Large Filing Separator Sheet

Case Number: 09-256-EL-UNC

Date Filed: 3/27/2009

Section: 2 of 2

Number of Pages: 135

Description of Document: Application for approval of transmission cost recovery rider

THE DAYTON POWER AND LIGHT COMPANY
CASE NO. 09-256-EL-UNC

Transmission Cost Recovery Rider (TCRR)

Schedule B-1
Total Projected Jurisdictional
TCRR Net Costs

The Dayton Pow Company

Part 2

13b

The Dayton Power and Light Company
Case No. 09-256-EL-UNC
Summary of Projected Jurisdictional TCRR Net Costs
August 2008 - April 2010
(Revenue)/Expense in $

Schedule B-1
Page 1 of 1
Witness Responsible:
Sharon Schroder

Data: Actual and Forecasted
Type of Filing: Original
Work Paper Reference No(s).: None

Line (A)	Description (B)	Demand/Energy (C)	Total Deferral & Carrying Costs to be collected May 09-Apr 10 (D) Schedule C-1a, Page 2 Col (J)	"Current" Cycle Total May 09-Apr 10 (E) Schedule C-1, Page 2 Col (H)	Total Costs/Revenues May 09-Apr 10 (F) = (D) + (E)
1	Transmission Enhancement Charges (RTEP)	Demand	$ 491,899	$ 465,952	$ 957,851
2	Alliance RTO Start-up Costs	Energy	$ -	$ 3,990,576	$ 3,990,576
3	Reactive Supply and Voltage Control from Gen Sources	Reactive Demand	$ (506,321)	$ 4,231,876	$ 3,725,555
4	Regulation	Energy	$ 1,572,338	$ 10,353,763	$ 11,926,101
5	Synchronized (Spinning) Reserves	Energy	$ (1,670,002)	$ 108,814	$ (1,561,188)
6	Operating Reserves	Energy	$ (82,763)	$ 6,369,946	$ 6,287,183
7	RTO Start-up Cost Recovery - AEP zone	Energy	$ 71	$ 89	$ 159
8	Synchronous Condensing	Energy	$ 55,367	$ 86,832	$ 142,199
9	Reliability Pricing Model (RPM)[1]	Demand	$ 9,445,971	$ 32,587,465	$ 42,033,436
10	Black Start Service	Energy	$ 42,049	$ 109,773	$ 151,821
11	PJM Annual Membership Fee	Energy	$ 1,935	$ 3,870	$ 5,805
12	TO Scheduling System Control and Dispatch Service	Energy	$ (63,469)	$ 1,178,458	$ 1,114,989
13	NERC/RFC Charges	Energy	$ 86,416	$ 212,446	$ 298,863
14	PJM Default Charges	Energy	$ 52,196	$ -	$ 52,196
15	Transmission Congestion	Energy	$ (349,040)	$ 410,059	$ 61,018
16	Generation Loss Factor	Energy	$ (1,635,259)	$ (4,588,568)	$ (6,223,826)
17	Transmission Losses	Energy	$ 7,543,392	$ 5,357,424	$ 12,900,816
18	Firm PTP Transmission Service	Demand	$ (425,158)	$ (2,323,741)	$ (2,748,899)
19	Non-Firm PTP Transmission Service	Demand	$ (188,067)	$ (509,619)	$ (697,686)
20	Network Integration Transmission Service	Demand	$ 357,461	$ 40,796,102	$ 41,153,562
21	FTR/ARR Auction	Energy	$ (1,712,138)	$ (4,189,498)	$ (5,901,635)
22	Expansion Cost Recovery Charges (ECRC)	Energy	$ (99,338)	$ (265,452)	$ (364,790)
23	PJM Scheduling System Control and Dispatch Service (Admin Fee)	Energy	$ (586,592)	$ 2,620,170	$ 2,033,578
24	PUCO Consultant fees	Energy	$ -	$ -	$ -
25	SubTotal		$ 12,330,847	$ 97,006,736	$ 109,337,683
26					
27	TCRR Deferral carrying costs		$ 1,410,519	$ -	$ 1,410,519
28	SubTotal		$ 13,741,465	$ 97,006,736	$ 110,748,202
29					
30	Gross Revenue Conversion Factor [2]		$ 1.021	$ 1.021	$ 1.021
31					
32	**Totals Including carrying costs (Line 28 * Line 30)**		**$ 14,030,036**	**$ 99,043,878**	**$ 113,073,914**

[1] RPM includes the following PJM invoice line items: Locational Reliability Charges, Capacity Resource Deficiency, RPM Auction Revenues, Generation Resource Rating Test, and Peak Hour Period Availability

[2] Case No. 08-1094, Schedule A-4, Col (C), Line 28

THE DAYTON POWER AND LIGHT COMPANY
CASE NO. 09-256-EL-UNC

Transmission Cost Recovery Rider (TCRR)

Schedule B-2
Current vs Proposed Revenues

The Dayton Power & Light Company

The Dayton Power and Light Company
Case No. 09-256-EL-UNC
Summary of Current versus Proposed Revenues

Data: Forecasted
Type of Filing: Original
Work Paper Reference No(s).: WPB-2

Schedule B-2
Page 1 of 1
Witness Responsible:
Sharon Schroder

May 2009 - April 2010

Line (A)	Tariff Class (B)	Forecasted Standard Offer Billing Determinants (C) WPB-2, Col (C)	Current TCRR Rate (D)	Current TCRR-related Revenue (E) WPB-2, Col (R)	Proposed TCRR Rate (F) Schedule C-3	Proposed TCRR Revenue (G) = (C) * (F)	$ Difference (H) = (G) - (E)	% Difference (I) = (H) / (E)
1	Residential	3,695,004,444 kWh	n/a	$ 16,402,125	$ 0.00852	$ 31,486,943	$ 15,084,819	91.97%
2	Residential Heat	1,921,827,265 kWh	n/a	$ 8,530,991	$ 0.00851	$ 16,357,575	$ 7,826,584	91.74%
3	Secondary[1]	530,228,586 kWh	n/a	$ 2,353,685	$ 0.00665	$ 3,525,956	$ 1,172,272	49.81%
4		10,624,898 kW	n/a	$ 20,974,185	$ 4.05765	$ 43,112,075	$ 22,137,890	105.55%
5	Primary	1,642,467,340 kWh	n/a	$ 638,920	$ 0.00034	$ 563,990	$ (74,929)	-11.73%
6		4,857,645 kW	n/a	$ 8,883,467	$ 2.93185	$ 14,241,893	$ 5,358,427	60.32%
7		2,877,987 kVar	n/a	$ 863,396	$ 0.20876	$ 600,795	$ (262,601)	-30.41%
8	Substation	96,192,490 kWh	n/a	$ 37,419	$ 0.00033	$ 32,106	$ (5,313)	-14.20%
9		267,219 kW	n/a	$ 488,679	$ 3.03410	$ 810,767	$ 322,088	65.91%
10		122,844 kVar	n/a	$ 36,853	$ 0.27842	$ 34,202	$ (2,651)	-7.19%
11	High Voltage	106,702,698 kWh	n/a	$ 41,507	$ 0.00031	$ 33,275	$ (8,232)	-19.83%
12		278,483 kW	n/a	$ 509,279	$ 3.01732	$ 840,274	$ 330,995	64.99%
13		179,864 kVar	n/a	$ 53,959	$ 0.19708	$ 35,447	$ (18,512)	-34.31%
14	Private Outdoor Lighting	31,835,957 kWh	n/a	$ 141,320	$ 0.00881	$ 280,562	$ 139,242	98.53%
15	School	77,415,560 kWh	n/a	$ 343,648	$ 0.00825	$ 638,988	$ 295,340	85.94%
16	Streetlighting	55,097,946 kWh	n/a	$ 244,580	$ 0.00870	$ 479,089	$ 234,509	95.88%
17	Total			$ 60,544,012		$ 113,073,940	$ 52,529,927	

[1] Secondary customers are charged for all kW over 5kW of Billing Demand and for the first 1,500 kWh

THE DAYTON POWER AND LIGHT COMPANY
CASE NO. 09-256-EL-UNC

Transmission Cost Recovery Rider (TCRR)

Schedule B-3
Current and Proposed Rates

The Dayton Power & Light Company

The Dayton Power and Light Company
Case No. 09-256-EL-UNC
Summary of Current and Proposed Rates

Schedule B-3
Page 1 of 1
Witness Responsible:
Sharon Schroder

Data: Actual and Forecasted
Type of Filing: Original
Work Paper Reference No(s).: WPB-3

Line	Tariff Class	Current TCRR-related Rate	Billing Units	Proposed TCRR Rate	Billing Units	$ Difference	% Difference
(A)	(B)	(C)	(D)	(E)	(F)	(G) = (E) - (C)	(H) = (G) / (C)
		WPB-3, Col (K)		Schedule C-3 Rows 11-13			
1	Residential	$ 0.00444	kWh	$ 0.00852	kWh	$ 0.00408	91.97%
2	Residential Heat	$ 0.00444	kWh	$ 0.00851	kWh	$ 0.00407	91.74%
3	Secondary[1]	$ 0.00444	kWh	$ 0.00665	kWh	$ 0.00221	49.81%
4		$ 1.97406	kW	$ 4.05765	kW	$ 2.08359	105.55%
5	Primary	$ 0.00039	kWh	$ 0.00034	kWh	$ (0.00005)	-11.73%
6		$ 1.82876	kW	$ 2.93185	kW	$ 1.10309	60.32%
7		$ 0.30000	kVar	$ 0.20876	kVar	$ (0.09124)	-30.41%
8	Primary Substation	$ 0.00039	kWh	$ 0.00033	kWh	$ (0.00006)	-14.20%
9		$ 1.82876	kW	$ 3.03410	kW	$ 1.20534	65.91%
10		$ 0.30000	kVar	$ 0.27842	kVar	$ (0.02158)	-7.19%
11	High Voltage	$ 0.00039	kWh	$ 0.00031	kWh	$ (0.00008)	-19.83%
12		$ 1.82876	kW	$ 3.01732	kW	$ 1.18856	64.99%
13		$ 0.30000	kVar	$ 0.19708	kVar	$ (0.10292)	-34.31%
14	Private Outdoor Lighting[2]	$ 0.00444	kWh	$ 0.00881	kWh	$ 0.00437	98.53%
15	School	$ 0.00444	kWh	$ 0.00825	kWh	$ 0.00382	85.94%
16	Streetlighting	$ 0.00444	kWh	$ 0.00870	kWh	$ 0.00426	95.88%

[1] Secondary customers are charged for all kW over 5kW of Billing Demand and for the first 1,500 kWh
[2] Private Outdoor Lighting $/kWh rates are based on assumed usage. Current rates are charged per fixture.

THE DAYTON POWER AND LIGHT COMPANY
CASE NO. 09-256-EL-UNC

Transmission Cost Recovery Rider (TCRR)

Schedule B-4
Graphs

The Dayton Power & Light Company

The Dayton Power and Light Company
Case No. 09-256-EL-UNC
Projected and Actual Costs and Revenues
Transmission Enhancement Charges
Calendar 2007 through First Quarter 2010

Data: Actual and Forecasted
Type of Filing: Original
Work Paper Reference No(s).: None

Witness Responsible:
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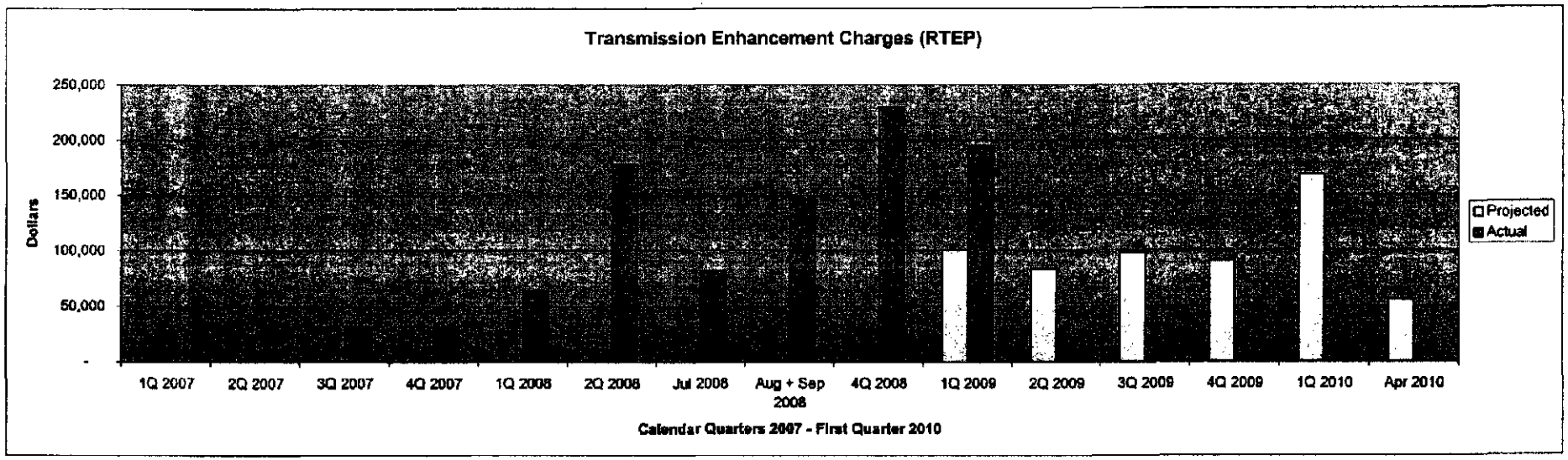

RTEP Charges	First Quarter 2007 Projected	First Quarter 2007 Actual	Second Quarter 2007 Projected	Second Quarter 2007 Actual	Third Quarter 2007 Projected	Third Quarter 2007 Actual	Fourth Quarter 2007 Projected	Fourth Quarter 2007 Actual	First Quarter 2008 Projected	First Quarter 2008 Actual	Second Quarter 2008 Projected	Second Quarter 2008 Actual	Third Quarter 2008 July 2008 Projected	Third Quarter 2008 July 2008 Actual	Third Quarter 2008 August and September 2008 Projected	Third Quarter 2008 August and September 2008 Actual	Fourth Quarter 2008 Projected	Fourth Quarter 2008 Actual
Total Amount	-	-	-	10,680	-	32,080	-	32,070	-	63,496	-	176,154	-	82,184	-	164,368	-	258,440
Allocation Factor	N/A	N/A	0.889	0.889	0.889	0.889	0.889	0.889	0.889	0.889	0.889	0.889	0.889	0.889	0.889	0.889	0.889	0.889
Allocated Amount	-	-	-	9,495	-	28,501	-	28,510	-	56,448	-	156,379	-	73,062	-	146,123	-	229,753
RTEP Credits																		
Total Amount	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Allocation Factor	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	1.000	1.000	1.000	1.000
Allocated Amount	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Net Allocated Amount	-	-	-	9,495	-	28,501	-	28,510	-	56,448	-	156,379	-	73,062	-	146,123	-	229,753

RTEP Charges	First Quarter 2009 Projected	First Quarter 2009 Actual	Second Quarter 2009 Projected	Second Quarter 2009 Actual	Third Quarter 2009 Projected	Third Quarter 2009 Actual	Fourth Quarter 2009 Projected	Fourth Quarter 2009 Actual	First Quarter 2010 Projected	First Quarter 2010 Actual	April 2010 Projected	April 2010 Actual
Total Amount	112,965	219,088	94,441	-	110,230	-	101,972	-	189,198	-	63,036	-
Allocation Factor	0.889	0.889	0.889	0.889	0.889	0.889	0.889	0.889	0.889	0.889	0.889	0.889
Allocated Amount	100,426	194,769	83,958	-	97,994	-	90,653	-	168,117	-	56,039	-
RTEP Credits												
Total Amount	-	-	-	-	-	-	-	-	-	-	-	-
Allocation Factor	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
Allocated Amount	-	-	-	-	-	-	-	-	-	-	-	-
Net Allocated Amount	100,426	194,769	83,958	-	97,994	-	90,653	-	168,117	-	56,039	-

The Dayton Power and Light Company
Case No. 09-256-EL-UNC
Projected and Actual Costs and Revenues
Reactive Supply and Voltage from Generation Sources Charges
Calendar 2007 through First Quarter 2010

Data: Actual and Forecasted
Type of Filing: Original
Work Paper Reference No(s).: None

Witness Responsible:
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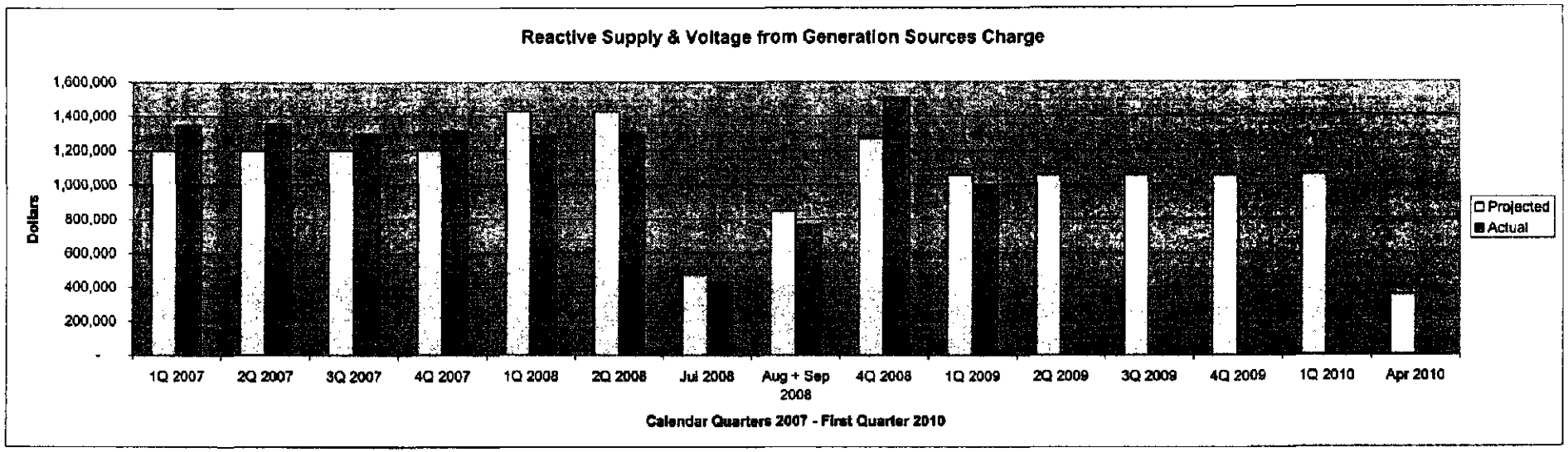


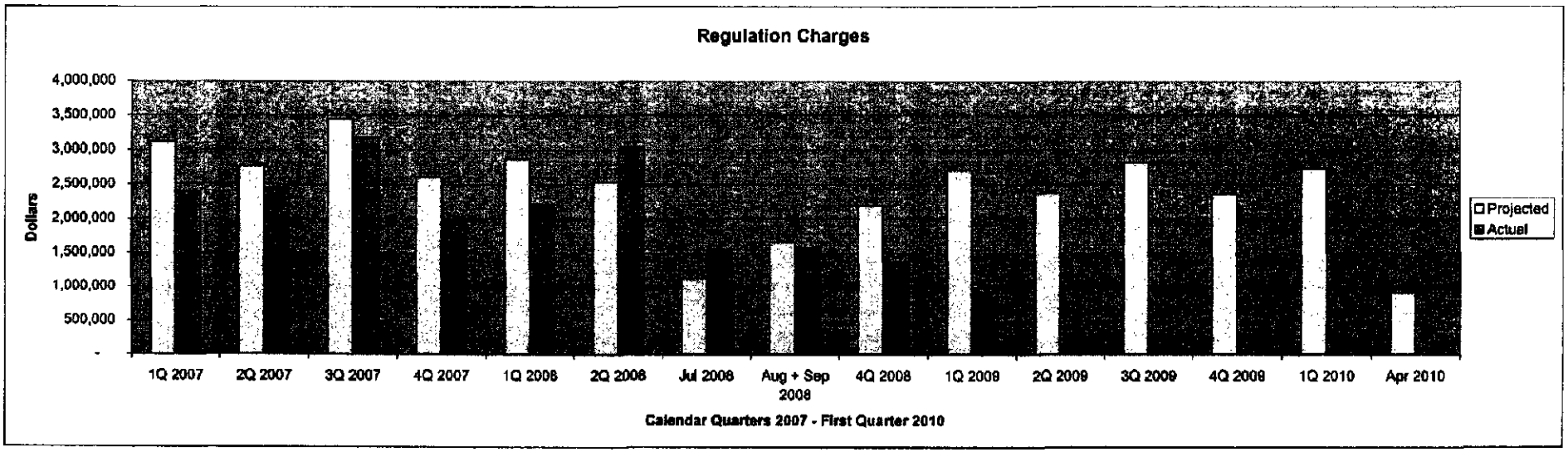
	First Quarter 2007		Second Quarter 2007		Third Quarter 2007		Fourth Quarter 2007		First Quarter 2008		Second Quarter 2008		Third Quarter 2008 July 2008		Third Quarter 2008 August and September 2008		Fourth Quarter 2008	
Reactive Supply Charges	Projected	Actual	Projected	Actual	Projected	Actual	Projected	Actual	Projected	Actual	Projected	Actual	Projected	Actual	Projected	Actual	Projected	Actual
Total Amount	1,200,145	1,345,438	1,200,145	1,356,525	1,200,145	1,300,332	1,200,145	1,317,421	1,426,741	1,287,283	1,426,741	1,290,075	475,580	433,184	951,161	860,170	1,426,741	1,696,593
Allocation Factor	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0.889	0.889	0.889	0.889
Allocated Amount	1,200,145	1,345,438	1,200,145	1,356,525	1,200,145	1,300,332	1,200,145	1,317,421	1,426,741	1,287,283	1,426,741	1,290,075	475,580	433,184	845,582	764,691	1,268,373	1,508,360
Reactive Supply Credits																		
Total Amount	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Allocation Factor	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	1.000	1.000	1.000	1.000
Allocated Amount	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Net Allocated Amount	1,200,145	1,345,438	1,200,145	1,356,525	1,200,145	1,300,332	1,200,145	1,317,421	1,426,741	1,287,283	1,426,741	1,290,075	475,580	433,184	845,582	764,691	1,268,373	1,508,360

	First Quarter 2009		Second Quarter 2009		Third Quarter 2009		Fourth Quarter 2009		First Quarter 2010		April 2010	
Reactive Supply Charges	Projected	Actual *	Projected	Actual	Projected	Actual	Projected	Actual	Projected	Actual	Projected	Actual
Total Amount	1,190,067	1,120,101	1,190,067	-	1,190,066	-	1,190,066	-	1,190,066	-	396,689	-
Allocation Factor	0.889	0.889	0.889	0.889	0.889	0.889	0.889	0.889	0.889	0.889	0.889	0.889
Allocated Amount	1,057,970	995,770	1,057,969	-	1,057,969	-	1,057,969	-	1,057,969	-	352,656	-
Reactive Supply Credits												
Total Amount	-	-	-	-	-	-	-	-	-	-	-	-
Allocation Factor	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
Allocated Amount	-	-	-	-	-	-	-	-	-	-	-	-
Net Allocated Amount	1,057,970	995,770	1,057,969	-	1,057,969	-	1,057,969	-	1,057,969	-	352,656	-

The Dayton Power and Light Company
Case No. 09-256-EL-UNC
Projected and Actual Costs and Revenues
Regulation Charges
Calendar 2007 through First Quarter 2010

Data: Actual and Forecasted
Type of Filing: Original
Work Paper Reference No(s).: None

Witness Responsible:
G.S. Campbell



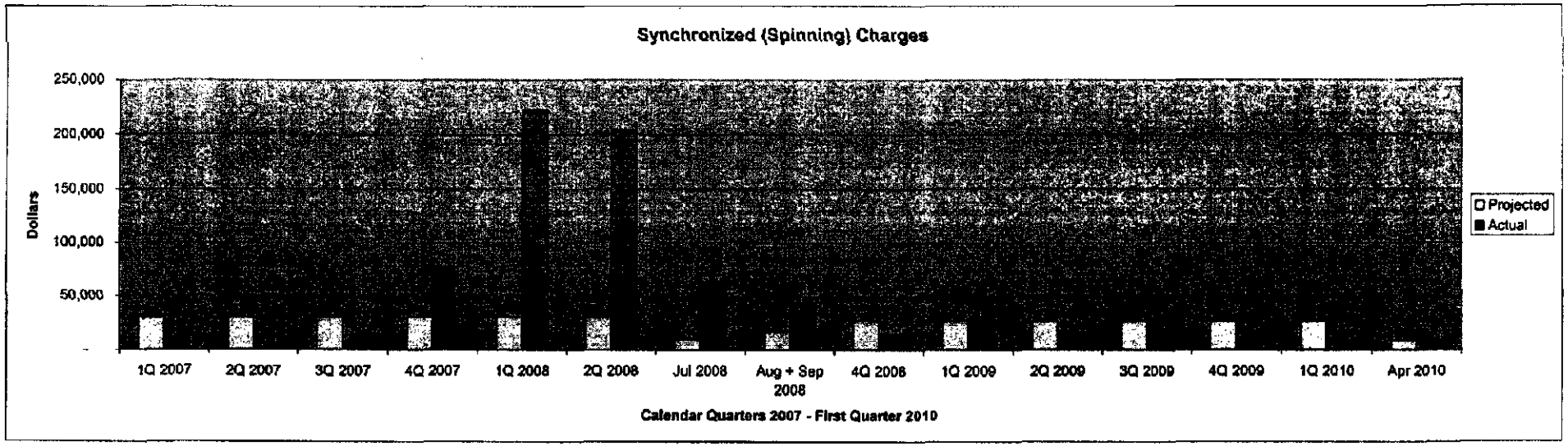
Regulation Charges	First Quarter 2007		Second Quarter 2007		Third Quarter 2007		Fourth Quarter 2007		First Quarter 2008		Second Quarter 2008		Third Quarter 2008				Fourth Quarter 2008	
													July 2008		August and September 2008			
	Projected	Actual	Projected	Actual	Projected	Actual	Projected	Actual	Projected	Actual	Projected	Actual	Projected	Actual	Projected	Actual	Projected	Actual
Total Amount	3,119,141	2,390,749	2,764,661	2,444,022	3,442,694	3,183,444	2,604,259	1,970,576	2,864,370	2,205,520	2,537,292	3,041,927	1,123,214	1,558,388	1,867,285	1,780,600	2,469,490	1,541,752
Allocation Factor	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0.889	0.889	0.889	0.889
Allocated Amount	3,119,141	2,390,749	2,764,661	2,444,022	3,442,694	3,183,444	2,604,259	1,970,576	2,864,370	2,205,520	2,537,292	3,041,927	1,123,214	1,558,388	1,660,016	1,582,953	2,195,377	1,370,618
Regulation Credits																		
Total Amount	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Allocation Factor	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	1.000	1.000	1.000	1.000
Allocated Amount	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Net Allocated Amount	3,119,141	2,390,749	2,764,661	2,444,022	3,442,694	3,183,444	2,604,259	1,970,576	2,864,370	2,205,520	2,537,292	3,041,927	1,123,214	1,558,388	1,660,016	1,582,953	2,195,377	1,370,618

Regulation Charges	First Quarter 2009		Second Quarter 2009		Third Quarter 2009		Fourth Quarter 2009		First Quarter 2010		April 2010	
	Projected	Actual *	Projected	Actual	Projected	Actual	Projected	Actual	Projected	Actual	Projected	Actual
Total Amount	3,052,050	958,957	2,671,134	-	3,175,166	-	2,663,460	-	3,066,702	-	1,022,234	-
Allocation Factor	0.889	0.889	0.889	0.889	0.889	0.889	0.889	0.889	0.889	0.889	0.889	0.889
Allocated Amount	2,713,272	852,513	2,374,638	-	2,822,722	-	2,367,816	-	2,726,298	-	908,766	-
Regulation Credits												
Total Amount	-	-	-	-	-	-	-	-	-	-	-	-
Allocation Factor	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
Allocated Amount	-	-	-	-	-	-	-	-	-	-	-	-
Net Allocated Amount	2,713,272	852,513	2,374,638	-	2,822,722	-	2,367,816	-	2,726,298	-	908,766	-

The Dayton Power and Light Company
Case No. 09-256-EL-UNC
Projected and Actual Costs and Revenues
Synchronized (Spinning) Charges
Calendar 2007 through First Quarter 2010

Data: Actual and Forecasted
Type of Filing: Original
Work Paper Reference No(s).: None

Witness Responsible:
G.S. Campbell



	First Quarter 2007		Second Quarter 2007		Third Quarter 2007		Fourth Quarter 2007		First Quarter 2008		Second Quarter 2008		Third Quarter 2008				Fourth Quarter 2008	
													July 2008		August and September 2008			
Synchronized Reserve Charges	Projected	Actual	Projected	Actual	Projected	Actual	Projected	Actual	Projected	Actual	Projected	Actual	Projected	Actual	Projected	Actual	Projected	Actual
Total Amount	30,600	5,473	30,600	2,663	30,600	5,328	30,600	77,006	30,589	222,643	30,573	203,582	10,191	63,665	20,383	49,902	30,575	17,865
Allocation Factor	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0.889	0.889	0.889	0.889
Allocated Amount	30,600	5,473	30,600	2,663	30,600	5,328	30,600	77,006	30,589	222,643	30,573	203,582	10,191	63,665	18,120	44,363	27,182	15,885
Synchronized Reserve Credits																		
Total Amount	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Allocation Factor	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	1.000	1.000	1.000	1.000
Allocated Amount	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Net Allocated Amount	30,600	5,473	30,600	2,663	30,600	5,328	30,600	77,006	30,589	222,643	30,573	203,582	10,191	63,665	18,120	44,363	27,182	15,885

	First Quarter 2009		Second Quarter 2009		Third Quarter 2009		Fourth Quarter 2009		First Quarter 2010		April 2010	
Synchronized Reserve Charges	Projected	Actual *	Projected	Actual	Projected	Actual	Projected	Actual	Projected	Actual	Projected	Actual
Total Amount	30,600	32,432	30,600	-	30,600	-	30,600	-	30,600	-	10,200	-
Allocation Factor	0.889	0.889	0.889	0.889	0.889	0.889	0.889	0.889	0.889	0.889	0.889	0.889
Allocated Amount	27,203	28,832	27,203	-	27,203	-	27,203	-	27,203	-	9,068	-
Synchronized Reserve Credits												
Total Amount	-	-	-	-	-	-	-	-	-	-	-	-
Allocation Factor	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
Allocated Amount	-	-	-	-	-	-	-	-	-	-	-	-
Net Allocated Amount	27,203	28,832	27,203	-	27,203	-	27,203	-	27,203	-	9,068	-

The Dayton Power and Light Company
Case No. 09-256-EL-UNC
Projected and Actual Costs and Revenues
Operating Reserve Charges
Calendar 2007 through First Quarter 2010

Data: Actual and Forecasted
Type of Filing: Original
Work Paper Reference No(s).: None

Witness Responsible
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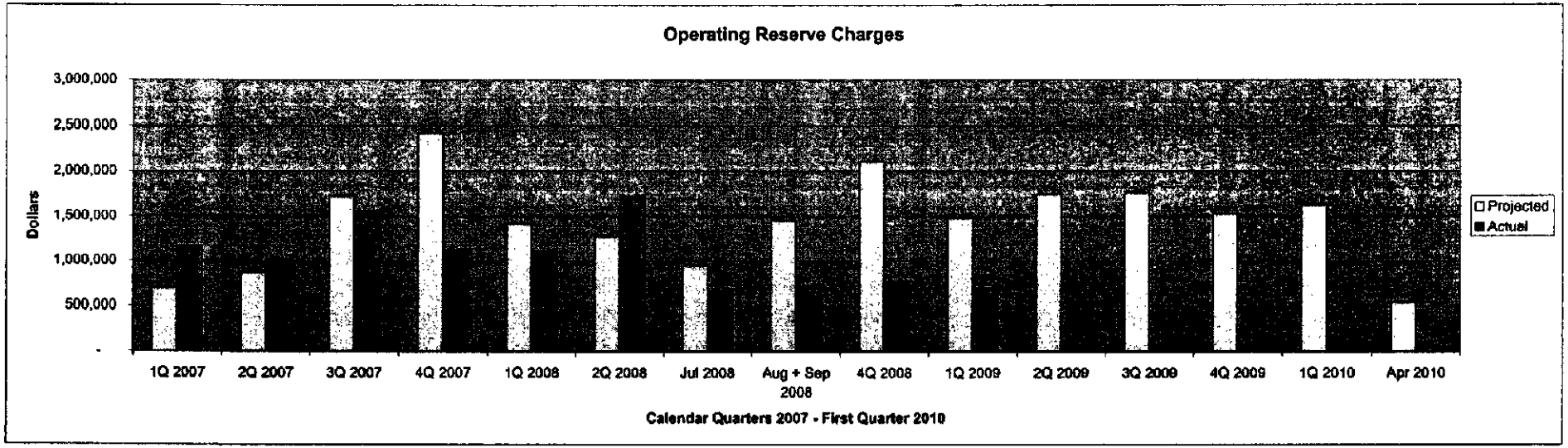

Operating Reserve Charges	First Quarter 2007 Projected	First Quarter 2007 Actual	Second Quarter 2007 Projected	Second Quarter 2007 Actual	Third Quarter 2007 Projected	Third Quarter 2007 Actual	Fourth Quarter 2007 Projected	Fourth Quarter 2007 Actual	First Quarter 2008 Projected	First Quarter 2008 Actual	Second Quarter 2008 Projected	Second Quarter 2008 Actual	Third Quarter 2008 July 2008 Projected	Third Quarter 2008 July 2008 Actual	Third Quarter 2008 August and September 2008 Projected	Third Quarter 2008 August and September 2008 Actual	Fourth Quarter 2008 Projected	Fourth Quarter 2008 Actual
Total Amount	701,504	1,159,860	869,948	1,028,331	1,722,040	1,549,289	2,422,375	1,124,079	1,422,402	1,099,501	1,270,816	1,725,639	947,810	664,879	1,878,495	935,469	2,720,406	1,001,428
Allocation Factor	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0.774	0.774	0.774	0.774
Allocated Amount	701,504	1,159,860	869,948	1,028,331	1,722,040	1,549,289	2,422,375	1,124,079	1,422,402	1,099,501	1,270,816	1,725,639	947,810	664,879	1,453,955	724,053	2,105,594	775,105
Operating Reserve Credits																		
Total Amount	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Allocation Factor	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	1.000	1.000	1.000	1.000
Allocated Amount	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Net Allocated Amount	701,504	1,159,860	869,948	1,028,331	1,722,040	1,549,289	2,422,375	1,124,079	1,422,402	1,099,501	1,270,816	1,725,639	947,810	664,879	1,453,955	724,053	2,105,594	775,105

Operating Reserve Charges	First Quarter 2009 Projected	First Quarter 2009 Actual *	Second Quarter 2009 Projected	Second Quarter 2009 Actual	Third Quarter 2009 Projected	Third Quarter 2009 Actual	Fourth Quarter 2009 Projected	Fourth Quarter 2009 Actual	First Quarter 2010 Projected	First Quarter 2010 Actual	April 2010 Projected	April 2010 Actual
Total Amount	1,911,755	892,249	2,259,046	-	2,274,852	-	1,970,788	-	2,104,440	-	701,480	-
Allocation Factor	0.774	0.774	0.774	0.774	0.774	0.774	0.774	0.774	0.774	0.774	0.774	0.774
Allocated Amount	1,479,698	690,601	1,748,502	-	1,760,735	-	1,525,390		1,628,836	-	542,945	-
Operating Reserve Credits												
Total Amount	-	-	-	-	-	-	-	-	-	-	-	-
Allocation Factor	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
Allocated Amount	-	-	-	-	-	-	-	-	-	-	-	-
Net Allocated Amount	1,479,698	690,601	1,748,502	-	1,760,735	-	1,525,390	-	1,628,836	-	542,945	-

The Dayton Power and Light Company
Case No. 09-256-EL-UNC
Projected and Actual Costs and Revenues
RTO Start-up Cost Recovery - AEP Zone Charges
Calendar 2007 through First Quarter 2010

Data: Actual and Forecasted
Type of Filing: Original
Work Paper Reference No(s).: None

Witness Responsible:
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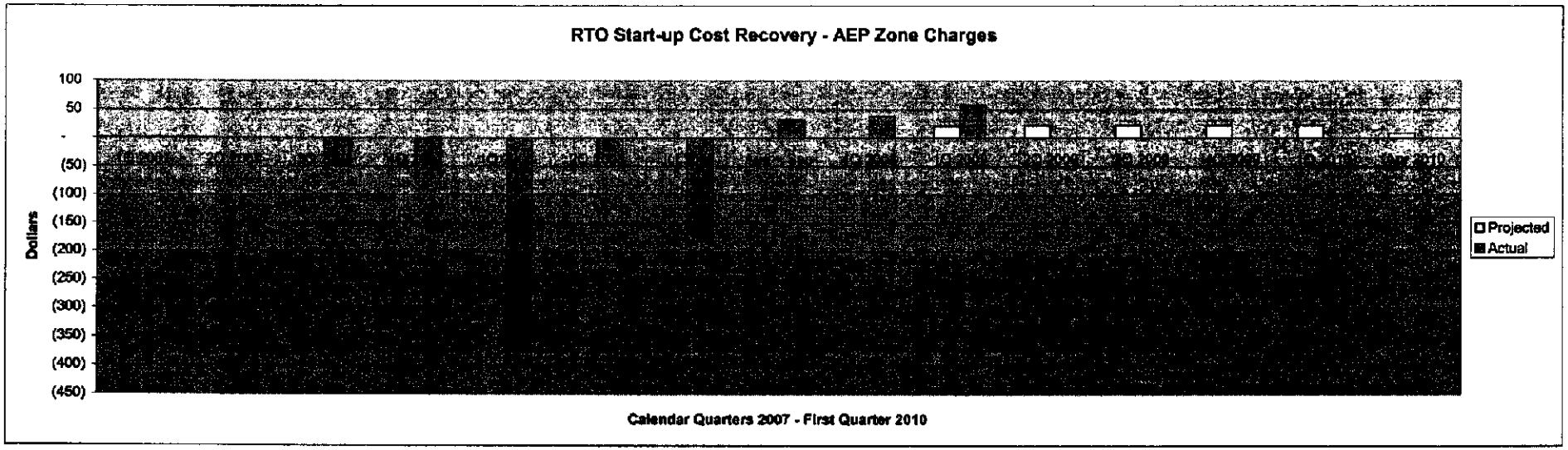

RTO Start-up AEP Zone Chan	First Quarter 2007 Projected	First Quarter 2007 Actual	Second Quarter 2007 Projected	Second Quarter 2007 Actual	Third Quarter 2007 Projected	Third Quarter 2007 Actual	Fourth Quarter 2007 Projected	Fourth Quarter 2007 Actual	First Quarter 2008 Projected	First Quarter 2008 Actual	Second Quarter 2008 Projected	Second Quarter 2008 Actual	Third Quarter 2008 July 2008 Projected	Third Quarter 2008 July 2008 Actual	Third Quarter 2008 August and September 2008 Projected	Third Quarter 2008 August and September 2008 Actual	Fourth Quarter 2008 Projected	Fourth Quarter 2008 Actual
Total Amount	-	-	-	-	-	(47)	-	(71)	-	(384)	-	(42)	-	(170)	-	35	-	42
Allocation Factor	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0.889	0.889	0.889	0.889
Allocated Amount	-	-	-	-	-	(47)	-	(71)	-	(384)	-	(42)	-	(170)	-	31	-	37
RTO Start-up AEP Zone Credits																		
Total Amount	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Allocation Factor	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	1.000	1.000	1.000	1.000
Allocated Amount	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Net Allocated Amount	-	-	-	-	-	(47)	-	(71)	-	(384)	-	(42)	-	(170)	-	31	-	37

RTO Start-up AEP Zone Chan	First Quarter 2009 Projected	First Quarter 2009 Actual *	Second Quarter 2009 Projected	Second Quarter 2009 Actual	Third Quarter 2009 Projected	Third Quarter 2009 Actual	Fourth Quarter 2009 Projected	Fourth Quarter 2009 Actual	First Quarter 2010 Projected	First Quarter 2010 Actual	April 2010 Projected	April 2010 Actual
Total Amount	24	65	25	-	25	-	25	-	25	-	8	-
Allocation Factor	0.889	0.889	0.889	0.889	0.889	0.889	0.889	0.889	0.889	0.889	0.889	0.889
Allocated Amount	21	58	22	-	22	-	22	-	22	-	7	-
RTO Start-up AEP Zone Credits												
Total Amount	-	-	-	-	-	-	-	-	-	-	-	-
Allocation Factor	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
Allocated Amount	-	-	-	-	-	-	-	-	-	-	-	-
Net Allocated Amount	21	58	22	-	22	-	22	-	22	-	7	-

The Dayton Power and Light Company
Case No. 09-256-EL-UNC
Projected and Actual Costs and Revenues
Synchronous Condensing Charges
Calendar 2007 through First Quarter 2010

Data: Actual and Forecasted
Type of Filing: Original
Work Paper Reference No(s).: None

Witness Responsible:
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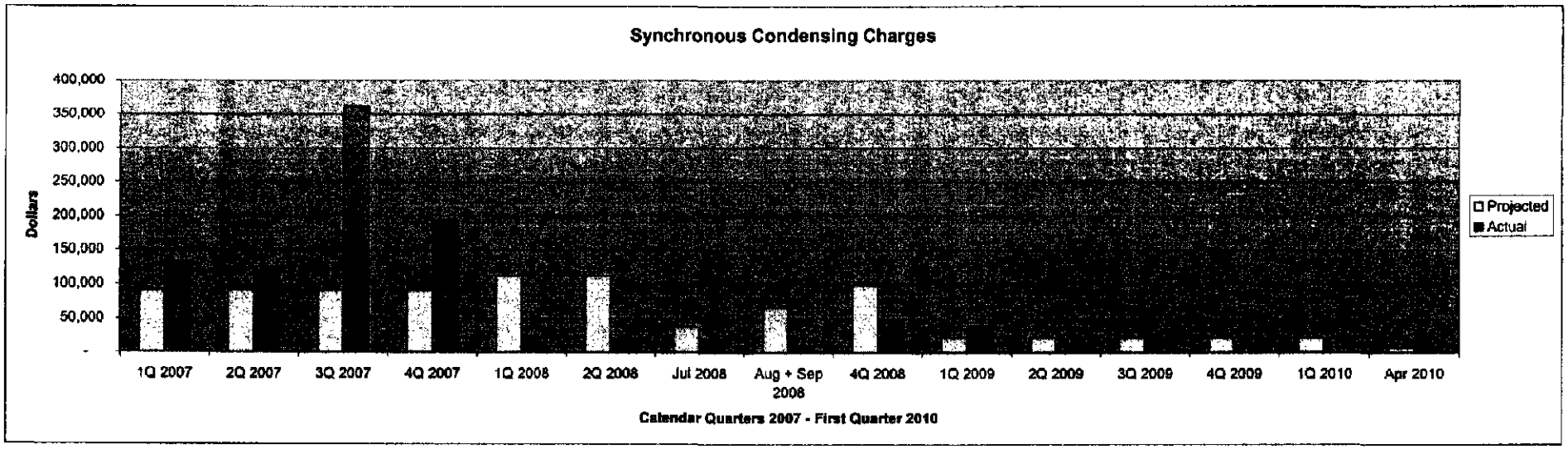

	First Quarter 2007		Second Quarter 2007		Third Quarter 2007		Fourth Quarter 2007		First Quarter 2008		Second Quarter 2008		Third Quarter 2008				Fourth Quarter 2008	
													July 2008		August and September 2008			
Synchronous Condensing Chs	Projected	Actual	Projected	Actual	Projected	Actual	Projected	Actual	Projected	Actual	Projected	Actual	Projected	Actual	Projected	Actual	Projected	Actual
Total Amount	91,277	133,432	91,277	120,125	91,277	361,844	91,277	194,334	111,873	22,777	111,813	20,657	37,273	19,514	74,545	11,412	111,822	52,062
Allocation Factor	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0.889	0.889	0.889	0.889
Allocated Amount	91,277	133,432	91,277	120,125	91,277	361,844	91,277	194,334	111,873	22,777	111,813	20,657	37,273	19,514	66,270	10,145	99,410	46,301
Synchronous Condensing Credits																		
Total Amount	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Allocation Factor	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	1.000	1.000	1.000	1.000
Allocated Amount	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Net Allocated Amount	91,277	133,432	91,277	120,125	91,277	361,844	91,277	194,334	111,873	22,777	111,813	20,657	37,273	19,514	66,270	10,145	99,410	46,301

	First Quarter 2009		Second Quarter 2009		Third Quarter 2009		Fourth Quarter 2009		First Quarter 2010		April 2010	
Synchronous Condensing Chs	Projected	Actual *	Projected	Actual	Projected	Actual	Projected	Actual	Projected	Actual	Projected	Actual
Total Amount	24,417	44,786	24,418	-	24,418	-	24,418	-	24,418	-	8,139	-
Allocation Factor	0.889	0.889	0.889	0.889	0.889	0.889	0.889	0.889	0.889	0.889	0.889	0.889
Allocated Amount	21,707	39,815	21,708	-	21,708	-	21,708	-	21,708	-	7,236	-
Synchronous Condensing Credits												
Total Amount	-	-	-	-	-	-	-	-	-	-	-	-
Allocation Factor	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
Allocated Amount	-	-	-	-	-	-	-	-	-	-	-	-
Net Allocated Amount	21,707	39,815	21,708	-	21,708	-	21,708	-	21,708	-	7,236	-

The Dayton Power and Light Company
Case No. 09-256-EL-UNC
Projected and Actual Costs and Revenues
Reliability Pricing Model (RPM) Charges and Credits
Calendar 2007 through First Quarter 2010

Data: Actual and Forecasted
Type of Filing: Original
Work Paper Reference No(s).: None

Witness Responsible:
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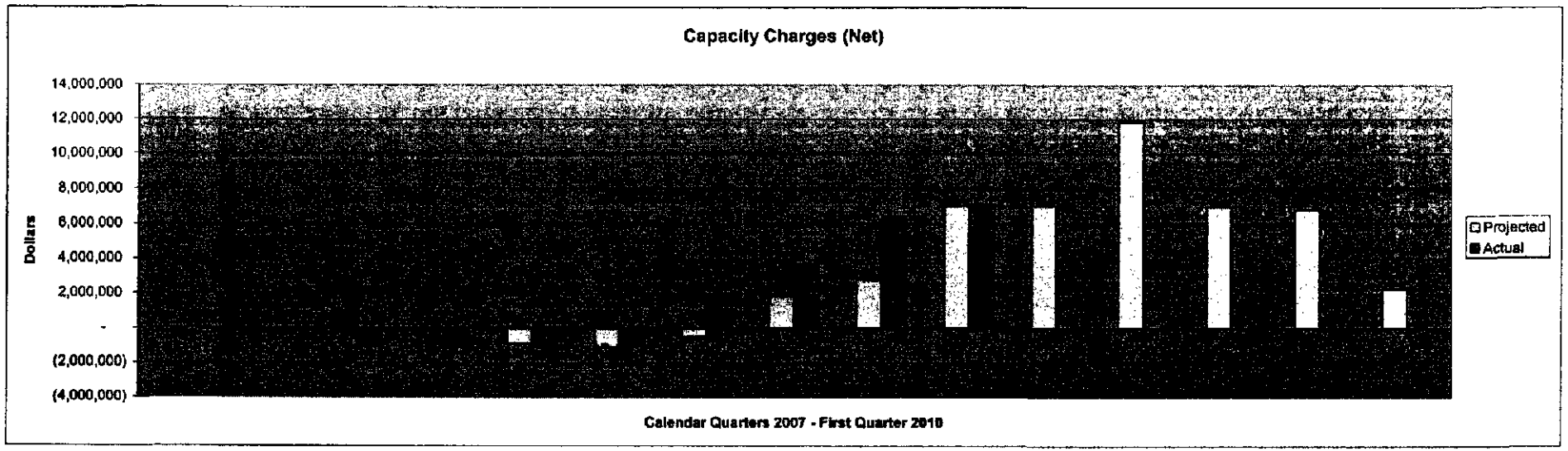

	First Quarter 2007		Second Quarter 2007		Third Quarter 2007		Fourth Quarter 2007		First Quarter 2008		Second Quarter 2008		Third Quarter 2008				Fourth Quarter 2008	
													July 2008		August and September 2008			
Capacity Charges	Projected	Actual	Projected	Actual	Projected	Actual	Projected	Actual	Projected	Actual	Projected	Actual	Projected	Actual	Projected	Actual	Projected	Actual
Total Amount	-	-	-	3,984,247	-	12,218,357	-	12,218,357	12,300,000	12,065,551	19,678,187	19,119,234	11,478,187	11,384,063	22,956,373	22,400,865	34,434,603	33,785,293
Allocation Factor	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0.889	0.889	0.889	0.889
Allocated Amount	-	-	-	3,984,247	-	12,218,357	-	12,218,357	12,300,000	12,065,551	19,678,187	19,119,234	11,478,187	11,384,063	20,408,216	19,914,360	30,612,382	30,035,125
Capacity Credits																		
Total Amount	(154,677)	(2,352)	(104,836)	(4,335,291)	0.2	(13,296,108)	0	(13,298,754)	(13,200,000)	(13,159,570)	(20,778,471)	(20,742,775)	(11,978,471)	(10,283,102)	(23,958,943)	(20,958,647)	(35,935,414)	(30,596,134)
Allocation Factor	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0.774	0.774	0.774	0.774
Allocated Amount	(154,677)	(2,352)	(104,836)	(4,335,291)	0	(13,296,108)	0	(13,298,754)	(13,200,000)	(13,159,570)	(20,778,471)	(20,742,775)	(11,978,471)	(10,283,102)	(18,542,674)	(16,221,993)	(27,814,010)	(23,682,956)
Net Allocated Amount	(154,677)	(2,352)	(104,836)	(351,044)	0	(1,077,751)	0	(1,080,397)	(900,000)	(1,074,019)	(1,100,285)	(1,623,541)	(500,285)	1,100,961	1,865,542	3,692,367	2,798,352	6,352,170

	First Quarter 2009		Second Quarter 2009		Third Quarter 2009		Fourth Quarter 2009		First Quarter 2010		April 2010	
Capacity Charges	Projected	Actual *	Projected	Actual	Projected	Actual	Projected	Actual	Projected	Actual	Projected	Actual
Total Amount	33,907,059	25,087,786	33,460,857	-	37,636,845	-	32,138,845	-	31,438,218	-	10,479,406	-
Allocation Factor	0.889	0.889	0.889	0.889	0.889	0.889	0.889	0.889	0.889	0.889	0.889	0.889
Allocated Amount	30,143,376	22,303,042	29,746,702	-	33,459,155	-	28,568,855	-	27,948,576	-	9,316,192	-
Capacity Credits												
Total Amount	(29,844,699)	(19,624,336)	(29,331,776)	-	(27,918,022)	-	(27,918,022)	-	(27,311,108)	-	(9,103,703)	-
Allocation Factor	0.774	0.774	0.774	0.774	0.774	0.774	0.774	0.774	0.774	0.774	0.774	0.774
Allocated Amount	(23,099,797)	(15,189,236)	(22,702,795)	-	(21,608,549)	-	(21,608,549)	-	(21,138,798)	-	(7,046,268)	-
Net Allocated Amount	7,043,579	7,113,806	7,043,907	-	11,850,606	-	6,961,106	-	6,809,778	-	2,269,926	-

* Actual data for the First Quarter 2009 includes January and February only.

The Dayton Power and Light Company
Case No. 09-256-EL-UNC
Projected and Actual Costs and Revenues
Black Start Charges
Calendar 2007 through First Quarter 2010

Data: Actual and Forecasted
Type of Filing: Original
Work Paper Reference No(s).: None

Witness Responsible:
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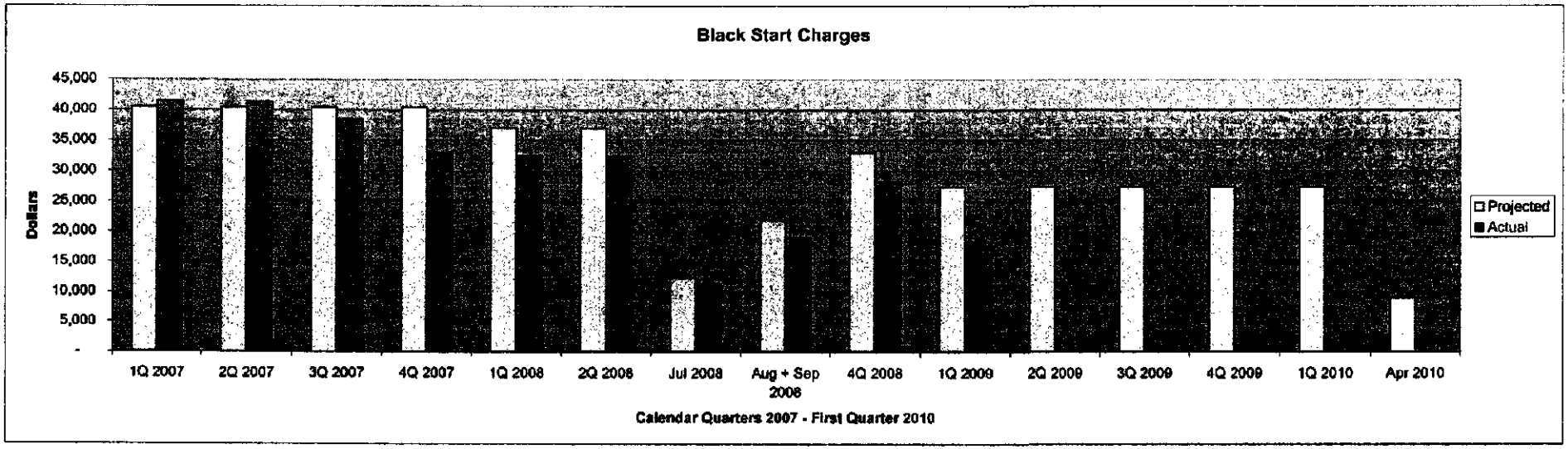

	First Quarter 2007		Second Quarter 2007		Third Quarter 2007		Fourth Quarter 2007		First Quarter 2008		Second Quarter 2008		Third Quarter 2008				Fourth Quarter 2008	
													July 2008		August and September 2008			
Black Start Charges	Projected	Actual	Projected	Actual	Projected	Actual	Projected	Actual	Projected	Actual	Projected	Actual	Projected	Actual	Projected	Actual	Projected	Actual
Total Amount	40,464	41,436	40,464	41,269	40,464	38,472	40,464	33,079	37,037	32,459	37,037	32,442	12,346	11,503	24,691	21,514	37,037	31,826
Allocation Factor	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0.889	0.889	0.889	0.889
Allocated Amount	40,464	41,436	40,464	41,269	40,464	38,472	40,464	33,079	37,037	32,459	37,037	32,442	12,346	11,503	21,951	19,126	32,926	28,295
Black Start Credits																		
Total Amount	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Allocation Factor	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	1.000	1.000	1.000	1.000
Allocated Amount	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Net Allocated Amount	40,464	41,436	40,464	41,269	40,464	38,472	40,464	33,079	37,037	32,459	37,037	32,442	12,346	11,503	21,951	19,126	32,926	28,295

	First Quarter 2009		Second Quarter 2009		Third Quarter 2009		Fourth Quarter 2009		First Quarter 2010		April 2010	
Black Start Charges	Projected	Actual *	Projected	Actual	Projected	Actual	Projected	Actual	Projected	Actual	Projected	Actual
Total Amount	30,870	20,676	30,870	-	30,870	-	30,870	-	30,870	-	10,290	-
Allocation Factor	0.889	0.889	0.889	0.889	0.889	0.889	0.889	0.889	0.889	0.889	0.889	0.889
Allocated Amount	27,443	18,381	27,443	-	27,443	-	27,443	-	27,443	-	9,148	-
Black Start Credits												
Total Amount	-	-	-	-	-	-	-	-	-	-	-	-
Allocation Factor	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
Allocated Amount	-	-	-	-	-	-	-	-	-	-	-	-
Net Allocated Amount	27,443	18,381	27,443	-	27,443	-	27,443	-	27,443	-	9,148	-

The Dayton Power and Light Company
Case No. 09-256-EL-UNC
Projected and Actual Costs and Revenues
Transmission Owner Scheduling System Control & Dispatch Charges
Calendar 2007 through First Quarter 2010

Data: Actual and Forecasted
Type of Filing: Original
Work Paper Reference No(s).: None

Witness Responsible
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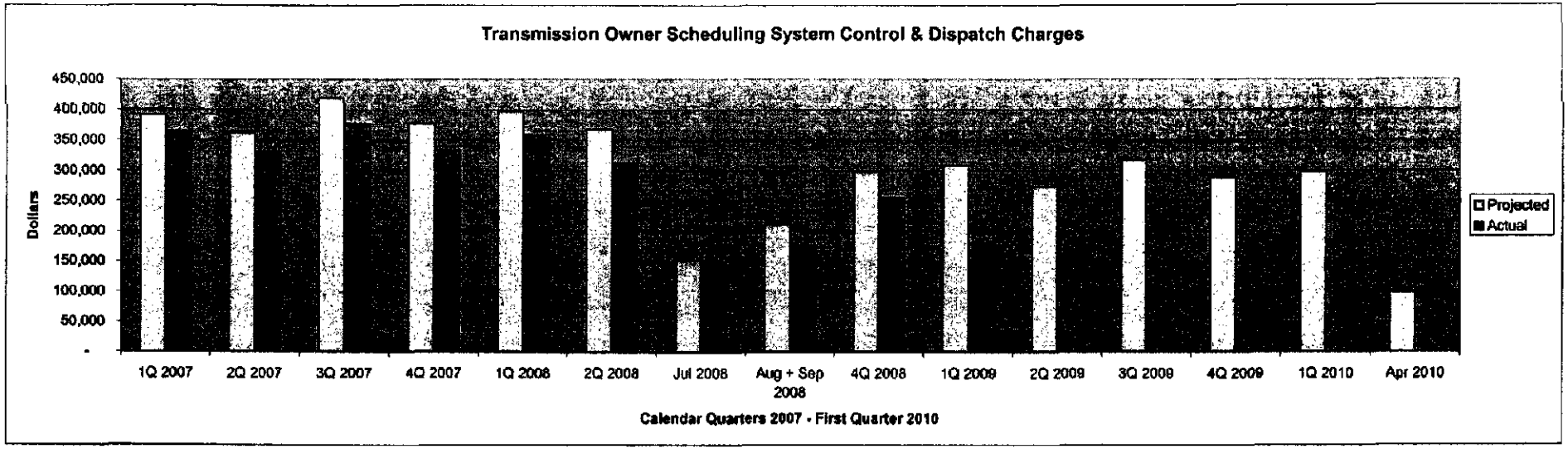

	First Quarter 2007		Second Quarter 2007		Third Quarter 2007		Fourth Quarter 2007		First Quarter 2008		Second Quarter 2008		Third Quarter 2008 July 2008		Third Quarter 2008 August and September 2008		Fourth Quarter 2008	
TO Scheduling Charges	Projected	Actual	Projected	Actual	Projected	Actual	Projected	Actual	Projected	Actual	Projected	Actual	Projected	Actual	Projected	Actual	Projected	Actual
Total Amount	391,302	365,179	362,751	330,565	418,739	376,790	377,724	333,955	396,987	359,038	368,895	312,967	151,748	127,669	273,890	229,577	383,711	330,160
Allocation Factor	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0.774	0.774	0.774	0.774
Allocated Amount	391,302	365,179	362,751	330,565	418,739	376,790	377,724	333,955	396,987	359,038	368,895	312,967	151,748	127,669	211,836	177,693	296,992	255,544
TO Scheduling Credits																		
Total Amount	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Allocation Factor	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	1.000	1.000	1.000	1.000
Allocated Amount	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Net Allocated Amount	391,302	365,179	362,751	330,565	418,739	376,790	377,724	333,955	396,987	359,038	368,895	312,967	151,748	127,669	211,836	177,693	296,992	255,544

	First Quarter 2009		Second Quarter 2009		Third Quarter 2009		Fourth Quarter 2009		First Quarter 2010		April 2010	
TO Scheduling Charges	Projected	Actual *	Projected	Actual	Projected	Actual	Projected	Actual	Projected	Actual	Projected	Actual
Total Amount	399,325	231,993	353,010	-	409,546	-	373,582	-	384,383	-	128,128	-
Allocation Factor	0.774	0.774	0.774	0.774	0.774	0.774	0.774	0.774	0.774	0.774	0.774	0.774
Allocated Amount	309,078	179,563	273,230	-	316,989	-	289,152	-	297,512	-	99,171	-
TO Scheduling Credits												
Total Amount	-	-	-	-	-	-	-	-	-	-	-	-
Allocation Factor	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
Allocated Amount	-	-	-	-	-	-	-	-	-	-	-	-
Net Allocated Amount	309,078	179,563	273,230	-	316,989	-	289,152	-	297,512	-	99,171	-

The Dayton Power and Light Company
Case No. 09-256-EL-UNC
Projected and Actual Costs and Revenues
NERC & RFC Charges
Calendar 2007 through First Quarter 2010

Data: Actual and Forecasted
Type of Filing: Original
Work Paper Reference No(s).: None

Witness Responsible:
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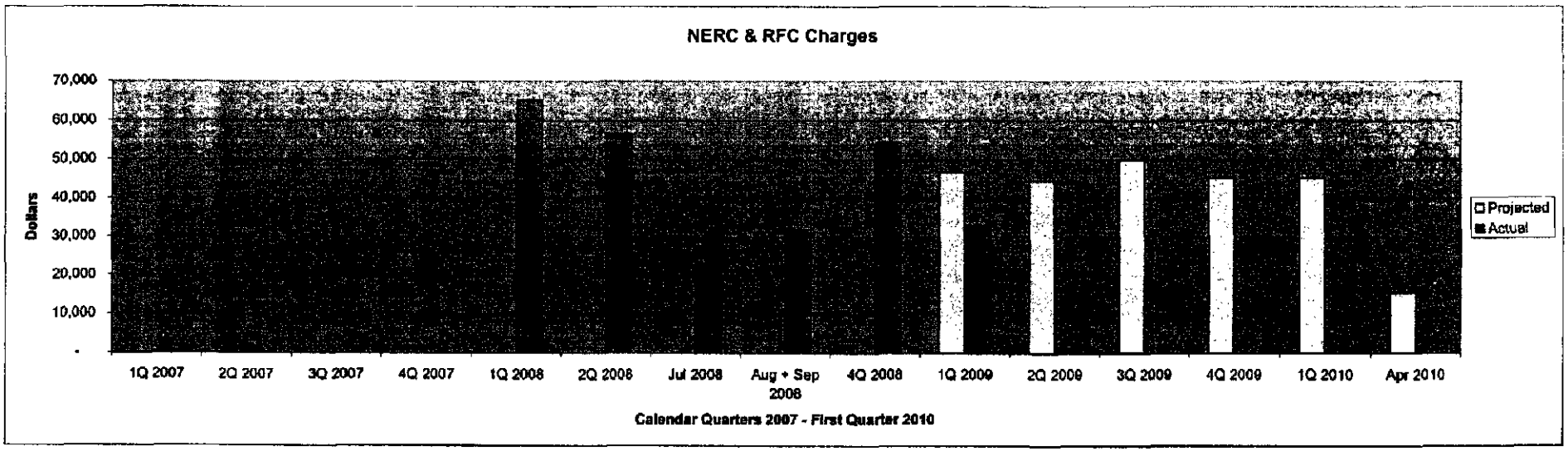

NERC & RFC Charges	First Quarter 2007		Second Quarter 2007		Third Quarter 2007		Fourth Quarter 2007		First Quarter 2008		Second Quarter 2008		Third Quarter 2008				Fourth Quarter 2008	
													July 2008		August and September 2008			
	Projected	Actual	Projected	Actual	Projected	Actual	Projected	Actual	Projected	Actual	Projected	Actual	Projected	Actual	Projected	Actual	Projected	Actual
Total Amount	-	-	-	-	-	-	-	-	-	65,226	-	56,688	-	23,084	-	41,324	-	70,425
Allocation Factor	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0.774	0.774	0.774	0.774
Allocated Amount	-	-	-	-	-	-	-	-	-	65,226	-	56,688	-	23,084	-	31,985	-	54,509
NERC & RFC Credits																		
Total Amount	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Allocation Factor	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	1.000	1.000	1.000	1.000
Allocated Amount	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Net Allocated Amount	-	-	-	-	-	-	-	-	-	65,226	-	56,688	-	23,084	-	31,985	-	54,509

NERC & RFC Charges	First Quarter 2009		Second Quarter 2009		Third Quarter 2009		Fourth Quarter 2009		First Quarter 2010		April 2010	
	Projected	Actual *	Projected	Actual	Projected	Actual	Projected	Actual	Projected	Actual	Projected	Actual
Total Amount	60,276	42,478	57,727	-	64,545	-	58,547	-	58,547	-	20,151	-
Allocation Factor	0.774	0.774	0.774	0.774	0.774	0.774	0.774	0.774	0.774	0.774	0.774	0.774
Allocated Amount	46,654	32,878	44,681	-	49,958	-	45,315	-	45,315	-	15,597	-
NERC & RFC Credits												
Total Amount	-	-	-	-	-	-	-	-	-	-	-	-
Allocation Factor	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
Allocated Amount	-	-	-	-	-	-	-	-	-	-	-	-
Net Allocated Amount	46,654	32,878	44,681	-	49,958	-	45,315	-	45,315	-	15,597	-

The Dayton Power and Light Company
Case No. 09-256-EL-UNC
Projected and Actual Costs and Revenues
PJM Default Charges
Calendar 2007 through First Quarter 2010

Data: Actual and Forecasted
Type of Filing: Original
Work Paper Reference No(s).: None

Witness Responsible:
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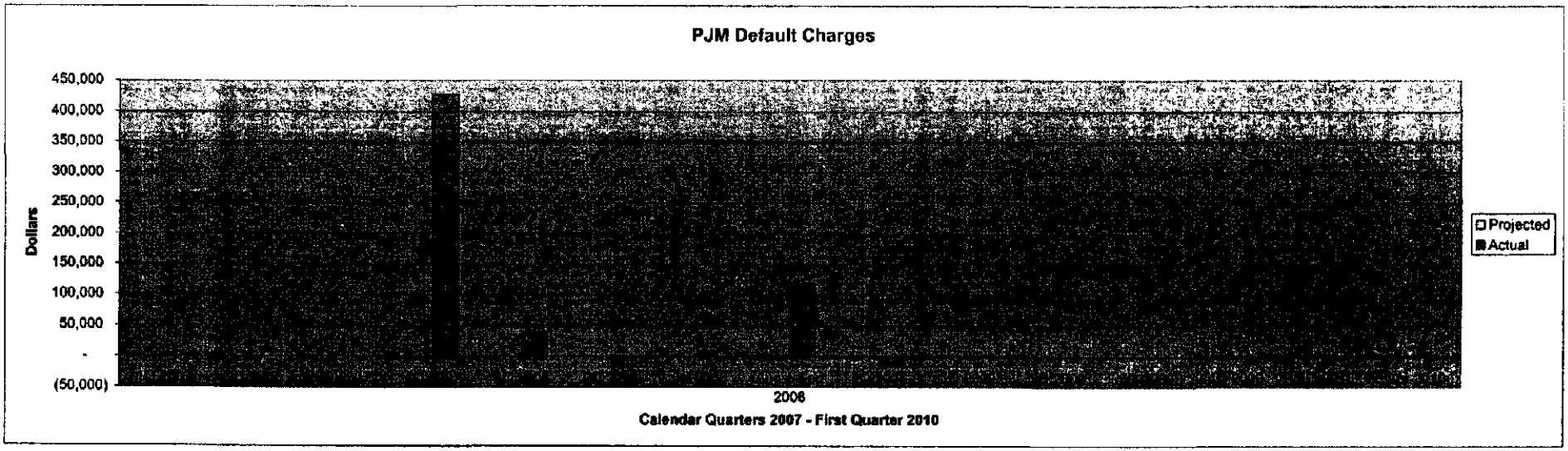

Default Charges	First Quarter 2007 Projected	First Quarter 2007 Actual	Second Quarter 2007 Projected	Second Quarter 2007 Actual	Third Quarter 2007 Projected	Third Quarter 2007 Actual	Fourth Quarter 2007 Projected	Fourth Quarter 2007 Actual	First Quarter 2008 Projected	First Quarter 2008 Actual	Second Quarter 2008 Projected	Second Quarter 2008 Actual	Third Quarter 2008 July 2008 Projected	Third Quarter 2008 July 2008 Actual	Third Quarter 2008 August and September 2008 Projected	Third Quarter 2008 August and September 2008 Actual	Fourth Quarter 2008 Projected	Fourth Quarter 2008 Actual
Total Amount	-	-	-	-	-	-	-	426,669	-	37,827	-	(14,509)	-	-	-	118,000	-	(13,608)
Allocation Factor	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	1.000	1.000	1.000	1.000
Allocated Amount	-	-	-	-	-	-	-	426,669	-	37,827	-	(14,509)	-	-	-	118,000	-	(13,608)
Default Credits																		
Total Amount	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Allocation Factor	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	1.000	1.000	1.000	1.000
Allocated Amount	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Net Allocated Amount	-	-	-	-	-	-	-	426,669	-	37,827	-	(14,509)	-	-	-	118,000	-	(13,608)

Default Charges	First Quarter 2009 Projected	First Quarter 2009 Actual *	Second Quarter 2009 Projected	Second Quarter 2009 Actual	Third Quarter 2009 Projected	Third Quarter 2009 Actual	Fourth Quarter 2009 Projected	Fourth Quarter 2009 Actual	First Quarter 2010 Projected	First Quarter 2010 Actual	April 2010 Projected	April 2010 Actual
Total Amount	-	-	-	-	-	-	-	-	-	-	-	-
Allocation Factor	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
Allocated Amount	-	-	-	-	-	-	-	-	-	-	-	-
Default Credits												
Total Amount	-	-	-	-	-	-	-	-	-	-	-	-
Allocation Factor	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
Allocated Amount	-	-	-	-	-	-	-	-	-	-	-	-
Net Allocated Amount	-	-	-	-	-	-	-	-	-	-	-	-

The Dayton Power and Light Company
Case No. 09-256-EL-UNC
Projected and Actual Costs and Revenues
Transmission Congestion Charges and Credits
Calendar 2007 through First Quarter 2010

Data: Actual and Forecasted
Type of Filing: Original
Work Paper Reference No(s).: None

Witness Responsible
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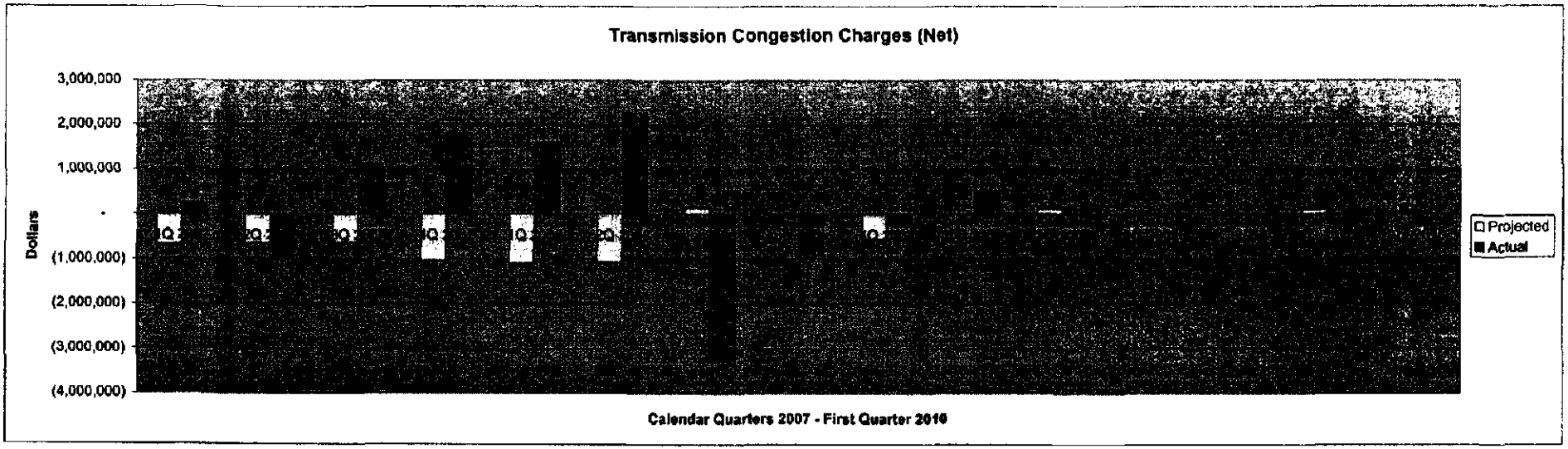

Congestion Charges	First Quarter 2007 Projected	First Quarter 2007 Actual	Second Quarter 2007 Projected	Second Quarter 2007 Actual	Third Quarter 2007 Projected	Third Quarter 2007 Actual	Fourth Quarter 2007 Projected	Fourth Quarter 2007 Actual	First Quarter 2008 Projected	First Quarter 2008 Actual	Second Quarter 2008 Projected	Second Quarter 2008 Actual	Third Quarter 2008 July 2008 Projected	Third Quarter 2008 July 2008 Actual	Third Quarter 2008 August and September 2008 Projected	Third Quarter 2008 August and September 2008 Actual	Fourth Quarter 2008 Projected	Fourth Quarter 2008 Actual
Total Amount	-	(101,133)	-	(477,640)	-	650,014	-	1,640,407	-	1,327,939	-	1,942,725	-	(3,326,237)	-	(2,649,230)	-	(837,523)
Allocation Factor	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0.387	0.387	0.387	0.387
Allocated Amount	-	(101,133)	-	(477,640)	-	650,014	-	1,640,407	-	1,327,939	-	1,942,725	-	(3,326,237)	-	(1,025,252)	-	(324,121)
Congestion Credits																		
Total Amount	(671,721)	342,626	(647,553)	(468,126)	(636,005)	455,801	(1,045,399)	170,960	(1,100,863)	261,867	(1,070,539)	316,165	154,260	65,432	(99,574)	91,444	(1,127,190)	118,051
Allocation Factor	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0.500	0.500	0.500	0.500
Allocated Amount	(671,721)	342,626	(647,553)	(468,126)	(636,005)	455,801	(1,045,399)	170,960	(1,100,863)	261,867	(1,070,539)	316,165	154,260	65,432	(49,787)	45,722	(563,595)	59,026
Net Allocated Amount	(671,721)	241,493	(647,553)	(945,766)	(636,005)	1,105,815	(1,045,399)	1,811,367	(1,100,863)	1,589,806	(1,070,539)	2,258,890	154,260	(3,260,805)	(49,787)	(979,530)	(563,595)	(265,096)

Congestion Charges	First Quarter 2009 Projected	First Quarter 2009 Actual *	Second Quarter 2009 Projected	Second Quarter 2009 Actual	Third Quarter 2009 Projected	Third Quarter 2009 Actual	Fourth Quarter 2009 Projected	Fourth Quarter 2009 Actual	First Quarter 2010 Projected	First Quarter 2010 Actual	April 2010 Projected	April 2010 Actual
Total Amount	-	1,266,166	316,165	-	156,876	-	118,051	-	281,809	-	139,958	-
Allocation Factor	0.387	0.387	0.387	0.387	0.387	0.387	0.387	0.387	0.387	0.387	0.387	0.387
Allocated Amount	-	490,006	122,356	-	60,711	-	45,686	-	109,060	-	54,164	-
Congestion Credits												
Total Amount	(19,942)	24,694	-	-	-	-	-	-	-	-	-	-
Allocation Factor	0.500	0.500	0.500	0.500	0.500	0.500	0.500	0.500	0.500	0.500	0.500	0.500
Allocated Amount	(9,971)	12,347	-	-	-	-	-	-	-	-	-	-
Net Allocated Amount	(9,971)	502,353	122,356	-	60,711	-	45,686	-	109,060	-	54,164	-

The Dayton Power and Light Company
Case No. 09-256-EL-UNC
Projected and Actual Costs and Revenues
Transmission Losses Charges and Credits
Calendar 2007 through First Quarter 2010

Data: Actual and Forecasted
Type of Filing: Original
Work Paper Reference No(s) : None

Witness Responsible
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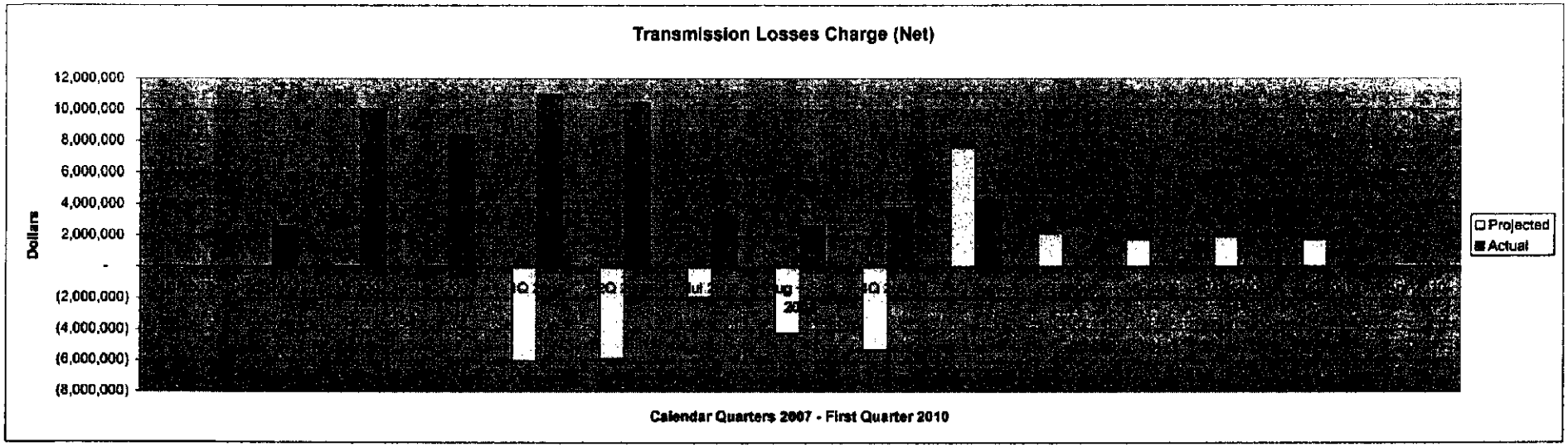

	First Quarter 2007		Second Quarter 2007		Third Quarter 2007		Fourth Quarter 2007		First Quarter 2008		Second Quarter 2008		Third Quarter 2008				Fourth Quarter 2008	
													July 2008		August and September 2008			
Loss Charges	Projected	Actual	Projected	Actual	Projected	Actual	Projected	Actual	Projected	Actual	Projected	Actual	Projected	Actual	Projected	Actual	Projected	Actual
Total Amount	69,300	67,136	69,300	4,843,986	69,300	16,374,029	69,300	13,592,795	-	17,749,641	-	17,490,622	-	7,525,629	-	8,808,937	-	10,653,123
Allocation Factor	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0.774	0.774	0.774	0.774
Allocated Amount	69,300	67,136	69,300	4,843,986	69,300	16,374,029	69,300	13,592,795	-	17,749,641	-	17,490,622	-	7,525,629	-	6,663,317	-	8,245,517
Loss Credits																		
Total Amount	-	(250,369)	-	(2,059,733)	-	(6,331,716)	-	(5,173,848)	(6,000,000)	(6,768,500)	(5,900,000)	(7,050,360)	(1,900,000)	(4,034,892)	(4,800,000)	(4,575,168)	(6,000,000)	(5,053,006)
Allocation Factor	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0.889	0.889	0.889	0.889
Allocated Amount	-	(250,369)	-	(2,059,733)	-	(6,331,716)	-	(5,173,848)	(6,000,000)	(6,768,500)	(5,900,000)	(7,050,360)	(1,900,000)	(4,034,892)	(4,267,200)	(4,067,324)	(5,334,000)	(4,492,122)
Net Allocated Amount	69,300	(183,233)	69,300	2,584,253	69,300	10,042,313	69,300	8,418,947	(6,000,000)	10,981,141	(5,900,000)	10,440,262	(1,900,000)	3,490,737	(4,267,200)	2,595,993	(5,334,000)	3,753,395

	First Quarter 2009		Second Quarter 2009		Third Quarter 2009		Fourth Quarter 2009		First Quarter 2010		April 2010	
Loss Charges	Projected	Actual *	Projected	Actual	Projected	Actual	Projected	Actual	Projected	Actual	Projected	Actual
Total Amount	17,939,973	9,782,433	10,779,076	-	11,881,860	-	11,009,302	-	11,750,279	-	2,582,821	-
Allocation Factor	0.774	0.774	0.774	0.774	0.774	0.774	0.774	0.774	0.774	0.774	0.774	0.774
Allocated Amount	13,885,539	7,571,603	8,343,005	-	9,196,560	-	8,521,200	-	9,094,716	-	1,999,103	-
Loss Credits												
Total Amount	(7,071,340)	(3,737,027)	(6,963,207)	-	(8,386,705)	-	(7,451,370)	-	(8,228,212)	-	(2,289,258)	-
Allocation Factor	0.889	0.889	0.889	0.889	0.889	0.889	0.889	0.889	0.889	0.889	0.889	0.889
Allocated Amount	(6,286,421)	(3,322,217)	(6,181,401)	-	(7,455,781)	-	(6,624,288)	-	(7,314,881)	-	(2,035,151)	-
Net Allocated Amount	7,599,118	4,249,386	2,161,604	-	1,740,779	-	1,896,932	-	1,779,836	-	(36,047)	-

The Dayton Power and Light Company
Case No. 09-256-EL-UNC
Projected and Actual Costs and Revenues
Firm Point-to-Point Transmission Service Credits
Calendar 2007 through First Quarter 2010

Data: Actual and Forecasted
Type of Filing: Original
Work Paper Reference No(s).: None

Witness Responsible
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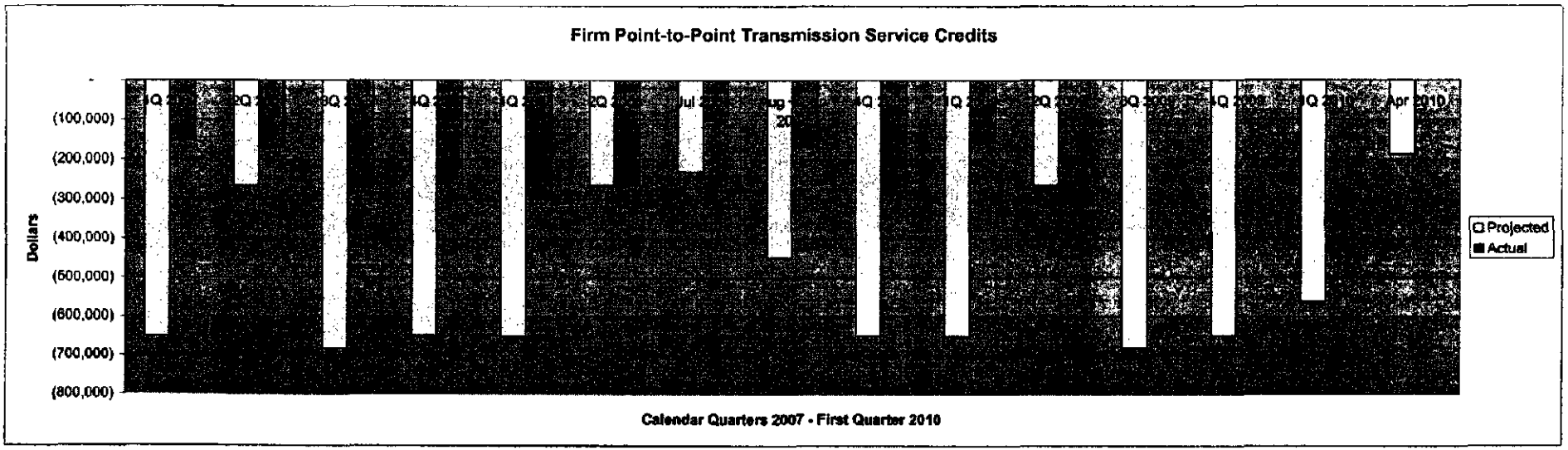

Firm PTP Charges	First Quarter 2007 Projected	First Quarter 2007 Actual	Second Quarter 2007 Projected	Second Quarter 2007 Actual	Third Quarter 2007 Projected	Third Quarter 2007 Actual	Fourth Quarter 2007 Projected	Fourth Quarter 2007 Actual	First Quarter 2008 Projected	First Quarter 2008 Actual	Second Quarter 2008 Projected	Second Quarter 2008 Actual	Third Quarter 2008 July 2008 Projected	Third Quarter 2008 July 2008 Actual	Third Quarter 2008 August and September 2008 Projected	Third Quarter 2008 August and September 2008 Actual	Fourth Quarter 2008 Projected	Fourth Quarter 2008 Actual
Total Amount	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Allocation Factor	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	1.000	1.000	1.000	1.000
Allocated Amount	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Firm PTP Credits																		
Total Amount	(652,423)	(151,984)	(266,567)	(169,268)	(682,331)	(283,268)	(650,514)	(262,356)	(652,423)	(291,082)	(266,567)	(264,781)	(232,212)	(100,267)	(450,119)	(166,609)	(650,514)	(281,293)
Allocation Factor	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	1.000	1.000	1.000	1.000
Allocated Amount	(652,423)	(151,984)	(266,567)	(169,268)	(682,331)	(283,268)	(650,514)	(262,356)	(652,423)	(291,082)	(266,567)	(264,781)	(232,212)	(100,267)	(450,119)	(166,609)	(650,514)	(281,293)
Net Allocated Amount	(652,423)	(151,984)	(266,567)	(169,268)	(682,331)	(283,268)	(650,514)	(262,356)	(652,423)	(291,082)	(266,567)	(264,781)	(232,212)	(100,267)	(450,119)	(166,609)	(650,514)	(281,293)

Firm PTP Charges	First Quarter 2009 Projected	First Quarter 2009 Actual *	Second Quarter 2009 Projected	Second Quarter 2009 Actual	Third Quarter 2009 Projected	Third Quarter 2009 Actual	Fourth Quarter 2009 Projected	Fourth Quarter 2009 Actual	First Quarter 2010 Projected	First Quarter 2010 Actual	April 2010 Projected	April 2010 Actual
Total Amount	-	-	-	-	-	-	-	-	-	-	-	-
Allocation Factor	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
Allocated Amount	-	-	-	-	-	-	-	-	-	-	-	-
Firm PTP Credits												
Total Amount	(652,423)	(158,350)	(266,567)	-	(682,331)	-	(650,514)	-	(562,959)	-	(187,653)	-
Allocation Factor	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
Allocated Amount	(652,423)	(158,350)	(266,567)	-	(682,331)	-	(650,514)	-	(562,959)	-	(187,653)	-
Net Allocated Amount	(652,423)	(158,350)	(266,567)	-	(682,331)	-	(650,514)	-	(562,959)	-	(187,653)	-

The Dayton Power and Light Company
Case No. 09-256-EL-UNC
Projected and Actual Costs and Revenues
Non-Firm Point-to-Point Transmission Service Credits
Calendar 2007 through First Quarter 2010

Data: Actual and Forecasted
Type of Filing: Original
Work Paper Reference No(s).: None

Witness Responsible:
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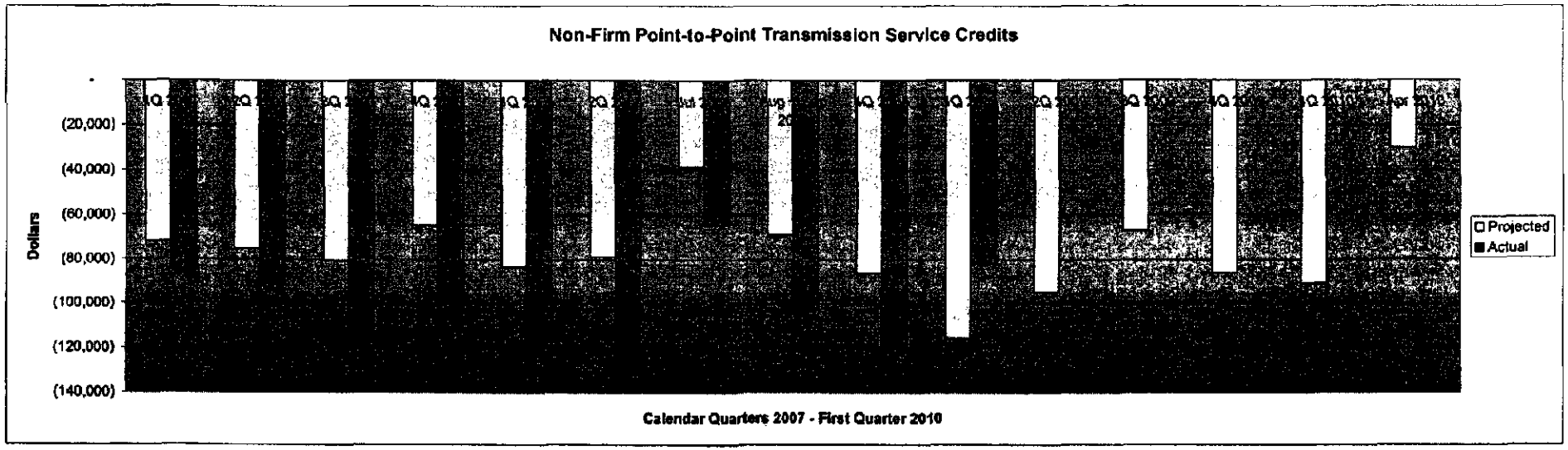


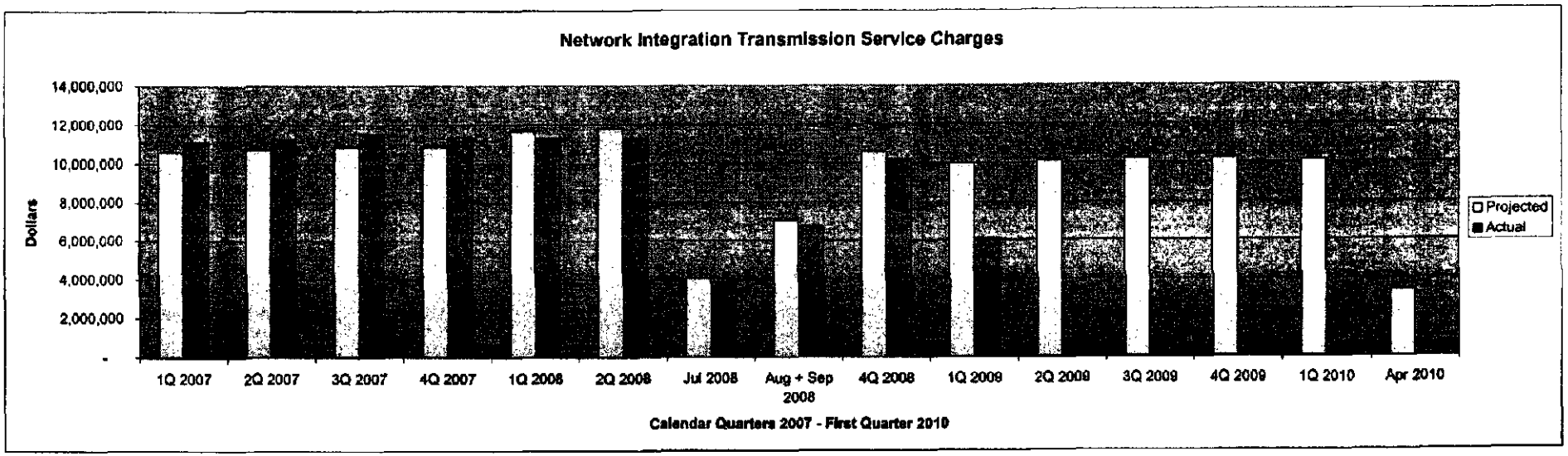
Non-Firm PTP Charges	First Quarter 2007 Projected	First Quarter 2007 Actual	Second Quarter 2007 Projected	Second Quarter 2007 Actual	Third Quarter 2007 Projected	Third Quarter 2007 Actual	Fourth Quarter 2007 Projected	Fourth Quarter 2007 Actual	First Quarter 2008 Projected	First Quarter 2008 Actual	Second Quarter 2008 Projected	Second Quarter 2008 Actual	Third Quarter 2008 July 2008 Projected	Third Quarter 2008 July 2008 Actual	Third Quarter 2008 August and September 2008 Projected	Third Quarter 2008 August and September 2008 Actual	Fourth Quarter 2008 Projected	Fourth Quarter 2008 Actual
Total Amount	1,729	-	2,522	-	479	-	1,862	-	1,104	-	11,988	-	2,052	-	1,943	-	3,452	-
Allocation Factor	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	1.000	1.000	1.000	1.000
Allocated Amount	1,729	-	2,522	-	479	-	1,862	-	1,104	-	11,988	-	2,052	-	1,943	-	3,452	-
Non-Firm PTP Credits																		
Total Amount	(73,560)	(84,484)	(77,747)	(90,873)	(80,923)	(111,865)	(66,410)	(99,678)	(84,484)	(117,008)	(90,873)	(124,506)	(40,785)	(64,543)	(70,900)	(102,078)	(89,678)	(119,114)
Allocation Factor	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	1.000	1.000	1.000	1.000
Allocated Amount	(73,560)	(84,484)	(77,747)	(90,873)	(80,923)	(111,865)	(66,410)	(99,678)	(84,484)	(117,008)	(90,873)	(124,506)	(40,785)	(64,543)	(70,900)	(102,078)	(89,678)	(119,114)
Net Allocated Amount	(71,831)	(84,484)	(75,225)	(90,873)	(80,444)	(111,865)	(64,548)	(99,678)	(83,380)	(117,008)	(78,885)	(124,506)	(38,713)	(64,543)	(68,957)	(102,078)	(86,226)	(119,114)

Non-Firm PTP Charges	First Quarter 2009 Projected	First Quarter 2009 Actual *	Second Quarter 2009 Projected	Second Quarter 2009 Actual	Third Quarter 2009 Projected	Third Quarter 2009 Actual	Fourth Quarter 2009 Projected	Fourth Quarter 2009 Actual	First Quarter 2010 Projected	First Quarter 2010 Actual	April 2010 Projected	April 2010 Actual
Total Amount	1,157	-	29,614	-	99,563	-	3,452	-	33,600	-	11,200	-
Allocation Factor	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
Allocated Amount	1,157	-	29,614	-	99,563	-	3,452	-	33,600	-	11,200	-
Non-Firm PTP Credits												
Total Amount	(117,008)	(81,614)	(124,506)	-	(166,621)	-	(89,678)	-	(124,453)	-	(41,484)	-
Allocation Factor	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
Allocated Amount	(117,008)	(81,614)	(124,506)	-	(166,621)	-	(89,678)	-	(124,453)	-	(41,484)	-
Net Allocated Amount	(115,851)	(81,614)	(94,892)	-	(66,958)	-	(86,226)	-	(90,854)	-	(30,285)	-

The Dayton Power and Light Company
Case No. 09-256-EL-UNC
Projected and Actual Costs and Revenues
Network Integration Transmission Service Charges
Calendar 2007 through First Quarter 2010

Witness Responsible
G.S. Campbell

Data: Actual and Forecasted
Type of Filing: Original
Work Paper Reference No(s).: None



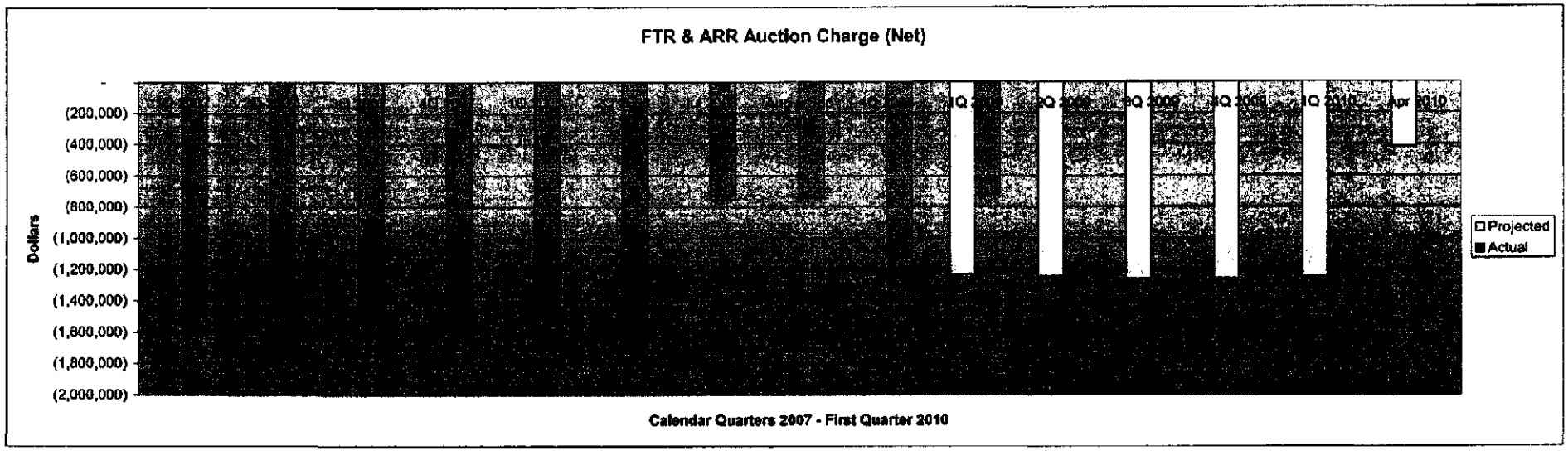
	First Quarter 2007		Second Quarter 2007		Third Quarter 2007		Fourth Quarter 2007		First Quarter 2008		Second Quarter 2008		Third Quarter 2008				Fourth Quarter 2008	
													July 2008		August and September 2008			
NITS Charges	Projected	Actual	Projected	Actual	Projected	Actual	Projected	Actual	Projected	Actual	Projected	Actual	Projected	Actual	Projected	Actual	Projected	Actual
Total Amount	10,612,518	11,127,356	10,730,435	11,248,555	10,848,352	11,519,061	10,848,352	11,388,644	11,681,192	11,315,774	11,796,952	11,315,818	4,018,880	3,854,937	7,907,816	7,585,521	11,928,497	11,440,861
Allocation Factor	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0.889	0.889	0.889	0.889
Allocated Amount	10,612,518	11,127,356	10,730,435	11,248,555	10,848,352	11,519,061	10,848,352	11,388,644	11,681,192	11,315,774	11,796,952	11,315,818	4,018,880	3,854,937	7,030,049	6,743,528	10,602,656	10,170,925
NITS Credits																		
Total Amount	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Allocation Factor	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	1.000	1.000	1.000	1.000
Allocated Amount	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Net Allocated Amount	10,612,518	11,127,356	10,730,435	11,248,555	10,848,352	11,519,061	10,848,352	11,388,644	11,681,192	11,315,774	11,796,952	11,315,818	4,018,880	3,854,937	7,030,049	6,743,528	10,602,656	10,170,925

	First Quarter 2009		Second Quarter 2009		Third Quarter 2009		Fourth Quarter 2009		First Quarter 2010		April 2010	
NITS Charges	Projected	Actual *	Projected	Actual	Projected	Actual	Projected	Actual	Projected	Actual	Projected	Actual
Total Amount	11,245,754	6,960,182	11,364,041	-	11,482,327	-	11,482,327	-	11,393,612	-	3,797,871	-
Allocation Factor	0.889	0.889	0.889	0.889	0.889	0.889	0.889	0.889	0.889	0.889	0.889	0.889
Allocated Amount	9,997,476	6,098,702	10,102,632	-	10,207,788	-	10,207,788	-	10,128,921	-	3,376,307	-
NITS Credits												
Total Amount	-	-	-	-	-	-	-	-	-	-	-	-
Allocation Factor	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
Allocated Amount	-	-	-	-	-	-	-	-	-	-	-	-
Net Allocated Amount	9,997,476	6,098,702	10,102,632	-	10,207,788	-	10,207,788	-	10,128,921	-	3,376,307	-

The Dayton Power and Light Company
Case No. 09-256-EL-UNC
Projected and Actual Costs and Revenues
FTR & ARR Auction Charges and Credits
Calendar 2007 through First Quarter 2010

Data: Actual and Forecasted
Type of Filing: Original
Work Paper Reference No(s).: None

Witness Responsible:
G.S. Campbell



FTR Charges	First Quarter 2007 Projected	First Quarter 2007 Actual	Second Quarter 2007 Projected	Second Quarter 2007 Actual	Third Quarter 2007 Projected	Third Quarter 2007 Actual	Fourth Quarter 2007 Projected	Fourth Quarter 2007 Actual	First Quarter 2008 Projected	First Quarter 2008 Actual	Second Quarter 2008 Projected	Second Quarter 2008 Actual
Total Amount	-	70,682	-	63,191	-	34,298	-	(122)	-	(7,100)	-	5,536
Allocation Factor	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Allocated Amount	-	70,682	-	63,191	-	34,298	-	(122)	-	(7,100)	-	5,536
ARR Credits												
Total Amount	-	(1,600,673)	-	(1,571,092)	-	(1,541,236)	-	(1,527,718)	-	(1,520,914)	-	(1,736,859)
Allocation Factor	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Allocated Amount	-	(1,600,673)	-	(1,571,092)	-	(1,541,236)	-	(1,527,718)	-	(1,520,914)	-	(1,736,859)
Net Allocated Amount	-	(1,529,991)	-	(1,507,901)	-	(1,506,938)	-	(1,527,840)	-	(1,528,014)	-	(1,731,323)

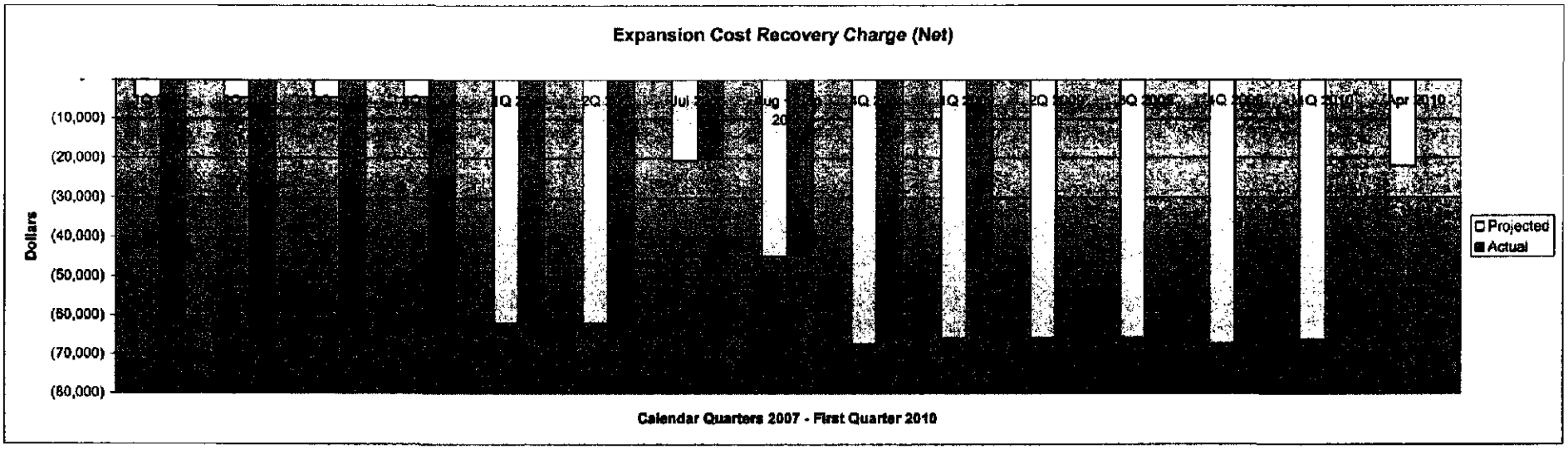
FTR Charges	Third Quarter 2008 July 2008 Projected	Third Quarter 2008 July 2008 Actual	Third Quarter 2008 August and September 2008 Projected	Third Quarter 2008 August and September 2008 Actual	Fourth Quarter 2008 Projected	Fourth Quarter 2008 Actual
Total Amount	-	(2,007)	-	(3,952)	-	(5,960)
Allocation Factor	N/A	N/A	0.500	0.500	0.500	0.500
Allocated Amount	-	(2,007)	-	(1,976)	-	(2,980)
ARR Credits						
Total Amount	-	(755,022)	-	(1,485,689)	-	(2,240,767)
Allocation Factor	N/A	N/A	0.500	0.500	0.500	0.500
Allocated Amount	-	(755,022)	-	(742,845)	-	(1,120,384)
Net Allocated Amount	-	(757,029)	-	(744,821)	-	(1,123,364)

FTR Charges	First Quarter 2009 Projected	First Quarter 2009 Actual *	Second Quarter 2009 Projected	Second Quarter 2009 Actual	Third Quarter 2009 Projected	Third Quarter 2009 Actual	Fourth Quarter 2009 Projected	Fourth Quarter 2009 Actual	First Quarter 2010 Projected	First Quarter 2010 Actual	April 2010 Projected	April 2010 Actual
Total Amount	-	(3,822)	-	-	-	-	-	-	-	-	-	-
Allocation Factor	0.500	0.500	0.500	0.500	0.500	0.500	0.500	0.500	0.500	0.500	0.500	0.500
Allocated Amount	-	(1,911)	-	-	-	-	-	-	-	-	-	-
ARR Credits												
Total Amount	(2,465,753)	(1,437,126)	(2,493,151)	-	(2,520,548)	-	(2,520,548)	-	(2,500,000)	-	(833,333)	-
Allocation Factor	0.500	0.500	0.500	0.500	0.500	0.500	0.500	0.500	0.500	0.500	0.500	0.500
Allocated Amount	(1,232,877)	(718,563)	(1,246,575)	-	(1,260,274)	-	(1,260,274)	-	(1,250,000)	-	(416,667)	-
Net Allocated Amount	(1,232,877)	(720,474)	(1,246,575)	-	(1,260,274)	-	(1,260,274)	-	(1,250,000)	-	(416,667)	-

The Dayton Power and Light Company
Case No. 09-258-EL-UNC
Projected and Actual Costs and Revenues
Expansion Cost Recovery Charges and Credits
Calendar 2007 through First Quarter 2010

Data: Actual and Forecasted
Type of Filing: Original
Work Paper Reference No(s).: None

Witness Responsible:
G.S. Campbell



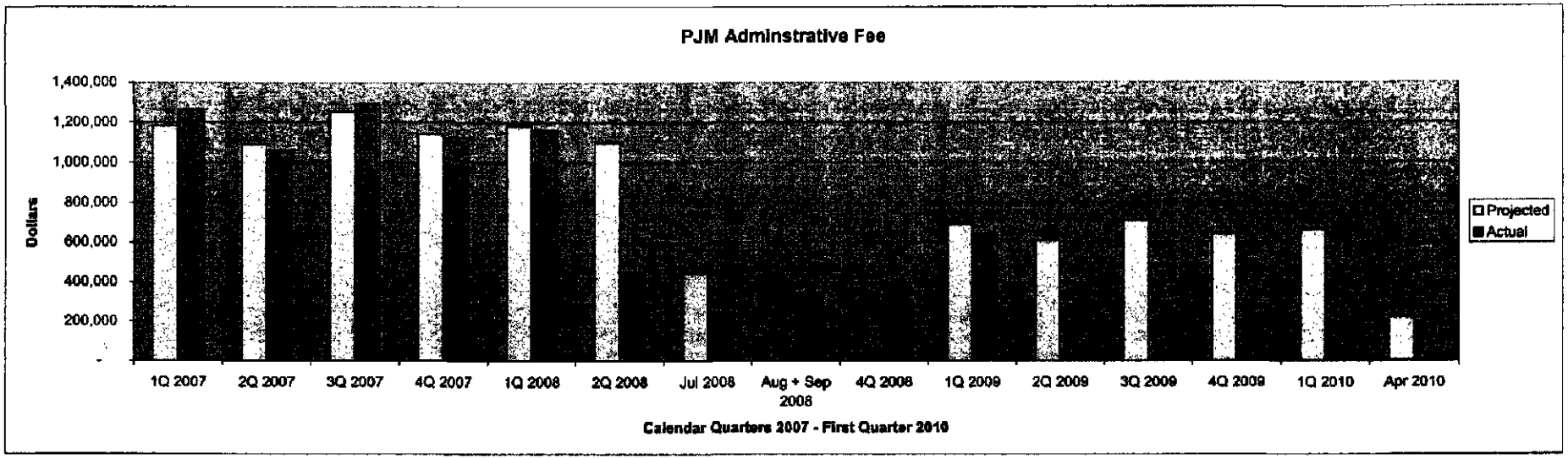
ECRC Charges	First Quarter 2007 Projected	First Quarter 2007 Actual	Second Quarter 2007 Projected	Second Quarter 2007 Actual	Third Quarter 2007 Projected	Third Quarter 2007 Actual	Fourth Quarter 2007 Projected	Fourth Quarter 2007 Actual	First Quarter 2008 Projected	First Quarter 2008 Actual	Second Quarter 2008 Projected	Second Quarter 2008 Actual	Third Quarter 2008 July 2008 Projected	Third Quarter 2008 July 2008 Actual	Third Quarter 2008 August and September 2008 Projected	Third Quarter 2008 August and September 2008 Actual	Fourth Quarter 2008 Projected	Fourth Quarter 2008 Actual
Total Amount	50,499	47,973	50,499	47,964	50,499	47,964	50,499	47,994	47,973	49,602	47,964	49,603	15,988	16,535	31,976	33,070	47,994	49,607
Allocation Factor	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0.889	0.889	0.889	0.889
Allocated Amount	50,499	47,973	50,499	47,964	50,499	47,964	50,499	47,994	47,973	49,602	47,964	49,603	15,988	16,535	28,427	29,399	42,667	44,101
ECRC Credits																		
Total Amount	(55,028)	(110,036)	(55,028)	(110,030)	(55,028)	(109,997)	(55,028)	(110,020)	(110,036)	(109,965)	(110,030)	(109,965)	(36,674)	(36,655)	(73,323)	(73,311)	(110,020)	(109,966)
Allocation Factor	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	1.000	1.000	1.000	1.000
Allocated Amount	(55,028)	(110,036)	(55,028)	(110,030)	(55,028)	(109,997)	(55,028)	(110,020)	(110,036)	(109,965)	(110,030)	(109,965)	(36,674)	(36,655)	(73,323)	(73,311)	(110,020)	(109,966)
Net Allocated Amount	(4,529)	(62,063)	(4,529)	(62,066)	(4,529)	(62,033)	(4,529)	(62,026)	(62,063)	(60,363)	(62,066)	(60,362)	(20,686)	(20,120)	(44,896)	(43,912)	(67,353)	(65,865)

ECRC Charges	First Quarter 2009 Projected	First Quarter 2009 Actual *	Second Quarter 2009 Projected	Second Quarter 2009 Actual	Third Quarter 2009 Projected	Third Quarter 2009 Actual	Fourth Quarter 2009 Projected	Fourth Quarter 2009 Actual	First Quarter 2010 Projected	First Quarter 2010 Actual	April 2010 Projected	April 2010 Actual
Total Amount	49,602	32,017	49,603	-	49,605	-	47,994	-	49,201	-	16,400	-
Allocation Factor	0.889	0.889	0.889	0.889	0.889	0.889	0.889	0.889	0.889	0.889	0.889	0.889
Allocated Amount	44,096	28,463	44,097	-	44,099	-	42,667	-	43,740	-	14,580	-
ECRC Credits												
Total Amount	(109,965)	(73,446)	(109,965)	-	(109,966)	-	(110,020)	-	(109,979)	-	(36,660)	-
Allocation Factor	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
Allocated Amount	(109,965)	(73,446)	(109,965)	-	(109,966)	-	(110,020)	-	(109,979)	-	(36,660)	-
Net Allocated Amount	(65,869)	(44,983)	(65,868)	-	(65,867)	-	(67,353)	-	(66,239)	-	(22,080)	-

The Dayton Power and Light Company
Case No. 09-256-EL-UNC
Projected and Actual Costs and Revenues
PJM Administrative Charges
Calendar 2007 through First Quarter 2010

Data: Actual and Forecasted
Type of Filing: Original
Work Paper Reference No(s).: None

Witness Responsible:
G.S. Campbell



	First Quarter 2007		Second Quarter 2007		Third Quarter 2007		Fourth Quarter 2007		First Quarter 2008		Second Quarter 2008		Third Quarter 2008				Fourth Quarter 2008	
													July 2008		August and September 2008			
Admin Charges	Projected	Actual	Projected	Actual	Projected	Actual	Projected	Actual	Projected	Actual	Projected	Actual	Projected	Actual	Projected	Actual	Projected	Actual
Total Amount	1,180,661	1,260,822	1,088,811	1,059,149	1,254,068	1,291,371	1,141,229	1,125,189	1,179,861	1,161,425	1,097,957	455,645	445,969	247,217	807,690	347,967	1,136,236	387,372
Allocation Factor	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Allocated Amount	1,180,661	1,260,822	1,088,811	1,059,149	1,254,068	1,291,371	1,141,229	1,125,189	1,179,861	1,161,425	1,097,957	455,645	445,969	247,217	807,690	347,967	1,136,236	387,372
Admin Credits																		
Total Amount	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Allocation Factor	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	1.000	1.000	1.000	1.000
Allocated Amount	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Net Allocated Amount	1,180,661	1,260,822	1,088,811	1,059,149	1,254,068	1,291,371	1,141,229	1,125,189	1,179,861	1,161,425	1,097,957	455,645	445,969	247,217	807,690	347,967	1,136,236	387,372

	First Quarter 2009		Second Quarter 2009		Third Quarter 2009		Fourth Quarter 2009		First Quarter 2010		April 2010	
Admin Charges	Projected	Actual *	Projected	Actual	Projected	Actual	Projected	Actual	Projected	Actual	Projected	Actual
Total Amount	775,607	640,573	683,951	-	798,057	-	722,075	-	745,584	-	248,528	-
Allocation Factor	0.889	N/A	0.889	0.889	0.889	0.889	0.889	0.889	0.889	0.889	0.889	0.889
Allocated Amount	689,515	640,573	608,032	-	707,694	-	641,925	-	662,824	-	220,941	-
Admin Credits												
Total Amount	-	-	-	-	-	-	-	-	-	-	-	-
Allocation Factor	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
Allocated Amount	-	-	-	-	-	-	-	-	-	-	-	-
Net Allocated Amount	689,515	640,573	608,032	-	707,694	-	641,925	-	662,824	-	220,941	-

THE DAYTON POWER AND LIGHT COMPANY
CASE NO. 09-256-EL-UNC

Transmission Cost Recovery Rider (TCRR)

Schedule B-5
Typical Bill Comparisons

The Dayton Power & Light Company

The Dayton Power and Light Company
Case No. 09-256-EL-UNC
Typical Bill Comparison
Residential

Data: 0 Months Actual, 12 Months Estimated
Type of Filing: Original
Work Paper Reference: None

Witness Responsible:
Sharon Schroder

Line No.	Level of (kW)	Level of (kWh)	Current Bill	Bills with TCRR	Dollar Increase	Percent Increase
	(A)	(B)	(C)	(D)	(E = D - C)	(F = E / C)
1	0.0	50	$9.89	$10.09	$0.20	2.02%
2	0.0	100	$15.41	$15.81	$0.40	2.60%
3	0.0	200	$26.47	$27.29	$0.82	3.10%
4	0.0	400	$48.61	$50.24	$1.63	3.35%
5	0.0	500	$59.68	$61.71	$2.03	3.40%
6	0.0	750	$87.35	$90.40	$3.05	3.49%
7	0.0	1,000	$111.44	$115.52	$4.08	3.66%
8	0.0	1,200	$130.70	$135.61	$4.91	3.76%
9	0.0	1,400	$149.99	$155.71	$5.72	3.81%
10	0.0	1,500	$159.65	$165.76	$6.11	3.83%
11	0.0	2,000	$207.83	$215.99	$8.16	3.93%
12	0.0	2,500	$255.82	$266.01	$10.19	3.98%
13	0.0	3,000	$303.77	$316.01	$12.24	4.03%
14	0.0	4,000	$399.70	$416.03	$16.33	4.09%
15	0.0	5,000	$495.64	$516.05	$20.41	4.12%
16	0.0	7,500	$735.51	$766.11	$30.60	4.16%

The Dayton Power and Light Company
Case No. 09-256-EL-UNC
Typical Bill Comparison
Residential Heat (Summer)

Data: 0 Months Actual, 12 Months Estimated
Type of Filing: Original
Work Paper Reference: None

Witness Responsible:
Sharon Schroder

Line No.	Level of (kW)	Level of (kWh)	Current Bill	Bills with TCRR	Dollar Increase	Percent Increase
	(A)	(B)	(C)	(D)	(E = D - C)	(F = E / C)
1	0.0	50	$9.89	$10.09	$0.20	2.02%
2	0.0	100	$15.41	$15.81	$0.40	2.60%
3	0.0	200	$26.47	$27.29	$0.82	3.10%
4	0.0	400	$48.61	$50.23	$1.62	3.33%
5	0.0	500	$59.68	$61.71	$2.03	3.40%
6	0.0	750	$87.35	$90.39	$3.04	3.48%
7	0.0	1,000	$111.44	$115.51	$4.07	3.65%
8	0.0	1,200	$130.70	$135.59	$4.89	3.74%
9	0.0	1,400	$149.99	$155.70	$5.71	3.81%
10	0.0	1,500	$159.65	$165.75	$6.10	3.82%
11	0.0	2,000	$207.83	$215.97	$8.14	3.92%
12	0.0	2,500	$255.82	$265.99	$10.17	3.98%
13	0.0	3,000	$303.77	$315.98	$12.21	4.02%
14	0.0	4,000	$399.70	$415.99	$16.29	4.08%
15	0.0	5,000	$495.64	$516.00	$20.36	4.11%
16	0.0	7,500	$735.51	$766.04	$30.53	4.15%

The Dayton Power and Light Company
Case No. 09-256-EL-UNC
Typical Bill Comparison
Residential Heat (Winter)

Data: 0 Months Actual, 12 Months Estimated
Type of Filing: Original
Work Paper Reference: None

Witness Responsible:
Sharon Schroder

Line No.	Level of (kW)	Level of (kWh)	Current Bill	Bills with TCRR	Dollar Increase	Percent Increase
	(A)	(B)	(C)	(D)	(E = D - C)	(F = E / C)
1	0.0	50	$9.89	$10.09	$0.20	1.98%
2	0.0	100	$15.41	$15.81	$0.40	2.60%
3	0.0	200	$26.47	$27.29	$0.82	3.11%
4	0.0	400	$48.61	$50.23	$1.62	3.34%
5	0.0	500	$59.68	$61.71	$2.03	3.39%
6	0.0	750	$87.35	$90.39	$3.04	3.48%
7	0.0	1,000	$105.13	$109.20	$4.07	3.87%
8	0.0	1,200	$119.34	$124.23	$4.89	4.10%
9	0.0	1,400	$133.58	$139.29	$5.71	4.27%
10	0.0	1,500	$140.70	$146.80	$6.10	4.33%
11	0.0	2,000	$176.26	$184.40	$8.14	4.62%
12	0.0	2,500	$211.61	$221.78	$10.17	4.81%
13	0.0	3,000	$246.95	$259.16	$12.21	4.95%
14	0.0	4,000	$317.62	$333.91	$16.29	5.13%
15	0.0	5,000	$388.30	$408.66	$20.36	5.24%
16	0.0	7,500	$565.00	$595.53	$30.53	5.40%

The Dayton Power and Light Company
Case No. 09-256-EL-UNC
Typical Bill Comparison
Secondary Unmetered

Data: 0 Months Actual, 12 Months Estimated
Type of Filing: Original
Work Paper Reference: None

Witness Responsible:
Sharon Schroder

Line No.	Level of (kW)	Level of (kWh)	Current Bill	Bills with TCRR	Dollar Increase	Percent Increase
	(A)	(B)	(C)	(D)	(E = D - C)	(F = E / C)
1	0.0	50	$11.93	$12.03	$0.10	0.84%
2	0.0	100	$17.10	$17.31	$0.21	1.23%
3	0.0	150	$22.27	$22.59	$0.32	1.44%
4	0.0	200	$27.41	$27.86	$0.45	1.64%
5	0.0	300	$37.74	$38.39	$0.65	1.72%
6	0.0	400	$48.06	$48.94	$0.88	1.83%
7	0.0	500	$58.41	$59.50	$1.09	1.87%
8	0.0	600	$68.71	$70.04	$1.33	1.94%
9	0.0	800	$89.36	$91.12	$1.76	1.97%
10	0.0	1,000	$110.00	$112.21	$2.21	2.01%
11	0.0	1,200	$130.63	$133.29	$2.66	2.04%
12	0.0	1,400	$151.29	$154.39	$3.10	2.05%
13	0.0	1,600	$165.77	$169.03	$3.26	1.97%
14	0.0	2,000	$182.36	$185.46	$3.10	1.70%
15	0.0	2,200	$190.55	$193.57	$3.02	1.58%
16	0.0	2,400	$198.74	$201.69	$2.95	1.48%

Secondary customers are charged for all kW over 5kW of Billing Demand and for the first 1,500 kWh

The Dayton Power and Light Company
Case No. 09-256-EL-UNC
Typical Bill Comparison
Secondary Single Phase

Data: 0 Months Actual, 12 Months Estimated
Type of Filing: Original
Work Paper Reference: None

Witness Responsible:
Sharon Schroder

Line No.	Level of (kW)	Level of (kWh)	Current Bill	Bills with TCRR	Dollar Increase	Percent Increase
	(A)	(B)	(C)	(D)	(E = D - C)	(F = E / C)
1	5	750	$86.21	$87.86	$1.65	1.91%
2	5	1,500	$163.62	$166.92	$3.30	2.02%
3	10	1,500	$239.99	$253.70	$13.71	5.71%
4	25	5,000	$612.76	$656.36	$43.60	7.12%
5	25	7,500	$715.21	$757.84	$42.63	5.96%
6	25	10,000	$817.66	$859.32	$41.66	5.10%
7	50	15,000	$1,404.41	$1,496.20	$91.79	6.54%
8	50	25,000	$1,808.60	$1,896.50	$87.90	4.86%
9	200	50,000	$5,110.05	$5,500.78	$390.73	7.65%
10	200	100,000	$7,131.12	$7,502.40	$371.28	5.21%
11	300	125,000	$9,668.92	$10,238.82	$569.90	5.89%
12	500	200,000	$15,353.72	$16,311.16	$957.44	6.24%
13	1,000	300,000	$26,497.07	$28,457.42	$1,960.35	7.40%
14	1,000	500,000	$33,511.03	$35,393.58	$1,882.55	5.62%
15	2,500	750,000	$65,187.64	$70,098.31	$4,910.67	7.53%
16	2,500	1,000,000	$73,803.84	$78,617.26	$4,813.42	6.52%

Secondary customers are charged for all kW over 5kW of Billing Demand and for the first 1,500 kWh

The Dayton Power and Light Company
Case No. 09-256-EL-UNC
Typical Bill Comparison
Secondary Three Phase

Data: 0 Months Actual, 12 Months Estimated
Type of Filing: Original
Work Paper Reference: None

Witness Responsible:
Sharon Schroder

Line No.	Level of (kW)	Level of (kWh)	Current Bill	Bills with TCRR	Dollar Increase	Percent Increase
	(A)	(B)	(C)	(D)	(E = D - C)	(F = E / C)
1	5	500	$67.75	$68.84	$1.09	1.61%
2	5	1,500	$170.97	$174.27	$3.30	1.93%
3	10	1,500	$247.34	$261.05	$13.71	5.54%
4	25	5,000	$620.11	$663.71	$43.60	7.03%
5	25	7,500	$722.56	$765.19	$42.63	5.90%
6	25	10,000	$825.01	$866.67	$41.66	5.05%
7	50	25,000	$1,815.95	$1,903.85	$87.90	4.84%
8	200	50,000	$5,117.40	$5,508.13	$390.73	7.64%
9	200	125,000	$8,148.99	$8,510.54	$361.55	4.44%
10	500	200,000	$15,361.07	$16,318.51	$957.44	6.23%
11	1,000	300,000	$26,504.42	$28,464.77	$1,960.35	7.40%
12	1,000	500,000	$33,518.38	$35,400.93	$1,882.55	5.62%
13	2,500	750,000	$65,194.99	$70,105.66	$4,910.67	7.53%
14	2,500	1,000,000	$73,811.19	$78,624.61	$4,813.42	6.52%
15	5,000	1,500,000	$129,075.13	$138,903.02	$9,827.89	7.61%
16	5,000	2,000,000	$146,157.20	$155,790.59	$9,633.39	6.59%

Secondary customers are charged for all kW over 5kW of Billing Demand and for the first 1,500 kWh

The Dayton Power and Light Company
Case No. 09-256-EL-UNC
Typical Bill Comparison
Primary Service

Data: 0 Months Actual, 12 Months Estimated
Type of Filing: Original
Work Paper Reference: None

Witness Responsible:
Sharon Schroder

Line No.	Level of (kW)	Level of (kWh)	Current Bill	Bills with TCRR	Dollar Increase	Percent Increase
	(A)	(B)	(C)	(D)	(E = D - C)	(F = E / C)
1	5	1,000	$207.21	$212.21	$5.00	2.41%
2	5	2,500	$258.30	$263.24	$4.94	1.91%
3	10	5,000	$420.48	$430.37	$9.89	2.35%
4	25	7,500	$738.29	$763.25	$24.96	3.38%
5	25	10,000	$822.66	$847.50	$24.84	3.02%
6	50	20,000	$1,546.42	$1,596.09	$49.67	3.21%
7	50	30,000	$1,878.36	$1,927.57	$49.21	2.62%
8	200	50,000	$4,876.38	$5,076.47	$200.09	4.10%
9	200	75,000	$5,706.20	$5,905.14	$198.94	3.49%
10	200	100,000	$6,535.99	$6,733.80	$197.81	3.03%
11	500	250,000	$16,183.27	$16,677.78	$494.51	3.06%
12	1,000	500,000	$32,261.96	$33,251.00	$989.04	3.07%
13	2,500	1,000,000	$72,048.81	$74,532.80	$2,483.99	3.45%
14	5,000	2,500,000	$159,381.97	$164,327.15	$4,945.18	3.10%
15	10,000	5,000,000	$317,904.99	$327,795.36	$9,890.37	3.11%
16	25,000	7,500,000	$632,040.40	$656,994.42	$24,954.02	3.95%
17	25,000	10,000,000	$712,757.22	$737,597.19	$24,839.97	3.49%
18	50,000	15,000,000	$1,263,221.85	$1,313,129.89	$49,908.04	3.95%

The Dayton Power and Light Company
Case No. 09-256-EL-UNC
Typical Bill Comparison
Primary Substation

Data: 0 Months Actual, 12 Months Estimated
Type of Filing: Original
Work Paper Reference: None

Witness Responsible:
Sharon Schroder

Line No.	Level of (kW)	Level of (kWh)	Current Bill	Bills with TCRR	Dollar Increase	Percent Increase
	(A)	(B)	(C)	(D)	(E = D - C)	(F = E / C)
1	3,000	1,000,000	$76,602.54	$80,098.58	$3,496.04	4.56%
2	5,000	2,000,000	$137,366.69	$143,175.01	$5,808.32	4.23%
3	5,000	3,000,000	$168,322.11	$174,075.20	$5,753.09	3.42%
4	10,000	4,000,000	$273,799.34	$285,415.98	$11,616.64	4.24%
5	10,000	5,000,000	$304,754.77	$316,316.18	$11,561.41	3.79%
6	15,000	6,000,000	$410,232.00	$427,656.97	$17,424.97	4.25%
7	15,000	7,000,000	$441,187.42	$458,557.16	$17,369.74	3.94%
8	15,000	8,000,000	$472,142.85	$489,457.36	$17,314.51	3.67%
9	25,000	9,000,000	$652,141.88	$681,238.72	$29,096.84	4.46%
10	25,000	10,000,000	$683,097.31	$712,138.92	$29,041.61	4.25%
11	30,000	12,500,000	$835,007.67	$869,829.99	$34,822.32	4.17%
12	30,000	15,000,000	$912,396.23	$947,080.47	$34,684.24	3.80%
13	50,000	17,500,000	$1,287,872.02	$1,346,093.32	$58,221.30	4.52%
14	50,000	20,000,000	$1,365,260.58	$1,423,343.80	$58,083.22	4.25%
15	50,000	25,000,000	$1,520,037.70	$1,577,844.77	$57,807.07	3.80%

The Dayton Power and Light Company
Case No. 09-256-EL-UNC
Typical Bill Comparison
High Voltage Service

Data: 0 Months Actual, 12 Months Estimated
Type of Filing: Original
Work Paper Reference: None

Witness Responsible:
Sharon Schroder

Line No.	Level of (kW)	Level of (kWh)	Current Bill	Bills with TCRR	Dollar Increase	Percent Increase
	(A)	(B)	(C)	(D)	(E = D - C)	(F = E / C)
1	1,000	500,000	$30,157.73	$31,204.80	$1,047.07	3.47%
2	2,000	1,000,000	$59,884.53	$61,978.66	$2,094.13	3.50%
3	3,000	1,500,000	$89,309.72	$92,450.92	$3,141.20	3.52%
4	3,500	2,000,000	$111,686.58	$115,332.01	$3,645.43	3.26%
5	5,000	2,500,000	$148,160.12	$153,395.45	$5,235.33	3.53%
6	7,500	3,000,000	$198,730.44	$206,641.28	$7,910.84	3.98%
7	7,500	4,000,000	$229,387.37	$237,221.06	$7,833.69	3.42%
8	10,000	5,000,000	$295,286.11	$305,756.76	$10,470.65	3.55%
9	10,000	6,000,000	$325,943.03	$336,336.53	$10,393.50	3.19%
10	12,500	7,000,000	$391,841.82	$404,872.26	$13,030.44	3.33%
11	12,500	8,000,000	$422,498.75	$435,452.04	$12,953.29	3.07%
12	15,000	9,000,000	$488,397.48	$503,987.72	$15,590.24	3.19%
13	20,000	10,000,000	$589,538.08	$610,479.37	$20,941.29	3.55%
14	40,000	20,000,000	$1,178,042.03	$1,219,924.62	$41,882.59	3.56%
15	60,000	30,000,000	$1,766,545.99	$1,829,369.87	$62,823.88	3.56%

The Dayton Power and Light Company
Case No. 09-256-EL-UNC
Typical Bill Comparison
Private Outdoor Lighting

Data: 0 Months Actual, 12 Months Estimated
Type of Filing: Original
Work Paper Reference: None

Witness Responsible:
Sharon Schroder

Line No.	Level of (kW)	Level of (kWh)	Current Bill	Bills with TCRR	Dollar Increase	Percent Increase
	(A)	(B)	(C)	(D)	(E = D - C)	(F = E / C)
1	7000					
2	Mercury	75	$14.79	$15.12	$0.33	2.23%
3	21000					
4	Mercury	154	$23.33	$24.00	$0.67	2.87%
5	2500					
6	Incandescent	64	$14.46	$14.75	$0.29	2.01%
7	7000					
8	Fluorescent	66	$15.89	$16.18	$0.29	1.83%
9	4000					
10	Mercury	43	$16.58	$16.77	$0.19	1.15%

Note: Current and proposed bills included monthly charge for 1 fixture, 1 pole, and 1 span

The Dayton Power and Light Company
Case No. 09-256-EL-UNC
Typical Bill Comparison
School Rate

Data: 0 Months Actual, 12 Months Estimated
Type of Filing: Original
Work Paper Reference: None

Witness Responsible:
Sharon Schroder

Line No.	Level of (kW)	Level of (kWh)	Current Bill	Bills with TCRR	Dollar Increase	Percent Increase
	(A)	(B)	(C)	(D)	(E = D - C)	(F = E / C)
1	0.0	1,000	$136.74	$140.55	$3.81	2.79%
2	0.0	2,500	$283.18	$292.71	$9.53	3.37%
3	0.0	5,000	$526.41	$545.48	$19.07	3.62%
4	0.0	10,000	$1,012.91	$1,051.06	$38.15	3.77%
5	0.0	15,000	$1,499.43	$1,556.65	$57.22	3.82%
6	0.0	25,000	$2,466.82	$2,562.19	$95.37	3.87%
7	0.0	50,000	$4,885.33	$5,076.08	$190.75	3.90%
8	0.0	75,000	$7,303.85	$7,589.97	$286.12	3.92%
9	0.0	100,000	$9,722.35	$10,103.85	$381.50	3.92%
10	0.0	150,000	$14,559.38	$15,131.63	$572.25	3.93%
11	0.0	200,000	$19,396.40	$20,159.40	$763.00	3.93%
12	0.0	250,000	$24,233.43	$25,187.18	$953.75	3.94%
13	0.0	300,000	$29,070.44	$30,214.94	$1,144.50	3.94%
14	0.0	350,000	$33,907.47	$35,242.72	$1,335.25	3.94%
15	0.0	400,000	$38,744.49	$40,270.49	$1,526.00	3.94%
16	0.0	450,000	$43,581.52	$45,298.27	$1,716.75	3.94%
17	0.0	500,000	$48,418.53	$50,326.03	$1,907.50	3.94%

The Dayton Power and Light Company
Case No. 09-256-EL-UNC
Typical Bill Comparison
Street Lighting

Data: 0 Months Actual, 12 Months Estimated
Type of Filing: Original
Work Paper Reference: None

Witness Responsible:
Sharon Schroder

Line No.	Level of (kW)	Level of (kWh)	Current Bill	Bills with TCRR	Dollar Increase	Percent Increase
	(A)	(B)	(C)	(D)	(E = D - C)	(F = E / C)
1	0.0	50	$4.83	$5.03	$0.20	4.14%
2	0.0	100	$7.56	$7.98	$0.42	5.56%
3	0.0	200	$13.01	$13.87	$0.86	6.61%
4	0.0	400	$23.93	$25.63	$1.70	7.10%
5	0.0	500	$29.42	$31.54	$2.12	7.21%
6	0.0	750	$43.05	$46.23	$3.18	7.39%
7	0.0	1,000	$56.68	$60.94	$4.26	7.52%
8	0.0	1,200	$67.59	$72.70	$5.11	7.56%
9	0.0	1,400	$78.51	$84.47	$5.96	7.59%
10	0.0	1,600	$89.43	$96.24	$6.81	7.61%
11	0.0	2,000	$111.26	$119.77	$8.51	7.65%
12	0.0	2,500	$138.36	$148.99	$10.63	7.68%
13	0.0	3,000	$165.39	$178.16	$12.77	7.72%
14	0.0	4,000	$219.52	$236.54	$17.02	7.75%
15	0.0	5,000	$273.65	$294.93	$21.28	7.78%

THE DAYTON POWER AND LIGHT COMPANY
CASE NO. 09-256-EL-UNC

Transmission Cost Recovery Rider (TCRR)

Schedule C-1
Projected TCRR Costs/Revenues

The Dayton Power & Light Company

The Dayton Power and Light Company
Case No. 09-256-EL-UNC
Projected Monthly Jurisdictional Net TCRR Costs
May 2009 - April 2010
(Revenue)/Expense in $

Schedule C-1
Page 1 of 2
Witness Responsible:
G.S. Campbell

Data: Actual and Forecasted
Type of Filing: Original
Work Paper Reference No(s).: WPC-1a

Line (A)	Description (B)	Forecast May (C)	Jun (D)	Jul (E)	Aug (F)	Sep (G)	Oct (H)	Nov (I)	Dec (J)	Total Forecast May - Dec 2009 (K) = sum (C) thru (J)
		WPC-1a, Col (J), lines 1 thru 28	WPC-1a, Col (J), lines 29 thru 56	WPC-1a, Col (J), lines 57 thru 84	WPC-1a, Col (J), lines 85 thru 112	WPC-1a, Col (J), lines 113 thru 140	WPC-1a, Col (J), lines 141 thru 168	WPC-1a, Col (J), lines 169 thru 196	WPC-1a, Col (J), lines 197 thru 224	
1	Transmission Enhancement Charges (RTEP)	$ 26,574	$ 26,574	$ 35,307	$ 33,532	$ 29,155	$ 26,477	$ 29,078	$ 33,100	$ 241,796
2	Alliance RTO Start-up Costs	$ 332,548	$ 332,548	$ 332,548	$ 332,548	$ 332,548	$ 332,548	$ 332,548	$ 332,548	$ 2,660,384
3	Reactive Supply and Voltage Control from Gen Sources	$ 352,656	$ 352,656	$ 352,656	$ 352,656	$ 352,656	$ 352,656	$ 352,655	$ 352,656	$ 2,821,251
4	Regulation	$ 764,081	$ 764,081	$ 1,059,015	$ 1,013,283	$ 750,444	$ 733,904	$ 770,311	$ 863,600	$ 6,718,699
5	Synchronized (Spinning) Reserves	$ 9,068	$ 9,068	$ 9,068	$ 9,068	$ 9,068	$ 9,068	$ 9,068	$ 9,068	$ 72,542
6	Operating Reserves	$ 456,019	$ 456,019	$ 604,269	$ 686,695	$ 459,772	$ 507,219	$ 435,021	$ 583,150	$ 4,198,164
7	RTO Start-up Cost Recovery - AEP zone	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 59
8	Synchronous Condensing	$ 7,236	$ 7,236	$ 7,236	$ 7,236	$ 7,236	$ 7,236	$ 7,236	$ 7,236	$ 57,888
9	Reliability Pricing Model (RPM) [1]	$ 2,426,122	$ 2,269,926	$ 2,345,590	$ 2,345,590	$ 7,159,426	$ 2,346,590	$ 2,269,926	$ 2,345,590	$ 23,507,761
10	Black Start Service	$ 9,148	$ 9,148	$ 9,148	$ 9,148	$ 9,148	$ 9,148	$ 9,148	$ 9,148	$ 73,182
11	PJM Annual Membership Fee	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,870	$ -	$ 3,870
12	TO Scheduling System Control and Dispatch Service	$ 87,817	$ 87,817	$ 113,618	$ 109,001	$ 94,370	$ 90,786	$ 93,171	$ 105,196	$ 781,775
13	NERC/RFC Charges	$ 15,680	$ 15,680	$ 20,499	$ 19,773	$ 17,108	$ 16,233	$ 16,809	$ 19,007	$ 140,790
14	PJM Default Charges	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15	Transmission Congestion	$ 66,674	$ 66,674	$ 25,322	$ 21,015	$ 14,374	$ 30,654	$ 884	$ 14,167	$ 239,745
16	Generation Loss Factor	$ (350,272)	$ (395,291)	$ (467,168)	$ (415,836)	$ (363,556)	$ (348,495)	$ (346,311)	$ (423,857)	$ (3,110,794)
17	Transmission Losses	$ (364,079)	$ 340,002	$ 489,712	$ 676,715	$ 574,352	$ 716,610	$ 760,809	$ 419,514	$ 3,613,635
18	Firm PTP Transmission Service	$ (26,937)	$ (213,347)	$ (232,212)	$ (236,567)	$ (213,652)	$ (220,988)	$ (211,156)	$ (218,390)	$ (1,573,129)
19	Non-Firm PTP Transmission Service	$ (40,478)	$ (46,904)	$ (64,543)	$ (53,574)	$ (48,504)	$ (29,922)	$ (30,845)	$ (28,911)	$ (343,681)
20	Network Integration Transmission Service	$ 3,437,648	$ 3,437,648	$ 3,437,648	$ 3,437,648	$ 3,332,492	$ 3,437,648	$ 3,332,492	$ 3,437,648	$ 27,290,873
21	FTR/ARR Auction	$ (424,658)	$ (410,959)	$ (424,658)	$ (424,658)	$ (410,959)	$ (424,658)	$ (410,959)	$ (424,658)	$ (3,356,164)
22	Expansion Cost Recovery Charges (ECRC)	$ (21,956)	$ (21,956)	$ (21,956)	$ (21,956)	$ (21,956)	$ (22,454)	$ (22,451)	$ (22,448)	$ (177,133)
23	PJM Scheduling System Control and Dispatch Service (Admin Fee)	$ 193,393	$ 193,393	$ 252,824	$ 243,870	$ 211,000	$ 200,202	$ 207,306	$ 234,417	$ 1,736,404
24	PUCO Consultant fees	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25	SubTotal	$ 6,956,292	$ 7,280,022	$ 7,883,935	$ 8,145,175	$ 12,304,629	$ 7,771,491	$ 7,608,596	$ 7,647,778	$ 65,597,917
26	TCRR Deferral carrying costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
27	**Totals including carrying costs**	**$ 6,956,292**	**$7,280,022**	**$7,883,935**	**$8,145,175**	**$12,304,629**	**$7,771,491**	**$7,608,596**	**$ 7,647,778**	**$ 65,597,917**

[1] RPM includes the following PJM invoice line items: Locational Reliability Charges, Capacity Resource Deficiency, RPM Auction Revenues, Generation Resource Rating Test, and Peak Hour Period Availability

The Dayton Power and Light Company
Case No. 08-256-EL-UNC
Projected Monthly Jurisdictional Net TCRR Costs
May 2009 - April 2010
(Revenue)/Expense in $

Schedule C-1
Page 2 of 2
Witness Responsible:
G.S. Campbell

Data: Actual and Forecasted
Type of Filing: Original
Work Paper Reference No(s).: WPC-1a

Line (A)	Description (B)	Forecast Jan (C) WPC-1a, Col (J), lines 225 thru 252	Forecast Feb (D) WPC-1a, Col (J), lines 253 thru 280	Forecast Mar (E) WPC-1a, Col (J), lines 281 thru 308	Forecast April (F) WPC-1a, Col (J), lines 309 thru 336	Total Forecast Jan - April 2010 (G) = sum (C) thru (F)	"Current" Cycle Total 5/09-4/10 (H) = Page 1 (K) + Page 2 (G)
28	Transmission Enhancement Charges (RTEP)	$ 56,039	$ 56,039	$ 56,039	$ 56,039	$ 224,156	$ 465,952
29	Alliance RTO Start-up Costs	$ 332,548	$ 332,548	$ 332,548	$ 332,548	$ 1,330,192	$ 3,990,576
30	Reactive Supply and Voltage Control from Gen Sources	$ 352,656	$ 352,656	$ 352,656	$ 352,656	$ 1,410,625	$ 4,231,878
31	Regulation	$ 908,766	$ 908,766	$ 908,766	$ 908,766	$ 3,635,064	$ 10,353,763
32	Synchronized (Spinning) Reserves	$ 9,068	$ 9,068	$ 9,068	$ 9,068	$ 36,271	$ 106,814
33	Operating Reserves	$ 542,945	$ 542,945	$ 542,945	$ 542,945	$ 2,171,782	$ 6,369,946
34	RTO Start-up Cost Recovery - AEP zone	$ 7	$ 7	$ 7	$ 7	$ 30	$ 89
35	Synchronous Condensing	$ 7,236	$ 7,236	$ 7,236	$ 7,236	$ 28,944	$ 86,832
36	Reliability Pricing Model (RPM) [1]	$ 2,345,590	$ 2,116,598	$ 2,345,590	$ 2,269,926	$ 9,079,704	$ 32,587,465
37	Black Start Service	$ 9,148	$ 8,146	$ 9,148	$ 9,148	$ 36,591	$ 109,773
38	PJM Annual Membership Fee	$ -	$ -	$ -	$ -	$ -	$ 3,870
39	TO Scheduling System Control and Dispatch Service	$ 99,171	$ 99,171	$ 99,171	$ 99,171	$ 396,683	$ 1,178,458
40	NERC/RFC Charges	$ 17,914	$ 17,914	$ 17,914	$ 17,914	$ 71,657	$ 212,446
41	PJM Default Charges	$ -	$ -	$ -	$ -	$ -	$ -
42	Transmission Congestion	$ 93,604	$ 15,456	$ 7,089	$ 54,164	$ 170,313	$ 410,059
43	Generation Loss Factor	$ (404,548)	$ (413,996)	$ (323,865)	$ (335,365)	$ (1,477,774)	$ (4,588,568)
44	Transmission Losses	$ 560,973	$ 741,532	$ 477,331	$ (36,047)	$ 1,743,789	$ 5,357,424
45	Firm PTP Transmission Service	$ (187,653)	$ (187,653)	$ (187,653)	$ (187,653)	$ (750,612)	$ (2,323,741)
46	Non-Firm PTP Transmission Service	$ (41,484)	$ (41,484)	$ (41,484)	$ (41,484)	$ (165,938)	$ (509,619)
47	Network Integration Transmission Service	$ 3,376,307	$ 3,376,307	$ 3,376,307	$ 3,376,307	$ 13,505,228	$ 40,796,102
48	FTR/ARR Auction	$ (208,333)	$ (208,333)	$ (208,333)	$ (208,333)	$ (833,333)	$ (4,189,498)
49	Expansion Cost Recovery Charges (ECRC)	$ (22,080)	$ (22,080)	$ (22,080)	$ (22,080)	$ (88,319)	$ (265,452)
50	PJM Scheduling System Control and Dispatch Service (Admin Fee)	$ 220,941	$ 220,941	$ 220,941	$ 220,941	$ 883,766	$ 2,620,170
51	PUCO Consultant fees	$ -	$ -	$ -	$ -	$ -	$ -
52	SubTotal	$ 8,068,816	$ 7,934,786	$ 7,979,343	$ 7,425,875	$ 31,408,819	$ 97,006,736
53	TCRR Deferral carrying costs	$ -	$ -	$ -	$ -	$ -	$ -
54	**Totals including carrying costs**	**$ 8,068,816**	**$ 7,934,786**	**$ 7,979,343**	**$ 7,425,875**	**$ 31,408,819**	**$ 97,006,736**

[1] RPM includes the following PJM invoice line items: Locational Reliability Charges, Capacity Resource Deficiency, RPM Auction Revenues, Generation Resource Rating Test, and Peak Hour Period Availability

THE DAYTON POWER AND LIGHT COMPANY
CASE NO. 09-256-EL-UNC

Transmission Cost Recovery Rider (TCRR)

Schedule C-1a
Deferred TCRR Costs/Revenues

The Dayton Power & Light Company

The Dayton Power and Light Company
Case No. 09-256-EL-UNC
Summary of Deferred Jurisdictional Net TCRR Costs
August 2008 - April 2009
(Revenue)/Expense in $

Data: Actual and Forecasted
Type of Filing: Original
Work Paper Reference No(s).: WPC-1c

Witness Responsible:
G.S. Campbell

Line (A)	Description (B)	2008 Aug (C) WPC-1c, Col (J), lines 1 thru 28	Sep (D) WPC-1c, Col (J), lines 29 thru 56	Oct (E) WPC-1c, Col (J), lines 57 thru 84	Nov (F) WPC-1c, Col (J), lines 85 thru 112	Dec (G) WPC-1c, Col (J), lines 113 thru 140	Total Deferral 2008 (H) = sum (C) thru (G)
1	Transmission Enhancement Charges (RTEP)	$ 427,458	$ 73,062	$ 76,092	$ 76,826	$ 76,835	$ 730,273
2	Alliance RTO Start-up Costs	$ -	$ -	$ -	$ -	$ -	$ -
3	Reactive Supply and Voltage Control from Gen Sources	$ (166,494)	$ (133,119)	$ 37,898	$ (13,222)	$ 56,633	$ (208,304)
4	Regulation	$ 703,712	$ 392,849	$ 229,030	$ 250,380	$ 234,788	$ 1,810,758
5	Synchronized (Spinning) Reserves	$ (348,589)	$ (341,389)	$ (320,327)	$ (304,666)	$ (349,963)	$ (1,664,933)
6	Operating Reserves	$ (12,252)	$ 51,301	$ (64,931)	$ (99,842)	$ 15,681	$ (110,043)
7	RTO Start-up Cost Recovery - AEP zone	$ 16	$ 15	$ 7	$ 15	$ 15	$ 69
8	Synchronous Condensing	$ 2,245	$ 7,900	$ 15,638	$ 12,045	$ 18,618	$ 56,447
9	Reliability Pricing Model (RPM) [1]	$ 1,621,183	$ 2,071,184	$ 2,140,314	$ 2,071,233	$ 2,140,622	$ 10,044,536
10	Black Start Service	$ 9,614	$ 9,512	$ 9,286	$ 9,299	$ 9,709	$ 47,421
11	PJM Annual Membership Fee	$ -	$ -	$ -	$ 3,870	$ -	$ 3,870
12	TO Scheduling System Control and Dispatch Service	$ (3,783)	$ (14,352)	$ (5,312)	$ (2,678)	$ (1,542)	$ (27,668)
13	NERC/RFC Charges	$ 19,722	$ 17,016	$ 18,571	$ 17,118	$ 28,919	$ 99,346
14	PJM Default Charges	$ -	$ 118,000	$ (9,000)	$ (4,608)	$ -	$ 104,392
15	Transmission Congestion	$ (2,060,306)	$ 1,080,776	$ (290,384)	$ 95,494	$ (70,206)	$ (1,244,626)
16	Generation Loss Factor	$ (386,735)	$ (371,047)	$ (311,541)	$ (307,161)	$ (373,341)	$ (1,749,825)
17	Transmission Losses	$ 639,566	$ 1,956,427	$ 716,968	$ 1,599,777	$ 1,436,649	$ 6,349,387
18	Firm PTP Transmission Service	$ (105,603)	$ (61,006)	$ (91,576)	$ (90,783)	$ (98,934)	$ (447,902)
19	Non-Firm PTP Transmission Service	$ (53,574)	$ (48,504)	$ (41,675)	$ (39,740)	$ (37,699)	$ (221,192)
20	Network Integration Transmission Service	$ 280,656	$ 270,082	$ 793,884	$ 673,085	$ 348,064	$ 2,365,772
21	FTR/ARR Auction	$ (378,515)	$ (366,305)	$ (378,515)	$ (366,305)	$ (378,543)	$ (1,868,185)
22	Expansion Cost Recovery Charges (ECRC)	$ (21,956)	$ (21,956)	$ (21,956)	$ (21,956)	$ (21,954)	$ (109,778)
23	PJM Scheduling System Control and Dispatch Service (Admin Fee)	$ -	$ -	$ -	$ -	$ -	$ -
24	PUCO Consultant fees	$ -	$ -	$ -	$ -	$ -	$ -
25	SubTotal	$ 176,364	$ 4,690,446	$ 2,500,473	$ 3,558,181	$ 3,034,352	$ 13,959,816
26	TCRR Deferral carrying costs[2]	$ 8,134	$ 12,353	$ 29,972	$ 44,911	$ 61,227	$ 156,598
27							
28	**Totals including carrying costs**	**$ 184,499**	**$ 4,702,799**	**$ 2,530,445**	**$ 3,603,092**	**$ 3,095,579**	**$ 14,116,414**

[1] RPM includes the following PJM invoice line items: Locational Reliability Charges, Capacity Resource Deficiency, RPM Auction Revenues, Generation Resource Rating Test, and Peak Hour Period Availability
[2] August 2008 also includes carrying costs for RTEP charges from June 07 through July 08

The Dayton Power and Light Company
Case No. 09-256-EL-UNC
Summary of Deferred Jurisdictional Net TCRR Costs
August 2008 - April 2009
(Revenue)/Expense in $

Schedule C-1a
Page 2 of 2
Witness Responsible:
G.S. Campbell

Data: Actual and Forecasted
Type of Filing: Original
Work Paper Reference No(s).: WPC-1c

Line (A)	Description (B)	2009 Jan (C) WPC-1c, Col (J), lines 141 thru 168	2009 Feb (D) WPC-1c, Col (J), lines 169 thru 196	2009 Forecast Mar (E) WPC-1c, Col (J), lines 197 thru 224	2009 Forecast Apr (F) WPC-1c, Col (J), lines 225 thru 252	Total Deferral 2009 (G) = sum (C) thru (F)	Total Deferral and Carrying Costs thru Apr-09 (H) Page 1 (H) + Page 2(G)	Carrying Costs to be collected 5/09-4/10 (I) WPC-1b	Total Deferral & Carrying Costs to be collected May 09 - April 10 (J) = (H)/2 + (I)
29	Transmission Enhancement Charges (RTEP)	$ 97,384.49	$ 97,384.50	$ 31,414.59	$ 27,342.08	$ 253,526	$ 983,799		$ 491,899
30	Alliance RTO Start-up Costs	$ -	$ -	$ -	$ -	$ -	$ -		$ -
31	Reactive Supply and Voltage Control from Gen Sources	$ (152,699)	$ (109,721.40)	$ (299,253.48)	$ (242,663.48)	$ (804,338)	$ (1,012,642)		$ (506,321)
32	Regulation	$ 171,880	$ 106,875.09	$ 568,212.81	$ 487,169.52	$ 1,333,917	$ 3,144,675		$ 1,572,338
33	Synchronized (Spinning) Reserves	$ (425,990)	$ (412,246.59)	$ (437,666.20)	$ (399,168.20)	$ (1,675,071)	$ (3,340,004)		$ (1,670,002)
34	Operating Reserves	$ (77,497)	$ (40,974.62)	$ 4,498.66	$ 58,489.90	$ (55,483)	$ (165,525)		$ (82,763)
35	RTO Start-up Cost Recovery - AEP zone	$ 30	$ 27.38	$ 7.41	$ 7.41	$ 73	$ 141		$ 71
36	Synchronous Condensing	$ 25,022	$ 14,793.16	$ 7,235.57	$ 7,235.57	$ 54,286	$ 110,733		$ 55,367
37	Reliability Pricing Model (RPM) [1]	$ 2,141,001	$ 1,932,423.79	$ 2,426,121.19	$ 2,347,859.48	$ 8,847,406	$ 18,891,942		$ 9,445,971
38	Black Start Service	$ 9,102	$ 9,279.16	$ 9,147.81	$ 9,147.81	$ 36,676	$ 84,097		$ 42,049
39	PJM Annual Membership Fee	$ -	$ -	$ -	$ -	$ -	$ 3,870		$ 1,935
40	TO Scheduling System Control and Dispatch Service	$ (19,061)	$ (29,969.10)	$ (24,421.19)	$ (25,819.88)	$ (99,271)	$ (126,939)		$ (63,469)
41	NERC/RFC Charges	$ 20,669	$ 17,094.84	$ 17,661.94	$ 17,661.94	$ 73,487	$ 172,833		$ 86,416
42	PJM Default Charges	$ -	$ -	$ -	$ -	$ -	$ 104,392		$ 52,196
43	Transmission Congestion	$ 421,475	$ 80,877.94	$ (9,971.00)	$ 54,163.75	$ 546,545	$ (698,080)		$ (349,040)
44	Generation Loss Factor	$ (453,333)	$ (424,429.07)	$ (321,465.00)	$ (321,465.00)	$ (1,520,692)	$ (3,270,518)		$ (1,635,259)
45	Transmission Losses	$ 2,713,193	$ 1,536,194.63	$ 2,302,329.42	$ 2,185,680.34	$ 8,737,397	$ 15,086,784		$ 7,543,392
46	Firm PTP Transmission Service	$ (90,918)	$ (67,432.00)	$ (217,762.00)	$ (26,283.00)	$ (402,415)	$ (850,317)		$ (425,158)
47	Non-Firm PTP Transmission Service	$ (48,797)	$ (32,817.37)	$ (36,204.00)	$ (37,124.00)	$ (154,942)	$ (376,134)		$ (188,067)
48	Network Integration Transmission Service	$ (556,615)	$ (655,209.40)	$ (329,350.68)	$ (109,674.94)	$ (1,650,850)	$ 714,921		$ 357,461
49	FTR/ARR Auction	$ (378,554)	$ (341,919.80)	$ (424,657.50)	$ (410,959.00)	$ (1,556,091)	$ (3,424,275)		$ (1,712,138)
50	Expansion Cost Recovery Charges (ECRC)	$ (22,492)	$ (22,492.73)	$ (21,956.27)	$ (21,956.27)	$ (88,898)	$ (198,676)		$ (99,338)
51	PJM Scheduling System Control and Dispatch Service (Admin Fee)	$ -	$ (175,038.76)	$ (525,261.18)	$ (472,884.95)	$ (1,173,185)	$ (1,173,185)		$ (586,592)
52	PUCO Consultant fees	$ -	$ -	$ -	$ -	$ -	$ -		$ -
53	SubTotal	$ 3,373,578	$ 1,482,700	$ 2,718,841	$ 3,126,959	$ 10,702,078	$ 24,661,894		$ 12,330,947
54	TCRR Deferral carrying costs	$ 77,172	$ 89,407	$ 100,102	$ 114,864	$ 381,545	$ 538,143	$ 1,141,447	$ 1,410,519
55									
56	Totals including carrying costs	$ 3,450,750	$ 1,572,106	$ 2,818,943	$ 3,241,823	$ 11,083,623	$ 25,200,037	$ 1,141,447	$ 13,741,465

[1] RPM includes the following PJM Invoice line items: Locational Reliability Charges, Capacity Resource Deficiency, RPM Auction Revenues, Generation Resource Rating Test, and Peak Hour Period Availability

THE DAYTON POWER AND LIGHT COMPANY
CASE NO. 09-256-EL-UNC

Transmission Cost Recovery Rider (TCRR)

Schedule C-2
Projected TCRR Costs by Tariff Class

The Dayton Power & Light Company

The Dayton Power and Light Company
Case No. 09-256-EL-UNC
Projected Monthly TCRR Costs by Tariff Class
August 2008 - April 2010

Schedule C-2
Page 1 of 1
Witness Responsible:
Sharon Schroder

Data: Actual and Forecasted
Type of Filing: Original
Work Paper Reference No(s).: WPC-2

2009 Forecast

Line (A)	Description (B)	Tariff Allocator (C)	Deferral Total Aug 08 - Apr 09 (D)	May (E)	Jun (F)	Jul (G)	Aug (H)	Sep (I)	Oct (J)	Nov (K)	Dec (L)	Source (M)
	TCRR Costs	WPC-2 Col (K)	Schedule C-1a, Col (H)									
1			$ 25,200,037	$ 6,956,292	$ 7,280,022	$ 7,883,935	$ 8,145,175	$ 12,304,629	$ 7,771,491	$ 7,608,596	$ 7,647,778	Schedule C-1, Row 26 and 52
2	Tariff Class											
3	Residential	27.85%	$ 7,017,283	$ 1,937,071	$ 2,027,218	$ 2,195,386	$ 2,268,131	$ 3,426,386	$ 2,164,074	$ 2,118,714	$ 2,129,625	Col (c) * Row 1
4	Residential Heat	14.47%	$ 3,645,503	$ 1,006,315	$ 1,053,147	$ 1,140,510	$ 1,178,302	$ 1,780,020	$ 1,124,244	$ 1,100,679	$ 1,106,347	Col (c) * Row 1
5	Secondary	41.25%	$ 10,393,911	$ 2,869,165	$ 3,002,690	$ 3,251,778	$ 3,359,528	$ 5,075,120	$ 3,205,399	$ 3,138,212	$ 3,154,373	Col (c) * Row 1
6	Primary	13.63%	$ 3,433,585	$ 947,817	$ 991,926	$ 1,074,211	$ 1,109,806	$ 1,676,545	$ 1,058,890	$ 1,036,695	$ 1,042,034	Col (c) * Row 1
7	Primary Substation	0.78%	$ 195,468	$ 53,958	$ 56,469	$ 61,153	$ 63,179	$ 95,443	$ 60,281	$ 59,017	$ 59,321	Col (c) * Row 1
8	High Voltage	0.80%	$ 202,582	$ 55,921	$ 58,524	$ 63,379	$ 65,479	$ 98,918	$ 62,475	$ 61,165	$ 61,480	Col (c) * Row 1
9	Private Outdoor Lighting	0.25%	$ 62,527	$ 17,260	$ 18,063	$ 19,562	$ 20,210	$ 30,531	$ 19,283	$ 18,879	$ 18,976	Col (c) * Row 1
10	School	0.57%	$ 142,407	$ 39,310	$ 41,140	$ 44,553	$ 46,029	$ 69,534	$ 43,917	$ 42,997	$ 43,218	Col (c) * Row 1
11	Street Lighting	0.42%	$ 106,771	$ 29,473	$ 30,845	$ 33,404	$ 34,511	$ 52,134	$ 32,927	$ 32,237	$ 32,403	Col (c) * Row 1
12	Total TCRR Costs	100.00%	$ 25,200,037	$ 6,956,292	$ 7,280,022	$ 7,883,935	$ 8,145,175	$ 12,304,629	$ 7,771,491	$ 7,608,596	$ 7,647,778	Sum (row 3 thru 11)

2010 Forecast

Line (N)	Description (O)	Tariff Allocator (P)	Jan (Q)	Feb (R)	Mar (S)	April (T)	Source (U)	Deferral Total Aug 08-Apr 09 (V) = Col (D)	Total Costs May 09-Apr 10 (W) = sum (E) thru (T)
	TCRR Costs	WPC-2 Col (K)							
13			$ 8,068,816	$ 7,934,786	$ 7,979,343	$ 7,425,875	Schedule C-1, Row 78		
14	Tariff Class								
15	Residential	27.85%	$ 2,246,868	$ 2,209,546	$ 2,221,953	$ 2,067,833	Col (o) * Row 13	$ 7,017,283	$ 27,012,805
16	Residential Heat	14.47%	$ 1,167,256	$ 1,147,867	$ 1,154,312	$ 1,074,246	Col (o) * Row 13	$ 3,645,503	$ 14,033,248
17	Secondary	41.25%	$ 3,328,033	$ 3,272,752	$ 3,291,129	$ 3,062,848	Col (o) * Row 13	$ 10,393,911	$ 40,011,027
18	Primary	13.63%	$ 1,099,402	$ 1,081,140	$ 1,087,211	$ 1,011,799	Col (o) * Row 13	$ 3,433,585	$ 13,217,475
19	Primary Substation	0.78%	$ 62,587	$ 61,547	$ 61,893	$ 57,600	Col (o) * Row 13	$ 195,468	$ 752,449
20	High Voltage	0.80%	$ 64,865	$ 63,787	$ 64,146	$ 59,696	Col (o) * Row 13	$ 202,582	$ 779,833
21	Private Outdoor Lighting	0.25%	$ 20,021	$ 19,686	$ 19,799	$ 18,425	Col (o) * Row 13	$ 62,527	$ 240,698
22	School	0.57%	$ 45,597	$ 44,840	$ 45,092	$ 41,964	Col (o) * Row 13	$ 142,407	$ 548,192
23	Street Lighting	0.42%	$ 34,187	$ 33,619	$ 33,808	$ 31,463	Col (o) * Row 13	$ 106,771	$ 411,013
24	Total TCRR Costs	100.00%	$ 8,068,815.68	$ 7,934,786.17	$ 7,979,342.52	$ 7,425,874.79	Sum (row 15 thru 23)	$ 25,200,037	$ 97,006,736

THE DAYTON POWER AND LIGHT COMPANY
CASE NO. 09-256-EL-UNC

Transmission Cost Recovery Rider (TCRR)

Schedule C-3
Proposed TCRR Rates

The Dayton Power & Light Company

The Dayton Power and Light Company
Case No. 09-256-EL-UNC
Summary of Proposed TCRR Rates
May 2009 - April 2010

Schedule C-3
Page 1 of 1
Witness Responsible:
Sharon Schroder

Data: Forecasted
Type of Filing: Original
Work Paper Reference No(s).: None

TCRR Rates
May 09 - April 10

Line (A)	Description (B)		Residential (D)	Residential Heat (E)	Secondary[1] (F)	Primary (G)	Primary Substation (H)	High Voltage (I)	Private Outdoor Lighting (J)	School (K)	Street Lighting (L)	Source (M)
1	Summary of TCRR Base Rates											
2	Demand (kWh, kW)		$ 0.0068588	$ 0.0068506	$ 3.5329410	$ 2.5527259	$ 2.6417486	$ 2.5271446	$ 0.0070830	$ 0.0066433	$ 0.0069965	Schedule C-3a, Line 19
3	Energy (kWh)		$ 0.0002732	$ 0.0002729	$ 0.0028204	$ 0.0003006	$ 0.0002924	$ 0.0002732	$ 0.0002826	$ 0.0002647	$ 0.0002788	Schedule C-3a, Line 39
4	Reactive (kWh, kVar)		$ 0.0003323	$ 0.0003319	$ 0.0034300	$ 0.2087553	$ 0.2784207	$ 0.1970768	$ 0.0003437	$ 0.0003219	$ 0.0003391	Schedule C-3a, Line 49
5												
6	Summary of TCRR Incremental Rates											
7	Demand (kWh, kW)		$ 0.0010186	$ 0.0010174	$ 0.5247052	$ 0.3781257	$ 0.3923471	$ 0.3901782	$ 0.0010534	$ 0.0009867	$ 0.0010394	Schedule C-3b, Line 20
8	Energy (kWh)		$ 0.0000387	$ 0.0000387	$ 0.0003995	$ 0.0000428	$ 0.0000414	$ 0.0000387	$ 0.0000400	$ 0.0000375	$ 0.0000395	Schedule C-3b, Line 21
9												
10												
11	**Total TCRR Rates**	**$/kW**			$ 4.0576462	$ 2.9318515	$ 3.0340957	$ 3.0173228				
12		**$/kWh**	$ 0.0085215	$ 0.0085115	$ 0.0066499	$ 0.0003434	$ 0.0003338	$ 0.0003119	$ 0.0088127	$ 0.0082840	$ 0.0086952	
13		**$/kVar**				$ 0.2087553	$ 0.2784207	$ 0.1970768				

[1] Secondary customers are charged for all kW over 5kW of Billing Demand and for the first 1,500 kWh

THE DAYTON POWER AND LIGHT COMPANY
CASE NO. 09-256-EL-UNC

Transmission Cost Recovery Rider (TCRR)

Schedule C-3a
Development of Proposed TCRR Base Rates

The Dayton Power & Light Company

The Dayton Power and Light Company
Case No. 09-256-EL-UNC
Development of Proposed TCRR Base Rates
May 2009 - April 2010

Data: Forecasted
Type of Filing: Original
Work Paper Reference No(s).: WPC-2, WPC-3

Witness Responsible:
Sharon Schroder

May 09 - April 10

Line (A)	Description (B)	"Current" Cycle Base TCRR Costs (C) Schedule B-1, Col (E)	Residential (D)	Residential Heat (E)	Secondary[2] (F)	Primary (G)	Primary Substation (H)	High Voltage (I)	Private Outdoor Lighting (J)	School (K)	Street Lighting (L)	Source (M)
1	Allocators (WPC-2, Col (K))		27.85%	14.47%	41.25%	13.63%	0.78%	0.80%	0.25%	0.57%	0.42%	
2												
3	Demand-Based Components											
4	Transmission Enhancement Charges (RTEP)	$ 465,952	$ 129,750	$ 67,406	$ 192,185	$ 63,487	$ 3,614	$ 3,746	$ 1,156	$ 2,633	$ 1,974	Line 1 * Col (C)
5	Regulation	$ 10,353,763	$ 2,883,142	$ 1,497,602	$ 4,270,474	$ 1,410,733	$ 80,311	$ 83,233	$ 25,690	$ 58,510	$ 43,868	Line 1 * Col (C)
6	Synchronized (Spinning) Reserves	$ 108,814	$ 30,301	$ 15,741	$ 44,881	$ 14,826	$ 844	$ 875	$ 270	$ 615	$ 461	Line 1 * Col (C)
7	Operating Reserves	$ 6,369,946	$ 1,773,795	$ 921,493	$ 2,627,323	$ 867,925	$ 49,410	$ 51,206	$ 15,805	$ 35,997	$ 26,989	Line 1 * Col (C)
8	Reliability Pricing Model (RPM) [1]	$ 32,587,465	$ 9,074,409	$ 4,714,187	$ 13,440,901	$ 4,440,145	$ 252,770	$ 261,969	$ 80,857	$ 184,154	$ 138,072	Line 1 * Col (C)
9	Black Start Service	$ 109,773	$ 30,568	$ 15,880	$ 45,277	$ 14,957	$ 851	$ 882	$ 272	$ 620	$ 465	Line 1 * Col (C)
10	TO Scheduling System Control and Dispatch Service	$ 1,178,458	$ 328,157	$ 170,479	$ 486,062	$ 160,589	$ 9,141	$ 9,474	$ 2,924	$ 6,660	$ 4,993	Line 1 * Col (C)
11	Firm PTP Transmission Service	$ (2,323,741)	$ (647,076)	$ (336,158)	$ (958,441)	$ (316,617)	$ (18,024)	$ (18,680)	$ (5,766)	$ (13,132)	$ (9,846)	Line 1 * Col (C)
12	Non-Firm PTP Transmission Service	$ (609,619)	$ (141,910)	$ (73,723)	$ (210,195)	$ (69,437)	$ (3,953)	$ (4,097)	$ (1,264)	$ (2,880)	$ (2,159)	Line 1 * Col (C)
13	Network Integration Transmission Service	$ 40,796,102	$ 11,360,212	$ 5,901,670	$ 16,826,604	$ 5,556,596	$ 316,442	$ 327,958	$ 101,224	$ 230,542	$ 172,851	Line 1 * Col (C)
14	Subtotal	$ 89,136,912	$ 24,821,349	$ 12,894,777	$ 36,765,070	$ 12,145,187	$ 691,405	$ 716,568	$ 221,189	$ 503,719	$ 377,669	Sum Lines 4 thru 13
15	Gross Revenue Conversion Factor	$ 1.021	$ 1.021	$ 1.021	$ 1.021	$ 1.021	$ 1.021	$ 1.021	$ 1.021	$ 1.021	$ 1.021	Case No. 08-1094, Schedule A-4, Col (C), Line 28
16	Total Demand-Based Component Cost	$ 91,008,787	$ 25,342,597	$ 13,165,567	$ 37,537,136	$ 12,400,236	$ 705,925	$ 731,616	$ 225,813	$ 514,297	$ 385,800	Line 14 * Line 15
17												
18	Projected Billing Determinants (kWh, kW)		3,895,004,444	1,921,827,265	10,624,898	4,857,645	267,219	276,483	31,835,957	77,415,560	55,097,946	WPC-3, Column (U)
19	Demand Portion of TCRR Rate		$ 0.0068586	$ 0.0068505	$ 3.5329410	$ 2.5527259	$ 2.6417486	$ 2.6271446	$ 0.0070930	$ 0.0066433	$ 0.0069935	Line 16 / Line 18
20	Energy-Based Components											
21	Alliance RTO Start-up Costs	$ 3,990,676	$ 1,111,229	$ 577,287	$ 1,645,938	$ 543,729	$ 30,954	$ 32,080	$ 9,902	$ 22,551	$ 16,908	Line 1 * Col (C)
22	RTO Start-up Cost Recovery - AEP zone	$ 89	$ 25	$ 13	$ 37	$ 12	$ 1	$ 1	$ 0	$ 1	$ 0	Line 1 * Col (C)
23	PJM Annual Membership Fee	$ 3,870	$ 1,078	$ 560	$ 1,596	$ 527	$ 30	$ 31	$ 10	$ 22	$ 16	Line 1 * Col (C)
24	NERC/RFC Charges	$ 212,446	$ 59,158	$ 30,733	$ 87,625	$ 28,946	$ 1,648	$ 1,708	$ 527	$ 1,201	$ 900	Line 1 * Col (C)
25	PJM Default Charges	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	Line 1 * Col (C)
26	Transmission Congestion	$ 410,059	$ 114,186	$ 59,320	$ 169,131	$ 55,872	$ 3,181	$ 3,296	$ 1,017	$ 2,317	$ 1,737	Line 1 * Col (C)
27	Generation Loss Factor	$ (4,588,568)	$ (1,277,747)	$ (663,794)	$ (1,892,583)	$ (625,207)	$ (35,592)	$ (36,887)	$ (11,385)	$ (25,930)	$ (19,442)	Line 1 * Col (C)
28	Transmission Losses	$ 5,357,424	$ 1,491,845	$ 775,019	$ 2,209,702	$ 729,966	$ 41,556	$ 43,068	$ 13,293	$ 30,275	$ 22,699	Line 1 * Col (C)
29	FTR/ARR Auction	$ (4,189,498)	$ (1,166,621)	$ (606,064)	$ (1,727,984)	$ (570,832)	$ (32,497)	$ (33,679)	$ (10,395)	$ (23,675)	$ (17,751)	Line 1 * Col (C)
30	Expansion Cost Recovery Charges (ECRC)	$ (265,452)	$ (73,919)	$ (38,401)	$ (109,487)	$ (36,169)	$ (2,059)	$ (2,134)	$ (659)	$ (1,500)	$ (1,125)	Line 1 * Col (C)
31	PJM Scheduling System Control and Dispatch Service (Admin Fee)	$ 2,620,170	$ 729,621	$ 379,041	$ 1,080,705	$ 357,006	$ 20,324	$ 21,063	$ 6,501	$ 14,807	$ 11,102	Line 1 * Col (C)
32	PUCO Consultant fees	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	Line 1 * Col (C)
33	Subtotal	$ 3,551,116	$ 988,855	$ 513,714	$ 1,464,680	$ 483,851	$ 27,545	$ 28,547	$ 8,811	$ 20,068	$ 15,046	Sum Line 22 thru 33
34	Gross Revenue Conversion Factor	$ 1.021	$ 1.021	$ 1.021	$ 1.021	$ 1.021	$ 1.021	$ 1.021	$ 1.021	$ 1.021	$ 1.021	Case No. 08-1094, Schedule A-4, Col (C), Line 28
35	Total Energy-Based Components Cost	$ 3,625,689	$ 1,009,621	$ 524,502	$ 1,495,438	$ 494,012	$ 28,123	$ 29,147	$ 8,996	$ 20,489	$ 15,362	Line 34 * Line 35
36												
37	Projected Billing Determinants (kWh)		3,895,004,444	1,921,827,265	530,228,586	1,642,467,340	96,192,490	106,702,698	31,835,957	77,415,560	55,097,946	WPC-3, Column (U)
38	Energy Portion of TCRR Rate		$ 0.0002732	$ 0.0002729	$ 0.0028204	$ 0.0003008	$ 0.0002924	$ 0.0002732	$ 0.0002826	$ 0.0002647	$ 0.0002788	Line 36 / Line 36
39												
40	Reactive-Based Components											
41	Reactive Supply and Voltage Control from Gen Sources	$ 4,231,876	$ 1,178,422	$ 612,194	$ 1,745,464	$ 576,607	$ 32,826	$ 34,020	$ 10,600	$ 23,915	$ 17,930	Line 1 * Col (C)
42	Synchronous Condensing	$ 86,832	$ 24,180	$ 12,561	$ 35,814	$ 11,831	$ 674	$ 698	$ 215	$ 491	$ 368	Line 1 * Col (C)
43	Subtotal	$ 4,318,708	$ 1,202,601	$ 624,756	$ 1,781,278	$ 588,438	$ 33,499	$ 34,718	$ 10,716	$ 24,405	$ 18,298	Sum Lines 42 thru 43
44	Gross Revenue Conversion Factor	$ 1.021	$ 1.021	$ 1.021	$ 1.021	$ 1.021	$ 1.021	$ 1.021	$ 1.021	$ 1.021	$ 1.021	Case No. 08-1094, Schedule A-4, Col (C), Line 28
45	Total Reactive-Based Components Cost	$ 4,409,401	$ 1,227,856	$ 637,675	$ 1,818,685	$ 600,795	$ 34,202	$ 35,447	$ 10,941	$ 24,918	$ 18,682	Line 44 * Line 45
46												
47	Projected Billing Determinants (kWh, kVar)		3,895,004,444	1,921,827,265	530,228,586	2,877,987	122,844	179,864	31,835,957	77,415,560	55,097,946	WPC-3, Column (U)
48	Reactive Portion of TCRR Rate		$ 0.0003323	$ 0.0003319	$ 0.0034300	$ 0.2087553	$ 0.2784207	$ 0.1970768	$ 0.0003437	$ 0.0003219	$ 0.0003391	Line 46 / Line 48
49												
50	Total Base TCRR Component Cost	$ 99,043,578										Sum of Line 15, 34, 43

[1] RPM includes the following PJM Invoice line items: Locational Reliability Charges, Capacity Resource Deficiency, RPM Auction Revenues, Generation Resource Rating Test, and Peak Hour Period Availability

[2] Secondary customers are charged for all kW over 5kW of Billing Demand and for the first 1,500 kWh

THE DAYTON POWER AND LIGHT COMPANY
CASE NO. 09-256-EL-UNC

Transmission Cost Recovery Rider (TCRR)

Schedule C-3b
Development of Proposed TCRR Incremental Rates

The Dayton Power & Light Company

The Dayton Power and Light Company
Case No. 09-258-EL-UNC
Development of Proposed TCRR Incremental Rates
May 2009 - April 2010

Data: Actual and Forecasted
Type of Filing: Original
Work Paper Reference No(s).: WPC-2, WPC-3

Schedule C-3b
Page 1 of 1
Witness Responsible:
Sharon Schroder

Incremental TCRR Rates
May 09 - April 10

Line (A)	Description (B)	Total Deferral Recovery Costs (C)	(D)	Residential (E)	Residential Heat (F)	Secondary[1] (G)	Primary (H)	Primary Substation (I)	High Voltage (J)	Private Outdoor Lighting (K)	School (L)	Street Lighting (M)	Source (N)
1	Allocators (WPC-2, Col (K))			27.85%	14.47%	41.25%	13.63%	0.76%	0.80%	0.25%	0.57%	0.42%	
2													
3	TCRR Deferral Recovery Costs (Schedule C-1a, Page 2 of 2, Col (J))	$ 13,741,465		$ 3,826,492	$ 1,987,876	$ 5,667,752	$ 1,872,318	$ 106,588	$ 110,467	$ 34,096	$ 77,654	$ 58,222	Col (C) * Line 1
4	Gross Revenue Conversion Factor	$ 1.021		$ 1.021	$ 1.021	$ 1.021	$ 1.021	$ 1.021	$ 1.021	$ 1.021	$ 1.021	$ 1.021	Case No. 08-1094, Schedule A-4, Col (C), Line 28
5	Total	$ 14,030,036		$ 3,826,493	$ 1,987,877	$ 5,667,753	$ 1,872,319	$ 106,589	$ 110,468	$ 34,097	$ 77,655	$ 58,223	Line 3 * Line 4
6													
7	Base TCRR Component Costs												
8	Total Demand-Based Component Cost	$ 95,418,188											Schedule C-3a, Col (C), Line 16 + Line 46
9	Total Energy-Based Components Cost	$ 3,625,689											Schedule C-3a, Col (C), Line 36
10	Total Base TCRR Component Cost	$ 99,043,878											Line 8 + Line 9
11													
12	Demand Portion of Base Component Line 8 / Line 10	96.34%	$ 13,516,440	$ 3,763,831	$ 1,955,323	$ 5,574,939	$ 1,841,658	$ 104,842	$ 108,658	$ 33,537	$ 76,382	$ 57,269	Col (D) * Line 1
13	Energy Portion of Base Component Line 9 / Line 10	3.66%	$ 513,596	$ 143,018	$ 74,298	$ 211,836	$ 69,979	$ 3,984	$ 4,129	$ 1,274	$ 2,902	$ 2,176	Col (D) * Line 1
14	Total	100.00%	$ 14,030,036	$ 3,906,849	$ 2,029,621	$ 5,786,775	$ 1,911,637	$ 108,826	$ 112,787	$ 34,812	$ 79,285	$ 59,445	Line 12 + Line 13
15													
16	Projected Billing Determinants (kWh, kW)			3,695,004,444	1,921,827,265	10,624,898	4,857,645	267,219	278,483	31,835,957	77,415,560	55,097,946	WPC-3, Column (U)
17	Projected Billing Determinants (kWh)			3,695,004,444	1,921,827,265	530,228,588	1,642,467,340	96,192,490	106,702,698	31,835,957	77,415,560	55,097,946	WPC-3, Column (U)
18													
19	TCRR Incremental Rates												
20	Demand Portion of TCRR Rate (kWh, kW)			$ 0.0010186	$ 0.0010174	$ 0.5247052	$ 0.3791257	$ 0.3923471	$ 0.3901782	$ 0.0010534	$ 0.0009867	$ 0.0010394	Line 12 / Line 16
21	Energy Portion of TCRR Rate (kWh)			$ 0.0000387	$ 0.0000387	$ 0.0003995	$ 0.0000426	$ 0.0000414	$ 0.0000387	$ 0.0000400	$ 0.0000375	$ 0.0000395	Line 13 / Line 17

[1] Secondary customers are charged for all kW over 5kW of Billing Demand and for the first 1,500 kWh

THE DAYTON POWER AND LIGHT COMPANY
CASE NO. 09-256-EL-UNC

Transmission Cost Recovery Rider (TCRR)

Workpapers

The Dayton Power & Light Company

The Dayton Power and Light Company
Case No. 09-256-EL-UNC
Current Rates and Revenues

Data: Forecasted
Type of Filing: Original
Work Paper Reference No(s).: WPC-3

Workpaper B-2
Page 1 of 1
Witness Responsible:
Sharon Schroder

May 2009 - April 2010

Line	Tariff Class	Forecasted Billing Determinants	Network Integration Transmission Service Rate	Network Integration Transmission Service Revenue	TO Scheduling System Control and Dispatch Service Rate	TO Scheduling System Control and Dispatch Service Revenue	Reactive Supply and Voltage Control from Gen Sources Rate	Reactive Supply and Voltage Control from Gen Sources Revenue	Regulation Rate	Regulation Revenue	Synchronized (Spinning) Reserves Rate	Synchronized (Spinning) Reserves Revenue	Operating Reserves (Supplemental) Rate	Operating Reserves (Supplemental) Revenue	PJM Scheduling System Control and Dispatch Service (Admin Fee) Rate	PJM Scheduling System Control and Dispatch Service (Admin Fee) Revenue	Total Revenues
(A)	(B)	(C)	(D)	(E) = (C) * (D)	(F)	(G) = (C) * (F)	(H)	(I) = (C) * (H)	(J)	(K) = (C) * (J)	(L)	(M) = (C) * (L)	(N)	(O) = (C) * (N)	(P)	(Q) = (C) * (P)	(R) = sum of Columns (E),(G),(I),(K),(M),(O),(Q)
		Schedule C-3	WPB-3 Col (D)		WPB-3 Col (E)		WPB-3 Col (F)		WPB-3 Col (G)		WPB-3 Col (H)		WPB-3 Col (I)		WPB-3 Col (J)		
1	Residential	3,695,004,444 kWh	$ 0.00270	$ 9,976,512	$ 0.00007	$ 258,650	$ 0.00045	$ 1,662,752	$ 0.00021	$ 775,951	$ 0.00032	$ 1,182,401	$ 0.00030	$ 1,108,501	$ 0.000389	$ 1,437,357	$ 16,402,125
2	Residential Heat	1,921,827,265 kWh	$ 0.00270	$ 5,188,934	$ 0.00007	$ 134,528	$ 0.00045	$ 864,822	$ 0.00021	$ 403,584	$ 0.00032	$ 614,985	$ 0.00030	$ 576,548	$ 0.000389	$ 747,591	$ 8,530,991
3	Secondary[1]	530,228,586 kWh	$ 0.00270	$ 1,431,617	$ 0.00007	$ 37,116	$ 0.00045	$ 238,603	$ 0.00021	$ 111,348	$ 0.00032	$ 169,673	$ 0.00030	$ 158,069	$ 0.000389	$ 206,259	$ 2,353,685
4		10,624,898 kW	$ 1.30616	$ 13,877,816	$ 0.04765	$ 506,276	$ 0.21800	$ 2,316,226	$ 0.10333	$ 1,097,871	$ 0.15500	$ 1,646,559	$ 0.14392	$ 1,529,135		$ -	$ 20,974,185
5	Primary	1,642,467,340 kWh		$ -		$ -		$ -		$ -		$ -		$ -	$ 0.000389	$ 638,920	$ 638,920
6		4,857,645 kW	$ 1.30616	$ 6,344,861	$ 0.04765	$ 231,467	$ 0.07270	$ 353,151	$ 0.10333	$ 501,940	$ 0.15500	$ 752,935	$ 0.14392	$ 699,112		$ -	$ 8,883,467
7		2,877,987 kVar		$ -		$ -	$ 0.30000	$ 863,396		$ -		$ -		$ -		$ -	$ 863,396
8	Primary Substation	96,192,490 kWh		$ -		$ -		$ -		$ -		$ -		$ -	$ 0.000389	$ 37,419	$ 37,419
9		267,219 kW	$ 1.30616	$ 349,030	$ 0.04765	$ 12,733	$ 0.07270	$ 19,427	$ 0.10333	$ 27,612	$ 0.15500	$ 41,419	$ 0.14392	$ 38,458		$ -	$ 488,679
10		122,844 kVar		$ -		$ -	$ 0.30000	$ 36,853		$ -		$ -		$ -		$ -	$ 36,853
11	High Voltage	106,702,598 kWh		$ -		$ -		$ -		$ -		$ -		$ -	$ 0.000389	$ 41,507	$ 41,507
12		278,483 kW	$ 1.30616	$ 363,744	$ 0.04765	$ 13,270	$ 0.07270	$ 20,246	$ 0.10333	$ 28,776	$ 0.15500	$ 43,165	$ 0.14392	$ 40,079		$ -	$ 509,279
13		179,664 kVar		$ -		$ -	$ 0.30000	$ 53,959		$ -		$ -		$ -		$ -	$ 53,959
14	Private Outdoor Lighting[2]	31,835,957 kWh	$ 0.00270	$ 85,957	$ 0.00007	$ 2,229	$ 0.00045	$ 14,326	$ 0.00021	$ 6,685	$ 0.00032	$ 10,188	$ 0.00030	$ 9,551	$ 0.000389	$ 12,384	$ 141,320
15	School	77,415,560 kWh	$ 0.00270	$ 209,022	$ 0.00007	$ 5,419	$ 0.00045	$ 34,837	$ 0.00021	$ 16,257	$ 0.00032	$ 24,773	$ 0.00030	$ 23,225	$ 0.000389	$ 30,115	$ 343,848
16	Streetlighting	55,097,946 kWh	$ 0.00270	$ 148,764	$ 0.00007	$ 3,857	$ 0.00045	$ 24,794	$ 0.00021	$ 11,571	$ 0.00032	$ 17,631	$ 0.00030	$ 16,529	$ 0.000389	$ 21,433	$ 244,580
17	Total			$ 37,976,258		$ 1,205,545		$ 6,503,394		$ 2,981,595		$ 4,904,029		$ 4,200,208		$ 3,172,984	$ 60,544,012

[1] Secondary customers are charged for all kW over 5kW of Billing Demand and for the first 1,500 kWh
[2] Private Outdoor Lighting $/kWh rates are based on assumed usage. Current rates are charged per fixture.

The Dayton Power and Light Company
Case No. 09-256-EL-UNC
Current Rates

Data: Actual
Type of Filing: Original
Work Paper Reference No(s).: None

Witness Responsible:
Sharon Schroder

Line (A)	Tariff Class (B)	(C)	Network Integration Transmission Service (D) Tariff Sheet T8	TO Scheduling System Control and Dispatch Service (E) Tariff Sheet T9	Reactive Supply and Voltage Control from Gen Sources (F) Tariff Sheet T10	Regulation (G) Tariff Sheet T11	Synchronized (Spinning) Reserves (H) Tariff Sheet T12	Operating Reserves (Supplemental) (I) Tariff Sheet T13	PJM Scheduling System Control and Dispatch Service (Admin Fee) (J) Tariff Sheet T14	Total Rate (K) = sum (D) thru (J)
1	Residential	kWh	$ 0.00270	$ 0.00007	$ 0.00045	$ 0.00021	$ 0.00032	$ 0.00030	$ 0.000389	$ 0.00444
2	Residential Heat	kWh	$ 0.00270	$ 0.00007	$ 0.00045	$ 0.00021	$ 0.00032	$ 0.00030	$ 0.000389	$ 0.00444
3	Secondary[1]	kWh	$ 0.00270	$ 0.00007	$ 0.00045	$ 0.00021	$ 0.00032	$ 0.00030	$ 0.000389	$ 0.00444
4		kW	$ 1.30616	$ 0.04765	$ 0.21800	$ 0.10333	$ 0.15500	$ 0.14392		$ 1.97406
5	Primary	kWh							$ 0.000389	$ 0.00039
6		kW	$ 1.30616	$ 0.04765	$ 0.07270	$ 0.10333	$ 0.15500	$ 0.14392		$ 1.82876
7		kVar			$ 0.30000					$ 0.30000
8	Primary Substation	kWh							$ 0.000389	$ 0.00039
9		kW	$ 1.30616	$ 0.04765	$ 0.07270	$ 0.10333	$ 0.15500	$ 0.14392		$ 1.82876
10		kVar			$ 0.30000					$ 0.30000
11	High Voltage	kWh							$ 0.000389	$ 0.00039
12		kW	$ 1.30616	$ 0.04765	$ 0.07270	$ 0.10333	$ 0.15500	$ 0.14392		$ 1.82876
13		kVar			$ 0.30000					$ 0.30000
14	Private Outdoor Lighting[2]	kWh	$ 0.00270	$0.00007	$ 0.00045	$ 0.00021	$ 0.00032	$ 0.00030	$ 0.000389	$ 0.00444
15	School	kWh	$ 0.00270	$ 0.00007	$ 0.00045	$ 0.00021	$ 0.00032	$ 0.00030	$ 0.000389	$ 0.00444
16	Streetlighting	kWh	$ 0.00270	$ 0.00007	$ 0.00045	$ 0.00021	$ 0.00032	$ 0.00030	$ 0.000389	$ 0.00444

[1] Secondary customers are charged for all kW over 5kW of Billing Demand and for the first 1,500 kWh
[2] Private Outdoor Lighting $/kWh rates are based on assumed usage. Current rates are charged per fixture.

The Dayton Power and Light Company
Case No. 09-256-EL-UNC
Projected Charges and Revenues
August 2008 - April 2010
(Revenue)/Expense in $

Data: Forecasted
Type of Filing: Original
Work Paper Reference No(s).: WPC-1d

Witness Responsible:
G.S. Campbell

May 2009 - Forecast

Line (A)	Description (B)	Total PJM Bill Charges (C)	Total PJM Bill Revenues (D)	Jurisdictional Allocation Factors Charges (E)	Jurisdictional Allocation Factors Revenues (F)	Allocated PJM Bill Charges (G) = (C)*(E)	Allocated PJM Bill Revenues (H) = (D)*(F)	Retail Revenues (I)	Total Net Costs (J) = (G)+(H)+(I)
1	Transmission Enhancement Charges (RTEP)	$ 29,892	NA	88.9%	NA	$ 26,574			$ 26,574
2	Alliance RTO Start-up Costs	$ 332,548	NA	100.0%	NA	$ 332,548			$ 332,548
3	Reactive Supply and Voltage Control from Gen Sources	$ 396,689	NA	88.9%	NA	$ 352,656			$ 352,656
4	Regulation	$ 859,483	NA	88.9%	NA	$ 764,081			$ 764,081
5	Synchronized (Spinning) Reserves	$ 10,200	NA	88.9%	NA	$ 9,068			$ 9,068
6	Operating Reserves	$ 589,172	NA	77.4%	NA	$ 456,019			$ 456,019
7	RTO Start-up Cost Recovery - AEP zone	$ 8	NA	88.9%	NA	$ 7			$ 7
8	Synchronous Condensing	$ 8,139	NA	88.9%	NA	$ 7,236			$ 7,236
9	Reliability Pricing Model (RPM) [1]	$ 11,679,098	$ (10,279,841)	88.9%	77.4%	$ 10,382,718	$ (7,956,597)		$ 2,426,122
10	Black Start Service	$ 10,290	NA	88.9%	NA	$ 9,148			$ 9,148
11	PJM Annual Membership Fee	$ -	NA	77.4%	NA	$ -			$ -
12	TO Scheduling System Control and Dispatch Service	$ 113,459	NA	77.4%	NA	$ 87,817			$ 87,817
13	NERC/RFC Charges	$ 17,638	NA	88.9%	NA	$ 15,680			$ 15,680
14	PJM Default Charges	$ -	NA	100.0%	NA	$ -			$ -
15	Transmission Congestion	$ 172,285	$ -	38.7%	50.0%	$ 66,674	$ -		$ 66,674
16	Generation Loss Factor	$ -	NA	NA	NA			$ (350,272)	$ (350,272)
17	Transmission Losses	$ 2,247,543	$ (2,366,341)	77.4%	88.9%	$ 1,739,598	$ (2,103,677)		$ (364,079)
18	Firm PTP Transmission Service	NA	$ (26,937)	NA	100.0%		$ (26,937)		$ (26,937)
19	Non-Firm PTP Transmission Service	NA	$ (40,478)	NA	100.0%		$ (40,478)		$ (40,478)
20	Network Integration Transmission Service	$ 3,866,871	NA	88.9%	NA	$ 3,437,648			$ 3,437,648
21	FTR/ARR Auction	$ -	$ (849,315)	50.0%	50.0%	$ -	$ (424,658)		$ (424,658)
22	Expansion Cost Recovery Charges (ECRC)	$ 16,534	$ (36,655)	88.9%	100.0%	$ 14,699	$ (36,655)		$ (21,956)
23	PJM Scheduling System Control and Dispatch Service (Admin Fee)	$ 217,539	NA	88.9%	NA	$ 193,393			$ 193,393
24	PUCO Consultant fees	$ -	NA	88.9%	NA	$ -			$ -
25	SubTotal	$ 20,567,390	$ (13,599,567)			$ 17,895,565	$ (10,589,001)	$ (350,272)	$ 6,956,292
26	TCRR Deferral carrying costs								
27									
28	**Totals including carrying costs**	$ 20,567,390	$ (13,599,567)			$ 17,895,565	$ (10,589,001)	$ (350,272)	$ 6,956,292

[1] RPM includes the following PJM invoice line items: Locational Reliability Charges, Capacity Resource Deficiency, RPM Auction Revenues, Generation

The Dayton Power and Light Company
Case No. 09-256-EL-UNC
Projected Charges and Revenues
August 2008 - April 2010
(Revenue)/Expense in $

Data: Forecasted
Type of Filing: Original
Work Paper Reference No(s).: WPC-1d

Witness Responsible:
G.S. Campbell

June 2009 - Forecast

Line (A)	Description (B)	Total PJM Bill Charges (C)	Total PJM Bill Revenues (D)	Jurisdictional Allocation Factors Charges (E)	Jurisdictional Allocation Factors Revenues (F)	Allocated PJM Bill Charges (G) = (C)*(E)	Allocated PJM Bill Revenues (H) = (D)*(F)	Retail Revenues (I)	Total Net Costs (J) = (G)+(H)+(I)
29	Transmission Enhancement Charges (RTEP)	$ 29,892	NA	88.9%	NA	$ 26,574			$ 26,574
30	Alliance RTO Start-up Costs	$ 332,548	NA	100.0%	NA	$ 332,548			$ 332,548
31	Reactive Supply and Voltage Control from Gen Sources	$ 396,689	NA	88.9%	NA	$ 352,656			$ 352,656
32	Regulation	$ 859,483	NA	88.9%	NA	$ 764,081			$ 764,081
33	Synchronized (Spinning) Reserves	$ 10,200	NA	88.9%	NA	$ 9,068			$ 9,068
34	Operating Reserves	$ 589,172	NA	77.4%	NA	$ 456,019			$ 456,019
35	RTO Start-up Cost Recovery - AEP zone	$ 8	NA	88.9%	NA	$ 7			$ 7
36	Synchronous Condensing	$ 8,139	NA	88.9%	NA	$ 7,236			$ 7,236
37	Reliability Pricing Model (RPM) [1]	$ 10,479,406	$ (9,103,703)	88.9%	77.4%	$ 9,316,192	$ (7,046,266)		$ 2,269,926
38	Black Start Service	$ 10,290	NA	88.9%	NA	$ 9,148			$ 9,148
39	PJM Annual Membership Fee	$ -	NA	77.4%	NA	$ -			$ -
40	TO Scheduling System Control and Dispatch Service	$ 113,459	NA	77.4%	NA	$ 87,817			$ 87,817
41	NERC/RFC Charges	$ 17,638	NA	88.9%	NA	$ 15,680			$ 15,680
42	PJM Default Charges	$ -	NA	100.0%	NA	$ -			$ -
43	Transmission Congestion	$ 172,285	$ -	38.7%	50.0%	$ 66,674	$ -		$ 66,674
44	Generation Loss Factor	$ -	NA	NA	NA			$ (395,291)	$ (395,291)
45	Transmission Losses	$ 3,508,467	$ (2,672,161)	77.4%	88.9%	$ 2,715,553	$ (2,375,551)		$ 340,002
46	Firm PTP Transmission Service	NA	$ (213,347)	NA	100.0%		$ (213,347)		$ (213,347)
47	Non-Firm PTP Transmission Service	NA	$ (46,904)	NA	100.0%		$ (46,904)		$ (46,904)
48	Network Integration Transmission Service	$ 3,866,871	NA	88.9%	NA	$ 3,437,648			$ 3,437,648
49	FTR/ARR Auction	$ -	$ (821,918)	50.0%	50.0%	$ -	$ (410,959)		$ (410,959)
50	Expansion Cost Recovery Charges (ECRC)	$ 16,534	$ (36,655)	88.9%	100.0%	$ 14,699	$ (36,655)		$ (21,956)
51	PJM Scheduling System Control and Dispatch Service (Admin Fee)	$ 217,539	NA	88.9%	NA	$ 193,393			$ 193,393
52	PUCO Consultant fees	$ -	NA	88.9%	NA	$ -			$ -
53	SubTotal	$ 20,628,622	$ (12,894,687)			$ 17,804,994	$ (10,129,682)	$ (395,291)	$ 7,280,022
54	TCRR Deferral carrying costs								
55									
56	**Totals including carrying costs**	$ 20,628,622	$ (12,894,687)			$ 17,804,994	$ (10,129,682)	$ (395,291)	$ 7,280,022

[1] RPM includes the following PJM invoice line items: Locational Reliability Charges, Capacity Resource Deficiency, RPM Auction Revenues, Generation

The Dayton Power and Light Company
Case No. 09-256-EL-UNC
Projected Charges and Revenues
August 2008 - April 2010
(Revenue)/Expense in $

Data: Forecasted
Type of Filing: Original
Work Paper Reference No(s).: WPC-1d

Witness Responsible:
G.S. Campbell

July 2009 - Forecast

Line (A)	Description (B)	Total PJM Bill Charges (C)	Total PJM Bill Revenues (D)	Jurisdictional Allocation Factors Charges (E)	Jurisdictional Allocation Factors Revenues (F)	Allocated PJM Bill Charges (G) = (C)*(E)	Allocated PJM Bill Revenues (H) = (D)*(F)	Retail Revenues (I)	Total Net Costs (J) = (G)+(H)+(I)
57	Transmission Enhancement Charges (RTEP)	$ 39,716	NA	88.9%	NA	$ 35,307			$ 35,307
58	Alliance RTO Start-up Costs	$ 332,548	NA	100.0%	NA	$ 332,548			$ 332,548
59	Reactive Supply and Voltage Control from Gen Sources	$ 396,689	NA	88.9%	NA	$ 352,656			$ 352,656
60	Regulation	$ 1,191,244	NA	88.9%	NA	$ 1,059,015			$ 1,059,015
61	Synchronized (Spinning) Reserves	$ 10,200	NA	88.9%	NA	$ 9,068			$ 9,068
62	Operating Reserves	$ 780,709	NA	77.4%	NA	$ 604,269			$ 604,269
63	RTO Start-up Cost Recovery - AEP zone	$ 8	NA	88.9%	NA	$ 7			$ 7
64	Synchronous Condensing	$ 8,139	NA	88.9%	NA	$ 7,236			$ 7,236
65	Reliability Pricing Model (RPM) [1]	$ 10,828,719	$ (9,407,159)	88.9%	77.4%	$ 9,626,732	$ (7,281,141)		$ 2,345,590
66	Black Start Service	$ 10,290	NA	88.9%	NA	$ 9,148			$ 9,148
67	PJM Annual Membership Fee	$ -	NA	77.4%	NA	$ -			$ -
68	TO Scheduling System Control and Dispatch Service	$ 146,793	NA	77.4%	NA	$ 113,618			$ 113,618
69	NERC/RFC Charges	$ 23,059	NA	88.9%	NA	$ 20,499			$ 20,499
70	PJM Default Charges	$ -	NA	100.0%	NA	$ -			$ -
71	Transmission Congestion	$ 65,432	$ -	38.7%	50.0%	$ 25,322	$ -		$ 25,322
72	Generation Loss Factor	$ -	NA	NA	NA			$ (467,166)	$ (467,166)
73	Transmission Losses	$ 4,145,836	$ (3,058,678)	77.4%	88.9%	$ 3,208,877	$ (2,719,165)		$ 489,712
74	Firm PTP Transmission Service	NA	$ (232,212)	NA	100.0%		$ (232,212)		$ (232,212)
75	Non-Firm PTP Transmission Service	NA	$ (64,543)	NA	100.0%		$ (64,543)		$ (64,543)
76	Network Integration Transmission Service	$ 3,866,871	NA	88.9%	NA	$ 3,437,648			$ 3,437,648
77	FTR/ARR Auction	$ -	$ (849,315)	50.0%	50.0%	$ -	$ (424,658)		$ (424,658)
78	Expansion Cost Recovery Charges (ECRC)	$ 16,535	$ (36,655)	88.9%	100.0%	$ 14,700	$ (36,655)		$ (21,955)
79	PJM Scheduling System Control and Dispatch Service (Admin Fee)	$ 284,392	NA	88.9%	NA	$ 252,824			$ 252,824
80	PUCO Consultant fees	$ -	NA	88.9%	NA	$ -			$ -
81	SubTotal	$ 22,147,179	$ (13,648,563)			$ 19,109,475	$ (10,758,374)	$ (467,166)	$ 7,883,935
82	TCRR Deferral carrying costs								
83									
84	**Totals including carrying costs**	$ 22,147,179	$ (13,648,563)			$ 19,109,475	$ (10,758,374)	$ (467,166)	$ 7,883,935

[1] RPM includes the following PJM invoice line items: Locational Reliability Charges, Capacity Resource Deficiency, RPM Auction Revenues, Generation

The Dayton Power and Light Company
Case No. 09-256-EL-UNC
Projected Charges and Revenues
August 2008 - April 2010
(Revenue)/Expense in $

Witness Responsible:
G.S. Campbell

Data: Forecasted
Type of Filing: Original
Work Paper Reference No(s).: WPC-1d

August 2009 - Forecast

Line (A)	Description (B)	Total PJM Bill Charges (C)	Total PJM Bill Revenues (D)	Jurisdictional Allocation Factors Charges (E)	Jurisdictional Allocation Factors Revenues (F)	Allocated PJM Bill Charges (G) = (C)*(E)	Allocated PJM Bill Revenues (H) = (D)*(F)	Retail Revenues (I)	Total Net Costs (J) = (G)+(H)+(I)
85	Transmission Enhancement Charges (RTEP)	$ 37,718	NA	88.9%	NA	$ 33,532			$ 33,532
86	Alliance RTO Start-up Costs	$ 332,548	NA	100.0%	NA	$ 332,548			$ 332,548
87	Reactive Supply and Voltage Control from Gen Sources	$ 396,689	NA	88.9%	NA	$ 352,656			$ 352,656
88	Regulation	$ 1,139,778	NA	88.9%	NA	$ 1,013,263			$ 1,013,263
89	Synchronized (Spinning) Reserves	$ 10,200	NA	88.9%	NA	$ 9,068			$ 9,068
90	Operating Reserves	$ 887,203	NA	77.4%	NA	$ 686,695			$ 686,695
91	RTO Start-up Cost Recovery - AEP zone	$ 8	NA	88.9%	NA	$ 7			$ 7
92	Synchronous Condensing	$ 8,139	NA	88.9%	NA	$ 7,236			$ 7,236
93	Reliability Pricing Model (RPM) [1]	$ 10,828,719	$ (9,407,159)	88.9%	77.4%	$ 9,626,732	$ (7,281,141)		$ 2,345,590
94	Black Start Service	$ 10,290	NA	88.9%	NA	$ 9,148			$ 9,148
95	PJM Annual Membership Fee	$ -	NA	77.4%	NA	$ -			$ -
96	TO Scheduling System Control and Dispatch Service	$ 140,828	NA	77.4%	NA	$ 109,001			$ 109,001
97	NERC/RFC Charges	$ 22,242	NA	88.9%	NA	$ 19,773			$ 19,773
98	PJM Default Charges	$ -	NA	100.0%	NA	$ -			$ -
99	Transmission Congestion	$ 54,303	$ -	38.7%	50.0%	$ 21,015	$ -		$ 21,015
100	Generation Loss Factor	$ -	NA	NA	NA			$ (415,836)	$ (415,836)
101	Transmission Losses	$ 4,194,239	$ (2,890,468)	77.4%	88.9%	$ 3,246,341	$ (2,569,626)		$ 676,715
102	Firm PTP Transmission Service	NA	$ (236,567)	NA	100.0%		$ (236,567)		$ (236,567)
103	Non-Firm PTP Transmission Service	NA	$ (53,574)	NA	100.0%		$ (53,574)		$ (53,574)
104	Network Integration Transmission Service	$ 3,866,871	NA	88.9%	NA	$ 3,437,648			$ 3,437,648
105	FTR/ARR Auction	$ -	$ (849,315)	50.0%	50.0%	$ -	$ (424,658)		$ (424,658)
106	Expansion Cost Recovery Charges (ECRC)	$ 16,535	$ (36,655)	88.9%	100.0%	$ 14,700	$ (36,655)		$ (21,955)
107	PJM Scheduling System Control and Dispatch Service (Admin Fee)	$ 274,319	NA	88.9%	NA	$ 243,870			$ 243,870
108	PUCO Consultant fees	$ -	NA	88.9%	NA	$ -			$ -
109	SubTotal	$ 22,220,631	$ (13,473,739)			$ 19,163,233	$ (10,602,221)	$ (415,836)	$ 8,145,175
110	TCRR Deferral carrying costs								
111									
112	**Totals including carrying costs**	$ 22,220,631	$ (13,473,739)			$ 19,163,233	$ (10,602,221)	$ (415,836)	$ 8,145,175

[1] RPM includes the following PJM invoice line items: Locational Reliability Charges, Capacity Resource Deficiency, RPM Auction Revenues, Generation

The Dayton Power and Light Company
Case No. 09-256-EL-UNC
Projected Charges and Revenues
August 2008 - April 2010
(Revenue)/Expense in $

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Witness Responsible:
G.S. Campbell

September 2009 - Forecast

Line (A)	Description (B)	Total PJM Bill Charges (C)	Total PJM Bill Revenues (D)	Jurisdictional Allocation Factors Charges (E)	Jurisdictional Allocation Factors Revenues (F)	Allocated PJM Bill Charges (G) = (C)*(E)	Allocated PJM Bill Revenues (H) = (D)*(F)	Retail Revenues (I)	Total Net Costs (J) = (G)+(H)+(I)
113	Transmission Enhancement Charges (RTEP)	$ 32,796	NA	88.9%	NA	$ 29,155			$ 29,155
114	Alliance RTO Start-up Costs	$ 332,548	NA	100.0%	NA	$ 332,548			$ 332,548
115	Reactive Supply and Voltage Control from Gen Sources	$ 396,689	NA	88.9%	NA	$ 352,656			$ 352,656
116	Regulation	$ 844,144	NA	88.9%	NA	$ 750,444			$ 750,444
117	Synchronized (Spinning) Reserves	$ 10,200	NA	88.9%	NA	$ 9,068			$ 9,068
118	Operating Reserves	$ 606,940	NA	77.4%	NA	$ 469,772			$ 469,772
119	RTO Start-up Cost Recovery - AEP zone	$ 8	NA	88.9%	NA	$ 7			$ 7
120	Synchronous Condensing	$ 8,139	NA	88.9%	NA	$ 7,236			$ 7,236
121	Reliability Pricing Model (RPM) [1]	$ 15,979,406	$ (9,103,703)	88.9%	77.4%	$ 14,205,692	$ (7,046,266)		$ 7,159,426
122	Black Start Service	$ 10,290	NA	88.9%	NA	$ 9,148			$ 9,148
123	PJM Annual Membership Fee	$ -	NA	77.4%	NA	$ -			$ -
124	TO Scheduling System Control and Dispatch Service	$ 121,925	NA	77.4%	NA	$ 94,370			$ 94,370
125	NERC/RFC Charges	$ 19,244	NA	88.9%	NA	$ 17,108			$ 17,108
126	PJM Default Charges	$ -	NA	100.0%	NA	$ -			$ -
127	Transmission Congestion	$ 37,141	$ -	38.7%	50.0%	$ 14,374	$ -		$ 14,374
128	Generation Loss Factor	$ -	NA	NA	NA			$ (363,556)	$ (363,556)
129	Transmission Losses	$ 3,541,785	$ (2,437,559)	77.4%	88.9%	$ 2,741,342	$ (2,166,990)		$ 574,352
130	Firm PTP Transmission Service	NA	$ (213,552)	NA	100.0%		$ (213,552)		$ (213,552)
131	Non-Firm PTP Transmission Service	NA	$ (48,504)	NA	100.0%		$ (48,504)		$ (48,504)
132	Network Integration Transmission Service	$ 3,748,585	NA	88.9%	NA	$ 3,332,492			$ 3,332,492
133	FTR/ARR Auction	$ -	$ (821,918)	50.0%	50.0%	$ -	$ (410,959)		$ (410,959)
134	Expansion Cost Recovery Charges (ECRC)	$ 16,535	$ (36,656)	88.9%	100.0%	$ 14,700	$ (36,656)		$ (21,956)
135	PJM Scheduling System Control and Dispatch Service (Admin Fee)	$ 237,346	NA	88.9%	NA	$ 211,000			$ 211,000
136	PUCO Consultant fees	$ -	NA	88.9%	NA	$ -			$ -
137	SubTotal	$ 25,943,721	$ (12,661,891)			$ 22,591,112	$ (9,922,927)	$ (363,556)	$ 12,304,629
138	TCRR Deferral carrying costs								
139									
140	**Totals including carrying costs**	$ 25,943,721	$ (12,661,891)			$ 22,591,112	$ (9,922,927)	$ (363,556)	$ 12,304,629

[1] RPM includes the following PJM invoice line items: Locational Reliability Charges, Capacity Resource Deficiency, RPM Auction Revenues, Generation

The Dayton Power and Light Company
Case No. 09-256-EL-UNC
Projected Charges and Revenues
August 2008 - April 2010
(Revenue)/Expense in $

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Witness Responsible:
G.S. Campbell

October 2009 - Forecast

Line (A)	Description (B)	Total PJM Bill Charges (C)	Total PJM Bill Revenues (D)	Jurisdictional Allocation Factors Charges (E)	Jurisdictional Allocation Factors Revenues (F)	Allocated PJM Bill Charges (G) = (C)*(E)	Allocated PJM Bill Revenues (H) = (D)*(F)	Retail Revenues (I)	Total Net Costs (J) = (G)+(H)+(I)
141	Transmission Enhancement Charges (RTEP)	$ 32,033	NA	88.9%	NA	$ 28,477			$ 28,477
142	Alliance RTO Start-up Costs	$ 332,548	NA	100.0%	NA	$ 332,548			$ 332,548
143	Reactive Supply and Voltage Control from Gen Sources	$ 396,689	NA	88.9%	NA	$ 352,656			$ 352,656
144	Regulation	$ 825,539	NA	88.9%	NA	$ 733,904			$ 733,904
145	Synchronized (Spinning) Reserves	$ 10,200	NA	88.9%	NA	$ 9,068			$ 9,068
146	Operating Reserves	$ 655,322	NA	77.4%	NA	$ 507,219			$ 507,219
147	RTO Start-up Cost Recovery - AEP zone	$ 8	NA	88.9%	NA	$ 7			$ 7
148	Synchronous Condensing	$ 8,139	NA	88.9%	NA	$ 7,236			$ 7,236
149	Reliability Pricing Model (RPM) [1]	$ 10,828,719	$ (9,407,159)	88.9%	77.4%	$ 9,626,732	$ (7,281,141)		$ 2,345,590
150	Black Start Service	$ 10,290	NA	88.9%	NA	$ 9,148			$ 9,148
151	PJM Annual Membership Fee	$ -	NA	77.4%	NA	$ -			$ -
152	TO Scheduling System Control and Dispatch Service	$ 117,294	NA	77.4%	NA	$ 90,786			$ 90,786
153	NERC/RFC Charges	$ 18,259	NA	88.9%	NA	$ 16,233			$ 16,233
154	PJM Default Charges	$ -	NA	100.0%	NA	$ -			$ -
155	Transmission Congestion	$ 79,210	$ -	38.7%	50.0%	$ 30,654	$ -		$ 30,654
156	Generation Loss Factor	$ -	NA	NA	NA			$ (348,495)	$ (348,495)
157	Transmission Losses	$ 3,652,804	$ (2,374,196)	77.4%	88.9%	$ 2,827,270	$ (2,110,660)		$ 716,610
158	Firm PTP Transmission Service	NA	$ (220,968)	NA	100.0%		$ (220,968)		$ (220,968)
159	Non-Firm PTP Transmission Service	NA	$ (29,922)	NA	100.0%		$ (29,922)		$ (29,922)
160	Network Integration Transmission Service	$ 3,866,871	NA	88.9%	NA	$ 3,437,648			$ 3,437,648
161	FTR/ARR Auction	$ -	$ (849,315)	50.0%	50.0%	$ -	$ (424,658)		$ (424,658)
162	Expansion Cost Recovery Charges (ECRC)	$ 15,988	$ (36,667)	88.9%	100.0%	$ 14,213	$ (36,667)		$ (22,454)
163	PJM Scheduling System Control and Dispatch Service (Admin Fee)	$ 225,199	NA	88.9%	NA	$ 200,202			$ 200,202
164	PUCO Consultant fees	$ -	NA	88.9%	NA	$ -			$ -
165	SubTotal	$ 21,075,114	$ (12,918,228)			$ 18,224,002	$ (10,104,016)	$ (348,495)	$ 7,771,491
166	TCRR Deferral carrying costs								
167									
168	**Totals including carrying costs**	$ 21,075,114	$ (12,918,228)			$ 18,224,002	$ (10,104,016)	$ (348,495)	$ 7,771,491

[1] RPM includes the following PJM invoice line items: Locational Reliability Charges, Capacity Resource Deficiency, RPM Auction Revenues, Generation

The Dayton Power and Light Company
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August 2008 - April 2010
(Revenue)/Expense in $

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Witness Responsible:
G.S. Campbell

November 2009 - Forecast

Line (A)	Description (B)	Total PJM Bill Charges (C)	Total PJM Bill Revenues (D)	Jurisdictional Allocation Factors Charges (E)	Jurisdictional Allocation Factors Revenues (F)	Allocated PJM Bill Charges (G) = (C)*(E)	Allocated PJM Bill Revenues (H) = (D)*(F)	Retail Revenues (I)	Total Net Costs (J) = (G)+(H)+(I)
169	Transmission Enhancement Charges (RTEP)	$ 32,707	NA	88.9%	NA	$ 29,076			$ 29,076
170	Alliance RTO Start-up Costs	$ 332,548	NA	100.0%	NA	$ 332,548			$ 332,548
171	Reactive Supply and Voltage Control from Gen Sources	$ 396,689	NA	88.9%	NA	$ 352,656			$ 352,656
172	Regulation	$ 866,492	NA	88.9%	NA	$ 770,311			$ 770,311
173	Synchronized (Spinning) Reserves	$ 10,200	NA	88.9%	NA	$ 9,068			$ 9,068
174	Operating Reserves	$ 562,042	NA	77.4%	NA	$ 435,021			$ 435,021
175	RTO Start-up Cost Recovery - AEP zone	$ 8	NA	88.9%	NA	$ 7			$ 7
176	Synchronous Condensing	$ 8,139	NA	88.9%	NA	$ 7,236			$ 7,236
177	Reliability Pricing Model (RPM) [1]	$ 10,479,406	$ (9,103,703)	88.9%	77.4%	$ 9,316,192	$ (7,046,266)		$ 2,269,926
178	Black Start Service	$ 10,290	NA	88.9%	NA	$ 9,148			$ 9,148
179	PJM Annual Membership Fee	$ 5,000	NA	77.4%	NA	$ 3,870			$ 3,870
180	TO Scheduling System Control and Dispatch Service	$ 120,375	NA	77.4%	NA	$ 93,171			$ 93,171
181	NERC/RFC Charges	$ 18,907	NA	88.9%	NA	$ 16,809			$ 16,809
182	PJM Default Charges	$ -	NA	100.0%	NA	$ -			$ -
183	Transmission Congestion	$ 2,233	$ -	38.7%	50.0%	$ 864	$ -		$ 864
184	Generation Loss Factor	$ -	NA	NA	NA			$ (346,311)	$ (346,311)
185	Transmission Losses	$ 3,580,635	$ (2,261,645)	77.4%	88.9%	$ 2,771,411	$ (2,010,602)		$ 760,809
186	Firm PTP Transmission Service	NA	$ (211,156)	NA	100.0%		$ (211,156)		$ (211,156)
187	Non-Firm PTP Transmission Service	NA	$ (30,845)	NA	100.0%		$ (30,845)		$ (30,845)
188	Network Integration Transmission Service	$ 3,748,585	NA	88.9%	NA	$ 3,332,492			$ 3,332,492
189	FTR/ARR Auction	$ -	$ (821,918)	50.0%	50.0%	$ -	$ (410,959)		$ (410,959)
190	Expansion Cost Recovery Charges (ECRC)	$ 16,003	$ (36,678)	88.9%	100.0%	$ 14,227	$ (36,678)		$ (22,451)
191	PJM Scheduling System Control and Dispatch Service (Admin Fee)	$ 233,190	NA	88.9%	NA	$ 207,306			$ 207,306
192	PUCO Consultant fees	$ -	NA	88.9%	NA	$ -			$ -
193	SubTotal	$ 20,423,450	$ (12,465,944)			$ 17,701,413	$ (9,746,506)	$ (346,311)	$ 7,608,596
194	TCRR Deferral carrying costs								
195									
196	**Totals including carrying costs**	$ 20,423,450	$ (12,465,944)			$ 17,701,413	$ (9,746,506)	$ (346,311)	$ 7,608,596

[1] RPM includes the following PJM invoice line items: Locational Reliability Charges, Capacity Resource Deficiency, RPM Auction Revenues, Generation

The Dayton Power and Light Company
Case No. 09-256-EL-UNC
Projected Charges and Revenues
August 2008 - April 2010
(Revenue)/Expense In $

Data: Forecasted
Type of Filing: Original
Work Paper Reference No(s).: WPC-1d

Witness Responsible:
G.S. Campbell

December 2009 - Forecast

Line (A)	Description (B)	Total PJM Bill Charges (C)	Total PJM Bill Revenues (D)	Jurisdictional Allocation Factors Charges (E)	Jurisdictional Allocation Factors Revenues (F)	Allocated PJM Bill Charges (G) = (C)*(E)	Allocated PJM Bill Revenues (H) = (D)*(F)	Retail Revenues (I)	Total Net Costs (J) = (G)+(H)+(I)
197	Transmission Enhancement Charges (RTEP)	$ 37,232	NA	88.9%	NA	$ 33,100			$ 33,100
198	Alliance RTO Start-up Costs	$ 332,548	NA	100.0%	NA	$ 332,548			$ 332,548
199	Reactive Supply and Voltage Control from Gen Sources	$ 396,689	NA	88.9%	NA	$ 352,656			$ 352,656
200	Regulation	$ 971,429	NA	88.9%	NA	$ 863,600			$ 863,600
201	Synchronized (Spinning) Reserves	$ 10,200	NA	88.9%	NA	$ 9,068			$ 9,068
202	Operating Reserves	$ 753,424	NA	77.4%	NA	$ 583,150			$ 583,150
203	RTO Start-up Cost Recovery - AEP zone	$ 8	NA	88.9%	NA	$ 7			$ 7
204	Synchronous Condensing	$ 8,139	NA	88.9%	NA	$ 7,236			$ 7,236
205	Reliability Pricing Model (RPM) [1]	$ 10,828,719	$ (9,407,159)	88.9%	77.4%	$ 9,626,732	$ (7,281,141)		$ 2,345,590
206	Black Start Service	$ 10,290	NA	88.9%	NA	$ 9,148			$ 9,148
207	PJM Annual Membership Fee	$ -	NA	77.4%	NA	$ -			$ -
208	TO Scheduling System Control and Dispatch Service	$ 135,912	NA	77.4%	NA	$ 105,196			$ 105,196
209	NERC/RFC Charges	$ 21,380	NA	88.9%	NA	$ 19,007			$ 19,007
210	PJM Default Charges	$ -	NA	100.0%	NA	$ -			$ -
211	Transmission Congestion	$ 36,608	$ -	38.7%	50.0%	$ 14,167	$ -		$ 14,167
212	Generation Loss Factor	$ -	NA	NA	NA			$ (423,867)	$ (423,867)
213	Transmission Losses	$ 3,775,863	$ (2,815,528)	77.4%	88.9%	$ 2,922,518	$ (2,503,004)		$ 419,514
214	Firm PTP Transmission Service	NA	$ (218,390)	NA	100.0%		$ (218,390)		$ (218,390)
215	Non-Firm PTP Transmission Service	NA	$ (28,911)	NA	100.0%		$ (28,911)		$ (28,911)
216	Network Integration Transmission Service	$ 3,866,871	NA	88.9%	NA	$ 3,437,648			$ 3,437,648
217	FTR/ARR Auction	$ -	$ (849,315)	50.0%	50.0%	$ -	$ (424,658)		$ (424,658)
218	Expansion Cost Recovery Charges (ECRC)	$ 16,003	$ (36,675)	88.9%	100.0%	$ 14,227	$ (36,675)		$ (22,448)
219	PJM Scheduling System Control and Dispatch Service (Admin Fee)	$ 263,686	$ -	88.9%	NA	$ 234,417			$ 234,417
220	PUCO Consultant fees	$ -	$ -	88.9%	NA	$ -			$ -
221	SubTotal	$ 21,465,002	$ (13,355,979)			$ 18,564,424	$ (10,492,779)	$ (423,867)	$ 7,647,778
222	TCRR Deferral carrying costs								
223									
224	**Totals including carrying costs**	$ 21,465,002	$ (13,355,979)			$ 18,564,424	$ (10,492,779)	$ (423,867)	$ 7,647,778

[1] RPM includes the following PJM invoice line items: Locational Reliability Charges, Capacity Resource Deficiency, RPM Auction Revenues, Generation

The Dayton Power and Light Company
Case No. 09-256-EL-UNC
Projected Charges and Revenues
August 2008 - April 2010
(Revenue)/Expense in $

Data: Forecasted
Type of Filing: Original
Work Paper Reference No(s).: WPC-1d

Witness Responsible:
G.S. Campbell

January 2010 - Forecast

Line (A)	Description (B)	Total PJM Bill Charges (C)	Total PJM Bill Revenues (D)	Jurisdictional Allocation Factors Charges (E)	Jurisdictional Allocation Factors Revenues (F)	Allocated PJM Bill Charges (G) = (C)*(E)	Allocated PJM Bill Revenues (H) = (D)*(F)	Retail Revenues (I)	Total Net Costs (J) = (G)+(H)+(I)
225	Transmission Enhancement Charges (RTEP)	$ 63,036	NA	88.9%	NA	$ 56,039			$ 56,039
226	Alliance RTO Start-up Costs	$ 332,548	NA	100.0%	NA	$ 332,548			$ 332,548
227	Reactive Supply and Voltage Control from Gen Sources	$ 396,689	NA	88.9%	NA	$ 352,656			$ 352,656
228	Regulation	$ 1,022,234	NA	88.9%	NA	$ 908,766			$ 908,766
229	Synchronized (Spinning) Reserves	$ 10,200	NA	88.9%	NA	$ 9,068			$ 9,068
230	Operating Reserves	$ 701,480	NA	77.4%	NA	$ 542,945			$ 542,945
231	RTO Start-up Cost Recovery - AEP zone	$ 8	NA	88.9%	NA	$ 7			$ 7
232	Synchronous Condensing	$ 8,139	NA	88.9%	NA	$ 7,236			$ 7,236
233	Reliability Pricing Model (RPM) [1]	$ 10,828,719	$ (9,407,159)	88.9%	77.4%	$ 9,626,732	$ (7,281,141)		$ 2,345,590
234	Black Start Service	$ 10,290	NA	88.9%	NA	$ 9,148			$ 9,148
235	PJM Annual Membership Fee	$ -	NA	77.4%	NA	$ -			$ -
236	TO Scheduling System Control and Dispatch Service	$ 128,128	NA	77.4%	NA	$ 99,171			$ 99,171
237	NERC/RFC Charges	$ 20,151	NA	88.9%	NA	$ 17,914			$ 17,914
238	PJM Default Charges	$ -	NA	100.0%	NA	$ -			$ -
239	Transmission Congestion	$ 241,872	$ -	38.7%	50.0%	$ 93,604	$ -		$ 93,604
240	Generation Loss Factor	$ -	NA	NA	NA			$ (404,548)	$ (404,548)
241	Transmission Losses	$ 4,230,919	$ (3,052,597)	77.4%	88.9%	$ 3,274,731	$ (2,713,759)		$ 560,973
242	Firm PTP Transmission Service	NA	$ (187,653)	NA	100.0%		$ (187,653)		$ (187,653)
243	Non-Firm PTP Transmission Service	NA	$ (41,484)	NA	100.0%		$ (41,484)		$ (41,484)
244	Network Integration Transmission Service	$ 3,797,871	NA	88.9%	NA	$ 3,376,307			$ 3,376,307
245	FTR/ARR Auction	$ -	$ (416,667)	50.0%	50.0%	$ -	$ (208,333)		$ (208,333)
246	Expansion Cost Recovery Charges (ECRC)	$ 16,400	$ (36,660)	88.9%	100.0%	$ 14,580	$ (36,660)		$ (22,080)
247	PJM Scheduling System Control and Dispatch Service (Admin Fee)	$ 248,528	NA	88.9%	NA	$ 220,941			$ 220,941
248	PUCO Consultant fees	$ -	NA	88.9%	NA	$ -			$ -
249	SubTotal	$ 22,057,213	$ (13,142,220)			$ 18,942,394	$ (10,469,030)	$ (404,548)	$ 8,068,816
250	TCRR Deferral carrying costs								
251									
252	**Totals including carrying costs**	$ 22,057,213	$ (13,142,220)			$ 18,942,394	$ (10,469,030)	$ (404,548)	$ 8,068,816

[1] RPM includes the following PJM invoice line items: Locational Reliability Charges, Capacity Resource Deficiency, RPM Auction Revenues, Generation

The Dayton Power and Light Company
Case No. 09-256-EL-UNC
Projected Charges and Revenues
August 2008 - April 2010
(Revenue)/Expense in $

Data: Forecasted
Type of Filing: Original
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Witness Responsible:
G.S. Campbell

February 2010 - Forecast

Line (A)	Description (B)	Total PJM Bill Charges (C)	Total PJM Bill Revenues (D)	Jurisdictional Allocation Factors Charges (E)	Jurisdictional Allocation Factors Revenues (F)	Allocated PJM Bill Charges (G) = (C)*(E)	Allocated PJM Bill Revenues (H) = (D)*(F)	Retail Revenues (I)	Total Net Costs (J) = (G)+(H)+(I)
253	Transmission Enhancement Charges (RTEP)	$ 63,036	NA	88.9%	NA	$ 56,039			$ 56,039
254	Alliance RTO Start-up Costs	$ 332,548	NA	100.0%	NA	$ 332,548			$ 332,548
255	Reactive Supply and Voltage Control from Gen Sources	$ 396,689	NA	88.9%	NA	$ 352,656			$ 352,656
256	Regulation	$ 1,022,234	NA	88.9%	NA	$ 908,766			$ 908,766
257	Synchronized (Spinning) Reserves	$ 10,200	NA	88.9%	NA	$ 9,068			$ 9,068
258	Operating Reserves	$ 701,480	NA	77.4%	NA	$ 542,945			$ 542,945
259	RTO Start-up Cost Recovery - AEP zone	$ 8	NA	88.9%	NA	$ 7			$ 7
260	Synchronous Condensing	$ 8,139	NA	88.9%	NA	$ 7,236			$ 7,236
261	Reliability Pricing Model (RPM) [1]	$ 9,780,779	$ (8,496,789)	88.9%	77.4%	$ 8,695,112	$ (6,576,515)		$ 2,118,598
262	Black Start Service	$ 10,290	NA	88.9%	NA	$ 9,148			$ 9,148
263	PJM Annual Membership Fee	$ -	NA	77.4%	NA	$ -			$ -
264	TO Scheduling System Control and Dispatch Service	$ 128,128	NA	77.4%	NA	$ 99,171			$ 99,171
265	NERC/RFC Charges	$ 20,151	NA	88.9%	NA	$ 17,914			$ 17,914
266	PJM Default Charges	$ -	NA	100.0%	NA	$ -			$ -
267	Transmission Congestion	$ 39,937	$ -	38.7%	50.0%	$ 15,456	$ -		$ 15,456
268	Generation Loss Factor	$ -	NA	NA	NA			$ (413,996)	$ (413,996)
269	Transmission Losses	$ 3,807,541	$ (2,480,883)	77.4%	88.9%	$ 2,947,037	$ (2,205,505)		$ 741,532
270	Firm PTP Transmission Service	NA	$ (187,653)	NA	100.0%		$ (187,653)		$ (187,653)
271	Non-Firm PTP Transmission Service	NA	$ (41,484)	NA	100.0%		$ (41,484)		$ (41,484)
272	Network Integration Transmission Service	$ 3,797,671	NA	88.9%	NA	$ 3,376,307			$ 3,376,307
273	FTR/ARR Auction	$ -	$ (416,667)	50.0%	50.0%	$ -	$ (208,333)		$ (208,333)
274	Expansion Cost Recovery Charges (ECRC)	$ 16,400	$ (36,660)	88.9%	100.0%	$ 14,580	$ (36,660)		$ (22,080)
275	PJM Scheduling System Control and Dispatch Service (Admin Fee)	$ 248,528	NA	88.9%	NA	$ 220,941			$ 220,941
276	PUCO Consultant fees	$ -	NA	88.9%	NA	$ -			$ -
277	SubTotal	$ 20,383,959	$ (11,660,136)			$ 17,604,932	$ (9,256,150)	$ (413,996)	$ 7,934,786
278	TCRR Deferral carrying costs								
279									
280	**Totals including carrying costs**	$ 20,383,959	$ (11,660,136)			$ 17,604,932	$ (9,256,150)	$ (413,996)	$ 7,934,786

[1] RPM includes the following PJM invoice line items: Locational Reliability Charges, Capacity Resource Deficiency, RPM Auction Revenues, Generation

The Dayton Power and Light Company
Case No. 09-256-EL-UNC
Projected Charges and Revenues
August 2008 - April 2010
(Revenue)/Expense in $

Data: Forecasted
Type of Filing: Original
Work Paper Reference No(s).: WPC-1d

Witness Responsible:
G.S. Campbell

March 2010 - Forecast

Line (A)	Description (B)	Total PJM Bill Charges (C)	Total PJM Bill Revenues (D)	Jurisdictional Allocation Factors Charges (E)	Jurisdictional Allocation Factors Revenues (F)	Allocated PJM Bill Charges (G) = (C)*(E)	Allocated PJM Bill Revenues (H) = (D)*(F)	Retail Revenues (I)	Total Net Costs (J) = (G)+(H)+(I)
281	Transmission Enhancement Charges (RTEP)	$ 63,036	NA	88.9%	NA	$ 56,039			$ 56,039
282	Alliance RTO Start-up Costs	$ 332,548	NA	100.0%	NA	$ 332,548			$ 332,548
283	Reactive Supply and Voltage Control from Gen Sources	$ 396,689	NA	88.9%	NA	$ 352,656			$ 352,656
284	Regulation	$ 1,022,234	NA	88.9%	NA	$ 908,766			$ 908,766
285	Synchronized (Spinning) Reserves	$ 10,200	NA	88.9%	NA	$ 9,068			$ 9,068
286	Operating Reserves	$ 701,480	NA	77.4%	NA	$ 542,945			$ 542,945
287	RTO Start-up Cost Recovery - AEP zone	$ 8	NA	88.9%	NA	$ 7			$ 7
288	Synchronous Condensing	$ 8,139	NA	88.9%	NA	$ 7,236			$ 7,236
289	Reliability Pricing Model (RPM) [1]	$ 10,828,719	$ (9,407,159)	88.9%	77.4%	$ 9,628,732	$ (7,281,141)		$ 2,345,590
290	Black Start Service	$ 10,290	NA	88.9%	NA	$ 9,148			$ 9,148
291	PJM Annual Membership Fee	$ -	NA	77.4%	NA	$ -			$ -
292	TO Scheduling System Control and Dispatch Service	$ 128,128	NA	77.4%	NA	$ 99,171			$ 99,171
293	NERC/RFC Charges	$ 20,151	NA	88.9%	NA	$ 17,914			$ 17,914
294	PJM Default Charges	$ -	NA	100.0%	NA	$ -			$ -
295	Transmission Congestion	$ -	$ 14,179	38.7%	50.0%	$ -	$ 7,089		$ 7,089
296	Generation Loss Factor	$ -	NA	NA	NA			$ (323,865)	$ (323,865)
297	Transmission Losses	$ 3,711,819	$ (2,694,732)	77.4%	88.9%	$ 2,872,948	$ (2,395,617)		$ 477,331
298	Firm PTP Transmission Service	NA	$ (187,653)	NA	100.0%		$ (187,653)		$ (187,653)
299	Non-Firm PTP Transmission Service	NA	$ (41,484)	NA	100.0%		$ (41,484)		$ (41,484)
300	Network Integration Transmission Service	$ 3,797,871	NA	88.9%	NA	$ 3,376,307			$ 3,376,307
301	FTR/ARR Auction	$ -	$ (416,667)	50.0%	50.0%	$ -	$ (208,333)		$ (208,333)
302	Expansion Cost Recovery Charges (ECRC)	$ 16,400	$ (36,660)	88.9%	100.0%	$ 14,580	$ (36,660)		$ (22,080)
303	PJM Scheduling System Control and Dispatch Service (Admin Fee)	$ 248,528	NA	88.9%	NA	$ 220,941			$ 220,941
304	PUCO Consultant fees	$ -	NA	88.9%	NA	$ -			$ -
305	SubTotal	$ 21,296,241	$ (12,770,176)			$ 18,447,007	$ (10,143,799)	$ (323,865)	$ 7,979,343
306	TCRR Deferral carrying costs								
307									
308	**Totals including carrying costs**	$ 21,296,241	$ (12,770,176)			$ 18,447,007	$ (10,143,799)	$ (323,865)	$ 7,979,343

[1] RPM includes the following PJM invoice line items: Locational Reliability Charges, Capacity Resource Deficiency, RPM Auction Revenues, Generation

The Dayton Power and Light Company
Case No. 09-256-EL-UNC
Projected Charges and Revenues
August 2008 - April 2010
(Revenue)/Expense in $

Data: Forecasted
Type of Filing: Original
Work Paper Reference No(s).: WPC-1d

Witness Responsible:
G.S. Campbell

April 2010 - Forecast

Line (A)	Description (B)	Total PJM Bill Charges (C)	Total PJM Bill Revenues (D)	Jurisdictional Allocation Factors Charges (E)	Jurisdictional Allocation Factors Revenues (F)	Allocated PJM Bill Charges (G) = (C)*(E)	Allocated PJM Bill Revenues (H) = (D)*(F)	Retail Revenues (I)	Total Net Costs (J) = (G)+(H)+(I)
309	Transmission Enhancement Charges (RTEP)	$ 63,036	NA	88.9%	NA	$ 56,039			$ 56,039
310	Alliance RTO Start-up Costs	$ 332,548	NA	100.0%	NA	$ 332,548			$ 332,548
311	Reactive Supply and Voltage Control from Gen Sources	$ 396,689	NA	88.9%	NA	$ 352,656			$ 352,656
312	Regulation	$ 1,022,234	NA	88.9%	NA	$ 908,766			$ 908,766
313	Synchronized (Spinning) Reserves	$ 10,200	NA	88.9%	NA	$ 9,068			$ 9,068
314	Operating Reserves	$ 701,480	NA	77.4%	NA	$ 542,945			$ 542,945
315	RTO Start-up Cost Recovery - AEP zone	$ 8	NA	88.9%	NA	$ 7			$ 7
316	Synchronous Condensing	$ 8,139	NA	88.9%	NA	$ 7,236			$ 7,236
317	Reliability Pricing Model (RPM) [1]	$ 10,479,406	$ (9,103,703)	88.9%	77.4%	$ 9,316,192	$ (7,046,266)		$ 2,269,926
318	Black Start Service	$ 10,290	NA	88.9%	NA	$ 9,148			$ 9,148
319	PJM Annual Membership Fee	$ -	NA	77.4%	NA	$ -			$ -
320	TO Scheduling System Control and Dispatch Service	$ 128,128	NA	77.4%	NA	$ 99,171			$ 99,171
321	NERC/RFC Charges	$ 20,151	NA	88.9%	NA	$ 17,914			$ 17,914
322	PJM Default Charges	$ -	NA	100.0%	NA	$ -			$ -
323	Transmission Congestion	$ 139,958	$ -	38.7%	50.0%	$ 54,164	$ -		$ 54,164
324	Generation Loss Factor	$ -	NA	NA	NA			$ (335,365)	$ (335,365)
325	Transmission Losses	$ 2,582,821	$ (2,289,258)	77.4%	88.9%	$ 1,999,103	$ (2,035,150)		$ (36,047)
326	Firm PTP Transmission Service	NA	$ (187,653)	NA	100.0%		$ (187,653)		$ (187,653)
327	Non-Firm PTP Transmission Service	NA	$ (41,484)	NA	100.0%		$ (41,484)		$ (41,484)
328	Network Integration Transmission Service	$ 3,797,871	NA	88.9%	NA	$ 3,376,307			$ 3,376,307
329	FTR/ARR Auction	$ -	$ (416,667)	50.0%	50.0%	$ -	$ (208,333)		$ (208,333)
330	Expansion Cost Recovery Charges (ECRC)	$ 16,400	$ (36,660)	88.9%	100.0%	$ 14,580	$ (36,660)		$ (22,080)
331	PJM Scheduling System Control and Dispatch Service (Admin Fee)	$ 248,528	NA	88.9%	NA	$ 220,941			$ 220,941
332	PUCO Consultant fees	$ -	NA	88.9%	NA	$ -			$ -
333	SubTotal	$ 19,957,887	$ (12,075,424)			$ 17,316,786	$ (9,555,547)	$ (335,365)	$ 7,425,875
334	TCRR Deferral carrying costs								
335									
336	**Totals including carrying costs**	$ 19,957,887	$ (12,075,424)			$ 17,316,786	$ (9,555,547)	$ (335,365)	$ 7,425,875

[1] RPM includes the following PJM invoice line items: Locational Reliability Charges, Capacity Resource Deficiency, RPM Auction Revenues, Generation

The Dayton Power and Light Company
Case No. 09-256-EL-UNC
Calculation of Carrying Costs
June 2007 - April 2009

Data: Actual and Forecasted
Type of Filing: Original
Work Paper Reference No(s).: None

Workpaper C-1b
Page 1 of 1
Witness Responsible:
G.S. Campbell

		MONTHLY ACTIVITY							CARRYING COST CALCULATION		
Line No.	Period	First of Month Balance	New TCRR Charges	Amount Collected (CR)	NET AMOUNT	End of Month before Carrying Cost	Carrying Cost @ 5.86%	End of Month Balance	End of Month Balance	Less: One-half Monthly Amount	Total Applicable to Carrying Cost
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)
					(F) = (D) + (E)	(G) = (C) + (F)	(H) = (L) * (5.86% / 12)	(I) = (G) + (H)	(J) = (G)	(K) = - (F) * .5	(L) = (J) + (K)
1	Jun-07	-	9,494.39	-	9,494.39	9,494.39	23.18	9,517.57	9,494.39	(4,747.19)	4,747.19
2	Jul-07	9,517.57	9,494.39	-	9,494.39	19,011.96	69.66	19,081.62	19,011.96	(4,747.19)	14,264.76
3	Aug-07	19,081.62	9,503.49	-	9,503.49	28,585.11	116.39	28,701.49	28,585.11	(4,751.75)	23,833.36
4	Sep-07	28,701.49	9,503.49	-	9,503.49	38,204.98	163.36	38,368.34	38,204.98	(4,751.75)	33,453.24
5	Oct-07	38,368.34	9,503.49	-	9,503.49	47,871.83	210.57	48,082.40	47,871.83	(4,751.75)	43,120.09
6	Nov-07	48,082.40	9,503.49	-	9,503.49	57,585.89	258.01	57,843.90	57,585.89	(4,751.75)	52,834.15
7	Dec-07	57,843.90	9,503.49	-	9,503.49	67,347.39	305.68	67,653.07	67,347.39	(4,751.75)	62,595.65
8	Jan-08	67,653.07	9,433.65	-	9,433.65	77,086.72	353.41	77,440.12	77,086.72	(4,716.83)	72,369.89
9	Feb-08	77,440.12	9,433.65	-	9,433.65	86,873.77	401.20	87,274.97	86,873.77	(4,716.83)	82,156.95
10	Mar-08	87,274.97	37,580.24	-	37,580.24	124,855.22	517.95	125,373.17	124,855.22	(18,790.12)	106,065.09
11	Apr-08	125,373.17	37,580.24	-	37,580.24	162,953.41	704.00	163,657.41	162,953.41	(18,790.12)	144,163.29
12	May-08	163,657.41	42,261.48	-	42,261.48	205,918.89	902.38	206,821.27	205,918.89	(21,130.74)	184,788.15
13	Jun-08	206,821.27	78,538.22	-	78,538.22	285,359.49	1,201.74	286,561.23	285,359.49	(39,269.11)	246,090.38
14	Jul-08	286,561.23	73,062.01	-	73,062.01	359,623.25	1,577.77	361,201.01	359,623.25	(36,531.01)	323,092.24
15	Aug-08	361,201.01	(178,031.26)	-	(178,031.26)	183,169.76	1,329.17	184,498.93	183,169.76	89,015.63	272,185.38
16	Sep-08	184,498.93	4,690,445.89	-	4,690,445.89	4,874,944.82	12,353.48	4,887,298.29	4,874,944.82	(2,345,222.95)	2,529,721.87
17	Oct-08	4,887,298.29	2,500,473.12	-	2,500,473.12	7,387,771.41	29,971.63	7,417,743.04	7,387,771.41	(1,250,236.56)	6,137,534.85
18	Nov-08	7,417,743.04	3,558,180.56	-	3,558,180.56	10,975,923.60	44,911.20	11,020,834.80	10,975,923.60	(1,779,090.28)	9,196,833.32
19	Dec-08	11,020,834.80	3,034,351.86	-	3,034,351.86	14,055,186.66	61,227.29	14,116,413.94	14,055,186.66	(1,517,175.93)	12,538,010.73
20	Jan-09	14,116,413.94	3,373,578.12	-	3,373,578.12	17,489,992.06	77,172.31	17,567,164.37	17,489,992.06	(1,686,789.06)	15,803,203.00
21	Feb-09	17,567,164.37	1,482,699.56	-	1,482,699.56	19,049,863.93	89,406.58	19,139,270.51	19,049,863.93	(741,349.78)	18,308,514.15
22	Mar-09	19,139,270.51	2,718,841.00	-	2,718,841.00	21,858,111.51	100,101.94	21,958,213.45	21,858,111.51	(1,359,420.50)	20,498,691.01
23	Apr-09	21,958,213.45	3,126,959.00	-	3,126,959.00	25,085,172.45	114,864.27	25,200,036.72	25,085,172.45	(1,563,479.50)	23,521,692.95
24	May-09	25,200,036.72	-	(1,050,001.53)	(1,050,001.53)	24,150,035.19	120,496.43	24,270,531.61	24,150,035.19	525,000.76	24,675,035.95
25	Jun-09	24,270,531.61	-	(1,050,001.53)	(1,050,001.53)	23,220,530.08	115,957.34	23,336,487.42	23,220,530.08	525,000.76	23,745,530.85
26	Jul-09	23,336,487.42	-	(1,050,001.53)	(1,050,001.53)	22,286,485.89	111,396.09	22,397,881.99	22,286,485.89	525,000.76	22,811,486.66
27	Aug-09	22,397,881.99	-	(1,050,001.53)	(1,050,001.53)	21,347,880.46	106,812.57	21,454,693.03	21,347,880.46	525,000.76	21,872,881.22
28	Sep-09	21,454,693.03	-	(1,050,001.53)	(1,050,001.53)	20,404,691.50	102,206.66	20,506,898.16	20,404,691.50	525,000.76	20,929,692.26
29	Oct-09	20,506,898.16	-	(1,050,001.53)	(1,050,001.53)	19,456,896.63	97,578.27	19,554,474.90	19,456,896.63	525,000.76	19,981,897.40
30	Nov-09	19,554,474.90	-	(1,050,001.53)	(1,050,001.53)	18,504,473.37	92,927.27	18,597,400.63	18,504,473.37	525,000.76	19,029,474.13
31	Dec-09	18,597,400.63	-	(1,050,001.53)	(1,050,001.53)	17,547,399.10	88,253.55	17,635,652.66	17,547,399.10	525,000.76	18,072,399.87
32	Jan-10	17,635,652.66	-	(1,050,001.53)	(1,050,001.53)	16,585,651.13	83,557.02	16,669,208.14	16,585,651.13	525,000.76	17,110,651.89
33	Feb-10	16,669,208.14	-	(1,050,001.53)	(1,050,001.53)	15,619,206.61	78,837.55	15,698,044.16	15,619,206.61	525,000.76	16,144,207.38
34	Mar-10	15,698,044.16	-	(1,050,001.53)	(1,050,001.53)	14,648,042.63	74,095.03	14,722,137.66	14,648,042.63	525,000.76	15,173,043.39
35	Apr-10	14,722,137.66	-	(1,050,001.53)	(1,050,001.53)	13,672,136.13	69,329.35	13,741,465.48	13,672,136.13	525,000.76	14,197,136.89

June 2007 - July 2008 only for Transmission Enhancement Charges (RTEP)

The Dayton Power and Light Company
Case No. 09-256-EL-UNC
Actual and Projected Charges and Revenues
August 2008 - April 2009
(Revenue)/Expense in $

Data: Actual and Forecasted
Type of Filing: Original
Work Paper Reference No(s).: WPC-1b, WPC-1d

Witness Responsible:
G.S. Campbell

August 2008 - Actual

Line (A)	Description (B)	Total PJM Bill Charges (C)	Total PJM Bill Revenues (D)	Jurisdictional Allocation Factors Charges (E)	Jurisdictional Allocation Factors Revenues (F)	Allocated PJM Bill Charges (G) = (C)*(E)	Allocated PJM Bill Revenues (H) = (D)*(F)	Retail Revenues (I)	Total Net Costs (J) = (G)+(H)+(I)
1	Transmission Enhancement Charges (RTEP)	$ 480,830	NA	88.9%	NA	$ 427,458			$ 427,458
2	Alliance RTO Start-up Costs	$ -	NA	100.0%	NA	$ -			$ -
3	Reactive Supply and Voltage Control from Gen Sources	$ 426,615	NA	88.9%	NA	$ 379,261		$ (535,754)	$ (156,494)
4	Regulation	$ 1,069,493	NA	88.9%	NA	$ 950,779		$ (247,068)	$ 703,712
5	Synchronized (Spinning) Reserves	$ 27,565	NA	88.9%	NA	$ 24,505		$ (373,094)	$ (348,589)
6	Operating Reserves	$ 433,870	NA	77.4%	NA	$ 335,816		$ (348,068)	$ (12,252)
7	RTO Start-up Cost Recovery - AEP zone	$ 18	NA	88.9%	NA	$ 16			$ 16
8	Synchronous Condensing	$ 2,526	NA	88.9%	NA	$ 2,245			$ 2,245
9	Reliability Pricing Model (RPM) [1]	$ 11,384,063	$ (10,980,943)	88.9%	77.4%	$ 10,120,432	$ (8,499,250)		$ 1,621,183
10	Black Start Service	$ 10,814	NA	88.9%	NA	$ 9,614			$ 9,614
11	PJM Annual Membership Fee	$ -	NA	77.4%	NA	$ -			$ -
12	TO Scheduling System Control and Dispatch Service	$ 123,119	NA	77.4%	NA	$ 95,294		$ (99,077)	$ (3,783)
13	NERC/RFC Charges	$ 22,184	NA	88.9%	NA	$ 19,722			$ 19,722
14	PJM Default Charges	$ -	NA	100.0%	NA	$ -			$ -
15	Transmission Congestion	$ (5,393,946)	$ 54,303	38.7%	50.0%	$ (2,087,457)	$ 27,151		$ (2,060,306)
16	Generation Loss Factor	NA	NA	NA	NA			$ (386,735)	$ (386,735)
17	Transmission Losses	$ 3,857,374	$ (2,638,967)	77.4%	88.9%	$ 2,985,808	$ (2,346,042)		$ 639,566
18	Firm PTP Transmission Service	NA	$ (105,603)	NA	100.0%		$ (105,603)		$ (105,603)
19	Non-Firm PTP Transmission Service	NA	$ (53,574)	NA	100.0%		$ (53,574)		$ (53,574)
20	Network Integration Transmission Service	$ 3,854,937	NA	88.9%	NA	$ 3,427,039		$ (3,146,383)	$ 280,656
21	FTR/ARR Auction	$ (2,008)	$ (755,022)	50.0%	50.0%	$ (1,004)	$ (377,511)		$ (378,515)
22	Expansion Cost Recovery Charges (ECRC)	$ 16,535	$ (36,655)	88.9%	100.0%	$ 14,699	$ (36,655)		$ (21,956)
23	PJM Scheduling System Control and Dispatch Service (Admin Fee)	NA	NA	NA	NA			NA	$ -
24	PUCO Consultant fees	$ -	NA	88.9%	NA	$ -			$ -
25	SubTotal	$ 16,313,989	$ (14,516,461)			$ 16,704,027	$ (11,391,483)	$ (5,136,179)	$ 176,364
26	TCRR Deferral carrying costs (WPC-1b)[2]								$ 8,134
27									
28	**Totals including carrying costs**	$ 16,313,989	$ (14,516,461)			$ 16,704,027	$ (11,391,483)	$ (5,136,179)	$ 184,499

[1] RPM includes the following PJM invoice line items: Locational Reliability Charges, Capacity Resource Deficiency, RPM Auction Revenues, Generation Resource Rating Test, and Peak Hour Period Availability
[2] Also includes carrying costs for RTEP charges from June 07 through July 08

The Dayton Power and Light Company
Case No. 09-256-EL-UNC
Actual and Projected Charges and Revenues
August 2008 - April 2009
(Revenue)/Expense in $

Witness Responsible:
G.S. Campbell

Data: Actual and Forecasted
Type of Filing: Original
Work Paper Reference No(s).: WPC-1b, WPC-1d

September 2008 - Actual

Line (A)	Description (B)	Total PJM Bill Charges (C)	Total PJM Bill Revenues (D)	Jurisdictional Allocation Factors Charges (E)	Jurisdictional Allocation Factors Revenues (F)	Allocated PJM Bill Charges (G) = (C)*(E)	Allocated PJM Bill Revenues (H) = (D)*(F)	Retail Revenues (I)	Total Net Costs (J) = (G)+(H)+(I)
29	Transmission Enhancement Charges (RTEP)	$ 82,184	NA	88.9%	NA	$ 73,062			$ 73,062
30	Alliance RTO Start-up Costs	$ -	NA	100.0%	NA	$ -			$ -
31	Reactive Supply and Voltage Control from Gen Sources	$ 433,555	NA	88.9%	NA	$ 385,431		$ (518,549)	$ (133,119)
32	Regulation	$ 711,107	NA	88.9%	NA	$ 632,174		$ (239,325)	$ 392,849
33	Synchronized (Spinning) Reserves	$ 22,337	NA	88.9%	NA	$ 19,858		$ (361,247)	$ (341,389)
34	Operating Reserves	$ 501,599	NA	77.4%	NA	$ 388,238		$ (336,937)	$ 51,301
35	RTO Start-up Cost Recovery - AEP zone	$ 17	NA	88.9%	NA	$ 15			$ 15
36	Synchronous Condensing	$ 8,886	NA	88.9%	NA	$ 7,900			$ 7,900
37	Reliability Pricing Model (RPM) [1]	$ 11,016,792	$ (9,977,704)	88.9%	77.4%	$ 9,793,928	$ (7,722,743)		$ 2,071,184
38	Black Start Service	$ 10,700	NA	88.9%	NA	$ 9,512			$ 9,512
39	PJM Annual Membership Fee	$ -	NA	77.4%	NA	$ -			$ -
40	TO Scheduling System Control and Dispatch Service	$ 106,458	NA	77.4%	NA	$ 82,399		$ (96,751)	$ (14,352)
41	NERC/RFC Charges	$ 19,140	NA	88.9%	NA	$ 17,016			$ 17,016
42	PJM Default Charges	$ 118,000	NA	100.0%	NA	$ 118,000			$ 118,000
43	Transmission Congestion	$ 2,744,716	$ 37,141	38.7%	50.0%	$ 1,062,205	$ 18,571		$ 1,080,776
44	Generation Loss Factor	NA	NA	NA	NA			$ (371,047)	$ (371,047)
45	Transmission Losses	$ 4,751,563	$ (1,936,201)	77.4%	88.9%	$ 3,677,710	$ (1,721,282)		$ 1,956,427
46	Firm PTP Transmission Service	NA	$ (61,006)	NA	100.0%		$ (61,006)		$ (61,006)
47	Non-Firm PTP Transmission Service	NA	$ (48,504)	NA	100.0%		$ (48,504)		$ (48,504)
48	Network Integration Transmission Service	$ 3,730,584	NA	88.9%	NA	$ 3,316,489		$ (3,046,407)	$ 270,082
49	FTR/ARR Auction	$ (1,944)	$ (730,667)	50.0%	50.0%	$ (972)	$ (365,333)		$ (366,305)
50	Expansion Cost Recovery Charges (ECRC)	$ 16,535	$ (36,656)	88.9%	100.0%	$ 14,700	$ (36,656)		$ (21,956)
51	PJM Scheduling System Control and Dispatch Service (Admin Fee)	NA	NA	NA	NA			NA	$ -
52	PUCO Consultant fees		NA	88.9%	NA	$ -			$ -
53	SubTotal	$ 24,272,230	$ (12,753,597)			$ 19,597,663	$ (9,936,954)	$ (4,970,263)	$ 4,690,446
54	TCRR Deferral carrying costs (WPC-1b)								$ 12,353
55									
56	**Totals including carrying costs**	$ 24,272,230	$ (12,753,597)			$ 19,597,663	$ (9,936,954)	$ (4,970,263)	$ 4,702,799

[1] RPM includes the following PJM Invoice line items: Locational Reliability Charges, Capacity Resource Deficiency, RPM Auction Revenues, Generation Resource Rating Test, and Peak Hour Period Availability

The Dayton Power and Light Company
Case No. 09-256-EL-UNC
Actual and Projected Charges and Revenues
August 2008 - April 2009
(Revenue)/Expense in $

Witness Responsible:
G.S. Campbell

Data: Actual and Forecasted
Type of Filing: Original
Work Paper Reference No(s).: WPC-1b, WPC-1d

October 2008 - Actual

Line (A)	Description (B)	Total PJM Bill Charges (C)	Total PJM Bill Revenues (D)	Jurisdictional Allocation Factors Charges (E)	Jurisdictional Allocation Factors Revenues (F)	Allocated PJM Bill Charges (G) = (C)*(E)	Allocated PJM Bill Revenues (H) = (D)*(F)	Retail Revenues (I)	Total Net Costs (J) = (G)+(H)+(I)
57	Transmission Enhancement Charges (RTEP)	$ 85,593	NA	88.9%	NA	$ 76,092			$ 76,092
58	Alliance RTO Start-up Costs	$ -	NA	100.0%	NA	$ -			$ -
59	Reactive Supply and Voltage Control from Gen Sources	$ 548,519	NA	88.9%	NA	$ 487,633		$ (449,735)	$ 37,898
60	Regulation	$ 490,526	NA	88.9%	NA	$ 436,078		$ (207,048)	$ 229,030
61	Synchronized (Spinning) Reserves	$ (9,075)	NA	88.9%	NA	$ (8,068)		$ (312,259)	$ (320,327)
62	Operating Reserves	$ 292,221	NA	77.4%	NA	$ 226,179		$ (291,110)	$ (64,931)
63	RTO Start-up Cost Recovery - AEP zone	$ 8	NA	88.9%	NA	$ 7			$ 7
64	Synchronous Condensing	$ 17,590	NA	88.9%	NA	$ 15,638			$ 15,638
65	Reliability Pricing Model (RPM) [1]	$ 11,384,063	$ (10,310,230)	88.9%	77.4%	$ 10,120,432	$ (7,980,118)		$ 2,140,314
66	Black Start Service	$ 10,446	NA	88.9%	NA	$ 9,286			$ 9,286
67	PJM Annual Membership Fee	$ -	NA	77.4%	NA	$ -			$ -
68	TO Scheduling System Control and Dispatch Service	$ 102,955	NA	77.4%	NA	$ 79,687		$ (84,999)	$ (5,312)
69	NERC/RFC Charges	$ 18,640	NA	88.9%	NA	$ 16,571			$ 16,571
70	PJM Default Charges	$ (9,000)	NA	100.0%	NA	$ (9,000)			$ (9,000)
71	Transmission Congestion	$ (852,684)	$ 79,210	38.7%	50.0%	$ (329,989)	$ 39,605		$ (290,384)
72	Generation Loss Factor	NA	NA	NA	NA			$ (311,541)	$ (311,541)
73	Transmission Losses	$ 2,707,462	$ (1,550,739)	77.4%	88.9%	$ 2,095,575	$ (1,378,607)		$ 716,968
74	Firm PTP Transmission Service	NA	$ (91,576)	NA	100.0%		$ (91,576)		$ (91,576)
75	Non-Firm PTP Transmission Service	NA	$ (41,675)	NA	100.0%		$ (41,675)		$ (41,675)
76	Network Integration Transmission Service	$ 3,854,937	NA	88.9%	NA	$ 3,427,039		$ (2,633,154)	$ 793,884
77	FTR/ARR Auction	$ (2,008)	$ (755,022)	50.0%	50.0%	$ (1,004)	$ (377,511)		$ (378,515)
78	Expansion Cost Recovery Charges (ECRC)	$ 16,535	$ (36,655)	88.9%	100.0%	$ 14,699	$ (36,655)		$ (21,956)
79	PJM Scheduling System Control and Dispatch Service (Admin Fee)	NA	NA	NA	NA			NA	$ -
80	PUCO Consultant fees		NA	88.9%	NA	$ -			$ -
81	SubTotal	$ 18,658,726	$ (12,706,687)			$ 16,656,856	$ (9,866,537)	$ (4,289,846)	$ 2,500,473
82	TCRR Deferral carrying costs (WPC-1b)								$ 29,972
83									
84	**Totals including carrying costs**	$ 18,658,726	$ (12,706,687)			$ 16,656,856	$ (9,866,537)	$ (4,289,846)	$ 2,530,445

[1] RPM Includes the following PJM invoice line items: Locational Reliability Charges, Capacity Resource Deficiency, RPM Auction Revenues, Generation Resource Rating Test, and Peak Hour Period Availability

The Dayton Power and Light Company
Case No. 09-256-EL-UNC
Actual and Projected Charges and Revenues
August 2008 - April 2009
(Revenue)/Expense in $

Data: Actual and Forecasted
Type of Filing: Original
Work Paper Reference No(s).: WPC-1b, WPC-1d

Witness Responsible:
G.S. Campbell

November 2008 - Actual

Line (A)	Description (B)	Total PJM Bill Charges (C)	Total PJM Bill Revenues (D)	Jurisdictional Allocation Factors Charges (E)	Jurisdictional Allocation Factors Revenues (F)	Allocated PJM Bill Charges (G) = (C)*(E)	Allocated PJM Bill Revenues (H) = (D)*(F)	Retail Revenues (I)	Total Net Costs (J) = (G)+(H)+(I)
85	Transmission Enhancement Charges (RTEP)	$ 86,419	NA	88.9%	NA	$ 76,826			$ 76,826
86	Alliance RTO Start-up Costs	$ -	NA	100.0%	NA	$ -			$ -
87	Reactive Supply and Voltage Control from Gen Sources	$ 492,967	NA	88.9%	NA	$ 438,248		$ (451,470)	$ (13,222)
88	Regulation	$ 515,331	NA	88.9%	NA	$ 458,129		$ (207,749)	$ 250,380
89	Synchronized (Spinning) Reserves	$ 9,890	NA	88.9%	NA	$ 8,793		$ (313,458)	$ (304,666)
90	Operating Reserves	$ 248,667	NA	77.4%	NA	$ 192,469		$ (292,310)	$ (99,842)
91	RTO Start-up Cost Recovery - AEP zone	$ 17	NA	88.9%	NA	$ 15			$ 15
92	Synchronous Condensing	$ 13,549	NA	88.9%	NA	$ 12,045			$ 12,045
93	Reliability Pricing Model (RPM) [1]	$ 11,016,792	$ (9,977,642)	88.9%	77.4%	$ 9,793,928	$ (7,722,695)		$ 2,071,233
94	Black Start Service	$ 10,461	NA	88.9%	NA	$ 9,299			$ 9,299
95	PJM Annual Membership Fee	$ 5,000	NA	77.4%	NA	$ 3,870			$ 3,870
96	TO Scheduling System Control and Dispatch Service	$ 105,785	NA	77.4%	NA	$ 81,878		$ (84,556)	$ (2,678)
97	NERC/RFC Charges	$ 19,255	NA	88.9%	NA	$ 17,118			$ 17,118
98	PJM Default Charges	$ (4,608)	NA	100.0%	NA	$ (4,608)			$ (4,608)
99	Transmission Congestion	$ 243,869	$ 2,233	38.7%	50.0%	$ 94,377	$ 1,117		$ 95,494
100	Generation Loss Factor	NA	NA	NA	NA			$ (307,161)	$ (307,161)
101	Transmission Losses	$ 3,965,609	$ (1,653,099)	77.4%	88.9%	$ 3,069,381	$ (1,469,605)		$ 1,599,777
102	Firm PTP Transmission Service	NA	$ (90,783)	NA	100.0%		$ (90,783)		$ (90,783)
103	Non-Firm PTP Transmission Service	NA	$ (39,740)	NA	100.0%		$ (39,740)		$ (39,740)
104	Network Integration Transmission Service	$ 3,730,584	NA	88.9%	NA	$ 3,316,489		$ (2,643,404)	$ 673,085
105	FTR/ARR Auction	$ (1,944)	$ (730,667)	50.0%	50.0%	$ (972)	$ (365,333)		$ (366,305)
106	Expansion Cost Recovery Charges (ECRC)	$ 16,535	$ (36,656)	88.9%	100.0%	$ 14,700	$ (36,656)		$ (21,956)
107	PJM Scheduling System Control and Dispatch Service (Admin Fee)	NA	NA	NA	NA			NA	$ -
108	PUCO Consultant fees		NA	88.9%	NA	$ -			$ -
109	SubTotal	$ 20,474,177	$ (12,526,353)			$ 17,581,984	$ (9,723,695)	$ (4,300,109)	$ 3,558,181
110	TCRR Deferral carrying costs (WPC-1b)								$ 44,911
111									
112	**Totals including carrying costs**	$ 20,474,177	$ (12,526,353)			$ 17,581,984	$ (9,723,695)	$ (4,300,109)	$ 3,603,092

[1] RPM includes the following PJM invoice line items: Locational Reliability Charges, Capacity Resource Deficiency, RPM Auction Revenues, Generation Resource Rating Test, and Peak Hour Period Availability

The Dayton Power and Light Company
Case No. 09-256-EL-UNC
Actual and Projected Charges and Revenues
August 2008 - April 2009
(Revenue)/Expense in $

Witness Responsible:
G.S. Campbell

Data: Actual and Forecasted
Type of Filing: Original
Work Paper Reference No(s).: WPC-1b, WPC-1d

December 2008 - Actual

Line (A)	Description (B)	Total PJM Bill Charges (C)	Total PJM Bill Revenues (D)	Jurisdictional Allocation Factors Charges (E)	Jurisdictional Allocation Factors Revenues (F)	Allocated PJM Bill Charges (G) = (C)*(E)	Allocated PJM Bill Revenues (H) = (D)*(F)	Retail Revenues (I)	Total Net Costs (J) = (G)+(H)+(I)
113	Transmission Enhancement Charges (RTEP)	$ 86,426	NA	88.9%	NA	$ 76,835			$ 76,835
114	Alliance RTO Start-up Costs	$ -	NA	100.0%	NA	$ -			$ -
115	Reactive Supply and Voltage Control from Gen Sources	$ 655,207	NA	88.9%	NA	$ 582,479		$ (525,846)	$ 56,633
116	Regulation	$ 535,895	NA	88.9%	NA	$ 476,411		$ (241,622)	$ 234,788
117	Synchronized (Spinning) Reserves	$ 17,053	NA	88.9%	NA	$ 15,160		$ (365,123)	$ (349,963)
118	Operating Reserves	$ 460,540	NA	77.4%	NA	$ 356,458		$ (340,777)	$ 15,681
119	RTO Start-up Cost Recovery - AEP zone	$ 17	NA	88.9%	NA	$ 15			$ 15
120	Synchronous Condensing	$ 20,943	NA	88.9%	NA	$ 18,618			$ 18,618
121	Reliability Pricing Model (RPM) [1]	$ 11,384,438	$ (10,310,262)	88.9%	77.4%	$ 10,120,765	$ (7,980,143)		$ 2,140,622
122	Black Start Service	$ 10,921	NA	88.9%	NA	$ 9,709			$ 9,709
123	PJM Annual Membership Fee	$ -	NA	77.4%	NA	$ -			$ -
124	TO Scheduling System Control and Dispatch Service	$ 121,420	NA	77.4%	NA	$ 93,979		$ (95,521)	$ (1,542)
125	NERC/RFC Charges	$ 32,630	NA	88.9%	NA	$ 28,919			$ 28,919
126	PJM Default Charges	$ -	NA	100.0%	NA	$ -			$ -
127	Transmission Congestion	$ (228,708)	$ 36,608	38.7%	50.0%	$ (88,510)	$ 18,304		$ (70,206)
128	Generation Loss Factor	NA	NA	NA	NA			$ (373,341)	$ (373,341)
129	Transmission Losses	$ 3,980,052	$ (1,849,168)	77.4%	88.9%	$ 3,080,560	$ (1,643,911)		$ 1,436,649
130	Firm PTP Transmission Service	NA	$ (98,934)	NA	100.0%		$ (98,934)		$ (98,934)
131	Non-Firm PTP Transmission Service	NA	$ (37,699)	NA	100.0%		$ (37,699)		$ (37,699)
132	Network Integration Transmission Service	$ 3,855,340	NA	88.9%	NA	$ 3,427,397		$ (3,079,333)	$ 348,064
133	FTR/ARR Auction	$ (2,008)	$ (755,078)	50.0%	50.0%	$ (1,004)	$ (377,539)		$ (378,543)
134	Expansion Cost Recovery Charges (ECRC)	$ 16,537	$ (36,655)	88.9%	100.0%	$ 14,701	$ (36,655)		$ (21,954)
135	PJM Scheduling System Control and Dispatch Service (Admin Fee)	NA	NA	NA	NA			NA	$ -
136	PUCO Consultant fees		NA	88.9%	NA	$ -			$ -
137	SubTotal	$ 20,946,603	$ (13,051,189)			$ 18,212,492	$ (10,156,577)	$ (5,021,563)	$ 3,034,352
138	TCRR Deferral carrying costs (WPC-1b)								$ 61,227
139									
140	**Totals including carrying costs**	$ 20,946,603	$ (13,051,189)			$ 18,212,492	$ (10,156,577)	$ (5,021,563)	$ 3,095,579

[1] RPM includes the following PJM invoice line items: Locational Reliability Charges, Capacity Resource Deficiency, RPM Auction Revenues, Generation Resource Rating Test, and Peak Hour Period Availability

The Dayton Power and Light Company
Case No. 09-256-EL-UNC
Actual and Projected Charges and Revenues
August 2008 - April 2009
(Revenue)/Expense in $

Witness Responsible:
G.S. Campbell

Data: Actual and Forecasted
Type of Filing: Original
Work Paper Reference No(s).: WPC-1b, WPC-1d

January 2009 - Actual

Line (A)	Description (B)	Total PJM Bill Charges (C)	Total PJM Bill Revenues (D)	Jurisdictional Allocation Factors Charges (E)	Jurisdictional Allocation Factors Revenues (F)	Allocated PJM Bill Charges (G) = (C)*(E)	Allocated PJM Bill Revenues (H) = (D)*(F)	Retail Revenues (I)	Total Net Costs (J) = (G)+(H)+(I)
141	Transmission Enhancement Charges (RTEP)	$ 109,544	NA	88.9%	NA	$ 97,384			$ 97,384
142	Alliance RTO Start-up Costs	$ -	NA	100.0%	NA	$ -			$ -
143	Reactive Supply and Voltage Control from Gen Sources	$ 554,619	NA	88.9%	NA	$ 493,056		$ (645,755)	$ (152,699)
144	Regulation	$ 525,296	NA	88.9%	NA	$ 466,988		$ (295,328)	$ 171,660
145	Synchronized (Spinning) Reserves	$ 22,700	NA	88.9%	NA	$ 20,180		$ (446,170)	$ (425,990)
146	Operating Reserves	$ 437,821	NA	77.4%	NA	$ 338,873		$ (416,370)	$ (77,497)
147	RTO Start-up Cost Recovery - AEP zone	$ 34	NA	88.9%	NA	$ 30			$ 30
148	Synchronous Condensing	$ 28,146	NA	88.9%	NA	$ 25,022			$ 25,022
149	Reliability Pricing Model (RPM) [1]	$ 11,384,838	$ (10,310,232)	88.9%	77.4%	$ 10,121,121	$ (7,980,120)		$ 2,141,001
150	Black Start Service	$ 10,238	NA	88.9%	NA	$ 9,102			$ 9,102
151	PJM Annual Membership Fee	$ -	NA	77.4%	NA	$ -			$ -
152	TO Scheduling System Control and Dispatch Service	$ 126,905	NA	77.4%	NA	$ 98,224		$ (117,285)	$ (19,061)
153	NERC/RFC Charges	$ 23,249	NA	88.9%	NA	$ 20,669			$ 20,669
154	PJM Default Charges	$ -	NA	100.0%	NA	$ -			$ -
155	Transmission Congestion	$ 1,176,187	$ (67,419)	38.7%	50.0%	$ 455,184	$ (33,710)		$ 421,475
156	Generation Loss Factor	NA	NA	NA	NA			$ (453,333)	$ (453,333)
157	Transmission Losses	$ 6,171,574	$ (2,321,267)	77.4%	88.9%	$ 4,776,798	$ (2,063,606)		$ 2,713,193
158	Firm PTP Transmission Service	NA	$ (90,918)	NA	100.0%		$ (90,918)		$ (90,918)
159	Non-Firm PTP Transmission Service	NA	$ (48,797)	NA	100.0%		$ (48,797)		$ (48,797)
160	Network Integration Transmission Service	$ 3,604,502	$ (3,947,559)	88.9%	NA	$ 3,204,403		$ (3,761,018)	$ (556,615)
161	FTR/ARR Auction	$ (2,008)	$ (755,100)	50.0%	50.0%	$ (1,004)	$ (377,550)		$ (378,554)
162	Expansion Cost Recovery Charges (ECRC)	$ 16,009	$ (36,724)	88.9%	100.0%	$ 14,232	$ (36,724)		$ (22,492)
163	PJM Scheduling System Control and Dispatch Service (Admin Fee)	NA	NA	NA	NA			NA	$ -
164	PUCO Consultant fees		NA	88.9%	NA	$ -			$ -
165	SubTotal	$ 24,189,653	$ (17,576,016)			$ 20,140,263	$ (10,631,424)	$ (6,135,260)	$ 3,373,578
166	TCRR Deferral carrying costs (WPC-1b)								$ 77,172
167									
168	**Totals including carrying costs**	$ 24,189,653	$ (17,576,016)			$ 20,140,263	$ (10,631,424)	$ (6,135,260)	$ 3,450,750

[1] RPM includes the following PJM invoice line items: Locational Reliability Charges, Capacity Resource Deficiency, RPM Auction Revenues, Generation Resource Rating Test, and Peak Hour Period Availability

The Dayton Power and Light Company
Case No. 09-256-EL-UNC
Actual and Projected Charges and Revenues
August 2008 - April 2009
(Revenue)/Expense in $

Data: Actual and Forecasted
Type of Filing: Original
Work Paper Reference No(s).: WPC-1b, WPC-1d

Witness Responsible:
G.S. Campbell

February 2009 - Actual

Line (A)	Description (B)	Total PJM Bill Charges (C)	Total PJM Bill Revenues (D)	Jurisdictional Allocation Factors Charges (E)	Jurisdictional Allocation Factors Revenues (F)	Allocated PJM Bill Charges (G) = (C)*(E)	Allocated PJM Bill Revenues (H) = (D)*(F)	Retail Revenues (I)	Total Net Costs (J) = (G)+(H)+(I)
169	Transmission Enhancement Charges (RTEP)	$ 109,544	NA	88.9%	NA	$ 97,385			$ 97,385
170	Alliance RTO Start-up Costs	$ -	NA	100.0%	NA	$ -			$ -
171	Reactive Supply and Voltage Control from Gen Sources	$ 565,482	NA	88.9%	NA	$ 502,713		$ (612,435)	$ (109,721)
172	Regulation	$ 433,661	NA	88.9%	NA	$ 385,524		$ (278,649)	$ 106,875
173	Synchronized (Spinning) Reserves	$ 9,732	NA	88.9%	NA	$ 8,652		$ (420,898)	$ (412,247)
174	Operating Reserves	$ 454,428	NA	77.4%	NA	$ 351,727		$ (392,702)	$ (40,975)
175	RTO Start-up Cost Recovery - AEP zone	$ 31	NA	88.9%	NA	$ 27			$ 27
176	Synchronous Condensing	$ 16,640	NA	88.9%	NA	$ 14,793			$ 14,793
177	Reliability Pricing Model (RPM) [1]	$ 10,282,948	$ (9,314,104)	88.9%	77.4%	$ 9,141,540	$ (7,209,117)		$ 1,932,424
178	Black Start Service	$ 10,438	NA	88.9%	NA	$ 9,279			$ 9,279
179	PJM Annual Membership Fee	$ -	NA	77.4%	NA	$ -			$ -
180	TO Scheduling System Control and Dispatch Service	$ 105,088	NA	77.4%	NA	$ 81,338		$ (111,307)	$ (29,969)
181	NERC/RFC Charges	$ 19,229	NA	88.9%	NA	$ 17,095			$ 17,095
182	PJM Default Charges	$ -	NA	100.0%	NA	$ -			$ -
183	Transmission Congestion	$ 89,979	$ 92,113	38.7%	50.0%	$ 34,822	$ 46,056		$ 80,878
184	Generation Loss Factor	NA	NA	NA	NA			$ (424,429)	$ (424,429)
185	Transmission Losses	$ 3,610,859	$ (1,415,760)	77.4%	88.9%	$ 2,794,805	$ (1,258,611)		$ 1,536,195
186	Firm PTP Transmission Service	NA	$ (67,432)	NA	100.0%		$ (67,432)		$ (67,432)
187	Non-Firm PTP Transmission Service	NA	$ (32,817)	NA	100.0%		$ (32,817)		$ (32,817)
188	Network Integration Transmission Service	$ 3,255,680	$ (3,565,537)	88.9%	NA	$ 2,894,299		$ (3,549,509)	$ (655,209)
189	FTR/ARR Auction	$ (1,814)	$ (682,026)	50.0%	50.0%	$ (907)	$ (341,013)		$ (341,920)
190	Expansion Cost Recovery Charges (ECRC)	$ 16,008	$ (36,724)	88.9%	100.0%	$ 14,232	$ (36,724)		$ (22,493)
191	PJM Scheduling System Control and Dispatch Service (Admin Fee)	$ 289,616	NA	100.0%	NA	$ 289,616		$ (464,655)	$ (175,039)
192	PUCO Consultant fees		NA	88.9%	NA	$ -			$ -
193	SubTotal	$ 19,267,547	$ (15,022,288)			$ 16,636,940	$ (8,899,657)	$ (6,254,583)	$ 1,482,700
194	TCRR Deferral carrying costs (WPC-1b)								$ 89,407
195									
196	**Totals including carrying costs**	$ 19,267,547	$ (15,022,288)			$ 16,636,940	$ (8,899,657)	$ (6,254,583)	$ 1,572,106

[1] RPM includes the following PJM invoice line items: Locational Reliability Charges, Capacity Resource Deficiency, RPM Auction Revenues, Generation Resource Rating Test, and Peak Hour Period Availability

The Dayton Power and Light Company
Case No. 09-256-EL-UNC
Actual and Projected Charges and Revenues
August 2008 - April 2009
(Revenue)/Expense In $

Data: Actual and Forecasted
Type of Filing: Original
Work Paper Reference No(s).: WPC-1b, WPC-1d

Witness Responsible:
G.S. Campbell

March 2009 - Forecast

Line (A)	Description (B)	Total PJM Bill Charges (C)	Total PJM Bill Revenues (D)	Jurisdictional Allocation Factors Charges (E)	Jurisdictional Allocation Factors Revenues (F)	Allocated PJM Bill Charges (G) = (C)*(E)	Allocated PJM Bill Revenues (H) = (D)*(F)	Retail Revenues (I)	Total Net Costs (J) = (G)+(H)+(I)
197	Transmission Enhancement Charges (RTEP)	$ 35,337	NA	88.9%	NA	$ 31,415			$ 31,415
198	Alliance RTO Start-up Costs	$ -	NA	100.0%	NA	$ -			$ -
199	Reactive Supply and Voltage Control from Gen Sources	$ 396,689	NA	88.9%	NA	$ 352,657		$ (651,910)	$ (299,253)
200	Regulation	$ 972,263	NA	88.9%	NA	$ 864,342		$ (296,129)	$ 568,213
201	Synchronized (Spinning) Reserves	$ 10,200	NA	88.9%	NA	$ 9,068		$ (446,734)	$ (437,666)
202	Operating Reserves	$ 543,913	NA	77.4%	NA	$ 420,989		$ (416,490)	$ 4,499
203	RTO Start-up Cost Recovery - AEP zone	$ 8	NA	88.9%	NA	$ 7			$ 7
204	Synchronous Condensing	$ 8,139	NA	88.9%	NA	$ 7,236			$ 7,236
205	Reliability Pricing Model (RPM) [1]	$ 11,679,098	$ (10,279,841)	88.9%	77.4%	$ 10,382,718	$ (7,956,597)		$ 2,426,121
206	Black Start Service	$ 10,290	NA	88.9%	NA	$ 9,148			$ 9,148
207	PJM Annual Membership Fee	$ -	NA	77.4%	NA	$ -			$ -
208	TO Scheduling System Control and Dispatch Service	$ 125,138	NA	77.4%	NA	$ 96,857		$ (121,278)	$ (24,421)
209	NERC/RFC Charges	$ 20,092	NA	88.9%	NA	$ 17,862			$ 17,862
210	PJM Default Charges	$ -	NA	100.0%	NA	$ -			$ -
211	Transmission Congestion	$ -	$ (19,942)	38.7%	50.0%	$ -	$ (9,971)		$ (9,971)
212	Generation Loss Factor	NA	NA	NA	NA			$ (321,465)	$ (321,465)
213	Transmission Losses	$ 5,387,426	$ (2,100,718)	77.4%	88.9%	$ 4,169,868	$ (1,867,538)		$ 2,302,329
214	Firm PTP Transmission Service	NA	$ (217,782)	NA	100.0%		$ (217,782)		$ (217,782)
215	Non-Firm PTP Transmission Service	NA	$ (36,204)	NA	100.0%		$ (36,204)		$ (36,204)
216	Network Integration Transmission Service	$ 3,866,871	NA	88.9%	NA	$ 3,437,648		$ (3,766,999)	$ (329,351)
217	FTR/ARR Auction	$ -	$ (849,315)	50.0%	50.0%	$ -	$ (424,658)		$ (424,658)
218	Expansion Cost Recovery Charges (ECRC)	$ 16,534	$ (36,655)	88.9%	100.0%	$ 14,699	$ (36,655)		$ (21,956)
219	PJM Scheduling System Control and Dispatch Service (Admin Fee)	$ 244,892	NA	88.9%	NA	$ 217,709		$ (742,970)	$ (525,261)
220	PUCO Consultant fees	$ -	NA	88.9%	NA	$ -			$ -
221	SubTotal	$ 23,316,890	$ (13,540,457)			$ 20,032,221	$ (10,549,405)	$ (6,763,975)	$ 2,718,841
222	TCRR Deferral carrying costs (WPC-1b)								$ 100,102
223									
224	**Totals including carrying costs**	$ 23,316,890	$ (13,540,457)			$ 20,032,221	$ (10,549,405)	$ (6,763,975)	$ 2,818,943

[1] RPM includes the following PJM invoice line items: Locational Reliability Charges, Capacity Resource Deficiency, RPM Auction Revenues, Generation Resource Rating Test, and Peak Hour Period Availability

The Dayton Power and Light Company
Case No. 09-256-EL-UNC
Actual and Projected Charges and Revenues
August 2008 - April 2009
(Revenue)/Expense in $

Data: Actual and Forecasted
Type of Filing: Original
Work Paper Reference No(s).: WPC-1b, WPC-1d

Witness Responsible:
G.S. Campbell

April 2009 - Forecast

Line (A)	Description (B)	Total PJM Bill Charges (C)	Total PJM Bill Revenues (D)	Jurisdictional Allocation Factors Charges (E)	Jurisdictional Allocation Factors Revenues (F)	Allocated PJM Bill Charges (G) = (C)*(E)	Allocated PJM Bill Revenues (H) = (D)*(F)	Retail Revenues (I)	Total Net Costs (J) = (G)+(H)+(I)
225	Transmission Enhancement Charges (RTEP)	$ 30,756	NA	88.9%	NA	$ 27,342			$ 27,342
226	Alliance RTO Start-up Costs	$ -	NA	100.0%	NA	$ -			$ -
227	Reactive Supply and Voltage Control from Gen Sources	$ 396,689	NA	88.9%	NA	$ 352,657		$ (595,320)	$ (242,663)
228	Regulation	$ 852,680	NA	88.9%	NA	$ 758,033		$ (270,863)	$ 487,170
229	Synchronized (Spinning) Reserves	$ 10,200	NA	88.9%	NA	$ 9,068		$ (408,236)	$ (399,168)
230	Operating Reserves	$ 567,027	NA	77.4%	NA	$ 438,879		$ (380,389)	$ 58,490
231	RTO Start-up Cost Recovery - AEP zone	$ 8	NA	88.9%	NA	$ 7			$ 7
232	Synchronous Condensing	$ 8,139	NA	88.9%	NA	$ 7,236			$ 7,236
233	Reliability Pricing Model (RPM) [1]	$ 11,302,353	$ (9,948,233)	88.9%	77.4%	$ 10,047,792	$ (7,699,932)		$ 2,347,859
234	Black Start Service	$ 10,290	NA	88.9%	NA	$ 9,148			$ 9,148
235	PJM Annual Membership Fee	$ -	NA	77.4%	NA	$ -			$ -
236	TO Scheduling System Control and Dispatch Service	$ 112,557	NA	77.4%	NA	$ 87,119		$ (112,939)	$ (25,820)
237	NERC/RFC Charges	$ 20,092	NA	88.9%	NA	$ 17,862			$ 17,862
238	PJM Default Charges	$ -	NA	100.0%	NA	$ -			$ -
239	Transmission Congestion	$ 139,958	$ -	38.7%	50.0%	$ 54,164	$ -		$ 54,164
240	Generation Loss Factor	NA	NA	NA	NA			$ (321,465)	$ (321,465)
241	Transmission Losses	$ 5,023,066	$ (1,914,705)	77.4%	88.9%	$ 3,887,853	$ (1,702,173)		$ 2,185,680
242	Firm PTP Transmission Service	NA	$ (26,283)	NA	100.0%		$ (26,283)		$ (26,283)
243	Non-Firm PTP Transmission Service	NA	$ (37,124)	NA	100.0%		$ (37,124)		$ (37,124)
244	Network Integration Transmission Service	$ 3,748,585	NA	88.9%	NA	$ 3,332,492		$ (3,442,167)	$ (109,675)
245	FTR/ARR Auction	$ -	$ (821,918)	50.0%	50.0%	$ -	$ (410,959)		$ (410,959)
246	Expansion Cost Recovery Charges (ECRC)	$ 16,534	$ (36,655)	88.9%	100.0%	$ 14,699	$ (36,655)		$ (21,956)
247	PJM Scheduling System Control and Dispatch Service (Admin Fee)	$ 219,782	NA	88.9%	NA	$ 195,386		$ (668,271)	$ (472,885)
248	PUCO Consultant fees	$ -	NA	88.9%	NA	$ -			$ -
249	SubTotal	$ 22,458,716	$ (12,784,918)			$ 19,239,735	$ (9,913,126)	$ (6,199,650)	$ 3,126,959
250	TCRR Deferral carrying costs (WPC-1b)								$ 114,864
251									
252	**Totals including carrying costs**	$ 22,458,716	$ (12,784,918)			$ 19,239,735	$ (9,913,126)	$ (6,199,650)	$ 3,241,823

[1] RPM includes the following PJM invoice line items: Locational Reliability Charges, Capacity Resource Deficiency, RPM Auction Revenues, Generation Resource Rating Test, and Peak Hour Period Availability

The Dayton Power and Light Company
Case No. 09-256-EL-UNC
Jurisdictional Allocators

Workpaper C-1d
Page 1 of 1
Witness Responsible:
Sharon Schroder

Data: Actuals
Type of Filing: Original
Work Paper Reference No(s).: None

Line (A)	(B)	DP&L 2008 Actuals, (10K) (C)	DP&L 2008 Actuals (D)	DP&L 2008 Adjusted (E)	Source (F)
1	Retail Sales	14,932 [1]	11,721	12,962	Col (C) Row 1 - Row 2
2	DPLER Sales		3,211	1,618 [2]	PUCO Form MM1.1 CRES Reports
3	Wholesale Sales	2,173	2,173	2,173	DP&L 2008 10K
4	Total	17,105	17,105	16,753	Line 1+ Line 2+ Line 3
5					
6					
7	**Load Allocator**				
8	Retail			88.9%	Line 1 / (Line 1+ Line 2)
9	DPLER			11.1%	Line 2 / (Line 1+ Line 2)
10	Total			100.0%	Line 8 + Line 9
11					
12	**Wholesale/Retail Allocator**				
13	Retail			77.4%	Line 1 / Line 4
14	Wholesale			22.6%	(Line 2+ Line 3) / Line 4
15	Total			100.0%	Line 13 + Line 14

[1] Footnote in 10K: DP&L sells power to DPLER (a subsidiary of DPL). These sales are classified as wholesale sales for DP&L and retail sales for DPL. The kWh volumes contain all volumes distributed on the DP&L system which include the retail sales by DPLER. The sales for resale volumes are omitted to avoid duplicate reporting.

[2] 352 GWh impact due to GM and DHL and certain DPLER contracts return to Standard Offer beginning January 1, 2009

The Dayton Power and Light Company
Case No. 09-256-EL-UNC
Summary of TCRR Revenues by Tariff Class
2008 Actuals

Data: Actual
Type of Filing: Original
Work Paper Reference No(s).: None

Witness Responsible:
Sharon Schroder

2008 Actuals

Line	Tariff Class	Network Integration Transmission Service	TO Scheduling System Control and Dispatch Service	Reactive Supply and Voltage Control from Gen Sources	Regulation	Synchronized (Spinning) Reserves	Operating Reserves (Supplemental)	PJM Scheduling System Control and Dispatch Service (Admin Fee)	Total Transmission & Ancillary Services	% of Total Rev
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J) = sum (C) thru (I)	(K)
1	**Tariff Class**									
2	Residential	$ 9,714,184	$ 251,837	$ 1,619,158	$ 755,631	$ 1,151,347	$ 1,079,619	$ 2,116,386	$ 16,688,162	27.85%
3	Residential Heat	$ 5,054,057	$ 131,053	$ 842,391	$ 393,124	$ 599,020	$ 561,650	$ 1,088,263	$ 8,669,558	14.47%
4	Secondary	$ 14,807,340	$ 525,324	$ 2,472,276	$ 1,170,503	$ 1,757,068	$ 1,632,996	$ 2,352,788	$ 24,718,296	41.25%
5	Primary	$ 4,658,855	$ 169,887	$ 899,254	$ 388,552	$ 552,859	$ 513,345	$ 1,002,834	$ 8,165,585	13.63%
6	Primary Substation	$ 265,011	$ 9,668	$ 42,811	$ 20,965	$ 31,448	$ 29,200	$ 65,749	$ 464,853	0.78%
7	High Voltage	$ 269,987	$ 9,849	$ 54,158	$ 21,359	$ 32,039	$ 29,749	$ 64,631	$ 481,771	0.80%
8	Private Outdoor Lighting	$ 86,148	$ 3,201	$ 13,732	$ 7,531	$ 9,485	$ 9,229	$ 19,373	$ 148,699	0.25%
9	School	$ 197,183	$ 5,112	$ 32,864	$ 15,336	$ 23,370	$ 21,909	$ 42,891	$ 338,666	0.57%
10	Street Lighting	$ 147,798	$ 3,831	$ 24,834	$ 11,495	$ 17,516	$ 16,422	$ 32,221	$ 253,919	0.42%
11	**Total Revenue**	**$ 35,200,563**	**$ 1,109,763**	**$ 6,001,277**	**$ 2,764,497**	**$ 4,174,155**	**$ 3,894,119**	**$ 6,785,134**	**$ 59,929,508**	100.00%

The Dayton Power and Light Company
Case No. 09-256-EL-UNC
Projected Monthly Billing Determinants
May 2009 - April 2010
kWh/kW/kVar

Data: Forecasted
Type of Filing: Original
Work Paper Reference No(s).: none

Witness Responsible:
Sharon Schroder

2009 Forecast

Line (A)	Tariff Class (B)	Units (C)	May (D)	Jun (E)	Jul (F)	Aug (G)	Sep (H)	Oct (I)	Nov (J)	Dec (K)	Total May - Dec 2009 (L)
1	Residential	kWh	242,475,104	346,699,209	471,684,992	366,838,992	277,570,973	238,404,148	227,014,625	346,413,525	2,517,101,568
2	Residential Heat	kWh	100,988,211	93,170,580	135,666,513	119,707,125	90,201,632	110,008,942	142,354,612	254,456,808	1,046,554,422
3	Secondary[1]	kWh	48,701,437	45,790,177	45,923,046	47,243,300	37,659,951	44,102,626	39,419,288	47,256,470	356,096,295
4		kW	875,371	894,623	936,870	937,305	947,536	917,275	877,040	837,550	7,222,568
5	Primary	kWh	133,231,935	161,133,399	132,118,872	157,113,299	138,747,026	119,982,510	120,567,181	119,587,564	1,082,481,786
6		kW	368,174	465,407	505,049	483,538	424,948	321,390	340,849	402,060	3,311,415
7		kVar	216,746	274,766	296,651	282,857	247,514	187,664	199,952	239,971	1,946,122
8	Primary Substation	kWh	5,415,652	8,959,213	8,946,666	12,157,358	11,779,402	8,224,572	10,877,128	8,896,850	75,256,841
9		kW	15,331	19,820	35,907	35,571	30,609	23,216	25,384	28,996	214,833
10		kVar	7,340	9,043	15,624	16,223	13,459	10,476	11,823	12,930	96,919
11	High Voltage	kWh	11,379,383	10,046,812	9,481,038	13,360,572	10,859,443	10,037,681	9,438,598	8,078,802	82,682,330
12		kW	24,475	31,645	31,011	31,852	27,390	19,940	22,724	23,533	212,570
13		kVar	13,566	18,682	18,406	18,423	15,749	10,836	17,004	16,960	129,627
14	Private Outdoor Lighting	kWh	2,657,126	2,669,734	2,655,407	2,671,941	2,663,359	2,677,344	2,657,381	2,654,506	21,306,798
15	School	kWh	7,728,249	6,172,061	4,976,698	6,086,037	5,930,459	6,889,764	5,057,741	6,631,121	49,472,129
16	Streetlighting	kWh	4,632,757	4,566,034	4,613,906	4,611,725	4,595,182	4,584,716	4,585,753	4,571,260	36,761,333

2010 Forecast

Line (M)	Tariff Class (N)	Units (O)	Jan (P)	Feb (Q)	Mar (R)	Apr (S)	Total Jan - Apr 2010 (T)
17	Residential	kWh	394,739,084	264,809,708	290,386,813	227,967,270	1,177,902,876
18	Residential Heat	kWh	285,604,610	235,413,857	266,644,289	87,610,086	875,272,843
19	Secondary[1]	kWh	47,751,444	36,004,190	45,320,326	45,056,331	174,132,291
20		kW	831,829	847,689	865,120	857,692	3,402,329
21	Primary	kWh	135,676,199	142,552,494	123,220,848	158,536,012	559,985,553
22		kW	452,257	385,418	370,834	337,720	1,546,230
23		kVar	273,959	232,278	223,860	201,769	931,865
24	Primary Substation	kWh	1,632,481	4,462,190	5,546,374	9,294,605	20,935,649
25		kW	7,280	15,385	15,502	14,219	52,385
26		kVar	4,538	8,262	6,785	6,340	25,925
27	High Voltage	kWh	6,234,163	3,556,495	4,864,921	9,364,790	24,020,368
28		kW	15,872	14,024	14,558	21,458	65,913
29		kVar	14,339	12,211	11,938	11,750	50,237
30	Private Outdoor Lighting	kWh	2,652,526	2,647,949	2,536,797	2,691,887	10,529,159
31	School	kWh	9,832,091	4,837,051	7,040,114	6,234,174	27,943,431
32	Streetlighting	kWh	4,617,361	4,651,919	4,536,675	4,530,659	18,336,614

Total Forecast May 09 - Apr 2010 (U)
3,695,004,444 kWh
1,921,827,265 kWh
530,228,586 kWh
10,624,898 kW
1,642,467,340 kWh
4,857,645 kW
2,877,987 kVar
96,192,490 kWh
267,219 kW
122,844 kVar
106,702,698 kWh
278,483 kW
179,864 kVar
31,835,957 kWh
77,415,560 kWh
55,097,946 kWh

[1] Secondary customers are charged for all kW over 5kW of Billing Demand and for the first 1,500 kWh

BEFORE THE

PUBLIC UTILITIES COMMISSION OF OHIO

THE DAYTON POWER AND LIGHT COMPANY
CASE NO. 09-256-EL-UNC

Transmission Cost Recovery Rider (TCRR)

DIRECT TESTIMONY

OF GREGORY S. CAMPBELL, CPA

- ☐ MANAGEMENT POLICIES, PRACTICES, AND ORGANIZATION
- ■ OPERATING INCOME
- ☐ RATE BASE
- ☐ ALLOCATIONS
- ☐ RATE OF RETURN
- ☐ RATES AND TARIFFS
- ■ OTHER

BEFORE THE

PUBLIC UTILITIES COMMISSION OF OHIO

DIRECT TESTIMONY OF

GREGORY S. CAMPBELL, CPA

ON BEHALF OF
THE DAYTON POWER AND LIGHT COMPANY

TABLE OF CONTENTS

I. INTRODUCTION 1

II. TRANSMISSION COST RECOVERY RIDER (TCRR) COMPONENTS 4

III. DEFERRAL AND FORECASTED TCRR 11

IV. CONCLUSION 14

1 **I. INTRODUCTION**

2 **Q. Please state your name and business address.**

3 A. My name is Gregory S. Campbell. My business address is 1065 Woodman
4 Drive, Dayton, Ohio.

5 **Q. By whom and in what capacity are you employed?**

6 A. I am employed by The Dayton Power and Light Company ("DP&L" or
7 "Company") as Director, Accounting Policy and External Reporting.

8 **Q. How long have you been in your present position?**

9 A. I assumed my present position on June 18, 2008. Prior to that, I had been
10 employed from 1981 through 2008 by American Electric Power, serving in a
11 number of accounting and financial positions with that company.

12 **Q. What are your responsibilities in your current position and to whom do you**
13 **report?**

14 A. In my current position, I am responsible for financial reporting to certain
15 regulatory bodies, including the SEC and FERC. I am also responsible for
16 reviewing certain accounting transactions to insure adherence to Generally
17 Accepted Accounting Principles. I report to the Assistant Controller of DP&L.

18 **Q. Will you describe briefly your educational and business background?**

19 A. I received a Bachelor of Business Administration degree in Accounting from the
20 College of William and Mary in 1977, and am a Certified Public Accountant.

1 From 1977 to 1981, I worked for two large public accounting firms: Coopers and
2 Lybrand, and Peat, Marwick and Mitchell. During the years 1981 through 1984, I
3 worked in the Accounting Department of one of American Electric Power's
4 electric operating subsidiaries, Appalachian Power Company. From 1984 until
5 2008, I worked for the American Electric Power Service Corporation in a variety
6 of jobs, including Accounting Policy and Research for fourteen years, accounting
7 for fiber optic operations, and accounting and financial analysis for regulated and
8 non-regulated operations. In June 2008, I accepted my current position at DP&L.

9 **Q. Have you previously provided testimony before the Public Utilities**
10 **Commission of Ohio ("PUCO" or the "Commission")?**

11 A. Yes. I recently provided testimony on behalf of the Dayton Power and Light
12 Company in support of its Electric Security Plan in Case No. 08-1094-EL-SSO. I
13 have also sponsored testimony before the PUCO in a number of cases on behalf
14 of Columbus Southern Power and Ohio Power Company, two subsidiaries of
15 American Electric Power. My previous testimony included both base rate and
16 fuel cases.

17 **Q. What is the purpose of this testimony?**

18 A. The purpose of this testimony is to request Commission approval for recovery of
19 the Company's April 30, 2009 deferred retail jurisdictional Regional Transmission
20 Organization-related (RTO-related) net costs over the twenty-four month period
21 starting May 1, 2009 through April 30, 2011 using a Transmission Cost Recovery
22 Rider (TCRR). Deferral of certain of these costs beginning June 1, 2007 was
23 authorized in Case No. 07-1287-EL-AAM. The remaining costs were incurred

1 during the period July 31, 2008 through April 30, 2009 and were authorized for
2 deferral by the Commission in its order in Case No. 08-1209-EL-AAM. The
3 deferred costs also include a carrying cost return at 5.86% per annum. This rate
4 is the weighted cost of long-term debt that is included in the stipulation in DP&L's
5 Electric Security Plan case, Case No. 08-1094-EL-SSO et al. We are using this
6 rate to reduce the impact of carrying costs on our customers versus the 7.27%
7 rate authorized in Case Nos. 07-1287-EL-AAM and 08-1209-EL-AAM. The
8 Company is also requesting recovery of forecasted net retail jurisdictional RTO-
9 related costs for the twelve month period May 1, 2009 through April 30, 2010 be
10 included in the TCRR that would be effective May 1, 2009.

11 **Q. What Schedules and Workpapers are you sponsoring?**

12 A. I am sponsoring the following Schedules and associated Workpapers:

13 Schedule B-4- Graphs;

14 Schedule C-1 – Projected Monthly Jurisdictional Net TCRR Costs;

15 Schedule C-1a – Summary of Deferred Jurisdictional Net TCRR Costs;

16 Workpaper C-1a – Projected Charges and Revenues;

17 Workpaper C-1b – Calculation of Carrying Costs;

18 Workpaper C-1c – Actual and Projected Charges and Revenues;

19 **Q. Were they prepared by you or under your supervision?**

20 A. Yes.

II. TRANSMISSION COST RECOVERY RIDER (TCRR) COMPONENTS

Q. What types of costs is the Company proposing be included in the TCRR?

A. The Commission has broad authority to permit recovery of costs charged and credited to DP&L by PJM. Ohio Senate Bill 221 provides for a reconcilable rider to recover prudently-incurred, net RTO-related costs. DP&L is requesting a TCRR that will be effective on May 1, 2009 and includes transmission, transmission-related, and other RTO-related and FERC approved costs, such as reliability pricing model charges and credits. DP&L requested and was granted authority in Case No. 07-1287-EL-AAM to defer Transmission Enhancement Charges ("TEC"), imposed upon DP&L by PJM. S.B. 221, which became effective after DP&L filed its application to defer the TEC, permits the recovery of a broader category of RTO-related costs beyond the TEC. As a result, after S.B. 221 became effective, DP&L sought and was granted Commission approval to defer the excess of incremental RTO-related costs directly related to our internal load customers over the revenues in tariffs that will be replaced by the TCRR. These tariffs are the transmission charge, scheduling charge, reactive supply charge, regulation frequency responsibility charge, spinning reserves charge, supplemental reserves charge and PJM administrative fee charge (P.U.C.O. No.17 Tariff Sheets No. T8 – T14). The deferral was approved by the Commission on February 19, 2009 in Case No. 08-1209-EL-AAM and was effective beginning July 31, 2008. We also recorded a return on these deferred costs at the rate of 5.86%. This is the overall weighted cost of long-term debt

filed with the Commission in DP&L's Electric Security Plan Case No. 08-1094-EL-SSO. We are seeking recovery of these deferred costs over the twenty-four month period beginning May 1, 2009.

The Company is also seeking recovery of the twelve month estimated RTO-related costs directly related to its internal load customers for the period May 1, 2009 through April 30, 2010 beginning May 1, 2009.

Q. What specific charges/credits do you propose be included in the TCRR?

A. The following is a list of accounts and charges/credits that the Company believes to appropriately be included in the TCRR, along with a brief description of the nature of the costs.

- **407.3 Regulatory Debits** – This account includes transmission and transmission-related costs that were deferred for future recovery. The transmission and transmission-related costs include the following:

  Alliance Regional Transmission Organization (RTO) Start-Up Cost Recovery Charges – These costs are associated with the development of the Alliance RTO. DP&L is seeking recovery of the deferred balance at April 30, 2009 for recovery during the twenty-four month period from May 1, 2009 through April 30, 2011.

- **555 Purchased Power** – This account includes transmission and transmission-related costs associated with PJM. The RTO-related costs include the following:

  Reactive Supply and Voltage Control from Generation Sources Services Charges – These costs are related to maintaining voltages within acceptable

limits and are allocated based upon monthly peak usage of the PJM transmission system.

Regulation Charges – Each load serving entity has an hourly regulation charge equal to its real-time load ratio share. It is priced at the regulation market clearing price plus a share of opportunity costs paid to the generators supplying the power that can be instantly increased or decreased to regulate load.

Synchronized (Spinning) Reserve Charges – These costs are charged to each load serving entity based on its synchronized reserve obligation. The obligation is based on the load ratio share.

Operating Reserve Charges – These costs are charged to load serving entities in proportion to their load or deviations from that load for the day.

RTO Start-Up Cost Recovery Charges – These costs are charged to PJM customers to cover costs incurred in creating the PJM system.

Synchronous Condensing Charges – These costs are the daily costs of synchronous condensing (voltage regulator) and are allocated based upon real-time load and the export ratio share.

Black Start Service Charges – These are costs that are incurred to compensate generators that are able to start their unit without an outside electrical supply.

Locational Reliability Charges – These are the costs charged to load serving entities for their daily unforced capacity obligations. It is priced at the zonal capacity price for the delivery year.

Transmission Enhancement Charges – These are Regional Transmission Expansion Plan (RTEP) costs charged to load serving entities throughout PJM to compensate certain transmission owners that have made improvements to their transmission systems pursuant to the RTEP process.

This account also includes the recovery of DP&L's April 30, 2009 estimated balance of previously deferred costs related to these projects over the twenty-four month period from May 1, 2009 through April 30, 2011. This deferral was previously approved by the Commission in Case No. 07-1287-EL-AAM.

Capacity Resource Deficiency Charges – These are costs charged to generators that are unable to deliver their capacity.

Reliability Pricing Model (RPM) Auction Charges – These are costs charged to successful buyers in the RPM auction.

Generation Resource Rating Test Charges – These are costs charged to generators that do not meet the capacity test.

Peak Hour Period Availability Charges – These are costs charged to generators that are short in resource availability during critical peak hours.

- **556 System Control and Load Dispatching** – This account includes some RTO-related costs, including the following:

North American Electric Reliability Council (NERC) Charges – These are administrative-type costs associated with the scheduling and dispatching for the PJM system.

Reliability First Corporation (RFC) Charges – These are administrative-type costs associated with the scheduling and dispatching for the PJM system.

Transmission Owner Scheduling, System Control and Dispatch Service Charges – These are costs associated with the scheduling and dispatching for the PJM system by individual transmission owners.

PJM Annual Membership Fees – These are costs to be a member of PJM.

- **561 Load Dispatch –** This account includes some RTO-related costs, including the following:

PJM Scheduling, System Control and Dispatch Service Charges – These are PJM costs associated with the scheduling and dispatching of the PJM system, otherwise known as the PJM Administrative Fee. DP&L currently has a PJM Administrative Fee Retail Rider (P.U.C.O. No.17 Tariff Sheet T14) which it is proposing to withdraw, and these costs will then be incorporated into the TCRR.

- **565 Transmission of Electricity by Others –** This account includes some RTO-related costs, including the following:

Network Integration Transmission Service Charges – These are costs associated with a daily demand charge to recover the cost of service of the individual PJM transmission owners' system based on a coincident peak. These Charges are outlined the PJM Tariff, Attachment H. DP&L currently has a Network Integration Transmission Service Retail Rate (P.U.C.O. No. 17 Tariff Sheet T8) which it is proposing to withdraw, and this rate will be incorporated into the TCRR.

Expansion Cost Recovery Charges (ECRC) - These costs are charged to all PJM customers to cover certain costs incurred by AEP, DP&L and Commonwealth Edison in joining the PJM system.

Firm and Non-Firm Point-to-Point Transmission Service Charges - These costs are charged to PJM customers to reserve capacity on a firm or non-firm basis from one point to another within the PJM system.

Transmission Congestion Charges – These are the increased costs related to the power that is moved through the parts of the transmission system that have constrained line availability.

Financial Transmission Right (FTR) Auction Charges – These are the costs incurred to obtain FTRs that are used by the load serving entity.

Transmission Loss Charges – These are costs related to the power that is lost through resistance in moving it through the transmission system.

- **923 Outside Services Employed** – This account will include some RTO-related costs, including the following:

PUCO Consultant Charges – These are costs that may be incurred associated with the consultant the PUCO may select to review the TCRR costs and credits. These will not be reflected on a PJM bill.

- **447 Sales for Resale** – This account includes some RTO-related revenues, including the following:

1 **Capacity Resource Deficiency Credits** – These are amounts credited to load
2 serving entities from generators that are unable to deliver their capacity.

3 **Reliability Pricing Model (RPM) Auction Credits** – These are amounts
4 credited to successful sellers in the RPM auction.

5 **Generation Resource Rating Test Credits** – These are costs credited to load
6 serving entities from generators that do not meet the capacity test.

7 **Peak Hour Period Availability Credits** – These are costs credited to generators
8 that exceed their resource availability during critical peak hours.

9 • **456 Other Electric Revenues** – This account includes some RTO-related
10 revenues, including the following:

11 **Financial Transmission Right (FTR) Auction Credits** – These are the credits
12 received from the sale of FTRs in the annual and monthly FTR auctions.

13 **FTR/Auction Revenue Right (ARR) Auction Credits** –These are credits
14 received by firm transmission service customers that entitle the holder to receive
15 an allocation of revenue from the annual FTR auction.

16 **Transmission Congestion Credits** – These credits are an allocation of the
17 transmission congestion charges collected related to the increased costs for the
18 power that is moved through the parts of the transmission system that have
19 constrained line availability.

1 **Transmission Loss Credits –** These credits are an allocation of the
2 transmission loss charges collected related to the power that is lost through
3 resistance in moving it through the transmission system.

4 **Expansion Cost Recovery Credits (ECRC) -** These credits are DP&L's
5 allocation of the charges collected from all PJM customers to cover the costs
6 incurred by AEP, DP&L and Commonwealth Edison in joining the PJM system.

7 **Q. Will there be any other costs or credits that the Company believes should**
8 **be charged or credited via the TCRR in the future?**

9 A. There may be, but none that I am aware of at this time. The PJM environment is
10 one that is constantly changing and evolving, and the costs associated with PJM
11 are continually under review and adjustment by PJM, its members and the
12 Federal Energy Regulatory Commission (FERC). There may be changes to the
13 way in which PJM markets work, or the manner in which they assess fees, costs
14 or credits. To the extent that occurs, DP&L will work with PUCO Staff and
15 interested parties to ensure those costs are properly reflected in the TCRR.

16 **Q. How are these costs and credits allocated to the retail jurisdiction?**

17 A. As discussed in more detail by witness Schroder, these costs and credits are
18 allocated to the retail jurisdiction based upon the nature of the cost or credit and
19 how it is incurred.

20 **III. <u>DEFERRAL AND FORECASTED TCRR</u>**

21 **Q. Where on the books are these net costs deferred, what are the carrying**
22 **costs and what is the expected recovery period?**

1 A. Each month, these net costs are deferred in account 182.3, Other Regulatory
2 Assets. We are recording an additional deferral as a carrying cost at the rate of
3 5.86%. We are requesting recovery of the deferred costs at April 30, 2009 over a
4 twenty-four month period from May 1, 2009 through April 30, 2011 with a carrying
5 cost return until the deferral is fully recovered. We also plan to record deferred
6 federal income taxes associated with these deferred RTO-related costs.

7 In a similar manner, each month beginning in May 2009, the revenues and actual
8 jurisdictional costs would be compared to each other. If the costs exceed the
9 revenues, a deferral would be recorded in account 182.3, Other Regulatory
10 Assets. If the revenues exceed the costs, a deferral would be recorded in
11 account 254, Other Regulatory Liabilities. A carrying cost return or obligation at
12 5.86% per annum would be recorded on the net balance owed to the Company
13 or owed by the Company to customers. We will also record deferred federal
14 income taxes on the net regulatory asset or liability account. Any over or under
15 recovery remaining at April 30, 2010 will be rolled into the next TCRR expected
16 to be effective May 1, 2010.

17 **Q. How did you account for the retail revenues collected during the deferral**
18 **period from July 31, 2008 through April 30, 2009 that are related to**
19 **transmission and ancillary service rates that will be replaced by the TCRR?**

20 A. These revenues were treated as an offset to the costs being deferred in Account
21 182.3 for every month in the deferral period.

22 **Q. What is the estimated balance of the deferred retail jurisdictional TCRR**
23 **costs as of April 30, 2009?**

A. The estimated balance of the deferred retail jurisdictional TCRR costs at April 30, 2009 is $25.2 million as shown on Schedule C-1a, Page 2 of 2, Column (H). This balance includes actual results for the period August 2008 through February 2009, and estimated results for the months of March and April 2009. The total costs are allocated to the Ohio jurisdiction on the pages in Schedule C-1c using the factors provided by witness Schroder.

Q. What is the estimated incremental retail jurisdictional TCRR costs forecast for the period May 1, 2009 through April 30, 2010?

A. The estimated incremental retail jurisdictional TCRR costs forecast for the period May 1, 2009 through April 30, 2010 is $36.5 million. This is derived by taking the total estimated costs of $97.0 million as shown on Schedule C-1, Page 2 of 2, and subtracting the annual amount being collected in the current tariff riders of approximately $60.5 million.

The forecasted net cost numbers are based on information received from PJM or our reasonable estimates, based upon the best data available at the time, of the future costs. They are then allocated to the Ohio jurisdiction using the factors provided by witness Schroder.

The forecasted current revenue rider numbers of $60.5 million are from Schroder Schedule B-2. These revenue riders will be replaced by the TCRR revenue rider when new rates go into effect on May 1, 2009.

Q. What is shown on the graphs included in Schedule B-4?

A. Consistent with the Commission's rules in the Appendix to Rule 4901:1-36-03, Schedule B-4 contains twenty pages of bar graphs that show the actual and forecasted costs by quarter from January 2007 forward. Each page is a separate component of the TCRR net costs.

IV. CONCLUSION

Q. Please summarize your testimony.

A. In summary, DP&L is seeking authorization to recover the April 30, 2009 deferred retail jurisdictional RTO-related costs beginning May 1, 2009 over the twenty-four month period ending April 30, 2011 along with a carrying cost return on the unrecovered balance.

We are also seeking Commission approval to recover the ongoing retail jurisdictional RTO-related costs as forecasted beginning May 1, 2009.

Q. Does this conclude your direct testimony?

A. Yes, it does.

BEFORE THE

PUBLIC UTILITIES COMMISSION OF OHIO

THE DAYTON POWER AND LIGHT COMPANY
CASE NO. 09-256-EL-UNC

Transmission Cost Recovery Rider (TCRR)

DIRECT TESTIMONY

OF SHARON SCHRODER

- ☐ MANAGEMENT POLICIES, PRACTICES, AND ORGANIZATION
- ■ OPERATING INCOME
- ■ RATE BASE
- ■ ALLOCATIONS
- ☐ RATE OF RETURN
- ■ RATES AND TARIFFS
- ■ OTHER

BEFORE THE

PUBLIC UTILITIES COMMISSION OF OHIO

DIRECT TESTIMONY OF

SHARON SCHRODER

ON BEHALF OF
THE DAYTON POWER AND LIGHT COMPANY

TABLE OF CONTENTS

I. INTRODUCTION 1

II. TRANSMISSION COST RECOVERY RIDER (TCRR) COMPONENTS 4

III. RETAIL ALLOCATION OF TCRR COMPONENTS 9

IV. TCRR RATE DEVELOPMENT 16

V. TARIFF MODIFICATIONS 20

VI. CONCLUSION 21

1 **I. INTRODUCTION**

2 **Q. Please state your name and business address.**

3 A. My name is Sharon Schroder. My business address is 1065 Woodman Drive,
4 Dayton, Ohio.

5 **Q. By whom and in what capacity are you employed?**

6 A. I am employed by The Dayton Power and Light Company ("DP&L" or "Company")
7 as Manager, FERC Pricing and Policy.

8 **Q. How long have you been in your current position?**

9 A. I assumed my present position on March 11, 2005. Prior to this position, I was
10 Senior Regulatory and Pricing Analyst since January 29, 1999. I joined DP&L as
11 Rate Analyst on April 15, 1996.

12 **Q. What are your responsibilities in your current position and to whom do you**
13 **report?**

14 A. I am responsible for formulating regulatory and rate filings at the Federal Energy
15 Regulatory Commission ("FERC") and ensuring that DP&L's tariffs and regulatory
16 compliance obligations are satisfied, particularly wholesale activities and those
17 involving participation within PJM Interconnection, L.L.C. ("PJM"). I am on the
18 PJM Tariff Working Group and also am a voting member of the PJM Transmission
19 Owners' Administrative–Advisory Committee. I also have responsibility for various
20 assignments relating to retail and wholesale electric rate development, evaluation
21 of federal and state regulatory and legislative initiatives that impact base rates and
22 regulatory operations. I report to the Director of Regulatory Operations of DP&L.

1 **Q. Will you describe briefly your educational and business background?**

2 A. I received a Bachelor of Science degree in International Business from Miami
3 University in Oxford, Ohio in 1989. I achieved a Master of Science in Social and
4 Applied Economics from Wright State University in Dayton, Ohio in 1990.
5 Additionally, I earned a Master of Arts in Economics from The Ohio State
6 University in Columbus, Ohio in 1994. I have been employed by DP&L in the
7 Pricing Services Department, formerly known as the Rates Department, since
8 1996. Prior to joining DP&L, I was a Senior Analyst for a consulting firm for the
9 utility industry.

10 **Q. Have you previously provided testimony before the Public Utilities**
11 **Commission of Ohio ("PUCO" or the "Commission")?**

12 A. No. However, I have sponsored testimony before the FERC in a number of cases
13 on behalf of DP&L. In addition, I have sponsored testimony before the FERC on
14 behalf of DPL Energy, L.L.C. ("DPLE"), an affiliate of DP&L.

15 **Q. What testimony have you submitted before the FERC?**

16 A. I submitted testimony on behalf of DP&L: on (i) August 31, 2001 with regard to the
17 Federal Power Act ("FPA") Section 205 filing of the former Alliance Companies in
18 Docket No. RT01-88-006; (ii) December 11, 2002 with regard to the FPA Section
19 205 filing of the Alliance Companies in Docket No. ER03-262-000; (iii) October 14,
20 2003 with regard to the elimination of through-and-out rates in Docket Nos. EL03-
21 212, et al.; (iv) July 30, 2004 with regard to the FPA Section 205 filing of American
22 Electric Power ("AEP") and DP&L to join PJM in Docket No. ER04-1068-000; (v)
23 April 29, 2005, May 13, 2005 and August 29, 2005 with regard to the FPA Section

205 filing to support DP&L's lost revenues in the Seams Elimination Charge/Cost Adjustment/Assignment ("SECA") proceedings, Docket Nos. ER05-6, et al.; and (vi) November 22, 2005 with regard to the Commission's FPA Section 206 filing to investigate PJM's rate design. On May 30, 2008, I submitted testimony on behalf of DPLE to support its revenue requirement for providing Reactive Support and Voltage Control from Generation Sources Service ("Reactive Power") in Docket No. ER08-1039.

Q. What Schedules and Workpapers are you sponsoring?

A. I am sponsoring the following Schedules:

Schedule A-1 - Proposed Tariffs
Schedule A-2 - Red-Lined Current Tariffs
Schedule B-1 - Summary of Projected Jurisdictional TCRR Net Costs
Schedule B-2 - Summary of Current versus Proposed Revenues
Schedule B-3 - Summary of Current and Proposed Rates
Schedule B-5 - Typical Bill Comparisons
Schedule C-2 - Projected Monthly TCRR Costs by Tariff Class
Schedule C-3 - Summary of Proposed TCRR Rates
Schedule C-3a - Development of Proposed TCRR Base Rates
Schedule C-3b - Development of Proposed TCRR Incremental Rates
Workpaper B-2 - Current Rates and Revenues
Workpaper B-3 - Current Rates
Workpaper C-2 - Summary of TCRR Revenues by Tariff Class – 2008
Workpaper C-3 - Projected Monthly Billing Determinants
Workpaper C-1d – Jurisdictional Allocators

Q. Were these Schedules prepared by you, or under your direction?

A. Yes, they were.

Q. What is the purpose of this testimony?

A. The purpose of this testimony is to support the development of the Company's Transmission Cost Recovery Rider rates. The proposed TCRR rates are based on the Company's forecasted retail jurisdictional RTO-related net costs for the twelve month period beginning May 1, 2009 through April 30, 2010.

This testimony supports the Company's request that the deferred net costs incurred from July 31, 2008 through April 30, 2009, and authorized for deferral by the Commission in its February 19, 2009 Finding and Order in Case No. 08-1209-EL-AAM be recovered within the TCRR over the twenty-four month period beginning May 1, 2009 through April 30, 2011. The deferred costs and associated carrying charges are discussed in Witness Campbell's testimony.

Finally, I support the necessary tariff modifications consistent with the proposed TCRR.

II. TRANSMISSION COST RECOVERY RIDER (TCRR) COMPONENTS

Q. Why is the Company requesting to implement a TCRR?

A. Ohio Revised Code §4928.05(A)(2) along with other authority provided to the Commission, authorizes the Commission to permit the Company to recover the net RTO-related costs through a reconcilable rider.

Q. What types of costs are included in your proposed TCRR?

A. Consistent with DP&L's application to defer costs in Case No. 08-1209-EL-AAM, and as described more fully in Witness Campbell's testimony, DP&L is proposing to include the following RTO-related net costs in the TCRR:

Transmission Enhancement Charges (associated with PJM's Regional Transmission Expansion Plan, "RTEP")
Reactive Supply and Voltage Control from Generation Sources
Regulation
Synchronized (Spinning) Reserves
Operating Reserves
RTO Start-up Cost Recovery – AEP zone
Synchronous Condensing
Locational Reliability Charges (LRC)
Capacity Resource Deficiency Charges/Credits
RPM Auction Charges/Credits
Generation Resource Rating Test Charges/Credits
Peak Hour Period Availability Charges/Credits
Black Start Service
PJM Annual Membership Fee
Transmission Owner Scheduling, System Control and Dispatch Service
North American Electric Reliability Corporation (NERC) Charges
Reliability First Corporation (RFC) Charges
PJM Default Charges
Transmission Congestion Charges/Credits
Generation Loss Factor
Transmission Losses Charges/Credits
Firm Point-to-Point Transmission Service Credits
Non-Firm Point-to-Point Transmission Service Charges/Credits
Network Integration Transmission Service
Financial Transmission Rights Auction Charges/Credits
Auction Revenue Rights Credits
Expansion Cost Recovery Charges (ECRC)/Credits
PJM Scheduling System Control and Dispatch Service (Admin Fee)
PUCO Consultant Fees

Q. Are most of these components currently included in the monthly invoices DP&L receives from PJM?

A. Yes, the majority of the proposed components listed above are currently included on the PJM invoices. However, the following charges/credits are not included in the invoices from PJM:

- Alliance RTO Start-up Cost Recovery: similar to the RTO Start-up Cost Recovery currently being charged by PJM on behalf of AEP and ComEd, DP&L also has certain RTO Start-up Costs related to the formation of the Alliance RTO.

- PUCO Consultant Fees: while these fees have not been incurred to date, OAC Chapter 4901:1-36-03 (C) states that "the Commission may order that consultants be hired, with the costs billed to the electric utility and recoverable through the rider, to conduct prudence and/or financial reviews of the costs incurred and recovered through the transmission cost recovery rider." DP&L seeks approval to include this component in its TCRR in the event consultant fees are incurred in the future.

- Generation Loss Factor: this is an estimate of the amount currently embedded in retail generation rates for losses and is credited against the transmission losses charged by PJM.

In addition, some of the components listed above may not appear on every monthly PJM invoice.

Q. Please explain why you have proposed to include Reliability Pricing Model (RPM)-related charges and credits in the TCRR.

A. Locational Reliability Charges (LRC), Capacity Resource Deficiency Charges and Credits, RPM Auction Revenues, Generation Resource Rating Test Charges and Credits, and Peak Hour Period Availability Charges and Credits are all included in the proposed TCRR because the Commission has broad authority to allow recovery of these RTO-related components through a reconcilable rider, and inclusion of these RPM-related costs within the TCRR makes sense from a policy and administrative standpoint. These RPM-related charges and credits, along with

1 the other transmission, transmission-related, ancillary and congestion costs as
2 described by Revised Code §4928.05(A)(2) are all net RTO-related costs, which
3 are largely outside of DP&L's control and are all by-passable to customers that
4 shop. Inclusion of these net costs within one mechanism will allow the proper
5 tracking, reconciliation and recovery. Moreover, such consolidation into one rider
6 will be administratively efficient for the Commission to audit as provided for in the
7 Ohio Administrative Code.

8
9 **Q. Have you considered a separate Rider for these RPM-related charges and**
10 **credits?**

11 A. Yes; however, as described above, all RTO-related net charges would be best
12 tracked and reconciled in one combined rider. In addition to the reasons set forth
13 above, combining all of the PJM-related charges/credits into one Rider will simplify
14 our retail rate structure. Through this filing, we are also proposing to combine the
15 existing PJM Admin Fee, the RTEP deferral, and the existing retail transmission
16 and ancillary service rates all into this Rider. All of the charges proposed to be
17 included in the TCRR are by-passable by customers that shop. Finally, the TCRR
18 filing and review process provides a structured approach for the Commission to
19 review DP&L's RPM-related net cost recovery and provides for an appropriate due
20 process review.

21 **Q. Why is it appropriate to include PJM's RPM charges and credits in the**
22 **TCRR?**

23 A. The Company would note that despite the TCRR name, many of the components
24 included in DP&L's proposed Rider (and permitted by the Commission for inclusion

by other Ohio Companies in their TCR's) would be more accurately labeled as reliability-related or RTO-related because they are costs incurred by generation facilities that support the reliability of the transmission system. For example,

- Reactive Supply and Voltage Control from Generation Sources
- Regulation
- Synchronized (Spinning) Reserves
- Operating Reserves
- Synchronous Condensing
- Black Start Service
- Losses

In addition, other charges are not specifically tied to a particular transmission line; rather, they are ancillary costs and simply tied to PJM administrative charges, such as:

- PJM Admin Fee
- PJM Default Charges
- NERC/RFC Charges
- PJM Annual Membership Fees

These charges/credits (as well as the RPM-related components) are billed by PJM – a regional transmission organization. We receive these charges/credits as a result of DP&L's transmission business joining PJM, and all the costs are incurred in support of maintaining reliability, we believe all of these components are appropriately included within the TCRR, or RTO-related Rider.

1 **Q. Could the Company separate RPM-related components from the other RTO**
2 **components, and create two separate RTO-related riders?**

3 A. Yes. The Company could separate out the RPM components from the other RTO-
4 related charges/credits and bill these costs as two separate riders. However, the
5 two riders would be recovered in the same manner and charged to the same
6 customers. Therefore, the Company is proposing to include all charges/credits
7 that are assessed by PJM to DP&L on behalf of the load the Company serves
8 within its service territory (standard offer customers) within one rider, the TCRR.

9 **III. <u>RETAIL ALLOCATION OF TCRR COMPONENTS</u>**

10 **Q. How are the proposed RTO-related costs and credits allocated to the retail**
11 **jurisdiction?**

12 A. The RTO-related costs and credits are allocated to the retail jurisdiction based
13 upon their nature. I have used three allocators: Load, Wholesale/Retail, and
14 Congestion. In addition, certain credits are allocated 100% to retail load. These
15 allocators and their calculations are reflected in Workpaper C-1d.

16 **Q. Which components are allocated 100% to DP&L's retail load?**

17 A. The following components are charged or credited to DP&L solely based on the
18 load it serves and therefore I have allocated the entire amounts to retail load:

19 - Alliance RTO Start-up Cost Recovery
20 - PJM Default Charges
21 - Firm Point-to-Point Transmission Service Credits

- Non-Firm Point-to-Point Transmission Service Credits
- Expansion Cost Recovery Credits (ECRC)

Q. What is the Load allocator and which costs/credits are allocated with by this method?

A. The Load allocator assigns 88.9% of the total cost/credit to DP&L's retail load. This amount is based on costs/credits reflected on DP&L's bills that are assigned to DP&L's retail load versus load served by DP&L's affiliate, DPL Energy Resources (DPLER). DP&L transacts with PJM on behalf of DPLER, so certain costs/credits received on its bills are ultimately assigned to DPLER, based on its load share of DP&L's total load.

The following components are assigned using this Load allocator:

- Transmission Enhancement Charges (RTEP)
- Reactive Supply and Voltage Control from Generation Sources
- Regulation
- Synchronized (Spinning) Reserves
- RTO Start-up Cost Recovery – AEP Zone
- Synchronous Condensing
- Locational Reliability Charges (LRC)
- Capacity Resource Deficiency Charges
- RPM Auction Charges
- Generation Resource Rating Test Charges
- Peak Hour Period Availability Charges
- Black Start Service

- North American Electric Reliability Corporation (NERC) Charges
- Reliability First Corporation (RFC) Charges
- Transmission Losses Credits
- Network Integration Transmission Service
- Expansion Cost Recovery Charges (ECRC)
- PJM Scheduling System Control and Dispatch Service (Admin Fee)
- PUCO Consultant Fees

Q. The Load allocator you used for the PJM Admin Fee appears to change depending on the month. Why?

A. Since February, 2006, the Company has been charging its retail customers a PJM Administrative Fee Rider (P.U.C.O. No.17, Tariff Sheet T14). This PJM Admin Fee Rider included an incremental component to recover deferred PJM Admin Fee costs, which ended January 31, 2009. Therefore, during that timeframe I have indicated "NA" as the allocator since there are no associated costs identified in the workpapers. In other words, no amounts were deferred during those months as the Company was charging this Rider at an amount equal to the cost PJM charged DP&L.

DP&L's deferral recovery ended January 31, 2009 so the amount charged in February 2009 was only for the real-time recovery of PJM's current Admin Fee. Therefore the Company could identify that portion charged directly to DP&L (as opposed to DPLER), and as a result, no allocation was necessary.

1 Beginning March 1, 2009 the Company began to forecast amounts for the TCRR
2 components. DPL forecasts on a total holding company basis (which includes
3 DPLER), so the Load allocator described above is necessary for each of the
4 forecasted months.

5 **Q. What is the Wholesale/Retail allocator and which costs/credits are allocated**
6 **with by this method?**

7 A. The Wholesale/Retail allocator assigns 77.4% of the total cost/credit to DP&L's
8 retail load. This amount is based on costs/credits reflected on DP&L's bills that
9 are ultimately assigned to DP&L's wholesale activity, unrelated to its retail load
10 obligation. This amount is calculated using the 2008 percentage of wholesale
11 sales to total Company sales, as reflected in Workpaper C-1d and cited in the
12 Company's most recent 10K.

13 The following components are assigned using this Wholesale/Retail allocator:

14 - Operating Reserves
15 - Capacity Resource Deficiency Credits
16 - RPM Auction Credits
17 - Generation Resource Rating Test Credits
18 - Peak Hour Period Availability Credits
19 - PJM Annual Membership Fee
20 - Transmission Owner Scheduling, System Control and Dispatch
21 Service
22 - Transmission Congestion Charges
23 - Transmission Losses Charges

Q. What is the Congestion allocator and which costs/credits are allocated with by this method?

A. The Congestion allocator assigns 50% of the total cost/credit to DP&L's retail load. The Company proposes a 50% allocation of congestion-related costs and credits due to the nature of congestion and PJM's related hedging process. DP&L's proposal regarding the division of congestion-related costs and credits is more fully described in Witness Crusey's testimony.

The following components are assigned using this Congestion Allocator:

- Transmission Congestion Charges/Credits
- Financial Transmission Rights Auction Charges/Credits
- Auction Revenue Rights Credits

Q. For certain TCRR components, you have used a different allocator for costs and credits. Please explain.

A. It is appropriate to use one allocator for the associated costs and a different allocator for the related credits for certain TCRR components. I address each component below:

<u>RPM-related Charges and Credits</u> – PJM bills all RPM-related charges to the load-serving entity, so I have allocated these costs using the Load allocator. However, DP&L receives credits for its generation capacity based on the total amount of generation, which is used for both wholesale and retail activities. Therefore, I have used the Wholesale/Retail allocator for the RPM-related credits.

1 Transmission Congestion Charges and Credits – PJM bills congestion to
2 transmission customers for all transactions on the PJM system. Therefore, DP&L
3 receives charges related to both wholesale and retail activities, so I have used the
4 Wholesale/Retail allocator for these costs. Note, this amount is then further
5 assigned using the Congestion allocator, based on the methodology described in
6 Witness Crusey's testimony (77.4% * 50% = 38.7%). The transmission
7 congestion credits are provided by PJM to load that has paid the increased costs
8 to receive power across the constrained system. Therefore, these credits are
9 provided to the load and not split by the Wholesale/Retail allocator.
10 Transmission Losses Charges and Credits – PJM charges Transmission Losses
11 on all transactions that move through the PJM system; therefore, DP&L's
12 wholesale activity is allocated a portion of these charges. On the other hand,
13 transmission losses credits are assigned by PJM to load, therefore the Load
14 allocator was used.
15 Expansion Cost Recovery Charges (ECRC) and Credits – PJM charges ECRC to
16 all PJM load, therefore DP&L receives these charges associated with both its retail
17 load obligation and its wholesale load. Consequently, these charges are assigned
18 using the Load Allocator. However, the ECRC credits which DP&L receives are
19 provided 100% to DP&L's retail load.

20 **Q. Does DP&L currently receive revenues from retail customers for any of the**
21 **RTO-related costs proposed to be included in the TCRR?**

22 A. Yes. The Company currently receives retail revenues under the following Tariff
23 Sheets:

T8	Retail Transmission Service
T9	Scheduling, System Control, and Dispatch Service
T10	Reactive Supply and Voltage Control Service
T11	Regulation and Frequency Response Service
T12	Operating Reserve – Spinning Reserve Service
T13	Operating Reserve – Supplemental Reserve Service
T14	PJM Administration Fee Rider

The proposed TCRR (Tariff Sheet T15) will replace all of these rates and tariff sheets. In addition, as described more fully in Witness Campbell's testimony, these historical retail revenues were credited against the charges calculated during the deferral period.

Q. Are the RPM-related costs/credits being charged to the Company by PJM and which DP&L proposes to include in its TCRR included in any other schedule or rider in DP&L's tariffs on file with the Commission?

A. No. PJM's capacity market (known as the Reliability Pricing Model or RPM) structure came about after rates in DP&L's current rate plan were established. However, certain retail ancillary service rates do include a reserve obligation pursuant to reliability requirements in place at the time DP&L set its cost-based ancillary service rates. These ancillary service rates, including the associated reserve obligation amounts, will be replaced by the TCRR.

Q. Are there any other retail revenues the Company proposes to net against the TCRR charges?

A. Yes, an estimated Generation Loss Factor. This is an estimate of the amount currently embedded in retail generation rates for losses and is credited against the transmission losses charged by PJM.

Q. How was the amount currently embedded in retail generation rates for losses calculated?

A. This amount was calculated by multiplying the retail load kWh by the transmission loss percentage to determine the embedded loss kWh. DP&L's most recent loss study establishes its transmission loss percentage at 2.7%. Then, the embedded loss kWh was multiplied by the Company's embedded fuel rate to determine the embedded fuel cost for the loss kWh. DP&L's latest estimate of its embedded fuel cost is 1.3 cents per kWh, as established in its last Electric Fuel Component ("EFC") case and later rolled into DP&L's current base generation rates.

IV. TCRR RATE DEVELOPMENT

Q. How did you develop the TCRR rates for each Tariff Class?

A. First, I took the net "current cycle" costs summarized in Schedule B-1, grossed them up by the Gross Revenue Conversion Factor, and allocated them across the Company's Tariff Classes using a ratio of the 2008 total transmission and ancillary services revenues by class, as shown in Workpaper C-2. The "current cycle" amounts reflect those forecasted amounts to be collected during the first year the TCRR is in place, May 2009 – April 2010.

Q. Why did you gross up the costs by a Gross Revenue Conversion Factor?

A. In order to collect the state tax which is based on revenues, I grossed up the net costs by multiplying them by a factor of 1.021. This is the same approach used in DP&L's ESP case, as summarized in DP&L's Application for Approval of its Electric Security Plan, Case Nos. 08-1094-EL-SSO, et al., Schedule A-4, column (C), line 28 and sponsored by Witness Hergenrather in that case. This approach was not modified by the Stipulation and recommendation which has been filed and entered into evidence, but not yet approved by the Commission.

Q. Schedule B-1 reflects a large increase in the "current cycle" net costs compared to the deferred net costs. Please explain.

A. The main difference between the historical net costs and those forecasted for the "current cycle" is that we have assumed the existing retail transmission and ancillary service rates/revenues will be replaced by the TCRR. In other words, during the deferral period the retail revenues received for transmission and ancillary services are netted against the TCRR costs from the PJM bills; these average approximately $5 million per month. Additionally, the Company is proposing to recover the deferred amount over twenty-four months, so only half of the total deferred amount is summarized in Schedule B-1. In addition, the deferral period is ten months compared to the twelve month "current cycle".

Q. What was the next step in developing the TCRR rates?

A. Next, I separated the TCRR components into those to be charged on an energy, demand, and reactive demand basis, as shown in Schedule C-3a. I then summed each of these components and divided by forecasted tariff class billing determinants to calculate the Base TCRR rates.

1 **Q. What do you mean by Base TCRR rates?**

2 A. The Base TCRR rates are the portion of the total TCRR rates that are intended to
3 recover the "current cycle" amounts described above.

4 **Q. How did you develop the forecasted billing determinants by tariff class?**

5 A. The Company does not currently forecast sales by tariff class; rather, sales are
6 forecasted by revenue class. Therefore, I first reviewed actual billing determinants
7 by revenue class and by tariff class from 2008. Using this relationship, I used the
8 Company's forecasted sales by revenue class to determine the forecasted sales
9 by tariff class. The total tariff class sales used in the development of the TCRR
10 rates matches the total Company forecasted sales (by revenue class), adjusted for
11 switching customers.

12 **Q. Why did you make these adjustments to the total Company sales forecast?**

13 A. The Company retail sales forecast includes all metered retail sales, therefore it
14 includes retail customers that take competitive retail electric service. Those billing
15 determinants were removed prior to developing the TCRR rates since DP&L is
16 proposing to charge only standard offer customers the TCRR.

17 **Q. What was your next step in developing the TCRR rates?**

18 A. I calculated the Incremental portion of the TCRR rates, which are intended to
19 recover the deferred amounts summarized in Schedule B-1. This was done in the
20 same manner as the rate development for the Base TCRR rates and is reflected in
21 Schedule C3-b. As described more fully in Witness Campbell's testimony, this

portion of the TCRR rate is proposed to recover the deferred TCRR net costs over twenty-four months.

Q. Will this Incremental portion of the TCRR rate be removed after the twenty-four months?

A. The Company plans to recover the deferred amounts during the proposed twenty-four months; however, we intend to keep in place this Incremental portion of the TCRR rate to recover any over/under collections on an on-going basis. Consistent with the provisions of OAC Chapter 4901:1-36 and Witness Campbell's testimony, the Company will to update the TCRR annually with actual costs/credits and this portion of the rate will remain to reflect that over/under collection.

Q. Can you summarize the total TCRR rates?

A. Yes. For each of DP&L's existing tariff classes, there will be a total TCRR rate, which is the sum of the Base and Incremental portions. As described above, certain amounts will be recovered on an energy, demand and reactive demand basis.

Schedule C-3 summarizes the proposed TCRR rates by class. In addition, Schedule B-5 shows typical bill comparisons.

Q. What is the typical bill impact of this filing on a residential customer that uses 750 kWh per month?

A. The TCRR for a Residential customer is $0.0085215/kWh and is included in the Transmission Related Charges portion of the bill. A customer using 750 kWh will experience a net increase of $3.05 on their monthly bill.

1 **V. TARIFF MODIFICATIONS**

2 **Q. What Tariff modifications to do you propose?**

3 A. The Company currently has the following retail Tariff Sheets that will be eliminated
4 and superseded by the proposed TCRR Tariff Sheet, T15:

5 T8 Retail Transmission Service
6 T9 Scheduling, System Control, and Dispatch Service
7 T10 Reactive Supply and Voltage Control Service
8 T11 Regulation and Frequency Response Service
9 T12 Operating Reserve – Spinning Reserve Service
10 T13 Operating Reserve – Supplemental Reserve Service
11 T14 PJM Administration Fee Rider

12 **Q. Were there any other Tariff modifications made?**

13 A. Yes. I removed the references to the Company's Transmission tariff sheets within
14 the Required Services portion of each of the Distribution Tariff Sheets. This was
15 updated to be consistent with current practices associated with shopping
16 customers. In other words, shopping customers are not required to take
17 transmission and ancillary services from the Company. In addition, I removed
18 outdated references to a Company Storm Rider.

19 **Q. Were the Required Services changed for Standard Offer customers?**

20 A. Yes. Within each of the Generation Standard Offer Service Tariff Sheets, I
21 modified the Required Services section to require those customers to take

1 transmission, ancillary, and RTO-related services from the Company under the
2 new TCRR Tariff Sheet, T15.

3 **VI. CONCLUSION**

4 **Q. Please summarize your testimony.**

5 A. In summary, DP&L is requesting permission to recover the current level of
6 forecasted retail jurisdictional RTO-related costs beginning May 1, 2009. These
7 amounts are designed to be recovered through the Base portion of the TCRR
8 rates.

9 The Company also requests permission to recover the April 30, 2009 deferred
10 retail jurisdictional RTO-related costs beginning May 1, 2009 over the twenty-four
11 month period ending April 30, 2011 with a carrying cost return on the unrecovered
12 balance. These amounts are designed to be recovered through the Incremental
13 portion of the TCRR rates.

14 The total TCRR rates are equal to the sum of the Base and Incremental portions
15 and will be charged on an energy, demand and reactive demand basis. The
16 Company plans to update these rates annually based on actual net costs.

17 **Q. Does this conclude your direct testimony?**

18 A. Yes, it does.

BEFORE THE

PUBLIC UTILITIES COMMISSION OF OHIO

THE DAYTON POWER AND LIGHT COMPANY
CASE NO. 09-256-EL-UNC

Transmission Cost Recovery Rider (TCRR)

DIRECT TESTIMONY

OF DAVID J. CRUSEY

- ☐ MANAGEMENT POLICIES, PRACTICES, AND ORGANIZATION
- ☐ OPERATING INCOME
- ☐ RATE BASE
- ☐ ALLOCATIONS
- ☐ RATE OF RETURN
- ☐ RATES AND TARIFFS
- ■ OTHER

BEFORE THE

PUBLIC UTILITIES COMMISSION OF OHIO

DIRECT TESTIMONY OF

DAVID J. CRUSEY

ON BEHALF OF
THE DAYTON POWER AND LIGHT COMPANY

TABLE OF CONTENTS

I. INTRODUCTION 1

II. CONGESTION HEDGING PROCESS 3

III. PJM RELIABILITY PRICING MODEL 6

IV. CONCLUSION 10

1 **I. INTRODUCTION**

2 **Q. Please state your name and business address.**

3 A. My name is David J. Crusey. My business address is 1065 Woodman Drive,
4 Dayton, Ohio.

5 **Q. By whom and in what capacity are you employed?**

6 A. I am employed by The Dayton Power and Light Company ("DP&L" or
7 "Company") as Director, Trading.

8 **Q. How long have you been in your present position?**

9 A. I have been working at my present position as Director, Trading since May 2007.
10 Prior to this position, I worked in various commercial wholesale commodity and
11 marketing roles for DP&L since 1995. From 1989 to 1995 I worked in various
12 engineering roles within DP&L's Engineering, Rates Department and Major
13 Account areas. I have approximately 20 years of energy industry experience at
14 DP&L.

15 **Q. What are your responsibilities in your current position and to whom do you**
16 **report?**

17 A. In my current position, I am responsible for managing DP&L's commodity
18 position for coal, power, emissions, natural gas and oil. I am also responsible for
19 DP&L's market functions within the PJM power pool as they relate to energy
20 markets, Auction Revenue Rights ("ARRs")/Financial Transmission Rights

("FTRs"), and the Reliability Pricing Model ("RPM"). I report to the Vice President, Commercial Operations.

Q. Will you describe briefly your educational and business background?

A. I received a Bachelor of Science degree in Electrical Engineering from the University of Dayton in 1989. I received a Masters Degree in Business Administration from the University of Dayton in 1993. I completed post Masters work in Finance at the University of Dayton in 1999. I am a CFA Charterholder as well as a certified Financial Risk Manager (FRM).

Q. Have you previously provided testimony before the Public Utilities Commission of Ohio ("PUCO" or the "Commission")?

A. No. However I have sponsored testimony on behalf of DP&L in a proceeding before the Federal Energy Regulatory Commission ("FERC").

Q. What testimony have you submitted before the FERC?

A. I sponsored testimony on behalf of DP&L in a case before the FERC involving a contract and billing dispute with a municipal aggregator.

Q. What is the purpose of your testimony?

A. The purpose of this testimony is twofold. I will first describe the PJM congestion hedging process and DP&L's proposal for sharing the charges and credits with its retail customers which may flow from that process. Next I will describe PJM's Reliability Pricing Model ("RPM") construct and the RPM related charges and

1 credits, and explain why inclusion of these RPM charges and credits in the TCRR
2 is appropriate.

3 **II. CONGESTION HEDGING PROCESS**

4 **Q. Please describe the PJM congestion hedging process.**

5 A. As a network transmission customer in PJM, DP&L has the right to request
6 congestion hedging instruments from PJM. These hedging instruments are
7 called Auction Revenue Rights ("ARRs") and Financial Transmission Rights
8 ("FTRs"). The purpose of these instruments is to provide a method to hedge the
9 congestion price risk associated with moving the Company's energy from its
10 generators to its load zone.

11 DP&L is compensated based on the Locational Marginal Price ("LMP") at each of
12 its generators for the energy it produces and DP&L pays PJM the LMP for its load
13 at the Dayton zone. This settlement is done on an hourly basis. Each PJM
14 network transmission customer has the right to request ARRs up to its peak load
15 amount during the annual PJM ARR allocation process. PJM determines the
16 amount of ARRs that are awarded based on its total system capability.

17 After this ARR allocation process is completed, PJM conducts an FTR auction in
18 which any market participant can attempt to buy or sell FTRs. The value of an
19 ARR is essentially the right to the revenue from the annual FTR auction for the
20 same source-sink ARR path. The value of an FTR in the annual FTR auction can
21 be either positive or negative. The holder of the ARR can then choose to simply
22 take the value from the FTR auction and receive dollars or it can use the dollar
23 proceeds to buy other FTRs in the annual FTR auction. An FTR holder can

either sell the FTR in a later auction or allow the FTR to settle each day in the day ahead energy market. Again, the value can be either positive or negative for the owner. The FTR clears or settles each day based on the day-ahead price difference between the source and sink location.

Q. What is the Company's overall approach to using ARRs/FTRs to hedge its congestion risk?

A. The Company is both an owner of generating assets as well as a network transmission customer and Load Serving Entity in PJM. It therefore has a right to request ARRs/FTRs, however, it also is exposed to congestion risk or price risk for the difference between the LMP at its generators and the LMP at its load zone. ARRs/FTRs are financial instruments that can be used to protect customers from significant cost exposure due to congestion. While a degree of protection can be achieved through a relatively passive process of requesting and holding ARRs/FTRs, a more active management, that involves investing people and resources offers opportunities to hedge risks and obtain additional benefits.

Q. Can you elaborate on the difference between what you refer to as a passive approach and a more active management approach?

A. Yes. This effort goes beyond the simple process that the Company would use to protect or "hedge" against congestion pricing risks. The simplest alternative for DP&L to take would be to select paths from its base load generators to its load zone. The ARRs/FTRs associated with these transmission paths could have either positive or negative values that move in the opposite direction of congestion prices. Thus, this approach hedges congestion risk by reducing the price risk between generators and load. It also means that when

congestion related costs decrease, any additional benefits are eliminated because the position has been hedged. This simple approach would not be financially optimal for either the Company or its customers. DP&L, therefore, invests people and resources to analyze and identify the transmission paths where ARRs/FTRs are likely to have positive values, and requesting or obtaining ARRs/FTRs on those paths. At the same time, DP&L would not request ARRs/FTRs on transmission paths where the associated ARRs/FTRs are likely to have a negative value. This is not an easy analytical exercise and requires an extensive knowledge of how power flows historically within PJM and how those flows may change during a given year due to transmission or generation outages, new construction, or shifts in load. The Company has been able to make this right and opportunity to obtain ARRs/FTRs profitable because it takes risks and invests resources in the process. The Company is proposing a method to share the risks and benefits with our customers through the TCRR.

Q. How does the Company propose to allocate costs and/or credits associated with the FTR and ARR hedging instruments?

A. The Company proposes a 50/50 sharing arrangement under which all of the congestion and FTR/ARR charges and credits will be shared equally between shareholders and retail customers.

Q. Why is this FTR/ARR costs/credits sharing arrangement proposed by the Company appropriate?

A. The 50/50 sharing arrangement proposed by the Company is appropriate. The opportunity to actively buy and sell ARRs and FTRs is a right the Company has and not an obligation. Sharing the charges and credits as proposed provides the proper incentive going forward for both the Company and its customers to continue to enhance revenues and decrease the net congestion costs. In addition, the Company invests resources and takes risks to increase the value of its ARR/FTR opportunity. The Company is proposing to split the related charges and revenues on a 50/50 basis, which allows for a sharing of value with customers, yet fairly compensates shareholders for the Company's resource investments.

III. PJM RELIABILITY PRICING MODEL

Q. Please describe the operation of the RPM construct as it exists today within PJM?

A. The reliability construct within PJM today is called the Reliability Pricing Model ("RPM"). RPM is best described by looking at generating units and load separately which is how RPM is administered by PJM. Generation owners within PJM are required to offer their units into the RPM auctions which take place three years in advance of the delivery year. These offers are binding on behalf of the owner and if the generating unit is "cleared" or sold in the auction the owner is financially committed for the auction period. PJM also conducts incremental auctions prior to the delivery year to allow a generation owner the ability to buy and sell RPM replacement resources in the event its position changes. Generators receive payments during the delivery year for generation that were "cleared" in that auction. PJM's RPM construct also can assess charges and

1 credits on generators based on certain testing and performance requirements. In
2 summary and in almost all circumstances, generation owners are required to
3 offer their generation into the RPM auctions, generators get paid if they clear the
4 market, and generators are subject to additional charges and credits associated
5 with actual performance.

6

7 Within RPM, each Load Serving Entity (LSE) in PJM is charged the locational
8 reliability charge for its load obligation. The LSE's load obligation is purchased
9 three years in advance of the delivery year. The LSE's role in RPM is a passive
10 function compared to the generator's active role. The LSE does not have to bid
11 or enter transactions in PJM's systems, or even contact PJM regarding its load.
12 PJM completes the load forecast for each LSE and buys the load for the LSE in
13 the auction. In its simplest terms, the LSE simply gets a bill from PJM.

14 **Q. Please describe the RPM charges and credits.**

15 A. DP&L pays a locational reliability charge for its load obligation in PJM. The rate
16 for the charge is determined in the RPM auction. The quantity of the charge is
17 PJM's peak load forecast for DP&L including a reliability reserve margin, and
18 control over this charge falls largely outside of DP&L's control. This charge is
19 included on each of DP&L's monthly PJM invoices.

20 Additionally, there are other RPM related charges and credits that PJM can
21 assess:

1) Capacity Resource Deficiency Charge and Credit. This is assessed for instances when a generator cannot meet the capacity amount it offered and committed to in the auction. The shortfall can be due to a decrease in capacity or from an increase in the units forced outage rate. The Resource Deficiency can also result in a credit when generators at other entities pay the charge and these payments are then allocated back to LSEs.

2) Generation Resource Rating Test Charge and Credit. This charge or credit involves the summer and winter capacity test levels committed to by the generator in the auction. Again, depending on the performance of the specific generator and the other generators in PJM, this can be either a charge or a credit.

3) Peak Hour Period Availability Charge and Credit. PJM charges a generator if its performance during the peak hours in the summer and winter periods is lower than its performance of the same measure for the average of the past five years. Likewise, if a generator's performance is higher than its average five year history, the generator can receive a credit. In 2008 for the 2007/08 delivery year, DP&L received a credit from PJM of $650,000 for the Peak Hour Period Availability Credit for its entire generation portfolio. In summary, these additional RPM items can be either a charge or credit, both of which will be included in the TCRR.

Q. Why does PJM assess DP&L these RPM charges and credits?

A. PJM's RPM construct is focused on reliability. The LSE's pay the locational reliability charge to ensure that there are sufficient resources available across peak periods to ensure the reliability of the system. Without adequate RPM

generating resources, including the reserve margin, the overall reliability of the grid and therefore reliability to DP&L's customers can not be maintained. The RPM construct in PJM results in DP&L's customers needing fewer resources to be served reliably because DP&L's peak is not typically coincident with the PJM peak load and the reliability risks associated with generator outages are spread across PJM. Generators in PJM receive payments to compensate them and create an incentive to build and/or to maintain their resources over time. Together, this facilitates the overall goal of maintaining reliability in the PJM system. Thus, the RPM charges and credits DP&L seeks to include in the TCRR are incurred in large part to ensure reliability of service for DP&L's customers. An important part of PJM's RPM construct involves having adequate resources located in places where it is deliverable to loads in an amount sufficient to meet peak system conditions. RPM was implemented to ensure the reliability of the grid. DP&L, as a member of PJM, has a requirement to participate in the RPM construct to support the reliability of the transmission grid.

Q. Are there any RPM related credits the Company will be including or "crediting" back to retail customers through the TCRR?

A. Yes. The Company is proposing to include the payments (RPM Auction Credits) it receives from PJM as a credit in the TCRR. The effect of this is that DP&L's customers are paying the locational reliability charge for their load and they are also receiving the payments from the RPM auction from the DP&L generators. The customers will also receive the charges and credits that are associated with RPM for the DP&L generators as explained earlier. As is the case with the

1 administration of the transmission, transmission-related, congestion, and ancillary
2 costs, the RPM costs will be netted with the RPM revenues.

3 **Q. Are these RPM charges and credits related to reliability?**

4 A. Yes. The entire RPM construct and therefore all RPM charges are reliability
5 related. The focus of RPM is to ensure sufficient generation for load and to
6 maintain the current and future reliability of the transmission grid. The RPM
7 requirements thus facilitate a reliable transmission grid, and the related charges
8 imposed on LSEs by PJM are a critical part of system reliability and are
9 inherently linked to transmission related charges. The RPM charges and credits
10 imposed by PJM—like transmission-related costs—help ensure reliability of the
11 grid.

12 **Q. Why should RPM related charges and credits be included in the TCRR?**

13 A. In addition to the reasons stated by Witness Schroder in her testimony, RPM
14 related charges and credits should be included in the TCRR because RPM
15 charges and credits are part of the cost of providing for reliable grid operations
16 for our customers. These charges and credits are a mandatory element of our
17 participation in PJM. RPM related charges and credits flow through a common
18 PJM bill with other grid related costs.

19 **IV. <u>CONCLUSION</u>**

20 **Q. Please summarize your testimony.**

21 A. In summary, DP&L is proposing to share its net ARR/FTR and congestion
22 charges and credits on a 50/50 basis between the Company and its retail

1 customers. The Company is proposing a shared benefit approach that will
2 continue to incent the Company to pursue and maximize its ARR/FTR
3 opportunities while at the same time lowering the cost of electricity for its
4 customers. The ARR/FTR decision the Company makes is a right and an
5 opportunity, not an obligation. The proposed structure is appropriate in terms of
6 equity and incentives.

7 The Company is also requesting the recovery of the net RPM related charges
8 and credits associated with DP&L's retail load obligation and generating units.
9 The TCRR impact is therefore the net of the RPM credits DP&L receives and the
10 RPM charges the Company incurs. PJM's RPM construct is focused on
11 maintaining the reliability of the transmission grid. Including the RPM related
12 charges and credits in the TCRR is both administratively expedient and
13 appropriate because these PJM-imposed charges and credits relate to functions
14 which, like transmission functions, are critical for grid reliability.

15 **Q. Does this conclude your direct testimony?**

16 A. Yes, it does.