## Volume 2-A

TO3 - Cycle 6 Filing 12-Month True-Up Period Cost Statements, True-Up Adjustment Report, Sunrise Powerlink Project Report, & Retail True-Up Adjustment Calculation

TO3-Cycle 6 Filing (August 15, 2012)

Docket No. ER12- -

# San Diego Gas & Electric Company Derivation of Retail and ISO Wholesale True-Up Adjustments Table of Contents

## PART – I TRUE-UP ADJUSTMENT REPORT, SUNRISE POWERLINK REPORT & RELATED EXHIBITBS

A. TO3-Cycle 6 12-Month True-Up Adjustment Report	Page 1–9
B. TO3-Cycle 6 True-Up Adjustment Report "Exhibits 1 – 3"	Page 1-3
C. Sunrise Powerlink Project Report	Page 1-6

## PART – II TO3-CYCLE 6 12-MONTH RETAIL TRUE-UP ADJUSTMENT COST STATEMENTS

# Section 1 – Cost Statements Used to Derive the Retail and ISO True-Up Cost of Service for the 12-Month Period Between April 2011 through March 2012

	Statement AD – Cost of Plant	Page 1 of 14
В.	Statement AE – Accumulated Depreciation & Amortization	Page 2 of 14
C.	Statement AF – Specified Deferred Credits	Page 3 of 14
	Statement AG – Specified Plant Account	1 484 5 01 1 1
	(Other than Plant in Service) and Deferred Debits	Page 4 of 14
E.	Statement AH – Operation and Maintenance Expenses	Page 5 of 14
	Statement AI – Wages and Salaries	Page 6 of 14
G.	Statement AJ – Depreciation and Amortization Expenses	Page 7 of 14
	Statement AK – Taxes Other than Income Taxes	Page 8 of 14
I.	Statement AL – Working Capital	Page 9 of 14
J.	Statement AQ – Federal Income Tax Deductions	
	Other than Interests	Page 10 of 14
K.	Statement AR – Federal Income Tax Adjustments	Page 11 of 14
	Statement AU – Revenue Credits	Page 12 of 14
M.	Statement AV – Cost of Capital and Fair Rate of Return	Page 13 of 14
	Statement AV – Cost of Capital and Fair Rate of Return	Page 14 of 14

## <u>Page</u> (The page numbers referenced below apply to the page numbers on the upper right hand corner of each page beginning in Section 2 of the true-up calculation).

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

1-4	Section 2.1A - Summary of Retail True-Up Adjustment
	Retail TU Adjustment Calculation:
	Sum of monthly recorded revenues less the sum of monthly true-up cost of
	service revenues during the true-up period.
5-7	Amortization of Cycle 5 True-Up Adjustment (Sep. 2011 – Mar. 2012).
8-10	Amortization of Cycle 4 True-Up Adjustment (Apr. 2011 – Aug. 2011).
11-13	Amortization of Cycle 4 Interest True-Up Adjustment (Sep. 2011 – Mar. 2012).
14-16	Amortization of Cycle 3 Interest True-Up Adjustment (Apr. 2011 – Aug. 2011).
17-19	Amortization of Cycle 3 Interest TU Adjustment Accrued After Fully Amortized (Sep. 2011 – Mar. 2012).
20-22	Amortization of Cycle 2 Interest TU Adjustment (Apr. 2011 – Aug. 2011).
23-25	Amortization of TO2 Final Interest TU Adjustment Accrued After Fully Amortized (Apr. 2011 – Aug. 2011).
26	Section 2.1B – Summary of Retail Interest True-Up Adjustment
27-29	TO3-Cycle 5 Interest True-Up Adjustment Calculation.
30-32	TO3-Cycle 5 Interest True-Up Adjustment Amortization Rate Calculation
33-35	TO3-Cycle 4 Interest True-Up Adjustment Calculation
36-38	TO3-Cycle 4 Interest True-Up Adjustment Amortization Rate Calculation
39-40	Section 2.2 – Summary of Monthly Retail TU Period Recorded Revenues
37-40	Retail Actual Monthly Recorded revenues for the TU Period
	Retail Actual Monthly Recorded revenues for the 10 Terrod
41-46	Section 2.3 - Derivation of Retail True-Up Period Cost of Service
	Statement BK-1 - Derivation of retail true-up cost of service using the cost
	statements AD through AV as shown in Section 1, for the 12-month period April
	2011 through March 2012.
47	Statement BB – Allocation Demand & Capability Data
48	Statement BD – Allocation Energy and Supporting Data
49-67	Section 2.3.1 – Derivation of Retail TU Period Cost of Service Rates
	Derivation of Retail TU Period Cost Of Service Rates
68-82	Section 2.3.2 Derivation of Retail Monthly COS Revenues for TU Period

Using the Retail Rates Developed in Section 2.3.1

Derivation of Retail monthly Cost of Service Revenues for TU Period.

# TO3 Cycle 6 True-Up Adjustment "Report"

#### TO3 CYCLE 6 TRUE-UP ADJUSTMENT REPORT

#### I. SUMMARY

The purpose of the True-Up ("TU") Adjustment in Cycle 6 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 6 TU Period, *i.e.*, twelve months ending March 31, 2012, and demonstrates that costs were overcollected during that period because SDG&E's recorded revenues were greater than SDG&E's Cost of Service during the TU Period. Revenue was undercollected by approximately \$9.6 million. 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 overcollection.

#### II. CYCLE 6 TWELVE-MONTH TU ADJUSTMENT

## A. Derivation of \$9.6 million Cycle 6 True-Up Adjustment Undercollection

SDG&E's Cost of Service during the TU Period is \$ 9.6 million higher than recorded revenues during the same period; thus the TU Adjustment is undercollected. As explained in Section III below, the TU Adjustment has primarily three causes for the undercollection. First, there was an overcollection that reflects Sunrise Cycle 5 revenues being included in Cycle 6 TU Period recorded revenues, but Sunrise costs not being in the Cycle 6 TU cost of service. Second, there was an undercollection caused by lower sales during the Cycle 6 TU Period. Third, the *Order on Compliance Filing* ("Cycle 5 Order"), 2 issued in SDG&E's Cycle 5 proceeding,

<sup>&</sup>lt;sup>1</sup> Volume 2A, Section 2.1A, page 3, Line 38.

<sup>&</sup>lt;sup>2</sup> San Diego Gas & Elec. Co., 140 FERC ¶61,108 (2012).

required SDG&E to expense all wildfire insurance premiums and Wildfire Property Costs,<sup>3</sup> ("Wildfire Costs") to Account 925, without capitalizing any portion those costs ("Wildfire Capitalized Amounts") As a result of that directive, transmission-related Administrative and General ("A&G") Expenses reflect an undercollection of Wildfire Costs, as compared to Cycle 5 recorded revenues, which reflect Wildfire Capitalized Amounts.<sup>4</sup> The Cycle 6 Supplemental Filing, which will be filed on concurrently with the Cycle 5 Compliance Filing on October 2nd, will reflect an adjustment of the Cycle 5 recorded revenues to eliminate all Wildfire Capitalized Amounts and expense and charge all Wildfire Costs to Account 925, consistent with the *Cycle 5 Order*.

Exhibit No. 1 shows the components of the TU Adjustment. Column A and Column B of Exhibit No. 1 show the costs that were used to set the rates that were in effect during the TU Period. The costs were reported in SDG&E's TO3 Cycles 4 and 5 filings.<sup>5</sup> The resulting rates, when applied to sales, determined the amount of revenue that was collected.

In Columns C, D, and E of Exhibit No. 1, the Cycles 4 and 5 costs are prorated for the amount of revenue for those periods that was recovered during the TU Period. During the TU Period, Cycle 4 rates were in effect for the first five months (April 2011 through August 2011) and Cycle 5 rates were in effect for the last seven months (September 2011 through March 2012). To reflect the Cycle 4 costs that were being recovered in rates during the first five months of the TU Period, SDG&E has multiplied total Cycle 4 costs by 38.17%, as shown in

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<sup>&</sup>lt;sup>3</sup> Paragraph 1 of the *Cycle 5 Order* defined Wildfire Property Costs as "uninsured, wildfire-related, third-party property losses and legal expenses."

<sup>&</sup>lt;sup>4</sup> Pursuant to the *Cycle 5 Order*, on October 2, 2012, SDG&E will file a Cycle 5 Compliance Filing expenses all Cycle 5 Wildfire Costs to Account 925 while eliminating all Wildfire Capitalized Amounts.

<sup>&</sup>lt;sup>5</sup> Cycle 4 costs are per FERC Docket ER10-2235-000 and Cycle 5 costs are per Docket ER11-4318-000. Cycle 4 costs exclude TU adjustments of approximately \$32.2 million for the Cycle 4 TU period. Cycle 5 costs exclude TU adjustments of approximately \$15.3 million for the Cycle 5 TU period. These adjustments are shown on Statement BK-1, page 5, of the Cycle 4 and Cycle 5 filings.

Column C of Exhibit No. 1. The 38.17% was derived by dividing the revenues recorded during the first five months of the TU Period (\$112.7 million) by the total Cycle 4 revenue requirement, less TU adjustments (\$295.3 million). To reflect the Cycle 5 costs that were being recovered in rates during the last seven months of the TU Period, SDG&E has multiplied total Cycle 5 costs times 54.30%, as shown in Column D of Exhibit No. 1. The 54.30% was derived by dividing the revenues recorded during the last seven months of the TU Period (\$202.9 million) by the total Cycle 5 revenue requirement, less TU adjustments (\$373.6 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 \$315.6 million shown on Line 11.

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

To properly compare the costs from Cycles 4 and 5 to the TU Period Cost of Service (Column G, line 11, \$325.1 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 B and is equal to \$19.7 million. TU Adjustment WP-3 in Vol. 3 shows how the \$19.7 million was prorated and added to each line item in Column E of Exhibit No. 1 to increase these 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 11 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 \$10.2 million overcollected shown on Line 11.

The sum of the \$10.2 million overcollection, less the offsetting impact of \$19.7 million due to lower sales, shown on Line 12, and interest of \$0.1 million from Vol. 2A Section 2.1A, Page 3, Line 33, shown on Line 13, is equal to the total TU Adjustment, which is an undercollection equal to \$9.6 million shown on Line 14. III.

### III. SUMMARY OF THE TU ADJUSTMENT

As explained above, the Cycle 6 TU Adjustment equals a \$9.6 million undercollection and consists of those differences shown in Column H, Lines 2 through 13. The three largest components of the \$9.6 million undercollection are as follows: A) an overcollection caused by the inclusion of a portion of the cost of the Sunrise Powerlink project in the last seven months of TU Period recorded revenues compared to the TU cost of service that did not contain those Sunrise costs, B) an offsetting undercollection caused by lower than forecasted sales, and C) an undercollection caused by expensing the Wildfire Costs to Account 925 and then allocating them to transmission using transmission labor ratios, consistent with the *Cycle 5 Order*.

#### A. Overcollection Caused by Sunrise

As indicated above, the Sunrise overcollection was caused by Sunrise recorded revenues from Cycle 5 for the last seven months of the TU Period being reflected as recorded revenues, but no Sunrise costs being included in the TU cost of service. A revenue requirement of \$36.1 million for these costs is included in TU Period revenue. The derivation of the \$36.1 million is shown in TU Adjustment WP-4.

#### B. Lower Sales - \$19.7 Million Undercollection

As explained above, a factor contributing to the net overcollection was a \$19.7 million undercollection caused by lower than forecasted sales. As shown on the next page in Table 1, SDG&E's sales during the TU Period were significantly lower than forecast:

Table 1: Lower Sales during the TU Period

	A	В	C	D
		Cycle 4 <sup>6</sup>	Cycle 5 <sup>7</sup>	<u>Total</u>
1	Portion of TU Period	1 <sup>st</sup> 5 Months	Last 7 Months	12 Months
2	Forecasted Sales (GWh)	8,441	12,121	20,562
3	Actual Sales (GWh)	<u>7,865</u>	11,568	19,433
4	Below Forecast (GWh) (L2-L3)	576	553	1,129
5	Below Forecast % (L4/L2)	6.82%	4.56%	5.49%
6	Rate (cents per kWh) <sup>8</sup>	1.61	1.88	
7	Dollar Impact (L4 x L6/100) (Undercollected)	\$ 9.3M	\$ 10.4M	\$ 19.7M

As indicated in Column D of the above table, the dollar impact of lower sales was \$19.7 million not collected related to Cycle 4 and Cycle 5. The Cycle 4 and Cycle 5 sales forecasts that SDG&E used, which were from the California Energy Commission's 2009 Adopted Forecast, did not anticipate the unusually cool summer in 2011 and worse-than-expected economic conditions.

#### C. Undercollection of the Wildfire Costs

The undercollection in Cycle 6 A&G expenses is attributable to SDG&E's compliance with the directive in *Cycle 5 Order* requiring SDG&E to expense and charge all wildfire costs to electric Account 925 and then to labor ratio these amounts to transmission service. Exhibit No. 3 to this Report, as discussed below, compares the A&G expenses in the Cycle 6 TU Cost of

<sup>&</sup>lt;sup>6</sup> Column B, Lines 2 through 5 are from Line 6 of Vol. 3, TU Adjustment WP-2.

<sup>&</sup>lt;sup>7</sup> Column C, Lines 2 through 5 are from Line 15 of Vol. 3, TU Adjustment WP-2.

<sup>&</sup>lt;sup>8</sup> The rates in Line 6 are from Vol. 3, TU Adjustment WP-2, Lines 25 and 26.

Service with the A&G expenses recovered in recorded revenues from prior cycles. Exhibit No. 3, column F, shows A&G expenses recovered in recorded revenues from prior periods and column G indicates the expenses recorded in the Cycle 6 TU Cost of Service. As indicated in Exhibit 3, Part C, lines 15 and 16, once total A&G expenses from part A are allocated to transmission service, approximately \$32 million (\$8.8 M plus \$23.2 M) of wildfire costs are undercollected as part of the Cycle 6 TU Adjustment.

#### IV. ANALYSIS OF TU ADJUSTMENT COST DIFFERENCES

Column H, Lines 2 through 11 of Exhibit No. 1 show the differences between costs recorded in the TU Period and costs recorded prior period Cycles 4 and 5. 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 undercollected by \$1.2 million in total. Exhibit No. 2 shows the differences that contributed the most to this total, the largest of which are as follows:

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

The primary contributors to the \$1.1 million increase in this account included \$0.4 million for an engineering study of integration of intermittent renewable energy, \$0.3 million for security at SDG&E's Mission location and Kearny Maintenance and Operations center, and \$0.2 million labor and services for engineering and information systems support in the Electric Grid Operations department.

## 2. Account 563 (Electric Transmission Operation – Overhead Line Expenses)

The \$1.0 million increase in this account was primarily due to payments of about \$0.8 million for contractor and engineering services, related to a LiDAR study, to survey and assess

bulk transmission lines to verify that actual field conditions meet design criteria. These expenses were necessary to meet NERC requirements.

## 3. Account 566 (Electric Transmission Operation – Miscellaneous Transmission Expense)

The \$1.8 million decrease in this account is primarily due to the revenue impact of \$4.5 of wildfire insurance expenses that were charged to this account in 2009, as reflected in SDG&E's Cycle 4, when SDG&E directly expensed wildfire insurance premiums to electric transmission O&M. The expenses were later transferred to A&G Account 925, pursuant to FERC's Compliance Order.<sup>9</sup>

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

SDG&E's total 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 \$35.9 million. This amount is transmission's portion of the \$248.2 million increase in total electric A&G expenses between prior periods and the TU Period, as shown in Exhibit No. 3 column H Line 7.

Part A, Column H, Line 7 of Exhibit No. 3 shows \$248.2 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 column H. Part B shows the allocators that are multiplied by total electric A&G expenses in Part A to yield Part C or the \$36 million of A&G expense differences that are undercollected after being allocated to transmission service.

7

<sup>&</sup>lt;sup>9</sup> See Order on Annual Formula Rate Filing, and Directing Accounting Change, 133 FERC ¶61,016 (2010).

The main reasons for the \$97.6 million increase in total electric A&G expenses are explained by FERC account, as follows:

## 1. Account 921 (Office Supplies and Expenses)

The increase of \$6.0 million in this account had primarily two causes. The first was the TU impact of a \$4.0 million credit adjustment in 2009 for an over-accrual of purchased services in December 2008. The second was an increase in overhead allocations of Information Technology costs during the TU Period.

## 2. Account 925.4 (Injuries and Damages – Wildfire Insurance Premiums)

As shown in Exhibit No. 3, line 3, SDG&E's wildfire insurance premium expenses increased by \$60.7 million. SDG&E began incurring these expenses in July 2009. Only \$11.8 million of these expenses were included in recorded revenues during the TU Period, compared with TU Period insurance premiums of \$72.5 million.

## 3. Account 925.4 (Injuries and Damages – Wildfire Damage Claims

SDG&E's wildfire damage claim expenses are for fire-related, third-party damages that have exceeded SDG&E's liability insurance coverage. SDG&E did not begin incurring these expenses until March 2011, therefore there were no expenses included in Cycle 6 recorded revenues. Expenses during the TU Period that were assigned to total electric A&G expenses were \$159.2 million, as shown in Exhibit No. 3, Line 4.<sup>10</sup> \$23.2 million of this amount is allocated to transmission service, as shown in Exhibit No. 3, Line 16.<sup>11</sup>

8

<sup>&</sup>lt;sup>10</sup> Also see Vol. 3, wildfire property damages workpaper AHWP6, Column E, Line 14.

<sup>&</sup>lt;sup>11</sup> Also see Vol. 3, wildfire property damages workpaper AHWP6, Column I, Line 16.

## 4. Account 926 (Employee Pension and Benefits)

The increase of \$8.1 million in this Account was caused primarily by increased funding of 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.

#### C. Return on Rate Base

SDG&E experienced an overcollection of return on rate base equal to \$56.6 million, as shown in Column H, Line 7, of Exhibit No. 1. The primary cause of the overcollection, as explained in Section III A. above and TU Adjustment WP-4, is the inclusion in revenue of \$36.1 million for costs of the Sunrise Powerlink that are not included in the TU cost of service. The overcollection was partially offset by exclusion from TU Period recorded revenues of return on a portion of the rate base growth that occurred between January 2009 and March 2011, inherent in the TO3 Formula.

## TO3-Cycle 6 True-Up Adjustment

"Exhibits 1 - 3"

			103	Sar Cycle 6 For 12 M	Diego True-L onths	o Gas & Jp (TU) F April 1,	Electric Period / 2011 to	San Diego Gas & Electric Company Cycle 6 True-Up (TU) Period Adjustment Anal For 12 Months April 1, 2011 to March 31, 2012	San Diego Gas & Electric Company O3 Cycle 6 True-Up (TU) Period Adjustment Analysis For 12 Months April 1, 2011 to March 31, 2012	Sis						EX	Exhibit No. 1 BK-1	No. 1 BK-1
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ო	Transmission Related A&G			23.5		29.5		9.0		16.0	55		26.5		62.4		35.9	က
4	Depreciation and Amortization			45.1		48.8		17.2		26.5	4	43.7	46.4		54.4		8.0	4
ည	Other			12.6		14.4		4.8		7.8	12	12.6	13.4		14.8	€9	4.	5
φ	Total Expense	ΣL2L5	\$	132.0	क	136.3	↔	50.4	49	74.0	\$ 124.4	<u> </u>	132.2	es	178.9	4	46.7	9
7	B. Return on Rate Base and Plant Adds		ક્ર	159.5	क	232.9	ઝ	6.09	8	126.5	\$ 187.3	⊢	199.0	₩	142.4	ľ	(26.6)	7
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2	¥.			3.8		4.5		1.4		2.4	(,)	3.9	4.1		3.8	)	(0.3)	9
<del></del>	Total excluding impact of lower sales	L9 + L10	ક્ક	295.3	<del>ഗ</del>	373.6	₩	112.7	\$	202.9	\$ 315.6	8 9	335.3	↔	325.1		(10.2)	<u></u>
12	Costs not collected due to lower sales	Cols. F - E					i					_				\$	19.7	12
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<u>4</u>	Total Under/(Over)collection	ΣL11L12														<del>ss</del>	9.6	4
5																	İ	15
16	Footnotes																	16
17																		17
9	<u>(a)</u>	ints for bas	se peri	ods and	forecas	sted plan	t additic	ons. Reve	periods and forecasted plant additions. Revenue requirements for prior true-up	irement	s for pric	r true-	珨					9
19		the Cycle	0 TO	Adjustme	ent sho	uld not t	rue up t	he true-u	TU Adjustment should not true up the true-ups prior cycles. The TO3 Cycle 4	ycles. T	he TO3	Cycle 4						19
22		J) Adjustm	ents to	otaling \$3	2.2 mi	llion for t	he TO3	Cycle 4	TU Perio	մ. The 1	- - - - - - - - - - - - - - - - - - -	e 5 tota	드					20
2 2		aling \$15.	βmillic e	n for the	ဋ	Sycle 5 T	U perio	d. These	TU adjus	tments	are shov	.⊑ ∀						53
3 6	Statement DN-1, page 5 of the Cycle 4 and Cycle 5 filings	nd Cycle a	S IIIII G															2 2
3 42	<u> </u>	% is derive	o Aq be	lividina t	le reve	annes rec	corded f	or Cycle	4 durina t	he first	five mon	ths of t	e d					3 4
25	TU Period (\$112.7 million) by Col.A, L11. 54.30% is derived by dividing the revenues recorded for Cycle 5 during the last seven months	54.30% i	s deriv	ed by div	iding t	he reven	nes rec	orded for	Cycle 5 c	Juring t	ne last se	even m	onths					52
7 6		6,L11. Sē	e - Ce	-Up Aaju	stment	r workpa	per-1 in	. Vol. 3.										
7 8 2	(c) The adjustment for sales equals Col. E multiplied by the adjustment factor calculated in TU Adjustment Workpaper-3. L14 (106.2%)	nultiplied by	v the a	diustmer	t facto	r calcula	ted in T	U Adiust	ment Wor	kpaper	-3. L14 (	106.2%						7 %
	1									2	1						$\frac{1}{2}$	3

San Diego Gas & Electric Company TO3 Cycle 6 True-Up (TU) Period Adjustment - O&M For 12 Months April 1, 2011 to March 31, 2012 (\$ in Millions)

Line   No.   FERC Prime Account   Line   No.   FERC Prime Account   Line   No.   FERC Prime Account   Line   Lin					٧		В	ပ		Ω	Е	$\vdash$	Ш	ტ		Ŧ	
TO3 TO3 4/11 - 8/11 9/11 - 3/12 4/11 - 3/12 Service in Cycle 4 Cycle 5 = A* = B* 12 Mos. Adjusted for TU Period 2009 2010 38.17% 54.30% C+D Sales (b) 4/11-3/12 G-F ervision and Engineering \$ 6.3 \$ 6.6 \$ \$ 2.4 \$ 3.6 \$ 6.0 \$ 6.4 \$ 7.4 \$ 1.1 \$ 1.2 \$ 1.0 \$					Base P	eriod	ङ्	Re	venue	3 Recorder	in TU Pe	riod	(a)	Cost	٦	True Up	_
Cycle 4         Cycle 5         = A*         = B*         12 Mos.         Adjusted for 2009         TU Period (\$C+D         Reprince of Pales (b)         Tu Period (\$C+D         Sales (b)         Sales (b)         Sales (b)         Sales (b)         Sales (b)         Sales (c)         Sal					T03	ř		4/11 - 8/11	<u> </u>	11 - 3/12	4/11 - 3/1.	2 4	/11 - 3/12	Service	Ē.	Adjust-	_
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\$ 7.4 \$ 1.1 2.2 1.0 9.0 (1.9) 28.3 0.9	No.	FERC I	Prime Account	• •	2009	7	210	38.17%		54.30%	C+D		Sales (b)	4/11-3/	12	G-F	Š
2.2 9.0 (1.9) 28.3 0.9 \$ 46.9	-	260	Operation Supervision and Engineering	↔	6.3		9.9			3.6	\$ 6.0				7.4	1.1	-
\$ 46.9 \$ 1.1	7	563	OH Line Expenses		1.0		<del>د</del> .	0.4	<del></del>	0.7	÷	_	1.2	.,	2.2	1.0	7
\$ 46.9	ო	266	Miscellaneous Transmission Expense		15.4		8.0	3.6		4.4	10.	2	10.9		9.0	(1.9	е (
\$ 46.9	4		All other accounts		28.0		27.8	10.7	_	15.1	25.8	ထ	27.4	7	3.3	0.9	4
\$ 1.1	2																2
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	თ 	Footno	tes														6
	 6	(a) Imp	act of lower sales on revenue: 38.17% is de	rived	by divid	ing th	ne revel	nues recorde	ed dur	ing the first	t five montl	βş					10
	7	oft	he TU Period (\$112.7 million) by the Cycle 4	rever	ue requ	irem	ent, les	s TU Adjusti	ments	(\$295.3).	54.30% is c	derive	þe				7
	12	þ þ	dividing the revenues recorded during the last	st sev	en mont	hs of	the TU	Period (\$20	<b>J2.9 m</b>	illion) by th	te Cycle 5						12
14 (b) The adjustment for sales equals Col. E multiplied by the adjustment factor calculated in TU Adjustment Workpaper-3. L14 (106.2%).	13	rev	enue requirement, less TU Adjustments (\$3;	73.6).	See TU	Adju	stment	Workpaper-	<del>.</del> .								13
	14	(b) The	adjustment for sales equals Col. E multiplie	d by t	he adjus	tmen	nt factor	calculated	in TU,	Adjustmen	t Workpape	er-3,	L14 (106.2)	%).			4

San Diego Gas & Electric Company TO3 Cycle 6 True-Up (TU) Period Adjustment - A&G For 12 Months April 1, 2011 to March 31, 2012 (\$ in Millions)

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I	True Up	Adjust-	ment	G-F		0.9	60.7	159.2	8.1	14.3	248.2							0.9	8.8	23.2	1.2	1.9	36.0								
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	Revenue Recorded in TU Period	4/1	12	ပ		€9					မှာ							<del>(y)</del>					<del>S</del>			fiver	of the TU Period (\$112.7 million) by the Cycle 4 revenue requirement, less TU Adjustments (\$295.3), 54.30% is derived	seven months of the TU Period (\$202.9 million) by the Cycle 5		i S	Factor, which is used for Accounts other than Account 924, is derived in Statement Al.
	cord	12		<u> </u>		4.2	1.1		27.5	61.5	104.3							0.6	1.7	_	4.2	9.5	16.0			first	3).5	y.		rived	coun
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					A. Before Allocation to Electric Transmission	921	925	925	926				B. Allocation Factors	Transm. Plant Prop. Insurance Alloc. Factor (b)	Transm. Wages and Salaries Alloc. Factor (c)		C. After Allocation to Electric Transmission	921	925	925	926				Footnotes	(a) Impact of lower sales on revenue: 38.17% is derived by dividing the revenues recorded during the first five months	ੁ <b>ਰ</b>	Ð	ត	(b) The Transmission Plant Property Insurance Allocation Factor, which is used for Account 924, is derived in Statement AH.	(c) The Transmission Wages and Salaries Allocation
-			Line	No.	_	7	က	4	Ŋ	9	- /		<del>"</del>	5	1	12	13	4	15	16	17	9	19	22				22	56		58

Sunrise Powerlink Project Report

#### SUNRISE POWERLINK PROJECT REPORT

### I. INTRODUCTION

SDG&E has included approximately \$1.617 billion¹ of unweighted capitalized costs in the Cycle 6 Forecast Period associated with the Sunrise Powerlink Project ("Sunrise" or "Project") in Cycle 6 filing. The Sunrise Project is comprised of new electric transmission lines between the existing Imperial Valley and Sycamore Canyon Substations, a proposed new Suncrest Substation, and other system modifications to reliably operate the new line. The bulk of Sunrise went into service on June 17, 2012 with the remainder (some minor tielines and three substations went into service prior to June 17) expected to go into service by the end of Q4, 2012. Sunrise traverses approximately 117 miles between the El Centro area of Imperial County and southwestern San Diego County, in southern California. In addition, three system upgrades (reconductors from Sycamore Canyon Substation to Pomerado, Scripps and Elliott substations) are required as part of this Project. The segment of the Sunrise Project line between the existing Imperial Valley Substation located in Imperial County and the Suncrest Substation in San Diego County will be a 500 kV steel tower overhead transmission line. The segment of the Sunrise Project between the Suncrest Substation and Sycamore Canyon Substation is a double circuit 230 kV transmission line.

The Sunrise Project was approved by the California Public Utilities Commission ("CPUC") in "Decision Granting a Certificate of Public Convenience and Necessity for the Sunrise Powerlink Transmission Project," issued December 18, 2008 ("Decision" or "CPCN").<sup>2</sup> The Decision found that Sunrise would: (1) enhance regional reliability<sup>3</sup> and mitigate congestion

Of this amount, \$1.608 billion receives a 100% weighting covering facilities that are in service from April 2012 through September 2012 pursuant to how SDG&E transmission formula weights capital additions.

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: <a href="http://docs.cpuc.ca.gov/published/proceedings/A0608010.htm">http://docs.cpuc.ca.gov/published/proceedings/A0608010.htm</a>.

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

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.

within the National Interest Electric Transmission Corridor, <sup>4</sup> (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<sup>5</sup> and (3) provide economic benefits to customers utilizing the transmission grid operated by the California Independent System Operator.

#### II. COST STATEMENTS CONTAINING SUNRISE PROJECT COSTS

SDG&E has prepared Exhibit No. 1 to explain where the various Sunrise cost segments appear in the Cycle 6 cost statements. The costs in Exhibit No. 1 reflect only capital costs and no operations and maintenance expenses are included in the filing consistent with SDG&E's TO3 Settlement. In other words, only capital costs are included for transmission projects in the Forecast Period. Line 7, Column 2 indicates Sunrise's total project costs in transmission service equal to approximately \$1.718 billion. Included at the end of Volume 3B under the tab "Sunrise" is workpaper SR WP-6. This workpaper reflects the total unweighted segmented costs for each primary facility of the Sunrise project and shows a total project amount of \$1.826 billion, which excludes the majority of the fire mitigation requirements. The difference between this Sunrise total of \$1.826 billion and the \$1.718 billion in transmission service is attributable mostly to the following items: 1) offsetting revenues received from Citizens Sunrise Transmission LLC ("Citizens") for the lease of a portion of the transfer capability in the Border East Line of the Project; 2) a portion of communication equipment allocated to distribution service; 3) SDG&E's first fire mitigation payment and 4) 2012 post construction environmental costs. What follows is an explanation of each Sunrise segment and its applicable costs.

## A. Sunrise High Voltage/Low Voltage Costs Prior to and Including June 2012 plus Other Additions Beyond June 2012

Column 2 Line 1 of Exhibit No. 1 includes the High Voltage and Low Voltage facility segments in the Cycle 6 Forecast Period. The High Voltage facility segments comprise the majority of the Sunrise costs. Low Voltage upgrades are addressed in more detail in Section B of this report. As shown in column 3 of Exhibit No. 1 the forecast amounts are shown in

2

<sup>&</sup>lt;sup>4</sup> 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 §8240, one of which encompasses San Diego County. *Id.* at 57025.

<sup>&</sup>lt;sup>5</sup> *Id.*, Findings of Fact 15 and 19.

Volume 3B under the tab entitled "Forecast Plant Additions. The amounts shown in the lower portion of this cost statement consist primarily of the following High Voltage Sunrise segments:

•	500 kV transmission lines	\$934 million
•	230 kV overhead line	\$233 million
•	230 kV undergrounding	\$210 million
•	Suncrest 500/230 kV Substation	\$186 million

To the extent most of these High Voltage facilities are estimated to go into service by September 2012 and will provide customers with 12 months of service during the entire Cycle 6 Rate Effective Period (September 2012 through August 2013), they are given a weighting of 100% for revenue recovery in the Forecast Period.

## B. Sunrise Substation Upgrades and Tie Lines that Went into Service by March 31, 2012 and Facilities Going in to Service During the Forecast Period

Some of the Low and High Voltage upgrades for Sunrise went into service prior to the first month of the Forecast Period (April 2012) and the remaining upgrades are estimated to go into service by December 2012 of the Forecast Period. The substation and tie line upgrades that went into service prior to April 2012 are shown in column A below and in Lines 2 and 3 of Exhibit No. 1. The cost statements where these costs appear are referenced in the column 3 of Exhibit No. 1.

Also, some of the Low and High Voltage upgrades for Sunrise are estimated to go into service by December 2012 of the Forecast Period and these amounts are embedded in line 1 column 2 of Exhibit No. 1 and in Column B below. The individual project forecast costs shown in column B below are shown in Volume 3B under the tab entitled "Forecast Plant" for the specific month these upgrades are estimated to go into service.

[Remainder of page intentionally left blank]

## All Figures in Millions Substation Upgrades

		A	В	C
		Currently	In Forecast	A+B
		<u>In-service</u>	<u>Period</u>	<u>Total</u>
		As of		
		03/31/12		
•	Imperial Valley	\$17.7	\$1.0	\$18.7
•	Sycamore Canyon	\$ 0.0	\$15.5	\$15.5
•	South Bay	\$ 0.9	\$ 0.0	\$ 0.9
•	Encina	\$ 0.0	\$25.3	\$25.3
•	San Luis Rey	\$ 1.3	\$ 8.4	\$ 9.7
•	Pomerado	\$ 0.0	\$ 0.7	\$0.7
•	Scripps	\$ 0.7	\$ 0.0	<u>\$0.7</u>
	Total Substations:	\$ 20.6	\$50.9	\$71.5
		Transmission	Line Upgrade	<u>s</u>
•	Tie Line 639	\$ 3.3	\$0.1	\$3.4
•	Tie Line 6916	\$ 6.1	\$0.0	\$6.1
•	Tie Line 6915/6924	<u>\$ 0.2</u>	<u>\$3.5</u>	<u>\$3.7</u>
	Total Lines:	\$ 9.6	\$3.6	\$13.2

## C. Sunrise Leased Right of Ways Recorded in Plant Held for Future Use and Land

Plant held for future use ("PHFU") - Line 4 reflects approximately \$66.3 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 PHFU with their amortization commencing June 2012. This amount is shown in the True-Up ("TU") Period cost statement AG in Volume 3B and is reflected as a 13 month average in the statement.

Land - Line 5 reflects approximately \$2.6 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 3B, 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 above criteria and, therefore, the purchased land is recorded in Account 350.<sup>6</sup>

#### D. Sunrise Communication Equipment

Line 6 shows the communication equipment allocated to the project. As indicated in footnote 2, the total communication equipment required by Sunrise is approximately \$14.6 M, which will be directly booked to electric general plant, Account 397 (Communication Equipment). As a result of this booking, only a labor ratio portion of these communication facilities is allocated to transmission service. In the instant Cycle 6 filing, the 14.6% transmission labor ratio times the total communication facilities will be assigned to transmission service. This amount is shown in Exhibit No. 1 column 2 line 6. The 2011 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. Line 8 indicates the remaining portion of the Sunrise communication equipment that is allocated to CPUC distribution service and recorded to Account 397, Communication Equipment.

## E. Subtraction of Citizens' Lease Amount (\$85.194 M) from Sunrise's Total Costs

Line 9 reflects half the cost of 30 miles of Sunrise 500 kV line from the Imperial Valley Substation going west to the Imperial County line. This cost represents SDG&E's lease of 50% of the transfer capability of this 30 mile segment to Citizens Energy. This cost is approximately \$85.194 million. The lease of this transfer capability was approved by the FERC and the CPUC.<sup>7</sup> The lease was signed by Citizens on July 3, 2012.

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<sup>&</sup>lt;sup>6</sup> Currently there are three parcels of land going through a condemnation process. Their amounts in the land segment is estimate at approximately \$2.9 M.

<sup>&</sup>lt;sup>7</sup> D.11-05-048, <a href="http://docs.cpuc.ca.gov/WORD\_PDF/FINAL\_DECISION/136211.PDF">http://docs.cpuc.ca.gov/WORD\_PDF/FINAL\_DECISION/136211.PDF</a>; 129 FERC ¶61,242 (2009). (verify cites)

## F. Sunrise Fire Mitigation Costs and Post Construction Environmental Costs

In approving the Sunrise Project, the CPUC imposed a fire mitigation requirement on SDG&E. The costs associated with this requirement are approximately \$3 M per year. SDG&E will pay this amount each year in April to a trust account, similar to a checking account at the bank. In turn, each year those homeowners and entities who qualify to use money from this trust account will receive disbursement from the account for carrying out fire hardening and other fire mitigation measures. From SDG&E's ratepayer's perspective, these annual costs will be treated as annual pay-as-you-go capitalized costs. That is, each year SDG&E will capitalize these amounts to transmission capital. SDG&E views these costs as environmental permitting costs and as such, these costs should be capitalized. Once capitalized, each year's cost will be amortized over the remaining life of the Sunrise facilities.

In April 2012, SDG&E paid \$3 M to this trust account and recorded the amount to Construction Work In Progress. This amount is reflected as a transmission capital addition in June 2012 in the Forecast Period. Because SDG&E will make another \$3 M payment to the trust account in April 2013, this amount is also shown as a transmission capital addition in Forecast Period. These two amounts are shown in the Forecast Capital Additions in Volume 3B under the tab entitled "Forecast Plant Additions".

In addition to the fire mitigation requirement, the CPUC also imposed post-construction environmental obligations on SDG&E as a permitting condition. Some of the environmental obligations pertain to developing and implementing: (1) a Raven Control Plan to protect the flat tailed horned lizard habitat, (2) a long term plan to protect National Register of Historic Places (NRHP) from impacts such as erosion, native seeding of treated sites, and (3) a long term plan to control invasive plant species that are disruptive to Peninsular Bighorn Sheep. SDG&E has capitalized \$3.5 of costs associated with these post-construction environmental obligations and included them in the Forecast Capital Additions in Volume 3B under the tab entitled "Forecast Plant Additions."

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

• As indicated above, line 7 of Exhibit No.1, shows Sunrise unweighted costs that provide SDG&E transmission service included in its Cycle 6 filing as part of transmission revenue requirements.

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<sup>&</sup>lt;sup>8</sup> Fire mitigation reference in EIR/EIS, page d.15.75

- Separately, line 8 and 9 shows those parts of Sunrise that are not included in SDG&E's Cycle 6 Base Transmission Revenue Requirements.
- Line 10 shows total Sunrise costs.
- Lines 11 through 13 show the post construction environmental costs and the annual pay as you go fire mitigation costs as explained in item F above. To quantify the Sunrise revenues included in Cycle 6, Sunrise Workpaper (WP) 1 at the end of Volume 3B calculates this revenue amount.

	Sunrise Cost Components in SDG&E TO3 Cycle 6 All amounts in \$1,000		Exhibit No.
		2	3
e E		Unweighted	
2	Description	Total	Reference
-	Portion of Sunrise portion in the Forecast Period	1,617,155	Volume 3B, Tab "Forecast Plant Adds" Pg 4 of 8, Line 74
2	Substations and related upgrades currently in service	20,610	20,610 Volume 2A, Tab "Sunrise Powerlink Report" Page 4
ြက	Tie lines and related upgrades currently in service	9,588	9.588 Volume 2A, Tab "Sunrise Powerlink Report" Page 4
4	Leased Right of Ways in PHFU as of March 2012 <sup>(1)</sup>	66,274	Vol. 3B; Statement AG; AG4, Pg 2 of 2, line 8, column S
2	Land in TU Cost of Service as of March 2012	2,552	Vol. 3B; Statement AD; AD11, Pg 2 of 2, line 14, column S
9	Communication Equipment not Included in Transmission Plant, but allocated to Transmission (2),	2,137	See Footnote (2) below
    -	Subtotal Sunrise Costs Reflected in Transmission Service	1,718,316	
8	Communication Equip Allocated to Distribution (2)	12,501	To be recovered in CPUC Distribution Rates. See Footnote (2) below
6	Citizens Leased Portion (3)	85,194	Not included in Forecast. See Vol 3B, Tab "Sunrise" WP SR WP-6
9 0	Sunrise Project Costs Less Fire Mitigation Costs and Post Construction Costs	1,816,011	
$\top$			
1	Post Construction Environmental Expenses July 2012 - August 2013	3,518	Volume 3B, Tab "Forecast Plant Adds" Pg 4 of 8, Line 78
12 /	Annual Fire Mitigation Cost Pay as you go Capitalized ISD June 2012 (4)	3,091	April 2012 payment of \$3,050 + AFUDC of \$41. See Volume 3B, Tab "Forecast Plant Adds" Po 4 of 8. Line 76
13	Annual Fire Mitigation Cost Pay as you go capitalized ISD April 2013 <sup>(5)</sup>	3,111	Volume 3B, Tab "Forecast Plant Adds" Pg 4 of 8, Line 77
4	(1) PHFU = Plant Held for Future Use		
5 H	(2) Total Sunrise communication of \$14,638 will be booked to Account 397, Electric General Communication Eequipment. Amount allocated to transmission 14,638 * 14.60% = 2,137. \$14,638-2,137= 12,501.		See Vol 3B, Tab "Sunrise", SR-WP-6
16	(3) 30 mile section of the 500 kV Sunrise Powerlink located in Imperial County that SDG&E leases to Citizens Energy	SDG&E leases to (	Sitzens Energy
17	(4) 1st installment of annual Fire Mitigation payments. Payment of \$3.050 million made April 2012 +	ide April 2012 + \$4	\$41 of AFUDC through June 2012.
18	(5) 2 <sup>nd</sup> installment of annual Fire Mitigation payments is scheduled for April 2013.		
t			

## Part - II

TO3-Cycle 6
12-Month Period Retail True-Up
Adjustment Cost Statements in
Volume 2-A

True-Up Period Statement – AD Cost of Plant

#### SAN DIEGO GAS AND ELECTRIC COMPANY

## Statement AD

#### **Cost of Plant**

## True Up Period (4/1/2011 - 3/31/2012)

(\$1,000)

Lin No		Amounts	Reference	Line No
	-	 Allouns	Reference	140
1 <b>2</b>	Total Electric Miscellaneous Intangible Plant <sup>2</sup>	\$ 19,096	Stmnt AD WP; Col C, Line 1	1 2
3 4	Total Steam Production Plant	416,826	Stmnt AD WP; Col C, Line 3	3
5 6	Total Nuclear Production Plant	1,459,735	Stmnt AD WP; Col C, Line 5	5 6
7 8	Total Hydraulic Production Plant	-	Stmnt AD WP; Col C, Line 7	7 8
9 10	Total Other Production Plant	 369,432	Stmnt AD WP; Col C, Line 9	9 10
11 12	Total Production Plant and Intangible plant	\$ 2,265,089	Sum Lines 1 thru 9	11 12
13 14	Total Distribution Plant	4,713,651	Stmnt AD WP; Col C, Line 13	13 14
15 16	Total Transmission Plant <sup>1</sup>	1,767,820	Stmnt AD WP; Col C, Line 15	15 16
17 18	Total General Plant <sup>2</sup>	198,722	Stmnt AD WP; Col C, Line 17	17 18
19 20	Total Common Plant <sup>2</sup>	 482,971	Stmnt AD WP; Col C, Line 19	19 20
21 22	Total Plant in Service	\$ 9,428,253	Sum Lines 11 thru 19	21 22
23 24	Transmission Plant	1,767,820	Stmnt AD WP; Col C, Line 23	23 24
25 26	Transmission Wages and Salaries Allocation Factor	14.60%	Statement AI; Line 19	25 26
27 28	Transmission Related Electric Miscellaneous Intangible Plant	2,788	Line 1 x Line 25	27 28
29 30	Transmission Related General Plant	29,013	Line 17 x Line 25	29 30
31 32	Transmission Related Common Plant	 70,514	Line 19 x Line 25	31 32
33 34	Transmission Related Plant in Service	 1,870,135	Sum Lines 23; 27; 29; 31	33 34.
35	Transmission Plant Allocation Factor <sup>3</sup>	 19.84%	Line 33 / Line 21	35

#### NOTES:

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.

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.

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

# True-Up Period Statement – AE Accumulated Depreciation and Amortization

#### SAN DIEGO GAS AND ELECTRIC COMPANY

#### Statement AE

#### Accumulated Depreciation and Amortization True Up Period (4/1/2011 - 3/31/2012) (\$1,000)

Line	2		· ·	Line
No		 Amounts	Reference	No
1 2	Transmission Depreciation Reserve <sup>1</sup>	\$ 522,258	Stmnt AE WP; Col C, Line 1	1 2
3 4	Electric Miscellaneous Intangible Plant Amortization Reserve <sup>2</sup>	15,124	Stmnt AE WP; Col C, Line 3	3 4
5 6	General Plant Depreciation Reserve <sup>2</sup>	85,811	Stmnt AE WP; Col C, Line 5	5 6
7 8	Common Plant Depreciation Reserve <sup>2</sup>	248,426	Stmnt AE WP; Col C, Line 7	7 8
9 10	Transmission Wages and Salaries Allocation Factor	 14.60%	Statement AI; Line 19	9 10
11 12	Transmission Related Electric Miscellaneous Intangible Plant Amortization Reserve	\$ 2,208	Line 3 x Line 9	11 12
13 14	Transmission Related General Plant Depreciation Reserve	12,528	Line 5 x Line 9	13 14
15 16	Transmission Related Common Plant Depreciation Reserve	 36,270	Line 7 x Line 9	15 16
17	Transmission Related Accumulated Depreciation Reserve	 573,264	Sum Lines 1; 11; 13;15	17

#### **NOTES:**

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.

<sup>&</sup>lt;sup>2</sup> 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.

# True-Up Period Statement – AF Specified Deferred Credits

### SAN DIEGO GAS AND ELECTRIC COMPANY

## Statement AF

## Deferred Credits True Up Period (4/1/2011 - 3/31/2012)

(\$1,000)

Line No	Amounts	Reference	Line No
1 Transmission Related ADIT- Excluding Bonus Depreciation	(154,171)	Stmnt AF1 WP; Col. C; Line 1	1
3 Transmission Related ADIT From Bonus Depreciation 4	(29,468)	Stmnt AF1 WP; Col. C; Line 3	3
5 Total Transmission Related Accumulated Deferred Taxes	\$ (183,638)	Sum of Line 1 and 3	5

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

#### SAN DIEGO GAS AND ELECTRIC COMPANY

#### Statement AG

### Specified Plant Accounts (Other Than Plant in Service) True Up Period (4/1/2011 - 3/31/2012)

(\$1,000)

Lin	e			Line
_No	<u>)</u>	 Amounts	Reference	No
1 2	Transmission Plant Held for Future Use	 64,62	Stmt AG WP; Page-AG1; Line 3	1 2
3	Total	 64,62	Sum of Line 1	3

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 Salt Creek 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.

True-Up Period
Statement – AH
Operation and Maintenance Expenses

Docket No. ER12- -000

#### Statement AH

#### Operation and Maintenance Expenses True Up Period (4/1/2011 - 3/31/2012) (\$1,000)

	(31,000)				
Line No.		,	Amounts	Reference	Line No.
	=			1101010100	110.
1	Derivation of Transmission Operation and Maintenance Expense:				1
2	Total Transmission Expenses	\$	64,368	Stmnt AH WP; Page-AH1; Line 2	2
3	Less: Account (561) - Load Dispatching		(9,520)	Stmnt AH WP; Page-AH1; Line 3	3
4	Less: Account (565) - Transmission of Electricity by Others		(5,086)	Stmnt AH WP; Page-AH1; Line 4	4
5	Less: Account (566) - Miscellaneous Transmission Expenses		(2,822)	Stmnt AH WP; Page-AH1; Line 5	5
6	Less: Account (566) - Miscellaneous Transmission Expenses		-	Stmnt AH WP; Page-AH1; Line 6	6
7	Less: Account (575) - Market Administration Monitor		46.040	Stmnt AH WP; Page-AH1; Line 7	7
8	Total Transmission O&M Expenses Including Intervener Compensation Costs	\$	46,940	Sum Lines 2 through 7	8
9	Less: CPUC Intervener Funding Expenses (See Statement BK1; Page 1; Line 6)		16010	Stmnt AH WP; Page-AH1; Line 9	9
10	Total Transmission O&M Expense (See Statement BK1; Page 1; Line 2)	\$	46,940	Sum Lines 8 through 9	10
11					11
12					12
13	<u> </u>	\$	454,917	Stmnt AH WP; Page-AH1; Line 13	13
14	3				14
15	Nuclear Property Insurance Expenses		-	Stmnt AH WP; Page-AH1; Line 15	15
16	<b>,</b>		(788)	Stmnt AH WP; Page-AH1; Line 16	16
1 <b>7</b>	Wildfire Insurance Premium Allocation		7,905	Stmnt AH WP; Page-AH1; Line 17	17
18	CPUC Reimbursement Fees		(4,826)	Stmnt AH WP; Page-AH1; Line 18	18
19	Litigation Expense		(424)	Stmnt AH WP; Page-AH1; Line 19	19
20	,		(39,640)	Stmnt AH WP; Page-AH1; Line 20	20
21	Wildfire Damage Claims Alloc - Cycle 6		17,352	Stmnt AH WP; Page-AH1; Line 21	21
22	6, , , , , , , , , , , , , , , , , , ,		(10,534)	Stmnt AH WP; Page-AH1; Line 22	22
23	AMI Lease Facilities		(417)	Stmnt AH WP; Page-AH1; Line 23	23
24	Hazardous Substances		(6)	Stmnt AH WP; Page-AH1; Line 24	24
25	Total Adjusted A&G Expenses Before Excluding Property Insurance	\$	423,539	Sum Lines 13 thru 24	25
26	Property Insurance (Reflected on Line 44 below due to different allocation factor)		(6,127)	Stmnt AH WP; Page-AH1; Line 25	26
27	Total Adjusted A&G Expenses Excluding Property Insurance	\$	417,412	Sum Lines 25 thru 26	27
28	Transmission Wages and Salaries Allocation Factor		14.60%	Statement AI; Line 19	28
29	Total Transmission Related Administrative and General Expense	\$	60,942	Line 27 x Line 28	29
30					30
31	Derivation of Transmission Plant Property Insurance Allocation Factor:				31
32	Transmission Plant	\$	1,767,820	Statement AD-WP; Line 23	32
33	Transmission Related General Plant		29,013	Statement AD-WP; Line 29	33
34	Transmission Related Common Plant		70,514	Statement AD-WP; Line 31	34
35	Total	\$	1,867,347	Sum Lines (32 thru 34)	35
36			<del></del>		36
37	Total Transmission Plant	\$	1,767,820	Statement AD-WP; Line 23	37
38		*	416,826	Statement AD-WP; Line 3	38
39			369,432	Statement AD-WP; Line 9	39
40	Total Nuclear Production Plant		-	N/A in Ratio Development	40
41	Total Distribution plant		4,713,651	Statement AD-WP; Col.C; Line 13	41
42	Total General Plant		198,722	Statement AD-WP; Col.C; Line 17	42
43	Total Common Plant		482,971	Statement AD-WP; Col.C; Line 19	43
44	Total Plant in Service Excluding SONGS	\$	7,949,422	Sum Lines (37 thru 43)	44
45	Total I failt in Service Exciduing SONOS	<u> </u>	1,949,422	Sum Lines (37 tillu 43)	
					45
46	Transmission Plant Property Insurance Allocation Factor		23.49%	Line 35 / Line 44	46
47					47
48	Total Property Insurance	\$	6,127	See Line 26 Above	48
49					49
50	Property Insurance Allocated to Transmission, General, and Common Plant		1,439	Line 46 x Line 48	50
51	·		•		<b>5</b> 1
52	Transmission Related A & G Expenses		60,942	See Line 29 Above	52
53	•		<del></del>		53
54	Transmission Related A & G Expenses Including Property Insurance	\$	62,381	Line 50 + Line 52	54

True-Up Period
Statement – AI
Wages and Salaries

Docket No. ER12-\_\_\_-

#### Statement AI

# Wages and Salaries True Up Period (4/1/2011 - 3/31/2012) (\$1,000)

Lin	e				Line
No	<u>-</u>		Amounts	Reference	No.
1	Production Wages & Salaries	\$	8,930	Stmnt AI WP; Page-AI1; Line 1	1
2				, 5 ,	2
3	Transmission Wages & Salaries		17,432	Stmnt AI WP; Page-AI1; Line 3	3
4					4
5	Distribution Wages & Salaries		52,886	Stmnt AI WP; Page-AI1; Line 5	5
6					6
7	Customer Accounts Wages & Salaries		24,290	Stmnt AI WP; Page-AI1; Line 7	7
8					8
9	Customer Services and Informational Wages & Salaries		15,831	Stmnt AI WP; Page-AI1; Line 9	9
10					10
11	Sales Wages & Salaries		<u>-</u>	Stmnt AI WP; Page-AI1; Line 11	11
12					12
13	Subtotal	\$	119,369	Sum { Lines 1 thru 11}	13
14					14
15	Administrative Wages & Salaries		30,210	Stmnt AI WP; Page-AI1; Line 15	15
16					16
17	Total Operating & Maintenance Wages & Salaries	<u>\$</u>	149,579	Line 13 + Line 15	17
18					18
19	Transmission Wages and Salaries Allocation Factor		14.60%	Line 3 / Line 13	19

# True-Up Period Statement – AJ Depreciation and Amortization Expenses

Docket No. ER12-\_\_-

#### Statement AJ

#### Depreciation and Amortization Expense True Up Period (4/1/2011 - 3/31/2012) (\$1,000)

Line	j (02)000)				Line
No.			Amounts	Reference	No.
1	Depreciation Expense for Transmission Plant	\$	46,349	Stmnt AJ WP; Page-AJ1; Line 1	1
2			<del>,</del>	, ,	2
3	General Plant Depreciation Expense	\$	8,959	Stmnt AJ WP; Page-AJ1; Line 3	3
4				, ,	4
5	Transmission Wages and Salaries Allocation Factor		14.60%	Statement AI; Line 19	5
6					6
7	Transmission Related General Plant Depreciation Expense	\$	1,308	Line 3 x Line 5	7
8			<del></del>		8
9	Common Plant Depreciation Expense	\$	45,443	Stmnt AJ WP; Page-AJ1; Line 9	9
10					10
11	Tranmission Related Common Plant Depreciation Expense	\$	6,635	Line 9 x Line 5	11
12		<u> </u>			12
13	Electric Miscellaneous Intangible Plant Depreciation Expense	\$	1,073	Stmnt AJ WP; Page-AJ1; Line 13	13
14					14
15	Transmission Related Electric Miscellaneous Intangible Plant Depreciation Expense	\$	157	Line 13 x Line 5	15
16					16
17	Total Transmission, Intangible, General and Common Depreciation & Amortization Exp	\$	54,449	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

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

Docket No. ER12-\_\_\_-

#### Statement AK

# Taxes Other Than Income Taxes True Up Period (4/1/2011 - 3/31/2012) (\$1,000)

<b>~</b> .		(,)				
Line No.				Amounts	Reference	Line No.
1 2	Total Property Taxes		\$	52,163	Stmnt AK WP; Page-AK1; Line 1	1 2
3	Other Taxes (Business license taxes)		\$	15	Stmnt AK WP; Page-AK1; Line 3	3
5	SONGS Property Taxes			3,922	Stmnt AK WP; Page-AK1; Line 7	5
6 7	Property Taxes Less SONGS		\$	48,226	Line 1 - Line 3 - Line 5	6 7
8 9						8 9
10 11	<u>Derivation of Transmission Related Property Tax Allocation Factor:</u> Transmission Plant		\$	1,767,820	Statement AD-WP; Line 23	10 11
12	Total Miscellaneous Intangible Plant		•	2,788	Statement AD-WP; Line 27	12
13 14	Transmission Related General Plant Transmission Related Common Plant			29,013 70,514	Statement AD-WP; Line 29 Statement AD-WP; Line 31	13 14
15 16	Total		\$	1,870,135	Sum Lines 11 thru 14	15 16
17	Total Nuclear Plant		\$	416.006	N/A in Ratio Development	17
18 19	Total Steam Plant Total Other Production Plant			416,826 369,432	Statement AD-WP; Line 3 Statement AD-WP; Line 9	18 19
20 21	Total Transmission plant Total Miscellaneous Intangible Plant			1,767,820 19,096	Statement AD-WP; Line 23 Statement AD-WP; Line 1	20 21
22 23	Total Distribution plant Total General Plant			4,713,651 198,722	Statement AD-WP; Col.C; Line 13 Statement AD-WP; Col.C; Line 17	22 23
24	Total Common Plant			482,971	Statement AD-WP; Col.C; Line 19	24
25 26	Total Investment in Plant Excluding SONGS			7,968,518	Sum Lines 17 thru 24	25 26
27 28	Transmission Related Property Tax Allocation Factor			23.47%	Line 15 / Line 25	27 28
29 30 31	Transmission Related Property Taxes Expense		\$	11,319	Line 7 x Line 27	29 30 31
	Payroll Taxes:		\$	13,744	Stmnt AK WP; Page-AK1; Line 11	32 33
34 35	Transmission Wages and Salaries Allocation Factor			14.60%	Statement AI; Line 19	34 35
36	Transmission Related Payroll Taxes Expense		\$	2,007	Line 32 x Line 34	36

True-Up Period Statement – AL Working Capital

Docket No. ER12- -000

#### Statement AL

# Working Capital True Up Period (4/1/2011 - 3/31/2012) (\$1,000)

Lir	ne v v				Line
No	<u>.</u>	A	mounts	Reference	No.
1 2	Plant Materials and Operating Supplies	\$	56,587	Stmnt AL WP; Page-AL1; Line 1	1
3	Transmission Plant Allocation Factor		19.84%	Statement AD WP; Line 35	3
5 6	Transmission Related Materials and Supplies	\$	11,227	(Line 1 x Line 3)	5 6
7 8	Prepayment		31,241	Stmnt AL WP; Page-AL1; Line 7	7 8
9	Transmission Related Prepayments	\$	6,198	(Line 3 x Line 7)	9
10 11	Derivation of Transmission Related Cash Working Capital:				10 11
12	Transmission Operation & Maintenance Expense	\$	46,940	Statement AH; Page -AH1; Line 10	12
13 14			62,381	Statement AH; Page-AH1; Line 54 Statement AH; Page-AH1; Line 9	13 14
15 16	***	\$	109,321	Sum Lines 12; 13; 14	15 16
17 18	č č		12.50%	FERC Method = 1/8 of O & M	17 18
19 20	j		12.50%	Line 17 / 1	19 20
21	Transmission Related Cash Working Capital - Retail Customers		13,665	Line 15 x Line 19	21 22
23	Transmission Related Cash Working Capital - Wholesale Customers	\$	13,665	(Line 12 + Line 13) x Line 19	23

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

Docket No. ER12-\_\_\_-

#### Statement AQ

#### Federal Income Tax Deductions, Other Than Interest True Up Period (4/1/2011 - 3/31/2012) (\$1,000)

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

# True-Up Period Statement – AR Federal Income Tax Adjustments

Docket No. ER12-\_\_\_-

#### Statement AR

# Federal Tax Adjustments True Up Period (4/1/2011 - 3/31/2012). (\$1,000)

Line No.		An	nounts	Reference	Line No.
	<del>-</del>				
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		-	Stmnt AR WP; Page-AR1; Line 3	3
4					4
5	Total	\$	(265)	Stmnt AR WP; Page-AR1; Line 5	5

True-Up Period Statement – AU Revenue Credits

Docket No. ER12-\_\_\_-

#### Statement AU

#### **Revenue Credits**

#### True Up Period (4/1/2011 - 3/31/2012)

(\$1,000)

Lin	e			Line
No	<u>.</u>	 Amounts	Reference	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	(ASA) Don't Comp Electric Borner	570	G. ALLYD D. ALLI I. 5	4
3	(454) Rent from Electric Property	578	Stmnt AU WP; Page-AU1; Line 5	5
6 7	(455) Interdepartmental Rents	_	Stmnt AU WP; Page-AU1; Line 7	0 7
8	(455) Interdepartmental Rents	-	Sumit AO W1,1 age-AO1, Line /	8
9	(456) Other Electric Revenues	1,958	Stmnt AU WP; Page-AU1; Line 9	9
. 10		,	,,,	10
11	(456) Overcollection Revenues	_	Stmnt AU WP: Page-AU1: Line 11	11
12		 	, , ,	12
13	Transmission Related Revenue Credits - RETAIL CUSTOMERS	\$ 2,536	Sum Lines 1; 3; 5; 7; 9; 11	13
14				14
15	Transmission Related Revenue Credits - WHOLESALE CUSTOMERS	\$ 2,536	Sum Lines 1; 3; 5; 7; 9; 11	15
16		<del>-</del>		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
12 13 14 15	Transmission Related Revenue Credits - RETAIL CUSTOMERS  Transmission Related Revenue Credits - WHOLESALE CUSTOMERS	\$ 2,536	Sum Lines 1; 3; 5; 7; 9; 11	13 14 15 16

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

Docket No. ER12- -000

#### Statement AV

#### Cost of Capital and Fair Rate of Return True Up Period (4/1/2011 - 3/31/2012) (\$1,000)

Lin	e			(81,000)				Line
No	<u>.</u>				·	Amounts	Reference	No.
1	Long-Term Debt Component - Deno	ominator:						1
2	(Plus): Account 221 - Bonds	•			\$	3,536,905	Stmnt AV WP; Page-AV1; Line 2	2
3	(Less): Account 222 - Reacquired B		0.40			-	Stmnt AV WP; Page-AV1; Line 3	3
4	(Plus): Account 224 - Other Long-To					253,720	Stmnt AV WP; Page-AV1; Line 4	4
5	(Plus): Account 225 - Unamortized I			-1. ta		10.165	Stmnt AV WP; Page-AV1; Line 5	5
6 7	(Less): Account 226 - Unamortized Total Long Term Debt (LTD)	Discount on Long	- Term Debt-D	ebit	-\$	12,165	Stmnt AV WP; Page-AV1; Line 6	6
	Total Long Term Debt (LTD)				<u> </u>	3,778,460	Lines 2-3+4+5-6	7
8 9	Long Town Dakt Common at Many							8
9 10	Long-Term Debt Component - Num (Plus): Account 427 - Interest on Lo				•	150 520	C/	9
					\$	158,538	Stmnt AV WP; Page-AV1; Line 10	10
11 12						2,494	Stmnt AV WP; Page-AV1; Line 11	11
13						3,388	Stmnt AV WP; Page-AV1; Line 12	12
14				radit		-	Stmnt AV WP; Page-AV1; Line 13 Stmnt AV WP; Page-AV1; Line 14	13
15	Total LTD Interest = (i)	ii oi Gaili oli Reac	quired Debi-C	icuit	\$	164,420		14
16	Total E1D Interest – (1)				<u> </u>	104,420	Lines 10+11+12-13-14	15
17	Cost of Long-Term Debt:					4 250/	Time 16 /Time 7	16
	Cost of Long-Term Debt.					4.35%	Line 15 / Line 7	17
18 19								18
20	Preferred Equity Component:							19
	PF = Preferred Stock - Account 204				æ	70 475	Charact AM MD. Danie AM1. I in a 21	20
22		oformad Stanles A	accumt 427		\$	78,475	Stront AV WP; Page-AV1; Line 21	21
23	Cost of Preferred Equity	eieiieu Stocks - A	ecount 437			4,820 6.14%	Stmnt AV WP; Page-AV1; Line 22 Line 22 / Line 21	22
24	Cost of Freienca Equity					0.1476	Line 22 / Line 21	23
25								24
26	Common Equity Component:							25
27					æ	3,923,527	Street AM MD: Dogs AM1. Line 27	26
28	(Less): Account 204 Preferred Stock				\$	3,923,327 78,475	Stmnt AV WP; Page-AV1; Line 27 Stmnt AV WP; Page-AV1; Line 28	27 28
29	(Less): Account 216.1 Unappropriate		Subsidioru For	inas		70,473	Stmnt AV WP; Page-AV1; Line 29	28 29
	CS = Common Stock	ed Olidisii ibuled s	subsidiary Eari	ınıgs	\$	3,845,052	Line 27 - Line 28 - Line 29	30
31	es common stock				Ψ	3,643,032	Line 27 - Line 28 - Line 29	
32	Cost of Common Equity - Per Settler	mant				11.35%	Annandiy 9: Daga 29: Itam (a) iii	31 32
33	Cost of Common Equity - Fel Settler		(h)	(-)	(4)		Appendix 8; Page 28; Item (a) iii	
34		(a)	(b) Cap. Struct.	(c)		= (b) x (c) Weighted		33
35	Weighted Cost of Capital:	Amount	Ratio	Cost of Capital		st of Capital		34
36	weighted Cost of Capital.	Amount	Kano	Cost of Capital	Cos	si oi Capitai		35
	Long-Term Debt	\$ 3,778,460	49.06%	4.35%		2.13%	Col. C = Line 17 Above	36 27
	Preferred Equity	78,475	1.02%	6.14%		0.06%	Col. C = Line 17 Above	37 38
39	Common Equity	3,845,052	49.92%	11.35%		5.67%	Col. C = Line 23 Above	39
40	Total Capital	\$ 7,701,987	100.00%	11.3370		7.86%	Sum Lines 37; 38; 39	39 40
41	10m Capitai	Ψ 1,101,301	100.0076			7.0070	Jun Lines 31, 30, 39	
42								41 42
43	Cost of Equity Component (Preferred	1 & Common):				5.73%	Sum Lines 38; 39	42 43
73	Cost of Equity Component (Fictories	a ce Common).				3.1370	Suill Lines 30, 39	43

#### Statement AV

#### Cost of Capital and Fair Rate of Return True Up Period (4/1/2011 - 3/31/2012) (\$1,000)

Lin	e			Line
No	<u>.</u>	 Amounts	Reference	No.
1	Derivation of Cost of Capital Rate:			1
. 2	a) Federal Income Tax Component:			2
4	a) redetai meome rax component.			3
5	Where:			5
6	A = Sum of Preferred Stock and Return on Equity Component	5.73%	Statement AV; Page 13; Line 43	6
7	B = Trans. Related Amort, of ITC and Excess Deferred Tax Liab.	\$ 265	(Statement AR; Page 11; Line 5)	7
8	C = Equity AFUDC Component of Transmission Depreciation Expense	\$ -	(Statement 1 dt, 1 age 11, Ellie 3)	8
9	D = Transmission Rate Base	\$ 1,208,944	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 = $(A + [(C - B)/D])(FT) =$ 1 - FT	3.0736%		13
14				14
15				15
16				16
17	b) State Income Tax Component:			17
18				18
19	. <del></del>			19
20		5.73%	Statement AV; Page 13; Line 43	20
21		\$ 265	(Statement AR; Page 11; Line 5)	21
22	1 ,	\$ -		22
23 24		\$ 1,208,944	Statement BK1; Page 2; Line 20	23
		0.050.00	0	24
25 26	1	3.0736%	Statement AV; Page 14, Line 13	25
27	· · · · · · · · · · · · · · · · · · ·	8.84%	State Income Tax Rate	26
28		0.8516%		27
29		0.8310%		28 29
30				30
31		3.9252%	Sum Lines 13 and Line 28	
32		3.923270	Sum Lines 13 and Line 28	31
33	d) Total Weighted Cost of Capital:	7.8600%	Statement AV; Page 13; Line 40	32 33
34	2/ 10ml 11 vicinou Cost of Capital.	 7.000070	Statement Av, rage 13, Line 40	33 34
35	e) Cost of Capital Rate:	11 70500/	Line 21 + Line 22	
33	et cost of capital Rate.	 11.7852%	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. ER12- -000

# Section 2.1A San Diego Gas Electric Co. TO3-Cycle 6 RETAIL True-Up Adjustment Calculation

	-: -1	L	7							ſ
ž			Anr-11	May-11	3 -	Lyde:4	Tul-11		Aug-11	
3			11-14-1	TT-(nr.r			7.73		TI-Sny	Τ
- (	Beginning Balance (Overcollection)/Undercollection:	S	•	3,199,177	&	8,037,059	\$ 12,462,597	2,597 \$	16,745,597	597
4 W	Total Recorded Retail Revenues @ Meter Level	69	22,971,976	\$ 24,531,023	€9	25,962,284	\$ 26,153,852	3,852 \$	26,632,040	040
4 W	Amortization of True-Up Adjustment and Interest True-Up Adjustment:									
9 1	a) Amortization of Cycle 5 True-Up Adjustment and Interest True-Up Adjustment:									
<u> </u>	i. Amortization of Cycle 5 True-Up Adjustment.									
× 0	<ol> <li>Amortization of Cycle 5 interest 1 rue-Up Adjustment.</li> </ol>									
10	ত্র									
11		<b>69</b>	(2,245,705)	\$ (2,415,551)	69	(2,548,255)	\$ (2,52	(2,524,132)	(3,623,769)	(69/
12 :	ii. Amortization of Cycle 4 Interest True-Up Adjustment.									
4 7	i Amortization of Cycle 3 Interest True-Up Adjustment:		(71777)	(138 16)		(74.666)	Ö	(04 430)	(33 /	(33 473)
7 2			(+1,131)	191,12)		(000,+4)	9	(404,4	r,(CC)	(c/+,
17	ŕ									
- 28			(3,167)	(3,407)		(3.594)	٠	(3.560)	(4.6	(4.697)
19			,							<u> </u>
20	e) Amortization of TO2 Final Interest True-Up Adjustment:									
21			(4,741)	(5,099)	_	(5,379)	ت	(5,328)	(5,3	(5,354)
22								_		
23	Total Amortization of True-Up Adjustments	ses	(2,275,350)	\$ (2,447,438)	€9	(2,581,894)	\$ (2,55)	(2,557,452)	(3,667,293)	293)
4 6		(	,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,		ļ			-+		!
3 %	Adjusted I otal Recorded Refall Revenues @ Meter Level	A	070,090,02	\$ 77,083,383	en .	0%5,0%5,52	\$ 23,596,400	6,400 - S	22,964,747	747
27	Total True-Up Revenues (TU Cost of Service)	s s	23.891.490	\$ 26.905.770	69	27.778.345	\$ 27.840.022	0.022	28.284.941	941
78			_			-		+		
29	Net Monthly (Overcollection)/Undercollection:	ક્ક	3,194,864	\$ 4,822,185	S	4,397,955	\$ 4,24	4,243,622   \$	5,320,194	194
30	_							_		
31	Interest Expense Calculations:	6		e	6		·		·	Ş
3 %		4	1 597 432	5 605 957	9	10 216 027	5 12,462,597 2 121 811	2,402,397   \$	6 903 719	7,67
8			1,597,432	5,605,957		10,216,027	14,58	14,584,408	19,366,316	316
35			0.27000%	0.28000%	.0	0.27000%	0.27	0.27000%	0.28000%	%00
36	Interest Expense	ક્ક	4,313	\$ 15,697	89	27,583	3:	39,378 \$		54,226
37	_		1							
38	Ending Balance (Overcollection)/Undercollection:	S	3,199,177	\$ 8,037,059	9	12,462,597	\$ 16,745,597	5,597   \$	22,120,016	910
<u>~]</u> :						1	;	$\dagger$		Т
<del></del>			Apr-11	May-11		Jun-11	Jul-11	-	Aug-11	
4.			3.25%	3.25%	. <del>.</del> •	3.25%		3.25%	3.2	3.25%
4 5	_		365	365	<u> </u>	365		365		365
<del>.</del> 4	Days in interest Rate - Calculated		0.00000	0.28000%		05 000020	0.27	27000%	31 %000% 0.0%	31
45	_		0.27000%	0.28000%		0.0000	0.27	2,000,=0	0.28000%	. %
4			0.0000000	0.00000	1 2	0.0000000	000	0.0000000	%000000	
	7							2.22		

# Section 2.1A San Diego Gas Electric Co. TO3-Cycle 6 RETAIL True-Up Adjustment Calculation

T in	TOS Exemila Civila in Effect		المراجع والمرك		ع دادیک	L	ع دامنان	č	12	7	
, g			Sep-11		Oct-11		Nov-11	ŠĮŠ	Dec-11	Jan-12	
- 0	Beginning Balance (Overcollection)/Undercollection:	69	22,120,016	s <sub>2</sub>	24,020,981	69	20,557,106	s 1	18,558,942	\$ 16,410,027	0,027
7 m ·	Total Recorded Retail Revenues @ Meter Level	89	33,362,799	69	32,829,594	€9	30,307,336	8	31,691,633	\$ 31,586,810	6,810
4 2 9 7 8	Amortization of True-Up Adjustment and Interest True-Up Adjustment:  a) Amortization of Cycle 5 True-Up Adjustment and Interest True-Up Adjustment:  i. Amortization of Cycle 5 True-Up Adjustment.  ii. Amortization of Cycle 5 Interest True-Up Adjustment.	↔	(2,884,098)	89	(2,528,641)	69	(2,423,300)	€	(2,589,821)	\$ (2,537	(2,537,211)
6 2 1 2 2	b) Amortization of Cycle 4 True-Up Adjustment and Interest True-Up Adjustment:  i. Amortization of Cycle 4 True-Up Adjustment.  ii. Amortization of Cycle 4 Interest True-Up Adjustment.	<del>69</del>	(74,428)	64	(65,255)	€9	(62,537)	€4	(66,834)	\$ (65	(65,476)
14 51 61 81	e) Amortization of Cycle 3 Interest True-Up Adjustment:  i. Amortization of Cycle 3 Interest True-Up Adjustment ii. Amortization of Cycle 3 Interest True-Up Adjustment - Part 2.  d) Amortization of TO3 Cycle 2 True-Up Adjustment and Interest True-Up Adjustment: i. Amortization of Cycle 2 Interest TU Adjustment - Part 2.		(2,605)		(2,284)		(2,189)		(2,339)	(2	(2,292)
2 2 2 2	e) Amortization of TO2 Final Interest True-Up Adjustment: i. Amortization of TO2 Final True-Up Adjustment Accrued After Fully Amortized		•		ı		,		ı		ı
183	Total Amortization of True-Up Adjustments	89	(2,961,131)	69	(2,596,180)	69	(2,488,026)	8	(2,658,994)	\$ (2,604	(2,604,979)
4 22 %	Adjusted Total Recorded Retail Revenues @ Meter Level	es.	30,401,668	69	30,233,414	69	27,819,310	S	29,032,639	\$ 28,981,831	1,831
27	Total True-Up Revenues (TU Cost of Service)	ક્ક	32,240,679	69	26,707,217	69	25,768,578	S	26,835,158	\$ 26,792,613	2,613
8 28 88	Net Monthly (Overcollection)/Undercollection:	S	1,839,011	બ	(3,526,197)	69	(2,050,732)	S	(2,197,481)	\$ (2,189	(2,189,218)
33 33 33 33	Interest Expense Calculations:  Beginning Balance for Interest Calculation  Monthly Activity Included in Interest Calculation Basis	€9	12,462,597	€9	24,020,981	€9	24,020,981 (4.551.563)	8	24,020,981	\$ 16,410,027	0,027
35			22,945,918 0.27000%		22,257,883		19,469,418		17,345,312	15,315,419	5,315,419
36	Interest Expense	ક્ક	61,954	S	62,322	69	52,567	S	48,567	\$ 42	42,883
38 6	Ending Balance (Overcollection)/Undercollection:	69	24,020,981	89	20,557,106	69	18,558,942	S 1	16,410,027	\$ 14,263,693	3,693
<del>4</del> ;	_		Sep-11	$\coprod$	Oct-11		Nov-11	Ď	Dec-11	Jan-12	
47 41	FERC INTEREST RATE Days in Year		3.25% 365		3.25%		3.25%		3.25%	m	3.25%
<b>4</b>			30 27000%		31 0 28000%		30		31	0.280	31
45			0.27000%		0.28000%		0.27000%		0.28000%	0.280	0.28000%
4	Difference		0.00000%	╛	0.00000		0.00000%		0.00000%	0.00(	0.00000.0

Page 2

Section 2.1A
San Diego Gas Electric Co.
TO3-Cycle 6 RETAIL True-Up Adjustment Calculation

Line	TO3-Fo		Cycle - 5	Cycle - 5		,	Line
Š.	Lescription		Feb-12	Mar-12	Total	Reference	o N
	Beginning Balance (Overcollection)/Undercollection:	69	14,263,693	\$ 12,503,336	s	Previous Month's Balance	- (
4 m -	Total Recorded Retail Revenues @ Meter Level	€9	29,202,549	\$ 32,310,345	\$ 347,542,241	Vol. 2; Section 2.2; Page 1; Line 11	7 m
4 vv v	Amortization of True-Up Adjustment and Interest True-Up Adjustment:					SECTION 2.1A	4 w /
0 ~ ~ 0	i. Amortization of Cycle 5 Interest True-Up Adjustment.	₩	(2,350,765)	\$ (2,616,084)	\$ (17,929,920)	Section 2.1A; Page 6; Line 19; Cols.(a)-(g) Not Applicable in TO3-Cycle 6 Filing	0 1 00 0
10							2 01
11 12	i. Amortization of Cycle 4 True-Up Adjustment. ii. Amortization of Cycle 4 Interest True-Up Adjustment.	6-9	(60,665)	\$ (67,512)	(13,357,412)	Section 2.1A; Pages 8-10; Line 19; Cols.(h)-(l) Section 2.1A; Pages 11-13: Line 19; Cols.(a)-(g)	11 21
13							13
4 <del>7</del>	c) Amortization of Cycle 3 Interest True-Up Adjustment: i Amortization of Cycle 3 Interest True-IIn Adjustment				(127 689)	Santista (1 1 - 0 - 10 - 10 - 10 - 10 - 10 - 10	4 7
16			(2,123)	(2,363)	(16,195)		16
17	d) Amortization of TO3 Cycle 2 True-Up Adjustment and Interest True-Up Adjustment:						17
19				'	(18,423)	Section 2.1A; Pages 20-22; Line 19; Cols.(h)-(l)	2 2
20	ଷ						20
22	i. Amortization of TO2 Final True-Up Adjustment Accrued After Fully Amortized		i	ı	(25,901)	Section 2.1A; Pages 23-25; Line 19; Cols.(h)-(l)	21
23	Total Amortization of True-Up Adjustments	89	(2,413,553)	\$ (2,685,959)	\$ (31,938,249)	Sum Lines 7 through 22	23
25	Adjusted Total Recorded Retail Revenues @ Meter Level	64	9 966 887.96	985 769 66 8	315 603 992	Sum 1 ines 3 & 93	47 4
8		<del>)</del>					36
27	Total True-Up Revenues (TU Cost of Service)	9	24,993,998	\$ 26,708,189	\$ 324,747,000	Section 2.3.2; Page 2; Line 11	27
78 78	Net Monthly (Overcollection)/Undercollection:	es.	(1,794,998)	\$ (2,916,197)	\$ 9,143,008	Line 27 Minus Line 25	23 65
က္က	_						ಜ
32	Interest Expense Calculations: Beginning Balance for Interest Calculation	69	16.410.027	\$ 16,410,027		Beginning Onarterly Balances	31
33		,				Interest Calculation Basis	33
34	Basis for Interest Expense Calculation Monthly Interest Beta		13,323,311	10,967,714		Sum Lines 32 & 33	34
3 %		S	-	\$ 30,710	\$ 474,840	Line 34 x Line 35	ર જ
37			-				37
39 8	Ending Balance (Uvercollection)/Undercollection:	9	12,503,336	5 9,617,849	9,617,849	Sum Lines 1; 29; & 36	38
40			Feb-12	Mar-12			40
4 4	FEKCINIEKESI KAIE Daws in Vear		3.25%	3.25%	398	Annual Interest Rate - FERC Website	4 <i>t</i>
43			29	31	366	_	7 7
4			0.26000%	0.28000%	3.29000%		3 4
45			0.26000%	0.28000%	3.29000%	Monthly I	45
₽	Directore		0.00000%	0.00000%	0.00000%	Line 44 - Line 45	46

#### Section 2.1 – Retail True-Up Adjustment

# Section (a): Amortization of Cycle 5 True-Up Adjustment and Interest True-Up Adjustment

Part (i): Amortization of Cycle 5 True-Up Adjustment (September 2011 – March 2012)

- The amortization of the Cycle-5 True-Up Adjustment in the instant Cycle-6 filing is from September 2011 through March 2012.
- The remaining balance of the Cycle-5 True-Up Adjustment will be amortized from April 2012 through August 2012 and will be reflected in the Final TO3 true-up adjustment.

Docket No. ER12-	
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# Section 2.1 San Diego Gas Electric Co. TO3-Cycle 6 Annual Transmission Formulaic Filing Amortization Schedule of TO3-Cycle 5 True-Up Adjustment

Line No.	e Description	(a) Amounts	(p)	(0)	(p)	(9)	(£)	(g)	(h)
_	Derivation of Amortization Rates:								
7	TO3-Cycle 5 Retail True-Up Adjustment	\$ 32,144,533							
m	Forecast Sales TO3-Cycle 5 (kWh)	20,694,913,495							
4	Estimated Amortization Rate Per kWh	\$ 0.00155							
5									
9									
7	Derivation of Forecast Sales: 1	Sep-11	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12
∞	Total Per TO3-Cycle 5 Filing - MWH (Statement BD)	1,946,695	1,712,997	1,667,110	1,718,629	1,770,104	1,662,031	1,643,248	1,581,745
6	Exclude Sale for Resale	2	2	2	2	2	2	2	2
10	Total Forecast Sales Net of Resale - MWH	1,946,693	1,712,996	1,667,108	1,718,628	1,770,103	1,662,030	1,643,246	1,581,743
=	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	1,946,693,495	1,712,995,645	1,667,108,057	1,718,627,828	1,770,102,954	1,662,029,725	1,643,246,433	1,581,743,038
13									
14									
15	15 Amortization of TO3-Cycle 5 True-Up Adjustment: 2	Sep-11	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12
16	Beginning Retail True-Up Adjustment Balance	\$ 32,144,533	\$ 29,260,435	\$ 26,731,794	\$ 24,308,494	\$ 21,718,673	\$ 19,181,462	\$ 16,830,697	
17	Recorded Sales in Total kWh	1,860,708,394	1,631,381,518	1,563,419,204	1,670,852,042	1,636,910,207	1,516,622,552	1,687,796,399	
	Amortization Rate Per kWh	\$ 0.00155	\$ 0.00155	\$ 0.00155	\$ 0.00155	\$ 0.00155	\$ 0.00155	\$ 0.00155	\$ 0.00155
19	Amortization of TO3-Cycle 5 True-Up Adjustment 3	\$ 2,884,098	\$ 2,528,641	\$ 2,423,300	\$ 2,589,821	\$ 2,537,211	\$ 2,350,765 \$	\$ 2,616,084	
70	20 Ending TO3-Cycle 5 True-Up Adjusment Balance	\$ 29,260,435	\$ 26,731,794	\$ 24,308,494	\$ 21,718,673	\$ 19,181,462	\$ 16,830,697	\$ 14,214,613	
21									

- 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.
  - amortization rate during the rate effective period.

    On lines 16 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 2011 through August 2012.
- The monthly true-up adjustment amortization amount shown on line 19 from 9/1/2011 through 3/31/2012 is included in the cycle 6 true-up adjustment period. Future monthly amortization amounts have not been shown since the amounts will be shown in the instant Final TO3 filing.

# Section 2.1 San Diego Gas Electric Co. TO3-Cycle 6 Annual Transmission Formulaic Filing Amortization Schedule of TO3-Cycle 5 True-Up Adjustment

- <sup>1</sup> 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.
  - On lines 16 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 2011 through August 2012.
- The monthly true-up adjustment amortization amount shown on line 19 from 9/1/2011 through 3/31/2012 is included in the cycle 6 true-up adjustment period. Future monthly amortization amounts have not been shown since the amounts will be shown in the instant Final TO3 filing.

## Section 2.1 – Retail True-Up Adjustment

# Section (b): Amortization of Cycle 4 True-Up Adjustment and Interest TrueUp Adjustment

# Part (i): Amortization of TO3 Cycle 4 True-Up Adjustment (April 2011 – August 2011)

- The amortization of the Cycle 4 True-Up Adjustment in the instant Cycle 6 filing picks up the amounts amortized from April 2011 through August 2011.
- The amortization of the Cycle 5 True-Up Adjustment from September 2010 through March 2011 was picked up in the TO3 Cycle 5 filing last year.

Docket No. ER12-\_\_\_-

Section 2.1
San Diego Gas Electric Co.
TO3-Cycle 6 Annual Transmission Formulaic Filing
Amortization Schedule of TO3-Cycle 4 True-Up Adjustment

Line No.	e Description	(a) Amounts	(q)	(0)	(p)	(e)	(£)	(g)	(h)
	Derivation of Amortization Rates:								
7	TO3-Cycle 4 Retail True-Up Adjustment	\$ 31,743,336							
m	Forecast Sales TO3-Cycle 4 (kWh)	20,392,502,467							
4	Estimated Amortization Rate Per kWh	\$ 0.00156							
3									
9				•					
7	Derivation of Forecast Sales: 1	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11
∞	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
6	Exclude Sale for Resale	2	2	2	2	2	2	2	2
2	Total Forecast Sales Net of Resale - MWH	1,922,247	1,690,304	1,643,646	1,693,673	1,744,800	1,637,716	1,618,730	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
17	Total Forecast Sales Net of Resale - kWh	1,922,247,102	1,690,304,137	1,643,646,297	1,693,673,037	1,744,800,253	1,637,715,946	1,618,730,179	1,557,543,693
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	-	\$ 15,848,687	\$ 13,357,412
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	1,439,554,405
28	18 Amortization Rate Per kWh	\$ 0.00156	\$ 0.00156	\$ 0.00156	\$ 0.00156	\$ 0.00156	\$ 0.00156	\$ 0.00156	\$ 0.00156
19	19 Amortization of TO3-Cycle 4 True-Up Adjustment <sup>3</sup>	\$ 2,892,580	\$ 2,719,111	\$ 2,501,110	\$ 2,593,639	\$ 2,728,943	\$ 2,459,266	\$ 2,491,275	\$ 2,245,705
70	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	\$ 11,111,707
21									

- 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.
  - amortization rate during the rate effective period. On lines 16 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.
    - The monthly true-up adjustment amortization amount shown on line 19 from 9/1/2010 through 3/31/2011 was included in the cycle 5 true-up adjustment period. The monthly amortization amounts shown from April 2011 through August 2011 is included in the TO3 C6 instant filing.

Section 2.1
San Diego Gas Electric Co.
TO3-Cycle 6 Annual Transmission Formulaic Filing
Amortization Schedule of TO3-Cycle 4 True-Up Adjustment

	i i	(j)	(f)	(k)	(1)	(m)	, k	Line
. <u>‡</u>	Derivation of Amortization Rates:						TO3 Ciole d'Eiling	<u>0</u> -
18	TO3-Cycle 4 Retail True-Up Adjustment						Vol. 2-A; Section 2 -1A; Pg.3; Line 30	7 7
rec	Forecast Sales TO3-Cycle 4 (kWh)						See Line 12 Below	٣
itim	Estimated Amortization Rate Per kWh						Line 2 / Line 3	4
								5
								9
Ę.	Derivation of Forecast Sales: 1	May-11	Jun-11	Jul-11	Aug-11	Total		7
व्य	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	~
ź	Exclude Sale for Resale	2	2	2	2	61	Sale for Resale	6
텵	Total Forecast Sales Net of Resale - MWH	1,563,384	1,651,389	1,813,252	1,855,818	20,392,502	Line 8 Minus Line 9	10
onc.	Conversion Factor from MWH to kWh	1,000	1,000	1,000	1,000	1,000	MWH Conversion Factor	11
otal	Total Forecast Sales Net of Resale - kWh	1,563,383,686	1,651,388,739	1,813,251,582	1,855,817,817	20,392,502,467	Line 10 x Line 11	12
								13
			•					14
8	Amortization of TO3-Cycle 4 True-Up Adjustment: 2	May-11	Jun-11	Jul-11	Aug-11	Total		15
ige	Beginning Retail True-Up Adjustment Balance	\$ 11,111,707	\$ 8,696,156	\$ 6,147,901	\$ 3,623,769		Beginning Balance	16
600	Recorded Sales in Total kWh	1,548,429,979	1,633,497,061	1,618,033,345	1,625,857,955	19,651,221,316	Recorded Sales	17
mog	Amortization Rate Per kWh	\$ 0.00156	\$ 0.00156	\$ 0.00156			See Line 4 Above	18
Ö	Amortization of TO3-Cycle 4 True-Up Adjustment 3	\$ 2,415,551	\$ 2,548,255	\$ 2,524,132 \$	\$ 3,623,769	\$ 31,743,336	Line 17 x Line 18	19
μĒ	Ending TO3-Cycle 4 True-Up Adjusment Balance	\$ 8,696,156	\$ 6,147,901	\$ 3,623,769			Line 16 Minus Line 19	20
								21

- 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.
  - On lines 16 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.
    - The monthly true-up adjustment amortization amount shown on line 19 from 9/1/2010 through 3/31/2011 was included in the cycle 5 true-up adjustment period. The monthly amortization amounts shown from April 2011 through August 2011 is included in the TO3 C6 instant filing.

### Section 2.1 – Retail True-Up Adjustment

# Section (b): Amortization of Cycle 4 True-Up Adjustment and Interest TrueUp Adjustment

# Part (ii): Amortization of TO3 Cycle 4 Interest True-Up Adjustment (September 2011 – March 2012)

- The amortization of the Cycle 4 Interest True-Up Adjustment in the instant Cycle 6 filing picks up the amounts amortized from September 2011 through March 2012.
- The remaining balance of the TO3 Cycle 4 Interest True-Up Adjustment will be amortized from April 2012 through August 2012 and will be reflected in the Final TO3 true-up adjustment.

Docket No. ER12- -

Section 2.1
San Diego Gas Electric Company
TO3-Cycle 6 Annual Transmission Formulaci Filing
Amortization of Interest True-Up Adjustment Applicable to TO3-Cycle 4

Line		(a)	(p)	(3)	(p)	(ə)	(J)	(g)	(h)
No.	Description	Amounts							
1	Derivation of Amortization Rates:								
7	TO3-Cycle 4 Interest True-Up Adjustment	\$ 874,191							
m	Forecast Sales TO3-Cycle 5 (kWh)	20,694,913,495							
4	Estimated Amortization Rate Per kWh	\$ 0.00004						-	
5									
9									
7	Derivation of Forecast Sales:	Sep-11	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12
∞	Total Per TO3-Cycle 5 Filing - MWH (Statement BD)	1,946,695	1,712,997	1,667,110	1,718,629	1,770,104	1,662,031	1,643,248	1,581,745
9	Exclude Sale for Resale	2	2	2	2	2	2	2	2
10	Total Forecast Sales Net of Resale - MWH	1,946,693	1,712,996	1,667,108	1,718,628	1,770,103	1,662,030	1,643,246	1,581,743
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	1,946,693,495	1,712,995,645	1,667,108,057	1,718,627,828	1,770,102,954	1,662,029,725	1,643,246,433	1,581,743,038
13			-						
14									
15	Amortization TO3-Cycle 4 Interest True-Up Adjustment:	Sep-11	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12
16	Beginning Interest True-Up Adjustment Balance	\$ 874,191	\$ 799,763	\$ 734,508	\$ 671,971	\$ 605,137	\$ 539,661	\$ 478,996	-
17	Recorded Sales in Total kWh	1,860,708,394	1,631,381,518	1,563,419,204	1,670,852,042	1,636,910,207	1,516,622,552	1,687,796,399	ı
18	Amortization Rate Per kWh	\$ 0.00004	\$ 0.00004	\$ 0.00004	\$ 0.00004	\$ 0.00004	\$ 0.00004	\$ 0.00004	. \$
I	19 Amortization of TO3-C4 Interest True-Up Adjustment <sup>3</sup>	\$ 74,428	\$ 65,255	\$ 62,537	\$ 66,834	\$ 65,476	\$ 60,665	\$ 67,512	
20	Ending TO3-Cycle 4 True-Up Adjusment Balance	\$ 799,763	\$ 734,508	\$ 671,971	\$ 605,137	\$ 539,661	\$ 478,996	\$ 411,484	- \$
21									

- 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.
  - 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 interest true-up adjustment over the rate effective September 2011 through March 2012.
    - The monthly true-up adjustment amortization amount shown on line 19 has been calculated through 3/31/2012, which is the end of the cycle 4 true-up adjustment period. Future monthly amortization amounts have not been shown since the amounts will be shown in the instant Final TO3 filing.

# Section 2.1 San Diego Gas Electric Company TO3-Cycle 6 Annual Transmission Formulaci Filing Amortization of Interest True-Up Adjustment Applicable to TO3-Cycle 4

	(j)	9	(k)	(1)	(m)		Line
Description						Reference	Ņ.
Derivation of Amortization Rates:		٠				TO3-Cycle 5 Filing	1
TO3-Cycle 4 Interest True-Up Adjustment						Vol. 2 of 3; Section 2.1B; Pg.2; Line 20	7
Forecast Sales TO3-Cycle 5 (kWh)						See Line 12 Below	ю
Estimated Amortization Rate Per kWh						Line 2 / Line 3	4
							5
			•				9
Derivation of Forecast Sales:	May-12	Jun-12	Jul-12	Aug-12	Total		7
Total Per TO3-Cycle 5 Filing - MWH (Statement BD)	1,587,961	1,677,623	1,841,938	1,884,850	20,694,932	True-Up Period; Statement BDWPs	∞
Exclude Sale for Resale	2	2	2	2	61	Sale for Resale	6
Total Forecast Sales Net of Resale - MWH	1,587,959	1,677,622	1,841,936	1,884,849	20,694,913	Line 8 Minus Line 9	10
Conversion Factor from MWH to kWh	1,000	1,000	1,000	1,000	1,000	MWH Conversion Factor	11
Total Forecast Sales Net of Resale - kWh	1,587,959,374	1,677,621,946	1,841,936,291	1,884,848,709	20,694,913,495	Line 10 x Line 11	12
							13
							14
Amortization TO3-Cycle 4 Interest True-Up Adjustment:	May-12	Jun-12	Jul-12	Aug-12	Total		15
Beginning Interest True-Up Adjustment Balance	· -	- \$	- \$	- 59		Beginning Balance	16
Recorded Sales in Total kWh	•	•	1	•	11,567,690,316	Recorded Sales	17
Amortization Rate Per kWh	-	۱ %	- \$	\$ -		See Line 4 Above	18
19 Amortization of TO3-C4 Interest True-Up Adjustment <sup>3</sup>	- \$	- \$		\$ -	\$ 462,707	Line 17 x Line 18	19
20 Ending TO3-Cycle 4 True-Up Adjusment Balance	- \$	- \$	- \$	- \$		Line 16 Minus Line 19	20
							7.1

- 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
  - 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 interest true-up adjustment over
    - the rate effective September 2011 through March 2012. The monthly true-up adjustment amortization amount shown on line 19 has been calculated through 3/31/2012, which is the end of the cycle 4 true-up adjustment period. Future monthly amortization amounts have not been shown since the amounts will be shown in the instant Final TO3 filing.

## Section 2.1 – Retail True-Up Adjustment

# Section (c): Amortization of TO3 Cycle 3 Interest True-Up Adjustment

## Part (i): Amortization of TO3 Cycle 3 Interest True-Up Adjustment (April 2011–August 2011)

- The amortization of the TO3 Cycle 3 Interest True-Up Adjustment in the instant Cycle 6 filing picks up the amounts amortized from April 2011 through August 2011.
- The amortization of the Cycle 3 True-Up Adjustment from September 2010 through March 2011 was picked up in the TO3 C5 filing last year.

Docket No. ER12- -

Section 2.1
San Diego Gas Electric Co.
TO3-Cycle 6 Annual Transmission Formulaic Filing
Amortization Schedule of TO3-Cycle 3 Interest True-Up Adjustment

Line No.	le Description	(a) Amounts	(p)	(0)	(p)	(e)	(t)	(g)	(h)
1 2	<u>s:</u> <sup>1</sup> p Adjustment	\$ 245,548							\$ 127,689
ω 4	Forecast Sales TO3-Cycle 4 (kWh) Estimated Amortization Rate Per kWh	20,392,502,467		•					8,441,385,517
ς.									
9									
7	Derivation of Forecast Sales: 1	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11
∞	Total Per TO3-Cycle 3 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	1,922,247	1,690,304	1,643,646	1,693,673	1,744,800	1,637,716	1,618,730	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	1,922,247,102	1,690,304,137	1,643,646,297	1,693,673,037	1,744,800,253	1,637,715,946	1,618,730,179	1,557,543,693
13									
14									
15	15 Amortization of TO3-Cycle 3 Interest True-Up Adjustment:	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11
16	16 Beginning Retail True-Up Adjustment Balance	\$ 245,548	\$ 227,006	\$ 209,576	\$ 193,543	\$ 176,917	\$ 159,424	\$ 143,659	\$ 127,689
17	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	1,439,554,405
31	18 Amortization Rate Per kWh	\$ 0.00001	\$ 0.00001	\$ 0.00001	\$ 0.00001	\$ 0.00001	\$ 0.00001	\$ 0.00001	\$ 0.00002
15	19 Amortization of TO3-Cycle 3 Interest True-Up Adjustment <sup>3</sup>	\$ 18,542	\$ 17,430	\$ 16,033	\$ 16,626	\$ 17,493	\$ 15,765	\$ 15,970	\$ 21,737
7	20 Ending TO3-Cycle 4 True-Up Adjusment Balance	\$ 227,006	\$ 209,576	\$ 193,543	\$ 176,917	\$ 159,424	\$ 143,659	\$ 127,689	\$ 105,952
21									

- 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.
  - amortization rate during the rate effective period.

    On lines 16 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.
- The monthly true-up adjustment amortization amount shown on line 19 from 9/1/2010 through 3/31/2011 was included in the cycle 5 true-up adjustment period. The monthly amortization amounts shown from April 2011 through August 2011 is included in the TO3 C6 instant filing.

Section 2.1

San Diego Gas Electric Co.

TO3-Cycle 6 Annual Transmission Formulaic Filing
Amortization Schedule of TO3-Cycle 3 Interest True-Up Adjustment

Description   Description   Description   Description   Description   Description   Description   Derivation of Amortization Rate Per kWh     Estimated Amortization Rate Per kWh     Derivation of Forecast Sales:	Line Reference No.	TO3-Cycle 4 Filing	Vol. 2-A; Section 2-1B; Pg.2; Line 20 2	See Line 12 Below 3	Line 2 / Line 3 4	5	9	7	True-Up Period; Statement BDWPs 8	Sale for Resale 9	Line 8 Minus Line 9	MWH Conversion Factor	Line 10 x Line 11 12	13	14	15	Beginning Balance 16	Recorded Sales 17	See Line 4 Above 18	Line 17 x Line 18 19	
Description   Description   Description   Description   Description   Description   Derivation of Amortization Rate Per kWh      Proceast Sales TO3-Cycle 3 Retail Interest True-Up Adjustment   Proceast Sales Net of Resale - MWH (Statement BD)   1,563,385   1,651,390   1,813,253     Derivation of Forecast Sales   May-11   Jun-11   Ju	(m)							Total	_		20,392,502	1,000	20,392,502,467			Total		19,651,221,316			
Description	(1)							Aug-11	1,855,819	2	1,855,818	1,000	1,855,817,817			Aug-11	\$ 33,473	1,625,857,955	\$ 0.00002		6
Description   Description	(K)							Jul-11	1,813,253	2	1,813,252	1,000				Jul-11	\$ 57,905	1,618,033,345	\$ 0.00002	24,432	CLV CC 9
Description  Derivation of Amortization Rates:  TO3-Cycle 3 Retail Interest True-Up Adjustment Forecast Sales TO3-Cycle 4 (kWh)  Estimated Amortization Rate Per kWh  Estimated Amortization of Forecast Sales:  Total Per TO3-Cycle 3 Filing - MWH  Conversion Pactor from MWH to kWh  Total Forecast Sales Net of Resale - MWH  Conversion Pactor from MWH to kWh  Total Forecast Sales Net of Resale - kWh  Amortization of TO3-Cycle 3 Interest True-Up Adjustment:  Beginning Retail True-Up Adjustment Balance  S 105,952  1,548,429,979  Amortization of TO3-Cycle 3 Interest True-Up Adjustment  S 0,00002  Amortization of TO3-Cycle 3 Interest True-Up Adjustment  S 23,381	(j)							Jun-11	1,651,390	2	1,651,389	1,000				Jun-11		1,633,497,061		24,666	2000
Description  Derivation of Amortization Rates: TO3-Cycle 3 Retail Interest True-Up Adjustment Forecast Sales TO3-Cycle 4 (kWh) Estimated Amortization Rate Per kWh  Estimated Amortization Rate Per kWh  Total Per TO3-Cycle 3 Filing - MWH (Statement BD)  Exclude Sale for Resale  Total Forecast Sales Net of Resale - MWH  Conversion Factor from MWH to kWh  Total Forecast Sales Net of Resale - kWh  Amortization of TO3-Cycle 3 Interest True-Up Adjustment: Beginning Retail True-Up Adjustment Balance Recorded Sales in Total kWh  Amortization Rate Per kWh  Amortization of TO3-Cycle 3 Interest True-Up Adjustment 3  Fording TO3 Cycle 4 True In Adjustment Balance	(i)							May-11	1,563,385	2	1,563,384	1,000	1,563,383,686			May-11	105,952	1,548,429,979	$\dashv$	-	00 571
Line No. 1. 1. 1. 1. 1. 2. 2. 2. 2. 2. 2. 2. 2. 2. 2. 2. 2. 2.		Derivation of Amortization Rates:	TO3-Cycle 3 Retail Interest True-Up Adjustment	Forecast Sales TO3-Cycle 4 (kWh)	Estimated Amortization Rate Per kWh			Derivation of Forecast Sales: 1	Total Per TO3-Cycle 3 Filing - MWH (Statement BD)	Exclude Sale for Resale	Total Forecast Sales Net of Resale - MWH	Conversion Factor from MWH to kWh	Total Forecast Sales Net of Resale - kWh			15 Amortization of TO3-Cycle 3 Interest True-Up Adjustment:	Beginning Retail True-Up Adjustment Balance	Recorded Sales in Total kWh	Amortization Rate Per kWh	Amortization of TO3-Cycle 3 Interest True-Up Adjustment 3	Friding TO3_Cycle 4 True_III A dimement Balance

- 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.
   On lines 16 through 20, SDG&E is taking the product between
  - On lines 16 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.
- The monthly true-up adjustment amortization amount shown on line 19 from 9/1/2010 through 3/31/2011 was included in the cycle 5 true-up adjustment period. The monthly amortization amounts shown from April 2011 through August 2011 is included in the TO3 C6 instant filing.

### Section 2.1 – Retail True-Up Adjustment

# Section (c): Amortization of Cycle 3 Interest True-Up Adjustment

Part (ii): Amortization of Cycle 3 Interest True-Up Adjustment Accrued After Fully Amortized (September 2011–March 2012)

- The amortization of the Cycle 3 Interest True-Up Adjustment Accrued after fully amortized in the instant Cycle 6 filing picks up the amounts amortized from September 2011 through March 2012.
- The remaining balance of the Cycle 3 fully amortized Interest True-Up Adjustment will be amortized from April 2012 through August 2012, and will be reflected in the Final TO3 true-up adjustment.

Docket No. ER12- -

San Diego Gas Electric Company
TO3-Cycle 6 Annual Transmission Formulaci Filing
Amortization of Interest True-Up Adjustment Applicable to TO3-Cycle 3

Sep-11		(a)	0	(q)	(0)	(p)	(e)	(t)	(g)	(h)
Sep-11	Description	Amo	unts							
Sep-11   Oct-11   Nov-11   Dec-11   Jan-12   Feb-12   Mar-1946,695   1,712,997   1,667,110   1,718,629   1,770,104   1,662,031   1,646,693,495   1,712,995,645   1,667,108,057   1,718,627,828   1,770,102,954   1,662,029,725   1,643,22   1,646,693,495   1,712,995,645   1,667,108,057   1,718,627,828   1,770,102,954   1,662,029,725   1,643,22   1,646,693,495   1,667,108,057   1,718,627,828   1,770,102,954   1,662,029,725   1,643,22   1,643,22   1,643,22   1,643,22   1,643,22   1,643,22   1,643,22   1,643,22   1,643,22   1,643,22   1,643,22   1,643,22   1,643,22   1,643,22   1,643,22   1,643,22   1,643,22   1,643,22   1,643,22   1,642,029,725   1,643,22	st True-Up Adjustment	89	29,894							
Sep-11	-Cycle 5 (kWh)	20,694,9	913,495							
Sep-11	ation Rate Per kWh	8	100000							
Sep-11   Oct-11   Nov-11   Dec-11   Jan-12   Feb-12   Mar-12   Mar-12   Mar-13   Mar-146,695   1,712,995   1,667,108   1,000										
Sep-11   Oct-11   Nov-11   Dec-11   Jan-12   Feb-12   Mar-12   J.946,695   J.712,997   J.667,110   J.718,629   J.770,104   J.662,031   J										
1,946,695	recast Sales:	Sep-	-11	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12
1,946,693	cle 5 Filing - MWH (Statement BD)		946,695	1,712,997	1,667,110	1,718,629	1,770,104	1,662,031	1,643,248	1,581,745
1,946,693   1,712,996   1,667,108   1,718,628   1,770,103   1,662,030   1,643,24   1,946,693,495   1,712,995,645   1,667,108,057   1,718,627,828   1,770,102,954   1,662,029,725   1,643,24   1,946,693,495   1,712,995,645   1,667,108,057   1,718,627,828   1,770,102,954   1,662,029,725   1,643,24	tesale		2	2	2	2	2	2	2	2
1,946,693,495	es Net of Resale - MWH	1,9	946,693	1,712,996	1,667,108	1,718,628	1,770,103	1,662,030	1,643,246	1,581,743
1,946,693,495	from MWH to kWh		1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
Sep-11   Oct-11   Nov-11   Dec-11   Jan-12   Feb-12   Mar-   Mar-   Sep-11   Oct-11   Nov-11   Dec-11   Jan-12   Feb-12   Mar-   Mar-   Sep-12   Sep-13	ss Net of Resale - kWh	1,946,6	693,495	1,712,995,645	1,667,108,057	1,718,627,828	1,770,102,954	1,662,029,725	1,643,246,433	1,581,743,038
Sep-11   Oct-11   Nov-11   Dec-11   Jan-12   Feb-12   Mar-12   Mar-12   Sep-11   Oct-11   Sep-12   Mar-12   Sep-12   Mar-13   Sep-13   S										
Sep-11   Oct-11   Nov-11   Dec-11   Jan-12   Feb-12   Mar-   Mar-   Sep-11   Jan-12   Sep-12   Mar-   Sep-11   Sep-12   Mar-   Sep-12   Sep-12   Mar-   Sep-13   Se										
29,894         \$         27,289         \$         25,005         \$         22,816         \$         20,477         \$         18,185         \$           1,860,708,394         1,631,381,518         1,563,419,204         1,670,852,042         1,636,910,207         1,516,622,552         1,687,75           0.000001         \$         0.000001         \$         0.000001         \$         0.000001         \$         0.000001           \$         2,605         \$         2,284         \$         2,189         \$         2,339         \$         2,292         \$         2,123         \$           27,289         \$         22,816         \$         20,477         \$         18,185         \$         16,062         \$	03-Cycle 3 Interest True-Up Adjus		-11	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12
1,860,708,394 1,631,381,518 1,563,419,204 1,670,852,042 1,636,910,207 1,516,622,552 1,687,75 s 0.000001 \$ 0.00	t True-Up Adjustment Balance	€9	29,894						\$ 16,062	
\$ 0.000001 \$ 0.000001 \$ 0.000001 \$ 0.000001 \$ 0.000001 \$ 0.000001 \$ 0.000001 \$ 0.000001 \$ 0.000001 \$ 0.000001 \$ 0.000001 \$ 0.00000001 \$ 0.0000001 \$ 0.0000001 \$ 0.0000001 \$ 0.0000001 \$ 0.0000001 \$ 0.0000001 \$ 0.0000001 \$ 0.0000001 \$ 0.0000001 \$ 0.0000001 \$ 0.0000001 \$ 0.0000001 \$ 0.0000001 \$ 0.0000001 \$ 0.0000001 \$ 0.0000001 \$ 0.0000001 \$ 0.0000001 \$ 0.000001 \$ 0.0000001 \$ 0.0000001 \$ 0.0000001 \$ 0.0000001 \$ 0.000001 \$ 0.000001 \$ 0.000001 \$ 0.0000001 \$ 0.00000	Total kWh	1,860,7	708,394	1,631,381,518	1,563,419,204	1,670,852,042	1,636,910,207	1,516,622,552	1,687,796,399	ı
s 2,605 \$ 2,284 \$ 2,189 \$ 2,339 \$ 2,292 \$ 2,123 \$ \$ 2,205 \$ 2,205 \$ 2,2,305 \$ 2,2,315 \$ 20,477 \$ 18,185 \$ 16,062 \$ 1	e Per kWh		.000001	\$ 0.000001					\$ 0.000001	- 8
\$ 27,289 \$ 25,005 \$ 22,816 \$ 20,477 \$ 18,185 \$ 16,062 \$ 1	'03-C4 Interest True-Up Adjustmen		2,605	1					\$ 2,363	59
	e 4 True-Up Adjusment Balance	\$	_	25,005	22,816				\$ 13,699	- \$

- 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.
  - 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 interest true-up adjustment over the rate effective September 2011 through March 2012.
    - The monthly true-up adjustment amortization amount shown on line 19 has been calculated through 3/31/2012, which is the end of the cycle 4 true-up adjustment period. Future monthly amortization amounts have not been shown since the amounts will be shown in the instant Final TO3 filing.

# Section 2.1 San Diego Gas Electric Company TO3-Cycle 6 Annual Transmission Formulaci Filing Amortization of Interest True-Up Adjustment Applicable to TO3-Cycle 3

Jun-12 1,677,623 2 1,677,622 1,000 1,000 1,677,621,946
May-12 Jun-12  1,587,961 1,677,623  2 2  1,587,959 1,677,623  1,000 1,000  1,587,959,374 1,677,621,946    May-12 Jun-12   \$    May-12 Jun-12   \$    \$ - \$ - \$    \$ -

### NOTES:

- 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.
  - 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 interest true-up adjustment over
- the rate effective September 2011 through March 2012.

  The monthly true-up adjustment amortization amount shown on line 19 has been calculated through 3/31/2012, which is the end of the cycle 4 true-up adjustment period. Future monthly amortization amounts have not been shown since the amounts will be shown in the instant Final TO3 filing.

### Section 2.1 – Retail True-Up Adjustment

### Section (d): Amortization of TO3 Cycle 2 Interest True-Up Adjustment

### Part (i): Amortization of Cycle 2 Interest True-Up Adjustment (April 2011–August 2011)

- The amortization of the Cycle 2 Interest True-Up Adjustment in the instant Cycle 6 filing picks up the amounts amortized from April 2011 through August 2011.
- The amortization of the Cycle 2 Interest True-Up Adjustment from September 2010 through March 2011 was picked up in the TO3 C5 filing last year.

Docket No. ER12-\_\_-

# Section 2.1 San Diego Gas Electric Co. TO3-Cycle 6 Annual Transmission Formulaic Filing Amortization Schedule of TO3-Cycle 2 Interest True-Up Adjustment

Line		(a)	(p)	(0)	(p)	(e)	(J)	(g)	(h)
g -	Т	Amounts							
<b>→</b> (	Derivation of Amortization Kates:								
7	103-Cycle 2 Retail Interest True-Up Adjustment	\$ 30,210							\$ 18,425
m	Forecast Sales TO3-Cycle 4 (kWh)	20,392,502,467							8,441,385,517
4	Estimated Amortization Rate Per kWh	\$ 0.000001							\$ 0.000002
5									
9									
7	Derivation of Forecast Sales:	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11
∞	Total Per TO3-Cycle 2 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
6	Exclude Sale for Resale	2	2	2	2	2	2	2	. 7
10	Total Forecast Sales Net of Resale - MWH	1,922,247	1,690,304	1,643,646	1,693,673	1,744,800	1,637,716	1,618,730	1,557,544
=		1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
12	Total Forecast Sales Net of Resale - kWh	1,922,247,102	1,690,304,137	1,643,646,297	1,693,673,037	1,744,800,253	1,637,715,946	1,618,730,179	1,557,543,693
13									
14									
15	Amortization of TO3-Cycle 2 Interest True-Up Adjustment:	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11
16		\$ 30,210	\$ 28,356	\$ 26,613	\$ 25,010	\$ 23,347	\$ 21,598	\$ 20,022	\$ 18,425
17		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	1,439,554,405
18	Amortization Rate Per kWh	\$ 0.000001	\$ 0.000001	\$ 0.000001	\$ 0.000001	\$ 0.000001	\$ 0.000001	\$ 0.000001	\$ 0.000002
16	Amortization of TO3-Cycle 2 Interest True-Up Adjustment 3	\$ 1,854	\$ 1,743	\$ 1,603	\$ 1,663	\$ 1,749	\$ 1,576	\$ 1,597	\$ 3,167
50	Ending TO3-Cycle 2 True-Up Adjustment Balance	\$ 28,356	\$ 26,613	\$ 25,010	\$ 23,347	\$ 21,598	\$ 20,022	\$ 18,425	\$ 15,258
21									

### NOTES:

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.

amortization rate during the rate effective period.

On lines 16 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.

The monthly true-up adjustment amortization amount shown on line 19 from 9/1/2010 through 3/31/2011 was included in the cycle 5 true-up adjustment period. The monthly amortization amounts shown from April through August 2011 is included in the TO3 C6 instant filing.

# Section 2.1 San Diego Gas Electric Co. TO3-Cycle 6 Annual Transmission Formulaic Filing Amortization Schedule of TO3-Cycle 2 Interest True-Up Adjustment

Line No.		20 2	m	4	5	9	7		6	10	11	12	13	14	15	16	17	18	19	20	
Reference	TO3-Cycle 4 Filing	Vol. 2-A; Section 2-1B; Part 2-A; Pg.2; Line 20	See Line 12 Below	Line 2 / Line 3				True-Up Period; Statement BDWPs	Sale for Resale	Line 8 Minus Line 9	MWH Conversion Factor	Line 10 x Line 11				Beginning Balance	Recorded Sales	See Line 4 Above	Line 17 x Line 18	Line 16 Minus Line 19	
(m)							Total	20,392,521	19	20,392,502	1,000	20,392,502,467			Total		19,651,221,316		\$ 30,210		
(1)							Aug-11	1,855,819	2	1,855,818	1,000	1,855,817,817			Aug-11	\$ 4,697	1,625,857,955	\$ 0.000002	\$ 4,697	- \$	
(x)							Jul-11	1,813,253	2	1,813,252	1,000	1,813,251,582			Jul-11	\$ 8,257	1,618,033,345	\$ 0.000002	\$ 3,560	\$ 4,697	
(j)					;		Jun-11	1,651,390	2	1,651,389	1,000	1,651,388,739			Jun-11	\$ 11,851	1,633,497,061	\$ 0.000002	\$ 3,594	\$ 8,257	
(I)							May-11	1,563,385	2	1,563,384	1,000	1,563,383,686			May-11	\$ 15,258	1,548,429,979	\$ 0.000002	\$ 3,407	\$ 11,851	
Description	Derivation of Amortization Rates:	TO3-Cycle 2 Retail Interest True-Up Adjustment	Forecast Sales TO3-Cycle 4 (kWh)	Estimated Amortization Rate Per kWh			Derivation of Forecast Sales:	Total Per TO3-Cycle 2 Filing - MWH (Statement BD)	Exclude Sale for Resale	Total Forecast Sales Net of Resale - MWH	Conversion Factor from MWH to kWh	Total Forecast Sales Net of Resale - kWh			Amortization of TO3-Cycle 2 Interest True-Up Adjustment:	Beginning Retail True-Up Adjustment Balance	Recorded Sales in Total kWh	Amortization Rate Per kWh	Amortization of TO3-Cycle 2 Interest True-Up Adjustment 3	Ending TO3-Cycle 2 True-Up Adjustment Balance	
	Deri	Ţ	F0	贸		L	$\Box$	₽	Щ	Н	$^{\circ}$	Ĕ	_ !		⋖	ф	24	⋖	⋖	闰	_

### NOTES:

- 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.
  - <sup>2</sup> On lines 16 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.
- The monthly true-up adjustment amortization amount shown on line 19 from 9/1/2010 through 3/31/2011 was included in the cycle 5 true-up adjustment period. The monthly amortization amounts shown from April through August 2011 is included in the TO3 C6 instant filing.

### Section 2.1 – Retail True-Up Adjustment

### Section (e): Amortization of TO2 Final Interest True-Up Adjustment Accrued After Fully Amortized (April 2011 – August 2011)

### Part (i): Amortization of TO2 Final Interest True-Up Adjustment (April 2011 – August 2011)

- The amortization of the Final TO2 Interest True-Up Adjustment accrued after fully amortized in the instant Cycle 6 filing picks up the amounts amortized from April 2011 through August 2011.
- The amortization of the Final TO 2 Interest True-Up Adjustment from September 2010 through March 2011 was picked up in the TO3 C5 filing last year.

Docket No. ER12- -

### Section 2.1 San Diego Gas Electric Co. TO3-Cycle 6 Annual Transmission Formulaic Filing Amortization Schedule of TO2 Final Interest True-Up Adjustment

Line No.	Description	(a) Amounts	(q)	(0)	(p)	(9)	(t)	(g)	(h)
	Derivation of Amortization Rates:	027 761						i	
4 W	Forecast Sales TO3-Cycle 4 (kWh)	20.392.502.467							\$ 25,901
4	Estimated Amortization Rate Per kWh	\$ 0.00001						'	0.000003
5									
9									
7	Derivation of Forecast Sales: 1	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11
∞	Total Per TO2 Final 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	1,922,247	1,690,304	1,643,646	1,693,673	1,744,800	1,637,716	1,618,730	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	1,922,247,102	1,690,304,137	1,643,646,297	1,693,673,037	1,744,800,253	1,637,715,946	1,618,730,179	1,557,543,693
13									
14									
15	Amortization of TO2 Final Interest True-Up Adjustment: 2	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11
16		\$ 143,760	\$ 125,218	\$ 107,788	\$ 91,755	\$ 75,129	\$ 57,636	\$ 41,871	\$ 25,901
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	1,439,554,405
18	Amortization Rate Per kWh	\$ 0.00001	\$ 0.00001	\$ 0.00001	\$ 0.00001	\$ 0.00001	\$ 0.00001	\$ 0.00001	\$ 0.000003
19	19 Amortization of TO2 Final Interest True-Up Adjustment 3	\$ 18,542	\$ 17,430	\$ 16,033	\$ 16,626	\$ 17,493	\$ 15,765	\$ 15,970	\$ 4,741
70	20 Ending TO2 Final Interest True-Up Adjustment Balance	\$ 125,218	\$ 107,788	\$ 91,755	\$ 75,129	\$ 57,636	\$ 41,871	\$ 25,901	\$ 21,160
21									

### NOTES

- 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.
  - On lines 16 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.
- The monthly true-up adjustment amortization amount shown on line 19 from 9/1/2010 through 3/31/2011 was included in the cycle 5 true-up adjustment period. The monthly amortization amounts shown from April 2011 thorugh August 2011 is included in the TO3 C6 instant filing.

Section 2.1

San Diego Gas Electric Co.

TO3-Cycle 6 Annual Transmission Formulaic Filing
Amortization Schedule of TO2 Final Interest True-Up Adjustment

### NOTES

- 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.
  - amortization rate during the rate effective period.

    On lines 16 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.
- The monthly true-up adjustment amortization amount shown on line 19 from 9/1/2010 through 3/31/2011 was included in the cycle 5 true-up adjustment period. The monthly amortization amounts shown from April 2011 thorugh August 2011 is included in the TO3 C6 instant filing.

### Section -2

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

### Section 2.1B

Summary of Retail Interest True-Up Adjustment

Docket No. ER12- -

### San Diego Gas & Electric Company

### **PART 1.A**

TO3-Cycle 5 Interest True-Up

Adjustment Calculation

Docket No. ER12-\_\_\_-

### Derivation of Interest True-Up Adjustment Applicable to TO3-Cycle 5 San Diego Gas and Electric Company TO3-Cycle 6 Annual Transmission Formulaic Rate Filing Section 2.1B-Part 1.A

Line No.	ne Description	(a) Apr-11	(b) May-11	(c) Jun-11	(d) Jul-11	(e) Aug-11	(f) Sep-11	(g) Oct-11	(h) Nov-11
	Beginning Balance (Overcollection)/Undercollection TO3-C5	\$ 32,144,533	\$ 32,231,323	\$ 32,321,328	\$ 32,408,118	\$ 32,495,620	\$ 32,586,363	\$ 29,655,448	\$ 27.091.945
7				,		ł	ı	1	1
2	Part Al: Amortization of TU Balance:						100,000,000	1 (21 201 510	
^		1	ı	•	•	1	1,860,/08,394	810,186,160,1	1,563,419,204
· ∞ ·	Rate Per KWH	. 69	-		·	-	\$ 0.00162	\$ 0.00162	\$ 0.00162
6 0	Amortization of True-Up Balance	-	-	· •	- -	- 69	\$ 3,014,348	\$ 2,642,838	\$ 2,532,739
11 12	1   Net Monthly Collection/(Refunds)		· ·	·	ا ج	· 69	\$ (3,014,348)	\$ (2,642,838)	\$ (2,532,739)
E	3   Part A2: Calculation of Interest on Remaining TII Balance:								
15									
16		\$ 32,144,533	\$ 32,144,533	\$ 32,144,533	\$ 32,408,118	\$ 32,408,118	\$ 32,408,118	\$ 29,655,448	\$ 29,655,448
17	7 Monthly Activity Included in Interest Calculation Basis <sup>2</sup>	0	0	0	0	0	(1,507,174)	(1,321,419)	(3,909,208)
18		32,144,533	32,144,533	32,144,533	32,408,118	32,408,118	30,900,944	28,334,029	25,746,241
19	2	0.27%	0.28%	0.27%	0.27%	0.28%	0.27%	.0.28%	0.27%
20	Interest Expense	\$ 86,790	\$ 90,005	86,790	\$ 87,502	\$ 90,743	\$ 83,433	\$ 79,335	\$ 69,515
21 22	1   Ending Balance (Overcollection)/Undercollection	\$ 32,231,323	\$ 32,321,328	\$ 32.408.118	\$ 32,495,620	\$ 32.586.363	\$ 29 655 448	\$ 27 091 945	\$ 24 628 721
23		Apr-11	May-11	Jun-11	Jul-11	Aug-11		ı	
24	_		3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%
25		365	365	365	365	365	365	365	365
78		30	31	30	31	31	30	31	30
27		0.27%	0.28%	0.27%	0.28%	0.28%	0.27%	0.28%	0.27%
78		0.27%	0.28%	0.27%	0.27%	0.28%	0.27%	0.28%	0.27%
29	) Difference	%00.0	0.00%	0.00%	%10.0	%00.0	0.00%	%00'0	0,00%

Month Quarter as Interest is Compounded Quarterly on these amounts pursuant to FERC Interest Methodology - per 18 CFR Section 35.19 Beginning Balance for Interest Calculation Remains Constant for 3 (2) (iii) (B)

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 +

<sup>(</sup>Column C, Line 12 Divided by 2). Column D, E, F, etc. repeats the process outlined in (a), (b), and (c) above.

# Section 2.1B-Part 1.A San Diego Gas and Electric Company TO3-Cycle 6 Annual Transmission Formulaic Rate Filing Derivation of Interest True-Up Adjustment Applicable to TO3-Cycle 5

Line No.	Description	(i) Dec-11	(j) Jan-12	(k) Feb-12	(1) Mar-12	(m) Total	Reference	Line No.
1	Beginning Balance (Overcollection)/Undercollection TO3-C5	\$ 24,628,721	\$ 21,986,695	\$ 19,392,750	\$ 16,982,898	\$ 32,144,533	Previous Month's Ending Balance (Line 22)	
2 2	Part A1: Amortization of TU Balance:							2 %
9 /	Total Recorded Sales KWHs	1,670,852,042	1,636,910,207	1,516,622,552	1,687,796,399	11,567,690,316	Section 2.3.2; Pgs 71-72; Line 15; Col (F)-(L)	9 1
~ ∞ o	Rate Per KWH	\$ 0.00162	\$ 0.00162	\$ 0.00162	\$ 0.00162		Section 2.1B; Page 32; Col.M; Line 10	~ <b>«</b>
10 :	Amortization of True-Up Balance	\$ 2,706,780	\$ 2,651,795	\$ 2,456,929	\$ 2,734,230	\$ 18,739,659	Line 6 x Line 8	و 5
12 1	Net Monthly Collection/(Refunds)	\$ (2,706,780)	\$ (2,651,795)	\$ (2,456,929)	\$ (2,734,230)	\$ (18,739,659)	Minus Line 10 (Columns a to 1)	11 12
Ω <u>4</u>	Part A2: Calculation of Interest on Remaining TU Balance:							13
15	Interest Expense Calculations: 1  Reginning Balance for Interest Calculation	\$ 20.655.448	\$ 21 086 605	31 082 405	31 005 505			15
17	Monthly Activity Included in Interest Calculation Basis <sup>2</sup>					-	Datatice at Degittining of Quarter (See Foothote 1)  See Foothote 2	0 1
38		23,126,481	20,660,798	18,106,436	15,510,856		Line 16 + Line 17	18
19	Monthly Interest Rate	0.28%	0.28%	0.26%	0.28%		FERC Monthly Rates	19
70	Interest Expense	\$ 64,754	\$ 57,850	\$ 47,077	\$ 43,430	\$ 887,224	Line 18 x Line 19 (Columns a to 1)	70
21	Ending Balance (Overcollection)/Undercollection	\$ 21,986,695	\$ 19,392,750	\$ 16,982,898	\$ 14,292,098	\$ 14,292,098	Line 1 + Line 12 + Line 20	12 23
23		Dec-11	Jan-12	Feb-12	Mar-12			23
24		3.25%	3.25%	3.25%	3.25%		Annual Interest Rate - FERC Website	24
22		365	365	398	365	365	Number of Days Per Year	25
76	_	31	31		31	396	Number of Days Per Month	56
27		0.28%	0.28%		0.28%	3.30%	(Line 24)/(Line 25)x(Line 26)	27
78		0.28%	0.28%	0.26%	0.28%	3.29%	Monthly Interest Rate - FERC Website	28
77	Unterence	0.00%	0.00%	0.00%	0.00%	0.01%	Line 27 - Line 28	59

### NOTES:

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)

### <sup>2</sup> 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.

### San Diego Gas & Electric Company

### **PART 1.B**

TO3-Cycle 5 Interest True-Up

Adjustment Amortization Rate

Calculation

Docket No. ER12-\_\_-

### Section 2.1B (Part B) San Diego Gas Electric Company TO3 Cycle 6 Annual Transmission Formula Filing Derivation of Amortization Rate for TO3 Cycle 5

Line	ə	(a)	(q)	(၁)	(p)	(e)	<b>(</b> £)	(g)	(h)
ģ	. Description	Sep-11	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12
	Derivation of Amortization Rate for TO3-Cycle 5:			-					
7	2 Beginning Balance (Overcollection)/Undercollection								
<u>~</u>									
4	4 Recorded Sales Sept 11 - March 12:	1,860,708,394	1,631,381,518	708,394   1,631,381,518   1,563,419,204   1,670,852,042	1,670,852,042	1,636,910,207	1,516,622,552   1,687,796,399	1,687,796,399	
S									
9	6 Estimated Sales April 12 - Aug 12:		-						1,581,743,038
7	-								
∞	Forecast Sales TO3-Cycle 5 (kWh)								
6									
10	10 Estimated Amortization Rate Per kWh								
Ξ									

### Page 2 of 2

Section 2.1B (Part B)
San Diego Gas Electric Company
TO3 Cycle 6 Annual Transmission Formula Filing
Derivation of Amortization Rate for TO3 Cycle 5

ine		Θ	9	(k)	(1)	(m)		Line
No.	Description	May-12	Jun-12	Jul-12	Aug-12	Total	Reference	Š.
	Derivation of Amortization Rate for TO3-Cycle 5:						From TO3-Cycle 5 Filing	_
7	2 Beginning Balance (Overcollection)/Undercollection					\$ 32,586,363	\$ 32,586,363 Vol. 2 of 3; Section 2.1B; Pg. 1; Line 1; Col. f	7
m								т
4	Recorded Sales Sept 11 - March 12:					11,567,690,316	11,567,690,316 TO3-Cycle 6; Sect. 2.3.2; Pages 2&3; Line 15	4
S								S
9	6 Estimated Sales April 12 - Aug 12:	1,587,959,374	1,587,959,374   1,677,621,946   1,841,936,291	1,841,936,291	1,884,848,709	1,884,848,709 8,574,109,359	TO3-Cycle 6; Statement BD; Page 1	9
_								7
00	Forecast Sales TO3-Cycle 5 (kWh)					20,141,799,675	Sum Lines 4 & 6	∞
6								6
10	10 Estimated Amortization Rate Per kWh					\$ 0.00162	Line 2 / Line 8	10
11								Ξ

### San Diego Gas & Electric Company

### Part 2.A

TO3-Cyle 4 Interest True-Up Adjustment Calculation

Docket No. ER12-\_\_\_-

### San Diego Gas and Electric Company TO3-Cycle 6 Annual Transmission Formulaic Rate Filing Derivation of Interest True-Up Adjustment Applicable to TO3-Cycle 4

Remaining Undercollection Bala  Interest True-Up Adjustment to  Part Al: Amortization of TU Bal  Total Recorded Sales KWHs  Total Recorded Sales KWHs  Amortization of True-Up Balance  Il Amortization of True-Up Balance  Il Net Monthly Collection/(Refunds)  Bart A2: Calculation of Interest  Monthly Activity Included in Ib  Basis for Interest Expense Calculations:  Monthly Activity Included in Ib  Basis for Interest Expense Calculations:  Monthly Interest Rate  Interest Expense  Interest Expense  Ending Balance (Overcollection)/U	Remaining Undercollection Balance from TO3-Cycle 4 Used to Derive the Interest True-Up Adjustment to Include in TO3-Cycle 6 Filing     Part A1: Amortization of TU Balance:     Total Recorded Sales KWHs     Rate Per KWH as reflected in TO3 Cycle 4 filing (see reference)     Amortization of True-Up Balance     Net Monthly Collection/(Refunds)     Net Monthly Collection/(Refunds)     Apart A2: Calculation of Interest on Remaining TII Ralance     Apart A3: Calculation of Interest on Remaining TII Ralance	\$ 13,						3	5		
	p Adjustment to Include in TO3-Cycle 6 Filing ization of TU Balance: Sales KWHs s reflected in TO3 Cycle 4 filing (see reference) True-Up Balance llection/(Refunds)	\$ 13,					day day	<u>-</u>			TLACK
	ization of TU Balance: Sales KWHs s reflected in TO3 Cycle 4 filing (see reference) True-Up Balance llection/(Refunds)	1,439,	13,878,027	\$ 11,623,516	\$ 9,190,515	\$ 6,614,392	\$ 4,056,105	- 8	€9		· •
	ization of TU Balance: Sales KWHs Sales KWHs True-Up Balance Ilection/(Refunds)	1,439,									
	Sales KWHs s reflected in TO3 Cycle 4 filing (see reference) True-Up Balance llection/(Refunds)	1,439,									
	s reflected in TO3 Cycle 4 filing (see reference)  True-Up Balance  lection/(Refunds)		1,439,554,405	1,548,429,979	1,633,497,061	1,618,033,345	1,625,857,955			•	•
	S renected in 103 Cycle 4 filing (see reference)  True-Up Balance  lection/(Refunds)										,
10   Amortization of Ti   11   12   Net Monthly Colle   13   Part A2: Calcular   14   Part A2: Calcular   15   Interest Expense C   Beginning Ball   17   Monthly Activ   18   Basis for Interest Expe   19   Monthly Interest Expe   20   Interest Expe   21   Ending Balance (C   22   Ending Balance (C   23   Monthly Interest Expe   24   Monthly Interest Expe   25   Ending Balance (C   27   Monthly Interest Expe   27   Ending Balance (C   27   Monthly Interest Expe   27   Monthl	True-Up Balance lection/(Refunds)	æ	65100.0	\$ 0.00159	\$ 0.00159	\$ 0.00159	\$ 0.00159	·	÷		9
11   Net Monthly Colle     13	llection/(Refunds) often of Interest on Bemaining III Balance	\$ 2,	2,288,892	\$ 2,462,004	\$ 2,597,260	\$ 2,572,673	\$ 4,061,735	\$	8	ı	S
13 14 Part A2: Calcular 15 Interest Expense C 16 Beginning Balt 17 Monthly Activ 18 Basis for Interest 20 Interest Expe 21 22 Ending Balance (C 23	otion of Interest on Remaining TII Releases	& C)	(2.288.892)	\$ (2,462,004)	\$ (2.597.260)	\$ (2.572.673)	\$ (4.061.735)	٠ جو	64	ı	64
14 Part A2: Calcular 15 Interest Expense C 16 Beginning Bal 17 Monthly Activ 18 Basis for Interest Expe 20 Interest Expe 21 Ending Balance (C 22	stion of Interest on Remaining TII Ralance:		1_	1				_	$\frac{1}{1}$	ĺ	
En En	ation of anterest on technical to parameter					-					
End	Calculations: 1										
End	Beginning Balance for Interest Calculation	\$ 13,	13,878,027	\$ 13,878,027	\$ 13,878,027	\$ 6,614,392	\$ 6,614,392	€9	69	,	6
	Monthly Activity Included in Interest Calculation Basis 2	(1)	(1,144,446)	(3,519,894)	(6,049,526)	(1,286,337)	(4,603,541	~	0	0	0
	Basis for Interest Expense Calculation	12,	12,733,581	10,358,133	7,828,501	5,328,056	2,010,852		0	0	0
	rest Rate		0.27%	0.28%	0.27%	0.27%	0.28%		0.27%	0.28%	0.27%
	pense	s	34,381	\$ 29,003	\$ 21,137	\$ 14,386	\$ 5,630	- 8	59		-
23 mms Darance (2	Ending Belonce (Ocervallection)[Indercallection	-	11 603 516	0 100 515	6 6611300	3 4 054 105	6	ç	6		6
24 000000000000000000000000000000000000		ı	21		ľ	Γ			9		,
		AP.	Apr-11	May-11	-unc	T-mc	Aug-11	Sep-		Oct-11	Nov-11
24 FERCINIERESI KAIE	IT RATE		3.25%	3.25%	 	 	3.25%		3.25%	3.25%	3.25%
25 Days in Year			365	365		m	365		365	365	365
26 Days in Month			30	31	30	31	31		30	31	30
27 Monthly Interest R	Rate - Calculated		0.27%	0.28%	0.27%	0.27%	0.28%		0.27%	0.28%	0.27%
28 FERC Interest Rates - Website	ates - Website		0.27%	0.28%	0.27%	0.27%	0.28%		0.27%	0.28%	0.27%
29 Difference			0.00%	0.00%	0.00%	0.00%	0.00%		%00.0	0.00%	0.00%

<u>NOTES:</u>
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)

### <sup>2</sup> 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.

### San Diego Gas and Electric Company TO3-Cycle 6 Annual Transmission Formulaic Rate Filing Derivation of Interest True-Up Adjustment Applicable to TO3-Cycle 4

Tine			(9)		(E	3	ŀ	€	H	(E)		T in
Š	Description	ñ	Dec-11	Jar	Jan-12	(m) Feb-12		Mar-12		(m.) Total	Reference	No.
1	Remaining Undercollection Balance from TO3-Cycle 4 Used to Derive the Interest True-Up Adjustment to Include in TO3-Cycle 6 Filing	\$	-	S	-	69	€9	1	69	13,878,027	Previous Month's Ending Balance (Line 22)	1
7									$\vdash$			2
S	Part A1: Amortization of TU Balance:											S
9 1	Total Recorded Sales KWHs	-	•		'	ı		į		7,865,372,745	Section 2.3.2; Page 71; Line 15; Col (A)-(E)	91
<b>~</b> «	Rate Per KWH as reflected in TO3 Cycle 4 filing (see reference)	69	ı	8	'	649	€>	'			Section 2.1B; Page 38; Col.M; Line 10	~ «
6												6
20	10 Amortization of True-Up Balance	€9		S	•	· &S	બ	•	8	13,982,564	Line 6 x Line 8	10
11	Net Monthly Collection/(Refunds)	69	•	69	1	· 69	69	ı	69	(13,982,564)	Minus Line 10 (Columns a to 1)	11
13									_			13
14	14 Part A2: Calculation of Interest on Remaining TU Balance:											14
15	15 Interest Expense Calculations: 1											15
16	Beginning Balance for Interest Calculation	€9	•	es.	•	•	69	•			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			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	S	•	\$	-	·	8	•	S	104,537	Line 18 x Line 19 (Columns A to L)	20
21												21
22	Ending Balance (Overcollection)/Undercollection	s,	•	S	,	-	\$	•	8	•	Line 1 + Line 12 + Line 20	22
23		Å	Dec-11	Jar	Jam-12	Feb-12		Mar-12	7			23
24	FERC INTEREST RATE		3.25%		3.25%	3.25%	%	3.25%	%		Annual Interest Rate - FERC Website	24
22	Days in Year		365		365	<b>κ</b>	365	m	365	365	Number of Days Per Year	25
26	Days in Month		31		31		53		31	366		56
27	27 Monthly Interest Rate - Calculated		0.28%		0.28%	0.26%	%	0.28%	%	3.29%	(Line 24)/(Line 25)x(Line 26)	27
78	FERC Interest Rates - Website		0.28%		0.28%	0.26%	%	0.28%	%	3.29%	Monthly Interest Rate - FERC Website	28
3	Difference		0.00%		0.00%	0.00%	<u>~</u>	0.00%	%	0.00%		29
							l		l			

<sup>1</sup> 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)

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),

### San Diego Gas & Electric Company

### Part 2.B

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

Docket No. ER12-\_\_\_-

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 4

	(a)	( <b>9</b> )	(3)	(þ)	(e)	(£)	(g)	(h)
Description	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11
Derivation of Amortization Rate for TO3-Cycle 4: Beginning Balance (Overcollection)/Undercollection								
Recorded Sales Sept 10 - March 11:	1,854,217,871	1,743,019,823	1,743,019,823 1,603,275,846	1,662,588,802	1,749,322,152	1,576,452,657	1,596,971,420	
Estimated Sales April 11 - Aug 11:								1,557,543,693
Forecast Sales TO3-Cycle 4 (kWh)								
Estimated Amortization Rate Per kWh								

Page 2 of 2

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 4

Line		Θ	€	(k)	(1)	(m)		Line
ģ	Description	May-11	Jun-11	Jul-11	Aug-11	Total	Reference	s. Š
_	1 Derivation of Amortization Rate for TO3-Cycle 4:						From TO3-Cycle 5 Filing	-
7	2 Beginning Balance (Overcollection)/Undercollection	-				\$ 32,182,851	\$ 32,182,851 Vol. 2 of 3; Section 2.1B; Pg. 1; Line 22; Col. e	7
٣								m
4	Recorded Sales Sept 10 - March 11:					11,785,848,571	TO3-Cycle 5; Sect. 2.3.2; Pages 2&3; Line 15	4
S				-				5
9	6 Estimated Sales April 11 - Aug 11:	1,563,383,686		1,651,388,739   1,813,251,582   1,855,817,817	1,855,817,817	8,441,385,517	TO3-Cycle 4; Statement BD; Page 1	9
7		•						7
∞	8 Forecast Sales TO3-Cycle 4 (kWh)					20,227,234,088	Sum Lines 4 & 6	∞
6								6
10	10 Estimated Amortization Rate Per kWh					\$ 0.00159	Line 2 / Line 8	10
11								11

### Section - 2

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

### Section 2.2

Summary of Monthly Retail True-Up Recorded Revenues

Docket No. ER12-\_\_-

Page - 1

Section 2.2
SAN DIEGO GAS AND ELECTRIC COMPANY
Monthly Retail True-Up Period Recorded Revenues
12-Month Period (April 1, 2011 - March 31, 2012)

\* Medium & Large C&I customer revenue adjustment related to Camp Stewart (U.S. Marine Corps).

### Section -2

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

### Section 2.3 Derivation of Retail True-Up Cost of Service

Docket No. ER12-\_\_\_-

### Section 2.3 San Diego Gas & Electric Company Statement BK-1

Line					Line
No.			Amounts	Reference	No.
1 2	Transmission Operation & Maintenance Expense	\$	46,940	Statement AH; Page 5, Line 10	1 2
3 4	Transmission Related A&G Expenses		62,381	Statement AH; Page 5, Line 54	3 4
5	CPUC Intervener Funding Expense			Statement AH; Page 5, Line 9	5
7 8	Total O&M Expenses	\$	109,321	Sum Lines 1; 3; and 5	7 8
9 10	Transmission, Intangible, General and Common Depr. & Amort. Expense		54,449	Statement AJ; Page 7, Line 17	9 10
11 12	Valley Rainbow Project Cost Amortization Expense		1,893	Statement AJ; Page 7, Line 19	11 12
13 14	Transmission Related Property Taxes Expense		11,319	Statement AK; Page 8, Line 29	13 14
15 16	Transmission Related Payroll Taxes Expense	·	2,007	Statement AK; Page 8, Line 36	15 16
17 18	Subtotal Expense	\$	178,989	Sum Lines 7 thru 15	17 18
19 20	Cost of Capital Rate (AFCR CP)	_	11.7852%	Statement AV; Page 14, Line 35	19 20
21 22	Transmission Rate Base	_\$	1,208,944	Statement BK-1; Pg 2, Line 20	21 22
23 24 25 26	Return and Associated Income Taxes South Georgia Income Tax Adjustment Transmission Related Amortization of ITC Transmission Related Amort of Excess Deferred Tax Liability	\$	142,476 2,333 (265)	(Line 19 x Line 21) Statement AQ; Page 10, Line 1 Statement AR; Page 11, Line 5 Statement AR; Page 11, Line 3	23 24 25 26
27 28 29	Transmission Related Revenue Credits  End of Prior Veer Pevenue (PVPP)	<u> </u>	(2,536)	Statement AU; Page 12, Line 13	27 28
30 31	End of Prior Year Revenue (PYRR <sub>EU</sub> )  Transmission Related Municipal Franchise Expenses	Ф	320,996	Line 17 + Sum of Lines (23 thru 27)  Calculated Below	29 30 31
32 33	Transmission Related Uncollectible Expense		<del>-</del>	Calculated Below	32 33
34	End of Prior Year Revenue (PYRR <sub>EU</sub> )	\$	320,996	Sum Lines (29 thru 32)	34

### Section 2.3

### San Diego Gas & Electric Company Statement BK-1

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	(42,000)			
		Amazzata	Dafaranaa	Line No.
		Amounts	Reference	NO.
Net Transmission Plant:				1
Transmission Plant	\$	1,245,562	Statement BK-1; Pg 3; Line 16	2
Electric Miscellaneous Intangible Plant		580	Statement BK-1; Pg 3; Line 17	3
Transmission Related General Plant		16,485	Statement BK-1; Pg 3; Line 18	4
Transmission Related Common Plant		34,244	Statement BK-1; Pg 3; Line 19	5
Net Transmission Plant	\$	1,296,871	Sum Lines (2 thru 5)	6
				7
Rate Base Reductions:				8
Transmission Related Accumulated Deferred Taxes	\$	(183,638)	Statement AF; Page 3, Line 5	9
				10
Rate Base Additions				11
Transmission Plant Held for Future Use	\$	64,621	Statement AG; Page 4, Line 3	12
				13
Working Capital:				14
Transmission Related Material and Supplies	\$	11,227	Statement AL; Page 9, Line 5	15
Tranmission Related Prepayments		6,198	Statement AL; Page 9, Line 9	16
Transmission Related Cash Working Capital - Retail		13,665	Statement AL; Page 9, Line 21	17
Total Working Capital		31,090	Sum Lines (15 thru 17)	18
• •			,	19
Total Transmission Rate Base	\$	1,208,944	Sum Lines 6; 9; 12; 18	20
	Transmission Plant Electric Miscellaneous Intangible Plant Transmission Related General Plant Transmission Related Common Plant Net Transmission Plant  Rate Base Reductions: Transmission Related Accumulated Deferred Taxes  Rate Base Additions Transmission Plant Held for Future Use  Working Capital: Transmission Related Material and Supplies Transmission Related Prepayments Transmission Related Cash Working Capital - Retail Total Working Capital	Net Transmission Plant:  Transmission Plant  Electric Miscellaneous Intangible Plant  Transmission Related General Plant  Transmission Related Common Plant  Net Transmission Plant  \$  Rate Base Reductions:  Transmission Related Accumulated Deferred Taxes  \$  Rate Base Additions  Transmission Plant Held for Future Use  \$  Working Capital:  Transmission Related Material and Supplies  Transmission Related Prepayments  Transmission Related Cash Working Capital - Retail  Total Working Capital  \$	Net Transmission Plant:Transmission Plant\$ 1,245,562Electric Miscellaneous Intangible Plant580Transmission Related General Plant16,485Transmission Related Common Plant34,244Net Transmission Plant\$ 1,296,871Rate Base Reductions:Transmission Related Accumulated Deferred Taxes\$ (183,638)Rate Base Additions\$ 64,621Transmission Plant Held for Future Use\$ 64,621Working Capital:\$ 11,227Transmission Related Material and Supplies\$ 11,227Transmission Related Prepayments6,198Transmission Related Cash Working Capital - Retail13,665Total Working Capital\$ 31,090	Net Transmission Plant:Transmission Plant\$ 1,245,562Statement BK-1; Pg 3; Line 16Electric Miscellaneous Intangible Plant580Statement BK-1; Pg 3; Line 17Transmission Related General Plant16,485Statement BK-1; Pg 3; Line 18Transmission Related Common Plant34,244Statement BK-1; Pg 3; Line 19Net Transmission Plant\$ 1,296,871Sum Lines (2 thru 5)Rate Base Reductions:Transmission Related Accumulated Deferred Taxes\$ (183,638)Statement AF; Page 3, Line 5Rate Base Additions\$ 64,621Statement AG; Page 4, Line 3Transmission Plant Held for Future Use\$ 64,621Statement AG; Page 9, Line 5Working Capital:\$ 11,227Statement AL; Page 9, Line 5Transmission Related Material and Supplies\$ 11,227Statement AL; Page 9, Line 5Transmission Related Prepayments6,198Statement AL; Page 9, Line 9Transmission Related Cash Working Capital - Retail13,665Statement AL; Page 9, Line 21Total Working Capital\$ 31,090Sum Lines (15 thru 17)

### Section 2.3 San Diego Gas & Electric Company Statement BK-1

		(+-,)			
Line					Line
No.			 Amounts	Reference	No.
1	Gross Transmission Plant:				1
2	Transmission Plant		\$ 1,767,820	Statement AD; Page 1, Line 23	2
3	Electric Miscellaneous Intangible Plant		2,788	Statement AD; Page 1, Line 27	3
4	Transmission Related General Plant		29,013	Statement AD; Page 1, Line 29	4
5	Transmission Related Common Plant		70,514	Statement AD; Page 1, Line 31	5
6	Gross Transmission Plant		\$ 1,870,135	Sum Lines (2 thru 5)	6
7			 	, ,	7
8	Accumulated Depreciation Reserve:				8
9	Transmission Related Depreciation Reserve		\$ 522,258	Statement AE; Page 2, Line 1	9
10	Electric Miscellaneous Intangible Depreciation Reserve		2,208	Statement AE; Page 2, Line 11	10
11	Transmission Related General Plant Depr Reserve		12,528	Statement AE; Page 2, Line 13	11
12	Transmission Related Common Plant Depr Reserve		36,270	Statement AE; Page 2, Line 15	12
13	Total Transmission Related Depreciation Reserve		\$ 573,264	Sum Lines (9 thru 12)	13
14					14
15	Net Transmission Plant:				15
16	Transmission Plant		\$ 1,245,562	Line 2 Minus Line 9	16
17	Electric Miscellaneous Intangible Plant		580	Line 3 Minus Line 10	17
18	Transmission Related General Plant		16,485	Line 4 Minus Line 11	18
19	Transmission Related Common Plant		34,244	Line 5 Minus Line 12	19
20	Total Net Plant		\$ 1,296,871	Sum Lines (16 thru 19)	20

### 000045

### Section 2.3 San Diego Gas & Electric Company Statement BK-1

	(#1,000)				
Line No.		,	Amounts	Reference	Line No.
1	A. Derivation of Annual Fix Charge Rate Applicable to Forecast Period Capit	al Plant A	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		<u>-</u>	Calculated Below	10
11	Subtotal	\$	-	Sum Lines (7 thru 10)	11
12					12
13	Gross Electric Transmission Plant	\$	1,870,135	Statement BK-1; Page 3, Line 6	13
14					14
15	Annual Fix Charge Rate (AFCR <sub>EU</sub> )		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 Additions	\$	-	N/A True-Up Adjustment Calculation	20
21					21
22	Annual Fix Charge Rate (AFCR <sub>EU</sub> )		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 (4/1/2011 - 3/31/2012) (\$1,000)

00004F

Line				Line
No.		 Amounts	Reference	No.
	Public Control Promise Promise A (DTDP)			
ī	End Use Customer Base Transmission Revenue Requirement (BTRR <sub>FU</sub> ):			1
2				2
3	True-Up Period Revenue Requirements (TUR EU)	\$ 320,996	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	\$ 320,996	Line 3 + Line 5	7
8				8
9	Transmission Related Municipal Franchise Expenses	3,298	Line 9 x 1.0275%	9
10	Transmission Related Uncollectible Expense	 453_	Line 9 x .1410%	10
11		-		11
12	Total Retail TUR EU	\$ 324,747	Sum Lines (7 thru 10)	12

Section 2.3
Statement BB
SAN DIEGO GAS AND ELECTRIC COMPANY
Allocation Demond and Combility Date

Allocation Demand and Capability Data (Information Based on Five-Year Average Recorded Data: 2005 - 2009)

Line	_	7	Э	4	5	9	7	∞	6	10	11	12	13	14	15	16	
Reference	Statement BB WP: Page-1: Line 1	Statement BB WP; Page-1; Line 2		Statement BB WP; Page-1; Line 22	Statement BB WP; Page-1; Line 23	Statement BB WP; Page-1; Line 24	Sum Lines 4; 5; 6		Statement BB WP; Page-1; Line 4		Statement BB WP; Page-1; Line 28	Statement BB WP; Page-1; Line 29	Statement BB WP; Page-1; Line 30	Sum Lines 11; 12; 13		Sum Lines 1; 2; 7; 9; 14	
12-CP Allocation Percentages @ Transmission Level	39.87%	11.88%		34.88%	8.27%	3.36%	46.51%		0.37%		0.10%	0.75%	0.51%	1.36%		100.00%	
(c) = (a) x (b)  5-Year Average Of 12-CPS; Kilowatts @ Transmission Level	15,983,180	4,762,672		13,982,142	3,316,562	1,346,288	18,644,992		149,182		41,508	299,225	205,246	545,979		40,086,005	
(b) Transmission Loss Factors	1.0457	1.0457		1.0457	1.0108	1.0000	1.0359		1.0457		1.0457	1.0108	1.0000	1.0093		1.04062	
(a) 5-Year Average Of 12-CPS Kilowatts @ Meter Level	15,284,671	4,554,530		13,371,083	3,281,126	1,346,288	17,998,497	٠	142,662		39,694	296,028	205,246	540,968		38,521,328	
Customer Class	Residential Customers	Small Commercial Customers	Medium-Large Commercial Customers	Secondary	Primary	Transmission	Total Medium-Large Commercial		Street Lighting	Standby Customers	Secondary	Primary	Transmission	Total Standby Customers		System Total	
Line No.		7	n	4	5	9	7	∞	6	10	=	12	13	14	15	16	

Notes:

SDG&E Load Research Data: 2005 - 2009.

Section 2.3

## SAN DIEGO GAS AND ELECTRIC COMPANY

Allocation Energy and Supporting Data 12 Month True-Up Period - (April 2011 through March 31, 2012)

	Line No.	); Line 1   1	; Line 2 2	); Line 3   3	); Line 4   4	); Line 5   5	); Line 6 6	); Line 7   7	); Line 8 8	; Line 9 9	; Line 10   10	; Line 11   11	; Line 12   12	13	_ 7T _
	Reference	Stmnt BDWP; Page 2.1; Cols. C & D; Line 1	Stmnt BDWP; Page 2.1; Cols. C & D; Line	Stmnt BDWP; Page 2.1; Cols. C & D; Line 3	Stmnt BDWP; Page 2.1; Cols. C & D; Line 4	Stmnt BDWP; Page 2.1; Cols. C & D; Line 5	Stmnt BDWP; Page 2.1; Cols. C & D; Line 6	Stmnt BDWP; Page 2.1; Cols. C & D; Line 7	Stmnt BDWP; Page 2.1; Cols. C & D; Line 8	Stmnt BDWP; Page 2.1; Cols. C & D; Line 9	Stmnt BDWP; Page 2.1; Cols. C & D; Line 10	Stmnt BDWP; Page 2.1; Cols. C & D; Line	Stmnt BDWP; Page 2.1; Cols. C & D; Line 12		
	Energy Sales  @ Transmission Level	1,498,027	1,611,325	1,699,847	1,683,755	1,691,898	1,936,288	1,697,646	1,626,923	1,738,719	1,703,399	1,578,225	1,756,352		
Retail	Energy Sales  (a) Meter Level	1,439,554	1,548,430	1,633,497	1,618,033	1,625,858	1,860,708	1,631,382	1,563,419	1,670,852	1,636,910	1,516,623	1,687,796		
	Months	April-11	May-11	June-11	July-11	August-11	September-11	October-11	November-11	December-11	January-12	February-12	March-12		
	Line No.	_	7	3	4	2	9	7	<b>∞</b>	6	10	11	12	13	

Notes:

### 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. ER12-\_\_\_-

Section 2.3.1
SAN DIEGO GAS AND ELECTRIC COMPANY
TO3-Cycle 6 Annual Transmission Formulaic Rate Filing
True-Up Period Rate Design Information
For the True-Up Period - (April 1, 2011 - March 31, 2012)
Summary of Transmission Rates

Line No.	_	0 W	4 v	9 1	~ & 6	10 11 12	15 16 17	1, 18 19 20
Reference	Section 2.3.1; Page 3; Line 7	Section 2.3.1; Page 4; Line 7		Section 2.3.1; Page 5; Lines 35;34;33	Section 2.3.1; Page 6; Lines 8;7;6	Section 2.3.1; Page 7; Lines 37; 36; 35 Section 2.3.1; Page 8; Lines 30; 29; 28	Section 2.3.1; Page 9; Lines 37; 36; 35 Section 2.3.1; Page 10; Lines 33; 32; 31	Section 2.3.1; Page 11; Line 7 Section 2.3.1; Page 12; Lines 35;34;33
(D) Secondary Level Demand Rates \$/kW-Mo				5.7481007	5.1732906	1.1361238	1 1	2.4747146
(C) Primary Level Demand Rates \$\frac{1}{8}\kW-Mo}				5.5565073 \$	5.0008566	1.0980775 \$	1.3008397 \$	2.3817490
(B) Transmission Level Demand Rates S/kW-Mo				\$ 5.4967653 \$	\$ 4.9470888 \$	\$ 1.0845020 \$ \$ 0.2326318 \$	\$ 1.2922404 \$ \$ 0.2558354 \$	\$ 2.3594911 \$
(A) Transmission Energy Rates \$/kWh	\$ 0.0176143	\$ 0.0191241						\$ 0.0115728
Customer Classes	Residential	Small Commercial	Medium & Large Commercial/Industrial	Non-Coincident Demand (100%) <sup>1</sup>	Non-Coincident Demand (90%) <sup>2</sup>	Maximum On-Peak Period Demand <sup>3</sup> Summer Winter	Maximum Demand at the Time of System Peak <sup>4</sup> Summer Winter	Street Lighting Standby Rate
Line No.			4 v	9 1	~ & 6	12 12 12		18 20 20 8

NOTES:

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

<sup>&</sup>lt;sup>2</sup> NCD (90%) rates are applicable to the following CPUC tariffs: Schedules AY-TOU, AL-TOU, AL-TOU-DER, DG-R, and A6-TOU.

<sup>&</sup>lt;sup>3</sup> Maximum On-Peak Demand rates are applicable to the following CPUC tariffs: Schedules AY-TOU, AL-TOU, AL-TOU-DER and DG-R

<sup>&</sup>lt;sup>4</sup> Maximum Demand at the Time of System Peak rates are applicable to the following CPUC tariffs: Schedule A6-TOU

SAN DIEGO GAS AND ELECTRIC COMPANY
TO3-Cycle 6 Annual Transmission Formulaic Rate Filing
Derivation of Retail True-Up Cos of Service Rates
For the True-Up Period - (April 1, 2011 - March 31, 2012)
Allocation of Base Transmission Revenue Requirements (BTRR) Based on 12 CPs
(\$1,000)

			Line	No.	ı	2	Ж	4	5	9,	7	∞	6	10	11	12	
				Reference	Section 2.3; Page 5 of 5; Line 12			Col.C Ln $4 = \text{Col C Ln 1} \times \text{Col B. Ln 4}$	Col.C Ln $5 = \text{Col C Ln1} \times \text{Col B. Ln } 5$	Col.C Ln 6 = Col C Ln1 x Col B. Ln 6	Col.C Ln $7 = \text{Col C Ln 1} \times \text{Col B. Ln } 7$	Col.C Ln $8 = \text{Col C Ln 1} \times \text{Col B. Ln } 8$		Sum Lines 4 thru 8		Line 10	
(C)	Allocated Base	Transmission	Revenue	Requirement	324,747			129,484	38,584	151,047	1,209	4,423		324,747		324,747	
	*	_			↔			%	%	%	~	%		8%		69	_
(B)				Percentages 3				39.872%	11.881%	46.512%	0.372%	1.362%		100.00%			
(A)			Total 12 CPs @	Transmission Level <sup>2</sup>				15,983,180	4,762,672	18,644,992	149,182	545,979		40,086,005		40,086,005	
				Customer Classes	Total Base Transmission Revenue Requirement 1		Allocation of BTRR Based on 12-CP:	Residential	Small Commercial	Medium & Large Commercial/Industrial	Street Lighting Revenues	Standby Revenues		Total		Total	
	_		Line	No.	1 7	7	3	4 <del>Ā</del>	5 S	<u>9</u>	7	<u>«</u>	6	10	11	12 T	
Ь					 												

### NOTES:

N

Total Base TRR comes from TO3-Cycle 6; Section 2.3; Statement BK1; Page 5 of 5; Line 12

See Statement BL; Page 9; Column D.

See Statement BL; Page 9; Column E.

# SAN DIEGO GAS AND ELECTRIC COMPANY

TO3-Cycle 6 Annual Transmission Formulaic Rate Filing Derivation of Retail True-Up Cos of Service Rates For the True-Up Period - (April 1, 2011 - March 31, 2012)

Residential Customers 1

(8000)

Line No.	1	3 8	4 2	7	∞ o	10	
Reference	Section 2.3.1; Page 2; Line 4	Section 2.3.1; Page 16.1; Line 4	Line 1 / Line 3	Line 5, Rounded to 7 Decimal Places	Line 7 x Line 3	Line 1 - Line 9	
Derivation of Commodity Rate & Proof of Revenues Calculation	129,484	7,351,090	0.0176143	0.0176143	129,484		
	\$		——		₩	Difference \$	<u> </u>
Description	Residential - Allocated Transmission Revenue Requirements	Billing Determinants - Residential Customer Class (MWh):	Residential Energy Rate Per kWh	Residential Energy Rate Per kWh - Rounded	Proof of Revenues	Diff	
Line No.		3 2	4 v	9	<b>%</b> 0	10	

### NOTES:

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

Section 2.3.1
SAN DIEGO GAS AND ELECTRIC COMPANY
TO3-Cycle 6 Annual Transmission Formulaic Rate Filing

Derivation of Retail True-Up Cos of Service Rates For the True-Up Period - (April 1, 2011 - March 31, 2012) Small Commercial Customers <sup>1</sup>

(8000)

Line No.	1	2	4 2	9	<b>%</b> 6	10	
Reference	Section 2.3.1; Page 2; Line 5	Section 2.3.1; Page 16.1; Line 5	Line 1 / Line 3	Line 5, Rounded to 7 Decimal Places	Line 7 x Line 3	Line 1 - Line 9	
Derivation of Commodity Rate & Proof of Revenues Calculation	38,584	2,017,561	0.0191241	0.0191241	38,584	1	
C <sub>C</sub>	€9		€9	↔	8	8	
Description	Small Commercial - Allocated Transmission Revenue Requirement	Billing Determinants - Small Commercial (MWh):	Rate Per kWh Calculation	Rate Per kWh Calculation - Rounded	Proof of Revenues	Difference \$	
Line No.	1	2 %	4 2	9	<b>%</b> 0	10	

### NOTES:

<sup>1</sup> Small commercial customers include the following California Public Utilities Commission (CPUC) tariffs:

A, A-TC, A-TOU, PA.

### Section 2.3.1

### SAN DIEGO GAS AND ELECTRIC COMPANY TO3-Cycle 6 Annual Transmission Formulaic Rate Filing Derivation of Retail True-Up Cos of Service Rates For the True-Up Period - (April 1, 2011 - March 31, 2012)

Medium-Large Commercial Customers <sup>1</sup>

(\$000)

Line No. Descrip  1 Med-Lrg C&I - Demand Revenue Requirement	otion	Derivation of Commodity Rate & Proof of Revenues		Line
No. Descrip  1 Med-Lrg C&I - Demand Revenue Requirement	otion	Proof of Revenues		Line
No. Descrip  1 Med-Lrg C&I - Demand Revenue Requirement	ption	li l		I inc
No. Descrip  1 Med-Lrg C&I - Demand Revenue Requirement	ption	i I		
1 Med-Lrg C&I - Demand Revenue Requirement		Calculation	Reference	No.
I I -				
1 - 1		\$ 151,047	Section 2.3.1; Page 2; Line 6	1
2 Demand Determinants @ Transmission Level				2
3 Total Class Revenues to Voltage Level with Lo				3
4 Secondary	33 1 ucioi Augustment (11117) .	21,812	Section 2.3.1; Page 15; Col. D; Line 23	4
1 1				5
1 1 "		4,280	Section 2.3.1; Page 15; Col. D; Line 24	1
6 Tranmission		1,387	Section 2.3.1; Page 15; Col. D; Line 25	6
7 Total		27,479	Sum Lines 4; 5; 6	7
8 Allocation Factors Per Above to Allocate				8
9 Demand Revenue Requirements to Voltage Le	<u>evel:</u>			9
10 Secondary		79.38%	Line 4 / Line 7	10
11 Primary		15.58%	Line 5 / Line 7	11
12 Tranmission		5.05%	Line 6 / Line 7	12
13 Total		100.00%	Sum Lines 10; 11; 12	13
14				14
15 Allocation of Revenue Requirements to Voltage	t Level			15
16 Secondary	. —	\$ 119,897	Line 1 x Line 10	16
17 Primary		\$ 23,526	Line 1 x Line 11	17
18 Tranmission		\$ 7,624	Line 1 x Line 12	18
19 Total		\$ 151,047	Sum Lines 16; 17; 18	19
		J 131,047	Sum Emes 10, 17, 18	
20				20
21 Demand Determinants By Voltage Level @ Me	ter Level (MW)			21
22 Secondary		20,859	Section 2.3.1; Page 15; Col. B; Line 23	22
23 Primary		4,234	Section 2.3.1; Page 15; Col. B; Line 24	23
24 Tranmission		1,387	Section 2.3.1; Page 15; Col. B; Line 25	24
25 Total		26,479	Sum Lines 22; 23; 24	25
26				26
27 Demand Rate By Voltage @ Meter				27
28 Secondary		\$ 5.7481007	Line 16 / Line 22	28
29 Primary		\$ 5,5565073	Line 17 / Line 23	29
30 Tranmission		\$ 5.4967653	Line 18 / Line 24	30
31		,,,,,,,	20, 2m 2.	31
32 Demand Rate By Voltage @ Meter (Rounded)				32
33   Secondary	•	\$ 5.7481007	Line 28, Rounded to 7 Decimal Places	33
34 Primary		\$ 5.5565073	Line 29, Rounded to 7 Decimal Places	34
l l *				35
		\$ 5.4967653	Line 30, Rounded to 7 Decimal Places	
36				36
37 Proof of Revenue Calculations:				37
38 Secondary		\$ 119,897	Line 22 x Line 33	38
39 Primary		\$ 23,526	Line 23 x Line 34	39
40 Tranmission		\$ 7,624	Line 24 x Line 35	40
41 Total		\$ 151,047	Sum Lines 38; 39; 40	41
42				42
43	Difference	\$ -	Line 1 - Line 41	43

### NOTES:

<sup>&</sup>lt;sup>1</sup> 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.

 $<sup>^2</sup>$  LF = Transmission Loss Factor; Secondary Level = 1.0457; Primary Level = 1.0108; Transmission Level = 1.0000

<sup>&</sup>lt;sup>3</sup> 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

## SAN DIEGO GAS AND ELECTRIC COMPANY TO3-Cycle 6 Annual Transmission Formulaic Rate Filing Derivation of Retail True-Up Cos of Service Rates For the True-Up Period - (April 1, 2011 - March 31, 2012)

Medium-Large Commercial Customers (\$000)

	(3000)	Т.	Namination of		1
ŀ			Derivation of		1
T			nmodity Rate &		
Line			of of Revenues	D. C.	Line
No.	Description	-	Calculation	Reference	No.
1	Rate Proposal 90% of Total M&L C&I NCD Rates; 1		90.00%		1
2	Secondary	\$	5.1732906	90% x Section 2.3.1; Page 5; Line 33	2
3	Primary	\$	5.0008566	90% x Section 2.3.1; Page 5; Line 34	3
4	Tranmission	\$	4.9470888	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	\$	5.1732906	Line 2, Rounded to 7 Decimal Places	6
7	Primary	\$	5.0008566	Line 3, Rounded to 7 Decimal Places	7
8	Tranmission	\$	4.9470888	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 <sup>4</sup>		19,900	Section 2.3.1; Page 15; Col. B; Line 10	11
12	Primary <sup>4</sup>		3,894	Section 2.3.1; Page 15; Col. B; Line 11	12
13	Transmission 4		308	Section 2.3.1; Page 15; Col. B; Line 12	13
14	Total		24,103	Sum Lines 11; 12; 13	14
15	Annual Revenues from Current NCD Rate 100% of Total M&L C&I NCD Rates:	+	24,105	Juli Lines 11, 12, 13	15
16	Secondary	\$	114,390	Line 11 x Section 2.3.1; Page 5; Line 33	16
17	Primary	\$	21,637	Line 12 x Section 2.3.1; Page 5; Line 33	17
18	Tranmission	1 '	- 1	· -	18
19		\$	1,694	Line 13 x Section 2.3.1; Page 5; Line 35	19
	Total	12	137,721	Sum Lines 16; 17; 18	4 1
20	Annual Revenues from Proposed NCD Rate 90% of Total M&L C&I NCD Rates:	1	100.051	71 6 71 11	20
21	Secondary	\$	102,951	Line 6 x Line 11	21
22	Primary	\$	19,473	Line 7 x Line 12	22
23	Tranmission	\$	1,524	Line 8 x Line 13	23
24	Total	\$	123,948	Sum Lines 21; 22; 23	24
25	Revenue Reallocation to Maximum On-Peak Period Demands:		44.420		25
26	Secondary	\$	11,439	Line 16 - Line 21	26
27	Primary	\$	2,164	Line 17 - Line 22	27
28	Transmission	\$	170	Line 18 - Line 23	28
29	Total - Reallocated to MAXIMUM ON-PEAK PERIOD DEMANDS	\$	13,773	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 <sup>4</sup>	1	200	Section 2.3.1; Page 15; Col. B; Line 18	33
34	Transmission 4		1,079	Section 2.3.1; Page 15; Col. B; Line 19	34
35	Total		1,279	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	\$	1,112	Line 33 x Section 2.3.1; Page 5; Line 34	38
39	Tranmission	\$	5,930	Line 34 x Section 2.3.1; Page 5; Line 35	39
40	Total	\$	7,042	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	\$	1,001	Line 7 x Line 39	43
44	Tranmission	\$	5,337	Line 8 x Line 40	44
45	Total	\$	6,338	Sum Lines 42; 43; 44	45
46	Revenue Reallocation to Maximum Demand at the Time of System Peak:	1			46
47	Secondary	<b> </b> \$	_	Line 37 - Line 42	47
48	Primary	\$	111	Line 38 - Line 43	48
49	Tranmission	\$	593	Line 39 - Line 44	49
50	Total	\$	704	Sum Lines 47; 48; 49	50
	MOTES:		, , , ,		

<sup>&</sup>lt;sup>1</sup> 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

<sup>&</sup>lt;sup>2</sup> 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

<sup>&</sup>lt;sup>3</sup> 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

<sup>&</sup>lt;sup>4</sup> Represents NCD billing determinants based on Maximum On-Peak Period Demand during the period in which the new rate structure was in effect. TO3 C6 TU- Statement BL - FINAL - REVISED.xlsx - Medium&Large C-I Part 2 Page - 6

### Section 2.3.1

### SAN DIEGO GAS AND ELECTRIC COMPANY

### TO3-Cycle 6 Annual Transmission Formulaic Rate Filing Derivation of Retail True-Up Cos of Service Rates For the True-Up Period - (April 1, 2011 - March 31, 2012)

Medium-Large Commercial Customers (\$000)

		I	Derivation of		
		Con	nmodity Rate &		i
Line		Pro	of of Revenues		Line
No.	Description		Calculation	Reference	No.
1	Med-Lrg C&I Maximum On-Peak Period Demand Proposal			-	1
2	Revenue Reallocation to Maximum On-Peak Period Demands: 1	<b> </b> \$	13,773	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	ľ	7,853	Section 2.3.1; Page 15; Col. B; Line 30	5
6	Primary		1,675	Section 2.3.1; Page 15; Col. B; Line 31	6
7	Transmission	1	237	Section 2.3.1; Page 15; Col. B; Line 32	7
8	Total		9,765	Sum Lines 5; 6; 7	8
9				· · · · · · · · · · · · · · · · · · ·	9
10	Summer - Maximum On-Peak Period Demands By Voltage Level @ Trans. Level (MW)				10
11	Secondary		8,212	Section 2.3.1; Page 15; Col. D; Line 30	11
12	Primary		1,693	Section 2.3.1; Page 15; Col. D; Line 31	12
13	Transmission		237	Section 2.3.1; Page 15; Col. D; Line 32	13
14	Total		10,142	Sum Lines 11; 12; 13	14
15					15
16	Summer Maximum On-Peak Period Allocation to Voltage Levels				16
17	Secondary		80.97%	Line 11 / Line 14	17
18	Primary		16.69%	Line 12 / Line 14	18
19	Tranmission		2.34%	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	\$	8,922	(Line 2 x Line 21) x Line 17	23
24	Primary	\$	1,839	(Line 2 x Line 21) x Line 18	24
25	Transmission	\$	257	(Line 2 x Line 21) x Line 19	25
26	Total	\$	11,018	Sum Lines 23; 24; 25	26
27	• •••				27
28	Summer Maximum On-Peak Period Demand Rates <sup>3</sup>		\$/kW		28
29	Secondary	\$	1.1361238	Line 23 / Line 5	29
30	Primary	\$	1.0980775	Line 24 / Line 6	30
31	Transmission	\$	1.0845020	Line 25 / Line 7	31
32					32
33	<del></del>				33
34	Summer Maximum On-Peak Period Demand Rates (Rounded)		\$/kW		34
35	Secondary	\$	1.1361238	Line 29, Rounded to 7 Decimal Places	35
36	Primary	\$	1.0980775	Line 30, Rounded to 7 Decimal Places	36
37	Transmission	\$	1.0845020	Line 31, Rounded to 7 Decimal Places	37
38					38

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

<sup>&</sup>lt;sup>2</sup> Summer Maximum On-Peak Period Determinants for the following California Public Utilities Commission (CPUC) tariffs: AY-TOU, AL-TOU, AL-TOU-DER, DG-R

<sup>&</sup>lt;sup>3</sup> 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

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

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

<sup>&</sup>lt;sup>6</sup> 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 6 Annual Transmission Formulaic Rate Filing Derivation of Retail True-Up Cos of Service Rates For the True-Up Period - (April 1, 2011 - March 31, 2012)

Medium-Large Commercial Customers (\$000)

	(8000)	I	Derivation of		1
		1	nmodity Rate &		1
Line			of of Revenues		Line
No.	Description			D. C	
-	Description		Calculation	Reference	No.
1	Winter Maximum On-Peak Period Demands By Voltage Level @ Meter Level (MW) 4				1
2	Secondary		9,214	Section 2.3.1; Page 15; Col. B; Line 35	2
3	Primary		2,049	Section 2.3.1; Page 15; Col. B; Line 36	3
4	Transmission		219	Section 2.3.1; Page 15; Col. B; Line 37	4
5	Total		11,482	Sum Lines 3; 4; 5	5
6	Winter Maximum On-Peak Period Demands @ Transmission Level (MW)				6
7	Secondary		9,635	Section 2.3.1; Page 15; Col. D; Line 35	7
8	Primary		2,071	Section 2.3.1; Page 15; Col. D; Line 36	8
9	Transmission		219	Section 2.3.1; Page 15; Col. D; Line 37	9
10	Total		11,925	Sum Lines 3; 4; 5	10
11	Winter Maximum On-Peak Period Allocation to Voltage Levels				11
12	Secondary		80.80%	Line 7 / Line 10	12
13	Primary		17.37%	Line 8 / Line 10	13
14	Tranmission		1.84%	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	\$	2,226	(Page 7; Line 2 x Page 8; Line 16) x Line 12	18
19	Primary	\$	478	(Page 7; Line 2 x Page 8; Line 16) x Line 13	19
20	Transmission	\$	51	(Page 7; Line 2 x Page 8; Line 16) x Line 14	20
21	Total	\$	2,755	Sum Lines 18; 19; 20	21
22	Winter Maximum On-Peak Period Demand Rates 5	-	\$/kW		22
23	Secondary	\$	0.2415850	Line 18 / Line 2	23
24	Primary	\$	0.2332883	Line 19 / Line 3	24
25	Transmission	\$	0,2326318	Line 20 / Line 4	25
26	1141151111551011	1 3	0,2320316	Line 20 / Line 4	26
27	Winter Manipular On Dark Brain & Daniel		Φ. Ι. ΥΥ <i>γ</i>		
28	Winter Maximum On-Peak Period Demand Rates (Rounded)	,	\$/kW	1: 22 P   11/ (IP : 1N	27
29	Secondary	\$	0.2415850	Line 23, Rounded to 7 Decimal Places	28
1 1	Primary	\$	0.2332883	Line 24, Rounded to 7 Decimal Places	29
30 31	Transmission	\$	0.2326318	Line 25, Rounded to 7 Decimal Places	30
	D. C.CD. COLLEGE				31
32	Proof of Revenue Calculations:	_		m = 7.1 - 00 / 7 - 7.1 - 1.1	32
33	Secondary	\$	11,148	(Page 7; Line 23) + (Page 8; Line 18)	33
34	Primary	\$	2,317	(Page 7; Line 24) + (Page 8, Line 19)	34
35	Transmission	\$	308	(Page 7; Line 25) + (Page 8; Line 20)	35
36	Total Total	\$	13,773	Sum Lines 33; 34; 35	36
37	Difference	\$	(0)	Page 7; Line 2 - Page 8; Line 36	37
38					38

<u>NOTES</u>

<sup>&</sup>lt;sup>1</sup> 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

<sup>&</sup>lt;sup>2</sup> Summer Maximum On-Peak Period Determinants for the following California Public Utilities Commission (CPUC) tariffs: AY-TOU, AL-TOU, AL-TOU-DER, DG-R

<sup>&</sup>lt;sup>3</sup> 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

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

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

<sup>&</sup>lt;sup>6</sup> 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 6 Annual Transmission Formulaic Rate Filing Derivation of Retail True-Up Cos of Service Rates

For the True-Up Period - (April 1, 2011 - March 31, 2012) Medium-Large Commercial Customers

(\$000)

	(0000)	T 1	Derivation of		1
!					
<b>.</b> .			modity Rate &		ļ.,
Line	<b>5</b>		of of Revenues	D 4	Line
No.	Description	_	Calculation	Reference	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	\$	704	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		64	Section 2.3.1; Page 15; Col. B; Line 43	6
7	Transmission		371	Section 2.3.1; Page 15; Col. B; Line 44	7
8	Total		435	Sum Lines 5; 6; 7	8
9					9
10	Summer Maximum Demand at the Time of System Peak @ Transmission Level (MW)	1			10
11	Secondary		-	Section 2.3.1; Page 15; Col. D; Line 42	111
12	Primary		64	Section 2.3.1; Page 15; Col. D; Line 43	12
13	Transmission		371	Section 2.3.1; Page 15; Col. D; Line 44	13
14	Total		435	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		14,71%	Line 12 / Line 14	18
19	Transmission		85.29%	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%	<u> </u>	21
22	Revenues for Proposed Summer Maximum Demand at the Time of System Peak Rates				22
23	Secondary	<b>S</b>	_	(Line 2 x Line 21) x Line 17	23
24	Primary	\$	83	(Line 2 x Line 21) x Line 18	24
25	Transmission	\$	480	(Line 2 x Line 21) x Line 19	25
26	Total	\$	563	Sum Lines 23; 24; 25	26
27		+			27
28	Summer Maximum Demand at the Time of System Peak Rates <sup>3</sup>		\$/kW		28
29	Secondary	\$	-	Line 23 / Line 5	29
30	Primary	\$	1.3008397	Line 24 / Line 6	30
31	Transmission	\$	1.2922404	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	\$	1.3008397	Line 30, Rounded to 7 Decimal Places	36
37	Transmission	\$	1.2922404	Line 31, Rounded to 7 Decimal Places	37
38	***************************************	*	1.2,22,104	Zino 21, Rounded to / Doomidi I labor	38
70	NOTES				70

<sup>1</sup> 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:

<sup>&</sup>lt;sup>2</sup> Summer Maximum Demand at the time of System Peak Determinants for the following California Public Utilities Commission (CPUC) tariffs: A6-TOU

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

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

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

### Section 2.3.1 SAN DIEGO GAS AND ELECTRIC COMPANY

### TO3-Cycle 6 Annual Transmission Formulaic Rate Filing Derivation of Retail True-Up Cos of Service Rates For the True-Up Period - (April 1, 2011 - March 31, 2012) Medium-Large Commercial Customers

(\$000)

	(\$000)			
		Derivation of	•	
i		Commodity Rate &		ı
Line		Proof of Revenues		Line
No.	Description	Calculation	Reference	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	86	Section 2.3.1; Page 15; Col. B; Line 48	3
4	Transmission	465	Section 2.3.1; Page 15; Col. B; Line 49	4
5	Total	551	Sum Lines 2; 3; 4	5
6			July 2, 5, 1	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	86	Section 2.3.1; Page 15; Col. D; Line 48	9
10	Transmission	465	Section 2.3.1; Page 15; Col. D; Line 49	10
11	Total	551	Sum Lines 8; 9; 10	11
12	Total	331	Sum Lines 8, 9, 10	12
13	Winter Manimum Demand at the Time of Contant Deals Allegation to Welface I and			13
14	Winter Maximum Demand at the Time of System Peak Allocation to Voltage Levels	0.00%	, I in a 0 / I in a 11	
15	Secondary		Line 8/Line 11	14
1	Primary	15.61%	Line 9 / Line 11	15
16 17	Transmission	84.39%	Line 10 / Line 11	16
	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	\$ 22	(Page 9; Line 2 x Page 10; Line 18) x Line 15	21
22	Transmission	\$ 119	(Page 9; Line 2 x Page 10; Line 18) x Line 16	22
23	Total	\$ 141	Sum Lines 20; 21; 22	23
24		İ		24
25	Winter Maximum Demand at the Time of System Peak Rates 5	\$/kW		25
26	Secondary	\$ -	Line 20 / Line 2	26
27	Primary	\$ 0.2572664	Line 21 / Line 3	27
28	Transmission	\$ 0.2558354	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	\$ 0.2572664	Line 27, Rounded to 7 Decimal Places	32
33	Transmission	\$ 0.2558354	Line 28, Rounded to 7 Decimal Places	33
34			,	34
35	Proof of Revenue Calculations:			35
36	Secondary	s -	(Page 9; Line 23) + (Page 10; Line 20)	36
37	Primary	\$ 105	(Page 9; Line 24) + (Page 10; Line 21)	37
38	Transmission	\$ 599	(Page 9; Line 25) + (Page 10; Line 22)	38
39	Total	\$ 704	Sum Lines 36; 37; 38	39
40	Difference		Page 9; Line 2 - Page 10; Line 39	40
_ <del>7</del> 0	Difference	[ (0)	rage 9, Line 4 - Page 10, Line 39	40

<sup>1</sup> 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:

<sup>&</sup>lt;sup>2</sup> Summer Maximum Demand at the time of System Peak Determinants for the following California Public Utilities Commission (CPUC) tariffs: A6-TOLL

<sup>&</sup>lt;sup>3</sup> Summer Maximum Demand at the time of System Peak Demand Charges for the following California Public Utilities Commission (CPUC) tariffs: A6-TOU

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

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

 $<sup>^6</sup>$  LF = Transmission Loss Factor; Secondary Level = 1.0457; Primary Level = 1.0108; Transmission Level = 1.0000

TO3-Cycle 6 Annual Transmission Formulaic Rate Filing For the True-Up Period - (April 1, 2011 - March 31, 2012) Derivation of Retail True-Up Cos of Service Rates SAN DIEGO GAS AND ELECTRIC COMPANY Section 2.3.1

Street Lighting Customers

			Line	No.		2	3	4	5	9	S 7	∞	6	10	11	
				Reference	Section 2.3.1; Page 2; Line 7		Statement 2.3.1; Page 16.1; Line 9		Line 1 / Line 3		Line 5, Rounded to 7 Decimal Places		Line 3 x Line 7		Line 1 - Line 9	
	Derivation of	Commodity Rate &	Proof of Revenues	Calculation	\$ 1,209		104,469		\$ 0.0115728		\$ 0.0115728		\$ 1,209		ı	
(\$000)				Description	Street Lighting - Allocated Transmission Revenue Requirement		Billing Determinants - Street Lighting Customers (MWh) <sup>1</sup> :		Rate Per kWh Calculation		Rate Per kWh Calculation - Rounded		Proof of Revenues:		Difference	
			Line	No.	-	2	т	4	2	9	7	∞	6	10	Π.	

## NOTES:

<sup>1</sup> 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 6 Annual Transmission Formulaic Rate Filing Derivation of Retail True-Up Cos of Service Rates For the True-Up Period - (April 1, 2011 - March 31, 2012) Standby Revenues Calculation

(\$000)

	(\$000)			
		Derivation of		
		Standby Surcharge &		
Line		Proof of Revenues		Line
No.	Description	Calculation	Reference	No.
1	Standby - Demand Revenue Requirement	\$ 4,423	Section 2.3.1; Page 2; Line 8	1
2	Demand Determinants (a), Transmission Level Used to Allocate		, ,	2
3	Total Class Revenues to Voltage Level with Loss Factor Adjustment (MW) 1:			3
4	Secondary	150	Section 2.3.1; Page 15; Col. D; Line 57	4
5	Primary	1,042	Section 2.3.1; Page 15; Col. D; Line 58	5
6	Tranmission	684	Section 2.3.1; Page 15; Col. D; Line 59	6
7	Total	1,876	Sum Lines 4; 5; 6	7
		1,670	Sum Lines 4, 5, 0	
8	Allocation Factors Per Above to Allocate			8
9	Demand Revenue Requirements to Voltage Level:			9
10	Secondary	8.00%	Line 4 / Line 7	10
11	Primary	55.54%	Line 5 / Line 7	11
12	Tranmission	36.46%	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	\$ 354	Line 1 x Line 10	16
17	Primary	\$ 2,456	Line 1 x Line 11	17
18	Tranmission	\$ 1,613	Line 1 x Line 12	18
19	Total	\$ 4,423	Sum Lines 16; 17; 18	19
20				20
21	Demand Determinants By Voltage Level @ Meter (MW)			21
22	Secondary	143	Section 2.3.1; Page 15; Col. B; Line 57	22
23	Primary	1,031	Section 2.3.1; Page 15; Col. B; Line 58	23
24	Tranmission	684	Section 2.3.1; Page 15; Col. B; Line 59	24
25	Total	1,858	Sum Lines 22; 23; 24	25
26	·	1,030	Juni Lines 22, 23, 24	
	D. ID. D. IV. L. 1016		<del> </del>	26
27	Demand Rate By Voltage Level @ Meter		7: 46/71 00	27
28	Secondary	\$ 2.4747146	Line 16 / Line 22	28
29	Primary	\$ 2.3817490	Line 17 / Line 23	29
30	Tranmission	\$ 2.3594911	Line 18 / Line 24	30
31				31
32	Demand Rate By Voltage Level @ Meter (Rounded)			32
33	Secondary	\$ 2.4747146	Line 28, Rounded to 7 Decimal Places	33
34	Primary	\$ 2.3817490	Line 29, Rounded to 7 Decimal Places	34
35	Tranmission	\$ 2.3594911	Line 30, Rounded to 7 Decimal Places	35
36				36
37	Proof of Revenue Calculations:			37
38	Secondary	\$ 354	Line 22 x Line 33	38
39	Primary	\$ 2,456	Line 23 x Line 34	39
40	Tranmission	\$ 1,613	Line 24 x Line 35	40
41	Total	\$ 4,423	Sum Lines 38; 39; 40	41
42				42
43	Difference	\$ -	Line 1 - Line 41	43
		· · · · · · · · · · · · · · · · ·		
		L		1

<sup>&</sup>lt;sup>1</sup> LF = Transmission Loss Factor; Secondary Level = 1.0457; Primary Level = 1.0108; Transmission Level = 1.0000

SAN DIEGO GAS AND ELECTRIC COMPANY
TO3-Cycle 6 Annual Transmission Formulaic Rate Filing
Derivation of Retail True-Up Cos of Service Rates
For the True-Up Period - (April 1, 2011 - March 31, 2012)
Summary of Proof of Revenues

(\$1,000)

			€	<b>(B)</b>		(O)		
		Total	Total Revenues	Total Revenues	venues			
Line		Per	Per Cost of	Per Rate	tate			Line
No.	Customer Classes	Servi	Service Study	Design	ign	Difference	Reference	No.
_	Residential Customers	↔	129,484	\$ 1	129,484	· •	Section 2.3.1; Pages 2 & 3	1
7								7
m	Small Commercial		38,584		38,584	ı	Statement 2.3.1; Pages 2 & 4	ю
4								4
2	Medium-Large Commercial		151,047	1	151,047	1	Statement 2.3.1; Pages 2 & 5	2
9								9
7	Street Lighting		1,209		1,209	ı	Statement 2.3.1; Pages 2 & 11	7
∞								∞
6	Standby Revenues	`	4,423		4,423	1	Statement 2.3.1; Pages 2 & 12	6
10								10
11	Grand Total	\$	324,747	\$ 3	324,747	-	Sum Lines 1 thru 9	11

Section 2.3.1
SAN DIEGO GAS AND ELECTRIC COMPANY
TO3-Cycle 6 Annual Transmission Formulaic Rate Filing
Derivation of Retail True-Up Cos of Service Rates
For the True-Up Period - (April 1, 2011 - March 31, 2012)
Development of 12-CP Allocation Factors Using Recorded Data: 2005-2009

		Line No.	-	. 2	3	4	2	9	7	∞	6	10	11	12	13	14	15	16	17	18
(g)		Reference		Statement BB; Page 1; Line 1	Statement BB; Page 1; Line 2		Statement BB; Page 1; Line 4	Statement BB; Page 1; Line 5	Statement BB; Page 1; Line 6	Sum Lines 5; 6; 7		Statement BB; Page 1; Line 9		Statement BB; Page 1; Line 11	Statement BB; Page 1; Line 12	Statement BB; Page 1; Line 13	Sum Lines 12; 13; 14		Sum Lines 2; 3; 8; 10; 15	
(e)		Ratio		39.87%	11.88%		34.88%	8.27%	3.36%	46.51%		0.37%		0.10%	0.75%	0.51%	1.36%		100.00%	
$(c) \times (c) = (b)$	5-Year Average Of 12 CPs	Kilowat @ Transmission Level		15,983,180	4,762,672		13,982,142	3,316,562	1,346,288	18,644,992		149,182		41,508	299,225	205,246	545,979		40,086,005	
(၁)		Transmission Loss Factors		1.0457	1.0457		1.0457	1.0108	1.0000	1.0359		1.0457		1.0457	1.0108	1.0000	1.0093		1.04062	
(q)	5-Year Average Of 12 CPs	Kilowat @ Meter Level		15,284,671	4,554,530	•	13,371,083	3,281,126	1,346,288	17,998,497		142,662		39,694	296,028	205,246	540,968		38,521,328	
(a)		Customer Class	5 Year Average - 12CP Allocation Factors:	Residential Customers	Small Commercial Customers	Medium-Large Commercial Customers	Secondary	Primary	Transmission	Total Medium-Large Commercial		Street Lighting	Standby Customers	Secondary	Primary	Transmission	Total Standby Customers		System Total	
		Line No.		7	m	4	5	9	7	<b>∞</b>	6	2	Ξ	12	13	14	15	16	17	-81
Щ			L																	

## Section 2.3.1 SAN DIEGO GAS AND ELECTRIC COMPANY TO3-Cycle 6 Annual Transmission Formulaic Rate Filing Derivation of Retail True-Up Cos of Service Rates For the True-Up Period - (April 1, 2011 - March 31, 2012) Development of 12-CP Allocation Factors

}			tion Factors			· <del></del>	
	(A)	(B)	(C)	$(D) = (B) \times (C)$	(E)		
		Recorded Demand		Recorded Demand			1
1.1		Determinants		Determinants			
Line		Megawatt @	Transmission	Megawatt @			Line
No.	Customer Class	Meter Level	Loss Factors	Transmission Level	Ratios	Reference	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	958	1.0457	1,002	87.66%	Col. B=Page 16.1; Col. E; Line 3	3
4	Primary 2	140	1,0108	141	12.34%		4
5	Transmission <sup>3</sup>	1,10					1
6	Total	1 000	1.0000		0.00%	Col. B=Page 16.1; Col. E; Line 5	5
	10(2)	1,098		1,143	100,00%	Sum Lines 3; 4; 5	6
7							7
	Non-Coincident Demand Determinants Pertaining to Customers on Schedules @ 90% NCD Rate	1					8
9	with Maximum On-Peak Period Demand						9
10	Secondary	19,900	1.0457	20,810	83.06%	Col. B=Page 16.2; Col. E; Line 10	10
11	Primary	3,894	1.0108	3,936	15.71%	Col. B=Page 16.2; Col. E; Line 11	11
12	Transmission	308	1.0000	308	1.23%	Col. B=Page 16.2; Col. E; Line 12	12
13	Total	24,103		25,054	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 16.3; Col. E; Line 17	17
18	Primary	200	1,0108	202	15,77%	Col. B=Page 16.3; Col. E; Line 18	18
19	Transmission	1,079	1,0000	1,079	84.23%	Col. B=Page 16.3; Col. E; Line 19	19
20	Total	1,279	1,0000	1,281	100.00%	Sum Lines 17; 18; 19	20
21		1,275		1,201	100.0076	Duni Duno 17, 10, 17	21
22	Total New Colonidat Daniel Determines Determines Determines A. M. Him, L Commission of Colonidate						
23	Total Non-Coincident Demand Determinants Pertaining to Medium-Large Commercial Customers	20.050		21 212	=0.0004		22
	Secondary	20,859	1.0457	21,812	79.38%	Sum Lines 3; 10; 17	23
24	Primary	4,234	1.0108	4,280	15.58%	Sum Lines 4; 11; 18	24
25	Transmission	1,387	1.0000	1,387	5.05%	Sum Lines 5; 12; 19	25
26	Total	26,479		27,479	100.01%	Sum Lines 23; 24; 25	26
27				İ			27
28	Maximum On-Peak Period Demand Determinants			I			28
29	Summer Months = (May, June, July, August, September)						29
30	Secondary	7,853	1.0457	8,212	80.97%	Col. B=Page 16.2; Col. E; Line 30	30
31	Primary	1,675	1.0108	1,693	16.69%	Col. B=Page 16.2; Col. E; Line 31	31
32	Transmission	237	1,0000	237	2.34%	Col. B=Page 16.2; Col. E; Line 32	32
33	Total	9,765		10,142	100,00%	Sum Lines 30; 31; 32	33
34	Winter Months = (October, November, December, January, February, March, April)					,,	34
35	Secondary	9,214	1,0457	9,635	80.80%	Col. B=Page 16.2; Col. E; Line 35	35
36	Primary	2,049	1.0108	2,071	17,37%	Col. B=Page 16.2; Col. E; Line 36	36
37	Transmission	219	1.0000	219			
38	Total		1.0000		1.84%	Col. B=Page 16.2; Col. E; Line 37	37
39	Grand Total	11,482		11,925	100.01%	Sum Lines 35; 36; 37	38
1 1		21,247		22,067			39
	Maximum Demand at the Time of System Peak Determinants						40
41	Summer						41
42	Secondary	-	1.0457	-	0.00%	Col. B=Page 16.3; Col. E; Line 42	42
43	Primary	64	1.0108	64	14.71%	Col. B=Page 16.3; Col. E; Line 43	43
44	Transmission	371	1,0000	371	85.29%	Col. B=Page 16.3; Col. E; Line 44	44
45	Total	435		435	100.00%	Sum Lines 42; 43; 44	45
46	Winter						46
47	Secondary	.	1.0457	_ ]	0.00%	Col. B=Page 16.3; Col. E; Line 47	47
48	Primary	86	1,0108	86	15.61%	Col. B=Page 16.31; Col. E; Line 48	
49	Transmission	465	1.0000	465	84,39%	Col. B=Page 16.31; Col. E; Line 49	49
50	Total	551	1,0000	551	100.00%	Sum Lines 47; 48; 49	50
51	Grand Total	986		986	100,00%	3mii 1.0m3 47; 48; 47	51
	Stand Istal	760	-	760			
52							52
53		Recorded Demand		Recorded Demand			53
54		Determinants	_	Determinants	ļ		54
55		Megawatt @	Transmission	Megawatt @			55
	Forecast Demand Determinants for Standby Customers:	Meter Level	Loss Factors	Transmission Level	Ratios		56
	Contracted Demand Determinants	1 7					57
58	Secondary	143	1.0457	150	8.00%	Col. B=Page 16.3; Line 114	58
59	Primary	1,031	1.0108	1,042	55.54%	Col. B=Page 16.3; Line 115	59
60	Transmission	684	1,0000	684	36.46%	Col. B=Page 16.3; Line 116	60
ابيا	Total	1,858		1,876	100.00%	Sum Lines 57; 58; 59	61
61							

L					3	Section 231	A STATE OF								Γ
Line	6)				San Dieg	San Diego Gas & Electric	etric	100							Line
ģ			Reco	Recorded Sales fo	or the True-	es for the True-Up Period: April 2011		- March 2012	12						No.
	SDG&E: System Delivery Determinants	Winter	Summer	Summer	Summer	Summer	Summer	Winter	Winter	Winter	Winter	Winter	Winter	Total	1
7															7
m	Customer Class Deliveries (MWh)	$\overline{\text{Apr-}11}$	May-11	Jun-11	Jul-11		Sep-11	Oct-11	Nov-11	<u>Dec-11</u>	Jan-12	Feb-12	<u>Mar-12</u>	Total	m
4	Residential	550,729	556,589	560,646	628,559	633,536	668,187	583,078	578,648	663,469	712,816	613,721	601,110	7,351,090	4
S	Small Commercial	149,917	162,512	170,081	175,600	178,863	188,865	169,297	160,943	163,594	171,297	161,540	165,051	2,017,561	5
9	Med. & Large Comm./Ind. (AD + PA-T-1)	17,291	24,144	28,449	28,489	27,197	30,456	26,232	21,763	20,065	20,783	19,501	20,278	284,647	9
7	Med. & Large Comm./Ind. (AL + AY + DGR)	666,187	747,739	808,304	737,717	771,870	829,777	787,540	736,510	744,451	694,066	716,755	761,127	9,002,044	7
∞	Med. & Large Comm./Ind. (A6)	49,476	48,039	53,342	41,776	68,979	71,142	55,637	56,503	72,005	27,507	-4,411	133,257	673,252	- 00
0	Lighting	5,954	9,406	12,675	5,892	-54,587	72,281	9,597	9,052	7,268	10,441	9,516	6,974	104,469	0
10		2.3	4.2	0:0	<u>6.2</u>	0.1	2.7	2.4	0:0	00	1.2	9.0	0.0	19.6	10
= = =	Total System	1,439,557	1,548,434	1,633,497	1,618,040 1	1,625,858	1,860,711	1,631,384	1,563,419	1,670,852	1,636,911	1,516,623	1,687,796	19,433,083	Ξ:
7		ŀ													12
13	Med. & Large Comm./Ind. Rate Schedule Billing Determinants														13
15	Schedules AD / PA-T-1:	Apr-11	Mav-11	.Inn-11	Inl-11	Δ10-11	Sen-11	Oct-11	Nov-11	Dec-11	Ian-17	Feb. 12	Mar. 12	Total	15
17	Total Deliv	17,291	24,144	28,449	⊗	7	30,456	26,232	21,763	20,065	20,783	19,501	20,278	284,647	17
18															18
20	Total Deliveries (%)  % @ Secondary Service	92.16%	84 84%	85 62%	%90.68	%59 06	92 05%	%8688	89 91%	%57.9%	85 74%	%2 5 570%	82 84%	%400%	61 5
21	_	7 84%	15.16%	14 38%	10.94%	935%	7.65%	11 02%	10.09%	13.75%	14.26%	14.43%	17 16%	12 01%	3 5
52		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%	100.001	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	13
24	Total Deliveries (MWh)														24
25		15,935	20,484	24,358	25,372	24,654	28,035	23,341	19,567	17,406	17,820	16,687	16,798	250,457	25
76		1,356	3,660	4,091	3,117	2,543	2,421	2,891	2,196	2,659	2,964	2,814	3,480	34,190	56
27	MWh @ Transmission Service	O 70	01;	0 9	0 9	O 1	0	01	0 ;	01 ;	0	OI ;	01	01	27
8 6	_	17,291	24,144	28,449	28,489	27,197	30,456	26,232	21,763	20,065	20,783	19,501	20,278	284,647	78
2 %	Non-Coincident Demand (%)	0.4858%	0 3882%	0.3527%	0 3281%	0.3302%	0 3283%	0 3409%	0.4071%	0.4504%	0.4170%	0.44480%	0.4300%	0.36250	5 2
31		0.6570%	0.3506%	0.4643%	0.3582%	0.4392%	0.3858%	0.3388%	0.4183%	0.4505%	0.4264%	0.3837%	0.3763%	0.4092%	31
32		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	Non-Coincident Demand (MW)														33
35		77.414	79.518	85.910	83.246	81.407	92.037	79.571	79.658	78.398	74.308	74.223	72.383	958.073	35
36		8.906	12.833	18.994	11.164	11.168	9.341	9.794	9.185	11.977	12.637	10.797	13.094	139.892	36
37	MW @ Transmission Service	0.000 86.320	0.000 92.350	0.000 104.905	0.000 94.410	0 <u>.000</u> 92.576	0.000	0.000 89 364	0.000 88 844	0.000 90 375	0.000 86 945	0.000 85.021	0.000 85 477	0.000	37
39														1,0,1,1	3 6
40											-				4
4															41

															ſ
Line			Berr	Recorded Sales f	San Die	San Diego Gas & Electric he True-I'n Period: Apri	ectric April 2011	Section 2.3.1  San Diego Gas & Electric les for the True In Period: Annil 2011 - March 2012	2						Line
4 <del>2</del> <del>2</del> <del>2</del> <del>2</del> <del>2</del> <del>2</del> <del>2</del> <del>2</del> <del>2</del> <del>2</del>	Schedules AL-TOU / AY-TOU / DG-R: Total Deliveries (MWh)	Apr-11 666,187	Mav-11 747,739	Jun-11 808,304	Jul-11 737,717	Aug-11 771,870	Sep-11 829,777	Oct-11 787,540	Nov-11 736,510	Dec-11 744,451	<u>Jan-12</u> 694,066	Feb-12 716,755	Mar-12 761,127	<b>Total</b> 9,002,044	42 43
4 <del>3</del>	Total Deliveries (%)														44 4
46		80.29%	79.08%	78.85%	78.99%	78.91%	%09.08	78.34%	78.48%	78.29%	82.74%	80.11%	78.00%	79.36%	46
47		18.91%	19.68%	16.73%	19.53%	19.44%	17.34%	20.68%	19.44%	20.14%	17.93%	18.73%	18.37%		47
8 4 6	% @ Transmission Service	0.80% 100.00%	1.24% 100.00%	4.42% 100.00%	$\frac{1.48\%}{100.00\%}$	1.65 <u>%</u> 100.00%	<u>2.06%</u> 100.00%	0.98 <u>%</u> 100.00%	2 <u>.08%</u> 100.00%	1.57% 100.00%	-0.67% 100.00%	1.16% 100.00%	3.63% 100.00%	100.00%	48 49
50					1						1		;		50
3 21	MWh @ Secondary Service	534,882	591,312	637,348	582,723	609,083	668,801	616,959	578,013	582,830	574,270	574,192	593,679		51
53		5,329	9.272 9.272	35,727	10.918	12,736	17,093	7.718	145,178	11,688	4,650	8,314 8,314	27,629	157,094	23
54		666,187	747,739	808,304	737,717	771,870	829,777	787,540	736,510	744,451	694,066	716,755	761,127	9,002,044	54
55		70000	2000	2000											55
3 6	% @ Secondary Service % @ Primary Service	0.2872%	0.2835%	0.2662%	0.2694%	0.2747%	0.2838%	0.2882%	0.2927%	0.2739%	0.2676%	0.2784%	0.2777%	0.2786%	56
58		0.2548%	0.2247%	0.1759%	0.1902%	0.2049%	0.2065%	0.2258%	0.1874%	0.1106%	0.0068%	0.1626%	0.2044%		58
59	CANAGE ALL CALLED TO THE CALL OF THE CALL														59
61		1,536.180	1,676.370	1,696.620	1,569.856	1,673.150	1,898.056	1,778.076	1,691.844	1,596.372	1,536.747	1,598.551	1,648.647	19,900.469	60 61
62		298.815	333.012	311.298	324.460	334.765	343.450	384.683	330.311	332.550	286.350	302.327	311.936	3,893.956	62
8 4	MW @ Transmission Service	13.580 1.848.575	2.030.216	62.844 2.070.762	20.766 1.915.082	<u>26.096</u> 2.034.011	35.298 2.276.804	$\frac{17.427}{2.180.187}$	28.709 2.050.863	12.927 1.941.849	-0.316 1.822.781	13.519 1.914.397	<u>56.473</u> 2.017.056	308.156	63
65	On-Peak Demand (%)		·		•			,							65
99		0.2307%	0.2402%	0.2490%	0.2526%	0.2582%	0.2693%	0.2500%	0.2349%	0.2178%	0.2121%	0.2224%	0.2216%	0.2389%	99
67	% @ Primary Service % @ Transmission Service	0.2097%	0.2083%	0.2354%	0.2308%	0.2373%	0.2511%	0.2318%	0.2059%	0.2002%	0.2082%	0.2092%	0.1948%	0.2189%	67
69		2000	0.1205.0	0.17071.0	0.4.04.0	0.011.0	0.000	0.0000.0	0.51140.0	0.002.0	0.0470.0	0.1001.0	0.50405.0		8 8
70		Winter		Summer	Summer	Summer	Summer	Winter	Winter	Winter	Winter	Winter	Winter	Total	2
71		1,233.972	1,420.332	1,586.996	1,471.958	1,572.651	1,801.080	1,542.398	1,357.752	1,269.405	1,218.027	1,277.003	1,315.593	17,067.168	71
22 5		264.172	306.524	318.330	332.528	356.072	361.291	377.517	294.803	300.165	259.097	280.847	272.367	3,723.712	72
2, 4	MW @ 1 ransmission Service	20.353 1,518.497	35.428 1,762.284	69.025 1,974.351	31.35/ 1,835.843	52.688 1,981.412	48.47/ 2.210.848	45.2/3 1,965.188	32.875 1,685.430	31.440 1.601.010	- <u>26.720</u> 1.450.403	15.273 1.573.124	$\frac{100.735}{1.688,695}$	456.206 21.247.086	73
75											,				75
76				2000											76

Line	9 6	2 79	80		83			98			8 8		92		, 4, 1		6 6	_	8 S				105	106		•	109		112					118
	Total	673,252		0.00%	14.84%	85.16%	100.00%	•	) <b>6</b>	99,932	<u>573,320</u> 673,252		0.0000%	0.2002%	0.1882%		0.000	, 010,10,	1.278.948		0.0000%	0.1494%	0.1459%	Total	0.000	149.319	836.591	707.71	Total	143.047	1,031.175	683.622	1,857.844	
11,22,301, 122,74, 1	Mor 17	133,257		0.00%	7.35%	92.65%	100.00%	•	0 107	9,794	133,257		0.0000%	0.1975%	0.1806%	,	0.000	19.544	<u>222.973</u> 242.317		0.0000%	0.1509%	0.1474%	Winter	0.000	14.780	181.984	100.04	<u>Mar-12</u>	11.518	85.229	59.524	156.271	
100	Tab 12	4,411		0.00%	-237.33%	337.33%	100.00%	•	0 77.01	10,468	-14,8/ <u>9</u> -4,411	,	0.00000	0.1972%	0.7082%		0.000	20.045	-39.905 -19.262		0.0000.0	0.1353%	0.2069%	Winter	0.000	14.163	-30.784	10.021	Feb-12	11.668	84.233	59.524	155.425	
and the second s	Lon 12	27,507		0.00%	19.88%	80.12%	100.00%	•	0	2,468	27,507	,	0.00000	0.0945%	0.1899%	•	0.000	2.100	41.851 47.019		0.0000%	0.1873%	0.1382%	Winter	0.000	10.242	<u>30.457</u> 40.699	10.01	Jan-12	11.668	84.158	59.839	155.665	
15 15 15 15 15 15 15 15 15 15 15 15 15 1	Noc-11	72,005		0.00%	17.64%	82.36%	100.00%	•	0 0	12,702	72,005		0.00000	0.1973%	0.176170		0.000	25.000	130.680		0.0000%	0.1676%	0.1246%	Winter	0.000	21.288	73.892	201.57	Dec-11	11.667	86.294	60.441	158.402	
2012	Nov-11	56,503		0.00%	11.70%	88.30%	100.00%	•	0	0,611	56,503		0.0000%	0.1785%	0.1940%	•	0.000	11.800	97.090 108.891		0.0000%	0.0586%	0.1488%	Winter	0.000	3.874	74.240	1100	Nov-11	11.938	88.693	56.678	157.309	
WMarch	Orf-11	55,637		0.00%	13.89%	86.11%	100.00%	•	0 00.7.7	7,128	55,637		0.0000%	0.1145%	0.192670	6	0.000	0.047	92.368 101.217		0.0000.0	0.1155%	0.1508%	Winter	0.000	8.926	72.247 81.172		Oct-11	11.938	88.693	56.678	157.309	
lectric	Sen-11	71,142		0.00%	15.36%	84.64%	100.00%	•	0 00 01	10,927	71,142		0.0000%	0.2596%	0.132370	•	0.000	115 012	144.281		0.0000%	0.1346%	0.1633%	Summer	0.000	14.708	98.331 113.039		Sep-11	12.088	88.027	56.682	156.797	
Section 2.3.1 San Diego Gas & Electric the True-Up Period: April	Δ110-11	68,979		0.00%	14.32%	85.68%	100.00%	•	0 040	50.101	68,979		0.0000%	0.2282%	0.172470	6	0.000	101 000	124.432	,	0.0000%	0.1350%	0.1387%	Summer	0.000	13.335	95 308		Aug-11	12.088	86.580	57.992	156.660	- 8
Section 2.3.1  San Diego Gas & Electric les for the True-Up Period: April 2011	Ĭn1.11	41,776		0.00%	7.68%	92.32%	100.00%	•	3 208	007,0	41,776		0.0000%	0.1259%	0.202070	•	0.000	1.007	83.411		0.0000.0	0.3672%	0.1701%	Summer:	0.000	11.781	<u>65.603</u> 77.384		Jul-11	12.089	85.362	58.139	155.590	4.5 4.7
Recorded Sales	.T.m.11	53,342		0.00%	19.53%	80.47%	100.00%	•	0 010	10,418	53,342		0.0000%	0.2204%	0.70402.0	0	0.000	07.501	110.526		0.0000%	0.1600%	0.1632%	Summer	0.000	16.668	70.052 86 72 1		60-unf	12.089	85.774	58.335	156.198	
	Mav-11	48,039		0.00%	10.39%	89.61%	100.00%	•	7 00 1	12,721	48,039		0.0000%	0.2754%	0.20102.0	6	0.000	96 971	100.617		0.00000	0.1465%	0.1289%	Summer	0.000	7.312	62.801		<u>May-11</u>	12.149	84.284	49.475	145.908	100
	Apr-11	49,476		0.00%	15.64%	84.36%	100.00%	<	0 2 7 7 7 2 8	738	41,738		0.0000%	0.2273%	0.2020	0	0.000	07.723	87.232 104.820		0.0000%	0.1582%	0.1512%	8000000	0.000	12.242	$\frac{63.107}{75.349}$		<u>Apr-11</u>	12.149	83.848	50.315	146.312	
	Schedule A6-TOII:	1				ice		<b>a</b> l:	71Ce	9	100	( <u>%) pu</u>		92	2	MW)	99		TVICE	(%) pu			% @ 1ransmission Service Coincident Demand at Time of System of Peak	nd (MW)	8		rvice		Schedule S: Standby Determinants:	ee		rvice		
	Schedule	Total Deliveries (MWh)	Total Deliveries (%)	% @ Secondary Service	% @ Primary Service	% @ Transmission Service		Total Deliveries (MWh)	MWh @ Secondary Service	MWII @ rillinary Service	MWII (@ 11cmmoonioo	Non-Coincident Demand (%)	% @ Secondary Service	% @ Primary Service % @ Transmission Service	70 (# 114msmission Serv.	Non-Coincident Demand (MW)	MW @ Secondary Service MW @ Primary Service	MW @ Transmission Ser	M W @ 1 ransmission Service	Coincident Peak Demand (%)	% @ Secondary Service	% @ Primary Service	% (a) 1 ransmission Service Coincident Demand at Ti	Coincident Peak Demand (MW)	MW @ Secondary Service	MW @ Primary Service	MW (a) Iransmission Service		Schedule S: Standby Determing Contracted Standby Demand (MW)	MW @ Secondary Service	MW @ Primary Service	MW @ Transmission Service		
Line No.	78		8 <u>2</u>						/ ×					2, 2			7 %						105				109	111	112	• • •	115		117	NOME ( 1000 000 000 000

### 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. ER12- -

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

	Line No.	-	٠ ,	7 m	4	5	9	7	∞	6	10	11	
	Reference	(a)=Section 2 3 7. Pare 7. I ine 1	(4) Section 2.3.2, 1 ago 2, 1 me 1	(a)=Section 2.3.1; rage 2; Line 4 (a)=Section 2.3.2; Page 2; Line 3	(b)=Section 2.3.1; Page 2; Line 5	(a)=Section 2.3.2; Page 2; Line 5	(b)=Section 2.3.1; Page 2; Line 6	(a)=Section 2.3.2; Page 2; Line 7	(b)=Section 2.3.1; Page 2; Line 7	(a)=Section 2.3.2; Page 2; Line 9	(b)=Section 2.3.1; Page 2; Line 8	Sum Lines 1 through 9	
(d) = (c)/(a)	(%) Change	%00 0		00:00		%00.0		%00.0		%00.0		%00.0	
(c) = (a) - (b)	(\$) Change	500		\$ 43		\$ (343)		æ		\$ (1)		0 \$	
 (9)	True-Up Period Total Cost of Service	129 484 000		\$ 38,584,000		\$ 151,047,000		\$ 1,209,000		\$ 4,423,000		\$ 324,747,000	
(a)	Transmission Revenues @ Proposed Rates	129 484 299		38,584,043		151,046,657		1,209,003		4,422,999		\$ 324,747,000	
	Customer Classes	Residential Customers		Small Commercial Customers		Medium-Large Commercial Customers		Street Lighting Customers		Standby Customers		Grand Total	
	Line No.	-	٠ ر	4 W	4	2	9	7	<b>∞</b>	6	10	11	

## 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, 2011 - March 31, 2012

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	Θ	5	§	Ð	(M)
	Apr-11	May-11	Jun-11	Jਘੋ-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	
	Winter	Summer	Summer	Summer	Summer	Summer	Winter	Winter	Winter	Winter	Winter	Winter	
Customer Class													Total
Decidential Cuctomere	712 002 0 3	0 003 031	0 707 777 1 0 002 200 0 1 027 200 0 1 1 071 224 0 1	8 11 071 634	Ø 11 150 206	257 052 11 3	01202013	027 701 01 3	287 287 11 3	0 10 555 750	6700001	201000000	100 404 000
	\$17,007,7 ¢	166,600,6 6	000,010,7 4	+co,1/0,11 &	067,461,11	0.00,407,11	010,0/2,01	1,127,270   11,707,025   10,270,010   10,172,477   11,000,247   12,513,726   10,810,202   10,288,135   129,484,299	41,080,11 6	\$ 12,535,738	\$ 10,810,262	\$ 10,588,135	\$ 129,484,299
Small Commercial 2	2,867,031	3,107,902	3,252,646	3,358,193	3,420,590	3,611,876	3,237,653	3,077,894	3,128,594	3,275,904	3,089,316	3,156,443	38,584,043
Medium-Large Commercial 3	10,906,355	13,537,538	14,131,780	12,971,601	13,963,819	15,649,347	12,713,469	12,018,933	11,558,897	10,469,613	10,614,345	12,510,958	151,046,657
	68,903	108,855	146,689	68,187	(631,722)	836,489	111,067	104,755	84,107	120,831	110,132	80,709	1,209,003
										-			
	348,487	347,543	371,850	370,406	372,958	373,313	374,517	374,517	377,013	370,508	369,943	371,944	4,422,999
	\$ 23,891,490	\$ 26,905,770	\$ 27,778,345	\$ 27,840,022	\$ 28,284,941	\$ 32,240,679	\$ 26,707,217	\$ 23,891,490   \$ 26,905,770   \$ 27,778,345   \$ 27,778,345   \$ 28,284,941   \$ 32,240,679   \$ 26,707,217   \$ 25,708,578   \$ 26,835,158   \$ 26,732,613   \$ 24,793,998   \$ 26,798,189   \$ 324,747,000	\$ 26,835,158	\$ 26,792,613	\$ 24,993,998	\$ 26,708,189	\$ 324,747,000

NOTES

See Pages 3 & 4; Line 25.

See Pages 3 & 4; Line 27.

See Pages 3 & 4; Lines 29 through 33. See Pages 3 & 4; Line 35.

See Pages 3 & 4; Line 37.

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-Lip Period Annil 1, 2011 - March 31, 2012

Line No

				For	True-Up Period	For True-Up Period April 1, 2011 - March 31, 2012	March 31, 2012						
		(A)	)	(B)	,	(C)		(D)		(E)		(F)	
		Apr-11	11	May-1	-11	I-m/	11	11-ln/	1	Aug-1	11	Sep-1	
Line	92	Billing Determinants	erminants	Billing Determinants	eminants	Billing Determinants	rminants	Billing Determinants	rminants	Billing Determinants	rminants	Billing Determinants	minants Li
ģ	Customer Classes	Energy (kWh) Demand (kW)	Demand (kW)	Energy (kWh) Demand (kW)	Demand (kW)	Energy (kWh) Demand (kW)	Demand (kW)	Energy (kWh)   Demand (kW)	Demand (kW)	Energy (kWh)   Demand (kW)	Demand (kW)	Energy (kWh) Demand (kW)	Demand (kW) N
	Pacidential Customere	\$50 770 440	ı	566 580 305	,	167 577 075		367 033 669		331 763 667		126 501 022	
- 0		200,000	1	000,000,000	1	120,040,000	•	054,600,070		551,055,550		1/5,/01,000	
n	Small Commercial	149,917,195	,	162,512,335	•	170,081,023	•	175,600,080	٠	178,862,780	•	188,865,172	•
4					•								
3	Medium-Large Commercial	732,953,867		819,922,226		680,260,068		807,981,837		868,045,813		931,375,233	
9	Non-Coincident (100%)		86,320		92,350		104,905		94,410		92,576		101,378
7	Non-Coincident (90%)		1,953,395		2,130,833		2,181,288		1,998,493		2,158,442		2,421,084
*	Maximum On-Peak Period Demand		1,518,497		1,762,284		1,974,351		1,835,843		1,981,412		2,210,848
0	Maximum Demand at the Time of System Peak		75,349		62,801		86,721		77,384	•	95,308		113,039
<u> </u>													
Ξ	11 Street Lighting	5,953,894	•	9,406,113		12,675,328	•	5,891,993	•	(54,586,793)	•	72,280,618	•
=	13 Standby Customers	1	146,312	•	145,908	•	156,198	•	155,590	•	156,660	-	156,797
-													
<u>::</u>	15 TOTAL	1,439,554,405		1,548,429,979		1,633,497,061		1,618,033,345		1,625,857,955		1,860,708,394	

NOTES: The above billing determinants are the recorded determinants from April 2011 through March 2012.

	(A)	(B)		(C)		1)		9		£	
	Apr-11	May-1	11	J-mr-1	11	Jul-1	11	Aug-11	-11	Sep-11	1
Line	Changed Transmission Rates		nission Rates	Changed Transi	mission Rates	Changed Trans	mission Rates	Changed Transi	mission Rates	Changed Transmission Rates   Changed Transmis	nission Rates
No. Customer Classes	Energy (kWh) Demand (kW)	(W) Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh) Demand (kW) Energy (kWh) Demand (kW) Energy (kWh) Demand (kW) Energy (kWh) Demand (kW) Energy (kWh) Demand (kW) Energy (kWh) No.	Demand (kW)
16   Residential Customers 1	\$ 0.0176143	\$ 0.0176143		\$ 0.0176143		\$ 0.0176143		\$ 0.0176143		\$ 0.0176143	
17											
18 Small Commercial 1	\$ 0.0191241	\$ 0.0191241		\$ 0.0191241		\$ 0.0191241		\$ 0.0191241		\$ 0.0191241	
19											
20 Medium-Large Commercial 1											
21				•							
22 Street Lighting 1	\$ 0.0115728	\$ 0.0115728		\$ 0.0115728		\$ 0.0115728		\$ 0.0115728		\$ 0.0115728	
23											
24 Standby Customers 1						_					

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

		(A)	(B)	)	(C)	)	(D)	((	(E)	6	Œ		
	¥	Apr-11	May-1	-11	11-mf	11	Jul-11	11	1-guy	11.5	Sep-11	-11	_
Line	Revenues @	Revenues @ Changed Rates	Revenues @ Changed Rates	hanged Rates	Revenues @ Changed Rates	hanged Rates	Revenues @ Changed Rates	hanged Rates	Revenues @ Changed Rates	hanged Rates	Revenues @ C	Revenues @ Changed Rates	Line
No. Customer Classes	Energy (kWh	Energy (kWh) Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh) Demand (kW)	Demand (kW)	Energy (kWh)	Energy (kWh) Demand (kW)		Energy (kWh) Demand (kW)	Energy (kWh)	Demand (kW)	ģ
											;		
Zo Kesidential Customers	\$ 9,700,714	4	3,803,951		085,5/8,6		\$ 11,0/1,634		\$ 11,159,296		\$ 11,769,653		23
26													56
27 Small Commercial	\$ 2,867,031	1	\$ 3,107,902		\$ 3,252,646		\$ 3,358,193		\$ 3,420,590		\$ 3,611,876		27
28									_				28
Ž	69		•		·		•		69		·		63
30 Non-Coincident (100%)		\$ 494,469		\$ 528,380		\$ 599,364		\$ 540,538		\$ 529,995	<u>.</u>	\$ 580,944	30
31 Non-Coincident (90%)		\$10,028,120		\$10,939,260		\$11,192,776		\$10,259,487		\$11,075,686		\$12,426,655	31
32 Maximum On-Peak Period Demand		\$ 364,472		\$ 1,988,682		\$ 2,227,433		\$ 2,071,475		\$ 2,234,862	•	\$ 2,495,549	32
33 Maximum Demand at the Time of System Peak	em Peak	\$ 19,294		\$ 81,217		\$ 112,207		\$ 100,100		\$ 123,276		\$ 146,200	33
34											_		34
35 Street Lighting	\$ 68,903	<u>n</u>	\$ 108,855		\$ 146,689		\$ 68,187		\$ (631,722)		\$ 836,489		35
36													36
37 Standby Customers		\$ 348,487		\$ 347,543		\$ 371,850		\$ 370,406		\$ 372,958		\$ 373,313	
													38
39 TOTAL	\$ 12,636,64	\$ 12,636,648 \$11,254,842 \$	\$ 13,020,688	\$13,885,081	\$ 13,274,716	\$14,503,630	\$ 14,498,015	\$13,342,007	\$ 13,948,164	\$14,336,777	\$ 16,218,018	\$16,022,660	39
40		,											9
41 Grand Total		\$23,891,490		\$26,905,770		\$27,778,345		\$27,840,022		\$28,284,941		\$32,240,679	4
	,												

NOTES: The revenues above are derived by multiplying the forecast billing determinants by the rates, except for Med. & Lig. C-I and Standby customers. The derivation of revenues for Med. & Lig. 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, 2011 - March 31, 2012

Line No.

	(9)		(H)		(I)		(J)		(K)		(T)		(M)	
	Oct-1]	11	Nov-11	11	Dec-1	11	Jan-12	2	Feb-12	12	Mar-12	12	Total	
63	Billing Determinants	rminants	Billing Determinants	rminants	Billing Determinants	rminants	Billing Determinants	rminants	Billing Determinants	rminants	Billing Determinants	minants	Billing Determinants	rminants
Customer Classes	Energy (kWh)	Demand (kW)	Energy (kWh)   Demand (kW)   Energy (kWh)   Demand (kW)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh) Demand (kW)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)   Demand (kW)	Demand (kW)	Energy (kWh)	Demand (kW)
Residential Customers	583,077,961	•	578,647,962	•	663,469,258	,	712,816,164		613,720,804	,	601,110,205		7,351,089,690	,
Small Commercial	169,297,006	,	160,943,217	•	163,594,306	•	171,297,139		161,540,451	·	165,050,532	,	2,017,561,236	,
Medium-Large Commercial	869,409,273		814,776,186		836,520,849		742,355,942		731,844,877		914,661,596		9,959,942,788	
Non-Coincident (100%) Non-Coincident (90%)		89,364 2,281,403		88,844 2,159,754		90,375		86,945		85,021 1,895,135		85,477		1,097,964
Maximum On-Peak Period Demand		1,965,188		1,685,430		1,601,010		1,450,403		1,573,124		1,688,695		21,247,086
Maximum Demand at the Time of System Peak		81,172		78,114		95,180		40,699		(16,621)		196,764		985,910
Street Lighting	9,597,278	•	9,051,839	•	7,267,629		10,440,962	•	9,516,420	•	6,974,066	•	104,469,347	•
Standby Customers	•	157,309		157,309		158,402		155,665		155,425		156,271	·	1,857,844
TOTAL	1,631,381,518		1,563,419,204		1,670,852,042		1,636,910,207		1,516,622,552		1,687,796,399		19,433,063,061	

NOTES: The above billing determinants are the recorded determinants from April 2011 through March 2012.

_		(Đ)		(H)		(I)		€		3		Œ	_	₹ E	Ç	
		Oct-11	_	Nov-11	11	Dec-11	1	Jan-12	7	Feb-12	12	Mar-12	:12	To	Total	1
Line		Changed Transmission Rates Changed Transmission Rates	ission Rates	Changed Transr	_	Changed Transmission Rates Changed Transmission Rates Changed Transmission Rates	ission Rates	Changed Transn	nission Rates	Changed Transp.	nission Rates	Changed Transr		Changed Transmission Rates	smission Rates	Line
No.	Customer Classes	Energy (kWh)   Demand (kW)   Energy (kWh)   Demand (kW)	Demand (kW)	Energy (kWh)		Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh) Demand (kW) Energy (kWh) Demand (kW) Energy (kWh) Demand (kW) Energy (kWh) Demand (kW)	Demand (kW)	Energy (kWh)	Demand (kW)		Demand (kW)	ž
																L
16 Res	16 Residential Customers 1	\$ 0.0176143		\$ 0.0176143		\$ 0.0176143		\$ 0.0176143		\$ 0.0176143		\$ 0.0176143				16
17																17
18 Sm.	18 Small Commercial 1	\$ 0.0191241		\$ 0.0191241		\$ 0.0191241		\$ 0.0191241	-	\$ 0.0191241		\$ 0.0191241				18
19																19
20 Mex	20 Medium-Large Commercial 1															8
21																21
22 Stre	22 Street Lighting 1	\$ 0.0115728		\$ 0.0115728		\$ 0.0115728		\$ 0.0115728		\$ 0.0115728	_	\$ 0.0115728				23
23																23
24 Star	24 Standby Customers 1															24

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

kW) Energy (kWh) Demand (kW) Energy (kWh) Demand (kW) Energy (kWh) Demand (kW) Energy (kWh) Demand (kW
Revenues @ Changed Rates Revenues @ Changed Rates Revenues @ Changed Rates  Energy (kWh)   Demand (kW)   Energy (kWh)   Demand (kW)
Revenues @ Changed Rates   Revenues @ Changed Rates   Revenues @ Changed Rates   Energy (kWh)   Demand (kW)   Dema
Revenues @ Changed Rates
Revenues @ Changed Rates Energy (kWh) Demand (kW)
Revenues @ Changed Rates
Revenues @ Changed Rates   Revenues @ Changed Rates   Energy (kWh)   Demand (kW)   Energy (kWh)   Demand (kW)
Revenues @ Changed Rates
Revenues ( Energy (kW)
Customer Classes

Los, the revenues toove are aerived by manipping ine jorecasi building aetermannis by the tales, except jo The derivation of revenues for Med. & Lig. C-1 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, 2011 - March 31, 2012 Medium and Large Commercial & Industrial Customers

Line	No.	11; Line 5 2		5 ine 37						13					ń	. 61		44						m	m ñ				m	m i	m č		
	Reference	Section 2.3.2; Pages 9, 10 & 11; Line 5	Line 2 x Line 3	Section 2.3.2: Page 12: Line 37	Section 2.3.2; Page 12; Line 39	Section 2.3.2; Page 12; Line 41	Succession 2.2. Breast 1.1.	section 2.3.2; rages 1.1; Line 43	Line 10 - Line 11		Section 2.3.1; Page 1; Line 6D	Section 2.3.1; Page 1; Line 6C	Section 2.3.1; Page 1; Line 6B	Line 7 x Line 15	Line 8 x Line 16	Line 9 x Line 17	Sum Lines 19; 20; 21		Section 2.3.2; Page 12; Line 46	Section 2.3.2; Page 12; Line 47	Section 2.3.2; Page 12; Line 48	Sum Lines 25; 26; 27	Section 2.3.2; Pages 1.1; Line 49	Line 28 - Line 29		Section 2 3 1: Page 1: Line 8D	Section 2.3.1; Page 1; Line 8C	Section 2.3.1; Page 1; Line 8B		Line 25 x Line 33	Line 26 x Line 34	Cum f ince 37: 38: 30	ים יים כיווות אוווים
	Total	9,959,942,788		958.073	139,892	1 007 964	1,007,064	+04,740,1	-					\$ 5,507,099	\$ 777,309		6,284,408		19,900,469	4,094,063	1,386,998	25,381,530	25,381,530	•						_	\$ 20,473,822	13	AUTO-COLOUR
Winter	Mar-12	914,661,596		72.383	13,094	- 85 477	05 477	//+,00	•				\$ 5.4967653	\$ 416,063	72,756	•	\$ 488,819		1,648,647	331,280	279,447	2,259,374	2,259,374	•		9062213		\$ 4,9470888			1,656,685	+	
Winter	Feb-12	731,844,877	\$	74.223	10,797	85.021	140,50	170,00	-		5.7481007	5.5565073	\$ 5.4967653	\$ 426,643	59,995	•	\$ 486,638		1,598,551	322,970	(26,386)	1,895,135	1,895,135	-		\$ \$ 1732906	5.0008566	\$ 4.9470888			(521,516,1		7,104,000
Winter	Jan-12	742,355,942	\$	74.308	12,637	- 86 945	24,00	C+6,00	-				\$ 5,4967653	\$ 427,130	70,219		\$ 497,349		1,536,747	291,518	41,535	1,869,799	1,869,799	-		\$ 5.1732906		\$ 4.9470888		\$ 7,950,037	1,457,839	0/4,002	1
Winter	Dec-11	836,520,849	, ,	78.398	11,977	90 375							\$ 5.4967653	\$ 450,641	66,551	-	\$ 517,192		1,596,372	357,610	118,546	2,072,529	2,072,529	-		\$ 5.1732906		\$ 4.9470888		\$ 8,258,499	1,788,339	\$ 10.633.317	
Winter	Nov-11	814,776,186	\$	79.658	6,185	88 844	l	110,00			(A)	69 (	\$ 5.4967653	\$ 457,883	51,039	•	\$ 508,922		<u>-</u>		125,799	2,159,754	2,159,754	•		\$ 5.1732906	69	\$ 4.9470888		8,752,400	1,710,848	5	
Winter	Oct-11	869,409,273	8	19.57	9,794	798 384		100,00	•		59	69 (	\$ 5.4967653	\$ 457,379	54,420	•	\$ 511,799		1,778,076		109,795	2,281,403	2,281,403	•		\$ 5.1732906	64	\$ 4.9470888		\$ 9,198,505	1,967,996	2	1
Summer	Sep-11	- 6	\$	92.037		101 378	L	0/6,101	-		64	69 6	\$ 5.4967653	\$ 529,040	51,904		\$ 580,944		1,898,056			╽	2,421,084	٠		\$ 5.1732906	69	\$ 4.9470888		64	1,859,405	\$ 12	<u>ال</u>
Summer	Aug-11	868,045,813	8	81.407		97 576	8	2,5			<del>59</del>	\$ 5.5565	\$ 5.4967653	\$ 467,938	62,058		\$ 529,995		_		127	2,158,	2,158,442	·		\$ 5.1732906	s	\$ 4.9470888		8,655,691	1,786,836	5	
Summer	Jul-11	807,981,837	\$	83.246		94410	l				<del>5</del> 9	<del>69</del> 6	\$ 5.4967653	\$ 478,506	62,032	•	\$ 540,538		-		100,138		1,998,493	•		\$ 5.1732906	69	\$ 4.9470888		8 8,121,321		5	-1-
Summer	Jun-11	890,690,088		85.910		104 905	L		•		59	<del>69</del> 6	\$ 5.4967653	٠	105,542	•	\$ 599,364		1,696,620		1	1	2,181,288	•		\$ 5.1732906	<b>69</b>	\$ 4.9470888	•	64	1,5/1,5/8	21.	1
Summer	May-11	819,922,226	· ·	815.67		- 00	L				so.	69 6	\$ 5.4967653	8	71,305	•	\$ 528,380		1,676,370	346,758	107,705	1	2,130,833			\$ 5.1732906	69	\$ 4.9470888	4	5 <del>4</del>	1,734,086	8	<u>.</u>
Winter	Apr-11	732,953,867	s	77,414	8,906	- 86 320	02,22	075,00	,				\$ 5.4967653	\$ 444,981	49,488	•	\$ 494,469		1,536,180	316,404	100,811	1,953,395	1,953,395	•		\$ 5.1732906		\$ 4.9470888		\$ 7,947,107	1,582,289	\$ 10.028.120	
	Description	Energy.Revenues Commodity Sales - kWh	Total Commodity Revenues	Non-Coincident Demand (100%) (kW)!: Secondary	Primary	Transmission Total	Charle Eigens	Circle Figure	Difference	Non-Coincident Demand (100%) Rates (\$/kW):	Secondary	Primary	Transmission	Non-Coincident Demand (100%) - Revenues: Secondary	Primary	Transmission	Subtotal	Non-Coincident Demand (90%) (kW)*:	Secondary	Primary	Transmission	Total	Check Figure	Difference	Non-Coincident Demand (90%) Dates (CRW).	Secondary	Primary	Transmission	Non-Coincident Demand (90%) - Revenues:	Secondary	Frimary	Subtotal	Subjections
Line	No.		, 4	2 9 7 S	· ••	6 5	? :	= :	- 21	5 7 S	15	9 :	_		20	21	52	ង	52	56	27	78	59	30		·	34	35	_	37	× S	, Q	<u> </u>

NOTES:

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

Non-Coincident Demand (NCD) (100%) rates are applicable to the following CPUC tariffs: Schedules AY-TOU, AL-TOU, AL-TOU-DER, DG-R, and A6-TOU.

Naximum on-Peak Demand rates are applicable to the following CPUC tariffs: Schedule AA-TOU, AL-TOU-DER, and DG-R

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, 2011 - March 31, 2012

						Medium a	m and Large Com	ommercial & Indus	Medium and Large Commercial & Industrial Customers							
Lin		Winter	Summer	Summer	Summer	Summer	Summer	Winter	Winter	Winter	Winter	Winter	Winter			Line
Š	Description	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Total	Reference	2
-	Maximum On-Peak Period Demand (kW)*:															_
7	Secondary	1,233,972	1,420,332	1,586,996	1,471,958	1,572,651	1,801,080	1,542,398	1,357,752	1,269,405	1,218,027	1,277,003	1,315,593	17,067,168	Section 2.3.2; Pages 12; Line 17 x 1000	- 7
m	Primary	264,172	306,524	318,330	332,528	356,072	361,291	377,517	294,803	300,165	259,097	280,847	272,367	3,723,712	Section 2.3.2; Pages 12; Line 18 x 1000	6
4	Transmission	20,353	35,428	69,025	31,357	52,688	48,477	45,273	32,875	31,440	(26,720)	15,273	100,735	456.206	Section 2.3.2: Pares 12: Line 19 x 1000	4
'n	Total	1,518,497	1,762,284	1,974,351	1,835,843	1,981,412	2,210,848	1,965,188	1,685,430	1,601,010	1,450,403	1,573,124	1,688,695	21,247,086	Sum Lines 2: 3: 4	٠,
9	Check Figure	1,518,497	1,762,284	1,974,351	1,835,843	1,981,412	2,210,848	1,965,188	1,685,430	1,601,010	1,450,403	1,573,124	1,688,695	21,247,086	Section 2.3.2; Pages 12; Line 20	. 40
1	Difference								,						I in S - I in S	, ,
• •															o all'a c all'a	- 0
	Maximum On Bank Baried Bornes d Bates (\$400).	Winter	Chammon	Cummon	Commence		3	MESSES	1	116						× 0
, <u>s</u>	Secondary	\$ 0.2415850	\$ 1 13K1238	6	9	Summiter 9	3mmmel e 1 1261729	ç	0.2416950	W III E	v Juler	Willer				ο ;
2 :	Primary		\$ 1,0080775	9 5	9 6	5 1.1361236 1.0960775		0.2413630	0.2415650	3 0.2413630 3	3 0.2413830 3	0.2415850	3 0.2415850		Section 2.3.1; Page 1; Line 11D; 12D	0 ;
: 2	Transmission			• •	9 69	\$ 1.0845020	1.0845020	0.2326318		0.2326318	0.2326318	0.2326318	\$ 0.232883	,	Section 2.3.1; Page 1; Line 11C; 12C	= 5
13	Maximum On-Peak Period Demand - Revenues:						_								200000 2:2:1, 1 age 1, 120, 120	7 2
14	Secondary	\$ 298,109	\$ 1,613,673	\$ 1,803,024	\$ 1,672,327	\$ 1,786,727	\$ 2,046,250	\$ 372,620	\$ 328,013	\$ 306,669	\$ 294,257 \$	308,505	\$ 317,827 \$	11,148,001	Line 2 x Line 10	4
15	Primary	61,628	336,587	349,551	365,141	390,995	396,726	88,070	68,774	70,025	60,444	815,53	63,540 \$		Line 3 x Line 11	15
16	Transmission	4,735	38,422	74,857	34,007	57,140	\$2,573	10,532	7,648	7,314	(6,216)	3,553	23,434		Line 4 x Line 12	16
17	Subtotal	\$ 364,472	\$ 1,988,682	\$ 2,227,433	\$ 2,071,475	\$ 2,234,862	\$ 2,495,549	\$ 471,223	\$ 404,434 \$	S 384,008 S	\$ 348,485 \$	\$ 377,576 \$	\$ 404,802 \$	13,773,001	Sum Lines 14; 15; 16	17
18										-						8
19	Maximum Demand at the Time of System Peak (kW)*	Winter	Summer	Summer	Summer	Summer	Summer	Winter	Winter	Winter	Winter	Winter	Winter		•	19
70	Secondary									•				•	Section 2.3.2; Pages 12; Line 30 x 1000	8
21	Primary	12,242	7,312	16,668	11,781	13,335	14,708	8,926	3,874	21,288	10,242	14,163	14,780	149,319	Section 2.3.2; Pages 12; Line 31 x 1000	77
52	Transmission	63,107	55,489	70,052	65,603	81,973	98,331	72,247	74,240	73,892	30,457	(30,784)	181,984	836,591	Section 2.3.2; Pages 12; Line 32 x 1000	22
23	Total	75,349	62,801	86,721	77,384	95,308	113,039	81,172	78,114	95,180	40,699	(16,621)	196,764	985,910	Sum Lines 20; 21; 22	23
24	Check Figure	75,349	62,801	86,721	77,384	95,308	113,039	81,172	78,114	95,180	40,699	(16,621)	196,764	985,910	Section 2.3.2; Pages 12; Line 33	- 42
25	Difference	•	-			[		,				•			Line 23 - Line 24	55
56																26
27	Maximum Demand at the Time of System Penk Rates (SAW);	Winter	Summer	Summer	Summer	Summer	Summer	Winter	Winter	Winter	Winter	Winter	Winter			3 5
78	Secondary	59		. %		se		t	5	59	ı	1	,		Section 2 3 1: Page 1: 1 inc 15D: 16D	1 8
52	Primary	\$ 0.2572664	\$ 1.3008397	\$ 1.3008397		\$ 1.3008397	1.3008397	0.2572664	0.2572664	S 0.2572664   \$	0.2572664	0.2572664	\$ 0.2572664		Section 2.3.1, Lage 1, Line 150, 160	3 2
30	Transmission	\$ 0.2558354	\$ 1.2922404	\$ 1.2922404	\$ 1,2922404	\$ 1.2922404	\$ 1.2922404	0.2558354	_	0.2558354	0,2558354	0.2558354			Section 2.3.1; Page 1; Line 15B; 16B	٠ ا
31	Muximum Demand at the Time of System Penk - Revenues:															3
32	Secondary	•	•	S	S	,	•			· · s				•	Line 20 x Line 28	33
8	Primary	3,149	9,512	21,683		17,347	19,133	2,296	266	5,477	2,635	3,644	3,802 \$	105,000	Line 21 x Line 29	33
34	Transmission	16.145	71,705	90,524		105,929	127,067	18,483	18,993	18,904	7,792	(7,876)	46,558 \$	299,000	Line 22 x Line 30	34
35	Subtotal	\$ 19,294	\$ 81,217	\$ 112,207	\$ 100,100	\$ 123,276	\$ 146,200	\$ 20,780	\$ 19,990	\$ 24,381 \$	s 10,427 S	3 (4,232) \$	\$ 50,360 \$	704,000	Sum Lines 32; 33; 34	35
36												-				36
37	Revenues at Changed Rates:	Winter	Summer	Summer	-	Summer	Summer	Winter	Winter	Winter	Winter	Winter	Winter			37
38	Secondary		\$ 10,743,095	\$ 11,073,956	69	\$ 10,910,355	_	_		\$ 9,015,809	\$ 8,671,424 \$	9,004,917	\$ 9,262,818	119,606,011	Pg.5 (Lines 19;37) + Pg.6(Lines 14;32)	38
39	Primary	\$ 1,696,554	\$ 2,151,490	\$ 2,148,354	\$ 2,085,276	\$ 2,257,236	\$ 2,327,168	\$ 2,112,783	\$ 1,831,657 \$	1,930,411	\$ 1,591,137 \$	3 1,744,282 \$	\$ 1,796,783 \$	23,673,131	Pa.5 (Lines 20:38) + Pa.6(Lines 15:33)	39
4	Transmission		\$ 642,953	\$ 909,470		\$ 796,229	\$ 927,695	\$ 572,182	\$ 648,980 \$	6 612,677 \$	\$ 207,052 \$				Pg.5 (Lines 21:39) + Pg.6(Lines 16:34)	6
41	Total	\$ 10,906,354	\$ 13,537,538	\$ 14,131,780	S 12,971,601	\$ 13,963,820	_	S 12,713,470		S 11,558,897 S	밁	10,614,345	-	15	Sum Lines 38; 39; 40	: 4
5 t	Total December of Control of Control	10000 254	13 537 530	9	100 120 61	0.00.000	27.077.51.0		_			_	_	l	,	5
}	TOTAL NEVERBER AL VIRGIES CONTROL		200000000000000000000000000000000000000	3 17,122,130	100,11,5,11	070,505,51	45,540,51 e	0/4/07/77	3 14,010,935 3	6 /68,850,11 6	5 10,409,013	3 10,014,345 3	3 12,512,042 3	151,047,742	See Line 41	<u>5</u>

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-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-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, 2011 - March 31, 2012

	No.	_		m	4	'n	9	7	•	0	10	Ξ	12	13	14	15	16	17	. 82	6 6	₹
	Reference		Section 2.3.2; Page 11.3; Line 114 x 1000	Section 2.3.2; Page 11.3; Line 115 x 1000	Section 2.3.2; Page 11.3; Line 116 x 1000	Sum Lines 2; 3; 4	Section 2.3.2; Page 11.3; Line 117 x 1000	Line 5 Less Line 6			Section 2.3.1; Page 1; Line 20D	Section 2.3.1; Page 1; Line 20C	Section 2.3.1; Page 1; Line 20B			Line 2 x Line 10	Line 3 x Line 11	Line 4 x Line 12	Sum Lines 15; 16; 17	01 01	Line 18
	Total		143,047	1,031,175	683,622	1,857,844	1,857,844									\$ 354,000	2,455,999	1,613,000	\$ 4,422,999		4,422,777
	Mar-12		11,518	85,229	59,524	156,271	156,271	-			\$ 2.4747146	\$ 2,3817490	\$ 2.3594911			\$ 28,504	202,994	140,446	\$ 371,944	\$ 371 044	1,7,44
	Feb-12		11,668	84,233	59,524	155,425	155,425	•			\$ 2.4747146   \$ 2.4747146   \$ 2.4747146	\$ 2.3817490	\$ 2.3594911			\$ 28,875	``	140,446	\$ 369,943	3 170 122 3 270 032 3 803 022 3 210 222 3 215 722 3 215 722 3 215 222	C+7,700
	Jan-12		11,668	84,158	59,839	155,665	155,665	-			\$ 2.4747146	\$ 2.3817490   \$ 2.3817490	\$ 2.3594911	•		\$ 28,875	200,443	141,190	\$ 370,508	370 508	90000
!	Dec-11		11,667	86,294	60,441	158,402	158,402	-			\$ 2.4747146		\$ 2.3594911			69	205,531	142,610	\$ 377,013	\$ 377.013	C10,110
s	Nov-11		11,938	88,693	56,678	157,309	157,309	•			\$ 2.4747146 \$ 2.4747146	\$ 2.3817490   \$ 2.3817490   \$ 2.3817490	\$ 2.3594911			\$ 29,542	211,244	133,731	\$ 374,517	214 517	110,410
Standby Customers	Oct-11		11,938	88,693	56,678	157,309	157,309	1			\$ 2.4747146	\$ 2.3817490	\$ 2.3594911			\$ 29,542	211,244	133,731	\$ 374,517	212 475	7,1,01,
Stan	Sep-11		12,088	88,027	56,682	156,797	156,797	-			\$ 2.4747146	\$ 2.3817490	\$ 2.3594911		_	\$ 29,914	209,658	133,741	\$ 373,313		
	Aug-11		12,088	86,580	57,992	156,660	156,660	•			\$ 2.4747146	\$ 2.3817490	\$ 2.3594911			\$ 29,914	206,212	136,832	\$ 372,958	3 850 628	200,200
	Jul-11		12,089	85,362	58,139	155,590	155,590	-			\$ 2,4747146   \$ 2,4747146   \$ 2,4747146   \$ 2,4747146	\$ 2.3817490   \$ 2.3817490   \$ 2.3817490	\$ 2.3594911				٠.	137,178	\$ 370,406	3 48 487 \$ 347 543 \$ 371 850 \$ 370 406	2010
	Jun-11		12,089	85,774	58,335	156,198	156,198				\$ 2.4747146	\$ 2.3817490	\$ 2,3594911				204,292	137,641	\$ 371,850	\$ 371.850	2001
	May-11		12,149	84,284	49,475	145,908	145,908	•			\$ 2.4747146	\$ 2,3817490   \$ 2,3817490	\$ 2.3594911   \$ 2.3594911			\$ 30,064 \$		116,736	\$ 347,543	\$ 347 543	27,772
	Apr-11		12,149	83,848	50,315	146,312	146,312	•			\$ 2,4747146	\$ 2,3817490	\$ 2.3594911			\$ 30,064 \$	199,705	118,718	\$ 348,487	3 348 487	
	Line Description	Demand - Billing Determinants (kW);	Secondary	Primary	1 Transmission	5 Total	5 Check Figure	7 Difference		집	0 Secondary	1 Primary	2 Transmission		14 Revenues at Changed Rates:	15 Secondary	6 Primary	7 Transmission	8 Total	19 20 Total Revenues at Changed Rates	
	F. S.			m	4	~	9		90	6	<u> </u>		-	<b>∹</b>	<u>-</u>	=	16	Ξ	18	5 5	1

SAN DIEGO GAS AND ELECTRIC COMPANY
Transmission Revenue Data to Reflect Changed Rates
Transmission Recorded Billing Determinants Section 2.3.2

			Tru	-Up Period (A)	e-Up Period (April 1, 2011 - March 31, 2012)	ch 31, 2012)							
	(A)	)	(B)		(C)		(Φ)	7	(E)		(F)		
	Apr-1	11	May-11	.11	Jun-11	1	Jul-11	11	Aug-11	-11	Sep-1		
Line	Billing Determinants	етminants	Billing Determinants	rminants	Billing Determinants	rminants	Billing Determinants	erminants	Billing Determinants	erminants	Billing Determinants		Line
No. Customer Classes	Energy (kWh) Demand (kW)	Demand (kW)	Energy (kWb)	Demand (kW)	Energy (kWh)   Demand (kW)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Energy (kWh)   Demand (kW)	Energy (kWh)   Demand (kW)		No.
1 Residential Customers	550,729,449		556,589,305		560,645,621		628,559,435		633,536,155		668,187,371		-
2				_									7
3 Small Commercial	149,917,195		162,512,335	•	170,081,023		175,600,080		178,862,780		188,865,172		m
4					-								4
5 Medium-Large Commercial	732,953,867		819,922,226		890,095,089		807,981,837		868,045,813		931,375,233		2
6 Non-Coincident (100%) <sup>1</sup>		86,320		92,350		104,905		94,410		92.576		101.378	9
7 Non-Coincident (90%) <sup>2</sup>		1,953,395		2,130,833		2,181,288		1,998,493		2.158,442		2.421.084	
8 Maximum On-Peak Period Demand <sup>3</sup>		1,518,497		1,762,284		1,974,351		1,835,843		1,981,412		2,210,848	• ••
9 Maximum Demand at the Time of System Peak		75 349		62 801		86.721		77 384		905 308		113 030	
_		1				1		1000		2000		,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,	, <u> </u>
11 Street Lighting	5,953,894		9,406,113		12,675,328		5,891,993		(54,586,793)		72.280.618		2 =
12									•				17
13 Sale for Resale	2,303		4,223		ı		6,207		78		2,682		13
14													14
15 Standby Customers		146,312		145,908		156,198		155,590		156,660		156,797	15
16													16
17 TOTAL	1,439,556,708		1,548,434,202		1,633,497,061		1,618,039,552		1,625,858,033		1,860,711,076		17

NOTES.

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

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

<sup>3</sup> Maximum On-Peak Demand rates are applicable to the following CPUC tariffs: Schedules AY-TOU, AL-TOU, AL-TOU-DER and DG-R
<sup>4</sup> 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

				Tra	ne-Up Period (A	e-Up Period (April 1, 2011 - March 31, 2012)	arch 31, 2012)							
		(Đ)	(	(H)		Œ		(C)	(	(K)		£		
		Oct-11	-11:	Nov-1	11	Dec-11	.11	Jan-12	.12	Feb-12	.12	Mar-12	2	
		Billing Determinants	erminants	Billing Determinants	rminants	Billing Determinants	rminants	Billing Determinants	erminants	Billing Determinants	erminants	Billing Determinants		Line
	Customer Classes	Energy (kWh)	Energy (kWh) Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh) Demand (kW)	Demand (kW)	Energy (kWh) Demand (kW)	Demand (kW)	Energy (kWh) Demand (kW)	Demand (kW)	Energy (kWh)	Demand (kW)	No.
:														
esidentia	Residential Customers	583,077,961		578,647,962		663,469,258		712,816,164		613,720,804		601,110,205		
;														7
Small Commercial	mercial	169,297,006		160,943,217		163,594,306		171,297,139		161,540,451		165,050,532		3
														4
fedium-I	Medium-Large Commercial	869,409,273		814,776,186		836,520,849		742,355,942		731,844,877		914,661,596		2
Non-C	Non-Coincident (100%)1		89,364		88,844		90,375		86,945		85,021		85,477	9
Non-C	Non-Coincident (90%) <sup>2</sup>		2,281,403		2,159,754		2,072,529		1,869,799		1,895,135		2,259,374	7
Maxim	Maximum On-Peak Period Demand3		1,965,188		1,685,430		1,601,010		1,450,403		1,573,124		1,688,695	<b>∞</b>
Maxim	Maximum Demand at the Time of System Peak <sup>4</sup>		81,172		78,114		95,180		40,699		(16,621)		196.764	- 6
									,		,			. 2
Street Lighting	ting	9,597,278		9,051,839		7,267,629		10,440,962		9,516,420		6,974,066	_	=======================================
													_	12
Sale for Resale	esale	2,352		1		•		1,184		611		ı		13
														14
tandby C	15 Standby Customers		157,309		157,309		158,402		155,665		155,425		156,271	15
														16
TOTAL		1,631,383,870		1,563,419,204		1,670,852,042		1,636,911,391		1,516,623,163		1,687,796,399		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-DER, DG-R, and A6-TOU.

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

<sup>4</sup> Maximum Denand 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, 2011 - March 31, 2012)

			(M)	
		12 Month	12 Months to Date	,
Line		Billing De	Billing Determinants	Line
No.	Customer Classes	Energy (kWh)	Demand (kW)	No.
_	Residential Customers	7,351,089,690	•	-
7				7
3	Small Commercial	2,017,561,236	1	3
4				4
5	Medium-Large Commercial	9,959,942,788		5
9	Non-Coincident (100%) <sup>1</sup>		1,097,964	9
7	Non-Coincident (90%) <sup>2</sup>		25,381,530	7
<b>∞</b>	Maximum On-Peak Period Demand <sup>3</sup>		21,247,086	∞
6	Maximum Demand at the Time of System Peak <sup>4</sup>		985,910	6
10				10
11	Street Lighting	104,469,347	ſ	11
12				12
13	Sale for Resale	19,640	1	13
14				14
15	Standby Customers	_	1,857,844	15
16				16
17	TOTAL	19,433,063,061	50,570,334	17

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

. :	3				Š	Section 2.3.2									artistano II
No.			Reco	rded Sales f	san Die or the True	San Diego Gas & Electric Recorded Sales for the True-Up Period: April 2011 - March 2012	ectric April 2011	- March 20	11.2					34	Line No.
	SDG&E: System Delivery Determinants	Winter	Summer	Summer	Summer	Summer	Summer	Winter	Winter	Winter	Winter	Winter	Winter	Total	
7 m	Customer Class Deliveries (WWh)	Anr-11	Mav-11	.Inn-11	.m-11	Αυσ-11	Sen-11	Ort-11	Nov-11	Dec-11	.Ian-12	Keh-12	3-012	Total	C1 "
4	Residential	550,729	556,589	560,646	628.559	633.536	668.187	583.078	578.648	663,469	712.816	613.721	601.110	7.351.090	. 4
٠٧	Small Commercial	149,917	162,512	170,081	175,600	178,863	188,865	169,297	160,943	163,594	171,297	161,540	165,051	2,017,561	٠ ٧
9	Med. & Large Comm./Ind. (AD + PA-T-1)	17,291	24,144	28,449	28,489	27,197	30,456	26,232	21,763	20,065	20,783	19,501	20,278	284,647	9
7	Med. & Large Comm./Ind. (AL + AY + DGR)	666,187	747,739	808,304	737,717	771,870	829,777	787,540	736,510	744,451	694,066	716,755	761,127	9,002,044	7
∞ •	Med. & Large Comm./Ind. (A6)	49,476	48,039	53,342	41,776	68,979	71,142	55,637	56,503	72,005	27,507	4,411	133,257	673,252	∞
o	Lighting Sale for Recale	5,954	9,406	12,675	5,892	-54,587	72,281	9,597	9,052	7,268	10,441	9,516	6,974	104,469	ο 5
: : :		1,439,557	1,548,434		1,618,040		1,860,711	1,631,384	1,563,419	1,670,852	1,636,911	1,516,623	1,687,796	19,433,083	
1 E 1	Med. & Large Comm./Ind. Rate Schedule Billing Determinants														
15	Schedules AD / PA-T-1:	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12	3-012	Total	15
17	Total Deliv	17,291	24,144	28,449	28,489	27,197	30,456	26,232	21,763	20,065	20,783	19,501	20,278	284,647	
19 2	Total Deliveries (%) % @ Secondary Service	92 16%	84 84%	85 67%	89 06%	%59 06	92 05%	%8688	89 91%	%57.98	85 74%	%22 528	82 84%	7000/8	10 2
21		7.84%	15.16%	14.38%	10.94%	9.35%	7.95%	11.02%	10.09%	13.25%	14.26%	14.43%	17.16%	12.01%	3 2
22 22	% @ Transmission Service	00.00 100.001	0.00%	0.00% 100.00%	0.00% 100.00%	0.00% 100 00%	0.00% 100.00%	0.00% 100 00%	0.00% 100.00%	0.00% 100 00%	100 00%	0.00% 100.00%	0.00% 100.00%	0.00%	3 2
24 4		36031	707	0 7 0	00000	747			100	17.40	t				
3 %	MWh @ Primary Service	1,356	3,660	4,091	3,117	2,543	2,421	2,341	2.196	2.659	2.964	2.814	3.480	34 190	3 %
27		01	OI	OI	01	01	OI	01	01	0	0	0	O	0	
5 28	_	17,291	24,144	28,449	28,489	27,197	30,456	26,232	21,763	20,065	20,783	19,501	20,278	284,647	(1)
\$ R	Non-Coincident Demand [76]   % @ Secondary Service	0.4858%	0.3882%	0.3527%	0.3281%	0.3302%	0.3283%	0.3409%	0.4071%	0.4504%	0.4170%	0.4448%	0.4309%	0.3825%	3 8
31		0.6570%	0.3506%	0.4643%	0.3582%	0.4392%	0.3858%	0.3388%	0.4183%	0.4505%	0.4264%	0.3837%	0.3763%	0.4092%	
3 %		0.0000.0	0.0000.0	0.0000.0	0.000070	0.0000.0	0.0000.0	0,0000,0	0.000070	0.000070	0.00000	0.0000%	0.0000%	0.0000%	7 6
8 %		17	0.5	0.50	24.0	01 403	60	1.5	037.00	9	2.00		600		
3, 6		8.906	12.833	18.994	11.164	11.168	92.03/	9.794	9.185	11.977	/4.308 12.637	10.797	13.094	139.892	3 %
37		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	
3 8		020.00	000.20	204:401	71.10	010.27	101.378	100.00	0.00	6/6:06	00.940	03.021	03.477	1,097.904	3 68
9 4															9 4
4 4 5	Schedules AL-TOU / AY-TOU / DG-R: Total Deliveries (MWh)	<u>Apr-11</u> 666,187	<u>May-11</u> 747,739	<u>Jun-11</u> 808,304	<u>Jul-11</u> 737,717	<u>Aug-11</u> 771,870	Sep-11 829,777	Oct-11 787,540	Nov-11 736,510	<u>Dec-11</u> 744,451	<u>Jan-12</u> 694,066	Feb-12 716,755	3-012 761,127	<u>Total</u> 9,002,044	
4 4 4		7000 00	700 02	70 000	79 000%	70.010	7007 00	707707	10 100/	1000	000	791	1	70,000	
4 4		18.91%	19.68%	16.73%	19.53%	19.44%	17.34%	78.34% 20.68%	/8.48% 19.44%	78.29% 20.14%	82.74% 17.93%	80.11%	/8.00% 18.37%	79.36%	<del>4</del> <del>4</del>
48	% @ Transmission Service	0.80%	1.24%	4.42%	100 00%	100 00%	2.06%	0.98% 100.000	2.08%	100 000	<u>-0.67%</u>	1.16%	3.63%	100 000	
}		100.0078	100.0078	100.0078	100.0078	100.00%	100.00%	100,0070	100.00%	100.0070	100.00%	100.0078	100.00%	100.00%	<del>5</del>

Line				Section 2.3.2  San Diego Gas & Electric	San Dieg	Section 2.3.2		Stoc 15-19							Line
0, 2	.1	234 000	86	070 200	200 000	ob oo			25000	000	20100	100.100	000		20 1
52	MWh @ Primary Service	125,976	147,155	135,229	382,723 144,076	150,052	143,883	162,863	143,178	382,830 149,932	124,446	134,248	139,819	1,700,858	22 22
£ 5		<u>5.329</u> 666 187	9 <u>,272</u> 747 739	35,727 808 304	10.918 737.717	12,736 771 870	17,093 829,777	787 540	736 510	11,688	4,650	8,314	<u>27,629</u> 761 127	157,094	53
55		5		,		2),		5	21,00	į.	200,'1	10,10	121,101	,,00,,	55
56		0.2872%	0.2835%	0.2662%	0.2694%		0.2838%	0.2882%	0.2927%	0.2739%	0.2676%	0.2784%	0.2777%	0.2786%	26
28	% @ Frimary Service % @ Transmission Service	0.2548%	0.2247%	0.1759%	0.12252% 0.1902%	0.2049%	0.2065%	0.2362% 0.2258%	0.2307%	0.2218%	0.2301% 0.0068%	0.2252% 0.1626%	0.2231% 0.2044%	0.2289%	57
29	Non-Coincident Demand (MW)														65 5
9 19		1.536.180	1.676.370	1.696.620	1.569.856	1.673.150 1	1.898.056 1	1 778 076 1	1 691 844	1 596 372	1 536 747	1 598 551	1 648 647	19 900 469	3 2
62											286.350	302.327	311.936	3,893.956	5 2
& 4	MW @ Transmission Service	13.580	20.834	62.844 2.070.762	20.766	26.096	35.298	17.427 2 180 187 2	28.709	12.927	-0.316 1 872 781	13.519	2017 056	308.156	63
65	On-Peak Demand (%)										1,01,01			707.707.7	5 2
99		0.2307%	0.2402%	0.2490%	0.2526%			0.2500%	0.2349%	0.2178%	0.2121%	0.2224%	0.2216%	0.2389%	99
67		0.2097%	0.2083%	0.2354%	0.2308%			0.2318%	0.2059%	0.2002%	0.2082%	0.2092%	0.1948%	0.2189%	67
8 8	% @ Iransmission Service Maximim On Peak Period Demand (MW)	0.3819%	0.5821%	0.1952%	0.2872%	0.4137%	0.2836%	0.5866%	0.2146%	0.2690%	0.5746%	0.1837%	0.3646%	0.2904%	8 9
3 8		Winter					in distinction of	Window	W/5-46-2	20/2010	Witness	475-4	W	E	3 6
7	•	اءِ 🏲	1.420.332	1.586.996 I	1 471 958 1	1 572.651 1	Summer 1 801 080 1	1 542 398 1	winter   357 752	winter 1 269 405	1 218 027	1 277 003	1 315 593	17 067 168	2 5
2									294.803	300.165	259.097	280.847	272.367	3 723 712	2
73	MW @ Transmission Service		35.428	69.025	31.357	52.688	48.477	45.273	32.875	31.440	-26.720	15.273	100,735	456.206	ξ.
<b>4</b>		1,518.497	1,762.284	1,974.351	1,835.843 1	1,981.412 2	2,210.848 1	1,965.188 1	1,685.430	1,601.010	1,450.403	1,573.124	1,688.695	21,247.086	4 4
7, 2			Ī		- 1								27		2 %
12															2 12
8 6	Schedule A6-TOU:	Apr-11	May-11	Jun-11 53 347	Jul-11	Aug-11 5	Sep-11	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12	3-012	Total	8 6
8 /	_	0/1,64	40,039	245,55	41,770	6/6,00	71,142	75055	20,202	7,003	700,77	4, 14,	/57,561	757,610	₹ %
81	_		;	;											8 18
\$ 8		0.00%	0.00%	0.00%	0.00%	%00.0	0.00%	0.00%	%00.0	0.00%	%00.0	%00.0	%00.0	%00.0	<b>%</b>
3 2	% @ rimary Service % @ Transmission Service	13.04% 84.36%	10.39% 89.61%	19.53% 80.47%	7.08% 92.32%	14.32% 85.68%	15.36% 84.64%	13.89% 86.11%	88.30%	17.04% 82.36%	19.88% 80.12%	-237.33% 337.33%	7.35% 92.65%	14.84% 85.16%	<del>2</del> 2
85	Total Dalivacies (MANA)	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%	8 9
87		C	C	O	C	c	C	C	c	c	c	c	c	c	2 &
88		7,738	4,991	10,418	3,208	9,878	10,927	7,728	6,611	12,702	5,468	10,468	9,794	99,932	88
\$ 8		41.738	43.048	42,924	38,567	<u>59,101</u>	60,215	47,909	49,892	<u>59,304</u>	22,038	-14,879	123,463	573,320	
9 2	Non-Coincident Demand (%)	47,470	40,034	24,50	41,770	616,00	/1,142	/ 50,55	50,505	72,003	705,77	<b>4</b> ,	/57,561	757,570	3 5
6 2		0.0000%	%00	0.0000.0	0.0000%			0.0000%	0.0000%	0.0000%	0.0000.0	%0000'0	0.0000%	0.0000%	7 27
93	% @ Primary Service % @ Transmission Service	0.2273%	0.2754%	0.2204%	0.1259%	0.2282%	0.2596%	0.1145%	0.1785%	0.1973%	0.0945%	0.1972%	0.1975%	0.2002%	8 3
95									0/21/1:0	200	0.101.0	2001	0.1500	0.188270	£ %
96				;	;	;	:								96
76 86		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0000	0.000	0.000	
8 8	MW @ Transmission Service	87.232	86.871	87.565	79.371	101.890	115.913	92.368	97.090	105.620	41.851	-39.905	222.973	1,078.841	
9		104.820	100.617	110.526	83.411	124.432	144.281	101.217	108.891	130.680	47.019	-19.262	242.317	1,278.948	100

L					S	Section 2.3.2	3								2,000
Line	le.				San Die	San Diego Gas & Electri	Іестіс								디
No.			Rec	Recorded Sales for the True-Up Period: April 2011 - March 2012	or the True	-Up Period:	April 2011	- March 20	11.2				1		z
<u> </u>	101 Coincident Peak Demand (%)														<u> </u>
10.	102 % @ Secondary Service	%0000.0	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	<u> </u>
10	103 % @ Primary Service	0.1582%	0.1465%	0.1600%	0.3672%	0.1350%	0.1346%	0.1155%	0.0586%	0.1676%	0.1873%	0.1353%	0.1509%	0.1494% 10	<u> =</u>
10	104  % @ Transmission Service	0.1512%	0.1289%	0.1632%	0.1701%	0.1387%	0.1633%	0.1508%	0.1488%	0.1246%	0.1382%	0.2069%	_	0.1459% 10	<u>۲</u>
10.	105 Coincident Demand at Time of System of Peak														<u> =</u>
<u>1</u> 0	106 Coincident Peak Demand (MW)	Winter	Summer	Sammer	Summer	Summer	Sammer	Winter	Winter	Winter	Winter	Winter	Winter	Total	은
10	107 MW @ Secondary Service	0.000	0.000	000'0	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.00	0.000	2
10	108 MW @ Primary Service	12.242	7.312	16.668	11.781	13.335	14.708	8.926	3.874	21.288	10.242	14.163	14.780	149.319	2
<u>0</u>	109 MW @ Transmission Service	63.107	55.489	70.052	65.603	81.973	98.331	72.247	74.240	73.892	30.457	-30.784	181.984	836.591	2
110	0	75.349	62.801	86.721	77.384	95.308	113.039	81.172	78.114	95.180	40.699	-16.621	196.764	985.910	=
=	1														Ξ
112	2 Schedule S: Standby Determinants:	<u>Apr-11</u>	May-11	Jun-09	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	<u>Dec-11</u>	Jan-12	Feb-12	3-012	Total	Ξ
Ξ	13 Contracted Standby Demand (MW)														Ξ
Ï	114 MW @ Secondary Service	12.149	12.149	12.089	12.089	12.088	12.088	11.938	11.938	11.667	11.668	11.668	11.518	143.047	=
Ξ	115 MW @ Primary Service	83.848	84.284	85.774	85.362	86.580	88.027	88.693	88.693	86.294	84.158	84.233	85.229	1,031.175	Ξ
Ĭ	116 MW @ Transmission Service	50.315	49,475	58,335	58.139	<u>57.992</u>	<u>56.682</u>	56.678	56.678	<u>60.441</u>	59.839	59.524	59.524	683,622	=
117	7	146.312	145.908	156.198	155.590	156.660	156.797	157.309	157.309	158.402	155.665	155.425	156.271	1,857.844	=
118	8														Ξ
119	6														Ξ
120	0							=							7

							2.3.2			T. Carlo						730
Line No.			FEF	C Recorde	San Diego Gas & FERC Recorded Sales for the True	o Gas & El be True-Ur	Electric Company Up Period: April 2011		- March 2012						Reference	S. Ei
-		Winter	Summer	Summer	Summer	Summer	Sammer	Winter	Winter	Winter	Winter	Winter	Winter	Total		
N 10	Schedules AD / PA-T-1:	<u>Apr-11</u>	<u>Mav-11</u>	Jun-11	Jul-11	Aug-11	Sep-11	<u>Oct-11</u>	Nov-11	<u>Dec-11</u>	Jan-12	Feb-12	Mar-12	Total		7
	MW @ Secondary Service	77.414	79.518	85.910	83,246	81.407	92.037	79.571	79.658	78.398	74.308	74 223	77 383	958 073	Section 2 3 2: Page 14 1: Line 35	m s
ς_Σ	MW @ Primary Service	8.906	12.833	18.994	11.164	11.168	9.341	9.794	9.185	11.977	12.637	10.797	13.094	139.892	Section 2.3.2: Page 14.1: Line 36	۰ ۲
9	MW @ Transmission Service	0.000	0.000	0000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	000'0	Section 2.3.2; Page 14.1; Line 37	9
۲ «	Sub-Total	86.320	92.350	104.905	94.410	92.576	101.378	89.364	88.844	90.375	86.945	85.021	85.477	1,097.964	Sum Lines 4; 5; 6	7
	Schedules AL TOII / AV-TOII / D.C.B.					1										ω ·
	Non-Coincident Demand (MW) - 90%															ν 0
	MW @ Secondary Service	1,536.180	1,676.370	1,696.620	1,569.856	1,673.150	1,898.056	1,778.076	1,691.844	1,596.372	1,536.747	1,598.551	1,648.647	19,900,469	Section 2.3.2; Page 14.2; Line 61	: =
	MW @ Primary Service	298.815	333,012	311.298	324.460	334.765	343.450	384,683	330,311	332.550	286.350	302.327	311,936	3,893.956	Section 2.3.2; Page 14.2; Line 62	12
	MW @ Transmission Service	13,580	20.834	62.844	20.766	26.096	35.298	17.427	28.709	12.927	-0.316	13.519	56.473	308.156	Section 2.3.2; Page 14.2; Line 63	13
4 7	Sub-Total	1,848.575	2,030.216	2,070.762	1,915.082	2,034.011	2,276.804	2,180.187	2,050.863	1,941.849	1,822.781	1,914.397	2,017.056	24,102.582	Sum Lines 11, 12, 13	4
	On-Peak Demand (MW)															15 16
	MW @ Secondary Service	1,233.972	1,420.332	1,586.996	1,471.958	1,572.651	1,801.080	1,542.398	1,357.752	1,269.405	1,218.027	1,277.003	1,315.593	17,067.168	Section 2.3.2; Page 14.2; Line 71	17
	MW @ Primary Service	264.172	306.524	318.330	332.528	356.072	361.291	377.517	294.803	300.165	259.097	280.847	272.367	3,723.712	Section 2.3.2; Page 14.2; Line 72	18
_	MW @ Transmission Service	20.353	35.428	69.025	31,357	52.688	48.477	45.273	32.875	31.440	-26.720	15.273	100.735	456.206	Section 2.3.2; Page 14.2; Line 73	19
20	Sub-Total	1,518.497	1,762.284	1,974.351	1,835.843	1,981.412	2,210.848	1,965.188	1,685.430	1,601.010	1,450.403	1,573.124	1,688.695	21,247.086	Sum Lines 17; 18; 19	8 8
	Schedule A6-TOU:															7 23
	Non-Coincident Demand (MW) - 90%	000	000	000	0	0	0	0	0	0	0					23
	MAX @ Driman, Senice	17.588	20000	22.062	7.030	0000	000.0	0.000	0.000	0.000	0.000	0.000	0.000	0000	Section 2.3.2; Page 14.2; Line 97	24
_	MW @ Transmission Service	87.232	86.871	87.565	4.039	101 890	115 913	8.849	07.000	105 620	5.168	20.043	19.344	200.107	Section 2.3.2; Page 14.2; Line 98	2 2
	Sub-Total	104.820	100.617	110.526	83.411	124 432	144.281	101 217	108 801	130.680	47.019	19.762	242.313	1,076.041	Section 2.3.2; Page 14.2; Line 99	9 8
78											<u>.</u>			Ch.	June 24, EJ, 20	28 6
8 8	Coincident Peak Demand (MW)					,	;									 ମ କ୍ଷ
	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
	IMW @ Frimary Service	12.242	7.312	16.668	11.781	13.335	14.708	8.926	3.874	21.288	10.242	14.163	14.780	149.319	Section 2.3.2; Page 14.3; Line 108	31
	MW @ 1 ransmission Service	63.107	55.489	70.052	65.603	81.973	98.331	72.247	74.240	73.892	30.457	-30.784	181.984	836.591	Section 2.3.2; Page 14.3; Line 109	32
3 %	Sub-1 otal	75.349	62.801	86.721	77.384	95.308	113.039	81.172	78.114	95.180	40.699	-16.621	196.764	985.910	Sum Lines 30; 31; 32	8 %
38 38 38 38	TOTAL SUMMARY Non-Coincident Demand (MWH) @ 100%															35
	MW @ Secondary Service	1,613,594	1,755,887	1,782,531	1,653,102	1,754,557	1,990,093	1,857,647	1,771,502	1,674,771	1,611,055	1,672,774	1,721,029	20,858,542	Apr-Aug; Lines (4, 11 and 24) x 1000	37
38	MW @ Primary Service	325,310	359 591	353,253	339 663	368 475	381 158	403 326	351 206	885 096	304 155	137 252	244 274	1 232 055	Sep-Mar; (Line 4 x 1000)	88 8
_									2	,	201,100	10110	+ / 0.4.	006,000,	Apr-Aug, Lines (5, 12 and 25) x 1000	λ (
	MW @ Transmission Service	100,811	107,705	150,409	100,138	127,986	151,211	109,795	125,799	118,546	41,535	-26,386	279,447	1,386,998	Sep-Mar; (Line 5 x 1000) Apr-Aug; Lines (6, 13 and 26) x 1000	<del>4</del> 4
													- [		Sep-Mar; (Line $6 \times 1000$ )	42
3 4 5	Lotal - NON Coincident Demand @ 100%	2,039,715	2,223,183	2,286,193	2,092,902	2,251,018	2,522,463	2,370,768	2,248,597	2,162,905	1,956,744	1,980,156	2,344,850	26,479,494	Sum Lines 37 thru 42	t 4
24 24 M	Non-Coincident Demand (MWH) @ 90% MW @ Secondary Service	1,536,180	1,676,370	1,696,620	1,569,856	1,673,150	1,898,056	1,778,076	1,691,844	1,596,372	1,536,747	1,598,551	1,648,647	19,900,469	Sep-Mar: ((Lines 11 & 24) × 1000)	45
47 M	MW @ Primary Service	316,404	346,758	334,258	328,499	357,306	371,817	393,532	342,111	357,610	291,518	322,970	331,280	4,094,063	Sep-Mar; ((Lines 12 & 25) x 1000)	47
	MW @ Transmission Service	100,811	107,705	150,409	_	127,986	151,211	109,795	125,799	118,546	41,535	-26,386	279,447	1,386,998	Sep-Mar; ((Lines 13 & 26) x 1000)	84
50 To	Total - NONCoincident Demand @ 90%	1,953,395	2,130,833	2,181,288	1,998,493	2,158,442	2,421,084	2,281,403	2,159,754	2,072,529	1,869,799	1,895,135	2,259,374	25,381,530	Sum Lines 46 thru 48	<b>⊕</b> (
		1														