

Line No.	(a)	(b)	(c)	(d)
		2005 Actual	U-14275 2005 Plan	2005 Variance
1				
2	Generation & Fuel			
3	- GWh	50,075	51,070	(995)
4	- \$1,000	\$ 750,616	\$ 693,888	\$ 56,728
5	- \$/MWh	\$ 14.99	\$ 13.59	\$ 1.40
6				
7	Ludington Losses			
8	- GWH	(566)	(501)	(65)
9				
10	Emission Allowance			
11	NOx - \$1,000	\$ 14,515	\$ 2,366	\$ 12,149
12				
13	Purchased Power			
14	- GWh	6,377	4,724	1,653
15	- \$1,000	\$ 573,841	\$ 216,371	\$ 357,470
16		\$ 89.99	\$ 45.80	\$ 44.18
17	Third Party Wholesale Power Sales & Energy Imbalance Credit			
19	- GWh	5,217	5,919	(702)
20	- \$1,000	\$ 379,815	\$ 246,142	\$ 133,673
21		\$ 72.80	\$ 41.59	\$ 31.22
22	Bundled Transmission			
23	- \$1,000	\$ 187,354	\$ 205,283	\$ (17,929)
24				
25	Detroit Edison System NSO			
26	- GWh	50,669	49,374	1,295
27	- \$1,000	\$ 1,146,511	\$ 871,766	\$ 274,745
28	- \$/MWh	\$ 22.63	\$ 17.66	\$ 4.97
29				
30	Wolverine Adjustment			
31	- GWh	1,743	1,743	-
32	- \$1,000	\$ 32,999	\$ 23,531	\$ 9,468
33				
34	R-10 Adjustment			
35	Energy - GWh	1,441	1,416	25
36	- \$1,000	\$ 53,151	\$ 36,583	\$ 16,568
37	Transmission - \$1,000	\$ 5,328	\$ 6,347	\$ (1,018.6)
38				
39	PSCR Fuel & Purchase Power			
40	- GWh	47,485	46,215	1,270
41	- \$1,000	\$ 1,055,032	\$ 821,312	\$ 233,721
42	- \$/MWh	\$ 22.22	\$ 17.77	\$ 4.45

Michigan Public Service Commission
The Detroit Edison Company
2005 Electric Generation By Plant

Case No.: U-14275-R
Exhibit A-2 (JHB-2)
Page: 1 of 1
Witness : J. H. Byron

	(a)	(b)	(c)	(d)	(e)
Line No.	Plant	Primary Fuel Type	Actual Generation (GWh)	U-14275 2005 Plan (GWh)	Variance (GWh)
1					
2	Belle River ⁽¹⁾	Coal	6,684	7,059	(375)
3	Conners Creek	Gas/Oil	78	6	72
4	Fermi 2	Nuclear	8,754	9,452	(698)
5					
6	Greenwood	Gas/Oil	659	296	363
7					
8	Harbor Beach	Coal	357	281	76
9					
10	Monroe	Coal	18,711	18,557	154
11					
12	River Rouge	Coal	2,939	2,898	41
13					
14	St. Clair	Coal	7,378	7,757	(379)
15					
16	Trenton Channel	Coal	4,227	4,385	(158)
17					
18	Peakers	Gas/Oil	287	379	(92)
19					
20	Total System		50,075	51,070	(995)
21					
22	Ludington Loss	Generation	1,478	1,158	320
23		Pumping	2,043	1,659	384
24		Net	(566)	(501)	(65)

(1) DECo Ownership Share.

Line No.	(a) Plant	(b) Net Demonstrated Operating Capability (Winter) (MW)	(c) 2005 Actual Capacity Factor (%)	(d) U-14275 2005 Plan Capacity Factor ⁽²⁾ (%)	(e) Variance (%)
1					
2	Belle River 1 ⁽¹⁾	509	78.9	83.8	(4.9)
3	Belle River 2 ⁽¹⁾	517	68.9	73.3	(4.4)
4					
5	Conners Creek	215	4.2	0.3	3.9
6					
7	Fermi	1131	88.4	95.4	(7.0)
8					
9	Greenwood	785	9.6	4.3	5.3
10					
11	Harbor Beach	103	39.6	31.2	8.4
12					
13	Marysville	84	0.0	0.0	0.0
14					
15	Monroe 1	770	69.6	74.5	(4.9)
16	Monroe 2	795	56.8	52.6	4.2
17	Monroe 3	795	70.6	71.1	(0.5)
18	Monroe 4	775	75.8	72.5	3.3
19					
20	River Rouge 2	247	77.3	69.3	8.0
21	River Rouge 3	280	51.7	57.0	(5.3)
22					
23	St. Clair 1	153	57.2	49.5	7.7
24	St. Clair 2	162	53.4	47.0	6.4
25	St. Clair 3	171	50.1	56.9	(6.8)
26	St. Clair 4	158	62.5	59.8	2.7
27	St. Clair 6	321	67.6	72.2	(4.6)
28	St. Clair 7	450	60.0	68.9	(8.9)
29					
30	Trenton Channel H.P.	210	64.9	55.7	9.2
31	Trenton Channel 9	520	66.6	73.8	(7.2)
32					
33	Peakers	1371	2.4	3.15	(0.7)
34					
35	Ludington (generation)	917	18.4	14.4	4.0
36					
37	Total System	11439	50.0	52.3	(2.4)
38					
39					

40 (1) Detroit Edison Ownership Portion
41 (2) Based on Winter Capability

Michigan Public Service Commission
The Detroit Edison Company
2005 Purchases of Power and Energy Summary

Case No.:
Exhibit No.:
Page:
Witness:

U-14275-R
A-4 (JHB-4)
1 of 1
J. H. Byron,
M.W.Shields

Line No.	(a) Purchases	(b) 2005 Actual	(c) U-14275 2005 Plan	(d) 2005 Variance
1				
2	Wholesale			
3	- GWh	1,425	3,090	(1,665)
4	- \$1,000	\$ 88,155	\$ 108,996	\$ (20,841)
5				
6	MISO Energy Purchases			
7	- GWh	3,306		3,306
8	- \$1,000	\$ 354,061		\$ 354,061
9				
10	Sub-total Wholesale + MISO			
11	- GWh	4,731	3,090	1,641
12	- \$1,000	\$ 442,216	\$ 108,996	\$ 333,220
13				
14	Energy Imbalance			
15	- GWh	321		321
16	- \$1,000	\$ 15,806		\$ 15,806
17				
18	Summer Contracts (5x16)			
19	- MW	0	500	(500)
20	- GWh	0	529	(529)
21	- \$1,000	\$ -	\$ 30,558	\$ (30,558)
22				
23	Summer Calls			
24	- MW	1,685	1,344	341
25	- GWh	787	325	462
26	Energy - \$1,000	\$ 62,486	\$ 23,883	\$ 38,603
27	Premium - \$1,000	\$ 15,643	\$ 12,823	\$ 2,820
28				
29	Transmission & Other			
30	- \$1,000	\$ 1,824	\$ -	\$ 1,824
31				
32	PURPA Qualifying Facilities			
33	- GWh	539	780	(241)
34	- \$1,000	\$ 28,428	\$ 40,111	\$ (11,683)
35				
36	MISO Energy Market			
37	- \$1,000	\$ 7,439	\$ 16,008	\$ (8,569)
38				
39	Total Purchases			
40	- GWh	6,377	4,724	1,653
41	- \$1,000	\$ 573,841	\$ 232,379	\$ 341,462
42		\$ 89.99	\$ 49.19	

Michigan Public Service Commission
The Detroit Edison Company
2005 Summary of Third Party Wholesale Power Sales

Case No.:
Exhibit No.:
Page:
Witness:

U-14275-R
A-5 (JHB-5) REVISED
1 of 1
J. H. Byron

Line No.	(a) Sales	(b) 2005 Actual	(c) U-14275 2005 Plan	(d) 2005 Variance
1				
2	Wholesale Spot			
3	- GWh	3,875	5,919	(2,044)
4	- \$1,000	\$ 198,308	\$246,142	\$ (47,834)
5				
6	MISO Energy Sales			
7	- GWh	1,300		1,300
8	- \$1,000	\$ 180,786	\$ -	\$ 180,786
9				
10	Third Party Sales			
11	- GWh	5,175	5,919	(744)
12	- \$1,000	\$ 379,094	246,142	\$ 132,952
13				
14	Energy Imbalance Credit			
15	- GWh	42		42
16	- \$1,000	\$ 721		\$ 721
17				
18				
19	Third Party + Energy Imbalance			
20	- GWh	5,217	5,919	(702)
21	- \$1,000	\$ 379,815	\$ 246,142	\$ 133,673
22		\$ 72.80	\$ 41.59	
23				
24				

Line No.	(a)	(b)	(c)	(d)	(e)	(e)	(f)	(g)
1	2005 PSCR Plan Forward Market Power Price				MECS			
2		On-Peak	Off-Peak			(Cinergy + \$3.4)		
3		<u>Average</u>	<u>Average</u>	<u>Avg RTC</u>	<u>On-Peak</u>	<u>Off-Peak</u>	<u>Avg RTC</u> ⁽²⁾	
4	Jan-05	\$53.30	\$32.38	\$42.42	\$52.31	\$33.27	\$42.34	
5	Feb-05	\$53.30	\$32.38	\$42.42	\$49.52	\$30.49	\$39.55	
6	Mar-05	\$50.30	\$28.88	\$39.16	\$56.60	\$36.24	\$45.94	
7	Apr-05	\$50.30	\$28.88	\$39.16	\$56.78	\$30.85	\$43.20	
8	May-05	\$47.38	\$24.75	\$35.61	\$48.44	\$24.96	\$36.14	
9	Jun-05	\$51.13	\$25.63	\$37.87	\$65.93	\$30.50	\$47.36	
10	Jul-05	\$61.25	\$29.63	\$44.81	\$77.36	\$42.50	\$59.10	
11	Aug-05	\$61.25	\$29.63	\$44.81	\$88.02	\$45.45	\$65.72	
12	Sep-05	\$45.88	\$24.88	\$34.96	\$85.75	\$41.72	\$62.69	
13	Oct-05	\$43.53	\$26.25	\$34.54	\$77.42	\$38.17	\$56.86	
14	Nov-05	\$43.53	\$26.25	\$34.54	\$61.42	\$38.17	\$50.84	
15	Dec-05	\$43.53	\$26.25	\$34.54	\$86.81	\$38.17	\$69.77	
16								
17	Annual ⁽¹⁾	\$50.39	\$27.98	\$38.74	\$67.20	\$35.87	\$51.62	
18	April-December ⁽¹⁾	\$49.75	\$26.90	\$37.87	\$71.99	\$36.72	\$54.63	
19								
20	June - December ⁽¹⁾	\$50.01	\$26.93	\$38.01	\$77.53	\$39.24	\$58.91	
21								
22								
23		Actual DECO Load Node LMP			Real Time			
24		<u>On-Peak</u>	<u>Off-Peak</u>	<u>Avg RTC</u>	<u>On-Peak</u>	<u>Off-Peak</u>	<u>Avg RTC</u>	
25	Apr-05	\$57.41	\$30.67	\$43.15	\$54.94	\$32.41	\$42.92	
26	May-05	\$44.52	\$23.06	\$33.07	\$45.59	\$23.39	\$33.75	
27	Jun-05	\$72.18	\$35.48	\$53.42	\$63.30	\$33.32	\$47.97	
28	Jul-06	\$80.93	\$46.16	\$61.11	\$79.39	\$45.11	\$59.85	
29	Aug-05	\$88.09	\$46.50	\$67.08	\$91.02	\$48.92	\$69.74	
30	Sep-05	\$88.66	\$42.10	\$63.83	\$84.76	\$40.35	\$61.08	
31	Oct-05	\$82.64	\$36.03	\$57.08	\$82.21	\$39.47	\$58.77	
32	Nov-05	\$59.20	\$34.75	\$46.16	\$57.91	\$32.74	\$44.49	
33	Dec-05	\$86.84	\$48.57	\$65.85	\$81.70	\$45.62	\$61.92	
34								
35	April-December	\$73.39	\$38.15	\$54.53	\$71.20	\$37.93	\$53.39	
36								
37	June - December ⁽¹⁾	\$79.79	\$41.37	\$59.22	\$77.18	\$40.79	\$57.69	
38								
39		Actual Michigan Hub LMP			Real Time			
40		<u>On-Peak</u>	<u>Off-Peak</u>	<u>Avg RTC</u>	<u>On-Peak</u>	<u>Off-Peak</u>	<u>Avg RTC</u>	
41	Apr-05	\$57.07	\$30.51	\$42.91	\$54.51	\$34.50	\$43.84	
42	May-05	\$44.26	\$22.96	\$32.90	\$44.74	\$22.82	\$33.05	
43	Jun-05	\$70.65	\$34.94	\$52.40	\$61.65	\$32.13	\$46.56	
44	Jul-06	\$79.33	\$45.57	\$60.09	\$79.28	\$43.24	\$58.74	
45	Aug-05	\$87.08	\$45.96	\$66.30	\$87.44	\$46.72	\$66.86	
46	Sep-05	\$88.01	\$41.98	\$63.46	\$83.67	\$40.42	\$60.60	
47	Oct-05	\$82.78	\$36.09	\$57.17	\$82.04	\$39.42	\$58.67	
48	Nov-05	\$59.66	\$34.67	\$46.33	\$57.90	\$32.65	\$44.44	
49	Dec-05	\$86.11	\$48.23	\$65.34	\$80.91	\$45.36	\$61.42	
50								
51	April-December	\$72.77	\$37.88	\$54.10	\$70.24	\$37.47	\$52.68	
52								
53	June - December ⁽¹⁾	\$79.09	\$41.06	\$58.73	\$76.13	\$39.99	\$56.75	
54								

(1) Simple monthly average

(2) Average calculated as 80 hours on-peak & 88 hours off-peak per week

Line No.	(a)	(b)	(c)		(d)	(e)
			Actual			U-14275
			June-Sept 2004	May-Sept 2005		2005 Plan May - Sept 2005
1	Fossil Fuel Generation	GWh	13,707	18,496		17,283
2						
3	Beginning Balance of Allowances	Tons	7,265	8,061		5,521
4						
5	DECo Annual Allocation From EPA (Excluding Belle River)	Tons	16,273	16,273		16,273
6	Allowances Purchased before respective vintage year	Tons		725		725
7	Purchase of Allowances	Tons	450	6,062		
8	swap		2,836	(3,202)		-
9	Total Available Allowance	Tons	26,824	27,919		22,519
10						
11	Expected Allowances to be Consumed	Tons	(18,763)	(24,302)		(18,885)
12						
13	Banked Tons from Prior Year	Tons		4,811		5,521
14	Banked Allowances needed to cover consumption	Tons		1,194		1,887
15	Flow Control Value	%		0.25		0.25
16	Banked Tons for use at 1:1	Tons		1,203		1,380
17	Banked Tons for use at 2:1	Tons		3,608		4,141
18						
19	Banked Tons used at 1:1	Tons		1,194		1,380
20	Banked Tons used at 2:1	Tons				1,013
21	Banked Tons used	Tons		1,194		2,394
22						
23	Tons Lost to Flow Control	Tons				507
24						
25	Ending Balance	Tons	8,061	3,616		3,127
26						
27						
28	Beginning Balance of Allowances	\$000	\$ 1,529	\$ 1,307		\$ 365
29						
30	DECo Annual Allocation From EPA (Excluding Belle River)	\$000				\$ -
31	Allowances Purchased before respective vintage year	\$000	\$ 7	\$ 2,387		\$ 2,382
32	Purchase of Allowances	\$000	\$ 1,021	\$ 16,098		
33	Swap	\$000				\$ -
34						
35	Total Available Allowance	\$000	\$ 2,562	\$ 19,792		\$ 2,747
36						
37	Expected Allowances to be Consumed	\$000	\$ (1,250)	\$ (14,515)		\$ (2,304)
38	Flow Control Allowances Consumed					\$ (62)
39						
40	Total Allowances Consumed	\$000	\$ (1,250)	\$ (14,515)		\$ (2,366)
41						
42	Ending Balance Current NOx Allowances Asset Account	\$000	\$ 1,307	\$ 5,277		\$ 382
43						
44						
45	DECo Annual Allocation From EPA (Excluding Belle River)	\$/Ton				
46	Allowances Purchased before respective vintage year	\$/Ton		\$ 3,293		\$ 3,286
47	Purchase of Allowances	\$/Ton	\$ 2,268	\$ 2,571		\$ -
48						\$ -
49	Total Average Cost of Available Allowances	\$/Ton	\$ 162	\$ 1,459		\$ 122

Line No.	(a)	(b) Equivalent Availability Factor (%)	(c) Forced Rate (%)	(d) Derate Rate (%)	(e) Force + Derate (%)	(f) Periodic Rate (%)	(g) Plant Generation (GWh)
1							
2	2001	82.4	6.2	2.7	8.9	8.6	48,598
3							
4	2002	81.3	6.5	3.4	9.8	8.9	48,723
5							
6	2003	81.8	7.1	3.8	10.9	7.4	46,659
7							
8	2004	85.2	4.7	3.2	7.9	6.9	48,420
9							
10	Average 2001 - 2004	82.7	6.1	3.3	9.4	7.9	48,100
11							
12	2005	83.8	7.5	2.9	10.4	5.8	50,075
13							
14	2005 Adjusted For Belle River 2,	85.3	5.9	2.9	8.8	5.8	
15	River Rouge 3 and Fermi Outages						

2005 PSCR Periodic Maintenance

Week Starting	Jan					Feb				Mar				Apr				May					Jun				Jul				Aug				Sep				Oct					Nov				Dec							
	2	9	16	23	30	6	13	20	27	6	13	20	27	3	10	17	24	1	8	15	22	29	5	12	19	26	3	10	17	24	7	14	21	28	4	11	18	25	2	9	16	23	30	6	13	20	27	4	11	18	25				
Belle River 1						FC												FC																	FC																				
Belle River 2			FC															FC																	4 Week Boiler Periodic																				
Connors Creek										12 Week Periodic Boiler, RH, SH, Gen Rewind																																													
Greenwood										12 Week Periodic Boiler, RH, SH, Gen Rewind																																													
Harbor Beach																						FC																																	
Monroe 1												FC																																											
Monroe 2						12 Week Periodic SSH, HP,IP,LP Turbine																																																	
Monroe 3																						FC																																	
Monroe 4													FC																																		4 Week Boiler Periodic								
River Rouge 2		FC	FC	FC																																																			
River Rouge 3													FC																		11 Week Periodic Boiler, Turbine, RH & Bullnose Tubes																								
St. Clair 1	12 Week Periodic LNB, DCS, Turbine, Boiler																																																						
St. Clair 2												FC																			10 Week Periodic LNB, DCS, Boiler																								
St. Clair 3												FC																																											
St. Clair 4													FC																																										
St. Clair 6																																																							
St. Clair 7					FC																																																		
Trenton 7																																																							
Trenton 8										4 Week Boiler Periodic																																													
Trenton 9																						FC																																	
Ludington																																															U1 Gen Inspection								
Fermi 2																																																							

Note: Outages are shown for full weeks only, starting on Sundays.
 Typically the outage will start the Friday evening prior to the date shown.

2005 Actual Periodic Maintenance from P3M

Week Starting	Jan					Feb				Mar				Apr				May					Jun				Jul				Aug				Sep				Oct					Nov				Dec						
	2	9	16	23	30	6	13	20	27	6	13	20	27	3	10	17	24	1	8	15	22	29	5	12	19	26	3	10	17	24	7	14	21	28	4	11	18	25	2	9	16	23	30	6	13	20	27	4	11	18	25			
Belle River 1	FC																				FC																																	
Belle River 2						FC																																	5 Week Boiler Periodic															
Connors Creek										12 Week Periodic Boiler, RH, SH, Gen Rewind																																												
Greenwood										12 Week Periodic Boiler, RH, SH, Gen Rewind																																												
Harbor Beach																		FC																																				
Monroe 1										11 Week Periodic SSH, HP, IP, LP Turbine																																												
Monroe 2										11 Week Periodic SSH, HP, IP, LP Turbine																			SR																									
Monroe 3										FC	FC																																											
Monroe 4																																																						
River Rouge 2																					FC																																	
River Rouge 3																		FC																	9 Week Periodic Boiler, Turbine, RH & Bullnose Tubes																			
St. Clair 1										Turbine Valves																																												
St. Clair 2														FC																																								
St. Clair 3																																																						
St. Clair 4																																																						
St. Clair 6																																																						
St. Clair 7																																																						
Trenton 7																																			4 Week Boiler Periodic																			
Trenton 8																																			4 Week Boiler Periodic																			
Trenton 9																																																						
Ludington						U4 Gen Inspection										U1 Gen Inspection																																						
Fermi 2																																							U2 Gen Inspection															

Note: Outages are shown for full weeks only, starting on Sundays.
 Typically the outage will start the Friday evening prior to the date shown.

The Detroit Edison Company
Schedule of Power Supply Costs other than Fuel
For the year ended December 31, 2005

MPSC Case No. U-14275-R
Exhibit No. A-11 (SMD-1)
Witness: S.M. DiGaetano
Page 1 of 1

Third Party Wholesale Revenue													(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
Line no.	Account 447	January	February	March	April	May	June	July	August	September	October	November	December	Total										
1	1 Month	\$ 38,349,858	\$ 24,792,899	\$ 16,130,260	\$ 14,074,440	\$ 11,221,761	\$ 8,526,961	\$ 20,604,146	\$ 17,758,414	\$ 11,302,769	\$ 12,397,092	\$ 11,393,026	\$ 12,697,276	\$ 199,248,904										
2	MISO Market Revenue				6,083,010	7,632,872	28,950,702	25,061,022	27,392,252	37,232,886	17,375,121	3,441,958	27,616,670	180,786,492										
3	Monthly Total	\$ 38,349,858	\$ 24,792,899	\$ 16,130,260	\$ 20,157,450	\$ 18,854,633	\$ 37,477,664	\$ 45,665,168	\$ 45,150,666	\$ 48,535,655	\$ 29,772,213	\$ 14,834,984	\$ 40,313,946	\$ 380,035,396										
4																								
5	Year-to-Date	\$ 38,349,858	\$ 63,142,757	\$ 79,273,017	\$ 99,430,467	\$ 118,285,100	\$ 155,762,763	\$ 201,427,931	\$ 246,578,598	\$ 295,114,253	\$ 324,886,466	\$ 339,721,450	\$ 380,035,396											
6																								
7	Purchased Power and Transmission Expense																							
8	Account 555 - Purchase Power																							
9																								
10	1 Month	\$ 41,462,532	\$ 12,290,742	\$ 19,065,336	\$ 8,198,659	\$ 7,384,207	\$ 23,636,296	\$ 47,751,557	\$ 34,385,139	\$ 10,636,055	\$ 3,291,929	\$ 3,596,772	\$ 2,345,366	\$ 214,044,591										
11	MISO Market Expenses				8,270,950	15,448,459	48,607,352	60,389,220	59,850,501	74,720,093	49,499,688	8,476,599	26,024,233	351,287,094										
12	MISO Market Administrative Charges				909,723	900,726	888,660	1,088,934	1,216,148	622,117	506,214	735,463	571,362	7,439,347										
13	Schedule 7 & 8		4,856		7,158		1,054,915	543,258	(539,740)					1,070,446										
14	Schedule 16 & 17 Deferral				(354,792)	(351,283)	(346,578)	(424,684)	(474,298)	(242,626)	(197,424)	(230,701)	(150,830)	(2,773,214)										
15	Monthly Total	\$ 41,462,532	\$ 12,295,598	\$ 19,065,336	\$ 17,031,698	\$ 23,382,109	\$ 73,840,646	\$ 109,348,284	\$ 94,437,750	\$ 85,735,640	\$ 53,100,408	\$ 12,578,133	\$ 28,790,131	\$ 571,068,265										
16																								
17	Year-to-Date	\$ 41,462,532	\$ 53,758,130	\$ 72,823,466	\$ 89,855,165	\$ 113,237,274	\$ 187,077,920	\$ 296,426,203	\$ 390,863,953	\$ 476,599,593	\$ 529,700,001	\$ 542,278,134	\$ 571,068,265											
18																								
19																								
20	Account 565 - Transmission																							
21																								
22	1 Month	\$ 11,189,833	\$ 10,278,494	\$ 10,518,651	\$ 9,367,741	\$ 10,169,403	\$ 17,270,530	\$ 17,672,149	\$ 18,917,202	\$ 15,884,145	\$ 13,202,042	\$ 13,673,947	\$ 12,148,721	\$ 160,292,857										
23	Deferred Charges	(1,442,726)	(1,059,316)	(1,317,827)	(1,191,301)	(1,243,462)	(2,078,107)	(2,149,572)	(2,354,685)	(2,210,708)	(1,718,695)	(2,213,672)	(712,577)	(19,692,648)										
24	Monthly Total	\$ 9,747,107	\$ 9,219,178	\$ 9,200,824	\$ 8,176,440	\$ 8,925,941	\$ 15,192,423	\$ 15,522,577	\$ 16,562,517	\$ 13,673,436	\$ 11,483,347	\$ 11,460,274	\$ 11,436,145	\$ 140,600,209										
25																								
26	Year-to-Date	\$ 9,747,107	\$ 18,966,285	\$ 28,167,109	\$ 36,343,549	\$ 45,269,490	\$ 60,461,913	\$ 75,984,489	\$ 92,547,006	\$ 106,220,443	\$ 117,703,790	\$ 129,164,064	\$ 140,600,209											
27																								
28	Account 566 - Transmissior																							
29																								
30	1 Month	\$ 2,701,861	\$ 2,563,796	\$ 5,973,328	\$ 1,844,375	\$ 1,823,425	\$ 1,509,387	\$ 2,136,734	\$ 2,265,014	\$ 2,082,054	\$ 1,753,928	\$ 1,814,534	\$ 1,663,503	\$ 28,131,940										
31	Deferred Charges	(1,055,683)	(933,164)	(2,336,006)	(683,528)	(672,136)	(549,660)	(794,326)	(792,544)	(721,189)	(593,221)	(616,857)	(236,240)	(9,984,554)										
32	Monthly Total	\$ 1,646,178	\$ 1,630,632	\$ 3,637,322	\$ 1,160,847	\$ 1,151,289	\$ 959,727	\$ 1,342,408	\$ 1,472,470	\$ 1,360,864	\$ 1,160,708	\$ 1,197,677	\$ 1,427,263	\$ 18,147,386										
33																								
34	Year-to-Date	\$ 1,646,178	\$ 3,276,810	\$ 6,914,132	\$ 8,074,979	\$ 9,226,268	\$ 10,185,995	\$ 11,528,403	\$ 13,000,874	\$ 14,361,738	\$ 15,522,446	\$ 16,720,123	\$ 18,147,386											
35																								
36	Total Transmission Expense																							
37																								
38	1 Month	\$ 13,891,693	\$ 12,842,290	\$ 16,491,979	\$ 11,212,116	\$ 11,992,828	\$ 18,779,917	\$ 19,808,883	\$ 21,182,217	\$ 17,966,198	\$ 14,955,970	\$ 15,488,481	\$ 13,812,224	\$ 188,424,797										
39	Schedule 7 & 8	-	(4,856)	-	(7,158)	-	(1,054,915)	(543,258)	539,740	-	-	-	-	(1,070,446)										
40	Deferred Charges	(2,498,409)	(1,992,480)	(3,653,833)	(1,874,829)	(1,915,597)	(2,627,768)	(2,943,899)	(3,147,230)	(2,931,898)	(2,311,915)	(2,830,529)	(948,816)	(29,677,202)										
41	Monthly Total	\$ 11,393,285	\$ 10,844,955	\$ 12,838,146	\$ 9,330,129	\$ 10,077,230	\$ 15,097,235	\$ 16,321,727	\$ 18,574,727	\$ 15,034,301	\$ 12,644,055	\$ 12,657,951	\$ 12,863,408	\$ 157,677,148										
42																								
43	Year-to-Date	\$ 11,393,285	\$ 22,238,239	\$ 35,076,385	\$ 44,406,514	\$ 54,483,745	\$ 69,580,979	\$ 85,902,707	\$ 104,477,434	\$ 119,511,734	\$ 132,155,789	\$ 144,813,741	\$ 157,677,148											

The Detroit Edison Company
Transmission Expense by Month
For the year ended December 31, 2005

MPSC Case No. U-14275-R
Exhibit No. A-12 (SMD-2)
Witness: S.M. DiGaetano
Page 1 of 1

Network Transmission

Line No.		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
		Schedule 1	Schedule 2 (FESC)	Schedule 7	Schedule 8	Schedule 9	Total for Network Transmission	Schedule 2 (FESC) Deferred	Schedule 9 Deferred	Net Network Transmission
1	January	\$ 347,500	\$ -	\$ -	\$ 0	\$ 10,842,332	\$ 11,189,833	\$ -	\$ 1,442,726	\$ 9,747,107
2	February	329,799	-	-	4,856	9,943,839	10,278,494	-	1,059,316	9,219,178
3	March	367,625	-	-	-	10,151,026	10,518,651	-	1,317,827	9,200,824
4	April	252,796	-	-	7,158	9,107,787	9,367,741	-	1,191,301	8,176,440
5	May	326,264	-	-	-	9,843,138	10,169,403	-	1,243,462	8,925,941
6	June	554,118	-	1,054,915	-	15,661,497	17,270,530	-	2,078,107	15,192,423
7	July	558,618	306,621	543,258	-	16,263,652	17,672,149	119,582.08	2,029,990	15,522,577
8	August	635,038	240,026	(539,740)	-	18,581,877	18,917,202	93,610.24	2,261,075	16,562,517
9	September	521,337	172,805	-	-	15,190,003	15,884,145	67,393.81	2,143,315	13,673,436
10	October	458,301	97,679	-	-	12,646,062	13,202,042	38,094.86	1,680,600	11,483,347
11	November	394,002	254,717	-	-	13,025,227	13,673,947	99,339.75	2,114,333	11,460,274
12	December	388,070	103,607	-	-	11,657,045	12,148,721	31,470.34	681,106	11,436,145
13										
14	Total	\$ 5,133,470	\$ 1,175,455	\$ 1,058,433	\$ 12,014	\$ 152,913,486	\$ 160,292,857	\$ 449,491	\$ 19,243,157	\$ 140,600,209

Administrative and other Transmission Charges

Line No.						Total Administrative	Schedule 10	Schedule 18	Schedule 22	Net Administrative
		Schedule 10	Schedule 18	Schedule 22	FERC Charges	and Other	Deferred	Deferred	Deferred	and Other
19	January	\$ 706,716	\$ 83,333	\$ 1,811,812	\$ 100,000	\$ 2,701,861	\$ 286,744	\$ 33,812	\$ 735,127	\$ 1,646,178
20	February	664,990	83,333	1,715,473	100,000	2,563,796	252,025	31,584	649,555	1,630,632
21	March	605,280	83,333	5,184,715	100,000	5,973,328	237,427	32,688	2,065,891	3,637,322
22	April	660,013	84,362	1,000,000	100,000	1,844,375	260,468	33,060	390,000	1,160,847
23	May	639,477	83,948	1,000,000	100,000	1,823,425	249,396	32,740	390,000	1,151,289
24	June	988,145	83,336	337,907	100,000	1,509,387	385,376	32,500	131,784	959,727
25	July	990,916	85,528	960,291	100,000	2,136,734	386,457	33,356	374,513	1,342,408
26	August	1,127,466	84,458	820,241	232,850	2,265,014	439,712	32,938	319,894	1,472,470
27	September	948,163	84,523	816,517	232,850	2,082,054	369,784	32,964	318,442	1,360,864
28	October	620,095	84,467	816,517	232,850	1,753,928	241,837	32,942	318,442	1,160,708
29	November	849,634	(84,467)	816,517	232,850	1,814,534	331,357	(32,942)	318,442	1,197,677
30	December	614,136	-	816,517	232,850	1,663,503	108,924	(3,619)	130,936	1,427,263
31										
32	Total	\$ 9,415,029	\$ 756,154	\$ 16,096,507	\$ 1,864,250	\$ 28,131,940	\$ 3,549,507	\$ 292,022	\$ 6,143,025	\$ 18,147,386

Total PSCR Transmission

Line No.		Total for Network	Total Administrative	Schedule 7 & 8	Total	Network Transmission	Total Administrative	Net PSCR
		Transmission	and Other	Adjustments		Deferred	and Other Deferred	Transmission Expense
38	January	\$ 11,189,833	\$ 2,701,861	\$ (0)	\$ 13,891,693	\$ 1,442,726	\$ 1,055,683	\$ 11,393,285
39	February	10,278,494	2,563,796	(4,856)	12,837,434	1,059,316	933,164	10,844,954
40	March	10,518,651	5,973,328	-	16,491,979	1,317,827	2,336,006	12,838,146
41	April	9,367,741	1,844,375	(7,158)	11,204,958	1,191,301	683,528	9,330,129
42	May	10,169,403	1,823,425	-	11,992,828	1,243,462	672,136	10,077,230
43	June	17,270,530	1,509,387	(1,054,915)	17,725,003	2,078,107	549,660	15,097,235
44	July	17,672,149	2,136,734	(543,258)	19,265,626	2,149,572	794,326	16,321,727
45	August	18,917,202	2,265,014	539,740	21,721,956	2,354,685	792,544	18,574,727
46	September	15,884,145	2,082,054	-	17,966,198	2,210,708	721,189	15,034,301
47	October	13,202,042	1,753,928	-	14,955,970	1,718,695	593,221	12,644,055
48	November	13,673,947	1,814,534	-	15,488,481	2,213,672	616,857	12,657,951
49	December	12,148,721	1,663,503	-	13,812,224	712,577	236,240	12,863,408
50								
51	Total	\$ 160,292,857	\$ 28,131,940	\$ (1,070,446)	\$ 187,354,350	\$ 19,692,648	\$ 9,984,554	\$ 157,677,148

The Detroit Edison Company
 Electric Department Fuel Cost
 For the year ended December 31, 2005

MPSC Case No. U-14275-R Exhibit No. A-13 (SMD-3) Witness: S.M. DiGaetano Page 1 of 1

Electric Department Fuel Consumed Expense (Accounts 501, 509, 518 and 547)*		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(j)	(k)	(l)
Line No.		January	February	March	April	May	June	July	August	September	October	November	December	Total
1	Coal	\$ 46,719,808	\$ 51,751,884	\$ 47,277,828	\$ 39,484,280	\$ 37,761,010	\$ 57,701,626	\$ 59,260,422	\$ 55,137,444	\$ 47,431,777	\$ 46,411,094	\$ 46,984,283	\$ 56,440,615	\$ 592,362,070
2														
3	Oil	3,809,373	1,178,531	884,719	814,607	1,099,160	4,950,859	2,663,206	4,242,777	1,968,428	1,525,259	1,131,630	4,726,242	28,994,791
4														
5	Gas	7,408,350	1,094,615	1,592,185	1,828,002	1,047,934	15,429,857	22,179,648	17,213,192	10,481,277	5,136,391	3,204,868	6,079,315	92,695,634
6														
7	Total Fossil Fuel	\$57,937,530	\$54,025,030	\$49,754,731	\$42,126,889	\$39,908,104	\$78,082,342	\$84,103,276	\$76,593,413	\$59,881,481	\$53,072,744	\$51,320,781	\$67,246,173	\$714,052,494
8														
9	NOX Emission Allowance	-	-	-	-	1,460,809	2,290,483	2,854,809	3,849,435	3,882,188	-	177,084	-	14,514,808
10														
11	Total Fossil Fuel with NOX Allowance	57,937,530	54,025,030	49,754,731	42,126,889	41,368,914	80,372,825	86,958,085	80,442,848	63,763,669	53,072,744	51,497,865	67,246,173	728,567,303
12														
13	Nuclear	2,574,432	2,376,393	3,350,117	3,215,518	3,342,220	2,707,480	1,669,725	3,498,911	3,393,655	3,492,738	3,420,257	3,521,959	36,563,406
14														
15	Total Fuel Expense	\$ 60,511,963	\$ 56,401,423	\$ 53,104,848	\$ 45,342,407	\$ 44,711,134	\$ 83,080,306	\$ 88,627,809	\$ 83,941,759	\$ 67,157,325	\$ 56,565,483	\$ 54,918,122	\$ 70,768,132	\$ 765,130,709

**The Detroit Edison Company
Nuclear Fuel Costs Summary
For the year ended December 31, 2005**

MPSC Case No. U-14275-R Exhibit No. A-14 (SMD-4) Witness: S.M. DiGaetano Page 1 of 1

Line No.	Month/Year	(a) Front End Amortization	(b) Regulatory Costs	(c) Nuclear Fuel Expense	(d) Year To Date
1	Jan-2005	\$ 1,895,882	\$ 678,550	\$ 2,574,432	\$ 2,574,432
2	Feb-2005	1,747,954	628,439	2,376,393	4,950,826
3	Mar-2005	2,486,067	864,049	3,350,117	8,300,942
4	1st Quarter	6,129,903	2,171,039	8,300,942	
5					
6	Apr-2005	2,396,531	818,987	3,215,518	11,516,461
7	May-2005	2,497,082	845,137	3,342,220	14,858,680
8	Jun-2005	2,019,615	687,865	2,707,480	17,566,161
9	2nd Quarter	6,913,228	2,351,990	9,265,218	
10					
11	Jul-2005	1,225,278	444,446	1,669,725	19,235,885
12	Aug-2005	2,667,580	831,330	3,498,911	22,734,796
13	Sep-2005	2,582,487	811,168	3,393,655	26,128,452
14	3rd Quarter	6,475,346	2,086,945	8,562,291	
15					
16	Oct-2005	2,652,126	840,612	3,492,738	29,621,190
17	Nov-2005	2,592,645	827,612	3,420,257	33,041,447
18	Dec-2005	2,668,717	853,242	3,521,959	36,563,406
19	4th Quarter	7,913,488	2,521,467	10,434,955	
20					
21	Year Total	\$ 27,431,964	\$ 9,131,442	\$ 36,563,406	\$ -

Michigan Public Service Commission
 The Detroit Edison Company
 Unit Fuel Cost Comparison
 2005

<u>Line No.</u>		<u>2005 ACTUAL</u> <u>¢/MMBtu</u>	<u>2005 PSCR PLAN</u> <u>¢/MMBtu</u>	<u>PERCENTAGE DIFFERENCE</u> <u>ACTUAL PLAN</u>
3	<u>FUEL TYPE</u>			
5	COAL	147.7	145.4	1.6%
7	No.2 OIL	1,144.2	857.4	33.4%
9	No.6 OIL	525.6	475.2	10.6%
11	TOTAL OIL	656.4	567.9	15.6%
13	NATURAL GAS	887.3	660.7	34.3%
15	TOTAL SYSTEM - FOSSIL	171.7	156.9	9.4%
17	NUCLEAR	39.5	39.0	1.2%
19	TOTAL SYSTEM	147.7	134.4	9.9%

20
 21 Note: Unit fuel costs represent total Electric Department fuel expense including industrial steam.

**Detroit Edison Company
2005 PSCR Reconciliation
Power Supply Expenses and Direct Assignments**

Line No.		January	February	March	April	May	June	July
-								
1	Electric Department Fuel Consumed Expense	\$ 60,714,360	\$ 56,587,746	\$ 53,333,257	\$ 45,513,595	\$ 43,407,683	\$ 80,941,331	\$ 85,897,177
2	NOX Emission Expense	\$ -	\$ -	\$ -	\$ -	\$ 1,460,809	\$ 2,290,483	\$ 2,854,809
3	Cost of Steam Sales	\$ 201,857	\$ 185,540	\$ 228,186	\$ 179,718	\$ 177,954	\$ 143,011	\$ 124,384
4	Fuel Costs for Electric Generation	\$ 60,512,503	\$ 56,402,206	\$ 53,105,071	\$ 45,333,877	\$ 44,690,538	\$ 83,088,803	\$ 88,627,602
5								
6	Total Transmission Expense - Uncapped	\$ 13,891,693	\$ 12,837,434	\$ 16,491,979	\$ 11,204,958	\$ 11,992,828	\$ 17,725,003	\$ 19,265,626
7	Deferred Transmission Expense	\$ 2,498,409	\$ 1,992,480	\$ 3,653,833	\$ 1,874,829	\$ 1,915,597	\$ 2,627,768	\$ 2,943,899
8	Net Transmission Expense - Capped	\$ 11,393,285	\$ 10,844,954	\$ 12,838,146	\$ 9,330,129	\$ 10,077,230	\$ 15,097,235	\$ 16,321,727
9								
10	Purchased Power Expense - Uncapped	\$ 41,462,532	\$ 12,295,599	\$ 19,065,336	\$ 17,386,490	\$ 23,733,393	\$ 74,187,223	\$ 109,772,968
11	Interconnection Revenue	\$ 37,592,026	\$ 24,369,749	\$ 15,864,982	\$ 19,848,877	\$ 17,881,610	\$ 40,720,341	\$ 44,983,543
12	Purch and Net Interchange Power Expense - Uncapped	\$ 3,870,507	\$ (12,074,150)	\$ 3,200,354	\$ (2,462,387)	\$ 5,851,782	\$ 33,466,882	\$ 64,789,425
13					\$ 17,031,698	\$ 23,382,109	\$ 73,840,646	\$ 109,348,284
14	Deferred Purchased Power Expense	\$ -	\$ -	\$ -	\$ 354,792	\$ 351,283	\$ 346,578	\$ 424,684
15	Purch and Net Interchange Power Expense - Capped	\$ 3,870,507	\$ (12,074,150)	\$ 3,200,354	\$ (2,817,179)	\$ 5,500,499	\$ 33,120,304	\$ 64,364,740
16								
17	Expenses of R10	\$ 2,581,445	\$ 1,642,091	\$ 2,226,609	\$ 1,599,547	\$ 1,900,572	\$ 4,293,905	\$ 3,786,835
18	Expenses of D8 in the Buyout Mode	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 101,752
19	Expenses of LCC8 in the Buyout Mode	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 10,787
20	Cost Attributable to LCC10 Interruptible Sales	\$ 438,857	\$ 269,768	\$ 371,162	\$ 265,280	\$ 332,842	\$ 614,140	\$ 676,847
21	Cost Attributable to FERC Interruptible Sales	\$ 668,417	\$ 390,643	\$ 508,330	\$ 350,459	\$ 342,360	\$ 944,729	\$ 1,237,761
22	D8/LCC Special Buy-Out Related Charges	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 112,540
23	R10 (incl. LCC) Option Premium & Transmission Charges	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 76,087	\$ 61,294
24	Return to Service Market Priced Power (MPP) Revenue	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
25	Total Expenses of Direct Assignment Customers	\$ 3,688,719	\$ 2,302,502	\$ 3,106,101	\$ 2,215,286	\$ 2,575,773	\$ 5,928,861	\$ 5,987,817
26								
27	R10 Sales	kWh 92,199,647	89,888,323	88,516,056	88,000,644	77,622,783	101,696,057	70,563,375
28	D8 Sales in the Buyout Mode	kWh -	-	-	-	-	-	1,026,910
29	LCC8 Sales in the Buyout Mode	kWh -	-	-	-	-	-	108,850
30	LCC10 Interruptible Sales	kWh 13,962,946	13,388,030	14,382,142	14,240,899	14,413,574	15,450,174	13,198,341
31	FERC Interruptible Sales	kWh 18,462,161	15,508,807	14,687,524	12,381,438	10,687,116	15,302,408	16,824,499
32	Total Sales of Direct Assignment Customers	kWh 124,624,754	118,785,160	117,585,722	114,622,981	102,723,473	132,448,639	101,721,975

**Detroit Edison Company
2005 PSCR Reconciliation
Power Supply Expenses and Direct Assignments**

Line No.		August	September	October	November	December	Totals
-							
1	Electric Department Fuel Consumed Expense	\$ 80,199,400	\$ 63,411,295	\$ 56,715,321	\$ 54,904,200	\$ 70,991,182	\$ 752,616,546
2	NOX Emission Expense	\$ 3,849,435	\$ 3,882,188	\$ -	\$ 177,084	\$ -	\$ 14,514,808
3	Cost of Steam Sales	\$ 107,925	\$ 125,823	\$ 176,986	\$ 183,868	\$ 242,703	\$ 2,077,954
4	Fuel Costs for Electric Generation	\$ 83,940,910	\$ 67,167,660	\$ 56,538,335	\$ 54,897,416	\$ 70,748,479	\$ 765,053,400
5							
6	Total Transmission Expense - Uncapped	\$ 21,721,956	\$ 17,966,198	\$ 14,955,970	\$ 15,488,481	\$ 13,812,224	\$ 187,354,350
7	Deferred Transmission Expense	\$ 3,147,230	\$ 2,931,898	\$ 2,311,915	\$ 2,830,529	\$ 948,816	\$ 29,677,202
8	Net Transmission Expense - Capped	\$ 18,574,727	\$ 15,034,301	\$ 12,644,055	\$ 12,657,951	\$ 12,863,408	\$ 157,677,148
9							
10	Purchased Power Expense - Uncapped	\$ 94,912,048	\$ 85,978,266	\$ 53,297,831	\$ 12,808,834	\$ 28,940,961	\$ 573,841,480
11	Interconnection Revenue	\$ 45,150,667	\$ 48,535,655	\$ 29,772,213	\$ 14,834,984	\$ 40,260,459	\$ 379,815,107
12	Purch and Net Interchange Power Expense - Uncapped	\$ 49,761,381	\$ 37,442,611	\$ 23,525,618	\$ (2,026,150)	\$ (11,319,498)	\$ 194,026,373
13		\$ 94,437,750	\$ 85,735,640	\$ 53,100,408	\$ 12,578,133	\$ 28,790,131	\$ 571,068,266
14	Deferred Purchased Power Expense	\$ 474,298	\$ 242,626	\$ 197,424	\$ 230,701	\$ 150,830	\$ 2,773,214
15	Purch and Net Interchange Power Expense - Capped	\$ 49,287,083	\$ 37,199,985	\$ 23,328,194	\$ (2,256,851)	\$ (11,470,328)	\$ 191,253,159
16							
17	Expenses of R10	\$ 6,056,203	\$ 3,998,962	\$ 3,703,855	\$ 2,253,458	\$ 2,289,476	\$ 36,332,957
18	Expenses of D8 in the Buyout Mode	\$ 216,172	\$ -	\$ -	\$ -	\$ -	\$ 317,924
19	Expenses of LCC8 in the Buyout Mode	\$ 20,468	\$ -	\$ -	\$ -	\$ -	\$ 31,256
20	Cost Attributable to LCC10 Interruptible Sales	\$ 923,363	\$ 648,302	\$ 581,125	\$ 366,611	\$ 359,047	\$ 5,847,342
21	Cost Attributable to FERC Interruptible Sales	\$ 1,569,627	\$ 1,231,692	\$ 908,195	\$ 742,596	\$ 1,038,612	\$ 9,933,421
22	D8/LCC Special Buy-Out Related Charges	\$ 236,640	\$ -	\$ -	\$ -	\$ -	\$ 349,180
23	R10 (incl. LCC) Option Premium & Transmission Charges	\$ 102,520	\$ -	\$ -	\$ -	\$ -	\$ 239,901
24	Return to Service Market Priced Power (MPP) Revenue	\$ -	\$ -	\$ -	\$ -	\$ 98,632	\$ 98,632
25	Total Expenses of Direct Assignment Customers	\$ 9,124,992	\$ 5,878,956	\$ 5,193,175	\$ 3,362,665	\$ 3,785,766	\$ 53,150,613
26							
27	R10 Sales kWh	107,569,448	95,416,011	93,334,911	83,029,940	81,330,603	1,069,167,798
28	D8 Sales in the Buyout Mode kWh	1,872,379	-	-	-	-	2,899,289
29	LCC8 Sales in the Buyout Mode kWh	176,838	-	-	-	-	285,688
30	LCC10 Interruptible Sales kWh	16,495,370	15,488,125	14,937,273	12,777,478	11,855,534	170,589,886
31	FERC Interruptible Sales kWh	18,871,937	18,013,244	15,898,986	18,317,173	22,859,220	197,814,513
32	Total Sales of Direct Assignment Customers kWh	144,985,972	128,917,380	124,171,170	114,124,591	116,045,357	1,440,757,174

**Detroit Edison Company
2005 PSCR Reconciliation
Monthly Over (Under) Recovery
Commercial & Industrial Customers**

Case No. U-14275-R
Exhibit No. A-17 (KDJ-2) REVISED
Witness K. D. Johnston
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Line No.		August	September	October	November	December	Total
1	Total System Sales	kWh 5,021,910,521	4,076,944,405	3,745,330,631	3,678,317,887	3,903,680,219	47,466,147,238
2	Adjustment for LCC, R10	kWh (1,676,048)	5,194,843	34,341,996	(39,390,710)	32,827,545	3,010,079
3	Adjusted Sales	kWh 5,020,234,473	4,082,139,248	3,779,672,627	3,638,927,177	3,936,507,764	47,469,157,317
4							
5	Less: Unmetered	kWh 31,062,751	33,011,756	36,561,416	37,865,046	39,736,809	405,692,358
6	Less: Resale	kWh 198,833,478	205,644,459	203,628,698	200,447,641	206,108,934	2,329,130,539
7	Less: D8 in Buyout	kWh 1,872,379	-	-	-	-	2,899,289
8	Less: LCC8 in Buyout	kWh 176,838	-	-	-	-	285,688
9	Less: R10	kWh 107,569,448	95,416,011	93,334,911	83,029,940	81,330,603	1,069,167,798
10	Less: LCC10 Interruptible	kWh 16,495,370	15,488,125	14,937,273	12,777,478	11,855,534	170,589,886
11	PSCR Sales	kWh 4,664,224,209	3,732,578,897	3,431,210,329	3,304,807,072	3,597,475,884	43,491,391,759
12							
13	Adjusted Sales	kWh 5,020,234,473	4,082,139,248	3,779,672,627	3,638,927,177	3,936,507,764	47,469,157,317
14	Less: Total Sales of Direct Assignment Customers	kWh 144,985,972	128,917,380	124,171,170	114,124,591	116,045,357	1,440,757,174
15							
16	Adjusted Total Sales	kWh 4,875,248,501	3,953,221,868	3,655,501,457	3,524,802,586	3,820,462,407	46,028,400,143
17							
18	PSCR Allocation Factor	0.9567	0.9442	0.9386	0.9376	0.9416	0.9449
19							
20	Fuel Costs for Electric Generation	\$ 83,940,910	\$ 67,167,660	\$ 56,538,335	\$ 54,897,416	\$ 70,748,479	\$ 765,053,400
21	Purchased and Net Interchange Power	\$ 49,761,381	\$ 37,442,611	\$ 23,525,618	\$ (2,026,150)	\$ (11,319,498)	\$ 194,026,373
22	Total Power Supply Expenses	\$ 133,702,290	\$ 104,610,271	\$ 80,063,953	\$ 52,871,266	\$ 59,428,980	\$ 959,079,773
23	Less: Total Expenses of Direct Assignment Customers	\$ 9,124,992	\$ 5,878,956	\$ 5,193,175	\$ 3,362,665	\$ 3,785,766	\$ 53,150,613
24	Net Power Supply Expense (pre-adjustments)	\$ 124,577,298	\$ 98,731,315	\$ 74,870,778	\$ 49,508,601	\$ 55,643,214	\$ 905,929,160
25							
26	Less: LCC Cogenerator Adjustment	\$ 28,963	\$ 28,963	\$ 28,963	\$ 28,963	\$ 28,963	\$ 347,555
27	Net Power Supply Expense	\$ 124,548,335	\$ 98,702,352	\$ 74,841,815	\$ 49,479,638	\$ 55,614,251	\$ 905,581,605
28							
29	Applicable PSCR Energy Expense	\$ 119,155,392	\$ 93,194,761	\$ 70,246,528	\$ 46,392,109	\$ 52,366,379	\$ 857,622,886
30							
31	Transmission Expense	\$21,721,956.33	\$17,966,198.35	\$14,955,970.31	\$15,488,480.69	\$13,812,224.13	\$ 187,354,350
32	PSCR Transmission Allocation Factor	0.9603	0.9531	0.9482	0.9524	0.9540	0.9561
33	Applicable PSCR Transmission Expense	\$20,859,594.66	\$17,123,583.65	\$14,181,251.05	\$14,751,229.01	\$13,176,861.82	\$ 179,135,797
34							
35	Total Applicable PSCR Expense	\$140,014,987.05	\$110,318,344.88	\$84,427,778.79	\$61,143,338.05	\$65,543,240.95	\$ 1,036,758,683
36							
37	U-13808 Base Cost	Mills/kWh 17.32	17.32	17.32	17.32	17.32	17.32
38	U-13808 Loss Multiplier	1.072	1.072	1.072	1.072	1.072	1.072
39	Base Cost including Multiplier	Mills/kWh 18.56704	18.56704	18.56704	18.56704	18.56704	18.56704
40	PSCR Sales	kWh 4,664,224,209	3,732,578,897	3,431,210,329	3,304,807,072	3,597,475,884	43,491,391,759
41	Base Power Supply Revenues	\$ 86,600,837	\$ 69,302,942	\$ 63,707,419	\$ 61,360,485	\$ 66,794,479	\$ 807,506,410
42							
43	PSCR Factor	Mills/kWh 0.48	0.48	0.48	0.48	0.48	
44	PSCR Revenues	\$ 2,238,828	\$ 1,791,638	\$ 1,646,981	\$ 1,586,307	\$ 1,452,353	\$ (14,753,021)
45							
46	Total Revenues	\$ 88,839,665	\$ 71,094,580	\$ 65,354,400	\$ 62,946,792	\$ 68,246,831	\$ 792,753,390
47							
48	Monthly Over (Under) Recovery	\$ (51,175,322)	\$ (39,223,765)	\$ (19,073,378)	\$ 1,803,454	\$ 2,703,591	\$ (244,005,293)
49	Less Residential Over (Under) Recovery	\$ (19,588,861)	\$ (12,019,766)	\$ (3,954,502)	\$ 3,641,662	\$ 2,102,250	\$ (71,076,507)
50	Less Residential Deferral	\$ 3,621,527	\$ 3,174,523	\$ 2,509,339	\$ 3,061,230	\$ 1,099,646	\$ 32,450,417
51	Over (Under) Recovery Beginning Balance	\$ (32,523,229)	\$ (60,488,162)	\$ (84,517,639)	\$ (97,127,176)	\$ (95,904,154)	\$ (94,203,167)
52	Over (Under) Recovery Ending Balance	\$ (60,488,162)	\$ (84,517,639)	\$ (97,127,176)	\$ (95,904,154)	\$ (94,203,167)	\$ (94,203,167)
53	Over (Under) Recovery Average Balance	\$ (46,505,696)	\$ (72,502,900)	\$ (90,822,407)	\$ (96,515,665)	\$ (95,053,660)	\$ (95,053,660)
54	Annual Interest Rate	3.7571%	3.9288%	4.3605%	4.4386%	4.3625%	
55	Monthly Interest Rate	0.003131	0.003274	0.003634	0.003699	0.003635	
56	Interest	\$ (145,609)	\$ (237,374)	\$ (330,049)	\$ (357,011)	\$ (345,520)	\$ 448,116
57							
58	Cumulative Over (Under) Recovery	\$ (58,770,092)	\$ (83,036,942)	\$ (95,976,528)	\$ (95,110,517)	\$ (93,755,051)	\$ (93,755,051)
59							
60							
61							

Note 1: December billed sales computed using 0.48 Mills/kWh and unbilled sales computed using 0.38 Mills/kWh.

**Detroit Edison Company
2005 PSCR Reconciliation
Monthly Over (Under) Recovery
Residential Customers**

Line No.		January	February	March	April	May	June
1	PSCR Sales (Exhibit No. A-17 (KDJ-2), Line 11)	3,488,911,220	3,138,133,290	3,364,854,886	2,955,376,609	3,205,694,874	4,076,395,600
2	Residential PSCR Sales	1,453,099,402	1,292,666,611	1,302,629,302	1,072,115,321	1,061,295,635	1,630,424,504
3	Residential Energy Ratio (Line 2/Line 1)	0.4165	0.4119	0.3871	0.3628	0.3311	0.4000
4							
5	Adjusted Sales	3,826,826,308	3,456,382,661	3,694,139,286	3,277,192,766	3,516,737,879	4,400,888,209
6	Less Resale	192,749,445	178,537,983	191,891,187	188,091,133	189,581,825	179,425,173
7	Plus PLD Sales	20,027,848	21,798,440	22,100,050	23,973,998	25,077,142	19,919,415
8	Total Transmission Sales	3,654,104,711	3,299,643,118	3,524,348,149	3,113,075,631	3,352,233,196	4,241,382,451
9	Residential Transmission Ratio (Line 2/Line 8)	0.3977	0.3918	0.3696	0.3444	0.3166	0.3844
10							
11	Applicable PSCR Energy Expense	\$ 57,171,005	\$ 39,485,195	\$ 50,022,675	\$ 37,966,157	\$ 45,013,392	\$ 105,620,957
12	Residential PSCR Energy Expense (Line 3 * Line 11)	\$ 23,811,197	\$ 16,264,826	\$ 19,365,175	\$ 13,772,897	\$ 14,902,390	\$ 42,244,918
13							
14	Total Transmission Expense	\$ 13,891,693	\$ 12,837,434	\$ 16,491,979	\$ 11,204,958	\$ 11,992,828	\$ 17,725,003
15	Residential PSCR Trans Expense (Line 9 * Line 14)	\$ 5,524,202	\$ 5,029,187	\$ 6,095,577	\$ 3,858,887	\$ 3,796,853	\$ 6,813,646
16							
17	Total Residential Expense (Line 12 + Line 15)	\$ 29,335,399	\$ 21,294,013	\$ 25,460,752	\$ 17,631,784	\$ 18,699,243	\$ 49,058,564
18	Less Residential Deferrals (WP KDJ-2)	\$ 2,498,409	\$ 1,992,480	\$ 3,653,833	\$ 2,229,621	\$ 2,266,880	\$ 2,974,345
19	Net Residential Expense (Line 17 - Line 18)	\$ 26,836,990	\$ 19,301,534	\$ 21,806,919	\$ 15,402,163	\$ 16,432,363	\$ 46,084,218
20							
21	Base Cost including Multiplier Mills/kWh)	18.56704	18.56704	18.56704	18.56704	18.56704	18.56704
22	PSCR Factor (Mills/kWh)	(2.00)	(2.00)	(2.00)	(2.00)	(2.00)	0.48
23	Residential PSCR Revenue	\$ 24,073,556	\$ 21,415,659	\$ 21,580,712	\$ 17,761,777	\$ 17,582,527	\$ 31,054,761
24							
25	Residential Over/(under)Recovery	\$ (2,763,434)	\$ 2,114,126	\$ (226,207)	\$ 2,359,614	\$ 1,150,165	\$ (15,029,458)
26	Over (Under) Recovery Beginning Balance	\$ 29,577,490	\$ 26,814,056	\$ 28,928,182	\$ 28,701,975	\$ 31,061,589	\$ 32,211,754
27	Over (Under) Recovery Ending Balance	\$ 26,814,056	\$ 28,928,182	\$ 28,701,975	\$ 31,061,589	\$ 32,211,754	\$ 17,182,296
28	Over (Under) Recovery Average Balance	\$ 28,195,773	\$ 27,871,119	\$ 28,815,078	\$ 29,881,782	\$ 31,636,671	\$ 24,697,025
29	Annual Interest Rate	11.0000%	11.0000%	11.0000%	11.0000%	11.0000%	11.0000%
30	Monthly Interest Rate	0.009167	0.009167	0.009167	0.009167	0.009167	0.009167
31	Interest	\$ 258,471	\$ 255,495	\$ 264,148	\$ 273,926	\$ 290,013	\$ 226,398
32							
33	Cumulative Over (Under) Recovery	\$ 27,072,527	\$ 29,442,147	\$ 29,480,088	\$ 32,113,628	\$ 33,553,806	\$ 18,750,746

**Detroit Edison Company
2005 PSCR Reconciliation
Monthly Over (Under) Recovery
Residential Customers**

Line No.		July	August	September	October	November	December	Total
1	PSCR Sales (Exhibit No. A-17 (KDJ-2), Line 11)	4,531,728,889	4,664,224,209	3,732,578,897	3,431,210,329	3,304,807,072	3,597,475,884	43,491,391,759
2	Residential PSCR Sales	1,991,132,097	2,115,463,254	1,445,906,685	1,162,819,088	1,063,883,764	1,211,020,840	16,802,456,503
3	Residential Energy Ratio (Line 2/Line 1)	0.4394	0.4536	0.3874	0.3389	0.3219	0.3366	0.3863
4								
5	Adjusted Sales	4,839,508,919	5,020,234,473	4,082,139,248	3,779,672,627	3,638,927,177	3,936,507,764	47,469,157,317
6	Less Resale	194,190,583	198,833,478	205,644,459	203,628,698	200,447,641	206,108,934	2,329,130,539
7	Plus PLD Sales	27,658,902	35,764,380	39,759,748	42,632,632	31,398,952	40,632,756	350,744,263
8	Total Transmission Sales	4,672,977,238	4,857,165,375	3,916,254,537	3,618,676,561	3,469,878,488	3,771,031,586	45,490,771,041
9	Residential Transmission Ratio (Line 2/Line 8)	0.4261	0.4355	0.3692	0.3213	0.3066	0.3211	0.3694
10								
11	Applicable PSCR Energy Expense	\$ 140,988,336	\$ 119,155,392	\$ 93,194,761	\$ 70,246,528	\$ 46,392,109	\$ 52,366,379	857,622,886
12	Residential PSCR Energy Expense (Line 3 * Line 11)	\$ 61,946,866	\$ 54,043,040	\$ 36,101,294	\$ 23,806,178	\$ 14,934,552	\$ 17,628,131	338,821,463
13								
14	Total Transmission Expense	\$ 19,265,626	\$ 21,721,956	\$ 17,966,198	\$ 14,955,970	\$ 15,488,481	\$ 13,812,224	187,354,350
15	Residential PSCR Trans Expense (Line 9 * Line 14)	\$ 8,208,986	\$ 9,460,662	\$ 6,633,237	\$ 4,805,925	\$ 4,748,853	\$ 4,435,627	69,411,643
16								
17	Total Residential Expense (Line 12 + Line 15)	\$ 70,155,852	\$ 63,503,702	\$ 42,734,531	\$ 28,612,103	\$ 19,683,405	\$ 22,063,759	\$ 408,233,106
18	Less Residential Deferrals (WP KDJ-2)	\$ 3,368,583	\$ 3,621,527	\$ 3,174,523	\$ 2,509,339	\$ 3,061,230	\$ 1,099,646	32,450,417
19	Net Residential Expense (Line 17 - Line 18)	\$ 66,787,269	\$ 59,882,175	\$ 39,560,008	\$ 26,102,764	\$ 16,622,175	\$ 20,964,112	\$ 375,782,689
20								
21	Base Cost including Multiplier Mills/kWh)	18.56704	18.56704	18.56704	18.56704	18.56704	18.56704	
22	PSCR Factor (Mills/kWh)	0.48	0.48	0.48	0.48	0.48	0.48	
23	Residential PSCR Revenue	\$ 37,925,173	\$ 40,293,313	\$ 27,540,242	\$ 22,148,262	\$ 20,263,837	\$ 23,066,362	304,706,182
24								
25	Residential Over/(under)Recovery	\$ (28,862,096)	\$ (19,588,861)	\$ (12,019,766)	\$ (3,954,502)	\$ 3,641,662	\$ 2,102,250	(71,076,507)
26	Over (Under) Recovery Beginning Balance	\$ 17,182,296	\$ (11,679,800)	\$ (31,268,662)	\$ (43,288,427)	\$ (47,242,929)	\$ (43,601,267)	
27	Over (Under) Recovery Ending Balance	\$ (11,679,800)	\$ (31,268,662)	\$ (43,288,427)	\$ (47,242,929)	\$ (43,601,267)	\$ (41,499,017)	
28	Over (Under) Recovery Average Balance	\$ 2,751,248	\$ (21,474,231)	\$ (37,278,545)	\$ (45,265,678)	\$ (45,422,098)	\$ (42,550,142)	
29	Annual Interest Rate	11.0000%	3.7571%	3.9288%	4.3605%	4.4386%	4.3625%	
30	Monthly Interest Rate	0.009167	0.003131	0.003274	0.003634	0.003699	0.003635	
31	Interest	\$ 25,221	\$ (67,236)	\$ (122,050)	\$ (164,495)	\$ (168,016)	\$ (154,670)	917,204
32								
33	Cumulative Over (Under) Recovery	\$ (10,086,129)	\$ (29,742,227)	\$ (41,884,042)	\$ (46,003,040)	\$ (42,529,394)	\$ (40,581,813)	(40,581,813)

**Detroit Edison Company
2005 PSCR Reconciliation
Calculation of 2005 PSCR Reconciliation Billing Factors
Commercial & Industrial Customers**

Line No.	(a) U-14275-R Interest Calculation on year-end 2005 Under - Recovery (\$) (Note 1/Note 2)	(b) U-14275-R Reconciliation Under- Recovery Interest (\$)	(c) U-14275-R Reconciliation Under - Recovery Principal (\$)	(d) Total 2005 Under - Recovery (\$)	(e) Surcharge Period	(f) Starting Surcharge Month	(g) Estimated Surcharge Period PSCR Sales MWH (Note 3)	(h) 2005 PSCR Reconciliation Factor Mills/kWh (d) / (f) (Note 4)
1								
2								
3	\$93,755,051 x 0.046793 x 6.5							
4	-----	(2,376,335)	+ (93,755,051)	= (96,131,386)	12 months	Jul-06	29,066,752	3.39
5	12							
6								
7								
8	\$93,755,051 x 0.046793 x 6.5							
9	-----	(2,376,335)	+ (93,755,051)	= (96,131,386)	18 months	Jul-06	43,883,453	2.27
10	12							
11								
12								
13	\$98,142,131 x 0.046793 x 0.5							
14	-----	(202,902)	+ (98,142,131)	= (98,345,033)	6 months	Jan-07	13,943,299	7.14
15	12							
16								
17								
18	\$98,142,131 x 0.046793 x 0.5							
19	-----	(202,902)	+ (98,142,131)	= (98,345,033)	12 months	Jan-07	28,760,000	3.50
20	12							
21								
22								
23								
24								
25								
26								
27								
28	Note 1: January Short Term Interest Rate = 4.6793%							
29	Note 2: Interest in 2007 reflects annual compounding of interest for the year 2006.							
30	: \$93,755,051 x 0.046793 = \$ (4,387,080)							
31	\$93,755,051 + \$4,387,080 = \$98,142,131 at 12-31-2006							
32	Note 3: Surcharge Period Sales taken from 2006 PSCR Plan Case No. U-14702 & November 2005 Corporate Energy Forecast.							
33	Sales are adjusted using 2006 PSCR Plan C&I sales factor for 2006 = 29,363,000,000 / 48,401,000,000 = 0.6067							
34	and using 2006 PSCR Plan C&I sales factor for 2007 = 28,760,000,000 / 46,199,000,000 = 0.6225							
35	Note 4: Reflects Short Term Interest Rate of 4.6793% for the Surcharge Period							

**Detroit Edison Company
2004/2005 PEM Reconciliation
Monthly Over (Under) Recovery**

Case No. U-14275-R
Exhibit No. A-20 (KDJ-5)
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Line No.	2004	January-05	February-05	March-05	April-05	May-05	June-05
1 Pension Over (Under)Recovery	\$1,092,000	\$852,417	\$852,417	\$852,417	\$852,417	\$852,417	\$852,417
2 Over (Under) Recovery Beginning Balance	\$0	\$1,093,417	\$1,945,834	\$2,798,251	\$3,650,667	\$4,503,084	\$5,355,501
3 Over (Under) Recovery Ending Balance	\$1,092,000	\$1,945,834	\$2,798,251	\$3,650,667	\$4,503,084	\$5,355,501	\$6,207,917
4 Over (Under) Recovery Average Balance	\$546,000	\$1,519,626	\$2,372,042	\$3,224,459	\$4,076,876	\$4,929,292	\$5,781,709
5 Annual Interest Rate	3.1153%	3.2292%	2.6405%	2.8757%	3.0473%	3.2875%	3.3936%
6 Monthly Interest Rate	<u>0.002596</u>	<u>0.002691</u>	<u>0.0022</u>	<u>0.002396</u>	<u>0.002539</u>	<u>0.00274</u>	<u>0.002828</u>
7 Interest	\$1,417	\$4,089	\$5,218	\$7,726	\$10,351	\$13,506	\$16,351
8 Cumulative Pension Over/(under) Recovery	\$1,093,417	\$1,949,923	\$2,807,559	\$3,667,701	\$4,530,469	\$5,396,392	\$6,265,159

**Detroit Edison Company
2004/2005 PEM Reconciliation
Monthly Over (Under) Recovery**

**Case No. U-14275-R
Exhibit No. A-20 (KDJ-5)
Witness K. D. Johnston
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Line No.		July-05	August-05	September-05	October-05	November-05	December-05	Total
1	Pension Over (Under)Recovery	\$852,417	\$852,417	\$852,417	\$852,417	\$852,417	\$852,417	\$11,321,000
2	Over (Under) Recovery Beginning Balance	\$6,207,917	\$7,060,334	\$7,912,751	\$8,765,167	\$9,617,584	\$10,470,001	
3	Over (Under) Recovery Ending Balance	\$7,060,334	\$7,912,751	\$8,765,167	\$9,617,584	\$10,470,001	\$11,322,417	
4	Over (Under) Recovery Average Balance	\$6,634,126	\$7,486,542	\$8,338,959	\$9,191,376	\$10,043,792	\$10,896,209	
5	Annual Interest Rate	3.5170%	3.7571%	3.9288%	4.3605%	4.4386%	4.3625%	
6	Monthly Interest Rate	<u>0.002931</u>	<u>0.003131</u>	<u>0.003274</u>	<u>0.003634</u>	<u>0.003699</u>	<u>0.003635</u>	
7	Interest	\$19,445	\$23,440	\$27,302	\$33,401	\$37,152	\$39,608	\$239,007
8	Cumulative Pension Over/(under) Recovery	\$7,137,020	\$8,012,877	\$8,892,596	\$9,778,414	\$10,667,983	\$11,560,007	\$11,560,007

Detroit Edison Company
2004/005 PEM Reconciliation
Calculation of Refund Billing Factors

Line No.	(a) U-14275-R Interest Calculation on year-end 2005 Over - Recovery (\$) (Note 1/Note 2)	(b) U-14275-R Reconciliation Over - Recovery Interest (\$)	(c) U-14275-R Reconciliation Over - Recovery Principal (\$)	(d) Total 2004/ 2005 Over - Recovery (\$)	(e) Refund Month	(f) Estimated Monthly PEM Sales MWH (Note 3)	(g) 2004/2005 PEM Reconciliation C & I Mills/kWh (Note 4)	(h) 2004/2005 PEM Reconciliation Electric Choice Mills/kWh (Note 5)	(i) 2004/2005 PEM Reconciliation Residential Mills/kWh (Note 6)	(j) 2004/2005 PEM Reconciliation UnMetered % (Note 7)		
1												
2												
3	$\$11,560,007 \times 0.046793 \times 10.5$											
4	----- =	473,311	+	11,560,007	=	12,033,318	Nov-06	3,956,447	(3.11)	(0.82)	(3.81)	-4.23%
5	12											
6												
7												
8	$\$11,560,007 \times 0.046793 \times 11.5$											
9	----- =	518,389	+	11,560,007	=	12,078,396	Dec-06	4,214,297	(2.93)	(0.78)	(3.59)	-3.98%
10	12											
11												
12												
13	$\$12,100,934 \times 0.046793 \times 0.5$											
14	----- =	23,593	+	12,100,934	=	12,124,527	Jan-07	4,242,225	(2.93)	(0.78)	(3.58)	-3.97%
15	12											
16												
17												
18	$\$12,100,934 \times 0.046793 \times 1.5$											
19	----- =	70,780	+	12,100,934	=	12,171,714	Feb-07	3,881,385	(3.21)	(0.85)	(3.93)	-4.36%
20	12											
21												
22												
23	$\$12,100,934 \times 0.046793 \times 2.5$											
24	----- =	117,966	+	12,100,934	=	12,218,900	Mar-07	4,103,368	(3.05)	(0.81)	(3.73)	-4.14%
25	12											
26												
27												
28												
29												

30 Note 1: Short term interest rate = 4.6793%
31 Note 2: Interest in 2006 reflects annual compounding of interest for the year 2006.
32 : $\$11,560,007 \times 0.046793 = \$ 540,927$
33 $\$11,560,007 + \$540,927 = \$12,100,934$ at 12-31-2006
34 Note 3: Monthly Sales taken from 2006 PSCR Plan Case No. U-14702. Sales are adjusted
35 using 2005 Non-LCC sales factor = $50,362,551,534 / 52,414,967,420 = 0.9608$
36 using 2006 PSCR Plan jurisdictional sales factor for 2006 = $52,721,000,000 / 55,401,000,000 = 0.9516$
37 and using 2006 PSCR Plan jurisdictional sales factor for 2007 = $52,300,000,000 / 53,199,000,000 = 0.9831$
38 Note 4: C & I Revenue factor of 52.61% and Sales factor of 51.38%
39 Note 5: Electric Choice Revenue factor of 3.92% and Sales factor of 14.45%
40 Note 6: Residential Revenue factor of 41.80% and Sales factor of 33.36%
41 Note 7: Unmetered Revenue factor of 1.67%, Sales factor of 0.81%, and average revenue of \$0.15/kWh

Line

1	Section 1 - Pension expense recoverable in rates:	
2	Annual pension expense	\$113,300
3	Proportion transferred and capitalized	<u>22.00%</u>
4	Amount transferred and capitalized	<u>(24,926)</u>
5	Net pension expense	88,374
6	Jurisdictional factor	<u>0.9817</u>
7	Net jurisdictional expense	86,757
8	Proportion of net expense collected	<u>61%</u>
9	Annual net pension expense collected	52,922
10	Proportion applicable to 2004	<u>10.41%</u>
11	Net pension expense collected	<u><u>\$5,510</u></u>
12	Section 2 - Actual pension expense in 2004:	
13	Annual pension expense	\$100,265
14	Proportion transferred and capitalized	<u>29.32%</u>
15	Amount transferred and capitalized	<u>(29,400)</u>
16	Net pension expense	70,865
17	Jurisdictional factor	<u>0.9817</u>
18	Net jurisdictional expense	69,568
19	Proportion of net expense collected	<u>61%</u>
20	Annual net pension expense collected	42,437
21	Proportion applicable to 2004	<u>10.41%</u>
22	Net pension expense collected	<u><u>\$4,418</u></u>
23	Amount of PEM liability for December 2004	<u><u>(\$1,092)</u></u>

The Detroit Edison
Pension Equalization Mechanism
Year 2005
(\$ Thousands)

Case No. U-14275-R
Exhibit No. A-23 (REK-2)
Witness: R. E. Kelly

Line

1	Section 1 - Pension expense recoverable in rates:	
2	Annual pension expense	\$113,300
3	Proportion transferred and capitalized	<u>22.00%</u>
4	Amount transferred and capitalized	<u>(24,926)</u>
5	Net pension expense	88,374
6	Jurisdictional factor	<u>0.9817</u>
7	Net jurisdictional expense	86,757
8	Proportion of net expense collected	<u>72%</u>
9	Net pension expense collected	<u><u>\$62,465</u></u>
10	Section 2 - Actual pension expense in 2005:	
11	Annual pension expense	\$105,302
12	Proportion transferred and capitalized	<u>29.82%</u>
13	Amount transferred and capitalized	<u>(31,400)</u>
14	Net pension expense	73,902
15	Jurisdictional factor	<u>0.9817</u>
16	Net jurisdictional expense	72,550
17	Proportion of net expense collected	<u>72%</u>
18	Net pension expense	<u><u>\$52,236</u></u>
19	Amount of PEM liability for 2005	<u><u>(\$10,229)</u></u>

Line No.	(a)	(b)	
	<u>2005 as-filed</u>	<u>2005 actual</u>	<u>Diff: (b-a)</u>
1	CURRENT TRANSMISSION COSTS		
2	Network Transmission		
3	Schedule 1 -\$1000	\$5,710	\$5,133 (\$576)
4	Schedule 9 - \$1000	\$157,664	\$152,913 (\$4,750)
5			
6	MISO Schedule 10		
7	-\$1000	\$10,029	\$9,415 (\$614)
8			
9	Schedule 10 FERC Transmission		
10	-\$1000	\$3,039	\$1,864 (\$1,174)
11			
12	Schedule 18		
13	-\$1000	\$750	\$756 \$6
14			
15	Schedule 21 (later called Schedule 2 - IPP)		
16	-\$1000	\$1,292	\$1,175 (\$116)
17			
18	Seams Elimination Charge Adjustment (SECA) Adder (Schedule 22)		
19	-\$1000	\$26,800	\$16,097 (\$10,703)
20			
21	Total Current Bundled Transmission		
22	-\$1000	\$205,283	\$187,354 (\$17,929)
23			
24	MISO ENERGY MARKET		
25	MISO Schedule 16		
26	-\$1000	\$4,657	\$1,333 (\$3,323)
27			
28	MISO Schedule 17		
29	-\$1000	\$6,334	\$6,106 (\$228)
30			
31	FTR Purchases		
32	-\$1000	\$1,314	\$0 (\$1,314)
33			
34	Congestion Cost		
35	-\$1000	\$3,703	N/A N/A
36			
37	MISO Uplift/Misc. Market Charges		
38	-\$1000	\$0	N/A N/A
39			
40	Total Energy Market Bundled Transmission		
41	-\$1000	\$16,008	\$7,439 (\$8,568)
42			
43	Total Bundled Transmission		
44	-\$1000	\$221,291	\$194,794 (\$26,497)

Line No.		YTD TOTAL
1	DA Asset Energy Amount	215,172,265
2	DA Congestion Rebate on Carve-out GFA	(1,295,957)
3	DA Congestion Rebate on Option B GFA	0
4	DA Financial Bilateral Transaction Congestion Amount	4,568,056
5	DA Financial Bilateral Transaction Loss Amount	9,861,060
6	DA Loss Rebate on Carve-out GFA	(2,626,952)
7	DA Loss Rebate on Option B GFA	0
8	DA Market Administration Amount	5,516,302
9	DA Non-Asset Energy Amount	(1,694,492)
10	DA Revenue Sufficiency Guarantee Distribution Amount	3,684,131
11	DA Revenue Sufficiency Guarantee Make Whole Payment Amount	(3,559,972)
12	DA Virtual Energy Amount	30,981,522
13	FTR Hourly Allocation Amount	(17,458,872)
14	FTR Market Administration Amount	1,324,679
15	FTR Monthly Allocation Amount	(251,611)
16	FTR Transaction Amount	0
17	FTR Yearly Allocation Amount	0
18	RT Asset Energy Amount	(44,362,091)
19	RT Congestion Rebate on Carve-out GFA	(954,068)
20	RT Distribution of Losses Amount	(16,149,073)
21	RT Financial Bilateral Transaction Congestion Amount	821,414
22	RT Financial Bilateral Transaction Loss Amount	1,712,191
23	RT Loss Rebate on Carve-out GFA	(1,360,461)
24	RT Market Administration Amount	655,042
25	RT Miscellaneous Amount	112,847
26	RT Net Inadvertent Distribution Amount	(2,205,651)
27	RT Non-Asset Energy Amount	(4,832,199)
28	RT Revenue Neutrality Uplift Amount	21,681,777
29	RT Revenue Sufficiency Guarantee First Pass Dist Amount	30,088,001
30	RT Revenue Sufficiency Guarantee Make Whole Payment Amount	(13,727,938)
31	RT Uninstructed Deviation Amount	798,884
32	RT Virtual Energy Amount	(35,335,045)
33	RT Admin Fee Rebate	(93,440)
34		
35	TOTAL	\$181,070,350