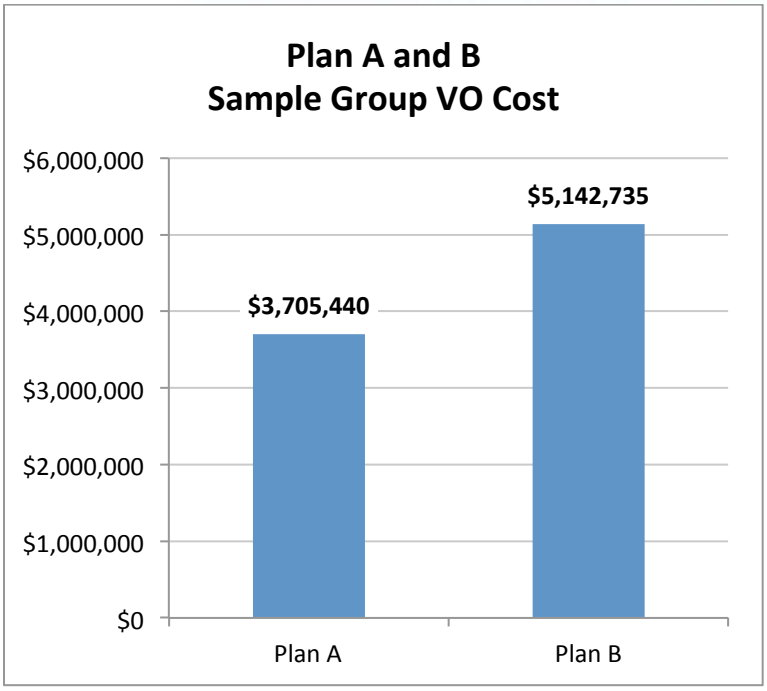


Figure 13 - Sample Group Total VO Cost

Table 30 - Plan A VO Upgrades

OH Line Reconductor (mi)	0.62
Station Regulator Addition (#)	0
In-Line Voltage Regulator Addition	7
OH & UG Line or Transformer Tap Changes (#)	10
OH Phase Upgrades (mi)	0.16
Fixed 600 kVAR Capacitor Additions (#)	38
Switched 600 kVAR Capacitor Additions (#)	150
Feeder Source & Regulator Metering (#)	58
EOL Voltmeters (#)	60
EOL Voltage Feedback Sensing (#)	4
IVVC Application ($)	$250,000
Total VO Upgrade Cost ($)	$3,705,440
VO Upgrade Cost (w/ Isolation Adders)	$3,705,440

Plan A system was designed for minimum primary EOL voltages of 120.0 volts. The overall evaluated BCR is 1.928, with average customer energy savings of 314.5 kWh per year.

The ***highest energy saving*** alternative VO plan studied is Plan B, with an installed cost of $5,142,735 (or $109,420 per feeder) and total energy savings 27,138.9 MWh/yr (or 577.4 MWh/yr per feeder). Plan B has the same system improvements as Plan A plus additional upgrades as needed. Plan B upgrades are summarized in Table 31.

Plan B is designed for minimum primary EOL voltages of 119.0 volts. The overall evaluated BCR is 1.920, with customer average savings of 434.6 kWh per year.

6.14.3 Plan A and Plan B Summary Comparison

Table 32 compares Plan A and Plan B general substation/feeder information, VO energy savings potential, and benefit cost projections.

Plan A benefits and costs for use with energy efficiency measure initiatives are given for VO Energy Savings (end-use savings) and VO System Loss Savings (ComEd system savings) as follows:

VO Energy Saving:	18,422.5 kWh/yr,	$370,544 cost,	$11,117 OM cost, and 15-year life.
VO Loss Saving:	1,216.4kWh/yr,	$3,334,896 cost,	$100,046 OM cost, and 33-year life.
Totals:	19,639.0	$3,705,440	$111,163

Plan B benefits and costs for use with energy efficiency measure initiatives are given for VO Energy Savings (end-use savings) and VO System Loss Savings (ComEd system savings) as follows:

VO Energy Saving:	24,173.7 kWh/yr,	$514,220 cost,	$15,427 OM cost, and 15-year life.
VO Loss Saving:	2,965.2 kWh/yr,	$4,628,515 cost,	$138,855 OM cost, and 33-year life.
Totals:	27,138.9	$5,142,735	$154,282

Table 31 - Plan B VO Upgrades

OH Line Reconductor (mi)	1.91
Station Regulator Addition (#)	1
In-Line Voltage Regulator Addition	18
OH & UG Line or Transformer Tap Changes (#)	49
OH Phase Upgrades (mi)	1.22
Fixed 600 kVAR Capacitor Additions (#)	38
Switched 600 kVAR Capacitor Additions (#)	149
Feeder Source & Regulator Metering (#)	68
EOL Voltmeters (#)	61
EOL Voltage Feedback Sensing (#)	4
IVVC Application ($)	$252,000
Total VO Upgrade Cost ($)	$5,142,735

Table 32 - Plan Comparison Summary

	Plan A	Plan B
General Substation Information		
Number of Substations Investigated		
Total Customers Served (#)	62,445	62,445
Number of Feeders (Viable and Non-viable) Investigated (#)	56	56
Number of Feeders (Viable) Investigated (#)	47	47
Substation Annual Peak Demand (kW)	278,298	278,298
Total Annual Energy Consumed (MWh/yr)	977,504	977,504
VO Energy Savings Potential		
Average Primary Voltage Pre-VO (V)	124.13	124.13
Average Primary Voltage Post-VO (V)	120.57	119.56
Average Customer VO Voltage Change (%)	2.96%	3.81%
Substation Weighted Average VO factor	0.761	0.761
VO Energy Savings (MWh/y)	18,422.5	24,173.7
Line Loss Energy Savings (MWh/y)	395.6	1,923.2
No-Load Loss Energy Savings (MWh/y)	820.8	1,042.0
Distribution Line and Transf no-load loss (%)	2.51%	2.33%
Total Energy Savings (MWh/y)	19,639.0	27,138.9
Total Coincidental Demand Reduction (kW)	3,892.6	5,879.3
Customer Average Energy Savings (kWh/yr)	314.5	434.6
Benefit Cost Projections		
Total VO Upgrade Cost - First Year ($)	$3,705,440	$5,142,735
Annual O&M First Year Costs ($)	$74,109	$102,855
Total VO Upgrade Cost (NPV)	$4,827,873	$6,700,547
Total VO Energy Savings (NPV)	$9,309,375	$12,864,490
NPV Revenue Requirement Savings ($)	$4,481,502	$6,163,943
VO Benefit Cost Ratio (BCR)	1.928	1.920

7. Extrapolation to System Level

A primary objective of the feasibility study was to develop accurate and defendable estimates of VO cost and energy savings potential. The research plan accomplished this through a multi-stage analysis that applied formula-based engineering to a study group based on feeder-specific load flow simulations on a representative sample of feeders. Sampling statistics were then used to extrapolate the results to the system level.

7.1 Project Study Groups

The feasibility study conducted an engineering analysis of individual feeders and substation groups. From a sample design perspective, VO costs and savings were evaluated at the feeder level using the four key project groups described below.

Group 1 - ComEd System Population. The ComEd system population is defined as the total number of primary network feeders and associated substations within ComEd's service territory, and is composed of 5655 feeders fed from 806 substations. Specifically excluded are 129 secondary networks in the downtown Chicago area deemed not appropriate for voltage optimization. The system population was developed based on data provided by ComEd's Distribution Planning Group. Individual feeder and substation data was derived primarily from ComEd's CYME and GIS databases.

Group 2 - Project Study Group. The project study group is a subset of feeders and substations included in the analysis. The study group consists of 3757 feeders and 543 substations, which is approximately two-thirds of the total system population. Not all feeders/substations were included; i.e., 1898 feeders and 264 substations were excluded. Five (5) of 19 initially selected ComEd regions were excluded due to unexpected data issues and project time constraints. In addition, feeders from the included 14 regions were excluded due to data issues. It was assumed these excluded feeders are adequately represented by feeders included in the study group.

Group 3 - Viable Feeder Study Group. The Task 3 screening analysis was conducted on all 3757 feeders of the project study group. Of these, 1837 were deemed non-viable for VO application due to their voltage class (less than 11 kV or higher than 29 kV), or customer make-up (large commercial and industrial >1000 kW). The remaining 1920 feeders and 543 substations make up the viable feeder study group. Preliminary VO costs and savings based on formula-based engineering analysis were developed for each of these feeders as documented in the project Task 3 report.

Group 4 - Sample Group. The sample group identified in Task 3 (screening) consisted of 16 substations and 70 feeders (50 viable and 20 non-viable). A later assessment reduced the total number of feeders from 70 to 61 as explained below.

The Chicago South substation (TSS104) consisted of 3 power transformers, 1 dedicated and 2 paralleled. The dedicated transformer (TR71) served 4 viable and 1 non-viable feeders. The paralleled transformers (TR72 and TR73) served 4 viable and 5 non-viable feeders. One of the viable feeders, Z10432, was reclassified to non-viable because it served Midway Airport, reducing the viable feeder count for the paralleled transformers (from 4 to 3), and increasing the non-viable feeder count (from 10 to 6). Since Midway is a sensitive load, re-configuration was not attempted. With only 3 viable feeders sharing a common bus with 11 non-viable feeders, isolation costs would have been too high to consider. Therefore, the 9 paralleled transformer feeders were excluded from the study, reducing the total feeder count from 70 to 61, and the viable feeder count from 50 to 46.

A feeder was then added to substation DCH38 (located in the Dixon region) by splitting H385 into two feeders, one serving the North and the other serving the South (H385 North and H385 South), increasing the viable feeder count from 46 to 47.

Because feeders need to be modeled as substation groups to capture interactive voltage effects across feeders in the same voltage control zone, the sample was drawn at the substation level. Substations were grouped into strata based on energy savings potential (ESP) and VO Costs:

HH Substations with high ESP$ > $1,474,535 and high VO Cost > $362,267
HL Substations with high ESP$ > $1,474,535 and low VO Cost <= $362,267
LH Substations with low ESP$ < $161,347 and high VO Cost > $362,267
LL Substations with low ESP$ < $161,347 and low VO Cost <= $362,267

The sample extrapolation process is shown in Figure 14.

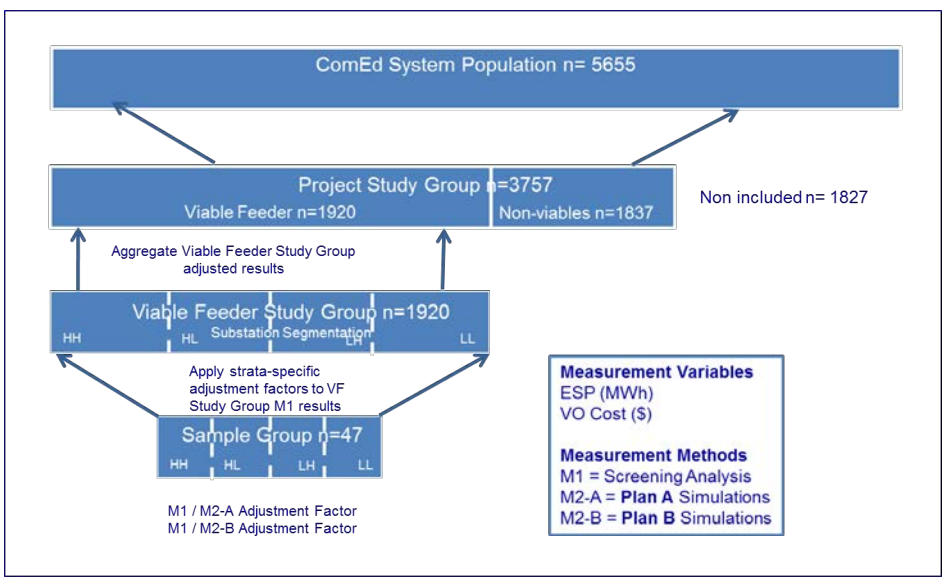


Figure 14 - Sample Extrapolation Process

7.2 VO Estimation Methods

The research plan used a sample-based two-stage estimation procedure. First, simplified cost and savings estimates were developed using a formulaic engineering analysis on all viable feeders in the study group (referred to as Method 1 or M1). Next, detailed load flow simulations and customized cost build-ups were performed on a representative sample of substation feeder groups (Method 2, or M2).

Three scenarios were modeled: a) Base Case; b) Low Cost (M2-A) (Plan A); and c) Maximum Energy Savings (M2-B) (Plan B). The two study groups are directly linked through a stratified random sampling approach of substation feeder groups and expanded to the population of viable feeders using a statistical ratio estimate. This sample design allows for extrapolation of M1 and M2 results to the ComEd system level with quantifiable levels of precision.

7.3 System Level Results

Summarized in Table 33 are system-level results for VO costs and ESP (MWh-yr). The lower cost scenario (Plan A) VO approach has a potential total cost of $425 million and results in energy savings of 1350 GWh per year. This is equivalent to a levelized cost of energy of $0.035/kWh. The maximum savings scenario approach (Plan B) has a total cost of $574 million and a savings potential of 1,912 GWh per year, or approximately 2.1% of ComEd's 2013 retail kWh sales.

Table 34 summarizes the relative precision of the sample-based M2-A and M2-B results extrapolated to the system population. The relative precision is calculated at a 90% confidence level. The precision estimates refer to the sampling error of performing the detailed M2 methodology on only a sample of 47 feeders as compared to results that would have been achieved had we performed the detailed M2 methodology on all 2,890 viable feeders in the ComEd population. It does not factor in the measurement error of the M2 simulation methodology compared to actual field observations.

Table 35 provides feeder-based extrapolation values resulting from sample group, study group and system population extrapolations. Table 36 provides similar extrapolations results based on substation values. (See Appendix 12.1 for a prioritized ranking of all 346 viable substations based on benefit-cost ratios.)

Table 33 - System-Level Results

	Total	Average per Feeder	Average per Substation
Plan A Results			
VO Cost	$425,466,877	$147,220	$826,902
VO ESP (MWh-yr)	1,350,371	467	2,624
Plan B Results			
VO Cost	$574,232,508	$198,696	$1,116,030
VO ESP (MWh-yr)	1,912,952	662	3,718

Table 34 - Relative Precision

	Total		Relative Precision at 90% Confidence	
Plan A Results				
VO Cost	$425,466,877	+/-	*66,946,483*	*15.7%*
VO ESP (MWh-yr)	1,350,371	+/-	*136,589*	*10.1%*
Plan B Results				
VO Cost	$574,232,508	+/-	*91,843,098*	*16.0%*
VO ESP (MWh-yr)	1,912,952	+/-	139,278	7.3%

Table 35 - Extrapolation Results - Feeder-Based

ComEd VO Feasibility Study
Feeder Sample Extrapolation

	Total ComEd System n=5655				
# of Feeders	5655				
# Viable / Non-viable	**2,890**	**2765**	**Relative Precision at 90% Confidence**		
Total VO ESP (MWh) - A	**1,350,371**		*+/-*	*136,589*	*10.1%*
Total VO Costs ($) - A	**$425,466,877**		*+/-*	*66,946,483*	*15.7%*
BCR Scenario A (Preliminary)	**1.50**				
Total VO ESP (MWh) - B	**1,912,952**		*+/-*	*139,278*	*7.3%*
Total VO Costs ($) - B	**$574,232,508**		*+/-*	*91,843,098*	*16.0%*
BCR Scenario B (Preliminary)	**1.58**				

	Project Study Group n= 3757				
	Viable Feeders	Non-Viable	-included Feeders		
# of Feeders	1920	1837	1898	**Relative Precision at 90% Confidence**	
Total VO ESP (MWh) - A	**897,143**		*+/-*	*90,745*	*10.1%*
Total VO Costs ($) - A	**$282,666,500**		*+/-*	*44,477,089*	*15.7%*
Total VO ESP (MWh) - B	**1,270,904**		*+/-*	*92,532*	*7.3%*
Total VO Costs ($) - B	**$381,501,597**		*+/-*	*61,017,598*	*16.0%*

	Viable Feeder Study Group n=1920			
Substation Strata	HH	HL	LH	LL
# of Feeders	1285	152	386	97
Avg. Feeder ESP - M1	412	377	322	191
Avg. Feeder VO Cost M1	$163,531	$108,826	$230,985	$137,353
Adjusted ESP- A	**483**	**539**	**417**	**351**
Adjusted VO Cost - A	**$159,943**	**$67,649**	**$140,420**	**$130,460**
Adjusted ESP - B	**694**	**693**	**591**	**466**
Adjusted VO Cost - B	**$203,273**	**$96,975**	**$227,298**	**$183,699**

Strata Definitions
HH - High ESP / High Cost
HL - High ESP / Low Cost
LH - Low ESP / High Cost
LL - Low ESP / Low Cost

M1= Screening analysis results
M2-A= Simulation results - **Plan A**
M2-B= Simulation results - **Plan B**

h	Sample Group n=47				
Substation Strata	HH	HL	LH	LL	*Total*
# of Feeders	21	11	9	6	*47*
Avg. Feeder ESP-M1	329	318	367	205	
Avg. Feeder VO Cost-M1	$114,826	$132,555	$176,150	$105,156	
Avg. Feeder ESP M2-A	385	455	476	379	
Avg. Feeder VO Cost M2-A	$112,307	$82,399	$107,085	$99,879	*Avg Adj Factor*
Adjustment Factor ESP A	**1.17**	**1.43**	**1.30**	**1.84**	***1.31***
Adjustment Factor VO Cost A	**0.98**	**0.62**	**0.61**	**0.95**	***0.79***
Avg. Feeder ESP M2-B	554	584	674	503	
Avg. Feeder VO Cost M2-B	$142,731	$118,119	$173,338	$140,639	
Adjustment Factor ESP B	**1.68**	**1.84**	**1.84**	**2.45**	***1.82***
Adjustment Factor VO Cost B	**1.24**	**0.89**	**0.98**	**1.34**	***1.10***

Table 36 - Extrapolation Results - Substation-Based

ComEd VO Feasibility Study
Substation Sample Extrapolation

	Total ComEd System n=806				
# of Substations	806				
# Viable / Non-viable	515	291	Relative Precision at 90% Confidence		
Total VO ESP (MWh) - A	1,315,746		+/-	210,902	16.0%
Total VO Costs ($) - A	$421,705,974		+/-	50,583,681	12.0%
BCR Scenario A (Preliminary)	1.48				
Total VO ESP (MWh) - B	1,861,114		+/-	215,012	11.6%
Total VO Costs ($) - B	$568,093,150		+/-	49,938,781	8.8%
BCR Scenario B (Preliminary)	1.55				

	Project Study Group n= 542					
	Viable Substations	Non-Viable	Non-included Substations			
# of Substations	346	196	264	Relative Precision at 90% Confidence		
Total VO ESP (MWh) - A	884,782			+/-	141,823	16.0%
Total VO Costs ($) - A	$283,578,955			+/-	34,015,329	12.0%
Total VO ESP (MWh) - B	1,251,519			+/-	144,586	11.6%
Total VO Costs ($) - B	$382,017,974			+/-	33,581,662	8.8%

	Viable Substation Study Group n=346			
Substation Strata	HH	HL	LH	LL
# of Substations	86	86	87	87
Avg. Feeder ESP - M1	6153	667	1427	212
Avg. Feeder VO Cost M1	$2,443,459	$192,343	$1,024,830	$153,140
Adjusted ESP- A	7199	919	1851	294
Adjusted VO Cost - A	$2,389,849	$130,175	$623,014	$145,455
Adjusted ESP - B	10359	1148	2622	389
Adjusted VO Cost - B	$3,037,275	$177,401	$1,008,471	$204,813

Strata Definitions
HH - High ESP / High Cost
HL - High ESP / Low Cost
LH - Low ESP / High Cost
LL - Low ESP / Low Cost

M1= Screening analysis results
M2-A= Simulation results - **Plan A**
M2-B= Simulation results - **Plan B**

	Sample Group n=16				
Substation Strata	HH	HL	LH	LL	*Total*
# of Substations	2	6	3	5	*16*
Avg. Feeder ESP-M1	3454	632	1100	246	
Avg. Feeder VO Cost-M1	$1,205,672	$250,140	$528,450	$126,188	
Avg. Feeder ESP M2-A	4041	871	1427	341	
Avg. Feeder VO Cost M2-A	$1,179,220	$169,292	$321,255	$119,855	*Avg Adj Factor*
Adjustment Factor ESP A	1.17	1.38	1.30	1.38	*1.25*
Adjustment Factor VO Cost A	0.98	0.68	0.61	0.95	*0.79*
Avg. Feeder ESP M2-B	5815	1087	2022	451	
Avg. Feeder VO Cost M2-B	$1,498,678	$230,708	$520,015	$168,767	
Adjustment Factor ESP B	1.68	1.72	1.84	1.83	*1.74*
Adjustment Factor VO Cost B	1.24	0.92	0.98	1.34	*1.10*

7.4 Factors Affecting Potential Results

The results presented in this study were generated using ComEd supplied data sources combined with a variety of industry accepted engineering calculations, statistical methods, commercial load flow modeling tools (CYME), and professional judgment. At every juncture, care was taken to ensure that the results from the study are both representative of the ComEd system, and unbiased. Table 37 provides a qualitative sensitivity analysis of the key parameters or methods used in the study.

Table 37 - Factors Affecting Potential Results

Parameter / Method	Source	Key Assumptions	Sensitivity
Feeder Peak Load (kW_7)	ComEd distribution planning data in CYME	Values are assumed to be measured values that accurately reflect historical feeder loadings	Feeder Peak kW is a key determinant of energy loads and savings. Distribution planners tend to overestimate kW loadings, which would negatively impact VO ESP.
Load Factor	Estimated for screening (M1); recorded (when available) or estimated for simulations (M2)	M1 = .35 M2 = .401 (avg.) Both load factors are considered conservative.	Load factor directly affects kWh savings. Conservative assumptions would underestimate savings potential
Engineering models and impedance calculations of voltage drops	Engineering calculations (M1) and CYME-DIST Load flow model (M2)	All calculations are based on industry accepted engineering methods	Load flow simulation results tend to be stable.
VO Factor	Estimated based on analysis of ComEd end-use characteristics and feeder-specific customer composition	The average VO factor of .753 is assumed to be conservative.	Energy savings is directly related to VO Factor. A bias up or down can significantly impact results.
Sampling and extrapolation methods	Random sampling and ratio estimation used for the sample and study groups. Feeder counts used to extrapolate from the study group to the system population level	Sample selection was unbiased. Excluded 4 regions were statistically similar to the other 14 regions.	Sampling precision is calculated as +/- 7% - 16% at 90% confidence levels
Existing System Power Factor	Estimated at 98%	Assumption based on industry standards.	Overestimating power factor increases voltage drop and energy savings potential

8. Benefit-Cost Analysis on Representative Feeders

8.1 DSMore Input Development

AEG and ComEd conducted a benefit-cost analysis of two voltage optimization (VO) plans at select feeders within ComEd's service territory. The analysis was based on system-level energy savings potential of high and low cost scenarios, which were inputted into the Demand Side Management Option Risk Evaluator (DSMore) cost-effectiveness analysis tool. Key parameters and economic assumptions used to develop the DSMore inputs are shown in Table 38. DSMore inputs were developed using the same methodology for each plan.

Table 38 - DSMore Input Parameters

Parameter	Plan A	Plan B
Energy Savings Potential (MWh)	1,350,371	1,912,952
First Year Capital Cost	$425,466,877	$574,232,508
Annual O&M Costs	$8,509,338	$11,484,650
Annual O&M Costs (% of First Year)	2%	2%
Replacement Cost (% of First Year)	10%	10%
Measure Life (years)	15	15
Equipment Life (years)	33	33
Replacement Year	10	10
Salvage Year	15	15

Energy savings potential and first year capital costs were taken directly from the system-level simulation results described in Task 8. Other economic assumptions based on generic industry specifications were used to develop the DSMore inputs.

8.2 Participation, Program Costs, and Credits

The VO program is counted as a single participant in the first year of the program. Energy savings potential represents annual energy savings attributable to the VO program. Free ridership is assumed to be zero since only customers serviced by feeders where VO is deployed will be

impacted by the program. The DSMore cost-effectiveness tool allows for the four main utility cost categories described in Table 39.

Table 39 - DSMore Utility Cost Categories

DSMore Input	Description
Annual Administration Costs	Annual O&M costs
Implementation / Participation Costs	First year capital costs
Incentives	The VO program does not include incentives.
Other / Miscellaneous Costs	Replacement costs minus salvage value

The measured life is defined as the total number of years the VO program may be deployed to achieve savings. By contrast, equipment life reflects the total useful life of VO equipment. The first year capital cost represents the total utility outlay for equipment and system upgrades needed for the VO program. The annual O&M costs are estimated as a percentage of first year capital costs for each subsequent year of the program.

Asset depreciation and replacement costs used generic program economic assumptions. Replacement costs were determined as a percentage of the first year capital cost. At the end of the program, the utility is entitled to a credit equal to the depreciated asset value of VO equipment.

8.3 DSMore Load Shapes

Load shapes reflect the average weekday and weekend hourly savings by month and season for 2013. Hourly savings for each scenario were developed based on the total hourly load of customers serviced by feeders where VO is deployed. The total energy savings for each scenario were extrapolated to each hour based on the hourly load factor, which was normalized to achieve an average VO load factor of approximately 0.60. Table 40 summarizes calculations performed to develop DSMore load shapes.

Table 40 - DSMore Load Shape Parameters

Variable	Definition
Source Hourly Load	Total hourly customer load serviced by feeders where VO is deployed.
Normalized Source Load Factor	Proportion of source hourly load to max hourly load normalized to achieve 0.60 VO factor.
Hourly Savings	Annual savings for each scenario multiplied by normalized source load factor

Load shapes are presented in Figure 15.

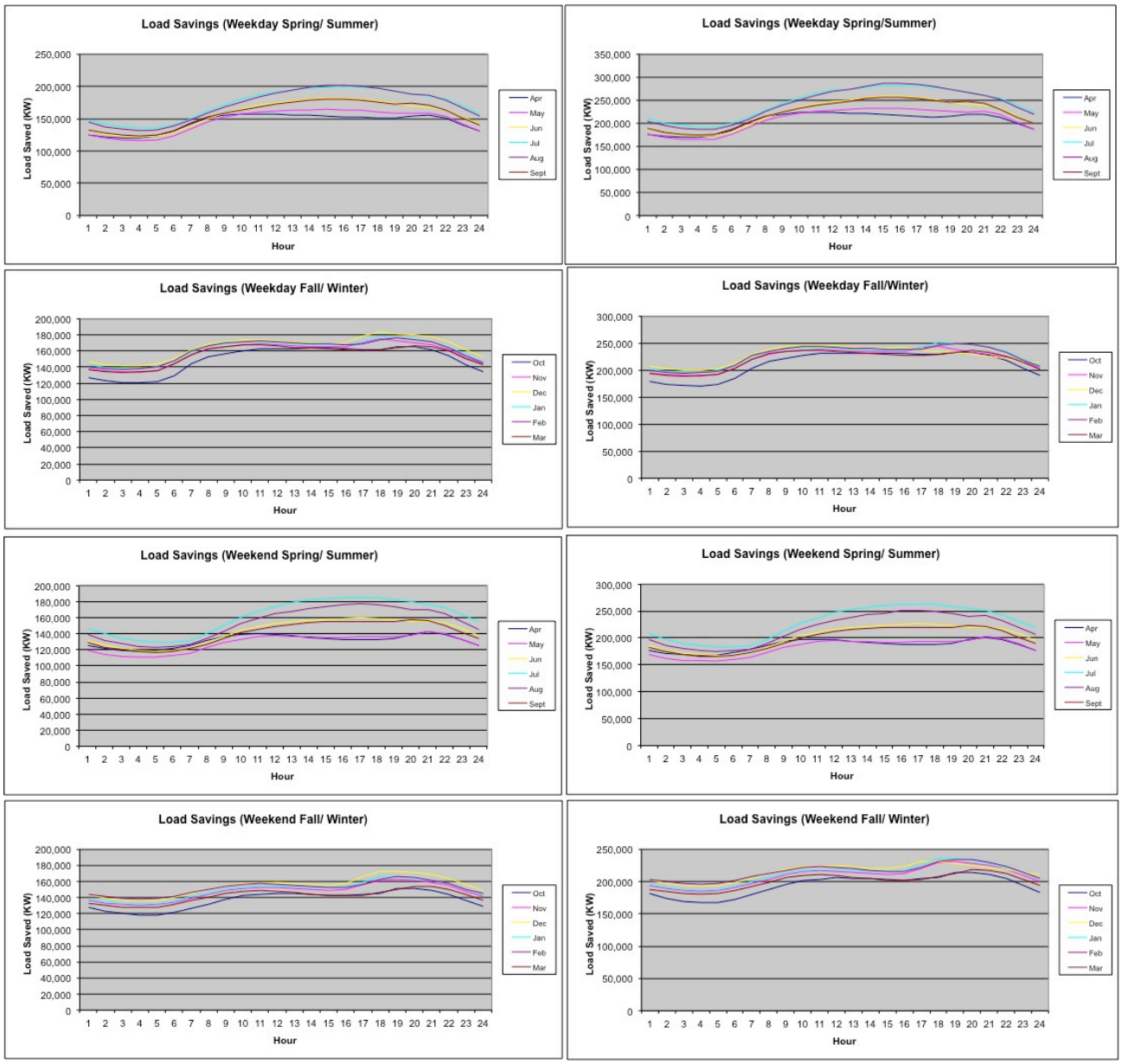


Figure 15 - DSMore Load Shapes

DSMore benefit-cost results are presented in Table 41 for Plan A and Table 42 for Plan B.

Table 41 - Plan A DSMore B-C Results

Present Values (PVs) of Costs and Benefits Per Test	Cost Based	Market-Based				
		Minimum	Today	Alternate	Option	Maximum
Utility (PAC) Test						
Avoided Electric Production	$608,926,671.80	$408,387,082.11	$608,926,671.80	$1,302,393,048.05	$1,006,035,825.48	$8,964,342,220.65
Avoided Electric Production Adders	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Avoided Electric Capacity	$13,944,339.33	$13,944,339.33	$13,944,339.33	$13,944,339.33	$13,944,339.33	$13,944,339.33
Avoided T&D Electric	$247,306,622.44	$247,306,622.44	$247,306,622.44	$247,306,622.44	$247,306,622.44	$247,306,622.44
Avoided Ancillary	$82,568,793.61	$80,814,484.49	$82,568,793.61	$82,568,793.61	$82,568,793.61	$84,107,629.00
Avoided Gas Production	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Avoided Gas Capacity	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total	$952,746,427.19	$750,452,528.37	$952,746,427.19	$1,646,212,803.43	$1,349,855,580.87	$9,309,700,811.42
Administration Costs	$74,686,648.13	$74,686,648.13	$74,686,648.13	$74,686,648.13	$74,686,648.13	$74,686,648.13
Implementation / Participation Costs	$425,466,877.29	$425,466,877.29	$425,466,877.29	$425,466,877.29	$425,466,877.29	$425,466,877.29
Other / Miscellaneous Costs	-$67,451,684.79	-$67,451,684.79	-$67,451,684.79	-$67,451,684.79	-$67,451,684.79	-$67,451,684.79
Incentives	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total	$432,701,840.63	$432,701,840.63	$432,701,840.63	$432,701,840.63	$432,701,840.63	$432,701,840.63
Reduced Arrears	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Test Results	2.20	1.73	2.20	3.80	3.12	21.52
TRC Test						
Avoided Electric Production	$608,926,671.80	$408,387,082.11	$608,926,671.80	$1,302,393,048.05	$1,006,035,825.48	$8,964,342,220.65
Avoided Electric Production Adders	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Avoided Electric Capacity	$13,944,339.33	$13,944,339.33	$13,944,339.33	$13,944,339.33	$13,944,339.33	$13,944,339.33
Avoided T&D Electric	$247,306,622.44	$247,306,622.44	$247,306,622.44	$247,306,622.44	$247,306,622.44	$247,306,622.44
Avoided Ancillary	$82,568,793.61	$80,814,484.49	$82,568,793.61	$82,568,793.61	$82,568,793.61	$84,107,629.00
Avoided Gas Production	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Avoided Gas Capacity	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total	$952,746,427.19	$750,452,528.37	$952,746,427.19	$1,646,212,803.43	$1,349,855,580.87	$9,309,700,811.42
Administration Costs	$74,686,648.13	$74,686,648.13	$74,686,648.13	$74,686,648.13	$74,686,648.13	$74,686,648.13
Implementation / Participation Costs	$425,466,877.29	$425,466,877.29	$425,466,877.29	$425,466,877.29	$425,466,877.29	$425,466,877.29
Other / Miscellaneous Costs	-$67,451,684.79	-$67,451,684.79	-$67,451,684.79	-$67,451,684.79	-$67,451,684.79	-$67,451,684.79
Total	$432,701,840.63	$432,701,840.63	$432,701,840.63	$432,701,840.63	$432,701,840.63	$432,701,840.63
Reduced Arrears	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Participant Costs (net)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Participant Tax Credits (net)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Environmental Benefits	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Other Benefits	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Test Results	2.20	1.73	2.20	3.80	3.12	21.52
RIM Test						
Avoided Electric Production	$608,926,671.80	$408,387,082.11	$608,926,671.80	$1,302,393,048.05	$1,006,035,825.48	$8,964,342,220.65
Avoided Electric Production Adders	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Avoided Electric Capacity	$13,944,339.33	$13,944,339.33	$13,944,339.33	$13,944,339.33	$13,944,339.33	$13,944,339.33
Avoided T&D Electric	$247,306,622.44	$247,306,622.44	$247,306,622.44	$247,306,622.44	$247,306,622.44	$247,306,622.44
Avoided Ancillary	$82,568,793.61	$80,814,484.49	$82,568,793.61	$82,568,793.61	$82,568,793.61	$84,107,629.00
Avoided Gas Production	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Avoided Gas Capacity	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total	$952,746,427.19	$750,452,528.37	$952,746,427.19	$1,646,212,803.43	$1,349,855,580.87	$9,309,700,811.42
Administration Costs	$74,686,648.13	$74,686,648.13	$74,686,648.13	$74,686,648.13	$74,686,648.13	$74,686,648.13
Implementation / Participation Costs	$425,466,877.29	$425,466,877.29	$425,466,877.29	$425,466,877.29	$425,466,877.29	$425,466,877.29
Other / Miscellaneous Costs	-$67,451,684.79	-$67,451,684.79	-$67,451,684.79	-$67,451,684.79	-$67,451,684.79	-$67,451,684.79
Incentives	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total	$432,701,840.63	$432,701,840.63	$432,701,840.63	$432,701,840.63	$432,701,840.63	$432,701,840.63
Reduced Arrears	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue (Electric)	$789,626,886.81	$786,492,622.60	$789,626,886.81	$789,626,886.81	$789,626,886.81	$792,673,721.10
Lost Revenue (Gas)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total	$789,626,886.81	$786,492,622.60	$789,626,886.81	$789,626,886.81	$789,626,886.81	$792,673,721.10
Net Fuel Lost Revenue (Electric)	$480,709,182.49	$478,562,658.26	$480,709,182.49	$480,709,182.49	$480,709,182.49	$482,739,294.39
Net Fuel Lost Revenue (Gas)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total	$480,709,182.49	$478,562,658.26	$480,709,182.49	$480,709,182.49	$480,709,182.49	$482,739,294.39
Test Results	0.78	0.62	0.78	1.35	1.10	7.60
Societal Test	1.04	0.82	1.04	1.80	1.48	10.17
Avoided Electric Production	$608,926,671.80	$408,387,082.11	$608,926,671.80	$1,302,393,048.05	$1,006,035,825.48	$8,964,342,220.65
Avoided Electric Production Adders	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Avoided Electric Capacity	$13,944,339.33	$13,944,339.33	$13,944,339.33	$13,944,339.33	$13,944,339.33	$13,944,339.33
Avoided T&D Electric	$247,306,622.44	$247,306,622.44	$247,306,622.44	$247,306,622.44	$247,306,622.44	$247,306,622.44
Avoided Ancillary	$82,568,793.61	$80,814,484.49	$82,568,793.61	$82,568,793.61	$82,568,793.61	$84,107,629.00
Avoided Gas Production	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Avoided Gas Capacity	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total	$952,746,427.19	$750,452,528.37	$952,746,427.19	$1,646,212,803.43	$1,349,855,580.87	$9,309,700,811.42
Administration Costs	$74,686,648.13	$74,686,648.13	$74,686,648.13	$74,686,648.13	$74,686,648.13	$74,686,648.13
Implementation / Participation Costs	$425,466,877.29	$425,466,877.29	$425,466,877.29	$425,466,877.29	$425,466,877.29	$425,466,877.29
Other / Miscellaneous Costs	-$67,451,684.79	-$67,451,684.79	-$67,451,684.79	-$67,451,684.79	-$67,451,684.79	-$67,451,684.79
Total	$432,701,840.63	$432,701,840.63	$432,701,840.63	$432,701,840.63	$432,701,840.63	$432,701,840.63
Reduced Arrears	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Participant Costs (net)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Environmental Benefits	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Other Benefits	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Test Results	2.20	1.73	2.20	3.80	3.12	21.52

Table 42 - Plan B DSMore B-C Results

Present Values (PVs) of Costs and Benefits Per Test						
	Cost Based	Market-Based				
		Minimum	Today	Alternate	Option	Maximum
Utility (PAC) Test						
Avoided Electric Production	$858,912,292.07	$576,538,188.06	$858,912,292.07	$1,837,081,447.82	$1,419,009,203.74	$12,643,608,166.63
Avoided Electric Production Adders	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Avoided Electric Capacity	$19,753,715.14	$19,753,715.14	$19,753,715.14	$19,753,715.14	$19,753,715.14	$19,753,715.14
Avoided T&D Electric	$350,337,470.75	$350,337,470.75	$350,337,470.75	$350,337,470.75	$350,337,470.75	$350,337,470.75
Avoided Ancillary	$116,296,139.25	$113,941,873.32	$116,296,139.25	$116,296,139.25	$116,296,139.25	$118,188,633.06
Avoided Gas Production	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Avoided Gas Capacity	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total	$1,345,299,617.22	$1,060,571,247.27	$1,345,299,617.22	$2,323,468,772.96	$1,905,396,528.89	$13,131,887,985.58
Administration Costs	$100,801,034.22	$100,801,034.22	$100,801,034.22	$100,801,034.22	$100,801,034.22	$100,801,034.22
Implementation / Participation Costs	$574,232,507.87	$574,232,507.87	$574,232,507.87	$574,232,507.87	$574,232,507.87	$574,232,507.87
Other / Miscellaneous Costs	-$91,036,346.62	-$91,036,346.62	-$91,036,346.62	-$91,036,346.62	-$91,036,346.62	-$91,036,346.62
Incentives	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total	$583,997,195.46	$583,997,195.46	$583,997,195.46	$583,997,195.46	$583,997,195.46	$583,997,195.46
Reduced Arrears	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Test Results	2.30	1.82	2.30	3.98	3.26	22.49
TRC Test						
Avoided Electric Production	$858,912,292.07	$576,538,188.06	$858,912,292.07	$1,837,081,447.82	$1,419,009,203.74	$12,643,608,166.63
Avoided Electric Production Adders	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Avoided Electric Capacity	$19,753,715.14	$19,753,715.14	$19,753,715.14	$19,753,715.14	$19,753,715.14	$19,753,715.14
Avoided T&D Electric	$350,337,470.75	$350,337,470.75	$350,337,470.75	$350,337,470.75	$350,337,470.75	$350,337,470.75
Avoided Ancillary	$116,296,139.25	$113,941,873.32	$116,296,139.25	$116,296,139.25	$116,296,139.25	$118,188,633.06
Avoided Gas Production	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Avoided Gas Capacity	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total	$1,345,299,617.22	$1,060,571,247.27	$1,345,299,617.22	$2,323,468,772.96	$1,905,396,528.89	$13,131,887,985.58
Administration Costs	$100,801,034.22	$100,801,034.22	$100,801,034.22	$100,801,034.22	$100,801,034.22	$100,801,034.22
Implementation / Participation Costs	$574,232,507.87	$574,232,507.87	$574,232,507.87	$574,232,507.87	$574,232,507.87	$574,232,507.87
Other / Miscellaneous Costs	-$91,036,346.62	-$91,036,346.62	-$91,036,346.62	-$91,036,346.62	-$91,036,346.62	-$91,036,346.62
Total	$583,997,195.46	$583,997,195.46	$583,997,195.46	$583,997,195.46	$583,997,195.46	$583,997,195.46
Reduced Arrears	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Participant Costs (net)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Participant Tax Credits (net)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Environmental Benefits	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Other Benefits	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Test Results	2.30	1.82	2.30	3.98	3.26	22.49
RIM Test						
Avoided Electric Production	$858,912,292.07	$576,538,188.06	$858,912,292.07	$1,837,081,447.82	$1,419,009,203.74	$12,643,608,166.63
Avoided Electric Production Adders	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Avoided Electric Capacity	$19,753,715.14	$19,753,715.14	$19,753,715.14	$19,753,715.14	$19,753,715.14	$19,753,715.14
Avoided T&D Electric	$350,337,470.75	$350,337,470.75	$350,337,470.75	$350,337,470.75	$350,337,470.75	$350,337,470.75
Avoided Ancillary	$116,296,139.25	$113,941,873.32	$116,296,139.25	$116,296,139.25	$116,296,139.25	$118,188,633.06
Avoided Gas Production	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Avoided Gas Capacity	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total	$1,345,299,617.22	$1,060,571,247.27	$1,345,299,617.22	$2,323,468,772.96	$1,905,396,528.89	$13,131,887,985.58
Administration Costs	$100,801,034.22	$100,801,034.22	$100,801,034.22	$100,801,034.22	$100,801,034.22	$100,801,034.22
Implementation / Participation Costs	$574,232,507.87	$574,232,507.87	$574,232,507.87	$574,232,507.87	$574,232,507.87	$574,232,507.87
Other / Miscellaneous Costs	-$91,036,346.62	-$91,036,346.62	-$91,036,346.62	-$91,036,346.62	-$91,036,346.62	-$91,036,346.62
Incentives	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total	$583,997,195.46	$583,997,195.46	$583,997,195.46	$583,997,195.46	$583,997,195.46	$583,997,195.46
Reduced Arrears	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue (Electric)	$1,114,173,804.88	$1,108,436,588.47	$1,114,173,804.88	$1,114,173,804.88	$1,114,173,804.88	$1,119,898,818.50
Lost Revenue (Gas)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total	$1,114,173,804.88	$1,108,436,588.47	$1,114,173,804.88	$1,114,173,804.88	$1,114,173,804.88	$1,119,898,818.50
Net Fuel Lost Revenue (Electric)	$678,192,441.40	$674,327,040.72	$678,192,441.40	$678,192,441.40	$678,192,441.40	$682,004,755.18
Net Fuel Lost Revenue (Gas)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total	$678,192,441.40	$674,327,040.72	$678,192,441.40	$678,192,441.40	$678,192,441.40	$682,004,755.18
Test Results	0.79	0.63	0.79	1.37	1.12	7.71
Societal Test	1.07	0.84	1.07	1.84	1.51	10.37
Avoided Electric Production	$858,912,292.07	$576,538,188.06	$858,912,292.07	$1,837,081,447.82	$1,419,009,203.74	$12,643,608,166.63
Avoided Electric Production Adders	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Avoided Electric Capacity	$19,753,715.14	$19,753,715.14	$19,753,715.14	$19,753,715.14	$19,753,715.14	$19,753,715.14
Avoided T&D Electric	$350,337,470.75	$350,337,470.75	$350,337,470.75	$350,337,470.75	$350,337,470.75	$350,337,470.75
Avoided Ancillary	$116,296,139.25	$113,941,873.32	$116,296,139.25	$116,296,139.25	$116,296,139.25	$118,188,633.06
Avoided Gas Production	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Avoided Gas Capacity	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total	$1,345,299,617.22	$1,060,571,247.27	$1,345,299,617.22	$2,323,468,772.96	$1,905,396,528.89	$13,131,887,985.58
Administration Costs	$100,801,034.22	$100,801,034.22	$100,801,034.22	$100,801,034.22	$100,801,034.22	$100,801,034.22
Implementation / Participation Costs	$574,232,507.87	$574,232,507.87	$574,232,507.87	$574,232,507.87	$574,232,507.87	$574,232,507.87
Other / Miscellaneous Costs	-$91,036,346.62	-$91,036,346.62	-$91,036,346.62	-$91,036,346.62	-$91,036,346.62	-$91,036,346.62
Total	$583,997,195.46	$583,997,195.46	$583,997,195.46	$583,997,195.46	$583,997,195.46	$583,997,195.46
Reduced Arrears	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Participant Costs (net)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Environmental Benefits	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Other Benefits	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Test Results	2.30	1.82	2.30	3.98	3.26	22.49

9. VO Staged Deployment Recommendation

A VO staged deployment is recommended to accomplish the following objectives:

a) Confirm methods used to estimate energy savings.
b) Validate residential and commercial VO factors.
c) Test voltage optimization strategies.
d) Validate LDC voltage control schemes.
e) Test EOL voltage feedback for overriding LDC controls.
f) Validate switched capacitor VAR control schemes.
g) Validate measurement and verification (M&V) protocol.
h) Test effectiveness of IVVC applications.

A pilot typically consists of at least two distribution substations with 4-to-6 feeders each, has a mix of at least 8000 residential and 800 commercial commercials (<1000 kW each). All substation, feeders, and EOL locations typically have primary metering for compliance and validation testing. If available, AMI customer metering can be used to provide detailed voltage and loading statistics.

Pre-demonstration engineering and operational characteristics include preparing single-line diagrams of substations, feeders, voltage control zones, regulator and capacitor locations, and large load customers. Expected feeder and VCZ maximum loadings, voltage ranges, and VAR flows must be provided. Service area GIS mapping data and distribution load flow analysis for each VCZ must be available. Location of meters and data available for each must be known. Control setting parameters for LDC controllers, capacitor VAR controllers, and IVVC controls must be available. Normal and emergency operating guidelines for VO controls, line switching, and outage reporting must be known.

It is recommended VO controls be operated at least once each day (i.e., turned “ON” and “OFF”) by changing the LDC settings from 119 volts (with R-settings) to 124.8 volts (with no R-settings). Voltages should be monitored to indicate non-compliance with minimum primary voltage requirements of 118.6 volts. Capacitor VAR control is continuously applied for both “ON” and “OFF” operational periods.

The ideal monitoring period is two years, with assessments every three months. However, a one-year period is acceptable, with assessments every two months. Shorter test periods make it difficult to adequately account for the large number of small changes that occur every day and differentiate between “real” and “noise” results. Measurements need to be made at each voltage control zone (VCZ) source and at end-users (if AMI data is available).

9.1 Implementation – Comprehensive List of Typical Components

9.1.1 Distribution System Planning and Design Engineering

- Pilot distribution substation and associated feeder selection
- Distribution system modeling
- Load flow simulations
- Energy savings estimates
- Distribution system upgrades
    - Shunt capacitors
    - Phase balancing
    - Source and line voltage regulators
    - Phase upgrades
    - Line reconductoring

9.1.2 Distribution Equipment Specification, Procurement, and Installation

- In-line voltage regulators
- Fixed shunt capacitors 600 kVAR
- Switched shunt capacitors 600 kVAR
- Capacitor switching VAR controls with voltage backup override
- Capacitor Volt-VAR sensing/metering
- EOL feedback communication interfaced to IVVC and/or LDC controllers
- LDC controllers for power transformers
- LDC controllers for in-line voltage regulators
- IVVC controllers at substations having one or more isolated feeders
- IVVC communication interfaced with station LDC controllers
- IVVC communication interfaced with line devices, and metering

9.1.3 Metering Specification, Procurement, and Insulation

- Power transformer LTC MW & MVAr, phase amps, and hourly voltage profile metering
- Feeder source MW & MVAr and hourly voltage profile metering
- Regulator MW & MVAr, phase amps, and hourly voltage profile metering
- EOL hourly voltage profile metering
- Metering data collection and storage infrastructure
- AMI customer profile metering (if available)
- Metering data evaluation, analysis, and reporting

9.1.4 Operation Control Engineering

- Line drop compensation
- Voltage feedback control
- VAR controls with voltage override
- IVVC controller parameters
- Metering integration and control
- SCADA interface communications, alarms, and supervisory controls

9.1.5 Engineering Assessment Standard Guidelines

- Application scenario selection strategies
- Planning, design, installation, and operation guidelines
- Engineering and operations training procedures
- System loss assessment methods and procedures
- Feeder energy savings and demand reduction M&V protocol development
- Engineering savings estimates, economic evaluations, and reporting templates

9.1.6 Implementation and trial testing

- Operational performance demonstration
- Metering data collection and storage
- Pilot trial operations “ON” and “OFF” testing
- Trial data statistical assessments (VO factor and average voltage formulations)
- Performance review and compliance validation

9.1.7 Operational Performance Assessment

- Voltage operational and performance control evaluation
- Power transformer LTC voltage bandwidth impact assessment
- VAR management performance validation
- VO factor assessment for M&V use
- M&V protocol guideline, average voltage formulation, and testing validation
- Customer impact and response assessments

9.2 Demonstration Scenarios

It is recommended the VO application scenarios described below be demonstrated (using different substations).

Scenario 1 - LDC (local control). LDC is applied only on viable feeders with local control for all source and line voltage regulators along with switched 600 kVAR capacitor banks having VAR sensing and control with voltage override backup. VCZ maximum voltage drops are less than 4 Volts. All LDC voltage settings are at 119 volts (with the R settings) voltage rises equal to the maximum voltage drop. All feeder VAR flows are at +/- 300 kVAR.

Scenario 2 - LDC (local control with remote voltage feedback override). LDC is applied only on viable feeders with local control and remote voltage feedback override for all source and line voltage regulators. The minimum primary voltage is 118.6 volts. Switched 600 kVAR capacitor banks are applied with VAR sensing and voltage override backup. VCZ maximum voltage drops are less than 4 Volts. All LDC voltage settings are at 119 volts (with R settings) voltage rises equal to the maximum voltage drop. All feeder VAR flows are at +/- 300 kVAR.

Scenario 3 - IVVC (remote voltage and VAR feedback) - IVVC applied on non-viable feeders maintains voltage levels of 122 volts to 124 volts. IVVC control interfaces with existing substation LTC LDC controller to adjust viable feeder voltage regulation. Non-viable VO feeders have EOL voltage feedback and volt-VAR sensing along the feeder. IVVC optimally controls feeder voltage profiles and minimizes VAR flows. Switched 600 kVAR capacitor banks with volt-VAR sensing are applied as needed to control customer voltages within specified limits.

Application scenarios are measured against the following criteria:

- VO performance threshold compliance
- Change in system losses from Existing Case
- Change in weighted annual average voltage from Base Case
- Potential energy savings from Base Case
- Present value cost of energy saved
- Present value cost of upgrades, including threshold compliance upgrades
- Resulting BCR

9.3 Verification

VO implementation requires ongoing compliance measurements to ensure performance thresholds are met. Feeder source and VCZ regulator metering (hourly profile MW and MVAr) and primary EOL feeder and VCZ metering (hourly voltage) are applied to all feeders. Metering can be accomplished using relays, regulator controls, or standalone meter sets.

Measurements also provide performance information regarding LDC voltage regulation, capacitor VAR management, and feeder voltage profiles. Demonstration includes adequate annunciation to allow for corrective SCADA actions in case of equipment or control malfunction. Demonstration includes assessment guidelines and operational control expectations; and documentation of customer complaints, equipment malfunctions, and/or control irregularities.

Feeder analysis is done on a substation basis. All feeders served from the same voltage control substation bus (i.e., LTC or voltage regulator) are considered to be in the same VCZ. Each in-line voltage regulator also forms a new VCZ. Changes to voltage regulator set points will impact all feeders and/or loads served by the same VCZ.

Meter data is used to verify average voltage calculation procedures. The protocol is to be revised to meet ComEd-specific needs. Procedures and application methods are to be developed. Performance thresholds are to be reviewed and revised as necessary. Application templates are to be developed to facilitate VO application by regional planning engineers, operations, and energy efficiency specialists. The protocol should include VO design process and control application guidelines.

The M&V protocol establishes a basis for measuring and verifying energy savings. Protocol methods are based on Equipment Condition Monitoring (ECM) guidelines that comply with requirements set forth in the Federal Energy Management Program (FEMP) M&V guidelines, Version 2.2, and International Performance Measurement & Verification Protocol (IPMVP), Volume I, March 2002.

The protocol defines an annual energy VO factor for estimating end-user energy savings from reduced average annual voltages. Typically, VO factors are based on load types and characteristics, consumption patterns, appliance use, and ambient weather conditions. Global residential and commercial annual energy VO factors based on ComEd customer loading and weather characteristics developed in Task 4.

VO factors are used with average feeder voltage-change formulations to determine total end-use energy savings. VO factors do not include distribution line or no-load (transformer core) loss savings, which are calculated separately.

Metering data collected for “ON” and “OFF” demonstration settings validate VO factors to be used with the protocol. Measurements are typically collected once each hour.

10. VO Feasibility Study Results, Findings, and Recommendations

10.1 Results

The VO feasibility study results estimate the potential to reduce energy consumption by as much as 1900 GWh-yr while reducing peak loads by approximately 360 MW. These results are based on the Plan B (Maximum Energy Savings) analysis. The total upfront cost to implement Plan B is approximately $575 million, which represents an average savings per viable feeder of 3.5% at a levelized cost of energy (LCOE) of $0.0185/kWh-saved. It is estimated that VO is viable on 515 of ComEd's 806 substations, representing 2890 feeders. The minimum cost Plan A generates 1350 GWh-yr of savings at a cost of $425 million. A summary of Plan A and Plan B results are presented in Table 43.

Table 43 - Summary of Project Results

	Plan A	Plan B
Total VO Savings Potential		
- Energy (MWh-yr)	1,350,371	1,912,952
- Peak Load (MW)	257	364
Total VO Installed Costs	$425,466,877	$574,232,508
VO Program TRC	2.20	2.30
Levelized Cost of Energy ($/kWh)	$0.0193	$0.0185
Number of Viable Feeders	2,890	2,890
Number of Viable Substations	515	515
Average Energy Savings (MWh-yr)		
- per viable feeder	467	662
- per viable substation	2,624	3,718
Average VO Cost		
- per viable feeder	$147,222	$198,699
- per viable substation	$826,902	$1,116,030

Energy savings from VO occur in two forms: Distribution line loss reductions and end-use load reductions. As seen in Figure 16, a majority of the energy savings comes from end-use load reductions. For Plan A, only 6% of total savings comes from distribution loss reduction. For Plan B, which includes more system improvements, distribution savings increase to 11%.

VO benefits are achieved through a number of capital improvements and operation changes on the distribution system. Total capital expenditures to achieve these benefits are $425 million for Plan A (minimum cost) and $574 million for Plan B (maximum savings). This equates to average costs per substation of $826,902 and $1,116,030 for Plans A and B respectively (Figure 17).

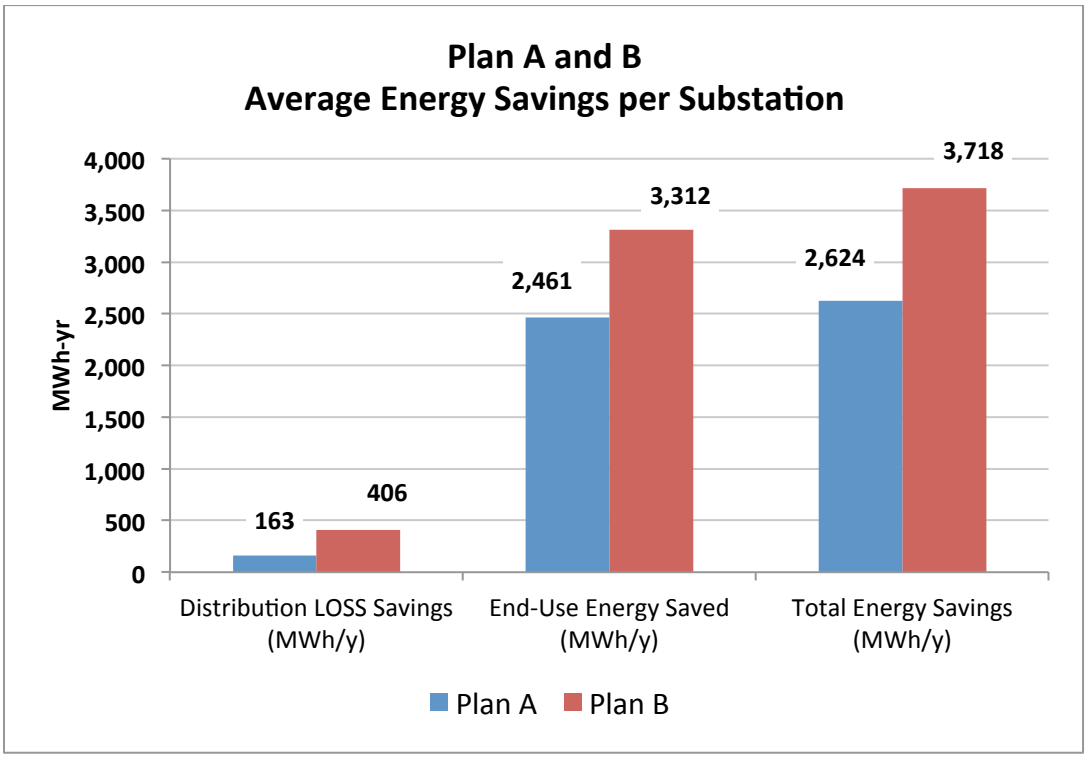


Figure 16 - Average Savings per Substation

Capacitor banks, both switched and fixed, represent the largest single capital expense (CapEx) item, accounting for over half of the total costs for both Plan A and Plan B. Voltage regulators and sensors are the next two largest expense categories. Additional voltage regulators and system upgrades (such as line reconductoring and phase upgrades) account for most of the additional Plan B costs. Integrated Volt/VAR Control (IVVC) is used primarily for isolating non-viable feeders with comparable costs in both plans.

Table 44 and Figure 18 compare itemized VO costs for Plan A and Plan B.

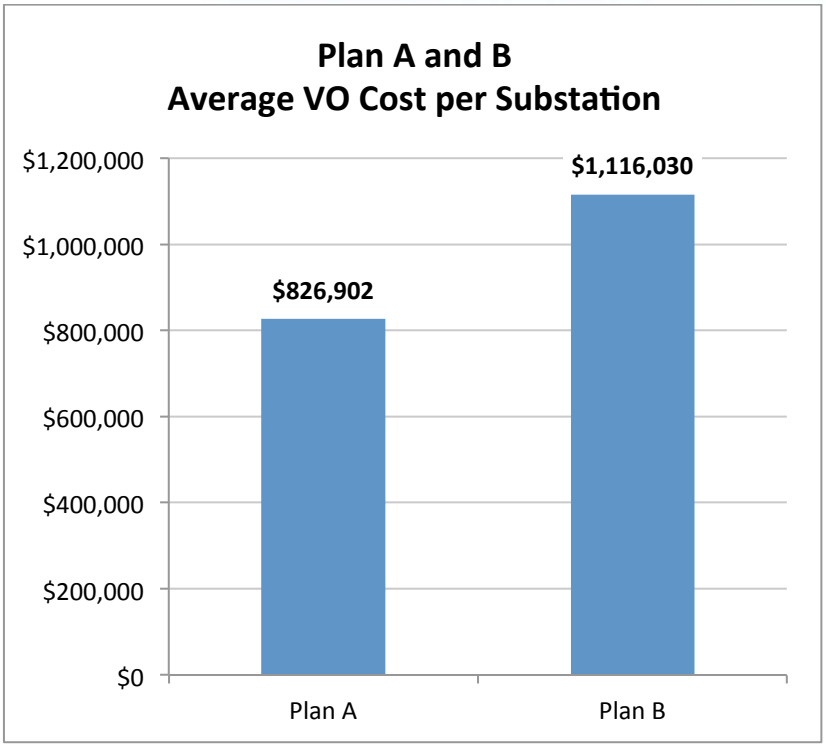
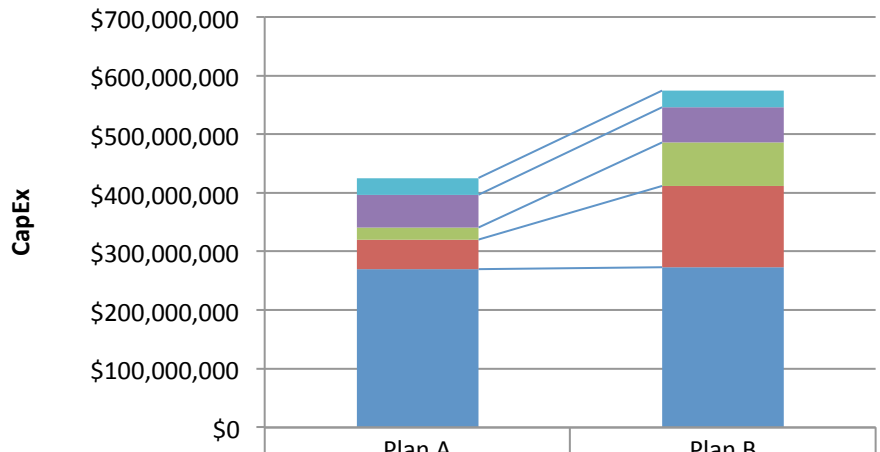


Figure 17 - Average VO Cost per Substation

Table 44 - System Level Itemization of VO Costs

		Plan A System-level		Plan B System-level	
	unit costs	Upgrades	Cost	Upgrades	Cost
OH line reconductoring (mi)	$225,000	71	$16,019,171	213	$47,983,438
Station regulator addition (#)	$110,000	0	$0	112	$12,281,974
In-line volt-regulator addition (#)	$63,000	804	$50,641,249	2010	$126,615,982
OH & UG line or transfer tap changes (#)	$2,000	1148	$2,296,655	5471	$10,942,122
OH phase upgrades (mi)	$110,000	18	$2,021,057	136	$14,984,008
Fixed 600 kVAR capacitor add (#)	$5,500	2067	$11,368,444	4243	$23,335,750
Switched 600 kVAR capacitors (#)	$15,000	17225	$258,373,721	16636	$249,547,372
Feeder source & regulator metering (#)	$5,000	6660	$33,301,502	7592	$37,962,464
EOL voltmeter (#)	$3,000	6890	$20,669,898	6811	$20,432,738
EOL volt feedback sensing (#)	$4,500	459	$2,066,990	447	$2,009,777
IVVC Application ($)	$50,000	574	$28,708,191	563	$28,136,885
			$425,466,877		$574,232,508



	Plan A	Plan B
IVVC	$28,708,191	$28,136,885
Sensors	$56,038,389	$60,404,979
System Upgrades	$20,336,883	$73,909,567
Voltage Regulators	$50,641,249	$138,897,955
Capacitor Banks	$269,742,165	$272,883,121

Figure 18 - VO Cost Itemization

A key study result is the screening and ranking of substations by VO cost and savings potential. This data can then be used to develop VO energy efficiency (EE) supply curves that present how much savings is available at a given cost. Figure 19 presents substation-based VO EE supply curves. While rankings were only developed for substations in the 14-region study group, the supply curves depicted in Figure 20 have been extrapolated to the system level.

A key driver of the VO Feasibility Study was to assess the cost effectiveness of using VO to meet ICC EE program goals. Figure 20 provides an analysis of cost and savings potential in relationship to ComEd's 2014-2016 program goals. EE program data comes from ComEd's ICC filings for program years 2014, 2015, and 2016 and is based on total 3-year program costs and savings potential. VO cost and savings estimates are based on Plan B results and assume the entire VO program is implemented over the same 3-year period. This assumption may or may not be ComEd's actual implementation roadmap, but provides a basis of comparison between the two program types.

The key take-away from the chart in Figure 20 *is that VO has the potential to double ComEd's EE potential at a comparable cost to other EE program options.*

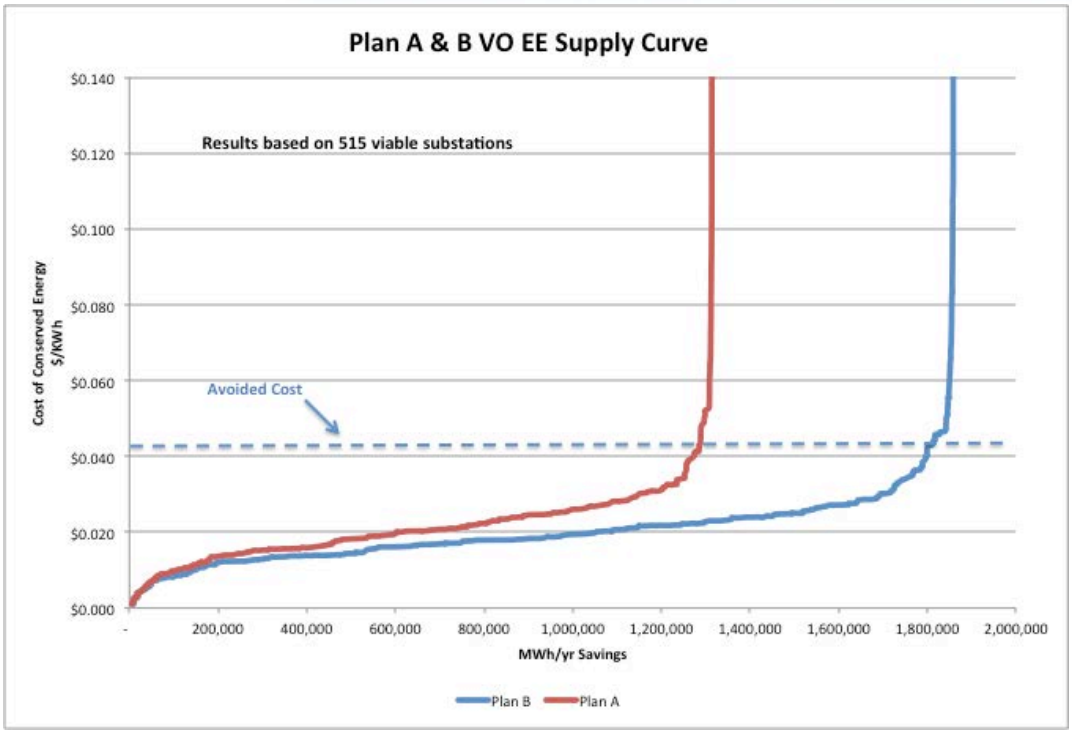


Figure 19 - VO EE Supply Curves

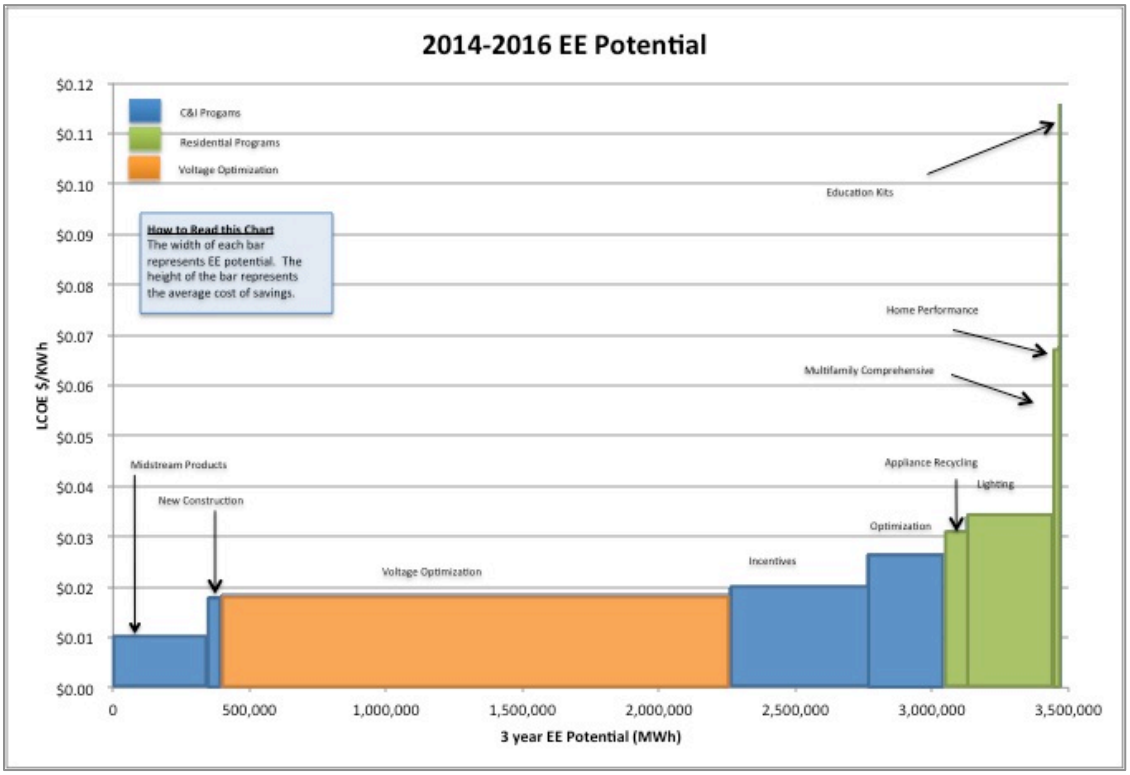


Figure 20 - EE and VO Benchmark Supply Curve

10.2 Key Findings

1. The potential to achieve cost-effective energy savings and demand reductions for VO on the ComEd distribution network is significant. The study found cost-effective energy savings of as much as 1,900 GWh-yr, equal to approximately 2% of ComEd's retail sales, at a cost of approximately $0.0185/kWh.

2. It is estimated that 515 substations (64%) and 2890 feeders (51%) are viable candidates for VO implementation. The average savings per viable feeder is 3.5%. This high savings estimate relative to other utility VO programs can attributable to a number of factors related to the ComEd system, including low voltage drops across feeders due to short runs and a relatively efficient distribution system, relatively good system efficiencies (good phase and load balancing), favorable end-use load composition (low saturation of electric resistance heat), and current voltage settings (conservatively high).

3. The primary determinants of feeder VO non-viability were voltage level (>25kV and <11kV urban networks were excluded), and customer class (large commercial and industrial loads are not good candidates for VO).

4. A majority of the distribution system requires efficiency upgrades (best industry practices) for VO to be effective. For example, Plan A (minimum cost scenario) requires a $425 million investment to allow average voltages at the customer meter to be reduced by 2.96%, accounting for the majority of energy savings.

5. ComEd design guidelines specify maximum secondary voltage drops of 6.0 volts. However, for the VO study, a utility best practice of 3.6 volts was used (or 3% on a 120-volt base) to allow potential energy savings to be maximized.

6. The maximum amount VO energy savings (Plan B) can be achieved by investing an additional $150 million – a total of $575 million – resulting in average voltage reduction of 3.81%. The incremental investments of Plan B increase the total program TRC B-C ratio from 2.20 to 2.30.

7. Isolating non-viable feeders from viable feeders on the same substation is one of the key challenges to VO implementation. The use of IVVC rather than substation-mounted voltage regulator banks is the recommended feeder isolation solution.

8. Capital cost recovery, lost revenues adjustments, and energy efficiency program inclusion are key regulatory hurdles for ComEd's VO strategy.

10.3 Additional Findings

9. Global annual energy VO factor development resulted in 0.69 for residential and 0.90 for commercial customers (<1000 kW). The overall average VO factor for the sample service area was 0.753.

10. Average customer energy savings are 314.5 kWh/yr for Plan A and 434.6 kWh/yr for Plan B.

11. Total feeder energy losses are 25,741.6 MWh/yr, representing 2.63% of total energy delivered (977,504 MWh/yr).

12. The average maximum voltage drop was 3.9 volts (lower than the 4.8 volt threshold). Maximum primary voltage drops ranged from 0.3 volts to 13.4 volts.

13. The lowest average voltage was 120.6 volts (higher than the 118.6 volt threshold). Lowest voltages ranged from 111.1 volts to 124.5 volts.

14. The average phase imbalance was 10.5%. Feeder phase amp imbalances ranged from 2.1% to 31.1% (compared to a threshold of 25% or less).

15. Feeder/substation load profile and M&V guidelines are needed for VO implementation to:

    a) Establish total annual energy per feeder.
    b) Determine the amount/size of fixed and switched capacitor banks per feeder.
    c) Determine annual feeder load factors (for average voltage calculations).
    d) Identify VCZ and non-coincidental load issues.
    e) Verify annual peak MW/MVAr loading.
    f) Determine maximum feeder imbalances at peak (assuming phase amps are available).

    If only peak MW load values are available, the following VO assumptions are typically made which may not fairly represent actual system performance:

    a) VCZ feeders peak at the same time.
    b) Annual load factor is set at 35% or as estimated from annual hourly PI amp data (assuming phase amps are available).
    c) Substation energy is distributed to sister feeders according to feeder peaks.
    d) Existing VAR compensation is adequate, with 100% VAR switching available.

    If load profile data is available for some feeders but not others, the data can be used to determine VO assumptions for similar feeders.

16. Detailed substation analyses required certain feeders to be isolated from sister feeders to allow for larger voltage reductions at the substations. Isolation techniques and associated costs were detailed in Task 6. It general, minimum isolated feeder EOL voltages were assumed to be 121

volts. However, if lower voltages are allowed, adjustments can be made accordingly. Adding in-line voltage regulators has the highest degree of controllability for maintaining voltages but may not be cost effective or feasible (e.g., physical space limitations).

17. Feeders requiring significant re-conductoring were considered non-viable since this cost is typically not a VO cost. However, once completed, the feeders should be considered potential VO candidates.

10.4 Recommendations

1. Design/implement a VO staged deployment per the outline in Section 9 and detailed in Task 9. Provide monthly/annual metering assessment reports to facilitate the VO verification process outlined in Task 6 and Task 9.

2. Develop and implement VO analysis training materials for distribution planning engineers, distribution operations personnel, and energy efficiency engineers. Contents to include engineering modeling assessments, economic analysis methods, capacitor placement methods, LTC/regulator/capacitor control settings, and annual volt/VAR maintenance and reporting procedures.

3. Improve feeder VAR management with smaller capacitor banks (600 kVAR). Include VAR sensing and local control on all switched banks. Follow the VAR application guidelines developed in Task 6 to determine the number/location of the banks. Apply voltage control override under emergency conditions. If possible, industry best practices suggest hourly VAR swings should be limited to less than 300 kVAR lagging and 300 kVAR leading for a total of 600 kVAR swing.

4. Install EOL volt meters on every VO feeder and VCZ at the lowest voltage location to collect/transmit data and provide annual reporting of voltage performance. Use voltage and VAR feedback on non-viable feeders for use with IVVC applications.

5. Examine AMI voltage/loading data to determine actual feeder voltage drop and load profiles. The results can be used to establish standards for addressing maximum allowable voltage drops (distribution transformer and secondary voltage drops) and minimum allowable primary voltages (i.e., 118.6 volts for an allowed 3.6 volt drop). Evaluate potential impacts (probability of customer transformers needing replacement) of primary voltages violating minimum standards. Revise transformer sizing guidelines based on this customer loading information.

6. Maintain, correct, and/or upgrade GIS-CYMDist interface, software, and distribution system models at least annually or as needed.

7. Develop in-house "normal design/operating standards" for maximum allowed phase load imbalances of < 25%, maximum allowed primary voltage drops < 4V, conductor loadings < 70% of normal max, station and in-line voltage regulator voltage bandwidths of 2 volts (plus/minus 1 volt), and maximum allowed secondary voltage drops < 3.6 volts.

8. Provide all in-line feeder voltage regulators with hourly profile metering (MW, MVAr, and volts). Implement monthly data collection processes.

9. Develop application guidelines for EOL voltage feedback sensing/control and backup override of LDC controls for VO feeders with less than a 80% coincidence factor compared to sister feeders in the same VCZ.

10. Apply LDC settings for viable VO feeders with voltage settings at 119 volts with Volt-Rise equal to the maximum voltage drop under peak conditions. Determine control R settings using R&X application guidelines developed in Task 6 for a 110% peak load probability. With hourly power factor near unity, X settings can be set to zero.

11. Apply IVVC to isolate feeders (large commercial/industrial loads, non-coincidental loads) in the same VCZ to maintain higher sustained voltages using EOL voltage feedback, source MW/MVAr metering, SCADA supervisory controls, substation IVVC feeder controllers, switched capacitors (VAR/voltage sensing), and existing LDC controllers. This will allow viable feeder voltages to be lowered and increase energy savings potential.

12. Provide substation power transformers with load-side 3-phase hourly profile metering (MW, MVAr, and volts). Implement monthly data collection processes.

13. Conduct annual inspections of capacitor banks and associated controls.

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12. Appendix

12.1 Viable Substations (346) Ranked by Benefit-Cost Ratio (BCR)

Rank	SUB ID	ESP MWH/YR	VO COST	BCR
1	DCW236	3,732	$61,713	41.81
2	DCW346	2,011	$38,795	35.84
3	DCW202	783	$19,138	28.30
4	DCW354	831	$22,362	25.69
5	DCW343	768	$26,142	20.31
6	DCB46	605	$25,495	16.42
7	DCD114	726	$31,311	16.03
8	DCG99	767	$33,433	15.85
9	DCW51	2,299	$105,518	15.07
10	DCD242	585	$27,375	14.76
11	TDC457	617	$32,569	13.10
12	DCE59	924	$57,654	11.08
13	DCW31	1,681	$108,766	10.69
14	DCH78	1,359	$88,485	10.62
15	DCW302	1,644	$116,669	9.74
16	DCW71	1,764	$125,462	9.72
17	DCE35	1,658	$118,205	9.70
18	DCC61	961	$70,829	9.38
19	DCE8	1,391	$109,815	8.76
20	DCD89	558	$44,168	8.73
21	DCW30	3,572	$299,266	8.25
22	DCW29	1,230	$112,992	7.52
23	DCW115	1,458	$134,658	7.49
24	TDC446	628	$58,221	7.46

(Continued)

Rank	SUB ID	ESP MWH/YR	VO COST	BCR
25	SS311	606	$58,471	7.16
26	DCG121	732	$71,405	7.09
27	DCW50	2,255	$245,743	6.34
28	DCD80	847	$92,808	6.31
29	SS459	1,554	$171,119	6.28
30	DCD62	1,348	$149,177	6.25
31	DCD63	2,043	$226,507	6.24
32	DCH56	387	$43,633	6.13
33	DCG909	333	$37,814	6.09
34	TSS134	13,207	$1,594,750	5.73
35	DCD16	887	$109,273	5.61
36	TDC470	6,030	$746,611	5.58
37	TDC372	3,145	$392,244	5.54
38	TDC435	653	$81,748	5.53
39	DCJ87	927	$117,339	5.46
40	DCC21	325	$41,172	5.45
41	TDC505	8,499	$1,106,653	5.31
42	DCC85	679	$89,119	5.27
43	DCE17	683	$89,695	5.26
44	DCJ19	1,406	$187,939	5.17
45	DCD69	693	$92,817	5.16
46	TDC814	5,759	$773,694	5.15
47	DCE46	614	$82,918	5.12
48	TDC222	687	$92,981	5.11
49	DCD20	672	$92,808	5.01
50	TSS179	556	$76,902	5.00
51	DCW216	805	$112,234	4.96

(Continued)

Rank	SUB ID	ESP MWH/YR	VO COST	BCR
52	SS834	234	$32,767	4.95
53	DCD40	1,779	$248,820	4.95
54	DCB96	602	$86,058	4.84
55	DCW119	1,045	$151,719	4.76
56	DCW348	677	$100,446	4.66
57	DCG42	914	$135,535	4.66
58	TDC414	7,451	$1,131,081	4.56
59	DCC66	459	$70,491	4.50
60	DCE72	668	$103,876	4.44
61	DCH76	720	$113,045	4.40
62	DCC25	324	$51,800	4.32
63	TSS118	9,186	$1,480,427	4.29
64	DCD115	366	$59,847	4.22
65	DCB54	499	$81,792	4.22
66	DCH27	714	$118,695	4.16
67	DCG88	725	$120,613	4.16
68	DCW25	1,532	$258,240	4.10
69	DCW28	679	$114,750	4.09
70	DCE16	1,420	$240,548	4.08
71	TDC444	3,473	$589,021	4.08
72	DCD351	1,560	$267,382	4.03
73	DCE29	2,171	$375,492	4.00
74	DCE28	1,861	$324,745	3.96
75	DCD46	1,568	$273,798	3.96
76	DCH65	1,850	$329,428	3.88
77	TDC549	5,044	$918,506	3.80
78	TDC317	3,630	$663,140	3.78

(Continued)

Rank	SUB ID	ESP MWH/YR	VO COST	BCR
79	DCH70	591	$108,708	3.76
80	TSS89	15,176	$2,803,640	3.74
81	TSS63	13,684	$2,536,758	3.73
82	TDC205	5,298	$982,842	3.73
83	SS553	1,297	$242,822	3.69
84	TDC469	7,388	$1,394,064	3.66
85	TDC552	5,427	$1,038,273	3.61
86	TDC568	5,031	$963,820	3.61
87	DCC80	555	$106,968	3.59
88	SS884	159	$30,721	3.57
89	TDC550	9,564	$1,853,867	3.57
90	DCE79	467	$91,739	3.52
91	TDC216	7,474	$1,472,287	3.51
92	TDC510	1,566	$314,042	3.45
93	SS513	2,214	$447,947	3.42
94	TDC517	5,940	$1,202,291	3.42
95	TDC595	14,810	$3,007,256	3.41
96	DCF45	965	$196,993	3.39
97	TDC499	6,894	$1,420,202	3.36
98	TSS172	18,696	$3,863,928	3.35
99	TDC215	4,485	$928,158	3.34
100	TSS117	10,163	$2,110,588	3.33
101	DCW41	959	$199,663	3.32
102	TDC268	21,162	$4,411,396	3.32
103	DCJ92	1,108	$231,410	3.31
104	DCB53	1,397	$292,086	3.31
105	DCW304	1,328	$278,770	3.29

(Continued)

Rank	SUB ID	ESP MWH/YR	VO COST	BCR
106	TSS60	14,647	$3,093,089	3.27
107	DCB51	1,239	$262,929	3.26
108	TDC559	6,392	$1,359,023	3.25
109	DCW46	1,260	$271,647	3.21
110	TDC436	14,699	$3,183,464	3.19
111	DCW35	1,299	$283,839	3.16
112	SS853	922	$203,228	3.14
113	TSS85	10,097	$2,225,929	3.14
114	TSS104	5,629	$1,300,780	2.99
115	TSS140	5,717	$1,334,032	2.96
116	DCW148	1,209	$282,171	2.96
117	TDC260	8,663	$2,053,506	2.92
118	TSS111	1,346	$325,962	2.86
119	TDC419	21,555	$5,221,075	2.85
120	TSS152	21,677	$5,286,509	2.84
121	TDC220	9,008	$2,212,292	2.82
122	TSS133	334	$82,920	2.78
123	TDC555	5,454	$1,357,595	2.78
124	DCH23	1,081	$269,520	2.77
125	TSS56	7,453	$1,875,255	2.75
126	TDC451	13,969	$3,515,579	2.75
127	DCW44	1,176	$296,057	2.75
128	TDC431	12,101	$3,074,588	2.72
129	TSS41	6,924	$1,772,204	2.70
130	DCB90	897	$229,772	2.70
131	SS741	695	$177,995	2.70
132	TDC648	11,036	$2,837,072	2.69

(Continued)

Rank	SUB ID	ESP MWH/YR	VO COST	BCR
133	TSS51	5,579	$1,435,086	2.69
134	TDC557	5,321	$1,369,971	2.69
135	DCE82	1,003	$258,422	2.68
136	DCW336	1,949	$502,609	2.68
137	DCW73	594	$156,331	2.63
138	TDC240	4,819	$1,275,694	2.61
139	DCW334	727	$192,473	2.61
140	DCC33	549	$145,963	2.60
141	TSS129	9,313	$2,480,724	2.60
142	TDC487	4,841	$1,301,432	2.57
143	TSS88	6,656	$1,790,984	2.57
144	TDC566	19,305	$5,204,162	2.57
145	TDC213	19,287	$5,203,097	2.56
146	TDC581	13,454	$3,640,984	2.56
147	TDC411	5,360	$1,460,840	2.54
148	TDC221	5,306	$1,448,360	2.53
149	DCD187	1,168	$319,370	2.53
150	TSS120	9,967	$2,741,869	2.51
151	TSS57	8,322	$2,293,854	2.51
152	TDC454	10,370	$2,859,661	2.51
153	TDC440	4,769	$1,318,715	2.50
154	DCW211	852	$238,688	2.47
155	TSS59	4,724	$1,328,461	2.46
156	TDC259	8,744	$2,464,591	2.45
157	TDC416	10,355	$2,938,158	2.44
158	DCD47	585	$165,966	2.44
159	SS501	539	$154,504	2.41

(Continued)

Rank	SUB ID	ESP MWH/YR	VO COST	BCR
160	TSS64	6,313	$1,824,508	2.39
161	DCH25	1,045	$302,403	2.39
162	TDC569	5,624	$1,638,994	2.37
163	TDC562	14,994	$4,386,073	2.36
164	TDC204	16,637	$4,925,515	2.34
165	DCJ13	636	$188,268	2.33
166	DCW10	1,066	$316,853	2.33
167	TDC439	5,067	$1,508,960	2.32
168	TSS149	1,296	$390,569	2.29
169	TDC572	6,031	$1,827,140	2.28
170	TDC574	13,491	$4,115,462	2.27
171	TSS79	3,585	$1,093,461	2.27
172	DCF17	947	$289,503	2.26
173	DCD255	739	$228,817	2.23
174	DCJ49	1,183	$367,607	2.23
175	TDC592	8,437	$2,621,954	2.23
176	TDC577	6,833	$2,127,235	2.22
177	TDC375	5,237	$1,638,333	2.21
178	DCE71	1,054	$333,857	2.18
179	TDC214	15,991	$5,089,788	2.17
180	DCD99	543	$174,408	2.15
181	DCE69	2,081	$672,593	2.14
182	DCB28	589	$191,288	2.13
183	TSS46	7,667	$2,494,497	2.13
184	TDC531	7,349	$2,397,480	2.12
185	DCJ18	627	$204,462	2.12
186	TDC461	13,024	$4,254,893	2.12

(Continued)

Rank	SUB ID	ESP MWH/YR	VO COST	BCR
187	DCE12	1,099	$359,228	2.12
188	TDC840	15,393	$5,033,663	2.11
189	TDC443	6,675	$2,193,079	2.10
190	STA13-2	10,395	$3,419,460	2.10
191	DCW384	614	$204,688	2.07
192	TDC563	5,735	$1,912,912	2.07
193	TSS83	5,599	$1,868,220	2.07
194	DCB30	1,716	$575,311	2.06
195	TSS33	6,924	$2,322,893	2.06
196	DCJ68	1,073	$360,289	2.06
197	TDC225	3,214	$1,080,003	2.06
198	TDC580	9,869	$3,320,984	2.05
199	DCD133	544	$183,753	2.05
200	TDC539	6,207	$2,140,700	2.00
201	TDC570	11,571	$3,997,314	2.00
202	TDC561	11,856	$4,110,412	1.99
203	TSS101	8,944	$3,130,191	1.98
204	TDC458	4,016	$1,409,573	1.97
205	DCB35	155	$55,169	1.94
206	DCW340	334	$119,226	1.94
207	TDC465	7,214	$2,576,539	1.94
208	TDC406	6,119	$2,187,681	1.93
209	TSS76	4,932	$1,773,506	1.92
210	TSS136	16,183	$5,826,644	1.92
211	TSS78	5,021	$1,812,478	1.92
212	TDC593	2,970	$1,072,267	1.92
213	TSS43	4,601	$1,664,369	1.91

(Continued)

Rank	SUB ID	ESP MWH/YR	VO COST	BCR
214	TSS106	4,399	$1,595,115	1.91
215	STAll	9,589	$3,489,315	1.90
216	DCE19	1,212	$444,432	1.89
217	DCJ29	494	$182,224	1.88
218	TSS48	3,387	$1,251,174	1.87
219	DCE77	1,305	$484,910	1.86
220	TDC258	6,580	$2,451,098	1.86
221	STA13	14,562	$5,440,015	1.85
222	DCW17	466	$174,093	1.85
223	DCJ69	1,405	$526,717	1.84
224	TSS145	16,161	$6,070,949	1.84
225	DCB26	202	$76,902	1.81
226	DCJ24	222	$84,801	1.81
227	DCH14	1,257	$483,171	1.80
228	TDC248	8,933	$3,456,151	1.79
229	DCJ32	487	$188,886	1.78
230	DCJ33	633	$245,456	1.78
231	DCW33	1,406	$547,073	1.78
232	TDC560	3,627	$1,425,655	1.76
233	DCW38	1,251	$492,016	1.76
234	TSS150	16,206	$6,534,163	1.72
235	DCD130	501	$202,377	1.71
236	TSS47	5,390	$2,196,205	1.70
237	TDC212	9,589	$3,910,589	1.70
238	TSS131	4,989	$2,034,469	1.70
239	TSS102	13,569	$5,552,856	1.69
240	DCC20	1,222	$500,097	1.69

(Continued)

Rank	SUB ID	ESP MWH/YR	VO COST	BCR
241	DCB36	865	$356,770	1.68
242	TSS103	9,379	$3,892,047	1.67
243	TDC521	2,357	$980,777	1.66
244	DCH53	1,091	$467,380	1.61
245	TSS135	3,806	$1,633,513	1.61
246	TDC565	5,593	$2,405,491	1.61
247	TSS198	11,021	$4,741,621	1.61
248	TSS174	7,637	$3,305,104	1.60
249	DCH67	593	$258,773	1.58
250	DCH43	438	$191,084	1.58
251	TDC433	944	$414,005	1.58
252	DCF149	1,019	$447,737	1.57
253	DCW19	1,058	$466,429	1.57
254	DCW48	717	$319,236	1.55
255	DCC34	599	$270,327	1.53
256	TSS137	12,170	$5,528,829	1.52
257	TSS52	4,203	$1,918,266	1.52
258	DCE20	1,466	$677,457	1.50
259	SS316	2,650	$1,234,347	1.48
260	DCG128	451	$212,914	1.47
261	DCB57	366	$176,729	1.43
262	DCW152	616	$298,413	1.43
263	TSS55	3,132	$1,529,642	1.42
264	DCW118	1,003	$492,093	1.41
265	SS422	1,102	$540,477	1.41
266	DCF96	614	$302,706	1.40
267	TDC235	4,214	$2,122,402	1.37

(Continued)

Rank	SUB ID	ESP MWH/YR	VO COST	BCR
268	DCW39	1,191	$602,628	1.37
269	TDC474	3,376	$1,725,216	1.35
270	TSS151	4,576	$2,361,906	1.34
271	TSS75	7,954	$4,166,054	1.32
272	DCH91	214	$112,260	1.32
273	DCW20	827	$436,359	1.31
274	DCW12	585	$315,403	1.28
275	DCH44	341	$184,063	1.28
276	DCB86	148	$80,078	1.28
277	TDC456	2,297	$1,249,771	1.27
278	TDC217	2,279	$1,241,554	1.27
279	TSS193	6,029	$3,302,053	1.26
280	DCW335	511	$283,868	1.24
281	DCJ23	517	$287,546	1.24
282	DCE18	791	$440,381	1.24
283	TDC250	915	$511,199	1.24
284	DCW233	530	$298,878	1.23
285	DCJ65	207	$117,740	1.22
286	DCW26	648	$374,188	1.20
287	SS460	1,435	$833,972	1.19
288	DCE21	510	$296,574	1.19
289	DCH39	828	$486,599	1.18
290	DCJ66	528	$315,143	1.16
291	DCB27	521	$311,996	1.15
292	DCE26	1,341	$803,933	1.15
293	DCH47	490	$298,120	1.14
294	DCH38	197	$122,792	1.11

(Continued)

Rank	SUB ID	ESP MWH/YR	VO COST	BCR
295	DCJ17	727	$462,742	1.09
296	TDC233	5,825	$3,762,478	1.07
297	DCH54	170	$110,337	1.07
298	DCD229	451	$293,941	1.06
299	DCH26	602	$392,701	1.06
300	DCH40	514	$335,861	1.06
301	DCF122	460	$301,519	1.05
302	DCE24	579	$383,422	1.04
303	DCH41	153	$101,521	1.04
304	TDC556	1,719	$1,143,866	1.04
305	DCB64	597	$398,594	1.03
306	DCW102	483	$331,190	1.01
307	TDC206	5,701	$3,913,760	1.01
308	DCC3	503	$346,624	1.00
309	DCJ21	406	$282,949	0.99
310	TDC253	8,202	$5,734,188	0.99
311	DCB16	962	$679,167	0.98
312	SS558	1,272	$951,750	0.92
313	DCC19	360	$270,073	0.92
314	DCW16	619	$473,615	0.90
315	SS450	617	$472,360	0.90
316	DCK15	233	$182,224	0.89
317	DCC91	430	$344,386	0.86
318	DCH60	439	$363,555	0.84
319	DCD67	351	$292,337	0.83
320	DCB89	225	$187,021	0.83
321	DCB29	897	$783,212	0.79

(Continued)

Rank	SUB ID	ESP MWH/YR	VO COST	BCR
322	SS249	1,212	$1,132,759	0.74
323	DCW14	263	$250,074	0.73
324	DCJ16	317	$310,320	0.71
325	DCJ76	347	$343,425	0.70
326	DCH36	417	$427,934	0.67
327	DCH49	455	$468,543	0.67
328	DCW64	348	$375,791	0.64
329	DCJ28	320	$359,310	0.62
330	DCH66	196	$230,993	0.59
331	DCH10	370	$460,608	0.56
332	DCH52	349	$434,733	0.55
333	SS312	161	$210,438	0.53
334	DCE38	236	$318,217	0.51
335	DCH28	142	$196,839	0.50
336	DCH57	232	$360,663	0.45
337	DCB52	282	$449,705	0.43
338	DCK19	285	$456,371	0.43
339	TSS132	231	$401,394	0.40
340	DCH62	25	$55,169	0.32
341	DCB17	183	$403,989	0.31
342	SS871	41	$90,339	0.31
343	TDC207	1,765	$4,485,676	0.27
344	SS894	53	$208,611	0.18
345	DCJ58	21	$119,006	0.12
346	DCJ62	18	$171,525	0.07