San Diego Gas & Electric Company

Volume 2-A

TO3 – Cycle 5 Filing
12-Month True-Up Period
Cost Statements, True-Up Adjustment Report, Wildfire Cost Recovery/Inverse Condemnation Report, & Retail 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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San Diego Gas & Electric Company

TO3-Cycle 5 True-Up Adjustment

"Report"

Docket No. ER11-____-____

TO3 CYCLE 5 TRUE-UP ADJUSTMENT REPORT

I. SUMMARY

The purpose of the True-Up ("TU") Adjustment in Cycle 5 of San Diego Gas & Electric Company's ("SDG&E") Third Transmission Owner Formula ("TO3") is to ensure customers pay no more and no less than SDG&E's Cost of Service. This Report explains the causes of the TU Adjustment applicable to the TO3 Cycle 5 TU Period, *i.e.*, twelve months ending March 31, 2011, and demonstrates that costs were undercollected during that period because SDG&E's TU Cost of Service was greater than recorded revenues. Revenue was undercollected by approximately $32.1 million.[1] Section II, through the use of Exhibit No. 1, explains how the TU Adjustment is derived. Sections III and IV explain the causes of the undercollection.

II. CYCLE 5 TWELVE-MONTH TU ADJUSTMENT

A. Derivation of $32.1 million Cycle 5 True-Up Adjustment Undercollection

SDG&E's TU Cost of Service during the TU Period is $32.1 million higher than recorded revenues during the same period; thus the TU is undercollected. The undercollection is driven primarily by differences between SDG&E's costs during the TU Period and costs that were incurred during the years 2008 (base period for Cycle 3) and 2009 (base period for Cycle 4), which were the basis for the rates that were in effect during the TU Period. Exhibit No. 1 shows the components of the increase.

Column A and Column B of Exhibit No. 1 show the prior period costs that were used to set the rates that were in effect during the TU Period. Those rates, when applied to sales,

[1] Volume 2A, Section 2.1A, page 3, Line 35.

determined the amount of revenue that was collected. The prior period costs were reported in SDG&E's TO3 Cycles 3 and 4 filings.[2]

In Columns C, D, and E of Exhibit No. 1, the prior period costs are prorated for the amount of revenue for those periods that was recovered during the TU Period. During the TU Period, Cycle 3 rates were in effect for the first five months (April 2010 through August 2010) and Cycle 4 rates were in effect for the last seven months (September 2010 through March 2011). To reflect the Cycle 3 costs that were being recovered in rates during the first five months of the TU Period, SDG&E has multiplied total Cycle 3 costs by 37.09%, as shown in Column C of Exhibit No. 1. The 37.09% was derived by dividing the revenues recorded during the first five months of the TU Period ($96.4 million) by the total Cycle 3 revenue requirement, less TU adjustments ($260.0 million). To reflect the Cycle 4 costs that were being recovered in rates during the last seven months of the TU Period, SDG&E has multiplied total Cycle 4 costs times 56.61%, as shown in Column D of Exhibit No. 1. The 56.61% was derived by dividing the revenues recorded during the last seven months of the TU Period ($167.2 million) by the total Cycle 4 revenue requirement, less TU adjustments ($295.3 million). See Vol. 3 TU Adjustment WP-1 for the derivation of the preceding percentages. Column E is the sum of Columns C and D and reflects the total revenues that were collected during the TU Period equal to $263.6 million shown on Line 12.

B. Normalization of Prior Period Recorded Costs (Column E), to Adjust for Lower Recorded Sales

As indicated below in Section III, Part A, one of the main drivers of the TU Adjustment undercollection is lower recorded sales. The reason why a portion of the costs incurred in Cycles

[2] Cycle 3 costs are per FERC Docket ER09-1601-000 and Cycle 4 costs are per Docket ER10-2235-000, August 13, 2010. Cycle 3 costs exclude TU adjustments of approximately $11.2 million for the 12-month TO3 Cycle 3 TU period. Cycle 4 costs exclude TU adjustments of approximately $32.2 million for the 12-month TO3 Cycle 4 TU period. These adjustments are shown on Statement BK-1, page 5, of the Cycle 3 and Cycle 4 filings.

3 and 4 was not collected in the TU Period is that sales during the TU Period were lower than the forecasted sales in Cycles 3 and 4.

To properly compare the prior period costs from Cycles 3 and 4 to the TU Period Cost of Service (Column G, $295.0 million), Column E was adjusted to reflect balances that would have occurred had recorded revenues matched the forecasted sales. To do this, the prior period revenues were increased by the amount due to the sales reduction. This adjustment is calculated and explained below in Section III A and is equal to $14.8 million. TU Adjustment WP-3 in Vol. 3 shows how the $14.8 million was prorated per Column A and added to each line item in Column E of Exhibit No. 1 to increase these prior period costs due to the lower sales in the TU Period. The result of this adjustment is shown in Column F. This normalization adjustment allows costs to be compared as though recorded revenues had matched the forecasted sales.

Column H, Lines 2 through 12 of Exhibit No. 1 show the cost differences between Column G (TU Period costs) and Column F (prior period costs), excluding the impact of lower sales (Line 13). These cost differences total the $16.7 million shown on Line 12. The sum of the $16.7 million of cost differences, plus the impact of $14.8 million due to lower sales, shown on Line 13, and interest of $0.7 million from Vol. 2A Section 2.1A, Page 3, Line 33, shown on Line 14, is equal to the total TU Adjustment, which is an undercollection equal to $32.1 million shown on Line 15. Had the Cycle 3 and Cycle 4 sales forecasts matched actual sales during the TU Period, the undercollection would have been $17.3 million ($32.1 million minus $14.8 million), or $14.8 million lower, excluding interest, than the actual $32.1 million TU Adjustment. For more discussion of the impact of sales on the TU Adjustment, see Section III, Part A below.

III. SUMMARY OF THE TU ADJUSTMENT

As explained above, the Cycle 5 TU Adjustment equals $32.1 million and consists of those differences shown in Column H, Lines 2 through 14. Most of the differences are caused by two items: lower than forecasted sales and amortization of inverse condemnation costs. These items are explained below.

A. Lower Sales - $14.8 Million

As shown in Table 1 below, SDG&E's sales during the TU Period were significantly lower than forecast:

Table 1: Lower Sales during the TU Period

	A	B	C	D
		Cycle 3	Cycle 4	Total
1	Portion of TU Period	1st 5 Months	Last 7 Months	12 Months
2	Forecasted Sales (GWh)	8,779	11,951	20,730
3	Actual Sales (GWh)	7,844	11,786	19,630
4	Below Forecast (GWh)	935	165	1,100
5	Below Forecast %	10.65%	1.38%	5.31%
6	Rate (cents per kWh)	1.29	1.61	
7	Dollar Impact (L4 x L6/100)	$ 12.1M	$ 2.6M	$ 14.8M

As indicated in Column D of the above table, the dollar impact of lower sales was $14.8 million not collected related to Cycle 3 and Cycle 4. This means that if actual sales during the TU Period had equaled forecasted sales, the undercollection would have been $14.8 million lower, excluding interest. The Cycle 3 sales forecast SDG&E used, which was from the

California Energy Commission's 2007 Integrated Energy Policy Report, did not anticipate the worse-than-expected economic recession. The above sales amounts are shown in Vol. 3 TU Adjustment WP-2.

B. Inverse Condemnation Amortization Expense ($19.7 Million)

During the TU Period SDG&E charged $19.7 million of transmission-related inverse condemnation costs to FERC Account 404, Amortization of Limited-Term Electric Plant. See Column H, Line 5, of Exhibit No. 1. For more information about this item, see the Inverse Condemnation Report.

C. Impact on the TU Adjustment

Excluding the unusual items described in III. A and B above, the TU Adjustment would have been a $2.4 million overcollection instead of the $32.1 million undercollection.

IV. ANALYSIS OF TU ADJUSTMENT COST DIFFERENCES

Column H, Lines 2 through 12 of Exhibit No. 1 show the differences between costs recorded in the TU Period and costs recorded prior period Cycles 3 and 4. The following is an explanation of these differences.

A. Transmission O&M Expense Differences (Exhibit No. 2)

As shown in Column H, Line 2 of Exhibit No. 1, transmission O&M expenses are overcollected by $1.3 million in total. Exhibit No. 2 shows the differences that contributed the most to this total, which are as follows:

1. Account 560 (Electric Transmission Operation – Engineering and Supervision)

The $0.6 million increase in this account was primarily due to an increase in costs incurred in the Electric Grid Operations department. This department incurred increased

expenses to meet reliability standards promulgated by the North American Electric Reliability Corporation ("NERC") to improve transmission reliability and security.

2. Account 566 (Electric Transmission Operation – Miscellaneous Transmission Expenses)

The $3.6 million decrease in this account is caused primarily by two items charged in the Cycle 4 2009 Base Period that are not included in the Cycle 5 TU cost of service. These include $4.5 million of 2009 wildfire insurance expenses that are now recorded in Account 925 (Damages and Injuries), pursuant to the Federal Energy Regulatory Commission's ("FERC") directive[3] and $2.4 million of Sunrise Powerlink intervener compensation expenses. The impact of these two items on the TU Adjustment is $4.0 million. The decrease was partially offset by a $0.4 million increase in security expenses to meet NERC requirements.

3. Account 570 (Electric Transmission Maintenance – Station Equipment)

The $0.9 million increase in this account was caused primarily by an increase in expenses at Imperial Valley Substation caused by an earthquake that occurred nearby on April 4, 2010, and higher expenses for maintenance of circuit breakers and transformers.

B. A&G Expenses (Exhibit No. 3)

SDG&E's electric A&G expenses support its generation, transmission, and distribution services. A portion is allocated to SDG&E's transmission services, primarily on a labor ratio basis. As shown in Column H, Line 3, of Exhibit No. 1, A&G expenses allocated to transmission are undercollected by $6.4 million. This amount is transmission's portion of a $35.5 million increase in total electric A&G expenses between prior periods and the TU Period, as shown on Line 6 of Exhibit No. 3.

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[3] *See Order on Annual Formula Rate Filing, and Directing Accounting Change,* 133 FERC ¶61,016 (2010).

Part A, Column H, Line 6 of Exhibit No. 3 shows SDG&E's $35.5 million of total electric service A&G expense cost differences, before the allocation to transmission. To explain the causes of the TU differences for A&G, we will explain the differences for electric A&G in total, which is shown in Part A. Part B shows the allocators that are multiplied by total electric A&G expenses in Part A to yield the $6.4 million of A&G expenses that are allocated to transmission service, which are shown in Part C.

The main reasons for the $35.5 million increase in total electric A&G expenses are explained by FERC account, as follows:

1. Account 923 (Outside Services)

The $5.0 million increase in this account shown in Exhibit No. 3, Line 2 is primarily due to costs allocated to SDG&E from the Sempra Corporate Center.

2. Account 925 (Injuries and Damages)

Account 925 increased by $25.1 million, due primarily to wildfire insurance premium expenses. In accordance with the FERC directive to charge wildfire insurance premium expenses to A&G,[4] SDG&E began charging to Account 925 the wildfire insurance premium expenses that it incurs on an ongoing basis. SDG&E also transferred expenses that it had previously direct charged to transmission and distribution O&M expenses since July 2009.

3. Account 926 (Employee Pensions and Benefits)

The increase of $3.5 million in this Account was caused primarily by increased funding to SDG&E's employee pension plan during the TU Period, to compensate for a lower return received on pension fund assets as a result of activities in the financial market.

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[4] *Id.*

C. Depreciation and Amortization – Inverse Condemnation Expenses

The increase of $19.7 million is due to transmission-related inverse condemnation costs that were amortized during the TU Period. These expenses are referenced in III. B, above.

D. Return on Rate Base

SDG&E experienced an overcollection of return on rate base equal to $7.8 million, as shown in Column H, Line 8, of Exhibit No. 1. The overcollection had two causes. First, as shown in Table III below, cost of capital during the 2008 and 2009 Base Period was higher than during the TU Period. The higher cost of capital during the Base Periods compared to the TU Period contributed about $3.0 million to the overcollection of return on rate base.

Table III: Decrease in Cost of Capital

	2008	2009	Mar. 2011 12-MTD (TU Period)
Cost of Capital	13.21%	12.75%	12.52%

The other cause of the overcollection of return on rate base was lower growth in plant stemming from transmission plant additions forecasted in previous cyclical filings. This was due to the previously forecasted plant additions going into service at a later date or at lower cost. Approximately $4.8 million of the overcollection is attributed to this item.

San Diego Gas & Electric Company

TO3-Cycle 5 True-Up Adjustment

"Exhibits 1- 3"

Docket No. ER11-____-____

San Diego Gas & Electric Company — **Exhibit No. 1**

TO3 Cycle 5 True-Up (TU) Period Adjustment Analysis

For 12 Months April 1, 2010 to March 31, 2011

($ in Millions)

Line No.	Description		A	B	C	D	E	F	G	H	Line No.
			Prior Period Revenue Requirements (a)		**Revenue Recorded in TU Period**				**True-Up**	**True-Up**	
			TO3 Cycle 3 2008	TO3 Cycle 4 2009	TO3 Cycle 3 5 Mos. 4/10 - 8/10 = A * 37.09% (b)	TO3 Cycle 4 7 Mos. 9/10 - 3/11 = B * 56.61% (b)	12 Mos. 4/10 - 3/11 12 Mos. C + D	12 Mos. 4/10 - 3/11 Adjusted for Sales (c)	**Period COS** 4/10-3/11	**Adjust-ment** G - F	
1	**A. Expense**										1
2	Transmission O&M		$ 39.5	$ 50.8	$ 14.7	$ 28.7	$ 43.4	$ 45.8	$ 44.6	$ (1.3)	2
3	Transmission Related A&G		21.9	23.5	8.1	13.3	21.4	22.6	29.1	6.4	3
4	Depreciation and Amortization		44.1	50.9	16.3	28.8	45.2	47.7	49.8	2.1	4
5	Dep.& Amort. - Inv. Condemnation Exp.		-	-	-	-	-	-	19.7	19.7	5
6	Other		10.8	12.6	4.0	7.1	11.2	11.8	9.4	(2.4)	6
7	Total Expense	∑L2...L6	$ 116.3	$ 137.8	$ 43.1	$ 78.0	$ 121.2	$ 128.0	$ 152.5	$ 24.5	7
8	**B. Return on Rate Base and Plant Adds**		$ 140.5	$ 153.7	$ 52.1	$ 87.0	$ 139.1	$ 146.9	$ 139.1	$ (7.8)	8
9	**C. Total**										9
10	Total Before FF&U	L7 + L8	$ 256.8	$ 291.6	$ 95.3	$ 165.1	$ 260.3	$ 274.9	$ 291.6	$ 16.7	10
11	FF&U		3.1	3.8	1.2	2.1	3.3	3.5	3.4	(0.1)	11
12	Total excluding impact of lower sales	L10 + L11	$ 260.0	$ 295.3	$ 96.4	$ 167.2	$ 263.6	$ 278.4	$ 295.0	$ 16.7	12
13	Costs not collected due to lower sales	Cols. F - E								14.8	13
14	Interest									0.7	14
15	Total Under/(Over)collection (d)	∑L12...L14								$ 32.1	15
16											16

17 Footnotes

18

19 (a) Columns A and B are revenue requirements for base periods and forecasted plant additions. Revenue requirements for prior true-up
20 (TU) adjustments are excluded, because the Cycle 5 TU Adjustment should not true up the true-ups of prior cycles. The TO3 Cycle 3
21 total in Col. A, L12 excludes True-Up (TU) Adjustments totaling $11.2 million for the TO3 Cycle 3 TU Period. The TO3 Cycle 4 total in
22 Col. B, L12 excludes TU Adjustments totaling $32.2 million for the TO3 Cycle 4 TU period. These TU adjustments are shown in
23 Statement BK-1, page 5 of the Cycle 3 and Cycle 4 filings.

24

25 (b) Impact of lower sales on revenue: 37.09% is derived by dividing the revenues recorded for Cycle 3 during the first five months of the
26 TU Period ($96.4 million) by Col. A, L12. 56.61% is derived by dividing the revenues recorded for Cycle 4 during the last seven months
27 of the TU Period ($167.2 million) by Col. B, L12. See True-Up Adjustment Workpaper-1 in Vol. 3.

28

29 (c) The adjustment for sales equals Col. E multiplied by the adjustment factor calculated in TU Adjustment Workpaper-3, L14 (105.6%).

30

31 (d) Excluding Depreciation and Amortization - Condemnation Expense (L5), the total undercollection is $11.9 million.

Exhibit No. 2

San Diego Gas & Electric Company
TO3 Cycle 5 True-Up (TU) Period Adjustment - O&M
For 12 Months April 1, 2010 to March 31, 2011
($ in Millions)

Line No.	FERC Prime Account		A Base Periods TO3 Cycle 3 2008	B Base Periods TO3 Cycle 4 2009	C Revenue Recorded in TU Period (a) 4/10 - 8/10 = A * 37.09%	D Revenue Recorded in TU Period (a) 9/10 - 3/11 = B * 56.61%	E Revenue Recorded in TU Period (a) 4/10 - 3/11 12 Mos. C + D	F Revenue Recorded in TU Period (a) 4/10 - 3/11 Adjusted for Sales (b)	G Cost of Service in TU Period 4/10-3/11	H True Up Adjust-ment G - F	Line No.
1	560	Operation Supervision and Engineering	$ 6.0	$ 6.3	$ 2.2	$ 3.6	$ 5.8	$ 6.1	$ 6.7	$ 0.6	1
2	566	MiscellaneousTransmission Expense	7.4	15.4	2.8	8.7	11.5	12.1	8.5	(3.6)	2
3	570	Maint. of Station Eqpt	5.4	5.8	2.0	3.3	5.3	5.6	6.5	0.9	3
4		All other accounts	20.7	23.3	7.7	13.2	20.8	22.0	22.8	0.8	4
5											5
6		Total	$ 39.5	$ 50.8	$ 14.7	$ 28.7	$ 43.4	$ 45.8	$ 44.6	$ (1.3)	6
7											7
8											8
9	Footnotes										9
10	(a) Impact of lower sales on revenue: 37.09% is derived by dividing the revenues recorded during the first five months										10
11	of the TU Period ($96.4 million) by the Cycle 3 revenue requirement, less TU Adjustments ($260.0). 56.61% is derived										11
12	by dividing the revenues recorded during the last seven months of the TU Period ($167.2 million) by the Cycle 4										12
13	revenue requirement, less TU Adjustments ($295.3). See TU Adjustment Workpaper-1.										13
14	(b) The adjustment for sales equals Col. E multiplied by the adjustment factor calculated in TU Adjustment Workpaper-3, L14 (105.6%).										14

Exhibit No. 3

San Diego Gas & Electric Company
TO3 Cycle 5 True-Up (TU) Period Adjustment - A&G
For 12 Months April 1, 2010 to March 31, 2011
($ in Millions)

Line No.	FERC Prime Account	A Base Periods TO3 Cycle 3 2008	B Base Periods TO3 Cycle 4 2009	C Revenue Recorded in TU Period (a) 4/10 - 8/10 = A * 37.09%	D Revenue Recorded in TU Period (a) 9/10 - 3/11 = B * 56.61%	E Revenue Recorded in TU Period (a) 4/10 - 3/11 12 Mos. C + D	F Revenue Recorded in TU Period (a) 4/10 - 3/11 Adjusted for Sales (d)	G Cost of Service in TU Period 4/10-3/11	H True Up Adjust-ment G - F	Line No.
1	**A. Before Allocation to Electric Transmission**									1
2	923 Outside Services	52.5	58.3	19.5	33.0	52.5	55.4	60.4	5.0	2
3	925 Damages & Injuries	12.9	10.1	4.8	5.7	10.5	11.1	36.2	25.1	3
4	926 Employee Pension & Benefits	43.5	51.2	16.1	29.0	45.1	47.7	51.1	3.5	4
5	All other accounts	41.7	39.4	15.5	22.3	37.8	39.9	41.8	1.9	5
6	Total	$ 150.6	$ 159.1	$ 55.9	$ 90.1	$ 145.9	$ 154.1	$ 189.6	$ 35.5	6
7										7
8	**B. Allocation Factors**									8
9	Transm. Plant Prop. Insurance Alloc. Factor (b)	22.54%	23.45%					23.50%		9
10	Transm. Wages and Salaries Alloc. Factor (c)	14.38%	14.61%					15.19%		10
11										11
12	**C. After Allocation to Electric Transmission**									12
13	923 Outside Services	7.5	8.5	2.8	4.8	7.6	8.0	9.2	1.1	13
14	925 Damages & Injuries	1.8	1.5	0.7	0.8	1.5	1.6	5.5	3.9	14
15	926 Employee Pension & Benefits	6.3	7.5	2.3	4.2	6.6	6.9	7.8	0.8	15
16	All other accounts (L19-∑(L14...L17)	6.2	6.0	2.3	3.4	5.7	6.1	6.6	0.6	16
17	Total	$ 21.9	$ 23.5	$ 8.1	$ 13.3	$ 21.4	$ 22.6	$ 29.1	$ 6.4	17
18										18
19										19
20	Footnotes									20
21	(a) Impact of lower sales on revenue: 37.09% is derived by dividing the revenues recorded during the first five months									21
22	of the TU Period ($96.4 million) by the Cycle 3 revenue requirement, less TU Adjustments ($260.0). 56.61% is derived									22
23	by dividing the revenues recorded during the last seven months of the TU Period ($167.2 million) by the Cycle 4									23
24	revenue requirement, less TU Adjustments ($295.3). See TU Adjustment Workpaper-1.									24
25	(b) The Transmission Plant Property Insurance Allocation Factor, which is used for Account 924, is derived in Statement AH.									25
26	(c) The Transmission Wages and Salaries Allocation Factor, which is used for Accounts other than Account 924, is derived in Statement AI.									26
27	(d) The adjustment for sales equals Col. E multiplied by the adjustment factor calculated in TU Adjustment Workpaper-3, L14 (105.6%).									27

San Diego Gas & Electric Company

Sunrise Powerlink Project Report

Docket No. ER11-____-____

SUNRISE POWERLINK PROJECT REPORT

I. INTRODUCTION

SDG&E has included approximately $518 million[1] of weighted capitalized costs associated with the Sunrise Powerlink Project ("Sunrise" or "Project"). Sunrise is a 500/230 kV transmission line that runs approximately 117 miles between the Imperial Valley and the San Diego service area and is estimated to go into service in June 2012 at an un-weighted cost of approximately $1.883 billion. On August 3, 2006, the California Independent System Operator Corporation ("CAISO") Board of Governors unanimously approved the Project and directed SDG&E and its partners, Imperial Irrigation District ("IID") and Citizens Energy, to proceed with the necessary permitting and construction of the Project.[2] IID eventually declined to participate in the Project. The CAISO approval obligated SDG&E to construct Sunrise, subject to SDG&E obtaining all necessary approvals and property rights under applicable federal, state and local laws necessary to complete the construction of the required transmission additions or upgrades[3]

The California Public Utilities Commission ("CPUC") authorized SDG&E to construct the Project in "Decision Granting a Certificate of Public Convenience and Necessity for the

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[1] This amount reflects, for the predominant portion of Sunrise, a weighting of 3 months divided by 12 months or 25% of the total estimated cost of the Project, based on a forecast June 2012 in-service date for Sunrise.

[2] Because the minutes and resolution of this Board meeting are not archived electronically on the CAISO's website, SDG&E has included them as work papers in Volume 3 of this Informational Filing.

[3] Section 24, Transmission Expansion, of the CAISO FERC Tariff ("Tariff"), Third Replacement Volume No. 1, in effect when the CAISO approved Sunrise, provided that "[a] Participating TO ("PTO") shall be obligated to construct all transmission additions and upgrades that are determined to be needed in accordance with the requirements of this Section 24" and that "[the] obligation to construct…shall be subject to the [PTO's] ability…to obtain all necessary approvals and property rights under applicable federal, state and local laws." (See work papers in Volume 3 for a copy of the then-applicable Tariff). While succeeding iterations of Section 24 may have changed the processes and procedures for obtaining CAISO approval, what has not changed is the fact that CAISO approval triggers the PTO's obligation to construct, subject to obtaining the requisite approvals and property rights under applicable federal, state and local laws. *See* Section 24, Comprehensive Transmission Planning Process, of the CAISO FERC Electric Tariff, Fifth Replacement Volume No. 1. http://www.caiso.com/2b53/2b539142652a0.html.

Sunrise Powerlink Transmission Project," issued December 18, 2008 ("Decision" or "CPCN").[4] The Decision found that Sunrise would: (1) enhance regional reliability[5] and mitigate congestion within the National Interest Electric Transmission Corridor, [6] (2) advance the State's renewable goals of reducing greenhouse gas emissions through renewable generation procurement at a 33% Renewable Portfolio Standards by 2020 by facilitating the development of renewable generation in the Imperial Valley area[7] and (3) provide economic benefits to customers utilizing the transmission grid operated by the CAISO.

II. COST STATEMENTS REFLECTING SUNRISE PROJECT COSTS

SDG&E has prepared Exhibit No. 1 to explain where Sunrise costs appear in the various Cycle 5 cost statements. The costs indicated in Exhibit No. 1 reflect only capital costs and no operations and maintenance expenses are included in the instant filing pursuant to the operation of SDG&E's TO3 Settlement. Line 10, Column 2 of the exhibit indicates total Project costs equal to the $1.883 billion cost cap adopted in the CPCN. What follows is an explanation that reconciles the costs in other lines to this total amount.

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[4] Decision ("D.") 08-12-058, 2008, Cal. PUC LEXIS 534. http://docs.cpuc.ca.gov/WORD_PDF/FINAL_DECISION/95750.PDF.

The CPUC's website contains all of the procedural filings, including SDG&E's application at the following link: http://docs.cpuc.ca.gov/published/proceedings/A0608010.htm.

In addition, all of the environmental documents are located on the CPUC's website at the following link: http://www.cpuc.ca.gov/Environment/info/aspen/sunrise/sunrise.htm.

[5] D.08-12-058 found that there exists a "reliability need" for SDG&E's service area by 2014 and perhaps sooner, given the many uncertainties in the modeling assumptions adopted in the decision. Finding of Fact 7, *mimeo* at 283.

[6] 72 Fed. Reg. 56992 (October 5, 2007). The DOE designated two National Interest Electric Transmission Corridors pursuant to section 204 of the Federal Power Act, 16 USC §824o, one of which encompasses San Diego County. *Id.* at 57025.

[7] *Id.*, Findings of Fact 15 and 19.

A. Sunrise Costs Included in the Cycle 5 Forecast Period (April 2011 through August 2012)

- Line 1 of Exhibit No. 1 shows the bulk of the Project that is shown in the Cycle 5 Forecast Period for an in service date ("ISD") of June 2012. As indicated in column 3 this amount is shown in Volume 3 under the tab entitled "Forecast Plant Additions" in the month of June 2012. The amount, shown in the lower portion of this cost statement, consists of the following primary segments of Sunrise and embedded mitigation costs:[8]

  - 500 kV transmission lines $944 million
  - 230 kV overhead line $234 million
  - 230 kV undergrounding $348 million
  - Suncrest 500/230 kV Substation $240 million

- These segments are shown on a map in Exhibit No. 2. To the extent these facilities represented by these costs have an ISD of June 2012, and provide customers with 3 months of service (June 2012 through August 2012) during the Cycle 5 Rate Effective Period (September 2011 through August 2012), they are given of weighting of 3 months divided by 12 months or 25% for revenue recovery purposes.

- Line 2 shows amounts for upgrades to existing substations and transmission tie lines. See Volume 3 under the tab entitled "Forecast Plant Additions" for detailed information. The un-weighted costs of these substation and transmission line upgrades are as follows:

[8] SDG&E is responding to key mitigation measures that various permitting governmental agencies imposed on it through detailed: (1) fire mitigation measures and creation of a trust to meet some of these measures, (2) environmental consultants for biological monitoring during construction and (3) purchase of mitigation land and establishment of endowment for third-party to manage the mitigation land.

Substation Upgrades

- Imperial Valley $17.4 million
- Sycamore Canyon $16.5 million
- South Bay $ 0.9 million
- Encina $31.2 million
- San Luis Rey $ 7.3 million
- Pomerado $ 1.5 million
- Scripps $ 1.3 million

Transmission Line Upgrades

- Tie Line 639 $ 5.2 million
- Tie Line 6916 $ 8.3 million
- Tie Line 6915/6924 $ 1.5 million

- See the map in Exhibit No 2 for the location of these upgrades. These upgrades have different in-service dates, depending upon when they are energized, and the forecast period costs are weighted accordingly. See Forecast Capital Additions in Volume 3 under the tab entitled "Forecast Plant Additions."

- Line 3 indicates that all of the South Bay Substation and portions of the San Luis Rey Substation upgrades were energized in November 2010 and December 2010, respectively. Those costs are included in Statement AD of the True-Up ("TU") Period work papers in Volume 3 on a 13-month-average weighted basis. These amounts are also shown in Volume 3 in "Forecast Plant Additions."

- Line 4 shows the communication equipment allocated to the Project. As indicated in line 13, the Sunrise project requires approximately $25.7 million of communication equipment but because this communication equipment will be directly booked to electric general plant, Account 397 (Communication Equipment), only a labor ratio portion of these communication facilities is allocated to transmission service. In the instant filing, the 15.19% transmission labor ratio times the total communication facilities are assigned to transmission service. The 2010 Base Period cost statement AI, located in Volume 1 derives this labor ratio. The remaining portion of communication facilities not assigned to transmission will be recovered through CPUC distribution rates.

B. Lease Right of Way and Land Purchased for Sunrise

- Line 5 reflects approximately $57.6 million of leased land rights of way ("ROW") that were purchased in 2010 primarily from the Bureau of Land Management, U.S. Department of Interior. Because they were purchased in 2010, they are not shown in the Forecast Period but are booked as Plant Held for Future Use; amortization will commence effective June 2012. This amount is shown in the TU Period cost statement AG in Volume 3 and is reflected as a 13 month average in the statement.

- Line 6 reflects approximately $2.3 million of land that SDG&E purchased from third parties for land ROW related to the new Sunrise transmission lines and Suncrest substation. This land in shown in a work paper in Volume 3, Tab entitled cost statement "AD" for the TU Period, transmission plant in service. Typically for land, if the construction of a transmission project starts within 12

months after the land is purchased, SDG&E will book this land to Account 350, transmission Land and Land Rights. For example, since the construction of Sunrise started in 2009, this start date meets the 12 month rule and therefore the purchased land is recorded in Account 350. The amount shown may change slightly as some of the parcels purchased are currently in condemnation process. Any changes to the land amounts will not affect the total cost of the project as these costs will be covered by the contingency in the total project.

C. Summary of Total Sunrise Costs in SDG&E's Transmission Cost of Service

Line 7 shows the sum of lines 1 through 6, which reflects the total costs of the Project SDG&E has included in its Cycle 5 filing as part of transmission cost of service.

D. Exclusion from Transmission Cost of Service of Citizens Energy Lease Cost and Allocated Portion of Communication Equipment

- Line 8 reflects half the cost of 30 miles of Sunrise 500 kV line from the Imperial Valley Substation going west to the Imperial County line because of SDG&E's lease to Citizens Energy. This cost is approximately $83 million. This arrangement has been approved by the FERC and by the CPUC.[9]

- Line 9 indicates the remaining portion of the Sunrise communication equipment that is allocated to CPUC distribution service and recorded to Account 397, Communication Equipment.

[9] D.11-05-048, http://docs.cpuc.ca.gov/WORD_PDF/FINAL_DECISION/136211.PDF; 129 FERC ¶61,242, 2009 FERC LEXIS 2568 (FERC 2009).

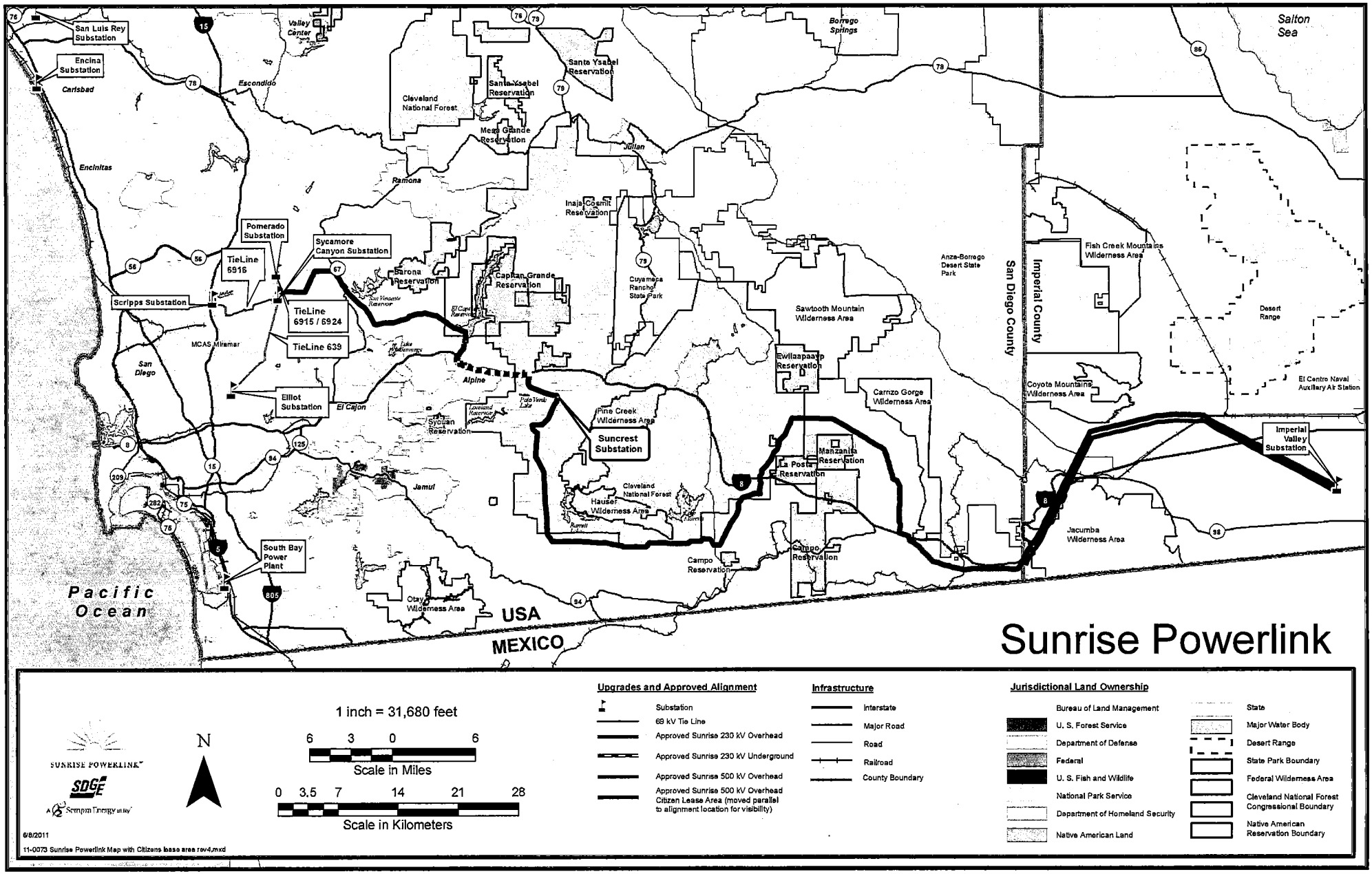
E. Summary of Sunrise Cost Statements

As noted in Exhibit 1, once SDG&E adds line 7, Sunrise costs in SDG&E's transmission cost of service, to lines 8 and 9, Sunrise costs not in transmission cost in service, the total reconciles to $1.883 billion.

Sunrise Cost Components in SDG&E TO3 Cycle 5 **Exhibit No. 1**

All amounts in $1,000

Line No	1 Description	2 Amount	3 Reference
1	Sunrise Forecast Plant Add in June 2012 (1)	1,623,095	Vol. 3, Section 3A; Tab "Forecast Plant Adds", Pg 2 of 6; Lines 64
2	Upgrades to Existing Substation & Tie lines - Various in service dates	89,007	Vol. 3, Section 3A; Tab "Forecast Plant Adds", Pg 2 of 6; Lines 55 - 63
3	Existing South Bay & San Luis Rey Substation Upgrades currently in service(2)	2,178	See footnote (2)
4	Communications Equip Allocated to Transmission(3)	3,900	see caculation below, line 14
5	Leased Right of Way in PHFU as of March 2011(4)	57,656	Vol. 3, Section 3B; Statement AG; AG3, line 10
6	Land as of March 2011	2,328	Vol. 3, Section 3B; Statement AD; AD-11, Pg 2 of 2, line 17 (in account 350.1- Transmission plant)
7	**Subtotal Sunrise Costs Reflected in Transmission Service**	**1,778,164**	
8	Citizens Lease (5)	83,064	Not included in transmission plant
9	Communication Equip Not Include in Transmission Plant	21,772	To be recovered in CPUC Distribution Rates
10	**Subtotal Reflected in Forecast of Plant Additions**	**1,883,000**	
		==========	
11	(1) As shown on line 1, $1.623 billion will be included in SDG&E's forecast period for the month of June 2012. Since this project will go into service in June 2012 and customers will benefit from the project for the last 3 months of the rate effective period, this cost will be weighted 25% (3/12 months).		
12	(2) South Bay Substation upgrade of $879 K went into service in Nov 2010 and a portion of the San Luis Ray substation upgrade equal to $1,299K went into service Dec 2010. These costs are embedded in Statement AD, transmission plant in service.		
13	(3) Communication equipment is booked in Acct 397 (Communication Equipment) in General Plant and is allocated to transmission using a 15.19% labor ratio. Thus, the following amount of communication equipment is assigned to transmission		
	Total Communication	$ 25,672	Vol. 3, Section 3A; Tab "Summary of Monthly General, Common, & IT Plant Adds"; Pg 3 of 3, line 12
14	Communication Equip allocated toTrans ($25,672 X 15.19%)	$ (3,900)	
	Communication not included in Transmission	$ 21,772	
15	(4) PHFU = Plant Held for Future Use		
16	(5) 30 mile section of the 500 kV Sunrise Powerlink located in Imperial County that SDG&E will lease to Citizens Energy		



Sunrise Powerlink

1 inch = 31,680 feet

N

6 3 0 6
Scale in Miles

0 3.5 7 14 21 28
Scale in Kilometers

SUNRISE POWERLINK™
SDGE
A Sempra Energy utility

Upgrades and Approved Alignment

- Substation
- 69 kV Tie Line
- Approved Sunrise 230 kV Overhead
- Approved Sunrise 230 kV Underground
- Approved Sunrise 500 kV Overhead
- Approved Sunrise 500 kV Overhead Citizen Lease Area (moved parallel to alignment location for visibility)

Infrastructure

- Interstate
- Major Road
- Road
- Railroad
- County Boundary

Jurisdictional Land Ownership

- Bureau of Land Management
- U. S. Forest Service
- Department of Defense
- Federal
- U. S. Fish and Wildlife
- National Park Service
- Department of Homeland Security
- Native American Land
- State
- Major Water Body
- Desert Range
- State Park Boundary
- Federal Wilderness Area
- Cleveland National Forest Congressional Boundary
- Native American Reservation Boundary

6/8/2011

11-0073 Sunrise Powerlink Map with Citizens lease area rev4.mxd

San Diego Gas & Electric Company

Wildfire Cost Recovery/Inverse Condemnation Report

Docket No. ER11-____-____

WILDFIRE COST RECOVERY/INVERSE CONDEMNATION REPORT

I. INTRODUCTION

This Report summarizes the rationale for and accounting treatment of the settlement costs and legal costs associated with the uninsured third-party real property losses arising from the October 2007 wildfires in San Diego County ("the Wildfire Property Costs").[1] The TO3, Cycle 5 filing includes approximately $19.687 million in Wildfire Property Costs that have been borne by San Diego Gas & Electric Company ("SDG&E") attributable to the Witch Fire, which was attributable to transmission assets. In total, SDG&E has incurred $44.489 million in Wildfire Property Costs, but, subject to the Commission's approval of SDG&E's proposed recovery herein of $19.687 million, SDG&E will account for the $24.802 million attributable to the Rice and Guejito Fires, which were attributable to distribution assets in a separate account not included in the BTRR calculations under the TO3 Tariff.[2]

Because the land owners affected by the Witch Fire are pursuing compensation for the "taking" of private property for public use, as defined under California law, SDG&E proposes to account for these real property-related costs in this Cycle 5 *via*: (1) FERC Account 350, Land and Land Rights; (2) FERC Account 404, Amortization of Limited-Term Electric Plant; (3) FERC Account 111, Accumulated Provision for Amortization of Electric Utility Plan and (4) Electric Plant Instruction 7. Charging these transmission costs to Account 350 complies with the definition contained in the FERC Uniform System of Accounts ("USoA") and appropriately assigns costs directly to the relevant customer class. The USoA states that "condemnation

[1] *See* page 208 and associated footnotes of SDG&E's Form 3Q, filed May 31, 2011, set forth in Volume 3 of this Informational Filing.

[2] *See* Exhibit No. SDG-1, attached hereto.

proceedings, including court and counsel costs" are "items of cost to be included in the accounts for land and land rights." *See* 18 C.F.R. Part 101, Electric Plant Instruction 7(I)(4). SDG&E will fully amortize the Wildfire Property Costs charged to Account 350 in the same month in which they are paid out *via* FERC Account 404 and Account 111 which means that SDG&E will not earn a return on its limited-term interest in the land rights acquired through inverse condemnation. Similarly, SDG&E proposes to account for the Wildfire Property Costs associated with the Rice and Guejito Fires *via* the corresponding accounts related to Distribution Plant: (1) FERC Account 360, Land and Land Rights; (2) FERC Account 404, Amortization of Limited-Term Electric Plant; (3) FERC Account 111, Accumulated Provision for Amortization of Electric Utility Plant and (4) Electric Plant Instruction 7.

SDG&E believes this proposed accounting treatment is consistent with the USoA, the TO3 settlement, and the filed-rate doctrine. Moreover, this proposed treatment is consistent with (1) California law on inverse condemnation and (2) the accounting principle that because these costs are directly attributable to transmission, they should be directly assigned to transmission.

II. BACKGROUND

In October 2007, San Diego County experienced several catastrophic wildfires. Reports issued by the California Department of Forestry and Fire Protection (Cal Fire) concluded that two of these fires (the Witch and Rice Fires) were caused by SDG&E power lines and that a third fire (the Guejito Fire) occurred when a wire securing a Cox Communications' fiber optic cable came into contact with an SDG&E power line "causing an arc and starting the fire." The Witch Fire was related to an SDG&E transmission line, while the Rice and Guejito Fires were related to distribution assets. SDG&E proposes in this filing to seek recovery *via* the TO3 Tariff of the Wildfire Property Costs associated with the Witch Fire only, although SDG&E's proposed

accounting for all of the Wildfire Property Costs is being done on a consistent basis using the appropriate Transmission Plant and Distribution Plant Accounts.

III. INVERSE CONDEMNATION

A. Principle

An inverse condemnation action is an eminent domain proceeding initiated by the property owner instead of by the public utility in which the property owner claims that his or her property was taken or damaged, either on a temporary or permanent basis, for a public use without just compensation. Inverse condemnation is a constitutional rather than a tort claim. The California Court of Appeal has held that inverse condemnation liability claims may be asserted against public utilities in the context of wildfire claims, noting that "[t]he fundamental policy underlying the concept of inverse condemnation is to spread among the benefiting community any burden disproportionately borne by a member of that community, to establish a public undertaking for the benefit of all."[3] The Court explained that in the context of a transmission-line initiated fire, when the line serves a number of households, the line is for the benefit of the public.[4] The Court thus concluded that harm to property from a fire caused by that line was a taking for public use, *i.e.*, condemnation.[5]

Here, third party claimants pursuing inverse condemnation claims have contended that SDG&E, as a public utility, has deprived them of the full use and enjoyment of their property rights. The California Superior Court has specifically found that inverse condemnation claims can be pursued against SDG&E because SDG&E is a public entity for purposes of such claims

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[3] *Barham v. Southern California Edison Co.*, 74 Cal. App. 4th 744, 752-53 (1999).

[4] The *Barham* Court stated, "The evidence reflects the circuit, of which the subject pole and transmission wires were a part, provides electric service to more than 1,000 households. Based upon the above cited authority, we must conclude that the transmission of electric power through the facilities that caused damage to the Barham's property was for the benefit of the public." *Id.* at 754, citing *Slemons v. Southern Cal. Edison Co.*, *supra*, 252 Cal. App. 2d 1022, 1026 (1967) [electric transmission lines to three customers was a public use]."

[5] *Id*.

and because the taking was for a public use, *i.e.*, providing electricity to customers.[6] SDG&E is now incurring costs to resolve these condemnation claims.

B. Accounting Treatment

A basic accounting premise is to use direct charging first, followed by causal allocation methods and finally more generic allocation methods. According to these basic principles, claim costs associated with the Witch Fire would be charged to the transmission business and claim costs associated with the Rice and Guejito Fires to the distribution business.

Because the primary claim being advanced by third parties is inverse condemnation, a California constitutional claim derived from condemnation proceedings involving strict liability without regard to negligence or intentional wrongdoing, SDG&E proposes to account for the Wildfire Property Costs in the appropriate real property accounts for Transmission Plant and Distribution Plant. Specifically, FERC Account 350 includes "the cost of…land rights used in connection with transmission operations." Electric Plant Instruction 7, subsection I (4), provides that Account 350 "shall include costs associated with condemnation proceedings, including court and counsel costs." Electric Plant Instruction 7(H) further confirms that "limited-term interests in land" are appropriately included in Account 350 and specifies the use of Accounts 111 and 404 to "apportion equitably the cost of each interest over the life thereof." SDG&E will use FERC Account 360 (Land and Land Rights for Distribution Plant) for the Rice and Guejito Fires.

Accordingly, SDG&E has charged the $19.687 million in Wildfire Property Costs associated with the Witch Fire to FERC Account 350 and amortized its limited term interest in this land right in the same period to FERC Account 404 Amortization of Limited-Term Electric Plant, with an offsetting credit to FERC Account 111 Accumulated Provision for Amortization

[6] The Court's ruling appears as a work paper in Volume 3 of this Informational Filing.

of Electric Utility Plant. In sum, charging the Wildfire Property Costs to Account 350 complies with the USoA and fairly assigns costs directly to the most appropriate customer. Moreover, by fully amortizing these costs in the same month in which they are paid out *via* FERC Account 404 and Account 111, SDG&E does not earn a return on its limited-term interest in the land rights acquired through inverse condemnation.

IV. COST STATEMENTS REFLECTING THE WILDFIRE PROPERTY COSTS

- Based upon the above, $19.687 million of Wildfire Property Costs are included in SDG&E's True-Up Cost of service, 12-month ended March 2011. These costs were recorded in March 2011 and are shown in the True-Up Cost of Service work papers in Cost Statement AD, transmission FERC Account 350, based upon a 13 month average of this amount. Also in March 2011, a credit of $19.687 million is reflected in Cost Statement AE, transmission accumulated depreciation FERC Account 111. This amount appears in Statement AE and also is based upon a 13 month average. As a result of the two above entries, the net change to transmission net plant for the True-Up Cost of Service is "zero."
- The last accounting entry that is made to address this matter is to Cost Statement AJ, depreciation and amortization expense, to reflect the debit to this account of $19.687 million. When this debit was made and as indicated above, a corresponding offsetting credit was made to accumulated depreciation, Statement AE.

SDG&E Wildfire Inverse Condemnation Costs
TO3 Cycle 5
($ in millions)

Line No.		CPUC Distribution Rice Fire	CPUC Distribution Guejito Fire	FERC Transmission Witch Fire	Total	Line No.
1	Legal Costs (deductibles)	1.0	1.0	1.0	3.0	1
2	Legal Costs (after deductibles)	0.7	2.1	2.4	5.2	2
3	Wildfire Inverse Condemnation Costs	5.1	14.9	16.3	36.3	3
4	Total	6.8	18.0	19.7	44.5	4

San Diego Gas & Electric Company

Part – II

TO3-Cyle 5
12-Month Period Retail True-Up
Adjustment Cost Statements in
Volume 2-A

Docket No. ER11-____-____

San Diego Gas & Electric Company

True-Up Period
Statement AD –Cost of Plant

Docket No. ER11-____-____

SAN DIEGO GAS AND ELECTRIC COMPANY
Statement AD
Cost of Plant
True Up Period (4/1/2010 - 3/31/2011)
($1,000)

Line No		Amounts	Reference	Line No
1	Total Electric Miscellaneous Intangible Plant [2]	$ 28,039	Stmnt AD WP; Col C, Line 1	1
2				2
3	Total Steam Production Plant	343,909	Stmnt AD WP; Col C, Line 3	3
4				4
5	Total Nuclear Production Plant	1,369,640	Stmnt AD WP; Col C, Line 5	5
6				6
7	Total Hydraulic Production Plant	-	Stmnt AD WP; Col C, Line 7	7
8				8
9	Total Other Production Plant	289,817	Stmnt AD WP; Col C, Line 9	9
10				10
11	Total Production Plant and Intangible plant	$ 2,031,404	Sum Lines 1 thru 9	11
12				12
13	Total Distribution Plant	4,489,770	Stmnt AD WP; Col C, Line 13	13
14				14
15	Total Transmission Plant [1]	1,646,488	Stmnt AD WP; Col C, Line 15	15
16				16
17	Total General Plant [2]	182,263	Stmnt AD WP; Col C, Line 17	17
18				18
19	Total Common Plant [2]	483,398	Stmnt AD WP; Col C, Line 19	19
20				20
21	Total Plant in Service	$ 8,833,323	Sum Lines 11 thru 19	21
22				22
23	Transmission Plant	1,646,488	Stmnt AD WP; Col C, Line 23	23
24				24
25	Transmission Wages and Salaries Allocation Factor	15.19%	Statement AI; Line 19	25
26				26
27	Transmission Related Electric Miscellaneous Intangible Plant	4,259	Line 1 x Line 25	27
28				28
29	Transmission Related General Plant	27,686	Line 17 x Line 25	29
30				30
31	Transmission Related Common Plant	73,428	Line 19 x Line 25	31
32				32
33	Transmission Related Plant in Service	$ 1,751,861	Sum Lines 23; 27; 29; 31	33
34				34
35	Transmission Plant Allocation Factor [3]	19.83%	Line 33 / Line 21	35

NOTES:

[1] The amounts stated above are ratemaking utility plant in service and are derived by multiplying the book utility plant in service by the FERC's Seven Element Adjustment Factors.

[2] Electric Miscellaneous Intangible Plant, General Plant, and Common Plant have a Seven Element Adjustment Factor of "1" because there is no transfer of transmission or distribution plant among these categories.

[3] Used to allocate all elements of working capital, other than working cash, in conformance with TO-3 settlement, Appendix VIII, Page 139, Item 3

San Diego Gas & Electric Company

True-Up Period
Statement - AE
Accumulated Depreciation and Amortization

Docket No. ER11-____-____

SAN DIEGO GAS AND ELECTRIC COMPANY
Statement AE
Accumulated Depreciation and Amortization
True Up Period (4/1/2010 - 3/31/2011)
($1,000)

Line No		Amounts	Reference	Line No
1	Transmission Depreciation Reserve [1]	$ 500,155	Stmnt AE WP; Page-AE1; Col C, Line 1	1
2				2
3	Electric Miscellaneous Intangible Plant Amortization Reserve [2]	26,110	Stmnt AE WP; Page-AE1; Col C, Line 3	3
4				4
5	General Plant Depreciation Reserve [2]	78,271	Stmnt AE WP; Page-AE1; Col C, Line 5	5
6				6
7	Common Plant Depreciation Reserve [2]	268,994	Stmnt AE WP; Page-AE1; Col C, Line 7	7
8				8
9	Transmission Wages and Salaries Allocation Factor	15.19%	Statement AI; Line 19	9
10				10
11	Transmission Related Electric Miscellaneous Intangible Plant Amortization Reserve	$ 3,966	Line 3 x Line 9	11
12				12
13	Transmission Related General Plant Depreciation Reserve	11,889	Line 5 x Line 9	13
14				14
15	Transmission Related Common Plant Depreciation Reserve	40,860	Line 7 x Line 9	15
16				16
17	Transmission Related Accumulated Depreciation Reserve	$ 556,870	Sum Lines 1; 11; 13 ;15	17

NOTES:

[1] The amounts stated above are ratemaking accumulated depreciation reserve and are derived by multiplying the book accumulated depreciation reserve by the FERC's Seven Element Adjustment Factors.

[2] Electric Miscellaneous Intangible Plant, General Plant, and Common Plant have a Seven Element Adjustment Factor of "1" because there is no transfer of transmission or distribution reserve among these categories.

San Diego Gas & Electric Company

True-Up Period
Statement - AF
Specified Deferred Credits

Docket No. ER11-____-____

SAN DIEGO GAS AND ELECTRIC COMPANY
Statement AF
Deferred Credits
True Up Period (4/1/2010 - 3/31/2011)
($1,000)

Line No		Amounts	Reference	Line No
1	Transmission Related Accumulated Deferred Taxes	$ (148,838)	Stmnt AF WP; Page-AF1; Col. C; Line 1	1
2				2
3	Total	$ (148,838)	Sum of Line 1	3

San Diego Gas & Electric Company

True-Up Period
Statement - AG
Specified Plant Account (Other than Plant in Service) and Deferred Debits

Docket No. ER11-____-____

SAN DIEGO GAS AND ELECTRIC COMPANY
Statement AG
Specified Plant Accounts (Other Than Plant in Service)
True Up Period (4/1/2010 - 3/31/2011)
($1,000)

Line No		Amounts	Reference	Line No
1	Transmission Plant Held for Future Use	$ 39,893	Stmt AG WP; Page-AG1; Line 3	1
2				2
3	Total	$ 39,893	Sum of Line 1	3

[1] The balances for Transmission plant held for future use are derived based on a 13-month weighted average balance.
Plant Held for Future Use represents the parcels of land purchased for the Jamul and Torrey Pines/Sorrento Mesa substations as well as various landrights acquisitions from the Bureau of Land Management, US Forest Service, and other various agencies for the Sunrise Powerlink.

San Diego Gas & Electric Company

True-Up Period
Statement - AH
Operation and Maintenance Expenses

Docket No. ER11-____-____

SAN DIEGO GAS AND ELECTRIC COMPANY
Statement AH
Operation and Maintenance Expenses
True Up Period (4/1/2010 - 3/31/2011)
($1,000)

Line No.		Amounts	Reference	Line No.
1	Derivation of Transmission Operation and Maintenance Expense:			1
2	Total Transmission Expenses	$ 39,804	Stmnt AH WP; Page-AH1; Line 2	2
3	Less: Account (561) - Load Dispatching	(2,355)	Stmnt AH WP; Page-AH1; Line 3	3
4	Less: Account (565) - Transmission of Electricity by Others	(407)	Stmnt AH WP; Page-AH1; Line 4	4
5	Less: Account (566) - Miscellaneous Transmission Expenses	808	Stmnt AH WP; Page-AH1; Line 5	5
6	Less: Account (566) - Miscellaneous Transmission Expenses	6,707	Stmnt AH WP; Page-AH1; Line 6	6
7	Less: Account (575) - Market Administration Monitor	-	Stmnt AH WP; Page-AH1; Line 7	7
8	Total Transmission O&M Expenses Including Intervener Compensation Costs	$ 44,557	Sum Lines 2 through 7	8
9	Less: CPUC Intervener Funding Expenses (See Statement BK1; Page 1; Line 6)	-	Stmnt AH WP; Page-AH1; Line 9	9
10	Total Transmission O&M Expense (See Statement BK1; Page 1; Line 2)	$ 44,557	Sum Lines 8 through 9	10
11				11
12	Derivation of Administrative and General Expense:			12
13	Total Administrative & General Expenses	$ 289,190	Stmnt AH WP; Page-AH1; Line 13	13
14	Adjustments to Per Book A&G expenses:	-		14
15	Nuclear Property Insurance Expenses	(1)	Stmnt AH WP; Page-AH1; Line 15	15
16	Nuclear Liability Insurance Expenses	(1,264)	Stmnt AH WP; Page-AH1; Line 16	16
17	Wildfire Insurance Premium Allocation	(61,183)	Stmnt AH WP; Page-AH1; Line 17	17
18	CPUC Reimbursement Fees	(5,248)	Stmnt AH WP; Page-AH1; Line 18	18
19	Litigation Expense	(2,238)	Stmnt AH WP; Page-AH1; Line 19	19
20	CPSD Wildfire Investigation Settlement	(14,350)	Stmnt AH WP; Page-AH1; Line 20	20
21	CPUC Energy Effeciency Programs Expenses	(14,288)	Stmnt AH WP; Page-AH1; Line 21	21
22	AMI Lease Facilities	(816)	Stmnt AH WP; Page-AH1; Line 22	22
23	Hazardous Substances	(221)	Stmnt AH WP; Page-AH1; Line 23	23
24	Total Adjusted A&G Expenses Before Excluding Property Insurance	$ 189,581	Sum Lines 13 thru 23	24
25	Property Insurance (Reflected on Line 44 below due to different allocation factor)	(3,426)	Stmnt AH WP; Page-AH1; Line 25	25
26	Total Adjusted A&G Expenses Excluding Property Insurance	$ 186,155	Sum Lines 24 thru 25	26
27	Transmission Wages and Salaries Allocation Factor	15.19%	Statement AI; Line 19	27
28	Total Transmission Related Administrative and General Expense	$ 28,277	Line 26 x Line 27	28
29				29
30	Derivation of Transmission Plant Property Insurance Allocation Factor:			30
31	Transmission Plant	$ 1,646,488	Statement AD-WP; Line 23	31
32	Transmission Related General Plant	27,686	Statement AD-WP; Line 29	32
33	Transmission Related Common Plant	73,428	Statement AD-WP; Line 31	33
34	Total	$ 1,747,602	Sum Lines (31 thru 33)	34
35				35
36	Total Transmission Plant	$ 1,646,488	Statement AD-WP; Line 23	36
37	Total Steam Production Plant	343,909	Statement AD-WP; Line 3	37
38	Total Other Production Plant	289,817	Statement AD-WP; Line 9	38
39	Total Nuclear Production Plant	-	N/A in Ratio Development	39
40	Total Distribution plant	4,489,770	Statement AD-WP; Col.C; Line 13	40
41	Total General Plant	182,263	Statement AD-WP; Col.C; Line 17	41
42	Total Common Plant	483,398	Statement AD-WP; Col.C; Line 19	42
43	Total Plant in Service Excluding SONGS	$ 7,435,645	Sum Lines (36 thru 42)	43
44				44
45	Transmission Plant Property Insurance Allocation Factor	23.50%	Line 34 / Line 43	45
46				46
47	Total Property Insurance	$ 3,426	See Line 25 Above	47
48				48
49	Property Insurance Allocated to Transmission, General, and Common Plant	805	Line 45 x Line 47	49
50				50
51	Transmission Related A & G Expenses	28,277	See Line 28 Above	51
52				52
53	Transmission Related A & G Expenses Including Property Insurance	$ 29,082	Line 49 + Line 51	53

San Diego Gas & Electric Company

True-Up Period
Statement - AI
Wages and Salaries

Docket No. ER11-____-____

SAN DIEGO GAS AND ELECTRIC COMPANY
Statement AI
Wages and Salaries
True Up Period (4/1/2010 - 3/31/2011)
($1,000)

Line No.		Amounts	Reference	Line No.
1	Production Wages & Salaries	$ 8,067	Stmnt AI WP; Page-AI1; Line 1	1
2				2
3	Transmission Wages & Salaries	17,790	Stmnt AI WP; Page-AI1; Line 3	3
4				4
5	Distribution Wages & Salaries	51,999	Stmnt AI WP; Page-AI1; Line 5	5
6				6
7	Customer Accounts Wages & Salaries	24,761	Stmnt AI WP; Page-AI1; Line 7	7
8				8
9	Customer Services and Informational Wages & Salaries	14,525	Stmnt AI WP; Page-AI1; Line 9	9
10				10
11	Sales Wages & Salaries	-	Stmnt AI WP; Page-AI1; Line 11	11
12				12
13	Subtotal	$ 117,141	Sum { Lines 1 thru 11}	13
14				14
15	Administrative Wages & Salaries	22,213	Stmnt AI WP; Page-AI1; Line 15	15
16				16
17	Total Operating & Maintenance Wages & Salaries	$ 139,353	Line 13 + Line 15	17
18				18
19	Transmission Wages and Salaries Allocation Factor	15.19%	Line 3 / Line 13	19

NOTES:

San Diego Gas & Electric Company

True-Up Period
Statement - AJ
Depreciation and Amortization Expenses

Docket No. ER11-____-____

SAN DIEGO GAS AND ELECTRIC COMPANY
Statement AJ
Depreciation and Amortization Expense
True Up Period (4/1/2010 - 3/31/2011)
($1,000)

Line No.		Amounts	Reference	Line No.
1	Depreciation Expense for Transmission Plant [1]	$ 62,240	Stmnt AJ WP; Page-AJ1; Line 1	1
2				2
3	General Plant Depreciation Expense	$ 8,162	Stmnt AJ WP; Page-AJ1; Line 3	3
4				4
5	Transmission Wages and Salaries Allocation Factor	15.19%	Statement AI; Line 19	5
6				6
7	Transmission Related General Plant Depreciation Expense	$ 1,240	Line 3 x Line 5	7
8				8
9	Common Plant Depreciation Expense	$ 38,690	Stmnt AJ WP; Page-AJ1; Line 9	9
10				10
11	Tranmission Related Common Plant Depreciation Expense	$ 5,877	Line 9 x Line 5	11
12				12
13	Electric Miscellaneous Intangible Plant Depreciation Expense	$ 925	Stmnt AJ WP; Page-AJ1; Line 13	13
14				14
15	Transmission Related Electric Miscellaneous Intangible Plant Depreciation Expense	$ 140	Line 13 x Line 5	15
16				16
17	Total Transmission, Intangible, General and Common Depreciation & Amortization Exp	$ 69,497	Sum Lines (1; 7; 11; 15)	17
18				18
19	Valley Rainbow Project Cost Amortization Expense	$ 1,893	Stmnt AJ WP; Page-AJ1; Line 19	19

[1] Embedded in account 350 is $19.687M of inverse condemnation expenses booked in March 2011 and amortized to FERC account 404 (Limited-Term Electric Plant) in the same period.

San Diego Gas & Electric Company

True-Up Period
Statement - AK
Taxes Other Than Income Taxes

Docket No. ER11-____-____

SAN DIEGO GAS AND ELECTRIC COMPANY
Statement AK
Taxes Other Than Income Taxes
True Up Period (4/1/2010 - 3/31/2011)
($1,000)

Line No.		Amounts	Reference	Line No.
1	Total Property Taxes	$ 50,109	Stmnt AK WP; Page-AK1; Line 1	1
2				2
3	SONGS Property Taxes	2,920	Stmnt AK WP; Page-AK1; Line 3	3
4				4
5	Property Taxes Less SONGS	$ 47,189	Line 1 Minus Line 3	5
6				6
7				7
8	Derivation of Transmission Related Property Tax Allocation Factor:			8
9	Transmission Plant	$ 1,646,488	Statement AD-WP; Line 23	9
10	Total Miscellaneous Intangible Plant	4,259	Statement AD-WP; Line 27	10
11	Transmission Related General Plant	27,686	Statement AD-WP; Line 29	11
12	Transmission Related Common Plant	73,428	Statement AD-WP; Line 31	12
13	Total	$ 1,751,861	Sum Lines 9 thru 12	13
14				14
15	Total Nuclear Plant	$ -	N/A in Ratio Development	15
16	Total Steam Plant	343,909	Statement AD-WP; Line 3	16
17	Total Other Production Plant	289,817	Statement AD-WP; Line 9	17
18	Total Transmission plant	1,646,488	Statement AD-WP; Line 23	18
19	Total Miscellaneous Intangible Plant	28,039	Statement AD-WP; Line 1	19
20	Total Distribution plant	4,489,770	Statement AD-WP; Col.C; Line 13	20
21	Total General Plant	182,263	Statement AD-WP; Col.C; Line 17	21
22	Total Common Plant	483,398	Statement AD-WP; Col.C; Line 19	22
23	Total Investment in Plant Excluding SONGS	$ 7,463,685	Sum Lines 15 thru 22	23
24				24
25	Transmission Related Property Tax Allocation Factor	23.47%	Line 13 / Line 23	25
26				26
27	Transmission Related Property Taxes Expense	$ 11,075	Line 5 x Line 25	27
28				28
29				29
30	Payroll Taxes:	$ 12,872	Stmnt AK WP; Page-AK1; Line 7	30
31				31
32	Transmission Wages and Salaries Allocation Factor	15.19%	Statement AI; Line 19	32
33				33
34	Transmission Related Payroll Taxes Expense	$ 1,955	Line 30 x Line 32	34

San Diego Gas & Electric Company

True-Up Period
Statement AL - Working Capital

Docket No. ER11-____-____

SAN DIEGO GAS AND ELECTRIC COMPANY
Statement AL
Working Capital
True Up Period (4/1/2010 - 3/31/2011)
($1,000)

Line No.		Amounts	Reference	Line No.
1	Plant Materials and Operating Supplies	$ 53,783	Stmnt AL WP; Page-AL1; Line 1	1
2				2
3	Transmission Plant Allocation Factor	19.83%	Statement AD WP; Line 35	3
4				4
5	Transmission Related Materials and Supplies	$ 10,665	(Line 1 x Line 3)	5
6				6
7	Prepayment	27,541	Stmnt AL WP; Page-AL1; Line 7	7
8				8
9	Transmission Related Prepayments	$ 5,461	(Line 3 x Line 7)	9
10				10
11	Derivation of Transmission Related Cash Working Capital:			11
12	Transmission Operation & Maintenance Expense	$ 44,557	Statement AH; Page -AH1; Line 10	12
13	Transmission Related Administrative & General Expenses	29,082	Statement AH; Page- AH1; Line 54	13
14	Intervenor Compensation Expenses	-	Statement AH; Page-AH1; Line 9	14
15	Total	$ 73,639	Sum Lines 12; 13; 14	15
16				16
17	One Eighth of O & M Percentage Rate	12.50%	FERC Method = 1/8 of O & M	17
18				18
19	Adjust O&M Percentage Rate to Account for 12-Month Period	12.50%	Line 17 / 1	19
20				20
21	Transmission Related Cash Working Capital - Retail Customers	$ 9,205	Line 15 x Line 19	21
22				22
23	Transmission Related Cash Working Capital - Wholesale Customers	$ 9,205	(Line 12 + Line 13) x Line 19	23

San Diego Gas & Electric Company

True-Up Period
Statement - AQ
Federal Income Tax Deductions – Other Than Interest

Docket No. ER11-____-____

SAN DIEGO GAS AND ELECTRIC COMPANY
Statement AQ
Federal Income Tax Deductions, Other Than Interest
True Up Period (4/1/2010 - 3/31/2011)
($1,000)

Line No.		Amounts	Reference	Line No.
1	South Georgia Income Tax Adjusment	$ 2,333	Stmnt AQ WP; Page-AQ1; Line 1	1

San Diego Gas & Electric Company

True-Up Period
Statement - AR
Federal Income Tax Adjustments

Docket No. ER11-____-____

SAN DIEGO GAS AND ELECTRIC COMPANY
Statement AR
Federal Tax Adjustments
True Up Period (4/1/2010 - 3/31/2011)
($1,000)

Line No.		Amounts	Reference	Line No.
1	Transmission Related Amortization of Investment Tax Credits	$ (265)	Stmnt AR WP; Page-AR1; Line 1	1
2				2
3	Transmission Related Amortization of Excess Deferred Tax Liabilities	(3)	Stmnt AR WP; Page-AR1; Line 3	3
4				4
5	Total	$ (268)	Line 1 + Line 3	5

San Diego Gas & Electric Company

True-Up Period
Statement AU - Revenue Credits

Docket No. ER11-____-____

SAN DIEGO GAS AND ELECTRIC COMPANY
Statement AU
Revenue Credits
True Up Period (4/1/2010 - 3/31/2011)
($1,000)

Line No.		Amounts		Reference	Line No.
1	(451) Miscellaneous Service Revenues	$ -		Stmnt AU WP; Page-AU1; Line 1	1
2					2
3	(453) Sales of Water and Water Power	-		Stmnt AU WP; Page-AU1; Line 3	3
4					4
5	(454) Rent from Electric Property	650		Stmnt AU WP; Page-AU1; Line 5	5
6					6
7	(455) Interdepartmental Rents	-		Stmnt AU WP; Page-AU1; Line 7	7
8					8
9	(456) Other Electric Revenues	1,834		Stmnt AU WP; Page-AU1; Line 9	9
10					10
11	(456) Overcollection Revenues	5,127	[1]	Stmnt AU WP; Page-AU1; Line 11	11
12					12
13	Transmission Related Revenue Credits - RETAIL CUSTOMERS	$ 7,611		Sum Lines 1; 3; 5; 7; 9; 11	13
14					14
15	Transmission Related Revenue Credits - WHOLESALE CUSTOMERS	$ 2,484	[2]	Sum Lines 1; 3; 5; 7; 9	15
16					16
17	(411.6 & 411.7) Gain or Loss From Sale of Plant Held for Future Use	$ -		FERC Accounts 411.6 and 411.7	17

NOTES

[1] An adjustment was made for $5.1M to refund back to retail customers the amount that was overcollected from September 2010 through March 2011. This adjustment was not booked in the general ledger, but per the refund report order in FERC docket ER10-2235, SDG&E will refund back the overcollection in its upcoming TO3-Cycle 5 annual formulaic rate filing. The refund to retail customers will begin in September 1, 2011.

[2] The Transmisison Revenue Credit amount for Wholesale Customers is $2.484 because it excludes the $5.1 million over collection that is applicable only to retail customers. The revenues that will be refunded back to wholesale customers will be processed by the CAISO.

San Diego Gas & Electric Company

True-Up Period
Statement - AV
Cost of Capital and Fair Rate of Return

Docket No. ER11-____-____

SAN DIEGO GAS AND ELECTRIC COMPANY
Statement AV
Cost of Capital and Fair Rate of Return
True Up Period (4/1/2010 - 3/31/2011)
($1,000)

Line No.		Amounts	Reference	Line No.
1	Long-Term Debt Component - Denominator:			1
2	(Plus): Account 221 - Bonds	$ 2,686,905	Stmnt AV WP; Page-AV1; Line 2	2
3	(Less): Account 222 - Reacquired Bonds	-	Stmnt AV WP; Page-AV1; Line 3	3
4	(Plus): Account 224 - Other Long-Term Debt (Acct. 224)	253,720	Stmnt AV WP; Page-AV1; Line 4	4
5	(Plus): Account 225 - Unamortized Premium on Long-Term Debt	-	Stmnt AV WP; Page-AV1; Line 5	5
6	(Less): Account 226 - Unamortized Discount on Long-Term Debt-Debit	9,271	Stmnt AV WP; Page-AV1; Line 6	6
7	Total Long Term Debt (LTD)	$ 2,931,354	Lines 2-3+4+5-6	7
8				8
9	Long-Term Debt Component - Numerator:			9
10	(Plus): Account 427 - Interest on Long-Term Debt	$ 138,022	Stmnt AV WP; Page-AV1; Line 10	10
11	(Plus): Account 428 - Amort. of Debt Disc. and Expense	2,027	Stmnt AV WP; Page-AV1; Line 11	11
12	(Plus): Account 428.1 - Amortization of Loss on Reacquired Debt	3,510	Stmnt AV WP; Page-AV1; Line 12	12
13	(Less): Account 429 - Amort. of Premium on Debt-Credit	-	Stmnt AV WP; Page-AV1; Line 13	13
14	(Less): Account 429.1 - Amortization of Gain on Reacquired Debt-Credit	-	Stmnt AV WP; Page-AV1; Line 14	14
15	Total LTD Interest = (i)	$ 143,559	Lines 10+11+12-13-14	15
16				16
17	Cost of Long-Term Debt:	4.90%	Line 15 / Line 7	17
18				18
19				19
20	Preferred Equity Component:			20
21	PF = Preferred Stock - Account 204	$ 78,475	Stmnt AV WP; Page-AV1; Line 21	21
22	d(pf) = Total Dividends Declared-Preferred Stocks - Account 437	4,820	Stmnt AV WP; Page-AV1; Line 22	22
23	Cost of Preferred Equity	6.14%	Line 22 / Line 21	23
24				24
25				25
26	Common Equity Component:			26
27	Proprietary Capital	$ 3,476,377	Stmnt AV WP; Page-AV1; Line 27	27
28	(Less): Account 204 Preferred Stock	78,475	Stmnt AV WP; Page-AV1; Line 28	28
29	(Less): Account 216.1 Unappropriated Undistributed Subsidiary Earnings	-	Stmnt AV WP; Page-AV1; Line 29	29
30	CS = Common Stock	$ 3,397,902	Line 27 - Line 28 - Line 29	30
31				31
32	Cost of Common Equity - Per Settlement:	11.35%	Appendix 8; Page 28; Item (a) iii	32

Line No.	Weighted Cost of Capital:	(a) Amount	(b) Cap. Struct. Ratio	(c) Cost of Capital	(d) = (b) x (c) Weighted Cost of Capital		Line No.
33							33
34							34
35							35
36							36
37	Long-Term Debt	$ 2,931,354	45.75%	4.90%	2.24%	Col. C = Line 17 Above	37
38	Preferred Equity	78,475	1.23%	6.14%	0.08%	Col. C = Line 23 Above	38
39	Common Equity	3,397,902	53.03%	11.35%	6.02%	Col. C = Line 32 Above	39
40	Total Capital	$ 6,407,732	100.00%		8.34%	Sum Lines 37; 38; 39	40
41							41
42							42
43	Cost of Equity Component (Preferred & Common):				6.10%	Sum Lines 38; 39	43

SAN DIEGO GAS AND ELECTRIC COMPANY
Statement AV
Cost of Capital and Fair Rate of Return
True Up Period (4/1/2010 - 3/31/2011)
($1,000)

Line No.			Amounts	Reference	Line No.
1	Derivation of Cost of Capital Rate:				1
2					2
3	a) Federal Income Tax Component:				3
4					4
5	Where:				5
6	A = Sum of Preferred Stock and Return on Equity Component		6.10%	Statement AV; Page 13; Line 43	6
7	B = Trans. Related Amort. of ITC and Excess Deferred Tax Liab.	$	268	(Statement AR; Page 11; Line 5)	7
8	C = Equity AFUDC Component of Transmission Depreciation Expense	$	-		8
9	D = Transmission Rate Base	$	1,111,377	Statement BK1; Page 2; Line 20	9
10					10
11	FT = Federal Income Tax Rate July 1, 2010		35%	Federal Income Tax Rate	11
12					12
13	Federal Income Tax = $\frac{(A + [(C - B) / D]) (FT)}{1 - FT}$ =		3.2716%		13
14					14
15					15
16					16
17	b) State Income Tax Component:				17
18					18
19	Where:				19
20	A = Sum of Preferred Stock and Return on Equity Component		6.10%	Statement AV; Page 13; Line 43	20
21	B = Trans. Related Amort. of ITC and Excess Deferred Tax Liab.	$	268	(Statement AR; Page 11; Line 5)	21
22	C = Equity AFUDC Component of Transmission Depreciation Expense	$	-		22
23	D = Transmission Rate Base	$	1,111,377	Statement BK1; Page 2; Line 20	23
24					24
25	FT = Federal Income Tax Expense Rate		3.2716%	Statement AV; Page14, Line 13	25
26	ST = State Income Tax Rate July 1, 2010		8.84%	State Income Tax Rate	26
27					27
28	State Income Tax = $\frac{(A + [(C - B) / D] + \text{Federal Income Tax}) (ST)}{1 - ST}$ =		0.9065%		28
29					29
30					30
31	c) Total Federal & State Income Tax Expense Rate:		4.1781%	Sum Lines 13 and Line 28	31
32					32
33	d) Total Weighted Cost of Capital:		8.3400%	Statement AV; Page 13; Line 40	33
34					34
35	e) Cost of Capital Rate:		12.5181%	Line 31 + Line 33	35

Section – 2

Derivation of Retail (End Use Customer)
True-Up Adjustment

Section 2.1A

Summary of Retail True-Up Adjustment

Docket No. ER11-____-____

Section 2.1A
San Diego Gas Electric Co.
TO3-Cycle 5 Retail True-Up Adjustment Calculation

Line No.	TO3-Formula Cycle in Effect / Description	Cycle - 3 Apr-10	Cycle - 3 May-10	Cycle - 3 Jun-10	Cycle - 3 Jul-10	Cycle - 3 Aug-10
1	**Beginning Balance (Overcollection)/Undercollection:**	**$ -**	**$ 4,448,729**	**$ 9,023,111**	**$ 13,465,347**	**$ 18,295,431**
2						
3	Total Recorded Revenues	$ 18,694,588	$ 18,170,421	$ 20,445,534	$ 22,658,338	$ 21,406,203
4						
5	**Amortization of True-Up Adjustment and Interest True-Up Adjustment:**					
6	**a) Amortization of Cycle 4 TU Adjustment and Interest True-Up Adjusment:**					
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 Adjusment:**					
10	i. Amortization of Cycle 3 True-Up Adjustment	(641,105)	(606,971)	(656,518)	(717,162)	(1,272,418)
11	ii. Amortization of Cycle 3 Interest True-Up Adjustment					
12	**c) Amortization of Cycle 2 True-Up Adjustment and Interest True-Up Adjusment:**					
13	i. Amortization of Cycle 2 TU Adjustment	-	-	-	-	-
14	ii. Amortization of Cycle 2 Interest True-Up Adjustment	(30,529)	(28,903)	(31,263)	(34,151)	(39,198)
15	iii. Amortization of Cycle 2 Interest True-Up Adjustment Accrued After Fully Amortized					
16	**d) Amortization of TO2 Final True-Up Adjustment and Interest True-Up Adjusment:**					
17	i. Amortization of TO2 Final True-Up Adjustment	-	-	-	-	-
18	ii. Amortization of TO2 Final True-Up - Interest TU Adjustment	(137,380)	(130,065)	(140,683)	(153,678)	(319,786)
19	iii. Amortization of TO2 Final Interest TU Adjustment Accrued After Fully Amortized					
20	Total Amortization of True-Up Adjustments	$ (809,014)	$ (765,939)	$ (828,464)	$ (904,991)	$ (1,631,402)
21						
22	**Adjusted Total Recorded Revenues**	**$ 17,885,574**	**$ 17,404,482**	**$ 19,617,070**	**$ 21,753,347**	**$ 19,774,801**
23						
24	**Total True-Up Revenues (TU Cost of Service)**	**$ 22,328,306**	**$ 21,960,047**	**$ 24,029,053**	**$ 26,539,029**	**$ 25,042,309**
25						
26	**Net Monthly (Overcollection)/Undercollection:**	**$ 4,442,731**	**$ 4,555,565**	**$ 4,411,984**	**$ 4,785,681**	**$ 5,267,508**
27						
28	Interest Expense Calculations:					
29	Beginning Balance for Interest Calculation	$ -	$ -	$ -	$ 13,465,347	$ 13,465,347
30	Monthly Activity Included in Interest Calculation Basis	2,221,366	6,720,514	11,204,288	2,392,841	7,419,435
31	Basis for Interest Expense Calculation	2,221,366	6,720,514	11,204,288	15,858,187	20,884,782
32	Monthly Interest Rate	0.27000%	0.28000%	0.27000%	0.28000%	0.28000%
33	**Interest Expense**	**$ 5,998**	**$ 18,817**	**$ 30,252**	**$ 44,403**	**$ 58,477**
34						
35	**Ending Balance (Overcollection)/Undercollection:**	**$ 4,448,729**	**$ 9,023,111**	**$ 13,465,347**	**$ 18,295,431**	**$ 23,621,416**
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 2.1A
San Diego Gas Electric Co.
TO3-Cycle 5 Retail True-Up Adjustment Calculation

Line No.	TO3-Formula Cycle 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:**	**$ 23,621,416**	**$ 28,290,107**	**$ 28,107,823**	**$ 28,857,205**	**$ 29,745,947**
2						
3	Total Recorded Revenues	$ 27,022,152	$ 28,883,272	$ 25,743,058	$ 26,406,391	$ 27,709,822
4						
5	**Amortization of True-Up Adjustment and Interest True-Up Adjustment:**					
6	**a) Amortization of Cycle 4 TU Adjustment and Interest True-Up Adjusment:**					
7	i. Amortization of Cycle 4 True-Up Adjustment	(2,892,580)	(2,719,111)	(2,501,110)	(2,593,639)	(2,728,943)
8	ii. Amortization of Cycle 4 Interest True-Up Adjustment.					
9	**b) Amortization of Cycle 3 True-Up Adjustment and Interest True-Up Adjusment:**					
10	i. Amortization of Cycle 3 True-Up Adjustment					
11	ii. Amortization of Cycle 3 Interest True-Up Adjustment	(18,542)	(17,430)	(16,033)	(16,626)	(17,493)
12	**c) Amortization of Cycle 2 True-Up Adjustment and Interest True-Up Adjusment:**					
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 True-Up Adjustment Accrued After Fully Amortized	(1,854)	(1,743)	(1,603)	(1,663)	(1,749)
16	**d) Amortization of TO2 Final True-Up Adjustment and Interest True-Up Adjusment:**					
17	i. Amortization of TO2 Final True-Up Adjustment	-	-	-	-	-
18	ii. Amortization of TO2 Final True-Up - Interest TU Adjustment	-	-	-	-	-
19	iii. Amortization of TO2 Final Interest TU Adjustment Accrued After Fully Amortized	(18,542)	(17,430)	(16,033)	(16,626)	(17,493)
20	Total Amortization of True-Up Adjustments	$ (2,931,518)	$ (2,755,714)	$ (2,534,779)	$ (2,628,554)	$ (2,765,678)
21						
22	**Adjusted Total Recorded Revenues**	**$ 24,090,634**	**$ 26,127,558**	**$ 23,208,279**	**$ 23,777,837**	**$ 24,944,144**
23						
24	**Total True-Up Revenues (TU Cost of Service)**	**$ 28,689,617**	**$ 25,866,427**	**$ 23,881,074**	**$ 24,585,085**	**$ 25,756,476**
25						
26	**Net Monthly (Overcollection)/Undercollection:**	**$ 4,598,983**	**$ (261,131)**	**$ 672,795**	**$ 807,247**	**$ 812,332**
27						
28	Interest Expense Calculations:					
29	Beginning Balance for Interest Calculation	$ 13,465,347	$ 28,290,107	$ 28,290,107	$ 28,290,107	$ 29,745,947
30	Monthly Activity Included in Interest Calculation Basis	12,352,680	(130,566)	75,267	815,288	406,166
31	Basis for Interest Expense Calculation	25,818,027	28,159,542	28,365,374	29,105,395	30,152,113
32	Monthly Interest Rate	0.27000%	0.28000%	0.27000%	0.28000%	0.28000%
33	**Interest Expense**	**$ 69,709**	**$ 78,847**	**$ 76,587**	**$ 81,495**	**$ 84,426**
34						
35	**Ending Balance (Overcollection)/Undercollection:**	**$ 28,290,107**	**$ 28,107,823**	**$ 28,857,205**	**$ 29,745,947**	**$ 30,642,705**
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%

000003

Section 2.1A
San Diego Gas Electric Co.
TO3-Cycle 5 Retail True-Up Adjustment Calculation

Line No.	TO3-Formula Cycle in Effect Description	Cycle - 4 Feb-11	Cycle - 4 Mar-11	Total	Reference	Line No.
1	**Beginning Balance (Overcollection)/Undercollection:**	**$ 30,642,705**	**$ 31,478,700**	$ -	Previous Month's Balance	1
2						2
3	Total Recorded Revenues	$ 24,815,815	$ 25,230,125	$ 287,185,720	Section 2.2; Page 40; Line 11	3
4						4
5	**Amortization of True-Up Adjustment and Interest True-Up Adjustment:**					5
6	**a) Amortization of Cycle 4 TU Adjustment and Interest True-Up Adjusment:**					6
7	i. Amortization of Cycle 4 True-Up Adjustment	(2,459,266)	(2,491,275)	(18,385,924)	Section 2.1A; Page 6; Line 19; Cols (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 Adjusment:**					9
10	i. Amortization of Cycle 3 True-Up Adjustment			(3,894,174)	Section 2.1A; Pgs 9-10; Line 19; Cols (h)-(l)	10
11	ii. Amortization of Cycle 3 Interest True-Up Adjustment	(15,765)	(15,970)	(117,859)	Section 2.1A; Page 12; Line 19; Cols (a)-(g)	11
12	**c) Amortization of Cycle 2 True-Up Adjustment and Interest True-Up Adjusment:**					12
13	i. Amortization of Cycle 2 TU Adjustment	-	-	-		13
14	ii. Amortization of Cycle 2 Interest True-Up Adjustment	-	-	(164,044)	Section 2.1A; Pgs 15-16; Line 19; Cols (h)-(l)	14
15	iii. Amortization of Cycle 2 Interest True-Up Adjustment Accrued After Fully Amortized	(1,576)	(1,597)	(11,785)	Section 2.1A; Page 18; Line 19; Cols (a)-(g)	15
16	**d) Amortization of TO2 Final True-Up Adjustment and Interest True-Up Adjusment:**					16
17	i. Amortization of TO2 Final True-Up Adjustment	-	-	-		17
18	ii. Amortization of TO2 Final True-Up - Interest TU Adjustment	-	-	(881,592)	Section 2.1A; Pgs 21-22; Line 19; Cols (h)-(l)	18
19	iii. Amortization of TO2 Final Interest TU Adjustment Accrued After Fully Amortized	(15,765)	(15,970)	(117,859)	Section 2.1A; Page 24; Line 19; Cols (a)-(g)	19
20	Total Amortization of True-Up Adjustments	$ (2,492,372)	$ (2,524,812)	$ (23,573,237)	Sum Lines 7 through 19	20
21						21
22	**Adjusted Total Recorded Revenues**	**$ 22,323,443**	**$ 22,705,313**	**$ 263,612,483**	Sum Lines 3 & 20	22
23						23
24	**Total True-Up Revenues (TU Cost of Service)**	**$ 23,082,094**	**$ 23,282,650**	**$ 295,042,166**	Page 70; Line 11	24
25						25
26	**Net Monthly (Overcollection)/Undercollection:**	**$ 758,651**	**$ 577,337**	**$ 31,429,683**	Line 17 Minus Line 19	26
27						27
28	Interest Expense Calculations:					28
29	Beginning Balance for Interest Calculation	$ 29,745,947	$ 29,745,947		Beginning Quarterly Balances	29
30	Monthly Activity Included in Interest Calculation Basis	1,191,657	1,859,651		Interest Calculation Basis	30
31	Basis for Interest Expense Calculation	30,937,605	31,605,599		Sum Lines 24 & 25	31
32	Monthly Interest Rate	0.25000%	0.28000%		FERC Monthly Rates	32
33	**Interest Expense**	**$ 77,344**	**$ 88,496**	**$ 714,850**	Line 26 x Line 27	33
34						34
35	**Ending Balance (Overcollection)/Undercollection:**	**$ 31,478,700**	**$ 32,144,533**	**$ 32,144,533**	Sum Lines 1; 21; & 28	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 33)/(Line 34)x(Line 35)	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%	Line 36 - Line 37	43

Section 2.1 – Retail 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 the amortization schedule will be shown in next year's Cycle-6 filing.

Section 2.1A
San Diego Gas Electric Co.
TO3-Cycle 5 RETAIL TrueUp Adjustment Calculation

Line No.	Description	(a) Amounts	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	**Derivation of Amortization Rates:**								
2	TO3-Cycle 4 Retail True-Up Adjustment	$ 31,743,336							
3	Forecast Sales TO3-Cycle 4 (kWh)	20,392,503,000							
4	Estimated Amortization Rate Per kWh	$ 0.00156							
5									
6									
7	**Derivation of Forecast Sales:** [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	Conversion Factor from MWH to kWh	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
12	Total Forecast Sales Net of Resale - kWh	1,922,247,500	1,690,304,500	1,643,646,500	1,693,673,500	1,744,800,500	1,637,715,500	1,618,730,500	1,557,543,500
13									
14									
15	**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
16	Beginning Retail True-Up Adjustment Balance	$ 31,743,336	$ 28,850,756	$ 26,131,645	$ 23,630,535	$ 21,036,896	$ 18,307,953	$ 15,848,687	$ -
17	Recorded Sales in Total kWh	1,854,217,871	1,743,019,823	1,603,275,846	1,662,588,802	1,749,322,152	1,576,452,657	1,596,971,420	-
18	Amortization Rate Per kWh	$ 0.00156	$ 0.00156	$ 0.00156	$ 0.00156	$ 0.00156	$ 0.00156	$ 0.00156	$ -
19	Amortization of TO3-Cycle 4 True-Up Adjustment [3]	**$ 2,892,580**	**$ 2,719,111**	**$ 2,501,110**	**$ 2,593,639**	**$ 2,728,943**	**$ 2,459,266**	**$ 2,491,275**	$ -
20	Ending TO3-Cycle 4 True-Up Adjusment Balance	$ 28,850,756	$ 26,131,645	$ 23,630,535	$ 21,036,896	$ 18,307,953	$ 15,848,687	$ 13,357,412	$ -
21									

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 17, 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 19 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 2.1A
San Diego Gas Electric Co.
TO3-Cycle 5 RETAIL TrueUp Adjustment Calculation

Line No.	Description	(i)	(j)	(k)	(l)	(m)	Reference	Line No.
1	**Derivation of Amortization Rates:**						TO3-Cycle 4 Filing	1
2	TO3-Cycle 4 Retail True-Up Adjustment						Vol. 2-A; Section 2.1A; Pg.1; Line 30	2
3	Forecast Sales TO3-Cycle 4 (kWh)						See Line 12 Below	3
4	Estimated Amortization Rate Per kWh						Line 2 / Line 3	4
5								5
6								6
7	**Derivation of Forecast Sales:** [1]	May-11	Jun-11	Jul-11	Aug-11	Total		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	Conversion Factor from MWH to kWh	1,000	1,000	1,000	1,000	1,000	MWH Conversion Factor	11
12	Total Forecast Sales Net of Resale - kWh	1,563,383,500	1,651,388,500	1,813,251,500	1,855,817,500	20,392,503,000	Line 10 x Line 11	12
13								13
14								14
15	**Amortization of TO3-Cycle 4 True-Up Adjustment:** [2]	May-11	Jun-11	Jul-11	Aug-11	Total		15
16	Beginning Retail True-Up Adjustment Balance	$ -	$ -	$ -	$ -		Beginning Balance	16
17	Recorded Sales in Total kWh	-	-	-	-	11,785,848,571	Recorded Sales	17
18	Amortization Rate Per kWh	$ -	$ -	$ -	$ -		See Line 4 Above	18
19	Amortization of TO3-Cycle 4 True-Up Adjustment [3]	$ -	$ -	$ -	$ -	$ 18,385,924	Line 17 x Line 18	19
20	Ending TO3-Cycle 4 True-Up Adjusment Balance	$ -	$ -	$ -	$ -		Line 16 Minus Line 19	20
21								21

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 17, 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 19 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 2.1 – Retail 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 picks up the amounts amortized 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 2.1
San Diego Gas Electric Co.
TO3-Cycle 4 Annual Transmission Formulaic Filing
Amortization Schedule of TO3-Cycle 3 True-Up Adjustment

Line No.	Description	(a) Amounts	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	**Derivation of Amortization Rates:**								
2	TO3-Cycle 3 Retail True-Up Adjustment	$ 8,824,617							
3	Forecast Sales TO3-Cycle 3 (kWh)	21,102,710,000							
4	Estimated Amortization Rate Per kWh	$ 0.00042							
5									
6									
7	**Derivation of Forecast Sales:** [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	Conversion Factor from MWH to kWh	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
12	Total Forecast Sales Net of Resale - kWh	2,010,444,000	1,718,509,000	1,693,221,000	1,751,697,000	1,787,371,000	1,686,420,000	1,675,583,000	1,576,624,000
13									
14									
15	**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
16	Beginning Retail True-Up Adjustment Balance	$ 8,824,617	$ 8,020,531	$ 7,294,372	$ 6,604,645	$ 5,900,945	$ 5,191,364	$ 4,526,914	$ 3,894,174
17	Recorded Sales in Total kWh	1,914,490,629	1,728,949,088	1,642,207,251	1,675,476,167	1,689,477,704	1,582,023,160	1,506,524,014	1,526,440,542
18	Amortization Rate Per kWh	$ 0.00042	$ 0.00042	$ 0.00042	$ 0.00042	$ 0.00042	$ 0.00042	$ 0.00042	$ 0.00042
19	Amortization of TO3-Cycle 3 True-Up Adjustment [3]	$ 804,086	$ 726,159	$ 689,727	$ 703,700	$ 709,581	$ 664,450	$ 632,740	**$ 641,105**
20	Ending TO3-Cycle 3 True-Up Adjusment Balance	$ 8,020,531	$ 7,294,372	$ 6,604,645	$ 5,900,945	$ 5,191,364	$ 4,526,914	$ 3,894,174	$ 3,253,069
21									

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 17, 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 19 from 9/1/2010 through 3/31/2010 was included in the cycle 4 true-up adjustment period. The monthly amortization amounts from April 2010 through August 2010 is included in the instant TO3, Cycle 5 filing.

Section 2.1
San Diego Gas Electric Co.
TO3-Cycle 4 Annual Transmission Formulaic Filing
Amortization Schedule of TO3-Cycle 3 True-Up Adjustment

Line No.	Description	(i)	(j)	(k)	(l)	(m)	Reference	Line No.
1	**Derivation of Amortization Rates:**						TO3-Cycle 3 Filing	1
2	TO3-Cycle 3 Retail True-Up Adjustment						Vol. 2 of 3; Section 2.1B; Pg.1.2; Line 21	2
3	Forecast Sales TO3-Cycle 3 (kWh)						See Line 12 Below	3
4	Estimated Amortization Rate Per kWh						Line 2 / Line 3	4
5								5
6								6
7	**Derivation of Forecast Sales:** [1]	May-10	Jun-10	Jul-10	Aug-10	Total		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	Conversion Factor from MWH to kWh	1,000	1,000	1,000	1,000	1,000	MWH Conversion Factor	11
12	Total Forecast Sales Net of Resale - kWh	1,615,028,000	1,719,826,000	1,935,600,000	1,932,387,000	21,102,710,000	Line 10 x Line 11	12
13								13
14								14
15	**Amortization of TO3-Cycle 3 True-Up Adjustment:** [2]	May-10	Jun-10	Jul-10	Aug-10	Total		15
16	Beginning Retail True-Up Adjustment Balance	$ 3,253,069	$ 2,646,098	$ 1,989,580	$ 1,272,418		Beginning Balance	16
17	Recorded Sales in Total kWh	1,445,169,701	1,563,139,156	1,707,529,502	1,601,642,774	19,583,069,688	Recorded Sales	17
18	Amortization Rate Per kWh	$ 0.00042	$ 0.00042	$ 0.00042	$ 0.00042		See Line 4 Above	18
19	Amortization of TO3-Cycle 3 True-Up Adjustment [3]	**$ 606,971**	**$ 656,518**	**$ 717,162**	**$ 1,272,418**	$ 8,824,617	Line 17 x Line 18	19
20	Ending TO3-Cycle 3 True-Up Adjusment Balance	$ 2,646,098	$ 1,989,580	$ 1,272,418	$ -		Line 16 Minus Line 19	20
21								21

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 17, 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 19 from 9/1/2010 through 3/31/2010 was included in the cycle 4 true-up adjustment period. The monthly amortization amounts from April 2010 through August 2010 is included in the instant TO3, Cycle 5 filing.

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Section 2.1 – Retail True-Up Adjustment

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

Part (ii): Amortization of TO3-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 picks up the amounts amortized from September 2010 through March 2011.
- The remaining balance of the TO3-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 2.1
San Diego Gas Electric Co.
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-C3 Interest True-Up Adjustment Calced/Filed in Cycle 4	$ 245,548							
3	Forecast Sales TO3-Cycle 4 (kWh)	20,392,503,000							
4	Estimated Amortization Rate Per kWh	$ 0.00001							
5									
6									
7	**Derivation of Forecast Sales:**[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	Conversion Factor from MWH to kWh	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
12	Total Forecast Sales Net of Resale - kWh	1,922,247,500	1,690,304,500	1,643,646,500	1,693,673,500	1,744,800,500	1,637,715,500	1,618,730,500	1,557,543,500
13									
14									
15	**Amortization TO3-Cycle 3 Interes True-Up Adjustment:**[2]	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11
16	Beginning Interest True-Up Adjustment Balance	$ 245,548	$ 227,006	$ 209,576	$ 193,543	$ 176,917	$ 159,424	$ 143,659	$ -
17	Recorded Sales in Total kWh	1,854,217,871	1,743,019,823	1,603,275,846	1,662,588,802	1,749,322,152	1,576,452,657	1,596,971,420	-
18	Amortization Rate Per kWh	$ 0.00001	$ 0.00001	$ 0.00001	$ 0.00001	$ 0.00001	$ 0.00001	$ 0.00001	$ -
19	Amortization of TO3-C3 Interest True-Up Adjustment[3]	**$ 18,542**	**$ 17,430**	**$ 16,033**	**$ 16,626**	**$ 17,493**	**$ 15,765**	**$ 15,970**	$ -
20	Ending Balance C3 Interest True-Up Adjustment Calced/Filed in Cycle 4	$ 227,006	$ 209,576	$ 193,543	$ 176,917	$ 159,424	$ 143,659	$ 127,689	$ -
21									

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 17, 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 19 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 2.1
San Diego Gas Electric Co.
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 3 Filing	1
2	TO3-C3 Interest True-Up Adjustment Calced/Filed in Cycle 4						Vol. 2 of 3; Section 2.1A; Pg.1.2; Line 20	2
3	Forecast Sales TO3-Cycle 4 (kWh)						See Line 12 Below	3
4	Estimated Amortization Rate Per kWh						Line 2 / Line 3	4
5								5
6								6
7	**Derivation of Forecast Sales:**[1]	May-11	Jun-11	Jul-11	Aug-11	Total		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	Conversion Factor from MWH to kWh	1,000	1,000	1,000	1,000	1,000	MWH Conversion Factor	11
12	Total Forecast Sales Net of Resale - kWh	1,563,383,500	1,651,388,500	1,813,251,500	1,855,817,500	20,392,503,000	Line 10 x Line 11	12
13								13
14								14
15	**Amortization TO3-Cycle 3 Interes True-Up Adjustment:**[2]	May-11	Jun-11	Jul-11	Aug-11	Total		15
16	Beginning Interest True-Up Adjustment Balance	$ -	$ -	$ -	$ -		Beginning Balance	16
17	Recorded Sales in Total kWh	-	-	-	-	11,785,848,571	Recorded Sales	17
18	Amortization Rate Per kWh	$ -	$ -	$ -	$ -		See Line 4 Above	18
19	Amortization of TO3-C3 Interest True-Up Adjustment [3]	$ -	$ -	$ -	$ -	$ 117,859	Line 17 x Line 18	19
20	Ending Balance C3 Interest True-Up Adjustment Calced/Filed in Cycle 4	$ -	$ -	$ -	$ -		Line 16 Minus Line 19	20
21								21

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 17, 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 19 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 2.1 – Retail True-Up Adjustment

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

Part (ii): Amortization of 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 picks up the amounts amortized from April 2010 through March 2010.

- The amortization of the Cycle -2 Interest True-Up Adjustment from September 2009 through March 2010 was picked up in the TO3 Cycle-4 filing last year.

Section 2.1
San Diego Gas Electric Company
TO3-Cycle 5 Annual Transmission Formulaci Filing
Amortization of Interest True-Up Adjustment Applicable to TO3-Cycle 2

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	$ 398,827							
3	Forecast Sales TO3-Cycle 3 (kWh)	21,102,710,000							
4	Estimated Amortization Rate Per kWh	$ 0.00002							
5									
6									
7	**Derivation of Forecast Sales:**[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	Conversion Factor from MWH to kWh	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
12	Total Forecast Sales Net of Resale - kWh	2,010,444,000	1,718,509,000	1,693,221,000	1,751,697,000	1,787,371,000	1,686,420,000	1,675,583,000	1,576,624,000
13									
14									
15	**Amortization TO3-Cycle 3 Interes True-Up Adjustment:**[2]	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	**Apr-10**
16	Beginning Interest True-Up Adjustment Balance	$ 398,827	$ 360,537	$ 325,958	$ 293,114	$ 259,604	$ 225,814	$ 194,174	$ 164,044
17	Recorded Sales in Total kWh	1,914,490,629	1,728,949,088	1,642,207,251	1,675,476,167	1,689,477,704	1,582,023,160	1,506,524,014	1,526,440,542
18	Amortization Rate Per kWh	$ 0.00002	$ 0.00002	$ 0.00002	$ 0.00002	$ 0.00002	$ 0.00002	$ 0.00002	$ 0.00002
19	Amortization of TO3-C3 Interest True-Up Adjustment [3]	$ 38,290	$ 34,579	$ 32,844	$ 33,510	$ 33,790	$ 31,640	$ 30,130	**$ 30,529**
20	Ending TO3-Cycle 3 True-Up Adjusment Balance	$ 360,537	$ 325,958	$ 293,114	$ 259,604	$ 225,814	$ 194,174	$ 164,044	$ 133,515
21									

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 17, 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 19 from 9/1/2010 through 3/31/2010 was included in the cycle 4 true-up adjustment period. The monthly amortization amounts from April 2010 through August 2010 is included in the instant TO3, Cycle 5 filing.

Section 2.1
San Diego Gas Electric Company
TO3-Cycle 5 Annual Transmission Formulaci Filing
Amortization of Interest True-Up Adjustment Applicable to TO3-Cycle 2

Line No.	Description	(i)	(j)	(k)	(l)	(m)	Reference	Line No.
1	**Derivation of Amortization Rates:**						TO3-Cycle 3 Filing	1
2	TO3-Cycle 3 Interest True-Up Adjustment						Vol. 2 of 3; Section 2.1B; Pg.1.2; Line 20	2
3	Forecast Sales TO3-Cycle 3 (kWh)						See Line 12 Below	3
4	Estimated Amortization Rate Per kWh						Line 2 / Line 3	4
5								5
6								6
7	**Derivation of Forecast Sales:**[1]	May-10	Jun-10	Jul-10	Aug-10	Total		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	Conversion Factor from MWH to kWh	1,000	1,000	1,000	1,000	1,000	MWH Conversion Factor	11
12	Total Forecast Sales Net of Resale - kWh	1,615,028,000	1,719,826,000	1,935,600,000	1,932,387,000	21,102,710,000	Line 10 x Line 11	12
13								13
14								14
15	**Amortization TO3-Cycle 3 Interes True-Up Adjustment:**[2]	**May-10**	**Jun-10**	**Jul-10**	**Aug-10**	Total		15
16	Beginning Interest True-Up Adjustment Balance	$ 133,515	$ 104,612	$ 73,349	$ 39,198		Beginning Balance	16
17	Recorded Sales in Total kWh	1,445,169,701	1,563,139,156	1,707,529,502	1,601,642,774	19,583,069,688	Recorded Sales	17
18	Amortization Rate Per kWh	$ 0.00002	$ 0.00002	$ 0.00002	$ 0.00002		See Line 4 Above	18
19	Amortization of TO3-C3 Interest True-Up Adjustment[3]	**$ 28,903**	**$ 31,263**	**$ 34,151**	**$ 39,198**	$ 398,827	Line 17 x Line 18	19
20	Ending TO3-Cycle 3 True-Up Adjusment Balance	$ 104,612	$ 73,349	$ 39,198	$ -		Line 16 Minus Line 19	20
21								21

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 17, 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 19 from 9/1/2010 through 3/31/2010 was included in the cycle 4 true-up adjustment period. The monthly amortization amounts from April 2010 through August 2010 is included in the instant TO3, Cycle 5 filing.

Section 2.1 – Retail True-Up Adjustment

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

Part (iii): Amortization of Cycle 2 Interest True-Up Adjustment Accrued After Fully Amortized (September 2010-March 2011).

- The amortization of the Cycle-2 Interest True-Up Adjustment Accrued after fully amortized in the instant Cycle-5 filing picks up the amounts amortized from September 2010 through March 2011.
- The remaining balance of the Cycle 2 fully amortized 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 2.1
San Diego Gas Electric Co.
TO3-Cycle 5 Annual Transmission Formulaic Rate Filing
Amortization Schedule of TO3-Cycle 2 Interest True-Up Adjustment

Line No.	Description	(a) Amounts	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	**Derivation of Amortization Rates:**								
2	TO3-C2 Interest True-Up Adjustment Calced/Filed in Cycle 4	$ 30,210							
3	Forecast Sales TO3-Cycle 4 (kWh)	20,392,503,000							
4	Estimated Amortization Rate Per kWh	$ 0.000001							
5									
6									
7	**Derivation of Forecast Sales:**[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	Conversion Factor from MWH to kWh	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
12	Total Forecast Sales Net of Resale - kWh	1,922,247,500	1,690,304,500	1,643,646,500	1,693,673,500	1,744,800,500	1,637,715,500	1,618,730,500	1,557,543,500
13									
14									
15	**Amortization TO3-Cycle 2 Interes True-Up Adjustment:**[2]	**Sep-10**	**Oct-10**	**Nov-10**	**Dec-10**	**Jan-11**	**Feb-11**	**Mar-11**	Apr-11
16	Beginning Interest True-Up Adjustment Balance	$ 30,210	$ 28,356	$ 26,613	$ 25,010	$ 23,347	$ 21,598	$ 20,022	$ -
17	Recorded Sales in Total kWh	1,854,217,871	1,743,019,823	1,603,275,846	1,662,588,802	1,749,322,152	1,576,452,657	1,596,971,420	-
18	Amortization Rate Per kWh	$ 0.000001	$ 0.000001	$ 0.000001	$ 0.000001	$ 0.000001	$ 0.000001	$ 0.000001	$ -
19	Amortization of TO3-C2 Interest True-Up Adjustment [3]	**$ 1,854**	**$ 1,743**	**$ 1,603**	**$ 1,663**	**$ 1,749**	**$ 1,576**	**$ 1,597**	$ -
20	Ending Balance C3 Interest True-Up Adjustment Calced/Filed in Cycle 4	$ 28,356	$ 26,613	$ 25,010	$ 23,347	$ 21,598	$ 20,022	$ 18,425	$ -
21									

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 17, 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 19 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 2.1
San Diego Gas Electric Co.
TO3-Cycle 5 Annual Transmission Formulaic Rate Filing
Amortization Schedule of TO3-Cycle 2 Interest True-Up Adjustment

Line No.	Description	(i)	(j)	(k)	(l)	(m)	Reference	Line No.
1	**Derivation of Amortization Rates:**						TO3-Cycle 3 Filing	1
2	TO3-C2 Interest True-Up Adjustment Calced/Filed in Cycle 4						Vol. 2 of 3; Section 2.1A; Pg.1.2; Line 20	2
3	Forecast Sales TO3-Cycle 4 (kWh)						See Line 12 Below	3
4	Estimated Amortization Rate Per kWh						Line 2 / Line 3	4
5								5
6								6
7	**Derivation of Forecast Sales:**[1]	May-11	Jun-11	Jul-11	Aug-11	Total		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	Conversion Factor from MWH to kWh	1,000	1,000	1,000	1,000	1,000	MWH Conversion Factor	11
12	Total Forecast Sales Net of Resale - kWh	1,563,383,500	1,651,388,500	1,813,251,500	1,855,817,500	20,392,503,000	Line 10 x Line 11	12
13								13
14								14
15	**Amortization TO3-Cycle 2 Interes True-Up Adjustment:**[2]	May-11	Jun-11	Jul-11	Aug-11	Total		15
16	Beginning Interest True-Up Adjustment Balance	$ -	$ -	$ -	$ -		Beginning Balance	16
17	Recorded Sales in Total kWh	-	-	-	-	11,785,848,571	Recorded Sales	17
18	Amortization Rate Per kWh	$ -	$ -	$ -	$ -		See Line 4 Above	18
19	Amortization of TO3-C2 Interest True-Up Adjustment[3]	$ -	$ -	$ -	$ -	$ 11,785	Line 17 x Line 18	19
20	Ending Balance C3 Interest True-Up Adjustment Calced/Filed in Cycle 4	$ -	$ -	$ -	$ -		Line 16 Minus Line 19	20
21								21

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 17, 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 19 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 2.1 – Retail True-Up Adjustment

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

Part (ii): Amortization of TO2 Final Interest Adjustment (April 2010 – August 2010)

- The amortization of the Interest True-Up Adjustment on the FINAL TO2 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.

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Section 2.1
San Diego Gas Electric Co.
TO3-Cycle 4 Annual Transmission Formulaic Filing
Amortization Schedule of the Interest True-Up Adjustment Applicable to TO2 Final 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	$ 1,938,115							
3	Forecast Sales TO3-Cycle 3 (kWh)	21,102,710,000							
4	Estimated Amortization Rate Per kWh	$ 0.00009							
5									
6									
7	**Derivation of Forecast Sales:**	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	Conversion Factor from MWH to kWh	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
12	Total Forecast Sales Net of Resale - kWh	2,010,444,000	1,718,509,000	1,693,221,000	1,751,697,000	1,787,371,000	1,686,420,000	1,675,583,000	1,576,624,000
13									
14									
15	**Amortization of TO3-Cycle 3 Interes True-Up Adjustment:**	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	**Apr-10**
16	Beginning Interest True-Up Adjustment Balance	$ 1,938,115	$ 1,765,811	$ 1,610,206	$ 1,462,407	$ 1,311,614	$ 1,159,561	$ 1,017,179	$ 881,592
17	Recorded Sales in Total kWh	1,914,490,629	1,728,949,088	1,642,207,251	1,675,476,167	1,689,477,704	1,582,023,160	1,506,524,014	1,526,440,542
18	Amortization Rate Per kWh	$ 0.00009	$ 0.00009	$ 0.00009	$ 0.00009	$ 0.00009	$ 0.00009	$ 0.00009	$ 0.00009
19	True-Up Adjustment Revenue Piece of Total Revenues	$ 172,304	$ 155,605	$ 147,799	$ 150,793	$ 152,053	$ 142,382	$ 135,587	**$ 137,380**
20	Ending TO3-Cycle 3 True-Up Adjusment Balance	$ 1,765,811	$ 1,610,206	$ 1,462,407	$ 1,311,614	$ 1,159,561	$ 1,017,179	$ 881,592	$ 744,212
21									

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 17, 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 19 from 9/1/2010 through 3/31/2010 was included in the cycle 4 true-up adjustment period. The monthly amortization amounts from April 2010 through August 2010 is included in the instant TO3, Cycle 5 filing.

Section 2.1
San Diego Gas Electric Co.
TO3-Cycle 4 Annual Transmission Formulaic Filing
Amortization Schedule of the Interest True-Up Adjustment Applicable to TO2 Final True-Up Adjustment

Line No.	Description	(i)	(j)	(k)	(l)	(m)	Reference	Line No.
1	**Derivation of Amortization Rates:**						TO3-Cycle 3 Filing	1
2	TO3-Cycle 3 Interest True-Up Adjustment						Vol. 2; Section 2.1A; Pg.2.2; Line 20	2
3	Forecast Sales TO3-Cycle 3 (kWh)						See Line 12 Below	3
4	Estimated Amortization Rate Per kWh						Line 2 / Line 3	4
5								5
6								6
7	**Derivation of Forecast Sales:**	May-10	Jun-10	Jul-10	Aug-10	Total		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	Conversion Factor from MWH to kWh	1,000	1,000	1,000	1,000	1,000	MWH Conversion Factor	11
12	Total Forecast Sales Net of Resale - kWh	1,615,028,000	1,719,826,000	1,935,600,000	1,932,387,000	21,102,710,000	Line 10 x Line 11	12
13								13
14								14
15	**Amortization of TO3-Cycle 3 Interes True-Up Adjustment:**	**May-10**	**Jun-10**	**Jul-10**	**Aug-10**	Total		15
16	Beginning Interest True-Up Adjustment Balance	$ 744,212	$ 614,147	$ 473,464	$ 319,786		Beginning Balance	16
17	Recorded Sales in Total kWh	1,445,169,701	1,563,139,156	1,707,529,502	1,601,642,774	19,583,069,688	Recorded Sales	17
18	Amortization Rate Per kWh	$ 0.00009	$ 0.00009	$ 0.00009	$ 0.00009		See Line 4 Above	18
19	True-Up Adjustment Revenue Piece of Total Revenues	**$ 130,065**	**$ 140,683**	**$ 153,678**	**$ 319,786**	$ 1,938,115	Line 17 x Line 18	19
20	Ending TO3-Cycle 3 True-Up Adjusment Balance	$ 614,147	$ 473,464	$ 319,786	$ -		Line 16 Minus Line 19	20
21								21

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 17, 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 19 from 9/1/2010 through 3/31/2010 was included in the cycle 4 true-up adjustment period. The monthly amortization amounts from April 2010 through August 2010 is included in the instant TO3, Cycle 5 filing.

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Section 2.1 – Retail True-Up Adjustment

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

Part (iii): Amortization of TO2 Final Interest True-Up Adjustment Accrued after Fully Amortized (September 2010 – 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 2.1
San Diego Gas Electric Co.
TO3-Cycle 5 Annual Transmission Formulaic Rate Filing
Amortization Schedule 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 Calced/Filed in Cycle 4	$ 143,760							
3	Forecast Sales TO3-Cycle 4 (kWh)	20,392,503,000							
4	Estimated Amortization Rate Per kWh	$ 0.00001							
5									
6									
7	**Derivation of Forecast Sales:**[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	Conversion Factor from MWH to kWh	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
12	Total Forecast Sales Net of Resale - kWh	1,922,247,500	1,690,304,500	1,643,646,500	1,693,673,500	1,744,800,500	1,637,715,500	1,618,730,500	1,557,543,500
13									
14									
15	**Amortization TO2-FINAL Interest True-Up Adjustment:**[2]	**Sep-10**	**Oct-10**	**Nov-10**	**Dec-10**	**Jan-11**	**Feb-11**	**Mar-11**	Apr-11
16	Beginning Interest True-Up Adjustment Balance	$ 143,760	$ 125,218	$ 107,788	$ 91,755	$ 75,129	$ 57,636	$ 41,871	$ -
17	Recorded Sales in Total kWh	1,854,217,871	1,743,019,823	1,603,275,846	1,662,588,802	1,749,322,152	1,576,452,657	1,596,971,420	-
18	Amortization Rate Per kWh	$ 0.000010	$ 0.000010	$ 0.000010	$ 0.000010	$ 0.000010	$ 0.000010	$ 0.000010	$ -
19	Amortization TO2-FINAL Interest True-Up Adjustment [3]	**$ 18,542**	**$ 17,430**	**$ 16,033**	**$ 16,626**	**$ 17,493**	**$ 15,765**	**$ 15,970**	$ -
20	Ending Balance C3 Interest True-Up Adjustment Calced/Filed in Cycle 4	$ 125,218	$ 107,788	$ 91,755	$ 75,129	$ 57,636	$ 41,871	$ 25,901	$ -
21									

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 17, 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 19 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 2.1
San Diego Gas Electric Co.
TO3-Cycle 5 Annual Transmission Formulaic Rate Filing
Amortization Schedule 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 3 Filing	1
2	TO2-FINAL Interest True-Up Adjustment Calced/Filed in Cycle 4						Vol. 2 of 3; Section 2.1A; Pg.1.2; Line 20	2
3	Forecast Sales TO3-Cycle 4 (kWh)						See Line 12 Below	3
4	Estimated Amortization Rate Per kWh						Line 2 / Line 3	4
5								5
6								6
7	**Derivation of Forecast Sales:**[1]	May-11	Jun-11	Jul-11	Aug-11	Total		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	Conversion Factor from MWH to kWh	1,000	1,000	1,000	1,000	1,000	MWH Conversion Factor	11
12	Total Forecast Sales Net of Resale - kWh	1,563,383,500	1,651,388,500	1,813,251,500	1,855,817,500	20,392,503,000	Line 10 x Line 11	12
13								13
14								14
15	**Amortization TO2-FINAL Interest True-Up Adjustment:**[2]	May-11	Jun-11	Jul-11	Aug-11	Total		15
16	Beginning Interest True-Up Adjustment Balance	$ -	$ -	$ -	$ -		Beginning Balance	16
17	Recorded Sales in Total kWh	-	-	-	-	11,785,848,571	Recorded Sales	17
18	Amortization Rate Per kWh	$ -	$ -	$ -	$ -		See Line 4 Above	18
19	Amortization TO2-FINAL Interest True-Up Adjustment[3]	$ -	$ -	$ -	$ -	$ 117,859	Line 17 x Line 18	19
20	Ending Balance C3 Interest True-Up Adjustment Calced/Filed in Cycle 4	$ -	$ -	$ -	$ -		Line 16 Minus Line 19	20
21								21

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 17, 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 19 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 – 2

Derivation of Retail (End Use Customer) True-Up Adjustment

Section 2.1B

Summary of Retail Interest True-Up Adjustment

Docket No. ER11-____-____

San Diego Gas & Electric Company

Part 1.A

TO3-Cycle 4 Interest True-Up Adjustment Calculation

Docket No. ER11-____-____

Section 2.1B-Part 1.A
San Diego Gas and Electric Company
TO3-Cycle 5 Annual Transmission Formulaic Rate Filing
Derivation of Interest True-Up Adjustment Applicable to TO3-Cycle 4

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	**Beginning Balance (Overcollection)/Undercollection TO3-C4**	$ 31,743,336	$ 31,829,043	$ 31,917,924	$ 32,003,631	$ 32,093,241	$ 32,182,851	$ 29,317,075	$ 26,623,881
2									
5	**Part A1: Amortization of TU Balance:**								
6	Total Recorded Sales KWHs	-	-	-	-	-	1,854,217,871	1,743,019,823	1,603,275,846
7									
8	Rate Per KWH	$ -	$ -	$ -	$ -	$ -	$ 0.00159	$ 0.00159	$ 0.00159
9									
10	Amortization of True-Up Balance	$ -	$ -	$ -	$ -	$ -	$ 2,948,206	$ 2,771,402	$ 2,549,209
11									
12	Net Monthly Collection/(Refunds)	$ -	$ -	$ -	$ -	$ -	$ (2,948,206)	$ (2,771,402)	$ (2,549,209)
13									
14	**Part A2: Calculation of Interest on Remaining TU Balance:**								
15	Interest Expense Calculations: [1]								
16	Beginning Balance for Interest Calculation	$ 31,743,336	$ 31,743,336	$ 31,743,336	$ 32,003,631	$ 32,003,631	$ 32,003,631	$ 29,317,075	$ 29,317,075
17	Monthly Activity Included in Interest Calculation Basis [2]	0	0	0	0	0	(1,474,103)	(1,385,701)	(4,046,007)
18	Basis for Interest Expense Calculation	31,743,336	31,743,336	31,743,336	32,003,631	32,003,631	30,529,528	27,931,374	25,271,069
19	Monthly Interest Rate	0.27%	0.28%	0.27%	0.28%	0.28%	0.27%	0.28%	0.27%
20	Interest Expense	**$ 85,707**	**$ 88,881**	**$ 85,707**	**$ 89,610**	**$ 89,610**	**$ 82,430**	**$ 78,208**	**$ 68,232**
21									
22	Ending Balance (Overcollection)/Undercollection	$ 31,829,043	$ 31,917,924	$ 32,003,631	$ 32,093,241	$ 32,182,851	$ 29,317,075	$ 26,623,881	$ 24,142,904
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	0.27%	0.28%	0.27%	0.28%	0.28%	0.27%	0.28%	0.27%
28	FERC Interest Rates - Website	0.27%	0.28%	0.27%	0.28%	0.28%	0.27%	0.28%	0.27%
29	Difference	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

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 - per 18 CFR Section 35.19 (2) (iii) (B)

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). Column D, E, F, etc. repeats the process outlined in (a), (b), and (c) above.

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Section 2.1B-Part 1.A
San Diego Gas and Electric Company
TO3-Cycle 5 Annual Transmission Formulaic Rate Filing
Derivation of Interest True-Up Adjustment Applicable to TO3-Cycle 4

Line No.	Description	(i) Dec-10	(j) Jan-11	(k) Feb-11	(l) Mar-11	(m) Total	Reference	Line No.
1	**Beginning Balance (Overcollection)/Undercollection TO3-C4**	$ 24,142,904	$ 21,562,877	$ 18,837,937	$ 16,375,197	$ 31,743,336	Previous Month's Ending Balance (Line 22)	1
2								2
5	**Part A1: Amortization of TU Balance:**							5
6	Total Recorded Sales KWHs	1,662,588,802	1,749,322,152	1,576,452,657	1,596,971,420	11,785,848,571	Section 2.3.2; Pgs 71-72; Line 15; Col (F)-(L)	6
7								7
8	Rate Per KWH	$ 0.00159	$ 0.00159	$ 0.00159	$ 0.00159		Section 2.1B; Page 32; Col.M; Line 10	8
9								9
10	Amortization of True-Up Balance	$ 2,643,516	$ 2,781,422	$ 2,506,560	$ 2,539,185	$ 18,739,500	Line 6 x Line 8	10
11								11
12	Net Monthly Collection/(Refunds)	$ (2,643,516)	$ (2,781,422)	$ (2,506,560)	$ (2,539,185)	$ (18,739,500)	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	$ 29,317,075	$ 21,562,877	$ 21,562,877	$ 21,562,877		Balance at Beginning of Quarter (See Footnote 1)	16
17	Monthly Activity Included in Interest Calculation Basis [2]	(6,642,369)	(1,390,711)	(4,034,702)	(6,557,575)		See Footnote 2	17
18	Basis for Interest Expense Calculation	22,674,706	20,172,166	17,528,175	15,005,303		Line 16 + Line 17	18
19	Monthly Interest Rate	0.28%	0.28%	0.25%	0.28%		FERC Monthly Rates	19
20	Interest Expense	**$ 63,489**	**$ 56,482**	**$ 43,820**	**$ 42,015**	**$ 874,191**	Line 18 x Line 19 (Columns a to l)	20
21								21
22	Ending Balance (Overcollection)/Undercollection	$ 21,562,877	$ 18,837,937	$ 16,375,197	$ 13,878,027	$ 13,878,027	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	0.28%	0.28%	0.25%	0.28%	3.29%	(Line 24)/(Line 25)x(Line 26)	27
28	FERC Interest Rates - Website	0.28%	0.28%	0.25%	0.28%	3.29%	Monthly Interest Rate - FERC Website	28
29	Difference	0.00%	0.00%	0.00%	0.00%	0.00%	Line 27 - Line 28	29

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 - per 18 CFR Section 35.19 (2) (iii) (B)

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). Column D, E, F, etc. repeats the process outlined in (a), (b), and (c) above.

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San Diego Gas & Electric Company

Part 1.B

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

Docket No. ER11-____-____

Section 2.1B-Part 1.B
San Diego Gas and Electric Company
TO3-Cycle 5 Annual Transmission Formula Filing
Derivation of Amortization Rate for TO3-Cycle 4

Line No.	Description	(a) Sep-10	(b) Oct-10	(c) Nov-10	(d) Dec-10	(e) Jan-11	(f) Feb-11	(g) Mar-11	(h) Apr-11
1	**Derivation of Amortization Rate for TO3-Cycle 4:**								
2	Beginning Balance (Overcollection)/Undercollection								
3									
4	Recorded Sales Sept 10 - March 11:	1,854,217,871	1,743,019,823	1,603,275,846	1,662,588,802	1,749,322,152	1,576,452,657	1,596,971,420	
5									
6	Estimated Sales April 11 - Aug 11:								1,557,543,693
7									
8	Forecast Sales TO3-Cycle 4 (kWh)								
9									
10	Estimated Amortization Rate Per kWh								
11									

000031

Section 2.1B-Part 1.B
San Diego Gas and Electric Company
TO3-Cycle 5 Annual Transmission Formula Filing
Derivation of Amortization Rate for TO3-Cycle 4

Line No.	Description	(i) May-11	(j) Jun-11	(k) Jul-11	(l) Aug-11	(m) Total	Reference	Line No.
1	**Derivation of Amortization Rate for TO3-Cycle 4:**						From TO3-Cycle 5 Filing	1
2	Beginning Balance (Overcollection)/Undercollection					$ 32,182,851	Vol. 2 of 3; Section 2.1B; Pg. 1; Line 22; Col. e	2
3								3
4	Recorded Sales Sept 10 - March 11:					11,785,848,571	TO3-Cycle 5; Sect. 2.3.2; Pages 2&3; Line 15	4
5								5
6	Estimated Sales April 11 - Aug 11:	1,563,383,686	1,651,388,739	1,813,251,582	1,855,817,817	8,441,385,517	TO3-Cycle 4; Statement BD; Page 1	6
7								7
8	Forecast Sales TO3-Cycle 4 (kWh)					20,227,234,088	Sum Lines 4 & 6	8
9								9
10	Estimated Amortization Rate Per kWh					$ 0.00159	Line 2 / Line 8	10
11								11

000032

San Diego Gas & Electric Company

Part 2.A

TO3-Cycle 3 Interest True-Up Adjustment Calculation

Docket No. ER11-____-____

Section 2.1B-Part 2.A
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

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	**Remaining Undercollection Balance from TO3-Cycle 3 Used to Derive the Interest True-Up Adjustment to Include in TO3-Cycle 5 Filing**	$ 3,904,939	$ 3,242,942	$ 2,615,230	$ 1,933,534	$ 1,186,583	$ -	$ -	$ -
2									
5	**Part A1: Amortization of TU Balance:**								
6	Total Recorded Sales KWHs	1,526,440,542	1,445,169,701	1,563,139,156	1,707,529,502	1,601,642,774	-	-	-
7									
8	Rate Per KWH as reflected in TO3 Cycle 4 filing (see reference)	$ 0.00044	$ 0.00044	$ 0.00044	$ 0.00044	$ 0.00044	$ -	$ -	$ -
9									
10	Amortization of True-Up Balance	$ 671,634	$ 635,875	$ 687,781	$ 751,313	$ 1,188,230	$ -	$ -	$ -
11									
12	Net Monthly Collection/(Refunds)	$ (671,634)	$ (635,875)	$ (687,781)	$ (751,313)	$ (1,188,230)	$ -	$ -	$ -
13									
14	**Part A2: Calculation of Interest on Remaining TU Balance:**								
15	Interest Expense Calculations: [1]								
16	Beginning Balance for Interest Calculation	$ 3,904,939	$ 3,904,939	$ 3,904,939	$ 1,933,534	$ 1,933,534	$ -	$ -	$ -
17	Monthly Activity Included in Interest Calculation Basis [2]	(335,817)	(989,572)	(1,651,400)	(375,657)	(1,345,428)	0	0	0
18	Basis for Interest Expense Calculation	3,569,122	2,915,368	2,253,540	1,557,878	588,106	0	0	0
19	Monthly Interest Rate	0.27%	0.28%	0.27%	0.28%	0.28%	0.27%	0.28%	0.27%
20	Interest Expense	**$ 9,637**	**$ 8,163**	**$ 6,085**	**$ 4,362**	**$ 1,647**	$ -	$ -	$ -
21									
22	Ending Balance (Overcollection)/Undercollection	$ 3,242,942	$ 2,615,230	$ 1,933,534	$ 1,186,583	$ 0	$ -	$ -	$ -
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	0.27%	0.28%	0.27%	0.28%	0.28%	0.27%	0.28%	0.27%
28	FERC Interest Rates - Website	0.27%	0.28%	0.27%	0.28%	0.28%	0.27%	0.28%	0.27%
29	Difference	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

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 - per 18 CFR Section 35.19 (2) (iii) (B)

[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). Column D, E, F, etc. repeats the process outlined in (a), (b), and (c) above.

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Section 2.1B-Part 2.A
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

Line No.	Description	(i) Dec-10	(j) Jan-11	(k) Feb-11	(l) Mar-11	(m) Total	Reference	Line No.
1	**Remaining Undercollection Balance from TO3-Cycle 3 Used to Derive the Interest True-Up Adjustment to Include in TO3-Cycle 5 Filing**	$ -	$ -	$ -	$ -	$ 3,904,939	Previous Month's Ending Balance (Line 22)	1
2								2
5	**Part A1: Amortization of TU Balance:**							5
6	Total Recorded Sales KWHs	-	-	-	-	7,843,921,675	Section 2.3.2; Page 71; Line 15; Col (A)-(E)	6
7								7
8	Rate Per KWH as reflected in TO3 Cycle 4 filing (see reference)	$ -	$ -	$ -	$ -		Section 2.1B; Page 38; Col.M; Line 10	8
9								9
10	Amortization of True-Up Balance	$ -	$ -	$ -	$ -	$ 3,934,833	Line 6 x Line 8	10
11								11
12	Net Monthly Collection/(Refunds)	$ -	$ -	$ -	$ -	$ (3,934,833)	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]	0	0	0	0		See Footnote 2	17
18	Basis for Interest Expense Calculation	0	0	0	0		Line 16 + Line 17	18
19	Monthly Interest Rate	0.28%	0.28%	0.25%	0.28%		FERC Monthly Rates	19
20	Interest Expense	$ -	$ -	$ -	$ -	**$ 29,894**	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	0.28%	0.28%	0.25%	0.28%	3.29%	(Line 24)/(Line 25)x(Line 26)	27
28	FERC Interest Rates - Website	0.28%	0.28%	0.25%	0.28%	3.29%	Monthly Interest Rate - FERC Website	28
29	Difference	0.00%	0.00%	0.00%	0.00%	0.00%		29

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 - per 18 CFR Section 35.19 (2) (iii) (B)

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). Column D, E, F, etc. repeats the process outlined in (a), (b), and (c) above.

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San Diego Gas & Electric Company

Part 2.B

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

Docket No. ER11-____-____

Section 2.1B-Part 2.B
San Diego Gas and Electric Company
TO3-Cycle 5 Annual Transmission Formula Filing
Derivation of Amortization Rate for TO3-Cycle 3

Line No.	Description	(a) Sep-09	(b) Oct-09	(c) Nov-09	(d) Dec-09	(e) Jan-10	(f) Feb-10	(g) Mar-10	(h) Apr-10
1	**Derivation of Amortization Rate for TO3-Cycle 3:**								
2	Beginning Balance (Overcollection)/Undercollection								
3									
4	Recorded Sales Sept 09 - March 10:	1,914,490,629	1,728,949,088	1,642,207,251	1,675,476,167	1,689,477,704	1,582,023,160	1,506,524,014	
5									
6	Estimated Sales April 10 - Aug 10:								1,576,624,000
7									
8	Forecast Sales TO3-Cycle 3 (kWh)								
9									
10	Estimated Amortization Rate Per kWh								
11									

000037

Section 2.1B-Part 2.B
San Diego Gas and Electric Company
TO3-Cycle 5 Annual Transmission Formula Filing
Derivation of Amortization Rate for TO3-Cycle 3

Line No.	Description	(i) May-10	(j) Jun-10	(k) Jul-10	(l) Aug-10	(m) Total	Reference	Line No.
1	**Derivation of Amortization Rate for TO3-Cycle 3:**						From TO3-Cycle 4 Filing	1
2	Beginning Balance (Overcollection)/Undercollection					$ 8,949,464	Vol. 2 of 3; Section 2.1B; Pg. 1; Line 22;	2
3								3
4	Recorded Sales Sept 09 - March 10:					11,739,148,013	TO3-Cycle 4; Sect. 2.3.2; Pages 3&4; Line 15	4
5								5
6	Estimated Sales April 10 - Aug 10:	1,615,028,000	1,719,826,000	1,935,600,000	1,932,387,000	8,779,465,000	TO3-Cycle 3; Statement BD; Page 1	6
7								7
8	Forecast Sales TO3-Cycle 3 (kWh)					20,518,613,013	Sum Lines 4 & 6	8
9								9
10	Estimated Amortization Rate Per kWh					$ 0.00044	Line 2 / Line 8	10
11								11

000038

Section – 2
Derivation of Retail (End Use Customer) True-Up Adjustment

Section 2.2
Summary of Monthly Retail True-Up Recorded Revenues

Docket No. ER11-____-____

Section 2.2
SAN DIEGO GAS AND ELECTRIC COMPANY
Monthly Retail True-Up Period Recorded Revenues
12-Month Period (April 1, 2010 - March 31, 2011)

Line No.	Customer Class	(A) Apr-10	(B) May-10	(C) Jun-10	(D) Jul-10	(E) Aug-10	(F) Sep-10	(a) Oct-10	(b) Nov-10	(c) Dec-10	(d) Jan-11	(e) Feb-11	(f) Mar-11	(g) Total	Line No.
1	Residential Customers	$ 7,582,700	$ 6,998,026	$ 7,451,205	$ 8,030,387	$ 7,983,086	$ 10,226,008	$ 10,660,204	$ 9,830,307	$ 11,207,158	$ 12,068,947	$ 10,477,345	$ 10,172,219	$ 112,687,591	1
2															2
3	Small Commercial	2,494,867	2,171,170	2,567,059	2,802,803	2,586,188	3,287,733	3,486,024	3,199,138	3,224,049	3,369,932	3,143,707	3,154,391	35,487,062	3
4															4
5	Medium-Large Commercial	8,834,867	8,625,777	10,032,510	11,418,289	10,408,929	13,149,594	14,238,985	12,235,206	11,478,027	11,752,122	10,705,928	8,221,326	131,101,559	5
6															6
7	Street Lighting	132,506	62,406	96,143	98,099	100,044	75,983	138,233	109,300	150,792	70,536	111,237	150,425	1,295,704	7
8															8
9	Standby Revenues	(350,352)	313,043	298,617	308,760	327,955	282,834	359,826	369,107	346,365	448,286	377,598	329,840	3,411,879	9
10															10
11	TOTAL Recorded	$ 18,694,588	$ 18,170,421	$ 20,445,534	$ 22,658,338	$ 21,406,203	$ 27,022,152	$ 28,883,272	$ 25,743,058	$ 26,406,391	$ 27,709,822	$ 24,815,815	$ 22,028,200	$ 283,983,795	11
12															12
13	Customer Rebilling Adjustment *												$ 3,201,925	$ 3,201,925	13
14													$ 25,230,125	$ 287,185,720	14

* Medium & Large C&I customer revenue adjustment related to Haybarn and Camp Stewart.

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Section – 2

Derivation of Retail (End Use Customer) True-Up Adjustment

Section 2.3.1

Derivation of Retail True-Up Cost of Service Rates

Docket No. ER11-____-____

Section 2.3.1
SAN DIEGO GAS AND ELECTRIC COMPANY
TO3-Cycle 5 Annual Transmission Formulaic Rate Filing
True-Up Period Rate Design Information
For the True-Up Period - (April 1, 2010 - March 31, 2011)
Summary of Transmission Rates

Line No.	Customer Classes	(A) Transmission Energy Rates $/kWh	(B) Transmission Level Demand Rates $/kW-Mo	(C) Primary Level Demand Rates $/kW-Mo	(D) Secondary Level Demand Rates $/kW-Mo	Reference	Line No.
1	Residential	$ 0.0158151				Section 2.3.1; Page 3; Line 7	1
2							2
3	Small Commercial	$ 0.0180830				Section 2.3.1; Page 4; Line 7	3
4							4
5	Medium & Large Commercial/Industrial						5
6	Non-Coincident Demand (100%)[1]		$ 4.9132451	$ 4.9647503	$ 5.1364982	Section 2.3.1; Page 5; Lines 35;34;33	6
7							7
8	Non-Coincident Demand (90%)[2]		$ 4.4219206	$ 4.4682753	$ 4.6228484	Section 2.3.1; Page 6; Lines 8;7;6	8
9							9
10	Maximum On-Peak Period Demand [3]						10
11	Summer		$ 0.9956104	$ 1.0069345	$ 1.0414937	Section 2.3.1; Page 7; Lines 37; 36; 35	11
12	Winter		$ 0.2061251	$ 0.2065435	$ 0.2139162	Section 2.3.1; Page 8; Lines 30; 29; 28	12
13							13
14	Maximum Demand at the Time of System Peak[4]						14
15	Summer		$ 1.1202075	$ 1.1392972	$ -	Section 2.3.1; Page 9; Lines 37; 36; 35	15
16	Winter		$ 0.2176482	$ 0.2158957	$ -	Section 2.3.1; Page 10; Lines 33; 32; 31	16
17							17
18	Street Lighting	$ 0.0092284				Section 2.3.1; Page 11; Line 7	18
19							19
20	Standby Rate		$ 2.0984537	$ 2.1226808	$ 2.1998938	Section 2.3.1; Page 12; Lines 35;34;33	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 2.3.1
SAN DIEGO GAS AND ELECTRIC COMPANY
TO3-Cycle 5 Annual Transmission Formulaic Rate Filing
Derivation of Retail True-Up Cos of Service Rates
For the True-Up Period - (April 1, 2010 - March 31, 2011)
Allocation of Base Transmission Revenue Requirements (BTRR) Based on 12 CPs
($1,000)

Line No.	Customer Classes	(A) Total 12 CPs @ Transmission Level [2]	(B) Percentages [3]	(C) Allocated Base Transmission Revenue Requirement	Reference	Line No.
1	Total Base Transmission Revenue Requirement [1]			$ 295,044	Section 2.3; Page 5 of 5; Line 12	1
2						2
3	Allocation of BTRR Based on 12-CP:					3
4	Residential	15,742,820	39.46%	$ 116,423	Col.C4 = Col C Ln1 x Col B. Ln 4	4
5	Small Commercial	4,848,321	12.15%	35,855	Col.C5 = Col C Ln1 x Col B. Ln 5	5
6	Medium & Large Commercial/Industrial	18,659,462	46.77%	137,992	Col.C6 = Col C Ln1 x Col B. Ln 6	6
7	Street Lighting Revenues	146,179	0.37%	1,081	Col.C7 = Col C Ln1 x Col B. Ln 7	7
8	Standby Revenues	499,375	1.25%	3,693	Col.C8 = Col C Ln1 x Col B. Ln 8	8
9						9
10	Total	39,896,157	100.00%	$ 295,044	Sum Lines 4 thru 8	10
11						11
12	Total	39,896,157		$ 295,044	Line 10	12

NOTES:

1 Total Base TRR comes from TO3-Cycle 5; Section 2.3; Statement BK1; Page 5 of 5; Line 12

2 See Statement BL; Page 9; Column D.

3 See Statement BL; Page 9; Column E.

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Section 2.3.1
SAN DIEGO GAS AND ELECTRIC COMPANY
TO3-Cycle 5 Annual Transmission Formulaic Rate Filing
Derivation of Retail True-Up Cos of Service Rates
For the True-Up Period - (April 1, 2010 - March 31, 2011)
Residential Customers [1]
($000)

Line No.	Description	Derivation of Commodity Rate & Proof of Revenues Calculation	Reference	Line No.
1	Residential - Allocated Transmission Revenue Requirements	$ 116,423	Section 2.3.1; Page 2; Line 4	1
2				2
3	Billing Determinants - Residential Customer Class (MWh):	7,361,513	Section 2.3.1; Page 16.1; Line 4	3
4				4
5	Residential Energy Rate Per kWh	$ 0.0158151	Line 1 / Line 3	5
6				6
7	Residential Energy Rate Per kWh - Rounded	$ 0.0158151	Line 5, Rounded to 7 Decimal Places	7
8				8
9	Proof of Revenues	$ 116,423	Line 7 x Line 3	9
10				10
11	Difference	$ -	Line 1 - Line 9	11

NOTES:

[1] Residential customers include the following California Public Utilities Commission (CPUC) tariffs:
DR, DR-LI, DR-TOU, DR-TOU-DER, DR-SES, DM, DS, DT, DT-RV, EV-TOU, EV-TOU-2, EV-TOU-3.

Section 2.3.1
SAN DIEGO GAS AND ELECTRIC COMPANY
TO3-Cycle 5 Annual Transmission Formulaic Rate Filing
Derivation of Retail True-Up Cos of Service Rates
For the True-Up Period - (April 1, 2010 - March 31, 2011)
Small Commercial Customers [1]
($000)

Line No.	Description	Derivation of Commodity Rate & Proof of Revenues Calculation		Reference	Line No.
1	Small Commercial - Allocated Transmission Revenue Requirement	$	35,855	Section 2.3.1; Page 2; Line 5	1
2					2
3	Billing Determinants - Small Commercial (MWh):		1,982,802	Section 2.3.1; Page 16.1; Line 5	3
4					4
5	Rate Per kWh Calculation	$	0.0180830	Line 1 / Line 3	5
6					6
7	Rate Per kWh Calculation - Rounded	$	0.0180830	Line 5, Rounded to 7 Decimal Places	7
8					8
9	Proof of Revenues	$	35,855	Line 7 x Line 3	9
10					10
11	Difference	$	-	Line 1 - Line 9	11

NOTES:

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

Section 2.3.1
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TO3-Cycle 5 Annual Transmission Formulaic Rate Filing
Derivation of Retail True-Up Cos of Service Rates
For the True-Up Period - (April 1, 2010 - March 31, 2011)
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 - Demand Revenue Requirement	$ 137,992	Section 2.3.1; Page 2; Line 6	1
2	***Demand Determinants @ Transmission Level Used to Allocate***			2
3	***Total Class Revenues to Voltage Level with Loss Factor Adjustment (MW) [2]:***			3
4	Secondary	22,208	Section 2.3.1; Page 15; Col. D; Line 23	4
5	Primary	4,326	Section 2.3.1; Page 15; Col. D; Line 24	5
6	Tranmission	1,559	Section 2.3.1; Page 15; Col. D; Line 25	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	Tranmission	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	$ 109,085	Line 1 x Line 10	16
17	Primary	$ 21,249	Line 1 x Line 11	17
18	Tranmission	$ 7,658	Line 1 x Line 12	18
19	Total	$ 137,992	Sum Lines 16; 17; 18	19
20				20
21	Demand Determinants By Voltage Level @ Meter Level (MW)			21
22	Secondary	21,237	Section 2.3.1; Page 15; Col. B; Line 23	22
23	Primary	4,280	Section 2.3.1; Page 15; Col. B; Line 24	23
24	Tranmission	1,559	Section 2.3.1; Page 15; Col. B; Line 25	24
25	Total	27,076	Sum Lines 22; 23; 24	25
26				26
27	Demand Rate By Voltage @ Meter			27
28	Secondary	$ 5.1364982	Line 16 / Line 22	28
29	Primary	$ 4.9647503	Line 17 / Line 23	29
30	Tranmission	$ 4.9132451	Line 18 / Line 24	30
31				31
32	Demand Rate By Voltage @ Meter (Rounded)			32
33	Secondary	$ 5.1364982	Line 28, Rounded to 7 Decimal Places	33
34	Primary	$ 4.9647503	Line 29, Rounded to 7 Decimal Places	34
35	Tranmission	$ 4.9132451	Line 30, Rounded to 7 Decimal Places	35
36				36
37	Proof of Revenue Calculations:			37
38	Secondary	$ 109,085	Line 22 x Line 33	38
39	Primary	$ 21,249	Line 23 x Line 34	39
40	Tranmission	$ 7,658	Line 24 x Line 35	40
41	Total	$ 137,992	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-DER, DGR, A6-TOU, PA-T-1.

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

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

Section 2.3.1
SAN DIEGO GAS AND ELECTRIC COMPANY
TO3-Cycle 5 Annual Transmission Formulaic Rate Filing
Derivation of Retail True-Up Cos of Service Rates
For the True-Up Period - (April 1, 2010 - March 31, 2011)
Medium-Large Commercial Customers
($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	$ 4.6228484	90% x Section 2.3.1; Page 5; Line 33	2
3	Primary	$ 4.4682753	90% x Section 2.3.1; Page 5; Line 34	3
4	Tranmission	$ 4.4219206	90% x Section 2.3.1; Page 5; Line 35	4
5	**Rate Proposal 90% of Total M&L C&I NCD Rates (Rounded):**			5
6	Secondary	$ 4.6228484	Line 2, Rounded to 7 Decimal Places	6
7	Primary	$ 4.4682753	Line 3, Rounded to 7 Decimal Places	7
8	Tranmission	$ 4.4219206	Line 4, Rounded to 7 Decimal Places	8
9	**Pertaining to Schedules @ 90% NCD with Maximum On-Peak Period Demand:** [2]			9
10	NCD Determinants By Voltage Level @ Meter Level (MW)			10
11	Secondary [4]	20,261	Section 2.3.1; Page 15; Col. B; Line 10	11
12	Primary [4]	3,981	Section 2.3.1; Page 15; Col. B; Line 11	12
13	Transmission [4]	256	Section 2.3.1; Page 15; Col. B; Line 12	13
14	Total	24,498	Sum Lines 11; 12; 13	14
15	**Annual Revenues from Current NCD Rate 100% of Total M&L C&I NCD Rates:**			15
16	Secondary	$ 104,071	Line 11 x Section 2.3.1; Page 5; Line 33	16
17	Primary	$ 19,764	Line 12 x Section 2.3.1; Page 5; Line 34	17
18	Tranmission	$ 1,256	Line 13 x Section 2.3.1; Page 5; Line 35	18
19	Total	$ 125,091	Sum Lines 16; 17; 18	19
20	**Annual Revenues from Proposed NCD Rate 90% of Total M&L C&I NCD Rates:**			20
21	Secondary	$ 93,664	Line 6 x Line 11	21
22	Primary	$ 17,787	Line 7 x Line 12	22
23	Tranmission	$ 1,130	Line 8 x Line 13	23
24	Total	$ 112,581	Sum Lines 21; 22; 23	24
25	**Revenue Reallocation to Maximum On-Peak Period Demands:**			25
26	Secondary	$ 10,407	Line 16 - Line 21	26
27	Primary	$ 1,977	Line 17 - Line 22	27
28	Tranmission	$ 126	Line 18 - Line 23	28
29	Total - **Reallocated to MAXIMUM ON-PEAK PERIOD DEMANDS**	$ 12,510	Sum Lines 26; 27; 28	29
30	**Pertaining to Schedules @ 90% NCD with Maximum Demand at Time of System Peak:** [3]			30
31	NCD Determinants By Voltage Level @ Meter Level (MW)			31
32	Secondary [4]	-	Section 2.3.1; Page 15; Col. B; Line 17	32
33	Primary [4]	160	Section 2.3.1; Page 15; Col. B; Line 18	33
34	Transmission [4]	1,303	Section 2.3.1; Page 15; Col. B; Line 19	34
35	Total	1,463	Sum Lines 32; 33; 34	35
36	**Annual Revenues from Current NCD Rate 100% of Total M&L C&I NCD Rates:**			36
37	Secondary	$ -	Line 32 x Section 2.3.1; Page 5; Line 33	37
38	Primary	$ 796	Line 33 x Section 2.3.1; Page 5; Line 34	38
39	Tranmission	$ 6,402	Line 34 x Section 2.3.1; Page 5; Line 35	39
40	Total	$ 7,198	Sum Lines 37; 38; 39	40
41	**Annual Revenues from Proposed NCD Rate 90% of Total M&L C&I NCD Rates:**			41
42	Secondary	$ -	Line 6 x Line 38	42
43	Primary	$ 717	Line 7 x Line 39	43
44	Tranmission	$ 5,762	Line 8 x Line 40	44
45	Total	$ 6,479	Sum Lines 42; 43; 44	45
46	**Revenue Reallocation to Maximum Demand at the Time of System Peak:**			46
47	Secondary	$ -	Line 37 - Line 42	47
48	Primary	$ 79	Line 38 - Line 43	48
49	Tranmission	$ 640	Line 39 - Line 44	49
50	Total	$ 719	Sum Lines 47; 48; 49	50

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

[4] Represents NCD billing determinants based on Maximum On-Peak Period Demand during the period in which the new rate structure was in effect.

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Derivation of Retail True-Up Cos of Service Rates
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Medium-Large Commercial Customers
($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]	$ 12,510	Section 2.3.1; Page 6; Line 29	2
3				3
4	Summer - Maximum On-Peak Period Demands By Voltage Level @ Meter Level (MW) [2]			4
5	Secondary	7,819	Section 2.3.1; Page 15; Col. B; Line 30	5
6	Primary	1,723	Section 2.3.1; Page 15; Col. B; Line 31	6
7	Transmission	130	Section 2.3.1; 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 By Voltage Level @ Trans. Level (MW)			10
11	Secondary	8,176	Section 2.3.1; Page 15; Col. D; Line 30	11
12	Primary	1,742	Section 2.3.1; Page 15; Col. D; Line 31	12
13	Transmission	130	Section 2.3.1; 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			22
23	Secondary	$ 8,143	(Line 2 x Line 21) x Line 17	23
24	Primary	$ 1,735	(Line 2 x Line 21) x Line 18	24
25	Transmission	$ 129	(Line 2 x Line 21) x Line 19	25
26	Total	$ 10,007	Sum Lines 23; 24; 25	26
27				27
28	Summer Maximum On-Peak Period Demand Rates [3]	$/kW		28
29	Secondary	$ 1.0414937	Line 23 / Line 5	29
30	Primary	$ 1.0069345	Line 24 / Line 6	30
31	Transmission	$ 0.9956104	Line 25 / Line 7	31
32				32
33				33
34	Summer Maximum On-Peak Period Demand Rates (Rounded)	$/kW		34
35	Secondary	$ 1.0414937	Line 29, Rounded to 7 Decimal Places	35
36	Primary	$ 1.0069345	Line 30, Rounded to 7 Decimal Places	36
37	Transmission	$ 0.9956104	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

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SAN DIEGO GAS AND ELECTRIC COMPANY
TO3-Cycle 5 Annual Transmission Formulaic Rate Filing
Derivation of Retail True-Up Cos of Service Rates
For the True-Up Period - (April 1, 2010 - March 31, 2011)
Medium-Large Commercial Customers
($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 2.3.1; Page 15; Col. B; Line 35	2
3	Primary	2,043	Section 2.3.1; Page 15; Col. B; Line 36	3
4	Transmission	277	Section 2.3.1; Page 15; Col. B; Line 37	4
5	Total	11,777	Sum Lines 3; 4; 5	5
6	Winter Maximum On-Peak Period Demands @ Transmission Level (MW)			6
7	Secondary	9,889	Section 2.3.1; Page 15; Col. D; Line 35	7
8	Primary	2,065	Section 2.3.1; Page 15; Col. D; Line 36	8
9	Transmission	277	Section 2.3.1; Page 15; Col. D; Line 37	9
10	Total	12,231	Sum Lines 3; 4; 5	10
11	Winter Maximum On-Peak Period Allocation to Voltage Levels			11
12	Secondary	80.85%	Line 7 / Line 10	12
13	Primary	16.88%	Line 8 / Line 10	13
14	Tranmission	2.26%	Line 9 / Line 10	14
15	Total	100.00%	Sum Lines 12; 13; 14	15
16	Share of Total Revenue Allocation to Winter Peak Period (October through April)	20.00%		16
17	Revenues for Proposed Winter Maximum On-Peak Period Demand Rates			17
18	Secondary	$ 2,023	(Page 7; Line 2 x Page 8; Line 16) x Line 12	18
19	Primary	$ 422	(Page 7; Line 2 x Page 8; Line 16) x Line 13	19
20	Transmission	$ 57	(Page 7; Line 2 x Page 8; Line 16) x Line 14	20
21	Total	$ 2,502	Sum Lines 18; 19; 20	21
22	Winter Maximum On-Peak Period Demand Rates [5]	$/kW		22
23	Secondary	$ 0.2139162	Line 18 / Line 2	23
24	Primary	$ 0.2065435	Line 19 / Line 3	24
25	Transmission	$ 0.2061251	Line 20 / Line 4	25
26				26
27	Winter Maximum On-Peak Period Demand Rates (Rounded)	$/kW		27
28	Secondary	$ 0.2139162	Line 23, Rounded to 7 Decimal Places	28
29	Primary	$ 0.2065435	Line 24, Rounded to 7 Decimal Places	29
30	Transmission	$ 0.2061251	Line 25, Rounded to 7 Decimal Places	30
31				31
32	Proof of Revenue Calculations:			32
33	Secondary	$ 10,166	(Page 7; Line 23) + (Page 8; Line 18)	33
34	Primary	$ 2,157	(Page 7; Line 24) + (Page 8; Line 19)	34
35	Transmission	$ 186	(Page 7; Line 25) + (Page 8; Line 20)	35
36	Total	$ 12,509	Sum Lines 33; 34; 35	36
37	Difference	$ 1	Page 7; Line 2 - Page 8; Line 36	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

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Medium-Large Commercial Customers
($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]	$ 719	Section 2.3.1; Page 6; Line 50	2
3				3
4	Summer Maximum Demand at the Time of System Peak By Voltage Level @ Meter Level (MW) [2]			4
5	Secondary	-	Section 2.3.1; Page 15; Col. B; Line 42	5
6	Primary	47	Section 2.3.1; Page 15; Col. B; Line 43	6
7	Transmission	465	Section 2.3.1; Page 15; Col. B; Line 44	7
8	Total	512	Sum Lines 5; 6; 7	8
9				9
10	Summer Maximum Demand at the Time of System Peak @ Transmission Level (MW)			10
11	Secondary	-	Section 2.3.1; Page 15; Col. D; Line 42	11
12	Primary	48	Section 2.3.1; Page 15; Col. D; Line 43	12
13	Transmission	465	Section 2.3.1; Page 15; Col. D; Line 44	13
14	Total	513	Sum Lines 11; 12; 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	Transmission	90.64%	Line 13 / Line 14	19
20	Total	100.00%	Sum Lines 17; 18; 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			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	Transmission	$ 521	(Line 2 x Line 21) x Line 19	25
26	Total	$ 575	Sum Lines 23; 24; 25	26
27				27
28	Summer Maximum Demand at the Time of System Peak Rates [3]	$/kW		28
29	Secondary	$ -	Line 23 / Line 5	29
30	Primary	$ 1.1392972	Line 24 / Line 6	30
31	Transmission	$ 1.1202075	Line 25 / Line 7	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	$ 1.1392972	Line 30, Rounded to 7 Decimal Places	36
37	Transmission	$ 1.1202075	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

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Medium-Large Commercial Customers
($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 2.3.1; Page 15; Col. B; Line 47	2
3	Primary	88	Section 2.3.1; Page 15; Col. B; Line 48	3
4	Transmission	570	Section 2.3.1; 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 2.3.1; Page 15; Col. D; Line 47	8
9	Primary	89	Section 2.3.1; Page 15; Col. D; Line 48	9
10	Transmission	570	Section 2.3.1; 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	Transmission	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			19
20	Secondary	$ -	(Page 9; Line 2 x Page 10; Line 18) x Line 14	20
21	Primary	$ 19	(Page 9; Line 2 x Page 10; Line 18) x Line 15	21
22	Transmission	$ 124	(Page 9; Line 2 x Page 10; Line 18) x Line 16	22
23	Total	$ 143	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 2	26
27	Primary	$ 0.2158957	Line 21 / Line 3	27
28	Transmission	$ 0.2176482	Line 22 / Line 4	28
29				29
30	Winter Maximum Demand at the Time of System Peak Rates (Rounded)	$/kW		30
31	Secondary	$ -	Line 26, Rounded to 7 Decimal Places	31
32	Primary	$ 0.2158957	Line 27, Rounded to 7 Decimal Places	32
33	Transmission	$ 0.2176482	Line 28, Rounded to 7 Decimal Places	33
34				34
35	Proof of Revenue Calculations:			35
36	Secondary	$ -	(Page 9; Line 23) + (Page 10; Line 20)	36
37	Primary	$ 73	(Page 9; Line 24) + (Page 10; Line 21)	37
38	Transmission	$ 645	(Page 9; Line 25) + (Page 10; Line 22)	38
39	Total	$ 718	Sum Lines 36; 37; 38	39
40	Difference	$ 1	Page 9; Line 2 - Page 10; Line 39	40

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 2.3.1
SAN DIEGO GAS AND ELECTRIC COMPANY
TO3-Cycle 5 Annual Transmission Formulaic Rate Filing
Derivation of Retail True-Up Cos of Service Rates
For the True-Up Period - (April 1, 2010 - March 31, 2011)
Street Lighting Customers
($000)

Line No.	Description	Derivation of Commodity Rate & Proof of Revenues Calculation	Reference	Line No.
1	Street Lighting - Allocated Transmission Revenue Requirement	$ 1,081	Section 2.3.1; Page 2; Line 7	1
2				2
3	Billing Determinants - Street Lighting Customers (MWh) [1]:	117,138	Statement 2.3.1; Page 15; Line 9	3
4				4
5	Rate Per kWh Calculation	$ 0.0092284	Line 1 / Line 3	5
6				6
7	Rate Per kWh Calculation - Rounded	$ 0.0092284	Line 5, Rounded to 7 Decimal Places	7
8				8
9	Proof of Revenues:	$ 1,081	Line 3 x Line 7	9
10				10
11	Difference	$ -	Line 1 - Line 9	11

NOTES:

[1] Street lighting customers include the following California Public Utilities Commission (CPUC) tariffs: DWL, OL-1, LS-1, LS-2, LS-3.

Section 2.3.1
SAN DIEGO GAS AND ELECTRIC COMPANY
TO3-Cycle 5 Annual Transmission Formulaic Rate Filing
Derivation of Retail True-Up Cos of Service Rates
For the True-Up Period - (April 1, 2010 - March 31, 2011)
Standby Revenues Calculation
($000)

Line No.	Description	Derivation of Standby Surcharge & Proof of Revenues Calculation	Reference	Line No.
1	Standby - Demand Revenue Requirement	$ 3,693	Section 2.3.1; Page 2; Line 8	1
2	*Demand Determinants @ Transmission Level Used to Allocate*			2
3	*Total Class Revenues to Voltage Level with Loss Factor Adjustment (MW)* [1]:			3
4	Secondary	152	Section 2.3.1; Page 15; Col. D; Line 57	4
5	Primary	1,014	Section 2.3.1; Page 15; Col. D; Line 58	5
6	Tranmission	593	Section 2.3.1; Page 15; Col. D; Line 59	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	$ 319	Line 1 x Line 10	16
17	Primary	$ 2,129	Line 1 x Line 11	17
18	Tranmission	$ 1,245	Line 1 x Line 12	18
19	Total	$ 3,693	Sum Lines 16; 17; 18	19
20				20
21	Demand Determinants By Voltage Level @ Meter (MW)			21
22	Secondary	145	Section 2.3.1; Page 15; Col. B; Line 57	22
23	Primary	1,003	Section 2.3.1; Page 15; Col. B; Line 58	23
24	Tranmission	593	Section 2.3.1; Page 15; Col. B; Line 59	24
25	Total	1,741	Sum Lines 22; 23; 24	25
26				26
27	Demand Rate By Voltage Level @ Meter			27
28	Secondary	$ 2.1998938	Line 16 / Line 22	28
29	Primary	$ 2.1226808	Line 17 / Line 23	29
30	Tranmission	$ 2.0984537	Line 18 / Line 24	30
31				31
32	Demand Rate By Voltage Level @ Meter (Rounded)			32
33	Secondary	$ 2.1998938	Line 28, Rounded to 7 Decimal Places	33
34	Primary	$ 2.1226808	Line 29, Rounded to 7 Decimal Places	34
35	Tranmission	$ 2.0984537	Line 30, Rounded to 7 Decimal Places	35
36				36
37	Proof of Revenue Calculations:			37
38	Secondary	$ 319	Line 22 x Line 33	38
39	Primary	$ 2,129	Line 23 x Line 34	39
40	Tranmission	$ 1,245	Line 24 x Line 35	40
41	Total	$ 3,693	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 2.3.1
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TO3-Cycle 5 Annual Transmission Formulaic Rate Filing
Derivation of Retail True-Up Cos of Service Rates
For the True-Up Period - (April 1, 2010 - March 31, 2011)
Summary of Proof of Revenues
($1,000)

Line No.	Customer Classes	(A) Total Revenues Per Cost of Service Study	(B) Total Revenues Per Rate Design	(C) Difference	Reference	Line No.
1	Residential Customers	$ 116,423	$ 116,423	$ -	Section 2.3.1; Pages 2 & 3	1
2						2
3	Small Commercial	35,855	35,855	-	Statement 2.3.1; Pages 2 & 4	3
4						4
5	Medium-Large Commercial	137,992	137,992	-	Statement 2.3.1; Pages 2 & 5	5
6						6
7	Street Lighting	1,081	1,081	-	Statement 2.3.1; Pages 2 & 11	7
8						8
9	Standby Revenues	3,693	3,693	-	Statement 2.3.1; Pages 2 & 12	9
10						10
11	Grand Total	$ 295,044	$ 295,044	$ -	Sum Lines 1 thru 9	11

Section 2.3.1
SAN DIEGO GAS AND ELECTRIC COMPANY
TO3-Cycle 5 Annual Transmission Formulaic Rate Filing
Derivation of Retail True-Up Cos of Service Rates
For the True-Up Period - (April 1, 2010 - March 31, 2011)
Development of 12-CP Allocation Factors Using Recorded Data: 2004-2008

Line No.	(a) Customer Class	(b) 5-Year Average Of 12 CPs Kilowat @ Meter Level	(c) Transmission Loss Factors	(d) = (b) x (c) 5-Year Average Of 12 CPs Kilowat @ Transmission Level	(e) Ratio	(g) Reference	Line No.
1	5 Year Average - 12CP Allocation Factors:						1
2	Residential Customers	15,054,815	1.0457	15,742,820	39.46%	Statement BB; Page 1; Line 1	2
3	Small Commercial Customers	4,636,436	1.0457	4,848,321	12.15%	Statement BB; Page 1; Line 2	3
4	Medium-Large Commercial Customers						4
5	Secondary	13,510,244	1.0457	14,127,662	35.41%	Statement BB; Page 1; Line 4	5
6	Primary	3,295,181	1.0108	3,330,769	8.35%	Statement BB; Page 1; Line 5	6
7	Transmission	1,201,031	1.0000	1,201,031	3.01%	Statement BB; Page 1; Line 6	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%	Statement BB; Page 1; Line 9	10
11	Standby Customers						11
12	Secondary	38,310	1.0457	40,061	0.10%	Statement BB; Page 1; Line 11	12
13	Primary	293,448	1.0108	296,617	0.74%	Statement BB; Page 1; Line 12	13
14	Transmission	162,697	1.0000	162,697	0.41%	Statement BB; Page 1; Line 13	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

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Section 2.3.1
SAN DIEGO GAS AND ELECTRIC COMPANY
TO3-Cycle 5 Annual Transmission Formulaic Rate Filing
Derivation of Retail True-Up Cos of Service Rates
For the True-Up Period - (April 1, 2010 - March 31, 2011)
Development of 12-CP Allocation Factors

Line No.	(A) Customer Class	(B) Recorded Demand Determinants Megawatt @ Meter Level	(C) Transmission Loss Factors	(D) = (B) x (C) Recorded Demand Determinants Megawatt @ Transmission Level	(E) Ratios	Reference	Line No.
1	Recorded 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]	976	1.0457	1,021	87.94%	Col. B=Page 15.1; Col. E; Line 3	3
4	Primary [2]	139	1.0108	140	12.06%	Col. B=Page 15.1; Col. E; Line 4	4
5	Transmission [3]	-	1.0000	-	0.00%	Col. B=Page 15.1; Col. E; Line 5	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%	Col. B=Page 15.1; Col. E; Line 10	10
11	Primary	3,981	1.0108	4,024	15.80%	Col. B=Page 15.1; Col. E; Line 11	11
12	Transmission	256	1.0000	256	1.01%	Col. B=Page 15.1; Col. E; Line 12	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%	Col. B=Page 15.1; Col. E; Line 17	17
18	Primary	160	1.0108	162	11.06%	Col. B=Page 15.1; Col. E; Line 18	18
19	Transmission	1,303	1.0000	1,303	88.94%	Col. B=Page 15.1; Col. E; Line 19	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 Months = (May, June, July, August, September)						29
30	Secondary	7,819	1.0457	8,176	81.37%	Col. B=Page 15.1; Col. E; Line 30	30
31	Primary	1,723	1.0108	1,742	17.34%	Col. B=Page 15.1; Col. E; Line 31	31
32	Transmission	130	1.0000	130	1.29%	Col. B=Page 15.1; Col. E; Line 32	32
33	Total	9,671		10,048	100.00%	Sum Lines 30; 31; 32	33
34	Winter Months = (October, November, December, January, February, March, April)						34
35	Secondary	9,457	1.0457	9,889	80.85%	Col. B=Page 15.1; Col. E; Line 35	35
36	Primary	2,043	1.0108	2,065	16.88%	Col. B=Page 15.1; Col. E; Line 36	36
37	Transmission	277	1.0000	277	2.26%	Col. B=Page 15.1; Col. E; Line 37	37
38	Total	11,777		12,231	99.99%	Sum Lines 35; 36; 37	38
39	Grand Total	21,448		22,279			39
40	Maximum Demand at the Time of System Peak Determinants						40
41	Summer						41
42	Secondary	-	1.0457	-	0.00%	Col. B=Page 15.1; Col. E; Line 42	42
43	Primary	47	1.0108	48	9.36%	Col. B=Page 15.1; Col. E; Line 43	43
44	Transmission	465	1.0000	465	90.64%	Col. B=Page 15.1; Col. E; Line 44	44
45	Total	512		513	100.00%	Sum Lines 42; 43; 44	45
46	Winter						46
47	Secondary	-	1.0457	-	0.00%	Col. B=Page 15.1; Col. E; Line 47	47
48	Primary	88	1.0108	89	13.51%	Col. B=Page 15.1; Col. E; Line 48	48
49	Transmission	570	1.0000	570	86.49%	Col. B=Page 15.1; Col. E; Line 49	49
50	Total	658		659	100.00%	Sum Lines 47; 48; 49	50
51	Grand Total	1,170		1,172			51
52							52
53		Recorded Demand		Recorded Demand			53
54		Determinants		Determinants			54
55		Megawatt @	Transmission	Megawatt @			55
56	Forecast Demand Determinants for Standby Customers:	Meter Level	Loss Factors	Transmission Level	Ratios		56
57	Contracted Demand Determinants						57
58	Secondary	145	1.0457	152	8.64%	Col. B=Page 16.3; Line 114	58
59	Primary	1,003	1.0108	1,014	57.65%	Col. B=Page 16.3; Line 115	59
60	Transmission	593	1.0000	593	33.71%	Col. B=Page 16.3; Line 116	60
61	Total	1,741		1,759	100.00%	Sum Lines 57; 58; 59	61

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San Diego Gas & Electric

Recorded Sales for the True-Up Period: April 2010 - March 2011

Line No.	SDG&E: System Delivery Determinants	Winter	Summer	Summer	Summer	Summer	Summer	Winter	Winter	Winter	Winter	Winter	Winter	Total	Line No.
1															1
2															2
3	**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**	3
4	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	4
5	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	5
6	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	6
7	Med. & Large Comm./Ind. (AL + AY + 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	7
8	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	8
9	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	9
10	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	10
11	**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**	11
12															12
13	**Med. & Large Comm./Ind.**														13
14	**Rate Schedule Billing Determinants**														14
15															15
16	**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**	16
17	**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	17
18															18
19	**Total Deliveries (%)**														19
20	% @ 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%	20
21	% @ 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%	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	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	25
26	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	26
27	MWh @ Transmission Service	0	0	0	0	0	0	0	0	0	0	0	0	0	27
28		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	28
29	**Non-Coincident Demand (%)**														29
30	% @ 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%	30
31	% @ 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%	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	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	35
36	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	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		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	38
39															39
40															40
41															41

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San Diego Gas & Electric

Recorded Sales for the True-Up 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.
42															42
43	**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	43
44															44
45	**Total Deliveries (%)**														45
46	% @ 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%	46
47	% @ 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%	47
48	% @ 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%	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	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	51
52	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	52
53	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	53
54		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	54
55	**Non-Coincident Demand (%)**														55
56	% @ 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%	56
57	% @ 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%	57
58	% @ 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%	58
59															59
60	**Non-Coincident Demand (MW)**														60
61	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	61
62	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	62
63	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	63
64		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	64
65	**On-Peak Demand (%)**														65
66	% @ 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%	66
67	% @ 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%	67
68	% @ 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%	68
69	**Maximum On-Peak Period Demand (MW)**														69
70	**On-Peak Demand (MW)**	Winter	Summer	Summer	Summer	Summer	Summer	Winter	Winter	Winter	Winter	Winter	Winter	Total	70
71	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	71
72	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	72
73	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	73
74		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	74
75															75
76															76
77															77

Section 2.3.1

San Diego Gas & Electric

Recorded Sales for the True-Up Period: April 2010 - March 2011

Line No.	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	Line No.
78															78
79	**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	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	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%	83
84	% @ 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%	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	8,731	4,726	6,767	8,602	4,555	9,913	6,302	4,870	10,800	4,788	8,396	10,580	89,029	88
89	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	89
90		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	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	0.1456%	0.1068%	0.1203%	0.1390%	0.1158%	0.1729%	0.0952%	0.1239%	0.1838%	0.4118%	0.2249%	0.2801%	0.1802%	93
94	% @ 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%	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	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	98
99	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	99
100		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	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	0.1613%	0.1705%	0.1914%	0.1550%	0.0572%	0.1054%	0.1824%	0.1712%	0.1941%	0.1286%	0.1544%	0.1324%	0.1521%	103
104	% @ 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%	104
105	**Coincident Demand at Time of System of Peak**														105
106	**Coincident Peak Demand (MW)**	Winter	Summer	Summer	Summer	Summer	Summer	Winter	Winter	Winter	Winter	Winter	Winter	Total	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	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	108
109	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	109
110		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	110
111															111
112	**Schedule S: Standby Determinants:**	**Apr-10**	**May-10**	**Jun-09**	**Jul-10**	**Aug-10**	**Sep-10**	**Oct-10**	**Nov-10**	**Dec-10**	**Jan-11**	**Feb-11**	**Mar-11**	**Total**	112
113	**Contracted Standby Demand (MW)**														113
114	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	114
115	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	115
116	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	116
117		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	117
118															118
119															119
120															120

Section – 2

Derivation of Retail (End Use Customer)
True-Up Adjustment

Section 2.3.2

Derivation of Retail Monthly Cost of Service (COS) for True-Up Period Using the Retail Rates Developed in Section 2.3.1

Docket No. ER11-____-____

Section 2.3.2
SAN DIEGO GAS & ELECTRIC COMPANY
Transmission Revenues Data to Reflect Changed Rates
Comparison of Revenues
Recorded Billing Determinants

Line No.	Customer Classes	(a) Transmission Revenues @ Proposed Rates	(b) True-Up Period Total Cost of Service	(c) = (a) - (b) ($) Change	(d) = (c)/(a) (%) Change	Reference	Line No.
1	Residential Customers	$ 116,423,070	$ 116,423,000	$ 70	0.00%	(a)=Section 2.3.2; Page 2; Line 1	1
2						(b)=Section 2.3.1; Page 2; Line 4	2
3	Small Commercial Customers	35,855,007	$ 35,855,000	$ 7	0.00%	(a)=Section 2.3.2; Page 2; Line 3	3
4						(b)=Section 2.3.1; Page 2; Line 5	4
5	Medium-Large Commercial Customers	137,990,093	$ 137,992,000	$ (1,907)	0.00%	(a)=Section 2.3.2; Page 2; Line 5	5
6						(b)=Section 2.3.1; Page 2; Line 6	6
7	Street Lighting Customers	1,080,998	$ 1,081,000	$ (2)	0.00%	(a)=Section 2.3.2; Page 2; Line 7	7
8						(b)=Section 2.3.1; Page 2; Line 7	8
9	Standby Customers	3,692,998	$ 3,693,000	$ (2)	0.00%	(a)=Section 2.3.2; Page 2; Line 9	9
10						(b)=Section 2.3.1; Page 2; Line 8	10
11	Grand Total	$ 295,042,166	$ 295,044,000	$ (1,834)	0.00%	Sum Lines 1 through 9	11

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Section 2.3.2
SAN DIEGO GAS AND ELECTRIC COMPANY
Derivation of Monthly Retail Cost of Service
Revenues for True-Up Period Using Retail Rates Developed in Section 2.3.1
For True-Up Period April 1, 2010 - March 31, 2011

Line No.		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	Line No.
	Season	Apr-10 Winter	May-10 Summer	Jun-10 Summer	Jul-10 Summer	Aug-10 Summer	Sep-10 Summer	Oct-10 Winter	Nov-10 Winter	Dec-10 Winter	Jan-11 Winter	Feb-11 Winter	Mar-11 Winter		
	Customer Class													Total	
1	Residential Customers [1]	$ 8,862,529	$ 8,179,593	$ 8,707,930	$ 9,386,440	$ 9,336,289	$ 10,853,077	$ 10,120,469	$ 9,320,597	$ 10,626,718	$ 11,453,441	$ 9,932,830	$ 9,643,159	$ 116,423,070	1
2															2
3	Small Commercial [2]	2,857,104	2,483,257	2,937,266	3,206,943	2,959,297	3,422,154	3,207,153	2,938,609	2,965,604	3,093,787	2,886,120	2,897,714	35,855,007	3
4															4
5	Medium-Large Commercial [3]	10,187,835	10,936,469	11,990,784	13,548,445	12,348,759	14,026,901	12,138,797	11,232,909	10,561,562	10,840,675	9,864,903	10,312,053	137,990,093	5
6															6
7	Street Lighting [4]	117,577	55,476	87,199	87,361	89,685	79,210	97,680	86,630	118,443	56,385	87,653	117,699	1,080,998	7
8															8
9	Standby Revenues [5]	303,260	305,252	305,874	309,840	308,279	308,276	302,328	302,328	312,759	312,189	310,588	312,025	3,692,998	9
10															10
11	TOTAL	$ 22,328,306	$ 21,960,047	$ 24,029,053	$ 26,539,029	$ 25,042,309	$ 28,689,617	$ 25,866,427	$ 23,881,074	$ 24,585,085	$ 25,756,476	$ 23,082,094	$ 23,282,650	$ 295,042,166	11

NOTES:

1 See Pages 3 & 4; Line 25.

2 See Pages 3 & 4; Line 27.

3 See Pages 3 & 4; Lines 29 through 33.

4 See Pages 3 & 4; Line 35.

5 See Pages 3 & 4; Line 37.

Section 2.3.2
SAN DIEGO GAS AND ELECTRIC COMPANY
Derivation of Monthly Retail Cost of Service
Revenues for True-Up Period Using Retail Rates Developed in Section 2.3.1
For True-Up Period April 1, 2010 - March 31, 2011

Line No.	Customer Classes	(A) Apr-10 Billing Determinants		(B) May-10 Billing Determinants		(C) Jun-10 Billing Determinants		(D) Jul-10 Billing Determinants		(E) Aug-10 Billing Determinants		(F) Sep-10 Billing Determinants		Line No.
		Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	
1	Residential Customers	560,384,025	-	517,201,486	-	550,608,582	-	593,511,237	-	590,340,168	-	686,247,737	-	1
2														2
3	Small Commercial	157,999,420	-	137,325,486	-	162,432,452	-	177,345,748	-	163,650,780	-	189,247,007	-	3
4														4
5	Medium-Large Commercial	795,316,271		784,631,262		840,649,109		927,206,006		837,933,458		970,139,846		5
6	Non-Coincident (100%)		98,052		80,217		92,699		94,843		96,525		97,615	6
7	Non-Coincident (90%)		2,034,961		1,918,448		2,065,535		2,345,999		2,128,997		2,423,828	7
8	Maximum On-Peak Period Demand		1,586,125		1,559,317		1,855,801		2,108,481		1,941,801		2,205,799	8
9	Maximum Demand at the Time of System Peak		80,268		108,872		103,395		113,024		73,796		113,403	9
10														10
11	Street Lighting	12,740,826	-	6,011,467	-	9,449,013	-	9,466,511	-	9,718,368	-	8,583,281	-	11
12														12
13	Standby Customers	-	142,994	-	143,941	-	144,234	-	146,132	-	145,397	-	145,396	13
14														14
15	TOTAL	1,526,440,542		1,445,169,701		1,563,139,156		1,707,529,502		1,601,642,774		1,854,217,871		15

NOTES: The above billing determinants are the recorded determinants from April 2010 through March 2011.

Line No.	Customer Classes	(A) Apr-10 Changed Transmission Rates		(B) May-10 Changed Transmission Rates		(C) Jun-10 Changed Transmission Rates		(D) Jul-10 Changed Transmission Rates		(E) Aug-10 Changed Transmission Rates		(F) Sep-10 Changed Transmission Rates		Line No.
		Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	
16	Residential Customers [1]	$ 0.0158151		$ 0.0158151		$ 0.0158151		$ 0.0158151		$ 0.0158151		$ 0.0158151		16
17														17
18	Small Commercial [1]	$ 0.0180830		$ 0.0180830		$ 0.0180830		$ 0.0180830		$ 0.0180830		$ 0.0180830		18
19														19
20	Medium-Large Commercial [1]													20
21														21
22	Street Lighting [1]	$ 0.0092284		$ 0.0092284		$ 0.0092284		$ 0.0092284		$ 0.0092284		$ 0.0092284		22
23														23
24	Standby Customers [1]													24

[1] ***The changed rates information comes from the Summary of Rates in Section 2.3.1; Page 1.***

Line No.	Customer Classes	(A) Apr-10 Revenues @ Changed Rates		(B) May-10 Revenues @ Changed Rates		(C) Jun-10 Revenues @ Changed Rates		(D) Jul-10 Revenues @ Changed Rates		(E) Aug-10 Revenues @ Changed Rates		(F) Sep-10 Revenues @ Changed Rates		Line No.
		Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	
25	Residential Customers	$ 8,862,529		$ 8,179,593		$ 8,707,930		$ 9,386,440		$ 9,336,289		$ 10,853,077		25
26														26
27	Small Commercial	$ 2,857,104		$ 2,483,257		$ 2,937,266		$ 3,206,943		$ 2,959,297		$ 3,422,154		27
28														28
29	Medium-Large Commercial	$ -		$ -		$ -		$ -		$ -		$ -		29
30	Non-Coincident (100%)		$ 502,264		$ 410,465		$ 473,850		$ 485,116		$ 493,702		$ 499,314	30
31	Non-Coincident (90%)		$ 9,331,156		$ 8,791,356		$ 9,479,603		$10,755,011		$ 9,763,617		$11,117,324	31
32	Maximum On-Peak Period Demand		$ 336,969		$ 1,612,534		$ 1,921,259		$ 2,181,454		$ 2,008,724		$ 2,283,029	32
33	Maximum Demand at the Time of System Peak		$ 17,446		$ 122,113		$ 116,072		$ 126,864		$ 82,717		$ 127,234	33
34														34
35	Street Lighting	$ 117,577		$ 55,476		$ 87,199		$ 87,361		$ 89,685		$ 79,210		35
36														36
37	Standby Customers		$ 303,260		$ 305,252		$ 305,874		$ 309,840		$ 308,279		$ 308,276	37
38														38
39	TOTAL	$ 11,837,210	$10,491,095	$ 10,718,326	$11,241,721	$ 11,732,395	$12,296,658	$ 12,680,743	$13,858,285	$ 12,385,271	$12,657,038	$ 14,354,440	$14,335,177	39
40														40
41	Grand Total		$22,328,306		$21,960,047		$24,029,053		$26,539,029		$25,042,309		$28,689,617	41

NOTES: The revenues above are derived by multiplying the forecast billing determinants by the rates, except for Med. & Lrg. C-I and Standby customers.
The derivation of revenues for Med. & Lrg. C-I and Standby customers are shown on pages 5 and 6.

Section 2.3.2
SAN DIEGO GAS AND ELECTRIC COMPANY
Derivation of Monthly Retail Cost of Service
Revenues for True-Up Period Using Retail Rates Developed in Section 2.3.1
For True-Up Period April 1, 2010 - March 31, 2011

Line No.	Customer Classes	(G) Oct-10 Billing Determinants		(H) Nov-10 Billing Determinants		(I) Dec-10 Billing Determinants		(J) Jan-11 Billing Determinants		(K) Feb-11 Billing Determinants		(L) Mar-11 Billing Determinants		(M) Total Billing Determinants		Line No.
		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)	
1	Residential Customers	639,924,451	-	589,347,947	-	671,934,904	-	724,209,188	-	628,059,871	-	609,743,783	-	7,361,513,379	-	1
2																2
3	Small Commercial	177,357,359	-	162,506,741	-	163,999,530	-	171,088,138	-	159,604,069	-	160,245,208	-	1,982,801,938	-	3
4																4
5	Medium-Large Commercial	915,153,323		842,033,781		813,819,782		847,914,923		779,290,550		814,228,471		10,168,316,782		5
6	Non-Coincident (100%)		97,053		93,463		90,115		85,711		94,937		93,686		1,114,915	6
7	Non-Coincident (90%)		2,440,915		2,258,496		2,122,935		2,186,194		1,970,747		2,063,879		25,960,933	7
8	Maximum On-Peak Period Demand		2,018,640		1,745,906		1,615,435		1,674,350		1,516,609		1,619,596		21,447,858	8
9	Maximum Demand at the Time of System Peak		117,165		121,824		88,991		86,873		87,318		75,294		1,170,222	9
10																10
11	Street Lighting	10,584,690	-	9,387,377	-	12,834,586	-	6,109,903	-	9,498,167	-	12,753,958	-	117,138,147	-	11
12																12
13	Standby Customers	-	142,559	-	142,559	-	147,423	-	147,156	-	146,405	-	147,082	-	1,741,278	13
14																14
15	TOTAL	1,743,019,823		1,603,275,846		1,662,588,802		1,749,322,152		1,576,452,657		1,596,971,420		19,629,770,246		15

NOTES: The above billing determinants are the recorded determinants from April 2010 through March 2011.

Line No.	Customer Classes	(G) Oct-10 Changed Transmission Rates		(H) Nov-10 Changed Transmission Rates		(I) Dec-10 Changed Transmission Rates		(J) Jan-11 Changed Transmission Rates		(K) Feb-11 Changed Transmission Rates		(L) Mar-11 Changed Transmission Rates		(M) Total Changed Transmission Rates		Line No.
		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)	
16	Residential Customers [1]	$ 0.0158151		$ 0.0158151		$ 0.0158151		$ 0.0158151		$ 0.0158151		$ 0.0158151				16
17																17
18	Small Commercial [1]	$ 0.0180830		$ 0.0180830		$ 0.0180830		$ 0.0180830		$ 0.0180830		$ 0.0180830				18
19																19
20	Medium-Large Commercial [1]															20
21																21
22	Street Lighting [1]	$ 0.0092284		$ 0.0092284		$ 0.0092284		$ 0.0092284		$ 0.0092284		$ 0.0092284				22
23																23
24	Standby Customers [1]															24

[1] *The changed rates information comes from the Summary of Rates in Section 2.3.1; Page 1.*

Line No.	Customer Classes	(G) Oct-10 Revenues @ Changed Rates		(H) Nov-10 Revenues @ Changed Rates		(I) Dec-10 Revenues @ Changed Rates		(J) Jan-11 Revenues @ Changed Rates		(K) Feb-11 Revenues @ Changed Rates		(L) Mar-11 Revenues @ Changed Rates		(M) Total Revenues @ Changed Rates		Line No.
		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)	
25	Residential Customers	$ 10,120,469		$ 9,320,597		$ 10,626,718		$ 11,453,441		$ 9,932,830		$ 9,643,159		$ 116,423,070	$ -	25
26																26
27	Small Commercial	$ 3,207,153		$ 2,938,609		$ 2,965,604		$ 3,093,787		$ 2,886,120		$ 2,897,714		$ 35,855,007	$ -	27
28																28
29	Medium-Large Commercial	$ -		$ -		$ -		$ -		$ -		$ -		$ -		29
30	Non-Coincident (100%)		$ 496,442		$ 478,124		$ 461,114		$ 438,054		$ 485,005		$ 479,472		$ 5,702,922	30
31	Non-Coincident (90%)		$11,188,155		$10,357,482		$ 9,737,822		$10,027,957		$ 9,038,699		$ 9,471,989		$ 119,060,171	31
32	Maximum On-Peak Period Demand		$ 428,720		$ 370,804		$ 343,294		$ 355,767		$ 322,217		$ 344,230		$ 12,509,000	32
33	Maximum Demand at the Time of System Peak		$ 25,481		$ 26,500		$ 19,332		$ 18,897		$ 18,982		$ 16,363		$ 718,000	33
34																34
35	Street Lighting	$ 97,680		$ 86,630		$ 118,443		$ 56,385		$ 87,653		$ 117,699		$ 1,080,998	$ -	35
36																36
37	Standby Customers		$ 302,328		$ 302,328		$ 312,759		$ 312,189		$ 310,588		$ 312,025	$ -	$ 3,692,998	37
38																38
39	TOTAL	$ 13,425,302	$12,441,125	$ 12,345,837	$11,535,237	$ 13,710,764	$10,874,321	$ 14,603,612	$11,152,864	$ 12,906,603	$10,175,491	$ 12,658,572	$10,624,078	$ 153,359,075	$ 141,683,091	39
40																40
41	Grand Total		$25,866,427		$23,881,074		$24,585,085		$25,756,476		$23,082,094		$23,282,650		$ 295,042,166	41

NOTES: The revenues above are derived by multiplying the forecast billing determinants by the rates, except for Med. & Lrg. C-I and Standby customers.
The derivation of revenues for Med. & Lrg. C-I and Standby customers are shown on pages 5 and 6.

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Section 2.3.2
SAN DIEGO GAS AND ELECTRIC COMPANY
Derivation of Monthly Retail Cost of Service
Revenues for True-Up Period Using Retail Rates Developed in Section 2.3.1
For True-Up Period April 1, 2010 - March 31, 2011
Medium and Large Commercial & Industrial Customers

Line No.	Description	Winter Apr-10	Summer May-10	Summer Jun-10	Summer Jul-10	Summer Aug-10	Summer Sep-10	Winter Oct-10	Winter Nov-10	Winter Dec-10	Winter Jan-11	Winter Feb-11	Winter Mar-11	Total	Reference	Line No.
1	Energy Revenues															1
2	Commodity Sales - kWh	795,316,271	784,631,262	840,649,109	927,206,006	837,933,458	970,139,846	915,153,323	842,033,781	813,819,782	847,914,923	779,290,550	814,228,471	10,168,316,782	Section 2.3.2; Pages 9, 10 & 11; Line 5	2
3	Commodity Rate - $/kWh	-	-	-	-	-	-	-	-	-	-	-	-	-	Not Applicable	3
4	Total Commodity Revenues	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	Line 2 x Line 3	4
5																5
6	Non-Coincident Demand (100%) (kW)[1]:															6
7	Secondary	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	Section 2.3.2; Page 12; Line 37	7
8	Primary	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	Section 2.3.2; Page 12; Line 39	8
9	Transmission	-	-	-	-	-	-	-	-	-	-	-	-	-	Section 2.3.2; Page 12; Line 41	9
10	Total	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	Sum Lines 7; 8; 9	10
11	Check Figure	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	Section 2.3.2; Pages 1.1; Line 43	11
12	Difference	-	-	-	-	-	-	-	-	-	-	-	-	-	Line 10 - Line 11	12
13																13
14	Non-Coincident Demand (100%) Rates ($/kW):															14
15	Secondary	$ 5.1364982	$ 5.1364982	$ 5.1364982	$ 5.1364982	$ 5.1364982	$ 5.1364982	$ 5.1364982	$ 5.1364982	$ 5.1364982	$ 5.1364982	$ 5.1364982	$ 5.1364982		Section 2.3.1; Page 1; Line 6D	15
16	Primary	$ 4.9647503	$ 4.9647503	$ 4.9647503	$ 4.9647503	$ 4.9647503	$ 4.9647503	$ 4.9647503	$ 4.9647503	$ 4.9647503	$ 4.9647503	$ 4.9647503	$ 4.9647503		Section 2.3.1; Page 1; Line 6C	16
17	Transmission	$ 4.9132451	$ 4.9132451	$ 4.9132451	$ 4.9132451	$ 4.9132451	$ 4.9132451	$ 4.9132451	$ 4.9132451	$ 4.9132451	$ 4.9132451	$ 4.9132451	$ 4.9132451		Section 2.3.1; Page 1; Line 6B	17
18	Non-Coincident Demand (100%) - Revenues:															18
19	Secondary	$ 462,385	$ 365,114	$ 407,365	$ 426,002	$ 433,090	$ 438,982	$ 436,548	$ 421,832	$ 410,129	$ 374,481	$ 408,808	$ 429,069	$ 5,013,804	Line 7 x Line 15	19
20	Primary	39,879	45,351	66,485	59,114	60,612	60,332	59,893	56,292	50,985	63,573	76,197	50,404	$ 689,118	Line 8 x Line 16	20
21	Transmission	-	-	-	-	-	-	-	-	-	-	-	-	$ -	Line 9 x Line 17	21
22	Subtotal	$ 502,264	$ 410,465	$ 473,850	$ 485,116	$ 493,702	$ 499,314	$ 496,442	$ 478,124	$ 461,114	$ 438,054	$ 485,005	$ 479,472	$ 5,702,922	Sum Lines 19; 20; 21	22
23																23
24	Non-Coincident Demand (90%) (kW)[2]:															24
25	Secondary	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	Section 2.3.2; Page 12; Line 46	25
26	Primary	333,076	318,407	291,536	405,275	350,997	389,751	378,847	350,881	320,339	350,681	326,744	324,638	4,141,172	Section 2.3.2; Page 12; Line 47	26
27	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	Section 2.3.2; Page 12; Line 48	27
28	Total	2,034,961	1,918,448	2,065,535	2,345,999	2,128,997	2,423,828	2,440,915	2,258,496	2,122,935	2,186,194	1,970,747	2,063,879	25,960,933	Sum Lines 25; 26; 27	28
29	Check Figure	2,034,961	1,918,448	2,065,535	2,345,999	2,128,997	2,423,828	2,440,915	2,258,496	2,122,935	2,186,194	1,970,747	2,063,879	25,960,933	Section 2.3.2; Pages 1.1; Line 49	29
30	Difference	-	-	-	-	-	-	-	-	-	-	-	-	-	Line 28 - Line 29	30
31																31
32	Non-Coincident Demand (90%) Rates ($/kW):															32
33	Secondary	$ 4.6228484	$ 4.6228484	$ 4.6228484	$ 4.6228484	$ 4.6228484	$ 4.6228484	$ 4.6228484	$ 4.6228484	$ 4.6228484	$ 4.6228484	$ 4.6228484	$ 4.6228484		Section 2.3.1; Page 1; Line 8D	33
34	Primary	$ 4.4682753	$ 4.4682753	$ 4.4682753	$ 4.4682753	$ 4.4682753	$ 4.4682753	$ 4.4682753	$ 4.4682753	$ 4.4682753	$ 4.4682753	$ 4.4682753	$ 4.4682753		Section 2.3.1; Page 1; Line 8C	34
35	Transmission	$ 4.4219206	$ 4.4219206	$ 4.4219206	$ 4.4219206	$ 4.4219206	$ 4.4219206	$ 4.4219206	$ 4.4219206	$ 4.4219206	$ 4.4219206	$ 4.4219206	$ 4.4219206		Section 2.3.1; Page 1; Line 8B	35
36	Non-Coincident Demand (90%) - Revenues:															36
37	Secondary	$ 7,299,816	$ 6,749,773	$ 7,649,063	$ 8,338,026	$ 7,663,558	$ 8,772,353	$ 8,675,250	$ 8,152,201	$ 7,719,539	$ 7,926,636	$ 7,110,835	$ 7,607,026	$ 93,664,076	Line 25 x Line 33	37
38	Primary	1,488,275	1,422,731	1,302,665	1,810,880	1,568,350	1,741,514	1,692,794	1,567,833	1,431,362	1,566,938	1,459,983	1,450,570	$ 18,503,894	Line 26 x Line 34	38
39	Transmission	543,065	618,853	527,875	606,105	531,708	603,457	820,110	637,448	586,921	534,383	467,881	414,393	$ 6,892,200	Line 27 x Line 35	39
40	Subtotal	$ 9,331,156	$ 8,791,356	$ 9,479,603	$ 10,755,011	$ 9,763,617	$ 11,117,324	$ 11,188,155	$ 10,357,482	$ 9,737,822	$ 10,027,957	$ 9,038,699	$ 9,471,989	$ 119,060,171	Sum Lines 37; 38; 39	40

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 2.3.2
SAN DIEGO GAS AND ELECTRIC COMPANY
Derivation of Monthly Retail Cost of Service
Revenues for True-Up Period Using Retail Rates Developed in Section 2.3.1
For True-Up Period April 1, 2010 - March 31, 2011
Medium and Large Commercial & Industrial Customers

Line No.	Description	Winter Apr-10	Summer May-10	Summer Jun-10	Summer Jul-10	Summer Aug-10	Summer Sep-10	Winter Oct-10	Winter Nov-10	Winter Dec-10	Winter Jan-11	Winter Feb-11	Winter Mar-11	Total	Reference	Line No.
1	**Maximum On-Peak Period Demand (kW)[2]:**															1
2	Secondary	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	Section 2.3.2; Pages 12; Line 17 x 1000	2
3	Primary	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	Section 2.3.2; Pages 12; Line 18 x 1000	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 2.3.2; Pages 12; Line 19 x 1000	4
5	Total	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	Sum Lines 2; 3; 4	5
6	Check Figure	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	Section 2.3.2; Pages 12; Line 20	6
7	Difference	-	-	-	-	-	-	-	-	-	-	-	-	-	Line 5 - Line 6	7
8																8
9	**Maximum On-Peak Period Demand Rates ($/kW):**	Winter	Summer	Summer	Summer	Summer	Summer	Winter	Winter	Winter	Winter	Winter	Winter			9
10	Secondary	$ 0.2139162	$ 1.0414937	$ 1.0414937	$ 1.0414937	$ 1.0414937	$ 1.0414937	$ 0.2139162	$ 0.2139162	$ 0.2139162	$ 0.2139162	$ 0.2139162	$ 0.2139162		Section 2.3.1; Page 1; Line 11D; 12D	10
11	Primary	$ 0.2065435	$ 1.0069345	$ 1.0069345	$ 1.0069345	$ 1.0069345	$ 1.0069345	$ 0.2065435	$ 0.2065435	$ 0.2065435	$ 0.2065435	$ 0.2065435	$ 0.2065435		Section 2.3.1; Page 1; Line 11C; 12C	11
12	Transmission	$ 0.2061251	$ 0.9956104	$ 0.9956104	$ 0.9956104	$ 0.9956104	$ 0.9956104	$ 0.2061251	$ 0.2061251	$ 0.2061251	$ 0.2061251	$ 0.2061251	$ 0.2061251		Section 2.3.1; Page 1; Line 11B; 12B	12
13	**Maximum On-Peak Period Demand - Revenues:**															13
14	Secondary	$ 272,275	$ 1,287,029	$ 1,594,589	$ 1,766,224	$ 1,620,218	$ 1,874,939	$ 342,613	$ 296,577	$ 280,124	$ 288,759	$ 260,454	$ 282,199	$ 10,166,000	Line 2 x Line 10	14
15	Primary	55,587	298,963	298,255	392,727	361,665	383,391	73,576	62,687	54,419	61,290	59,139	55,302	$ 2,157,000	Line 3 x Line 11	15
16	Transmission	9,108	26,542	28,415	22,503	26,841	24,699	12,531	11,539	8,752	5,717	2,624	6,729	$ 186,000	Line 4 x Line 12	16
17	Subtotal	$ 336,969	$ 1,612,534	$ 1,921,259	$ 2,181,454	$ 2,008,724	$ 2,283,029	$ 428,720	$ 370,804	$ 343,294	$ 355,767	$ 322,217	$ 344,230	$ 12,509,000	Sum Lines 14; 15; 16	17
18																18
19	**Maximum Demand at the Time of System Peak (kW)[4]**	Winter	Summer	Summer	Summer	Summer	Summer	Winter	Winter	Winter	Winter	Winter	Winter			19
20	Secondary	-	-	-	-	-	-	-	-	-	-	-	-	-	Section 2.3.2; Pages 12; Line 30 x 1000	20
21	Primary	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	Section 2.3.2; Pages 12; Line 31 x 1000	21
22	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 2.3.2; Pages 12; Line 32 x 1000	22
23	Total	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	Sum Lines 20; 21; 22	23
24	Check Figure	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	Section 2.3.2; Pages 12; Line 33	24
25	Difference	-	-	-	-	-	-	-	-	-	-	-	-	-	Line 23 - Line 24	25
26																26
27	**Maximum Demand at the Time of System Peak Rates ($/kW):**	Winter	Summer	Summer	Summer	Summer	Summer	Winter	Winter	Winter	Winter	Winter	Winter			27
28	Secondary	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		Section 2.3.1; Page 1; Line 15D; 16D	28
29	Primary	$ 0.2158957	$ 1.1392972	$ 1.1392972	$ 1.1392972	$ 1.1392972	$ 1.1392972	$ 0.2158957	$ 0.2158957	$ 0.2158957	$ 0.2158957	$ 0.2158957	$ 0.2158957		Section 2.3.1; Page 1; Line 15C; 16C	29
30	Transmission	$ 0.2176482	$ 1.1202075	$ 1.1202075	$ 1.1202075	$ 1.1202075	$ 1.1202075	$ 0.2176482	$ 0.2176482	$ 0.2176482	$ 0.2176482	$ 0.2176482	$ 0.2176482		Section 2.3.1; Page 1; Line 15B; 16B	30
31	**Maximum Demand at the Time of System Peak - Revenues:**															31
32	Secondary	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	Line 20 x Line 28	32
33	Primary	3,040	9,181	14,757	15,190	2,968	11,904	2,482	1,800	4,526	1,329	2,799	3,024	$ 73,000	Line 21 x Line 29	33
34	Transmission	14,405	112,932	101,314	111,675	79,749	115,330	22,999	24,700	14,806	17,568	16,183	13,339	$ 645,000	Line 22 x Line 30	34
35	Subtotal	$ 17,446	$ 122,113	$ 116,072	$ 126,864	$ 82,717	$ 127,234	$ 25,481	$ 26,500	$ 19,332	$ 18,897	$ 18,982	$ 16,363	$ 718,000	Sum Lines 32; 33; 34	35
36																36
37	**Revenues at Changed Rates:**	Winter	Summer	Summer	Summer	Summer	Summer	Winter	Winter	Winter	Winter	Winter	Winter			37
38	Secondary	$ 8,034,476	$ 8,401,916	$ 9,651,017	$ 10,530,253	$ 9,716,866	$ 11,086,274	$ 9,454,412	$ 8,870,610	$ 8,409,792	$ 8,589,875	$ 7,780,097	$ 8,318,293	$ 108,843,881	Pg.5 (Lines 19;37) + Pg.6(Lines 14;32)	38
39	Primary	$ 1,586,781	$ 1,776,226	$ 1,682,163	$ 2,277,910	$ 1,993,595	$ 2,197,140	$ 1,828,745	$ 1,688,612	$ 1,541,291	$ 1,693,131	$ 1,598,118	$ 1,559,300	$ 21,423,012	Pg.5 (Lines 20;38) + Pg.6(Lines 15;33)	39
40	Transmission	$ 566,578	$ 758,327	$ 657,605	$ 740,283	$ 638,298	$ 743,486	$ 855,640	$ 673,688	$ 610,479	$ 557,668	$ 486,688	$ 434,461	$ 7,723,200	Pg.5 (Lines 21;39) + Pg.6(Lines 16;34)	40
41	**Total**	$ 10,187,835	$ 10,936,469	$ 11,990,785	$ 13,548,446	$ 12,348,759	$ 14,026,900	$ 12,138,797	$ 11,232,910	$ 10,561,562	$ 10,840,674	$ 9,864,903	$ 10,312,054	$ 137,990,093	Sum Lines 38; 39; 40	41
42																42
43	**Total Revenues at Changed Rates:**	$ 10,187,835	$ 10,936,469	$ 11,990,785	$ 13,548,446	$ 12,348,759	$ 14,026,900	$ 12,138,797	$ 11,232,910	$ 10,561,562	$ 10,840,674	$ 9,864,903	$ 10,312,054	$ 137,990,093	See Line 41	43

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 2.3.2
SAN DIEGO GAS AND ELECTRIC COMPANY
Derivation of Monthly Retail Cost of Service
Revenues for True-Up Period Using Retail Rates Developed in Section 2.3.1
For True-Up Period April 1, 2010 - March 31, 2011
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	11,224	11,224	11,226	11,124	11,124	11,123	12,075	12,075	13,498	13,498	13,408	13,408	145,007	Section 2.3.2; Page 11.3; Line 114 x 1000	2
3	Primary	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	Section 2.3.2; Page 11.3; Line 115 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 2.3.2; Page 11.3; Line 116 x 1000	4
5	Total	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	Sum Lines 2; 3; 4	5
6	Check Figure	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	Section 2.3.2; Page 11.3; Line 117 x 1000	6
7	Difference	-	-	-	-	-	-	-	-	-	-	-	-	-	Line 5 Less Line 6	7
8																8
9	Demand Rates ($/kW):															9
10	Secondary	$ 2.1998938	$ 2.1998938	$ 2.1998938	$ 2.1998938	$ 2.1998938	$ 2.1998938	$ 2.1998938	$ 2.1998938	$ 2.1998938	$ 2.1998938	$ 2.1998938	$ 2.1998938		Section 2.3.1; Page 1; Line 20D	10
11	Primary	$ 2.1226808	$ 2.1226808	$ 2.1226808	$ 2.1226808	$ 2.1226808	$ 2.1226808	$ 2.1226808	$ 2.1226808	$ 2.1226808	$ 2.1226808	$ 2.1226808	$ 2.1226808		Section 2.3.1; Page 1; Line 20C	11
12	Transmission	$ 2.0984537	$ 2.0984537	$ 2.0984537	$ 2.0984537	$ 2.0984537	$ 2.0984537	$ 2.0984537	$ 2.0984537	$ 2.0984537	$ 2.0984537	$ 2.0984537	$ 2.0984537		Section 2.3.1; Page 1; Line 20B	12
13																13
14	Revenues at Changed Rates:															14
15	Secondary	$ 24,692	$ 24,692	$ 24,696	$ 24,472	$ 24,472	$ 24,469	$ 26,564	$ 26,564	$ 29,694	$ 29,694	$ 29,496	$ 29,496	$ 319,001	Line 2 x Line 10	15
16	Primary	180,050	180,432	181,099	180,475	178,914	178,914	170,835	170,835	177,815	177,002	175,599	177,029	2,128,999	Line 3 x Line 11	16
17	Transmission	98,518	100,128	100,079	104,893	104,893	104,893	104,929	104,929	105,250	105,493	105,493	105,500	1,244,998	Line 4 x Line 12	17
18	Total	$ 303,260	$ 305,252	$ 305,874	$ 309,840	$ 308,279	$ 308,276	$ 302,328	$ 302,328	$ 312,759	$ 312,189	$ 310,588	$ 312,025	$ 3,692,998	Sum Lines 15; 16; 17	18
19																19
20	Total Revenues at Changed Rates	$ 303,260	$ 305,252	$ 305,874	$ 309,840	$ 308,279	$ 308,276	$ 302,328	$ 302,328	$ 312,759	$ 312,189	$ 310,588	$ 312,025	$ 3,692,998	Line 18	20

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Section 2.3.2
SAN DIEGO GAS AND ELECTRIC COMPANY
Transmission Revenue Data to Reflect Changed Rates
Recorded Billing Determinants
True-Up Period (April 1, 2010 - March 31, 2011)

Line No.	Customer Classes	(A) Apr-10 Billing Determinants		(B) May-10 Billing Determinants		(C) Jun-10 Billing Determinants		(D) Jul-10 Billing Determinants		(E) Aug-10 Billing Determinants		(F) Sep-10 Billing Determinants		Line No.
		Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	
1	Residential Customers	560,384,025		517,201,486		550,608,582		593,511,237		590,340,168		686,247,737		1
2														2
3	Small Commercial	157,999,420		137,325,486		162,432,452		177,345,748		163,650,780		189,247,007		3
4														4
5	Medium-Large Commercial	795,316,271		784,631,262		840,649,109		927,206,006		837,933,458		970,139,846		5
6	Non-Coincident (100%)[1]		98,052		80,217		92,699		94,843		96,525		97,615	6
7	Non-Coincident (90%)[2]		2,034,961		1,918,448		2,065,535		2,345,999		2,128,997		2,423,828	7
8	Maximum On-Peak Period Demand[3]		1,586,125		1,559,317		1,855,801		2,108,481		1,941,801		2,205,799	8
9	Maximum Demand at the Time of System Peak[4]		80,268		108,872		103,395		113,024		73,796		113,403	9
10														10
11	Street Lighting	12,740,826		6,011,467		9,449,013		9,466,511		9,718,368		8,583,281		11
12														12
13	Sale for Resale	1,500		-		3,500		-		1,500		-		13
14														14
15	Standby Customers		142,994		143,941		144,234		146,132		145,397		145,396	15
16														16
17	TOTAL	1,526,442,042		1,445,169,701		1,563,142,656		1,707,529,502		1,601,644,274		1,854,217,871		17

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 2.3.2
SAN DIEGO GAS AND ELECTRIC COMPANY
Transmission Revenue Data to Reflect Changed Rates
Recorded Billing Determinants
True-Up Period (April 1, 2010 - March 31, 2011)

Line No.	Customer Classes	(G) Oct-10 Billing Determinants		(H) Nov-10 Billing Determinants		(I) Dec-10 Billing Determinants		(J) Jan-11 Billing Determinants		(K) Feb-11 Billing Determinants		(L) Mar-11 Billing Determinants		Line No.
		Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	
1	Residential Customers	639,924,451		589,347,947		671,934,904		724,209,188		628,059,871		609,743,783		1
2														2
3	Small Commercial	177,357,359		162,506,741		163,999,530		171,088,138		159,604,069		160,245,208		3
4														4
5	Medium-Large Commercial	915,153,323		842,033,781		813,819,782		847,914,923		779,290,550		814,228,471		5
6	Non-Coincident (100%)[1]		97,053		93,463		90,115		85,711		94,937		93,686	6
7	Non-Coincident (90%)[2]		2,440,915		2,258,496		2,122,935		2,186,194		1,970,747		2,063,879	7
8	Maximum On-Peak Period Demand[3]		2,018,640		1,745,906		1,615,435		1,674,350		1,516,609		1,619,596	8
9	Maximum Demand at the Time of System Peak[4]		117,165		121,824		88,991		86,873		87,318		75,294	9
10														10
11	Street Lighting	10,584,690		9,387,377		12,834,586		6,109,903		9,498,167		12,753,958		11
12														12
13	Sale for Resale	6,408		-		2,116		1,710		3,620		-		13
14														14
15	Standby Customers		142,559		142,559		147,423		147,156		146,405		147,082	15
16														16
17	TOTAL	1,743,026,231		1,603,275,846		1,662,590,918		1,749,323,862		1,576,456,277		1,596,971,420		17

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 2.3.2
SAN DIEGO GAS AND ELECTRIC COMPANY
Transmission Revenue Data to Reflect Changed Rates
Recorded Billing Determinants
True-Up Period (April 1, 2010 - March 31, 2011)

Line No.	Customer Classes	(M) 12 Months to Date Billing Determinants Energy (kWh)	Demand (kW)	Line No.
1	Residential Customers	7,361,513,379	-	1
2				2
3	Small Commercial	1,982,801,938	-	3
4				4
5	Medium-Large Commercial	10,168,316,782		5
6	Non-Coincident (100%)[1]		1,114,915	6
7	Non-Coincident (90%)[2]		25,960,933	7
8	Maximum On-Peak Period Demand[3]		21,447,858	8
9	Maximum Demand at the Time of System Peak[4]		1,170,222	9
10				10
11	Street Lighting	117,138,147	-	11
12				12
13	Sale for Resale	20,354	-	13
14				14
15	Standby Customers	-	1,741,278	15
16				16
17	TOTAL	19,629,770,246	51,435,207	17

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 2.3.2

San Diego Gas & Electric

Recorded Sales for the True-Up Period: April 2010 - March 2011

Line No.	SDG&E: System Delivery Determinants	Winter	Summer	Summer	Summer	Summer	Summer	Winter	Winter	Winter	Winter	Winter	Winter	Total	Line No.
1															1
2															2
3	**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**	3
4	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	4
5	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	5
6	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	6
7	Med. & Large Comm./Ind. (AL + AY + 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	7
8	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	8
9	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	9
10	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	10
11	**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**	11
12															12
13	**Med. & Large Comm./Ind.**														13
14	**Rate Schedule Billing Determinants**														14
15															15
16	**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**	16
17	**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	17
18															18
19	**Total Deliveries (%)**														19
20	% @ 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%	20
21	% @ 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%	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	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	25
26	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	26
27	MWh @ Transmission Service	0	0	0	0	0	0	0	0	0	0	0	0	0	27
28		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	28
29	**Non-Coincident Demand (%)**														29
30	% @ 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%	30
31	% @ 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%	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	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	35
36	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	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		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	38
39															39
40															40
41															41
42	**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**	42
43	**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	43
44															44
45	**Total Deliveries (%)**														45
46	% @ 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%	46
47	% @ 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%	47
48	% @ 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%	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

Section 2.3.2

San Diego Gas & Electric

Recorded Sales for the True-Up Period: April 2010 - March 2011

Line No.															Line No.
50	**Total Deliveries (MWh)**														50
51	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	51
52	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	52
53	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	53
54		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	54
55	**Non-Coincident Demand (%)**														55
56	% @ 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%	56
57	% @ 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%	57
58	% @ 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%	58
59															59
60	**Non-Coincident Demand (MW)**														60
61	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	61
62	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	62
63	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	63
64		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	64
65	**On-Peak Demand (%)**														65
66	% @ 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%	66
67	% @ 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%	67
68	% @ 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%	68
69	**Maximum On-Peak Period Demand (MW)**														69
70	**On-Peak Demand (MW)**	Winter	Summer	Summer	Summer	Summer	Summer	Winter	Winter	Winter	Winter	Winter	Winter	Total	70
71	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	71
72	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	72
73	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	73
74		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	74
75															75
76															76
77															77
78	**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**	78
79	**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	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	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%	83
84	% @ 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%	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	8,731	4,726	6,767	8,602	4,555	9,913	6,302	4,870	10,800	4,788	8,396	10,580	89,029	88
89	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	89
90		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	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	0.1456%	0.1068%	0.1203%	0.1390%	0.1158%	0.1729%	0.0952%	0.1239%	0.1838%	0.4118%	0.2249%	0.2801%	0.1802%	93
94	% @ 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%	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	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	98
99	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	99
100		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	100

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Section 2.3.2

San Diego Gas & Electric

Recorded Sales for the True-Up Period: April 2010 - March 2011

Line No.															Line No.
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	0.1613%	0.1705%	0.1914%	0.1550%	0.0572%	0.1054%	0.1824%	0.1712%	0.1941%	0.1286%	0.1544%	0.1324%	0.1521%	103
104	% @ 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%	104
105	**Coincident Demand at Time of System of Peak**														105
106	**Coincident Peak Demand (MW)**	**Winter**	**Summer**	**Summer**	**Summer**	**Summer**	**Summer**	**Winter**	**Winter**	**Winter**	**Winter**	**Winter**	**Winter**	**Total**	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	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	108
109	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	109
110		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	110
111															111
112	**Schedule S: Standby Determinants:**	**Apr-10**	**May-10**	**Jun-09**	**Jul-10**	**Aug-10**	**Sep-10**	**Oct-10**	**Nov-10**	**Dec-10**	**Jan-11**	**Feb-11**	**Mar-11**	**Total**	112
113	**Contracted Standby Demand (MW)**														113
114	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	114
115	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	115
116	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	116
117		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	117
118															118
119															119
120															120

Section 2.3.2

San Diego Gas & Electric Company

FERC Recorded Sales for the True-Up Period: April 2010 - March 2011

Line No.		Winter	Summer	Summer	Summer	Summer	Summer	Winter	Winter	Winter	Winter	Winter	Winter	Total	Reference	Line No.
1																1
2	**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**		2
3	**Non-Coincident Demand (MW) - 100%**															3
4	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	Section 2.3.2; Page 14.1; Line 35	4
5	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	Section 2.3.2; Page 14.1; Line 36	5
6	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	Section 2.3.2; Page 14.1; Line 37	6
7	Sub-Total	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	Sum Lines 4; 5; 6	7
8																8
9	**Schedules AL-TOU / AY-TOU / DG-R:**															9
10	**Non-Coincident Demand (MW) - 90%**															10
11	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	Section 2.3.2; Page 14.2; Line 61	11
12	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	Section 2.3.2; Page 14.2; Line 62	12
13	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	Section 2.3.2; Page 14.2; Line 63	13
14	Sub-Total	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	Sum Lines 11; 12; 13	14
15																15
16	**On-Peak Demand (MW)**															16
17	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	Section 2.3.2; Page 14.2; Line 71	17
18	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	Section 2.3.2; Page 14.2; Line 72	18
19	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	Section 2.3.2; Page 14.2; Line 73	19
20	Sub-Total	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	Sum Lines 17; 18; 19	20
21																21
22	**Schedule A6-TOU:**															22
23	**Non-Coincident Demand (MW) - 90%**															23
24	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	Section 2.3.2; Page 14.2; Line 97	24
25	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	Section 2.3.2; Page 14.2; Line 98	25
26	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	Section 2.3.2; Page 14.2; Line 99	26
27	Sub-Total	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	Sum Lines 24; 25; 26	27
28																28
29	**Coincident Peak Demand (MW)**															29
30	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	Section 2.3.2; Page 14.3; Line 107	30
31	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	Section 2.3.2; Page 14.3; Line 108	31
32	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	Section 2.3.2; Page 14.3; Line 109	32
33	Sub-Total	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	Sum Lines 30; 31; 32	33
34																34
35	**TOTAL SUMMARY**															35
36	**Non-Coincident Demand (MWH) @ 100%**															36
37	MW @ Secondary Service	1,669,093	1,531,172	1,733,929	1,886,592	1,742,073	1,983,071	1,961,592	1,845,583	1,749,712	1,787,571	1,617,782	1,729,061	21,237,231	Apr-Aug; Lines (4, 11 and 24) x 1000	37
38															Sep-Mar; (Line 4 x 1000)	38
39	MW @ Primary Service	341,108	327,542	304,928	417,182	363,205	401,903	390,911	362,219	330,608	363,486	342,092	334,790	4,279,974	Apr-Aug; Lines (5, 12 and 25) x 1000	39
40															Sep-Mar; (Line 5 x 1000)	40
41	MW @ Transmission Service	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	Apr-Aug; Lines (6, 13 and 26) x 1000	41
42															Sep-Mar; (Line 6 x 1000)	42
43	Total - NONCoincident Demand @ 100%	2,133,013	1,998,665	2,158,234	2,440,842	2,225,522	2,521,443	2,537,968	2,351,959	2,213,050	2,271,905	2,065,684	2,157,564	27,075,849	Sum Lines 37 thru 42	43
44																44
45	**Non-Coincident Demand (MWH) @ 90%**															45
46	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	Sep-Mar; ((Lines 11 & 24) x 1000)	46
47	MW @ Primary Service	333,076	318,407	291,536	405,275	350,997	389,751	378,847	350,881	320,339	350,681	326,744	324,638	4,141,172	Sep-Mar; ((Lines 12 & 25) x 1000)	47
48	MW @ Transmission Service	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	Sep-Mar; ((Lines 13 & 26) x 1000)	48
49	Total - NONCoincident Demand @ 90%	2,034,961	1,918,448	2,065,535	2,345,999	2,128,997	2,423,828	2,440,915	2,258,496	2,122,935	2,186,194	1,970,747	2,063,879	25,960,933	Sum Lines 46 thru 48	49
50																50

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Section – 2

Derivation of Retail (End Use Customer) True-Up Adjustment

Section 2.3

Derivation of Retail True-Up Cost of Service

Docket No. ER11-____-____

Section 2.3
San Diego Gas & Electric Company
Statement BK-1
Derivation of Transmission 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 10	1
2				2
3	Transmission Related A&G Expenses	29,082	Statement AH; Page 5, Line 54	3
4				4
5	CPUC Intervener Funding Expense	-	Statement AH; Page 5, Line 8	5
6				6
7	Total O&M Expenses	$ 73,639	Sum Lines 1; 3; and 5	7
8				8
9	Transmission, Intangible, General and Common 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 35	19
20				20
21	Transmission Rate Base	$ 1,111,377	Statement BK-1; 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	2,333	Statement AQ; Page 10, Line 1	24
25	Transmission Related Amortization of ITC	(265)	Statement AR; Page 11, Line 1	25
26	Transmission Related Amort of Excess Deferred Tax Liability	(3)	Statement AR; Page 11, Line 3	26
27	Transmission Related Revenue Credits	(7,611)	Statement AU; Page 12, Line 13	27
28				28
29	End of Prior Year Revenue ($PYRR_{EU}$)	$ 291,636	Line 17 + Sum of Lines (23 thru 27)	29
30				30
31	Transmission Related Municipal Franchise Expenses	-	Calculated Below	31
32	Transmission Related Uncollectible Expense	-	Calculated Below	32
33				33
34	End of Prior Year Revenue ($PYRR_{EU}$)	$ 291,636	Sum Lines (29 thru 32)	34

Section 2.3
San Diego Gas & Electric Company
Statement BK-1
Derivation of Transmission 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-1; Pg 3; Line 16	2
3	Electric Miscellaneous Intangible Plant	293	Statement BK-1; Pg 3; Line 17	3
4	Transmission Related General Plant	15,797	Statement BK-1; Pg 3; Line 18	4
5	Transmission Related Common Plant	32,568	Statement BK-1; 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	Transmission Plant Held for Future Use	$ 39,893	Statement AG; Page 4, Line 3	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 - Retail	9,205	Statement AL; Page 9, Line 21	17
18	Total Working Capital	$ 25,331	Sum Lines (15 thru 17)	18
19				19
20	Total Transmission Rate Base	$ 1,111,377	Sum Lines 6; 9; 12; 18	20

Section 2.3
San Diego Gas & Electric Company
Statement BK-1
Derivation of Transmission 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	Total 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 2.3
San Diego Gas & Electric Company
Statement BK-1
Derivation of Transmission Cost of Service
True Up Period (4/1/2010 - 3/31/2011)
($1,000)

Line No.		Amounts	Reference	Line No.
1	A. Derivation of Annual Fix Charge Rate Applicable to Forecast Period Capital Plant Addtions:			1
2	PYRR $_{EU}$ Excluding Franchise and Uncollectible	$ -	Statement BK-1; Page 1, Line 30	2
3	Valley Rainbow (VR) Project Cost Amortization	-	Statement BK-1; Page 1; Line 12	3
4	South Georgia Income Tax Adjustment	-	Statement BK-1; Page 1; Line 25	4
5	Transmission Related Amortization of Investment Tax Credit	-	Statement BK-1; Page 1; Line 26	5
6	Transmission Related Amortization of Excess Deferred Tax Liabilities	-	Statement BK-1; Page 1; Line 27	6
7	Adjusted Transmission Revenue	$ -	Sum Lines (2 thru 6)	7
8				8
9	Transmission Related Municipal Franchise Expenses	-	Calculated Below	9
10	Transmission Related Uncollectible Expense	-	Calculated Below	10
11	Subtotal	$ -	Sum Lines (7 thru 10)	11
12				12
13	Gross Electric Transmission Plant	$ 1,751,861	Statement BK-1; Page 3, Line 6	13
14				14
15	Annual Fix Charge Rate (AFCR $_{EU}$)	0.00%	N/A True-Up Adjustment Calculation	15
16				16
17				17
18				18
19	B. Derivation of Forecast Period Capital Additions Revenue Requirements:			19
20	Weighted Forecast Plant Addtions	$ -	N/A True-Up Adjustment Calculation	20
21				21
22	Annual Fix Charge Rate (AFCR $_{EU}$)	0.00%	Statement BK-1; Page 4, Line 15	22
23				23
24	Forecast Period Capital Additions Revenue Requirements	$ -	Line 20 x Line 22	24

Section 2.3
San Diego Gas & Electric Company
Statement BK-1
Derivation of Transmission Cost of Service
True Up Period (4/1/2010 - 3/31/2011)
($1,000)

Line No.		Amounts	Reference	Line No.
1	End Use Customer Base Transmission Revenue Requirement (BTRR $_{EU}$):			1
2				2
3	True-Up Period Revenue Requirements (TUR $_{EU}$)	$ 291,636	Statement BK-1; Page 1, Line 34	3
4				4
5	Forecast Period Cap Adds Revenue Requirements	-	N/A in TU Calculation	5
6				6
7	Subtotal	$ 291,636	Line 3 + Line 5	7
8				8
9	Transmission Related Municipal Franchise Expenses	2,997	Line 9 x 1.0275%	9
10	Transmission Related Uncollectible Expense	411	Line 9 x .01410%	10
11				11
12	Total Retail TUR $_{EU}$	$ 295,044	Sum Lines (7 thru 10)	12

Section 2.3
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 2.3

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 9	14

Notes: