP sends HAND De-Provision Request to AHE via ESB	HEMP	AHE	ESB		HAND De-Provision Request	Request sent from HEMP to AHE for the de-provisioning of a HAND.	IEC 61968-9	DELETE(HANDDeviceAssets)		HAN-07

Msg ID	Name of Process/Transaction	Description of Process/Transaction	Producer (Actor 1)	Receiver (Actor 2)	Transport Network	Network Protocols	Information Object Name	Information Object Description	Interface Standard	Standard Msg Name	Standard Msg Code	Use Case
25.a.7	UHAN De-Commission Request Transfer	HEMP sends UHAN De-Commission Request to AHE via ESB	HEMP	AHE	ESB		UHAN De-Commission Request	Request from HEMP to AHE for de-commissioning of the UHAN.	IEC 61968-9	CREATE(HANDeviceControl s)	12.23.6.68	HAN-08
25.a.8	DR Event Msg Transfer	HEMP sends DR Event Msg Transfer to AHE	HEMP	AHE	ESB		DR Event Msg	Msg from HEMP to AHE that contains the load curtailment details for a specific MTR. Details are based upon the type of DR event and user defined preferences in the HEMP.	IEC 61968-9	CREATE(HANDeviceControl s)	12.15.6.236	UDR-02
25.a.9	HEMP Settings Update Transfer	HEMP sends HEMP Settings Update to AHE via ESB	HEMP	AHE	ESB		HEMP Settings Update	Msg from HEMP to AHE containing changes to the HEMP settings including set point, fan operation and daily/weekly schedule.	IEC 61968-9	CREATE(PANDeviceAssets)		SEU-06
25.a.10	HEMP Settings Update Transfer	HEMP sends HEMP Settings Update to AHE via ESB	HEMP	AHE	ESB		HEMP Settings Update	Msg from HEMP to AHE containing changes to the HEMP settings. Includes schedule and on/off state.	IEC 61968-9	CREATE(PANDeviceAssets)		SEU-07
25.a.11	Commission HAN Command Transfer	HEMP (or other Utility back-office system) sends Commission HAN Command to AHE via ESB	HEMP	AHE	ESB		Commission HAN Command	Command from HEMP to AHE for commissioning the UHAN.	IEC 61968-9	CREATE(HANDeviceControl s)	12.23.6.42	HAN-01
25.b.1	Ready-to-Pair Response Transfer	AHE sends Ready-to-Pair Response to HEMP via ESB	AHE	HEMP	ESB		Ready-to-Pair Response	Response from AHE to HEMP indicating UHAN is commissioned and ESI is ready to begin the pairing process.	IEC 61968-9	CREATED(EndDeviceEvents)	12.7.7.76	HAN-02
25.b.2	Provision Complete Response Transfer	AHE sends Provision Complete Response to HEMP via ESB	AHE	HEMP	ESB		Provision Complete Response	Response from AHE to MDM and HEMP indicating that HAND has been provisioned to ESI.	IEC 61968-9	CREATED(EndDeviceEvents)	12.7.16.242	HAN-02
25.b.3	Text Msg Response Transfer	AHE sends Text Msg Response to HEMP via ESB	AHE	HEMP	ESB		Text Msg Response	Confirmation from AHE to HEMP (or other originating system) that CUST acknowledged receipt of text Msg. Requirement for this Msg is controlled by the Text Msg. For FAN-delivered Text Msgs, AHE also sends this response to MDM.	IEC 61968-9	CREATED(HANDeviceEvent s)	12.19.17.290	HAN-03
25.b.4	Cancel Text Msg Confirmation Transfer	AHE sends Cancel Text Msg Confirmation to HEMP via ESB	AHE	HEMP	ESB		Cancel Text Msg Confirmation	Optional Msg from AHE to HEMP (or other originating system) and MDM indicating successful cancellation of a previously sent text Msg. Requirement for this Msg is controlled by the Cancel Text Msg Request.	IEC 61968-9	CREATED(HANDeviceEvent s)	12.19.17.24	HAN-04
25.b.5	HAND Info Response Transfer	AHE sends HAND Info Response to HEMP via ESB	AHE	HEMP	ESB		HAND Info Response	Response from AHE to HEMP (or originating Utility back-office system) containing HAND information. Response includes MAC Address, Device Type, Installation Code, Installation Date and Pair ID.	IEC 61968-9	REPLY(HANDeviceAssets)		HAN-06
25.b.6	HAND Pairing Info Response Transfer	AHE sends HAND Pairing Info Response to HEMP via ESB	AHE	HEMP	ESB		HAND Pairing Info Response	Response from AHE to HEMP (or originating Utility back-office system) containing HAND pairing information. Response includes MAC Address, Device Type and Pair ID.	IEC 61968-9	REPLY(HANDeviceAssets)		HAN-06
25.b.7	HAND De-Provision Confirmation Transfer	AHE sends HAND De-Provision Confirmation to HEMP via ESB	AHE	HEMP	ESB		HAND De-Provision Confirmation	Confirmation from AHE to HEMP and MDM that the HAND has been de-provisioned.	IEC 61968-9	CREATED(EndDeviceEvents)	12.39.17.212 12.40.17.212 12.41.17.212 12.42.17.212 12.43.17.212 12.44.17.212 12.45.17.212 12.46.17.212 12.47.17.212	HAN-07
25.b.8	UHAN De-Commission Confirmation Transfer	AHE sends UHAN De-Commission Confirmation to HEMP via ESB	AHE	HEMP	ESB		UHAN De-Commission Confirmation	Response from AHE to HEMP and MDM confirming that the UHAN has been de-commissioned.	IEC 61968-9	CREATED(HANDeviceEvent s)	12.23.17.68	HAN-08
25.b.9	DR Event Received Acknowledgement Transfer	AHE sends DR Event Received Acknowledgement to HEMP via ESB	AHE	HEMP	ESB		DR Event Received Acknowledgement	Response Msg from AHE to HEMP indicating that the demand response event has been scheduled at the PCT.	IEC 61968-9	CREATED(HANDeviceEvent s)	12.15.17.236	UDR-02
25.b.10	PCT Settings Update Transfer	AHE sends PCT Settings Update to HEMP via ESB	AHE	HEMP	ESB		PCT Settings Update	Msg from AHE to HEMP containing changes to the PT settings including set point, fan operation and daily/weekly schedule.	IEC 61968-9	CREATED(PANDeviceAsset s)		SEU-06
25.b.11	DR Event Started Msg Transfer	AHE sends DR Event Started Msg to HEMP via ESB	AHE	HEMP	ESB		DR Event Started Msg	Msg from AHE to HEMP indicating that the demand response event has started.	IEC 61968-9	CREATED(HANDeviceEvent s)	TBD	UDR-02
25.b.12	DR Event Completed Msg Transfer	AHE sends DR Event Completed Msg to HEMP via ESB	AHE	HEMP	ESB		DR Event Completed Msg	Msg from AHE to HEMP indicating that the demand response event has ended.	IEC 61968-9	CREATED(HANDeviceEvent s)	TBD	UDR-02

Msg ID	Name of Process/Transaction	Description of Process/Transaction	Producer (Actor 1)	Receiver (Actor 2)	Transport Network	Network Protocols	Information Object Name	Information Object Description	Interface Standard	Standard Msg Name	Standard Msg Code	Use Case
25.b.13	HAN Commissioned Response Transfer	AHE sends HAN Commissioned Response to HEMP (or originating Utility back-office system) via ESB	AHE	HEMP	ESB		HAN Commissioned Response	Response from AHE to MDM and HEMP indicating that ESI has been enabled and the UHAN has been established. Contains Meter ID and HAN Network ID.	IEC 61968-9	CREATED(HANDeviceEvents)	12.23.17.42	HAN-01
25.b.14	Meter Interval and Register Reads Transfer	AHE sends Meter Interval and Register Reads to HEMP via Legacy MQ.	AHE	HEMP	Legacy MQ	SFTP	Meter Interval and Register Reads	The file contains day-behind meter reads (interval and register). Legacy MQ process used to re-format the file received from AHE (converted each meters' interval reads to register reads) before being sent to HEMP.	N/A	N/A		
26.a.1	Grid-Connected DER Status Update Transfer	RTAC sends Grid-Connected DER Status Update to DDC via DAN.	RTAC	DDC	DAN	DNP3	Grid-Connected DER Status Update	The message will contain the current value for either a digital or analog status point that is associated with the Grid-Connected DER. Depending on the point, the message is triggered by any change in value or by the defined polling period configured in DDC.	IEEE 1815	Various		
26.b.1	Grid-Connected DER Control Signal Transfer	DDC sends Grid-Connected DER Control Signal to RTAC via DAN.	DDC	RTAC	DAN	DNP3	Grid-Connected DER Control Signal	The message will contain the desired value for either a digital or analog control point that is associated with the Grid-Connected DER. The message is triggered anytime the DDC receives a Grid-Connected DER Control Signal from the upstream system (D-SCADA).	IEEE 1815	Various		
27.a.1			CIS	MWFM								
27.b.1	Customer-ready-to-disconnect Msg (triggers remote disconnect)		MWFM	CIS								
28.a.1			HANG	DER								
28.b.1			DER	HANG								
29.a.1	Single Sign-On Authentication Assertion Response Transfer	Customer logged into ALNK portal clicks on button to navigate to HEMP. After HEMP sends Assertion Request to ALNK, ALNK sends Assertion Response to HEMP to finish Single Sign-On process.	ALINK	HEMP	Internet	TCP/IP	Single Sign-On Authentication Assertion Response	Only Customers that are enrolled in HEMP program can see button from their ALNK session. Customers aren't allowed access to the HEMP until ALNK sends the Assertion Response to HEMP.	SAML	N/A		
29.b.1	Single Sign-On Authentication Assertion Request Transfer	After Customer navigates to HEMP, HEMP sends Assertion Request to ALNK to verify Customer already has an active ALNK session.	HEMP	ALINK	Internet	TCP/IP	Single Sign-On Authentication Assertion Request	Customers aren't allowed access to the HEMP until ALNK responds to the Assertion Request sent by ALNK.	SAML	N/A		
30.a.1	Customer Status Transfer	CIS sends current Customer Status Data to GIS via the Back Office Network.	CIS	GIS	Back Office Network	SFTP	Customer Status Data	A shadow database containing the current status for each customer is extracted from CIS and sent to GIS to synchronize all of the customers on each Point of Service in GIS. This database includes Service Point ID, Point of Service, and Transformer for each customer.	N/A	N/A		
30.b.1	Customer Connectivity Status Change Transfer	GIS sends current Customer Connectivity Data to CIS via the Back Office Network. A portion of this process involves manual interaction.	GIS	CIS	Back Office Network	SFTP	Customer Connectivity Data	Current mapping between Service Point ID, Point of Service, and Transformer is retrieved from GIS and sent to CIS via a daily batch process. This data ensures CIS stays in sync with GIS after a customer is added to a Point of Service, removed from a Point of Service, or moved to a different Point of Service.	N/A	N/A		
31.a.1	Customer Account Information Transfer	CIS sends Customer Account Information to HEMP.	CIS	HEMP	Private Connection	SFTP	Customer Account Information	This information includes customers' enrollment status, rates, and daily price true-ups.	N/A	N/A		

Msg ID	Name of Process/Transaction	Description of Process/Transaction	Producer (Actor 1)	Receiver (Actor 2)	Transport Network	Network Protocols	Information Object Name	Information Object Description	Interface Standard	Standard Msg Name	Standard Msg Code	Use Case
32.a.1	Customer Status Transfer	CIS sends current Customer Status Data to DERM.	CIS	DERM	Private Connection	SFTP	Customer Status Data	A shadow database containing the the current status for each customer is extracted from CIS and sent to DERM. This database includes Service Point ID, Point of Service, and Transformer for each customer.	N/A	N/A		
33.a.1	Interval data and register reads		DMAT	MDM								
33.b.1	Request interval data		MDM	DMAT								
34.a.1	Internal Process Communication from EVCS to PEV	These messages are used for internal application logic to enable the EVCS to safely charge a PEV at the proper rate.	EVCS	PEV	SAE J1772 Level II Connector	SAE J1772	Internal Process Data	This data is used for internal application logic for a given EVCS to charge a PEV.	SAE J1772	N/A		
34.b.1	Internal Process Communication from PEV to EVCS	These messages are used for internal application logic to enable the EVCS to safely charge a PEV at the proper rate.	PEV	EVCS	SAE J1772 Level II Connector	SAE J1772	Internal Process Data	This data is used for internal application logic for a given EVCS to charge a PEV.	SAE J1772	N/A		
35.a.1			BMS	DER								
35.b.1			DER	BMS								
36.a.1	Internal Process Communication	These messages are used for internal processes.	DAC	DAC	DAC Internal	Siemens Proprietary	Internal Process Data	This data is used for internal control processes.	N/A	N/A		
37.a.1	Customer Status Transfer	CIS sends current Customer Status Data to OMS (DMS sub-system) via the Back Office Network.	CIS	OMS (DMS)	Back Office Network	SFTP	Customer Status Data	A shadow database containing the the current status for each customer is extracted from CIS and sent to OMS on a weekly basis. This database includes Service Point ID, Point of Service, and Transformer for each customer.	N/A	N/A		
38.a.1			CRM	DERM								
39.a.1			CRM	HEMP								
40.a.1	Meter Interval and Register Reads Transfer	AHE sends Meter Interval and Register Reads to DMAT.	AHE	DMAT	Private Connection & Internet	SFTP	Meter Interval and Register Reads	The files contain day-behind meter reads (interval and register).	N/A	N/A		
41.a.1												
41.b.1												
42.a.1												
42.b.1												
43.a.1												
43.b.1												
44.a.1												
44.b.1												
45.a.1												
45.b.1												
46.a.1												
46.b.1												
47.a.1												
47.b.1												
48.a.1												
48.b.1												
49.a.1												
49.b.1												

Msg ID	Name of Process/Transaction	Description of Process/Transaction	Producer (Actor 1)	Receiver (Actor 2)	Transport Network	Network Protocols	Information Object Name	Information Object Description	Interface Standard	Standard Msg Name	Standard Msg Code	Use Case
50.a.1	On-Demand Meter Read Request Transfer	MFR sends On-Demand Meter Read Request to MMB	MFR	MMB	Meter Internal	L+G Proprietary	On-Demand Meter Read Request	Request from AHE to MMB's internal reading table for current meter usage data.	L+G Proprietary	Command(OnDemandRead)		AMI-02
50.a.2	Gap-Filling Meter Read Request Transfer	MFR sends Gap-Filling Meter Read Request to MMB	MFR	MMB	Meter Internal	L+G Proprietary	Gap-Filling Meter Read Request	Request from AHE to MMB for a specific set of interval and/or register MTR data.	L+G Proprietary	GET(MeterReading)	TBD	AMI-04
50.a.3	On-Demand Meter Status Request Transfer	MFR sends On-Demand Meter Status Request to MMB	MFR	MMB	Meter Internal	L+G Proprietary	On-Demand Meter Status Request	Request from AHE to MMB's internal reading table for current meter reading data. This data is used to determine meter status.	L+G Proprietary	Command(OnDemandRead)		AMI-03
50.a.4	MTR Program Update Transfer	MFR sends MTR Program Update to MMB	MFR	MMB	Meter Internal	L+G Proprietary	MTR Program Update	TBD	TBD	TBD	TBD	AMI-12
50.a.5	MTR Configuration Update Transfer	MFR sends MTR Configuration Update to MMB	MFR	MMB	Meter Internal	L+G Proprietary	MTR Configuration Update	TBD	TBD	TBD	TBD	AMI-12
50.a.6	MMB Firmware Update Transfer	MFR sends MMB Firmware Update to MMB	MFR	MMB	Meter Internal	L+G Proprietary	MMB Firmware Update	TBD	TBD	TBD	TBD	AMI-12
50.b.1	On-Demand Meter Read Data Transfer	MMB sends On-Demand Meter Read Data to MFR	MMB	MFR	Meter Internal	L+G Proprietary	On-Demand Meter Read Data	Current meter usage data retrieved from MMB's internal reading table and sent to AHE.	L+G Proprietary	Response(Readings)		AMI-02
50.b.2	Interval Meter Read Data Transfer	MMB sends Interval Meter Read Data to MFR	MMB	MFR	Meter Internal	L+G Proprietary	Interval Meter Read Data	ANSI C12.19 formatted interval usage data generated and stored in the MMB's reading table and sent to MFR.	L+G Proprietary	IntervalReadings		AMI-04
50.b.3	Register Meter Read Data Transfer	MMB sends Register Meter Read Data to MFR	MMB	MFR	Meter Internal	L+G Proprietary	Register Meter Read Data	ANSI C12.19 formatted total daily usage reading generated and stored in the MMB's register and sent to MFR.	L+G Proprietary	RegisterReadings		AMI-04
50.b.4	Advisory Event Msg Transfer	ESI, MMB, or MFR sends Advisory Event Msg to MFR	MMB	MFR	Meter Internal	L+G Proprietary	Advisory Event Msg	Msg generated in a MTR sub-device and sent to the MFR. Contains any MTR events defined as "advisory".	L+G Proprietary	Various. See AMI-06 for details.	Various. See AMI-06 for details.	AMI-06
50.b.5	Log Only Event Msg Transfer	ESI, MMB, or MFR sends Log Only Event Msg to MFR	MMB	MFR	Meter Internal	L+G Proprietary	Log Only Event Msg	Msg generated in a MTR sub-device and sent to the MFR. Contains any MTR events defined as "log only".	L+G Proprietary	Various. See AMI-07 for details.	Various. See AMI-07 for details.	AMI-07
50.b.6	Alarm Event Msg Transfer	ESI, MMB, or MFR sends Alarm Event Msg to MFR	MMB	MFR	Meter Internal	L+G Proprietary	Alarm Event Msg	Msg generated in a MTR sub-device and sent to the MFR. Contains any MTR events defined as "alarm".	L+G Proprietary	Various. See AMI-05 for details.	Various. See AMI-05 for details.	AMI-05
50.b.7	On-Demand Meter Status Response Transfer	MMB sends On-Demand Meter Status Response to MFR	MMB	MFR	Meter Internal	L+G Proprietary	On-Demand Meter Status Response	Current meter reading data retrieved from MMB's internal reading table and sent to AHE. This data is used to determine meter status.	L+G Proprietary	Response(Readings)		AMI-03
50.b.8	MTR Program Update Confirmation Transfer	MMB sends MTR Program Update Confirmation to MFR	MMB	MFR	Meter Internal	L+G Proprietary	MTR Program Update Confirmation	TBD	TBD	TBD	TBD	AMI-12
50.b.9	MTR Configuration Update Confirmation Transfer	MMB sends MTR Configuration Update Confirmation to MFR	MMB	MFR	Meter Internal	L+G Proprietary	MTR Configuration Update Confirmation	TBD	TBD	TBD	TBD	AMI-12
50.b.10	MMB Firmware Update Confirmation Transfer	MMB sends MMB Firmware Update Confirmation to MFR	MMB	MFR	Meter Internal	L+G Proprietary	MMB Firmware Update Confirmation	TBD	TBD	TBD	TBD	AMI-12
50.b.11	Gap-Filling Meter Read Data Transfer	MMB sends Gap-Filling Meter Read Data to MFR	MMB	MFR	Meter Internal	L+G Proprietary	Gap-Filling Meter Read Data	Interval and/or register MTR data for a specific period of time that is retrieved from MMB and sent to AHE.	L+G Proprietary	REPLY(MeterReadings)	TBD	AMI-04
50.c.1					Meter Internal	L+G Proprietary			L+G Proprietary			
50.d.1					Meter Internal	L+G Proprietary			L+G Proprietary			
50.e.1					Meter Internal	L+G Proprietary			L+G Proprietary			
50.f.1	Commission HAN Command Transfer	MFR sends Commission HAN Command to ESI	MFR	ESI	Meter Internal	L+G Proprietary	Commission HAN Command	Command from the AHE to the MTR to turn on the ESI and enable the UHAN.	L+G Proprietary	Command(CommissionHAN)		HAN-01
50.f.2	Provision HAND Command Transfer	MFR sends Provision HAND Command to ESI	MFR	ESI	Meter Internal	L+G Proprietary	Provision HAND Command	Request from AHE to MTR for HAND provisioning. Contains Meter ID, HAND MAC Address and HAND Install Code, and Allow Joining duration.	L+G - Aligns with SEP 1.0	Command(ProvisionHANDDevice)		HAN-02
50.f.3	Text Msg Transfer	MFR sends Text Msg to ESI	MFR	ESI	Meter Internal	L+G Proprietary	Text Msg	Request from AHE to ESI to send a text Msg to HAND. Contains text Msg, start time, duration and confirmation flag.	L+G - Aligns with SEP 1.0	Command(HANMsg)		HAN-03
50.f.4	Cancel Text Msg Request Transfer	MFR sends Cancel Text Msg Request to ESI	MFR	ESI	Meter Internal	L+G Proprietary	Cancel Text Msg Request	Request from AHE to ESI to cancel a previously sent text Msg. Includes ID of previously sent Msg and, optionally, requests an acknowledgement of receipt.	L+G - Aligns with SEP 1.0	Command(CancelTextMsg)		HAN-04
50.f.5	Pricing Signals Transfer	MFR sends Pricing Signals to ESI	MFR	ESI	Meter Internal	L+G Proprietary	Pricing Signals	Pricing information sent from AHE to ESI. Contains flat, time-of-use, or critical peak pricing.	L+G - Aligns with SEP 1.0	Command(HANPricing)		HAN-05
50.f.6	HAND Pairing Info Request Transfer	MFR sends HAND Pairing Info Request to ESI	MFR	ESI	Meter Internal	L+G Proprietary	HAND Pairing Info Request	Request from AHE to ESI for HAND pairing information.	L+G - Aligns with SEP 1.0	Command(GetPairingDetails)		HAN-06

Msg ID	Name of Process/Transaction	Description of Process/Transaction	Producer (Actor 1)	Receiver (Actor 2)	Transport Network	Network Protocols	Information Object Name	Information Object Description	Interface Standard	Standard Msg Name	Standard Msg Code	Use Case
50.f.7	HAND De-Provision Request Transfer	MFR sends HAND De-Provision Request to ESI	MFR	ESI	Meter Internal	L+G Proprietary	HAND De-Provision Request	Request sent from AHE to ESI for the de-provisioning of a HAN.	L+G - Aligns with SEP 1.0	Command(DeProvisionHANDevice)		HAN-07
50.f.8	UHAN De-Commission Request Transfer	MFR sends UHAN De-Commission Request to ESI	MFR	ESI	Meter Internal	L+G Proprietary	UHAN De-Commission Request	Request from AHE to ESI for de-commissioning of the UHAN.	L+G Proprietary	Command(DeCommissionHAN)		HAN-08
50.f.9	DR Event Msg Transfer	MFR sends DR Event Msg to ESI	MFR	ESI	Meter Internal	L+G Proprietary	DR Event Msg	Msg from AHE to ESI, through MFR, that contains the load curtailment details for a specific MTR. Details are based upon the type of DR event and user defined preferences in the HEMP.	L+G - Aligns with SEP 1.0	Command(LoadControl)	TBD	UDR-02
50.f.10	ESI Firmware Update Transfer	MFR sends ESI Firmware Update to ESI	MFR	ESI	Meter Internal	L+G Proprietary	ESI Firmware Update	TBD	TBD	TBD	TBD	AMI-12
50.f.11	Daily Bill TrueUp Msg Transfer	MFR sends Daily Bill TrueUp Msg to ESI	MFR	ESI	Meter Internal	L+G Proprietary	Daily Bill TrueUp Msg	Tunnel Text Msg from AHE to ESI that contains Daily Bill TrueUp data.	L+G - Aligns with SEP 1.0	Command(HANMsg)		SEU-03
50.f.12	HEMP Settings Update Transfer	MFR sends HEMP Settings Update to ESI	MFR	ESI	Meter Internal	L+G Proprietary	HEMP Settings Update	Msg from AHE to ESI containing changes to the HEMP settings including set point, fan operation and daily/weekly schedule.	ZigBee SEP 1.0	Thermostat Settings Attribute Set	ZCL 1.0 § 6.3.2.2.2	SEU-06
50.f.13	HEMP Settings Update Transfer	MFR sends HEMP Settings Update to ESI	MFR	ESI	Meter Internal	L+G Proprietary	HEMP Settings Update	Msg from AHE to ESI containing changes to the HEMP settings. Includes schedule and on/off state.	Aligns with SEP 1.0	Demand Resonse and Load Control Cluster	ZigBee SEP 1.0 § D.2	SEU-07
50.g.1	HAN Commissioned Response Transfer	ESI sends HAN Commissioned Response to MFR	ESI	MFR	Meter Internal	L+G Proprietary	HAN Commissioned Response	Response from the ESI to the AHE indicating that the ESI has been enabled and the UHAN has been established. Contains Meter ID and HAN Network ID.	L+G Proprietary	Response(HANCommissioned)		HAN-01
50.g.2	Ready-toPair Response Transfer	ESI sends Ready-to-Pair Response to MFR	ESI	MFR	Meter Internal	L+G Proprietary	Ready-to-Pair Response	Response from MTR to AHE indicating UHAN is commissioned and ESI is ready to begin the pairing process.	L+G - Aligns with SEP 1.0	Response(Ready-to-Pair)		HAN-02
50.g.3	Provision Complete Response Transfer	ESI sends Provision Complete Response to MFR	ESI	MFR	Meter Internal	L+G Proprietary	Provision Complete Response	Response from MTR to AHE indicating that HAN has been provisioned to ESI.	L+G - Aligns with SEP 1.0	Response(PairingComplete)		HAN-02
50.g.4	Advisory Event Msg Transfer	ESI, MMB, or MFR sends Alarm Event Msg to MFR	ESI	MFR	Meter Internal	L+G Proprietary	Advisory Event Msg	Msg generated in a MTR sub-device and sent to the MFR. Contains any MTR events defined as "advisory".	L+G Proprietary	Various. See AMI-06 for details.	Various. See AMI-06 for details.	AMI-06
50.g.5	Log Only Event Msg Transfer	ESI, MMB, or MFR sends Log Only Event Msg to MFR	ESI	MFR	Meter Internal	L+G Proprietary	Log Only Event Msg	Msg generated in a MTR sub-device and sent to the MFR. Contains any MTR events defined as "log only".	L+G Proprietary	Various. See AMI-07 for details.	Various. See AMI-07 for details.	AMI-07
50.g.6	Alarm Event Msg Transfer	ESI, MMB, or MFR sends Alarm Event Msg to MFR	ESI	MFR	Meter Internal	L+G Proprietary	Alarm Event Msg	Msg generated in a MTR sub-device and sent to the MFR. Contains any MTR events defined as "alarm".	L+G Proprietary	Various. See AMI-05 for details.	Various. See AMI-05 for details.	AMI-05
50.g.7	Text Msg Response Transfer	ESI sends Text Msg Response to MFR	ESI	MFR	Meter Internal	L+G Proprietary	Text Msg Response	Confirmation from ESI to AHE that CUST acknowledged receipt of text Msg. Requirement for this Msg is controlled by the Text Msg.	L+G - Aligns with SEP 1.0	Response(TextMsgCreated)		HAN-03
50.g.8	Cancel Text Msg Confirmation Transfer	ESI sends Cancel Text Msg Confirmation to MFR	ESI	MFR	Meter Internal	L+G Proprietary	Cancel Text Msg Confirmation	Optional Msg from ESI to AHE indicating successful cancellation of a previously sent text Msg. Requirement for this Msg is controlled by the Cancel Text Msg Request.	L+G - Aligns with SEP 1.0	Response(TextMsgCancelled)		HAN-04
50.g.9	Pricing Signals Acknowledgement Transfer	ESI sends Pricing Signals Acknowledgement to MFR	ESI	MFR	Meter Internal	L+G Proprietary	Pricing Signals Acknowledgement	Acknowledgement from ESI to AHE that Pricing Signals were received. Requirement for this Msg is controlled by the Pricing Signals.	L+G - Aligns with SEP 1.0	Response(HANPricing)		HAN-05
50.g.10	HAND Pairing Info Response Transfer	ESI sends HAND Pairing Info Response to MFR	ESI	MFR	Meter Internal	L+G Proprietary	HAND Pairing Info Response	Response from ESI to AHE containing HAND pairing information. Response includes MAC Address, Device Type and Pair ID.	L+G - Aligns with SEP 1.0	Response(PairingDetails)		HAN-06
50.g.11	HAND De-Provision Confirmation Transfer	ESI sends HAND De-Provision Confirmation to MFR	ESI	MFR	Meter Internal	L+G Proprietary	HAND De-Provision Confirmation	Confirmation from ESI to AHE that the HAN has been de-provisioned.	L+G - Aligns with SEP 1.0	Response(HANDeviceDeprovisioned)		HAN-07
50.g.12	UHAN De-Commission Confirmation Transfer	ESI sends UHAN De-Commission Confirmation to MFR	ESI	MFR	Meter Internal	L+G Proprietary	UHAN De-Commission Confirmation	Response from ESI to AHE confirming that the UHAN has been de-commissioned.	L+G Proprietary	Response(HANDecommissioned)		HAN-08
50.g.13	DR Event Received Acknowledgement Transfer	ESI sends DR Event Received Acknowledgement to MFR	ESI	MFR	Meter Internal	L+G Proprietary	DR Event Received Acknowledgement	Response Msg from ESI to AHE, through MFR, indicating that the demand response event has been scheduled at the PCT.	L+G - Aligns with SEP 1.0	Response(LoadControl)		UDR-02
50.g.14	ESI Firmware Update Confirmation Transfer	ESI sends ESI Firmware Update Confirmation to MFR	ESI	MFR	Meter Internal	L+G Proprietary	ESI Firmware Update Confirmation	TBD	TBD	TBD	TBD	AMI-12
50.g.15	PCT Settings Update Transfer	ESI sends PCT Settings Update to MFR	ESI	MFR	Meter Internal	L+G Proprietary	PCT Settings Update	Msg from ESI to AHE containing changes to the PCT settings including set point, fan operation and daily/weekly schedule.	ZigBee SEP 1.0	Thermostat Settings Attribute Set	ZCL 1.0 § 6.3.2.2.2	SEU-06

Msg ID	Name of Process/Transaction	Description of Process/Transaction	Producer (Actor 1)	Receiver (Actor 2)	Transport Network	Network Protocols	Information Object Name	Information Object Description	Interface Standard	Standard Msg Name	Standard Msg Code	Use Case
50.g.16	DR Event Started Msg Transfer	ESI sends DR Evnet Started Msg to MFR	ESI	MFR	Meter Internal	L+G Proprietary	DR Event Started Msg	Msg from ESI to AHE, through MFR, indicating that the demand response event has started.	L+G - Aligns with SEP 1.0	Response(LoadControl)	n/a	UDR-02
50.g.17	DR Event Completed Msg Transfer	ESI sends DR Evnet Completed Msg to MFR	ESI	MFR	Meter Internal	L+G Proprietary	DR Event Completed Msg	Msg from ESI to AHE, through MFR, indicating that the demand response event has ended.	L+G - Aligns with SEP 1.0	Response(LoadControl)	n/a	UDR-02
50.h.1					Meter Internal	L+G Proprietary			L+G Proprietary			
51.a.1	Text Msg Transfer	IPI sends Text Msg to CHR	IPI	CHR	HANG Internal	Tendrill Proprietary	Text Message	Request from HEMP to CHR to send a text Msg to HAND. Contains text Msg, start time, duration and confirmation flag.	Tendrill - Aligns with SEP 1.0			HAN-03
51.a.2	Provision HAND Command Transfer	IPI sends Provision HAND Command Transfer to CHR	IPI	CHR	HANG Internal	Tendrill Proprietary	Provision HAND Command	Command from HEMP to CHR to open the provision window and allow HANDs to join the HAN.	Tendrill - Aligns with SEP 1.0	Proprietary		SEU-05
51.a.3	HEMP Settings Update Transfer	IPI sends HEMP Settings Update to CHR	IPI	CHR	HANG Internal	Tendrill Proprietary	HEMP Settings Update	Msg from HEMP to CHR containing changes to the HEMP settings including set point, fan operation and daily/weekly schedule.	Tendrill - Aligns with SEP 1.0			SEU-06
51.a.4	HEMP Settings Update Transfer	IPI sends HEMP Settings Update to CHR	IPI	CHR	HANG Internal	Tendrill Proprietary	HEMP Settings Update	Msg from HEMP to CHR containing changes to the HEMP settings. Includes schedule and on/off state.	Tendrill - Aligns with SEP 1.0			SEU-07
51.a.5	HAND De-Provision Request Transfer	IPI sends HAND De-Provision Request to CHR	IPI	CHR	HANG Internal	Tendrill Proprietary	HAND De-Provision Request	Request from HEMP to CHR to de-provision a HAND from the HANG.	Aligns with ZigBee SEP 1.0			SEU-08
51.a.6	Cancel Text Msg Transfer	IPI sends Cancel Text Msg to CHR	IPI	CHR	HANG Internal	Tendrill Proprietary	Cancel Text Msg Request	Request from HEMP to CHR to cancel a previously sent text Msg. Includes ID of previously sent text Msg and, optionally, requests an acknowledgement of receipt.	Tendrill - Aligns with SEP 1.0			HAN-04
51.b.1	Text Msg Response Transfer	CHR sends Text Msg Response to IPI	CHR	IPI	HANG Internal	Tendrill Proprietary	Text Msg Response	Confirmation from CHR to HEMP that CUST acknowledged receipt of text Msg. Requirement for this Msg is controlled by the Text Msg.	Tendrill - Aligns with SEP 1.0			HAN-03
51.b.2	Ready-to-Pair Response Transfer	CHR sends Ready-to-Pair Response to IPI	CHR	IPI	HANG Internal	Tendrill Proprietary	Ready-to-Pair Response	Response from CHR to HEMP acknowledging that the provision window is open and the CHR is ready to join new HANDs to the HAN.	Tendrill - Aligns with SEP 1.0	Proprietary		SEU-05
51.b.3	Provision Complete Response Transfer	CHR sends Provision Complete Response to IPI	CHR	IPI	HANG Internal	Tendrill Proprietary	Provision Complete Response	Response from CHR to HEMP indicating that the HAND has been provisioned to the CHR and joined the HAN.	Tendrill - Aligns with SEP 1.0	Proprietary		SEU-05
51.b.4	PCT Settings Update Transfer	CHR sends PCT Settings Update to IPI	CHR	IPI	HANG Internal	Tendrill Proprietary	PCT Settings Update	Msg from CHR to HEMP containing changes to the PCT settings including set point, fan operation and daily/weekly schedule.	Tendrill - Aligns with SEP 1.0			SEU-06
51.b.5	HAND De-Provision Confirmation Transfer	CHR sends HAND De-Provision Confirmation to IPI	CHR	IPI	HANG Internal	Tendrill Proprietary	HAND De-Provision Confirmation	Confirmation from CHR to HEMP that HAND has been de-provisioned from HANG.	Aligns with ZigBee SEP 1.0			SEU-08
51.b.6	Cancel Text Msg Response Transfer	CHR sends Cancel Text Msg Response to IPI	CHR	IPI	HANG Internal	Tendrill Proprietary	Cancel Text Msg Confirmation	Confirmation from CHR to HEMP indicating successful cancellation of a previously sent text Msg.	Tendrill - Aligns with SEP 1.0			HAN-04
52.a.1	Text Msg Transfer	ESI sends Text Msg to HAND via UHAN	ESI	HAND	UHAN	IEEE 802.15.4	Text Msg	Request from ESI to HAND to display a text Msg. Contains text Msg, start time, duration and confirmation flag.	ZigBee SEP 1.0	Display Msg	SEP 1.0 § D.5.2.3.1	HAN-03
52.a.2	Cancel Text Msg Request Transfer	ESI sends Cancel Text Msg Request to HAND via UHAN	ESI	HAND	UHAN	IEEE 802.15.4	Cancel Text Msg Request	Request from ESI to HAND to cancel a previously sent text Msg. Includes ID of previously sent Msg and, optionally, requests an acknowledgement of receipt.	ZigBee SEP 1.0	Cancel Msg	SEP 1.0 § D.5.2.3.2	HAN-04
52.a.3	Pricing Signals Transfer	ESI sends Pricing Signals to HAND via UHAN	ESI	HAND	UHAN	IEEE 802.15.4	Pricing Signals	Pricing information sent from ESI to HAND. Contains flat, time-of-use, or critical peak pricing.	ZigBee SEP 1.0	Publish Price	SEP 1.0 § D.4.2.4.1	HAN-05
52.a.4	HAND Pairing Info Request Transfer	ESI sends HAND Pairing Info Request to HAND via UHAN	ESI	HAND	UHAN	IEEE 802.15.4	HAND Pairing Info Request	Request from ESI to HAND for HAND pairing information.	ZigBee SEP 1.0	Device Discovery	ZigBee-2007 § 2.4.2.1	HAN-06
52.a.5	HAND De-Provision Request Transfer	ESI sends HAND De-Provision Request to HAND via UHAN	ESI	HAND	UHAN	IEEE 802.15.4	HAND De-Provision Request	Request from ESI to HAND for the HAND to leave the UHAN.	ZigBee SEP 1.0	Leave Command	ZigBee-2007 § 3.4.4	HAN-07 HAN-08

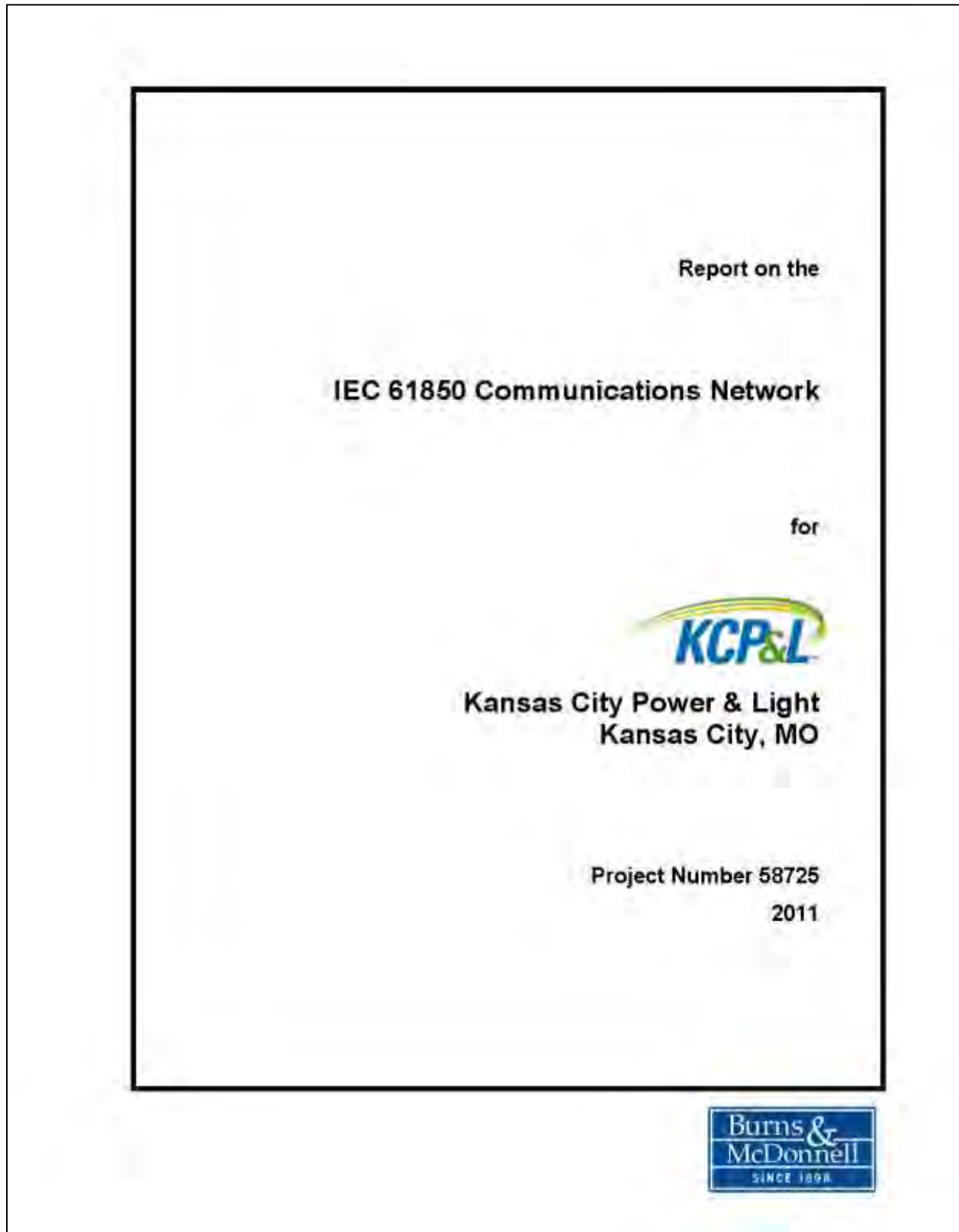
Msg ID	Name of Process/Transaction	Description of Process/Transaction	Producer (Actor 1)	Receiver (Actor 2)	Transport Network	Network Protocols	Information Object Name	Information Object Description	Interface Standard	Standard Msg Name	Standard Msg Code	Use Case
52.a.6	DR Event Msg Transfer	ESI sends DR Event Msg to PCT via UHAN	ESI	PCT	UHAN	IEEE 802.15.4	DR Event Msg	Msg from ESI to PCT that contains the load curtailment details for a specific MTR. Details are based upon the type of DR event and user defined preferences in the HEMP.	ZigBee SEP 1.0	Load Control Event	n/a	UDR-02
52.a.7	Daily Bill TrueUp Msg Transfer	ESI sends Daily Bill TrueUp Msg to IHD via UHAN	ESI	IHD	UHAN	IEEE 802.15.4	Daily Bill TrueUp Msg	Tunnel Text Msg from ESI to IHD that contains Daily Bill TrueUp data.	ZigBee SEP 1.0	Display Msg	SEP 1.0 § D.5.2.3.1	SEU-03
52.a.8	Real-Time Energy Usage Response Transfer	ESI sends Real-Time Energy Usage Response to IHD via UHAN	ESI	IHD	UHAN	IEEE 802.15.4	Real-Time Energy Usage Response	Response from ESI to IHD containing real-time energy usage.	ZigBee SEP 1.0	Instantaneous Demand	SEP 1.0 § D.3.2.2.5.1	SEU-02
52.a.9	Current Price Response Transfer	ESI sends Current Price Response to IHD via UHAN	ESI	IHD	UHAN	IEEE 802.15.4	Current Price Response	Response from ESI to IHD containing current energy prices.	ZigBee SEP 1.0	Publish Price	SEP 1.0 § D.4.2.4.1	SEU-02
52.a.10	Text Msg Response Transfer	ESI sends Text Msg Response to IHD via UHAN	ESI	IHD	UHAN	IEEE 802.15.4	Text Msg Response	Response from ESI to IHD containing the latest utility-generated text Msg.	ZigBee SEP 1.0	Display Msg	SEP 1.0 § D.5.2.3.1	SEU-02
52.a.11	HEMP Settings Update Transfer	ESI sends HEMP Settings Update to PCT via UHAN	ESI	PCT	UHAN	IEEE 802.15.4	HEMP Settings Update	Msg from ESI to PCT containing changes to the HEMP settings including set point, fan operation and daily/weekly schedule.	ZigBee SEP 1.0	Thermostat Settings Attribute Cluster	ZCL 1.0 § 6.3.2.2.2	SEU-06
52.a.12	HEMP Settings Update Transfer	ESI sends HEMP Settings Update to LCS via UHAN	ESI	LCS	UHAN	IEEE 802.15.4	HEMP Settings Update	Messe from ESI to LCS containing changes to the HEMP settings. Includes schedule and on/off state.	ZigBee SEP 1.0	Demand Resonse and Load Control Cluster	ZigBee SEP 1.0 § D.2	SEU-07
52.a.13	ZigBee Command Transfer	ESI sends ZigBee Command to HAND via UHAN	ESI	HAND	UHAN	IEEE 802.15.4	ZigBee Command	Generic ZigBee compliant command originating from either the ESI or a HAND. The destination could be a HAND or the ESI.	ZigBee SEP 1.0	Various	n/a	NWK-03
52.b.1	Text Msg Resonse Transfer	HAND sends Text Msg Response to ESI via UHAN	HAND	ESI	UHAN	IEEE 802.15.4	Text Msg Response	Confirmation from HAND to ESI that CUST acknowledged receipt of text Msg. Requirement for this Msg is controlled by the Text Msg.	ZigBee SEP 1.0	Msg Confirmation	SEP 1.0 § D.5.3.3.2	HAN-03
52.b.2	Cancel Text Msg Confirmation Transfer	HAND sends Cancel Text Msg Confirmation to ESI via UHAN	HAND	ESI	UHAN	IEEE 802.15.4	Cancel Text Msg Confirmation	Optional Msg from HAND to ESI indicating successful cancellation of a previously sent text Msg. Requirement for this Msg is controlled by the Cancel Text Msg Request.	ZigBee SEP 1.0	Msg Confirmation	SEP 1.0 § D.5.3.3.2	HAN-04
52.b.3	Pricing Signals Acknowledgement Transfer	HAND sends Pricing Signals Acknowledgement to ESI via UHAN	HAND	ESI	UHAN	IEEE 802.15.4	Pricing Signals Acknowledgement	Acknowledgement from HAND to ESI that Pricing Signals were received. Requirement for this Msg is controlled by the Pricing Signals.	ZigBee SEP 1.0	Publish Price Response	SEP 1.0 § D.4.2.4.1	HAN-05
52.b.4	HAND Pairing Info Response Transfer	HAND sends HAND Pairing Info Response to ESI via UHAN	HAND	ESI	UHAN	IEEE 802.15.4	HAND Pairing Info Response	Response from HAND to ESI containing HAND pairing information. Response includes MAC Address, Device Type and Pair ID.	ZigBee SEP 1.0	Simple Descriptor Startup Parameters Attribute Set	ZigBee 2007 § 2.3.2.5 ZCL 2008 § 3.15.2.2.1	HAN-06
52.b.5	DR Event Received Acknowledgement Transfer	PCT sends DR Event Received Acknowledgement to ESI via UHAN	PCT	ESI	UHAN	IEEE 802.15.4	DR Event Received Acknowledgement	Response from PCT to ESI indicating that the demand response event has been scheduled at the PCT.	ZigBee SEP 1.0	Report Event Status Command	n/a	UDR-02
52.b.6	Real-Time Energy Usage Request Transfer	IHD sends Real-Time Energy Usage Request to ESI via UHAN	IHD	ESI	UHAN	IEEE 802.15.4	Real-Time Energy Request	Request from IHD to ESI for real-time energy usage.	ZigBee SEP 1.0	Instantaneous Demand	SEP 1.0 § D.3.2.2.5.1	SEU-02
52.b.7	Current Price Request Transfer	IHD sends Current Price Request to ESI via UHAN	IHD	ESI	UHAN	IEEE 802.15.4	Current Price Request	Request from IHD to ESI for current energy prices.	ZigBee SEP 1.0	Get Current Price	SEP 1.0 § D.4.2.3.1	SEU-02
52.b.8	Text Msg Request Transfer	IHD sends Text Msg Request to ESI via UHAN	IHD	ESI	UHAN	IEEE 802.15.4	Text Msg Request	Request from IHD to ESI for latest utility-generated text Msg.	ZigBee SEP 1.0	Get Last Msg	SEP 1.0 § D.5.3.3.1	SEU-02
52.b.9	PCT Settings Update Transfer	PCT sends PCT Settings Update to ESI via UHAN	PCT	ESI	UHAN	IEEE 802.15.4	PCT Settings Update	Msg from PCT to ESI containing changes to the PCT settings including set point, fan operation and daily/weekly schedule.	ZigBee SEP 1.0	Thermostat Settings Attribute Cluster	ZCL 1.0 § 6.3.2.2.2	SEU-06
52.b.10	ZigBee Command Transfer	HAND sends ZigBee Command to ESI via UHAN	HAND	ESI	UHAN	IEEE 802.15.4	ZigBee Command	Generic ZigBee compliant command originating from either the ESI or a HAND. The destination could be a HAND or the ESI.	ZigBee SEP 1.0	Various	n/a	NWK-03
52.b.11	DR Event Started Msg Transfer	PCT sends DR Event Started Msg to ESI via UHAN	PCT	ESI	UHAN	IEEE 802.15.4	DR Event Started Msg	Msg from PCT to ESI indicating that the demand response event has started.	ZigBee SEP 1.0	Report Event Status Command	n/a	UDR-02
52.b.12	DR Event Completed Msg Transfer	PCT sends DR Evnet Completed Msg to ESI via UHAN	PCT	ESI	UHAN	IEEE 802.15.4	DR Event Completed Msg	Msg from PCT to ESI indicating that the demand response event has ended.	ZigBee SEP 1.0	Report Event Status Command	n/a	UDR-02
52.c.1	ZigBee Command Transfer	HAND sends ZigBee Command to another HAND via UHAN	HAND	HAND	UHAN	IEEE 802.15.4	ZigBee Command	Generic ZigBee compliant command originating from either the ESI or a HAND. The destination could be a HAND or the ESI.	ZigBee SEP 1.0	Various	n/a	NWK-03

Msg ID	Name of Process/Transaction	Description of Process/Transaction	Producer (Actor 1)	Receiver (Actor 2)	Transport Network	Network Protocols	Information Object Name	Information Object Description	Interface Standard	Standard Msg Name	Standard Msg Code	Use Case
53.a.1	Text Msg Transfer	CHR sends Text Msg to HAND via CHAN	CHR	HAND	CHAN	IEEE 802.15.4	Text Msg	Request from CHR to HAND to display a text Msg. Contains text Msg, start time, duration and confirmation flag.	ZigBee SEP 1.0	Display Msg	SEP 1.0 § D.5.2.3.1	HAN-03
53.a.2	HEMP Settings Update Transfer	CHR sends HEMP Settings Update to LCS via CHAN	CHR	LCS	CHAN	IEEE 802.15.4	HEMP Settings Update	Msg from CHR to LCS containing changes to the HEMP settings. Includes schedule and on/off state.	ZigBee SEP 1.0	Demand Response and Load Control Cluster	ZigBee SEP 1.0 § D.2	SEU-07
53.a.3	HAND De-Provision Request	CHR sends HAND De-Provision Request to HAND via CHAN	CHR	HAND	CHAN	IEEE 802.15.4	HAND De-Provision Request	Request from CHR to HAND to de-provision a HAND from the HANG.	ZigBee SEP 1.0	Leave Command	ZigBee 2007 § 3.4.4	SEU-08
53.a.4	ZigBee Command Transfer	CHR sends ZigBee Command to HAND via CHAN	CHR	HAND	CHAN	IEEE 802.15.4	ZigBee Command	Generic ZigBee compliant command originating from either the CHR or a HAND. The destination could be a HAND or the CHR.	ZigBee SEP 1.0	Various	n/a	NWK-04
53.a.5	Cancel Text Msg Transfer	CHR sends Cancel Text Msg request to HAND via CHAN	CHR	HAND	CHAN	IEEE 802.15.4	Cancel Text Msg Request	Request from CHR to HAND to cancel a previously sent text Msg. Includes ID of previously sent Msg and, optionally, requests an acknowledgement of receipt.	ZigBee SEP 1.0	Cancel Msg	SEP 1.0 § D.5.2.3.2	HAN-04
53.a.6	HEMP Settings Update Transfer	CHR sends HEMP Settings Update to PCT via UHAN	CHR	PCT	CHAN	IEEE 802.15.4	HEMP Settings Update	Msg from CHR to PCT containing changes to the HEMP settings including set point, fan operation and daily/weekly schedule.	ZigBee SEP 1.0	Thermostat Settings Attribute Cluster	ZCL 1.0 § 6.3.2.2.2	SEU-06
53.b.1	Text Msg Response Transfer	HAND sends Text Msg Response to CHR via CHAN	HAND	CHR	CHAN	IEEE 802.15.4	Text Msg Response	Confirmation from HAND to CHR that CUST acknowledged receipt of text Msg. Requirement for this Msg is controlled by the Text Msg.	ZigBee SEP 1.0	Msg Confirmation	SEP 1.0 § D.5.3.3.2	HAN-03
53.b.2	ZigBee Command Transfer	HAND sends ZigBee Command to CHR via CHAN	HAND	CHR	CHAN	IEEE 802.15.4	ZigBee Command	Generic ZigBee compliant command originating from either the CHR or a HAND. The destination could be a HAND or the CHR.	ZigBee SEP 1.0	Various	n/a	NWK-04
53.b.3	Cancel Text Msg Response Transfer	HAND sends Cancel Text Msg Response to CHR via CHAN	HAND	CHR	CHAN	IEEE 802.15.4	Cancel Text Msg Confirmation	Confirmation from HAND to CHR indicating successful cancellation of a previously sent text Msg.	ZigBee SEP 1.0	Msg Confirmation	SEP 1.0 § D.5.3.3.2	HAN-04
53.b.4	PCT Settings Update Transfer	PCT sends PCT Settings Update to CHR via CHAN	PCT	CHR	CHAN	IEEE 802.15.5	PCT Settings Update	Msg from PCT to CHR containing changes to the PCT settings including set point, fan operation and daily/weekly schedule.	ZigBee SEP 1.0	Thermostat Settings Attribute Cluster	ZCL 1.0 § 6.3.2.2.2	SEU-06
53.c.1	ZigBee Command Transfer	HAND sends ZigBee Command to another HAND via CHAN	HAND	HAND	CHAN	IEEE 802.15.4	ZigBee Command	Generic ZigBee compliant command originating from either the CHR or a HAND. The destination could be a HAND or the CHR.	ZigBee SEP 1.0	Various	n/a	NWK-04
54.a.1	GOOSE Broadcast Message Transfer	Feeder Relay (Substation DAD) sends GOOSE Broadcast Message out to all other Substation DADs via SPDN.	Substation DAD	Substation DAD	SDPN	GOOSE	GOOSE Broadcast Message	Each GOOSE message broadcasted by a Feeder Relay contains a trip indicator, breaker position, event record indicator, average total load, average sheddable load, and ground fault indicator. The relay sends out a message anytime its status changes and on a 1-second interval otherwise.	IEC 61850	Various		
54.a.2	GOOSE Broadcast Message Transfer	Main Bus Relay (Substation DAD) sends GOOSE Broadcast Message out to all other Substation DADs via SPDN.	Substation DAD	Substation DAD	SDPN	GOOSE	GOOSE Broadcast Message	Each GOOSE message broadcasted by a Main Bus Relay contains a trip indicator, breaker position, event record indicator, load shed indicator, feeder shed indicator, load scheme status, and fault indicator. The relay sends out a message anytime its status changes and on a 1-second interval otherwise.	IEC 61850	Various		
54.a.3	GOOSE Broadcast Message Transfer	Bus Tie Relay (Substation DAD) sends GOOSE Broadcast Message out to all other Substation DADs via SPDN.	Substation DAD	Substation DAD	SDPN	GOOSE	GOOSE Broadcast Message	Each GOOSE message broadcasted by a Bus Tie Relay contains a trip indicator, breaker position, event record indicator, close-from-main indicator, load values, lockout contacts, and fault indicator. The relay sends out a message anytime its status changes and on a 1-second interval otherwise.	IEC 61850	Various		
54.a.4	GOOSE Broadcast Message Transfer	Bus Differential Relay (Substation DAD) sends GOOSE Broadcast Message out to all other Substation DADs via SPDN.	Substation DAD	Substation DAD	SDPN	GOOSE	GOOSE Broadcast Message	Each GOOSE message broadcasted by a Bus Differential Relay contains a trip indicator for each bus feeder, event record indicator, and lockout contact. The relay sends out a message anytime its status changes and on a 1-second interval otherwise.	IEC 61850	Various		

Msg ID	Name of Process/Transaction	Description of Process/Transaction	Producer (Actor 1)	Receiver (Actor 2)	Transport Network	Network Protocols	Information Object Name	Information Object Description	Interface Standard	Standard Msg Name	Standard Msg Code	Use Case
54.a.5	GOOSE Broadcast Message Transfer	Transformer Differential Relay (Substation DAD) sends GOOSE Broadcast Message out to all other Substation DADs via SPDN.	Substation DAD	Substation DAD	SDPN	GOOSE	GOOSE Broadcast Message	Each GOOSE message broadcasted by a Transformer Differential Relay contains a trip indicator, breaker position, event record indicator, average available load for both downstream buses, and transformer lockout contact. The relay sends out a message anytime its status changes and on a 1-second interval otherwise.	IEC 61850	Various		
54.b.1	Internal Process Communication	These messages are used for internal application logic to enable a Substation DAD to analyze and/or operate based upon its local protection scheme.	Substation DAD	Substation DAD	Substation DAD Internal	SEL Proprietary	Internal Process Data	This data is used for internal application logic for a given Substation DAD's local protection scheme.	N/A	N/A		
55.a.1	Internal Process Communication	These messages are used for internal application logic to enable a Field DAD to analyze and/or operate based upon its local configuration profile or protection scheme.	Field DAD	Field DAD	Field DAD Internal	Proprietary	Internal Process Data	This data is used for internal application logic for a given Field DAD's local configuration profile or protection scheme.	N/A	N/A		
56A.a.1	Grid-Connected DER Status Update Transfer	SMS sends Grid-Connected DER Status Update to RTAC.	SMS	RTAC	DER Internal	DNP3	Grid-Connected DER Status Update	The message will contain the current value for either a digital or analog status point that is associated with the Grid-Connected DER. Depending on the point, the message is triggered by any change in value or by the defined polling period configured in RTAC.	IEEE 1815	Various		
56A.b.1	Grid-Connected DER Control Signal Transfer	RTAC sends Grid-Connected DER Control Signal to SMS.	RTAC	SMS	DER Internal	DNP3	Grid-Connected DER Control Signal	The message will contain the desired value for either a digital or analog control point that is associated with the Grid-Connected DER. The message is triggered anytime the RTAC receives a Grid-Connected DER Control Signal from the upstream system (DDC).	IEEE 1815	Various		
56B.a.1	Grid-Connected DER Status Update Transfer	DESS sends Grid-Connected DER Status Update to SMS.	DESS	SMS	DER Internal	MODBUS	Grid-Connected DER Status Update	The message will contain the current value for either a digital or analog status point that is associated with the Grid-Connected DER. The message is triggered by any change in value for the status point.	N/A	N/A		
56B.b.1	Grid-Connected DER Control Signal Transfer	SMS sends Grid-Connected DER Control Signal to DESS.	SMS	DESS	DER Internal	MODBUS	Grid-Connected DER Control Signal	The message will contain the desired value for either a digital or analog control point that is associated with the Grid-Connected DER. The message is triggered anytime the SMS receives a Grid-Connected DER Control Signal from the upstream system (RTAC).	N/A	N/A		
56C.a.1	Internal Process Communication	These messages are used for internal processes.	DESS	DESS	DER Internal	Kokam Proprietary	Internal Process Data	This data is used for internal control processes.	N/A	N/A		
57.a.1												
57.b.1												
58.a.1	Internal Process Communication	These messages are used for internal processes.	Residential DER	Residential DER	DER Internal	Sunverge Proprietary	Internal Process Data	This data is used for internal control processes.	N/A	N/A		
100.a.1	Data Packet Transfer	MFR sends RF Data Packet to another MFR via RF mesh	MFR	MFR		L+G Proprietary	RF Data Packet	Any packet of data sent via RF mesh from the FANC to the MFR or from the MFR to the FANC.	L+G Proprietary	Any data transmitted via the FAN		NWK-01
101.a.1	Data Packet Transfer	FANE sends RF Data Packet to MFR via RF mesh	FANE	MFR		L+G Proprietary	RF Data Packet	Any packet of data sent via RF mesh from the FANC to the MFR or from the MFR to the FANC.	L+G Proprietary	Any data transmitted via the FAN		NWK-01
101.b.1	Data Packet Transfer	MFR sends RF Data Packet to FANE via RF mesh	MFR	FANE		L+G Proprietary	RF Data Packet	Any packet of data sent via RF mesh from the FANC to the MFR or from the MFR to the FANC.	L+G Proprietary	Any data transmitted via the FAN		NWK-01
102.a.1	Data Packet Transfer	FANR sends RF Data Packet to MFR via RF mesh	FANR	MFR		L+G Proprietary	RF Data Packet	Any packet of data sent via RF mesh from the FANC to the MFR or from the MFR to the FANC.	L+G Proprietary	Any data transmitted via the FAN		NWK-01

Msg ID	Name of Process/Transaction	Description of Process/Transaction	Producer (Actor 1)	Receiver (Actor 2)	Transport Network	Network Protocols	Information Object Name	Information Object Description	Interface Standard	Standard Msg Name	Standard Msg Code	Use Case
102.b.1	Data Packet Transfer	MFR sends RF Data Packet to FANR via RF mesh	MFR	FANR		L+G Proprietary	RF Data Packet	Any packet of data sent via RF mesh from the FANC to the MFR or from the MFR to the FANC.	L+G Proprietary	Any data transmitted via the FAN		NWK-01
103.a.1	Data Packet Transfer	FANC sends RF Data Packet to MFR via RF mesh	FANC	MFR		L+G Proprietary	RF Data Packet	Any packet of data sent via RF mesh from the FANC to the MFR or from the MFR to the FANC.	L+G Proprietary	Any data transmitted via the FAN		NWK-01
103.b.1	Data Packet Transfer	MFR sends RF Data Packet to FANC via RF mesh	MFR	FANC		L+G Proprietary	RF Data Packet	Any packet of data sent via RF mesh from the FANC to the MFR or from the MFR to the FANC.	L+G Proprietary	Any data transmitted via the FAN		NWK-01
104.a.1	Data Packet Transfer	FANE sends RF Data Packet to another FANE via RF mesh	FANE	FANE		L+G Proprietary	RF Data Packet	Any packet of data sent via RF mesh from the FANC to the MFR or from the MFR to the FANC.	L+G Proprietary	Any data transmitted via the FAN		NWK-01
105.a.1	Data Packet Transfer	FANR sends RF Data Packet to FANE via RF mesh	FANR	FANE		L+G Proprietary	RF Data Packet	Any packet of data sent via RF mesh from the FANC to the MFR or from the MFR to the FANC.	L+G Proprietary	Any data transmitted via the FAN		NWK-01
105.b.1	Data Packet Transfer	FANE sends RF Data Packet to FANR via RF mesh	FANE	FANR		L+G Proprietary	RF Data Packet	Any packet of data sent via RF mesh from the FANC to the MFR or from the MFR to the FANC.	L+G Proprietary	Any data transmitted via the FAN		NWK-01
106.a.1	Data Packet Transfer	FANC sends RF Data Packet to FANE via RF mesh	FANC	FANE		L+G Proprietary	RF Data Packet	Any packet of data sent via RF mesh from the FANC to the MFR or from the MFR to the FANC.	L+G Proprietary	Any data transmitted via the FAN		NWK-01
106.b.1	Data Packet Transfer	FANE sends RF Data Packet to FANC via RF mesh	FANE	FANC		L+G Proprietary	RF Data Packet	Any packet of data sent via RF mesh from the FANC to the MFR or from the MFR to the FANC.	L+G Proprietary	Any data transmitted via the FAN		NWK-01
107.a.1	Data Packet Transfer	FANR sends RF Data Packet to another FANR via RF mesh	FANR	FANR		L+G Proprietary	RF Data Packet	Any packet of data sent via RF mesh from the FANC to the MFR or from the MFR to the FANC.	L+G Proprietary	Any data transmitted via the FAN		NWK-01
108.a.1	Data Packet Transfer	FANC sends RF Data Packet to FANR via RF mesh	FANC	FANR		L+G Proprietary	RF Data Packet	Any packet of data sent via RF mesh from the FANC to the MFR or from the MFR to the FANC.	L+G Proprietary	Any data transmitted via the FAN		NWK-01
108.b.1	Data Packet Transfer	FANR sends RF Data Packet to FANC via RF mesh	FANR	FANC		L+G Proprietary	RF Data Packet	Any packet of data sent via RF mesh from the FANC to the MFR or from the MFR to the FANC.	L+G Proprietary	Any data transmitted via the FAN		NWK-01
109.a.1	Data Packet Transfer	AHE sends TCP/IP Data Packet to FANC via the Backhaul WAN	AHE	FANC		TCP/IP	TCP/IP Data Packet	Any TCP/IP formatted packet of data sent from the AHE to the FANC or from the FANC to the AHE.	TCP/IP	Any data transmitted via the FAN		NWK-01
109.b.1	Data Packet Transfer	FANC sends TCP/IP Data Packet to AHE via the Backhaul WAN	FANC	AHE		TCP/IP	TCP/IP Data Packet	Any TCP/IP formatted packet of data sent from the AHE to the FANC or from the FANC to the AHE.	TCP/IP	Any data transmitted via the FAN		NWK-01
110.a.1			DDC	FANC								
110.b.1			FANC	DDC								
111.a.1			FANE	DADC								
111.b.1			DADC	FANE								
112.a.1			FANE	DERC								
112.b.1			DERC	FANE								

Appendix D IEC 61850 Communications Network



IEC 61850 Substation Control Network

prepared for

**Kansas City Power & Light
Kansas City, Missouri**

January 2011

Project No. 58725

prepared by

Burns & McDonnell Engineering Company, Inc.





January 7, 2011

Scott Grafelman, P.E.
Mgr. Asset Management & Planning
Kansas City Power & Light
P.O. Box 418679
Kansas City, MO 64141-9679

KCP&L Smart Grid Demonstration Project – IEC 61850 Communications Network

Dear Mr. Grafelman:

We are pleased to submit the final version of the report *IEC 61850 Communications Network for the Midtown Substation*. This report provides recommendations for configuration of an Ethernet communications network to support protection and control functions including IEC 61850 GOOSE messaging between protective relays at the Midtown Substation. The report also includes background information which forms the basis of many aspects of the associated technical specification for this network.

Our recommendation outlines the operating parameters that should be considered during the design and equipment selection processes, as well as when implementing the communications network to support protective relaying applications. This report contains sections on the operations, infrastructure, configuration, and security which detail the impacts various decisions are likely to have on the network performance and reliability. The report is intended to be a reference for the Network Services, Substation Protection, and Relay System Protection departments of KCP&L as they work together to design and operate this network.

The following sections are included in the report:

- Operations: Outlines operational implications of installing communications equipment in power delivery substations.
- Infrastructure: Details interconnection and hardware requirements of the network.
- Configuration: Details device configuration parameters that should be implemented in the network hardware.
- Security: Details setting that should be configured to secure the network.

Thank you for the opportunity to continue our consulting services to Kansas City Power & Light.

Sincerely,

Matthew Olson P.E.
Project Manager

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Tel: 816 333-9400 • Fax: 816 333-3690 • www.burnsmcd.com

INDEX AND CERTIFICATION

IEC 61850 Substation Control Network

Project 58725

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Certification

I hereby certify, as a Professional Engineer in the state of Missouri, that the information in the document was assembled under my direct personal charge. This report is not intended or represented to be suitable for reuse by the Kansas City Power & Light or others without specific verification or adaptation by the Engineer. This certification is made in accordance with the provisions of the applicable laws and rules of the State of Missouri.



James G. Cupp, PE Missouri License # 25698

Date: 1/2/11

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IEC 61850 Substation Control Network

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Kansas City Power & Light

TOC-2

Burns & McDonnell

1.0 INTRODUCTION

Kansas City Power & Light (KCP&L) is currently conducting its Smart Grid Demonstration Project, which seeks to deploy a broad range of advanced power delivery technologies. One of the key initiatives being pursued is the “Smart Substation”, an upgrade to KCP&L’s Midtown Substation that distributes electric power to the Green Impact Zone. This project includes upgrades to protection and control equipment and the deployment of an Ethernet-based substation control network utilizing the IEC 61850 network architecture.

This report presents a high-level design for the IEC 61850 control network, and provides recommended specifications for the design and procurement of the network. This report provides recommendations for designing, provisioning, and operating an IEC 61850 control network jointly between the Network Services, Substation Protection, and Relay System Protection departments of KCP&L. The recommendations provided are not all-inclusive, but are meant to identify the new operating and design requirements to each department operating this joint network.

The recommended specifications provided in this report are universally applicable to IEC 61850 networks at KCP&L, and not limited to Midtown Substation. Many of the recommendations assume that the networks will be deployed in distribution automation applications – other considerations may apply when deploying IEC 61850 networks in transmission infrastructure.

Topics discussed in this report include:

- Documentation and Operating Considerations
- Network Topology and Fiber Infrastructure
- Network Availability and Reliability
- Network Security

* * * * *

2.0 OPERATIONS

The deployment of Smart Grid technologies presents various new challenges to the utility industry. For instance, the implementation of IEC 61850 and the reliance on communication networks instead of direct wiring represents a fundamental change in protection and control system design and operation. This shift in philosophy requires different departments within an organization to bring their various knowledge bases and skill sets together. In many cases, these are departments that have limited experience working together. Therefore it is beneficial for these groups to develop a strategic plan defining each group's roles and responsibilities in operating and maintaining new assets. Deployment of IEC 61850 networks requires Network Services, Substation Protection, and Relay System Protection departments to develop such strategies for a number of items including network documentation, deployment, and maintenance.

2.1 NETWORK MANAGEMENT STRATEGY

Other utilities have assigned the responsibility for managing all protection and control equipment, including the network hardware and associated access credentials, to the protection control engineering and maintenance departments. Enterprise change management processes are often established to facilitate incorporation of the expertise of the network engineering and security groups into the network. These groups are involved in the equipment selection, network design, and modification processes before implementation. In addition, they provide consultation and assist in troubleshooting on an as needed basis.

2.2 DOCUMENTATION

The IEC 61850 network should be treated like any other protection and control system, and should only be used for protection and control purposes. Using a dedicated network for protection and control prevents other network systems or applications in the substation from being required to follow the documentation, testing, and outage coordination procedures required for changes to protection and control systems. Therefore, it is advantageous to keep complete documentation readily available to substation personnel who may need access. Network device settings should be recorded and filed with the associated relay settings and other substation

documentation. Likewise, the physical wiring of the network should be documented on drawings maintained with the related substation drawings.

2.3 DEPLOYMENT AND MAINTANANCE

The IEC 61850 network equipment will be installed in limited-access areas such as distribution switchgear, which can be hazardous to personnel. The network equipment should only be installed and serviced by relay technicians or other personnel trained to work in these hazardous areas.

Field deployment of incorrect equipment configurations or settings could negatively impact the reliability of the power grid. Therefore, new settings should be verified in a laboratory environment prior to actual field deployment. Any changes to the settings should be coordinated with the Electrical System Operator in order to obtain scheduled outages. These changes should be performed onsite while locally connected to the network, removing any risk of a configuration change disabling the network and interrupting service.

Spare network hardware should be stored and maintained following the processes currently in place for protection and control equipment. The network devices should be capable of copying their configuration data and firmware to locally attached flash memory on a daily basis to facilitate a rapid and up-to-date transfer of the configuration to a spare device if needed. This aids rapid deployment and field replacement of networking equipment by providing the substation technicians who maintain the network access to equipment and configuration information.

By implementing the above recommendations, a clear understanding of roles and responsibilities can be established while incorporating the collective knowledge of the enterprise into the design and operation of the IEC 61850 network.

* * * * *

3.0 NETWORK INFRASTRUCTURE

Substation control networks are deployed in harsh environments and transport critical data, which results in demanding requirements of the network and its components. The network must have high availability and low latency, providing fast, reliable communication between networked devices. Networking equipment deployed in these networks must be environmentally hardened, as it may be deployed in enclosures with limited climate control, requiring the equipment to operate across extreme humidity and temperature ranges. Therefore, a reliable physical architecture for the network is needed along with ruggedized, highly reliable network components. Recommended network architecture and hardware requirements are presented below.

3.1 NETWORK ARCHITECTURE

The recommended IEC 61850 substation control network configuration consists of redundant 1 Gbps Ethernet backbones routed throughout the substation. These backbones will interconnect remote primary and backup Ethernet switches installed in various switchgear enclosures to main Ethernet switches located in the main control enclosure. Protective relays, equipped with redundant Ethernet ports, will connect to the appropriate primary and backup remote switches using 100 Mbps Ethernet.

3.1.1 Network Topology

Topology selection is based on a balance of several factors. The chosen topology of a highly reliable control network should achieve the following.

- Provide high-bandwidth, low-latency communications
- Minimize or eliminate single points of failure for cabling and equipment
- Minimize infrastructure costs

The recommended approach is to deploy the IEC 61850 network using a redundant Ethernet ring architecture.

Ring architectures allow for self-healing networks, increasing availability and reliability. The Ethernet switches comprising the network are arranged in rings, providing redundant pathways between two points in the network via the Ethernet backbone. This configuration protects

against loss of communication between devices due to failure of a communication link or loss of an intermediate switch. Loss of communication only occurs when there is a failure in the edge switch to which one of the two communicating devices is connected.

To further increase reliability, redundant rings can be deployed. This allows devices with redundant Ethernet interfaces to take advantage of a standby Ethernet network, reducing the probability of a loss of station control due to failure of any single piece of network equipment. This redundant ring configuration eliminates single points of failure for all Ethernet hardware when the communication devices are configured in fail-over mode.

Aside from enhanced fault recovery, the additional redundancy can significantly ease maintenance of the network, as any single network device can be completely removed from service without network disruption or loss of station control. Direct connections should be made between primary and backup switches in each control enclosure, providing a local link for traffic in the event any enclosure is isolated from the rest of the network.

3.1.2 Fiber Optic Infrastructure

The network should be constructed using fiber optic cabling in order to be confidently extended beyond the control enclosure and throughout the substation switchyard. Fiber-based communications are immune to the electromagnetic interference (EMI) that is prevalent in high voltage facilities. The use of fiber allows the Ethernet network cabling to be installed along side control cables without concern about equipment damage due to ground potential differences within the substation or EMI affecting inter-relay communications.

Gigabit Ethernet can be carried over multimode (1000BaseSX) or single-mode fiber (1000BaseLX). Communication links using 1000BaseSX over distances in excess of 500 feet are susceptible to signal degradation due to dispersion. Therefore, 1000BaseLX, which can reach distances of 10 kilometers or more, is recommended for the 1 Gbps Ethernet backbones connecting the switches distributed throughout the substation. Deployment of single-mode fiber will allow the network to be extended as required, without distance limitation concerns, and will also allow higher bandwidth to be used in the future. (10 Gbps Ethernet is easily supported on

single-mode fiber.) This additional bandwidth capacity could be valuable should future plans involve more data intensive applications such as IEC 61850 process bus and phasor measurement. The cost difference between deploying single-mode and multimode fiber is negligible.

While single-mode fiber is optimal for the Ethernet backbone, multimode fiber should be used for the shorter 100 Mbps Ethernet (100BaseFX) connections between relays and switches. This is because the Ethernet interfaces commonly available in the relays only support multimode fiber.

3.2 MIDTOWN SUBSTATION NETWORK CONFIGURATION

3.2.1 Electrical and Communications Network Topology

The electrical network configuration at Midtown Substation consists of a 161-kV four bay ring bus with a transmission line and distribution transformer in each bay. Three of the four distribution transformers have dual secondary windings, each feeding separate distribution buses connected to four distribution feeders. Each distribution bus has a tie to another bus that forms a ring around the low side of the substation. This configuration is shown in Figure 3.1.

A key part of the Smart Substation design is to automate restoration of service to customers after a fault. Breakers will be operated using traditional hard wired relay logic. Generic Object Oriented Substation Event (GOOSE) messaging will be used to operate the tie bus remediation scheme, serving as a test case to monitor the control function of the IEC 61850 network.

Distributing the communications infrastructure into the switchgear ensures that communication between adjacent switchgear can remain operational even if a failure damages other parts of the station. Key benefits of substation automation may not be realized unless a decentralized communication design that mimics the automation architecture is used. See Figure 3.2 for a diagram of GOOSE information flow at the Midtown Substation.

IEC 61850 Substation Control Network

Network Infrastructure

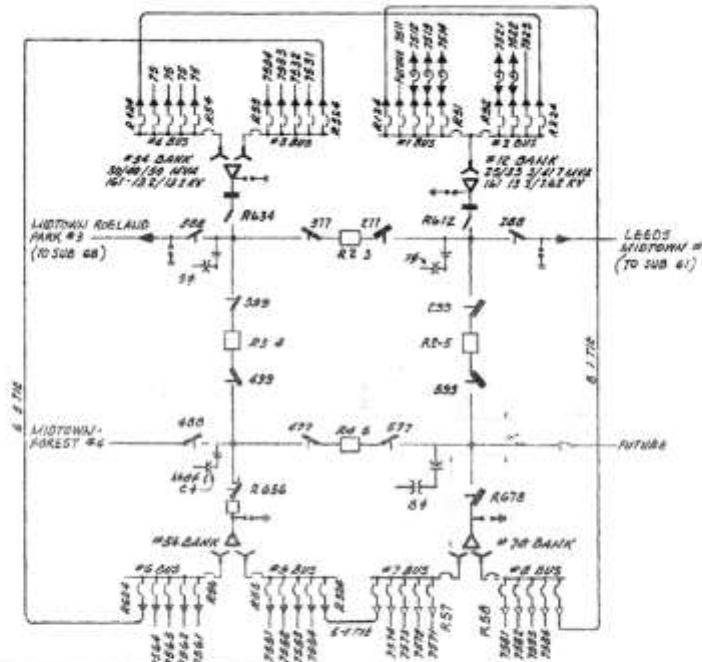


Figure 3.1. Midtown Substation One Line Diagram

It is recommended that the switches comprising the Ethernet rings be interconnected in a configuration mimicking the electrical configuration of the station. Each Ethernet ring should contain one main switch located in the control enclosure, and four remote switches distributed throughout the substation switchgear. This gives control equipment in each switchgear enclosure direct access to its adjacent facilities without passing network traffic through a centralized switch. This arrangement (illustrated in Figure 3.3) reduces latency for GOOSE messages and decentralizes the risk of failures in other parts of the station without introducing excessive latency for SCADA messages between the SICAM data concentrator and relays using the IEC 61850 Manufacture Message Specification (MMS). The redundant main switches in the control enclosure will connect to the Siemens SICAM data concentrator, transformer relay equipment, and the human machine interface. The remote switches will connect to the relay equipment located in the switchgear and to the 1000BaseLX Ethernet backbone. This arrangement is illustrated in Figure 3.3.

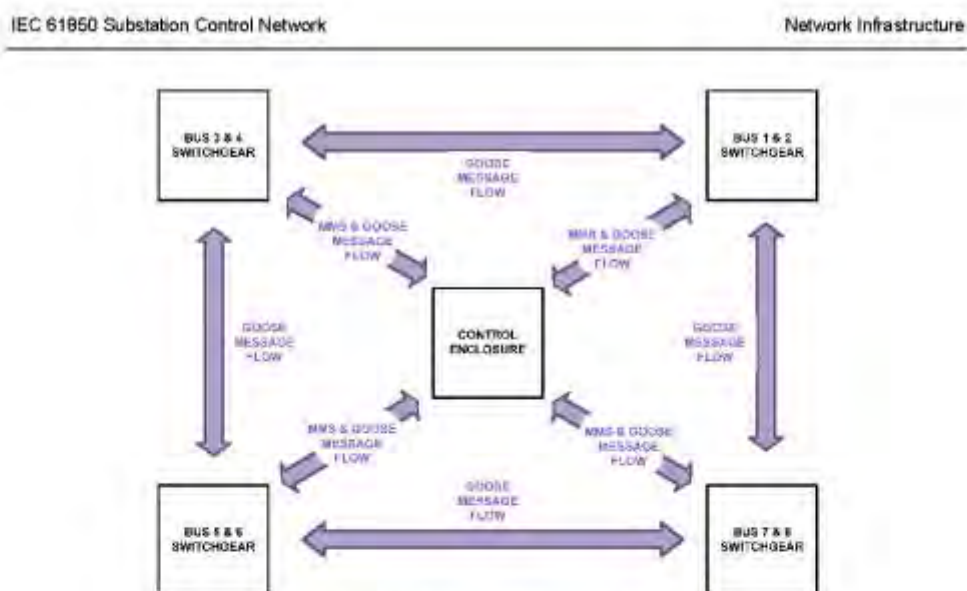


Figure 3.2. Midtown Substation IEC 61850 Information Flow

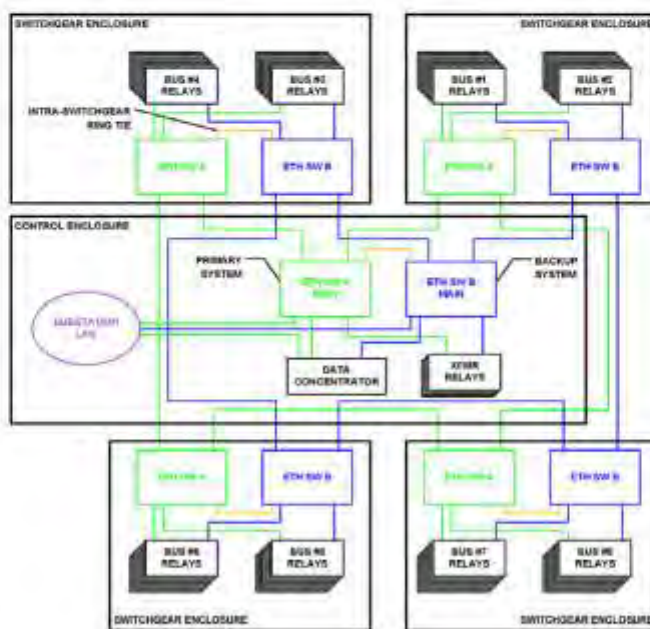


Figure 3.3. Proposed Midtown Substation Ethernet Network Configuration

The typical equipment arrangement at Midtown Substation consists of two independent distribution buses within the same switchgear enclosure. The remote switches support protection and control equipment for the two buses. It is recommended that the primary switch be installed in an auxiliary panel associated with one of the buses, while the backup switch is installed in an auxiliary panel associated with the other bus. Switch installation in different locations within the switchgear adds reliability. For example, the primary remote switch might be installed in panels related to Bus 1, while the backup switch is located in panels for Bus 2. Relays within the same switchgear enclosure should be connected to both the primary and backup remote switches located within that enclosure. This arrangement is illustrated in Figure 3.4.

3.2.2 Hardware Requirements

All Ethernet switches must have the following features in order to implement these recommendations:

- (16) 100BaseFX fiber ports for connections to protection and control equipment
- (2) 1000BaseLX fiber ports for connections between Ethernet switches

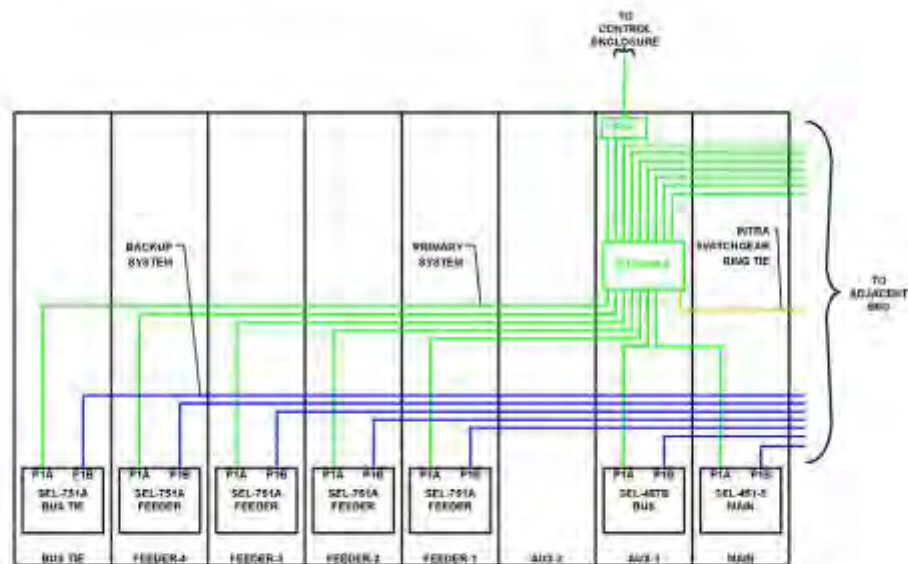


Figure 3.4. Proposed Midtown Substation Switchgear Enclosure Wiring

- (1) 100BaseT copper port for technician access

All relay equipment must have the following features in order to implement these recommendations:

- (2) 100BaseFX fiber ports for connections to the primary and backup Ethernet rings
- Fail-over capabilities for switching between Ethernet interfaces during a network fault

3.2.3 Physical Considerations

The Midtown Substation physical infrastructure is laid out in a star configuration with one cable trench for each bay in the ring bus. These trenches extend from the control enclosure, which is in the center of the substation, out to each switchgear enclosure. The recommended architecture consists of two twelve-fiber, single-mode fiber optic cables installed between each switchgear enclosure and the main control enclosure. Fiber distribution panels (FDPs) would be installed in each switch location, as well as within the control enclosure.

For the specific case at Midtown Substation, it is impractical to install new conduit directly between each switchgear enclosure to create a truly physical ring, so it is recommended that the Ethernet switches be connected in a ring by patching in the FDPs located in the control enclosure. These new fiber optic cables will be installed in the existing cable trench with other control cables. Figure 3.5 illustrates of how the fiber optic cabling should be routed and where FDPs should be installed at Midtown Substation.

3.2.4 Reliability versus Complexity

The fundamental design criteria for IEC 61850 network operations is reliable information flow. Traditionally reliability has been improved by adding redundancy to protection and control applications, especially in more critical systems such as those protecting high voltage transmission infrastructure. The benefits, cost, and complexity of each additional degree of reliability added to the design should be considered. This application of IEC 61850 is part of a pilot, and the recommended design provides KCP&L with opportunities to test a variety of configurations, some of which may not economically optimal for all deployments. The Midtown Substation is a distribution substation, which is a lower risk location to test IEC 61850 than

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transmission station. However, it is recommended that the pilot network be designed for transmission-grade reliability, facilitating testing networks with varying levels of redundancy in a single location. For example, distribution-only configurations may require less redundancy, and can be easily tested at the pilot location by eliminating redundant connections as desired.

The choice of how redundant designs are for future projects will have to be considered based on the results of this pilot and needs of the future deployment. Choosing where to add redundancy in a given network design is a balance between determining where to place redundancy to eliminate likely failure points and the likelihood that this new redundancy will increase the risk of failure due to operational complexity. At Midtown substation this balance is tested in three aspects of the design.

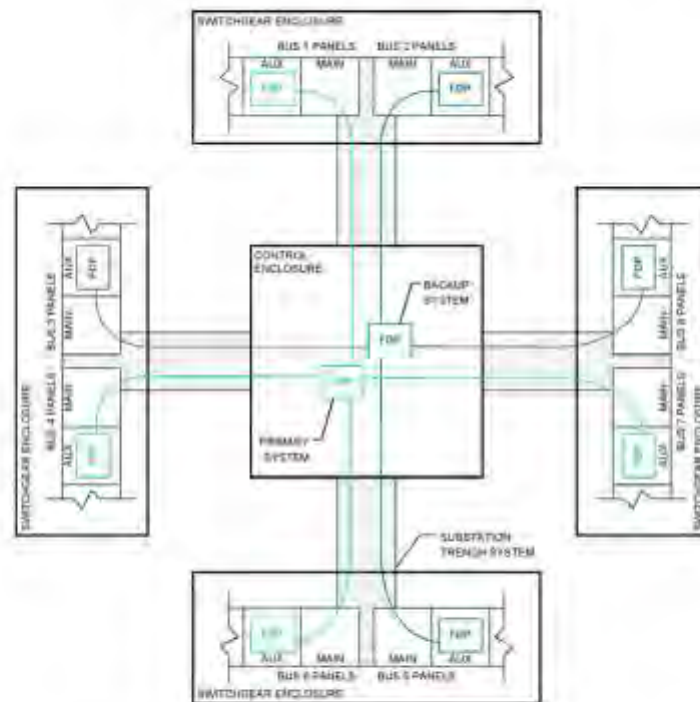


Figure 3.5. Proposed Midtown Substation Fiber Routing

First, all devices are specified to have redundancy, which is required because the time needed to repair a failed interface is outside of the acceptable operating parameters. Secondly, the recommendation to implement redundant rings is made because the cost and complexity of doing so are minimal. The devices have the spare interfaces, the fiber is available, and the time to connect and configure this is negligible if the layer two loop blocking protocol handles this added complexity transparently. If the protocol supported by the selected switch requires manual, link-specific configuration, then having two rings becomes less appealing as the complexity of the configuration increases significantly. Lastly, the choice to have redundant fiber cables between the control enclosure and switch gear adds minimal complexity to the operation of the network, but only marginally improves the reliability while increasing costs. Given that the likelihood of fiber cable failure is low and there is no diversity between the two cable routes at the pilot site since they must reside in the same cable trench, implementation of this configuration is less desirable at Midtown Substation, but may be applicable elsewhere.

3.3 ENVIRONMENTAL AND PHYSICAL HARDWARE REQUIREMENTS

Substation environments place atypical requirements on communications equipment. The equipment may be installed in locations that have no form of climate control. Available power sources and mounting locations often differ from those normally encountered in more traditional telecommunications applications. Also, the equipment is exposed to EMI and electrical surges not typically encountered except in high voltage environments. These issues should be addressed when procuring the networking equipment deployed as part of the IEC 61850 substation control network.

3.3.1 Environmental Operating Requirements

All hardware comprising the IEC 61850 substation control network should be designed for operation in harsh environments. The equipment should meet the IEEE 1613 and IEC 61850-3 requirements for operational humidity and temperature ranges. (5 % to 95 % (non-condensing); -40°C to -85°C, respectively.) This is especially important at Midtown Substation, where some of the switchgear enclosures where the Ethernet switches and relays will be installed are not climate controlled. Further, the equipment should be convectively cooled, employing no moving parts or fans.

Networking hardware installed in electrical transmission facilities should also meet a number of electrical requirements. This hardware should have undergone type testing for surge withstand capability, immunity to radiated electromagnetic fields, and immunity to electrostatic discharge, all according to the IEEE C37.90 series of standards.

3.3.2 Substation Integration Requirements

Substation battery systems commonly operate at 125 VDC rather than the -48 VDC normally used for telecommunications equipment, and provide a floating power system without a reference to ground. It is therefore recommended that the network equipment deployed in the IEC 61850 network be capable of operating at floating voltages from 90 VDC to 155 VDC for compatibility with the substation facility. The selected equipment should also have provisions for redundant power supplies, should future applications require additional levels of reliability.

Equipment mounting requirements can also pose challenges in substations, especially when mounting equipment inside of switchgear. Equipment in substations is normally mounted in panels rather than racks, and is wired from the rear. This is atypical of most networking hardware, which requires rack mounting and front panel wiring. Nevertheless, network devices that support panel mounting and wiring from the rear are available for substation applications. Ethernet ports and associated port indication lighting, as well as screw terminal power connections should be provided on the rear of the selected networking hardware. The selected hardware should also have port and system indication lighting on the front of the device as well, so that device status can be easily observed without accessing the wiring side of the control panel. Often, as is the case at Midtown Substation, space behind the panel face is limited, and thus the depth of the switch, including fiber connections, cable management trays, and other such hardware should not exceed 18" if being flush mounted in a panel. Because of this depth limitation, the switch should be mounted on the inside face of the door as shown in Figure 3.6, which illustrates a potential arrangement for mounting the network hardware and wiring in a panel.

IEC 61850 Substation Control Network

Network Infrastructure

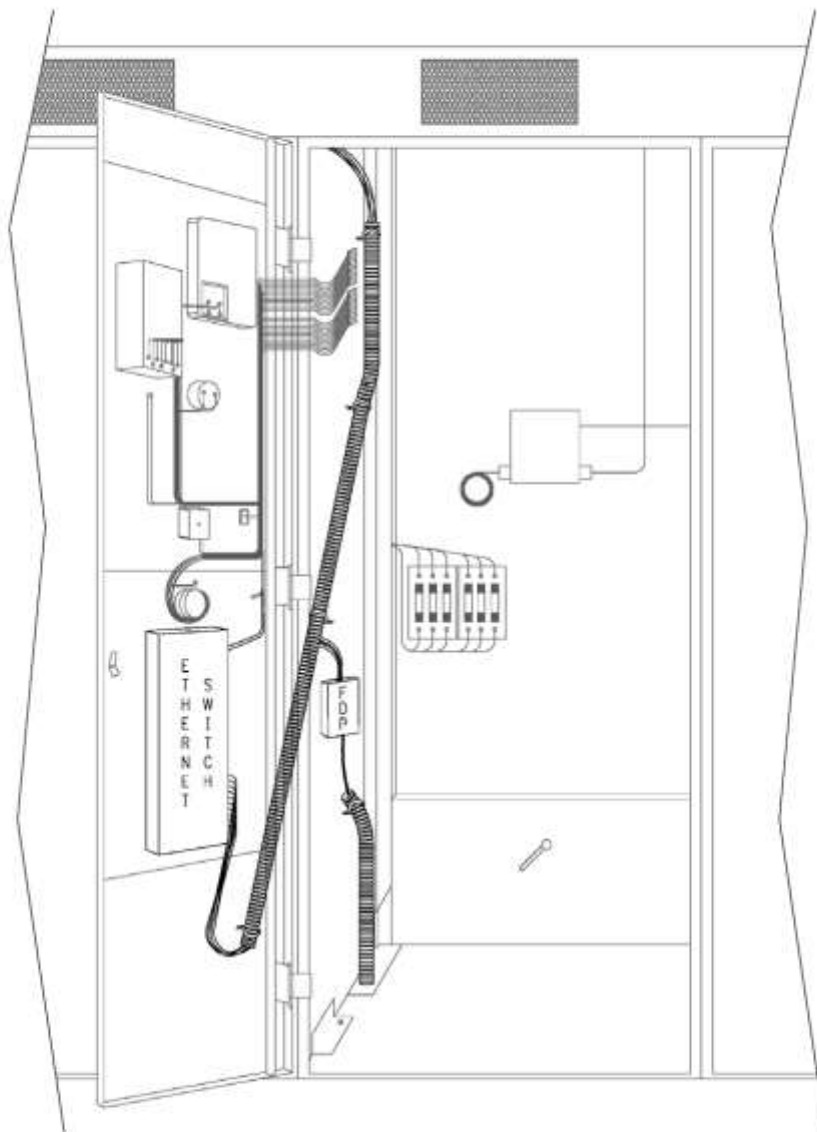


Figure 3.6. Network Hardware Mounted in Panel

4.0 NETWORK PERFORMANCE

Protection and control algorithms are designed to isolate faults in the electrical system as quickly as possible. When using a communication-enabled protection scheme, it is critical that the control information be reliably delivered across a network with minimum delay. Failure of timely communication on the network may lead to safety concerns, significant loss of revenue, equipment damage, and system instability.

4.1 LATENCY AND JITTER REQUIREMENTS

Network latency is the maximum time required for a message to traverse the network.

Implementation of GOOSE messaging requires that the network to be able to consistently forward messages with latency of no more than 4 milliseconds, with inter-frame jitter less than 500 microseconds. To ensure these latency and jitter criteria are met, the network equipment should support quality of service (QoS), virtual local area networks (VLANs), and traffic limiting functionality.

4.1.1 Quality of Service

The network infrastructure should be configured to support QoS as defined by the IEEE 802.1p standard. QoS uses the class of service bits within an IEEE 802.1q VLAN header to prioritize traffic forwarded across the network. GOOSE messages should be configured to use class of service (CoS) value of “6”, making it the highest priority traffic on the network besides network configuration traffic. The classification for GOOSE should be based on Ethernet frame type 0x88b8 used to designate the GOOSE protocol. To ensure the QoS policy is implemented consistently across the network, when a packet ingresses the network at a access port it should be checked for proper QoS classification and re-marked appropriately. All other IEC 61850 traffic should be re-marked with a CoS value of “5” or lower. Further, the switches should be configured to use the strict priority queuing algorithm to ensure the lowest jitter and latency for GOOSE messages. Because this is a dedicated network where link congestion is not anticipated, a QoS policing policy is not recommended.

4.1.2 Application of VLANs

The use of virtual LANs adds limited benefit, because the single-purposed network being recommended is intended to support only protection and control applications. Nevertheless, configuring all ports to mark traffic for a specific VLAN ensures that all protection and control traffic on the network is transported in a VLAN dedicated to this purpose, and any traffic on other VLANs should be investigated. If other protection and control applications are added in the future, other VLANs might be put into service to support them.

All unused ports should be administratively shutdown and added to a VLAN ID dedicated to inactive ports. This ensures that unintentional or unwanted device connections to unused ports do not function. These measures improve network security, and make the network less susceptible to disturbances which may introduce latency.

4.1.3 Broadcast Storm Control and Port Rate Limiting

Limiting data transported across the network from individual devices is a way to prevent inadvertent or malicious network congestion, which in turn reduces jitter and latency. Broadcast storm control and port rate limiting are features that should be supported by the Ethernet switches for implementing this concept.

Broadcast storm control should be enabled and configured on all interfaces, limiting broadcast traffic on an interface to no more than 20% of all traffic. This feature should be tested on all switch hardware to ensure that GOOSE multicast traffic is not counted against this total. If it is, then this parameter should be raised to 60%.

Port rate limiting should be enabled on all 100 Mbps interfaces. Rate limits on each device port should be set to 10% of the hardware speed, or 10 Mbps. This provides sufficient bandwidth to support relay communications. This restricts network flow from a port to a fraction of the total bandwidth available, ensuring that malfunctioning or maliciously programmed devices cannot deny service to other network ports by “flooding” the network with traffic.

4.2 NETWORK FAULT RECOVERY

The required level of network availability can be made possible by using ringed or meshed network topologies, high-speed layer two loop blocking algorithms, and unidirectional link failure detection to enable rapid fault recovery. However, the features implemented for this purpose should be capable of fault recovery in an acceptable time frame. Selection and configuration of these features should account for the time delays associated with the network failure detection mechanisms of the networked equipment and the recovery time of the layer two loop blocking algorithm employed.

4.2.1 Network Fault Recovery in Ethernet Switches

Physical network rings, as recommended here, provide redundancy resulting in higher network availability. However, the Ethernet protocol cannot function properly when the logical network consists of rings. Layer two loop blocking algorithms prevent the occurrence of logical rings by blocking certain ports when connected in a physical ring. Each time a link is added or removed from the network, the layer two loop blocking algorithm will determine which links should be removed from the ring to prevent a loop in the network. This is accomplished by blocking frame forwarding on one end of the disabled link. If a fault occurs on an active link, the algorithm activates the blocked ports, restoring connectivity.

Standard layer two loop blocking algorithms like Spanning Tree Protocol (STP) and Rapid Spanning Tree Protocol (rSTP) allow a network to reconfigure itself and recover after an equipment or link failure. Traditional STP recovery times can be up to 30 seconds, and rSTP can take up to two seconds, both failing to meet the recovery times required for protection and control applications. However, a number of manufacturers of environmentally-hardened switches have developed proprietary loop blocking algorithms based on STP, which are capable of loop fault recovery in under 50 milliseconds.

The proprietary nature of these layer two loop blocking protocols needs to be a key point of consideration in equipment selection for IEC 61850 networks. These protocols are vendor specific, so the entire network must be built from hardware that supports that proprietary protocol. This often requires the entire IEC 61850 network to be built from one manufacturer's

equipment, and possibly from only one series of devices. For example, different switches and router products from the same manufacture may not support the same protocol. Further, the level of complexity required to implement these protocols varies among switch manufacturers, as does the amount of quality documentation available. For example, some protocols require link specific parameters to be configured, while others simply require the protocol to be enabled on the chassis. Therefore, the complexity of implementing and maintain the system should factor in to the hardware selection process.

4.2.2 Network Fault Recovery in Connected Equipment

Each of the SEL relays being used on this project has two Ethernet interfaces, and supports two modes of operation. The first mode is a method in which adjacent relays are connected together forming a chain of relays. The relays do not support layer two loop blocking protocols, making this feature incompatible with Ethernet switch rings. This method is primarily intended for applications in stations without Ethernet switches.

In the second mode of operation, only one of the Ethernet interfaces is active at a time, and the redundant interface is in standby mode. When the relay detects a failure of the active interface, it activates the standby interface. The relay then operates on this standby interface until it detects a failure or the relay is restarted. This second mode of failure detection has maximum recovery times of 104 milliseconds in SEL 7XX series relays and 4 milliseconds in the SEL4XX series relays.

The network should support link aggregation groups to facilitate redundant Ethernet connections between the switch core and other redundantly connected devices such as the SICAM data concentrator, human machine interface, and the uplink to the firewall for connection to other networks. Multi-chassis link aggregation is the best method for providing redundant network connections to end devices supporting simultaneous operation of both links. This feature increases available bandwidth, while decreasing failure recovery times without the use of a layer 2 loop blocking protocol.

4.2.3 Unidirectional Link Failure Detection

An additional consideration arises when using fiber optic connections between the switches. A network fault can occur in which one of the fibers comprising a link becomes inoperable, creating a unidirectional communication link. These links can be difficult for failure detection algorithms to identify because only one of the communicating devices will detect the failure.

Unidirectional link failure detection features should be enabled in the Ethernet hardware to detect this type of fault and expedite recovery. Here, the device that detects the failure turns off its transmitter, letting the other device know there is a problem. These devices can then use the aforementioned loop blocking protection algorithms to detect and circumvent the fault. Without this feature enabled, it can take significantly more time for the network to detect the fault, raising recovery times from 50 milliseconds to 500 milliseconds or more.

4.3 NETWORK MANAGEMENT

Operations, maintenance, and network engineering all serve roles in system operation, so they each need network information reported into the information management systems that they use to operate the network. The network hardware selected for this application should support the network management protocols and features used by these groups.

The Relay and System Protection Department is focused on the operation of the protection and control system as a whole. This IEC 61850 network is a part of that system, and thus should be compatible with the substation monitoring systems that they use. The human machine interface used by the System Protection Department may not support the Simple Network Management Protocol (SNMP) which is often used by Network Services to manage network equipment. Thus the network equipment selected for the IEC 61850 substation network should support commonly used SCADA protocols including MODBUS and DNP. These protocols should support the display of device status, link status, and layer two loop blocking protocol status information.

The Network Services Department will have a shared responsibility for reliable network operation, and will likely prefer to manage the network using Secure Shell (SSH) and SNMP. The SNMP implementation on the IEC 61850 network should be capable of reporting resource

IEC 61850 Substation Control Network

Network Performance

statistics such as memory, processor, and link utilization. Other conditions such as temperature, power supply failures, interface state changes, and login failures should also be reported.

The network should use the network time protocol (NTP) for time coordination between network devices to facilitate event correlation across the network.

Due to the static nature of protective relay devices, the use of dynamic network protocols including IP address assignment and host name lookup are not required. All devices on the network shall have statically assigned IP addresses used to address all nodes on the network, eliminating the need for a DHCP or DNS server.

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Kansas City Power & Light

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5.0 SECURITY

5.1 ZONES OF SECURITY

To provide security to the protection and control network, multiple zones of security should be defined within the network. Boundaries should be created where the threat severity and operational requirements among contained devices are similar. Four zones are readily defined in and around the substation as follows.

- A field area network zone around the substation generally along the substation's distribution feeder network where distribution automation and metering equipment is located
- A wide area network zone encompassing equipment connecting the substation to other stations and the control center
- A substation local area network comprised of all locally-connected, non-protection-related devices
- A protection and control local area network connecting all protection and control devices

Security devices such as firewalls are recommended between each zone of security to limit communication between zones to authorize messages. Using isolated zones minimizes access points to the protection and control equipment, acting to mitigate the lack of security functions supported by the relays. (Note: many relays still do not support centralized authentication, logging, or port authentication.) Isolating the protection and control network also minimizes concerns about possible breaches of security by using virtual networks or software-based resource reservations of memory, link capacity, or processor usage.

5.2 REGULATORY COMPLIANCE

KCP&L does not currently consider the Midtown Substation to be a critical asset. Therefore, the recommended network has not been designed for complete compliance with the Critical Infrastructure Protection (CIP) Section 5, Version 3 regulations set forth by the North American Electric Corporation (NERC). However, where implementation of a feature that enables compliance with a specific requirement did not increase cost or complexity of the design, that feature was recommended. If protection and control devices with Ethernet interfaces and associated with the Midtown distribution facilities are declared critical cyber assets, metal clad

switchgear housing these devices will have to be physically secured regardless of where network switches are installed. The implementation of the MACsec protocol (IEEE 802.1AE) for link security between network switches would facilitate NERC CIP compliance, but was not recommended because of the lack of support on most currently available networking equipment.

5.3 OTHER SECURITY CONSIDERATIONS

The following protocols and practices are recommended to secure the network equipment. The network equipment should:

- Support and be configured to use an authenticating, authorizing, and accounting server to verify all user login requests using the RADIUS or TACACS+ protocols.
- Support and be configured to report all system events and alarms to a centralized log server using the Syslog protocol to facilitate system maintenance and system intrusion detection.
- Support port spanning and remote port spanning to copy all network traffic on all interfaces to a common span port where an intrusion detection probe could be connected.
- Be configured so all unused physical and logical ports are disabled.

If there is a choice of using a secure, encrypted protocol for a given purpose, it should be utilized and the unsecured variant should be disabled. This would include using SSH instead of Telnet, HTTPS instead of HTTP, SNMPv3 instead of SNMPv2c, and DNSSec instead of DNS.

While the Midtown Substation is not a NERC Critical Asset, using the requirements of the regulation as a guideline when they do not add cost or complexity makes good business sense. The use of centralized authentication and logging services, which are assumed to be used in the organization today is one such case where following the standard is recommended. However, the cost and complexity considerations change if these services become considered critical themselves because the sites they support are declared as NERC critical assets. Other utilities have created independent authentication and logging services for power delivery applications to address this concern, as they were already doing to support their critical asset facilities.

* * * * *

6.0 RECOMMENDATIONS

6.1 SUMMARY OF ANALYSIS

The physical layout of the Midtown Substation, the networking components of the protective relaying equipment being deployed, and the desired functionality of the network have all been considered and investigated. The resulting information was analyzed in comparison with key industry standards and recommended best practices in order to determine the most appropriate design and operating criteria for the IEC 61850 control network. The resulting findings are detailed in this report, and the accompanying Specification provides detailed recommendations for network topology, hardware selection criteria, minimum network performance criteria, and key network operating procedures.

6.2 KEY RECOMMENDATIONS

- The network should be constructed using highly-ruggedized hardware that complies with relevant IEC and IEEE standards for equipment installed in electric power transmission facilities.
- Establish redundant Ethernet rings with networking devices distributed throughout the station switchgear for increased reliability.
- The network hardware should support security features that facilitate compliance with the Critical Infrastructure Protection (CIP) regulations set forth by the North American Electric Reliability Corporation (NERC).
- Network documentation should be maintained in the same location and manner as other protection and control documentation, and maintenance of the IEC 61850 control network equipment should be performed by technical personnel trained to work with and around protection and control equipment.

* * * * *

APPENDIX A – SPECIFICATION

A.0 SPECIFICATION

This Specification sets forth recommendations and standards for establishing an Ethernet-based local area network capable of facilitating communications for the IEC 61850 substation control network. Recommended physical characteristics of the networking hardware and network topology are provided, and the environmental and network performance criteria for the networking hardware are defined. Recommendations for monitoring, securing, and operating the network are also presented.

A.1 STANDARDS COMPLIANCE

The IEC 61850 substation control network and its components shall comply with the latest revisions, supplements, and amendments of the following:

- IEC 61850-3 – Communication Networks and Systems in Substations Part 3: General Requirements
- IEEE C37.90 – IEEE Standard for Relays and Relay Systems Associated with Electric Power Apparatus
- IEEE C37.90.1 – IEEE Standard for Surge Withstand Capability Tests for Relays and Relay Systems Associated with Electric Power Apparatus
- IEEE C37.90.2 – IEEE Standard for Withstand Capability of Relay Systems to Radiated Electromagnetic Interference from Transceivers
- IEEE C37.90.3 – IEEE Standard Electrostatic Discharge Tests for Protect. Relays
- IEEE 802.1AX – Link Aggregation
- IEEE 802.1p – Priority Queuing
- IEEE 802.1Q – VLAN Tagging
- IEEE 1613 – IEEE Standard Environmental and Testing Requirements for Communications Networking Devices Installed in Electric Power Substations

A.2 INFRASTRUCTURE

A.2.1 Recommended Configuration

The recommended IEC 61850 substation control network configuration consists of redundant (primary and backup) 1Gbps Ethernet backbones. These redundant Ethernet backbones shall be established using single-mode fiber deployed throughout the substation via the existing duct bank and trench systems in physical star, logical ring configurations. These fiber rings will

interconnect remote primary and backup switches installed in various switchgear enclosures and primary and backup main switches located within the main control enclosure. Protective relays, equipped with redundant Ethernet ports, will connect to the appropriate primary and redundant remote Ethernet switches using 100 Mbps Ethernet via multimode fiber.

A.2.2 Environmental and Physical Hardware Requirements

Networking hardware deployed as part of the IEC 61850 substation control network shall meet the following environmental and physical requirements in order to be easily and reliably integrated into a substation facility.

All hardware shall:

- Have an operational temperature range of -40°C to $+85^{\circ}\text{C}$, as defined by IEEE 1613
- Operate across an ambient humidity range of 5 % to 95 % (non-condensing)
- Have passed type testing for surge withstand capability in accordance with IEEE C37.90.1
- Have passed type testing for immunity to radiated, single-frequency electromagnetic fields in accordance with IEEE C37.90.2
- Have passed type testing for electrostatic discharge immunity in accordance with IEEE C37.90.3
- Be cooled by means which employ no moving parts or fans
- Be capable of rack or panel mounting, when panel mounted it shall be cable of maintaining the arc flash rating of the panel and be no more than 18" deep including fiber management
- Operate at 90 VDC to 155 VDC
- Have screw terminal power connections
- Have power connections on the rear
- Be capable of supporting redundant power supplies

Ethernet switches shall:

- Have jacks and port indication lighting for network connections on the rear
- Have port and system indication lights on the front
- Have provisions for simultaneously supporting a minimum of one (1) 100BaseT copper connection, (16) 100BaseFX fiber connections, and two (2) 1000BaseLX fiber connections

- Have provisions for copying configuration and firmware files to a locally attached flash memory at specified time intervals

Relay equipment shall:

- Have provisions for supporting two (2) 100BaseFX fiber Ethernet connections

A.3 PERFORMANCE

The IEC 61850 substation control network shall meet or exceed the following network performance criteria.

- Communication links between all Ethernet switches shall be 1000BaseLX
- Communication links between IEDs and switches shall be 100BaseFX
- Maximum network latency shall not exceed 4 ms under normal operation
- Maximum network jitter shall not exceed 500 μ s
- Network shall be designed so no device sees more than two 158 ms outages per year
- GOOSE messages shall be prioritized at Class of Service priority level 6
- The maximum layer 2 loop blocking fault recovery time of the network shall be 50 ms

The networking hardware components comprising the IEC 61850 substation control network shall provide a means of:

- Implementing quality of service features (QOS, IEEE 802.1p)
- Implementing virtual local area network tagging (VLANs, IEEE 802.1Q)
- Implementing link aggregation groups (LAG, IEEE 802.1AX)
- Detecting unidirectional link failure
- Implement broadcast storm control by allowing broadcast traffic to be limited to a percent of total network traffic
- Port-based rate limiting
- Implementing high-performance (less than 50 ms convergence), layer two loop blocking algorithms
- Use static IP address assignments, and IP address in place of host names
- Implementing network management and monitoring capabilities including Simple Network Management Protocol (SNMP)

- Supporting management information bases that describe processor, memory, and link utilization as well as layer two port forwarding state for monitoring any layer two blocking algorithms
- Centrally reporting network device log events to a centralized server using the Syslog protocol
- Implement the NTP time protocol for coordinating log file time stamps
- Implement the MODBUS or DNP3.0 standard for monitoring device and alarm status using common SCADA protocols
- Authenticating, authorizing, and accounting for all user login requests using RADIUS or TACACS+ protocols
- Disabling of all physical ports and network managed protocols
- Implementing port spanning to facilitate the installation of intrusion detection system probes

A.4 OPERATIONS

Recommended procedures for documentation and operation of the IEC 61850 substation control network follow.

- This network shall be used solely for protection and controls applications
- Network equipment shall be located within switchgear housings which are electrically hazardous. Access to these areas is restricted to qualified personnel; therefore all work will be performed by relay technicians.
- Network configuration changes shall be verified in a testing lab prior to field deployment
- Network settings changes and firmware updates shall be carried out on site while locally connected to the network. Changes shall be coordinated with the Electrical System Operator in order to obtain scheduled outages
- Network device settings shall be recorded by updating settings documents filed with associated relay settings and other substation documentation
- Changes to physical wiring shall be recorded by updating associated drawings
- Devices shall copy their configuration and firmware to a locally attached flash on a daily basis or when the configuration is saved to support simplified device replacement in the field
- Spare network hardware shall be stored and maintained following the processes currently in place for relaying equipment

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Appendix E IEC 61850 Substation Ethernet Switch Test Results



Kansas City Power & Light 61850 Substation Ethernet Switch Configuration and Test Results

Version 1.2
March 14, 2012

Prepared by Burns & McDonnell

KCP&L 61850 Substation Ethernet Switch Configuration and Test Results

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KCP&L 61850 Substation Ethernet Switch Configuration and Test Results

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KCP&L 61850 Substation Ethernet Switch Configuration and Test Results

1. Background

Ethernet switch testing was conducted to verify the configuration and performance of a multi-vendor, IEC 61850 LAN. Cisco CGS 2520 and RuggedCom 2100 Ethernet switches were selected by KCP&L for the Midtown Substation 61850 LAN trial.

The primary purpose of the inter-vendor testing was to determine the performance of using the proprietary Layer 2 loop-reduction protocols offered by each vendor. In addition to the industry-standard IEEE 802.1w, Rapid Spanning Tree Protocol (RSTP), each vendor offers a proprietary algorithm with faster than RSTP performance.

Cisco offers Resilient Ethernet Protocol (REP), which is designed to interoperate with RSTP. As specified in the Cisco Resilient Ethernet Protocol whitepaper, published by Cisco, "REP is designed to provide network and application convergence within 50 ms. In some scenarios, the network convergence times may increase to within 250 ms."

RuggedCom offers Enhanced Rapid Spanning Tree Protocol (eRSTP), which is designed as an extension of RSTP and offers backwards compatibility with RSTP. In a ring topology, RuggedCom estimates the worst case fault recovery time at 5 ms per switch in the ring. In KCP&L's ring of five switches, the worst case recovery time is estimated at 25 ms or less. RuggedCom advises that the 5 ms per switch estimate is very conservative.

2. LAN Topology

The topology KCP&L selected for the Midtown Substation 61850 LAN trial was tested in three parts, the Cisco ring, the RuggedCom ring, and the combined rings. These are shown here for reference later in this document.

KCP&L 61850 Substation Ethernet Switch Configuration and Test Results

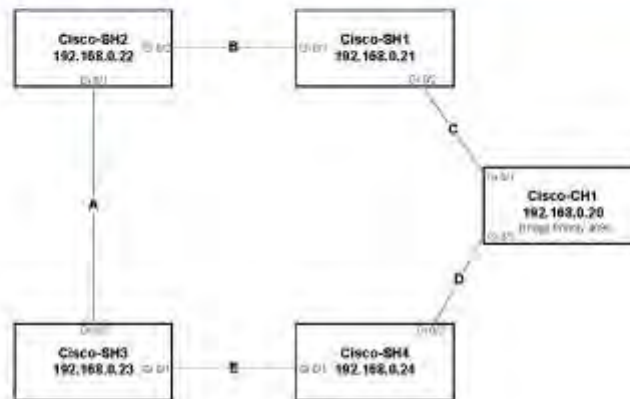


Figure 1 - Cisco Ring

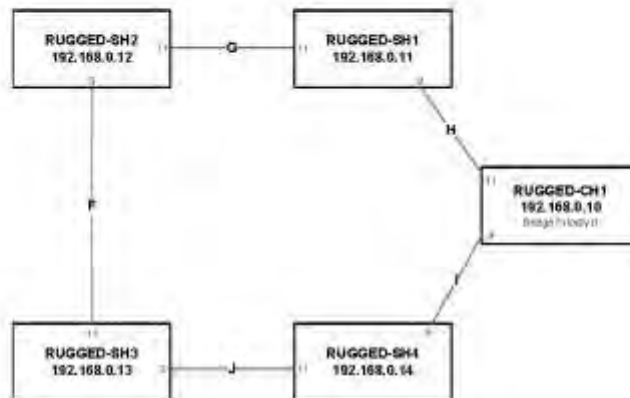


Figure 2 - RuggedCom Ring

KCP&L 61850 Substation Ethernet Switch Configuration and Test Results

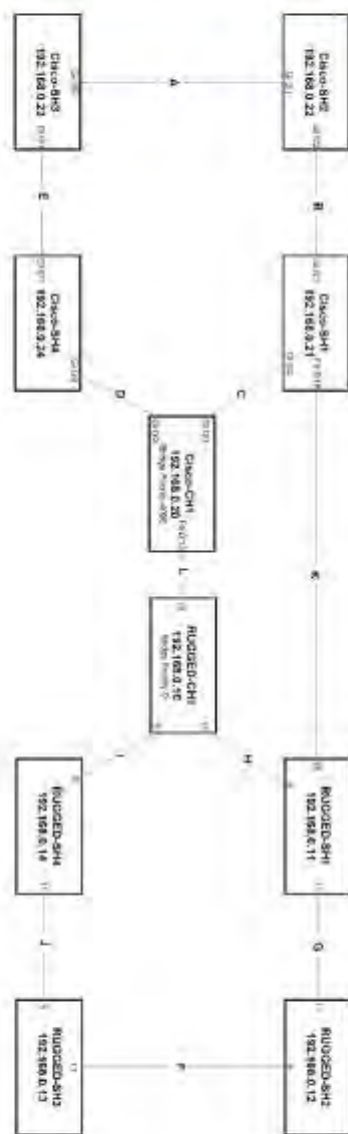


Figure 3 - Combined Rings

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3. Switch Configuration Parameters

3.1. VLAN configuration

VLANs are configured on the KCP&L 61850 network to segregate the network and allow inter-vendor VLAN operation. SEL relays have a limitation when it comes to VLAN tagging their own packets. The SEL devices transmit and receive VLAN-tagged GOOSE messages, but are limited to untagged messages for MMS and IP remote access. Switch manufacturers handle mixed tagged/untagged traffic in different ways since a typical device will either VLAN-tag all packets or send all traffic untagged.

The Cisco and RuggedCom switches treat mixed untagged and tagged packets going into a trunk port in different ways. In addition to VLAN tags, GOOSE messages in the KCP&L 61850 substation also use the 802.1p Priority Code Point (PCP), also known as Class of Service (COS), tags to give GOOSE messages a different priority or Quality of Service (QoS) than other traffic on the LAN.

3.1.1. Cisco native VLAN implementation

By default, Cisco switches place untagged packets going into a trunk port onto VLAN 1 because VLAN 1 is considered the default VLAN. Changing the native VLAN of these ports is just changing the default VLAN for untagged traffic on the ingress of a trunk port. If a trunk port with a native VLAN receives a VLAN-tagged packet that matches the native VLAN number the switch will remove the VLAN tag from the packet on egress from another port with the same native VLAN. The desired behavior is to retain the VLAN tag from relay to relay in order to retain the VLAN tag on a GOOSE message, the VLAN number on a GOOSE message must be different than the native VLAN set on relay ports. This was the driver behind creating two VLANs for traffic leaving a relay port.

On an edge port (non-trunk port) the native VLAN would not be used since there would be no tagged traffic entering or leaving the port. Instead of using the native VLAN, the port would be set using the "switchport access" command to set the port VLAN.

3.1.2. RuggedCom PVID implementation

RuggedCom does not remove the VLAN tag from a GOOSE message even if it is the same as the Port VLAN ID (PVID) VLAN number. RuggedCom uses the term PVID to describe functionality similar to the Cisco native VLAN. The PVID is also used to set the VLAN for an untagged, edge port as well. The ports are configured as untagged trunk ports, meaning the ports will accept tagged and untagged traffic, as well as having the PVID set to put the untagged packets from the SEL relays on a specified VLAN.

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3.1.3. VLAN assignments for the network

VLANs are numbered and designated for a specific type of traffic as follows for the Midtown Substation 61850 LAN trial on all switches:

VLAN ID	Traffic/Purpose
1	Unused
10	61850 GOOSE messages
20	All non-61850 GOOSE SEL relay traffic
75	Ethernet switch management

3.1.4. Cisco relay port VLAN configuration

Note that configurations for the Cisco switches will be shown as they appear in the configuration files, but RuggedCom configurations are shown as tables as the switches are configured using an ASCII menu instead of a command line interface (CLI).

The following is a typical relay port VLAN configuration on the Cisco CGS 2520:

```
interface FastEthernet0/1
  port-type nni
  switchport trunk native vlan 20
  switchport mode trunk
```

The relay ports are configured as trunk ports to allow VLAN tagged packets with a native VLAN of 20 to tag untagged packets on port ingress. The default port type setting on each port is network node interface (NNI) which is not changed as there is no technical reason to set the port as enhanced network interface (ENI) or user-network interface (UNI).

3.1.5. RuggedCom relay port VLAN configuration

On the RuggedCom switches, the relay ports are configured with the following parameters:

Parameter	Value
Type	Trunk
PVID	20
PVID Format	Untagged

The PVID is set to 20 for untagged traffic, and configured as a trunk for all tagged traffic. PVID format is set to untagged, meaning the PVID is applied to untagged traffic upon ingress into the port.

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3.1.6. Cisco inter-switch port VLAN configuration

For any port facing another Ethernet switch, the following is a typical configuration for VLAN parameters:

```
Interface GigabitEthernet0/i
port-type nnl
switchport mode trunk
```

Ports are left in the default configuration of NNL and configured as trunk ports. No native VLAN is configured since all traffic is tagged by the transmitting device or will be tagged at ingress to the LAN.

3.1.7. RuggedCom inter-switch port VLAN configuration

Parameter	Value
Type	Trunk
PVID	1
PVID Format	Tagged

Similar to the Cisco configuration, the PVID is not changed from the default value of "1" since all traffic sent between Ethernet switches will be tagged. The PVID format is set to "Tagged" as there should be no untagged traffic sent between switches.

3.2. QoS configuration

QoS classification in the Midtown Substation 61850 LAN trial is based on the layer 2, 802.1p class of service (COS) bits in the 802.1q VLAN tag. COS values are applied by the relays to each GOOSE message as it is transmitted. A COS value of "4" is being used for all GOOSE messages and COS value "4" is mapped to a high priority queue in the Ethernet switches to give GOOSE messages higher priority on the 61850 LAN than other relay traffic.

3.2.1. Cisco QoS setup procedure

The process for configuring QoS per the Cisco CGS 2520 documentation is as follows.

- Define a traffic class. Use the class-map [match-all | match-any] class-map-name global configuration command to define a traffic class and to enter class-map configuration mode. A traffic class contains three elements: a name, an instruction on how to evaluate the configured match commands (if more than one match command is configured in the class map), and a series of match commands.
- Create a traffic policy to associate the traffic class with one or more QoS features. You use the policy-map policy-map-name global configuration command to create a traffic policy and to enter policy-map configuration mode. A traffic policy defines

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the QoS features to associate with the specified traffic class. A traffic policy contains three elements: a name, a traffic class (specified with the class policy-map configuration command), and the QoS policies configured in the class.

- c. Attach the traffic policy to an interface. You use the service-policy interface configuration command to attach the policy map to an interface for packets entering or leaving the interface. You must specify whether the traffic policy characteristics should be applied to incoming or outgoing packets. For example, entering the service-policy output class1 interface configuration command attaches all the characteristics of the traffic policy named class1 to the specified interface. All packets leaving the specified interface are evaluated according to the criteria specified in the traffic policy named class1.

Policy maps are either input policy maps or output policy maps, attached to packets as they enter or leave the switch by service policies applied to interfaces. Input policy maps perform policing and marking on received traffic. Policed packets can be dropped or reduced in priority (marked down) if they exceed the maximum permitted rates. Output policy maps perform scheduling and queuing on traffic as it leaves the switch.

Input policies and output policies have the same basic structure; the difference is in the characteristics that they regulate. Input policy map classification criteria include matching a CoS, a DSCP, or an IP precedence value or matching an access control list (ACL) or VLAN ID (for per-port, per-VLAN QoS). Output policy map classification criteria include matching a CoS, a DSCP, an IP precedence, or a QoS group value.

Classification distinguishes one kind of traffic from another by examining the fields in the packet header. When a packet is received, the switch examines the header and identifies all key packet fields. A packet can be classified based on an ACL, on the DSCP, the CoS, or the IP precedence value in the packet, or by the VLAN ID. Figure 36-3 has examples of classification information carried in a Layer 2 or a Layer 3 IP packet header, using six bits from the deprecated IP type of service (ToS) field to carry the classification information.

As explained previously, you use an MQC class map to name a specific traffic flow (or class) and to isolate it from all other traffic. A class map defines the criteria used to match against a specific traffic flow to further classify it. If you have more than one type of traffic that you want to classify, you can create another class map and use a different name. When you enter the class-map command with a class-map name, the switch enters the class-map configuration mode. In this mode, you define the match criterion for the traffic by using the match class-map configuration command. After a packet is matched against the class-map criteria, it is acted on by the associated action specified in a policy map.

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You can match more than one criterion for classification. You can also create a class map that requires that all matching criteria in the class map be in the packet header by using the class map match-all class-map name global configuration command to enter class map configuration mode.

To configure the type of content used to classify packets, you use the match class-map configuration command to specify the classification criteria. If a packet matches the configured criteria, it belongs to a specific class and is forwarded according to the specified policy. For example, you can use the match class-map command with CoS, IP DSCP, and IP precedence values. These values are referred to as markings on a packet. You can also match an access group, a QoS group, or a VLAN ID or ID range for per-port, per-VLAN QoS.

3.2.2. Cisco QoS configuration

Using the Cisco process for implementing QoS, the following was configured on all Cisco Ethernet switches:

```
class-map match-any GOOSE
 match cos 4

policy-map output1
 class GOOSE
  priority

policy-map input1
 class GOOSE
 set cos 4

interface FastEthernet0/1
 service-policy input input1

interface GigabitEthernet0/1
 service-policy output output1
```

The class-map is applied to check for COS value of "4" and the map is named "GOOSE." The output policy-map is named "output1" and gives anything classified by the "GOOSE" class-map priority forwarding. Priority queuing can be applied to a single class of traffic to apply a strict queuing scheme to that class of traffic. The input policy-map is named "input1" and is applied to the "GOOSE" class-map to set the COS value to "4." This input policy is required because the Cisco CGS 2520 removes the COS tag at port ingress and a policy must be put in place to write the value back onto each GOOSE message. There is no setting to honor the COS value that was set by a relay and forward the packet with the value. It must be removed and rewritten on network ingress.

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Device ports configured with the input policy applied to re-tag the packets on ingress. Inter-switch ports are configured with the output policy to ensure that traffic being forwarded between switches is done with GOOSE set as priority traffic.

3.2.3. RuggedCom QoS configuration

QoS on the RuggedCom Ethernet switches is applied with the following configuration:

Parameter	Value
CoS Weighting	8:4:2:1
Port Default Priority	0
Inspect TOS	Yes
COS Value 0 Priority	Normal
COS Value 4 Priority	Critical
Ingress Limit	1000 kbps
Ingress Type	Broadcast

Traffic queuing is configured with a fair policy of 8:4:2:1, which is the ratio applied to queuing packets from each of the four queues in the RuggedCom switches. The high and medium queues are currently not in use, which leaves the GOOSE (critical) to non-GOOSE (normal) traffic ratio at 8:1. Individual ports are set with a default priority of "0" meaning that all traffic is normal by default, but the ports are also set to inspect the TOS (COS) value and apply it if it is present. This allows the switch to honor the COS bits set by the relays on GOOSE messages.

COS value of "0" is mapped to the normal queue and the COS value of "4" is mapped to the critical queue. Additionally, the port ingress limiter is set to 1000 kbps of broadcast traffic to limit any device transmitting more than 1000 kbps of broadcast traffic at any given time to limit how much of the network bandwidth a broadcast storm can affect at any time.

3.3. IP configuration

Switch management IP addresses are configured in the 192.168.0.0/24 address space. There were no IP addresses assigned by KCP&L and the 192.168.0.0/24 space was known to be available. The management addresses were assigned as place-holder addresses until permanent addresses could be assigned.

3.3.1. Cisco management IP configuration

IP addressing on the Cisco switches is applied to the VLAN 75 interface as follows where "X" is set to a unique value for each Ethernet switch:

```
interface Vlan75
 ip address 192.168.0.X 255.255.255.0
```

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3.3.2. RuggedCom management IP configuration

IP addressing on the RuggedCom switches is applied to VLAN 75 as follows:

Parameter	Value
Type	VLAN
VLAN ID	75
Address Type	Static
Address	192.168.0.X
Subnet	255.255.255.0

3.4. Layer 2 loop-reduction protocol configuration

Given that Ethernet does not allow active loops to exist in the network, a layer 2 loop-reduction protocol must be used to allow redundant links to be connected without causing broadcast loops in the network. As discussed in section 0, Cisco allows the use of REP and RSTP, and RuggedCom allows the use of eRSTP and RSTP.

Both REP and RSTP were evaluated on the Cisco ring since both protocols cannot be run on the same links at the same time and there were issues with REP and RSTP interoperability. In the RuggedCom configuration, eRSTP is backward compatible with RSTP, so there was no need to test the protocols separately.

3.4.1. Cisco REP configuration

REP was configured for testing using the following topology in the Cisco ring:

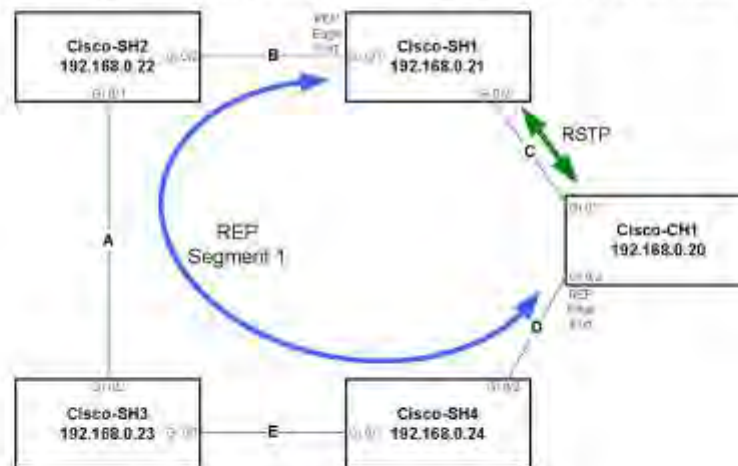


Figure 4 - Cisco REP Topology

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This topology, with the RSTP link, allows the addition of the RuggedCom ring that is not REP compatible. The REP/RSTP configuration was designed using the Cisco Resilient Ethernet Protocol whitepaper, similar to the design shown in Figure 5.

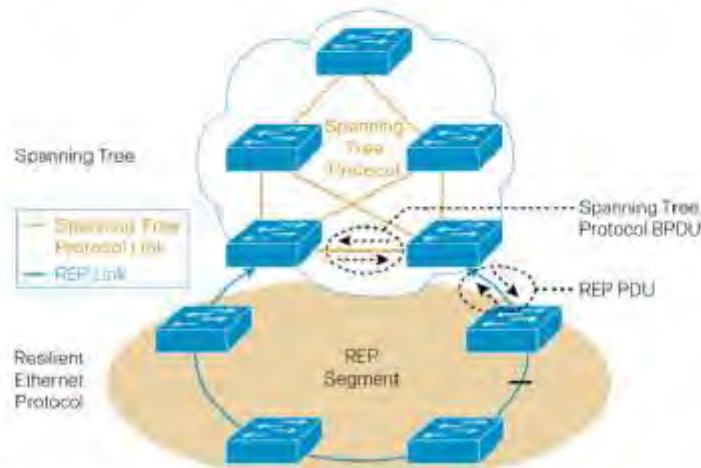


Figure 5 - Cisco REP/RSTP reference design from Cisco REP whitepaper

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The following commands were run on the Cisco Ethernet switches to configure REP:

Cisco-CH1:

```
rep admin vlan 75
spanning-tree mode rapid-pvst

interface GigabitEthernet0/1

interface GigabitEthernet0/2
port-type nni
switchport mode trunk
rep segment 1 edge
rep stcn stp
```

Cisco-SH1:

```
rep admin vlan 75
spanning-tree mode rapid-pvst

interface GigabitEthernet0/1
port-type nni
switchport mode trunk
rep segment 1 edge
rep stcn stp

interface GigabitEthernet0/2
```

Cisco-SH2:

```
rep admin vlan 75
spanning-tree mode rapid-pvst

interface GigabitEthernet0/1
port-type nni
switchport mode trunk
rep segment 1

interface GigabitEthernet0/2
port-type nni
switchport mode trunk
rep segment 1
```

Cisco-SH3:

```
rep admin vlan 75
spanning-tree mode rapid-pvst
```

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```
interface GigabitEthernet0/1
port-type nni
switchport mode trunk
rep segment 1
```

```
interface GigabitEthernet0/2
port-type nni
switchport mode trunk
rep segment 1
```

Cisco-SH4:

```
rep admin vlan 75
spanning-tree mode rapid-pvst
```

```
interface GigabitEthernet0/1
port-type nni
switchport mode trunk
rep segment 1
```

```
interface GigabitEthernet0/2
port-type nni
switchport mode trunk
rep segment 1
```

This configuration will enable RSTP on link “C” by default since REP is not enabled on that link. All other links are part of REP segment 1 with REP edge ports set on Cisco-SH1 port Gi 0/2 and Cisco-CH1 port Gi 0/1.

3.4.2. Cisco RSTP configuration

Testing on the Cisco Ethernet switches using only RSTP was also conducted due to difficulties with REP/RSTP interoperability that are discussed in in the test results. The Cisco RSTP configuration is as follows on all inter-switch links. All REP configuration was removed from all ports prior to enable RSTP and Cisco-CH1 was configured with a priority of 4096 which, in the combined topology, would make it the secondary root switch, or the primary root switch in the Cisco ring.

Cisco-CH1:

```
spanning-tree mode rapid-pvst
spanning-tree vlan 1-4094 priority 4096
```

Cisco-SH1:

```
spanning-tree mode rapid-pvst
```

Cisco-SH2:

```
spanning-tree mode rapid-pvst
```

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Cisco-SH3:

```
spanning-tree mode rapid-pvst
```

Cisco-SH4:

```
spanning-tree mode rapid-pvst
```

Ports facing non-switch devices:

```
spanning-tree portfast trunk
```

The ports are set to portfast to prevent blocking on the port when the spanning-tree protocol sends a Topology Change Notification (TCN) to prevent unnecessary downtime on the port during convergence. This also provides a safety mechanism in the instance that another Ethernet switch is connected to a device port, RSTP is still enabled on the port to prevent switching loops.

3.4.3. RuggedCom eRSTP configuration

Default values for the inter-switch links were used, and the eRSTP configuration was left running with default values with the exception of the bridge priority of Rugged-CH1. It was changed to "0" designating it as the primary root bridge in the RuggedCom ring and combined rings. Some of the RSTP timers needed to be lowered to achieve faster convergence in the combined rings.

eRSTP Parameters:

Parameter	Value
Max Network Diameter	4*MaxAgeTime
BPDU Guard Timeout	Don't Shutdown
Fast Root Failover	On
IEEE802.1w Interoperability	On
Cost Style	32 bit

eRSTP parameters were left set as default values. The parameter of note is that 802.1w interoperability was left enabled for RSTP interoperability with the Cisco devices.

Bridge RSTP Parameters:

Parameter	Value
Version Support	RSTP
Bridge Priority (excluding CH1)	32768
Hello Time	1 s
Max Age Time	6 s

Bridge RSTP parameters were tuned for lower failover times, specifically Hello and Max Age were lowered to the lowest possible values.

Port RSTP Parameters (Typical):

Parameter	Value

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Enabled	Enabled
STP Cost	1 s
RSTP Cost	6 s
Edge Port	Auto

On each relay port, RSTP is enabled and each relay port is configured to detect if it is an edge port. If no RSTP bridge protocol data units (BPDUs) are received on a port, it is set to an edge port and will not go into a blocking state when a TCN is sent out on the network, which is the same as the Cisco portfast setting. This is set to automatic to provide a safety mechanism in the event that another Ethernet switch were connected to a relay port. RSTP would still be active on the port to prevent any loops in the network.

4. Network Testing

There were two types of tests run on the network to determine network convergence following two types of failures that can occur on an Ethernet LAN: Port failures and link failures.

4.1. Port failure testing

4.1.1. Port failure test setup

To test port failure in a practical situation, an SEL-451 relay was connected to the network with redundant interfaces. Since GOOSE is a layer 2 multicast message, there are no issues with aging packets out of the MAC table. This means that no special protocols or timers are needed to make sure GOOSE messages are transmitted or received once a relay interface switches to a redundant switch.

There is an issue with IP communications following a port switchover. Relays must provide a gratuitous ARP upon interface switchover to advertise to the network that the interface MAC has moved to a new switch. This topic is beyond the scope of this testing as it is not dependent on the Ethernet LAN but on the relay itself. This information is being included here for completeness.

The relay is the same during all tests; the internal relay interface failover is a constant during the tests. The failover was performed by disconnecting the 100BaseT copper interface from one of the switches, causing a failover to the 100BaseFX fiber interface of the relay. This measures the difference between the vendors in detecting the connection on the 100BaseFX interface and bringing up the link. Additionally, this prevented a situation where a fiber is being disconnected from a port with light from the fiber still being seen by the switch and/or relay during disconnect and keeping the interface active after the intended disconnect time.

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To measure the outage duration, GOOSE messages were generated from the relay at an interval of approximately 0.01 seconds between messages giving a 10 ms resolution for the test results. A packet capture was set up on another network port, configured as a device port to capture packets as they would be seen by another relay on the network. This recreates a scenario similar to an event where a port fails while a relay is attempting to send a trip message.

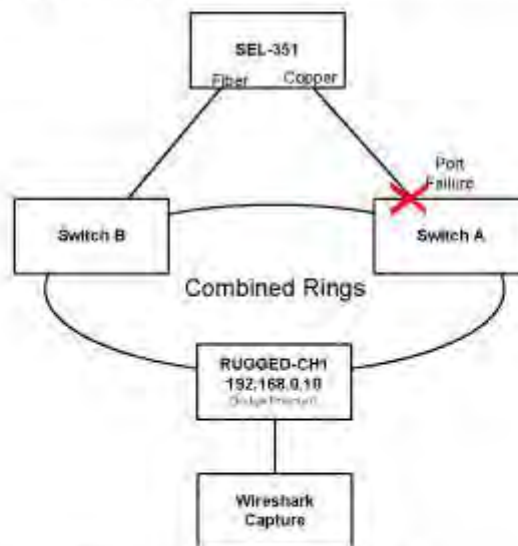


Figure 6 - Relay interface failover setup

4.1.2. Port failure test results – Failing RuggedCom to Cisco

With the copper interface of the relay active and connected to the RuggedCom switch, the copper cable was disconnected to fail the relay over to the fiber interface.

Test	Outage Duration
Trial #1	150 ms
Trial #2	130 ms
Trial #3	170 ms
Trial #4	140 ms
Trial #5	140 ms

Test Summary	Outage Duration
Min	130 ms
Max	170 ms

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Average	150 ms

4.1.1. Port failure test results – Failing Cisco to RuggedCom

With the copper interface of the relay active and connected to the RuggedCom switch, the copper cable was disconnected to fail the relay over to the fiber interface.

Test	Outage Duration
Trial #1	290 ms
Trial #2	250 ms
Trial #3	250 ms
Trial #4	280 ms
Trial #5	270 ms

Test Summary	Outage Duration
Min	250 ms
Max	290 ms
Average	270 ms

Given the difference in times between the Cisco and RuggedCom failover times, a test was conducted with the relay only connected to RuggedCom switches. The results were nearly identical with the inter-vendor failover testing.

Test	Outage Duration
Trial #1	260 ms
Trial #2	280 ms

4.1.1. Port failure test results – Summary

During the tests, the average time required to fail an interface to a Cisco switch was 150 ms, and the average time required to fail an interface to a RuggedCom switch was 270 ms.

The test records were shown for inter-vendor failures since the current network design uses both vendors, and no device is planned to have two interfaces connected to a single vendor's Ethernet switch. Additional tests were run to confirm the difference in results on the RuggedCom switches to be the result of the time it takes to establish the optical connection between the RuggedCom switch and the SEL-451 and not an issue between the vendors.

A note for final implementation: The ports on the Cisco CGS switches used in the lab may require attenuators or different optics when connected to SEL relays within the substation. The optical transmit power on the 100BaseFX optics in the Cisco CGS are

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10 km range optics and were too bright for the optical receiver in the SEL relay used for lab testing. This may not be the case depending on relays and conditions in the substation, but it was an issue during lab testing that required the use of an air gap to act as an optical attenuator.

4.2. Layer 2 loop reduction protocol test setup

Testing REP, eRSTP and RSTP was done using a packet generator sending GOOSE packets at 1000 packets/second. This packet rate was chosen to give 1 ms resolution to the results. The packets were received by a packet capture at the furthest logical point in the network from the source. This means that the generator and capture were placed on opposite sides of the blocking port for REP or eRSTP, forcing the packets on the longest path through the network. A link on the active traffic path was failed and the outage time for GOOSE messages was measured. The outage time was recorded as the difference in time between the reception of the first GOOSE message after repair and the last message received before the break.

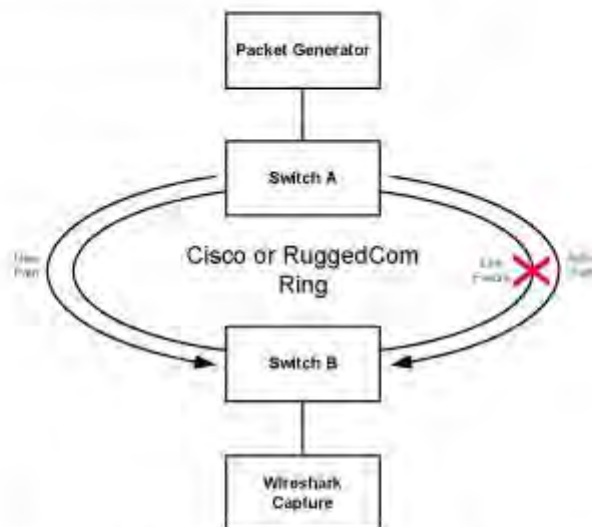


Figure 7 - Typical inter-switch link failure scenario

4.3. Cisco failover testing

4.3.1. Cisco REP link failure test setup

An example of the REP topology is provided below for reference with a sample failure scenario.

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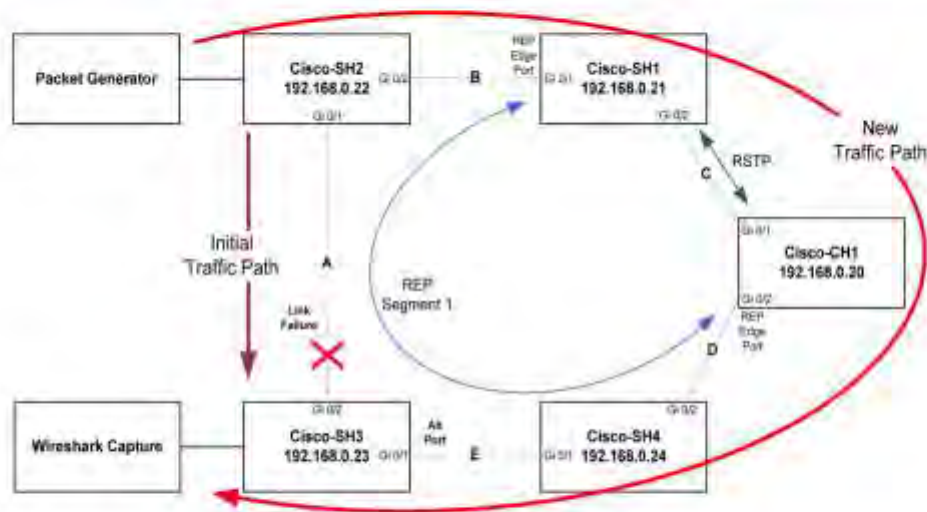


Figure 8 - Cisco REP typical link failure setup

To test network convergence times for the REP protocol, links were failed according to the location of the Alternate Port. Traffic was generated across the shortest path between the traffic generation and capture with the Alt (blocking) port on an adjacent link (this is shown as link E in Figure 8). A port on the shortest path (in Figure 8, this would be a port on link "A") was disconnected forcing the traffic to travel the longest path to reach the capture. This was done to simulate the worst case failure on this topology.

4.3.2. Cisco REP link failure test results

The table below details the test results from the Cisco REP link failure tests. The table gives the test results according to test number, outage duration, which link was broken, and which port was blocking the loop prior to the link failure.

Test	Outage Duration	Link Broken	Alt Port – Before Break
Trial #1	36 ms	B	SH2 - Gi 0/1
Trial #2	43 ms	A	SH3 - Gi 0/1
Trial #3	113 ms	A	SH3 - Gi 0/1
Trial #4	96 ms	A	SH3 - Gi 0/1
Trial #5	7 ms	E	SH3 - Gi 0/2
Trial #6	119 ms	E	SH3 - Gi 0/2
Trial #7	99 ms	E	SH3 - Gi 0/2

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Trial #8	39 ms	A	SH2 - Gi 0/2
Trial #9	76 ms	A	SH2 - Gi 0/2
Trial #10	141 ms	A	SH2 - Gi 0/2

Table 1 - Cisco REP test results

Test Summary	Outage Duration
Min	7 ms
Max	141 ms
Average	77 ms

Table 2 - Cisco REP test summary

The REP convergence time varied greatly between tests depending on which link was broken. The first two tests showed sub 50 ms convergence times in accordance with the Cisco whitepaper. Unless configured specifically to avoid this behavior, the REP Alt port will move onto the last link that was failed. If all links are active, a network running RSTP will always converge with the same blocking port due to how costs are calculated in the network.

The third test exposed an odd behavior with REP so additional tests were conducted to establish a pattern. If a link is failed the Alt port moves to the failed link when it is reconnected. If the Alt port is moved back to the original link by failing a different port, and the original failure is repeated, the convergence time goes up to values at or over 100 ms. The highest measured value was 141 ms.

To clarify how this was repeated, assume that the network state is that shown in Figure 8, and link "A" is failed and the outage is measured. A port on link "A" will now become the Alt port. To repeat the same test, link "E" is failed which will move the Alt port back to link "E" as shown in the diagram, and now link "A" can be failed again and measured. The second failure of "A" is where REP did not meet the sub 50 ms convergence time.

4.3.3. Cisco REP+RSTP link failure test results

The next test conducted tested the ability to fail the RSTP link "C" in the Cisco ring. STCN notifications were set on both REP edge ports, but failing the RSTP link isolates switches on either side of the Alt port. It is expected that a REP TCN notification would be sent into the REP segment to unblock the Alt port, but this is not the case. The Alt port remained after the failure.

KCP&L 61850 Substation Ethernet Switch Configuration and Test Results

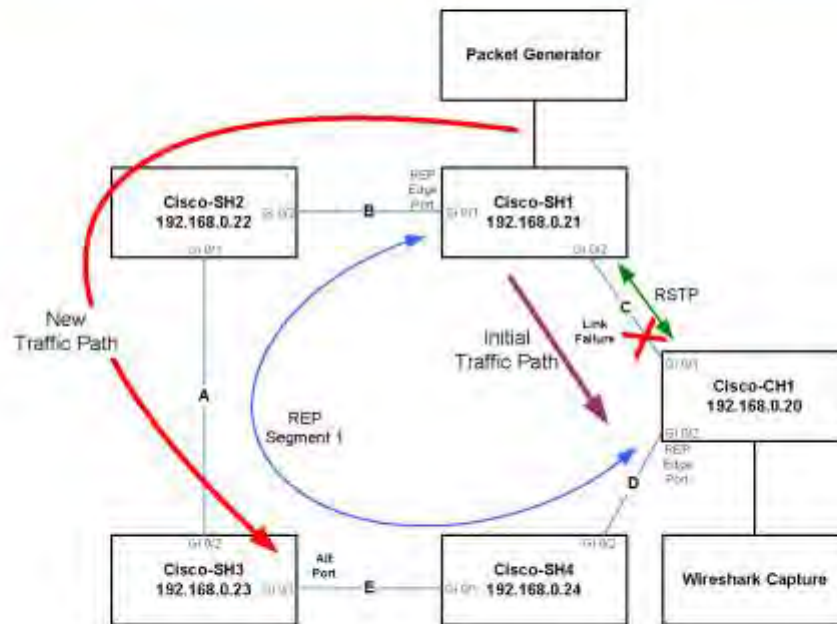


Figure 9 - Cisco REP+RSTP link failure setup

Test	Outage Duration	Switchback Time
Trial #1	N/A	N/A
Trial #2	N/A	N/A

4.3.4. Cisco RSTP link failure test results

Given the issue with REP and RSTP, the Cisco ring was reset to use only RSTP in the configuration show in Figure 10.

KCP&L 61850 Substation Ethernet Switch Configuration and Test Results

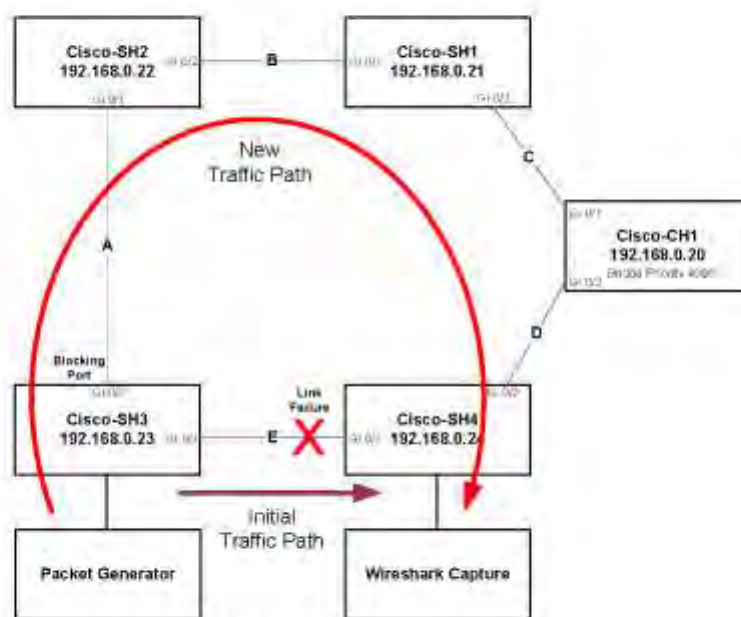


Figure 10 - Cisco RSTP link failure test setup

Test	Outage Duration	Switchback Time
Trial #1	94 ms	Not Recorded
Trial #2	143 ms	24 ms
Trial #3	164 ms	24 ms
Trial #4	123 ms	33 ms
Trial #5	154 ms	32 ms

Table 3 - Cisco RSTP test results

Test Summary	Outage Duration	Switchback Time
Min	94 ms	24 ms
Max	154 ms	33 ms
Average	136 ms	27 ms

Table 4 - Cisco RSTP test summary

Cisco RSTP convergence times were more consistent than the REP convergence times and the repair times only varied by 7 ms from the minimum to maximum measured values.

KCP&L 61850 Substation Ethernet Switch Configuration and Test Results

4.4. RuggedCom failover testing

4.4.1. RuggedCom eRSTP link failure test results

The RuggedCom ring and traffic generators were setup similar to the Cisco REP and RSTP test configuration, which the traffic generator and capture on an adjacent link that was failed to force the traffic on the longest path in the network as shown in Figure 11.

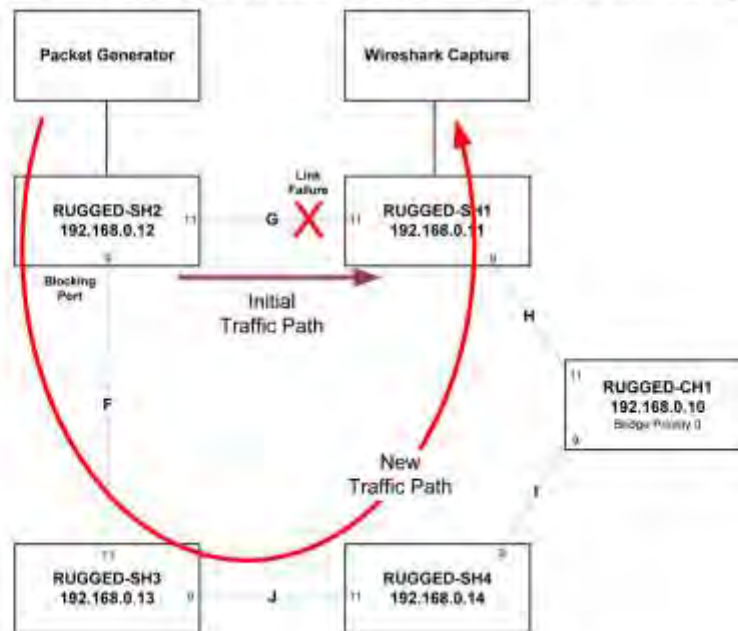


Figure 11- RuggedCom link failure test setup

Test	Outage Duration	Switchback Time
Trial #1	14 ms	Not Recorded
Trial #2	13 ms	6 ms
Trial #3	13 ms	6 ms
Trial #4	14 ms	4 ms
Trial #5	14 ms	6 ms

Table 5 - RuggedCom eRSTP test results

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Test Summary	Outage Duration	Switchback Time
Min	13 ms	4 ms
Max	14 ms	6 ms
Average	14 ms	6 ms

Table 6 - RuggedCom eRSTP test summary

Failover times and repair times were very consistent with eRSTP. Using the method provided by RuggedCom, 25 ms would be the budgeted convergence time for the network, which was higher than the 14 ms measured convergence time.

4.5. Combined ring failover testing

On the combined ring, three tests were conducted: A failure between two Cisco switches, a failure between two RuggedCom switches, and a failure between a Cisco and RuggedCom switch. Due to the difficulties with setting up REP + RSTP in the same configuration, the Cisco switches were configured with only RSTP and the RuggedCom switches were configured with eRSTP.

KCP&L 61850 Substation Ethernet Switch Configuration and Test Results

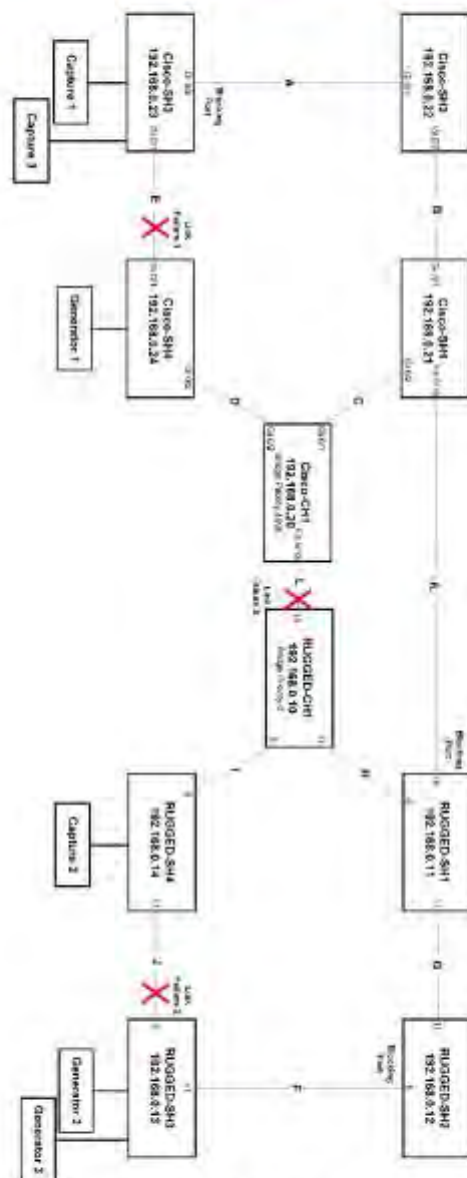


Figure 12 - Combined ring test setup

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4.5.1. Cisco-Cisco link failure test results

Link "E" was failed in the network to test a failure in the Cisco ring as shown in Figure 12.

Test	Outage Duration	Switchback Time
Trial #1	152 ms	26 ms
Trial #2	132 ms	27 ms
Trial #3	124 ms	26 ms
Trial #4	142 ms	27 ms
Trial #5	185 ms	26 ms

Table 7 – Cisco-Cisco combined ring test results

Test Summary	Outage Duration	Switchback Time
Min	124 ms	26 ms
Max	185 ms	27 ms
Average	147 ms	26 ms

Table 8 - Cisco-Cisco combined ring test summary

These test results were consistent with the tests conducted on the Cisco ring, with the average convergence time 11 ms more than the average time from the previous tests and the average repair time within 1 ms of the previous average.

4.5.2. RuggedCom-RuggedCom link failure test results

Link "I" was failed in the network to test a failure in the Cisco ring as shown in Figure 12.

Test	Outage Duration	Switchback Time
Trial #1	30 ms	9 ms
Trial #2	29 ms	9 ms
Trial #3	30 ms	10 ms
Trial #4	30 ms	10 ms
Trial #5	30 ms	10 ms

Table 9 – RuggedCom-RuggedCom combined ring test results

Test Summary	Outage Duration	Switchback Time
Min	29 ms	9 ms
Max	30 ms	10 ms
Average	30 ms	10 ms

Table 10 - RuggedCom-RuggedCom combined ring test summary

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These test results had an average convergence time of 16 ms more than the average time from the previous tests and the average repair time 4 ms more than the previous average. The convergence results agree with the method RuggedCom uses to estimate convergence time, which is estimated at 50 ms using the RuggedCom method which gives conservative results.

4.5.1 Cisco-RuggedCom link failure test results

Link “L” was failed in the network to test a failure between the rings as shown in Figure 12.

Test	Outage Duration	Switchback Time
Trial #1	5.802 s	7.99 s

Table 11 – Cisco-RuggedCom combined ring test results

The test between vendors proved to have some interoperability difficulties as the convergence time and repair time were over 5 seconds. This time is the result of timeout values in the RuggedCom RSTP settings. This test was conducted several times, the first of which was using the default RSTP timers on the RuggedCom switches which were set at 60 seconds, and the convergence time was around 60 seconds.

5. Summary

Throughout the testing, intra-vendor performance was mostly consistent with each of the vendors. There was a reproducible anomaly with specific failure scenarios with REP in the Cisco ring. Other convergence times in the Cisco ring were in the sub 50 ms range. Cisco RSTP convergence was very consistent with repair times, but the convergence times were never under 50 ms, and typically more than 100 ms. Additionally there was difficulty configuring REP to interoperate with RSTP in an intra-vendor setup, so there was no testing conducted in an inter-vendor configuration.

Cisco showed consistently better times when failing a single relay port by approximately 120 ms on average with an SEL-451. There were no other relays available for comparison so this could be an issue with the SEL-451 specifically.

The RuggedCom implementation of eRSTP is very consistent with convergence and repair times and was across every test that was run on the RuggedCom and combined rings. Both convergence and repair times on each test were within 1 ms of every other respective convergence and repair time for each configuration.

VLAN configuration had to be adapted, and an extra VLAN was added to accommodate the way Cisco handles tagged traffic going into a trunk port with a native VLAN.

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Although the workaround poses no operational issues, the difference in the way each manufacturer handles both tagged and untagged packets on a trunk port caused some issues during the initial configuration.

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6. Follow-up Testing

Another test network was setup and configured in the Burns & McDonnell lab after the initial testing at KCP&L to perform additional tests on the devices to investigate two specific issues. These issues are: 1) The greater than 50 ms recovery time when failing the Cisco-Cisco REP segments and 2) the greater than five second recovery time observed when failing the Cisco-RuggedCom links.

During a follow-up conversation with Cisco regarding the issue, Cisco confirmed that they were able to reproduce the first issue with REP failure times exceeding 50 ms. They mentioned the possibility of light from the fiber jumpers shining into the SFP optical receiver during the disconnection causing the connection to stay up but no valid data reaching the other end. They were able to achieve the desired sub 50 ms recovery times by issuing a "shutdown" command to a port to cause the link failure. It is Burns & McDonnell's that this does not simulate an actual failure in the network for two reasons: 1) An equipment failure or fiber cut is never initiated with software and 2) it is possible that the code in the router is written to send the notification that the port is down immediately before actually shutting down the port. If the second scenario is true, it would show better-than-actual failover times. It is Burns & McDonnell's opinion that feasible failure scenarios must be initiated external to the router during normal operation, i.e. power failure, link failure through disconnection, and removing interface and management cards.

To eliminate the possibility of optical receivers causing issues with the link failure times, another test was designed to remove the entire SFP module instead of just unplugging the fiber jumper. With this method of link failure, the connection being broken is no longer an optical link but instead a low voltage, electrical connection. An optical connection may not have enough attenuation to be considered failed by the equipment until it has been removed several millimeters. The electrical connection from the chassis to the SFP is broken as soon as the electrical contacts are physically separated. The Cisco-Cisco REP link failure was then tested again to determine if this was the issue or if the issue is caused by the REP protocol. The test results from the testing at KCP&L's facilities were not consistent, but there was a reliable means to reproduce recovery times over 50 ms. Similar results were achieved by pulling the SFP modules versus pulling the fiber optic jumper connections.

The second issue with the Cisco-RuggedCom connection causing greater than five second recovery times was also tested again in the Burns & McDonnell lab. This issue was not thoroughly investigated during the testing at KCP&L's facility due to time constraints. After further testing and configuration, the recovery time from a failure is not an issue, but the multi-second delay is caused when reconnecting a specific connection. There also appears to be an issue with RSTP between the vendors in general, the Cisco switches will become the root switch even when a RuggedCom has a lower STP priority. This doesn't appear to cause a forwarding loop in the network, but it is abnormal behavior for RSTP to have two root switches in the network. The link that causes the delay when reconnected is

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the link between the Cisco root switch and the RuggedCom root switch. Changing the forwarding delay on the Cisco switches directly affects the recovery time when that link is reconnected, the recovery time is approximately twice the value of the forwarding delay. Changing the forwarding delay on the RuggedCom switches does not affect the recovery time. This value can only be set as low as four seconds per the standard, which allows an 8 second recovery time for a reconnection between the two rings.

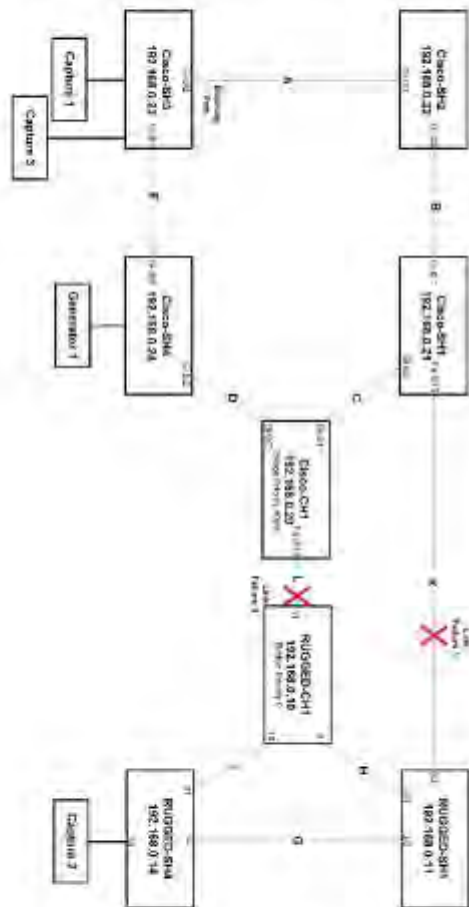


Figure 13 – Additional test setup

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Appendix F Device Points List

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F.1 Substation Devices

F.1.1 Bus Differential Relay

SEL-487B: Bus Differential Relay

Name	Point Type	61850 Name	ICCP Name
86B Lockout Operated	Status	ANN.IN1GGIO9.Ind01.stVal	KCPD1:DATAVALUE~ANN\$IN1GGIO9\$Ind01\$ssVal0007510.state
Software or Hardware Alarm	Status	ANN.OUT1GGIO14.Ind06.stVal	KCPD1:DATAVALUE~ANN\$OUT1GGIO14\$Ind06\$ssVal0007510.state

F.1.2 Bus Main Relay

SEL 451-5: Bus Main Breaker

Name	Point Type	61850 Name	ICCP Name
Device Status	Status	PRO.BKR1CSWI1.Pos.stVal	KCPLD1:DATAVALUE~PRO\$BKR1CSW1\$Pos\$Val0007510.state
Local - Remote	Status	ANN.IN1GGIO14.Ind03.stVal	KCPLD1:DATAVALUE~ANN\$IN1GGIO14\$Ind03\$Val0007510.state
86M Lockout Operated	Status	ANN.IN2GGIO15.Ind01.stVal	KCPLD1:DATAVALUE~ANN\$IN2GGIO15\$Ind01\$Val0007510.state
Slow Breaker Indication	Status	ANN.KCPLGGIO20.Ind01.stVal	KCPLD1:DATAVALUE~ANN\$KCPLGGIO20\$Ind01\$Val0007510.state
Loss of Potential	Status	ANN.KCPLGGIO20.Ind02.stVal	KCPLD1:DATAVALUE~ANN\$KCPLGGIO20\$Ind02\$Val0007510.state
Contact Wear - 3 Phase	Status	ANN.KCPLGGIO20.Ind03.stVal	KCPLD1:DATAVALUE~ANN\$KCPLGGIO20\$Ind03\$Val0007510.state
Hardware Alarm	Status	ANN.KCPLGGIO20.Ind04.stVal	KCPLD1:DATAVALUE~ANN\$KCPLGGIO20\$Ind04\$Val0007510.state
Software Alarm	Status	ANN.KCPLGGIO20.Ind05.stVal	KCPLD1:DATAVALUE~ANN\$KCPLGGIO20\$Ind05\$Val0007510.state
Fault - Phase A	Status	ANN.KCPLGGIO20.Ind06.stVal	KCPLD1:DATAVALUE~ANN\$KCPLGGIO20\$Ind06\$Val0007510.state
Fault - Phase B	Status	ANN.KCPLGGIO20.Ind07.stVal	KCPLD1:DATAVALUE~ANN\$KCPLGGIO20\$Ind07\$Val0007510.state
Fault - Phase C	Status	ANN.KCPLGGIO20.Ind08.stVal	KCPLD1:DATAVALUE~ANN\$KCPLGGIO20\$Ind08\$Val0007510.state
Fault - Ground	Status	ANN.KCPLGGIO20.Ind09.stVal	KCPLD1:DATAVALUE~ANN\$KCPLGGIO20\$Ind09\$Val0007510.state
Trip Coil Monitor	Status	ANN.KCPLGGIO20.Ind12.stVal	KCPLD1:DATAVALUE~ANN\$KCPLGGIO20\$Ind12\$Val0007510.state

F.1.3 Feeder Breaker

SEL-751A: Feeder Breaker

Name	Point Type	61850 Name	ICCP Name
Device Status	Status	PRO.BKR1CSWI1.Pos.stVal	KCPD1:DATAVALUE~PRO\$BKR1CSWI1\$Pos\$Val0007514.state
Local - Remote	Status	ANN.INCGGIO13.Ind01.stVal	KCPD1:DATAVALUE~ANN\$INCGGIO13\$Ind01\$Val0007514.state
79CO - Reclose - Enabled Status	Status	ANN.LTGGIO5.Ind08.stVal	KCPD1:DATAVALUE~ANN\$LTGGIO5\$Ind08\$Val0007514.state
50CO - Ground - Enabled Status	Status	ANN.LTGGIO5.Ind05.stVal	KCPD1:DATAVALUE~ANN\$LTGGIO5\$Ind05\$Val0007514.state
Close Failure	Status	ANN.LTGGIO5.Ind03.stVal	KCPD1:DATAVALUE~ANN\$LTGGIO5\$Ind03\$Val0007514.state
Under Frequency Trip	Status	ANN.LTGGIO5.Ind02.stVal	KCPD1:DATAVALUE~ANN\$LTGGIO5\$Ind02\$Val0007514.state
High Current Lockout	Status	ANN.LTGGIO5.Ind07.stVal	KCPD1:DATAVALUE~ANN\$LTGGIO5\$Ind07\$Val0007514.state
Slow Breaker Indication	Status	ANN.SVTGGIO4.Ind11.stVal	KCPD1:DATAVALUE~ANN\$SVTGGIO4\$Ind11\$Val0007514.state
Contact Wear - 3 Phase	Status	ANN.KCPLGGIO24.Ind01.stVal	KCPD1:DATAVALUE~ANN\$KCPLGGIO24\$Ind01\$Val0007514.state
Feeder Lockout Operated	Status	ANN.LTGGIO5.Ind01.stVal	KCPD1:DATAVALUE~ANN\$LTGGIO5\$Ind01\$Val0007514.state
Trip Coil Monitor	Status	ANN.SVTGGIO4.Ind08.stVal	KCPD1:DATAVALUE~ANN\$SVTGGIO4\$Ind08\$Val0007514.state
Instantaneous	Status	ANN.TLEDGGIO6.Ind03.stVal	KCPD1:DATAVALUE~ANN\$TLEDGGIO6\$Ind03\$Val0007514.state
Phase Overcurrent	Status	ANN.TLEDGGIO6.Ind04.stVal	KCPD1:DATAVALUE~ANN\$TLEDGGIO6\$Ind04\$Val0007514.state
Ground Neutral Overcurrent	Status	ANN.TLEDGGIO6.Ind05.stVal	KCPD1:DATAVALUE~ANN\$TLEDGGIO6\$Ind05\$Val0007514.state
Negative Sequence Overcurrent	Status	ANN.TLEDGGIO6.Ind06.stVal	KCPD1:DATAVALUE~ANN\$TLEDGGIO6\$Ind06\$Val0007514.state
Over Under Frequency	Status	ANN.TLEDGGIO6.Ind07.stVal	KCPD1:DATAVALUE~ANN\$TLEDGGIO6\$Ind07\$Val0007514.state
Breaker Failure	Status	ANN.TLEDGGIO6.Ind08.stVal	KCPD1:DATAVALUE~ANN\$TLEDGGIO6\$Ind08\$Val0007514.state
Hardware Alarm	Status	ANN.KCPLGGIO24.Ind02.stVal	KCPD1:DATAVALUE~ANN\$KCPLGGIO24\$Ind02\$Val0007514.state
Software Alarm	Status	ANN.KCPLGGIO24.Ind03.stVal	KCPD1:DATAVALUE~ANN\$KCPLGGIO24\$Ind03\$Val0007514.state
Fault - Phase A	Status	ANN.KCPLGGIO24.Ind04.stVal	KCPD1:DATAVALUE~ANN\$KCPLGGIO24\$Ind04\$Val0007514.state
Fault - Phase B	Status	ANN.KCPLGGIO24.Ind05.stVal	KCPD1:DATAVALUE~ANN\$KCPLGGIO24\$Ind05\$Val0007514.state
Fault - Phase C	Status	ANN.KCPLGGIO24.Ind06.stVal	KCPD1:DATAVALUE~ANN\$KCPLGGIO24\$Ind06\$Val0007514.state
Fault - Ground	Status	ANN.KCPLGGIO24.Ind07.stVal	KCPD1:DATAVALUE~ANN\$KCPLGGIO24\$Ind07\$Val0007514.state
Loss of Potential	Status	PRO.LOPPTUV3.Str.general	KCPD1:DATAVALUE~PRO\$LOPPTUV3\$Str\$general0007514.state
EMS - DMS Indicator	Status	ANN.LTGGIO5.Ind04.stVal	KCPD1:DATAVALUE~ANN\$LTGGIO5\$Ind04\$Val0007514.state
Device Operate	Control	CON.RBGGIO2.SPCSO11.ctlVal/CON.RBGGIO2.SPCSO12.ctlVal	KCPD1:DeviceOperate~CON\$DevOp\$c0007514
79CO - Reclose	Control	CON.RBGGIO2.SPCSO13.ctlVal/CON.RBGGIO2.SPCSO14.ctlVal	KCPD1:DeviceOperate~CON\$RclsEnbl\$c0007514
50CO - Ground	Control	CON.RBGGIO2.SPCSO15.ctlVal/CON.RBGGIO2.SPCSO16.ctlVal	KCPD1:DeviceOperate~CON\$GndEnbl\$c0007514
Real Power - 3 Phase	Analog	MET.METMMXU1.TotW.mag	KCPD1:DATAVALUE~MET\$METMMXU1\$TotW\$mag0007514.value
Reactive Power - 3 Phase	Analog	MET.METMMXU1.TotVar.mag	KCPD1:DATAVALUE~MET\$METMMXU1\$TotVar\$mag0007514.value
Apparent Power - 3 Phase	Analog	MET.METMMXU1.TotVA.mag	KCPD1:DATAVALUE~MET\$METMMXU1\$TotVA\$mag0007514.value
Power Factor - 3 Phase	Analog	MET.METMMXU1.TotPF.mag	KCPD1:DATAVALUE~MET\$METMMXU1\$TotPF\$mag0007514.value
Current - Phase A	Analog	MET.METMMXU1.A.phsA.cVal.mag	KCPD1:DATAVALUE~MET\$METMMXU1\$A\$phsA\$mag0007514.value
Current - Phase B	Analog	MET.METMMXU1.A.phsB.cVal.mag	KCPD1:DATAVALUE~MET\$METMMXU1\$A\$phsB\$mag0007514.value
Current - Phase C	Analog	MET.METMMXU1.A.phsC.cVal.mag	KCPD1:DATAVALUE~MET\$METMMXU1\$A\$phsC\$mag0007514.value

SEL-751A: Feeder Breaker

Name	Point Type	61850 Name	ICCP Name
Voltage - Phase A	Analog	MET.METMMXU1.PhV.phsA.cVal.mag	KCPLD1:DATAVALUE~MET\$METMMXU1\$PhV\$phsA\$mag0007514.value
Voltage - Phase B	Analog	MET.METMMXU1.PhV.phsB.cVal.mag	KCPLD1:DATAVALUE~MET\$METMMXU1\$PhV\$phsB\$mag0007514.value
Voltage - Phase C	Analog	MET.METMMXU1.PhV.phsC.cVal.mag	KCPLD1:DATAVALUE~MET\$METMMXU1\$PhV\$phsC\$mag0007514.value
Current - Neutral	Analog	MET.METMMXU1.A.neut.cVal.mag	KCPLD1:DATAVALUE~MET\$METMMXU1\$A\$neut\$mag0007514.value
Real Power - Phase A	Analog	MET.METMMXU1.W.phsA.mag	KCPLD1:DATAVALUE~MET\$METMMXU1\$W\$phsA\$mag0007514.value
Real Power - Phase B	Analog	MET.METMMXU1.W.phsB.mag	KCPLD1:DATAVALUE~MET\$METMMXU1\$W\$phsB\$mag0007514.value
Real Power - Phase C	Analog	MET.METMMXU1.W.phsC.mag	KCPLD1:DATAVALUE~MET\$METMMXU1\$W\$phsC\$mag0007514.value
Reactive Power - Phase A	Analog	MET.METMMXU1.VAr.phsA.mag	KCPLD1:DATAVALUE~MET\$METMMXU1\$VAr\$phsA\$mag0007514.value
Reactive Power - Phase B	Analog	MET.METMMXU1.VAr.phsB.mag	KCPLD1:DATAVALUE~MET\$METMMXU1\$VAr\$phsB\$mag0007514.value
Reactive Power - Phase C	Analog	MET.METMMXU1.VAr.phsC.mag	KCPLD1:DATAVALUE~MET\$METMMXU1\$VAr\$phsC\$mag0007514.value
Apparent Power - Phase A	Analog	MET.METMMXU1.VA.phsA.mag	KCPLD1:DATAVALUE~MET\$METMMXU1\$VA\$phsA\$mag0007514.value
Apparent Power - Phase B	Analog	MET.METMMXU1.VA.phsB.mag	KCPLD1:DATAVALUE~MET\$METMMXU1\$VA\$phsB\$mag0007514.value
Apparent Power - Phase C	Analog	MET.METMMXU1.VA.phsC.mag	KCPLD1:DATAVALUE~MET\$METMMXU1\$VA\$phsC\$mag0007514.value
Power Factor - Phase A	Analog	MET.METMMXU1.PF.phsA.mag	KCPLD1:DATAVALUE~MET\$METMMXU1\$PF\$phsA\$mag0007514.value
Power Factor - Phase B	Analog	MET.METMMXU1.PF.phsB.mag	KCPLD1:DATAVALUE~MET\$METMMXU1\$PF\$phsB\$mag0007514.value
Power Factor - Phase C	Analog	MET.METMMXU1.PF.phsC.mag	KCPLD1:DATAVALUE~MET\$METMMXU1\$PF\$phsC\$mag0007514.value
Current - Positive Sequence	Analog	MET.METMSQI1.SeqA.c1.cVal.mag	KCPLD1:DATAVALUE~MET\$METMSQI1\$SeqA\$c1\$mag0007514.value
Current - Negative Sequence	Analog	MET.METMSQI1.SeqA.c2.cVal.mag	KCPLD1:DATAVALUE~MET\$METMSQI1\$SeqA\$c2\$mag0007514.value
Current - Zero Sequence	Analog	MET.METMSQI1.SeqA.c3.cVal.mag	KCPLD1:DATAVALUE~MET\$METMSQI1\$SeqA\$c3\$mag0007514.value
Voltage - Positive Sequence	Analog	MET.METMSQI1.SeqV.c1.cVal.mag	KCPLD1:DATAVALUE~MET\$METMSQI1\$SeqV\$c1\$mag0007514.value
Voltage - Negative Sequence	Analog	MET.METMSQI1.SeqV.c2.cVal.mag	KCPLD1:DATAVALUE~MET\$METMSQI1\$SeqV\$c2\$mag0007514.value
Voltage - Zero Sequence	Analog	MET.METMSQI1.SeqV.c3.cVal.mag	KCPLD1:DATAVALUE~MET\$METMSQI1\$SeqV\$c3\$mag0007514.value
Current Imbalance	Analog	MET.METMSQI1.MaxImbA.mag	KCPLD1:DATAVALUE~MET\$METMSQI1\$MaxImbA\$mag0007514.value
Voltage Imbalance	Analog	MET.METMSQI1.MaxImbV.mag	KCPLD1:DATAVALUE~MET\$METMSQI1\$MaxImbV\$mag0007514.value
Current - Average	Analog	MET.METMSTA1.AvAmps.mag	KCPLD1:DATAVALUE~MET\$METMSTA1\$AvAmps\$mag0007514.value
Current - Max - Phase A	Analog	MET.METMSTA1.MaxA.phsA.mag	KCPLD1:DATAVALUE~MET\$METMSTA1\$MaxA\$phA\$mag0007514.value
Current - Max - Phase B	Analog	MET.METMSTA1.MaxA.phsB.mag	KCPLD1:DATAVALUE~MET\$METMSTA1\$MaxA\$phB\$mag0007514.value
Current - Max - Phase C	Analog	MET.METMSTA1.MaxA.phsC.mag	KCPLD1:DATAVALUE~MET\$METMSTA1\$MaxA\$phC\$mag0007514.value
Current - Max - Neutral	Analog	MET.METMSTA1.MaxA.neut.mag	KCPLD1:DATAVALUE~MET\$METMSTA1\$MaxA\$neu\$mag0007514.value

F.1.4 Feeder Breaker – Non Smart Grid Feeder

SEL-751A: Feeder Breaker (Non Smart Grid Feeder)

Name	Point Type	61850 Name	ICCP Name
Device Status	Status	PRO.BKR1CSWI1.Pos.stVal	KCPLD1:DATAVALUE~PRO\$BKR1CSWI1\$Pos\$Val0007511.state
Local - Remote	Status	ANN.INCGGIO13.Ind01.stVal	KCPLD1:DATAVALUE~ANN\$INCGGIO13\$Ind01\$Val0007511.state
79CO - Reclose - Enabled Status	Status	ANN.LTGGIO5.Ind08.stVal	KCPLD1:DATAVALUE~ANN\$LTGGIO5\$Ind08\$Val0007511.state
50CO - Ground - Enabled Status	Status	ANN.LTGGIO5.Ind05.stVal	KCPLD1:DATAVALUE~ANN\$LTGGIO5\$Ind05\$Val0007511.state
Close Failure	Status	ANN.LTGGIO5.Ind03.stVal	KCPLD1:DATAVALUE~ANN\$LTGGIO5\$Ind03\$Val0007511.state
Under Frequency Trip	Status	ANN.LTGGIO5.Ind02.stVal	KCPLD1:DATAVALUE~ANN\$LTGGIO5\$Ind02\$Val0007511.state
High Current Lockout	Status	ANN.LTGGIO5.Ind07.stVal	KCPLD1:DATAVALUE~ANN\$LTGGIO5\$Ind07\$Val0007511.state
Slow Breaker Indication	Status	ANN.SVTGGIO4.Ind11.stVal	KCPLD1:DATAVALUE~ANN\$SVTGGIO4\$Ind11\$Val0007511.state
Contact Wear - 3 Phase	Status	ANN.KCPLGGIO24.Ind01.stVal	KCPLD1:DATAVALUE~ANN\$KCPLGGIO24\$Ind01\$Val0007511.state
Feeder Lockout Operated	Status	ANN.LTGGIO5.Ind01.stVal	KCPLD1:DATAVALUE~ANN\$LTGGIO5\$Ind01\$Val0007511.state
Trip Coil Monitor	Status	ANN.SVTGGIO4.Ind08.stVal	KCPLD1:DATAVALUE~ANN\$SVTGGIO4\$Ind08\$Val0007511.state
Instantaneous	Status	ANN.TLEDGGIO6.Ind03.stVal	KCPLD1:DATAVALUE~ANN\$TLEDGGIO6\$Ind03\$Val0007511.state
Phase Overcurrent	Status	ANN.TLEDGGIO6.Ind04.stVal	KCPLD1:DATAVALUE~ANN\$TLEDGGIO6\$Ind04\$Val0007511.state
Ground Neutral Overcurrent	Status	ANN.TLEDGGIO6.Ind05.stVal	KCPLD1:DATAVALUE~ANN\$TLEDGGIO6\$Ind05\$Val0007511.state
Negative Sequence Overcurrent	Status	ANN.TLEDGGIO6.Ind06.stVal	KCPLD1:DATAVALUE~ANN\$TLEDGGIO6\$Ind06\$Val0007511.state
Over Under Frequency	Status	ANN.TLEDGGIO6.Ind07.stVal	KCPLD1:DATAVALUE~ANN\$TLEDGGIO6\$Ind07\$Val0007511.state
Breaker Failure	Status	ANN.TLEDGGIO6.Ind08.stVal	KCPLD1:DATAVALUE~ANN\$TLEDGGIO6\$Ind08\$Val0007511.state
Hardware Alarm	Status	ANN.KCPLGGIO24.Ind02.stVal	KCPLD1:DATAVALUE~ANN\$KCPLGGIO24\$Ind02\$Val0007511.state
Software Alarm	Status	ANN.KCPLGGIO24.Ind03.stVal	KCPLD1:DATAVALUE~ANN\$KCPLGGIO24\$Ind03\$Val0007511.state
Fault - Phase A	Status	ANN.KCPLGGIO24.Ind04.stVal	KCPLD1:DATAVALUE~ANN\$KCPLGGIO24\$Ind04\$Val0007511.state
Fault - Phase B	Status	ANN.KCPLGGIO24.Ind05.stVal	KCPLD1:DATAVALUE~ANN\$KCPLGGIO24\$Ind05\$Val0007511.state
Fault - Phase C	Status	ANN.KCPLGGIO24.Ind06.stVal	KCPLD1:DATAVALUE~ANN\$KCPLGGIO24\$Ind06\$Val0007511.state
Fault - Ground	Status	ANN.KCPLGGIO24.Ind07.stVal	KCPLD1:DATAVALUE~ANN\$KCPLGGIO24\$Ind07\$Val0007511.state
Loss of Potential	Status	PRO.LOPPTUV3.Str.general	KCPLD1:DATAVALUE~PRO\$LOPPTUV3\$Str\$general0007511.state
Real Power - 3 Phase	Analog	MET.METMMXU1.TotW.mag	KCPLD1:DATAVALUE~MET\$METMMXU1\$TotW\$mag0007511.value
Reactive Power - 3 Phase	Analog	MET.METMMXU1.TotVAr.mag	KCPLD1:DATAVALUE~MET\$METMMXU1\$TotVAr\$mag0007511.value
Apparent Power - 3 Phase	Analog	MET.METMMXU1.TotVA.mag	KCPLD1:DATAVALUE~MET\$METMMXU1\$TotVA\$mag0007511.value
Power Factor - 3 Phase	Analog	MET.METMMXU1.TotPF.mag	KCPLD1:DATAVALUE~MET\$METMMXU1\$TotPF\$mag0007511.value
Current - Phase A	Analog	MET.METMMXU1.A.phsA.cVal.mag	KCPLD1:DATAVALUE~MET\$METMMXU1\$A\$phsA\$mag0007511.value
Current - Phase B	Analog	MET.METMMXU1.A.phsB.cVal.mag	KCPLD1:DATAVALUE~MET\$METMMXU1\$A\$phsB\$mag0007511.value
Current - Phase C	Analog	MET.METMMXU1.A.phsC.cVal.mag	KCPLD1:DATAVALUE~MET\$METMMXU1\$A\$phsC\$mag0007511.value
Voltage - Phase A	Analog	MET.METMMXU1.PhV.phsA.cVal.mag	KCPLD1:DATAVALUE~MET\$METMMXU1\$PhV\$phsA\$mag0007511.value
Voltage - Phase B	Analog	MET.METMMXU1.PhV.phsB.cVal.mag	KCPLD1:DATAVALUE~MET\$METMMXU1\$PhV\$phsB\$mag0007511.value
Voltage - Phase C	Analog	MET.METMMXU1.PhV.phsC.cVal.mag	KCPLD1:DATAVALUE~MET\$METMMXU1\$PhV\$phsC\$mag0007511.value
Current - Neutral	Analog	MET.METMMXU1.A.neut.cVal.mag	KCPLD1:DATAVALUE~MET\$METMMXU1\$A\$neut\$mag0007511.value

SEL-751A: Feeder Breaker (Non Smart Grid Feeder)

Name	Point Type	61850 Name	ICCP Name
Real Power - Phase A	Analog	MET.METMMXU1.W.phsA.mag	KCPLD1:DATAVALUE~MET\$METMMXU1\$W\$phsA\$mag0007511.value
Real Power - Phase B	Analog	MET.METMMXU1.W.phsB.mag	KCPLD1:DATAVALUE~MET\$METMMXU1\$W\$phsB\$mag0007511.value
Real Power - Phase C	Analog	MET.METMMXU1.W.phsC.mag	KCPLD1:DATAVALUE~MET\$METMMXU1\$W\$phsC\$mag0007511.value
Reactive Power - Phase A	Analog	MET.METMMXU1.VAr.phsA.mag	KCPLD1:DATAVALUE~MET\$METMMXU1\$VAr\$phsA\$mag0007511.value
Reactive Power - Phase B	Analog	MET.METMMXU1.VAr.phsB.mag	KCPLD1:DATAVALUE~MET\$METMMXU1\$VAr\$phsB\$mag0007511.value
Reactive Power - Phase C	Analog	MET.METMMXU1.VAr.phsC.mag	KCPLD1:DATAVALUE~MET\$METMMXU1\$VAr\$phsC\$mag0007511.value
Apparent Power - Phase A	Analog	MET.METMMXU1.VA.phsA.mag	KCPLD1:DATAVALUE~MET\$METMMXU1\$VA\$phsA\$mag0007511.value
Apparent Power - Phase B	Analog	MET.METMMXU1.VA.phsB.mag	KCPLD1:DATAVALUE~MET\$METMMXU1\$VA\$phsB\$mag0007511.value
Apparent Power - Phase C	Analog	MET.METMMXU1.VA.phsC.mag	KCPLD1:DATAVALUE~MET\$METMMXU1\$VA\$phsC\$mag0007511.value
Power Factor - Phase A	Analog	MET.METMMXU1.PF.phsA.mag	KCPLD1:DATAVALUE~MET\$METMMXU1\$PF\$phsA\$mag0007511.value
Power Factor - Phase B	Analog	MET.METMMXU1.PF.phsB.mag	KCPLD1:DATAVALUE~MET\$METMMXU1\$PF\$phsB\$mag0007511.value
Power Factor - Phase C	Analog	MET.METMMXU1.PF.phsC.mag	KCPLD1:DATAVALUE~MET\$METMMXU1\$PF\$phsC\$mag0007511.value
Current - Positive Sequence	Analog	MET.METMSQ11.SeqA.c1.cVal.mag	KCPLD1:DATAVALUE~MET\$METMSQ11\$SeqA\$c1\$mag0007511.value
Current - Negative Sequence	Analog	MET.METMSQ11.SeqA.c2.cVal.mag	KCPLD1:DATAVALUE~MET\$METMSQ11\$SeqA\$c2\$mag0007511.value
Current - Zero Sequence	Analog	MET.METMSQ11.SeqA.c3.cVal.mag	KCPLD1:DATAVALUE~MET\$METMSQ11\$SeqA\$c3\$mag0007511.value
Voltage - Positive Sequence	Analog	MET.METMSQ11.SeqV.c1.cVal.mag	KCPLD1:DATAVALUE~MET\$METMSQ11\$SeqV\$c1\$mag0007511.value
Voltage - Negative Sequence	Analog	MET.METMSQ11.SeqV.c2.cVal.mag	KCPLD1:DATAVALUE~MET\$METMSQ11\$SeqV\$c2\$mag0007511.value
Voltage - Zero Sequence	Analog	MET.METMSQ11.SeqV.c3.cVal.mag	KCPLD1:DATAVALUE~MET\$METMSQ11\$SeqV\$c3\$mag0007511.value
Current Imbalance	Analog	MET.METMSQ11.MaxImbA.mag	KCPLD1:DATAVALUE~MET\$METMSQ11\$MaxImbA\$mag0007511.value
Voltage Imbalance	Analog	MET.METMSQ11.MaxImbV.mag	KCPLD1:DATAVALUE~MET\$METMSQ11\$MaxImbV\$mag0007511.value
Current - Average	Analog	MET.METMSTA1.AvAmps.mag	KCPLD1:DATAVALUE~MET\$METMSTA1\$AvAmps\$mag0007511.value
Current - Max - Phase A	Analog	MET.METMSTA1.MaxA.phsA.mag	KCPLD1:DATAVALUE~MET\$METMSTA1\$MaxA\$phA\$mag0007511.value
Current - Max - Phase B	Analog	MET.METMSTA1.MaxA.phsB.mag	KCPLD1:DATAVALUE~MET\$METMSTA1\$MaxA\$phB\$mag0007511.value
Current - Max - Phase C	Analog	MET.METMSTA1.MaxA.phsC.mag	KCPLD1:DATAVALUE~MET\$METMSTA1\$MaxA\$phC\$mag0007511.value
Current - Max - Neutral	Analog	MET.METMSTA1.MaxA.neut.mag	KCPLD1:DATAVALUE~MET\$METMSTA1\$MaxA\$neu\$mag0007511.value

F.1.5 Load Tap Changer

Eberle REG-DA: Load Tap Changer

Name	Point Type	61850 Name	ICCP Name
Auto - Manual	Status	A/ATCC.Auto.stVal	KCPLD1:DATAVALUE~ATCC\$Auto\$stVal1847437.state
Position - Status	Status	A/ATCC.TapChg.valWTr.posVal	KCPLD1:DATAVALUE~ATCC\$Tapchg\$valWTr\$pos1847437.state
Position - Control	Control	A/ATCC.TapChg.Oper.ctlVal	KCPLD1:DeviceOperate~ATCC\$Tapchg\$Oper\$1847437
Auto - Manual	Control	A/ATCC.Auto.Oper.ctlVal	KCPLD1:DeviceOperate~ATCC\$Auto\$Oper\$1847437

F.1.6 Tie Breaker

SEL-751A: Tie Breaker

Name	Point Type	61850 Name	ICCP Name
Device Status	Status	PRO.BKR1CSW1.Pos.stVal	KCPLD1:DATAVALUE~PRO\$BKR1CSW1\$Pos\$Val0007519.state
Local - Remote	Status	ANN.INCGGIO13.Ind01.stVal	KCPLD1:DATAVALUE~ANN\$INCGGIO13\$Ind01\$Val0007519.state
Auto - Manual	Status	ANN.LTGGIO5.Ind02.stVal	KCPLD1:DATAVALUE~ANN\$LTGGIO5\$Ind02\$Val0007519.state
Slow Breaker Indication	Status	ANN.SVTGGIO4.Ind11.stVal	KCPLD1:DATAVALUE~ANN\$SVTGGIO4\$Ind11\$Val0007519.state
Contact Wear - 3 Phase	Status	ANN.KCPLGGIO24.Ind01.stVal	KCPLD1:DATAVALUE~ANN\$KCPLGGIO24\$Ind01\$Val0007519.state
86BT Lockout Operated	Status	ANN.INCGGIO13.Ind04.stVal	KCPLD1:DATAVALUE~ANN\$INCGGIO13\$Ind04\$Val0007519.state
Trip Coil Monitor	Status	ANN.SVTGGIO4.Ind08.stVal	KCPLD1:DATAVALUE~ANN\$SVTGGIO4\$Ind08\$Val0007519.state
Instantaneous	Status	ANN.TLEDGGIO6.Ind03.stVal	KCPLD1:DATAVALUE~ANN\$TLEDGGIO6\$Ind03\$Val0007519.state
Phase Overcurrent	Status	ANN.TLEDGGIO6.Ind04.stVal	KCPLD1:DATAVALUE~ANN\$TLEDGGIO6\$Ind04\$Val0007519.state
Ground Neutral Overcurrent	Status	ANN.TLEDGGIO6.Ind05.stVal	KCPLD1:DATAVALUE~ANN\$TLEDGGIO6\$Ind05\$Val0007519.state
Negative Sequence Overcurrent	Status	ANN.TLEDGGIO6.Ind06.stVal	KCPLD1:DATAVALUE~ANN\$TLEDGGIO6\$Ind06\$Val0007519.state
Over Under Frequency	Status	ANN.TLEDGGIO6.Ind07.stVal	KCPLD1:DATAVALUE~ANN\$TLEDGGIO6\$Ind07\$Val0007519.state
Breaker Failure	Status	ANN.TLEDGGIO6.Ind08.stVal	KCPLD1:DATAVALUE~ANN\$TLEDGGIO6\$Ind08\$Val0007519.state
Hardware Alarm	Status	ANN.KCPLGGIO24.Ind02.stVal	KCPLD1:DATAVALUE~ANN\$KCPLGGIO24\$Ind02\$Val0007519.state
Software Alarm	Status	ANN.KCPLGGIO24.Ind03.stVal	KCPLD1:DATAVALUE~ANN\$KCPLGGIO24\$Ind03\$Val0007519.state
Fault - Phase A	Status	ANN.KCPLGGIO20.Ind04.stVal	KCPLD1:DATAVALUE~ANN\$KCPLGGIO24\$Ind04\$Val0007519.state
Fault - Phase B	Status	ANN.KCPLGGIO20.Ind05.stVal	KCPLD1:DATAVALUE~ANN\$KCPLGGIO24\$Ind05\$Val0007519.state
Fault - Phase C	Status	ANN.KCPLGGIO20.Ind06.stVal	KCPLD1:DATAVALUE~ANN\$KCPLGGIO24\$Ind06\$Val0007519.state
Fault - Ground	Status	ANN.KCPLGGIO24.Ind07.stVal	KCPLD1:DATAVALUE~ANN\$KCPLGGIO24\$Ind07\$Val0007519.state
Loss of Potential	Status	PRO.LOPPTUV3.Str.general	KCPLD1:DATAVALUE~PRO\$LOPPTUV3\$Str\$general0007519.state
Real Power - 3 Phase	Analog	MET.METMMXU1.TotW.mag	KCPLD1:DATAVALUE~MET\$METMMXU1\$TotW\$mag0007519.value
Reactive Power - 3 Phase	Analog	MET.METMMXU1.TotVAr.mag	KCPLD1:DATAVALUE~MET\$METMMXU1\$TotVAr\$mag0007519.value
Apparent Power - 3 Phase	Analog	MET.METMMXU1.TotVA.mag	KCPLD1:DATAVALUE~MET\$METMMXU1\$TotVA\$mag0007519.value
Power Factor - 3 Phase	Analog	MET.METMMXU1.TotPF.mag	KCPLD1:DATAVALUE~MET\$METMMXU1\$TotPF\$mag0007519.value
Current - Phase A	Analog	MET.METMMXU1.A.phsA.cVal.mag	KCPLD1:DATAVALUE~MET\$METMMXU1\$A\$phsA\$mag0007519.value
Current - Phase B	Analog	MET.METMMXU1.A.phsB.cVal.mag	KCPLD1:DATAVALUE~MET\$METMMXU1\$A\$phsB\$mag0007519.value
Current - Phase C	Analog	MET.METMMXU1.A.phsC.cVal.mag	KCPLD1:DATAVALUE~MET\$METMMXU1\$A\$phsC\$mag0007519.value
Voltage - Phase A	Analog	MET.METMMXU1.PhV.phsA.cVal.mag	KCPLD1:DATAVALUE~MET\$METMMXU1\$PhV\$phsA\$mag0007519.value
Voltage - Phase B	Analog	MET.METMMXU1.PhV.phsB.cVal.mag	KCPLD1:DATAVALUE~MET\$METMMXU1\$PhV\$phsB\$mag0007519.value
Voltage - Phase C	Analog	MET.METMMXU1.PhV.phsC.cVal.mag	KCPLD1:DATAVALUE~MET\$METMMXU1\$PhV\$phsC\$mag0007519.value
Current - Neutral	Analog	MET.METMMXU1.A.neut.cVal.mag	KCPLD1:DATAVALUE~MET\$METMMXU1\$A\$neut\$mag0007519.value
Real Power - Phase A	Analog	MET.METMMXU1.W.phsA.mag	KCPLD1:DATAVALUE~MET\$METMMXU1\$W\$phsA\$mag0007519.value
Real Power - Phase B	Analog	MET.METMMXU1.W.phsB.mag	KCPLD1:DATAVALUE~MET\$METMMXU1\$W\$phsB\$mag0007519.value
Real Power - Phase C	Analog	MET.METMMXU1.W.phsC.mag	KCPLD1:DATAVALUE~MET\$METMMXU1\$W\$phsC\$mag0007519.value
Reactive Power - Phase A	Analog	MET.METMMXU1.VAr.phsA.mag	KCPLD1:DATAVALUE~MET\$METMMXU1\$VAr\$phsA\$mag0007519.value

SEL-751A: Tie Breaker

Name	Point Type	61850 Name	ICCP Name
Reactive Power - Phase B	Analog	MET.METMMXU1.VAr.phsB.mag	KCPLD1:DATAVALUE~MET\$METMMXU1\$VAr\$phsB\$mag0007519.value
Reactive Power - Phase C	Analog	MET.METMMXU1.VAr.phsC.mag	KCPLD1:DATAVALUE~MET\$METMMXU1\$VAr\$phsC\$mag0007519.value
Apparent Power - Phase A	Analog	MET.METMMXU1.VA.phsA.mag	KCPLD1:DATAVALUE~MET\$METMMXU1\$VA\$phsA\$mag0007519.value
Apparent Power - Phase B	Analog	MET.METMMXU1.VA.phsB.mag	KCPLD1:DATAVALUE~MET\$METMMXU1\$VA\$phsB\$mag0007519.value
Apparent Power - Phase C	Analog	MET.METMMXU1.VA.phsC.mag	KCPLD1:DATAVALUE~MET\$METMMXU1\$VA\$phsC\$mag0007519.value
Power Factor - Phase A	Analog	MET.METMMXU1.PF.phsA.mag	KCPLD1:DATAVALUE~MET\$METMMXU1\$PF\$phsA\$mag0007519.value
Power Factor - Phase B	Analog	MET.METMMXU1.PF.phsB.mag	KCPLD1:DATAVALUE~MET\$METMMXU1\$PF\$phsB\$mag0007519.value
Power Factor - Phase C	Analog	MET.METMMXU1.PF.phsC.mag	KCPLD1:DATAVALUE~MET\$METMMXU1\$PF\$phsC\$mag0007519.value
Current - Positive Sequence	Analog	MET.METMSQI1.SeqA.c1.cVal.mag	KCPLD1:DATAVALUE~MET\$METMSQI1\$SeqA\$c1\$mag0007519.value
Current - Negative Sequence	Analog	MET.METMSQI1.SeqA.c2.cVal.mag	KCPLD1:DATAVALUE~MET\$METMSQI1\$SeqA\$c2\$mag0007519.value
Current - Zero Sequence	Analog	MET.METMSQI1.SeqA.c3.cVal.mag	KCPLD1:DATAVALUE~MET\$METMSQI1\$SeqA\$c3\$mag0007519.value
Voltage - Positive Sequence	Analog	MET.METMSQI1.SeqV.c1.cVal.mag	KCPLD1:DATAVALUE~MET\$METMSQI1\$SeqV\$c1\$mag0007519.value
Voltage - Negative Sequence	Analog	MET.METMSQI1.SeqV.c2.cVal.mag	KCPLD1:DATAVALUE~MET\$METMSQI1\$SeqV\$c2\$mag0007519.value
Voltage - Zero Sequence	Analog	MET.METMSQI1.SeqV.c3.cVal.mag	KCPLD1:DATAVALUE~MET\$METMSQI1\$SeqV\$c3\$mag0007519.value
Current Imbalance	Analog	MET.METMSQI1.MaxImbA.mag	KCPLD1:DATAVALUE~MET\$METMSQI1\$MaxImbA\$mag0007519.value
Voltage Imbalance	Analog	MET.METMSQI1.MaxImbV.mag	KCPLD1:DATAVALUE~MET\$METMSQI1\$MaxImbV\$mag0007519.value
Current - Average	Analog	MET.METMSTA1.AvAmps.mag	KCPLD1:DATAVALUE~MET\$METMSTA1\$AvAmps\$mag0007519.value
Current - Max - Phase A	Analog	MET.METMSTA1.MaxA.phsA.mag	KCPLD1:DATAVALUE~MET\$METMSTA1\$MaxA\$phA\$mag0007519.value
Current - Max - Phase B	Analog	MET.METMSTA1.MaxA.phsB.mag	KCPLD1:DATAVALUE~MET\$METMSTA1\$MaxA\$phB\$mag0007519.value
Current - Max - Phase C	Analog	MET.METMSTA1.MaxA.phsC.mag	KCPLD1:DATAVALUE~MET\$METMSTA1\$MaxA\$phC\$mag0007519.value
Current - Max - Neutral	Analog	MET.METMSTA1.MaxA.neut.mag	KCPLD1:DATAVALUE~MET\$METMSTA1\$MaxA\$neu\$mag0007519.value

F.1.7 Transformer Differential Relay

SEL-487E: Transformer Differential Relay

Name	Point Type	61850 Name	ICCP Name
Device Status	Status	PRO.S52AXCBR1.Pos.stVal	KCPLD1:DATAVALUE~PRO\$S52AXCBR1\$Pos\$stVal1856556.state
Real Power - 3 Phase - Terminal T	Analog	MET.METMMXU2.TotW.mag.f	KCPLD1:DATAVALUE~MET\$METMMXU2\$TotW\$mag1856556.value
Reactive Power - 3 Phase - Terminal T	Analog	MET.METMMXU2.TotVar.mag.f	KCPLD1:DATAVALUE~MET\$METMMXU2\$TotVar\$mag1856556.value
Apparent Power - 3 Phase - Terminal T	Analog	MET.METMMXU2.TotVA.mag.f	KCPLD1:DATAVALUE~MET\$METMMXU2\$TotVA\$mag1856556.value
Power Factor - 3 Phase - Terminal T	Analog	MET.METMMXU2.TotPF.mag.f	KCPLD1:DATAVALUE~MET\$METMMXU2\$TotPF\$mag1856556.value
Frequency - Terminal T	Analog	MET.METMMXU2.Hz.mag.f	KCPLD1:DATAVALUE~MET\$METMMXU2\$Hz\$mag1856556.value
Current - Phase A - Terminal T	Analog	MET.METMMXU2.A1.phsA.cVal.mag.f	KCPLD1:DATAVALUE~MET\$METMMXU2\$A\$phsA\$mag1856556.value
Current - Phase B - Terminal T	Analog	MET.METMMXU2.A1.phsB.cVal.mag.f	KCPLD1:DATAVALUE~MET\$METMMXU2\$A\$phsB\$mag1856556.value
Current - Phase C - Terminal T	Analog	MET.METMMXU2.A1.phsC.cVal.mag.f	KCPLD1:DATAVALUE~MET\$METMMXU2\$A\$phsC\$mag1856556.value
Real Power - 3 Phase - Terminal U	Analog	MET.METUMMXU3.TotW.mag.f	KCPLD1:DATAVALUE~MET\$METUMMXU3\$TotW\$mag1856556.value
Reactive Power - 3 Phase - Terminal U	Analog	MET.METUMMXU3.TotVar.mag.f	KCPLD1:DATAVALUE~MET\$METUMMXU3\$TotVar\$mag1856556.value
Apparent Power - 3 Phase - Terminal U	Analog	MET.METUMMXU3.TotVA.mag.f	KCPLD1:DATAVALUE~MET\$METUMMXU3\$TotVA\$mag1856556.value
Power Factor - 3 Phase - Terminal U	Analog	MET.METUMMXU3.TotPF.mag.f	KCPLD1:DATAVALUE~MET\$METUMMXU3\$TotPF\$mag1856556.value
Frequency - Terminal U	Analog	MET.METUMMXU3.Hz.mag.f	KCPLD1:DATAVALUE~MET\$METUMMXU3\$Hz\$mag1856556.value
Current - Phase A - Terminal U	Analog	MET.METUMMXU3.A1.phsA.cVal.mag.f	KCPLD1:DATAVALUE~MET\$METUMMXU3\$A\$phsA\$mag1856556.value
Current - Phase B - Terminal U	Analog	MET.METUMMXU3.A1.phsB.cVal.mag.f	KCPLD1:DATAVALUE~MET\$METUMMXU3\$A\$phsB\$mag1856556.value
Current - Phase C - Terminal U	Analog	MET.METUMMXU3.A1.phsC.cVal.mag.f	KCPLD1:DATAVALUE~MET\$METUMMXU3\$A\$phsC\$mag1856556.value
Voltage - Phase A - Terminal V	Analog	MET.METSMMXU1.PhV1.phsA.cVal.mag.f	KCPLD1:DATAVALUE~MET\$METSMMXU1\$PV1\$phsA\$mag1856556.value
Voltage - Phase B - Terminal V	Analog	MET.METSMMXU1.PhV1.phsB.cVal.mag.f	KCPLD1:DATAVALUE~MET\$METSMMXU1\$PV1\$phsB\$mag1856556.value
Voltage - Phase C - Terminal V	Analog	MET.METSMMXU1.PhV1.phsC.cVal.mag.f	KCPLD1:DATAVALUE~MET\$METSMMXU1\$PV1\$phsC\$mag1856556.value
Voltage - Phase A - Terminal Z	Analog	MET.METSMMXU1.PhV2.phsA.cVal.mag.f	KCPLD1:DATAVALUE~MET\$METSMMXU1\$PV2\$phsA\$mag1856556.value
Voltage - Phase B - Terminal Z	Analog	MET.METSMMXU1.PhV2.phsB.cVal.mag.f	KCPLD1:DATAVALUE~MET\$METSMMXU1\$PV2\$phsB\$mag1856556.value
Voltage - Phase C - Terminal Z	Analog	MET.METSMMXU1.PhV2.phsC.cVal.mag.f	KCPLD1:DATAVALUE~MET\$METSMMXU1\$PV2\$phsC\$mag1856556.value

F.2 Field Devices

F.2.1 Battery Controller

SEL 3530-4: Battery Controller

Name	Point Type	DNP Point	ICCP Name
BESS Status	DI	0	KCPD1:DATAVALUE~ANN\$BESSSts\$1111111.state
Schedule Override Status	DI	1	KCPD1:DATAVALUE~ANN\$SchdIOvrd\$1111111.state
Alarm - Warning	DI	2	KCPD1:DATAVALUE~ANN\$AlmMast\$1111111.state
Alarm - Isolate	DI	3	KCPD1:DATAVALUE~ANN\$AlmIso\$1111111.state
Alarm - Inhibit	DI	4	KCPD1:DATAVALUE~ANN\$AlmInh\$1111111.state
Alarm - Trip Offline	DI	5	KCPD1:DATAVALUE~ANN\$AlmTrpOff\$1111111.state
Local - Remote	DI	6	KCPD1:DATAVALUE~ANN\$LocRem\$1111111.state
BESS Active	DO	0	KCPD1:DeviceOperate~CON\$BESSAct\$1111111
Schedule Override	DO	1	KCPD1:DeviceOperate~CON\$SchdIOvrd\$1111111
Reset Battery	DO	2	KCPD1:DeviceOperate~CON\$Rst\$1111111
Energy Available (%)	AI	0	KCPD1:DATAVALUE~MET\$SEAvail\$1111111.value
Active State	AI	1	KCPD1:DATAVALUE~MET\$ActSte\$1111111.value
Active Status	AI	2	KCPD1:DATAVALUE~MET\$ActSts\$1111111.value
Power Mode	AI	3	KCPD1:DATAVALUE~MET\$PwrMode\$1111111.value
Reactive Mode	AI	4	KCPD1:DATAVALUE~MET\$VARMode\$1111111.value
Charge Mode	AI	5	KCPD1:DATAVALUE~MET\$CrgMode\$1111111.value
kW - Max Discharge Rate	AI	6	KCPD1:DATAVALUE~MET\$skWMax\$1111111.value
kW - Load Following	AI	7	KCPD1:DATAVALUE~MET\$skWLF\$1111111.value
kW - Discharge Start Time (2400)	AI	8	KCPD1:DATAVALUE~MET\$skWStart\$1111111.value
kW - Discharge Duration (min)	AI	9	KCPD1:DATAVALUE~MET\$skWDur\$1111111.value
kVAR - Max Discharge Rate	AI	10	KCPD1:DATAVALUE~MET\$skVARMax\$1111111.value
kVAR - Fixed PF	AI	11	KCPD1:DATAVALUE~MET\$FxdPF\$1111111.value
kVAR - Discharge Start Time (2400)	AI	12	KCPD1:DATAVALUE~MET\$skVARStart\$1111111.value
kVAR - Discharge Duration (min)	AI	13	KCPD1:DATAVALUE~MET\$skVARDur\$1111111.value
kW - Max Charge Rate	AI	14	KCPD1:DATAVALUE~MET\$CrgMax\$1111111.value
kW - Charge Following	AI	15	KCPD1:DATAVALUE~MET\$CrgLF\$1111111.value
kW - Charge Start Time (2400)	AI	16	KCPD1:DATAVALUE~MET\$CrgStart\$1111111.value
kW - Charge Duration (min)	AI	17	KCPD1:DATAVALUE~MET\$CrgDur\$1111111.value
Recalculation Time (sec)	AI	18	KCPD1:DATAVALUE~MET\$Recalc\$1111111.value
Set Power Mode	AO	0	KCPD1:DeviceOperate~COS\$PwrMode\$1111111
Set Reactive Mode	AO	1	KCPD1:DeviceOperate~COS\$VARMode\$1111111
Set Charge Mode	AO	2	KCPD1:DeviceOperate~COS\$CrgMode\$1111111
kW - Set Max Discharge Rate	AO	3	KCPD1:DeviceOperate~COS\$kWMax\$1111111
kW - Set Load Following	AO	4	KCPD1:DeviceOperate~COS\$kWLF\$1111111
kW - Set Discharge Start Time (2400)	AO	5	KCPD1:DeviceOperate~COS\$kWStart\$1111111

SEL 3530-4: Battery Controller

Name	Point Type	DNP Point	ICCP Name
kW - Set Discharge Duration (min)	AO	6	KCPLD1:DeviceOperate~CO\$kWDur\$11111111
kVAR - Set Max Discharge Rate	AO	7	KCPLD1:DeviceOperate~CO\$kVARMa\$11111111
kVAR - Set Fixed PF	AO	8	KCPLD1:DeviceOperate~CO\$FxdPF\$11111111
kVAR - Set Discharge Start Time (2400)	AO	9	KCPLD1:DeviceOperate~CO\$kVARStart\$11111111
kVAR - Set Discharge Duration (min)	AO	10	KCPLD1:DeviceOperate~CO\$kVARDur\$11111111
kW - Set Max Charge Rate	AO	11	KCPLD1:DeviceOperate~CO\$CrgMax\$11111111
kW - Set Charge Following	AO	12	KCPLD1:DeviceOperate~CO\$CrgLF\$11111111
kW - Set Charge Start Time (2400)	AO	13	KCPLD1:DeviceOperate~CO\$CrgStart\$11111111
kW - Set Charge Duration (min)	AO	14	KCPLD1:DeviceOperate~CO\$CrgDur\$11111111
Set Recalculation Time (sec)	AO	15	KCPLD1:DeviceOperate~CO\$Recalc\$11111111

F.2.2 Cap Bank Controller – Standard

S&C IntelliCAP Plus: Capacitor Bank Controller (Standard)

Name	Point Type	DNP Point	ICCP Name
Device Status	DI	0	KCPLD1:DATAVALUE~ANN\$DevSts\$222222.state
Auto - Manual Status	DI	2	KCPLD1:DATAVALUE~ANN\$AutoMan\$222222.state
Local - Remote	DI	3	KCPLD1:DATAVALUE~ANN\$LocRem\$222222.state
Alarm Summary	DI	4	KCPLD1:DATAVALUE~ANN\$AlmSum\$222222.state
SCADA Override Status	DI	5	KCPLD1:DATAVALUE~ANN\$SCADAOverd\$222222.state
Over Voltage	DI	6	KCPLD1:DATAVALUE~ANN\$OverV\$222222.state
Under Voltage	DI	7	KCPLD1:DATAVALUE~ANN\$UndrV\$222222.state
Emergency Voltage Override	DI	8	KCPLD1:DATAVALUE~ANN\$EmerVOvrd\$222222.state
Reclose Block	DI	9	KCPLD1:DATAVALUE~ANN\$RclsBlck\$222222.state
Maximum Daily Cycles	DI	10	KCPLD1:DATAVALUE~ANN\$MaxDayCyc\$222222.state
Load Fuse Blown	DI	11	KCPLD1:DATAVALUE~ANN\$FuseBlwn\$222222.state
Temperature Sensor Error	DI	12	KCPLD1:DATAVALUE~ANN\$TmpSnsErr\$222222.state
Neutral Sensor - Lockout	DI	18	KCPLD1:DATAVALUE~ANN\$NeuSnsLOS\$222222.state
Neutral Sensor - Continuous	DI	19	KCPLD1:DATAVALUE~ANN\$NeuSnsCont\$222222.state
Neutral Sensor - Zero	DI	20	KCPLD1:DATAVALUE~ANN\$NeuSnsO\$222222.state
Device Operate	DO	0	KCPLD1:DeviceOperate~CON\$DevOp\$222222
Auto - Manual	DO	1	KCPLD1:DeviceOperate~CON\$AutoMan\$222222
SCADA Override Mode	DO	2	KCPLD1:DeviceOperate~CON\$SCADAOverd\$222222
Reset Neutral Lockout	DO	3	KCPLD1:DeviceOperate~CON\$RstNeuLOS\$222222
Reset Alarms	DO	5	KCPLD1:DeviceOperate~CON\$RstAlm\$222222
Inhibit Automatic Operation Timer	DO	6	KCPLD1:DeviceOperate~CON\$InhbtAuto\$222222
Control Strategy	AI	2	KCPLD1:DATAVALUE~MET\$CtrlStrgy\$222222.value
Voltage - Secondary	AI	4	KCPLD1:DATAVALUE~MET\$SecV\$222222.value
Time Remaining in SCADA Override Mode	AI	6	KCPLD1:DATAVALUE~MET\$SCADAOverdTmr\$222222.value
Current - Neutral RMS - Fundamental	AI	7	KCPLD1:DATAVALUE~MET\$NeuCur\$222222.value
THD - Voltage	AI	13	KCPLD1:DATAVALUE~MET\$THDV\$222222.value
THD - Neutral	AI	21	KCPLD1:DATAVALUE~MET\$THDNeu\$222222.value
Last Switch In or Out Voltage Delta	AI	25	KCPLD1:DATAVALUE~MET\$SwVdlt\$222222.value

S&C IntelliCAP Plus: Capacitor Bank Controller (Standard)

Name	Point Type	DNP Point	ICCP Name
Current - Neutral RMS - Total	AI	26	KCPD1:DATAVALUE~MET\$TotNeuCur\$2222222.value
Last Switch Operation Reason	AI	28	KCPD1:DATAVALUE~MET\$OpCode\$2222222.value

F.2.3 Cap Bank Controller – VAR

S&C IntelliCAP Plus: Capacitor Bank Controller (VAR)

Name	Point Type	DNP Point	ICCP Name
Device Status	DI	0	KCPLD1:DATAVALUE~ANN\$DevSts\$3333333.state
Auto - Manual Status	DI	2	KCPLD1:DATAVALUE~ANN\$AutoMan\$3333333.state
Local - Remote	DI	3	KCPLD1:DATAVALUE~ANN\$LocRem\$3333333.state
Alarm Summary	DI	4	KCPLD1:DATAVALUE~ANN\$AlmSum\$3333333.state
SCADA Override Status	DI	5	KCPLD1:DATAVALUE~ANN\$SCADAOverd\$3333333.state
Over Voltage	DI	6	KCPLD1:DATAVALUE~ANN\$OverV\$3333333.state
Under Voltage	DI	7	KCPLD1:DATAVALUE~ANN\$UndrV\$3333333.state
Emergency Voltage Override	DI	8	KCPLD1:DATAVALUE~ANN\$EmerVOvrd\$3333333.state
Reclose Block	DI	9	KCPLD1:DATAVALUE~ANN\$RclsBlck\$3333333.state
Maximum Daily Cycles	DI	10	KCPLD1:DATAVALUE~ANN\$MaxDayCyc\$3333333.state
Load Fuse Blown	DI	11	KCPLD1:DATAVALUE~ANN\$FuseBlwn\$3333333.state
Temperature Sensor Error	DI	12	KCPLD1:DATAVALUE~ANN\$TmpSnsErr\$3333333.state
Neutral Sensor - Option	DI	16	KCPLD1:DATAVALUE~ANN\$NeuSnsOpt\$3333333.state
Neutral Sensor - Lockout	DI	18	KCPLD1:DATAVALUE~ANN\$NeuSnsLO\$3333333.state
Neutral Sensor - Continuous	DI	19	KCPLD1:DATAVALUE~ANN\$NeuSnsCont\$3333333.state
Neutral Sensor - Zero	DI	20	KCPLD1:DATAVALUE~ANN\$NeuSnsO\$3333333.state
VAR Option	DI	21	KCPLD1:DATAVALUE~ANN\$VAROpt\$3333333.state
Current Direction	DI	22	KCPLD1:DATAVALUE~ANN\$CurDir\$3333333.state
Low Switching VAR Delta	DI	23	KCPLD1:DATAVALUE~ANN\$LoSwVARDlt\$3333333.state
Current Sensor Location	DI	26	KCPLD1:DATAVALUE~ANN\$CurSnsLoc\$3333333.state
Device Operate	DO	0	KCPLD1:DeviceOperate~CON\$DevOp\$3333333
Auto - Manual	DO	1	KCPLD1:DeviceOperate~CON\$AutoMan\$3333333
SCADA Override Mode	DO	2	KCPLD1:DeviceOperate~CON\$SCADAOverd\$3333333
Reset Neutral Lockout	DO	3	KCPLD1:DeviceOperate~CON\$RstNeuLO\$3333333
Reset Alarms	DO	5	KCPLD1:DeviceOperate~CON\$RstAlm\$3333333
Inhibit Automatic Operation Timer	DO	6	KCPLD1:DeviceOperate~CON\$InhbtAuto\$3333333
Control Strategy	AI	2	KCPLD1:DATAVALUE~MET\$CtrlStrgy\$3333333.value
Voltage - Secondary	AI	4	KCPLD1:DATAVALUE~MET\$SecV\$3333333.value
Voltage - Primary (kV)	AI	5	KCPLD1:DATAVALUE~MET\$PriV\$3333333.value
Time Remaining in SCADA Override Mode	AI	6	KCPLD1:DATAVALUE~MET\$SCADAOverdTmr\$3333333.value
Current - Neutral RMS - Fundamental	AI	7	KCPLD1:DATAVALUE~MET\$NeuCur\$3333333.value
Current - Phase A	AI	8	KCPLD1:DATAVALUE~MET\$Cur\$3333333.value
Reactive Power - 3 Phase (kVAR)	AI	10	KCPLD1:DATAVALUE~MET\$TotVAR\$3333333.value
Apparent Power - 3 Phase (kVA)	AI	11	KCPLD1:DATAVALUE~MET\$TotVA\$3333333.value
Real Power - 3 Phase (kW)	AI	12	KCPLD1:DATAVALUE~MET\$TotW\$3333333.value

S&C IntelliCAP Plus: Capacitor Bank Controller (VAR)

Name	Point Type	DNP Point	ICCP Name
THD - Voltage	AI	13	KCPD1:DATAVALUE~MET\$THDV\$3333333.value
THD - Current	AI	17	KCPD1:DATAVALUE~MET\$THDCur\$3333333.value
THD - Neutral	AI	21	KCPD1:DATAVALUE~MET\$THDNeu\$3333333.value
Last Switch In or Out Voltage Delta	AI	25	KCPD1:DATAVALUE~MET\$SwVDIt\$3333333.value
Current - Neutral RMS - Total	AI	26	KCPD1:DATAVALUE~MET\$TotNeuCur\$3333333.value
Last kVAR Delta	AI	27	KCPD1:DATAVALUE~MET\$VARDIt\$3333333.value
Last Switch Operation Reason	AI	28	KCPD1:DATAVALUE~MET\$OpCode\$3333333.value

F.2.4 FCI Indicators and Receiver

Horstmann: Fault Current Indicators and Receiver

Name	Point Type	DNP Point	ICCP Name
FCI Comm Failure	DI	0	KCPLD1:DATAVALUE~ANN\$CommFail\$8888888.state
Smart Controller Reporter Operational	DI	2	KCPLD1:DATAVALUE~ANN\$DeviceOn\$8888888.state
Voltage - Low DC	DI	4	KCPLD1:DATAVALUE~ANN\$LoDCV\$8888888.state
Reset Smart Reporter Controller	DO	0	KCPLD1:DeviceOperate~CON\$RstSmtRptCtrl\$8888888
Reset All Momentary and Permanent Fault Counters	DO	1	KCPLD1:DeviceOperate~CON\$RstFltCnt\$8888888
Reset All FCIs	DO	2	KCPLD1:DeviceOperate~CON\$RstFCIs\$8888888
FCI Comm Fail	AI	0	KCPLD1:DATAVALUE~MET\$CommFail\$8888888.value
Low Battery	AI	1	KCPLD1:DATAVALUE~MET\$LoBatt\$8888888.value
Over Current - Phase A	DI	5	KCPLD1:DATAVALUE~ANN\$OverCur1PhA\$8888888.state
Permanent Fault - Phase A	DI	6	KCPLD1:DATAVALUE~ANN\$PermFlt1PhA\$8888888.state
Momentary Fault - Phase A	DI	7	KCPLD1:DATAVALUE~ANN\$MmtFlt1PhA\$8888888.state
Overhead Line Current Loss - Phase A	DI	8	KCPLD1:DATAVALUE~ANN\$OvhdCurLoss1PhA\$8888888.state
Loss of Voltage - Phase A	DI	9	KCPLD1:DATAVALUE~ANN\$VLoss1PhA\$8888888.state
Over Current - Phase B	DI	10	KCPLD1:DATAVALUE~ANN\$OverCur1PhB\$8888888.state
Permanent Fault - Phase B	DI	11	KCPLD1:DATAVALUE~ANN\$PermFlt1PhB\$8888888.state
Momentary Fault - Phase B	DI	12	KCPLD1:DATAVALUE~ANN\$MmtFlt1PhB\$8888888.state
Overhead Line Current Loss - Phase B	DI	13	KCPLD1:DATAVALUE~ANN\$OvhdCurLoss1PhB\$8888888.state
Loss of Voltage - Phase B	DI	14	KCPLD1:DATAVALUE~ANN\$VLoss1PhB\$8888888.state
Over Current - Phase C	DI	15	KCPLD1:DATAVALUE~ANN\$OverCur1PhC\$8888888.state
Permanent Fault - Phase C	DI	16	KCPLD1:DATAVALUE~ANN\$PermFlt1PhC\$8888888.state
Momentary Fault - Phase C	DI	17	KCPLD1:DATAVALUE~ANN\$MmtFlt1PhC\$8888888.state

Horstmann: Fault Current Indicators and Receiver

Name	Point Type	DNP Point	ICCP Name
Overhead Line Current Loss - Phase C	DI	18	KCPLD1:DATAVALUE~ANN\$OvhdCurLoss1PhC\$8888888.state
Loss of Voltage - Phase C	DI	19	KCPLD1:DATAVALUE~ANN\$VLoss1PhC\$8888888.state
Temporary Faults - Phase A	CTR	0	KCPLD1:DATAVALUE~CTR\$TempFlt1PhA\$8888888.value
Permanent Faults - Phase A	CTR	1	KCPLD1:DATAVALUE~CTR\$PermFlt1PhA\$8888888.value
Temporary Faults - Phase B	CTR	2	KCPLD1:DATAVALUE~CTR\$TempFlt1PhB\$8888888.value
Permanent Faults - Phase B	CTR	3	KCPLD1:DATAVALUE~CTR\$PermFlt1PhB\$8888888.value
Temporary Faults - Phase C	CTR	4	KCPLD1:DATAVALUE~CTR\$TempFlt1PhC\$8888888.value
Permanent Faults - Phase C	CTR	5	KCPLD1:DATAVALUE~CTR\$PermFlt1PhC\$8888888.value
Fault Current - Phase A	AI	2	KCPLD1:DATAVALUE~MET\$FltCur1PhA\$8888888.value
Fault Duration - Phase A	AI	3	KCPLD1:DATAVALUE~MET\$FltDur1PhA\$8888888.value
Last Known Good Current - Phase A	AI	4	KCPLD1:DATAVALUE~MET\$LKGCur1PhA\$8888888.value
Current - Average - Phase A	AI	5	KCPLD1:DATAVALUE~MET\$CurAvg1PhA\$8888888.value
Fault Current - Phase B	AI	11	KCPLD1:DATAVALUE~MET\$FltCur1PhB\$8888888.value
Fault Duration - Phase B	AI	12	KCPLD1:DATAVALUE~MET\$FltDur1PhB\$8888888.value
Last Known Good Current - Phase B	AI	13	KCPLD1:DATAVALUE~MET\$LKGCur1PhB\$8888888.value
Current - Average - Phase B	AI	14	KCPLD1:DATAVALUE~MET\$CurAvg1PhB\$8888888.value
Fault Current - Phase C	AI	20	KCPLD1:DATAVALUE~MET\$FltCur1PhC\$8888888.value

Horstmann: Fault Current Indicators and Receiver

Name	Point Type	DNP Point	ICCP Name
Fault Duration - Phase C	AI	21	KCPLD1:DATAVALUE~MET\$FltDur1PhC\$8888888.value
Last Known Good Current - Phase C	AI	22	KCPLD1:DATAVALUE~MET\$LKGCur1PhC\$8888888.value
Current - Average - Phase C	AI	23	KCPLD1:DATAVALUE~MET\$CurAvg1PhC\$8888888.value
Over Current - Phase A	DI	20	KCPLD1:DATAVALUE~ANN\$OverCur2PhA\$8888888.state
Permanent Fault - Phase A	DI	21	KCPLD1:DATAVALUE~ANN\$PermFlt2PhA\$8888888.state
Momentary Fault - Phase A	DI	22	KCPLD1:DATAVALUE~ANN\$MmtFlt2PhA\$8888888.state
Overhead Line Current Loss - Phase A	DI	23	KCPLD1:DATAVALUE~ANN\$OvhdCurLoss2PhA\$8888888.state
Loss of Voltage - Phase A	DI	24	KCPLD1:DATAVALUE~ANN\$VLoss2PhA\$8888888.state
Over Current - Phase B	DI	25	KCPLD1:DATAVALUE~ANN\$OverCur2PhB\$8888888.state
Permanent Fault - Phase B	DI	26	KCPLD1:DATAVALUE~ANN\$PermFlt2PhB\$8888888.state
Momentary Fault - Phase B	DI	27	KCPLD1:DATAVALUE~ANN\$MmtFlt2PhB\$8888888.state
Overhead Line Current Loss - Phase B	DI	28	KCPLD1:DATAVALUE~ANN\$OvhdCurLoss2PhB\$8888888.state
Loss of Voltage - Phase B	DI	29	KCPLD1:DATAVALUE~ANN\$VLoss2PhB\$8888888.state
Over Current - Phase C	DI	30	KCPLD1:DATAVALUE~ANN\$OverCur2PhC\$8888888.state
Permanent Fault - Phase C	DI	31	KCPLD1:DATAVALUE~ANN\$PermFlt2PhC\$8888888.state
Momentary Fault - Phase C	DI	32	KCPLD1:DATAVALUE~ANN\$MmtFlt2PhC\$8888888.state
Overhead Line Current Loss - Phase C	DI	33	KCPLD1:DATAVALUE~ANN\$OvhdCurLoss2PhC\$8888888.state

Horstmann: Fault Current Indicators and Receiver

Name	Point Type	DNP Point	ICCP Name
Loss of Voltage - Phase C	DI	34	KCPLD1:DATAVALUE~ANN\$VLoss2PhC\$8888888.state
Temporary Faults - Phase A	CTR	6	KCPLD1:DATAVALUE~CTR\$TempFlt2PhA\$8888888.value
Permanent Faults - Phase A	CTR	7	KCPLD1:DATAVALUE~CTR\$PermFlt2PhA\$8888888.value
Temporary Faults - Phase B	CTR	8	KCPLD1:DATAVALUE~CTR\$TempFlt2PhB\$8888888.value
Permanent Faults - Phase B	CTR	9	KCPLD1:DATAVALUE~CTR\$PermFlt2PhB\$8888888.value
Temporary Faults - Phase C	CTR	10	KCPLD1:DATAVALUE~CTR\$TempFlt2PhC\$8888888.value
Permanent Faults - Phase C	CTR	11	KCPLD1:DATAVALUE~CTR\$PermFlt2PhC\$8888888.value
Fault Current - Phase A	AI	29	KCPLD1:DATAVALUE~MET\$FltCur2PhA\$8888888.value
Fault Duration - Phase A	AI	30	KCPLD1:DATAVALUE~MET\$FltDur2PhA\$8888888.value
Last Known Good Current - Phase A	AI	31	KCPLD1:DATAVALUE~MET\$LKGCur2PhA\$8888888.value
Current - Average - Phase A	AI	32	KCPLD1:DATAVALUE~MET\$CurAvg2PhA\$8888888.value
Fault Current - Phase B	AI	38	KCPLD1:DATAVALUE~MET\$FltCur2PhB\$8888888.value
Fault Duration - Phase B	AI	39	KCPLD1:DATAVALUE~MET\$FltDur2PhB\$8888888.value
Last Known Good Current - Phase B	AI	40	KCPLD1:DATAVALUE~MET\$LKGCur2PhB\$8888888.value
Current - Average - Phase B	AI	41	KCPLD1:DATAVALUE~MET\$CurAvg2PhB\$8888888.value
Fault Current - Phase C	AI	47	KCPLD1:DATAVALUE~MET\$FltCur2PhC\$8888888.value
Fault Duration - Phase C	AI	48	KCPLD1:DATAVALUE~MET\$FltDur2PhC\$8888888.value

Horstmann: Fault Current Indicators and Receiver

Name	Point Type	DNP Point	ICCP Name
Last Known Good Current - Phase C	AI	49	KCPLD1:DATAVALUE~MET\$LKGCur2PhC\$8888888.value
Current - Average - Phase C	AI	50	KCPLD1:DATAVALUE~MET\$CurAvg2PhC\$8888888.value
Over Current - Phase A	DI	35	KCPLD1:DATAVALUE~ANN\$OverCur3PhA\$8888888.state
Permanent Fault - Phase A	DI	36	KCPLD1:DATAVALUE~ANN\$PermFIt3PhA\$8888888.state
Momentary Fault - Phase A	DI	37	KCPLD1:DATAVALUE~ANN\$MmtFIt3PhA\$8888888.state
Overhead Line Current Loss - Phase A	DI	38	KCPLD1:DATAVALUE~ANN\$OvhdCurLoss3PhA\$8888888.state
Loss of Voltage - Phase A	DI	39	KCPLD1:DATAVALUE~ANN\$VLoss3PhA\$8888888.state
Over Current - Phase B	DI	40	KCPLD1:DATAVALUE~ANN\$OverCur3PhB\$8888888.state
Permanent Fault - Phase B	DI	41	KCPLD1:DATAVALUE~ANN\$PermFIt3PhB\$8888888.state
Momentary Fault - Phase B	DI	42	KCPLD1:DATAVALUE~ANN\$MmtFIt3PhB\$8888888.state
Overhead Line Current Loss - Phase B	DI	43	KCPLD1:DATAVALUE~ANN\$OvhdCurLoss3PhB\$8888888.state
Loss of Voltage - Phase B	DI	44	KCPLD1:DATAVALUE~ANN\$VLoss3PhB\$8888888.state
Over Current - Phase C	DI	45	KCPLD1:DATAVALUE~ANN\$OverCur3PhC\$8888888.state
Permanent Fault - Phase C	DI	46	KCPLD1:DATAVALUE~ANN\$PermFIt3PhC\$8888888.state
Momentary Fault - Phase C	DI	47	KCPLD1:DATAVALUE~ANN\$MmtFIt3PhC\$8888888.state
Overhead Line Current Loss - Phase C	DI	48	KCPLD1:DATAVALUE~ANN\$OvhdCurLoss3PhC\$8888888.state
Loss of Voltage - Phase C	DI	49	KCPLD1:DATAVALUE~ANN\$VLoss3PhC\$8888888.state

Horstmann: Fault Current Indicators and Receiver

Name	Point Type	DNP Point	ICCP Name
Temporary Faults - Phase A	CTR	12	KCPLD1:DATAVALUE~CTR\$TempFlt3PhA\$8888888.value
Permanent Faults - Phase A	CTR	13	KCPLD1:DATAVALUE~CTR\$PermFlt3PhA\$8888888.value
Temporary Faults - Phase B	CTR	14	KCPLD1:DATAVALUE~CTR\$TempFlt3PhB\$8888888.value
Permanent Faults - Phase B	CTR	15	KCPLD1:DATAVALUE~CTR\$PermFlt3PhB\$8888888.value
Temporary Faults - Phase C	CTR	16	KCPLD1:DATAVALUE~CTR\$TempFlt3PhC\$8888888.value
Permanent Faults - Phase C	CTR	17	KCPLD1:DATAVALUE~CTR\$PermFlt3PhC\$8888888.value
Fault Current - Phase A	AI	56	KCPLD1:DATAVALUE~MET\$FltCur3PhA\$8888888.value
Fault Duration - Phase A	AI	57	KCPLD1:DATAVALUE~MET\$FltDur3PhA\$8888888.value
Last Known Good Current - Phase A	AI	58	KCPLD1:DATAVALUE~MET\$LKGCur3PhA\$8888888.value
Current - Average - Phase A	AI	59	KCPLD1:DATAVALUE~MET\$CurAvg3PhA\$8888888.value
Fault Current - Phase B	AI	65	KCPLD1:DATAVALUE~MET\$FltCur3PhB\$8888888.value
Fault Duration - Phase B	AI	66	KCPLD1:DATAVALUE~MET\$FltDur3PhB\$8888888.value
Last Known Good Current - Phase B	AI	67	KCPLD1:DATAVALUE~MET\$LKGCur3PhB\$8888888.value
Current - Average - Phase B	AI	68	KCPLD1:DATAVALUE~MET\$CurAvg3PhB\$8888888.value
Fault Current - Phase C	AI	74	KCPLD1:DATAVALUE~MET\$FltCur3PhC\$8888888.value
Fault Duration - Phase C	AI	75	KCPLD1:DATAVALUE~MET\$FltDur3PhC\$8888888.value
Last Known Good Current - Phase C	AI	76	KCPLD1:DATAVALUE~MET\$LKGCur3PhC\$8888888.value

Horstmann: Fault Current Indicators and Receiver

Name	Point Type	DNP Point	ICCP Name
Current - Average - Phase C	AI	77	KCPLD1:DATAVALUE~MET\$CurAvg3PhC\$8888888.value
Over Current - Phase A	DI	50	KCPLD1:DATAVALUE~ANN\$OverCur4PhA\$8888888.state
Permanent Fault - Phase A	DI	51	KCPLD1:DATAVALUE~ANN\$PermFlt4PhA\$8888888.state
Momentary Fault - Phase A	DI	52	KCPLD1:DATAVALUE~ANN\$MmtFlt4PhA\$8888888.state
Overhead Line Current Loss - Phase A	DI	53	KCPLD1:DATAVALUE~ANN\$OvhdCurLoss4PhA\$8888888.state
Loss of Voltage - Phase A	DI	54	KCPLD1:DATAVALUE~ANN\$VLoss4PhA\$8888888.state
Over Current - Phase B	DI	55	KCPLD1:DATAVALUE~ANN\$OverCur4PhB\$8888888.state
Permanent Fault - Phase B	DI	56	KCPLD1:DATAVALUE~ANN\$PermFlt4PhB\$8888888.state
Momentary Fault - Phase B	DI	57	KCPLD1:DATAVALUE~ANN\$MmtFlt4PhB\$8888888.state
Overhead Line Current Loss - Phase B	DI	58	KCPLD1:DATAVALUE~ANN\$OvhdCurLoss4PhB\$8888888.state
Loss of Voltage - Phase B	DI	59	KCPLD1:DATAVALUE~ANN\$VLoss4PhB\$8888888.state
Over Current - Phase C	DI	60	KCPLD1:DATAVALUE~ANN\$OverCur4PhC\$8888888.state
Permanent Fault - Phase C	DI	61	KCPLD1:DATAVALUE~ANN\$PermFlt4PhC\$8888888.state
Momentary Fault - Phase C	DI	62	KCPLD1:DATAVALUE~ANN\$MmtFlt4PhC\$8888888.state
Overhead Line Current Loss - Phase C	DI	63	KCPLD1:DATAVALUE~ANN\$OvhdCurLoss4PhC\$8888888.state
Loss of Voltage - Phase C	DI	64	KCPLD1:DATAVALUE~ANN\$VLoss4PhC\$8888888.state
Temporary Faults - Phase A	CTR	18	KCPLD1:DATAVALUE~CTR\$TempFlt4PhA\$8888888.value
Permanent Faults - Phase A	CTR	19	KCPLD1:DATAVALUE~CTR\$PermFlt4PhA\$8888888.value
Temporary Faults - Phase B	CTR	20	KCPLD1:DATAVALUE~CTR\$TempFlt4PhB\$8888888.value
Permanent Faults - Phase B	CTR	21	KCPLD1:DATAVALUE~CTR\$PermFlt4PhB\$8888888.value
Temporary Faults - Phase C	CTR	22	KCPLD1:DATAVALUE~CTR\$TempFlt4PhC\$8888888.value
Permanent Faults - Phase C	CTR	23	KCPLD1:DATAVALUE~CTR\$PermFlt4PhC\$8888888.value
Fault Current - Phase A	AI	83	KCPLD1:DATAVALUE~MET\$FltCur4PhA\$8888888.value
Fault Duration - Phase A	AI	84	KCPLD1:DATAVALUE~MET\$FltDur4PhA\$8888888.value
Last Known Good Current - Phase A	AI	85	KCPLD1:DATAVALUE~MET\$LKGCur4PhA\$8888888.value
Current - Average - Phase A	AI	86	KCPLD1:DATAVALUE~MET\$CurAvg4PhA\$8888888.value
Fault Current - Phase B	AI	92	KCPLD1:DATAVALUE~MET\$FltCur4PhB\$8888888.value
Fault Duration - Phase B	AI	93	KCPLD1:DATAVALUE~MET\$FltDur4PhB\$8888888.value
Last Known Good Current - Phase B	AI	94	KCPLD1:DATAVALUE~MET\$LKGCur4PhB\$8888888.value
Current - Average - Phase B	AI	95	KCPLD1:DATAVALUE~MET\$CurAvg4PhB\$8888888.value
Fault Current - Phase C	AI	101	KCPLD1:DATAVALUE~MET\$FltCur4PhC\$8888888.value
Fault Duration - Phase C	AI	102	KCPLD1:DATAVALUE~MET\$FltDur4PhC\$8888888.value
Last Known Good Current - Phase C	AI	103	KCPLD1:DATAVALUE~MET\$LKGCur4PhC\$8888888.value
Current - Average - Phase C	AI	104	KCPLD1:DATAVALUE~MET\$CurAvg4PhC\$8888888.value

F.2.5 Recloser Controller

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Name	Point Type	DNP Point	ICCP Name
Enabled	DI	0	KCPLD1:DATAVALUE~ANN\$Enbl\$4444444.state
Device Status	DI	1	KCPLD1:DATAVALUE~ANN\$DevSts\$4444444.state
Loss of Potential	DI	2	KCPLD1:DATAVALUE~ANN\$PotentialLoss\$4444444.state
Fault - Phase C	DI	3	KCPLD1:DATAVALUE~ANN\$FltPhC\$4444444.state
Fault - Phase B	DI	4	KCPLD1:DATAVALUE~ANN\$FltPhB\$4444444.state
Fault - Phase A	DI	5	KCPLD1:DATAVALUE~ANN\$FltPhA\$4444444.state
Sync Check Elements	DI	6	KCPLD1:DATAVALUE~ANN\$SyncChkElem\$4444444.state
Cabinet Door	DI	7	KCPLD1:DATAVALUE~ANN\$CabDoor\$4444444.state
SOCO - Ground Overcurrent Status	DI	8	KCPLD1:DATAVALUE~ANN\$GndEnbl\$4444444.state
79CO - Reclosing Status	DI	9	KCPLD1:DATAVALUE~ANN\$RclsEnbl\$4444444.state
Local - Remote	DI	10	KCPLD1:DATAVALUE~ANN\$LocRem\$4444444.state
Fast Curves Status	DI	11	KCPLD1:DATAVALUE~ANN\$FstCrv\$4444444.state
Push Buttons Locked	DI	12	KCPLD1:DATAVALUE~ANN\$PshButLock\$4444444.state
Hot Line Tag Status	DI	13	KCPLD1:DATAVALUE~ANN\$HotLnTag\$4444444.state
Aux 1 Status	DI	14	KCPLD1:DATAVALUE~ANN\$Aux1\$4444444.state
Aux 2 Status	DI	15	KCPLD1:DATAVALUE~ANN\$Aux2\$4444444.state
Aux 3 Status	DI	16	KCPLD1:DATAVALUE~ANN\$Aux3\$4444444.state
Battery Failure	DI	17	KCPLD1:DATAVALUE~ANN\$BattFail\$4444444.state
External Power	DI	18	KCPLD1:DATAVALUE~ANN\$ExtPwr\$4444444.state
Lockout	DI	19	KCPLD1:DATAVALUE~ANN\$RclsLO\$4444444.state
Current Direction	DI	20	KCPLD1:DATAVALUE~ANN\$CurDir\$4444444.state
Contact Wear - 3 Phase	DI	21	KCPLD1:DATAVALUE~ANN\$BCW3Ph\$4444444.state
Clock Present	DI	22	KCPLD1:DATAVALUE~ANN\$ClkPres\$4444444.state
Hardware Alarm	DI	23	KCPLD1:DATAVALUE~ANN\$HWAlm\$4444444.state
Software Alarm	DI	24	KCPLD1:DATAVALUE~ANN\$SWAlm\$4444444.state
Aux 1	DO	25	KCPLD1:DeviceOperate~CON\$Aux1\$4444444
Aux 2	DO	26	KCPLD1:DeviceOperate~CON\$Aux2\$4444444
Aux 3	DO	27	KCPLD1:DeviceOperate~CON\$Aux3\$4444444
SOCO - Ground Overcurrent	DO	29	KCPLD1:DeviceOperate~CON\$GndEnbl\$4444444
79CO - Reclosing	DO	30	KCPLD1:DeviceOperate~CON\$RclsEnbl\$4444444
Fast Curves	DO	31	KCPLD1:DeviceOperate~CON\$FstCrv\$4444444
Hot Line Tag	DO	32	KCPLD1:DeviceOperate~CON\$HotLnTag\$4444444
Device Operate	DO	33	KCPLD1:DeviceOperate~CON\$DevOp\$4444444
Reset Front Panel Targets	DO	34	KCPLD1:DeviceOperate~CON\$RstFrntPnlTgt\$4444444
Active Settings Group	CTR	0	KCPLD1:DATAVALUE~CTR\$ActSetGrp\$4444444.value

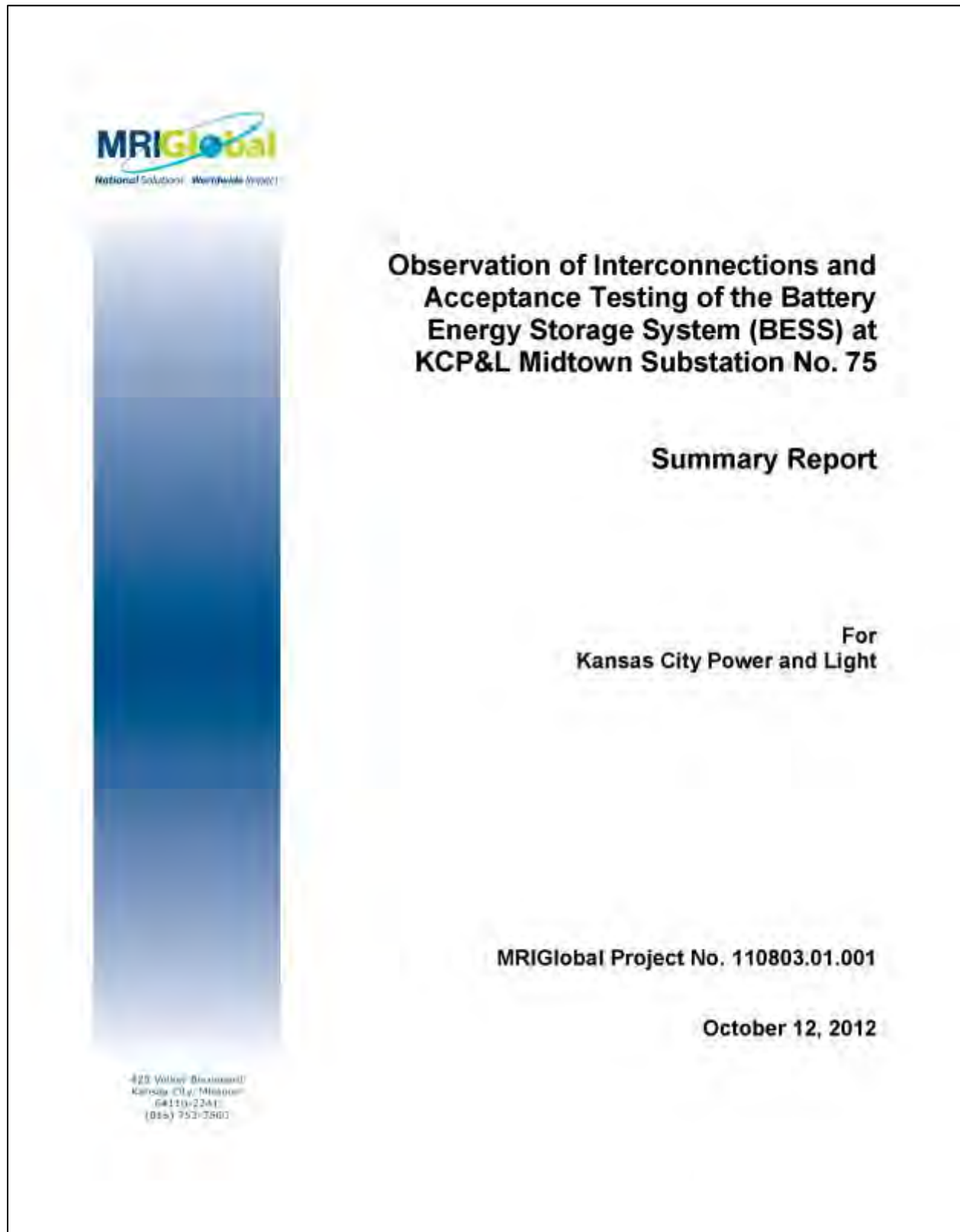
SEL 651R: Recloser Controller

Name	Point Type	DNP Point	ICCP Name
Internal Breaker Trips - Phase A	CTR	1	KCPLD1:DATAVALUE~CTR\$IntBrkTripPhA\$4444444.value
Internal Breaker Trips - Phase B	CTR	2	KCPLD1:DATAVALUE~CTR\$IntBrkTripPhB\$4444444.value
Internal Breaker Trips - Phase C	CTR	3	KCPLD1:DATAVALUE~CTR\$IntBrkTripPhC\$4444444.value
External Breaker Trips - Phase A	CTR	4	KCPLD1:DATAVALUE~CTR\$ExtBrkTripPhA\$4444444.value
External Breaker Trips - Phase B	CTR	5	KCPLD1:DATAVALUE~CTR\$ExtBrkTripPhB\$4444444.value
External Breaker Trips - Phase C	CTR	6	KCPLD1:DATAVALUE~CTR\$ExtBrkTripPhC\$4444444.value
Current - Phase A	AI	0	KCPLD1:DATAVALUE~MET\$CurPhA\$4444444.value
Current - Phase B	AI	1	KCPLD1:DATAVALUE~MET\$CurPhB\$4444444.value
Current - Phase C	AI	2	KCPLD1:DATAVALUE~MET\$CurPhC\$4444444.value
Current - Neutral	AI	3	KCPLD1:DATAVALUE~MET\$CurNeu\$4444444.value
Current - Ground	AI	4	KCPLD1:DATAVALUE~MET\$CurGnd\$4444444.value
Voltage - Phase A - Y (kV)	AI	5	KCPLD1:DATAVALUE~MET\$VPhAY\$4444444.value
Voltage - Phase B - Y (kV)	AI	6	KCPLD1:DATAVALUE~MET\$VPhBY\$4444444.value
Voltage - Phase C - Y (kV)	AI	7	KCPLD1:DATAVALUE~MET\$VPhCY\$4444444.value
Voltage - Phase A - Z (kV)	AI	8	KCPLD1:DATAVALUE~MET\$VPhAZ\$4444444.value
Voltage - Phase B - Z (kV)	AI	9	KCPLD1:DATAVALUE~MET\$VPhBZ\$4444444.value
Voltage - Phase C - Z (kV)	AI	10	KCPLD1:DATAVALUE~MET\$VPhCZ\$4444444.value
Real Power - Phase A (kW)	AI	11	KCPLD1:DATAVALUE~MET\$KWPhA\$4444444.value
Real Power - Phase B (kW)	AI	12	KCPLD1:DATAVALUE~MET\$KWPhB\$4444444.value
Real Power - Phase C (kW)	AI	13	KCPLD1:DATAVALUE~MET\$KWPhC\$4444444.value
Real Power - 3 Phase (kW)	AI	14	KCPLD1:DATAVALUE~MET\$KW3Ph\$4444444.value
Reactive Power - Phase A (kVAR)	AI	15	KCPLD1:DATAVALUE~MET\$KVARPhA\$4444444.value
Reactive Power - Phase B (kVAR)	AI	16	KCPLD1:DATAVALUE~MET\$KVARPhB\$4444444.value
Reactive Power - Phase C (kVAR)	AI	17	KCPLD1:DATAVALUE~MET\$KVARPhC\$4444444.value
Reactive Power - 3 Phase (kVAR)	AI	18	KCPLD1:DATAVALUE~MET\$KVAR3Ph\$4444444.value
Frequency	AI	19	KCPLD1:DATAVALUE~MET\$Freq\$4444444.value
Contact Wear - Phase A	AI	20	KCPLD1:DATAVALUE~MET\$BCWPhA\$4444444.value
Contact Wear - Phase B	AI	21	KCPLD1:DATAVALUE~MET\$BCWPhB\$4444444.value
Contact Wear - Phase C	AI	22	KCPLD1:DATAVALUE~MET\$BCWPhC\$4444444.value
Fault Type	AI	23	KCPLD1:DATAVALUE~MET\$FltType\$4444444.value
Fault Recloser Shot Counter	AI	24	KCPLD1:DATAVALUE~MET\$FltRclsShotCnt\$4444444.value
Fault Time	AI	25	KCPLD1:DATAVALUE~MET\$FltTm\$4444444.value
Fault Current - Phase A	AI	26	KCPLD1:DATAVALUE~MET\$FltCurPhA\$4444444.value
Fault Current - Phase B	AI	27	KCPLD1:DATAVALUE~MET\$FltCurPhB\$4444444.value
Fault Current - Phase C	AI	28	KCPLD1:DATAVALUE~MET\$FltCurPhC\$4444444.value

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Name	Point Type	DNP Point	ICCP Name
Fault Current - Ground	AI	29	KCPLD1:DATAVALUE~MET\$FltCurGnd\$4444444.value
Apparent Power - Phase A (kVA)	AI	30	KCPLD1:DATAVALUE~MET\$KVAPhA\$4444444.value
Apparent Power - Phase B (kVA)	AI	31	KCPLD1:DATAVALUE~MET\$KVAPhB\$4444444.value
Apparent Power - Phase C (kVA)	AI	32	KCPLD1:DATAVALUE~MET\$KVAPhC\$4444444.value
Apparent Power - 3 Phase (kVA)	AI	33	KCPLD1:DATAVALUE~MET\$KVA3Ph\$4444444.value
THD - Current - Phase A	AI	34	KCPLD1:DATAVALUE~MET\$THDCurPhA\$4444444.value
THD - Current - Phase B	AI	35	KCPLD1:DATAVALUE~MET\$THDCurPhB\$4444444.value
THD - Current - Phase C	AI	36	KCPLD1:DATAVALUE~MET\$THDCurPhC\$4444444.value
THD - Current - Neutral	AI	37	KCPLD1:DATAVALUE~MET\$THDCurNeu\$4444444.value
THD - Voltage - Phase A - Y	AI	38	KCPLD1:DATAVALUE~MET\$THDVPhAY\$4444444.value
THD - Voltage - Phase B - Y	AI	39	KCPLD1:DATAVALUE~MET\$THDVPhBY\$4444444.value
THD - Voltage - Phase C - Y	AI	40	KCPLD1:DATAVALUE~MET\$THDVPhCY\$4444444.value
THD - Voltage - Phase A - Z	AI	41	KCPLD1:DATAVALUE~MET\$THDVPhAZ\$4444444.value
THD - Voltage - Phase B - Z	AI	42	KCPLD1:DATAVALUE~MET\$THDVPhBZ\$4444444.value
THD - Voltage - Phase C - Z	AI	43	KCPLD1:DATAVALUE~MET\$THDVPhCZ\$4444444.value
Battery Voltage	AI	44	KCPLD1:DATAVALUE~MET\$BattV\$4444444.value
Battery Current	AI	45	KCPLD1:DATAVALUE~MET\$BattCur\$4444444.value
Set Active Settings Group	AO	0	KCPLD1:DeviceOperate~CO\$ActSetGrp\$4444444

Appendix G BESS Acceptance Test Report



**Observation of Interconnections and
Acceptance Testing of the Battery
Energy Storage System (BESS) at
KCP&L Midtown Substation No. 75**

Summary Report

For
Kansas City Power and Light
1200 Main
Kansas City, Missouri 64141

MRIGlobal Project No. 110803.01.001

October 12, 2012

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Attachment

Attachment A—Statement of Work

Section 1. Introduction

MRIGlobal was contracted to provide technical advisory support to Kansas City Power and Light (KCP&L) throughout acceptance testing of the Battery Energy Storage System (BESS) at KCP&L Midtown Substation No. 75 in Kansas City, Missouri (Attachment A provides the Statement of Work for this contract). The BESS testing was conducted from mid-May through the end of June 2012, and additional testing may be conducted during fall of 2012. This report fulfills the requirements of Item 1d in the Statement of Work, which requires MRIGlobal to provide a letter summary of observations, review of battery performance, and any other special observations or recommendations regarding potential future use of the battery. In case additional testing is done in the future, MRIGlobal will draft an addendum to this report.

Major system components included (1) BESS, provided by Exergonix; and (2) a Storage Management System (SMS), provided by S&C. The SMS is a two-way inverter which acts as the controller and integrator of the BESS to the overall KCP&L electrical grid.

Initial testing began on May 17 and continued through May 23, at which point a failure in improperly rated wiring was installed in a critical area which caused an arc that resulted in electrical damage forcing a delay to testing activities. On June 28, testing resumed and all needed technical observations were completed.

Section 2. General Observations

In preparation for the testing, MRIGlobal reviewed the following documents:

- “*Acceptance Testing of the BESS at Midtown Substation*,” authored by S&C Equipment
- “*Grid Connected Battery System Functional Specification*,” authored by KCP&L
- “*Exergonix Energy Storage Systems*,” authored by Exergonix

The first two documents were supplied by KCP&L in support of the Statement of Work while Exergonix supplied the third document directly to MRIGlobal. These documents were well written and covered the points needed to verify that the equipment being supplied would meet the needs of the Smart Grid Design.

Based on the information in these documents, MRIGlobal assumed that every system element would be in place, checked, and ready for testing as a complete system prior to the start of Phase 1 testing. However, in actual practice at the site, only a partial test of separate components was conducted by staff who may not have been well-versed enough to actually provide interconnection of the BESS to an electric utility distribution system. Staff performing the BESS integration and testing were professional and completed assignments successfully, but they appeared to lack the detailed documentation necessary and were only available intermittently to support these efforts. For future work we recommend that KCP&L dedicate a representative mix of key personnel to this project with no conflicting assignments. See Section 4 for additional specific recommendations.

During the first phase of testing (conducted in May), MRIGlobal observed that although the contractor, Exergonix, was assigned responsibility for the testing in the “*BESS Commissioning Report*” by KCP&L (March 27, 2012), they were never onsite except for a few brief visits to check in. Instead, Exergonix relied on Myungshin, a subcontractor, and S&C to handle all the site work. Additional onsite staffing on their part may have provided better support to KCP&L, Myungshin, and S&C to resolve the technical and contractual issues that arose throughout testing. Myungshin and S&C worked together at the site on interconnections and software issues but significant delays were caused by miscommunications and an inability for the onsite personnel from Myungshin to provide S&C the information needed to finalize software parameters critical to effective communications between the SMS and the BESS control systems.

Section 3.

Specific Technical and Organizational Observations

MRIGlobal had numerous technical and organizational observations during the first and second phases of testing, which are described in the following subsections.

3.1 Technical Observations During the Phase 1 Testing (May 18 to May 23)

Upon arrival at the site, MRIGlobal noted that some one-line diagrams and additional limited schematics were available; however, the team needed more detailed information to properly wire up the potential transformers, current transformers, and S&C controls. There were no wiring diagrams to show what S&C required for connections. In addition, no kilowatt hour meter was installed initially to monitor the input/output of the BESS. In spite of these issues, the KCP&L relay crew was proficient and accepting of MRIGlobal oversight which resulted in a successful connection.

Subsequently, based on MRIGlobal's recommendations, a digital grid kilowatt hour meter was installed to meter and record the kW, kVAR, kVA, volts, amps, and harmonics of the energy flowing in and out of the BESS system. The installed meter was a grid-type meter based on PT/CT metrology instead of a standard kWh meter used at an industrial service drop as originally planned. Although there are protective measures within the SMS and the BESS to warn of failure of a component, this type of meter will provide the added measure of early warning of a component failure. However, as of testing completion, the meter was not working correctly after installation and this was mentioned to the KCP&L System Protection staff.

In response to observed electrical interference, Exergonix arranged for a thorough check-out of the BESS to determine the root cause of substantial interference in the electronics. After this checkout, Myungshin personnel installed a hospital-grade isolation transformer which did not correct the interference. This did rule out the control power source, 480-V feed from the site transformer, as the cause of the problem. It is quite probable the cause of the problem is from within the BESS. However, technical diagrams of the internal components were not provided and, as of testing completion, the root cause of the interference was not determined. Potential causes include low-voltage wiring, Ethernet cables co-located with high-voltage/high-current cables, or twisted pair shielded cable (if used) that may be grounded at both ends or not grounded at all. It is quite probable the source of the problem is within the BESS, given that the first BESS unit produced by the vendor (installed at another utility) is having similar problems with noise/interference.

From May 18 through May 22, 2012, various system checks were performed and system parameters were adjusted in order to get all components communicating properly. Successful testing of the BESS was completed, including a full charge (above 95% depth of charge with a full recharge taking approximately 59 minutes), and a full discharge (below 20% depth of charge, taking approximately 49 minutes). Verbal guidance for testing by Exergonix and its

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subcontractors advised against discharging below 20% depth of charge. A full range of VAR (volt-ampere reactive) control, both leading and lagging, was successfully completed by the SMS/BESS system.

On May 23, training of SMS and BESS for KCP&L site crew was completed prior to attempting another full charge of the BESS. During charge, the SMS display showed that one of the BESS's battery banks was not charging properly, at which point it was discovered that the insulation rating on a cable feeding a newly added DC-to-DC inverter, necessary for the BESS to supply its own control power, was inadequate. The DC-to-DC inverter arrived and was installed prior to this charge cycle. The lack of insulation and proximity caused a DC arc across both banks of 800-V breakers and ignited a minor electrical fire that subsequently halted testing until June 28 (start of Phase 2), after repairs were completed. It is fortunate that there were no personnel in proximity to the breakers when the arc occurred. This event underscores the importance of conducting a detailed review of any electrical modifications to the BESS that are conducted in the field to ensure that design and components are adequate for their intended purpose. In response to the arc, MRIGlobal recommended the following, which were corrected prior to Phase 2 testing:

- a. Clean up the DC breaker junction boxes of arc products.
- b. Clean up the DC cables and replace shrink tubing on the DC cables.
- c. Replace the DC terminal blocks just below the DC breakers.
- d. Replace all the small conductors in the junction boxes.
- e. Replace the capacitors in the junction boxes.
- f. Replace the DC current sensors in the junction boxes.
- g. Rerun all the tests that were done. The DC arcing might have damaged the electronic components in both the BESS and the SMS.
- h. Replace 800-V DC-to-DC converter and install cable rated for 1,200 V and use 1,200 V-rated fuses to connect the 800-V DC-to-DC converter to the 800-V buss.

Overall, S&C has a very good unit for controlling the BESS. However, there are some issues with the SMS that KCP&L and S&C should be aware of:

1. A pure third harmonic current was measured on the 13.2-kV current transformers of 3.14 amps primary. It is not obvious where the third harmonic is coming from. It is possibly from the SMS or the BESS.
2. Why is the 480-V potential transformer's secondary wired into the main board as delta? If the 480-V PTs are wired phase-to-ground and the secondary into the main computer board as delta, that introduces a 30-degree shift into the sensing and will not give correct matching to the step down 13.2-kV/480-V transformer. Is this phase shift accounted for in the control software? The voltage sensing was rewired to regulate on the 13.2-kV side and the delta connection on the main board was connected wye. When the 13.2-kV PTs out on the pole are installed and wired, the main computer board may need to be rewired to wye. MRIGlobal recommends having the S&C territory manager ask the factory to

explain why the delta connections are used and why S&C wants to regulate on the 480 buss in the SMS.

3.2 Technical Observations During the Phase 2 Testing (June 28)

Charging and discharging of the BESS began on June 28, at approximately 10:20 a.m. The weather was hot, approximately 100°F, which was beneficial to measure the elevated temperature response of the BESS as the internal battery cells were subjected to more severe cycling than normal operation and under high ambient temperatures. As anticipated, the cell temperature ran a little higher than the previous commissioning tests, up to 47°C.

The first full discharge that was attempted resulted in a trip of the system after about 16 minutes into the test. Apparently, the SEL (Schweitzer Engineering Laboratories) relay on the 13-kV feed measured a three-phase fault of about 150 amps and sent an instantaneous trip (Reference Code No. 50) to the SMS "E-STOP." This in turn tripped the three breakers in the SMS and the two DC breakers in the BESS. The fault data was downloaded from the SEL relay showing that the bank of three-phase SCR's *all fired at the same time* creating single phase instead of three-phase current. The S&C technician postulated that the Myungshin technicians may have caused a "lockup" of the computer chip in the SMS control system when they repaired the BESS by failing to disconnect them from the SMS during the repair. The S&C technician requested that S&C send a new SMS board which still had not arrived by completion of testing. During one-and-a-half subsequent cycles of charge and discharge the problem was not observed again. MRIGlobal cannot confirm that the Myungshin technicians caused the breakers to trip, but this seems like a reasonable hypothesis.

Some other problems that were found and corrected were as follows:

1. A warning signal from the BESS is interpreted as an alarm as the SMS was not programed to handle both warning and alarm messages. Therefore, warning signals would shut down the SMS choppers prematurely. As a temporary fix, the warning thresholds within the BESS control system were raised to be equal with the alarm/trip thresholds.
2. The failed cable from the 800-V DC breakers to the 800 DC-to-DC converter was replaced by higher-rated cable, 600 V versus the previous 300 V, and as an added precaution, a single conductor pair was used for each feed, positive and negative, to ensure adequate insulation and protection from arcing. The single conductor in each phase including the cable jacket should give the phase a 1,200-V capacity. Theoretically, the phase-to-ground voltage at the highest voltage should only be 395 and 456 V, resulting in some margin of safety going forward.

3.3 Organizational Observations

The Burns & McDonnell Project Manager took charge of holding the site meetings and coordination of the various groups plus writing the daily reports. The KCP&L crews gave great

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support and helped in every way they could. During our presence at the site, MRIGlobal did not observe Exergonix providing any sort of site support and there were no Exergonix representatives who took part in the testing or commissioning of the units during either Phase 1 or Phase 2 of testing.

Section 4.

Summary of Recommendations

Based on observations from Phase 1 and Phase 2 testing events, MRIGlobal offers the following technical and organizational recommendations for KCP&L's consideration for continued testing of the BESS system or similar projects in the future.

4.1 Technical Recommendations

1. Document the detailed specifications for the desired and the current system(s) as was done on this project.
2. Acquire or establish comprehensive single line technical diagrams and connections diagrams from each equipment supplier.
 - a. S&C Electric one-line drawings need to be updated to "*as built*."
 - b. S&C Electric SMS control system one-line display also needs to be updated to "*as built*."
3. After acquiring one-line technical diagrams, prepare a complete one line diagram of the entire system and detailed interconnection prints.
4. Develop the detailed testing specifications and procedures, for the complete system, in advance of testing activities.
5. In order to provide a more complete consultation, MRIGlobal will need the meter software to read and/or interpret the data on the installed kilowatt meter. It is recommended that the following data be made available to MRIGlobal to evaluate the performance of the BESS:
 - a. In/Out kWh
 - b. In/Out kVAR
 - c. In/Out kW demand 15 or 30 minute basis
 - d. Power Factor
 - e. Harmonics to the 32nd

4.2 Organizational Recommendations

MRIGlobal has the following recommendations for KCP&L to enhance the organizational and project coordination aspects of such a project in the future.

1. To the extent possible, arrange for a project team that is 100% dedicated to the project and ensure that they have the support from other departments as necessary so that the organization as a whole has pride of ownership in the installed system.

2. Assign a project manager that can dedicate 100% of their time to the project. Select the project manager or their assistant with extensive experience in electrical distribution systems, digital relay systems, metering systems, SCADA software, and demonstrated team leading skills.

Attachment

MPGridz-RTSD-110693-01-001_F

Attachment A

Statement of Work

STANDALONE STATEMENT OF WORK FOR THE PURCHASE OF CONSULTING SERVICES

THIS STANDALONE STATEMENT OF WORK is dated May 16, 2012, by and between Great Plains Energy Services Incorporated ("GPES") and MRIGlobal ("Supplier").

A. Scope of Consulting Services

GPES's Battery Energy Storage System (BESS) will be undergoing site acceptance testing during installation and commissioning procedures at the GPES Midtown Substation for GPES's Smart Grid demonstration project. Supplier will provide oversight in the development of the acceptance testing protocols in the following areas:

1. Provide technical advisory support to GPES during the development and oversight of acceptance testing protocols.
8. *Perform or simulate all modes listed in the BESS specifications document.*
9. *Perform a full discharge cycle followed by a full charge cycle. This test shall demonstrate that the BESS's capabilities, efficiencies, response, and features are as proposed by the battery provider.*
10. *Check total harmonic distortion to verify that the BESS outputs clean power at a variety of power output levels.*

Specifically, technical advisory support will include the following tasks:

- a. Provide technical review of acceptance testing protocols and documentation developed by the battery provider and modify the protocol and supporting documentation as necessary for application to the GPES Smart Grid system.
- b. Provide onsite technical advisory support and oversight during actual acceptance testing activities in Kansas City in the mid-May to early June 2012 timeframe (estimated to require onsite presence at the project site not exceeding 5 days). The onsite presence will not include performing any tests or install/operate any test equipment.
- c. Review technical reports prepared by the battery provider for documentation of the acceptance testing results.
- d. Prepare a letter report not exceeding 5 pages in length summarizing observations during the tests conducted, review of the battery performance results obtained during the installation and commissioning process, and any special observations and recommendations regarding the potential future use of the battery.

B. Project Managers

The Project Managers for the Consulting Services related to this Statement of Work are as follows:

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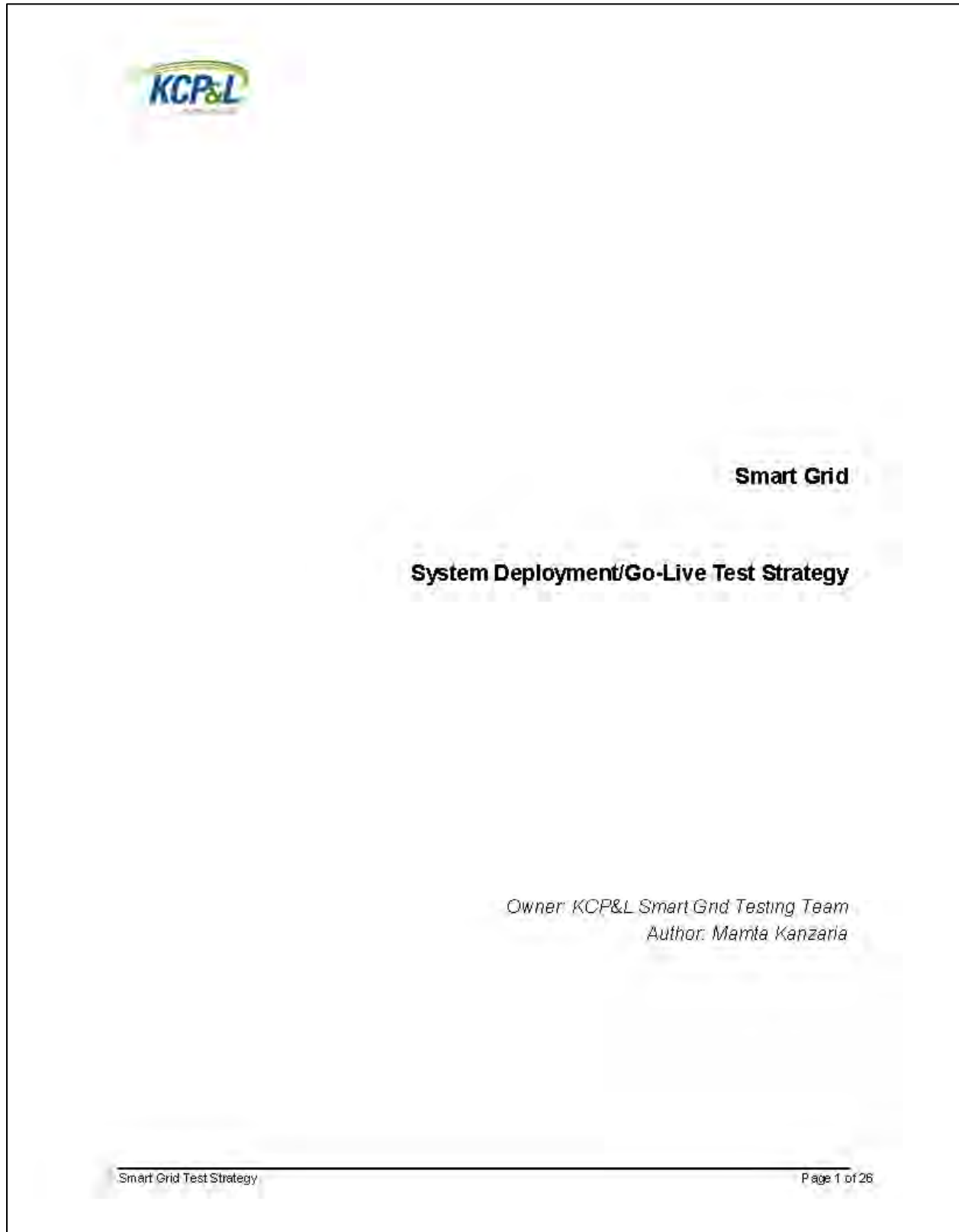
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Appendix H System Deployment/Go-Live Test Strategy





Document History

Revision History

Revision Number	Revision Date	Summary of Changes	Author
0.1	January 5, 2012	Initial Draft	M. Kanzaria
0.2	January 12, 2012	Revised draft	M. Kanzaria
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Approvals

This document requires following approvals.

Name	Title	Date
Ed Hedges	SmartGrid Senior SG SME	



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1.0 Project Introduction

This document represents the Testing Strategy for the Kansas City Power & Light Company (KCP&L) SmartGrid Demonstration (Demonstration Project). The KCP&L SmartGrid Demonstration Project is classified as a Regional Demonstration. For the Demonstration Project, KCP&L intends to deploy an end-to-end Smart Grid that will include advanced renewable generation, distributed energy storage resources, leading edge substation and distribution automation and control, energy management interfaces, and innovative end-use devices. The Project will focus on the area served by KCP&L's Midtown Substation, involving approximately 14,000 commercial and residential customers across twelve circuits and encompassing five square miles. This Project will be accomplished in cooperation with the Green Impact Zone of Missouri which is addressing transportation and urban revitalization in the same area through grants from the U.S. Department of Transportation and other sources.

The KCP&L SmartGrid Demonstration intends to:

- Create a complete, end-to-end Smart Grid – from smart generation to smart end-use – that will deliver improved operational performance, electricity reliability, and customer service focused on a major substation in an urban location.
- Apply new technologies, applications, protocols, communications, and business models that will be evaluated, demonstrated, and refined to achieve improved operations, increased energy efficiency, reduced energy delivery costs, and improved environmental performance.
- Demonstrate a best-in-class approach to technology integration, application development, and partnership collaboration, allowing KCP&L to advance the progression of complete smart grid solutions, employing interoperability standards, rather than single, packaged applications.
- Provide the critical energy infrastructure required to support a targeted urban revitalization effort—Kansas City's Green Impact Zone.

The Demonstration Project will introduce new technologies in the substation and the distribution network as well as advanced renewable supply resources such as large-scale energy storage to improve electricity delivery and offset peak electrical demand. Also, in conjunction with smart meters, end-users will be provided historical and actual real-time usage information, web-based energy management tools, and innovative end-use devices to allow them to optimize energy consumption.

There will be 6 project vendor partners teams involved in this effort:

Project Component	Partner
SmartSubstation, Distribution Management System (DMS), ADA First Responder, Meter Data Management (MDM)	Siemens Energy, Inc.
Distributed Energy Resource Management System (DERM)	Open Access Technology, Inc. (OATI)
Automated Metering Infrastructure (AMI)	Landis+Gyr AG
Home Energy Management & Devices	Tendril, Inc.
Grid Connected Battery Storage IED	Exergonix, Inc.
Technical Project Assistance	EPRI



1.1 Document Identification

This test strategy document is aimed at detailing the testing approach to support The KCP&L SmartGrid Demonstration Project. This document is a “living” document and will continuously evolve.

The integration of testing into the overall project and/or operational life cycle is a critical aspect for any real-time operational organization. The planning, managing, and execution of testing begins with efforts to define & refine the integration of it into the normal project activities.

It begins with proactively engaging a testing team (testing team being either as part of the IT organization or as defined for a given project) as early as possible allows for testing activities/planning to begin when information is first readily available. Any type of early participation from a testing team can increase not just the quality of the product/solution but reduce the number of defects/issues that can normally occur when testing is fully engaged). It is aimed at establishing a common understanding between all parties. This document serves as a means of communicating the overall testing approach in order to:

- Gain agreement and enable a coordinated effort among all stakeholders on the overall testing approach
- Demonstrate to management and other stakeholders that the approach is sound and achievable
- Define how the overall appropriate testing principles and practices will be applied in order to mitigate the project risks, manage the testing risks, and identify any exposures
- Provide a common approach and a common terminology to use for testing across the project
- Serves a foundation for future efforts, specifically test planning



2.0 Types of Testing

This section defines the types and levels of testing that will be performed across the KCP&L SmartGrid Demonstration Project. The levels correspond with different stages of development and represent known levels of physical integration and quality. The test types describe what kind of functional and structural testing will be performed.

The program will be tested in steps, in line with the build releases for each project stream, from individual units of code through integrated subsystems to the deployed releases and to the final system.

2.1 Test Levels

Testing proceeds through various physical levels of the program lifecycle. Each completed level represents a milestone on the project plan and each stage represents a known level of physical integration and quality.

At a high-level, these are the potential levels of testing that could occur within the KCP&L SmartGrid Demonstration Project:

1. **Requirements/Use Case Testing:** Requirements/use case testing involves the verification and validation of requirements through static and dynamic tests. The validation testing of requirements is covered under User Acceptance Testing
2. **Unit Testing:** Unit level test is the initial testing of new and changed code in a module. It verifies the program specifications to the internal logic of the program or module and validates the logic. Unit testing of integration points also will be performed at this time. Unit testing is primarily performed by the vendor.
3. **System Testing:** System level tests verify proper execution of the entire application components. Both functional and structural types of tests are performed to verify that the system is functionally and operationally sound. This testing will be led by designated sub project lead.
4. **Integration Testing:** Integration level tests verify proper execution of application components. Communication between modules within the sub-system is tested in a controlled and isolated environment within the project. This testing will be primarily covered by application system testing but tracked by the integration test lead.
5. **FAT:** Factory Acceptance Test verifies that the configured system (Hardware and Software) meets the functional requirements described in the approved design requirements. FAT will only occur for the DMS and will be performed KCP&L with the vendor observing. DERM may do some DMS related testing at this time.
6. **SAT:** Site Acceptance Test follows a similar structure as the FAT with confirmation that the system integrates properly with the field wiring and substation equipment, reconfirming the functional requirements. SAT will only occur for DMS and will be coordinated by KCP&L. DERM may do some DMS related testing at this time.
7. **User Acceptance Testing:** Acceptance tests verify that the system meets user requirements as specified. It simulates the user environment and emphasizes security, documentation and regression tests and will demonstrate that the system performs as expected to the sponsor and



end-user so that they may accept the system. This testing will be led by designated sub project lead.

8. **Interoperability Testing:** Operability tests verify that the application can operate in the production environment. Interoperability testing will be focused on end-to-end transactions based upon predefined scenarios and will be more process focused compared to integration testing. This will be led by the integration test lead in coordination with the KCP&L SmartGrid Demonstration Project Management Office and SmartGrid Technology Planning Manager.
9. **Performance Testing:** A structural type of test which verifies that the application meets the expected level of performance in a production-like environment. This testing still needs to be defined for the Smart Grid demonstration project.
10. **Security Testing:** Testing to determine that an information system protects data and maintains functionality as intended and designated security controls are applied. This testing should take place primarily during system testing, with the VPN connection being tested during integration testing.



2.2 Functional Types of Test

The following is a list of the types of functional tests which may be included as part of testing:

Audit and Controls: Verifies the adequacy and effectiveness of controls and completeness of configuration file testing and data processing results. It is normally carried out as part of System Testing once the primary application functions have been stabilized.

Conversion: Verifies the compatibility of converted programs, data and procedures with the "old" ones that are being converted or replaced. It normally starts early in development and continues.

(User) Documentation and Procedures: Verifies that the interface between the system and the people works and is useable. It also, verifies that the instruction guides are helpful and accurate. It is normally done after the externals of the system are stabilized.

Error Handling: A functional type of test that verifies the system functions for detecting and responding to exception conditions. Completeness of error handling determines the usability of a system and ensures that errors are properly handled.

Function: Verifies that each business function operates according to the Detailed Requirements, the External and Internal Design documents. It is normally done as part of Integration, System and User Acceptance Testing.

Installation: Verifies that applications/power system components can be easily installed and run in the target environment. It is normally done for network systems, multiple location installs and vendor packages after System Testing/FAT, possibly in parallel with Business Acceptance Testing.

Interface/Inter-system: Verifies that the interconnection between applications and systems functions correctly. It is normally done as part of System Testing.

Parallel: Verifies that same input on "old" and "new" systems produces same results. It is more an implementation than a testing strategy and is normally done to compare an old application with its replacement or when automating manual systems.

Regression: Verifies that, as a result of making changes to one part of the system, unwanted changes were not introduced to other parts. It is normally done as the last part of System Testing.

Transaction Flow: Verifies the proper and complete processing of a transaction from the time it enters the system to the time of its completion or exit from the system. It is normally done in interoperability when the application is demonstrably stable.

Usability: Verifies that the final product is user-friendly and easy to use. It is normally done as part of functional testing during User Acceptance Testing.

Security: A test focus area defined as the assurance that the system/data resources will be protected against accidental and/or intentional modification or misuse



3.0 Test Roles & Responsibilities

The following section details the typical roles & responsibilities associated with a testing effort and/or testing team. The roles & responsibilities detailed in this section are simply guidelines and can be modified accordingly.

Interoperability Test Lead

- Development of testing strategy and the management of test planning for interoperability testing efforts
- Assignment of testers to actual test functions (this will include business users, as well as the members of the Integration Testing Team within the PMO) for interoperability testing efforts
- Ensure adherence to the defined testing scope for integration testing efforts
- Management of test design by ensuring testers are collaborating with each other and the appropriate development and/or business representatives for interoperability testing efforts
- Controlling and monitoring test execution and prioritizing issues, coordinating with testers, developers, users and project managers for interoperability testing efforts
- Providing routine test status and defect tracking reports for interoperability testing efforts
- Coordinate with KCP&L IT Team to define responsibilities and ensure unified and coordinated approach to interoperability testing
- Coordinate with vendors to determine which environments will be available for interoperability testing
- Providing insight on defect and testing management tracking systems
- Provide guidance to sub-project leads for testing efforts

Sub-Project Leads

- Responsible for coordinating and managing testing efforts in assigned project areas
- Development of testing strategy and the management of test planning for respective assigned project areas
- Assignment of testers to actual test functions (this will include assigned business users, as well as the members of the Integration Testing Team within the PMO) for respective assigned project areas
- Ensure adherence to the defined testing scope for respective assigned project areas
- Management of test design by ensuring testers are collaborating with each other and the appropriate development and/or business representatives for respective assigned project areas
- Controlling and monitoring test execution and prioritizing issues, coordinating with testers, developers, users and project managers for respective assigned project areas
- Provide testing updates and defect tracking reports in their respective assigned project areas
- Tracking of issues and resolutions related to their assigned project areas
- Ensure adherence to defined testing scope in assigned project areas

Testers (Integration and Sub-project)

- Plan and document test coverage for assigned areas of test
- Execute planned testing
- Report issues and defects through defect tracking process
- Retest "fixed" defects until appropriately resolved
- Report (as scheduled) progress and issues
- Notify immediately if progress is halted due to issues/defect



4.0 Test Control Procedures

The following section describes procedures followed during the testing phases. These procedures help to monitor, evaluate, and manage the progress and effectiveness of the testing effort. They are vital to ensuring the success of the testing effort.

4.1 Test Deliverables Reviews

The respective sub project teams will perform reviews of key test deliverables for each test type (i.e. test plans, test results, etc.). A meeting notice, with related documents, will be e-mailed to each participant. These reviews should take place before testing begins to ensure agreement on testing goals and artifacts. The reviews should also be conducted following testing to verify that the tests have adequately verified system functionality.

4.2 Defect Management

A regular meeting will be held to discuss reported defects encountered during testing. The vendor development staff will provide status updates on all defects reported and the Testing team will provide additional defect information if needed. Members of the project team will participate as needed to resolve open issues.

In addition a call will be needed to review open defects with vendors. This call may be combined with the aforementioned call or held separately depending on the number of defects opened.

Each sub area lead will be responsible for managing defects and following up for resolution.

4.3 Issue Management

When issues are encountered during testing, the testers will create an issue report and will either communicate it to the appropriate lead/manager and/or log it within the appropriate defect management tool. When an issue is resolved or more information is required, the developer will change the status of the issue to indicate the current state. Once an issue is verified as resolved by the testers, the testers will close the defect.



5.0 Test Execution Criteria

The Entry and Exit Criteria describe the requirements that must be met before the system begins the testing phase and completes the testing phase, respectively. Suspend criteria describe the conditions under which the testing effort will stop temporarily. Resumption criteria are the conditions that must be met in order to resume testing following a suspension of activity. The following section provides examples for those criteria.

5.1 Entry Criteria

The system may enter the testing phase once all dependent deliverables have been met and all testing artifacts are ready for use. It will be at the discretion of the lead and/or testing manager to determine additional criteria is necessary to ensure sufficient testing coverage of the system.

Testing Type	Entry Criteria
Unit	- Design specifications must be completed and approved. - Unit Test Plan and respective test data are completed - Exit Criteria for Unit Testing are established and approved - Interfaces have been set up - Test data has been completed
Integration	- Unit Testing is successfully completed for all systems - Integration test plan and test data are completed - Exit Criteria for Integration Testing are established and approved
User Acceptance	- Unit Testing complete, Integration Testing complete - Other system(s) participating in user acceptance testing have passed their own Unit Testing, and Integration Testing - User Acceptance Test Plan and test data are completed - Exit Criteria for User Acceptance Testing are established and approved
Regression	- Issues causing Regression Testing have been identified (if applicable) - Other system(s) participating in Regression Testing have passed their own Unit Testing - Test cases and scripts to be used for Regression Testing are identified (typically use either System Integration Test or User Acceptance Test scripts and data) - Exit Criteria for Regression Testing are established and approved (typically use the exit criteria from the test scripts and data used to conduct Regression Testing; User Acceptance Testing or System Testing)
Performance	- Unit Testing and Integration Testing are complete - Other system(s) participating in performance testing have passed their own Unit Testing and Integration Testing - Performance test plan and test data are completed - Exit Criteria for Performance Testing are established and approved



5.2 Exit Criteria

The system may leave the testing phase once all testing objectives for all types of testing have been met successfully. The objectives for each type of testing will be documented in the testing deliverables. Each testing type will document testing objectives. As a guide, the following conditions must be met for any type of testing.

- The system passes the test cases without significant unresolved issues or problems.
- Any unresolved issue or problem has been documented and accepted by the business and technical leaders. In this case, the issue or problem must have a clear path to resolution.

5.3 Suspension Criteria

Testing activity will be suspended if certain criteria are encountered. Those criteria include but not limited to:

- Hardware/software/testing environment is not available at the times indicated in the project schedule.
- Source code contains one or more critical defects, which seriously prevents or drastically limits testing progress.
- Assigned test resources are not available when needed by the test team.

5.4 Resumption Criteria

If testing is suspended, resumption will only occur when the problem(s) that caused the suspension has been resolved. When a critical defect is the cause of the suspension, it must be resolved by the development, Testing and/or operations staff, as applicable, before testing is resumed.

6.0 Testing Deliverables

This section provides a detailed description of the expected deliverables for testing. Unless otherwise stated, the functional business owners are (see Roles and Responsibilities section) responsible for creating and managing the deliverables for the respective testing activity. Testing templates will be provided for each of the deliverables which will be used project wide to ensure consistency among documentation.



6.1 Test Plan

A test plan defines the objectives and scope of the testing effort and identifies the methodology/approach that the tester/testing team will use to facilitate the tests. Where possible, it will also identify the hardware, software and/or tools required for testing and the features and functions that will be tested, if applicable. It will include any risks factors, a testing schedule, and responsible testers. Smart Grid vendors will be responsible for providing initial test plans to be included in testing efforts.

6.2 Test Case

A test case describes a sequence of steps using data input, action, or event and an expected response, to determine if a feature of the system is working according to the design specifications. Test cases will be driven from use cases or requirements (when available).

6.3 Test Status Reports

The respective team and/or individual will produce testing status reports as testing activity is conducted. The content of the status reports should remain focused on the testing objective, scope and scheduled milestones currently being addressed. It is useful to state each of these at the beginning of each status report and then publish the achievements or goals accomplished during the current reporting period, as well as those that will be accomplished during the next reporting period. Any known risks that will directly impact the testing effort need to be itemized here, especially any "showstoppers" that will prevent any further testing of one or more aspects of the system. Templates will be provided.

6.4 Test Data

Test data will be used during the various types of testing. Test Data must contain a reasonable sample of both valid and invalid data to be used in normal and exception conditions to adequately test the system component and/or system.

Due to the nature of this project and the number of vendors involved, vendors will need to create data and coordination of "end-to-end" test data will be required.

6.5 Test Results

Test Results will be the collection of test cases and test data used in the execution of the testing activity. These test results will be made of test cases marked with the actual testing results and include any artifact(s) used to verify successful completion of the test or error discovered during the testing.



7.0 Defect Management

During the course of testing, defects will be recorded and managed using the incident reporting/defect management tool. Currently KCP&L does not have a defect management tool, but appropriate diligence will be done to find or create one. Vendors may have their own defect management systems which will may require coordination with KCP&L's system. At a minimum, the following data will be captured for each defect reported:

Field	Description
Defect Description (Short):	Intended to be a short one sentence description of the issue.
Defect Identified By	Name of person who discovered defect
Identification Date/Time:	Date/time the defect was identified
Test Case Impacted:	Indicate the Test Case ID# for the test case that was being executed when the defect was identified; the project management team will identify and flag any dependent or downstream test cases that may be blocked or otherwise impacted by this defect.
System Impact:	List the system(s) where this defect occurred/sub process
Estimated Severity	Severity (Critical - Low) rating based on impact as perceived by the person who discovered the defect; this may be modified by the project management team once additional impacts have been fully assessed
Assigned To:	Name of resource assigned to investigate and resolve the issue
Defect Description (Long)	Long form description of the issue which should include a list of steps taken that led to the defect, the difference between the expected result of the test case and the actual result per the defect, any screenshots, test data being used, and any other information that will be useful for reporting, tracking, management and resolution of the defect
Steps to Reproduce	Summary of the steps necessary to reproduce this defect
Category	Defect category (will be a drop down menu)
Status	Status of defect
Add related issue	Linked defects
Due date	Date defect is expected to be resolved
Vendor Defect Management Tool #	To track defect in vendor's defect management system
Domain	Domain in Smart Grid project
Phase	Phase
Sub Project Area	Which sub project area this testing occurred in

All high/medium reported defects should be resolved prior to beginning the next phase of testing.



7.1 Defect Severities

The following defect severities serve as a guideline and can be modified accordingly.

Critical – Defects marked as Critical priority are considered showstoppers and prohibit further testing. These defects should be given highest priority. This priority should be used only for issues which affect areas which are on the required SmartGrid demonstration list.

High – Defects marked as high priority are considered high importance and prohibit further testing for functionality not listed on the required SmartGrid demonstration list. Furthermore, these defects will be given priority attention after 'Critical' defects and should be resolved promptly to ensure the integrity of the testing timeline. This will be used for non-required demonstration functionality while critical will be used for required demonstration functionality.

Medium – Defects marked as Medium priority are considered of medium importance to the testing timeline and do not prohibit further testing. Medium defects will be handled after "Critical" and "High" priority defects have been resolved.

Low – Defects marked as Low priority are considered of minor importance to the testing timeline and do not prohibit further testing. Low defects will be handled after all 'High' and 'Medium' defects have been resolved.

Enhancement – Defects marked as an "Enhancement" can be delayed to a future release/iteration or not addressed at all. It can also be defined as a recommendation to be addressed in a future release/iteration.

7.2 Defect Types

The following defect types serve as a guideline and can be modified accordingly.

Training/User Error – Defect which does not require a resolution because the tester misinterpreted the requirements/design or was unfamiliar with the system functionality.

Code Defect – Defect that includes all standard application code as well as stored procedures, scripts, etc.

Database Defect/Configuration – Defect that includes problems with metadata, database schema, indexes, field characteristics, permissions, etc.

Environment Configuration – Defect that includes server permissions, application configuration on or between servers, memory configuration, corrupted build, incorrect build, etc.

Documentation – Defect in which the requirement or design specification was incorrect, Defect is resolved through a documentation change, not a code change.

Unit Testing – Defect in which should have been found during unit testing prior to delivery to UAT and/or Performance. This will be limited to evident defects agreed to by the Development and Test Managers which should have been noted in Unit Test. An example includes clicking on an O.K. button in a GUI screen and the GUI crashes or no data flowing between integrated applications.



Enhancement – Additional functionality identified during test that was not part of previously defined scope or requirements. Initially this may be considered a defect but later realized to be an enhancement.

Duplicate – Defects identified in a previous trouble ticket but not realized until after a new ticket has been opened. In this case, one ticket would be closed as a duplicate in favor of the other.

Security/Security violation – This will be used to track security-related issues

ESB/Integration – This will be used to track issues with the ESB, etc.



Appendix – Glossary of Testing Terms

This glossary defines the testing terms used in this test strategy and the subsequent test documents.

Term	Definition
Acceptance Criteria	The definition of the results expected from the test cases used for acceptance testing. The product must meet these criteria before implementation can be approved.
Acceptance Testing	(1) Formal testing conducted to determine whether or not a system satisfies its acceptance criteria and to enable the client to determine whether or not to accept the system. (2) Formal testing conducted to enable a user, client, or other authorized entity to determine whether to accept a system or component.
Acceptance Test Plan	Describes the steps the client will use to verify that the constructed system meets the acceptance criteria. It defines the approach to be taken for acceptance testing activities. The plan identifies the items to be tested, the test objectives, the acceptance criteria, the testing to be performed, test schedules, entry/exit criteria, staff requirements, reporting requirements, evaluation criteria, and any risks requiring contingency planning.
Ad-hoc Testing	A loosely structured testing approach that allows test developers to be creative in their test selection and execution. Ad-hoc testing is targeted at known or suspected problem areas.
Audit and Controls Testing	A functional type of test that verifies the adequacy and effectiveness of controls and completeness of data processing results.
Backup and Recovery Testing	A structural type of test that verifies the capability of the application to be restarted after a failure.
Black Box Testing	Evaluation techniques that are executed without knowledge of the program's implementation. The tests are based on an analysis of the specification of the component without reference to its internal workings.
Bottom-up Testing	Approach to integration testing where the lowest level components/devices are tested first then used to facilitate the testing of higher level components. This process is repeated until the component at the top of the hierarchy is tested. See "Top-down."
Branch Testing	A white box testing technique that requires each branch or decision point to be taken once.
Build	(1) An operational version of a system or component that incorporates a specified subset of the capabilities that the final product will provide. Builds are defined whenever the complete system cannot be developed and delivered in a single increment. (2) A collection of programs within a system that are functionally independent. A build can be tested as a unit and can be installed independent of the rest of the system.
Business Function	A set of related activities that comprise a stand-alone unit of business. It may be defined as a process that results in the achievement of a business objective. It is characterized by well-defined start and finish activities and a workflow or pattern.



Term	Definition
Causal Analysis	The evaluation of the cause of major errors, to determine actions that will prevent reoccurrence of similar errors.
Change Control	The process, by which a change is proposed, evaluated, approved or rejected, scheduled, and tracked.
Change Management	A process methodology to identify the configuration of a release and to manage all changes through change control, data recording, and updating of baselines.
Change Request	A documented proposal for a change of one or more work items or work item parts.
Condition Testing	A white box test method that requires all decision conditions be executed once for true and once for false.
Configuration Management	(1) The process of identifying and defining the configuration items in a system, controlling the release and change of these items throughout the system life cycle, recording and reporting the status of configuration items and change requests, and verifying the completeness and correctness of configuration items. (2) A discipline applying technical and administrative direction and surveillance to (a) identify and document the functional and physical characteristics of a configuration items, (b) control changes to those characteristics, and (c) record and report change processing and implementation status.
Conversion testing	A functional type of test that verifies the compatibility of converted programs, data and procedures with the "old" ones that are being converted or replaced.
Coverage	The extent to which test data tests a program's functions, parameters, inputs, paths, branches, statements, conditions, modules or data flow paths.
Coverage Matrix	Documentation procedure to indicate the testing coverage of test cases compared to possible elements of a program environment (i.e., inputs, outputs, parameters, paths, cause-effects, equivalence partitioning, etc.)
Continuity of Processing	A test focus area defined as the ability to continue processing if problems occur. Included is the ability to backup and recover after a failure.
Correctness	A test focus area defined as the ability to process data according to prescribed rules and configuration. Controls over data flow across systems provide an assurance on accuracy and completeness.
Data flow Testing	Testing in which test cases are designed based on variable usage within the code.
Debugging	The process of locating, analyzing, and correcting suspected faults. Compare with testing.
Decision Coverage	Percentage of decision outcomes that have been exercised through (white box) testing.
Defect	A variance from expectations : (1) An accidental condition that causes a functional unit to fail to perform its required functions. (2) A manifestation of an error in software. A fault if encountered may cause a failure. Synonymous with bug.



Term	Definition
Defect Management	A set of processes to manage the tracking and fixing of defects found during testing and to perform causal analysis.
Documentation and Procedures Testing	A functional type of test that verifies that the interface between the system and the people works and is usable. It also verifies that the instruction guides are helpful and accurate.
Design Review	(1) A formal meeting at which the preliminary or detailed design of a system is presented to the user, customer or other interested parties for comment and approval. (2) The formal review of an existing or proposed design for the purpose of detection and remedy of design deficiencies that could affect fitness-for-use and environmental aspects of the product, process or service, and/or for identification of potential improvements of performance, safety and economic aspects.
Desk Check	Testing of software by the manual simulation of its execution. It is one of the static testing techniques.
Detailed Test Plan	The detailed plan for a specific level of dynamic testing. It defines what is to be tested and how it is to be tested. The plan typically identifies the items to be tested, the test objectives, the testing to be performed, test schedules, personnel requirements, reporting requirements, evaluation criteria, and any risks requiring contingency planning. It also includes the testing tools and techniques, test environment set up, entry and exit criteria, and administrative procedures and controls.
Driver	A program that exercises a system or system component by simulating the activity of a higher level component.
Dynamic Testing	Testing that is carried out by executing the code. Dynamic testing is a process of validation by exercising a work product and observing the behavior of its logic and its response to inputs.
Entry Criteria	A checklist of activities or work items that must be complete or exist, respectively, before the start of a given task within an activity or sub-activity.
Environment	See Test Environment.
Error	(1) A discrepancy between a computed, observed or measured value or condition and the true specified or theoretically correct value or condition. (2) A human action that results in software containing a fault. This includes omissions or misinterpretations, etc.
Error Guessing	A test case selection process that identifies test cases based on the knowledge and ability of the individual to anticipate probable errors.
Error Handling Testing	A functional type of test that verifies the system functions for detecting and responding to exception conditions. Completeness of error handling determines the usability of a system and ensures that errors are properly handled.
Execution Procedure	A sequence of manual or automated steps required to carry out part or all of a test design or execute a set of test cases.
Exit Criteria	(1) Actions that must happen before an activity is considered complete. (2) A checklist of activities or work items that must be complete or exist, respectively, prior to the end of a given process stage, activity, or sub-activity.



Term	Definition
Expected Results	Predicted output data and file conditions associated with a particular test case. Expected results, if achieved, will indicate whether the test was successful or not. Generated and documented with the test case prior to execution of the test.
Full Lifecycle Testing	The process of verifying the consistency, completeness, and correctness of software and related work products (such as documents and processes) at each stage of the development life cycle.
Function	(1) A specific purpose of an entity or its characteristic action. (2) A set of related control statements that perform a related operation. Functions are sub-units of modules.
Function Testing	A functional type of test, which verifies that each business function operates according to the detailed requirements, the external and internal design specifications.
Functional Testing	Selecting and executing test cases based on specified function requirements without knowledge or regard of the program structure. Also known as black box testing. See "Black Box Testing."
Functional Test Types	Those kinds of tests used to assure that the designed system meets the business requirements, including business functions, interfaces, usability, and error handling etc. See also Structural Test Types.
Implementation	(1) A realization of an abstraction in more concrete terms; in particular, in terms of hardware, software, or both (2) The process by which the Power System is commission into production (3) The process by which software release is installed in production and made available to end users
Inspection	(1) A group review quality improvement process for written material, consisting of two aspects: product (document itself) improvement and process improvement (of both document production and inspection) (3) A formal evaluation procedure in which the Power System design is inspected against as built (2) A formal evaluation technique in which software requirements, design, or code are examined in detail by a person or group other than the author to detect faults, violations of development standards, and other problems. Contrast with walk-through.
Installation Testing	A functional type of test which verifies that the hardware, software and applications can be easily installed and run in the target environment.
Interface/Inter-system Testing	A functional type of test which verifies that the interconnection between applications and systems functions correctly.
Level of Testing	Refers to the progression of software and hardware testing through static and dynamic testing. Examples of <i>static testing</i> levels are Project Objectives Review, Requirements Walkthrough, Design (External and Internal) Review, Material and Code Inspection. Examples of <i>dynamic testing</i> levels are: Unit Testing, Development Integration Testing (DIT), Factory Acceptance testing (FAT), Site Acceptance Testing (SAT), Systems Integration Testing (SIT), User Acceptance Testing (UAT) and End to End Testing. Also known as a test level.



Term	Definition
Lifecycle	The software development process stages. Requirements, Design, Construction and Implementation.
Logical Path	A path that begins at an entry or decision statement and ends at a decision statement or exit.
Maintainability	A test focus area defined as the ability to locate and fix an error in the system. Can also be the ability to make dynamic changes to the system environment without making system changes.
Operability	A test focus area defined as the effort required (of support personnel) to learn and operate a manual or automated system. Contrast with Usability.
Operability Testing	A level of dynamic testing in which the operations of the system are validated in the real or closely simulated production environment.
Operational Testing	A structural type of test that verifies the ability of the power systems/applications to operate at an acceptable level of service in the production-like environment.
Parallel Testing	A functional type of test, which verifies that the same input on "old" and "new" systems, produces the same results. It is more of an implementation than a testing strategy.
Performance	A test focus area defined as the ability of the system to perform certain functions within a prescribed time.
Performance Testing	A structural type of test which verifies that the application meets the expected level of performance in a production-like environment.
Portability	A test focus area defined as ability for a system to operate in multiple operating environments.
Regression Testing	A functional type of test, which verifies that changes to one part of the system have not caused unintended adverse effects to other parts.
Reliability	A test focus area defined as the extent to which the system will provide the intended function without failing.
Requirement	(1) A condition or capability needed by the user to solve a problem or achieve an objective. (2) A condition or capability that must be met or possessed by a system or system component to satisfy a contract, standard, specification, or other formally imposed document. The set of all requirements forms the basis for subsequent development of the system or system component.
Review	A process or meeting during which a work product, or set of work products, is presented to project personnel, managers, users or other interested parties for comment or approval.
Root Cause Analysis	See Causal Analysis.
Security	A test focus area defined as the assurance that the system/data resources will be protected against accidental and/or intentional modification or misuse.



Term	Definition
Security Testing	A structural type of test which verifies that the application provides an adequate level of protection for confidential information and data belonging to other systems.
Software Quality	(1) The totality of features and characteristics of a software product that bear on its ability to satisfy given needs; for example, conform to specifications. (2) The degree to which software possesses a desired combination of attributes. (3) The degree to which a customer or user perceives that software meets his or her composite expectations. (4) The composite characteristics of software that determine the degree to which the software in use will meet the expectations of the customer.
Software Reliability	(1) The probability that software will not cause the failure of a system for a specified time under specified conditions. The probability is a function of the inputs to and use of the system as well as a function of the existence of faults in the software. The inputs to the system determine whether existing faults, if any, are encountered. (2) The ability of a program to perform a required function under stated conditions for a stated period of time.
Statement Testing	A white box testing technique that requires all code or logic statements to be executed at least once.
Static Testing	(1) The detailed examination of a work product's characteristics to an expected set of attributes, experiences and standards. The product under scrutiny is static and not exercised and therefore its behavior to changing inputs and environments cannot be assessed. (2) The process of evaluating a program without executing the program. See also desk checking, inspection, walk-through.
Stress/Volume Testing	A structural type of test that verifies that the power system/application has acceptable performance characteristics under peak load conditions.
Structural Function	Structural functions describe the technical attributes of a system.
Structural Test Types	Those kinds of tests that may be used to assure that the system is technically sound.
Sub-system	(1) A group of assemblies or components or both combined to perform a single function. (2) A group of functionally related components that are defined as elements of a system but not separately packaged.
System	A collection of components organized to accomplish a specific function or set of functions.
Systems Integration Testing	A dynamic level of testing which ensures that the systems integration activities appropriately address the integration of application subsystems, integration of applications with the infrastructure, and impact of change on the current live environment.
System Testing	A dynamic level of testing in which all the components that comprise a system are tested to verify that the system functions together as a whole.



Term	Definition
Test Bed	(1) A test environment containing the hardware, instrumentation tools, simulators, and other support software necessary for testing a system or system component. (2) A set of test files, (including databases and reference files), in a known state, used with input test data to test one or more test conditions, measuring against expected results.
Test Case	(1) A set of test inputs, execution conditions, and expected results developed for a particular objective, such as to exercise a particular program path or to verify compliance with a specific requirement. (2) The detailed objectives, data, procedures and expected results to conduct a test or part of a test.
Test Condition	A functional or structural attribute of an application, system, network, or component thereof to be tested.
Test Conditions Matrix	A worksheet used to formulate the test conditions that, if met, will produce the expected result. It is a tool used to assist in the design of test cases.
Test Conditions Coverage Matrix	A worksheet that is used for planning and for illustrating that all test conditions are covered by one or more test cases. Each test set has a Test Conditions Coverage Matrix. Rows are used to list the test conditions and columns are used to list all test cases in the test set.
Test Coverage Matrix	A worksheet used to plan and cross check to ensure all requirements and functions are covered adequately by test cases.
Test Data	The input data and file conditions associated with a specific test case.
Test Environment	The external conditions or factors that can directly or indirectly influence the execution and results of a test. This includes the physical as well as the operational environments. Examples of what is included in a test environment are: I/O and storage devices, data files, programs, JCL, communication lines, access control and security, databases, reference tables and files (version controlled), etc.
Test Focus Areas	Those attributes of an application/components that must be tested in order to assure that the business and structural requirements are satisfied
Test Level	See Level of Testing.
Test Log	A chronological record of all relevant details of a testing activity.
Test Matrices	A collection of tables and matrices used to relate functions to be tested with the test cases that do so. Worksheets used to assist in the design and verification of test cases.
Test Objectives	The tangible goals for assuring that the Test Focus areas previously selected as being relevant to a particular Business or Structural Function are being validated by the test.
Test Plan	A document prescribing the approach to be taken for intended testing activities. The plan typically identifies the items to be tested, the test objectives, the testing to be performed, test schedules, entry/exit criteria, personnel requirements, reporting requirements, evaluation criteria, and any risks requiring contingency planning.
Test Procedure	Detailed instructions for the setup, operation, and evaluation of results for a given test. A set of associated procedures is often combined to form a test procedures document.



Term	Definition
Test Report	A document describing the conduct and results of the testing carried out for a system or system component.
Test Run	A dated, time-stamped execution of a set of test cases.
Test Scenario	A high-level description of how a given business or technical requirement will be tested, including the expected outcome; later decomposed into sets of test conditions, each in turn, containing test cases.
Test Script	A sequence of actions that executes a test case. Test scripts include detailed instructions for set up, execution, and evaluation of results for a given test case.
Test Set	A collection of test conditions. Test sets are created for purposes of test execution only. A test set is created such that its size is manageable to run and its grouping of test conditions facilitates testing. The grouping reflects the application build strategy.
Test Sets Matrix	A worksheet that relates the test conditions to the test set in which the condition is to be tested. Rows list the test conditions and columns list the test sets. A checkmark in a cell indicates the test set will be used for the corresponding test condition.
Test Strategy	A high level description of major system-wide activities which collectively achieve the overall desired result as expressed by the testing objectives, given the constraints of time and money and the target level of quality. It outlines the approach to be used to ensure that the critical attributes of the system are tested adequately.
Test Type	See Type of Testing.
Testing	The process of exercising or evaluating a program, product, or system, by manual or automated means, to verify that it satisfies specified requirements, to identify differences between expected and actual results.
Top-down	Approach to integration testing where the component at the top of the component hierarchy is tested first, with lower level components being simulated by stubs. Tested components are then used to test lower level components. The process is repeated until the lowest level components have been tested.
Transaction Flow Testing	A functional type of test that verifies the proper and complete processing of a transaction from the time it enters the system to the time of its completion or exit from the system.
Unit Testing	The first level of dynamic testing and is the verification of new or changed code in a module to determine whether all new or modified paths function correctly.
Usability	A test focus area defined as the end-user effort required to learn and use the system. Contrast with Operability.
Usability Testing	A functional type of test which verifies that the final product is user-friendly and easy to use.
User Acceptance Testing	See Acceptance Testing.



Term	Definition
Validation	(1) The act of demonstrating that a work item is in compliance with the original requirement. For example, the code of a module would be validated against the input requirements it is intended to implement. Validation answers the question "Is the right system being built?" (2) Confirmation by examination and provision of objective evidence that the particular requirements for a specific intended use have been fulfilled. See "Verification."
Variance	A mismatch between the actual and expected results occurring in testing. It may result from errors in the item being tested, incorrect expected results, invalid test data, etc. See "Error."
Verification	(1) The act of demonstrating that a work item is satisfactory by using its predecessor work item. For example, the system is verified against module level design. Verification answers the question "Is the system being built right?" (2) Confirmation by examination and provision of objective evidence that specified requirements have been fulfilled. See "Validation."
Walkthrough	A review technique characterized by the author of the object under review guiding the progression of the review. Observations made in the review are documented and addressed. Less formal evaluation technique than an inspection.
White Box Testing	Evaluation techniques that are executed with the knowledge of the implementation of the components and programs. The objective of white box testing is to test the components/program's statements, configuration files, code paths, conditions, or data flow paths.
Work Item	A software development lifecycle work product.

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I.1 System Test Books

System Test Book - HMI FAT: Document Verification Checklist						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.HMI.FAT001:1	Verify that the single line diagram is provided during the FAT.	N/A				
SYS.HMI.FAT001:2	Verify that the functional design specification is provided during the FAT.	N/A				
SYS.HMI.FAT001:3	Verify that the network architecture is provided during the FAT.	N/A				
SYS.HMI.FAT001:4	Verify that the network architecture of test system is provided during the FAT.	N/A				
SYS.HMI.FAT001:5	Verify that the system configuration description is provided during the FAT.	N/A				
SYS.HMI.FAT001:6	Verify that the signal is provided during the FAT.	N/A				
System Test Book - HMI FAT: Equipment Hardware Checklist						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.HMI.FAT002:1	Verify that two SICAM PAS Station Units 2.20 are provided during the FAT.	N/A				
SYS.HMI.FAT002:2	Verify that one SEL 487B is provided during the FAT.	N/A				
SYS.HMI.FAT002:3	Verify that one SEL 487E is provided during the FAT.	N/A				
SYS.HMI.FAT002:4	Verify that one SEL 451 is provided during the FAT.	N/A				
SYS.HMI.FAT002:5	Verify that one SEL 751A is provided during the FAT.	N/A				
SYS.HMI.FAT002:6	Verify that one Arbiter GPS Clock is provided during the FAT.	N/A				
SYS.HMI.FAT002:7	Verify that one RSG2100 RuggedCom Ethernet Switch is provided during the FAT.	N/A				
SYS.HMI.FAT002:8	Verify that one Cisco Ethernet Switch is provided during the FAT.	N/A				
SYS.HMI.FAT002:9	Verify that one A-Eberle Tap Changer is provided during the FAT.	N/A				
SYS.HMI.FAT002:10	Verify that two HMI Servers are provided during the FAT.	N/A				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.HMI.FAT002:1.1	Verify that two HMI Clients are provided during the FAT.	N/A				
System Test Book - HMI FAT: Equipment Software Checklist						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.HMI.FAT003:1.1	Verify that the SICAM PAS Station Unit has Windows XP Embedded OS SP3.	N/A				
SYS.HMI.FAT003:1.2.1	Verify that the SICAM PAS Station Unit has the SICAM PAS V7.01 Runtime & Configuration Dongle.	N/A				
SYS.HMI.FAT003:1.2.2	Verify that the SICAM PAS Station Unit has PAS Runtime.	N/A				
SYS.HMI.FAT003:1.2.3	Verify that the SICAM PAS Station Unit has PAS IUI Large.	N/A				
SYS.HMI.FAT003:1.2.4	Verify that the SICAM PAS Station Unit has IEC61850 Client.	N/A				
SYS.HMI.FAT003:1.2.5	Verify that the SICAM PAS Station Unit has DNP3.0 MASTER.	N/A				
SYS.HMI.FAT003:1.2.6	Verify that the SICAM PAS Station Unit has DNP3.0 SLAVE.	N/A				
SYS.HMI.FAT003:1.2.7	Verify that the SICAM PAS Station Unit has AUTOMATION.	N/A				
SYS.HMI.FAT003:1.2.8	Verify that the SICAM PAS Station Unit has IEC61850 Server.	N/A				
SYS.HMI.FAT003:2.1	Verify that the SIMATIC RACK PC has Windows 2008 Server Standard installed.	N/A				
SYS.HMI.FAT003:2.2.1	Verify that the SIMATIC RACK PC has WinCC Redundancy V7.0 installed.	N/A				
SYS.HMI.FAT003:2.2.2	Verify that the SIMATIC RACK PC has WinCC Server V7.0 installed.	N/A				
SYS.HMI.FAT003:2.2.3	Verify that the SIMATIC RACK PC has WinCC Runtime and Configuration (2048 tags) installed.	N/A				
SYS.HMI.FAT003:2.2.4	Verify that the SIMATIC RACK PC has WinCC Runtime (2048 tags) V7.0 installed.	N/A				
SYS.HMI.FAT003:2.2.5	Verify that the SIMATIC RACK PC has WinCC Runtime (128 tags) V7.0 installed.	N/A				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.HMI.FAT003:2,2,6	Verify that the SIMATIC RACK PC has SiCAM SCC upgrade Runtime and Configuration V7.01 installed.	N/A				
SYS.HMI.FAT003:2,2,7	Verify that the SIMATIC RACK PC has SiCAM SCC upgrade Runtime V7.01 installed.	N/A				
System Test Book - HMI FAT: Redundancy & Self Healing at HMI Level						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.HMI.FAT024:1	Verify that HMI-A and HMI-B are connected to the assigned Master Station Unit.	N/A				
SYS.HMI.FAT024:2	Simulate HMI-A failure by switching off the power supply.	Verify that communication to HMI-A is lost, and that HMI-B is still working and communicating to the station unit.				
SYS.HMI.FAT024:3	Return power to HMI-A by switching on the power supply.	Verify that HMI-A connects to the Master Station Unit.				
SYS.HMI.FAT024:4	Simulate HMI-B failure by switching off the power supply.	Verify that communication to HMI-B is lost, and that HMI-A is still working and communicating to the station unit.				
SYS.HMI.FAT024:5	Return power to HMI-B by switching on the power supply.	Verify that HMI-B connects to the Master Station Unit.				
SYS.HMI.FAT024:6	Disconnect one of the LAN cables connected to HMI-A.	Verify that the HMI is still in service and communicating to the Station server, and that there is no change in the Master standby assignment.				
System Test Book - HMI FAT: Communication Test						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.HMI.FAT005:1.1	Ping the SEL 487E from HMI-A.	Verify ping is successful.				
SYS.HMI.FAT005:1.2	Ping the SEL 487B from HMI-A.	Verify ping is successful.				
SYS.HMI.FAT005:1.3	Ping the SEL 451-5 from HMI-A.	Verify ping is successful.				
SYS.HMI.FAT005:1.4	Ping the SEL 751A from HMI-A.	Verify ping is successful.				
SYS.HMI.FAT005:1.5	Ping the A-Eberle Tap Changer from HMI-A.	Verify ping is successful.				
SYS.HMI.FAT005:1.6	Ping the Station unit-1 from HMI-A.	Verify ping is successful.				
SYS.HMI.FAT005:1.7	Ping the Station unit-2 from HMI-A.	Verify ping is successful.				
SYS.HMI.FAT005:1.8	Ping the SEL 487E from HMI-B.	Verify ping is successful.				
SYS.HMI.FAT005:1.9	Ping the SEL 487B from HMI-B.	Verify ping is successful.				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.HMI.FAT005:1.10	Ping the SEL 451-5 from HMI-B.	Verify ping is successful.				
SYS.HMI.FAT005:1.11	Ping the SEL 751A from HMI-B.	Verify ping is successful.				
SYS.HMI.FAT005:1.12	Ping the A-Eberle Tap Changer from HMI-B.	Verify ping is successful.				
SYS.HMI.FAT005:1.13	Ping the Station unit-1 from HMI-B.	Verify ping is successful.				
SYS.HMI.FAT005:1.14	Ping the Station unit-2 from HMI-B.	Verify ping is successful.				
SYS.HMI.FAT005:2.1	Disconnect both network connections from HMI-A.	Verify that HMI-A is now pending up in SICAM PAS UI Operation.				
SYS.HMI.FAT005:2.2	Disconnect both network connections from HMI-B.	Verify that HMI-B is now pending up in SICAM PAS UI Operation.				
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.HMI.FAT005:3.1	Reconnect both network connections to HMI-A.	Verify that the connection to HMI-A is established and that HMI-A is now displayed as running in SICAM PAS UI Operation.				
SYS.HMI.FAT005:3.2	Reconnect both network connections to HMI-B.	Verify that the connection to HMI-B is established and that HMI-B is now displayed as running in SICAM PAS UI Operation.				
SYS.HMI.FAT005:4.1	Disconnect and then reconnect a network port from the Ruggedcom network switch.	Verify that the port goes down and then back up on both HMI-A and HMI-B.				
SYS.HMI.FAT005:4.2	Disconnect and then reconnect a network port from the Cisco network switch.	Verify that the port goes down and then back up on both HMI-A and HMI-B.				
System Test Book - HMI FAT: Time synchronization						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.HMI.FAT006:1.1	Drift the time by five minutes on the HMI-A.	Verify that HMI-A resyncs with the GPS clock in 15-20 minutes time.				
SYS.HMI.FAT006:1.2	Drift the time by five minutes on the HMI-B.	Verify that HMI-B resyncs with the GPS clock in 15-20 minutes time.				
SYS.HMI.FAT006:1.3	Drift the time by five minutes on the HMI-C.	Verify that HMI-C resyncs with the GPS clock in 15-20 minutes time.				
SYS.HMI.FAT006:1.4	Drift the time by five minutes on the HMI-D.	Verify that HMI-D resyncs with the GPS clock in 15-20 minutes time.				
System Test Book - HMI FAT: One-Line Screen						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.HMI.FAT007:1.1	Verify that the header of the screen is labeled as "Single line view".	N/A				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.HMI.FAT007:1.2	Verify the naming conventions in the screen are as per the approved HMI screenshots.	N/A				
SYS.HMI.FAT007:1.3	Verify the information present in the screen are as per the approved HMI screenshots.	N/A				
SYS.HMI.FAT007:2.1	Simulate the binary indication to simulate breaker open/close from the SEL 487E relay.	Verify the change in the breaker status on the HMI as mentioned in the approved FDS.				
SYS.HMI.FAT007:2.2	From the A-Eberle Tap Changer simulate the Auto/Manual status.	Verify the text in the status box correspondingly changes on the HMI.				
SYS.HMI.FAT007:2.3	Increment the tap-position from the tap changer.	Verify the corresponding tap-position is being indicated on the screen.				
SYS.HMI.FAT007:3.1	Inject three phase voltage and current in SEL-487E relay in order to simulate active power and reactive power.	Verify the readings in the HMI screen matches with the front-panel display of the relay.				
SYS.HMI.FAT007:4.1	Operate a breaker on the HMI screen.	Verify the command is successfully passed to the relay.				
SYS.HMI.FAT007:4.2	Simulate the feedback from a successful breaker operation.	Verify the breaker status is updated on the HMI.				
SYS.HMI.FAT007:4.3	Verify that the command is recorded in the event list.	N/A				
System Test Book – HMI FAT: Bus Detail Screen						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.HMI.FAT008:1.1	Verify that the header of the screen is labelled as per the approved HMI screenshots.	N/A				
SYS.HMI.FAT008:1.2	Verify the naming conventions in the screen are as per the approved HMI screenshots.	N/A				
SYS.HMI.FAT008:1.3	Verify the information present in the screen are as per the approved HMI screenshots.	N/A				
SYS.HMI.FAT008:2.1	Simulate the binary indication to simulate breaker open/close from the SEL 751A relay.	Verify the change in the breaker status in the HMI as mentioned in the approved FDS.				
SYS.HMI.FAT008:2.2	Simulate the local/remote from the SEL-751A by energizing the corresponding binary input.	Verify there is a corresponding change in the status box in the HMI screen.				
SYS.HMI.FAT008:2.3	Simulate the auto/manual from the SEL-751A by energizing the corresponding binary input.	Verify there is a corresponding change in the status box in the HMI screen.				
SYS.HMI.FAT008:2.4	Simulate the local/remote from the SEL-451 by energizing the corresponding binary input.	Verify there is a corresponding change in the status box in the HMI screen.				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.HMI.FAT008:2.5	Verify all the tested signals are recorded in the event list and/or alarm list.	N/A				
SYS.HMI.FAT008:3.1	Inject three phase voltage and current in SEL 751A relay in order to simulate few analog measurements.	Verify the readings in the HMI screen matches with the frontpanel display of the relay.				
SYS.HMI.FAT008:3.2	Inject three phase voltage and current in SEL 487E relay in order to simulate few analog measurements.	Verify the readings in the HMI screen matches with the front-panel display of the relay.				
SYS.HMI.FAT008:4.1	Operate a breaker on the HMI screen.	Verify the command is successfully passed to the relay.				
SYS.HMI.FAT008:4.2	Simulate the feedback from a successful breaker operation.	Verify the breaker status is updated on the HMI.				
SYS.HMI.FAT008:4.3	Verify that the command is recorded in the event list.	N/A				
System Test Book - HMI FAT: Network Overview Screen						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.HMI.FAT009:1.1	Unplug any fiber-optic connection between two switches in the ring to simulate a failure.	Verify the corresponding line depicting the network cable starts blinking in the HMI for Ruggedcom.				
SYS.HMI.FAT009:1.2	Unplug any fiber-optic connection between two switches in the ring to simulate a failure.	Verify that the Ruggedcom switch starts blinking due to faulty connection detected in one of its ports.				
SYS.HMI.FAT009:1.3	Click on the push button to verify the status of the port being disconnected in the port assignment table.	Verify the corresponding message is also being reported in the Event and Alarm list for the Ruggedcom switch.				
SYS.HMI.FAT009:1.4	Plug the network cable back into the port.	Verify blinking in the corresponding line depicting the network cable stops for the Ruggedcom switch.				
SYS.HMI.FAT009:1.5	Unplug the fiber-optic connection on the SEL 751A to simulate a failure.	Verify the corresponding line depicting the network cable starts blinking in the HMI for the Ruggedcom switch.				
SYS.HMI.FAT009:1.5	Unplug any fiber-optic connection on the SEL 751A to simulate a failure.	Verify that the Ruggedcom switch starts blinking due to faulty connection detected in one of its ports.				
SYS.HMI.FAT009:1.5	Click on the push button to verify the status of the port being disconnected in the port assignment table.	Verify the corresponding message is also being reported in the Event and Alarm list for the Ruggedcom switch.				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.HMI.FAT009:1.5	Plug the network cable back into the port.	Verify blinking in the corresponding line depicting the network cable stops for the Ruggedcom switch.				
SYS.HMI.FAT009:1.6	Unplug the fiber-optic connection on the SEL 487B to simulate a failure.	Verify the corresponding line depicting the network cable starts blinking in the HMI for the Ruggedcom switch.				
SYS.HMI.FAT009:1.6	Unplug any fiber-optic connection on the SEL 487B to simulate a failure.	Verify that the Ruggedcom switch starts blinking due to faulty connection detected in one of its ports.				
SYS.HMI.FAT009:1.6	Click on the push button to verify the status of the port being disconnected in the port assignment table.	Verify the corresponding message is also being reported in the Event and Alarm list for the Ruggedcom switch.				
SYS.HMI.FAT009:1.6	Plug the network cable back into the port.	Verify blinking in the corresponding line depicting the network cable stops for the Ruggedcom switch.				
SYS.HMI.FAT009:1.7	Unplug the fiber-optic connection on the SEL 487E to simulate a failure.	Verify the corresponding line depicting the network cable starts blinking in the HMI for the Ruggedcom switch.				
SYS.HMI.FAT009:1.7	Unplug any fiber-optic connection on the SEL 487E to simulate a failure.	Verify that the Ruggedcom switch starts blinking due to faulty connection detected in one of its ports.				
SYS.HMI.FAT009:1.7	Click on the push button to verify the status of the port being disconnected in the port assignment table.	Verify the corresponding message is also being reported in the Event and Alarm list for the Ruggedcom switch.				
SYS.HMI.FAT009:1.7	Plug the network cable back into the port.	Verify blinking in the corresponding line depicting the network cable stops for the Ruggedcom switch.				
SYS.HMI.FAT009:1.8	Unplug the fiber-optic connection on the SEL 451 to simulate a failure.	Verify the corresponding line depicting the network cable starts blinking in the HMI for the Ruggedcom switch.				
SYS.HMI.FAT009:1.8	Unplug any fiber-optic connection on the SEL 451 to simulate a failure.	Verify that the Ruggedcom switch starts blinking due to faulty connection detected in one of its ports.				
SYS.HMI.FAT009:1.8	Click on the push button to verify the status of the port being disconnected in the port assignment table.	Verify the corresponding message is also being reported in the Event and Alarm list for the Ruggedcom switch.				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.HMI.FAT009:1.8	Plug the network cable back into the port.	Verify blinking in the corresponding line depicting the network cable stops for the Ruggedcom switch.				
SYS.HMI.FAT009:1.9	Unplug the fiber-optic connection on the REG-DA to simulate a failure.	Verify the corresponding line depicting the network cable starts blinking in the HMI for the Ruggedcom switch.				
SYS.HMI.FAT009:1.9	Unplug any fiber-optic connection on the REG-DA to simulate a failure.	Verify that the Ruggedcom switch starts blinking due to faulty connection detected in one of its ports.				
SYS.HMI.FAT009:1.9	Click on the push button to verify the status of the port being disconnected in the port assignment table.	Verify the corresponding message is also being reported in the Event and Alarm list for the Ruggedcom switch.				
SYS.HMI.FAT009:1.9	Plug the network cable back into the port.	Verify blinking in the corresponding line depicting the network cable stops for the Ruggedcom switch.				
SYS.HMI.FAT009:2.1	Unplug any fiber-optic connection between two switches in the ring to simulate a failure.	Verify the corresponding line depicting the network cable starts blinking in the HMI for Cisco.				
SYS.HMI.FAT009:2.2	Unplug any fiber-optic connection between two switches in the ring to simulate a failure.	Verify that the Cisco switch starts blinking due to faulty connection detected in one of its ports.				
SYS.HMI.FAT009:2.3	Click on the push button to verify the status of the port being disconnected in the port assignment table.	Verify the corresponding message is also being reported in the Event and Alarm list for the Cisco switch.				
SYS.HMI.FAT009:2.4	Plug the network cable back into the port.	Verify blinking in the corresponding line depicting the network cable stops for the Cisco switch.				
SYS.HMI.FAT009:2.5	Unplug the fiber-optic connection on the SEL 751A to simulate a failure.	Verify the corresponding line depicting the network cable starts blinking in the HMI for the Cisco switch.				
SYS.HMI.FAT009:2.5	Unplug any fiber-optic connection on the SEL 751A to simulate a failure.	Verify that the Cisco switch starts blinking due to faulty connection detected in one of its ports.				
SYS.HMI.FAT009:2.5	Click on the push button to verify the status of the port being disconnected in the port assignment table.	Verify the corresponding message is also being reported in the Event and Alarm list for the Cisco switch.				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.HMI.FAT009:2.5	Plug the network cable back into the port.	Verify blinking in the corresponding line depicting the network cable stops for the Cisco switch.				
SYS.HMI.FAT009:2.6	Unplug the fiber-optic connection on the SEL 487B to simulate a failure.	Verify the corresponding line depicting the network cable starts blinking in the HMI for the Cisco switch.				
SYS.HMI.FAT009:2.6	Unplug any fiber-optic connection on the SEL 487B to simulate a failure.	Verify that the Cisco switch starts blinking due to faulty connection detected in one of its ports.				
SYS.HMI.FAT009:2.6	Click on the push button to verify the status of the port being disconnected in the port assignment table.	Verify the corresponding message is also being reported in the Event and Alarm list for the Cisco switch.				
SYS.HMI.FAT009:2.6	Plug the network cable back into the port.	Verify blinking in the corresponding line depicting the network cable stops for the Cisco switch.				
SYS.HMI.FAT009:2.7	Unplug the fiber-optic connection on the SEL 487E to simulate a failure.	Verify the corresponding line depicting the network cable starts blinking in the HMI for the Cisco switch.				
SYS.HMI.FAT009:2.7	Unplug any fiber-optic connection on the SEL 487E to simulate a failure.	Verify that the Cisco switch starts blinking due to faulty connection detected in one of its ports.				
SYS.HMI.FAT009:2.7	Click on the push button to verify the status of the port being disconnected in the port assignment table.	Verify the corresponding message is also being reported in the Event and Alarm list for the Cisco switch.				
SYS.HMI.FAT009:2.7	Plug the network cable back into the port.	Verify blinking in the corresponding line depicting the network cable stops for the Cisco switch.				
SYS.HMI.FAT009:2.8	Unplug the fiber-optic connection on the SEL 451 to simulate a failure.	Verify the corresponding line depicting the network cable starts blinking in the HMI for the Cisco switch.				
SYS.HMI.FAT009:2.8	Unplug any fiber-optic connection on the SEL 451 to simulate a failure.	Verify that the Cisco switch starts blinking due to faulty connection detected in one of its ports.				
SYS.HMI.FAT009:2.8	Click on the push button to verify the status of the port being disconnected in the port assignment table.	Verify the corresponding message is also being reported in the Event and Alarm list for the Cisco switch.				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.HMI.FAT009:2.8	Plug the network cable back into the port.	Verify blinking in the corresponding line depicting the network cable stops for the Cisco switch.				
SYS.HMI.FAT009:2.9	Unplug the fiber-optic connection on the REG-DA to simulate a failure.	Verify the corresponding line depicting the network cable starts blinking in the HMI for the Cisco switch.				
SYS.HMI.FAT009:2.9	Unplug any fiber-optic connection on the REG-DA to simulate a failure.	Verify that the Cisco switch starts blinking due to faulty connection detected in one of its ports.				
SYS.HMI.FAT009:2.9	Click on the push button to verify the status of the port being disconnected in the port assignment table.	Verify the corresponding message is also being reported in the Event and Alarm list for the Cisco switch.				
SYS.HMI.FAT009:2.9	Plug the network cable back into the port.	Verify blinking in the corresponding line depicting the network cable stops for the Cisco switch.				
System Test Book - HMI FAT: Device Diagnostic Screen						
ID	Test Description	Expected result	Status	Actual Result	Test Date	Tested By
SYS.HMI.FAT010:1	Turn off the power supply to the SEL 451.	Verify that the status text for the device shows "Faulty".				
SYS.HMI.FAT010:1	Turn on the power supply to the SEL 451.	Verify that the status text for the device shows "Normal".				
SYS.HMI.FAT010:2	Turn off the power supply to the SEL 487B.	Verify that the status text for the device shows "Faulty".				
SYS.HMI.FAT010:2	Turn on the power supply to the SEL 487B.	Verify that the status text for the device shows "Normal".				
SYS.HMI.FAT010:3	Turn off the power supply to the SEL 751A.	Verify that the status text for the device shows "Faulty".				
SYS.HMI.FAT010:3	Turn on the power supply to the SEL 751A.	Verify that the status text for the device shows "Normal".				
SYS.HMI.FAT010:4	Turn off the power supply to the SEL 487E.	Verify that the status text for the device shows "Faulty".				
SYS.HMI.FAT010:4	Turn on the power supply to the SEL 487E.	Verify that the status text for the device shows "Normal".				
SYS.HMI.FAT010:5	Turn off the power supply to the RSG2100.	Verify that the status text for the device shows "Faulty".				
SYS.HMI.FAT010:5	Turn on the power supply to the RSG2100.	Verify that the status text for the device shows "Normal".				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.HMI.FAT010:6	Turn off the power supply to the CSG2520.	Verify that the status text for the device shows "Faulty".				
SYS.HMI.FAT010:6	Turn on the power supply to the CSG2520.	Verify that the status text for the device shows "Normal".				
SYS.HMI.FAT010:7	Turn off the power supply to the REG-DA.	Verify that the status text for the device shows "Faulty".				
SYS.HMI.FAT010:7	Turn on the power supply to the REG-DA.	Verify that the status text for the device shows "Normal".				
System Test Book - HMI FAT: Help Screen Checklist						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.HMI.FAT021:1	Verify that the header of the screen is correct.	N/A				
SYS.HMI.FAT021:2	Verify explanation of used symbols.	N/A				
System Test Book - HMI FAT: User Administration Checklist						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.HMI.FAT012:1.1	Login to HMI as Operator.	Operator word appears in Current User window of Basic Signaling Window.				
SYS.HMI.FAT012:1.2	Verify Operator can navigate through various displays including alarm list & event list.	N/A				
SYS.HMI.FAT012:1.3	Verify Operator can acknowledge the alarms.	N/A				
SYS.HMI.FAT012:1.4	Verify Operator cannot issue a control command.	N/A				
SYS.HMI.FAT012:2.1	Login to HMI as IT Admin.	IT Admin word appears in Current User window of Basic Signaling Window.				
SYS.HMI.FAT012:2.2	Verify IT Admin can navigate only to "Network Overview" screen including alarm list & event list.	N/A				
SYS.HMI.FAT012:2.3	Verify IT Admin can acknowledge alarms.	N/A				
SYS.HMI.FAT012:2.4	Verify IT Admin cannot issue a control command.	N/A				
SYS.HMI.FAT012:3.1	Login to HMI as OT Admin.	OT Admin word appears in Current User window of Basic Signaling Window.				
SYS.HMI.FAT012:3.2	Verify OT Admin can navigate to all screens including alarm list & event list except "Network Screen".	N/A				
SYS.HMI.FAT012:3.3	Verify OT Admin can acknowledge the alarms.	N/A				
SYS.HMI.FAT012:3.4	Verify OT Admin cannot issue a control command.	N/A				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.HMI.FAT012:4.1	Login to HMI as Administrator	Administrator word appears in Current User window of Basic Signaling Window.				
SYS.HMI.FAT012:4.2	Verify Administrator can navigate through various displays including alarm & event list.	N/A				
SYS.HMI.FAT012:4.3	Administrator can acknowledge the alarms.	N/A				
SYS.HMI.FAT012:4.4	Administrator can issue a control command.	N/A				
SYS.HMI.FAT012:4.5	Administrator can access all programs of HMIs.	N/A				
System Test Book - HMI FAT: User Administration Checklist						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.HMI.FAT017:2.1	Generate a persisting Alarm.	New persisting alarm appears in the alarm list in red background and white foreground with correct date and time stamping in the bottom of the list.				
SYS.HMI.FAT017:2.2	Generate a non-persisting Alarm.	New non-persisting alarm appears in the alarm list in green color.				
SYS.HMI.FAT017:2.3	Acknowledge persisting alarm.	Verify the text color and background color of the alarm message changes as stated above.				
SYS.HMI.FAT017:2.4	Acknowledge non-persistent alarm.	Verify the alarm is no longer present in the alarm list.				
SYS.HMI.FAT017:2.5	Check naming convention of alarms of one typical feeder according to signal list.	N/A				
SYS.HMI.FAT017:3.1	Generate many alarms from different panels, and apply filter for a specific feeder or device.	Only filtered alarms appear in list.				
SYS.HMI.FAT017:3.2	Scroll up and down in the Alarm list to see the previous/next alarms.	Scrolling facility is working.				
SYS.HMI.FAT017:3.3	Generate a persisting Alarm.	New persisting alarm appears in the event list in red background and white foreground with correct date and time stamping in the bottom of the list.				
SYS.HMI.FAT017:3.4	Generate a non-persisting Alarm.	New non-persisting alarm appears in the event list in green color.				
SYS.HMI.FAT017:3.5	Acknowledge persisting alarm.	Verify the text color and background color of the event message changes as stated above.				
SYS.HMI.FAT017:3.6	Acknowledge non-persistent alarm.	Verify the alarm is no longer present in the event list.				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.HMI.FAT017-3.7	Check naming convention of alarms of one typical feeder according to signal list.	N/A				
SYS.HMI.FAT017-3.8	Generate many alarms from different panels, and apply filter for a specific feeder or device.	Only filtered events appear in list.				
SYS.HMI.FAT017-3.9	Scroll up and down in the Event list to see the previous/next alarms.	Scrolling facility is working.				

Supplemental SAT Test Book: FAT-003						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.HMLSAT.FAT003.1	Verify SICAM status changes are reported and logged at the CC and HMI					
SYS.HMLSAT.FAT003.2	Verify that IED scanning is happening and data is correct not only that the application is running					
SYS.HMLSAT.FAT003.3	Verify users log on and log off					
SYS.HMLSAT.FAT003.4	Verify system management and configuration displays and tools					
SYS.HMLSAT.FAT003.5	Verify correct operation of the system components (system configuration overview, servers status, communications status, applications running,...)					
SYS.HMLSAT.FAT003.6	Verify data consistency at all levels starting at the HMI and InService					
SYS.HMLSAT.FAT003.7	Verify communication path status from the HMI					
Supplemental SAT Test Book: FAT-024						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.HMLSAT.FAT024.1	Verify lan failure recovery for SICAM					
SYS.HMLSAT.FAT024.2	Verify HMI servers and clients operation with LAN failures					
SYS.HMLSAT.FAT024.3	Verify HMI operation with SICAMs with LAN failures					
SYS.HMLSAT.FAT024.4	Verify HMI redundancy at the application level (caused by SW decisions, problems or errors)					
SYS.HMLSAT.FAT024.5	Verify system behavior during individual servers power failures					
SYS.HMLSAT.FAT024.6	Verify SICAM status changes are reported and logged at the CC and HMI					
SYS.HMLSAT.FAT024.7	Verify how servers' power failure affect HMI Clients.					
Supplemental SAT Test Book: FAT-005						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.HMLSAT.FAT005.1	Verify communication failover and redundancy for communication or application errors/problems.					

Supplemental SAT Test Book: FAT-007						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.HMLSAT.FAT007.1	Verify analog controls (set points), raise/lower (no return),...					
SYS.HMLSAT.FAT007.2	Verify control action propagation in all modules and that execution is synchronized					
SYS.HMLSAT.FAT007.3	Verify control command failures					
Supplemental SAT Test Book: FAT-008						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.HMLSAT.FAT008.1	Verify analog controls (set points), raise/lower (no return),...					
SYS.HMLSAT.FAT008.2	Verify control action propagation in all modules and that execution is synchronized					
SYS.HMLSAT.FAT008.3	Verify control command failures					
SYS.HMLSAT.FAT008.4	Check that all types of points and values are tested					
SYS.HMLSAT.FAT008.5	Verify value representation, values and data quality					
SYS.HMLSAT.FAT008.6	Verify data presented in Tabular displays					
SYS.HMLSAT.FAT008.7	Verify alarm events					
SYS.HMLSAT.FAT008.8	Verify all the alarm types and event reporting caused by data processing					
SYS.HMLSAT.FAT008.9	Verify analog data deadband defined in the devices by checking the reported values in HMI. This will verify that there is no deadband defined at the SICAM level					
SYS.HMLSAT.FAT008.10	Verify time needed for data presentation and control execution to and from the Control Center					
Supplemental SAT Test Book: FAT-010						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.HMLSAT.FAT010.1	Verify status reporting and logging at the HMI and CC					
SYS.HMLSAT.FAT010.2	Verify communication management capabilities like force DNP3 scan, force alternative communication path,...					

Supplemental SAT Test Book: FAT-021						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.HMLSAT.FAT021.1	Verify the availability of Help screen (Not only SICAM help)					
SYS.HMLSAT.FAT021.2	Verify definition and use of KCPL defined help screens					
Supplemental SAT Test Book: FAT-012						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.HMLSAT.FAT012.1	Verify only defined users can log on					
SYS.HMLSAT.FAT012.2	Verify change in AOR					
SYS.HMLSAT.FAT012.3	Verify authorization and permission changes for an AOR					
SYS.HMLSAT.FAT012.4	Verify alarm and event list access					
Supplemental SAT Test Book: FAT-017						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.HMLSAT.FAT017.1	Verify alarm management capabilities (acknowledge,					
SYS.HMLSAT.FAT017.2	Verify alarm list functions like filtering, queries, paging,...					
SYS.HMLSAT.FAT017.3	Verify that alarm error conditions and problems are reported and logged (list full, alarm processing not working,...)					
SYS.HMLSAT.FAT017.4	Verify alarm management special conditions like max number of alarms reached, reduced view,...					
SYS.HMLSAT.FAT017.5	Verify reporting and logging of alarm issues and list					
SYS.HMLSAT.FAT017.6	Verify queries and filtering capabilities in logs					

System Test Book - SICAM FAT: Document Verification Checklist						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.SCMS.FAT001:1	Verify that the single line diagram is provided during the FAT.	N/A				
SYS.SCMS.FAT001:2	Verify that the functional design specification is provided during the FAT.	N/A				
SYS.SCMS.FAT001:3	Verify that the network architecture is provided during the FAT.	N/A				
SYS.SCMS.FAT001:4	Verify that the network architecture of test system is provided during the FAT.	N/A				
SYS.SCMS.FAT001:5	Verify that the system configuration description is provided during the FAT.	N/A				
SYS.SCMS.FAT001:6	Verify that the signal is provided during the FAT.	N/A				
System Test Book - SICAM FAT: Equipment Hardware Checklist						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.SCMS.FAT002:1	Verify that two SICAM PAS Station Units 2.20 are provided during the FAT.	N/A				
SYS.SCMS.FAT002:2	Verify that one SEL 487B is provided during the FAT.	N/A				
SYS.SCMS.FAT002:3	Verify that one SEL 487E is provided during the FAT.	N/A				
SYS.SCMS.FAT002:4	Verify that one SEL 451 is provided during the FAT.	N/A				
SYS.SCMS.FAT002:5	Verify that one SEL 751A is provided during the FAT.	N/A				
SYS.SCMS.FAT002:6	Verify that one Arbiter GPS Clock is provided during the FAT.	N/A				
SYS.SCMS.FAT002:7	Verify that one RSG2100 RuggedCom Ethernet Switch is provided during the FAT.	N/A				
SYS.SCMS.FAT002:8	Verify that one Cisco Ethernet Switch is provided during the FAT.	N/A				
SYS.SCMS.FAT002:9	Verify that one A-Eberle Tap Changer is provided during the FAT.	N/A				

System Test Book - SICAM FAT: Equipment Software Checklist						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.SCMS.FAT003:1.1	Verify that the SICAM PAS Station Unit has Windows XP Embedded OS SP3 .	N/A				
SYS.SCMS.FAT003:1.2.1	Verify that the SICAM PAS Station Unit has the SICAM PAS V7.01 Runtime & Configuration Dongle.	N/A				
SYS.SCMS.FAT003:1.2.2	Verify that the SICAM PAS Station Unit has PAS Runtime.	N/A				
SYS.SCMS.FAT003:1.2.3	Verify that the SICAM PAS Station Unit has PAS UI Large.	N/A				
SYS.SCMS.FAT003:1.2.4	Verify that the SICAM PAS Station Unit has IEC61850 Client.	N/A				
SYS.SCMS.FAT003:1.2.5	Verify that the SICAM PAS Station Unit has DNP3.0 MASTER.	N/A				
SYS.SCMS.FAT003:1.2.6	Verify that the SICAM PAS Station Unit has DNP3.0 SLAVE.	N/A				
SYS.SCMS.FAT003:1.2.7	Verify that the SICAM PAS Station Unit has AUTOMATION.	N/A				
SYS.SCMS.FAT003:1.2.8	Verify that the SICAM PAS Station Unit has IEC61850 Server.	N/A				
SYS.SCMS.FAT003:1.3.1	SICAM PAS Backup DVD	N/A				
System Test Book - SICAM FAT: System Startup Behavior Checklist						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.SCMS.FAT004:0.1	Verify that the SICAM station unit is connected to power.	N/A				
SYS.SCMS.FAT004:0.2	Verify that the SICAM station unit is connected to the network.	N/A				
SYS.SCMS.FAT004:0.3	Verify access to SICAM station unit available through external monitor or remote desktop session.	N/A				
SYS.SCMS.FAT004:1	Open UI Operation and verify that all applications within the UI Operation are running with GREEN icon indication on HVPAS1.	N/A				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.SCMS.FAT004:2	Open UI Operation and verify that all applications within the UI Operation are running with GREEN Icon Indication on HVPAS2.	N/A				
System Test Book - SICAM FAT: Redundancy & Self Healing at Station Level						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.SCMS.FAT005:1.1.1	Verify that Station Unit 1 is the assigned Active system.	N/A				
SYS.SCMS.FAT005:1.1.2	Verify that Station Unit 2 is the assigned Standby.	N/A				
SYS.SCMS.FAT005:1.1.3	Verify that DCADA Computers are connected to Active system (This is verified through PAS Operation).	N/A				
SYS.SCMS.FAT005:1.2	Simulate the Station Unit 1 Failure by switching off the power supplies to the station unit.	Verify that Station Unit 2 is assigned as the new active Station Unit and Station unit 1 is not communicating, and verify that DCADA computers are connected to the Active system (Station unit 2).				
SYS.SCMS.FAT005:1.3	Return power to Station Unit 1.	Verify that Station Unit 1 is assigned as the Standby system and Station unit 2 is assigned as Active, and verify that DCADA computers are still connected to the Active system.				
SYS.SCMS.FAT005:1.4.1	Disconnect any one redundant cable connection to the network switch.	Verify that ValueViewer indicates defected cable.				
SYS.SCMS.FAT005:1.4.2	Disconnect any one redundant cable connection to the network switch.	Verify that Station Unit 1 is still in service and communicating to the DCADA.				
SYS.SCMS.FAT005:1.4.3	Disconnect any one redundant cable connection to the network switch.	Verify that there is no change in the Active standby assignment in SICAM PAS Operation.				
SYS.SCMS.FAT005:2.1	Simulate the Station Unit 2 Failure by switching off the power supplies to the station unit.	Verify that Station Unit 1 is assigned as the new active Station Unit and Station unit 2 is not communicating, and verify that DCADA computers are connected to the Active system (Station unit 1).				
SYS.SCMS.FAT005:2.2	Return power to Station Unit 2.	Verify that Station Unit 2 is assigned as the Standby system and Station unit 1 is assigned as Active, and verify that DCADA computers are still connected to the Active system.				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.SCMS.FAT005:2.3.1	Disconnect any one redundant cable connection to the network switch.	Verify that ValueViewer Indicates detected cable.				
SYS.SCMS.FAT005:2.3.2	Disconnect any one redundant cable connection to the network switch.	Verify that Station Unit 2 is still in service and communicating to the DCADA.				
SYS.SCMS.FAT005:2.3.3	Disconnect any one redundant cable connection to the network switch.	Verify that there is no change in the Active standby assignment in SICAM PAS Operation.				
SYS.SCMS.FAT005:3.1.1	Unplug the network cables from Station unit 1.	Verify that Station unit 2 is assigned as Active and Station unit 1 is not communicating.				
SYS.SCMS.FAT005:3.1.2	Unplug the network cables from Station unit 1.	Verify the DCADA computers connect to the Active system (Station unit 2).				
SYS.SCMS.FAT005:3.2.1	Connect the network cables back to Station unit 1.	Verify that Station unit 1 is assigned as Active and Station unit 2 is standby.				
SYS.SCMS.FAT005:3.2.2	Connect the network cables back to Station unit 1.	Verify the DCADA computers connect to Active system (Station unit 1).				
SYS.SCMS.FAT005:3.3.1	Unplug the network cables from Station unit 2.	Verify that Station unit 1 is still assigned as Active system and Station unit 2 is not communicating.				
SYS.SCMS.FAT005:3.3.2	Unplug the network cables from Station unit 2.	Verify the DCADA computers connect to the Active system (Station unit 1).				
SYS.SCMS.FAT005:3.4.1	Connect the network cables back to Station unit 2.	Verify that Station unit 1 remains as Active system and Station unit 2 is standby.				
SYS.SCMS.FAT005:3.4.2	Connect the network cables back to Station unit 2.	Verify the DCADA computers connect to the Active system (Station unit 1).				
System Test Book- SICAM FAT: Communication Test:						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.SCMS.FAT006:1.1.1	Ping the SEL 487E from station unit 1.	Verify ping is successful.				
SYS.SCMS.FAT006:1.1.2	Ping the SEL 487B from station unit 1.	Verify ping is successful.				
SYS.SCMS.FAT006:1.1.3	Ping the SEL 451-5 from station unit 1.	Verify ping is successful.				
SYS.SCMS.FAT006:1.1.4	Ping the SEL 751A from station unit 1.	Verify ping is successful.				
SYS.SCMS.FAT006:1.1.5	Ping the A-Eberle Tap Changer from station unit 1.	Verify ping is successful.				
SYS.SCMS.FAT006:1.1.6	Ping the Rugged-SH1 from station unit 1.	Verify ping is successful.				
SYS.SCMS.FAT006:1.1.7	Ping the Rugged-SH2 from station unit 1.	Verify ping is successful.				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.SCMS.FAT006:1.1.8	Ping the Rugged-SH3 from station unit 1.	Verify ping is successful.				
SYS.SCMS.FAT006:1.1.9	Ping the Rugged-SH4 from station unit 1.	Verify ping is successful.				
SYS.SCMS.FAT006:1.1.10	Ping the Rugged-CH1 from station unit 1.	Verify ping is successful.				
SYS.SCMS.FAT006:1.1.11	Ping the Cisco-SH1 from station unit 1.	Verify ping is successful.				
SYS.SCMS.FAT006:1.1.12	Ping the Cisco-SH2 from station unit 1.	Verify ping is successful.				
SYS.SCMS.FAT006:1.1.13	Ping the Cisco-SH3 from station unit 1.	Verify ping is successful.				
SYS.SCMS.FAT006:1.1.14	Ping the Cisco-SH4 from station unit 1.	Verify ping is successful.				
SYS.SCMS.FAT006:1.1.15	Ping the Cisco-CH1 from station unit 1.	Verify ping is successful.				
SYS.SCMS.FAT006:1.2.1	Ping the SEL 487E from station unit 2.	Verify ping is successful.				
SYS.SCMS.FAT006:1.2.2	Ping the SEL 487B from station unit 2.	Verify ping is successful.				
SYS.SCMS.FAT006:1.2.3	Ping the SEL 452-5 from station unit 2.	Verify ping is successful.				
SYS.SCMS.FAT006:1.2.4	Ping the SEL 752A from station unit 2.	Verify ping is successful.				
SYS.SCMS.FAT006:1.2.5	Ping the A-Eberle Tap Changer from station unit 2.	Verify ping is successful.				
SYS.SCMS.FAT006:1.2.6	Ping the Rugged-SH2 from station unit 2.	Verify ping is successful.				
SYS.SCMS.FAT006:1.2.7	Ping the Rugged-SH2 from station unit 2.	Verify ping is successful.				
SYS.SCMS.FAT006:1.2.8	Ping the Rugged-SH3 from station unit 2.	Verify ping is successful.				
SYS.SCMS.FAT006:1.2.9	Ping the Rugged-SH4 from station unit 2.	Verify ping is successful.				
SYS.SCMS.FAT006:1.2.10	Ping the Rugged-CH2 from station unit 2.	Verify ping is successful.				
SYS.SCMS.FAT006:1.2.11	Ping the Cisco-SH2 from station unit 2.	Verify ping is successful.				
SYS.SCMS.FAT006:1.2.12	Ping the Cisco-SH2 from station unit 2.	Verify ping is successful.				
SYS.SCMS.FAT006:1.2.13	Ping the Cisco-SH3 from station unit 2.	Verify ping is successful.				
SYS.SCMS.FAT006:1.2.14	Ping the Cisco-SH4 from station unit 2.	Verify ping is successful.				
SYS.SCMS.FAT006:1.2.15	Ping the Cisco-CH2 from station unit 2.	Verify ping is successful.				
SYS.SCMS.FAT006:2.1	Verify that Relays are available and in "running mode" (Green Play Button) mode on SICAM PAS UI Operation.	N/A				
SYS.SCMS.FAT006:2.2.1	Disconnect the SEL751A from the network.	Verify that the disconnected relay changes mode to "pending up" (Blue Up Arrow) on SICAM PAS UI Operation.				
SYS.SCMS.FAT006:2.2.2	Disconnect the SEL 451-5 from the network.	Verify that the disconnected relay changes mode to "pending up" (Blue Up Arrow) on SICAM PAS UI Operation.				
SYS.SCMS.FAT006:2.2.3	Disconnect the SEL 487B from the network.	Verify that the disconnected relay changes mode to "pending up" (Blue Up Arrow) on SICAM PAS UI Operation.				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.SCMS.FAT006:2.2.4	Disconnect the SEL 487E from the network.	Verify that the disconnected relay changes mode to "pending up" (Blue Up Arrow) on SICAM PAS UI Operation.				
SYS.SCMS.FAT006:2.2.5	Disconnect the REG-DA from the network.	Verify that the disconnected relay changes mode to "pending up" (Blue Up Arrow) on SICAM PAS UI Operation.				
SYS.SCMS.FAT006:2.3.1	Reconnect the SEL751A from the network.	Verify that the reconnected relay changes mode to "Running" (Green Play Button) on SICAM PAS UI Operation.				
SYS.SCMS.FAT006:2.3.2	Reconnect the SEL 451-5 from the network.	Verify that the reconnected relay changes mode to "Running" (Green Play Button) on SICAM PAS UI Operation.				
SYS.SCMS.FAT006:2.3.3	Reconnect the SEL 487B from the network.	Verify that the reconnected relay changes mode to "Running" (Green Play Button) on SICAM PAS UI Operation.				
SYS.SCMS.FAT006:2.3.4	Reconnect the SEL 487E from the network.	Verify that the reconnected relay changes mode to "Running" (Green Play Button) on SICAM PAS UI Operation.				
SYS.SCMS.FAT006:2.3.5	Reconnect the REG-DA from the network.	Verify that the reconnected relay changes mode to "Running" (Green Play Button) on SICAM PAS UI Operation.				
SYS.SCMS.FAT006:3.1.1	Unplug one cable from any active port of switch Ruggedcom-SH1	Verify the status of that port in the value viewer.				
SYS.SCMS.FAT006:3.1.2	Unplug one cable from any active port of switch Ruggedcom-SH2	Verify the status of that port in the value viewer.				
SYS.SCMS.FAT006:3.1.3	Unplug one cable from any active port of switch Ruggedcom-SH3	Verify the status of that port in the value viewer.				
SYS.SCMS.FAT006:3.1.4	Unplug one cable from any active port of switch Ruggedcom-SH4	Verify the status of that port in the value viewer.				
SYS.SCMS.FAT006:3.1.5	Unplug one cable from any active port of switch Ruggedcom-CH1	Verify the status of that port in the value viewer.				
SYS.SCMS.FAT006:3.2.1	Unplug one cable from any active port of switch Cisco-SH1	Verify the status of that port in the value viewer.				
SYS.SCMS.FAT006:3.2.2	Unplug one cable from any active port of switch Cisco-SH2	Verify the status of that port in the value viewer.				
SYS.SCMS.FAT006:3.2.3	Unplug one cable from any active port of switch Cisco-SH3	Verify the status of that port in the value viewer.				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.SCMS.FAT006:3.2.4	Unplug one cable from any active port of switch Cisco-SH4	Verify the status of that port in the value viewer.				
SYS.SCMS.FAT006:3.2.5	Unplug one cable from any active port of switch Cisco-CH1	Verify the status of that port in the value viewer.				
System Test Book - SICAM FAT: Signal Test						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.SCMS.FAT007:1.1.1	Trigger each indication, as per the signal list, from the 487B.	Verify that the triggered signal changed status in the SICAM Value Viewer.				
SYS.SCMS.FAT007:1.1.2	Inject the measurement signal, as per the signal list, into the 487B using Omicron test set.	Verify that the measurement signal was recognized by the 487B, and that the value in the SICAM Value Viewer matches.				
SYS.SCMS.FAT007:1.1.3	Issue a command from SICAM Value Viewer as per the signal list or from the DCADA system.	Verify the 487B received the command and performs the designated action.				
SYS.SCMS.FAT007:1.2.1	Trigger each indication, as per the signal list, from the 487E.	Verify that the triggered signal changed status in the SICAM Value Viewer.				
SYS.SCMS.FAT007:1.2.2	Inject the measurement signal, as per the signal list, into the 487E using Omicron test set.	Verify that the measurement signal was recognized by the 487E, and that the value in the SICAM Value Viewer matches.				
SYS.SCMS.FAT007:1.2.3	Issue a command from SICAM Value Viewer as per the signal list or from the DCADA system.	Verify the 487E received the command and performs the designated action.				
SYS.SCMS.FAT007:1.3.1	Trigger each indication, as per the signal list, from the 751A.	Verify that the triggered signal changed status in the SICAM Value Viewer.				
SYS.SCMS.FAT007:1.3.2	Inject the measurement signal, as per the signal list, into the 751A using Omicron test set.	Verify that the measurement signal was recognized by the 751A, and that the value in the SICAM Value Viewer matches.				
SYS.SCMS.FAT007:1.3.3	Issue a command from SICAM Value Viewer as per the signal list or from the DCADA system.	Verify the 751A received the command and performs the designated action.				
SYS.SCMS.FAT007:1.4.1	Trigger each indication, as per the signal list, from the 451.	Verify that the triggered signal changed status in the SICAM Value Viewer.				
SYS.SCMS.FAT007:1.4.2	Inject the measurement signal, as per the signal list, into the 451 using Omicron test set.	Verify that the measurement signal was recognized by the 451, and that the value in the SICAM Value Viewer matches.				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.SCMS.FAT007:1.4.3	Issue a command from SICAM Value Viewer as per the signal list or from the DCADA system.	Verify the 451 received the command and performs the designated action.				
SYS.SCMS.FAT007:1.5.1	Trigger each indication, as per the signal list, from the REG-DA.	Verify that the triggered signal changed status in the SICAM Value Viewer.				
SYS.SCMS.FAT007:1.5.2	Inject the measurement signal, as per the signal list, into the REG-DA using Omicron test set.	Verify that the measurement signal was recognized by the REG-DA, and that the value in the SICAM Value Viewer matches.				
SYS.SCMS.FAT007:1.5.3	Issue a command from SICAM Value Viewer as per the signal list or from the DCADA system.	Verify the REG-DA received the command and performs the designated action.				
System Test Book - SICAM FAT: Time Synchronization Test						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.SCMS.FAT008:1.1.1	Disconnect the network cables from the GPS Clocks.	NTP Trace on Station Unit - check that the actual time server gets timed out. This can take 3-5 min.				
SYS.SCMS.FAT008:1.1.2	Check that the stratum of the SICAM PAS Station Unit 1 changes from 1 to 11 (10+1).	N/A				
SYS.SCMS.FAT008:1.1.3	Reconnect network cables.	NTP Trace on Station Unit - check that the stratum of the station controllers changes to 2.				
SYS.SCMS.FAT008:1.1.4	Disconnect the network cables from the GPS Clocks.	N/A				
SYS.SCMS.FAT008:1.2.1	Disconnect the network cables from the GPS Clocks.	NTP Trace on Station Unit - check that the actual time server gets timed out. This can take 3-5 min.				
SYS.SCMS.FAT008:1.2.2	Check that the stratum of the SICAM PAS Station Unit 2 changes from 1 to 11 (10+1).	N/A				
SYS.SCMS.FAT008:1.2.3	Reconnect network cables.	NTP Trace on Station Unit - check that the stratum of the station controllers changes to 2.				
SYS.SCMS.FAT008:1.2.4	Disconnect the network cables from the GPS Clocks.	N/A				
SYS.SCMS.FAT008:1.3.1	Stop the NTP service from Station unit 1. and run ntptrace.	Verify the connection is timed.				
SYS.SCMS.FAT008:1.3.2	Run ntptrace-sag on station unit 2.	Check that the stratum of the station controller is 11.				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.SCMS.FAT008:1.4.1	Run the "ntpq-sag -p" command in the command shell. Keep running the command for about 7 to 10 minutes.	Verify that you get "*" mark on the left of the IP address of the clock. This verifies that the station unit is synchronized with the clock.				
SYS.SCMS.FAT008:1.4.2	Run the "ntpq-sag -p" command in station unit 2.	Verify that it was already synchronized with the clock.				
SYS.SCMS.FAT008:1.4.3	Run the "ntpq-sag -p" command in the command shell. Keep running the command for about 7 to 10 minutes.	Verify that you get "*" mark on the left of the IP address of the clock. This verifies that the station unit is synchronized with the clock.				
SYS.SCMS.FAT008:1.4.4	Run the "ntpq-sag -p" command in station unit 1.	Verify that it was already synchronized with the clock.				
SYS.SCMS.FAT008:2.1	Remove the IRIG-B connection from behind the relay	In the Value viewer, verify that IRIG status MMS message signal is changes value from 1 to 0.				
SYS.SCMS.FAT008:2.2	Plug the IRIG-B connection back onto the relay.	In the ValueViewer, verify that IRIG status MMS message signal changes from 0 to 1.				

Supplemental SICAM SAT Test Book: SAT-003						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.SCMS.SAT.SAT003.1	Verify system management and configuration displays and tools	N/A				
Supplemental SICAM SAT Test Book: SAT-004						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.SCMS.SAT.SAT004.1	Verify SICAM status changes are reported and logged at the CC and HMI	N/A				
SYS.SCMS.SAT.SAT004.2	Verify that IED scanning is happening and data is correct not only that the application is running	N/A				
SYS.SCMS.SAT.SAT004.3	Verify correct operation of the system components. (system configuration overview, servers status, communications status, applications running,...)	N/A				
SYS.SCMS.SAT.SAT004.4	Verify data consistency at all levels starting at the HMI and InService	N/A				
SYS.SCMS.SAT.SAT004.5	Verify users log on and log off	N/A				
SYS.SCMS.SAT.SAT004.6	Verify only defined users can log on	N/A				
SYS.SCMS.SAT.SAT004.7	Verify configuration of ADRs and permissions for different users	N/A				
Supplemental SICAM SAT Test Book: SAT-005						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.SCMS.SAT.SAT005.1	Verify LAN failure recovery for SICAM	N/A				
SYS.SCMS.SAT.SAT005.2	Verify system behavior during individual servers power failures	N/A				
SYS.SCMS.SAT.SAT005.3	Verify SICAM status changes are reported and logged at the CC and HMI	N/A				
SYS.SCMS.SAT.SAT005.4	After Power Failure, verify that IED scanning is happening and data is correct not only that the application is running	N/A				
SYS.SCMS.SAT.SAT005.5	Verify data is correct after failover at all levels of redundancy	N/A				

Supplemental SICAM SAT Test Book: SAT-006						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.SCMS.SAT.SAT006.1	Verify that all error conditions detected in the communication with the IEDs, are reported upstream. (change signal from 61850 to dnp for instance)	N/A				
SYS.SCMS.SAT.SAT006.2	Verify communication error reporting and logging at the Control Center	N/A				
SYS.SCMS.SAT.SAT006.3	Verify IED and SICAM communication management at the Control Center	N/A				
SYS.SCMS.SAT.SAT006.4	Verify communication management capabilities at the CC	N/A				
SYS.SCMS.SAT.SAT006.5	Verify communication failover and redundancy for communication or application errors/problems.	N/A				
SYS.SCMS.SAT.SAT006.6	Verify SICAM redundancy at the application level (caused by SW decisions, problems or errors)	N/A				
SYS.SCMS.SAT.SAT006.7	Verification of communication redundancy at the protocol level. Failover caused by protocol errors like number of fail attempts, IED reporting errors,...	N/A				
SYS.SCMS.SAT.SAT006.8	Verify system response to communication failure at the IED side (port unavailable, tropos router down,...)	N/A				
SYS.SCMS.SAT.SAT006.9	Verify communication management capabilities like force DNP3 scan, force alternative communication path,...	N/A				
SYS.SCMS.SAT.SAT006.10	Verify IED configuration related to port, protocol, profile,...	N/A				

Supplemental SICAM SAT Test Book: SAT-007						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
IEC61850 - SEL487B (Values)						
SYS.SCMS.SAT.SAT007.1.1	Verify analog data deadband defined in the devices by checking the reported values in HMI. This will verify that there is no deadband defined at the SICAM level.	N/A				
IEC61850 - SEL487B Controls						
SYS.SCMS.SAT.SAT007.1.2	Verify analog controls (set points), raise/lower (no return),...	N/A				
SYS.SCMS.SAT.SAT007.1.3	Verify control action propagation in all modules and that execution is synchronized	N/A				
SYS.SCMS.SAT.SAT007.1.4	Verify control command failures	N/A				
IEC61850 - SEL487E (Values)						
SYS.SCMS.SAT.SAT007.2.1	Verify analog data deadband defined in the devices by checking the reported values in HMI. This will verify that there is no deadband defined at the SICAM level.	N/A				
IEC61850 - SEL487E Controls						
SYS.SCMS.SAT.SAT007.2.2	Verify analog controls (set points), raise/lower (no return),...	N/A				
SYS.SCMS.SAT.SAT007.2.3	Verify control action propagation in all modules and that execution is synchronized	N/A				
SYS.SCMS.SAT.SAT007.2.4	Verify control command failures	N/A				
IEC61850 - SEL751A (Values)						
SYS.SCMS.SAT.SAT007.3.1	Verify analog data deadband defined in the devices by checking the reported values in HMI. This will verify that there is no deadband defined at the SICAM level.	N/A				
IEC61850 - SEL751A Controls						
SYS.SCMS.SAT.SAT007.3.2	Verify analog controls (set points), raise/lower (no return),...	N/A				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.SCMS.SAT.SAT007.3.3	Verify control action propagation in all modules and that execution is synchronized	N/A				
SYS.SCMS.SAT.SAT007.3.4	Verify control command failures	N/A				
IEC61850 - SEL451 (Values)						
SYS.SCMS.SAT.SAT007.4.1	Verify analog data deadband defined in the devices by checking the reported values in HMI. This will verify that there is no deadband defined at the SICAM level.	N/A				
IEC61850 - SEL451 Controls						
SYS.SCMS.SAT.SAT007.4.2	Verify analog controls (set points), raise/lower (no return),...	N/A				
SYS.SCMS.SAT.SAT007.4.3	Verify control action propagation in all modules and that execution is synchronized	N/A				
SYS.SCMS.SAT.SAT007.4.4	Verify control command failures	N/A				
IEC61850 - REG-DA (Values)						
SYS.SCMS.SAT.SAT007.5.1	Verify analog data deadband defined in the devices by checking the reported values in HMI. This will verify that there is no deadband defined at the SICAM level	N/A				
IEC61850 - REG-DA Controls						
SYS.SCMS.SAT.SAT007.5.2	Verify analog controls (set points), raise/lower (no return),...	N/A				
SYS.SCMS.SAT.SAT007.5.3	Verify control action propagation in all modules and that execution is synchronized	N/A				
SYS.SCMS.SAT.SAT007.5.4	Verify control command failures	N/A				
SYS.SCMS.SAT.SAT007.5.5	Verify error reporting and logging. Some error conditions need to be generated.	N/A				
SYS.SCMS.SAT.SAT007.5.6	Verify all the alarm types and event reporting caused by data processing	N/A				
SYS.SCMS.SAT.SAT007.5.7	Verify time needed for data presentation and control execution to and from the Control Center	N/A				

Supplemental SICAM SAT Test Book: SAT-009						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
DNP3 - Intellicap (Values)						
SYS.SCMS.SAT.SAT009.1.1	Verify analog data deadband defined in the devices by checking the reported values in HMI. This will verify that there is no deadband defined at the SICAM level.	N/A				
DNP3 - Intellicap (Commands)						
SYS.SCMS.SAT.SAT009.1.2	Verify analog controls (set points), raise/lower (no return),...	N/A				
SYS.SCMS.SAT.SAT009.1.3	Verify control action propagation in all modules and that execution is synchronized	N/A				
SYS.SCMS.SAT.SAT009.1.4	Verify control command failures	N/A				
DNP3 - FCI (Values)						
SYS.SCMS.SAT.SAT009.2.1	Verify analog data deadband defined in the devices by checking the reported values in HMI. This will verify that there is no deadband defined at the SICAM level.	N/A				
DNP3 - FCI (Commands)						
SYS.SCMS.SAT.SAT009.2.2	Verify analog controls (set points), raise/lower (no return),...	N/A				
SYS.SCMS.SAT.SAT009.2.3	Verify control action propagation in all modules and that execution is synchronized	N/A				
SYS.SCMS.SAT.SAT009.2.4	Verify control command failures	N/A				
DNP3 - Recloser (Values)						
SYS.SCMS.SAT.SAT009.3.1	Verify analog data deadband defined in the devices by checking the reported values in HMI. This will verify that there is no deadband defined at the SICAM level.	N/A				
DNP3 - Recloser (Commands)						
SYS.SCMS.SAT.SAT009.3.2	Verify analog controls (set points), raise/lower (no return),...	N/A				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.SCMS.SAT.SAT009.3.3	Verify control action propagation in all modules and that execution is synchronized	N/A				
SYS.SCMS.SAT.SAT009.3.4	Verify control command failures	N/A				
DNP3 - Recloser (Counters)						
SYS.SCMS.SAT.SAT009.3.5	Verify error reporting and logging	N/A				
SYS.SCMS.SAT.SAT009.3.6	Verify all the alarm types and event reporting caused by data processing	N/A				
SYS.SCMS.SAT.SAT009.3.7	Verify time needed for data presentation and control execution to and from the Control Center	N/A				
SYS.SCMS.SAT.SAT009.3.8	Verify that the SICAM can synchronize IEDs using DNP3	N/A				

System Test Book - DCADA (Phase 3 FAT): Control Transfer						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DCADA(P3FAT).TC2.1.1	Starting the UI: Testing the startup sequence of the Control Transfer UI	N/A				
SYS.DCADA(P3FAT).TC2.1.2	Mastership at DMS: Test that UI can transfer mastership at DMS	N/A				
SYS.DCADA(P3FAT).TC2.1.3	Mastership at DCADA: Test that UI can transfer mastership to DCADA	N/A				
SYS.DCADA(P3FAT).TC2.2.1	Transfer Control – DCADA Closed Loop: Verify that Control (mastership) is transferred back to DMS when problems arise when DCADA is in closed loop control for a region.	N/A				
SYS.DCADA(P3FAT).TC2.2.2	Transfer Control – Exit Closed Loop at DMS: Verify that Closed Loop Operation is suspended when problem is encountered while applications are running in closed loop in DMS.	N/A				
SYS.DCADA(P3FAT).TC2.3.1	Verification – DCADA Closed Loop: Verify that DMS Operator is able to perform all actions besides "Control" when mastership is at DCADA.	N/A				
SYS.DCADA(P3FAT).TC2.3.2	Verification – DMS Manual: Verify that DMS Operator is able to perform all actions including "Control" when mastership is at DMS with control type of Manual Control.	N/A				
SYS.DCADA(P3FAT).TC2.3.3	Verification – DMS Closed Loop: Verify that DMS Operator is able to perform all actions besides "Control" when Mastership is at DMS with Control Type of Closed Loop Control.	N/A				

System Test Book - DCADA (Phase 3 FAT): Closed Loop Operation						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DCADA(P3FAT).TC3.1.1	Receiving Messages at DMS sent by DMS applications: Testing message propagation at DMS location sent by DMS applications when DMS has mastership and run in Close Loop or Advisory (manual) operation mode.	N/A				
SYS.DCADA(P3FAT).TC3.1.2	Messages at DMS sent by DCADA applications: Testing propagation of messages to DMS location sent by DCADA applications when DCADA has mastership and operates in Closed Loop control mode	N/A				
SYS.DCADA(P3FAT).TC3.2.1	FDIR – normal operation at DCADA master: Testing of the FDIR operation at DCADA with mastership in closed loop control mode.	N/A				
SYS.DCADA(P3FAT).TC3.2.2	VVC – normal operation at DCADA master: Testing of the VVC operation at DCADA with mastership in closed loop control mode.	N/A				
SYS.DCADA(P3FAT).TC3.2.3	FLT – normal operation at DCADA master: Testing of the FLT operation at DCADA with mastership in closed loop control mode.	N/A				
SYS.DCADA(P3FAT).TC3.3.1	FDIR – normal operation at DMS master: Testing of the FDIR operation at DMS with mastership in closed loop control mode.	N/A				
SYS.DCADA(P3FAT).TC3.3.2	VVC – normal operation at DMS master: Testing of the VVC operation at DMS with mastership in closed loop control mode.	N/A				
SYS.DCADA(P3FAT).TC3.3.3	FLT – normal operation at DMS master: Testing of the FLT operation at DMS with mastership in closed loop control mode.	N/A				

System Test Book - DCADA (Phase 3 SAT)						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DCADA(P3SAT).62	Verify presentation of the control and application status for the substation and the CC	N/A				
SYS.DCADA(P3SAT).64	Verify Manual transfer of DNA control to DMS	N/A				
SYS.DCADA(P3SAT).64	Verify Manual transfer of DNA control to DCADA	N/A				
SYS.DCADA(P3SAT).419	Verify that the Mastership control UI or status and control operations are accessible in DCADA DNA in case DMS is not accessible	N/A				
SYS.DCADA(P3SAT).420	Verify automatic transfer of control from DCADA close loop to DMS: - Boundary switch closed - Connection between DCADA and SICAM lost - FLT/FISR/VVC error condition in DCADA DNA - Loss of communication between DCADA and DMS	N/A				
SYS.DCADA(P3SAT).421	Verify of automatic control authority removal from DMS close loop when : - Boundary switch closed - Connection between DMS and SICAM is lost - FISR/FLT/VVC error condition in DMS DNA - Loss of communication between DCADA and DMS	N/A				
SYS.DCADA(P3SAT).422	Verify normal operation of DMS except for controls when DCADA is master	N/A				
SYS.DCADA(P3SAT).424	Verify normal operation of DMS including controls when DMS is Master and in manual mode	N/A				
SYS.DCADA(P3SAT).425	Verify normal operation of DMS except controls when DMS is Master in Close Loop	N/A				
SYS.DCADA(P3SAT).426	Verify DCADA can not be set to close loop operation when DMS is Master	N/A				
SYS.DCADA(P3SAT).427	Verify DMS can not be set to close loop operation for Midtown when DCADA is Master	N/A				
SYS.DCADA(P3SAT).428	Verify notification of Control Mastership in DCADA and DMS UIs	N/A				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DCADA(P3SAT).196	Enable - disable applications independently in DCADA and DMS	N/A				
SYS.DCADA(P3SAT).208	From InService demonstrate access to PowerFlow connecting to the DNA in DCADA	N/A				
SYS.DCADA(P3SAT).219	Run DSSE from DCADA DNA UI and verify results	N/A				
SYS.DCADA(P3SAT).220	Verify DSSE different modes of execution from DCADA	N/A				
SYS.DCADA(P3SAT).221	Verify reporting of execution errors or problems from DCADA	N/A				
SYS.DCADA(P3SAT).222	Verify access to application alarms or program output from DCADA	N/A				
SYS.DCADA(P3SAT).224	Introduce manual data changes and verify results	N/A				
SYS.DCADA(P3SAT).236	Run Power Flow from DCADA DNA UI and verify results	N/A				
SYS.DCADA(P3SAT).237	Verify PowerFlow different modes of execution from the DCADA	N/A				
SYS.DCADA(P3SAT).241	Introduce manual data changes and verify results from the DCADA	N/A				
SYS.DCADA(P3SAT).243	Verify access to list and summaries using DNA UI in DCADA	N/A				
SYS.DCADA(P3SAT).245	Verify alarms generated in DCADA by Limit violation or other operational conditions like non convergence.	N/A				
SYS.DCADA(P3SAT).246	Verify DNA PF simultaneous execution in DMS and DCADA (Event Triggered)	N/A				
SYS.DCADA(P3SAT).247	Verify and compare PF results	N/A				
SYS.DCADA(P3SAT).266	Verify FLT running from DCADA	N/A				
SYS.DCADA(P3SAT).289	Verify authority transfer from DCADA to DMS when a solution is not found	N/A				
SYS.DCADA(P3SAT).316	Verify interaction with application in InService	N/A				
SYS.DCADA(P3SAT).317	Verify interaction with application in DNA UI	N/A				
SYS.DCADA(P3SAT).319	Verify access to application alarms or program output	N/A				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DCADA(P3SAT).344	Verify notification to Operator in DMS when authority is transferred	N/A				
SYS.DCADA(P3SAT).371	Verification of VVC configuration and Manual execution	N/A				
SYS.DCADA(P3SAT).375	Verify authority transfer from DCADA to DMS when a solution is not found	N/A				
SYS.DCADA(P3SAT).384	Verify VVC execution triggered by different conditions	N/A				
SYS.DCADA(P3SAT).386	Verify VVC results of the sequence generated and executed	N/A				
SYS.DCADA(P3SAT).389	Verify VVC operation after DCADA failover occurs and stable situation is reestablished	N/A				
SYS.DCADA(P3SAT).402	Verify Close Loop Operation in DCADA	N/A				
SYS.DCADA(P3SAT).407	Verify coordinated Close Loop Operation in DCADA and DMS together	N/A				
SYS.DCADA(P3SAT).408	Verify configuration of close loop in DCADA and DMS together	N/A				
SYS.DCADA(P3SAT).409	Verify Operator's notification in DMS	N/A				
SYS.DCADA(P3SAT).410	Verify authority transfer from DCADA to DMS when a solution is not found	N/A				
SYS.DCADA(P3SAT).411	Verify notification to Operator's in DMS when authority is transferred	N/A				

System Test Book - DMS (Phase 1 Factory Acceptance Test) - SmartSubstation Testing						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P1FAT).1	Verify the IEC61850- GOOSE & MMS and DNP/IP Communication between SICAM PAS and the process IEDs. This includes report by exception and periodic verification poll.	N/A				
SYS.DMS(P1FAT).2	Verify SCMS equipments - Hardware & Software	N/A				
SYS.DMS(P1FAT).3	Verify Relay Communication	N/A				
SYS.DMS(P1FAT).4	Verify Signal	N/A				
SYS.DMS(P1FAT).5	Verify Time synchronization	N/A				
System Test Book - DMS (Phase 1 Factory Acceptance Test) -DMS System Testing						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P1FAT).6	Identify all the substation devices and data points mapping on D-SCADA, InService and ICCP.	N/A				
SYS.DMS(P1FAT).7	Test communication from iSCADA to Substation Devices. - Receive Analog Input data from Devices - Receive Digital Input data from Devices - Simulate devices and measurement. Verify the status/analog data changes. - Verify the supervisory control on devices from iSCADA, verify all the alarms generated from operations	N/A				
SYS.DMS(P1FAT).8	Login in as different users and test permissions. Ack/Cancel alarm, etc.	N/A				
SYS.DMS(P1FAT).9	Verify all the Hardware & Software (running processes) of DMS	N/A				

System Test Book - DMS (Phase 1 Site Acceptance Test) - Feeder / Tie Breaker (751A Profile 1) : Status Points						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P1SAT-P2P-SUB).1	Verify point "Breaker Status"	Values Displayed: - OPEN - CLOSED				
SYS.DMS(P1SAT-P2P-SUB).2	Verify point "Local Remote"	Values Displayed: - LOCAL - REMOTE				
SYS.DMS(P1SAT-P2P-SUB).3	Verify point "79CO"	Values Displayed: - OFF - ON				
SYS.DMS(P1SAT-P2P-SUB).4	Verify point "50CO"	Values Displayed: - OFF - ON				
SYS.DMS(P1SAT-P2P-SUB).5	Verify point "Close Failure"	Values Displayed: - FALSE - TRUE				
SYS.DMS(P1SAT-P2P-SUB).6	Verify point "Under Frequency Trip"	Values Displayed: - FALSE - TRUE				
SYS.DMS(P1SAT-P2P-SUB).7	Verify point "High Current Lockout"	Values Displayed: - FALSE - TRUE				
SYS.DMS(P1SAT-P2P-SUB).8	Verify point "Slow Breaker Indication"	Values Displayed: - FALSE - TRUE				
SYS.DMS(P1SAT-P2P-SUB).9	Verify point "Contact Wear"	Values Displayed: - FALSE - TRUE				
SYS.DMS(P1SAT-P2P-SUB).10	Verify point "Feeder Lockout Operated"	Values Displayed: - FALSE - TRUE				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P1SAT-P2P-SUB).11	Verify point "Trip Coil Monitor"	Values Displayed: - FALSE - TRUE				
SYS.DMS(P1SAT-P2P-SUB).12	Verify point "Latched LED 1"	Values Displayed: - FALSE - TRUE				
SYS.DMS(P1SAT-P2P-SUB).13	Verify point "Latched LED 2"	Values Displayed: - FALSE - TRUE				
SYS.DMS(P1SAT-P2P-SUB).14	Verify point "Latched LED 3"	Values Displayed: - FALSE - TRUE				
SYS.DMS(P1SAT-P2P-SUB).15	Verify point "Latched LED 4"	Values Displayed: - FALSE - TRUE				
SYS.DMS(P1SAT-P2P-SUB).16	Verify point "Latched LED 5"	Values Displayed: - FALSE - TRUE				
SYS.DMS(P1SAT-P2P-SUB).17	Verify point "Latched LED 6"	Values Displayed: - FALSE - TRUE				
SYS.DMS(P1SAT-P2P-SUB).18	Verify point "Hardware Alarm"	Values Displayed: - FALSE - TRUE				
SYS.DMS(P1SAT-P2P-SUB).19	Verify point "Software Alarm"	Values Displayed: - FALSE - TRUE				
SYS.DMS(P1SAT-P2P-SUB).20	Verify point "FAULT"	Values Displayed: - FALSE - TRUE				
SYS.DMS(P1SAT-P2P-SUB).21	Verify point "Synchronism Check Element 1"	Values Displayed: - FALSE - TRUE				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P1SAT-P2P-SUB).22	Verify point "Synchronism Check Element 2"	Values Displayed: - FALSE - TRUE				
SYS.DMS(P1SAT-P2P-SUB).23	Verify point "Healthy Voltage Vp for Synchronism Check"	Values Displayed: - FALSE - TRUE				
SYS.DMS(P1SAT-P2P-SUB).24	Verify point "Healthy Voltage Vs for Synchronism Check"	Values Displayed: - FALSE - TRUE				
SYS.DMS(P1SAT-P2P-SUB).25	Verify point "Loss of Potential"	Values Displayed: - FALSE - TRUE				
System Test Book - DMS (Phase 1 Site Acceptance Test) - Feeder / Tie Breaker (751A Profile 1) - Control Points						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P1SAT-P2P-SUB).26	Verify point "Breaker Open"	Values Displayed: - N/A - OPEN				
SYS.DMS(P1SAT-P2P-SUB).27	Verify point "Breaker Close"	Values Displayed: - N/A - CLOSE				
SYS.DMS(P1SAT-P2P-SUB).28	Verify point "79CO Off"	Values Displayed: - N/A - OFF				
SYS.DMS(P1SAT-P2P-SUB).29	Verify point "79CO On"	Values Displayed: - N/A - ON				
SYS.DMS(P1SAT-P2P-SUB).30	Verify point "50CO Off"	Values Displayed: - N/A - OFF				
SYS.DMS(P1SAT-P2P-SUB).31	Verify point "50CO On"	Values Displayed: - N/A - ON				

System Test Book - DMS (Phase 1 Site Acceptance Test) - Feeder / Tie Breaker (751A Profile 1) : Analog Points						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P1SAT-P2P-SUB).32	Verify point "Real Power - 3 Phase"	N/A				
SYS.DMS(P1SAT-P2P-SUB).33	Verify point "Reactive Power - 3 Phase"	N/A				
SYS.DMS(P1SAT-P2P-SUB).34	Verify point "Amps - Phase A"	N/A				
SYS.DMS(P1SAT-P2P-SUB).35	Verify point "Amps - Phase B"	N/A				
SYS.DMS(P1SAT-P2P-SUB).36	Verify point "Amps - Phase C"	N/A				
SYS.DMS(P1SAT-P2P-SUB).37	Verify point "Voltage - Phase A"	N/A				
SYS.DMS(P1SAT-P2P-SUB).38	Verify point "Voltage - Phase B"	N/A				
SYS.DMS(P1SAT-P2P-SUB).39	Verify point "Voltage - Phase C"	N/A				
SYS.DMS(P1SAT-P2P-SUB).40	Verify point "Apparent Power - 3 Phase"	N/A				
SYS.DMS(P1SAT-P2P-SUB).41	Verify point "Power Factor - 3 Phase"	N/A				
SYS.DMS(P1SAT-P2P-SUB).42	Verify point "Frequency"	N/A				
SYS.DMS(P1SAT-P2P-SUB).43	Verify point "Voltage - Angle - Phase A"	N/A				
SYS.DMS(P1SAT-P2P-SUB).44	Verify point "Voltage - Angle - Phase B"	N/A				
SYS.DMS(P1SAT-P2P-SUB).45	Verify point "Voltage - Angle - Phase C"	N/A				
SYS.DMS(P1SAT-P2P-SUB).46	Verify point "Voltage - Residual"	N/A				
SYS.DMS(P1SAT-P2P-SUB).47	Verify point "Voltage - Angle - Neutral"	N/A				
SYS.DMS(P1SAT-P2P-SUB).48	Verify point "Amps - Angle - Phase A"	N/A				
SYS.DMS(P1SAT-P2P-SUB).49	Verify point "Amps - Angle - Phase B"	N/A				
SYS.DMS(P1SAT-P2P-SUB).50	Verify point "Amps - Angle - Phase C"	N/A				
SYS.DMS(P1SAT-P2P-SUB).51	Verify point "Amps - Neutral"	N/A				
SYS.DMS(P1SAT-P2P-SUB).52	Verify point "Amps - Angle - Neutral"	N/A				
SYS.DMS(P1SAT-P2P-SUB).53	Verify point "Amps - Residual"	N/A				
SYS.DMS(P1SAT-P2P-SUB).54	Verify point "Amps - Angle - Residual"	N/A				
SYS.DMS(P1SAT-P2P-SUB).55	Verify point "Real Power - Phase A"	N/A				
SYS.DMS(P1SAT-P2P-SUB).56	Verify point "Real Power - Phase B"	N/A				
SYS.DMS(P1SAT-P2P-SUB).57	Verify point "Real Power - Phase C"	N/A				
SYS.DMS(P1SAT-P2P-SUB).58	Verify point "Reactive Power - Phase A"	N/A				
SYS.DMS(P1SAT-P2P-SUB).59	Verify point "Reactive Power - Phase B"	N/A				
SYS.DMS(P1SAT-P2P-SUB).60	Verify point "Reactive Power - Phase C"	N/A				
SYS.DMS(P1SAT-P2P-SUB).61	Verify point "Apparent Power - Phase A"	N/A				
SYS.DMS(P1SAT-P2P-SUB).62	Verify point "Apparent Power - Phase B"	N/A				
SYS.DMS(P1SAT-P2P-SUB).63	Verify point "Apparent Power - Phase C"	N/A				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P1SAT-P2P-SUB).64	Verify point "Power Factor - Phase A"	N/A				
SYS.DMS(P1SAT-P2P-SUB).65	Verify point "Power Factor - Phase B"	N/A				
SYS.DMS(P1SAT-P2P-SUB).66	Verify point "Power Factor - Phase C"	N/A				
SYS.DMS(P1SAT-P2P-SUB).67	Verify point "Amps - Positive Sequence"	N/A				
SYS.DMS(P1SAT-P2P-SUB).68	Verify point "Amps - Angle - Positive Sequence"	N/A				
SYS.DMS(P1SAT-P2P-SUB).69	Verify point "Amps - Negative Sequence"	N/A				
SYS.DMS(P1SAT-P2P-SUB).70	Verify point "Amps - Angle - Negative Sequence"	N/A				
SYS.DMS(P1SAT-P2P-SUB).71	Verify point "Amps - Zero Sequence"	N/A				
SYS.DMS(P1SAT-P2P-SUB).72	Verify point "Amps - Angle - Zero Sequence"	N/A				
SYS.DMS(P1SAT-P2P-SUB).73	Verify point "Voltage - Positive Sequence"	N/A				
SYS.DMS(P1SAT-P2P-SUB).74	Verify point "Voltage - Angle - Positive Sequence"	N/A				
SYS.DMS(P1SAT-P2P-SUB).75	Verify point "Voltage Negative Sequence"	N/A				
SYS.DMS(P1SAT-P2P-SUB).76	Verify point "Voltage - Angle - Negative Sequence"	N/A				
SYS.DMS(P1SAT-P2P-SUB).77	Verify point "Voltage - Zero Sequence"	N/A				
SYS.DMS(P1SAT-P2P-SUB).78	Verify point "Voltage - Angle - Zero Sequence"	N/A				
SYS.DMS(P1SAT-P2P-SUB).79	Verify point "Current Imbalance"	N/A				
SYS.DMS(P1SAT-P2P-SUB).80	Verify point "Voltage Imbalance"	N/A				
SYS.DMS(P1SAT-P2P-SUB).81	Verify point "Amps - Average"	N/A				
SYS.DMS(P1SAT-P2P-SUB).82	Verify point "Amps - Max - Phase A"	N/A				
SYS.DMS(P1SAT-P2P-SUB).83	Verify point "Amps - Max - Phase B"	N/A				
SYS.DMS(P1SAT-P2P-SUB).84	Verify point "Amps - Max - Phase C"	N/A				
SYS.DMS(P1SAT-P2P-SUB).85	Verify point "Amps - Max - Neutral"	N/A				
SYS.DMS(P1SAT-P2P-SUB).86	Verify point "Amps - Max - Residual"	N/A				
SYS.DMS(P1SAT-P2P-SUB).87	Verify point "Amps - Min - Phase A"	N/A				
SYS.DMS(P1SAT-P2P-SUB).88	Verify point "Amps - Min - Phase B"	N/A				
SYS.DMS(P1SAT-P2P-SUB).89	Verify point "Amps - Min - Phase C"	N/A				
SYS.DMS(P1SAT-P2P-SUB).90	Verify point "Amps - Min - Neutral"	N/A				
SYS.DMS(P1SAT-P2P-SUB).91	Verify point "Amps - Min - Residual"	N/A				
SYS.DMS(P1SAT-P2P-SUB).92	Verify point "Voltage - Average"	N/A				
SYS.DMS(P1SAT-P2P-SUB).93	Verify point "Voltage - Max - Phase A"	N/A				
SYS.DMS(P1SAT-P2P-SUB).94	Verify point "Voltage - Max - Phase B"	N/A				
SYS.DMS(P1SAT-P2P-SUB).95	Verify point "Voltage - Max - Phase C"	N/A				
SYS.DMS(P1SAT-P2P-SUB).96	Verify point "Voltage - Min - Phase A"	N/A				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P1SAT-P2P-SUB).97	Verify point "Voltage - Min - Phase B"	N/A				
SYS.DMS(P1SAT-P2P-SUB).98	Verify point "Voltage - Min - Phase C"	N/A				
SYS.DMS(P1SAT-P2P-SUB).99	Verify point "Apparent Power - Max - 3 Phase"	N/A				
SYS.DMS(P1SAT-P2P-SUB).100	Verify point "Apparent Power - Min - 3 Phase"	N/A				
SYS.DMS(P1SAT-P2P-SUB).101	Verify point "Real Power - Max - 3 Phase"	N/A				
SYS.DMS(P1SAT-P2P-SUB).102	Verify point "Real Power - Min - 3 Phase"	N/A				
SYS.DMS(P1SAT-P2P-SUB).103	Verify point "Reactive Power - Max - 3 Phase"	N/A				
SYS.DMS(P1SAT-P2P-SUB).104	Verify point "Reactive Power - Min - 3 Phase"	N/A				
SYS.DMS(P1SAT-P2P-SUB).105	Verify point "Amps - Demand - Phase A"	N/A				
SYS.DMS(P1SAT-P2P-SUB).106	Verify point "Amps - Demand - Phase B"	N/A				
SYS.DMS(P1SAT-P2P-SUB).107	Verify point "Amps - Demand - Phase C"	N/A				
SYS.DMS(P1SAT-P2P-SUB).108	Verify point "Amps - Demand - Residual"	N/A				
SYS.DMS(P1SAT-P2P-SUB).109	Verify point "Amps - Peak Demand - Phase A"	N/A				
SYS.DMS(P1SAT-P2P-SUB).110	Verify point "Amps - Peak Demand - Phase B"	N/A				
SYS.DMS(P1SAT-P2P-SUB).111	Verify point "Amps - Peak Demand - Phase C"	N/A				
SYS.DMS(P1SAT-P2P-SUB).112	Verify point "Amps - Peak Demand - Residual"	N/A				
System Test Book - DMS (Phase 1 Site Acceptance Test) - Feeder / Tie Breaker (751A Profile 2) : Status Points						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P1SAT-P2P-SUB).113	Verify point "Breaker Status"	Values Displayed: - OPEN - CLOSED				
SYS.DMS(P1SAT-P2P-SUB).114	Verify point "Local Remote"	Values Displayed: - LOCAL - REMOTE				
SYS.DMS(P1SAT-P2P-SUB).115	Verify point "Manual Auto"	Values Displayed: - AUTO - MANUAL				
SYS.DMS(P1SAT-P2P-SUB).116	Verify point "Slow Breaker Indication"	Values Displayed: - FALSE - TRUE				
SYS.DMS(P1SAT-P2P-SUB).117	Verify point "Contact Wear"	Values Displayed: - FALSE - TRUE				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P1SAT-P2P-SUB).118	Verify point "86BT Lockout Operated"	Values Displayed: - FALSE - TRUE				
SYS.DMS(P1SAT-P2P-SUB).119	Verify point "Trip Coil Monitor"	Values Displayed: - FALSE - TRUE				
SYS.DMS(P1SAT-P2P-SUB).120	Verify point "Latched LED 1"	Values Displayed: - FALSE - TRUE				
SYS.DMS(P1SAT-P2P-SUB).121	Verify point "Latched LED 2"	Values Displayed: - FALSE - TRUE				
SYS.DMS(P1SAT-P2P-SUB).122	Verify point "Latched LED 3"	Values Displayed: - FALSE - TRUE				
SYS.DMS(P1SAT-P2P-SUB).123	Verify point "Latched LED 4"	Values Displayed: - FALSE - TRUE				
SYS.DMS(P1SAT-P2P-SUB).124	Verify point "Latched LED 5"	Values Displayed: - FALSE - TRUE				
SYS.DMS(P1SAT-P2P-SUB).125	Verify point "Latched LED 6"	Values Displayed: - FALSE - TRUE				
SYS.DMS(P1SAT-P2P-SUB).126	Verify point "Hardware Alarm"	Values Displayed: - FALSE - TRUE				
SYS.DMS(P1SAT-P2P-SUB).127	Verify point "Software Alarm"	Values Displayed: - FALSE - TRUE				
SYS.DMS(P1SAT-P2P-SUB).128	Verify point "FAULT"	Values Displayed: - FALSE - TRUE				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P1SAT-P2P-SUB).129	Verify point "Synchronism Check Element 1"	Values Displayed: - FALSE - TRUE				
SYS.DMS(P1SAT-P2P-SUB).130	Verify point "Synchronism Check Element 2"	Values Displayed: - FALSE - TRUE				
SYS.DMS(P1SAT-P2P-SUB).131	Verify point "Healthy Voltage Vp for Synchronism Check"	Values Displayed: - FALSE - TRUE				
SYS.DMS(P1SAT-P2P-SUB).132	Verify point "Healthy Voltage Vs for Synchronism Check"	Values Displayed: - FALSE - TRUE				
SYS.DMS(P1SAT-P2P-SUB).133	Verify point "Loss of Potential"	Values Displayed: - FALSE - TRUE				
System Test Book - DMS (Phase 1 Site Acceptance Test) - Feeder / Tie Breaker (751A Profile 2) : Control Points						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P1SAT-P2P-SUB).134	Verify point "Breaker Open"	Values Displayed: - N/A - OPEN				
SYS.DMS(P1SAT-P2P-SUB).135	Verify point "Breaker Close"	Values Displayed: - N/A - CLOSE				
SYS.DMS(P1SAT-P2P-SUB).136	Verify point "Manual"	Values Displayed: - N/A - MANUAL				
SYS.DMS(P1SAT-P2P-SUB).137	Verify point "Auto"	Values Displayed: - N/A - AUTO				
System Test Book - DMS (Phase 1 Site Acceptance Test) - Feeder / Tie Breaker (751A Profile 2) : Analog Points						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P1SAT-P2P-SUB).138	Verify point "Real Power - 3 Phase"	N/A				
SYS.DMS(P1SAT-P2P-SUB).139	Verify point "Reactive Power - 3 Phase"	N/A				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P1SAT-P2P-SUB).140	Verify point "Amps - Phase A"	N/A				
SYS.DMS(P1SAT-P2P-SUB).141	Verify point "Amps - Phase B"	N/A				
SYS.DMS(P1SAT-P2P-SUB).142	Verify point "Amps - Phase C"	N/A				
SYS.DMS(P1SAT-P2P-SUB).143	Verify point "Voltage - Phase A"	N/A				
SYS.DMS(P1SAT-P2P-SUB).144	Verify point "Voltage - Phase B"	N/A				
SYS.DMS(P1SAT-P2P-SUB).145	Verify point "Voltage - Phase C"	N/A				
SYS.DMS(P1SAT-P2P-SUB).146	Verify point "Apparent Power - 3 Phase"	N/A				
SYS.DMS(P1SAT-P2P-SUB).147	Verify point "Power Factor - 3 Phase"	N/A				
SYS.DMS(P1SAT-P2P-SUB).148	Verify point "Frequency"	N/A				
SYS.DMS(P1SAT-P2P-SUB).149	Verify point "Voltage - Angle - Phase A"	N/A				
SYS.DMS(P1SAT-P2P-SUB).150	Verify point "Voltage - Angle - Phase B"	N/A				
SYS.DMS(P1SAT-P2P-SUB).151	Verify point "Voltage - Angle - Phase C"	N/A				
SYS.DMS(P1SAT-P2P-SUB).152	Verify point "Voltage - Residual"	N/A				
SYS.DMS(P1SAT-P2P-SUB).153	Verify point "Voltage - Angle - Neutral"	N/A				
SYS.DMS(P1SAT-P2P-SUB).154	Verify point "Amps - Angle - Phase A"	N/A				
SYS.DMS(P1SAT-P2P-SUB).155	Verify point "Amps - Angle - Phase B"	N/A				
SYS.DMS(P1SAT-P2P-SUB).156	Verify point "Amps - Angle - Phase C"	N/A				
SYS.DMS(P1SAT-P2P-SUB).157	Verify point "Amps - Neutral"	N/A				
SYS.DMS(P1SAT-P2P-SUB).158	Verify point "Amps - Angle - Neutral"	N/A				
SYS.DMS(P1SAT-P2P-SUB).159	Verify point "Amps - Residual"	N/A				
SYS.DMS(P1SAT-P2P-SUB).160	Verify point "Amps - Angle - Residual"	N/A				
SYS.DMS(P1SAT-P2P-SUB).161	Verify point "Real Power - Phase A"	N/A				
SYS.DMS(P1SAT-P2P-SUB).162	Verify point "Real Power - Phase B"	N/A				
SYS.DMS(P1SAT-P2P-SUB).163	Verify point "Real Power - Phase C"	N/A				
SYS.DMS(P1SAT-P2P-SUB).164	Verify point "Reactive Power - Phase A"	N/A				
SYS.DMS(P1SAT-P2P-SUB).165	Verify point "Reactive Power - Phase B"	N/A				
SYS.DMS(P1SAT-P2P-SUB).166	Verify point "Reactive Power - Phase C"	N/A				
SYS.DMS(P1SAT-P2P-SUB).167	Verify point "Apparent Power - Phase A"	N/A				
SYS.DMS(P1SAT-P2P-SUB).168	Verify point "Apparent Power - Phase B"	N/A				
SYS.DMS(P1SAT-P2P-SUB).169	Verify point "Apparent Power - Phase C"	N/A				
SYS.DMS(P1SAT-P2P-SUB).170	Verify point "Power Factor - Phase A"	N/A				
SYS.DMS(P1SAT-P2P-SUB).171	Verify point "Power Factor - Phase B"	N/A				
SYS.DMS(P1SAT-P2P-SUB).172	Verify point "Power Factor - Phase C"	N/A				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P1SAT-P2P-SUB).173	Verify point "Amps - Positive Sequence"	N/A				
SYS.DMS(P1SAT-P2P-SUB).174	Verify point "Amps - Angle - Positive Sequence"	N/A				
SYS.DMS(P1SAT-P2P-SUB).175	Verify point "Amps - Negative Sequence"	N/A				
SYS.DMS(P1SAT-P2P-SUB).176	Verify point "Amps - Angle - Negative Sequence"	N/A				
SYS.DMS(P1SAT-P2P-SUB).177	Verify point "Amps - Zero Sequence"	N/A				
SYS.DMS(P1SAT-P2P-SUB).178	Verify point "Amps - Angle - Zero Sequence"	N/A				
SYS.DMS(P1SAT-P2P-SUB).179	Verify point "Voltage - Positive Sequence"	N/A				
SYS.DMS(P1SAT-P2P-SUB).180	Verify point "Voltage - Angle - Positive Sequence"	N/A				
SYS.DMS(P1SAT-P2P-SUB).181	Verify point "Voltage Negative Sequence"	N/A				
SYS.DMS(P1SAT-P2P-SUB).182	Verify point "Voltage - Angle - Negative Sequence"	N/A				
SYS.DMS(P1SAT-P2P-SUB).183	Verify point "Voltage - Zero Sequence"	N/A				
SYS.DMS(P1SAT-P2P-SUB).184	Verify point "Voltage - Angle - Zero Sequence"	N/A				
SYS.DMS(P1SAT-P2P-SUB).185	Verify point "Current Imbalance"	N/A				
SYS.DMS(P1SAT-P2P-SUB).186	Verify point "Voltage Imbalance"	N/A				
SYS.DMS(P1SAT-P2P-SUB).187	Verify point "Amps - Average"	N/A				
SYS.DMS(P1SAT-P2P-SUB).188	Verify point "Amps - Max - Phase A"	N/A				
SYS.DMS(P1SAT-P2P-SUB).189	Verify point "Amps - Max - Phase B"	N/A				
SYS.DMS(P1SAT-P2P-SUB).190	Verify point "Amps - Max - Phase C"	N/A				
SYS.DMS(P1SAT-P2P-SUB).191	Verify point "Amps - Max - Neutral"	N/A				
SYS.DMS(P1SAT-P2P-SUB).192	Verify point "Amps - Max - Residual"	N/A				
SYS.DMS(P1SAT-P2P-SUB).193	Verify point "Amps - Min - Phase A"	N/A				
SYS.DMS(P1SAT-P2P-SUB).194	Verify point "Amps - Min - Phase B"	N/A				
SYS.DMS(P1SAT-P2P-SUB).195	Verify point "Amps - Min - Phase C"	N/A				
SYS.DMS(P1SAT-P2P-SUB).196	Verify point "Amps - Min - Neutral"	N/A				
SYS.DMS(P1SAT-P2P-SUB).197	Verify point "Amps - Min - Residual"	N/A				
SYS.DMS(P1SAT-P2P-SUB).198	Verify point "Voltage - Average"	N/A				
SYS.DMS(P1SAT-P2P-SUB).199	Verify point "Voltage - Max - Phase A"	N/A				
SYS.DMS(P1SAT-P2P-SUB).200	Verify point "Voltage - Max - Phase B"	N/A				
SYS.DMS(P1SAT-P2P-SUB).201	Verify point "Voltage - Max - Phase C"	N/A				
SYS.DMS(P1SAT-P2P-SUB).202	Verify point "Voltage - Min - Phase A"	N/A				
SYS.DMS(P1SAT-P2P-SUB).203	Verify point "Voltage - Min - Phase B"	N/A				
SYS.DMS(P1SAT-P2P-SUB).204	Verify point "Voltage - Min - Phase C"	N/A				
SYS.DMS(P1SAT-P2P-SUB).205	Verify point "Apparent Power - Max - 3 Phase"	N/A				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P1SAT-P2P-SUB).206	Verify point "Apparent Power - Min - 3 Phase"	N/A				
SYS.DMS(P1SAT-P2P-SUB).207	Verify point "Real Power - Max - 3 Phase"	N/A				
SYS.DMS(P1SAT-P2P-SUB).208	Verify point "Real Power - Min - 3 Phase"	N/A				
SYS.DMS(P1SAT-P2P-SUB).209	Verify point "Reactive Power - Max - 3 Phase"	N/A				
SYS.DMS(P1SAT-P2P-SUB).210	Verify point "Reactive Power - Min - 3 Phase"	N/A				
SYS.DMS(P1SAT-P2P-SUB).211	Verify point "Amps - Demand - Phase A"	N/A				
SYS.DMS(P1SAT-P2P-SUB).212	Verify point "Amps - Demand - Phase B"	N/A				
SYS.DMS(P1SAT-P2P-SUB).213	Verify point "Amps - Demand - Phase C"	N/A				
SYS.DMS(P1SAT-P2P-SUB).214	Verify point "Amps - Demand - Residual"	N/A				
SYS.DMS(P1SAT-P2P-SUB).215	Verify point "Amps - Peak Demand - Phase A"	N/A				
SYS.DMS(P1SAT-P2P-SUB).216	Verify point "Amps - Peak Demand - Phase B"	N/A				
SYS.DMS(P1SAT-P2P-SUB).217	Verify point "Amps - Peak Demand - Phase C"	N/A				
SYS.DMS(P1SAT-P2P-SUB).218	Verify point "Amps - Peak Demand - Residual"	N/A				
System Test Book - DMS (Phase 1 Site Acceptance Test) - Substation Main Breaker (451-5)						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P1SAT-P2P-SUB).219	Verify point "Breaker Status"	Values Displayed: - OPEN - CLOSED				
SYS.DMS(P1SAT-P2P-SUB).220	Verify point "Local Remote"	Values Displayed: - LOCAL - REMOTE				
SYS.DMS(P1SAT-P2P-SUB).221	Verify point "86M Lockout Operated"	Values Displayed: - FALSE - TRUE				
SYS.DMS(P1SAT-P2P-SUB).222	Verify point "Slow Breaker Indication"	Values Displayed: - FALSE - TRUE				
SYS.DMS(P1SAT-P2P-SUB).223	Verify point "Loss of Potential"	Values Displayed: - FALSE - TRUE				
SYS.DMS(P1SAT-P2P-SUB).224	Verify point "Contact Wear"	Values Displayed: - FALSE - TRUE				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P1SAT-P2P-SUB).225	Verify point "Hardware Alarm"	Values Displayed: - FALSE - TRUE				
SYS.DMS(P1SAT-P2P-SUB).226	Verify point "Software Alarm"	Values Displayed: - FALSE - TRUE				
SYS.DMS(P1SAT-P2P-SUB).227	Verify point "Healthy Voltage Vs for Synchornism Check"	Values Displayed: - FALSE - TRUE				
SYS.DMS(P1SAT-P2P-SUB).228	Verify point "Healthy Voltage Vp for Synchornism Check"	Values Displayed: - FALSE - TRUE				
SYS.DMS(P1SAT-P2P-SUB).229	Verify point "Circuit Breaker 1 Angle 1 within Window 1"	Values Displayed: - FALSE - TRUE				
SYS.DMS(P1SAT-P2P-SUB).230	Verify point "Circuit Breaker 1 Angle 2 within Window 2"	Values Displayed: - FALSE - TRUE				
SYS.DMS(P1SAT-P2P-SUB).231	Verify point "FAULT"	Values Displayed: - FALSE - TRUE				
SYS.DMS(P1SAT-P2P-SUB).232	Verify point "Protection Timer Output 1"	Values Displayed: - FALSE - TRUE				
SYS.DMS(P1SAT-P2P-SUB).233	Verify point "Trip Coil Monitor"	Values Displayed: - FALSE - TRUE				
SYS.DMS(P1SAT-P2P-SUB).234	Verify point "Protection Timer Output 3"	Values Displayed: - FALSE - TRUE				
SYS.DMS(P1SAT-P2P-SUB).235	Verify point "Protection Timer Output 4"	Values Displayed: - FALSE - TRUE				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P1SAT-P2P-SUB).236	Verify point "Protection Timer Output 5"	Values Displayed: - FALSE - TRUE				
SYS.DMS(P1SAT-P2P-SUB).237	Verify point "Protection Timer Output 6"	Values Displayed: - FALSE - TRUE				
System Test Book - DMS (Phase 1 Site Acceptance Test) - Substation Transformer Differential (4B7E)						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P1SAT-P2P-SUB).238	Verify point "Breaker Status"	Values Displayed: - OPEN - CLOSED				
SYS.DMS(P1SAT-P2P-SUB).239	Verify point "Real Power - 3 Phase - Terminal T"	N/A				
SYS.DMS(P1SAT-P2P-SUB).240	Verify point "Reactive Power - 3 Phase - Terminal T"	N/A				
SYS.DMS(P1SAT-P2P-SUB).241	Verify point "Real Power - 3 Phase - Terminal U"	N/A				
SYS.DMS(P1SAT-P2P-SUB).242	Verify point "Reactive Power - 3 Phase - Terminal U"	N/A				
SYS.DMS(P1SAT-P2P-SUB).243	Verify point "Voltage - Phase A - V"	N/A				
SYS.DMS(P1SAT-P2P-SUB).244	Verify point "Voltage - Phase B - V"	N/A				
SYS.DMS(P1SAT-P2P-SUB).245	Verify point "Voltage - Phase C - V"	N/A				
SYS.DMS(P1SAT-P2P-SUB).246	Verify point "Voltage - Phase A - Z"	N/A				
SYS.DMS(P1SAT-P2P-SUB).247	Verify point "Voltage - Phase B - Z"	N/A				
SYS.DMS(P1SAT-P2P-SUB).248	Verify point "Voltage - Phase C - Z"	N/A				
System Test Book - DMS (Phase 1 Site Acceptance Test) - Load Tap Changer (REG-DA)						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P1SAT-P2P-SUB).249	Verify point "Position Value"	Values Displayed: - -16 - -15				
SYS.DMS(P1SAT-P2P-SUB).250	Verify point "Manual Auto"	Values Displayed: - MANUAL - AUTO				
SYS.DMS(P1SAT-P2P-SUB).251	Verify point "Position Control"	Values Displayed: - STOP - LOWER				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P1SAT-P2P-SUB).252	Verify point "Manual Auto"	Values Displayed: - MANUAL - AUTO				
System Test Book - DMS (Phase I Site Acceptance Test) - Substation Bus Differential (487-B)						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P1SAT-P2P-SUB).253	Verify point "86B Lockout Operated"	Values Displayed: - FALSE - TRUE				
SYS.DMS(P1SAT-P2P-SUB).254	Verify point "Software or Hardware Alarm"	Values Displayed: - FALSE - TRUE				

System Test Book – DMS (Phase 2 Factory Acceptance Test): Redundancy - Verify Configuration						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P2FAT-REDUNDANCY).1	Verify system Test Environment (HW & SW), including simulation and tools, before starting FAT	N/A				
SYS.DMS(P2FAT-REDUNDANCY).2	Verify system management and configuration displays and tools	N/A				
System Test Book – DMS (Phase 2 Factory Acceptance Test): Redundancy - Verify System Components, Tools, DBs						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P2FAT-REDUNDANCY).3	Verify correct operation of the system components (system configuration overview, servers status, communications status, applications running,...)	N/A				
SYS.DMS(P2FAT-REDUNDANCY).4	Verify redundancy in the system network at each level (CC, Substation)	N/A				
System Test Book – DMS (Phase 2 Factory Acceptance Test): Redundancy - Basic UI (Power CC)						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P2FAT-REDUNDANCY).5	Verify users log on and log off	N/A				
SYS.DMS(P2FAT-REDUNDANCY).6	Verify only defined users can log on	N/A				
SYS.DMS(P2FAT-REDUNDANCY).7	Verify reporting and logging	N/A				
SYS.DMS(P2FAT-REDUNDANCY).8	Verify Tabular displays availability and access	N/A				
SYS.DMS(P2FAT-REDUNDANCY).9	Verify that at least system logging reporting can be defined and activated	N/A				
SYS.DMS(P2FAT-REDUNDANCY).10	Verify queries, filtering and sorting capabilities in logs and lists	N/A				
SYS.DMS(P2FAT-REDUNDANCY).11	Verification of management functionality for logs and lists	N/A				
SYS.DMS(P2FAT-REDUNDANCY).12	Verify that at least system statistics can be defined and activated	N/A				
System Test Book – DMS (Phase 2 Factory Acceptance Test): Redundancy - Spontaneous Reporting of Selected Data Points						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P2FAT-REDUNDANCY).13	Verify that there is no dead band defined in DSCADA	N/A				
SYS.DMS(P2FAT-REDUNDANCY).14	Verify time needed for data presentation and control execution to and from the Control Center	N/A				
SYS.DMS(P2FAT-REDUNDANCY).15	Verify data presented in Tabular displays	N/A				
SYS.DMS(P2FAT-REDUNDANCY).16	Verify alarm and event list access	N/A				

System Test Book – DMS (Phase 2 Factory Acceptance Test): Redundancy - Areas of Responsibilities and Controls						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P2FAT-REDUNDANCY).17	Verify reporting and logging of AOR issues and management (authorizations and permissions)	N/A				
SYS.DMS(P2FAT-REDUNDANCY).18	Verification of control action cancellation by the operator	N/A				
SYS.DMS(P2FAT-REDUNDANCY).19	Verification of control action time-out	N/A				
SYS.DMS(P2FAT-REDUNDANCY).20	Verification of control action failed	N/A				
SYS.DMS(P2FAT-REDUNDANCY).21	Verify control action propagation in all modules and that execution is synchronized	N/A				
SYS.DMS(P2FAT-REDUNDANCY).22	Verify analog controls (set points), raise/lower (no return),...	N/A				
SYS.DMS(P2FAT-REDUNDANCY).23	Verify control command failures	N/A				
SYS.DMS(P2FAT-REDUNDANCY).24	Verification of system behavior in case of control "rejected" or "failed"	N/A				
SYS.DMS(P2FAT-REDUNDANCY).25	Verify interlocking conditions :Raise/Lower Limit reached	N/A				
SYS.DMS(P2FAT-REDUNDANCY).26	Verify interlocking conditions :Control in Progress	N/A				
SYS.DMS(P2FAT-REDUNDANCY).27	Verify interlocking conditions :Multiple user/consoles	N/A				
SYS.DMS(P2FAT-REDUNDANCY).28	Verify reporting and logging of control actions, successful and failed	N/A				
System Test Book – DMS (Phase 2 Factory Acceptance Test): Redundancy - Manual Changes and Tags						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P2FAT-REDUNDANCY).29	Verify validity checking for manual entries	N/A				
SYS.DMS(P2FAT-REDUNDANCY).30	Verify manual changes are updated in all modules (data synchronization)	N/A				
SYS.DMS(P2FAT-REDUNDANCY).31	Verify reporting and logging of manual changes, successful and failed	N/A				
SYS.DMS(P2FAT-REDUNDANCY).32	Verify JC&G functionality	N/A				
SYS.DMS(P2FAT-REDUNDANCY).33	Verify reporting and logging of temporary elements in the model	N/A				
SYS.DMS(P2FAT-REDUNDANCY).34	Verification of tagging propagation to the different modules of the system	N/A				
SYS.DMS(P2FAT-REDUNDANCY).35	Verification of locking conditions when tags are set	N/A				
SYS.DMS(P2FAT-REDUNDANCY).36	Verify reporting and logging of tagging actions	N/A				

System Test Book – DMS (Phase 2 Factory Acceptance Test): Redundancy - Time Synchronization						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P2FAT-REDUNDANCY).37	Verify time synch reporting and logging when it happens.	N/A				
System Test Book – DMS (Phase 2 Factory Acceptance Test): Redundancy – ICCP						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P2FAT-REDUNDANCY).38	Verification of the association table definition	N/A				
SYS.DMS(P2FAT-REDUNDANCY).39	Verification of association table definition error's reporting	N/A				
SYS.DMS(P2FAT-REDUNDANCY).40	Verification of the data flow through ICCP link, checking the different types of data in both directions	N/A				
SYS.DMS(P2FAT-REDUNDANCY).41	Verification ICCP link status display	N/A				
SYS.DMS(P2FAT-REDUNDANCY).42	Verification of the ICCP link management	N/A				
SYS.DMS(P2FAT-REDUNDANCY).43	Verification of the ICCP link redundancy	N/A				
SYS.DMS(P2FAT-REDUNDANCY).44	Verification communications error reporting	N/A				
System Test Book – DMS (Phase 2 Factory Acceptance Test): Redundancy - Switch Mastership						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P2FAT-REDUNDANCY).45	Manually Switch Mastership (switch PowerCC Master and Standby)	N/A				
SYS.DMS(P2FAT-REDUNDANCY).46	DCADA Manually Switch Mastership (switch PowerCC Master and Standby)	N/A				
System Test Book – DMS (Phase 2 Factory Acceptance Test): Redundancy - Communications Failover						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P2FAT-REDUNDANCY).47	Verify status reporting and logging at the CC	N/A				
SYS.DMS(P2FAT-REDUNDANCY).48	Verify system response to communication failure at the IED side (port unavailable, tropos router down,...)	N/A				
SYS.DMS(P2FAT-REDUNDANCY).49	Verify communication management capabilities like force DNP3 scan, force alternative communication path,...	N/A				
SYS.DMS(P2FAT-REDUNDANCY).50	Verify status reporting and logging at the HMI and CC	N/A				
SYS.DMS(P2FAT-REDUNDANCY).51	Verify status reporting and logging at the CC	N/A				

System Test Book – DMS (Phase 2 Factory Acceptance Test): Redundancy - Application Failover						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P2FAT-REDUNDANCY).52	Verify data is correct after failover at all levels of redundancy	N/A				
SYS.DMS(P2FAT-REDUNDANCY).53	Verify InService redundancy and failover when problems exist in the application or SW	N/A				
SYS.DMS(P2FAT-REDUNDANCY).54	Verify manual InService failover	N/A				
SYS.DMS(P2FAT-REDUNDANCY).55	Verify alarms availability and retention during and after failovers	N/A				
SYS.DMS(P2FAT-REDUNDANCY).56	Verify error handling and redundancy for reporting function.	N/A				
SYS.DMS(P2FAT-REDUNDANCY).57	Verify logging of reporting activities	N/A				
System Test Book – DMS (Phase 2 Factory Acceptance Test): Redundancy - DB Management and Model Propagation						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P2FAT-REDUNDANCY).58	Based on the DB generation process defined and provided by Siemens and Intergraph, verify that the data definition and DB generation works across all systems and modules	N/A				
SYS.DMS(P2FAT-REDUNDANCY).59	Verify display management	N/A				
SYS.DMS(P2FAT-REDUNDANCY).60	Verify general system DB management tools provided with the system (DB Jobs, DB Job propagation, DB Job roll back,...)	N/A				
SYS.DMS(P2FAT-REDUNDANCY).61	Verify DB error reporting and logging	N/A				
System Test Book – DMS (Phase 2 Factory Acceptance Test): Redundancy - Backup & Restore						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P2FAT-REDUNDANCY).62	Verify DB archiving	N/A				
SYS.DMS(P2FAT-REDUNDANCY).63	Verify system tools to backup and restore SW and data	N/A				
SYS.DMS(P2FAT-REDUNDANCY).64	Verify reporting and logging of archiving and restoration activities	N/A				
SYS.DMS(P2FAT-REDUNDANCY).65	Verify system tools to save reports to external media	N/A				
System Test Book – DMS (Phase 2 Factory Acceptance Test): Redundancy - LAN Failures						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P2FAT-REDUNDANCY).66	LAN Failure (single and double)	N/A				
SYS.DMS(P2FAT-REDUNDANCY).67	DCADA LAN Failure (single and double)	N/A				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P2FAT-REDUNDANCY).68	Verify SCADA applications operation	N/A				
SYS.DMS(P2FAT-REDUNDANCY).69	Verify communication with SICAM and check correct recovery from LAN failure	N/A				
SYS.DMS(P2FAT-REDUNDANCY).70	Verify operation with InService when LAN fails and after correct recovery	N/A				
SYS.DMS(P2FAT-REDUNDANCY).71	Verify status reporting and logging	N/A				
System Test Book – DMS (Phase 2 Factory Acceptance Test): Redundancy - System Startups						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P2FAT-REDUNDANCY).72	Automatic Startup - UI Client (PowerCC starts after restarting windows)	N/A				
SYS.DMS(P2FAT-REDUNDANCY).73	DCADA Manual Startup (Manually start PowerCC server)	N/A				
SYS.DMS(P2FAT-REDUNDANCY).74	DCADA Automatic Startup - DMS Master (PowerCC starts after restarting windows)	N/A				
SYS.DMS(P2FAT-REDUNDANCY).75	DCADA Automatic Startup - DMS Standby (PowerCC starts after restarting windows)	N/A				
System Test Book – DMS (Phase 2 Factory Acceptance Test): Redundancy - Availability : Power Failure						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P2FAT-REDUNDANCY).76	Verify system behavior during individual servers power failures	N/A				
SYS.DMS(P2FAT-REDUNDANCY).77	Verify applications run up to operational status without human intervention after power failure	N/A				
SYS.DMS(P2FAT-REDUNDANCY).78	After Power Failure, verify that IED scanning is happening and data is correct not only that the application is running	N/A				
System Test Book – DMS (Phase 2 Factory Acceptance Test): Redundancy - System Cold/Start Up						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P2FAT-REDUNDANCY).79	Verify execution of the System Start Up procedure	N/A				
SYS.DMS(P2FAT-REDUNDANCY).80	Verify SCADA applications and InService run up to operational status without human intervention after power failure	N/A				
SYS.DMS(P2FAT-REDUNDANCY).81	Verify SICAM status changes are reported and logged at the CC and HMI	N/A				

System Test Book – DMS (Phase 2 Factory Acceptance Test): Consolidated UI – Digital Indication/Change						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS.P2FAT.UI.1	Identify a breaker. Simulate opening of the breaker (status) in IED.	The breaker is shown opened in InService Map. An alarm is generated in the iAlarm list showing the breaker OPEN.				
SYS.DMS.P2FAT.UI.2	Simulate closing of the breaker.	Breaker is shown closed in map. An alarm is generated in the iAlarm list showing the breaker CLOSE.				
SYS.DMS.P2FAT.UI.3	Simulate Local/Remote status of the breaker to "Local".	Local/Remote Flag is shown "Local" in the properties window of the Breaker. An alarm is generated in the iAlarm list showing the change in status.				
SYS.DMS.P2FAT.UI.4	Simulate Local/Remote status of the breaker to "Remote".	Local/Remote status is shown "Remote" in the properties window of the Breaker. An alarm is generated in the iAlarm list showing the change in status.				
SYS.DMS.P2FAT.UI.5	Simulate a digital status change such that an alarm such as "High Current Lockout" is set in IED.	Status is shown "True" in properties window for the Breaker. An alarm is generated in the iAlarm list showing the alarm condition.				
SYS.DMS.P2FAT.UI.6	Clear the alarm condition in IED.	Status is shown "False" in properties window for the Breaker. An alarm is generated in the iAlarm list showing the alarm disappear condition.				
SYS.DMS.P2FAT.UI.7	Simulate a change in the Tap Position for a tap changer.	The Tap position is shown in properties window for device.				
SYS.DMS.P2FAT.UI.8	Simulate a change of the Manual/Auto status for a Tap or Breaker to "Auto".	Manual/Auto status is shown as "Auto" in the properties window of the Tap or Breaker. An alarm is generated in the iAlarm list showing the change in status.				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS.P2FAT.UI.9	Simulate a change of the Manual/Auto status for a Tap or Breaker to "Manual".	Manual/Auto status is shown as "Manual" in the properties window of the Tap or Breaker. An alarm is generated in the iAlarm list showing the change in status.				
System Test Book – DMS (Phase 2 Factory Acceptance Test): Consolidated UI – Analog Change						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS.P2FAT.UI.10	Identify a device such as a breaker in the InService map. Simulate a change in an analog measurement (eg Amps – Phase A) associated with the device, in the IED associated with the device.	The corresponding measurement is shown in the properties window of the Breaker. The measurement is associated with the correct phase.				
SYS.DMS.P2FAT.UI.11	Simulate a change in the measurement such that the measurement is out of high limit.	The corresponding measurement is shown in the properties window of the Breaker. An alarm is generated showing the limit violation.				
SYS.DMS.P2FAT.UI.12	Change the measurement such that the measurement is within limits.	The corresponding measurement is shown in the properties window of the Breaker. An alarm is generated showing return to limits for the measurement.				
SYS.DMS.P2FAT.UI.13	Simulate a change in the measurement such that the measurement is out of low limit.	The corresponding measurement is shown in the properties window of the Breaker. An alarm is generated showing the limit violation.				
SYS.DMS.P2FAT.UI.14	Change the measurement such that the measurement is within limits.	The corresponding measurement is shown in the properties window of the Breaker. An alarm is generated showing return to limits for the measurement.				

System Test Book – DMS (Phase 2 Factory Acceptance Test): Consolidated UI – Controls						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS,P2FAT.UI.15	Identify a breaker on map that can be remotely operated. Using IDispatcher Open dialog, open the breaker.	Operation is successful. Breaker is shown Open in the UI. A message is generated in the message log.				
SYS.DMS,P2FAT.UI.16	Close the Breaker using Close dialog from InService menu.	Operation is successful. Breaker is shown Closed in the UI. A message is generated in the message log.				
SYS.DMS,P2FAT.UI.17	Configure the IED or SICAM PAS, so that control for Breaker would be rejected. Then try to Open the breaker using InService Open dialog.	Operation is unsuccessful. Breaker still shows Closed. An alarm is generated showing operation failure.				
SYS.DMS,P2FAT.UI.18	Identify a device that supports ManualAuto controls. Using InService UI, set the state of the device to Manual.	Operation is successful. ManualAuto status is shown as Manual in the properties window of the device. A message is generated in the message log.				
SYS.DMS,P2FAT.UI.19	Change the ManualAuto from the previous step to Auto.	Operation is successful. ManualAuto status is shown as Auto in the properties window of the device. A message is generated in the message log.				
SYS.DMS,P2FAT.UI.20	Raise Tap position of a Tap.	The Tap position is raised and is reflected in the properties window of the device.				
SYS.DMS,P2FAT.UI.21	Lower Tap position of a Tap.	The Tap position is lowered and is reflected in the properties window of the device.				

System Test Book - DMS (Phase 2 Site Acceptance Test) - Capacitor Bank Point to Point Checkout: Profile 1 - DI						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P2SAT-P2P-CB).1	Verify point "Device Status"	Values Displayed: - OPEN - CLOSED				
SYS.DMS(P2SAT-P2P-CB).2	Verify point "Auto - Manual Status"	Values Displayed: - MANUAL - AUTO				
SYS.DMS(P2SAT-P2P-CB).3	Verify point "Local - Remote"	Values Displayed: - LOCAL - REMOTE				
SYS.DMS(P2SAT-P2P-CB).4	Verify point "Alarm Summary"	Values Displayed: - OK - ALARM				
SYS.DMS(P2SAT-P2P-CB).5	Verify point "SCADA Override Status"	Values Displayed: - DISABLED - ENABLED				
SYS.DMS(P2SAT-P2P-CB).6	Verify point "Over Voltage"	Values Displayed: - OK - ALARM				
SYS.DMS(P2SAT-P2P-CB).7	Verify point "Under Voltage"	Values Displayed: - OK - ALARM				
SYS.DMS(P2SAT-P2P-CB).8	Verify point "Emergency Voltage Override"	Values Displayed: - OK - ALARM				
SYS.DMS(P2SAT-P2P-CB).9	Verify point "Reclose Block"	Values Displayed: - OK - ALARM				
SYS.DMS(P2SAT-P2P-CB).10	Verify point "Maximum Daily Cycles"	Values Displayed: - OK - ALARM				
SYS.DMS(P2SAT-P2P-CB).11	Verify point "Load Fuse Blown"	Values Displayed: - OK - ALARM				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P2SAT-P2P-CB).12	Verify point "Temperature Sensor Error"	Values Displayed: - OK - ALARM				
SYS.DMS(P2SAT-P2P-CB).13	Verify point "Neutral Sensor - Lockout"	Values Displayed: - OK - ALARM				
SYS.DMS(P2SAT-P2P-CB).14	Verify point "Neutral Sensor - Continuous"	Values Displayed: - OK - ALARM				
SYS.DMS(P2SAT-P2P-CB).15	Verify point "Neutral Sensor - Zero"	Values Displayed: - OK - ALARM				
System Test Book - DMS (Phase 2 Site Acceptance Test) - Capacitor Bank Point to Point Checkout: Profile 1 - DO						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P2SAT-P2P-CB).16	Verify point "Device Operate"	Values Displayed: - OPEN - CLOSED				
SYS.DMS(P2SAT-P2P-CB).17	Verify point "Auto - Manual"	Values Displayed: - MANUAL - AUTO				
SYS.DMS(P2SAT-P2P-CB).18	Verify point "SCADA Override Mode"	Values Displayed: - DISABLED - ENABLED				
SYS.DMS(P2SAT-P2P-CB).19	Verify point "Reset Neutral Lockout"	Values Displayed: - NA - RESET				
SYS.DMS(P2SAT-P2P-CB).20	Verify point "Reset Alarms"	Values Displayed: - NA - RESET				
SYS.DMS(P2SAT-P2P-CB).21	Verify point "Inhibit Automatic Operation Timer"	Values Displayed: - DISABLED - ENABLED				
System Test Book - DMS (Phase 2 Site Acceptance Test) - Capacitor Bank Point to Point Checkout: Profile 1 - AI						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P2SAT-P2P-CB).22	Verify point "Control Strategy"	N/A				
SYS.DMS(P2SAT-P2P-CB).23	Verify point "Voltage - Secondary"	N/A				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P2SAT-P2P-CB).24	Verify point "Time Remaining in SCADA Override Mode"	N/A				
SYS.DMS(P2SAT-P2P-CB).25	Verify point "Current - Neutral RMS - Fundamental"	N/A				
SYS.DMS(P2SAT-P2P-CB).26	Verify point "THD - Voltage"	N/A				
SYS.DMS(P2SAT-P2P-CB).27	Verify point "THD - Neutral"	N/A				
SYS.DMS(P2SAT-P2P-CB).28	Verify point "Current - Neutral RMS - Total"	N/A				
SYS.DMS(P2SAT-P2P-CB).29	Verify point "Last Switch Operation Reason"	N/A				
System Test Book - DMS (Phase 2 Site Acceptance Test) - Capacitor Bank Point to Point Checkout: Profile 2 - DI						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P2SAT-P2P-CB).1	Verify point "Device Status"	Values Displayed: - OPEN - CLOSED				
SYS.DMS(P2SAT-P2P-CB).2	Verify point "Auto - Manual Status"	Values Displayed: - MANUAL - AUTO				
SYS.DMS(P2SAT-P2P-CB).3	Verify point "Local - Remote"	Values Displayed: - LOCAL - REMOTE				
SYS.DMS(P2SAT-P2P-CB).4	Verify point "Alarm Summary"	Values Displayed: - OK - ALARM				
SYS.DMS(P2SAT-P2P-CB).5	Verify point "SCADA Override Status"	Values Displayed: - DISABLED - ENABLED				
SYS.DMS(P2SAT-P2P-CB).6	Verify point "Over Voltage"	Values Displayed: - OK - ALARM				
SYS.DMS(P2SAT-P2P-CB).7	Verify point "Under Voltage"	Values Displayed: - OK - ALARM				
SYS.DMS(P2SAT-P2P-CB).8	Verify point "Emergency Voltage Override"	Values Displayed: - OK - ALARM				
SYS.DMS(P2SAT-P2P-CB).9	Verify point "Reclose Block"	Values Displayed: - OK - ALARM				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS{P2SAT-P2P-CB}.10	Verify point "Maximum Daily Cycles"	Values Displayed: - OK - ALARM				
SYS.DMS{P2SAT-P2P-CB}.11	Verify point "Load Fuse Blown"	Values Displayed: - OK - ALARM				
SYS.DMS{P2SAT-P2P-CB}.12	Verify point "Temperature Sensor Error"	Values Displayed: - OK - ALARM				
SYS.DMS{P2SAT-P2P-CB}.13	Verify point "Neutral Sensor - Option"	Values Displayed: - NOT PRESENT - PRESENT				
SYS.DMS{P2SAT-P2P-CB}.14	Verify point "Neutral Sensor - Lockout"	Values Displayed: - OK - ALARM				
SYS.DMS{P2SAT-P2P-CB}.15	Verify point "Neutral Sensor - Continuous"	Values Displayed: - OK - ALARM				
SYS.DMS{P2SAT-P2P-CB}.16	Verify point "Neutral Sensor - Zero"	Values Displayed: - OK - ALARM				
SYS.DMS{P2SAT-P2P-CB}.17	Verify point "VAR Option"	Values Displayed: - NOT PRESENT - PRESENT				
SYS.DMS{P2SAT-P2P-CB}.18	Verify point "Current Direction"	Values Displayed: - NORMAL - REVERSED				
SYS.DMS{P2SAT-P2P-CB}.19	Verify point "Low Switching VAR Delta"	Values Displayed: - OK - ALARM				
SYS.DMS{P2SAT-P2P-CB}.20	Verify point "Current Sensor Location"	Values Displayed: - SOURCE - LOAD				

System Test Book - DMS (Phase 2 Site Acceptance Test) - Capacitor Bank Point to Point Checkout: Profile 2 - DO						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P2SAT-P2P-CB).21	Verify point "Device Operate"	Values Displayed: - OPEN - CLOSED				
SYS.DMS(P2SAT-P2P-CB).22	Verify point "Auto - Manual"	Values Displayed: - MANUAL - AUTO				
SYS.DMS(P2SAT-P2P-CB).23	Verify point "SCADA Override Mode"	Values Displayed: - DISABLED - ENABLED				
SYS.DMS(P2SAT-P2P-CB).24	Verify point "Reset Neutral Lockout"	Values Displayed: - NA - RESET				
SYS.DMS(P2SAT-P2P-CB).25	Verify point "Reset Alarms"	Values Displayed: - NA - RESET				
SYS.DMS(P2SAT-P2P-CB).26	Verify point "Inhibit Automatic Operation Timer"	Values Displayed: - DISABLED - ENABLED				
System Test Book - DMS (Phase 2 Site Acceptance Test) - Capacitor Bank Point to Point Checkout: Profile 2 - AI						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P2SAT-P2P-CB).27	Verify point "Control Strategy"	N/A				
SYS.DMS(P2SAT-P2P-CB).28	Verify point "Voltage - Secondary"	N/A				
SYS.DMS(P2SAT-P2P-CB).29	Verify point "Voltage - Primary"	N/A				
SYS.DMS(P2SAT-P2P-CB).30	Verify point "Time Remaining in SCADA Override Mode"	N/A				
SYS.DMS(P2SAT-P2P-CB).31	Verify point "Current - Neutral RMS - Fundamental"	N/A				
SYS.DMS(P2SAT-P2P-CB).32	Verify point "Current - Phase A"	N/A				
SYS.DMS(P2SAT-P2P-CB).33	Verify point "Reactive Power - 3 Phase"	N/A				
SYS.DMS(P2SAT-P2P-CB).34	Verify point "Apparent Power - 3 Phase"	N/A				
SYS.DMS(P2SAT-P2P-CB).35	Verify point "Real Power - 3 Phase"	N/A				
SYS.DMS(P2SAT-P2P-CB).36	Verify point "THD - Voltage"	N/A				
SYS.DMS(P2SAT-P2P-CB).37	Verify point "THD - Current"	N/A				
SYS.DMS(P2SAT-P2P-CB).38	Verify point "THD - Neutral"	N/A				
SYS.DMS(P2SAT-P2P-CB).39	Verify point "Current - Neutral RMS - Total"	N/A				
SYS.DMS(P2SAT-P2P-CB).40	Verify point "Last Switch Operation Reason"	N/A				

System Test Book - DMS (Phase 2 Site Acceptance Test) - FCI Point to Point Checkout: Profile 0 - DI						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P2SAT-P2P-FCI).1	Verify point "FCI Comm Failure"	Values Displayed: - OK - ALARM				
SYS.DMS(P2SAT-P2P-FCI).2	Verify point "Smart Controller Reporter Operational"	Values Displayed: - OK - ALARM				
SYS.DMS(P2SAT-P2P-FCI).3	Verify point "Voltage - Low DC"	Values Displayed: - OK - ALARM				
System Test Book - DMS (Phase 2 Site Acceptance Test) - FCI Point to Point Checkout: Profile 0 - DO						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P2SAT-P2P-FCI).4	Verify point "Device Operate"	Values Displayed: - NA - RESET				
SYS.DMS(P2SAT-P2P-FCI).5	Verify point "Auto - Manual"	Values Displayed: - NA - RESET				
SYS.DMS(P2SAT-P2P-FCI).6	Verify point "SCADA Override Mode"	Values Displayed: - NA - RESET				
System Test Book - DMS (Phase 2 Site Acceptance Test) - FCI Point to Point Checkout: Profile 0 - AI						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P2SAT-P2P-FCI).7	Verify point "Device Status"	N/A				
SYS.DMS(P2SAT-P2P-FCI).8	Verify point "Auto - Manual Status"	N/A				
System Test Book - DMS (Phase 2 Site Acceptance Test) - FCI Point to Point Checkout: Profile 3 - DI						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P2SAT-P2P-FCI).1	Verify point "Over Current - Phase A"	Values Displayed: - OK - FAULT				
SYS.DMS(P2SAT-P2P-FCI).2	Verify point "Permanent Fault - Phase A"	Values Displayed: - OK - FAULT				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P2SAT-P2P-FCI).3	Verify point "Momentary Fault - Phase A"	Values Displayed: - OK - FAULT				
SYS.DMS(P2SAT-P2P-FCI).4	Verify point "Overhead Line Current Loss - Phase A"	Values Displayed: - OK - LOSS OF CURRENT				
SYS.DMS(P2SAT-P2P-FCI).5	Verify point "Loss of Voltage - Phase A"	Values Displayed: - OK - LOSS OF VOLTAGE				
SYS.DMS(P2SAT-P2P-FCI).6	Verify point "Over Current - Phase B"	Values Displayed: - OK - FAULT				
SYS.DMS(P2SAT-P2P-FCI).7	Verify point "Permanent Fault - Phase B"	Values Displayed: - OK - FAULT				
SYS.DMS(P2SAT-P2P-FCI).8	Verify point "Momentary Fault - Phase B"	Values Displayed: - OK - FAULT				
SYS.DMS(P2SAT-P2P-FCI).9	Verify point "Overhead Line Current Loss - Phase B"	Values Displayed: - OK - LOSS OF CURRENT				
SYS.DMS(P2SAT-P2P-FCI).10	Verify point "Loss of Voltage - Phase B"	Values Displayed: - OK - LOSS OF VOLTAGE				
SYS.DMS(P2SAT-P2P-FCI).11	Verify point "Over Current - Phase C"	Values Displayed: - OK - FAULT				
SYS.DMS(P2SAT-P2P-FCI).12	Verify point "Permanent Fault - Phase C"	Values Displayed: - OK - FAULT				
SYS.DMS(P2SAT-P2P-FCI).13	Verify point "Momentary Fault - Phase C"	Values Displayed: - OK - FAULT				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P2SAT-P2P-FCI).14	Verify point "Overhead Line Current Loss - Phase C"	Values Displayed: - OK - LOSS OF CURRENT				
SYS.DMS(P2SAT-P2P-FCI).15	Verify point "Loss of Voltage - Phase C"	Values Displayed: - OK - LOSS OF VOLTAGE				
System Test Book - DMS (Phase 2 Site Acceptance Test) - FCI Point to Point Checkout: Profile 3 - CTR						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P2SAT-P2P-FCI).16	Verify point "Temporary Faults - Phase A"	N/A				
SYS.DMS(P2SAT-P2P-FCI).17	Verify point "Permanent Faults - Phase A"	N/A				
SYS.DMS(P2SAT-P2P-FCI).18	Verify point "Temporary Faults - Phase B"	N/A				
SYS.DMS(P2SAT-P2P-FCI).19	Verify point "Permanent Faults - Phase B"	N/A				
SYS.DMS(P2SAT-P2P-FCI).20	Verify point "Temporary Faults - Phase C"	N/A				
SYS.DMS(P2SAT-P2P-FCI).21	Verify point "Permanent Faults - Phase C"	N/A				
System Test Book - DMS (Phase 2 Site Acceptance Test) - FCI Point to Point Checkout: Profile 3 - AI						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P2SAT-P2P-FCI).21	Verify point "Fault Current - Phase A"	N/A				
SYS.DMS(P2SAT-P2P-FCI).22	Verify point "Fault Duration - Phase A"	N/A				
SYS.DMS(P2SAT-P2P-FCI).23	Verify point "Last Known Good Current - Phase A"	N/A				
SYS.DMS(P2SAT-P2P-FCI).24	Verify point "Current - Average - Phase A"	N/A				
SYS.DMS(P2SAT-P2P-FCI).25	Verify point "Fault Current - Phase B"	N/A				
SYS.DMS(P2SAT-P2P-FCI).26	Verify point "Fault Duration - Phase B"	N/A				
SYS.DMS(P2SAT-P2P-FCI).27	Verify point "Last Known Good Current - Phase B"	N/A				
SYS.DMS(P2SAT-P2P-FCI).28	Verify point "Current - Average - Phase B"	N/A				
SYS.DMS(P2SAT-P2P-FCI).29	Verify point "Fault Current - Phase C"	N/A				
SYS.DMS(P2SAT-P2P-FCI).30	Verify point "Fault Duration - Phase C"	N/A				
SYS.DMS(P2SAT-P2P-FCI).31	Verify point "Last Known Good Current - Phase C"	N/A				
SYS.DMS(P2SAT-P2P-FCI).32	Verify point "Current - Average - Phase C"	N/A				

System Test Book – DMS (Phase 2 Site Acceptance Test): Redundancy - Verify Configuration						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P2SAT-REDUNDANCY).1	Verify system Test Environment (HW & SW), including simulation and tools, before starting FAT	N/A				
SYS.DMS(P2SAT-REDUNDANCY).2	Verify system management and configuration displays and tools	N/A				
System Test Book – DMS (Phase 2 Site Acceptance Test): Redundancy - Verify System Components, Tools, DBs						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P2SAT-REDUNDANCY).3	Verify correct operation of the system components (system configuration overview, servers status, communications status, applications running,...)	N/A				
SYS.DMS(P2SAT-REDUNDANCY).4	Verify redundancy in the system network at each level (CC, Substation)	N/A				
System Test Book – DMS (Phase 2 Site Acceptance Test): Redundancy - Basic UI (Power CC)						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P2SAT-REDUNDANCY).5	Verify users log on and log off	N/A				
SYS.DMS(P2SAT-REDUNDANCY).6	Verify only defined users can log on	N/A				
SYS.DMS(P2SAT-REDUNDANCY).7	Verify reporting and logging	N/A				
SYS.DMS(P2SAT-REDUNDANCY).8	Verify Tabular displays availability and access	N/A				
SYS.DMS(P2SAT-REDUNDANCY).9	Verify that at least system logging reporting can be defined and activated	N/A				
SYS.DMS(P2SAT-REDUNDANCY).10	Verify queries, filtering and sorting capabilities in logs and lists	N/A				
SYS.DMS(P2SAT-REDUNDANCY).11	Verification of management functionality for logs and lists	N/A				
SYS.DMS(P2SAT-REDUNDANCY).12	Verify that at least system statistics can be defined and activated	N/A				
System Test Book – DMS (Phase 2 Site Acceptance Test): Redundancy - Spontaneous Reporting of Selected Data Points						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P2SAT-REDUNDANCY).13	Verify that there is no dead band defined in DSCADA	N/A				
SYS.DMS(P2SAT-REDUNDANCY).14	Verify time needed for data presentation and control execution to and from the Control Center	N/A				
SYS.DMS(P2SAT-REDUNDANCY).15	Verify data presented in Tabular displays	N/A				
SYS.DMS(P2SAT-REDUNDANCY).16	Verify alarm and event list access	N/A				

System Test Book – DMS (Phase 2 Site Acceptance Test): Redundancy - Areas of Responsibilities and Controls						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P2SAT-REDUNDANCY).17	Verify reporting and logging of AQR issues and management (authorizations and permissions)	N/A				
SYS.DMS(P2SAT-REDUNDANCY).18	Verification of control action cancellation by the operator	N/A				
SYS.DMS(P2SAT-REDUNDANCY).19	Verification of control action time-out	N/A				
SYS.DMS(P2SAT-REDUNDANCY).20	Verification of control action failed	N/A				
SYS.DMS(P2SAT-REDUNDANCY).21	Verify control action propagation in all modules and that execution is synchronized	N/A				
SYS.DMS(P2SAT-REDUNDANCY).22	Verify analog controls (set points), raise/lower (no return),...	N/A				
SYS.DMS(P2SAT-REDUNDANCY).23	Verify control command failures	N/A				
SYS.DMS(P2SAT-REDUNDANCY).24	Verification of system behavior in case of control "rejected" or "failed"	N/A				
SYS.DMS(P2SAT-REDUNDANCY).25	Verify interlocking conditions :Raise/Lower Limit reached	N/A				
SYS.DMS(P2SAT-REDUNDANCY).26	Verify interlocking conditions :Control In Progress	N/A				
SYS.DMS(P2SAT-REDUNDANCY).27	Verify interlocking conditions :Multiple user/consols	N/A				
SYS.DMS(P2SAT-REDUNDANCY).28	Verify reporting and logging of control actions, successful and failed	N/A				
System Test Book – DMS (Phase 2 Site Acceptance Test): Redundancy - Manual Changes and Tags						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P2SAT-REDUNDANCY).29	Verify validity checking for manual entries	N/A				
SYS.DMS(P2SAT-REDUNDANCY).30	Verify manual changes are updated in all modules (data synchronization)	N/A				
SYS.DMS(P2SAT-REDUNDANCY).31	Verify reporting and logging of manual changes, successful and failed	N/A				
SYS.DMS(P2SAT-REDUNDANCY).32	Verify JC&G functionality	N/A				
SYS.DMS(P2SAT-REDUNDANCY).33	Verify reporting and logging of temporary elements in the model	N/A				
SYS.DMS(P2SAT-REDUNDANCY).34	Verification of tagging propagation to the different modules of the system	N/A				
SYS.DMS(P2SAT-REDUNDANCY).35	Verification of locking conditions when tags are set	N/A				
SYS.DMS(P2SAT-REDUNDANCY).36	Verify reporting and logging of tagging actions	N/A				

System Test Book – DMS (Phase 2 Site Acceptance Test): Redundancy - Time Synchronization						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P2SAT-REDUNDANCY).37	Verify time synch reporting and logging when it happens.	N/A				
System Test Book – DMS (Phase 2 Site Acceptance Test): Redundancy - ICCP						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P2SAT-REDUNDANCY).38	Verification of the association table definition	N/A				
SYS.DMS(P2SAT-REDUNDANCY).39	Verification of association table definition error's reporting	N/A				
SYS.DMS(P2SAT-REDUNDANCY).40	Verification of the data flow through ICCP link, checking the different types of data in both directions	N/A				
SYS.DMS(P2SAT-REDUNDANCY).41	Verification ICCP link status display	N/A				
SYS.DMS(P2SAT-REDUNDANCY).42	Verification of the ICCP link management	N/A				
SYS.DMS(P2SAT-REDUNDANCY).43	Verification of the ICCP link redundancy	N/A				
SYS.DMS(P2SAT-REDUNDANCY).44	Verification communications error reporting	N/A				
System Test Book – DMS (Phase 2 Site Acceptance Test): Redundancy - Switch Mastership						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P2SAT-REDUNDANCY).45	Manually Switch Mastership (switch PowerCC Master and Standby)	N/A				
SYS.DMS(P2SAT-REDUNDANCY).46	DCADA Manually Switch Mastership (switch PowerCC Master and Standby)	N/A				
System Test Book – DMS (Phase 2 Site Acceptance Test): Redundancy - Communications Failover						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P2SAT-REDUNDANCY).47	Verify status reporting and logging at the CC	N/A				
SYS.DMS(P2SAT-REDUNDANCY).48	Verify system response to communication failure at the IED side (port unavailable, tropos router down,...)	N/A				
SYS.DMS(P2SAT-REDUNDANCY).49	Verify communication management capabilities like force DNP3 scan, force alternative communication path,...	N/A				
SYS.DMS(P2SAT-REDUNDANCY).50	Verify status reporting and logging at the HMI and CC	N/A				
SYS.DMS(P2SAT-REDUNDANCY).51	Verify status reporting and logging at the CC	N/A				

System Test Book – DMS (Phase 2 Site Acceptance Test): Redundancy - Application Failover						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P2SAT-REDUNDANCY).52	Verify data is correct after failover at all levels of redundancy	N/A				
SYS.DMS(P2SAT-REDUNDANCY).53	Verify InService redundancy and failover when problems exist in the application or SW	N/A				
SYS.DMS(P2SAT-REDUNDANCY).54	Verify manual InService failover	N/A				
SYS.DMS(P2SAT-REDUNDANCY).55	Verify alarms availability and retention during and after failovers	N/A				
SYS.DMS(P2SAT-REDUNDANCY).56	Verify error handling and redundancy for reporting function.	N/A				
SYS.DMS(P2SAT-REDUNDANCY).57	Verify logging of reporting activities	N/A				
System Test Book – DMS (Phase 2 Site Acceptance Test): Redundancy - DB Management and Model Propagation						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P2SAT-REDUNDANCY).58	Based on the DB generation process defined and provided by Siemens and Intergraph, verify that the data definition and DB generation works across all systems and modules	N/A				
SYS.DMS(P2SAT-REDUNDANCY).59	Verify display management	N/A				
SYS.DMS(P2SAT-REDUNDANCY).60	Verify general system DB management tools provided with the system (DB Jobs, DB Job propagation, DB Job roll back,...)	N/A				
SYS.DMS(P2SAT-REDUNDANCY).61	Verify DB error reporting and logging	N/A				
System Test Book – DMS (Phase 2 Site Acceptance Test): Redundancy - Backup & Restore						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P2SAT-REDUNDANCY).62	Verify DB archiving	N/A				
SYS.DMS(P2SAT-REDUNDANCY).63	Verify system tools to backup and restore SW and data	N/A				
SYS.DMS(P2SAT-REDUNDANCY).64	Verify reporting and logging of archiving and restoration activities	N/A				
SYS.DMS(P2SAT-REDUNDANCY).65	Verify system tools to save reports to external media	N/A				
System Test Book – DMS (Phase 2 Site Acceptance Test): Redundancy - LAN Failures						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P2SAT-REDUNDANCY).66	LAN Failure (single and double)	N/A				
SYS.DMS(P2SAT-REDUNDANCY).67	DCADA LAN Failure (single and double)	N/A				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P2SAT-REDUNDANCY).68	Verify SCADA applications operation	N/A				
SYS.DMS(P2SAT-REDUNDANCY).69	Verify communication with SiCAM and check correct recovery from LAN failure	N/A				
SYS.DMS(P2SAT-REDUNDANCY).70	Verify operation with InService when LAN fails and after correct recovery	N/A				
SYS.DMS(P2SAT-REDUNDANCY).71	Verify status reporting and logging	N/A				
System Test Book – DMS (Phase 2 Site Acceptance Test): Redundancy - System Startups						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P2SAT-REDUNDANCY).72	Automatic Startup - UI Client (PowerCC starts after restarting windows)	N/A				
SYS.DMS(P2SAT-REDUNDANCY).73	DCADA Manual Startup (Manually start PowerCC server)	N/A				
SYS.DMS(P2SAT-REDUNDANCY).74	DCADA Automatic Startup - DMS Master (PowerCC starts after restarting windows)	N/A				
SYS.DMS(P2SAT-REDUNDANCY).75	DCADA Automatic Startup - DMS Standby (PowerCC starts after restarting windows)	N/A				
System Test Book – DMS (Phase 2 Site Acceptance Test): Redundancy - Availability - Power Failure						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P2SAT-REDUNDANCY).76	Verify system behavior during individual servers power failures	N/A				
SYS.DMS(P2SAT-REDUNDANCY).77	Verify applications run up to operational status without human intervention after power failure	N/A				
SYS.DMS(P2SAT-REDUNDANCY).78	After Power Failure, verify that IED scanning is happening and data is correct not only that the application is running	N/A				
System Test Book – DMS (Phase 2 Site Acceptance Test): Redundancy - System Cold/Start Up						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P2SAT-REDUNDANCY).79	Verify execution of the System Start Up procedure	N/A				
SYS.DMS(P2SAT-REDUNDANCY).80	Verify SCADA applications and InService run up to operational status without human intervention after power failure	N/A				
SYS.DMS(P2SAT-REDUNDANCY).81	Verify SiCAM status changes are reported and logged at the CC and HMI	N/A				

System Test Book – DMS (Phase 2 Site Acceptance Test): Integrated UI – Verify System Components, Tools, DBs						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P2SAT-UI).1	Verify correct operation of the system components (system configuration overview, servers status, communications status, applications running,...)	N/A				
System Test Book – DMS (Phase 2 Site Acceptance Test): Integrated UI – Basic UI						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P2SAT-UI).2	Verify navigational functions in InService	N/A				
SYS.DMS(P2SAT-UI).3	Verify Tabular displays availability and access	N/A				
SYS.DMS(P2SAT-UI).4	Verify geographical queries in InService	N/A				
SYS.DMS(P2SAT-UI).5	Verify alarm list functions like filtering, queries, paging,...	N/A				
SYS.DMS(P2SAT-UI).6	Verify definition and use of KCPL defined help screens	N/A				
SYS.DMS(P2SAT-UI).7	Verify queries, filtering and sorting capabilities in logs and lists	N/A				
SYS.DMS(P2SAT-UI).8	Digital Indication Change	N/A				
System Test Book – DMS (Phase 2 Site Acceptance Test): Integrated UI – Spontaneous Reporting of Selected Data Points						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P2SAT-UI).9	Verify status reporting and logging at the HMI and CC	N/A				
SYS.DMS(P2SAT-UI).10	Verify all the alarm types and event reporting caused by data processing	N/A				
SYS.DMS(P2SAT-UI).11	Verify alarm events	N/A				
SYS.DMS(P2SAT-UI).12	Verify time needed for data presentation and control execution to and from the Control Center	N/A				
SYS.DMS(P2SAT-UI).13	Verify value representation, values and data quality	N/A				
SYS.DMS(P2SAT-UI).14	Verify data presented in Tabular displays	N/A				
SYS.DMS(P2SAT-UI).15	Verify alarm and event list access	N/A				
SYS.DMS(P2SAT-UI).16	Verify different types of alarms and events	N/A				
SYS.DMS(P2SAT-UI).17	Verify alarm management capabilities (acknowledge, deletion,...)	N/A				
System Test Book – DMS (Phase 2 Site Acceptance Test): Integrated UI – Areas of Responsibilities and Controls						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P2SAT-UI).19	Verify configuration of AORs and permissions for different users	N/A				
SYS.DMS(P2SAT-UI).20	Verify change in AOR	N/A				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P2SAT-UI).21	Verify authorization and permission changes for an AOR	N/A				
SYS.DMS(P2SAT-UI).22	Verify reporting and logging of AOR issues and management (authorizations and permissions)	N/A				
SYS.DMS(P2SAT-UI).23	Verify control action procedure	N/A				
SYS.DMS(P2SAT-UI).24	Verification of control action in progress representation in displays	N/A				
SYS.DMS(P2SAT-UI).25	Verification of control action cancellation by the operator	N/A				
SYS.DMS(P2SAT-UI).26	Verification of control action time-out	N/A				
SYS.DMS(P2SAT-UI).27	Verification of control action failed	N/A				
SYS.DMS(P2SAT-UI).28	Verify analog controls (set points), raise/lower (no return),...	N/A				
SYS.DMS(P2SAT-UI).29	Verify control command failures	N/A				
SYS.DMS(P2SAT-UI).30	Verification of system behavior in case of control "rejected" or "failed"	N/A				
SYS.DMS(P2SAT-UI).31	Verify interlocking conditions :Raise/Lower Limit reached	N/A				
SYS.DMS(P2SAT-UI).32	Verify interlocking conditions :Multiple user/consoles	N/A				
System Test Book – DMS (Phase 2 Site Acceptance Test): Integrated UI – Manual Changes and Tags						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P2SAT-UI).33	Verify Manual valid substitution function	N/A				
SYS.DMS(P2SAT-UI).34	Verification of manual entries representation in displays	N/A				
SYS.DMS(P2SAT-UI).35	Verify validity checking for manual entries	N/A				
SYS.DMS(P2SAT-UI).36	Verify reporting and logging of manual changes, successful and failed	N/A				
SYS.DMS(P2SAT-UI).37	Verify Jumpers/Cuts/Grounding functionality	N/A				
SYS.DMS(P2SAT-UI).38	Verification of temporary element representation in displays	N/A				
SYS.DMS(P2SAT-UI).39	Verify reporting and logging of temporary elements in the model	N/A				
SYS.DMS(P2SAT-UI).40	Verification of Tag setting, comments, removal	N/A				
SYS.DMS(P2SAT-UI).41	Verification of tagging representation in displays	N/A				
SYS.DMS(P2SAT-UI).42	Verification of multiple tags for the same device and different device types	N/A				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P2SAT-UI).43	Verification of tagging lists (system-wise, tag type,...)	N/A				
SYS.DMS(P2SAT-UI).44	Verification of tagging propagation to the different modules of the system	N/A				
SYS.DMS(P2SAT-UI).45	Verification of locking conditions when tags are set	N/A				
System Test Book – DMS (Phase 2 Site Acceptance Test): Integrated UI – Time Synchronization						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P2SAT-UI).46	Verify time synch reporting and logging when it happens.	N/A				
System Test Book – DMS (Phase 2 Site Acceptance Test): Integrated UI – Alarm List Management						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P2SAT-UI).47	Verify that alarm error conditions and problems are reported and logged (list full, alarm processing not working,...)	N/A				
SYS.DMS(P2SAT-UI).48	Verify alarm management special conditions like max number of alarms reached, reduced view,...	N/A				
SYS.DMS(P2SAT-UI).49	Verify reporting and logging of alarm issues and list management	N/A				
System Test Book – DMS (Phase 2 Site Acceptance Test): Integrated UI – ICCP						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P2SAT-UI).50	Verification of the data flow through ICCP link, checking the different types of data in both directions	N/A				
SYS.DMS(P2SAT-UI).51	Verification ICCP link status display	N/A				
SYS.DMS(P2SAT-UI).52	Verification of the ICCP link management	N/A				
SYS.DMS(P2SAT-UI).53	Verification of the ICCP link redundancy	N/A				
System Test Book – DMS (Phase 2 Site Acceptance Test): Integrated UI – Communications Failover/Redundancy						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P2SAT-UI).54	Verify communication failover and redundancy for communication or application errors/problems.	N/A				
System Test Book – DMS (Phase 2 Site Acceptance Test): Integrated UI – Application Failover/Redundancy						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P2SAT-UI).55	Verify data is correct after failover at all levels of redundancy	N/A				
SYS.DMS(P2SAT-UI).56	Verify InService operation	N/A				

System Test Book - DMS (Phase 3 Factory Acceptance Test) - Recloser Points Checkout: Type DI						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P3FAT-651R).1	Verify point "Enabled"	Values Displayed: - DISABLED - ENABLED				
SYS.DMS(P3FAT-651R).2	Verify point "Device Status"	Values Displayed: - OPEN - CLOSE				
SYS.DMS(P3FAT-651R).3	Verify point "Loss of Potential"	Values Displayed: - OK - ALARM				
SYS.DMS(P3FAT-651R).4	Verify point "Fault - Phase C"	Values Displayed: - OK - ALARM				
SYS.DMS(P3FAT-651R).5	Verify point "Fault - Phase B"	Values Displayed: - OK - ALARM				
SYS.DMS(P3FAT-651R).6	Verify point "Fault - Phase A"	Values Displayed: - OK - ALARM				
SYS.DMS(P3FAT-651R).7	Verify point "Sync Check Elements"	Values Displayed: - OK - ALARM				
SYS.DMS(P3FAT-651R).8	Verify point "Cabinet Door"	Values Displayed: - OK - ALARM				
SYS.DMS(P3FAT-651R).9	Verify point "50CO - Ground Overcurrent Status"	Values Displayed: - DISABLED - ENABLED				
SYS.DMS(P3FAT-651R).10	Verify point "79CO - Reclosing Status"	Values Displayed: - DISABLED - ENABLED				
SYS.DMS(P3FAT-651R).11	Verify point "Local - Remote"	Values Displayed: - LOCAL - REMOTE				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P3FAT-651R).12	Verify point "Fast Curves Status"	Values Displayed: - DISABLED - ENABLED				
SYS.DMS(P3FAT-651R).13	Verify point "Push Buttons Locked"	Values Displayed: - UNLOCKED - LOCKED				
SYS.DMS(P3FAT-651R).14	Verify point "Hot Line Tag Status"	Values Displayed: - DISABLED - ENABLED				
SYS.DMS(P3FAT-651R).15	Verify point "Aux 1 Status"	Values Displayed: - DISABLED - ENABLED				
SYS.DMS(P3FAT-651R).16	Verify point "Aux 2 Status"	Values Displayed: - DISABLED - ENABLED				
SYS.DMS(P3FAT-651R).17	Verify point "Aux 3 Status"	Values Displayed: - DISABLED - ENABLED				
SYS.DMS(P3FAT-651R).18	Verify point "Battery Failure"	Values Displayed: - OK - ALARM				
SYS.DMS(P3FAT-651R).19	Verify point "External Power"	Values Displayed: - OFF - ON				
SYS.DMS(P3FAT-651R).20	Verify point "Lockout"	Values Displayed: - OK - ALARM				
SYS.DMS(P3FAT-651R).21	Verify point "Current Direction"	Values Displayed: - NORMAL - REVERSED				
SYS.DMS(P3FAT-651R).22	Verify point "Contact Wear - 3 Phase"	Values Displayed: - OK - ALARM				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P3FAT-651R).23	Verify point "Clock Present"	Values Displayed: - NOT PRESENT - PRESENT				
SYS.DMS(P3FAT-651R).24	Verify point "Hardware Alarm"	Values Displayed: - OK - ALARM				
SYS.DMS(P3FAT-651R).25	Verify point "Software Alarm"	Values Displayed: - OK - ALARM				
System Test Book - DM5 (Phase 3 Factory Acceptance Test) - Recloser Points Checkout: Type DO						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P3FAT-651R).26	Verify point "Aux 1"	Values Displayed: - DISABLED - ENABLED				
SYS.DMS(P3FAT-651R).27	Verify point "Aux 2"	Values Displayed: - DISABLED - ENABLED				
SYS.DMS(P3FAT-651R).28	Verify point "Aux 3"	Values Displayed: - DISABLED - ENABLED				
SYS.DMS(P3FAT-651R).29	Verify point "Aux 4"	Values Displayed: - DISABLED - ENABLED				
SYS.DMS(P3FAT-651R).30	Verify point "50CO - Ground Overcurrent"	Values Displayed: - DISABLED - ENABLED				
SYS.DMS(P3FAT-651R).31	Verify point "79CO - Reclosing"	Values Displayed: - DISABLED - ENABLED				
SYS.DMS(P3FAT-651R).32	Verify point "Fast Curves"	Values Displayed: - DISABLED - ENABLED				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P3FAT-651R).33	Verify point "Hot Line Tag"	Values Displayed: - DISABLED - ENABLED				
SYS.DMS(P3FAT-651R).34	Verify point "Device Operate"	Values Displayed: - OPEN - CLOSE				
SYS.DMS(P3FAT-651R).35	Verify point "Reset Front Panel Targets"	Values Displayed: - NA - RESET				
System Test Book - DMS (Phase 3 Factory Acceptance Test) - Recloser Points Checkout: Type CTR						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P3FAT-651R).36	Verify point "Active Settings Group"	N/A				
SYS.DMS(P3FAT-651R).37	Verify point "Internal Breaker Trips - Phase A"	N/A				
SYS.DMS(P3FAT-651R).38	Verify point "Internal Breaker Trips - Phase B"	N/A				
SYS.DMS(P3FAT-651R).39	Verify point "Internal Breaker Trips - Phase C"	N/A				
SYS.DMS(P3FAT-651R).40	Verify point "External Breaker Trips - Phase A"	N/A				
SYS.DMS(P3FAT-651R).41	Verify point "External Breaker Trips - Phase B"	N/A				
SYS.DMS(P3FAT-651R).42	Verify point "External Breaker Trips - Phase C"	N/A				
System Test Book - DMS (Phase 3 Factory Acceptance Test) - Recloser Points Checkout: Type AI						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P3FAT-651R).43	Verify point "Current - Phase A"	N/A				
SYS.DMS(P3FAT-651R).44	Verify point "Current - Phase B"	N/A				
SYS.DMS(P3FAT-651R).45	Verify point "Current - Phase C"	N/A				
SYS.DMS(P3FAT-651R).46	Verify point "Current - Neutral"	N/A				
SYS.DMS(P3FAT-651R).47	Verify point "Current - Ground"	N/A				
SYS.DMS(P3FAT-651R).48	Verify point "Voltage - Phase A - Y"	N/A				
SYS.DMS(P3FAT-651R).49	Verify point "Voltage - Phase B - Y"	N/A				
SYS.DMS(P3FAT-651R).50	Verify point "Voltage - Phase C - Y"	N/A				
SYS.DMS(P3FAT-651R).51	Verify point "Voltage - Phase A - Z"	N/A				
SYS.DMS(P3FAT-651R).52	Verify point "Voltage - Phase B - Z"	N/A				
SYS.DMS(P3FAT-651R).53	Verify point "Voltage - Phase C - Z"	N/A				
SYS.DMS(P3FAT-651R).54	Verify point "Real Power - Phase A"	N/A				
SYS.DMS(P3FAT-651R).55	Verify point "Real Power - Phase B"	N/A				
SYS.DMS(P3FAT-651R).56	Verify point "Real Power - Phase C"	N/A				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P3FAT-651R).57	Verify point "Real Power - 3 Phase"	N/A				
SYS.DMS(P3FAT-651R).58	Verify point "Reactive Power - Phase A"	N/A				
SYS.DMS(P3FAT-651R).59	Verify point "Reactive Power - Phase B"	N/A				
SYS.DMS(P3FAT-651R).60	Verify point "Reactive Power - Phase C"	N/A				
SYS.DMS(P3FAT-651R).61	Verify point "Reactive Power - 3 Phase"	N/A				
SYS.DMS(P3FAT-651R).62	Verify point "Frequency"	N/A				
SYS.DMS(P3FAT-651R).63	Verify point "Contact Wear - Phase A"	N/A				
SYS.DMS(P3FAT-651R).64	Verify point "Contact Wear - Phase B"	N/A				
SYS.DMS(P3FAT-651R).65	Verify point "Contact Wear - Phase C"	N/A				
SYS.DMS(P3FAT-651R).66	Verify point "Fault Type"	N/A				
SYS.DMS(P3FAT-651R).67	Verify point "Fault Recloser Shot Counter"	N/A				
SYS.DMS(P3FAT-651R).68	Verify point "Fault Time"	N/A				
SYS.DMS(P3FAT-651R).69	Verify point "Fault Current - Phase A"	N/A				
SYS.DMS(P3FAT-651R).70	Verify point "Fault Current - Phase B"	N/A				
SYS.DMS(P3FAT-651R).71	Verify point "Fault Current - Phase C"	N/A				
SYS.DMS(P3FAT-651R).72	Verify point "Fault Current - Ground"	N/A				
SYS.DMS(P3FAT-651R).73	Verify point "Apparent Power - Phase A"	N/A				
SYS.DMS(P3FAT-651R).74	Verify point "Apparent Power - Phase B"	N/A				
SYS.DMS(P3FAT-651R).75	Verify point "Apparent Power - Phase C"	N/A				
SYS.DMS(P3FAT-651R).76	Verify point "Apparent Power - 3 Phase"	N/A				
SYS.DMS(P3FAT-651R).77	Verify point "THD - Current - Phase A"	N/A				
SYS.DMS(P3FAT-651R).78	Verify point "THD - Current - Phase B"	N/A				
SYS.DMS(P3FAT-651R).79	Verify point "THD - Current - Phase C"	N/A				
SYS.DMS(P3FAT-651R).80	Verify point "THD - Current - Neutral"	N/A				
SYS.DMS(P3FAT-651R).81	Verify point "THD - Voltage - Phase A - Y"	N/A				
SYS.DMS(P3FAT-651R).82	Verify point "THD - Voltage - Phase B - Y"	N/A				
SYS.DMS(P3FAT-651R).83	Verify point "THD - Voltage - Phase C - Y"	N/A				
SYS.DMS(P3FAT-651R).84	Verify point "THD - Voltage - Phase A - Z"	N/A				
SYS.DMS(P3FAT-651R).85	Verify point "THD - Voltage - Phase B - Z"	N/A				
SYS.DMS(P3FAT-651R).86	Verify point "THD - Voltage - Phase C - Z"	N/A				
SYS.DMS(P3FAT-651R).87	Verify point "Battery Voltage"	N/A				
SYS.DMS(P3FAT-651R).88	Verify point "Battery Current"	N/A				
System Test Book - DMS (Phase 3 Factory Acceptance Test) - Recloser Points Checkout: Type AO						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P3FAT-651R).89	Verify point "Set Active Settings Group"	N/A				

System Test Book - DMS (Phase 3 FAT): Configuration Verification						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P3FAT).1	Verify FAT system environment diagram	N/A				
SYS.DMS(P3FAT).2	Verify system Test Environment (H/W & SW), including simulation and tools, before starting FAT	N/A				
SYS.DMS(P3FAT).3	Verify system management and configuration displays and tools	N/A				
SYS.DMS(P3FAT).4	Verify correct operation of the system components (system configuration overview, servers status, communications status, applications running,...)	N/A				
System Test Book - DMS (Phase 3 FAT): Computer System Management						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P3FAT).6	Verify that servers and applications synch using NTP	N/A				
SYS.DMS(P3FAT).12	Verify redundancy for DNA modules	N/A				
SYS.DMS(P3FAT).13	Verify communication redundancy between CC and substation	N/A				
SYS.DMS(P3FAT).20	Verify DNA applications operation	N/A				
SYS.DMS(P3FAT).22	Verify communication with SICAM and check correct recovery from LAN failure	N/A				
SYS.DMS(P3FAT).24	Verify operation with InService when LAN fails and after correct recovery	N/A				
SYS.DMS(P3FAT).26	Verify status reporting and logging	N/A				
SYS.DMS(P3FAT).28	Verify data consistency including DNA	N/A				
SYS.DMS(P3FAT).30	Verify data is correct after failover at all levels of redundancy from DNA perspective	N/A				
SYS.DMS(P3FAT).32	Verify system behavior during DNA servers power failures and vice versa	N/A				
SYS.DMS(P3FAT).35	Verify applications run up to operational status without human intervention after power failure	N/A				
SYS.DMS(P3FAT).36	Verify SICAM status status changes are reported and logged at the CC and HMI	N/A				
SYS.DMS(P3FAT).44	Verify DNA applications run up to operational status without human intervention after power failure	N/A				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P3FAT).48	Verify Cyber security rules and conditions for DNA applications (Similar to the ones defined for the rest of the system components) There are basic security requirements for the systems that need to be verified for this solution: - Users definition (password hardening, authorities, permissions) - Log On/Off characteristics (allowed attempts, time outs,...) - Logging of all actions - System users/passwords - Remote log ins and connections	N/A				
System Test Book - DMS (Phase 3 FAT): Functional Redundancy						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P3FAT).55	Verify automatic failover at the substation level when DCADA application has problems or the SW detects errors	N/A				
SYS.DMS(P3FAT).56	Verify status reporting and logging at the CC	N/A				
SYS.DMS(P3FAT).59	Verify DSCADA and DNA redundancy and failover caused by application or SW problems	N/A				
SYS.DMS(P3FAT).60	Verify DNA, SCADA functions manual failover	N/A				
SYS.DMS(P3FAT).61	Verify status reporting and logging at the CC	N/A				
SYS.DMS(P3FAT).62	Verify presentation of the control and application status for the substation and the CC	N/A				
SYS.DMS(P3FAT).64	Verify Manual transfer of DNA control	N/A				
SYS.DMS(P3FAT).419	Verify that the Mastership control UI or status and control operations are accesible in DCADA DNA in case DMS is not accesible	N/A				
SYS.DMS(P3FAT).420	Verify automatic transfer of control from DCADA close loop to DMS: - Boundary switch closed - Connection between DCADA and SICAM lost - FLT/FISR/VVC error condition in DCADA DNA - Loss of communication between DCADA and DMS	N/A				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P3FAT).421	Verify of automatic control authority removal from DMS close loop when : - Boundary switch closed - Connection between DMS and SICAM is lost - FISR/FLT/VVC error condition in DMS DNA - Loss of communication between DCADA and DMS	N/A				
SYS.DMS(P3FAT).422	Verify normal operation of DMS except for controls when DCADA is master	N/A				
SYS.DMS(P3FAT).423	Verify normal operation of DMS including controls when DCADA is master for subsystems outside the DCADA area	N/A				
SYS.DMS(P3FAT).424	Verify normal operation of DMS including controls when DMS is Master and in manual mode	N/A				
SYS.DMS(P3FAT).425	Verify normal operation of DMS except controls when DMS is Master in Close Lopp	N/A				
SYS.DMS(P3FAT).426	Verify DCADA can not be set to close loop operation when DMS is Master	N/A				
SYS.DMS(P3FAT).427	Verify DMS can not be set to close loop operation for Midtown when DCADA is Master	N/A				
SYS.DMS(P3FAT).428	Verify notification of Control Mastership in DCADA and DMS Uis	N/A				
SYS.DMS(P3FAT).67	Verify status reporting and logging at the CC	N/A				
System Test Book - DMS (Phase 3 FAT): Data Acquisition						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P3FAT).77	Verify status reporting to the DNA	N/A				
System Test Book - DMS (Phase 3 FAT): Data Propagation						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P3FAT).93	Verification of the data flow through ICCP link to DNA	N/A				
System Test Book - DMS (Phase 3 FAT): Data Base Management						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P3FAT).99	Based on the DB generation process defined and provided by Siemens and Intergraph, verify that the data definition and DB generation works for DNA	N/A				
SYS.DMS(P3FAT).103	Verify DB management tools with DNA model (DB Jobs, DB Job propagation, DB Job roll back,...)	N/A				
SYS.DMS(P3FAT).105	Verify DNA DB archiving	N/A				
SYS.DMS(P3FAT).106	Verify DB error reporting and logging	N/A				

System Test Book - DMS (Phase 3 FAT): User Interface						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P3FAT).108	Verify users log on and log off in DNA	N/A				
SYS.DMS(P3FAT).110	Verify only defined users can log on in DNA	N/A				
SYS.DMS(P3FAT).111	Verify reporting and logging	N/A				
SYS.DMS(P3FAT).116	Verify Tabular displays availability and access in DNA	N/A				
SYS.DMS(P3FAT).118	Verify data presented in Tabular displays in DNA	N/A				
SYS.DMS(P3FAT).134	Verify configuration of AORs and permissions for different in DNA	N/A				
SYS.DMS(P3FAT).136	Verify change in AOR for DNA	N/A				
SYS.DMS(P3FAT).138	Verify authorization and permission changes for an AOR in DNA	N/A				
SYS.DMS(P3FAT).139	Verify reporting and logging of AOR issues and management (authorizations and permissions)	N/A				
SYS.DMS(P3FAT).146	Verify control action propagation in all modules and that execution is synchronized starting from DNA	N/A				
SYS.DMS(P3FAT).154	Verify Switching Plan management and execution (Switching sequences module)	N/A				
SYS.DMS(P3FAT).159	Verify manual changes are updated in DNA (data synchronization)	N/A				
SYS.DMS(P3FAT).160	Verify reporting and logging of manual changes, successful and failed	N/A				
SYS.DMS(P3FAT).162	Verify JC&G functionality in DNA	N/A				
SYS.DMS(P3FAT).164	Verify propagation of temporary elements to all affected modules	N/A				
SYS.DMS(P3FAT).165	Verifies DNA execution when setting or removing temporary elements	N/A				
SYS.DMS(P3FAT).166	Verify reporting and logging of temporary elements in the model	N/A				
SYS.DMS(P3FAT).172	Verification of tagging propagation to DNA	N/A				
SYS.DMS(P3FAT).174	Verify reporting and logging of tagging actions	N/A				
System Test Book - DMS (Phase 3 FAT): Data Archive & Backup						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P3FAT).177	Verify system tools to save event log, system log and specific DNA data to external media	N/A				
SYS.DMS(P3FAT).178	Verify reporting and logging of information archiving activities	N/A				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P3FAT).180	Verify system tools to backup and restore SW and data	N/A				
SYS.DMS(P3FAT).181	Verify reporting and logging of archiving and restoration activities	N/A				
System Test Book - DMS (Phase 3 FAT): Reporting						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P3FAT).193	Verify application statistics displays for VVC, FLT and FSR	N/A				
System Test Book - DMS (Phase 3 FAT): Distribution Network Applications – General DNA System Testing						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P3FAT).194	Test DNA hierarchical operation: (monitor and control)	N/A				
SYS.DMS(P3FAT).195	Locking conditions to avoid overlaps between DCADA and DMS	N/A				
SYS.DMS(P3FAT).196	Enable – disable applications independently in DCADA and DMS	N/A				
SYS.DMS(P3FAT).197	Verify User Log On to the DNA Web UI in DMS	N/A				
SYS.DMS(P3FAT).198	Verify User Log On to the DNA Web UI in DNA	N/A				
SYS.DMS(P3FAT).199	Verify access denial to undefined users or wrong password	N/A				
SYS.DMS(P3FAT).200	Verify use of permissions for different users	N/A				
SYS.DMS(P3FAT).201	Verify context management	N/A				
SYS.DMS(P3FAT).202	Verify access to study context and case management	N/A				
SYS.DMS(P3FAT).203	Verify simultaneous use of multiple contexts and cases	N/A				
SYS.DMS(P3FAT).204	Verify reporting and logging	N/A				
System Test Book - DMS (Phase 3 FAT): Distribution Network Applications - State Estimation (DSSE) & Power Flow (DSPF)						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P3FAT).205	From InService demonstrate access to PowerFlow connecting to the DNA in DMS	N/A				
SYS.DMS(P3FAT).206	Verify reporting of execution errors or problems	N/A				
SYS.DMS(P3FAT).207	Verify access to application alarms or program output	N/A				
SYS.DMS(P3FAT).208	From InService demonstrate access to PowerFlow connecting to the DNA in DCADA	N/A				
SYS.DMS(P3FAT).209	Verify reporting of execution errors or problems	N/A				
SYS.DMS(P3FAT).210	Verify access to application alarms or program output	N/A				
SYS.DMS(P3FAT).211	Run DSSE from DMS DNA UI and verify results	N/A				
SYS.DMS(P3FAT).212	Verify DSSE different modes of execution in DMS	N/A				
SYS.DMS(P3FAT).213	Verify DNA DSSE operation with multiple users	N/A				
SYS.DMS(P3FAT).214	Verify DNA DSSE operation with simultaneous execution from multiple users	N/A				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P3FAT).215	Verify reporting of execution errors or problems	N/A				
SYS.DMS(P3FAT).216	Verify access to application alarms or program output	N/A				
SYS.DMS(P3FAT).217	Introduce model changes and verify results	N/A				
SYS.DMS(P3FAT).A	Reverse flow verification/alarm	N/A				
SYS.DMS(P3FAT).B	Verify island condition	N/A				
SYS.DMS(P3FAT).218	Introduce manual data changes and verify results	N/A				
SYS.DMS(P3FAT).219	Run DSSE from DCADA DNA UI and verify results	N/A				
SYS.DMS(P3FAT).220	Verify DSSE different modes of execution from DCADA	N/A				
SYS.DMS(P3FAT).221	Verify reporting of execution errors or problems	N/A				
SYS.DMS(P3FAT).222	Verify access to application alarms or program output	N/A				
SYS.DMS(P3FAT).223	Introduce model changes and verify results	N/A				
SYS.DMS(P3FAT).224	Introduce manual data changes and verify results	N/A				
SYS.DMS(P3FAT).225	Verify DNA DSEE simultaneous execution in DMS and DCADA (Event Triggered)	N/A				
SYS.DMS(P3FAT).226	Verify and compare DSSE results	N/A				
SYS.DMS(P3FAT).227	Verify reporting of execution errors or problems	N/A				
SYS.DMS(P3FAT).228	Run Power Flow from DMS DNA UI and verify results	N/A				
SYS.DMS(P3FAT).229	Verify PowerFlow different modes of execution from the DMS	N/A				
SYS.DMS(P3FAT).230	Verify DNA PF operation with multiple users	N/A				
SYS.DMS(P3FAT).231	Verify DNA PF operation with simultaneous execution from multiple users	N/A				
SYS.DMS(P3FAT).232	Verify reporting of execution errors or problems	N/A				
SYS.DMS(P3FAT).233	Verify access to application alarms or program output	N/A				
SYS.DMS(P3FAT).234	Introduce model changes and verify results	N/A				
SYS.DMS(P3FAT).235	Introduce manual data changes and verify results	N/A				
SYS.DMS(P3FAT).236	Run Power Flow from DCADA DNA UI and verify results	N/A				
SYS.DMS(P3FAT).237	Verify PowerFlow different modes of execution from the DCADA	N/A				
SYS.DMS(P3FAT).238	Verify reporting of execution errors or problems	N/A				
SYS.DMS(P3FAT).239	Verify access to application alarms or program output	N/A				
SYS.DMS(P3FAT).240	Introduce model changes and verify results	N/A				
SYS.DMS(P3FAT).241	Introduce manual data changes and verify results	N/A				
SYS.DMS(P3FAT).242	Verify access to list and summaries using DNA UI in the DMS	N/A				
SYS.DMS(P3FAT).243	Verify access to list and summaries using DNA UI in DCADA	N/A				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P3FAT).244	Verify alarms generated by Limit violation or other operational conditions like non convergence	N/A				
SYS.DMS(P3FAT).245	Verify alarms generated in DCADA by Limit violation or other operational conditions like non convergence.	N/A				
SYS.DMS(P3FAT).246	Verify DNA PF simultaneous execution in DMS and DCADA (Event Triggered)	N/A				
SYS.DMS(P3FAT).247	Verify and compare PF results	N/A				
SYS.DMS(P3FAT).248	Verify reporting of execution errors or problems	N/A				
SYS.DMS(P3FAT).249	Verify alarm notifications	N/A				
SYS.DMS(P3FAT).250	Verify DSSE operation when DNA failover occurs	N/A				
SYS.DMS(P3FAT).251	Verify PF operation when DNA failover occurs	N/A				
SYS.DMS(P3FAT).252	Verify DSSE operation after DNA failover occurs and stable situation is reestablished	N/A				
SYS.DMS(P3FAT).253	Verify PF operation after DNA failover occurs and stable situation is reestablished	N/A				
SYS.DMS(P3FAT).254	Verify DSSE operation when DNA failover occurs	N/A				
SYS.DMS(P3FAT).255	Verify PF operation when DNA failover occurs	N/A				
SYS.DMS(P3FAT).256	Verify DSSE operation after DNA failover occurs and stable situation is reestablished	N/A				
SYS.DMS(P3FAT).257	Verify PF operation after DNA failover occurs and stable situation is reestablished	N/A				
SYS.DMS(P3FAT).258	Verify Simulation mode	N/A				
SYS.DMS(P3FAT).259	Verify use and options in Simulation mode	N/A				
SYS.DMS(P3FAT).260	Verify visual differentiation of operational mode: Real Time and Simulation	N/A				
SYS.DMS(P3FAT).261	Verify reporting of execution errors or problems in Simulation Mode	N/A				
System Test Book - DMS (Phase 3 FAT): Distribution Network Applications - Feeder Load Transfer (FLT)						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P3FAT).262	Verify access to FLT from InService	N/A				
SYS.DMS(P3FAT).263	Verify FLT running from DMS (Switching Sequence?)	N/A				
SYS.DMS(P3FAT).264	Verify reporting of execution errors or problems	N/A				
SYS.DMS(P3FAT).265	Verify access to application alarms or program output	N/A				
SYS.DMS(P3FAT).266	Verify FLT running from DCADA (Switching Sequence execution?)	N/A				
SYS.DMS(P3FAT).267	Verify reporting of execution errors or problems	N/A				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P3FAT).268	Verify access to application alarms or program output	N/A				
SYS.DMS(P3FAT).269	Verify FLT execution and sequence interruption in DMS	N/A				
SYS.DMS(P3FAT).270	Verify FLT execution in close loop	N/A				
SYS.DMS(P3FAT).271	Verify Operator's notification (InService?)	N/A				
SYS.DMS(P3FAT).272	Verify reporting of execution errors or problems	N/A				
SYS.DMS(P3FAT).273	Verify validation steps	N/A				
SYS.DMS(P3FAT).274	Verify switching failures and/or confirmation of steps' execution	N/A				
SYS.DMS(P3FAT).275	Verify access to application alarms or program output	N/A				
SYS.DMS(P3FAT).276	Verify FLT execution and sequence interruption in DCADA	N/A				
SYS.DMS(P3FAT).277	Verify FLT execution in close loop	N/A				
SYS.DMS(P3FAT).278	Verify Operator's notification (InService?)	N/A				
SYS.DMS(P3FAT).279	Verify reporting of execution errors or problems	N/A				
SYS.DMS(P3FAT).280	Verify validation steps	N/A				
SYS.DMS(P3FAT).281	Verify switching failures and/or confirmation of steps' execution	N/A				
SYS.DMS(P3FAT).282	Verify access to application alarms or program output	N/A				
SYS.DMS(P3FAT).283	Access to FLT results and info from InService	N/A				
SYS.DMS(P3FAT).284	Verify FLT operation when DNA failover occurs	N/A				
SYS.DMS(P3FAT).285	Verify FLT operation after DNA failover occurs and stable situation is reestablished	N/A				
SYS.DMS(P3FAT).286	Verify coordinated Close Loop Operation in DCADA and DMS together	N/A				
SYS.DMS(P3FAT).287	Verify configuration of close loop in DCADA and DMS together	N/A				
SYS.DMS(P3FAT).288	Verify Operator's notification in DMS	N/A				
SYS.DMS(P3FAT).289	Verify authority transfer from DCADA to DMS when a solution is not found	N/A				
SYS.DMS(P3FAT).290	Verify notification to Operator in DMS when authority is transferred	N/A				
SYS.DMS(P3FAT).291	Verify FLT operation when DNA in DMS failover occurs while running. Check authority status and notification	N/A				
SYS.DMS(P3FAT).292	Verify FLT operation and notification after DNA in DMS failover occurs and stable situation is reestablished	N/A				
SYS.DMS(P3FAT).293	Verify FLT operation when DNA in DCADA failover occurs while running. Check authority status and notification	N/A				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P3FAT).294	Verify FLT operation and notification after DNA in DCADA failover occurs and stable situation is reestablished	N/A				
SYS.DMS(P3FAT).295	Verify FLT operation when DCADA and DMS get disconnected (communication failure).	N/A				
SYS.DMS(P3FAT).296	Verify FLT operation when DNA in DCADA is stopped or not available: - Automatic transfer of Authority - Operation stability	N/A				
SYS.DMS(P3FAT).297	Verify FLT operation when DNA in DMS is stopped or not available: - Automatic transfer of Authority - Operation stability	N/A				
SYS.DMS(P3FAT).298	Verify FLT running in simulation mode	N/A				
SYS.DMS(P3FAT).299	Verify use and options in Simulation mode	N/A				
SYS.DMS(P3FAT).300	Verify visual differentiation of operational mode: Real Time and Simulation	N/A				
SYS.DMS(P3FAT).301	Verify that generated and tested sequence in simulated mode can be transferred to Real Time	N/A				
SYS.DMS(P3FAT).302	Verify reporting of execution errors or problems in Simulation Mode	N/A				
System Test Book - DMS (Phase 3 FAT): Distribution Network Applications - Fault Location (FLOC)						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P3FAT).303	Verify that FLOC runs and results can be shown in the map.	N/A				
SYS.DMS(P3FAT).304	Verify geographical access to results (Navigation)	N/A				
SYS.DMS(P3FAT).305	Verify reporting of execution errors or problems in InService	N/A				
SYS.DMS(P3FAT).306	Verify interaction with application in InService	N/A				
SYS.DMS(P3FAT).307	Verify interaction with application in DNA UI	N/A				
SYS.DMS(P3FAT).308	Verify reporting of execution errors or problems	N/A				
SYS.DMS(P3FAT).309	Verify access to application alarms or program output	N/A				
SYS.DMS(P3FAT).310	Verify FLOC operation in different conditions	N/A				
SYS.DMS(P3FAT).311	Verify FLOC when setting temporary elements in InService	N/A				
SYS.DMS(P3FAT).312	Verify FLOC is not trigger by Operator's controls or switching sequence operations	N/A				
SYS.DMS(P3FAT).313	Verify that only permanent reclosure faults triggers FLOC	N/A				
SYS.DMS(P3FAT).314	Verify geographical access to results (Navigation)	N/A				
SYS.DMS(P3FAT).315	Verify reporting of execution errors or problems in InService	N/A				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P3FAT).316	Verify interaction with application in InService	N/A				
SYS.DMS(P3FAT).317	Verify interaction with application in DNA UI	N/A				
SYS.DMS(P3FAT).318	Verify reporting of execution errors or problems	N/A				
SYS.DMS(P3FAT).319	Verify access to application alarms or program output	N/A				
SYS.DMS(P3FAT).320	Verify FLOC application UI displays	N/A				
SYS.DMS(P3FAT).321	Verify FLOC interfaces with FSR and OMS	N/A				
SYS.DMS(P3FAT).322	Verify reporting of execution errors or problems	N/A				
SYS.DMS(P3FAT).323	Verify FLOC operation when DNA failover occurs	N/A				
SYS.DMS(P3FAT).324	Verify FLOC operation after DNA failover occurs and stable situation is reestablished	N/A				
System Test Book - DMS (Phase 3 FAT): Distribution Network Applications - Fault Isolation and Service Restoration (FISR)						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P3FAT).325	Verify FISR execution and service restoration	N/A				
SYS.DMS(P3FAT).326	Verify Operator's notification (InService?)	N/A				
SYS.DMS(P3FAT).327	Verify reporting of execution errors or problems	N/A				
SYS.DMS(P3FAT).328	Verify interaction with application in InService	N/A				
SYS.DMS(P3FAT).329	Verify geographical access to results (Navigation)	N/A				
SYS.DMS(P3FAT).331	Verify FISR execution with multiple faults at the same time <- FLOC Triggered	N/A				
SYS.DMS(P3FAT).332	Verify FISR execution and service restoration in close loop	N/A				
SYS.DMS(P3FAT).333	Verify Operator's notification (InService?)	N/A				
SYS.DMS(P3FAT).334	Verify reporting of execution errors or problems	N/A				
SYS.DMS(P3FAT).335	Verify geographical access to results (Navigation)	N/A				
SYS.DMS(P3FAT).336	Verify Switching Procedure export to OMS	N/A				
SYS.DMS(P3FAT).337	Verify Switching Procedure execution in InService	N/A				
SYS.DMS(P3FAT).338	Verify FISR operation when DNA failover occurs	N/A				
SYS.DMS(P3FAT).339	Verify FISR operation after DNA failover occurs and stable situation is reestablished	N/A				
SYS.DMS(P3FAT).340	Verify coordinated Close Loop Operation in DCADA and DMS together	N/A				
SYS.DMS(P3FAT).341	Verify configuration of close loop in DCADA and DMS together	N/A				
SYS.DMS(P3FAT).342	Verify Operator's notification in DMS	N/A				
SYS.DMS(P3FAT).343	Verify authority transfer from DCADA to DMS when a solution is not found	N/A				
SYS.DMS(P3FAT).344	Verify notification to Operator in DMS when authority is transferred	N/A				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P3FAT).345	Verify FISR operation when DNA in DMS failover occurs while running. Check authority status and notification	N/A				
SYS.DMS(P3FAT).346	Verify FISR operation and notification after DNA in DMS failover occurs and stable situation is reestablished	N/A				
SYS.DMS(P3FAT).347	Verify FISR operation when DNA in DCADA failover occurs while running. Check authority status and notification	N/A				
SYS.DMS(P3FAT).348	Verify FISR operation and notification after DNA in DCADA failover occurs and stable situation is reestablished	N/A				
SYS.DMS(P3FAT).349	Verify FISR operation and notification when DCADA and DMS get disconnected (communication failure).	N/A				
SYS.DMS(P3FAT).350	Verify FISR operation when DNA in DCADA is stopped or not available: - Automatic transfer of Authority - Operation stability	N/A				
SYS.DMS(P3FAT).351	Verify FISR operation when DNA in DMS is stopped or not available: - Automatic transfer of Authority - Operation stability	N/A				
SYS.DMS(P3FAT).352	Verify use and management of Study Context (Create, save & restore cases)	N/A				
SYS.DMS(P3FAT).353	Verify use of multiple Study contexts at the same time	N/A				
SYS.DMS(P3FAT).354	Verify FISR results in Study context	N/A				
SYS.DMS(P3FAT).355	Verify FISR operation in case of abnormal situations, user errors, ... in Study context	N/A				
SYS.DMS(P3FAT).356	Verify reporting of execution errors or problems in Study context	N/A				
System Test Book - DMS (Phase 3 FAT): Distribution Network Applications - Voltage and VAR control (VVC)						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P3FAT).357	Verify VVC execution in Open Loop and access to the Open Loop configuration	N/A				
SYS.DMS(P3FAT).358	Verify VVC application management: - Add and remove devices - Reject proposed switching plan - Adjust configuration and rerun	N/A				
SYS.DMS(P3FAT).359	Verify Operator's notification (InService?)	N/A				
SYS.DMS(P3FAT).360	Verify reporting of execution errors or problems	N/A				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P3FAT).361	Verify geographical access to results (Navigation)	N/A				
SYS.DMS(P3FAT).362	Verification of VVC configuration and Manual execution	N/A				
SYS.DMS(P3FAT).363	Verify Operator's notification (InService?)	N/A				
SYS.DMS(P3FAT).364	Verify reporting of execution errors or problems	N/A				
SYS.DMS(P3FAT).365	Verify geographical access to results (Navigation)	N/A				
SYS.DMS(P3FAT).366	Verify multiple Study context at the same time	N/A				
SYS.DMS(P3FAT).367	Verify result in Study context (simulation)	N/A				
SYS.DMS(P3FAT).368	Verify result in Study context can be used in real time context	N/A				
SYS.DMS(P3FAT).369	Verify Switching Procedure export to OMS	N/A				
SYS.DMS(P3FAT).370	Verify Switching Procedure execution in InService	N/A				
SYS.DMS(P3FAT).371	Verification of VVC configuration and Manual execution	N/A				
SYS.DMS(P3FAT).372	Verify reporting of execution errors or problems	N/A				
SYS.DMS(P3FAT).373	Verify Switching Procedure execution	N/A				
SYS.DMS(P3FAT).374	Verify Operator's notification in DMS	N/A				
SYS.DMS(P3FAT).375	Verify authority transfer from DCADA to DMS when a solution is not found	N/A				
SYS.DMS(P3FAT).376	Verify notification to Operator's in DMS when authority is transferred	N/A				
SYS.DMS(P3FAT).377	Verify VVC execution triggered by different conditions	N/A				
SYS.DMS(P3FAT).378	Verify that DDSE will run automatically when needed	N/A				
SYS.DMS(P3FAT).379	Verify VVC results of the sequence generated and executed	N/A				
SYS.DMS(P3FAT).380	Verify VVC reaction multiple trigger actions at the same time	N/A				
SYS.DMS(P3FAT).381	Verify VVC operation when DNA failover occurs while running	N/A				
SYS.DMS(P3FAT).382	Verify VVC operation after DNA failover occurs and stable situation is reestablished	N/A				
SYS.DMS(P3FAT).383	Verify reporting of execution errors or problems	N/A				
SYS.DMS(P3FAT).384	Verify VVC execution triggered by different conditions	N/A				
SYS.DMS(P3FAT).385	Verify that DDSE will run automatically when needed	N/A				
SYS.DMS(P3FAT).386	Verify VVC results of the sequence generated and executed	N/A				
SYS.DMS(P3FAT).387	Verify VVC reaction multiple trigger actions at the same time	N/A				
SYS.DMS(P3FAT).388	Verify VVC operation when DNA failover occurs while running	N/A				
SYS.DMS(P3FAT).389	Verify VVC operation after DNA failover occurs and stable situation is reestablished	N/A				
SYS.DMS(P3FAT).390	Verify reporting of execution errors or problems	N/A				
SYS.DMS(P3FAT).391	Verify VVC execution defining different objectives.	N/A				
SYS.DMS(P3FAT).392	Verify VVC execution using only controllable devices	N/A				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P3FAT).	Verify VVC execution after transferring capacitors to another circuit	N/A				
SYS.DMS(P3FAT).393	Verify VVC execution with tagged devices	N/A				
SYS.DMS(P3FAT).394	Verify VVC execution of control sequence when control fails	N/A				
SYS.DMS(P3FAT).395	Verify VVC reaction to a situation with no controllable devices	N/A				
SYS.DMS(P3FAT).396	Verify VVC reaction to topology changes between calculation and execution	N/A				
SYS.DMS(P3FAT).397	Verify reporting of execution errors or problems	N/A				
SYS.DMS(P3FAT).398	Verify Close Loop Operation in DMS	N/A				
SYS.DMS(P3FAT).399	Verify that DDSE will run automatically when needed as part of the VVC close loop execution	N/A				
SYS.DMS(P3FAT).400	Verify Close Loop execution failures and system reaction: - Control fails - Device Tagging - Device already in requested position ...	N/A				
SYS.DMS(P3FAT).401	Verify Close Loop execution with limit conditions: - Max number of daily operations - Usability Time runs out - Control values out of range ...	N/A				
SYS.DMS(P3FAT).402	Verify Close Loop Operation in DCADA	N/A				
SYS.DMS(P3FAT).403	Verify that DDSE will run automatically when needed as part of the VVC close loop execution	N/A				
SYS.DMS(P3FAT).404	Verify Close Loop execution failures and system reaction: - Control fails - Device Tagging - Device already in requested position ...	N/A				
SYS.DMS(P3FAT).405	Verify Close Loop execution with limit conditions: - Max number of daily operations - Usability Time runs out - Control values out of range ...	N/A				
SYS.DMS(P3FAT).406	Verify Operator's notification (InService?)	N/A				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P3FAT).407	Verify coordinated Close Loop Operation in DCADA and DMS together	N/A				
SYS.DMS(P3FAT).408	Verify configuration of close loop in DCADA and DMS together	N/A				
SYS.DMS(P3FAT).409	Verify Operator's notification in DMS	N/A				
SYS.DMS(P3FAT).410	Verify authority transfer from DCADA to DMS when a solution is not found	N/A				
SYS.DMS(P3FAT).411	Verify notification to Operator's in DMS when authority is transferred	N/A				
SYS.DMS(P3FAT).412	Verify VVC operation when DNA in DMS failover occurs while running. Check authority status and notification	N/A				
SYS.DMS(P3FAT).413	Verify VVC operation and notification after DNA in DMS failover occurs and stable situation is reestablished	N/A				
SYS.DMS(P3FAT).414	Verify VVC operation when DNA in DCADA failover occurs while running. Check authority status and notification	N/A				
SYS.DMS(P3FAT).415	Verify VVC operation and notification after DNA in DCADA failover occurs and stable situation is reestablished	N/A				
SYS.DMS(P3FAT).416	Verify VVC operation when DCADA and DMS get disconnected (communication failure).	N/A				
SYS.DMS(P3FAT).417	Verify VVC operation when DNA in DCADA is stopped or not available: - Automatic transfer of Authority - Operation stability	N/A				
SYS.DMS(P3FAT).418	Verify VVC operation when DNA in DMS is stopped or not available: - Automatic transfer of Authority - Operation stability	N/A				

System Test Book - DMS (Phase 3 Factory Acceptance Test) - Battery Points Checkout - User Interface (Graphical Display)						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P3FAT-RTAC).1	Verify battery representation and data presented in UI (Device ID, Active Power Mode, Active Reactive Mode, Active Charge Mode, Active State, Active Status)	N/A				
SYS.DMS(P3FAT-RTAC).2	Verify Change in symbol and tag color based on active status	N/A				
System Test Book - DMS (Phase 3 Factory Acceptance Test) - Battery Points Checkout - User Interface (BESS - HMI Application)						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P3FAT-RTAC).3	Verify access to BESS from InService	N/A				
SYS.DMS(P3FAT-RTAC).4	Verify BESS basic functions (One-Line Screen, System Status Screen, Snapshot Screen, Trend Data Screens, Stopping the BESS Remotely and Starting the BESS Remotely)	N/A				
System Test Book - DMS (Phase 3 Factory Acceptance Test) - Battery Points Checkout - Status Points : Indicators (DI)						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P3FAT-RTAC).5	Verify P-to-P check for all indicator points (Active State, Active Status, Energy Available, etc.)	N/A				
SYS.DMS(P3FAT-RTAC).6	Verify status point propagation in all modules is synchronized (InService => SCADA => SICAM => Battery Automation Controller RTAC)	N/A				
SYS.DMS(P3FAT-RTAC).7	Verify value representation, values and data quality	N/A				
SYS.DMS(P3FAT-RTAC).8	Verify data presented in Tabular displays	N/A				
SYS.DMS(P3FAT-RTAC).9	Verify all the alarm types and event reporting	N/A				
SYS.DMS(P3FAT-RTAC).10	Verify alarm and event list access	N/A				
System Test Book - DMS (Phase 3 Factory Acceptance Test) - Battery Points Checkout - Value Points (AI)						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P3FAT-RTAC).10	Verify P-to-P check for all value points (Analog values reporting from the battery controller)	N/A				
SYS.DMS(P3FAT-RTAC).11	Verify value representation, values and data quality	N/A				
SYS.DMS(P3FAT-RTAC).12	Verify data presented in Tabular displays	N/A				
SYS.DMS(P3FAT-RTAC).13	Verify all the alarm types and event reporting	N/A				
SYS.DMS(P3FAT-RTAC).14	Verify alarm and event list access	N/A				

System Test Book - DMS (Phase 3 Factory Acceptance Test) - Battery Points Checkout - Operational Control Points (CO)						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P3FAT-RTAC).15	Verify P-to-P check for all control points (BESS Operation ENABLE/DISABLE, Schedule Override, Reset BESS Alarms)	N/A				
SYS.DMS(P3FAT-RTAC).16	Verify control action procedure	N/A				
SYS.DMS(P3FAT-RTAC).17	Verification of control action time-out	N/A				
SYS.DMS(P3FAT-RTAC).18	Verification of control action failed	N/A				
SYS.DMS(P3FAT-RTAC).19	Verify control command failures (e.g when Active Power Mode, Set KVAR discharged rate)	N/A				
SYS.DMS(P3FAT-RTAC).20	Verification of system behavior in case of control "rejected" or "failed"	N/A				
SYS.DMS(P3FAT-RTAC).21	Verify reporting and logging of control actions, successful and failed	N/A				
SYS.DMS(P3FAT-RTAC).22	Verify error reporting and logging (Some error conditions need to be generated)	N/A				
System Test Book - DMS (Phase 3 Factory Acceptance Test) - Battery Points Checkout - Operational Mode Set Points						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P3FAT-RTAC).22	Verify that the BESS must be "ENABLED" to accept Operator's controls	N/A				
SYS.DMS(P3FAT-RTAC).23	Verify analog controls set points: Operational Modes Set Points (Power, Reactive, Charge)	N/A				
SYS.DMS(P3FAT-RTAC).24	Verify Power Mode set points: 0 = OFF 1 = Fixed kW 2 = Load Following (Circuit) 3 = Load Following (Bus) 4 = Load Following (Transformer) 5 = DERM (Not part of scope at the moment) 6 = Islanding (Not part of scope at the moment)	N/A				
SYS.DMS(P3FAT-RTAC).25	Verify control completion (returned value/point)	N/A				
SYS.DMS(P3FAT-RTAC).26	Verify set control failures	N/A				
SYS.DMS(P3FAT-RTAC).27	Verification of system behavior in case of set points are "rejected" or "failed"	N/A				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P3FAT-RTAC).28	Verify interlocking conditions: Check for set point limits and values out of range as invalid input	N/A				
SYS.DMS(P3FAT-RTAC).29	Verify interlocking conditions: Multiple user/consoles	N/A				
SYS.DMS(P3FAT-RTAC).30	Verify reporting and logging of control actions, successful and failed	N/A				
SYS.DMS(P3FAT-RTAC).31	Verify error reporting and logging (Some error conditions need to be generated)	N/A				
SYS.DMS(P3FAT-RTAC).32	Verify Reactive Mode set points: 0 = OFF 1 = Fixed kVAR 2 = Fixed Power Factor (Circuit) 3 = Fixed Power Factor (Bus) 4 = Fixed Power Factor (Transformer)	N/A				
SYS.DMS(P3FAT-RTAC).33	Verify control completion (returned value/point)	N/A				
SYS.DMS(P3FAT-RTAC).34	Verify set control failures	N/A				
SYS.DMS(P3FAT-RTAC).35	Verification of system behavior in case of set points are "rejected" or "failed"	N/A				
SYS.DMS(P3FAT-RTAC).36	Verify interlocking conditions: Check for set point limits and values out of range as invalid input	N/A				
SYS.DMS(P3FAT-RTAC).37	Verify interlocking conditions: Multiple user/consoles	N/A				
SYS.DMS(P3FAT-RTAC).38	Verify reporting and logging of control actions, successful and failed	N/A				
SYS.DMS(P3FAT-RTAC).39	Verify error reporting and logging (Some error conditions need to be generated)	N/A				
SYS.DMS(P3FAT-RTAC).40	Verify Charge Mode set points: 0 = OFF 1 = Fixed kW 2 = Load Following Circuit (Circuit) 3 = Load Following (Bus) 4 = Load Following (Transformer) 5 = DERM (Not part of scope at the moment)	N/A				
SYS.DMS(P3FAT-RTAC).41	Verify control completion (returned value/point)	N/A				
SYS.DMS(P3FAT-RTAC).42	Verify set control failures	N/A				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P3FAT-RTAC).43	Verification of system behavior in case of set points are "rejected" or "failed"	N/A				
SYS.DMS(P3FAT-RTAC).44	Verify interlocking conditions: Check for set point limits and values out of range as invalid input	N/A				
SYS.DMS(P3FAT-RTAC).45	Verify interlocking conditions: Multiple user/consoles	N/A				
SYS.DMS(P3FAT-RTAC).46	Verify reporting and logging of control actions, successful and failed	N/A				
SYS.DMS(P3FAT-RTAC).47	Verify error reporting and logging (Some error conditions need to be generated)	N/A				
System Test Book - DMS (Phase 3 Factory Acceptance Test) - Battery Points Checkout - Value Set Points (AO)						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P3FAT-RTAC).48	Verify analog value controls (set points): Operator Keyed Set Points (Max Charge rate, LF, Discharge time, duration, etc.)	N/A				
SYS.DMS(P3FAT-RTAC).49	Verify control completion (value change)	N/A				
SYS.DMS(P3FAT-RTAC).50	Verify set control failures	N/A				
SYS.DMS(P3FAT-RTAC).51	Verification of system behavior in case of set points are "rejected" or "failed"	N/A				
SYS.DMS(P3FAT-RTAC).52	Verify interlocking conditions: Check for set point limits	N/A				
SYS.DMS(P3FAT-RTAC).53	Verify interlocking conditions: Multiple user/consoles	N/A				
SYS.DMS(P3FAT-RTAC).54	Verify reporting and logging of control actions, successful and failed	N/A				
SYS.DMS(P3FAT-RTAC).55	Verify error reporting and logging (Some error conditions need to be generated)	N/A				

System Test Book – DMS (Phase 3 Site Acceptance Test): DNA – System Test						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P3SAT).48	Verify Cyber security rules and conditions for DNA applications (Similar to the ones defined for the rest of the system components) There are basic security requirements for the systems that need to be verified for this solution: - Users definition (password hardening, authorities, permissions) - Log On/Off characteristics (allowed attempts, time outs,...) - Logging of all actions - System users/passwords - Remote log ins and connections	N/A				
SYS.DMS(P3SAT).55	Verify automatic failover at the substation level when DCADA application has problems or the SW detects errors	N/A				
SYS.DMS(P3SAT).59	Verify DSCADA and DNA redundancy and failover caused by application or SW problems	N/A				
SYS.DMS(P3SAT).60	Verify DNA, SCADA functions manual failover	N/A				
SYS.DMS(P3SAT).177	Verify system tools to save event log, system log and specific DNA data to external media	N/A				
SYS.DMS(P3SAT).416	Verify VVC operation when DCADA and DMS get disconnected (communication failure)	N/A				
System Test Book – DMS (Phase 3 Site Acceptance Test): DNA – Core Distribution Management System						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P3SAT).162	Verify JC&G functionality in DNA	N/A				
SYS.DMS(P3SAT).165	Verifies DNA execution when setting or removing temporary elements	N/A				
SYS.DMS(P3SAT).172	Verification of tagging propagation to DNA	N/A				
SYS.DMS(P3SAT).199	Verify access denial to undefined users or wrong password	N/A				
SYS.DMS(P3SAT).200	Verify use of permissions for different users	N/A				
SYS.DMS(P3SAT).201	Verify context management	N/A				
SYS.DMS(P3SAT).202	Verify access to study context and case management	N/A				
SYS.DMS(P3SAT).203	Verify simultaneous use of multiple contexts and cases	N/A				

System Test Book – DMS (Phase 3 Factory Acceptance Test): DNA - Distribution System Power Flow (DSPF)						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P3SAT).205	From InService demonstrate access to PowerFlow connecting to the DNA in DMS	N/A				
SYS.DMS(P3SAT).207	Verify access to application alarms or program output	N/A				
SYS.DMS(P3SAT).228	Run Power Flow from DMS DNA UI and verify results	N/A				
SYS.DMS(P3SAT).242	Verify access to list and summaries using DNA UI in the DMS	N/A				
SYS.DMS(P3SAT).229	Verify PowerFlow execution "on demand"	N/A				
SYS.DMS(P3SAT).229a	Verify PowerFlow execution in loop	N/A				
SYS.DMS(P3SAT).230	Verify DNA PF operation with multiple users	N/A				
SYS.DMS(P3SAT).231	Verify DNA PF operation with simultaneous execution from multiple users	N/A				
SYS.DMS(P3SAT).235	Introduce manual data changes (JC&G) and verify results	N/A				
SYS.DMS(P3SAT).244	Verify alarms generated by limit violation or other operational conditions like non convergence	N/A				
SYS.DMS(P3SAT).258	Verify Simulation mode	N/A				
SYS.DMS(P3SAT).259	Verify use and options in Simulation mode	N/A				
SYS.DMS(P3SAT).260	Verify visual differentiation of operational mode: Real Time and Simulation	N/A				
System Test Book – DMS (Phase 3 Site Acceptance Test): DNA - Distribution System State Estimation (DSSE)						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P3SAT).211	Run DSSE from DMS DNA UI and verify results - On Demand	N/A				
SYS.DMS(P3SAT).212	Verify DSSE different modes of execution in DMS: - Periodic - Measurements validation display	N/A				
SYS.DMS(P3SAT).212a	Verify DSSE execution triggered by Event	N/A				
SYS.DMS(P3SAT).216	Verify access to application alarms or program output	N/A				
SYS.DMS(P3SAT).212b	Verify DSSE execution triggered by Overload	N/A				
SYS.DMS(P3SAT).212c	Verify DSSE execution triggered by Over/Under Voltage	N/A				
SYS.DMS(P3SAT).213	Verify DNA DSSE operation with multiples execution types (cyclic, spontaneous, on demand)	N/A				
SYS.DMS(P3SAT).214	Verify DNA DSSE operation with simultaneous execution from multiple users	N/A				
SYS.DMS(P3SAT).217a	Reverse flow verification/alarm	N/A				
SYS.DMS(P3SAT).217b	Verify island condition	N/A				
SYS.DMS(P3SAT).218	Introduce manual data changes and verify results	N/A				

System Test Book – DMS (Phase 3 Site Acceptance Test): DNA - Fault Isolation & Service Restoration (FISR)						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P3SAT).331i	Verify FISR execution in Restore to Normal mode	N/A				
SYS.DMS(P3SAT).331n	Verify FISR execution in Look Ahead Mode	N/A				
SYS.DMS(P3SAT).352	Verify use and management of Study Context (create, save & restore cases)	N/A				
SYS.DMS(P3SAT).353	Verify use of multiple Study contexts at the same time	N/A				
SYS.DMS(P3SAT).354	Verify FISR results in Study context	N/A				
SYS.DMS(P3SAT).355	Verify FISR operation in case of abnormal situations, user errors,... in Study context	N/A				
SYS.DMS(P3SAT).330	Verify FISR execution manually	N/A				
SYS.DMS(P3SAT).330a	Verify FISR execution to isolate a device	N/A				
SYS.DMS(P3SAT).330b	Verify FISR execution triggered by FLOC	N/A				
System Test Book – DMS (Phase 3 Site Acceptance Test): DNA - Fault Location (FLOC)						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P3SAT).320	Verify FLOC application UI displays	N/A				
SYS.DMS(P3SAT).303a	Verify that FLOC runs when fault detected in between reclosers	N/A				
SYS.DMS(P3SAT).303b	Verify that FLOC runs when recloser open	N/A				
SYS.DMS(P3SAT).303c	Verify that FLOC runs substation switch open	N/A				
SYS.DMS(P3SAT).303d	Verify that FLOC runs when fault detected	N/A				
SYS.DMS(P3SAT).303e	Verify that FLOC runs when fault detected in between reclosers away from the FI	N/A				
SYS.DMS(P3SAT).306	Verify interaction with application in InService	N/A				
SYS.DMS(P3SAT).307	Verify interaction with application in DNA UI	N/A				
SYS.DMS(P3SAT).309	Verify access to application alarms or program output	N/A				
SYS.DMS(P3SAT).310a	Verify FLOC operation with multiple simultaneous faults	N/A				
SYS.DMS(P3SAT).310f	Verify FLOC provides correct pre-Fault status	N/A				
SYS.DMS(P3SAT).313	Verify that only permanent reclosure faults triggers FLOC	N/A				
SYS.DMS(P3SAT).321	Verify FLOC interfaces with FISR and OMS	N/A				
System Test Book – DMS (Phase 3 Site Acceptance Test): DNA - Feeder Load Transfer (FLT)						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P3SAT).262	Verify access to FLT from InService	N/A				
SYS.DMS(P3SAT).263	Verify FLT running from DMS	N/A				
SYS.DMS(P3SAT).275	Verify access to application alarms or program output	N/A				
SYS.DMS(P3SAT).283	Access to FLT results and info from InService	N/A				
SYS.DMS(P3SAT).298	Verify FLT running in simulation mode	N/A				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P3SAT).299	Verify use and options in Simulation mode	N/A				
SYS.DMS(P3SAT).300	Verify visual differentiation of operational mode: Real Time and Simulation	N/A				
SYS.DMS(P3SAT).302	Verify reporting of execution errors or problems in Simulation Mode	N/A				
System Test Book – DMS (Phase 3 Site Acceptance Test): DNA – Volt Var Control (VVC)						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P3SAT).357	Verify VVC execution in Open Loop and access to the Open Loop configuration from Inservice UI	N/A				
SYS.DMS(P3SAT).358	Verify VVC application management from Inservice UI	N/A				
SYS.DMS(P3SAT).362	Verification of VVC configuration and parameters from DNA UI	N/A				
SYS.DMS(P3SAT).362a	VVC Manual execution	N/A				
SYS.DMS(P3SAT).362	Verification of VVC parameters in Study Context	N/A				
SYS.DMS(P3SAT).366	Verify multiple Study context at the same time	N/A				
SYS.DMS(P3SAT).367	Verify result in Study context (simulation)	N/A				
SYS.DMS(P3SAT).377	Verify VVC execution triggered by high/low limit violations	N/A				
SYS.DMS(P3SAT).377a	Verify VVC execution triggered by topology change	N/A				
SYS.DMS(P3SAT).377b	Verify VVC execution cyclic triggering	N/A				
SYS.DMS(P3SAT).377c	Verify VVC execution triggered by event while cyclic execution enabled	N/A				
SYS.DMS(P3SAT).378	Verify that DDSE will run automatically when needed	N/A				
SYS.DMS(P3SAT).379	Verify VVC results of the sequence generated and executed	N/A				
SYS.DMS(P3SAT).380	Verify VVC reaction multiple trigger actions at the same time	N/A				
SYS.DMS(P3SAT).391	Verify VVC execution defining Remove/Mitigate limit violation objective.	N/A				
SYS.DMS(P3SAT).391a	Verify VVC execution defining Power Loss minimization without limit violations	N/A				
SYS.DMS(P3SAT).391b	Verify VVC execution defining Minimization of Active load consumption objective	N/A				
SYS.DMS(P3SAT).391c	Verify VVC execution defining Minimization of Reactive load consumption objective.	N/A				
SYS.DMS(P3SAT).391e	Verify VVC execution defining Power Loss Minimization with limit violations	N/A				
SYS.DMS(P3SAT).392	Verify VVC execution using only controllable devices	N/A				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P3SAT).392g	Verify that VVC considers Power Factor limits at the feeder head	N/A				
SYS.DMS(P3SAT).392h	Constrains relaxation	N/A				
SYS.DMS(P3SAT).393	Verify VVC execution with tagged devices	N/A				
SYS.DMS(P3SAT).394	Verify VVC execution of control sequence when control fails	N/A				
SYS.DMS(P3SAT).395	Verify VVC reaction to a situation with no controllable devices	N/A				
SYS.DMS(P3SAT).396	Verify VVC reaction to topology changes between calculation and execution	N/A				
SYS.DMS(P3SAT).397	Verify reporting of execution errors or problems	N/A				
SYS.DMS(P3SAT).398	Verify Close Loop Operation in DMS	N/A				
SYS.DMS(P3SAT).399	Verify that DDSE will run automatically when needed as part of the VVC close loop execution	N/A				
SYS.DMS(P3SAT).400	Verify Close Loop execution failures and system reaction: - Control fails - Device Tagging - Device already in requested position	N/A				
SYS.DMS(P3SAT).401	Verify Close Loop execution with limit conditions: - Max number of daily operations - Usability Time runs out - Control values out of range	N/A				
SYS.DMS(P3SAT).420	Verify that VVC sends a SCADA Override signal to Cap Banks in Manual and Remote in the selected injection area	N/A				
SYS.DMS(P3SAT).421	Verify that VVC sends a SCADA Override signal to Cap Banks in Manual and Remote in the selected area	N/A				
SYS.DMS(P3SAT).422	Verify that the Heart Beat signal is sent every 45 minutes	N/A				
SYS.DMS(P3SAT).424	Leave Open Loop mode	N/A				
SYS.DMS(P3SAT).426	Enter VVC Closed Loop	N/A				
SYS.DMS(P3SAT).427	Run VVC Closed Loop Mode with excluded injections	N/A				
SYS.DMS(P3SAT).428	Leave VVC Closed Loop Mode for All Injections (Master Settings)	N/A				

System Test Book - DMS (Phase 3 Site Acceptance Test) - Recloser Point to Point Checkout: Type DI						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P3SAT-P2P-651R).1	Verify point "Enabled"	Values Displayed: - DISABLED - ENABLED				
SYS.DMS(P3SAT-P2P-651R).2	Verify point "Device Status"	Values Displayed: - OPEN - CLOSE				
SYS.DMS(P3SAT-P2P-651R).3	Verify point "Loss of Potential"	Values Displayed: - OK - ALARM				
SYS.DMS(P3SAT-P2P-651R).4	Verify point "Fault - Phase C"	Values Displayed: - OK - ALARM				
SYS.DMS(P3SAT-P2P-651R).5	Verify point "Fault - Phase B"	Values Displayed: - OK - ALARM				
SYS.DMS(P3SAT-P2P-651R).6	Verify point "Fault - Phase A"	Values Displayed: - OK - ALARM				
SYS.DMS(P3SAT-P2P-651R).7	Verify point "Sync Check Elements"	Values Displayed: - OK - ALARM				
SYS.DMS(P3SAT-P2P-651R).8	Verify point "Cabinet Door"	Values Displayed: - OK - ALARM				
SYS.DMS(P3SAT-P2P-651R).9	Verify point "50CO - Ground Overcurrent Status"	Values Displayed: - DISABLED - ENABLED				
SYS.DMS(P3SAT-P2P-651R).10	Verify point "79CO - Reclosing Status"	Values Displayed: - DISABLED - ENABLED				
SYS.DMS(P3SAT-P2P-651R).11	Verify point "Local - Remote"	Values Displayed: - LOCAL - REMOTE				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P3SAT-P2P-651R).12	Verify point "Fast Curves Status"	Values Displayed: - DISABLED - ENABLED				
SYS.DMS(P3SAT-P2P-651R).13	Verify point "Push Buttons Locked"	Values Displayed: - UNLOCKED - LOCKED				
SYS.DMS(P3SAT-P2P-651R).14	Verify point "Hot Line Tag Status"	Values Displayed: - DISABLED - ENABLED				
SYS.DMS(P3SAT-P2P-651R).15	Verify point "Aux 1 Status"	Values Displayed: - DISABLED - ENABLED				
SYS.DMS(P3SAT-P2P-651R).16	Verify point "Aux 2 Status"	Values Displayed: - DISABLED - ENABLED				
SYS.DMS(P3SAT-P2P-651R).17	Verify point "Aux 3 Status"	Values Displayed: - DISABLED - ENABLED				
SYS.DMS(P3SAT-P2P-651R).18	Verify point "Battery Failure"	Values Displayed: - OK - ALARM				
SYS.DMS(P3SAT-P2P-651R).19	Verify point "External Power"	Values Displayed: - OFF - ON				
SYS.DMS(P3SAT-P2P-651R).20	Verify point "Lockout"	Values Displayed: - OK - ALARM				
SYS.DMS(P3SAT-P2P-651R).21	Verify point "Current Direction"	Values Displayed: - NORMAL - REVERSED				
SYS.DMS(P3SAT-P2P-651R).22	Verify point "Contact Wear - 3 Phase"	Values Displayed: - OK - ALARM				
SYS.DMS(P3SAT-P2P-651R).23	Verify point "Clock Present"	Values Displayed: - NOT PRESENT - PRESENT				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P3SAT-P2P-651R).24	Verify point "Hardware Alarm"	Values Displayed: - OK - ALARM				
SYS.DMS(P3SAT-P2P-651R).25	Verify point "Software Alarm"	Values Displayed: - OK - ALARM				
System Test Book - DMS (Phase 3 Site Acceptance Test) - Recloser Point to Point Checkout: Type DO						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P3SAT-P2P-651R).26	Verify point "Aux 1"	Values Displayed: - DISABLED - ENABLED				
SYS.DMS(P3SAT-P2P-651R).27	Verify point "Aux 2"	Values Displayed: - DISABLED - ENABLED				
SYS.DMS(P3SAT-P2P-651R).28	Verify point "Aux 3"	Values Displayed: - DISABLED - ENABLED				
SYS.DMS(P3SAT-P2P-651R).29	Verify point "Aux 4"	Values Displayed: - DISABLED - ENABLED				
SYS.DMS(P3SAT-P2P-651R).30	Verify point "50CO - Ground Overcurrent"	Values Displayed: - DISABLED - ENABLED				
SYS.DMS(P3SAT-P2P-651R).31	Verify point "79CO - Reclosing"	Values Displayed: - DISABLED - ENABLED				
SYS.DMS(P3SAT-P2P-651R).32	Verify point "Fast Curves"	Values Displayed: - DISABLED - ENABLED				
SYS.DMS(P3SAT-P2P-651R).33	Verify point "Hot Line Tag"	Values Displayed: - DISABLED - ENABLED				
SYS.DMS(P3SAT-P2P-651R).34	Verify point "Device Operate"	Values Displayed: - OPEN - CLOSE				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P3SAT-P2P-651R).35	Verify point "Reset Front Panel Targets"	Values Displayed: - NA - RESET				
System Test Book - DMS (Phase 3 Site Acceptance Test) - Recloser Point to Point Checkout: Type CTR						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P3SAT-P2P-651R).36	Verify point "Active Settings Group"	N/A				
SYS.DMS(P3SAT-P2P-651R).37	Verify point "Internal Breaker Trips - Phase A"	N/A				
SYS.DMS(P3SAT-P2P-651R).38	Verify point "Internal Breaker Trips - Phase B"	N/A				
SYS.DMS(P3SAT-P2P-651R).39	Verify point "Internal Breaker Trips - Phase C"	N/A				
SYS.DMS(P3SAT-P2P-651R).40	Verify point "External Breaker Trips - Phase A"	N/A				
SYS.DMS(P3SAT-P2P-651R).41	Verify point "External Breaker Trips - Phase B"	N/A				
SYS.DMS(P3SAT-P2P-651R).42	Verify point "External Breaker Trips - Phase C"	N/A				
System Test Book - DMS (Phase 3 Site Acceptance Test) - Recloser Point to Point Checkout: Type AI						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P3SAT-P2P-651R).43	Verify point "Current - Phase A"	N/A				
SYS.DMS(P3SAT-P2P-651R).44	Verify point "Current - Phase B"	N/A				
SYS.DMS(P3SAT-P2P-651R).45	Verify point "Current - Phase C"	N/A				
SYS.DMS(P3SAT-P2P-651R).46	Verify point "Current - Neutral"	N/A				
SYS.DMS(P3SAT-P2P-651R).47	Verify point "Current - Ground"	N/A				
SYS.DMS(P3SAT-P2P-651R).48	Verify point "Voltage - Phase A - Y"	N/A				
SYS.DMS(P3SAT-P2P-651R).49	Verify point "Voltage - Phase B - Y"	N/A				
SYS.DMS(P3SAT-P2P-651R).50	Verify point "Voltage - Phase C - Y"	N/A				
SYS.DMS(P3SAT-P2P-651R).51	Verify point "Voltage - Phase A - Z"	N/A				
SYS.DMS(P3SAT-P2P-651R).52	Verify point "Voltage - Phase B - Z"	N/A				
SYS.DMS(P3SAT-P2P-651R).53	Verify point "Voltage - Phase C - Z"	N/A				
SYS.DMS(P3SAT-P2P-651R).54	Verify point "Real Power - Phase A"	N/A				
SYS.DMS(P3SAT-P2P-651R).55	Verify point "Real Power - Phase B"	N/A				
SYS.DMS(P3SAT-P2P-651R).56	Verify point "Real Power - Phase C"	N/A				
SYS.DMS(P3SAT-P2P-651R).57	Verify point "Real Power - 3 Phase"	N/A				
SYS.DMS(P3SAT-P2P-651R).58	Verify point "Reactive Power - Phase A"	N/A				
SYS.DMS(P3SAT-P2P-651R).59	Verify point "Reactive Power - Phase B"	N/A				
SYS.DMS(P3SAT-P2P-651R).60	Verify point "Reactive Power - Phase C"	N/A				
SYS.DMS(P3SAT-P2P-651R).61	Verify point "Reactive Power - 3 Phase"	N/A				
SYS.DMS(P3SAT-P2P-651R).62	Verify point "Frequency"	N/A				
SYS.DMS(P3SAT-P2P-651R).63	Verify point "Contact Wear - Phase A"	N/A				
SYS.DMS(P3SAT-P2P-651R).64	Verify point "Contact Wear - Phase B"	N/A				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P3SAT-P2P-651R).65	Verify point "Contact Wear - Phase C"	N/A				
SYS.DMS(P3SAT-P2P-651R).66	Verify point "Fault Type"	N/A				
SYS.DMS(P3SAT-P2P-651R).67	Verify point "Fault Recloser Shot Counter"	N/A				
SYS.DMS(P3SAT-P2P-651R).68	Verify point "Fault Time"	N/A				
SYS.DMS(P3SAT-P2P-651R).69	Verify point "Fault Current - Phase A"	N/A				
SYS.DMS(P3SAT-P2P-651R).70	Verify point "Fault Current - Phase B"	N/A				
SYS.DMS(P3SAT-P2P-651R).71	Verify point "Fault Current - Phase C"	N/A				
SYS.DMS(P3SAT-P2P-651R).72	Verify point "Fault Current - Ground"	N/A				
SYS.DMS(P3SAT-P2P-651R).73	Verify point "Apparent Power - Phase A"	N/A				
SYS.DMS(P3SAT-P2P-651R).74	Verify point "Apparent Power - Phase B"	N/A				
SYS.DMS(P3SAT-P2P-651R).75	Verify point "Apparent Power - Phase C"	N/A				
SYS.DMS(P3SAT-P2P-651R).76	Verify point "Apparent Power - 3 Phase"	N/A				
SYS.DMS(P3SAT-P2P-651R).77	Verify point "THD - Current - Phase A"	N/A				
SYS.DMS(P3SAT-P2P-651R).78	Verify point "THD - Current - Phase B"	N/A				
SYS.DMS(P3SAT-P2P-651R).79	Verify point "THD - Current - Phase C"	N/A				
SYS.DMS(P3SAT-P2P-651R).80	Verify point "THD - Current - Neutral"	N/A				
SYS.DMS(P3SAT-P2P-651R).81	Verify point "THD - Voltage - Phase A - Y"	N/A				
SYS.DMS(P3SAT-P2P-651R).82	Verify point "THD - Voltage - Phase B - Y"	N/A				
SYS.DMS(P3SAT-P2P-651R).83	Verify point "THD - Voltage - Phase C - Y"	N/A				
SYS.DMS(P3SAT-P2P-651R).84	Verify point "THD - Voltage - Phase A - Z"	N/A				
SYS.DMS(P3SAT-P2P-651R).85	Verify point "THD - Voltage - Phase B - Z"	N/A				
SYS.DMS(P3SAT-P2P-651R).86	Verify point "THD - Voltage - Phase C - Z"	N/A				
SYS.DMS(P3SAT-P2P-651R).87	Verify point "Battery Voltage"	N/A				
SYS.DMS(P3SAT-P2P-651R).88	Verify point "Battery Current"	N/A				
System Test Book - DMS (Phase 3 Site Acceptance Test) - Recloser Point to Point Checkout: Type AO						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DMS(P3SAT-P2P-651R).89	Verify point "Set Active Settings Group"	N/A				

System Test Book - HIS (Phase 3 SAT)						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.HIS(P3SAT).1	User Access Right: Verify user access to HIS based on defined authorization	N/A				
SYS.HIS(P3SAT).2	User Access Right: Verify valid user access denied because of authorization	N/A				
SYS.HIS(P3SAT).3	User Access Right: Verify change of permissions while user connected	N/A				
SYS.HIS(P3SAT).5	Chart Data: Verify that User views can be saved (Public and Private)	N/A				
SYS.HIS(P3SAT).6	Export Data: Verify charting capabilities of the HIS	N/A				
SYS.HIS(P3SAT).7	Print Data: Verify HIS data exporting capabilities	N/A				
SYS.HIS(P3SAT).8	Filter Data: Verify HIS printing capabilities	N/A				
SYS.HIS(P3SAT).9	SCADA Data collection: Demonstrate filtering capabilities of the HIS UI	N/A				
SYS.HIS(P3SAT).10	SCADA Data collection: Verify that SCADA data is collected properly in HIS for Status	N/A				
SYS.HIS(P3SAT).11	SCADA Data collection: Verify that SCADA data is collected properly in HIS for Analog Values	N/A				
SYS.HIS(P3SAT).12	SCADA Data collection: Verify that SCADA data is collected properly in HIS for Accumulators	N/A				
SYS.HIS(P3SAT).13	SCADA Data collection: Verify that "Archive" flag in DB "True" or "False" change point archiving in HIS	N/A				
SYS.HIS(P3SAT).14	SCADA Data collection: Verify that Manual changes in InService are stored in HIS	N/A				
SYS.HIS(P3SAT).16	SCADA Data collection: Verify that Data Quality is archived with the values	N/A				
SYS.HIS(P3SAT).17	Collection Rates: Change collection rates for SCADA points and verify archiving in HIS	N/A				
SYS.HIS(P3SAT).19	Formula Calculations: Define a new calculation and verify values	N/A				
SYS.HIS(P3SAT).20	Data compression: Verify that data compression works according to user definition	N/A				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.HIS(P3SAT).21	Aggregation Calculations: Verify correct calculation of Min, Max, Average and integrals (15m, 1 hour)	N/A				
SYS.HIS(P3SAT).22	Data Modification: Verify editing and logging of manual changes	N/A				
SYS.HIS(P3SAT).23	Data Modification: Verify recalculation of formulas and past values when historic value is changed	N/A				
SYS.HIS(P3SAT).24	Data Modification: Verify that HIS data remain in the archive after deleting a point in SCADA	N/A				
SYS.HIS(P3SAT).25	DMS failover: Verify that no data is lost in HIS when a failover occurs	N/A				
SYS.HIS(P3SAT).27	DMS failover: Verify that system buffer store data while HIS(ORACLE) is not available and that data is archived when available	N/A				
SYS.HIS(P3SAT).28	DMS failover: Verify HIS function/application redundancy	N/A				
SYS.HIS(P3SAT).30	DMS failover: Verify that HIS report "information", "warning" or "error" conditions	N/A				
SYS.HIS(P3SAT).31	Health Monitor Tool: Data Collection	N/A				
SYS.HIS(P3SAT).32	SQL Plus: Compression and aggregation	N/A				
SYS.HIS(P3SAT).33	SQL Plus: Demonstrate access to HIS data using SQL	N/A				

System Test Book - DERM: Base Data (BD)						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DERM.BD4	Tariff and rate definition: Verify user can create tariff and rate and all objects and associated attributes.	User can create and maintain all objects and attributes associated with a specific tariff and rate.				
SYS.DERM.BD5	Grid Model Administration: Verify user can create and view Grid Model data.	User can view all objects and attributes associated with a specific Grid Model.				
SYS.DERM.BD6	Controls Administration: Verify user can create, modify and delete a device control.	User can create, modify and delete a control.				
SYS.DERM.BD7	Wholesale Product Administration: Verify that user can add, modify, and delete Wholesale Product.	N/A.				
SYS.DERM.BD8	Calendar Administration: Verify that user can view the Holidays and Season and update the dates.	N/A.				
SYS.DERM.BD9	Region Administration: Verify that user can view, create, modify, and delete the Region.	N/A.				
SYS.DERM.BD10	Weather Summary: Verify that user can view the weather Forecast and change the weather zone and weather station.	N/A.				
System Test Book - DERM: Enrollment and Contract Management (ENR)						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DERM.ENR5	Customer Asset Enrollment: Verify user can create and maintain all objects and attributes associated with a specific end use customer asset.	User can create and maintain all objects and attributes associated with a specific end use customer.				
SYS.DERM.ENR3	Asset Administration: Verify user can view Asset data associated with a customer.	User can view Asset attributes				
SYS.DERM.ENR10	Meter Summary Interface: Verify user can view list of all meters with key attributes.	User can view list of all meters with key attributes.				
System Test Book - DERM: DR Program Creation and Administration (PCA)						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DERM.PCA4.1	Program Entry/Modification: Verify user can view display allowing creation of a new DR Program, and modification of an existing DR Program attributes.	User can view display allowing entry and modification of Program attributes.				
SYS.DERM.PCA4.2	Program Summary: Verify user can view display listing available programs and their major attributes.	User can view display listing available programs and their major attributes.				
SYS.DERM.PCA4.3	Program Category: Verify user can view display listing all Programs according to their correct Category, Class and Type.	User can view display listing all Programs according to their correct Category, Class and Type.				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DERM.PCA4.4	Tariff Entry/Modification: Verify user can view display allowing entry of tariff with its multiple attributes.	User can view display allowing entry of Tariff with its multiple attributes.				
SYS.DERM.PCA4.5	Tariff Summary: Verify user can view display listing all available Tariffs and their attributes.	User can view display listing all available Tariffs and their attributes.				
System Test Book - DERM: Customer Baseline Load Calculation (CBL)						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DERM.CBL1	Definition: Verify user can select the following CBL types: Similar Day Statistical Average and NAESB/FERC.	User can select the following CBL types: Similar Day Statistical Average and NAESB/FERC.				
SYS.DERM.CBL2	Attributes: Verify user can specify the following parameter for each CBL type: Statistical Average (Number of days, smoothing factor, morning adjustment – number of hours before DR Event and NAESB/FERC (highest energy usage days, past non-event days, number of hours before DR to be used for Adjustment).	User can specify each of the listed parameters for each CBL type.				
SYS.DERM.CBL3	Similar Day Statistic: Verify user can calculate Similar Day Statistic Average using average consumption values from non-event days in the recent past.	User can calculate Similar Day Statistic Average using average consumption values from non-event days in the recent past.				
SYS.DERM.CBL6	X out of Y – NAESB/FERC CBL Calculation: Verify user can make NAESB/FERC CBL calculations.	User can make NAESB/FERC CBL calculations.				
SYS.DERM.CBL8	Definition Display: Verify user can view display allowing user to review/modify existing CBLs and/or create new CBLs.	User can view display allowing user to review/modify existing CBLs and/or create new CBLs.				
SYS.DERM.CBL9	Summary Display: Verify user can view display allowing the user to view CBL summary data or select a baseline to view and update.	User can view display allowing the user to view CBL summary data or select a baseline to view and update.				
System Test Book - DERM: Aggregation and Virtual Power Plant Creation (AVP)						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DERM.AVP1-3	Axes of Aggregation: Verify user can create DR Resources based on asset type, customer category/class/type, demand response programs, and grid location.	User can create DR Resources based on asset type, customer category/class/type, demand response programs, and grid location.				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DERM.AVP2	Multiple Program Enrollments: Verify user can register an asset under more than one program, and be part of more than one aggregated Resource.	User can register an asset under more than one program and can be part of more than one aggregated Resource.				
SYS.DERM.AVP4	Dynamic Resource: Verify user can create a resource as a Dynamic Resource by specifying filters.	User can create a resource as a Dynamic Resource by specifying filters.				
SYS.DERM.AVP5	Static Resource: Verify user can create a resource as a Static Resource consisting of all assets that are assigned to the resource.	User can create a resource as a Static Resource consisting of all assets that are assigned to the resource.				
SYS.DERM.AVP7	Asset to Resource Re-assignment: Verify user can update the list of Assets within the Program Default Resource on demand.	User can update the list of Assets within the Program Default Resource on demand.				
SYS.DERM.AVP13	Modify Existing Resource: Verify user can call up an existing Static or Dynamic Resource and modify its definition.	User can call up an existing Static or Dynamic Resource and modify its definition.				
SYS.DERM.AVP16	Resource Summary: Verify that the Resource Summary display shows the list of all the Resources created in the system with the corresponding attributes.	Resource Summary display shows the list of all the Resources created in the system with the corresponding attributes.				
System Test Book - DERM: DR Availability Assessment and Forecasting (AVF)						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DERM.AVF1	Assets and DR Programs Constraint: Verify user can determine available DR capabilities for the current time as well as a time period in the future at different locations, DR program(s), Product, Asset Type, Customer Type, or for an existing Resource.	User can determine available DR capabilities for the current time as well as a time period in the future at different locations, DR program(s), Product, Asset Type, Customer Type, or for an existing Resource.				
SYS.DERM.AVF2+3	Availability Factor Profile: Verify user can view the availability factor profile and can specify the hourly availability factor.	User can view the various defined availability factor profile and can specify the hourly availability factor as a function of heat index.				
SYS.DERM.AVF4+5	Availability Factor Dependency and Availability factor Assignment: Verify that the Availability Factor of an asset can be a function of time (time of the day) and heat index.	The Availability Factor of an asset can be a function of time (time of the day) and heat index.				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DERM.AVF8	DR Program Constraints: Verify that the availability assessment takes into account all the constraints related to selected DR Program.	Availability assessment takes into account all the constraints related to selected DR Program.				
System Test Book - DERM: DR Scheduling and Optimization (SCH)						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DERM.SCH1-20+26	OATI webDistribute Schedule – General Requirements: Verify user can create a DR Schedule.	User can create a DR Schedule				
SYS.DERM.SCH21	OATI webDistribute Schedule – General Requirements: Verify that user can view the list of all DR Schedules that have been entered in webDistribute through Schedule Summary display.	User can view the list of all DR Schedules that have been entered in webDistribute through the Schedule Summary display.				
SYS.DERM.SCH27	User Interface: Verify that a display is provided to allow user to create a DR Schedule by specifying a DR Schedule Period (Start and End date/time).	Display is provided to allow user to create a DR Schedule by specifying a DR Schedule Period (Start and End date/time).				
SYS.DERM.SCH28	User Interface: Verify that a display is provided to show a summary of available DR Schedules with the specified profile and status.	A display is provided to show a summary of available DR Schedules with the specified profile and status.				
System Test Book - DERM: Distribution Grid Management (DGM)						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DERM.DGM1	Distribution Grid Overloads: The DMS operator will send information on grid overloads. webDistribute will use measured voltages, current, and flow, and using the ratings of equipment will determine the amount of DR required.	User can monitor the information received from DMS and verify the calculated DR requested.				
SYS.DERM.DGM2	Determination of the required DR to alleviate overloads and the availability of DR for the same: Verify that the program has the capability to determine the amount of DR required to alleviate the overloads and its capability to determine the amount of DR that is available.	The level of KW overload can be calculated based on the calculated Voltage and ampere measurements, and the amount of DR available to deal with the overload can be calculated.				
SYS.DERM.DGM3	Selection of level of DR and Scheduling DR Events: Verify that that the user can select the amount of DR and schedule resources to deal with the selected overloads.	The user can select all or some portion of the available DR capability and schedule DR events.				
System Test Book - DERM: DR Performance Monitoring (PFM)						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DERM.PFM1	Real-Time Performance Monitoring: Using Real-Time DR monitoring, verify user can monitor DR performance using the latest energy meter readings and/or telemetry (RTU) measurements received through SCADA.	User can monitor DR values using the latest energy meter readings and/or telemetry (RTU) measurements received through SCADA.				
SYS.DERM.PFM2	After-the-Fact PFM for DR Event, Program, Zone, UDC: Verify that After-the-Fact PFM can be calculated by comparing the metered energy consumption of each participating DR customer and corresponding adjusted CBL values.	After-the-Fact PFM can be calculated by comparing the metered energy consumption of each participating DR customer and corresponding adjusted CBL values.				
SYS.DERM.PFM3	After-the-Fact Grid Topology Based DR PFM: Verify that by using a combination of DMS/D-SCADA historical archived data together with AMI energy meters, user can monitor DR performance per distribution grid topology (feeder/substation).	User can monitor DR performance per distribution grid topology (feeder/substation).				
SYS.DERM.PFM4	PFM User Interface: Verify that PFM User Interface (UI) is presented in the form of tables and graphs.	PFM User Interface (UI) is presented in the form of tables and graphs.				
System Test Book - DERM: Customer Configuration (KCPL)						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DERM.KCPL1	Asset Type Configuration: Verify KCP&L asset classifications are defined to correspond to the requested KCP&L Program types.	KCP&L asset classifications are defined to correspond to the requested KCP&L Program types.				
SYS.DERM.KCPL2	Asset Grouping Configuration: Verify asset groups are created to balance across phases, transformers and feeders.	Asset groups are created to balance across phases, transformers and feeders.				
SYS.DERM.KCPL3	Program Type Configuration: Verify configuration of KCP&L required program types.	KCP&L required program types are configured.				
SYS.DERM.KCPL4	Customer Class Configuration: Verify KCP&L's customer class name is the default customer type name for the class.	KCP&L's customer class name is the default customer type name for the class.				
SYS.DERM.KCPL5	Product Configuration: Verify that only one KCP&L products is configured: Energy.	Only one KCP&L products is configured: Energy.				
SYS.DERM.KCPL7	Weather Station Configuration: Verify that only a single weather station will be used for creating the Load Forecast and for calculating asset availability assessments.	A single weather station will be used for creating the Load Forecast and for calculating asset availability assessments.				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.DERM.KCPL8	Contract and Rate Configuration: Verify implementation of KCP&L contract parameters, program parameters and performance metrics.	KCP&L contract parameters, program parameters and performance metrics are implemented.				

System Test Book – Meter Data Management (MDM): MDM Setup & Configuration						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.MDM.INT.SETUP.1	Access EnergyIP (EIP) web based user interface	N/A				
SYS.MDM.INT.SETUP.2	Access EnergyIP (EIP) SFTP server - Push Billing Account	N/A				
SYS.MDM.INT.SETUP.3	Access EnergyIP (EIP) SFTP server - Meter Reads Account	N/A				
SYS.MDM.INT.SETUP.4	Access EnergyIP (EIP) web services server	N/A				
SYS.MDM.INT.SETUP.5	Access EnergyIP (EIP) web service for MDM FlexSync interface	N/A				
SYS.MDM.INT.SETUP.6	Access EnergyIP (EIP) web service for MDM Pull Billing Interface	N/A				
System Test Book – Meter Data Management (MDM): Role Based Access Control						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.MDM.INT.RBAC.1	Validate capabilities of the PIPEOP operational user role	N/A				
SYS.MDM.INT.RBAC.2	Validate capabilities of the PIPEMGR data manager role	N/A				
SYS.MDM.INT.RBAC.3	Validate capabilities of the PIPEADMIN data manager role	N/A				
SYS.MDM.INT.RBAC.4	Validate user/role assignments for Test environment	N/A				
System Test Book – Meter Data Management (MDM): General User Interface Functionality						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.MDM.INT.UI.1	Shakeout basic functionality using the “operational user” account.	N/A				
SYS.MDM.INT.UI.2	Shakeout basic functionality using the “data manager” account.	N/A				
SYS.MDM.INT.UI.3	Shakeout basic functionality using the “systems administrator” account.	N/A				
System Test Book – Meter Data Management (MDM): Monthly Meter Read Schedule Setup						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.MDM.INT.MMRS.1	Validate Monthly Meter Read Schedule file format.	N/A				
SYS.MDM.INT.MMRS.2	Validate that the Monthly Meter Read Schedule has been loaded successfully in MDM	N/A				
System Test Book – Meter Data Management (MDM): MDM Validation, Estimation, Editing (VEE) Functionality						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.MDM.INT.VEE.1	Validate Manual VEE Capabilities	N/A				
SYS.MDM.INT.VEE.2	MDM Register Read Estimator will perform “Extrapolation” on missing interval reads	N/A				
SYS.MDM.INT.VEE.3	MDM Register Read Estimator will replace “Extrapolated” values with actual values when received	N/A				
SYS.MDM.INT.VEE.4	MDM Register Read Estimator will perform “Interpolation” on missing interval reads	N/A				
SYS.MDM.INT.VEE.5	MDM Register Read Estimator will replace “Interpolated” values with actual values when received	N/A				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.MDM.INT.VEE.6	MDM Register Read Estimator will perform "Extrapolation" on missing register reads	N/A				
SYS.MDM.INT.VEE.7	MDM Register Read Estimator will replace "Extrapolated" register read values with actual values when received	N/A				
SYS.MDM.INT.VEE.8	MDM Register Read Estimator will perform "Interpolation" on missing register reads	N/A				
SYS.MDM.INT.VEE.8	MDM Register Read Estimator will replace "Interpolated" register read values with actual values when received	N/A				
System Test Book – Meter Data Management (MDM): MDM Reports						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.MDM.INT.RPTS.1	Validate the following EIP report: AMR Installation Status.	N/A				
SYS.MDM.INT.RPTS.2	Validate the following EIP report: Billing Data Change Report.	N/A				
SYS.MDM.INT.RPTS.3	Validate the following EIP report: Billing No Reads Report.	N/A				
SYS.MDM.INT.RPTS.4	Validate the following EIP report: Billing Service Summary Report.	N/A				
SYS.MDM.INT.RPTS.5	Validate the following EIP report: DBSync Exception Report.	N/A				
SYS.MDM.INT.RPTS.6	Validate the following EIP report: Estimation Failure Detail Report.	N/A				
SYS.MDM.INT.RPTS.7	Validate the following EIP report: Excessive Missing Reads Report.	N/A				
SYS.MDM.INT.RPTS.8	Validate the following EIP report: Framer Exception Report.	N/A				
SYS.MDM.INT.RPTS.9	Validate the following EIP report: Framer Exception Report.	N/A				
SYS.MDM.INT.RPTS.10	Validate the following EIP report: Missing Reads Report.	N/A				
SYS.MDM.INT.RPTS.11	Validate the following EIP report: Service Request Summary Report.	N/A				
SYS.MDM.INT.RPTS.12	Validate the following EIP report: Unauthorized Usage Report.	N/A				
SYS.MDM.INT.RPTS.13	Validate the following EIP report: Validation Failure Detail Report.	N/A				
SYS.MDM.INT.RPTS.14	Validate the following EIP report: VEE Summary Report.	N/A				
System Test Book – Meter Data Management (MDM): MDM – Other						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.MDM.INT.OTHER.1	Validate creation and retrieval of the Push Billing File by MDM to KCP&L	N/A				
SYS.MDM.INT.OTHER.2	Validate that CT/PT was applied to meter read data to calculate proper kWh usage values.	N/A				

System Test Book – AMI Head End (AHE): Core Capability - Command Center Initial Configuration						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.AHE(Core).1	Command Center Installation and Verification	Collector in NORMAL Mode, with ability to PING the Collector				
SYS.AHE(Core).2	Configure Users	Create a NEW User				
System Test Book – AMI Head End (AHE): Core Capability - Meter Manufacturing File Import						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.AHE(Core).3	Import MMF file	Upload MMF successfully, and meters transition to Discovered state				
System Test Book – AMI Head End (AHE): Core Capability - Installation File Import						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.AHE(Core).4	Import Meter Installation File	Import IIF file, with proper Meter LAT/LONGs. Meters should appear with full 13 digit meter number, with SP ID, and transition to Normal mode				
System Test Book – AMI Head End (AHE): Core Capability - Customer File Import						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.AHE(Core).5	Import Customer file in CSV format	N/A				
System Test Book – AMI Head End (AHE): Core Capability - Send Command to Meter						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.AHE(Core).6	Ability to send PING command to meter	Send PING and On-Demand read				
System Test Book – AMI Head End (AHE): Core Capability - EMED Meter Read File Export						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.AHE(Core).7	Export EMED (Every Meter Every Day) meter file (KCPL-custom EMED format)	Created customized KCPL EMED file format, Extract Spec, and verify file save to destination target with expected content				
SYS.AHE(Core).8	Export EMED (Every Meter Every Day) meter file (eMeter EnergyIP MDM-custom EMED format)	Created customized EMED file format, "emed_mdm", for use with the eMeter EnergyIP Meter Data Management (MDM) system and verify file save to destination target with expected content				

System Test Book – AMI Head End (AHE): Core Capability - Interval Reads File Export						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.AHE(Core).9	California Meter Exchange Protocol (CMEP)	Generate Interval read file in CMEP format				
SYS.AHE(Core).10	MV90 - Handheld Reader File Format (HHF)	Generate Interval read file in HHF format				
System Test Book – AMI Head End (AHE): Core Capability - EVENTS File Export						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.AHE(Core).11	Export meter read Events File to file path destination	Generate Events File extract				
System Test Book – AMI Head End (AHE): Core Capability - HAN Extract File Export						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.AHE(Core).12	Create manual HAN extract file from Command Center	Generate list of HAN devices with current HAN Status in Excel, CSV format				
System Test Book – AMI Head End (AHE): Core Capability - Meter Extract File Export						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.AHE(Core).13	Create scheduled Meter Extract file	Generate list of Meter devices with current Status in CSV format				
System Test Book – AMI Head End (AHE): Core Capability - External Integration Testing						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.AHE(Core).14	Outage Management Integration – Web Service Based	Outage Management Integration – Web Service Based				
SYS.AHE(Core).15	Customer Information System Integration - Web Service Based	Setup and verify MQ Broker integration with CIS				
SYS.AHE(Core).16	MDM Integration - SFTP Based	Custom EMED_MDM and standard CMEP Interval files load successfully to Siemens-hosted eMeter EnergyIP Meter Data Management				
System Test Book – AMI Head End (AHE): Core Capability - CIM-based Web Service Commands						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.AHE(Core).17	Validate that commands can successfully be sent via HAN CIM Interface to meter	Successful commands sent to meter via the CIM interfaces				

System Test Book - AMI Head End (AHE): Core Capability - Layered Routing Change						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.AHE(Core).18	Validate that metered endpoints are showing good reads	Recent midnight read dates observed in Endpoint Information screen for all normal mode meters				
SYS.AHE(Core).19	Validate successful Meter Command Reports – post Layered routing	Verify successful commands sent after layered routing was configured				
SYS.AHE(Core).20	Verify meter file extract receipt – post Layered routing	2 meter files per day between chosen testing dates				
SYS.AHE(Core).21	Verify meter reads – post Layered routing	Normal Meters show read data, with current meter read date/time				
SYS.AHE(Core).22	Verify interval reads – post Layered routing	Normal Meters show interval data, with current meter read date/time				
SYS.AHE(Core).23	Meter read consistency - post Layered routing	Verify meter read consistency over multiple days, with no major meter read spikes				

System Test Book – AMI Head End (AHE): Basic Commands for Integrated Focus AX Meters						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.AHE(Meter).1	HAN: Register Device	N/A				
SYS.AHE(Meter).2	HAN: Get Network Info	N/A				
SYS.AHE(Meter).3	HAN: Get Device Info	N/A				
SYS.AHE(Meter).4	HAN: Get All Devices Info	N/A				
SYS.AHE(Meter).5	HAN: Get Firmware	N/A				
SYS.AHE(Meter).6	HAN: Ping Device	N/A				
SYS.AHE(Meter).7	HAN: Send Message	N/A				
SYS.AHE(Meter).8	HAN: Delete Device	N/A				
SYS.AHE(Meter).9	HAN: Clear Devices	N/A				
SYS.AHE(Meter).10	HAN: Decommission Network	N/A				
System Test Book – AMI Head End (AHE): Basic Commands for Enhanced S4e Meters						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.AHE(Meter).11	HAN: Register Device	N/A				
SYS.AHE(Meter).12	HAN: Get Network Info	N/A				
SYS.AHE(Meter).13	HAN: Get Device Info	N/A				
SYS.AHE(Meter).14	HAN: Get All Devices Info	N/A				
SYS.AHE(Meter).15	HAN: Get Firmware	N/A				
SYS.AHE(Meter).16	HAN: Ping Device	N/A				
SYS.AHE(Meter).17	HAN: Send Message	N/A				
SYS.AHE(Meter).18	HAN: Delete Device	N/A				
SYS.AHE(Meter).19	HAN: Clear Devices	N/A				
SYS.AHE(Meter).20	HAN: Decommission Network	N/A				
System Test Book – AMI Head End (AHE): Broadcast Commands for Integrated Focus AX Meters						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.AHE(Meter).21	HAN: Firmware Download	N/A				
SYS.AHE(Meter).22	HAN: Get All Devices Info	N/A				
SYS.AHE(Meter).23	HAN: Get Firmware	N/A				
SYS.AHE(Meter).24	HAN: Get Network Info	N/A				
SYS.AHE(Meter).25	HAN: Send Message	N/A				

System Test Book – AMI Head End (AHE): Broadcast Commands for Enhanced S4e Meters						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.AHE(Meter).26	HAN: Firmware Download	N/A				
SYS.AHE(Meter).27	HAN: Get All Devices Info	N/A				
SYS.AHE(Meter).28	HAN: Get Firmware	N/A				
SYS.AHE(Meter).29	HAN: Get Network Info	N/A				
SYS.AHE(Meter).30	HAN: Send Message	N/A				

System Test Book – Home Energy Management Portal (HEMP): Web Portal SSO Functionality						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.HEMP.PRTL_01_A	Verify SSO process is working properly	N/A				
System Test Book – Home Energy Management Portal (HEMP): Web Portal Energy Usage Data Presentation						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.HEMP.PRTL_02_A	Verify that Web Portal dashboard is accumulating usage information	N/A				
SYS.HEMP.PRTL_02_B	Verify that graphs are accumulating usage cost information	N/A				
SYS.HEMP.PRTL_02_C	Verify that instantaneous consumption is displayed and updated regularly for HAN users	N/A				
System Test Book – Home Energy Management Portal (HEMP): Web Portal Pricing Information						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.HEMP.PRTL_03_A	Verify accurate pricing information is received and displayed by Web Portal	N/A				
System Test Book – Home Energy Management Portal (HEMP): Web Portal (Estimated) Billing Information						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.HEMP.PRTL_04_A	Verify Bill TrueUps are received by Web Portal and displayed properly	N/A				
SYS.HEMP.PRTL_04_B	“Soak” test Web Portal for a week to verify accuracy of estimated billing information	N/A				
System Test Book – Home Energy Management Portal (HEMP): HAN Device Registration						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.HEMP.PRTL_05_A	HAN Gateway can be registered to HAN user account via Web Portal	N/A				
System Test Book – Home Energy Management Portal (HEMP): HAN Device Connectivity Status						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.HEMP.PRTL_06_A	HAN Device current status appears in Web Portal	N/A				
System Test Book – Home Energy Management Portal (HEMP): HAN Device Information						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.HEMP.PRTL_07_A	HAN Device MAC Address appears in Web Portal	N/A				
SYS.HEMP.PRTL_07_B	HAN Device can be renamed by user in Web Portal	N/A				

System Test Book – Home Energy Management Portal (HEMP): HAN Device Monitoring and Control						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.HEMP.PRTL_08_A	Real-time usage instantaneous demand information is displayed in Web Portal	N/A				
SYS.HEMP.PRTL_08_B	PCT set point and schedule can be set via Web Portal	N/A				
SYS.HEMP.PRTL_08_C	LCSs can be switched on/off via Web Portal	N/A				
System Test Book – Home Energy Management Portal (HEMP): HAN Device Text Messaging						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.HEMP.PRTL_09_A	HAN Devices receive text messages sent via administrative Web Portal	N/A				
System Test Book – Home Energy Management Portal (HEMP): Demand Response Notification						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.HEMP.PRTL_10_A	DR event notification is received and displayed in Web Portal	N/A				
SYS.HEMP.PRTL_10_B	DR event details are displayed in Web Portal	N/A				
System Test Book – Home Energy Management Portal (HEMP): Demand Response Opt Out						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.HEMP.PRTL_11_A	PCT/HAN user DR event participation status is displayed in Web Portal	N/A				
SYS.HEMP.PRTL_11_B	PCT/HAN user can opt out/in for DR event participation via Web Portal	N/A				
System Test Book – Home Energy Management Portal (HEMP): HAN Device Unregistration						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.HEMP.PRTL_12_A	HAN Gateway can be unregistered from HAN user account via administrative Web Portal	N/A				

System Test Book – Home Area Network (HAN): In Home Displays (IHD)						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.HAN.1	Monitor IHD during entire CC 5.6 upgrade process to make sure it “makes the trip”	N/A				
SYS.HAN.2	Provision IHD from “HAN” tab	N/A				
SYS.HAN.3	Provision IHD using “HAN: Register Device” command	N/A				
SYS.HAN.4	Send “HAN: Get Device Info” command to IHD	N/A				
SYS.HAN.5	Send “HAN: Ping Device” command to IHD	N/A				
SYS.HAN.6	Send “HAN: Send Message” command to IHD	N/A				
SYS.HAN.7	Broadcast “HAN: Send Message” command to all meters	N/A				
SYS.HAN.8	Verify that IHD appears as “Normal” in the “HAN” tab	N/A				
SYS.HAN.9	Verify that IHD is accumulating usage information on “Home Screen”	N/A				
SYS.HAN.10	Verify pricing information is received by IHD	N/A				
SYS.HAN.11	Verify that graphs in “Daily Cost” box are accumulating cost information	N/A				
SYS.HAN.12	Verify that instantaneous consumption is displayed and updated regularly	N/A				
SYS.HAN.13	Verify Bill TrueUps are received by IHD when data is processed and sent by IT	N/A				
SYS.HAN.14	“Soak” test IHD(s) for a week to verify accuracy of estimated billing information (use IHD Soak Test Spreadsheet)	N/A				
SYS.HAN.15	Monitor Error Log in Command Center to verify that no ZigBee communications errors occur on any meter	N/A				
SYS.HAN.16	De-provision IHD from “HAN” tab	N/A				
SYS.HAN.17	Power cycle IHD and make sure it stay on network	N/A				
SYS.HAN.18	De-provision IHD using “HAN: Delete Device” command	N/A				
SYS.HAN.19	De-provision IHD using “HAN: Clear Devices” command	N/A				
SYS.HAN.20	De-provision IHD using “HAN: Decommission Network” command	N/A				
System Test Book – Home Area Network (HAN): Tendril Set Point 218 Thermostat (TSTAT)						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.HAN.21	Monitor TSTAT during entire CC 5.6 upgrade process to make sure it “makes the trip”	N/A				
SYS.HAN.22	Provision TSTAT from “HAN” tab	N/A				
SYS.HAN.23	Provision TSTAT using “HAN: Register Device” command	N/A				
SYS.HAN.24	Send “HAN: Get Device Info” command to TSTAT	N/A				
SYS.HAN.25	Send “HAN: Ping Device” command to TSTAT	N/A				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.HAN.26	Send "HAN: Send Message" command to TSTAT	N/A				
SYS.HAN.27	Broadcast "HAN: Send Message" command to all meters	N/A				
SYS.HAN.28	Verify that TSTAT appears as "Normal" in the "HAN" tab	N/A				
SYS.HAN.29	Verify pricing information is received by TSTAT	N/A				
SYS.HAN.30	Verify that Text Messages can be sent to TSTAT from Command Center	N/A				
SYS.HAN.31	Monitor Error Log in Command Center to verify that no ZigBee communications errors occur on any meter	N/A				
SYS.HAN.32	De-provision TSTAT from "HAN" tab	N/A				
SYS.HAN.33	Power cycle TSTAT and make sure it stay on network	N/A				
SYS.HAN.34	De-provision TSTAT using "HAN: Delete Device" command	N/A				
SYS.HAN.35	De-provision TSTAT using "HAN: Clear Devices" command	N/A				
SYS.HAN.36	De-provision TSTAT using "HAN: Decommission Network" command	N/A				
System Test Book – Home Area Network (HAN): HAN Gateway						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.HAN.37	Monitor HAN devices during entire CC 5.6 upgrade process to make sure they all "makes the trip"	N/A				
SYS.HAN.38	Provision HAN devices from "HAN" tab	N/A				
SYS.HAN.39	Provision HAN devices using "HAN: Register Device" command	N/A				
SYS.HAN.40	Send "HAN: Get Device Info" command to HAN devices	N/A				
SYS.HAN.41	Send "HAN: Ping Device" command to HAN devices	N/A				
SYS.HAN.42	Send "HAN: Send Message" command to GW and see if TSTAT gets it	N/A				
SYS.HAN.43	Send "HAN: Send Message" command to TSTAT	N/A				
SYS.HAN.44	Broadcast "HAN: Send Message" command to all meters	N/A				
SYS.HAN.45	Verify that all HAN devices appear as "Normal" in the "HAN" tab	N/A				
SYS.HAN.46	Verify that GW is accumulating usage information in Energize portal	N/A				
SYS.HAN.47	Verify pricing information is received by TSTAT	N/A				
SYS.HAN.48	Monitor Error Log in Command Center to verify that no ZigBee communications errors occur on any meter	N/A				
SYS.HAN.49	De-provision HAN devices from "HAN" tab	N/A				
SYS.HAN.50	Power cycle HAN devices and make sure it stay on network	N/A				
SYS.HAN.51	De-provision HAN devices using "HAN: Delete Device" command	N/A				
SYS.HAN.52	De-provision HAN devices using "HAN: Clear Devices" command	N/A				
SYS.HAN.53	De-provision HAN devices using "HAN: Decommission Network" command	N/A				

System Test Book – Home Area Network (HAN) Additional Tests: In-Home Display (IHD) Test Cases- Network Commissioning and IHD Provisioning						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.HANXTRA.IHD_01_A	Provision IHD from "HAN" tab	N/A				
SYS.HANXTRA.IHD_01_B	Provision IHD using "HAN: Register Device" command	N/A				
System Test Book – Home Area Network (HAN) Additional Tests: In-Home Display (IHD) Test Cases- IHD Connectivity Status						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.HANXTRA.IHD_02_A	Monitor IHD during entire CC upgrade process to make sure it "makes the trip"	N/A				
SYS.HANXTRA.IHD_02_B	Send "HAN: Get Device Info" command to IHD	N/A				
SYS.HANXTRA.IHD_02_C	Send "HAN: Ping Device" command to IHD	N/A				
SYS.HANXTRA.IHD_02_D	Verify that IHD appears as "Normal" in the "HAN" tab	N/A				
SYS.HANXTRA.IHD_02_E	Monitor Error Log in Command Center to verify that no ZigBee communications errors occur on any meter	N/A				
SYS.HANXTRA.IHD_02_F	Power cycle IHD and make sure it remains communicating with the HAN network	N/A				
System Test Book – Home Area Network (HAN) Additional Tests: In-Home Display (IHD) Test Cases- IHD Device Information						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.HANXTRA.IHD_03_A	Verify that device appears as "In Premise Display" in Command Center	N/A				
SYS.HANXTRA.IHD_03_B	Send "HAN: Get Device Info" command to IHD	N/A				
SYS.HANXTRA.IHD_03_C	Send "HAN: Get All Devices Info" command to IHD	N/A				
System Test Book – Home Area Network (HAN) Additional Tests: In-Home Display (IHD) Test Cases- IHD Energy Usage Data Presentation						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.HANXTRA.IHD_04_A	Verify that IHD is accumulating usage information on "Home Screen"	N/A				
SYS.HANXTRA.IHD_04_B	Verify that graphs in "Daily Cost" box are accumulating cost information	N/A				
SYS.HANXTRA.IHD_04_C	Verify that instantaneous consumption is displayed and updated regularly	N/A				
SYS.HANXTRA.IHD_04_D	Verify Bill TrueUps are received by IHD when data is processed and sent by IT	N/A				
SYS.HANXTRA.IHD_04_E	"Soak" test IHD(s) for a week to verify accuracy of estimated billing information (use IHD Soak Test Spreadsheet)	N/A				
System Test Book – Home Area Network (HAN) Additional Tests: In-Home Display (IHD) Test Cases- IHD Pricing Information						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.HANXTRA.IHD_05_A	Verify accurate pricing information is received by IHD (should match Web Portal pricing information)	N/A				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.HANXTRA.IHD_05_B	Verify that graphs in "Daily Cost" box are accumulating cost information	N/A				
System Test Book – Home Area Network (HAN) Additional Tests: In-Home Display (IHD) Test Cases- IHD (Estimated) Billing Information						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.HANXTRA.IHD_06_A	Verify Bill TrueUps are received by IHD when data is processed and sent by IT	N/A				
SYS.HANXTRA.IHD_06_B	"Soak" test IHD(s) for a week to verify accuracy of estimated billing information (use IHD Soak Test Spreadsheet)	N/A				
System Test Book – Home Area Network (HAN) Additional Tests: In-Home Display (IHD) Test Cases- IHD Text Messaging						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.HANXTRA.IHD_07_A	Send "HAN: Send Message" command to IHD	N/A				
SYS.HANXTRA.IHD_07_B	Broadcast "HAN: Send Message" command to multiple meters	N/A				
System Test Book – Home Area Network (HAN) Additional Tests: In-Home Display (IHD) Test Cases- IHD Monitoring						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.HANXTRA.IHD_08_A	"Soak" test IHD(s) for a week to verify accuracy of estimated billing information (use IHD Soak Test Spreadsheet)	N/A				
System Test Book – Home Area Network (HAN) Additional Tests: In-Home Display (IHD) Test Cases- Network De-Commissioning and IHD De-Provisioning						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.HANXTRA.IHD_09_A	De-provision IHD from "HAN" tab	N/A				
SYS.HANXTRA.IHD_09_B	De-provision IHD using "HAN: Delete Device" command	N/A				
SYS.HANXTRA.IHD_09_C	De-provision IHD using "HAN: Clear Devices" command	N/A				
SYS.HANXTRA.IHD_09_D	De-provision IHD using "HAN: Decommission Network" command	N/A				
System Test Book – Home Area Network (HAN) Additional Tests: Standalone Thermostat (PCT)- Network Commissioning and PCT Provisioning						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.HANXTRA.PCT_01_A	Provision PCT from "HAN" tab	N/A				
SYS.HANXTRA.PCT_01_B	Provision PCT using "HAN: Register Device" command	N/A				
System Test Book – Home Area Network (HAN) Additional Tests: Standalone Thermostat (PCT)- PCT Portal Registration						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.HANXTRA.PCT_02_A	Click "Scan for More Devices" and verify that remaining PCT appears in the device list	N/A				
System Test Book – Home Area Network (HAN) Additional Tests: Standalone Thermostat (PCT)- PCT Connectivity Status						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.HANXTRA.PCT_03_A	Monitor PCT during entire CC upgrade process to make sure it "makes the trip"	N/A				
SYS.HANXTRA.PCT_03_B	Send "HAN: Get Device Info" command to PCT	N/A				
SYS.HANXTRA.PCT_03_C	Send "HAN: Ping Device" command to PCT	N/A				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.HANXTRA.PCT_03_D	Verify that PCT appears as "Normal" in the "HAN" tab	N/A				
SYS.HANXTRA.PCT_03_E	Monitor Error Log in Command Center to verify that no ZigBee communications errors occur on any meter	N/A				
SYS.HANXTRA.PCT_03_F	Power cycle PCT and make sure it remains communicating with the HAN network	N/A				
System Test Book – Home Area Network (HAN) Additional Tests: Standalone Thermostat (PCT)- PCT Device Information						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.HANXTRA.PCT_04_A	Verify that device appears as "PCT" in Command Center	N/A				
SYS.HANXTRA.PCT_04_B	Send "HAN: Get Device Info" command to PCT	N/A				
SYS.HANXTRA.PCT_04_C	Send "HAN: Get All Devices Info" command to PCT	N/A				
System Test Book – Home Area Network (HAN) Additional Tests: Standalone Thermostat (PCT)- PCT Pricing Information						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.HANXTRA.PCT_05_A	Verify accurate pricing information is received by PCT (should match Web Portal pricing information)	N/A				
System Test Book – Home Area Network (HAN) Additional Tests: Standalone Thermostat (PCT)- PCT Monitoring and Control						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.HANXTRA.PCT_06_A	"Soak" test PCT for a week to verify functionality and network connectivity	N/A				
System Test Book – Home Area Network (HAN) Additional Tests: Standalone Thermostat (PCT)- PCT Demand Response Notification						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.HANXTRA.PCT_07_A	Verify PCT receives Demand Response event request	N/A				
SYS.HANXTRA.PCT_07_B	Verify PCT starts Demand Response event at expected "start time"	N/A				
SYS.HANXTRA.PCT_07_C	Verify PCT ends Demand Response event at expected "end time"	N/A				
System Test Book – Home Area Network (HAN) Additional Tests: Standalone Thermostat (PCT)- PCT Demand Response Opt Out						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.HANXTRA.PCT_08_A	Verify that PCT opt-in to Demand Response events automatically	N/A				
SYS.HANXTRA.PCT_08_B	Verify that PCT respond appropriately when Demand Response event opt-out is performed	N/A				
System Test Book – Home Area Network (HAN) Additional Tests: Standalone Thermostat (PCT)- PCT Text Messaging						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.HANXTRA.PCT_09_A	Send "HAN: Send Message" command to PCT	N/A				
SYS.HANXTRA.PCT_09_B	Broadcast "HAN: Send Message" command to multiple meters	N/A				

System Test Book – Home Area Network (HAN) Additional Tests: Standalone Thermostat (PCT)- PCT Unregistration						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.HANXTRA.PCT_10_A	Provision PCT from “HAN” tab	N/A				
SYS.HANXTRA.PCT_10_B	Provision PCT using “HAN: Register Device” command	N/A				
System Test Book – Home Area Network (HAN) Additional Tests: Standalone Thermostat (PCT)- Network De-Commissioning and PCT De-Provisioning						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.HANXTRA.PCT_11_A	De-provision PCT from “HAN” tab	N/A				
SYS.HANXTRA.PCT_11_B	De-provision PCT using “HAN: Delete Device” command	N/A				
SYS.HANXTRA.PCT_11_C	De-provision PCT using “HAN: Clear Devices” command	N/A				
SYS.HANXTRA.PCT_11_D	De-provision PCT using “HAN: Decommission Network” command	N/A				
System Test Book – Home Area Network (HAN) Additional Tests: Home Area Network (HAN) Devices - Network Commissioning and HAN Device Provisioning						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.HANXTRA.HAN_01_A	Provision HAN devices from “HAN” tab	N/A				
SYS.HANXTRA.HAN_01_B	Provision HAN devices using “HAN: Register Device” command	N/A				
System Test Book – Home Area Network (HAN) Additional Tests: Home Area Network (HAN) Devices - HAN Device Portal Registration						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.HANXTRA.HAN_02_A	Input HAN Gateway ID on “Device Settings” page in Portal and verify that the HAN Gateway appears in the device list	N/A				
SYS.HANXTRA.HAN_02_B	Click “Scan for More Devices” and verify that remaining HAN devices appear in the device list	N/A				
System Test Book – Home Area Network (HAN) Additional Tests: Home Area Network (HAN) Devices - HAN Device Connectivity Status						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.HANXTRA.HAN_03_A	Monitor HAN devices during entire CC upgrade process to make sure it “makes the trip”	N/A				
SYS.HANXTRA.HAN_03_B	Send “HAN: Ping Device” command to HAN devices	N/A				
SYS.HANXTRA.HAN_03_C	Verify that HAN devices appears as “Normal” in the “HAN” tab	N/A				
SYS.HANXTRA.HAN_03_D	Monitor Error Log in Command Center to verify that no ZigBee communications errors occur on any meter	N/A				
SYS.HANXTRA.HAN_03_E	Power cycle HAN devices and make sure they remains communicating with the HAN network	N/A				
System Test Book – Home Area Network (HAN) Additional Tests: Home Area Network (HAN) Devices - HAN Device Information						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.HANXTRA.HAN_04_A	Verify that HAN devices appears as “Energy Service Portal”, “PCT”, and “Load Control Device” in Command Center	N/A				
SYS.HANXTRA.HAN_04_B	Send “HAN: Get Device Info” command to HAN devices	N/A				
SYS.HANXTRA.HAN_04_C	Send “HAN: Get All Devices Info” command to HAN devices	N/A				

System Test Book – Home Area Network (HAN) Additional Tests: Home Area Network (HAN) Devices - HAN Device Pricing Information						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.HANXTRA.HAN_05_A	Verify accurate pricing information is received by HAN devices	N/A				
System Test Book – Home Area Network (HAN) Additional Tests: Home Area Network (HAN) Devices - HAN Device Monitoring and Control						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.HANXTRA.HAN_06_A	"Soak" test HAN devices for a week to verify functionality and network connectivity	N/A				
System Test Book – Home Area Network (HAN) Additional Tests: Home Area Network (HAN) Devices - HAN Device Demand Response Notification						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.HANXTRA.HAN_07_A	Verify HAN devices receives Demand Response event request	N/A				
SYS.HANXTRA.HAN_07_B	Verify HAN devices starts Demand Response event at expected "start time"	N/A				
SYS.HANXTRA.HAN_07_C	Verify HAN devices ends Demand Response event at expected "end time"	N/A				
System Test Book – Home Area Network (HAN) Additional Tests: Home Area Network (HAN) Devices - HAN Device Demand Response Opt Out						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.HANXTRA.HAN_08_A	Verify that HAN devices opt-in to Demand Response events automatically	N/A				
SYS.HANXTRA.HAN_08_B	Verify that HAN devices respond appropriately when Demand Response event opt-out is performed	N/A				
System Test Book – Home Area Network (HAN) Additional Tests: Home Area Network (HAN) Devices - HAN Device Text Messaging						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.HANXTRA.HAN_09_A	Send "HAN: Send Message" command to HAN devices	N/A				
SYS.HANXTRA.HAN_09_B	Broadcast "HAN: Send Message" command to multiple meters	N/A				
System Test Book – Home Area Network (HAN) Additional Tests: Home Area Network (HAN) Devices - HAN Device Unregistration						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.HANXTRA.HAN_10_A	Provision HAN devices from "HAN" tab	N/A				
SYS.HANXTRA.HAN_10_B	Provision HAN devices using "HAN: Register Device" command	N/A				
System Test Book – Home Area Network (HAN) Additional Tests: Home Area Network (HAN) Devices - Network De-Commissioning and HAN Device De-Provisioning						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
SYS.HANXTRA.HAN_11_A	De-provision HAN devices from "HAN" tab	N/A				
SYS.HANXTRA.HAN_11_B	De-provision HAN devices using "HAN: Delete Device" command	N/A				
SYS.HANXTRA.HAN_11_C	De-provision HAN devices using "HAN: Clear Devices" command	N/A				
SYS.HANXTRA.HAN_11_D	De-provision HAN devices using "HAN: Decommission Network" command	N/A				

1.2 Integration Test Books

Integration Test Book – DMS Interfaces to DERM (Joint): Configuration Verification						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
INT.DMS-DERM.A1.1	Verify FAT system environment diagram	N/A				
INT.DMS-DERM.A1.2	Verify system Test Environment (HW & SW), including communication infrastructure	N/A				
INT.DMS-DERM.A1.3	Verify system management and configuration displays and tools	N/A				
INT.DMS-DERM.A1.4	Verify users access to the DNA's Interface management tools	N/A				
INT.DMS-DERM.A1.5	Verify users access to the DERM's Interface management tools	N/A				
INT.DMS-DERM.A1.6	Verify correct operation of the system components (system configuration overview, servers status, communications status, applications running,...)	N/A				
Integration Test Book – DMS Interfaces to DERM (Joint): Computer System Management (Servers, Clients, Functions, Environments)						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
INT.DMS-DERM.A1.7	Redundancy (Comms, Networks): Verify communication redundancy	N/A				
INT.DMS-DERM.A1.8	Communications Failure: Verify communication redundancy between DERM and DMS	N/A				
INT.DMS-DERM.A1.9	Communications Failure: Verify DNA LAN failures	N/A				
INT.DMS-DERM.A1.10	Communications Failure: Verify DNA LAN failures restoration	N/A				
INT.DMS-DERM.A1.11	Communications Failure: Verify VPN failure	N/A				
INT.DMS-DERM.A1.12	Communications Failure: Verify that the data model is correct after system is restored	N/A				
INT.DMS-DERM.A1.13	Communications Failure: Verify reporting and logging	N/A				
INT.DMS-DERM.A1.14	Power Failure: Verify interface behavior during DNA servers power failures	N/A				
INT.DMS-DERM.A1.15	Power Failure: Verify interface behavior during DERM power failures	N/A				
INT.DMS-DERM.A1.16	Power Failure: Verify that the data model is correct after system is restored	N/A				
Integration Test Book – DMS Interfaces to DERM (Joint): Functional Redundancy						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
INT.DMS-DERM.A1.17	DNA Failover: Verify interface operation when a failover of the DNA applications occurs	N/A				
INT.DMS-DERM.A1.18	DNA Failover: Verify message exchange interruption caused by DNA failover	N/A				
INT.DMS-DERM.A1.19	DNA Failover: Verify status reporting and logging at the CC	N/A				
INT.DMS-DERM.A1.20	DERM Failover: Verify interface operation when a failover of the DERM applications occurs	N/A				
INT.DMS-DERM.A1.21	DERM Failover: Verify message exchange interruption caused by DERM failover	N/A				
INT.DMS-DERM.A1.22	DERM Failover: Verify status reporting and logging at the CC	N/A				

Integration Test Book – DMS Interfaces to DERM (Joint): Data Base Management						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
INT.DMS-DERM.A1.23	DB Model Management: Verify DB change in DNA is propagated to DERM correctly	N/A				
INT.DMS-DERM.A1.24	Model Export: Verify CIM RDF DB model export from DNA	N/A				
INT.DMS-DERM.A1.25	Model Import: Verify CIM RDF DB model import to DERM	N/A				
INT.DMS-DERM.A1.26	Model Import: Verify behavior when sftp goes down during CIM RDF model transfer	N/A				
INT.DMS-DERM.A1.27	Model Import: Verify behavior when DMS goes down during CIM RDF model transfer	N/A				
INT.DMS-DERM.A1.28	Model Import: Verify behavior when DERM goes down during CIM RDF model transfer	N/A				
INT.DMS-DERM.A1.29	Model Import: Verify DB Synch monitoring or mismatch reporting	N/A				
INT.DMS-DERM.A1.30	Model Import: Interrupt DB synchronization and verify reporting error	N/A				
INT.DMS-DERM.A1.31	Model Import: Verify model archiving and management	N/A				
INT.DMS-DERM.A1.32	Model Import: Verify reporting and logging of DB synchronization and errors	N/A				
Integration Test Book – DMS Interfaces to DERM (Joint): User Interface						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
INT.DMS-DERM.A1.33	Interface Management: Verify control enable/disable interface in DNA	N/A				
INT.DMS-DERM.A1.34	Interface Management: Verify control enable/disable interface in DERM	N/A				
INT.DMS-DERM.A1.35	Interface Management: Verify reporting and logging of Interface Status	N/A				
INT.DMS-DERM.A1.36	Simultaneous Operation: Verify simultaneous operation of the requests from DNA and user operation in DERM	N/A				
Integration Test Book – DMS Interfaces to DERM (Joint): Message Transfer						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
INT.DMS-DERM.A1.37	Interface handshaking: Verify interface status	N/A				
INT.DMS-DERM.A1.38	Interface handshaking: Verify system behavior on error or negative handshaking conditions from DERM	N/A				
INT.DMS-DERM.A1.39	Interface handshaking: Verify system behavior on error or negative handshaking conditions from DNA	N/A				
INT.DMS-DERM.A1.40	Interface handshaking: Verify reporting and logging	N/A				
INT.DMS-DERM.A1.41	Interface handshaking: Verify behavior when JMS Adapter goes down during message exchange	N/A				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
INT.DMS-DERM.A1.42	Interface handshaking: Verify behavior when ESB goes down during message exchange	N/A				
INT.DMS-DERM.A1.43	Interface handshaking: Verify behavior when DMS goes down during message exchange	N/A				
INT.DMS-DERM.A1.44	Interface handshaking: Verify behavior when DERM goes down during message exchange	N/A				
INT.DMS-DERM.A1.45	GetDiscreteMeasurements: Verify requests from DERM	N/A				
INT.DMS-DERM.A1.46	GetDiscreteMeasurements: Verify requests from DERM (multiple users)	N/A				
INT.DMS-DERM.A1.47	GetDiscreteMeasurements: Verify incorrect interface handshaking	N/A				
INT.DMS-DERM.A1.48	GetDiscreteMeasurements: Verify correct response	N/A				
INT.DMS-DERM.A1.49	GetDiscreteMeasurements: Verify incorrect response (data mapping errors, model mismatch,...)	N/A				
INT.DMS-DERM.A1.50	GetDiscreteMeasurements: Verify no response - Time out	N/A				
INT.DMS-DERM.A1.51	GetDiscreteMeasurements: Verify reporting and logging	N/A				
INT.DMS-DERM.A1.52	Report spontaneous switch changes: Verify change of status is sent from DNA to DERM	N/A				
INT.DMS-DERM.A1.53	Report spontaneous switch changes: Verify incorrect response (no ack)	N/A				
INT.DMS-DERM.A1.54	Report spontaneous switch changes: Verify no response (ack) - Time out	N/A				
INT.DMS-DERM.A1.55	Report spontaneous switch changes: Verify incorrect Interface handshaking	N/A				
INT.DMS-DERM.A1.56	Report spontaneous switch changes: Verify correct status change and new measure values	N/A				
INT.DMS-DERM.A1.57	Report spontaneous switch changes: Verify multiple consecutive status changes from DNA (1 or several messages)	N/A				
INT.DMS-DERM.A1.58	Report spontaneous switch changes: Verify erroneous switch reporting (not in the model or incorrect mapping)	N/A				
INT.DMS-DERM.A1.59	Report spontaneous switch changes: Verify reporting and logging	N/A				
INT.DMS-DERM.A1.60	Power Flow limit violations: Verify PF limit violations are sent from DNA to DERM	N/A				
INT.DMS-DERM.A1.61	Power Flow limit violations: Verify incorrect response (no ack)	N/A				
INT.DMS-DERM.A1.62	Power Flow limit violations: Verify no response (ack) - Time out	N/A				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
INT.DMS-DERM.A1.63	Power Flow limit violations: Verify limit violations are created, changed and deleted; - ChangedDistributionPowerFlowLimitViolation - CreatedDistributionPowerFlowLimitViolation - DeleteDistributionPowerFlowLimitViolation	N/A				
INT.DMS-DERM.A1.64	Power Flow limit violations: Verify erroneous message sequence (delete a violation that was not previously created,...)	N/A				
INT.DMS-DERM.A1.65	Power Flow limit violations: Verify incorrect Interface handshaking	N/A				
INT.DMS-DERM.A1.66	Power Flow limit violations: Verify reporting and logging	N/A				
INT.DMS-DERM.A1.67	CreatedDemandResourceControls: Verify requests from DERM	N/A				
INT.DMS-DERM.A1.68	CreatedDemandResourceControls: Verify incorrect response (no ack)	N/A				
INT.DMS-DERM.A1.69	CreatedDemandResourceControls: Verify no response - Time out	N/A				
INT.DMS-DERM.A1.70	CreatedDemandResourceControls: Verify correct information is received in DNA	N/A				
INT.DMS-DERM.A1.71	CreatedDemandResourceControls: Verify the rest of DR event sequence : Event start when time arrives, notification, information about action taken, completion	N/A				
INT.DMS-DERM.A1.72	CreatedDemandResourceControls: Verify incorrect Interface handshaking	N/A				
INT.DMS-DERM.A1.73	CreatedDemandResourceControls: Verify reporting and logging	N/A				
INT.DMS-DERM.A1.74	DeleteDemandResourceControls: Verify requests from DERM	N/A				
INT.DMS-DERM.A1.75	DeleteDemandResourceControls: Verify incorrect response (no ack)	N/A				
INT.DMS-DERM.A1.76	DeleteDemandResourceControls: Verify no response - Time out	N/A				
INT.DMS-DERM.A1.77	DeleteDemandResourceControls: Verify incorrect Interface handshaking	N/A				
INT.DMS-DERM.A1.78	DeleteDemandResourceControls: Verify correct information is received in DNA	N/A				
INT.DMS-DERM.A1.79	DeleteDemandResourceControls: Verify reporting and logging	N/A				
INT.DMS-DERM.A1.80	GetDemandResourceControls ReplyResourceControls: Verify requests from DNA	N/A				
INT.DMS-DERM.A1.81	GetDemandResourceControls ReplyResourceControls: Verify incorrect response (no ack)	N/A				
INT.DMS-DERM.A1.82	GetDemandResourceControls ReplyResourceControls: Verify no response - Time out	N/A				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
INT.DMS-DERM.A1.83	GetDemandResourceControls ReplyResourceControls: Verify incorrect interface handshaking	N/A				
INT.DMS-DERM.A1.84	GetDemandResourceControls ReplyResourceControls: Verify correct information is received in DNA	N/A				
INT.DMS-DERM.A1.85	GetDemandResourceControls ReplyResourceControls: Verify behavior when incorrect data reported as part of events(not in the model or incorrect mapping)	N/A				
INT.DMS-DERM.A1.86	GetDemandResourceControls ReplyResourceControls: Verify reporting and logging	N/A				
Integration Test Book – DMS interfaces to DERM (Joint): Full Scenario Tests						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
INT.DMS-DERM.A1.87	DERM Initialization Base Case: Verify that CIM RDF data file can be loaded in DERM	N/A				
INT.DMS-DERM.A1.88	DERM Initialization Base Case: Request synchronization of device statuses from DERM GUI and verify receipt via consistent DMS and DERM Uis.	N/A				
INT.DMS-DERM.A1.89	DERM Initialization Base Case: Simulate a device status change in the DMS and verify that the device status change appears in the DERM UI.	N/A				
INT.DMS-DERM.A1.90	Feeder Load Management Base Case: Create study case in DMS with specific time period and verify that the study case is published to DERM	N/A				
INT.DMS-DERM.A1.91	Feeder Load Management Base Case: Verify behavior when DERM study case is not properly created	N/A				
INT.DMS-DERM.A1.92	Feeder Load Management Base Case: Input study case (injection correction factor into DMS GUI and verify behavior on DMS study case	N/A				
INT.DMS-DERM.A1.93	Feeder Load Management Base Case: Set target network topology in DMS GUI by hand	N/A				
INT.DMS-DERM.A1.94	Feeder Load Management Base Case: Set target network topology in DMS GUI from InService switching orders	N/A				
INT.DMS-DERM.A1.95	Feeder Load Management Base Case: Verify that both types of network topology updates have been applied in the DMS GUI	N/A				
INT.DMS-DERM.A1.96	Feeder Load Management Base Case: Verify that the network topology updates have been sent to the DERM (via DERM GUI? How will we verify?)	N/A				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
INT.DMS-DERM.A1.97	Feeder Load Management Base Case: Invoke Power Flow on study case from DMS and verify that line overloads for hourly peak are displayed on the DMS UI	N/A				
INT.DMS-DERM.A1.98	Feeder Load Management Base Case: Run FLT to mitigate overload in study case and verify that switching procedures are displayed on the DMS UI	N/A				
INT.DMS-DERM.A1.99	Feeder Load Management Base Case: Execute switching procedure steps in the study case using SPM and verify that remaining overloads for the peak hour of study case are displayed on the DMS UI	N/A				
INT.DMS-DERM.A1.100	Feeder Load Management Base Case: Verify that switch changes from switching procedure are sent from DMS to DERM and are applied to the DERM network model	N/A				
INT.DMS-DERM.A1.101	Feeder Load Management Base Case: Initiate PF simulation scheduler (for hourly PF) from DMS GUI and verify that DMS runs the hourly PF	N/A				
INT.DMS-DERM.A1.102	Feeder Load Management Base Case: Verify that hourly PF violations are sent from DMS to DERM and that results are displayed on DERM UI	N/A				
INT.DMS-DERM.A1.103	Feeder Load Management Base Case: Verify that user can select feeder/section requiring load reduction and that DERM returns DR/DER available on the DERM UI	N/A				
INT.DMS-DERM.A1.104	Feeder Load Management Base Case: Select DR/DER to apply and verify that message is sent to DMS with load reductions per transformer/node/hour	N/A				
INT.DMS-DERM.A1.105	Feeder Load Management Base Case: Verify that DR/DER load reduction applied notification is displayed on the DMS UI	N/A				
INT.DMS-DERM.A1.106	Feeder Load Management Base Case: Request PF re-run from the DMS UI and verify that DMS takes proposed DR reductions into account	N/A				
INT.DMS-DERM.A1.107	Feeder Load Management Base Case: Verify that updated line overloads per hour are displayed on the DMS UI and that these overloads are sent to the DERM to continue applying DR/DER to resolve	N/A				
INT.DMS-DERM.A1.108	Feeder Load Management Base Case: If there are no additional line overloads, verify that none are displayed on DMS UI	N/A				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
INT.DMS-DERM.A1.109	Feeder Load Management Base Case: From DERM UI, request that proposed DR/DER is scheduled and verify that event schedule is returned to user via DERM UI	N/A				
INT.DMS-DERM.A1.110	Feeder Load Management Base Case: Approve and commit DR/DER in DERM UI and verify that message is sent to DMS	N/A				
INT.DMS-DERM.A1.111	Feeder Load Management Base Case: At event time, confirm that DMS UI notifies user that there are FLT switching procedures to be executed	N/A				
INT.DMS-DERM.A1.112	Feeder Load Management Base Case: Execute the switching procedures and verify that the feeder is reconfigured	N/A				
INT.DMS-DERM.A1.113	Feeder Load Management Base Case: Verify that DERM dispatches DR at the scheduled time	N/A				
INT.DMS-DERM.A1.114	Feeder Load Management Follow-Up Tests: Create second study case during same time period as first, and verify that study case starts from nominal network state and includes the previously committed DR/DER from study case #1	N/A				
INT.DMS-DERM.A1.115	Feeder Load Management Follow-Up Tests: Invoke Power Flow on study case #2 from DMS and verify that PF incorporates previously committed DR/DER from study case #1	N/A				
INT.DMS-DERM.A1.116	Feeder Load Management Follow-Up Tests: Verify behavior in DMS and DERM when conditions change between time when study case was created and time when study case execution is to occur	N/A				
INT.DMS-DERM.A1.117	Feeder Load Management Follow-Up Tests: Verify behavior when two study cases are created simultaneously with an overlapping time frame	N/A				
INT.DMS-DERM.A1.118	Feeder Load Management Follow-Up Tests: Verify that DERM can schedule VVC for planning purposes	N/A				
INT.DMS-DERM.A1.119	Feeder Load Shed Base Case: Simulate a feeder overload condition and verify that: - PF detects it and creates an alert - FLT is invoked to mitigate - FLT recommended switching procedures are displayed on the DMS UI - Switching procedures are executed - Loads are transferred - Next iteration of DSSE runs and results are displayed	N/A				
INT.DMS-DERM.A1.120	Feeder Load Shed Base Case: Verify that DSSE remaining overload results are sent to DERM and displayed on DERM UI	N/A				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
INT.DMS-DERM.A1.121	Feeder Load Shed Base Case: Verify that user can select feeder/section requiring load reduction and that DERM returns DR/DER available on the DERM UI	N/A				
INT.DMS-DERM.A1.122	Feeder Load Shed Base Case: Select DR/DER to apply and verify that commit messages are sent to relevant DR control authorities	N/A				
INT.DMS-DERM.A1.123	Feeder Load Shed Base Case: Verify that DR/DER applied in DERM UI is sent to DMS and used to update real time load model	N/A				
INT.DMS-DERM.A1.124	Feeder Load Shed Base Case: Wait for 5 minutes and verify that load reduction has occurred via next DSSE run	N/A				
INT.DMS-DERM.A1.125	Feeder Load Shed Base Case: Verify that remaining overloads are displayed on DMS UI and that these overloads are sent to the DERM to continue applying DR/DER to resolve	N/A				
INT.DMS-DERM.A1.126	Feeder Load Shed Base Case: If there are no additional line overloads, verify that none are displayed on DMS UI	N/A				
INT.DMS-DERM.A1.127	Feeder Load Shed Follow-Up Tests: Verify behavior when two operators simultaneously try to solve an overload	N/A				

Integration Test Book – DMS Interfaces to DERM (DERM Focus): XML Verification						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
INT.DMS-DERM.A2.1	GetDiscreteMeasurements: Verify that the user can synchronize the dynamic network model with the DMS system that can be synchronizing with RT, after re-start of the DERM system of synchronization with a study case when a new study is created or a different data set of dynamic data has been loaded.	User synchronized the DERM network with the DMS data.				
INT.DMS-DERM.A2.2	Opening/Closing a switch (ChangedDiscreteMeasurements): Broadcasts all spontaneous switch status changes.	The state of the selected switch status has been changed.				
INT.DMS-DERM.A2.3	Receive Power Flow Limit Violation Results: The event messages ChangedDistributionPowerFlowLimitViolation, CreatedDistributionPowerFlowLimitViolation and DeletedDistributionPowerFlowLimitViolation are used to report when a violation occurs, disappears, or changes in value. Like all event messages, they have a header and a payload.	Verify that DMS sends power flow violation results back to DERM.				
INT.DMS-DERM.A2.4	CreatedDemandResourceControls: Verify that DERM can send a message to SCADA/DMS that the DR event has been scheduled.	User can create and schedule DR Load Control event. The message will be sent to the DMS.				
INT.DMS-DERM.A2.5	DeletedDemandResourceControls: Verify that DERM can send a message to SCADA/DMS that the DR event has been un-scheduled.	User can un-schedule DR Load Control event. The message will be sent to the DMS.				
INT.DMS-DERM.A2.6	GetDemandResourceControls/ReplyResourceControls: This message GetDemandResourceControls enables DMS to request all Demand Response (DR) events that are currently scheduled. The response message from DERM to DMS is ReplyDemandResourceControls.	All requested DR events were sent by DERM and received by DMS.				

Integration Test Book – ESB Interfaces to Misc Systems: Simulated Outage/Restoration Event						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
INT.ESB-MISC.B1.OUT.1	Confirm that the specified event scenario is transmitted from the AMI/AHE infrastructure through the KCP&L ESB to the MDM (via the eMeter EIP L+G 5.1 Adapter) and then from the MDM via ESB to the OMS system.	Specified event is visible in the ESB Logs and MDM.				
INT.ESB-MISC.B1.OUT.2	Confirm that the specified event scenario is transmitted from the AMI/AHE infrastructure through the KCP&L ESB to the MDM (via the eMeter EIP L+G 5.1 Adapter) and then from the MDM via ESB to the OMS system.	Specified event is visible in the ESB Logs and MDM.				
INT.ESB-MISC.B1.RES.1	Confirm that the specified event scenario is transmitted from the AMI/AHE infrastructure through the KCP&L ESB to the MDM (via the eMeter EIP L+G 5.1 Adapter) and then from the MDM via ESB to the OMS system.	Specified event is visible in the ESB Logs and MDM.				
INT.ESB-MISC.B1.RES.2	Confirm that the specified event scenario is transmitted from the AMI/AHE infrastructure through the KCP&L ESB to the MDM (via the eMeter EIP L+G 5.1 Adapter) and then from the MDM via ESB to the OMS system.	Specified event is visible in the ESB Logs and MDM.				
Integration Test Book – ESB Interfaces to Misc Systems: Meter Lab Outage/Restoration Event (w/o OMS)						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
INT.ESB-MISC.B1.OUT.3	Confirm that the specified event scenario is transmitted from the AMI/AHE infrastructure through the KCP&L ESB to the MDM (via the eMeter EIP L+G 5.1 Adapter) and then from the MDM via ESB to the OMS system.	Specified event is visible in the AHE and MDM.				
INT.ESB-MISC.B1.RES.3	Confirm that the specified event scenario is transmitted from the AMI/AHE infrastructure through the KCP&L ESB to the MDM (via the eMeter EIP L+G 5.1 Adapter) and then from the MDM via ESB to the OMS system.	Specified event is visible in the AHE and MDM.				

Integration Test Book – ESB Interfaces to Misc Systems: Meter Lab Outage/Restoration Event (w/OMS)						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
INT.ESB-MISC.B1.OUT.4	Confirm that the specified event scenario is transmitted from the AMI/AHE infrastructure through the KCP&L ESB to the MDM (via the eMeter EIP L+G 5.1 Adapter) and then from the MDM via ESB to the OMS system.	Specified event is visible in the AHE, MDM and OMS.				
INT.ESB-MISC.B1.RES.4	Confirm that the specified event scenario is transmitted from the AMI/AHE infrastructure through the KCP&L ESB to the MDM (via the eMeter EIP L+G 5.1 Adapter) and then from the MDM via ESB to the OMS system.	Specified event is visible in the AHE, MDM and OMS.				

Integration Test Book – ESB Interfaces to Misc Systems: Outage Derivation in MDM via FlexSync						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
INT, ESB-MISC.B2, FS.1	Generate a single FlexSync Message from CIS test environment via ESB to the MDM with the modified SDP-Meter Association date and verify the results.	(1) Confirm that FlexSync message is sent to MDM with modified SDP-Meter Association date (2) Verify that MDM processes the message (3) Verify that MDM derives the Outage Service for the SDP				
INT, ESB-MISC.B2, FS.2	Generate a multiple FlexSync Message from CIS test environment via ESB to the MDM with the modified SDP-Meter Association date and verify the results.	(1) Confirm that FlexSync message is sent to MDM with modified SDP-Meter Association date (2) Verify that MDM processes the message (3) Verify that MDM derives the Outage Service for the SDP				
INT, ESB-MISC.B2, FS.3	Generate a single FlexSync Message from CIS test environment via ESB to the MDM with the modified SDP-Meter Association date and verify the results.	(1) Confirm that FlexSync message is sent to MDM with modified SDP-Meter Association date (2) Verify that MDM processes the message (3) Verify that MDM derives the Outage Service for the SDP				

Integration Test Book – ESB Interfaces to Misc Systems: Power Status Verification - Unit Testing						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
INT.ESB-MISC.C.3	Validate setup and configuration of the OMS, ESB, MDM, and AHE to support Power Status Verification	A) Verify that the OMS is configured to write PSV request messages to the OMS_AMI_REPLY queue and read PSV reply messages from the OMS_AMI_INPUT_PSV queue B) Verify that the ESB is configured to read PSV request messages from the OMS_AMI_REPLY queue, send PSV request messages to the MDM, and write PSV reply messages to the OMS_AMI_INPUT_PSV queue C) Verify that the MDM is configured to send PSV request and reply messages to the ESB D) Verify that the AHE is configured to send PSV reply messages to the ESB				
INT.ESB-MISC.C.4	Confirm that the OMS is generating the appropriate outbound PSV request message to the MDM via the ESB	A) Verify that the OMS generates the appropriate outbound PSV request message and sends it to the ESB on the OMS_AMI_REPLY queue to be transformed and sent to the MDM				
INT.ESB-MISC.C.5	Confirm that the ESB is properly transforming PSV request message from the OMS to the MDM	A) Verify that the ESB reads the PSV request message from the OMS_AMI_REPLY queue B) Verify that the ESB makes WebService call to the CIS to check for "MeterEnergized" status C) Verify that the ESB transforms the PSV request message to the proper format for the MDM to process D) Verify that the ESB sends the transformed PSV request message to the MDM				
INT.ESB-MISC.C.6	Confirm that the MDM is generating the appropriate outbound PSV request message to the AHE via the ESB	A) Verify that the MDM receives the PSV request message from the ESB B) Verify that the MDM generates the appropriate outbound PSV request message (endpoint on-demand read request) and sends it to the AHE via the ESB				
INT.ESB-MISC.C.7	Confirm that the AHE receives the PSV request message from the MDM via the ESB	A) Verify that the AHE receives the PSV request message (endpoint on-demand read request) from the MDM via the ESB and sends the PSV request message to the target AMI meter				
INT.ESB-MISC.C.8	Confirm that the AHE is processing the PSV request message and generating the appropriate outbound PSV reply message to the MDM via	A) Verify that the AHE receives PSV reply message from the target AMI meter and generates the appropriate outbound PSV reply message (endpoint on-demand read reply) and sends it to the MDM via the ESB				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
INT.ESB-MISC.C.9	Confirm that the MDM is generating the appropriate outbound PSV reply message to the OMS via the ESB	A) MDM generates a "meter on" PSV reply message and sends it to the ESB				
INT.ESB-MISC.C.10	Confirm that the ESB is properly transforming the PSV reply message from the MDM to the OMS	A) Verify that the ESB receives the PSV reply message from the MDM B) Verify that the ESB transforms the PSV reply message to the proper format for the OMS to process C) Verify that ESB sends the transformed PSV reply message to the OMS_AMI_INPUT_PSV queue				
INT.ESB-MISC.C.11	Confirm that the OMS is processing the PSV reply message	A) Verify that OMS reads the PSV reply message from the OMS_AMI_INPUT_PSV queue				
INT.ESB-MISC.C.12	Test Plan review	Review test plan PRIOR TO testing. Consult your PA to determine attendees. Review unit test results if necessary.				
INT.ESB-MISC.C.13	Code review – Include diffs	Repeat code review if changes were made during unit testing.				
Integration Test Book – ESB Interfaces to Misc Systems: Power Status Verification - System/Scenario Testing						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
INT.ESB-MISC.C.14	PSV is manually initiated from the OMS to a target meter that is	N/A				
INT.ESB-MISC.C.15	PSV is manually initiated from the OMS to a target meter that is	N/A				
INT.ESB-MISC.C.16	PSV is manually initiated from the OMS to a target meter that is not "energized" in CIS (service disconnected)	A) Verify that the OMS generates the appropriate outbound PSV request message and sends it to the ESB on the OMS_AMI_REPLY queue to be transformed and sent to the MDM B) Verify that the ESB reads the PSV request message from the OMS_AMI_REPLY queue, makes WebService call to the CIS to check for "MeterEnergized=N" status, creates the appropriate PSV reply message in the proper format for the OMS to process, and sends the created PSV reply message to the OMS_AMI_INPUT_PSV queue C) Verify that OMS reads the PSV reply message from the OMS_AMI_INPUT_PSV queue				

Integration Test Book – DERM Interfaces to HEMP (DERM Focus): XML Verification						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
INT.DERM-HEMP.D.1	DR Schedule – Load Control Switch message: Verify user can create and maintain all objects and attributes associated with a specific schedule that involves the load control switch operation.	User can create and schedule DR Load Control Switch event. The message will be sent to the HEMP devices. It will be verified that the devices operate properly. (Two venIDs)				
INT.DERM-HEMP.D.2	DR Schedule – Thermostat delta value: Verify user can create and maintain all objects and attributes associated with a specific schedule that involves the thermostat operation.	User can create and schedule DR Thermostat event. The message will be sent to the HEMP device, it will be verified that the devices operate properly. (Temperature changes by delta value - two venIDs)				
INT.DERM-HEMP.D.3	Load Control sent to invalid Network ID: Verify user can create and maintain all objects and attributes associated with a specific schedule that involves the load control switch operation.	User can create and schedule DR Load Control event. The message will be sent to the invalid HEMP device. It will be verified that HEMP responds with an error message.				
INT.DERM-HEMP.D.4	Load Control with customer OptOut option: Verify user can create and maintain all objects and attributes associated with a specific schedule that involves the load control switch with customer OptOut operation.	User can create and schedule DR Load Control event. The message will be sent to the HEMP devices. The second end user will OptOut from this operation. It will be verified that the device operates properly and the OptOut message is sent back to DERM. (Two venIDs)				
INT.DERM-HEMP.D.5	Thermostat delta value schedule with OptOut option: Verify user can create and maintain all objects and attributes associated with a specific schedule that involves the thermostat and OptOut operation.	User can create and schedule DR Thermostat event. The message will be sent to the HEMP devices. The second end user will OptOut from this operation. It will be verified that the device operates properly and the OptOut message is sent back to DERM (Two venIDs).				
INT.DERM-HEMP.D.6	SIMPLE schedule (LOW): Verify user can create and maintain all objects and attributes associated with a SIMPLE schedule.	User can create a SIMPLE schedule. The message will be sent to the HEMP device. It will be verified that the devices operate properly and the response message is sent back to DERM.				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
INT.DERM-HEMP.D.7	SIMPLE schedule (MEDIUM): Verify user can create and maintain all objects and attributes associated with a SIMPLE schedule.	User can create a SIMPLE schedule. The message will be sent to the HEMP device. It will be verified that the devices operate properly and the response message is sent back to DERM.				
INT.DERM-HEMP.D.8	SIMPLE schedule (HIGH): Verify user can create and maintain all objects and attributes associated with a SIMPLE schedule.	User can create a SIMPLE schedule. The message will be sent to the HEMP device. It will be verified that the devices operate properly and the response message is sent back to DERM.				
INT.DERM-HEMP.D.9	CYCLING-LCS schedule: Verify user can create and maintain all objects and attributes associated with a CYCLING-LCS schedule.	User can create a CYCLING schedule. The message will be sent to the HEMP device. It will be verified that the devices operate properly and the response message is sent back to DERM.				
INT.DERM-HEMP.D.10	DR Schedule - modified: Verify user can modify and maintain all objects and attributes associated with a CYCLING-LCS schedule.	User can modify a schedule (INT 1). The message will be sent to the HEMP device. It will be verified that the devices operate properly and the response message is sent back to DERM.				
INT.DERM-HEMP.D.11	DR Schedule - cancelled: Verify user can cancel a CYCLING-LCS schedule.	User can cancel a schedule (INT 10). The message will be sent to the HEMP device. It will be verified that the devices operate properly and the response message is sent back to DERM.				
INT.DERM-HEMP.D.12	DR Schedule - Load Control Switch message: Verify user can create and maintain all objects and attributes associated with a specific schedule that involves the load control switch operation.	User can create and schedule DR Load Control Switch event. The message will be sent to the HEMP devices. It will be verified that the devices operate properly (OptIn – OptOut - OptIn).				

Integration Test Book – MDM Interfaces to FlexSync: MDM General User Functionality Regression Testing						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
INT.FS-MDM.E1.USER.1	Confirm that KCP&L personnel may access the EIP user interface and browse through various screens. This is not intended to test any specific functionality of the EIP system.	KCP&L personnel are able to access the EIP user interface, successfully log in and browse through the system.				
INT.FS-MDM.E1.USER.2	Confirm that KCP&L personnel may access the EIP SFTP server using the Push Billing account and post/retrieve files.	KCP&L personnel are able to access the EIP SFTP server and then post and retrieve files successfully.				
INT.FS-MDM.E1.USER.3	Confirm that KCP&L personnel may access the EIP SFTP server using the Meter Reads account and post/retrieve files.	KCP&L personnel are able to access the EIP SFTP server and then post and retrieve files successfully.				
INT.FS-MDM.E1.USER.4	Confirm that KCP&L personnel may access the EIP server which runs EIP web services.	KCP&L personnel are able to access the EIP web server.				
INT.FS-MDM.E1.USER.5	Confirm that KCP&L is able to access the MDM FlexSync web service.	KCP&L MQ Broker interface is able to access the MDM FlexSync web service and get a response - either valid or error is acceptable as the purpose is to confirm that we have connectivity.				
INT.FS-MDM.E1.USER.6	Confirm that KCP&L is able to access the MDM FlexSync web service.	KCP&L MQ Broker interface is able to access the MDM FlexSync web service and get a response - either valid or error is acceptable as the purpose is to confirm that we have connectivity.				
INT.FS-MDM.E1.USER.7	Tester will log in to the EIP UI using the "systems administrator" account and visit each of the major screens and links. Errors or other non-functional links/pages will be logged for report back to Siemens.	Tester can log into the EIP UI and visit all of the pages noted below. The tester may click on additional links/buttons as desired to further review the UI.				
INT.FS-MDM.E1.USER.8	Ensure that the specified report is generated by the MDM system and if appropriate distributed by email to the KCP&L report distribution list.	The named report is generated by EIP and viewable in the EIP UI. The named report is automatically sent via email to the KCP&L report distribution list.				

Integration Test Book – MDM Interfaces to FlexSync: MDM System Interface Regression Testing						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
INT.FS-MDM.E1.IF.1	FlexSync Batch Jobs will populate FlexSync staging tables with a limited number of records per test case requirements. The FlexSync MQ Broker interface will select these records from the staging tables, create an XML message per the MDM Functional/Technical Specification and then send the XML message to the Siemens hosted eMeter EnergyIP MDM system web service using SOAP. The MDM web service will reply with a success or failure message as appropriate and this reply message will be logged.	(1) MDM FlexSync UCA Process and corresponding jobs will run to select Account/SDP changes from CISPROD for submission to the MDM. NOTE: The appropriate changes must have been made to accounts (i.e. rate changes, move-in/out, etc.) to trigger their appearance in the selection query (2) MQ Broker will successfully generate and send a SOAP message to MDM with valid data and receive a valid "success" response which is logged. The record will be updated correctly in MDM. (3) MQ Broker will successfully generate and send a SOAP message to MDM with invalid data and receive a valid "error" response which is logged. The record will not be updated in MDM				
INT.FS-MDM.E1.IF.2	On a daily basis, KCP&L will transfer an MDM specific formatted EMED file generated by L+G Command Center 5.1 via the MQ File Mover Interface to the Siemens hosted server via SFTP. The TEST EMED file contains daily register reads for 4 SmartGrid Lab meters. The PROD EMED file contains daily register reads for the previous day for all SmartGrid meters (~14,000).	Command Center will generate the file in the specified format. MQ File Mover will find the daily file in the specified location and successfully move it to Siemens via SFTP. EIP adapter will pick up the file and load it into the MDM system. Meter data values from the file will be viewable in the EIP UI.				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
INT.FS-MDM.E1.IF.3	On a daily basis, KCP&L will transfer an standard formatted Intervals file generated by I+G Command Center 5.1 via the MQ File Mover Interface to the Siemens hosted server via SFTP.	Command Center will generate the file in the specified format. MQ File Mover will find the daily file in the specified location and successfully move it to Siemens via SFTP. EIP adapter will pick up the file and load it into the MDM system. Meter data values from the file will be viewable in the EIP UI.				
Integration Test Book – MDM Interfaces to FlexSync: MDM Validation, Estimation, Editing (VEE) Functionality						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
INT.FS-MDM.E1.VEE.1	Test user can perform manual validation, estimation and editing in the MDM GUI in the Data Administration module and specifically the "Interval Editing" function.	Test user can view, validate, edit and create values using the EIP UI.				
INT.FS-MDM.E1.VEE.2	MDM will estimate any gaps in interval reads that it encounters. It will only estimate these values if it has both a read prior to and following the gap; open-ended gaps will not be estimated. 90 days of meter read history are desirable to produce a more accurate estimated value.	MDM will fill the gaps in the interval read values.				
INT.FS-MDM.E1.VEE.3	If the MDM receives actual values for a slot where it had previously Estimated a value, it will replace the estimated value with the actual value.	If a valid read is then received for a specific slot, the actual read will replace either an extrapolated or interpolated read.				
INT.FS-MDM.E1.VEE.4	If the MDM determines it is missing the most recent meter read value, it will extrapolate a value based on prior reads	MDM populates the most recent "empty" read slot with an extrapolated value that makes sense based on prior data.				
INT.FS-MDM.E1.VEE.5	If the MDM receives actual values for a slot where it had previously either Extrapolated or Interpolated a value, it will replace the estimated value with the actual value	If a valid read is then received for a specific slot, the actual read will replace either an extrapolated or interpolated read.				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
INT.FS-MDM.E1.VEE.6	If the MDM determines it is missing the most recent meter read value, it will extrapolate a value based on prior reads. This includes both daily register reads and 15 minute interval reads. If MDM then receives valid reads after the gap period, it will re-estimate the original missing reads using interpolation.	MDM will re-estimate previously extrapolated reads by interpolation.				
INT.FS-MDM.E1.VEE.7	If the MDM receives actual values for a slot where it had previously either Extrapolated or Interpolated a value, it will replace the estimated value with the actual value.	If a valid read is then received for a specific slot, the actual read will replace either an extrapolated or interpolated read.				
Integration Test Book – MDM Interfaces to FlexSync: MDM TOU Setup & Usage Framing						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
INT.FS-MDM.E1.TOU.1	Regular rate setup process will be followed in MDM	1TOUA and 1TOAA rates in MDM will be available for mapping SDP/account to the corresponding TOU calendar.				
INT.FS-MDM.E1.TOU.2	This scenario covers the TOU Calendar setup – Seasons, Day Type, Peak/Off-Peak Times – in each of the key systems.	For testing, the 2011 TOU Test calendar will be set up with November 2011 as a "Summer" month and December 2011 as a "Winter" month for 1TOUA and with November 2011 as a "Winter" month and December 2011 as a "Summer" month for 1TOAA. This may be modified depending on the actual date of the testing to ensure that both seasons are validated.				
INT.FS-MDM.E1.TOU.3	Customers who enroll in TOU will be framed per the TOU calendar beginning on their TOU effective date as communicated from CIS to MDM. Assumption is that 1TOUA and 1TOAA frame consistently, so the regression test only requires validation of the more common 1TOUA rate.	MDM will correctly frame usage for all customers enrolled in the 1TOUA rate.				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
INT.FS-MDM.E1.TOU.4	KCP&L will use MQ Broker to request and retrieve usage data from MDM on a daily basis for all TOU customers. This usage data will be written to a staging table for further processing outside this test case.	TOU Calculator staging table is populated with usage data for 1TOUA customers.				

Integration Test Book – MDM Interfaces via VPN: MDM General User Functionality Regression Testing						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
INT.MDM-VPN.E2.USER.1	Confirm that KCP&L personnel may access the EIP user interface and browse through various screens. This is not intended to test any specific functionality of the EIP system.	KCP&L personnel are able to access the EIP user interface, successfully log in and browse through the system.				
INT.MDM-VPN.E2.USER.2	Confirm that KCP&L personnel may access the EIP SFTP server using the Push Billing account and post/retrieve files.	KCP&L personnel are able to access the EIP SFTP server and then post and retrieve files successfully.				
INT.MDM-VPN.E2.USER.3	Confirm that KCP&L personnel may access the EIP SFTP server using the Meter Reads account and post/retrieve files.	KCP&L personnel are able to access the EIP SFTP server and then post and retrieve files successfully.				
INT.MDM-VPN.E2.USER.4	Confirm that KCP&L personnel may access the EIP server which runs EIP web services.	KCP&L personnel are able to access the EIP web server.				
INT.MDM-VPN.E2.USER.5	Confirm that KCP&L is able to access the MDM FlexSync web service.	KCP&L MQ Broker interface is able to access the MDM FlexSync web service and get a response - either valid or error is acceptable as the purpose is to confirm that we have connectivity.				
INT.MDM-VPN.E2.USER.6	Confirm that KCP&L is able to access the MDM FlexSync web service.	KCP&L MQ Broker interface is able to access the MDM FlexSync web service and get a response - either valid or error is acceptable as the purpose is to confirm that we have connectivity.				
INT.MDM-VPN.E2.USER.7	Tester will log in to the EIP UI using the "systems administrator" account and visit each of the major screens and links. Errors or other non-functional links/pages will be logged for report back to Siemens.	Tester can log into the EIP UI and visit all of the pages noted below. The tester may click on additional links/buttons as desired to further review the UI.				
INT.MDM-VPN.E2.USER.8	Ensure that the specified report is generated by the MDM system and if appropriate distributed by email to the KCP&L report distribution list.	The named report is generated by EIP and viewable in the EIP UI. The named report is automatically sent via email to the KCP&L report distribution list.				

Integration Test Book – MDM Interfaces via VPN: MDM System Interface Regression Testing						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
INT.MDM-VPN.E2.IF.1	Confirm that FlexSync process is able to access the new kcp1testelp1.mdmhosting.com domain within the VPN.	(1) FlexSync flows are able to access the new domain name.				
INT.MDM-VPN.E2.IF.2	Confirm that Pull Billing process is able to access the new kcp1testelp1.mdmhosting.com domain within the VPN.	(1) Pull Billing flows are able to access the new domain name.				
INT.MDM-VPN.E2.IF.3	On a daily basis, KCP&L will transfer an MDM specific formatted EMED file generated by L+G Command Center 5.1 via the MQ File Mover interface to the Siemens hosted server via SFTP. The TEST EMED file contains daily register reads for 4 SmartGrid Lab meters. The PROD EMED file contains daily register reads for the previous day for all SmartGrid meters (~14,000).	Command Center will generate the file in the specified format. MQ File Mover will find the daily file in the specified location and successfully move it to Siemens via SFTP. EIP adapter will pick up the file and load it into the MDM system. Meter data values from the file will be viewable in the EIP UI.				
INT.MDM-VPN.E2.IF.4	On a daily basis, KCP&L will transfer an standard formatted intervals file generated by L+G Command Center 5.1 via the MQ File Mover interface to the Siemens hosted server via SFTP.	Command Center will generate the file in the specified format. MQ File Mover will find the daily file in the specified location and successfully move it to Siemens via SFTP. EIP adapter will pick up the file and load it into the MDM system. Meter data values from the file will be viewable in the EIP UI.				
Integration Test Book – MDM Interfaces via VPN: MDM Validation, Estimation, Editing (VEE) Functionality						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
INT.MDM-VPN.E2.VEE.1	MDM will estimate any gaps in interval reads that it encounters. It will only estimate these values if it has both a read prior to and following the gap; open-ended gaps will not be estimated. 90 days of meter read history are desirable to produce a more accurate estimated value.	MDM will fill the gaps in the interval read values.				
INT.MDM-VPN.E2.VEE.2	If the MDM receives actual values for a slot where it had previously Estimated a value, it will replace the estimated value with the actual value.	If a valid read is then received for a specific slot, the actual read will replace either an extrapolated or interpolated read.				
INT.MDM-VPN.E2.VEE.3	If the MDM determines it is missing the most recent meter read value, it will extrapolate a value based on prior reads.	MDM populates the most recent "empty" read slot with an extrapolated value that makes sense based on prior data.				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
INT.MDM-VPN.E2.VEE.4	If the MDM receives actual values for a slot where it had previously either Extrapolated or Interpolated a value, it will replace the estimated value with the actual value.	If a valid read is then received for a specific slot, the actual read will replace either an extrapolated or interpolated read.				
INT.MDM-VPN.E2.VEE.5	If the MDM determines it is missing the most recent meter read value, it will extrapolate a value based on prior reads. This includes both daily register reads and 15 minute interval reads. If MDM then receives valid reads after the gap period, it will re-estimate the original missing reads using interpolation.	MDM will re-estimate previously extrapolated reads by interpolation.				
INT.MDM-VPN.E2.VEE.6	If the MDM receives actual values for a slot where it had previously either Extrapolated or Interpolated a value, it will replace the estimated value with the actual value.	If a valid read is then received for a specific slot, the actual read will replace either an extrapolated or interpolated read.				
Integration Test Book – MDM Interfaces via VPN: MDM TOU Functionality						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
INT.MDM-VPN.E2.TOU.1	Customers who enroll in TOU will be framed per the TOU calendar beginning on their TOU effective date as communicated from CIS to MDM. Assumption is that 1TOUA and 1TOAA frame consistently, so the regression test only requires validation of the more common 1TOUA rate.	MDM will correctly frame usage for all customers enrolled in the 1TOUA rate.				
INT.MDM-VPN.E2.TOU.2	KCP&L will use manually generate a billing request via the MDM GUI and verify that the file is exported for processing by KCP&L.	Billing request is successfully generated and "billing determinants" file is created for retrieval by KCP&L.				

Integration Test Book – AHE Interfaces to Meter: End Point Processing Checks						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
INT.AHE-MTR.E3.1	Validate AMI meter is switched off for Remote Disconnect Order – AHE Status	Cross-reference screenshots in supplemental documentation.				
INT.AHE-MTR.E3.2	Validate AMI meter is switched off for Remote Disconnect Order – Meter Status	Cross-reference screenshots in supplemental documentation.				
INT.AHE-MTR.E3.3	Validate that ODR is returned for Remote Disconnect Order – AHE Status	Cross-reference screenshots in supplemental documentation.				
INT.AHE-MTR.E3.4	Validate AMI meter is switched on for Remote Connect Order – AHE Status	Cross-reference screenshots in supplemental documentation.				
INT.AHE-MTR.E3.5	Validate AMI meter is switched on for Remote Connect Order – Meter Status	Cross-reference screenshots in supplemental documentation.				
INT.AHE-MTR.E3.6	Validate that ODR is returned for Remote Connect Order – AHE Status	Cross-reference screenshots in supplemental documentation.				

Integration Test Book – AHE Interfaces to MDM: MDM- AHE For EndDeviceControls Request						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
INT.AHE-MDM.E4.GROUP1.1	Validate to get the synchronous Request (CreateEndDeviceControls) from MDM Via Soap.	N/A				
INT.AHE-MDM.E4.GROUP1.2	Check whether we receive both incoming synchronous messages in IEC-61968 format.	N/A				
INT.AHE-MDM.E4.GROUP1.3	Verify the Audit logs whether we are logging the incoming message properly or not	N/A				
INT.AHE-MDM.E4.GROUP1.4	Route the message to ESB based on the incoming messageType. A) KCPLHeader.MessageType = "createEndDeviceControls" Then send the message to ESB_ROUTE_ENDDEVICECONTROLS queue. B) KCPLHeader.MessageType = "getMeterReadings" Then send the message to ESB_ROUTE_METERREADINGS queue.	N/A				
INT.AHE-MDM.E4.GROUP1.5	Check whether we added Kcpl Header before sending to ESB.	N/A				
INT.AHE-MDM.E4.GROUP1.6	Verify the audit table whether we are logging every thing to log table for every adapter.	N/A				
INT.AHE-MDM.E4.GROUP1.7	Validate the incoming Message from the ESB queue have the kcpl header and that includes request message or not.	N/A				
INT.AHE-MDM.E4.GROUP1.8	Verify whether the environment variables set properly in order to determine whether the incoming message is request or reply message.	N/A				
INT.AHE-MDM.E4.GROUP1.9	Route the Request message (If createEndDeviceControls) To AHE inbound queue (AHE_ADAPTER_CREATEENDDEVICECONTROLS_INBOUND) by deleting the Kcpl Header.	N/A				
INT.AHE-MDM.E4.GROUP1.10	Verify whether we send the proper request message to the AHE Inbound queue or not.	N/A				
INT.AHE-MDM.E4.GROUP1.11	Check whether we are making proper web service call (AHE)	N/A				
INT.AHE-MDM.E4.GROUP1.12	Make sure to add Kcpl Header to the response before sending to ESB (ESB_ROUTE_ENDDEVICECONTROLS) queue.	N/A				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
INT.AHE-MDM.E4.GROUP1.13	Check whether we receive the proper response with Kcpl Header	N/A				
INT.AHE-MDM.E4.GROUP1.14	Route the Response message (If replyEndDeviceControls) MDM_ADAPTER_REPLYENDDEVICECONTROLS_INBOUND queue.	N/A				
INT.AHE-MDM.E4.GROUP1.15	Verify to send the Asynchronous response (EndDeviceEvents) back to MDM.	N/A				
INT.AHE-MDM.E4.GROUP1.17	Test whether we added the reply Identifier before sending reply.	N/A				
Integration Test Book – AHE Interfaces to MDM: MDM- AHE For GetMeterReadings Request						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
INT.AHE-MDM.E4.GROUP2.1	Validate to get the synchronous Request (getMeterReadings) from MDM Via Soap.	N/A				
INT.AHE-MDM.E4.GROUP2.2	Check whether we receive both incoming synchronous messages in IEC-61968 format.	N/A				
INT.AHE-MDM.E4.GROUP2.3	Verify the Audit logs whether we are logging the incoming message properly or not	N/A				
INT.AHE-MDM.E4.GROUP2.4	Route the message to ESB based on the incoming messageType. A) KcplHeader.MessageType = "getMeterReadings" Then send the message to ESB_ROUTE_METERREADINGS queue.	N/A				
INT.AHE-MDM.E4.GROUP2.5	Check whether we added Kcpl Header before sending to ESB.	N/A				
INT.AHE-MDM.E4.GROUP2.6	Verify the audit table whether we are logging every thing to log table for every adapter..	N/A				
INT.AHE-MDM.E4.GROUP2.7	Validate the incoming Message from the ESB queue have the kcpl header and that includes request message or not.	N/A				
INT.AHE-MDM.E4.GROUP2.8	Verify whether the environment variables set properly in order to determine whether the incoming message is request or reply message..	N/A				
INT.AHE-MDM.E4.GROUP2.9	Route the Request message (If createEndDeviceControls) To AHE inbound queue (AHE_ADAPTER_GETMETERREADINGS_INBOUND) by deleting the Kcpl Header	N/A				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
INT.AHE-MDM.E4.GROUP2.10	Verify whether we send the proper request message to the AHE Inbound queue or not.	N/A				
INT.AHE-MDM.E4.GROUP2.11	Check whether we are making proper web service call (AHE)	N/A				
INT.AHE-MDM.E4.GROUP2.12	Make sure to add Kcpl Header to the response before sending to ESB (ESB_ROUTE_METERREADINGS) queue.	N/A				
INT.AHE-MDM.E4.GROUP2.13	Check whether we receive the proper response with Kcpl Header	N/A				
INT.AHE-MDM.E4.GROUP2.14	Route the Response message (If replyMeterReadings) MDM_ADAPTER_REPLYMETERREADINGS_INBOUND queue	N/A				
INT.AHE-MDM.E4.GROUP2.15	Verify to send the Asynchronous response (MeterReadings) back to MDM.	N/A				
INT.AHE-MDM.E4.GROUP2.16	Verify AHE generates the Asynchronous response for the given MeterReadings Request.	N/A				
INT.AHE-MDM.E4.GROUP2.17	Check for the audit logs whether we log everything to the table.	N/A				
INT.AHE-MDM.E4.GROUP2.18	Test whether we are logging proper payload message and related response to the ESB Log table (KCPL_ESB_AUDIT).	N/A				

Integration Test Book – ESB Interfaces to Misc Systems: Simulated Outage/Restoration Event						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
INT.ESB-MISC.B1.OUT.1	Confirm that the specified event scenario is transmitted from the AMI/AHE infrastructure through the KCP&L ESB to the MDM (via the eMeter EIP L+G 5.1 Adapter) and then from the MDM via ESB to the OMS system.	Specified event is visible in the ESB Logs and MDM.				
INT.ESB-MISC.B1.OUT.2	Confirm that the specified event scenario is transmitted from the AMI/AHE infrastructure through the KCP&L ESB to the MDM (via the eMeter EIP L+G 5.1 Adapter) and then from the MDM via ESB to the OMS system.	Specified event is visible in the ESB Logs and MDM.				
INT.ESB-MISC.B1.RES.1	Confirm that the specified event scenario is transmitted from the AMI/AHE infrastructure through the KCP&L ESB to the MDM (via the eMeter EIP L+G 5.1 Adapter) and then from the MDM via ESB to the OMS system.	Specified event is visible in the ESB Logs and MDM.				
INT.ESB-MISC.B1.RES.2	Confirm that the specified event scenario is transmitted from the AMI/AHE infrastructure through the KCP&L ESB to the MDM (via the eMeter EIP L+G 5.1 Adapter) and then from the MDM via ESB to the OMS system.	Specified event is visible in the ESB Logs and MDM.				
Integration Test Book – ESB Interfaces to Misc Systems: Meter Lab Outage/Restoration Event (w/o OMS)						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
INT.ESB-MISC.B1.OUT.3	Confirm that the specified event scenario is transmitted from the AMI/AHE infrastructure through the KCP&L ESB to the MDM (via the eMeter EIP L+G 5.1 Adapter) and then from the MDM via ESB to the OMS system.	Specified event is visible in the AHE and MDM.				
INT.ESB-MISC.B1.RES.3	Confirm that the specified event scenario is transmitted from the AMI/AHE infrastructure through the KCP&L ESB to the MDM (via the eMeter EIP L+G 5.1 Adapter) and then from the MDM via ESB to the OMS system.	Specified event is visible in the AHE and MDM.				

Integration Test Book – ESB Interfaces to Misc Systems: Meter Lab Outage/Restoration Event (w/OMS)						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
INT.ESB-MISC.B1.OUT.4	Confirm that the specified event scenario is transmitted from the AMI/AHE infrastructure through the KCP&L ESB to the MDM (via the eMeter EIP L+G 5.1 Adapter) and then from the MDM via ESB to the OMS system.	Specified event is visible in the AHE, MDM and OMS.				
INT.ESB-MISC.B1.RES.4	Confirm that the specified event scenario is transmitted from the AMI/AHE infrastructure through the KCP&L ESB to the MDM (via the eMeter EIP L+G 5.1 Adapter) and then from the MDM via ESB to the OMS system.	Specified event is visible in the AHE, MDM and OMS.				

Integration Test Book – ESB Interfaces to Misc Systems: Outage Derivation in MDM via FlexSync						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
INT, ESB-MISC.B2, FS.1	Generate a single FlexSync Message from CIS test environment via ESB to the MDM with the modified SDP-Meter Association date and verify the results.	(1) Confirm that FlexSync message is sent to MDM with modified SDP-Meter Association date (2) Verify that MDM processes the message (3) Verify that MDM derives the Outage Service for the SDP				
INT, ESB-MISC.B2, FS.2	Generate a multiple FlexSync Message from CIS test environment via ESB to the MDM with the modified SDP-Meter Association date and verify the results.	(1) Confirm that FlexSync message is sent to MDM with modified SDP-Meter Association date (2) Verify that MDM processes the message (3) Verify that MDM derives the Outage Service for the SDP				
INT, ESB-MISC.B2, FS.3	Generate a single FlexSync Message from CIS test environment via ESB to the MDM with the modified SDP-Meter Association date and verify the results.	(1) Confirm that FlexSync message is sent to MDM with modified SDP-Meter Association date (2) Verify that MDM processes the message (3) Verify that MDM derives the Outage Service for the SDP				

Integration Test Book – ESB Interfaces to Misc Systems: Power Status Verification - Unit Testing						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
INT.ESB-MISC.C.3	Validate setup and configuration of the OMS, ESB, MDM, and AHE to support Power Status Verification	A) Verify that the OMS is configured to write PSV request messages to the OMS_AMI_REPLY queue and read PSV reply messages from the OMS_AMI_INPUT_PSV queue B) Verify that the ESB is configured to read PSV request messages from the OMS_AMI_REPLY queue, send PSV request messages to the MDM, and write PSV reply messages to the OMS_AMI_INPUT_PSV queue C) Verify that the MDM is configured to send PSV request and reply messages to the ESB D) Verify that the AHE is configured to send PSV reply messages to the ESB				
INT.ESB-MISC.C.4	Confirm that the OMS is generating the appropriate outbound PSV request message to the MDM via the ESB	A) Verify that the OMS generates the appropriate outbound PSV request message and sends it to the ESB on the OMS_AMI_REPLY queue to be transformed and sent to the MDM				
INT.ESB-MISC.C.5	Confirm that the ESB is properly transforming PSV request message from the OMS to the MDM	A) Verify that the ESB reads the PSV request message from the OMS_AMI_REPLY queue B) Verify that the ESB makes WebService call to the CIS to check for "MeterEnergized" status C) Verify that the ESB transforms the PSV request message to the proper format for the MDM to process D) Verify that the ESB sends the transformed PSV request message to the MDM				
INT.ESB-MISC.C.6	Confirm that the MDM is generating the appropriate outbound PSV request message to the AHE via the ESB	A) Verify that the MDM receives the PSV request message from the ESB B) Verify that the MDM generates the appropriate outbound PSV request message (endpoint on-demand read request) and sends it to the AHE via the ESB				
INT.ESB-MISC.C.7	Confirm that the AHE receives the PSV request message from the MDM via the ESB	A) Verify that the AHE receives the PSV request message (endpoint on-demand read request) from the MDM via the ESB and sends the PSV request message to the target AMI meter				
INT.ESB-MISC.C.8	Confirm that the AHE is processing the PSV request message and generating the appropriate outbound PSV reply message to the MDM via	A) Verify that the AHE receives PSV reply message from the target AMI meter and generates the appropriate outbound PSV reply message (endpoint on-demand read reply) and sends it to the MDM via the ESB				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
INT.ESB-MISC.C.9	Confirm that the MDM is generating the appropriate outbound PSV reply message to the OMS via the ESB	A) MDM generates a "meter on" PSV reply message and sends it to the ESB				
INT.ESB-MISC.C.10	Confirm that the ESB is properly transforming the PSV reply message from the MDM to the OMS	A) Verify that the ESB receives the PSV reply message from the MDM B) Verify that the ESB transforms the PSV reply message to the proper format for the OMS to process C) Verify that ESB sends the transformed PSV reply message to the OMS_AMI_INPUT_PSV queue				
INT.ESB-MISC.C.11	Confirm that the OMS is processing the PSV reply message	A) Verify that OMS reads the PSV reply message from the OMS_AMI_INPUT_PSV queue				
INT.ESB-MISC.C.12	Test Plan review	Review test plan PRIOR TO testing. Consult your PA to determine attendees. Review unit test results if necessary.				
INT.ESB-MISC.C.13	Code review – Include diffs	Repeat code review if changes were made during unit testing.				
Integration Test Book – ESB Interfaces to Misc Systems: Power Status Verification – System/Scenario Testing						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
INT.ESB-MISC.C.14	PSV is manually initiated from the OMS to a target meter that is	N/A				
INT.ESB-MISC.C.15	PSV is manually initiated from the OMS to a target meter that is	N/A				
INT.ESB-MISC.C.16	PSV is manually initiated from the OMS to a target meter that is not "energized" in CIS (service disconnected)	A) Verify that the OMS generates the appropriate outbound PSV request message and sends it to the ESB on the OMS_AMI_REPLY queue to be transformed and sent to the MDM B) Verify that the ESB reads the PSV request message from the OMS_AMI_REPLY queue, makes WebService call to the CIS to check for "MeterEnergized=N" status, creates the appropriate PSV reply message in the proper format for the OMS to process, and sends the created PSV reply message to the OMS_AMI_INPUT_PSV queue C) Verify that OMS reads the PSV reply message from the OMS_AMI_INPUT_PSV queue				

Integration Test Book – MDM Interfaces to CIS: Request 55443R MDM Aggregation						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
INT.MDM-CIS.F1.4	SGD301 – Get parameters for service points, meters.	Verify SQL per supplemental documentation.				
INT.MDM-CIS.F1.5	sg_sp_param_assoc_master_t BEFORE master table was updated. Shows old values from CIS.	Verify SQL per supplemental documentation.				
INT.MDM-CIS.F1.6	sg_sp_param_assoc_today_t Shows new values from GIS. Circuit ID is no longer all 9s.	Verify SQL per supplemental documentation.				
INT.MDM-CIS.F1.7	sg_sp_list_prev_t	Verify SQL per supplemental documentation.				
INT.MDM-CIS.F1.8	sg_sp_list_today_t	Verify SQL per supplemental documentation.				
INT.MDM-CIS.F1.9	sg_sp_compare_list_t	Verify SQL per supplemental documentation.				
INT.MDM-CIS.F1.10	mdm_sdp_t NOTE: MRID = SP ID The ID fields are all defined as 50 characters (even though we don't use that many) because that is the field size used by the vendor. The extra size causes blank space to appear when selecting the columns for display.	Verify SQL per supplemental documentation.				

Integration Test Book – MDM Interfaces to CIS: Remote Service Order						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
INT.MDM-CIS.F2.4	Validate adding a new meter model without a Remote Disconnect Switch (RDS) flag produces an error message "Remote Disconnect Switch Flag must be Y or N"	N/A				
INT.MDM-CIS.F2.5	Validate adding a new meter model with an RDS flag not equal to "N" or "Y" produces error message "Remote Disconnect Switch Flag must be Y or N"	N/A				
INT.MDM-CIS.F2.6	Validate able to successfully add a new meter model with RDS flag equal to "N"	N/A				
INT.MDM-CIS.F2.7	Validate audit trail entry (CTCMODE) shows added entry with RDS = "N"	N/A				
INT.MDM-CIS.F2.8	Validate audit trail by time (CTCMODT) shows added entry with RDS = "N"	N/A				
INT.MDM-CIS.F2.9	Validate able to successfully add a new meter model with RDS flag equal to "Y"	N/A				
INT.MDM-CIS.F2.10	Validate audit trail entry (CTCMODE) shows added entry with RDS = "Y"	N/A				
INT.MDM-CIS.F2.11	Validate audit trail by time (CTCMODT) shows added entry with RDS = "Y"	N/A				
INT.MDM-CIS.F2.12	Change existing model's RDS flag from "N" to " " and validate error message received stating "Remote Disconnect Switch Flag must be Y or N"	N/A				
INT.MDM-CIS.F2.13	Change an existing model's RDS flag from "N" to a non-"Y" value and validate error message received stating "Remote Disconnect Switch Flag must be Y or N"	N/A				
INT.MDM-CIS.F2.14	Validate able to successfully change existing model's RDS flag from "N" to "Y"	N/A				
INT.MDM-CIS.F2.15	Validate audit trail entry (CTCMODE) shows changed entry with RDS = "Y"	N/A				
INT.MDM-CIS.F2.16	Validate audit trail by time (CTCMODT) shows changed entry with RDS = "Y"	N/A				
INT.MDM-CIS.F2.17	Change existing model's RDS flag from "Y" to " " and validate error message received stating RDS value is required	N/A				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
INT.MDM-CIS.F2.18	Change an existing model's RDS flag from "Y" to a non-"N" value and validate error message received stating invalid RDS value	N/A				
INT.MDM-CIS.F2.19	Validate able to successfully change existing model's RDS flag from "Y" to "N"	N/A				
INT.MDM-CIS.F2.20	Validate audit trail entry (CTCMODE) shows changed entry with RDS = "N"	N/A				
INT.MDM-CIS.F2.21	Validate audit trail by time (CTCMODT) shows changed entry with RDS = "N"	N/A				
INT.MDM-CIS.F2.22	Validate model listing includes RDS column with valid values	N/A				
INT.MDM-CIS.F2.23	Validate the Service Order Auto Completion skips RSO orders	N/A				
INT.MDM-CIS.F2.24	Validate MOBILE Extract does not select RSO eligible orders	N/A				
INT.MDM-CIS.F2.25	Confirm that CIS+ does not send multiple/duplicate RSO requests	N/A				
INT.MDM-CIS.F2.26	Validate that the RSO Service Order Auto Completion only includes connects and disconnects scheduled to be processed on that day (Request)	N/A				
INT.MDM-CIS.F2.27	Validate that CIS+ can process and post the final meter reading as appropriate Completed order	N/A				

Integration Test Book – MDM Interfaces to CIS: Remote Service Order End to End (Turn On Read Orders)						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
INT.MDM-CIS.F3.3	Turn On-Read: Meter @ SP Status = OffS	Received error message "Invalid Turn On SubType"				
INT.MDM-CIS.F3.4	Turn On-Read: RSO Ineligible – CellNet Meter – Succession Orders (ON-R #1)	Neither Account (ID)/Order Control ID are selected for new RSO batch (Query below shows accounts that are selected for RSO batch and are listed in numerical order)				
INT.MDM-CIS.F3.5	Turn On-Read: RSO Ineligible – CellNet Meter (ON-R #1)	Account (ID)/Order Control ID are not selected for new RSO batch (Query below shows accounts that are selected for RSO batch and are listed in numerical order)				
INT.MDM-CIS.F3.6	Turn On-Read: RSO Eligible Meter – Succession Orders (ON-R #1)	- Showing meter XXXXXXXXXX has a disconnect switch (indicated by the "G") - Remaining 7/31 pending orders for meters with a disconnect switch after SOAUTC and Mobile Extract - ACCOUNT_ID SO_ID PREMISE_ID SO_T - XXXXXXX (Removed in TPR due to confidentiality) - ON-R account XXXXXXXXX is selected for new RSO batch and OFF-I account XXXXXXXXX is not (Query below shows accounts that are selected for RSO batch and are listed in numerical order)				
INT.MDM-CIS.F3.7	Turn On-Read: RSO Eligible Meter – Succession Orders & LL Revert (ON-R #1)	N/A				
INT.MDM-CIS.F3.8	Turn On-Read: RSO Eligible Meter – TOU Rates (ON-R #1)	- Time of Use Rate (TOUA) on a meter with remote disconnect switch - Neither Account (ID)/Order Control ID are selected for new RSO batch (Query below shows accounts that are selected for RSO batch and are listed in numerical order)				
INT.MDM-CIS.F3.9	Turn On-Read: RSO Ineligible – Field Order – Succession Orders (ON-R#2)	- District Area 7 – No Mobile, only paper orders; Pending ON-R order - Neither Account (ID)/Order Control ID are selected for new RSO batch (Query below shows accounts that are selected for RSO batch and are listed in numerical order)				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
INT.MDM-CIS.F3.10	Turn On-Read: RSO Eligible Meter – SP Status is “OffP” (ON-R #2)	- Meter @ SP Status has been changed to “OffP” - Account (ID)/Order Control ID are not selected for new RSO batch (Query below shows accounts that are selected for RSO batch and are listed in numerical order)				
INT.MDM-CIS.F3.11	Turn On-Read: RSO & Switch Eligible (ON-R#3)	- Meter @ SP Status is “Conn On” at time ON-R order is entered - Meter @ SP Status has changed to “Conn OffS” before order date. No pending Off order. Off Read manually completed with a 7/30 date - Account (ID)/Order Control ID are selected for new RSO batch (Query below shows accounts that are selected for RSO batch and are listed in numerical order)				
INT.MDM-CIS.F3.12	Turn On-Read: RSO Eligible but Not Switch Eligible (ON-R#24)	- Pending ON-R and completed OFF-I (dated 8/2 originally but changed to end date of 7/25 in green screens) - Meter @ SP Status is “Conn On” but not linked to a customer - Account (ID)/Order Control ID are selected for new RSO batch (Query below shows accounts that are selected for RSO batch and are listed in numerical order)				
INT.MDM-CIS.F3.13	Turn On-Read: RSO & Switch Eligible	- No pending same day off order - Account (ID)/Order Control ID are selected for new RSO batch (Query below shows accounts that are selected for RSO				
INT.MDM-CIS.F3.14	Turn On-Read: RSO Eligible but Not Switch Eligible – Reads don’t exist (ON-R#26)	N/A				
INT.MDM-CIS.F3.15	Turn On-Read: RSO & Switch Eligible – Switch Unknown (ON-	N/A				
INT.MDM-CIS.F3.16	Turn On-Read: RSO & Switch Eligible – Switch Fails (ON-R #16)	N/A				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
INT.MDM-CIS.F3.17	Turn On-Read: RSO & Switch Eligible – Change Date	Remaining RSO order (After SOAUTC ran) SO_T ACCOUNT_ID METER_ID STD_FORM_ADDR ON R XXXXXXXX (Removed in TPR to to confidentiality) Mobile Extract Skipped Orders KMDFSRB_push_rep08:XXXXXXXXXXXX Skipping RSO eligible OC (XXXXXXXXXX) Type (ON R)				
INT.MDM-CIS.F3.18	Cancel Turn On-Read: RSO Eligible Meter	Account (ID)/Order Control ID are not selected for new RSO batch (Query below shows accounts that are selected for RSO batch and are listed in numerical order)				
Integration Test Book – MDM Interfaces to CIS: Remote Service Order End to End (Turn Off Read Orders)						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
INT.MDM-CIS.F3.19	Turn Off-Read: RSO Ineligible – CellNet Meter (OFF-R #1)	Account (ID)/Order Control ID are not selected for new RSO batch (Query below shows accounts that are selected for RSO batch and are listed in numerical order)				
INT.MDM-CIS.F3.20	Turn Off-Read: RSO Ineligible – CellNet Meter – LL Revert (OFF-R #1)	Neither Account (ID)/Order Control ID are selected for new RSO batch (Query below shows accounts that are selected for RSO batch and are listed in numerical order)				
INT.MDM-CIS.F3.21	Turn Off-Read: RSO Ineligible – Mobile – LL Revert (OFF-R #2)	- South District works off paper orders which are printed in the office - Account (ID)/Order Control ID are not selected for new RSO batch (Query below shows accounts that are selected for RSO batch and are listed in numerical order)				
INT.MDM-CIS.F3.22	Turn Off-Read: RSO Ineligible – Mobile (OFF-R #2)	- East District works off paper orders which are printed in the office - Account (ID)/Order Control ID are not selected for new RSO batch (Query below shows accounts that are selected for RSO batch and are listed in numerical order)				
INT.MDM-CIS.F3.23	Turn Off-Read: RSO & Switch Eligible (OFF-R #3)	- No LL revert, life support or sensitive load. No pending same day On order - Account (ID)/Order Control ID are selected for new RSO				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
INT.MDM-CIS.F3.24	Turn Off-Read: RSO & Switch Eligible – Pending ON-R in the future (OFF-R #3)	- Pending ON-R and OFF-J for 8/2/12. Changed OFF-J to OFF-R and 7/31/12 - No LL revert, life support or sensitive load. - Account (ID)/Order Control ID are selected for new RSO batch (Query below shows accounts that are selected for RSO batch and are listed in numerical order)				
INT.MDM-CIS.F3.25	Turn Off-Read: RSO but Not Switch Eligible – LL Revert (OFF-R #23)	Account (ID)/Order Control ID are selected for new RSO batch (Query below shows accounts that are selected for RSO batch and are listed in numerical order)				
INT.MDM-CIS.F3.26	Turn Off-Read: RSO Eligible but Not Switch Eligible – Premise has Life Support (OFF-R #23)	Account (ID)/Order Control ID are selected for new RSO batch (Query below shows accounts that are selected for RSO batch and are listed in numerical order)				
INT.MDM-CIS.F3.27	Turn Off-Read: RSO Eligible but Not Switch Eligible – Person has Life Support (OFF-R #23)	Account (ID)/Order Control ID are selected for new RSO batch (Query below shows accounts that are selected for RSO batch and are listed in numerical order)				
INT.MDM-CIS.F3.28	Turn Off-Read: RSO Eligible but Not Switch Eligible – Premise has Sensitive Load (OFF-R #23)	Account (ID)/Order Control ID are selected for new RSO batch (Query below shows accounts that are selected for RSO batch and are listed in numerical order)				
INT.MDM-CIS.F3.29	Turn Off-Read: RSO Eligible but Not Switch Eligible – Person has Sensitive Load (OFF-R #23)	- Mobile Data Extract Skipped Orders: KMDFSRB_push_rep08: XXXXXXXXXX Skipping RSO eligible OC (XXXXXXXXXX) Type (OFFR) - Account (ID)/Order Control ID are selected for new RSO batch (Query below shows accounts that are selected for RSO batch and are listed in numerical order)				
INT.MDM-CIS.F3.30	Turn Off-Read: RSO & Switch Eligible – Switch Unknown – Resubmit Switch Successful (OFF-R #23)	N/A				
INT.MDM-CIS.F3.31	Turn Off-Read: RSO & Switch Eligible – Switch Unknown – Resubmit On-Demand Read	N/A				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
INT.MDM-CIS.F3.32	Turn Off-Read: RSO & Switch Eligible – Switch Fails – Resubmit On-Demand Read	N/A				
INT.MDM-CIS.F3.33	Turn Off-Read: RSO & Switch Eligible – Change Date #1	- Original order date is 8/15/12. Order changed to 7/31/12 - No LL revert, life support or sensitive load. - Account (ID)/Order Control ID are selected for new RSO batch on 7/31/12 (Query below shows accounts that are				
INT.MDM-CIS.F3.34	Turn Off-Read: RSO & Switch Eligible – Change Date #2	- Original order date is 7/31/12. Change order date to 8/1/12 - No LL revert, life support or sensitive load. No same day pending On order - Mobile Data Extract Skipped Orders: KMDFSRB_push_rep08: XXXXXXXXXX Skipping RSO eligible OC (XXXXXXXXXX) Type (OFFR) - Account (ID)/Order Control ID are selected for new RSO batch (Query below shows accounts that are selected for RSO batch and are listed in numerical order)				
INT.MDM-CIS.F3.35	Cancel Turn Off-Read: RSO Eligible Meter	- Order voided 1 day prior to the order date - Account (ID)/Order Control ID are not selected for new RSO batch (Query below shows accounts that are selected for RSO				
Integration Test Book – MDM Interfaces to CIS: Remote Service Order End to End (Turn On At Meter Orders)						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
INT.MDM-CIS.F3.36	Turn On-At Meter: RSO Ineligible – CellNet Meter (ON-A #1)	Account (ID)/Order Control ID are not selected for new RSO batch (Query below shows accounts that are selected for RSO batch and are listed in numerical order)				
INT.MDM-CIS.F3.37	Turn On-At Meter: RSO Ineligible – Itron Meter (ON-A #1)	Account (ID)/Order Control ID are not selected for new RSO batch (Query below shows accounts that are selected for RSO batch and are listed in numerical order)				
INT.MDM-CIS.F3.38	Turn On-At Meter: RSO Eligible Meter – SP Status is not “OffS” (ON-A #1)	Account (ID)/Order Control ID are not selected for new RSO batch (Query below shows accounts that are selected for RSO batch and are listed in numerical order)				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
INT.MDM-CIS.F3.39	Turn On-At Meter: RSO Eligible Meter – Previously CNP'd (ON-A #1)	Account (ID)/Order Control ID are not selected for new RSO batch (Query below shows accounts that are selected for RSO batch and are listed in numerical order)				
INT.MDM-CIS.F3.40	Turn On-At Meter: RSO & Switch Eligible (ON-A #2)	- No pending same day Off order - Mobile Data Extract Skipped Order: KMDFSRB_push_rep08: XXXXXXXX Skipping RSO eligible OC (XXXXXXXX) Type (ON				
INT.MDM-CIS.F3.41	Turn On-At Meter: RSO Eligible Meter – Sensitive Load (ON-A #2)	- Premise is designated as Sensitive Load. This should not affect RSO eligibility. - No pending same day Off order - Account (ID)/Order Control ID are selected for new RSO batch (Query below shows accounts that are selected for RSO batch and are listed in numerical order)				
INT.MDM-CIS.F3.42	Turn On-At Meter: RSO Eligible but Not Switch Eligible (ON-A	- No pending same day Off order - Need to change to "Conn On" after Mobile Extract				
INT.MDM-CIS.F3.43	Turn On-At Meter: RSO & Switch Eligible – Switch Fails (ON-A #16)	N/A				
INT.MDM-CIS.F3.44	Turn On-At Meter: RSO & Switch Eligible – Change Date #1	- Original order date is 8/10/12. Order date changed to 7/31/12 - No pending same day Off order - Account (ID)/Order Control ID are selected for new RSO batch (Query below shows accounts that are selected for RSO batch and are listed in numerical order)				
INT.MDM-CIS.F3.45	Turn On-At Meter: RSO & Switch Eligible – Change Date #2	- Original order date 7/31/12, Change to 8/2/12 - Account (ID)/Order Control ID are not selected for new RSO batch on 7/31/12 (Query below shows accounts that are selected for RSO batch and are listed in numerical order)				
INT.MDM-CIS.F3.46	Cancel Turn On-At Meter: RSO	N/A				
Integration Test Book -- MDM Interfaces to CIS: Remote Service Order End to End (Turn Off at Meter Orders)						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
INT.MDM-CIS.F3.47	Turn Off-Off at Meter: RSO Ineligible – CellNet Meter (OFF-O #1)	Account (ID)/Order Control ID are not selected for new RSO batch (Query below shows accounts that are selected for RSO batch and are listed in numerical order)				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
INT.MDM-CIS.F3.48	Turn Off-Off at Meter: RSO Ineligible – CellNet Meter – LL Revert (OFF-O #1)	- Landlord revert information for premise - Account (ID)/Order Control ID are not selected for new RSO batch (Query below shows accounts that are selected for RSO batch and are listed in numerical order)				
INT.MDM-CIS.F3.49	Turn Off-Off at Meter: RSO Ineligible – Mobile (OFF-O #1)	- Reference Test #10 for XXXXXXXX, KS after this test is complete - District Area 7 – No Mobile, only paper orders - Account (ID)/Order Control ID are not selected for new RSO batch (Query below shows accounts that are selected for RSO batch and are listed in numerical order)				
INT.MDM-CIS.F3.50	Turn Off-Off at Meter: RSO & Switch Eligible (OFF-O #2)	- No pending same day On order - Account (ID)/Order Control ID are selected for new RSO batch (Query below shows accounts that are selected for RSO				
INT.MDM-CIS.F3.51	Turn Off-Off at Meter: RSO & Switch Eligible – LL Revert #1 (OFF-O #2)	- Premise has a landlord revert - No same day On order - Account (ID)/Order Control ID are selected for new RSO batch (Query below shows accounts that are selected for RSO batch and are listed in numerical order)				
INT.MDM-CIS.F3.52	Turn Off-Off at Meter: RSO & Switch Eligible – LL Revert #2 (OFF-O #2)	- Landlord revert information (below) is the same acct that the electric service is currently linked to (above) - No pending same day On order - Account (ID)/Order Control ID are selected for new RSO batch (Query below shows accounts that are selected for RSO batch and are listed in numerical order)				
INT.MDM-CIS.F3.53	Turn Off-Off at Meter: RSO & Switch Eligible – Premise has Life Support (OFF-O #2)	- Premise has life support - No pending same day On order - Account (ID)/Order Control ID are selected for new RSO batch (Query below shows accounts that are selected for RSO batch and are listed in numerical order)				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
INT.MDM-CIS.F3.54	Turn Off-Off at Meter: RSO & Switch Eligible – Premise has Sensitive Load (OFF-O #2)	- Premise has sensitive load - No pending same day On order - Account (ID)/Order Control ID are selected for new RSO batch (Query below shows accounts that are selected for RSO batch and are listed in numerical order)				
INT.MDM-CIS.F3.55	Turn Off-Off at Meter: RSO & Switch Eligible – Person has Life Support (OFF-O #2)	- Person has life support - No pending same day On order - Account (ID)/Order Control ID are selected for new RSO batch (Query below shows accounts that are selected for RSO batch and are listed in numerical order)				
INT.MDM-CIS.F3.56	Turn Off-Off at Meter: RSO & Switch Eligible – Person has Sensitive Load (OFF-O #2)	- Person is marked as sensitive load - No pending same day On order - Account (ID)/Order Control ID are selected for new RSO batch (Query below shows accounts that are selected for RSO batch and are listed in numerical order)				
INT.MDM-CIS.F3.57	Turn Off-Off at Meter: RSO & Switch Eligible – CIS+ Fails (OFF-	No pending same day On order				
INT.MDM-CIS.F3.58	Turn Off-Off at Meter: RSO Eligible but Not Switch Eligible (OFF-O #22)	Mobile Data Extract Skipped Orders KMDFSRB_push_rep08: XXXXXXXXX Skipping RSO eligible OC (XXXXXXXXX) Type (OFFO) KMDFSRB_push_rep08: XXXXXXXXX Skipping RSO eligible OC (XXXXXXXXX) Type (ON R)				
INT.MDM-CIS.F3.59	Turn Off-Off at Meter: RSO & Switch Eligible – Change Date	- Order originally dated for 8/17/12 - No pending same day On order - Mobile Data Extract Skipped Order: KMDFSRB_push_rep08: XXXXXXXXX Skipping RSO eligible OC (XXXXXXXXX) Type (OFFO)				
INT.MDM-CIS.F3.60	Cancel Turn Off-Off at Meter: RSO Eligible Meter	- Pending OFF-O order. Order is now voided - Account (ID)/Order Control ID are not selected for new RSO batch (Query below shows accounts that are selected for RSO				

Integration Test Book – MDM Interfaces to CIS: Remote Service Order End to End (Miscellaneous)						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
INT.MDM-CIS.F3.61	Turn On-Install Meter: RSO Ineligible	Account (ID)/Order Control ID are not selected for new RSO batch (Query below shows accounts that are selected for RSO				
INT.MDM-CIS.F3.62	Turn Off-Remove Meter	Account (ID)/Order Control ID are not selected for new RSO batch (Query below shows accounts that are selected for RSO				
INT.MDM-CIS.F3.63	Turn Off-Remove Service	Account (ID)/Order Control ID are not selected for new RSO batch (Query below shows accounts that are selected for RSO				
INT.MDM-CIS.F3.64	Pending ON-J & OFF-J (Same Day) Orders: RSO Ineligible	- Pending OFF-J. Pending ON-J - Error report after SO Auto-completion. - Account (ID)/Order Control ID are not selected for new RSO batch (Query below shows accounts that are selected for RSO				
INT.MDM-CIS.F3.65	Service Investigation Order: Install Medical Seal	N/A				
INT.MDM-CIS.F3.66	RSO Eligible Meter: Meter Exchange	Account (ID)/Order Control ID are not selected for new RSO batch (Query below shows accounts that are selected for RSO batch and are listed in numerical order)				

Integration Test Book – MDM Interfaces to CIS: Remote Service Order Online GUI						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
INT.MDM-CIS.F4.3	Validate able to enter ON-A for a meter with a Meter Disconnect Switch (MDS)	Added Successfully				
INT.MDM-CIS.F4.4	Validate able to enter ON-R for a meter with a MDS	N/A				
INT.MDM-CIS.F4.5	Validate not able to enter ON-R for a meter with a MDS where the Service Point is "OffP" after a CNP	N/A				
INT.MDM-CIS.F4.6	Validate able to enter OFF-O for a meter with a MDS	N/A				
INT.MDM-CIS.F4.7	Validate able to enter OFF-R for a meter with a MDS	N/A				
INT.MDM-CIS.F4.8	Validate able to enter OFF-J for a meter with a MDS	N/A				
INT.MDM-CIS.F4.9	Validate able to enter ON-A for a meter without a MDS	N/A				
INT.MDM-CIS.F4.10	Validate able to enter ON-R for a meter without a MDS	N/A				
INT.MDM-CIS.F4.11	Validate able to enter OFF-O for a meter without a MDS	N/A				
INT.MDM-CIS.F4.12	Validate able to enter OFF-R for a meter without a MDS	N/A				
INT.MDM-CIS.F4.13	Validate able to delete pending order for a meter without a MDS	N/A				
INT.MDM-CIS.F4.14	Validate able to enter OFF-J for a meter without a MDS	N/A				
INT.MDM-CIS.F4.15	Validate able to void order for a meter without a MDS	N/A				
INT.MDM-CIS.F4.16	Validate able to manually change Meter @ SP Status to 'Meter Off Switched' for a SP with a MDS meter	N/A				
INT.MDM-CIS.F4.17	Validate SP audit log (SPAEL) captures changes to/from "Meter Off Switched" status	(See previous test) Shows Meter At SP Status for Service Point XXXXXXXXX changed to "S" and then back to "O"				
INT.MDM-CIS.F4.18	Validate not able to manually change Meter @ SP Status to "Meter Off Switched" for a SP without a MDS meter	N/A				
INT.MDM-CIS.F4.19	Validate Service Point Status is "Conn OffS" when meter has been remotely disconnected	N/A				
INT.MDM-CIS.F4.20	Validate "**Remotely Disconnected**" appears in JetSearch when meter has been remotely disconnected	N/A				

Integration Test Book – MDM Interfaces to CIS: Remote Service Order Web Services						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
INT.MDM-CIS.F5.3	ON-A Remote Service Order	N/A				
INT.MDM-CIS.F5.4	ON-R Remote Service Order	N/A				
INT.MDM-CIS.F5.5	OFF-O Remote Service Order	N/A				
INT.MDM-CIS.F5.6	OFF-R Remote Service Order	N/A				

Integration Test Book – MDM Interfaces to FlexSync: MDM General User Functionality Regression Testing						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
INT.FS-MDM.E1.USER.1	Confirm that KCP&L personnel may access the EIP user interface and browse through various screens. This is not intended to test any specific functionality of the EIP system.	KCP&L personnel are able to access the EIP user interface, successfully log in and browse through the system.				
INT.FS-MDM.E1.USER.2	Confirm that KCP&L personnel may access the EIP SFTP server using the Push Billing account and post/retrieve files.	KCP&L personnel are able to access the EIP SFTP server and then post and retrieve files successfully.				
INT.FS-MDM.E1.USER.3	Confirm that KCP&L personnel may access the EIP SFTP server using the Meter Reads account and post/retrieve files.	KCP&L personnel are able to access the EIP SFTP server and then post and retrieve files successfully.				
INT.FS-MDM.E1.USER.4	Confirm that KCP&L personnel may access the EIP server which runs EIP web services.	KCP&L personnel are able to access the EIP web server.				
INT.FS-MDM.E1.USER.5	Confirm that KCP&L is able to access the MDM FlexSync web service.	KCP&L MQ Broker interface is able to access the MDM FlexSync web service and get a response - either valid or error is acceptable as the purpose is to confirm that we have connectivity.				
INT.FS-MDM.E1.USER.6	Confirm that KCP&L is able to access the MDM FlexSync web service.	KCP&L MQ Broker interface is able to access the MDM FlexSync web service and get a response - either valid or error is acceptable as the purpose is to confirm that we have connectivity.				
INT.FS-MDM.E1.USER.7	Tester will log in to the EIP UI using the "systems administrator" account and visit each of the major screens and links. Errors or other non-functional links/pages will be logged for report back to Siemens.	Tester can log into the EIP UI and visit all of the pages noted below. The tester may click on additional links/buttons as desired to further review the UI.				
INT.FS-MDM.E1.USER.8	Ensure that the specified report is generated by the MDM system and if appropriate distributed by email to the KCP&L report distribution list.	The named report is generated by EIP and viewable in the EIP UI. The named report is automatically sent via email to the KCP&L report distribution list.				

Integration Test Book – MDM Interfaces to FlexSync: MDM System Interface Regression Testing						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
INT.FS-MDM.E1.IF.1	FlexSync Batch Jobs will populate FlexSync staging tables with a limited number of records per test case requirements. The FlexSync MQ Broker interface will select these records from the staging tables, create an XML message per the MDM Functional/Technical Specification and then send the XML message to the Siemens hosted eMeter EnergyIP MDM system web service using SOAP. The MDM web service will reply with a success or failure message as appropriate and this reply message will be logged.	(1) MDM FlexSync UCA Process and corresponding jobs will run to select Account/SDP changes from CISPROD for submission to the MDM. NOTE: The appropriate changes must have been made to accounts (i.e. rate changes, move-in/out, etc.) to trigger their appearance in the selection query (2) MQ Broker will successfully generate and send a SOAP message to MDM with valid data and receive a valid "success" response which is logged. The record will be updated correctly in MDM. (3) MQ Broker will successfully generate and send a SOAP message to MDM with invalid data and receive a valid "error" response which is logged. The record will not be updated in MDM				
INT.FS-MDM.E1.IF.2	On a daily basis, KCP&L will transfer an MDM specific formatted EMED file generated by L+G Command Center 5.1 via the MQ File Mover Interface to the Siemens hosted server via SFTP. The TEST EMED file contains daily register reads for 4 SmartGrid Lab meters. The PROD EMED file contains daily register reads for the previous day for all SmartGrid meters (~14,000).	Command Center will generate the file in the specified format. MQ File Mover will find the daily file in the specified location and successfully move it to Siemens via SFTP. EIP adapter will pick up the file and load it into the MDM system. Meter data values from the file will be viewable in the EIP UI.				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
INT.FS-MDM.E1.IF.3	On a daily basis, KCP&L will transfer an standard formatted Intervals file generated by I+G Command Center 5.1 via the MQ File Mover Interface to the Siemens hosted server via SFTP.	Command Center will generate the file in the specified format. MQ File Mover will find the daily file in the specified location and successfully move it to Siemens via SFTP. EIP adapter will pick up the file and load it into the MDM system. Meter data values from the file will be viewable in the EIP UI.				
Integration Test Book – MDM Interfaces to FlexSync: MDM Validation, Estimation, Editing (VEE) Functionality						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
INT.FS-MDM.E1.VEE.1	Test user can perform manual validation, estimation and editing in the MDM GUI in the Data Administration module and specifically the "Interval Editing" function.	Test user can view, validate, edit and create values using the EIP UI.				
INT.FS-MDM.E1.VEE.2	MDM will estimate any gaps in interval reads that it encounters. It will only estimate these values if it has both a read prior to and following the gap; open-ended gaps will not be estimated. 90 days of meter read history are desirable to produce a more accurate estimated value.	MDM will fill the gaps in the interval read values.				
INT.FS-MDM.E1.VEE.3	If the MDM receives actual values for a slot where it had previously Estimated a value, it will replace the estimated value with the actual value.	If a valid read is then received for a specific slot, the actual read will replace either an extrapolated or interpolated read.				
INT.FS-MDM.E1.VEE.4	If the MDM determines it is missing the most recent meter read value, it will extrapolate a value based on prior reads	MDM populates the most recent "empty" read slot with an extrapolated value that makes sense based on prior data.				
INT.FS-MDM.E1.VEE.5	If the MDM receives actual values for a slot where it had previously either Extrapolated or Interpolated a value, it will replace the estimated value with the actual value	If a valid read is then received for a specific slot, the actual read will replace either an extrapolated or interpolated read.				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
INT.FS-MDM.E1.VEE.6	If the MDM determines it is missing the most recent meter read value, it will extrapolate a value based on prior reads. This includes both daily register reads and 15 minute interval reads. If MDM then receives valid reads after the gap period, it will re-estimate the original missing reads using interpolation.	MDM will re-estimate previously extrapolated reads by interpolation.				
INT.FS-MDM.E1.VEE.7	If the MDM receives actual values for a slot where it had previously either Extrapolated or Interpolated a value, it will replace the estimated value with the actual value.	If a valid read is then received for a specific slot, the actual read will replace either an extrapolated or interpolated read.				
Integration Test Book – MDM Interfaces to FlexSync: MDM TOU Setup & Usage Framing						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
INT.FS-MDM.E1.TOU.1	Regular rate setup process will be followed in MDM	1TOUA and 1TOAA rates in MDM will be available for mapping SDP/account to the corresponding TOU calendar.				
INT.FS-MDM.E1.TOU.2	This scenario covers the TOU Calendar setup – Seasons, Day Type, Peak/Off-Peak Times – in each of the key systems.	For testing, the 2011 TOU Test calendar will be set up with November 2011 as a "Summer" month and December 2011 as a "Winter" month for 1TOUA and with November 2011 as a "Winter" month and December 2011 as a "Summer" month for 1TOAA. This may be modified depending on the actual date of the testing to ensure that both seasons are validated.				
INT.FS-MDM.E1.TOU.3	Customers who enroll in TOU will be framed per the TOU calendar beginning on their TOU effective date as communicated from CIS to MDM. Assumption is that 1TOUA and 1TOAA frame consistently, so the regression test only requires validation of the more common 1TOUA rate.	MDM will correctly frame usage for all customers enrolled in the 1TOUA rate.				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
INT.FS-MDM.E1.TOU.4	KCP&L will use MQ Broker to request and retrieve usage data from MDM on a daily basis for all TOU customers. This usage data will be written to a staging table for further processing outside this test case.	TOU Calculator staging table is populated with usage data for 1TOUA customers.				

Integration Test Book – MDM Interfaces via VPN: MDM General User Functionality Regression Testing						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
INT.MDM-VPN.E2.USER.1	Confirm that KCP&L personnel may access the EIP user interface and browse through various screens. This is not intended to test any specific functionality of the EIP system.	KCP&L personnel are able to access the EIP user interface, successfully log in and browse through the system.				
INT.MDM-VPN.E2.USER.2	Confirm that KCP&L personnel may access the EIP SFTP server using the Push Billing account and post/retrieve files.	KCP&L personnel are able to access the EIP SFTP server and then post and retrieve files successfully.				
INT.MDM-VPN.E2.USER.3	Confirm that KCP&L personnel may access the EIP SFTP server using the Meter Reads account and post/retrieve files.	KCP&L personnel are able to access the EIP SFTP server and then post and retrieve files successfully.				
INT.MDM-VPN.E2.USER.4	Confirm that KCP&L personnel may access the EIP server which runs EIP web services.	KCP&L personnel are able to access the EIP web server.				
INT.MDM-VPN.E2.USER.5	Confirm that KCP&L is able to access the MDM FlexSync web service.	KCP&L MQ Broker interface is able to access the MDM FlexSync web service and get a response - either valid or error is acceptable as the purpose is to confirm that we have connectivity.				
INT.MDM-VPN.E2.USER.6	Confirm that KCP&L is able to access the MDM FlexSync web service.	KCP&L MQ Broker interface is able to access the MDM FlexSync web service and get a response - either valid or error is acceptable as the purpose is to confirm that we have connectivity.				
INT.MDM-VPN.E2.USER.7	Tester will log in to the EIP UI using the "systems administrator" account and visit each of the major screens and links. Errors or other non-functional links/pages will be logged for report back to Siemens.	Tester can log into the EIP UI and visit all of the pages noted below. The tester may click on additional links/buttons as desired to further review the UI.				
INT.MDM-VPN.E2.USER.8	Ensure that the specified report is generated by the MDM system and if appropriate distributed by email to the KCP&L report distribution list.	The named report is generated by EIP and viewable in the EIP UI. The named report is automatically sent via email to the KCP&L report distribution list.				

Integration Test Book – MDM Interfaces via VPN: MDM System Interface Regression Testing						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
INT.MDM-VPN.E2.IF.1	Confirm that FlexSync process is able to access the new kcp1testelp1.mdmhosting.com domain within the VPN.	(1) FlexSync flows are able to access the new domain name.				
INT.MDM-VPN.E2.IF.2	Confirm that Pull Billing process is able to access the new kcp1testelp1.mdmhosting.com domain within the VPN.	(1) Pull Billing flows are able to access the new domain name.				
INT.MDM-VPN.E2.IF.3	On a daily basis, KCP&L will transfer an MDM specific formatted EMED file generated by L+G Command Center 5.1 via the MQ File Mover interface to the Siemens hosted server via SFTP. The TEST EMED file contains daily register reads for 4 SmartGrid Lab meters. The PROD EMED file contains daily register reads for the previous day for all SmartGrid meters (~14,000).	Command Center will generate the file in the specified format. MQ File Mover will find the daily file in the specified location and successfully move it to Siemens via SFTP. EIP adapter will pick up the file and load it into the MDM system. Meter data values from the file will be viewable in the EIP UI.				
INT.MDM-VPN.E2.IF.4	On a daily basis, KCP&L will transfer an standard formatted intervals file generated by L+G Command Center 5.1 via the MQ File Mover interface to the Siemens hosted server via SFTP.	Command Center will generate the file in the specified format. MQ File Mover will find the daily file in the specified location and successfully move it to Siemens via SFTP. EIP adapter will pick up the file and load it into the MDM system. Meter data values from the file will be viewable in the EIP UI.				
Integration Test Book – MDM Interfaces via VPN: MDM Validation, Estimation, Editing (VEE) Functionality						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
INT.MDM-VPN.E2.VEE.1	MDM will estimate any gaps in interval reads that it encounters. It will only estimate these values if it has both a read prior to and following the gap; open-ended gaps will not be estimated. 90 days of meter read history are desirable to produce a more accurate estimated value.	MDM will fill the gaps in the interval read values.				
INT.MDM-VPN.E2.VEE.2	If the MDM receives actual values for a slot where it had previously Estimated a value, it will replace the estimated value with the actual value.	If a valid read is then received for a specific slot, the actual read will replace either an extrapolated or interpolated read.				
INT.MDM-VPN.E2.VEE.3	If the MDM determines it is missing the most recent meter read value, it will extrapolate a value based on prior reads.	MDM populates the most recent "empty" read slot with an extrapolated value that makes sense based on prior data.				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
INT.MDM-VPN.E2.VEE.4	If the MDM receives actual values for a slot where it had previously either Extrapolated or Interpolated a value, it will replace the estimated value with the actual value.	If a valid read is then received for a specific slot, the actual read will replace either an extrapolated or interpolated read.				
INT.MDM-VPN.E2.VEE.5	If the MDM determines it is missing the most recent meter read value, it will extrapolate a value based on prior reads. This includes both daily register reads and 15 minute interval reads. If MDM then receives valid reads after the gap period, it will re-estimate the original missing reads using interpolation.	MDM will re-estimate previously extrapolated reads by interpolation.				
INT.MDM-VPN.E2.VEE.6	If the MDM receives actual values for a slot where it had previously either Extrapolated or Interpolated a value, it will replace the estimated value with the actual value.	If a valid read is then received for a specific slot, the actual read will replace either an extrapolated or interpolated read.				
Integration Test Book – MDM Interfaces via VPN: MDM TOU Functionality						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
INT.MDM-VPN.E2.TOU.1	Customers who enroll in TOU will be framed per the TOU calendar beginning on their TOU effective date as communicated from CIS to MDM. Assumption is that 1TOUA and 1TOAA frame consistently, so the regression test only requires validation of the more common 1TOUA rate.	MDM will correctly frame usage for all customers enrolled in the 1TOUA rate.				
INT.MDM-VPN.E2.TOU.2	KCP&L will use manually generate a billing request via the MDM GUI and verify that the file is exported for processing by KCP&L.	Billing request is successfully generated and "billing determinants" file is created for retrieval by KCP&L.				

Integration Test Book – ESB Interfaces to Misc Systems: Simulated Outage/Restoration Event						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
INT.ESB-MISC.B1.OUT.1	Confirm that the specified event scenario is transmitted from the AMI/AHE infrastructure through the KCP&L ESB to the MDM (via the eMeter EIP L+G 5.1 Adapter) and then from the MDM via ESB to the OMS system.	Specified event is visible in the ESB Logs and MDM.				
INT.ESB-MISC.B1.OUT.2	Confirm that the specified event scenario is transmitted from the AMI/AHE infrastructure through the KCP&L ESB to the MDM (via the eMeter EIP L+G 5.1 Adapter) and then from the MDM via ESB to the OMS system.	Specified event is visible in the ESB Logs and MDM.				
INT.ESB-MISC.B1.RES.1	Confirm that the specified event scenario is transmitted from the AMI/AHE infrastructure through the KCP&L ESB to the MDM (via the eMeter EIP L+G 5.1 Adapter) and then from the MDM via ESB to the OMS system.	Specified event is visible in the ESB Logs and MDM.				
INT.ESB-MISC.B1.RES.2	Confirm that the specified event scenario is transmitted from the AMI/AHE infrastructure through the KCP&L ESB to the MDM (via the eMeter EIP L+G 5.1 Adapter) and then from the MDM via ESB to the OMS system.	Specified event is visible in the ESB Logs and MDM.				
Integration Test Book – ESB Interfaces to Misc Systems: Meter Lab Outage/Restoration Event (w/o OMS)						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
INT.ESB-MISC.B1.OUT.3	Confirm that the specified event scenario is transmitted from the AMI/AHE infrastructure through the KCP&L ESB to the MDM (via the eMeter EIP L+G 5.1 Adapter) and then from the MDM via ESB to the OMS system.	Specified event is visible in the AHE and MDM.				
INT.ESB-MISC.B1.RES.3	Confirm that the specified event scenario is transmitted from the AMI/AHE infrastructure through the KCP&L ESB to the MDM (via the eMeter EIP L+G 5.1 Adapter) and then from the MDM via ESB to the OMS system.	Specified event is visible in the AHE and MDM.				

Integration Test Book – ESB Interfaces to Misc Systems: Meter Lab Outage/Restoration Event (w/OMS)						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
INT.ESB-MISC.B1.OUT.4	Confirm that the specified event scenario is transmitted from the AMI/AHE infrastructure through the KCP&L ESB to the MDM (via the eMeter EIP L+G 5.1 Adapter) and then from the MDM via ESB to the OMS system.	Specified event is visible in the AHE, MDM and OMS.				
INT.ESB-MISC.B1.RES.4	Confirm that the specified event scenario is transmitted from the AMI/AHE infrastructure through the KCP&L ESB to the MDM (via the eMeter EIP L+G 5.1 Adapter) and then from the MDM via ESB to the OMS system.	Specified event is visible in the AHE, MDM and OMS.				

Integration Test Book – ESB Interfaces to Misc Systems: Power Status Verification - Unit Testing						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
INT.ESB-MISC.C.3	Validate setup and configuration of the OMS, ESB, MDM, and AHE to support Power Status Verification	A) Verify that the OMS is configured to write PSV request messages to the OMS_AMI_REPLY queue and read PSV reply messages from the OMS_AMI_INPUT_PSV queue B) Verify that the ESB is configured to read PSV request messages from the OMS_AMI_REPLY queue, send PSV request messages to the MDM, and write PSV reply messages to the OMS_AMI_INPUT_PSV queue C) Verify that the MDM is configured to send PSV request and reply messages to the ESB D) Verify that the AHE is configured to send PSV reply messages to the ESB				
INT.ESB-MISC.C.4	Confirm that the OMS is generating the appropriate outbound PSV request message to the MDM via the ESB	A) Verify that the OMS generates the appropriate outbound PSV request message and sends it to the ESB on the OMS_AMI_REPLY queue to be transformed and sent to the MDM				
INT.ESB-MISC.C.5	Confirm that the ESB is properly transforming PSV request message from the OMS to the MDM	A) Verify that the ESB reads the PSV request message from the OMS_AMI_REPLY queue B) Verify that the ESB makes WebService call to the CIS to check for "MeterEnergized" status C) Verify that the ESB transforms the PSV request message to the proper format for the MDM to process D) Verify that the ESB sends the transformed PSV request message to the MDM				
INT.ESB-MISC.C.6	Confirm that the MDM is generating the appropriate outbound PSV request message to the AHE via the ESB	A) Verify that the MDM receives the PSV request message from the ESB B) Verify that the MDM generates the appropriate outbound PSV request message (endpoint on-demand read request) and sends it to the AHE via the ESB				
INT.ESB-MISC.C.7	Confirm that the AHE receives the PSV request message from the MDM via the ESB	A) Verify that the AHE receives the PSV request message (endpoint on-demand read request) from the MDM via the ESB and sends the PSV request message to the target AMI meter				
INT.ESB-MISC.C.8	Confirm that the AHE is processing the PSV request message and generating the appropriate outbound PSV reply message to the MDM via	A) Verify that the AHE receives PSV reply message from the target AMI meter and generates the appropriate outbound PSV reply message (endpoint on-demand read reply) and sends it to the MDM via the ESB				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
INT.ESB-MISC.C.9	Confirm that the MDM is generating the appropriate outbound PSV reply message to the OMS via the ESB	A) MDM generates a "meter on" PSV reply message and sends it to the ESB				
INT.ESB-MISC.C.10	Confirm that the ESB is properly transforming the PSV reply message from the MDM to the OMS	A) Verify that the ESB receives the PSV reply message from the MDM B) Verify that the ESB transforms the PSV reply message to the proper format for the OMS to process C) Verify that ESB sends the transformed PSV reply message to the OMS_AMI_INPUT_PSV queue				
INT.ESB-MISC.C.11	Confirm that the OMS is processing the PSV reply message	A) Verify that OMS reads the PSV reply message from the OMS_AMI_INPUT_PSV queue				
INT.ESB-MISC.C.12	Test Plan review	Review test plan PRIOR TO testing. Consult your PA to determine attendees. Review unit test results if necessary.				
INT.ESB-MISC.C.13	Code review – Include diffs	Repeat code review if changes were made during unit testing.				
Integration Test Book – ESB Interfaces to Misc Systems: Power Status Verification – System/Scenario Testing						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
INT.ESB-MISC.C.14	PSV is manually initiated from the OMS to a target meter that is	N/A				
INT.ESB-MISC.C.15	PSV is manually initiated from the OMS to a target meter that is	N/A				
INT.ESB-MISC.C.16	PSV is manually initiated from the OMS to a target meter that is not "energized" in CIS (service disconnected)	A) Verify that the OMS generates the appropriate outbound PSV request message and sends it to the ESB on the OMS_AMI_REPLY queue to be transformed and sent to the MDM B) Verify that the ESB reads the PSV request message from the OMS_AMI_REPLY queue, makes WebService call to the CIS to check for "MeterEnergized=N" status, creates the appropriate PSV reply message in the proper format for the OMS to process, and sends the created PSV reply message to the OMS_AMI_INPUT_PSV queue C) Verify that OMS reads the PSV reply message from the OMS_AMI_INPUT_PSV queue				

Integration Test Book – HEMP Interfaces to AHE: Meter ESI to Device Communication						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
INT.HEMP-AHE.G.1	Device Commissioning/Joining: Devices commissioned to meter utilizing ETM tool and verify device joining at device and with ETM tool.	N/A				
INT.HEMP-AHE.G.2	Device Commissioning/Joining: Devices commissioned to meter utilizing ETM tool. After verification of joining, devices are removed utilizing ETM tool and network leave verified.	N/A				
INT.HEMP-AHE.G.3	Device Commissioning/Joining: Device is commissioned to meter without previously creating HAN.	N/A				
INT.HEMP-AHE.G.4	Device Commissioning/Joining: After joining device to meter messages initiated with past and future effective date/time received properly by device and verified with ZigBee "sniffer" capture	N/A				
INT.HEMP-AHE.G.5	Device Commissioning/Joining: After joining device to meter and message having been sent, power cycling of meter then device should result in GetLastMessage command visible by ZigBee "sniffer"	N/A				
INT.HEMP-AHE.G.6	Device Commissioning/Joining: After joining device to meter send two messages with start time of now. Second message should replace first	N/A				
INT.HEMP-AHE.G.7	Messaging/HAN Notifications: After joining a device to the meter, verify messages can be received to device from meter ESI	N/A				
INT.HEMP-AHE.G.8	Messaging/HAN Notifications: After joining device to meter and message having been received by device, issue cancelation and verify message removal	N/A				
INT.HEMP-AHE.G.9	Messaging/HAN Notifications: After joining device to meter and message having been received by the device, the device is power-cycled for verification that message remaining time is accurate	N/A				

Integration Test Book – HEMP Interfaces to AHE: Broadband Network Communication						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
INT.HEMA-AHE.G.10	Device Commissioning/Joining: Devices commissioning to meter in meterformed HAN with Gateway. Device registration confirmed in Command Center and Tendril user portal	N/A				
INT.HEMA-AHE.G.11	Device Commissioning/Joining: After joining devices to HAN, devices are removed from Han and removal is confirmed at device UI, Command center and in Tendril User Portal.	N/A				
INT.HEMA-AHE.G.12	Device Commissioning/Joining: After joining devices to meter, devices are removed with confirmation of removal and rejoined confirmed in Command Center and Tendril user portal	N/A				
INT.HEMA-AHE.G.13	Device Commissioning/Joining: After joining a device to the HAN, Test the joining of a second device joining by means of communication through the previously joined device	N/A				
INT.HEMA-AHE.G.14	Device Commissioning/Joining: After joining the HAN a device receives and displays the correct date and time	N/A				
INT.HEMA-AHE.G.15	Messaging: Text message sent with a start time of now and in the future without request for user acknowledgement, confirming messages are displayed correctly at the proper time with the proper duration, at the correct importance level.	N/A				
INT.HEMA-AHE.G.16	Messaging: Text messages sent with start times of now and in the future with requests for customer acknowledgement, verifying messages display properly, at the proper time for the proper duration, at the proper importance level and user acknowledgments are communicated properly.	N/A				
INT.HEMA-AHE.G.17	Messaging: Text message sent with a start time of now and in the future without request for user acknowledgement and devices powered off at the time of the message being sent but powered on within the message active window, confirming messages are displayed correctly at the proper time with the proper duration, at the correct importance level.	N/A				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
INT.HEMP-AHE.G.18	Messaging: Text messages sent with start times of now and in the future with requests for customer acknowledgement and the devices powered off at the time of message initiation but powered on during the message active window, verifying messages display properly, at the proper time for the proper duration, at the proper importance level and user acknowledgments are communicated	N/A				
INT.HEMP-AHE.G.19	Load Control: LC events for varying criticality levels initiated for HVAC device class with specified offset, start time and duration verifying correct start and duration and events appearing properly in UI and participation reporting appearing properly in Tendril admin portal	N/A				
INT.HEMP-AHE.G.20	Load Control: LC event initiated for HVAC and simple misc. LC devices with specified offset, start time and duration verifying correct start and duration and events appearing properly in UI and participation reporting appearing properly in Tendril admin portal	N/A				
INT.HEMP-AHE.G.21	Load Control: LC event initiated for simple misc. LC devices with start time and duration verifying thermostats do not participate.	N/A				
INT.HEMP-AHE.G.22	Load Control: LC event initiated for HVAC device class with specified offset, start time and duration. Opting out of event from thermostat after start of event verifying opt-out is reported properly and participation is reported properly "partial opt-out"	N/A				
INT.HEMP-AHE.G.23	Load Control: LC event initiated for HVAC device class with specified offset, start time and duration. Opting out of event from thermostat after start of event and back in prior to conclusion of event verifying participation is reported properly "partial opt-in"	N/A				
INT.HEMP-AHE.G.24	Load Control: LC event scheduled and canceled prior to the scheduled start time. Verification that prior to cancellation the event appears properly in the user and admin interfaces for scheduled events and after cancellation the event does not start at the device and appears properly as canceled in the event status.	N/A				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
INT. HEMP-AHE.G.25	Load Control: LC event initiated and properly initiated on the device and canceled within the active period and canceled from the Tendril admin portal, verifying the event is terminated properly on the device and displayed properly at the device, user portal and reported properly.	N/A				
INT. HEMP-AHE.G.26	Load Control: Initiate device embedded software/firmware update by means of Over the Air update (OTA) from the Tendril admin portal. Verify successful delivery and installation of OTA image on device.	N/A				
INT. HEMP-AHE.G.27	Load Control: Initiate gateway embedded software/firmware update by means of Over the Internet update (OTI) from the tendril admin interface. Verify the successful delivery and installation of the OTI image on the gateway.	N/A				
Integration Test Book – HEMP Interfaces to AHE: AMI Network Communication						
ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
INT. HEMP-AHE.G.28	Device Commissioning/Joining: Devices commissioning to meter in meterformed HAN without a gateway. Device registration confirmed in Command Center and device find control successfully associates device on AMI network to user's account Tendril connect Database and devices appear on User portal.	N/A				
INT. HEMP-AHE.G.29	Device Commissioning/Joining: After joining devices to HAN, devices are removed from HAN and removal is confirmed at device UI, Command center and in the Tendril User portal	N/A				
INT. HEMP-AHE.G.30	Device Commissioning/Joining: After joining devices to meter, devices are removed with confirmation of removal and rejoined to the HAN. Device leave and re-joining confirmed in Command Center and Tendril user portal	N/A				
INT. HEMP-AHE.G.31	Device Commissioning/Joining: After joining a device to the HAN, Test the joining of a second device joining by means of communication through the previously joined device	N/A				
INT. HEMP-AHE.G.32	Device Commissioning/Joining: After joining the HAN a device receives and displays the correct data and time.	N/A				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
INT.HEMP-AHE.G.33	Messaging: Text message sent with a start time of now and in the future without request for user acknowledgement, confirming messages are displayed correctly at the proper time with the popper duration, at the correct importance level.	N/A				
INT.HEMP-AHE.G.34	Messaging: Text messages sent with start times of now and in the future with requests for customer acknowledgement, verifying messages display properly, at the proper time for the proper duration, at the proper importance level and user acknowledgments are communicated properly.	N/A				
INT.HEMP-AHE.G.35	Messaging: Text message sent with a start time of now and in the future without request for user acknowledgement and devices powered off at the time of the message being sent but powered on within the message active window, confirming messages are displayed correctly at the proper time with the popper duration, at the correct importance level.	N/A				
INT.HEMP-AHE.G.36	Messaging: Text messages sent with start times of now and in the future with requests for customer acknowledgement and the devices powered off at the time of message initiation but powered on during the message active window, verifying messages display properly, at the proper time for the proper duration, at the proper importance level and user acknowledgments are communicated properly.	N/A				
INT.HEMP-AHE.G.37	Load Control: LC events for varying criticality levels initiated for HVAC device class with specified offset, start time and duration verifying correct start and duration and events appearing properly in UI and participation reporting appearing properly in Tendril admin portal	N/A				
INT.HEMP-AHE.G.38	Load Control: LC event initiated for HVAC and simple misc. LC devices with specified offset, start time and duration verifying correct start and duration and events appearing properly in UI and participation reporting appearing properly in Tendril admin portal	N/A				

ID	Test Description	Expected Result	Status	Actual Result	Test Date	Tested By
INT. HEMP-AHE.G.39	Load Control: LC event initiated for simple misc. LC devices with start time and duration verifying thermostats do not participate.	N/A				
INT. HEMP-AHE.G.40	Load Control: LC event initiated for HVAC device class with specified offset, start time and duration. Opting out of event from thermostat after start of event verifying opt-out is reported properly and participation is reported properly.	N/A				
INT. HEMP-AHE.G.41	Load Control: LC event initiated for HVAC device class with specified offset, start time and duration. Opting out of event from thermostat after start of event and back in prior to conclusion of event verifying participation is reported properly "partial opt-in"	N/A				
INT. HEMP-AHE.G.42	Load Control: LC event scheduled and canceled prior to the scheduled start time. Verification that prior to cancellation the event appears properly in the user and admin interfaces for scheduled events and after cancellation the event does not start at the device and appears properly as canceled in the event status.	N/A				
INT. HEMP-AHE.G.43	Load Control: LC event initiated and properly initiated on the device and canceled within the active period and canceled from the Tendril admin portal, verifying the event is terminated properly on the device and displayed properly at the device, user portal and reported properly.	N/A				

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Appendix J End-to-End Interoperability Testing Documentation

J.1	Remote Connect and Disconnect	J-3
J.2	Demand Response – AMI Thermostat.....	J-25
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J.13	Battery Grid Operation – Load Following (Discharge).....	J-155

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Remote Connect and Disconnect



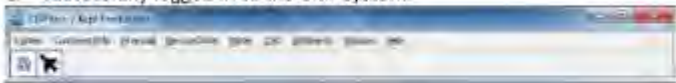
Remote Connect and On-Demand Read

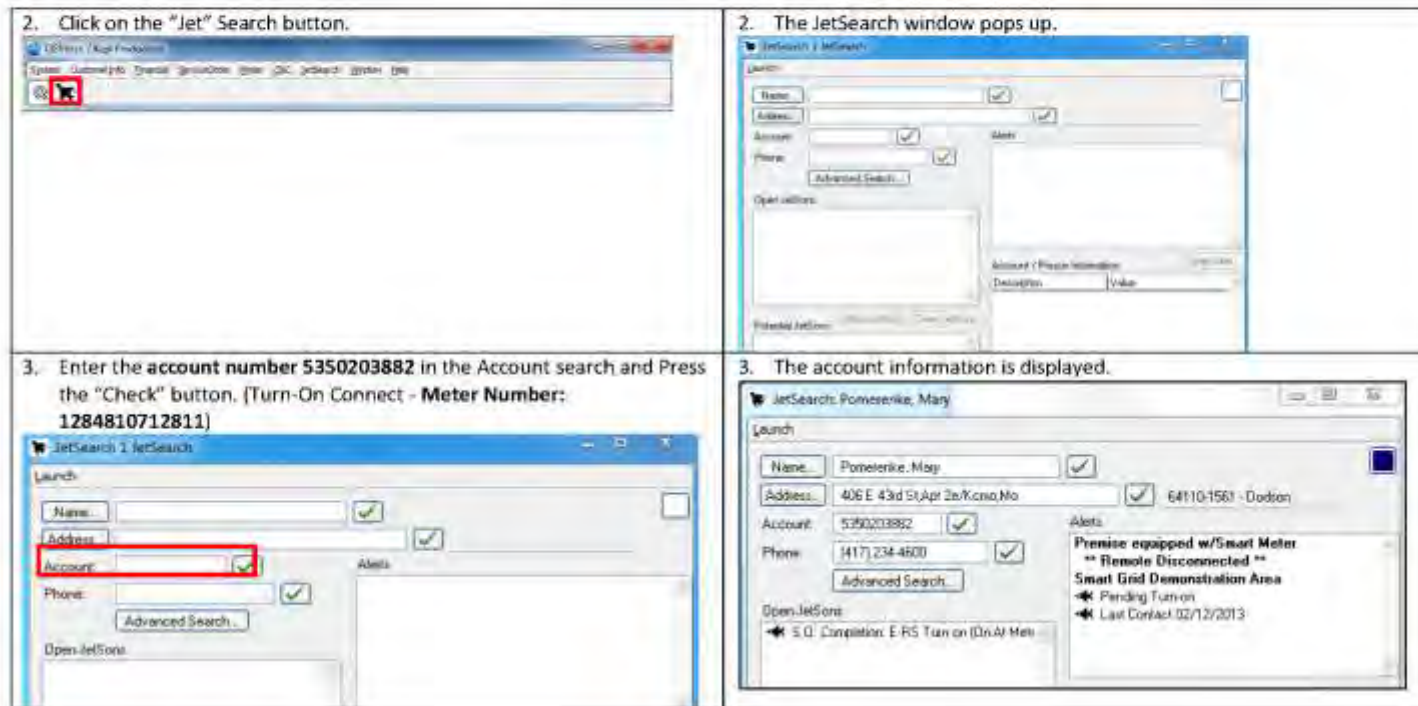
Precondition:

- Prior to entering a turn on order in GUI, make sure to change the Positive ID flag to 'P' in the green screens for each customer. In CIS+, pull up the customer ID on the PER screen (green screen) and panel left once for Positive ID field. Enter a 'C' in the Action field, 'P' in the Positive ID field and press Enter. (This is to verify that customer can open the account and turn on the meter. This has to be done before the meter service request)
- Meter has disconnect switch and Source is connected

Remote Connect Meter Info – Production:

- Meter ID: 1284810439383

Steps	Expected Results
1. Log in to the CIS system. 	1. Successfully logged in to the CIS+ system. 



4. Select Customer Info > Service Point.



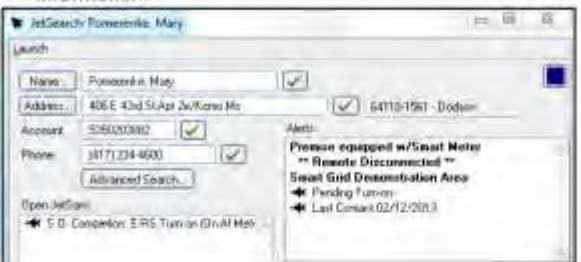
4. A new window "Service Point" pops with detailed information on the entered account number.

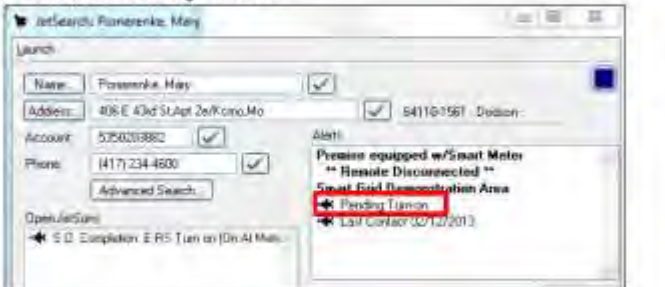


5. Click on the "Jet" Search button.



5. The JetSearch window with searched meter ID pops up with information.



6. Click on "Pending Turn-on". 	6. A new S. O. Completion window pops up with Service Order "Pending". 
7. Wait for the UC4 process to kick off.	7. UC4 process is executed.

8. Select Action > Refresh.

S.O. Completion: E-RS Turn on (On At Meter)

Action	
Refresh	Alt+R
Complete	Alt+C
Delete	Alt+D
Unblock	Alt+U
Void	Alt+V

96527344 Initiated On 02/12/2013 By Ivie, Kelly

Turn on (On At Meter)

Complete on 02/14/2013 09:19 by Mdm, System Fld Order:

24790610 Conn On E-RS, 1RS1A, 10712811G, ON, PH1

Acct/Premise: 5350203882 Pomerenke, Mary / 406 E 43rd St Apt 2e/Kcmo,Mo

8. The service order is "acknowledged".

S.O. Maintenance: E-RS Turn on (On At Meter)

Action

Service Order: 559057344 Initiated on 02/12/2013 by Ivie, Kelly

Status: Pending Fld Order: 118005832588 Acknowledged

Service Point: 6524790610 Conn On E-RS, 1RS1A, 10712811G, ON, PH1, 02/08/13 1350M/AM

Acct/Premise: 5350203882 Pomerenke, Mary / 406 E 43rd St Apt 2e/Kcmo,Mo

Order Type: Turn On Order Date: 02/14/2013

Order Subtype: Turn on (On At Meter)

Origin: T - Telephone

Ordered by: Mary Service Person:

Urgency: C - Customer Convenience

Block User: ☒ Blocked Date:

Instructions: on at meter: 13022467072

Comments:

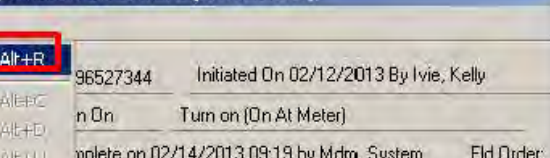
Turn On Info:

Premise Phone: (417) 234-4637 ☐ Key at Premise ☐ OK to Enter

Work Phone:

Mailing Address: 406 E 43rd St, 2e/Kansas Cty, Mo 64110-1561

9. Select Action > Refresh.



S.O. Completion: E-RS Turn on (On At Meter)

Action

Refresh Alt+R

96527344 Initiated On 02/12/2013 By Ivie, Kelly

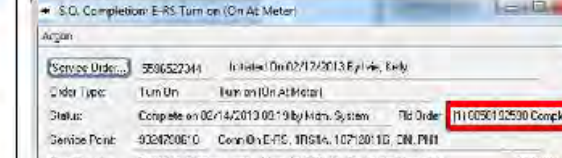
Complete Alt+C

Delete Alt+D

Unblock Alt+U

Void Alt+V

Acct/Premise: 5350203882 Pomerence, Mary / 406 E 43rd St Apt 2e/Kcmo,Mo



S.O. Completion: E-RS Turn on (On At Meter)

Service Order: 5350203882 Initiated On 02/12/2013 By Ivie, Kelly

Order Type: Turn On Turn on (On At Meter)

Status: Complete on 02/14/2013 09:19 by Mdm, System Fld Order: **11005612530 Completed**

Service Point: 932420610 Conn On E-RS, 1RS1A, 10712811G, ON, PH1

Acct/Premise: 5350203882 Pomerence, Mary / 406 E 43rd St Apt 2e/Kcmo,Mo ASSEM/AL

Order Date: 02/14/2013 PR Number: 04 Override Work

Effective Start Time: 02/14/2013 9:19 am Reason for Placement:

Work Order: 10712811G Mktg: 0

Comments:

Meta:

Meta: 10712811G Init: 120552 1/2010

MID	Reading	MID Details	Last Read Date/Type	Last Reading
10712811G	10712811G	10712811G	10712811G	10712811G

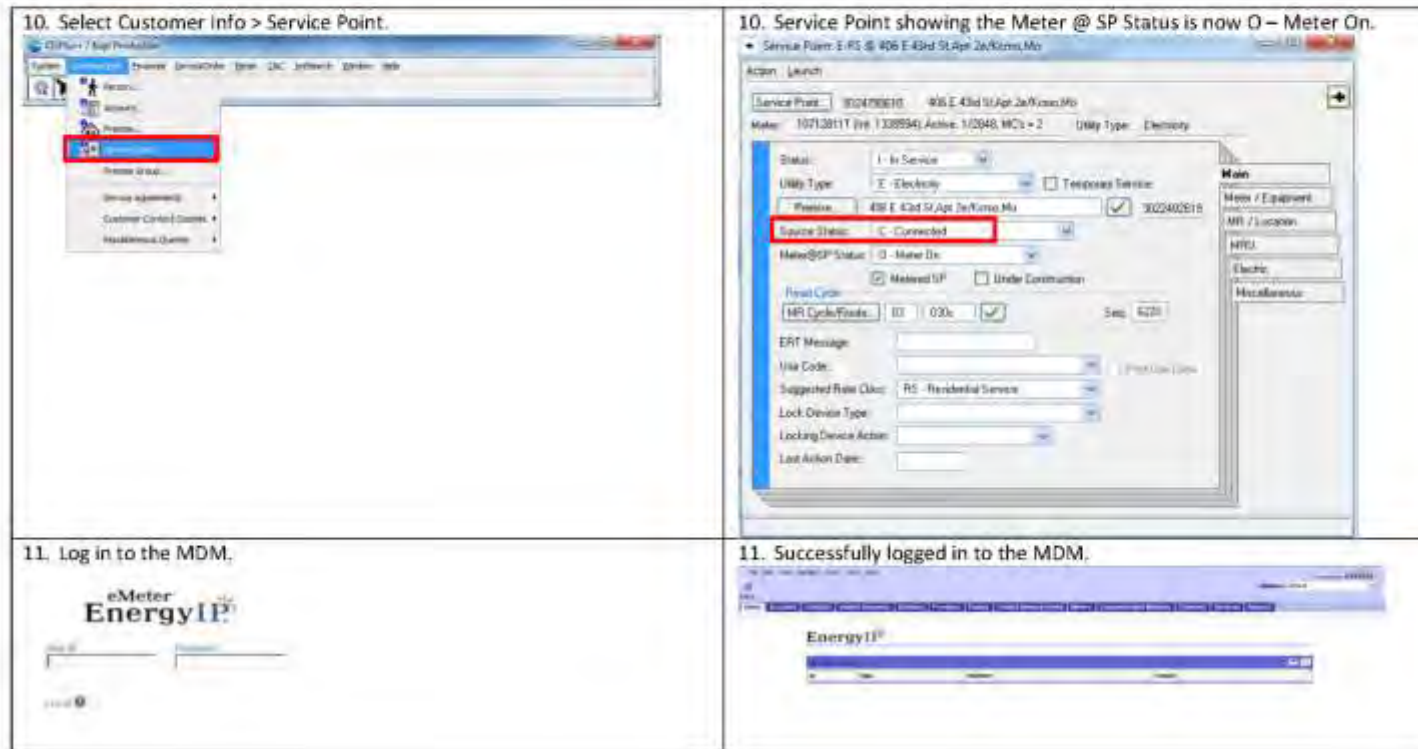
Reading: 10712811G Reason for Reading:

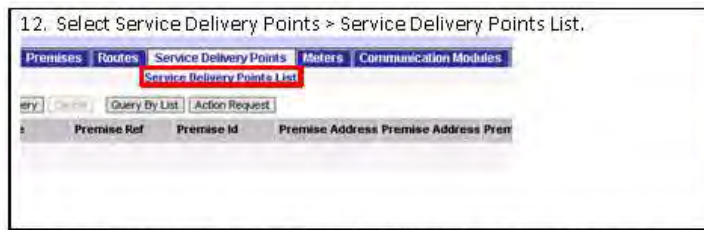
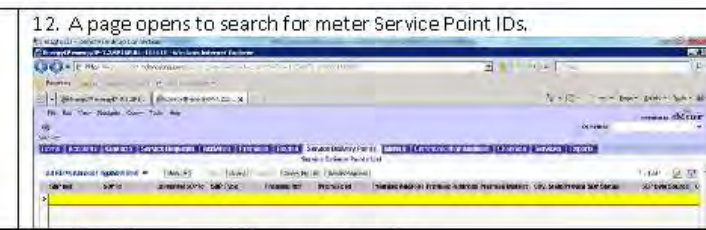
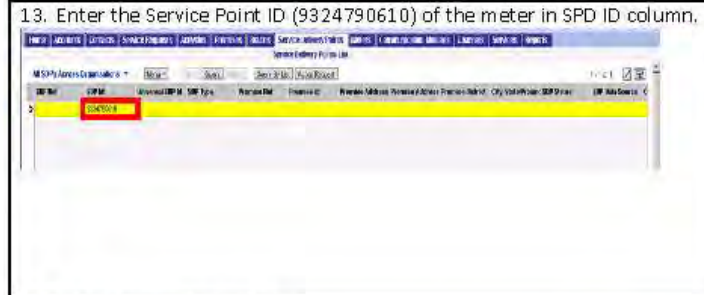
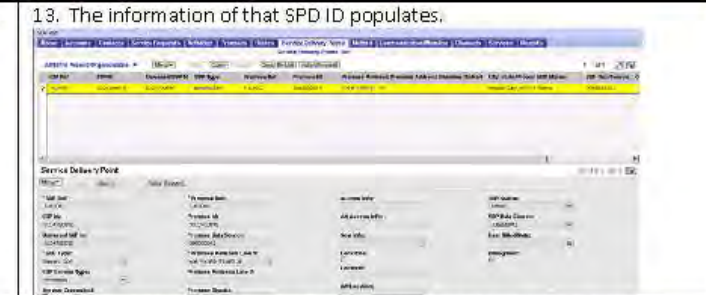
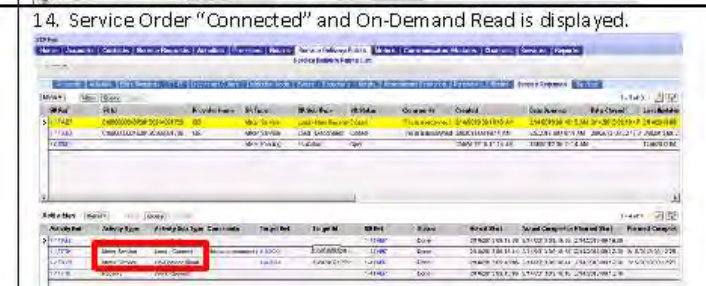
Last Order Type: Last Device Action:

Last Action Date:

Feed Name: Feed Order:

USA Info: E-RS 1RS1A 1 USA Update:



12. Select Service Delivery Points > Service Delivery Points List. 	12. A page opens to search for meter Service Point IDs. 
13. Enter the Service Point ID (9324790610) of the meter in SPD ID column. 	13. The information of that SPD ID populates. 
14. Select Service Requests tab. 	14. Service Order "Connected" and On-Demand Read is displayed. 

15. Log in to the AHE Command Center.



15. Successfully logged in to the AHE Command Center.



16. Enter Meter ID (1284810712811) in the search box and press Search.



16. A new window with the meter information is displayed.



Gridstream RF Endpoint Information		
Meter #1284810712811 Endpoint ID/RF 4028137333(F0107F75)		
Status: Normal	Last Reading: 10000.6282 - 2/19/2013 12:07 AM	
Model: RF (Registered Focus All)	Latitude: 30.046575 Longitude: -94.281478	
Configuration Group: LG RF Readerless (Configuration C)	Utility Address: 40.74.70.63 8F.2D	
Collection: Local	Client Version: 5/16/2013 12:07 AM (Win4)	
ApTitle: r/c		
General Manage Readings Interval Data History RF		
Search State	Connectivity	Multiplex
Demand Multiplier: 1	Meter Read Digits / RH	5 / 7.5
Initial/Latest kWh: 0 / 10094.6282	Module Firmware Version	151107-07.04
Meter Firmware Version: 8.55	Module Firmware Version	09904-05.07.04
DCW Version: 1.02.03.02	Module No	28
Number of Neighbors: 23	Initial Programming	12/18/2010 8:01 AM (Thermostat Log)
Last Programming: 1/28/2011 12:00 AM	Last Good Packet	2/19/2013 12:17:42 AM
Reading Firmware Version	Firmware Download Status	Success
Will Be Activated On	Next Demand Read Date	2/26/2013 12:00:00 AM
Grid Location	Custom #1	
Pole Number	Custom #2	
Meter Position	Map Location	
Customer ID	Billing Cycle	01
Account Number	Revenue Class	10004
Service Location		
CSN Date	Billing Address	

17. Select the "Manage" tab.



Gridstream RF Endpoint Information
Meter #1204010712011 Endpoint S/N 4020137333(F0107F75)

Status: Normal
Model: RF Integrated Router 4M
Configuration Group: US 37 Americas - Configuration 2
Dylerite: US37
400-2-4300-07, 4000, NO 54110100
Latitude: 30.249073 Longitude: -94.351470
Address: 4074 TUBB RD
Current Neighbor S/N: 4020137333(F0107F75) (Normal)
Altitude: n/a

General Manage Readings Intervals Data History Help

17. "Endpoint On-Demand Read" command is displayed in the message log.



Gridstream RF Endpoint Information
Meter #1204010712011 Endpoint S/N 4020137333(F0107F75)

Status: Normal
Model: RF Integrated Router 4M
Configuration Group: US 37 Americas - Configuration 2
Dylerite: US37
400-2-4300-07, 4000, NO 54110100
Latitude: 30.249073 Longitude: -94.351470
Address: 4074 TUBB RD
Current Neighbor S/N: 4020137333(F0107F75) (Normal)
Altitude: n/a

General Readings Intervals Data History Help

Issue Commands

Endpoint tracing and commands: On Off On: none
Results limited to 100 rows, so full trace may not be reflected.

Command	Issued	Start	Completed	Status	Trace
On-Demand Read	2/14/2012 9:10:07 AM	2/14/2012 9:10:07 AM	2/14/2012 9:10:24 AM	Success	View

18. Click on the "Endpoint On Demand Read" in the Command column to view the On Demand Read.



Gridstream RF Endpoint Information
Meter #1204010712011 Endpoint S/N 4020137333(F0107F75)

Status: Normal
Model: RF Integrated Router 4M
Configuration Group: US 37 Americas - Configuration 2
Dylerite: US37
400-2-4300-07, 4000, NO 54110100
Latitude: 30.249073 Longitude: -94.351470
Address: 4074 TUBB RD
Current Neighbor S/N: 4020137333(F0107F75) (Normal)
Altitude: n/a

General Readings Intervals Data History Help

Issue Commands

Endpoint tracing and commands: On Off On: none
Results limited to 100 rows, so full trace may not be reflected.

Command	Issued	Start	Completed	Status	Trace
On-Demand Read	2/14/2012 9:10:07 AM	2/14/2012 9:10:07 AM	2/14/2012 9:10:24 AM	Success	View

18. A new window with On Demand Read information pops up.



Gridstream RF Endpoint Information
Meter #1204010712011 Endpoint S/N 4020137333(F0107F75)
Command: On Demand Read
Trace: RF Protocol Default MultiSpeak OnDemand Read

Name	Value
Lat	30.249073
Forward Response Time (at 0.5m)	3.2344
Received Lat	0
RF Lat	15.001968
Disconnection Time	0 seconds
Latency Time	0 seconds
Time To Live	17 seconds
Disconnection Code	0
Disconnection Time	0
Time To Live	0

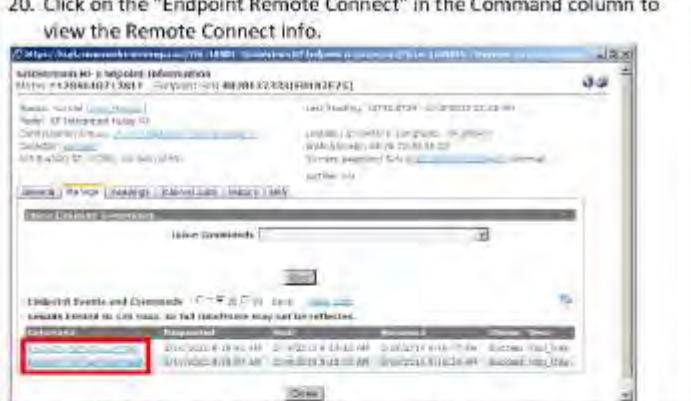
19. Press the "Refresh" Button.



19. "Endpoint Remote Connect" command is displayed in the message log.



20. Click on the "Endpoint Remote Connect" in the Command column to view the Remote Connect Info.



20. A new window with Remote Connect information pops up.



21. Check ESB/back end for the verification of the messages. Database: CMB2DEV. Check Source and Target column in the table "KCPL_ESB_AUDIT".

21. Column REQ_RSP_IND to verify if the message sent is a request or response (REQ or RSP) checked.

Remote Disconnect and On-Demand Read (Demo)

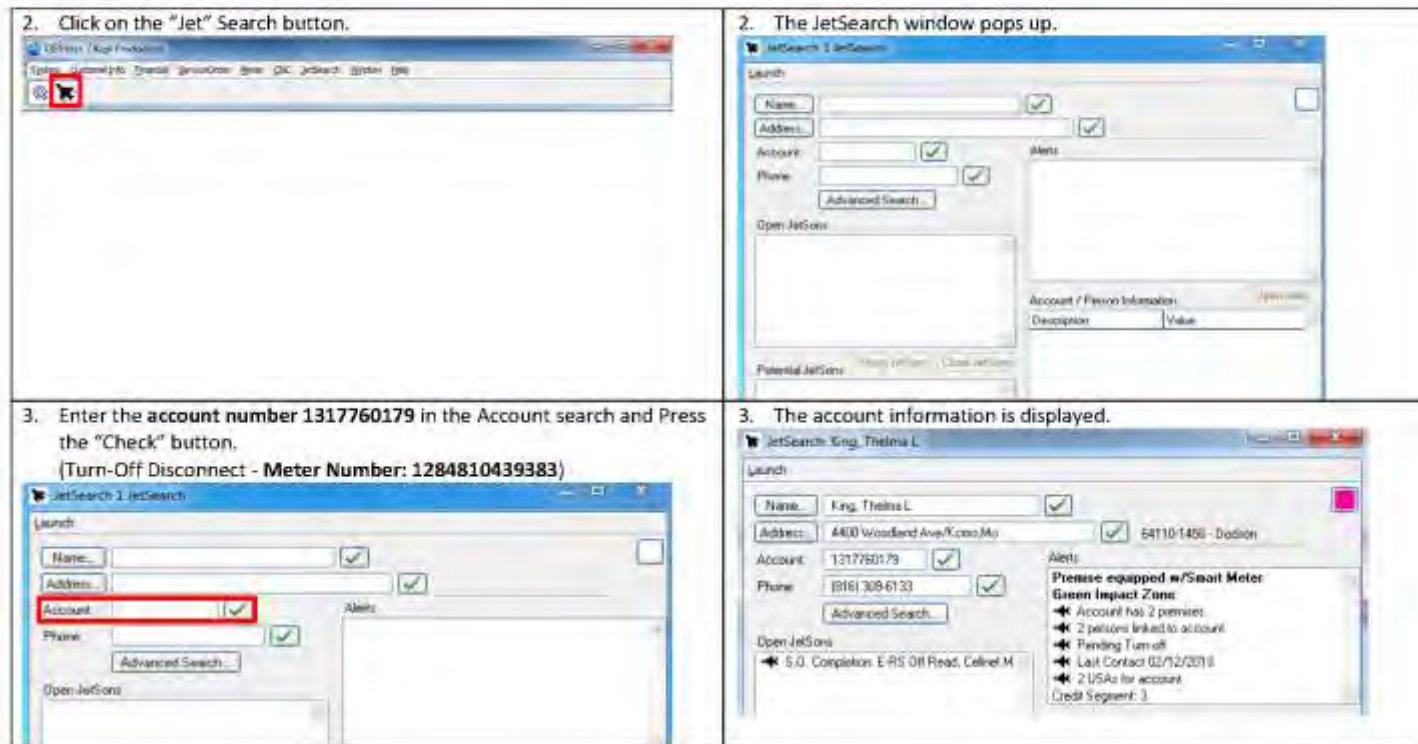
Precondition:

- Assume each scenario does not have a pending turn on, pending turn off, LL revert, current resident at the premise, life support, sensitive load, etc. unless it is noted.
- Meter has disconnect switch and Source is connected
- Meter at SP status = "On"

Remote Disconnect Meter Info – Production:

- Meter ID: 1284810439383
- Service Point ID: 6779916584
- Account Number: 1317760179

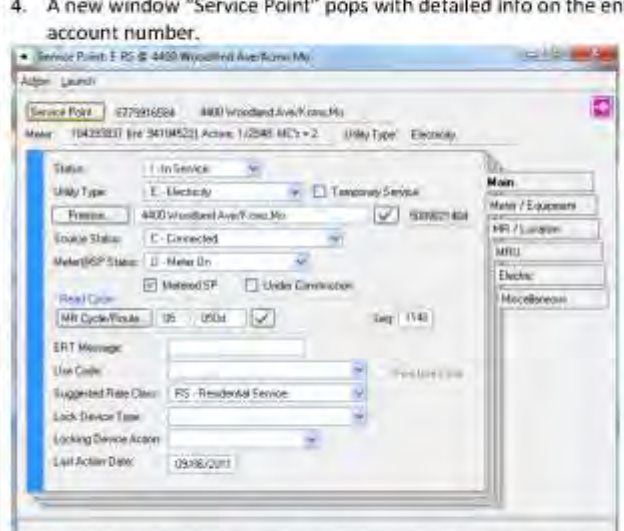
<i>Steps</i>	<i>Expected Results</i>
1. Log in to the CIS+ system. 	1. Successfully logged in to the CIS+ system. 



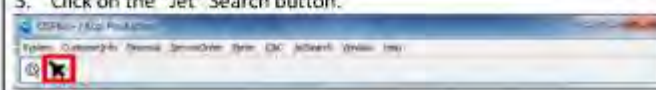
4. Select Customer Info > Service Point.



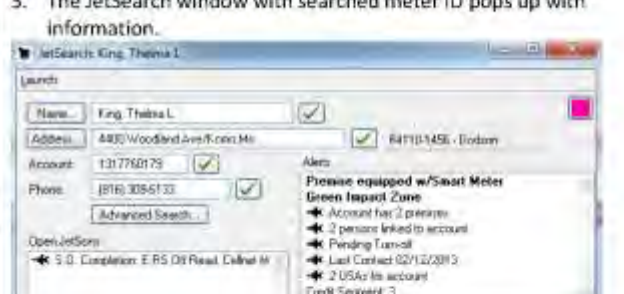
4. A new window "Service Point" pops with detailed info on the entered account number.

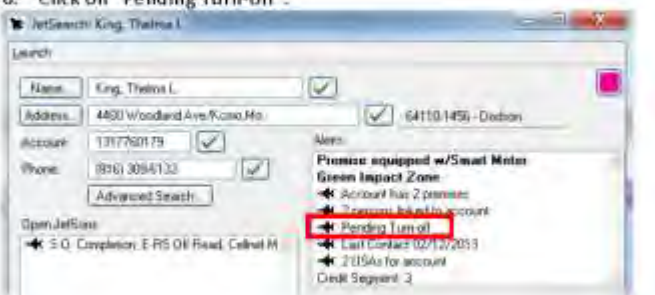
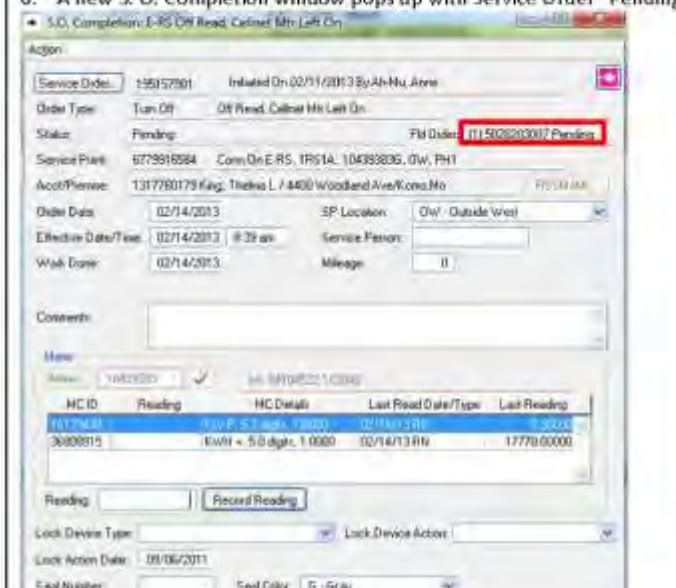


5. Click on the "Jet" Search button.



5. The JetSearch window with searched meter ID pops up with information.



6. Click on "Pending Turn-off".  The screenshot shows a 'Launch' window with fields for Name, Address, Account, and Phone. Under the 'Alerts' section, there is a list of alerts. The alert 'Pending Turn-off' is highlighted with a red box.	6. A new S.O. Completion window pops up with Service Order "Pending".  The screenshot shows an 'S.O. Completion' window. The 'Status' is 'Pending' and the 'Fid Status' is '(1) S.O.2013017 Pending', both highlighted with red boxes. Below the status fields is a table with columns: HC ID, Reading, HC Details, Last Read Date/Type, and Last Reading. <table border="1"> <thead> <tr> <th>HC ID</th> <th>Reading</th> <th>HC Details</th> <th>Last Read Date/Type</th> <th>Last Reading</th> </tr> </thead> <tbody> <tr> <td>16179633</td> <td>5000</td> <td>S-2 digts, 10000</td> <td>02/14/2013</td> <td>5000</td> </tr> <tr> <td>30808013</td> <td>17770</td> <td>S-8 digts, 10000</td> <td>02/14/2013</td> <td>17770</td> </tr> </tbody> </table>	HC ID	Reading	HC Details	Last Read Date/Type	Last Reading	16179633	5000	S-2 digts, 10000	02/14/2013	5000	30808013	17770	S-8 digts, 10000	02/14/2013	17770
HC ID	Reading	HC Details	Last Read Date/Type	Last Reading												
16179633	5000	S-2 digts, 10000	02/14/2013	5000												
30808013	17770	S-8 digts, 10000	02/14/2013	17770												
7. Wait for UC4 Process to kick off.	7. UC4 Process is executed.															

8. Select Action > Refresh.

S.O. Completion: E-RS Off Read, Cellnet Mtr Left On

Action	5157901	Initiated On 02/11/2013 By Ah-Mu, Anne
Complete: Alt+C	in Diff	Off Read, Cellnet Mtr Left On
Delete: Alt+D	Complete on 02/14/2013 09:18 by Mdm, System	Fld Drd
Unblock: Alt+U	9916584	Conn Offs E-RS, 1RS1A, 10439383G, QW, F
Void: Alt+V	1317760179	King, Thelma L / 4400 Woodland Ave/Kcmo, Mo

8. The service order is "acknowledged".

S.O. Maintenance: L-15 Off Read, Cellnet Mtr Left On

Service Order: 1317760179 Initiated on 02/11/2013 by Ah-Mu, Anne

Status: Pending Fld Order: 1115028276007 Acknowledged

Service Order: 62289 5564 Conn On E-RS, 1RS1A, 10439383G, QW, F

Acc/Premise: 1317760179 King, Thelma L / 4400 Woodland Ave/Kcmo, Mo

Order Date: 02/11/2013 Order Time: 09:18:33

Order Subject: Off Read, Cellnet Mtr Left On

Origin: Telephone

Entered by: Thelma

Priority: 3 Service Position:

Company: Company/Department

Block User: Blocked Date:

Installation: L1502 J01 0690

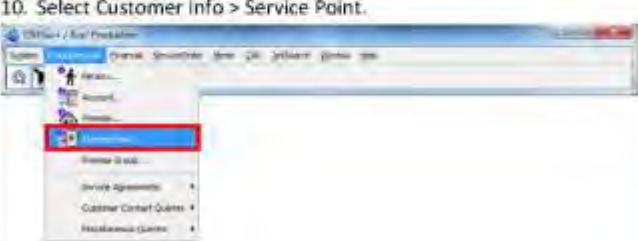
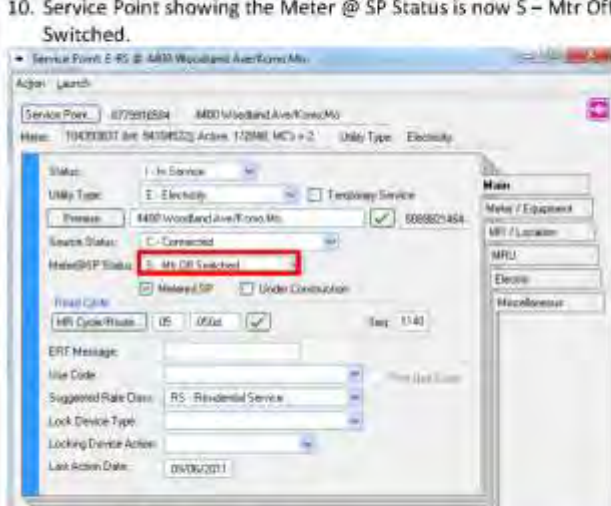
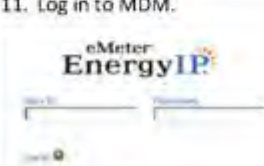
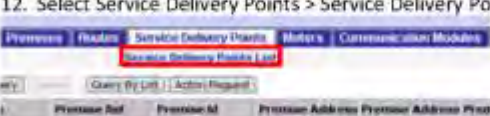
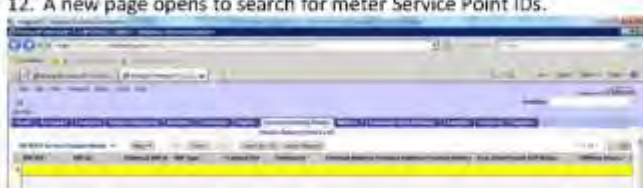
Comments:

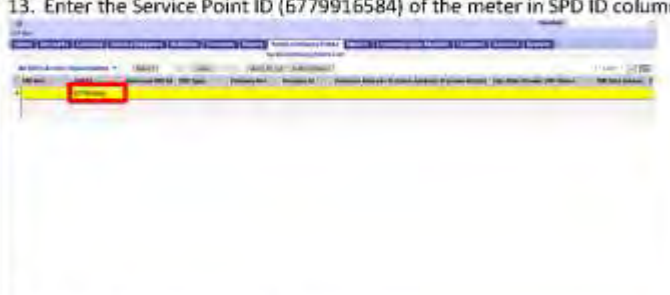
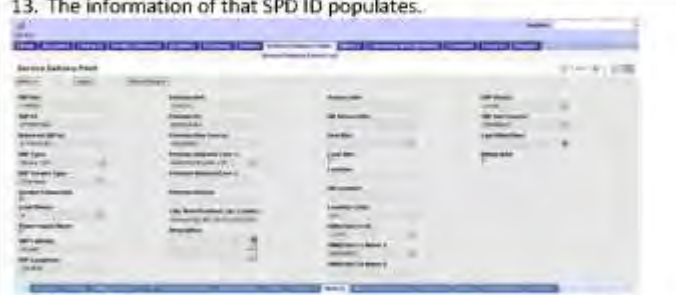
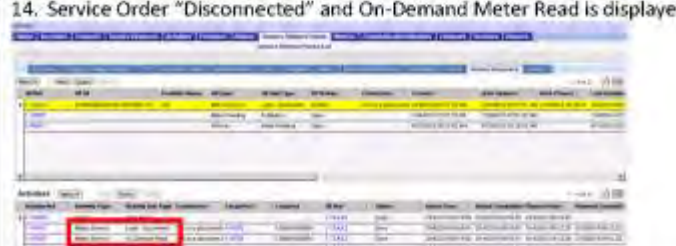
Turn Off Info:

Address: 4400 Woodland Ave/Kcmo, Mo 64130 1518

Turn On Info:

Installation/Commissioning/Address:

10. Select Customer info > Service Point. 	10. Service Point showing the Meter @ SP Status is now S – Mtr Off Switched. 
11. Log in to MDM. 	11. Successfully logged in to MDM. 
12. Select Service Delivery Points > Service Delivery Points List. 	12. A new page opens to search for meter Service Point IDs. 

13. Enter the Service Point ID (6779916584) of the meter in SPD ID column. 	13. The information of that SPD ID populates. 
14. Select Service Requests tab. 	14. Service Order "Disconnected" and On-Demand Meter Read is displayed. 
15. Log in to the AHE Command Center. 	15. Successfully logged in to the AHE Command Center. 

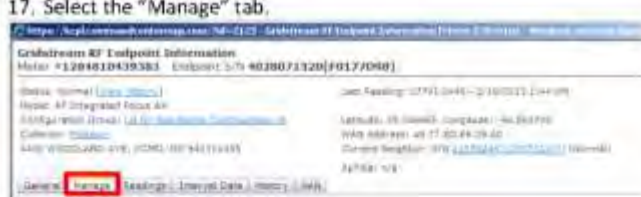
16. Enter the Meter ID (1284810439383) in the search box and press Search.



16. A new window with the meter information is displayed.



17. Select the "Manage" tab.



17. "Endpoint Remote Disconnect" command is displayed in the log.



18. Click on the "Endpoint Remote Disconnect" from the Command column to view the Remote Disconnect info.



18. A new window with Remote Disconnect Information pops up.



19. Press the "Refresh" button.

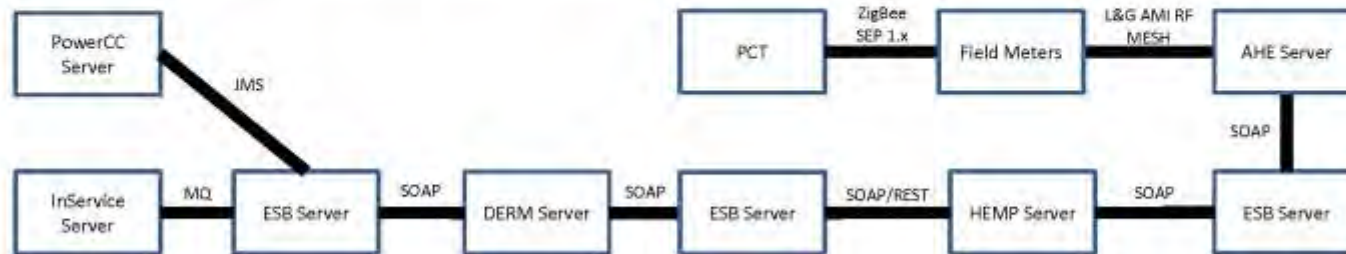


19. "Endpoint On Demand Read" command is displayed in the log.



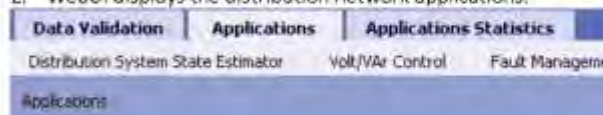
20. Click on the "Endpoint On Demand Read" from the Command column to view the On Demand Read. 	20. A new window with On Demand Read information pops up.  <table border="1"> <thead> <tr> <th>Name</th> <th>Value</th> </tr> </thead> <tbody> <tr> <td>Request</td> <td>1/1/1/1/1/1</td> </tr> <tr> <td>Response</td> <td>1/1/1/1/1/1</td> </tr> <tr> <td>Request Time</td> <td>1/1/1/1/1/1</td> </tr> <tr> <td>Response Time</td> <td>1/1/1/1/1/1</td> </tr> <tr> <td>Request Size</td> <td>1/1/1/1/1/1</td> </tr> <tr> <td>Response Size</td> <td>1/1/1/1/1/1</td> </tr> <tr> <td>Total Time</td> <td>1/1/1/1/1/1</td> </tr> </tbody> </table>	Name	Value	Request	1/1/1/1/1/1	Response	1/1/1/1/1/1	Request Time	1/1/1/1/1/1	Response Time	1/1/1/1/1/1	Request Size	1/1/1/1/1/1	Response Size	1/1/1/1/1/1	Total Time	1/1/1/1/1/1
Name	Value																
Request	1/1/1/1/1/1																
Response	1/1/1/1/1/1																
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Response Time	1/1/1/1/1/1																
Request Size	1/1/1/1/1/1																
Response Size	1/1/1/1/1/1																
Total Time	1/1/1/1/1/1																
21. Check ESB/back end for the verification of the messages. Database: CMB2DEVC Check Source and Target column in the table "KCPL_ESB_AUDIT".	21. Column REQ_RSP_IND to verify if the message sent is a request or response (REQ or RSP) checked.																

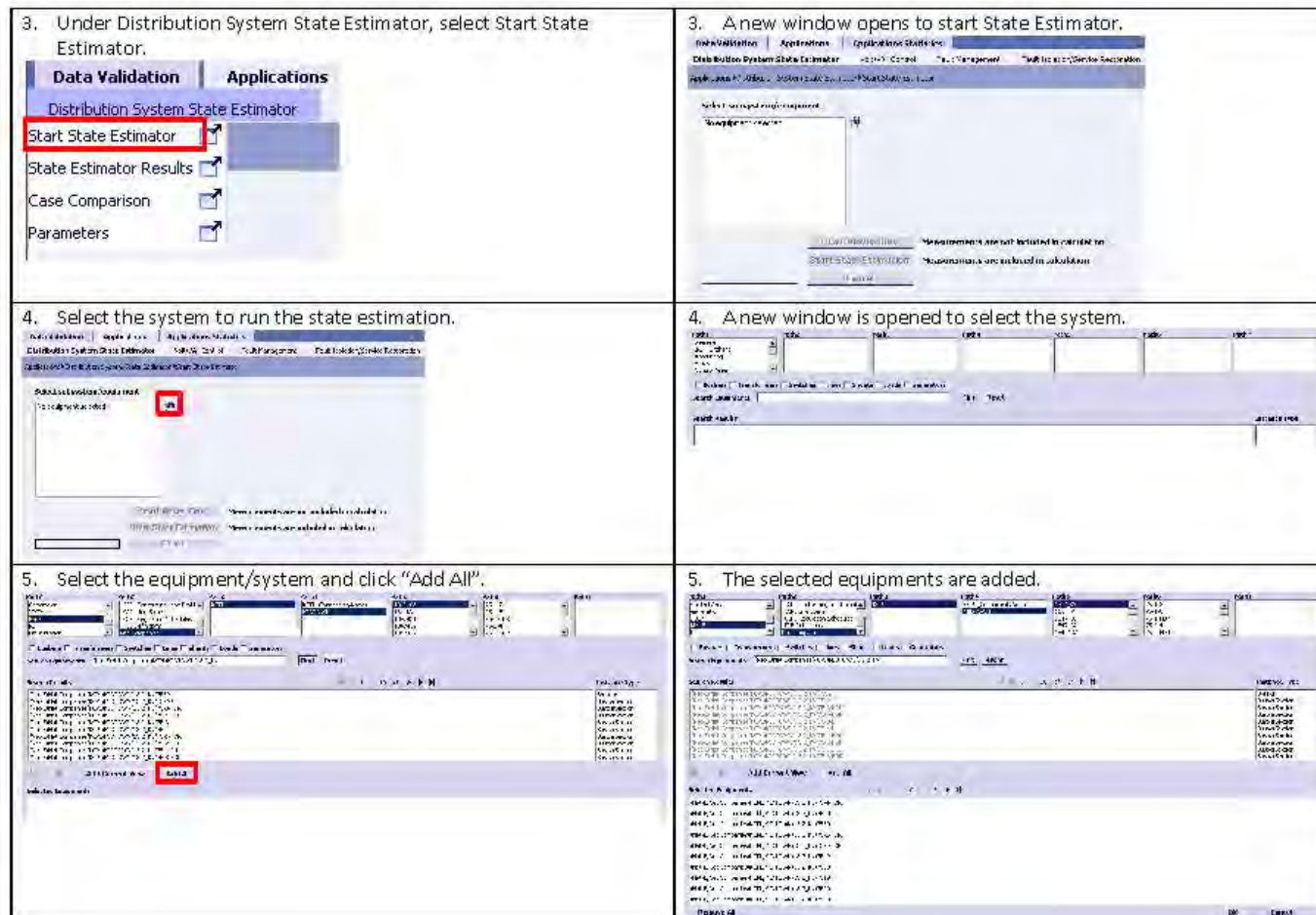
Demand Response – AMI Thermostat

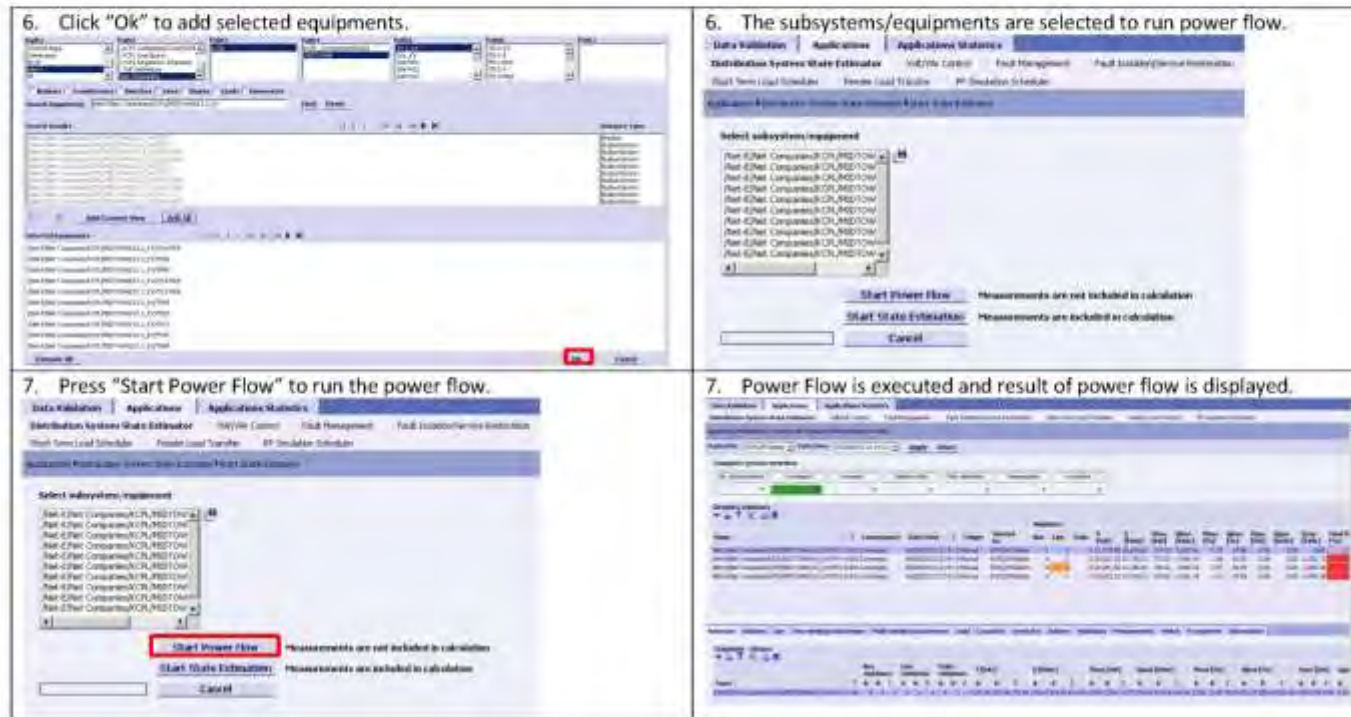


Scheduled Demand Response: AMI Thermostat Operation

Pre-Condition: An overload is occurred in a feeder.

1. Log in to PowerCC/DMS. 	1. Successfully logged in to PowerCC/DMS. 
2. Select Applications. 	2. WebUI displays the distribution network applications. 





8. Verify in the DMS server log that the message has been sent to DERM. Go to Network > DMS01 > powercc > temp > DERM. And select
OUT_RT_MsgCreatedDistributionPowerFlowLimitViolations51.xml with the latest time stamp.



8. The log file is opened that verified that violations have been sent to DERM.



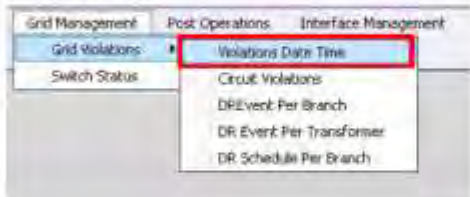
9. Log in to the DERM webUI.



9. Successful log in to DERM webUI.



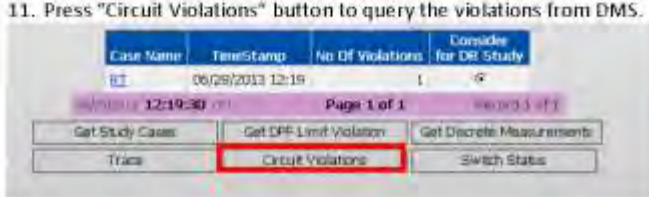
10. Under Grid Management, select Grid Violations and then Violations Date Time.



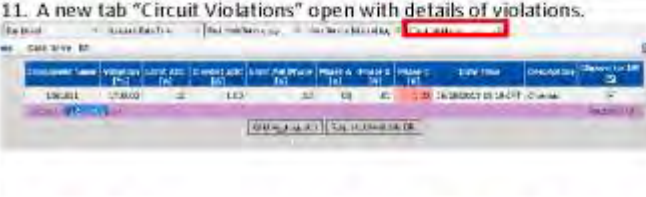
10. A new window/tab with violations is opened.



11. Press "Circuit Violations" button to query the violations from DMS.



11. A new tab "Circuit Violations" open with details of violations.



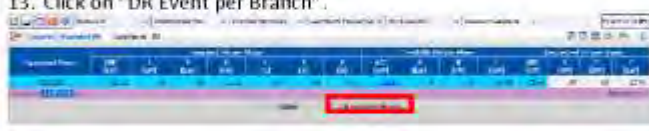
12. Since there is only 1 overload, click "Grid Aggregation".



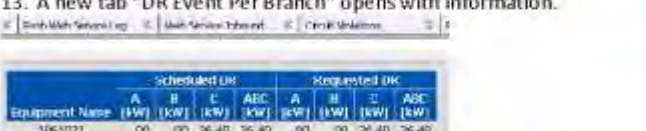
12. A new tab "Required\Available DR" opens with required and available DR.



13. Click on "DR Event per Branch".



13. A new tab "DR Event Per Branch" opens with information.



14. Click on "DR Event per Transformer".

06/28/2013 12:21:11 CPT Page 1 of 1 Record 1 of 1

DR Event per Transformer

14. A new tab "DR Event Per Transformer" opens with DR that will be scheduled from each transformer.

06/28/2013 12:21:22 CPT Page 1 of 1 Record 1 of 1

Schedule DR Controls

15. Click on "Schedule DR Controls".

06/28/2013 12:21:22 CPT Page 1 of 1 Record 1 of 1

Schedule DR Controls

15. A schedule DR controls opens and pops up a window to enter schedule information.

Enter Schedule Information

Schedule Name: Grid/Inverter_FT_100_Test_1 (14/21/2013)

Schedule Date: 06/28/2013

Start Time: 12:00

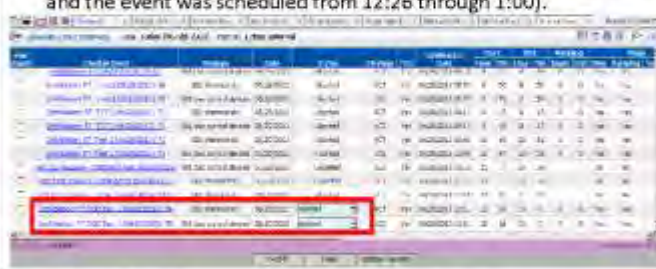
End Time: 12:00

Create Cancel

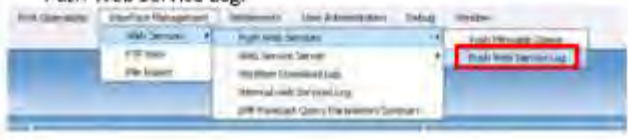
16. Enter the schedule information and press "create".



16. A new page opens that shows the DR events that were committed as a result of the overload, (notification was sent to the HEMP at 12:21, and the event was scheduled from 12:26 through 1:00).

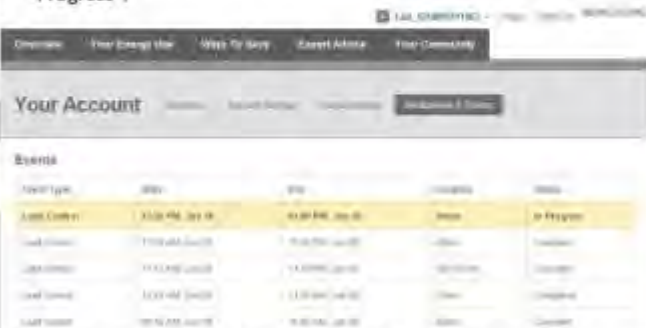


17. Go to Interface Management > Web Services > Push Web Services > Push Web Service Log.



17. This verifies DR message has been sent to HEMP.



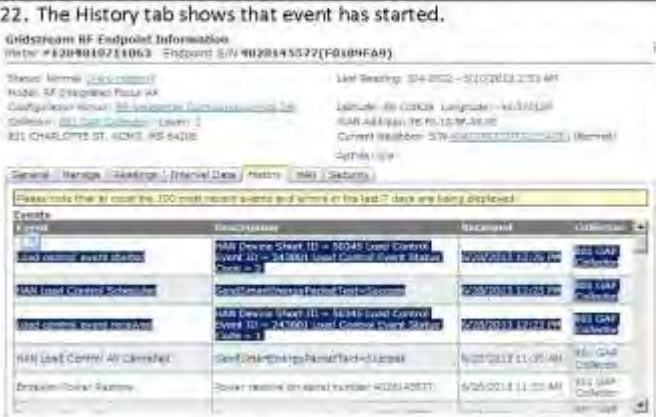
18. Log in to KCP&L portal (HEMP) to verify the devices are off. (DR event is process).	18. The devices connected to the meter ID 1284810711063 are "In Progress".  The screenshot shows the 'Your Account' page with a navigation bar at the top. Below the navigation bar, there's a section titled 'Your Account' with a sub-section 'Events'. A table lists events with columns: Event Type, Date, Time, Status, and Action. The first row is highlighted in yellow, showing 'In Progress' status for meter ID 1284810711063.
19. Check the portal for the DR event completion. (After – event)	19. The devices connected to the meter ID 1284810711063 are "Completed".  The screenshot shows the 'Your Account' page with a navigation bar at the top. Below the navigation bar, there's a section titled 'Your Account' with a sub-section 'Events'. A table lists events with columns: Event Type, Date, Time, Status, and Action. The first row is highlighted in yellow, showing 'Completed' status for meter ID 1284810711063.



22. Select the "History" tab.



22. The History tab shows that event has started.



Event	Description	Timestamp	Collection
Load control event status	RAH Device Sheet ID = 30345 Load Control Event ID = 243801 Load Control Event Status Scale = 1	5/20/2013 1:00 PM	001 GAP Collection
RAH Load Control Schedule	GridStream Energy Services Inc.	5/20/2013 1:00 PM	001 GAP Collection
Load control event status	RAH Device Sheet ID = 30345 Load Control Event ID = 243801 Load Control Event Status Scale = 1	5/20/2013 1:00 PM	001 GAP Collection
RAH Load Control All Cleared	GridStream Energy Services Inc.	5/20/2013 1:00 PM	001 GAP Collection
RAH Load Control All Cleared	GridStream Energy Services Inc.	5/20/2013 1:00 PM	001 GAP Collection

23. Check the History tab for the DR event completion. (After – event)

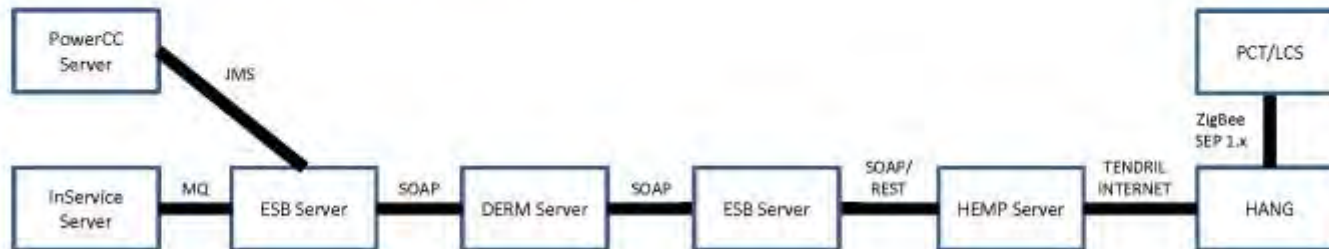


23. The result shows that the event has been successfully completed.



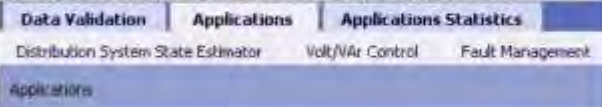
Event	Description	Timestamp	Collection
Load control event completed	RAH Device Sheet ID = 30345 Load Control Event ID = 243801 Load Control Event Status Scale = 1	5/20/2013 1:00 PM	001 GAP Collection
Load control event status	RAH Device Sheet ID = 30345 Load Control Event ID = 243801 Load Control Event Status Scale = 1	5/20/2013 1:00 PM	001 GAP Collection
RAH Load Control Schedule	GridStream Energy Services Inc.	5/20/2013 1:00 PM	001 GAP Collection
Load control event status	RAH Device Sheet ID = 30345 Load Control Event ID = 243801 Load Control Event Status Scale = 1	5/20/2013 1:00 PM	001 GAP Collection
RAH Load Control All Cleared	GridStream Energy Services Inc.	5/20/2013 1:00 PM	001 GAP Collection

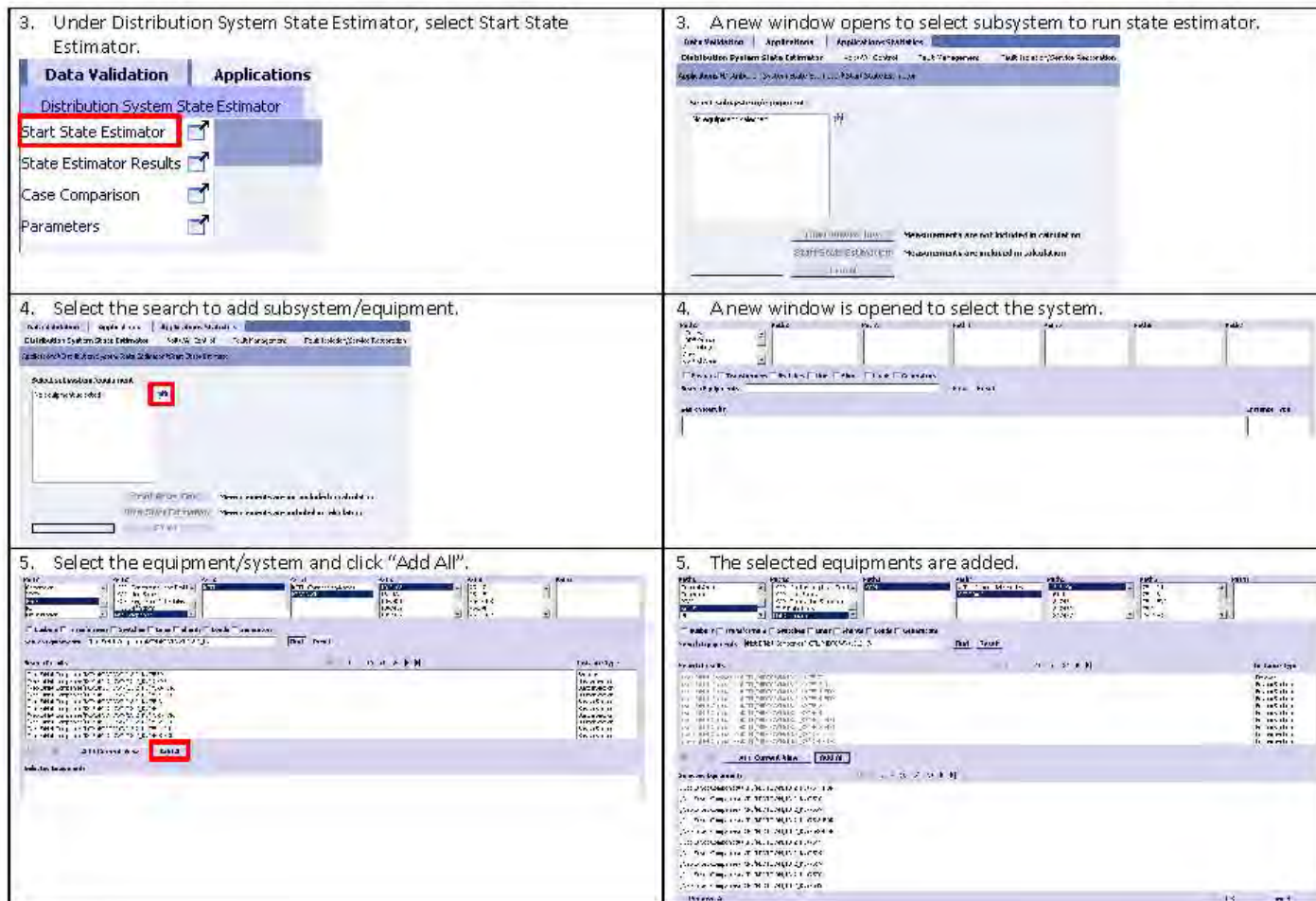
Demand Response – HAN Devices



Scheduled Demand Response: HAN Devices Operation

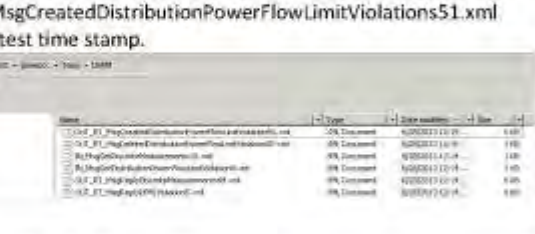
Pre-Condition: An overload is occurred in a feeder.

Steps	Expected Result
1. Log in to PowerCC/DMS. 	1. Successfully logged in to PowerCC/DMS. 
2. Go to Applications. 	2. WebUI displays the distribution network applications. 





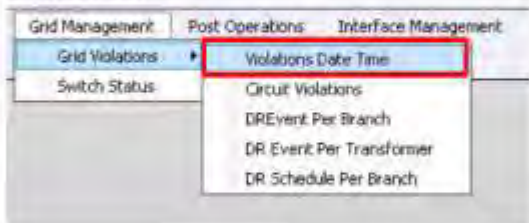
8. Verify in the DMS server log that the message has been sent to DERM. Go to Network > DMS01 > powercc > temp > DERM. And select OUT_RT_MsgCreatedDistributionPowerFlowLimitViolations\$1.xml with the latest time stamp.



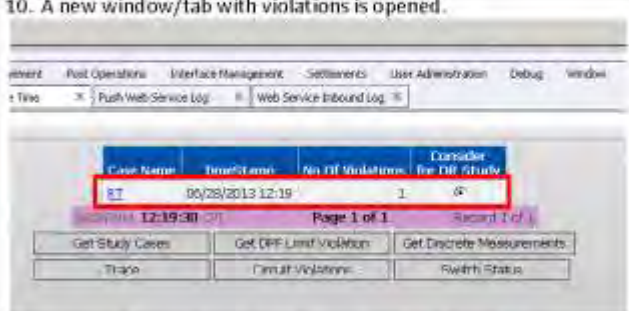
8. The log file is opened that verified that violations have been sent to DERM.



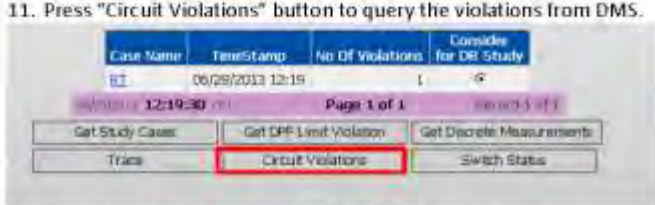
10. Under Grid Management, select Grid Violations and then Violations Date Time.



10. A new window/tab with violations is opened.



11. Press "Circuit Violations" button to query the violations from DMS.



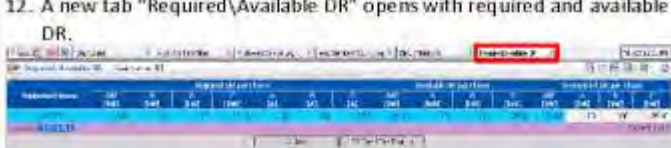
11. A new tab "Circuit Violations" open with details of violations.



12. Since there is only 1 overload, click "Grid Aggregation".



12. A new tab "Required\Available DR" opens with required and available DR.



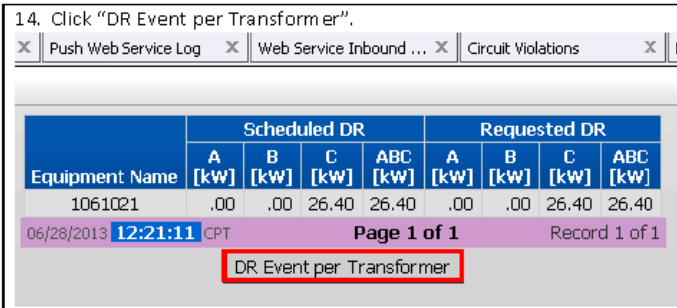
13. Click "DR Event per Branch".



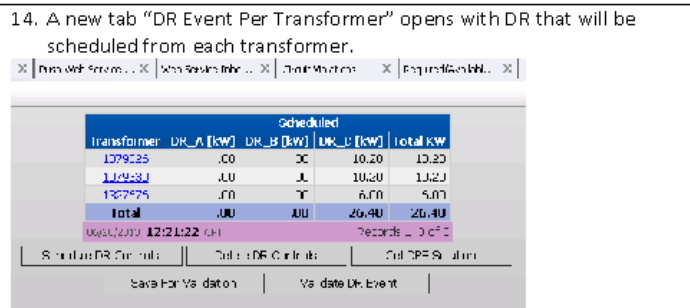
13. A new tab "DR Event Per Branch" opens with information.



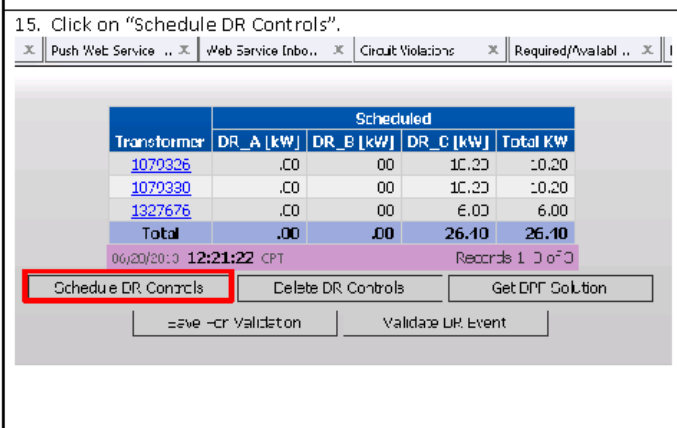
14. Click "DR Event per Transformer".



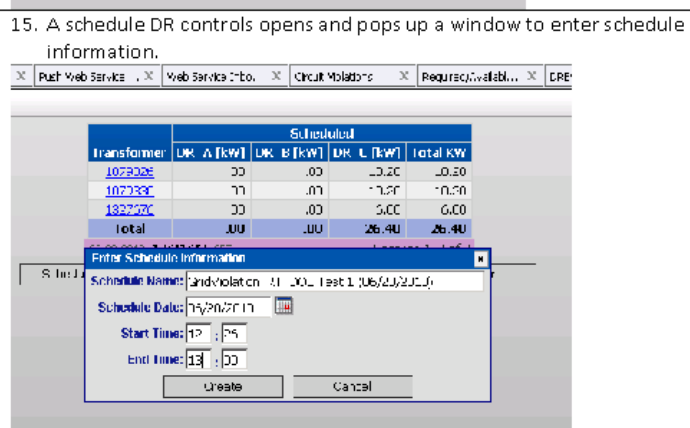
14. A new tab "DR Event Per Transformer" opens with DR that will be scheduled from each transformer.



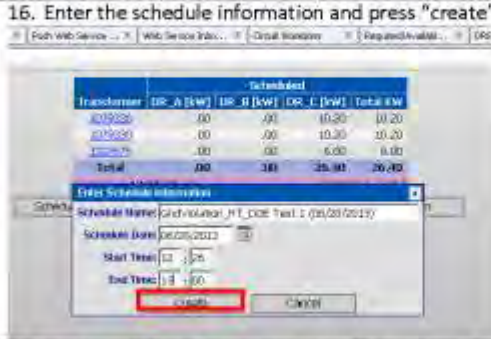
15. Click on "Schedule DR Controls".



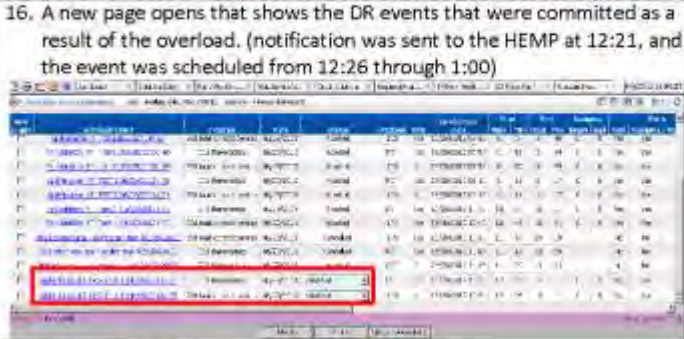
15. A schedule DR controls opens and pops up a window to enter schedule information.



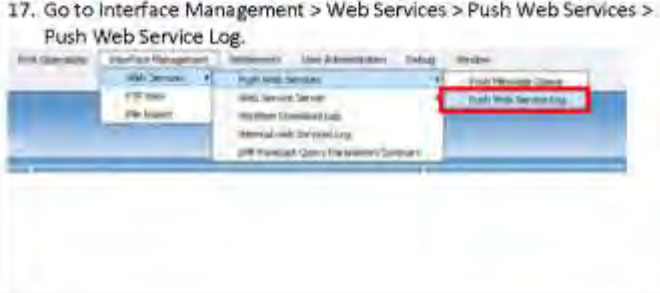
16. Enter the schedule information and press "create".



16. A new page opens that shows the DR events that were committed as a result of the overload. (notification was sent to the HEMP at 12:21, and the event was scheduled from 12:26 through 1:00)



17. Go to Interface Management > Web Services > Push Web Services > Push Web Service Log.



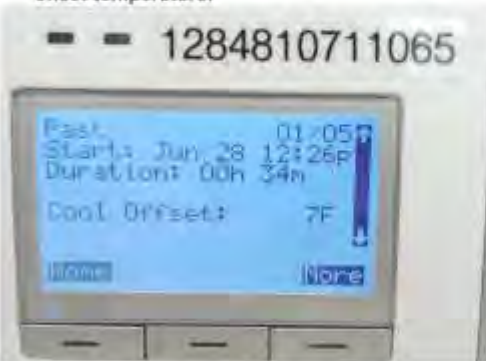
17. This verifies DR message has been sent to HEMP.



18. Verify the DR events in HAN devices. Check the thermostat before the event starts. (Pre-event)	18. The thermostat shows the start date, start time and duration.  A close-up of a thermostat screen. At the top, the address "1284810711065" is displayed. The screen shows "Pending" at the top, followed by "Start: Jun 28 12:26p" and "Duration: 00h 34m". Below this, it says "Cool Offset: 7F". At the bottom, there are three buttons: "Cancel", "Accept", and "More". <table border="1"><thead><tr><th>Field</th><th>Value</th></tr></thead><tbody><tr><td>Address</td><td>1284810711065</td></tr><tr><td>Status</td><td>Pending</td></tr><tr><td>Start</td><td>Jun 28 12:26p</td></tr><tr><td>Duration</td><td>00h 34m</td></tr><tr><td>Cool Offset</td><td>7F</td></tr></tbody></table>	Field	Value	Address	1284810711065	Status	Pending	Start	Jun 28 12:26p	Duration	00h 34m	Cool Offset	7F				
Field	Value																
Address	1284810711065																
Status	Pending																
Start	Jun 28 12:26p																
Duration	00h 34m																
Cool Offset	7F																
19. Check the thermostat for temperature offset before the event start. (Pre-event)	19. Temperature before the event.  A close-up of a thermostat screen. At the top, the address "1284810711065" is displayed. The screen shows "End Jun 28 12:24p" at the top. The current temperature is "73°F" and the setpoint is "70°F". Below this, it says "Cool away Auto 52". At the bottom, it shows "11:00 AM" and "80.074 kWh". There are three buttons: "Cancel", "Accept", and "Message". <table border="1"><thead><tr><th>Field</th><th>Value</th></tr></thead><tbody><tr><td>Address</td><td>1284810711065</td></tr><tr><td>Status</td><td>End Jun 28 12:24p</td></tr><tr><td>Temp</td><td>73°F</td></tr><tr><td>Setpoint</td><td>70°F</td></tr><tr><td>Mode</td><td>Cool away Auto 52</td></tr><tr><td>Time</td><td>11:00 AM</td></tr><tr><td>Energy</td><td>80.074 kWh</td></tr></tbody></table>	Field	Value	Address	1284810711065	Status	End Jun 28 12:24p	Temp	73°F	Setpoint	70°F	Mode	Cool away Auto 52	Time	11:00 AM	Energy	80.074 kWh
Field	Value																
Address	1284810711065																
Status	End Jun 28 12:24p																
Temp	73°F																
Setpoint	70°F																
Mode	Cool away Auto 52																
Time	11:00 AM																
Energy	80.074 kWh																

20. Log in to KCP&L portal (HEMP) to verify the devices are off. (DR event is process)	20. The devices connected to the meter ID 1284810711065 are off.  The screenshot shows the KCP&L portal interface. The 'Your Account' section is highlighted with a red box, showing a temperature of 73°. Below it, the 'Events' table lists several events, with the first two highlighted in yellow and red boxes around the 'Status' column. <table border="1"> <thead> <tr> <th>Event/Exception</th> <th>Event Type</th> <th>Start</th> <th>End</th> <th>Duration</th> <th>Status</th> </tr> </thead> <tbody> <tr> <td>Up to</td> <td>Load Control</td> <td>11:00 PM, Jan 26</td> <td>11:00 PM, Jan 26</td> <td>1 Hour</td> <td>As Expected</td> </tr> <tr> <td>Up to</td> <td>Load Control</td> <td>11:00 PM, Jan 26</td> <td>11:00 PM, Jan 26</td> <td>1 Hour</td> <td>As Expected</td> </tr> </tbody> </table>	Event/Exception	Event Type	Start	End	Duration	Status	Up to	Load Control	11:00 PM, Jan 26	11:00 PM, Jan 26	1 Hour	As Expected	Up to	Load Control	11:00 PM, Jan 26	11:00 PM, Jan 26	1 Hour	As Expected
Event/Exception	Event Type	Start	End	Duration	Status														
Up to	Load Control	11:00 PM, Jan 26	11:00 PM, Jan 26	1 Hour	As Expected														
Up to	Load Control	11:00 PM, Jan 26	11:00 PM, Jan 26	1 Hour	As Expected														
21. Log in to the KCP&L Portal to verify the temperature.	21. The portal shows that the temperature has been set to the preset temperature of 73°F.  The screenshot shows the KCP&L portal interface. The 'Your Account' section is highlighted with a red box, showing a temperature of 77°. Below it, the 'Events' table lists several events, with the first two highlighted in yellow and red boxes around the 'Status' column. <table border="1"> <thead> <tr> <th>Event/Exception</th> <th>Event Type</th> <th>Start</th> <th>End</th> <th>Duration</th> <th>Status</th> </tr> </thead> <tbody> <tr> <td>Up to</td> <td>Load Control</td> <td>11:00 PM, Jan 26</td> <td>11:00 PM, Jan 26</td> <td>1 Hour</td> <td>As Expected</td> </tr> <tr> <td>Up to</td> <td>Load Control</td> <td>11:00 PM, Jan 26</td> <td>11:00 PM, Jan 26</td> <td>1 Hour</td> <td>As Expected</td> </tr> </tbody> </table>	Event/Exception	Event Type	Start	End	Duration	Status	Up to	Load Control	11:00 PM, Jan 26	11:00 PM, Jan 26	1 Hour	As Expected	Up to	Load Control	11:00 PM, Jan 26	11:00 PM, Jan 26	1 Hour	As Expected
Event/Exception	Event Type	Start	End	Duration	Status														
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Up to	Load Control	11:00 PM, Jan 26	11:00 PM, Jan 26	1 Hour	As Expected														

22. Verify the DR events in HAN devices. Check the thermostat before the event starts. (During event)	22. The thermostat shows the DR event start date, time, duration, time remaining and offset temperature.  The thermostat screen displays the following information: Active: 01:05, Start: Jun 28 12:26p, Duration: 00h 34m, Remaining: 00:01:17, Cool Offset: 7F. The screen also shows the address 1284810711065 and three buttons: Home, Message, and Message.
23. Check the thermostat for temperature offset during the event. (during-event)	23. Thermostat shows the temperature offset by DR event.  The thermostat screen displays the following information: Fri Jun 28 12:58p, 73°F, 77°F, Cool Away, Auto, and a price of \$0.074/kWh. The screen also shows the address 1284810711065 and three buttons: Home, Message, and Message.

24. Check the thermostat for the DR event completion. (After – event)	24. The thermostat displays the DR event start date, time, duration and offset temperature.  The thermostat screen displays the following information: - Address: 1284810711065 - Fast: 01:05 - Start: Jun. 28 12:26p - Duration: 00h 34m - Cool Offset: 7F - Buttons: Home, None
25. Check the thermostat for the temperature offset. (After-event)	25. Thermostat shows the temperature offset.  The thermostat screen displays the following information: - Address: 1284810711065 - Fast: Jun. 28 1:01p - Current Temp: 73°F - Setpoint: 70°F - Cool Away: Auto S2 - Cost: \$0.024/kWh - Buttons: Home, Menu, Message

26. Log in to KCP&L portal to verify the devices are on. (DR event complete)

26. The devices connected to the meter ID 1284810711065 are on.



27. In the KCP&L Portal, verify the temperature offset. (After event)

27. The portal shows that the temperature has been set to the preset temperature of 73°F. (After event)



28. Log in to Tendril Utility Load Control to see the DR Event in the Load Control.

28. Load Control summary for the DR Event.

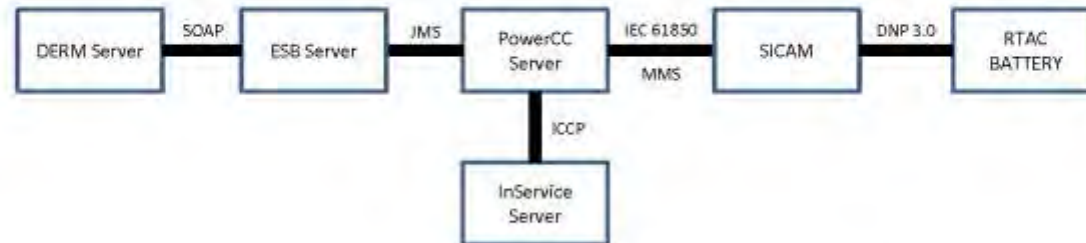
The screenshot displays the 'Load Control' summary for a DR event. It features a table with columns: Load ID, Description, Type, Status, and Load Name. Below the table, there are several sections: 'Load Control' with a 'Load ID' field, 'Load Name' field, and a 'Load Status' dropdown; 'Load Control' with a 'Load ID' field, 'Load Name' field, and a 'Load Status' dropdown; and 'Load Control' with a 'Load ID' field, 'Load Name' field, and a 'Load Status' dropdown. There are also checkboxes for 'Load Control' and 'Load Status'.

29. DR event as seen in the load control.

29. DR event summary of the device for the given device ID.

The screenshot displays the 'DR event summary of the device for the given device ID'. It features a table with columns: Device ID, Description, Type, Status, and Device Name. Below the table, there are several sections: 'Device ID' with a 'Device ID' field, 'Device Name' field, and a 'Device Status' dropdown; 'Device ID' with a 'Device ID' field, 'Device Name' field, and a 'Device Status' dropdown; and 'Device ID' with a 'Device ID' field, 'Device Name' field, and a 'Device Status' dropdown. There are also checkboxes for 'Device ID' and 'Device Status'.

Demand Response – Battery



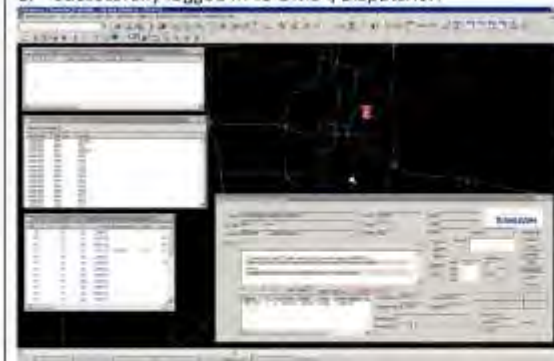
Scheduled Demand Response: Battery Operation

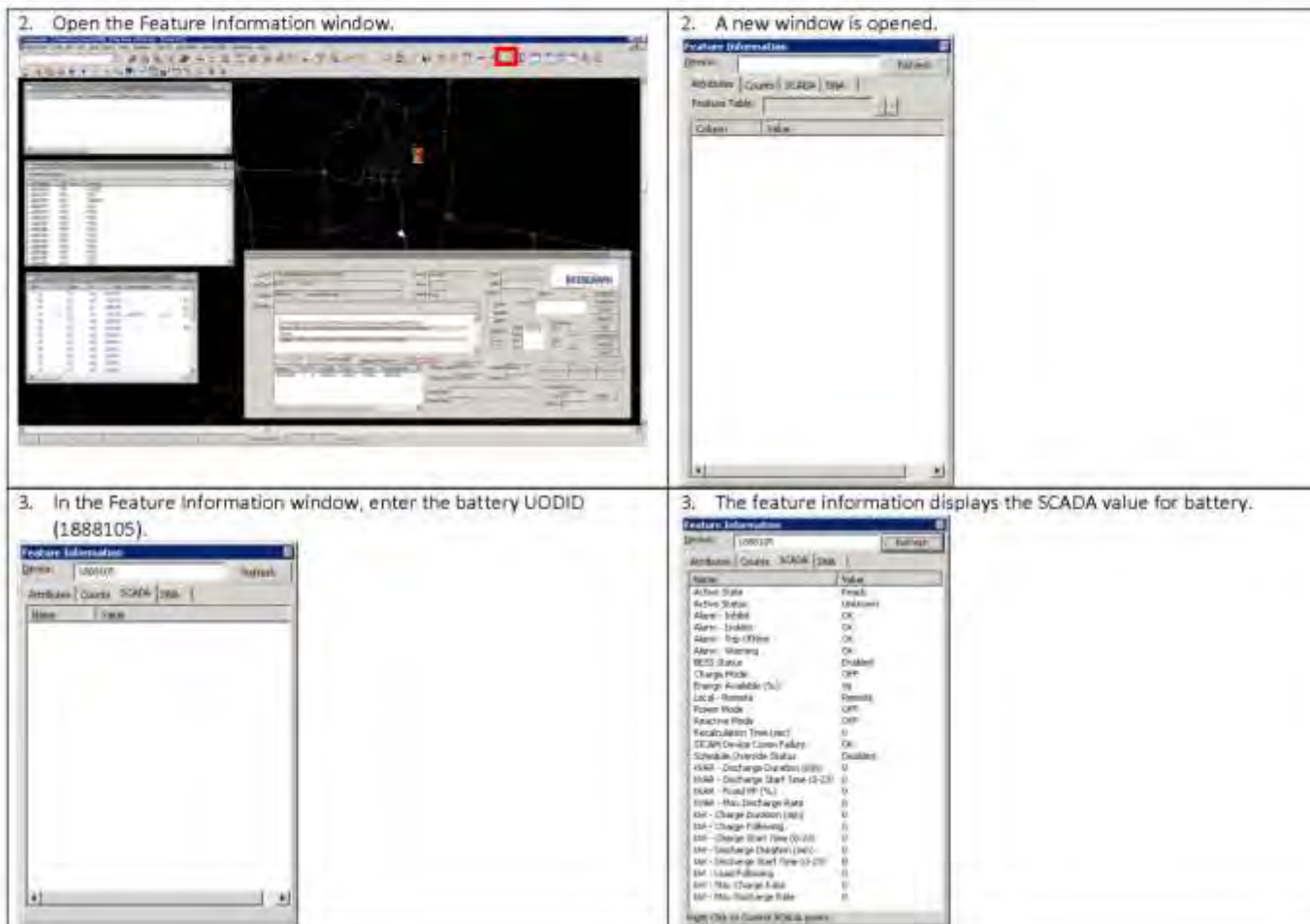
Pre-Condition: Battery must be fully charged

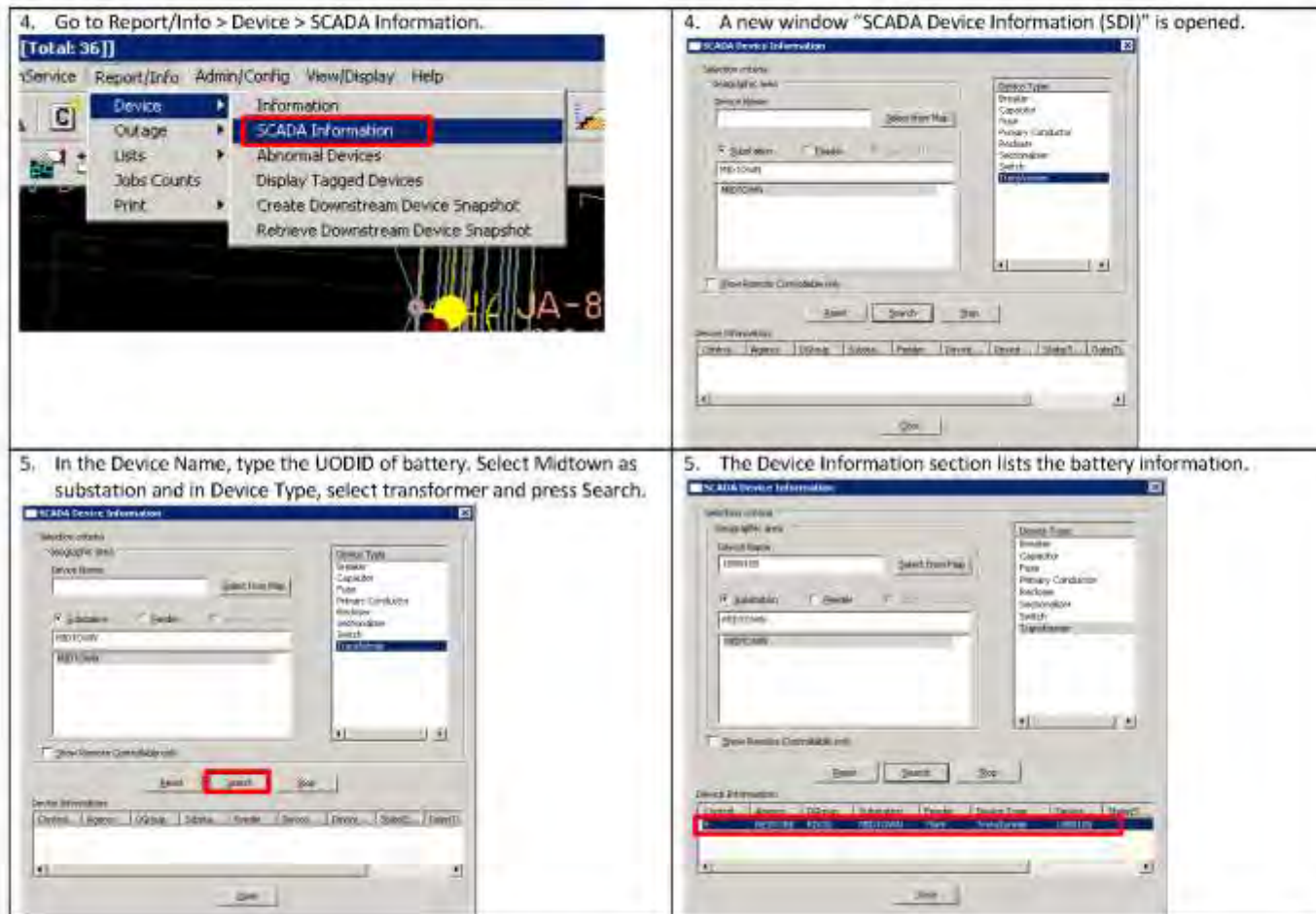
1. Log in to OMS i/Dispatcher.



1. Successfully logged in to OMS i/Dispatcher.







6. Go to Set Power Mode and select DERM.



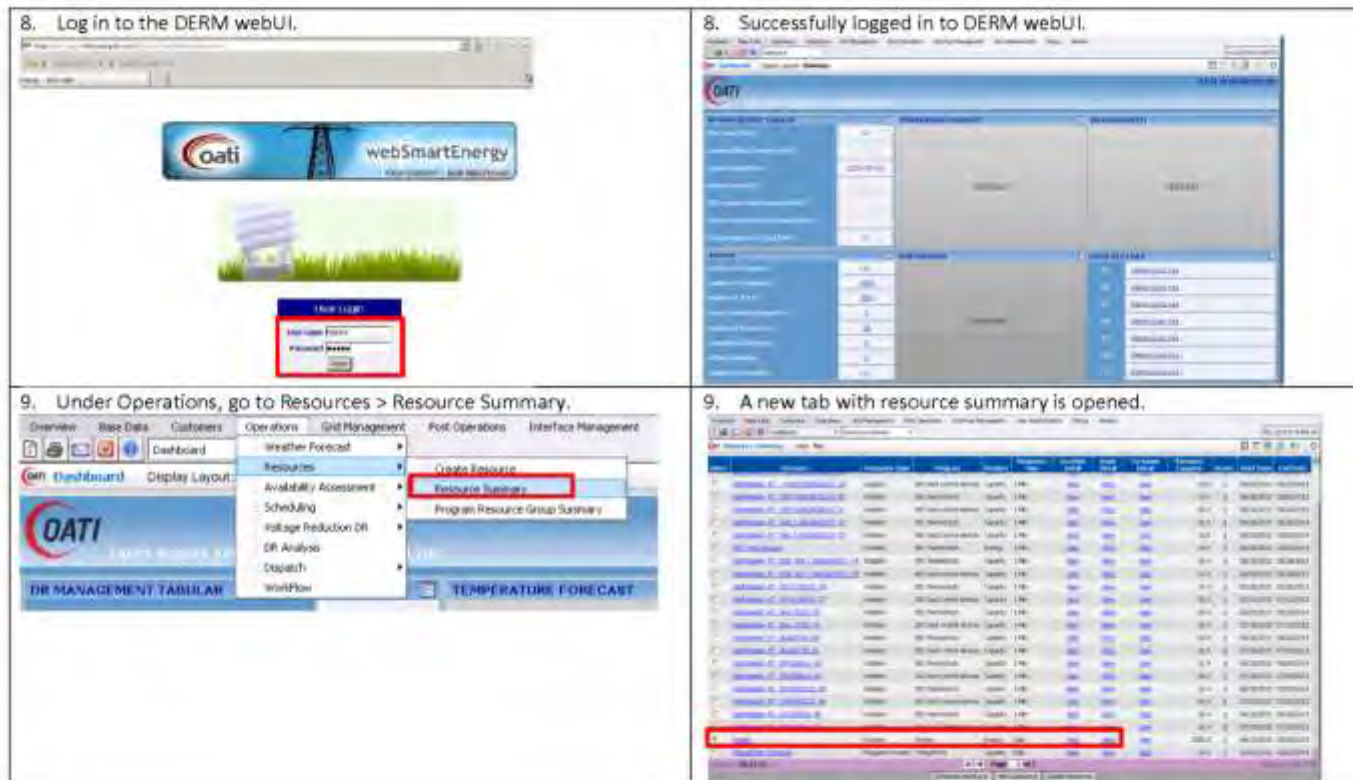
6. The Battery is now set to DERM mode.

7. Open the Feature Information window and enter the battery UODID (1888105).



7. The power mode is updated to DERM mode.





10. Select the battery from the list of resources and press "Schedule Resource".



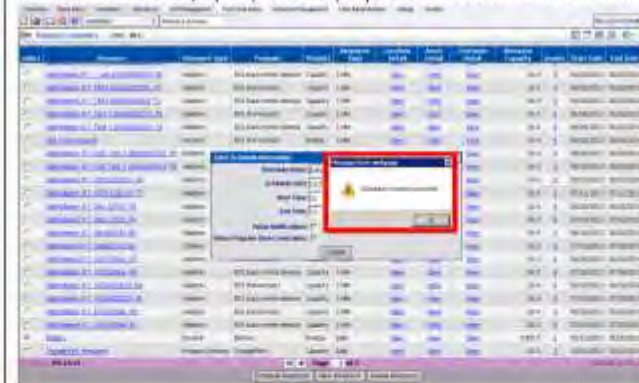
10. A new window pops up to enter the schedule information.



11. Enter the schedule information with name, date, start and end time. Then press Create.



11. A new window pops up that displays the schedule has been created.

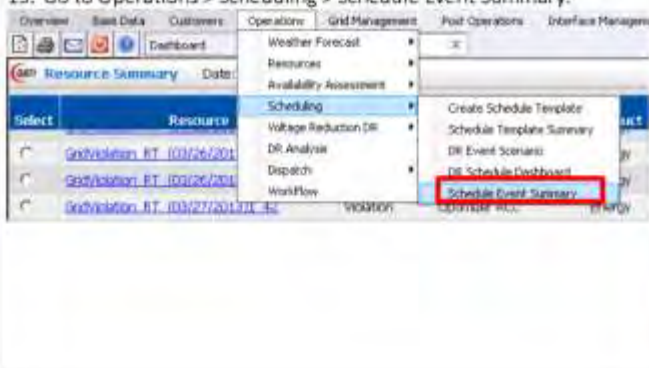


12. Press OK.



12. The event has been created.

13. Go to Operations > Scheduling > Schedule Event Summary.



13. A new tab with Schedule Event Summary appears.



14. Notice that the event is "Committed" now. After the event has been sent to ESB, the status will change to "Notified".

Event ID	Event Name	Status	Created Time	Updated Time	Event Type	Event Data
1	Event 1	Committed	2013-10-10 10:10:10	2013-10-10 10:10:10	Event Type 1	Event Data 1
2	Event 2	Committed	2013-10-10 10:10:10	2013-10-10 10:10:10	Event Type 2	Event Data 2
3	Event 3	Committed	2013-10-10 10:10:10	2013-10-10 10:10:10	Event Type 3	Event Data 3
4	Event 4	Committed	2013-10-10 10:10:10	2013-10-10 10:10:10	Event Type 4	Event Data 4
5	Event 5	Committed	2013-10-10 10:10:10	2013-10-10 10:10:10	Event Type 5	Event Data 5
6	Event 6	Committed	2013-10-10 10:10:10	2013-10-10 10:10:10	Event Type 6	Event Data 6
7	Event 7	Committed	2013-10-10 10:10:10	2013-10-10 10:10:10	Event Type 7	Event Data 7
8	Event 8	Committed	2013-10-10 10:10:10	2013-10-10 10:10:10	Event Type 8	Event Data 8
9	Event 9	Committed	2013-10-10 10:10:10	2013-10-10 10:10:10	Event Type 9	Event Data 9
10	Event 10	Committed	2013-10-10 10:10:10	2013-10-10 10:10:10	Event Type 10	Event Data 10

14. Notice that the event has the status "Notified".

Event ID	Event Name	Status	Created Time	Updated Time	Event Type	Event Data
1	Event 1	Notified	2013-10-10 10:10:10	2013-10-10 10:10:10	Event Type 1	Event Data 1
2	Event 2	Notified	2013-10-10 10:10:10	2013-10-10 10:10:10	Event Type 2	Event Data 2
3	Event 3	Notified	2013-10-10 10:10:10	2013-10-10 10:10:10	Event Type 3	Event Data 3
4	Event 4	Notified	2013-10-10 10:10:10	2013-10-10 10:10:10	Event Type 4	Event Data 4
5	Event 5	Notified	2013-10-10 10:10:10	2013-10-10 10:10:10	Event Type 5	Event Data 5
6	Event 6	Notified	2013-10-10 10:10:10	2013-10-10 10:10:10	Event Type 6	Event Data 6
7	Event 7	Notified	2013-10-10 10:10:10	2013-10-10 10:10:10	Event Type 7	Event Data 7
8	Event 8	Notified	2013-10-10 10:10:10	2013-10-10 10:10:10	Event Type 8	Event Data 8
9	Event 9	Notified	2013-10-10 10:10:10	2013-10-10 10:10:10	Event Type 9	Event Data 9
10	Event 10	Notified	2013-10-10 10:10:10	2013-10-10 10:10:10	Event Type 10	Event Data 10

15. Go to Interface Management > Web Services > Web Service Server > Web Service Inbound Log.

Web Service Name	Web Service URL	Web Service Inbound Log	Web Service Outbound Log	Web Service Error Log
1	Web Service 1	Web Service Inbound Log	Web Service Outbound Log	Web Service Error Log
2	Web Service 2	Web Service Inbound Log	Web Service Outbound Log	Web Service Error Log
3	Web Service 3	Web Service Inbound Log	Web Service Outbound Log	Web Service Error Log
4	Web Service 4	Web Service Inbound Log	Web Service Outbound Log	Web Service Error Log
5	Web Service 5	Web Service Inbound Log	Web Service Outbound Log	Web Service Error Log
6	Web Service 6	Web Service Inbound Log	Web Service Outbound Log	Web Service Error Log
7	Web Service 7	Web Service Inbound Log	Web Service Outbound Log	Web Service Error Log
8	Web Service 8	Web Service Inbound Log	Web Service Outbound Log	Web Service Error Log
9	Web Service 9	Web Service Inbound Log	Web Service Outbound Log	Web Service Error Log
10	Web Service 10	Web Service Inbound Log	Web Service Outbound Log	Web Service Error Log

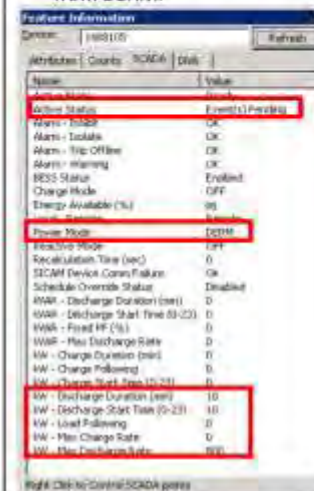
15. A new tab with Web Service Inbound Log is opened. The oadrCreatedEvent was successful.

Web Service Name	Web Service URL	Web Service Inbound Log	Web Service Outbound Log	Web Service Error Log
1	Web Service 1	Web Service Inbound Log	Web Service Outbound Log	Web Service Error Log
2	Web Service 2	Web Service Inbound Log	Web Service Outbound Log	Web Service Error Log
3	Web Service 3	Web Service Inbound Log	Web Service Outbound Log	Web Service Error Log
4	Web Service 4	Web Service Inbound Log	Web Service Outbound Log	Web Service Error Log
5	Web Service 5	Web Service Inbound Log	Web Service Outbound Log	Web Service Error Log
6	Web Service 6	Web Service Inbound Log	Web Service Outbound Log	Web Service Error Log
7	Web Service 7	Web Service Inbound Log	Web Service Outbound Log	Web Service Error Log
8	Web Service 8	Web Service Inbound Log	Web Service Outbound Log	Web Service Error Log
9	Web Service 9	Web Service Inbound Log	Web Service Outbound Log	Web Service Error Log
10	Web Service 10	Web Service Inbound Log	Web Service Outbound Log	Web Service Error Log

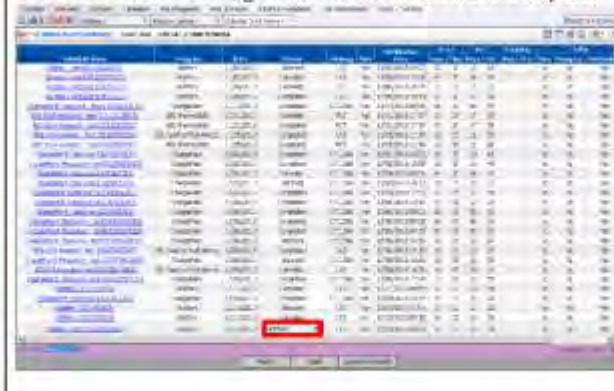
16. In I/Dispatcher, press Refresh in the feature information window, to view the DR event sent by DERM.



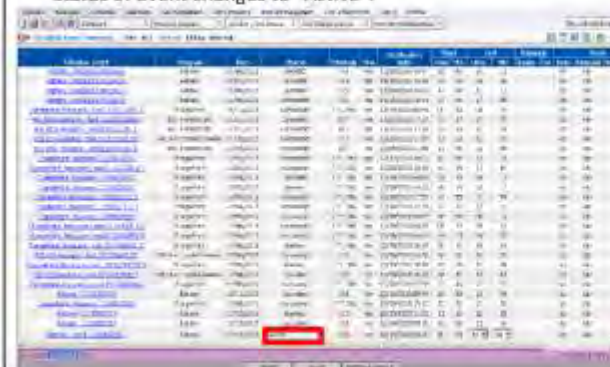
16. The SCADA values are updated after OMS receives the DR event from DERM.

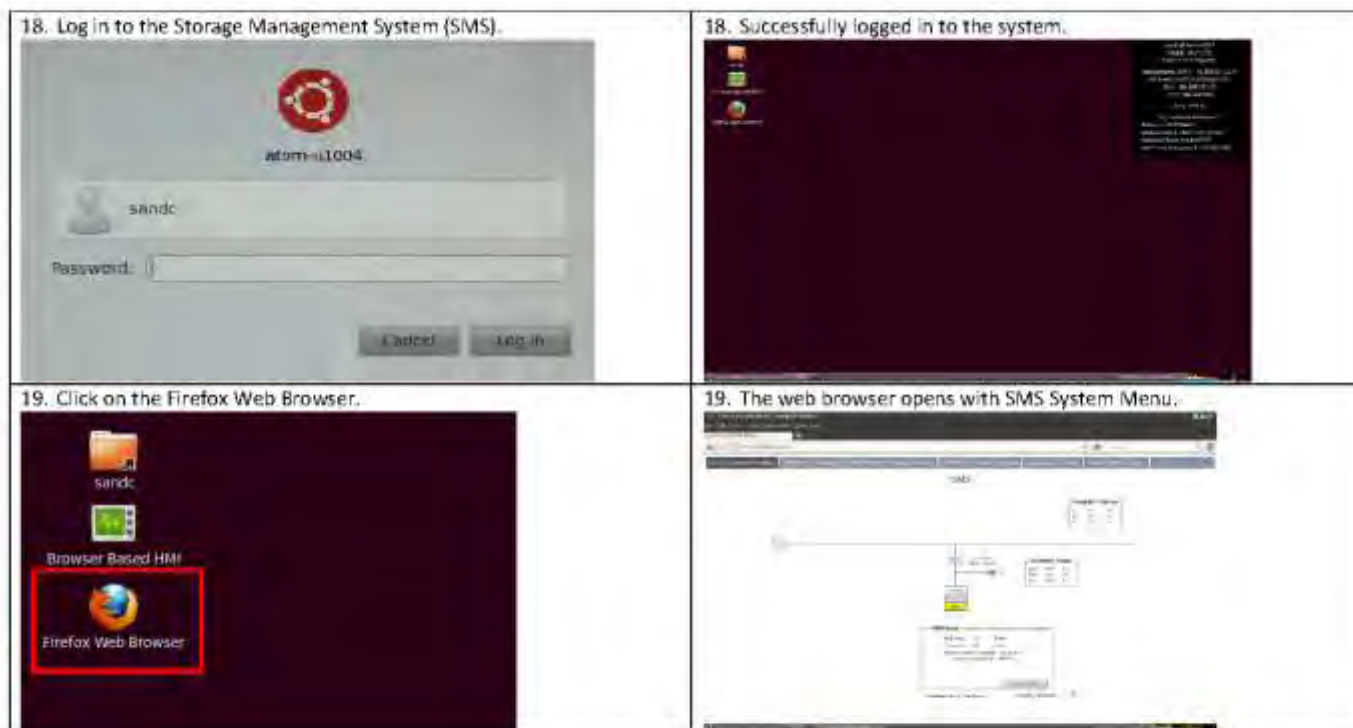


17. In the DERM WebUI, go to the Schedule Event Summary tab.



17. In Schedule Event Summary tab, when the DR event has started, the status of event changes to "Active".



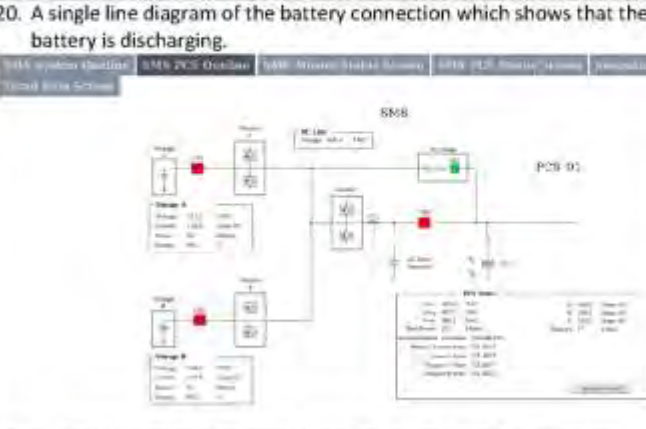


20. Select the SMS PCS Online tab.



The screenshot shows a web interface titled "SMS SYSTEM MENU - Multiple Dispatch". Below the title bar, there are several tabs: "SMS SYSTEM MENU", "SMS PCS Online", "SMS Status Summary", and "SMS PCS Status Summary". The "SMS PCS Online" tab is highlighted with a red box.

20. A single line diagram of the battery connection which shows that the battery is discharging.



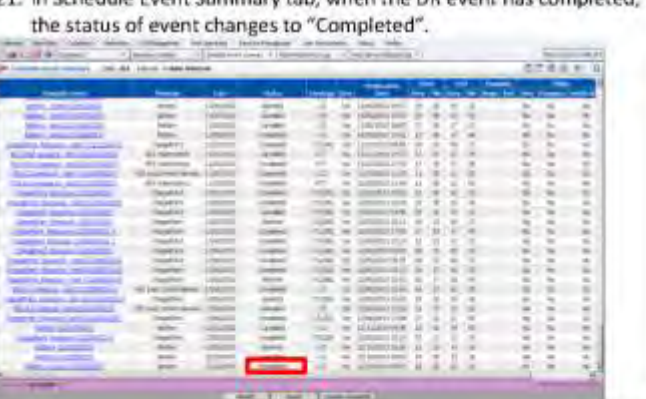
The diagram shows a single line connection between a "SM8" (Source) and a "PCB 02" (Battery). The battery is represented by a symbol with a red arrow pointing out, indicating it is discharging. The diagram includes various electrical symbols and labels for components like "SM8", "PCB 02", and "B1".

21. In the DERM webUI, go to the Schedule Event Summary tab.



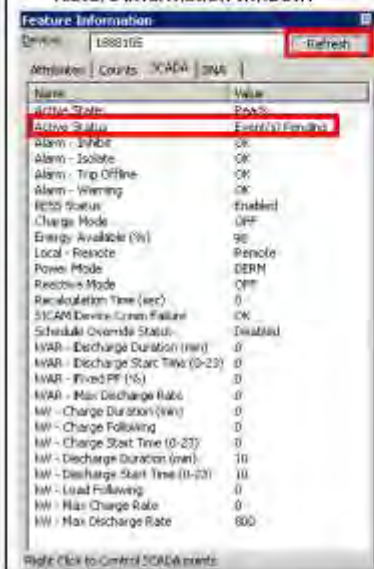
The screenshot shows a table of scheduled events. The table has columns for "Event ID", "Event Name", "Event Type", "Event Status", "Event Start", "Event End", "Event Duration", "Event Location", "Event Priority", "Event Assigned To", "Event Assigned By", "Event Assigned Date", "Event Assigned Time", "Event Assigned Status", "Event Assigned Comment", "Event Assigned User", "Event Assigned Date", "Event Assigned Time", "Event Assigned Status", "Event Assigned Comment", "Event Assigned User". The "Event Status" column is highlighted with a red box.

21. In Schedule Event Summary tab, when the DR event has completed, the status of event changes to "Completed".

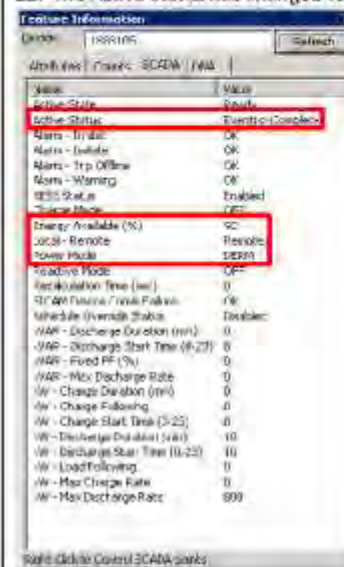


The screenshot shows the same table of scheduled events. The "Event Status" column is highlighted with a red box, and the status of the event has changed to "Completed".

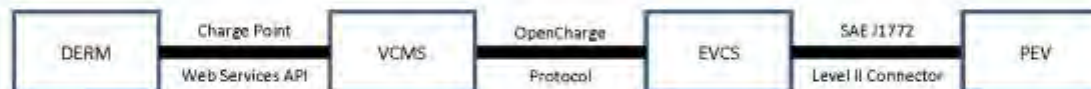
22. In I/Dispatcher, after the event has completed, hit refresh in the feature information window.



22. The Active status has changed to Event(s) Complete.



Demand Response – EVCS



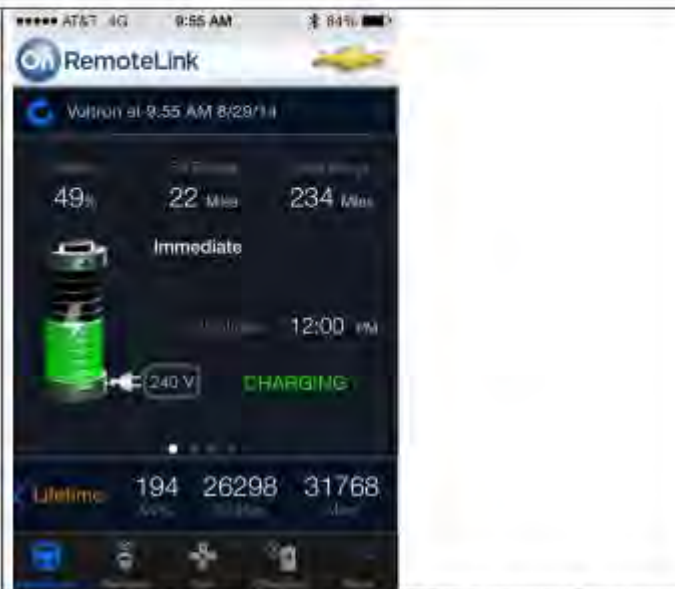
Scheduled Demand Response: Electric Vehicle Charging Station Operation

Pre-Condition: Electric vehicle is at the Midtown Substation charge station and requires charge.

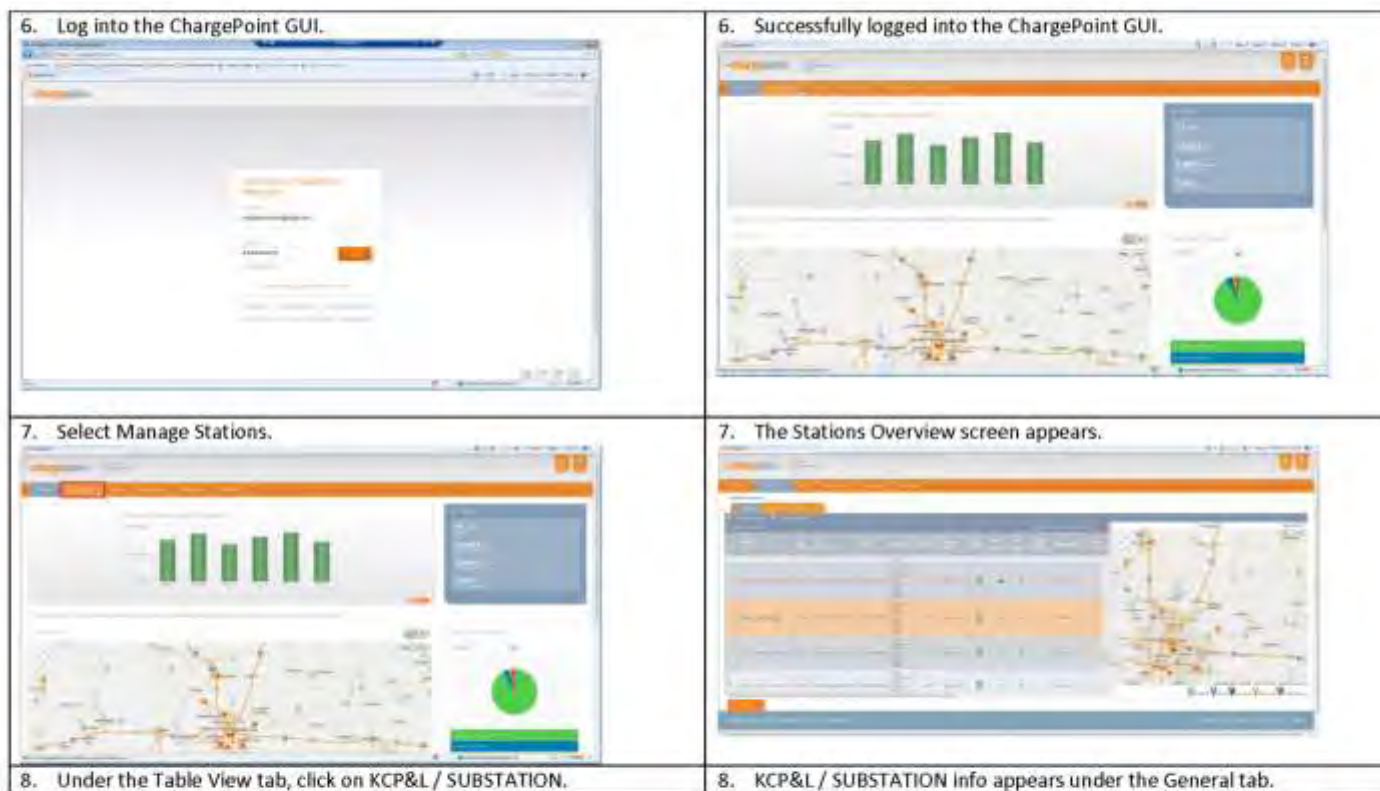
1. Start the Chevy Volt (prior to plugging in) to see current state of battery charge.	1. Based on the Volt's dashboard, the vehicle has 24 miles remaining on the battery prior to requiring additional charging. 
2. Turn on OnStar phone application to get another view of the vehicle's status.	2. According to the OnStar app, the Volt's battery is currently 48% charged.



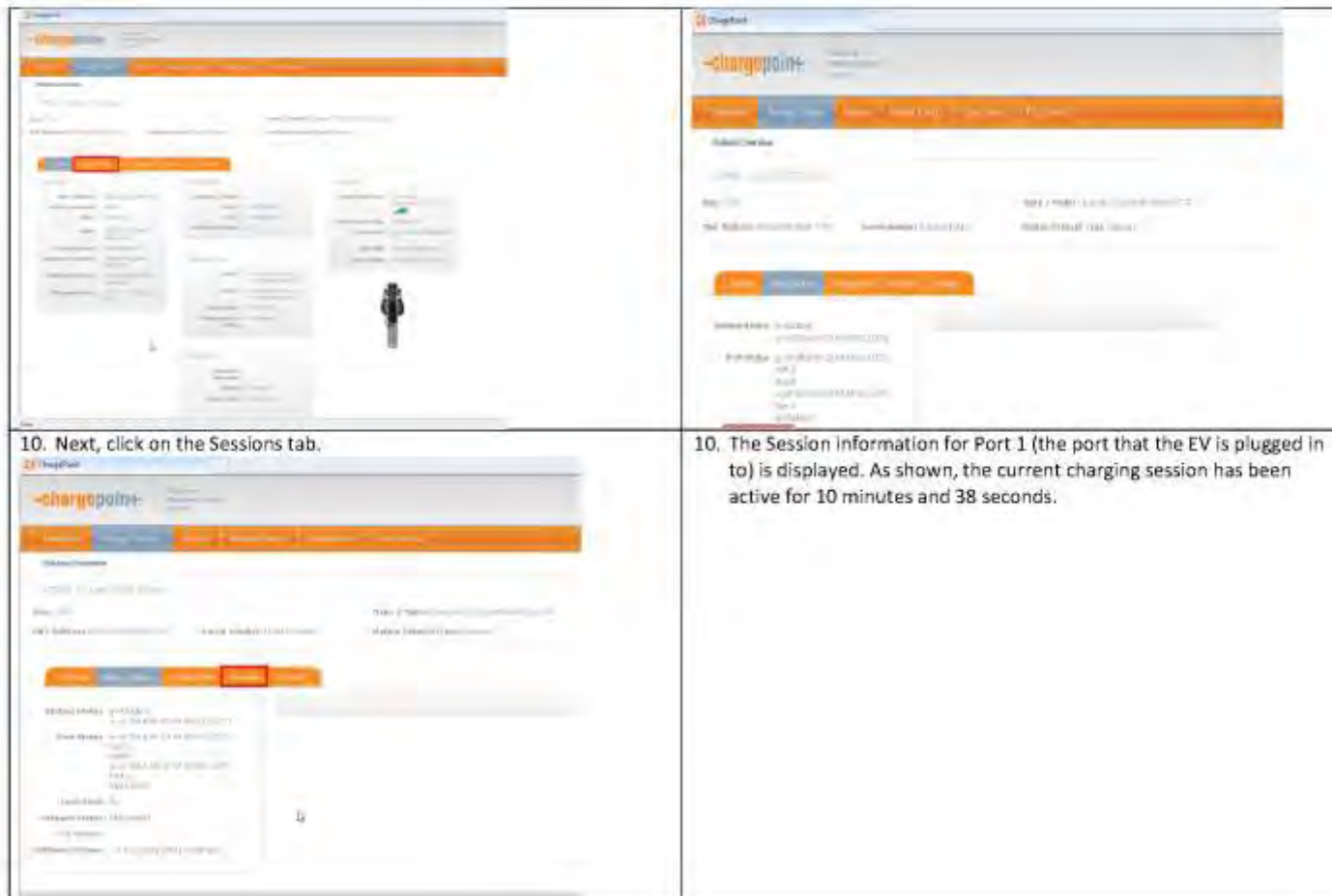
	
4. Turn on OnStar phone application to get another view of the vehicle's status.	4. According to the OnStar app, the Volt's battery is currently "CHARGING" and is now 49% charged.

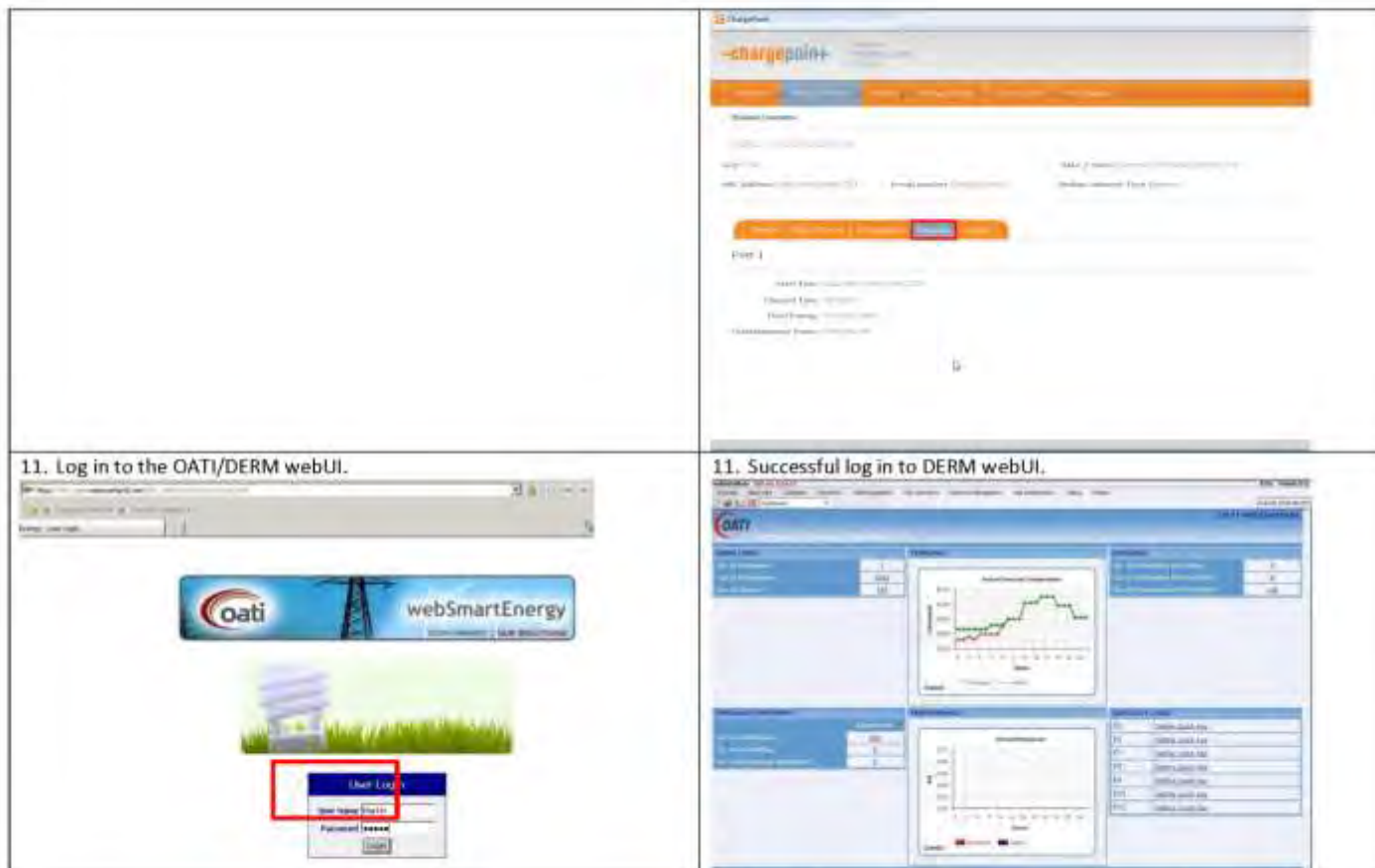
	
5. Look at the charging station's electronic display for the status of Port 1 and Port 2.	5. The charge station display reads (where "..." indicates scrolling to the next screen): "KCP&L SUBSTATION...CHARGEPOINT STATION: 7703.....#1 CHARGING 00:01:32 / 3.36 KW / TAP CARD TO END...#2 AVAILABLE TAP CARD TO START" This indicates that a vehicle has been plugged in and charging from Port 1 for 1 minute and 32 seconds. The 3.36kW indicates the rate of charge, i.e. kWh.

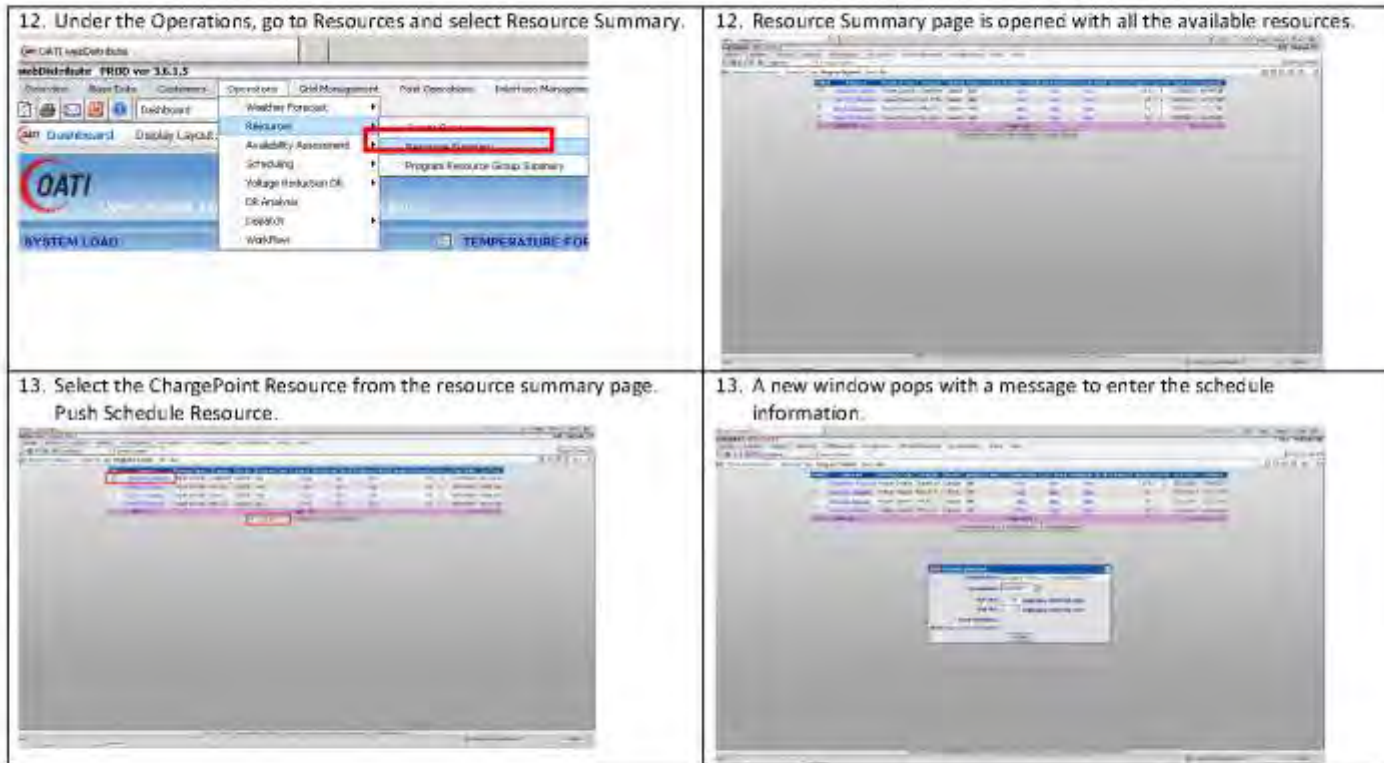


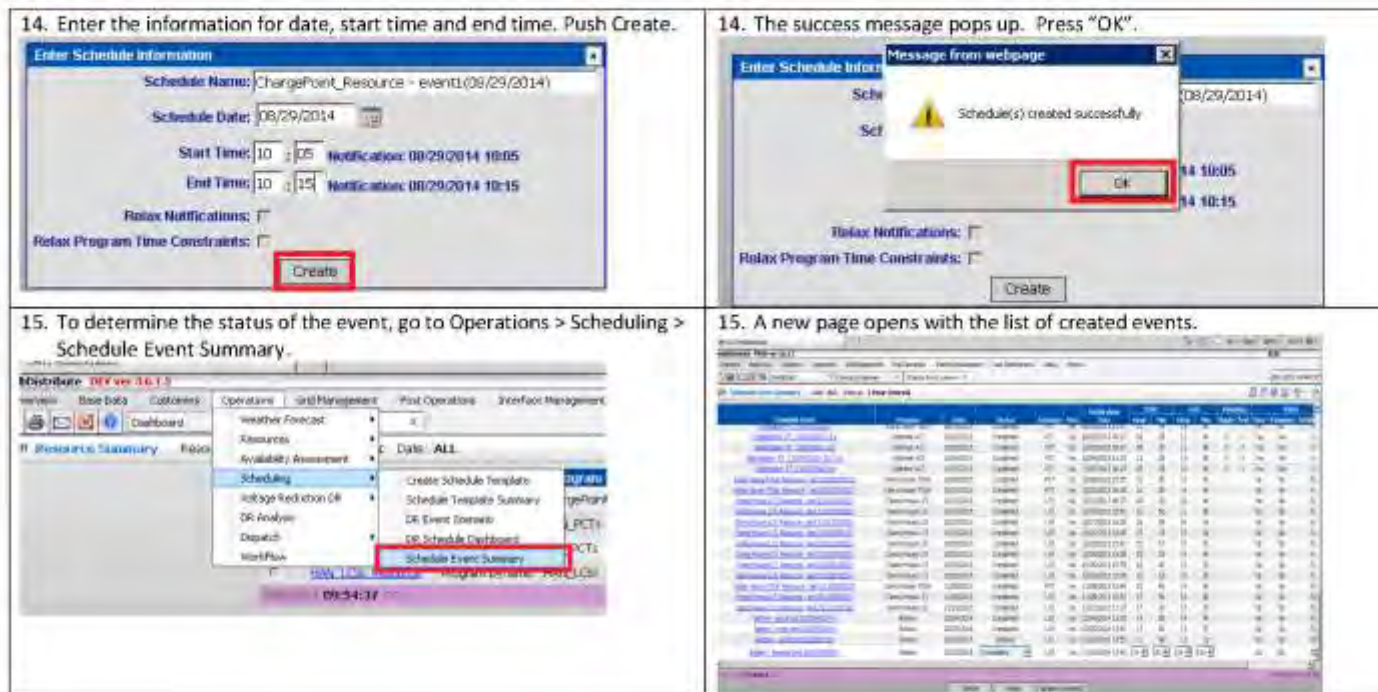


	
9. Click on the Status/Actions tab.	9. The following information about the Midtown charging station appears. As displayed, Port 1 is "INUSE" and Port 2 is "AVAILABLE." Load Shed = No, designating that no DR events are presently occurring.

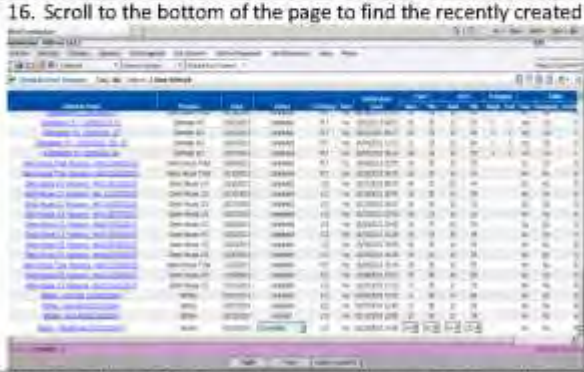








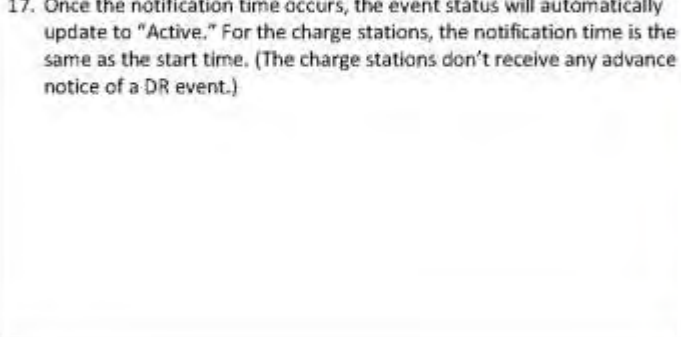
16. Scroll to the bottom of the page to find the recently created event.



16. Note that it is in a "Committed" state.



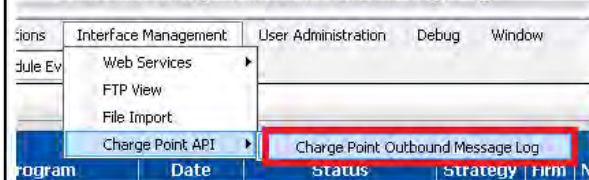
17. Once the notification time occurs, the event status will automatically update to "Active." For the charge stations, the notification time is the same as the start time. (The charge stations don't receive any advance notice of a DR event.)



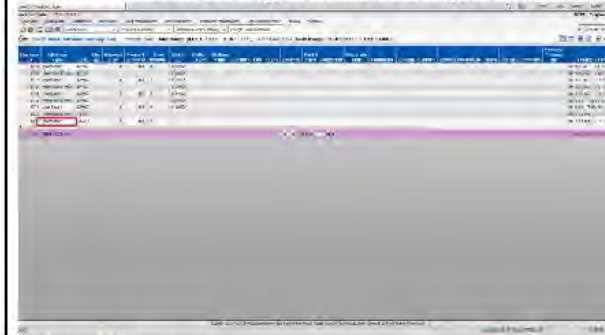
17. Check that the status has changed to "Active".



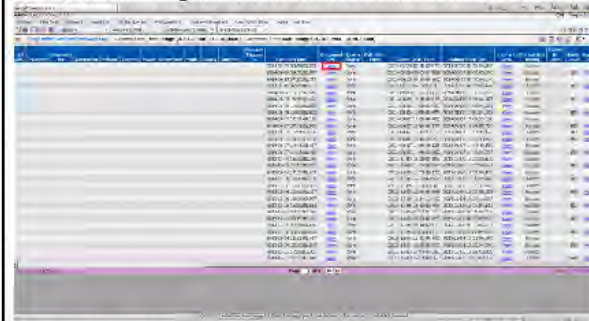
18. To view the event payload, go to Interface Management > Charge Point API > Charge Point Outbound Message Log.



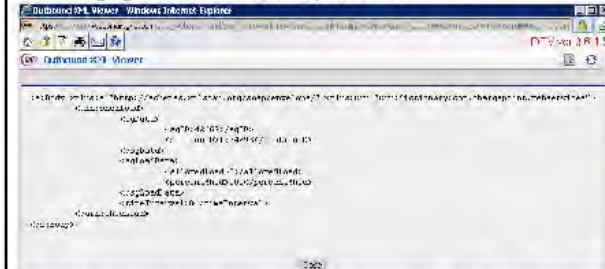
18. A new page with the list of messages is opened. There is a new message called "Shed Load" indicating that the DR event message was sent from OATI to Charge Point via the Charge Point API.



19. Scroll to the right and click on View under the Outbound XML column.



19. The Outbound XML message opens in a new window. It shows that the allowedLoad = 0 and the percentShed = 100, meaning that the charging station is completely disabled.



20. Go back to the ChargePoint GUI to view the current state of Port 1. Go to Manage Stations > Status/ Actions.

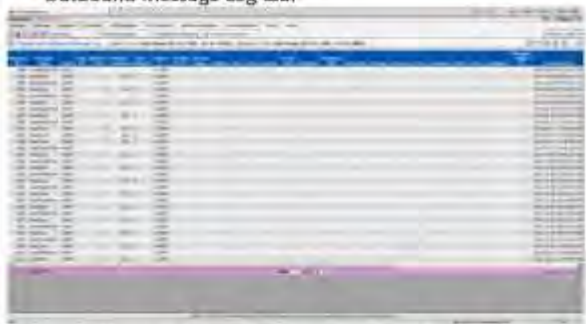
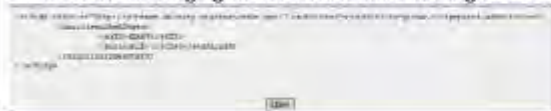
20. As shown, the Load Shed status is currently "Yes 100%." If another vehicle was plugged into Port 2 at Midtown Substation, the charge session would also be suspended there.

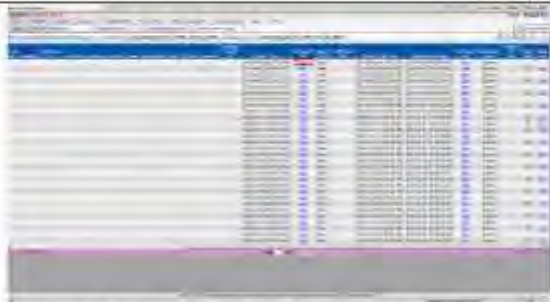
									
21. To view the information about current session (the vehicle plugged in to Port 1), go to Manage Stations > Sessions. 	21. Based on the session information, the vehicle has been plugged into Port 1 for 15 minutes and 38 seconds. The total energy transferred is 0.655281kWh, and the instantaneous power is 0kW (since the DR event is currently active). Port 1 <table border="1"> <tbody> <tr> <td>Start Time</td> <td>2014-08-29 09:52:50 (CDT)</td> </tr> <tr> <td>Elapsed Time</td> <td>00:15:38</td> </tr> <tr> <td>Total Energy</td> <td>0.655281 kWh</td> </tr> <tr> <td>Instantaneous Power</td> <td>0.000000 kW</td> </tr> </tbody> </table>	Start Time	2014-08-29 09:52:50 (CDT)	Elapsed Time	00:15:38	Total Energy	0.655281 kWh	Instantaneous Power	0.000000 kW
Start Time	2014-08-29 09:52:50 (CDT)								
Elapsed Time	00:15:38								
Total Energy	0.655281 kWh								
Instantaneous Power	0.000000 kW								
22. Look at cell phone text messages to see DR event status notifications.	22. The cell phone received two text messages in regards to the DR event.								

23. Look at the car's dashboard to see the status of the charging session. According to the dashboard, the charge cord is still connected.	23. Despite being plugged in, the vehicle's dashboard shows "Not Able to Charge" due to the current DR event.
24. Look at the charging station's electronic display for the status of Port 1 and Port 2.	24. The charge station display reads (where "..." indicates scrolling to the next screen): "KCP&L SUBSTATION...CHARGEPOINT STATION: 7703.....#1 SUSPENDED LOAD SHED IN PROGRESS / TAP CARD TO END...#2 AVAILABLE LOAD SHED IN PROGRESS / TAP CARD TO START" These messages indicate that a vehicle has been plugged in and charging from Port 1 and Port 2 is available, but that both Ports are currently participating in a DR event.





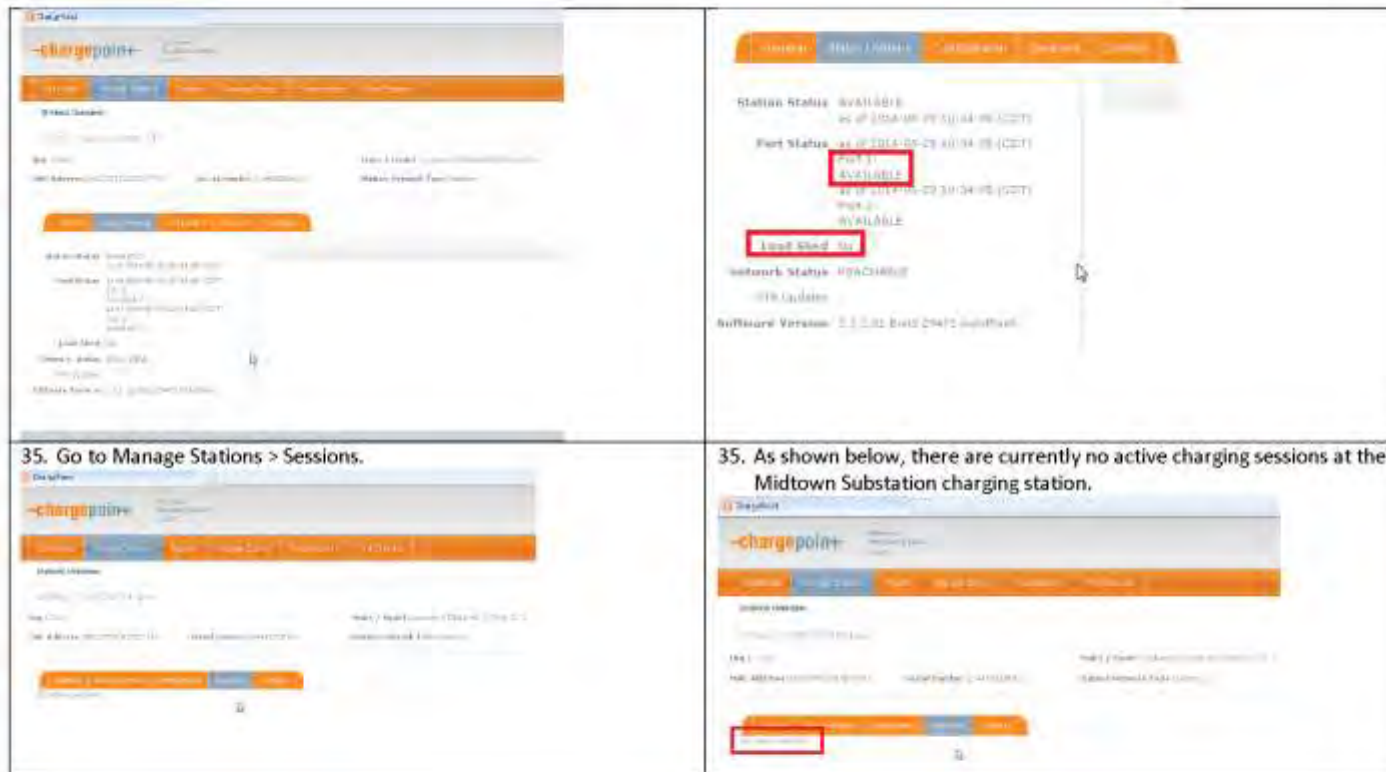
																																																																							
26. To view the completion XML message, go to the Charge Point Outbound Message Log tab. 	26. There is a new message called "Shed Load" indicating that the DR event message was sent from OATI to Charge Point via the Charge Point API.  <table border="1"> <thead> <tr> <th>Message ID</th> <th>Message Title</th> <th>Seq ID</th> <th>Seq ID</th> <th>Allowed Load</th> <th>Percent Scheduled</th> <th>Next Interval</th> <th>Interval ID</th> <th>Station ID</th> <th>Station Name</th> <th>Address</th> <th>City</th> <th>State</th> <th>Date</th> </tr> </thead> <tbody> <tr> <td>0040</td> <td>Shed Load</td> <td>42667</td> <td></td> <td></td> <td></td> <td></td> <td></td> <td>104000</td> <td></td> <td></td> <td></td> <td></td> <td></td> </tr> <tr> <td>0049</td> <td>Shed Load</td> <td>42667</td> <td></td> <td>0</td> <td>100</td> <td>0</td> <td>104000</td> <td></td> <td></td> <td></td> <td></td> <td></td> <td></td> </tr> <tr> <td>0050</td> <td>Shed Load</td> <td>42667</td> <td></td> <td>0</td> <td>100</td> <td>0</td> <td>104000</td> <td></td> <td></td> <td></td> <td></td> <td></td> <td></td> </tr> <tr> <td>0051</td> <td>Shed Load</td> <td>42667</td> <td></td> <td>0</td> <td>100</td> <td>0</td> <td>104000</td> <td></td> <td></td> <td></td> <td></td> <td></td> <td></td> </tr> </tbody> </table>	Message ID	Message Title	Seq ID	Seq ID	Allowed Load	Percent Scheduled	Next Interval	Interval ID	Station ID	Station Name	Address	City	State	Date	0040	Shed Load	42667						104000						0049	Shed Load	42667		0	100	0	104000							0050	Shed Load	42667		0	100	0	104000							0051	Shed Load	42667		0	100	0	104000						
Message ID	Message Title	Seq ID	Seq ID	Allowed Load	Percent Scheduled	Next Interval	Interval ID	Station ID	Station Name	Address	City	State	Date																																																										
0040	Shed Load	42667						104000																																																															
0049	Shed Load	42667		0	100	0	104000																																																																
0050	Shed Load	42667		0	100	0	104000																																																																
0051	Shed Load	42667		0	100	0	104000																																																																
27. Scroll to the right and click on View under the Outbound XML column.	27. The Outbound XML message opens in a new window, directing ChargePoint to clearShedState. At this point, Port 1 at the Midtown Substation charging station is now able to charge the vehicle again. 																																																																						

	
28. Go back to the ChargePoint GUI to view the status of the current session. Go to Manage Stations > Status / Actions. 	28. As shown, the Load Shed status is currently "No," meaning that there is no longer an active DR event going on at the charging station. Port 1 is "INUSE" because the vehicle is still plugged in (and is now charging again) and Port 2 is "AVAILABLE." 
29. Next, view the status of the current charging session in the ChargePoint GUI. Go to Manage Stations > Sessions.	29. Based on the session information, the vehicle has been plugged into Port 1 for 25 minutes and 38 seconds. The total energy transferred is 0.793216kWh, and the instantaneous power is 3.66119kW.

	Port 1 Start Time: 2014-06-29 09:52:50 (COT) Elapsed Time: 00:25:38 Total Energy: 0.793216 kWh Instantaneous Power: 3.356219 kW
30. Look at the car's dashboard to see the status of the charging session. According to the dashboard, the charge cord is still connected. 	30. Now that the DR event is over, the vehicle's dashboard shows a status of "Charging." Because of the short DR event, the Charge Complete time moved from 12:00 PM to 12:15 PM. 
31. Look at the OnStar phone application to get another view of the vehicle's status.	31. According to the OnStar app, the Volt's battery is currently "CHARGING" again, and the battery is now 55% charged (up from 49%).

	
32. Look at the charging station's electronic display for the status of Port 1 and Port 2.	32. The charge station display reads (where "..." indicates scrolling to the next screen): "KCP&L SUBSTATION...CHARGEPOINT STATION: 7703...#1 CHARGING 00:25:27 / 3.36 KW / TAP CARD TO END...#2 AVAILABLE TAP CARD TO START" These messages indicate that the vehicle is again charging in Port 1 of the Midtown charging station. Port 2 is still available for use. 

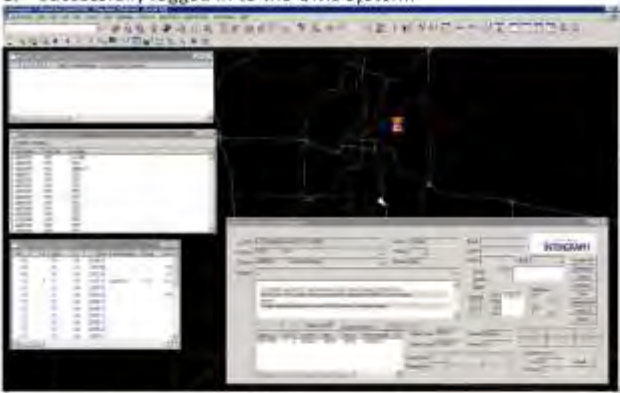
	
33. Going back to the ChargePoint GUI one last time, look at Manage Sessions > Sessions. 	33. Based on the session information, the vehicle has been plugged into Port 1 for 35 minutes and 38 seconds. The total energy transferred is 1.352927kWh, and the instantaneous power is 3.323965kW. Port 1 Start Time 2014-08-29 09:52:50 (CDT) Elapsed Time 00:35:38 Total Energy 1.352927 kWh Instantaneous Power 3.323965 kW
34. Lastly, unplug the vehicle from the charging station. Go to Manage Stations > Status / Actions.	34. As shown below, the Port 1 status is now "AVAILABLE" since the vehicle is unplugged from the charging station. The Load Shed is still "No" because there are no active DR events.

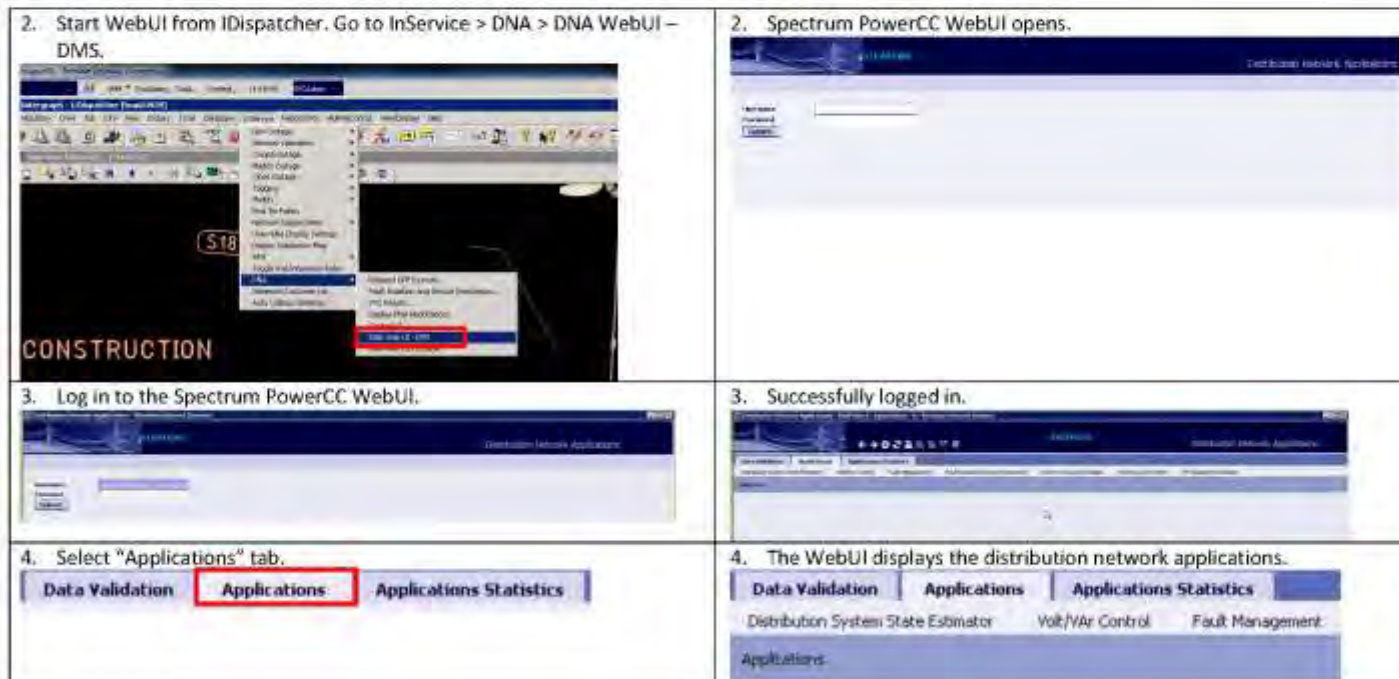


1st Responder Function – Volt/Var Control

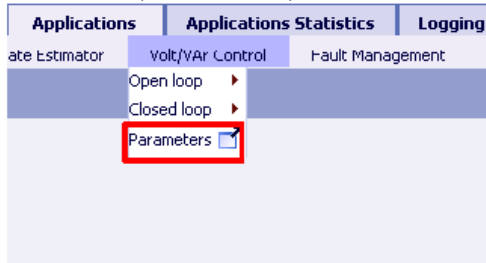


VVC in Open Loop Mode

Steps	Expected Results
1. Log in to I/Dispatcher OMS system. 	1. Successfully logged in to the OMS system. 

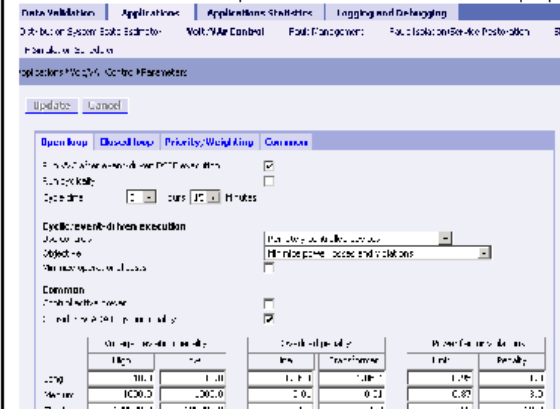


5. Under Volt/VAr Control tab, select Parameters.



The screenshot shows the 'Applications' tab with sub-tabs: 'State Estimator', 'Volt/VAr Control', and 'Fault Management'. Under 'Volt/VAr Control', there are three options: 'Open loop', 'Closed loop', and 'Parameters'. The 'Parameters' option is highlighted with a red rectangular box.

5. A new window with parameters to be entered is displayed.



The screenshot shows a 'Parameters' window for 'Voltage/VAr Control Parameters'. It has tabs for 'Open loop', 'Closed loop', 'Priority/Weighting', and 'Constraints'. The 'Open loop' tab is active. It contains several checkboxes and dropdown menus. At the bottom, there are three tables for 'On-line mode', 'On-line priority', and 'Power factor limits'.

On-line mode		On-line priority		Power factor limits	
High	Low	High	Low	Limit	Priority
100.0	1.00	1.00	1.00	0.95	1.0
100.0	1.00	1.00	1.00	0.95	1.0
100.0	1.00	1.00	1.00	0.95	1.0

6. Enter the parameters in Open Loop tab and press update button. Verify that the limits and penalty are within the range.

6. Parameters entered are updated and displayed.

7. In Spectrum PowerCC DNA WebUI, under Volt/Var Control tab, select Close loop > Settings.

7. A new page opens to select the injection point.

Injection	Included	Exclusion time	Exclusion reason
Net-Eden-Compress/KCP/MD/ROW/161_KV/75-1-4-BD		12/15/2013 16:51:05	Excluded by default
Net-Eden-Compress/KCP/MD/ROW/161_KV/75-1-4-BD		12/15/2013 16:51:05	Excluded by default
Net-Eden-Compress/KCP/MD/ROW/161_KV/75-1-4-BD		12/13/2013 13:09:38	Excluded by default
Net-Eden-Compress/KCP/MD/ROW/161_KV/75-7-8-BD		12/16/2013 16:51:05	Excluded by default

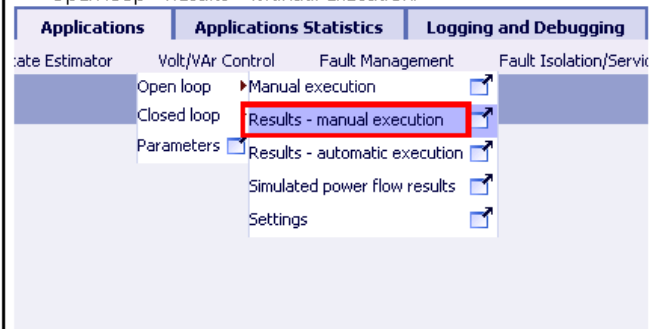
8. Click on the edit button to include the injection point.

8. Now you can select the injection points.

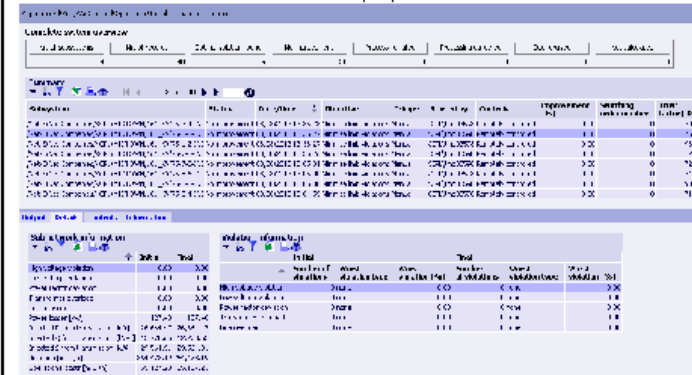
9. Select the injection point to include. And press Update.

9. The selected injection point is included in VVC calculation.

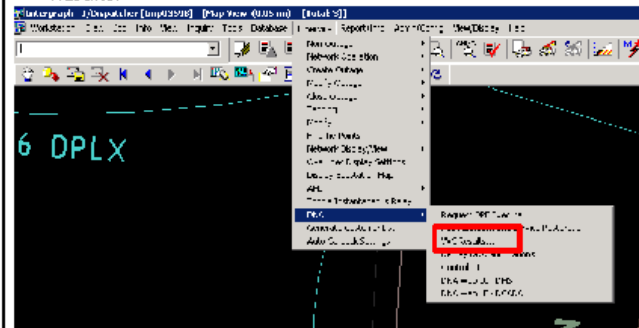
10. In Spectrum PowerCC DNA WebUI, under Volt/Var Control tab, select Open loop > Results – Manual execution.



10. A new window for execution is displayed.



11. Open the OMS I/Dispatcher window. And go to InService > DNA > VVC Results.



11. A new window "VVC Results" pops up to request VVC

