residential customers and small to medium commercial customers. LDCs were applied to all substation LTC and in-line voltage regulators.

If additional voltage regulators were required for the Base Case to meet VO thresholds, they were included in all VO plans. If additional LDC controllers were necessary, they were also included in all plans.

6.9.4 Capacitor VAR Management

All viable feeder candidates were assumed to have capacitor VAR management modified to yield near zero VAR flows of ±300 kVAR for all hours. The Base Case and Improved Case capacitor sizing, placement, and capacitor type (fixed or switched), and capacitor control settings were based on feeder annual historical VAR profiles. Historical VAR profiles were used to determine minimum and maximum VARs for adequate hourly VAR compensation.

Reactive power does not spin kWh meters and performs no useful work, but must be supplied. Using line shunt capacitors to supply reactive power reduces the amount of line current. Since line losses are a function of the current squared, reducing reactive power flows significantly reduces losses. By reducing the annual hourly VAR loading to near zero throughout the length of feeder, accumulated voltage drops are minimized, reducing line losses and eliminating the need for regulator reactive voltage %X compensation.

All feeders were assumed to have been modified for near 100% VAR flow. For Base Case and proposed case simulations, all feeder-connected capacitors were disconnected. All feeder voltages sources were assumed fixed at 124.8 volts with bandwidths set at 0.8 volts. *All feeder source loads were 110% annual peak kW loads at 98% power factor lagging*. In-line voltage regulators were set at 124.8 volts. Substation capacitors were not considered in the kVAR analysis.

As data was available either with feeder phase amps, MW and MVAr phase demands, and/or MW and MVAr hourly load profiles, peak load and phase contributions were assigned to each feeder. If no MVAr load profile data was available, existing capacitor kVARs were assumed to equal total kVAR feeder loading. Estimated fixed kVARs were assumed to be 50% of the total kVAR, and switched kVARs at 50% of the total. All capacitor banks were assumed to be 600 kVAR for both fixed and switched.

Capacitor switch controllers normally have counters to record the number of operations. Counters help to identify maintenance and control setting problems. It was assumed all capacitors are serviced at least once per year.

Other control methods, including automated VAR feedback controls, can be applied if the net result is a maximum leading or lagging kVAR that is less than compensation targets at the feeder source for every hour of the year. Feedback and/or IVVC can also be used to override VAR controls under emergency or abnormal conditions. If feeders can be operated from either

direction, it is important the controller mode be capable of handling operations bi-directional flows.

For non-viable feeders connected within VCZs with viable sister feeders, VCZ voltage regulation requires augmentation to account for non-viable and viable voltage needs.

Non-viable feeders were assumed to have voltages representative of existing voltages. Substation or VCZ voltage regulation was assumed to be controlled via LDCs based on viable feeder loads. Non-viable feeders were equipped with EOL primary voltage feedback sensing as input to an IVVC master control station. IVVC controls non-viable feeder capacitors to maintain feeder primary voltages within existing or improved voltage limits. Primary voltage limits were 121 volts to 124 volts.

The number of switched capacitors needed for IVVC feeder systems to raise primary average voltage by 2 volts was determined from load flow simulations at 2/3 of the distance from the source. The VCZ source LDC loading was modified using IVVC to subtract non-viable feeder loadings from the LDC controller. The VCZ source LDC then became the non-viable feeder backup control in the event of an IVVC malfunction.

All selected representative sample viable feeder candidates VAR flows were modified to yield near zero var flows of ±300 kVAR for all hours.

6.9.5 AMI Applications

AMI can provide additional information to help improve energy efficiencies and minimize implementation costs. The data can be used to accurately assess customer load impacts and evaluate secondary voltage drops to establish reliable minimum primary voltage standards for feeder and substation voltage regulators. Secondary systems include distribution transformers and secondary service drops. For this study, ComEd AMI meter data was not evaluated or used.

6.9.6 IVVC Applications

IVVC applications monitor real-time voltages, watts and VARs from LTCs, regulators, capacitors, EOL voltage sensors, and additional monitoring points such as customer meters. Using this real-time data, the IVVC application triggers a control period during which real-time power factors and voltage measurements assign operational costs. Operational costs are determined by comparing analog measurements to substation power factor and voltage targets. The IVVC application objective is to minimize operational costs by managing real-time power factors and voltages and primary voltage targets.

IVVC control schemes ensure optimum performance. For most VO applications with residential and light-to-medium commercial customers, traditional LDC controls and VAR management schemes with switched VAR capacitor controls provide more cost-effective operation

performance. However, when adjacent (sister) feeders are connected to the same voltage regulator or power transformer with significantly different load profiles and peak kW coincidence (i.e., < 80%) and high amounts of large commercial and/or industrial customer loading, traditional voltage regulation and VAR management approaches become less effective.

Large commercial and industrial customers require higher service entrance voltages compared to residential customers. Higher voltages are needed to coordinate with inefficient end-use electrical systems typically requiring end-use voltage drops greater than ANSI standards.

For this study, IVVC was used to maintain and isolate voltages for large commercial and industrial feeders (classified as non-viable candidates) by integrating with switched shunt capacitor banks, voltage measurement and VAR sensing along the feeder, source voltage regulation LDC controllers, and monitoring secondary service voltages for customers with AMI (Figure 11).

6.10 VO Improvements Common to all VO Plans

Substation and feeder source MW and MVAr profiles metering was added to all feeders. All viable candidates had capacitor VAR performance modified to yield near-zero VAR flows of ± 300 kVAR for all hours. All substation power transformer LTCs and in-line voltage regulators controls were assumed to have LDCs. Each viable feeder VCZ had EOL voltage metering installed. In cases where adjacent non-viable feeders were served from a common voltage regulation source, IVVC equipment was added to isolate the feeder from the viable feeders. IVVC additions included volt-VAR station controllers, EOL voltage feedback sensing, and switched capacitors. These IVVC additions were common to all plans.

6.10.1 Substation and Feeder Metering Applications

Substation and feeder metering data is needed to plan, design, operate, and monitor VO systems. The accuracy and completeness of engineering modeling and system performance (metering) is increased. Since VO operational impacts are small (i.e., losses, voltage service levels, voltage drops) as are performance tolerances (i.e., minimum voltage margins, feeder coincidence peak load factors, operation requirements), accurate data is important to success.

For VO design, it is best to have 12 months of substation power transformer and feeder source metered data (kWh and kW demand and annual kWh). In addition, phase amps and volts sensing are collected for in-line volt-regulators equipped with source metering. VAR sensing is typically installed along the feeders along with EOL voltage sensing. Meter data does not have to be real time, but can be manually downloaded every six months using SCADA.

kW and kWh annual data is needed to determine accurate VCZ annual load factors and energy delivered. Annual peak kW is used with load flow simulations to determine maximum primary voltage drops for average voltage calculations. VCZ source meters and EOL voltmeters are used

during the Pre-VO and Post-VO verification test period. EOL metering also is used to verify on-going compliance. Annual source measurements along with verification measurements provide the necessary elements to determine average annual voltages for Pre-VO and Post-VO conditions. Load profile metering is required if M&V testing and validation of VO savings are required. Power transformer and distribution line metering is used to estimate load and loss factors to estimate system losses and evaluate loss impacts.

For this study, it was assumed all power transformers, feeders, and line regulators had metering installed common to all plans, with EOL metering on feeder lowest voltage locations.

6.10.2 Feeder VAR Management Applications

All viable VO feeder candidates were assumed to have capacitor VAR performance modified to yield near zero VAR flows of nearly 100% reactive load compensation ±300 kVAR for all hours to meet performance thresholds. For ComEd, most capacitors are 1200 kVAR fixed for viable feeders. Base Case VAR management was modified to upgrade existing fixed banks with 600 kVAR and/or additional fixed and switched VAR controlled banks. Capacitor sizing, placement, type (fixed or switched), and control settings were based on feeder annual historical VAR profiles. Historical VAR profiles are used to determine minimum and maximum feeder VARs. Capacitor modifications and/or additions for the Base Case were included in all plans.

6.10.3 IVVC and EOL Voltage Feedback and Control Application

If IVVC was required in the Base Case, IVVC applications were included in all VO plans. IVVC was used to isolate non-viable feeders by integrating with switched shunt capacitor banks, voltage measurement and var sensing along the feeder, EOL voltage sensing, source voltage regulation LDC controllers, and AMI for secondary service voltages. In some cases, only EOL voltage feedback, sensing, and control were required for feeders exhibiting lower feeder coincidence factors when compared to their adjacent (sister) feeders.

All IVVC and EOL voltage feedback control applications required for the Base Case were included in all VO plans.

6.11 Existing Case VO Performance Threshold Assessment

Minimum efficiency performance VO threshold objectives were identified (e.g., max voltage drops, min power factors, max phase unbalance, etc.).

System loss reductions and lower the customer average voltages were generally achieved. However, it was not always possible or practical to achieve all of VO thresholds due to specific loading and geographical constraints.

Maximum primary volt drops for substation service areas ranged from 0.30 volts to 13.4 volts. The average maximum voltage drop was 3.95 volts (lower than the 4.8 volt threshold).

Lowest primary voltages for substation service areas ranged from 124.5 volts to 111.1 volts. The average lowest voltage was 116.26 volts (higher than the 118.6 volt threshold).

Feeder phase amp imbalances for substation service areas ranged from 1.2% to 31.1% (<25% phase amp imbalance threshold). The average imbalance was 10.5%.

Maximum feeder conductor and cable length for correcting the substation service area overloads was 0.62 miles.

Capacitor additions to maintain annual var flow of 300 kVAR for all hours for substation service areas were 18 fixed 600 kVAR banks and 150 switched 600 kVAR banks. All switched capacitor banks needed for the Base Case were assumed to have VAR sensing with voltage override capability.

Existing case compliance with VO thresholds is summarized in Table 17. Highlighted values indicate non-compliance with VO thresholds.

Table 17 - Summary of Existing Case Compliance with VO Thresholds

Feeder Id	Sub Id	Source Volts	Source VCZ Max VoltDrop (V)	Source VCZ Lowest Primary Voltage (V)	Amp Phase Imbalance (pu)	Overloaded Line > 100% of Normal (mi)
B285	DCB28	124.8	4.70	120.1	0.077	
B286	DCB28	124.8	5.10	119.7	0.103	
D690	DCD69	124.8	3.90	120.9	0.050	
D470	DCD69	124.8	2.00	120.0	0.100	
D472	DCD69	124.8	2.00	120.0	0.100	
E717	DCE71	124.8	4.70	120.1	0.162	
E718	DCE71	124.8	3.90	120.9	0.134	
E715	DCE71	124.8	2.00	120.0	0.100	
E716	DCE71	124.8	2.00	120.0	0.100	
E791	DCE79	124.8	5.00	119.8	0.165	0.019
E792	DCE79	124.8	4.70	120.1	0.074	
H385	DCH38	124.8	9.70	115.1	0.097	
H385-North	DCH38	124.8	5.60	119.2	0.097	
W386	DCW38	124.8	3.90	120.9	0.108	
W387	DCW38	124.8	6.30	118.5	0.136	
W4801	DCW48	124.8	1.80	123.0	0.063	
W4802	DCW48	124.8	5.50	119.3	0.131	0.441
W711	DCW71	124.8	3.50	121.3	0.080	
W712	DCW71	124.8	1.80	123.0	0.012	
W731	DCW73	125.0	7.30	117.7	0.130	
W140	DCW148	124.8	2.60	122.2	0.086	
W142	DCW148	124.8	1.60	123.2	0.094	
B7501	TDC375	124.5	10.70	113.8	0.040	

Note: Highlighted values indicate non-compliance with VO thresholds.

Table 17 - Summary of Existing Case Compliance with VO Thresholds (Continued)

Feeder Id	Sub Id	Source Volts	Source VCZ Max VoltDrop (V)	Source VCZ Lowest Primary Voltage (V)	Amp Phase Imbalance (pu)	Overloaded Line > 100% of Normal (mi)
B7502	TDC375	124.5	5.20	119.3	0.060	
B7503	TDC375	124.5	2.20	122.3	0.029	
B7506	TDC375	124.5	3.60	120.9	0.222	
B7583	TDC375	124.5	6.80	117.7	0.252	
B7584	TDC375	124.5	2.20	122.3	0.089	
B7504	TDC375	124.5	13.40	111.1	0.077	
B7505	TDC375	124.5	5.90	118.6	0.023	
B7507	TDC375	124.5	3.00	121.5	0.070	
B7570	TDC375	124.5	0.50	124.0	0.030	
B7582	TDC375	124.5	5.80	118.7	0.276	
W178	DCW17	124.8	3.70	121.1	0.132	
W332	DCW233	124.8	2.40	122.4	0.083	0.063
W593	TDC559	124.8	3.60	121.2	0.172	
W594	TDC559	124.8	5.40	119.4	0.194	
W595	TDC559	124.8	2.20	122.6	0.154	
W596	TDC559	124.8	3.10	121.7	0.100	
W597	TDC559	124.8	3.80	121.0	0.127	
W5910	TDC559	124.8	2.90	121.9	0.093	
W590	TDC559	124.8	4.70	120.1	0.187	
W591	TDC559	124.8	2.60	122.2	0.114	
W592	TDC559	124.8	5.20	119.6	0.311	
W598	TDC559	124.8	4.10	120.7	0.083	
W599	TDC559	124.8	4.00	120.8	0.110	0.025
W5911	TDC559	124.8	3.60	121.2	0.301	
W1310	SS513	124.8	4.40	120.4	0.052	0.074
W1311	SS513	124.8	2.00	120.0	0.100	
W1312	SS513	124.8	1.00	123.8	0.032	
W1313	SS513	124.8	3.50	121.3	0.021	
Z10439	TSS104	124.8	3.90	120.9	0.073	
Z10440	TSS104	124.8	1.40	123.4	0.091	
Z10441	TSS104	124.8	4.20	120.6	0.132	
Z10442	TSS104	124.8	0.30	124.5	0.021	
Z10443	TSS104	124.8	0.40	124.4	0.031	

Note: Highlighted values indicate non-compliance with VO thresholds.

6.12 Plan A – Low Cost Solution

6.12.1 Summary

Plan A improvements include those identified for the Base Case and are common to all VO plans. Plan A meets threshold requirements for a minimum cost of $3,705,440. Overall energy saved is 19,639 MWh/yr. The average savings per substation is 1227.4 MWh/yr and the average per viable feeder is 417.9 MWh/yr. The average primary voltage Pre-VO is 124.13 V and Post-VO is 120.57 V (2.97% reduction). All LDC settings have a voltage set point of 120.0 volts. The total end-use energy savings are 18,422.5 MWh/yr. Average customer savings are 314.5 kWh/yr.

6.12.2 Plan A VO Improvements and Installed Costs

Plan A improvements and associated costs are summarized in Table 18 and Table 19.

Table 18 - Plan A VO Improvements

Sub Id	OH Line Reconductor (mi)	Station Regulator Addition (#)	In-line volt-regulator Addition (#)	OH & UG line or transf tap changes (#)	OH phase upgrades (mi)	Fixed 600 kVAr capacitor add (#)	Switched 600 kVAr capacitor add (#)
DCB28	0.00	0	0	0	0.00	0	2
DCD69	0.00	0	1	2	0.10	0	3
DCE71	0.00	0	0	0	0.00	3	4
DCE79	0.02	0	0	0	0.00	0	6
DCH38	0.00	0	1	3	0.00	0	2
DCW38	0.00	0	1	0	0.06	3	4
DCW48	0.44	0	0	0	0.00	1	4
DCW71	0.00	0	0	0	0.00	3	8
DCW73	0.00	0	1	0	0.00	1	2
DCW148	0.00	0	0	0	0.00	3	4
TDC375	0.00	0	3	5	0.00	0	53
DCW17	0.00	0	0	0	0.00	1	1
DCW233	0.06	0	0	0	0.00	1	3
TDC559	0.03	0	0	0	0.00	2	25
SS513	0.07	0	0	0	0.00	0	9
TSS104	0.00	0	0	0	0.00	0	20
	0.62	0	7	10	0.16	18	150

Table 19 - Plan A VO Improvements and Costs

Sub Id	Feeder Source & Regulator metering (#)	EOL Voltmeter (#)	EOL volt feedback sensing (#)	IVVC Application ($)	VO Upgrade Cost ($)
DCB28	2	2	0	$0	$46,000
DCD69	1	1	0	$0	$131,440
DCE71	2	2	0	$0	$92,500
DCE79	2	2	0	$0	$110,275
DCH38	5	5	0	$0	$139,000
DCW38	3	3	0	$0	$169,550
DCW48	2	2	0	$0	$180,725
DCW71	2	2	0	$0	$152,500
DCW73	1	2	0	$0	$109,500
DCW148	2	2	0	$0	$92,500
TDC375	14	15	1	$50,000	$1,163,500
DCW17	1	1	0	$0	$28,500
DCW233	1	1	0	$0	$72,675
TDC559	12	12	2	$150,000	$646,625
SS513	3	3	0	$0	$175,650
TSS104	5	5	1	$50,000	$394,500
	58	60	4	$250,000	$3,705,440

6.12.3 Average Voltage and End-Use Savings

Plan A average voltage reductions and end-use energy savings for each of the 16 substations are given in Table 20. The average primary Post-VO voltage is 120.57 volts compared to a baseline Pre-VO of 124.13 volts. The weighted annual average reduction in customer voltage for the sample substation areas is 3.55 volts or 2.96%.

6.12.4 System Line and No-Load Loss Savings

Plan A system line and no-load losses for each of the 16 substations are given in Table 21. The feeder service area total system loss reduction is 24,525.1 MWh for a savings of 1216.4 MWh. There is a no-load reduction of 820.8 MWh and line loss savings of 395.6 MWh. Total peak loss reduction is 387.5 kW (293.8 kW for line and 93.7 kW for no-load). Average feeder energy losses are 2.51% for Plan A compared to 2.68% for the Existing Case.

Table 20 - Plan A Average Voltage Reduction and End-Use Energy Savings

Sub Id	Existing kW Demand	Annual MWh Load	VO Factor (weighted)	Base Case Pre-VO Avg Volts	Post-VO Avg Volts	Voltage Change (pu)	End-Use Load Savings (MWh)
DCB28	4,793	15,577	0.752	123.89	120.91	0.0249	291.2
DCD69	7,020	19,868	0.846	124.02	120.30	0.0310	521.3
DCE71	12,138	33,852	0.758	124.13	120.67	0.0288	736.8
DCE79	11,533	33,375	0.702	124.15	119.81	0.0361	854.2
DCH38	3,377	10,375	0.760	124.04	120.77	0.0272	213.9
DCW38	15,575	47,753	0.783	124.21	120.61	0.0300	1,123.3
DCW48	11,274	31,421	0.746	124.30	120.50	0.0317	743.3
DCW71	14,025	62,809	0.771	124.11	120.68	0.0286	1,391.5
DCW73	5,620	16,819	0.731	124.30	120.65	0.0305	374.7
DCW148	10,980	33,315	0.759	124.43	120.36	0.0339	859.7
TDC375	63,190	259,799	0.760	123.32	121.69	0.0135	2,471.6
DCW17	4,387	12,200	0.735	124.21	120.59	0.0302	271.0
DCW233	5,532	15,450	0.784	124.47	120.33	0.0344	416.9
TDC559	63,731	218,503	0.742	124.05	119.44	0.0384	5,177.5
SS513	17,696	49,439	0.795	124.30	120.50	0.0316	1,248.3
TSS104	27,427	116,949	0.749	124.12	121.37	0.0230	1,727.4
	278,298	977,504.0					18,422.5

Table 21 - Plan A System Line and No-Load Losses

Sub Id	Annual MWh Load	Existing Line and No-Load Losses (MWh)	Revised Peak Line Loss (kW)	Reduction in Peak Line Loss (kW)	Savings in Line Loss (MWh)	Reduction in Peak No-Load Loss (kW)	Savings in No-Load Loss (MWh)	Revised Total Loss (MWh)	% Loss	Total Loss Energy Savings (MWh)
DCB28	15,577	595.0	81.3	0.0	0.0	2.6	22.6	572.4	3.67%	22.6
DCD69	19,868	498.8	102.0	1.6	1.9	2.5	22.2	474.7	2.39%	24.1
DCE71	33,852	897.7	187.5	0.0	0.0	4.2	36.9	860.8	2.54%	36.9
DCE79	33,375	1,043.6	350.4	3.5	4.6	4.5	39.8	999.2	2.99%	44.4
DCH38	10,375	686.1	94.2	6.4	8.8	3.3	28.6	648.7	6.25%	37.4
DCW38	47,753	883.9	209.4	4.6	6.3	3.9	34.0	843.5	1.77%	40.3
DCW48	31,421	681.9	11.3	217.6	255.0	2.9	25.5	401.4	1.28%	280.5
DCW71	62,809	1,240.8	129.9	0.0	0.0	5.8	50.7	1,190.1	1.89%	50.7
DCW73	16,819	425.7	139.1	2.2	2.9	1.6	13.9	408.8	2.43%	16.8
DCW148	33,315	829.2	92.8	0.0	0.0	5.2	45.4	783.9	2.35%	45.4
TDC375	259,799	7,264.8	1,603.3	34.3	83.0	10.5	92.1	7,089.6	2.73%	175.1
DCW17	12,200	293.1	47.3	0.0	0.0	1.6	13.7	279.3	2.29%	13.7
DCW233	15,450	387.8	34.0	5.2	6.1	2.6	22.4	359.4	2.33%	28.5
TDC559	218,503	5,725.8	1,001.7	7.9	14.6	27.7	242.9	5,468.3	2.50%	257.5
SS513	49,439	1,921.8	229.7	10.5	12.4	8.7	76.0	1,833.4	3.71%	88.3
TSS104	116,949	2,365.6	249.3	0.0	0.0	6.2	54.1	2,311.5	1.98%	54.1
	977,504	25,741.6	4,563.2	293.8	395.6	93.7	820.8	24,525.1	2.51%	1,216

6.12.5 VO Economic Analysis

Plan A demonstrates an annual energy savings of 19,639.0 MWh/yr (2.01% reduction) and 3892.6 kW coincidental feeder demand reduction. The feeder system loss is 2.51% of the total energy delivered compared to existing system losses of 2.63%.

Plan A substations have a relatively moderate overall BCR of 1.928 with total installed costs of $3,705,440 ($78,839/fdr). The net overall present value reduction in revenue requirements is $4,054,077 ($86,257/fdr). Total annual energy savings is 19,639.0 MWh/yr (417.9/fdr) for a program measure life of 15 years.

Plan A substation first year costs, O&M costs, energy saved, demand reduction, and BCR are shown in Table 22. Overall VO economic results are given in Table 23.

Table 22 - Plan A Economic Analysis Summary by Substation

Substation id	Number of Customers	VO Upgrade Costs (w/o Isolation Adders) (First Year $)	VO Upgrade Costs (w/ Isolation Adders) (First Year $)	Annual O&M Costs ($/y)	NPV of VO Upgrade Costs (w/ Isolation Adders) ($)	NPV of VO Energy Savings ($)	NPV of Revenue Requirement Savings ($)	Total VO Energy Saved MWh/y	Total Peak Demand Reduction kW/y	Benefit Cost Ratio
DCB28	1,031	$46,000	$46,000	$920	$59,934	$148,748	$88,814	313.8	58.0	2.48
DCD69	589	$131,440	$131,440	$2,629	$171,255	$258,526	$87,271	545.4	103.3	1.51
DCE71	2,182	$92,500	$92,500	$1,850	$120,520	$366,770	$246,250	773.7	144.4	3.04
DCE79	3,114	$110,275	$110,275	$2,206	$143,679	$425,940	$282,261	898.6	170.6	2.96
DCH38	660	$139,000	$139,000	$2,780	$181,105	$119,093	-$62,013	251.2	50.3	0.66
DCW38	1,687	$169,550	$169,550	$3,391	$220,909	$551,590	$330,681	1,163.6	222.2	2.50
DCW48	1,862	$180,725	$180,725	$3,615	$235,469	$485,314	$249,845	1,023.8	361.9	2.06
DCW71	2,581	$152,500	$152,500	$3,050	$198,695	$683,636	$484,942	1,442.2	270.5	3.44
DCW73	950	$109,500	$109,500	$2,190	$142,669	$185,609	$42,940	391.6	75.1	1.30
DCW148	3,417	$92,500	$92,500	$1,850	$120,520	$429,034	$308,515	905.1	168.7	3.56
TDC375	13,801	$1,163,500	$1,163,500	$23,270	$1,515,942	$1,254,628	-$261,313	2,646.8	515.1	0.83
DCW17	1,030	$28,500	$28,500	$570	$37,133	$134,995	$97,862	284.8	53.1	3.64
DCW233	1,397	$72,675	$72,675	$1,454	$94,689	$211,135	$116,445	445.4	87.1	2.23
TDC559	18,039	$646,625	$646,625	$12,933	$842,497	$2,576,315	$1,733,817	5,435.0	1,020.7	3.06
SS513	5,197	$175,650	$175,650	$3,513	$228,857	$633,579	$404,722	1,336.6	256.7	2.77
TSS104	4,908	$394,500	$394,500	$7,890	$514,000	$844,463	$330,464	1,781.5	334.8	1.64
	62,445	$3,705,440	$3,705,440	$74,109	$4,827,873	$9,309,375	$4,481,502	19,639	3,893	1.928

Table 23 - Plan A Economic Analysis Summary - Overall

	Plan A
General Substation Information	
Number of Substations Investigated	
Total Customers Served (#)	62,445
Number of Feeders (Viable and Non-viable) Investigated (#)	56
Number of Feeders (Viable) Investigated (#)	47
Substation Annual Peak Demand (kW)	278,298
Total Annual Energy Consumed (MWh/yr)	977,504
VO Energy Savings Potential	
Average Primary Voltage Pre-VO (V)	124.13
Average Primary Voltage Post-VO (V)	120.57
Average Customer VO Voltage Change (%)	2.96%
Substation Weighted Average VO factor	0.761
VO Energy Savings (MWh/y)	18,422.5
Line Loss Energy Savings (MWh/y)	395.6
No-Load Loss Energy Savings (MWh/y)	820.8
Distribution Line and Transf no-load loss (%)	2.51%
Total Energy Savings (MWh/y)	19,639.0
Total Coincidental Demand Reduction (kW)	3,892.6
Customer Average Energy Savings (kWh/yr)	314.5
Benefit Cost Projections	
Total VO Upgrade Cost - First Year ($)	$3,705,440
Annual O&M First Year Costs ($)	$74,109
Total VO Upgrade Cost (NPV)	$4,827,873
Total VO Energy Savings (NPV)	$9,309,375
NPV Revenue Requirement Savings ($)	$4,481,502
VO Benefit Cost Ratio (BCR)	1.928

6.13 Plan B – High Savings Solution

6.13.1 Summary

Plan B improvements include those identified for the Base Case plus additional upgrades. Plan B meets threshold requirements for a cost of $5,142,735. The maximum overall energy saved is 27,138.9 MWh/yr. The average savings per substation is 1696.2 MWh/yr and the average per viable feeder is 577.4 MWh/yr. The average primary voltage Pre-VO is 124.13 V and Post-VO is 119.56 V (3.81% reduction). Average voltage calculation methods are provided in Sections 2.8.4 and 7. All LDC settings have a voltage set point of 119.0 volts. Average Customer saves 434.6 kWh/yr.

6.13.2 Plan B VO Improvements and Installed Costs

Plan B improvements and associated costs are summarized in Table 24 and Table 25.

Table 24 - Plan B VO Improvements

Sub Id	OH Line Reconductor (mi)	Station Regulator Addition (#)	In-line volt-regulator Addition (#)	OH & UG line or transf tap changes (#)	OH phase upgrades (mi)	Fixed 600 kVAr capacitor add (#)	Switched 600 kVAr capacitor add (#)
DCB28	0.00	0	1	1	0.01	0	2
DCD69	0.00	0	1	2	0.10	0	3
DCE71	0.84	0	0	2	0.00	3	4
DCE79	0.02	0	0	0	0.00	0	6
DCH38	0.00	0	2	9	0.00	0	2
DCW38	0.21	0	1	5	1.09	3	4
DCW48	0.58	0	0	2	0.02	1	4
DCW71	0.00	0	0	3	0.00	3	8
DCW73	0.00	0	2	0	0.00	1	2
DCW148	0.00	0	0	0	0.00	3	4
TDC375	0.00	1	4	8	0.00	0	58
DCW17	0.00	0	0	6	0.00	1	1
DCW233	0.20	0	0	0	0.00	1	3
TDC559	0.00	0	3	9	0.00	22	19
SS513	0.07	0	2	1	0.00	0	9
TSS104	0.00	0	2	1	0.00	0	20
	1.91	1	18	49	1.22	38	149

Table 25 - Plan B VO Improvements and Costs

Sub Id	Feeder Source & Regulator metering (#)	EOL Voltmeter (#)	EOL volt feedback sensing (#)	IVVC Application ($)	VO Upgrade Cost ($)
DCB28	2	2	0	$0	$111,880
DCD69	1	1	0	$0	$131,440
DCE71	2	2	0	$0	$285,500
DCE79	2	2	0	$0	$110,275
DCH38	6	6	0	$0	$222,000
DCW38	3	3	0	$0	$339,200
DCW48	2	2	0	$0	$217,415
DCW71	2	2	0	$0	$158,500
DCW73	1	2	0	$0	$172,500
DCW148	2	2	0	$0	$92,500
TDC375	16	16	1	$50,000	$1,430,500
DCW17	1	1	0	$0	$40,500
DCW233	1	1	0	$0	$102,375
TDC559	15	7	2	$152,000	$870,000
SS513	5	5	0	$0	$319,650
TSS104	7	7	1	$50,000	$538,500
	68	61	4	$252,000	$5,142,735

6.13.3 Average Voltage and End-Use Savings

Plan B average voltage reductions and end-use energy savings are given in Table 26. The average Post-VO voltage is 119.56 volts compared to a baseline Pre-VO of 124.13 volts. The weighted annual average reduction in customer voltage for the sample substation areas is 4.57 volts or 3.81%. The total end-use energy savings are 24,173.7 MWh/yr.

6.13.4 System Line and No-Load Loss Savings

Plan B system line and no-load losses for each of the 16 substations are given in Table 27. The feeder service area total system loss is 22,776.4 MWh for a savings of 2965.2 MWh. There is a no-load reduction of 1042.0 MWh and line loss savings of 1923.2 MWh. The total peak loss reduction is 1280.0 kW (1161.1 kW for line and 118.9 kW for no-load). Average feeder energy losses are 2.33% for Plan B compared to 2.68% for the Existing Case.

Table 26 - Plan B Average Voltage Reduction and End-Use Energy Savings

Sub Id	Existing kW Demand	Annual MWh Load	VO Factor (weighted)	Base Case Pre-VO Avg Volts	Post-VO Avg Volts	Voltage Change (pu)	End-Use Load Savings (MWh)
DCB28	4,793	15,577	0.752	123.89	119.61	0.0357	419.1
DCD69	7,020	19,868	0.846	124.02	119.30	0.0393	661.4
DCE71	12,138	33,852	0.758	124.13	119.58	0.0379	972.4
DCE79	11,533	33,375	0.702	124.15	119.72	0.0369	867.2
DCH38	3,377	10,375	0.760	124.04	119.65	0.0365	288.0
DCW38	15,575	47,753	0.783	124.21	119.54	0.0389	1,457.5
DCW48	11,274	31,421	0.746	124.30	119.45	0.0405	948.3
DCW71	14,025	62,809	0.771	124.11	119.62	0.0375	1,820.0
DCW73	5,620	16,819	0.731	124.30	119.54	0.0397	488.8
DCW148	10,980	33,315	0.759	124.43	119.36	0.0422	1,070.6
TDC375	63,190	259,799	0.760	123.32	120.00	0.0277	5,003.6
DCW17	4,387	12,200	0.735	124.21	119.48	0.0395	354.1
DCW233	5,532	15,450	0.784	124.47	119.29	0.0432	522.7
TDC559	63,731	218,503	0.742	124.05	119.69	0.0364	4,958.3
SS513	17,696	49,439	0.795	124.30	119.26	0.0420	1,654.1
TSS104	27,427	116,949	0.749	124.12	119.84	0.0357	2,687.7
	278,298	977,504					24,173.7

6.13.5 VO Economic Analysis

Plan B demonstrates an annual energy savings of 27,138.9 MWh/yr (2.78% reduction) and 5879.3 kW coincidental feeder demand reduction. The feeder system loss is 2.33% of the total energy delivered compared to existing system losses of 2.63%.

Plan B substations have a relatively moderate overall BCR of 1.920, which is less than the 2.5 target demonstrating maximum optimal savings potential. Total installed upgrade costs are $5,142,735 ($109,420/fdr). The overall net present value reduction in revenue requirements is $5,597,064 ($119,086/fdr). Total annual energy savings is 27,138.9 MWh/yr (577.4/fdr) for a program measure life of 15 years.

Plan B first year costs, O&M costs, energy saved, demand reductions, and BCR are shown in Table 28. Overall VO economic results are given in Table 29.

Table 27 - Plan B System Line and No-Load Losses

Sub Id	Annual MWh Load	Existing Line and No-Load Losses (MWh)	Revised Peak Line Loss (kW)	Reduction in Peak Line Loss (kW)	Savings in Line Loss (MWh)	Reduction in Peak No-Load Loss (kW)	Savings in No-Load Loss (MWh)	Revised Total Loss (MWh)	% Loss	Total Loss Energy Savings (MWh)
DCB28	15,577	595.0	11.6	69.7	105.4	3.7	32.0	457.6	2.94%	137.4
DCD69	19,868	498.8	102.0	1.6	1.9	3.2	27.8	469.1	2.36%	29.7
DCE71	33,852	897.7	168.3	19.2	22.5	5.5	48.4	826.7	2.44%	71.0
DCE79	33,375	1,043.6	98.2	255.7	321.3	4.7	41.4	680.9	2.04%	362.7
DCH38	10,375	686.1	94.3	6.3	8.7	4.3	37.9	639.5	6.16%	46.6
DCW38	47,753	883.9	199.2	14.8	20.3	5.0	43.6	820.0	1.72%	63.9
DCW48	31,421	681.9	105.6	123.3	144.5	3.6	31.9	505.5	1.61%	176.4
DCW71	62,809	1,240.8	129.4	0.5	1.2	7.4	65.1	1,174.5	1.87%	66.3
DCW73	16,819	425.7	137.8	3.5	4.6	2.0	18.0	403.1	2.40%	22.6
DCW148	33,315	829.2	92.8	0.0	0.0	6.4	55.8	773.4	2.32%	55.8
TDC375	259,799	7,264.8	1,049.8	508.8	1,052.9	20.7	181.7	6,030.1	2.32%	1,234.6
DCW17	12,200	293.1	46.2	1.1	1.3	2.0	17.7	274.1	2.25%	19.0
DCW233	15,450	387.8	25.5	13.7	16.1	3.2	27.7	344.0	2.23%	43.8
TDC559	218,503	5,725.8	881.1	128.5	201.1	26.4	231.4	5,293.3	2.42%	432.5
SS513	49,439	1,921.8	229.4	10.8	12.7	11.3	98.7	1,810.3	3.66%	111.4
TSS104	116,949	2,365.6	245.7	3.6	8.6	9.4	82.8	2,274.2	1.94%	91.4
	977,504	25,741.6	3,616.9	1,161.1	1,923.2	118.9	1,042.0	22,776.4	2.33%	2,965

Table 28 - Plan B Economic Analysis Summary by Substation

Substation id	Number of Customers	VO Upgrade Costs (w/o Isolation Adders) (First Year $)	VO Upgrade Costs (w/ Isolation Adders) (First Year $)	Annual O&M Costs (First year $)	NPV of VO Upgrade Costs (w/ Isolation Adders) ($)	NPV of VO Energy Savings ($)	NPV of Revenue Requirement Savings ($)	Total VO Energy Saved MWh/y	Total Peak Demand Reduction kW/y	Benefit Cost Ratio
DCB28	1,031	$111,880	$111,880	$2,238	$145,770	$263,795	$118,025	556.5	153.1	1.81
DCD69	589	$131,440	$131,440	$2,629	$171,255	$327,591	$156,336	691.1	130.6	1.91
DCE71	2,182	$285,500	$285,500	$5,710	$371,982	$494,571	$122,589	1,043.3	209.7	1.33
DCE79	3,114	$110,275	$110,275	$2,206	$143,679	$583,021	$439,342	1,229.9	425.4	4.06
DCH38	660	$222,000	$222,000	$4,440	$289,247	$158,600	-$130,647	334.6	65.4	0.55
DCW38	1,687	$339,200	$339,200	$6,784	$441,949	$721,194	$279,246	1,521.4	297.1	1.63
DCW48	1,862	$217,415	$217,415	$4,348	$283,273	$533,134	$249,861	1,124.7	307.4	1.88
DCW71	2,581	$158,500	$158,500	$3,170	$206,512	$894,144	$687,632	1,886.3	354.2	4.33
DCW73	950	$172,500	$172,500	$3,450	$224,753	$242,390	$17,638	511.3	98.5	1.08
DCW148	3,417	$92,500	$92,500	$1,850	$120,520	$533,925	$413,406	1,126.4	210.1	4.43
TDC375	13,801	$1,430,500	$1,430,500	$28,610	$1,863,820	$2,957,074	$1,093,254	6,238.2	1,481.5	1.59
DCW17	1,030	$40,500	$40,500	$810	$52,768	$176,864	$124,096	373.1	70.5	3.35
DCW233	1,397	$102,375	$102,375	$2,048	$133,386	$268,532	$135,146	566.5	116.3	2.01
TDC559	18,039	$870,000	$870,000	$17,400	$1,133,536	$2,555,383	$1,421,847	5,390.8	1,098.3	2.25
SS513	5,197	$319,650	$319,650	$6,393	$416,477	$836,911	$420,434	1,765.5	336.8	2.01
TSS104	4,908	$538,500	$538,500	$10,770	$701,620	$1,317,360	$615,740	2,779.1	524.4	1.88
	62,445	$5,142,735	$5,142,735	$102,855	$6,700,547	$12,864,490	$6,163,943	27,139	5,879	1.920

Table 29 - Plan B Economic Analysis for Substations

	Plan B
General Substation Information	
Number of Substations Investigated	
Total Customers Served (#)	62,445
Number of Feeders (Viable and Non-viable) Investigated (#)	56
Number of Feeders (Viable) Investigated (#)	47
Substation Annual Peak Demand (kW)	278,298
Total Annual Energy Consumed (MWh/yr)	977,504
VO Energy Savings Potential	
Average Primary Voltage Pre-VO (V)	124.13
Average Primary Voltage Post-VO (V)	119.56
Average Customer VO Voltage Change (%)	3.81%
Substation Weighted Average VO factor	0.761
VO Energy Savings (MWh/y)	24,173.7
Line Loss Energy Savings (MWh/y)	1,923.2
No-Load Loss Energy Savings (MWh/y)	1,042.0
Distribution Line and Transf no-load loss (%)	2.33%
Total Energy Savings (MWh/y)	27,138.9
Total Coincidental Demand Reduction (kW)	5,879.3
Customer Average Energy Savings (kWh/yr)	434.6
Benefit Cost Projections	
Total VO Upgrade Cost - First Year ($)	$5,142,735
Annual O&M First Year Costs ($)	$102,855
Total VO Upgrade Cost (NPV)	$6,700,547
Total VO Energy Savings (NPV)	$12,864,490
NPV Revenue Requirement Savings ($)	$6,163,943
VO Benefit Cost Ratio (BCR)	1.920

6.14 Comparison of Alternative VO Plans

6.14.1 Economic Evaluation Analysis Methodology

The objective of the VO economic evaluations[9] was to identify solutions that maximize energy savings while meeting acceptable VO thresholds and ComEd BCR targets. As more system improvements were added, incremental energy saved diminished, resulting in lower BCRs. The economic analysis assumes no incentives are applied to ComEd first-year costs. The equipment life of 33 years is considered short, which also lowers the BCR.

The net present value of savings (reduced revenue requirements) is another consideration when comparing alternative plans. If net PV savings are zero, the BCR is 1.0, resulting in no change in net revenue requirements. The alternative plan development goal is to have BCRs greater than 1.5 to provide a cushion for possible inflation and financial risk (i.e., higher improvement costs, lower marginal costs, and higher inflation rates).

Net PV system improvement estimates include first year investment costs; net present value of annual fixed charges and O&M expenses; expected future equipment salvage; present worth value investment factors; and inflation rates. The energy efficiency measure (EEM) program life is assumed to be 15 years based on the NWPCC Simplified VO M&V Protocol. The VO savings life is 15 years, and the system improvement loss saving measure equipment life is set at 33 years. However, the VO energy savings measure program life can be extended (e.g., 20 years) if costs are added in a future year (e.g., at year 10 and 20) as a percentage of first year investment costs. In this study, the VO life is set at 15 years. A lump sum cost adder is included in year 10 costs, assuming 10% of the initial installed cost is needed to maintain the installation and sustain the annual savings. All system loss savings benefits and investment costs beyond the program life of 15 years are discounted and credited in the 15th year.

The avoided marginal cost of purchased power is assumed to be $0.042/kWh for the base year (2014) with an energy cost inflation rate of 3.0% per year thereafter.

[9] The detailed economic analysis was performed using economic principles described in D. G. Newnan, T. G. Eschenbach, J. P. Lavelle, *Engineering Economic Analysis, Ninth Edition*, Oxford University Press, Inc., New York, 2004.

6.14.2 Summary of Economic Comparison

A comparison of Plan A and Plan B results for the 16 substations and 56 feeders (consisting of 47 viable and 9 non-viable feeder candidates) is shown in Figure 12 and Figure 13. Included are expected energy savings and upgrade NPV costs; an overview applied upgrades; minimum primary voltages allowed; BCRs; and end-use MWh/yr savings.

VO energy savings are divided into two categories: 1) VO Energy Savings (end-use savings) and 2) VO System Loss Savings (ComEd system savings). The costs for impact of peak demand reductions were not evaluated in the study.

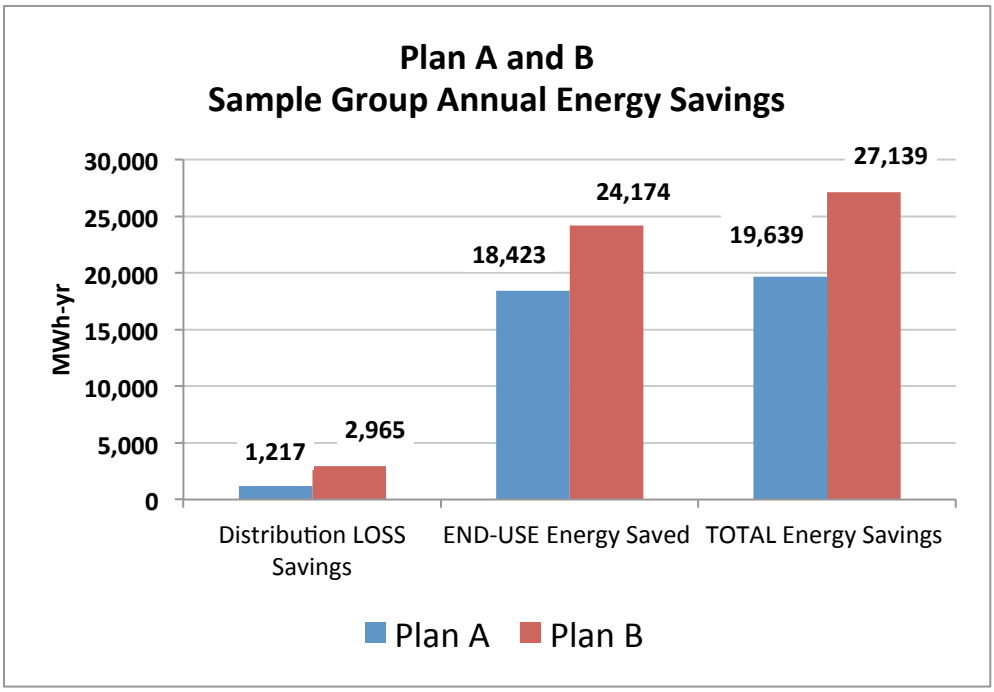

Figure 12 - Sample Group Total Energy Savings Potential

The ***lowest cost*** alternative VO plan is Plan A, with an installed first-year cost of $3,705,440 (or $78,839 per feeder) and total energy savings 19,639.0 MWh/yr (or 417.9 MWh/yr per feeder). Plan A includes improvements and upgrades necessary to meet VO thresholds. Plan A upgrades are summarized in Table 30.