San Diego Gas & Electric Company

Volume 2-B

TO3 - Cycle 5 Filing
12-Month CAISO Wholesale True-Up
Period Cost Statements & True-Up
Adjustment Calculation

TO3-Cycle 5 Filing
(August 15, 2011)

Docket No. ER11-_____-_____

San Diego Gas & Electric Company
Derivation of Retail and ISO Wholesale True-Up Adjustments
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Section – 3
Derivation of ISO Wholesale True-Up Adjustment

Section 3.1A
Summary of ISO True-Up Adjustment

Docket No. ER11-____-____

Section 3.1A
San Diego Gas Electric Co.
TO3-Cycle 5 Wholesale True-Up Adjustment Calculation

Line	TO3-Formula Cycle Transmission Rates in Effect	Cycle - 3	Cycle - 3	Cycle - 3	Cycle - 3	Cycle - 3
No.	Description	Apr-10	May-10	Jun-10	Jul-10	Aug-10
1	**Beginning Balance (Overcollection)/Undercollection**	$ -	$ 4,348,259	$ 8,699,757	$ 13,468,605	$ 18,750,798
2						
3	**Total Recorded Revenues**	$ 18,772,316	$ 18,377,192	$ 20,104,237	$ 22,193,606	$ 20,944,318
4						
5	**Amortization of True-Up Adjustment and Interest True-Up Adjustment:**					
6	**a) Amortization of Cycle 4 True-Up Adjustment and Interest True-Up Adjustment:**					
7	i. Amortization of Cycle 4 True-Up Adjustment					
8	ii. Amortization of Cycle 4 Interest True-Up Adjustment					
9	**b) Amortization of Cycle 3 True-Up Adjustment and Interest True-Up Adjustment:**					
10	i. Amortization of Cycle 3 True-Up Adjustment	(429,002)	(406,083)	(439,251)	(479,804)	(795,656)
11	ii. Amortization of Cycle 3 Interest True-Up Adjustment					
12	**c) Amortization of Cycle 2 True-Up Adjustment and Interest True-Up Adjustment:**					
13	i. Amortization of Cycle 2 TU Adjustment					
14	ii. Amortization of Cycle 2 Interest True-Up Adjustment	(31,778)	(30,080)	(32,537)	(35,541)	(78,653)
15	iii. Amortization of Cycle 2 Interest TU Adjustment Accrued After Fully Amortized					
16	**d) Amortization of TO2 FINAL True-Up Adjustment and Interest True-Up Adjustment:**					
17	i. Amortization of TO2 Final True-Up Adjustment					
18	ii. Amortization of TO2 FINAL Interest True-Up Adjustment	(143,001)	(135,361)	(146,417)	(159,935)	(325,039)
19	iii. Amort. of TO2 FINAL Interest TU Adjustment Accrued After Fully Amortized					
20	Total Amortization of True-Up Adjustments	$ (603,781)	$ (571,524)	$ (618,205)	$ (675,280)	$ (1,199,348)
21						
22	**Adjusted Total Recorded Revenues**	$ 18,168,535	$ 17,805,668	$ 19,486,032	$ 21,518,326	$ 19,744,970
23						
24	**Total True-Up Revenues (TU Cost of Service)**	$ 22,510,932	$ 22,138,941	$ 24,225,058	$ 26,755,475	$ 25,246,654
25						
26	**Net Monthly (Overcollection)/Undercollection**	$ 4,342,397	$ 4,333,273	$ 4,739,025	$ 5,237,149	$ 5,501,684
27						
28	Interest Expense Calculations:					
29	Beginning Balance for Interest Calculation	$ -	$ -	$ -	$ 13,468,605	$ 13,468,605
30	Monthly Activity Included in Interest Calculation Basis	2,171,199	6,509,033	11,045,183	2,618,575	7,987,991
31	Basis for Interest Expense Calculation	2,171,199	6,509,033	11,045,183	16,087,180	21,456,596
32	Monthly Interest Rate	0.27000%	0.28000%	0.27000%	0.28000%	0.28000%
33	**Interest Expense**	$ 5,862	$ 18,225	$ 29,822	$ 45,044	$ 60,078
34						
35	**Ending Balance (Overcollection)/Undercollection**	$ 4,348,259	$ 8,699,757	$ 13,468,605	$ 18,750,798	$ 24,312,561
36						
37		Apr-10	May-10	Jun-10	Jul-10	Aug-10
38	FERC INTEREST RATE	3.25%	3.25%	3.25%	3.25%	3.25%
39	Days in Year	365	365	365	365	365
40	Days in Month	30	31	30	31	31
41	Monthly Interest Rate - Calculated	0.27000%	0.28000%	0.27000%	0.28000%	0.28000%
42	FERC Interest Rates - Website	0.27000%	0.28000%	0.27000%	0.28000%	0.28000%
43	Difference	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%

Section 3.1A
San Diego Gas Electric Co.
TO3-Cycle 5 Wholesale True-Up Adjustment Calculation

Line No.	TO3-Formula Cycle Transmission Rates in Effect / Description	Cycle - 4 Sep-10	Cycle - 4 Oct-10	Cycle - 4 Nov-10	Cycle - 4 Dec-10	Cycle - 4 Jan-11
1	**Beginning Balance (Overcollection)/Undercollection**	**$ 24,312,561**	**$ 26,371,394**	**$ 28,258,912**	**$ 29,999,878**	**$ 31,845,694**
2						
3	**Total Recorded Revenues**	**$ 29,387,471**	**$ 26,573,944**	**$ 24,535,851**	**$ 25,228,057**	**$ 26,414,916**
4						
5	**Amortization of True-Up Adjustment and Interest True-Up Adjustment:**					
6	**a) Amortization of Cycle 4 True-Up Adjustment and Interest True-Up Adjustment:**					
7	i. Amortization of Cycle 4 True-Up Adjustment	(2,412,253)	(2,267,552)	(2,085,751)	(2,163,613)	(2,276,583)
8	ii. Amortization of Cycle 4 Interest True-Up Adjustment					
9	**b) Amortization of Cycle 3 True-Up Adjustment and Interest True-Up Adjustment:**					
10	i. Amortization of Cycle 3 True-Up Adjustment					
11	ii. Amortization of Cycle 3 Interest True-Up Adjustment	(19,298)	(18,140)	(16,686)	(17,309)	(18,213)
12	**c) Amortization of Cycle 2 True-Up Adjustment and Interest True-Up Adjustment:**					
13	i. Amortization of Cycle 2 TU Adjustment					
14	ii. Amortization of Cycle 2 Interest True-Up Adjustment					
15	iii. Amortization of Cycle 2 Interest TU Adjustment Accrued After Fully Amortized	(3,860)	(3,628)	(3,337)	(3,462)	(3,643)
16	**d) Amortization of TO2 FINAL True-Up Adjustment and Interest True-Up Adjustment:**					
17	i. Amortization of TO2 Final True-Up Adjustment					
18	ii. Amortization of TO2 FINAL Interest True-Up Adjustment					
19	iii. Amort. of TO2 FINAL Interest TU Adjustment Accrued After Fully Amortized	(19,298)	(18,140)	(16,686)	(17,309)	(18,213)
20	Total Amortization of True-Up Adjustments	$ (2,454,709)	$ (2,307,460)	$ (2,122,460)	$ (2,201,693)	$ (2,316,652)
21						
22	**Adjusted Total Recorded Revenues**	**$ 26,932,762**	**$ 24,266,484**	**$ 22,413,391**	**$ 23,026,364**	**$ 24,098,264**
23						
24	**Total True-Up Revenues (TU Cost of Service)**	**$ 28,923,547**	**$ 26,077,627**	**$ 24,076,019**	**$ 24,786,151**	**$ 25,966,451**
25						
26	**Net Monthly (Overcollection)/Undercollection**	**$ 1,990,785**	**$ 1,811,143**	**$ 1,662,628**	**$ 1,759,786**	**$ 1,868,187**
27						
28	Interest Expense Calculations:					
29	Beginning Balance for Interest Calculation	$ 13,468,605	$ 26,371,394	$ 26,371,394	$ 26,371,394	$ 31,845,694
30	Monthly Activity Included in Interest Calculation Basis	11,734,226	905,572	2,642,457	4,353,665	934,093
31	Basis for Interest Expense Calculation	25,202,831	27,276,965	29,013,851	30,725,058	32,779,788
32	Monthly Interest Rate	0.27000%	0.28000%	0.27000%	0.28000%	0.28000%
33	**Interest Expense**	**$ 68,048**	**$ 76,376**	**$ 78,337**	**$ 86,030**	**$ 91,783**
34						
35	**Ending Balance (Overcollection)/Undercollection**	**$ 26,371,394**	**$ 28,258,912**	**$ 29,999,878**	**$ 31,845,694**	**$ 33,805,665**
36						
37		Sep-10	Oct-10	Nov-10	Dec-10	Jan-11
38	FERC INTEREST RATE	3.25%	3.25%	3.25%	3.25%	3.25%
39	Days in Year	365	365	365	365	365
40	Days in Month	30	31	30	31	31
41	Monthly Interest Rate - Calculated	0.27000%	0.28000%	0.27000%	0.28000%	0.28000%
42	FERC Interest Rates - Website	0.27000%	0.28000%	0.27000%	0.28000%	0.28000%
43	Difference	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%

Section 3.1A
San Diego Gas Electric Co.
TO3-Cycle 5 Wholesale True-Up Adjustment Calculation

Line No.	TO3-Formula Cycle Transmission Rates in Effect / Description	Cycle - 4 Feb-11	Cycle - 4 Mar-11	Total	Reference	Line No.
1	**Beginning Balance (Overcollection)/Undercollection**	$ 33,805,665	$ 35,563,352	$ -	Previous Month's Balance	1
2						2
3	**Total Recorded Revenues**	$ 23,686,858	$ 23,905,753	$ 280,124,518	Section 3.2.3; Page 82; Line 15	3
4						4
5	**Amortization of True-Up Adjustment and Interest True-Up Adjustment:**					5
6	**a) Amortization of Cycle 4 True-Up Adjustment and Interest True-Up Adjustment:**					6
7	i. Amortization of Cycle 4 True-Up Adjustment	(2,051,430)	(2,077,839)	(15,335,021)	Section 3.1A; Page 6; Line 22; (a) - (g)	7
8	ii. Amortization of Cycle 4 Interest True-Up Adjustment					8
9	**b) Amortization of Cycle 3 True-Up Adjustment and Interest True-Up Adjustment:**					9
10	i. Amortization of Cycle 3 True-Up Adjustment			(2,549,796)	Section 3.1A; Pgs 9-10; Ln. 22; Cols. (h)-(l)	10
11	ii. Amortization of Cycle 3 Interest True-Up Adjustment	(16,411)	(16,623)	(122,680)	Section 3.1A; Page 12; Line 22; (a) - (g)	11
12	**c) Amortization of Cycle 2 True-Up Adjustment and Interest True-Up Adjustment:**					12
13	i. Amortization of Cycle 2 TU Adjustment			-		13
14	ii. Amortization of Cycle 2 Interest True-Up Adjustment			(208,589)	Section 3.1A; Pgs 15-16; Ln. 22; Cols. (h)-(l)	14
15	iii. Amortization of Cycle 2 Interest TU Adjustment Accrued After Fully Amortized	(3,282)	(3,325)	(24,537)	Section 3.1A; Page 18; Line 22; (a) - (g)	15
16	**d) Amortization of TO2 FINAL True-Up Adjustment and Interest True-Up Adjustment:**					16
17	i. Amortization of TO2 Final True-Up Adjustment			-		17
18	ii. Amortization of TO2 FINAL Interest True-Up Adjustment			(909,753)	Section 3.1A; Pgs 21-22; Ln. 22; Cols. (h)-(l)	18
19	iii. Amort. of TO2 FINAL Interest TU Adjustment Accrued After Fully Amortized	(16,411)	(16,623)	(122,680)	Page 24; Line 22; Columns (a) - (g)	19
20	Total Amortization of True-Up Adjustments	$ (2,087,534)	$ (2,114,410)	$ (19,273,056)	Sum Lines (7 thru 19)	20
21						21
22	**Adjusted Total Recorded Revenues**	$ 21,599,324	$ 21,791,343	$ 260,851,463	Sum Lines 3 & 20	22
23						23
24	**Total True-Up Revenues (TU Cost of Service)**	$ 23,270,638	$ 23,473,105	$ 297,450,597	Section 3.3.3; Page 127; Line 15	24
25						25
26	**Net Monthly (Overcollection)/Undercollection**	$ 1,671,314	$ 1,681,762	$ 36,599,134	Line 24 Minus Line 22	26
27						27
28	Interest Expense Calculations:					28
29	Beginning Balance for Interest Calculation	$ 31,845,694	$ 31,845,694		Beginning Quarterly Balances	29
30	Monthly Activity Included in Interest Calculation Basis	2,703,844	4,380,382		Interest Calculation Basis	30
31	Basis for Interest Expense Calculation	34,549,538	36,226,076		Sum Lines 29 & 30	31
32	Monthly Interest Rate	0.25000%	0.28000%		FERC Monthly Rates	32
33	**Interest Expense**	$ 86,374	$ 101,433	$ 747,413	Line 31 x Line 32	33
34						34
35	**Ending Balance (Overcollection)/Undercollection**	$ 35,563,352	$ 37,346,547	$ 37,346,547	Sum Lines 1; 26; & 33	35
36						36
37		Feb-11	Mar-11			37
38	FERC INTEREST RATE	3.25%	3.25%		Annual Interest Rate - FERC Website	38
39	Days in Year	365	365	365	Number of Days Per Year	39
40	Days in Month	28	31	365	Number of Days Per Month	40
41	Monthly Interest Rate - Calculated	0.25000%	0.28000%	3.29000%	(Line 38)/(Line 39)x(Line 40)	41
42	FERC Interest Rates - Website	0.25000%	0.28000%	3.29000%	Monthly Interest Rate - FERC Website	42
43	Difference	0.00000%	0.00000%	0.00000%		43

Section 3.1 – Wholesale True-Up Adjustment

Section (a): Amortization of Cycle 4 True-Up Adjustment and Interest True-Up Adjustment

Part (i): Amortization of Cycle 4 True-Up Adjustment (September 2010 – March 2011)

- The amortization of the Cycle-4 True-Up Adjustment in the instant Cycle-5 filing is from September 2010 through March 2011.

- The remaining balance of the Cycle-4 True-Up Adjustment will be amortized from April 2011 through August 2011, and will be shown in next year's Cycle 6 filing.

Section 3.1A
SAN DIEGO GAS ELECTRIC
TO3-Cycle 5 Annual Transmission Formulaic Rate Filing
Amortization of TO3-Cycle 4

Line No.	Description	(a) Amounts	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	**Derivation of Amortization Rates:**								
2	TO3-Cycle 4 TU Adjustment (See Refund Report Filing)	$ **26,556,669**							
3	TO3-Cycle 4 Forecast Sales @ Transmission Level (kWh)	21,224,655,611							
4	Amortization Rate Per kWh @ ***Transmission Level***	$ **0.00125**							
5									
6		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
7	**Derivation of Forecast Sales @ Transmission Level:** [1]	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11
8	TO3-Cycle 4 Filing - MWh (Statement BD)	1,922,249	1,690,306	1,643,648	1,693,675	1,744,802	1,637,717	1,618,732	1,557,545
9	Exclude Sale for Resale	2	2	2	2	2	2	2	2
10	Total Forecast Sales Net of Resale - MWh	1,922,248	1,690,305	1,643,647	1,693,674	1,744,801	1,637,716	1,618,731	1,557,544
11	Transmission Level Adjustment Factor from (TO3-Cycle 4)	1.04081	1.04081	1.04081	1.04081	1.04081	1.04081	1.04081	1.04081
12	Conversion Factor from MWh to kWh	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
13	Total Forecast Sales Net of Resale - kWh	2,000,688,252	1,759,280,403	1,710,718,439	1,762,786,881	1,816,000,210	1,704,545,414	1,684,785,697	1,621,101,852
14									
15	**Cyclical Period Filing**	**Cycle - 5**	**Cycle - 5**	**Cycle - 5**	**Cycle - 5**	**Cycle - 5**	**Cycle - 5**	**Cycle - 5**	Cycle - 6
16	**Amortization of TO3-Cycle 4 True-Up Adjustment:** [2]	**Sep-10**	**Oct-10**	**Nov-10**	**Dec-10**	**Jan-11**	**Feb-11**	**Mar-11**	Apr-11
17	Beginning True-Up Adjustment Balance	$ 26,556,669	$ 24,144,416	$ 21,876,864	$ 19,791,113	$ 17,627,500	$ 15,350,917	$ 13,299,487	$ -
18	Recorded Sales Less Sale for Resale@***Transmission Level***	1,929,802	1,814,041	1,668,601	1,730,891	1,821,266	1,641,144	1,662,271	-
19	Conversion Factor from MWh to kWh	1,000	1,000	1,000	1,000	1,000	1,000	1,000	-
20	Recorded Sales in Total kWh @ ***Transmission Level***	1,929,802,429	1,814,041,416	1,668,601,019	1,730,890,762	1,821,266,163	1,641,143,985	1,662,270,810	-
21	Amortization Rate Per kWh @ ***Transmission Level***	$ 0.00125	$ 0.00125	$ 0.00125	$ 0.00125	$ 0.00125	$ 0.00125	$ 0.00125	$ -
22	TO3-Cycle 4 True-Up Adjustment Amortization Amount [3]	$ **2,412,253**	$ **2,267,552**	$ **2,085,751**	$ **2,163,613**	$ **2,276,583**	$ **2,051,430**	$ **2,077,839**	$ -
23	Ending TO3-Cycle 4 True-Up Adjusment Balance	$ 24,144,416	$ 21,876,864	$ 19,791,113	$ 17,627,500	$ 15,350,917	$ 13,299,487	$ 11,221,648	$ -
24									

NOTES:

1 The derivation of forecast sales shown on lines 8 through 12 indicates the forecast sales used on line 3 to develop the amortization rate during the rate effective period.

2 On lines 15 through 20, SDG&E is taking the product between the amortization rate on line 4 and the recorded sales on 20, to indicate the amortization of the true-up adjustment over the rate effective September 2010 through August 2011.

3 The monthly true-up adjustment amortization amount shown on line 22 has been calculated through 3/31/2011, which is the end of the cycle 5 true-up adjustment period. Future monthly amortization amounts have not been shown since the amounts will be shown in the instant statement of the TO3; Cycle 6 filing.

Section 3.1A
SAN DIEGO GAS ELECTRIC
TO3-Cycle 5 Annual Transmission Formulaic Rate Filing
Amortization of TO3-Cycle 4

Line No.	Description	(i)	(j)	(k)	(l)	(m)	Reference	Line No.
1	**Derivation of Amortization Rates:**							1
2	TO3-Cycle 4 TU Adjustment (See Refund Report Filing)						Refund Report; Section 3.1A; Page 50; Line 30	2
3	TO3-Cycle 4 Forecast Sales @ Transmission Level (kWh)						See Line 13 Below	3
4	Amortization Rate Per kWh @ ***Transmission Level***						Line 2 / Line 3	4
5								5
6		(i)	(j)	(k)	(l)	(m)		6
7	**Derivation of Forecast Sales @ Transmission Level:** [1]	May-11	Jun-11	Jul-11	Aug-11	Total	TO3-Cycle 4	7
8	TO3-Cycle 4 Filing - MWh (Statement BD)	1,563,385	1,651,390	1,813,253	1,855,819	20,392,521	True-Up Period; Statement BDWPs	8
9	Exclude Sale for Resale	2	2	2	2	18	Sale for Resale	9
10	Total Forecast Sales Net of Resale - MWh	1,563,384	1,651,389	1,813,252	1,855,818	20,392,503	Line 8 Minus Line 9	10
11	Transmission Level Adjustment Factor from (TO3-Cycle 4)	1.04081	1.04081	1.04081	1.04081		Statement BB; Page 1; Col.(B);Line 16	11
12	Conversion Factor from MWh to kWh	1,000	1,000	1,000	1,000		MWH Conversion Factor	12
13	Total Forecast Sales Net of Resale - kWh	1,627,180,164	1,718,776,366	1,887,244,475	1,931,547,457	21,224,655,611	Line 10 x Line 11 x Line 12	13
14								14
15	**Cyclical Period Filing**	Cycle - 6	Cycle - 6	Cycle - 6	Cycle - 6			15
16	**Amortization of TO3-Cycle 4 True-Up Adjustment:** [2]	May-11	Jun-11	Jul-11	Aug-11	Total	Amortization Period 9/10 - 8/11	16
17	Beginning True-Up Adjustment Balance	$ -	$ -	$ -	$ -		Beginning Balance	17
18	Recorded Sales Less Sale for Resale@***Transmission Level***	-	-	-	-		Section 3.3.3; Page 12.1; Line 28; Sep-Mar.	18
19	Conversion Factor from MWh to kWh	-	-	-	-		Conversion Factor	19
20	Recorded Sales in Total kWh @ ***Transmission Level***	-	-	-	-	12,268,016,583	Line 18 x Line 19	20
21	Amortization Rate Per kWh @ ***Transmission Level***	$ -	$ -	$ -	$ -		See Line 4 Above; Column (a)	21
22	TO3-Cycle 4 True-Up Adjustment Amortization Amount [3]	$ -	$ -	$ -	$ -	$ 15,335,021	Line 20 x Line 21	22
23	Ending TO3-Cycle 4 True-Up Adjusment Balance	$ -	$ -	$ -	$ -		Line 17 Minus Line 22	23
24								24

NOTES:

1 The derivation of forecast sales shown on lines 8 through 12 indicates the forecast sales used on line 3 to develop the amortization rate during the rate effective period.

2 On lines 15 through 20, SDG&E is taking the product between the amortization rate on line 4 and the recorded sales on 20, to indicate the amortization of the true-up adjustment over the rate effective September 2010 through August 2011.

3 The monthly true-up adjustment amortization amount shown on line 22 has been calculated through 3/31/2011, which is the end of the cycle 5 true-up adjustment period. Future monthly amortization amounts have not been shown since the amounts will be shown in the instant statement of the TO3; Cycle 6 filing.

Section 3.1 – Wholesale True-Up Adjustment

Section (b): Amortization of Cycle 3 True-Up Adjustment and Interest True-Up Adjustment

Part (i): Amortization of Cycle 3 True-Up Adjustment (April 2010 – August 2010)

- The amortization of the Cycle-3 True-Up Adjustment in the instant Cycle 5 filing is from April 2010 through August 2010.

- The amortization of the Cycle 3 True-Up Adjustment from September 2009 through March 2010 was picked up in the TO3 Cycle 4 filing last year.

Section 3.1A
San Diego Gas and Electric Company
TO3-Cycle5 Annual Transmission Formula Filing
Amortization of TO3-Cycle 3 True-Up Adjustment - CAISO WHOLESALE

Line No.	Description	(a) Amounts	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	**Derivation of Amortization Rates:**								
2	TO3-Cycle 3 True-Up Adjustments	**$ 5,849,399**							
3	TO3-Cycle 3 Forecast Sales @ Transmission Level (kWh)	21,965,833,823							
4	Amortization Rate Per kWh @ ***Transmission Level***	**$ 0.00027**							
5									
6		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
7	**Derivation of Forecast Sales @ Transmission Level:** [1]	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10
8	Total Per TO3-Cycle 3 Filing - MWh (Statement BD)	2,010,448	1,718,513	1,693,225	1,751,701	1,787,375	1,686,424	1,675,587	1,576,628
9	Exclude Sale for Resale	4	4	4	4	4	4	4	4
10	Total Forecast Sales Net of Resale - MWh	2,010,444	1,718,509	1,693,221	1,751,697	1,787,371	1,686,420	1,675,583	1,576,624
11	Transmission Level Adjustment Factor (TO3-Cycle 3)	1.04090	1.04090	1.04090	1.04090	1.04090	1.04090	1.04090	1.04090
12	Conversion Factor from MWh to kWh	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
13	Total Forecast Sales Net of Resale - kWh	2,092,673,349	1,788,797,890	1,762,475,583	1,823,343,315	1,860,476,421	1,755,396,415	1,744,116,170	1,641,109,639
14									
15		Cycle - 4	Cycle - 4	Cycle - 4	Cycle - 4	Cycle - 4	Cycle - 4	Cycle - 4	**Cycle - 5**
16	**Amortization of TO3-Cycle 3 True-Up Adjustment:** [2]	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	**Apr-10**
17	Beginning True-Up Adjustment Balance	$ 5,849,399	$ 5,311,248	$ 4,825,353	$ 4,363,887	$ 3,892,942	$ 3,417,958	$ 2,973,259	$ 2,549,796
18	Recorded Sales in Total MWh Excludes Sale for Resale	1,993,153	1,799,611	1,709,134	1,744,239	1,759,201	1,647,034	1,568,382	1,588,897
19	Conversion Factor from MWh to kWh	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
20	Recorded Sales in Total kWh @ ***Transmission Level***	1,993,152,560	1,799,610,814	1,709,134,141	1,744,239,008	1,759,201,392	1,647,034,236	1,568,381,768	1,588,896,642
21	Amortization Rate Per kWh @ ***Transmission Level***	$ 0.00027	$ 0.00027	$ 0.00027	$ 0.00027	$ 0.00027	$ 0.00027	$ 0.00027	$ 0.00027
22	Amortization of TO3-Cycle 3 True-Up Adjustment [3]	$ 538,151	$ 485,895	$ 461,466	$ 470,945	$ 474,984	$ 444,699	$ 423,463	**$ 429,002**
23	Ending TO3-Cycle 3 True-Up Adjusment Balance	$ 5,311,248	$ 4,825,353	$ 4,363,887	$ 3,892,942	$ 3,417,958	$ 2,973,259	$ 2,549,796	$ 2,120,794
24									

NOTES:

1 The derivation of forecast sales shown on lines 8 through 12 indicates the forecast sales used on line 3 to develop the amortization rate during the rate effective period.

2 On lines 15 through 20, SDG&E is taking the product between the amortization rate on line 4 and the recorded sales on 20, to indicate the amortization of the true-up adjustment over the rate effective September 2009 through August 2010.

3 The monthly true-up adjustment amortization amount shown on line 22 has been calculated through 8/31/2010, which is the end of the cycle 5 true-up adjustment period. The amounts from April 2010 - August 2010 are included in Cycle 5.

Section 3.1A
San Diego Gas and Electric Company
TO3-Cycle5 Annual Transmission Formula Filing
Amortization of TO3-Cycle 3 True-Up Adjustment - CAISO WHOLESALE

Line No.	Description	(i)	(j)	(k)	(l)	(m)	Reference	Line No.
1	**Derivation of Amortization Rates:**						TO3-Cycle 3	1
2	TO3-Cycle 3 True-Up Adjustments						Vol. 2 of 3; Section 3.1B; Pg.XX; Line 21	2
3	TO3-Cycle 3 Forecast Sales @ Transmission Level (kWh)						See Line 13 Below	3
4	Amortization Rate Per kWh @ ***Transmission Level***						Line 2 / Line 3	4
5								5
6		(i)	(j)	(k)	(l)	(m)		6
7	**Derivation of Forecast Sales @ Transmission Level:** [1]	May-10	Jun-10	Jul-10	Aug-10	Total	TO3-Cycle 3	7
8	Total Per TO3-Cycle 3 Filing - MWh (Statement BD)	1,615,032	1,719,830	1,935,604	1,932,391	21,102,758	True-Up Period; Statement BDWPs	8
9	Exclude Sale for Resale	4	4	4	4	48	Sale for Resale	9
10	Total Forecast Sales Net of Resale - MWh	1,615,028	1,719,826	1,935,600	1,932,387	21,102,710	Line 8 Minus Line 9	10
11	Transmission Level Adjustment Factor (TO3-Cycle 3)	1.04090	1.04090	1.04090	1.04090		Statement BB; Page 1; Col.(B);Line 16	11
12	Conversion Factor from MWh to kWh	1,000	1,000	1,000	1,000		MWH Conversion Factor	12
13	Total Forecast Sales Net of Resale - kWh	1,681,084,404	1,790,168,757	2,014,768,148	2,011,423,733	21,965,833,823	Line 10 x Line 11 x Line 12	13
14								14
15		Cycle - 5	Cycle - 5	Cycle - 5	Cycle - 5			15
16	**Amortization of TO3-Cycle 3 True-Up Adjustment:** [2]	**May-10**	**Jun-10**	**Jul-10**	**Aug-10**	Total	Amortization Period 9/09 - 8/10	16
17	Beginning True-Up Adjustment Balance	$ 2,120,794	$ 1,714,711	$ 1,275,460	$ 795,656		Beginning Balance	17
18	Recorded Sales in Total MWh Excludes Sale for Resale	1,504,010	1,626,856	1,777,050	1,667,144		Section 3.3.3; Page 12.1; Line 28; Sep-Mar.	18
19	Conversion Factor from MWh to kWh	1,000	1,000	1,000	1,000		Conversion Factor	19
20	Recorded Sales in Total kWh @ ***Transmission Level***	1,504,009,827	1,626,856,156	1,777,050,414	1,667,144,323	20,384,711,282	Line 18 x Line 19	20
21	Amortization Rate Per kWh @ ***Transmission Level***	$ 0.00027	$ 0.00027	$ 0.00027	$ 0.00027		See Line 4 Above; Column (a)	21
22	Amortization of TO3-Cycle 3 True-Up Adjustment [3]	$ **406,083**	$ **439,251**	$ **479,804**	$ **795,656**	$ 5,849,399	Line 20 x Line 21	22
23	Ending TO3-Cycle 3 True-Up Adjusment Balance	$ 1,714,711	$ 1,275,460	$ 795,656	$ -		Line 17 Minus Line 22	23
24								24

NOTES:

1 The derivation of forecast sales shown on lines 8 through 12 indicates the forecast sales used on line 3 to develop the amortization rate during the rate effective period.

2 On lines 15 through 20, SDG&E is taking the product between the amortization rate on line 4 and the recorded sales on 20, to indicate the amortization of the true-up adjustment over the rate effective September 2009 through August 2010.

3 The monthly true-up adjustment amortization amount shown on line 22 has been calculated through 8/31/2010, which is the end of the cycle 5 true-up adjustment period. The amounts from April 2010 - August 2010 are included in Cycle 5.

Section 3.1 – Wholesale True-Up Adjustment

Section (b): Amortization of Cycle 3 True-Up Adjustment and Interest True-Up Adjustment

Part (ii): Amortization of Cycle 3 Interest True-Up Adjustment (September 2010 – March 2011)

- The amortization of the Cycle 3 Interest True-Up Adjustment in the instant Cycle 5 filing is from September 2010 through March 2011.
- The remaining balance of the Cycle 3 Interest True-Up Adjustment will be amortized from April 2011 through August 2011, and will be shown in next year's Cycle 6 filing.

Section 3.1A
SAN DIEGO GAS ELECTRIC
TO3-Cycle 5 Annual Transmission Formulaic Rate Filing
Amortization of TO3-Cycle 3 Interest True-Up Adjustment

Line No.	Description	(a) Amounts	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	**Derivation of Amortization Rates:**								
2	TO3-Cycle 3 Interest True-Up Adjustment from Cycle 4	$ **163,548**							
3	TO3-Cycle 4 Forecast Sales @ Transmission Level (kWh)	21,224,655,611							
4	Amortization Rate Per kWh @ ***Transmission Level***	$ **0.00001**							
5									
6		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
7	**Derivation of Forecast Sales @ Transmission Level:** [1]	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11
8	Total Per TO3-Cycle 4 Filing - MWh (Statement BD)	1,922,249	1,690,306	1,643,648	1,693,675	1,744,802	1,637,717	1,618,732	1,557,545
9	Exclude Sale for Resale	2	2	2	2	2	2	2	2
10	Total Forecast Sales Net of Resale - MWh	1,922,248	1,690,305	1,643,647	1,693,674	1,744,801	1,637,716	1,618,731	1,557,544
11	Transmission Level Adjustment Factor from (TO3-Cycle 4)	1.04081	1.04081	1.04081	1.04081	1.04081	1.04081	1.04081	1.04081
12	Conversion Factor from MWh to kWh	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
13	Total Forecast Sales Net of Resale - kWh	2,000,688,252	1,759,280,403	1,710,718,439	1,762,786,881	1,816,000,210	1,704,545,414	1,684,785,697	1,621,101,852
14									
15	**Cyclical Period Filing**	**Cycle - 5**	**Cycle - 5**	**Cycle - 5**	**Cycle - 5**	**Cycle - 5**	**Cycle - 5**	**Cycle - 5**	Cycle - 6
16	**Amortization of TO3-Cycle 3 Interest TU Adjustment:** [2]	**Sep-10**	**Oct-10**	**Nov-10**	**Dec-10**	**Jan-11**	**Feb-11**	**Mar-11**	Apr-11
17	Beginning True-Up Adjustment Balance	$ 163,548	$ 144,250	$ 126,110	$ 109,424	$ 92,115	$ 73,902	$ 57,491	$ -
18	Recorded Sales Less Sale for Resale@***Transmission Level***	1,929,802	1,814,041	1,668,601	1,730,891	1,821,266	1,641,144	1,662,271	-
19	Conversion Factor from MWh to kWh	1,000	1,000	1,000	1,000	1,000	1,000	1,000	-
20	Recorded Sales in Total kWh @ ***Transmission Level***	1,929,802,429	1,814,041,416	1,668,601,019	1,730,890,762	1,821,266,163	1,641,143,985	1,662,270,810	-
21	Amortization Rate Per kWh @ ***Transmission Level***	$ 0.00001	$ 0.00001	$ 0.00001	$ 0.00001	$ 0.00001	$ 0.00001	$ 0.00001	$ -
22	Amortization of TO3-Cycle 3 Interest TU Adjustment [3]	$ **19,298**	$ **18,140**	$ **16,686**	$ **17,309**	$ **18,213**	$ **16,411**	$ **16,623**	$ -
23	Ending TO3-Cycle 3 Interest TU Adjusment Balance	$ 144,250	$ 126,110	$ 109,424	$ 92,115	$ 73,902	$ 57,491	$ 40,868	$ -
24									

NOTES:

1 The derivation of forecast sales shown on lines 8 through 12 indicates the forecast sales used on line 3 to develop the amortization rate during the rate effective period.

2 On lines 15 through 20, SDG&E is taking the product between the amortization rate on line 4 and the recorded sales on 20, to indicate the amortization of the true-up adjustment over the rate effective September 2010 through August 2011.

3 The monthly true-up adjustment amortization amount shown on line 22 has been calculated through 3/31/2011, which is the end of the cycle 5 true-up adjustment period. Future monthly amortization amounts have not been shown since the amounts will be shown in the instant statement of the TO3; Cycle 6 filing.

Section 3.1A
SAN DIEGO GAS ELECTRIC
TO3-Cycle 5 Annual Transmission Formulaic Rate Filing
Amortization of TO3-Cycle 3 Interest True-Up Adjustment

Line No.	Description	(i)	(j)	(k)	(l)	(m)	Reference	Line No.
1	**Derivation of Amortization Rates:**						TO3-Cycle 4	1
2	TO3-Cycle 3 Interest True-Up Adjustment from Cycle 4						Vol. 2 of 3; Section 3.1B; Pg.1.2; Line 21	2
3	TO3-Cycle 4 Forecast Sales @ Transmission Level (kWh)						See Line 13 Below	3
4	Amortization Rate Per kWh @ ***Transmission Level***						Line 2 / Line 3	4
5								5
6		(i)	(j)	(k)	(l)	(m)		6
7	**Derivation of Forecast Sales @ Transmission Level:** [1]	May-11	Jun-11	Jul-11	Aug-11	Total	TO3-Cycle 4	7
8	Total Per TO3-Cycle 4 Filing - MWh (Statement BD)	1,563,385	1,651,390	1,813,253	1,855,819	20,392,521	True-Up Period; Statement BDWPs	8
9	Exclude Sale for Resale	2	2	2	2	18	Sale for Resale	9
10	Total Forecast Sales Net of Resale - MWh	1,563,384	1,651,389	1,813,252	1,855,818	20,392,503	Line 8 Minus Line 9	10
11	Transmission Level Adjustment Factor from (TO3-Cycle 4)	1.04081	1.04081	1.04081	1.04081		Statement BB; Page 1; Col.(B);Line 16	11
12	Conversion Factor from MWh to kWh	1,000	1,000	1,000	1,000		MWH Conversion Factor	12
13	Total Forecast Sales Net of Resale - kWh	1,627,180,164	1,718,776,366	1,887,244,475	1,931,547,457	21,224,655,611	Line 10 x Line 11 x Line 12	13
14								14
15	**Cyclical Period Filing**	Cycle - 6	Cycle - 6	Cycle - 6	Cycle - 6			15
16	**Amortization of TO3-Cycle 3 Interest TU Adjustment:** [2]	May-11	Jun-11	Jul-11	Aug-11	Total	Amortization Period 9/10 - 8/11	16
17	Beginning True-Up Adjustment Balance	$ -	$ -	$ -	$ -		Beginning Balance	17
18	Recorded Sales Less Sale for Resale@***Transmission Level***	-	-	-	-		Section 3.3.3; Page 12.1; Line 28; Sep-Mar.	18
19	Conversion Factor from MWh to kWh	-	-	-	-		Conversion Factor	19
20	Recorded Sales in Total kWh @ ***Transmission Level***	-	-	-	-	12,268,016,583	Line 18 x Line 19	20
21	Amortization Rate Per kWh @ ***Transmission Level***	$ -	$ -	$ -	$ -		See Line 4 Above; Column (a)	21
22	Amortization of TO3-Cycle 3 Interest TU Adjustment [3]	$ -	$ -	$ -	$ -	$ 122,680	Line 20 x Line 21	22
23	Ending TO3-Cycle 3 Interest TU Adjusment Balance	$ -	$ -	$ -	$ -		Line 17 Minus Line 22	23
24								24

NOTES:

1 The derivation of forecast sales shown on lines 8 through 12 indicates the forecast sales used on line 3 to develop the amortization rate during the rate effective period.

2 On lines 15 through 20, SDG&E is taking the product between the amortization rate on line 4 and the recorded sales on 20, to indicate the amortization of the true-up adjustment over the rate effective September 2010 through August 2011.

3 The monthly true-up adjustment amortization amount shown on line 22 has been calculated through 3/31/2011, which is the end of the cycle 5 true-up adjustment period. Future monthly amortization amounts have not been shown since the amounts will be shown in the instant statement of the TO3; Cycle 6 filing.

Section 3.1 – Wholesale True-Up Adjustment

Section (c): Amortization of TO3 Cycle 2 True-Up Adjustment and Interest True-Up Adjustment

Part (ii): Amortization of TO3-Cycle 2 Interest True-Up Adjustment (April 2010 – August 2010)

- The amortization of the Cycle 2 Interest True-Up Adjustment in the instant Cycle 5 filing is from April 2010 through August 2010.

- The amortization of the Cycle 2 Interest True-Up Adjustment from September 2009 through March 2010 was picked up in the Cycle 4 filing last year.

Section 3.1A
San Diego Gas and Electric Company
TO3-Cycle 5 Annual Transmission Formula Filing
Amortization of TO3-Cycle 2 Interest True-Up Adjustment - CAISO WHOLESALE

Line No.	Description	(a) Amounts	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	**Interest True-Up Adjustment Amortization Rates:**								
2	Interest True-Up on TO3-Cycle 2 True-Up Adjustment	**$ 453,005**							
3	TO3-Cycle 3 Forecast Sales @ Transmission Level (kWh)	21,965,833,823							
4	Estimated Amortization Rate Per kWh @ ***Transmission Level***	**$ 0.00002**							
5									
6		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
7	**Derivation of Forecast Sales @ Transmission Level:** [1]	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10
8	Total Per TO3-Cycle 3 Filing - MWh (Statement BD)	2,010,448	1,718,513	1,693,225	1,751,701	1,787,375	1,686,424	1,675,587	1,576,628
9	Exclude Sale for Resale	4	4	4	4	4	4	4	4
10	Total Forecast Sales Net of Resale - MWh	2,010,444	1,718,509	1,693,221	1,751,697	1,787,371	1,686,420	1,675,583	1,576,624
11	Transmission Level Adjustment Factor (TO3-Cycle 3)	1.04090	1.04090	1.04090	1.04090	1.04090	1.04090	1.04090	1.04090
12	Conversion Factor from MWh to kWh	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
13	Total Forecast Sales Net of Resale - kWh	2,092,673,349	1,788,797,890	1,762,475,583	1,823,343,315	1,860,476,421	1,755,396,415	1,744,116,170	1,641,109,639
14									
15		Cycle - 4	Cycle - 4	Cycle - 4	Cycle - 4	Cycle - 4	Cycle - 4	Cycle - 4	**Cycle - 5**
16	**Amortization of Interest TU Adjustment Applicable to TO3-Cycle 2:** [2]	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	**Apr-10**
17	Beginning True-Up Adjustment Balance	$ 453,005	$ 413,142	$ 377,150	$ 342,967	$ 308,082	$ 272,898	$ 239,957	$ 208,589
18	Recorded Sales in Total MWh Excludes Sale for Resale	1,993,153	1,799,611	1,709,134	1,744,239	1,759,201	1,647,034	1,568,382	1,588,897
19	Conversion Factor from MWh to kWh	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
20	Recorded Sales in Total kWh @ ***Transmission Level***	1,993,152,560	1,799,610,814	1,709,134,141	1,744,239,008	1,759,201,392	1,647,034,236	1,568,381,768	1,588,896,642
21	Amortization Rate Per kWh @ ***Transmission Level***	$ 0.00002	$ 0.00002	$ 0.00002	$ 0.00002	$ 0.00002	$ 0.00002	$ 0.00002	$ 0.00002
22	Amortization of TO3-Cycle 2 Interest True-Up Adjustment [3]	$ 39,863	$ 35,992	$ 34,183	$ 34,885	$ 35,184	$ 32,941	$ 31,368	**$ 31,778**
23	Ending TO3-Cycle 2 Intereset True-Up Adjusment Balance	$ 413,142	$ 377,150	$ 342,967	$ 308,082	$ 272,898	$ 239,957	$ 208,589	$ 176,811
24									

NOTES:

1. The derivation of forecast sales shown on lines 8 through 13 indicates the forecast sales used on line 3 to develop the amortization rate during the rate effective period.
2. On lines 17 through 21, SDG&E is taking the product between the amortization rate on line 4 and the recorded sales on 20, to indicate the amortization of the true-up adjustment over the rate effective September 2009 through August 2010.
3. The monthly true-up adjustment amortization amount shown on line 22 calculated from September 2009 through March was included in the cycle 4 true-up adjustment. The monthly true-up amortization amount shown on line 19 from April 2010 through August 2010 is included in this cycle 5 filing. This completes the amortization of of TO3 Cycle 2 True-Up Adjustment.

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Section 3.1A
San Diego Gas and Electric Company
TO3-Cycle 5 Annual Transmission Formula Filing
Amortization of TO3-Cycle 2 Interest True-Up Adjustment - CAISO WHOLESALE

Line No.	Description	(i)	(j)	(k)	(l)	(m)	Reference	Line No.
1	**Interest True-Up Adjustment Amortization Rates:**						TO3-Cycle 3	1
2	Interest True-Up on TO3-Cycle 2 True-Up Adjustment						Vol. 2 of 3; Section 3.1A; Pg.1.2; Line 20	2
3	TO3-Cycle 3 Forecast Sales @ Transmission Level (kWh)						See Line 13 Below	3
4	Estimated Amortization Rate Per kWh @ ***Transmission Level***						Line 2 / Line 3	4
5								5
6		(i)	(j)	(k)	(l)	(m)		6
7	**Derivation of Forecast Sales @ Transmission Level:** [1]	May-10	Jun-10	Jul-10	Aug-10	Total	TO3-Cycle 3	7
8	Total Per TO3-Cycle 3 Filing - MWh (Statement BD)	1,615,032	1,719,830	1,935,604	1,932,391	21,102,758	True-Up Period; Statement BDWPs	8
9	Exclude Sale for Resale	4	4	4	4	48	Sale for Resale	9
10	Total Forecast Sales Net of Resale - MWh	1,615,028	1,719,826	1,935,600	1,932,387	21,102,710	Line 8 Minus Line 9	10
11	Transmission Level Adjustment Factor (TO3-Cycle 3)	1.04090	1.04090	1.04090	1.04090		Statement BB; Page 1; Col.(B);Line 16	11
12	Conversion Factor from MWh to kWh	1,000	1,000	1,000	1,000		MWH Conversion Factor	12
13	Total Forecast Sales Net of Resale - kWh	1,681,084,404	1,790,168,757	2,014,768,148	2,011,423,733	21,965,833,823	Line 10 x Line 11 x Line 12	13
14								14
15		**Cycle - 5**	**Cycle - 5**	**Cycle - 5**	**Cycle - 5**			15
16	**Amortization of Interest TU Adjustment Applicable to TO3-Cycle 2:** [2]	**May-10**	**Jun-10**	**Jul-10**	**Aug-10**	Total	Amortization Period 9/09 - 8/10	16
17	Beginning True-Up Adjustment Balance	$ 176,811	$ 146,731	$ 114,194	$ 78,653		Beginning Balance	17
18	Recorded Sales in Total MWh Excludes Sale for Resale	1,504,010	1,626,856	1,777,050	1,667,144		Section 3.3.3; Page 12.1; Line 28; Sep-Mar.	18
19	Conversion Factor from MWh to kWh	1,000	1,000	1,000	1,000		Conversion Factor	19
20	Recorded Sales in Total kWh @ ***Transmission Level***	1,504,009,827	1,626,856,156	1,777,050,414	1,667,144,323	20,384,711,282	Line 18 x Line 19	20
21	Amortization Rate Per kWh @ ***Transmission Level***	$ 0.00002	$ 0.00002	$ 0.00002	$ 0.00002		See Line 4 Above; Column (a)	21
22	Amortization of TO3-Cycle 2 Interest True-Up Adjustment [3]	**$ 30,080**	**$ 32,537**	**$ 35,541**	**$ 78,653**	$ 453,005	Line 20 x Line 21	22
23	Ending TO3-Cycle 2 Intereset True-Up Adjusment Balance	$ 146,731	$ 114,194	$ 78,653	$ -		Line 17 Minus Line 22	23
24								24

NOTES:

1 The derivation of forecast sales shown on lines 8 through 13 indicates the forecast sales used on line 3 to develop the amortization rate during the rate effective period.

2 On lines 17 through 21, SDG&E is taking the product between the amortization rate on line 4 and the recorded sales on 20, to indicate the amortization of the true-up adjustment over the rate effective September 2009 through August 2010.

3 The monthly true-up adjustment amortization amount shown on line 22 calculated from September 2009 through March was included in the cycle 4 true-up adjustment. The monthly true-up amortization amount shown on line 19 from April 2010 through August 2010 is included in this cycle 5 filing. This completes the amortization of of TO3 Cycle 2 True-Up Adjustment.

Section 3.1 – Wholesale True-Up Adjustment

Section (c): Amortization of TO3 Cycle 2 True-Up Adjustment and Interest True-Up Adjustment

Part (iii): Amortization of TO3-Cycle 2 Interest True-Up Adjustment Accrued After Fully Amortized

- The amortization of the TO3 Cycle 2 Interest True-Up Adjustment Accrued After Fully Amortized in the instant Cycle 5 filing is from September 2010 through March 2011.
- The amortization of the TO3 Cycle 2 Interest True-Up Adjustment Accrued After Full Amortization from April 2011 through August 2011will be picked up in the Cycle 6 filing.

Section 3.1A
San Diego Gas & Electric
TO3 Cycle 5 Annual Transmission Formula Filing
Amortization of TO3 Cycle 2 Interest TU Adjustment Accrued After Fully Amortized

Line No.	Description	(a) Amounts	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	**Derivation of Amortization Rates:**								
2	TO3-Cycle 2 Interest True-Up Adjustment from Cycle 4	$ **34,045**							
3	TO3-Cycle 4 Forecast Sales @ Transmission Level (kWh)	21,224,655,611							
4	Amortization Rate Per kWh @ ***Transmission Level***	$ **0.000002**							
5									
6		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
7	**Derivation of Forecast Sales @ Transmission Level:** [1]	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11
8	Total Per TO3-Cycle 4 Filing - MWh (Statement BD)	1,922,249	1,690,306	1,643,648	1,693,675	1,744,802	1,637,717	1,618,732	1,557,545
9	Exclude Sale for Resale	2	2	2	2	2	2	2	2
10	Total Forecast Sales Net of Resale - MWh	1,922,248	1,690,305	1,643,647	1,693,674	1,744,801	1,637,716	1,618,731	1,557,544
11	Transmission Level Adjustment Factor (TO3-Cycle 4)	1.04081	1.04081	1.04081	1.04081	1.04081	1.04081	1.04081	1.04081
12	Conversion Factor from MWh to kWh	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
13	Total Forecast Sales Net of Resale - kWh	2,000,688,252	1,759,280,403	1,710,718,439	1,762,786,881	1,816,000,210	1,704,545,414	1,684,785,697	1,621,101,852
14									
15		Cycle - 5	Cycle - 5	Cycle - 5	Cycle - 5	Cycle - 5	Cycle - 5	Cycle - 5	Cycle - 6
16	**Amortization of TO3-Cycle 2 Interst TU Adjustment:** [2]	**Sep-10**	**Oct-10**	**Nov-10**	**Dec-10**	**Jan-11**	**Feb-11**	**Mar-11**	Apr-11
17	Beginning True-Up Adjustment Balance	$ 34,045	$ 30,185	$ 26,557	$ 23,220	$ 19,758	$ 16,115	$ 12,833	$ -
18	Recorded Sales Less Sale for Resale@***Transmission Level***	1,929,802	1,814,041	1,668,601	1,730,891	1,821,266	1,641,144	1,662,271	-
19	Conversion Factor from MWh to kWh	1,000	1,000	1,000	1,000	1,000	1,000	1,000	-
20	Recorded Sales in Total kWh @ ***Transmission Level***	1,929,802,429	1,814,041,416	1,668,601,019	1,730,890,762	1,821,266,163	1,641,143,985	1,662,270,810	-
21	Amortization Rate Per kWh @ ***Transmission Level***	$ 0.000002	$ 0.000002	$ 0.000002	$ 0.000002	$ 0.000002	$ 0.000002	$ 0.000002	$ -
22	Amortization of TO3-Cycle 2 Interest TU Adjustment [3]	$ **3,860**	$ **3,628**	$ **3,337**	$ **3,462**	$ **3,643**	$ **3,282**	$ **3,325**	$ -
23	Ending TO3-Cycle 2 Interest TU Adjusment Balance	$ 30,185	$ 26,557	$ 23,220	$ 19,758	$ 16,115	$ 12,833	$ 9,508	$ -
24									

NOTES:

1 The derivation of forecast sales shown on lines 8 through 12 indicates the forecast sales used on line 3 to develop the amortization rate during the rate effective period.

2 On lines 15 through 20, SDG&E is taking the product between the amortization rate on line 4 and the recorded sales on 20, to indicate the amortization of the true-up adjustment over the rate effective September 2010 through August 2011.

3 The monthly true-up adjustment amortization amount shown on line 22 has been calculated through 3/31/2011, which is the end of the cycle 5 true-up adjustment period. Future monthly amortization amounts have not been shown since the amounts will be shown in the instant statement of the TO3; Cycle 6 filing.

Section 3.1A
San Diego Gas & Electric
TO3 Cycle 5 Annual Transmission Formula Filing
Amortization of TO3 Cycle 2 Interest TU Adjustment Accrued After Fully Amortized

Line No.	Description	(i)	(j)	(k)	(l)	(m)	Reference	Line No.
1	**Derivation of Amortization Rates:**						TO3-Cycle 4	1
2	TO3-Cycle 2 Interest True-Up Adjustment from Cycle 4						Vol. 2 of 3; Section 3.1B; Pg.1.2; Line 21	2
3	TO3-Cycle 4 Forecast Sales @ Transmission Level (kWh)						See Line 13 Below	3
4	Amortization Rate Per kWh @ ***Transmission Level***						Line 2 / Line 3	4
5								5
6		(i)	(j)	(k)	(l)	(m)		6
7	**Derivation of Forecast Sales @ Transmission Level:** [1]	May-11	Jun-11	Jul-11	Aug-11	Total	TO3-Cycle 4	7
8	Total Per TO3-Cycle 4 Filing - MWh (Statement BD)	1,563,385	1,651,390	1,813,253	1,855,819	20,392,521	True-Up Period; Statement BDWPs	8
9	Exclude Sale for Resale	2	2	2	2	18	Sale for Resale	9
10	Total Forecast Sales Net of Resale - MWh	1,563,384	1,651,389	1,813,252	1,855,818	20,392,503	Line 8 Minus Line 9	10
11	Transmission Level Adjustment Factor (TO3-Cycle 4)	1.04081	1.04081	1.04081	1.04081		Statement BB; Page 1; Col.(B);Line 16	11
12	Conversion Factor from MWh to kWh	1,000	1,000	1,000	1,000		MWH Conversion Factor	12
13	Total Forecast Sales Net of Resale - kWh	1,627,180,164	1,718,776,366	1,887,244,475	1,931,547,457	21,224,655,611	Line 10 x Line 11 x Line 12	13
14								14
15		Cycle - 6	Cycle - 6	Cycle - 6	Cycle - 6			15
16	**Amortization of TO3-Cycle 2 Interst TU Adjustment:** [2]	May-11	Jun-11	Jul-11	Aug-11	Total	Amortization Period 9/10 - 8/11	16
17	Beginning True-Up Adjustment Balance	$ -	$ -	$ -	$ -		Beginning Balance	17
18	Recorded Sales Less Sale for Resale@***Transmission Level***	-	-	-	-		Section 3.3.3; Page 12.1; Line 28; Sep-Mar.	18
19	Conversion Factor from MWh to kWh	-	-	-	-		Conversion Factor	19
20	Recorded Sales in Total kWh @ ***Transmission Level***	-	-	-	-	12,268,016,583	Line 18 x Line 19	20
21	Amortization Rate Per kWh @ ***Transmission Level***	$ -	$ -	$ -	$ -		See Line 4 Above; Column (a)	21
22	Amortization of TO3-Cycle 2 Interest TU Adjustment [3]	$ -	$ -	$ -	$ -	$ 24,537	Line 20 x Line 21	22
23	Ending TO3-Cycle 2 Interest TU Adjusment Balance	$ -	$ -	$ -	$ -		Line 17 Minus Line 22	23
24								24

NOTES:

1 The derivation of forecast sales shown on lines 8 through 12 indicates the forecast sales used on line 3 to develop the amortization rate during the rate effective period.

2 On lines 15 through 20, SDG&E is taking the product between the amortization rate on line 4 and the recorded sales on 20, to indicate the amortization of the true-up adjustment over the rate effective September 2010 through August 2011.

3 The monthly true-up adjustment amortization amount shown on line 22 has been calculated through 3/31/2011, which is the end of the cycle 5 true-up adjustment period. Future monthly amortization amounts have not been shown since the amounts will be shown in the instant statement of the TO3; Cycle 6 filing.

Section 3.1 – Wholesale True-Up Adjustment

Section (d): Amortization of TO2 Final True-Up Adjustment and Interest True-Up Adjustment

Part (ii): Amortization of the Final TO2 Interest True-Up Adjustment (April 2010 – August 2010)

- The amortization of the Final TO2 Interest True-Up Adjustment in the instant Cycle 5 filing is from April 2010 through August 2010.

- The amortization of the Final TO2 Interest True-Up Adjustment from September 2009 through March 2010 was picked up in the TO3 Cycle 4 filing.

Section 3.1A
San Diego Gas and Electric Company
TO3-Cycle 5 Annual Transmission Formula Filing
Amortization of TO2 FINAL Interest True-Up Adjustment - CAISO WHOLESALE

Line No.	Description	(a) Amounts	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	**Interest True-Up Adjustment Amortization Rates:**									
2	Interest True-Up on TO2-Final True-Up Adjustments	$ **2,009,621**								
3	TO3-Cycle 3 Forecast Sales @ Transmission Level (kWh)	21,965,833,823								
4	Estimated Amortization Rate Per kWh @ ***Transmission Level***	$ **0.00009**								
5										
6		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
7	**Derivation of Forecast Sales @ Transmission Level:** [1]	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10
8	Total Per TO3-Cycle 3 Filing - MWh (Statement BD)	2,010,448	1,718,513	1,693,225	1,751,701	1,787,375	1,686,424	1,675,587	1,576,628	1,615,032
9	Exclude Sale for Resale	4	4	4	4	4	4	4	4	4
10	Total Forecast Sales Net of Resale - MWh	2,010,444	1,718,509	1,693,221	1,751,697	1,787,371	1,686,420	1,675,583	1,576,624	1,615,028
11	Transmission Level Adjustment Factor (TO3-Cycle 3)	1.04090	1.04090	1.04090	1.04090	1.04090	1.04090	1.04090	1.04090	1.04090
12	Conversion Factor from MWh to kWh	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
13	Total Forecast Sales Net of Resale - kWh	2,092,673,349	1,788,797,890	1,762,475,583	1,823,343,315	1,860,476,421	1,755,396,415	1,744,116,170	1,641,109,639	1,681,084,404
14										
15		Cycle - 4	Cycle - 4	Cycle - 4	Cycle - 4	Cycle - 4	Cycle - 4	Cycle - 4	**Cycle - 5**	**Cycle - 5**
16	**Amortization of Interest TU Adjustment (TO2-Final TU):** [2]	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	**Apr-10**	**May-10**
17	Beginning True-Up Adjustment Balance	$ 2,009,621	$ 1,830,237	$ 1,668,272	$ 1,514,450	$ 1,357,468	$ 1,199,140	$ 1,050,907	$ 909,753	$ 766,752
18	Recorded Sales in Total MWh Excludes Sale for Resale	1,993,153	1,799,611	1,709,134	1,744,239	1,759,201	1,647,034	1,568,382	1,588,897	1,504,010
19	Conversion Factor from MWh to kWh	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
20	Recorded Sales in Total kWh @ ***Transmission Level***	1,993,152,560	1,799,610,814	1,709,134,141	1,744,239,008	1,759,201,392	1,647,034,236	1,568,381,768	1,588,896,642	1,504,009,827
21	Amortization Rate Per kWh @ ***Transmission Level***	$ 0.00009	$ 0.00009	$ 0.00009	$ 0.00009	$ 0.00009	$ 0.00009	$ 0.00009	$ 0.00009	$ 0.00009
22	Amortization of TO2 FINAL Interest True-Up Adjustment [3]	$ 179,384	$ 161,965	$ 153,822	$ 156,982	$ 158,328	$ 148,233	$ 141,154	$ **143,001**	$ **135,361**
23	Ending TO2-Final TU Interest True-Up Adjusment Balance	$ 1,830,237	$ 1,668,272	$ 1,514,450	$ 1,357,468	$ 1,199,140	$ 1,050,907	$ 909,753	$ 766,752	$ 631,391
24										

NOTES:

1 The derivation of forecast sales shown on lines 8 through 12 indicates the forecast sales used on line 3 to develop the amortization rate during the rate effective period.

2 On lines 15 through 20, SDG&E is taking the product between the amortization rate on line 4 and the recorded sales on 20, to indicate the amortization of the true-up adjustment over the rate effective September 2009 through August 2010.

3 The monthly true-up adjustment amortization amount shown on line 22 calculated from 9/2010 through 3/31/2010 was included in the Cycle 4 true-adjustmnet. The monthly true-up amortization amounts shown on line 19 from April 2010 through August 2010 is included in this cycle 5 filing. This completes the amortization of TO2 Final Interest True-Up Adjustment.

Section 3.1A
San Diego Gas and Electric Company
TO3-Cycle 5 Annual Transmission Formula Filing
Amortization of TO2 FINAL Interest True-Up Adjustment - CAISO WHOLESALE

Line No.	Description	(j)	(k)	(l)	(m)	Reference	Line No.
1	**Interest True-Up Adjustment Amortization Rates:**					TO3-Cycle 3	1
2	Interest True-Up on TO2-Final True-Up Adjustments					Vol. 2 of 3; Section 3.1A; Pg.2.2; Line 20	2
3	TO3-Cycle 3 Forecast Sales @ Transmission Level (kWh)					See Line 13 Below	3
4	Estimated Amortization Rate Per kWh @ ***Transmission Level***					Line 2 / Line 3	4
5							5
6		(j)	(k)	(l)	(m)		6
7	**Derivation of Forecast Sales @ Transmission Level:** [1]	Jun-10	Jul-10	Aug-10	Total	TO3-Cycle 3	7
8	Total Per TO3-Cycle 3 Filing - MWh (Statement BD)	1,719,830	1,935,604	1,932,391	21,102,758	True-Up Period; Statement BDWPs	8
9	Exclude Sale for Resale	4	4	4	48	Sale for Resale	9
10	Total Forecast Sales Net of Resale - MWh	1,719,826	1,935,600	1,932,387	21,102,710	Line 8 Minus Line 9	10
11	Transmission Level Adjustment Factor (TO3-Cycle 3)	1.04090	1.04090	1.04090		Statement BB; Page 1; Line 16	11
12	Conversion Factor from MWh to kWh	1,000	1,000	1,000		MWH Conversion Factor	12
13	Total Forecast Sales Net of Resale - kWh	1,790,168,757	2,014,768,148	2,011,423,733	21,965,833,823	Line 10 x Line 11 x Line 12	13
14							14
15		**Cycle - 5**	**Cycle - 5**	**Cycle - 5**			15
16	**Amortization of Interest TU Adjustment (TO2-Final TU):** [2]	**Jun-10**	**Jul-10**	**Aug-10**	Total	Amortization Period 9/09 - 8/10	16
17	Beginning True-Up Adjustment Balance	$ 631,391	$ 484,974	$ 325,039		Beginning Balance	17
18	Recorded Sales in Total MWh Excludes Sale for Resale	1,626,856	1,777,050	1,667,144		Section 3.3.3; Page 12.1; Line 28; Sep-Mar.	18
19	Conversion Factor from MWh to kWh	1,000	1,000	1,000		Conversion Factor	19
20	Recorded Sales in Total kWh @ ***Transmission Level***	1,626,856,156	1,777,050,414	1,667,144,323	20,384,711,282	Line 18 x Line 19	20
21	Amortization Rate Per kWh @ ***Transmission Level***	$ 0.00009	$ 0.00009	$ -		See Line 4 Above; Column (a)	21
22	Amortization of TO2 FINAL Interest True-Up Adjustment [3]	**$ 146,417**	**$ 159,935**	**$ 325,039**	$ 2,009,621	Line 20 x Line 21	22
23	Ending TO2-Final TU Interest True-Up Adjusment Balance	$ 484,974	$ 325,039	$ -		Line 17 Minus Line 22	23
24							24

NOTES:

1 The derivation of forecast sales shown on lines 8 through 12 indicates the forecast sales used on line 3 to develop the amortization rate during the rate effective period.

2 On lines 15 through 20, SDG&E is taking the product between the amortization rate on line 4 and the recorded sales on 20, to indicate the amortization of the true-up adjustment over the rate effective September 2009 through August 2010.

3 The monthly true-up adjustment amortization amount shown on line 22 calculated from 9/2010 through 3/31/2010 was included in the Cycle 4 true-adjustmnet. The monthly true-up amortization amounts shown on line 19 from April 2010 through August 2010 is included in this cycle 5 filing. This completes the amortization of TO2 Final Interest True-Up Adjustment.

Section 3.1 – Wholesale True-Up Adjustment

Section (d): Amortization of TO2 Final True-Up Adjustment and Interest True-Up Adjustment

Part (iii): Amortization of the Final TO2 Interest True-Up Adjustment Accrued After Fully Amortized (September 2010 through March 2011)

- The amortization of the Final TO2 Interest True-Up Adjustment accrued after fully amortized in the instant Cycle 5 filing is from September 2010 through March 2011.

- The remaining balance of the interest accrued after full amortization will be from April 2011 through August 2011 and will be shown in next year's Cycle 6 filing.

Section 3.1A
SAN DIEGO GAS ELECTRIC
TO3-Cycle 5 Annual Transmission Formulaic Rate Filing
Amortization of TO2-Final Interest True-Up Adjustment

Line No.	Description	(a) Amounts	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	**Derivation of Amortization Rates:**								
2	TO2-FINAL Interest True-Up Adjustment from Cycle 4	**$ 149,469**							
3	TO3-Cycle 4 Forecast Sales @ Transmission Level (kWh)	21,224,655,611							
4	Amortization Rate Per kWh @ ***Transmission Level***	**$ 0.00001**							
5									
6		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
7	**Derivation of Forecast Sales @ Transmission Level:** [1]	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11
8	Total Per TO3-Cycle 4 Filing - MWh (Statement BD)	1,922,249	1,690,306	1,643,648	1,693,675	1,744,802	1,637,717	1,618,732	1,557,545
9	Exclude Sale for Resale	2	2	2	2	2	2	2	2
10	Total Forecast Sales Net of Resale - MWh	1,922,248	1,690,305	1,643,647	1,693,674	1,744,801	1,637,716	1,618,731	1,557,544
11	Transmission Level Adjustment Factor (TO3-Cycle 4)	1.04081	1.04081	1.04081	1.04081	1.04081	1.04081	1.04081	1.04081
12	Conversion Factor from MWh to kWh	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
13	Total Forecast Sales Net of Resale - kWh	2,000,688,252	1,759,280,403	1,710,718,439	1,762,786,881	1,816,000,210	1,704,545,414	1,684,785,697	1,621,101,852
14									
15		**Cycle - 5**	**Cycle - 5**	**Cycle - 5**	**Cycle - 5**	**Cycle - 5**	**Cycle - 5**	**Cycle - 5**	Cycle - 6
16	**Amortization of TO2-FINAL Interest TU Adjustment:** [2]	**Sep-10**	**Oct-10**	**Nov-10**	**Dec-10**	**Jan-11**	**Feb-11**	**Mar-11**	Apr-11
17	Beginning True-Up Adjustment Balance	$ 149,469	$ 130,171	$ 112,031	$ 95,345	$ 78,036	$ 59,823	$ 43,412	$ -
18	Recorded Sales Less Sale for Resale@***Transmission Level***	1,929,802	1,814,041	1,668,601	1,730,891	1,821,266	1,641,144	1,662,271	-
19	Conversion Factor from MWh to kWh	1,000	1,000	1,000	1,000	1,000	1,000	1,000	-
20	Recorded Sales in Total kWh @ ***Transmission Level***	1,929,802,429	1,814,041,416	1,668,601,019	1,730,890,762	1,821,266,163	1,641,143,985	1,662,270,810	-
21	Amortization Rate Per kWh @ ***Transmission Level***	$ 0.00001	$ 0.00001	$ 0.00001	$ 0.00001	$ 0.00001	$ 0.00001	$ 0.00001	$ -
22	Amortization of TO2-FINAL Interest TU Adjustment [3]	**$ 19,298**	**$ 18,140**	**$ 16,686**	**$ 17,309**	**$ 18,213**	**$ 16,411**	**$ 16,623**	$ -
23	Ending TO2-FINAL Interest TU Adjusment Balance	$ 130,171	$ 112,031	$ 95,345	$ 78,036	$ 59,823	$ 43,412	$ 26,789	$ -
24									

NOTES:

1 The derivation of forecast sales shown on lines 8 through 12 indicates the forecast sales used on line 3 to develop the amortization rate during the rate effective period.

2 On lines 15 through 20, SDG&E is taking the product between the amortization rate on line 4 and the recorded sales on 20, to indicate the amortization of the true-up adjustment over the rate effective September 2010 through August 2011.

3 The monthly true-up adjustment amortization amount shown on line 22 has been calculated through 3/31/2011, which is the end of the cycle 5 true-up adjustment period. Future monthly amortization amounts have not been shown since the amounts will be shown in the instant statement of the TO3; Cycle 6 filing.

Section 3.1A
SAN DIEGO GAS ELECTRIC
TO3-Cycle 5 Annual Transmission Formulaic Rate Filing
Amortization of TO2-Final Interest True-Up Adjustment

Line No.	Description	(i)	(j)	(k)	(l)	(m)	Reference	Line No.
1	**Derivation of Amortization Rates:**						TO3-Cycle 4	1
2	TO2-FINAL Interest True-Up Adjustment from Cycle 4						Vol. 2 of 3; Section 3.1B; Pg.1.2; Line 21	2
3	TO3-Cycle 4 Forecast Sales @ Transmission Level (kWh)						See Line 13 Below	3
4	Amortization Rate Per kWh @ ***Transmission Level***						Line 2 / Line 3	4
5								5
6		(i)	(j)	(k)	(l)	(m)		6
7	**Derivation of Forecast Sales @ Transmission Level:** [1]	May-11	Jun-11	Jul-11	Aug-11	Total	TO3-Cycle 4	7
8	Total Per TO3-Cycle 4 Filing - MWh (Statement BD)	1,563,385	1,651,390	1,813,253	1,855,819	20,392,521	True-Up Period; Statement BDWPs	8
9	Exclude Sale for Resale	2	2	2	2	18	Sale for Resale	9
10	Total Forecast Sales Net of Resale - MWh	1,563,384	1,651,389	1,813,252	1,855,818	20,392,503	Line 8 Minus Line 9	10
11	Transmission Level Adjustment Factor (TO3-Cycle 4)	1.04081	1.04081	1.04081	1.04081		Statement BB; Page 1; Col.(B);Line 16	11
12	Conversion Factor from MWh to kWh	1,000	1,000	1,000	1,000		MWH Conversion Factor	12
13	Total Forecast Sales Net of Resale - kWh	1,627,180,164	1,718,776,366	1,887,244,475	1,931,547,457	21,224,655,611	Line 10 x Line 11 x Line 12	13
14								14
15		Cycle - 6	Cycle - 6	Cycle - 6	Cycle - 6			15
16	**Amortization of TO2-FINAL Interest TU Adjustment:** [2]	May-11	Jun-11	Jul-11	Aug-11	Total	Amortization Period 9/10 - 8/11	16
17	Beginning True-Up Adjustment Balance	$ -	$ -	$ -	$ -		Beginning Balance	17
18	Recorded Sales Less Sale for Resale@***Transmission Level***	-	-	-	-		Section 3.3.3; Page 12.1; Line 28; Sep-Mar.	18
19	Conversion Factor from MWh to kWh	-	-	-	-		Conversion Factor	19
20	Recorded Sales in Total kWh @ ***Transmission Level***	-	-	-	-	12,268,016,583	Line 18 x Line 19	20
21	Amortization Rate Per kWh @ ***Transmission Level***	$ -	$ -	$ -	$ -		See Line 4 Above; Column (a)	21
22	Amortization of TO2-FINAL Interest TU Adjustment [3]	$ -	$ -	$ -	$ -	$ 122,680	Line 20 x Line 21	22
23	Ending TO2-FINAL Interest TU Adjusment Balance	$ -	$ -	$ -	$ -		Line 17 Minus Line 22	23
24								24

NOTES:

1 The derivation of forecast sales shown on lines 8 through 12 indicates the forecast sales used on line 3 to develop the amortization rate during the rate effective period.

2 On lines 15 through 20, SDG&E is taking the product between the amortization rate on line 4 and the recorded sales on 20, to indicate the amortization of the true-up adjustment over the rate effective September 2010 through August 2011.

3 The monthly true-up adjustment amortization amount shown on line 22 has been calculated through 3/31/2011, which is the end of the cycle 5 true-up adjustment period. Future monthly amortization amounts have not been shown since the amounts will be shown in the instant statement of the TO3; Cycle 6 filing.

Section – 3

Derivation of ISO Wholesale
True-Up Adjustment

Section 3.1B

Summary of CAISO-WHOLESALE
Interest True-Up Adjustment

Docket No. ER11-____-____

TO3-Cycle 4 CAISO-WHOLESALE

Interest True-Up Adjustment Calculation

Docket No. ER11-____-____

Section 3.1B

San Diego Gas and Electric Company

TO3-Cycle 5 Annual Transmission Formulaic Rate Filing

Deriviation of Interest True-Up Adjustment Applicable to TO3-Cycle 4 - CAISO Wholesale

Line No.	Description	(a) Apr-10	(b) May-10	(c) Jun-10	(d) Jul-10	(e) Aug-10	(f) Sep-10	(g) Oct-10	(h) Nov-10
	From TO3-Cycle 4 Filing; Vol. 2; Sect 3.1B; Page 1.2; Line 21								
1	**Beginning Balance (Overcollection)/Undercollection:**	$ 26,556,669	$ 26,628,372	$ 26,702,731	$ 26,774,434	$ 26,849,402	$ 26,924,371	$ 24,526,514	$ 22,269,965
2									
5	**Part A1: Amortization of TU Balance:**								
6	Total Recorded Sales kWhs @ ***Transmission Level***	-	-	-	-	-	1,929,802,424	1,814,041,412	1,668,601,015
7									
8	Rate Per kWh @ ***Transmission Level***	$ -	$ -	$ -	$ -	$ -	$ 0.00128	$ 0.00128	$ 0.00128
9									
10	Amortization of True-Up Balance	$ -	$ -	$ -	$ -	$ -	$ 2,470,147	$ 2,321,973	$ 2,135,809
11									
12	Net Monthly Collection/(Refunds)	$ -	$ -	$ -	$ -	$ -	$ (2,470,147)	$ (2,321,973)	$ (2,135,809)
13									
14	**Part A2: Calculation of Interest on Remaining TU Balance:**								
15	Interest Expense Calculations: [1]								
16	Beginning Balance for Interest Calculation	$ 26,556,669	$ 26,556,669	$ 26,556,669	$ 26,774,434	$ 26,774,434	$ 26,774,434	$ 24,526,514	$ 24,526,514
17	Monthly Activity Included in Interest Calculation Basis [2]	0	0	0	0	0	0	(1,160,987)	(3,389,878)
18	Basis for Interest Expense Calculation	26,556,669	26,556,669	26,556,669	26,774,434	26,774,434	26,774,434	23,365,528	21,136,637
19	Monthly Interest Rate	0.27000%	0.28000%	0.27000%	0.28000%	0.28000%	0.27000%	0.28000%	0.27000%
20	Interest Expense	$ 71,703	$ 74,359	$ 71,703	$ 74,968	$ 74,968	$ 72,291	$ 65,423	$ 57,069
21									
22	Ending Balance (Overcollection)/Undercollection	$ 26,628,372	$ 26,702,731	$ 26,774,434	$ 26,849,402	$ 26,924,371	$ 24,526,514	$ 22,269,965	$ 20,191,225
23		Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10
24	FERC INTEREST RATE	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%
25	Days in Year	365	365	365	365	365	365	365	365
26	Days in Month	30	31	30	31	31	30	31	30
27	Monthly Interest Rate - Calculated	0.27000%	0.28000%	0.27000%	0.28000%	0.28000%	0.27000%	0.28000%	0.27000%
28	FERC Interest Rates - Website	0.27000%	0.28000%	0.27000%	0.28000%	0.28000%	0.27000%	0.28000%	0.27000%
29	Difference	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%

NOTES:

1 Beginning Balance for Interest Calculation Remains Constant for 3 Month Quarter as Interest is Compounded Quarterly on these Amounts Pursuant to FERC Interest Methodology

2 Monthly Activity Calculated as Follows:

a) 1st Month of Quarter = Column A, Line 12 Divided by 2

b) 2nd Month of Quarter = Column A, Line 12 + (Column B, Line 12 Divided by 2)

c) 3rd Month of Quarter = Column A, Line 12 + Column B, Line 12 + (Column C, Line 12 Divided by 2)

Columns D, E, F, etc, Repeat Process as Indicated in a, b & c above

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Section 3.1B
San Diego Gas and Electric Company
TO3-Cycle 5 Annual Transmission Formulaic Rate Filing
Deriviation of Interest True-Up Adjustment Applicable to TO3-Cycle 4 - CAISO Wholesale

Line No.	Description	(i) Dec-10	(j) Jan-11	(k) Feb-11	(l) Mar-11	(m) Total	Reference	Line No.
	From TO3-Cycle 4 Filing; Vol. 2; Sect 3.1B; Page 1.2; Line 21							
1	**Beginning Balance (Overcollection)/Undercollection:**	$ 20,191,225	$ 18,028,776	$ 15,744,771	$ 13,680,725	$ 26,556,669	Previous Month's Ending Balance (Line 22)	1
2								2
5	**Part A1: Amortization of TU Balance:**							5
6	Total Recorded Sales kWhs @ ***Transmission Level***	1,730,890,758	1,821,266,159	1,641,143,981	1,662,270,806	12,268,016,555	Section 3.3.2; Page 121; Line 20; Sep 2010-Mar 2011.	6
7								7
8	Rate Per kWh @ ***Transmission Level***	$ 0.00128	$ 0.00128	$ 0.00128	$ 0.00128		Section 3.1B; Page 31; Line 10	8
9								9
10	Amortization of True-Up Balance	$ 2,215,540	$ 2,331,221	$ 2,100,664	$ 2,127,707	$ 15,703,061	Line 6 x Line 8	10
11								11
12	Net Monthly Collection/(Refunds)	$ (2,215,540)	$ (2,331,221)	$ (2,100,664)	$ (2,127,707)	$ (15,703,061)	Minus Line 10 (Columns a to l)	12
13								13
14	**Part A2: Calculation of Interest on Remaining TU Balance:**							14
15	Interest Expense Calculations: [1]							15
16	Beginning Balance for Interest Calculation	$ 24,526,514	$ 18,028,776	$ 18,028,776	$ 18,028,776		Balance at Beginning of Quarter (See Footnote 1)	16
17	Monthly Activity Included in Interest Calculation Basis [2]	(5,565,552)	(1,165,611)	(3,381,553)	(5,495,739)		See Footnote 2	17
18	Basis for Interest Expense Calculation	18,960,962	16,863,165	14,647,223	12,533,037		Line 16 + Line 17	18
19	Monthly Interest Rate	0.28000%	0.28000%	0.25000%	0.28000%		FERC Monthly Rates (Compounded Quarterly)	19
20	Interest Expense	$ 53,091	$ 47,217	$ 36,618	$ 35,093	$ 734,503	Line 18 x Line 19 (Columns A to L)	20
21								21
22	Ending Balance (Overcollection)/Undercollection	$ 18,028,776	$ 15,744,771	$ 13,680,725	$ 11,588,111	$ 11,588,111	Line 1 + Line 12 + Line 20	22
23		Dec-10	Jan-11	Feb-11	Mar-11			23
24	FERC INTEREST RATE	3.25%	3.25%	3.25%	3.25%		Annual Interest Rate - FERC Website	24
25	Days in Year	365	365	365	365	365	Number of Days Per Year	25
26	Days in Month	31	31	28	31	365	Number of Days Per Month	26
27	Monthly Interest Rate - Calculated	0.28000%	0.28000%	0.25000%	0.28000%	3.29000%	(Line 24)/(Line 25)x(Line 26)	27
28	FERC Interest Rates - Website	0.28000%	0.28000%	0.25000%	0.28000%	3.29000%	Monthly Interest Rate - FERC Website	28
29	Difference	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%		29

NOTES:

1 Beginning Balance for Interest Calculation Remains Constant for 3 M Amounts Pursuant to FERC Interest Methodology

2 Monthly Activity Calculated as Follows:
a) 1st Month of Quarter = Column A, Line 12 Divided by 2
b) 2nd Month of Quarter = Column A, Line 12 + (Column B, Line 12
c) 3rd Month of Quarter = Column A, Line 12 + Column B, Line 12 + Columns D, E, F, etc, Repeat Process as Indicated in a, b & c above

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TO3-Cycle 4 CAISO-WHOLESALE
Interest True-Up Adjustment
Amortization Rate Calculation

Docket No. ER11-____-____

Section 3.1B
San Diego Gas and Electric Company
TO3-Cycle 5 Annual Transmission Formulaic Rate Filing
Derivation of Amortization Rate for TO3-Cycle 4 - CAISO Wholesale

Line No.	Description	(a) Total	(b) Sep-10	(c) Oct-10	(d) Nov-10	(e) Dec-10	(f) Jan-11	(g) Feb-11	(h) Mar-11
1	**Derivation of Amortization Rate for TO3-Cycle 4:**								
2	Beginning Balance (Overcollection)/Undercollection	$ 26,924,371							
3									
4	Recorded Sales Sept 10-March 11 @ ***Transmission Level:***	12,268,016,555	1,929,802,424	1,814,041,412	1,668,601,015	1,730,890,758	1,821,266,159	1,641,143,981	1,662,270,806
5									
6	Estimated Sales April 11-Aug 11 @ ***Transmission Level:***	8,785,351,775							
7									
8	Total Sales (kWh) - ***Transmission Level:***	21,053,368,330							
9									
10	Amortization Rate Per kWh @ ***Transmission Level:***	$ 0.00128							
11									

000031

Section 3.1B
San Diego Gas and Electric Company
TO3-Cycle 5 Annual Transmission Formulaic Rate Filing
Derivation of Amortization Rate for TO3-Cycle 4 - CAISO Wholesale

Line No.	Description	(a) Total	(i) Apr-11	(j) May-11	(k) Jun-11	(l) Jul-11	(m) Aug-11	Reference	Line No.
1	**Derivation of Amortization Rate for TO3-Cycle 4:**							TO3-Cycle 5 Filing	1
2	Beginning Balance (Overcollection)/Undercollection	$ 26,924,371						Vol. 2B; Section 3.1B; Pg. 1; Line 22	2
3								TO3-Cycle 5 Filing	3
4	Recorded Sales Sept 10-March 11 @ ***Transmission Level:***	12,268,016,555						Vol. 2B; Sect. 3.3.3; Pg. 12.1; Line 28 x 1000	4
5								TO3-Cycle 5 Filing	5
6	Estimated Sales April 11-Aug 11 @ ***Transmission Level:***	8,785,351,775	1,620,950,970	1,626,948,227	1,718,506,009	1,887,192,716	1,931,753,853	Vo. 2B; Section 3.2.2; Page 16.1; Line 21	6
7									7
8	Total Sales (kWh) - ***Transmission Level:***	21,053,368,330						Sum Lines 4 & 6	8
9									9
10	Amortization Rate Per kWh @ ***Transmission Level:***	$ 0.00128						Line 28 / Line 34	10
11									11

000032

TO3-Cycle 3 CAISO-WHOLESALE
Interest True-Up Adjustment Calculation

Docket No. ER11-____-____

Section 3.1B
San Diego Gas and Electric Company
TO3-Cycle 5 Annual Transmission Formulaic Rate Filing
Derivation of Interest True-Up Adjustment Applicable to TO3-Cycle 3 - CAISO Wholesale

Line No.	Description	(a) Apr-10	(b) May-10	(c) Jun-10	(d) Jul-10	(e) Aug-10	(f) Sep-10	(g) Oct-10	(h) Nov-10
1	**From TO3-Cycle 4 Filing; Vol. 2; Sect 3.1B; Page 1.2; Line 21 Beginning Balance (Overcollection)/Undercollection:**	$ 2,591,135	$ 2,152,639	$ 1,736,936	$ 1,285,459	$ 790,788	$ -	$ -	$ -
2									
5	**Part A1: Amortization of TU Balance:**								
6	Total Recorded Sales kWhs @ ***Transmission Level***	1,588,896,642	1,504,009,827	1,626,856,156	1,777,050,414	1,667,144,323	-	-	-
7									
8	Rate Per kWh @ ***Transmission Level***	$ 0.00028	$ 0.00028	$ 0.00028	$ 0.00028	$ 0.00028	$ -	$ -	$ -
9									
10	Amortization of True-Up Balance	$ 444,891	$ 421,123	$ 455,520	$ 497,574	$ 791,885	$ -	$ -	$ -
11									
12	Net Monthly Collection/(Refunds)	$ (444,891)	$ (421,123)	$ (455,520)	$ (497,574)	$ (791,885)	$ -	$ -	$ -
13									
14	**Part A2: Calculation of Interest on Remaining TU Balance:**								
15	Interest Expense Calculations: [1]								
16	Beginning Balance for Interest Calculation	$ 2,591,135	$ 2,591,135	$ 2,591,135	$ 1,285,459	$ 1,285,459	$ -	$ -	$ -
17	Monthly Activity Included in Interest Calculation Basis [2]	(222,446)	(655,453)	(1,093,774)	(248,787)	(893,517)	-	-	-
18	Basis for Interest Expense Calculation	2,368,689	1,935,682	1,497,361	1,036,672	391,943	-	-	-
19	Monthly Interest Rate	0.27000%	0.28000%	0.27000%	0.28000%	0.28000%	0.27000%	0.28000%	0.27000%
20	Interest Expense	$ 6,395	$ 5,420	$ 4,043	$ 2,903	$ 1,097	$ -	$ -	$ -
21									
22	Ending Balance (Overcollection)/Undercollection	$ 2,152,639	$ 1,736,936	$ 1,285,459	$ 790,788	$ -	$ -	$ -	$ -
23		Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10
24	FERC INTEREST RATE	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%
25	Days in Year	365	365	365	365	365	365	365	365
26	Days in Month	30	31	30	31	31	30	31	30
27	Monthly Interest Rate - Calculated	0.27000%	0.28000%	0.27000%	0.28000%	0.28000%	0.27000%	0.28000%	0.27000%
28	FERC Interest Rates - Website	0.27000%	0.28000%	0.27000%	0.28000%	0.28000%	0.27000%	0.28000%	0.27000%
29	Difference	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%

NOTES:

1 Beginning Balance for Interest Calculation Remains Constant for 3 Month Quarter as Interest is Compounded Quarterly on these Amounts Pursuant to FERC Interest Methodology

2 Monthly Activity Calculated as Follows:
a) 1st Month of Quarter = Column A, Line 12 Divided by 2
b) 2nd Month of Quarter = Column A, Line 12 + (Column B, Line 12 Divided by 2)
c) 3rd Month of Quarter = Column A, Line 12 + Column B, Line 12 + (Column C, Line 12 Divided by 2)
Columns D, E, F, etc, Repeat Process as Indicated in a, b & c above

Section 3.1B
San Diego Gas and Electric Company
TO3-Cycle 5 Annual Transmission Formulaic Rate Filing
Derivation of Interest True-Up Adjustment Applicable to TO3-Cycle 3 - CAISO Wholesale

Line No.	Description	(i) Dec-10	(j) Jan-11	(k) Feb-11	(l) Mar-11	(m) Total	Reference	Line No.
	From TO3-Cycle 4 Filing; Vol. 2; Sect 3.1B; Page 1.2; Line 21							
1	**Beginning Balance (Overcollection)/Undercollection:**	$ -	$ -	$ -	$ -	$ 2,591,135	Previous Month's Ending Balance (Line 22)	1
2								2
5	**Part A1: Amortization of TU Balance:**							5
6	Total Recorded Sales kWhs @ ***Transmission Level***	-	-	-	-	8,163,957,363	Section 3.3.2; Page 121; Line 20; Apr. 2010-Aug 2010.	6
7								7
8	Rate Per kWh @ ***Transmission Level***	$ -	$ -	$ -	$ -		Section 3.1B; Page 37; Line 10	8
9								9
10	Amortization of True-Up Balance	$ -	$ -	$ -	$ -	$ 2,610,993	Line 6 x Line 8	10
11								11
12	Net Monthly Collection/(Refunds)	$ -	$ -	$ -	$ -	$ (2,610,993)	Minus Line 10 (Columns a to l)	12
13								13
14	**Part A2: Calculation of Interest on Remaining TU Balance:**							14
15	Interest Expense Calculations: [1]							15
16	Beginning Balance for Interest Calculation	$ -	$ -	$ -	$ -		Balance at Beginning of Quarter (See Footnote 1)	16
17	Monthly Activity Included in Interest Calculation Basis [2]	-	-	-	-		See Footnote 2	17
18	Basis for Interest Expense Calculation	-	-	-	-		Line 16 + Line 17	18
19	Monthly Interest Rate	0.28000%	0.28000%	0.25000%	0.28000%		FERC Monthly Rates (Compounded Quarterly)	19
20	Interest Expense	$ -	$ -	$ -	$ -	$ 19,858	Line 18 x Line 19 (Columns A to L)	20
21								21
22	Ending Balance (Overcollection)/Undercollection	$ -	$ -	$ -	$ -	$ 0	Line 1 + Line 12 + Line 20	22
23		Dec-10	Jan-11	Feb-11	Mar-11			23
24	FERC INTEREST RATE	3.25%	3.25%	3.25%	3.25%		Annual Interest Rate - FERC Website	24
25	Days in Year	365	365	365	365	365	Number of Days Per Year	25
26	Days in Month	31	31	28	31	365	Number of Days Per Month	26
27	Monthly Interest Rate - Calculated	0.28000%	0.28000%	0.25000%	0.28000%	3.29000%	(Line 24)/(Line 25)x(Line 26)	27
28	FERC Interest Rates - Website	0.28000%	0.28000%	0.25000%	0.28000%	3.29000%	Monthly Interest Rate - FERC Website	28
29	Difference	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%		29

NOTES:

1 Beginning Balance for Interest Calculation Remains Constant for 3 M Amounts Pursuant to FERC Interest Methodology

2 Monthly Activity Calculated as Follows:
a) 1st Month of Quarter = Column A, Line 12 Divided by 2
b) 2nd Month of Quarter = Column A, Line 12 + (Column B, Line 12 :
c) 3rd Month of Quarter = Column A, Line 12 + Column B, Line 12 + Columns D, E, F, etc, Repeat Process as Indicated in a, b & c above

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TO3-Cycle 3 CAISO-WHOLESALE
Interest True-Up Adjustment
Amortization Rate Calculation

Docket No. ER11-____-____

Section 3.1B-Part 1.B
San Diego Gas and Electric Company
TO3-Cycle 5 Annual Transmission Formula Filing
Derivation of Amortization Rate for TO3-Cycle 3 - CAISO WHOLESALE

Line No.	Description	(a) Total	(b) Sep-09	(c) Oct-09	(d) Nov-09	(e) Dec-09	(f) Jan-10	(g) Feb-10	(h) Mar-10
1	**Derivation of Amortization Rate for TO3-Cycle 3:**								
2	Beginning Balance (Overcollection)/Undercollection	$ 5,932,154							
3									
4	Recorded Sales Sept 09-March 10 @ ***Transmission Level:***	12,220,753,919	1,993,152,560	1,799,610,814	1,709,134,141	1,744,239,008	1,759,201,392	1,647,034,236	1,568,381,768
5									
6	Estimated Sales April 10-Aug 10 @ ***Transmission Level:***	9,138,740,928							
7									
8	Forecast Sales TO3-Cycle 3 (kWh) ***Transmission Level:***	21,359,494,847							
9									
10	Amortization Rate Per kWh @ ***Transmission Level:***	$ 0.00028							
11									

Section 3.1B-Part 1.B
San Diego Gas and Electric Company
TO3-Cycle 5 Annual Transmission Formula Filing
Derivation of Amortization Rate for TO3-Cycle 3 - CAISO WHOLESALE

Line No.	Description	(i) Apr-10	(j) May-10	(k) Jun-10	(l) Jul-10	(m) Aug-10	Reference	Line No.
1	<u>**Derivation of Amortization Rate for TO3-Cycle 3:**</u>						TO3-Cycle 3 Filing	1
2	Beginning Balance (Overcollection)/Undercollection						Vol. 2 of 3; Section 3.1B; Pg. 1.2; Line 21	2
3							TO3-Cycle 4 Filing	3
4	Recorded Sales Sept 09-March 10 @ ***Transmission Level:***						Vol. 2; Sect. 3.3.3; Pg. 12.1; Line 28 x 1000	4
5							TO3-Cycle 4 Filing	5
6	Estimated Sales April 10-Aug 10 @ ***Transmission Level:***	1,641,153,286	1,680,923,228	1,790,005,613	2,014,955,398	2,011,703,403	Vo. 2; Section 3.2.2; Page 16.1; Line 21	6
7								7
8	Forecast Sales TO3-Cycle 3 (kWh) ***Transmission Level:***						Sum Lines 4 & 6	8
9								9
10	Amortization Rate Per kWh @ ***Transmission Level:***						Line 28 / Line 34	10
11								11

Section – 3.2

Derivation of Monthly Recorded ISO True-Up Revenues

Section 3.2.1

Derivation of ISO Cost of Service Rates in Effect for the First 5 Months of the TU Period Based on SDG&E's TO3-3rd Cycle ISO Wholesale Cost of Service.

Docket No. ER11-____-____

Section 3.2.1

SAN DIEGO GAS AND ELECTRIC COMPANY
TO3-Cycle 5 Annual Transmission Formulaic Rate Filing
Allocation of CYCLE-3 WHOLESALE Cost of Service to Customer Classes
Based on TO3-CYCLE-3 12 CPs
($1,000)

Line No.	Customer Classes	(a) Total 12 CPs @ Transmission Level [2]	(b) 12 CP Allocation Percentages @ Transmission Level [3]	(c) Allocated Base Transmission Revenue Requirement	(d) Reference	Line No.
1	Total Base Transmission Revenue Requirement [1]			$ 265,570	TO3-Cycle 3; Docket No. ER09-1601	1
2					Statement BK2; Pg 8 of 8; Ln 15; Col. 1	2
3	<u>Allocation of BTRR Based on 12-CP:</u>					3
4	Residential	14,606,871	39.47%	$ 104,820	Col.C4 = Col (c) Ln1 x Col B. Ln 4	4
5	Small Commercial	4,797,362	12.96%	34,418	Col.C5 = Col (c) Ln1 x Col B. Ln 5	5
6	Medium & Large Commercial/Industrial	16,875,789	45.61%	121,126	Col.C6 = Col (c) Ln1 x Col B. Ln 6	6
7	Street Lighting Revenues	144,681	0.39%	1,036	Col.C7 = Col (c) Ln1 x Col B. Ln 7	7
8	Standby Revenues	579,517	1.57%	4,169	Col.C8 = Col (c) Ln1 x Col B. Ln 8	8
9						9
10	Total	37,004,220	100.00%	$ 265,569	Sum Lines 4 thru 8	10
11						11
12	Total	37,004,220		$ 265,569	Line 10	12

NOTES:

1 Statement refers to SDG&E's TO3, Cycle 3, Cost Statements as derived by SDG&E in Docket No. ER09-1601, filed on August 15, 2009 and approved by the FERC on September 29, 2009. See Statement BK-2; Page 8 of 8; Line 15.

2 See Section 3.2.2; Page 9; Column D. Information comes from the TO3, Cycle 3 transmission rate case filing Docket No. ER09-1601 filed with the FERC on August 15, 2009 and approved on September 29, 2009.

3 See Section 3.2.2; Page 9; Column E.

Section 3.2.1

SAN DIEGO GAS AND ELECTRIC COMPANY
TO3-Cycle 5 Annual Transmission Formulaic Rate Filing
Derivation of TO3-CYCLE-3 WHOLESALE Rates Using TO3-CYCLE-3 Billing Determinants
Residential Customers [1]
($000)

Line No.	Customer Classes	Derivation of Commodity Rate & Proof of Revenues Calculation	Reference	Line No.
1	Residential - Allocated Transmission Revenue Requirements	$ 104,820	Section 3.2.1; Page 1; Line 4	1
2				2
3	Billing Determinants - Residential Customer Class @ MWh:	7,913,871	Section 3.2.1; Page 16.1; Line 4	3
4				4
5	Transmission Level Adjustment Factor	1.04570	Section 3.2.1; Page 14; Col. B; Line 2	5
6				6
7	Billing Determinants @ Transmission Level	8,275,535	Line 3 x Line 5	7
8				8
9	Residential Energy Rate Per kWh	$ 0.0126663	Line 1 / Line 7	9
10				10
11	Residential Energy Rate Per kWh - Rounded	$ 0.0126663	Line 9, Rounded to 7 Decimal Places	11
12				12
13	Proof of Revenues	$ 104,820	Line 7 x Line 11	13
14				14
15	Difference	$ (0)	Line 1 - Line 13	15

Notes:

1 Residential customers include the following California Public Utilities Commission (CPUC) tariffs: DR, DR-LI, DR-TOU, EV-TOU, EV-TOU-2, EV-TOU-3, DR-TV, D-SMF.

Section 3.2.1

SAN DIEGO GAS AND ELECTRIC COMPANY
TO3-Cycle 5 Annual Transmission Formulaic Rate Filing
Derivation of TO3-CYCLE-3 WHOLESALE Rates Using TO3-CYCLE-3 Billing Determinants
Small Commercial Customers [1]
($000)

Line No.	Customer Classes	Derivation of Commodity Rate & Proof of Revenues Calculation	Reference	Line No.
1	Small Commercial - Allocated Transmission Revenue Requirement	$ 34,418	Section 3.2.1; Page 1; Line 5	1
2				2
3	Billing Determinants - Small Commercial @ MWh:	2,219,947	Section 3.2.1; Page 16.1; Line 8	3
4				4
5	Transmission Level Adjustment Factor	1.04570	Section 3.2.1; Page 14; Col. B; Line 3	5
6				6
7	Billing Determinants @ Transmission Level	2,321,398	Line 3 x Line 5	7
8				8
9	Energy Rate Per kWh @ Transmission Level	$ 0.0148264	Line 1 / Line 7	9
10				10
11	Energy Rate Per kWh - Rounded @ Transmission Level	$ 0.0148264	Line 9, Rounded to 7 Decimal Places	11
12				12
13	Proof of Revenues	$ 34,418	Line 7 x Line 11	13
14				14
15	Difference	$ 0	Line 1 - Line 13	15

Notes:

1 Small commercial customers include the following California Public Utilities Commission (CPUC) tariffs: A, A-TC, A-TOU, PA.

Section 3.2.1
SAN DIEGO GAS AND ELECTRIC COMPANY
TO3-Cycle 5 Annual Transmission Formulaic Rate Filing
Derivation of TO3-CYCLE-3 WHOLESALE Rates Using TO3-CYCLE-3 Billing Determinants
Medium-Large Commercial Customers [1]
($000)

Line No.	Customer Classes	Derivation of Demand Rates & Proof of Revenues Calculation	Reference	Line No.
1	**Med-Lrg C&I - Demand Revenue Requirement:**	$ 121,126	Section 3.2.1; Page 1; Line 6	1
2	*Non-Coincident Demand Determinants @ Transmission Level Used*			2
3	*to Allocate Total Customer Class Revenues to Voltage Level:*			3
4	Secondary [2]	23,725	Section 3.2.1; Page 14; Line 22; Col. C.	4
5	Primary [2]	4,571	Section 3.2.1; Page 14; Line 23; Col. C.	5
6	Transmission [2]	1,335	Section 3.2.1; Page 14; Line 24; Col. C.	6
7	Total	29,631	Sum Lines 4; 5; 6	7
8	*Allocation Factors Per Above to Allocate*			8
9	*Demand Revenue Requirements to Voltage Level:*			9
10	Secondary	80.07%	Line 4 / Line 7	10
11	Primary	15.43%	Line 5 / Line 7	11
12	Transmission	4.51%	Line 6 / Line 7	12
13	Total	100.00%	Sum Lines 10; 11; 12	13
14				14
15	**Allocation of Revenue Requirements to Voltage Level:**			15
16	Secondary	$ 96,983	Line 1 x Line 10	16
17	Primary	18,685	Line 1 x Line 11	17
18	Transmission	5,457	Line 1 x Line 12	18
19	Total	$ 121,125	Sum Lines 16; 17; 18	19
20				20
21	**Non-Coincident Demand Determinants by Voltage Level @ Transmission Level:**			21
22	Secondary	23,725	Section 3.2.1; Page 14; Line 22; Col. C.	22
23	Primary	4,571	Section 3.2.1; Page 14; Line 23; Col. C.	23
24	Transmission	1,335	Section 3.2.1; Page 14; Line 24; Col. C.	24
25	Total	29,631	Sum Lines 22; 23; 24	25
26				26
27	**Non-Coincident Demand Rate By Voltage Level @ Transmission:**			27
28	Secondary	$ 4.0877977	Line 16 / Line 22	28
29	Primary	$ 4.0877270	Line 17 / Line 23	29
30	Transmission	$ 4.0876404	Line 18 / Line 24	30
31				31
32	**Non-Coincident Demand Rate By Voltage Level @ Transmission Level:**			32
33	Secondary	$ 4.0877977	Line 28 Rounded to 7 Decimal Places	33
34	Primary	$ 4.0877270	Line 29 Rounded to 7 Decimal Places	34
35	Transmission	$ 4.0876404	Line 30 Rounded to 7 Decimal Places	35
36				36
37	**Proof of Revenue Calculations:**			37
38	Secondary	$ 96,983	Line 22 x Line 33	38
39	Primary	18,685	Line 23 x Line 34	39
40	Transmission	5,457	Line 24 x Line 35	40
41	Total	$ 121,125	Sum Lines 38; 39; 40	41
42				42
43	Difference	$ 1	Line 1 - Line 41	43

Notes:

1 Medium-Large commercial customers include the following California Public Utilities Commission (CPUC) tariffs: AD, AY-TOU, AL-TOU, AL-TOU-CP, AL-TOU-DER, A6-TOU, PA-T-1.

2 LF = Transmission Loss Factor; Secondary Level = 1.0457; Primary Level = 1.0108; Transmission Level = 1.0000

Section 3.2.1
SAN DIEGO GAS AND ELECTRIC COMPANY
TO3-Cycle 5 Annual Transmission Formulaic Rate Filing
Derivation of TO3-CYCLE-3 WHOLESALE Rates Using TO3-CYCLE-3 Billing Determinants
Medium-Large Commercial Customers [1]
($000)

Line No.	Description	Derivation of Commodity Rate & Proof of Revenues Calculation	Reference	Line No.
1	Rate Proposal 90% of Total M&L C&I NCD Rates [1]	90.00%		1
2	Secondary	$ 3.6790179	90% x Section 3.2.1; Page 4; Line 33	2
3	Primary	$ 3.6789543	90% x Section 3.2.1; Page 4; Line 34	3
4	Tranmission	$ 3.6788764	90% x Section 3.2.1; Page 4; Line 35	4
5				5
6	Rate Proposal 90% of Total M&L C&I NCD Rates (Rounded)			6
7	Secondary	$ 3.6790179	Line 2, Rounded to 7 Decimal Places	7
8	Primary	$ 3.6789543	Line 3, Rounded to 7 Decimal Places	8
9	Tranmission	$ 3.6788764	Line 4, Rounded to 7 Decimal Places	9
10				10
11	**Pertaining to Schedules @ 90% NCD with Maximum On-Peak Period Demand[2]**			11
12	NCD Determinants By Voltage Level @ TRANSMISSION Level (MW)			12
13	Secondary	22,665	Section 3.2.1; Page 15; Line 10	13
14	Primary	4,208	Section 3.2.1; Page 15; Line 11	14
15	Tranmission	336	Section 3.2.1; Page 15; Line 12	15
16	Total	27,209	Sum Lines 12; 13; 14	16
17				17
18	Annual Revenues from Current NCD Rate 100% of Total M&L C&I NCD Rates			18
19	Secondary	$ 92,650	Line 13 x Section 3.2.1; Page 4; Line 33	19
20	Primary	$ 17,201	Line 14 x Section 3.2.1; Page 4; Line 34	20
21	Tranmission	$ 1,373	Line 15 x Section 3.2.1; Page 4; Line 35	21
22	Total	$ 111,225	Sum Lines 19; 20; 21	22
23				23
24	Annual Revenues from Proposed NCD Rate 90% of Total M&L C&I NCD Rates			24
25	Secondary	$ 83,385	Line 7 x Line 13	25
26	Primary	$ 15,481	Line 8 x Line 14	26
27	Tranmission	$ 1,236	Line 9 x Line 15	27
28	Total	$ 100,102	Sum Lines 25; 26; 27	28
29				29
30	Revenue Reallocation to Maximum On-Peak Period Demands			30
31	Secondary	$ 9,265	Line 19 - Line 25	31
32	Primary	$ 1,720	Line 20 - Line 26	32
33	Tranmission	$ 137	Line 21 - Line 27	33
34	Total	$ 11,122	Sum Lines 31; 32; 33	34
35				35
36	Pertaining to Schedules @ 90% NCD with Maximum Demand at Time of System Peak[3]			36
37	NCD Determinants By Voltage Level @ TRANSMISSION Level (MW)			37
38	Secondary	-	Section 3.2.1; Page 15; Col. D; Line 17	38
39	Primary	242	Section 3.2.1; Page 15; Col. D; Line 18	39
40	Tranmission	999	Section 3.2.1; Page 15; Col. D; Line 19	40
41	Total	1,241	Sum Lines 18; 19; 20	41
42				42
43	Annual Revenues from Current NCD Rate 100% of Total M&L C&I NCD Rates			43
44	Secondary	$ -	Line 38 x Section 3.2.1; Page 4; Line 33	44
45	Primary	$ 989	Line 39 x Section 3.2.1; Page 4; Line 34	45
46	Tranmission	$ 4,084	Line 40 x Section 3.2.1; Page 4; Line 35	46
47	Total	$ 5,073	Sum Lines 44; 45; 46	47
48				48
49	Annual Revenues from Proposed NCD Rate 90% of Total M&L C&I NCD Rates			49
50	Secondary	$ -	Line 7 x Line 38	50
51	Primary	$ 890	Line 8 x Line 39	51
52	Tranmission	$ 3,675	Line 9 x Line 40	52
53	Total	$ 4,566	Sum Lines 50; 51; 52	53
54				54
55	Revenue Reallocation to Maximum Demand at the Time of System Peak			55
56	Secondary	$ -	Line 44 - Line 50	56
57	Primary	$ 99	Line 45 - Line 51	57
58	Tranmission	$ 408	Line 46 - Line 52	58
59	Total	$ 507	Sum Lines 56; 57; 58	59

NOTES:

[1] 90% NCD Rates are applicable to the following California Public Utilities Commission (CPUC) tariffs:
AY-TOU, AL-TOU, AL-TOU-DER, DG-R, A6-TOU

[2] 90% NCD Rates and Maximum On-Peak Period Demand charges are applicable to the following California Public Utilities Commission (CPUC) tariffs:
AY-TOU, AL-TOU, AL-TOU-DER, DG-R

[3] 90% NCD Rates and Maximum Demand at Time of System Peak charges are applicable to the following California Public Utilities Commission (CPUC) tariffs:
A6-TOU

Section 3.2.1
SAN DIEGO GAS AND ELECTRIC COMPANY
TO3-Cycle 5 Annual Transmission Formulaic Rate Filing
Derivation of TO3-CYCLE-3 WHOLESALE Rates Using TO3-CYCLE-3 Billing Determinants
Medium-Large Commercial Customers [1]
($000)

Line No.	Description	Derivation of Commodity Rate & Proof of Revenues Calculation		Reference	Line No.
1	Med-Lrg C&I Maximum On-Peak Period Demand Proposal				1
2	Revenue Reallocation to Maximum On-Peak Period Demands [1]	$	11,122	Section 3.2.1; Page 5; Line 34	2
3					3
4	Summer Maximum On-Peak Period Demands By Voltage Level @ **Meter** Level (MW) [2]				4
5	Secondary		8,798	Section 3.2.1; Page 15; Col. B; Line 30	5
6	Primary		1,842	Section 3.2.1; Page 15; Col. B; Line 31	6
7	Tranmission		286	Section 3.2.1; Page 15; Col. B; Line 32	7
8	Total		10,926	Sum Lines 5; 6; 7	8
9					9
10	Summer Maximum On-Peak Period Demands @ Transmission Level (MW)				10
11	Secondary		9,200	Section 3.2.1; Page 15; Col. D; Line 30	11
12	Primary		1,862	Section 3.2.1; Page 15; Col. D; Line 31	12
13	Tranmission		286	Section 3.2.1; Page 15; Col. D; Line 32	13
14	Total		11,348	Sum Lines 11; 12; 13	14
15					15
16	Summer Maximum On-Peak Period Allocation to Voltage Levels				16
17	Secondary		81.07%	Line 11 / Line 14	17
18	Primary		16.41%	Line 12 / Line 14	18
19	Tranmission		2.52%	Line 13 / Line 14	19
20	Total		100.00%	Sum Lines 17; 18; 19	20
21	Share of Total Revenue Allocation to Summer Peak Period		**80.00%**	Share of Total Revenue Allocation to Summer Peak	21
22	Revenues for Proposed Summer Maximum On-Peak Period Demand Rates	$	8,898	Line 2 x Line 21	22
23	Secondary	$	7,214	(Line 2 x Line 21) x Line 17	23
24	Primary	$	1,460	(Line 2 x Line 21) x Line 18	24
25	Tranmission	$	224	(Line 2 x Line 21) x Line 19	25
26	Total	$	8,898	Sum Lines 23; 24; 25	26
27					27
28	Summer Maximum On-Peak Period Demand Rates [3]		$/kW		28
29	Secondary	$	0.7840997	Line 23 / Line 5	29
30	Primary	$	0.7840997	Line 24 / Line 6	30
31	Tranmission	$	0.7840997	Line 25 / Line 7	31
32					32
33					33
34	Summer Maximum On-Peak Period Demand Rates (Rounded)		$/kW		34
35	Secondary	$	0.7840997	Line 29, Rounded to 7 Decimal Places	35
36	Primary	$	0.7840997	Line 30, Rounded to 7 Decimal Places	36
37	Tranmission	$	0.7840997	Line 31, Rounded to 7 Decimal Places	37
38					38

NOTES:

1 Revenues to be reallocated from NCD to recovery from Maximum On-Peak Period Demands for the following California Public Utilities Commission (CPUC) tariffs:
AY-TOU, AL-TOU, AL-TOU-DER, DG-R

2 Summer Maximum On-Peak Period Determinants for the following California Public Utilities Commission (CPUC) tariffs:
AY-TOU, AL-TOU, AL-TOU-DER, DG-R

3 Summer Maximum On-Peak Period Demand Charges for the following California Public Utilities Commission (CPUC) tariffs:
AY-TOU, AL-TOU, AL-TOU-DER, DG-R

4 Winter Maximum On-Peak Period Determinants for the following California Public Utilities Commission (CPUC) tariffs:
AY-TOU, AL-TOU, AL-TOU-DER, DG-R

5 Winter Maximum On-Peak Period Demand Charges for the following California Public Utilities Commission (CPUC) tariffs:
AY-TOU, AL-TOU, AL-TOU-DER, DG-R

6 LF = Transmission Loss Factor; Secondary Level = 1.0457; Primary Level = 1.0108; Transmission Level = 1.0000

Section 3.2.1
SAN DIEGO GAS AND ELECTRIC COMPANY
TO3-Cycle 5 Annual Transmission Formulaic Rate Filing
Derivation of TO3-CYCLE-3 WHOLESALE Rates Using TO3-CYCLE-3 Billing Determinants
Medium-Large Commercial Customers [1]
($000)

Line No.	Description	Derivation of Commodity Rate & Proof of Revenues Calculation	Reference	Line No.
1	Winter Maximum On-Peak Period Demands By Voltage Level @ Meter Level (MW) [4]			1
2	Secondary	9,973	Section 3.2.1; Page 15; Col. B; ; Line 35	2
3	Primary	2,094	Section 3.2.1; Page 15; Col. B; ; Line 36	3
4	Tranmission	308	Section 3.2.1; Page 15; Col. B; ; Line 37	4
5	Total	12,375	Sum Lines 2; 3; 4	5
6				6
7	Winter Maximum On-Peak Period Demands @ TRANSMISSION Level (MW)			7
8	Secondary	10,429	Section 3.2.1; Page 15; Col. D; ; Line 35	8
9	Primary	2,117	Section 3.2.1; Page 15; Col. D; ; Line 36	9
10	Tranmission	308	Section 3.2.1; Page 15; Col. D; ; Line 37	10
11	Total	12,854	Sum Lines 8; 9; 10	11
12				12
13	Winter Maximum On-Peak Period Allocation to Voltage Levels			13
14	Secondary	81.13%	Line 8 / Line 11	14
15	Primary	16.47%	Line 9 / Line 11	15
16	Tranmission	2.40%	Line 10 / Line 11	16
17	Total	100.00%	Sum Lines 14; 15; 16	17
18	Share of Total Revenue Allocation to Winter Peak Period	20.00%	Share of Total Revenue Allocation to Winter Peak Period	18
19	Revenues for Proposed Winter Maximum On-Peak Period Demand Rates	$ 2,224	(Section 3.2.1; Page 5; Line 34) x Line 18	19
20	Secondary	$ 1,805	(Section 3.2.1; Page 5; Line 34 x Line 18) x Line 14	20
21	Primary	$ 366	(Section 3.2.1; Page 5; Line 34 x Line 18) x Line 15	21
22	Tranmission	$ 53	(Section 3.2.1; Page 5; Line 34 x Line 18) x Line 16	22
23	Total	$ 2,224	Sum Lines 20; 21; 22	23
24				24
25	Winter Maximum On-Peak Period Demand Rates [5]	$/kW		25
26	Secondary	$ 0.1730583	Line 20 / Line 8	26
27	Primary	$ 0.1730583	Line 21 / Line 9	27
28	Tranmission	$ 0.1730583	Line 22 / Line 10	28
29				29
30				30
31	Winter Maximum On-Peak Period Demand Rates (Rounded)	$/kW		31
32	Secondary	$ 0.1730583	Line 26, Rounded to 7 Decimal Places	32
33	Primary	$ 0.1730583	Line 27, Rounded to 7 Decimal Places	33
34	Tranmission	$ 0.1730583	Line 28, Rounded to 7 Decimal Places	34
35				35
36				36
37	Proof of Revenue Calculations:			37
38	Secondary	$ 9,019	(Section 3.2.1; Page 6; Line 11 x Section 3.2.1;Page 6; Line 35) + (Line 8 x Line 32)	38
39	Primary	$ 1,826	(Section 3.2.1; Page 6; Line 12 x Section 3.2.1; Page 6; Line 36) + (Line 9 x Line 33)	39
40	Tranmission	$ 278	(Section 3.2.1; Page 6; Line 13 x Section 3.2.1; Page 6; Line 37) + (Line 10 x Line 34)	40
41	Total	$ 11,122	Sum Lines 38; 39; 40	41
42				42
43	Difference	$ (0)	Section 3.2.1; Page 6; Line 2 Minus Page 7; Line 41	43
44				44

NOTES:

[1] Revenues to be reallocated from NCD to recovery from Maximum On-Peak Period Demands for the following California Public Utilities Commission (CPUC) tariffs:
AY-TOU, AL-TOU, AL-TOU-DER, DG-R

[2] Summer Maximum On-Peak Period Determinants for the following California Public Utilities Commission (CPUC) tariffs:
AY-TOU, AL-TOU, AL-TOU-DER, DG-R

[3] Summer Maximum On-Peak Period Demand Charges for the following California Public Utilities Commission (CPUC) tariffs:
AY-TOU, AL-TOU, AL-TOU-DER, DG-R

[4] Winter Maximum On-Peak Period Determinants for the following California Public Utilities Commission (CPUC) tariffs:
AY-TOU, AL-TOU, AL-TOU-DER, DG-R

[5] Winter Maximum On-Peak Period Demand Charges for the following California Public Utilities Commission (CPUC) tariffs:
AY-TOU, AL-TOU, AL-TOU-DER, DG-R

[6] LF = Transmission Loss Factor; Secondary Level = 1.0457; Primary Level = 1.0108; Transmission Level = 1.0000

Section 3.2.1
SAN DIEGO GAS AND ELECTRIC COMPANY
TO3-Cycle 5 Annual Transmission Formulaic Rate Filing
Derivation of TO3-CYCLE-3 WHOLESALE Rates Using TO3-CYCLE-3 Billing Determinants
Medium-Large Commercial Customers [1]
($000)

Line No.	Description	Derivation of Commodity Rate & Proof of Revenues Calculation	Reference	Line No.
1	Med-Lrg C&I Maximum Demand at the Time of System Peak Proposal			1
2	Revenue Reallocation to Maximum Demand at the Time of System Peak [1]	$ 507	Section 3.2.1; Page 5; Line 59	2
3				3
4	Summer Maximum Demand at the Time of System Peak By Voltage Level @ **Meter** Level (MW) [2]			4
5	Secondary	-	Section 3.2.1; Page 15; Col. B; Line 42	5
6	Primary	55	Section 3.2.1; Page 15; Col. B; Line 43	6
7	Transmission	326	Section 3.2.1; Page 15; Col. B; Line 44	7
8	Total	380	Sum Lines 5; 6; and 7	8
9				9
10	Summer Maximum Demand at the Time of System Peak @ **TRANSMISSION** Level (MW)			10
11	Secondary	-	Section 3.2.1; Page 15; Col. D; Line 42	11
12	Primary	55	Section 3.2.1; Page 15; Col. D; Line 43	12
13	Tranmission	326	Section 3.2.1; Page 15; Col. D; Line 44	13
14	Total	381	Sum Lines 11; 12; and 13	14
15				15
16	Summer Maximum Demand at the time of System Peak Allocation to Voltage Levels (MW)			16
17	Secondary	0.00%	Line 11 / Line 14	17
18	Primary	14.44%	Line 12 / Line 14	18
19	Tranmission	85.56%	Line 13 / Line 14	19
20	Total	100.00%	Sum Lines 17; 18; and 19	20
21	Share of Total Revenue Allocation to Summer Maximum Demand at the Time of System Peak	**80.00%**		21
22	Revenues for Proposed Summer Maximum Demand at the Time of System Peak Rates	$ 406	Line 2 x Line 21	22
23	Secondary	$ -	(Line 2 x Line 21) x Line 17	23
24	Primary	$ 59	(Line 2 x Line 21) x Line 18	24
25	Tranmission	$ 347	(Line 2 x Line 21) x Line 19	25
26	Total	$ 406	Sum Lines 23; 24; and 25	26
27				27
28	Summer Maximum Demand at the Time of System Peak Rates [3]	$/kW		28
29	Secondary	$ -	Line 23 / Line 11	29
30	Primary	$ 1.0651511	Line 24 / Line 12	30
31	Tranmission	$ 1.0651511	Line 25 / Line 13	31
32				32
33				33
34	Summer Maximum Demand at the Time of System Peak Rates (Rounded)	$/kW		34
35	Secondary	$ -	Line 29, Rounded to 7 Decimal Places	35
36	Primary	$ 1.0651511	Line 30, Rounded to 7 Decimal Places	36
37	Tranmission	$ 1.0651511	Line 31, Rounded to 7 Decimal Places	37
38				38

NOTES:

[1] Revenues to be reallocated from NCD to recovery from Maximum Demand at the time of System Peak for the following California Public Utilities Commission (CPUC) tariffs:
A6-TOU

[2] Summer Maximum Demand at the time of System Peak Determinants for the following California Public Utilities Commission (CPUC) tariffs:
A6-TOU

[3] Summer Maximum Demand at the time of System Peak Demand Charges for the following California Public Utilities Commission (CPUC) tariffs:
A6-TOU

[4] Winter Maximum Demand at the time of System Peak Determinants for the following California Public Utilities Commission (CPUC) tariffs:
A6-TOU

[5] Winter Maximum Demand at the time of System Peak Demand Charges for the following California Public Utilities Commission (CPUC) tariffs:
A6-TOU

[6] LF = Transmission Loss Factor; Secondary Level = 1.0457; Primary Level = 1.0108; Transmission Level = 1.0000

Section 3.2.1
SAN DIEGO GAS AND ELECTRIC COMPANY
TO3-Cycle 5 Annual Transmission Formulaic Rate Filing
Derivation of TO3-CYCLE-3 WHOLESALE Rates Using TO3-CYCLE-3 Billing Determinants
Medium-Large Commercial Customers [1]
($000)

Line No.	Description	Derivation of Commodity Rate & Proof of Revenues Calculation	Reference	Line No.
1	Winter Maximum Demand at the Time of System Peak By Voltage Level @ Meter Level (MW) [4]			1
2	Secondary	-	Section 3.2.1; Page 15; Col. B; Line 47	2
3	Primary	74	Section 3.2.1; Page 15; Col. B; Line 48	3
4	Tranmission	406	Section 3.2.1; Page 15; Col. B; Line 49	4
5	Total	480	Sum Lines 2; 3; 4	5
6				6
7	Winter Maximum Demand at the Time of System Peak @ Transmission Level (MW)			7
8	Secondary	-	Section 3.2.1; Page 15; Col. D; Line 47	8
9	Primary	75	Section 3.2.1; Page 15; Col. D; Line 48	9
10	Tranmission	406	Section 3.2.1; Page 15; Col. D; Line 49	10
11	Total	481	Sum Lines 8; 9; 10	11
12				12
13	Winter Maximum Demand at the Time of System Peak Allocation to Voltage Levels			13
14	Secondary	0.00%	Line 8 / Line 11	14
15	Primary	15.59%	Line 9 / Line 11	15
16	Tranmission	84.41%	Line 10 / Line 11	16
17	Total	100.00%	Sum Lines 14; 15; 16	17
18	Share of Total Revenue Allocation to Winter Maximum Demand at the Time of System Peak	20.00%		18
19	Revenues for Proposed Winter Maximum Demand at the Time of System Peak Rates	$ 101	Section 3.2.1; Page 8; Line 2	19
20	Secondary	$ -	(Section 3.2.1; Page 8; Line 2 x Line 17) x Line 14	20
21	Primary	$ 16	(Section 3.2.1; Page 8; Line 2 x Line 18) x Line 15	21
22	Tranmission	$ 86	(Section 3.2.1; Page 8; Line 2 x Line 19) x Line 16	22
23	Total	$ 101	Sum Lines 20; 21; 22	23
24				24
25	Winter Maximum Demand at the Time of System Peak Rates [5]	$/kW		25
26	Secondary	$ -	Line 20 / Line 8	26
27	Primary	$ 0.2109265	Line 21 / Line 9	27
28	Tranmission	$ 0.2109265	Line 21 / Line 10	28
29				29
30				30
31	Winter Maximum Demand at the Time of System Peak Rates (Rounded)	$/kW		31
32	Secondary	$ -	Line 26, Rounded to 7 Decimal Places	32
33	Primary	$ 0.2109265	Line 27, Rounded to 7 Decimal Places	33
34	Tranmission	$ 0.2109265	Line 28, Rounded to 7 Decimal Places	34
35				35
36				36
37	Proof of Revenue Calculations:			37
38	Secondary	$ -	Section 3.2.1; Page 8 (Line 5 x Line 35) + Page 9; (Line 8 x Line 32)	38
39	Primary	$ 74	Section 3.2.1; Page 8 (Line 6 x Line 36) + Page 9; (Line 9 x Line 33)	39
40	Tranmission	$ 433	Section 3.2.1; Page 8 (Line 7 x Line 37) + Page 9; (Line 10 x Line 34)	40
41	Total	$ 507	Sum Lines 38; 39; and 40	41
42				42
43	Difference	$ 0	Section 3.2.1; Page 8; Line 2 Minus Page 9; Line 41	43
44				44

NOTES:

[1] Revenues to be reallocated from NCD to recovery from Maximum Demand at the time of System Peak for the following California Public Utilities Commission (CPUC) tariffs:
A6-TOU

[2] Summer Maximum Demand at the time of System Peak Determinants for the following California Public Utilities Commission (CPUC) tariffs:
A6-TOU

[3] Summer Maximum Demand at the time of System Peak Demand Charges for the following California Public Utilities Commission (CPUC) tariffs:
A6-TOU

[4] Winter Maximum Demand at the time of System Peak Determinants for the following California Public Utilities Commission (CPUC) tariffs:
A6-TOU

[5] Winter Maximum Demand at the time of System Peak Demand Charges for the following California Public Utilities Commission (CPUC) tariffs:
A6-TOU

[6] LF = Transmission Loss Factor; Secondary Level = 1.0457; Primary Level = 1.0108; Transmission Level = 1.0000

Section 3.2.1

SAN DIEGO GAS AND ELECTRIC COMPANY

TO3-Cycle 5 Annual Transmission Formulaic Rate Filing

Derivation of TO3-CYCLE-3 WHOLESALE Rates Using TO3-CYCLE-3 Billing Determinants

Street Lighting Customers

($000)

Line No.	Customer Classes	Derivation of Commodity Rate & Proof of Revenues Calculation	Reference	Line No.
1	Street Lighting - Allocated Transmission Revenue Requirement	$ 1,036	Section 3.2.1; Page 1; Line 7	1
2				2
3	Billing Determinants - Street Lighting Customers @ MWh [1]:	111,661	Section 3.2.1; Page 16.1; Line 16	3
4				4
5	Transmission Level Adjustment Factor	1.04570	Section 3.2.1; Page 14; Col. B; Line 10	5
6				6
7	Billing Determinants @ Transmission Level	116,764	Line 3 x Line 5	7
8				8
9	Energy Rate Per kWh @ Transmission Level	$ 0.0088726	Line 1 / Line 7	9
10				10
11	Energy Rate Per kWh - Rounded @ Transmission Level	$ 0.0088726	Line 9, Rounded to 7 Decimal Places	11
12				12
13	Proof of Revenues	$ 1,036	Line 7 x Line 11	13
14				14
15	Difference	$ 0	Line 1 - Line 13	15

Notes:

[1] Street lighting customers include the following California Public Utilities Commission (CPUC) tariffs: DWL, OL-1, LS-1, LS-2.

Section 3.2.1
SAN DIEGO GAS AND ELECTRIC COMPANY
TO3-Cycle 5 Annual Transmission Formulaic Rate Filing
Derivation of TO3-CYCLE-3 WHOLESALE Rates Using TO3-CYCLE-3 Billing Determinants
Standby Revenues Calculation
($000)

Line No.	Customer Classes	Derivation of Standby Surcharge & Proof of Revenues Calculation	Reference	Line No.
1	**Standby - Demand Revenue Requirement:**	$ 4,169	Section 3.2.1; Page 1; Line 8	1
2	*Demand Determinants @ Transmission Level Used to Allocate*			2
3	*Total Class Revenues to Voltage Level:*			3
4	Secondary [1]	158	Section 3.2.1; Page 15; Col. D; Line 54	4
5	Primary [1]	1,037	Section 3.2.1; Page 15; Col. D; Line 55	5
6	Tranmission [1]	834	Section 3.2.1; Page 15; Col. D; Line 56	6
7	Total	2,029	Sum Lines 4; 5; 6	7
8	*Allocation Factors Per Above to Allocate*			8
9	*Demand Revenue Requirements to Voltage Level:*			9
10	Secondary	7.79%	Line 4 / Line 7	10
11	Primary	51.11%	Line 5 / Line 7	11
12	Tranmission	41.10%	Line 6 / Line 7	12
13	Total	100.00%	Sum Lines 10; 11; 12	13
14				14
15	**Allocation of Revenue Requirements to Voltage Level:**			15
16	Secondary	$ 325	Line 1 x Line 10	16
17	Primary	2,131	Line 1 x Line 11	17
18	Tranmission	1,713	Line 1 x Line 12	18
19	Total	$ 4,169	Sum Lines 16; 17; 18	19
20				20
21	**Demand Determinants By Voltage Level @ Transmission:**			21
22	Secondary	158	Section 3.2.1; Page 15; Col. D; Line 54	22
23	Primary	1,037	Section 3.2.1; Page 15; Col. D; Line 55	23
24	Tranmission	834	Section 3.2.1; Page 15; Col. D; Line 56	24
25	Total	2,029	Sum Lines 22; 23; 24	25
26				26
27	**Demand Rate By Voltage Level @ Transmission:**			27
28	Secondary	$ 2.0569620	Line 16 / Line 22	28
29	Primary	$ 2.0549662	Line 17 / Line 23	29
30	Tranmission	$ 2.0539568	Line 18 / Line 24	30
31				31
32	**Demand Rate By Voltage Level @ Transmission (Rounded):**			32
33	Secondary	$ 2.0569620	Line 28 Rounded to 7 Decimal Places	33
34	Primary	$ 2.0549662	Line 29 Rounded to 7 Decimal Places	34
35	Tranmission	$ 2.0539568	Line 30 Rounded to 7 Decimal Places	35
36				36
37	**Proof of Revenue Calculations:**			37
38	Secondary	$ 325	Line 22 x Line 33	38
39	Primary	2,131	Line 23 x Line 34	39
40	Tranmission	1,713	Line 24 x Line 35	40
41	Total	$ 4,169	Sum Lines 38; 39; 40	41
42				42
43	Difference	$ -	Line 1 - Line 41	43

Notes:

[1] LF = Transmission Loss Factor; Secondary Level = 1.0457; Primary Level = 1.0108; Transmission Level = 1.0000

Section 3.2.1
SAN DIEGO GAS AND ELECTRIC COMPANY
TO3-Cycle 5 Annual Transmission Formulaic Rate Filing
WHOLESALE - Rate Design Information
Summary of TO3-CYCLE-3 Wholesale Transmission Rates Based on TO3-CYCLE-3 Wholesale Cost of Service Using TO3-CYCLE-3 Forecast Billing Determinants

Line No.	Customer Classes	Transmission Energy Rates $/kWh	Transmission Level Demand Rates $/kW-Mo	Primary Level Demand Rates $/kW-Mo	Secondary Level Demand Rates $/kW-Mo	Reference	Line No.
1	Residential	$ 0.0126663				Section 3.2.1; Page 2; Line 11	1
2							2
3	Small Commercial	$ 0.0148264				Section 3.2.1; Page 3; Line 11	3
4							4
5	Med & Lrg Commercial/Industrial						5
6	Non-Coincident Demand (100%) [1]		$ 4.0876404	$ 4.0877270	$ 4.0877977	Section 3.2.1; Page 4; Lines 33;34;35	6
7							7
8	Non-Coincident Demand (90%) [2]		$ 3.6788764	$ 3.6789543	$ 3.6790179	Section 3.2.1; Page 5; Lines 7;8;9	8
9							9
10	Maximum On-Peak Demand [3]						10
11	Summer		$ 0.7840997	$ 0.7840997	$ 0.7840997	Section 3.2.1; Page 6; Lines 35;36;37	11
12	Winter		$ 0.1730583	$ 0.1730583	$ 0.1730583	Section 3.2.1; Page 7; Lines 32;33;34	12
13							13
14	Maximum Demand at the Time of System Peak [4]						14
15	Summer		$ 1.0651511	$ 1.0651511	$ -	Section 3.2.1; Page 8; Lines 29;30;31	15
16	Winter		$ 0.2109265	$ 0.2109265	$ -	Section 3.2.1; Page 9; Lines 32;33;34	16
17							17
18	Street Lighting	$ 0.0088726				Section 3.2.1; Page 10; Line 11	18
19							19
20	Standby Rate		$ 2.0539568	$ 2.0549662	$ 2.0569620	Section 3.2.1; Page 11; Lns 33;34;35	20

NOTES:

[1] Non-Coincident Demand (NCD) (100%) rates are applicable to the following California Public Utilities Commission (CPUC) tariffs: Schedules AD and PA-T-1

[2] NCD (90%) rates are applicable to the following CPUC tariffs: Schedules AY-TOU, AL-TOU, AL-TOU-DER, DG-R, and A6-TOU.

[3] Maximum On-Peak Demand rates are applicable to the following CPUC tariffs: Schedules AY-TOU, AL-TOU, AL-TOU-DER and DG-R

[4] Maximum Demand at the Time of System Peak rates are applicable to the following CPUC tariffs: Schedule A6-TOU

Section 3.2.1

SAN DIEGO GAS AND ELECTRIC COMPANY

TO3-Cycle 5 Annual Transmission Formulaic Rate Filing

WHOLESALE - Rate Design Information

Summary of TO3-CYCLE-3 Proof of Revenues Based on TO3-CYCLE-3 Wholesale Cost of Service

($1,000)

Line No.	Customer Classes	Total Revenues Per Cost of Service Study	Total Revenues Per Rate Design	Difference	Reference	Line No.
1	Residential Customers	$ 104,820	$ 104,820	$ (0)	Sect. 3.2.1; Pg. 1; Ln. 4; Pg. 2; Ln. 13	1
2						2
3	Small Commercial	34,418	34,418	0	Sect. 3.2.1; Pg. 1; Ln. 5; Pg. 3; Ln. 13	3
4						4
5	Med & Lrg Commercial/Industrial	121,126	121,125	1	Sect. 3.2.1; Pg. 1; Ln. 6; Pg. 4; Ln. 41	5
6						6
7	Street Lighting	1,036	1,036	0	Sect. 3.2.1; Pg. 1; Ln. 7; Pg. 10; Ln. 13	7
8						8
9	Standby Revenues	4,169	4,169	-	Sect. 3.2.1; Pg. 1; Ln. 8; Pg. 11; Ln. 41	9
10						10
11	Grand Total	$ 265,569	$ 265,568	$ 1	Sum Lines 1 thru 9	11

Section 3.2.1
SAN DIEGO GAS AND ELECTRIC COMPANY
TO3-Cycle 5 Annual Transmission Formulaic Rate Filing
WHOLESALE - Rate Design Information
Development of TO3-CYCLE-3 12-CP Allocation Factors and Voltage Level Allocation Factors

Line No.	Customer Class	(A) 10 Year Average Ending 12/31/2007 Of 12 CPs Kilowat @ Meter Level	(B) Transmission Loss Factors	(C) = (A) x (B) 10 Year Average Ending 12/31/2007 Of 12 CPs Kilowat @ Transmission Level	(D) 12 CP Allocation Percentages @ Transmission Level	Reference	Line No.
1	10 Year Average - 12CP Allocation Factors:						1
2	Residential Customers	13,968,510	1.0457	14,606,871	39.47%	Docket No. ER09-1601	2
3	Small Commercial Customers	4,587,704	1.0457	4,797,362	12.96%	Docket No. ER09-1601	3
4	Medium-Large Commercial Customers						4
5	Secondary	12,318,373	1.0457	12,881,323	34.81%	Docket No. ER09-1601	5
6	Primary	2,927,364	1.0108	2,958,980	8.00%	Docket No. ER09-1601	6
7	Transmission	1,035,486	1.0000	1,035,486	2.80%	Docket No. ER09-1601	7
8	Total Medium-Large Commercial	16,281,223	1.0365	16,875,789	45.61%	Sum Lines 5; 6; 7	8
9							9
10	Street Lighting	138,358	1.0457	144,681	0.39%	Docket No. ER09-1601	10
11	Standby Customers						11
12	Secondary	43,082	1.0457	45,051	0.12%	Docket No. ER09-1601	12
13	Primary	293,087	1.0108	296,252	0.80%	Docket No. ER09-1601	13
14	Transmission	238,214	1.0000	238,214	0.64%	Docket No. ER09-1601	14
15	Total Standby Customers	574,383	1.0089	579,517	1.57%	Sum Lines 12; 13; 14	15
16							16
17	System Total	35,550,178	1.0409	37,004,220	100.00%	Sum Lines 2; 3; 8; 10; 15	17
18							18
19							19
20	Medium-Large Commercial Customers:	**Meter Level**		**Transmission Level**	**Ratios**		20
21	Billing Determinants - (Non-Coicident Demand)						21
22	Secondary	22,688	1.0457	23,725	80.07%	Docket No. ER09-1601	22
23	Primary	4,522	1.0108	4,571	15.43%	Docket No. ER09-1601	23
24	Transmission	1,335	1.0000	1,335	4.51%	Docket No. ER09-1601	24
25	Total	28,545	1.0380	29,631	100.01%	Sum Lines 22; 23; 24	25
26							26
27							27
28	Standby Customers:	**Meter Level**		**Transmission Level**	**Ratios**		28
29	Billing Determinants - (Contracted Standby Demand)						29
30	Secondary	151	1.0457	158	7.79%	Docket No. ER09-1601	30
31	Primary	1,026	1.0108	1,037	51.11%	Docket No. ER09-1601	31
32	Transmission	834	1.0000	834	41.10%	Docket No. ER09-1601	32
33	Total	2,011	1.0089	2,029	100.00%	Sum Lines 30; 31; 32	33

NOTES:
Information comes from SDG&E's TO3-Cycle 3 filed with the FERC in Docket No. ER09-1601-000 filed on August 17, 2009.

Section 3.2.1
SAN DIEGO GAS AND ELECTRIC COMPANY
TO3-Cycle 5 Annual Transmission Formulaic Rate Filing
WHOLESALE - Rate Design Information
Development of TO3-CYCLE-3 12-CP Allocation Factors and Voltage Level Allocation Factors

Line No.	(A) Customer Class	(B) Forecast Demand Determinants Megawatt @ Meter Level	(C) Transmission Loss Factors	(D) = (B) x (C) Forecast Demand Determinants Megawatt @ Transmission Level	(E) Ratios	Reference	Line No.
1	Forecast Demand Determinants for Medium-Large Commercial Customers:						1
2	Non-Coincident Demand Determinants Pertaining to Customers on Schedules @ 100% NCD Rate						2
3	Secondary	1,014	1.0457	1,061	89.76%	Section 3.2.1; Page 17.1; Line 35	3
4	Primary	119	1.0108	121	10.24%	Section 3.2.1; Page 17.1; Line 36	4
5	Transmission	-	1.0000	-	0.00%	Section 3.2.1; Page 17.1; Line 37	5
6	Total	1,134		1,182	100.00%	Sum Lines 3; 4; 5	6
7							7
8	Non-Coincident Demand Determinants Pertaining to Customers on Schedules @ 90% NCD Rate						8
9	with Maximum On-Peak Period Demand						9
10	Secondary	21,674	1.0457	22,665	83.30%	Section 3.2.1; Page 17.2; Line 61	10
11	Primary	4,163	1.0108	4,208	15.47%	Section 3.2.1; Page 17.2; Line 62	11
12	Transmission	336	1.0000	336	1.23%	Section 3.2.1; Page 17.2; Line 63	12
13	Total	26,173		27,209	100.00%	Sum Lines 10; 11; 12	13
14							14
15	Non-Coincident Demand Determinants Pertaining to Customers on Schedules @ 90% NCD Rate						15
16	with Maximum Demand at the Time of System Peak						16
17	Secondary	-	1.0457	-	0.00%	Section 3.2.1; Page 17.3; Line 97	17
18	Primary	239	1.0108	242	19.50%	Section 3.2.1; Page 17.3; Line 98	18
19	Transmission	999	1.0000	999	80.50%	Section 3.2.1; Page 17.3; Line 99	19
20	Total	1,239		1,241	100.00%	Sum Lines 17; 18; 19	20
21							21
22	Total Non-Coincident Demand Determinants Pertaining to Medium-Large Commercial Customers						22
23	Secondary	22,688	1.0457	23,725	80.07%	Sum Lines 3; 10; 17	23
24	Primary	4,522	1.0108	4,571	15.43%	Sum Lines 4; 11; 18	24
25	Transmission	1,335	1.0000	1,335	4.51%	Sum Lines 5; 12; 19	25
26	Total	28,545		29,631	100.01%	Sum Lines 23; 24; 25	26
27							27
28	Maximum On-Peak Period Demand Determinants						28
29	Summer (May, June, July, August, September)						29
30	Secondary	8,798	1.0457	9,200	81.07%	Section 3.2.1; Page 17.2; Line 71	30
31	Primary	1,842	1.0108	1,862	16.41%	Section 3.2.1; Page 17.2; Line 72	31
32	Transmission	286	1.0000	286	2.52%	Section 3.2.1; Page 17.2; Line 73	32
33	Total	10,926		11,348	100.00%	Sum Lines 30; 31; 32	33
34	Winter (October, November, December, January, February, March, April)						34
35	Secondary	9,973	1.0457	10,429	81.13%	Section 3.2.1; Page 17.2; Line 71	35
36	Primary	2,094	1.0108	2,117	16.47%	Section 3.2.1; Page 17.2; Line 72	36
37	Transmission	308	1.0000	308	2.40%	Section 3.2.1; Page 17.2; Line 73	37
38	Total	12,375		12,854	100.00%	Sum Lines 35; 36; 37	38
39							39
40	Maximum Demand at the Time of System Peak Determinants						40
41	Summer (May, June, July, August, September)						41
42	Secondary	-	1.0457	-	0.00%	Section 3.2.1; Page 17.3; Line 107	42
43	Primary	55	1.0108	55	14.44%	Section 3.2.1; Page 17.3; Line 108	43
44	Transmission	326	1.0000	326	85.56%	Section 3.2.1; Page 17.3; Line 109	44
45	Total	380		381	100.00%	Sum Lines 42; 43; 44	45
46	Winter (October, November, December, January, February, March, April)						46
47	Secondary	-	1.0457	-	0.00%	Section 3.2.1; Page 17.3; Line 107	47
48	Primary	74	1.0108	75	15.59%	Section 3.2.1; Page 17.3; Line 108	48
49	Transmission	406	1.0000	406	84.41%	Section 3.2.1; Page 17.3; Line 109	49
50	Total	480		481	100.00%	Sum Lines 47; 48; 49	50
51							51
52	Forecast Demand Determinants for Standby Customers:						52
53	Contracted Demand Determinants						53
54	Secondary	151	1.0457	158	7.79%	Section 3.2.1; Page 17.3; Line 114	54
55	Primary	1,026	1.0108	1,037	51.11%	Section 3.2.1; Page 17.3; Line 115	55
56	Transmission	834	1.0000	834	41.10%	Section 3.2.1; Page 17.3; Line 116	56
57	Total	2,011		2,029	100.00%	Sum Lines 56; 57; 58	57

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Section 3.2.1
San Diego Gas & Electric
TO3-CYCLE-3 FERC Forecast Period: September 2009 - August 2010

Line No.															Line No.
1	**System Delivery Determinants**														1
2															2
3	**Customer Class Deliveries (MWh)**	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Total	3
4	Residential	745,844	607,027	608,165	676,400	746,697	670,775	631,791	582,360	573,064	610,244	725,929	735,574	7,913,871	4
5	Transmission Level Adjustment Factor	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570		5
6	Residential @ Transmission Level	779,929	634,769	635,958	707,312	780,822	701,430	660,663	608,974	599,254	638,132	759,104	769,189	8,275,535	6
7															7
8	Small Commercial	213,108	185,083	178,547	179,267	177,555	174,213	175,040	165,623	170,969	183,594	209,027	207,920	2,219,947	8
9	Transmission Level Adjustment Factor	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570		9
10	Small Commercial @ Transmission Level	222,847	193,542	186,707	187,460	185,669	182,174	183,039	173,192	178,783	191,984	218,579	217,422	2,321,398	10
11															11
12	Med. & Lrg. Commercial/Industrial	1,042,203	917,093	897,188	886,692	853,874	832,171	859,476	819,349	861,685	916,662	991,303	979,536	10,857,232	12
13	Transmission Level Adjustment Factor	1.03652	1.03652	1.03652	1.03652	1.03652	1.03652	1.03652	1.03652	1.03652	1.03652	1.03652	1.03652		13
14	Med. & Large Comm./Ind. @ Transmission Le	1,080,263	950,584	929,951	919,073	885,056	862,560	890,863	849,270	893,153	950,138	1,027,504	1,015,307	11,253,722	14
15															15
16	Street Lighting	9,289	9,305	9,321	9,337	9,245	9,261	9,277	9,293	9,309	9,325	9,341	9,357	111,661	16
17	Transmission Level Adjustment Factor	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570		17
18	Street Lighting @ Transmission Level	9,714	9,731	9,747	9,764	9,667	9,684	9,701	9,717	9,734	9,751	9,768	9,785	116,764	18
19															19
20	Sale for Resale	4	4	4	4	4	4	4	4	4	4	4	4	48	20
21	Total System@Trans. Ex Sale for Resale	2,092,752	1,788,625	1,762,363	1,823,608	1,861,215	1,755,849	1,744,266	1,641,153	1,680,923	1,790,006	2,014,955	2,011,703	21,967,419	21
22	Total System@Meter Ex Sale for Resale	2,010,444	1,718,509	1,693,221	1,751,697	1,787,372	1,686,420	1,675,583	1,576,624	1,615,028	1,719,826	1,935,600	1,932,387	21,102,711	22
23	**Med. & Large Comm./Ind.**														23
24	**Service Voltage Determinants**														24
25															25
26	**Deliveries (MWh)**	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Total	26
27	Med & Large Comm./Ind.	1,042,203	917,093	897,188	886,692	853,874	832,171	859,476	819,349	861,685	916,662	991,303	979,536	10,857,232	27
28															28
29	**Deliveries (%)**														29
30	% @ Secondary Service	76.26%	75.76%	75.61%	75.57%	75.35%	75.23%	75.37%	75.18%	75.43%	75.73%	76.08%	76.03%	75.66%	30
31	% @ Primary Service	17.99%	17.94%	17.99%	17.97%	18.02%	18.01%	18.02%	17.98%	17.98%	17.97%	17.97%	17.96%	17.98%	31
32	% @ Transmission Service	5.75%	6.29%	6.40%	6.46%	6.63%	6.76%	6.61%	6.84%	6.59%	6.30%	5.96%	6.01%	6.36%	32
33		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	33
34	**Deliveries (MWh)**														34
35	MWh @ Secondary Service	794,800	694,817	678,327	670,080	643,363	626,038	647,819	616,015	649,967	694,169	754,158	744,698	8,214,250	35
36	MWh @ Primary Service	187,466	164,568	161,408	159,354	153,865	149,863	154,877	147,298	154,927	164,740	178,089	175,970	1,952,425	36
37	MWh @ Transmission Service	59,937	57,708	57,452	57,258	56,647	56,269	56,780	56,036	56,792	57,753	59,056	58,869	690,557	37
38		1,042,203	917,093	897,188	886,692	853,874	832,171	859,476	819,349	861,685	916,662	991,303	979,536	10,857,232	38
39	**Non-Coincident Demand (%)**														39
40	% @ Secondary Service	0.2765%	0.2768%	0.2761%	0.2763%	0.2755%	0.2756%	0.2755%	0.2760%	0.2761%	0.2764%	0.2767%	0.2767%	0.2762%	40
41	% @ Primary Service	0.2316%	0.2321%	0.2315%	0.2317%	0.2311%	0.2312%	0.2311%	0.2316%	0.2316%	0.2317%	0.2319%	0.2319%	0.2316%	41
42	% @ Transmission Service	0.1930%	0.1933%	0.1934%	0.1934%	0.1935%	0.1936%	0.1935%	0.1936%	0.1935%	0.1933%	0.1931%	0.1932%	0.1934%	42

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Section 3.2.1
San Diego Gas & Electric
TO3-CYCLE-3 FERC Forecast Period: September 2009 - August 2010

Line No.															Line No.
26															26
27	**Non-Coincident Demand (MW)**														27
28	MW @ Secondary Service	2,198	1,923	1,873	1,851	1,773	1,725	1,785	1,700	1,795	1,919	2,087	2,060	22,688	28
29	Voltage Level Adjustment Factor	1.0457	1.0457	1.0457	1.0457	1.0457	1.0457	1.0457	1.0457	1.0457	1.0457	1.0457	1.0457		29
30	MW @ Secondary Service @ Trans Level	2,298	2,011	1,958	1,936	1,854	1,804	1,867	1,778	1,877	2,006	2,182	2,155	23,725	30
31															31
32	MW @ Primary Service	434	382	374	369	356	347	358	341	359	382	413	408	4,522	32
33	Voltage Level Adjustment Factor	1.0108	1.0108	1.0108	1.0108	1.0108	1.0108	1.0108	1.0108	1.0108	1.0108	1.0108	1.0108		33
34	MW @ Primary Service @ Trans Level	439	386	378	373	359	350	362	345	363	386	417	412	4,571	34
35															35
36	MW @ Transmission Service	116	112	111	111	110	109	110	108	110	112	114	114	1,335	36
37	Total Non-Coincident Demand @ Trans	2,853	2,509	2,447	2,420	2,323	2,263	2,338	2,231	2,349	2,504	2,714	2,681	29,631	37
38	Total Non-Coincident Demand @ Meter	2,748	2,417	2,357	2,331	2,238	2,181	2,253	2,150	2,263	2,412	2,614	2,582	28,545	38
39	**Schedule S: Standby Determinants**														39
40															40
41	**Contracted Standby Demand (MW)**	**Sep-09**	**Oct-09**	**Nov-09**	**Dec-09**	**Jan-10**	**Feb-10**	**Mar-10**	**Apr-10**	**May-10**	**Jun-10**	**Jul-10**	**Aug-10**	**Total**	41
42	MW @ Secondary Service	13	13	13	13	13	13	13	13	13	13	13	13	151	42
43	Voltage Level Adjustment Factor	1.0457	1.0457	1.0457	1.0457	1.0457	1.0457	1.0457	1.0457	1.0457	1.0457	1.0457	1.0457		43
44	MW @ Secondary Service @ Trans Level	13	13	13	13	13	13	13	13	13	13	13	13	158	44
45															45
46	MW @ Primary Service	86	86	86	86	86	86	86	86	86	86	86	86	1,026	46
47	Voltage Level Adjustment Factor	1.0108	1.0108	1.0108	1.0108	1.0108	1.0108	1.0108	1.0108	1.0108	1.0108	1.0108	1.0108		47
48	MW @ Primary Service @ Trans Level	86	86	86	86	86	86	86	86	86	86	86	86	1,037	48
49															49
50	MW @ Transmission Service	70	70	70	70	70	70	70	70	70	70	70	70	834	50
51	Total Contract Demand @ Trans	169	169	169	169	169	169	169	169	169	169	169	169	2,029	51
52	Total Contract Demand @ Meter	168	168	168	168	168	168	168	168	168	168	168	168	2,011	52

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San Diego Gas & Electric
FERC Forecast Period: September 2009 - August 2010

Line No.															Line No.
1	**SDG&E: System Delivery Determinants**														1
2															2
3	**Customer Class Deliveries (MWh)**	**Sep-09**	**Oct-09**	**Nov-09**	**Dec-09**	**Jan-10**	**Feb-10**	**Mar-10**	**Apr-10**	**May-10**	**Jun-10**	**Jul-10**	**Aug-10**	**Total**	3
4	Residential	745,844	607,027	608,165	676,400	746,697	670,775	631,791	582,360	573,064	610,244	725,929	735,574	7,913,871	4
5	Small Commercial	213,108	185,083	178,547	179,267	177,555	174,213	175,040	165,623	170,969	183,594	209,027	207,920	2,219,947	5
6	Med. & Large Comm./Ind. (AD + PA-T-1)	29,907	27,535	22,542	23,607	18,119	17,979	18,328	19,802	21,735	25,131	29,503	28,948	283,137	6
7	Med. & Large Comm./Ind. (AY + AL + DGR)	963,084	840,325	825,392	813,811	786,614	765,030	791,966	750,344	790,727	842,288	912,537	901,304	9,983,422	7
8	Med. & Large Comm./Ind. (A6)	49,212	49,233	49,253	49,273	49,141	49,162	49,182	49,202	49,223	49,243	49,264	49,284	590,673	8
9	Lighting	9,289	9,305	9,321	9,337	9,245	9,261	9,277	9,293	9,309	9,325	9,341	9,357	111,661	9
10	Sale for Resale	3.99	3.99	3.99	3.99	3.98	3.98	3.98	3.98	3.98	3.98	3.98	3.98	47.83	10
11	**Total System**	**2,010,448**	**1,718,513**	**1,693,225**	**1,751,701**	**1,787,375**	**1,686,424**	**1,675,587**	**1,576,628**	**1,615,032**	**1,719,830**	**1,935,604**	**1,932,391**	**21,102,758**	11
12															12
13	**Med. & Large Comm./Ind.**														13
14	**Rate Schedule Billing Determinants**														14
15															15
16	**Schedules AD / PA-T-1:**	**Sep-09**	**Oct-09**	**Nov-09**	**Dec-09**	**Jan-10**	**Feb-10**	**Mar-10**	**Apr-10**	**May-10**	**Jun-10**	**Jul-10**	**Aug-10**	**Total**	16
17	**Total Deliveries (MWh)**	29,907	27,535	22,542	23,607	18,119	17,979	18,328	19,802	21,735	25,131	29,503	28,948	283,137	17
18															18
19	**Total Deliveries (%)**														19
20	% @ Secondary Service	91.99%	91.99%	91.99%	91.99%	91.99%	91.99%	91.99%	91.99%	91.99%	91.99%	91.99%	91.99%	91.99%	20
21	% @ Primary Service	8.01%	8.01%	8.01%	8.01%	8.01%	8.01%	8.01%	8.01%	8.01%	8.01%	8.01%	8.01%	8.01%	21
22	% @ Transmission Service	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	22
23		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	23
24	**Total Deliveries (MWh)**														24
25	MWh @ Secondary Service	27,512	25,330	20,737	21,716	16,668	16,539	16,860	18,216	19,994	23,118	27,140	26,629	260,458	25
26	MWh @ Primary Service	2,396	2,206	1,806	1,891	1,451	1,440	1,468	1,586	1,741	2,013	2,363	2,319	22,679	26
27	MWh @ Transmission Service	0	0	0	0	0	0	0	0	0	0	0	0	0	27
28		29,907	27,535	22,542	23,607	18,119	17,979	18,328	19,802	21,735	25,131	29,503	28,948	283,137	28
29	**Non-Coincident Demand (%)**														29
30	% @ Secondary Service	0.3894%	0.3894%	0.3894%	0.3894%	0.3894%	0.3894%	0.3894%	0.3894%	0.3894%	0.3894%	0.3894%	0.3894%	0.3894%	30
31	% @ Primary Service	0.5264%	0.5264%	0.5264%	0.5264%	0.5264%	0.5264%	0.5264%	0.5264%	0.5264%	0.5264%	0.5264%	0.5264%	0.5264%	31
32	% @ Transmission Service	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	32
33															33
34	**Non-Coincident Demand (MW)**														34
35	MW @ Secondary Service	107.130	98.635	80.749	84.564	64.904	64.401	65.652	70.934	77.858	90.021	105.681	103.693	1,014.223	35
36	MW @ Primary Service	12.610	11.610	9.505	9.954	7.640	7.581	7.728	8.350	9.165	10.596	12.440	12.206	119.384	36
37	MW @ Transmission Service	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	37
38		119.741	110.245	90.254	94.518	72.544	71.982	73.380	79.284	87.023	100.617	118.121	115.899	1,133.606	38
39															39

San Diego Gas & Electric
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Line No.															Line No.
40															40
41															41
42	**Schedules AL-TOU / AY-TOU / DG-R:**	**Sep-09**	**Oct-09**	**Nov-09**	**Dec-09**	**Jan-10**	**Feb-10**	**Mar-10**	**Apr-10**	**May-10**	**Jun-10**	**Jul-10**	**Aug-10**	**Total**	42
43	**Total Deliveries (MWh)**	963,084	840,325	825,392	813,811	786,614	765,030	791,966	750,344	790,727	842,288	912,537	901,304	9,983,422	43
44															44
45	**Total Deliveries (%)**														45
46	% @ Secondary Service	79.67%	79.67%	79.67%	79.67%	79.67%	79.67%	79.67%	79.67%	79.67%	79.67%	79.67%	79.67%	79.67%	46
47	% @ Primary Service	18.50%	18.50%	18.50%	18.50%	18.50%	18.50%	18.50%	18.50%	18.50%	18.50%	18.50%	18.50%	18.50%	47
48	% @ Transmission Service	1.83%	1.83%	1.83%	1.83%	1.83%	1.83%	1.83%	1.83%	1.83%	1.83%	1.83%	1.83%	1.83%	48
49		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	49
50	**Total Deliveries (MWh)**														50
51	MWh @ Secondary Service	767,289	669,487	657,590	648,363	626,695	609,500	630,959	597,799	629,972	671,051	727,018	718,069	7,953,793	51
52	MWh @ Primary Service	178,170	155,460	152,698	150,555	145,524	141,531	146,514	138,814	146,284	155,823	168,819	166,741	1,846,933	52
53	MWh @ Transmission Service	17,624	15,378	15,105	14,893	14,395	14,000	14,493	13,731	14,470	15,414	16,699	16,494	182,697	53
54		963,084	840,325	825,392	813,811	786,614	765,030	791,966	750,344	790,727	842,288	912,537	901,304	9,983,422	54
55	**Non-Coincident Demand (%)**														55
56	% @ Secondary Service	0.2725%	0.2725%	0.2725%	0.2725%	0.2725%	0.2725%	0.2725%	0.2725%	0.2725%	0.2725%	0.2725%	0.2725%	0.2725%	56
57	% @ Primary Service	0.2254%	0.2254%	0.2254%	0.2254%	0.2254%	0.2254%	0.2254%	0.2254%	0.2254%	0.2254%	0.2254%	0.2254%	0.2254%	57
58	% @ Transmission Service	0.1838%	0.1838%	0.1838%	0.1838%	0.1838%	0.1838%	0.1838%	0.1838%	0.1838%	0.1838%	0.1838%	0.1838%	0.1838%	58
59															59
60	**Non-Coincident Demand (MW)**														60
61	MW @ Secondary Service	2,090.862	1,824.352	1,791.932	1,766.790	1,707.745	1,660.887	1,719.364	1,629.002	1,716.674	1,828.614	1,981.124	1,956.738	21,674.085	61
62	MW @ Primary Service	401.596	350.407	344.180	339.351	328.010	319.010	330.242	312.886	329.725	351.226	380.519	375.835	4,162.987	62
63	MW @ Transmission Service	32.394	28.265	27.762	27.373	26.458	25.732	26.638	25.238	26.596	28.331	30.694	30.316	335.796	63
64		2,524.852	2,203.024	2,163.875	2,133.514	2,062.213	2,005.629	2,076.244	1,967.126	2,072.996	2,208.171	2,392.336	2,362.888	26,172.869	64
65	**On-Peak Demand (%)**														65
66	% @ Secondary Service	0.2504%	0.2246%	0.2246%	0.2246%	0.2246%	0.2246%	0.2246%	0.2246%	0.2504%	0.2504%	0.2504%	0.2504%	0.2360%	66
67	% @ Primary Service	0.2258%	0.2031%	0.2031%	0.2031%	0.2031%	0.2031%	0.2031%	0.2031%	0.2258%	0.2258%	0.2258%	0.2258%	0.2131%	67
68	% @ Transmission Service	0.3546%	0.3015%	0.3015%	0.3015%	0.3015%	0.3015%	0.3015%	0.3015%	0.3546%	0.3546%	0.3546%	0.3546%	0.3250%	68
69															69
70	**On-Peak Demand (MW)**	Summer	Winter	Winter	Winter	Winter	Winter	Winter	Winter	Summer	Summer	Summer	Summer	TOTAL	70
71	MW @ Secondary Service	1,921.291	1,503.668	1,476.947	1,456.224	1,407.558	1,368.937	1,417.135	1,342.657	1,577.450	1,680.312	1,820.453	1,798.044	18,770.675	71
72	MW @ Primary Service	402.309	315.740	310.129	305.777	295.558	287.449	297.569	281.930	330.310	351.849	381.194	376.502	3,936.317	72
73	MW @ Transmission Service	62.496	46.365	45.541	44.902	43.401	42.210	43.696	41.400	51.312	54.658	59.216	58.487	593.683	73
74		2,386.096	1,865.772	1,832.616	1,806.903	1,746.517	1,698.595	1,758.400	1,665.987	1,959.072	2,086.819	2,260.863	2,233.033	23,300.675	74
75															75

San Diego Gas & Electric
FERC Forecast Period: September 2009 - August 2010

Line No.		Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Total	Line No.
76															76
77															77
78	**Schedule A6-TOU:**	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Total	78
79	**Total Deliveries (MWh)**	49,212	49,233	49,253	49,273	49,141	49,162	49,182	49,202	49,223	49,243	49,264	49,284	590,673	79
80															80
81	**Total Deliveries (%)**														81
82	% @ Secondary Service	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	82
83	% @ Primary Service	14.02%	14.02%	14.02%	14.02%	14.02%	14.02%	14.02%	14.02%	14.02%	14.02%	14.02%	14.02%	14.02%	83
84	% @ Transmission Service	85.98%	85.98%	85.98%	85.98%	85.98%	85.98%	85.98%	85.98%	85.98%	85.98%	85.98%	85.98%	85.98%	84
85		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	85
86	**Total Deliveries (MWh)**														86
87	MWh @ Secondary Service	0	0	0	0	0	0	0	0	0	0	0	0	0	87
88	MWh @ Primary Service	6,900	6,902	6,905	6,908	6,890	6,892	6,895	6,898	6,901	6,904	6,907	6,910	82,812	88
89	MWh @ Transmission Service	42,313	42,330	42,348	42,365	42,252	42,269	42,287	42,304	42,322	42,339	42,357	42,375	507,860	89
90		49,212	49,233	49,253	49,273	49,141	49,162	49,182	49,202	49,223	49,243	49,264	49,284	590,673	90
91	**Non-Coincident Demand (%)**														91
92	% @ Secondary Service	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	92
93	% @ Primary Service	0.2891%	0.2891%	0.2891%	0.2891%	0.2891%	0.2891%	0.2891%	0.2891%	0.2891%	0.2891%	0.2891%	0.2891%	0.2891%	93
94	% @ Transmission Service	0.1968%	0.1968%	0.1968%	0.1968%	0.1968%	0.1968%	0.1968%	0.1968%	0.1968%	0.1968%	0.1968%	0.1968%	0.1968%	94
95															95
96	**Non-Coincident Demand (MW)**														96
97	MW @ Secondary Service	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	97
98	MW @ Primary Service	19.947	19.955	19.963	19.971	19.918	19.926	19.934	19.943	19.951	19.959	19.968	19.976	239.410	98
99	MW @ Transmission Service	83.271	83.306	83.340	83.375	83.151	83.186	83.220	83.255	83.289	83.324	83.359	83.393	999.469	99
100		103.218	103.261	103.303	103.346	103.069	103.112	103.155	103.197	103.240	103.283	103.326	103.369	1,238.880	100
101	**Coincident Peak Demand (%)**														101
102	% @ Secondary Service	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	102
103	% @ Primary Service	0.1585%	0.1530%	0.1530%	0.1530%	0.1530%	0.1530%	0.1530%	0.1530%	0.1585%	0.1585%	0.1585%	0.1585%	0.1553%	103
104	% @ Transmission Service	0.1538%	0.1372%	0.1372%	0.1372%	0.1372%	0.1372%	0.1372%	0.1372%	0.1538%	0.1538%	0.1538%	0.1538%	0.1441%	104
105															105
106	**Coincident Peak Demand (MW)**														106
107	MW @ Secondary Service	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	107
108	MW @ Primary Service	10.936	10.561	10.565	10.569	10.541	10.545	10.550	10.554	10.938	10.943	10.947	10.952	128.601	108
109	MW @ Transmission Service	65.077	58.077	58.101	58.125	57.969	57.993	58.017	58.041	65.091	65.118	65.145	65.172	731.928	109
110		76.012	68.638	68.666	68.695	68.510	68.539	68.567	68.596	76.029	76.061	76.092	76.124	860.529	110
111															111
112	**Schedule S: Standby Determinants:**	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Total	112
113	**Contracted Standby Demand (MW)**														113
114	MW @ Secondary Service	12.571	12.571	12.571	12.571	12.571	12.571	12.571	12.571	12.571	12.571	12.571	12.571	150.852	114
115	MW @ Primary Service	85.518	85.518	85.518	85.518	85.518	85.518	85.518	85.518	85.518	85.518	85.518	85.518	1,026.216	115
116	MW @ Transmission Service	69.507	69.507	69.507	69.507	69.507	69.507	69.507	69.507	69.507	69.507	69.507	69.507	834.084	116
117		167.596	167.596	167.596	167.596	167.596	167.596	167.596	167.596	167.596	167.596	167.596	167.596	2,011.152	117
118															118
119															119
120															120

Section – 3.2
Derivation of Monthly Recorded ISO True-Up Revenues

Section 3.2.2
Derivation of ISO Cost of Service Rates in Effect for the last 7 Months of the TU Period Based on SDG&E's TO3-4th Cycle ISO-Wholesale Cost of Service.

Docket No. ER11-____-____

Section 3.2.2

SAN DIEGO GAS AND ELECTRIC COMPANY
TO3-Cycle 5 Annual Transmission Formulaic Rate Filing
Allocation of CYCLE-4 WHOLESALE Cost of Service to Customer Classes
Based on TO3-CYCLE-4 12 CPs
($1,000)

Line No.	Customer Classes	(a) Total 12 CPs @ Transmission Level [2]	(b) 12 CP Allocation Percentages @ Transmission Level [3]	(c) Allocated Base Transmission Revenue Requirement	(d) Reference	Line No.
1	Total Base Transmission Revenue Requirement [1]			$ 312,770	TO3-Cycle 4; Docket No. ER10-2235	1
2					Refund Report Fling	2
3	Allocation of BTRR Based on 12-CP:				Statement BK2; Pg 11 of 11; Ln 15; Col. 1	3
4	Residential	15,742,820	39.46%	$ 123,419	Col.C4 = Col (c) Ln1 x Col B. Ln 4	4
5	Small Commercial	4,848,321	12.15%	38,002	Col.C5 = Col (c) Ln1 x Col B. Ln 5	5
6	Medium & Large Commercial/Industrial	18,659,462	46.77%	146,283	Col.C6 = Col (c) Ln1 x Col B. Ln 6	6
7	Street Lighting Revenues	146,179	0.37%	1,157	Col.C7 = Col (c) Ln1 x Col B. Ln 7	7
8	Standby Revenues	499,375	1.25%	3,910	Col.C8 = Col (c) Ln1 x Col B. Ln 8	8
9						9
10	Total	39,896,157	100.00%	$ 312,771	Sum Lines 4 thru 8	10
11						11
12	Total	39,896,157		$ 312,771	Line 10	12

NOTES:

1 Statement refers to SDG&E's TO3, Cycle 4, Cost Statements as derived by SDG&E in Docket No. ER10-2235, filed on August 13, 2010. SDG&E made a refund report filing as required by the FERC on November 8, 2010. See Statement BK-2; Page 11 of 11; Line 15.

2 See Section 3.2.2; Page 9; Column D. Information comes from the TO3, Cycle 4 transmission rate case filing Docket No. ER10-2235 filed with the FERC on August 13, 2010.

3 See Section 3.2.2; Page 9; Column E.

Section 3.2.2

SAN DIEGO GAS AND ELECTRIC COMPANY
TO3-Cycle 5 Annual Transmission Formulaic Rate Filing
Derivation of TO3-CYCLE-4 WHOLESALE Rates Using TO3-CYCLE-4 Billing Determinants
Residential Customers [1]
($000)

Line No.	Customer Classes	Derivation of Commodity Rate & Proof of Revenues Calculation	Reference	Line No.
1	Residential - Allocated Transmission Revenue Requirements	$ 123,419	Section 3.2.2; Page 1; Line 4	1
2				2
3	Billing Determinants - Residential Customer Class @ MWh:	7,747,660	Section 3.2.2; Page 16.1; Line 4	3
4				4
5	Transmission Level Adjustment Factor	1.04570	Section 3.2.2; Page 14; Col. C; Line 2	5
6				6
7	Billing Determinants @ Transmission Level	8,101,728	Line 3 x Line 5	7
8				8
9	Residential Energy Rate Per kWh	$ 0.0152337	Line 1 / Line 7	9
10				10
11	Residential Energy Rate Per kWh - Rounded	$ 0.0152337	Line 9, Rounded to 7 Decimal Places	11
12				12
13	Proof of Revenues	$ 123,419	Line 7 x Line 11	13
14				14
15	Difference	$ (0)	Line 1 - Line 13	15

Notes:

1 Residential customers include the following California Public Utilities Commission (CPUC) tariffs: DR, DR-LI, DR-TOU, EV-TOU, EV-TOU-2, EV-TOU-3, DR-TV, D-SMF.

Section 3.2.2

SAN DIEGO GAS AND ELECTRIC COMPANY
TO3-Cycle 5 Annual Transmission Formulaic Rate Filing
Derivation of TO3-CYCLE-4 WHOLESALE Rates Using TO3-CYCLE-4 Billing Determinants
Small Commercial Customers [1]
($000)

Line No.	Customer Classes	Derivation of Commodity Rate & Proof of Revenues Calculation	Reference	Line No.
1	Small Commercial - Allocated Transmission Revenue Requirement	$ 38,002	Section 3.2.2; Page 1; Line 5	1
2				2
3	Billing Determinants - Small Commercial @ MWh:	2,018,058	Section 3.2.2; Page 16.1; Line 8	3
4				4
5	Transmission Level Adjustment Factor	1.04570	Section 3.2.2; Page 14; Col. C; Line 3	5
6				6
7	Billing Determinants @ Transmission Level	2,110,283	Line 3 x Line 5	7
8				8
9	Energy Rate Per kWh @ Transmission Level	$ 0.0180080	Line 1 / Line 7	9
10				10
11	Energy Rate Per kWh - Rounded @ Transmission Level	$ 0.0180080	Line 9, Rounded to 7 Decimal Places	11
12				12
13	Proof of Revenues	$ 38,002	Line 7 x Line 11	13
14				14
15	Difference	$ 0	Line 1 - Line 13	15

Notes:

1 Small commercial customers include the following California Public Utilities Commission (CPUC) tariffs: A, A-TC, A-TOU, PA.

Section 3.2.2

SAN DIEGO GAS AND ELECTRIC COMPANY

TO3-Cycle 5 Annual Transmission Formulaic Rate Filing

Derivation of TO3-CYCLE-4 WHOLESALE Rates Using TO3-CYCLE-4 Billing Determinants

Medium-Large Commercial Customers [1]

($000)

Line No.	Customer Classes	Derivation of Demand Rates & Proof of Revenues Calculation	Reference	Line No.
1	**Med-Lrg C&I - Demand Revenue Requirement:**	$ 146,283	Section 3.2.2; Page 1; Line 6	1
2	*Non-Coincident Demand Determinants @ Transmission Level Used*			2
3	*to Allocate Total Customer Class Revenues to Voltage Level:*			3
4	Secondary [2]	22,818	Section 3.2.2; Page 14; Line 22; Col. C.	4
5	Primary [2]	4,478	Section 3.2.2; Page 14; Line 23; Col. C.	5
6	Transmission [2]	1,401	Section 3.2.2; Page 14; Line 24; Col. C.	6
7	Total	28,697	Sum Lines 4; 5; 6	7
8	*Allocation Factors Per Above to Allocate*			8
9	*Demand Revenue Requirements to Voltage Level:*			9
10	Secondary	79.51%	Line 4 / Line 7	10
11	Primary	15.60%	Line 5 / Line 7	11
12	Transmission	4.88%	Line 6 / Line 7	12
13	Total	100.00%	Sum Lines 10; 11; 12	13
14				14
15	**Allocation of Revenue Requirements to Voltage Level:**			15
16	Secondary	$ 116,315	Line 1 x Line 10	16
17	Primary	22,826	Line 1 x Line 11	17
18	Transmission	7,142	Line 1 x Line 12	18
19	Total	$ 146,283	Sum Lines 16; 17; 18	19
20				20
21	**Non-Coincident Demand Determinants by Voltage Level @ Transmission Level:**			21
22	Secondary	22,818	Section 3.2.2; Page 14; Line 22; Col. C.	22
23	Primary	4,478	Section 3.2.2; Page 14; Line 23; Col. C.	23
24	Transmission	1,401	Section 3.2.2; Page 14; Line 24; Col. C.	24
25	Total	28,697	Sum Lines 22; 23; 24	25
26				26
27	**Non-Coincident Demand Rate By Voltage Level @ Transmission:**			27
28	Secondary	$ 5.0975107	Line 16 / Line 22	28
29	Primary	$ 5.0973649	Line 17 / Line 23	29
30	Transmission	$ 5.0977873	Line 18 / Line 24	30
31				31
32	**Non-Coincident Demand Rate By Voltage Level @ Transmission Level:**			32
33	Secondary	$ 5.0975107	Line 28 Rounded to 7 Decimal Places	33
34	Primary	$ 5.0973649	Line 29 Rounded to 7 Decimal Places	34
35	Transmission	$ 5.0977873	Line 30 Rounded to 7 Decimal Places	35
36				36
37	**Proof of Revenue Calculations:**			37
38	Secondary	$ 116,315	Line 22 x Line 33	38
39	Primary	22,826	Line 23 x Line 34	39
40	Transmission	7,142	Line 24 x Line 35	40
41	Total	$ 146,283	Sum Lines 38; 39; 40	41
42				42
43	Difference	$ -	Line 1 - Line 41	43

Notes:

1 Medium-Large commercial customers include the following California Public Utilities Commission (CPUC) tariffs: AD, AY-TOU, AL-TOU, AL-TOU-CP, AL-TOU-DER, A6-TOU, PA-T-1.

2 LF = Transmission Loss Factor; Secondary Level = 1.0457; Primary Level = 1.0108; Transmission Level = 1.0000

Section 3.2.2
SAN DIEGO GAS AND ELECTRIC COMPANY
TO3-Cycle 5 Annual Transmission Formulaic Rate Filing
Derivation of TO3-CYCLE-4 WHOLESALE Rates Using TO3-CYCLE-4 Billing Determinants
Medium-Large Commercial Customers [1]
($000)

Line No.	Description	Derivation of Commodity Rate & Proof of Revenues Calculation	Reference	Line No.
1	Rate Proposal 90% of Total M&L C&I NCD Rates [1]	90.00%		1
2	Secondary	$ 4.5877596	90% x Section 3.2.2; Page 4; Line 33	2
3	Primary	$ 4.5876284	90% x Section 3.2.2; Page 4; Line 34	3
4	Tranmission	$ 4.5880086	90% x Section 3.2.2; Page 4; Line 35	4
5				5
6	Rate Proposal 90% of Total M&L C&I NCD Rates (Rounded)			6
7	Secondary	$ 4.5877596	Line 2, Rounded to 7 Decimal Places	7
8	Primary	$ 4.5876284	Line 3, Rounded to 7 Decimal Places	8
9	Tranmission	$ 4.5880086	Line 4, Rounded to 7 Decimal Places	9
10				10
11	**Pertaining to Schedules @ 90% NCD with Maximum On-Peak Period Demand[2]**			11
12	NCD Determinants By Voltage Level @ TRANSMISSION Level (MW)			12
13	Secondary	21,783	Section 3.2.2; Page 15; Line 10; Col. D.	13
14	Primary	4,049	Section 3.2.2; Page 15; Line 11; Col. D.	14
15	Tranmission	269	Section 3.2.2; Page 15; Line 12; Col. D.	15
16	Total	26,101	Sum Lines 12; 13; 14	16
17				17
18	Annual Revenues from Current NCD Rate 100% of Total M&L C&I NCD Rates			18
19	Secondary	$ 111,039	Line 13 x Section 3.2.2; Page 5; Line 33	19
20	Primary	$ 20,639	Line 14 x Statement BL; Page 5; Line 34	20
21	Tranmission	$ 1,371	Line 15 x Statement BL; Page 5; Line 35	21
22	Total	$ 133,050	Sum Lines 19; 20; 21	22
23				23
24	Annual Revenues from Proposed NCD Rate 90% of Total M&L C&I NCD Rates			24
25	Secondary	$ 99,935	Line 7 x Line 13	25
26	Primary	$ 18,575	Line 8 x Line 14	26
27	Tranmission	$ 1,234	Line 9 x Line 15	27
28	Total	$ 119,745	Sum Lines 25; 26; 27	28
29				29
30	Revenue Reallocation to Maximum On-Peak Period Demands			30
31	Secondary	$ 11,104	Line 19 - Line 25	31
32	Primary	$ 2,064	Line 20 - Line 26	32
33	Tranmission	$ 137	Line 21 - Line 27	33
34	Total	$ 13,305	Sum Lines 31; 32; 33	34
35				35
36	Pertaining to Schedules @ 90% NCD with Maximum Demand at Time of System Peak[3]			36
37	NCD Determinants By Voltage Level @ TRANSMISSION Level (MW)			37
38	Secondary	-	Section 3.2.2; Page 15; Col. D; Line 17	38
39	Primary	293	Section 3.2.2; Page 15; Col. D; Line 18	39
40	Tranmission	1,132	Section 3.2.2; Page 15; Col. D; Line 19	40
41	Total	1,425	Sum Lines 18; 19; 20	41
42				42
43	Annual Revenues from Current NCD Rate 100% of Total M&L C&I NCD Rates			43
44	Secondary = ($5.0975107 x 0)	$ -	Line 38 x Section 3.2.2; Page 5; Line 33	44
45	Primary = ($5.0973649 x 293)	$ 1,494	Line 39 x Section 3.2.2; Page 5; Line 34	45
46	Tranmission = ($5.0977873 x 1,132)	$ 5,771	Line 40 x Section 3.2.2; Page 5; Line 35	46
47	Total	$ 7,264	Sum Lines 44; 45; 46	47
48				48
49	Annual Revenues from Proposed NCD Rate 90% of Total M&L C&I NCD Rates			49
50	Secondary	$ -	Line 7 x Line 38	50
51	Primary	$ 1,344	Line 8 x Line 39	51
52	Tranmission	$ 5,194	Line 9 x Line 40	52
53	Total	$ 6,538	Sum Lines 50; 51; 52	53
54				54
55	Revenue Reallocation to Maximum Demand at the Time of System Peak			55
56	Secondary	$ -	Line 44 - Line 50	56
57	Primary	$ 149	Line 45 - Line 51	57
58	Tranmission	$ 577	Line 46 - Line 52	58
59	Total	$ 726	Sum Lines 56; 57; 58	59

NOTES:

[1] 90% NCD Rates are applicable to the following California Public Utilities Commission (CPUC) tariffs: AY-TOU, AL-TOU, AL-TOU-DER, DG-R, A6-TOU

[2] 90% NCD Rates and Maximum On-Peak Period Demand charges are applicable to the following California Public Utilities Commission (CPUC) tariffs: AY-TOU, AL-TOU, AL-TOU-DER, DG-R

[3] 90% NCD Rates and Maximum Demand at Time of System Peak charges are applicable to the following California Public Utilities Commission (CPUC) tariffs: A6-TOU

Section 3.2.2
SAN DIEGO GAS AND ELECTRIC COMPANY
TO3-Cycle 5 Annual Transmission Formulaic Rate Filing
Derivation of TO3-CYCLE-4 WHOLESALE Rates Using TO3-CYCLE-4 Billing Determinants
Medium-Large Commercial Customers [1]
($000)

Line No.	Description		Derivation of Commodity Rate & Proof of Revenues Calculation	Reference	Line No.
1	Med-Lrg C&I Maximum On-Peak Period Demand Proposal				1
2	Revenue Reallocation to Maximum On-Peak Period Demands [1]	$	13,305	Section 3.2.2; Page 5; Line 34	2
3					3
4	Summer Maximum On-Peak Period Demands By Voltage Level @ Meter Level (MW) [2]				4
5	Secondary		8,369	Section 3.3.2; Page 15; Col. B; Line 30	5
6	Primary		1,761	Section 3.3.2; Page 15; Col. B; Line 31	6
7	Tranmission		224	Section 3.3.2; Page 15; Col. B; Line 32	7
8	Total		10,354	Sum Lines 5; 6; 7	8
9					9
10	Summer Maximum On-Peak Period Demands @ Transmission Level (MW)				10
11	Secondary		8,752	Section 3.3.2; Page 15; Col. D; Line 30	11
12	Primary		1,780	Section 3.3.2; Page 15; Col. D; Line 31	12
13	Tranmission		224	Section 3.3.2; Page 15; Col. D; Line 32	13
14	Total		10,756	Sum Lines 11; 12; 13	14
15					15
16	Summer Maximum On-Peak Period Allocation to Voltage Levels				16
17	Secondary		81.37%	Line 11 / Line 14	17
18	Primary		16.55%	Line 12 / Line 14	18
19	Tranmission		2.08%	Line 13 / Line 14	19
20	Total		100.00%	Sum Lines 17; 18; 19	20
21	Share of Total Revenue Allocation to Summer Peak Period		80.00%		21
22	Revenues for Proposed Summer Maximum On-Peak Period Demand Rates	$	10,644	Line 2 x Line 21	22
23	Secondary	$	8,661	(Line 2 x Line 21) x Line 17	23
24	Primary	$	1,761	(Line 2 x Line 21) x Line 18	24
25	Tranmission	$	222	(Line 2 x Line 21) x Line 19	25
26	Total	$	10,644	Sum Lines 23; 24; 25	26
27					27
28	Summer Maximum On-Peak Period Demand Rates [3]		$/kW		28
29	Secondary	$	0.9895844	Line 23 / Line 5	29
30	Primary	$	0.9895844	Line 24 / Line 6	30
31	Tranmission	$	0.9895844	Line 25 / Line 7	31
32					32
33					33
34	Summer Maximum On-Peak Period Demand Rates (Rounded)		$/kW		34
35	Secondary	$	0.9895844	Line 29, Rounded to 7 Decimal Places	35
36	Primary	$	0.9895844	Line 30, Rounded to 7 Decimal Places	36
37	Tranmission	$	0.9895844	Line 31, Rounded to 7 Decimal Places	37
38					38

NOTES:
[1] Revenues to be reallocated from NCD to recovery from Maximum On-Peak Period Demands for the following California Public Utilities Commission (CPUC) tariffs:
AY-TOU, AL-TOU, AL-TOU-DER, DG-R
[2] Summer Maximum On-Peak Period Determinants for the following California Public Utilities Commission (CPUC) tariffs:
AY-TOU, AL-TOU, AL-TOU-DER, DG-R
[3] Summer Maximum On-Peak Period Demand Charges for the following California Public Utilities Commission (CPUC) tariffs:
AY-TOU, AL-TOU, AL-TOU-DER, DG-R
[4] Winter Maximum On-Peak Period Determinants for the following California Public Utilities Commission (CPUC) tariffs:
AY-TOU, AL-TOU, AL-TOU-DER, DG-R
[5] Winter Maximum On-Peak Period Demand Charges for the following California Public Utilities Commission (CPUC) tariffs:
AY-TOU, AL-TOU, AL-TOU-DER, DG-R
[6] LF = Transmission Loss Factor; Secondary Level = 1.0457; Primary Level = 1.0108; Transmission Level = 1.0000

Section 3.2.2
SAN DIEGO GAS AND ELECTRIC COMPANY
TO3-Cycle 5 Annual Transmission Formulaic Rate Filing
Derivation of TO3-CYCLE-4 WHOLESALE Rates Using TO3-CYCLE-4 Billing Determinants
Medium-Large Commercial Customers [1]
($000)

Line No.	Description	Derivation of Commodity Rate & Proof of Revenues Calculation	Reference	Line No.
1	Winter Maximum On-Peak Period Demands By Voltage Level @ Meter Level (MW) [4]			1
2	Secondary	9,658	Section 3.2.2; Page 15; Col. B; Line 35.	2
3	Primary	2,031	Section 3.2.2; Page 15; Col. B; Line 36.	3
4	Tranmission	253	Section 3.2.2; Page 15; Col. B; Line 37.	4
5	Total	11,941	Sum Lines 2; 3; 4	5
6				6
7	Winter Maximum On-Peak Period Demands @ TRANSMISSION Level (MW)			7
8	Secondary	10,099	Section 3.2.2; Page 15; Col. D; Line 35.	8
9	Primary	2,053	Section 3.2.2; Page 15; Col. D; Line 36.	9
10	Tranmission	253	Section 3.2.2; Page 15; Col. D; Line 37.	10
11	Total	12,405	Sum Lines 8; 9; 10	11
12				12
13	Winter Maximum On-Peak Period Allocation to Voltage Levels			13
14	Secondary	81.41%	Line 8 / Line 11	14
15	Primary	16.55%	Line 9 / Line 11	15
16	Tranmission	2.04%	Line 10 / Line 11	16
17	Total	100.00%	Sum Lines 14; 15; 16	17
18	Share of Total Revenue Allocation to Winter Peak Period	20.00%		18
19	Revenues for Proposed Winter Maximum On-Peak Period Demand Rates	$ 2,661	(Section 3.2.2; Page 5; Line 34) x Line 18	19
20	Secondary	$ 2,166	(Section 3.2.2; Page 5; Line 34 x Line 18) x Line 14	20
21	Primary	$ 440	(Section 3.2.2; Page 5; Line 34 x Line 18) x Line 15	21
22	Tranmission	$ 54	(Section 3.2.2; Page 5; Line 34 x Line 18) x Line 16	22
23	Total	$ 2,661	Sum Lines 20; 21; 22	23
24				24
25	Winter Maximum On-Peak Period Demand Rates [5]	$/kW		25
26	Secondary	$ 0.2145097	Line 20 / Line 8	26
27	Primary	$ 0.2145097	Line 21 / Line 9	27
28	Tranmission	$ 0.2145097	Line 22 / Line 10	28
29				29
30				30
31	Winter Maximum On-Peak Period Demand Rates (Rounded)	$/kW		31
32	Secondary	$ 0.2145097	Line 26, Rounded to 7 Decimal Places	32
33	Primary	$ 0.2145097	Line 27, Rounded to 7 Decimal Places	33
34	Tranmission	$ 0.2145097	Line 28, Rounded to 7 Decimal Places	34
35				35
36				36
37	Proof of Revenue Calculations:			37
38	Secondary	$ 10,827	(Section 3.3.2; Page 6; Line 11 x Section Page 6; Line 35) + (Line 8 x Line 32)	38
39	Primary	$ 2,202	(Section 3.3.2; Page 6; Line 12 x Section Page 6; Line 36) + (Line 9 x Line 33)	39
40	Tranmission	$ 276	(Section 3.3.2; Page 6; Line 13 x Section Page 6; Line 37) + (Line 10 x Line 34)	40
41	Total	$ 13,305	Sum Lines 38; 39; 40	41
42				42
43	Difference	$ (0)	Section 3.3.2; Page 6; Line 2 Minus Page 7; Line 41	43
44				44

NOTES:
[1] Revenues to be reallocated from NCD to recovery from Maximum On-Peak Period Demands for the following California Public Utilities Commission (CPUC) tariffs:
AY-TOU, AL-TOU, AL-TOU-DER, DG-R
[2] Summer Maximum On-Peak Period Determinants for the following California Public Utilities Commission (CPUC) tariffs:
AY-TOU, AL-TOU, AL-TOU-DER, DG-R
[3] Summer Maximum On-Peak Period Demand Charges for the following California Public Utilities Commission (CPUC) tariffs:
AY-TOU, AL-TOU, AL-TOU-DER, DG-R
[4] Winter Maximum On-Peak Period Determinants for the following California Public Utilities Commission (CPUC) tariffs:
AY-TOU, AL-TOU, AL-TOU-DER, DG-R
[5] Winter Maximum On-Peak Period Demand Charges for the following California Public Utilities Commission (CPUC) tariffs:
AY-TOU, AL-TOU, AL-TOU-DER, DG-R
[6] LF = Transmission Loss Factor; Secondary Level = 1.0457; Primary Level = 1.0108; Transmission Level = 1.0000

Section 3.2.2
SAN DIEGO GAS AND ELECTRIC COMPANY
TO3-Cycle 5 Annual Transmission Formulaic Rate Filing
Derivation of TO3-CYCLE-4 WHOLESALE Rates Using TO3-CYCLE-4 Billing Determinants
Medium-Large Commercial Customers [1]
($000)

Line No.	Description	Derivation of Commodity Rate & Proof of Revenues Calculation	Reference	Line No.
1	Med-Lrg C&I Maximum Demand at the Time of System Peak Proposal			1
2	Revenue Reallocation to Maximum Demand at the Time of System Peak [1]	$ 726	Section 3.3.2; Page 5; Line 59	2
3				3
4	Summer Maximum Demand at the Time of System Peak By Voltage Level @ **Meter** Level (MW) [2]			4
5	Secondary	-	Section 3.3.2; Page 15; Col. B; Line 42	5
6	Primary	67	Section 3.3.2; Page 15; Col. B; Line 43	6
7	Transmission	380	Section 3.3.2; Page 15; Col. B; Line 44	7
8	Total	447	Sum Lines 5; 6; and 7	8
9				9
10	Summer Maximum Demand at the Time of System Peak @ **TRANSMISSION** Level (MW)			10
11	Secondary	-	Section 3.3.2; Page 15; Col. D; Line 42	11
12	Primary	68	Section 3.3.2; Page 15; Col. D; Line 43	12
13	Tranmission	380	Section 3.3.2; Page 15; Col. D; Line 44	13
14	Total	448	Sum Lines 11; 12; and 13	14
15				15
16	Summer Maximum Demand at the time of System Peak Allocation to Voltage Levels (MW)			16
17	Secondary	0.00%	Line 11 / Line 14	17
18	Primary	15.18%	Line 12 / Line 14	18
19	Tranmission	84.82%	Line 13 / Line 14	19
20	Total	100.00%	Sum Lines 17; 18; and 19	20
21	Share of Total Revenue Allocation to Summer Maximum Demand at the Time of System Peak	80.00%		21
22	Revenues for Proposed Summer Maximum Demand at the Time of System Peak Rates	$ 581	Line 2 x Line 21	22
23	Secondary	$ -	(Line 2 x Line 21) x Line 17	23
24	Primary	$ 88	(Line 2 x Line 21) x Line 18	24
25	Tranmission	$ 493	(Line 2 x Line 21) x Line 19	25
26	Total	$ 581	Sum Lines 23; 24; and 25	26
27				27
28	Summer Maximum Demand at the Time of System Peak Rates [3]	$/kW		28
29	Secondary	$ -	Line 23 / Line 11	29
30	Primary	$ 1.2971826	Line 24 / Line 12	30
31	Tranmission	$ 1.2971826	Line 25 / Line 13	31
32				32
33				33
34	Summer Maximum Demand at the Time of System Peak Rates (Rounded)	$/kW		34
35	Secondary	$ -	Line 29, Rounded to 7 Decimal Places	35
36	Primary	$ 1.2971826	Line 30, Rounded to 7 Decimal Places	36
37	Tranmission	$ 1.2971826	Line 31, Rounded to 7 Decimal Places	37
38				38

NOTES:

1 Revenues to be reallocated from NCD to recovery from Maximum Demand at the time of System Peak for the following California Public Utilities Commission (CPUC) tariffs:
A6-TOU

2 Summer Maximum Demand at the time of System Peak Determinants for the following California Public Utilities Commission (CPUC) tariffs:
A6-TOU

3 Summer Maximum Demand at the time of System Peak Demand Charges for the following California Public Utilities Commission (CPUC) tariffs:
A6-TOU

4 Winter Maximum Demand at the time of System Peak Determinants for the following California Public Utilities Commission (CPUC) tariffs:
A6-TOU

5 Winter Maximum Demand at the time of System Peak Demand Charges for the following California Public Utilities Commission (CPUC) tariffs:
A6-TOU

6 LF = Transmission Loss Factor; Secondary Level = 1.0457; Primary Level = 1.0108; Transmission Level = 1.0000

Section 3.2.2
SAN DIEGO GAS AND ELECTRIC COMPANY
TO3-Cycle 5 Annual Transmission Formulaic Rate Filing
Derivation of TO3-CYCLE-4 WHOLESALE Rates Using TO3-CYCLE-4 Billing Determinants
Medium-Large Commercial Customers [1]
($000)

Line No.	Description	Derivation of Commodity Rate & Proof of Revenues Calculation	Reference	Line No.
1	Winter Maximum Demand at the Time of System Peak By Voltage Level @ Meter Level (MW) [4]			1
2	Secondary	-	Section 3.3.2; Page 15; Col. B; Line 47	2
3	Primary	92	Section 3.3.2; Page 15; Col. B; Line 48	3
4	Tranmission	477	Section 3.3.2; Page 15; Col. B; Line 49	4
5	Total	569	Sum Lines 2; 3; 4	5
6				6
7	Winter Maximum Demand at the Time of System Peak @ Transmission Level (MW)			7
8	Secondary	-	Section 3.3.2; Page 15; Col. D; Line 47	8
9	Primary	93	Section 3.3.2; Page 15; Col. D; Line 48	9
10	Tranmission	477	Section 3.3.2; Page 15; Col. D; Line 49	10
11	Total	570	Sum Lines 8; 9; 10	11
12				12
13	Winter Maximum Demand at the Time of System Peak Allocation to Voltage Levels			13
14	Secondary	0.00%	Line 8 / Line 11	14
15	Primary	16.32%	Line 9 / Line 11	15
16	Tranmission	83.68%	Line 10 / Line 11	16
17	Total	100.00%	Sum Lines 14; 15; 16	17
18	Share of Total Revenue Allocation to Winter Maximum Demand at the Time of System Peak	20.00%		18
19	Revenues for Proposed Winter Maximum Demand at the Time of System Peak Rates	$ 145	Section 3.3.2; Page 8; Line 2	19
20	Secondary	$ -	(Section 3.2.2; Page 8; Line 2 x Line 17) x Line 14	20
21	Primary	$ 24	(Section 3.2.2; Page 8; Line 2 x Line 18) x Line 15	21
22	Tranmission	$ 122	(Section 3.2.2; Page 8; Line 2 x Line 19) x Line 16	22
23	Total	$ 145	Sum Lines 20; 21; 22	23
24				24
25	Winter Maximum Demand at the Time of System Peak Rates [5]	$/kW		25
26	Secondary	$ -	Line 20 / Line 8	26
27	Primary	$ 0.2548850	Line 21 / Line 9	27
28	Tranmission	$ 0.2548850	Line 21 / Line 10	28
29				29
30				30
31	Winter Maximum Demand at the Time of System Peak Rates (Rounded)	$/kW		31
32	Secondary	$ -	Line 26, Rounded to 7 Decimal Places	32
33	Primary	$ 0.2548850	Line 27, Rounded to 7 Decimal Places	33
34	Tranmission	$ 0.2548850	Line 28, Rounded to 7 Decimal Places	34
35				35
36				36
37	Proof of Revenue Calculations:			37
38	Secondary	$ -	Section 3.2.2; Page 8 (Line 5 x Line 35) + Page 9; (Line 8 x Line 32)	38
39	Primary	$ 112	Section 3.2.2; Page 8 (Line 6 x Line 36) + Page 9; (Line 9 x Line 33)	39
40	Tranmission	$ 615	Section 3.2.2; Page 8 (Line 7 x Line 37) + Page 9; (Line 10 x Line 34)	40
41	Total	$ 726	Sum Lines 38; 39; and 40	41
42				42
43	Difference	$ 0	Section 3.3.2; Page 8; Line 2 Minus Page 9; Line 41	43
44				44

NOTES:
[1] Revenues to be reallocated from NCD to recovery from Maximum Demand at the time of System Peak for the following California Public Utilities Commission (CPUC) tariffs:
A6-TOU
[2] Summer Maximum Demand at the time of System Peak Determinants for the following California Public Utilities Commission (CPUC) tariffs:
A6-TOU
[3] Summer Maximum Demand at the time of System Peak Demand Charges for the following California Public Utilities Commission (CPUC) tariffs:
A6-TOU
[4] Winter Maximum Demand at the time of System Peak Determinants for the following California Public Utilities Commission (CPUC) tariffs:
A6-TOU
[5] Winter Maximum Demand at the time of System Peak Demand Charges for the following California Public Utilities Commission (CPUC) tariffs:
A6-TOU
[6] LF = Transmission Loss Factor; Secondary Level = 1.0457; Primary Level = 1.0108; Transmission Level = 1.0000

Section 3.2.2

SAN DIEGO GAS AND ELECTRIC COMPANY

TO3-Cycle 5 Annual Transmission Formulaic Rate Filing

Derivation of TO3-CYCLE-4 WHOLESALE Rates Using TO3-CYCLE-4 Billing Determinants

Street Lighting Customers

($000)

Line No.	Customer Classes	Derivation of Commodity Rate & Proof of Revenues Calculation	Reference	Line No.
1	Street Lighting - Allocated Transmission Revenue Requirement	$ 1,157	Section 3.2.2; Page 1; Line 7	1
2				2
3	Billing Determinants - Street Lighting Customers @ MWh [1]:	113,680	Section 3.2.2; Page 16.1; Line 16	3
4				4
5	Transmission Level Adjustment Factor	1.04570	Section 3.2.2; Page 14; Col. C; Line 10	5
6				6
7	Billing Determinants @ Transmission Level	118,875	Line 3 x Line 5	7
8				8
9	Energy Rate Per kWh @ Transmission Level	$ 0.0097329	Line 1 / Line 7	9
10				10
11	Energy Rate Per kWh - Rounded @ Transmission Level	$ 0.0097329	Line 9, Rounded to 7 Decimal Places	11
12				12
13	Proof of Revenues	$ 1,157	Line 7 x Line 11	13
14				14
15	Difference	$ 0	Line 1 - Line 13	15

Notes:

[1] Street lighting customers include the following California Public Utilities Commission (CPUC) tariffs: DWL, OL-1, LS-1, LS-2.

Section 3.2.2
SAN DIEGO GAS AND ELECTRIC COMPANY
TO3-Cycle 5 Annual Transmission Formulaic Rate Filing
Derivation of TO3-CYCLE-4 WHOLESALE Rates Using TO3-CYCLE-4 Billing Determinants
Standby Revenues Calculation
($000)

Line No.	Customer Classes	Derivation of Standby Surcharge & Proof of Revenues Calculation	Reference	Line No.
1	**Standby - Demand Revenue Requirement:**	$ 3,910	Section 3.2.2; Page 1; Line 8	1
2	*Demand Determinants @ Transmission Level Used to Allocate*			2
3	*Total Class Revenues to Voltage Level:*			3
4	Secondary [1]	138	Section 3.2.2; Page 15; Col. D; Line 54	4
5	Primary [1]	1,022	Section 3.2.2; Page 15; Col. D; Line 55	5
6	Tranmission [1]	560	Section 3.2.2; Page 15; Col. D; Line 56	6
7	Total	1,720	Sum Lines 4; 5; 6	7
8	*Allocation Factors Per Above to Allocate*			8
9	*Demand Revenue Requirements to Voltage Level:*			9
10	Secondary	8.02%	Line 4 / Line 7	10
11	Primary	59.42%	Line 5 / Line 7	11
12	Tranmission	32.56%	Line 6 / Line 7	12
13	Total	100.00%	Sum Lines 10; 11; 12	13
14				14
15	**Allocation of Revenue Requirements to Voltage Level:**			15
16	Secondary	$ 314	Line 1 x Line 10	16
17	Primary	2,323	Line 1 x Line 11	17
18	Tranmission	1,273	Line 1 x Line 12	18
19	Total	$ 3,910	Sum Lines 16; 17; 18	19
20				20
21	**Demand Determinants By Voltage Level @ Transmission:**			21
22	Secondary	138	Section 3.2.2; Page 15; Col. D; Line 54	22
23	Primary	1,022	Section 3.2.2; Page 15; Col. D; Line 55	23
24	Tranmission	560	Section 3.2.2; Page 15; Col. D; Line 56	24
25	Total	1,720	Sum Lines 22; 23; 24	25
26				26
27	**Demand Rate By Voltage Level @ Transmission:**			27
28	Secondary	$ 2.2753623	Line 16 / Line 22	28
29	Primary	$ 2.2729941	Line 17 / Line 23	29
30	Tranmission	$ 2.2732143	Line 18 / Line 24	30
31				31
32	**Demand Rate By Voltage Level @ Transmission (Rounded):**			32
33	Secondary	$ 2.2753623	Line 28 Rounded to 7 Decimal Places	33
34	Primary	$ 2.2729941	Line 29 Rounded to 7 Decimal Places	34
35	Tranmission	$ 2.2732143	Line 30 Rounded to 7 Decimal Places	35
36				36
37	**Proof of Revenue Calculations:**			37
38	Secondary	$ 314	Line 22 x Line 33	38
39	Primary	2,323	Line 23 x Line 34	39
40	Tranmission	1,273	Line 24 x Line 35	40
41	Total	$ 3,910	Sum Lines 38; 39; 40	41
42				42
43	Difference	$ -	Line 1 - Line 41	43

Notes:

[1] LF = Transmission Loss Factor; Secondary Level = 1.0457; Primary Level = 1.0108; Transmission Level = 1.0000

Section 3.2.2

SAN DIEGO GAS AND ELECTRIC COMPANY
TO3-Cycle 5 Annual Transmission Formulaic Rate Filing
WHOLESALE - Rate Design Information
Summary of TO3-CYCLE-4 Wholesale Transmission Rates Based on TO3-CYCLE-4 Wholesale Cost of Service
Using TO3-CYCLE-4 Forecast Billing Determinants

Line No.	Customer Classes	Transmission Energy Rates $/kWh	Transmission Level Demand Rates $/kW-Mo	Primary Level Demand Rates $/kW-Mo	Secondary Level Demand Rates $/kW-Mo	Reference	Line No.
1	Residential	$ 0.0152337				Section 3.2.2; Page 2; Line 11	1
2							2
3	Small Commercial	$ 0.0180080				Section 3.2.2; Page 3; Line 11	3
4							4
5	Med & Lrg Commercial/Industrial						5
6	Non-Coincident Demand (100%) [1]		$ 5.0977873	$ 5.0973649	$ 5.0975107	Section 3.2.2; Page 4; Lines 33;34;35	6
7							7
8	Non-Coincident Demand (90%) [2]		$ 4.5880086	$ 4.5876284	$ 4.5877596	Section 3.2.2; Page 5; Lines 7;8;9	8
9							9
10	Maximum On-Peak Demand [3]						10
11	Summer		$ 0.9895844	$ 0.9895844	$ 0.9895844	Section 3.2.2; Page 6; Lines 35;36;37	11
12	Winter		$ 0.2145097	$ 0.2145097	$ 0.2145097	Section 3.2.2; Page 7; Lines 32;33;34	12
13							13
14	Maximum Demand at the Time of System Peak [4]						14
15	Summer		$ 1.2971826	$ 1.2971826	$ -	Section 3.2.2; Page 8; Lines 29;30;31	15
16	Winter		$ 0.2548850	$ 0.2548850	$ -	Section 3.2.2; Page 9; Lines 32;33;34	16
17							17
18	Street Lighting	$ 0.0097329				Section 3.2.2; Page 10; Line 11	18
19							19
20	Standby Rate		$ 2.2732143	$ 2.2729941	$ 2.2753623	Section 3.2.2; Page 11; Lns 33;34;35	20

NOTES:

1 Non-Coincident Demand (NCD) (100%) rates are applicable to the following California Public Utilities Commission (CPUC) tariffs: Schedules AD and PA-T-1

2 NCD (90%) rates are applicable to the following CPUC tariffs: Schedules AY-TOU, AL-TOU, AL-TOU-DER, DG-R, and A6-TOU.

3 Maximum On-Peak Demand rates are applicable to the following CPUC tariffs: Schedules AY-TOU, AL-TOU, AL-TOU-DER and DG-R

4 Maximum Demand at the Time of System Peak rates are applicable to the following CPUC tariffs: Schedule A6-TOU

Section 3.2.2

SAN DIEGO GAS AND ELECTRIC COMPANY
TO3-Cycle 5 Annual Transmission Formulaic Rate Filing
WHOLESALE - Rate Design Information
Summary of TO3-CYCLE-4 Proof of Revenues Based on TO3-CYCLE-4 Wholesale Cost of Service
($1,000)

Line No.	Customer Classes	Total Revenues Per Cost of Service Study	Total Revenues Per Rate Design	Difference	Reference	Line No.
1	Residential Customers	$ 123,419	$ 123,419	$ (0)	Sect. 3.2.2; Pg. 1; Ln. 4; Pg. 2; Ln. 13	1
2						2
3	Small Commercial	38,002	38,002	0	Sect. 3.2.2; Pg. 1; Ln. 5; Pg. 3; Ln. 13	3
4						4
5	Med & Lrg Commercial/Industrial	146,283	146,283	-	Sect. 3.2.2; Pg. 1; Ln. 6; Pg. 4; Ln. 41	5
6						6
7	Street Lighting	1,157	1,157	0	Sect. 3.2.2; Pg. 1; Ln. 7; Pg. 10; Ln. 13	7
8						8
9	Standby Revenues	3,910	3,910	-	Sect. 3.2.2; Pg. 1; Ln. 8; Pg. 11; Ln. 41	9
10						10
11	Grand Total	$ 312,771	$ 312,771	$ (0)	Sum Lines 1 thru 9	11

Section 3.2.2

SAN DIEGO GAS AND ELECTRIC COMPANY
TO3-Cycle 5 Annual Transmission Formulaic Rate Filing
WHOLESALE - Rate Design Information
Development of TO3-CYCLE-4 12-CP Allocation Factors and Voltage Level Allocation Factors

Line No.	Customer Class	(A) 5 Year Average Ending 12/31/2008 Of 12 CPs Kilowat @ Meter Level [1]	(B) Transmission Loss Factors	(C) = (A) x (B) 5 Year Average Ending 12/31/2008 Of 12 CPs Kilowat @ Transmission Level	(D) 12 CP Allocation Percentages @ Transmission Level	Reference	Line No.
1	5-Year Average - 12CP Allocation Factors:					From Statement BB;	1
2	Residential Customers	15,054,815	1.0457	15,742,820	39.46%	Docket No. ER10-2235	2
3	Small Commercial Customers	4,636,436	1.0457	4,848,321	12.15%	Docket No. ER10-2235	3
4	Medium-Large Commercial Customers						4
5	Secondary	13,510,244	1.0457	14,127,662	35.41%	Docket No. ER10-2235	5
6	Primary	3,295,181	1.0108	3,330,769	8.35%	Docket No. ER10-2235	6
7	Transmission	1,201,031	1.0000	1,201,031	3.01%	Docket No. ER10-2235	7
8	Total Medium-Large Commercial	18,006,456	1.0363	18,659,462	46.77%	Sum Lines 5; 6; 7	8
9							9
10	Street Lighting	139,791	1.0457	146,179	0.37%	Docket No. ER10-2235	10
11	Standby Customers						11
12	Secondary	38,310	1.0457	40,061	0.10%	Docket No. ER10-2235	12
13	Primary	293,448	1.0108	296,617	0.74%	Docket No. ER10-2235	13
14	Transmission	162,697	1.0000	162,697	0.41%	Docket No. ER10-2235	14
15	Total Standby Customers	494,455	1.0100	499,375	1.25%	Sum Lines 12; 13; 14	15
16							16
17	System Total	38,331,953	1.0408	39,896,157	100.00%	Sum Lines 2; 3; 8; 10; 15	17
18							18
19							19
20	Medium-Large Commercial Customers:	**Meter Level**		**Transmission Level**	**Ratios**		20
21	Billing Determinants - (Non-Coicident Demand)						21
22	Secondary	21,821	1.0457	22,818	79.51%	Docket No. ER10-2235	22
23	Primary	4,430	1.0108	4,478	15.60%	Docket No. ER10-2235	23
24	Transmission	1,401	1.0000	1,401	4.88%	Docket No. ER10-2235	24
25	Total	27,652	1.0378	28,697	99.99%	Sum Lines 22; 23; 24	25
26							26
27							27
28	Standby Customers:	**Meter Level**		**Transmission Level**	**Ratios**		28
29	Billing Determinants - (Contracted Standby Demand)						29
30	Secondary	132	1.0457	138	8.02%	Docket No. ER10-2235	30
31	Primary	1,011	1.0108	1,022	59.42%	Docket No. ER10-2235	31
32	Transmission	560	1.0000	560	32.56%	Docket No. ER10-2235	32
33	Total	1,703	1.0100	1,720	100.00%	Sum Lines 30; 31; 32	33

NOTES:

1 Information comes from SDG&E's TO3-Cycle 4 filed with the FERC in Docket No. ER10-2235-000 filed on August 13, 2010. See Statement BB and Sales Forecast information.

Section 3.2.2
SAN DIEGO GAS AND ELECTRIC COMPANY
TO3-Cycle 5 Annual Transmission Formulaic Rate Filing
WHOLESALE - Rate Design Information
Development of TO3-CYCLE-4 12-CP Allocation Factors and Voltage Level Allocation Factors

Line No.	(A) Customer Class	(B) Forecast Demand Determinants Megawatt @ Meter Level	(C) Transmission Loss Factors	(D) = (B) x (C) Forecast Demand Determinants Megawatt @ Transmission Level	(E) Ratios	Reference	Line No.
1	Forecast Demand Determinants for Medium-Large Commercial Customers:						1
2	Non-Coincident Demand Determinants Pertaining to Customers on Schedules @ 100% NCD Rate						2
3	Secondary	990	1.0457	1,035	88.39%	Section 3.3.2; Page 17.1; Line 35	3
4	Primary	135	1.0108	136	11.61%	Section 3.3.2; Page 17.1; Line 36	4
5	Transmission	-	1.0000	-	0.00%	Section 3.3.2; Page 17.1; Line 37	5
6	Total	1,125		1,171	100.00%	Sum Lines 3; 4; 5	6
7							7
8	Non-Coincident Demand Determinants Pertaining to Customers on Schedules @ 90% NCD Rate						8
9	with Maximum On-Peak Period Demand						9
10	Secondary	20,831	1.0457	21,783	83.46%	Section 3.3.2; Page 17.2; Line 61	10
11	Primary	4,006	1.0108	4,049	15.51%	Section 3.3.2; Page 17.2; Line 62	11
12	Transmission	269	1.0000	269	1.03%	Section 3.3.2; Page 17.2; Line 63	12
13	Total	25,105		26,101	100.00%	Sum Lines 10; 11; 12	13
14							14
15	Non-Coincident Demand Determinants Pertaining to Customers on Schedules @ 90% NCD Rate						15
16	with Maximum Demand at the Time of System Peak						16
17	Secondary	-	1.0457	-	0.00%	Section 3.3.2; Page 17.3; Line 97	17
18	Primary	290	1.0108	293	20.56%	Section 3.3.2; Page 17.3; Line 98	18
19	Transmission	1,132	1.0000	1,132	79.44%	Section 3.3.2; Page 17.3; Line 99	19
20	Total	1,422		1,425	100.00%	Sum Lines 17; 18; 19	20
21							21
22	Total Non-Coincident Demand Determinants Pertaining to Medium-Large Commercial Customers						22
23	Secondary	21,821	1.0457	22,818	79.51%	Sum Lines 3; 10; 17	23
24	Primary	4,430	1.0108	4,478	15.60%	Sum Lines 4; 11; 18	24
25	Transmission	1,401	1.0000	1,401	4.88%	Sum Lines 5; 12; 19	25
26	Total	27,652		28,697	99.99%	Sum Lines 23; 24; 25	26
27							27
28	Maximum On-Peak Period Demand Determinants						28
29	Summer (May, June, July, August, September)						29
30	Secondary	8,369	1.0457	8,752	81.37%	Section 3.3.2; Page 17.2; Line 71	30
31	Primary	1,761	1.0108	1,780	16.55%	Section 3.3.2; Page 17.2; Line 72	31
32	Transmission	224	1.0000	224	2.08%	Section 3.3.2; Page 17.2; Line 73	32
33	Total	10,354		10,756	100.00%	Sum Lines 30; 31; 32	33
34	Winter (October, November, December, January, February, March, April)						34
35	Secondary	9,658	1.0457	10,099	81.41%	Section 3.3.2; Page 17.2; Line 71	35
36	Primary	2,031	1.0108	2,053	16.55%	Section 3.3.2; Page 17.2; Line 72	36
37	Transmission	253	1.0000	253	2.04%	Section 3.3.2; Page 17.2; Line 73	37
38	Total	11,941		12,405	100.00%	Sum Lines 35; 36; 37	38
39							39
40	Maximum Demand at the Time of System Peak Determinants						40
41	Summer (May, June, July, August, September)						41
42	Secondary	-	1.0457	-	0.00%	Section 3.3.2; Page 17.3; Line 107	42
43	Primary	67	1.0108	68	15.18%	Section 3.3.2; Page 17.3; Line 108	43
44	Transmission	380	1.0000	380	84.82%	Section 3.3.2; Page 17.3; Line 109	44
45	Total	447		448	100.00%	Sum Lines 42; 43; 44	45
46	Winter (October, November, December, January, February, March, April)						46
47	Secondary	-	1.0457	-	0.00%	Section 3.3.2; Page 17.3; Line 107	47
48	Primary	92	1.0108	93	16.32%	Section 3.3.2; Page 17.3; Line 108	48
49	Transmission	477	1.0000	477	83.68%	Section 3.3.2; Page 17.3; Line 109	49
50	Total	569		570	100.00%	Sum Lines 47; 48; 49	50
51							51
52	Forecast Demand Determinants for Standby Customers:						52
53	Contracted Demand Determinants						53
54	Secondary	132	1.0457	138	8.02%	Section 3.3.2; Page 17.3; Line 114	54
55	Primary	1,011	1.0108	1,022	59.42%	Section 3.3.2; Page 17.3; Line 115	55
56	Transmission	560	1.0000	560	32.56%	Section 3.3.2; Page 17.3; Line 116	56
57	Total	1,703		1,720	100.00%	Sum Lines 56; 57; 58	57

Section 3.2.2
San Diego Gas & Electric
TO3-CYCLE-4 FERC Forecast Period: September 2010 - August 2011

Line No.															Line No.
1	**System Delivery Determinants**														1
2															2
3	**Customer Class Deliveries (MWh)**	**Sep-10**	**Oct-10**	**Nov-10**	**Dec-10**	**Jan-11**	**Feb-11**	**Mar-11**	**Apr-11**	**May-11**	**Jun-11**	**Jul-11**	**Aug-11**	**Total**	3
4	Residential	736,026	624,534	602,078	670,318	733,824	649,002	618,864	571,210	561,403	589,706	673,271	717,425	7,747,660	4
5	Transmission Level Adjustment Factor	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570		5
6	Residential @ Transmission Level	769,662	653,075	629,593	700,951	767,359	678,661	647,146	597,315	587,059	616,656	704,040	750,211	8,101,728	6
7															7
8	Small Commercial	191,366	171,053	163,619	161,337	163,214	158,315	159,127	153,056	157,079	167,056	184,586	188,251	2,018,058	8
9	Transmission Level Adjustment Factor	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570		9
10	Small Commercial @ Transmission Level	200,111	178,870	171,096	168,710	170,673	165,550	166,400	160,051	164,258	174,690	193,021	196,854	2,110,283	10
11															11
12	Med. & Lrg. Commercial/Industrial	985,413	885,269	868,496	852,559	838,297	820,929	831,263	823,796	835,415	885,135	945,896	940,636	10,513,105	12
13	Transmission Level Adjustment Factor	1.03627	1.03627	1.03627	1.03627	1.03627	1.03627	1.03627	1.03627	1.03627	1.03627	1.03627	1.03627		13
14	Med. & Large Comm./Ind. @ Transmission Le	1,021,150	917,374	899,992	883,477	868,698	850,700	861,409	853,672	865,712	917,235	980,199	974,748	10,894,363	14
15															15
16	Street Lighting	9,442	9,448	9,454	9,460	9,465	9,470	9,476	9,481	9,486	9,491	9,499	9,506	113,680	16
17	Transmission Level Adjustment Factor	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570		17
18	Street Lighting @ Transmission Level	9,874	9,880	9,886	9,892	9,898	9,903	9,909	9,914	9,920	9,925	9,933	9,941	118,875	18
19															19
20	Sale for Resale	2	2	2	2	2	2	2	2	2	2	2	2	19	20
21	Total System@Trans. Ex Sale for Resale	2,000,797	1,759,199	1,710,567	1,763,030	1,816,628	1,704,814	1,684,863	1,620,951	1,626,948	1,718,506	1,887,193	1,931,754	21,225,250	21
22	Total System@Meter Ex Sale for Resale	1,922,247	1,690,304	1,643,646	1,693,673	1,744,800	1,637,716	1,618,730	1,557,544	1,563,384	1,651,389	1,813,252	1,855,818	20,392,502	22
23	**Med. & Large Comm./Ind.**														23
24	**Service Voltage Determinants**														24
25															25
26	**Deliveries (MWh)**	**Sep-10**	**Oct-10**	**Nov-10**	**Dec-10**	**Jan-11**	**Feb-11**	**Mar-11**	**Apr-11**	**May-11**	**Jun-11**	**Jul-11**	**Aug-11**	**Total**	26
27	Med & Large Comm./Ind.	985,413	885,269	868,496	852,559	838,297	820,929	831,263	823,796	835,415	885,135	945,896	940,636	10,513,105	27
28															28
29	**Deliveries (%)**														29
30	% @ Secondary Service	75.70%	75.19%	75.06%	74.94%	74.79%	74.67%	74.74%	74.72%	74.81%	75.15%	75.51%	75.47%	75.08%	30
31	% @ Primary Service	18.02%	17.99%	18.01%	18.02%	18.07%	18.06%	18.06%	18.04%	18.03%	18.01%	18.00%	18.01%	18.03%	31
32	% @ Transmission Service	6.28%	6.82%	6.93%	7.04%	7.14%	7.26%	7.19%	7.24%	7.16%	6.84%	6.49%	6.52%	6.89%	32
33		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	33
34	**Deliveries (MWh)**														34
35	MWh @ Secondary Service	745,959	665,640	651,892	638,928	626,979	612,992	621,308	615,526	624,993	665,146	714,272	709,910	7,893,544	35
36	MWh @ Primary Service	177,603	159,241	156,408	153,631	151,443	148,297	150,155	148,599	150,589	159,452	170,236	169,382	1,895,036	36
37	MWh @ Transmission Service	61,852	60,388	60,196	60,000	59,876	59,640	59,800	59,672	59,834	60,538	61,388	61,343	724,525	37
38		985,413	885,269	868,496	852,559	838,297	820,929	831,263	823,796	835,415	885,135	945,896	940,636	10,513,105	38
39	**Non-Coincident Demand (%)**														39
40	% @ Secondary Service	0.2769%	0.2771%	0.2767%	0.2764%	0.2756%	0.2756%	0.2756%	0.2760%	0.2763%	0.2767%	0.2771%	0.2770%	0.2764%	40
41	% @ Primary Service	0.2339%	0.2344%	0.2341%	0.2339%	0.2331%	0.2331%	0.2331%	0.2335%	0.2338%	0.2340%	0.2343%	0.2342%	0.2338%	41
42	% @ Transmission Service	0.1932%	0.1933%	0.1934%	0.1934%	0.1934%	0.1934%	0.1934%	0.1934%	0.1934%	0.1933%	0.1933%	0.1933%	0.1934%	42

Section 3.2.2
San Diego Gas & Electric
TO3-CYCLE-4 FERC Forecast Period: September 2010 - August 2011

Line No.															Line No.
26															26
27	**Non-Coincident Demand (MW)**														27
28	MW @ Secondary Service	2,065	1,844	1,804	1,766	1,728	1,689	1,713	1,699	1,727	1,840	1,980	1,966	21,821	28
29	Voltage Level Adjustment Factor	1.0457	1.0457	1.0457	1.0457	1.0457	1.0457	1.0457	1.0457	1.0457	1.0457	1.0457	1.0457		29
30	MW @ Secondary Service @ Trans Level	2,160	1,929	1,886	1,847	1,807	1,766	1,791	1,777	1,806	1,924	2,070	2,056	22,818	30
31															31
32	MW @ Primary Service	415	373	366	359	353	346	350	347	352	373	399	397	4,430	32
33	Voltage Level Adjustment Factor	1.0108	1.0108	1.0108	1.0108	1.0108	1.0108	1.0108	1.0108	1.0108	1.0108	1.0108	1.0108		33
34	MW @ Primary Service @ Trans Level	420	377	370	363	357	349	354	351	356	377	403	401	4,478	34
35															35
36	MW @ Transmission Service	120	117	116	116	116	115	116	115	116	117	119	119	1,401	36
37	Total Non-Coincident Demand @ Trans	2,699	2,423	2,373	2,326	2,280	2,231	2,260	2,243	2,277	2,418	2,592	2,575	28,697	37
38	Total Non-Coincident Demand @ Meter	2,600	2,335	2,286	2,242	2,197	2,150	2,178	2,161	2,194	2,330	2,497	2,481	27,652	38
39	**Schedule S: Standby Determinants**														39
40															40
41	**Contracted Standby Demand (MW)**	**Sep-10**	**Oct-10**	**Nov-10**	**Dec-10**	**Jan-11**	**Feb-11**	**Mar-11**	**Apr-11**	**May-11**	**Jun-11**	**Jul-11**	**Aug-11**	**Total**	41
42	MW @ Secondary Service	11	11	11	11	11	11	11	11	11	11	11	11	132	42
43	Voltage Level Adjustment Factor	1.0457	1.0457	1.0457	1.0457	1.0457	1.0457	1.0457	1.0457	1.0457	1.0457	1.0457	1.0457		43
44	MW @ Secondary Service @ Trans Level	11	11	11	11	11	11	11	11	11	11	11	11	138	44
45															45
46	MW @ Primary Service	84	84	84	84	84	84	84	84	84	84	84	84	1,011	46
47	Voltage Level Adjustment Factor	1.0108	1.0108	1.0108	1.0108	1.0108	1.0108	1.0108	1.0108	1.0108	1.0108	1.0108	1.0108		47
48	MW @ Primary Service @ Trans Level	85	85	85	85	85	85	85	85	85	85	85	85	1,022	48
49															49
50	MW @ Transmission Service	47	47	47	47	47	47	47	47	47	47	47	47	560	50
51	Total Contract Demand @ Trans	143	143	143	143	143	143	143	143	143	143	143	143	1,720	51
52	Total Contract Demand @ Meter	142	142	142	142	142	142	142	142	142	142	142	142	1,703	52

San Diego Gas & Electric
FERC Forecast Period: September 2010 - August 2011

Line No.															Line No.
1	**SDG&E: System Delivery Determinants**														1
2															2
3	**Customer Class Deliveries (MWh)**	**Sep-10**	**Oct-10**	**Nov-10**	**Dec-10**	**Jan-11**	**Feb-11**	**Mar-11**	**Apr-11**	**May-11**	**Jun-11**	**Jul-11**	**Aug-11**	**Total**	3
4	Residential	736,026	624,534	602,078	670,318	733,824	649,002	618,864	571,210	561,403	589,706	673,271	717,425	7,747,660	4
5	Small Commercial	191,366	171,053	163,619	161,337	163,214	158,315	159,127	153,056	157,079	167,056	184,586	188,251	2,018,058	5
6	Med. & Large Comm./Ind. (AD + PA-T-1)	29,183	27,526	24,494	22,575	17,499	16,764	17,341	19,342	21,121	24,808	29,840	28,490	278,984	6
7	Med. & Large Comm./Ind. (AY + AL + DGR)	899,273	800,769	787,011	772,976	763,774	747,125	756,865	747,381	757,204	803,221	858,932	855,005	9,549,534	7
8	Med. & Large Comm./Ind. (A6)	56,957	56,974	56,991	57,007	57,024	57,041	57,057	57,074	57,090	57,107	57,124	57,140	684,586	8
9	Lighting	9,442	9,448	9,454	9,460	9,465	9,470	9,476	9,481	9,486	9,491	9,499	9,506	113,680	9
10	Sale for Resale	1.54	1.54	1.54	1.54	1.54	1.54	1.54	1.54	1.54	1.54	1.54	1.54	18.50	10
11	**Total System**	**1,922,249**	**1,690,306**	**1,643,648**	**1,693,675**	**1,744,802**	**1,637,717**	**1,618,732**	**1,557,545**	**1,563,385**	**1,651,390**	**1,813,253**	**1,855,819**	**20,392,521**	11
12															12
13	**Med. & Large Comm./Ind.**														13
14	**Rate Schedule Billing Determinants**														14
15															15
16	**Schedules AD / PA-T-1:**	**Sep-10**	**Oct-10**	**Nov-10**	**Dec-10**	**Jan-11**	**Feb-11**	**Mar-11**	**Apr-11**	**May-11**	**Jun-11**	**Jul-11**	**Aug-11**	**Total**	16
17	**Total Deliveries (MWh)**	29,183	27,526	24,494	22,575	17,499	16,764	17,341	19,342	21,121	24,808	29,840	28,490	278,984	17
18															18
19	**Total Deliveries (%)**														19
20	% @ Secondary Service	90.33%	90.33%	90.33%	90.33%	90.33%	90.33%	90.33%	90.33%	90.33%	90.33%	90.33%	90.33%	90.33%	20
21	% @ Primary Service	9.67%	9.67%	9.67%	9.67%	9.67%	9.67%	9.67%	9.67%	9.67%	9.67%	9.67%	9.67%	9.67%	21
22	% @ Transmission Service	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	22
23		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	23
24	**Total Deliveries (MWh)**														24
25	MWh @ Secondary Service	26,361	24,865	22,125	20,392	15,807	15,143	15,665	17,472	19,079	22,409	26,954	25,735	252,006	25
26	MWh @ Primary Service	2,822	2,662	2,369	2,183	1,692	1,621	1,677	1,870	2,042	2,399	2,886	2,755	26,978	26
27	MWh @ Transmission Service	0	0	0	0	0	0	0	0	0	0	0	0	0	27
28		29,183	27,526	24,494	22,575	17,499	16,764	17,341	19,342	21,121	24,808	29,840	28,490	278,984	28
29	**Non-Coincident Demand (%)**														29
30	% @ Secondary Service	0.3929%	0.3929%	0.3929%	0.3929%	0.3929%	0.3929%	0.3929%	0.3929%	0.3929%	0.3929%	0.3929%	0.3929%	0.3929%	30
31	% @ Primary Service	0.4986%	0.4986%	0.4986%	0.4986%	0.4986%	0.4986%	0.4986%	0.4986%	0.4986%	0.4986%	0.4986%	0.4986%	0.4986%	31
32	% @ Transmission Service	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	32
33															33
34	**Non-Coincident Demand (MW)**														34
35	MW @ Secondary Service	103.573	97.693	86.930	80.121	62.107	59.496	61.546	68.646	74.961	88.044	105.904	101.113	990.134	35
36	MW @ Primary Service	14.071	13.272	11.810	10.885	8.437	8.083	8.361	9.326	10.184	11.961	14.387	13.736	134.511	36
37	MW @ Transmission Service	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	37
38		117.644	110.965	98.740	91.006	70.544	67.578	69.907	77.972	85.145	100.005	120.291	114.849	1,124.645	38
39															39

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San Diego Gas & Electric
FERC Forecast Period: September 2010 - August 2011

Line No.		Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Total	Line No.
40															40
41															41
42	**Schedules AL-TOU / AY-TOU / DG-R:**	**Sep-10**	**Oct-10**	**Nov-10**	**Dec-10**	**Jan-11**	**Feb-11**	**Mar-11**	**Apr-11**	**May-11**	**Jun-11**	**Jul-11**	**Aug-11**	**Total**	42
43	**Total Deliveries (MWh)**	899,273	800,769	787,011	772,976	763,774	747,125	756,865	747,381	757,204	803,221	858,932	855,005	9,549,534	43
44															44
45	**Total Deliveries (%)**														45
46	% @ Secondary Service	80.02%	80.02%	80.02%	80.02%	80.02%	80.02%	80.02%	80.02%	80.02%	80.02%	80.02%	80.02%	80.02%	46
47	% @ Primary Service	18.48%	18.48%	18.48%	18.48%	18.48%	18.48%	18.48%	18.48%	18.48%	18.48%	18.48%	18.48%	18.48%	47
48	% @ Transmission Service	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	48
49		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	49
50	**Total Deliveries (MWh)**														50
51	MWh @ Secondary Service	719,598	640,775	629,766	618,535	611,172	597,849	605,643	598,054	605,914	642,737	687,317	684,175	7,641,537	51
52	MWh @ Primary Service	166,186	147,982	145,440	142,846	141,145	138,069	139,869	138,116	139,931	148,435	158,731	158,005	1,764,754	52
53	MWh @ Transmission Service	13,489	12,012	11,805	11,595	11,457	11,207	11,353	11,211	11,358	12,048	12,884	12,825	143,243	53
54		899,273	800,769	787,011	772,976	763,774	747,125	756,865	747,381	757,204	803,221	858,932	855,005	9,549,534	54
55	**Non-Coincident Demand (%)**														55
56	% @ Secondary Service	0.2726%	0.2726%	0.2726%	0.2726%	0.2726%	0.2726%	0.2726%	0.2726%	0.2726%	0.2726%	0.2726%	0.2726%	0.2726%	56
57	% @ Primary Service	0.2270%	0.2270%	0.2270%	0.2270%	0.2270%	0.2270%	0.2270%	0.2270%	0.2270%	0.2270%	0.2270%	0.2270%	0.2270%	57
58	% @ Transmission Service	0.1875%	0.1875%	0.1875%	0.1875%	0.1875%	0.1875%	0.1875%	0.1875%	0.1875%	0.1875%	0.1875%	0.1875%	0.1875%	58
59															59
60	**Non-Coincident Demand (MW)**														60
61	MW @ Secondary Service	1,961.624	1,746.753	1,716.743	1,686.128	1,666.055	1,629.737	1,650.983	1,630.295	1,651.722	1,752.101	1,873.627	1,865.062	20,830.830	61
62	MW @ Primary Service	377.241	335.919	330.148	324.260	320.400	313.416	317.502	313.523	317.644	336.948	360.318	358.671	4,005.991	62
63	MW @ Transmission Service	25.292	22.522	22.135	21.740	21.481	21.013	21.287	21.020	21.296	22.591	24.157	24.047	268.581	63
64		2,364.158	2,105.194	2,069.026	2,032.128	2,007.936	1,964.166	1,989.772	1,964.838	1,990.662	2,111.640	2,258.103	2,247.780	25,105.402	64
65	**On-Peak Demand (%)**														65
66	% @ Secondary Service	0.2506%	0.2245%	0.2245%	0.2245%	0.2245%	0.2245%	0.2245%	0.2245%	0.2506%	0.2506%	0.2506%	0.2506%	0.2359%	66
67	% @ Primary Service	0.2283%	0.2044%	0.2044%	0.2044%	0.2044%	0.2044%	0.2044%	0.2044%	0.2283%	0.2283%	0.2283%	0.2283%	0.2148%	67
68	% @ Transmission Service	0.3578%	0.3140%	0.3140%	0.3140%	0.3140%	0.3140%	0.3140%	0.3140%	0.3578%	0.3578%	0.3578%	0.3578%	0.3331%	68
69															69
70	**On-Peak Demand (MW)**	Summer	Winter	Winter	Winter	Winter	Winter	Winter	Winter	Summer	Summer	Summer	Summer	TOTAL	70
71	MW @ Secondary Service	1,803.313	1,438.540	1,413.825	1,388.612	1,372.081	1,342.171	1,359.669	1,342.631	1,518.421	1,610.699	1,722.417	1,714.543	18,026.924	71
72	MW @ Primary Service	379.402	302.475	297.279	291.977	288.501	282.212	285.891	282.309	319.463	338.877	362.382	360.725	3,791.495	72
73	MW @ Transmission Service	48.264	37.716	37.068	36.407	35.974	35.190	35.648	35.202	40.639	43.109	46.099	45.888	477.204	73
74		2,230.979	1,778.732	1,748.172	1,716.996	1,696.556	1,659.573	1,681.209	1,660.142	1,878.523	1,992.685	2,130.898	2,121.157	22,295.622	74
75															75

San Diego Gas & Electric
FERC Forecast Period: September 2010 - August 2011

Line No.		Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Total	Line No.
76															76
77															77
78	**Schedule A6-TOU:**	**Sep-10**	**Oct-10**	**Nov-10**	**Dec-10**	**Jan-11**	**Feb-11**	**Mar-11**	**Apr-11**	**May-11**	**Jun-11**	**Jul-11**	**Aug-11**	**Total**	78
79	**Total Deliveries (MWh)**	56,957	56,974	56,991	57,007	57,024	57,041	57,057	57,074	57,090	57,107	57,124	57,140	684,586	79
80															80
81	**Total Deliveries (%)**														81
82	% @ Secondary Service	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	82
83	% @ Primary Service	15.09%	15.09%	15.09%	15.09%	15.09%	15.09%	15.09%	15.09%	15.09%	15.09%	15.09%	15.09%	15.09%	83
84	% @ Transmission Service	84.91%	84.91%	84.91%	84.91%	84.91%	84.91%	84.91%	84.91%	84.91%	84.91%	84.91%	84.91%	84.91%	84
85		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	85
86	**Total Deliveries (MWh)**														86
87	MWh @ Secondary Service	0	0	0	0	0	0	0	0	0	0	0	0	0	87
88	MWh @ Primary Service	8,595	8,597	8,600	8,602	8,605	8,607	8,610	8,612	8,615	8,617	8,620	8,622	103,304	88
89	MWh @ Transmission Service	48,363	48,377	48,391	48,405	48,419	48,433	48,447	48,461	48,475	48,490	48,504	48,518	581,282	89
90		56,957	56,974	56,991	57,007	57,024	57,041	57,057	57,074	57,090	57,107	57,124	57,140	684,586	90
91	**Non-Coincident Demand (%)**														91
92	% @ Secondary Service	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	92
93	% @ Primary Service	0.2807%	0.2807%	0.2807%	0.2807%	0.2807%	0.2807%	0.2807%	0.2807%	0.2807%	0.2807%	0.2807%	0.2807%	0.2807%	93
94	% @ Transmission Service	0.1948%	0.1948%	0.1948%	0.1948%	0.1948%	0.1948%	0.1948%	0.1948%	0.1948%	0.1948%	0.1948%	0.1948%	0.1948%	94
95															95
96	**Non-Coincident Demand (MW)**														96
97	MW @ Secondary Service	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	97
98	MW @ Primary Service	24.126	24.133	24.140	24.147	24.154	24.161	24.168	24.175	24.182	24.189	24.196	24.203	289.975	98
99	MW @ Transmission Service	94.210	94.238	94.265	94.293	94.320	94.348	94.375	94.403	94.430	94.458	94.485	94.513	1,132.338	99
100		118.336	118.371	118.405	118.440	118.474	118.509	118.543	118.578	118.612	118.647	118.682	118.716	1,422.312	100
101	**Coincident Peak Demand (%)**														101
102	% @ Secondary Service	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	102
103	% @ Primary Service	0.1556%	0.1524%	0.1524%	0.1524%	0.1524%	0.1524%	0.1524%	0.1524%	0.1556%	0.1556%	0.1556%	0.1556%	0.1537%	103
104	% @ Transmission Service	0.1569%	0.1408%	0.1408%	0.1408%	0.1408%	0.1408%	0.1408%	0.1408%	0.1569%	0.1569%	0.1569%	0.1569%	0.1475%	104
105															105
106	**Coincident Peak Demand (MW)**														106
107	MW @ Secondary Service	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	107
108	MW @ Primary Service	13.374	13.102	13.106	13.110	13.114	13.118	13.122	13.125	13.405	13.409	13.413	13.417	158.814	108
109	MW @ Transmission Service	75.881	68.114	68.134	68.154	68.174	68.194	68.214	68.234	76.058	76.080	76.102	76.125	857.464	109
110		89.255	81.217	81.240	81.264	81.288	81.312	81.335	81.359	89.463	89.489	89.515	89.541	1,016.277	110
111															111
112	**Schedule S: Standby Determinants:**	**Sep-10**	**Oct-10**	**Nov-10**	**Dec-10**	**Jan-11**	**Feb-11**	**Mar-11**	**Apr-11**	**May-11**	**Jun-11**	**Jul-11**	**Aug-11**	**Total**	112
113	**Contracted Standby Demand (MW)**														113
114	MW @ Secondary Service	10.995	10.995	10.995	10.995	10.995	10.995	10.995	10.995	10.995	10.995	10.995	10.995	131.940	114
115	MW @ Primary Service	84.223	84.223	84.223	84.223	84.223	84.223	84.223	84.223	84.223	84.223	84.223	84.223	1,010.676	115
116	MW @ Transmission Service	46.696	46.696	46.696	46.696	46.696	46.696	46.696	46.696	46.696	46.696	46.696	46.696	560.352	116
117		141.914	141.914	141.914	141.914	141.914	141.914	141.914	141.914	141.914	141.914	141.914	141.914	1,702.968	117
118															118

Section – 3.2

Derivation of Monthly Recorded
ISO True-Up Revenues

Section 3.2.3

Derivation of ISO Wholesale Recorded
Revenues During the 12-Month True-Up
Period Using SDG&E's ISO Retail
Rates from Cycles 3 and 4.

Docket No. ER011-____-____

Section 3.2.3

SAN DIEGO GAS AND ELECTRIC COMPANY
TO3-Cycle 5 Annual Transmission Formulaic Rate Filing
SUMMARY of Derived Revenues at Present Rates from the WHOLESALE Rates Developed in Cycle 3 and Cycle 4
For the 12-Month Period April 2010 through March 2011
True-Up Period (4/1/2010 - 3/31/2011)

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	
		Cycle 3	Cycle 3	Cycle 3	Cycle 3	Cycle 3	Cycle 4	Cycle 4	Cycle 4	Cycle 4	Cycle 4	Cycle 4	Cycle 4			
Line No.	Customer Class	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Total	Reference	Line No.
1	Residential Customers	$ 7,422,370	$ 6,850,411	$ 7,292,893	$ 7,861,145	$ 7,819,144	$ 10,931,844	$ 10,193,920	$ 9,388,242	$ 10,703,843	$ 11,536,566	$ 10,004,918	$ 9,713,145	$ 109,718,443	Section 3.2.3; Pages 19 & 20; Line 21	1
2																2
3	Small Commercial	2,449,618	2,129,090	2,518,347	2,749,562	2,537,236	3,563,704	3,339,810	3,060,159	3,088,269	3,221,755	3,005,499	3,017,572	34,680,621	Section 3.2.3; Pages 19 & 20; Line 23	3
4																4
5	Med-Lrg C&I @ 100% NCD	417,987	341,592	394,342	403,717	410,863	518,172	515,191	496,182	478,528	454,599	503,323	497,580	5,432,076	Section 3.2.3; Page 21; Line 21	5
6	Med-Lrg C&I @ 90% NCD	7,765,346	7,316,101	7,888,881	8,950,279	8,125,247	11,537,088	11,610,548	10,748,538	10,105,483	10,406,590	9,379,985	9,829,647	113,663,733	Section 3.2.3; Page 22; Line 21	6
7	Max On Peak Demand	285,062	1,269,456	1,512,505	1,717,331	1,581,352	2,268,307	449,544	388,807	359,974	373,085	337,926	360,972	10,904,321	Section 3.2.3; Page 23; Line 21	7
8	Max Dem-Time of System Peak	16,962	116,057	110,281	120,540	78,634	147,251	29,896	31,074	22,740	22,159	22,292	19,230	737,116	Section 3.2.3; Page 24; Line 21	8
9	Total Med-Lrg C&I	8,485,357	9,043,206	9,906,009	11,191,867	10,196,096	14,470,818	12,605,179	11,664,601	10,966,725	11,256,433	10,243,526	10,707,429	130,737,246	Sum Lines 5, 6, 7, 8	9
10																10
11	Street Lighting	118,210	55,775	87,669	87,831	90,168	87,358	107,728	95,542	130,627	62,185	96,669	129,806	1,149,567	Section 3.2.3; Pages 19 & 20; Line 27	11
12																12
13	Standby Revenues	296,760	298,710	299,319	303,200	301,674	333,747	327,307	327,307	338,594	337,978	336,245	337,801	3,838,642	Section 3.2.3; Page 25; Line 21	13
14																14
15	TOTAL Recorded	$ 18,772,316	$ 18,377,192	$ 20,104,237	$ 22,193,606	$ 20,944,318	$ 29,387,471	$ 26,573,944	$ 24,535,851	$ 25,228,057	$ 26,414,916	$ 23,686,858	$ 23,905,753	$ 280,124,518	Sum Lines 1, 3, 9, 11, 13	15

NOTES:
For the recorded revenues by customer class from April 2010 - March 2011, the transmission rates were based on the wholesale transmission revenue requirements of $265.570 million from FERC Docket No. ER09-1601, filed with the FERC on August 15, 2009 and approved on September 29, 2009. The derived rates were then applied to the recorded sales at transmission level from April 2010 - August 2010 in developing the recorded wholesale revenues at transmission level.

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Section 3.2.3

SAN DIEGO GAS AND ELECTRIC COMPANY

TO3-Cycle 5 Annual Transmission Formulaic Rate Filing

SUMMARY of Derived Revenues at Present Rates from the WHOLESALE Rates Developed in Cycle 3 and Cycle 4

For the 12-Month Period April 2010 through March 2011

True-Up Period (4/1/2010 - 3/31/2011)

		(A)		(B)		(C)		(D)		(E)		(F)		(F)		
		Apr-10		May-10		Jun-10		Jul-10		Aug-10		Sep-10		Sub-Total		
Line		Billing Determinants		Billing Determinants		Billing Determinants		Billing Determinants		Billing Determinants		Billing Determinants		Billing Determinants		Line
No.	Customer Classes	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	No.
1	Residential Customers	585,993,579	-	540,837,597	-	575,771,398	-	620,634,704	-	617,318,718	-	717,609,257	-	3,658,165,252	-	1
2																2
3	Small Commercial	165,219,991	-	143,601,259	-	169,855,612	-	185,450,446	-	171,129,618	-	197,895,590	-	1,033,152,516	-	3
4																4
5	Medium-Large Commercial	824,359,987	2,212,975	813,284,778	2,072,177	871,348,310	2,240,768	961,066,131	2,531,564	868,533,488	2,309,057	1,005,322,068	2,616,410	5,343,914,762	13,982,951	5
6																6
7	Street Lighting	13,323,085	-	6,286,193	-	9,880,836	-	9,899,133	-	10,162,500	-	8,975,509	-	58,527,257	-	7
8																8
9	Standby Customers	-	144,423	-	145,372	-	145,668	-	147,559	-	146,816	-	146,815	-	876,652	9
10																10
11	TOTAL	1,588,896,642	2,357,398	1,504,009,827	2,217,549	1,626,856,156	2,386,436	1,777,050,414	2,679,123	1,667,144,323	2,455,873	1,929,802,424	2,616,410	10,093,759,787	14,859,603	11

Note: The above billing determinants are recorded determinants from April 2010 through September 2010. Recorded sales were converted from retail to transmission level.

		(A)		(B)		(C)		(D)		(E)		(F)		(F)		
		Apr-10		May-10		Jun-10		Jul-10		Aug-10		Sep-10		Sub-Total		
Line		Derived Wholesale Transmission Rates		Derived Wholesale Transmission Rates		Derived Wholesale Transmission Rates		Derived Wholesale Transmission Rates		Derived Wholesale Transmission Rates		Derived Wholesale Transmission Rates		Derived Wholesale Transmission Rates		Line
No.	Customer Classes	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	No.
12	Residential Customers	$ 0.0126663		$ 0.0126663		$ 0.0126663		$ 0.0126663		$ 0.0126663		$ 0.0152337				12
13																13
14	Small Commercial	$ 0.0148264		$ 0.0148264		$ 0.0148264		$ 0.0148264		$ 0.0148264		$ 0.0180080				14
15																15
16	Medium-Large Commercial															16
17																17
18	Street Lighting	$ 0.0088726		$ 0.0088726		$ 0.0088726		$ 0.0088726		$ 0.0088726		$ 0.0097329				18
19																19
20	Standby Customers															20

Note: The wholesle transmission rates from April - August were derived from the wholelsale base transmission revenure requirements of $265.570 million from TO3-Cycle 3 Docket No. ER09-1601 filed with the FERC on August 15, 2009.
See Section 3.2.1, Page 12 for the Summary of Transmission Rates.

		(A)		(B)		(C)		(D)		(E)		(F)		(F)		
		Apr-10		May-10		Jun-10		Jul-10		Aug-10		Sep-10		Sub-Total		
Line		Revenues @ Present Rates		Revenues @ Present Rates		Revenues @ Present Rates		Revenues @ Present Rates		Revenues @ Present Rates		Revenues @ Present Rates		Revenues @ Changed Rates		Line
No.	Customer Classes	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	No.
21	Residential Customers	$ 7,422,370		$ 6,850,411		$ 7,292,893		$ 7,861,145		$ 7,819,144		$ 10,931,844		$ 48,177,809	$ -	21
22																22
23	Small Commercial	$ 2,449,618		$ 2,129,090		$ 2,518,347		$ 2,749,562		$ 2,537,236		$ 3,563,704		$ 15,947,557	$ -	23
24																24
25	Medium-Large Commercial	$ -	$ 8,485,357	$ -	$ 9,043,206	$ -	$ 9,906,009	$ -	$11,191,867	$ -	$10,196,096	$ -	$14,470,818	$ -	$ 63,293,353	25
26																26
27	Street Lighting	$ 118,210		$ 55,775		$ 87,669		$ 87,831		$ 90,168		$ 87,358		$ 527,011	$ -	27
28																28
29	Standby Customers		$ 296,760		$ 298,710		$ 299,319		$ 303,200		$ 301,674		$ 333,747	$ -	$ 1,833,410	29
30																30
31	TOTAL	$ 9,990,199	$ 8,782,117	$ 9,035,276	$ 9,341,916	$ 9,898,909	$10,205,328	$ 10,698,539	$11,495,067	$ 10,446,548	$10,497,770	$ 14,582,906	$14,804,565	$ 64,652,376	$ 65,126,763	31
32																32
33	Grand Total		$18,772,316		$18,377,192		$20,104,237		$22,193,606		$20,944,318		$29,387,471		$129,779,139	33

Note: The above revenues were derived by multiplying the above rates and billing determinants except Medium & Large C-I and Standby Customers where these revenues are derived on pages 21 through 24.

Section 3.2.3

SAN DIEGO GAS AND ELECTRIC COMPANY
TO3-Cycle 5 Annual Transmission Formulaic Rate Filing
SUMMARY of Derived Revenues at Present Rates from the WHOLESALE Rates Developed in Cycle 3 and Cycle 4
For the 12-Month Period April 2010 through March 2011
True-Up Period (4/1/2010 - 3/31/2011)

Line		(H)		(I)		(J)		(K)		(L)		(M)		(N)		(O)		Line
		Oct-10		Nov-10		Dec-10		Jan-11		Feb-11		Mar-11		Sub-Total		Grand-Total		
		Billing Determinants		Billing Determinants		Billing Determinants		Billing Determinants		Billing Determinants		Billing Determinants		Billing Determinants		Billing Determinants		
No.	Customer Classes	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	No.
1	Residential Customers	669,169,003	-	616,281,152	-	702,642,334	-	757,305,553	-	656,762,211	-	637,609,078	-	4,039,769,330	-	7,697,934,583	-	1
2																		2
3	Small Commercial	185,462,587	-	169,933,296	-	171,494,306	-	178,906,863	-	166,897,972	-	167,568,411	-	1,040,263,437	-	2,073,415,953	-	3
4																		4
5	Medium-Large Commercial	948,341,453	2,631,835	872,570,224	2,440,214	843,333,041	2,296,583	878,664,646	2,357,523	807,551,603	2,143,311	843,756,551	2,240,198	5,194,217,518	14,109,663	10,538,132,280	28,092,614	5
6																		6
7	Street Lighting	11,068,413	-	9,816,383	-	13,421,130	-	6,389,127	-	9,932,236	-	13,336,818	-	63,964,107	-	122,491,364	-	7
8																		8
9	Standby Customers	-	143,980	-	143,980	-	148,945	-	148,673	-	147,911	-	148,595	-	882,085	-	1,758,737	9
10																		10
11	TOTAL	1,814,041,457	2,775,815	1,668,601,055	2,584,194	1,730,890,811	2,445,527	1,821,266,189	2,506,196	1,641,144,023	2,291,222	1,662,270,858	2,388,794	10,338,214,393	14,991,747	20,431,974,180	29,851,351	11

Note: The above billing determinants are recorded determinants from October 2010 through March 2011. Recorded sales were converted from retail to transmission level.

Line		(H)		(I)		(J)		(K)		(L)		(M)		(N)		(O)		Line
		Oct-10		Nov-10		Dec-10		Jan-11		Feb-11		Mar-11		Sub-Total		Grand-Total		
		Transmission Rates @ Present		Transmission Rates @ Present		Transmission Rates @ Present		Transmission Rates @ Present		Transmission Rates @ Present		Transmission Rates @ Present		Transmission Rates @ Present		Changed Transmission Rates		
No.	Customer Classes	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	No.
12	Residential Customers	$ 0.0152337		$ 0.0152337		$ 0.0152337		$ 0.0152337		$ 0.0152337		$ 0.0152337						12
13																		13
14	Small Commercial	$ 0.0180080		$ 0.0180080		$ 0.0180080		$ 0.0180080		$ 0.0180080		$ 0.0180080						14
15																		15
16	Medium-Large Commercial																	16
17																		17
18	Street Lighting	$ 0.0097329		$ 0.0097329		$ 0.0097329		$ 0.0097329		$ 0.0097329		$ 0.0097329						18
19																		19
20	Standby Customers																	20

Note: The wholesle transmission rates from September - March were derived from the wholelsale base transmission revenue requirements of $312.770 million from TO3-Cycle 4 Docket No. ER10-2235 filed with the FERC on August 17, 2010.
See Section 3.2.2, Page 12 for the Summary of Transmission Rates.

Line		(H)		(I)		(J)		(K)		(L)		(M)		(N)		(O)		Line
		Oct-10		Nov-10		Dec-10		Jan-11		Feb-11		Mar-11		Sub-Total		Grand-Total		
		Revenues @ Present Rates		Revenues @ Present Rates		Revenues @ Present Rates		Revenues @ Present Rates		Revenues @ Present Rates		Revenues @ Present Rates		Revenues @ Changed Rates		Revenues @ Changed Rates		
No.	Customer Classes	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	No.
21	Residential Customers	$ 10,193,920		$ 9,388,242		$ 10,703,843		$ 11,536,566		$ 10,004,918		$ 9,713,145		$ 61,540,634	$ -	$ 109,718,443	$ -	21
22																		22
23	Small Commercial	$ 3,339,810		$ 3,060,159		$ 3,088,269		$ 3,221,755		$ 3,005,499		$ 3,017,572		$ 18,733,064	$ -	$ 34,680,621	$ -	23
24																		24
25	Medium-Large Commercial	$ -	$12,605,179	$ -	$11,664,601	$ -	$10,966,725	$ -	$11,256,433	$ -	$10,243,526	$ -	$10,707,429	$ -	$67,443,893	$ -	$ 130,737,246	25
26																		26
27	Street Lighting	$ 107,728		$ 95,542		$ 130,627		$ 62,185		$ 96,669		$ 129,806		$ 622,556	$ -	$ 1,149,567	$ -	27
28																		28
29	Standby Customers		$ 327,307		$ 327,307		$ 338,594		$ 337,978		$ 336,245		$ 337,801	$ -	$ 2,005,232	$ -	$ 3,838,642	29
30																		30
31	TOTAL	$ 13,641,458	$12,932,486	$ 12,543,943	$11,991,908	$ 13,922,738	$11,305,319	$ 14,820,505	$11,594,411	$ 13,107,087	$10,579,771	$ 12,860,523	$11,045,230	$ 80,896,254	$69,449,125	$ 145,548,630	$ 134,575,888	31
32																		32
33	Grand Total		$26,573,944		$24,535,851		$25,228,057		$26,414,916		$23,686,858		$23,905,753		$150,345,379		$ 280,124,518	33

Note: The above revenues were derived by multiplying the above rates and billing determinants except Medium & Large C-I and Standby Customers where these revenues are derived on pages 21 through 24.

Section 3.2.3

SAN DIEGO GAS AND ELECTRIC COMPANY

TO3-Cycle 5 Annual Transmission Formulaic Rate Filing

SUMMARY of Derived Revenues at Present Rates from the WHOLESALE Rates Developed in Cycle 3 and Cycle 4

For the 12-Month Period April 2010 through March 2011

True-Up Period (4/1/2010 - 3/31/2011)

Medium & Large Commercial and Industrial Customer

Line No.	Description	Cycle 3 Apr-10	Cycle 3 May-10	Cycle 3 Jun-10	Cycle 3 Jul-10	Cycle 3 Aug-10	Cycle 4 Sep-10	Cycle 4 Oct-10	Cycle 4 Nov-10	Cycle 4 Dec-10	Cycle 4 Jan-11	Cycle 4 Feb-11	Cycle 4 Mar-11	Total	Reference	Line No.
1	Non-Coincident Demand (KW): Applied to 100%:															1
2	Secondary	94,133	74,331	82,932	86,726	88,169	89,369	88,874	85,878	83,495	76,238	83,226	87,351	1,020,722	Section 3.2.3; Page 26.2; Ln. 39	2
3	Primary	8,119	9,233	13,536	12,035	12,340	12,283	12,194	11,461	10,380	12,943	15,513	10,262	140,301	Section 3.2.3; Page 26.2; Ln. 43	3
4	Transmission	-	-	-	-	-	-	-	-	-	-	-	-	-	Section 3.2.3; Page 26.2; Ln. 45	4
5	Total	102,253	83,564	96,468	98,762	100,510	101,652	101,068	97,338	93,875	89,181	98,739	97,613	1,161,023	Sum Lines 2; 3; 4	5
9																9
10	Non-Coindent Demand Rates Per ($/KW) @ 100%: [1]															10
11	Secondary	$ 4.0877977	$ 4.0877977	$ 4.0877977	$ 4.0877977	$ 4.0877977	$ 5.0975107	$ 5.0975107	$ 5.0975107	$ 5.0975107	$ 5.0975107	$ 5.0975107	$ 5.0975107		Page 12; Line 6	11
12	Primary	$ 4.0877270	$ 4.0877270	$ 4.0877270	$ 4.0877270	$ 4.0877270	$ 5.0973649	$ 5.0973649	$ 5.0973649	$ 5.0973649	$ 5.0973649	$ 5.0973649	$ 5.0973649		Page 12; Line 6	12
13	Transmission	$ 4.0876404	$ 4.0876404	$ 4.0876404	$ 4.0876404	$ 4.0876404	$ 5.0977873	$ 5.0977873	$ 5.0977873	$ 5.0977873	$ 5.0977873	$ 5.0977873	$ 5.0977873		Page 12; Line 6	13
14																14
15	Revenues @ Calculated Rates:															15
16	Secondary	$ 384,798	$ 303,849	$ 339,010	$ 354,520	$ 360,419	$ 455,559	$ 453,034	$ 437,762	$ 425,616	$ 388,622	$ 424,246	$ 445,271	$ 4,772,706	Line 2 x Line 11	16
17	Primary	33,189	37,743	55,332	49,197	50,444	62,613	62,157	58,420	52,912	65,977	79,077	52,309	659,370	Line 3 x Line 12	17
18	Transmission	-	-	-	-	-	-	-	-	-	-	-	-	-	Line 4 x Line 13	18
19	Total	$ 417,987	$ 341,592	$ 394,342	$ 403,717	$ 410,863	$ 518,172	$ 515,191	$ 496,182	$ 478,528	$ 454,599	$ 503,323	$ 497,580	$ 5,432,076	Sum Lines 16; 17; 18	19
20																20
21	Total Revenues @ Calculated Rates:	$ 417,987	$ 341,592	$ 394,342	$ 403,717	$ 410,863	$ 518,172	$ 515,191	$ 496,182	$ 478,528	$ 454,599	$ 503,323	$ 497,580	$ 5,432,076	Line 19	21

[1] Non-Coincident Demand (NCD) Rates are applicable to the following California Public Utilities Commission (CPUC) tariffs: AD, PA-T-1.

Section 3.2.3

SAN DIEGO GAS AND ELECTRIC COMPANY

TO3-Cycle 5 Annual Transmission Formulaic Rate Filing

SUMMARY of Derived Revenues at Present Rates from the WHOLESALE Rates Developed in Cycle 3 and Cycle 4

For the 12-Month Period April 2010 through March 2011

True-Up Period (4/1/2010 - 3/31/2011)

Medium & Large Commercial and Industrial Customer

Line No.	Description	Cycle 3 Apr-10	Cycle 3 May-10	Cycle 3 Jun-10	Cycle 3 Jul-10	Cycle 3 Aug-10	Cycle 4 Sep-10	Cycle 4 Oct-10	Cycle 4 Nov-10	Cycle 4 Dec-10	Cycle 4 Jan-11	Cycle 4 Feb-11	Cycle 4 Mar-11	Total	Reference	Line No.
1	Non-Coincident Demand (KW): Applied to 90%:															1
2																2
3	Schedules AL-TOU / AY-TOU / DG-R	1,651,237	1,526,816	1,730,237	1,886,083	1,733,516	1,984,328	1,962,364	1,844,048	1,746,179	1,793,025	1,608,489	1,720,729	21,187,051	Section 3.2.3; Page 26.2; Ln. 72	3
4	Schedule A6-TOU	-	-	-	-	-	-	-	-	-	-	-	-	-	Section 3.2.3; Page 26.2; Ln. 122	4
5	Secondary	1,651,237	1,526,816	1,730,237	1,886,083	1,733,516	1,984,328	1,962,364	1,844,048	1,746,179	1,793,025	1,608,489	1,720,729	21,187,051	Sum Lines 3 and 4	5
6																6
7	Schedules AL-TOU / AY-TOU / DG-R:	323,824	316,743	286,456	397,567	349,456	376,635	376,874	348,571	303,734	334,540	311,186	298,190	4,023,777	Section 3.2.3; Page 26.2; Ln. 76	7
8	Schedule A6-TOU	12,849	5,102	8,229	12,085	5,331	17,325	6,064	6,099	20,064	19,928	19,087	29,954	162,119	Section 3.2.3; Page 26.2; Ln. 126	8
9	Primary	336,673	321,846	294,685	409,652	354,787	393,960	382,939	354,670	323,798	354,468	330,273	328,144	4,185,895	Sum Lines 7 and 8	9
10																10
11	Schedules AL-TOU / AY-TOU / DG-R:	24,014	13,985	12,114	14,303	19,568	20,872	60,606	29,840	19,270	19,051	10,793	11,209	255,624	Section 3.2.3; Page 26.2; Ln. 78	11
12	Schedule A6-TOU	98,798	125,966	107,263	122,766	100,676	115,598	124,859	114,316	113,460	101,798	95,017	82,504	1,303,020	Section 3.2.3; Page 26.2; Ln. 128	12
13	Transmission	122,812	139,951	119,377	137,068	120,244	136,470	185,465	144,156	132,730	120,849	105,810	93,713	1,558,644	Sum Lines 11 and 12	13
14	Total	2,110,722	1,988,613	2,144,299	2,432,803	2,208,548	2,514,758	2,530,767	2,342,875	2,202,708	2,268,342	2,044,571	2,142,585	26,931,591	Sum Lines 5; 9; 13	14
18																18
19	Non-Coindent Demand Rates Per ($/KW) @ 90%:															19
20	Secondary	$ 3.6790179	$ 3.6790179	$ 3.6790179	$ 3.6790179	$ 3.6790179	$ 4.5877596	$ 4.5877596	$ 4.5877596	$ 4.5877596	$ 4.5877596	$ 4.5877596	$ 4.5877596		Page 12; Line 6	20
21	Primary	$ 3.6789543	$ 3.6789543	$ 3.6789543	$ 3.6789543	$ 3.6789543	$ 4.5876284	$ 4.5876284	$ 4.5876284	$ 4.5876284	$ 4.5876284	$ 4.5876284	$ 4.5876284		Page 12; Line 6	21
22	Transmission	$ 3.6788764	$ 3.6788764	$ 3.6788764	$ 3.6788764	$ 3.6788764	$ 4.5880086	$ 4.5880086	$ 4.5880086	$ 4.5880086	$ 4.5880086	$ 4.5880086	$ 4.5880086		Page 12; Line 6	22
23																23
24	Revenues @ Calculated Rates:															24
25	Secondary	$ 6,074,930	$ 5,617,182	$ 6,365,575	$ 6,938,932	$ 6,377,638	$ 9,103,622	$ 9,002,853	$ 8,460,051	$ 8,011,051	$ 8,225,968	$ 7,379,360	$ 7,894,289	$ 89,451,451	Line 5 x Line 20	25
26	Primary	1,238,605	1,184,056	1,084,133	1,507,090	1,305,247	1,807,343	1,756,781	1,627,096	1,485,466	1,626,168	1,515,170	1,505,401	17,642,556	Line 9 x Line 21	26
27	Transmission	451,811	514,863	439,173	504,257	442,362	626,123	850,914	661,391	608,966	554,454	485,455	429,957	6,569,726	Line 13 x Line 22	27
28	Total	$ 7,765,346	$ 7,316,101	$ 7,888,881	$ 8,950,279	$ 8,125,247	$ 11,537,088	$ 11,610,548	$ 10,748,538	$ 10,105,483	$ 10,406,590	$ 9,379,985	$ 9,829,647	$ 113,663,733	Sum Lines 25; 26; 27	28
29																29
30	Total Revenues @ Calculated Rates:	$ 7,765,346	$ 7,316,101	$ 7,888,881	$ 8,950,279	$ 8,125,247	$ 11,537,088	$ 11,610,548	$ 10,748,538	$ 10,105,483	$ 10,406,590	$ 9,379,985	$ 9,829,647	$ 113,663,733	Line 28	30

1 90% Non-Coincident Demand (NCD) Rates are applicable to the following California Public Utilities Commission (CPUC) tariffs: AY-TOU; AL-TOU; AL-TOU-DER, DG-R and A6-TOU.

Section 3.2.3

SAN DIEGO GAS AND ELECTRIC COMPANY

TO3-Cycle 5 Annual Transmission Formulaic Rate Filing

SUMMARY of Derived Revenues at Present Rates from the WHOLESALE Rates Developed in Cycle 3 and Cycle 4

For the 12-Month Period April 2010 through March 2011

True-Up Period (4/1/2010 - 3/31/2011)

Medium & Large Commercial and Industrial Customer

Line No.	Description	Cycle 3 Apr-10	Cycle 3 May-10	Cycle 3 Jun-10	Cycle 3 Jul-10	Cycle 3 Aug-10	Cycle 4 Sep-10	Cycle 4 Oct-10	Cycle 4 Nov-10	Cycle 4 Dec-10	Cycle 4 Jan-11	Cycle 4 Feb-11	Cycle 4 Mar-11	Total	Reference	Line No.
1	**On-Peak Demand (KW):**															1
2	Secondary	1,330,979	1,292,227	1,601,029	1,773,358	1,626,762	1,882,512	1,674,816	1,449,778	1,369,346	1,411,558	1,273,193	1,379,490	18,065,048	Section 3.2.3; Page 26.3; Ln. 90	2
3	Primary	272,034	300,111	299,400	394,234	363,053	384,862	360,072	306,784	266,320	299,948	289,420	270,640	3,806,879	Section 3.2.3; Page 26.3; Ln. 94	3
4	Transmission	44,186	26,659	28,540	22,602	26,959	24,808	60,793	55,981	42,458	27,738	12,730	32,646	406,100	Section 3.2.3; Page 26.3; Ln. 96	4
5	Total	1,647,199	1,618,997	1,928,970	2,190,194	2,016,774	2,292,182	2,095,681	1,812,543	1,678,125	1,739,243	1,575,343	1,682,776	22,278,026	Sum Lines 2; 3; 4	5
9		Cycle 3	Cycle 3	Cycle 3	Cycle 3	Cycle 3	Cycle 4	Cycle 4	Cycle 4	Cycle 4	Cycle 4	Cycle 4	Cycle 4			9
10	**Maximum On-Peak Demand Rates Per ($/KW):**	W	S	S	S	S	S	W	W	W	W	W	W			10
11	Secondary	$ 0.1730583	$ 0.7840997	$ 0.7840997	$ 0.7840997	$ 0.7840997	$ 0.9895844	$ 0.2145097	$ 0.2145097	$ 0.2145097	$ 0.2145097	$ 0.2145097	$ 0.2145097		Page 12; Lines 11 & 12	11
12	Primary	$ 0.1730583	$ 0.7840997	$ 0.7840997	$ 0.7840997	$ 0.7840997	$ 0.9895844	$ 0.2145097	$ 0.2145097	$ 0.2145097	$ 0.2145097	$ 0.2145097	$ 0.2145097		Page 12; Lines 11 & 12	12
13	Transmission	$ 0.1730583	$ 0.7840997	$ 0.7840997	$ 0.7840997	$ 0.7840997	$ 0.9895844	$ 0.2145097	$ 0.2145097	$ 0.2145097	$ 0.2145097	$ 0.2145097	$ 0.2145097		Page 12; Lines 11 & 12	13
14																14
15	**Revenues @ Calculated Rates:**															15
16	Secondary	$ 230,337	$ 1,013,235	$ 1,255,367	$ 1,390,489	$ 1,275,544	$ 1,862,904	$ 359,264	$ 310,991	$ 293,738	$ 302,793	$ 273,112	$ 295,914	$ 8,863,688	Line 2 x Line 11	16
17	Primary	47,078	235,317	234,760	309,119	284,670	380,854	77,239	65,808	57,128	64,342	62,083	58,055	1,876,453	Line 3 x Line 12	17
18	Transmission	7,647	20,904	22,378	17,723	21,138	24,549	13,041	12,008	9,108	5,950	2,731	7,003	164,180	Line 4 x Line 13	18
19	Total	$ 285,062	$ 1,269,456	$ 1,512,505	$ 1,717,331	$ 1,581,352	$ 2,268,307	$ 449,544	$ 388,807	$ 359,974	$ 373,085	$ 337,926	$ 360,972	$ 10,904,321	Sum Lines 16; 17; 18	19
20																20
21	**Total Revenues @ Calculated Rates:**	$ 285,062	$ 1,269,456	$ 1,512,505	$ 1,717,331	$ 1,581,352	$ 2,268,307	$ 449,544	$ 388,807	$ 359,974	$ 373,085	$ 337,926	$ 360,972	$ 10,904,321	Line 19	21

1 Maximum On-Peak Demand Rates are applicable to the following California Public Utilities Commission (CPUC) tariffs: AY-TOU; AL-TOU; AL- TOU, AL-TOU-DER and DG-R.

Section 3.2.3

SAN DIEGO GAS AND ELECTRIC COMPANY

TO3-Cycle 5 Annual Transmission Formulaic Rate Filing

SUMMARY of Derived Revenues at Present Rates from the WHOLESALE Rates Developed in Cycle 3 and Cycle 4

For the 12-Month Period April 2010 through March 2011

True-Up Period (4/1/2010 - 3/31/2011)

Medium & Large Commercial and Industrial Customer

Line No.	Description	Cycle 3 Apr-10	Cycle 3 May-10	Cycle 3 Jun-10	Cycle 3 Jul-10	Cycle 3 Aug-10	Cycle 4 Sep-10	Cycle 4 Oct-10	Cycle 4 Nov-10	Cycle 4 Dec-10	Cycle 4 Jan-11	Cycle 4 Feb-11	Cycle 4 Mar-11	Total	Reference	Line No.
1	**Coincident Peak Demand (KW):**															1
2	Secondary	-	-	-	-	-	-	-	-	-	-	-	-	-	Section 3.2.3; Page 26.4; Ln. 140	2
3	Primary	14,235	8,146	13,093	13,476	2,633	10,561	11,619	8,427	21,189	6,223	13,104	14,159	136,865	Section 3.2.3; Page 26.4; Ln. 144	3
4	Transmission	66,186	100,813	90,443	99,691	71,191	102,954	105,670	113,486	68,028	80,716	74,354	61,286	1,034,819	Section 3.2.3; Page 26.4; Ln. 146	4
5	Total	80,420	108,959	103,535	113,168	73,825	113,516	117,289	121,914	89,217	86,939	87,458	75,445	1,171,685	Sum Lines 2; 3; 4	5
9		Cycle 3	Cycle 3	Cycle 3	Cycle 3	Cycle 3	Cycle 4	Cycle 4	Cycle 4	Cycle 4	Cycle 4	Cycle 4	Cycle 4			9
10	**Coincident Peak Demand Rates Per ($/KW):**	W	S	S	S	S	S	W	W	W	W	W	W			10
11	Secondary	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		Page 12; Lines 15 and 16	11
12	Primary	$ 0.2109265	$ 1.0651511	$ 1.0651511	$ 1.0651511	$ 1.0651511	$ 1.2971826	$ 0.2548850	$ 0.2548850	$ 0.2548850	$ 0.2548850	$ 0.2548850	$ 0.2548850		Page 12; Lines 15 and 16	12
13	Transmission	$ 0.2109265	$ 1.0651511	$ 1.0651511	$ 1.0651511	$ 1.0651511	$ 1.2971826	$ 0.2548850	$ 0.2548850	$ 0.2548850	$ 0.2548850	$ 0.2548850	$ 0.2548850		Page 12; Lines 15 and 16	13
14																14
15	**Revenues @ Calculated Rates:**															15
16	Secondary	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	Line 2 x Line 11	16
17	Primary	3,002	8,676	13,946	14,354	2,805	13,700	2,962	2,148	5,401	1,586	3,340	3,609	75,529	Line 3 x Line 12	17
18	Transmission	13,960	107,381	96,335	106,186	75,829	133,551	26,934	28,926	17,339	20,573	18,952	15,621	661,587	Line 4 x Line 13	18
19	Total	$ 16,962	$ 116,057	$ 110,281	$ 120,540	$ 78,634	$ 147,251	$ 29,896	$ 31,074	$ 22,740	$ 22,159	$ 22,292	$ 19,230	$ 737,116	Sum Lines 16; 17; 18	19
20																20
21	**Total Revenues @ Calculated Rates:**	$ 16,962	$ 116,057	$ 110,281	$ 120,540	$ 78,634	$ 147,251	$ 29,896	$ 31,074	$ 22,740	$ 22,159	$ 22,292	$ 19,230	$ 737,116	Line 19	21

1 Maximum Demand Rates at Time of System Peak rates are applicable to the following California Public Utilities Commission (CPUC) tariffs: A6-TOU.

Section 3.2.3

SAN DIEGO GAS AND ELECTRIC COMPANY
TO3-Cycle 5 Annual Transmission Formulaic Rate Filing
SUMMARY of Derived Revenues at Present Rates from the WHOLESALE Rates Developed in Cycle 3 and Cycle 4
For the 12-Month Period April 2010 through March 2011
True-Up Period (4/1/2010 - 3/31/2011)
Standby Customers

Line No.	Description	Cycle 3 Apr-10	Cycle 3 May-10	Cycle 3 Jun-10	Cycle 3 Jul-10	Cycle 3 Aug-10	Cycle 4 Sep-10	Cycle 4 Oct-10	Cycle 4 Nov-10	Cycle 4 Dec-10	Cycle 4 Jan-11	Cycle 4 Feb-11	Cycle 4 Mar-11	Total	Reference	Line No.
1	Demand - Billing Determinants (KW):															1
2	Secondary	11,737	11,737	11,739	11,632	11,632	11,631	12,627	12,627	14,115	14,115	14,021	14,021	151,634	Section 3.2.3; Page 26.4; Ln. 153 x 1000	2
3	Primary	85,738	85,920	86,237	85,940	85,197	85,197	81,350	81,350	84,674	84,287	83,618	84,300	1,013,809	Section 3.2.3; Page 26.4; Ln. 157 x 1000	3
4	Transmission	46,948	47,715	47,692	49,986	49,986	49,986	50,003	50,003	50,156	50,272	50,272	50,275	593,294	Section 3.2.3; Page 26.4; Ln. 159 x 1000	4
5	Total	144,423	145,372	145,668	147,559	146,816	146,815	143,980	143,980	148,945	148,673	147,911	148,595	1,758,737	Sum Lines 2; 3; 4	5
9		Cycle 3	Cycle 3	Cycle 3	Cycle 3	Cycle 3	Cycle 4	Cycle 4	Cycle 4	Cycle 4	Cycle 4	Cycle 4	Cycle 4			9
10	Demand Rates Per ($/KW):	W	S	S	S	S	S	W	W	W	W	W	W			10
11	Secondary	$ 2.0569620	$ 2.0569620	$ 2.0569620	$ 2.0569620	$ 2.0569620	$ 2.2753623	$ 2.2753623	$ 2.2753623	$ 2.2753623	$ 2.2753623	$ 2.2753623	$ 2.2753623		Page 12; Line 20	11
12	Primary	$ 2.0549662	$ 2.0549662	$ 2.0549662	$ 2.0549662	$ 2.0549662	$ 2.2729941	$ 2.2729941	$ 2.2729941	$ 2.2729941	$ 2.2729941	$ 2.2729941	$ 2.2729941		Page 12; Line 20	12
13	Transmission	$ 2.0539568	$ 2.0539568	$ 2.0539568	$ 2.0539568	$ 2.0539568	$ 2.2732143	$ 2.2732143	$ 2.2732143	$ 2.2732143	$ 2.2732143	$ 2.2732143	$ 2.2732143		Page 12; Line 20	13
14																14
15	Revenues at Present Rates:															15
16	Secondary	$ 24,142	$ 24,142	$ 24,147	$ 23,927	$ 23,927	$ 26,465	$ 28,731	$ 28,731	$ 32,116	$ 32,116	$ 31,902	$ 31,902	$ 332,248	Line 2 x Line 10	16
17	Primary	176,189	176,563	177,215	176,604	175,078	193,653	184,908	184,908	192,463	191,583	190,064	191,613	2,210,841	Line 3 x Line 11	17
18	Transmission	96,429	98,005	97,957	102,669	102,669	113,629	113,668	113,668	114,015	114,279	114,279	114,286	1,295,553	Line 4 x Line 12	18
19	Total	$ 296,760	$ 298,710	$ 299,319	$ 303,200	$ 301,674	$ 333,747	$ 327,307	$ 327,307	$ 338,594	$ 337,978	$ 336,245	$ 337,801	$ 3,838,642	Sum Lines 15; 16; 17	19
20																20
21	Total Revenues at Present Rates	$ 296,760	$ 298,710	$ 299,319	$ 303,200	$ 301,674	$ 333,747	$ 327,307	$ 327,307	$ 338,594	$ 337,978	$ 336,245	$ 337,801	$ 3,838,642	Line 19	21

Section 3.2.2

San Diego Gas & Electric

FERC Recorded Sales @ Transmission Level for the Period: April 2010 - March 2011

Line No.															Line No.
1	**SDG&E: System Delivery Determinants**	Cycle 3	Cycle 3	Cycle 3	Cycle 3	Cycle 3	Cycle 4	Cycle 4	Cycle 4	Cycle 4	Cycle 4	Cycle 4	Cycle 4		1
2	**Customer Class Deliveries (MWh)**	**Apr-10**	**May-10**	**Jun-10**	**Jul-10**	**Aug-10**	**Sep-10**	**Oct-10**	**Nov-10**	**Dec-10**	**Jan-11**	**Feb-11**	**Mar-11**	**Total**	2
3	Residential	560,384	517,201	550,609	593,511	590,340	686,248	639,924	589,348	671,935	724,209	628,060	609,744	7,361,513	3
4	Transmission Level Adjustment Factor	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570		4
5	Residential @ Transmission Level	585,994	540,838	575,771	620,635	617,319	717,609	669,169	616,281	702,642	757,306	656,762	637,609	7,697,935	5
6															6
7	Small Commercial	157,999	137,325	162,432	177,346	163,651	189,247	177,357	162,507	164,000	171,088	159,604	160,245	1,982,802	7
8	Transmission Level Adjustment Factor	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570		8
9	Small Commercial @ Transmission Level	165,220	143,601	169,856	185,450	171,130	197,896	185,463	169,933	171,494	178,907	166,898	167,568	2,073,416	9
10															10
11	Med. & Large Comm./Ind. (AD + PA-T-1)	21,162	19,894	24,223	27,331	27,123	30,064	26,805	20,895	19,901	17,916	19,926	20,362	275,603	11
12	Transmission Level Adjustment Factor	1.03652	1.03652	1.03652	1.03652	1.03652	1.03627	1.03627	1.03627	1.03627	1.03627	1.03627	1.03627		12
13	Med&Lrg C/I (AD + PA-T-1)@Trans. Level	21,934	20,621	25,108	28,329	28,114	31,154	27,777	21,653	20,623	18,566	20,648	21,101	285,628	13
14															14
15	Med. & Large Comm./Ind. (AY + AL + DGR)	708,903	692,577	744,964	827,532	755,332	871,898	817,218	756,976	723,654	772,108	698,123	742,483	9,111,768	15
16	Transmission Level Adjustment Factor	1.03652	1.03652	1.03652	1.03652	1.03652	1.03627	1.03627	1.03627	1.03627	1.03627	1.03627	1.03627		16
17	Med&Lrg C/I (AY + AL + DGR)@Trans Level	734,791	717,869	772,169	857,752	782,915	903,517	846,855	784,428	749,897	800,109	723,440	769,409	9,443,152	17
18															18
19	Med. & Large Comm./Ind. (A6)	65,251	72,160	71,462	72,343	55,478	68,178	71,130	64,163	70,265	57,890	61,242	51,383	780,945	19
20	Transmission Level Adjustment Factor	1.03652	1.03652	1.03652	1.03652	1.03652	1.03627	1.03627	1.03627	1.03627	1.03627	1.03627	1.03627		20
21	Med. & Large Comm./Ind. (A6) @ Trans Level	67,634	74,795	74,071	74,985	57,504	70,651	73,710	66,490	72,813	59,990	63,463	53,246	809,352	21
22															22
23	Lighting	12,741	6,011	9,449	9,467	9,718	8,583	10,585	9,387	12,835	6,110	9,498	12,754	117,138	23
24	Transmission Level Adjustment Factor	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570		24
25	Street Lighting @ Transmission Level	13,323	6,286	9,881	9,899	10,163	8,976	11,068	9,816	13,421	6,389	9,932	13,337	122,491	25
26															26
27	Sale for Resale	1.5	0.0	3.5	0.0	1.5	0.0	6.4	0.0	2.1	1.7	3.6	0.0	20.4	27
28	Total System Delivery@Meter Exclude Resale	1,526,442	1,445,170	1,563,143	1,707,530	1,601,644	1,854,218	1,743,026	1,603,276	1,662,591	1,749,324	1,576,456	1,596,971	19,629,791	28
29	Total System Delivery@Trans. Exclude Resale	1,588,897	1,504,010	1,626,856	1,777,050	1,667,144	1,929,802	1,814,041	1,668,601	1,730,891	1,821,266	1,641,144	1,662,271	20,431,974	29
30	**Med. & Large Comm./Ind.**														30
31	**Rate Schedule Billing Determinants**														31
32		Cycle 3	Cycle 3	Cycle 3	Cycle 3	Cycle 3	Cycle 4	Cycle 4	Cycle 4	Cycle 4	Cycle 4	Cycle 4	Cycle 4		32
33	**Schedules AD / PA-T-1:Applicable to 100% NCD**	**Apr-10**	**May-10**	**Jun-10**	**Jul-10**	**Aug-10**	**Sep-10**	**Oct-10**	**Nov-10**	**Dec-10**	**Jan-11**	**Feb-11**	**Mar-11**	**Total**	33
34	**Total Deliveries (MWh)**	21,162	19,894	24,223	27,331	27,123	30,064	26,805	20,895	19,901	17,916	19,926	20,362	275,603	34
35															35
36	**Total Deliveries (%)**														36
37	% @ Secondary Service	91.58%	93.78%	93.65%	93.60%	91.70%	91.23%	90.41%	91.34%	91.56%	87.21%	85.53%	90.30%	91.15%	37
38	% @ Primary Service	8.42%	6.22%	6.35%	6.40%	8.30%	8.77%	9.59%	8.66%	8.44%	12.79%	14.47%	9.70%	8.85%	38
39	% @ Transmission Service	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	39
40		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	40
41	**Total Deliveries (MWh)**														41
42	MWh @ Secondary Service	19,380	18,657	22,685	25,582	24,872	27,427	24,234	19,085	18,221	15,625	17,043	18,387	251,199	42
43	MWh @ Primary Service	1,782	1,237	1,538	1,749	2,251	2,637	2,571	1,809	1,680	2,292	2,883	1,975	24,404	43
44	MWh @ Transmission Service	0	0	0	0	0	0	0	0	0	0	0	0	0	44
45		21,162	19,894	24,223	27,331	27,123	30,064	26,805	20,895	19,901	17,916	19,926	20,362	275,603	45

060090

Section 3.2.2

San Diego Gas & Electric

FERC Recorded Sales @ Transmission Level for the Period: April 2010 - March 2011

Line No.		Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Total	Line No.
46	**Non-Coincident Demand (%)**														46
47	% @ Secondary Service	0.4645%	0.3810%	0.3496%	0.3242%	0.3390%	0.3116%	0.3507%	0.4303%	0.4382%	0.4666%	0.4670%	0.4543%	0.3886%	47
48	% @ Primary Service	0.4508%	0.7382%	0.8706%	0.6807%	0.5423%	0.4609%	0.4693%	0.6266%	0.6114%	0.5588%	0.5323%	0.5140%	0.5688%	48
49	% @ Transmission Service	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	49
50															50
51	**Non-Coincident Demand (MW)**														51
52	MW @ Secondary Service	90.020	71.082	79.308	82.936	84.316	85.463	84.989	82.124	79.846	72.906	79.589	83.533	976.113	52
53	Transmission Level Adjustment Factor	1.0457	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570		53
54	Non-Coincident Demand @ Transmission Level	94.133	74.331	82.932	86.726	88.169	89.369	88.874	85.878	83.495	76.238	83.226	87.351	1,020.722	54
55															55
56	MW @ Primary Service	8.032	9.135	13.392	11.907	12.208	12.152	12.064	11.338	10.269	12.805	15.348	10.152	138.802	56
57	Transmission Level Adjustment Factor	1.0108	1.01080	1.01080	1.01080	1.01080	1.01080	1.01080	1.01080	1.01080	1.01080	1.01080	1.01080		57
58	Non-Coincident Demand @ Transmission Level	8.119	9.233	13.536	12.035	12.340	12.283	12.194	11.461	10.380	12.943	15.513	10.262	140.301	58
59															59
60	MW @ Transmission Service	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	60
61	Non-Coincident Demand @ Meter Level	98.052	80.217	92.699	94.843	96.525	97.615	97.053	93.463	90.115	85.711	94.937	93.686	1,114.915	61
62	Non-Coincident Demand @ Transmission Level	102.253	83.564	96.468	98.762	100.510	101.652	101.068	97.338	93.875	89.181	98.739	97.613	1,161.023	62
63															63
64															64
65	**Schedules AL-TOU / AY-TOU / DG-R:**	**Apr-10**	**May-10**	**Jun-10**	**Jul-10**	**Aug-10**	**Sep-10**	**Oct-10**	**Nov-10**	**Dec-10**	**Jan-11**	**Feb-11**	**Mar-11**	**Total**	65
66	Applicable to 90% NCD - **Total Deliveries (MWh)**	708,903	692,577	744,964	827,532	755,332	871,898	817,218	756,976	723,654	772,108	698,123	742,483	9,111,768	66
67															67
68	**Total Deliveries (%)**														68
69	% @ Secondary Service	79.27%	78.43%	82.11%	79.43%	78.58%	80.34%	77.71%	78.07%	81.77%	79.54%	79.60%	81.39%	79.68%	69
70	% @ Primary Service	19.02%	20.66%	17.19%	19.92%	20.47%	18.67%	19.01%	19.23%	17.28%	19.44%	19.90%	17.48%	19.02%	70
71	% @ Transmission Service	1.71%	0.91%	0.70%	0.65%	0.95%	0.99%	3.28%	2.70%	0.95%	1.02%	0.50%	1.13%	1.30%	71
72		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	72
73	**Total Deliveries (MWh)**														73
74	MWh @ Secondary Service	561,948	543,188	611,690	657,309	593,540	700,483	635,060	590,971	591,732	614,135	555,706	604,307	7,260,068	74
75	MWh @ Primary Service	134,833	143,086	128,059	164,844	154,616	162,783	155,353	145,567	125,047	150,098	138,926	129,786	1,733,001	75
76	MWh @ Transmission Service	12,122	6,302	5,215	5,379	7,176	8,632	26,805	20,438	6,875	7,876	3,491	8,390	118,700	76
77		708,903	692,577	744,964	827,532	755,332	871,898	817,218	756,976	723,654	772,108	698,123	742,483	9,111,768	77
78															78
79	**Non-Coincident Demand (%)**														79
80	% @ Secondary Service	0.2810%	0.2688%	0.2705%	0.2744%	0.2793%	0.2709%	0.2955%	0.2984%	0.2822%	0.2792%	0.2768%	0.2723%	0.2791%	80
81	% @ Primary Service	0.2376%	0.2190%	0.2213%	0.2386%	0.2236%	0.2289%	0.2400%	0.2369%	0.2403%	0.2205%	0.2216%	0.2273%	0.2297%	81
82	% @ Transmission Service	0.1981%	0.2219%	0.2323%	0.2659%	0.2727%	0.2418%	0.2261%	0.1460%	0.2803%	0.2419%	0.3092%	0.1336%	0.2154%	82
83															83
84	**Non-Coincident Demand (MW)**														84
85	MW @ Secondary Service	1,579.073	1,460.090	1,654.621	1,803.656	1,657.757	1,897.608	1,876.603	1,763.458	1,669.866	1,714.665	1,538.193	1,645.528	20,261.118	85
86	Transmission Level Adjustment Factor	1.0457	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570		86
87	Non-Coincident Demand @ Transmission Level	1,651.237	1,526.816	1,730.237	1,886.083	1,733.516	1,984.328	1,962.364	1,844.048	1,746.179	1,793.025	1,608.489	1,720.729	21,187.051	87

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San Diego Gas & Electric

FERC Recorded Sales @ Transmission Level for the Period: April 2010 - March 2011

Line No.															Line No.
88															88
89	MW @ Primary Service	320.364	313.359	283.395	393.319	345.722	372.611	372.848	344.847	300.489	330.966	307.861	295.004	3,980.785	89
90	Transmission Level Adjustment Factor	1.0108	1.01080	1.01080	1.01080	1.01080	1.01080	1.01080	1.01080	1.01080	1.01080	1.01080	1.01080		90
91	Non-Coincident Demand @ Transmission Level	323.824	316.743	286.456	397.567	349.456	376.635	376.874	348.571	303.734	334.540	311.186	298.190	4,023.777	91
92															92
93	MW @ Transmission Service	24.014	13.985	12.114	14.303	19.568	20.872	60.606	29.840	19.270	19.051	10.793	11.209	255.624	93
94	Non-Coincident Demand @ Meter Level	1,923.452	1,787.434	1,950.130	2,211.277	2,023.047	2,291.090	2,310.056	2,138.145	1,989.625	2,064.681	1,856.847	1,951.741	24,497.526	94
95	Non-Coincident Demand @ Transmission Level	1,999.075	1,857.544	2,028.807	2,297.952	2,102.540	2,381.835	2,399.843	2,222.460	2,069.183	2,146.616	1,930.468	2,030.127	25,466.452	95
96															96
97	**On-Peak Demand (%)**														97
98	% @ Secondary Service	0.2265%	0.2275%	0.2503%	0.2580%	0.2621%	0.2570%	0.2522%	0.2346%	0.2213%	0.2198%	0.2191%	0.2183%	0.2380%	98
99	% @ Primary Service	0.1996%	0.2075%	0.2313%	0.2366%	0.2323%	0.2339%	0.2293%	0.2085%	0.2107%	0.1977%	0.2061%	0.2063%	0.2173%	99
100	% @ Transmission Service	0.3645%	0.4230%	0.5473%	0.4202%	0.3757%	0.2874%	0.2268%	0.2739%	0.6176%	0.3522%	0.3647%	0.3891%	0.3421%	100
101															101
102	**On-Peak Demand (MW)**	W	S	S	S	S	S	W	W	W	W	W	W	Total	102
103	MW @ Secondary Service	1,272.812	1,235.753	1,531.060	1,695.857	1,555.668	1,800.241	1,601.622	1,386.419	1,309.502	1,349.869	1,217.551	1,319.202	17,275.554	103
104	Transmission Level Adjustment Factor	1.0457	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570		104
105	On-Peak Demand @ Transmission Level	1,330.979	1,292.227	1,601.029	1,773.358	1,626.762	1,882.512	1,674.816	1,449.778	1,369.346	1,411.558	1,273.193	1,379.490	18,065.048	105
106															106
107	MW @ Primary Service	269.128	296.904	296.201	390.022	359.174	380.750	356.225	303.506	263.475	296.743	286.327	267.749	3,766.204	107
108	Transmission Level Adjustment Factor	1.0108	1.01080	1.01080	1.01080	1.01080	1.01080	1.01080	1.01080	1.01080	1.01080	1.01080	1.01080		108
109	On-Peak Demand @ Transmission Level	272.034	300.111	299.400	394.234	363.053	384.862	360.072	306.784	266.320	299.948	289.420	270.640	3,806.879	109
110															110
111	MW @ Transmission Service	44.186	26.659	28.540	22.602	26.959	24.808	60.793	55.981	42.458	27.738	12.730	32.646	406.100	111
112	On-Peak Demand @ Meter Level	1,586.125	1,559.317	1,855.801	2,108.481	1,941.801	2,205.799	2,018.640	1,745.906	1,615.435	1,674.350	1,516.609	1,619.596	21,447.858	112
113	On-Peak Demand @ Transmission Level	1,647.199	1,618.997	1,928.970	2,190.194	2,016.774	2,292.182	2,095.681	1,812.543	1,678.125	1,739.243	1,575.343	1,682.776	22,278.026	113
114															114
115															115
116	**Schedule A6-TOU:**	**Apr-10**	**May-10**	**Jun-10**	**Jul-10**	**Aug-10**	**Sep-10**	**Oct-10**	**Nov-10**	**Dec-10**	**Jan-11**	**Feb-11**	**Mar-11**	**Total**	116
117	**Total Deliveries (MWh)**	65,251	72,160	71,462	72,343	55,478	68,178	71,130	64,163	70,265	57,890	61,242	51,383	780,945	117
118															118
119	**Total Deliveries (%)**														119
120	% @ Secondary Service	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	120
121	% @ Primary Service	13.38%	6.55%	9.47%	11.89%	8.21%	14.54%	8.86%	7.59%	15.37%	8.27%	13.71%	20.59%	11.40%	121
122	% @ Transmission Service	86.62%	93.45%	90.53%	88.11%	91.79%	85.46%	91.14%	92.41%	84.63%	91.73%	86.29%	79.41%	88.60%	122
123		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	123
124	**Total Deliveries (MWh)**														124
125	MWh @ Secondary Service	0	0	0	0	0	0	0	0	0	0	0	0	0	125
126	MWh @ Primary Service	8,731	4,726	6,767	8,602	4,555	9,913	6,302	4,870	10,800	4,788	8,396	10,580	89,029	126
127	MWh @ Transmission Service	56,521	67,434	64,694	63,741	50,923	58,265	64,828	59,293	59,465	53,103	52,846	40,803	691,916	127
128		65,251	72,160	71,462	72,343	55,478	68,178	71,130	64,163	70,265	57,890	61,242	51,383	780,945	128
129	**Non-Coincident Demand (%)**														129
130	% @ Secondary Service	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	130
131	% @ Primary Service	0.1456%	0.1068%	0.1203%	0.1390%	0.1158%	0.1729%	0.0952%	0.1239%	0.1838%	0.4118%	0.2249%	0.2801%	0.1802%	131
132	% @ Transmission Service	0.1748%	0.1868%	0.1658%	0.1926%	0.1977%	0.1984%	0.1926%	0.1928%	0.1908%	0.1917%	0.1798%	0.2022%	0.1883%	132

Section 3.2.2

San Diego Gas & Electric

FERC Recorded Sales @ Transmission Level for the Period: April 2010 - March 2011

Line No.															Line No.
133															133
134	**Non-Coincident Demand (MW)**														134
135	MW @ Secondary Service	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	135
136	Transmission Level Adjustment Factor	1.0457	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570		136
137	Non-Coincident Demand @ Transmission Level	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	137
138															138
139	MW @ Primary Service	12.712	5.048	8.141	11.956	5.274	17.140	6.000	6.034	19.850	19.715	18.883	29.634	160.387	139
140	Transmission Level Adjustment Factor	1.0108	1.01080	1.01080	1.01080	1.01080	1.01080	1.01080	1.01080	1.01080	1.01080	1.01080	1.01080		140
141	Non-Coincident Demand @ Transmission Level	12.849	5.102	8.229	12.085	5.331	17.325	6.064	6.099	20.064	19.928	19.087	29.954	162.119	141
142															142
143	MW @ Transmission Service	98.798	125.966	107.263	122.766	100.676	115.598	124.859	114.316	113.460	101.798	95.017	82.504	1,303.020	143
144	Non-Coincident Demand @ Meter Level	111.510	131.014	115.404	134.722	105.950	132.738	130.859	120.350	133.310	121.513	113.900	112.138	1,463.407	144
145	Non-Coincident Demand @ Transmission Level	111.647	131.068	115.492	134.851	106.007	132.923	130.924	120.416	133.524	121.726	114.104	112.458	1,465.139	145
146															146
147	**Coincident Peak Demand (%)**														147
148	% @ Secondary Service	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	148
149	% @ Primary Service	0.1613%	0.1705%	0.1914%	0.1550%	0.0572%	0.1054%	0.1824%	0.1712%	0.1941%	0.1286%	0.1544%	0.1324%	0.1521%	149
150	% @ Transmission Service	0.1171%	0.1495%	0.1398%	0.1564%	0.1398%	0.1767%	0.1630%	0.1914%	0.1144%	0.1520%	0.1407%	0.1502%	0.1496%	150
151															151
152	**Coincident Peak Demand (MW)**	W	S	S	S	S	S	W	W	W	W	W	W	Total	152
153	MW @ Secondary Service	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	153
154	Transmission Level Adjustment Factor	1.0457	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570		154
155	Coincident Peak Demand@Transmission Level	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	155
156															156
157	MW @ Primary Service	14.082	8.059	12.953	13.332	2.605	10.448	11.495	8.337	20.962	6.157	12.964	14.008	135.403	157
158	Transmission Level Adjustment Factor	1.0108	1.01080	1.01080	1.01080	1.01080	1.01080	1.01080	1.01080	1.01080	1.01080	1.01080	1.01080		158
159	Coincident Peak Demand@Transmission Level	14.235	8.146	13.093	13.476	2.633	10.561	11.619	8.427	21.189	6.223	13.104	14.159	136.865	159
160															160
161	MW @ Transmission Service	66.186	100.813	90.443	99.691	71.191	102.954	105.670	113.486	68.028	80.716	74.354	61.286	1,034.819	161
162	Coincident Peak Demand@Meter Level	80.268	108.872	103.395	113.024	73.796	113.403	117.165	121.824	88.991	86.873	87.318	75.294	1,170.222	162
163	Coincident Peak Demand@Transmission Level	80.420	108.959	103.535	113.168	73.825	113.516	117.289	121.914	89.217	86.939	87.458	75.445	1,171.685	163
164	**Schedule S: Standby Determinants:**	**Apr-10**	**May-10**	**Jun-10**	**Jul-10**	**Aug-10**	**Sep-10**	**Oct-10**	**Nov-10**	**Dec-10**	**Jan-11**	**Feb-11**	**Mar-11**	**Total**	164
165	**Contracted Standby Demand (MW)**														165
166	MW @ Secondary Service	11.224	11.224	11.226	11.124	11.124	11.123	12.075	12.075	13.498	13.498	13.408	13.408	145.007	166
167	Transmission Level Adjustment Factor	1.0457	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570		167
168	Standby Demand @ Transmission Level	11.737	11.737	11.739	11.632	11.632	11.631	12.627	12.627	14.115	14.115	14.021	14.021	151.634	168
169															169
170	MW @ Primary Service	84.822	85.002	85.316	85.022	84.287	84.287	80.481	80.481	83.769	83.386	82.725	83.399	1,002.977	170
171	Transmission Level Adjustment Factor	1.0108	1.01080	1.01080	1.01080	1.01080	1.01080	1.01080	1.01080	1.01080	1.01080	1.01080	1.01080		171
172	Standby Demand @ Transmission Level	85.738	85.920	86.237	85.940	85.197	85.197	81.350	81.350	84.674	84.287	83.618	84.300	1,013.809	172
173															173
174	MW @ Transmission Service	46.948	47.715	47.692	49.986	49.986	49.986	50.003	50.003	50.156	50.272	50.272	50.275	593.294	174
175	Standby Demand@Meter Level	142.994	143.941	144.234	146.132	145.397	145.396	142.559	142.559	147.423	147.156	146.405	147.082	1,741.278	175
176	Standby Demand@Transmission Level	144.423	145.372	145.668	147.559	146.816	146.815	143.980	143.980	148.945	148.673	147.911	148.595	1,758.737	176
177															177

Section 3.2.3

SAN DIEGO GAS AND ELECTRIC COMPANY
TO3-Cycle 5 Annual Transmission Formulaic Rate Filing
Revenue Data to Reflect Present Rates from the WHOLESALE Rates Developed in Cycle 3 and Cycle 4
For the 12-Month Period True-Up Period April 2010 through March 2011
Billing Determinants @ Transmission Level
True-Up Period (4/1/2010 - 3/31/2011)

Line No.	Customer Classes	(A) Apr-10 Billing Determinants Energy (kWh)	(A) Demand (kW)	(B) May-10 Billing Determinants Energy (kWh)	(B) Demand (kW)	(C) Jun-10 Billing Determinants Energy (kWh)	(C) Demand (kW)	(D) Jul-10 Billing Determinants Energy (kWh)	(D) Demand (kW)	(E) Aug-10 Billing Determinants Energy (kWh)	(E) Demand (kW)	(F) Sep-10 Billing Determinants Energy (kWh)	(F) Demand (kW)	(G) Sub-Total Billing Determinants Energy (kWh)	(G) Demand (kW)	Line No.
1	Residential Customers [1]	585,993,579		540,837,597		575,771,398		620,634,704		617,318,718		717,609,257		3,658,165,252	-	1
2																2
3	Small Commercial [2]	165,219,991		143,601,259		169,855,612		185,450,446		171,129,618		197,895,590		1,033,152,516	-	3
4																4
5	Medium-Large Commercial [3]	824,359,987	2,212,975	813,284,778	2,072,177	871,348,310	2,240,768	961,066,131	2,531,564	868,533,488	2,309,057	1,005,322,068	2,616,410	5,343,914,762	13,982,951	5
6																6
7	Street Lighting [4]	13,323,085		6,286,193		9,880,836		9,899,133		10,162,500		8,975,509		58,527,257	-	7
8																8
9	Sale for Resale [5]	1,500		-		3,500		-		1,500		-		6,500	-	9
10																10
11	Standby Customers [6]		144,423		145,372		145,668		147,559		146,816		146,815	-	876,652	11
12																12
13	TOTAL	1,588,898,142	2,357,398	1,504,009,827	2,217,549	1,626,859,656	2,386,436	1,777,050,414	2,679,123	1,667,145,823	2,455,873	1,929,802,424	2,763,225	10,093,766,287	14,859,603	13
14																14

NOTES:

1 See Section 3.2.3; Page 26.1; Line 5 x 1000.
2 See Section 3.2.3; Page 26.1; Line 9 x 1000.
3 See Section 3.2.3; Pages 26.1; 26.2; 26.3; 26.4; (Lines 13, 17, and 21) x 1000; (Lines 46, 79, and 129) x 1000.
4 See Section 3.2.3; Page 26.1; Line 25 x 1000.
5 See Section 3.2.3; Page 26.1; Line 27 x 1000.
6 See Section 3.2.3; Page 26.4; Line 160 x 1000.

Section 3.2.3

SAN DIEGO GAS AND ELECTRIC COMPANY

TO3-Cycle 5 Annual Transmission Formulaic Rate Filing

Revenue Data to Reflect Present Rates from the WHOLESALE Rates Developed in Cycle 3 and Cycle 4

For the 12-Month Period True-Up Period April 2010 through March 2011

Billing Determinants @ Transmission Level

True-Up Period (4/1/2010 - 3/31/2011)

		(H)		(I)		(J)		(K)		(L)		(M)		(N)		(O)		
		Oct-10		Nov-10		Dec-10		Jan-11		Feb-11		Mar-11		Sub-Total		Grand Total		
		Billing Determinants		Billing Determinants		Billing Determinants		Billing Determinants		Billing Determinants		Billing Determinants		Billing Determinants		Billing Determinants		
Line No.	Customer Classes	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Line No.
1	Residential Customers [1]	669,169,003		616,281,152		702,642,334		757,305,553		656,762,211		637,609,078		4,039,769,330	-	7,697,934,583	-	1
2																		2
3	Small Commercial [2]	185,462,587		169,933,296		171,494,306		178,906,863		166,897,972		167,568,411		1,040,263,437	-	2,073,415,953	-	3
4																		4
5	Medium-Large Commercial [3]	948,341,453	2,631,835	872,570,224	2,440,214	843,333,041	2,296,583	878,664,646	2,357,523	807,551,603	2,143,311	843,756,551	2,240,198	5,194,217,518	14,109,663	10,538,132,280	28,092,614	5
6																		6
7	Street Lighting [4]	11,068,413		9,816,383		13,421,130		6,389,127		9,932,236		13,336,818		63,964,107	-	122,491,364	-	7
8																		8
9	Sale for Resale [5]	6,408		-		2,116		1,710		3,620		-		13,854	-	20,354		9
10																		10
11	Standby Customers [6]		143,980		143,980		148,945		148,673		147,911		148,595	-	882,085	-	1,758,737	11
12																		12
13	TOTAL	1,814,047,865	2,775,815	1,668,601,055	2,584,194	1,730,892,927	2,445,527	1,821,267,899	2,506,196	1,641,147,643	2,291,222	1,662,270,858	2,388,794	10,338,228,247	14,991,747	20,431,994,534	29,851,351	13
14																		14

NOTES:

1. See Section 3.2.3; Page 26.1; Line 5 x 1000.
2. See Section 3.2.3; Page 26.1; Line 9 x 1000.
3. See Section 3.2.3; Pages 26.1; 26.2; 26.3; 26.4; (Lines 13, 17, and 21) x 1000; (Lines 46, 79, and 129) x 1000.
4. See Section 3.2.3; Page 26.1; Line 25 x 1000.
5. See Section 3.2.3; Page 26.1; Line 27 x 1000.
6. See Section 3.2.3; Page 26.4; Line 160 x 1000.

Section 3.2.3

SAN DIEGO GAS AND ELECTRIC COMPANY

TO3-Cycle 5 Annual Transmission Formulaic Rate Filing

Revenue Data to Reflect Present Rates from the WHOLESALE Rates Developed in Cycle 3 and Cycle 4

For the 12-Month Period True-Up Period April 2010 through March 2011

Total Billing Determinants @ Transmission Level

True-Up Period (4/1/2010 - 3/31/2011)

		(M)		
		12 Months to Date		
		Billing Determinants @ Transmission Level		
Line No.	Customer Classes	Energy (kWh)	Demand (kW)	Line No.
1	Residential Customers	7,697,934,583	-	1
2				2
3	Small Commercial	2,073,415,953	-	3
4				4
5	Medium-Large Commercial	10,538,132,280	28,092,614	5
6				6
7	Street Lighting	122,491,364	-	7
8				8
9	Sale for Resale	20,354		9
10				10
11	Standby Customers	-	1,758,737	11
12				12
13	TOTAL	20,431,994,534	29,851,351	13
14				14

Section 3.2.3

SAN DIEGO GAS AND ELECTRIC COMPANY
TO3-Cycle 5 Annual Transmission Formulaic Rate Filing
WHOLESALE - Rate Design Information
Summary of TO3-CYCLE-3 Wholesale Transmission Rates Based on TO3-CYCLE-3 Wholesale Cost of Service Using TO3-CYCLE-3 Forecast Billing Determinants

Line No.	Customer Classes	Transmission Energy Rates $/kWh	Transmission Level Demand Rates $/kW-Mo	Primary Level Demand Rates $/kW-Mo	Secondary Level Demand Rates $/kW-Mo	Reference	Line No.
1	Residential	$ 0.0126663				Section 3.2.1; Page 12; Line 1	1
2							2
3	Small Commercial	$ 0.0148264				Section 3.2.1; Page 12; Line 3	3
4							4
5	Med & Lrg Commercial/Industrial						5
6	Non-Coincident Demand (100%) [1]		$ 4.0876404	$ 4.0877270	$ 4.0877977	Section 3.2.1; Page 12; Line 6	6
7							7
8	Non-Coincident Demand (90%) [2]		$ 3.6788764	$ 3.6789543	$ 3.6790179	Section 3.2.1; Page 12; Line 8	8
9							9
10	Maximum On-Peak Demand [3]						10
11	Summer		$ 0.7840997	$ 0.7840997	$ 0.7840997	Section 3.2.1; Page 12; Line 11	11
12	Winter		$ 0.1730583	$ 0.1730583	$ 0.1730583	Section 3.2.1; Page 12; Line 12	12
13							13
14	Maximum Demand at the Time of System Peak [4]						14
15	Summer		$ 1.0651511	$ 1.0651511	$ -	Section 3.2.1; Page 12; Line 15	15
16	Winter		$ 0.2109265	$ 0.2109265	$ -	Section 3.2.1; Page 12; Line 16	16
17							17
18	Street Lighting	$ 0.0088726				Section 3.2.1; Page 12; Line 18	18
19							19
20	Standby Rate		$ 2.0539568	$ 2.0549662	$ 2.0569620	Section 3.2.1; Page 12; Line 20	20

NOTES:

[1] Non-Coincident Demand (NCD) (100%) rates are applicable to the following California Public Utilities Commission (CPUC) tariffs: Schedules AD and PA-T-1

[2] NCD (90%) rates are applicable to the following CPUC tariffs: Schedules AY-TOU, AL-TOU, AL-TOU-DER, DG-R, and A6-TOU.

[3] Maximum On-Peak Demand rates are applicable to the following CPUC tariffs: Schedules AY-TOU, AL-TOU, AL-TOU-DER and DG-R

[4] Maximum Demand at the Time of System Peak rates are applicable to the following CPUC tariffs: Schedule A6-TOU

Section 3.2.3
SAN DIEGO GAS AND ELECTRIC COMPANY
TO3-Cycle 5 Annual Transmission Formulaic Rate Filing
WHOLESALE - Rate Design Information
Summary of TO3-CYCLE-4 Wholesale Transmission Rates Based on TO3-CYCLE-4 Wholesale Cost of Service Using TO3-CYCLE-4 Forecast Billing Determinants

Line No.	Customer Classes	Transmission Energy Rates $/kWh	Transmission Level Demand Rates $/kW-Mo	Primary Level Demand Rates $/kW-Mo	Secondary Level Demand Rates $/kW-Mo	Reference	Line No.
1	Residential	$ 0.0152337				Section 3.2.2; Page 12; Line 1	1
2							2
3	Small Commercial	$ 0.0180080				Section 3.2.2; Page 12; Line 3	3
4							4
5	Med & Lrg Commercial/Industrial						5
6	Non-Coincident Demand (100%) [1]		$ 5.0977873	$ 5.0973649	$ 5.0975107	Section 3.2.2; Page 12; Line 6	6
7							7
8	Non-Coincident Demand (90%) [2]		$ 4.5880086	$ 4.5876284	$ 4.5877596	Section 3.2.2; Page 12; Line 8	8
9							9
10	Maximum On-Peak Demand [3]						10
11	Summer		$ 0.9895844	$ 0.9895844	$ 0.9895844	Section 3.2.2; Page 12; Line 11	11
12	Winter		$ 0.2145097	$ 0.2145097	$ 0.2145097	Section 3.2.2; Page 12; Line 12	12
13							13
14	Maximum Demand at the Time of System Peak [4]						14
15	Summer		$ 1.2971826	$ 1.2971826	$ -	Section 3.2.2; Page 12; Line 15	15
16	Winter		$ 0.2548850	$ 0.2548850	$ -	Section 3.2.2; Page 12; Line 16	16
17							17
18	Street Lighting	$ 0.0097329				Section 3.2.2; Page 12; Line 18	18
19							19
20	Standby Rate		$ 2.2732143	$ 2.2729941	$ 2.2753623	Section 3.2.2; Page 12; Line 20	20

NOTES:

1 Non-Coincident Demand (NCD) (100%) rates are applicable to the following California Public Utilities Commission (CPUC) tariffs: Schedules AD and PA-T-1

2 NCD (90%) rates are applicable to the following CPUC tariffs: Schedules AY-TOU, AL-TOU, AL-TOU-DER, DG-R, and A6-TOU.

3 Maximum On-Peak Demand rates are applicable to the following CPUC tariffs: Schedules AY-TOU, AL-TOU, AL-TOU-DER and DG-R

4 Maximum Demand at the Time of System Peak rates are applicable to the following CPUC tariffs: Schedule A6-TOU

Section – 3.3

Derivation of Monthly ISO True-Up Period Cost of Service (COS) Revenues

Section 3.3.1

Derivation of ISO Cost of Service (COS) for the True-Up Period.

Docket No. ER11-____-____

Section 3.3.1
San Diego Gas & Electric Company
Statement BK-2
Derivation of ISO Transmission Base Period Cost of Service
True Up Period (4/1/2010 - 3/31/2011)
($1,000)

Line No.			Amounts	Reference	Line No.
1	Transmission Operation & Maintenance Expense	$	44,557	Statement AH; Page 5, Line 6	1
2					2
3	Transmission Related A&G Expenses		29,082	Statement AH; Page 5, Line 52	3
4					4
5	CPUC Intervener Funding Expense		-	Not Recoverable From Wholesale Customers	5
6					6
7	Total O&M Expenses	$	73,639	Sum Lines 1; 3; and 5	7
8					8
9	Trans, Intang., Gen. and Comm. Depr. & Amort. Expense		69,497	Statement AJ; Page 7, Line 17	9
10					10
11	Valley Rainbow Project Cost Amortization Expense		1,893	Statement AJ; Page 7, Line 19	11
12					12
13	Transmission Related Property Taxes Expense		11,075	Statement AK; Page 8, Line 27	13
14					14
15	Transmission Related Payroll Taxes Expense		1,955	Statement AK; Page 8, Line 34	15
16					16
17	Subtotal Expense	$	158,059	Sum Lines (7 thru 15)	17
18					18
19	Cost of Capital Rate ($AFCR_{CP}$)		12.5181%	Statement AV; Page 14, Line 33	19
20					20
21	Transmission Rate Base	$	1,111,376	Statement BK-2; Pg 2, Line 20	21
22					22
23	Return and Associated Income Taxes	$	139,123	(Line 19 x Line 21)	23
24	South Georgia Income Tax Adjustment		-	Not Recoverable From Wholesale Customers	24
25	Transmission Related Amortization of ITC		(265)	Statement AR; Page 11, Line 1	25
26	Trans. Related Amort of Excess Deferred Tax Liability		(3)	Statement AR; Page 11, Line 3	26
27	Transmission Related Revenue Credits		(2,484)	Statement AU; Page 12, Line 15	27
28					28
29	End of Prior Year Revenue ($PYRR_{ISO}$)	$	294,430	Line 17 + Sum of Lines (23 thru 27)	29
30					30
31	Transmission Related Municipal Franchise Expenses		3,025	Line 29 x 1.0275%	31
32	Transmission Related Uncollectible Expense		-	Not Applicable on Wholesale Customers	32
33					33
34	End of Prior Year Revenue ($PYRR_{ISO}$)	$	297,455	Sum Lines (29 thru 32)	34

NOTE:

[1] The costs shown on Statement BK2 come from Volume 2 costs statements, or are derived in Statement BK2 and brought forward to Summary cost statement BK2, page 1.

Section 3.3.1
San Diego Gas & Electric Company
Statement BK-2
Derivation of ISO Transmission Base Period Cost of Service
True Up Period (4/1/2010 - 3/31/2011)
($1,000)

Line No.			Amounts	Reference	Line No.
1	Net Transmission Plant:				1
2	Transmission Plant	$	1,146,333	Statement BK-2; Pg 3; Line 16	2
3	Electric Miscellaneous Intangible Plant		293	Statement BK-2; Pg 3; Line 17	3
4	Transmission Related General Plant		15,797	Statement BK-2; Pg 3; Line 18	4
5	Transmission Related Common Plant		32,568	Statement BK-2; Pg 3; Line 19	5
6	Net Transmission Plant	$	1,194,991	Sum Lines (2 thru 5)	6
7					7
8	Rate Base Reductions:				8
9	Transmission Related Accumulated Deferred Taxes	$	(148,838)	Statement AF; Page 3, Line 3	9
10					10
11	Rate Base Additions				11
12	Plant Held for Future Use	$	39,893	Statement AG; Page 4, Line 4	12
13					13
14	Working Capital:				14
15	Transmission Related Material and Supplies	$	10,665	Statement AL; Page 9, Line 5	15
16	Tranmission Related Prepayments		5,461	Statement AL; Page 9, Line 9	16
17	Transmission Related Cash Working Capital - Wholesale		9,205	Statement AL; Page 9, Line 23	17
18	Total Working Capital	$	25,331	Sum Lines (15 thru 17)	18
19					19
20	Total Transmission Rate Base	$	1,111,376	Sum Lines 6; 9; 12; 18	20

Section 3.3.1
San Diego Gas & Electric Company
Statement BK-2
Derivation of ISO Transmission Base Period Cost of Service
True Up Period (4/1/2010 - 3/31/2011)
($1,000)

Line No.			Amounts	Reference	Line No.
1	Gross Transmission Plant:				1
2	Transmission Plant	$	1,646,488	Statement AD; Page 1, Line 23	2
3	Electric Miscellaneous Intangible Plant		4,259	Statement AD; Page 1, Line 27	3
4	Transmission Related General Plant		27,686	Statement AD; Page 1, Line 29	4
5	Transmission Related Common Plant		73,428	Statement AD; Page 1, Line 31	5
6	Gross Transmission Plant	$	1,751,861	Sum Lines (2 thru 5)	6
7					7
8	Accumulated Depreciation Reserve:				8
9	Transmission Related Depreciation Reserve	$	500,155	Statement AE; Page 2, Line 1	9
10	Electric Miscellaneous Intangible Depreciation Reserve		3,966	Statement AE; Page 2, Line 11	10
11	Transmission Related General Plant Depr Reserve		11,889	Statement AE; Page 2, Line 13	11
12	Transmission Related Common Plant Depr Reserve		40,860	Statement AE; Page 2, Line 15	12
13	Transmission Related Depreciation Reserve	$	556,870	Sum Lines (9 thru 12)	13
14					14
15	Net Transmission Plant:				15
16	Transmission Plant	$	1,146,333	Line 2 Minus Line 9	16
17	Electric Miscellaneous Intangible Plant		293	Line 3 Minus Line 10	17
18	Transmission Related General Plant		15,797	Line 4 Minus Line 11	18
19	Transmission Related Common Plant		32,568	Line 5 Minus Line 12	19
20	Total Net Plant	$	1,194,991	Sum Lines (16 thru 19)	20

Section 3.3.1
Statement BB
SAN DIEGO GAS AND ELECTRIC COMPANY
Allocation Demand and Capability Data
(Information Based on Five-Year Average Recorded Data: 2004 - 2008)

Line No.	Customer Class	(a) 5-Year Average Of 12-CPS Kilowatts @ Meter Level [1]	(b) Transmission Loss Factors	(c) = (a) x (b) 5-Year Average Of 12-CPS; Kilowatts @ Transmission Level	12-CP Allocation Percentages @ Transmission Level	Reference	Line No.
1	Residential Customers	15,054,815	1.0457	15,742,820	39.46%	Statement BB WP; Page-1; Line 1	1
2	Small Commercial Customers	4,636,436	1.0457	4,848,321	12.15%	Statement BB WP; Page-1; Line 2	2
3	Medium-Large Commercial Customers						3
4	Secondary	13,510,244	1.0457	14,127,662	35.41%	Statement BB WP; Page-1; Line 22	4
5	Primary	3,295,181	1.0108	3,330,769	8.35%	Statement BB WP; Page-1; Line 23	5
6	Transmission	1,201,031	1.0000	1,201,031	3.01%	Statement BB WP; Page-1; Line 24	6
7	Total Medium-Large Commercial	18,006,456	1.0363	18,659,462	46.77%	Sum Lines 4; 5; 6	7
8							8
9	Street Lighting	139,791	1.0457	146,179	0.37%	Statement BB WP; Page-1; Line 4	9
10	Standby Customers						10
11	Secondary	38,310	1.0457	40,061	0.10%	Statement BB WP; Page-1; Line 28	11
12	Primary	293,448	1.0108	296,617	0.74%	Statement BB WP; Page-1; Line 29	12
13	Transmission	162,697	1.0000	162,697	0.41%	Statement BB WP; Page-1; Line 30	13
14	Total Standby Customers	494,455	1.0100	499,375	1.25%	Sum Lines 11; 12; 13	14
15							15
16	System Total	38,331,953	1.04081	39,896,158	100.00%	Sum Lines 1; 2; 7; 9; 14	16

Notes:

[1] SDG&E Load Research Data: 2004 - 2008.

Section 3.3.1

Statement BD

SAN DIEGO GAS AND ELECTRIC COMPANY

Allocation Energy and Supporting Data

12 Month True-Up Period - (April 2010 through March 31, 2011)

Line No.	Months	Retail Energy Sales @ Meter Level	Energy Sales @ Transmission Level	Reference	Line No.
1	April-10	1,526,441	1,588,730	Stmnt BDWP; Page 2.1; Cols. C & D; Line 1	1
2	May-10	1,445,170	1,504,142	Stmnt BDWP; Page 2.1; Cols. C & D; Line 2	2
3	June-10	1,563,139	1,626,926	Stmnt BDWP; Page 2.1; Cols. C & D; Line 3	3
4	July-10	1,707,530	1,777,208	Stmnt BDWP; Page 2.1; Cols. C & D; Line 4	4
5	August-10	1,601,643	1,667,001	Stmnt BDWP; Page 2.1; Cols. C & D; Line 5	5
6	September-10	1,854,218	1,929,883	Stmnt BDWP; Page 2.1; Cols. C & D; Line 6	6
7	October-10	1,743,020	1,814,147	Stmnt BDWP; Page 2.1; Cols. C & D; Line 7	7
8	November-10	1,603,276	1,668,700	Stmnt BDWP; Page 2.1; Cols. C & D; Line 8	8
9	December-10	1,662,589	1,730,434	Stmnt BDWP; Page 2.1; Cols. C & D; Line 9	9
10	January-11	1,749,322	1,820,706	Stmnt BDWP; Page 2.1; Cols. C & D; Line 10	10
11	February-11	1,576,453	1,640,783	Stmnt BDWP; Page 2.1; Cols. C & D; Line 11	11
12	March-11	1,596,971	1,662,139	Stmnt BDWP; Page 2.1; Cols. C & D; Line 12	12
13					13
14	Total	19,629,770	20,430,799	Sum Lines 1 through 12	14

Notes:

Section – 3.3

Derivation of Monthly ISO True-Up Period Cost of Service (COS) Revenues

Section 3.3.2

Derivation of ISO Retail True-Up Period Cost of Service Rates

Docket No. ER11-____-____

Section 3.3.2
SAN DIEGO GAS AND ELECTRIC COMPANY
TO3-Cycle 5 Annual Transmission Formulaic Rate Filing
Allocation of CYCLE-5 WHOLESALE Base Transmission Revenue Requirements
Based on TO3-CYCLE-5 12 CPs
($1,000)

Line No.	Customer Classes	(a) Section 3.3.1 Statement BB Total 12 CPs @ Transmission Level [1]	(b) 12 CP Allocation Percentages @ Transmission Level [2]	(c) Allocated Base Transmission Revenue Requirement	(d) Reference	Line No.
1	Total Base Transmission Revenue Requirement			$ 297,455	TO3-Cycle 5; Section 3.3.1;	1
2					Page 1 of 3; Line 34	2
3	Allocation of BTRR Based on 12-CP:					3
4	Residential	15,742,820	39.46%	$ 117,376	Col.C4 = Col (c) Ln1 x Col B. Ln 4	4
5	Small Commercial	4,848,321	12.15%	36,141	Col.C5 = Col (c) Ln1 x Col B. Ln 5	5
6	Medium & Large Commercial/Industrial	18,659,462	46.77%	139,120	Col.C6 = Col (c) Ln1 x Col B. Ln 6	6
7	Street Lighting Revenues	146,179	0.37%	1,101	Col.C7 = Col (c) Ln1 x Col B. Ln 7	7
8	Standby Revenues	499,375	1.25%	3,718	Col.C8 = Col (c) Ln1 x Col B. Ln 8	8
9						9
10	Total	39,896,157	100.00%	$ 297,456	Sum Lines 4 thru 8	10
11						11
12	Total	39,896,157		$ 297,456	Line 10	12

NOTES:

1 See Volume 2.B; Section 3.3.2; Page 14; Column D for additional information.

2 See Volume 2.B; Section 3.3.2; Page 9; Column D. for additional information.

Section 3.3.2

SAN DIEGO GAS AND ELECTRIC COMPANY
TO3-Cycle 5 Annual Transmission Formulaic Rate Filing
Derivation of True-Up Period ISO Retail Rates Base on True-Up Period Cost of Service
Using TO3-CYCLE-5 True-Up Period Billing Determinants
Residential Customers [1]
($000)

Line No.	Customer Classes	Derivation of Commodity Rate & Proof of Revenues Calculation	Reference	Line No.
1	Residential - Allocated Transmission Revenue Requirements	$ 117,376	Section 3.3.2; Page 1; Line 4	1
2				2
3	Billing Determinants - Residential Customer Class @ MWh:	7,361,513	Section 3.3.2; Page 16.1; Line 3	3
4				4
5	Transmission Level Adjustment Factor	1.04570	Section 3.3.2; Page 14; Col. B; Line 2	5
6				6
7	Billing Determinants @ Transmission Level	7,697,935	Line 3 x Line 5	7
8				8
9	Residential Energy Rate Per kWh	$ 0.0152477	Line 1 / Line 7	9
10				10
11	Residential Energy Rate Per kWh - Rounded	$ 0.0152477	Line 9, Rounded to 7 Decimal Places	11
12				12
13	Proof of Revenues	$ 117,376	Line 7 x Line 11	13
14				14
15	Difference	$ 0	Line 1 - Line 13	15

Notes:

1 Residential customers include the following California Public Utilities Commission (CPUC) tariffs: DR, DR-LI, DR-TOU, EV-TOU, EV-TOU-2, EV-TOU-3, DR-TV, D-SMF.

Section 3.3.2

SAN DIEGO GAS AND ELECTRIC COMPANY
TO3-Cycle 5 Annual Transmission Formulaic Rate Filing
Derivation of True-Up Period ISO Retail Rates Base on True-Up Period Cost of Service
Using TO3-CYCLE-5 True-Up Period Billing Determinants
Small Commercial Customers [1]
($000)

Line No.	Customer Classes	Derivation of Commodity Rate & Proof of Revenues Calculation	Reference	Line No.
1	Small Commercial - Allocated Transmission Revenue Requirement	$ 36,141	Section 3.3.2; Page 1; Line 5	1
2				2
3	Billing Determinants - Small Commercial @ MWh:	1,982,802	Section 3.3.2; Page 16.1; Line 7	3
4				4
5	Transmission Level Adjustment Factor	1.04570	Section 3.3.2; Page 14; Col. B; Line 3	5
6				6
7	Billing Determinants @ Transmission Level	2,073,416	Line 3 x Line 5	7
8				8
9	Energy Rate Per kWh @ Transmission Level	$ 0.0174307	Line 1 / Line 7	9
10				10
11	Energy Rate Per kWh - Rounded @ Transmission Level	$ 0.0174307	Line 9, Rounded to 7 Decimal Places	11
12				12
13	Proof of Revenues	$ 36,141	Line 7 x Line 11	13
14				14
15	Difference	$ (0)	Line 1 - Line 13	15

Notes:

1 Small commercial customers include the following California Public Utilities Commission (CPUC) tariffs:
A, A-TC, A-TOU, PA.

Section 3.3.2
SAN DIEGO GAS AND ELECTRIC COMPANY
TO3-Cycle 5 Annual Transmission Formulaic Rate Filing
Derivation of True-Up Period ISO Retail Rates Base on True-Up Period Cost of Service
Using TO3-CYCLE-5 True-Up Period Billing Determinants
Medium-Large Commercial Customers [1]
($000)

Line No.	Customer Classes	Derivation of Demand Rates & Proof of Revenues Calculation	Reference	Line No.
1	**Med-Lrg C&I - Demand Revenue Requirement:**	$ 139,120	Section 3.3.2; Page 1; Line 6	1
2	*Non-Coincident Demand Determinants @ Transmission Level Used*			2
3	*to Allocate Total Customer Class Revenues to Voltage Level:*			3
4	Secondary [2]	22,208	Section 3.3.2; Page 14; Line 22; Col. C.	4
5	Primary [2]	4,326	Section 3.3.2; Page 14; Line 23; Col. C.	5
6	Transmission [2]	1,559	Section 3.3.2; Page 14; Line 24; Col. C.	6
7	Total	28,093	Sum Lines 4; 5; 6	7
8	*Allocation Factors % Per Above to Allocate*			8
9	*Demand Revenue Requirements to Voltage Level:*			9
10	Secondary	79.05%	Line 4 / Line 7	10
11	Primary	15.40%	Line 5 / Line 7	11
12	Transmission	5.55%	Line 6 / Line 7	12
13	Total	100.00%	Sum Lines 10; 11; 12	13
14				14
15	**Allocation of Revenue Requirements to Voltage Level:**			15
16	Secondary	$ 109,977	Line 1 x Line 10	16
17	Primary	21,423	Line 1 x Line 11	17
18	Transmission	7,720	Line 1 x Line 12	18
19	Total	$ 139,120	Sum Lines 16; 17; 18	19
20				20
21	**Non-Coincident Demand Determinants by Voltage Level @ Transmission:**			21
22	Secondary	22,208	Section 3.3.2; Page 14; Line 22; Col. C.	22
23	Primary	4,326	Section 3.3.2; Page 14; Line 23; Col. C.	23
24	Transmission	1,559	Section 3.3.2; Page 14; Line 24; Col. C.	24
25	Total	28,093	Sum Lines 22; 23; 24	25
26				26
27	**Non-Coincident Demand Rate By Voltage Level @ Transmission:**			27
28	Secondary	$ 4.9521344	Line 16 / Line 22	28
29	Primary	$ 4.9521498	Line 17 / Line 23	29
30	Transmission	$ 4.9518922	Line 18 / Line 24	30
31				31
32	**Non-Coincident Demand Rate By Voltage Level @ Transmission:**			32
33	Secondary	$ 4.9521344	Line 28 Rounded to 7 Decimal Places	33
34	Primary	$ 4.9521498	Line 29 Rounded to 7 Decimal Places	34
35	Transmission	$ 4.9518922	Line 30 Rounded to 7 Decimal Places	35
36				36
37	**Proof of Revenue Calculations:**			37
38	Secondary	$ 109,977	Line 22 x Line 33	38
39	Primary	21,423	Line 23 x Line 34	39
40	Transmission	7,720	Line 24 x Line 35	40
41	Total	$ 139,120	Sum Lines 38; 39; 40	41
42				42
43	Difference	$ -	Line 1 - Line 41	43

Notes:

1 Medium-Large commercial customers include the following California Public Utilities Commission (CPUC) tariffs: AD, AY-TOU, AL-TOU, AL-TOU-CP, AL-TOU-DER, A6-TOU, PA-T-1.

2 LF = Transmission Loss Factor; Secondary Level = 1.0457; Primary Level = 1.0108; Transmission Level = 1.0000

Section 3.3.2
SAN DIEGO GAS AND ELECTRIC COMPANY
TO3-Cycle 5 Annual Transmission Formulaic Rate Filing
Derivation of True-Up Period ISO Retail Rates Base on True-Up Period Cost of Service
Using TO3-CYCLE-5 True-Up Period Billing Determinants
Medium-Large Commercial Customers [1]
($000)

Line No.	Description	Derivation of Commodity Rate & Proof of Revenues Calculation	Reference	Line No.
1	Rate Proposal @ 90% of Total M&L C&I NCD Rates [1]	90.00%		1
2	Secondary	$ 4.4569210	90% x Section 3.3.2; Page 4; Line 33	2
3	Primary	$ 4.4569348	90% x Section 3.3.2; Page 4; Line 34	3
4	Tranmission	$ 4.4567030	90% x Section 3.3.2; Page 4; Line 35	4
5				5
6	Rate Proposal 90% of Total M&L C&I NCD Rates (Rounded)			6
7	Secondary	$ 4.4569210	Line 2, Rounded to 7 Decimal Places	7
8	Primary	$ 4.4569348	Line 3, Rounded to 7 Decimal Places	8
9	Tranmission	$ 4.4567030	Line 4, Rounded to 7 Decimal Places	9
10				10
11	**Pertaining to Schedules @ 90% NCD with Maximum On-Peak Period Demand[2]**			11
12	NCD Determinants By Voltage Level @ TRANSMISSION Level (MW)			12
13	Secondary	21,187	Section 3.3.2; Page 15; Line 10	13
14	Primary	4,024	Section 3.3.2; Page 15; Line 11	14
15	Tranmission	256	Section 3.3.2; Page 15; Line 12	15
16	Total	25,467	Sum Lines 12; 13; 14	16
17				17
18	Annual Revenues from Current NCD Rate 100% of Total M&L C&I NCD Rates			18
19	Secondary	$ 104,921	Line 13 x Section 3.3.2; Page 5; Line 33	19
20	Primary	$ 19,927	Line 14 x Section 3.3.2; Page 5; Line 34	20
21	Tranmission	$ 1,268	Line 15 x Section 3.3.2; Page 5; Line 35	21
22	Total	$ 126,116	Sum Lines 19; 20; 21	22
23				23
24	Annual Revenues from Proposed NCD Rate 90% of Total M&L C&I NCD Rates			24
25	Secondary	$ 94,429	Line 7 x Line 13	25
26	Primary	$ 17,935	Line 8 x Line 14	26
27	Tranmission	$ 1,141	Line 9 x Line 15	27
28	Total	$ 113,505	Sum Lines 25; 26; 27	28
29				29
30	Revenue Reallocation to Maximum On-Peak Period Demands			30
31	Secondary	$ 10,492	Line 19 - Line 25	31
32	Primary	$ 1,992	Line 20 - Line 26	32
33	Tranmission	$ 127	Line 21 - Line 27	33
34	Total	$ 12,611	Sum Lines 31; 32; 33	34
35				35
36	Pertaining to Schedules @ 90% NCD with Maximum Demand at Time of System Peak[3]			36
37	NCD Determinants By Voltage Level @ TRANSMISSION Level (MW)			37
38	Secondary	-	Section 3.3.2; Page 15; Col. D; Line 17	38
39	Primary	162	Section 3.3.2; Page 15; Col. D; Line 18	39
40	Tranmission	1,303	Section 3.3.2; Page 15; Col. D; Line 19	40
41	Total	1,465	Sum Lines 18; 19; 20	41
42				42
43	Annual Revenues from Current NCD Rate 100% of Total M&L C&I NCD Rates			43
44	Secondary	$ -	Line 38 x Section 3.3.2; Page 5; Line 33	44
45	Primary	$ 802	Line 39 x Section 3.3.2; Page 5; Line 34	45
46	Tranmission	$ 6,452	Line 40 x Section 3.3.2; Page 5; Line 35	46
47	Total	$ 7,254	Sum Lines 44; 45; 46	47
48				48
49	Annual Revenues from Proposed NCD Rate 90% of Total M&L C&I NCD Rates			49
50	Secondary	$ -	Line 7 x Line 38	50
51	Primary	$ 722	Line 8 x Line 39	51
52	Tranmission	$ 5,807	Line 9 x Line 40	52
53	Total	$ 6,529	Sum Lines 50; 51; 52	53
54				54
55	Revenue Reallocation to Maximum Demand at the Time of System Peak			55
56	Secondary	$ -	Line 44 - Line 50	56
57	Primary	$ 80	Line 45 - Line 51	57
58	Tranmission	$ 645	Line 46 - Line 52	58
59	Total	$ 725	Sum Lines 56; 57; 58	59

NOTES:

[1] 90% NCD Rates are applicable to the following California Public Utilities Commission (CPUC) tariffs:
AY-TOU, AL-TOU, AL-TOU-DER, DG-R, A6-TOU

[2] 90% NCD Rates and Maximum On-Peak Period Demand charges are applicable to the following California Public Utilities Commission (CPUC) tariffs:
AY-TOU, AL-TOU, AL-TOU-DER, DG-R

[3] 90% NCD Rates and Maximum Demand at Time of System Peak charges are applicable to the following California Public Utilities Commission (CPUC) tariffs:
A6-TOU

Section 3.3.2
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TO3-Cycle 5 Annual Transmission Formulaic Rate Filing
Derivation of True-Up Period ISO Retail Rates Base on True-Up Period Cost of Service
Using TO3-CYCLE-5 True-Up Period Billing Determinants
Medium-Large Commercial Customers [1]
($000)

Line No.	Description	Derivation of Commodity Rate & Proof of Revenues Calculation	Reference	Line No.
1	Med-Lrg C&I Maximum On-Peak Period Demand Proposal			1
2	Revenue Reallocation to Maximum On-Peak Period Demands [1]	$ 12,611	Section 3.3.2; Page 5; Line 34	2
3				3
4	Summer Maximum On-Peak Period Demands By Voltage Level @ Meter Level (MW) [2]			4
5	Secondary	7,819	Section 3.3.2; Page 15; Col. B; Line 30	5
6	Primary	1,723	Section 3.3.2; Page 15; Col. B; Line 31	6
7	Tranmission	130	Section 3.3.2; Page 15; Col. B; Line 32	7
8	Total	9,671	Sum Lines 5; 6; 7	8
9				9
10	Summer Maximum On-Peak Period Demands @ Transmission Level (MW)			10
11	Secondary	8,176	Section 3.3.2; Page 15; Col. D; Line 30	11
12	Primary	1,742	Section 3.3.2; Page 15; Col. D; Line 31	12
13	Tranmission	130	Section 3.3.2; Page 15; Col. D; Line 32	13
14	Total	10,048	Sum Lines 11; 12; 13	14
15				15
16	Summer Maximum On-Peak Period Allocation to Voltage Levels			16
17	Secondary	81.37%	Line 11 / Line 14	17
18	Primary	17.34%	Line 12 / Line 14	18
19	Tranmission	1.29%	Line 13 / Line 14	19
20	Total	100.00%	Sum Lines 17; 18; 19	20
21	Share of Total Revenue Allocation to Summer Peak Period	80.00%		21
22	Revenues for Proposed Summer Maximum On-Peak Period Demand Rates	$ **10,089**	Line 2 x Line 21	22
23	Secondary	$ 8,209	(Line 2 x Line 21) x Line 17	23
24	Primary	$ 1,749	(Line 2 x Line 21) x Line 18	24
25	Tranmission	$ 131	(Line 2 x Line 21) x Line 19	25
26	Total	$ **10,089**	Sum Lines 23; 24; 25	26
27				27
28	Summer Maximum On-Peak Period Demand Rates [3]	$/kW		28
29	Secondary	$ 1.0040605	Line 23 / Line 11	29
30	Primary	$ 1.0040605	Line 24 / Line 12	30
31	Tranmission	$ 1.0040605	Line 25 / Line 13	31
32				32
33				33
34	Summer Maximum On-Peak Period Demand Rates (Rounded)	$/kW		34
35	Secondary	$ 1.0040605	Line 29, Rounded to 7 Decimal Places	35
36	Primary	$ 1.0040605	Line 30, Rounded to 7 Decimal Places	36
37	Tranmission	$ 1.0040605	Line 31, Rounded to 7 Decimal Places	37
38				38

NOTES:

[1] Revenues to be reallocated from NCD to recovery from Maximum On-Peak Period Demands for the following California Public Utilities Commission (CPUC) tariffs:
AY-TOU, AL-TOU, AL-TOU-DER, DG-R

[2] Summer Maximum On-Peak Period Determinants for the following California Public Utilities Commission (CPUC) tariffs:
AY-TOU, AL-TOU, AL-TOU-DER, DG-R

[3] Summer Maximum On-Peak Period Demand Charges for the following California Public Utilities Commission (CPUC) tariffs:
AY-TOU, AL-TOU, AL-TOU-DER, DG-R

[4] Winter Maximum On-Peak Period Determinants for the following California Public Utilities Commission (CPUC) tariffs:
AY-TOU, AL-TOU, AL-TOU-DER, DG-R

[5] Winter Maximum On-Peak Period Demand Charges for the following California Public Utilities Commission (CPUC) tariffs:
AY-TOU, AL-TOU, AL-TOU-DER, DG-R

[6] LF = Transmission Loss Factor; Secondary Level = 1.0457; Primary Level = 1.0108; Transmission Level = 1.0000

Section 3.3.2
SAN DIEGO GAS AND ELECTRIC COMPANY
TO3-Cycle 5 Annual Transmission Formulaic Rate Filing
Derivation of True-Up Period ISO Retail Rates Base on True-Up Period Cost of Service
Using TO3-CYCLE-5 True-Up Period Billing Determinants
Medium-Large Commercial Customers [1]
($000)

Line No.	Description	Derivation of Commodity Rate & Proof of Revenues Calculation	Reference	Line No.
1	Winter Maximum On-Peak Period Demands By Voltage Level @ Meter Level (MW) [4]			1
2	Secondary	9,457	Section 3.3.2; Page 15; Col. B; Line 35	2
3	Primary	2,043	Section 3.3.2; Page 15; Col. B; Line 36	3
4	Tranmission	277	Section 3.3.2; Page 15; Col. B; Line 37	4
5	Total	11,777	Sum Lines 2; 3; 4	5
6				6
7	Winter Maximum On-Peak Period Demands @ TRANSMISSION Level (MW)			7
8	Secondary	9,889	Section 3.3.2; Page 15; Col. D; Line 35	8
9	Primary	2,065	Section 3.3.2; Page 15; Col. D; Line 36	9
10	Tranmission	277	Section 3.3.2; Page 15; Col. D; Line 37	10
11	Total	12,231	Sum Lines 8; 9; 10	11
12				12
13	Winter Maximum On-Peak Period Allocation to Voltage Levels			13
14	Secondary	80.85%	Line 8 / Line 11	14
15	Primary	16.88%	Line 9 / Line 11	15
16	Tranmission	2.26%	Line 10 / Line 11	16
17	Total	100.00%	Sum Lines 14; 15; 16	17
18	Share of Total Revenue Allocation to Winter Peak Period	20.00%		18
19	Revenues for Proposed Winter Maximum On-Peak Period Demand Rates	$ 2,522	(Section 3.3.2; Page 5; Line 34) x Line 18	19
20	Secondary	$ 2,039	(Section 3.3.2; Page 5; Line 34 x Line 18) x Line 14	20
21	Primary	$ 426	(Section 3.3.2; Page 5; Line 34 x Line 18) x Line 15	21
22	Tranmission	$ 57	(Section 3.3.2; Page 5; Line 34 x Line 18) x Line 16	22
23	Total	$ 2,522	Sum Lines 20; 21; 22	23
24				24
25	Winter Maximum On-Peak Period Demand Rates [5]	$/kW		25
26	Secondary	$ 0.2062137	Line 20 / Line 8	26
27	Primary	$ 0.2062137	Line 21 / Line 9	27
28	Tranmission	$ 0.2062137	Line 22 / Line 10	28
29				29
30				30
31	Winter Maximum On-Peak Period Demand Rates (Rounded)	$/kW		31
32	Secondary	$ 0.2062137	Line 26, Rounded to 7 Decimal Places	32
33	Primary	$ 0.2062137	Line 27, Rounded to 7 Decimal Places	33
34	Tranmission	$ 0.2062137	Line 28, Rounded to 7 Decimal Places	34
35				35
36				36
37	Proof of Revenue Calculations:			37
38	Secondary	$ 10,248	(Section 3.3.2; Page 6; Line 11 x Section Page 6; Line 35) + (Line 8 x Line 32)	38
39	Primary	$ 2,175	(Section 3.3.2; Page 6; Line 12 x Section Page 6; Line 36) + (Line 9 x Line 33)	39
40	Tranmission	$ 188	(Section 3.3.2; Page 6; Line 13 x Section Page 6; Line 37) + (Line 10 x Line 34)	40
41	Total	$ 12,611	Sum Lines 38; 39; 40	41
42				42
43	Difference	$ 0	Section 3.3.2; Page 6; Line 2 Minus Page 7; Line 41	43
44				44

NOTES:

[1] Revenues to be reallocated from NCD to recovery from Maximum On-Peak Period Demands for the following California Public Utilities Commission (CPUC) tariffs:
AY-TOU, AL-TOU, AL-TOU-DER, DG-R

[2] Summer Maximum On-Peak Period Determinants for the following California Public Utilities Commission (CPUC) tariffs:
AY-TOU, AL-TOU, AL-TOU-DER, DG-R

[3] Summer Maximum On-Peak Period Demand Charges for the following California Public Utilities Commission (CPUC) tariffs:
AY-TOU, AL-TOU, AL-TOU-DER, DG-R

[4] Winter Maximum On-Peak Period Determinants for the following California Public Utilities Commission (CPUC) tariffs:
AY-TOU, AL-TOU, AL-TOU-DER, DG-R

[5] Winter Maximum On-Peak Period Demand Charges for the following California Public Utilities Commission (CPUC) tariffs:
AY-TOU, AL-TOU, AL-TOU-DER, DG-R

[6] LF = Transmission Loss Factor; Secondary Level = 1.0457; Primary Level = 1.0108; Transmission Level = 1.0000

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TO3-Cycle 5 Annual Transmission Formulaic Rate Filing
Derivation of True-Up Period ISO Retail Rates Base on True-Up Period Cost of Service
Using TO3-CYCLE-5 True-Up Period Billing Determinants
Medium-Large Commercial Customers [1]
($000)

Line No.	Description	Derivation of Commodity Rate & Proof of Revenues Calculation	Reference	Line No.
1	Med-Lrg C&I Maximum Demand at the Time of System Peak Proposal			1
2	Revenue Reallocation to Maximum Demand at the Time of System Peak [1]	$ 725	Section 3.3.2; Page 5; Line 59	2
3				3
4	Summer Maximum Demand at the Time of System Peak By Voltage Level @ **Meter** Level (MW) [2]			4
5	Secondary	-	Section 3.3.2; Page 15; Col. B; Line 42	5
6	Primary	47	Section 3.3.2; Page 15; Col. B; Line 43	6
7	Transmission	465	Section 3.3.2; Page 15; Col. B; Line 44	7
8	Total	512	Sum Lines 5; 6; and 7	8
9				9
10	Summer Maximum Demand at the Time of System Peak @ **TRANSMISSION** Level (MW)			10
11	Secondary	-	Section 3.3.2; Page 15; Col. D; Line 42	11
12	Primary	48	Section 3.3.2; Page 15; Col. D; Line 43	12
13	Tranmission	465	Section 3.3.2; Page 15; Col. D; Line 44	13
14	Total	513	Sum Lines 11; 12; and 13	14
15				15
16	Summer Maximum Demand at the time of System Peak Allocation to Voltage Levels (MW)			16
17	Secondary	0.00%	Line 11 / Line 14	17
18	Primary	9.36%	Line 12 / Line 14	18
19	Tranmission	90.64%	Line 13 / Line 14	19
20	Total	100.00%	Sum Lines 17; 18; and 19	20
21	Share of Total Revenue Allocation to Summer Maximum Demand at the Time of System Peak	80.00%		21
22	Revenues for Proposed Summer Maximum Demand at the Time of System Peak Rates	$ **580**	Line 2 x Line 21	22
23	Secondary	$ -	(Line 2 x Line 21) x Line 17	23
24	Primary	$ 54	(Line 2 x Line 21) x Line 18	24
25	Tranmission	$ 526	(Line 2 x Line 21) x Line 19	25
26	Total	$ **580**	Sum Lines 23; 24; and 25	26
27				27
28	Summer Maximum Demand at the Time of System Peak Rates [3]	$/kW		28
29	Secondary	$ -	Line 23 / Line 11	29
30	Primary	$ 1.1306043	Line 24 / Line 12	30
31	Tranmission	$ 1.1306043	Line 25 / Line 13	31
32				32
33				33
34	Summer Maximum Demand at the Time of System Peak Rates (Rounded)	$/kW		34
35	Secondary	$ -	Line 29, Rounded to 7 Decimal Places	35
36	Primary	$ 1.1306043	Line 30, Rounded to 7 Decimal Places	36
37	Tranmission	$ 1.1306043	Line 31, Rounded to 7 Decimal Places	37
38				38

NOTES:

[1] Revenues to be reallocated from NCD to recovery from Maximum Demand at the time of System Peak for the following California Public Utilities Commission (CPUC) tariffs:
A6-TOU

[2] Summer Maximum Demand at the time of System Peak Determinants for the following California Public Utilities Commission (CPUC) tariffs:
A6-TOU

[3] Summer Maximum Demand at the time of System Peak Demand Charges for the following California Public Utilities Commission (CPUC) tariffs:
A6-TOU

[4] Winter Maximum Demand at the time of System Peak Determinants for the following California Public Utilities Commission (CPUC) tariffs:
A6-TOU

[5] Winter Maximum Demand at the time of System Peak Demand Charges for the following California Public Utilities Commission (CPUC) tariffs:
A6-TOU

[6] LF = Transmission Loss Factor; Secondary Level = 1.0457; Primary Level = 1.0108; Transmission Level = 1.0000

Section 3.3.2
SAN DIEGO GAS AND ELECTRIC COMPANY
TO3-Cycle 5 Annual Transmission Formulaic Rate Filing
Derivation of True-Up Period ISO Retail Rates Base on True-Up Period Cost of Service
Using TO3-CYCLE-5 True-Up Period Billing Determinants
Medium-Large Commercial Customers [1]
($000)

Line No.	Description	Derivation of Commodity Rate & Proof of Revenues Calculation	Reference	Line No.
1	Winter Maximum Demand at the Time of System Peak By Voltage Level @ Meter Level (MW) [4]			1
2	Secondary	-	Section 3.3.2; Page 15; Col. B; Line 47	2
3	Primary	88	Section 3.3.2; Page 15; Col. B; Line 48	3
4	Tranmission	570	Section 3.3.2; Page 15; Col. B; Line 49	4
5	Total	658	Sum Lines 2; 3; 4	5
6				6
7	Winter Maximum Demand at the Time of System Peak @ Transmission Level (MW)			7
8	Secondary	-	Section 3.3.2; Page 15; Col. D; Line 47	8
9	Primary	89	Section 3.3.2; Page 15; Col. D; Line 48	9
10	Tranmission	570	Section 3.3.2; Page 15; Col. D; Line 49	10
11	Total	659	Sum Lines 8; 9; 10	11
12				12
13	Winter Maximum Demand at the Time of System Peak Allocation to Voltage Levels			13
14	Secondary	0.00%	Line 8 / Line 11	14
15	Primary	13.51%	Line 9 / Line 11	15
16	Tranmission	86.49%	Line 10 / Line 11	16
17	Total	100.00%	Sum Lines 14; 15; 16	17
18	Share of Total Revenue Allocation to Winter Maximum Demand at the Time of System Peak	20.00%		18
19	Revenues for Proposed Winter Maximum Demand at the Time of System Peak Rates	$ 145	Section 3.3.2; Page 8; Line 2	19
20	Secondary	$ -	(Section 3.3.2; Page 8; Line 2 x Line 17) x Line 14	20
21	Primary	$ 20	(Section 3.3.2; Page 8; Line 2 x Line 18) x Line 15	21
22	Tranmission	$ 125	(Section 3.3.2; Page 8; Line 2 x Line 19) x Line 16	22
23	Total	$ 145	Sum Lines 20; 21; 22	23
24				24
25	Winter Maximum Demand at the Time of System Peak Rates [5]	$/kW		25
26	Secondary	$ -	Line 20 / Line 8	26
27	Primary	$ 0.2200303	Line 21 / Line 9	27
28	Tranmission	$ 0.2200303	Line 21 / Line 10	28
29				29
30				30
31	Winter Maximum Demand at the Time of System Peak Rates (Rounded)	$/kW		31
32	Secondary	$ -	Line 26, Rounded to 7 Decimal Places	32
33	Primary	$ 0.2200303	Line 27, Rounded to 7 Decimal Places	33
34	Tranmission	$ 0.2200303	Line 28, Rounded to 7 Decimal Places	34
35				35
36				36
37	Proof of Revenue Calculations:			37
38	Secondary	$ -	Section 3.3.2; Page 8 (Line 5 x Line 35) + Page 9; (Line 8 x Line 32)	38
39	Primary	$ 74	Section 3.3.2; Page 8 (Line 6 x Line 36) + Page 9; (Line 9 x Line 33)	39
40	Tranmission	$ 651	Section 3.3.2; Page 8 (Line 7 x Line 37) + Page 9; (Line 10 x Line 34)	40
41	Total	$ 725	Sum Lines 38; 39; and 40	41
42				42
43	Difference	$ 0	Section 3.3.2; Page 8; Line 2 Minus Page 9; Line 41	43
44				44

NOTES:

[1] Revenues to be reallocated from NCD to recovery from Maximum Demand at the time of System Peak for the following California Public Utilities Commission (CPUC) tariffs:
A6-TOU

[2] Summer Maximum Demand at the time of System Peak Determinants for the following California Public Utilities Commission (CPUC) tariffs:
A6-TOU

[3] Summer Maximum Demand at the time of System Peak Demand Charges for the following California Public Utilities Commission (CPUC) tariffs:
A6-TOU

[4] Winter Maximum Demand at the time of System Peak Determinants for the following California Public Utilities Commission (CPUC) tariffs:
A6-TOU

[5] Winter Maximum Demand at the time of System Peak Demand Charges for the following California Public Utilities Commission (CPUC) tariffs:
A6-TOU

[6] LF = Transmission Loss Factor; Secondary Level = 1.0457; Primary Level = 1.0108; Transmission Level = 1.0000

Section 3.3.2

SAN DIEGO GAS AND ELECTRIC COMPANY
TO3-Cycle 5 Annual Transmission Formulaic Rate Filing
Derivation of True-Up Period ISO Retail Rates Base on True-Up Period Cost of Service
Using TO3-CYCLE-5 True-Up Period Billing Determinants
Street Lighting Customers
($000)

Line No.	Customer Classes	Derivation of Commodity Rate & Proof of Revenues Calculation	Reference	Line No.
1	Street Lighting - Allocated Transmission Revenue Requirement	$ 1,101	Section 3.3.2; Page 1; Line 7	1
2				2
3	Billing Determinants - Street Lighting Customers @ MWh [1]:	117,138	Section 3.3.2; Page 16.1; Line 15	3
4				4
5	Transmission Level Adjustment Factor	1.04570	Section 3.3.2; Page 14; Col. B; Line 10	5
6				6
7	Billing Determinants @ Transmission Level	122,491	Line 3 x Line 5	7
8				8
9	Energy Rate Per kWh @ Transmission Level	$ 0.0089884	Line 1 / Line 7	9
10				10
11	Energy Rate Per kWh - Rounded @ Transmission Level	$ 0.0089884	Line 9, Rounded to 7 Decimal Places	11
12				12
13	Proof of Revenues	$ 1,101	Line 7 x Line 11	13
14				14
15	Difference	$ (0)	Line 1 - Line 13	15

Notes:

[1] Street lighting customers include the following California Public Utilities Commission (CPUC) tariffs: DWL, OL-1, LS-1, LS-2.

Section 3.3.2

SAN DIEGO GAS AND ELECTRIC COMPANY

TO3-Cycle 5 Annual Transmission Formulaic Rate Filing

Derivation of True-Up Period ISO Retail Rates Base on True-Up Period Cost of Service

Standby Revenues Calculation

($000)

Line No.	Customer Classes	Derivation of Standby Surcharge & Proof of Revenues Calculation	Reference	Line No.
1	**Standby - Demand Revenue Requirement:**	$ 3,718	Section 3.3.2; Page 1; Line 8	1
2	*Demand Determinants @ Transmission Level Used to Allocate*			2
3	*Total Class Revenues to Voltage Level:*			3
4	Secondary [1]	152	Section 3.3.2; Page 15; Col. D; Line 54	4
5	Primary [1]	1,014	Section 3.3.2; Page 15; Col. D; Line 55	5
6	Tranmission [1]	593	Section 3.3.2; Page 15; Col. D; Line 56	6
7	Total	1,759	Sum Lines 4; 5; 6	7
8	*Allocation Factors Per Above to Allocate*			8
9	*Demand Revenue Requirements to Voltage Level:*			9
10	Secondary	8.64%	Line 4 / Line 7	10
11	Primary	57.65%	Line 5 / Line 7	11
12	Tranmission	33.71%	Line 6 / Line 7	12
13	Total	100.00%	Sum Lines 10; 11; 12	13
14				14
15	**Allocation of Revenue Requirements to Voltage Level:**			15
16	Secondary	$ 321	Line 1 x Line 10	16
17	Primary	2,143	Line 1 x Line 11	17
18	Tranmission	1,253	Line 1 x Line 12	18
19	Total	$ 3,717	Sum Lines 16; 17; 18	19
20				20
21	**Demand Determinants By Voltage Level @ Transmission:**			21
22	Secondary	152	Section 3.3.2; Page 15; Col. D; Line 54	22
23	Primary	1,014	Section 3.3.2; Page 15; Col. D; Line 55	23
24	Tranmission	593	Section 3.3.2; Page 15; Col. D; Line 56	24
25	Total	1,759	Sum Lines 22; 23; 24	25
26				26
27	**Demand Rate By Voltage Level @ Transmission:**			27
28	Secondary	$ 2.1118421	Line 16 / Line 22	28
29	Primary	$ 2.1134122	Line 17 / Line 23	29
30	Tranmission	$ 2.1129848	Line 18 / Line 24	30
31				31
32	**Demand Rate By Voltage Level @ Transmission (Rounded):**			32
33	Secondary	$ 2.1118421	Line 28 Rounded to 7 Decimal Places	33
34	Primary	$ 2.1134122	Line 29 Rounded to 7 Decimal Places	34
35	Tranmission	$ 2.1129848	Line 30 Rounded to 7 Decimal Places	35
36				36
37	**Proof of Revenue Calculations:**			37
38	Secondary	$ 321	Line 22 x Line 33	38
39	Primary	2,143	Line 23 x Line 34	39
40	Tranmission	1,253	Line 24 x Line 35	40
41	Total	$ 3,717	Sum Lines 38; 39; 40	41
42				42
43	Difference	$ 1	Line 1 - Line 41	43

Notes:

[1] LF = Transmission Loss Factor; Secondary Level = 1.0457; Primary Level = 1.0108; Transmission Level = 1.0000

Section 3.3.2

SAN DIEGO GAS AND ELECTRIC COMPANY

TO3-Cycle 5 Annual Transmission Formulaic Rate Filing

WHOLESALE - Rate Design Information

Summary of TO3-CYCLE-5 Wholesale Transmission Rates Based on TO3-CYCLE-5 Wholesale True-Up Cost of Service

Using TO3-CYCLE-5 True-Up Period Billing Determinants (April 2010 - March 2011)

Line No.	Customer Classes	Transmission Energy Rates $/kWh	Transmission Level Demand Rates $/kW-Mo	Primary Level Demand Rates $/kW-Mo	Secondary Level Demand Rates $/kW-Mo	Reference	Line No.
1	Residential	$ 0.0152477				Section 3.3.2; Page 2; Line 11	1
2							2
3	Small Commercial	$ 0.0174307				Section 3.3.2; Page 3; Line 11	3
4							4
5	Med & Lrg Commercial/Industrial						5
6	Non-Coincident Demand (100%) [1]		$ 4.9518922	$ 4.9521498	$ 4.9521344	Section 3.3.2; Page 4; Lines 33;34;35	6
7							7
8	Non-Coincident Demand (90%) [2]		$ 4.4567030	$ 4.4569348	$ 4.4569210	Section 3.3.2; Page 5; Lines 7;8;9	8
9							9
10	Maximum On-Peak Demand [3]						10
11	Summer		$ 1.0040605	$ 1.0040605	$ 1.0040605	Section 3.3.2; Page 6; Lines 35;36;37	11
12	Winter		$ 0.2062137	$ 0.2062137	$ 0.2062137	Section 3.3.2; Page 7; Lines 32;33;34	12
13							13
14	Maximum Demand at the Time of System Peak [4]						14
15	Summer		$ 1.1306043	$ 1.1306043	$ -	Section 3.3.2; Page 8; Lines 29;30;31	15
16	Winter		$ 0.2200303	$ 0.2200303	$ -	Section 3.3.2; Page 9; Lines 35;36;37	16
17							17
18	Street Lighting	$ 0.0089884				Section 3.3.2; Page 10; Line 11	18
19							19
20	Standby Rate		$ 2.1129848	$ 2.1134122	$ 2.1118421	Section 3.3.2; Page 11; Lns 33;34;35	20

NOTES:

1. Non-Coincident Demand (NCD) (100%) rates are applicable to the following California Public Utilities Commission (CPUC) tariffs: Schedules AD and PA-T-1
2. NCD (90%) rates are applicable to the following CPUC tariffs: Schedules AY-TOU, AL-TOU, AL-TOU-DER, DG-R, and A6-TOU.
3. Maximum On-Peak Demand rates are applicable to the following CPUC tariffs: Schedules AY-TOU, AL-TOU, AL-TOU-DER and DG-R
4. Maximum Demand at the Time of System Peak rates are applicable to the following CPUC tariffs: Schedule A6-TOU

Section 3.3.2

SAN DIEGO GAS AND ELECTRIC COMPANY
TO3-Cycle 5 Annual Transmission Formulaic Rate Filing
WHOLESALE - Rate Design Information
Proof of Revenue Calculation Based on TO3-CYCLE-5 Wholesale True-Up Cost of Service
($1,000)

Line No.	Customer Classes	Total Revenues Per Cost of Service Study	Total Revenues Per Rate Design	Difference	Reference	Line No.
1	Residential Customers	$ 117,376	$ 117,376	$ 0	Sect. 3.3.2; Pg. 1; Ln. 4; Pg. 2; Ln. 13	1
2						2
3	Small Commercial	36,141	36,141	(0)	Sect. 3.3.2; Pg. 1; Ln. 5; Pg. 3; Ln. 13	3
4						4
5	Med & Lrg Commercial/Industrial	139,120	139,120	-	Sect. 3.3.2; Pg. 1; Ln. 6; Pg. 4; Ln. 41	5
6						6
7	Street Lighting	1,101	1,101	(0)	Sect. 3.3.2; Pg. 1; Ln. 7; Pg. 10; Ln. 13	7
8						8
9	Standby Revenues	3,718	3,717	1	Sect. 3.3.2; Pg. 1; Ln. 8; Pg. 11; Ln. 41	9
10						10
11	Grand Total	$ 297,456	$ 297,455	$ 1	Sum Lines 1 thru 9	11

Section 3.3.2

SAN DIEGO GAS AND ELECTRIC COMPANY
TO3-Cycle 5 Annual Transmission Formulaic Rate Filing
WHOLESALE - Rate Design Information
Development of TO3-CYCLE-4 12-CP Allocation Factors and Voltage Level Allocation Factors

Line No.	Customer Class	(A) 5 Year Average Ending 12/31/2008 Of 12 CPs Kilowat @ Meter Level [1]	(B) Transmission Loss Factors	(C) = (A) x (B) 5 Year Average Ending 12/31/2008 Of 12 CPs Kilowat @ Transmission Level	(D) 12 CP Allocation Percentages @ Transmission Level	Reference	Line No.
1	5-Year Average - 12CP Allocation Factors:						1
2	Residential Customers	15,054,815	1.0457	15,742,820	39.46%	From Statement BB;	2
3	Small Commercial Customers	4,636,436	1.0457	4,848,321	12.15%	From Statement BB;	3
4	Medium-Large Commercial Customers						4
5	Secondary	13,510,244	1.0457	14,127,662	35.41%	From Statement BB;	5
6	Primary	3,295,181	1.0108	3,330,769	8.35%	From Statement BB;	6
7	Transmission	1,201,031	1.0000	1,201,031	3.01%	From Statement BB;	7
8	Total Medium-Large Commercial	18,006,456	1.0363	18,659,462	46.77%	Sum Lines 5; 6; 7	8
9							9
10	Street Lighting	139,791	1.0457	146,179	0.37%	From Statement BB;	10
11	Standby Customers						11
12	Secondary	38,310	1.0457	40,061	0.10%	From Statement BB;	12
13	Primary	293,448	1.0108	296,617	0.74%	From Statement BB;	13
14	Transmission	162,697	1.0000	162,697	0.41%	From Statement BB;	14
15	Total Standby Customers	494,455	1.0100	499,375	1.25%	Sum Lines 12; 13; 14	15
16							16
17	System Total	38,331,953	1.0408	39,896,157	100.00%	Sum Lines 2; 3; 8; 10; 15	17
18							18
19							19
20	Medium-Large Commercial Customers:	**Meter Level**		**Transmission Level**	**Ratios**		20
21	Billing Determinants - (Non-Coicident Demand)						21
22	Secondary	21,237	1.0457	22,208	79.05%		22
23	Primary	4,280	1.0108	4,326	15.40%		23
24	Transmission	1,559	1.0000	1,559	5.55%		24
25	Total	27,076	1.0376	28,093	100.00%	Sum Lines 22; 23; 24	25
26							26
27							27
28	Standby Customers:	**Meter Level**		**Transmission Level**	**Ratios**		28
29	Billing Determinants - (Contracted Standby Demand)						29
30	Secondary	145	1.0457	152	8.64%		30
31	Primary	1,003	1.0108	1,014	57.65%		31
32	Transmission	593	1.0000	593	33.71%		32
33	Total	1,741	1.0102	1,759	100.00%	Sum Lines 30; 31; 32	33

NOTES:

Section 3.3.2
SAN DIEGO GAS AND ELECTRIC COMPANY
TO3-Cycle 5 Annual Transmission Formulaic Rate Filing
WHOLESALE - Rate Design Information
Development of TO3-CYCLE-4 12-CP Allocation Factors and Voltage Level Allocation Factors

Line No.	(A) Customer Class	(B) Forecast Demand Determinants Megawatt @ Meter Level	(C) Transmission Loss Factors	(D) = (B) x (C) Forecast Demand Determinants Megawatt @ Transmission Level	(E) Ratios	Reference	Line No.
1	Forecast Demand Determinants for Medium-Large Commercial Customers:						1
2	Non-Coincident Demand Determinants Pertaining to Customers on Schedules @ 100% NCD Rate						2
3	Secondary	976	1.0457	1,021	87.94%	Section 3.3.2; Page 17.1; Line 34	3
4	Primary	139	1.0108	140	12.06%	Section 3.3.2; Page 17.1; Line 35	4
5	Transmission	-	1.0000	-	0.00%	Section 3.3.2; Page 17.1; Line 36	5
6	Total	1,115		1,161	100.00%	Sum Lines 3; 4; 5	6
7							7
8	Non-Coincident Demand Determinants Pertaining to Customers on Schedules @ 90% NCD Rate						8
9	with Maximum On-Peak Period Demand						9
10	Secondary	20,261	1.0457	21,187	83.19%	Section 3.3.2; Page 17.2; Line 60	10
11	Primary	3,981	1.0108	4,024	15.80%	Section 3.3.2; Page 17.2; Line 61	11
12	Transmission	256	1.0000	256	1.01%	Section 3.3.2; Page 17.2; Line 62	12
13	Total	24,498		25,467	100.00%	Sum Lines 10; 11; 12	13
14							14
15	Non-Coincident Demand Determinants Pertaining to Customers on Schedules @ 90% NCD Rate						15
16	with Maximum Demand at the Time of System Peak						16
17	Secondary	-	1.0457	-	0.00%	Section 3.3.2; Page 17.3; Line 96	17
18	Primary	160	1.0108	162	11.06%	Section 3.3.2; Page 17.3; Line 97	18
19	Transmission	1,303	1.0000	1,303	88.94%	Section 3.3.2; Page 17.3; Line 98	19
20	Total	1,463		1,465	100.00%	Sum Lines 17; 18; 19	20
21							21
22	Total Non-Coincident Demand Determinants Pertaining to Medium-Large Commercial Customers						22
23	Secondary	21,237	1.0457	22,208	79.05%	Sum Lines 3; 10; 17	23
24	Primary	4,280	1.0108	4,326	15.40%	Sum Lines 4; 11; 18	24
25	Transmission	1,559	1.0000	1,559	5.55%	Sum Lines 5; 12; 19	25
26	Total	27,076		28,093	100.00%	Sum Lines 23; 24; 25	26
27							27
28	Maximum On-Peak Period Demand Determinants						28
29	Summer (May, June, July, August, September)						29
30	Secondary	7,819	1.0457	8,176	81.37%	Section 3.3.2; Page 17.2; Line 70	30
31	Primary	1,723	1.0108	1,742	17.34%	Section 3.3.2; Page 17.2; Line 71	31
32	Transmission	130	1.0000	130	1.29%	Section 3.3.2; Page 17.2; Line 72	32
33	Total	9,671		10,048	100.00%	Sum Lines 30; 31; 32	33
34	Winter (October, November, December, January, February, March, April)						34
35	Secondary	9,457	1.0457	9,889	80.85%	Section 3.3.2; Page 17.2; Line 70	35
36	Primary	2,043	1.0108	2,065	16.88%	Section 3.3.2; Page 17.2; Line 71	36
37	Transmission	277	1.0000	277	2.26%	Section 3.3.2; Page 17.2; Line 72	37
38	Total	11,777		12,231	99.99%	Sum Lines 35; 36; 37	38
39							39
40	Maximum Demand at the Time of System Peak Determinants						40
41	Summer (May, June, July, August, September)						41
42	Secondary	-	1.0457	-	0.00%	Section 3.3.2; Page 17.3; Line 106	42
43	Primary	47	1.0108	48	9.36%	Section 3.3.2; Page 17.3; Line 107	43
44	Transmission	465	1.0000	465	90.64%	Section 3.3.2; Page 17.3; Line 108	44
45	Total	512		513	100.00%	Sum Lines 42; 43; 44	45
46	Winter (October, November, December, January, February, March, April)						46
47	Secondary	-	1.0457	-	0.00%	Section 3.3.2; Page 17.3; Line 106	47
48	Primary	88	1.0108	89	13.51%	Section 3.3.2; Page 17.3; Line 107	48
49	Transmission	570	1.0000	570	86.49%	Section 3.3.2; Page 17.3; Line 108	49
50	Total	658		659	100.00%	Sum Lines 47; 48; 49	50
51							51
52	Forecast Demand Determinants for Standby Customers:						52
53	Contracted Demand Determinants						53
54	Secondary	145	1.0457	152	8.64%	Section 3.3.2; Page 17.3; Line 113	54
55	Primary	1,003	1.0108	1,014	57.65%	Section 3.3.2; Page 17.3; Line 114	55
56	Transmission	593	1.0000	593	33.71%	Section 3.3.2; Page 17.3; Line 115	56
57	Total	1,741		1,759	100.00%	Sum Lines 56; 57; 58	57

Section 3.3.2
San Diego Gas & Electric
FERC Recorded Sales @ Transmission Level for the Period: April 2010 - March 2011

Line No.															Line No.
1	**System Delivery Determinants**	Cycle 3	Cycle 3	Cycle 3	Cycle 3	Cycle 3	Cycle 4	Cycle 4	Cycle 4	Cycle 4	Cycle 4	Cycle 4	Cycle 4		1
2	**Customer Class Deliveries (MWh)**	**Apr-10**	**May-10**	**Jun-10**	**Jul-10**	**Aug-10**	**Sep-10**	**Oct-10**	**Nov-10**	**Dec-10**	**Jan-11**	**Feb-11**	**Mar-11**	**Total**	2
3	Residential	560,384	517,201	550,609	593,511	590,340	686,248	639,924	589,348	671,935	724,209	628,060	609,744	7,361,513	3
4	Transmission Level Adjustment Factor	**1.04570**	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570		4
5	Residential @ Transmission Level	585,994	540,838	575,771	620,635	617,319	717,609	669,169	616,281	702,642	757,306	656,762	637,609	7,697,935	5
6															6
7	Small Commercial	157,999	137,325	162,432	177,346	163,651	189,247	177,357	162,507	164,000	171,088	159,604	160,245	1,982,802	7
8	Transmission Level Adjustment Factor	**1.04570**	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570		8
9	Small Commercial @ Transmission Level	165,220	143,601	169,856	185,450	171,130	197,896	185,463	169,933	171,494	178,907	166,898	167,568	2,073,416	9
10															10
11	Med. & Lrg. Commercial/Industrial	795,316	784,631	840,649	927,206	837,933	970,140	915,153	842,034	813,820	847,915	779,291	814,228	10,168,317	11
12	Transmission Level Adjustment Factor	**1.03627**	1.03627	1.03627	1.03627	1.03627	1.03627	1.03627	1.03627	1.03627	1.03627	1.03627	1.03627		12
13	Med. & Large Comm./Ind. @ Transmission Le	824,158	813,086	871,135	960,831	868,321	1,005,322	948,341	872,570	843,333	878,665	807,552	843,757	10,537,072	13
14															14
15	Street Lighting	12,741	6,011	9,449	9,467	9,718	8,583	10,585	9,387	12,835	6,110	9,498	12,754	117,138	15
16	Transmission Level Adjustment Factor	**1.04570**	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570		16
17	Street Lighting @ Transmission Level	13,323	6,286	9,881	9,899	10,162	8,976	11,068	9,816	13,421	6,389	9,932	13,337	122,491	17
18															18
19	Sale for Resale	2	0	4	0	2	0	6	0	2	2	4	0	20	19
20	Total System@Trans. Ex Sale for Resale	1,588,695	1,503,811	1,626,643	1,776,816	1,666,932	1,929,802	1,814,041	1,668,601	1,730,891	1,821,266	1,641,144	1,662,271	20,430,914	20
21	Total System@Meter Ex Sale for Resale	1,526,441	1,445,170	1,563,139	1,707,530	1,601,643	1,854,218	1,743,020	1,603,276	1,662,589	1,749,322	1,576,453	1,596,971	19,629,770	21
22	**Med. & Large Comm./Ind.**														22
23	**Service Voltage Determinants**														23
24															24
25	**Deliveries (MWh)**	**Apr-10**	**May-10**	**Jun-10**	**Jul-10**	**Aug-10**	**Sep-10**	**Oct-10**	**Nov-10**	**Dec-10**	**Jan-11**	**Feb-11**	**Mar-11**	**Total**	25
26	Med & Large Comm./Ind.	795,316	784,631	840,649	927,206	837,933	970,140	915,153	842,034	813,820	847,915	779,291	814,228	10,168,317	26
27															27
28	**Deliveries (%)**														28
29	% @ Secondary Service	73.09%	71.61%	75.46%	73.65%	73.80%	75.03%	72.04%	72.45%	74.95%	74.27%	73.50%	76.48%	73.87%	29
30	% @ Primary Service	18.28%	19.00%	16.22%	18.89%	19.26%	18.07%	17.95%	18.08%	16.90%	18.54%	19.27%	17.48%	18.16%	30
31	% @ Transmission Service	8.63%	9.40%	8.32%	7.45%	6.93%	6.90%	10.01%	9.47%	8.15%	7.19%	7.23%	6.04%	7.97%	31
32		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	32
33	**Deliveries (MWh)**														33
34	MWh @ Secondary Service	581,328	561,845	634,375	682,891	618,412	727,910	659,294	610,057	609,953	629,760	572,748	622,694	7,511,267	34
35	MWh @ Primary Service	145,346	149,050	136,365	175,195	161,422	175,333	164,226	152,246	137,527	157,177	150,206	142,341	1,846,434	35
36	MWh @ Transmission Service	68,643	73,736	69,909	69,120	58,099	66,897	91,633	79,731	66,340	60,978	56,336	49,193	810,616	36
37		795,316	784,631	840,649	927,206	837,933	970,140	915,153	842,034	813,820	847,915	779,291	814,228	10,168,317	37
38	**Non-Coincident Demand (%)**														38
39	% @ Secondary Service	0.2871%	0.2725%	0.2733%	0.2763%	0.2817%	0.2724%	0.2975%	0.3025%	0.2869%	0.2838%	0.2825%	0.2777%	0.2827%	39
40	% @ Primary Service	0.2347%	0.2198%	0.2236%	0.2381%	0.2250%	0.2292%	0.2380%	0.2379%	0.2404%	0.2313%	0.2277%	0.2352%	0.2318%	40
41	% @ Transmission Service	0.1789%	0.1898%	0.1708%	0.1983%	0.2070%	0.2040%	0.2024%	0.1808%	0.2001%	0.1982%	0.1878%	0.1905%	0.1923%	41

Section 3.3.2
San Diego Gas & Electric
FERC Recorded Sales @ Transmission Level for the Period: April 2010 - March 2011

Line No.															Line No.
25															25
26	**Non-Coincident Demand (MW)**														26
27	MW @ Secondary Service	1,669	1,531	1,734	1,887	1,742	1,983	1,962	1,846	1,750	1,788	1,618	1,729	21,237	27
28	Voltage Level Adjustment Factor	1.0457	1.0457	1.0457	1.0457	1.0457	1.0457	1.0457	1.0457	1.0457	1.0457	1.0457	1.0457		28
29	MW @ Secondary Service @ Trans Level	1,745	1,601	1,813	1,973	1,822	2,074	2,051	1,930	1,830	1,869	1,692	1,808	22,208	29
30															30
31	MW @ Primary Service	341	328	305	417	363	402	391	362	331	363	342	335	4,280	31
32	Voltage Level Adjustment Factor	1.0108	1.0108	1.0108	1.0108	1.0108	1.0108	1.0108	1.0108	1.0108	1.0108	1.0108	1.0108		32
33	MW @ Primary Service @ Trans Level	345	331	308	422	367	406	395	366	334	367	346	338	4,326	33
34															34
35	MW @ Transmission Service	123	140	119	137	120	136	185	144	133	121	106	94	1,559	35
36	Total Non-Coincident Demand @ Trans	2,213	2,072	2,241	2,532	2,309	2,616	2,632	2,440	2,297	2,358	2,143	2,240	28,093	36
37	Total Non-Coincident Demand @ Meter	2,133	1,999	2,158	2,441	2,226	2,521	2,538	2,352	2,213	2,272	2,066	2,158	27,076	37
38	**Schedule S: Standby Determinants**														38
39															39
40	**Contracted Standby Demand (MW)**	**Apr-10**	**May-10**	**Jun-10**	**Jul-10**	**Aug-10**	**Sep-10**	**Oct-10**	**Nov-10**	**Dec-10**	**Jan-11**	**Feb-11**	**Mar-11**	**Total**	40
41	MW @ Secondary Service	11	11	11	11	11	11	12	12	13	13	13	13	145	41
42	Voltage Level Adjustment Factor	1.0457	1.0457	1.0457	1.0457	1.0457	1.0457	1.0457	1.0457	1.0457	1.0457	1.0457	1.0457		42
43	MW @ Secondary Service @ Trans Level	12	12	12	12	12	12	13	13	14	14	14	14	152	43
44															44
45	MW @ Primary Service	85	85	85	85	84	84	80	80	84	83	83	83	1,003	45
46	Voltage Level Adjustment Factor	1.0108	1.0108	1.0108	1.0108	1.0108	1.0108	1.0108	1.0108	1.0108	1.0108	1.0108	1.0108		46
47	MW @ Primary Service @ Trans Level	86	86	86	86	85	85	81	81	85	84	84	84	1,014	47
48															48
49	MW @ Transmission Service	47	48	48	50	50	50	50	50	50	50	50	50	593	49
50	Total Contract Demand @ Trans	144	145	146	148	147	147	144	144	149	149	148	149	1,759	50
51	Total Contract Demand @ Meter	143	144	144	146	145	145	143	143	147	147	146	147	1,741	51

San Diego Gas & Electric
FERC Recorded Sales @ Transmission Level for the Period: April 2010 - March 2011

Line No.		Cycle 3	Cycle 3	Cycle 3	Cycle 3	Cycle 3	Cycle 4	Cycle 4	Cycle 4	Cycle 4	Cycle 4	Cycle 4	Cycle 4		Line No.
1	**SDG&E: System Delivery Determinants**														1
2	**Customer Class Deliveries (MWh)**	**Apr-10**	**May-10**	**Jun-10**	**Jul-10**	**Aug-10**	**Sep-10**	**Oct-10**	**Nov-10**	**Dec-10**	**Jan-11**	**Feb-11**	**Mar-11**	**Total**	2
3	Residential	560,384	517,201	550,609	593,511	590,340	686,248	639,924	589,348	671,935	724,209	628,060	609,744	7,361,513	3
4	Small Commercial	157,999	137,325	162,432	177,346	163,651	189,247	177,357	162,507	164,000	171,088	159,604	160,245	1,982,802	4
5	Med. & Large Comm./Ind. (AD + PA-T-1)	21,162	19,894	24,223	27,331	27,123	30,064	26,805	20,895	19,901	17,916	19,926	20,362	275,603	5
6	Med. & Large Comm./Ind. (AY + AL + DGR)	708,903	692,577	744,964	827,532	755,332	871,898	817,218	756,976	723,654	772,108	698,123	742,483	9,111,768	6
7	Med. & Large Comm./Ind. (A6)	65,251	72,160	71,462	72,343	55,478	68,178	71,130	64,163	70,265	57,890	61,242	51,383	780,945	7
8	Lighting	12,741	6,011	9,449	9,467	9,718	8,583	10,585	9,387	12,835	6,110	9,498	12,754	117,138	8
9	Sale for Resale	1.50	0.00	3.50	0.00	1.50	0.00	6.41	0.00	2.12	1.71	3.62	0.00	20.35	9
10	**Total System**	**1,526,442**	**1,445,170**	**1,563,143**	**1,707,530**	**1,601,644**	**1,854,218**	**1,743,026**	**1,603,276**	**1,662,591**	**1,749,324**	**1,576,456**	**1,596,971**	**19,629,791**	10
11															11
12	**Med. & Large Comm./Ind.**														12
13	**Rate Schedule Billing Determinants**														13
14															14
15	**Schedules AD / PA-T-1:**	**Apr-10**	**May-10**	**Jun-10**	**Jul-10**	**Aug-10**	**Sep-10**	**Oct-10**	**Nov-10**	**Dec-10**	**Jan-11**	**Feb-11**	**Mar-11**	**Total**	15
16	**Total Deliveries (MWh)**	21,162	19,894	24,223	27,331	27,123	30,064	26,805	20,895	19,901	17,916	19,926	20,362	275,603	16
17															17
18	**Total Deliveries (%)**														18
19	% @ Secondary Service	91.58%	93.78%	93.65%	93.60%	91.70%	91.23%	90.41%	91.34%	91.56%	87.21%	85.53%	90.30%	91.15%	19
20	% @ Primary Service	8.42%	6.22%	6.35%	6.40%	8.30%	8.77%	9.59%	8.66%	8.44%	12.79%	14.47%	9.70%	8.85%	20
21	% @ Transmission Service	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	21
22		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	22
23	**Total Deliveries (MWh)**														23
24	MWh @ Secondary Service	19,380	18,657	22,685	25,582	24,872	27,427	24,234	19,085	18,221	15,625	17,043	18,387	251,199	24
25	MWh @ Primary Service	1,782	1,237	1,538	1,749	2,251	2,637	2,571	1,809	1,680	2,292	2,883	1,975	24,404	25
26	MWh @ Transmission Service	0	0	0	0	0	0	0	0	0	0	0	0	0	26
27		21,162	19,894	24,223	27,331	27,123	30,064	26,805	20,895	19,901	17,916	19,926	20,362	275,603	27
28	**Non-Coincident Demand (%)**														28
29	% @ Secondary Service	0.4645%	0.3810%	0.3496%	0.3242%	0.3390%	0.3116%	0.3507%	0.4303%	0.4382%	0.4666%	0.4670%	0.4543%	0.3886%	29
30	% @ Primary Service	0.4508%	0.7382%	0.8706%	0.6807%	0.5423%	0.4609%	0.4693%	0.6266%	0.6114%	0.5588%	0.5323%	0.5140%	0.5688%	30
31	% @ Transmission Service	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	31
32															32
33	**Non-Coincident Demand (MW)**														33
34	MW @ Secondary Service	90.020	71.082	79.308	82.936	84.316	85.463	84.989	82.124	79.846	72.906	79.589	83.533	976.113	34
35	MW @ Primary Service	8.032	9.135	13.392	11.907	12.208	12.152	12.064	11.338	10.269	12.805	15.348	10.152	138.802	35
36	MW @ Transmission Service	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	36
37		98.052	80.217	92.699	94.843	96.525	97.615	97.053	93.463	90.115	85.711	94.937	93.686	1,114.915	37
38															38

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San Diego Gas & Electric
FERC Recorded Sales @ Transmission Level for the Period: April 2010 - March 2011

Line No.	Schedules AL-TOU / AY-TOU / DG-R:	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Total	Line No.
39															39
40															40
42	**Total Deliveries (MWh)**	708,903	692,577	744,964	827,532	755,332	871,898	817,218	756,976	723,654	772,108	698,123	742,483	9,111,768	42
43															43
44	**Total Deliveries (%)**														44
45	% @ Secondary Service	79.27%	78.43%	82.11%	79.43%	78.58%	80.34%	77.71%	78.07%	81.77%	79.54%	79.60%	81.39%	79.68%	45
46	% @ Primary Service	19.02%	20.66%	17.19%	19.92%	20.47%	18.67%	19.01%	19.23%	17.28%	19.44%	19.90%	17.48%	19.02%	46
47	% @ Transmission Service	1.71%	0.91%	0.70%	0.65%	0.95%	0.99%	3.28%	2.70%	0.95%	1.02%	0.50%	1.13%	1.30%	47
48		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	48
49	**Total Deliveries (MWh)**														49
50	MWh @ Secondary Service	561,948	543,188	611,690	657,309	593,540	700,483	635,060	590,971	591,732	614,135	555,706	604,307	7,260,068	50
51	MWh @ Primary Service	134,833	143,086	128,059	164,844	154,616	162,783	155,353	145,567	125,047	150,098	138,926	129,786	1,733,001	51
52	MWh @ Transmission Service	12,122	6,302	5,215	5,379	7,176	8,632	26,805	20,438	6,875	7,876	3,491	8,390	118,700	52
53		708,903	692,577	744,964	827,532	755,332	871,898	817,218	756,976	723,654	772,108	698,123	742,483	9,111,768	53
54	**Non-Coincident Demand (%)**														54
55	% @ Secondary Service	0.2810%	0.2688%	0.2705%	0.2744%	0.2793%	0.2709%	0.2955%	0.2984%	0.2822%	0.2792%	0.2768%	0.2723%	0.2791%	55
56	% @ Primary Service	0.2376%	0.2190%	0.2213%	0.2386%	0.2236%	0.2289%	0.2400%	0.2369%	0.2403%	0.2205%	0.2216%	0.2273%	0.2297%	56
57	% @ Transmission Service	0.1981%	0.2219%	0.2323%	0.2659%	0.2727%	0.2418%	0.2261%	0.1460%	0.2803%	0.2419%	0.3092%	0.1336%	0.2154%	57
58															58
59	**Non-Coincident Demand (MW)**														59
60	MW @ Secondary Service	1,579.073	1,460.090	1,654.621	1,803.656	1,657.757	1,897.608	1,876.603	1,763.458	1,669.866	1,714.665	1,538.193	1,645.528	20,261.118	60
61	MW @ Primary Service	320.364	313.359	283.395	393.319	345.722	372.611	372.848	344.847	300.489	330.966	307.861	295.004	3,980.785	61
62	MW @ Transmission Service	24.014	13.985	12.114	14.303	19.568	20.872	60.606	29.840	19.270	19.051	10.793	11.209	255.624	62
63		1,923.452	1,787.434	1,950.130	2,211.277	2,023.047	2,291.090	2,310.056	2,138.145	1,989.625	2,064.681	1,856.847	1,951.741	24,497.526	63
64	**On-Peak Demand (%)**														64
65	% @ Secondary Service	0.2265%	0.2275%	0.2503%	0.2580%	0.2621%	0.2570%	0.2522%	0.2346%	0.2213%	0.2198%	0.2191%	0.2183%	0.2380%	65
66	% @ Primary Service	0.1996%	0.2075%	0.2313%	0.2366%	0.2323%	0.2339%	0.2293%	0.2085%	0.2107%	0.1977%	0.2061%	0.2063%	0.2173%	66
67	% @ Transmission Service	0.3645%	0.4230%	0.5473%	0.4202%	0.3757%	0.2874%	0.2268%	0.2739%	0.6176%	0.3522%	0.3647%	0.3891%	0.3421%	67
68															68
69	**On-Peak Demand (MW)**	W	S	S	S	S	S	W	W	W	W	W	W	Total	69
70	MW @ Secondary Service	1,272.812	1,235.753	1,531.060	1,695.857	1,555.668	1,800.241	1,601.622	1,386.419	1,309.502	1,349.869	1,217.551	1,319.202	17,275.554	70
71	MW @ Primary Service	269.128	296.904	296.201	390.022	359.174	380.750	356.225	303.506	263.475	296.743	286.327	267.749	3,766.204	71
72	MW @ Transmission Service	44.186	26.659	28.540	22.602	26.959	24.808	60.793	55.981	42.458	27.738	12.730	32.646	406.100	72
73		1,586.125	1,559.317	1,855.801	2,108.481	1,941.801	2,205.799	2,018.640	1,745.906	1,615.435	1,674.350	1,516.609	1,619.596	21,447.858	73
74															74

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San Diego Gas & Electric
FERC Recorded Sales @ Transmission Level for the Period: April 2010 - March 2011

Line No.		Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Total	Line No.
75															75
76															76
77	**Schedule A6-TOU:**	**Apr-10**	**May-10**	**Jun-10**	**Jul-10**	**Aug-10**	**Sep-10**	**Oct-10**	**Nov-10**	**Dec-10**	**Jan-11**	**Feb-11**	**Mar-11**	**Total**	77
78	**Total Deliveries (MWh)**	65,251	72,160	71,462	72,343	55,478	68,178	71,130	64,163	70,265	57,890	61,242	51,383	780,945	78
79															79
80	**Total Deliveries (%)**														80
81	% @ Secondary Service	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	81
82	% @ Primary Service	13.38%	6.55%	9.47%	11.89%	8.21%	14.54%	8.86%	7.59%	15.37%	8.27%	13.71%	20.59%	11.40%	82
83	% @ Transmission Service	86.62%	93.45%	90.53%	88.11%	91.79%	85.46%	91.14%	92.41%	84.63%	91.73%	86.29%	79.41%	88.60%	83
84		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	84
85	**Total Deliveries (MWh)**														85
86	MWh @ Secondary Service	0	0	0	0	0	0	0	0	0	0	0	0	0	86
87	MWh @ Primary Service	8,731	4,726	6,767	8,602	4,555	9,913	6,302	4,870	10,800	4,788	8,396	10,580	89,029	87
88	MWh @ Transmission Service	56,521	67,434	64,694	63,741	50,923	58,265	64,828	59,293	59,465	53,103	52,846	40,803	691,916	88
89		65,251	72,160	71,462	72,343	55,478	68,178	71,130	64,163	70,265	57,890	61,242	51,383	780,945	89
90	**Non-Coincident Demand (%)**														90
91	% @ Secondary Service	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	91
92	% @ Primary Service	0.1456%	0.1068%	0.1203%	0.1390%	0.1158%	0.1729%	0.0952%	0.1239%	0.1838%	0.4118%	0.2249%	0.2801%	0.1802%	92
93	% @ Transmission Service	0.1748%	0.1868%	0.1658%	0.1926%	0.1977%	0.1984%	0.1926%	0.1928%	0.1908%	0.1917%	0.1798%	0.2022%	0.1883%	93
94															94
95	**Non-Coincident Demand (MW)**														95
96	MW @ Secondary Service	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	96
97	MW @ Primary Service	12.712	5.048	8.141	11.956	5.274	17.140	6.000	6.034	19.850	19.715	18.883	29.634	160.387	97
98	MW @ Transmission Service	98.798	125.966	107.263	122.766	100.676	115.598	124.859	114.316	113.460	101.798	95.017	82.504	1,303.020	98
99		111.510	131.014	115.404	134.722	105.950	132.738	130.859	120.350	133.310	121.513	113.900	112.138	1,463.407	99
100	**Coincident Peak Demand (%)**														100
101	% @ Secondary Service	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	101
102	% @ Primary Service	0.1613%	0.1705%	0.1914%	0.1550%	0.0572%	0.1054%	0.1824%	0.1712%	0.1941%	0.1286%	0.1544%	0.1324%	0.1521%	102
103	% @ Transmission Service	0.1171%	0.1495%	0.1398%	0.1564%	0.1398%	0.1767%	0.1630%	0.1914%	0.1144%	0.1520%	0.1407%	0.1502%	0.1496%	103
104															104
105	**Coincident Peak Demand (MW)**														105
106	MW @ Secondary Service	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	106
107	MW @ Primary Service	14.082	8.059	12.953	13.332	2.605	10.448	11.495	8.337	20.962	6.157	12.964	14.008	135.403	107
108	MW @ Transmission Service	66.186	100.813	90.443	99.691	71.191	102.954	105.670	113.486	68.028	80.716	74.354	61.286	1,034.819	108
109		80.268	108.872	103.395	113.024	73.796	113.403	117.165	121.824	88.991	86.873	87.318	75.294	1,170.222	109
110															110
111	**Schedule S: Standby Determinants:**	**Apr-10**	**May-10**	**Jun-10**	**Jul-10**	**Aug-10**	**Sep-10**	**Oct-10**	**Nov-10**	**Dec-10**	**Jan-11**	**Feb-11**	**Mar-11**	**Total**	111
112	**Contracted Standby Demand (MW)**														112
113	MW @ Secondary Service	11.224	11.224	11.226	11.124	11.124	11.123	12.075	12.075	13.498	13.498	13.408	13.408	145.007	113
114	MW @ Primary Service	84.822	85.002	85.316	85.022	84.287	84.287	80.481	80.481	83.769	83.386	82.725	83.399	1,002.977	114
115	MW @ Transmission Service	46.948	47.715	47.692	49.986	49.986	49.986	50.003	50.003	50.156	50.272	50.272	50.275	593.294	115
116		142.994	143.941	144.234	146.132	145.397	145.396	142.559	142.559	147.423	147.156	146.405	147.082	1,741.278	116
117															117

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<u>Section – 3.3</u>
Derivation of Monthly ISO True-Up Period Cost of Service (COS) Revenues (True-Up Revenues)

<u>Section 3.3.3</u>
Derivation of ISO Monthly Cost of Service (COS) Revenues Applicable to the 12-Month True-Up Period (Monthly True-Up Revenues)

Docket No. ER11-____-____

Section 3.3.3
SAN DIEGO GAS AND ELECTRIC COMPANY
TO3-Cycle 5 Annual Transmission Formulaic Rate Filing
SUMMARY of Derived Revenues at Present Rates from the WHOLESALE Rates Developed in TO3-Cycle 5
For the True-Up Period April 2010 through March 2011

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	
Line No.	Customer Class	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Total	Reference	Line No.
1	Residential Customers	$ 8,935,054	$ 8,246,529	$ 8,779,190	$ 9,463,252	$ 9,412,691	$ 10,941,891	$ 10,203,288	$ 9,396,870	$ 10,713,680	$ 11,547,168	$ 10,014,113	$ 9,722,072	$ 117,375,797	Section 3.3.3; Pages 19 & 20; Line 21	1
2																2
3	Small Commercial	2,879,900	2,503,070	2,960,702	3,232,531	2,982,909	3,449,459	3,232,743	2,962,056	2,989,266	3,118,472	2,909,148	2,920,835	36,141,091	Section 3.3.3; Pages 19 & 20; Line 23	3
4																4
5	Med-Lrg C&I @ 100% NCD	506,368	413,821	477,724	489,082	497,738	503,396	500,501	482,032	464,883	441,636	488,972	483,392	5,749,545	Section 3.3.3; Page 21; Line 21	5
6	Med-Lrg C&I @ 90% NCD	9,407,299	8,863,064	9,556,951	10,842,786	9,843,301	11,208,054	11,279,394	10,441,984	9,817,269	10,109,798	9,112,475	9,549,318	120,031,693	Section 3.3.3; Page 22; Line 33	6
7	Max On Peak Demand	339,675	1,625,571	1,936,802	2,199,087	2,024,962	2,301,489	432,158	373,771	346,052	358,656	324,857	347,012	12,610,092	Section 3.3.3; Page 23; Line 21	7
8	Max Dem-Time of System Peak	17,695	123,190	117,058	127,947	83,466	128,342	25,808	26,824	19,630	19,129	19,243	16,600	724,932	Section 3.3.3; Page 24; Line 21	8
9	Total Med-Lrg C&I	10,271,037	11,025,646	12,088,535	13,658,902	12,449,467	14,141,281	12,237,861	11,324,611	10,647,834	10,929,219	9,945,547	10,396,322	139,116,262	Sum Lines 5, 6, 7, 8	9
10																10
11	Street Lighting	119,753	56,503	88,813	88,977	91,345	80,675	99,487	88,234	120,634	57,428	89,275	119,877	1,101,001	Section 3.3.3; Pages 19 & 20; Line 27	11
12																12
13	Standby Revenues	305,187	307,192	307,818	311,813	310,243	310,241	304,248	304,248	314,737	314,164	312,554	314,000	3,716,445	Section 3.3.3; Page 25; Line 21	13
14																14
15	TOTAL Recorded [1]	$ 22,510,932	$ 22,138,941	$ 24,225,058	$ 26,755,475	$ 25,246,654	$ 28,923,547	$ 26,077,627	$ 24,076,019	$ 24,786,151	$ 25,966,451	$ 23,270,638	$ 23,473,105	$ 297,450,597	Sum Lines 1, 3, 9, 11, 13	15

NOTES:

1 For the recorded revenues by customer class from April 2010 - March 2011, the transmission rates were based on the wholesale transmission revenue requirements derived from Statement BK2 of the current cycle filing.
The total True-Up Period Cost of Service from Section 3.3.1; Page 1 of 3; Line 34 is $297,455,000. The total shown in Column M, Line 15 is $297,450,597. The difference of $4,403 is due to rounding.

Section 3.3.3

SAN DIEGO GAS AND ELECTRIC COMPANY
TO3-Cycle 5 Annual Transmission Formulaic Rate Filing
SUMMARY of Derived Revenues at Present Rates from the WHOLESALE Rates Developed in TO3-Cycle 5
For the True-Up Period April 2010 through March 2011

Line No.	Customer Classes	(A) Apr-10 Billing Determinants Energy (kWh)	(A) Apr-10 Billing Determinants Demand (kW)	(B) May-10 Billing Determinants Energy (kWh)	(B) May-10 Billing Determinants Demand (kW)	(C) Jun-10 Billing Determinants Energy (kWh)	(C) Jun-10 Billing Determinants Demand (kW)	(D) Jul-10 Billing Determinants Energy (kWh)	(D) Jul-10 Billing Determinants Demand (kW)	(E) Aug-10 Billing Determinants Energy (kWh)	(E) Aug-10 Billing Determinants Demand (kW)	(F) Sep-10 Billing Determinants Energy (kWh)	(F) Sep-10 Billing Determinants Demand (kW)	(F) Sub-Total Billing Determinants Energy (kWh)	(F) Sub-Total Billing Determinants Demand (kW)	Line No.
1	Residential Customers	585,993,579	-	540,837,597	-	575,771,398	-	620,634,704	-	617,318,718	-	717,609,257	-	3,658,165,252	-	1
2																2
3	Small Commercial	165,219,991	-	143,601,259	-	169,855,612	-	185,450,446	-	171,129,618	-	197,895,590	-	1,033,152,516	-	3
4																4
5	Medium-Large Commercial	824,359,987	2,212,975	813,284,778	2,072,177	871,348,310	2,240,768	961,066,131	2,531,564	868,533,488	2,309,057	1,005,322,068	2,616,410	5,343,914,762	13,982,951	5
6																6
7	Street Lighting	13,323,085	-	6,286,193	-	9,880,836	-	9,899,133	-	10,162,500	-	8,975,509	-	58,527,257	-	7
8																8
9	Standby Customers	-	144,423	-	145,372	-	145,668	-	147,559	-	146,816	-	146,815	-	876,652	9
10																10
11	TOTAL	1,588,896,642	2,357,398	1,504,009,827	2,217,549	1,626,856,156	2,386,436	1,777,050,414	2,679,123	1,667,144,323	2,455,873	1,929,802,424	2,616,410	10,093,759,787	14,859,603	11

Note: The above billing determinants are recorded determinants from April 2010 through March 2011. Recorded sales were converted from retail to transmission level.

Line No.	Customer Classes	(A) Apr-10 Derived Wholesale Transmission Rates Energy (kWh)	(A) Apr-10 Derived Wholesale Transmission Rates Demand (kW)	(B) May-10 Derived Wholesale Transmission Rates Energy (kWh)	(B) May-10 Derived Wholesale Transmission Rates Demand (kW)	(C) Jun-10 Derived Wholesale Transmission Rates Energy (kWh)	(C) Jun-10 Derived Wholesale Transmission Rates Demand (kW)	(D) Jul-10 Derived Wholesale Transmission Rates Energy (kWh)	(D) Jul-10 Derived Wholesale Transmission Rates Demand (kW)	(E) Aug-10 Derived Wholesale Transmission Rates Energy (kWh)	(E) Aug-10 Derived Wholesale Transmission Rates Demand (kW)	(F) Sep-10 Derived Wholesale Transmission Rates Energy (kWh)	(F) Sep-10 Derived Wholesale Transmission Rates Demand (kW)	(F) Sub-Total Derived Wholesale Transmission Rates Energy (kWh)	(F) Sub-Total Derived Wholesale Transmission Rates Demand (kW)	Line No.
12	Residential Customers	$ 0.0152477		$ 0.0152477		$ 0.0152477		$ 0.0152477		$ 0.0152477		$ 0.0152477				12
13																13
14	Small Commercial	$ 0.0174307		$ 0.0174307		$ 0.0174307		$ 0.0174307		$ 0.0174307		$ 0.0174307				14
15																15
16	Medium-Large Commercial															16
17																17
18	Street Lighting	$ 0.0089884		$ 0.0089884		$ 0.0089884		$ 0.0089884		$ 0.0089884		$ 0.0089884				18
19																19
20	Standby Customers															20

Note: The wholesle transmission rates for the true-up period comes from Section 3.3.2, Page 12.
See Section 3.3.2, Page 12 for the Summary of Transmission Rates.

Line No.	Customer Classes	(A) Apr-10 Revenues @ Present Rates Energy (kWh)	(A) Apr-10 Revenues @ Present Rates Demand (kW)	(B) May-10 Revenues @ Present Rates Energy (kWh)	(B) May-10 Revenues @ Present Rates Demand (kW)	(C) Jun-10 Revenues @ Present Rates Energy (kWh)	(C) Jun-10 Revenues @ Present Rates Demand (kW)	(D) Jul-10 Revenues @ Present Rates Energy (kWh)	(D) Jul-10 Revenues @ Present Rates Demand (kW)	(E) Aug-10 Revenues @ Present Rates Energy (kWh)	(E) Aug-10 Revenues @ Present Rates Demand (kW)	(F) Sep-10 Revenues @ Present Rates Energy (kWh)	(F) Sep-10 Revenues @ Present Rates Demand (kW)	(F) Sub-Total Revenues @ Changed Rates Energy (kWh)	(F) Sub-Total Revenues @ Changed Rates Demand (kW)	Line No.
21	Residential Customers	$ 8,935,054		$ 8,246,529		$ 8,779,190		$ 9,463,252		$ 9,412,691		$ 10,941,891		$ 55,778,606	$ -	21
22																22
23	Small Commercial	$ 2,879,900		$ 2,503,070		$ 2,960,702		$ 3,232,531		$ 2,982,909		$ 3,449,459		$ 18,008,572	$ -	23
24																24
25	Medium-Large Commercial	$ -	$10,271,037	$ -	$11,025,646	$ -	$12,088,535	$ -	$13,658,902	$ -	$12,449,467	$ -	$14,141,281	$ -	$ 73,634,868	25
26																26
27	Street Lighting	$ 119,753		$ 56,503		$ 88,813		$ 88,977		$ 91,345		$ 80,675		$ 526,066	$ -	27
28																28
29	Standby Customers		$ 305,187		$ 307,192		$ 307,818		$ 311,813		$ 310,243		$ 310,241	$ -	$ 1,852,494	29
30																30
31	TOTAL	$ 11,934,708	$10,576,224	$ 10,806,103	$11,332,838	$ 11,828,705	$12,396,353	$ 12,784,760	$13,970,715	$ 12,486,944	$12,759,710	$ 14,472,025	$14,451,522	$ 74,313,244	$ 75,487,362	31
32																32
33	Grand Total		$22,510,932		$22,138,941		$24,225,058		$26,755,475		$25,246,654		$28,923,547		$149,800,606	33

Note: The above revenues were derived by multiplying the above rates and billing determinants except Medium & Large C-I and Standby Customers where these revenues are derived on pages 21 through 24.

Section 3.3.3

SAN DIEGO GAS AND ELECTRIC COMPANY
TO3-Cycle 5 Annual Transmission Formulaic Rate Filing
SUMMARY of Derived Revenues at Present Rates from the WHOLESALE Rates Developed in TO3-Cycle 5
For the True-Up Period April 2010 through March 2011

		(H)		(I)		(J)		(K)		(L)		(M)		(N)		(O)		
		Oct-10		Nov-10		Dec-10		Jan-11		Feb-11		Mar-11		Sub-Total		Grand Total		
		Billing Determinants		Billing Determinants		Billing Determinants		Billing Determinants		Billing Determinants		Billing Determinants		Billing Determinants		Billing Determinants		
Line No.	Customer Classes	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Line No.
1	Residential Customers	669,169,003	-	616,281,152	-	702,642,334	-	757,305,553	-	656,762,211	-	637,609,078	-	4,039,769,330	-	7,697,934,583	-	1
2																		2
3	Small Commercial	185,462,587	-	169,933,296	-	171,494,306	-	178,906,863	-	166,897,972	-	167,568,411	-	1,040,263,437	-	2,073,415,953	-	3
4																		4
5	Medium-Large Commercial	948,341,453	2,631,835	872,570,224	2,440,214	843,333,041	2,296,583	878,664,646	2,357,523	807,551,603	2,143,311	843,756,551	2,240,198	5,194,217,518	14,109,663	10,538,132,280	28,092,614	5
6																		6
7	Street Lighting	11,068,413	-	9,816,383	-	13,421,130	-	6,389,127	-	9,932,236	-	13,336,818	-	63,964,107	-	122,491,364	-	7
8																		8
9	Standby Customers	-	143,980	-	143,980	-	148,945	-	148,673	-	147,911	-	148,595	-	882,085	-	1,758,737	9
10																		10
11	TOTAL	1,814,041,457	2,775,815	1,668,601,055	2,584,194	1,730,890,811	2,445,527	1,821,266,189	2,506,196	1,641,144,023	2,291,222	1,662,270,858	2,388,794	10,338,214,393	14,991,747	20,431,974,180	29,851,351	11

Note: The above billing determinants are recorded determinants from September 2010 through March 2011. Recorded sales were converted from retail to transmission level.

		(H)		(I)		(J)		(K)		(L)		(M)		(N)		(O)		
		Oct-10		Nov-10		Dec-10		Jan-11		Feb-11		Mar-11		Sub-Total		Grand-Total		
		Transmission Rates @ Present		Transmission Rates @ Present		Transmission Rates @ Present		Transmission Rates @ Present		Transmission Rates @ Present		Transmission Rates @ Present		Transmission Rates @ Present		Changed Transmission Rates		
Line No.	Customer Classes	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Line No.
12	Residential Customers	$ 0.0152477		$ 0.0152477		$ 0.0152477		$ 0.0152477		$ 0.0152477		$ 0.0152477						12
13																		13
14	Small Commercial	$ 0.0174307		$ 0.0174307		$ 0.0174307		$ 0.0174307		$ 0.0174307		$ 0.0174307						14
15																		15
16	Medium-Large Commercial																	16
17																		17
18	Street Lighting	$ 0.0089884		$ 0.0089884		$ 0.0089884		$ 0.0089884		$ 0.0089884		$ 0.0089884						18
19																		19
20	Standby Customers																	20

Note: The wholesle transmission rates for the true-up period comes from Section 3.3.2, Page 12.
See Section 3.3.2, Page 12 for the Summary of Transmission Rates.

		(H)		(I)		(J)		(K)		(L)		(M)		(N)		(O)		
		Oct-10		Nov-10		Dec-10		Jan-11		Feb-11		Mar-11		Sub-Total		Grand-Total		
		Revenues @ Present Rates		Revenues @ Present Rates		Revenues @ Present Rates		Revenues @ Present Rates		Revenues @ Present Rates		Revenues @ Present Rates		Revenues @ Changed Rates		Revenues @ Changed Rates		
Line No.	Customer Classes	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Line No.
21	Residential Customers	$ 10,203,288		$ 9,396,870		$ 10,713,680		$ 11,547,168		$ 10,014,113		$ 9,722,072		$ 61,597,191	$ -	$ 117,375,797	$ -	21
22																		22
23	Small Commercial	$ 3,232,743		$ 2,962,056		$ 2,989,266		$ 3,118,472		$ 2,909,148		$ 2,920,835		$ 18,132,520	$ -	$ 36,141,091	$ -	23
24																		24
25	Medium-Large Commercial	$ -	$12,237,861	$ -	$11,324,611	$ -	$10,647,834	$ -	$10,929,219	$ -	$ 9,945,547	$ -	$10,396,322	$ -	$65,481,394	$ -	$ 139,116,262	25
26																		26
27	Street Lighting	$ 99,487		$ 88,234		$ 120,634		$ 57,428		$ 89,275		$ 119,877		$ 574,935	$ -	$ 1,101,001	$ -	27
28																		28
29	Standby Customers		$ 304,248		$ 304,248		$ 314,737		$ 314,164		$ 312,554		$ 314,000	$ -	$ 1,863,951	$ -	$ 3,716,445	29
30																		30
31	TOTAL	$ 13,535,518	$12,542,109	$ 12,447,160	$11,628,859	$ 13,823,580	$10,962,571	$ 14,723,068	$11,243,383	$ 13,012,537	$10,258,101	$ 12,762,783	$10,710,322	$ 80,304,646	$67,345,345	$ 154,617,890	$ 142,832,707	31
32																		32
33	Grand Total		$26,077,627		$24,076,019		$24,786,151		$25,966,451		$23,270,638		$23,473,105		$147,649,991		$ 297,450,597	33

Note: The above revenues were derived by multiplying the above rates and billing determinants except Medium & Large C-I and Standby Customers where these revenues are derived on pages 21 through 24.

Section 3.3.3

SAN DIEGO GAS AND ELECTRIC COMPANY

TO3-Cycle 5 Annual Transmission Formulaic Rate Filing

SUMMARY of Derived Revenues at Present Rates from the WHOLESALE Rates Developed in TO3-Cycle 5

Proof of Revenues - Medium & Large C&I Customers

Non-Coincident Demand @ 100%

Line No.	Description	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Total	Reference	Line No.
1	Non-Coincident Demand (KW): Applied to 100%:															1
2	Secondary	94,133	74,331	82,932	86,726	88,169	89,369	88,874	85,878	83,495	76,238	83,226	87,351	1,020,722	Section 3.3.3; Page 26.2; Ln. 54	2
3	Primary	8,119	9,233	13,536	12,035	12,340	12,283	12,194	11,461	10,380	12,943	15,513	10,262	140,301	Section 3.3.3; Page 26.2; Ln. 58	3
4	Transmission	-	-	-	-	-	-	-	-	-	-	-	-	-	Section 3.3.3; Page 26.2; Ln. 60	4
5	Total	102,253	83,564	96,468	98,762	100,510	101,652	101,068	97,338	93,875	89,181	98,739	97,613	1,161,023	Sum Lines 2; 3; 4	5
9																9
10	Non-Coindent Demand Rates Per ($/KW) @ 100%: [1]															10
11	Secondary	$ 4.9521344	$ 4.9521344	$ 4.9521344	$ 4.9521344	$ 4.9521344	$ 4.9521344	$ 4.9521344	$ 4.9521344	$ 4.9521344	$ 4.9521344	$ 4.9521344	$ 4.9521344		Section 3.3.2; Page 12; Line 6	11
12	Primary	$ 4.9521498	$ 4.9521498	$ 4.9521498	$ 4.9521498	$ 4.9521498	$ 4.9521498	$ 4.9521498	$ 4.9521498	$ 4.9521498	$ 4.9521498	$ 4.9521498	$ 4.9521498		Section 3.3.2; Page 12; Line 6	12
13	Transmission	$ 4.9518922	$ 4.9518922	$ 4.9518922	$ 4.9518922	$ 4.9518922	$ 4.9518922	$ 4.9518922	$ 4.9518922	$ 4.9518922	$ 4.9518922	$ 4.9518922	$ 4.9518922		Section 3.3.2; Page 12; Line 6	13
14																14
15	Revenues @ Calculated Rates:															15
16	Secondary	$ 466,161	$ 368,096	$ 410,691	$ 429,481	$ 436,627	$ 442,567	$ 440,114	$ 425,277	$ 413,478	$ 377,539	$ 412,147	$ 432,573	$ 5,054,751	Line 2 x Line 11	16
17	Primary	40,207	45,725	67,033	59,601	61,111	60,829	60,387	56,755	51,405	64,097	76,825	50,819	694,794	Line 3 x Line 12	17
18	Transmission	-	-	-	-	-	-	-	-	-	-	-	-	-	Line 4 x Line 13	18
19	Total	$ 506,368	$ 413,821	$ 477,724	$ 489,082	$ 497,738	$ 503,396	$ 500,501	$ 482,032	$ 464,883	$ 441,636	$ 488,972	$ 483,392	$ 5,749,545	Sum Lines 16; 17; 18	19
20																20
21	Total Revenues @ Calculated Rates:	$ 506,368	$ 413,821	$ 477,724	$ 489,082	$ 497,738	$ 503,396	$ 500,501	$ 482,032	$ 464,883	$ 441,636	$ 488,972	$ 483,392	$ 5,749,545	Line 19	21

[1] Non-Coincident Demand (NCD) Rates are applicable to the following California Public Utilities Commission (CPUC) tariffs: AD, PA-T-1.

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Section 3.3.3

SAN DIEGO GAS AND ELECTRIC COMPANY

TO3-Cycle 5 Annual Transmission Formulaic Rate Filing

SUMMARY of Derived Revenues at Present Rates from the WHOLESALE Rates Developed in TO3-Cycle 5

Proof of Revenues - Medium & Large C&I Customers

Non-Coincident Demand @ 90%

Line No.	Description	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Total	Reference	Line No.
1	Non-Coincident Demand (KW): Applied to 90%:															1
2																2
3	Schedules AL-TOU / AY-TOU / DG-R	1,651,237	1,526,816	1,730,237	1,886,083	1,733,516	1,984,328	1,962,364	1,844,048	1,746,179	1,793,025	1,608,489	1,720,729	21,187,051	Section 3.3.3; Page 26.2; Ln. 87	3
4	Schedule A6-TOU	-	-	-	-	-	-	-	-	-	-	-	-	-	Section 3.3.3; Page 26.3; Ln. 137	4
5	Total - Secondary	1,651,237	1,526,816	1,730,237	1,886,083	1,733,516	1,984,328	1,962,364	1,844,048	1,746,179	1,793,025	1,608,489	1,720,729	21,187,051	Sum Lines 3 and 4	5
6	Check Figure	1,651,237	1,526,816	1,730,237	1,886,083	1,733,516	1,984,328	1,962,364	1,844,048	1,746,179	1,793,025	1,608,489	1,720,729	21,187,051	Check Figure	6
7																7
8	Schedules AL-TOU / AY-TOU / DG-R:	323,824	316,743	286,456	397,567	349,456	376,635	376,874	348,571	303,734	334,540	311,186	298,190	4,023,777	Section 3.3.3; Page 26.3; Ln. 91	8
9	Schedule A6-TOU	12,849	5,102	8,229	12,085	5,331	17,325	6,064	6,099	20,064	19,928	19,087	29,954	162,119	Section 3.3.3; Page 26.4; Ln. 141	9
10	Total - Primary	336,673	321,846	294,685	409,652	354,787	393,960	382,939	354,670	323,798	354,468	330,273	328,144	4,185,895	Sum Lines 8 and 9	10
11	Check Figure	336,673	321,846	294,685	409,652	354,787	393,960	382,939	354,670	323,798	354,468	330,273	328,144	4,185,895	Check Figure	11
12																12
13	Schedules AL-TOU / AY-TOU / DG-R:	24,014	13,985	12,114	14,303	19,568	20,872	60,606	29,840	19,270	19,051	10,793	11,209	255,624	Section 3.3.3; Page 26.3; Ln. 93	13
14	Schedule A6-TOU	98,798	125,966	107,263	122,766	100,676	115,598	124,859	114,316	113,460	101,798	95,017	82,504	1,303,020	Section 3.3.3; Page 26.4; Ln. 143	14
15	Total - Transmission	122,812	139,951	119,377	137,068	120,244	136,470	185,465	144,156	132,730	120,849	105,810	93,713	1,558,644	Sum Lines 13 and 14	15
16	Check Figure	122,812	139,951	119,377	137,068	120,244	136,470	185,465	144,156	132,730	120,849	105,810	93,713	1,558,644	Check Figure	16
17	Total	2,110,722	1,988,613	2,144,299	2,432,803	2,208,548	2,514,758	2,530,767	2,342,875	2,202,708	2,268,342	2,044,571	2,142,585	26,931,591	Sum Lines 6; 11; 16	17
18																18
19	Non-Coindent Demand Rates Per ($/KW) @ 90%:															19
20	Secondary	$ 4.4569210	$ 4.4569210	$ 4.4569210	$ 4.4569210	$ 4.4569210	$ 4.4569210	$ 4.4569210	$ 4.4569210	$ 4.4569210	$ 4.4569210	$ 4.4569210	$ 4.4569210		Section 3.3.2; Page 12; Line 8	20
21	Primary	$ 4.4569348	$ 4.4569348	$ 4.4569348	$ 4.4569348	$ 4.4569348	$ 4.4569348	$ 4.4569348	$ 4.4569348	$ 4.4569348	$ 4.4569348	$ 4.4569348	$ 4.4569348		Section 3.3.2; Page 12; Line 8	21
22	Transmission	$ 4.4567030	$ 4.4567030	$ 4.4567030	$ 4.4567030	$ 4.4567030	$ 4.4567030	$ 4.4567030	$ 4.4567030	$ 4.4567030	$ 4.4567030	$ 4.4567030	$ 4.4567030		Section 3.3.2; Page 12; Line 8	22
23																23
24	Revenues @ Calculated Rates:															24
25	Secondary	$ 7,359,432	$ 6,804,897	$ 7,711,532	$ 8,406,122	$ 7,726,145	$ 8,843,995	$ 8,746,100	$ 8,218,778	$ 7,782,584	$ 7,991,371	$ 7,168,908	$ 7,669,151	$ 94,429,015	Line 5 x Line 20	25
26	Primary	1,500,530	1,434,446	1,313,392	1,825,792	1,581,265	1,755,855	1,706,733	1,580,743	1,443,148	1,579,841	1,472,005	1,462,515	18,656,265	Line 10 x Line 21	26
27	Transmission	547,337	623,721	532,027	610,872	535,891	608,204	826,561	642,463	591,537	538,586	471,562	417,652	6,946,413	Line 15 x Line 22	27
28	Total	$ 9,407,299	$ 8,863,064	$ 9,556,951	$ 10,842,786	$ 9,843,301	$ 11,208,054	$ 11,279,394	$ 10,441,984	$ 9,817,269	$ 10,109,798	$ 9,112,475	$ 9,549,318	$ 120,031,693	Sum Lines 25; 26; 27	28
29																29
30	Total Revenues @ Calculated Rates:	$ 9,407,299	$ 8,863,064	$ 9,556,951	$ 10,842,786	$ 9,843,301	$ 11,208,054	$ 11,279,394	$ 10,441,984	$ 9,817,269	$ 10,109,798	$ 9,112,475	$ 9,549,318	$ 120,031,693	Line 28	30

1 90% Non-Coincident Demand (NCD) Rates are applicable to the following California Public Utilities Commission (CPUC) tariffs: AY-TOU; AL-TOU; AL-TOU-DER, DG-R and A6-TOU.

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Section 3.3.3

SAN DIEGO GAS AND ELECTRIC COMPANY

TO3-Cycle 5 Annual Transmission Formulaic Rate Filing

SUMMARY of Derived Revenues at Present Rates from the WHOLESALE Rates Developed in TO3-Cycle 5

Proof of Revenues - Medium & Large C&I Customers

Maximum On Peak Period Demand Rates (Summer & Winter Rates)

Line No.	Description	W Apr-10	S May-10	S Jun-10	S Jul-10	S Aug-10	S Sep-10	W Oct-10	W Nov-10	W Dec-10	W Jan-11	W Feb-11	W Mar-11	Total	Reference	Line No.
1	**On-Peak Demand (KW):**															1
2	Secondary	1,330,979	1,292,227	1,601,029	1,773,358	1,626,762	1,882,512	1,674,816	1,449,778	1,369,346	1,411,558	1,273,193	1,379,490	18,065,048	Section 3.3.3; Page 26.3; Ln. 105	2
3	Primary	272,034	300,111	299,400	394,234	363,053	384,862	360,072	306,784	266,320	299,948	289,420	270,640	3,806,879	Section 3.3.3; Page 26.3; Ln. 109	3
4	Transmission	44,186	26,659	28,540	22,602	26,959	24,808	60,793	55,981	42,458	27,738	12,730	32,646	406,100	Section 3.3.3; Page 26.3; Ln. 111	4
5	Total	1,647,199	1,618,997	1,928,970	2,190,194	2,016,774	2,292,182	2,095,681	1,812,543	1,678,125	1,739,243	1,575,343	1,682,776	22,278,026	Sum Lines 2; 3; 4	5
6																6
7	**Maximum On-Peak Demand Rates Per ($/KW):**	W	S	S	S	S	S	W	W	W	W	W	W			7
8	Secondary	$ 0.2062137	$ 1.0040605	$ 1.0040605	$ 1.0040605	$ 1.0040605	$ 1.0040605	$ 0.2062137	$ 0.2062137	$ 0.2062137	$ 0.2062137	$ 0.2062137	$ 0.2062137		Section 3.3.2; Pg 12; Lns 11&12	8
9	Primary	$ 0.2062137	$ 1.0040605	$ 1.0040605	$ 1.0040605	$ 1.0040605	$ 1.0040605	$ 0.2062137	$ 0.2062137	$ 0.2062137	$ 0.2062137	$ 0.2062137	$ 0.2062137		Section 3.3.2; Pg 12; Lns 11&12	9
10	Transmission	$ 0.2062137	$ 1.0040605	$ 1.0040605	$ 1.0040605	$ 1.0040605	$ 1.0040605	$ 0.2062137	$ 0.2062137	$ 0.2062137	$ 0.2062137	$ 0.2062137	$ 0.2062137		Section 3.3.2; Pg 12; Lns 11&12	10
11																11
12	**Revenues @ Calculated Rates:**															12
13	Secondary	$ 274,466	$ 1,297,474	$ 1,607,530	$ 1,780,558	$ 1,633,367	$ 1,890,156	$ 345,370	$ 298,964	$ 282,378	$ 291,083	$ 262,550	$ 284,470	$ 10,248,366	Line 2 x Line 8	13
14	Primary	56,097	301,329	300,616	395,835	364,527	386,425	74,252	63,263	54,919	61,853	59,682	55,810	2,174,608	Line 3 x Line 9	14
15	Transmission	9,112	26,768	28,656	22,694	27,068	24,908	12,536	11,544	8,755	5,720	2,625	6,732	187,118	Line 4 x Line 10	15
16	Total	$ 339,675	$ 1,625,571	$ 1,936,802	$ 2,199,087	$ 2,024,962	$ 2,301,489	$ 432,158	$ 373,771	$ 346,052	$ 358,656	$ 324,857	$ 347,012	$ 12,610,092	Sum Lines 13; 14; 15	16
17																17
18	**Total Revenues @ Calculated Rates:**	$ 339,675	$ 1,625,571	$ 1,936,802	$ 2,199,087	$ 2,024,962	$ 2,301,489	$ 432,158	$ 373,771	$ 346,052	$ 358,656	$ 324,857	$ 347,012	$ 12,610,092	Line 16	18

1 Maximum On-Peak Demand Rates are applicable to the following California Public Utilities Commission (CPUC) tariffs: AY-TOU; AL-TOU; AL- TOU, AL-TOU-DER and DG-R.

Section 3.3.3

SAN DIEGO GAS AND ELECTRIC COMPANY

TO3-Cycle 5 Annual Transmission Formulaic Rate Filing

SUMMARY of Derived Revenues at Present Rates from the WHOLESALE Rates Developed in TO3-Cycle 5

Proof of Revenues - Medium & Large C&I Customers

Maximum Demand @ Time of System Peak (Summer & Winter Rates)

Line No.	Description	W Apr-10	S May-10	S Jun-10	S Jul-10	S Aug-10	S Sep-10	W Oct-10	W Nov-10	W Dec-10	W Jan-11	W Feb-11	W Mar-11	Total	Reference	Line No.
1	**Coincident Peak Demand (KW):**															1
2	Secondary	-	-	-	-	-	-	-	-	-	-	-	-	-	Section 3.3.3; Page 26.4; Ln. 155	2
3	Primary	14,235	8,146	13,093	13,476	2,633	10,561	11,619	8,427	21,189	6,223	13,104	14,159	136,865	Section 3.3.3; Page 26.4; Ln. 159	3
4	Transmission	66,186	100,813	90,443	99,691	71,191	102,954	105,670	113,486	68,028	80,716	74,354	61,286	1,034,819	Section 3.3.3; Page 26.4; Ln. 161	4
5	Total	80,420	108,959	103,535	113,168	73,825	113,516	117,289	121,914	89,217	86,939	87,458	75,445	1,171,685	Sum Lines 2; 3; 4	5
9																9
10	**Coincident Peak Demand Rates Per ($/KW):**	W	S	S	S	S	S	W	W	W	W	W	W			10
11	Secondary	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		Section 3.3.2; Pg 12; Lns 15&16	11
12	Primary	$ 0.2200303	$ 1.1306043	$ 1.1306043	$ 1.1306043	$ 1.1306043	$ 1.1306043	$ 0.2200303	$ 0.2200303	$ 0.2200303	$ 0.2200303	$ 0.2200303	$ 0.2200303		Section 3.3.2; Pg 12; Lns 15&16	12
13	Transmission	$ 0.2200303	$ 1.1306043	$ 1.1306043	$ 1.1306043	$ 1.1306043	$ 1.1306043	$ 0.2200303	$ 0.2200303	$ 0.2200303	$ 0.2200303	$ 0.2200303	$ 0.2200303		Section 3.3.2; Pg 12; Lns 15&16	13
14																14
15	**Revenues @ Calculated Rates:**															15
16	Secondary	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	Line 2 x Line 11	16
17	Primary	3,132	9,210	14,803	15,236	2,977	11,941	2,557	1,854	4,662	1,369	2,883	3,115	73,739	Line 3 x Line 12	17
18	Transmission	14,563	113,980	102,255	112,711	80,489	116,401	23,251	24,970	14,968	17,760	16,360	13,485	651,193	Line 4 x Line 13	18
19	Total	$ 17,695	$ 123,190	$ 117,058	$ 127,947	$ 83,466	$ 128,342	$ 25,808	$ 26,824	$ 19,630	$ 19,129	$ 19,243	$ 16,600	$ 724,932	Sum Lines 16; 17; 18	19
20																20
21	**Total Revenues @ Calculated Rates:**	$ 17,695	$ 123,190	$ 117,058	$ 127,947	$ 83,466	$ 128,342	$ 25,808	$ 26,824	$ 19,630	$ 19,129	$ 19,243	$ 16,600	$ 724,932	Line 19	21

[1] Maximum Demand Rates at Time of System Peak rates are applicable to the following California Public Utilities Commission (CPUC) tariffs: A6-TOU.

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Section 3.3.3
SAN DIEGO GAS AND ELECTRIC COMPANY
TO3-Cycle 5 Annual Transmission Formulaic Rate Filing
SUMMARY of Derived Revenues at Present Rates from the WHOLESALE Rates Developed in TO3-Cycle 5
Proof of Revenues - Medium & Large C&I Customers
Standby Customers

Line No.	Description	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Total	Reference	Line No.
1	Demand - Billing Determinants (KW):															1
2	Secondary	11,737	11,737	11,739	11,632	11,632	11,631	12,627	12,627	14,115	14,115	14,021	14,021	151,634	Section 3.3.3; Page 26.4; Ln. 168 x 1000	2
3	Primary	85,738	85,920	86,237	85,940	85,197	85,197	81,350	81,350	84,674	84,287	83,618	84,300	1,013,809	Section 3.3.3; Page 26.4; Ln. 172 x 1000	3
4	Transmission	46,948	47,715	47,692	49,986	49,986	49,986	50,003	50,003	50,156	50,272	50,272	50,275	593,294	Section 3.3.3; Page 26.4; Ln. 174 x 1000	4
5	Total	144,423	145,372	145,668	147,559	146,816	146,815	143,980	143,980	148,945	148,673	147,911	148,595	1,758,737	Sum Lines 2; 3; 4	5
9																9
10	Demand Rates Per ($/KW):															10
11	Secondary	$ 2.1118421	$ 2.1118421	$ 2.1118421	$ 2.1118421	$ 2.1118421	$ 2.1118421	$ 2.1118421	$ 2.1118421	$ 2.1118421	$ 2.1118421	$ 2.1118421	$ 2.1118421		Section 3.3.2; Pg 20; Ln. 20	11
12	Primary	$ 2.1134122	$ 2.1134122	$ 2.1134122	$ 2.1134122	$ 2.1134122	$ 2.1134122	$ 2.1134122	$ 2.1134122	$ 2.1134122	$ 2.1134122	$ 2.1134122	$ 2.1134122		Section 3.3.2; Pg 20; Ln. 20	12
13	Transmission	$ 2.1129848	$ 2.1129848	$ 2.1129848	$ 2.1129848	$ 2.1129848	$ 2.1129848	$ 2.1129848	$ 2.1129848	$ 2.1129848	$ 2.1129848	$ 2.1129848	$ 2.1129848		Section 3.3.2; Pg 20; Ln. 20	13
14																14
15	Revenues at Present Rates:															15
16	Secondary	$ 24,787	$ 24,787	$ 24,791	$ 24,566	$ 24,566	$ 24,564	$ 26,666	$ 26,666	$ 29,808	$ 29,808	$ 29,610	$ 29,610	$ 320,229	Line 2 x Line 10	16
17	Primary	181,200	181,584	182,255	181,627	180,057	180,057	171,926	171,926	178,950	178,132	176,720	178,160	2,142,594	Line 3 x Line 11	17
18	Transmission	99,200	100,821	100,772	105,620	105,620	105,620	105,656	105,656	105,979	106,224	106,224	106,230	1,253,622	Line 4 x Line 12	18
19	Total	$ 305,187	$ 307,192	$ 307,818	$ 311,813	$ 310,243	$ 310,241	$ 304,248	$ 304,248	$ 314,737	$ 314,164	$ 312,554	$ 314,000	$ 3,716,445	Sum Lines 15; 16; 17	19
20																20
21	Total Revenues at Present Rates	$ 305,187	$ 307,192	$ 307,818	$ 311,813	$ 310,243	$ 310,241	$ 304,248	$ 304,248	$ 314,737	$ 314,164	$ 312,554	$ 314,000	$ 3,716,445	Line 19	21

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Section 3.3.3

San Diego Gas & Electric

FERC Recorded Sales @ Transmission Level for the Period: April 2010 - March 2011

Line No.															Line No.
1	**SDG&E: System Delivery Determinants**	Cycle 3	Cycle 3	Cycle 3	Cycle 3	Cycle 3	Cycle 4	Cycle 4	Cycle 4	Cycle 4	Cycle 4	Cycle 4	Cycle 4		1
2	**Customer Class Deliveries (MWh)**	**Apr-10**	**May-10**	**Jun-10**	**Jul-10**	**Aug-10**	**Sep-10**	**Oct-10**	**Nov-10**	**Dec-10**	**Jan-11**	**Feb-11**	**Mar-11**	**Total**	2
3	Residential	560,384	517,201	550,609	593,511	590,340	686,248	639,924	589,348	671,935	724,209	628,060	609,744	7,361,513	3
4	Transmission Level Adjustment Factor	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570		4
5	Residential @ Transmission Level	585,994	540,838	575,771	620,635	617,319	717,609	669,169	616,281	702,642	757,306	656,762	637,609	7,697,935	5
6															6
7	Small Commercial	157,999	137,325	162,432	177,346	163,651	189,247	177,357	162,507	164,000	171,088	159,604	160,245	1,982,802	7
8	Transmission Level Adjustment Factor	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570		8
9	Small Commercial @ Transmission Level	165,220	143,601	169,856	185,450	171,130	197,896	185,463	169,933	171,494	178,907	166,898	167,568	2,073,416	9
10															10
11	Med. & Large Comm./Ind. (AD + PA-T-1)	21,162	19,894	24,223	27,331	27,123	30,064	26,805	20,895	19,901	17,916	19,926	20,362	275,603	11
12	Transmission Level Adjustment Factor	1.03652	1.03652	1.03652	1.03652	1.03652	1.03627	1.03627	1.03627	1.03627	1.03627	1.03627	1.03627		12
13	Med&Lrg C/I (AD + PA-T-1)@Trans. Level	21,934	20,621	25,108	28,329	28,114	31,154	27,777	21,653	20,623	18,566	20,648	21,101	285,628	13
14															14
15	Med. & Large Comm./Ind. (AY + AL + DGR)	708,903	692,577	744,964	827,532	755,332	871,898	817,218	756,976	723,654	772,108	698,123	742,483	9,111,768	15
16	Transmission Level Adjustment Factor	1.03652	1.03652	1.03652	1.03652	1.03652	1.03627	1.03627	1.03627	1.03627	1.03627	1.03627	1.03627		16
17	Med&Lrg C/I (AY + AL + DGR)@Trans Level	734,791	717,869	772,169	857,752	782,915	903,517	846,855	784,428	749,897	800,109	723,440	769,409	9,443,152	17
18															18
19	Med. & Large Comm./Ind. (A6)	65,251	72,160	71,462	72,343	55,478	68,178	71,130	64,163	70,265	57,890	61,242	51,383	780,945	19
20	Transmission Level Adjustment Factor	1.03652	1.03652	1.03652	1.03652	1.03652	1.03627	1.03627	1.03627	1.03627	1.03627	1.03627	1.03627		20
21	Med. & Large Comm./Ind. (A6) @ Trans Level	67,634	74,795	74,071	74,985	57,504	70,651	73,710	66,490	72,813	59,990	63,463	53,246	809,352	21
22															22
23	Lighting	12,741	6,011	9,449	9,467	9,718	8,583	10,585	9,387	12,835	6,110	9,498	12,754	117,138	23
24	Transmission Level Adjustment Factor	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570		24
25	Street Lighting @ Transmission Level	13,323	6,286	9,881	9,899	10,163	8,976	11,068	9,816	13,421	6,389	9,932	13,337	122,491	25
26															26
27	Sale for Resale	1.5	0.0	3.5	0.0	1.5	0.0	6.4	0.0	2.1	1.7	3.6	0.0	20.4	27
28	Total System Delivery@Meter Exclude Resale	1,526,441	1,445,170	1,563,139	1,707,530	1,601,643	1,854,218	1,743,020	1,603,276	1,662,589	1,749,322	1,576,453	1,596,971	19,629,770	28
29	Total System Delivery@Trans. Exclude Resale	1,588,897	1,504,010	1,626,856	1,777,050	1,667,144	1,929,802	1,814,041	1,668,601	1,730,891	1,821,266	1,641,144	1,662,271	20,431,974	29
30	**Med. & Large Comm./Ind.**														30
31	**Rate Schedule Billing Determinants**														31
32		W	S	S	S	S	S	W	W	W	W	W	W		32
33	**Schedules AD / PA-T-1:Applicable to 100% NCD**	**Apr-10**	**May-10**	**Jun-10**	**Jul-10**	**Aug-10**	**Sep-10**	**Oct-10**	**Nov-10**	**Dec-10**	**Jan-11**	**Feb-11**	**Mar-11**	**Total**	33
34	**Total Deliveries (MWh)**	21,162	19,894	24,223	27,331	27,123	30,064	26,805	20,895	19,901	17,916	19,926	20,362	275,603	34
35															35
36	**Total Deliveries (%)**														36
37	% @ Secondary Service	91.58%	93.78%	93.65%	93.60%	91.70%	91.23%	90.41%	91.34%	91.56%	87.21%	85.53%	90.30%	91.15%	37
38	% @ Primary Service	8.42%	6.22%	6.35%	6.40%	8.30%	8.77%	9.59%	8.66%	8.44%	12.79%	14.47%	9.70%	8.85%	38
39	% @ Transmission Service	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	39
40		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	40
41	**Total Deliveries (MWh)**														41
42	MWh @ Secondary Service	19,380	18,657	22,685	25,582	24,872	27,427	24,234	19,085	18,221	15,625	17,043	18,387	251,199	42
43	MWh @ Primary Service	1,782	1,237	1,538	1,749	2,251	2,637	2,571	1,809	1,680	2,292	2,883	1,975	24,404	43
44	MWh @ Transmission Service	0	0	0	0	0	0	0	0	0	0	0	0	0	44
45		21,162	19,894	24,223	27,331	27,123	30,064	26,805	20,895	19,901	17,916	19,926	20,362	275,603	45

Section 3.3.3

San Diego Gas & Electric

FERC Recorded Sales @ Transmission Level for the Period: April 2010 - March 2011

Line No.															Line No.
46	**Non-Coincident Demand (%)**														46
47	% @ Secondary Service	0.4645%	0.3810%	0.3496%	0.3242%	0.3390%	0.3116%	0.3507%	0.4303%	0.4382%	0.4666%	0.4670%	0.4543%	0.3886%	47
48	% @ Primary Service	0.4508%	0.7382%	0.8706%	0.6807%	0.5423%	0.4609%	0.4693%	0.6266%	0.6114%	0.5588%	0.5323%	0.5140%	0.5688%	48
49	% @ Transmission Service	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	49
50															50
51	**Non-Coincident Demand (MW)**														51
52	MW @ Secondary Service	90.020	71.082	79.308	82.936	84.316	85.463	84.989	82.124	79.846	72.906	79.589	83.533	976.113	52
53	Transmission Level Adjustment Factor	1.0457	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570		53
54	Non-Coincident Demand @ Transmission Level	94.133	74.331	82.932	86.726	88.169	89.369	88.874	85.878	83.495	76.238	83.226	87.351	1,020.722	54
55															55
56	MW @ Primary Service	8.032	9.135	13.392	11.907	12.208	12.152	12.064	11.338	10.269	12.805	15.348	10.152	138.802	56
57	Transmission Level Adjustment Factor	1.0108	1.01080	1.01080	1.01080	1.01080	1.01080	1.01080	1.01080	1.01080	1.01080	1.01080	1.01080		57
58	Non-Coincident Demand @ Transmission Level	8.119	9.233	13.536	12.035	12.340	12.283	12.194	11.461	10.380	12.943	15.513	10.262	140.301	58
59															59
60	MW @ Transmission Service	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	60
61	Non-Coincident Demand @ Meter Level	98.052	80.217	92.699	94.843	96.525	97.615	97.053	93.463	90.115	85.711	94.937	93.686	1,114.915	61
62	Non-Coincident Demand @ Transmission Level	102.253	83.564	96.468	98.762	100.510	101.652	101.068	97.338	93.875	89.181	98.739	97.613	1,161.023	62
63															63
64															64
65	**Schedules AL-TOU / AY-TOU / DG-R:**	**Apr-10**	**May-10**	**Jun-10**	**Jul-10**	**Aug-10**	**Sep-10**	**Oct-10**	**Nov-10**	**Dec-10**	**Jan-11**	**Feb-11**	**Mar-11**	**Total**	65
66	**Applicable to 90% NCD - Total Deliveries (MWh)**	708,903	692,577	744,964	827,532	755,332	871,898	817,218	756,976	723,654	772,108	698,123	742,483	9,111,768	66
67															67
68	**Total Deliveries (%)**														68
69	% @ Secondary Service	79.27%	78.43%	82.11%	79.43%	78.58%	80.34%	77.71%	78.07%	81.77%	79.54%	79.60%	81.39%	79.68%	69
70	% @ Primary Service	19.02%	20.66%	17.19%	19.92%	20.47%	18.67%	19.01%	19.23%	17.28%	19.44%	19.90%	17.48%	19.02%	70
71	% @ Transmission Service	1.71%	0.91%	0.70%	0.65%	0.95%	0.99%	3.28%	2.70%	0.95%	1.02%	0.50%	1.13%	1.30%	71
72		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	72
73	**Total Deliveries (MWh)**														73
74	MWh @ Secondary Service	561,948	543,188	611,690	657,309	593,540	700,483	635,060	590,971	591,732	614,135	555,706	604,307	7,260,068	74
75	MWh @ Primary Service	134,833	143,086	128,059	164,844	154,616	162,783	155,353	145,567	125,047	150,098	138,926	129,786	1,733,001	75
76	MWh @ Transmission Service	12,122	6,302	5,215	5,379	7,176	8,632	26,805	20,438	6,875	7,876	3,491	8,390	118,700	76
77		708,903	692,577	744,964	827,532	755,332	871,898	817,218	756,976	723,654	772,108	698,123	742,483	9,111,768	77
78															78
79	**Non-Coincident Demand (%)**														79
80	% @ Secondary Service	0.2810%	0.2688%	0.2705%	0.2744%	0.2793%	0.2709%	0.2955%	0.2984%	0.2822%	0.2792%	0.2768%	0.2723%	0.2791%	80
81	% @ Primary Service	0.2376%	0.2190%	0.2213%	0.2386%	0.2236%	0.2289%	0.2400%	0.2369%	0.2403%	0.2205%	0.2216%	0.2273%	0.2297%	81
82	% @ Transmission Service	0.1981%	0.2219%	0.2323%	0.2659%	0.2727%	0.2418%	0.2261%	0.1460%	0.2803%	0.2419%	0.3092%	0.1336%	0.2154%	82
83															83
84	**Non-Coincident Demand (MW)**														84
85	MW @ Secondary Service	1,579.073	1,460.090	1,654.621	1,803.656	1,657.757	1,897.608	1,876.603	1,763.458	1,669.866	1,714.665	1,538.193	1,645.528	20,261.118	85
86	Transmission Level Adjustment Factor	1.0457	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570		86
87	Non-Coincident Demand @ Transmission Level	1,651.237	1,526.816	1,730.237	1,886.083	1,733.516	1,984.328	1,962.364	1,844.048	1,746.179	1,793.025	1,608.489	1,720.729	21,187.051	87

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San Diego Gas & Electric

FERC Recorded Sales @ Transmission Level for the Period: April 2010 - March 2011

Line No.														
88														
89	MW @ Primary Service	320.364	313.359	283.395	393.319	345.722	372.611	372.848	344.847	300.489	330.966	307.861	295.004	3,980.785
90	Transmission Level Adjustment Factor	1.0108	1.01080	1.01080	1.01080	1.01080	1.01080	1.01080	1.01080	1.01080	1.01080	1.01080	1.01080	
91	Non-Coincident Demand @ Transmission Level	323.824	316.743	286.456	397.567	349.456	376.635	376.874	348.571	303.734	334.540	311.186	298.190	4,023.777
92														
93	MW @ Transmission Service	24.014	13.985	12.114	14.303	19.568	20.872	60.606	29.840	19.270	19.051	10.793	11.209	255.624
94	Non-Coincident Demand @ Meter Level	1,923.452	1,787.434	1,950.130	2,211.277	2,023.047	2,291.090	2,310.056	2,138.145	1,989.625	2,064.681	1,856.847	1,951.741	24,497.526
95	Non-Coincident Demand @ Transmission Level	1,999.075	1,857.544	2,028.807	2,297.952	2,102.540	2,381.835	2,399.843	2,222.460	2,069.183	2,146.616	1,930.468	2,030.127	25,466.452
96														
97	**On-Peak Demand (%)**													
98	% @ Secondary Service	0.2265%	0.2275%	0.2503%	0.2580%	0.2621%	0.2570%	0.2522%	0.2346%	0.2213%	0.2198%	0.2191%	0.2183%	0.2380%
99	% @ Primary Service	0.1996%	0.2075%	0.2313%	0.2366%	0.2323%	0.2339%	0.2293%	0.2085%	0.2107%	0.1977%	0.2061%	0.2063%	0.2173%
100	% @ Transmission Service	0.3645%	0.4230%	0.5473%	0.4202%	0.3757%	0.2874%	0.2268%	0.2739%	0.6176%	0.3522%	0.3647%	0.3891%	0.3421%
101														
102	**On-Peak Demand (MW)**	W	S	S	S	S	S	W	W	W	W	W	W	Total
103	MW @ Secondary Service	1,272.812	1,235.753	1,531.060	1,695.857	1,555.668	1,800.241	1,601.622	1,386.419	1,309.502	1,349.869	1,217.551	1,319.202	17,275.554
104	Transmission Level Adjustment Factor	1.0457	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	
105	On-Peak Demand @ Transmission Level	1,330.979	1,292.227	1,601.029	1,773.358	1,626.762	1,882.512	1,674.816	1,449.778	1,369.346	1,411.558	1,273.193	1,379.490	18,065.048
106														
107	MW @ Primary Service	269.128	296.904	296.201	390.022	359.174	380.750	356.225	303.506	263.475	296.743	286.327	267.749	3,766.204
108	Transmission Level Adjustment Factor	1.0108	1.01080	1.01080	1.01080	1.01080	1.01080	1.01080	1.01080	1.01080	1.01080	1.01080	1.01080	
109	On-Peak Demand @ Transmission Level	272.034	300.111	299.400	394.234	363.053	384.862	360.072	306.784	266.320	299.948	289.420	270.640	3,806.879
110														
111	MW @ Transmission Service	44.186	26.659	28.540	22.602	26.959	24.808	60.793	55.981	42.458	27.738	12.730	32.646	406.100
112	On-Peak Demand @ Meter Level	1,586.125	1,559.317	1,855.801	2,108.481	1,941.801	2,205.799	2,018.640	1,745.906	1,615.435	1,674.350	1,516.609	1,619.596	21,447.858
113	On-Peak Demand @ Transmission Level	1,647.199	1,618.997	1,928.970	2,190.194	2,016.774	2,292.182	2,095.681	1,812.543	1,678.125	1,739.243	1,575.343	1,682.776	22,278.026
114														
115														
116	**Schedule A6-TOU:**	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Total
117	**Total Deliveries (MWh)**	65,251	72,160	71,462	72,343	55,478	68,178	71,130	64,163	70,265	57,890	61,242	51,383	780,945
118														
119	**Total Deliveries (%)**													
120	% @ Secondary Service	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
121	% @ Primary Service	13.38%	6.55%	9.47%	11.89%	8.21%	14.54%	8.86%	7.59%	15.37%	8.27%	13.71%	20.59%	11.40%
122	% @ Transmission Service	86.62%	93.45%	90.53%	88.11%	91.79%	85.46%	91.14%	92.41%	84.63%	91.73%	86.29%	79.41%	88.60%
123		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
124	**Total Deliveries (MWh)**													
125	MWh @ Secondary Service	0	0	0	0	0	0	0	0	0	0	0	0	0
126	MWh @ Primary Service	8,731	4,726	6,767	8,602	4,555	9,913	6,302	4,870	10,800	4,788	8,396	10,580	89,029
127	MWh @ Transmission Service	56,521	67,434	64,694	63,741	50,923	58,265	64,828	59,293	59,465	53,103	52,846	40,803	691,916
128		65,251	72,160	71,462	72,343	55,478	68,178	71,130	64,163	70,265	57,890	61,242	51,383	780,945
129	**Non-Coincident Demand (%)**													
130	% @ Secondary Service	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
131	% @ Primary Service	0.1456%	0.1068%	0.1203%	0.1390%	0.1158%	0.1729%	0.0952%	0.1239%	0.1838%	0.4118%	0.2249%	0.2801%	0.1802%
132	% @ Transmission Service	0.1748%	0.1868%	0.1658%	0.1926%	0.1977%	0.1984%	0.1926%	0.1928%	0.1908%	0.1917%	0.1798%	0.2022%	0.1883%

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San Diego Gas & Electric

FERC Recorded Sales @ Transmission Level for the Period: April 2010 - March 2011

Line No.														Line No.
133														133
134	**Non-Coincident Demand (MW)**													134
135	MW @ Secondary Service	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	135
136	Transmission Level Adjustment Factor	1.0457	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570		136
137	Non-Coincident Demand @ Transmission Level	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	137
138															138
139	MW @ Primary Service	12.712	5.048	8.141	11.956	5.274	17.140	6.000	6.034	19.850	19.715	18.883	29.634	160.387	139
140	Transmission Level Adjustment Factor	1.0108	1.01080	1.01080	1.01080	1.01080	1.01080	1.01080	1.01080	1.01080	1.01080	1.01080	1.01080		140
141	Non-Coincident Demand @ Transmission Level	12.849	5.102	8.229	12.085	5.331	17.325	6.064	6.099	20.064	19.928	19.087	29.954	162.119	141
142															142
143	MW @ Transmission Service	98.798	125.966	107.263	122.766	100.676	115.598	124.859	114.316	113.460	101.798	95.017	82.504	1,303.020	143
144	Non-Coincident Demand @ Meter Level	111.510	131.014	115.404	134.722	105.950	132.738	130.859	120.350	133.310	121.513	113.900	112.138	1,463.407	144
145	Non-Coincident Demand @ Transmission Level	111.647	131.068	115.492	134.851	106.007	132.923	130.924	120.416	133.524	121.726	114.104	112.458	1,465.139	145
146															146
147	**Coincident Peak Demand (%)**														147
148	% @ Secondary Service	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	148
149	% @ Primary Service	0.1613%	0.1705%	0.1914%	0.1550%	0.0572%	0.1054%	0.1824%	0.1712%	0.1941%	0.1286%	0.1544%	0.1324%	0.1521%	149
150	% @ Transmission Service	0.1171%	0.1495%	0.1398%	0.1564%	0.1398%	0.1767%	0.1630%	0.1914%	0.1144%	0.1520%	0.1407%	0.1502%	0.1496%	150
151															151
152	**Coincident Peak Demand (MW)**	W	S	S	S	S	S	W	W	W	W	W	W	Total	152
153	MW @ Secondary Service	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	153
154	Transmission Level Adjustment Factor	1.0457	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570		154
155	Coincident Peak Demand@Transmission Level	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	155
156															156
157	MW @ Primary Service	14.082	8.059	12.953	13.332	2.605	10.448	11.495	8.337	20.962	6.157	12.964	14.008	135.403	157
158	Transmission Level Adjustment Factor	1.0108	1.01080	1.01080	1.01080	1.01080	1.01080	1.01080	1.01080	1.01080	1.01080	1.01080	1.01080		158
159	Coincident Peak Demand@Transmission Level	14.235	8.146	13.093	13.476	2.633	10.561	11.619	8.427	21.189	6.223	13.104	14.159	136.865	159
160															160
161	MW @ Transmission Service	66.186	100.813	90.443	99.691	71.191	102.954	105.670	113.486	68.028	80.716	74.354	61.286	1,034.819	161
162	Coincident Peak Demand@Meter Level	80.268	108.872	103.395	113.024	73.796	113.403	117.165	121.824	88.991	86.873	87.318	75.294	1,170.222	162
163	Coincident Peak Demand@Transmission Level	80.420	108.959	103.535	113.168	73.825	113.516	117.289	121.914	89.217	86.939	87.458	75.445	1,171.685	163
164	**Schedule S: Standby Determinants:**	**Apr-10**	**May-10**	**Jun-10**	**Jul-10**	**Aug-10**	**Sep-10**	**Oct-10**	**Nov-10**	**Dec-10**	**Jan-11**	**Feb-11**	**Mar-11**	**Total**	164
165	**Contracted Standby Demand (MW)**														165
166	MW @ Secondary Service	11.224	11.224	11.226	11.124	11.124	11.123	12.075	12.075	13.498	13.498	13.408	13.408	145.007	166
167	Transmission Level Adjustment Factor	1.0457	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570		167
168	Standby Demand @ Transmission Level	11.737	11.737	11.739	11.632	11.632	11.631	12.627	12.627	14.115	14.115	14.021	14.021	151.634	168
169															169
170	MW @ Primary Service	84.822	85.002	85.316	85.022	84.287	84.287	80.481	80.481	83.769	83.386	82.725	83.399	1,002.977	170
171	Transmission Level Adjustment Factor	1.0108	1.01080	1.01080	1.01080	1.01080	1.01080	1.01080	1.01080	1.01080	1.01080	1.01080	1.01080		171
172	Standby Demand @ Transmission Level	85.738	85.920	86.237	85.940	85.197	85.197	81.350	81.350	84.674	84.287	83.618	84.300	1,013.809	172
173															173
174	MW @ Transmission Service	46.948	47.715	47.692	49.986	49.986	49.986	50.003	50.003	50.156	50.272	50.272	50.275	593.294	174
175	Standby Demand@Meter Level	142.994	143.941	144.234	146.132	145.397	145.396	142.559	142.559	147.423	147.156	146.405	147.082	1,741.278	175
176	Standby Demand@Transmission Level	144.423	145.372	145.668	147.559	146.816	146.815	143.980	143.980	148.945	148.673	147.911	148.595	1,758.737	176
177															177

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Section 3.3.3
SAN DIEGO GAS AND ELECTRIC COMPANY
TO3-Cycle 5 Annual Transmission Formulaic Rate Filing
Revenue Data to Reflect Present Rates from the WHOLESALE Rates Developed for TO3-Cycle 5 True-Up Period Cost of Service
For the True-Up Period April 2010 through March 2011
Billing Determinants @ Transmission Level

Line No.	Customer Classes	(A) Apr-10 Billing Determinants Energy (kWh)	(A) Apr-10 Demand (kW)	(B) May-10 Billing Determinants Energy (kWh)	(B) May-10 Demand (kW)	(C) Jun-10 Billing Determinants Energy (kWh)	(C) Jun-10 Demand (kW)	(D) Jul-10 Billing Determinants Energy (kWh)	(D) Jul-10 Demand (kW)	(E) Aug-11 Billing Determinants Energy (kWh)	(E) Aug-11 Demand (kW)	(F) Sep-11 Billing Determinants Energy (kWh)	(F) Sep-11 Demand (kW)	(G) Sub-Total Billing Determinants Energy (kWh)	(G) Sub-Total Demand (kW)	Line No.
1	Residential Customers [1]	585,993,579		540,837,597		575,771,398		620,634,704		617,318,718		717,609,257		3,658,165,252	-	1
2																2
3	Small Commercial [2]	165,219,991		143,601,259		169,855,612		185,450,446		171,129,618		197,895,590		1,033,152,516	-	3
4																4
5	Medium-Large Commercial [3]	824,359,987	2,212,975	813,284,778	2,072,177	871,348,310	2,240,768	961,066,131	2,531,564	868,533,488	2,309,057	1,005,322,068	2,616,410	5,343,914,762	13,982,951	5
6																6
7	Street Lighting [4]	13,323,085		6,286,193		9,880,836		9,899,133		10,162,500		8,975,509		58,527,257	-	7
8																8
9	Sale for Resale [5]	1,500		-		3,500		-		1,500		-		6,500	-	9
10																10
11	Standby Customers [6]		144,423		145,372		145,668		147,559		146,816		146,815	-	876,652	11
12																12
13	TOTAL	1,588,898,142	2,357,398	1,504,009,827	2,217,549	1,626,859,656	2,386,436	1,777,050,414	2,679,123	1,667,145,823	2,455,873	1,929,802,424	2,763,225	10,093,766,287	14,859,603	13
14																14

NOTES:

1 See Section 3.3.3; Page 26.1; Line 5 x 1000.

2 See Section 3.3.3; Page 26.1; Line 9 x 1000.

3 See Section 3.3.3; Pages 26.1; 26.2; 26.3; 26.4; (Lines 13, 17, and 21) x 1000; (Lines 62, 95, and 145) x 1000.

4 See Section 3.3.3; Page 26.1; Line 25 x 1000.

5 See Section 3.3.3; Page 26.1; Line 27 x 1000.

6 See Section 3.3.3; Page 26.4; Line 176 x 1000.

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Section 3.3.3

SAN DIEGO GAS AND ELECTRIC COMPANY
TO3-Cycle 5 Annual Transmission Formulaic Rate Filing
Revenue Data to Reflect Present Rates from the WHOLESALE Rates Developed for TO3-Cycle 5 True-Up Period Cost of Service
For the True-Up Period April 2010 through March 2011
Billing Determinants @ Transmission Level

Line No.	Customer Classes	(H) Oct-10 Billing Determinants Energy (kWh)	(H) Oct-10 Demand (kW)	(I) Nov-10 Energy (kWh)	(I) Nov-10 Demand (kW)	(J) Dec-10 Energy (kWh)	(J) Dec-10 Demand (kW)	(K) Jan-11 Energy (kWh)	(K) Jan-11 Demand (kW)	(L) Feb-11 Energy (kWh)	(L) Feb-11 Demand (kW)	(M) Mar-11 Energy (kWh)	(M) Mar-11 Demand (kW)	(N) Sub-Total Energy (kWh)	(N) Sub-Total Demand (kW)	(O) Grand Total Energy (kWh)	(O) Grand Total Demand (kW)	Line No.
1	Residential Customers [1]	669,169,003		616,281,152		702,642,334		757,305,553		656,762,211		637,609,078		4,039,769,330	-	7,697,934,583	-	1
2																		2
3	Small Commercial [2]	185,462,587		169,933,296		171,494,306		178,906,863		166,897,972		167,568,411		1,040,263,437	-	2,073,415,953	-	3
4																		4
5	Medium-Large Commercial [3]	948,341,453	2,631,835	872,570,224	2,440,214	843,333,041	2,296,583	878,664,646	2,357,523	807,551,603	2,143,311	843,756,551	2,240,198	5,194,217,518	14,109,663	10,538,132,280	28,092,614	5
6																		6
7	Street Lighting [4]	11,068,413		9,816,383		13,421,130		6,389,127		9,932,236		13,336,818		63,964,107	-	122,491,364	-	7
8																		8
9	Sale for Resale [5]	6,408		-		2,116		1,710		3,620		-		13,854	-	20,354		9
10																		10
11	Standby Customers [6]		143,980		143,980		148,945		148,673		147,911		148,595	-	882,085	-	1,758,737	11
12																		12
13	TOTAL	1,814,047,865	2,775,815	1,668,601,055	2,584,194	1,730,892,927	2,445,527	1,821,267,899	2,506,196	1,641,147,643	2,291,222	1,662,270,858	2,388,794	10,338,228,247	14,991,747	20,431,994,534	29,851,351	13
14																		14

NOTES:

1 See Section 3.3.3; Page 26.1; Line 5 x 1000.
2 See Section 3.3.3; Page 26.1; Line 9 x 1000.
3 See Section 3.3.3; Pages 26.1; 26.2; 26.3; 26.4; (Lines 13, 17, and 21) x 1000; (Lines 62, 95, and 145) x 1000.
4 See Section 3.3.3; Page 26.1; Line 25 x 1000.
5 See Section 3.3.3; Page 26.1; Line 27 x 1000.
6 See Section 3.3.3; Page 26.4; Line 176 x 1000.

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Section 3.3.3

SAN DIEGO GAS AND ELECTRIC COMPANY

TO3-Cycle 5 Annual Transmission Formulaic Rate Filing

Revenue Data to Reflect Present Rates from the WHOLESALE Rates Developed for TO3-Cycle 5 True-Up Period Cost of Service

For the True-Up Period April 2010 through March 2011

Total Billing Determinants @ Transmission Level

Line No.	Customer Classes	(M) 12 Months to Date Billing Determinants @ Transmission Level Energy (kWh)	Demand (kW)	Line No.
1	Residential Customers	7,697,934,583	-	1
2				2
3	Small Commercial	2,073,415,953	-	3
4				4
5	Medium-Large Commercial	10,538,132,280	28,092,614	5
6				6
7	Street Lighting	122,491,364	-	7
8				8
9	Sale for Resale	20,354		9
10				10
11	Standby Customers	-	1,758,737	11
12				12
13	TOTAL	20,431,994,534	29,851,351	13
14				14

Section 3.3.3

SAN DIEGO GAS AND ELECTRIC COMPANY
TO3-Cycle 5 Annual Transmission Formulaic Rate Filing
Summary of TO3-CYCLE-5 Wholesale Transmission Rates
Based on TO3-CYCLE-5 Wholesale True-Up Period Cost of Service
Using TO3-CYCLE-5 True-Up Period Billing Determinants (April 2010 - March 2011)

Line No.	Customer Classes	Transmission Energy Rates $/kWh	Transmission Level Demand Rates $/kW-Mo	Primary Level Demand Rates $/kW-Mo	Secondary Level Demand Rates $/kW-Mo	Reference	Line No.
1	Residential	$ 0.0152477				Section 3.3.2; Page 2; Line 11	1
2							2
3	Small Commercial	$ 0.0174307				Section 3.3.2; Page 3; Line 11	3
4							4
5	Med & Lrg Commercial/Industrial						5
6	Non-Coincident Demand (100%) [1]		$ 4.9518922	$ 4.9521498	$ 4.9521344	Section 3.3.2; Page 4; Lines 33;34;35	6
7							7
8	Non-Coincident Demand (90%) [2]		$ 4.4567030	$ 4.4569348	$ 4.4569210	Section 3.3.2; Page 5; Lines 7;8;9	8
9							9
10	Maximum On-Peak Demand [3]						10
11	Summer		$ 1.0040605	$ 1.0040605	$ 1.0040605	Section 3.3.2; Page 6; Lines 35;36;37	11
12	Winter		$ 0.2062137	$ 0.2062137	$ 0.2062137	Section 3.3.2; Page 7; Lines 32;33;34	12
13							13
14	Maximum Demand at the Time of System Peak [4]						14
15	Summer		$ 1.1306043	$ 1.1306043	$ -	Section 3.3.2; Page 8; Lines 29;30;31	15
16	Winter		$ 0.2200303	$ 0.2200303	$ -	Section 3.3.2; Page 9; Lines 32;33;34	16
17							17
18	Street Lighting	$ 0.0089884				Section 3.3.2; Page 10; Line 11	18
19							19
20	Standby Rate		$ 2.1129848	$ 2.1134122	$ 2.1118421	Section 3.3.2; Page 11; Lns 33;34;35	20

NOTES:

1 Non-Coincident Demand (NCD) (100%) rates are applicable to the following California Public Utilities Commission (CPUC) tariffs: Schedules AD and PA-T-1

2 NCD (90%) rates are applicable to the following CPUC tariffs: Schedules AY-TOU, AL-TOU, AL-TOU-DER, DG-R, and A6-TOU.

3 Maximum On-Peak Demand rates are applicable to the following CPUC tariffs: Schedules AY-TOU, AL-TOU, AL-TOU-DER and DG-R

4 Maximum Demand at the Time of System Peak rates are applicable to the following CPUC tariffs: Schedule A6-TOU