Siemens PTI Report #R105-11

Transmission System Loss Study

Prepared for

ComEd

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Executive Summary

This report documents the results of the Transmission System Loss Study performed for Commonwealth Edison Company (ComEd). Headquartered in Chicago, ComEd is one of the largest electric delivery utilities in the United States and provides service to approximately 3.8 million customers across northern Illinois. ComEd is a transmission owner with extensive electric facilities operated at voltage levels 138 kV and above and is a member of PJM, a Regional Transmission Organization (RTO). PJM is the Planning Authority and Transmission Operator for the ComEd transmission system.

The Illinois Commerce Commission (ICC) in its final order in ICC Docket No. 10-0467 required that ComEd provide an updated transmission loss study by the end of 2011. Therefore, the focus of this study was only on transmission losses. As part of the study effort, the transmission system losses were calculated using 2010 data for the transmission facilities shown below.

- Transmission lines (138kV, 345kV and 765kV)
    1. Load loss component associated with the current flow through the line
    2. No-load loss component associated with the corona of the line
- Transmission transformers
    1. Load loss component associated with the current flow through the transformer
    2. No-load loss component associated with the excitation of the transformer
- Transmission Substation Auxiliary Load Losses

Demand and energy transmission losses were calculated for the ComEd system. For this study, Siemens Energy, Inc., Power Technologies International (Siemens PTI) used several techniques to perform both the transmission system loss study and the calculation of transmission loss percentages. Using Siemens PTI software and actual hourly data from the ComEd system, 138 kV, 345 kV and 765 kV facilities were modeled in detail to determine the losses in only ComEd's transmission system. Energy losses were calculated using the actual generation output levels, tie line flows and system load for 22 representative hours of the 8,760 hourly load profiles in 2010. Section 1 of the report provides an introduction to the study and Section 2 contains the details about the transmission loss explanations and calculation results for the individual losses.

A summary of the peak and minimum hour losses are shown below in Table ES-1. The peak hour loss percentages are 1.96% of zone energy or of zone plus net export interchange energy. The summary of the annual energy losses are shown below in Table ES-2. The annual energy loss percentages are 2.31% of zone energy or 1.78% of zone plus net export interchange energy. The net import interchange energy values were not included in the denominator of the percentage calculations because they represent a portion of the energy used to serve the zone load and therefore would be considered double counting.

Table ES-1. Peak and Minimum Hour Losses and Loss Percentages

	Peak[1]	Minimum[1]
Lines and Transformer Load Losses	389,260	204,390
Transmission Transformer No-Load Losses	16,953	16,953
Transmission Substation Auxiliary Load Losses	9,470	7,103[2]
Corona Losses	14,030	14,030
Total Hourly Demand Losses	429,713	242,476
Zone Energy	21,914,000	7,464,000
Net Export Interchange Energy	N/A	5,524,000
Net Import Interchange Energy	2,685,000	N/A
% of losses based on Zone Energy	1.96%	3.25%
% of losses based on Zone + Net Export Interchange Energy	1.96%	1.87%

Notes:

1. All loss values are listed in kWH
2. Substation Auxiliary Losses adjusted to 75% of peak for the minimum hour.

Table ES-2. Annual Energy Losses and Loss Percentages

	Annual[3]
Lines and Transformer Load Losses	2,064,259
Transmission Transformer No-Load Losses	148,506
Transmission Substation Auxiliary Load Losses	60,555
Corona Losses	122,906
Total Annual Energy Losses	2,396,226
Zone Energy	103,640,701
Net Export Interchange Energy	31,294,715
Net Import Interchange Energy	258,698
% of losses based on Zone Energy	2.31%
% of losses based on Zone + Net Export Interchange Energy	1.78%

Notes:

3. All loss values are listed in MWH

Section

1

Introduction

Headquartered in Chicago, ComEd is one of the largest electric delivery utilities in the United States and provides service to approximately 3.8 million customers across northern Illinois. ComEd is a transmission owner with extensive electric facilities operated at voltage levels 138 kV and above within Illinois and is a member of the PJM RTO. PJM is the Planning Authority and Transmission Operator for the ComEd transmission system and dispatches the generation located within the ComEd system. The Illinois Commerce Commission (ICC) in its final order in ICC Docket No. 10-0467 required that ComEd provide an updated transmission loss study by the end of 2011. This Transmission Loss Study based on 2010 data was completed to comply with that order.

ComEd's 2010 system peak demand was 21,914 Megawatts (MW) with 103,640,701 Megawatt-hours (MWH) of energy delivered within the ComEd zone. The company delivers energy across a networked transmission system consisting of 138 kV, 345 kV, and 765 kV facilities. The ComEd transmission system has 34 transmission interconnections or tie lines with neighboring utilities. It is interconnected with American Electric Power, American Transmission Company, ITC Midwest, Northern Indiana Public Service Company, Ameren and MidAmerican Energy Company. The large number of interconnection points can increase the impact of loop flows or inadvertent flows across the transmission system and therefore can increase the losses on the transmission system. The municipals within the ComEd system are Winnetka, Rock Falls, Rochelle, St Charles, Batavia, Geneva, and Naperville.

Since the last transmission loss study was completed in 1999 using 1998 data, ComEd's peak load has increased and its interchange patterns have changed significantly. The minimum and peak loads as well as the net interchange at the time of the minimum and peak loads are shown below in Table 1-1. While the minimum load has increased slightly, the peak load has increased 15.3%. The net interchange, however, has increased markedly. The ComEd system still imports power (negative values in the table) into their zone during the peak hour and this import has increased by 23.6% during the peak load hour. The ComEd system exports power (positive values in the table) out of their zone at considerably higher levels now than it did in 1998 during off-peak hours. This is evidenced by the 600% increase during minimum load conditions.

Table 1-1. Minimum and Peak Conditions Comparison between 1998 and 2010

	Loads (MW)		Interchange (MW)	
	Minimum	Peak	Minimum	Peak
1998	7,187	19,012	790	-2,172
2010	7,464	21,915	5,524	-2,685
% Change	3.9%	15.3%	599.2%	23.6%

There have been significant generation changes to the ComEd system since 1998. During that time 5,619 MW of generation has been retired and 11,694 MW of new generation has been built for a net addition of 6,075 MW. Of that net generation addition the great majority of the increase was natural gas and wind generation. The new generation is generally more remote from load centers than the retired generation, so the transmission system has to carry more energy to the load.

Another change since 1998 is that ComEd divested itself of all of its previously owned generation and electric choice has encouraged retail customers to choose alternative electric suppliers. Additionally, ComEd joined PJM in 2004 and the ComEd transmission system became a part of the PJM power market. As an RTO, PJM operates the high-voltage electric grid and manages the wholesale electricity market that serves 13 states and the District of Columbia. ComEd borders the Midwest ISO (MISO) and also is affected by market flows across the MISO system.

In order to maintain system reliability per applicable planning criteria requirements 77 miles of additional 345 kV transmission lines have been added as well as 103 miles of new 138 kV transmission lines. In addition to the new lines that have been constructed, 274 miles of existing 138 kV transmission lines have had their conductor replaced in order to increase their capacity.

The reinforcements to the transmission system make it more robust and increase the capability of transmitting energy from one location to another, as well as generally decreasing overall system losses. However, the changes associated with the generation on the system and especially the increases in system load and net interchange would tend to increase the overall system losses.

Section
2

Transmission System Losses

The ComEd transmission system is comprised of lines with 138 kV, 345 kV and 765 kV voltages and transformers with high and low side voltages in the same range. The operation of transmission lines and transformers results in losses which are proportional to the current squared and are referred to as load losses. Corona losses which are present on transmission lines are referred to as no-load losses because they are independent of the current being carried by the transmission line and are a function of the voltage squared. Excitation losses which are present in transformers and are a function of the voltage squared are also referred to as no-load losses. Both excitation and corona losses are relatively constant.

There is a demand component and an energy component for all load losses and no-load losses. The losses, both load and no-load, are calculated on a one hour demand basis and are given in units of kilowatts (kW). When multiplied by the hours that the losses are present this gives the energy in kilowatt-hours (kWH). For no-load losses, the hourly multiplier is 8,760, the number of hours in a year. For load losses, the hourly multiplier is the number of hours that the system was at that load condition so the hourly multiplier can vary, but the number of hours will still sum to 8,760.

2.1 Transmission Line and Transformer Load Losses

The load losses from the transmission lines and transformers were calculated from a set of power flow cases. The load losses (current squared times resistance) for the transmission lines and transformers within the ComEd system, are a function of the ComEd zone load, internal generation, purchases, power sales, wheeling, and inadvertent power flows through the ComEd transmission system. The procedure used to calculate the transmission system load losses was to simulate a number of different power flows that were representative of a number of system load conditions, from maximum to minimum load, taking into account the corresponding variations of generation and tie line flows.

Line losses are determined by using a computer program that calculates the power flows on the transmission system. The Siemens PTI computer program, Power System Simulator for Engineering (PSS®E), Revision 32 was used in this effort. PSS®E is an integrated program for simulating, analyzing, and optimizing power system performance that incorporates the most advanced and proven methods for performing power flow studies, unbalanced fault analysis, and dynamic stability simulation.

ComEd had hourly data values for 2010 for the following system variables:

- System Load
- Net Interchange

- Tie Line flows
- Generation output

The load on the ComEd system varied from a peak of 21,914 MW on August 12th, hour ending 1500, to a minimum load of 7,464 MW on April 4th, hour ending 0400. The load duration curve is shown in Figure 2-1. The load duration curve shows the load level and the relative number of hours that the load was above or below a specific load level, i.e. for 5,000 hours the load was 11,000 MW or greater. The load duration curve also shows a relatively constant slope from the knee of the curve located at approximately 14,000 MW and 1,100 hours to the minimum load at the 8,760th hour.

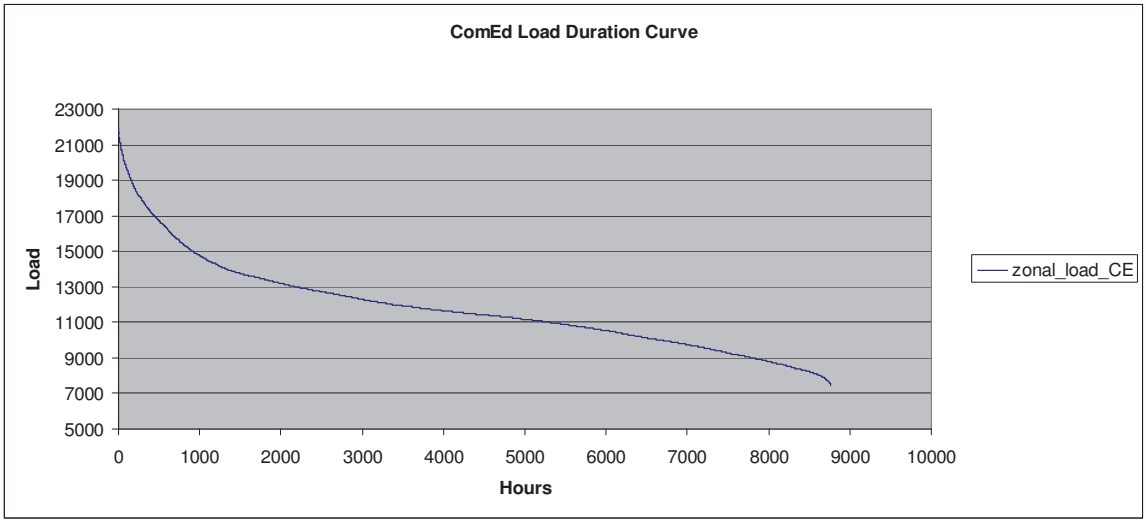

Figure 2-1. ComEd System Load Duration Curve

The net interchange during the year varied from a maximum export of 6,679 MW on October 24th, hour ending 1000 to a maximum import of -3,156 MW on May 24th, hour ending 1200. The net interchange duration curve is shown in Figure 2-2 . The net interchange duration curve has a similar shape to the load duration curve but contains positive and negative values, indicating power flow into or out of the ComEd system at different times of the year. The net Interchange is negative (importing power into the ComEd zone) 272 hours of the year and is over 2,000 MW (exporting out of the system) 7,580 hours of the year. There are 7,450 hours that the net interchange is between 2,000 MW and 5,800 MW where the curve has a relatively constant slope.

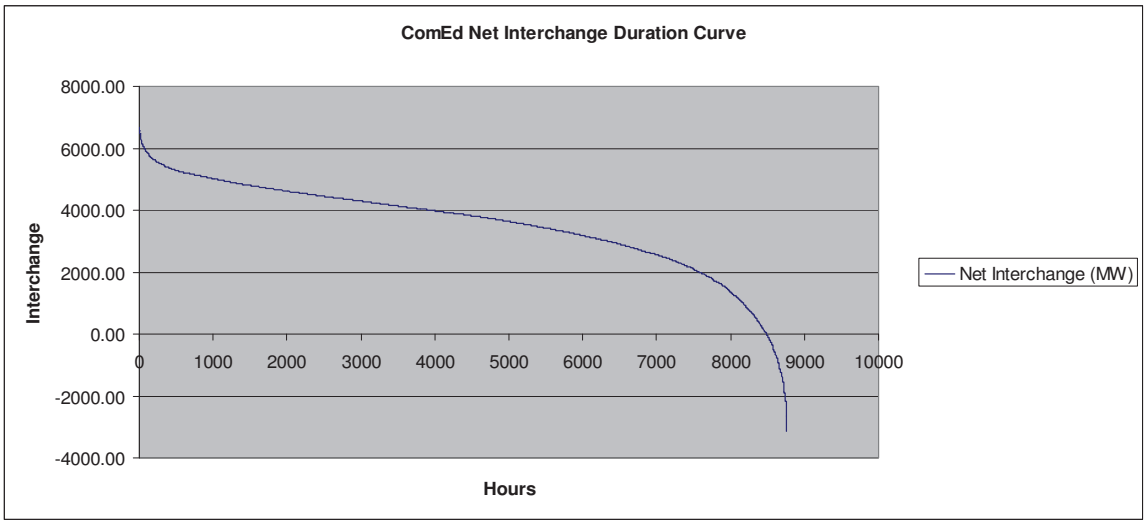

Figure 2-2. ComEd System Net Interchange Duration Curve

Figure 2-3 shows the correlation between system load and net interchange for all hours of 2010. It lists every hourly load and the corresponding net interchange for that load. While the load and net interchange duration curves show the individual hourly values for both the load and net interchange, Figure 2-3 pairs those values for each hour of the year and correlates the two values to one another. When the load and net interchange values are paired together, the picture of the ComEd transmission system's prevalent condition becomes much clearer.

Random checks of the data showed that the total system losses varied greatly with different conditions. Comparing a case at 20,000 MW load with 2,000 MW of net interchange with another case of the same amount of load but with -2,000 MW of net interchange, the total system losses differed by 14.1%. Therefore in order to accurately determine the load losses for the ComEd system, the load and net interchange pairs were broken down into 20 logical blocks based on the frequency of occurrence, which were labeled 1 through 20.

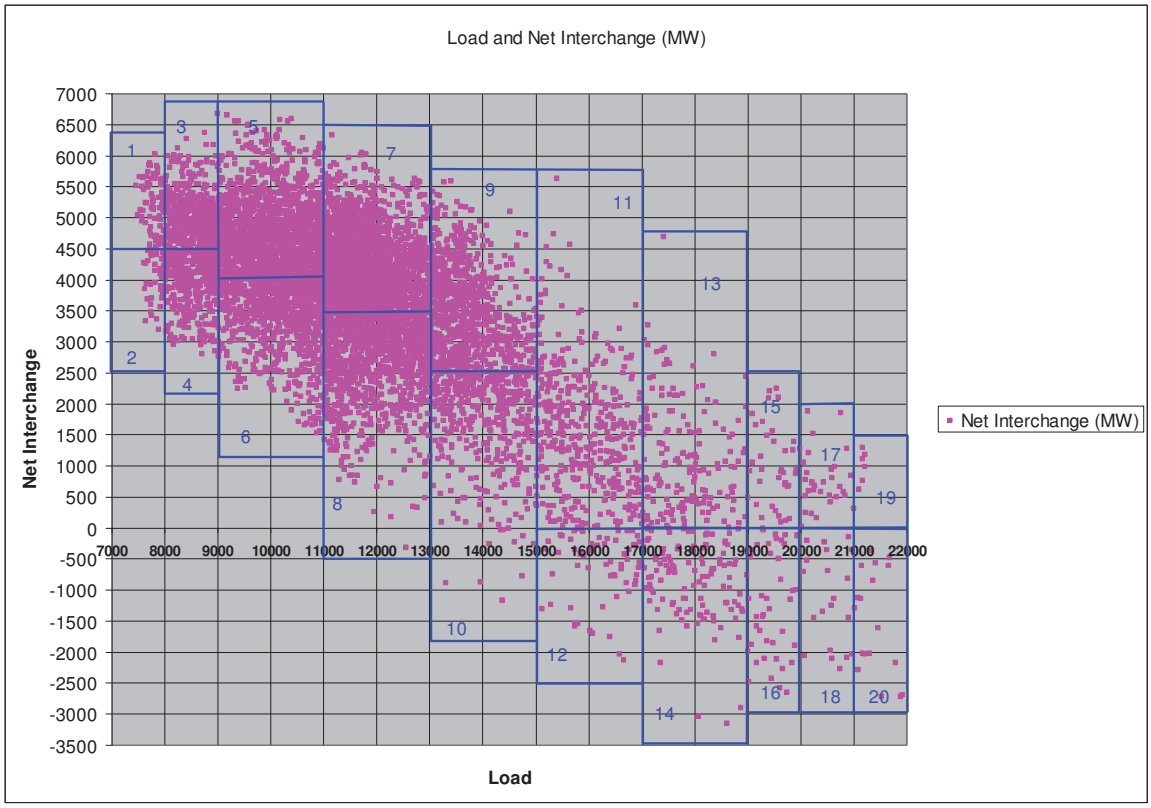

Figure 2-3. Load versus Net Interchange

Table 2-1 defines the 22 cases that were analyzed. The peak load hour and the minimum load hour were both analyzed as well, because they represent the upper and lower limit of the ComEd load in 2010. The rest of the blocks were defined based on load and net interchange. For example, Blocks 9 and 10 include 1,266 hours with loads between 13,000 MW and 15,000 MW. The average load of these hours is 13,788 MW. Block 9 represents the higher net interchange values and Block 10 represents the lower net interchange values. In Block 9 there are 856 hours and the average net interchange of these hours is 3,544 MW. In Block 10 there are 410 hours and the average net interchange of these hours is 1,725 MW.

Table 2-1. Block Definitions for Load/Net Interchange Analysis

	Load (MW)	Average Load (MW)	Average Net Interchange (MW)	Number of Hours
Minimum Load				1
Block 1	7000-8000	7809	5245	82
Block 2	7000-8000		3996	41
Block 3	8000-9000	8546	5075	445
Block 4	8000-9000		3932	392
Block 5	9000-11000	10073	4771	1679
Block 6	9000-11000		3371	820
Block 7	11000-13000	11876	4306	1919
Block 8	11000-13000		2709	1197
Block 9	13000-15000	13788	3544	856
Block 10	13000-15000		1725	410
Block 11	15000-17000	15917	1602	416
Block 12	15000-17000		-659	60
Block 13	17000-19000	17863	1097	166
Block 14	17000-19000		-859	119
Block 15	19000-20000	19479	1015	38
Block 16	19000-20000		-1173	44
Block 17	20000-21000	20458	770	30
Block 18	20000-21000		-1158	20
Block 19	21000-22000	21325	895	7
Block 20	21000-22000		-1515	17
Peak Load				1

Based on the actual load data supplied by ComEd, the closest hour for Block 9 was 2/9/10 the hour ending 20:00 and the closest hour for Block 10 was 5/29/10 the hour ending 19:00. These load and net interchange values are the closest to the average of each of the blocks as can be seen by the data in Table 2-2 .

Each of the hours listed in Table 2-2 represents the actual load and net interchange values closest to the average load and average net interchange value for each of Blocks 1 through 20. These values were represented in a detailed ComEd system model. The base model for the study started from a 2009 series Eastern Interconnection Reliability Assessment Group (ERAG) Multiregional Modeling Working Group (MMWG) case for the year 2010 summer peak. That model was then updated to show much greater detail for the ComEd system. The detail added to the model increased the accuracy of the results by ensuring that tie flows and generation values were accurate and that only transmission losses were counted while distribution losses were omitted from the results.

Table 2-2. Definition of Representative Hours for Blocks and Loads

	Representative Hour	Representative Hour System Load (MW)	Representative Hour Net Interchange (MW)
Minimum Load	4/4/2010 5:00	7464	5524
Block 1	9/19/2010 4:00	7786	5265
Block 2	5/3/2010 3:00	7821	3951
Block 3	11/7/2010 5:00	8565	5073
Block 4	10/13/2010 5:00	8543	3972
Block 5	3/21/2010 0:00	10069	4757
Block 6	12/12/2010 2:00	10142	3324
Block 7	9/28/2010 14:00	11869	4289
Block 8	7/7/2010 3:00	11870	2702
Block 9	2/9/2010 20:00	13782	3588
Block 10	5/29/2010 19:00	13780	1695
Block 11	6/18/2010 17:00	15950	1643
Block 12	8/19/2010 11:00	15996	-643
Block 13	7/16/2010 12:00	17874	1148
Block 14	8/20/2010 11:00	17800	-979
Block 15	8/9/2010 15:00	19632	898
Block 16	8/20/2010 17:00	19810	-1153
Block 17	8/10/2010 18:00	20421	732
Block 18	7/15/2010 13:00	20625	-1133
Block 19	8/11/2010 17:00	21214	986
Block 20	8/12/2010 14:00	21453	-1618
Peak Load	8/12/2010 16:00	21914	-2685

The model was further modified to represent each of the 34 transmission tie lines interconnected with the ComEd system as a load so that actual hourly tie flow data could be automatically read into the model. The generation buses were also modified so that the ComEd actual hourly generation data could be read into the model at the proper generator bus location. A python program was written to retrieve the proper hour's data for the given line and generator based on Excel spreadsheets containing all of the hourly data.

The PSS®E program automatically summed the losses of the individual elements in the ComEd transmission system. The loss value for each ComEd-owned transmission line and transformer in the system was summed to give the total load losses for each of the 22 cases described above. The losses for lines that are jointly owned by ComEd and another party were added based on ComEd's ownership percentage for the facility. For example, if ComEd owns 60% of a tie line and NIPSCO owns the other 40% and the losses on that line were 5.0 MW; then ComEd would be credited with 3 MW of losses (60% of 5.0 MW). Because there is no joint ownership of transmission transformers in the ComEd system this allocation was only used for transmission line losses.

The data for each of the 22 hours was reviewed for accuracy to update missing or incorrect data points prior to being used in each of the 22 cases. The hourly data was contained in the databases shown in Table 2-3. Any missing data points were either filled in based on review of the adjacent hourly data points or by using additional comparable data points. The

majority of the data points for each hour were valid, so very few data points had to be estimated based on other valid data points recorded for the hour.

Table 2-3. Hourly Database Values

Database	Quantity of Hourly Values	Values Recorded	Notes
Tie Lines	68	MW and Mvar	
Generators	71	MW only	Program dispatches vars, many hours zero for offline units
Net Interchange	1	MW only	
System Load	1	MW only	

The 22 power flow cases representing the average load and net interchange values for Block 1 through Block 20 as well as the minimum and maximum hours were individually solved. The load loss values for each ComEd-owned transmission element were summed to come up with an overall load loss value for each of the 22 cases. The load loss value for each case was then multiplied by the number of hours represented by the block. The load loss values for the minimum load hour, the maximum load hour and Blocks 1 through 20 are shown in Table A-1 in Appendix A. The sum of transmission line and transformer load losses for the year is 2,064,259 MWH.

2.2 Transmission Transformer No-Load Losses

Transformer no-load losses, which can be referred to as excitation losses, iron losses, or core losses, are caused by the excitation current or magnetizing current of the transformer creating heat energy and noise. Transformer no-load losses are always present as long as the transformer is energized and is a function of the voltage squared. These losses are nearly constant over the year and do not vary as a function of the load.

The no-load losses are calculated by taking the capacity of each transformer and multiplying it by the per unit no-load loss. The per-unit no-load loss is usually provided by the transformer manufacturer. Virtually all the transmission transformers on the ComEd system had manufacturer's no-load loss values available. When manufacturer data was not available, average values were used for similar transformers in the ComEd system. The calculated average values are shown in blue in the tables. The no-load loss values for the 345 kV – 138 kV transformers are shown in Table B-1 in Appendix B, the 765 kV – 345 kV transformers in Table B-2, and the 138 kV phase shifting transformers in Table B-3. Each table shows the demand loss portion of the no-load losses for each transformer.

The energy loss is calculated by multiplying the demand loss by two factors. The demand loss is first multiplied by the number of hours in the period, which in this case are 8,760. Next the bus voltages at the high side of the transformers from the 22 cases were used to calculate two average bus voltages: one value for the 765 kV transformer buses and one value for the 345 kV transformer buses. Each of the average per-unit bus voltages was squared and that value multiplied by the demand loss. The total no-load demand and energy losses are shown in Table B-4 in Appendix B. The no-load demand loss for the transmission

transformers is 16,356.65 kW and after adjusting for voltage is 16,952.68 kW. The annual 2010 no-load energy loss is 148,505,514 kWH.

2.3 Transmission Substation Auxiliary Load Losses

The only unmetered company use that is believed not to be otherwise accounted for are the losses from the transmission portion of the substations. There are 54 transmission-only substations and 69 substations that serve both a transmission and distribution function on the ComEd system.

ComEd substation engineers estimated the peak auxiliary demand for typical substations based on the size of the substation and the amount and type of equipment in the substation. The peak demand for both summer auxiliary load and winter auxiliary load was estimated for transmission-only substation and is shown in Table 2-4.

Table 2-4. Transmission Substation Auxiliary Losses

Number	Peak Auxiliary Load (kW)		Coincident Peak Demand (kW)		Energy Losses (kWH)		Annual Energy Losses (kWH)
	Summer	Winter	Summer	Winter	Summer	Winter	
10	19	45	180.5	427.5	553,413	936,225	1,489,638
1	44	57	41.8	54.2	128,159	118,589	246,748
18	58	140	991.8	2394.0	3,040,859	5,242,860	8,283,719
5	109	166	517.8	788.5	1,587,422	1,726,815	3,314,237
8	111	152	843.6	1155.2	2,586,478	2,529,888	5,116,366
9	159	191	1359.5	1633.1	4,168,074	3,576,380	7,744,454
1	184	200	174.8	190.0	535,937	416,100	952,037
2	209	216	397.1	410.4	1,217,509	898,776	2,116,285
Demand Loss Subtotal			**4506.9**	**7052.9**	**13,817,851**	**15,445,633**	**29,263,484**

An estimate for the non-coincident peak auxiliary summer and winter load was performed for each size transmission-only substation. From that estimate the peak summer and winter demand was calculated for the peak hourly demand and the annual energy losses based on the following assumptions:

- Coincidence Factor 0.95
- Utilization Factor 0.60
- Summer Months 7 (April – October)
- Winter Months 5 (November – March)

The same estimates of summer and winter auxiliary load were done for the substations that serve both the distribution and transmission functions. Any auxiliary load serving the distribution function was removed from the estimates so that only auxiliary load serving the transmission function was included in the substation auxiliary load estimates. Table 2 5 lists the demand estimates and the loss calculations.

Table 2-5. Transmission/Distribution Substation Auxiliary Losses

Number	Peak Auxiliary Load (kW)		Coincident Peak Demand (kW)		Energy Losses (kWH)		Annual Energy Losses (kWH)
	Summer	Winter	Summer	Winter	Summer	Winter	
33	19	45	595.7	1410.8	1,826,263	3,089,543	4,915,806
15	58	140	826.5	1995.0	2,534,049	4,369,050	6,903,099
1	83	153	78.9	145.4	241,754	318,317	560,071
2	109	166	207.1	315.4	634,969	690,726	1,325,695
4	111	152	421.8	577.6	1,293,239	1,264,944	2,558,183
6	159	191	906.3	1088.7	2,778,716	2,384,253	5,162,969
2	209	216	397.1	410.4	1,217,509	898,776	2,116,285
5	260	241	1235.0	1144.8	3,786,510	2,507,003	6,293,513
1	310	266	294.5	252.7	902,937	553,413	1,456,350
Demand Loss Subtotal			**4,962.9**	**7340.8**	**15,215,946**	**16,076,024**	**31,291,971**

The pertinent annual totals from the two different types of substations are as follows. The total summer peak demand in kW is the sum for the two types of substations [4,506.9 + 4,962.9] for a total of 9,469.8 kW. Since the demand is for only the peak hour the energy loss is the 9,469.8 kWH. The total annual energy loss for all transmission substations is 60,555,449 kWH.

2.4 Corona Losses

Under the proper weather conditions, the air surrounding the conductors of high voltage transmission lines becomes ionized and conducts electricity to a limited extent. As a result, a small part of the electric energy flowing in the transmission line leaks or discharges into the air resulting in electric losses which are called corona losses. The amount of the corona loss depends primarily on the voltage level, the diameter of the conductor and the weather conditions, and therefore is considered a no-load loss. Rain increases corona loss substantially. Other factors affect the corona discharge, such as: elevation, conductor spacing, and the presence of a shield wire.

Corona demand losses are calculated separately for the 138 kV, 345 kV and 765 kV transmission lines, using the Bonneville Power Administration computer program, CORONAII, Corona and Field Effects. Table C-1 and Table C-2 in Appendix C list the assumptions and dimensions used to model the ComEd transmission lines in the CORONAII program as well as the basic climatologic assumptions for wind speed, rain rate and altitude. Table C-3 in Appendix C lists the mileage of ComEd transmission lines by voltage and the mileage of each structure type defined in the CORONAII program. The loss values for the various weather conditions modeled are listed in the table as well as the corona energy loss value per year. The demand loss is 14,030.4 kW and the total annual corona energy losses are 122,906 MWH.

2.5 Summary of Losses and Loss Percentages

A summary of the peak and minimum hour losses are shown below in Table 2-6. The peak hour loss percentages are 1.96% of zone energy or of zone plus net export interchange energy. The summary of the annual energy losses are shown below in Table 2-7. The annual energy loss percentages are 2.31% of zone energy or 1.78% of zone plus net export interchange energy. The net import interchange energy values were not included in the

denominator of the percentage calculations because they represent a portion of the energy used to serve the zone load and therefore would be considered double counting.

Table 2-6. Peak and Minimum Hour Losses and Loss Percentages

	Peak[1]	Minimum[1]
Lines and Transformer Load Losses	389,260	204,390
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Zone Energy	21,914,000	7,464,000
Net Export Interchange Energy	N/A	5,524,000
Net Import Interchange Energy	2,685,000	N/A
% of losses based on Zone Energy	1.96%	3.25%
% of losses based on Zone + Net Export Interchange Energy	1.96%	1.87%

Notes:

1. All loss values are listed in kWH.
2. Substation Auxiliary Losses adjusted to 75% of peak for the minimum hour.

Table 2-7. Annual Energy Losses and Loss Percentages

	Annual[3]
Lines and Transformer Load Losses	2,064,259
Transmission Transformer No-Load Losses	148,506
Transmission Substation Auxiliary Load Losses	60,555
Corona Losses	122,906
Total Annual Energy Losses	2,396,226
Zone Energy	103,640,701
Net Export Interchange Energy	31,294,715
Net Import Interchange Energy	258,698
% of losses based on Zone Energy	2.31%
% of losses based on Zone + Net Export Interchange Energy	1.78%

Notes:

3. All Loss values are listed in MWH.

Appendix

A

Load Losses

Table A-1. Power Flow Case Load Loss Summary

	Transmission Load Loss (MW)	Number of Hours	Transmission Load Energy Loss (MHW)
Lowest Load	204.39	1	204.39
Block 1	175.81	82	14416.73
Block 2	180.21	41	7388.48
Block 3	252.97	445	112571.65
Block 4	231.68	392	90817.14
Block 5	229.19	1679	384810.01
Block 6	244.48	820	200476.64
Block 7	215.04	1919	412668.75
Block 8	245.60	1197	293983.20
Block 9	219.34	856	187755.04
Block 10	234.43	410	96116.30
Block 11	260.30	416	108284.89
Block 12	253.09	60	15185.49
Block 13	288.62	166	47910.92
Block 14	306.70	119	36497.30
Block 15	334.46	38	12709.38
Block 16	339.98	44	14959.12
Block 17	368.37	30	11051.10
Block 18	363.12	20	7262.40
Block 19	355.14	7	2485.98
Block 20	371.48	17	6315.16
Peak Load	389.26	1	389.26
Total			**2,064,259.33**

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Appendix
B

No Load Losses

Table B-1. 345-138 kV Transformer No-Load Losses

Substation	Transformer Number	Base Rating MVA	No Load Losses	
			Demand kW	Energy kWH
Bedford Park TSS 115	81	300	209.519	1,835,386
Bedford Park TSS 115	82	300	188.300	1,649,508
Bedford Park TSS 115	83	300	178.616	1,564,676
Bedford Park TSS 115	84	300	208.400	1,825,584
Bloom TSS 179	84	300	225.229	1,973,006
Blue Island TSS 76	81	300	129.300	1,132,668
Blue Island TSS 76	82	300	176.600	1,547,016
Blue Island TSS 76	83	300	242.100	2,120,796
Blue Island TSS 76	84	300	127.300	1,115,148
Burnham TSS 177	81	300	203.000	1,778,280
Burnham TSS 177	84	300	218.800	1,916,688
Cherry Valley TSS 156	81	300	212.000	1,857,120
Cherry Valley TSS 156	82	300	217.000	1,900,920
Cherry Valley TSS 156	83	300	200.334	1,754,926
Crawford STA 13	81	300	205.000	1,795,800
Crawford STA 13	82	300	182.866	1,601,906
Crawford STA 13	83	300	170.000	1,489,200
Crawford STA 13	84	300	173.600	1,520,736
Davis Creek TSS 86	82	300	178.393	1,562,723
Davis Creek TSS 86	83	300	190.722	1,670,725
Des Plaines TSS 46	81	300	213.000	1,865,880
Des Plaines TSS 46	82	300	135.350	1,185,666
Des Plaines TSS 46	83	300	179.115	1,569,047
Des Plaines TSS 46	84	300	218.000	1,909,680
Dresden STA 12	81	300	218.991	1,918,361
Dresden STA 12	83	300	221.000	1,935,960
Electric Junction TSS 111	81	300	231.050	2,023,998
Electric Junction TSS 111	82	300	128.000	1,121,280
Electric Junction TSS 111	83	300	118.420	1,037,359
Electric Junction TSS 111	84	300	140.000	1,226,400
Elmhurst TSS 135	81	300	213.600	1,871,136
Elmhurst TSS 135	83	300	219.100	1,919,316
Elmhurst TSS 135	84	300	135.350	1,185,666
Golf Mill TSS 172	81	300	217.800	1,907,928
Golf Mill TSS 172	82	300	217.700	1,907,052
Goodings Grove TSS 116	81	300	130.785	1,145,677
Goodings Grove TSS 116	82	300	133.990	1,173,752
Goodings Grove TSS 116	83	300	127.580	1,117,601
Itasca TSS 101	81	300	126.930	1,111,907
Itasca TSS 101	82	300	179.349	1,571,097
LaSalle STA 1	81	300	251.978	2,207,327
Libertyville TSS 154	81	300	165.880	1,453,109

Table B-1. 345-138 kV Transformer No-Load Losses (cont.)

Substation	Transformer Number	Base Rating MVA	No Load Losses	
			Demand kW	Energy kWH
Libertyville TSS 154	83	300	165.880	1,453,109
Lisle TSS 103	82	300	156.000	1,366,560
Lisle TSS 103	83	300	198.279	1,736,924
Lisle TSS 103	84	300	118.420	1,037,359
Lombard TSS 120	82	300	208.400	1,825,584
Lombard TSS 120	84	300	97.280	852,173
McCook TSS 51	82	300	262.166	2,296,574
McCook TSS 51	84	300	232.000	2,032,320
Nelson TSS 155	81	300	125.690	1,101,044
Nelson TSS 155	82	300	224.000	1,962,240
Nelson TSS 155	84	300	205.300	1,798,428
Northbrook TSS 159	81	300	220.093	1,928,015
Northbrook TSS 159	82	300	139.990	1,226,312
Prospect Height TSS 117	81	300	217.882	1,908,646
Prospect Height TSS 117	84	300	156.000	1,366,560
Silver Lake TSS 138	82	300	225.700	1,977,132
Silver Lake TSS 138	83	300	196.683	1,722,943
Skokie TSS 88	81	300	140.000	1,226,400
Skokie TSS 88	82	300	168.900	1,479,564
Skokie TSS 88	83	300	170.787	1,496,094
Skokie TSS 88	84	300	175.300	1,535,628
State Line STA 7	82	300	61.910	542,332
State Line STA 7	81	300	196.330	1,719,851
Taylor TSS 153	81	300	233.331	2,043,980
Taylor TSS 153	82	300	242.898	2,127,786
Wayne TSS 144	81	300	224.762	1,968,915
Wayne TSS 144	84	300	220.466	1,931,282
Wempletown TSS 171	84	300	223.670	1,959,349
Tollway TSS 185	83	300	186.398	1,632,846
Subtotal			13,154.562	115,223,961

Note: Blue Values were calculated from average values or similar transformers.

Table B-2. 765-345 kV Transformer No-Load Losses

Substation	Transformer Number	Base Rating MVA	No Load Losses	
			Demand kW	Energy kWH
Collins STA 23 Phase A	92	333	170.152	1,490,532
Phase B		333	168.382	1,475,026
Phase C		333	171.317	1,500,737
Plano TSS 167 Phase A	93	333	160.015	1,401,731
Phase B		333	160.015	1,401,731
Phase C		333	162.176	1,420,662
Plano TSS 167 Phase A	94	333	104.500	915,420
Phase B		333	104.000	911,040
Phase C		333	106.400	932,064
Wilton Center TSS 112 Phase A	93	333	162.370	1,422,361
Phase B		333	163.489	1,432,164
Phase C		333	164.599	1,441,887
Wilton Center TSS 112 Phase A	94	333	106.200	930,312
Phase B		333	94.640	829,046
Phase C		333	183.599	1,608,327
Subtotal			2,181.854	19,113,040

Table B-3. Phase-Shifting 138-345 kV Transformer No-Load Losses

Substation	Transformer Number	Base Rating MVA	No Load Losses	
			Demand kW	Energy kWH
Franklin Park TSS 78	L.3705	300	98.300	861,108
Franklin Park TSS 78	L.3710	300	72.200	632,472
Northwest TSS 114	L11413	300	121.800	1,066,968
Northwest TSS 114	L11418	300	121.800	1,066,968
Crawford STA 13	L-1321	300	114.240	1,000,742
Crawford STA 13	L-1323	300	102.800	900,528
State Line STA 7	0702	200	71.540	626,690
State Line STA 7	0705	200	71.540	626,690
Ridgeland TSS 192	L19209	195	153.080	1,340,981
Harbor TSS 170	L.17008	300	92.938	814,137
		Subtotal	1,020.238	8,937,284

Note: Blue values were calculated from average values or similar transformers.

Table B-4. Total Transformer No-Load Losses

Transformer Type	Demand kW	Energy kWH	Average Voltage	V2	Energy kWH
345-138 kV	13,154.56	115,233,961	1.017917	1.036155	119,400,245
765-345 kV	2,181.85	19,113,040	1.027227	1.055195	20,167,984
Phase Shifting	1,020.24	8,937,284	N/A		8,937,285
Total	**16,356.65**	**143,284,285**			**148,505,514**

Appendix
C

Corona Losses

Table C-1. Structure Assumption Details

ComEd Lines Nominal Voltages	Structure Type	Circuit Configuration	Subconductors per Phase	Subconductor Diameter	Spacing between Subconductors
kV				Inches	Inches
138	138-A	Double Ckt - Vert	1	1.259	N/A
345	345-A	Single Ckt - Hor	2	1.302	18
345	345-B	Double Ckt - Vert	1	1.762	N/A
765	765-A	Single Ckt - Hor	4	1.302	18
765	765-B	Single Ckt - Hor	4	1.6	24

Notes: **Wind Speed = 2mi/h**
Rain Rate = 1 in/h
Altitude = 650 ft

Table C-2. Structure Assumptions for Dimensions

ComEd Lines Nominal Voltages	Structure Type	Number of Phases per Structure and Phasing Sequence	Phases Horizontal Coordinates	Corresponding Phases Vertical Coordinates
kV			feet	feet
138	138-A	6 (A1, B1, C1, A2, B2, C2)	(-7, -10, -7, 7, 10, 7)	(46.6, 33.6, 20.6, 20.6, 33.6, 46.6)
345	345-A	3 (A, B, C)	(-24, 0, 24)	(24.7, 24.7, 24.7)
345	345-B	6 (A1, B1, C1, A2, B2, C2)	(-17, -27, -17, 17, 27, 17)	(72.7, 48.7, 24.7, 24.7, 48.7, 72.7)
765	765-A	3 (A, B, C)	(-44.5, 0.0, 44.5)	(33.2, 33.2, 33.2)
765	765-B	3 (A, B, C)	(-45, 0.0, 45)	(33.2, 33.2, 33.2)

Table C-3. Corona Losses for the ComEd Transmission System

ComEd Lines Nominal Voltages	Structure Type	Length of Circuit	Corona Loss under Heavy Rain	Foul Weather Maximum Loss	Foul Weather Yearly Average Loss	Fair Weather Yearly Average Loss	All Weather Yearly Average Loss	Demand Losses	Energy Losses
kV		miles	kW/mi	kW/mi	kW/mi	kW/mi	kW/mi	kW	MWH/year
138	138-A	2026.0	1.4	1.0	0.0	1.0	1.0	2091.2	18318.9
345	345-A	1103.0	38.2	28.3	0.9	1.7	2.6	2844.2	24915.2
345	345-B	1511.0	151.5	112.1	3.5	1.7	5.2	7833.8	68624.1
765	765-A	28.0	543.0	401.8	12.5	2.7	15.2	425.3	3725.6
765	765-B	62.0	468.8	346.9	10.8	2.7	13.5	835.9	7322.5
									122,906.3

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