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CASE NUMBER: 08-935-EL-SSO

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APPLICATION - VOLUME 3

4/17

FILE

Case No. 08-935-EL-SSO

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

IN THE MATTER OF THE APPLICATION

OHIO EDISON COMPANY
THE CLEVELAND ELECTRIC ILLUMINATING COMPANY
THE TOLEDO EDISON COMPANY

FOR AUTHORITY TO ESTABLISH A STANDARD SERVICE OFFER PURSUANT TO R.C. § 4928.143 IN THE FORM OF AN ELECTRIC SECURITY PLAN

VOLUME 3

Schedules 5a-5t, 6a-6j & 7a-7c

(Workpapers & Supporting Schedules)

Filing Date: July 31, 2008

Case No. 08-XXXX-EL-SSO
Ohio Edison Company
The Cleveland Electric Illuminating Company
The Toledo Edison Company

Witness: K. Warvell

2009

GENERATION RIDER CHARGES

			(A)	(B)	(C)	(D)	(E)	(F)
1	AVERAGE RETAIL GENERATION PRICE ($ PER MWH)					$75.00	$75.00	$75.00
2								
3	Rate	Customer Usage Category	Allocation Factors			OE	CEI	TE
4			Voltage	Season	TOU			
5								
6	RS	Non Time-of-Day						
7		Summer kWh						
8		FIRST 500 kWh *	1.0225	1.1180	1.0000	$0.080987	$0.080987	$0.080987
9		OVER 500 kWh *	1.0225	1.1180	1.0000	$0.090987	$0.090987	$0.090987
10		Non-Summer kWh	1.0225	0.9581	1.0000	$0.073474	$0.073474	$0.073474
11		Time-of-Day						
12		On-Peak Summer	1.0225	1.0000	1.5227	$0.116772	$0.116772	$0.116772
13		Off-Peak Summer	1.0225	1.0000	0.7578	$0.058114	$0.058114	$0.058114
14		On-Peak Non-Summer	1.0225	1.0000	1.2519	$0.096005	$0.096005	$0.096005
15		Off-Peak Non-Summer	1.0225	1.0000	0.7050	$0.054065	$0.054065	$0.054065
16								
17	GS	Non Time-of-Day						
18		Summer kWh	1.0225	1.1180	1.0000	$0.085737	$0.085737	$0.085737
19		Non-Summer kWh	1.0225	0.9581	1.0000	$0.073474	$0.073474	$0.073474
20		Time-of-Day						
21		On-Peak Summer	1.0225	1.0000	1.5227	$0.116772	$0.116772	$0.116772
22		Off-Peak Summer	1.0225	1.0000	0.7578	$0.058114	$0.058114	$0.058114
23		On-Peak Non-Summer	1.0225	1.0000	1.2519	$0.096005	$0.096005	$0.096005
24		Off-Peak Non-Summer	1.0225	1.0000	0.7050	$0.054065	$0.054065	$0.054065
25								
26	GP	Non Time-of-Day						
27		Summer kWh	0.9870	1.1180	1.0000	$0.082760	$0.082760	$0.082760
28		Non-Summer kWh	0.9870	0.9581	1.0000	$0.070923	$0.070923	$0.070923
29		Time-of-Day						
30		On-Peak Summer	0.9870	1.0000	1.5227	$0.112718	$0.112718	$0.112718
31		Off-Peak Summer	0.9870	1.0000	0.7578	$0.056096	$0.056096	$0.056096
32		On-Peak Non-Summer	0.9870	1.0000	1.2519	$0.092672	$0.092672	$0.092672
33		Off-Peak Non-Summer	0.9870	1.0000	0.7050	$0.052188	$0.052188	$0.052188
34								
35	GSU	Non Time-of-Day						
36		Summer kWh	0.9592	1.1180	1.0000	$0.080429	$0.080429	$0.080429
37		Non-Summer kWh	0.9592	0.9581	1.0000	$0.068926	$0.068926	$0.068926
38		Time-of-Day						
39		On-Peak Summer	0.9592	1.0000	1.5227	$0.109543	$0.109543	$0.109543
40		Off-Peak Summer	0.9592	1.0000	0.7578	$0.054516	$0.054516	$0.054516
41		On-Peak Non-Summer	0.9592	1.0000	1.2519	$0.090062	$0.090062	$0.090062
42		Off-Peak Non-Summer	0.9592	1.0000	0.7050	$0.050718	$0.050718	$0.050718
43								
44	GT	Non Time of Day						
45		Summer kWh	0.9583	1.1180	1.0000	$0.080353	$0.080353	$0.080353
46		Non-Summer kWh	0.9583	0.9581	1.0000	$0.068861	$0.068861	$0.068861
47		Time of Day						
48		On-Peak Summer	0.9583	1.0000	1.5227	$0.109440	$0.109440	$0.109440
49		Off-Peak Summer	0.9583	1.0000	0.7578	$0.054465	$0.054465	$0.054465
50		On-Peak Non-Summer	0.9583	1.0000	1.2519	$0.089977	$0.089977	$0.089977
51		Off-Peak Non-Summer	0.9583	1.0000	0.7050	$0.050670	$0.050670	$0.050670
52								
53	STL	Summer kWh	1.0225	1.1180	1.0000	$0.085737	$0.085737	$0.085737
54		Non-Summer kWh	1.0225	0.9581	1.0000	$0.073474	$0.073474	$0.073474
55								
56	POL	Summer kWh	1.0225	1.1180	1.0000	$0.085737	$0.085737	$0.085737
57		Non-Summer kWh	1.0225	0.9581	1.0000	$0.073474	$0.073474	$0.073474
58								
59	TRF	Summer kWh	1.0225	1.1180	1.0000	$0.085737	$0.085737	$0.085737
60		Non-Summer kWh	1.0225	0.9581	1.0000	$0.073474	$0.073474	$0.073474

NOTES

(A) Allocation factors based on service voltage. See Page 5 of Schedule 5a for more details.
(B) Allocation factors based on season. See Page 7 of Schedule 5a for more details.
(C) Allocation factors based on seasonal Time-of-Use. See Page 7 of Schedule 5a for more details.
(D) Calculation: Column D, Row 1 x Column A x Column B x Column C.
(E) Calculation: Column E, Row 1 x Column A x Column B x Column C.
(F) Calculation: Column F, Row 1 x Column A x Column B x Column C.
* Blocked RS summer rate. See page 4 of Schedule 5a for more details.

		2010						
		GENERATION RIDER CHARGES						
			(A)	(B)	(C)	(D)	(E)	(F)
1		AVERAGE RETAIL GENERATION PRICE ($ PER MWH)				$80.00	$80.00	$80.00
2								
3	Rate	Customer Usage Category	Allocation Factors			OE	CEI	TE
4			Voltage	Season	TOU			
5								
6	RS	Non Time-of-Day						
7		Summer kWh						
8		FIRST 500 kWh *	1.0225	1.1180	1.0000	$0.086702	$0.086702	$0.086702
9		OVER 500 kWh *	1.0225	1.1180	1.0000	$0.096702	$0.096702	$0.096702
10		Non-Summer kWh	1.0225	0.9581	1.0000	$0.078373	$0.078373	$0.078373
11		Time-of-Day						
12		On-Peak Summer	1.0225	1.0000	1.5227	$0.124557	$0.124557	$0.124557
13		Off-Peak Summer	1.0225	1.0000	0.7578	$0.061988	$0.061988	$0.061988
14		On-Peak Non-Summer	1.0225	1.0000	1.2519	$0.102405	$0.102405	$0.102405
15		Off-Peak Non-Summer	1.0225	1.0000	0.7050	$0.057669	$0.057669	$0.057669
16								
17	GS	Non Time-of-Day						
18		Summer kWh	1.0225	1.1180	1.0000	$0.091452	$0.091452	$0.091452
19		Non-Summer kWh	1.0225	0.9581	1.0000	$0.078373	$0.078373	$0.078373
20		Time-of-Day						
21		On-Peak Summer	1.0225	1.0000	1.5227	$0.124557	$0.124557	$0.124557
22		Off-Peak Summer	1.0225	1.0000	0.7578	$0.061988	$0.061988	$0.061988
23		On-Peak Non-Summer	1.0225	1.0000	1.2519	$0.102405	$0.102405	$0.102405
24		Off-Peak Non-Summer	1.0225	1.0000	0.7050	$0.057669	$0.057669	$0.057669
25								
26	GP	Non Time-of-Day						
27		Summer kWh	0.9870	1.1180	1.0000	$0.088277	$0.088277	$0.088277
28		Non-Summer kWh	0.9870	0.9581	1.0000	$0.075652	$0.075652	$0.075652
29		Time-of-Day						
30		On-Peak Summer	0.9870	1.0000	1.5227	$0.120232	$0.120232	$0.120232
31		Off-Peak Summer	0.9870	1.0000	0.7578	$0.059836	$0.059836	$0.059836
32		On-Peak Non-Summer	0.9870	1.0000	1.2519	$0.098850	$0.098850	$0.098850
33		Off-Peak Non-Summer	0.9870	1.0000	0.7050	$0.055667	$0.055667	$0.055667
34								
35	GSU	Non Time-of-Day						
36		Summer kWh	0.9592	1.1180	1.0000	$0.085791	$0.085791	$0.085791
37		Non-Summer kWh	0.9592	0.9581	1.0000	$0.073521	$0.073521	$0.073521
38		Time-of-Day						
39		On-Peak Summer	0.9592	1.0000	1.5227	$0.116846	$0.116846	$0.116846
40		Off-Peak Summer	0.9592	1.0000	0.7578	$0.058151	$0.058151	$0.058151
41		On-Peak Non-Summer	0.9592	1.0000	1.2519	$0.096066	$0.096066	$0.096066
42		Off-Peak Non-Summer	0.9592	1.0000	0.7050	$0.054099	$0.054099	$0.054099
43								
44	GT	Non Time of Day						
45		Summer kWh	0.9583	1.1180	1.0000	$0.085710	$0.085710	$0.085710
46		Non-Summer kWh	0.9583	0.9581	1.0000	$0.073452	$0.073452	$0.073452
47		Time of Day						
48		On-Peak Summer	0.9583	1.0000	1.5227	$0.116736	$0.116736	$0.116736
49		Off-Peak Summer	0.9583	1.0000	0.7578	$0.058096	$0.058096	$0.058096
50		On-Peak Non-Summer	0.9583	1.0000	1.2519	$0.095976	$0.095976	$0.095976
51		Off-Peak Non-Summer	0.9583	1.0000	0.7050	$0.054048	$0.054048	$0.054048
52								
53	STL	Summer kWh	1.0225	1.1180	1.0000	$0.091452	$0.091452	$0.091452
54		Non-Summer kWh	1.0225	0.9581	1.0000	$0.078373	$0.078373	$0.078373
55								
56	POL	Summer kWh	1.0225	1.1180	1.0000	$0.091452	$0.091452	$0.091452
57		Non-Summer kWh	1.0225	0.9581	1.0000	$0.078373	$0.078373	$0.078373
58								
59	TRF	Summer kWh	1.0225	1.1180	1.0000	$0.091452	$0.091452	$0.091452
60		Non-Summer kWh	1.0225	0.9581	1.0000	$0.078373	$0.078373	$0.078373

NOTES
(A) Allocation factors based on service voltage. See Page 5 of Schedule 5a for more details.
(B) Allocation factors based on season. See Page 7 of Schedule 5a for more details.
(C) Allocation factors based on seasonal Time-of-Use. See Page 7 of Schedule 5a for more details.
(D) Calculation: Column D, Row 1 x Column A x Column B x Column C.
(E) Calculation: Column E, Row 1 x Column A x Column B x Column C.
(F) Calculation: Column F, Row 1 x Column A x Column B x Column C.
* Blocked RS summer rate. See page 4 of Schedule 5a for more details.

2011

GENERATION RIDER CHARGES

Line	Rate	Customer Usage Category	(A)	(B)	(C)	(D)	(E)	(F)
1	AVERAGE RETAIL GENERATION PRICE ($ PER MWH)					$85.00	$85.00	$85.00
2								
3	Rate	Customer Usage Category	Allocation Factors			OE	CEI	TE
4			Voltage	Season	TOU			
5								
6	RS	Non Time-of-Day						
7		Summer kWh						
8		FIRST 500 kWh *	1.0225	1.1180	1.0000	$0.092418	$0.092418	$0.092418
9		OVER 500 kWh *	1.0225	1.1180	1.0000	$0.102418	$0.102418	$0.102418
10		Non-Summer kWh	1.0225	0.9581	1.0000	$0.083271	$0.083271	$0.083271
11		Time-of-Day						
12		On-Peak Summer	1.0225	1.0000	1.5227	$0.132342	$0.132342	$0.132342
13		Off-Peak Summer	1.0225	1.0000	0.7578	$0.065862	$0.065862	$0.065862
14		On-Peak Non-Summer	1.0225	1.0000	1.2519	$0.108806	$0.108806	$0.108806
15		Off-Peak Non-Summer	1.0225	1.0000	0.7050	$0.061273	$0.061273	$0.061273
16								
17	GS	Non Time-of-Day						
18		Summer kWh	1.0225	1.1180	1.0000	$0.097168	$0.097168	$0.097168
19		Non-Summer kWh	1.0225	0.9581	1.0000	$0.083271	$0.083271	$0.083271
20		Time-of-Day						
21		On-Peak Summer	1.0225	1.0000	1.5227	$0.132342	$0.132342	$0.132342
22		Off-Peak Summer	1.0225	1.0000	0.7578	$0.065862	$0.065862	$0.065862
23		On-Peak Non-Summer	1.0225	1.0000	1.2519	$0.108806	$0.108806	$0.108806
24		Off-Peak Non-Summer	1.0225	1.0000	0.7050	$0.061273	$0.061273	$0.061273
25								
26	GP	Non Time-of-Day						
27		Summer kWh	0.9870	1.1180	1.0000	$0.093795	$0.093795	$0.093795
28		Non-Summer kWh	0.9870	0.9581	1.0000	$0.080380	$0.080380	$0.080380
29		Time-of-Day						
30		On-Peak Summer	0.9870	1.0000	1.5227	$0.127747	$0.127747	$0.127747
31		Off-Peak Summer	0.9870	1.0000	0.7578	$0.063576	$0.063576	$0.063576
32		On-Peak Non-Summer	0.9870	1.0000	1.2519	$0.105028	$0.105028	$0.105028
33		Off-Peak Non-Summer	0.9870	1.0000	0.7050	$0.059146	$0.059146	$0.059146
34								
35	GSU	Non Time-of-Day						
36		Summer kWh	0.9592	1.1180	1.0000	$0.091153	$0.091153	$0.091153
37		Non-Summer kWh	0.9592	0.9581	1.0000	$0.078116	$0.078116	$0.078116
38		Time-of-Day						
39		On-Peak Summer	0.9592	1.0000	1.5227	$0.124149	$0.124149	$0.124149
40		Off-Peak Summer	0.9592	1.0000	0.7578	$0.061785	$0.061785	$0.061785
41		On-Peak Non-Summer	0.9592	1.0000	1.2519	$0.102070	$0.102070	$0.102070
42		Off-Peak Non-Summer	0.9592	1.0000	0.7050	$0.057480	$0.057480	$0.057480
43								
44	GT	Non Time of Day						
45		Summer kWh	0.9583	1.1180	1.0000	$0.091067	$0.091067	$0.091067
46		Non-Summer kWh	0.9583	0.9581	1.0000	$0.078043	$0.078043	$0.078043
47		Time of Day						
48		On-Peak Summer	0.9583	1.0000	1.5227	$0.124032	$0.124032	$0.124032
49		Off-Peak Summer	0.9583	1.0000	0.7578	$0.061727	$0.061727	$0.061727
50		On-Peak Non-Summer	0.9583	1.0000	1.2519	$0.101974	$0.101974	$0.101974
51		Off-Peak Non-Summer	0.9583	1.0000	0.7050	$0.057426	$0.057426	$0.057426
52								
53	STL	Summer kWh	1.0225	1.1180	1.0000	$0.097168	$0.097168	$0.097168
54		Non-Summer kWh	1.0225	0.9581	1.0000	$0.083271	$0.083271	$0.083271
55								
56	POL	Summer kWh	1.0225	1.1180	1.0000	$0.097168	$0.097168	$0.097168
57		Non-Summer kWh	1.0225	0.9581	1.0000	$0.083271	$0.083271	$0.083271
58								
59	TRF	Summer kWh	1.0225	1.1180	1.0000	$0.097168	$0.097168	$0.097168
60		Non-Summer kWh	1.0225	0.9581	1.0000	$0.083271	$0.083271	$0.083271

NOTES
(A) Allocation factors based on service voltage. See Page 5 of Schedule 5a for more details.
(B) Allocation factors based on season. See Page 7 of Schedule 5a for more details.
(C) Allocation factors based on seasonal Time-of-Use. See Page 7 of Schedule 5a for more details.
(D) Calculation: Column D, Row 1 x Column A x Column B x Column C.
(E) Calculation: Column E, Row 1 x Column A x Column B x Column C.
(F) Calculation: Column F, Row 1 x Column A x Column B x Column C.
* Blocked RS summer rate. See page 4 of Schedule 5a for more details.

Residential Generation Summer Rate Design

1	**2009**				
2	Average Retail G ($ / kWh)		$0.0750	Page 1 of Schedule 5a	
3	Conversion Factor		1.0225	Page 5 of Schedule 5a	
4	Seasonal Factor		1.1180	Page 7 of Schedule 5a	
5	Average Summer RS Price		$0.085737	Row 2 x Row 3 x Row 4	
6					
7	Block 2 Incremental Price		[redacted]		
8					
9		(A)	(B)	(C)	(D)
10		Summer KWH	Summer G Rev	Inv. Rate	Rev. Check
11	Below 500 KWH	2,388,307,029	$204,766,280	$0.080987	$193,422,202
12	Above 500 KWH	2,160,710,990	$185,252,878	$0.090987	$196,596,956
13		4,549,018,019	$390,019,158		$390,019,158
14					
15	**2010**				
16	Average Retail G ($ / kWh)		$0.0800	Page 1 of Schedule 5a	
17	Conversion Factor		1.0225	Page 5 of Schedule 5a	
18	Seasonal Factor		1.1180	Page 7 of Schedule 5a	
19	Average Summer RS Price		$0.091452	Row 16 x Row 17 x Row 18	
20					
21	Block 2 Incremental Price		[redacted]		
22					
23		(A)	(B)	(C)	(D)
24		Summer KWH	Summer G Rev	Inv. Rate	Rev. Check
25	Below 500 KWH	2,388,307,029	$218,415,454	$0.086702	$207,071,377
26	Above 500 KWH	2,160,710,990	$197,601,341	$0.096702	$208,945,419
27		4,549,018,019	$416,016,796		$416,016,796
28					
29	**2011**				
30	Average Retail G ($ / kWh)		$0.0850	Page 1 of Schedule 5a	
31	Conversion Factor		1.0225	Page 5 of Schedule 5a	
32	Seasonal Factor		1.1180	Page 7 of Schedule 5a	
33	Average Summer RS Price		$0.097168	Row 30 x Row 31 x Row 32	
34					
35	Block 2 Incremental Price		[redacted]		
36					
37		(A)	(B)	(C)	(D)
38		Summer KWH	Summer G Rev	Inv. Rate	Rev. Check
39	Below 500 KWH	2,388,307,029	$232,067,017	$0.092418	$220,722,940
40	Above 500 KWH	2,160,710,990	$209,951,965	$0.102418	$221,296,043
41		4,549,018,019	$442,018,983		$442,018,983
42					

NOTES

(A) Source: Schedule 1a.

(B) Calculation: Average Summer RS Price x Column A

(C) Block 1 Rate = $\frac{\text{Total Summer G Revenue - (Summer KWH Above 500 x Block 2 Incremental Price)}}{\text{Total Summer KWH}}$

Block 2 Rate = Block 1 Rate Block 2 Incremental Price.

(D) Calculation: Column A x Column C.

Case No. 08-XXXX-EL-SSO
Ohio Edison Company
The Cleveland Electric Illuminating Company
The Toledo Edison Company

Witness: K. Warvell

PRICE CONVERSION FACTOR CALCULATION

		CEI			OE			TE			Total		Price Conversion Factor*
		Retail GWh	D Loss Factor	Wholesale	Retail GWh	D Loss Factor	Wholesale	Retail GWh	D Loss Factor	Wholesale	Retail GWh	Wholesale	
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)
1	RS	5,604	6.7%	5,979	9,226	6.7%	9,844	2,481	6.7%	2,647	17,311	18,471	1.0225
2	GS	7,404	6.7%	7,900	7,001	6.7%	7,470	2,246	6.7%	2,397	16,651	17,767	1.0225
3	Lighting **	221	6.7%	236	186	6.7%	199	69	6.7%	74	476	508	1.0225
4	GP	500	3.0%	515	3,216	3.0%	3,312	1,137	3.0%	1,171	4,853	4,999	0.9870
5	GSU	3,904	0.1%	3,908	987	0.1%	988	103	0.1%	103	4,993	4,998	0.9592
6	GT	2,160	0.0%	2,160	5,402	0.0%	5,402	4,623	0.0%	4,623	12,186	12,186	0.9583
7	TOTAL	19,793		20,699	26,018		27,215	10,659		11,016	56,471	58,929	

NOTES
(A) Source: Schedule 1a.
(B) Source: Page 6 of Schedule 5a
(C) Calculation: Column A x (1 + Column B).
(D) Source: Schedule 1a.
(E) Source: Page 6 of Schedule 5a
(F) Calculation: Column D x (1 + Column E).
(G) Source: Schedule 1a.
(H) Source: Page 6 of Schedule 5a
(I) Calculation: Column G x (1 + Column H).
(J) Calculation: Column A + Column D + Column G.
(K) Calculation: Column C + Column F + Column I.
(L) Calculation: Column K / Column J x (Column J, Row 7 / Column K, Row 7)

* **Class Conversion Factor:**

1. $\text{Retail Price} \times \dfrac{\text{Total Retail Kwh}}{\text{Total Wholesale Kwh}} = \text{Wholesale Price}$

2. $\text{Class Price} = \text{Wholesale Price} \times \dfrac{\text{Class Wholesale Kwh}}{\text{Class Retail Kwh}}$

3. $\text{Class Price} = \text{Retail Price} \times \underbrace{\dfrac{\text{Total Retail Kwh}}{\text{Total Wholesale Kwh}} \times \dfrac{\text{Class Wholesale Kwh}}{\text{Class Retail Kwh}}}_{\text{Class Price Conversion Factor}}$

** Includes Rate Schedules STL, POL, and TRF.

Witness: *K. Warvell*

LINE LOSS FACTORS

Rate Schedule	Service Voltage Group	138 kV Factor	Group Factor	Losses T&D	Losses T*	Losses D Only
(A)	(B)	(C)	(D)	(E)=(C)+(D)	(F)	(G)=(E)-(F)
RS	2.4 kV	1.386%	8.100%	9.486%	2.786%	6.70%
GS	2.4 kV	1.386%	8.100%	9.486%	2.786%	6.70%
Lighting **	2.4 kV	1.386%	8.100%	9.486%	2.786%	6.70%
GP	2.4 kV to < 23kV	1.386%	4.400%	5.786%	2.786%	3.00%
GSU	23 kV to < 69kV	1.386%	1.500%	2.886%	2.786%	0.10%
GT	69 kV	1.386%	1.400%	2.786%	2.786%	0.00%

* 138 kV Factor + 69 kV Factor = 1.386% + 1.4% = 2.786%
** Includes STL, POL, and TRF

XIV. LOAD PROFILING AND FORECASTING

A. Customer Load and Weather Forecasting

The Certified Supplier is responsible for developing an aggregated load forecast for its Customer's load to satisfy obligations required by the Tariff, and the Transmission Provider OATT.

B. Forecasting Methodology

The *load forecast* developed by the Certified Supplier shall conform to Sections XIV (B.1) and XIV (B.2) as well as all other relevant sections of this Tariff and the Transmission Provider OATT.

1. **Monthly Metered Customer Forecasts**
The Company shall make available to the Certified Supplier hourly load profiles, transmission and distribution losses and rate class of the Company's retail customers that do not have interval metering. The Company at its discretion may update, add, or modify the load profiles for any or all customer rate classes during the term of the Tariff on a prospective basis.

2. **Hourly Metered Customer Forecasts**

The Certified Supplier shall forecast its Customers' load for hourly metered Customers, adjusted for the inclusion of losses.

C. Real Power Losses

Losses will be calculated by multiplying the Retail Customer(s) load times the *applicable Real Power Loss Factor specified below:*

Service Voltage Level	Cumulative Loss Factor
138 kV	Loss Factor in the Transmission Provider OATT for ATSI facilities 138kV and above ("138kV Factor")
69 kV	138kV Factor + 1.4%
23 kV to < 69 kV	138kV Factor + 1.5%
2.4 kV to < 23 kV	138kV Factor + 4.4%
2.4 kV	138kV Factor + 8.1%

Case No. 08-XXXX-EL-SSO
Ohio Edison Company
The Cleveland Electric Illuminating Company
The Toledo Edison Company

Witness: K. Warvell

TOU AND SEASONAL FACTORS

24 month (Jan 2006-Dec 2007) LMP Data FESR

1	Summer	4,416.00	215,423.85	$48.78	1.1180
2	Non-Summer	13,104.00	547,785.65	$41.80	0.9581
3	On Peak	8,144.00	469,431.31	$57.64	1.3211
4	Off Peak	9,376.00	293,778.19	$31.33	0.7181
5	On Peak Summer	2,080.00	138,187.93	$66.44	1.5227
6	On Peak Winter	6,064.00	331,243.38	$54.62	1.2519
7	Off Peak Summer	2,336.00	77,235.92	$33.06	0.7578
8	Off Peak Winter	7,040.00	216,542.27	$30.76	0.7050
9	Annual Average			$43.56	

NOTES
(B) Total number of hours from January 2006 - December 2007.
(C) Sum of hourly LMPs at FESR node from January 2006 - December 2007.
(D) Calculation: Column C / Column B.
(E) Calculation: [Column D / (Column D, Row 9) x (74.88 / 75.00)]
* Please note that (74.88 / 75.00) is an adjustment factor to reflect variances in load shape and seasonality between the time period January 2006 - December 2007 and the time that the revenue generated from this case will be collected.

Witness: K. Warvell

2009
GENERATION PHASE-IN CREDITS

			(A)	(B)	(C)	(D)	(E)	(F)
1	AVERAGE RETAIL GENERATION PHASE-IN CREDIT ($ PER MWH)					($7.50)	($7.50)	($7.50)
2								
3	Rate	Customer Usage Category	Allocation Factors			OE	CEI	TE
4			Voltage	Season	TOU			
5								
6	RS	Non Time-of-Day						
7		Summer kWh	1.0225	1.1180	1.0000	($0.008574)	($0.008574)	($0.008574)
8		Non-Summer kWh	1.0225	0.9581	1.0000	($0.007347)	($0.007347)	($0.007347)
9		Time-of-Day						
10		On-Peak Summer	1.0225	1.0000	1.5227	($0.011677)	($0.011677)	($0.011677)
11		Off-Peak Summer	1.0225	1.0000	0.7578	($0.005811)	($0.006811)	($0.005811)
12		On-Peak Non-Summer	1.0225	1.0000	1.2519	($0.009601)	($0.009601)	($0.009601)
13		Off-Peak Non-Summer	1.0225	1.0000	0.7050	($0.005406)	($0.005406)	($0.005406)
14								
15	GS	Non Time-of-Day						
16		Summer kWh	1.0225	1.1180	1.0000	($0.008574)	($0.008574)	($0.008574)
17		Non-Summer kWh	1.0225	0.9581	1.0000	($0.007347)	($0.007347)	($0.007347)
18		Time-of-Day						
19		On-Peak Summer	1.0225	1.0000	1.5227	($0.011677)	($0.011677)	($0.011677)
20		Off-Peak Summer	1.0225	1.0000	0.7578	($0.005811)	($0.005811)	($0.005811)
21		On-Peak Non-Summer	1.0225	1.0000	1.2519	($0.009601)	($0.009601)	($0.009601)
22		Off-Peak Non-Summer	1.0225	1.0000	0.7050	($0.005406)	($0.005406)	($0.005406)
23								
24	GP	Non Time-of-Day						
25		Summer kWh	0.9870	1.1180	1.0000	($0.008276)	($0.008276)	($0.008276)
26		Non-Summer kWh	0.9870	0.9581	1.0000	($0.007092)	($0.007092)	($0.007092)
27		Time-of-Day						
28		On-Peak Summer	0.9870	1.0000	1.5227	($0.011272)	($0.011272)	($0.011272)
29		Off-Peak Summer	0.9870	1.0000	0.7578	($0.005610)	($0.005610)	($0.005610)
30		On-Peak Non-Summer	0.9870	1.0000	1.2519	($0.009267)	($0.009267)	($0.009267)
31		Off-Peak Non-Summer	0.9870	1.0000	0.7050	($0.005219)	($0.005219)	($0.005219)
32								
33	GSU	Non Time-of-Day						
34		Summer kWh	0.9592	1.1180	1.0000	($0.008043)	($0.008043)	($0.008043)
35		Non-Summer kWh	0.9592	0.9581	1.0000	($0.006893)	($0.006893)	($0.006893)
36		Time-of-Day						
37		On-Peak Summer	0.9592	1.0000	1.5227	($0.010954)	($0.010954)	($0.010954)
38		Off-Peak Summer	0.9592	1.0000	0.7578	($0.005452)	($0.005452)	($0.005452)
39		On-Peak Non-Summer	0.9592	1.0000	1.2519	($0.009006)	($0.009006)	($0.009006)
40		Off-Peak Non-Summer	0.9592	1.0000	0.7050	($0.005072)	($0.005072)	($0.005072)
41								
42	GT	Non Time of Day						
43		Summer kWh	0.9583	1.1180	1.0000	($0.008035)	($0.008035)	($0.008035)
44		Non-Summer kWh	0.9583	0.9581	1.0000	($0.006886)	($0.006886)	($0.006886)
45		Time of Day						
46		On-Peak Summer	0.9583	1.0000	1.5227	($0.010944)	($0.010944)	($0.010944)
47		Off-Peak Summer	0.9583	1.0000	0.7578	($0.005446)	($0.005446)	($0.005446)
48		On-Peak Non-Summer	0.9583	1.0000	1.2519	($0.008998)	($0.008998)	($0.008998)
49		Off-Peak Non-Summer	0.9583	1.0000	0.7050	($0.005067)	($0.005067)	($0.005067)
50								
51	STL	Summer kWh	1.0225	1.1180	1.0000	($0.008574)	($0.008574)	($0.008574)
52		Non-Summer kWh	1.0225	0.9581	1.0000	($0.007347)	($0.007347)	($0.007347)
53								
54	POL	Summer kWh	1.0225	1.1180	1.0000	($0.008574)	($0.008574)	($0.008574)
55		Non-Summer kWh	1.0225	0.9581	1.0000	($0.007347)	($0.007347)	($0.007347)
56								
57	TRF	Summer kWh	1.0225	1.1180	1.0000	($0.008574)	($0.008574)	($0.008574)
58		Non-Summer kWh	1.0225	0.9581	1.0000	($0.007347)	($0.007347)	($0.007347)

NOTES
(A) Allocation factors based on service voltage. See Page 4 of Schedule 5b for more details.
(B) Allocation factors based on season. See Page 6 of Schedule 5b for more details.
(C) Allocation factors based on seasonal Time-of-Use. See Page 6 of Schedule 5e for more details.
(D) Calculation: Column D, Row 1 x Column A x Column B x Column C.
(E) Calculation: Column E, Row 1 x Column A x Column B x Column C.
(F) Calculation: Column F, Row 1 x Column A x Column B x Column C.

2010

GENERATION PHASE-IN CREDITS

Line	Rate	Customer Usage Category	Allocation Factors			OE	CEI	TE
			(A)	(B)	(C)	(D)	(E)	(F)
1	AVERAGE RETAIL GENERATION PHASE-IN CREDIT ($ PER MWH)					($8.50)	($8.50)	($8.50)
2								
3	Rate	Customer Usage Category	Allocation Factors			OE	CEI	TE
4			Voltage	Season	TOU			
5								
6	RS	Non Time-of-Day						
7		Summer kWh	1.0225	1.1180	1.0000	($0.009717)	($0.009717)	($0.009717)
8		Non-Summer kWh	1.0225	0.9581	1.0000	($0.008327)	($0.008327)	($0.008327)
9		Time-of-Day						
10		On-Peak Summer	1.0225	1.0000	1.5227	($0.013234)	($0.013234)	($0.013234)
11		Off-Peak Summer	1.0225	1.0000	0.7578	($0.006586)	($0.006586)	($0.006586)
12		On-Peak Non-Summer	1.0225	1.0000	1.2519	($0.010881)	($0.010881)	($0.010881)
13		Off-Peak Non-Summer	1.0225	1.0000	0.7050	($0.006127)	($0.006127)	($0.006127)
14								
15	GS	Non Time-of-Day						
16		Summer kWh	1.0225	1.1180	1.0000	($0.009717)	($0.009717)	($0.009717)
17		Non-Summer kWh	1.0225	0.9581	1.0000	($0.008327)	($0.008327)	($0.008327)
18		Time-of-Day						
19		On-Peak Summer	1.0225	1.0000	1.5227	($0.013234)	($0.013234)	($0.013234)
20		Off-Peak Summer	1.0225	1.0000	0.7578	($0.006586)	($0.006586)	($0.006586)
21		On-Peak Non-Summer	1.0225	1.0000	1.2519	($0.010881)	($0.010881)	($0.010881)
22		Off-Peak Non-Summer	1.0225	1.0000	0.7050	($0.006127)	($0.006127)	($0.006127)
23								
24	GP	Non Time-of-Day						
25		Summer kWh	0.9870	1.1180	1.0000	($0.009379)	($0.009379)	($0.009379)
26		Non-Summer kWh	0.9870	0.9581	1.0000	($0.008038)	($0.008038)	($0.008038)
27		Time-of-Day						
28		On-Peak Summer	0.9870	1.0000	1.5227	($0.012775)	($0.012775)	($0.012775)
29		Off-Peak Summer	0.9870	1.0000	0.7578	($0.006358)	($0.006358)	($0.006358)
30		On-Peak Non-Summer	0.9870	1.0000	1.2519	($0.010503)	($0.010503)	($0.010503)
31		Off-Peak Non-Summer	0.9870	1.0000	0.7050	($0.005915)	($0.005915)	($0.005915)
32								
33	GSU	Non Time-of-Day						
34		Summer kWh	0.9592	1.1180	1.0000	($0.009115)	($0.009115)	($0.009115)
35		Non-Summer kWh	0.9592	0.9581	1.0000	($0.007812)	($0.007812)	($0.007812)
36		Time-of-Day						
37		On-Peak Summer	0.9592	1.0000	1.5227	($0.012415)	($0.012415)	($0.012415)
38		Off-Peak Summer	0.9592	1.0000	0.7578	($0.006178)	($0.006178)	($0.006178)
39		On-Peak Non-Summer	0.9592	1.0000	1.2519	($0.010207)	($0.010207)	($0.010207)
40		Off-Peak Non-Summer	0.9592	1.0000	0.7050	($0.005748)	($0.005748)	($0.005748)
41								
42	GT	Non Time of Day						
43		Summer kWh	0.9583	1.1180	1.0000	($0.009107)	($0.009107)	($0.009107)
44		Non-Summer kWh	0.9583	0.9581	1.0000	($0.007804)	($0.007804)	($0.007804)
45		Time of Day						
46		On-Peak Summer	0.9583	1.0000	1.5227	($0.012403)	($0.012403)	($0.012403)
47		Off-Peak Summer	0.9583	1.0000	0.7578	($0.006173)	($0.006173)	($0.006173)
48		On-Peak Non-Summer	0.9583	1.0000	1.2519	($0.010197)	($0.010197)	($0.010197)
49		Off-Peak Non-Summer	0.9583	1.0000	0.7050	($0.005743)	($0.005743)	($0.005743)
50								
51	STL	Summer kWh	1.0225	1.1180	1.0000	($0.009717)	($0.009717)	($0.009717)
52		Non-Summer kWh	1.0225	0.9581	1.0000	($0.008327)	($0.008327)	($0.008327)
53								
54	POL	Summer kWh	1.0225	1.1180	1.0000	($0.009717)	($0.009717)	($0.009717)
55		Non-Summer kWh	1.0225	0.9581	1.0000	($0.008327)	($0.008327)	($0.008327)
56								
57	TRF	Summer kWh	1.0225	1.1180	1.0000	($0.009717)	($0.009717)	($0.009717)
58		Non-Summer kWh	1.0225	0.9581	1.0000	($0.008327)	($0.008327)	($0.008327)

NOTES

(A) Allocation factors based on service voltage. See Page 4 of Schedule 5b for more details.
(B) Allocation factors based on season. See Page 6 of Schedule 5b for more details.
(C) Allocation factors based on seasonal Time-of-Use. See Page 6 of Schedule 5e for more details.
(D) Calculation: Column D, Row 1 x Column A x Column B x Column C.
(E) Calculation: Column E, Row 1 x Column A x Column B x Column C.
(F) Calculation: Column F, Row 1 x Column A x Column B x Column C.

2011

GENERATION PHASE-IN CREDITS

			(A)	(B)	(C)	(D)	(E)	(F)
1	AVERAGE RETAIL GENERATION PHASE-IN CREDIT ($ PER MWH)					($9.50)	($9.50)	($9.50)
2								
3	Rate	Customer Usage Category	Allocation Factors			OE	CEI	TE
4			Voltage	Season	TOU			
5								
6	RS	Non Time-of-Day						
7		Summer kWh	1.0225	1.1180	1.0000	($0.010860)	($0.010860)	($0.010860)
8		Non-Summer kWh	1.0225	0.9581	1.0000	($0.009307)	($0.009307)	($0.009307)
9		Time-of-Day						
10		On-Peak Summer	1.0225	1.0000	1.5227	($0.014791)	($0.014791)	($0.014791)
11		Off-Peak Summer	1.0225	1.0000	0.7578	($0.007361)	($0.007361)	($0.007361)
12		On-Peak Non-Summer	1.0225	1.0000	1.2519	($0.012161)	($0.012161)	($0.012161)
13		Off-Peak Non-Summer	1.0225	1.0000	0.7050	($0.006848)	($0.006848)	($0.006848)
14								
15	GS	Non Time-of-Day						
16		Summer kWh	1.0225	1.1180	1.0000	($0.010860)	($0.010860)	($0.010860)
17		Non-Summer kWh	1.0225	0.9581	1.0000	($0.009307)	($0.009307)	($0.009307)
18		Time-of-Day						
19		On-Peak Summer	1.0225	1.0000	1.5227	($0.014791)	($0.014791)	($0.014791)
20		Off-Peak Summer	1.0225	1.0000	0.7578	($0.007361)	($0.007361)	($0.007361)
21		On-Peak Non-Summer	1.0225	1.0000	1.2519	($0.012161)	($0.012161)	($0.012161)
22		Off-Peak Non-Summer	1.0225	1.0000	0.7050	($0.006848)	($0.006848)	($0.006848)
23								
24	GP	Non Time-of-Day						
25		Summer kWh	0.9870	1.1180	1.0000	($0.010483)	($0.010483)	($0.010483)
26		Non-Summer kWh	0.9870	0.9581	1.0000	($0.008984)	($0.008984)	($0.008984)
27		Time-of-Day						
28		On-Peak Summer	0.9870	1.0000	1.5227	($0.014278)	($0.014278)	($0.014278)
29		Off-Peak Summer	0.9870	1.0000	0.7578	($0.007106)	($0.007106)	($0.007106)
30		On-Peak Non-Summer	0.9870	1.0000	1.2519	($0.011738)	($0.011738)	($0.011738)
31		Off-Peak Non-Summer	0.9870	1.0000	0.7050	($0.006610)	($0.006610)	($0.006610)
32								
33	GSU	Non Time-of-Day						
34		Summer kWh	0.9592	1.1180	1.0000	($0.010188)	($0.010188)	($0.010188)
35		Non-Summer kWh	0.9592	0.9581	1.0000	($0.008731)	($0.008731)	($0.008731)
36		Time-of-Day						
37		On-Peak Summer	0.9592	1.0000	1.5227	($0.013875)	($0.013875)	($0.013875)
38		Off-Peak Summer	0.9592	1.0000	0.7578	($0.006905)	($0.006905)	($0.006905)
39		On-Peak Non-Summer	0.9592	1.0000	1.2519	($0.011408)	($0.011408)	($0.011408)
40		Off-Peak Non-Summer	0.9592	1.0000	0.7050	($0.006424)	($0.006424)	($0.006424)
41								
42	GT	Non Time of Day						
43		Summer kWh	0.9583	1.1180	1.0000	($0.010178)	($0.010178)	($0.010178)
44		Non-Summer kWh	0.9583	0.9581	1.0000	($0.008722)	($0.008722)	($0.008722)
45		Time of Day						
46		On-Peak Summer	0.9583	1.0000	1.5227	($0.013862)	($0.013862)	($0.013862)
47		Off-Peak Summer	0.9583	1.0000	0.7578	($0.006899)	($0.006899)	($0.006899)
48		On-Peak Non-Summer	0.9583	1.0000	1.2519	($0.011397)	($0.011397)	($0.011397)
49		Off-Peak Non-Summer	0.9583	1.0000	0.7050	($0.006418)	($0.006418)	($0.006418)
50								
51	STL	Summer kWh	1.0225	1.1180	1.0000	($0.010860)	($0.010860)	($0.010860)
52		Non-Summer kWh	1.0225	0.9581	1.0000	($0.009307)	($0.009307)	($0.009307)
53								
54	POL	Summer kWh	1.0225	1.1180	1.0000	($0.010860)	($0.010860)	($0.010860)
55		Non-Summer kWh	1.0225	0.9581	1.0000	($0.009307)	($0.009307)	($0.009307)
56								
57	TRF	Summer kWh	1.0225	1.1180	1.0000	($0.010860)	($0.010860)	($0.010860)
58		Non-Summer kWh	1.0225	0.9581	1.0000	($0.009307)	($0.009307)	($0.009307)

NOTES

(A) Allocation factors based on service voltage. See Page 4 of Schedule 5b for more details.
(B) Allocation factors based on season. See Page 6 of Schedule 5b for more details.
(C) Allocation factors based on seasonal Time-of-Use. See Page 6 of Schedule 5e for more details.
(D) Calculation: Column D, Row 1 x Column A x Column B x Column C.
(E) Calculation: Column E, Row 1 x Column A x Column B x Column C.
(F) Calculation: Column F, Row 1 x Column A x Column B x Column C.

Witness: K. Warvell

PRICE CONVERSION FACTOR CALCULATION

		CEI			OE			TE			Total		Price Conversion Factor*
		Retail GWh	D Loss Factor	Wholesale	Retail GWh	D Loss Factor	Wholesale	Retail GWh	D Loss Factor	Wholesale	Retail GWh	Wholesale	
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)
1	RS	5,604	6.7%	5,979	9,226	6.7%	9,844	2,481	6.7%	2,647	17,311	18,471	1.0225
2	GS	7,404	6.7%	7,900	7,001	6.7%	7,470	2,246	6.7%	2,397	16,651	17,767	1.0225
3	Lighting **	221	6.7%	236	186	6.7%	199	69	6.7%	74	476	508	1.0225
4	GP	500	3.0%	515	3,216	3.0%	3,312	1,137	3.0%	1,171	4,853	4,998	0.9870
5	GSU	3,904	0.1%	3,908	987	0.1%	988	103	0.1%	103	4,993	4,998	0.9592
6	GT	2,160	0.0%	2,160	5,402	0.0%	5,402	4,623	0.0%	4,623	12,186	12,186	0.9583
7	TOTAL	19,793		20,699	26,018		27,215	10,659		11,015	56,471	58,929	

NOTES
(A) Source: Schedule 1a.
(B) Source: Page 5 of Schedule 5b
(C) Calculation: Column A x (1 + Column B).
(D) Source: Schedule 1a.
(E) Source: Page 5 of Schedule 5b
(F) Calculation: Column D x (1 + Column E).
(G) Source: Schedule 1a.
(H) Source: Page 5 of Schedule 5b
(I) Calculation: Column G x (1 + Column H).
(J) Calculation: Column A + Column D + Column G.
(K) Calculation: Column C + Column F + Column I.
(L) Calculation: Column K / Column J x (Column J, Row 7 / Column K, Row 7)

* **Class Conversion Factor:**

1. $\text{Retail Price} \times \dfrac{\text{Total Retail Kwh}}{\text{Total Wholesale Kwh}} = \text{Wholesale Price}$

2. $\text{Class Price} = \text{Wholesale Price} \times \dfrac{\text{Class Wholesale Kwh}}{\text{Class Retail Kwh}}$

3. $\text{Class Price} = \text{Retail Price} \times \underbrace{\dfrac{\text{Total Retail Kwh}}{\text{Total Wholesale Kwh}} \times \dfrac{\text{Class Wholesale Kwh}}{\text{Class Retail Kwh}}}_{\text{Class Price Conversion Factor}}$

** Includes Rate Schedules STL, POL, and TRF.

LINE LOSS FACTORS

Rate Schedule	Service Voltage Group	138 kV Factor	Group Factor	Losses T&D	Losses T*	Losses D Only
(A)	(B)	(C)	(D)	(E)=(C)+(D)	(F)	(G)=(E)-(F)
RS	2.4 kV	1.386%	8.100%	9.486%	2.786%	6.70%
GS	2.4 kV	1.386%	8.100%	9.486%	2.786%	6.70%
Lighting **	2.4 kV	1.386%	8.100%	9.486%	2.786%	6.70%
GP	2.4 kV to < 23kV	1.386%	4.400%	5.786%	2.786%	3.00%
GSU	23 kV to < 69kV	1.386%	1.500%	2.886%	2.786%	0.10%
GT	69 kV	1.386%	1.400%	2.786%	2.786%	0.00%

* 138 kV Factor + 69 kV Factor = 1.386% + 1.4% = 2.786%
** Includes STL, POL, and TRF

XIV. LOAD PROFILING AND FORECASTING

A. Customer Load and Weather Forecasting

The Certified Supplier is responsible for developing an aggregated load forecast for its Customer's load to satisfy obligations required by the Tariff, and the Transmission Provider OATT.

B. Forecasting Methodology

The load forecast developed by the Certified Supplier shall conform to Sections XIV (B.1) and XIV (B.2) as well as all other relevant sections of this Tariff and the Transmission Provider OATT.

1. Monthly Metered Customer Forecasts
The Company shall make available to the Certified Supplier hourly load profiles, transmission and distribution losses and rate class of the Company's retail customers that do not have interval metering. The Company at its discretion may update, add, or modify the load profiles for any or all customer rate classes during the term of the Tariff on a prospective basis.

2. Hourly Metered Customer Forecasts

The Certified Supplier shall forecast its Customers' load for hourly metered Customers, adjusted for the inclusion of losses.

C. Real Power Losses

Losses will be calculated by multiplying the Retail Customer(s) load times the applicable Real Power Loss Factor specified below:

Service Voltage Level	Cumulative Loss Factor
138 kV	Loss Factor in the Transmission Provider OATT for ATSI facilities 138kV and above ("138kV Factor")
69 kV	138kV Factor + 1.4%
23 kV to < 69 kV	138kV Factor + 1.5%
2.4 kV to < 23 kV	138kV Factor + 4.4%
2.4 kV	138kV Factor + 8.1%

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Schedule 5b
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Witness: K. Warvell

TOU AND SEASONAL FACTORS

24 month (Jan 2006-Dec 2007) LMP Data FESR

1	Summer	4,416.00	215,423.85	$48.78	1.1180
2	Non-Summer	13,104.00	547,785.65	$41.80	0.9581
3	On Peak	8,144.00	469,431.31	$57.64	1.3211
4	Off Peak	9,376.00	293,778.19	$31.33	0.7181
5	On Peak Summer	2,080.00	138,187.93	$66.44	1.5227
6	On Peak Winter	6,064.00	331,243.38	$54.62	1.2519
7	Off Peak Summer	2,336.00	77,235.92	$33.06	0.7578
8	Off Peak Winter	7,040.00	216,542.27	$30.76	0.7050
9	Annual Average			$43.56	

NOTES

(B) Total number of hours from January 2006 - December 2007.
(C) Sum of hourly LMPs at FESR node from January 2006 - December 2007.
(D) Calculation: Column C / Column B.
(E) Calculation: [Column D / (Column D, Row 9) x (74.88 / 75.00)]
* Please note that (74.88 / 75.00) is an adjustment factor to reflect variances in load shape and seasonality between the time period January 2006 - December 2007 and the time that the revenue generated from this case will be collected.

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Ohio Edison Company
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The Toledo Edison Company

Witness: K. Warvell

Rider Charge Calculation - Rider DGC
Option 1 - No Securitization

I. Calculation of Aggregate Levelized Rate (2011)

		TOTAL	OE	CEI	TE
(1)	2011 Levelized Revenue Requirement	$116,967,518	$53,987,435	$40,874,902	$22,105,182
(2)	2011 Forecasted Total Company MWH Sales	58,211,000	27,019,000	20,298,000	10,894,000
(3)	Levelized Rate ($ / KWH)	$0.002009			

NOTES
(1) Source: Schedule 6f (Option 1), Row 37, Column C.
(2) Source: Company's long-term forecast.
(3) Calculation: Row 1 / (Row 2 x 1,000).

II. Calculation of Voltage-Differentiated, Seasonal, and Time-of-Day Rates (2011)

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
	Rate Schedule	Customer Usage Category	Allocation Factors			DGC Charges		
			Voltage	Seasonal	TOD	OE	CEI	TE
(4)	RS	Non Time-of-Day						
(5)		Summer kWh	1.0225	1.1180	1.0000	$0.002297	$0.002297	$0.002297
(6)		Non-Summer kWh	1.0225	0.9581	1.0000	$0.001968	$0.001968	$0.001968
(7)		Time-of-Day						
(8)		On-Peak Summer	1.0225	1.0000	1.5227	$0.003128	$0.003128	$0.003128
(9)		Off-Peak Summer	1.0225	1.0000	0.7578	$0.001557	$0.001557	$0.001557
(10)		On-Peak Non-Summer	1.0225	1.0000	1.2519	$0.002572	$0.002572	$0.002572
(11)		Off-Peak Non-Summer	1.0225	1.0000	0.7050	$0.001448	$0.001448	$0.001448
(12)	GS	Non Time-of-Day						
(13)		Summer kWh	1.0225	1.1180	1.0000	$0.002297	$0.002297	$0.002297
(14)		Non-Summer kWh	1.0225	0.9581	1.0000	$0.001968	$0.001968	$0.001968
(15)		Time-of-Day						
(16)		On-Peak Summer	1.0225	1.0000	1.5227	$0.003128	$0.003128	$0.003128
(17)		Off-Peak Summer	1.0225	1.0000	0.7578	$0.001557	$0.001557	$0.001557
(18)		On-Peak Non-Summer	1.0225	1.0000	1.2519	$0.002572	$0.002572	$0.002572
(19)		Off-Peak Non-Summer	1.0225	1.0000	0.7050	$0.001448	$0.001448	$0.001448
(20)	GP	Non Time-of-Day						
(21)		Summer kWh	0.9869	1.1180	1.0000	$0.002217	$0.002217	$0.002217
(22)		Non-Summer kWh	0.9869	0.9581	1.0000	$0.001900	$0.001900	$0.001900
(23)		Time-of-Day						
(24)		On-Peak Summer	0.9869	1.0000	1.5227	$0.003019	$0.003019	$0.003019
(25)		Off-Peak Summer	0.9869	1.0000	0.7578	$0.001502	$0.001502	$0.001502
(26)		On-Peak Non-Summer	0.9869	1.0000	1.2519	$0.002482	$0.002482	$0.002482
(27)		Off-Peak Non-Summer	0.9869	1.0000	0.7050	$0.001398	$0.001398	$0.001398

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Schedule 5c
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Witness: K. Warvell

Rider Charge Calculation - Rider DGC
Option 1 - No Securitization

I. Calculation of Aggregate Levelized Rate (2011)

		TOTAL	OE	CEI	TE
(1)	2011 Levelized Revenue Requirement	$116,967,518	$53,987,435	$40,874,902	$22,105,182
(2)	2011 Forecasted Total Company MWH Sales	58,211,000	27,019,000	20,298,000	10,894,000
(3)	Levelized Rate ($ / KWH)	$0.002009			

NOTES
(1) Source: Schedule 6f (Option 1), Row 37, Column B.
(2) Source: Company's long-term forecast.
(3) Calculation: Row 1 / (Row 2 x 1,000).

II. Calculation of Voltage-Differentiated, Seasonal, and Time-of-Day Rates (2011)

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
	Rate Schedule	Customer Usage Category	Allocation Factors			DGC Charges		
			Voltage	Seasonal	TOD	OE	CEI	TE
(28)	GSU	Non Time-of-Day						
(29)		Summer kWh	0.9594	1.1180	1.0000	$0.002155	$0.002155	$0.002155
(30)		Non-Summer kWh	0.9594	0.9581	1.0000	$0.001847	$0.001847	$0.001847
(31)		Time-of-Day						
(32)		On-Peak Summer	0.9594	1.0000	1.5227	$0.002935	$0.002935	$0.002935
(33)		Off-Peak Summer	0.9594	1.0000	0.7578	$0.001461	$0.001461	$0.001461
(34)		On-Peak Non-Summer	0.9594	1.0000	1.2519	$0.002413	$0.002413	$0.002413
(35)		Off-Peak Non-Summer	0.9594	1.0000	0.7050	$0.001359	$0.001359	$0.001359
(36)	GT	Non Time of Day						
(37)		Summer kWh	0.9582	1.1180	1.0000	$0.002152	$0.002152	$0.002152
(38)		Non-Summer kWh	0.9582	0.9581	1.0000	$0.001844	$0.001844	$0.001844
(39)		Time of Day						
(40)		On-Peak Summer	0.9582	1.0000	1.5227	$0.002931	$0.002931	$0.002931
(41)		Off-Peak Summer	0.9582	1.0000	0.7578	$0.001459	$0.001459	$0.001459
(42)		On-Peak Non-Summer	0.9582	1.0000	1.2519	$0.002410	$0.002410	$0.002410
(43)		Off-Peak Non-Summer	0.9582	1.0000	0.7050	$0.001357	$0.001357	$0.001357
(44)	STL	Summer kWh	1.0238	1.1180	1.0000	$0.002300	$0.002300	$0.002300
(45)		Non-Summer kWh	1.0238	0.9581	1.0000	$0.001971	$0.001971	$0.001971
(46)	POL	Summer kWh	1.0238	1.1180	1.0000	$0.002300	$0.002300	$0.002300
(47)		Non-Summer kWh	1.0238	0.9581	1.0000	$0.001971	$0.001971	$0.001971
(48)	TRF	Summer kWh	1.0238	1.1180	1.0000	$0.002300	$0.002300	$0.002300
(49)		Non-Summer kWh	1.0238	0.9581	1.0000	$0.001971	$0.001971	$0.001971

NOTES
(C) Source: Page 5 of Schedule 5a.
(D) Source: Page 7 of Schedule 5a.
(E) Source: Page 7 of Schedule 5a.
(F) Calculation: Aggregate Levelized Rate from Row 3 x Column C x Column D x Column E.
(G) Calculation: Aggregate Levelized Rate from Row 3 x Column C x Column D x Column E.
(H) Calculation: Aggregate Levelized Rate from Row 3 x Column C x Column D x Column E.

Case No. 08-XXXX-EL-SSO
Ohio Edison Company
The Cleveland Electric Illuminating Company
The Toledo Edison Company

Witness: K. Warvell

Rider Charge Calculation - Rider DGC
Option 1 - No Securitization

I. Calculation of Aggregate Levelized Rate (2013)

		TOTAL	OE	CEI	TE
(1)	2013 Levelized Revenue Requirement	$192,752,493	$89,144,612	$67,339,276	$36,268,605
(2)	2013 Forecasted Total Company MWH Sales	59,273,000	27,598,000	20,640,000	11,035,000
(3)	Levelized Rate ($ / KWH)	$0.003252			

NOTES
(1) Source: Schedule 6f (Option 1) (Row 39, Column B + Row 48, Column B).
(2) Source: Company's long-term forecast.
(3) Calculation: Row 1 / (Row 2 x 1,000).

II. Calculation of Voltage-Differentiated, Seasonal, and Time-of-Day Rates (2013)

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
	Rate	Customer Usage	Allocation Factors			DGC Charges		
	Schedule	Category	Voltage	Seasonal	TOD	OE	CEI	TE
(4)	RS	Non Time-of-Day						
(5)		Summer kWh	1.0225	1.1180	1.0000	$0.003718	$0.003718	$0.003718
(6)		Non-Summer kWh	1.0225	0.9581	1.0000	$0.003186	$0.003186	$0.003186
(7)		Time-of-Day						
(8)		On-Peak Summer	1.0225	1.0000	1.5227	$0.005063	$0.005063	$0.005063
(9)		Off-Peak Summer	1.0225	1.0000	0.7578	$0.002520	$0.002520	$0.002520
(10)		On-Peak Non-Summer	1.0225	1.0000	1.2519	$0.004163	$0.004163	$0.004163
(11)		Off-Peak Non-Summer	1.0225	1.0000	0.7050	$0.002344	$0.002344	$0.002344
(12)	GS	Non Time-of-Day						
(13)		Summer kWh	1.0225	1.1180	1.0000	$0.003718	$0.003718	$0.003718
(14)		Non-Summer kWh	1.0225	0.9581	1.0000	$0.003186	$0.003186	$0.003186
(15)		Time-of-Day						
(16)		On-Peak Summer	1.0225	1.0000	1.5227	$0.005063	$0.005063	$0.005063
(17)		Off-Peak Summer	1.0225	1.0000	0.7578	$0.002520	$0.002520	$0.002520
(18)		On-Peak Non-Summer	1.0225	1.0000	1.2519	$0.004163	$0.004163	$0.004163
(19)		Off-Peak Non-Summer	1.0225	1.0000	0.7050	$0.002344	$0.002344	$0.002344
(20)	GP	Non Time-of-Day						
(21)		Summer kWh	0.9869	1.1180	1.0000	$0.003588	$0.003588	$0.003588
(22)		Non-Summer kWh	0.9869	0.9581	1.0000	$0.003075	$0.003075	$0.003075
(23)		Time-of-Day						
(24)		On-Peak Summer	0.9869	1.0000	1.5227	$0.004887	$0.004887	$0.004887
(25)		Off-Peak Summer	0.9869	1.0000	0.7578	$0.002432	$0.002432	$0.002432
(26)		On-Peak Non-Summer	0.9869	1.0000	1.2519	$0.004018	$0.004018	$0.004018
(27)		Off-Peak Non-Summer	0.9869	1.0000	0.7050	$0.002263	$0.002263	$0.002263

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The Toledo Edison Company

Witness: K. Warvell

Rider Charge Calculation - Rider DGC
Option 1 - No Securitization

I. Calculation of Aggregate Levelized Rate (2013)

		TOTAL	OE	CEI	TE
(1)	2013 Levelized Revenue Requirement	$192,752,493	$89,144,612	$67,339,276	$36,268,605
(2)	2013 Forecasted Total Company MWH Sales	59,273,000	27,598,000	20,640,000	11,035,000
(3)	Levelized Rate ($ / KWH)	$0.003252			

NOTES
(1) Source: Schedule 6f (Option 1) (Row 39, Column B + Row 48, Column B).
(2) Source: Company's long-term forecast.
(3) Calculation: Row 1 / (Row 2 x 1,000).

II. Calculation of Voltage-Differentiated, Seasonal, and Time-of-Day Rates (2013)

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
	Rate	Customer Usage	Allocation Factors			DGC Charges		
	Schedule	Category	Voltage	Seasonal	TOD	OE	CEI	TE
(28)	GSU	Non Time-of-Day						
(29)		Summer kWh	0.9594	1.1180	1.0000	$0.003488	$0.003488	$0.003488
(30)		Non-Summer kWh	0.9594	0.9581	1.0000	$0.002989	$0.002989	$0.002989
(31)		Time-of-Day						
(32)		On-Peak Summer	0.9594	1.0000	1.5227	$0.004751	$0.004751	$0.004751
(33)		Off-Peak Summer	0.9594	1.0000	0.7578	$0.002364	$0.002364	$0.002364
(34)		On-Peak Non-Summer	0.9594	1.0000	1.2519	$0.003906	$0.003906	$0.003906
(35)		Off-Peak Non-Summer	0.9594	1.0000	0.7050	$0.002200	$0.002200	$0.002200
(36)	GT	Non Time of Day						
(37)		Summer kWh	0.9582	1.1180	1.0000	$0.003484	$0.003484	$0.003484
(38)		Non-Summer kWh	0.9582	0.9581	1.0000	$0.002986	$0.002986	$0.002986
(39)		Time of Day						
(40)		On-Peak Summer	0.9582	1.0000	1.5227	$0.004745	$0.004745	$0.004745
(41)		Off-Peak Summer	0.9582	1.0000	0.7578	$0.002361	$0.002361	$0.002361
(42)		On-Peak Non-Summer	0.9582	1.0000	1.2519	$0.003901	$0.003901	$0.003901
(43)		Off-Peak Non-Summer	0.9582	1.0000	0.7050	$0.002197	$0.002197	$0.002197
(44)	STL	Summer kWh	1.0238	1.1180	1.0000	$0.003722	$0.003722	$0.003722
(45)		Non-Summer kWh	1.0238	0.9581	1.0000	$0.003190	$0.003190	$0.003190
(46)	POL	Summer kWh	1.0238	1.1180	1.0000	$0.003722	$0.003722	$0.003722
(47)		Non-Summer kWh	1.0238	0.9581	1.0000	$0.003190	$0.003190	$0.003190
(48)	TRF	Summer kWh	1.0238	1.1180	1.0000	$0.003722	$0.003722	$0.003722
(49)		Non-Summer kWh	1.0238	0.9581	1.0000	$0.003190	$0.003190	$0.003190

NOTES
(C) Source: Page 5 of Schedule 5a.
(D) Source: Page 7 of Schedule 5a.
(E) Source: Page 7 of Schedule 5a.
(F) Calculation: Aggregate Levelized Rate from Row 3 x Column C x Column D x Column E.
(G) Calculation: Aggregate Levelized Rate from Row 3 x Column C x Column D x Column E.
(H) Calculation: Aggregate Levelized Rate from Row 3 x Column C x Column D x Column E.

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Ohio Edison Company
The Cleveland Electric Illuminating Company
The Toledo Edison Company

Witness: K. Warvell

Rider Charge Calculation - Rider DGC
Option 1 - No Securitization

I. Calculation of Aggregate Levelized Rate (2021)

		TOTAL	OE	CEI	TE
(1)	2021 Levelized Revenue Requirement	$78,823,266	$36,906,508	$27,371,669	$14,545,089
(2)	2021 Forecasted Total Company MWH Sales	63,440,139	29,956,719	21,917,629	11,565,791
(3)	Levelized Rate ($ / KWH)	$0.001242			

NOTES
(1) Source: Schedule 6f (Option 1), Row 56, Column B.
(2) Source: Company's long-term forecast.
(3) Calculation: Row 1 / (Row 2 x 1,000).

II. Calculation of Voltage-Differentiated, Seasonal, and Time-of-Day Rates (2021)

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
	Rate Schedule	Customer Usage Category	Allocation Factors			DGC Charges		
			Voltage	Seasonal	TOD	OE	CEI	TE
(4)	RS	Non Time-of-Day						
(5)		Summer kWh	1.0225	1.1180	1.0000	$0.001420	$0.001420	$0.001420
(6)		Non-Summer kWh	1.0225	0.9581	1.0000	$0.001217	$0.001217	$0.001217
(7)		Time-of-Day						
(8)		On-Peak Summer	1.0225	1.0000	1.5227	$0.001934	$0.001934	$0.001934
(9)		Off-Peak Summer	1.0225	1.0000	0.7578	$0.000962	$0.000962	$0.000962
(10)		On-Peak Non-Summer	1.0225	1.0000	1.2519	$0.001590	$0.001590	$0.001590
(11)		Off-Peak Non-Summer	1.0225	1.0000	0.7050	$0.000895	$0.000895	$0.000895
(12)	GS	Non Time-of-Day						
(13)		Summer kWh	1.0225	1.1180	1.0000	$0.001420	$0.001420	$0.001420
(14)		Non-Summer kWh	1.0225	0.9581	1.0000	$0.001217	$0.001217	$0.001217
(15)		Time-of-Day						
(16)		On-Peak Summer	1.0225	1.0000	1.5227	$0.001934	$0.001934	$0.001934
(17)		Off-Peak Summer	1.0225	1.0000	0.7578	$0.000962	$0.000962	$0.000962
(18)		On-Peak Non-Summer	1.0225	1.0000	1.2519	$0.001590	$0.001590	$0.001590
(19)		Off-Peak Non-Summer	1.0225	1.0000	0.7050	$0.000895	$0.000895	$0.000895
(20)	GP	Non Time-of-Day						
(21)		Summer kWh	0.9869	1.1180	1.0000	$0.001370	$0.001370	$0.001370
(22)		Non-Summer kWh	0.9869	0.9581	1.0000	$0.001174	$0.001174	$0.001174
(23)		Time-of-Day						
(24)		On-Peak Summer	0.9869	1.0000	1.5227	$0.001866	$0.001866	$0.001866
(25)		Off-Peak Summer	0.9869	1.0000	0.7578	$0.000929	$0.000929	$0.000929
(26)		On-Peak Non-Summer	0.9869	1.0000	1.2519	$0.001534	$0.001534	$0.001534
(27)		Off-Peak Non-Summer	0.9869	1.0000	0.7050	$0.000864	$0.000864	$0.000864

Rider Charge Calculation - Rider DGC
Option 1 - No Securitization

I. Calculation of Aggregate Levelized Rate (2021)

		TOTAL	OE	CEI	TE
(1)	2021 Levelized Revenue Requirement	$78,823,266	$36,906,508	$27,371,669	$14,545,089
(2)	2021 Forecasted Total Company MWH Sales	63,440,139	29,956,719	21,917,629	11,565,791
(3)	Levelized Rate ($ / KWH)	$0.001242			

NOTES
(1) Source: Schedule 6f (Option 1), Row 56, Column B.
(2) Source: Company's long-term forecast.
(3) Calculation: Row 1 / (Row 2 x 1,000).

II. Calculation of Voltage-Differentiated, Seasonal, and Time-of-Day Rates (2021)

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
	Rate	Customer Usage	Allocation Factors			DGC Charges		
	Schedule	Category	Voltage	Seasonal	TOD	OE	CEI	TE
(28)	GSU	Non Time-of-Day						
(29)		Summer kWh	0.9594	1.1180	1.0000	$0.001332	$0.001332	$0.001332
(30)		Non-Summer kWh	0.9594	0.9581	1.0000	$0.001142	$0.001142	$0.001142
(31)		Time-of-Day						
(32)		On-Peak Summer	0.9594	1.0000	1.5227	$0.001814	$0.001814	$0.001814
(33)		Off-Peak Summer	0.9594	1.0000	0.7578	$0.000903	$0.000903	$0.000903
(34)		On-Peak Non-Summer	0.9594	1.0000	1.2519	$0.001492	$0.001492	$0.001492
(35)		Off-Peak Non-Summer	0.9594	1.0000	0.7050	$0.000840	$0.000840	$0.000840
(36)	GT	Non Time of Day						
(37)		Summer kWh	0.9582	1.1180	1.0000	$0.001331	$0.001331	$0.001331
(38)		Non-Summer kWh	0.9582	0.9581	1.0000	$0.001140	$0.001140	$0.001140
(39)		Time of Day						
(40)		On-Peak Summer	0.9582	1.0000	1.5227	$0.001812	$0.001812	$0.001812
(41)		Off-Peak Summer	0.9582	1.0000	0.7578	$0.000902	$0.000902	$0.000902
(42)		On-Peak Non-Summer	0.9582	1.0000	1.2519	$0.001490	$0.001490	$0.001490
(43)		Off-Peak Non-Summer	0.9582	1.0000	0.7050	$0.000839	$0.000839	$0.000839
(44)	STL	Summer kWh	1.0238	1.1180	1.0000	$0.001422	$0.001422	$0.001422
(45)		Non-Summer kWh	1.0238	0.9581	1.0000	$0.001218	$0.001218	$0.001218
(46)	POL	Summer kWh	1.0238	1.1180	1.0000	$0.001422	$0.001422	$0.001422
(47)		Non-Summer kWh	1.0238	0.9581	1.0000	$0.001218	$0.001218	$0.001218
(48)	TRF	Summer kWh	1.0238	1.1180	1.0000	$0.001422	$0.001422	$0.001422
(49)		Non-Summer kWh	1.0238	0.9581	1.0000	$0.001218	$0.001218	$0.001218

NOTES
(C) Source: Page 5 of Schedule 5a.
(D) Source: Page 7 of Schedule 5a.
(E) Source: Page 7 of Schedule 5a.
(F) Calculation: Aggregate Levelized Rate from Row 3 x Column C x Column D x Column E.
(G) Calculation: Aggregate Levelized Rate from Row 3 x Column C x Column D x Column E.
(H) Calculation: Aggregate Levelized Rate from Row 3 x Column C x Column D x Column E.

RIDER FTE

Fuel Transportation and Environmental Control Rider Explanation

RATE:

The Fuel Transportation Surcharge and Environmental Control Rider (FTE) is a charge per kWh calculated quarterly as follows:

FTE = $[[(TC + EC) / S_F - RE / S_F] / (1 - CAT)$

Where:

TC = the quarterly forecasted fuel transportation surcharge costs in excess of $30 million, $20 million, and $10 million annually for 2009, 1010, and 2011, respectively, at plants currently owned or controlled by FirstEnergy Solutions, or a subsidiary thereof, (collectively referred to as "FES") in MISO (including Ohio Valley Electric Corp. ("OVEC") arrangements and Fremont when placed in service, but excluding plants located in PJM - Beaver Valley and Seneca)

EC = the quarterly forecasted additional costs in excess of $50 million over the term of the Company's Electric Security Plan, of complying with new requirements for renewable resources other than those required by Am. Sub. S.B. 221, new taxes, and new environmental laws or new interpretations of existing environmental laws that take effect after January 1, 2008 at plants currently owned or controlled by FirstEnergy Solutions, or a subsidiary thereof, (collectively referred to as "FES") in MISO (including Ohio Valley Electric Corp. ("OVEC") arrangements and Fremont when placed in service, but excluding plants located in PJM - Beaver Valley and Seneca). It shall be assumed that: 100% of the FES generation used in support of the Company's Electric Security Plan ("ESP") is used to provide service under the ESP; taxes refers to any new tax on FES or the Companies arising out of any generation related item (to be construed in the broader sense); and that costs, refers to those of FES associated with the generation used to support the ESP.

RE = the over/(under) collection balance of actual recoverable fuel transportation surcharge and EC-related costs, including applicable interest, as of the end of the first month of each quarter immediately preceding the quarter during which the FTE will be charged

S_F = the applicable forecasted OE, CEI, and TE aggregate kWh sales for the quarter during which the FTE will be charged

CAT = Commercial Activity Tax Rate

RIDER UPDATES:

The charges contained in this Rider shall be updated and reconciled on a quarterly basis. No later than December 1st, March 1st, June 1st and September 1st of each year, the Company shall file with the PUCO a request for approval of the rider charges which, unless otherwise ordered by the PUCO, shall become effective on a service rendered basis on January 1st, April 1st, July 1st and October 1st of each year.

Case No. 08-XXXX-EL-SSO
Ohio Edison Company
The Cleveland Electric Illuminating Company
The Toledo Edison Company

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Witness: K. Warvell

Fuel Transportation Surcharge and
Environmental Control Rider

Illustrative Example

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(K)	(L)	(M)	(N)	(O)
		Jan-09	Feb-09	Mar-09	2009 Q1	Apr-09	May-09	Jun-09	2009 Q2	Jul-09	Aug-09	Sep-09	2009 Q2	Oct-09	Nov-09	Dec-09	2009 Q4
1	Transportation Surcharge Cost per MWH																
2	*Actual/Projected Fuel Transportation Surcharge Costs*	$3,000,000	$3,000,000	$3,000,000	$9,000,000	$3,000,000	$3,000,000	$3,000,000	$9,000,000	$3,600,000	$3,600,000	$3,600,000	$10,800,000	$3,600,000	$3,600,000	$4,000,000	$11,200,000
3	Annual Cumulative Includable Costs	$3,000,000	$6,000,000	$9,000,000		$12,000,000	$15,000,000	$18,000,000		$21,600,000	$25,200,000	$28,800,000		$32,400,000	$36,000,000	$40,000,000	
4	Annual Base				$30,000,000				$30,000,000				$30,000,000				$30,000,000
5	TC - Fuel Transportation Surcharge Costs in Excess of Base	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,400,000	$3,600,000	$4,000,000	$10,000,000
6																	
7	Projected Additional Environmental Control Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
8	Cumulative Includable Costs	$0	$0	$0		$0	$0	$0		$0	$0	$0		$0	$0	$0	
9	ESP Plan 3-Year Base				$50,000,000				$50,000,000				$50,000,000				$50,000,000
10	EC - Environmental Control Costs in Excess of $50 million	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
11																	
12	TC + EC - Total Projected Recoverable Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,400,000	$3,600,000	$4,000,000	$10,000,000
13	S_p - Forecasted Sales	4,500,000	4,900,000	5,200,000	14,600,000	5,100,000	4,500,000	4,600,000	14,200,000	4,500,000	4,900,000	5,100,000	14,500,000	4,800,000	4,800,000	4,400,000	14,000,000
14	(TC + EC) / S_p -- $/MWH Recoverable Cost				$0.0000				$0.0000				$0.0000				$0.7143
15	Reconciliation																
16	RE - Net Over/(Under) Collection				$0				$0				$0				[redacted]
17	S_p - Forecasted Sales				14,600,000				14,200,000				14,500,000				14,000,000
18	RE / S_p				$0.0000				$0.0000				$0.0000				$0.0000
19	CAT Gross-up																
20	CAT Rate				0.26%				0.26%				0.26%				0.26%
21	FTE - Fuel Trans Surch and Environmental Control Chg				$0.0000				$0.0000				$0.0000				$0.7161
22																	
23	SALES & REVENUE DATA	Jan-09	Feb-09	Mar-09		Apr-09	May-09	Jun-09		Jul-09	Aug-09	Sep-09		Oct-09	Nov-09	Dec-09	2009
24	Forecasted Mwh Sales (OE, CEI, & TE)	4,500,000	4,900,000	5,200,000		5,100,000	4,500,000	4,800,000		4,500,000	4,900,000	5,100,000		4,800,000	4,800,000	4,400,000	57,300,000
25	Actual Mwh Sales (OE, CEI, & TE)	4,725,000	5,145,000	5,460,000		5,355,000	4,725,000	4,370,000		4,275,000	4,655,000	4,845,000		4,560,000	4,560,000	4,180,000	56,855,000
26	FTE	$0.0000	$0.0000	$0.0000		$0.0000	$0.0000	$0.0000		$0.0000	$0.0000	$0.0000		$0.7161	$0.7161	$0.7161	
27	FTE Revenue	$0	$0	$0		$0	$0	$0		$0	$0	$0		$3,265,634	$3,265,634	$2,993,407	$9,524,764
28	CAT Rate	0.26%	0.26%	0.26%		0.26%	0.26%	0.26%		0.26%	0.26%	0.26%		0.26%	0.26%	0.26%	
29	CAT	$0	$0	$0		$0	$0	$0		$0	$0	$0		$8,491	$8,491	$7,783	$24,764
30	Fuel Trans Surcharge and Environmental Control Cost Recovery	$0	$0	$0		$0	$0	$0		$0	$0	$0		$3,257,143	$3,257,143	$2,985,714	$9,500,000
31																	
32	Actual Recoverable Costs Excluding Applicable Interest	$0	$0	$0		$0	$0	$0		$0	$0	$0		$2,280,000	$3,420,000	$3,800,000	$9,500,000
33	Applicable Interest	$0	$0	$0		$0	$0	$0		$0	$0	$0		$0	$3,461	$9,842	$13,303
34	Actual Recoverable Costs Including Applicable Interest	$0	$0	$0		$0	$0	$0		$0	$0	$0		$2,280,000	$3,416,539	$3,790,158	$9,486,697
35																	
33	Monthly Net Over/(Under) Recovery	$0	$0	$0		$0	$0	$0		$0	$0	$0		$977,143	($159,396)	($804,444)	$13,303
34	Balance Subject to Interest	$0	$0	$0		$0	$0	$0		$0	$0	$0		$488,571	$900,905	$425,387	
35	Interest Rate	0.70833%	0.70833%	0.70833%		0.70833%	0.70833%	0.70833%		0.70833%	0.70833%	0.70833%		0.70833%	0.70833%	0.70833%	
36	Monthly Interest	$0	$0	$0		$0	$0	$0		$0	$0	$0		$3,461	$6,381	$3,013	$12,855
37	Cumulative Interest	$0	$0	$0		$0	$0	$0		$0	$0	$0		$3,461	$9,842	$12,855	
38	Cumulative Over/(Under) Recovery Bal incl Interest	$0	$0	$0		$0	$0	$0		[redacted]	$0	$0		[illegible]	$827,559	$26,158	

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Witness: K. Warvell

Fuel Transportation Surcharge and
Environmental Control Rider
Illustrative Example

		(P)	(Q)	(R)	(S)	(T)	(U)	(V)	(W)	(X)	(Y)	(Z)	(AA)	(AB)	(AC	(AD)	(AE)
		Jan-10	Feb-10	Mar-10	2010 Q1	Apr-10	May-10	Jun-10	2010 Q2	Jul-10	Aug-10	Sep-10	2010 Q3	Oct-10	Nov-10	Dec-10	2010Q4
1	Transportation Surcharge Cost per MWH																
2	*Actual/Projected Fuel Transportation Surcharge Costs*	$2,500,000	$2,500,000	$2,500,000	$7,500,000	$2,500,000	$2,500,000	$2,500,000	$7,500,000	$2,500,000	$2,500,000	$2,500,000	$7,500,000	$2,500,000	$2,500,000	$2,500,000	$7,500,000
3	Annual Cumulative Includable Costs	$2,500,000	$5,000,000	$7,500,000		$10,000,000	$12,500,000	$15,000,000		$17,500,000	$20,000,000	$22,500,000		$25,000,000	$27,500,000	$30,000,000	
4	Annual Base				$20,000,000				$20,000,000				$20,000,000				$20,000,000
5	TC - Fuel Transportation Surcharge Costs in Excess of Base	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,500,000	$2,500,000	$2,500,000	$2,500,000	$2,500,000	$7,500,000
6																	
7	Projected Additional Environmental Control Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$3,500,000	$3,500,000	$7,000,000
8	Cumulative Includable Costs	$0	$0	$0		$0	$0	$0		$0	$0	$0		$0	$3,500,000	$7,000,000	
9	ESP Plan 3-Year Base				$50,000,000				$50,000,000				$50,000,000				$50,000,000
10	EC - Environmental Control Costs in Excess of $50 million	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
11																	
12	TC + EC - Total Projected Recoverable Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,500,000	$2,500,000	$2,500,000	$2,500,000	$2,500,000	$7,500,000
13	S_F - Forecasted Sales	4,500,000	4,900,000	5,200,000	14,600,000	5,100,000	4,500,000	4,800,000	14,200,000	4,500,000	4,900,000	5,100,000	14,500,000	4,800,000	4,800,000	4,400,000	14,000,000
14	$(TC + EC) / S_F$ -- $/MWH Recoverable Cost				$0.0000				$0.0000				$0.1724				$0.5357
15	Reconciliation																
16	RE - Net Over/(Under) Collection				[illegible]				[illegible]				[redacted]				[illegible]
17	S_F - Forecasted Sales				14,600,000				14,200,000				14,500,000				14,000,000
18	RE / S_F				$0.0672				($0.0197)				($0.0605)				$0.0183
19	CAT Gross-up																
20	CAT Rate				0.26%				0.26%				0.26%				0.26%
21	FTE - Fuel Trans Surch and Environmental Control Chg				($0.0673)				$0.0197				$0.2335				$0.5187
22																	
23	SALES & REVENUE DATA	Jan-10	Feb-10	Mar-10		Apr-10	May-10	Jun-10		Jul-10	Aug-10	Sep-10		Oct-10	Nov-10	Dec-10	2010
24	Forecasted Mwh Sales (OE, CEI, & TE)	4,500,000	4,900,000	5,200,000		5,100,000	4,500,000	4,800,000		4,500,000	4,900,000	5,100,000		4,800,000	4,800,000	4,400,000	57,300,000
25	Actual Mwh Sales (OE, CEI, & TE)	4,725,000	5,145,000	5,460,000		5,355,000	4,725,000	4,370,000		4,275,000	4,665,000	4,845,000		4,580,000	4,580,000	4,180,000	56,655,000
26	FTE	-$0.0673	-$0.0673	-$0.0673		$0.0197	$0.0197	$0.0197		$0.2335	$0.2335	$0.2335		$0.5187	$0.5187	$0.5187	
27	FTE Revenue	($318,180)	($346,463)	($367,675)		$105,577	$93,156	$86,157		$998,411	$1,087,159	$1,131,533		$2,365,348	$2,365,348	$2,168,296	$9,356,807
28	CAT Rate	0.26%	0.26%	0.26%		0.26%	0.26%	0.26%		0.26%	0.26%	0.26%		0.26%	0.26%	0.26%	
29	CAT	($827)	($901)	($956)		$274	$242	$224		$2,596	$2,827	$2,942		$6,150	$6,150	$5,637	$24,359
30	Fuel Trans Surcharge and Environmental Control Cost Recovery	($317,353)	($345,562)	($366,719)		$105,302	$92,914	$85,933		$995,815	$1,084,332	$1,128,591		$2,359,198	$2,359,198	$2,162,598	$9,344,249
31																	
32	Actual Recoverable Costs Excluding Applicable Interest	$0	$0	$0		$0	$0	$0		$0	$0	$2,625,000		$2,375,000	$2,375,000	$2,375,000	$9,750,000
33	*Applicable Interest*	$12,855	$11,962	$8,803		$3,172	($3,383)	($9,282)		($14,635)	($16,279)	($10,677)		($6,590)	($7,891)	($9,384)	($41,308)
34	Actual Recoverable Costs Including Applicable Interest	($12,855)	($11,962)	($8,803)		($3,172)	$3,383	$9,282		$14,635	$16,279	$2,635,677		$2,381,590	$2,382,891	$2,384,384	$9,791,308
35																	
33	Monthly Net Over/(Under) Recovery	($304,498)	($333,600)	($357,916)		$108,474	$89,531	$76,651		$981,181	$1,068,054	($1,507,086)		($22,391)	($23,693)	($221,786)	($447,059)
34	Balance Subject to Interest	($126,091)	($446,033)	($794,950)		($925,302)	($832,854)	($756,692)		($232,099)	$790,674	$576,961		($183,691)	($208,084)	($332,237)	
35	Interest Rate	0.70833%	0.70833%	0.70833%		0.70833%	0.70833%	0.70833%		0.70833%	0.70833%	0.70833%		0.70833%	0.70833%	0.70833%	
36	Monthly Interest	($893)	($3,159)	($5,631)		($6,554)	($5,899)	($5,353)		($1,644)	$5,602	$4,087		($1,301)	($1,474)	($2,353)	($24,673)
37	Cumulative Interest	$11,962	$8,803	$3,172		($3,383)	($9,282)	($14,635)		($16,279)	($10,677)	($6,590)		($7,891)	($9,384)	($11,718)	
38	*Cumulative Over/(Under) Recovery Bal Incl Interest*	[illegible]	($616,092)	($979,539)		[redacted]	($793,988)	($722,888)		[illegible]	$1,330,593	($172,496)		[illegible]	($221,354)	($445,474)	

Case No. 08-XXXX-EL-SSO
Ohio Edison Company
The Cleveland Electric Illuminating Company
The Toledo Edison Company

Witness: K. Warvell

Fuel Transportation Surcharge and
Environmental Control Rider
Illustrative Example

		(AF)	(AG)	(AH)	(AI)	(AJ)	(AK)	(AL)	(AM)	(AN)	(AO)	(AP)	(AR)	(AS)	(AT)	(AU)	(AV)
		Jan-11	Feb-11	Mar-11	2011 Q1	Apr-11	May-11	Jun-11	2011 Q2	Jul-11	Aug-11	Sep-11	2011 Q3	Oct-11	Nov-11	Dec-11	2011 Q4
1	Transportation Surcharge Cost per MWH																
2	Actual/Projected Fuel Transportation Surcharge Costs	$1,500,000	$1,500,000	$1,500,000	$4,500,000	$1,500,000	$1,500,000	$1,500,000	$4,500,000	$1,800,000	$1,800,000	$1,800,000	$5,400,000	$1,800,000	$1,800,000	$2,000,000	$5,600,000
3	Annual Cumulative Includable Costs	$1,500,000	$3,000,000	$4,500,000		$6,000,000	$7,500,000	$9,000,000		$10,800,000	$12,600,000	$14,400,000		$16,200,000	$18,000,000	$20,000,000	
4	Annual Base				$10,000,000				$10,000,000				$10,000,000				$10,000,000
5	TC - Fuel Transportation Surcharge Costs in Excess of Base	$0	$0	$0	$0	$0	$0	$0	$0	$800,000	$1,800,000	$1,800,000	$4,400,000	$1,800,000	$1,800,000	$2,000,000	$5,600,000
6																	
7	Projected Additional Environmental Control Costs	$3,500,000	$3,500,000	$3,500,000	$10,500,000	$3,500,000	$3,500,000	$3,500,000	$10,500,000	$5,000,000	$3,500,000	$5,000,000	$13,500,000	$5,000,000	$5,000,000	$5,000,000	$15,000,000
8	Cumulative Includable Costs	$10,500,000	$14,000,000	$17,500,000		$21,000,000	$24,500,000	$28,000,000		$33,000,000	$36,500,000	$41,500,000		$46,500,000	$51,500,000	$56,500,000	
9	ESP Plan 3-Year Base				$50,000,000				$50,000,000				$50,000,000				$50,000,000
10	EC - Environmental Control Costs in Excess of $50 million	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,500,000	$5,000,000	$6,500,000
11																	
12	TC + EC - Total Projected Recoverable Costs	$0	$0	$0	$0	$0	$0	$0	$0	$800,000	$1,800,000	$1,800,000	$4,400,000	$1,800,000	$3,300,000	$7,000,000	$12,100,000
13	S_F - Forecasted Sales	4,500,000	4,900,000	5,200,000	14,600,000	5,100,000	4,500,000	4,600,000	14,200,000	4,600,000	4,900,000	5,100,000	14,500,000	4,800,000	4,800,000	4,400,000	14,000,000
14	(TC + EC) / S_F —$/MWH Recoverable Cost				$0.0000				$0.0000				$0.3034				$0.8643
15	Reconciliation																
16	RE - Net Over/(Under) Collection				[illegible]				[redacted]				[illegible]				[illegible]
17	S_F - Forecasted Sales				14,600,000				14,200,000				14,500,000				14,000,000
18	RE / S_F				($0.0134)				($0.0279)				($0.0112)				$0.0381
19	CAT Gross-up																
20	CAT Rate				0.26%				0.26%				0.26%				0.26%
21	FTE - Fuel Trans Surch and Environmental Control Chg				$0.0135				$0.0280				$0.3155				$0.8284
22																	
23	SALES & REVENUE DATA	Jan-11	Feb-11	Mar-11		Apr-11	May-11	Jun-11		Jul-11	Aug-11	Sep-11		Oct-11	Nov-11	Dec-11	2011
24	Forecasted Mwh Sales (OE, CEI, & TE)	4,500,000	4,900,000	5,200,000		5,100,000	4,500,000	4,600,000		4,600,000	4,900,000	5,100,000		4,800,000	4,800,000	4,400,000	57,300,000
25	Actual Mwh Sales (OE, CEI, & TE)	4,725,000	5,145,000	5,460,000		5,355,000	4,725,000	4,370,000		4,275,000	4,655,000	4,845,000		4,560,000	4,560,000	4,180,000	56,855,000
26	FTE	$0.0135	$0.0135	$0.0135		$0.0280	$0.0280	$0.0280		$0.3155	$0.3155	$0.3155		$0.8284	$0.8284	$0.8284	
27	FTE Revenue	$63,858	$69,316	$73,560		$149,980	$132,335	$122,392		$1,348,683	$1,468,568	$1,528,507		$3,777,379	$3,777,379	$3,462,597	$15,974,351
28	CAT Rate	0.26%	0.26%	0.26%		0.26%	0.26%	0.26%		0.26%	0.26%	0.26%		0.26%	0.26%	0.26%	
29	CAT	$166	$180	$191		$390	$344	$318		$3,507	$3,818	$3,974		$9,821	$9,821	$9,003	$41,533
30	Fuel Trans Surcharge and Environmental Control Cost Recovery	$63,658	$69,136	$73,369		$149,590	$131,991	$122,074		$1,345,176	$1,464,747	$1,524,533		$3,767,557	$3,767,557	$3,453,594	$15,932,816
31																	
32	Actual Recoverable Costs Excluding Applicable Interest	$0	$0	$0		$0	$0	$0		$840,000	$1,890,000	$1,890,000		$1,710,000	$3,135,000	$8,850,000	$16,115,000
33	Applicable Interest	($11,718)	($14,690)	($17,307)		($19,551)	($21,152)	($21,911)		($21,928)	($19,879)	($17,881)		($16,400)	($13,260)	$1,333	($196,142)
34	Actual Recoverable Costs Including Applicable Interest	$11,718	$14,690	$17,307		$19,551	$21,152	$21,911		$861,928	$1,909,879	$1,907,881		$1,726,400	$3,148,260	$8,848,667	$16,311,142
35																	
33	Monthly Net Over/(Under) Recovery	$51,775	$54,446	$56,062		$130,039	$110,839	$100,163		$483,248	($445,132)	($383,148)		$2,039,157	$619,298	($3,195,073)	($378,324)
34	Balance Subject to Interest	($419,566)	($366,446)	($318,811)		($226,004)	($107,166)	($2,424)		$288,265	$310,372	($101,569)		$726,716	$2,060,084	$798,789	
35	Interest Rate	0.70833%	0.70833%	0.70833%		0.70833%	0.70833%	0.70833%		0.70833%	0.70833%	0.70833%		0.70833%	0.70833%	0.70833%	
36	Monthly Interest	($2,972)	($2,617)	($2,244)		($1,601)	($759)	($17)		$2,049	$2,198	($719)		$5,140	$14,592	$5,573	$18,624
37	Cumulative Interest	($14,690)	($17,307)	($19,551)		($21,152)	($21,911)	($21,928)		($19,879)	($17,881)	($18,400)		($13,260)	$1,333	$6,906	
38	Cumulative Over/(Under) Recovery Bal Incl Interest	[illegible]	($344,842)	($291,024)		[illegible]	($52,508)	$47,841		[illegible]	$90,004	($293,553)		[redacted]	$2,384,325	($805,174)	

RIDER FCA
Fuel Cost Adjustment Rider

RATE:

The Fuel Cost Adjustment Rider (FCA) is a charge per kWh calculated quarterly as follows:

$$FCA = [(C_{2011} - C_{2010} - EC) / S_F] \times (1 - CAT)$$

Where:

C_{2011} = 2011 forecasted cost of fuel for the quarter during which the FCA will be charged, excluding fuel transportation surcharge, emission allowance, fuel handling, disposal, lime, urea, and ammonia costs at plants currently owned or controlled by FirstEnergy Solutions, or a subsidiary thereof, (collectively referred to as "FES") in MISO (including Ohio Valley Electric Corp. ("OVEC") arrangements and Fremont when placed in service, but excluding plants located in PJM - Beaver Valley and Seneca). It shall be assumed that 100% of the FES generation used in support of the Company's Electric Security Plan ("ESP") is used to provide service under the ESP and that fuel costs refers to those of FES associated with the generation used to support the ESP.

C_{2010} = 2010 actual cost of fuel for the quarter during which the FCA will be charged, excluding fuel transportation surcharge, emission allowance, fuel handling, disposal, lime, urea, and ammonia costs at plants currently owned or controlled by FirstEnergy Solutions, or a subsidiary thereof, (collectively referred to as "FES") in MISO (including Ohio Valley Electric Corp. ("OVEC") arrangements and Fremont when placed in service, but excluding plants located in PJM - Beaver Valley and Seneca). It shall be assumed that 100% of the FES generation used in support of the Company's Electric Security Plan ("ESP") is used to provide service under the ESP and that fuel costs refers to those of FES associated with the generation used to support the ESP.

EC = the over/(under) collection balance of actual recoverable costs, including applicable interest, as of the end of the first month of each quarter immediately preceding the quarter during which the FCA will be charged.

S_F = the applicable forecasted OE, CEI, and TE aggregate kWh sales for the quarter during which the FCA will be charged

CAT = Commercial Activity Tax Rate

RIDER UPDATES:

The charges contained in this Rider shall be updated and reconciled on a quarterly basis. No later than December 1st, March 1st, June 1st and September 1st of each year, the Company shall file with the PUCO a request for approval of the rider charges which, unless otherwise ordered by the PUCO, shall become effective on a service rendered basis on January 1st, April 1st, July 1st and October 1st of each year.

Case No. 08-XXXX-EL-SSO
Ohio Edison Company
The Cleveland Electric Illuminating Company
The Toledo Edison Company

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Witness: K. Warvell

Fuel Cost Adjustment Rider
Illustrative Example

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
		Jan	Feb	Mar	Q1	Apr	May	Jun	Q2
1	**2011 Projected Fuel Costs**								
2	Projected Fossil Fuel Costs (Excl Fuel Trans Surcharge Costs)	$111,190,000	$108,171,000	$103,626,000	$322,987,000	$103,525,000	$109,989,000	$116,150,000	$329,664,000
3	OVEC	$6,565,000	$6,565,000	$6,565,000	$19,695,000	$6,565,000	$6,565,000	$6,565,000	$19,695,000
4	Nuclear Fuel Costs (Excl Disposal and Beaver Valley))	$7,979,000	$7,979,000	$3,434,000	$19,392,000	$8,383,000	$8,686,000	$8,484,000	$25,553,000
5	C_{2011} - **Total Projected Recoverable Fuel Costs**	$125,734,000	$122,715,000	$113,625,000	$362,074,000	$118,473,000	$125,240,000	$131,199,000	$374,912,000
6									
7	**2010 Base Costs (Actual Costs)**								
8	Fossil Fuel Costs (Excl Fuel Transportation Surcharge Costs)	$110,700,000	$107,100,000	$102,600,000	$320,400,000	$102,500,000	$108,900,000	$115,000,000	$326,400,000
9	OVEC	$6,500,000	$6,500,000	$6,500,000	$19,500,000	$6,500,000	$6,500,000	$6,500,000	$19,500,000
10	Nuclear Fuel Costs (Excl Disposal and Beaver Valley)	$7,900,000	$7,900,000	$3,400,000	$19,200,000	$8,300,000	$8,600,000	$8,400,000	$25,300,000
11	C_{2010} - **Total Base Fuel Costs**	$125,100,000	$121,500,000	$112,500,000	$359,100,000	$117,300,000	$124,000,000	$129,900,000	$371,200,000
12									
13	**Total Projected Recoverable Costs**	$634,000	$1,215,000	$1,125,000	$2,974,000	$1,173,000	$1,240,000	$1,299,000	$3,712,000
14	S_F **- Forecasted Sales**	4,500,000	4,900,000	5,200,000	14,600,000	5,100,000	4,500,000	4,600,000	14,200,000
15	**$(C_{2011} - C_{2010}) / S_F$ _ $/MWH Recoverable Cost**				$0.2037				$0.2614
16	**Reconciliation**								
17	Net Over/(Under) Collection				$0				($37,657)
18	Forecasted Sales				14,600,000				14,200,000
19	**EC Reconciliation Factor**				$0.0000				($0.0027)
20	**CAT Gross-up**								
21	CAT Rate				0.26%				0.26%
22	FCA				$0.2042				$0.2647
23									
24	**SALES & REVENUE DATA**	Jan-11	Feb-11	Mar-11		Apr-11	May-11	Jun-11	
25	Forecasted Mwh Sales (OE, CEI, & TE)	4,500,000	4,900,000	5,200,000		5,100,000	4,500,000	4,600,000	
26	Actual Mwh Sales (OE, CEI, & TE)	4,725,000	5,145,000	5,460,000		5,355,000	4,725,000	4,370,000	
27	FCA --$/MWH Recoverable Cost	$0.2042	$0.2042	$0.2042		$0.2647	$0.2647	$0.2647	
28	FCA Revenue	$964,985	$1,050,761	$1,115,094		$1,417,729	$1,250,938	$1,156,952	
29	CAT Rate	0.26%	0.26%	0.26%		0.26%	0.26%	0.26%	
30	CAT	$2,509	$2,732	$2,899		$3,686	$3,252	$3,008	
31	Fuel Cost Recovery	$962,476	$1,048,029	$1,112,195		$1,414,043	$1,247,685	$1,153,944	
32									
33	Actual Recoverable Costs Excluding Applicable Interest	$1,000,000	$1,200,000	$1,200,000		$1,200,000	$1,200,000	$1,500,000	
34	Applicable Interest	$0	($133)	($938)		($2,602)	($3,844)	($4,190)	
35	Actual Recoverable Costs Including Applicable Interest	$1,000,000	$1,200,133	$1,200,938		$1,202,602	$1,203,844	$1,504,190	
36									
37	Monthly Net Over/(Under) Recovery	($37,524)	($152,103)	($88,744)		$211,441	$43,841	($350,246)	
38	Balance Subject to Interest	($18,762)	($113,709)	($234,938)		($175,253)	($48,854)	($202,402)	
39	Interest Rate	0.70833%	0.70833%	0.70833%		0.70833%	0.70833%	0.70833%	
40	Monthly Interest	($133)	($805)	($1,664)		($1,241)	($346)	($1,434)	
41	Cumulative Interest	($133)	($938)	($2,602)		($3,844)	($4,190)	($5,624)	
42	Cumulative Over/(Under) Recovery Bal Incl Interest	($37,657)	($190,566)	($280,974)		($70,774)	($27,279)	($378,959)	

Case No. 08-XXXX-EL-SSO
Ohio Edison Company
The Cleveland Electric Illuminating Company
The Toledo Edison Company

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Witness: K. Warvell

Fuel Cost Adjustment Rider
Illustrative Example

		(I)	(J)	(K)	(K)	(L)	(M)	(N)	(O)
		Jul	Aug	Sep	Q3	Oct	Nov	Dec	Q4
1	**2011 Projected Fuel Costs**								
2	Projected Fossil Fuel Costs (Excl Fuel Trans Surcharge Costs)	$131,906,000	$130,997,000	$106,555,000	$369,458,000	$95,748,000	$95,546,000	$108,878,000	$300,172,000
3	OVEC	$6,565,000	$6,565,000	$6,565,000	$19,695,000	$6,565,000	$6,565,000	$6,565,000	$19,695,000
4	Nuclear Fuel Costs (Excl Disposal and Beaver Valley))	$9,090,000	$87,870,000	$8,383,000	$105,343,000	$8,181,000	$8,585,000	$8,585,000	$25,351,000
5	**C_{2011} - Total Projected Recoverable Fuel Costs**	$147,561,000	$225,432,000	$121,503,000	$494,496,000	$110,494,000	$110,696,000	$124,028,000	$345,218,000
6									
7	**2010 Base Costs (Actual Costs)**								
8	Fossil Fuel Costs (Excl Fuel Transportation Surcharge Costs)	$130,600,000	$129,700,000	$105,500,000	$365,800,000	$94,800,000	$94,600,000	$107,800,000	$297,200,000
9	OVEC	$6,500,000	$6,500,000	$6,500,000	$19,500,000	$6,500,000	$6,500,000	$6,500,000	$19,500,000
10	Nuclear Fuel Costs (Excl Disposal and Beaver Valley)	$9,000,000	$87,000,000	$8,300,000	$104,300,000	$8,100,000	$8,500,000	$8,500,000	$25,100,000
11	**C_{2010} - Total Base Fuel Costs**	$146,100,000	$223,200,000	$120,300,000	$489,600,000	$109,400,000	$109,600,000	$122,800,000	$341,800,000
12									
13	**Total Projected Recoverable Costs**	$1,461,000	$2,232,000	$1,203,000	$4,896,000	$1,094,000	$1,096,000	$1,228,000	$3,418,000
14	**S_F - Forecasted Sales**	4,500,000	4,900,000	5,100,000	14,500,000	4,800,000	4,800,000	4,400,000	14,000,000
15	**(C_{2011} - C_{2010}) / S_F , $/MWH Recoverable Cost**				$0.3377				$0.2441
16	**Reconciliation**								
17	Net Over/(Under) Collection				($70,774)				($423,071)
18	Forecasted Sales				14,500,000				14,000,000
19	**EC Reconciliation Factor**				($0.0049)				($0.0302)
20	**CAT Gross-up**								
21	CAT Rate				0.26%				0.26%
22	FCA				$0.3434				$0.2751
23									
24	**SALES & REVENUE DATA**	Jul-11	Aug-11	Sep-11		Oct-11	Nov-11	Dec-11	2011
25	Forecasted Mwh Sales (OE, CEI, & TE)	4,500,000	4,900,000	5,100,000		4,800,000	4,800,000	4,400,000	57,300,000
26	Actual Mwh Sales (OE, CEI, & TE)	4,276,000	4,655,000	4,845,000		4,560,000	4,560,000	4,180,000	56,855,000
27	FCA --$/MWH Recoverable Cost	$0.3434	$0.3434	$0.3434		$0.2751	$0.2751	$0.2751	
28	FCA Revenue	$1,468,159	$1,598,662	$1,663,914		$1,254,353	$1,254,353	$1,149,824	$15,345,724
29	CAT Rate	0.26%	0.26%	0.26%		0.26%	0.26%	0.26%	
30	CAT	$3,817	$4,157	$4,326		$3,261	$3,261	$2,990	$39,899
31	Fuel Cost Recovery	$1,464,342	$1,594,506	$1,659,588		$1,251,092	$1,251,092	$1,146,834	$15,305,825
32									
33	Actual Recoverable Costs Excluding Applicable Interest	$1,500,000	$1,500,000	$1,500,000		$1,200,000	$1,200,000	$1,200,000	$15,400,000
34	Applicable Interest	($5,624)	($8,454)	($11,146)		($13,027)	($14,260)	($15,237)	($79,455)
35	Actual Recoverable Costs Including Applicable Interest	$1,505,624	$1,508,454	$1,511,146		$1,213,027	$1,214,260	$1,215,237	$15,479,455
36									
37	Monthly Net Over/(Under) Recovery	($41,281)	$86,052	$148,442		$38,065	$36,832	($68,403)	($173,629)
38	Balance Subject to Interest	($399,600)	($380,045)	($265,490)		($174,118)	($137,903)	($154,665)	
39	Interest Rate	0.70833%	0.70833%	0.70833%		0.70833%	0.70833%	0.70833%	
40	Monthly Interest	($2,830)	($2,692)	($1,881)		($1,233)	($977)	($1,096)	($16,332)
41	Cumulative Interest	($8,454)	($11,146)	($13,027)		($14,260)	($15,237)	($16,332)	
42	Cumulative Over/(Under) Recovery Bal Incl Interest	($423,071)	($339,711)	($193,150)		($156,318)	($120,463)	($189,962)	

Calculation of 2009 Rider NDU Charge

	OE	CEI	TE	TOTAL
Total Company Unadjusted Revenues				
Retail Electric Sales				
(1) Generation	$1,143,159,374	$769,211,559	$367,655,907	$2,280,026,840
(2) Transition	$260,260,722	$404,875,930	$190,750,896	$855,887,548
(3) Transmission	$137,011,887	$92,740,063	$48,407,552	$278,159,502
(4) Distribution	$486,620,488	$421,856,480	$145,755,556	$1,054,232,523
(5) Other	$34,187,226	$10,697,692	$10,944,916	$55,829,834
(6) Subtotal - Retail Electric Sales	$2,061,239,696	$1,699,381,724	$763,514,826	$4,524,136,247
(7) Other Operating Revenues	$41,266,559	$31,407,055	$16,099,732	$88,773,346
(8) Total Company Unadjusted Revenues	$2,102,506,255	$1,730,788,780	$779,614,559	$4,612,909,594
Uncollectible Percentage				
(9) Revenue Associated with Uncollectible Expense	$2,102,506,255	$1,730,788,780	$779,614,559	$4,612,909,594
(10) Total Company Provision for Uncollectible Expense	$15,634,832	$10,276,431	$6,172,169	$32,083,432
(11) Total Company Uncollectible Expense Percentage	0.7436%	0.5937%	0.7917%	0.6955%
Customer Deposits Percentage				
(12) Customer Deposits Balance	($11,320,834)	($8,382,539)	($4,090,431)	($23,793,804)
(13) Tax Adjusted Weighted Average Cost of Capital	12.54%	12.57%	12.60%	
(14) Required Return on Customer Deposits Balance	($1,419,633)	($1,053,685)	($515,394)	($2,988,712)
(15) Total Interest Expense on Customer Deposits	$339,625	$251,476	$204,522	$795,623
(16) Net Required Return on Customer Deposits Balance	($1,080,008)	($802,209)	($310,872)	($2,193,089)
(17) Revenue Associated with Customer Deposits	$2,061,239,696	$1,699,381,724	$763,514,826	$4,524,136,247
(18) Customer Deposits Percentage	-0.0524%	-0.0472%	-0.0407%	-0.0485%
Rider NDU Charge Calculation				
(19) Uncollectible / Customer Deposits Percentage	0.6912%	0.5465%	0.7510%	0.6470%
Staff Adjusted Jurisdictional Distribution Revenue				
(20) Retail Electric Sales - Distribution	$487,733,318	$421,187,154	$146,976,810	$1,055,897,282
(21) Other Operating Revenues	$20,360,049	$14,781,812	$9,953,221	$45,095,082
(22) Total Staff Adjusted Jurisdictional Distribution Revenue	$508,093,367	$435,968,966	$156,930,031	$1,100,992,364
(23) Staff Adjusted Non-Distribution Revenue	$1,594,412,888	$1,294,819,814	$622,684,528	$3,511,917,229
(24) Uncollectible Expense Associated with Non-Distribution Revenue	$11,021,097	$7,076,866	$4,676,230	$22,773,992
(25) Prior Period Reconciliation	$0	$0	$0	$0
(26) CAT Tax Rate	0.26%	0.26%	0.26%	0.26%
(27) Applicable Total Company Annual MWh Sales	26,018,268	19,793,471	10,659,470	56,471,209
(28) Non-Distribution Uncollectible Charge (cents per kWh)	0.0425	0.0358	0.0440	0.0404

NOTES

(1)-(8) Source: Company Schedule C-2.1 from the Companies' Update Filing in Case No. 07-551-EL-AIR
(9) Line 8. (Note - this amount excludes Sales for Resale revenues).
(10) Source: Company Schedule C-2.1 from the Update Filing in Case No. 07-551-EL-AIR
(11) Calculation: Line 10 / Line 9.
(12) Source: Schedule B-6 from the PUCO Staff Report in Case No. 07-551-EL-AIR.
(13) Source: Rebuttal Exhibit WRR-2 from Case No. 07-551-EL-AIR.
(14) Calculation: Line 12 x Line 13.
(15) Source: Staff Schedule C-3.16 from Case No. 07-551-EL-AIR
(16) Calculation: Line 14 + Line 15.
(17) Line 6.
(18) Calculation: Line 16 / Line 17.
(19) Calculation: Line 11 + Line 18.
(20)-(22) Source: Revised Staff Report in Case No. 07-551-EL-AIR.
(23) Calculation: Line 9 - Line 22.
(24) Calculation: Line 19 x Line 23.
(25) There is no prior period reconciliation in the establishment of the initial NDU charge in 2009.
(26) Expected Commercial Activity Tax rate to be in effect in 2009.
(27) Source: Company forecast.
(28) Calculation: (Line 24 + Line 25) / (1 - Line 26) / Line 27 / 10.

Rider PUR Calculation / Reconciliation

The Rider PUR charge for period i (PUR $Charge_i$) will be calculated as follows:

$$\text{PUR Charge}_i = \frac{(PUE_i + RA_{i-1})}{S_i} \times \frac{1}{(1\text{-}CAT_i)} \times \frac{1}{1{,}000}\text{, where}$$

i = The period that the PUR charge being calculated will be in effect
i-1 = The period that the prior PUR charge was in effect

PUE_i = Forecasted PIPP Uncollectible Expense for period i

RA_{i-1} = Reconciliation Adjustment for period i-1
= $Rev_{i-1} \times (1 - CAT_{i-1}) - PUE_{i-1}$, where

Rev_{i-1} = Actual Rider PUR revenue earned during the period i-1
CAT_{i-1} = Actual Commercial Activity Tax Rate in effect for period i-1
PUE_{i-1} = Actual PIPP Uncollectible Expense incurred during the period i-1

S_i = Forecasted annual MWh sales for customers taking service under Rate Schedule RS for period i

CAT_i = Expected Commercial Activity Tax Rate to be in effect for period i

Case No. 08-XXXX-EL-SSO
Ohio Edison Company
The Cleveland Electric Illumnating Company
The Toledo Edison Company

Witness: G. Hussing

Illustrative Example of Rider PUR Charge Calculation *

	($ in thousands) OE	CEI	TE	TOTAL
(1) **Forecasted PIPP Uncollectible Expense (PUE_i)**	$1,500	$1,000	$750	$3,250
(2) Actual Rider PUR Revenue (Rev_{i-1})	$1,350	$1,150	$800	$3,300
(3) Actual CAT Rate (CAT_{i-1})	0.26%	0.26%	0.26%	0.26%
(4) Actual PIPP Uncollectible Expense (PUE_{i-1})	$1,300	$1,200	$850	$3,350
(5) **Reconciliation Adjustment (RA_{i-1}) (Ln 2 x (1 - Ln 3) - Ln 4)**	$46	($53)	($52)	($59)
(6) **Forecasted MWH Sales for RS Customers (S_i)**	12,500,000	7,500,000	2,500,000	22,500,000
(7) **Expected CAT Rate (CAT_i)**	0.26%	0.26%	0.26%	0.26%
(8) **Rider PUR $Charge_i$ ((Ln 1 + Ln 5) / Ln 6) x (1 / Ln 7)**	**$0.00012**	**$0.00013**	**$0.00028**	**$0.00014**

* All values are illustrative and are intended to demonstrate the mechanics of the Rider PUR charge calculation, including the reconciliation of the prior Rider PUR charge

Case No. 08-XXXX-EL-SSO
The Cleveland Electric Illuminating Company

Workpaper for Schedule 2 - Target Revenue for Base Distribution Rates

Witness: G. Hussing

			PROPOSED ANNUALIZED					
LINE NO.	RATE CODE (A)	CLASS/ DESCRIPTION (B)	CUSTOMER BILLS (C)	SALES (D1) (KWH)	BILLING UNITS (D2)	PROPOSED RATES (E) ($/kWh)	PROPOSED REVENUE LESS FUEL COST REVENUE (F) ($)	% OF REV TO TOTAL LESS FUEL COST REVENUE (G) (%)
1	RS	RESIDENTIAL SERVICE	8,085,501	5,603,870,615		$0.03856	$216,110,160	45.34
2								
3	GS	GENERAL SERVICE - SECONDARY	944,672	6,926,750,480		$0.02571	$178,074,521	37.36
4								
5	GP	GENERAL SERVICE - PRIMARY	617	283,426,278		$0.00932	$2,640,367	0.55
6								
7	GSU	GENERAL SERVICE - SUBTRANSMISSION	6,772	2,209,497,653		$0.00774	$17,104,314	3.59
8								
9	GT	GENERAL SERVICE - TRANSMISSION	72	195,678,174		$0.00435	$851,306	0.18
10								
11	SPC - GS	SPECIAL CONTRACT - GENERAL SERVICE - SECONDARY	902	178,634,978		$0.02159	$3,855,875	0.81
12								
13	SPC - GP	SPECIAL CONTRACT - GENERAL SERVICE - PRIMARY	73	40,764,497		$0.00858	$349,798	0.07
14								
15	SPC - GSU	SPECIAL CONTRACT - GENERAL SERVICE - SUBTRANSMISSION	625	864,421,072		$0.00459	$3,968,275	0.83
16								
17	SPC - GT	SPECIAL CONTRACT - GENERAL SERVICE - TRANSMISSION	0	0		$0.00000	$0	0.00
18								
19	SPC - U	SPECIAL CONTRACT - GENERAL SERVICE - UNIQUE						
20		GS - SECONDARY	5,466	298,638,943		$0.01363	$4,071,453	0.85
21		GP - PRIMARY	36	176,240,292		$0.00186	$328,353	0.07
22		GSU - SUBTRANSMISSION	288	829,708,431		$0.00466	$3,870,387	0.81
23		GT - TRANSMISSION	96	1,964,760,819		($0.00032)	($620,768)	(0.13)
24			5,886	3,269,348,484		$0.00234	$7,649,425	
25								
26	POL	PRIVATE OUTDOOR LIGHTING SERVICE	38,124	64,292,625		$0.12672	$8,147,021	1.71
27								
28	STL	STREET LIGHTING SERVICE	123,603	127,959,342		$0.12561	$16,073,519	3.37
29								
30	TRF	TRAFFIC LIGHTING SERVICE	46,042	28,827,210		$0.00474	$136,766	0.03
31								
32	MISCELLANEOUS CHARGES						$21,641,693	4.54
33								
34	TOTAL COMPANY		9,252,889	19,793,471,409		$0.02408	$476,603,038	100.00

Case No. 08-XXXX-EL-SSO
The Cleveland Electric Illuminating Company

Workpaper for Schedule 2 - Target Revenue for Base Distribution Rates

Witness: G. Hussing

			PROPOSED ANNUALIZED					
LINE NO.	RATE CODE	CLASS/ DESCRIPTION	CUSTOMER BILLS	SALES	BILLING UNITS	PROPOSED RATES	PROPOSED REVENUE LESS FUEL COST REVENUE	% OF REV TO TOTAL LESS FUEL COST REVENUE
	(A)	(B)	(C)	(D1)	(D2)	(E)	(F)	(G)
				(KWH)		($)	($)	(%)
	RS	RESIDENTIAL SERVICE						
1	PROPOSED							
2								
3	RS	RESIDENTIAL SERVICE						
4								
5		DISTRIBUTION CHARGES						
6								
7		CUSTOMER CHARGE						
8		BILLS	8,085,501			$4.00	$32,342,005	14.97
9								
10		ENERGY CHARGE						
11		UP TO 500 kWh, PER kWh		3,250,483,895		$0.02956	$96,084,304	44.46
12		OVER 500 kWh, PER kWh		2,353,386,720		$0.02956	$69,566,111	32.19
13								
14		CUSTOMER DISCOUNT						
15		ALL kWh, PER kWh		560,499,750		($0.01700)	($9,528,496)	(4.41)
16								
17		RIDER DSM - DEMAND SIDE MANAGEMENT						
18		ALL kWh, PER kWh		5,603,870,615		$0.00030	$1,681,161	0.78
19								
20		STATE kWh TAX						
21		FIRST 2,000 kWh, PER kWh		5,317,103,401		$0.00466	$24,763,101	11.46
22		NEXT 13,000 kWh, PER kWh		284,169,796		$0.00420	$1,192,529	0.55
23		ABOVE 15,000 kWh, PER kWh		2,597,513		$0.00364	$9,444	0.00
24				5,603,870,711			$25,965,074	
25								
26		TOTAL DISTRIBUTION - RS	8,085,501	5,603,870,615			$216,110,160	100.00

Workpaper for Schedule 2 - Target Revenue for Base Distribution Rates

Witness: G. Hussing

			PROPOSED ANNUALIZED					
LINE NO.	RATE CODE	CLASS/ DESCRIPTION	CUSTOMER BILLS	KWH SALES	BILLING UNITS	PROPOSED RATES	PROPOSED REVENUE LESS FUEL COST REVENUE	% OF REV TO TOTAL LESS FUEL COST REVENUE
	(A)	(B)	(C)	(D1)	(D2)	(E)	(F)	(G)
				(KWH)		($)	($)	(%)
		GENERAL SERVICE						
1	PROPOSED							
2								
3	GS	GENERAL SERVICE - SECONDARY						
4								
5		CUSTOMER CHARGE						
6		BILLS	944,672	6,926,750,480		$7.00	$6,612,704	3.08
7								
8		CAPACITY CHARGE						
9		UP TO 5 kW OF BILLING DEMAND			4,723,360	$14.73	$13,915,019	6.49
10		OVER 5 kW, PER kW			18,045,296	$7.53000	$135,881,079	63.35
11								
12		REACTIVE DEMAND CHARGE						
13		ALL rkVa, PER rkVa			10,331,872	$0.36000	$3,719,474	1.73
14								
15		CUSTOMER DISCOUNT						
16		ALL kWh, PER kWh		609,981,761		($0.01500)	($9,149,726)	(4.27)
17								
18		STATE kWh TAX						
19		FIRST 2,000 kWh, PER kWh		1,043,872,438		$0.00466	$4,861,579	2.27
20		NEXT 13,000 kWh, PER kWh		1,916,113,432		$0.00420	$8,041,040	3.75
21		ABOVE 15,000 kWh, PER kWh		3,903,924,465		$0.00364	$14,193,353	6.62
22				6,863,910,335			$27,095,972	
23								
24		TOTAL DISTRIBUTION - GS	944,672	6,926,750,480			$178,074,521	83.02

Workpaper for Schedule 2 - Target Revenue for Base Distribution Rates

Witness: G. Hussing

			PROPOSED ANNUALIZED					
LINE NO.	RATE CODE	CLASS/ DESCRIPTION	CUSTOMER BILLS	KWH SALES	BILLING UNITS	PROPOSED RATES	PROPOSED REVENUE LESS FUEL COST REVENUE	% OF REV TO TOTAL LESS FUEL COST REVENUE
	(A)	(B)	(C)	(D1)	(D2)	(E)	(F)	(G)
				(KWH)		($)	($)	(%)
25	GP	GENERAL SERVICE - PRIMARY						
26								
27		CUSTOMER CHARGE						
28		BILLS	617	283,426,278		$150.00	$92,588	0.04
29								
30		CAPACITY CHARGE						
31		ALL kW OF BILLING DEMAND, PER kW			652,800	$2.45000	$1,599,360	0.75
32								
33		REACTIVE DEMAND CHARGE						
34		ALL rkVa, PER rkVa			355,548	$0.36000	$127,997	0.06
35								
36		CUSTOMER DISCOUNT						
37		ALL kWh, PER kWh		42,841,969		($0.00500)	($214,210)	(0.10)
38								
39		STATE kWh TAX						
40		FIRST 2,000 kWh, PER kWh		1,144,297		$0.00466	$5,329	0.00
41		NEXT 13,000 kWh, PER kWh		7,169,217		$0.00420	$30,086	0.01
42		ABOVE 15,000 kWh, PER kWh		274,837,715		$0.00364	$999,217	0.47
43				283,151,229			$1,034,632	
44								
45		TOTAL DISTRIBUTION - GP	617	283,426,278			$2,640,367	1.23
46								
47								
48	GSU	GENERAL SERVICE - SUBTRANSMISSION						
49								
50		CUSTOMER CHARGE						
51		BILLS	6,772	2,209,497,653		$180.00	$1,218,924	0.57
52								
53		CAPACITY CHARGE						
54		ALL kW OF BILLING DEMAND, PER kW			5,073,561	$1.00700	$5,109,076	2.38
55								
56		REACTIVE DEMAND CHARGE						
57		ALL rkVa, PER rkVa			2,521,902	$0.36000	$907,885	0.42
58								
59		TRANSFORMER CHARGE						
60		ALL kW OF BILLING DEMAND, PER kW			4,052,749	$0.57000	$2,310,067	1.08
61								
62		CUSTOMER DISCOUNT						
63		ALL kWh, PER kWh		-		$0.00000	$0	0.00
64								
65		STATE kWh TAX						
66		FIRST 2,000 kWh, PER kWh		10,849,745		$0.00466	$50,530	0.02
67		NEXT 13,000 kWh, PER kWh		60,533,691		$0.00420	$254,032	0.12
68		ABOVE 15,000 kWh, PER kWh		1,995,179,668		$0.00364	$7,253,800	3.38
69				2,066,563,104			$7,558,362	
70								
71		TOTAL DISTRIBUTION - GSU	6,772	2,209,497,653			$17,104,314	7.97

Case No. 08-XXXX-EL-SSO
The Cleveland Electric Illuminating Company

Schedule 5h
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Workpaper for Schedule 2 - Target Revenue for Base Distribution Rates

Witness: G. Hussing

LINE NO.	RATE CODE (A)	CLASS/ DESCRIPTION (B)	PROPOSED ANNUALIZED CUSTOMER BILLS (C)	KWH SALES (D1) (KWH)	BILLING UNITS (D2)	PROPOSED RATES (E) ($)	PROPOSED REVENUE LESS FUEL COST REVENUE (F) ($)	% OF REV TO TOTAL LESS FUEL COST REVENUE (G) (%)
72	GT	GENERAL SERVICE - TRANSMISSION						
73								
74		CUSTOMER CHARGE						
75		BILLS	72	195,678,174		$320.00	$23,040	0.01
76								
77		CAPACITY CHARGE						
78		ALL kVa OF BILLING DEMAND, PER kVa			451,533	$0.00100	$452	0.00
79								
80		REACTIVE DEMAND CHARGE						
81		ALL rkVa, PER rkVa			-	$0.00000	$0	0.00
82								
83		TRANSFORMER CHARGE						
84		ALL kVa OF BILLING DEMAND, PER kVa			373,293	$0.31000	$115,721	0.05
85								
86		CUSTOMER DISCOUNT						
87		ALL kWh, PER kWh		-		$0.00000	$0	0.00
88								
89		STATE kWh TAX						
90		FIRST 2,000 kWh, PER kWh		144,317		$0.00466	$672	0.00
91		NEXT 13,000 kWh, PER kWh		938,060		$0.00420	$3,937	0.00
92		ABOVE 15,000 kWh, PER kWh		194,595,797		$0.00364	$707,485	0.33
93				195,678,174			$712,093	
94								
95		TOTAL DISTRIBUTION - GT	72	195,678,174			$851,306	0.40
96								
97								
98	SPC - GS	SPECIAL CONTRACT - GENERAL SERVICE - SECONDARY						
99								
100		CUSTOMER CHARGE						
101		BILLS	902	178,634,978		$7.00	$6,314	0.00
102								
103		CAPACITY CHARGE						
104		UP TO 5 kW OF BILLING DEMAND			4,510	$14.73	$13,286	0.01
105		OVER 5 kW, PER kW			461,693	$7.53000	$3,476,548	1.62
106								
107		REACTIVE DEMAND CHARGE						
108		ALL rkVa, PER rkVa			241,644	$0.36000	$86,992	0.04
109								
110		CUSTOMER DISCOUNT						
111		ALL kWh, PER kWh		211,914		($0.01500)	($3,179)	(0.00)
112								
113		CONTRACT DISCOUNT					($382,574)	(0.18)
114								
115		STATE kWh TAX						
116		FIRST 2,000 kWh, PER kWh		2,018,229		$0.00466	$9,399	0.00
117		NEXT 13,000 kWh, PER kWh		12,424,331		$0.00420	$52,139	0.02
118		ABOVE 15,000 kWh, PER kWh		164,192,418		$0.00364	$596,948	0.28
119				178,634,978			$658,487	
120								
121		TOTAL DISTRIBUTION - SPC-GS	902	178,634,978			$3,855,875	1.80

Workpaper for Schedule 2 - Target Revenue for Base Distribution Rates

Witness: G. Hussing

LINE NO.	RATE CODE	CLASS/ DESCRIPTION	CUSTOMER BILLS	KWH SALES	BILLING UNITS	PROPOSED RATES	PROPOSED REVENUE LESS FUEL COST REVENUE	% OF REV TO TOTAL LESS FUEL COST REVENUE
			PROPOSED ANNUALIZED					
	(A)	(B)	(C)	(D1)	(D2)	(E)	(F)	(G)
				(KWH)		($)	($)	(%)
122	SPC - GP	SPECIAL CONTRACT - GENERAL SERVICE - PRIMARY						
123								
124		CUSTOMER CHARGE						
125		BILLS	73	40,764,497		$150.00	$10,950	0.01
126								
127		CAPACITY CHARGE						
128		ALL kW OF BILLING DEMAND, PER kW			89,355	$2.45000	$218,921	0.10
129								
130		REACTIVE DEMAND CHARGE						
131		ALL rkVa, PER rkVa			46,715	$0.36000	$16,817	0.01
132								
133		CUSTOMER DISCOUNT						
134		ALL kWh, PER kWh		-		($0.08500)	$0	0.00
135								
136		CONTRACT DISCOUNT					($45,773)	(0.02)
137								
138		STATE kWh TAX						
139		FIRST 2,000 kWh, PER kWh		144,965		$0.00466	$675	0.00
140		NEXT 13,000 kWh, PER kWh		942,270		$0.00420	$3,954	0.00
141		ABOVE 15,000 kWh, PER kWh		39,677,262		$0.00364	$144,253	0.07
142				40,764,497			$148,883	
143								
144		TOTAL DISTRIBUTION - SPC-GP	73	40,764,497			$349,798	0.16
145								
146								
147	SPC - GSU	SPECIAL CONTRACT - GENERAL SERVICE - SUBTRANSMISSION						
148								
149		CUSTOMER CHARGE						
150		BILLS	625	864,421,072		$180.00	$112,410	0.05
151								
152		CAPACITY CHARGE						
153		ALL kW OF BILLING DEMAND, PER kW			1,858,725	$1.00700	$1,871,736	0.87
154								
155		REACTIVE DEMAND CHARGE						
156		ALL rkVa, PER rkVa			616,951	$0.36000	$222,102	0.10
157								
158		TRANSFORMER CHARGE						
159		ALL kW OF BILLING DEMAND, PER kW			1,712,375	$0.57000	$976,054	0.46
160								
161		CUSTOMER DISCOUNT						
162		ALL kWh, PER kWh		-		$0.00000	$0	0.00
163								
164		CONTRACT DISCOUNT					($824,753)	(0.38)
165								
166		STATE kWh TAX						
167		FIRST 2,000 kWh, PER kWh		1,032,965		$0.00466	$4,811	0.00
168		NEXT 13,000 kWh, PER kWh		6,616,636		$0.00420	$27,767	0.01
169		ABOVE 15,000 kWh, PER kWh		434,074,299		$0.00364	$1,578,148	0.74
170				441,723,901			$1,610,726	
171								
172		TOTAL DISTRIBUTION - SPC-GSU	625	864,421,072			$3,968,275	1.85

Case No. 08-XXXX-EL-SSO
The Cleveland Electric Illuminating Company

Workpaper for Schedule 2 - Target Revenue for Base Distribution Rates

Witness: G. Hussing

			PROPOSED ANNUALIZED					
LINE NO.	RATE CODE	CLASS/DESCRIPTION	CUSTOMER BILLS	KWH SALES	BILLING UNITS	PROPOSED RATES	PROPOSED REVENUE LESS FUEL COST REVENUE	% OF REV TO TOTAL LESS FUEL COST REVENUE
	(A)	(B)	(C)	(D1)	(D2)	(E)	(F)	(G)
				(KWH)		($)	($)	(%)
173	SPC - GT	SPECIAL CONTRACT - GENERAL SERVICE - TRANSMISSION						
174								
175		CUSTOMER CHARGE						
176		BILLS	-	-		$320.00	$0	0.00
177								
178		CAPACITY CHARGE						
179		ALL kVa OF BILLING DEMAND, PER kVa			-	$0.00100	$0	0.00
180								
181		REACTIVE DEMAND CHARGE						
182		ALL rkVa, PER rkVa			-	$0.00080	$0	0.00
183								
184		TRANSFORMER CHARGE						
185		ALL kVa OF BILLING DEMAND, PER kVa			-	$0.31000	$0	0.00
186								
187		CUSTOMER DISCOUNT						
188		ALL kWh, PER kWh		-		$0.00000	$0	0.00
189								
190		CONTRACT DISCOUNT						0.00
191								
192		STATE kWh TAX						
193		FIRST 2,000 kWh, PER kWh		-		$0.00466	$0	0.00
194		NEXT 13,000 kWh, PER kWh		-		$0.00420	$0	0.00
195		ABOVE 15,000 kWh, PER kWh		-		$0.00364	$0	0.00
196				-			$0	
197								
198		TOTAL DISTRIBUTION - SPC-GT	-	-			$0	0.00
199								
200								
201	SPC - U	SPECIAL CONTRACT - GENERAL SERVICE - UNIQUE						
202								
203		GS - SECONDARY	5,466	298,638,943			$4,071,453	1.90
204		GP - PRIMARY	36	176,240,292			$328,353	0.15
205		GSU - SUBTRANSMISSION	288	829,708,431			$3,870,387	1.80
206		GT - TRANSMISSION	96	1,964,760,819			($620,768)	(0.29)
207		TOTAL DISTRIBUTION - SPC-U	5,886	3,269,348,484			$7,649,425	3.57
208								
209								
210	TOTAL PROPOSED DISTRIBUTION		959,619	13,968,521,617			$214,493,879	100.00

Case No. 08-XXXX-EL-SSO
The Cleveland Electric Illuminating Company

Workpaper for Schedule 2 - Target Revenue for Base Distribution Rates

Witness: G. Hussing

LINE NO.	RATE CODE	CLASS/ DESCRIPTION	PROPOSED ANNUALIZED CUSTOMER BILLS	SALES	BILLING UNITS	PROPOSED RATES	PROPOSED REVENUE LESS FUEL COST REVENUE	% OF REV TO TOTAL LESS FUEL COST REVENUE
	(A)	(B)	(C)	(D1)	(D2)	(E)	(F)	(G)
				(KWH)		($)	($)	(%)
1	PROPOSED							
2								
3	TRF	TRAFFIC LIGHTING SERVICE						
4								
5		DISTRIBUTION CHARGES						
6								
7		ALL kWh, PER kWh	46,042	28,827,210		$0.00087	$25,080	18.34
8								
9		STATE kWh TAX						
10		FIRST 2,000 kWh, PER kWh		2,186,197		$0.00466	$10,182	7.44
11		NEXT 13,000 kWh, PER kWh		8,285,840		$0.00420	$34,772	25.42
12		ABOVE 15,000 kWh, PER kWh		18,355,173		$0.00364	$66,733	48.79
13				28,827,210			$111,687	
14								
15		TOTAL DISTIBUTION - TRF	46,042	28,827,210			$136,766	100.00

Workpaper for Schedule 2 - Target Revenue for Base Distribution Rates

Witness: G. Hussing

			PROPOSED ANNUALIZED					
LINE NO.	RATE CODE	CLASS/DESCRIPTION	FIXTURES	SALES	BILLING UNITS	PROPOSED RATES	PROPOSED REVENUE LESS FUEL COST REVENUE	% OF REV TO TOTAL LESS FUEL COST REVENUE
	(A)	(B)	(C)	(D1)	(D2)	(E)	(F)	(G)
				(KWH)		($)	($)	(%)
1	PROPOSED							
2								
3	STL	STREET LIGHTING SERVICE						
4								
5		DISTRIBUTION CHARGES						
6								
7		COMPANY-OWNED, INCANDESCENT STREET LIGHTING						
8		OVERHEAD SERVICE, PER LAMP	56	94,260		$11.040	$7,419	0.05
9		OVERHEAD-FED WOOD SERVICE, PER LAMP	0	0		$0.000	$0	0.00
10		OVERHEAD-FED STEEL SERVICE, PER LAMP	0	0		$0.000	$0	0.00
11		UNDERGROUND SERVICE, PER LAMP	57	56,772		$6.140	$4,200	0.03
12		UNDERGROUND SERVICE (DUAL LAMPS), PER LAMP	0	0		$0.000	$0	0.00
13								
14		COMPANY-OWNED, FLOURESCENT STREET LIGHTING						
15		OVERHEAD-FED STEEL SERVICE, PER LAMP	0	0		$0.000	$0	0.00
16		UNDERGROUND SERVICE, PER LAMP	0	0		$0.000	$0	0.00
17		UNDERGROUND SERVICE (DUAL LAMPS), PER LAMP	0	0		$0.000	$0	0.00
18								
19		COMPANY-OWNED, OVERHEAD-FED WOOD POLE LIGHTING						
20		100 WATT MERCURY	0	0		$0.000	$0	0.00
21		175 WATT MERCURY	37,368	30,940,497		$7.470	$3,349,645	20.84
22		175 WATT MERCURY (DUAL LAMPS)	0	0		$0.000	$0	0.00
23		250 WATT MERCURY	4,630	5,778,249		$8.890	$493,928	3.07
24		250 WATT MERCURY (DUAL LAMPS)	0	0		$0.000	$0	0.00
25		400 WATT MERCURY	10,374	19,668,196		$11.500	$1,431,343	8.91
26		400 WATT MERCURY (DUAL LAMPS)	0	0		$0.000	$0	0.00
27		400 WATT MERCURY (30 FT CONCRETE POLE)	0	0		$0.000	$0	0.00
28		400 WATT MERCURY (STEEL POLE, 2 BRACKETS)	0	0		$0.000	$0	0.00
29		700 WATT MERCURY	0	0		$0.000	$0	0.00
30		1,000 WATT MERCURY	137	624,720		$23.740	$39,029	0.24
31		70 WATT HP SODIUM	0	0		$0.000	$0	0.00
32		100 WATT HP SODIUM	4,735	2,386,389		$10.390	$590,297	3.67
33		100 WATT HP SODIUM (DUAL LAMP)	0	0		$0.000	$0	0.00
34		100 WATT HP SODIUM (ORNAMENTAL)	0	0		$0.000	$0	0.00
35		150 WATT HP SODIUM	18,467	13,739,448		$11.070	$2,453,156	15.26
36		150 WATT HP SODIUM (DUAL LAMPS)	0	0		$0.000	$0	0.00
37		200 WATT HP SODIUM	0	0		$0.000	$0	0.00
38		215 WATT HP SODIUM	0	0		$0.000	$0	0.00
39		250 WATT HP SODIUM	16,017	20,181,735		$13.330	$2,562,119	15.94
40		250 WATT HP SODIUM (DUAL LAMPS)	0	0		$0.000	$0	0.00
41		250 WATT HP SODIUM (STEEL POLE, 2 BRACKETS)	0	0		$0.000	$0	0.00
42		250 WATT HP SODIUM (DOWNTOWN)	0	0		$0.000	$0	0.00
43		310 WATT HP SODIUM	0	0		$0.000	$0	0.00
44		400 WATT HP SODIUM	2,618	5,120,319		$15.330	$481,561	3.00
45		400 WATT HP SODIUM (DUAL LAMPS)	0	0		$0.000	$0	0.00
46		400 WATT HP SODIUM (DUAL LAMPS, DAVIT POLE)	0	0		$0.000	$0	0.00
47		400 WATT HP SODIUM (DOWNTOWN)	0	0		$0.000	$0	0.00
48		1000 WATT HP SODIUM	0	0		$0.000	$0	0.00
49								

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The Cleveland Electric Illuminating Company

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Workpaper for Schedule 2 - Target Revenue for Base Distribution Rates

Witness: G. Hussing

		PROPOSED ANNUALIZED					
LINE NO. RATE CODE (A)	CLASS/ DESCRIPTION (B)	FIXTURES (C)	SALES (D1) (KWH)	BILLING UNITS (D2)	PROPOSED RATES (E) ($)	PROPOSED REVENUE LESS FUEL COST REVENUE (F) ($)	% OF REV TO TOTAL LESS FUEL COST REVENUE (G) (%)
50	COMPANY-OWNED, OVERHEAD-FED METAL POLE LIGHTING						
51	100 WATT MERCURY	0	0		$0.000	$0	0.00
52	175 WATT MERCURY	0	0		$0.000	$0	0.00
53	175 WATT MERCURY (DUAL LAMPS)	0	0		$0.000	$0	0.00
54	250 WATT MERCURY	0	0		$0.000	$0	0.00
55	250 WATT MERCURY (DUAL LAMPS)	0	0		$0.000	$0	0.00
56	400 WATT MERCURY	0	0		$0.000	$0	0.00
57	400 WATT MERCURY (DUAL LAMPS)	0	0		$0.000	$0	0.00
58	400 WATT MERCURY (30 FT CONCRETE POLE)	0	0		$0.000	$0	0.00
59	400 WATT MERCURY (STEEL POLE, 2 BRACKETS)	0	0		$0.000	$0	0.00
60	700 WATT MERCURY	0	0		$0.000	$0	0.00
61	1,000 WATT MERCURY	0	0		$0.000	$0	0.00
62	70 WATT HP SODIUM	0	0		$0.000	$0	0.00
63	100 WATT HP SODIUM	0	0		$0.000	$0	0.00
64	100 WATT HP SODIUM (DUAL LAMP)	0	0		$0.000	$0	0.00
65	100 WATT HP SODIUM (ORNAMENTAL)	0	0		$0.000	$0	0.00
66	150 WATT HP SODIUM	0	0		$0.000	$0	0.00
67	150 WATT HP SODIUM (DUAL LAMPS)	0	0		$0.000	$0	0.00
68	200 WATT HP SODIUM	0	0		$0.000	$0	0.00
69	215 WATT HP SODIUM	0	0		$0.000	$0	0.00
70	250 WATT HP SODIUM	0	0		$0.000	$0	0.00
71	250 WATT HP SODIUM (DUAL LAMPS)	0	0		$0.000	$0	0.00
72	250 WATT HP SODIUM (STEEL POLE, 2 BRACKETS)	0	0		$0.000	$0	0.00
73	250 WATT HP SODIUM (DOWNTOWN)	0	0		$0.000	$0	0.00
74	310 WATT HP SODIUM	0	0		$0.000	$0	0.00
75	400 WATT HP SODIUM	0	0		$0.000	$0	0.00
76	400 WATT HP SODIUM (DUAL LAMPS)	0	0		$0.000	$0	0.00
77	400 WATT HP SODIUM (DUAL LAMPS, DAVIT POLE)	0	0		$0.000	$0	0.00
78	400 WATT HP SODIUM (DOWNTOWN)	0	0		$0.000	$0	0.00
79	1000 WATT HP SODIUM	0	0		$0.000	$0	0.00
80							
81	COMPANY-OWNED, UNDERGROUND-FED POST LIGHTING						
82	100 WATT MERCURY	0	0		$0.000	$0	0.00
83	175 WATT MERCURY	4,840	4,007,320		$11.850	$688,829	4.29
84	175 WATT MERCURY (DUAL LAMPS)	0	0		$0.000	$0	0.00
85	250 WATT MERCURY	0	0		$0.000	$0	0.00
86	250 WATT MERCURY (DUAL LAMPS)	0	0		$0.000	$0	0.00
87	400 WATT MERCURY	0	0		$0.000	$0	0.00
88	400 WATT MERCURY (DUAL LAMPS)	0	0		$0.000	$0	0.00
89	400 WATT MERCURY (30 FT CONCRETE POLE)	0	0		$0.000	$0	0.00
90	400 WATT MERCURY (STEEL POLE, 2 BRACKETS)	0	0		$0.000	$0	0.00
91	700 WATT MERCURY	0	0		$0.000	$0	0.00
92	1,000 WATT MERCURY	0	0		$0.000	$0	0.00
93	70 WATT HP SODIUM	0	0		$0.000	$0	0.00
94	100 WATT HP SODIUM	10,715	5,400,360		$14.970	$1,924,843	11.98
95	100 WATT HP SODIUM (DUAL LAMP)	0	0		$0.000	$0	0.00
96	100 WATT HP SODIUM (ORNAMENTAL)	0	0		$0.000	$0	0.00
97	150 WATT HP SODIUM	0	0		$0.000	$0	0.00
98	150 WATT HP SODIUM (DUAL LAMPS)	0	0		$0.000	$0	0.00
99	200 WATT HP SODIUM	0	0		$0.000	$0	0.00
100	215 WATT HP SODIUM	0	0		$0.000	$0	0.00
101	250 WATT HP SODIUM	0	0		$0.000	$0	0.00
102	250 WATT HP SODIUM (DUAL LAMPS)	0	0		$0.000	$0	0.00
103	250 WATT HP SODIUM (STEEL POLE, 2 BRACKETS)	0	0		$0.000	$0	0.00
104	250 WATT HP SODIUM (DOWNTOWN)	0	0		$0.000	$0	0.00
105	310 WATT HP SODIUM	0	0		$0.000	$0	0.00
106	400 WATT HP SODIUM	0	0		$0.000	$0	0.00
107	400 WATT HP SODIUM (DUAL LAMPS)	0	0		$0.000	$0	0.00
108	400 WATT HP SODIUM (DUAL LAMPS, DAVIT POLE)	0	0		$0.000	$0	0.00
109	400 WATT HP SODIUM (DOWNTOWN)	0	0		$0.000	$0	0.00
110	1000 WATT HP SODIUM	0	0		$0.000	$0	0.00
111							

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The Cleveland Electric Illuminating Company

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Workpaper for Schedule 2 - Target Revenue for Base Distribution Rates

Witness: G. Hussing

		PROPOSED ANNUALIZED					
LINE NO. RATE CODE	CLASS/ DESCRIPTION	FIXTURES	SALES	BILLING UNITS	PROPOSED RATES	PROPOSED REVENUE LESS FUEL COST REVENUE	% OF REV TO TOTAL LESS FUEL COST REVENUE
(A)	(B)	(C)	(D1)	(D2)	(E)	(F)	(G)
			(KWH)		($)	($)	(%)
112	COMPANY-OWNED, UNDERGROUND-FED POLE LIGHTING						
113	100 WATT MERCURY	0	0		$0.000	$0	0.00
114	175 WATT MERCURY	64	52,992		$18.490	$14,200	0.09
115	175 WATT MERCURY (DUAL LAMPS)	0	0		$0.000	$0	0.00
116	250 WATT MERCURY	39	48,672		$20.740	$9,706	0.06
117	250 WATT MERCURY (DUAL LAMPS)	0	0		$0.000	$0	0.00
118	400 WATT MERCURY	261	494,856		$23.570	$73,821	0.46
119	400 WATT MERCURY (DUAL LAMPS)	0	0		$0.000	$0	0.00
120	400 WATT MERCURY (30 FT CONCRETE POLE)	36	68,256		$23.830	$10,295	0.06
121	400 WATT MERCURY (STEEL POLE, 2 BRACKETS)	3	11,376		$33.150	$1,193	0.01
122	700 WATT MERCURY	0	0		$0.000	$0	0.00
123	1,000 WATT MERCURY	7	31,920		$37.720	$3,168	0.02
124	70 WATT HP SODIUM	0	0		$0.000	$0	0.00
125	100 WATT HP SODIUM	105	53,920		$21.980	$27,695	0.17
126	100 WATT HP SODIUM (DUAL LAMP)	0	0		$0.000	$0	0.00
127	100 WATT HP SODIUM (ORNAMENTAL)	0	0		$0.000	$0	0.00
128	150 WATT HP SODIUM	896	666,624		$23.000	$247,296	1.54
129	150 WATT HP SODIUM (DUAL LAMPS)	0	0		$0.000	$0	0.00
130	200 WATT HP SODIUM	0	0		$0.000	$0	0.00
131	215 WATT HP SODIUM	0	0		$0.000	$0	0.00
132	250 WATT HP SODIUM	670	843,285		$25.110	$201,809	1.26
133	250 WATT HP SODIUM (DUAL LAMPS)	0	0		$0.000	$0	0.00
134	250 WATT HP SODIUM (STEEL POLE, 2 BRACKETS)	53	133,560		$37.830	$24,047	0.15
135	250 WATT HP SODIUM (DOWNTOWN)	0	0		$0.000	$0	0.00
136	310 WATT HP SODIUM	0	0		$0.000	$0	0.00
137	400 WATT HP SODIUM	100	195,600		$26.900	$32,280	0.20
138	400 WATT HP SODIUM (DUAL LAMPS)	0	0		$0.000	$0	0.00
139	400 WATT HP SODIUM (DUAL LAMPS, DAVIT POLE)	0	0		$0.000	$0	0.00
140	400 WATT HP SODIUM (DOWNTOWN)	0	0		$0.000	$0	0.00
141	1000 WATT HP SODIUM	0	0		$0.000	$0	0.00
142							
143	COMPANY-OWNED, BRIDGE OR UNDERPASS WALLPACK						
144	100 WATT MERCURY	0	0		$0.000	$0	0.00
145	175 WATT MERCURY	0	0		$0.000	$0	0.00
146	175 WATT MERCURY (DUAL LAMPS)	0	0		$0.000	$0	0.00
147	250 WATT MERCURY	0	0		$0.000	$0	0.00
148	250 WATT MERCURY (DUAL LAMPS)	0	0		$0.000	$0	0.00
149	400 WATT MERCURY	0	0		$0.000	$0	0.00
150	400 WATT MERCURY (DUAL LAMPS)	0	0		$0.000	$0	0.00
151	400 WATT MERCURY (30 FT CONCRETE POLE)	0	0		$0.000	$0	0.00
152	400 WATT MERCURY (STEEL POLE, 2 BRACKETS)	0	0		$0.000	$0	0.00
153	700 WATT MERCURY	0	0		$0.000	$0	0.00
154	1,000 WATT MERCURY	0	0		$0.000	$0	0.00
155	70 WATT HP SODIUM	0	0		$0.000	$0	0.00
156	100 WATT HP SODIUM	0	0		$0.000	$0	0.00
157	100 WATT HP SODIUM (DUAL LAMP)	0	0		$0.000	$0	0.00
158	100 WATT HP SODIUM (ORNAMENTAL)	0	0		$0.000	$0	0.00
159	150 WATT HP SODIUM	0	0		$0.000	$0	0.00
160	150 WATT HP SODIUM (DUAL LAMPS)	0	0		$0.000	$0	0.00
161	200 WATT HP SODIUM	0	0		$0.000	$0	0.00
162	215 WATT HP SODIUM	0	0		$0.000	$0	0.00
163	250 WATT HP SODIUM	0	0		$0.000	$0	0.00
164	250 WATT HP SODIUM (DUAL LAMPS)	0	0		$0.000	$0	0.00
165	250 WATT HP SODIUM (STEEL POLE, 2 BRACKETS)	0	0		$0.000	$0	0.00
166	250 WATT HP SODIUM (DOWNTOWN)	0	0		$0.000	$0	0.00
167	310 WATT HP SODIUM	0	0		$0.000	$0	0.00
168	400 WATT HP SODIUM	0	0		$0.000	$0	0.00
169	400 WATT HP SODIUM (DUAL LAMPS)	0	0		$0.000	$0	0.00
170	400 WATT HP SODIUM (DUAL LAMPS, DAVIT POLE)	0	0		$0.000	$0	0.00
171	400 WATT HP SODIUM (DOWNTOWN)	0	0		$0.000	$0	0.00
172	1000 WATT HP SODIUM	0	0		$0.000	$0	0.00
173							

Workpaper for Schedule 2 - Target Revenue for Base Distribution Rates

Witness: G. Hussing

LINE NO. RATE CODE (A)	CLASS/ DESCRIPTION (B)	PROPOSED ANNUALIZED FIXTURES (C)	SALES (D1) (KWH)	BILLING UNITS (D2)	PROPOSED RATES (E) ($)	PROPOSED REVENUE LESS FUEL COST REVENUE (F) ($)	% OF REV TO TOTAL LESS FUEL COST REVENUE (G) (%)
174	COMPANY-OWNED, SPECIAL ARCHITECTURAL INSTALLATIONS						
175	100 WATT MERCURY	0	0		$0.000	$0	0.00
176	175 WATT MERCURY	0	0		$0.000	$0	0.00
177	175 WATT MERCURY (DUAL LAMPS)	0	0		$0.000	$0	0.00
178	250 WATT MERCURY	0	0		$0.000	$0	0.00
179	250 WATT MERCURY (DUAL LAMPS)	0	0		$0.000	$0	0.00
180	400 WATT MERCURY	0	0		$0.000	$0	0.00
181	400 WATT MERCURY (DUAL LAMPS)	0	0		$0.000	$0	0.00
182	400 WATT MERCURY (30 FT CONCRETE POLE)	0	0		$0.000	$0	0.00
183	400 WATT MERCURY (STEEL POLE, 2 BRACKETS)	0	0		$0.000	$0	0.00
184	700 WATT MERCURY	0	0		$0.000	$0	0.00
185	1,000 WATT MERCURY	0	0		$0.000	$0	0.00
186	70 WATT HP SODIUM	0	0		$0.000	$0	0.00
187	100 WATT HP SODIUM	402	202,734		$21.900	$105,711	0.66
188	100 WATT HP SODIUM (DUAL LAMP)	0	0		$32.650	$0	0.00
189	100 WATT HP SODIUM (ORNAMENTAL)	0	0		$30.490	$0	0.00
190	150 WATT HP SODIUM	155	113,306		$21.720	$40,464	0.25
191	150 WATT HP SODIUM (DUAL LAMPS)	0	0		$33.510	$0	0.00
192	200 WATT HP SODIUM	0	0		$0.000	$0	0.00
193	215 WATT HP SODIUM	0	0		$0.000	$0	0.00
194	250 WATT HP SODIUM	136	171,366		$24.680	$40,278	0.25
195	250 WATT HP SODIUM (DUAL LAMPS)	31	78,126		$36.630	$13,626	0.08
196	250 WATT HP SODIUM (STEEL POLE, 2 BRACKETS)	0	0		$0.000	$0	0.00
197	250 WATT HP SODIUM (DOWNTOWN)	0	0		$0.000	$0	0.00
198	310 WATT HP SODIUM	0	0		$0.000	$0	0.00
199	400 WATT HP SODIUM	53	103,668		$26.670	$16,962	0.11
200	400 WATT HP SODIUM (DUAL LAMPS)	1	3,912		$39.440	$473	0.00
201	400 WATT HP SODIUM (DUAL LAMPS, DAVIT POLE)	0	0		$0.000	$0	0.00
202	400 WATT HP SODIUM (DOWNTOWN)	0	0		$0.000	$0	0.00
203	1000 WATT HP SODIUM	0	0		$0.000	$0	0.00
204							
205	CUSTOMER-OWNED, ALL LAMP TYPES						
206	ALL kWh, PER kWh	9,217	15,900,283		$0.036	$544,780	3.39
207							
208	CUSTOMER-OWNED, LIMITED MAINTENANCE, ALL LAMP TYPES						
209	ALL kWh, PER kWh	1,361	1,684,878		$0.097	$163,822	1.02
210							
211	STATE kWh TAX						
212	FIRST 2,000 kWh, PER kWh		2,895,217		$0.00466	$13,484	0.08
213	NEXT 13,000 kWh, PER kWh		12,740,548		$0.00420	$53,466	0.33
214	ABOVE 15,000 kWh, PER kWh		112,323,577		$0.00364	$408,371	2.54
215			127,959,342			$475,321	
216							
217	TOTAL DISTRIBUTION - BTL	123,603	127,959,342			$16,073,519	100.00

Workpaper for Schedule 2 - Target Revenue for Base Distribution Rates

Witness: G. Hussing

LINE NO.	RATE CODE (A)	CLASS/ DESCRIPTION (B)	PROPOSED ANNUALIZED FIXTURES (C)	SALES (D1) (KWH)	BILLING UNITS (D2)	PROPOSED RATES (E) ($)	PROPOSED REVENUE LESS FUEL COST REVENUE (F) ($)	% OF REV TO TOTAL LESS FUEL COST REVENUE (G) (%)
1	PROPOSED							
2								
3	POL	PRIVATE OUTDOOR LIGHTING SERVICE						
4								
5		DISTRIBUTION CHARGES						
6								
7		OVERHEAD-FED WOOD POLE LIGHTING						
8		175 WATT MERCURY	7,073	5,856,237		$8.71000	$739,244	9.07
9		400 WATT MERCURY	5,600	10,618,074		$16.15000	$1,085,328	13.32
10		1,000 WATT MERCURY	2,729	12,444,240		$25.73000	$842,606	10.34
11		HP SODIUM < 100 WATTS	866	436,212		$13.03000	$135,330	1.66
12		HP SODIUM 150 WATTS	639	475,602		$15.37000	$117,903	1.45
13		HP SODIUM 150 WATTS (DUAL LAMPS)	-	-		$0.00000	$0	0.00
14		HP SODIUM 200 WATTS	-	-		$0.00000	$0	0.00
15		HP SODIUM 250 WATTS	7,363	9,277,065		$16.94000	$1,496,700	18.37
16		HP SODIUM 250 WATTS (DUAL LAMPS)	-	-		$0.00000	$0	0.00
17		HP SODIUM 400 WATTS	-	-		$0.00000	$0	0.00
18		HP SODIUM > 400 WATTS	12,464	24,379,095		$21.11000	$3,157,317	38.75
19		METAL HALIDE, ALL LAMPS	-	-		$0.00000	$0	0.00
20								
21		ALL OTHER INSTALLATIONS						
22		175 WATT MERCURY	48	39,744		$11.07000	$6,376	0.08
23		400 WATT MERCURY	-	-		$0.00000	$0	0.00
24		1,000 WATT MERCURY	-	-		$0.00000	$0	0.00
25		HP SODIUM < 100 WATTS	1,188	598,626		$16.15000	$230,186	2.83
26		HP SODIUM 150 WATTS	82	60,822		$20.83000	$20,434	0.25
27		HP SODIUM 150 WATTS (DUAL LAMPS)	6	8,928		$33.03000	$2,378	0.03
28		HP SODIUM 200 WATTS	-	-		$0.00000	$0	0.00
29		HP SODIUM 250 WATTS	54	68,040		$23.75000	$15,390	0.19
30		HP SODIUM 250 WATTS (DUAL LAMPS)	8	20,160		$35.62000	$3,420	0.04
31		HP SODIUM 400 WATTS	5	9,780		$25.48000	$1,529	0.02
32		HP SODIUM > 400 WATTS	-	-		$0.00000	$0	0.00
33		METAL HALIDE, ALL LAMPS	-	-		$0.00000	$0	0.00
34								
35		ADDITIONAL FACILITIES						
36		ALL POLES, PER POLE	-	-		$0.00000	$0	0.00
37								
38		STATE kWh TAX[1]						
39		FIRST 2,000 kWh, PER kWh		54,828,921		$0.00466	$255,352	3.13
40		NEXT 13,000 kWh, PER kWh		8,250,486		$0.00420	$34,623	0.42
41		ABOVE 15,000 kWh, PER kWh		798,685		$0.00364	$2,904	0.04
42				63,878,092			$292,879	
43								
44		TOTAL DISTIBUTION - POL	38,124	84,292,625			$8,147,021	100.00

Workpaper for Schedule 2 - Target Revenue for Base Distribution Rates

Witness: G. Hussing

			PROPOSED ANNUALIZED					
LINE NO.	RATE CODE	CLASS/ DESCRIPTION	NUMBER OF OCCURENCES	SALES	BILLING UNITS	PROPOSED RATES	PROPOSED REVENUE LESS FUEL COST REVENUE	% OF REV TO TOTAL LESS FUEL COST REVENUE
	(A)	(B)	(C)	(D1)	(D2)	(E)	(F)	(G)
				(KWH)		($)	($)	(%)
	MISCELLANEOUS CHARGES							
1	PROPOSED							
2								
3	LATE PAYMENT CHARGES (FORFEITED DISCOUNTS) (450)							
4		TOTAL REVENUE					$5,371,212	24.82
5								
6	MISCELLANEOUS SERVICE REVENUES (451)							
7		TOTAL REVENUE					$3,269,303	15.11
8								
9	RENT FROM ELECTRIC PROPERTY (454)							
10		TOTAL REVENUE					$3,012,654	13.92
11								
12	OTHER ELECTRIC REVENUES (456)							
13		TOTAL REVENUE					$9,988,524	46.15
14								
15								
16	TOTAL OTHER ELECTRIC REVENUES		0			$0.00	$21,641,693	100.00

Workpaper for Schedule 2 - Target Revenue for Base Distribution Rates

Witness: G. Hussing

				Source:
CEI Increase	(a)	$	34,500,000	
Miscellaneous Revenue Increase	(b)	$	691,107	Update Filing in Case No. 07-551-EL-AIR
Electric Revenue Increase	(c) = (a) - (b)	$	33,808,893	
Current Revenues	(d)	$	442,137,742	Update Filing in Case No. 07-551-EL-AIR
Current Miscellaneous Revenues	(e)	$	20,950,586	Update Filing in Case No. 07-551-EL-AIR
Proposed Electric Revenue Target	(f) = (d) + (c) - (e)	$	**454,996,049**	

Rate		Proposed Revenue Proof (A)	Stipulated Revenue % (B)		Target Revenue (C)
RS	$	216,110,160	47.55%	$	216,350,621
GS	$	178,074,521	39.14%	$	178,085,454
GP	$	2,640,367	0.58%	$	2,638,977
GSU	$	17,104,314	3.76%	$	17,107,851
GT	$	851,306	0.17%	$	773,493
TRF	$	136,766	0.03%	$	136,499
STL	$	16,073,519	3.53%	$	16,061,361
POL	$	8,147,021	1.79%	$	8,144,429
Contracts	$	15,823,372	3.45%	$	15,697,364
Total Electric	$	454,961,345	100.00%	$	**454,996,049**
Miscellaneous	$	21,641,693		$	21,641,693
Total	$	476,603,038		$	476,637,742

(A) Pages 1-14 of CEI Schedule 5h - Workpaper for Schedule 2
(B) Stipulation in Case No. 07-551-EL-AIR
(C) B × Proposed Electric Revenue Target

Case No. 08-XXXX-EL-SSO
Ohio Edison Company

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Workpaper for Schedule 2 - Target Revenue for Base Distribution Rates

Witness: G. Hussing

			PROPOSED ANNUALIZED					
LINE NO.	RATE CODE (A)	CLASS/ DESCRIPTION (B)	CUSTOMER BILLS (C)	SALES (D1) (KWH)	BILLING UNITS (D2)	PROPOSED RATES (E) ($/kWh)	PROPOSED REVENUE LESS FUEL COST REVENUE (F) ($)	% OF REV TO TOTAL LESS FUEL COST REVENUE (G) (%)
1	RS	RESIDENTIAL SERVICE	11,163,837	9,225,981,525		$0.03798	$350,388,325	59.11
2								
3	GS	GENERAL SERVICE - SECONDARY	1,284,056	6,712,393,410		$0.02191	$147,076,452	24.81
4								
5	GP	GENERAL SERVICE - PRIMARY	12,329	3,098,384,784		$0.00911	$28,220,196	4.76
6								
7	GSU	GENERAL SERVICE - SUBTRANSMISSION	1,190	922,379,013		$0.00499	$4,600,308	0.78
8								
9	GT	GENERAL SERVICE - TRANSMISSION	2,288	4,895,106,911		$0.00243	$11,893,559	2.01
10								
11	SPC - GS	SPECIAL CONTRACT - GENERAL SERVICE - SECONDARY	0	0		$0.00000	$0	0.00
12								
13	SPC - GP	SPECIAL CONTRACT - GENERAL SERVICE - PRIMARY	0	0		$0.00000	$0	0.00
14								
15	SPC - GSU	SPECIAL CONTRACT - GENERAL SERVICE - SUBTRANSMISSION	24	64,215,647		$0.00502	$322,084	0.05
16								
17	SPC - GT	SPECIAL CONTRACT - GENERAL SERVICE - TRANSMISSION	0	0		$0.00000	$0	0.00
18								
19	SPC - U	SPECIAL CONTRACT - GENERAL SERVICE - UNIQUE						
20		GS - SECONDARY	9,267	288,862,939		$0.01496	$4,320,997	0.73
21		GP - PRIMARY	915	117,399,103		$0.01023	$1,201,364	0.20
22		GSU - SUBTRANSMISSION	0	0		$0.00000	$0	0.00
23		GT - TRANSMISSION	48	507,346,839		$0.00146	$742,787	0.13
24			10,230	913,608,881		$0.00686	$6,265,148	
25								
26	POL	PRIVATE OUTDOOR LIGHTING SERVICE	35,009	37,646,793		$0.11335	$4,267,402	0.72
27								
28	STL	STREET LIGHTING SERVICE	14,160	23,607,744		$0.05227	$1,233,937	0.21
29								
30	TRF	TRAFFIC LIGHTING SERVICE	46,957	22,396,480		$0.01504	$336,844	0.06
31								
32	ESIP	ESIP	4,143	102,546,440		$0.06334	$6,495,538	1.10
33								
34	MISCELLANEOUS CHARGES						$31,643,999	5.34
35								
36	TOTAL COMPANY		12,574,222	26,018,267,630		$0.02278	$592,743,794	100.00

Workpaper for Schedule 2 - Target Revenue for Base Distribution Rates

Witness: G. Hussing

			PROPOSED ANNUALIZED					
LINE NO.	RATE CODE	CLASS/ DESCRIPTION	CUSTOMER BILLS	SALES	BILLING UNITS	PROPOSED RATES	PROPOSED REVENUE LESS FUEL COST REVENUE	% OF REV TO TOTAL LESS FUEL COST REVENUE
	(A)	(B)	(C)	(D1)	(D2)	(E)	(F)	(G)
				(KWH)		($)	($)	(%)
	RS	RESIDENTIAL SERVICE						
1	PROPOSED							
2								
3	RS	RESIDENTIAL SERVICE						
4								
5		DISTRIBUTION CHARGES						
6								
7		CUSTOMER CHARGE						
8		BILLS	11,163,837			$4.00	$44,655,347	12.74
9								
10		ENERGY CHARGE						
11		UP TO 500 kWh, PER kWh		4,776,765,167		$0.03208	$153,229,073	43.73
12		OVER 500 kWh, PER kWh		4,449,216,358		$0.03208	$142,721,962	40.73
13								
14		CUSTOMER DISCOUNT						
15		ALL kWh, PER kWh		1,962,068,246		($0.01770)	($34,728,608)	(9.91)
16								
17		RIDER DSM - DEMAND SIDE MANAGEMENT						
18		ALL kWh, PER kWh		9,225,981,525		$0.00020	$1,845,196	0.53
19								
20		STATE kWh TAX						
21		FIRST 2,000 kWh, PER kWh		8,580,209,510		$0.00466	$39,960,215	11.40
22		NEXT 13,000 kWh, PER kWh		637,095,058		$0.00420	$2,673,593	0.76
23		ABOVE 15,000 kWh, PER kWh		8,676,958		$0.00364	$31,546	0.01
24				9,225,981,526			$42,665,354	
25								
26		TOTAL DISTRIBUTION - RS	11,163,837	9,225,981,525			$350,388,325	100.00

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Ohio Edison Company

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Workpaper for Schedule 2 - Target Revenue for Base Distribution Rates

Witness: G. Hussing

LINE NO.	RATE CODE (A)	CLASS/ DESCRIPTION (B)	PROPOSED ANNUALIZED CUSTOMER BILLS (C)	KWH SALES (D1) (KWH)	BILLING UNITS (D2)	PROPOSED RATES (E) ($)	PROPOSED REVENUE LESS FUEL COST REVENUE (F) ($)	% OF REV TO TOTAL LESS FUEL COST REVENUE (G) (%)
1	PROPOSED							
2								
3	GS	GENERAL SERVICE - SECONDARY						
4								
5		CUSTOMER CHARGE						
6		BILLS	1,284,056	6,712,393,410		$7.00	$8,988,392	4.53
7								
8		CAPACITY CHARGE						
9		UP TO 5 kW OF BILLING DEMAND			6,420,280	$14.79	$18,996,324	9.58
10		OVER 5 kW, PER kW			17,816,193	$5.40350	$96,269,799	48.53
11								
12		REACTIVE DEMAND CHARGE						
13		ALL rkVa, PER rkVa			400,157	$0.36000	$144,056	0.07
14								
15		CUSTOMER DISCOUNT						
16		ALL kWh, PER kWh		205,105,260		($0.02000)	($4,102,105)	(2.07)
17								
18		STATE kWh TAX						
19		FIRST 2,000 kWh, PER kWh		1,305,334,319		$0.00466	$6,079,273	3.06
20		NEXT 13,000 kWh, PER kWh		2,244,973,646		$0.00420	$9,421,114	4.75
21		ABOVE 15,000 kWh, PER kWh		3,102,487,518		$0.00364	$11,279,598	5.69
22				6,652,795,483			$26,779,986	
23								
24		TOTAL DISTRIBUTION - GS	1,284,056	6,712,393,410			$147,076,452	74.14

Workpaper for Schedule 2 - Target Revenue for Base Distribution Rates

Witness: G. Hussing

			PROPOSED ANNUALIZED					
LINE NO.	RATE CODE	CLASS/ DESCRIPTION	CUSTOMER BILLS	KWH SALES	BILLING UNITS	PROPOSED RATES	PROPOSED REVENUE LESS FUEL COST REVENUE	% OF REV TO TOTAL LESS FUEL COST REVENUE
	(A)	(B)	(C)	(D1)	(D2)	(E)	(F)	(G)
				(KWH)		($)	($)	(%)
25	GP	GENERAL SERVICE - PRIMARY						
26								
27		CUSTOMER CHARGE						
28		BILLS	12,329	3,098,384,784		$150.00	$1,849,275	0.93
29								
30		CAPACITY CHARGE						
31		ALL kW OF BILLING DEMAND, PER kW			6,743,910	$2.29650	$15,487,390	7.81
32								
33		REACTIVE DEMAND CHARGE						
34		ALL rkVa, PER rkVa			72,095	$0.36000	$25,954	0.01
35								
36		CUSTOMER DISCOUNT						
37		ALL kWh, PER kWh		346,364		($0.02000)	($6,927)	(0.00)
38								
39		STATE kWh TAX						
40		FIRST 2,000 kWh, PER kWh		23,274,940		$0.00466	$108,397	0.05
41		NEXT 13,000 kWh, PER kWh		138,496,391		$0.00420	$581,205	0.29
42		ABOVE 15,000 kWh, PER kWh		2,798,637,335		$0.00364	$10,174,902	5.13
43				2,960,408,666			$10,864,504	
44								
45		TOTAL DISTRIBUTION - GP	12,329	3,098,384,784			$28,220,196	14.23
46								
47								
48	GSU	GENERAL SERVICE - SUBTRANSMISSION						
49								
50		CUSTOMER CHARGE						
51		BILLS	1,190	922,379,013		$200.00	$238,050	0.12
52								
53		CAPACITY CHARGE						
54		ALL kVa OF BILLING DEMAND, PER kVa			2,112,855	$0.85945	$1,815,893	0.92
55								
56		REACTIVE DEMAND CHARGE						
57		ALL rkVa, PER rkVa			-	$0.00000	$0	0.00
58								
59		TRANSFORMER CHARGE						
60		ALL kVa OF BILLING DEMAND, PER kVa			-	$0.00000	$0	0.00
61								
62		CUSTOMER DISCOUNT						
63		ALL kWh, PER kWh		-		$0.00000	$0	0.00
64								
65		STATE kWh TAX						
66		FIRST 2,000 kWh, PER kWh		2,227,202		$0.00466	$10,373	0.01
67		NEXT 13,000 kWh, PER kWh		14,246,696		$0.00420	$59,787	0.03
68		ABOVE 15,000 kWh, PER kWh		681,087,621		$0.00364	$2,476,205	1.25
69				697,561,519			$2,546,364	
70								
71		TOTAL DISTRIBUTION - GSU	1,190	922,379,013			$4,600,308	2.32

Workpaper for Schedule 2 - Target Revenue for Base Distribution Rates

Witness: G. Hussing

			PROPOSED ANNUALIZED					
LINE NO.	RATE CODE	CLASS/ DESCRIPTION	CUSTOMER BILLS	KWH SALES	BILLING UNITS	PROPOSED RATES	PROPOSED REVENUE LESS FUEL COST REVENUE	% OF REV TO TOTAL LESS FUEL COST REVENUE
	(A)	(B)	(C)	(D1)	(D2)	(E)	(F)	(G)
				(KWH)		($)	($)	(%)
72	GT	GENERAL SERVICE - TRANSMISSION						
73								
74		CUSTOMER CHARGE						
75		BILLS	2,288	4,895,106,911		$330.00	$732,240	0.37
76								
77		CAPACITY CHARGE						
78		ALL kVa OF BILLING DEMAND, PER kVa			11,160,868	$0.37770	$4,215,460	2.12
79								
80		REACTIVE DEMAND CHARGE						
81		ALL rkVa, PER rkVa			-	$0.00000	$0	0.00
82								
83		TRANSFORMER CHARGE						
84		ALL kVa OF BILLING DEMAND, PER kVa			-	$0.00000	$0	0.00
85								
86		CUSTOMER DISCOUNT						
87		ALL kWh, PER kWh		-		$0.00000	$0	0.00
88								
89		STATE kWh TAX						
90		FIRST 2,000 kWh, PER kWh		3,992,952		$0.00466	$18,596	0.01
91		NEXT 13,000 kWh, PER kWh		25,583,743		$0.00420	$107,363	0.05
92		ABOVE 15,000 kWh, PER kWh		1,875,833,997		$0.00364	$6,819,900	3.44
93				1,905,410,692			$6,945,859	
94								
95		TOTAL DISTRIBUTION - GT	2,288	4,895,106,911			$11,893,559	6.00
96								
97								
98	SPC - GS	SPECIAL CONTRACT - GENERAL SERVICE - SECONDARY						
99								
100		CUSTOMER CHARGE						
101		BILLS	-	-		$7.00	$0	0.00
102								
103		CAPACITY CHARGE						
104		UP TO 5 kW OF BILLING DEMAND			-	$14.79	$0	0.00
105		OVER 5 kW, PER kW			-	$5.40350	$0	0.00
106								
107		REACTIVE DEMAND CHARGE						
108		ALL rkVa, PER rkVa			-	$0.36000	$0	0.00
109								
110		CUSTOMER DISCOUNT						
111		ALL kWh, PER kWh		-		($0.02000)	$0	0.00
112								
113		CONTRACT DISCOUNT					$0	0.00
114								
115		STATE kWh TAX						
116		FIRST 2,000 kWh, PER kWh		-		$0.00466	$0	0.00
117		NEXT 13,000 kWh, PER kWh		-		$0.00420	$0	0.00
118		ABOVE 15,000 kWh, PER kWh		-		$0.00364	$0	0.00
119				-			$0	
120								
121		TOTAL DISTRIBUTION - SPC-GS	-	-			$0	0.00

Workpaper for Schedule 2 - Target Revenue for Base Distribution Rates

Witness: G. Hussing

LINE NO.	RATE CODE	CLASS/ DESCRIPTION	CUSTOMER BILLS	KWH SALES	BILLING UNITS	PROPOSED RATES	PROPOSED REVENUE LESS FUEL COST REVENUE	% OF REV TO TOTAL LESS FUEL COST REVENUE
			PROPOSED ANNUALIZED					
	(A)	(B)	(C)	(D1)	(D2)	(E)	(F)	(G)
				(KWH)		($)	($)	(%)
122	SPC - GP	SPECIAL CONTRACT - GENERAL SERVICE - PRIMARY						
123								
124		CUSTOMER CHARGE						
125		BILLS	-	-		$150.00	$0	0.00
126								
127		CAPACITY CHARGE						
128		ALL kW OF BILLING DEMAND, PER kW			-	$2.29650	$0	0.00
129								
130		REACTIVE DEMAND CHARGE						
131		ALL rkVa, PER rkVa			-	$0.36000	$0	0.00
132								
133		CUSTOMER DISCOUNT						
134		ALL kWh, PER kWh		-		($0.02000)	$0	0.00
135								
136		CONTRACT DISCOUNT					$0	0.00
137								
138		STATE kWh TAX						
139		FIRST 2,000 kWh, PER kWh		-		$0.00466	$0	0.00
140		NEXT 13,000 kWh, PER kWh		-		$0.00420	$0	0.00
141		ABOVE 15,000 kWh, PER kWh		-		$0.00364	$0	0.00
142				-			$0	
143								
144		TOTAL DISTRIBUTION - SPC-GP	-	-			$0	0.00
145								
146								
147	SPC - GSU	SPECIAL CONTRACT - GENERAL SERVICE - SUBTRANSMISSION						
148								
149		CUSTOMER CHARGE						
150		BILLS	24	64,215,647		$200.00	$4,800	0.00
151								
152		CAPACITY CHARGE						
153		ALL kVa OF BILLING DEMAND, PER kVa			102,617	$0.85945	$88,194	0.04
154								
155		REACTIVE DEMAND CHARGE						
156		ALL rkVa, PER rkVa			-	$0.00000	$0	0.00
157								
158		TRANSFORMER CHARGE						
159		ALL kVa OF BILLING DEMAND, PER kVa			-	$0.00000	$0	0.00
160								
161		CUSTOMER DISCOUNT						
162		ALL kWh, PER kWh		-		$0.00000	$0	0.00
163								0.00
164		CONTRACT DISCOUNT					($3,859)	(0.00)
165								
166		STATE kWh TAX						
167		FIRST 2,000 kWh, PER kWh		48,366		$0.00466	$225	0.00
168		NEXT 13,000 kWh, PER kWh		314,379		$0.00420	$1,319	0.00
169		ABOVE 15,000 kWh, PER kWh		63,648,657		$0.00364	$231,405	0.12
170				64,011,402			$232,950	
171								
172		TOTAL DISTRIBUTION - SPC-GSU	24	64,215,647			$322,084	0.16

Workpaper for Schedule 2 - Target Revenue for Base Distribution Rates

Witness: G. Hussing

			PROPOSED ANNUALIZED					
LINE NO.	RATE CODE	CLASS/ DESCRIPTION	CUSTOMER BILLS	KWH SALES	BILLING UNITS	PROPOSED RATES	PROPOSED REVENUE LESS FUEL COST REVENUE	% OF REV TO TOTAL LESS FUEL COST REVENUE
	(A)	(B)	(C)	(D1)	(D2)	(E)	(F)	(G)
				(KWH)		($)	($)	(%)
173	SPC - GT	SPECIAL CONTRACT - GENERAL SERVICE - TRANSMISSION						
174								
175		CUSTOMER CHARGE						
176		BILLS	-	-		$320.00	$0	0.00
177								
178		CAPACITY CHARGE						
179		ALL kVs OF BILLING DEMAND, PER kW			-	$0.37770	$0	0.00
180								
181		REACTIVE DEMAND CHARGE						
182		ALL rkVa, PER rkVa			-	$0.00000	$0	0.00
183								
184		TRANSFORMER CHARGE						
185		ALL kVs OF BILLING DEMAND, PER kW			-	$0.00000	$0	0.00
186								
187		CUSTOMER DISCOUNT						
188		ALL kWh, PER kWh		-		$0.00000	$0	0.00
189								
190		CONTRACT DISCOUNT					$0	0.00
191								
192		STATE kWh TAX						
193		FIRST 2,000 kWh, PER kWh		-		$0.00466	$0	0.00
194		NEXT 13,000 kWh, PER kWh		-		$0.00420	$0	0.00
195		ABOVE 15,000 kWh, PER kWh		-		$0.00364	$0	0.00
196				-			$0	
197								
198		TOTAL DISTRIBUTION - SPC-GT	-	-			$0	0.00
199								
200								
201	SPC - U	SPECIAL CONTRACT - GENERAL SERVICE - UNIQUE						
202								
203		GS - SECONDARY	9,267	288,862,939			$4,320,997	2.18
204		GP - PRIMARY	915	117,399,103			$1,201,364	0.61
205		GSU - SUBTRANSMISSION	0	0			$0	0.00
206		GT - TRANSMISSION	48	507,346,839			$742,787	0.37
207		TOTAL DISTRIBUTION - SPC-U	10,230	913,608,881			$6,265,148	3.16
208								
209								
210	TOTAL PROPOSED DISTRIBUTION		1,310,117	16,606,088,648			$198,377,748	100.00

Workpaper for Schedule 2 - Target Revenue for Base Distribution Rates

Witness: G. Hussing

			PROPOSED ANNUALIZED					
LINE NO.	RATE CODE (A)	CLASS/ DESCRIPTION (B)	FIXTURES (C)	SALES (D1) (KWH)	BILLING UNITS (D2)	PROPOSED RATES (E) ($)	PROPOSED REVENUE LESS FUEL COST REVENUE (F) ($)	% OF REV TO TOTAL LESS FUEL COST REVENUE (G) (%)
1	PROPOSED							
2								
3	STL	STREET LIGHTING SERVICE						
4								
5		DISTRIBUTION CHARGES						
6								
7		COMPANY-OWNED, INCANDESCENT STREET LIGHTING						
8		OVERHEAD SERVICE, PER LAMP	0	0		$0.000	$0	0.00
9		OVERHEAD-FED WOOD SERVICE, PER LAMP	0	0		$0.000	$0	0.00
10		OVERHEAD-FED STEEL SERVICE, PER LAMP	0	0		$0.000	$0	0.00
11		UNDERGROUND SERVICE, PER LAMP	3	2,520		$17.020	$613	0.06
12		UNDERGROUND SERVICE (DUAL LAMPS), PER LAMP	0	0		$0.000	$0	0.00
13								
14		COMPANY-OWNED, FLOURESCENT STREET LIGHTING						
15		OVERHEAD-FED STEEL SERVICE, PER LAMP	0	0		$0.000	$0	0.00
16		UNDERGROUND SERVICE, PER LAMP	0	0		$0.000	$0	0.00
17		UNDERGROUND SERVICE (DUAL LAMPS), PER LAMP	0	0		$0.000	$0	0.00
18								
19		COMPANY-OWNED, OVERHEAD-FED WOOD POLE LIGHTING						
20		100 WATT MERCURY	35	17,028		$5.920	$2,344	0.22
21		175 WATT MERCURY	2,482	2,054,683		$5.160	$153,654	14.48
22		175 WATT MERCURY (DUAL LAMPS)	0	0		$0.000	$0	0.00
23		250 WATT MERCURY	34	42,432		$5.370	$2,191	0.21
24		250 WATT MERCURY (DUAL LAMPS)	0	0		$0.000	$0	0.00
25		400 WATT MERCURY	805	1,526,280		$5.360	$51,778	4.88
26		400 WATT MERCURY (DUAL LAMPS)	0	0		$0.000	$0	0.00
27		400 WATT MERCURY (30 FT CONCRETE POLE)	0	0		$0.000	$0	0.00
28		400 WATT MERCURY (STEEL POLE, 2 BRACKETS)	0	0		$0.000	$0	0.00
29		700 WATT MERCURY	0	0		$0.000	$0	0.00
30		1,000 WATT MERCURY	10	45,600		$5.450	$654	0.06
31		70 WATT HP SODIUM	7	2,436		$6.490	$545	0.05
32		100 WATT HP SODIUM	3,383	1,705,032		$6.150	$249,665	23.53
33		100 WATT HP SODIUM (DUAL LAMP)	0	0		$0.000	$0	0.00
34		100 WATT HP SODIUM (ORNAMENTAL)	0	0		$0.000	$0	0.00
35		150 WATT HP SODIUM	472	351,354		$5.790	$32,812	3.09
36		150 WATT HP SODIUM (DUAL LAMPS)	0	0		$0.000	$0	0.00
37		200 WATT HP SODIUM	0	0		$0.000	$0	0.00
38		215 WATT HP SODIUM	0	0		$6.160	$0	0.00
39		250 WATT HP SODIUM	860	1,082,970		$5.610	$57,863	5.45
40		250 WATT HP SODIUM (DUAL LAMPS)	0	0		$0.000	$0	0.00
41		250 WATT HP SODIUM (STEEL POLE, 2 BRACKETS)	0	0		$0.000	$0	0.00
42		250 WATT HP SODIUM (DOWNTOWN)	0	0		$0.000	$0	0.00
43		310 WATT HP SODIUM	0	0		$0.000	$0	0.00
44		400 WATT HP SODIUM	127	247,923		$5.570	$8,472	0.80
45		400 WATT HP SODIUM (DUAL LAMPS)	0	0		$0.000	$0	0.00
46		400 WATT HP SODIUM (DUAL LAMPS, DAVIT POLE)	0	0		$0.000	$0	0.00
47		400 WATT HP SODIUM (DOWNTOWN)	0	0		$0.000	$0	0.00
48		1000 WATT HP SODIUM	0	0		$7.940	$0	0.00
49								

Workpaper for Schedule 2 - Target Revenue for Base Distribution Rates

Witness: G. Hussing

		PROPOSED ANNUALIZED						
LINE NO.	RATE CODE	CLASS/ DESCRIPTION	FIXTURES	SALES	BILLING UNITS	PROPOSED RATES	PROPOSED REVENUE LESS FUEL COST REVENUE	% OF REV TO TOTAL LESS FUEL COST REVENUE
	(A)	(B)	(C)	(D1)	(D2)	(E)	(F)	(G)
				(KWH)		($)	($)	(%)
50		COMPANY-OWNED, OVERHEAD-FED METAL POLE LIGHTING						
51		100 WATT MERCURY	0	0		$0.000	$0	0.00
52		175 WATT MERCURY	0	0		$0.000	$0	0.00
53		175 WATT MERCURY (DUAL LAMPS)	0	0		$0.000	$0	0.00
54		250 WATT MERCURY	0	0		$0.000	$0	0.00
55		250 WATT MERCURY (DUAL LAMPS)	0	0		$0.000	$0	0.00
56		400 WATT MERCURY	0	0		$0.000	$0	0.00
57		400 WATT MERCURY (DUAL LAMPS)	0	0		$0.000	$0	0.00
58		400 WATT MERCURY (30 FT CONCRETE POLE)	0	0		$0.000	$0	0.00
59		400 WATT MERCURY (STEEL POLE, 2 BRACKETS)	0	0		$0.000	$0	0.00
60		700 WATT MERCURY	0	0		$0.000	$0	0.00
61		1,000 WATT MERCURY	0	0		$0.000	$0	0.00
62		70 WATT HP SODIUM	0	0		$14.430	$0	0.00
63		100 WATT HP SODIUM	36	18,144		$14.140	$6,108	0.58
64		100 WATT HP SODIUM (DUAL LAMP)	0	0		$0.000	$0	0.00
65		100 WATT HP SODIUM (ORNAMENTAL)	0	0		$0.000	$0	0.00
66		150 WATT HP SODIUM	0	0		$14.840	$0	0.00
67		150 WATT HP SODIUM (DUAL LAMPS)	0	0		$0.000	$0	0.00
68		200 WATT HP SODIUM	0	0		$0.000	$0	0.00
69		215 WATT HP SODIUM	0	0		$15.350	$0	0.00
70		250 WATT HP SODIUM	1	1,260		$14.990	$175	0.02
71		250 WATT HP SODIUM (DUAL LAMPS)	0	0		$0.000	$0	0.00
72		250 WATT HP SODIUM (STEEL POLE, 2 BRACKETS)	0	0		$0.000	$0	0.00
73		250 WATT HP SODIUM (DOWNTOWN)	0	0		$0.000	$0	0.00
74		310 WATT HP SODIUM	0	0		$0.000	$0	0.00
75		400 WATT HP SODIUM	9	17,604		$15.580	$1,683	0.16
76		400 WATT HP SODIUM (DUAL LAMPS)	0	0		$0.000	$0	0.00
77		400 WATT HP SODIUM (DUAL LAMPS, DAVIT POLE)	0	0		$0.000	$0	0.00
78		400 WATT HP SODIUM (DOWNTOWN)	0	0		$0.000	$0	0.00
79		1000 WATT HP SODIUM	0	0		$17.090	$0	0.00
80								
81		COMPANY-OWNED, UNDERGROUND-FED POST LIGHTING						
82		100 WATT MERCURY	27	13,932		$8.820	$2,858	0.27
83		175 WATT MERCURY	161	133,308		$8.590	$16,596	1.56
84		175 WATT MERCURY (DUAL LAMPS)	0	0		$0.000	$0	0.00
85		250 WATT MERCURY	2	2,496		$9.870	$237	0.02
86		250 WATT MERCURY (DUAL LAMPS)	0	0		$0.000	$0	0.00
87		400 WATT MERCURY	0	0		$0.000	$0	0.00
88		400 WATT MERCURY (DUAL LAMPS)	0	0		$0.000	$0	0.00
89		400 WATT MERCURY (30 FT CONCRETE POLE)	0	0		$0.000	$0	0.00
90		400 WATT MERCURY (STEEL POLE, 2 BRACKETS)	0	0		$0.000	$0	0.00
91		700 WATT MERCURY	0	0		$0.000	$0	0.00
92		1,000 WATT MERCURY	0	0		$0.000	$0	0.00
93		70 WATT HP SODIUM	11	3,828		$9.650	$1,274	0.12
94		100 WATT HP SODIUM	2,887	1,455,174		$9.670	$335,036	31.57
95		100 WATT HP SODIUM (DUAL LAMP)	0	0		$0.000	$0	0.00
96		100 WATT HP SODIUM (ORNAMENTAL)	0	0		$0.000	$0	0.00
97		150 WATT HP SODIUM	301	223,944		$9.960	$35,976	3.39
98		150 WATT HP SODIUM (DUAL LAMPS)	0	0		$0.000	$0	0.00
99		200 WATT HP SODIUM	0	0		$0.000	$0	0.00
100		215 WATT HP SODIUM	0	0		$0.000	$0	0.00
101		250 WATT HP SODIUM	0	0		$0.000	$0	0.00
102		250 WATT HP SODIUM (DUAL LAMPS)	0	0		$0.000	$0	0.00
103		250 WATT HP SODIUM (STEEL POLE, 2 BRACKETS)	0	0		$0.000	$0	0.00
104		250 WATT HP SODIUM (DOWNTOWN)	0	0		$0.000	$0	0.00
105		310 WATT HP SODIUM	0	0		$0.000	$0	0.00
106		400 WATT HP SODIUM	0	0		$0.000	$0	0.00
107		400 WATT HP SODIUM (DUAL LAMPS)	0	0		$0.000	$0	0.00
108		400 WATT HP SODIUM (DUAL LAMPS, DAVIT POLE)	0	0		$0.000	$0	0.00
109		400 WATT HP SODIUM (DOWNTOWN)	0	0		$0.000	$0	0.00
110		1000 WATT HP SODIUM	0	0		$0.000	$0	0.00

Case No. 08-XXXX-EL-SSO
Ohio Edison Company

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Workpaper for Schedule 2 - Target Revenue for Base Distribution Rates

Witness: G. Hussing

		PROPOSED ANNUALIZED						
LINE NO.	RATE CODE	CLASS/ DESCRIPTION	FIXTURES	SALES	BILLING UNITS	PROPOSED RATES	PROPOSED REVENUE LESS FUEL COST REVENUE	% OF REV TO TOTAL LESS FUEL COST REVENUE
	(A)	(B)	(C)	(D1)	(D2)	(E)	(F)	(G)
				(KWH)		($)	($)	(%)
111								
112		COMPANY-OWNED, UNDERGROUND-FED POLE LIGHTING						
113		100 WATT MERCURY	0	0		$0.000	$0	0.00
114		175 WATT MERCURY	9	7,245		$15.950	$1,675	0.16
115		175 WATT MERCURY (DUAL LAMPS)	0	0		$0.000	$0	0.00
116		250 WATT MERCURY	0	0		$0.000	$0	0.00
117		250 WATT MERCURY (DUAL LAMPS)	0	0		$0.000	$0	0.00
118		400 WATT MERCURY	0	0		$0.000	$0	0.00
119		400 WATT MERCURY (DUAL LAMPS)	0	0		$0.000	$0	0.00
120		400 WATT MERCURY (30 FT CONCRETE POLE)	0	0		$0.000	$0	0.00
121		400 WATT MERCURY (STEEL POLE, 2 BRACKETS)	0	0		$0.000	$0	0.00
122		700 WATT MERCURY	0	0		$0.000	$0	0.00
123		1,000 WATT MERCURY	0	0		$0.000	$0	0.00
124		70 WATT HP SODIUM	2	596		$16.780	$403	0.04
125		100 WATT HP SODIUM	144	72,576		$16.780	$28,996	2.73
126		100 WATT HP SODIUM (DUAL LAMP)	0	0		$0.000	$0	0.00
127		100 WATT HP SODIUM (ORNAMENTAL)	0	0		$0.000	$0	0.00
128		150 WATT HP SODIUM	19	14,136		$19.340	$4,410	0.42
129		150 WATT HP SODIUM (DUAL LAMPS)	0	0		$0.000	$0	0.00
130		200 WATT HP SODIUM	0	0		$20.040	$0	0.00
131		215 WATT HP SODIUM	0	0		$18.060	$0	0.00
132		250 WATT HP SODIUM	8	10,080		$19.840	$1,905	0.18
133		250 WATT HP SODIUM (DUAL LAMPS)	0	0		$0.000	$0	0.00
134		250 WATT HP SODIUM (STEEL POLE, 2 BRACKETS)	0	0		$0.000	$0	0.00
135		250 WATT HP SODIUM (DOWNTOWN)	0	0		$0.000	$0	0.00
136		310 WATT HP SODIUM	0	0		$20.800	$0	0.00
137		400 WATT HP SODIUM	0	0		$37.880	$0	0.00
138		400 WATT HP SODIUM (DUAL LAMPS)	0	0		$42.260	$0	0.00
139		400 WATT HP SODIUM (DUAL LAMPS, DAVIT POLE)	0	0		$0.000	$0	0.00
140		400 WATT HP SODIUM (DOWNTOWN)	0	0		$0.000	$0	0.00
141		1000 WATT HP SODIUM	0	0		$41.350	$0	0.00
142								
143		COMPANY-OWNED, BRIDGE OR UNDERPASS WALLPACK						
144		100 WATT MERCURY	0	0		$0.000	$0	0.00
145		175 WATT MERCURY	6	4,968		$7.630	$549	0.05
146		175 WATT MERCURY (DUAL LAMPS)	0	0		$0.000	$0	0.00
147		250 WATT MERCURY	0	0		$0.000	$0	0.00
148		250 WATT MERCURY (DUAL LAMPS)	0	0		$0.000	$0	0.00
149		400 WATT MERCURY	0	0		$0.000	$0	0.00
150		400 WATT MERCURY (DUAL LAMPS)	0	0		$0.000	$0	0.00
151		400 WATT MERCURY (30 FT CONCRETE POLE)	0	0		$0.000	$0	0.00
152		400 WATT MERCURY (STEEL POLE, 2 BRACKETS)	0	0		$0.000	$0	0.00
153		700 WATT MERCURY	0	0		$0.000	$0	0.00
154		1,000 WATT MERCURY	0	0		$0.000	$0	0.00
155		70 WATT HP SODIUM	0	0		$10.220	$0	0.00
156		100 WATT HP SODIUM	133	67,032		$10.940	$17,460	1.65
157		100 WATT HP SODIUM (DUAL LAMP)	0	0		$0.000	$0	0.00
158		100 WATT HP SODIUM (ORNAMENTAL)	0	0		$0.000	$0	0.00
159		150 WATT HP SODIUM	59	43,896		$10.720	$7,590	0.72
160		150 WATT HP SODIUM (DUAL LAMPS)	0	0		$0.000	$0	0.00
161		200 WATT HP SODIUM	0	0		$0.000	$0	0.00
162		215 WATT HP SODIUM	0	0		$9.600	$0	0.00
163		250 WATT HP SODIUM	0	0		$11.150	$0	0.00
164		250 WATT HP SODIUM (DUAL LAMPS)	0	0		$0.000	$0	0.00
165		250 WATT HP SODIUM (STEEL POLE, 2 BRACKETS)	0	0		$0.000	$0	0.00
166		250 WATT HP SODIUM (DOWNTOWN)	0	0		$0.000	$0	0.00
167		310 WATT HP SODIUM	0	0		$0.000	$0	0.00
168		400 WATT HP SODIUM	0	0		$0.000	$0	0.00
169		400 WATT HP SODIUM (DUAL LAMPS)	0	0		$0.000	$0	0.00
170		400 WATT HP SODIUM (DUAL LAMPS, DAVIT POLE)	0	0		$0.000	$0	0.00
171		400 WATT HP SODIUM (DOWNTOWN)	0	0		$0.000	$0	0.00
172		1000 WATT HP SODIUM	0	0		$0.000	$0	0.00

Case No. 08-XXXX-EL-SSO
Ohio Edison Company

Workpaper for Schedule 2 - Target Revenue for Base Distribution Rates

Witness: G. Hussing

		PROPOSED ANNUALIZED						
LINE NO.	RATE CODE (A)	CLASS/DESCRIPTION (B)	FIXTURES (C)	SALES (D1) (KWH)	BILLING UNITS (D2)	PROPOSED RATES (E) ($)	PROPOSED REVENUE LESS FUEL COST REVENUE (F) ($)	% OF REV TO TOTAL LESS FUEL COST REVENUE (G) (%)
173								
174		COMPANY-OWNED, SPECIAL ARCHITECTURAL INSTALLATIONS						
175		100 WATT MERCURY	0	0		$0.000	$0	0.00
176		175 WATT MERCURY	0	0		$0.000	$0	0.00
177		175 WATT MERCURY (DUAL LAMPS)	0	0		$0.000	$0	0.00
178		250 WATT MERCURY	0	0		$0.000	$0	0.00
179		250 WATT MERCURY (DUAL LAMPS)	0	0		$0.000	$0	0.00
180		400 WATT MERCURY	0	0		$0.000	$0	0.00
181		400 WATT MERCURY (DUAL LAMPS)	0	0		$0.000	$0	0.00
182		400 WATT MERCURY (30 FT CONCRETE POLE)	0	0		$0.000	$0	0.00
183		400 WATT MERCURY (STEEL POLE, 2 BRACKETS)	0	0		$0.000	$0	0.00
184		700 WATT MERCURY	0	0		$0.000	$0	0.00
185		1,000 WATT MERCURY	0	0		$0.000	$0	0.00
186		70 WATT HP SODIUM	0	0		$0.000	$0	0.00
187		100 WATT HP SODIUM	0	0		$0.000	$0	0.00
188		100 WATT HP SODIUM (DUAL LAMP)	0	0		$0.000	$0	0.00
189		100 WATT HP SODIUM (ORNAMENTAL)	0	0		$0.000	$0	0.00
190		150 WATT HP SODIUM	0	0		$0.000	$0	0.00
191		150 WATT HP SODIUM (DUAL LAMPS)	0	0		$0.000	$0	0.00
192		200 WATT HP SODIUM	0	0		$0.000	$0	0.00
193		215 WATT HP SODIUM	0	0		$0.000	$0	0.00
194		250 WATT HP SODIUM	0	0		$0.000	$0	0.00
195		250 WATT HP SODIUM (DUAL LAMPS)	0	0		$0.000	$0	0.00
196		250 WATT HP SODIUM (STEEL POLE, 2 BRACKETS)	0	0		$0.000	$0	0.00
197		250 WATT HP SODIUM (DOWNTOWN)	0	0		$0.000	$0	0.00
198		310 WATT HP SODIUM	0	0		$0.000	$0	0.00
199		400 WATT HP SODIUM	0	0		$0.000	$0	0.00
200		400 WATT HP SODIUM (DUAL LAMPS)	0	0		$0.000	$0	0.00
201		400 WATT HP SODIUM (DUAL LAMPS, DAVIT POLE)	0	0		$0.000	$0	0.00
202		400 WATT HP SODIUM (DOWNTOWN)	0	0		$0.000	$0	0.00
203		1000 WATT HP SODIUM	0	0		$0.000	$0	0.00
204								
205		CUSTOMER-OWNED, ALL LAMP TYPES						
206		ALL kWh, PER kWh	0	0		$0.00323	$0	0.00
207								
208		CUSTOMER-OWNED, LIMITED MAINTENANCE, ALL LAMP TYPES						
209		ALL kWh, PER kWh	0	0		$0.03477	$0	0.00
210								
211		STATE kWh TAX						
212		FIRST 2,000 kWh, PER kWh		2,396,783		$0.00466	$11,162	1.05
213		NEXT 13,000 kWh, PER kWh		3,334,674		$0.00420	$13,994	1.32
214		ABOVE 15,000 kWh, PER kWh		3,437,119		$0.00364	$12,496	1.18
215				9,168,576			$37,653	
216								
217		TOTAL DISTIBUTION - STL	12,030	9,168,576			$1,061,172	100.00

Workpaper for Schedule 2 - Target Revenue for Base Distribution Rates

Witness: G. Hussing

			PROPOSED ANNUALIZED					
LINE NO.	RATE CODE	CLASS/ DESCRIPTION	CUSTOMER BILLS	SALES	BILLING UNITS	PROPOSED RATES	PROPOSED REVENUE LESS FUEL COST REVENUE	% OF REV TO TOTAL LESS FUEL COST REVENUE
	(A)	(B)	(C)	(D1)	(D2)	(E)	(F)	(G)
				(KWH)		($)	($)	(%)
1	PROPOSED							
2								
3	ESIP							
4								
5		DISTRIBUTION CHARGES						
6								
7		ALL kWh, PER kWh	4,143	102,548,440		$0.05956	$6,107,666	94.03
8								
9		STATE kWh TAX						
10		FIRST 2,000 kWh, PER kWh		5,843,192		$0.00466	$27,213	0.42
11		NEXT 13,000 kWh, PER kWh		16,186,517		$0.00420	$67,927	1.05
12		ABOVE 15,000 kWh, PER kWh		80,516,731		$0.00364	$292,732	4.51
13				102,548,440			$387,872	
14								
15		TOTAL DISTIBUTION - ESIP	4,143	102,548,440			$6,495,538	100.00

Workpaper for Schedule 2 - Target Revenue for Base Distribution Rates

Witness: G. Hussing

PROPOSED ANNUALIZED

LINE NO.	RATE CODE	CLASS/ DESCRIPTION	CUSTOMER BILLS	SALES	BILLING UNITS	PROPOSED RATES	PROPOSED REVENUE LESS FUEL COST REVENUE	% OF REV TO TOTAL LESS FUEL COST REVENUE
	(A)	(B)	(C)	(D1)	(D2)	(E)	(F)	(G)
				(KWH)		($)	($)	(%)
1	PROPOSED							
2								
3	TRF	TRAFFIC LIGHTING SERVICE						
4								
5		DISTRIBUTION CHARGES						
6								
7		ALL kWh, PER kWh	46,957	22,398,480		$0.01091	$244,346	72.54
8								
9		STATE kWh TAX						
10		FIRST 2,000 kWh, PER kWh		7,073,479		$0.00466	$32,943	9.78
11		NEXT 13,000 kWh, PER kWh		6,858,236		$0.00420	$28,781	8.54
12		ABOVE 15,000 kWh, PER kWh		8,464,764		$0.00364	$30,775	9.14
13				22,398,480			$92,499	
14								
15		TOTAL DISTIBUTION - TRF	46,957	22,398,480			$336,844	100.00

Workpaper for Schedule 2 - Target Revenue for Base Distribution Rates

Witness: G. Hussing

LINE NO.	RATE CODE	CLASS/ DESCRIPTION	PROPOSED ANNUALIZED CUSTOMER BILLS	SALES	BILLING UNITS	PROPOSED RATES	PROPOSED REVENUE LESS FUEL COST REVENUE	% OF REV TO TOTAL LESS FUEL COST REVENUE
	(A)	(B)	(C)	(D1)	(D2)	(E)	(F)	(G)
				(KWH)		($)	($)	(%)
1	PROPOSED							
2								
3	POL	PRIVATE OUTDOOR LIGHTING SERVICE						
4								
5		DISTRIBUTION CHARGES						
6								
7		OVERHEAD-FED WOOD POLE LIGHTING						
8		175 WATT MERCURY	193	159,597		$6.53000	$15,104	0.35
9		400 WATT MERCURY	112	211,878		$8.34000	$11,184	0.26
10		1,000 WATT MERCURY	131	597,360		$9.51000	$14,950	0.35
11		HP SODIUM < 100 WATTS	8,241	4,153,590		$7.77000	$768,414	18.01
12		HP SODIUM 150 WATTS	-	-		$0.00000	$0	0.00
13		HP SODIUM 150 WATTS (DUAL LAMPS)	-	-		$0.00000	$0	0.00
14		HP SODIUM 200 WATTS	-	-		$0.00000	$0	0.00
15		HP SODIUM 250 WATTS	2,648	3,335,850		$10.17000	$323,101	7.57
16		HP SODIUM 250 WATTS (DUAL LAMPS)	-	-		$0.00000	$0	0.00
17		HP SODIUM 400 WATTS	-	-		$0.00000	$0	0.00
18		HP SODIUM > 400 WATTS	11,093	21,698,397		$10.93000	$1,454,991	34.10
19		METAL HALIDE, ALL LAMPS	2,471	4,936,167		$11.28000	$334,475	7.84
20								
21		ALL OTHER INSTALLATIONS						
22		175 WATT MERCURY	59	48,852		$10.97000	$7,767	0.18
23		400 WATT MERCURY	-	-		$0.00000	$0	0.00
24		1,000 WATT MERCURY	-	-		$0.00000	$0	0.00
25		HP SODIUM < 100 WATTS	4,925	2,482,326		$12.85000	$759,474	17.80
26		HP SODIUM 150 WATTS	-	-		$0.00000	$0	0.00
27		HP SODIUM 150 WATTS (DUAL LAMPS)	-	-		$0.00000	$0	0.00
28		HP SODIUM 200 WATTS	-	-		$0.00000	$0	0.00
29		HP SODIUM 250 WATTS	-	-		$0.00000	$0	0.00
30		HP SODIUM 250 WATTS (DUAL LAMPS)	-	-		$0.00000	$0	0.00
31		HP SODIUM 400 WATTS	-	-		$0.00000	$0	0.00
32		HP SODIUM > 400 WATTS	-	-		$0.00000	$0	0.00
33		METAL HALIDE, ALL LAMPS	26	22,776		$21.17000	$6,605	0.15
34								
35		ADDITIONAL FACILITIES						
36		ALL POLES, PER POLE	5,110	-		$6.48000	$397,354	9.31
37								
38		STATE kWh TAX						
39		FIRST 2,000 kWh, PER kWh		35,109,399		$0.00466	$163,513	3.83
40		NEXT 13,000 kWh, PER kWh		2,223,683		$0.00420	$9,332	0.22
41		ABOVE 15,000 kWh, PER kWh		313,711		$0.00364	$1,141	0.03
42				37,646,793			$173,986	
43								
44		TOTAL DISTIBUTION - POL	35,009	37,648,793			$4,267,402	100.00

Workpaper for Schedule 2 - Target Revenue for Base Distribution Rates

Witness: G. Hussing

PROPOSED ANNUALIZED

LINE NO.	RATE CODE	CLASS/ DESCRIPTION	NUMBER OF OCCURENCES	SALES	BILLING UNITS	PROPOSED RATES	PROPOSED REVENUE LESS FUEL COST REVENUE	% OF REV TO TOTAL LESS FUEL COST REVENUE
	(A)	(B)	(C)	(D1)	(D2)	(E)	(F)	(G)
				(KWH)		($)	($)	(%)
	MISCELLANEOUS CHARGES							
1	PROPOSED							
2								
3	LATE PAYMENT CHARGES (FORFEITED DISCOUNTS) (450)							
4		TOTAL REVENUE					$8,516,969	26.91
5								
6	MISCELLANEOUS SERVICE REVENUES (451)							
7		TOTAL REVENUE					$4,023,085	12.71
8								
9	RENT FROM ELECTRIC PROPERTY (454)							
10		TOTAL REVENUE					$6,519,865	20.60
11								
12	OTHER ELECTRIC REVENUES (456)							
13		TOTAL REVENUE					$12,584,080	39.77
14								
15								
16	TOTAL OTHER ELECTRIC REVENUES		0			$0.00	$31,643,999	100.00

Workpaper for Schedule 2 - Target Revenue for Base Distribution Rates

				Source:
OE Increase	(a)	$	75,000,000	Update Filing in Case No. 07-551-EL-AIR
Miscellaneous Revenue Increase	(b)	$	1,631,780	
Electric Revenue Increase	(c) = (a) - (b)	$	73,368,220	Update Filing in Case No. 07-551-EL-AIR
Current Revenues	(d)	$	517,745,537	Update Filing in Case No. 07-551-EL-AIR
Current Miscellaneous Revenues	(e)	$	30,012,219	
Proposed Electric Revenue Target	(f) = (d) + (c) - (e)	$	**561,101,538**	

Rate	Proposed Revenue Proof (A)	Stipulated Revenue % (B)	Target Revenue (C)
RS	$ 350,388,325	62.45%	$ 350,407,910
GS	$ 147,076,452	26.21%	$ 147,064,713
GP	$ 28,220,196	5.03%	$ 28,223,407
GSU	$ 4,600,308	0.82%	$ 4,601,033
GT	$ 11,893,559	2.12%	$ 11,895,353
TRF	$ 336,844	0.06%	$ 336,661
STL and ESIP	$ 7,729,475	1.39%	$ 7,799,311
POL	$ 4,267,402	0.76%	$ 4,264,372
Contracts	$ 6,587,233	1.16%	$ 6,508,778
Total Electric	$ 561,099,795	100.00%	$ **561,101,538**
Miscellaneous	$ 31,643,999		$ 31,643,999
Total	$ 592,743,794		$ 592,745,537

(A) Pages 1-15 of OE Schedule 5h - Workpaper for Schedule 2
(B) Stipulation in Case No. 07-551-EL-AIR
(C) B × Proposed Electric Revenue Target

Workpaper for Schedule 2 - Target Revenue for Base Distribution Rates

Witness: G. Hussing

PROPOSED ANNUALIZED

LINE NO.	RATE CODE (A)	CLASS/ DESCRIPTION (B)	CUSTOMER BILLS (C)	SALES (D1) (KWH)	BILLING UNITS (D2)	PROPOSED RATES (E) ($/kWh)	PROPOSED REVENUE LESS FUEL COST REVENUE (F) ($)	% OF REV TO TOTAL LESS FUEL COST REVENUE (G) (%)
1	RS	RESIDENTIAL SERVICE	3,332,523	2,481,166,258		$0.04393	$109,001,385	54.84
2								
3	GS	GENERAL SERVICE - SECONDARY	405,121	2,174,825,971		$0.02875	$62,536,343	31.46
4								
5	GP	GENERAL SERVICE - PRIMARY	3,710	1,074,307,524		$0.00870	$9,348,673	4.70
6								
7	GSU	GENERAL SERVICE - SUBTRANSMISSION	63	103,221,038		$0.00200	$206,913	0.10
8								
9	GT	GENERAL SERVICE - TRANSMISSION	483	1,548,766,213		$0.00174	$2,690,086	1.35
10								
11	SPC - GS	SPECIAL CONTRACT - GENERAL SERVICE - SECONDARY	12	191,582		$0.01904	$3,649	0.00
12								
13	SPC - GP	SPECIAL CONTRACT - GENERAL SERVICE - PRIMARY	23	27,659,296		$0.00707	$195,457	0.10
14								
15	SPC - GSU	SPECIAL CONTRACT - GENERAL SERVICE - SUBTRANSMISSION	0	0		$0.00000	$0	0.00
16								
17	SPC - GT	SPECIAL CONTRACT - GENERAL SERVICE - TRANSMISSION	58	279,906,271		$0.00096	$268,964	0.14
18								
19	SPC - U	SPECIAL CONTRACT - GENERAL SERVICE - UNIQUE						
20		GS - SECONDARY	3,315	79,813,988		$0.01475	$1,177,010	0.59
21		GP - PRIMARY	338	34,799,003		$0.01048	$364,684	0.18
22		GSU - SUBTRANSMISSION	0	0		$0.00000	$0	0.00
23		GT - TRANSMISSION	138	2,794,311,148		($0.00176)	($4,919,456)	(2.47)
24			3,791	2,908,924,139		($0.00116)	($3,377,761)	
25								
26								
27	POL	PRIVATE OUTDOOR LIGHTING SERVICE	10,378	11,415,531		$0.11362	$1,297,068	0.65
28								
29	STL	STREET LIGHTING SERVICE	44,109	46,264,101		$0.11653	$5,390,964	2.71
30								
31	TRF	TRAFFIC LIGHTING SERVICE	5,052	2,921,006		$0.03412	$99,679	0.05
32								
33	MISCELLANEOUS CHARGES						$11,117,719	5.59
34								
35	TOTAL COMPANY		3,805,322	10,659,568,931		$0.01865	$198,779,139	100.00

Workpaper for Schedule 2 - Target Revenue for Base Distribution Rates

Witness: G. Hussing

			PROPOSED ANNUALIZED					
LINE NO.	RATE CODE	CLASS/ DESCRIPTION	CUSTOMER BILLS	SALES	BILLING UNITS	PROPOSED RATES	PROPOSED REVENUE LESS FUEL COST REVENUE	% OF REV TO TOTAL LESS FUEL COST REVENUE
	(A)	(B)	(C)	(D1)	(D2)	(E)	(F)	(G)
				(KWH)		($)	($)	(%)
	RS	RESIDENTIAL SERVICE						
	PROPOSED							
1	RS	RESIDENTIAL SERVICE						
2								
3		DISTRIBUTION CHARGES						
4								
5		CUSTOMER CHARGE						
6		BILLS	3,332,523			$4.00	$13,330,093	12.23
7								
8		ENERGY CHARGE						
9		UP TO 500 kWh, PER kWh		1,407,872,003		$0.03611	$50,843,890	46.65
10		OVER 500 kWh, PER kWh		1,073,294,255		$0.03611	$38,760,949	35.56
11								
12		CUSTOMER DISCOUNT						
13		ALL kWh, PER kWh		309,301,269		($0.01760)	($5,443,702)	(4.99)
14								
15		RIDER DSM - DEMAND SIDE MANAGEMENT						
16		ALL kWh, PER kWh		2,481,166,258		$0.00000	$0	0.00
17								
18		STATE kWh TAX						
19		FIRST 2,000 kWh, PER kWh		2,380,710,098		$0.00466	$11,087,572	10.17
20		NEXT 13,000 kWh, PER kWh		99,979,782		$0.00420	$419,569	0.38
21		ABOVE 15,000 kWh, PER kWh		829,468		$0.00364	$3,016	0.00
22				2,481,519,349			$11,510,156	
23								
24		TOTAL DISTRIBUTION - RS	3,332,523	2,481,166,258			$109,001,385	100.00

Workpaper for Schedule 2 - Target Revenue for Base Distribution Rates

Witness: G. Hussing

			PROPOSED ANNUALIZED					
LINE NO.	RATE CODE	CLASS/ DESCRIPTION	CUSTOMER BILLS	KWH SALES	BILLING UNITS	PROPOSED RATES	PROPOSED REVENUE LESS FUEL COST REVENUE	% OF REV TO TOTAL LESS FUEL COST REVENUE
	(A)	(B)	(C)	(D1)	(D2)	(E)	(F)	(G)
				(KWH)		($)	($)	(%)
	PROPOSED							
1	GS	GENERAL SERVICE - SECONDARY						
2								
3		CUSTOMER CHARGE						
4		BILLS	405,121	2,174,825,971		$7.00	$2,835,847	3.95
5								
6		CAPACITY CHARGE						
7		UP TO 5 kW OF BILLING DEMAND			2,025,605	$13.93	$5,642,930	7.85
8		OVER 5 kW, PER kW			5,752,551	$7.96150	$45,798,935	63.72
9								
10		REACTIVE DEMAND CHARGE						
11		ALL rkVa, PER rkVa			673,804	$0.36000	$242,569	0.34
12								
13		CUSTOMER DISCOUNT						
14		ALL kWh, PER kWh		58,801,840		($0.01500)	($882,028)	(1.23)
15								
16		STATE kWh TAX						
17		FIRST 2,000 kWh, PER kWh		606,985,167		$0.00466	$2,826,884	3.93
18		NEXT 13,000 kWh, PER kWh		686,735,900		$0.00420	$2,881,912	4.01
19		ABOVE 15,000 kWh, PER kWh		877,224,682		$0.00364	$3,189,293	4.44
20				2,170,945,748			$8,898,089	
21								
22		TOTAL DISTRIBUTION - GS	405,121	2,174,825,971			$62,536,343	87.01

Case No. 08-XXXX-EL-SSO
The Toledo Edison Company

Schedule 5h
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Workpaper for Schedule 2 - Target Revenue for Base Distribution Rates

Witness: G. Hussing

			PROPOSED ANNUALIZED					
LINE NO.	RATE CODE	CLASS/ DESCRIPTION	CUSTOMER BILLS	KWH SALES	BILLING UNITS	PROPOSED RATES	PROPOSED REVENUE LESS FUEL COST REVENUE	% OF REV TO TOTAL LESS FUEL COST REVENUE
	(A)	(B)	(C)	(D1)	(D2)	(E)	(F)	(G)
				(KWH)		($)	($)	(%)
23	GP	GENERAL SERVICE - PRIMARY						
24								
25		CUSTOMER CHARGE						
26		BILLS	3,710	1,074,307,524		$150.00	$556,444	0.77
27								
28		CAPACITY CHARGE						
29		ALL kW OF BILLING DEMAND, PER kW			2,604,529	$1.77400	$4,620,435	6.43
30								
31		REACTIVE DEMAND CHARGE						
32		ALL rkVa, PER rkVa			1,046,934	$0.36000	$376,896	0.52
33								
34		CUSTOMER DISCOUNT						
35		ALL kWh, PER kWh		23,879,365		($0.00500)	($119,397)	(0.17)
36								
37		STATE kWh TAX						
38		FIRST 2,000 kWh, PER kWh		7,417,444		$0.00466	$34,545	0.05
39		NEXT 13,000 kWh, PER kWh		44,852,568		$0.00420	$188,225	0.26
40		ABOVE 15,000 kWh, PER kWh		1,015,364,727		$0.00364	$3,691,524	5.14
41				1,067,634,740			$3,914,294	
42								
43		TOTAL DISTRIBUTION - GP	3,710	1,074,307,524			$9,348,673	13.01
44								
45								
46	GSU	GENERAL SERVICE - SUBTRANSMISSION						
47								
48		CUSTOMER CHARGE						
49		BILLS	63	103,221,038		$200.00	$12,514	0.02
50								
51		CAPACITY CHARGE						
52		ALL kVA OF BILLING DEMAND, PER kVA			185,981	$0.46500	$86,481	0.12
53								
54		REACTIVE DEMAND CHARGE						
55		ALL rkVa, PER rkVa			-	$0.00000	$0	0.00
56								
57		TRANSFORMER CHARGE						
58		ALL kVA OF BILLING DEMAND, PER kVA			-	$0.00000	$0	0.00
59								
60		CUSTOMER DISCOUNT						
61		ALL kWh, PER kWh		-		$0.00000	$0	0.00
62								
63		STATE kWh TAX						
64		FIRST 2,000 kWh, PER kWh		94,462		$0.00466	$440	0.00
65		NEXT 13,000 kWh, PER kWh		614,006		$0.00420	$2,577	0.00
66		ABOVE 15,000 kWh, PER kWh		28,853,201		$0.00364	$104,901	0.15
67				29,561,670			$107,917	
68								
69		TOTAL DISTRIBUTION - GSU	63	103,221,038			$206,913	0.29

Workpaper for Schedule 2 - Target Revenue for Base Distribution Rates

Witness: G. Hussing

			PROPOSED ANNUALIZED					
LINE NO.	RATE CODE	CLASS/ DESCRIPTION	CUSTOMER BILLS	KWH SALES	BILLING UNITS	PROPOSED RATES	PROPOSED REVENUE LESS FUEL COST REVENUE	% OF REV TO TOTAL LESS FUEL COST REVENUE
	(A)	(B)	(C)	(D1)	(D2)	(E)	(F)	(G)
				(KWH)		($)	($)	(%)
70	GT	GENERAL SERVICE - TRANSMISSION						
71								
72		CUSTOMER CHARGE						
73		BILLS	483	1,548,766,213		$320.00	$154,601	0.22
74								
75		CAPACITY CHARGE						
76		ALL kVA OF BILLING DEMAND, PER kVA			3,433,618	$0.12750	$437,786	0.61
77								
78		REACTIVE DEMAND CHARGE						
79		ALL rkVa, PER rkVa			-	$0.00000	$0	0.00
80								
81		TRANSFORMER CHARGE						
82		ALL kVA OF BILLING DEMAND, PER kVA			588,057	$0.13000	$76,447	0.11
83								
84		CUSTOMER DISCOUNT						
85		ALL kWh, PER kWh		7,529,915		($0.00500)	($37,650)	(0.05)
86								
87		STATE kWh TAX						
88		FIRST 2,000 kWh, PER kWh		696,087		$0.00466	$3,242	0.00
89		NEXT 13,000 kWh, PER kWh		4,524,565		$0.00420	$18,988	0.03
90		ABOVE 15,000 kWh, PER kWh		560,192,801		$0.00364	$2,036,672	2.83
91				565,413,453			$2,058,901	
92								
93		TOTAL DISTRIBUTION - GT	483	1,548,766,213			$2,690,086	3.74
94								
95								
96	SPC - GS	SPECIAL CONTRACT - GENERAL SERVICE - SECONDARY						
97								
98		CUSTOMER CHARGE						
99		BILLS	12	191,582		$7.00	$84	0.00
100								
101		CAPACITY CHARGE						
102		UP TO 5 kW OF BILLING DEMAND			60	$13.93	$167	0.00
103		OVER 5 kW, PER kW			620	$7.96150	$4,936	0.01
104								
105		REACTIVE DEMAND CHARGE						
106		ALL rkVa, PER rkVa			-	$0.36000	$0	0.00
107								
108		CUSTOMER DISCOUNT						
109		ALL kWh, PER kWh		154,612		($0.01500)	($2,319)	(0.00)
110								
111		CONTRACT DISCOUNT						0.00
112								
113		STATE kWh TAX						
114		FIRST 2,000 kWh, PER kWh		23,561		$0.00466	$110	0.00
115		NEXT 13,000 kWh, PER kWh		106,813		$0.00420	$448	0.00
116		ABOVE 15,000 kWh, PER kWh		61,208		$0.00364	$223	0.00
117				191,582			$781	
118								
119		TOTAL DISTRIBUTION - SPC-GS	12	191,582			$3,649	0.01

Workpaper for Schedule 2 - Target Revenue for Base Distribution Rates

Witness: G. Hussing

			PROPOSED ANNUALIZED					
LINE NO.	RATE CODE	CLASS/ DESCRIPTION	CUSTOMER BILLS	KWH SALES	BILLING UNITS	PROPOSED RATES	PROPOSED REVENUE LESS FUEL COST REVENUE	% OF REV TO TOTAL LESS FUEL COST REVENUE
	(A)	(B)	(C)	(D1)	(D2)	(E)	(F)	(G)
				(KWH)		($)	($)	(%)
120	SPC - GP	SPECIAL CONTRACT - GENERAL SERVICE - PRIMARY						
121								
122		CUSTOMER CHARGE						
123		BILLS	23	27,659,296		$150.00	$3,450	0.00
124								
125		CAPACITY CHARGE						
126		ALL kW OF BILLING DEMAND, PER kW			65,117	$1.77400	$115,518	0.16
127								
128		REACTIVE DEMAND CHARGE						
129		ALL rkVa, PER rkVa			12,069	$0.36000	$4,345	0.01
130								
131		CUSTOMER DISCOUNT						
132		ALL kWh, PER kWh		-		($0.00500)	$0	0.00
133								
134		CONTRACT DISCOUNT					($28,630)	(0.04)
135								
136		STATE kWh TAX						
137		FIRST 2,000 kWh, PER kWh		46,000		$0.00466	$214	0.00
138		NEXT 13,000 kWh, PER kWh		299,000		$0.00420	$1,255	0.00
139		ABOVE 15,000 kWh, PER kWh		27,314,296		$0.00364	$99,306	0.14
140				27,659,296			$100,775	
141								
142		TOTAL DISTRIBUTION - SPC-GP	23	27,659,296			$195,457	0.27
143								
144								
145	SPC - GSU	SPECIAL CONTRACT - GENERAL SERVICE - SUBTRANSMISSION						
146								
147		CUSTOMER CHARGE						
148		BILLS	-	-		$200.00	$0	0.00
149								
150		CAPACITY CHARGE						
151		ALL kVA OF BILLING DEMAND, PER kVA			-	$0.46500	$0	0.00
152								
153		REACTIVE DEMAND CHARGE						
154		ALL rkVa, PER rkVa			-	$0.00000	$0	0.00
155								
156		TRANSFORMER CHARGE						
157		ALL kVA OF BILLING DEMAND, PER kVA			-	$0.00000	$0	0.00
158								
159		CUSTOMER DISCOUNT						
160		ALL kWh, PER kWh		-		$0.00000	$0	0.00
161								
162		CONTRACT DISCOUNT						0.00
163								
164		STATE kWh TAX						
165		FIRST 2,000 kWh, PER kWh		-		$0.00466	$0	0.00
166		NEXT 13,000 kWh, PER kWh		-		$0.00420	$0	0.00
167		ABOVE 15,000 kWh, PER kWh		-		$0.00364	$0	0.00
168				-			$0	
169								
170		TOTAL DISTRIBUTION - SPC-GSU	-	-			$0	0.00

Workpaper for Schedule 2 - Target Revenue for Base Distribution Rates

Witness: G. Hussing

			PROPOSED ANNUALIZED					
LINE NO.	RATE CODE	CLASS/ DESCRIPTION	CUSTOMER BILLS	KWH SALES	BILLING UNITS	PROPOSED RATES	PROPOSED REVENUE LESS FUEL COST REVENUE	% OF REV TO TOTAL LESS FUEL COST REVENUE
	(A)	(B)	(C)	(D1)	(D2)	(E)	(F)	(G)
				(KWH)		($)	($)	(%)
171	SPC - GT	SPECIAL CONTRACT - GENERAL SERVICE - TRANSMISSION						
172								
173		CUSTOMER CHARGE						
174		BILLS	58	279,906,271		$320.00	$18,560	0.03
175								
176		CAPACITY CHARGE						
177		ALL kVA OF BILLING DEMAND, PER kVA			545,271	$0.12750	$69,522	0.10
178								
179		REACTIVE DEMAND CHARGE						
180		ALL rkVa, PER rkVa			-	$0.00000	$0	0.00
181								
182		TRANSFORMER CHARGE						
183		ALL kVA OF BILLING DEMAND, PER kVA			-	$0.13000	$0	0.00
184								
185		CUSTOMER DISCOUNT						
186		ALL kWh, PER kWh		-		($0.00500)	$0	0.00
187								
188		CONTRACT DISCOUNT					($32,475)	(0.05)
189								
190		STATE kWh TAX						
191		FIRST 2,000 kWh, PER kWh		47,510		$0.00466	$221	0.00
192		NEXT 13,000 kWh, PER kWh		308,813		$0.00420	$1,296	0.00
193		ABOVE 15,000 kWh, PER kWh		58,267,254		$0.00364	$211,840	0.29
194				58,623,577			$213,357	
195								
196		TOTAL DISTRIBUTION - SPC-GT	58	279,906,271			$268,964	0.37
197								
198								
199	SPC - U	SPECIAL CONTRACT - GENERAL SERVICE - UNIQUE						
200								
201		GS - SECONDARY	3,315	79,813,988			$1,177,010	1.64
202		GP - PRIMARY	338	34,799,003			$364,684	0.51
203		GSU - SUBTRANSMISSION	0	0			$0	0.00
204		GT - TRANSMISSION	138	2,794,311,148			($4,919,456)	(6.84)
205		TOTAL DISTRIBUTION - SPC-U	3,791	2,908,924,139			($3,377,761)	(4.70)
206								
207								
208	TOTAL PROPOSED DISTRIBUTION		413,260	8,117,802,035			$71,872,324	100.00

Workpaper for Schedule 2 - Target Revenue for Base Distribution Rates

Witness: G. Hussing

LINE NO.	RATE CODE (A)	CLASS/ DESCRIPTION (B)	PROPOSED ANNUALIZED FIXTURES (C)	SALES (D1) (KWH)	BILLING UNITS (D2)	PROPOSED RATES (E) ($)	PROPOSED REVENUE LESS FUEL COST REVENUE (F) ($)	% OF REV TO TOTAL LESS FUEL COST REVENUE (G) (%)
1	PROPOSED							
2								
3	STL	STREET LIGHTING SERVICE						
4								
5		DISTRIBUTION CHARGES						
6								
7		COMPANY-OWNED, INCANDESCENT STREET LIGHTING						
8		OVERHEAD SERVICE, PER LAMP	0	0		$0.000	$0	0.00
9		OVERHEAD-FED WOOD SERVICE, PER LAMP	43	99,540		$10.920	$5,635	0.10
10		OVERHEAD-FED STEEL SERVICE, PER LAMP	17	34,116		$11.900	$2,428	0.05
11		UNDERGROUND SERVICE, PER LAMP	82	172,010		$18.070	$17,781	0.33
12		UNDERGROUND SERVICE (DUAL LAMPS), PER LAMP	1	5,806		$32.160	$386	0.01
13								
14		COMPANY-OWNED, FLOURESCENT STREET LIGHTING						
15		OVERHEAD-FED STEEL SERVICE, PER LAMP	4	12,677		$16.740	$804	0.01
16		UNDERGROUND SERVICE, PER LAMP	35	39,564		$15.010	$6,304	0.12
17		UNDERGROUND SERVICE (DUAL LAMPS), PER LAMP	17	38,434		$20.500	$4,182	0.08
18								
19		COMPANY-OWNED, OVERHEAD-FED WOOD POLE LIGHTING						
20		100 WATT MERCURY	0	0		$0.000	$0	0.00
21		175 WATT MERCURY	13,713	11,377,426		$5.960	$980,754	18.19
22		175 WATT MERCURY (DUAL LAMPS)	8	13,275		$10.130	$972	0.02
23		250 WATT MERCURY	2,896	3,615,322		$6.530	$226,891	4.21
24		250 WATT MERCURY (DUAL LAMPS)	0	0		$0.000	$0	0.00
25		400 WATT MERCURY	4,155	7,873,050		$8.220	$409,849	7.60
26		400 WATT MERCURY (DUAL LAMPS)	10	57,897		$14.490	$1,739	0.03
27		400 WATT MERCURY (30 FT CONCRETE POLE)	0	0		$0.000	$0	0.00
28		400 WATT MERCURY (STEEL POLE, 2 BRACKETS)	0	0		$0.000	$0	0.00
29		700 WATT MERCURY	16	55,095		$13.380	$2,569	0.05
30		1,000 WATT MERCURY	2	9,113		$15.820	$380	0.01
31		70 WATT HP SODIUM	0	0		$0.000	$0	0.00
32		100 WATT HP SODIUM	3,034	1,515,748		$9.120	$331,986	6.16
33		100 WATT HP SODIUM (DUAL LAMP)	1	1,008		$17.800	$214	0.00
34		100 WATT HP SODIUM (ORNAMENTAL)	0	0		$0.000	$0	0.00
35		150 WATT HP SODIUM	544	407,619		$10.320	$67,400	1.25
36		150 WATT HP SODIUM (DUAL LAMPS)	0	0		$18.800	$0	0.00
37		200 WATT HP SODIUM	10	19,590		$13.160	$1,579	0.03
38		215 WATT HP SODIUM	0	0		$0.000	$0	0.00
39		250 WATT HP SODIUM	672	849,989		$10.340	$83,320	1.55
40		250 WATT HP SODIUM (DUAL LAMPS)	16	40,189		$20.850	$3,972	0.07
41		250 WATT HP SODIUM (STEEL POLE, 2 BRACKETS)	0	0		$0.000	$0	0.00
42		250 WATT HP SODIUM (DOWNTOWN)	0	0		$0.000	$0	0.00
43		310 WATT HP SODIUM	0	0		$0.000	$0	0.00
44		400 WATT HP SODIUM	1,531	2,962,553		$13.540	$248,716	4.61
45		400 WATT HP SODIUM (DUAL LAMPS)	0	0		$0.000	$0	0.00
46		400 WATT HP SODIUM (DUAL LAMPS, DAVIT POLE)	0	0		$0.000	$0	0.00
47		400 WATT HP SODIUM (DOWNTOWN)	0	0		$0.000	$0	0.00
48		1000 WATT HP SODIUM	0	0		$0.000	$0	0.00
49								

Workpaper for Schedule 2 - Target Revenue for Base Distribution Rates

Witness: G. Hussing

		PROPOSED ANNUALIZED						
LINE NO.	RATE CODE	CLASS/DESCRIPTION	FIXTURES	SALES	BILLING UNITS	PROPOSED RATES	PROPOSED REVENUE LESS FUEL COST REVENUE	% OF REV TO TOTAL LESS FUEL COST REVENUE
	(A)	(B)	(C)	(D1)	(D2)	(E)	(F)	(G)
				(KWH)		($)	($)	(%)
50		COMPANY-OWNED, OVERHEAD-FED METAL POLE LIGHTING						
51		100 WATT MERCURY	0	0		$0.000	$0	0.00
52		175 WATT MERCURY	1,315	1,090,617		$8.230	$129,820	2.41
53		175 WATT MERCURY (DUAL LAMPS)	0	0		$0.000	$0	0.00
54		250 WATT MERCURY	448	559,373		$8.650	$46,502	0.86
55		250 WATT MERCURY (DUAL LAMPS)	0	0		$0.000	$0	0.00
56		400 WATT MERCURY	558	1,057,319		$10.910	$73,053	1.36
57		400 WATT MERCURY (DUAL LAMPS)	4	15,159		$17.140	$823	0.02
58		400 WATT MERCURY (30 FT CONCRETE POLE)	0	0		$0.000	$0	0.00
59		400 WATT MERCURY (STEEL POLE, 2 BRACKETS)	0	0		$0.000	$0	0.00
60		700 WATT MERCURY	5	17,217		$16.290	$977	0.02
61		1,000 WATT MERCURY	0	0		$0.000	$0	0.00
62		70 WATT HP SODIUM	0	0		$0.000	$0	0.00
63		100 WATT HP SODIUM	117	58,122		$10.960	$15,322	0.28
64		100 WATT HP SODIUM (DUAL LAMP)	0	0		$18.680	$0	0.00
65		100 WATT HP SODIUM (ORNAMENTAL)	0	0		$0.000	$0	0.00
66		150 WATT HP SODIUM	48	35,950		$11.640	$6,705	0.12
67		150 WATT HP SODIUM (DUAL LAMPS)	0	0		$19.240	$0	0.00
68		200 WATT HP SODIUM	68	71,684		$15.280	$12,468	0.23
69		215 WATT HP SODIUM	0	0		$0.000	$0	0.00
70		250 WATT HP SODIUM	152	191,770		$14.280	$25,961	0.48
71		250 WATT HP SODIUM (DUAL LAMPS)	0	0		$22.250	$0	0.00
72		250 WATT HP SODIUM (STEEL POLE, 2 BRACKETS)	0	0		$0.000	$0	0.00
73		250 WATT HP SODIUM (DOWNTOWN)	0	0		$0.000	$0	0.00
74		310 WATT HP SODIUM	0	0		$0.000	$0	0.00
75		400 WATT HP SODIUM	157	308,053		$16.960	$32,004	0.59
76		400 WATT HP SODIUM (DUAL LAMPS)	0	0		$0.000	$0	0.00
77		400 WATT HP SODIUM (DUAL LAMPS, DAVIT POLE)	0	0		$0.000	$0	0.00
78		400 WATT HP SODIUM (DOWNTOWN)	0	0		$0.000	$0	0.00
79		1000 WATT HP SODIUM	0	0		$0.000	$0	0.00
80								
81		COMPANY-OWNED, UNDERGROUND-FED POST LIGHTING						
82		100 WATT MERCURY	0	0		$0.000	$0	0.00
83		175 WATT MERCURY	0	0		$0.000	$0	0.00
84		175 WATT MERCURY (DUAL LAMPS)	0	0		$0.000	$0	0.00
85		250 WATT MERCURY	0	0		$0.000	$0	0.00
86		250 WATT MERCURY (DUAL LAMPS)	0	0		$0.000	$0	0.00
87		400 WATT MERCURY	0	0		$0.000	$0	0.00
88		400 WATT MERCURY (DUAL LAMPS)	0	0		$0.000	$0	0.00
89		400 WATT MERCURY (30 FT CONCRETE POLE)	0	0		$0.000	$0	0.00
90		400 WATT MERCURY (STEEL POLE, 2 BRACKETS)	0	0		$0.000	$0	0.00
91		700 WATT MERCURY	0	0		$0.000	$0	0.00
92		1,000 WATT MERCURY	0	0		$0.000	$0	0.00
93		70 WATT HP SODIUM	0	0		$0.000	$0	0.00
94		100 WATT HP SODIUM	0	0		$0.000	$0	0.00
95		100 WATT HP SODIUM (DUAL LAMP)	0	0		$0.000	$0	0.00
96		100 WATT HP SODIUM (ORNAMENTAL)	0	0		$0.000	$0	0.00
97		150 WATT HP SODIUM	0	0		$0.000	$0	0.00
98		150 WATT HP SODIUM (DUAL LAMPS)	0	0		$0.000	$0	0.00
99		200 WATT HP SODIUM	0	0		$0.000	$0	0.00
100		215 WATT HP SODIUM	0	0		$0.000	$0	0.00
101		250 WATT HP SODIUM	0	0		$0.000	$0	0.00
102		250 WATT HP SODIUM (DUAL LAMPS)	0	0		$0.000	$0	0.00
103		250 WATT HP SODIUM (STEEL POLE, 2 BRACKETS)	0	0		$0.000	$0	0.00
104		250 WATT HP SODIUM (DOWNTOWN)	0	0		$0.000	$0	0.00
105		310 WATT HP SODIUM	0	0		$0.000	$0	0.00
106		400 WATT HP SODIUM	0	0		$0.000	$0	0.00
107		400 WATT HP SODIUM (DUAL LAMPS)	0	0		$0.000	$0	0.00
108		400 WATT HP SODIUM (DUAL LAMPS, DAVIT POLE)	0	0		$0.000	$0	0.00
109		400 WATT HP SODIUM (DOWNTOWN)	0	0		$0.000	$0	0.00
110		1000 WATT HP SODIUM	0	0		$0.000	$0	0.00
111								

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The Toledo Edison Company

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Workpaper for Schedule 2 - Target Revenue for Base Distribution Rates

Witness: G. Hussing

			PROPOSED ANNUALIZED					
LINE NO.	RATE CODE	CLASS/ DESCRIPTION	FIXTURES	SALES	BILLING UNITS	PROPOSED RATES	PROPOSED REVENUE LESS FUEL COST REVENUE	% OF REV TO TOTAL LESS FUEL COST REVENUE
	(A)	(B)	(C)	(D1)	(D2)	(E)	(F)	(G)
				(KWH)		($)	($)	(%)
112		COMPANY-OWNED, UNDERGROUND-FED POLE LIGHTING						
113		100 WATT MERCURY	0	0		$0.000	$0	0.00
114		175 WATT MERCURY	4,783	3,903,204		$11.940	$673,846	12.50
115		175 WATT MERCURY (DUAL LAMPS)	0	0		$0.000	$0	0.00
116		250 WATT MERCURY	782	975,781		$12.480	$117,037	2.17
117		250 WATT MERCURY (DUAL LAMPS)	17	42,248		$17.470	$3,564	0.07
118		400 WATT MERCURY	788	1,492,658		$14.530	$137,352	2.55
119		400 WATT MERCURY (DUAL LAMPS)	26	98,532		$20.400	$6,365	0.12
120		400 WATT MERCURY (30 FT CONCRETE POLE)	0	0		$0.000	$0	0.00
121		400 WATT MERCURY (STEEL POLE, 2 BRACKETS)	0	0		$0.000	$0	0.00
122		700 WATT MERCURY	0	0		$0.000	$0	0.00
123		1,000 WATT MERCURY	0	0		$0.000	$0	0.00
124		70 WATT HP SODIUM	0	0		$0.000	$0	0.00
125		100 WATT HP SODIUM	3,723	1,878,017		$14.700	$656,693	12.18
126		100 WATT HP SODIUM (DUAL LAMP)	1	1,008		$22.910	$275	0.01
127		100 WATT HP SODIUM (ORNAMENTAL)	1,760	889,058		$25.960	$548,353	10.17
128		150 WATT HP SODIUM	214	160,464		$12.640	$32,497	0.60
129		150 WATT HP SODIUM (DUAL LAMPS)	1	749		$25.890	$311	0.01
130		200 WATT HP SODIUM	6	6,325		$19.210	$1,383	0.03
131		215 WATT HP SODIUM	0	0		$0.000	$0	0.00
132		250 WATT HP SODIUM	375	474,677		$15.980	$71,910	1.33
133		250 WATT HP SODIUM (DUAL LAMPS)	38	94,935		$28.480	$12,816	0.24
134		250 WATT HP SODIUM (STEEL POLE, 2 BRACKETS)	0	0		$0.000	$0	0.00
135		250 WATT HP SODIUM (DOWNTOWN)	0	0		$30.950	$0	0.00
136		310 WATT HP SODIUM	0	0		$0.000	$0	0.00
137		400 WATT HP SODIUM	271	530,890		$17.690	$57,528	1.07
138		400 WATT HP SODIUM (DUAL LAMPS)	0	0		$0.000	$0	0.00
139		400 WATT HP SODIUM (DUAL LAMPS, DAVIT POLE)	50	195,900		$23.000	$13,800	0.26
140		400 WATT HP SODIUM (DOWNTOWN)	10	19,590		$45.380	$5,446	0.10
141		1000 WATT HP SODIUM	0	0		$0.000	$0	0.00
142								
143		COMPANY-OWNED, BRIDGE OR UNDERPASS WALLPACK						
144		100 WATT MERCURY	0	0		$0.000	$0	0.00
145		175 WATT MERCURY	0	0		$0.000	$0	0.00
146		175 WATT MERCURY (DUAL LAMPS)	0	0		$0.000	$0	0.00
147		250 WATT MERCURY	0	0		$0.000	$0	0.00
148		250 WATT MERCURY (DUAL LAMPS)	0	0		$0.000	$0	0.00
149		400 WATT MERCURY	0	0		$0.000	$0	0.00
150		400 WATT MERCURY (DUAL LAMPS)	0	0		$0.000	$0	0.00
151		400 WATT MERCURY (30 FT CONCRETE POLE)	0	0		$0.000	$0	0.00
152		400 WATT MERCURY (STEEL POLE, 2 BRACKETS)	0	0		$0.000	$0	0.00
153		700 WATT MERCURY	0	0		$0.000	$0	0.00
154		1,000 WATT MERCURY	0	0		$0.000	$0	0.00
155		70 WATT HP SODIUM	0	0		$0.000	$0	0.00
156		100 WATT HP SODIUM	0	0		$0.000	$0	0.00
157		100 WATT HP SODIUM (DUAL LAMP)	0	0		$0.000	$0	0.00
158		100 WATT HP SODIUM (ORNAMENTAL)	0	0		$0.000	$0	0.00
159		150 WATT HP SODIUM	0	0		$0.000	$0	0.00
160		150 WATT HP SODIUM (DUAL LAMPS)	0	0		$0.000	$0	0.00
161		200 WATT HP SODIUM	0	0		$0.000	$0	0.00
162		215 WATT HP SODIUM	0	0		$0.000	$0	0.00
163		250 WATT HP SODIUM	0	0		$0.000	$0	0.00
164		250 WATT HP SODIUM (DUAL LAMPS)	0	0		$0.000	$0	0.00
165		250 WATT HP SODIUM (STEEL POLE, 2 BRACKETS)	0	0		$0.000	$0	0.00
166		250 WATT HP SODIUM (DOWNTOWN)	0	0		$0.000	$0	0.00
167		310 WATT HP SODIUM	0	0		$0.000	$0	0.00
168		400 WATT HP SODIUM	0	0		$0.000	$0	0.00
169		400 WATT HP SODIUM (DUAL LAMPS)	0	0		$0.000	$0	0.00
170		400 WATT HP SODIUM (DUAL LAMPS, DAVIT POLE)	0	0		$0.000	$0	0.00
171		400 WATT HP SODIUM (DOWNTOWN)	0	0		$0.000	$0	0.00
172		1000 WATT HP SODIUM	0	0		$0.000	$0	0.00
173								

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The Toledo Edison Company

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Workpaper for Schedule 2 - Target Revenue for Base Distribution Rates

Witness: G. Hussing

			PROPOSED ANNUALIZED					
LINE NO.	RATE CODE	CLASS/DESCRIPTION	FIXTURES	SALES	BILLING UNITS	PROPOSED RATES	PROPOSED REVENUE LESS FUEL COST REVENUE	% OF REV TO TOTAL LESS FUEL COST REVENUE
	(A)	(B)	(C)	(D1)	(D2)	(E)	(F)	(G)
				(KWH)		($)	($)	(%)
174		COMPANY-OWNED, SPECIAL ARCHITECTURAL INSTALLATIONS						
175		100 WATT MERCURY	0	0		$0.000	$0	0.00
176		175 WATT MERCURY	0	0		$0.000	$0	0.00
177		175 WATT MERCURY (DUAL LAMPS)	0	0		$0.000	$0	0.00
178		250 WATT MERCURY	0	0		$0.000	$0	0.00
179		250 WATT MERCURY (DUAL LAMPS)	0	0		$0.000	$0	0.00
180		400 WATT MERCURY	0	0		$0.000	$0	0.00
181		400 WATT MERCURY (DUAL LAMPS)	0	0		$0.000	$0	0.00
182		400 WATT MERCURY (30 FT CONCRETE POLE)	0	0		$0.000	$0	0.00
183		400 WATT MERCURY (STEEL POLE, 2 BRACKETS)	0	0		$0.000	$0	0.00
184		700 WATT MERCURY	0	0		$0.000	$0	0.00
185		1,000 WATT MERCURY	0	0		$0.000	$0	0.00
186		70 WATT HP SODIUM	0	0		$0.000	$0	0.00
187		100 WATT HP SODIUM	0	0		$0.000	$0	0.00
188		100 WATT HP SODIUM (DUAL LAMP)	0	0		$0.000	$0	0.00
189		100 WATT HP SODIUM (ORNAMENTAL)	0	0		$0.000	$0	0.00
190		150 WATT HP SODIUM	0	0		$0.000	$0	0.00
191		150 WATT HP SODIUM (DUAL LAMPS)	0	0		$0.000	$0	0.00
192		200 WATT HP SODIUM	0	0		$0.000	$0	0.00
193		215 WATT HP SODIUM	0	0		$0.000	$0	0.00
194		250 WATT HP SODIUM	0	0		$0.000	$0	0.00
195		250 WATT HP SODIUM (DUAL LAMPS)	0	0		$0.000	$0	0.00
196		250 WATT HP SODIUM (STEEL POLE, 2 BRACKETS)	0	0		$0.000	$0	0.00
197		250 WATT HP SODIUM (DOWNTOWN)	0	0		$0.000	$0	0.00
198		310 WATT HP SODIUM	0	0		$0.000	$0	0.00
199		400 WATT HP SODIUM	0	0		$0.000	$0	0.00
200		400 WATT HP SODIUM (DUAL LAMPS)	0	0		$0.000	$0	0.00
201		400 WATT HP SODIUM (DUAL LAMPS, DAVIT POLE)	0	0		$0.000	$0	0.00
202		400 WATT HP SODIUM (DOWNTOWN)	0	0		$0.000	$0	0.00
203		1000 WATT HP SODIUM	0	0		$0.000	$0	0.00
204								
205		CUSTOMER-OWNED, ALL LAMP TYPES						
206		ALL kWh, PER kWh	0	0		$0.00000	$0	0.00
207								
208		CUSTOMER-OWNED, LIMITED MAINTENANCE, ALL LAMP TYPES						
209		ALL kWh, PER kWh	1,669	2,914,777		$0.04623	$134,736	2.50
210								
211		STATE kWh TAX						
212		FIRST 2,000 kWh, PER kWh		4,673,357		$0.00466	$21,765	0.40
213		NEXT 13,000 kWh, PER kWh		4,604,279		$0.00420	$19,322	0.36
214		ABOVE 15,000 kWh, PER kWh		36,986,465		$0.00364	$134,470	2.49
215				49,284,101			$175,557	
216								
217		TOTAL DISTRIBUTION - STL	44,109	49,284,101			$5,390,964	100.00

Workpaper for Schedule 2 - Target Revenue for Base Distribution Rates

Witness: G. Hussing

			PROPOSED ANNUALIZED					
LINE NO.	RATE CODE	CLASS/ DESCRIPTION	CUSTOMER BILLS	SALES	BILLING UNITS	PROPOSED RATES	PROPOSED REVENUE LESS FUEL COST REVENUE	% OF REV TO TOTAL LESS FUEL COST REVENUE
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
				(KWH)		($)	($)	(%)
1	PROPOSED							
2								
3	TRF	TRAFFIC LIGHTING SERVICE						
4								
5		DISTRIBUTION CHARGES						
6								
7		ALL kWh, PER kWh	5,052	2,921,006		$0.02959	$86,433	86.71068%
8								
9		STATE kWh TAX						
10		FIRST 2,000 kWh, PER kWh		2,145,767		$0.00466	$9,993	10.02554%
11		NEXT 13,000 kWh, PER kWh		775,239		$0.00420	$3,253	3.26379%
12		ABOVE 15,000 kWh, PER kWh		0		$0.00364	$0	0.00000%
13				2,921,006			$13,247	
14								
15		TOTAL DISTIBUTION - TRF	5,052	2,921,006			$99,679	100.00000%

Workpaper for Schedule 2 - Target Revenue for Base Distribution Rates

Witness: G. Hussing

		PROPOSED ANNUALIZED						
LINE NO.	RATE CODE	CLASS/ DESCRIPTION	CUSTOMER BILLS	SALES	BILLING UNITS	PROPOSED RATES	PROPOSED REVENUE LESS FUEL COST REVENUE	% OF REV TO TOTAL LESS FUEL COST REVENUE
	(A)	(B)	(C)	(D1)	(D2)	(E)	(F)	(G)
1	PROPOSED							
2								
3	POL	PRIVATE OUTDOOR LIGHTING SERVICE						
4								
5		DISTRIBUTION CHARGES						
6								
7		OVERHEAD-FED WOOD POLE LIGHTING						
8		175 WATT MERCURY	7,267	6,016,662		$5.77000	$503,132	38.79
9		400 WATT MERCURY	391	741,336		$16.58000	$77,793	6.00
10		1,000 WATT MERCURY	17	77,520		$21.91000	$4,470	0.34
11		HP SODIUM < 100 WATTS	-	-		$0.00000	$0	0.00
12		HP SODIUM 150 WATTS	-	-		$0.00000	$0	0.00
13		HP SODIUM 150 WATTS (DUAL LAMPS)	-	-		$0.00000	$0	0.00
14		HP SODIUM 200 WATTS	467	493,152		$8.34000	$46,737	3.60
15		HP SODIUM 250 WATTS	-	-		$0.00000	$0	0.00
16		HP SODIUM 250 WATTS (DUAL LAMPS)	-	-		$0.00000	$0	0.00
17		HP SODIUM 400 WATTS	1,894	3,704,175		$14.64000	$332,694	25.65
18		HP SODIUM > 400 WATTS	-	-		$0.00000	$0	0.00
19		METAL HALIDE, ALL LAMPS	-	-		$0.00000	$0	0.00
20								
21		ALL OTHER INSTALLATIONS						
22		175 WATT MERCURY	343	283,797		$12.42000	$51,083	3.94
23		400 WATT MERCURY	-	-		$0.00000	$0	0.00
24		1,000 WATT MERCURY	-	-		$0.00000	$0	0.00
25		HP SODIUM < 100 WATTS	-	-		$0.00000	$0	0.00
26		HP SODIUM 150 WATTS	-	-		$0.00000	$0	0.00
27		HP SODIUM 150 WATTS (DUAL LAMPS)	-	-		$0.00000	$0	0.00
28		HP SODIUM 200 WATTS	-	-		$0.00000	$0	0.00
29		HP SODIUM 250 WATTS	-	-		$0.00000	$0	0.00
30		HP SODIUM 250 WATTS (DUAL LAMPS)	-	-		$0.00000	$0	0.00
31		HP SODIUM 400 WATTS	-	-		$0.00000	$0	0.00
32		HP SODIUM > 400 WATTS	-	-		$0.00000	$0	0.00
33		METAL HALIDE, ALL LAMPS	-	-		$0.00000	$0	0.00
34								
35		ADDITIONAL FACILITIES						
36		FOR INSTALLATIONS PRIOR TO 1/1/1974, FOR EACH POLE AND OVERHAD SPAN, PER MONTH		17,763		$2.48	$44,052	3.40
37		FOR INSTALLATION AFTER 1/1/1974, FOR EACH POLE AND OVERHEAD SPAN, PER MONTH		25,449		$4.87	$123,937	9.56
38		FOR EXISTING INSTALLATIONS, FOR EACH ADDITIONAL OVERHEAD SPAN EXTENTION, PER MONTH		55,677		$1.08	$60,131	4.64
39								
40								
41		STATE kWh TAX						
42		FIRST 2,000 kWh, PER kWh		11,139,377		$0.00466	$51,879	4.00
43		NEXT 13,000 kWh, PER kWh		276,154		$0.00420	$1,159	0.09
44		ABOVE 15,000 kWh, PER kWh		-		$0.00364	$0	0.00
45				11,415,531			$53,038	
46								
47		TOTAL DISTIBUTION - POL	10,378	11,415,531			$1,297,068	100.00

Workpaper for Schedule 2 - Target Revenue for Base Distribution Rates

Witness: G. Hussing

		PROPOSED ANNUALIZED						
LINE NO.	RATE CODE	CLASS/ DESCRIPTION	NUMBER OF OCCURENCES	SALES	BILLING UNITS	PROPOSED RATES	PROPOSED REVENUE LESS FUEL COST REVENUE	% OF REV TO TOTAL LESS FUEL COST REVENUE
	(A)	(B)	(C)	(D1)	(D2)	(E)	(F)	(G)
				(KWH)		($)	($)	(%)
	MISCELLANEOUS CHARGES							
1	PROPOSED							
2								
3	LATE PAYMENT CHARGES (FORFEITED DISCOUNTS) (450)							
4		TOTAL REVENUE					$2,662,748	23.95
5								
6	MISCELLANEOUS SERVICE REVENUES (451)							
7		TOTAL REVENUE					$2,028,657	18.25
8								
9	RENT FROM ELECTRIC PROPERTY (454)							
10		TOTAL REVENUE					$2,957,489	26.60
11								
12	OTHER ELECTRIC REVENUES (456)							
13		TOTAL REVENUE					$3,468,825	31.20
14								
15								
16	TOTAL OTHER ELECTRIC REVENUES		0			$0.00	$11,117,719	100.00

Workpaper for Schedule 2 - Target Revenue for Base Distribution Rates

Witness: G. Hussing

				Source:
TE Increase	(a)	$	40,500,000	
Miscellaneous Revenue Increase	(b)	$	(208,541)	Update Filing in Case No. 07-551-EL-AIR
Electric Revenue Increase	(c) = (a) - (b)	$	40,708,541	
Current Revenues	(d)	$	158,275,067	Update Filing in Case No. 07-551-EL-AIR
Current Miscellaneous Revenues	(e)	$	11,326,260	Update Filing in Case No. 07-551-EL-AIR
Proposed Electric Revenue Target	(f) = (d) + (c) - (e)	$	**187,657,348**	

Rate	Proposed Revenue Proof (A)	Stipulated Revenue % (B)	Target Revenue (C)
RS	$ 109,001,385	57.93%	$ 108,709,902
GS	$ 62,536,343	33.23%	$ 62,358,537
GP	$ 9,348,673	4.97%	$ 9,326,570
GSU	$ 206,913	0.11%	$ 206,423
GT	$ 2,690,086	1.43%	$ 2,683,500
TRF	$ 99,679	0.05%	$ 99,848
STL	$ 5,390,964	2.91%	$ 5,460,829
POL	$ 1,297,068	0.69%	$ 1,294,836
Contracts	$ (2,909,691)	-1.32%	$ (2,477,077)
Total Electric	$ 187,661,420	100.00%	$ **187,663,367**
Miscellaneous	$ 11,117,719		$ 11,117,719
Total	$ 198,779,139		$ 198,781,086

(A) Pages 1-14 of TE Schedule 5h - Workpaper for Schedule 2
(B) Stipulation in Case No. 07-551-EL-AIR
(C) B × Proposed Electric Revenue Target

Witness: G. Hussing

Rider Charge Calculation - Rider DSI

I. Allocation of Total DSI Revenue by Projected Capital Spend

	(A)	(B)	(C)	(D)	(E)
	Company	CapEx		Annual KWH	Annual
		$M	% Total	Sales	DSI Revenue
(1)	OE	$131	44.41%	26,018,267,630	$50,154,091
(2)	CEI	$118	40.00%	19,793,471,409	$45,176,967
(3)	TE	$46	15.59%	10,659,470,042	$17,611,360
(4)	TOTAL	$295	100.00%	56,471,209,081	$112,942,418

DSI Charge ($ / MWH)	$0.002000

NOTES
(B) Projected capital spend for 2009. Source: Energy Delivery.
(C) Percent of OH companies' total capital spend for 2009.
(D) Annual total company KWH sales.
(E) Calculation: Column C x (DSI Charge x OH companies' total annual KWH sales)

Case No. 08-XXXX-EL-SSO
Ohio Edison Company
The Cleveland Electric Illuminating Company
The Toledo Edison Company

Witness: G. Hussing

Rider Charge Calculation - Rider DSI

II. Allocation of Total DSI Revenue to RS and Non-RS (Based on Sales)

	(A)	(B)	(C)	(D)	(E)
	Company	Rate Schedule	Annual KWH Sales Total	Annual KWH Sales % Total	Annual DSI Revenue
(1)	OE	RS	9,225,981,525	45.16%	$22,649,506
(2)		GS	7,001,256,350	34.27%	$17,187,873
(3)		GP	3,215,783,887	15.74%	$7,894,652
(4)		GSU	986,594,660	4.83%	$2,422,060
(5)			20,429,616,422	100.00%	$50,154,091
(6)		Non-RS	11,203,634,897	54.84%	$27,504,585
(7)	CEI	RS	5,603,870,615	32.18%	$14,539,775
(8)		GS	7,404,024,401	42.52%	$19,210,445
(9)		GP	500,431,067	2.87%	$1,298,416
(10)		GSU	3,903,627,158	22.42%	$10,128,332
(11)			17,411,953,240	100.00%	$45,176,967
(12)		Non-RS	11,808,082,625	67.82%	$30,637,192
(13)	TE	RS	2,481,166,258	41.58%	$7,322,651
(14)		GS	2,246,181,610	37.64%	$6,629,143
(15)		GP	1,136,765,822	19.05%	$3,354,930
(16)		GSU	103,221,038	1.73%	$304,636
(17)			5,967,334,729	100.00%	$17,611,360
(18)		Non-RS	3,486,168,471	58.42%	$10,288,709
(19)	OH TOTAL	RS	17,311,018,398	39.51%	$44,511,932
(20)		GS	16,651,462,361	38.01%	$43,027,460
(21)		GP	4,852,980,777	11.08%	$12,547,999
(22)		GSU	4,993,442,854	11.40%	$12,855,027
(23)			43,808,904,391	100.00%	$112,942,418
(24)		Non-RS	26,497,885,993	60.49%	$68,430,486

NOTES
(C) Source: Schedule 1a.
(D) Calculation: Individual Rate Schedule Total / Total for RS, GS, GP, GSU
(E) Calculation: Annual DSI Revenue from Section I, Column E x Column D

Rider Charge Calculation - Rider DSI

III. Allocation of DSI Revenue Amongst Non-RS Schedules

	(A)	(B)	(C)	(D)	(E)	(F)
	Company	Rate Schedule	Stipulation Allocation % of Total	Stipulation Allocation % of Non-RS	Stipulation Allocation DSI Jurisd.	Annual DSI Revenue
(1)	OE	RS	62.45%	0.00%	0.00%	$0
(2)		GS	27.10%	72.17%	81.75%	$22,485,813
(3)		GP	5.20%	13.85%	15.69%	$4,315,286
(4)		GSU	0.85%	2.26%	2.56%	$703,486
(5)		GT	2.19%	5.84%	0.00%	$0
(6)		STL	1.39%	3.70%	0.00%	$0
(7)		POL	0.76%	2.02%	0.00%	$0
(8)		TRF	0.06%	0.16%	0.00%	$0
(9)			100.00%	100.00%	100.00%	$27,504,585
(10)		Subtotal (GT, STL, POL, TRF)		11.72%		
(11)	CEI	RS	47.55%	0.00%	0.00%	$0
(12)		GS	42.23%	80.52%	90.02%	$27,579,110
(13)		GP	0.63%	1.19%	1.33%	$408,684
(14)		GSU	4.06%	7.74%	8.65%	$2,649,398
(15)		GT	0.18%	0.35%	0.00%	$0
(16)		STL	3.53%	6.73%	0.00%	$0
(17)		POL	1.79%	3.41%	0.00%	$0
(18)		TRF	0.03%	0.06%	0.00%	$0
(19)			100.00%	100.00%	100.00%	$30,637,192
(20)		Subtotal (GT, STL, POL, TRF)		10.55%		
(21)	TE	RS	57.93%	0.00%	0.00%	$0
(22)		GS	32.13%	76.36%	86.74%	$8,924,401
(23)		GP	4.80%	11.42%	12.97%	$1,334,766
(24)		GSU	0.11%	0.25%	0.29%	$29,542
(25)		GT	1.38%	3.29%	0.00%	$0
(26)		STL	2.91%	6.92%	0.00%	$0
(27)		POL	0.69%	1.64%	0.00%	$0
(28)		TRF	0.05%	0.12%	0.00%	$0
(29)			100.00%	100.00%	100.00%	$10,288,709
(30)		Subtotal (GT, STL, POL, TRF)		11.96%		

NOTES
(C) Source: Stipulation in Case No. 07-551-EL-AIR.
(D) Calculation: Individual Non-RS Rate Schedule Total from Column C / (1 - RS Total from Column C).
(E) Besides customers taking service under Rate Schedule RS, Rider DSI is only applicable to customers taking service under Rate Schedule GS, GP, and GSU. Thus, the portion of the distribution rate increase allocated to Rate Schedules GT, STL, POL, and TRF per the Stipulation in Case No. 07-551-EL-AIR needs to be re-allocated across Rate Schedules GS, GP, GSU.
Calculation: (Subtotal of GT, STL, POL, TRF) x ((Column D) / Sum of GS, GP, GSU from Column D)
(F) Calculation: Total DIS Revenue Allocated to Non-RS customers from Section II x Column E.

Rider Charge Calculation - Rider DSI

IV. Rider DSI Charge Calculation - Rate RS

	(A)	(B)	(C)	(D)	(E)
	Company	Rate Schedule	Annual KWH Sales	Annual DSI Revenue	DSI Charge ($ / KWH)
(1)	OE	RS	9,225,981,525	$22,649,506	
(2)	CEI	RS	5,603,870,615	$14,539,775	
(3)	TE	RS	2,481,166,258	$7,322,651	
(4)			17,311,018,398	$44,511,932	$0.002571

NOTES
(C) Source: Schedule 1a.
(D) Source: Section II.
(E) Calculation: Column D / Column C.

V. Rider DSI Charge Calculation - Rate GS, Rate GP, Rate GSU

	(A)	(B)	(C)	(D)	(E)	
	Company	Rate Schedule	Annual DSI Revenue	Billing Units (kW / kVa)	DSI Charge ($ / kW or $ / kVa)	
(1)	OE	GS	$22,485,813	25,343,181	$0.887	per kW
(2)		GP	$4,315,286	7,103,952	$0.607	per kW
(3)		GSU	$703,486	2,215,472	$0.318	per kVa
(4)			$27,504,585			
(5)	CEI	GS	$27,579,110	24,134,406	$1.143	per kW
(6)		GP	$408,684	1,019,438	$0.401	per kW
(7)		GSU	$2,649,398	8,735,289	$0.303	per kW
(8)			$30,637,192			
(9)	TE	GS	$8,924,401	8,087,758	$1.103	per kW
(10)		GP	$1,334,766	2,790,440	$0.478	per kW
(11)		GSU	$29,542	185,981	$0.159	per kVa
(12)			$10,288,709			

NOTES
(C) Source: Section III.
(D) Source: Schedule 1a.
(E) Calculation: Column C / Column D.

Rider Charge Calculation - Rider DSI

IV. Rider DSI Charge Calculation - Rate RS

	(A)	(B)	(C)	(D)	(E)
	Company	Rate Schedule	Annual KWH Sales	Annual DSI Revenue	DSI Charge ($ / KWH)
(1)	OE	RS	9,225,981,525	$22,649,506	
(2)	CEI	RS	5,603,870,615	$14,539,775	
(3)	TE	RS	2,481,166,258	$7,322,651	
(4)			17,311,018,398	$44,511,932	$0.002571

NOTES
(C) Source: Schedule 1a.
(D) Source: Section II.
(E) Calculation: Column D / Column C.

V. Rider DSI Charge Calculation - Rate GS, Rate GP, Rate GSU

	(A)	(B)	(C)	(D)	(E)	
	Company	Rate Schedule	Annual DSI Revenue	Billing Units (kW / kVa)	DSI Charge ($ / kW or $ / kVa)	
(1)	OE	GS	$22,485,813	25,343,181	$0.887	per kW
(2)		GP	$4,315,286	7,103,952	$0.607	per kW
(3)		GSU	$703,486	2,215,472	$0.318	per kVa
(4)			$27,504,585			
(5)	CEI	GS	$27,579,110	24,134,406	$1.143	per kW
(6)		GP	$408,684	1,019,438	$0.401	per kW
(7)		GSU	$2,649,398	8,735,289	$0.303	per kW
(8)			$30,637,192			
(9)	TE	GS	$8,924,401	8,087,756	$1.103	per kW
(10)		GP	$1,334,766	2,790,440	$0.478	per kW
(11)		GSU	$29,542	185,981	$0.159	per kVa
(12)			$10,288,709			

NOTES
(C) Source: Section III.
(D) Source: Schedule 1a.
(E) Calculation: Column C / Column D.

RIDER CCA
Capacity Cost Adjustment Rider

RATE:

The Capacity Cost Adjustment Rider (CCA) charge for each Rate Schedule shall be calculated as follows:

$$CCA = \left(\frac{CC - E}{BU}\right)\left(\frac{1}{1 - CAT}\right)$$

Where:

CC	=	the Company's projected costs for capacity purchased to meet the planning reserve requirements for the period May 1 through September 30 of each calendar year of the Company's Electric Security Plan, allocated to each Rate Schedule.
E	=	the Company's over/(under) collection balance of CC-related costs, including applicable interest at April 30 of each year allocated to each Rate Schedule.
BU	=	Forecasted billing units for each Rate Schedule for the period during which the CCA will be effective.
CAT	=	Commercial Activity Tax Rate

RIDER UPDATES:

The charges contained in the Rider shall be updated and reconciled on an annual basis. No later than June 1st of each year, the Company shall file with the PUCO a request for approval of the rider charges which, unless otherwise ordered by the PUCO, shall become effective on a service rendered basis on July 1st of each year.

The Public Utilities Commission of Ohio (Commission) may increase the generation phase-in deferral amounts by the incremental CCA costs (planning reserve capacity costs) in excess of 1.5% of the annual revenue of non-shopping customers. The current CCA reflects recoverable costs that are not transferred to the generation phase-in deferral.

Case No. 08-XXXX-EL-SSO
Ohio Edison Company
The Cleveland Electric Illuminating Company
The Toledo Edison Company

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Witness: K. Warvell

Capacity Cost Adjustment Rider
Illustrative Example*

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(K)	(L)	(M)	(N)
				May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	CCA1
1	Capacity Cost per MWH															
2	Monthly Forecasted Reserve Planning Capacity Costs			$1,200,000	$1,200,000	$1,200,000	$1,200,000	$1,200,000	$0	$0	$0	$0	$0	$0	$0	$8,000,000
3	BU - Forecasted Mwh Sales			4,500,000	4,900,000	5,200,000	5,100,000	4,500,000	4,600,000	4,500,000	4,900,000	5,100,000	4,800,000	4,800,000	4,400,000	57,300,000
4	CC / BU --$/MWH Reserve Capacity Planning Cost															$0.1047
5	Reconciliation															
6	E - Net Over/(Under) Collection															$0
7	BU - Forecasted Mwh Sales															57,300,000
8	E / BU															$0.0000
9	CAT Gross-up															
10	CAT Rate															0.26%
11	CCA - Capacity Cost Adjustment															$0.1050
12																
13	SALES & REVENUE DATA	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	CCA1
14	Forecasted Mwh Sales	4,500,000	4,900,000	5,200,000	5,100,000	4,500,000	4,600,000	4,500,000	4,900,000	5,100,000	4,800,000	4,600,000	4,400,000	4,500,000	4,900,000	66,700,000
15	Actual Mwh Sales	4,725,000	5,145,000	5,460,000	5,355,000	4,725,000	4,830,000	4,725,000	4,655,000	4,845,000	4,560,000	4,560,000	4,180,000	4,275,000	4,655,000	66,695,000
16	CCA	$0.0000	$0.0000	$0.1050	$0.1050	$0.1050	$0.1050	$0.1050	$0.1050	$0.1050	$0.1050	$0.1050	$0.1050	$0.1050	$0.1050	
17	CCA Revenue	$0	$0	$573,216	$562,195	$496,054	$507,076	$496,054	$488,705	$508,652	$478,732	$478,732	$438,837	$448,811	$488,705	$5,965,773
18	CAT Rate	0.26%	0.26%	0.26%	0.26%	0.26%	0.26%	0.26%	0.26%	0.26%	0.26%	0.26%	0.26%	0.26%	0.26%	
19	CAT	$0	$0	$1,490	$1,462	$1,290	$1,318	$1,290	$1,271	$1,322	$1,245	$1,245	$1,141	$1,167	$1,271	$15,511
20	Capacity Cost Recovery	$0	$0	$571,726	$560,733	$494,764	$505,759	$494,764	$487,435	$507,330	$477,487	$477,487	$437,696	$447,644	$487,435	$5,950,262
21																
22	Actual Recoverable Costs Excluding Applicable Interest	$0	$1,000,000	$1,000,000	$1,000,000	$1,000,000	$0	$0	$0	$0	$0	$0	$0	$0	$2,400,000	$6,400,000
23	Applicable Interest	$0	$0	($3,542)	($12,179)	($24,007)	($39,391)	($55,107)	($67,725)	($77,389)	($84,113)	($87,968)	($89,077)	($87,581)	($83,563)	($711,641)
24	Actual Recoverable Costs Including Applicable Interest	$0	$1,000,000	$1,003,542	$1,012,179	$1,024,007	$39,391	$55,107	$67,725	$77,389	$84,113	$87,968	$89,077	$87,581	$2,483,563	$7,111,641
25																
26	Monthly Net Over/(Under) Recovery	$0	($1,000,000)	($431,814)	($451,446)	($529,242)	$466,368	$439,658	$419,710	$429,941	$393,374	$389,519	$348,619	$360,063	($1,996,129)	($1,161,379)
27	Balance Subject to Interest	$0	($500,000)	($1,219,449)	($1,669,717)	($2,171,886)	($2,218,709)	($1,781,412)	($1,364,347)	($949,186)	($544,251)	($156,660)	$211,300	$567,138	($248,878)	
28	Interest Rate	0.70833%	0.70833%	0.70833%	0.70833%	0.70833%	0.70833%	0.70833%	0.70833%	0.70833%	0.70833%	0.70833%	0.70833%	0.70833%	0.70833%	
29	Monthly Interest	$0	($3,542)	($8,638)	($11,827)	($15,384)	($15,716)	($12,618)	($9,664)	($6,723)	($3,855)	($1,110)	$1,497	$4,017	($1,749)	($85,312)
30	Cumulative Interest	$0	($3,542)	($12,179)	($24,007)	($39,391)	($55,107)	($67,725)	($77,389)	($84,113)	($87,968)	($89,077)	($87,581)	($83,563)	($85,312)	
31	Cumulative Over/(Under) Recovery Bal Incl Interest	$0	($1,003,542)	($1,443,993)	($1,907,267)	($2,451,893)	($2,001,241)	($1,574,201)	($1,164,156)	($740,939)	($351,419)	$36,990	$387,108	$751,167	($1,246,691)	

* This example assumes that the CCA for all Rate Schedules for all Companies is a charge per kwh. The actual CCA will be an energy (kwh) charge for residential and lighting rate schedules and a demand (kw or kva) charge for the remaining schedules. The actual reconciliation will be done on a total company basis and allocated to each rate schedule.

Case No. 08-XXXX-EL-SSO
Ohio Edison Company
The Cleveland Electric Illuminating Company
The Toledo Edison Company

Schedule 5]
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Witness: K. Warvell

Capacity Cost Adjustment Rider
Illustrative Example*

		(O)	(P)	(Q)	(r)	(S)	(T)	(U)	(V)	(W)	(X)	(Y)	(Z)	(AA)
		May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	CCA2
1	Capacity Cost per MWH													
2	Monthly Forecasted Reserve Planning Capacity Costs	$2,400,000	$2,400,000	$2,400,000	$2,400,000	$2,400,000	$0	$0	$0	$0	$0	$0	$0	$12,000,000
3	BU - Forecasted Mwh Sales	4,500,000	4,900,000	5,200,000	5,100,000	4,500,000	4,600,000	4,600,000	4,900,000	5,100,000	4,800,000	4,800,000	4,400,000	57,300,000
4	CC / BU --$/MWH Reserve Capacity Planning Cost													$0.2094
5	Reconciliation													
6	E - Net Over/(Under) Collection													$387,106
7	BU - Forecasted Mwh Sales													57,300,000
8	E / BU													$0.0068
9	CAT Gross-up													
10	CAT Rate													0.26%
11	CCA - Capacity Cost Adjustment													$0.2032
12														
13	SALES & REVENUE DATA	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	CCA2
14	Forecasted Mwh Sales	5,200,000	5,100,000	4,500,000	4,600,000	4,500,000	4,900,000	5,100,000	4,800,000	4,800,000	4,400,000	4,500,000	4,900,000	57,300,000
15	Actual Mwh Sales	5,460,000	5,355,000	4,725,000	4,830,000	4,725,000	4,665,000	4,845,000	4,560,000	4,560,000	4,180,000	4,275,000	4,655,000	56,825,000
16	CCA	$0.2032	$0.2032	$0.2032	$0.2032	$0.2032	$0.2032	$0.2032	$0.2032	$0.2032	$0.2032	$0.2032	$0.2032	
17	CCA Revenue	$1,109,454	$1,088,116	$960,104	$981,440	$960,104	$945,880	$984,488	$926,577	$926,577	$849,362	$868,666	$945,880	$11,546,648
18	CAT Rate	0.26%	0.26%	0.26%	0.26%	0.26%	0.26%	0.26%	0.26%	0.26%	0.26%	0.26%	0.26%	
19	CAT	$2,885	$2,829	$2,496	$2,552	$2,496	$2,459	$2,560	$2,409	$2,409	$2,208	$2,259	$2,459	$30,021
20	Capacity Cost Recovery	$1,106,569	$1,085,289	$957,608	$978,888	$957,608	$943,421	$981,928	$924,167	$924,167	$847,154	$866,407	$943,421	$11,516,627
21														
22	*Actual Recoverable Costs Excluding Applicable Interest*	$2,400,000	$2,400,000	$2,400,000	$0	$0	$0	$0	$0	$0	$0	$0	$3,600,000	$10,800,000
23	Applicable Interest	($85,312)	($99,026)	($23,701)	($133,094)	($60,207)	($163,685)	($85,075)	($182,792)	($98,515)	($190,776)	($101,308)	($188,564)	($1,412,045)
24	Actual Recoverable Costs Including Applicable Interest	$2,485,312	$2,499,026	$2,423,701	$133,094	$60,207	$163,685	$85,075	$182,792	$98,515	$190,776	$101,308	$3,788,564	$12,212,048
25														
26	Monthly Net Over/(Under) Recovery	($1,378,743)	($1,413,737)	($1,466,093)	$845,794	$897,400	$779,736	$896,853	$741,376	$825,652	$656,377	$765,099	($2,845,133)	($695,419)
27	Balance Subject to Interest	($1,936,082)	($3,346,016)	($4,809,632)	($5,153,850)	($4,316,760)	($3,510,783)	($2,697,357)	($1,897,349)	($1,127,274)	($394,244)	$313,701	($724,094)	
28	Interest Rate	0.70833%	0.70833%	0.70833%	0.70833%	0.70833%	0.70833%	0.70833%	0.70833%	0.70833%	0.70833%	0.70833%	0.70833%	
29	Monthly Interest	($13,714)	($23,701)	($34,068)	($36,506)	($30,691)	($24,868)	($19,106)	($13,440)	($7,985)	($2,793)	$2,222	($5,129)	($209,679)
30	Cumulative Interest	($99,026)	($23,701)	($133,094)	($60,207)	($163,685)	($85,075)	($182,792)	($98,515)	($190,776)	($101,308)	($188,554)	($193,683)	
31	Cumulative Over/(Under) Recovery Bal Incl Interest	($2,639,148)	($4,076,566)	($5,576,747)	($4,767,460)	($3,900,651)	($3,145,783)	($2,268,037)	($1,540,100)	($722,433)	($66,848)	$696,473	($2,151,789)	

* This example assumes that the CCA for all Rate Schedules for al Companies is a charge per kwh. The actual CCA will be an ener (kwh) charge for residential and lighting rate schedules and a demand (kw or kva) charge for the remaining schedules. The ac reconciliation will be done on a total company basis and allocatec each rate schedule.

Case No. 08-XXXX-EL-SSO
Ohio Edison Company
The Cleveland Electric Illuminating Company
The Toledo Edison Company

Schedule 5|
Page 4 of 4

Witness: K. Warvell

Capacity Cost Adjustment Rider

Illustrative Example*

		(AB)	(AC	(AD)	(AE)	(AF)	(AG)	(AH)	(AI)	(AJ)	(AK)	(AL)	(AM)	(AN)
		May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Jan-11	Feb-11	Mar-11	Apr-11	CCA3
1	Capacity Cost per MWH													
2	Monthly Forecasted Reserve Planning Capacity Costs	$3,600,000	$3,600,000	$3,600,000	$3,600,000	$3,600,000	$0	$0	$0	$0	$0	$0	$0	$18,000,000
3	BU - Forecasted Mwh Sales	4,500,000	4,900,000	5,200,000	5,100,000	4,500,000	4,600,000	4,600,000	4,900,000	5,100,000	4,800,000	4,800,000	4,400,000	57,300,000
4	CC / BU --$/MWH Reserve Capacity Planning Cost													$0.3141
5	Reconciliation													
6	E - Net Over/(Under) Collection													($66,848)
7	BU - Forecasted Mwh Sales													57,300,000
8	E / BU													($0.0012)
9	CAT Gross-up													
10	CAT Rate													0.26%
11	CCA - Capacity Cost Adjustment													$0.3162
12														
13	SALES & REVENUE DATA	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	CCA3
14	Forecasted Mwh Sales	5,200,000	5,100,000	4,500,000	4,600,000	4,500,000	4,900,000	5,100,000	4,800,000	4,800,000	4,400,000	4,500,000	4,900,000	57,300,000
15	Actual Mwh Sales	5,460,000	5,355,000	4,725,000	4,830,000	4,725,000	4,655,000	4,845,000	4,560,000	4,560,000	4,180,000	4,275,000	4,655,000	56,825,000
16	CCA	$0.3162	$0.3162	$0.3162	$0.3162	$0.3162	$0.3162	$0.3162	$0.3162	$0.3162	$0.3162	$0.3162	$0.3162	
17	CCA Revenue	$1,726,232	$1,693,035	$1,493,854	$1,527,051	$1,493,854	$1,471,723	$1,531,794	$1,441,688	$1,441,688	$1,321,547	$1,351,583	$1,471,723	$17,965,774
18	CAT Rate	0.26%	0.26%	0.26%	0.26%	0.26%	0.26%	0.26%	0.26%	0.26%	0.26%	0.26%	0.26%	
19	CAT	$4,488	$4,402	$3,884	$3,970	$3,884	$3,826	$3,983	$3,748	$3,748	$3,436	$3,514	$3,826	$46,711
20	Capacity Cost Recovery	$1,721,744	$1,688,633	$1,489,970	$1,523,081	$1,489,970	$1,467,897	$1,527,811	$1,437,940	$1,437,940	$1,318,111	$1,348,069	$1,467,897	$17,919,063
21														
22	Actual Recoverable Costs Excluding Applicable Interest	$3,600,000	$3,600,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$3,600,000	$10,800,000
23	Applicable Interest	($193,683)	($216,263)	($37,613)	($256,535)	($68,541)	($278,161)	($81,072)	($281,444)	($75,159)	($266,566)	($51,625)	($234,549)	($2,041,212)
24	Actual Recoverable Costs Including Applicable Interest	$3,793,683	$3,816,263	$37,613	$256,535	$68,541	$278,161	$81,072	$281,444	$75,159	$266,566	$51,625	$3,834,549	$12,841,212
25														
26	Monthly Net Over/(Under) Recovery	($2,071,940)	($2,127,630)	$1,452,357	$1,266,546	$1,421,430	$1,189,736	$1,446,739	$1,156,496	$1,362,781	$1,051,545	$1,296,444	($2,366,653)	$5,077,851
27	Balance Subject to Interest	($3,167,759)	($5,310,124)	($5,685,374)	($4,366,194)	($3,053,133)	($1,769,176)	($483,471)	$834,884	$2,100,418	$3,322,457	$4,519,936	$4,016,898	
28	Interest Rate	0.70833%	0.70833%	0.70833%	0.70833%	0.70833%	0.70833%	0.70833%	0.70833%	0.70833%	0.70833%	0.70833%	0.70833%	
29	Monthly Interest	($22,580)	($37,613)	($40,271)	($30,927)	($21,626)	($12,532)	($3,283)	$5,914	$14,878	$23,534	$32,017	$28,453	($84,038)
30	Cumulative Interest	($216,263)	($37,613)	($256,535)	($68,541)	($278,161)	($81,072)	($281,444)	($75,159)	($266,566)	($51,625)	($234,549)	($206,096)	
31	Cumulative Over/(Under) Recovery Bal Incl Interest	($4,246,309)	($6,411,552)	($4,999,467)	($3,763,848)	($2,384,044)	($1,186,840)	$256,616	$1,419,025	$2,796,884	$3,871,764	$5,200,224	$2,862,025	

* This example assumes that the CCA for all Rate Schedules for al
Companies is a charge per kwh. The actual CCA will be an ener
(kwh) charge for residential and lighting rate schedules and a
demand (kw or kva) charge for the remaining schedules. The ac
reconciliation will be done on a total company basis and allocate
each rate schedule.

Transmission Cost Recovery Index

Schedule	Description
A-1	Copy of Proposed Tariff Schedules
A-2	Copy of Redlined Current Tariff Schedules
B-1	Summary of Total Projected Transmission- and Ancillary Service-Related Costs
B-2	Summary of Current versus Proposed Transmission Revenues
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B-4	Graphs
B-5	Typical Bill Comparisons
C-1	Monthly Projected Transmission- and Ancillary Service-Related Costs
C-2	Monthly Projected Costs by Rate Schedule
C-3	Calculation of Rates, Energy & Demand Allocators
D-1	Reconciliation Adjustment - Actual Expenses by MISO Schedule
D-2	Reconciliation Adjustment - Actual Revenues by Rate Schedule
D-3	Reconciliation Adjustment - Monthly Over / Under Recovery Amounts
D-3a-c	Carrying Cost Calculation on Reconciliation Adjustment at OE, CEI, and TE
D-3d	Commercial Activity Tax (CAT) Schedule
D-3e	Calculation of Projected Balance of Reconciliation Deferral from 5/1/08 Filing
D-3f	Reconciliation of RTO Bill to Company Financials
D-3g	Reconciliation of throughput to Company Financials

RIDER TAS
Transmission and Ancillary Services Rider

APPLICABILITY:

Applicable to any customer who receives electric service under the Company's Generation Service Rider (GEN) or the Market Rate Provision of the Power Supply Reservation Rider (PSR). This Rider is not applied to customers during the period the customer takes electric generation service from a certified supplier.

PURPOSE:

The Transmission and Ancillary Services Rider (TAS) will recover all transmission and transmission-related costs, including ancillary and congestion costs, imposed on or charged to the Company by FERC or a RTO or a regional transmission organization, independent transmission operator, or similar organization approved by FERC.

RATE:

The TAS charge for each Rate Schedule shall be calculated as follows:

$$\mathbf{TAS} = \left[\frac{\mathbf{TAC - E}}{\mathbf{BU}}\right]\left[\frac{\mathbf{1}}{\mathbf{1 - CAT}}\right]$$

Where:

TAC = The amount of the Company's total projected Transmission and Ancillary Services-related costs for the Computation Period allocated to each Rate Schedule.

The Computation Period over which TAS will apply shall be January 1 through December 31 of each year.

E = For calendar period 2009, the unrecovered portion of the April 2007 to March 2008 reconciliation deferral as of December 31, 2008 plus the net over-or under-collection of the TAC, including applicable interest for the 6-month period ending September 30, 2008 allocated to Rate Schedules. Starting January 1, 2010, the net over or under-collection of the TAC, including applicable interest, for the 12-month period ending September 30 of each year that immediately precedes the Computation Period allocated to Rate Schedules.

BU = Forecasted billing units for the Computational Period for each Rate Schedule.

CAT = Commercial Activity Tax Rate

RIDER TAS
Transmission and Ancillary Services Rider

TAS charges:

RS (all kWhs, per kWh)	0.9291¢
GS* (per kW of Billing Demand)	$ 2.367
GP (per kW of Billing Demand)	$ 3.409
GSU (per kVa of Billing Demand)	$ 3.178
GT (per kVa of Billing Demand)	$ 2.797
STL (all kWhs, per kWh)	0.3840¢
TRF (all kWhs, per kWh)	0.3840¢
POL (all kWhs, per kWh)	0.3840¢

* Separately metered outdoor recreation facilities owned by non-profit governmental and educational institutions served under Rate GS will be charged per the TAS charge applicable to Rate Schedule POL.

RIDER UPDATES:

The charges contained in this Rider shall be updated and reconciled on an annual basis. The TAS Rider shall be filed with the Public Utilities Commission of Ohio on or before October 18 of each year and be effective for service rendered January 1 through December 31 of the subsequent year, unless otherwise ordered by the Commission.

RIDER TAS
Transmission and Ancillary Services Rider

APPLICABILITY:

Applicable to any customer who receives electric service under the Company's Generation Service Rider (GEN) or the Market Rate Provision of the Power Supply Reservation Rider (PSR). This Rider is not applied to customers during the period the customer takes electric generation service from a certified supplier.

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BU = Forecasted billing units for the Computational Period for each Rate Schedule.

CAT = Commercial Activity Tax Rate

RIDER TAS
Transmission and Ancillary Services Rider

TAS charges:

RS (all kWhs, per kWh)	0.7388¢
GS* (per kW of Billing Demand)	$ 2.107
GP (per kW of Billing Demand)	$ 2.699
GSU (per kW of Billing Demand)	$ 2.603
GT (per kVa of Billing Demand)	$ 2.341
STL (all kWhs, per kWh)	0.3711¢
TRF (all kWhs, per kWh)	0.3711¢
POL (all kWhs, per kWh)	0.3711¢

* Separately metered outdoor recreation facilities owned by non-profit governmental and educational institutions served under Rate GS will be charged per the TAS charge applicable to Rate Schedule POL.

RIDER UPDATES:

The charges contained in this Rider shall be updated and reconciled on an annual basis. The TAS Rider shall be filed with the Public Utilities Commission of Ohio on or before October 18 of each year and be effective for service rendered January 1 through December 31 of the subsequent year, unless otherwise ordered by the Commission.

RIDER TAS
Transmission and Ancillary Services Rider

APPLICABILITY:

Applicable to any customer who receives electric service under the Company's Generation Service Rider (GEN) or the Market Rate Provision of the Power Supply Reservation Rider (PSR). This Rider is not applied to customers during the period the customer takes electric generation service from a certified supplier.

PURPOSE:

The Transmission and Ancillary Services Rider (TAS) will recover all transmission and transmission-related costs, including ancillary and congestion costs, imposed on or charged to the Company by FERC or a RTO or a regional transmission organization, independent transmission operator, or similar organization approved by FERC.

RATE:

The TAS charge for each Rate Schedule shall be calculated as follows:

$$\mathbf{TAS} = \left[\frac{\mathbf{TAC - E}}{\mathbf{BU}}\right]\left[\frac{\mathbf{1}}{\mathbf{1 - CAT}}\right]$$

Where:

TAC = The amount of the Company's total projected Transmission and Ancillary Services-related costs for the Computation Period allocated to each Rate Schedule.

The Computation Period over which TAS will apply shall be January 1 through December 31 of each year.

E = For calendar period 2009, the unrecovered portion of the April 2007 to March 2008 reconciliation deferral as of December 31, 2008 plus the net over-or under-collection of the TAC, including applicable interest for the 6-month period ending September 30, 2008 allocated to Rate Schedules. Starting January 1, 2010, the net over or under-collection of the TAC, including applicable interest, for the 12-month period ending September 30 of each year that immediately precedes the Computation Period allocated to Rate Schedules.

BU = Forecasted billing units for the Computational Period for each Rate Schedule.

CAT = Commercial Activity Tax Rate

RIDER TAS
Transmission and Ancillary Services Rider

TAS charges:

RS (all kWhs, per kWh)	0.9291¢
GS* (per kW of Billing Demand)	$ 2.367
GP (per kW of Billing Demand)	$ 3.409
GSU (per kVa of Billing Demand)	$ 3.178
GT (per kVa of Billing Demand)	$ 2.797
STL (all kWhs, per kWh)	0.3840¢
TRF (all kWhs, per kWh)	0.3840¢
POL (all kWhs, per kWh)	0.3840¢

* Separately metered outdoor recreation facilities owned by non-profit governmental and educational institutions served under Rate GS will be charged per the TAS charge applicable to Rate Schedule POL.

RIDER UPDATES:

The charges contained in this Rider shall be updated and reconciled on an annual basis. The TAS Rider shall be filed with the Public Utilities Commission of Ohio on or before October 18 of each year and be effective for service rendered January 1 through December 31 of the subsequent year, unless otherwise ordered by the Commission.

Copy of Redlined Current Tariff Schedules

Red-lines are not provided because the schedules in A-1 supercede the following tariffs:

Ohio Edison Company

Residential Transmission and Ancillary Service Rider
Commercial Transmission and Ancillary Service Rider
Industrial Transmission and Ancillary Service Rider

The Cleveland Electric Illuminating Company

Residential Transmission and Ancillary Service Rider
Commercial Transmission and Ancillary Service Rider
Industrial Transmission and Ancillary Service Rider

The Toledo Edison Company

Residential Transmission and Ancillary Service Rider
Commercial Transmission and Ancillary Service Rider
Industrial Transmission and Ancillary Service Rider

Witness: Kevin Warvell

Summary of Total Projected Transmission Costs

Schedule B-1	Page 1 of 1

Schedule B-1 provides the projected transmission- and ancillary service-related costs to be charged to the Ohio Operating Companies during the 12 months in which the Rider charges will be in effect.

Schedule	Projected Demand-Related Expenses							
	Ohio Edison		Cleveland Electric		Toledo Edison		Total	
1	$	3,324,080	$	2,470,341	$	1,238,393	$	7,032,815
2	$	6,701,736	$	4,980,494	$	2,496,747	$	14,178,977
3	$	1,439,546	$	1,047,255	$	510,613	$	2,997,414
4	$	-	$	-	$	-	$	-
5	$	2,159,319	$	1,570,884	$	765,919	$	4,496,122
6	$	1,081,322	$	786,652	$	383,549	$	2,251,523
7 (69 kv)	$	-	$	-	$	-	$	-
7 (138 kv)	$	-	$	-	$	-	$	-
8 (69 kv)	$	-	$	-	$	-	$	-
8 (138 kv)	$	-	$	-	$	-	$	-
9 (69 kv)	$	38,143,112	$	-	$	10,696,082	$	48,839,194
9 (138 kv)	$	66,162,529	$	49,169,680	$	24,648,987	$	139,981,197
10	$	3,984,917	$	2,963,467	$	1,487,969	$	8,436,353
11	$	-	$	-	$	-	$	-
12	$	-	$	-	$	-	$	-
13	$	-	$	-	$	-	$	-
14	$	-	$	-	$	-	$	-
15	$	-	$	-	$	-	$	-
18	$	-	$	-	$	-	$	-
19	$	-	$	-	$	-	$	-
20	$	-	$	-	$	-	$	-
22	$	-	$	-	$	-	$	-
26	$	228,730	$	169,987	$	85,216	$	483,933
Total	**$**	**123,225,291**	**$**	**63,158,760**	**$**	**42,313,476**	**$**	**228,697,527**

Schedule	Projected Energy-Related Expenses							
	Ohio Edison		Cleveland Electric		Toledo Edison		Total	
3	$	9,268,242	$	6,736,797	$	3,864,302	$	19,869,341
5	$	1,134,162	$	824,387	$	472,878	$	2,431,427
6	$	974,671	$	708,457	$	406,378	$	2,089,506
16	$	660,679	$	500,232	$	278,476	$	1,439,386
17	$	8,808,662	$	6,669,451	$	3,712,848	$	19,190,961
24	$	714,412	$	546,763	$	294,784	$	1,555,959
FERC 10	$	1,737,668	$	1,291,376	$	647,371	$	3,676,415
Congestion Expense	$	8,010,416	$	6,065,060	$	3,376,386	$	17,451,861
FTR Credit	$	(10,282,997)	$	(7,785,738)	$	(4,334,281)	$	(22,403,016)
Net Losses	$	40,850,610	$	30,929,904	$	17,218,522	$	88,999,036
Revenue Neutrality	$	12,117,659	$	9,274,032	$	5,000,062	$	26,391,753
Rev. Sufficiency Guarantee	$	14,541,191	$	11,128,839	$	6,000,074	$	31,670,104
Total	**$**	**88,535,373**	**$**	**66,889,559**	**$**	**36,937,801**	**$**	**192,362,733**

Total Expenses	**$**	**211,760,664**	**$**	**130,048,319**	**$**	**79,251,277**	**$**	**421,060,260**

Note: These are placeholder expenses.

Witness: Kevin Warvell

Summary of Current versus Proposed Transmission Revenues

Schedule B-2 | Page 1 of 1

Schedule B-2 provides billing determinants for each class applied to current transmission cost recovery rider rates and proposed transmission cost recovery rider rates, including current and proposed class revenues, and the dollar and percentage differences.

Schedule	Billing Units	Billing Determinants	Current Rates	Current Total	Projected Rate [1]	Projected Total	$ Difference	% Difference
RS	All kWh, per kWh	9,225,981,525	N/A	N/A	0.009291	$ 85,717,893	$ -	0.0%
GS	All kW, per kW	25,343,181	N/A	N/A	2.367	$ 59,996,386	$ -	0.0%
GP	All kW, per kW	7,103,952	N/A	N/A	3.409	$ 24,216,645	$ -	0.0%
GSU	All kW/kVa, per kW/kVa	2,215,472	N/A	N/A	3.178	$ 7,041,631	$ -	0.0%
GT	All kVa, per kVa	12,369,962	N/A	N/A	2.797	$ 34,597,379	$ -	0.0%
LTG	All kWh, per kWh	186,197,457	N/A	N/A	0.003840	$ 715,075	$ -	0.0%
				$225,575,556		$212,285,008	$ (13,290,548)	-5.9%

Schedule	Billing Units	Billing Determinants	Current Rates	Current Total	Projected Rate [1]	Projected Total	$ Difference	% Difference
RS	All kWh, per kWh	5,603,870,615	N/A	N/A	0.007388	$ 41,399,685	$ -	0.0%
GS	All kW, per kW	24,134,406	N/A	N/A	2.107	$ 50,863,211	$ -	0.0%
GP	All kW, per kW	1,019,438	N/A	N/A	2.699	$ 2,751,583	$ -	0.0%
GSU	All kW/kVa, per kW/kVa	8,735,289	N/A	N/A	2.603	$ 22,735,276	$ -	0.0%
GT	All kVa, per kVa	5,039,889	N/A	N/A	2.341	$ 11,800,131	$ -	0.0%
LTG	All kWh, per kWh	221,079,177	N/A	N/A	0.003711	$ 820,447	$ -	0.0%
				$138,552,873		$130,370,334	$ (8,182,539)	-5.9%

Schedule	Billing Units	Billing Determinants	Current Rates	Current Total	Projected Rate [1]	Projected Total	$ Difference	% Difference
RS	All kWh, per kWh	2,481,166,258	N/A	N/A	0.008804	$ 21,844,303	$ -	0.0%
GS	All kW, per kW	8,087,766	N/A	N/A	2.268	$ 18,352,513	$ -	0.0%
GP	All kW, per kW	2,790,440	N/A	N/A	2.861	$ 7,982,321	$ -	0.0%
GSU	All kW/kVa, per kW/kVa	185,981	N/A	N/A	3.436	$ 639,035	$ -	0.0%
GT	All kVa, per kVa	9,346,977	N/A	N/A	3.247	$ 30,359,717	$ -	0.0%
LTG	All kWh, per kWh	69,151,680	N/A	N/A	0.003899	$ 269,623	$ -	0.0%
				$ 82,830,783		$ 79,447,512	$ (3,383,271)	-4.1%

[1] Rates have been grossed up for the Commercial Activity Tax (CAT) rate.
NOTE: These values are illustrative. The current total is higher than the proposed total because the former includes amortization expense associated with the 2006 transmission deferral, while the latter does not.

Witness: Kevin Warvell

Summary of Current and Proposed Rates

Schedule B-3 | Page 1 of 1

Schedule B-3 provides the current transmission cost recovery rider rate and proposed transmission cost recovery rider rates, the dollar difference, and percentage change.

[illegible]

Schedule	Billing Units	Current Rates	Projected Rate	$ Difference	% Difference
RS	All kWh, per kWh	N/A	0.009291	$ -	0.0%
GS	All kW, per kW	N/A	2.367	$ -	0.0%
GP	All kW, per kW	N/A	3.409	$ -	0.0%
GSU	All kW/kVa, per kW/kVa	N/A	3.178	$ -	0.0%
GT	All kVa, per kVa	N/A	2.797	$ -	0.0%
LTG	All kWh, per kWh	N/A	0.003840	$ -	0.0%

[illegible]

Schedule	Billing Units	Current Rates	Projected Rate	$ Difference	% Difference
RS	All kWh, per kWh	N/A	0.007388	$ -	0.0%
GS	All kW, per kW	N/A	2.107	$ -	0.0%
GP	All kW, per kW	N/A	2.699	$ -	0.0%
GSU	All kW/kVa, per kW/kVa	N/A	2.603	$ -	0.0%
GT	All kVa, per kVa	N/A	2.341	$ -	0.0%
LTG	All kWh, per kWh	N/A	0.003711	$ -	0.0%

TOLEDO EDISON

Schedule	Billing Units	Current Rates	Projected Rate	$ Difference	% Difference
RS	All kWh, per kWh	N/A	0.008804	$ -	0.0%
GS	All kW, per kW	N/A	2.269	$ -	0.0%
GP	All kW, per kW	N/A	2.861	$ -	0.0%
GSU	All kW/kVa, per kW/kVa	N/A	3.436	$ -	0.0%
GT	All kVa, per kVa	N/A	3.247	$ -	0.0%
LTG	All kWh, per kWh	N/A	0.003899	$ -	0.0%

NOTE: These values are illustrative.
Because these rate schedules will not exist until January 1, 2009, only the placeholder rates are shown.

Summary of Total Projected Transmission Costs

Schedule B-1	Page 1 of 1

Schedule B-1 provides the projected transmission- and ancillary service-related costs to be charged to the Ohio Operating Companies during the 12 months in which the Rider charges will be in effect.

Schedule	Projected Demand-Related Expenses			
	Ohio Edison	Cleveland Electric	Toledo Edison	Total
1	$ 3,324,080	$ 2,470,341	$ 1,238,393	$ 7,032,815
2	$ 6,701,736	$ 4,980,494	$ 2,496,747	$ 14,178,977
3	$ 1,439,546	$ 1,047,255	$ 510,613	$ 2,997,414
4	$ -	$ -	$ -	$ -
5	$ 2,159,319	$ 1,570,884	$ 765,919	$ 4,496,122
6	$ 1,081,322	$ 786,652	$ 383,549	$ 2,251,523
7 (69 kv)	$ -	$ -	$ -	$ -
7 (138 kv)	$ -	$ -	$ -	$ -
8 (69 kv)	$ -	$ -	$ -	$ -
8 (138 kv)	$ -	$ -	$ -	$ -
9 (69 kv)	$ 38,143,112	$ -	$ 10,696,082	$ 48,839,194
9 (138 kv)	$ 66,162,529	$ 49,169,680	$ 24,648,987	$ 139,981,197
10	$ 3,984,917	$ 2,963,467	$ 1,487,969	$ 8,436,353
11	$ -	$ -	$ -	$ -
12	$ -	$ -	$ -	$ -
13	$ -	$ -	$ -	$ -
14	$ -	$ -	$ -	$ -
15	$ -	$ -	$ -	$ -
18	$ -	$ -	$ -	$ -
19	$ -	$ -	$ -	$ -
20	$ -	$ -	$ -	$ -
22	$ -	$ -	$ -	$ -
26	$ 228,730	$ 169,987	$ 85,216	$ 483,933
Total	**$ 123,225,291**	**$ 63,158,760**	**$ 42,313,476**	**$ 228,697,527**

Schedule	Projected Energy-Related Expenses			
	Ohio Edison	Cleveland Electric	Toledo Edison	Total
3	$ 9,268,242	$ 6,736,797	$ 3,864,302	$ 19,869,341
5	$ 1,134,162	$ 824,387	$ 472,878	$ 2,431,427
6	$ 974,671	$ 708,457	$ 406,378	$ 2,089,506
16	$ 660,679	$ 500,232	$ 278,476	$ 1,439,386
17	$ 8,808,662	$ 6,669,451	$ 3,712,848	$ 19,190,961
24	$ 714,412	$ 546,763	$ 294,784	$ 1,555,959
FERC 10	$ 1,737,668	$ 1,291,376	$ 647,371	$ 3,676,415
Congestion Expense	$ 8,010,415	$ 6,065,060	$ 3,376,386	$ 17,451,861
FTR Credit	$ (10,282,997)	$ (7,785,738)	$ (4,334,281)	$ (22,403,016)
Net Losses	$ 40,850,610	$ 30,929,904	$ 17,218,522	$ 88,999,036
Revenue Neutrality	$ 12,117,659	$ 9,274,032	$ 5,000,062	$ 26,391,753
Rev. Sufficiency Guarantee	$ 14,541,191	$ 11,128,839	$ 6,000,074	$ 31,670,104
Total	**$ 88,535,373**	**$ 66,889,559**	**$ 36,937,801**	**$ 192,362,733**

Total Expenses	**$ 211,760,664**	**$ 130,048,319**	**$ 79,251,277**	**$ 421,060,260**

Note: These are placeholder expenses.

Witness: Kevin Warvell

Summary of Current versus Proposed Transmission Revenues

Schedule B-2 | Page 1 of 1

Schedule B-2 provides billing determinants for each class applied to current transmission cost recovery rider rates and proposed transmission cost recovery rider rates, including current and proposed class revenues, and the dollar and percentage differences.

Schedule	Billing Units	Billing Determinants	Current Rates	Current Total	Projected Rate [1]	Projected Total	$ Difference	% Difference
RS	All kWh, per kWh	9,225,981,525	N/A	N/A	0.009291	$ 85,717,893	$ -	0.0%
GS	All kW, per kW	25,343,181	N/A	N/A	2.367	$ 59,996,386	$ -	0.0%
GP	All kW, per kW	7,103,952	N/A	N/A	3.409	$ 24,216,645	$ -	0.0%
GSU	All kW/kVa, per kW/kVa	2,215,472	N/A	N/A	3.178	$ 7,041,631	$ -	0.0%
GT	All kVa, per kVa	12,369,962	N/A	N/A	2.797	$ 34,597,379	$ -	0.0%
LTG	All kWh, per kWh	186,197,457	N/A	N/A	0.003840	$ 715,075	$ -	0.0%
				$225,575,556		$212,285,008	$ (13,290,548)	-5.9%

Schedule	Billing Units	Billing Determinants	Current Rates	Current Total	Projected Rate [1]	Projected Total	$ Difference	% Difference
RS	All kWh, per kWh	5,603,870,615	N/A	N/A	0.007388	$ 41,399,885	$ -	0.0%
GS	All kW, per kW	24,134,406	N/A	N/A	2.107	$ 50,863,211	$ -	0.0%
GP	All kW, per kW	1,019,438	N/A	N/A	2.699	$ 2,751,583	$ -	0.0%
GSU	All kW/kVa, per kW/kVa	8,735,289	N/A	N/A	2.603	$ 22,735,276	$ -	0.0%
GT	All kVa, per kVa	5,039,889	N/A	N/A	2.341	$ 11,800,131	$ -	0.0%
LTG	All kWh, per kWh	221,079,177	N/A	N/A	0.003711	$ 820,447	$ -	0.0%
				$138,552,873		$130,370,334	$ (8,182,539)	-5.9%

Schedule	Billing Units	Billing Determinants	Current Rates	Current Total	Projected Rate [1]	Projected Total	$ Difference	% Difference
RS	All kWh, per kWh	2,481,166,258	N/A	N/A	0.008804	$ 21,844,303	$ -	0.0%
GS	All kW, per kW	8,087,756	N/A	N/A	2.269	$ 18,352,513	$ -	0.0%
GP	All kW, per kW	2,790,440	N/A	N/A	2.861	$ 7,982,321	$ -	0.0%
GSU	All kW/kVa, per kW/kVa	185,981	N/A	N/A	3.436	$ 639,035	$ -	0.0%
GT	All kVa, per kVa	9,348,977	N/A	N/A	3.247	$ 30,359,717	$ -	0.0%
LTG	All kWh, per kWh	69,151,680	N/A	N/A	0.003899	$ 269,623	$ -	0.0%
				$ 82,830,783		$ 79,447,512	$ (3,383,271)	-4.1%

[1] Rates have been grossed up for the Commercial Activity Tax (CAT) rate.
NOTE: These values are illustrative. The current total is higher than the proposed total because the former includes amortization expense associated with the 2005 transmission deferral, while the latter does not.

Summary of Current and Proposed Rates

Schedule B-3 | **Page 1 of 1**

Schedule B-3 provides the current transmission cost recovery rider rate and proposed transmission cost recovery rider rates, the dollar difference, and percentage change.

OHIO EDISON

Schedule	Billing Units	Current Rates	Projected Rate	$ Difference	% Difference
RS	All kWh, per kWh	N/A	0.009291	$ -	0.0%
GS	All kW, per kW	N/A	2.367	$ -	0.0%
GP	All kW, per kW	N/A	3.409	$ -	0.0%
GSU	All kW/kVa, per kW/kVa	N/A	3.178	$ -	0.0%
GT	All kVa, per kVa	N/A	2.797	$ -	0.0%
LTG	All kWh, per kWh	N/A	0.003840	$ -	0.0%

CLEVELAND ELECTRIC ILLUMINATING

Schedule	Billing Units	Current Rates	Projected Rate	$ Difference	% Difference
RS	All kWh, per kWh	N/A	0.007388	$ -	0.0%
GS	All kW, per kW	N/A	2.107	$ -	0.0%
GP	All kW, per kW	N/A	2.699	$ -	0.0%
GSU	All kW/kVa, per kW/kVa	N/A	2.603	$ -	0.0%
GT	All kVa, per kVa	N/A	2.341	$ -	0.0%
LTG	All kWh, per kWh	N/A	0.003711	$ -	0.0%

TOLEDO EDISON

Schedule	Billing Units	Current Rates	Projected Rate	$ Difference	% Difference
RS	All kWh, per kWh	N/A	0.008804	$ -	0.0%
GS	All kW, per kW	N/A	2.269	$ -	0.0%
GP	All kW, per kW	N/A	2.861	$ -	0.0%
GSU	All kW/kVa, per kW/kVa	N/A	3.436	$ -	0.0%
GT	All kVa, per kVa	N/A	3.247	$ -	0.0%
LTG	All kWh, per kWh	N/A	0.003899	$ -	0.0%

NOTE: These values are illustrative.
Because these rate schedules will not exist until January 1, 2009, only the placeholder rates are shown.

Summary of Total Projected Transmission Costs

Schedule B-1	Page 1 of 1

Schedule B-1 provides the projected transmission- and ancillary service-related costs to be charged to the Ohio Operating Companies during the 12 months in which the Rider charges will be in effect.

Schedule	Projected Demand-Related Expenses			
	Ohio Edison	Cleveland Electric	Toledo Edison	Total
1	$ 3,324,080	$ 2,470,341	$ 1,238,393	$ 7,032,815
2	$ 6,701,736	$ 4,980,494	$ 2,496,747	$ 14,178,977
3	$ 1,439,546	$ 1,047,255	$ 510,613	$ 2,997,414
4	$ -	$ -	$ -	$ -
5	$ 2,159,319	$ 1,570,884	$ 765,919	$ 4,496,122
6	$ 1,081,322	$ 786,652	$ 383,549	$ 2,251,523
7 (69 kv)	$ -	$ -	$ -	$ -
7 (138 kv)	$ -	$ -	$ -	$ -
8 (69 kv)	$ -	$ -	$ -	$ -
8 (138 kv)	$ -	$ -	$ -	$ -
9 (69 kv)	$ 38,143,112	$ -	$ 10,696,082	$ 48,839,194
9 (138 kv)	$ 66,162,529	$ 49,169,680	$ 24,648,987	$ 139,981,197
10	$ 3,984,917	$ 2,963,467	$ 1,487,969	$ 8,436,353
11	$ -	$ -	$ -	$ -
12	$ -	$ -	$ -	$ -
13	$ -	$ -	$ -	$ -
14	$ -	$ -	$ -	$ -
15	$ -	$ -	$ -	$ -
18	$ -	$ -	$ -	$ -
19	$ -	$ -	$ -	$ -
20	$ -	$ -	$ -	$ -
22	$ -	$ -	$ -	$ -
26	$ 228,730	$ 169,987	$ 85,216	$ 483,933
Total	**$ 123,225,291**	**$ 63,158,760**	**$ 42,313,476**	**$ 228,697,527**

Schedule	Projected Energy-Related Expenses			
	Ohio Edison	Cleveland Electric	Toledo Edison	Total
3	$ 9,268,242	$ 6,736,797	$ 3,864,302	$ 19,869,341
5	$ 1,134,162	$ 824,387	$ 472,878	$ 2,431,427
6	$ 974,671	$ 708,457	$ 406,378	$ 2,089,506
16	$ 660,679	$ 500,232	$ 278,476	$ 1,439,386
17	$ 8,808,662	$ 6,669,451	$ 3,712,848	$ 19,190,961
24	$ 714,412	$ 546,763	$ 294,784	$ 1,555,959
FERC 10	$ 1,737,668	$ 1,291,376	$ 647,371	$ 3,676,415
Congestion Expense	$ 8,010,415	$ 6,065,060	$ 3,376,386	$ 17,451,861
FTR Credit	$ (10,282,997)	$ (7,785,738)	$ (4,334,281)	$ (22,403,016)
Net Losses	$ 40,850,610	$ 30,929,904	$ 17,218,522	$ 88,999,036
Revenue Neutrality	$ 12,117,659	$ 9,274,032	$ 5,000,062	$ 26,391,753
Rev. Sufficiency Guarantee	$ 14,541,191	$ 11,128,839	$ 6,000,074	$ 31,670,104
Total	**$ 88,535,373**	**$ 66,889,559**	**$ 36,937,801**	**$ 192,362,733**

Total Expenses	**$ 211,760,664**	**$ 130,048,319**	**$ 79,251,277**	**$ 421,060,260**

Note: These are placeholder expenses.

Witness: Kevin Warvell

Summary of Total Projected Transmission Costs

Schedule B-1	Page 1 of 1

Schedule B-1 provides the projected transmission- and ancillary service-related costs to be charged to the Ohio Operating Companies during the 12 months in which the Rider charges will be in effect.

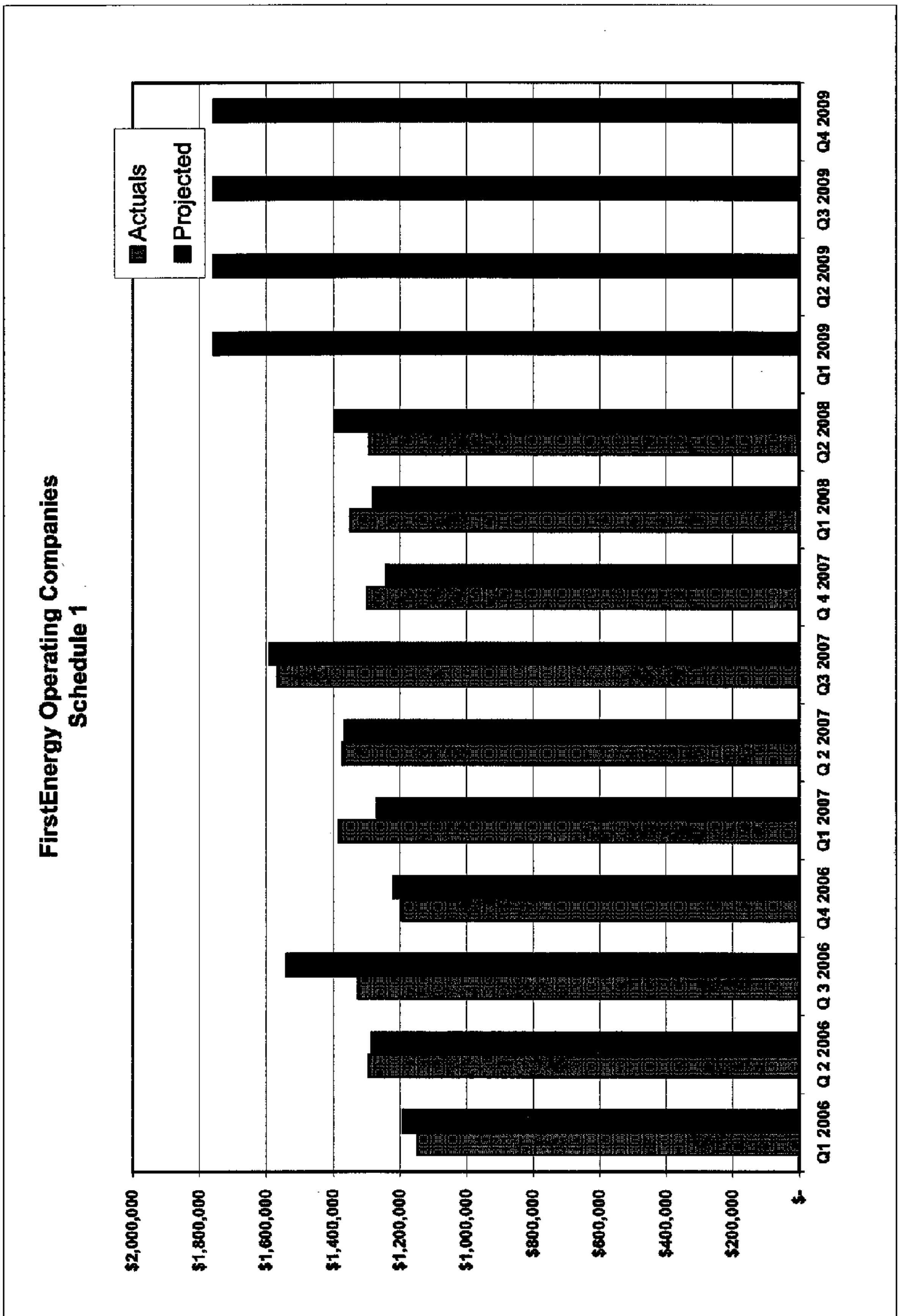
Schedule	Projected Demand-Related Expenses			
	Ohio Edison	Cleveland Electric	Toledo Edison	Total
1	$ 3,324,080	$ 2,470,341	$ 1,238,393	$ 7,032,815
2	$ 6,701,736	$ 4,980,494	$ 2,496,747	$ 14,178,977
3	$ 1,439,546	$ 1,047,255	$ 510,613	$ 2,997,414
4	$ -	$ -	$ -	$ -
5	$ 2,159,319	$ 1,570,884	$ 765,919	$ 4,496,122
6	$ 1,081,322	$ 786,652	$ 383,549	$ 2,251,523
7 (69 kv)	$ -	$ -	$ -	$ -
7 (138 kv)	$ -	$ -	$ -	$ -
8 (69 kv)	$ -	$ -	$ -	$ -
8 (138 kv)	$ -	$ -	$ -	$ -
9 (69 kv)	$ 38,143,112	$ -	$ 10,696,082	$ 48,839,194
9 (138 kv)	$ 66,162,529	$ 49,169,680	$ 24,648,987	$ 139,981,197
10	$ 3,984,917	$ 2,963,467	$ 1,487,969	$ 8,436,353
11	$ -	$ -	$ -	$ -
12	$ -	$ -	$ -	$ -
13	$ -	$ -	$ -	$ -
14	$ -	$ -	$ -	$ -
15	$ -	$ -	$ -	$ -
18	$ -	$ -	$ -	$ -
19	$ -	$ -	$ -	$ -
20	$ -	$ -	$ -	$ -
22	$ -	$ -	$ -	$ -
26	$ 228,730	$ 169,987	$ 85,216	$ 483,933
Total	**$ 123,225,291**	**$ 63,158,760**	**$ 42,313,476**	**$ 228,697,527**

Schedule	Projected Energy-Related Expenses			
	Ohio Edison	Cleveland Electric	Toledo Edison	Total
3	$ 9,268,242	$ 6,736,797	$ 3,864,302	$ 19,869,341
5	$ 1,134,162	$ 824,387	$ 472,878	$ 2,431,427
6	$ 974,671	$ 708,457	$ 406,378	$ 2,089,506
16	$ 660,679	$ 500,232	$ 278,476	$ 1,439,386
17	$ 8,808,662	$ 6,669,451	$ 3,712,848	$ 19,190,961
24	$ 714,412	$ 546,763	$ 294,784	$ 1,555,959
FERC 10	$ 1,737,668	$ 1,291,376	$ 647,371	$ 3,676,415
Congestion Expense	$ 8,010,415	$ 6,065,060	$ 3,376,386	$ 17,451,861
FTR Credit	$ (10,282,997)	$ (7,785,738)	$ (4,334,281)	$ (22,403,016)
Net Losses	$ 40,850,610	$ 30,929,904	$ 17,218,522	$ 88,999,036
Revenue Neutrality	$ 12,117,659	$ 9,274,032	$ 5,000,062	$ 26,391,753
Rev. Sufficiency Guarantee	$ 14,541,191	$ 11,128,839	$ 6,000,074	$ 31,670,104
Total	**$ 88,535,373**	**$ 66,889,559**	**$ 36,937,801**	**$ 192,362,733**

Total Expenses	**$ 211,760,664**	**$ 130,048,319**	**$ 79,251,277**	**$ 421,060,260**

Note: These are placeholder expenses.

Schedule B-4


FirstEnergy Operating Companies
Schedule 1
Actuals
Projected
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$1,800,000
$1,600,000
$1,400,000
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$1,000,000
$800,000
$600,000
$400,000
$200,000
$-
Q1 2006
Q 2 2006
Q 3 2006
Q4 2006
Q1 2007
Q 2 2007
Q3 2007
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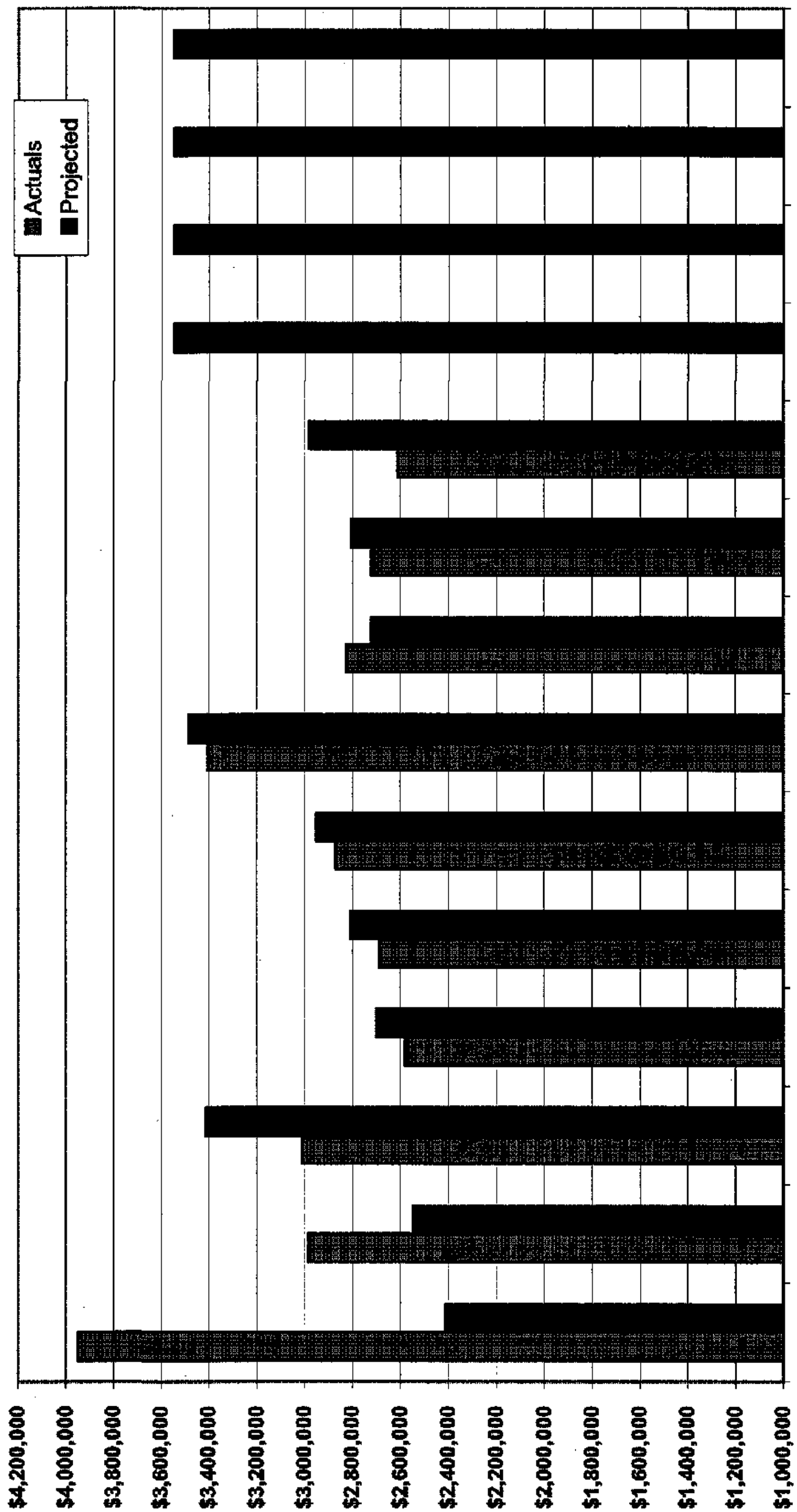
Q1 2009
Q2 2009
Q3 2009
Q4 2009

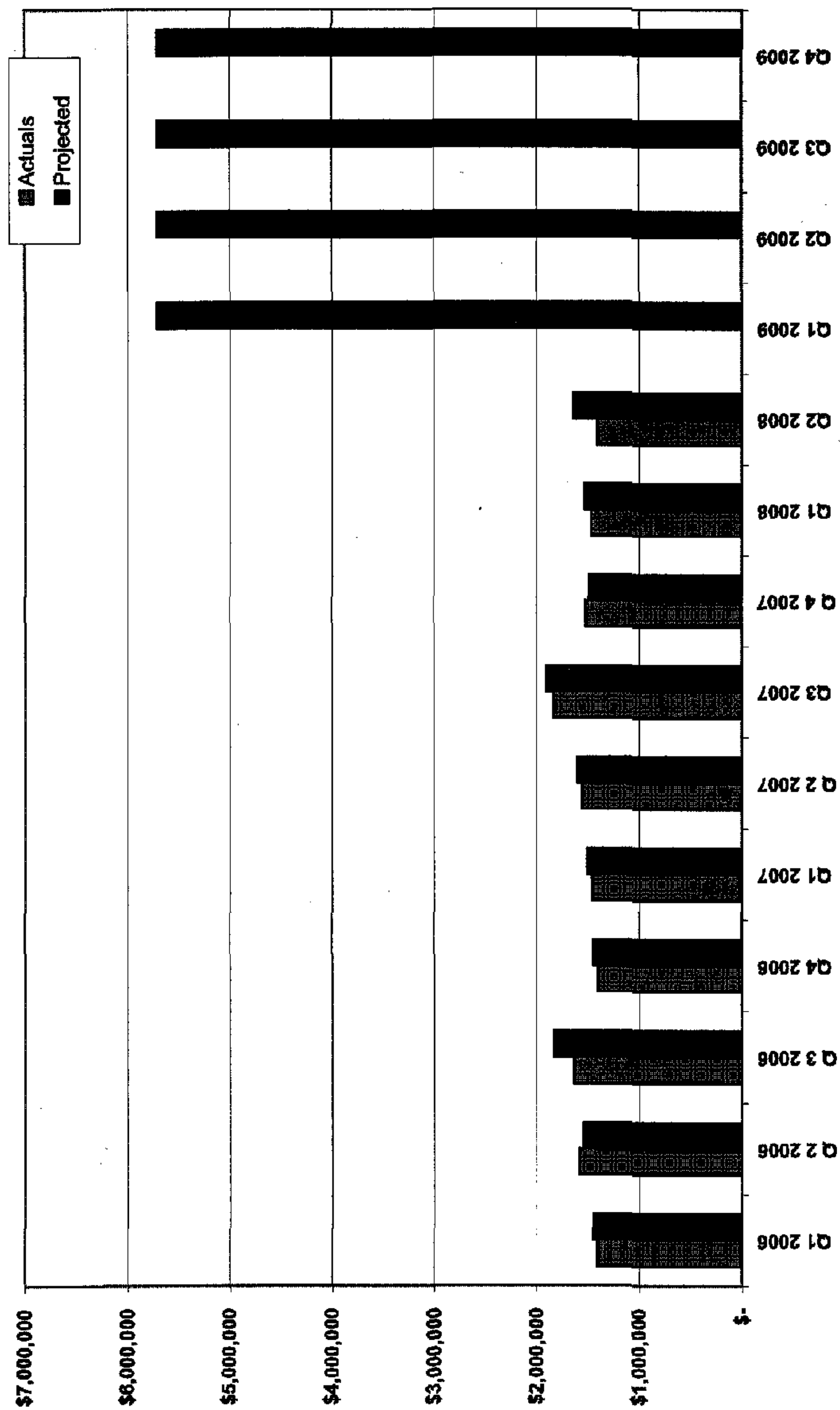
Schedule B-4

FirstEnergy Ohio Operating Companies
Schedule 2



Schedule B-4

FirstEnergy Ohio Operating Companies
Schedule 3

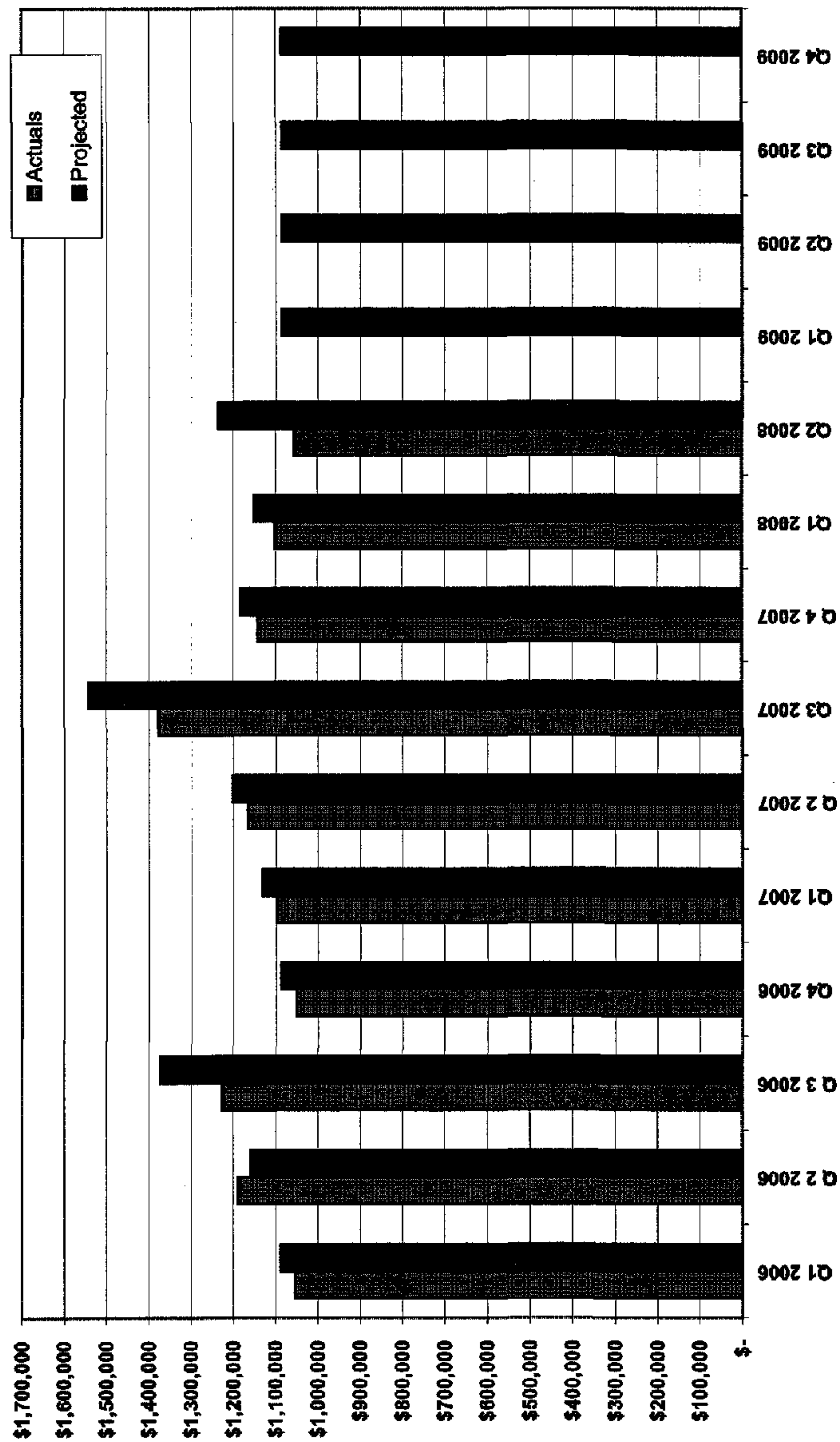


Schedule B-4

FirstEnergy Ohio Operating Companies
Schedule 5

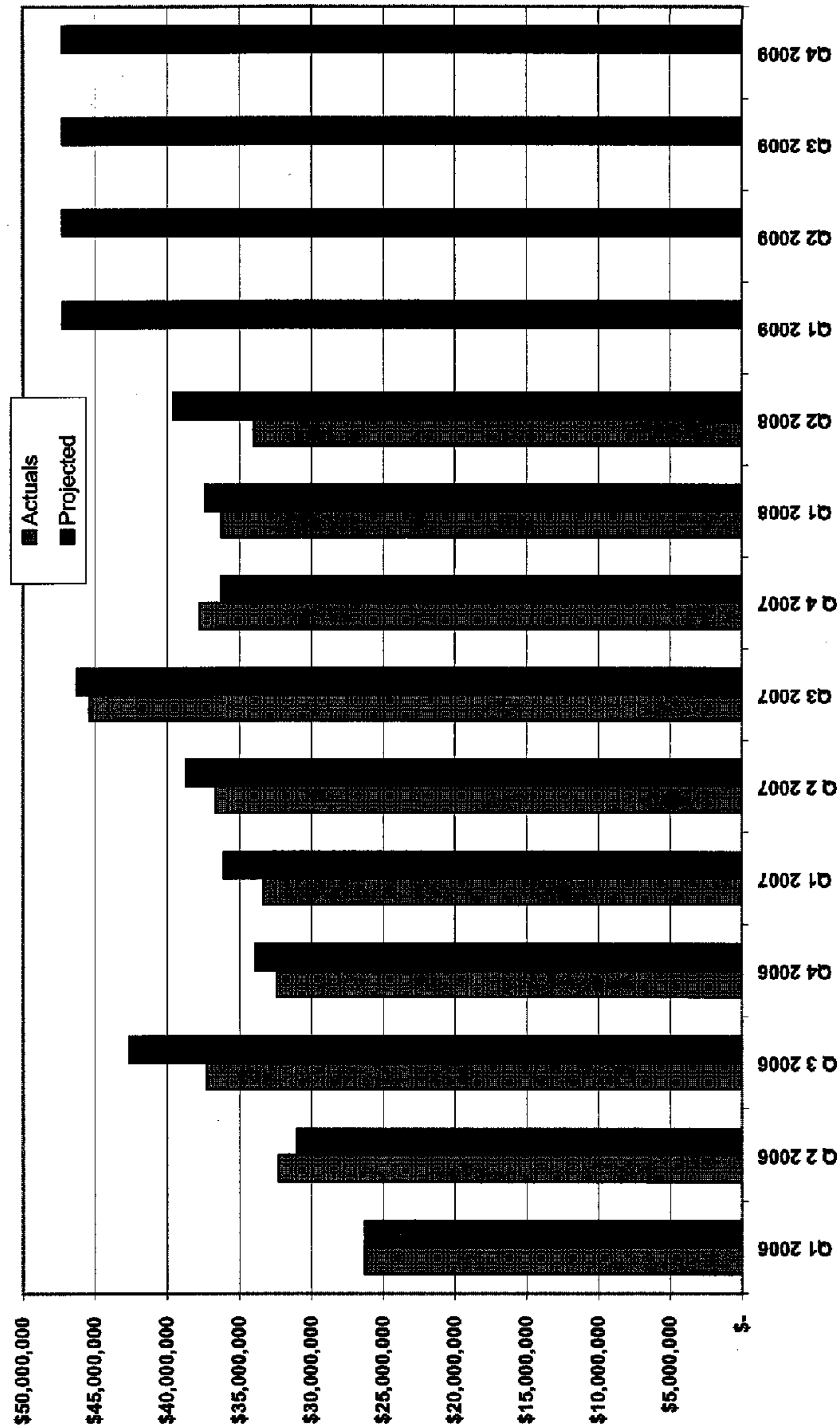
Schedule B-4

FirstEnergy Ohio Operating Companies
Schedule 6



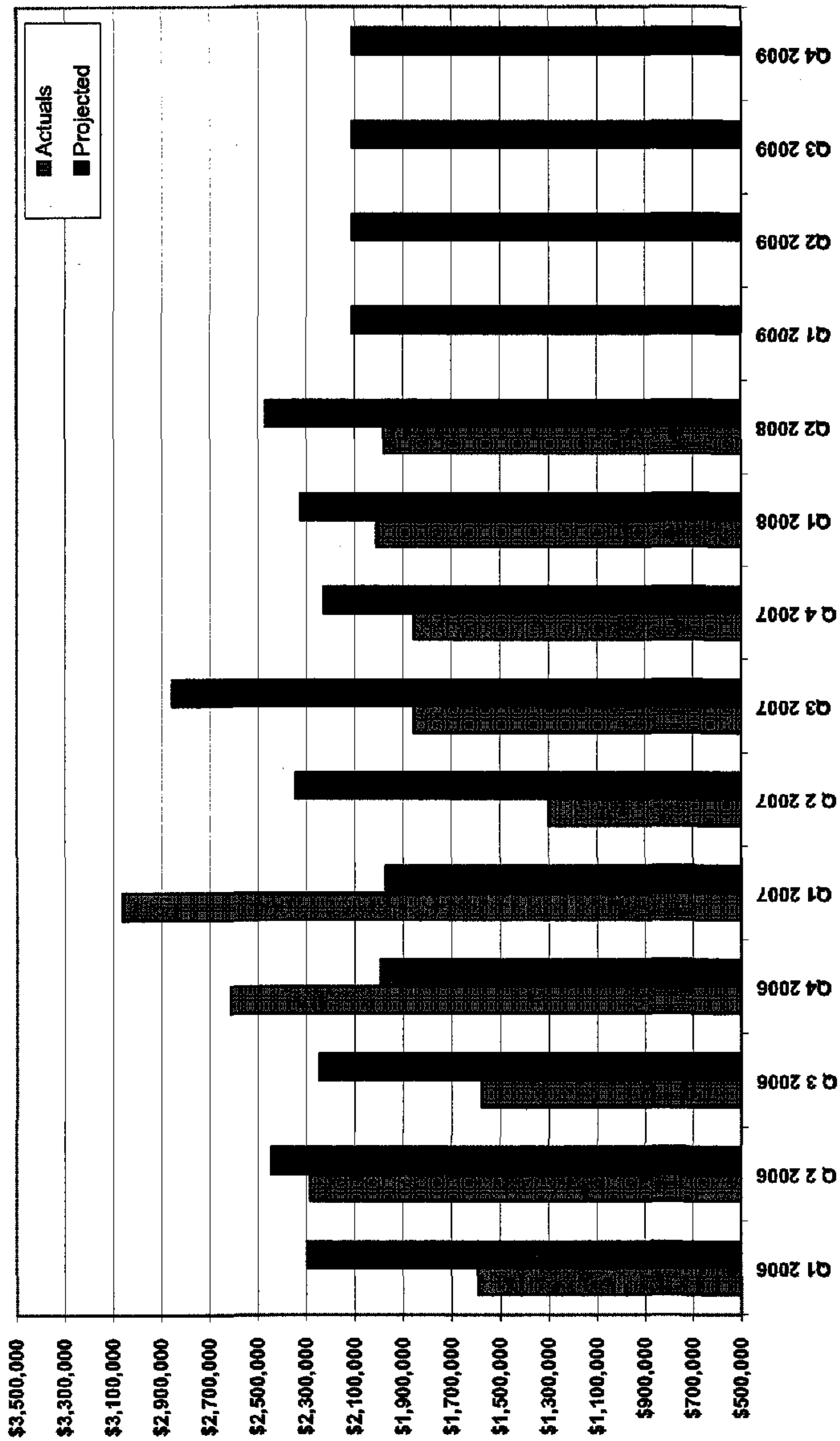
Schedule B-4

FirstEnergy Ohio Operating Companies
Schedule 9



Schedule B-4

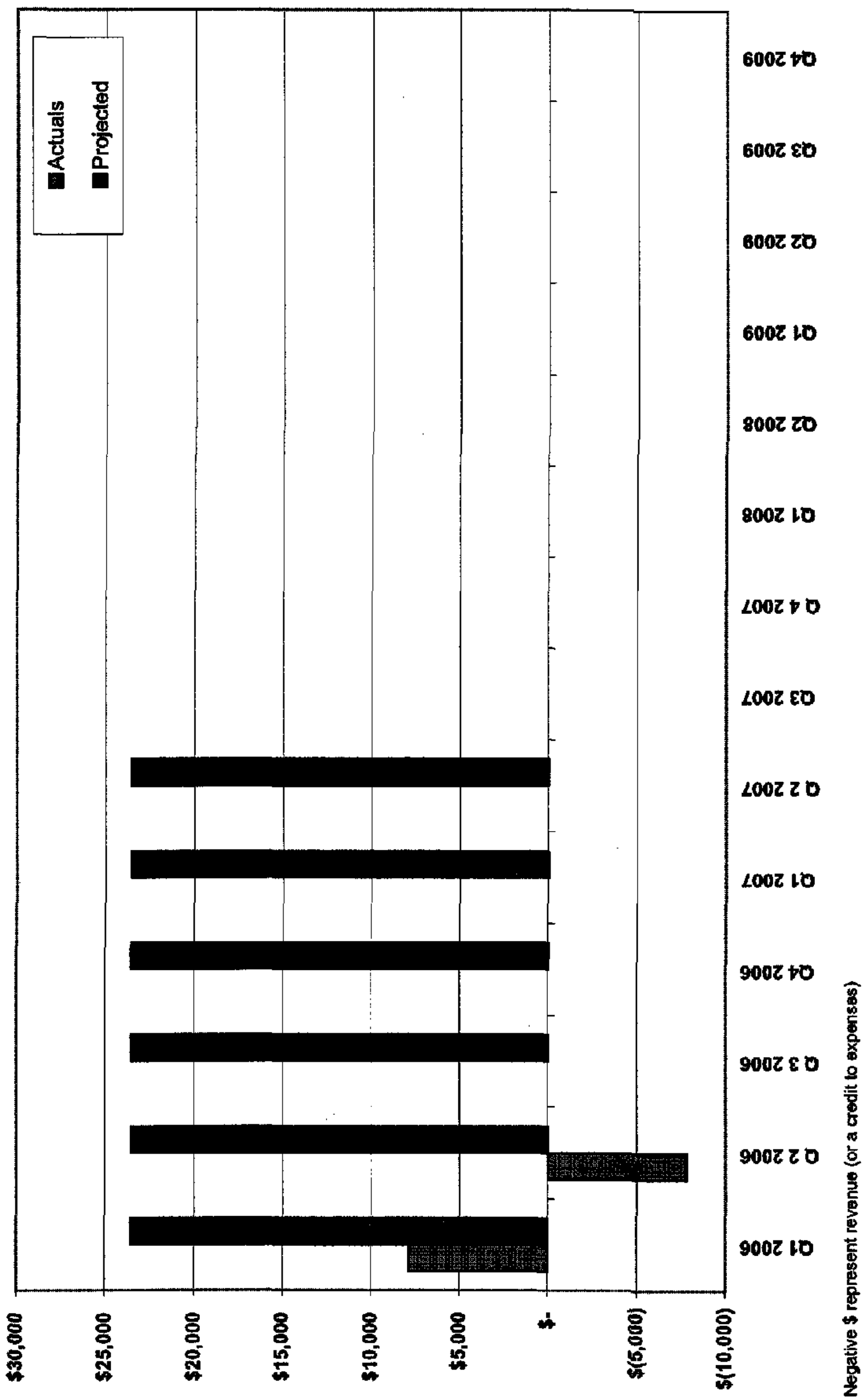
FirstEnergy Ohio Operating Companies
Schedule 10



Negative $ represent revenue (or a credit to expenses)

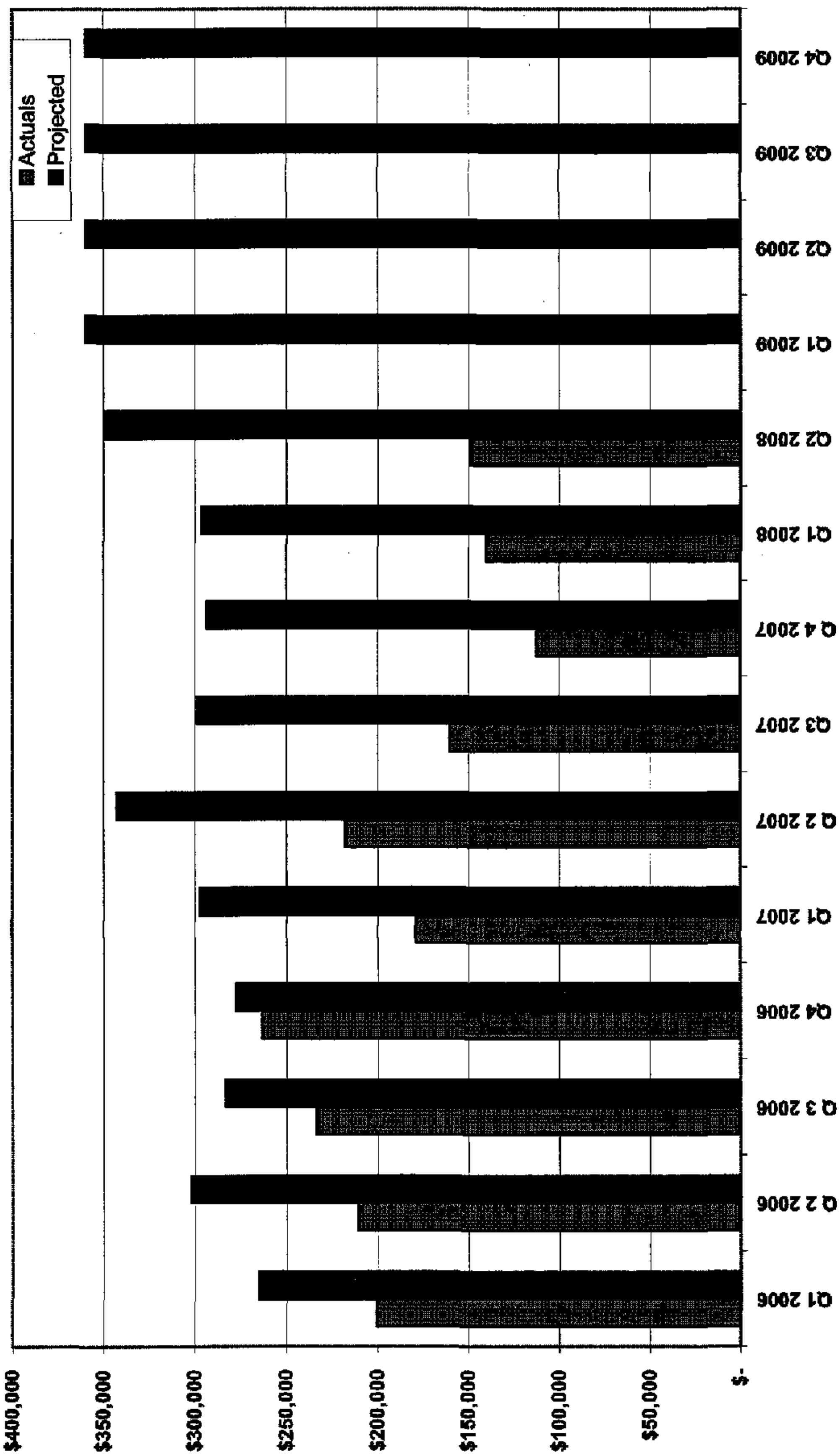
Schedule B-4

FirstEnergy Ohio Operating Companies
Schedule 15



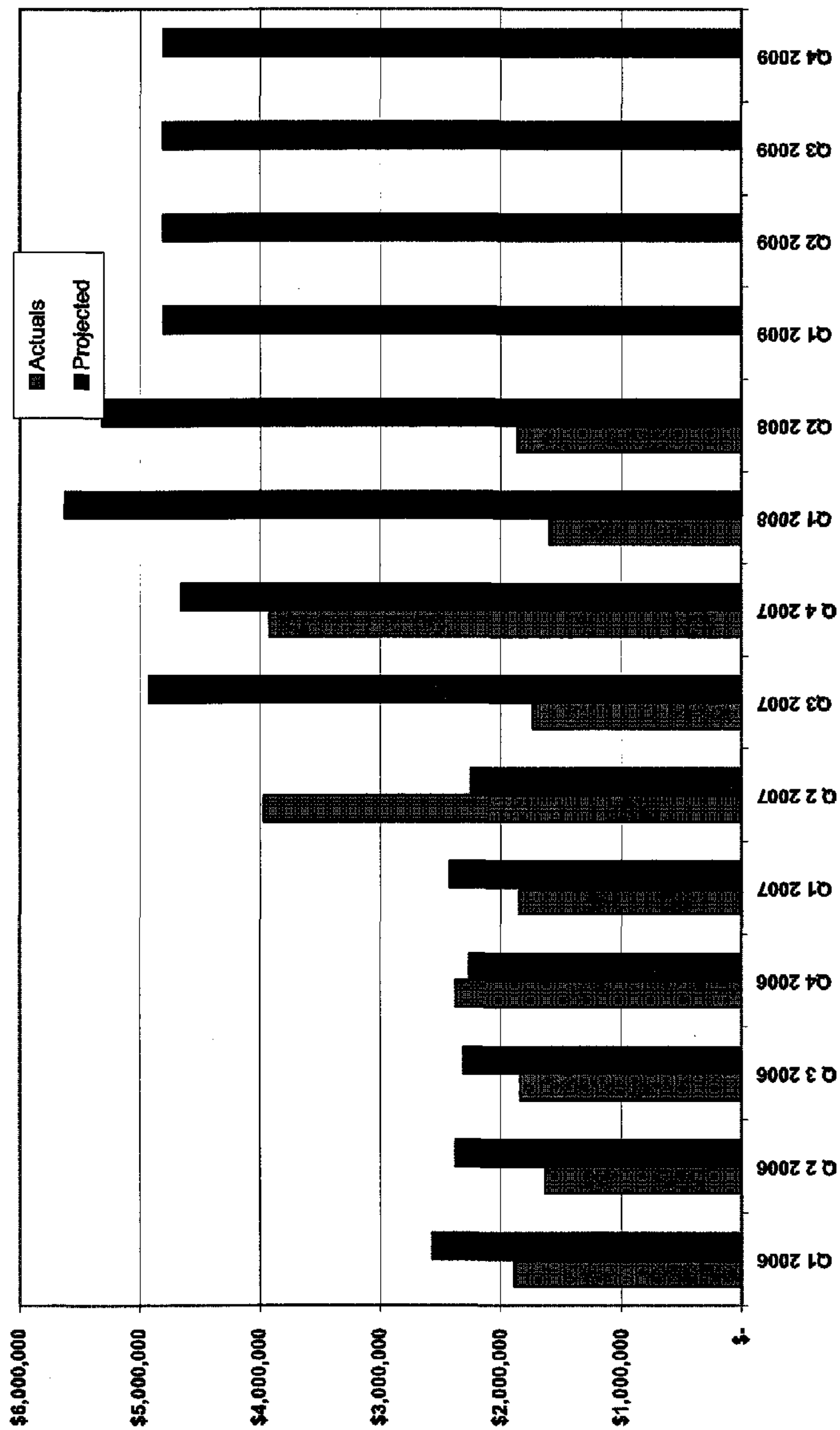
Schedule B-4

FirstEnergy Ohio Operating Companies
Schedule 16



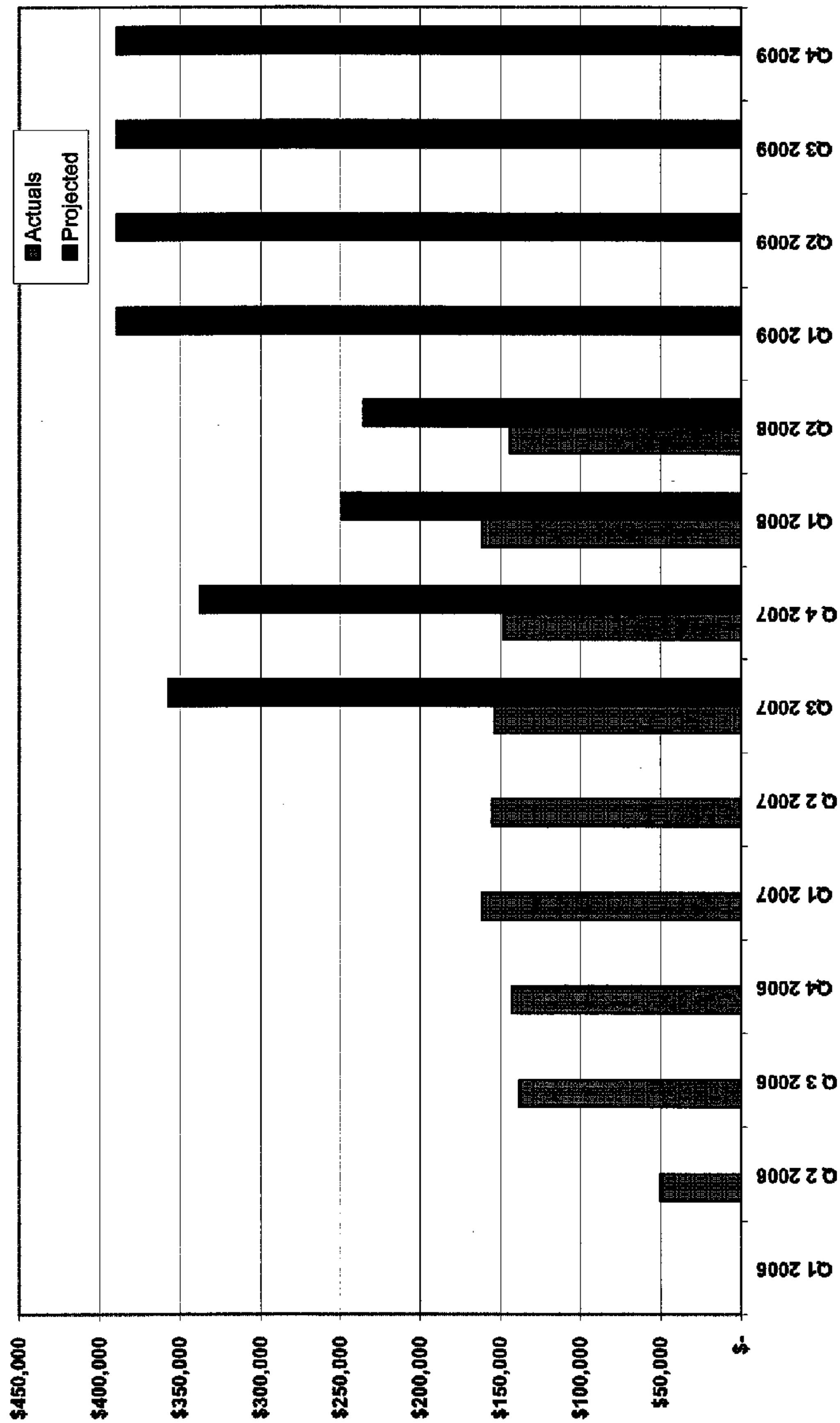
Schedule B-4

FirstEnergy Ohio Operating Companies
Schedule 17

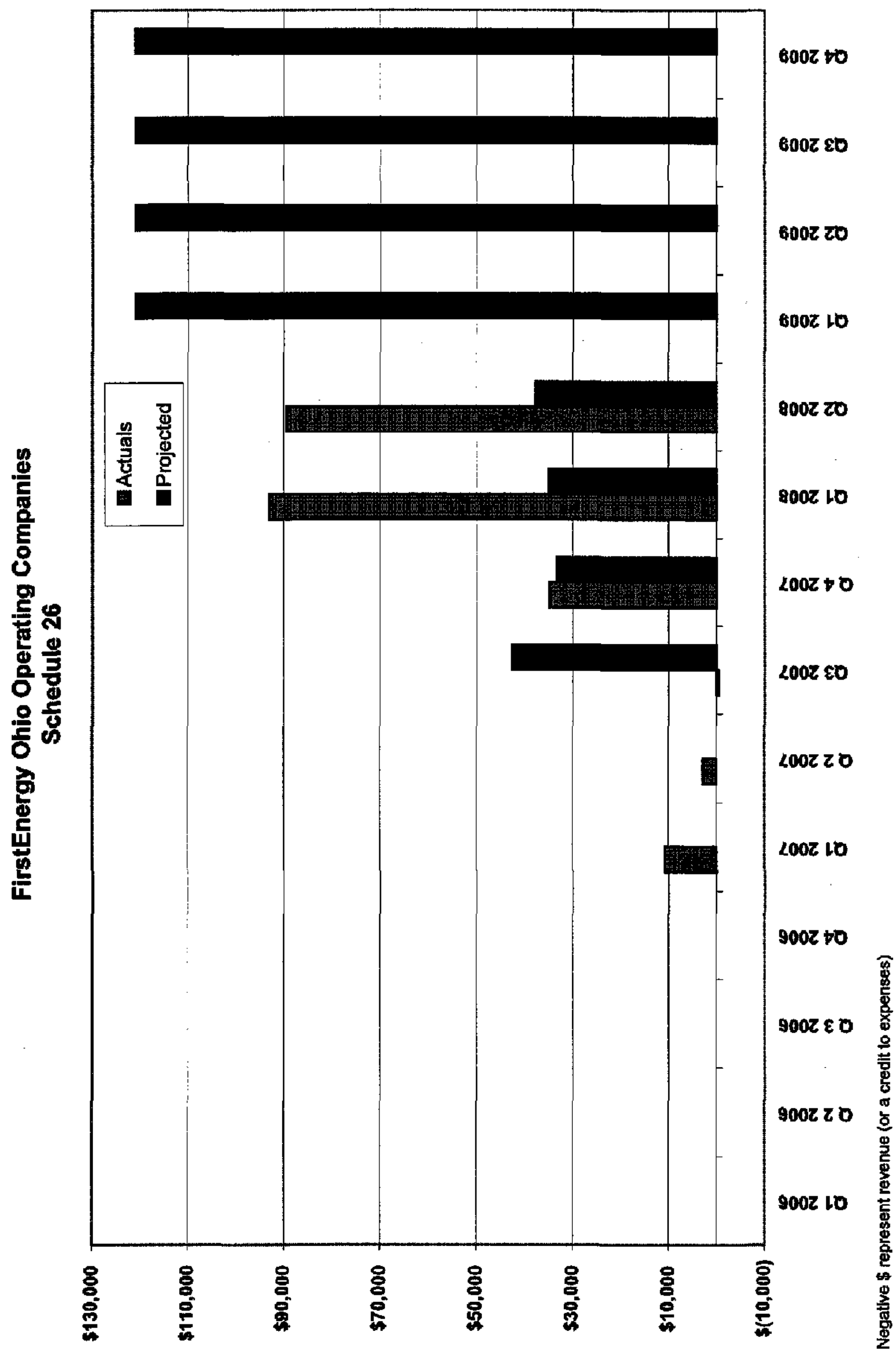


Schedule B-4

FirstEnergy Ohio Operating Companies
Schedule 24



Schedule B-4


FirstEnergy Ohio Operating Companies
Schedule 26
Actuals
Projected
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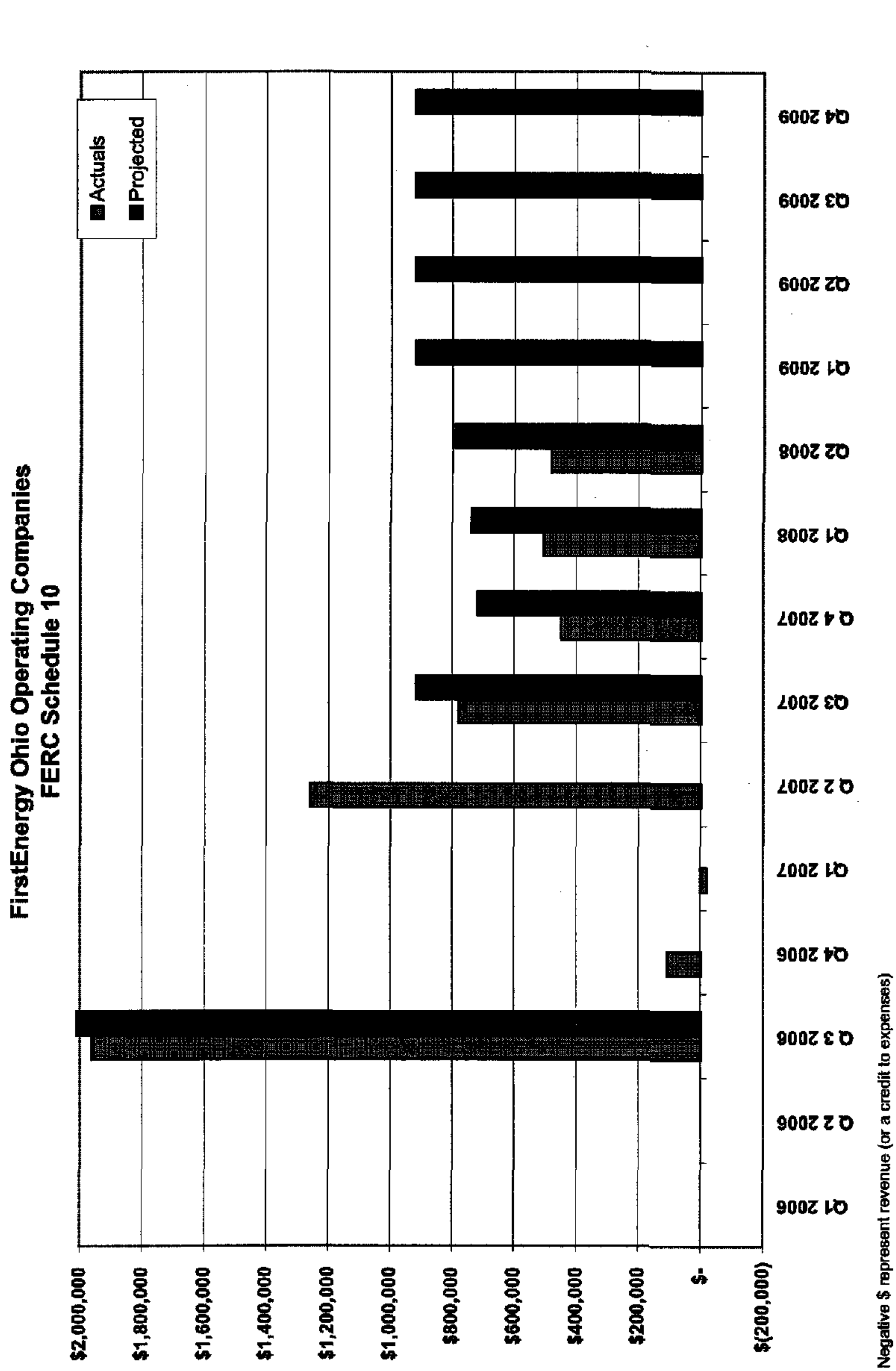
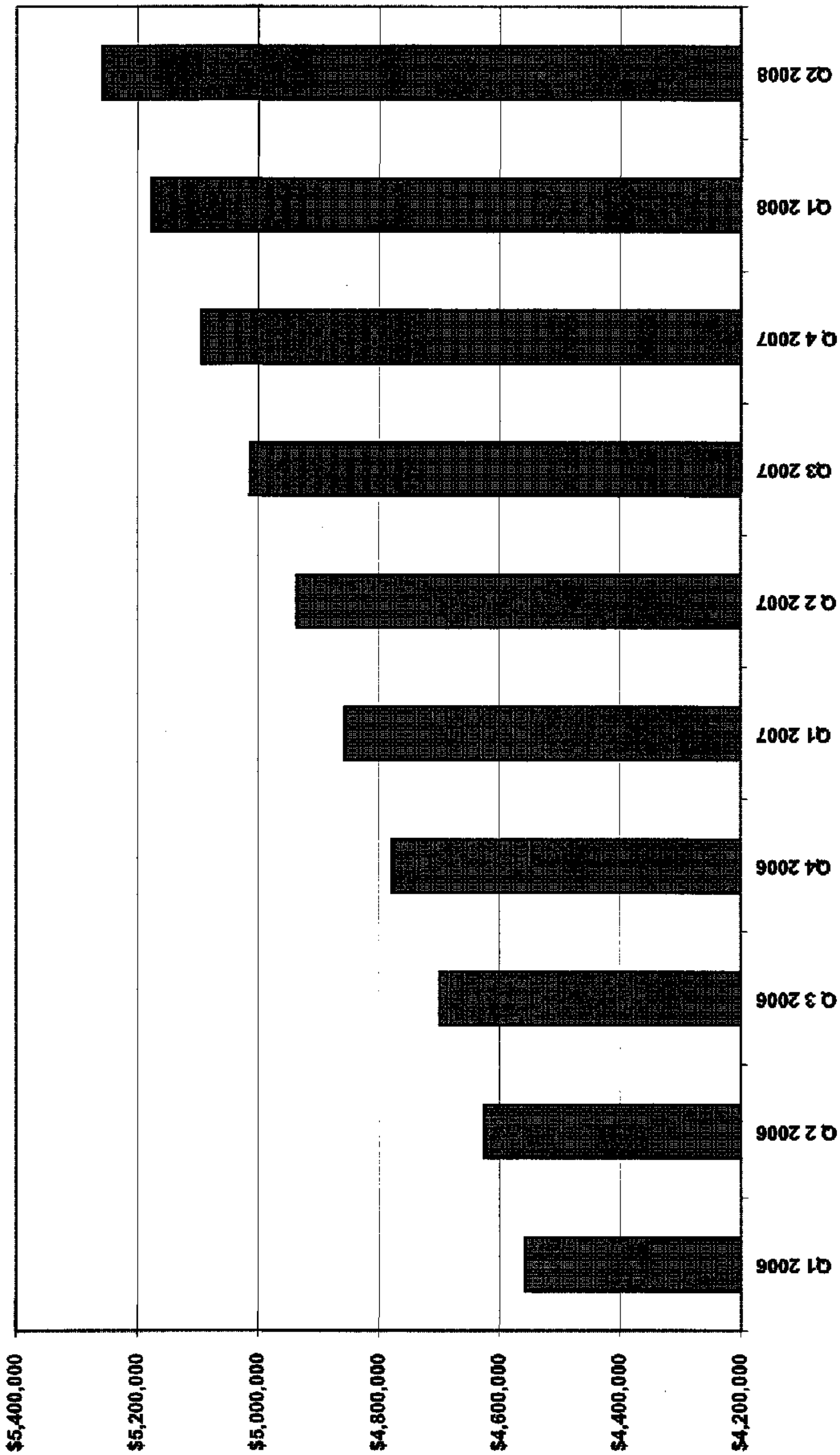
$110,000
$90,000
$70,000
$50,000
$30,000
$10,000
$(10,000)
Q1 2006
Q 2 2006
Q 3 2006
Q4 2006
Q1 2007
Q 2 2007
Q3 2007
Q 4 2007
Q1 2008
Q2 2008
Q1 2009
Q2 2009
Q3 2009
Q4 2009
Negative $ represent revenue (or a credit to expenses)

Schedule B-4

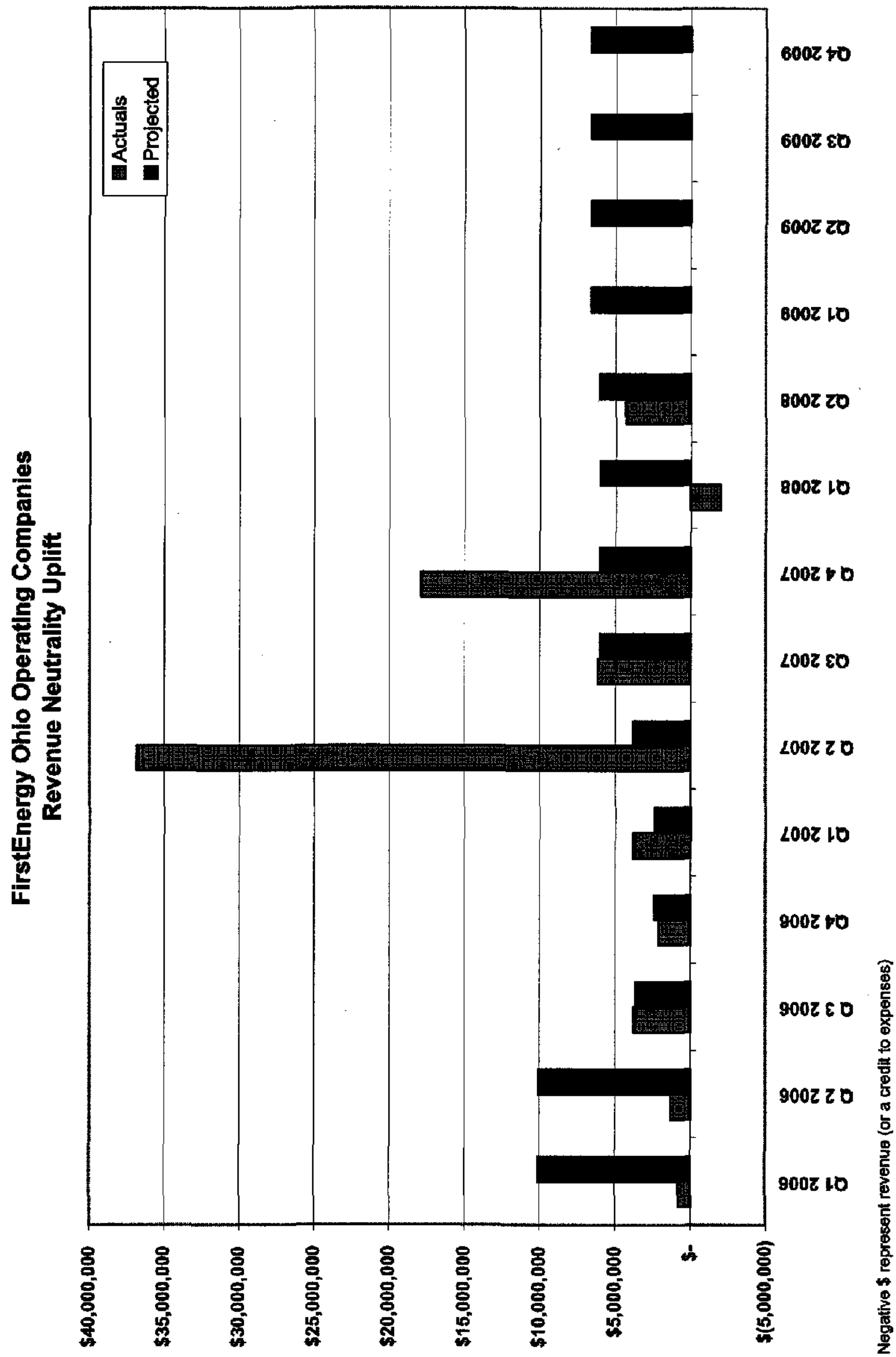

FirstEnergy Ohio Operating Companies
FERC Schedule 10
Actuals
Projected
$2,000,000
$1,800,000
$1,600,000
$1,400,000
$1,200,000
$1,000,000
$800,000
$600,000
$400,000
$200,000
$-
$(200,000)
Q1 2006
Q 2 2006
Q 3 2006
Q4 2006
Q1 2007
Q 2 2007
Q3 2007
Q 4 2007
Q1 2008
Q2 2008
Q1 2009
Q2 2009
Q3 2009
Q4 2009
Negative $ represent revenue (or a credit to expenses)

Schedule B-4

FirstEnergy Ohio Operating Companies
Amortization of 2005 Deferral



Schedule B-4


FirstEnergy Ohio Operating Companies
Revenue Neutrality Uplift
Actuals
Projected
$40,000,000
$35,000,000
$30,000,000
$25,000,000
$20,000,000
$15,000,000
$10,000,000
$5,000,000
$-
$(5,000,000)
Q1 2006
Q 2 2006
Q 3 2006
Q4 2006
Q1 2007
Q 2 2007
Q3 2007
Q 4 2007
Q1 2008
Q2 2008
Q1 2009
Q2 2009
Q3 2009
Q4 2009
Negative $ represent revenue (or a credit to expenses)

Transmission Cost Recovery Index

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B-3	Summary of Current and Proposed Rates
B-4	Graphs
B-5	Typical Bill Comparisons
C-1	Monthly Projected Transmission- and Ancillary Service-Related Costs
C-2	Monthly Projected Costs by Rate Schedule
C-3	Calculation of Rates, Energy & Demand Allocators
D-1	Reconciliation Adjustment - Actual Expenses by MISO Schedule
D-2	Reconciliation Adjustment - Actual Revenues by Rate Schedule
D-3	Reconciliation Adjustment - Monthly Over / Under Recovery Amounts
D-3a-c	Carrying Cost Calculation on Reconciliation Adjustment at OE, CEI, and TE
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D-3g	Reconciliation of throughput to Company Financials

Summary of Total Projected Transmission Costs | **Schedule B-1** | **Page 1 of 1**

Schedule B-1 provides the projected transmission- and ancillary service-related costs to be charged to the Ohio Operating Companies during the 12 months in which the Rider charges will be in effect.

Schedule	Projected Demand-Related Expenses			
	Ohio Edison	Cleveland Electric	Toledo Edison	Total
1	$ 3,324,080	$ 2,470,341	$ 1,238,393	$ 7,032,815
2	$ 6,701,736	$ 4,980,494	$ 2,496,747	$ 14,178,977
3	$ 1,439,546	$ 1,047,255	$ 510,613	$ 2,997,414
4	$ -	$ -	$ -	$ -
5	$ 2,159,319	$ 1,570,884	$ 765,919	$ 4,496,122
6	$ 1,081,322	$ 786,652	$ 383,549	$ 2,251,523
7 (69 kv)	$ -	$ -	$ -	$ -
7 (138 kv)	$ -	$ -	$ -	$ -
8 (69 kv)	$ -	$ -	$ -	$ -
8 (138 kv)	$ -	$ -	$ -	$ -
9 (69 kv)	$ 38,143,112	$ -	$ 10,696,082	$ 48,839,194
9 (138 kv)	$ 66,162,529	$ 49,169,680	$ 24,648,987	$ 139,981,197
10	$ 3,984,917	$ 2,963,467	$ 1,487,969	$ 8,436,353
11	$ -	$ -	$ -	$ -
12	$ -	$ -	$ -	$ -
13	$ -	$ -	$ -	$ -
14	$ -	$ -	$ -	$ -
15	$ -	$ -	$ -	$ -
18	$ -	$ -	$ -	$ -
19	$ -	$ -	$ -	$ -
20	$ -	$ -	$ -	$ -
22	$ -	$ -	$ -	$ -
26	$ 228,730	$ 169,987	$ 85,216	$ 483,933
Total	**$ 123,225,291**	**$ 63,158,760**	**$ 42,313,476**	**$ 228,697,527**

Schedule	Projected Energy-Related Expenses			
	Ohio Edison	Cleveland Electric	Toledo Edison	Total
3	$ 9,268,242	$ 6,736,797	$ 3,864,302	$ 19,869,341
5	$ 1,134,162	$ 824,387	$ 472,878	$ 2,431,427
6	$ 974,671	$ 708,457	$ 406,378	$ 2,089,506
16	$ 660,679	$ 500,232	$ 278,476	$ 1,439,386
17	$ 8,808,662	$ 6,669,451	$ 3,712,848	$ 19,190,961
24	$ 714,412	$ 546,763	$ 294,784	$ 1,555,959
FERC 10	$ 1,737,668	$ 1,291,376	$ 647,371	$ 3,676,415
Congestion Expense	$ 8,010,415	$ 6,065,060	$ 3,376,386	$ 17,451,861
FTR Credit	$ *(10,282,997)*	$ *(7,785,738)*	$ *(4,334,281)*	$ *(22,403,016)*
Net Losses	$ 40,850,610	$ 30,929,904	$ 17,218,622	$ 88,999,036
Revenue Neutrality	$ 12,117,659	$ 9,274,032	$ 5,000,062	$ 26,391,753
Rev. Sufficiency Guarantee	$ 14,541,191	$ 11,128,839	$ 6,000,074	$ 31,670,104
Total	**$ 88,535,373**	**$ 66,889,559**	**$ 36,937,801**	**$ 192,362,733**
Total Expenses	**$ 211,760,664**	**$ 130,048,319**	**$ 79,251,277**	**$ 421,060,260**

Note: These are placeholder expenses.

Summary of Current versus Proposed Transmission Revenues

Schedule B-2 | Page 1 of 1

Schedule B-2 provides billing determinants for each class applied to current transmission cost recovery rider rates and proposed transmission cost recovery rider rates, including current and proposed class revenues, and the dollar and percentage differences.

Schedule	Billing Units	Billing Determinants	Current Rates	Current Total	Projected Rate [1]	Projected Total	$ Difference	% Difference
RS	All kWh, per kWh	9,225,981,525	N/A	N/A	0.009291	$ 85,717,893	$ -	0.0%
GS	All kW, per kW	25,343,181	N/A	N/A	2.367	$ 59,996,386	$ -	0.0%
GP	All kW, per kW	7,103,952	N/A	N/A	3.409	$ 24,216,645	$ -	0.0%
GSU	All kW/kVa, per kW/kVa	2,215,472	N/A	N/A	3.178	$ 7,041,631	$ -	0.0%
GT	All kVa, per kVa	12,369,962	N/A	N/A	2.797	$ 34,597,379	$ -	0.0%
LTG	All kWh, per kWh	186,197,457	N/A	N/A	0.003840	$ 715,075	$ -	0.0%
				$225,575,556		$212,285,008	$ (13,290,548)	-5.9%

Schedule	Billing Units	Billing Determinants	Current Rates	Current Total	Projected Rate [1]	Projected Total	$ Difference	% Difference
RS	All kWh, per kWh	5,603,670,615	N/A	N/A	0.007388	$ 41,399,665	$ -	0.0%
GS	All kW, per kW	24,134,406	N/A	N/A	2.107	$ 50,863,211	$ -	0.0%
GP	All kW, per kW	1,019,438	N/A	N/A	2.699	$ 2,751,583	$ -	0.0%
GSU	All kW/kVa, per kW/kVa	8,735,289	N/A	N/A	2.603	$ 22,735,276	$ -	0.0%
GT	All kVa, per kVa	5,039,889	N/A	N/A	2.341	$ 11,800,131	$ -	0.0%
LTG	All kWh, per kWh	221,079,177	N/A	N/A	0.003711	$ 820,447	$ -	0.0%
				$138,552,873		$130,370,334	$ (8,182,539)	-5.9%

Schedule	Billing Units	Billing Determinants	Current Rates	Current Total	Projected Rate [1]	Projected Total	$ Difference	% Difference
RS	All kWh, per kWh	2,481,166,258	N/A	N/A	0.008804	$ 21,844,303	$ -	0.0%
GS	All kW, per kW	8,087,756	N/A	N/A	2.269	$ 18,352,513	$ -	0.0%
GP	All kW, per kW	2,790,440	N/A	N/A	2.861	$ 7,982,321	$ -	0.0%
GSU	All kW/kVa, per kW/kVa	185,981	N/A	N/A	3.436	$ 639,035	$ -	0.0%
GT	All kVa, per kVa	9,348,977	N/A	N/A	3.247	$ 30,359,717	$ -	0.0%
LTG	All kWh, per kWh	69,151,680	N/A	N/A	0.003899	$ 269,623	$ -	0.0%
				$ 82,830,783		$ 79,447,512	$ (3,383,271)	-4.1%

[1] Rates have been grossed up for the Commercial Activity Tax (CAT) rate.
NOTE: These values are illustrative. The current total is higher than the proposed total because the former includes amortization expense associated with the 2005 transmission deferral, while the latter does not.

Summary of Current and Proposed Rates

Schedule B-3 | Page 1 of 1

Schedule B-3 provides the current transmission cost recovery rider rate and proposed transmission cost recovery rider rates, the dollar difference, and percentage change.

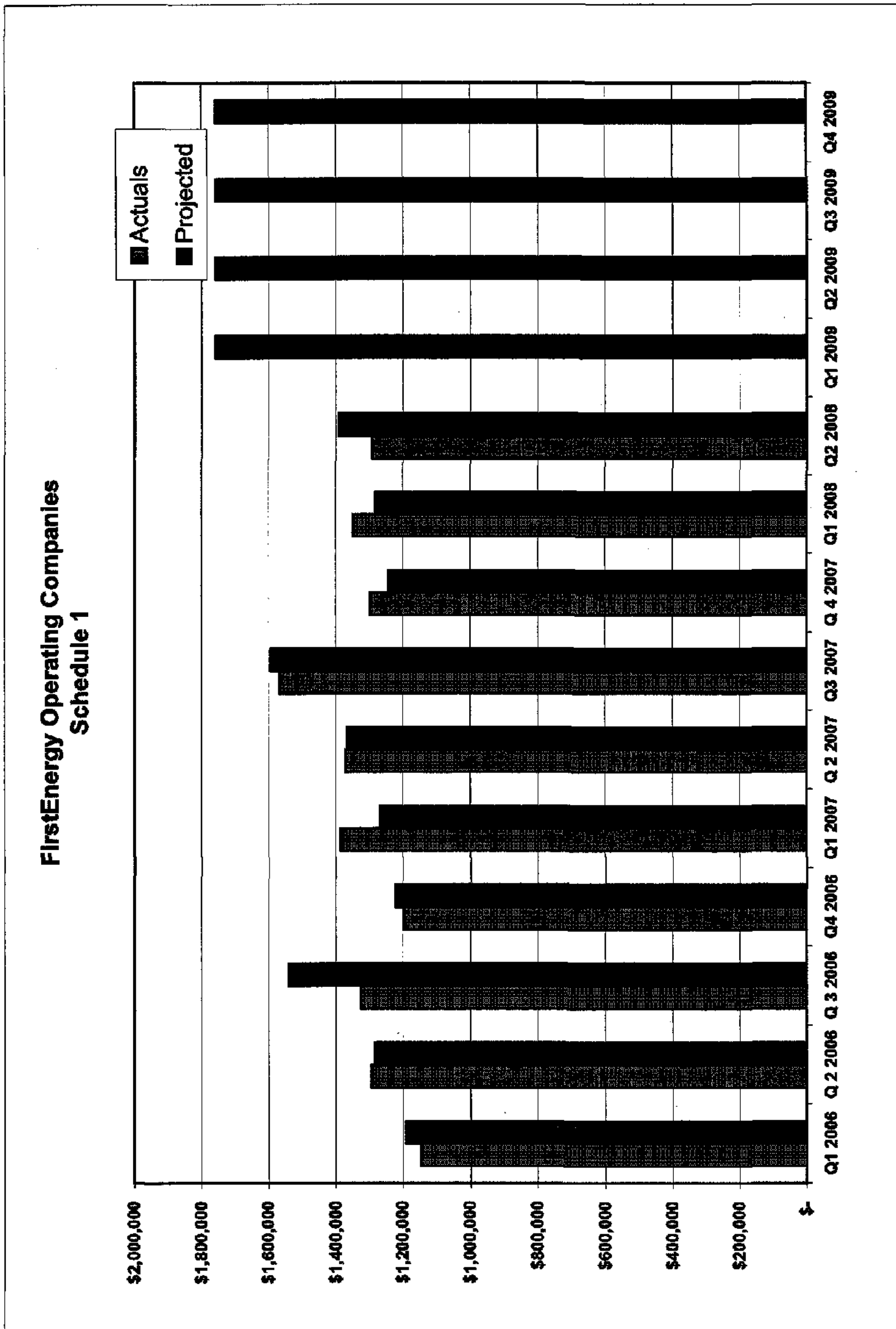
[illegible]					
Schedule	**Billing Units**	**Current Rates**	**Projected Rate**	**$ Difference**	**% Difference**
RS	All kWh, per kWh	N/A	0.009291	$ -	0.0%
GS	All kW, per kW	N/A	2.367	$ -	0.0%
GP	All kW, per kW	N/A	3.409	$ -	0.0%
GSU	All kW/kVa, per kW/kVa	N/A	3.178	$ -	0.0%
GT	All kVa, per kVa	N/A	2.797	$ -	0.0%
LTG	All kWh, per kWh	N/A	0.003840	$ -	0.0%

[illegible]					
Schedule	**Billing Units**	**Current Rates**	**Projected Rate**	**$ Difference**	**% Difference**
RS	All kWh, per kWh	N/A	0.007388	$ -	0.0%
GS	All kW, per kW	N/A	2.107	$ -	0.0%
GP	All kW, per kW	N/A	2.699	$ -	0.0%
GSU	All kW/kVa, per kW/kVa	N/A	2.603	$ -	0.0%
GT	All kVa, per kVa	N/A	2.341	$ -	0.0%
LTG	All kWh, per kWh	N/A	0.003711	$ -	0.0%

[illegible]					
Schedule	**Billing Units**	**Current Rates**	**Projected Rate**	**$ Difference**	**% Difference**
RS	All kWh, per kWh	N/A	0.008804	$ -	0.0%
GS	All kW, per kW	N/A	2.269	$ -	0.0%
GP	All kW, per kW	N/A	2.861	$ -	0.0%
GSU	All kW/kVa, per kW/kVa	N/A	3.436	$ -	0.0%
GT	All kVa, per kVa	N/A	3.247	$ -	0.0%
LTG	All kWh, per kWh	N/A	0.003899	$ -	0.0%

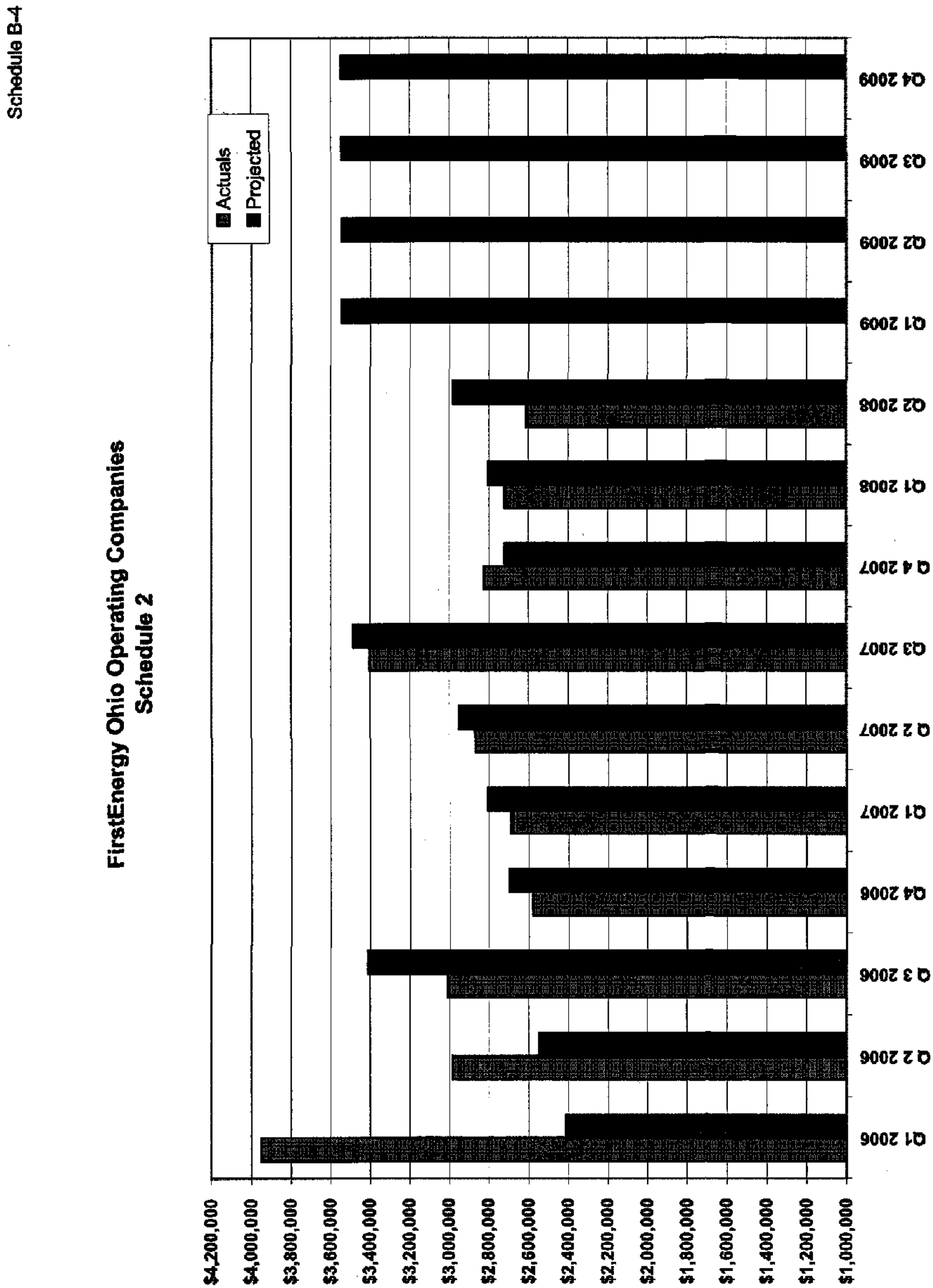
NOTE: These values are illustrative.
Because these rate schedules will not exist until January 1, 2009, only the placeholder rates are shown.

Schedule B-4


FirstEnergy Operating Companies
Schedule 1
Actuals
Projected
$2,000,000
$1,800,000
$1,600,000
$1,400,000
$1,200,000
$1,000,000
$800,000
$600,000
$400,000
$200,000
$-
Q1 2006
Q 2 2006
Q 3 2006
Q4 2006
Q1 2007
Q 2 2007
Q3 2007
Q 4 2007
Q1 2008
Q2 2008
Q1 2009
Q2 2009
Q3 2009
Q4 2009

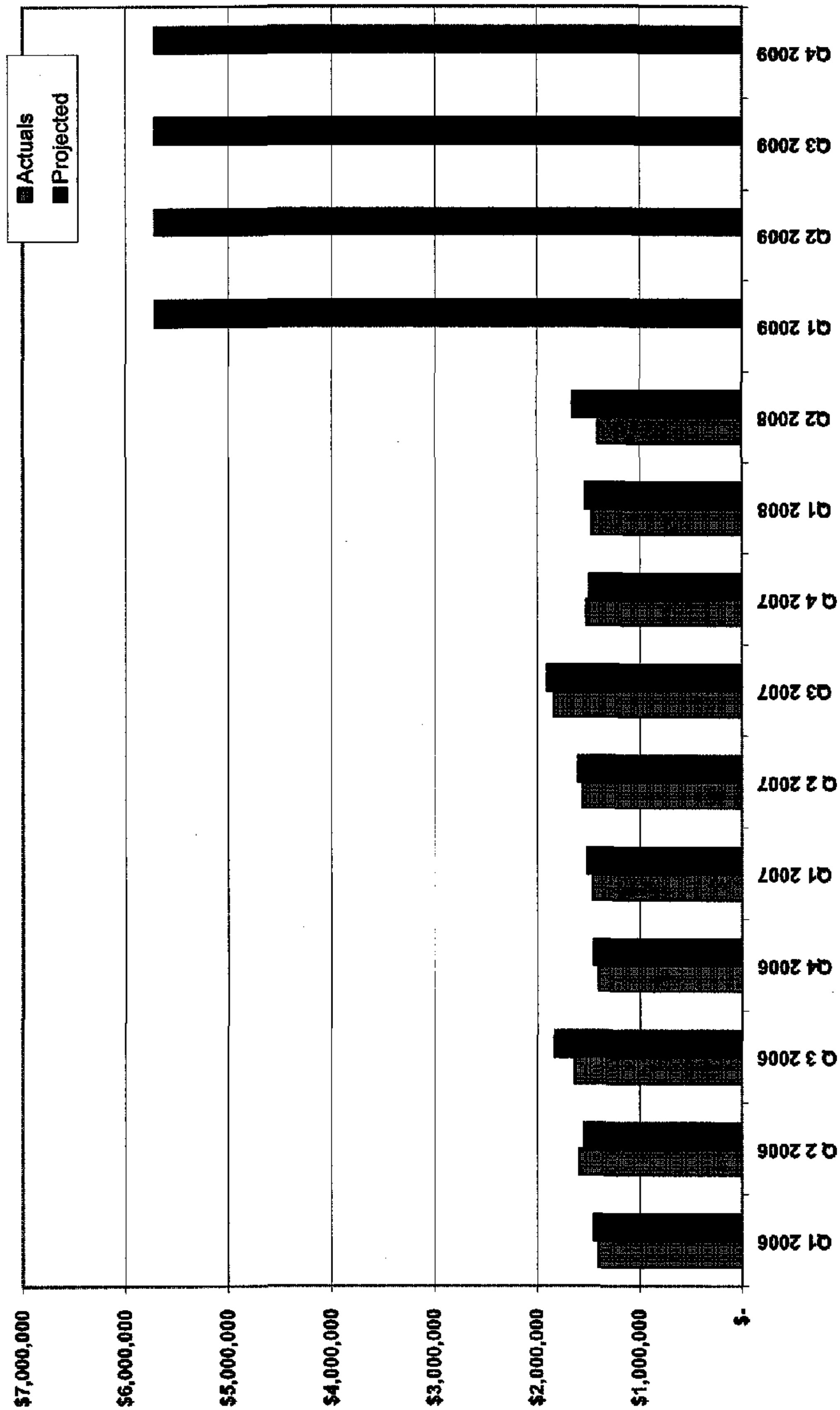
Case No. 08-XXXX-EL-SSO
Ohio Edison Company
The Cleveland Electric Illuminating Company
The Toledo Edison Company

Witness: Kevin Warvell



Schedule B-4

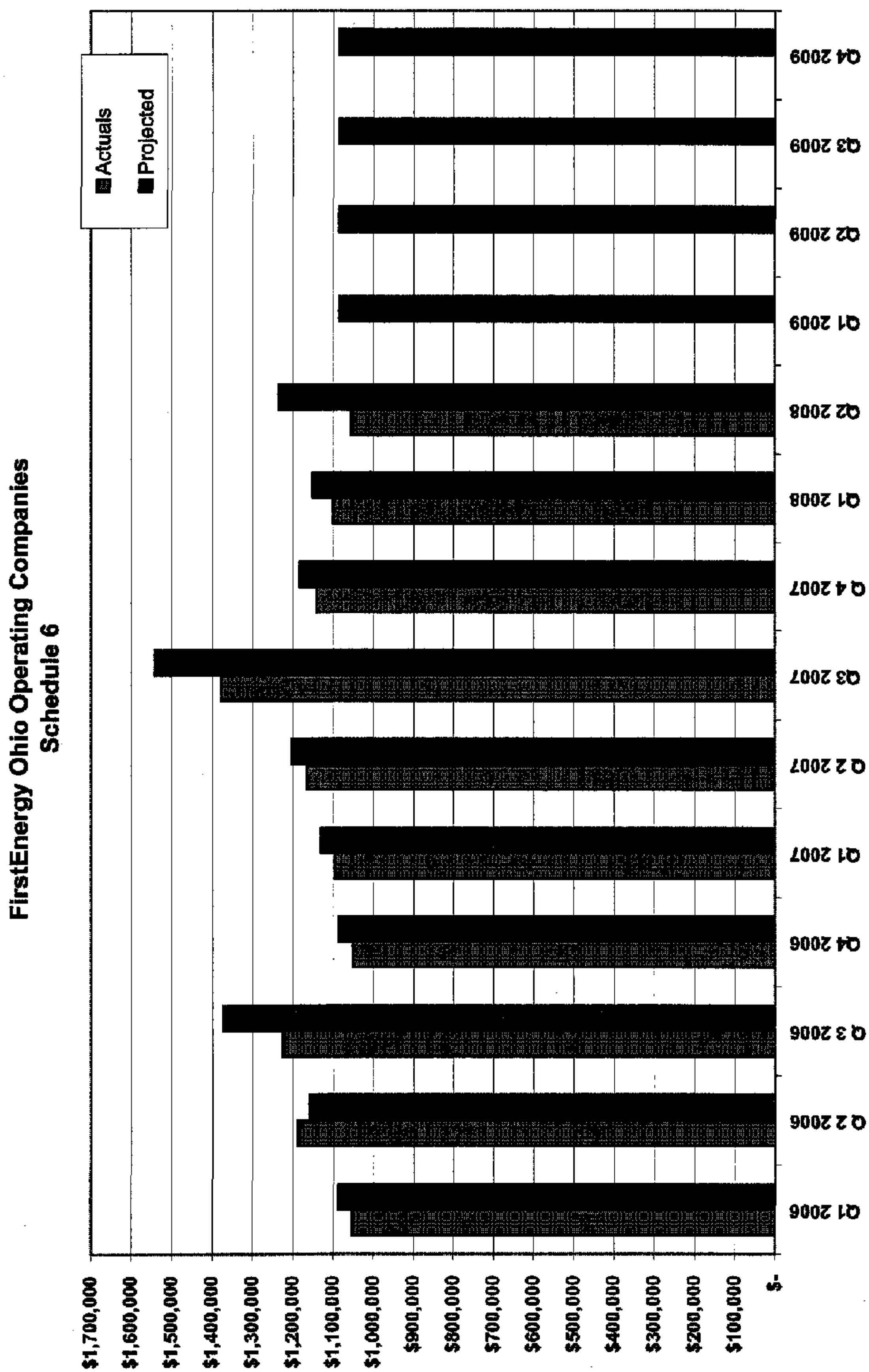
FirstEnergy Ohio Operating Companies
Schedule 3



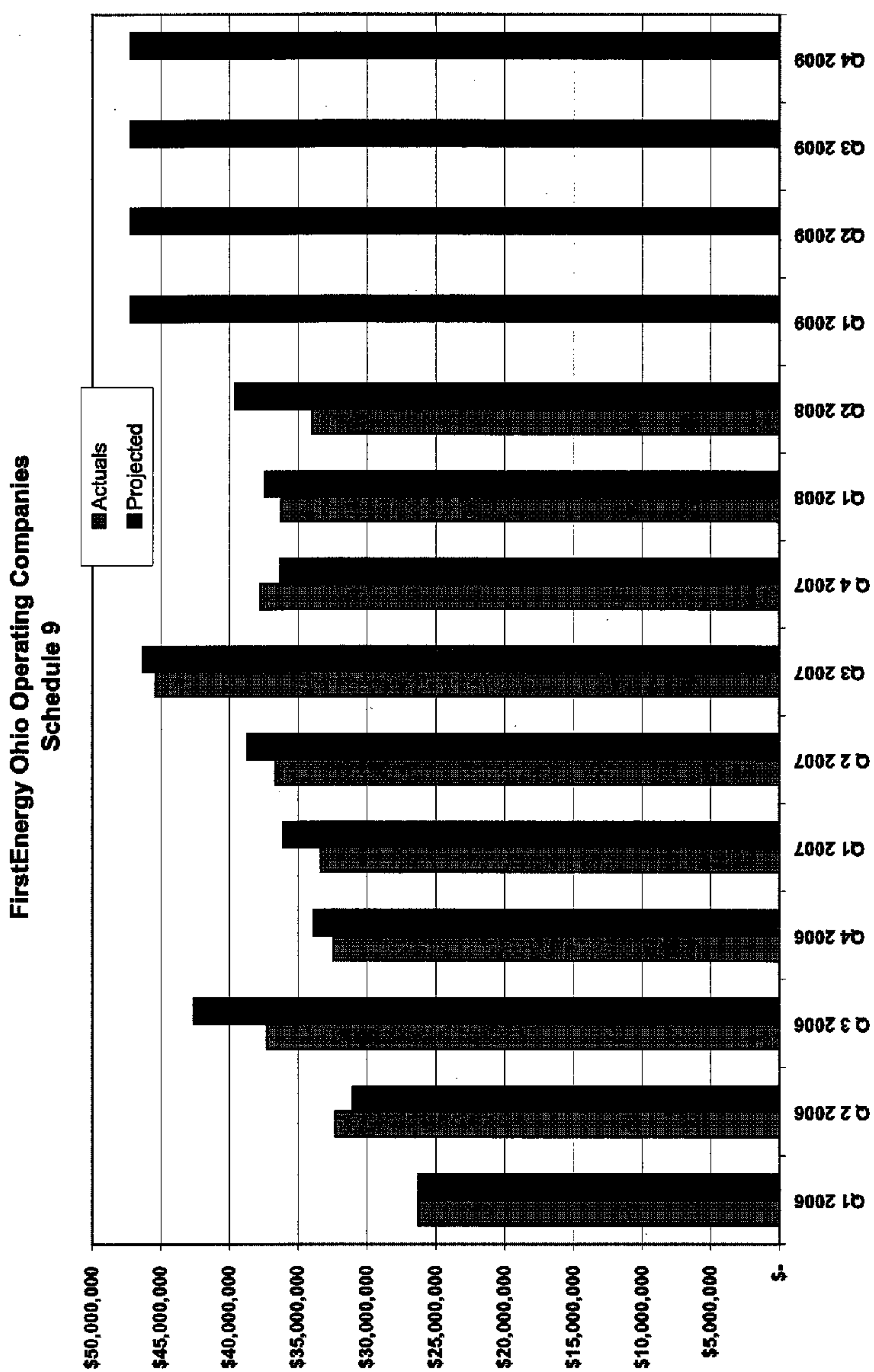
Schedule B-4

FirstEnergy Ohio Operating Companies
Schedule 5

Schedule B-4

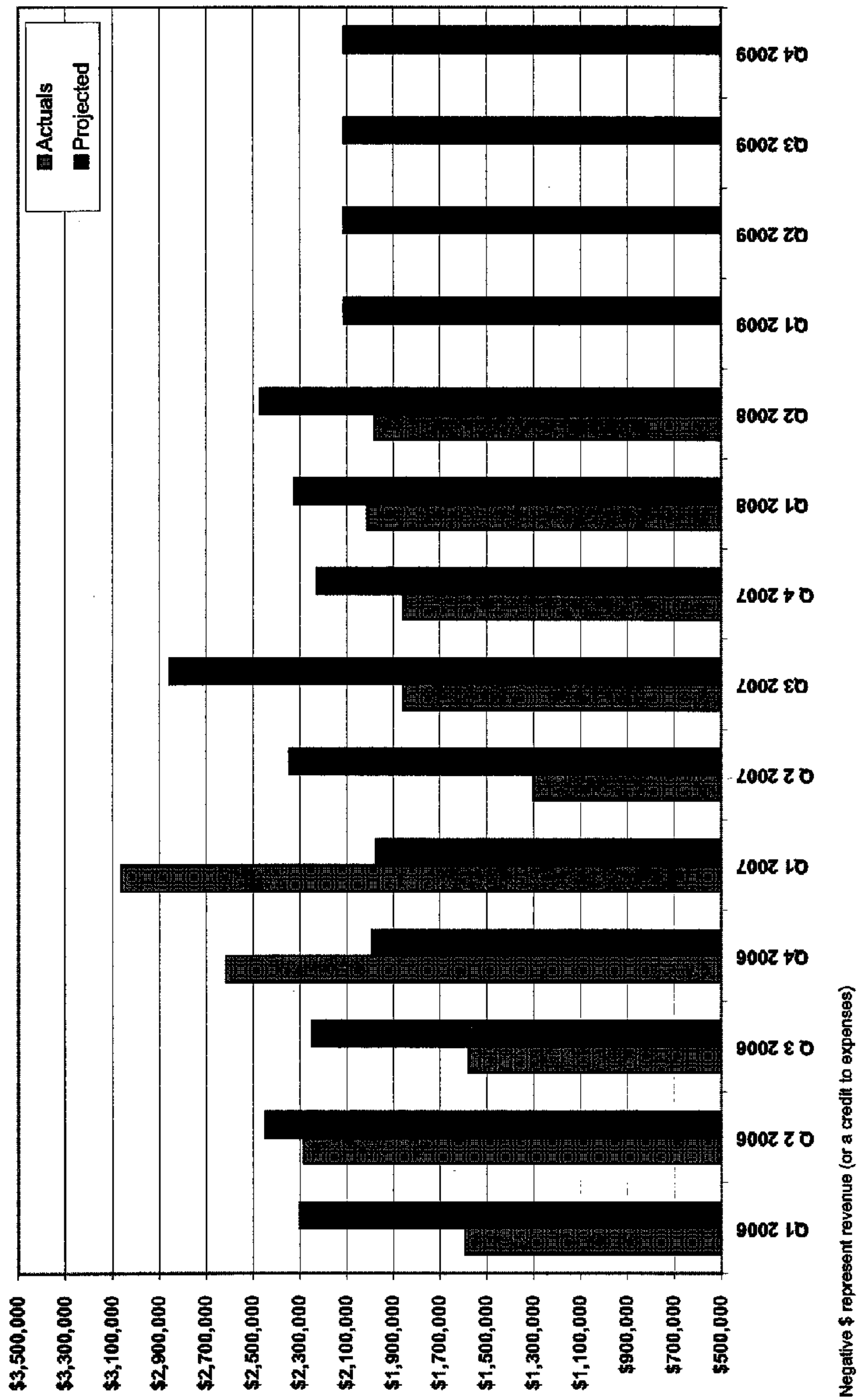

FirstEnergy Ohio Operating Companies
Schedule 6
Actuals
Projected
$1,700,000
$1,600,000
$1,500,000
$1,400,000
$1,300,000
$1,200,000
$1,100,000
$1,000,000
$900,000
$800,000
$700,000
$600,000
$500,000
$400,000
$300,000
$200,000
$100,000
$-
Q1 2006
Q 2 2006
Q 3 2006
Q4 2006
Q1 2007
Q 2 2007
Q3 2007
Q 4 2007
Q1 2008
Q2 2008
Q1 2009
Q2 2009
Q3 2009
Q4 2009

Schedule B-4


FirstEnergy Ohio Operating Companies
Schedule 9
Actuals
Projected
$50,000,000
$45,000,000
$40,000,000
$35,000,000
$30,000,000
$25,000,000
$20,000,000
$15,000,000
$10,000,000
$5,000,000
$-
Q1 2006
Q 2 2006
Q 3 2006
Q4 2006
Q1 2007
Q 2 2007
Q3 2007
Q 4 2007
Q1 2008
Q2 2008
Q1 2009
Q2 2009
Q3 2009
Q4 2009

Schedule B-4

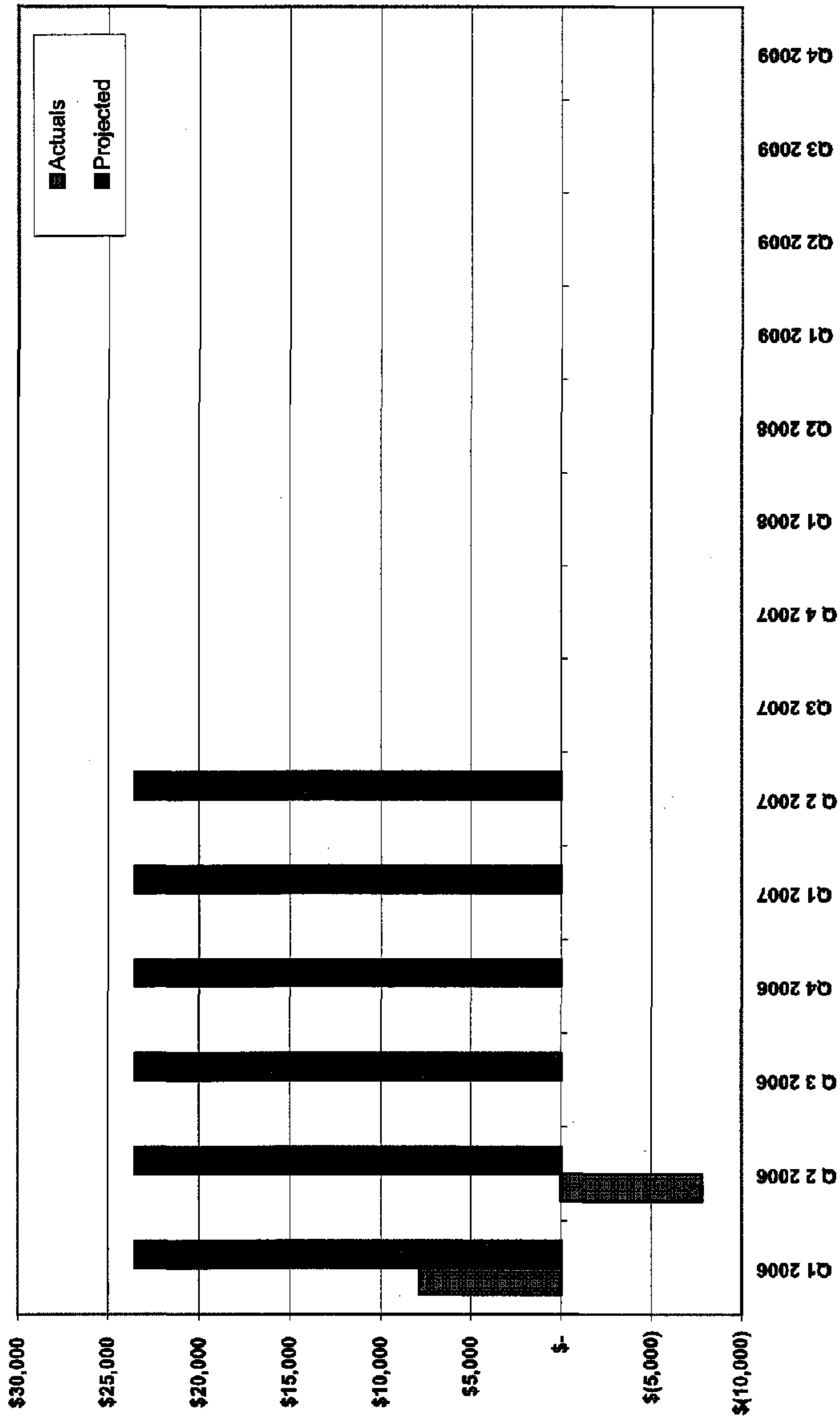
FirstEnergy Ohio Operating Companies
Schedule 10



Negative $ represent revenue (or a credit to expenses)

Schedule B-4

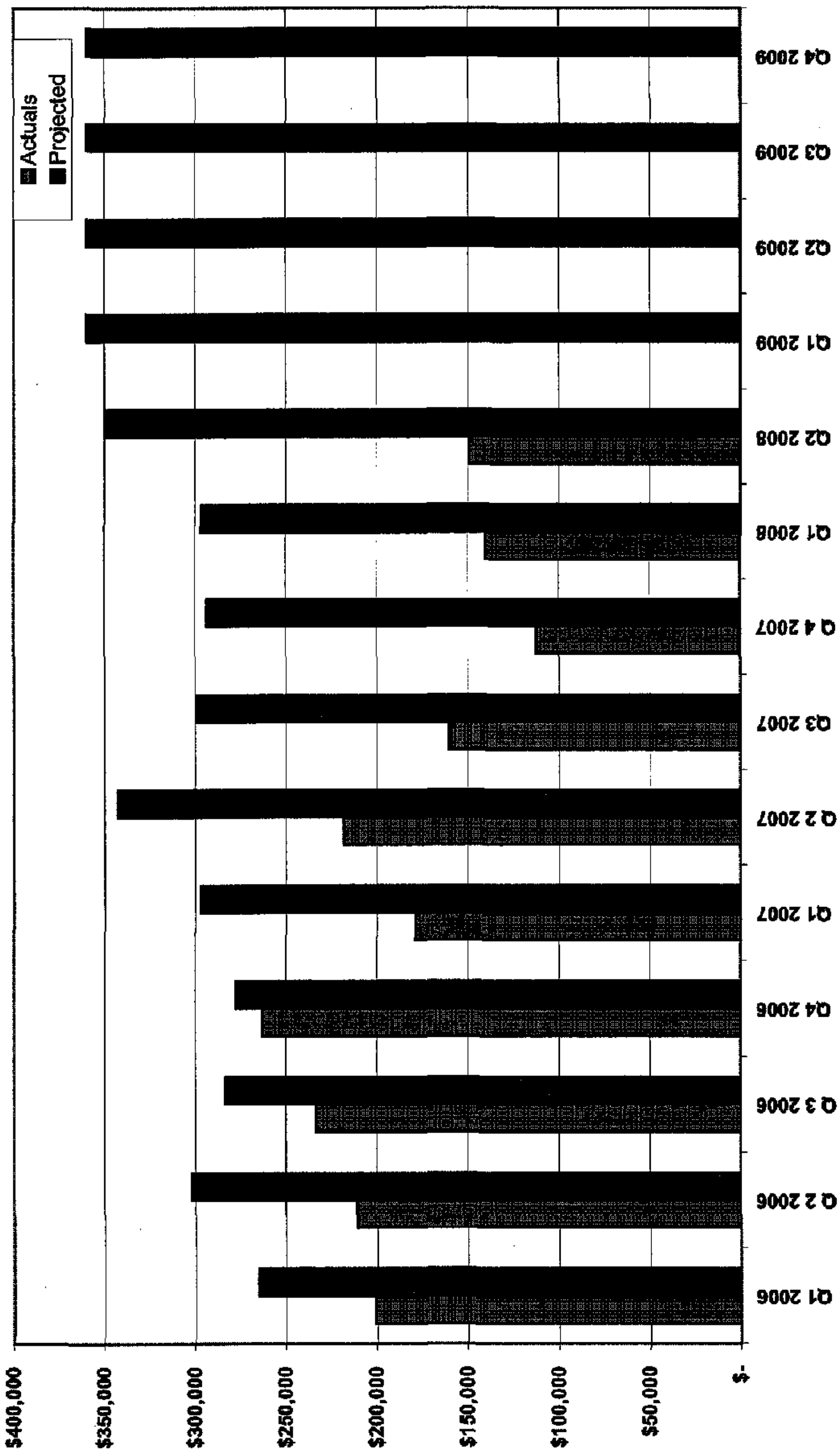
FirstEnergy Ohio Operating Companies
Schedule 15



Negative $ represent revenue (or a credit to expenses)

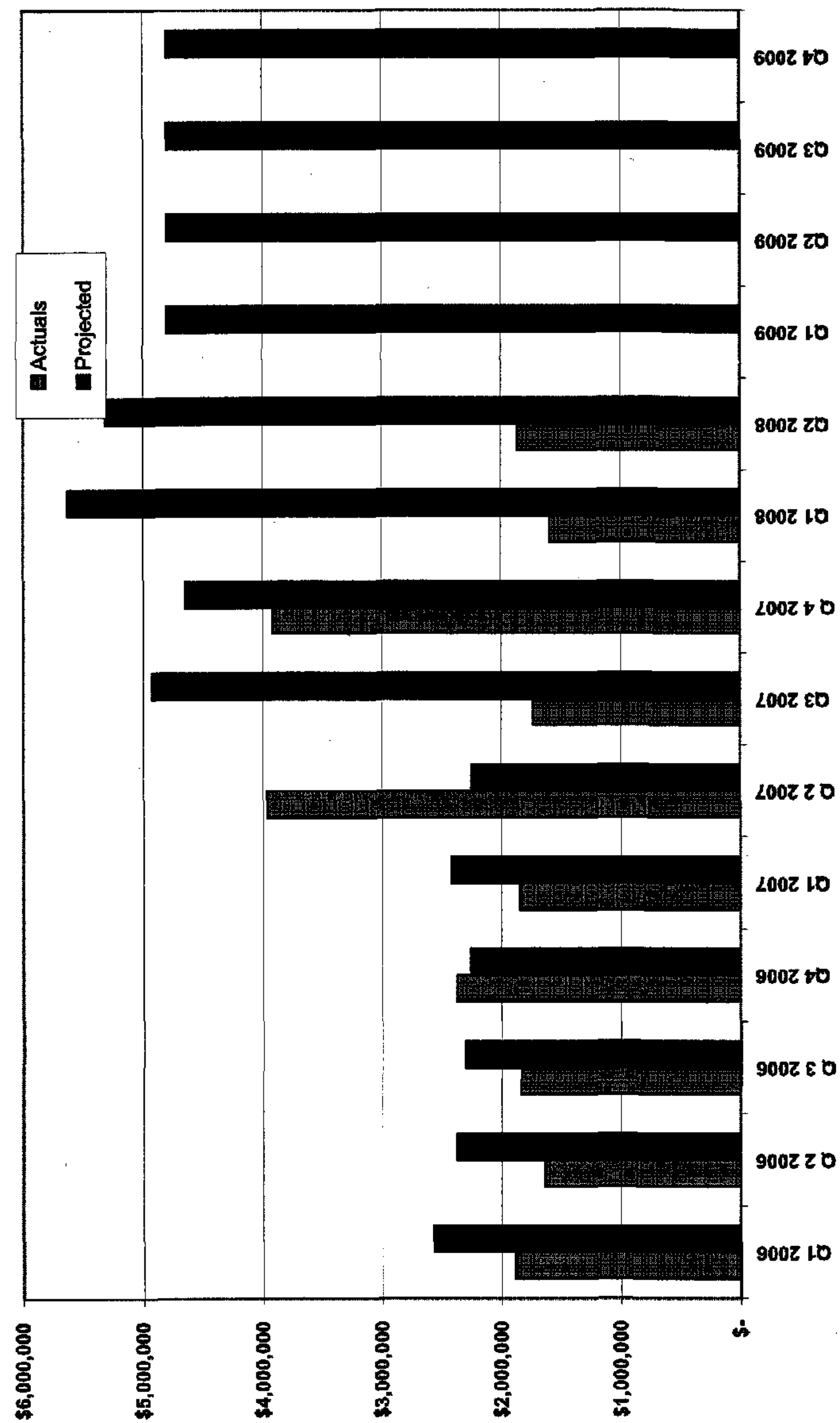
Schedule B-4

FirstEnergy Ohio Operating Companies
Schedule 16

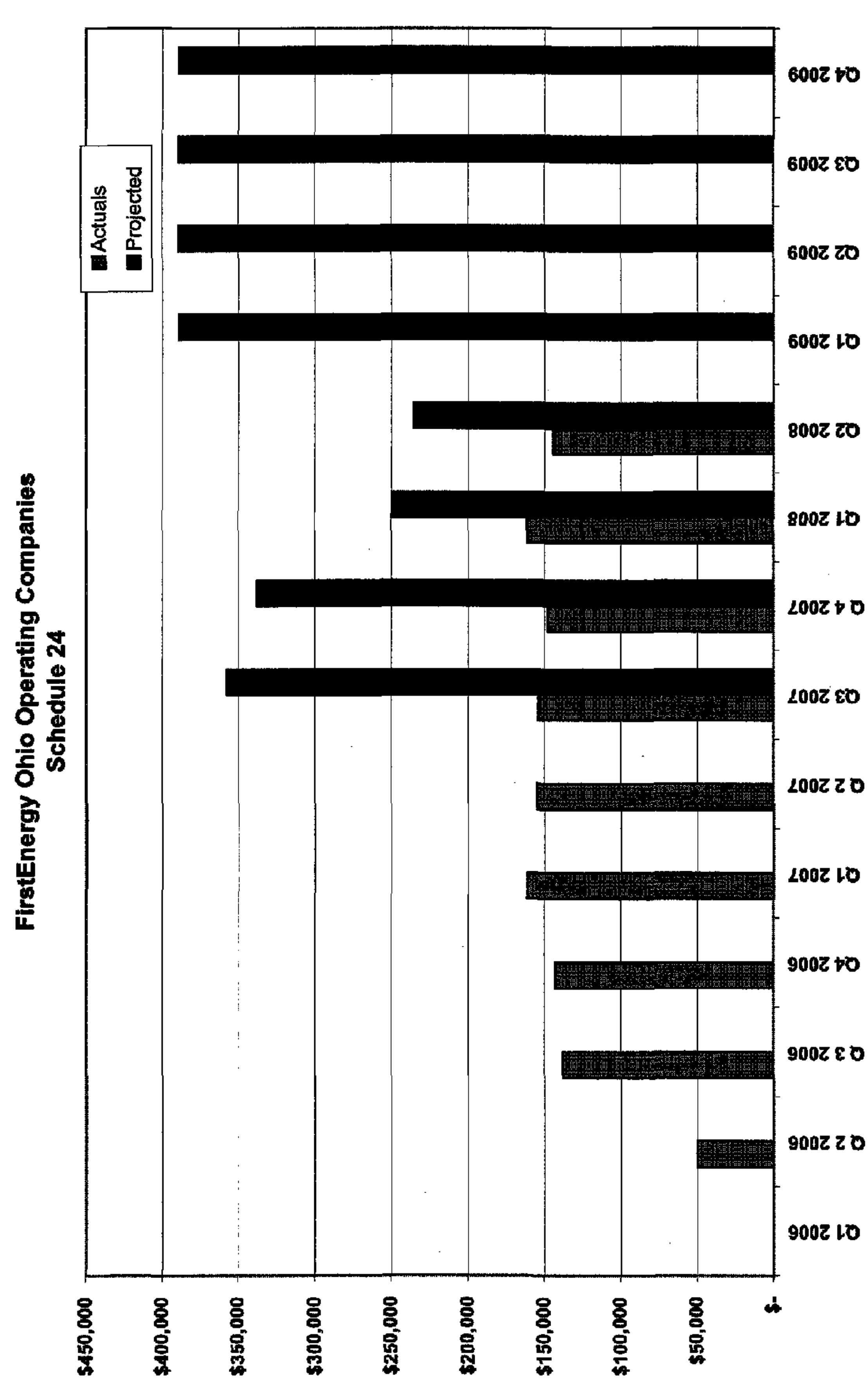


Schedule B-4

FirstEnergy Ohio Operating Companies
Schedule 17

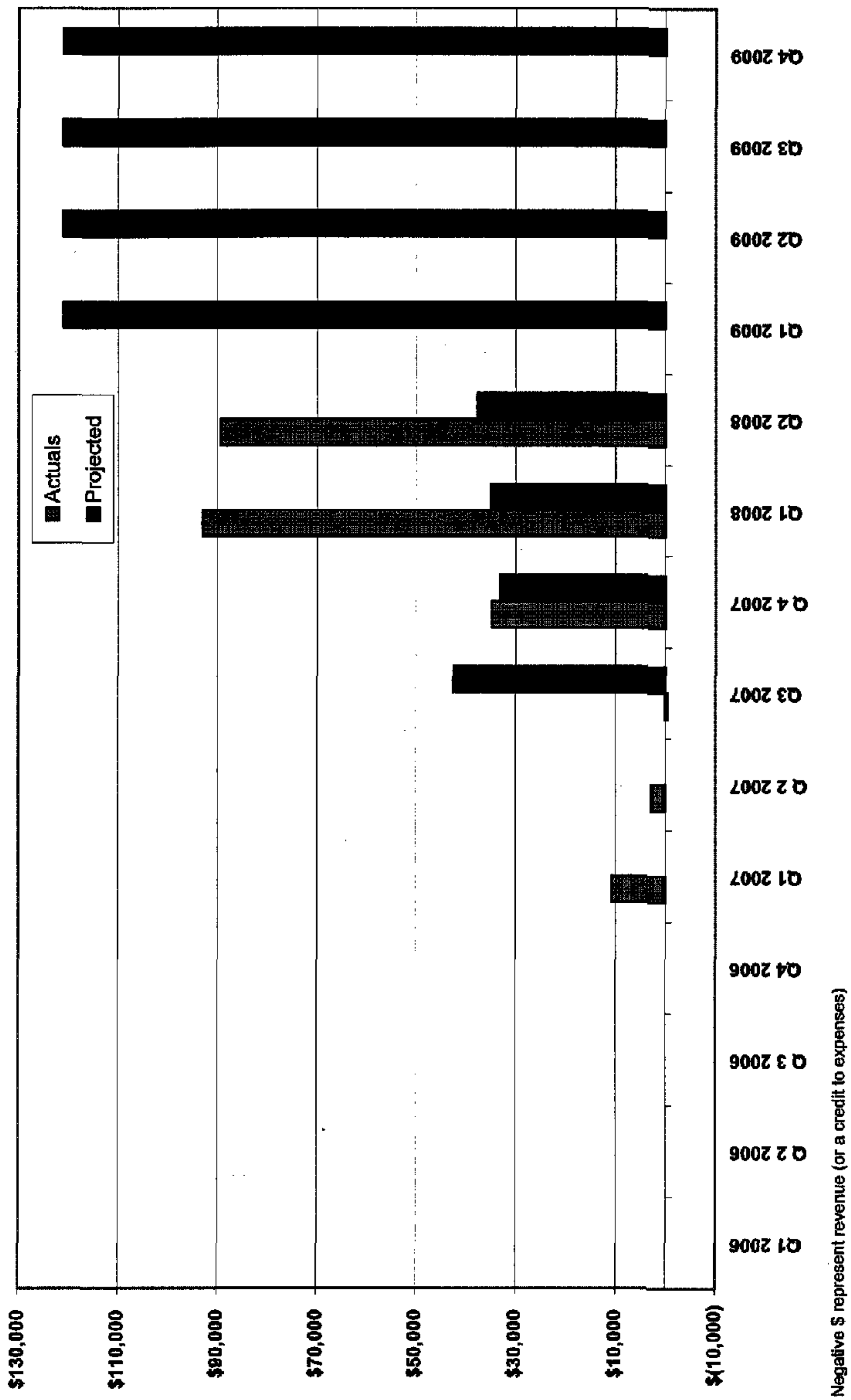


Schedule B-4

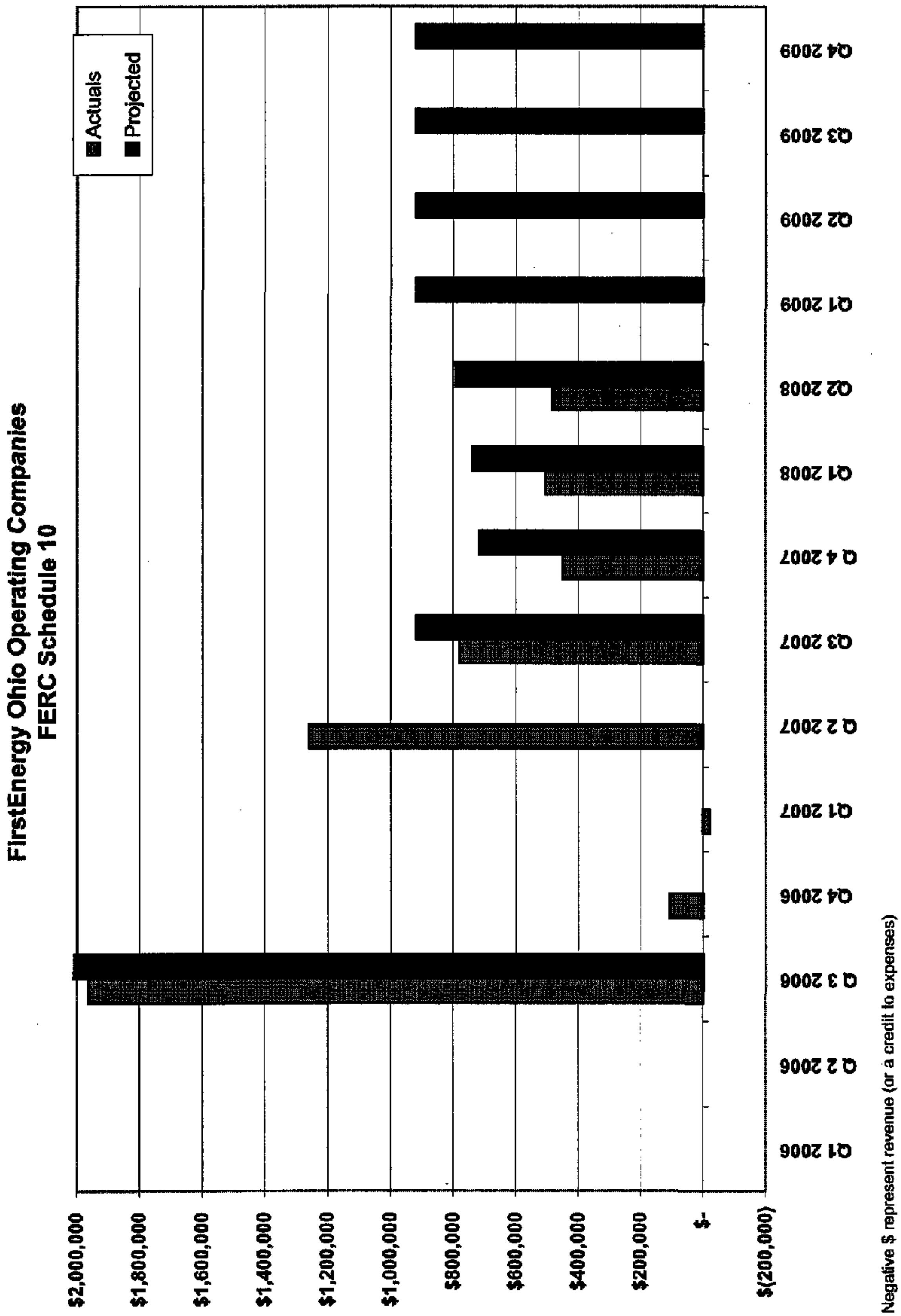

FirstEnergy Ohio Operating Companies
Schedule 24
Actuals
Projected
$450,000
$400,000
$350,000
$300,000
$250,000
$200,000
$150,000
$100,000
$50,000
$-
Q1 2006
Q 2 2006
Q 3 2006
Q4 2006
Q1 2007
Q 2 2007
Q3 2007
Q 4 2007
Q1 2008
Q2 2008
Q1 2009
Q2 2009
Q3 2009
Q4 2009

Schedule B-4

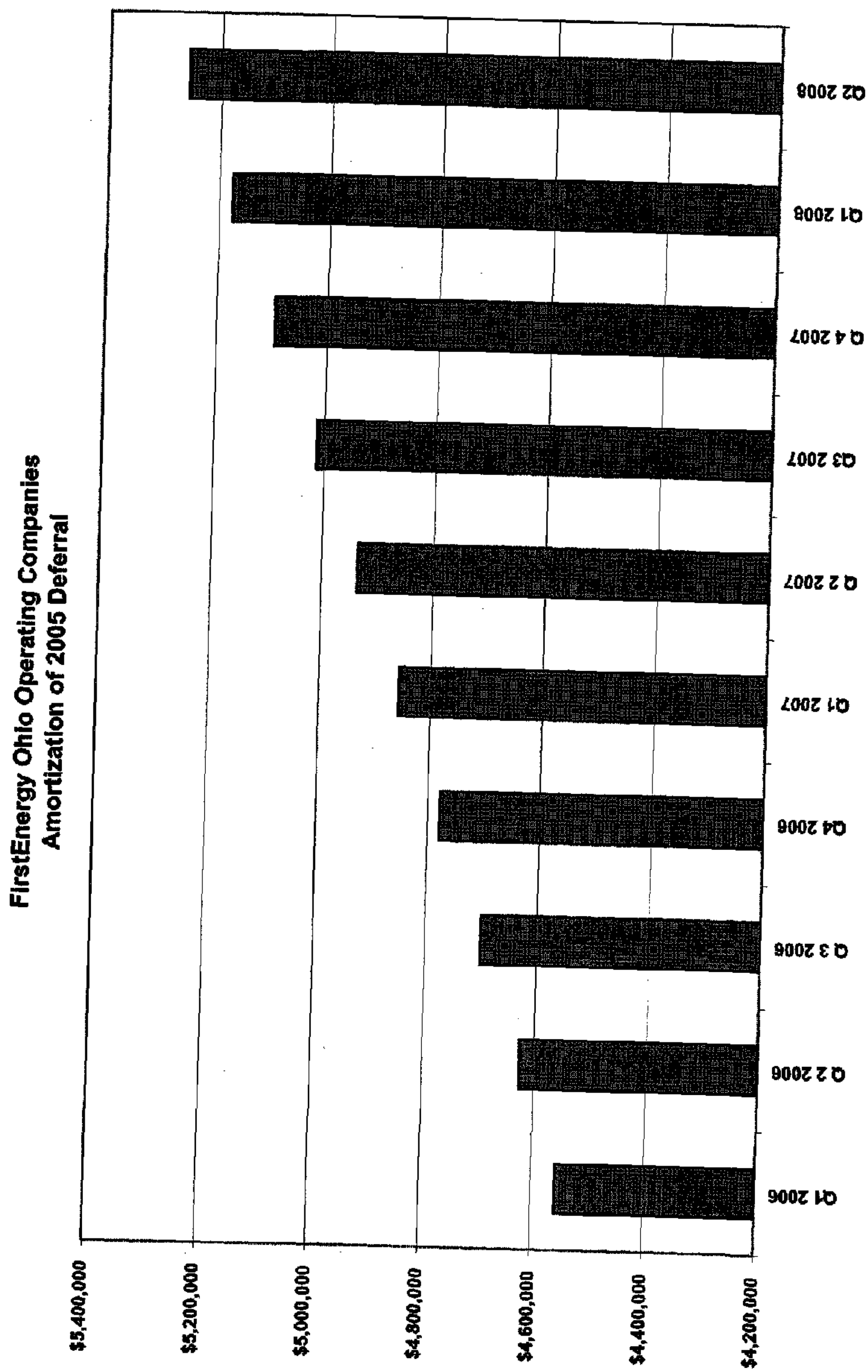
FirstEnergy Ohio Operating Companies
Schedule 26



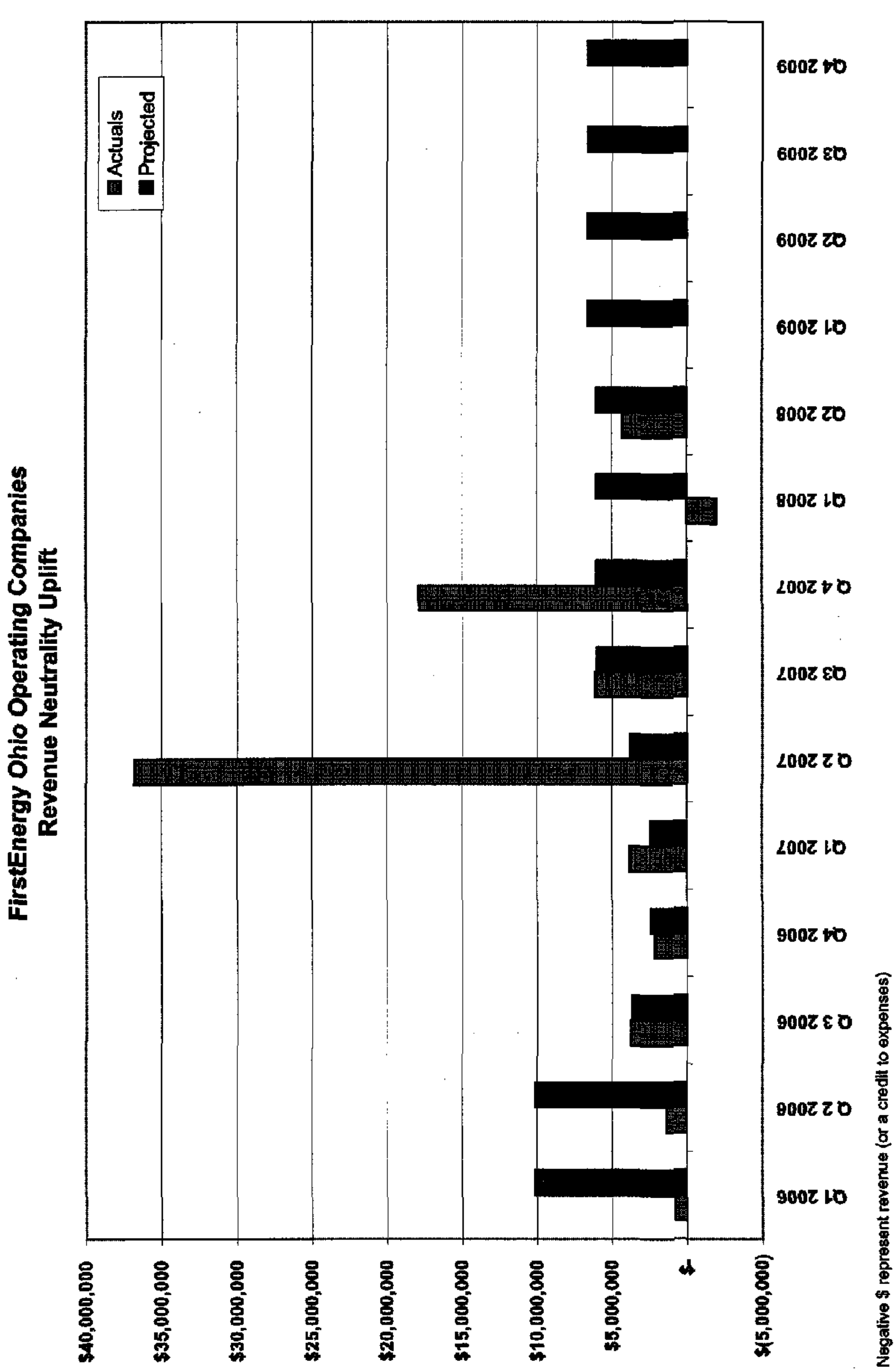
Schedule B-4


FirstEnergy Ohio Operating Companies
FERC Schedule 10
Actuals
Projected
$2,000,000
$1,800,000
$1,600,000
$1,400,000
$1,200,000
$1,000,000
$800,000
$600,000
$400,000
$200,000
$-
$(200,000)
Q1 2006
Q 2 2006
Q 3 2006
Q4 2006
Q1 2007
Q 2 2007
Q3 2007
Q 4 2007
Q1 2008
Q2 2008
Q1 2009
Q2 2009
Q3 2009
Q4 2009
Negative $ represent revenue (or a credit to expenses)

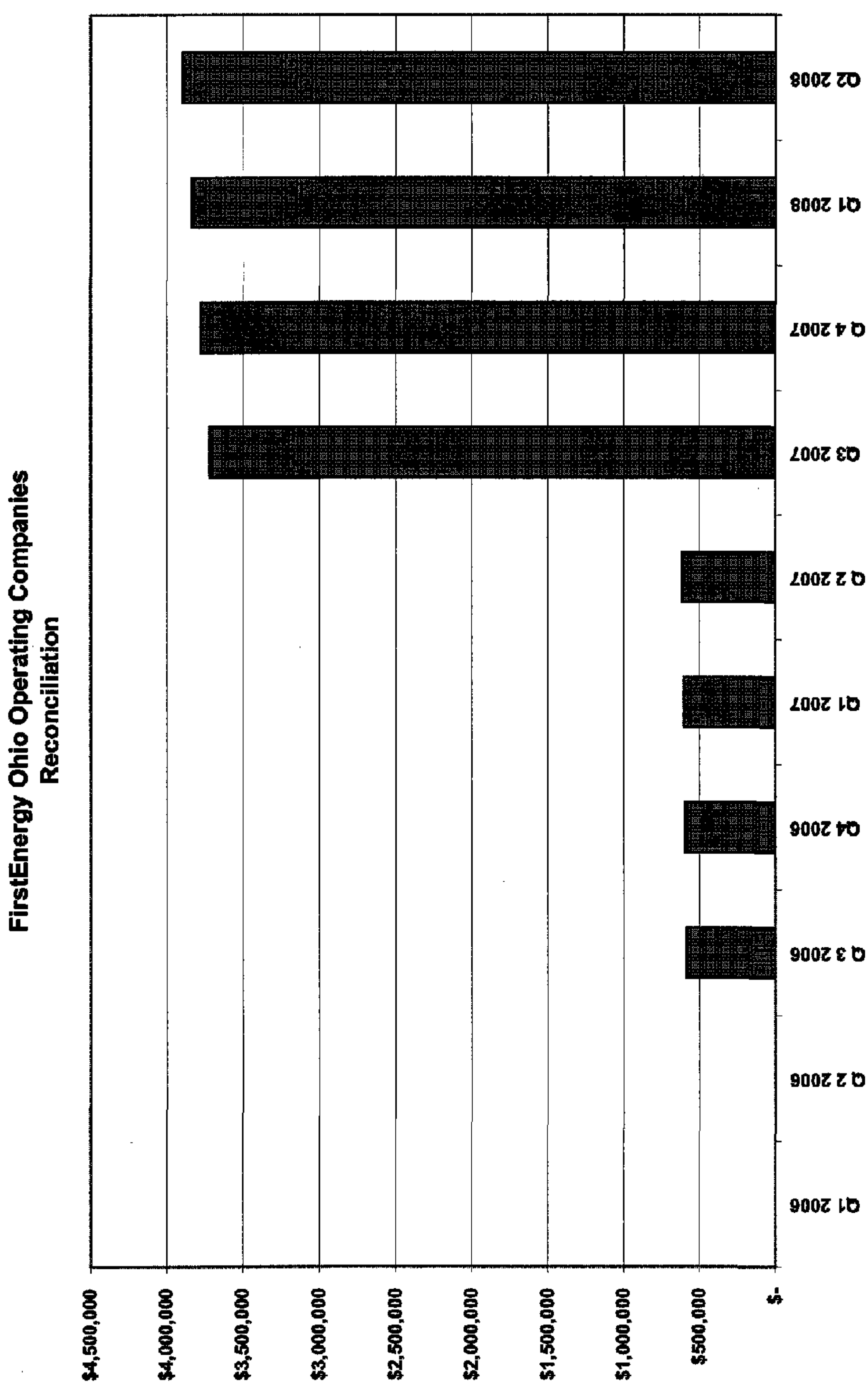
Schedule B-4


FirstEnergy Ohio Operating Companies
Amortization of 2005 Deferral
$5,400,000
$5,200,000
$5,000,000
$4,800,000
$4,600,000
$4,400,000
$4,200,000
Q2 2008
Q1 2008
Q 4 2007
Q3 2007
Q 2 2007
Q1 2007
Q4 2006
Q 3 2006
Q 2 2006
Q1 2006

Schedule B-4

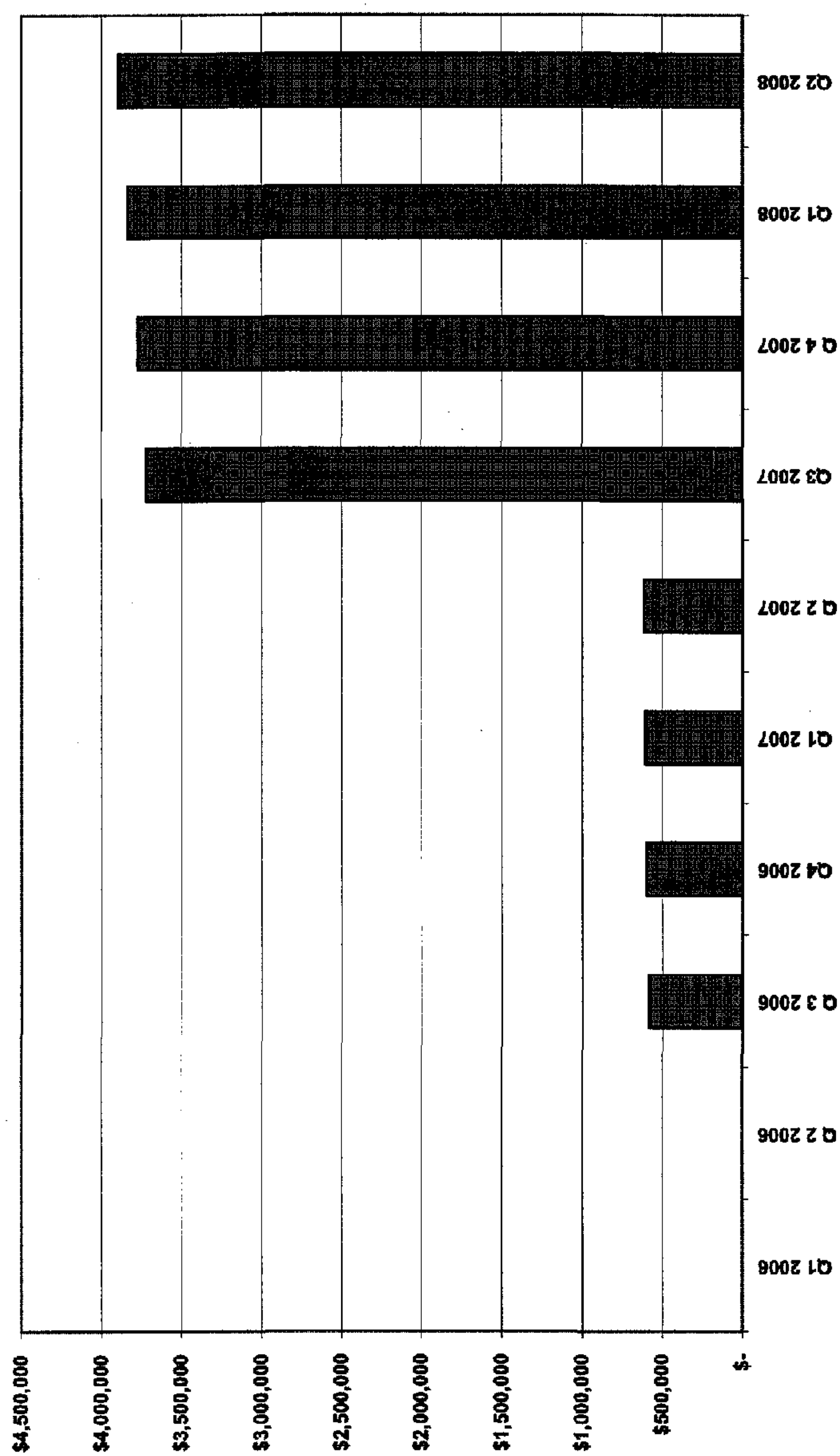

FirstEnergy Ohio Operating Companies
Revenue Neutrality Uplift
Actuals
Projected
$40,000,000
$35,000,000
$30,000,000
$25,000,000
$20,000,000
$15,000,000
$10,000,000
$5,000,000
$-
$(5,000,000)
Q1 2006
Q 2 2006
Q 3 2006
Q4 2006
Q1 2007
Q 2 2007
Q3 2007
Q 4 2007
Q1 2008
Q2 2008
Q1 2009
Q2 2009
Q3 2009
Q4 2009
Negative $ represent revenue (or a credit to expenses)

Schedule B-4

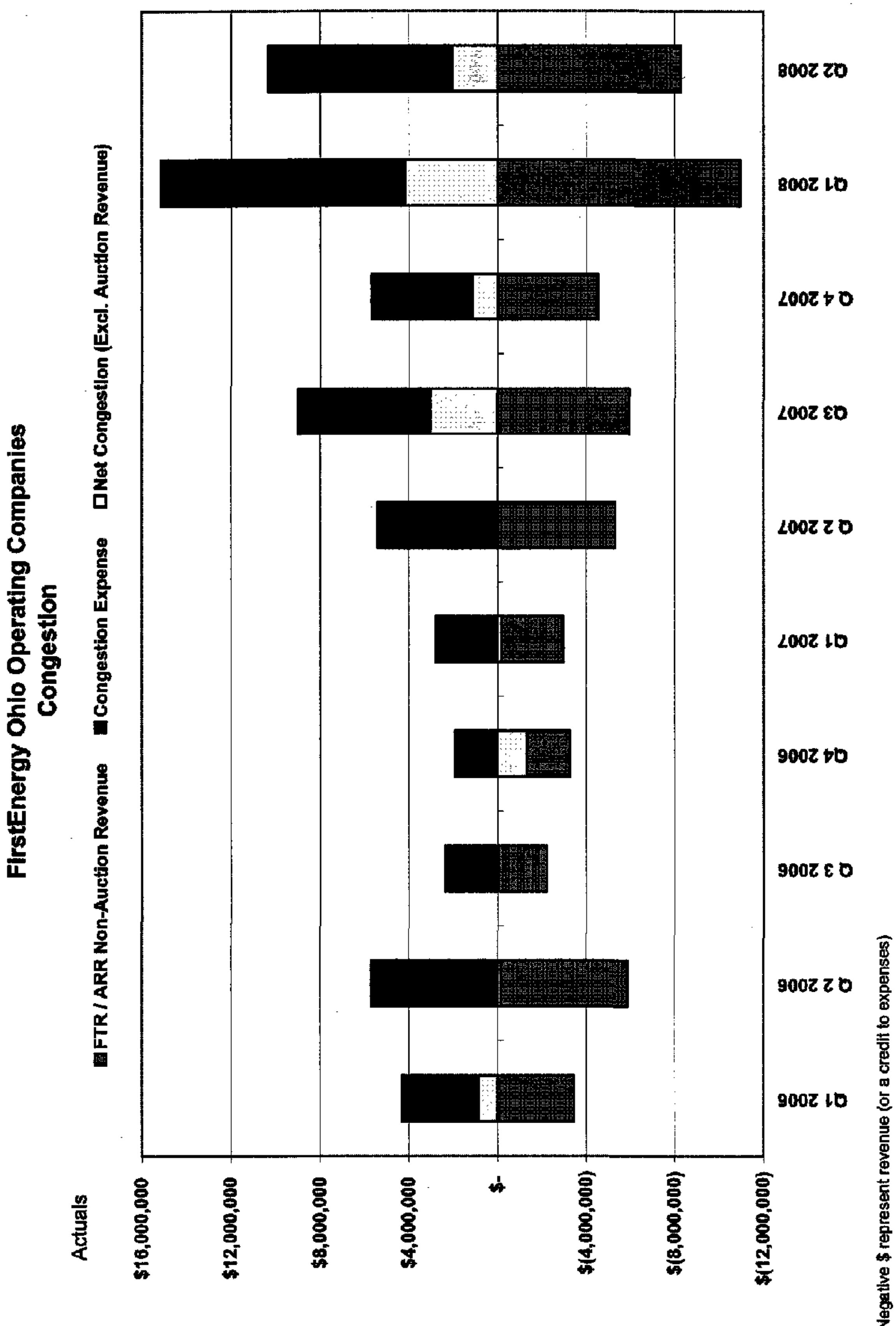

FirstEnergy Ohio Operating Companies
Reconciliation
$4,500,000
$4,000,000
$3,500,000
$3,000,000
$2,500,000
$2,000,000
$1,500,000
$1,000,000
$500,000
$-
Q1 2006
Q 2 2006
Q 3 2006
Q4 2006
Q1 2007
Q 2 2007
Q3 2007
Q 4 2007
Q1 2008
Q2 2008

Schedule B-4

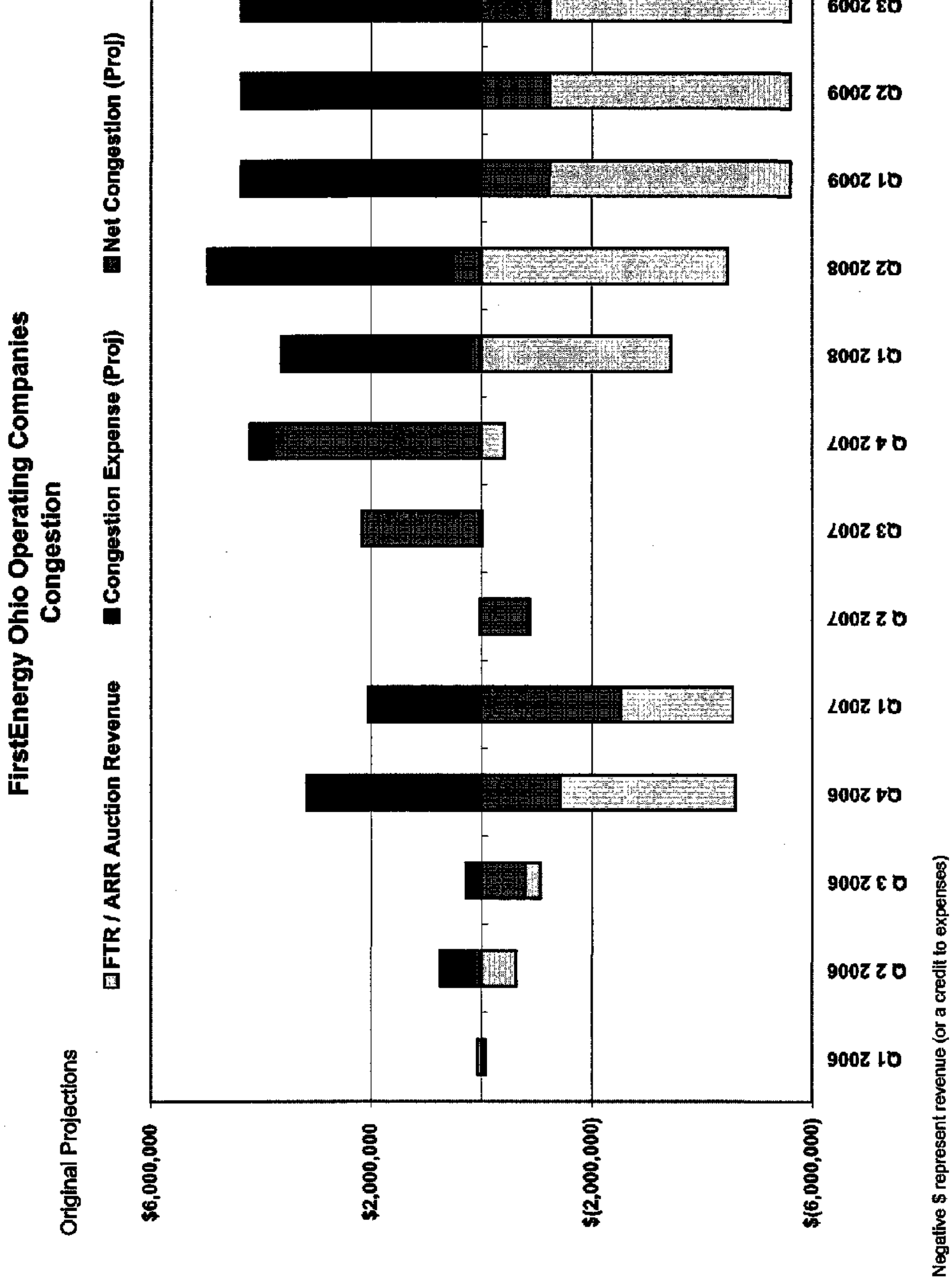
FirstEnergy Ohio Operating Companies
Reconciliation

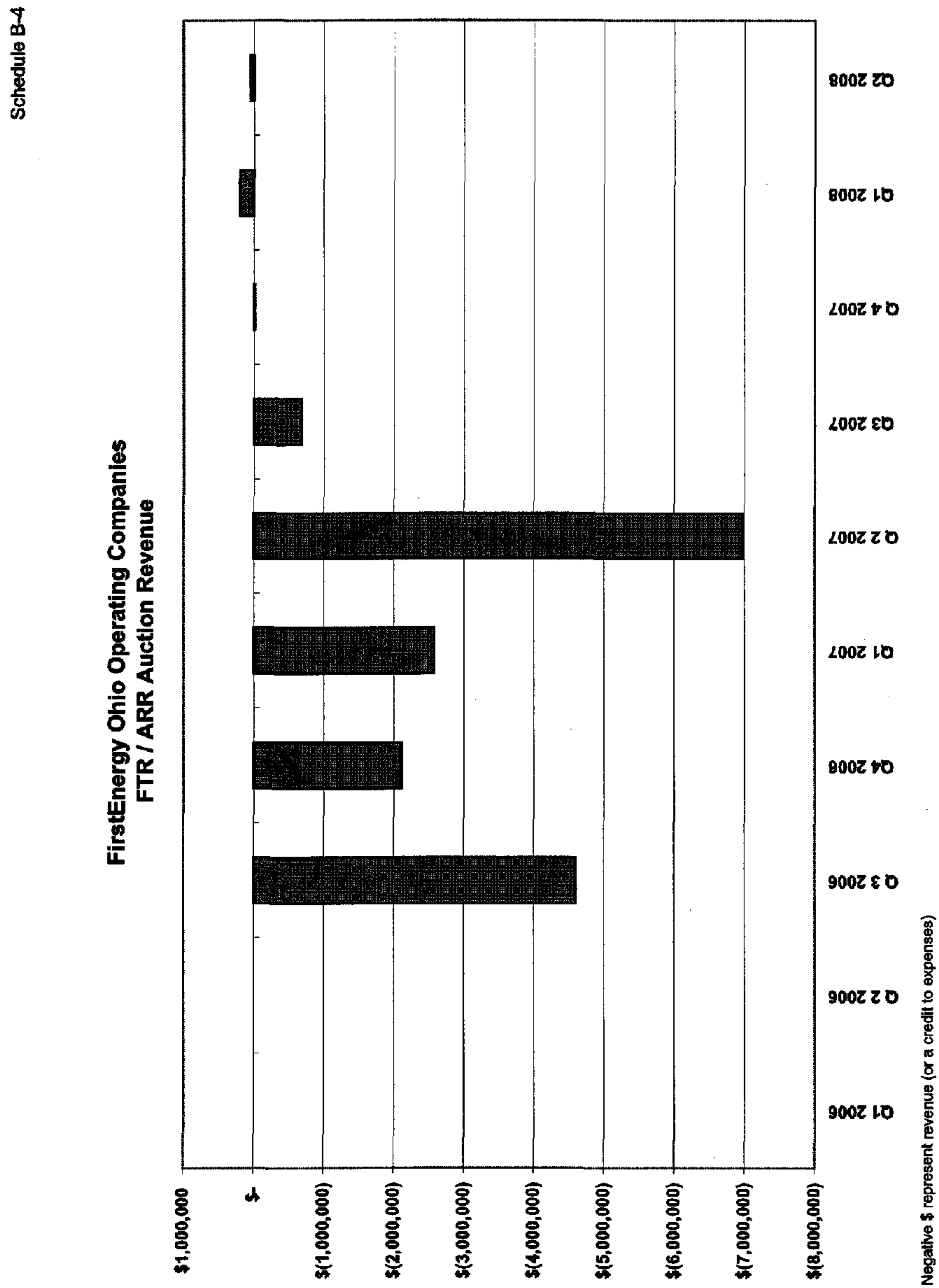


Schedule B-4


FirstEnergy Ohio Operating Companies
Congestion
FTR / ARR Non-Auction Revenue
Congestion Expense
Net Congestion (Excl. Auction Revenue)
Actuals
$16,000,000
$12,000,000
$8,000,000
$4,000,000
$-
$(4,000,000)
$(8,000,000)
$(12,000,000)
Q1 2006
Q 2 2006
Q 3 2006
Q4 2006
Q1 2007
Q 2 2007
Q3 2007
Q 4 2007
Q1 2008
Q2 2008
Negative $ represent revenue (or a credit to expenses)

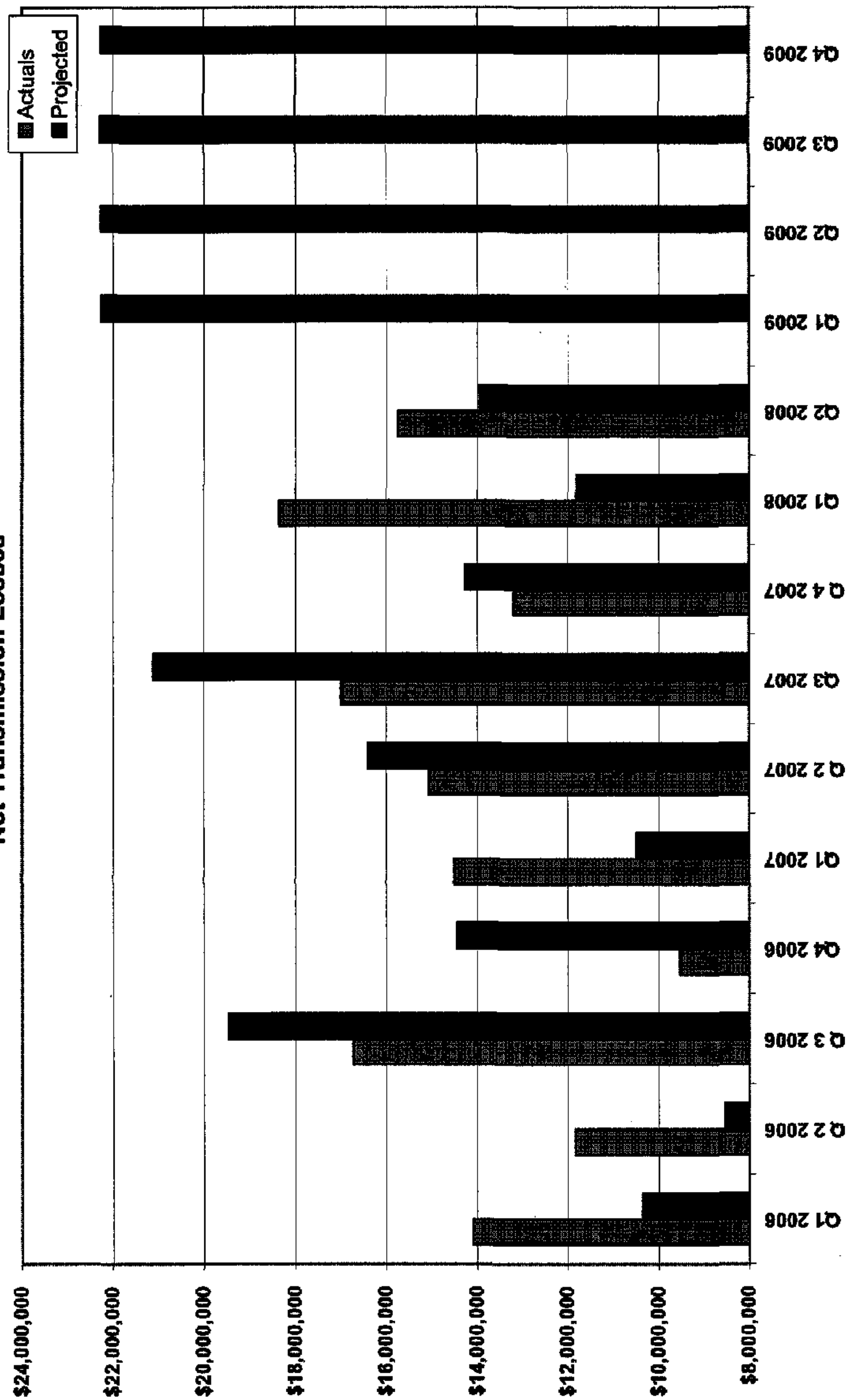
Schedule B-4


FirstEnergy Ohio Operating Companies
Congestion
FTR / ARR Auction Revenue
Congestion Expense (Proj)
Net Congestion (Proj)
Original Projections
$6,000,000
$2,000,000
$(2,000,000)
$(6,000,000)
Q1 2006
Q 2 2006
Q 3 2006
Q4 2006
Q1 2007
Q 2 2007
Q3 2007
Q 4 2007
Q1 2008
Q2 2008
Q1 2009
Q2 2009
Q3 2009
Q4 2009
Negative $ represent revenue (or a credit to expenses)


Schedule B-4
FirstEnergy Ohio Operating Companies
FTR / ARR Auction Revenue
$1,000,000
$ -
$(1,000,000)
$(2,000,000)
$(3,000,000)
$(4,000,000)
$(5,000,000)
$(6,000,000)
$(7,000,000)
$(8,000,000)
Q1 2006
Q 2 2006
Q 3 2006
Q4 2006
Q1 2007
Q 2 2007
Q3 2007
Q 4 2007
Q1 2008
Q2 2008
Negative $ represent revenue (or a credit to expenses)

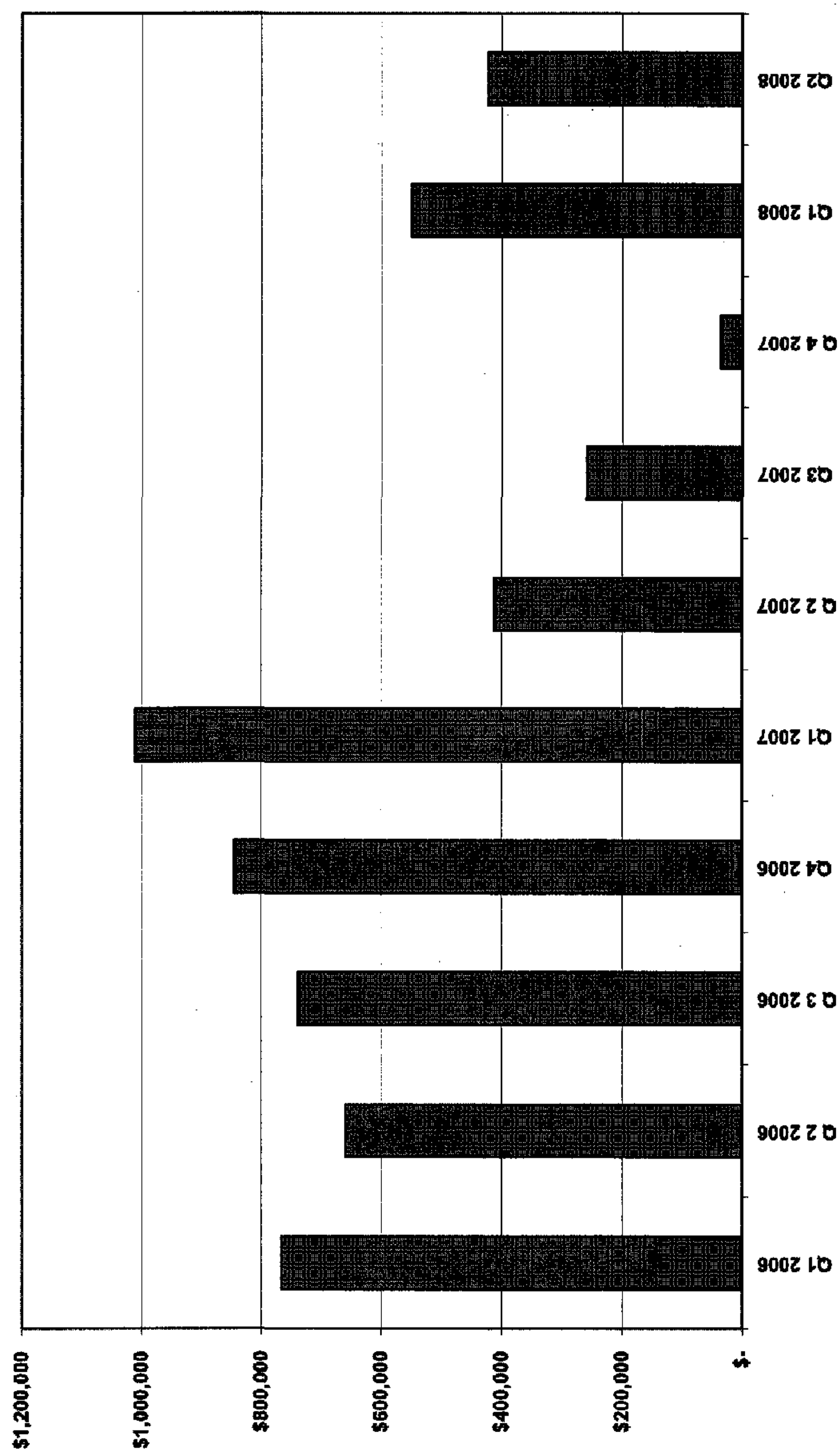
Schedule B-4

FirstEnergy Ohio Operating Companies
Net Transmission Losses



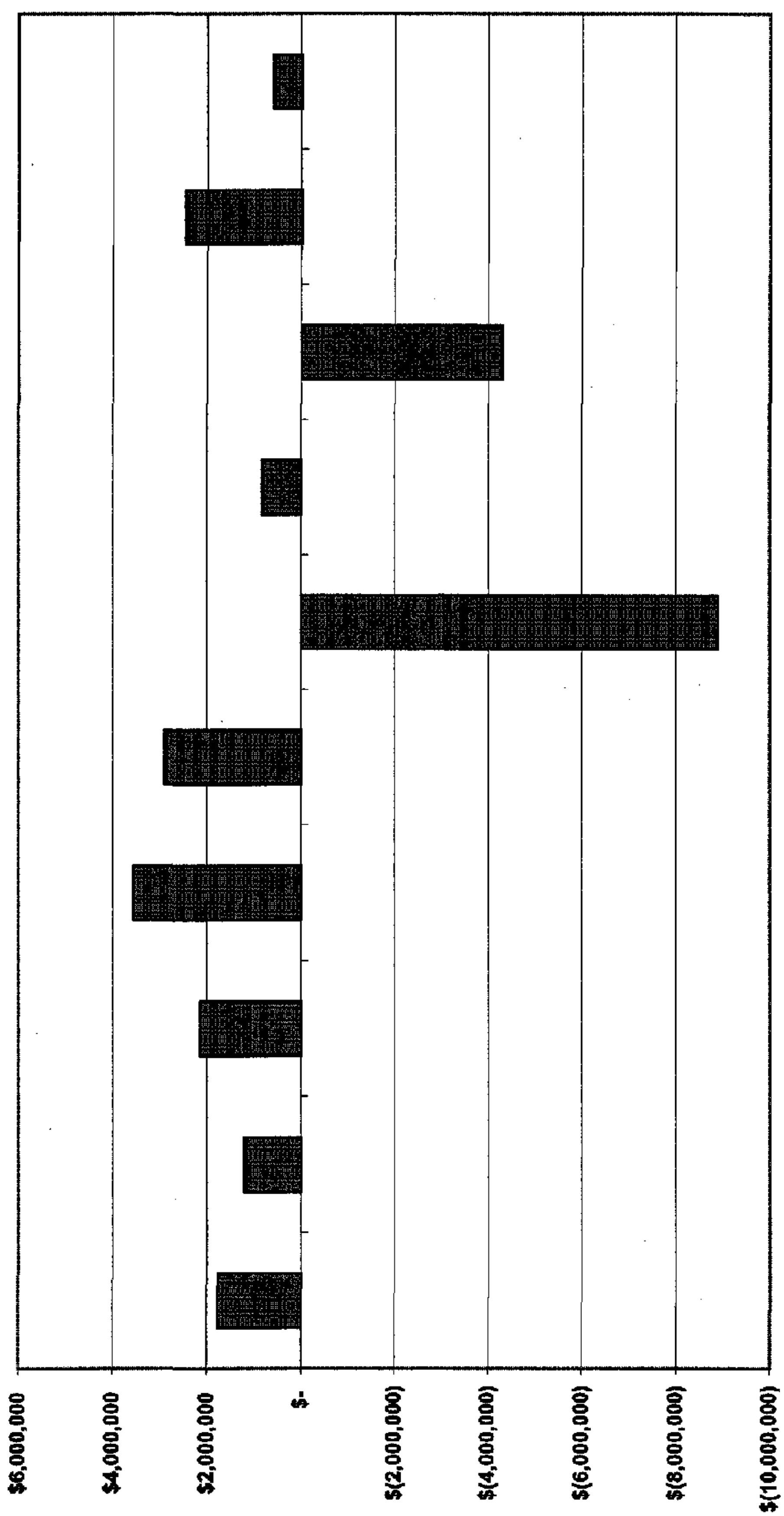
Schedule B-4

FirstEnergy Ohio Operating Companies
Day Ahead RSG



Schedule B-4

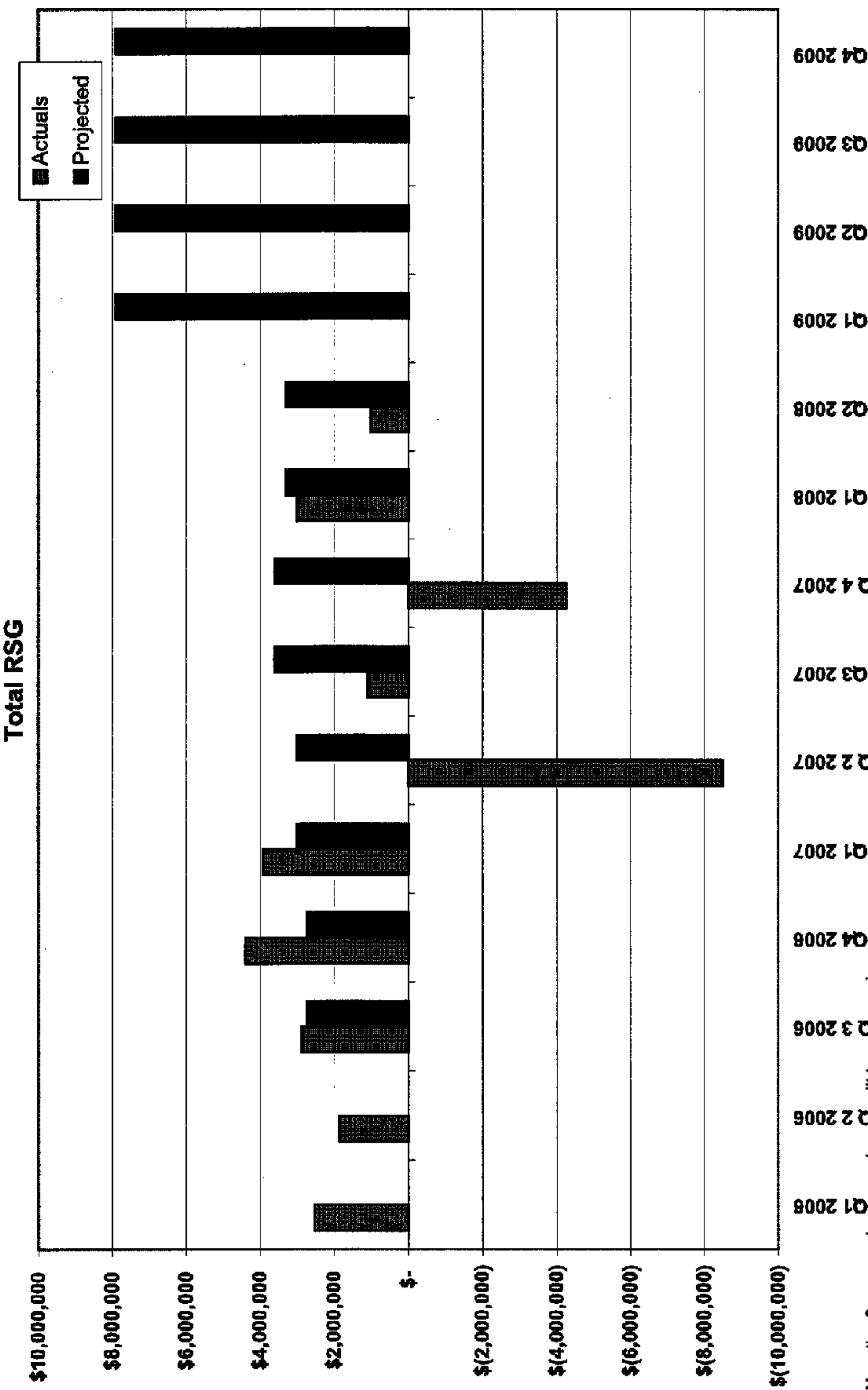
FirstEnergy Ohio Operating Companies
Real-Time RSG



Negative $ represent revenue (or a credit to expenses)
April 2005 - December 2005 based on operational data

Schedule B-4

FirstEnergy Ohio Operating Companies
Total RSG



Negative $ represent revenue (or a credit to expenses)
April 2005 - December 2005 based on operational data

Typical Bill Comparison

Schedule B-5 | Page 1 of 3

Schedule B-5 provides a typical bill comparison for each rate schedule affected by the proposed adjustments to the transmission cost recovery rider.

Note: These values are Illustrative. The current bills are higher than the proposed bills because the former include amortization expense associated with the 2005 transmission deferral, while the latter do not.

Ohio Edison

Residential Bill Impact
Rate: Standard Residential (OE-RS10AF); RS

kWh	Winter Rates Current Bill	New Bill	Dollar Change	Percent Change	Summer Rates Current Bill	New Bill	Dollar Change	Percent Change
500	$ 63.15	$ 62.68	$ (0.47)	-0.74%	$ 63.92	$ 63.42	$ (0.51)	-0.79%
750	$ 93.49	$ 92.79	$ (0.70)	-0.75%	$ 96.90	$ 95.95	$ (0.95)	-0.98%
1,000	$ 123.84	$ 122.91	$ (0.93)	-0.75%	$ 129.88	$ 128.48	$ (1.39)	-1.07%
Residential Average			**$ (0.70)**	**-0.75%**			**$ (0.95)**	**-0.95%**

Commercial Bill Impact
Rate: General Service - Secondary Voltages (OE-GS21F) / GS

kW	kWh	Current Bill	New Bill	Dollar Change	Percent Change
40	10,000	$ 1,382.77	$ 1,345.60	$ (37.17)	-2.69%
40	14,000	$ 1,523.69	$ 1,473.42	$ (50.28)	-3.30%
500	150,000	$ 17,986.37	$ 17,432.01	$ (554.36)	-3.08%
500	180,000	$ 19,026.45	$ 18,373.81	$ (652.65)	-3.43%
Commercial / GS Average				**$ (323.61)**	**-3.13%**

Rate: General Service - Secondary Voltages (OE-GS21F) / GP

kW	kWh	Current Bill	New Bill	Dollar Change	Percent Change
40	10,000	$ 1,382.77	$ 1,387.26	$ 4.49	0.32%
40	14,000	$ 1,523.69	$ 1,515.08	$ (8.62)	-0.57%
500	150,000	$ 17,986.37	$ 17,952.78	$ (33.59)	-0.19%
500	180,000	$ 19,026.45	$ 18,894.58	$ (131.88)	-0.69%
Commercial / GP Average				**$ (42.40)**	**-0.28%**

Industrial Bill Impact
Rate: General Service - Large Distribution Primary and Transmission Voltages (OE-GS23F) / GSU

kVA	kWh	Current Bill	New Bill	Dollar Change	Percent Change
1,000	200,000	$ 29,489.95	$ 29,055.38	$ (434.56)	-1.47%
1,000	400,000	$ 36,786.31	$ 36,351.74	$ (434.56)	-1.18%
1,000	550,000	$ 41,650.71	$ 41,216.14	$ (434.56)	-1.04%
Industrial / GSU Average				**$ (434.56)**	**-1.23%**

Rate: General Service - Large Distribution Primary and Transmission Voltages (OE-GS23F) / GT

kVA	kWh	Current Bill	New Bill	Dollar Change	Percent Change
1,000	200,000	$ 29,489.95	$ 28,673.88	$ (816.06)	-2.77%
1,000	400,000	$ 36,786.31	$ 35,970.24	$ (816.06)	-2.22%
1,000	550,000	$ 41,650.71	$ 40,834.64	$ (816.06)	-1.96%
Industrial / GT Average				**$ (816.06)**	**-2.31%**

Typical Bill Comparison

Schedule B-5 provides a typical bill comparison for each rate schedule affected by the proposed adjustments to the transmission cost recovery rider.

Note: These values are illustrative. The current bills are higher than the proposed bills because the former include amortization expense associated with the 2005 transmission deferral, while the latter do not.

Cleveland Electric Illuminating

Residential Bill Impact
Rate: Standard Residential (CE-RS50F) / RS

	Winter Rates				Summer Rates			
kWh	Current Bill	New Bill	Dollar Change	Percent Change	Current Bill	New Bill	Dollar Change	Percent Change
500	$ 59.42	$ 58.88	$ (0.54)	-0.90%	$ 70.14	$ 68.94	$ (1.19)	-1.70%
750	$ 87.67	$ 86.96	$ (0.71)	-0.81%	$ 103.74	$ 102.05	$ (1.70)	-1.64%
1,000	$ 115.92	$ 115.04	$ (0.89)	-0.76%	$ 137.35	$ 135.15	$ (2.20)	-1.60%
Residential Average			**$ (0.71)**	**-0.83%**			**$ (1.70)**	**-1.65%**

Commercial Bill Impact
Rate: Small General Service (CE-GS125F) (40 kW Example) / GS
Rate: Medium General Service (CE-GS145F) (500 kW Example) / GP

		Winter Rates				Summer Rates			
kW	kWh	Current Bill	New Bill	Dollar Change	Percent Change	Current Bill	New Bill	Dollar Change	Percent Change
40	10,000	$ 1,382.06	$ 1,353.50	$ (28.56)	-2.07%	$ 1,489.94	$ 1,454.28	$ (35.66)	-2.39%
40	14,000	$ 1,688.06	$ 1,659.50	$ (28.56)	-1.69%	$ 1,819.26	$ 1,783.60	$ (35.66)	-1.96%
500	150,000	$ 17,585.22	$ 17,254.77	$ (330.45)	-1.88%	$ 18,617.37	$ 18,181.77	$ (435.60)	-2.34%
500	180,000	$ 19,364.22	$ 19,033.77	$ (330.45)	-1.71%	$ 20,486.37	$ 20,050.77	$ (435.60)	-2.13%
Commercial / GS / GP Average				**$ (179.51)**	**-1.84%**			**$ (235.63)**	**-2.20%**

Industrial Bill Impact
Rate: Large General Service (CE-GS175F) / GSU

kVA	kWh	Current Bill	New Bill	Dollar Change	Percent Change
1,000	200,000	$ 31,070.13	$ 30,052.49	$ (1,017.63)	-3.28%
1,000	400,000	$ 41,772.21	$ 40,754.57	$ (1,017.63)	-2.44%
1,000	550,000	$ 46,352.78	$ 45,335.14	$ (1,017.63)	-2.20%
Industrial / GSU Average				**$ (1,017.63)**	**-2.64%**

Rate: Large General Service (CE-GS175F) / GT

kVA	kWh	Current Bill	New Bill	Dollar Change	Percent Change
1,000	200,000	$ 31,070.13	$ 29,791.15	$ (1,278.98)	-4.12%
1,000	400,000	$ 41,772.21	$ 40,493.23	$ (1,278.98)	-3.06%
1,000	550,000	$ 46,352.78	$ 45,073.80	$ (1,278.98)	-2.76%
Industrial / GSU Average				**$ (1,278.98)**	**-3.31%**

Typical Bill Comparison

Schedule B-5 | Page 3 of 3

Schedule B-5 provides a typical bill comparison for each rate schedule affected by the proposed adjustments to the transmission cost recovery rider.

Note: These values are illustrative. The current bills are higher than the proposed bills because the former include amortization expense associated with the 2005 transmission deferral, while the latter do not.

Toledo Edison

Residential Bill Impact
Rate: Standard Residential "R-01"(TE-RS511F)

kWh	Winter Rates Current Bill	New Bill	Dollar Change	Percent Change	Summer Rates Current Bill	New Bill	Dollar Change	Percent Change
500	$ 82.12	$ 80.37	$ (1.74)	-2.81%	$ 67.81	$ 65.54	$ (2.27)	-3.35%
750	$ 93.25	$ 90.64	$ (2.62)	-2.81%	$ 101.80	$ 98.40	$ (3.40)	-3.34%
1,000	$ 124.39	$ 120.90	$ (3.49)	-2.80%	$ 135.79	$ 131.25	$ (4.54)	-3.34%
Residential Average			**$ (2.62)**	**-2.81%**			**$ (3.40)**	**-3.34%**

Commercial Bill Impact
Rate: Small General Service (TE-GS669F) (40 kW Example) / GS
Rate: Medium General Service (TE-GS628F) (500 kW Example) / GP

kW	kWh	Winter Rates Current Bill	New Bill	Dollar Change	Percent Change	Summer Rates Current Bill	New Bill	Dollar Change	Percent Change
40	10,000	$ 1,419.94	$ 1,379.72	$ (40.21)	-2.83%	$ 1,532.91	$ 1,482.78	$ (50.13)	-3.27%
40	14,000	$ 1,734.64	$ 1,694.42	$ (40.21)	-2.32%	$ 1,870.01	$ 1,819.88	$ (50.13)	-2.68%
500	150,000	$ 19,484.00	$ 19,000.73	$ (483.27)	-2.48%	$ 21,300.56	$ 20,675.93	$ (624.63)	-2.93%
500	180,000	$ 21,255.38	$ 20,772.11	$ (483.27)	-2.27%	$ 23,194.04	$ 22,569.41	$ (624.63)	-2.69%
Commercial Average				**$ (261.74)**	**-2.48%**			**$ (337.38)**	**-2.89%**

Industrial Bill Impact
Rate: Large General Service "PV-45" (TE-GS647F) / GSU

kVA	kWh	Current Bill	New Bill	Dollar Change	Percent Change
1,000	200,000	$ 34,777.38	$ 34,484.85	$ (292.54)	-0.84%
1,000	400,000	$ 46,093.62	$ 45,801.09	$ (292.54)	-0.63%
1,000	550,000	$ 50,912.56	$ 50,620.03	$ (292.54)	-0.57%
Industrial Average				**$ (292.54)**	**-0.68%**

Rate: Large General Service "PV-45" (TE-GS647F) / GT

kVA	kWh	Current Bill	New Bill	Dollar Change	Percent Change
1,000	200,000	$ 34,777.38	$ 34,296.21	$ (481.17)	-1.38%
1,000	400,000	$ 46,093.62	$ 45,612.45	$ (481.17)	-1.04%
1,000	550,000	$ 50,912.56	$ 50,431.39	$ (481.17)	-0.95%
Industrial Average				**$ (481.17)**	**-1.12%**

Monthly Projected Cost by Component

Schedule C-1 provides the projected transmission- and ancillary service-related costs to be charged to the Ohio Operating Companies during the 12 months in which the Rider charges will be in effect. Pages 1 and 2 lay out costs based upon current MISO billing practices under which MISO bills the Ohio Operating Companies on a combined basis, while pages 3 through 8 show costs from each company's books. These values are illustrative and do not represent the Company's budget for 2009.

OHIO COMPANIES' TRANSMISSION- AND ANCILLARY SERVICE-RELATED COSTS

Schedule	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Total [1]
1	$ 586,068	$ 586,068	$ 586,068	$ 586,068	$ 586,068	$ 586,068	$ 3,516,408
2	$ 1,181,581	$ 1,181,581	$ 1,181,581	$ 1,181,581	$ 1,181,581	$ 1,181,581	$ 7,089,488
3	$ 249,784	$ 249,784	$ 249,784	$ 249,784	$ 249,784	$ 249,784	$ 1,498,707
4	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	$ 374,677	$ 374,677	$ 374,677	$ 374,677	$ 374,677	$ 374,677	$ 2,248,061
6	$ 187,627	$ 187,627	$ 187,627	$ 187,627	$ 187,627	$ 187,627	$ 1,125,761
7 (69 kv)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7 (138 kv)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8 (69 kv)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8 (138 kv)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9 (69 kv)	$ 4,069,933	$ 4,069,933	$ 4,069,933	$ 4,069,933	$ 4,069,933	$ 4,069,933	$ 24,419,597
9 (138 kv)	$ 11,665,100	$ 11,665,100	$ 11,665,100	$ 11,665,100	$ 11,665,100	$ 11,665,100	$ 69,990,598
10	$ 703,029	$ 703,029	$ 703,029	$ 703,029	$ 703,029	$ 703,029	$ 4,218,176
11	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15	$ -	$ -	$ -	$ -	$ -	$ -	$ -
18	$ -	$ -	$ -	$ -	$ -	$ -	$ -
19	$ -	$ -	$ -	$ -	$ -	$ -	$ -
20	$ -	$ -	$ -	$ -	$ -	$ -	$ -
22	$ -	$ -	$ -	$ -	$ -	$ -	$ -
26	$ 40,328	$ 40,328	$ 40,328	$ 40,328	$ 40,328	$ 40,328	$ 241,966
Total	$ 19,058,127	$ 19,058,127	$ 19,058,127	$ 19,058,127	$ 19,058,127	$ 19,058,127	$ 114,348,763

Schedule	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Total [2]
3	$ 1,655,778	$ 1,655,778	$ 1,655,778	$ 1,655,778	$ 1,655,778	$ 1,655,778	$ 9,934,671
5	$ 202,619	$ 202,619	$ 202,619	$ 202,619	$ 202,619	$ 202,619	$ 1,215,713
6	$ 174,125	$ 174,125	$ 174,125	$ 174,125	$ 174,125	$ 174,125	$ 1,044,753
16	$ 119,949	$ 119,949	$ 119,949	$ 119,949	$ 119,949	$ 119,949	$ 719,693
17	$ 1,599,247	$ 1,599,247	$ 1,599,247	$ 1,599,247	$ 1,599,247	$ 1,599,247	$ 9,595,480
24	$ 129,663	$ 129,663	$ 129,663	$ 129,663	$ 129,663	$ 129,663	$ 777,979
FERC 10	$ 306,368	$ 306,368	$ 306,368	$ 306,368	$ 306,368	$ 306,368	$ 1,838,208
Congestion Expense	$ 1,454,322	$ 1,454,322	$ 1,454,322	$ 1,454,322	$ 1,454,322	$ 1,454,322	$ 8,725,931
FTR Credit	$ (1,866,918)	$ (1,866,918)	$ (1,866,918)	$ (1,866,918)	$ (1,866,918)	$ (1,866,918)	$ (11,201,508)
Net Losses	$ 7,416,586	$ 7,416,586	$ 7,416,586	$ 7,416,586	$ 7,416,586	$ 7,416,586	$ 44,499,518
Revenue Neutrality	$ 2,199,313	$ 2,199,313	$ 2,199,313	$ 2,199,313	$ 2,199,313	$ 2,199,313	$ 13,195,877
Rev. Sufficiency Guarantee	$ 2,639,175	$ 2,639,175	$ 2,639,175	$ 2,639,175	$ 2,639,175	$ 2,639,175	$ 15,835,052
Total	$ 16,030,228	$ 16,030,228	$ 16,030,228	$ 16,030,228	$ 16,030,228	$ 16,030,228	$ 96,181,367

[1] *Projected monthly transmission- and ancillary service-related costs for the Ohio Operating Companies for the first 6 months of 2009.*
Demand-based costs reflect a coincident peak allocation basis, whereas energy-based costs are based on each Ohio Operating Company's contribution to the projected total Ohio kWh consumption.
[2] Calculation: Sum of 6 monthly values

Note: This schedule is based upon current MISO billing practices under which MISO bills the Ohio Operating Companies on a combined basis.

Witness: Kevin Warvell

Schedule C-1	Page 2 of 8

OHIO COMPANIES' TRANSMISSION- AND ANCILLARY SERVICE-RELATED COSTS

Schedule	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Total [2]	12 Month Total [3]
1	$ 586,068	$ 586,068	$ 586,068	$ 586,068	$ 586,068	$ 586,068	$ 3,516,408	$ 7,032,815
2	$ 1,181,581	$ 1,181,581	$ 1,181,581	$ 1,181,581	$ 1,181,581	$ 1,181,581	$ 7,089,488	$ 14,178,977
3	$ 249,784	$ 249,784	$ 249,784	$ 249,784	$ 249,784	$ 249,784	$ 1,498,707	$ 2,997,414
4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	$ 374,677	$ 374,677	$ 374,677	$ 374,677	$ 374,677	$ 374,677	$ 2,248,061	$ 4,496,122
6	$ 187,627	$ 187,627	$ 187,627	$ 187,627	$ 187,627	$ 187,627	$ 1,125,761	$ 2,251,523
7 (69 kv)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7 (138 kv)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8 (69 kv)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8 (138 kv)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9 (69 kv)	$ 4,069,933	$ 4,069,933	$ 4,069,933	$ 4,069,933	$ 4,069,933	$ 4,069,933	$ 24,419,597	$ 48,839,194
9 (138 kv)	$ 11,665,100	$ 11,665,100	$ 11,665,100	$ 11,665,100	$ 11,665,100	$ 11,665,100	$ 69,990,598	$ 139,981,197
10	$ 703,029	$ 703,029	$ 703,029	$ 703,029	$ 703,029	$ 703,029	$ 4,218,176	$ 8,436,353
11	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
18	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
19	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
20	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
22	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
26	$ 40,328	$ 40,328	$ 40,328	$ 40,328	$ 40,328	$ 40,328	$ 241,966	$ 483,933
Total	$ 19,058,127	$ 19,058,127	$ 19,058,127	$ 19,058,127	$ 19,058,127	$ 19,058,127	$ 114,348,763	$ 228,697,527

Schedule	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Total [2]	12 Month Total [3]
3	$ 1,655,778	$ 1,655,778	$ 1,655,778	$ 1,655,778	$ 1,655,778	$ 1,655,778	$ 9,934,671	$ 19,869,341
5	$ 202,619	$ 202,619	$ 202,619	$ 202,619	$ 202,619	$ 202,619	$ 1,215,713	$ 2,431,427
6	$ 174,125	$ 174,125	$ 174,125	$ 174,126	$ 174,125	$ 174,125	$ 1,044,753	$ 2,089,506
16	$ 119,949	$ 119,949	$ 119,949	$ 119,949	$ 119,949	$ 119,949	$ 719,693	$ 1,439,386
17	$ 1,599,247	$ 1,599,247	$ 1,599,247	$ 1,599,247	$ 1,599,247	$ 1,599,247	$ 9,595,480	$ 19,190,961
24	$ 129,663	$ 129,663	$ 129,663	$ 129,663	$ 129,663	$ 129,663	$ 777,979	$ 1,555,959
FERC 10	$ 306,368	$ 306,368	$ 306,368	$ 306,368	$ 306,368	$ 306,368	$ 1,838,208	$ 3,676,415
Congestion Expense	$ 1,454,322	$ 1,454,322	$ 1,454,322	$ 1,454,322	$ 1,454,322	$ 1,454,322	$ 8,725,931	$ 17,451,861
FTR Credit	$ (1,866,918)	$ (1,866,918)	$ (1,866,918)	$ (1,866,918)	$ (1,866,918)	$ (1,866,918)	$ (11,201,508)	$ (22,403,016)
Net Losses	$ 7,416,586	$ 7,416,586	$ 7,416,586	$ 7,416,586	$ 7,416,586	$ 7,416,586	$ 44,499,518	$ 88,999,036
Revenue Neutrality	$ 2,199,313	$ 2,199,313	$ 2,199,313	$ 2,199,313	$ 2,199,313	$ 2,199,313	$ 13,195,877	$ 26,391,753
Rev. Sufficiency Guarantee	$ 2,639,175	$ 2,639,175	$ 2,639,175	$ 2,639,175	$ 2,639,175	$ 2,639,175	$ 15,835,052	$ 31,670,104
Total	$ 16,030,228	$ 16,030,228	$ 16,030,228	$ 16,030,228	$ 16,030,228	$ 16,030,228	$ 96,181,367	$ 192,362,733

[1] Projected monthly transmission- and ancillary service-related costs for the Ohio Operating Companies for the last 6 months of 2009.
Demand-based costs reflect a coincident peak allocation basis, whereas energy-based costs are based on each Ohio Operating Company's contribution to the projected total Ohio kWh consumption.
[2] Calculation: Sum of 6 monthly values
[3] Calculation: Sum of 12 monthly values

Note: This schedule is based upon current MISO billing practices under which MISO bills the Ohio Operating Companies on a combined basis.

Witness: Kevin Warvell

OHIO EDISON'S TRANSMISSION- AND ANCILLARY SERVICE-RELATED COSTS

Schedule	[illegible]						Total [2]
	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	
1	$ 277,007	$ 277,007	$ 277,007	$ 277,007	$ 277,007	$ 277,007	$ 1,662,040
2	$ 558,478	$ 558,478	$ 558,478	$ 558,478	$ 558,478	$ 558,478	$ 3,350,868
3	$ 119,962	$ 119,962	$ 119,962	$ 119,962	$ 119,962	$ 119,962	$ 719,773
4							$ -
5	$ 179,943	$ 179,943	$ 179,943	$ 179,943	$ 179,943	$ 179,943	$ 1,079,659
6	$ 90,110	$ 90,110	$ 90,110	$ 90,110	$ 90,110	$ 90,110	$ 540,661
7 (69 kv)							$ -
7 (138 kv)							$ -
8 (69 kv)							$ -
8 (138 kv)							$ -
9 (69 kv)	$ 3,178,593	$ 3,178,593	$ 3,178,593	$ 3,178,593	$ 3,178,593	$ 3,178,593	$ 19,071,556
9 (138 kv)	$ 5,513,544	$ 5,513,544	$ 5,513,544	$ 5,513,544	$ 5,513,544	$ 5,513,544	$ 33,081,265
10	$ 332,076	$ 332,076	$ 332,076	$ 332,076	$ 332,076	$ 332,076	$ 1,992,459
11							$ -
12							$ -
13							$ -
14							$ -
15							$ -
18							$ -
19							$ -
20							$ -
22							$ -
26	$ 19,061	$ 19,061	$ 19,061	$ 19,061	$ 19,061	$ 19,061	$ 114,365
Total	$ 10,268,774	$ 10,268,774	$ 10,268,774	$ 10,268,774	$ 10,268,774	$ 10,268,774	$ 61,612,646

Schedule	[illegible]						Total [2]
	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	
3	$ 772,354	$ 772,354	$ 772,354	$ 772,354	$ 772,354	$ 772,354	$ 4,634,121
5	$ 94,514	$ 94,514	$ 94,514	$ 94,514	$ 94,514	$ 94,514	$ 567,081
6	$ 81,223	$ 81,223	$ 81,223	$ 81,223	$ 81,223	$ 81,223	$ 487,335
16	$ 55,057	$ 55,057	$ 55,057	$ 55,057	$ 55,057	$ 55,057	$ 330,339
17	$ 734,055	$ 734,055	$ 734,055	$ 734,055	$ 734,055	$ 734,055	$ 4,404,331
24	$ 59,534	$ 59,534	$ 59,534	$ 59,534	$ 59,534	$ 59,534	$ 357,206
FERC 10	$ 144,806	$ 144,806	$ 144,806	$ 144,806	$ 144,806	$ 144,806	$ 868,834
Congestion Expense	$ 667,535	$ 667,535	$ 667,535	$ 667,535	$ 667,535	$ 667,535	$ 4,005,208
FTR Credit	$ (856,916)	$ (856,916)	$ (856,916)	$ (856,916)	$ (856,916)	$ (856,916)	$ (5,141,499)
Net Losses	$ 3,404,217	$ 3,404,217	$ 3,404,217	$ 3,404,217	$ 3,404,217	$ 3,404,217	$ 20,425,305
Revenue Neutrality	$ 1,009,805	$ 1,009,805	$ 1,009,805	$ 1,009,805	$ 1,009,805	$ 1,009,805	$ 6,058,830
Rev. Sufficiency Guarantee	$ 1,211,766	$ 1,211,766	$ 1,211,766	$ 1,211,766	$ 1,211,766	$ 1,211,766	$ 7,270,595
Total	$ 7,377,948	$ 7,377,948	$ 7,377,948	$ 7,377,948	$ 7,377,948	$ 7,377,948	$ 44,267,688

[1] Projected monthly transmission- and ancillary service-related costs for Ohio Edison for the first 6 months of 2009.
Demand-based costs reflect a coincident peak allocation basis, whereas energy-based costs are based on each Ohio Operating Company's contribution to the projected total Ohio kWh consumption.
[2] Calculation: Sum of 6 monthly values

Witness: Kevin Warvell

OHIO EDISON'S TRANSMISSION- AND ANCILLARY SERVICE-RELATED COSTS

Schedule	[illegible]						Total [2]	12 Month Total [3]
	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09		
1	$ 277,007	$ 277,007	$ 277,007	$ 277,007	$ 277,007	$ 277,007	$ 1,662,040	$ 3,324,080
2	$ 558,478	$ 558,478	$ 558,478	$ 558,478	$ 558,478	$ 558,478	$ 3,350,868	$ 6,701,736
3	$ 119,962	$ 119,962	$ 119,962	$ 119,962	$ 119,962	$ 119,962	$ 719,773	$ 1,439,546
4							$ -	$ -
5	$ 179,943	$ 179,943	$ 179,943	$ 179,943	$ 179,943	$ 179,943	$ 1,079,659	$ 2,159,319
6	$ 90,110	$ 90,110	$ 90,110	$ 90,110	$ 90,110	$ 90,110	$ 540,661	$ 1,081,322
7 (69 kv)							$ -	$ -
7 (138 kv)							$ -	$ -
8 (69 kv)							$ -	$ -
8 (138 kv)							$ -	$ -
9 (69 kv)	$ 3,178,593	$ 3,178,593	$ 3,178,593	$ 3,178,593	$ 3,178,593	$ 3,178,593	$ 19,071,556	$ 38,143,112
9 (138 kv)	$ 5,513,544	$ 5,513,544	$ 5,513,544	$ 5,513,544	$ 5,513,544	$ 5,513,544	$ 33,081,265	$ 66,162,529
10	$ 332,076	$ 332,076	$ 332,076	$ 332,076	$ 332,076	$ 332,076	$ 1,992,459	$ 3,984,917
11							$ -	$ -
12							$ -	$ -
13							$ -	$ -
14							$ -	$ -
15							$ -	$ -
18							$ -	$ -
19							$ -	$ -
20							$ -	$ -
22							$ -	$ -
26	$ 19,061	$ 19,061	$ 19,061	$ 19,061	$ 19,061	$ 19,061	$ 114,365	$ 228,730
Total	$ 10,268,774	$ 10,268,774	$ 10,268,774	$ 10,268,774	$ 10,268,774	$ 10,268,774	$ 61,612,646	$ 123,225,291

Schedule	[illegible]						Total [2]	12 Month Total [3]
	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09		
3	$ 772,354	$ 772,354	$ 772,354	$ 772,354	$ 772,354	$ 772,354	$ 4,634,121	$ 9,268,242
5	$ 94,514	$ 94,514	$ 94,514	$ 94,514	$ 94,514	$ 94,514	$ 567,081	$ 1,134,162
6	$ 81,223	$ 81,223	$ 81,223	$ 81,223	$ 81,223	$ 81,223	$ 487,335	$ 974,671
16	$ 55,057	$ 55,057	$ 55,057	$ 55,057	$ 55,057	$ 55,057	$ 330,339	$ 660,679
17	$ 734,055	$ 734,055	$ 734,055	$ 734,055	$ 734,055	$ 734,055	$ 4,404,331	$ 8,808,662
24	$ 59,534	$ 59,534	$ 59,534	$ 59,534	$ 59,534	$ 59,534	$ 357,206	$ 714,412
FERC 10	$ 144,806	$ 144,806	$ 144,806	$ 144,806	$ 144,806	$ 144,806	$ 868,834	$ 1,737,668
Congestion Expense	$ 667,535	$ 667,535	$ 667,535	$ 667,535	$ 667,535	$ 667,535	$ 4,005,208	$ 8,010,415
FTR Credit	$ (856,916)	$ (856,916)	$ (856,916)	$ (856,916)	$ (856,916)	$ (856,916)	$ (5,141,499)	$ (10,282,997)
Net Losses	$ 3,404,217	$ 3,404,217	$ 3,404,217	$ 3,404,217	$ 3,404,217	$ 3,404,217	$ 20,425,305	$ 40,850,610
Revenue Neutrality	$ 1,009,805	$ 1,009,805	$ 1,009,805	$ 1,009,805	$ 1,009,805	$ 1,009,805	$ 6,058,830	$ 12,117,659
Rev. Sufficiency Guarantee	$ *1,211,766*	$ *1,211,766*	$ *1,211,766*	$ *1,211,766*	$ *1,211,766*	$ *1,211,766*	$ *7,270,595*	$ *14,541,191*
Total	$ 7,377,948	$ 7,377,948	$ 7,377,948	$ 7,377,948	$ 7,377,948	$ 7,377,948	$ 44,267,686	$ 88,535,373

[1] Projected monthly transmission- and ancillary service-related costs for Ohio Edison for the last 6 months of 2009.
Demand-based costs reflect a coincident peak allocation basis, whereas energy-based costs are based on each Ohio Operating Company's contribution to the projected total Ohio kWh consumption.
[2] Calculation: Sum of 6 monthly values
[3] Calculation: Sum of 12 monthly values

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CLEVELAND ELECTRIC ILLUMINATING'S TRANSMISSION- AND ANCILLARY SERVICE-RELATED COSTS

Schedule	[illegible]												Total [2]	
	Jan-09		Feb-09		Mar-09		Apr-09		May-09		Jun-09			
1	$	205,862	$	205,862	$	205,862	$	205,862	$	205,862	$	205,862	$	1,235,171
2	$	415,041	$	415,041	$	415,041	$	415,041	$	415,041	$	415,041	$	2,490,247
3	$	87,271	$	87,271	$	87,271	$	87,271	$	87,271	$	87,271	$	523,627
4													$	-
5	$	130,907	$	130,907	$	130,907	$	130,907	$	130,907	$	130,907	$	785,442
6	$	65,554	$	65,554	$	65,554	$	65,554	$	65,554	$	65,554	$	393,326
7 (69 kv)													$	-
7 (138 kv)													$	-
8 (69 kv)													$	-
8 (138 kv)													$	-
9 (69 kv)	$	-	$	-	$	-	$	-	$	-	$	-	$	-
9 (138 kv)	$	4,097,473	$	4,097,473	$	4,097,473	$	4,097,473	$	4,097,473	$	4,097,473	$	24,584,840
10	$	246,956	$	246,956	$	246,956	$	246,956	$	246,956	$	246,956	$	1,481,733
11													$	-
12													$	-
13													$	-
14													$	-
15													$	-
18													$	-
19													$	-
20													$	-
22													$	-
26	$	14,166	$	14,166	$	14,166	$	14,166	$	14,166	$	14,166	$	84,993
Total	$	5,263,230	$	5,263,230	$	5,263,230	$	5,263,230	$	5,263,230	$	5,263,230	$	31,579,380

Schedule	[illegible]												Total [2]	
	Jan-09		Feb-09		Mar-09		Apr-09		May-09		Jun-09			
3	$	561,400	$	561,400	$	561,400	$	561,400	$	561,400	$	561,400	$	3,368,399
5	$	68,699	$	68,699	$	68,699	$	68,699	$	68,699	$	68,699	$	412,193
6	$	59,038	$	59,038	$	59,038	$	59,038	$	59,038	$	59,038	$	354,229
16	$	41,686	$	41,686	$	41,686	$	41,686	$	41,686	$	41,686	$	250,116
17	$	555,788	$	555,788	$	555,788	$	555,788	$	555,788	$	555,788	$	3,334,725
24	$	45,564	$	45,564	$	45,564	$	45,564	$	45,564	$	45,564	$	273,381
FERC 10	$	107,615	$	107,615	$	107,615	$	107,615	$	107,615	$	107,615	$	645,688
Congestion Expense	$	505,422	$	505,422	$	505,422	$	505,422	$	505,422	$	505,422	$	3,032,530
FTR Credit	$	(648,812)	$	(648,812)	$	(648,812)	$	(648,812)	$	(648,812)	$	(648,812)	$	(3,892,869)
Net Losses	$	2,577,492	$	2,577,492	$	2,577,492	$	2,577,492	$	2,577,492	$	2,577,492	$	15,464,952
Revenue Neutrality	$	772,836	$	772,836	$	772,836	$	772,836	$	772,836	$	772,836	$	4,637,016
Rev. Sufficiency Guarantee	$	927,403	$	927,403	$	927,403	$	927,403	$	927,403	$	927,403	$	5,564,419
Total	$	5,574,130	$	5,574,130	$	5,574,130	$	5,574,130	$	5,574,130	$	5,574,130	$	33,444,780

[1] Projected monthly transmission- and ancillary service-related costs for CEI for the first 6 months of 2009.
Demand-based costs reflect a coincident peak allocation basis, whereas energy-based costs are based on each Ohio Operating Company's contribution to the projected total Ohio kWh consumption.
[2] Calculation: Sum of 6 monthly values

Witness: Kevin Warvell

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CLEVELAND ELECTRIC ILLUMINATING'S TRANSMISSION- AND ANCILLARY SERVICE-RELATED COSTS

Schedule	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Total ²	12 Month Total ³
1	$ 205,862	$ 205,862	$ 205,862	$ 205,862	$ 205,862	$ 205,862	$ 1,235,171	$ 2,470,341
2	$ 415,041	$ 415,041	$ 415,041	$ 415,041	$ 415,041	$ 415,041	$ 2,490,247	$ 4,980,494
3	$ 87,271	$ 87,271	$ 87,271	$ 87,271	$ 87,271	$ 87,271	$ 523,627	$ 1,047,255
4							$ -	$ -
5	$ 130,907	$ 130,907	$ 130,907	$ 130,907	$ 130,907	$ 130,907	$ 785,442	$ 1,570,884
6	$ 65,554	$ 65,554	$ 65,554	$ 65,554	$ 65,554	$ 65,554	$ 393,326	$ 786,652
7 (69 kv)							$ -	$ -
7 (138 kv)							$ -	$ -
8 (69 kv)							$ -	$ -
8 (138 kv)							$ -	$ -
9 (69 kv)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9 (138 kv)	$ 4,097,473	$ 4,097,473	$ 4,097,473	$ 4,097,473	$ 4,097,473	$ 4,097,473	$ 24,584,840	$ 49,169,680
10	$ 246,956	$ 246,956	$ 246,956	$ 246,956	$ 246,956	$ 246,956	$ 1,481,733	$ 2,963,467
11							$ -	$ -
12							$ -	$ -
13							$ -	$ -
14							$ -	$ -
15							$ -	$ -
18							$ -	$ -
19							$ -	$ -
20							$ -	$ -
22							$ -	$ -
26	$ 14,166	$ 14,166	$ 14,166	$ 14,166	$ 14,166	$ 14,166	$ 84,993	$ 169,987
Total	$ 5,263,230	$ 5,263,230	$ 5,263,230	$ 5,263,230	$ 5,263,230	$ 5,263,230	$ 31,579,380	$ 63,158,760

Schedule	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Total ²	12 Month Total ³
3	$ 561,400	$ 561,400	$ 561,400	$ 561,400	$ 561,400	$ 561,400	$ 3,368,399	$ 6,736,797
5	$ 68,699	$ 68,699	$ 68,699	$ 68,699	$ 68,699	$ 68,699	$ 412,193	$ 824,387
6	$ 59,038	$ 59,038	$ 59,038	$ 59,038	$ 59,038	$ 59,038	$ 354,229	$ 708,457
16	$ 41,686	$ 41,686	$ 41,686	$ 41,686	$ 41,686	$ 41,686	$ 250,116	$ 500,232
17	$ 555,788	$ 555,788	$ 555,788	$ 555,788	$ 555,788	$ 555,788	$ 3,334,725	$ 6,669,451
24	$ 45,564	$ 45,564	$ 45,564	$ 45,564	$ 45,564	$ 45,564	$ 273,381	$ 546,763
FERC 10	$ 107,615	$ 107,615	$ 107,615	$ 107,615	$ 107,615	$ 107,615	$ 645,688	$ 1,291,376
Congestion Expense	$ 505,422	$ 505,422	$ 505,422	$ 505,422	$ 505,422	$ 505,422	$ 3,032,530	$ 6,065,060
FTR Credit	$ (648,812)	$ (648,812)	$ (648,812)	$ (648,812)	$ (648,812)	$ (648,812)	$ (3,892,869)	$ (7,785,738)
Net Losses	$ 2,577,492	$ 2,577,492	$ 2,577,492	$ 2,577,492	$ 2,577,492	$ 2,577,492	$ 15,464,952	$ 30,929,904
Revenue Neutrality	$ 772,836	$ 772,836	$ 772,836	$ 772,836	$ 772,836	$ 772,836	$ 4,637,016	$ 9,274,032
Rev. Sufficiency Guarantee	$ 927,403	$ 927,403	$ 927,403	$ 927,403	$ 927,403	$ 927,403	$ 5,564,419	$ 11,128,839
Total	$ 5,574,130	$ 5,574,130	$ 5,574,130	$ 5,574,130	$ 5,574,130	$ 5,574,130	$ 33,444,780	$ 66,889,559

[1] Projected monthly transmission- and ancillary service-related costs for CEI for the last 6 months of 2009.
Demand-based costs reflect a coincident peak allocation basis, whereas energy-based costs are based on each Ohio Operating Company's contribution to the projected total Ohio kWh consumption.
[2] *Calculation: Sum of 6 monthly values*
[3] Calculation: Sum of 12 monthly values

Witness: Kevin Warvell

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TOLEDO EDISON'S TRANSMISSION- AND ANCILLARY SERVICE-RELATED COSTS

Schedule	[illegible]						Total [2]
	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	
1	$ 103,199	$ 103,199	$ 103,199	$ 103,199	$ 103,199	$ 103,199	$ 619,197
2	$ 208,062	$ 208,062	$ 208,062	$ 208,062	$ 208,062	$ 208,062	$ 1,248,373
3	$ 42,551	$ 42,551	$ 42,551	$ 42,551	$ 42,551	$ 42,551	$ 255,307
4							$ -
5	$ 63,827	$ 63,827	$ 63,827	$ 63,827	$ 63,827	$ 63,827	$ 382,959
6	$ 31,962	$ 31,962	$ 31,962	$ 31,962	$ 31,962	$ 31,962	$ 191,774
7 (69 kv)							$ -
7 (138 kv)							$ -
8 (69 kv)							$ -
8 (138 kv)							$ -
9 (69 kv)	$ 891,340	$ 891,340	$ 891,340	$ 891,340	$ 891,340	$ 891,340	$ 5,348,041
9 (138 kv)	$ 2,054,082	$ 2,054,082	$ 2,054,082	$ 2,054,082	$ 2,054,082	$ 2,054,082	$ 12,324,494
10	$ 123,997	$ 123,997	$ 123,997	$ 123,997	$ 123,997	$ 123,997	$ 743,984
11							$ -
12							$ -
13							$ -
14							$ -
15							$ -
18							$ -
19							$ -
20							$ -
22							$ -
26	$ 7,101	$ 7,101	$ 7,101	$ 7,101	$ 7,101	$ 7,101	$ 42,608
Total	$ 3,526,123	$ 3,526,123	$ 3,526,123	$ 3,526,123	$ 3,526,123	$ 3,526,123	$ 21,156,738

Schedule	[illegible]						Total [2]
	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	
3	$ 322,025	$ 322,025	$ 322,025	$ 322,025	$ 322,025	$ 322,025	$ 1,932,151
5	$ 39,406	$ 39,406	$ 39,406	$ 39,406	$ 39,406	$ 39,406	$ 236,439
6	$ 33,865	$ 33,865	$ 33,865	$ 33,865	$ 33,865	$ 33,865	$ 203,189
16	$ 23,206	$ 23,206	$ 23,206	$ 23,206	$ 23,206	$ 23,206	$ 139,238
17	$ 309,404	$ 309,404	$ 309,404	$ 309,404	$ 309,404	$ 309,404	$ 1,856,424
24	$ 24,565	$ 24,565	$ 24,565	$ 24,565	$ 24,565	$ 24,565	$ 147,392
FERC 10	$ 53,948	$ 53,948	$ 53,948	$ 53,948	$ 53,948	$ 53,948	$ 323,686
Congestion Expense	$ 281,365	$ 281,365	$ 281,365	$ 281,365	$ 281,365	$ 281,365	$ 1,688,193
FTR Credit	$ (361,190)	$ (361,190)	$ (361,190)	$ (361,190)	$ (361,190)	$ (361,190)	$ (2,167,140)
Net Losses	$ 1,434,877	$ 1,434,877	$ 1,434,877	$ 1,434,877	$ 1,434,877	$ 1,434,877	$ 8,609,261
Revenue Neutrality	$ 416,672	$ 416,672	$ 416,672	$ 416,672	$ 416,672	$ 416,672	$ 2,500,031
Rev. Sufficiency Guarantee	$ 500,006	$ 500,006	$ 500,006	$ 500,006	$ 500,006	$ 500,006	$ 3,000,037
Total	$ 3,078,150	$ 3,078,150	$ 3,078,150	$ 3,078,150	$ 3,078,150	$ 3,078,150	$ 18,468,901

[1] Projected monthly transmission- and ancillary service-related costs for Toledo Edison for the first 6 months of 2009.
Demand-based costs reflect a coincident peak allocation basis, whereas energy-based costs are based on each Ohio Operating Company's contribution to the projected total Ohio kWh consumption.
[2] Calculation: Sum of 6 monthly values

TOLEDO EDISON'S TRANSMISSION- AND ANCILLARY SERVICE-RELATED COSTS

Schedule	[illegible]						Total [1]	12 Month Total [2]
	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09		
1	$ 103,199	$ 103,199	$ 103,199	$ 103,199	$ 103,199	$ 103,199	$ 619,197	$ 1,238,393
2	$ 208,062	$ 208,062	$ 208,062	$ 208,062	$ 208,062	$ 208,062	$ 1,248,373	$ 2,496,747
3	$ 42,551	$ 42,551	$ 42,551	$ 42,551	$ 42,551	$ 42,551	$ 255,307	$ 510,613
4							$ -	$ -
5	$ 63,827	$ 63,827	$ 63,827	$ 63,827	$ 63,827	$ 63,827	$ 382,959	$ 766,919
6	$ 31,962	$ 31,962	$ 31,962	$ 31,962	$ 31,962	$ 31,962	$ 191,774	$ 383,549
7 (69 kv)							$ -	$ -
7 (138 kv)							$ -	$ -
8 (69 kv)							$ -	$ -
8 (138 kv)							$ -	$ -
9 (69 kv)	$ 891,340	$ 891,340	$ 891,340	$ 891,340	$ 891,340	$ 891,340	$ 5,348,041	$ 10,696,082
9 (138 kv)	$ 2,054,082	$ 2,054,082	$ 2,054,082	$ 2,054,082	$ 2,054,082	$ 2,054,082	$ 12,324,494	$ 24,648,987
10	$ 123,997	$ 123,997	$ 123,997	$ 123,997	$ 123,997	$ 123,997	$ 743,984	$ 1,487,969
11							$ -	$ -
12							$ -	$ -
13							$ -	$ -
14							$ -	$ -
15							$ -	$ -
18							$ -	$ -
19							$ -	$ -
20							$ -	$ -
22							$ -	$ -
26	$ 7,101	$ 7,101	$ 7,101	$ 7,101	$ 7,101	$ 7,101	$ 42,608	$ 85,216
Total	$ 3,526,123	$ 3,526,123	$ 3,526,123	$ 3,526,123	$ 3,526,123	$ 3,526,123	$ 21,156,738	$ 42,313,476

Schedule	[illegible]						Total [2]	12 Month Total [3]
	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09		
3	$ 322,025	$ 322,025	$ 322,025	$ 322,025	$ 322,025	$ 322,025	$ 1,932,151	$ 3,864,302
5	$ 39,406	$ 39,406	$ 39,406	$ 39,406	$ 39,406	$ 39,406	$ 236,439	$ 472,878
6	$ 33,865	$ 33,865	$ 33,865	$ 33,865	$ 33,865	$ 33,865	$ 203,189	$ 406,378
16	$ 23,206	$ 23,206	$ 23,206	$ 23,206	$ 23,206	$ 23,206	$ 139,238	$ 278,476
17	$ 309,404	$ 309,404	$ 309,404	$ 309,404	$ 309,404	$ 309,404	$ 1,856,424	$ 3,712,848
24	$ 24,565	$ 24,566	$ 24,565	$ 24,565	$ 24,565	$ 24,565	$ 147,392	$ 294,784
FERC 10	$ 53,948	$ 53,948	$ 53,948	$ 53,948	$ 53,948	$ 53,948	$ 323,686	$ 647,371
Congestion Expense	$ 281,365	$ 281,365	$ 281,366	$ 281,366	$ 281,365	$ 281,365	$ 1,688,193	$ 3,376,386
FTR Credit	$ (361,190)	$ (361,190)	$ (361,190)	$ (361,190)	$ (361,190)	$ (361,190)	$ (2,167,140)	$ (4,334,281)
Net Losses	$ 1,434,877	$ 1,434,877	$ 1,434,877	$ 1,434,877	$ 1,434,877	$ 1,434,877	$ 8,609,261	$ 17,218,522
Revenue Neutrality	$ 416,672	$ 416,672	$ 416,672	$ 416,672	$ 416,672	$ 416,672	$ 2,500,031	$ 5,000,062
Rev. Sufficiency Guarantee	$ 500,006	$ 500,006	$ 500,006	$ 500,006	$ 500,006	$ 500,006	$ 3,000,037	$ 6,000,074
Total	$ 3,078,150	$ 3,078,150	$ 3,078,150	$ 3,078,150	$ 3,078,150	$ 3,078,150	$ 18,468,901	$ 36,937,801

[1] Projected monthly transmission- and ancillary service-related costs for Toledo Edison for the last 6 months of 2009.
Demand-based costs reflect a coincident peak allocation basis, whereas energy-based costs are based on each Ohio Operating Company's contribution to the projected total Ohio kWh consumption.
[2] Calculation: Sum of 6 monthly values
[3] Calculation: Sum of 12 monthly values

Witness: Kevin Warvell

Monthly Projected Cost by Rate Schedule

Schedule C-2	Page 1 of 3

Schedule C-2 provides the projected transmission- and ancillary service-related costs to be charged to the Ohio Operating Companies during the 12 months in which the Rider charges will be in effect.
Total expenses are summarized by rate schedule for each Operating Company. These values are illustrative and do not represent the Company's budget for 2009.

OHIO EDISON'S TRANSMISSION- AND ANCILLARY SERVICE-RELATED COSTS

Schedule	[illegible]						Total [2]
	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	
RS	$ 7,125,514	$ 7,125,514	$ 7,125,514	$ 7,125,514	$ 7,125,514	$ 7,125,514	$ 42,753,085
GS	$ 4,987,350	$ 4,987,350	$ 4,987,350	$ 4,987,350	$ 4,987,350	$ 4,987,350	$ 29,924,097
GP	$ 2,013,069	$ 2,013,069	$ 2,013,069	$ 2,013,069	$ 2,013,069	$ 2,013,069	$ 12,078,415
GSU	$ 585,353	$ 585,353	$ 585,353	$ 585,353	$ 585,353	$ 585,353	$ 3,512,119
GT	$ 2,875,994	$ 2,875,994	$ 2,875,994	$ 2,875,994	$ 2,875,994	$ 2,875,994	$ 17,255,962
LTG	$ 59,442	$ 59,442	$ 59,442	$ 59,442	$ 59,442	$ 59,442	$ 356,654
Total	$ 17,646,722	$ 17,646,722	$ 17,646,722	$ 17,646,722	$ 17,646,722	$ 17,646,722	$ 105,880,332

Schedule	[illegible]						Total [2]	12 Month Total [3]
	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09		
RS	$ 7,125,514	$ 7,125,514	$ 7,125,514	$ 7,125,514	$ 7,125,514	$ 7,125,514	$ 42,753,085	$ 85,506,169
GS	$ 4,987,350	$ 4,987,350	$ 4,987,350	$ 4,987,350	$ 4,987,350	$ 4,987,350	$ 29,924,097	$ 59,848,195
GP	$ 2,013,069	$ 2,013,069	$ 2,013,069	$ 2,013,069	$ 2,013,069	$ 2,013,069	$ 12,078,415	$ 24,156,829
GSU	$ 585,353	$ 585,353	$ 585,353	$ 585,353	$ 585,353	$ 585,353	$ 3,512,119	$ 7,024,238
GT	$ 2,875,994	$ 2,875,994	$ 2,875,994	$ 2,875,994	$ 2,875,994	$ 2,875,994	$ 17,255,962	$ 34,511,923
LTG	$ 59,442	$ 59,442	$ 59,442	$ 59,442	$ 59,442	$ 59,442	$ 356,654	$ 713,309
Total	$ 17,646,722	$ 17,646,722	$ 17,646,722	$ 17,646,722	$ 17,646,722	$ 17,646,722	$ 105,880,332	$ 211,760,664

[1] Projected monthly transmission- and ancillary service-related costs for Ohio Edison for 2009.
Demand-based costs reflect a coincident peak allocation basis, whereas energy-based costs are based on each Ohio Operating Company's contribution to the projected total Ohio kWh consumption.
[2] Calculation: Sum of 6 monthly values
[3] Calculation: Sum of 12 monthly values

CLEVELAND ELECTRIC ILLUMINATING'S TRANSMISSION- AND ANCILLARY SERVICE-RELATED COSTS

Schedule	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Total [2]
RS	$ 3,441,452	$ 3,441,452	$ 3,441,452	$ 3,441,452	$ 3,441,452	$ 3,441,452	$ 20,648,714
GS	$ 4,228,132	$ 4,228,132	$ 4,228,132	$ 4,228,132	$ 4,228,132	$ 4,228,132	$ 25,368,789
GP	$ 228,732	$ 228,732	$ 228,732	$ 228,732	$ 228,732	$ 228,732	$ 1,372,393
GSU	$ 1,889,927	$ 1,889,927	$ 1,889,927	$ 1,889,927	$ 1,889,927	$ 1,889,927	$ 11,339,560
GT	$ 980,915	$ 980,915	$ 980,915	$ 980,915	$ 980,915	$ 980,915	$ 5,885,492
LTG	$ 68,202	$ 68,202	$ 68,202	$ 68,202	$ 68,202	$ 68,202	$ 409,210
Total	$ 10,837,360	$ 10,837,360	$ 10,837,360	$ 10,837,360	$ 10,837,360	$ 10,837,360	$ 65,024,160

Schedule	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Total [2]	12 Month Total [3]
RS	$ 3,441,452	$ 3,441,452	$ 3,441,452	$ 3,441,452	$ 3,441,452	$ 3,441,452	$ 20,648,714	$ 41,297,428
GS	$ 4,228,132	$ 4,228,132	$ 4,228,132	$ 4,228,132	$ 4,228,132	$ 4,228,132	$ 25,368,789	$ 50,737,579
GP	$ 228,732	$ 228,732	$ 228,732	$ 228,732	$ 228,732	$ 228,732	$ 1,372,393	$ 2,744,787
GSU	$ 1,889,927	$ 1,889,927	$ 1,889,927	$ 1,889,927	$ 1,889,927	$ 1,889,927	$ 11,339,560	$ 22,679,120
GT	$ 980,915	$ 980,915	$ 980,915	$ 980,915	$ 980,915	$ 980,915	$ 5,885,492	$ 11,770,985
LTG	$ 68,202	$ 68,202	$ 68,202	$ 68,202	$ 68,202	$ 68,202	$ 409,210	$ 818,420
Total	$ 10,837,360	$ 10,837,360	$ 10,837,360	$ 10,837,360	$ 10,837,360	$ 10,837,360	$ 65,024,160	$ 130,048,319

[1] Projected monthly transmission- and ancillary service-related costs for CEI for 2009.
Demand-based costs reflect a coincident peak allocation basis, whereas energy-based costs are based on each Ohio Operating Company's contribution to the projected total Ohio kWh consumption.
[2] Calculation: Sum of 6 monthly values
[3] Calculation: Sum of 12 monthly values

Witness: Kevin Warvell

Schedule C-2	Page 3 of 3

TOLEDO EDISON'S TRANSMISSION- AND ANCILLARY SERVICE-RELATED COSTS

Schedule	Month in which [illegible]						Total [2]
	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	
RS	$ 1,815,862	$ 1,815,862	$ 1,815,862	$ 1,815,862	$ 1,815,862	$ 1,815,862	$ 10,895,174
GS	$ 1,525,599	$ 1,525,599	$ 1,525,599	$ 1,525,599	$ 1,525,599	$ 1,525,599	$ 9,153,591
GP	$ 663,550	$ 663,550	$ 663,550	$ 663,550	$ 663,550	$ 663,550	$ 3,981,302
GSU	$ 53,121	$ 53,121	$ 53,121	$ 53,121	$ 53,121	$ 53,121	$ 318,728
GT	$ 2,523,727	$ 2,523,727	$ 2,523,727	$ 2,523,727	$ 2,523,727	$ 2,523,727	$ 15,142,364
LTG	$ 22,413	$ 22,413	$ 22,413	$ 22,413	$ 22,413	$ 22,413	$ 134,479
Total	$ 6,604,273	$ 6,604,273	$ 6,604,273	$ 6,604,273	$ 6,604,273	$ 6,604,273	$ 39,625,638

Schedule	Month in which [illegible]						Total [2]	12 Month Total [3]
	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09		
RS	$ 1,815,862	$ 1,815,862	$ 1,815,862	$ 1,815,862	$ 1,815,862	$ 1,815,862	$ 10,895,174	$ 21,790,348
GS	$ 1,525,599	$ 1,525,599	$ 1,525,599	$ 1,525,599	$ 1,525,599	$ 1,525,599	$ 9,153,591	$ 18,307,182
GP	$ 663,550	$ 663,550	$ 663,550	$ 663,550	$ 663,550	$ 663,550	$ 3,981,302	$ 7,962,605
GSU	$ 53,121	$ 53,121	$ 53,121	$ 53,121	$ 53,121	$ 53,121	$ 318,728	$ 637,457
GT	$ 2,523,727	$ 2,523,727	$ 2,523,727	$ 2,523,727	$ 2,523,727	$ 2,523,727	$ 15,142,364	$ 30,284,729
LTG	$ 22,413	$ 22,413	$ 22,413	$ 22,413	$ 22,413	$ 22,413	$ 134,479	$ 268,957
Total	$ 6,604,273	$ 6,604,273	$ 6,604,273	$ 6,604,273	$ 6,604,273	$ 6,604,273	$ 39,625,638	$ 79,251,277

[1] Projected monthly transmission- and ancillary service-related costs for Toledo Edison for 2009.
Demand-based costs reflect a coincident peak allocation basis, whereas energy-based costs are based on each Ohio Operating Company's contribution to the projected total Ohio kWh consumption.
[2] Calculation: Sum of 6 monthly values
[3] Calculation: Sum of 12 monthly values

Calculation of Projected Transmission Cost Recovery Rider Rates

Schedule C-3 provides all necessary support for the rate calculations.

Ohio Edison - Rate RS

The Computation Period over which TAS will apply shall be January 1 through December 31 of each year.

Let TAS = Transmission and Ancillary Services Rider.

Then TAS = $\left(\left(\frac{TAC - E}{BU}\right)\left(\frac{1}{(1-CAT)}\right)\right) = \left(\left(\frac{(TDC * DA)+(TEC * EA)-[(E * HDA * DA)+(E * HEA * EA)]}{BU}\right)\left(\frac{1}{(1-CAT)}\right)\right)$

Where

TAC = The amount of the Company's total projected Transmission and Ancillary Services-related costs for the Computation Period allocated to each Rate Schedule.
= $ 211,760,664

TDC = OE's projected total transmission- and ancillary service-related demand costs in the upcoming 12 months during which the Rider charge will be in effect (see Schedule B-1)
= $ 123,225,291

TEC = OE's projected total transmission- and ancillary service-related energy costs in the upcoming 12 months during which the Rider charge will be in effect (see Schedule B-1)
= $ 88,535,373

E = Initially, the unrecovered portion of the April 2007 to March 2008 reconciliation deferral as of December 31, 2008 plus the over-or under-collection of the TAC, including applicable interest for the 6-month period ending September 30, 2008 allocated to Rate Schedules. Thereafter, the net over- or under-collection of the TAC, including applicable interest, for the 12-month period ending September 30 of each year that immediately precedes the Computation Period allocated to Rate Schedules (see Schedule D-3).
= $ -

DA = the percentage of OE's TDC that is attributed to OE's RS Customers (see Schedule C-3)
= 43.38%

EA = the percentage of OE's TEC that is attributed to OE's RS Customers (see Schedule C-3)
= 38.21%

HDA Percent of OE's historical costs allocated on Demand (see Schedule D-1).
66.91%

HEA Percent of OE's historical costs allocated on Energy (see Schedule D-1).
33.09%

BU = Forecasted billing units for the Computational Period for each Rate Schedule (see Schedule B-2)
= 9,225,981,525

CAT = Commercial Activity Tax Rate (see Schedule D-3d)
= 0.2470%

So, TAS = $ 85,717,893

= $ 0.009291

Calculation of Projected Transmission Cost Recovery Rider Rates

Schedule C-3 provides all necessary support for the rate calculations.

Ohio Edison - Rate GS

The Computation Period over which TAS will apply shall be January 1 through December 31 of each year.

Let *TAS = Transmission and Ancillary Services Rider.*

Then TAS = $\boxed{\left(\frac{TAC - E}{BU}\right)\left(\frac{1}{(1-CAT)}\right)}$ = $\boxed{\left(\frac{(TDC * DA)+(TEC * EA)-[(E * HDA * DA)+(E * HEA * EA)]}{BU}\right)\left(\frac{1}{(1-CAT)}\right)}$

Where

TAC	=	The amount of the Company's total projected Transmission and Ancillary Services-related costs for the Computation Period allocated to each Rate Schedule.
	=	$ 211,760,664
TDC	=	OE's projected total transmission- and ancillary service-related demand costs in the upcoming 12 months during which the Rider charge will be in effect (see Schedule B-1)
	=	$ 123,225,291
TEC	=	OE's projected total transmission- and ancillary service-related energy costs in the upcoming 12 months during which the Rider charge will be in effect (see Schedule B-1)
	=	$ 88,535,373
E	=	Initially, the unrecovered portion of the April 2007 to March 2008 reconciliation deferral as of December 31, 2008 plus the over-or under-collection of the TAC, including applicable interest for the 6-month period ending September 30, 2008 allocated to Rate Schedules. Thereafter, the net over- or under-collection of the TAC, including applicable interest, for the 12-month period ending September 30 of each year that immediately precedes the Computation Period allocated to Rate Schedules (see Schedule D-3).
	=	$ -
DA	=	the percentage of OE's TDC that is attributed to OE's GS Customers (see Schedule C-3)
	=	28.83%
EA	=	the percentage of OE's TEC that is attributed to OE's GS Customers (see Schedule C-3)
	=	27.48%
HDA		Percent of OE's historical costs allocated on Demand (see Schedule D-1).
		66.91%
HEA		Percent of OE's historical costs allocated on Energy (see Schedule D-1).
		33.09%
BU	=	Forecasted billing units for the Computational Period for each Rate Schedule (see Schedule B-2)
	=	25,343,181
CAT	=	Commercial Activity Tax Rate (see Schedule D-3d)
	=	0.2470%

So, TAS = $ 59,996,386

= $ 2.367

Calculation of Projected Transmission Cost Recovery Rider Rates

Schedule C-3 provides all necessary support for the rate calculations.

Ohio Edison - Rate GP

The Computation Period over which TAS will apply shall be January 1 through December 31 of each year.

Let TAS = Transmission and Ancillary Services Rider.

Then TAS = $\left(\frac{TAC - E}{BU}\right)\left(\frac{1}{(1 - CAT)}\right) = \left(\frac{(TDC * DA) + (TEC * EA) - [(E * HDA * DA) + (E * HEA * EA)]}{BU}\right)\left(\frac{1}{(1 - CAT)}\right)$

Where

TAC = The amount of the Company's total projected Transmission and Ancillary Services-related costs for the Computation Period allocated to each Rate Schedule.
= $ 211,760,664

TDC = OE's projected total transmission- and ancillary service-related demand costs in the upcoming 12 months during which the Rider charge will be in effect (see Schedule B-1)
= $ 123,225,291

TEC = OE's projected total transmission- and ancillary service-related energy costs in the upcoming 12 months during which the Rider charge will be in effect (see Schedule B-1)
= $ 88,535,373

E = Initially, the unrecovered portion of the April 2007 to March 2008 reconciliation deferral as of December 31, 2008 plus the over-or under-collection of the TAC, including applicable interest for the 6-month period ending September 30, 2008 allocated to Rate Schedules. Thereafter, the net over- or under-collection of the TAC, including applicable interest, for the 12-month period ending September 30 of each year that immediately precedes the Computation Period allocated to Rate Schedules (see Schedule D-3).
= $ -

DA = the percentage of OE's TDC that is attributed to OE's GP Customers (see Schedule C-3)
= 10.84%

EA = the percentage of OE's TEC that is attributed to OE's GP Customers (see Schedule C-3)
= 12.19%

HDA Percent of OE's historical costs allocated on Demand (see Schedule D-1).
66.91%

HEA Percent of OE's historical costs allocated on Energy (see Schedule D-1).
33.09%

BU = Forecasted billing units for the Computational Period for each Rate Schedule (see Schedule B-2)
= 7,103,952

CAT = Commercial Activity Tax Rate (see Schedule D-3d)
= 0.2470%

So, TAS = $ 24,216,645

= $ 3.409

Calculation of Projected Transmission Cost Recovery Rider Rates

Schedule C-3 provides all necessary support for the rate calculations.

Ohio Edison - Rate GSU

The Computation Period over which TAS will apply shall be January 1 through December 31 of each year.

Let TAS = Transmission and Ancillary Services Rider.

Then TAS = $\left(\frac{TAC - E}{BU}\right)\left(\frac{1}{(1-CAT)}\right)$ = $\left(\frac{(TDC * DA)+(TEC * EA)-[(E * HDA * DA)+(E * HEA * EA)]}{BU}\right)\left(\frac{1}{(1-CAT)}\right)$

Where

TAC	=	The amount of the Company's total projected Transmission and Ancillary Services-related costs for the Computation Period allocated to each Rate Schedule.
	=	$ 211,760,664
TDC	=	OE's projected total transmission- and ancillary service-related demand costs in the upcoming 12 months during which the Rider charge will be in effect (see Schedule B-1)
	=	$ 123,225,291
TEC	=	OE's projected total transmission- and ancillary service-related energy costs in the upcoming 12 months during which the Rider charge will be in effect (see Schedule B-1)
	=	$ 88,535,373
E	=	Initially, the unrecovered portion of the April 2007 to March 2008 reconciliation deferral as of December 31, 2008 plus the over-or under-collection of the TAC, including applicable interest for the 6-month period ending September 30, 2008 allocated to Rate Schedules. Thereafter, the net over- or under-collection of the TAC, including applicable interest, for the 12-month period ending September 30 of each year that immediately precedes the Computation Period allocated to Rate Schedules (see Schedule D-3).
	=	$ -
DA	=	the percentage of OE's TDC that is attributed to OE's GSU Customers (see Schedule C-3)
	=	3.09%
EA	=	the percentage of OE's TEC that is attributed to OE's GSU Customers (see Schedule C-3)
	=	3.64%
HDA		Percent of OE's historical costs allocated on Demand (see Schedule D-1).
		66.91%
HEA		Percent of OE's historical costs allocated on Energy (see Schedule D-1).
		33.09%
BU	=	Forecasted billing units for the Computational Period for each Rate Schedule (see Schedule B-2)
	=	2,215,472
CAT	=	Commercial Activity Tax Rate (see Schedule D-3d)
	=	0.2470%

So, TAS = $ 7,041,631

= $ 3.178

Calculation of Projected Transmission Cost Recovery Rider Rates

Schedule C-3 provides all necessary support for the rate calculations.

Ohio Edison - Rate GT

The Computation Period over which TAS will apply shall be January 1 through December 31 of each year.

Let TAS = Transmission and Ancillary Services Rider.

Then TAS = $\left(\frac{TAC - E}{BU}\right)\left(\frac{1}{(1-CAT)}\right)$ = $\left(\frac{(TDC * DA)+(TEC * EA)-[(E * HDA * DA)+(E * HEA * EA)]}{BU}\right)\left(\frac{1}{(1-CAT)}\right)$

Where

TAC = The amount of the Company's total projected Transmission and Ancillary Services-related costs for the Computation Period allocated to each Rate Schedule.
= $ 211,760,664

TDC = OE's projected total transmission- and ancillary service-related demand costs in the upcoming 12 months during which the Rider charge will be in effect (see Schedule B-1)
= $ 123,225,291

TEC = OE's projected total transmission- and ancillary service-related energy costs in the upcoming 12 months during which the Rider charge will be in effect (see Schedule B-1)
= $ 88,535,373

E = Initially, the unrecovered portion of the April 2007 to March 2008 reconciliation deferral as of December 31, 2008 plus the over-or under-collection of the TAC, including applicable interest for the 6-month period ending September 30, 2008 allocated to Rate Schedules. Thereafter, the net over- or under-collection of the TAC, including applicable interest, for the 12-month period ending September 30 of each year that immediately precedes the Computation Period allocated to Rate Schedules (see Schedule D-3).
= $ -

DA = the percentage of OE's TDC that is attributed to OE's GT Customers (see Schedule C-3)
= 13.81%

EA = the percentage of OE's TEC that is attributed to OE's GT Customers (see Schedule C-3)
= 19.75%

HDA Percent of OE's historical costs allocated on Demand (see Schedule D-1).
66.91%

HEA Percent of OE's historical costs allocated on Energy (see Schedule D-1).
33.09%

BU = Forecasted billing units for the Computational Period for each Rate Schedule (see Schedule B-2)
= 12,369,962

CAT = Commercial Activity Tax Rate (see Schedule D-3d)
= 0.2470%

So, TAS = $ 34,597,379

= $ 2.797

Calculation of *Projected* Transmission Cost Recovery Rider Rates

Schedule C-3 provides all necessary support for the rate calculations.

Ohio Edison - Rate LTG

The Computation Period over which TAS will apply shall be January 1 through December 31 of each year.

Let TAS = Transmission and Ancillary Services Rider.

Then TAS = $\boxed{\left(\frac{TAC - E}{BU}\right)\left(\frac{1}{(1-CAT)}\right)}$ = $\boxed{\left(\frac{(TDC*DA)+(TEC*EA)-[(E*HDA*DA)+(E*HEA*EA)]}{BU}\right)\left(\frac{1}{(1-CAT)}\right)}$

Where

TAC	=	The amount of the Company's total projected Transmission and Ancillary Services-related costs for the Computation Period allocated to each Rate Schedule.
	=	$ 211,760,664
TDC	=	OE's projected total transmission- and ancillary service-related demand costs in the upcoming 12 months during which the Rider charge will be in effect (see Schedule B-1)
	=	$ 123,225,291
TEC	=	OE's projected total transmission- and ancillary service-related energy costs in the upcoming 12 months during which the Rider charge will be in effect (see Schedule B-1)
	=	$ 88,535,373
E	=	Initially, the unrecovered portion of the April 2007 to March 2008 reconciliation deferral as of December 31, 2008 plus the over-or under-collection of the TAC, including applicable interest for the 6-month period ending September 30, 2008 allocated to Rate Schedules. Thereafter, the net over- or under-collection of the TAC, including applicable interest, for the 12-month period ending September 30 of each year that immediately precedes the Computation Period allocated to Rate Schedules (see Schedule D-3).
	=	$ -
DA	=	the percentage of OE's TDC that is attributed to OE's LTG Customers (see Schedule C-3)
	=	0.05%
EA	=	the percentage of OE's TEC that is attributed to OE's LTG Customers (see Schedule C-3)
	=	0.73%
HDA		Percent of OE's historical costs allocated on Demand (see Schedule D-1).
		66.91%
HEA		Percent of OE's historical costs allocated on Energy (see Schedule D-1).
		33.09%
BU	=	Forecasted billing units for the Computational Period for each Rate Schedule (see Schedule B-2)
	=	186,197,457
CAT	=	Commercial Activity Tax Rate (see Schedule D-3d)
	=	0.2470%

So, TAS = $ 715,075

= $ 0.003840

Calculation of Projected Transmission Cost Recovery Rider Rates

Schedule C-3 provides all necessary support for the rate calculations.

Cleveland Electric Illuminating - Rate RS

The Computation Period over which TAS will apply shall be *January 1 through December* 31 of each year.

Let TAS = Transmission and Ancillary Services Rider.

Then TAS = $\left(\frac{TAC - E}{BU}\right)\left(\frac{1}{(1-CAT)}\right) = \left(\frac{(TDC * DA)+(TEC * EA)-[(E * HDA * DA)+(E * HEA * EA)]}{BU}\right)\left(\frac{1}{(1-CAT)}\right)$

Where

TAC = The amount of the Company's total projected Transmission and Ancillary Services-related costs for the Computation Period allocated to each Rate Schedule.
= $ 130,048,319

TDC = CEI's projected total transmission- and ancillary service-related demand costs in the upcoming 12 months during which the Rider charge will be in effect (see Schedule B-1)
= $ 63,158,760

TEC = CEI's projected total transmission- and ancillary service-related energy costs in the upcoming 12 months during which the Rider charge will be in effect (see Schedule B-1)
= $ 66,889,559

E = Initially, the unrecovered portion of the April 2007 to March 2008 reconciliation deferral as of December 31, 2008 plus the over-or under-collection of the TAC, including applicable interest for the 6-month period ending September 30, 2008 allocated to Rate Schedules. Thereafter, the net over- or under-collection of the TAC, including applicable interest, for the 12-month period ending September 30 of each year that immediately precedes the Computation Period allocated to Rate Schedules (see Schedule D-3).
= $ -

DA = the percentage of CEI's TDC that is attributed to CEI's RS Customers (see Schedule C-3)
= 34.86%

EA = the percentage of CEI's TEC that is attributed to CEI's RS Customers (see Schedule C-3)
= 28.82%

HDA Percent of CEI's historical costs allocated on Demand (see Schedule D-1).
58.96%

HEA Percent of CEI's historical costs allocated on Energy (see Schedule D-1).
41.04%

BU = Forecasted billing units for the Computational Period for each Rate Schedule (see Schedule B-2)
= 5,603,870,615

CAT = Commercial Activity Tax Rate (see Schedule D-3d)
= 0.2470%

So, TAS = $ 41,399,685
= $ 0.007388

Calculation of Projected Transmission Cost Recovery Rider Rates

Schedule C-3 provides all necessary support for the rate calculations.

Cleveland Electric Illuminating - Rate GS

The Computation Period over which TAS will apply shall be January 1 through December 31 of each year.

Let TAS = Transmission and Ancillary Services Rider.

Then TAS = $\left(\frac{TAC - E}{BU}\right)\left(\frac{1}{(1-CAT)}\right) = \left(\frac{(TDC*DA)+(TEC*EA)-[(E*HDA*DA)+(E*HEA*EA)]}{BU}\right)\left(\frac{1}{(1-CAT)}\right)$

Where

TAC = The amount of the Company's total projected Transmission and Ancillary Services-related costs for the Computation Period allocated to each Rate Schedule.
= $ 130,048,319

TDC = CEI's projected total transmission- and ancillary service-related demand costs in the upcoming 12 months during which the Rider charge will be in effect (see Schedule B-1)
= $ 63,158,760

TEC = CEI's projected total transmission- and ancillary service-related energy costs in the upcoming 12 months during which the Rider charge will be in effect (see Schedule B-1)
= $ 66,889,559

E = Initially, the unrecovered portion of the April 2007 to March 2008 reconciliation deferral as of December 31, 2008 plus the over-or under-collection of the TAC, including applicable interest for the 6-month period ending September 30, 2008 allocated to Rate Schedules. Thereafter, the net over- or under-collection of the TAC, including applicable interest, for the 12-month period ending September 30 of each year that immediately precedes the Computation Period allocated to Rate Schedules (see Schedule D-3).
= $ -

DA = the percentage of CEI's TDC that is attributed to CEI's GS Customers (see Schedule C-3)
= 40.00%

EA = the percentage of CEI's TEC that is attributed to CEI's GS Customers (see Schedule C-3)
= 38.08%

HDA Percent of CEI's historical costs allocated on Demand (see Schedule D-1).
58.96%

HEA Percent of CEI's historical costs allocated on Energy (see Schedule D-1).
41.04%

BU = Forecasted billing units for the Computational Period for each Rate Schedule (see Schedule B-2)
= 24,134,406

CAT = Commercial Activity Tax Rate (see Schedule D-3d)
= 0.2470%

So, TAS = $ 50,863,211

= $ 2.107

Calculation of Projected Transmission Cost Recovery Rider Rates

Schedule C-3 provides all necessary support for the rate calculations.

Cleveland Electric Illuminating - Rate GP

The Computation Period over which TAS will apply shall be January 1 through December 31 of each year.

Let TAS = Transmission and Ancillary Services Rider.

Then TAS = $\left(\frac{TAC - E}{BU}\right)\left(\frac{1}{(1-CAT)}\right) = \left(\frac{(TDC*DA)+(TEC*EA)-[(E*HDA*DA)+(E*HEA*EA)]}{BU}\right)\left(\frac{1}{(1-CAT)}\right)$

Where

TAC	=	The amount of the Company's total projected Transmission and Ancillary Services-related costs for the Computation Period allocated to each Rate Schedule.
	=	$ 130,048,319
TDC	=	CEI's projected total transmission- and ancillary service-related demand costs in the upcoming 12 months during which the Rider charge will be in effect (see Schedule B-1)
	=	$ 63,158,760
TEC	=	CEI's projected total transmission- and ancillary service-related energy costs in the upcoming 12 months during which the Rider charge will be in effect (see Schedule B-1)
	=	$ 66,889,559
E	=	Initially, the unrecovered portion of the April 2007 to March 2008 reconciliation deferral as of December 31, 2008 plus the over-or under-collection of the TAC, including applicable interest for the 6-month period ending September 30, 2008 allocated to Rate Schedules. Thereafter, the net over- or under-collection of the TAC, including applicable interest, for the 12-month period ending September 30 of each year that immediately precedes the Computation Period allocated to Rate Schedules (see Schedule D-3).
	=	$ -
DA	=	the percentage of CEI's TDC that is attributed to CEI's GP Customers (see Schedule C-3)
	=	1.71%
EA	=	the percentage of CEI's TEC that is attributed to CEI's GP Customers (see Schedule C-3)
	=	2.49%
HDA		Percent of CEI's historical costs allocated on Demand (see Schedule D-1).
		58.96%
HEA		Percent of CEI's historical costs allocated on Energy (see Schedule D-1).
		41.04%
BU	=	Forecasted billing units for the Computational Period for each Rate Schedule (see Schedule B-2)
	=	1,019,438
CAT	=	Commercial Activity Tax Rate (see Schedule D-3d)
	=	0.2470%

So, TAS = $ 2,751,583

= $ 2.699

Witness: Kevin Warvell

Calculation of Projected Transmission Cost Recovery Rider Rates

Schedule C-3 | Page 10 of 20

Schedule C-3 provides all necessary support for the rate calculations.

Cleveland Electric Illuminating - Rate GSU

The Computation Period over which TAS will apply shall be January 1 through December 31 of each year.

Let TAS = Transmission and Ancillary Services Rider.

Then TAS = $\left(\frac{TAC - E}{BU}\right)\left(\frac{1}{(1-CAT)}\right)$ = $\left(\frac{(TDC*DA)+(TEC*EA)-[(E*HDA*DA)+(E*HEA*EA)]}{BU}\right)\left(\frac{1}{(1-CAT)}\right)$

Where

TAC	=	The amount of the Company's total projected Transmission and Ancillary Services-related costs for the Computation Period allocated to each Rate Schedule.
	=	$ 130,048,319
TDC	=	CEI's projected total transmission- and ancillary service-related demand costs in the upcoming 12 months during which the Rider charge will be in effect (see Schedule B-1)
	=	$ 63,158,760
TEC	=	CEI's projected total transmission- and ancillary service-related energy costs in the upcoming 12 months during which the Rider charge will be in effect (see Schedule B-1)
	=	$ 66,889,559
E	=	Initially, the unrecovered portion of the April 2007 to March 2008 reconciliation deferral as of December 31, 2008 plus the over-or under-collection of the TAC, including applicable interest for the 6-month period ending September 30, 2008 allocated to Rate Schedules. Thereafter, the net over- or under-collection of the TAC, including applicable interest, for the 12-month period ending September 30 of each year that immediately precedes the Computation Period allocated to Rate Schedules (see Schedule D-3).
	=	$ -
DA	=	the percentage of CEI's TDC that is attributed to CEI's GSU Customers (see Schedule C-3)
	=	15.93%
EA	=	the percentage of CEI's TEC that is attributed to CEI's GSU Customers (see Schedule C-3)
	=	18.87%
HDA		Percent of CEI's historical costs allocated on Demand (see Schedule D-1).
		58.96%
HEA		Percent of CEI's historical costs allocated on Energy (see Schedule D-1).
		41.04%
BU	=	Forecasted billing units for the Computational Period for each Rate Schedule (see Schedule B-2)
	=	8,735,289
CAT	=	Commercial Activity Tax Rate (see Schedule D-3d)
	=	0.2470%
So,	TAS =	$ 22,735,276
	=	$ 2.603

Calculation of Projected Transmission Cost Recovery Rider Rates | Schedule C-3 | Page 11 of 20

Schedule C-3 provides all necessary support for the rate calculations.

Cleveland Electric Illuminating - Rate GT

The Computation Period over which TAS will apply shall be January 1 through December 31 of each year.

Let TAS = Transmission and Ancillary Services Rider.

Then TAS = $\left(\frac{TAC - E}{BU}\right)\left(\frac{1}{(1-CAT)}\right) = \left(\frac{(TDC*DA)+(TEC*EA)-[(E*HDA*DA)+(E*HEA*EA)]}{BU}\right)\left(\frac{1}{(1-CAT)}\right)$

Where

TAC = The amount of the Company's total projected Transmission and Ancillary Services-related costs for the Computation Period allocated to each Rate Schedule.
= $ 130,048,319

TDC = CEI's projected total transmission- and ancillary service-related demand costs in the upcoming 12 months during which the Rider charge will be in effect (see Schedule B-1)
= $ 63,158,760

TEC = CEI's projected total transmission- and ancillary service-related energy costs in the upcoming 12 months during which the Rider charge will be in effect (see Schedule B-1)
= $ 66,889,559

E = Initially, the unrecovered portion of the April 2007 to March 2008 reconciliation deferral as of December 31, 2008 plus the over-or under-collection of the TAC, including applicable interest for the 6-month period ending September 30, 2008 allocated to Rate Schedules. Thereafter, the net over- or under-collection of the TAC, including applicable interest, for the 12-month period ending September 30 of each year that immediately precedes the Computation Period allocated to Rate Schedules (see Schedule D-3).
= $ -

DA = the percentage of CEI's TDC that is attributed to CEI's GT Customers (see Schedule C-3)
= 7.41%

EA = the percentage of CEI's TEC that is attributed to CEI's GT Customers (see Schedule C-3)
= 10.60%

HDA Percent of CEI's historical costs allocated on Demand (see Schedule D-1).
58.96%

HEA Percent of CEI's historical costs allocated on Energy (see Schedule D-1).
41.04%

BU = Forecasted billing units for the Computational Period for each Rate Schedule (see *Schedule B-2*)
= 5,039,889

CAT = Commercial Activity Tax Rate (see Schedule D-3d)
= 0.2470%

So, TAS = $ 11,800,131

= $ 2.341

Calculation of Projected Transmission Cost Recovery Rider Rates

Schedule C-3 provides all necessary support for the rate calculations.

Cleveland Electric Illuminating - Rate LTG

The Computation Period over which TAS will apply shall be January 1 through December 31 of each year.

Let TAS = Transmission and Ancillary Services Rider.

Then TAS = $\left(\frac{TAC - E}{BU}\right)\left(\frac{1}{(1-CAT)}\right)$ = $\left(\frac{(TDC * DA)+(TEC * EA)-[(E * HDA * DA)+(E * HEA * EA)]}{BU}\right)\left(\frac{1}{(1-CAT)}\right)$

Where

TAC = The amount of the Company's total projected Transmission and Ancillary Services-related costs for the Computation Period allocated to each Rate Schedule.
= $ 130,048,319

TDC = CEI's projected total transmission- and ancillary service-related demand costs in the upcoming 12 months during which the Rider charge will be in effect (see Schedule B-1)
= $ 63,158,760

TEC = CEI's projected total transmission- and ancillary service-related energy costs in the upcoming 12 months during which the Rider charge will be in effect (see Schedule B-1)
= $ 66,889,559

E = Initially, the unrecovered portion of the April 2007 to March 2008 reconciliation deferral as of December 31, 2008 plus the over-or under-collection of the TAC, including applicable interest for the 6-month period ending September 30, 2008 allocated to Rate Schedules. Thereafter, the net over- or under-collection of the TAC, including applicable interest, for the 12-month period ending September 30 of each year that immediately precedes the Computation Period allocated to Rate Schedules (see Schedule D-3).
= $ -

DA = the percentage of CEI's TDC that is attributed to CEI's LTG Customers (see Schedule C-3)
= 0.09%

EA = the percentage of CEI's TEC that is attributed to CEI's LTG Customers (see Schedule C-3)
= 1.14%

HDA Percent of CEI's historical costs allocated on Demand (see Schedule D-1).
58.96%

HEA Percent of CEI's historical costs allocated on Energy (see Schedule D-1).
41.04%

BU = Forecasted billing units for the Computational Period for each Rate Schedule (see Schedule B-2)
= 221,079,177

CAT = Commercial Activity Tax Rate (see Schedule D-3d)
= 0.2470%

So, TAS = $ 820,447

= $ 0.003711

Calculation of Projected Transmission Cost Recovery Rider Rates

Schedule C-3 provides all necessary support for the rate calculations.

Toledo Edison - Rate RS

The Computation Period over which TAS will apply shall be January 1 through December 31 of each year.

Let TAS = Transmission and Ancillary Services Rider.

Then TAS = $\left(\frac{TAC - E}{BU}\right)\left(\frac{1}{(1-CAT)}\right) = \left(\frac{(TDC*DA)+(TEC*EA)-[(E*HDA*DA)+(E*HEA*EA)]}{BU}\right)\left(\frac{1}{(1-CAT)}\right)$

Where

TAC = The amount of the Company's total projected Transmission and Ancillary Services-related costs for the Computation Period allocated to each Rate Schedule.
= $ 79,251,277

TDC = TE's projected total transmission- and ancillary service-related demand costs in the upcoming 12 months during which the Rider charge will be in effect (see Schedule B-1)
= $ 42,313,476

TEC = TE's projected total transmission- and ancillary service-related energy costs in the upcoming 12 months during which the Rider charge will be in effect (see Schedule B-1)
= $ 36,937,801

E = Initially, the unrecovered portion of the April 2007 to March 2008 reconciliation deferral as of December 31, 2008 plus the over-or under-collection of the TAC, including applicable interest for the 6-month period ending September 30, 2008 allocated to Rate Schedules. Thereafter, the net over- or under-collection of the TAC, including applicable interest, for the 12-month period ending September 30 of each year that immediately precedes the Computation Period allocated to Rate Schedules (see Schedule D-3).
= $ -

DA = the percentage of TE's TDC that is attributed to TE's RS Customers (see Schedule C-3)
= 30.50%

EA = the percentage of TE's TEC that is attributed to TE's RS Customers (see Schedule C-3)
= 24.06%

HDA Percent of TE's historical costs allocated on Demand (see Schedule D-1).
61.94%

HEA Percent of TE's historical costs allocated on Energy (see Schedule D-1).
38.06%

BU = Forecasted billing units for the Computational Period for each Rate Schedule (see Schedule B-2)
= 2,481,166,258

CAT = Commercial Activity Tax Rate (see Schedule D-3d)
= 0.2470%

So, TAS = $ 21,844,303

= $ 0.008804

Calculation of Projected Transmission Cost Recovery Rider Rates

Schedule C-3 provides all necessary support for the rate calculations.

Toledo Edison - Rate GS

The Computation Period over which TAS will apply shall be January 1 through December 31 of each year.

Let TAS = Transmission and Ancillary Services Rider.

Then TAS = $\boxed{\left(\frac{TAC - E}{BU}\right)\left(\frac{1}{(1-CAT)}\right)}$ = $\boxed{\left(\frac{(TDC * DA)+(TEC * EA)-[(E * HDA * DA)+(E * HEA * EA)]}{BU}\right)\left(\frac{1}{(1-CAT)}\right)}$

Where

TAC	=	The amount of the Company's total projected Transmission and Ancillary Services-related costs for the Computation Period allocated to each Rate Schedule.
	=	$ 79,251,277
TDC	=	TE's projected total transmission- and ancillary service-related demand costs in the upcoming 12 months during which the Rider charge will be in effect (see Schedule B-1)
	=	$ 42,313,476
TEC	=	TE's projected total transmission- and ancillary service-related energy costs in the upcoming 12 months during which the Rider charge will be in effect (see Schedule B-1)
	=	$ 36,937,801
E	=	Initially, the unrecovered portion of the April 2007 to March 2008 reconciliation deferral as of December 31, 2008 plus the over-or under-collection of the TAC, including applicable interest for the 6-month period ending September 30, 2008 allocated to Rate Schedules. Thereafter, the net over- or under-collection of the TAC, including applicable interest, for the 12-month period ending September 30 of each year that immediately precedes the Computation Period allocated to Rate Schedules (see Schedule D-3).
	=	$ -
DA	=	the percentage of TE's TDC that is attributed to TE's GS Customers (see Schedule C-3)
	=	24.25%
EA	=	the percentage of TE's TEC that is attributed to TE's GS Customers (see Schedule C-3)
	=	21.78%
HDA		Percent of TE's historical costs allocated on Demand (see Schedule D-1).
		61.94%
HEA		Percent of TE's historical costs allocated on Energy (see Schedule D-1).
		38.06%
BU	=	Forecasted billing units for the Computational Period for each Rate Schedule (see Schedule B-2)
	=	8,087,756
CAT	=	Commercial Activity Tax Rate (see Schedule D-3d)
	=	0.2470%

So, TAS = $ 18,352,513

= $ 2.269

Calculation of Projected Transmission Cost Recovery Rider Rates

Schedule C-3 provides all necessary support for the rate calculations.

Toledo Edison - Rate GP

The Computation Period over which TAS will apply shall be January 1 through December 31 of each year.

Let TAS = Transmission and Ancillary Services Rider.

Then TAS = $\left(\frac{TAC - E}{BU}\right)\left(\frac{1}{(1-CAT)}\right)$ = $\left(\frac{(TDC * DA)+(TEC * EA)-[(E * HDA * DA)+(E * HEA * EA)]}{BU}\right)\left(\frac{1}{(1-CAT)}\right)$

Where

TAC = The amount of the Company's total projected Transmission and Ancillary Services-related costs for the Computation Period allocated to each Rate Schedule.
= $ 79,251,277

TDC = TE's projected total transmission- and ancillary service-related demand costs in the upcoming 12 months during which the Rider charge will be in effect (see Schedule B-1)
= $ 42,313,476

TEC = TE's projected total transmission- and ancillary service-related energy costs in the upcoming 12 months during which the Rider charge will be in effect (see Schedule B-1)
= $ 36,937,801

E = Initially, the unrecovered portion of the April 2007 to March 2008 reconciliation deferral as of December 31, 2008 plus the over-or under-collection of the TAC, including applicable interest for the 6-month period ending September 30, 2008 allocated to Rate Schedules. Thereafter, the net over- or under-collection of the TAC, including applicable interest, for the 12-month period ending September 30 of each year that immediately precedes the Computation Period allocated to Rate Schedules (see Schedule D-3).
= $ -

DA = the percentage of TE's TDC that is attributed to TE's GP Customers (see Schedule C-3)
= 9.52%

EA = the percentage of TE's TEC that is attributed to TE's GP Customers (see Schedule C-3)
= 10.65%

HDA Percent of TE's historical costs allocated on Demand (see Schedule D-1).
61.94%

HEA Percent of TE's historical costs allocated on Energy (see Schedule D-1).
38.06%

BU = Forecasted billing units for the Computational Period for each Rate Schedule (see Schedule B-2)
= 2,790,440

CAT = Commercial Activity Tax Rate (see Schedule D-3d)
= 0.2470%

So, TAS = $ 7,982,321

= $ 2.861

Calculation of Projected Transmission Cost Recovery Rider Rates

Schedule C-3 provides all necessary support for the rate calculations.

Toledo Edison - Rate GSU

The Computation Period over which TAS will apply shall be January 1 through December 31 of each year.

Let TAS = Transmission and Ancillary Services Rider.

Then TAS = $\left(\frac{TAC - E}{BU}\right)\left(\frac{1}{(1-CAT)}\right)$ = $\left(\frac{(TDC*DA)+(TEC*EA)-[(E*HDA*DA)+(E*HEA*EA)]}{BU}\right)\left(\frac{1}{(1-CAT)}\right)$

Where

TAC	=	The amount of the Company's total projected Transmission and Ancillary Services-related costs for the Computation Period allocated to each Rate Schedule.
	=	$ 79,251,277
TDC	=	TE's projected total transmission- and ancillary service-related demand costs in the upcoming 12 months during which the Rider charge will be in effect (see Schedule B-1)
	=	$ 42,313,476
TEC	=	TE's projected total transmission- and ancillary service-related energy costs in the upcoming 12 months during which the Rider charge will be in effect (see Schedule B-1)
	=	$ 36,937,801
E	=	Initially, the unrecovered portion of the April 2007 to March 2008 reconciliation deferral as of December 31, 2008 plus the over-or under-collection of the TAC, including applicable interest for the 6-month period ending September 30, 2008 allocated to Rate Schedules. Thereafter, the net over- or under-collection of the TAC, including applicable interest, for the 12-month period ending September 30 of each year that immediately precedes the Computation Period allocated to Rate Schedules (see Schedule D-3).
	=	$ -
DA	=	the percentage of TE's TDC that is attributed to TE's GSU Customers (see Schedule C-3)
	=	0.69%
EA	=	the percentage of TE's TEC that is attributed to TE's GSU Customers (see Schedule C-3)
	=	0.94%
HDA		Percent of TE's historical costs allocated on Demand (see Schedule D-1).
		61.94%
HEA		Percent of TE's historical costs allocated on Energy (see Schedule D-1).
		38.06%
BU	=	Forecasted billing units for the Computational Period for each Rate Schedule (see Schedule B-2)
	=	185,961
CAT	=	Commercial Activity Tax Rate (see Schedule D-3d)
	=	0.2470%

So, TAS = $ 639,035

= $ 3.436

Calculation of Projected Transmission Cost Recovery Rider Rates

Schedule C-3 provides all necessary support for the rate calculations.

Toledo Edison - Rate GT

The Computation Period over which TAS will apply shall be January 1 through December 31 of each year.

Let TAS = Transmission and Ancillary Services Rider.

Then TAS = $\left(\frac{TAC - E}{BU}\right)\left(\frac{1}{(1-CAT)}\right)$ = $\left(\frac{(TDC * DA) + (TEC * EA) - [(E * HDA * DA) + (E * HEA * EA)]}{BU}\right)\left(\frac{1}{(1-CAT)}\right)$

Where

TAC = The amount of the Company's total projected Transmission and Ancillary Services-related costs for the Computation Period allocated to each Rate Schedule.
= $ 79,261,277

TDC = TE's projected total transmission- and ancillary service-related demand costs in the upcoming 12 months during which the Rider charge will be in effect (see Schedule B-1)
= $ 42,313,476

TEC = TE's projected total transmission- and ancillary service-related energy costs in the upcoming 12 months during which the Rider charge will be in effect (see Schedule B-1)
= $ 36,937,801

E = Initially, the unrecovered portion of the April 2007 to March 2008 reconciliation deferral as of December 31, 2008 plus the over-or under-collection of the TAC, including applicable interest for the 6-month period ending September 30, 2008 allocated to Rate Schedules. Thereafter, the net over- or under-collection of the TAC, including applicable interest, for the 12-month period ending September 30 of each year that immediately precedes the Computation Period allocated to Rate Schedules (see Schedule D-3).
= $ -

DA = the percentage of TE's TDC that is attributed to TE's GT Customers (see Schedule C-3)
= 34.99%

EA = the percentage of TE's TEC that is attributed to TE's GT Customers (see Schedule C-3)
= 41.90%

HDA Percent of TE's historical costs allocated on Demand (see Schedule D-1).
61.94%

HEA Percent of TE's historical costs allocated on Energy (see Schedule D-1).
38.06%

BU = Forecasted billing units for the Computational Period for each Rate Schedule (see Schedule B-2)
= 9,348,977

CAT = Commercial Activity Tax Rate (see Schedule D-3d)
= 0.2470%

So, TAS = $ 30,359,717

= $ 3.247

Calculation of Projected Transmission Cost Recovery Rider Rates

Schedule C-3 provides all necessary support for the rate calculations.

Toledo Edison - Rate LTG

The Computation Period over which TAS will apply shall be January 1 through December 31 of each year.

Let TAS = Transmission and Ancillary Services Rider.

Then TAS = $$\left(\frac{TAC - E}{BU}\right)\left(\frac{1}{(1-CAT)}\right) = \left(\frac{(TDC*DA)+(TEC*EA)-[(E*HDA*DA)+(E*HEA*EA)]}{BU}\right)\left(\frac{1}{(1-CAT)}\right)$$

Where

TAC	=	The amount of the Company's total projected Transmission and Ancillary Services-related costs for the Computation Period allocated to each Rate Schedule.
	=	$ 79,251,277
TDC	=	TE's projected total transmission- and ancillary service-related demand costs in the upcoming 12 months during which the Rider charge will be in effect (see Schedule B-1)
	=	$ 42,313,476
TEC	=	TE's projected total transmission- and ancillary service-related energy costs in the upcoming 12 months during which the Rider charge will be in effect (see Schedule B-1)
	=	$ 36,937,801
E	=	Initially, the unrecovered portion of the April 2007 to March 2008 reconciliation deferral as of December 31, 2008 plus the over-or under-collection of the TAC, including applicable interest for the 6-month period ending *September 30, 2008 allocated to Rate Schedules. Thereafter, the net over- or under-collection of the* TAC, including applicable interest, for the 12-month period ending September 30 of each year that immediately precedes the Computation Period allocated to Rate Schedules (see Schedule D-3).
	=	$ -
DA	=	the percentage of TE's TDC that is attributed to TE's LTG Customers (see Schedule C-3)
	=	0.05%
EA	=	the percentage of TE's TEC that is attributed to TE's LTG Customers (see Schedule C-3)
	=	0.67%
HDA		Percent of TE's historical costs allocated on Demand (see Schedule D-1).
		61.94%
HEA		Percent of TE's historical costs allocated on Energy (see Schedule D-1).
		38.06%
BU	=	Forecasted billing units for the Computational Period for each Rate Schedule (see Schedule B-2)
	=	69,151,680
CAT	=	Commercial Activity Tax Rate (see Schedule D-3d)
	=	0.2470%

So, TAS = $ 269,623

= $ 0.003899

Monthly Projected Cost by Rate Schedule

Schedule C-3 provides the energy and demand allocators.

Demand Allocators

Ohio Operating Company	Customer Class	Company Peak (kW) June 2007	Company Peak (kW) July 2007	Company Peak (kW) Aug 2007	Company Peak (kW) Sep 2007	Company Peak (kW) Total	Demand Allocation Factor
OE	RS	2,127,715	1,831,029	2,281,122	1,720,766	7,960,631	**43.38%**
	GS	1,241,046	1,475,015	1,401,846	1,172,592	5,290,499	**28.83%**
	GP	488,268	507,025	504,167	490,477	1,989,937	**10.84%**
	GSUB	140,446	146,236	139,070	140,638	566,390	**3.09%**
	GT	634,131	682,684	613,042	605,476	2,535,333	**13.81%**
	LTG	2,480	2,448	2,475	2,480	9,883	**0.05%**
	TOTAL	4,634,086	4,644,437	4,941,722	4,132,429	18,352,673	100.00%
CEI	RS	1,417,084	1,200,319	1,393,127	1,095,464	5,105,994	**34.86%**
	GS	1,355,122	1,607,968	1,555,560	1,340,316	5,858,966	**40.00%**
	GP	63,913	66,784	57,081	62,977	250,755	**1.71%**
	GSUB	565,620	587,678	598,256	581,083	2,332,637	**15.93%**
	GT	292,212	247,964	286,913	257,665	1,084,755	**7.41%**
	LTG	3,308	3,347	3,350	3,405	13,410	**0.09%**
	TOTAL	3,697,260	3,714,059	3,894,287	3,340,910	14,646,517	100.00%
TE	RS	583,279	545,161	539,903	415,370	2,083,712	**30.50%**
	GS	389,656	465,933	439,323	362,245	1,657,156	**24.25%**
	GP	159,734	174,886	166,547	149,401	650,568	**9.52%**
	GSUB	14,544	12,994	9,508	9,791	46,837	**0.69%**
	GT	616,661	573,677	609,278	591,394	2,391,010	**34.99%**
	LTG	874	876	871	816	3,438	**0.05%**
	TOTAL	1,764,747	1,773,528	1,765,431	1,529,017	6,832,721	100.00%

Source: Distribution rate case billing units

Monthly Projected Cost by Rate Schedule | Schedule C-3 | Page 20 of 20

Schedule C-3 provides the energy and demand allocators.

Energy Allocators

Ohio Operating Company	Customer Class	Billing Units (kWh)	Loss Factor [1]	Sales Including T&D Losses	Energy Allocation Factor
OE	RS	9,225,981,525	1.09486	10,101,158,132	**36.21%**
	GS	7,001,256,350	1.09486	7,665,395,527	**27.48%**
	GP	3,215,783,887	1.05786	3,401,849,143	**12.19%**
	GSUB	986,594,660	1.02886	1,015,067,782	**3.64%**
	GT	5,402,453,751	1.02008	5,510,914,578	**19.75%**
	LTG	186,197,457	1.09486	203,860,148	**0.73%**
	TOTAL	26,018,267,630		27,898,245,310	100.00%
CEI	RS	5,603,870,615	1.09486	6,135,453,782	**28.82%**
	GS	7,404,024,401	1.09486	8,106,370,156	**38.08%**
	GP	500,431,067	1.05786	529,386,009	**2.49%**
	GSUB	3,903,627,156	1.02886	4,016,285,836	**18.87%**
	GT	2,160,438,992	1.04487	2,257,370,027	**10.60%**
	LTG	221,079,177	1.09486	242,050,747	**1.14%**
	TOTAL	19,793,471,409		21,286,916,557	100.00%
TE	RS	2,481,166,258	1.09486	2,716,529,689	**24.06%**
	GS	2,246,181,610	1.09486	2,459,254,398	**21.78%**
	GP	1,136,765,822	1.05786	1,202,539,093	**10.65%**
	GSUB	103,221,038	1.02886	106,199,997	**0.94%**
	GT	4,622,983,633	1.02347	4,731,473,569	**41.90%**
	LTG	69,151,681	1.09486	75,711,409	**0.67%**
	TOTAL	10,659,470,042		11,291,708,155	100.00%

[1] Loss factor for GT is weighted loss factor for 69 KV and 138 KV. Includes adjustment for meter location for CEI.
Source: Distribution rate case billing units

Reconciliation Adjustment

Schedule D-1	Page 1 of 4

Schedule D-1 provides actual transmission cost recovery rider costs for each component used to calculate the reconciliation adjustment.

For the initial filing, expenses will be shown for the 6-month period ending September 30, 2008. For subsequent filings, 12 months of data will be shown.
Page 4 provides the historical breakdown between demand- and energy-related costs at each Operating Company.

OHIO EDISON'S TRANSMISSION- AND ANCILLARY SERVICE-RELATED COSTS

Schedule	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Total[2]
1	$ 168,726	$ 165,093	$ 236,740	$ -	$ -	$ -	$ 570,559
2	$ 339,239	$ 332,847	$ 479,907	$ -	$ -	$ -	$ 1,151,993
3	$ 182,731	$ 179,268	$ 268,472	$ -	$ -	$ -	$ 620,471
4							$ -
5	$ 274,097	$ 268,901	$ 387,708	$ -	$ -	$ -	$ 930,707
6	$ 137,260	$ 134,656	$ 194,153	$ -	$ -	$ -	$ 466,070
7 (69 kv)							$ -
7 (138 kv)							$ -
8 (69 kv)							$ -
8 (138 kv)							$ -
9 (69 kv)	$ 1,895,584	$ 1,977,949	$ 3,145,639	$ -	$ -	$ -	$ 7,019,182
9 (138 kv)	$ 3,593,228	$ 3,347,393	$ 4,072,626	$ -	$ -	$ -	$ 11,013,248
10	$ 323,845	$ 245,658	$ 310,145	$ -	$ -	$ -	$ 879,648
11							$ -
12							$ -
13							$ -
14							$ -
15							$ -
18							$ -
19							$ -
20							$ -
22							$ -
26	$ 11,845	$ 11,360	$ 16,267	$ -	$ -	$ -	$ 39,472
Amortization[3]	$ 273,925	$ 284,720	$ 250,758	$ -	$ -	$ -	$ 809,402
Total	$ 7,200,491	$ 6,947,847	$ 9,352,415	$ -	$ -	$ -	$ 23,500,753

Schedule	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Total[2]
3	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	$ -	$ -	$ -	$ -	$ -	$ -	$ -
16	$ 11,845	$ 22,526	$ 30,553	$ -	$ -	$ -	$ 64,924
17	$ 236,213	$ 222,440	$ 352,314	$ -	$ -	$ -	$ 810,967
24	$ 21,383	$ 19,713	$ 21,825	$ -	$ -	$ -	$ 62,922
FERC 10	$ 62,357	$ 61,058	$ 88,943	$ -	$ -	$ -	$ 212,358
Congestion Expense	$ 7,721	$ (308,949)	$ 4,795,776	$ -	$ -	$ -	$ 4,494,548
FTR Credit	$ 82,045	$ 785,567	$ (6,308,687)	$ -	$ -	$ -	$ (5,441,075)
FTR Expense	$ -	$ -	$ 1,852,449				$ 1,852,449
Net Losses	$ 2,331,767	$ 1,494,248	$ 3,038,878	$ -	$ -	$ -	$ 6,864,893
Revenue Neutrality	$ 291,851	$ 317,165	$ 1,261,406	$ -	$ -	$ -	$ 1,870,422
Rev. Sufficiency Guarantee	$ 60,763	$ 58,650	$ 322,924	$ -	$ -	$ -	$ 442,337
Amortization[3]	$ 122,831	$ 114,194	$ 150,327	$ -	$ -	$ -	$ 387,352
Total	$ 3,228,776	$ 2,786,611	$ 5,606,711	$ -	$ -	$ -	$ 11,622,097

[1] Actual monthly transmission- and ancillary service-related costs for Ohio Edison for the 6 months ending September 30, 2008.
[2] Calculation: Sum of 6 monthly values
[3] "Amortization" represents the monthly portion of the deferred transmission- and ancillary service-related costs (and interest). This number is calculated by summing the balances remaining on Companies' books from the previous year's reconciliation. Amortization expense is further split between energy and demand, based upon the costs that were deferred.

Witness: Kevin Warvell

Schedule D-1	Page 2 of 4

CLEVELAND ELECTRIC ILLUMINATING'S TRANSMISSION- AND ANCILLARY SERVICE-RELATED COSTS

Schedule	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Total[2]
1	$ 130,812	$ 138,402	$ 215,640	$ -	$ -	$ -	$ 484,854
2	$ 262,963	$ 279,034	$ 437,136	$ -	$ -	$ -	$ 979,134
3	$ 141,646	$ 150,285	$ 235,437	$ -	$ -	$ -	$ 527,368
4							$ -
5	$ 212,469	$ 225,427	$ 353,155	$ -	$ -	$ -	$ 791,051
6	$ 106,398	$ 112,887	$ 176,850	$ -	$ -	$ -	$ 396,135
7 (69 kv)							$ -
7 (138 kv)							$ -
8 (69 kv)							$ -
8 (138 kv)							$ -
9 (69 kv)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9 (138 kv)	$ 2,782,053	$ 2,806,209	$ 3,856,637	$ -	$ -	$ -	$ 9,444,899
10	$ 253,539	$ 203,819	$ 280,656	$ -	$ -	$ -	$ 738,014
11							$ -
12							$ -
13							$ -
14							$ -
15							$ -
18							$ -
19							$ -
20							$ -
22							$ -
26	$ 9,195	$ 9,524	$ 14,817	$ -	$ -	$ -	$ 33,536
Amortization[3]	$ 165,896	$ 177,640	$ 154,116	$ -	$ -	$ -	$ 497,652
Total	$ 4,064,972	$ 4,103,227	$ 5,724,443	$ -	$ -	$ -	$ 13,892,641

Schedule	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Total[2]
3	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	$ -	$ -	$ -	$ -	$ -	$ -	$ -
16	$ 9,916	$ 18,651	$ 25,297	$ -	$ -	$ -	$ 53,865
17	$ 197,747	$ 184,177	$ 291,710	$ -	$ -	$ -	$ 673,634
24	$ 17,901	$ 16,322	$ 18,071	$ -	$ -	$ -	$ 52,294
FERC 10	$ 48,237	$ 51,312	$ 81,164	$ -	$ -	$ -	$ 180,714
Congestion Expense	$ 6,345	$ (256,032)	$ 3,970,815	$ -	$ -	$ -	$ 3,721,128
FTR Credit	$ 68,872	$ 650,110	$ (5,223,477)	$ -	$ -	$ -	$ (4,504,495)
FTR Expense	$ -	$ -	$ 1,533,794				$ 1,533,794
Net Losses	$ 1,947,145	$ 1,237,411	$ 2,516,135	$ -	$ -	$ -	$ 5,700,692
Revenue Neutrality	$ 247,332	$ 262,929	$ 1,044,421	$ -	$ -	$ -	$ 1,554,682
Rev. Sufficiency Guarantee	$ 51,208	$ 48,584	$ 267,376	$ -	$ -	$ -	$ 367,168
Amortization[3]	$ 110,398	$ 100,163	$ 125,203	$ -	$ -	$ -	$ 335,765
Total	$ 2,705,104	$ 2,313,628	$ 4,650,509	$ -	$ -	$ -	$ 9,669,241

[1] Actual monthly transmission- and ancillary service-related costs for CEI for the 6 months ending September 30, 2008.
[2] Calculation: Sum of 6 monthly values
[3] "Amortization" represents the monthly portion of the deferred transmission- and ancillary service-related costs (and interest). This number is calculated by summing the balances remaining on Companies' books from the previous year's reconciliation. Amortization expense is further split between energy and demand, based upon the costs that were deferred.

Witness: Kevin Warvell

Schedule D-1	Page 3 of 4

TOLEDO EDISON'S TRANSMISSION- AND ANCILLARY SERVICE-RELATED COSTS

Schedule	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Total[2]
1	$ 66,090	$ 67,873	$ 102,459	$ -	$ -	$ -	$ 236,422
2	$ 132,813	$ 136,840	$ 207,699	$ -	$ -	$ -	$ 477,352
3	$ 71,540	$ 73,700	$ 111,865	$ -	$ -	$ -	$ 257,105
4							$ -
5	$ 107,310	$ 110,550	$ 167,797	$ -	$ -	$ -	$ 385,658
6	$ 53,738	$ 55,360	$ 84,028	$ -	$ -	$ -	$ 193,126
7 (69 kv)							$ -
7 (138 kv)							$ -
8 (69 kv)							$ -
8 (138 kv)							$ -
9 (69 kv)	$ 492,867	$ 506,242	$ 936,129	$ -	$ -	$ -	$ 1,935,239
9 (138 kv)	$ 1,410,644	$ 1,376,175	$ 1,764,038	$ -	$ -	$ -	$ 4,550,857
10	$ 128,510	$ 100,407	$ 133,676	$ -	$ -	$ -	$ 362,593
11							$ -
12							$ -
13							$ -
14							$ -
15							$ -
18							$ -
19							$ -
20							$ -
22							$ -
26	$ 4,658	$ 4,670	$ 7,040	$ -	$ -	$ -	$ 16,368
Amortization[3]	$ 393,417	$ 411,694	$ 362,915	$ -	$ -	$ -	$ 1,168,026
Total	$ 2,861,588	$ 2,843,511	$ 3,877,646	$ -	$ -	$ -	$ 9,582,745

Schedule	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Total[2]
3	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	$ -	$ -	$ -	$ -	$ -	$ -	$ -
16	$ 5,406	$ 10,488	$ 14,225	$ -	$ -	$ -	$ 30,120
17	$ 107,813	$ 103,567	$ 164,036	$ -	$ -	$ -	$ 375,416
24	$ 9,760	$ 9,178	$ 10,162	$ -	$ -	$ -	$ 29,100
FERC 10	$ 24,345	$ 25,137	$ 38,538	$ -	$ -	$ -	$ 88,020
Congestion Expense	$ 3,411	$ (143,618)	$ 2,232,896	$ -	$ -	$ -	$ 2,092,688
FTR Credit	$ 37,627	$ 365,630	$ (2,937,301)	$ -	$ -	$ -	$ (2,534,045)
FTR Expense	$ -	$ -	$ 862,494				$ 862,494
Net Losses	$ 1,059,561	$ 895,515	$ 1,414,891	$ -	$ -	$ -	$ 3,169,966
Revenue Neutrality	$ 136,093	$ 147,348	$ 587,306	$ -	$ -	$ -	$ 870,747
Rev. Sufficiency Guarantee	$ 28,060	$ 27,284	$ 150,352	$ -	$ -	$ -	$ 205,696
Amortization[3]	$ 225,080	$ 210,015	$ 262,021	$ -	$ -	$ -	$ 697,116
Total	$ 1,637,156	$ 1,450,543	$ 2,799,619	$ -	$ -	$ -	$ 5,887,319

[1] Actual monthly transmission- and ancillary service-related costs for Toledo Edison for the 6 months *ending September 30, 2008.*
[2] Calculation: Sum of 6 monthly values
[3] "Amortization" represents the monthly portion of the deferred transmission- and ancillary service-related costs (and interest). This number is calculated by summing the balances remaining on Companies' books from the previous year's reconciliation. Amortization expense is further split between energy and demand, based upon the costs that were deferred.

Witness: Kevin Warvell

CALCULATION OF HISTORICAL ALLOCATION BETWEEN DEMAND AND ENERGY COSTS

Company	Company Demand-Based Costs[1]						Total[2]
	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	
OE	$ 7,200,491	$ 6,947,847	$ 9,352,415	$ -	$ -	$ -	$ 23,500,753
CEI	$ 4,064,972	$ 4,103,227	$ 5,724,443	$ -	$ -	$ -	$ 13,892,641
TE	$ 2,861,588	$ 2,843,511	$ 3,877,646	$ -	$ -	$ -	$ 9,582,745
Total	$ 14,127,050	$ 13,894,586	$ 18,954,503	$ -	$ -	$ -	$ 46,976,140

Company	Company Energy-Based Costs[1]						Total[2]
	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	
OE	$ 3,228,776	$ 2,786,611	$ 5,606,711	$ -	$ -	$ -	$ 11,622,097
CEI	$ 2,705,104	$ 2,313,628	$ 4,650,509	$ -	$ -	$ -	$ 9,669,241
TE	$ 1,637,156	$ 1,450,543	$ 2,799,619	$ -	$ -	$ -	$ 5,887,319
Total	$ 7,571,036	$ 6,550,783	$ 13,056,839	$ -	$ -	$ -	$ 27,178,658

Company	TOTAL DEMAND-BASED COSTS	TOTAL ENERGY-BASED COSTS	TOTAL COSTS	DEMAND % OF TOTAL	ENERGY % OF TOTAL
	2008	2008	2008	2008	2008
OE	$ 23,500,753	$ 11,622,097	$ 35,122,851	66.91%	33.09%
CEI	$ 13,892,641	$ 9,669,241	$ 23,561,883	58.96%	41.04%
TE	$ 9,582,745	$ 5,887,319	$ 15,470,064	61.94%	38.06%

Company	Amortization of Deferrals[7]					
	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08
OE	$ 396,755	$ 398,914	$ 401,085	$ -	$ -	$ 1,280,137
CEI	$ 276,295	$ 277,803	$ 279,319	$ -	$ -	$ 817,254
TE	$ 618,497	$ 621,708	$ 624,936	$ -	$ -	$ 828,254

[1] Company demand and energy-based costs are based on actual MISO schedules' bills for each Ohio Operating Company from April 2008 through September 2008.
[2] Calculation: Sum of 6 monthly totals.
[3] Calculation: Sum of 6 monthly totals for the time period April 2008 - September 2008.
[4] Calculation: Sum of 6 monthly totals (demand-based and energy-based).
[5] Calculation: (Total demand-based costs) / (Total Costs). These allocation percentages are referenced in Schedule C-3 as "HDA" to allocate the reconciliation adjustment between demand and energy.
[6] Calculation: (Total energy-based costs) / (Total Costs). These allocation percentages are referenced in Schedule C-3 as "HDA" to allocate the reconciliation adjustment between demand and energy.
[7] Deferral amount amortized by company. These values (taken from company books) are multiplied by the demand and energy allocation percentages above.

Monthly Revenues Collected by Rate Schedule

Schedule D-2	Page 1 of 1

Schedule D-2 provides actual transmission cost recovery rider revenues collected by each rate schedule and used to calculate the reconciliation adjustment.

For the initial filing, revenues will be shown for the 6-month period ending September 30, 2008. For subsequent filings, 12 months of data will be shown.

Ohio Edison Totals [1]

Total Transmission and Ancillary Service Revenue	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Total
RS							$ -
GS							$ -
GP							$ -
GSU							$ -
GT							$ -
LTG							$ -
TOTAL	$ 11,441,728	$ 12,282,791	$ 15,326,865	$ -	$ -	$ -	$ -

CEI Totals [1]

Total Transmission and Ancillary Service Revenue	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Total
RS							$ -
GS							$ -
GP							$ -
GSU							$ -
GT							$ -
LTG							$ -
TOTAL	$ 7,715,172	$ 8,346,534	$ 10,533,958	$ -	$ -	$ -	$ -

Toledo Edison Totals [1]

Total Transmission and Ancillary Service Revenue	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Total
RS							$ -
GS							$ -
GP							$ -
GSU							$ -
GT							$ -
LTG							$ -
TOTAL	$ 4,498,217	$ 4,602,883	$ 5,848,398	$ -	$ -	$ -	$ -

[1] Because these rate schedules will not exist until January 1, 2009, only the total revenues by operating company are shown.

Monthly Over and Under Recovery Amounts

Schedule D-3 | Page 1 of 1

Schedule D-3 provides monthly over and under recovery amounts.

Initially, the reconciliation amount will consist of the unrecovered portion of the April 2007 to March 2008 reconciliation deferral as of December 31, 2008 plus the net over-or under-collection of the TAC, including applicable interest for the 6-month period ending September 30, 2008 allocated to Rate Schedules. Thereafter, the reconciliation amount will consist of the net over- or under-collection of the TAC, including applicable interest, for the 12-month period ending September 30 of each year that immediately precedes the Computation Period.

Values are illustrative for July to September 2008 in order to develop a net reconciliation value of zero at each Operating Company.

Ohio Edison Totals	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Total
Total Transmission and Ancillary Service Revenue [1]	$ 11,441,728	$ 12,282,791	$ 15,326,865	$ 1,951,210	$ 1,951,210	$ 1,951,210	$ 44,905,014
Booked Costs [2]	$ 10,429,266	$ 9,734,459	$ 14,959,126	$ -	$ -	$ -	$ 35,122,851
Net Over / (Under) Collection of TAC [3]	$ 1,012,462	$ 2,548,332	$ 367,739	$ 1,951,210	$ 1,951,210	$ 1,951,210	$ 9,782,163
Interest on Net Over/Under on TAC [4]							$ 654,739
December 31, 2008 Reconciliation Deferral Balance [5]							$ (10,436,902)
Total Over / (Under) Recovery [6]							$ -

CEI Totals	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Total
Total Transmission and Ancillary Service Revenue [1]	$ 7,715,172	$ 8,346,534	$ 10,533,958	$ 827,588	$ 827,588	$ 827,588	$ 29,078,430
Booked Costs [2]	$ 6,770,076	$ 6,416,855	$ 10,374,952	$ -	$ -	$ -	$ 23,561,883
Net Over / (Under) Collection of TAC [3]	$ 945,097	$ 1,929,679	$ 159,006	$ 827,588	$ 827,588	$ 827,588	$ 5,516,547
Interest on Net Over/Under on TAC [4]							$ 387,281
December 31, 2008 Reconciliation Deferral Balance [5]							$ (5,903,827)
Total Over / (Under) Recovery [6]							$ -

Toledo Edison Totals	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Total
Total Transmission and Ancillary Service Revenue [1]	$ 4,498,217	$ 4,602,883	$ 5,848,398	$ 2,440,579	$ 2,440,579	$ 2,440,579	$ 22,271,235
Booked Costs [2]	$ 4,498,744	$ 4,294,055	$ 6,677,265	$ -	$ -	$ -	$ 15,470,064
Net Over / (Under) Collection of TAC [3]	$ (527)	$ 308,828	$ (828,867)	$ 2,440,579	$ 2,440,579	$ 2,440,579	$ 6,801,171
Interest on Net Over/Under on TAC [4]							$ 623,573
December 31, 2008 Reconciliation Deferral Balance [5]							$ (7,424,745)
Total Over / (Under) Recovery [6]							$ -

[1] Transmission and Ancillary Service revenues are based on Operating Company accounting records.
[2] Source: Company books and MISO invoices and amortization of deferrals associated with the prior Reconciliation Adjustment, including applicable interest.
[3] Calculation: Total Transmission and Ancillary Service Revenue - Booked Costs
[4] Source: Schedule D-3a-c. Sum of carrying charges through December 2009.
[5] Projected remaining balance of April 2007 to March 2008 reconciliation deferral as of December 31, 2008, including applicable interest. See Schedule D-3e.
[6] Calculation: Net Over / Under Collection of TAC + Interest on Net Over/Under on TAC + December 31, 2008 Reconciliation Deferral Balance

Witness: Kevin Warvell

Carrying Cost Calculation

Schedule D-3a	Page 1 of 1

Schedule D-3a provides the calculation of carrying costs for Ohio Edison. For the initial filing, interest will be calculated on the net over- or under-collection of the TAC for the 6 month period ending September 30, 2008. Future filings will consist of 12 months of data. Values for July - September 2008 are illustrative.

	Ohio Edison Totals						
	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Total
Net Over / (Under) Collection of TAC [1]	$ 1,012,462	$ 2,548,332	$ 367,739	$ 1,951,210	$ 1,951,210	$ 1,951,210	$ 9,782,163
Interest Base [2]	$ 506,231	2,289,197.13	$ 3,759,690	$ 4,939,623	$ 6,917,713	$ 8,906,567	$ 27,319,021
Carrying Charges [3]	$ 2,569	$ 12,457	$ 20,459	$ 26,880	$ 37,644	$ 48,467	$ 148,475
Total Reconciliation with Carrying Charges [4]	$ 1,015,031	$ 2,560,789	$ 388,198	$ 1,978,090	$ 1,988,854	$ 1,999,677	$ 9,930,639

[1] Source: Schedule D-3
[2] Calculation: (Monthly Difference x 0.5) + Cumulative Balance of the Reconciliation with Carrying Charges
[3] Carrying Charges are applied to the overage/underage each month and interest is compounded monthly. This calculation uses the interest rate authorized by the Commission in the Rate Stabilization Plan Case (Case No. 03-2144-EL-ATA).
[4] Calculation: Net Over / (Under) Collection of TAC + Carrying Charges

Total to be Reconciled through September 2008 [5]	$ 9,930,639
October 2008 Interest [6]	$ 54,039
November 2008 Interest [7]	$ 54,333
December 2008 Interest [8]	$ 54,629
Total to be Reconciled through December 2008 [9]	$ 10,093,640
Incremental Monthly Recovery [10]	$ 841,137
Monthly Nominal Interest Rate	0.54417%
Total Interest Earned January 2009 - December 2009 [13]	$ 343,262

	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09
Balance at end of Month [11]	$ 9,673,072	$ 8,831,935	$ 7,990,799	$ 7,149,662	$ 6,308,525	$ 5,467,389
Interest Earned During Month [12]	$ 52,638	$ 48,347	$ 44,033	$ 39,695	$ 35,334	$ 30,949

	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Total
Balance at end of Month [11]	$ 4,626,252	$ 3,785,115	$ 2,943,978	$ 2,102,842	$ 1,261,705	$ 420,568	$ 60,561,842
Interest Earned During Month [12]	$ 26,540	$ 22,108	$ 17,651	$ 13,170	$ 8,664	$ 4,134	$ 343,262

[5] The total amount to be reconciled, including all carrying charges, through September 2008. Source: Exhibit B-9 page 1. Since the Rider charges are in effect until December 31, 2008, this total earns compounded interest during October, November and December 2008.
[6] Calculation: .0054417 x Total to be Reconciled through September 2008
[7] Calculation: .0054417 x (Total to be Reconciled through September 2008 x (1.0054417))
[8] Calculation: .0054417 x [(Total to be Reconciled through September 2008 x (1.0054417)) x (1.0054417)]
[9] Calculation: Total to be Reconciled for the 12 months ending December 31, 2008
[10] The entire amount to be recovered in the 12 months ending December 31, 2009 is going to be collected on a monthly basis. It is assumed that the total will be recouped in equal monthly increments and that all customers will pay their bills by their respective deadlines (usually 2 weeks). This implies that OE will receive approximately half of the total monthly amount in the month that it is to be billed. Calculation: Total to be Recovered through December 2008 / 12
[11] Calculation: Total to be Recovered through September 2008 - Total Amount recovered through the indicated month
[12] Calculation: .0054417 x (interest earned in previous month(s) + Balance at end of current Month)
[13] Calculation: sum of interest earned *during the* 12 months ended December 31, 2009
[14] Calculation: Total to be Reconciled through September 2008 + (Total Interest earned January *2009 - December 2009*). This value represents the Ohio Edison Total to be Reconciled through the TAC during the time period that the Rider charges will be in effect, the 12 months ending December 2009. This total does not include the projected December 31, 2008 *Transmission Rider* reconciliation deferral balance that will be included in the initial filing.

Witness: Kevin Warvell

Carrying Cost Calculation

Schedule D-3b | Page 1 of 1

Schedule D-3b provides the calculation of carrying costs for CEI. For the initial filing, interest will be calculated on the net over- or under-collection of the TAC for the 6 month period ending September 30, 2008. Future filings will consist of 12 months of data. Values for July - September 2008 are illustrative.

CEI Totals	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Total
Net Over / (Under) Collection of TAC[1]	$ 945,097	$ 1,929,679	$ 159,006	$ 827,588	$ 827,588	$ 827,588	$ 5,516,547
Interest Base[2]	$ 472,548	1,912,515.54	$ 2,967,297	$ 3,476,791	$ 4,323,357	$ 5,174,543	$ 18,327,053
Carrying Charges[3]	$ 2,579	$ 10,439	$ 16,196	$ 18,977	$ 23,598	$ 28,244	$ 100,035
Total Reconciliation with Carrying Charges[4]	$ 947,676	$ 1,940,118	$ 175,203	$ 846,566	$ 851,187	$ 855,833	$ 5,616,582

[1] Source: Schedule D-3
[2] Calculation: (Monthly Difference x 0.5) + Cumulative Balance of the Reconciliation with Carrying Charges
[3] Carrying Charges are applied to the overage/underage each month and interest is compounded monthly. This calculation uses the interest rate authorized by the Commission in the Rate Stabilization Plan Case (Case No. 03-2144-EL-ATA).
[4] Calculation: Net Over / (Under) Collection of TAC + Carrying Charges

Total to be Reconciled through September 2008[5]	$ 5,616,582
October 2008 Interest[6]	$ 30,657
November 2008 Interest[7]	$ 30,825
December 2008 Interest[8]	$ 30,993
Total to be Reconciled through December 2008[9]	$ 5,709,056
Incremental Monthly Recovery[10]	$ 475,755
Monthly Nominal Interest Rate	0.54583%
Total Interest Earned January 2009 - December 2009[13]	$ 194,771
[redacted]	[redacted]

	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09
Balance at end of Month[11]	$ 5,471,179	$ 4,995,424	$ 4,519,670	$ 4,043,915	$ 3,568,160	$ 3,092,406
Interest Earned During Month[12]	$ 29,864	$ 27,430	$ 24,983	$ 22,522	$ 20,048	$ 17,561

	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Total
Balance at end of Month[11]	$ 2,616,651	$ 2,140,896	$ 1,665,141	$ 1,189,387	$ 713,632	$ 237,877	$ 34,254,338
Interest Earned During Month[12]	$ 15,060	$ 12,545	$ 10,017	$ 7,475	$ 4,919	$ 2,349	$ 194,771

[5] The total amount to be reconciled, including all carrying charges, through September 2008. Source: Exhibit B-9 page 1. Since the Rider charges are in effect until December 31, 2008, this total earns compounded interest during October, November and December 2008.
[6] Calculation: .0054583 x Total to be Reconciled through September 2008
[7] Calculation: .0054583 x (Total to be Reconciled through September 2008 x (1.0054583))
[8] Calculation: .0054583 x [(Total to be Reconciled through September 2008 x (1.0054583)) x (1.0054583)]
[9] Calculation: Total to be Reconciled for the 12 months ending December 31, 2008
[10] The entire amount to be recovered in the 12 months ending December 31, 2009 is going to be collected on a monthly basis. It is assumed that the total will be recouped in equal monthly increments and that all customers will pay their bills by their respective deadlines (usually 2 weeks). This implies that OE will receive approximately half of the total monthly amount in the month that it is to be billed. Calculation: Total to be Recovered through December 2008 / 12
[11] Calculation: Total to be Recovered through September 2008 - Total Amount recovered through the indicated month
[12] Calculation: .0054583 x (interest earned in previous month(s) + Balance at end of current Month)
[13] Calculation: sum of interest earned during the 12 months ended December 31, 2009
[14] Calculation: Total to be Reconciled through September 2008 + (Total Interest earned January 2009 - December 2009). This value represents the CEI Total to be Reconciled through the TAC during the time period that the Rider charges will be in effect, the 12 months ending December 2009. This total does not include the projected December 31, 2008 Transmission Rider reconciliation deferral balance that will be included in the initial filing.

Carrying Cost Calculation

Schedule D-3c | Page 1 of 1

Schedule D-3c provides the calculation of carrying costs for Toledo Edison. For the initial filing, interest will be calculated on the net over- or under-collection of the TAC for the 6 month period ending September 30, 2008. Future filings will consist of 12 months of data. Values for July - September 2008 are illustrative.

Toledo Edison Totals	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Total
Net Over / (Under) Collection of TAC [1]	$ 1,012,462	$ 2,548,332	$ 367,739	$ 1,951,210	$ 1,951,210	$ 1,951,210	$ 9,762,163
Interest Base [2]	$ 506,231	2,289,256.21	$ 3,759,177	$ 4,938,168	$ 6,915,016	$ 8,902,126	$ 27,309,974
Carrying Charges [3]	$ 2,628	$ 11,885	$ 19,517	$ 25,637	$ 35,901	$ 46,217	$ 141,785
Total Reconciliation with Carrying Charges [4]	$ 1,015,090	$ 2,560,217	$ 387,255	$ 1,976,848	$ 1,987,111	$ 1,997,427	$ 9,923,949

[1] Source: Schedule D-3
[2] Calculation: (Monthly Difference x 0.5) + Cumulative Balance of the Reconciliation with Carrying Charges
[3] Carrying Charges are applied to the overage/underage each month and interest is compounded monthly. This calculation uses the interest rate authorized by the Commission in the Rate Stabilization Plan Case (Case No. 03-2144-EL-ATA).
[4] Calculation: Net Over / (Under) Collection of TAC + Carrying Charges

Total to be Reconciled through September 2008 [5]	$ 9,923,949
October 2008 Interest [6]	$ 51,522
November 2008 Interest [7]	$ 51,790
December 2008 Interest [8]	$ 52,059
Total to be Reconciled through December 2008 [9]	$ 10,079,319
Incremental Monthly Recovery [10]	$ 839,943
Monthly Nominal Interest Rate	0.51917%
Total Interest Earned January 2009 - December 2009 [13]	$ 326,418
[redacted]	

	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09
Balance at end of Month [11]	$ 9,659,347	$ 8,819,404	$ 7,979,461	$ 7,139,518	$ 6,299,574	$ 5,459,631
Interest Earned During Month [12]	$ 50,148	$ 46,048	$ 41,926	$ 37,783	$ 33,619	$ 29,433

	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Total
Balance at end of Month [11]	$ 4,619,688	$ 3,779,745	$ 2,939,801	$ 2,099,858	$ 1,259,915	$ 419,972	$ 60,475,914
Interest Earned During Month [12]	$ 25,225	$ 20,995	$ 16,743	$ 12,469	$ 8,173	$ 3,855	$ 326,418

[5] The total amount to be reconciled, including all carrying charges, through September 2008. Source: Exhibit B-9 page 1. Since the Rider charges are in effect until December 31, 2008, this total earns compounded interest during October, November and December 2008.
[6] Calculation: .0051917 x Total to be Reconciled through September 2008
[7] Calculation: .0051917 x (Total to be Reconciled through September 2008 x (1.0051917))
[8] Calculation: .0051917 x [(Total to be Reconciled through September 2008 x (1.0051917)) x (1.0051917)]
[9] Calculation: Total to be Reconciled for the 12 months ending December 31, 2008
[10] The entire amount to be recovered in the 12 months ending December 31, 2009 is going to be collected on a monthly basis. It is assumed that the total will be recouped in equal monthly increments and that all customers will pay their bills by their respective deadlines (usually 2 weeks). This implies that OE will receive approximately half of the total monthly amount in the month that it is to be billed. Calculation: Total to be Recovered through December 2008 / 12
[11] Calculation: Total to be Recovered through September 2008 - Total Amount recovered through the indicated month
[12] Calculation: .0051917 x (Interest earned in previous month(s) + Balance at end of current Month)
[13] Calculation: sum of interest earned during the 12 months ended December 31, 2009
[14] Calculation: Total to be Reconciled through September 2008 + (Total Interest earned January 2009 - December 2009). This value represents the Toledo Edison Total to be Reconciled through the TAC during the time period that the Rider charges will be in effect, the 12 months ending December 2009. This total does not include the projected December 31, 2008 Transmission Rider reconciliation deferral balance that will be included in the initial filing.

Commercial Activity Tax Schedule

Schedule D-3d | **Page 1 of 1**

Schedule D-3d provides the calculations for the weighted CAT rate for 12 months in which the Rider charges will be in effect.

Tax Period	Base Tax Rate	Phase-in Percentage	*Effective Rate
July 1, 2005 to December 31, 2005	0.06%	N/A	0.0600%
January 1, 2006 to March 31, 2006	0.26%	23%	0.0598%
April 1, 2006 to March 31, 2007	0.26%	40%	0.1040%
April 1, 2007 to March 31, 2008	0.26%	60%	0.1560%
April 1, 2008 to March 31, 2009	0.26%	80%	0.2080%
After March 31, 2009	0.26%	100%	0.2600%

Source: http://tax.ohio.gov/divisions/communications/documents/faqs_commericial_activity_tax.pdf

	Months Effective	Effective Rate	Weighted Rate
January 1 to March 31, 2009	3	0.2080%	0.6240%
After March 31, 2009	9	0.2600%	2.3400%
January 1 to December 31, 2009	12	**0.2470%**	2.9640%

The effective CAT rate for the period January 1 to December 31, 2009 is 0.2470%.

Witness: Kevin Warvell

Projected Balance of Reconciliation Deferral

Schedule D-3e | Page 1 of 1

Schedule D-3e provides the calculations supporting the projected balance of the unrecovered portion of the April 2007 to March 2008 reconciliation deferral from the May 1, 2008 filing as of December 31, 2008.

Ohio Edison

	Total Beg. Deferred Balance G/L 182356 dr (cr)	Interest Monthly Rate	Interest Calc G/L 407518 cr (dr) CCtr 408048 offset 182356	Deferred Balance + Interest Expense	# of months remaining amortization period	Amortization Expense G/L 407375 dr (cr) CCtr 408048 offset 182356	Total Ending Deferred Balance G/L 182356 dr (cr)	Cumulative Interest	Cumulative Amortizations
Jul-08	20,205,069.10	0.0054417	109,949.25	20,315,018.35	12	1,692,918.20	18,622,100.15	109,949.25	1,692,918.20
Aug-08	18,622,100.15	0.0054417	101,335.26	18,723,435.41	11	1,702,130.49	17,021,304.92	211,284.51	3,395,048.69
Sep-08	17,021,304.92	0.0054417	92,624.27	17,113,929.19	10	1,711,392.92	15,402,536.27	303,908.78	5,106,441.61
Oct-08	15,402,536.27	0.0054417	83,815.47	15,486,351.74	9	1,720,705.75	13,765,645.99	387,724.25	6,827,147.36
Nov-08	13,765,645.99	0.0054417	74,908.06	13,840,554.05	8	1,730,069.26	12,110,484.79	462,632.31	8,557,216.62
Dec-08	12,110,484.79	0.0054417	65,901.22	12,176,386.01	7	1,739,483.72	[redacted]	528,533.53	10,296,700.34
Jan-09	10,436,902.29	0.0054417	56,794.14	10,493,696.43	6	1,748,949.41	8,744,747.02	585,327.67	12,045,649.75
Feb-09	8,744,747.02	0.0054417	47,586.00	8,792,333.02	5	1,758,466.60	7,033,866.42	632,913.67	13,804,116.35
Mar-09	7,033,866.42	0.0054417	38,275.96	7,072,142.38	4	1,768,035.60	5,304,106.78	671,189.63	15,572,151.95
Apr-09	5,304,106.78	0.0054417	28,863.18	5,332,969.96	3	1,777,656.65	3,555,313.31	700,052.81	17,349,808.60
May-09	3,555,313.31	0.0054417	19,346.83	3,574,660.14	2	1,787,330.07	1,787,330.07	719,399.64	19,137,138.67
Jun-09	1,787,330.07	0.0054417	9,726.05	1,797,056.12	1	1,797,056.12	0.00	729,125.69	20,934,194.79

Cleveland Electric Illuminating

	Total Beg. Deferred Balance G/L 182356 dr (cr)	Interest Monthly Rate	Interest Calc G/L 407518 cr (dr) CCtr 428048 offset G/L 182356	Deferred Balance + Interest Expense	# of months remaining amortization period	Amortization Expense G/L 407375 dr (cr) CCtr 428048 offset G/L 182356	Total Ending Deferred Balance G/L 182356 dr (cr)	Cumulative Interest	Cumulative Amortizations
Jul-08	11,428,237.78	0.0054583	62,378.75	11,490,616.53	12	957,551.38	10,533,065.15	62,378.75	957,551.38
Aug-08	10,533,065.15	0.0054583	57,492.63	10,590,557.78	11	962,777.98	9,627,779.80	119,871.38	1,920,329.36
Sep-08	9,627,779.80	0.0054583	52,551.31	9,680,331.11	10	968,033.11	8,712,298.00	172,422.69	2,888,362.47
Oct-08	8,712,298.00	0.0054583	47,554.34	8,759,852.34	9	973,316.93	7,786,535.41	219,977.03	3,861,679.40
Nov-08	7,786,535.41	0.0054583	42,501.25	7,829,036.66	8	978,629.58	6,850,407.08	262,478.28	4,840,308.98
Dec-08	6,850,407.08	0.0054583	37,391.58	6,887,798.66	7	983,971.24	[redacted]	299,869.86	5,824,280.22
Jan-09	5,903,827.42	0.0054583	32,224.86	5,936,052.28	6	989,342.05	4,946,710.23	332,094.72	6,813,622.27
Feb-09	4,946,710.23	0.0054583	27,000.63	4,973,710.86	5	994,742.17	3,978,968.69	359,095.35	7,808,364.44
Mar-09	3,978,968.69	0.0054583	21,718.40	4,000,687.09	4	1,000,171.77	3,000,515.32	380,813.75	8,808,536.21
Apr-09	3,000,515.32	0.0054583	16,377.71	3,016,893.03	3	1,005,631.01	2,011,262.02	397,191.46	9,814,167.22
May-09	2,011,262.02	0.0054583	10,978.07	2,022,240.09	2	1,011,120.05	1,011,120.04	408,169.53	10,825,287.27
Jun-09	1,011,120.04	0.0054583	5,519.00	1,016,639.04	1	1,016,639.04	(0.00)	413,688.53	11,841,926.31

Toledo Edison

	Total Deferred Balance G/L 182356	Interest Monthly Rate	Interest Calc G/L 407518 cr (dr) CCtr 418048 offset G/L 182356	Deferred Balance + Interest Expense	# of months remaining amortization period	Amortization Expense G/L 407375 dr (cr) CCtr 418048 offset G/L 182356	Deferred Balance net of amort expense	Cumulative Interest	Cumulative Amortizations
Jul-08	14,395,214.77	0.0051917	74,735.64	14,469,950.41	12	1,205,829.20	13,264,121.21	74,735.64	1,205,829.20
Aug-08	13,264,121.21	0.0051917	68,863.34	13,332,984.55	11	1,212,089.50	12,120,895.05	143,598.98	2,417,918.70
Sep-08	12,120,895.05	0.0051917	62,928.05	12,183,823.10	10	1,218,382.31	10,965,440.79	206,527.03	3,636,301.01
Oct-08	10,965,440.79	0.0051917	56,929.28	11,022,370.07	9	1,224,707.79	9,797,662.28	263,456.31	4,861,008.80
Nov-08	9,797,662.28	0.0051917	50,866.52	9,848,528.80	8	1,231,066.10	8,617,462.70	314,322.83	6,092,074.90
Dec-08	8,617,462.70	0.0051917	44,739.28	8,662,201.98	7	1,237,457.43	[redacted]	359,062.11	7,329,532.33
Jan-09	7,424,744.55	0.0051917	38,547.05	7,463,291.60	6	1,243,881.93	6,219,409.67	397,609.16	8,573,414.26
Feb-09	6,219,409.67	0.0051917	32,289.31	6,251,698.98	5	1,250,339.80	5,001,359.18	429,898.47	9,823,754.06
Mar-09	5,001,359.18	0.0051917	25,965.56	5,027,324.74	4	1,256,831.19	3,770,493.55	455,864.03	11,080,585.25
Apr-09	3,770,493.55	0.0051917	19,575.27	3,790,068.82	3	1,263,356.27	2,526,712.55	475,439.30	12,343,941.52
May-09	2,526,712.55	0.0051917	13,117.93	2,539,830.48	2	1,269,915.24	1,269,915.24	488,557.23	13,613,856.76
Jun-09	1,269,915.24	0.0051917	6,593.02	1,276,508.26	1	1,276,506.26	0.00	495,150.25	14,890,365.02

Schedule D-3f provides Reconciliation of one month's bill from the RTO (MISO) to Financial Records of the Operating Company.

For the initial filing, the reconciliation from MISO bills to the Company's financials has been shown for March 2008.

Pages 2-4 of Schedule D-3f provide support for demand-related MISO invoices, while pages 5-74 provide support for energy-related MISO invoices. Pages 75-81 are screen shots of the general ledger account information for each MISO schedule for the month of March. They are arranged in the same order as the line items in the May 1, 2008 Transmission Rider Exhibit B-6, however:

- Schedule 9 is separate on B-6, but it is combined into one G/L account.
- Schedule 10 is one item on B-6, and is comprised of three G/L accounts.
- Revenue Sufficiency Guarantee (RSG) is one item on B-6, and is comprised of two G/L accounts.

In each screen shot, the lighter yellow lines show the total JA (Journal entry for the accrual, which represents the current month's estimate as well as a November 2008 peak adjustment), JC (Cash activities), JE (Journal entry for the previous month's actuals, which therefore tie to the previous month's invoices), and JX (reversal of the previous month's estimate). The sum of the four parts is on the darker yellow/orange line, which ties to what was filed on May 1.

For example, the MISO Schedule 1 journal entries are as follows:
JA = 463,135.72 (Estimate of March 2008 expenses)
JC = - 1,397.93 (Cash adjustments)
JE = 438,639.92 (February 2008 actuals - see MISO invoice)
JX = - 451,468.65 (Reversal of February 2008 estimate)
These all add to 448,909, which ties to Exhibit B-6, page 2 of 9 (cell G67 in the Excel spreadsheet).

The other MISO expense schedules follow similarly.

MidwestISO
Energizing the Heartland

MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR, INC.

Invoice

Invoice Number: 8065056802

Attn: Accounts Payable
FIRSTENERGY SERVICE COMPANY
395 GHENT ROAD
AKRON OH 44333

Date	07-MAR-08
Customer ID	FESR
Purchase Order	

Description	Total
Schedule 01 Charges for Billing Period February	$ 438,639.92
Schedule 02 Charges for Billing Period February	884,347.09
Schedule 03 Charges for Billing Period February	476,299.24
Schedule 05 Charges for Billing Period February	714,448.87
Schedule 06 Charges for Billing Period February	357,774.86
Schedule 11 Charges for Billing Period February	0.00
Schedule 22 Charges for Billing Period February	0.00
TOTAL	$ 2,871,509.98

Midwest ISO, as agent for Transmission Owners, is submitting this invoice for transactions on the Transmission System of the Midwest ISO, and as agent is obligated to collect and distribute monies for transmission service from customers in accordance with the OATT and the Owners Agreement.

Electronic Payment Instructions:

ACH Payments
JP Morgan Chase Bank, NA
Indianapolis, IN
ABA: 074000010
ACCT: 633708425

Wire Instructions
JP Morgan Chase Bank, NA
Indianapolis, IN
ABA: 021000021
ACCT: 633708425

International Wire Instructions
JP Morgan Chase Bank, NA
Indianapolis, IN
Swift Code: CHASUS33
ABA: 021000021
ACCT: 633708425

Remittance Information:

Payment Terms	7 NET
Invoice Due Date	14-MAR-08

If the invoice due date falls on a Saturday, Sunday or holiday, the invoice payment is due on the following business day.

Remittance Address	Midwest ISO Accounts Receivable P.O. Box 4202 Carmel, IN 46082-4202
Billing Customer Service	AccountsReceivable@Midwestiso.org

MidwestISO
Energizing the Heartland

MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR, INC.

Invoice

Invoice Number: 8065056801

Attn: Accounts Payable
FIRSTENERGY SERVICE COMPANY
395 GHENT ROAD
AKRON OH 44333

Date	07-MAR-08
Customer ID	FESR
Purchase Order	

Description	Total
Schedule 07 Charges for Billing Period February	$ 0.00
Schedule 08 Charges for Billing Period February	0.00
Schedule 09 Charges for Billing Period February	11,792,672.40
Schedule 18 Charges for Billing Period February	0.00
Schedule 19 Charges for Billing Period February	0.00
Schedule 21 Charges for Billing Period February	0.00
Schedule 26 Charges for Billing Period February	30,183.05
TOTAL	$ 11,822,855.45

Midwest ISO, as agent for Transmission Owners, is submitting this invoice for transactions on the Transmission System of the Midwest ISO, and as agent is obligated to collect and distribute monies for transmission service from customers in accordance with the OATT and the Owners Agreement.

Electronic Payment Instructions: *** **ATTENTION: This payment must be sent to the trust account noted below.** ***

ACH Payments	Wire Instructions	International Wire Instructions
JP Morgan Chase Bank, NA	JP Morgan Chase Bank, NA	JP Morgan Chase Bank, NA
Indianapolis, IN	Indianapolis, IN	Indianapolis, IN
ABA: 074000010	ABA: 021000021	Swift Code: CHASUS33
ACCT: 708360607	ACCT: 708360607	ABA: 021000021
		ACCT: 708360607

Remittance Information:

Payment Terms	7 NET
Invoice Due Date	14-MAR-08

If the invoice due date falls on a Saturday, Sunday or holiday, the invoice payment is due on the following business day.

Remittance Address	Midwest ISO Accounts Receivable P.O. Box 4202 Carmel, IN 46082-4202
Billing Customer Service	AccountsReceivable@Midwestiso.org

MidwestISO
Energizing the Heartland

MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR, INC.

Invoice

Invoice Number: 8065056810

Attn: Accounts Payable
FIRSTENERGY SERVICE COMPANY
395 GHENT ROAD
AKRON OH 44333

Date	07-MAR-08
Customer ID	FESR
Purchase Order	

Description	Total
Schedule 10 FERC Demand Charges for February NITS -- 5,356,496.02 mWh * $0.0313 =	$ 167,658.33
Schedule 10 FERC Demand Credits for February NITS -- -130,848 mWh * $0.0313 =	(4,095.55)
Schedule 10 Demand Charges for February Customer NITS -- 5,356,496.02 mWh * $0.0447 =	239,435.37
Schedule 10 Energy Charges for February Customer NITS -- 4,314,657.54 mWh * $0.0841 =	362,862.70
TOTAL	$ 765,860.85

Electronic Payment Instructions:

ACH Payments
JP Morgan Chase Bank, NA
Indianapolis, IN
ABA: 074000010
ACCT: 633708425

Wire Instructions
JP Morgan Chase Bank, NA
Indianapolis, IN
ABA: 021000021
ACCT: 633708425

International Wire Instructions
JP Morgan Chase Bank, NA
Indianapolis, IN
Swift Code: CHASUS33
ABA: 021000021
ACCT: 633708425

Remittance Information:

Payment Terms	7 NET
Invoice Due Date	14-MAR-08

If the invoice due date falls on a Saturday, Sunday or holiday, the invoice payment is due on the following business day.

Remittance Address	Midwest ISO Accounts Receivable P.O. Box 4202 Carmel, IN 46082-4202
Billing Customer Service	AccountsReceivable@Midwestiso.org

2008

Midwest ISO
We manage power.

MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR, INC.
P.O. Box 4202
Carmel, IN 46082-4202

Invoice

Market Participant: Firstenergy Service Company
395 Ghent Road
Akron,OH 44333

Invoice Number: 1077720

For Statements Issued: 02/09/2008 - 02/15/2008

Invoice Date: 02/19/2008

Participant ID: FESR

Payment Due Date: 02/26/2008

Invoice Type: Administration Fee Invoice

Invoice Summary:	**Total:**
Current Net (Revenue)/Charge of Real Time and Day Ahead Markets:	**$98,057.25**
S55 Prior Period Adjustments:	**(18.35)**
S105 Prior Period Adjustments:	**45.05**
Other Adjustments:	**0.00**
Total Net Charge (Revenue):	**$98,083.95**

The Net Charge for this invoice is greater than the Net Revenue. Please make payment in immediately available funds on the payment due date.

Electronic Banking Instructions:

ACH Payments

JP Morgan Chase Bank, NA
Indianapolis, IN
ABA: 074000010
ACCT: 693193260

Wire Instructions

JP Morgan Chase Bank, NA
Indianapolis, IN
ABA: 021000021
ACCT: 693193260

International Wire Instructions

JP Morgan, Chase Bank, NA
Indianapolis, IN
Swift Code: CHASUS33
ABA: 021000021
ACCT: 693193260

For all inquiries contact:

MISO Accounts Receivable
accountsreceivable@midwestiso.org

Midwest ISO
We manage power.

MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR, INC.
P.O. Box 4202
Carmel, IN 46082-4202

Invoice

Market Participant: Firstenergy Service Company
395 Ghent Road
Akron,OH 44333

Invoice Number: 1077720

For Statements Issued: 02/09/2008 - 02/15/2008

Invoice Date: 02/19/2008

Participant ID: FESR

Invoice Type: Administration Fee Invoice

Payment Due Date: 02/26/2008

	Description	Settlement Date	Operating Date	Real-Time	Day-Ahead	Other	Total
Billing Period: Current (S7 and S14)							
S7	Market Administration Amount	02/02/2008	01/26/2008	$155.27	$11,145.76	$0.00	$11,301.03
S7	Market Administration Amount	02/03/2008	01/27/2008	134.25	10,524.05	0.00	10,658.30
S7	Market Administration Amount	02/04/2008	01/28/2008	324.65	11,671.64	0.00	11,996.29
S7	Market Administration Amount	02/05/2008	01/29/2008	146.42	11,637.38	0.00	11,783.80
S7	Market Administration Amount	02/06/2008	01/30/2008	235.44	12,582.55	0.00	12,817.99
S7	Market Administration Amount	02/07/2008	01/31/2008	274.64	12,480.64	0.00	12,755.28
S7	Market Administration Amount	02/08/2008	02/01/2008	174.75	15,088.37	0.00	15,263.12
S7	Transmission Rights Market Administration Amount	02/02/2008	01/26/2008	0.00	0.00	1,629.84	1,629.84
S7	Transmission Rights Market Administration Amount	02/03/2008	01/27/2008	0.00	0.00	1,629.84	1,629.84
S7	Transmission Rights Market Administration Amount	02/04/2008	01/28/2008	0.00	0.00	1,650.16	1,650.16
S7	Transmission Rights Market Administration Amount	02/05/2008	01/29/2008	0.00	0.00	1,650.16	1,650.16
S7	Transmission Rights Market Administration Amount	02/06/2008	01/30/2008	0.00	0.00	1,650.16	1,650.16
S7	Transmission Rights Market Administration Amount	02/07/2008	01/31/2008	0.00	0.00	1,650.16	1,650.16
S7	Transmission Rights Market Administration Amount	02/08/2008	02/01/2008	0.00	0.00	1,621.12	1,621.12
Total Net (Revenue)/Charge of Real Time and Day Ahead Markets:				$1,445.42	$85,130.39	$11,481.44	$98,057.25

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Payment Due Date: 02/26/2008

Description	Settlement Date	Operating Date	Real-Time	Day-Ahead	Other	Total
Billing Period: S55						
Market Administration Amount	02/09/2008	12/16/2007	$5.18	$0.00	$0.00	$5.18
Market Administration Amount	02/10/2008	12/17/2007	(22.72)	0.00	0.00	(22.72)
Market Administration Amount	02/11/2008	12/18/2007	2.90	0.00	0.00	2.90
Market Administration Amount	02/12/2008	12/19/2007	48.49	0.00	0.00	48.49
Market Administration Amount	02/13/2008	12/20/2007	19.92	0.00	0.00	19.92
Market Administration Amount	02/14/2008	12/21/2007	(50.72)	0.00	0.00	(50.72)
Market Administration Amount	02/15/2008	12/22/2007	(21.40)	0.00	0.00	(21.40)
Total Net (Revenue)/Charge of Real Time and Day Ahead Markets:			($18.35)	$0.00	$0.00	($18.35)

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Invoice Date: 02/19/2008

Participant ID: FESR

Invoice Type: Administration Fee Invoice

Payment Due Date: 02/26/2008

Description	Settlement Date	Operating Date	Real-Time	Day-Ahead	Other	Total
Billing Period: S105						
Market Administration Amount	02/09/2008	10/27/2007	$1.79	$0.00	$0.00	$1.79
Market Administration Amount	02/10/2008	10/28/2007	4.65	0.00	0.00	4.65
Market Administration Amount	02/11/2008	10/29/2007	5.10	0.00	0.00	5.10
Market Administration Amount	02/12/2008	10/30/2007	8.07	0.00	0.00	8.07
Market Administration Amount	02/13/2008	10/31/2007	5.34	0.00	0.00	5.34
Market Administration Amount	02/14/2008	11/01/2007	10.25	0.00	0.00	10.25
Market Administration Amount	02/15/2008	11/02/2007	9.85	0.00	0.00	9.85
Total Net (Revenue)/Charge of Real Time and Day Ahead Markets:			$45.05	$0.00	$0.00	$45.05

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MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR, INC.
P.O. Box 4202
Carmel, IN 46082-4202

2008

Invoice

Market Participant: Firstenergy Service Company
395 Ghent Road
Akron,OH 44333

Invoice Number: 1077719

For Statements Issued: 02/09/2008 - 02/15/2008

Invoice Date: 02/19/2008

Participant ID: FESR

Payment Due Date: 02/26/2008

Invoice Type: Market Invoice

Invoice Summary:	**Total:**
Current Net (Revenue)/Charge of Real Time and Day Ahead Markets:	**$3,928,124.62**
S55 Prior Period Adjustments:	**(293,089.73)**
S105 Prior Period Adjustments:	**(34,213.15)**
Other Adjustments:	**0.00**
Total Net Charge (Revenue):	**$3,600,821.74**

The Net Charge for this invoice is greater than the Net Revenue. Please make payment in immediately available funds on the payment due date.

Electronic Banking Instructions:

ACH Payments

JP Morgan Chase Bank, NA
Indianapolis, IN
ABA: 074000010
ACCT: 693193260

Wire Instructions

JP Morgan Chase Bank, NA
Indianapolis, IN
ABA: 021000021
ACCT: 693193280

International Wire Instructions

JP Morgan, Chase Bank, NA
Indianapolis, IN
Swift Code: CHASUS33
ABA: 021000021
ACCT: 693193260

For all inquiries contact:

MISO Accounts Receivable
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Invoice

Market Participant: Firstenergy Service Company
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Akron,OH 44333

Invoice Number: 1077719

For Statements Issued: 02/09/2008 - 02/15/2008

Invoice Date: 02/19/2008

Participant ID: FESR

Invoice Type: Market Invoice

Payment Due Date: 02/26/2008

Billing Period: Current (S7 and S14)

	Description	Settlement Date	Operating Date	Real-Time	Day-Ahead	Other	Total
S7	Asset Energy Amount	02/02/2008	01/26/2008	$88,031.87	$0.00	$0.00	$88,031.87
S7	Asset Energy Amount	02/03/2008	01/27/2008	20,787.65	0.00	0.00	20,787.85
S7	Asset Energy Amount	02/04/2008	01/28/2008	225,742.27	0.00	0.00	225,742.27
S7	Asset Energy Amount	02/05/2008	01/29/2008	12,200.59	0.00	0.00	12,200.59
S7	Asset Energy Amount	02/06/2008	01/30/2008	(18,211.32)	0.00	0.00	(18,211.32)
S7	Asset Energy Amount	02/07/2008	01/31/2008	217,687.77	0.00	0.00	217,687.77
S7	Asset Energy Amount	02/08/2008	02/01/2008	122,118.54	0.00	0.00	122,118.54
S7	Distribution of Losses Amount	02/02/2008	01/26/2008	(86,403.51)	0.00	0.00	(86,403.51)
S7	Distribution of Losses Amount	02/03/2008	01/27/2008	(61,621.56)	0.00	0.00	(61,621.56)
S7	Distribution of Losses Amount	02/04/2008	01/28/2008	(84,154.86)	0.00	0.00	(84,154.86)
S7	Distribution of Losses Amount	02/05/2008	01/29/2008	(86,604.74)	0.00	0.00	(86,604.74)
S7	Distribution of Losses Amount	02/06/2008	01/30/2008	(161,790.74)	0.00	0.00	(161,790.74)
S7	Distribution of Losses Amount	02/07/2008	01/31/2008	(181,808.36)	0.00	0.00	(181,808.36)
S7	Distribution of Losses Amount	02/08/2008	02/01/2008	(124,741.11)	0.00	0.00	(124,741.11)
S7	Financial Bilateral Transaction Congestion Amount	02/02/2008	01/26/2008	0.00	1,386,436.61	0.00	1,386,436.61
S7	Financial Bilateral Transaction Congestion Amount	02/03/2008	01/27/2008	0.00	459,051.64	0.00	459,051.64
S7	Financial Bilateral Transaction Congestion Amount	02/04/2008	01/28/2008	0.00	1,314,302.52	0.00	1,314,302.52
S7	Financial Bilateral Transaction Congestion Amount	02/05/2008	01/29/2008	0.00	141,468.92	0.00	141,468.92
S7	Financial Bilateral Transaction Congestion Amount	02/06/2008	01/30/2008	0.00	951,934.74	0.00	951,934.74
S7	Financial Bilateral Transaction Congestion Amount	02/07/2008	01/31/2008	0.00	231,955.57	0.00	231,955.57
S7	Financial Bilateral Transaction Congestion Amount	02/08/2008	02/01/2008	0.00	(43,170.17)	0.00	(43,170.17)
S7	Financial Bilateral Transaction Loss Amount	02/02/2008	01/26/2008	0.00	262,775.06	0.00	262,775.06
S7	Financial Bilateral Transaction Loss Amount	02/03/2008	01/27/2008	0.00	188,182.10	0.00	188,182.10
S7	Financial Bilateral Transaction Loss Amount	02/04/2008	01/28/2008	0.00	282,624.04	0.00	282,624.04
S7	Financial Bilateral Transaction Loss Amount	02/05/2008	01/29/2008	0.00	261,707.44	0.00	261,707.44
S7	Financial Bilateral Transaction Loss Amount	02/06/2008	01/30/2008	0.00	458,267.71	0.00	458,267.71
S7	Financial Bilateral Transaction Loss Amount	02/07/2008	01/31/2008	0.00	472,926.96	0.00	472,926.96
S7	Financial Bilateral Transaction Loss Amount	02/08/2008	02/01/2008	0.00	353,831.06	0.00	353,831.06
S7	Net Inadvertent Distribution Amount	02/02/2008	01/26/2008	(2,749.21)	0.00	0.00	(2,749.21)
S7	Net Inadvertent Distribution Amount	02/03/2008	01/27/2008	(1,422.91)	0.00	0.00	(1,422.91)

Total Net (Revenue)/Charge of Real Time and Day Ahead Markets:

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