UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

San Diego Gas & Electric Company) Docket No. ER11-4318-___

SAN DIEGO GAS & ELECTRIC COMPANY
COMPLIANCE FILING

NOVEMBER 14, 2011

SDGE

Georgetta Baker
Senior Counsel

101 Ash Street
San Diego, CA 92101

Tel: 619-699-5064
Fax: 619-699-5027
GBaker@semprautilities.com

November 14, 2011

Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: San Diego Gas & Electric Company, Docket No. ER11-4318-00___; Compliance Filing

Dear Secretary Bose:

Pursuant to *Order on Annual Formula Rate Filing, Directing Accounting Change and Establishing Hearing and Settlement Judge Procedures*, issued herein on October 14, 2011 ("Order"),[1] San Diego Gas & Electric Company ("SDG&E") submits an original and five (5) copies of this Compliance Filing ("Filing").

More specifically, the Order, among other things, directed SDG&E to file revised worksheets recording uninsured wildfire-related losses in Account 925 of the Uniform System of Accounts instead of in Account 350, Account 360 and Account 404, as SDG&E had originally proposed in its Informational Filing on August 15th. This Compliance Filing complies with that directive.

SDG&E will shortly submit an Offer of Settlement and Settlement Agreement ("Settlement") to resolve all other outstanding matters in this proceeding that the Order set for hearing and settlement judge procedures. SDG&E respectfully requests that the Federal Energy Regulatory Commission ("Commission") coordinate its approval of this Compliance Filing and the Settlement to facilitate expedited and efficient flow through of benefits to ratepayers resulting from reduced Base Transmission Revenue Requirements ("BTRR") and associated rates for both the Compliance Filing and the Settlement.

I. DESCRIPTION OF THE FILING AND LIST OF DOCUMENTS SUBMITTED

This Compliance Filing comports with the Order's directive and consists of the following:

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[1] *San Diego Gas & Electric Company,* 137 FERC ¶61,041 (2011).

1. Appendix I indicating SDG&E's California Independent System Operator Corporation's ("CAISO") High Voltage and Low Voltage Transmission Revenue Requirements;

2. Attestation;

3. Attachment I—Summary of Compliance Filing Revisions;

4. Revised Cost Statements BG, BK-1, BK-2 and BL, revised True-Up Period Cost Statements and other applicable work papers that support the revised Retail and Wholesale BTRR.

II. REFUND PROCEDURES

Pursuant to the ISO Tariff, SDG&E will provide refunds to the California Independent System Operator Corporation ("CAISO") based on the rates that result from the revised BTRR, with interest as required under 18 C.F.R. §35.19a. Within ten (10) business days of the date on which all necessary approvals of this Compliance Filing are obtained, SDG&E will request that the CAISO calculate and make refunds to Participating Transmission Owners ("PTO") and Scheduling Coordinators for Access Charges and Wheeling Access Charges, as appropriate, under the CAISO Tariff. SDG&E will also request that the CAISO adjust the Wheeling Access Charge revenues allocable to each PTO to reflect the refunds for Wheeling Access Charge service. Further, SDG&E will request that the CAISO, consistent with its Tariff, ensure that such adjustments to Wheeling Access Charge revenues be debited to each PTO's TRBA in the first restatement of SDG&E's and other PTOs' TRBAs following all approvals of this Compliance Filing.

Refunds for retail End Use Customers will be effectuated through the True-Up mechanism in Cycle 6. The refunds will be based upon a refund period from September 1, 2011 through the end of the month in which the Commission approves the Compliance Filing so long as the approval occurs 15 days prior to the end of that month. If the Commission approval occurs after the 15th of the month, the refund period will terminate at the end of the following month after Commission approval of the Compliance Filing to accommodate internal processes necessary for SDG&E to bill changed rates.

III. COMMUNICATIONS

Correspondence and other communications concerning this Informational Filing should be addressed to:[2]

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[2] SDG&E requests waiver of Rule 203(b)(3) to the extent necessary to permit each of the individuals identified above to be placed on the Commission's official service list in this proceeding.

Georgetta J. Baker
Senior Counsel
San Diego Gas & Electric Company
101 Ash Street, HQ12
San Diego, CA 92101
Phone: 619-699-5064
Fax: 619-699-5027
E-mail: gbaker@semprautilities.com

James F. Walsh
Senior Counsel
San Diego Gas & Electric Company
101 Ash Street, HQ12
San Diego, CA 92101
Phone: 619-699-5022
Fax: 619-699-5027
E-mail: jfwalsh@semprautilities.com

Ed Lucero
Gas & Electric Analysis Manager
San Diego Gas & Electric Company
8315 Century Park Court
San Diego, CA 92123-1550
Phone: 858-654-1781
Fax: 858-637-3770
E-mail: elucero@semprautilities.com

Steven Williams
FERC Case Manager
San Diego Gas & Electric Company
8330 Century Park Court
San Diego, CA 92123
Phone: 858-650-6158
Fax: 858-654-1788
E-mail: swilliams@semprautilities.com

IV. REQUEST FOR WAIVER AND SERVICE

SDG&E believes the data contained in this Filing provides sufficient information for the Commission to accept this Filing; however, to the extent necessary, SDG&E requests the Commission to waive its filing requirements contained in Section 35.13 of the Commission's Regulations, 18. C.F.R. ¶35.13.

A copy of this Filing is being served on all parties to Docket No. ER11-4318-000. In addition, this Filing is also being served on the California Public Utilities Commission, the CAISO, Pacific Gas and Electric Company, Southern California Edison Company and the CAISO-registered Scheduling Coordinators.

Respectfully submitted,

Georgetta J. Baker

Georgetta J. Baker
Attorney for San Diego Gas & Electric Company

San Diego Gas & Electric Co.

Appendix - I

APPENDIX - I
SDG&E's Transmission Revenue Requirement
Per Docket ER11- -000
Effective September 1, 2011

1. The Transmission Revenue Requirement shall be $383,737,966, which is equal to the Base Transmission Revenue Requirement (a) of $391,175,000 reduced by the (b) TRBAA of $2,569,294 and reduced by (c) Standby Transmission Revenue of $4,867,740.

2. For purposes of the ISO's calculation of Access Charges:

   a. The High Voltage Transmission Revenue Requirement shall be $196,882,170. [1]

   b. The Low Voltage Transmission Revenue Requirement shall be $186,855,796.

   c. Gross Load consistent with the High Voltage Transmission Revenue Requirement shall be 21,539,407 megawatt hours.

3. The amounts in (1) and (2) shall be effective September 1, 2011, or until amended by the Participating TO or modified by FERC.

Footnote (1): Transmission Revenue Requirements consist of the following:

BTRR per SDG&E's Compliance Filing in Docket ER11- -000	= $391,175,000
TRBAA per FERC Order in Docket ER11-2430-000	= (2,569,294)
Standby Revenues per SDG&E's Compliance Filing in ER11- -000	= (4,867,740)
TOTAL	= $383,737,966

[1] Pursuant to the ISO's July 5, 2005 filing in compliance with the Commission's December 21, 2004 order, 109 FERC ¶ 61,301 (December 21, Order) and June 2, 2005 order, 111 FERC ¶ 61,337 (June 2, Order), SDG&E in the instant filing has followed the ISO's new guidelines to separate all elements of its transmission facilities into High Voltage (HV) and Low Voltage (LV) components. TRBAA cost components shown in the instant filing are separated into HV and LV components applicable to the ISO's HV and LV guidelines effective January 1, 2005, pursuant to the ISO Tariff Appendix F, Schedule 3, and Section 8.1.

San Diego Gas & Electric Co.

Attestation Form

ATTESTATION REGARDING SAN DIEGO GAS & ELECTRIC COMPANY'S 2011 ANNUAL TRANSMISSION OWNER FORMULA CYCLE 5 COMPLIANCE FILING (18 CFR § 35.13 (d)(7))

I, Lee Schavrien, attest that I am Senior Vice President – Finance, Regulatory & Legislative Affairs of San Diego Gas & Electric Company ("SDG&E"), and to the best of my knowledge and belief, the cost of service statements and supporting data submitted as part of this filing are true, accurate, and current representations of SDG&E's books and other corporate documents.

November 10, 2011

Lee Schavrien

California All-Purpose Acknowledgement

State of California)
)
County of San Diego)

On November 10, 2011 before me, Annie Victoria Ruiz, Notary Public, personally appeared **Lee Schavrien**, who proved to me on the basis of satisfactory evidence to be the person whose name is subscribed to the within instrument and acknowledged to me that he executed the same in his authorized capacity, and that by his signature on the instrument the person, or the entity upon behalf of which the person acted, executed the instrument.

I certify under PENALTY OF PERJURY under the laws of the State of California that the foregoing paragraph is true and correct.

WITNESS my hand and official seal.

Annie Victoria Ruiz, Notary Public

ANNIE VICTORIA RUIZ
COMM. #1877490
NOTARY PUBLIC • CALIFORNIA
SAN DIEGO COUNTY
Commission Expires Jan 18, 2014
ST01

San Diego Gas & Electric Co.

Attachment - 1

Attachment 1
Summary of Compliance Filing Revisions

Part 1 - Introduction

As mandated by *Order on Annual Formula Rate Filing, Directing Accounting Change and Establishing Hearing and Settlement Judge Procedures*, issued herein on October 14, 2011 ("Order"), [1] this Compliance filing reflects revised worksheets recording uninsured wildfire-related losses in Account 925 of the Uniform System of Accounts instead of in Account 350 and Account 360, as SDG&E had originally proposed in this proceeding.

Exhibit No. 1 - Page 1 and Page 2 were prepared to show the Retail and California Independent System Operator Corporation ("CAISO") wholesale BTRR components as filed in SDG&E's TO3 Cycle 5 Informational Filing, dated August 15, 2011 (column A) compared to the lower BTRR (column C) resulting from the Order's mandate. Column B of Exhibit No. 1, Pages 1 and 2, reflects SDG&E's reduction in annual End Use Retail and CAISO Wholesale BTRRs as a result of booking uninsured wildfire related losses to Account 925. Column C line 8 of Exhibit No. 1, pages 1 and 2, reflects the annual End Use Retail and CAISO Wholesale BTRR of $388.943 million and 391.175 million, respectively, mandated by the Order.

Part 2 – Explanation of Work papers and Cost Statements

The Order's accounting directive resulted in changes to the following cost statements as indicated by check marks and **bold numbers.**

1. **Cost Statement BK-1** – indicates the derivation of SDG&E's retail BTRR. The only BTRR components that were affected by the mandated accounting change are the 12-month true-up adjustment and the related FF&U as shown on page 5 of 5 of Statement BK-1, and indicated by check marks and **bold numbers**. The retail true-up adjustment amount originates from Section 2.1A, Pages 1-3, and Line 35. As shown in Exhibit No.1 – Page 1, line 2 – treating the uninsured wildfire related losses as an A&G expense and booking it to Account No. 925 instead of as an inverse condemnation cost booked to Accounts 350, 360 and Depreciation and Amortization Expense, Account 404, reduced the Retail BTRR by $17.957 million.

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[1] *San Diego Gas & Electric Company,* 137 FERC ¶61,041 (2011).

- **<u>12-Month True-Up Adjustment</u>** – the True-Up cost of service was reduced by $17.749 million to $14.396 million as a result of the changes as indicated above for the True-Up period cost of service.

- **<u>Franchise Fees/Uncollectibles Expenses</u>** – decreased by $0.208 million due to the changes as explained above.

ISO Wholesale Transmission Revenue Requirements changed for similar reasons as explained above for the Retail BTRR.

2. **<u>Retail True-Up Cost of Service</u>** –The reclassification of uninsured wildfire related losses as inverse condemnation from Accounts 350 and 360, and Depreciation and Amortization Expense, Account 404, to A&G expense Account 925 have affected the following cost statements as described below. The applicable changes to the True-Up cost of service statement are made in **bold**.

   ISO Wholesale Transmission Revenue Requirements changed for similar reasons as explained above for the Retail BTRR.

3. **<u>Cost Statement AD (Cost of Plant)</u>** – The weighted average transmission plant balance decreased by $.820 million as a result of the reclassifying inverse condemnation as A&G expense in Account 925. In addition, the average distribution plant balance decreased by $12.402 million for the same reason.

4. **<u>Cost Statement AE (Accumulated Depreciation and Amortization)</u>** – The weighted average transmission related accumulated depreciation and amortization reserve balance decreased by $.820 million as a result of reclassifying inverse condemnation as A&G expense in Account 925.

5. **<u>Cost Statement AH (Operations & Maintenance Expense)</u>** – Transmission O&M expenses increased by $2.373 million which reflects the amount of uninsured wildfire liability losses allocated to transmission using the transmission wages and salaries allocation factor required by Account 925.

6. **<u>Cost Statement AJ (Depreciation & Amortization Expense)</u>** – Transmission Related Depreciation and Amortization expenses decreased by $19.687 million, as a result of the removal of uninsured wildfire liability losses that had been directly assigned to transmission as inverse condemnation costs.

7. **<u>Cost Statement AK (Taxes Other than Income Taxes)</u>** – Transmission Related Property Taxes expense increased by $.014 million, as a result of the increase in the Property Tax Allocation Factor caused by the removal of the uninsured wildfire liability losses from Accounts 350 and 360.

8. **<u>Cost Statement AL (Working Capital)</u>** – The working cash component of working capital for retail customers increased by $.297 million, as a result of the increase in transmission related A&G expenses.

9. **<u>Cost Statement AV (Rate of Return)</u>** – as indicated on page AV2, transmission rate base increased by $.314 million to $1,111,690. This increase had no effect on the Federal Income Tax Rate, State Income Tax Rate, and the Cost of Capital Rate.

Exhibit No. 1

San Diego Gas & Electric Company

Per Compliance Filing Retail BTRR Calculation (Statement BK1)

($ in Millions)

Line No.	Description	(a) As Filed BTRR [1]	(b) BTRR Adjustments to Comply With Suspension Order	(c) = (a) + (b) FERC Suspension Order BTRR [1]	Line No.
1	A. Prior Year Revenues	$ 267.186	$ -	$ 267.186	1
2	B. True-Up Adjustment	32.145	(17.749)	14.396	2
3	C. Foreacast Period Capital Additions Revenue	101.965	-	101.965	3
4	D. Interest True-Up Adjustment	0.904	-	0.904	4
5	E. Total Retail BTRR Before FF&U	$ 402.200	$ (17.749)	$ 384.451	5
6	F. Franchise Fees @ 1.0275%	4.133	(0.182)	3.950	6
7	G. Uncollectibles @ .141%	0.567	(0.025)	0.542	7
8	H. Total Retail BTRR - Compliance Filing	$ 406.900	$ (17.957)	$ 388.943	8

[1] BTRR = Base Transmission Revenue Requirements

[2] Of the $44.5 M in the total wildfire damange claims, $15.6 M is allocated to SDG&E's electric division, and then 15.19% (Transmission Labor Ratio) of the amount is allocated to transmission, $2.4 M.

	A	B	C	D	E	F
1						
2		Exhibit No. 1				
3		San Diego Gas & Electric Company				
4		Per Compliance Filing Wholelsale BTRR Calculation (Statement BK2)				
5		($ in Millions)				
6						
7			(a)	(b)	(c) = (a) + (b)	
8						
9				BTRR Adjustments	FERC	
10	Line		As Filed	to Comply With	Suspension Order	Line
11	No.	Description	BTRR [1]	Suspension Order	BTRR	No.
12						
13	1	A. Prior Year Revenues	$ 264.853	$ -	$ 264.853	1
14						
15	2	B. True-Up Adjustment	37.347	(17.724)	19.623	2
16						
17	3	C. Foreacast Period Capital Additions Revenue	101.965	-	101.965	3
18						
19	4	D. Interest True-Up Adjustment	0.755	-	0.755	4
20						
21	5	E. Total Wholesale BTRR Before FF&U	$ 404.920	$ (17.724)	$ 387.196	5
22						
23	6	F. Franchise Fees @ 1.0275%	4.161	(0.182)	3.978	6
24						
25	7	G. Uncollectibles	-	-	-	7
26						
27	8	H. Total Wholesale BTRR - Compliance Filing	$ 409.081	$ (17.906)	$ 391.175	8
28						
29						
30		[1] BTRR = Base Transmission Revenue Requirements				
31						
32		[2] Of the $44.5 M in the total wildfire damange claims, $15.6 M is allocated to SDG&E's electric division,				
33		and then 15.19% (Transmission Labor Ratio) of the amount is allocated to transmission, $2.4 M.				

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San Diego Gas & Electric Company

Base Period
Statement – BG
Revenue Data to Reflect Changed Rates

Docket No. ER11-4318-000

Statement BG

SAN DIEGO GAS AND ELECTRIC COMPANY

Transmission Revenues Data to Reflect Changed Rates

Comparison of Revenues

Rate Effective Period - Twelve Months Ending August 31, 2012

Line No.	Customer Classes	(A) 2011 Transmission Revenues @ Changed Rates	(B) 2011 Transmission Revenues @ Present Rates [1]	(C) = (A) - (B) ($) Change	(D) = (C)/(B) (%) Change	Reference	Line No.
1	Residential	$ 153,516,773	$ 126,549,723	$ 26,967,050	21.31%	(A): Statement BG, Page BG-2, Line 12	1
2						(B): Statement BH, Page BH-1, Line 12	2
3	Small Commercial	47,264,684	$ 38,855,754	$ 8,408,930	21.64%	(A): Statement BG, Page BG-2, Line 14;	3
4						(B): Statement BH, Page BH-1, Line 14	4
5	Medium and Large Commercial/Industrial	181,834,354	$ 153,500,749	$ 28,333,604	18.46%	(A): Statement BG, Page BG-2, Line 16;	5
6						(B): Statement BH, Page BH-1, Line 16	6
7	Street Lighting	1,439,528	$ 1,185,291	$ 254,236	21.45%	(A): Statement BG, Page BG-2, Line 18;	7
8						(B): Statement BH, Page BH-1, Line 18	8
9	Standby	4,867,740	$ 4,124,832	$ 742,908	18.01%	(A): Statement BG, Page BG-2, Line 20;	9
10						(B): Statement BH, Page BH-1, Line 20	10
11	Grand Total	$ 388,923,078	$ 324,216,350	$ 64,706,728	19.96%	Sum Lines 1 through 9	11

NOTES:

1 Present Rates are defined as rates effective pursuant to ER10-2235-001.

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Statement BG
SAN DIEGO GAS AND ELECTRIC COMPANY
Transmission Revenues Data to Reflect Changed Rates
Rate Effective Period - Twelve Months Ending August 31, 2012

Line No.	Customer Classes	(A) Sep-11	(B) Oct-11	(C) Nov-11	(D) Dec-11	(E) Jan-12	(F) Feb-12	(G)	Line No.
1	Residential [1]	$ 14,586,477	$ 12,380,770	$ 11,939,029	$ 13,295,445	$ 14,536,778	$ 12,856,644		1
2									2
3	Small Commercial [2]	4,471,025	3,998,610	3,827,024	3,775,785	3,823,353	3,709,383		3
4									4
5	Medium and Large Commercial/Industrial [3]	18,403,745	14,366,753	14,080,586	13,816,410	13,544,853	13,256,034		5
6									6
7	Street Lighting [4]	119,589	119,690	119,792	119,894	119,826	119,894		7
8									8
9	Standby [5]	405,645	405,645	405,645	405,645	405,645	405,645		9
10									10
11	TOTAL	$ 37,986,481	$ 31,271,468	$ 30,372,077	$ 31,413,179	$ 32,430,455	$ 30,347,600		11

Line No.	Customer Classes	(A) Mar-12	(B) Apr-12	(C) May-12	(D) Jun-12	(E) Jul-12	(F) Aug-12	(G) Total	Line No.
12	Residential [1]	$ 12,259,564	$ 11,315,296	$ 11,120,851	$ 11,681,267	$ 13,335,531	$ 14,209,121	$ 153,516,773	12
13									13
14	Small Commercial [2]	3,729,188	3,587,588	3,682,380	3,916,869	4,328,505	4,414,973	$ 47,264,684	14
15									15
16	Medium and Large Commercial/Industrial [3]	13,433,483	13,337,220	15,602,812	16,573,334	17,763,679	17,655,445	$ 181,834,354	16
17									17
18	Street Lighting [4]	119,962	120,028	120,095	120,161	120,252	120,344	$ 1,439,528	18
19									19
20	Standby [5]	405,645	405,645	405,645	405,645	405,645	405,645	$ 4,867,740	20
21									21
22	TOTAL	$ 29,947,842	$ 28,765,776	$ 30,931,783	$ 32,697,277	$ 35,953,612	$ 36,805,528	$ 388,923,078	22

NOTES:

1 Statement BG, Pages BG-3, -4, & -5, Line 25.
2 Statement BG, Pages BG-3, -4, & -5, Line 27.
3 Statement BG, Pages BG-3, -4, & -5, Sum Lines 30 through 33.
4 Statement BG, Pages BG-3, -4, & -5, Line 35.
5 Statement BG, Pages BG-3, -4, & -5, Line 37.

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Statement BG
SAN DIEGO GAS AND ELECTRIC COMPANY
Transmission Revenues Data to Reflect Changed Rates
Rate Effective Period - Twelve Months Ending August 31, 2012

Line No.	Customer Classes	(A) Sep-11 Billing Determinants [1] Energy (kWh)	(A) Demand (kW)	(B) Oct-11 Billing Determinants Energy (kWh)	(B) Demand (kW)	(C) Nov-11 Billing Determinants Energy (kWh)	(C) Demand (kW)	(D) Dec-11 Billing Determinants Energy (kWh)	(D) Demand (kW)	Line No.
1	Residential	742,692,311	-	630,385,458	-	607,893,559	-	676,957,499	-	1
2										2
3	Small Commercial	192,136,877	-	171,835,412	-	164,461,703	-	162,259,771	-	3
4										4
5	Medium and Large Commercial/Industrial	1,002,350,490		901,252,873		885,222,793		869,872,441		5
6	Non-coincident (100%)		119,225		112,660		100,301		92,465	6
7	Non-coincident (90%)		2,554,765		2,289,120		2,254,433		2,218,586	7
8	Maximum On-peak Period Demand		2,298,130		1,831,140		1,801,974		1,771,834	8
9	Maximum Demand at the Time of System Peak		93,577		84,837		84,862		84,886	9
10										10
11	Street Lighting	9,513,816	-	9,521,902	-	9,530,002	-	9,538,116	-	11
12										12
13	Standby	-	147,082	-	147,082	-	147,082	-	147,082	13
14										14
15	TOTAL	1,946,693,495		1,712,995,645		1,667,108,057		1,718,627,828		15

NOTES:

[1] Billing determinants are forecast determinants for the rate effective September 2011 through August 2012.

Line No.	Customer Classes	(A) Sep-11 Changed Transmission Rates Energy (kWh)	(A) Demand (kW)	(B) Oct-11 Changed Transmission Rates Energy (kWh)	(B) Demand (kW)	(C) Nov-11 Changed Transmission Rates Energy (kWh)	(C) Demand (kW)	(D) Dec-11 Changed Transmission Rates Energy (kWh)	(D) Demand (kW)	Line No.
16	Residential [2]	$ 0.01964		$ 0.01964		$ 0.01964		$ 0.01964		16
17										17
18	Small Commercial [2]	$ 0.02327		$ 0.02327		$ 0.02327		$ 0.02327		18
19										19
20	Medium and Large Commercial/Industrial [2]									20
21										21
22	Street Lighting [2]	$ 0.01257		$ 0.01257		$ 0.01257		$ 0.01257		22
23										23
24	Standby [2]									24

NOTES:

[2] The changed rates information comes from Statement BL, Page BL-1, Column A, Lines 1 through 18.

Line No.	Customer Classes	(A) Sep-11 Revenues @ Changed Rates [3] Energy (kWh)	(A) Demand (kW)	(B) Oct-11 Revenues @ Changed Rates Energy (kWh)	(B) Demand (kW)	(C) Nov-11 Revenues @ Changed Rates Energy (kWh)	(C) Demand (kW)	(D) Dec-11 Revenues @ Changed Rates Energy (kWh)	(D) Demand (kW)	Line No.
25	Residential	$ 14,586,477	$ -	$ 12,380,770	$ -	$ 11,939,029	$ -	$ 13,295,445	$ -	25
26										26
27	Small Commercial	$ 4,471,025	$ -	$ 3,998,610	$ -	$ 3,827,024	$ -	$ 3,775,785	$ -	27
28										28
29	Medium and Large Commercial/Industrial	$ -		$ -		$ -		$ -		29
30	Non-coincident (100%)		$ 762,316		$ 720,340		$ 641,322		$ 591,219	30
31	Non-coincident (90%)		$ 14,659,271		$ 13,132,717		$ 12,933,379		$ 12,727,377	31
32	Maximum On-peak Period Demand		$ 2,853,826		$ 490,790		$ 482,972		$ 474,894	32
33	Maximum Demand at the Time of System Peak		$ 128,332		$ 22,906		$ 22,913		$ 22,919	33
34										34
35	Street Lighting	$ 119,589	$ -	$ 119,690	$ -	$ 119,792	$ -	$ 119,894	$ -	35
36										36
37	Standby	$ -	$ 405,645	$ -	$ 405,645	$ -	$ 405,645	$ -	$ 405,645	37
38										38
39	TOTAL	$ 19,177,091	$ 18,809,390	$ 16,499,071	$ 14,772,398	$ 15,885,845	$ 14,486,231	$ 17,191,124	$ 14,222,055	39
40										40
41	Grand Total		$ 37,986,481		$ 31,271,468		$ 30,372,077		$ 31,413,179	41

NOTES:

[3] The revenues above are derived by multiplying the forecast billing determinants by the rates, except for Medium & Large Commercial/Industrial and Standby customers. The derivation of revenues for Medium & Large Commercial/Industrial and Standby customers are shown on pages BG-6 through BG-10.

Statement BG
SAN DIEGO GAS AND ELECTRIC COMPANY
Transmission Revenues Data to Reflect Changed Rates
Rate Effective Period - Twelve Months Ending August 31, 2012

Line No.	Customer Classes	(E) Jan-12 Billing Determinants [1] Energy (kWh)	(E) Demand (kW)	(F) Feb-12 Billing Determinants Energy (kWh)	(F) Demand (kW)	(G) Mar-12 Billing Determinants Energy (kWh)	(G) Demand (kW)	(H) Apr-12 Billing Determinants Energy (kWh)	(H) Demand (kW)	Line No.
1	Residential	740,161,834	-	654,615,264	-	624,214,046	-	576,135,213	-	1
2										2
3	Small Commercial	164,303,954	-	159,406,233	-	160,257,347	-	154,172,241	-	3
4										4
5	Medium and Large Commercial/Industrial	856,104,451		838,470,127		849,231,544		841,886,802		5
6	Non-coincident (100%)		71,404		68,344		70,750		79,241	6
7	Non-coincident (90%)		2,195,664		2,150,577		2,177,716		2,152,507	7
8	Maximum On-peak Period Demand		1,752,551		1,714,648		1,737,420		1,716,216	8
9	Maximum Demand at the Time of System Peak		84,911		84,936		84,961		84,985	9
10										10
11	Street Lighting	9,532,714	-	9,538,101	-	9,543,496	-	9,548,782	-	11
12										12
13	Standby	-	147,082	-	147,082	-	147,082	-	147,082	13
14										14
15	TOTAL	1,770,102,954		1,662,029,725		1,643,246,433		1,581,743,038		15

NOTES:

[1] Billing determinants are forecast determinants for the rate effective September 2011 through August 2012.

Line No.	Customer Classes	(E) Jan-12 Changed Transmission Rates Energy (kWh)	(E) Demand (kW)	(F) Feb-12 Changed Transmission Rates Energy (kWh)	(F) Demand (kW)	(G) Mar-12 Changed Transmission Rates Energy (kWh)	(G) Demand (kW)	(H) Apr-12 Changed Transmission Rates Energy (kWh)	(H) Demand (kW)	Line No.
16	Residential [2]	$ 0.01964		$ 0.01964		$ 0.01964		$ 0.01964		16
17										17
18	Small Commercial [2]	$ 0.02327		$ 0.02327		$ 0.02327		$ 0.02327		18
19										19
20	Medium and Large Commercial/Industrial [2]									20
21										21
22	Street Lighting [2]	$ 0.01257		$ 0.01257		$ 0.01257		$ 0.01257		22
23										23
24	Standby [2]									24

NOTES:

[2] The changed rates information comes from Statement BL, Page BL-1, Column A, Lines 1 through 18.

Line No.	Customer Classes	(E) Jan-12 Revenues @ Changed Rates [3] Energy (kWh)	(E) Demand (kW)	(F) Feb-12 Revenues @ Changed Rates Energy (kWh)	(F) Demand (kW)	(G) Mar-12 Revenues @ Changed Rates Energy (kWh)	(G) Demand (kW)	(H) Apr-12 Revenues @ Changed Rates Energy (kWh)	(H) Demand (kW)	Line No.
25	Residential	$ 14,536,778	$ -	$ 12,856,644	$ -	$ 12,259,564	$ -	$ 11,315,296	$ -	25
26										26
27	Small Commercial	$ 3,823,353	$ -	$ 3,709,383	$ -	$ 3,729,188	$ -	$ 3,587,588	$ -	27
28										28
29	Medium and Large Commercial/Industrial	$ -		$ -		$ -		$ -		29
30	Non-coincident (100%)		$ 456,553		$ 436,990		$ 452,374		$ 506,661	30
31	Non-coincident (90%)		$ 12,595,648		$ 12,336,545		$ 12,492,499		$ 12,347,625	31
32	Maximum On-peak Period Demand		$ 469,726		$ 459,567		$ 465,670		$ 459,987	32
33	Maximum Demand at the Time of System Peak		$ 22,926		$ 22,933		$ 22,939		$ 22,946	33
34										34
35	Street Lighting	$ 119,826	$ -	$ 119,894	$ -	$ 119,962	$ -	$ 120,028	$ -	35
36										36
37	Standby	$ -	$ 405,645	$ -	$ 405,645	$ -	$ 405,645	$ -	$ 405,645	37
38										38
39	TOTAL	$ 18,479,958	$ 13,950,498	$ 16,685,921	$ 13,661,679	$ 16,108,714	$ 13,839,128	$ 15,022,912	$ 13,742,865	39
40										40
41	Grand Total		$ 32,430,455		$ 30,347,600		$ 29,947,842		$ 28,765,776	41

NOTES:

[3] The revenues above are derived by multiplying the forecast billing determinants by the rates, except for Medium & Large Commercial/Industrial and Standby customers.
The derivation of revenues for Medium & Large Commercial/Industrial and Standby customers are shown on pages BG-6 through BG-10.

Statement BG
SAN DIEGO GAS AND ELECTRIC COMPANY
Transmission Revenue Data To Reflect Changed Rates
Rate Effective Period - Twelve Months Ending August 31, 2012

000006

Line No.	Customer Classes	(I) May-12 Billing Determinants [1]		(J) Jun-12 Billing Determinants		(K) Jul-12 Billing Determinants		(L) Aug-12 Billing Determinants		(M) Total Billing Determinants		Line No.
		Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	
1	Residential Customers	566,234,778	-	594,769,177	-	678,998,511	-	723,478,668	-	7,816,536,319	-	1
2												2
3	Small Commercial	158,245,823	-	168,322,707	-	186,012,233	-	189,728,097	-	2,031,142,400	-	3
4												4
5	Medium-Large Commercial	853,924,698		904,970,683		967,358,922		962,068,063		10,732,713,885		5
6	Non-Coincident (100%)		86,644		101,959		122,927		117,257		1,143,176	6
7	Non-Coincident (90%)		2,179,768		2,305,985		2,458,769		2,448,358		27,386,246	7
8	Max. On-Peak Period Demand		1,945,482		2,064,066		2,207,617		2,197,803		23,038,878	8
9	Max. Demand at the Time of System Peak		93,795		93,822		93,850		93,877		1,063,298	9
10												10
11	Street Lighting	9,554,076	-	9,559,379	-	9,566,625	-	9,573,881	-	114,520,891	-	11
12												12
13	Standby Customers	-	147,082	-	147,082	-	147,082	-	147,082	-	1,764,984	13
14												14
15	TOTAL	1,587,959,374		1,677,621,946		1,841,936,291		1,884,848,709		20,694,913,495		15

NOTES:

1 Billing determinants are forecast determinants for the rate effective September 2011 through August 2012.

Line No.	Customer Classes	(I) May-12 Changed Transmission Rates		(J) Jun-12 Changed Transmission Rates		(K) Jul-12 Changed Transmission Rates		(L) Aug-12 Changed Transmission Rates		(M) Total Changed Transmission Rates		Line No.
		Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	
16	Residential [2]	$ 0.01964		$ 0.01964		$ 0.01964		$ 0.01964				16
17												17
18	Small Commercial [2]	$ 0.02327		$ 0.02327		$ 0.02327		$ 0.02327				18
19												19
20	Medium and Large Commercial/Industrial [2]											20
21												21
22	Street Lighting [2]	$ 0.01257		$ 0.01257		$ 0.01257		$ 0.01257				22
23												23
24	Standby [2]											24

NOTES:

1 The changed rates information comes from Statement BL, Page BL-1, Column A, Lines 1 through 18.

Line No.	Customer Classes	(I) May-12 Revenues @ Changed Rates [3]		(J) Jun-12 Revenues @ Changed Rates		(K) Jul-12 Revenues @ Changed Rates		(L) Aug-12 Revenues @ Changed Rates		(M) Total Revenues @ Changed Rates		Line No.
		Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	
25	Residential Customers	$ 11,120,851	$ -	$ 11,681,267	$ -	$ 13,335,531	$ -	$ 14,209,121	$ -	$ 153,516,773	$ -	25
26												26
27	Small Commercial	$ 3,682,380	$ -	$ 3,916,869	$ -	$ 4,328,505	$ -	$ 4,414,973	$ -	$ 47,264,684	$ -	27
28												28
29	Medium-Large Commercial	$ -		$ -		$ -		$ -		$ -		29
30	Non-Coincident (100%)		$ 553,997		$ 651,918		$ 785,987		$ 749,736		$ 7,309,413	30
31	Non-Coincident (90%)		$ 12,504,277		$ 13,229,583		$ 14,107,560		$ 14,047,726		$ 157,114,207	31
32	Max. On-Peak Period Demand		$ 2,415,906		$ 2,563,164		$ 2,741,426		$ 2,729,239		$ 16,607,167	32
33	Max. Demand at the Time of System Peak		$ 128,632		$ 128,669		$ 128,707		$ 128,744		$ 803,567	33
34												34
35	Street Lighting	$ 120,095	$ -	$ 120,161	$ -	$ 120,252	$ -	$ 120,344	$ -	$ 1,439,528	$ -	35
36												36
37	Standby Customers	$ -	$ 405,645	$ -	$ 405,645	$ -	$ 405,645	$ -	$ 405,645	$ -	$ 4,867,740	37
38												38
39	TOTAL	$ 14,923,326	$ 16,008,457	$ 15,718,297	$ 16,978,979	$ 17,784,288	$ 18,169,324	$ 18,744,438	$ 18,061,090	$ 202,220,985	$ 186,702,094	39
40												40
41	Grand Total		$ 30,931,783		$ 32,697,277		$ 35,953,612		$ 36,805,528		$ 388,923,078	41

NOTES:

3 The revenues above are derived by multiplying the forecast billing determinants by the rates, except for Medium & Large Commercial/Industrial and Standby customers.
The derivation of revenues for Medium & Large Commercial/Industrial and Standby customers are shown on pages BG-6 through BG-10.

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Line No.	Description	(A) Sep-11	(B) Oct-11	(C) Nov-11	(D) Dec-11	(E) Jan-12	(F) Feb-12	(G)	Reference	Line No.
1	Energy Revenues:									1
2	Commodity Sales - kWh	1,002,350,490	901,252,873	885,222,793	869,872,441	856,104,451	838,470,127		Page BGWP-4, Line 120 [5]	2
3	Commodity Rate - $/kWh	0	0	0	0	0	0			3
4	Total Commodity Revenues	$ -	$ -	$ -	$ -	$ -	$ -		Line 2 x Line 3	4
5										5
6	Non-coincident Demand (100%) (kW) [1]:									6
7	Secondary	104,435	98,684	87,859	80,995	62,546	59,866		Page BGWP-1, Line 38 [5]	7
8	Primary	14,790	13,975	12,442	11,470	8,858	8,478		Page BGWP-1, Line 39	8
9	Transmission	-	-	-	-	-	-		Page BGWP-1, Line 40	9
10	Total	119,225	112,660	100,301	92,465	71,404	68,344		Sum Lines 7; 8; 9	10
11	Check Figure	119,225	112,660	100,301	92,465	71,404	68,344		Page BG-14, Line 6 [5]	11
12	Difference	-	-	-	-	-	-		Line 10 Less Line 11	12
13										13
14	Non-coincident Demand (100%)									14
15	Rates ($/kW):									15
16	Secondary	$ 6.42	$ 6.42	$ 6.42	$ 6.42	$ 6.42	$ 6.42		Statement BL, Page BL-1, Line 6D	16
17	Primary	$ 6.21	$ 6.21	$ 6.21	$ 6.21	$ 6.21	$ 6.21		Statement BL, Page BL-1, Line 6C	17
18	Transmission	$ 6.15	$ 6.15	$ 6.15	$ 6.15	$ 6.15	$ 6.15		Statement BL, Page BL-1, Line 6B	18
19	Non-coincident Demand (100%) -									19
20	Revenues at Changed Rates:									20
21	Secondary	$ 670,472	$ 633,553	$ 564,056	$ 519,989	$ 401,548	$ 384,341		Line 7 x Line 16	21
22	Primary	91,844	86,786	77,266	71,230	55,005	52,648		Line 8 x Line 17	22
23	Transmission	-	-	-	-	-	-		Line 9 x Line 18	23
24	Subtotal	$ 762,316	$ 720,340	$ 641,322	$ 591,219	$ 456,553	$ 436,990		Sum Lines 21; 22; 23	24

Line No.	Description	(A) Mar-12	(B) Apr-12	(C) May-12	(D) Jun-12	(E) Jul-12	(F) Aug-12	(G) Total	Reference	Line No.
25	Energy Revenues:									25
26	Commodity Sales - kWh	849,231,544	841,886,802	853,924,698	904,970,683	967,358,922	962,068,063	10,732,713,885	Page BGWP-4, Line 120 [5]	26
27	Commodity Rate - $/kWh	0	0	0	0	0	0	-		27
28	Total Commodity Revenues	$ -	$ -	$ -	$ -	$ -	$ -	$ -	Line 25 x Line 26	28
29										29
30	Non-coincident Demand (100%) (kW) [1]:									30
31	Secondary	61,974	69,411	75,896	89,311	107,678	102,712	1,001,367	Page BGWP-1, Line 38 [5]	31
32	Primary	8,776	9,830	10,748	12,648	15,249	14,546	141,810	Page BGWP-1, Line 39	32
33	Transmission	-	-	-	-	-	-	-	Page BGWP-1, Line 40	33
34	Total	70,750	79,241	86,644	101,959	122,927	117,257	1,143,176	Sum Lines 31; 32; 33	34
35	Check Figure	70,750	79,241	86,644	101,959	122,927	117,257	1,143,176	Page BG-15, Line 6 [5]	35
36	Difference	-	-	-	-	-	-	-	Line 33 Less Line 34	36
37										37
38	Non-coincident Demand (100%)									38
39	Rates ($/kW):									39
40	Secondary	$ 6.42	$ 6.42	$ 6.42	$ 6.42	$ 6.42	$ 6.42		Statement BL, Page BL-1, Line 6D	40
41	Primary	$ 6.21	$ 6.21	$ 6.21	$ 6.21	$ 6.21	$ 6.21		Statement BL, Page BL-1, Line 6C	41
42	Transmission	$ 6.15	$ 6.15	$ 6.15	$ 6.15	$ 6.15	$ 6.15		Statement BL, Page BL-1, Line 6B	42
43	Non-coincident Demand (100%) -									43
44	Revenues at Changed Rates:									44
45	Secondary	$ 397,872	$ 445,619	$ 487,251	$ 573,375	$ 691,291	$ 659,408	$ 6,428,776	Line 31 x Line 40	45
46	Primary	54,502	61,042	66,745	78,543	94,696	90,328	$ 880,637	Line 32 x Line 41	46
47	Transmission	-	-	-	-	-	-	$ -	Line 33 x Line 42	47
48	Subtotal	$ 452,374	$ 506,661	$ 553,997	$ 651,918	$ 785,987	$ 749,736	$ 7,309,413	Sum Lines 45; 46; 47	48

NOTES:

1 Non-coincident Demand (NCD) (100%) rates are applicable to the following California Public Utilities Commission (CPUC) tariffs: Schedules AD and PA-T-1.
2 NCD (90%) rates are applicable to the following CPUC tariffs: Schedules AY-TOU, AL-TOU, AL-TOU-DER, DG-R, and A6-TOU.
3 Maximum On-peak Demand rates are applicable to the following CPUC tariffs: Schedules AY-TOU, AL-TOU, AL-TOU-DER, and DG-R.
4 Maximum Demand at the Time of System Peak rates are applicable to the following CPUC tariff: Schedule A6-TOU.
5 Pages BGWP-1, BGWP-4, and BG-14 are found in Statement BG.

Statement BG
SAN DIEGO GAS AND ELECTRIC COMPANY
Transmission Revenues Data to Reflect Changed Rates
Medium & Large Commercial / Industrial Customers
Rate Effective Period - Twelve Months Ending August 31, 2012

Line No.	Description	(A) Sep-11	(B) Oct-11	(C) Nov-11	(D) Dec-11	(E) Jan-12	(F) Feb-12	(G)	Reference	Line No.
1	Non-coincident									1
2	Demand (90%) (kW) [2]:									2
3	Secondary	2,022,284	1,802,579	1,773,868	1,744,197	1,725,215	1,687,903		Page BGWP-2 & -3, Line 65 + Line 101 [5]	3
4	Primary	410,516	367,507	361,890	356,086	352,374	345,073		Page BGWP-2 & -3, Line 66 + Line 102	4
5	Transmission	121,964	119,034	118,675	118,303	118,075	117,600		Page BGWP-2 & -3, Line 67 + Line 103	5
6	Total	2,554,765	2,289,120	2,254,433	2,218,586	2,195,664	2,150,577		Sum Lines 3; 4; 5	6
7	Check Figure	2,554,765	2,289,120	2,254,433	2,218,586	2,195,664	2,150,577		Statement BG, Page BG-14, Line 7	7
8	Difference	-	-	-	-	-	-		Line 6 Less Line 7	8
9										9
10	Non-coincident Demand (90%)									10
11	Rates ($/kW):									11
12	Secondary	$ 5.78	$ 5.78	$ 5.78	$ 5.78	$ 5.78	$ 5.78		Statement BL, Page BL-1, Line 8D	12
13	Primary	$ 5.59	$ 5.59	$ 5.59	$ 5.59	$ 5.59	$ 5.59		Statement BL, Page BL-1, Line 8C	13
14	Transmission	$ 5.54	$ 5.54	$ 5.54	$ 5.54	$ 5.54	$ 5.54		Statement BL, Page BL-1, Line 8B	14
15	Non-coincident Demand (90%) -									15
16	Revenues at Changed Rates:									16
17	Secondary	$ 11,688,803	$ 10,418,906	$ 10,252,954	$ 10,081,460	$ 9,971,743	$ 9,756,081		Line 3 x Line 12	17
18	Primary	2,294,786	2,054,364	2,022,966	1,990,518	1,969,768	1,928,958		Line 4 x Line 13	18
19	Transmission	675,682	659,447	657,459	655,399	654,136	651,506		Line 5 x Line 14	19
20	Subtotal	$ 14,659,271	$ 13,132,717	$ 12,933,379	$ 12,727,377	$ 12,595,648	$ 12,336,545		Sum Lines 17; 18; 19	20

Line No.	Description	(A) Mar-12	(B) Apr-12	(C) May-12	(D) Jun-12	(E) Jul-12	(F) Aug-12	(G) Total	Reference	Line No.
21	Non-coincident									21
22	Demand (90%) (kW) [2]:									22
23	Secondary	1,710,320	1,689,447	1,711,964	1,816,315	1,942,635	1,933,999	21,560,727	Page BGWP-2 & -3, Line 65 + Line 101	23
24	Primary	349,466	345,384	349,796	370,230	394,965	393,279	4,396,566	Page BGWP-2 & -3, Line 66 + Line 102	24
25	Transmission	117,930	117,676	118,007	119,440	121,168	121,080	1,428,953	Page BGWP-2 & -3, Line 67 + Line 103	25
26	Total	2,177,716	2,152,507	2,179,768	2,305,985	2,458,769	2,448,358	27,386,246	Sum Lines 23; 24; 25	26
27	Check Figure	2,177,716	2,152,507	2,179,768	2,305,985	2,458,769	2,448,358	27,386,246	Statement BG, Page BG-15, Line 7	27
28	Difference	-	-	-	-	-	-	-	Line 26 Less Line 27	28
29										29
30	Non-coincident Demand (90%)									30
31	Rates ($/kW):									31
32	Secondary	$ 5.78	$ 5.78	$ 5.78	$ 5.78	$ 5.78	$ 5.78		Statement BL, Page BL-1, Line 8D	32
33	Primary	$ 5.59	$ 5.59	$ 5.59	$ 5.59	$ 5.59	$ 5.59		Statement BL, Page BL-1, Line 8C	33
34	Transmission	$ 5.54	$ 5.54	$ 5.54	$ 5.54	$ 5.54	$ 5.54		Statement BL, Page BL-1, Line 8B	34
35	Non-coincident Demand (90%) -									35
36	Revenues at Changed Rates:									36
37	Secondary	$ 9,885,652	$ 9,765,003	$ 9,895,155	$ 10,498,299	$ 11,228,431	$ 11,178,515	$ 124,621,003	Line 23 x Line 32	37
38	Primary	1,953,515	1,930,695	1,955,362	2,069,587	2,207,856	2,198,429	$ 24,576,804	Line 24 x Line 33	38
39	Transmission	653,331	651,928	653,760	661,697	671,273	670,782	$ 7,916,399	Line 25 x Line 34	39
40	Subtotal	$ 12,492,499	$ 12,347,625	$ 12,504,277	$ 13,229,583	$ 14,107,560	$ 14,047,726	$ 157,114,207	Sum Lines 37; 38; 39	40

NOTES:

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

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

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

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

5 Pages BGWP-2 and BGWP-3 are found in Statement BG.

Statement BG
SAN DIEGO GAS AND ELECTRIC COMPANY
Transmission Revenues Data to Reflect Changed Rates
Medium & Large Commercial / Industrial Customers
Rate Effective Period - Twelve Months Ending August 31, 2012

Line No.	Description	(A) Sep-11	(B) Oct-11	(C) Nov-11	(D) Dec-11	(E) Jan-12	(F) Feb-12	(G)	Reference	Line No.
1	Maximum On-peak									1
2	Period Demand (kW) [3]:									2
3	Secondary	1,851,078	1,469,324	1,445,920	1,421,735	1,406,263	1,375,849		Statement BG, Page BGWP-2, Line 75	3
4	Primary	399,329	318,421	313,349	308,108	304,755	298,164		Statement BG, Page BGWP-2, Line 76	4
5	Transmission	47,724	43,396	42,705	41,990	41,533	40,635		Statement BG, Page BGWP-2, Line 77	5
6	Total	2,298,130	1,831,140	1,801,974	1,771,834	1,752,551	1,714,648		Sum Lines 3; 4; 5	6
7	Check Figure	2,298,130	1,831,140	1,801,974	1,771,834	1,752,551	1,714,648		Statement BG, Page BG-14, Line 8	7
8	Difference	-	-	-	-	-	-		Line 6 Less Line 7	8
9										9
10	Maximum On-peak									10
11	Period Demand Rates ($/kW):									11
12	Secondary	$ 1.25	$ 0.27	$ 0.27	$ 0.27	$ 0.27	$ 0.27		Statement BL, Page BL-1, Lines 11D & 12D	12
13	Primary	$ 1.21	$ 0.26	$ 0.26	$ 0.26	$ 0.26	$ 0.26		Statement BL, Page BL-1, Lines 11C & 12C	13
14	Transmission	$ 1.19	$ 0.26	$ 0.26	$ 0.26	$ 0.26	$ 0.26		Statement BL, Page BL-1, Lines 11B & 12B	14
15	Maximum On-peak Period Demand -									15
16	Revenues at Changed Rates:									16
17	Secondary	$ 2,313,847	$ 396,717	$ 390,398	$ 383,869	$ 379,691	$ 371,479		Line 3 x Line 12	17
18	Primary	483,188	82,789	81,471	80,108	79,236	77,523		Line 4 x Line 13	18
19	Transmission	56,791	11,283	11,103	10,918	10,799	10,565		Line 5 x Line 14	19
20	Subtotal	$ 2,853,826	$ 490,790	$ 482,972	$ 474,894	$ 469,726	$ 459,567		Sum Lines 17; 18; 19	20

Line No.	Description	(A) Mar-12	(B) Apr-12	(C) May-12	(D) Jun-12	(E) Jul-12	(F) Aug-12	(G) Total	Reference	Line No.
21	Maximum On-peak									21
22	Period Demand (kW) [3]:									22
23	Secondary	1,394,122	1,377,107	1,567,030	1,662,546	1,778,172	1,770,267	18,519,411	Statement BG, Page BGWP-2, Line 75	23
24	Primary	302,124	298,436	338,052	358,657	383,601	381,895	4,004,889	Statement BG, Page BGWP-2, Line 76	24
25	Transmission	41,175	40,672	40,400	42,863	45,844	45,640	514,578	Statement BG, Page BGWP-2, Line 77	25
26	Total	1,737,420	1,716,216	1,945,482	2,064,066	2,207,617	2,197,803	23,038,878	Sum Lines 23; 24; 25	26
27	Check Figure	1,737,420	1,716,216	1,945,482	2,064,066	2,207,617	2,197,803	23,038,878	Statement BG, Page BG-15, Line 8	27
28	Difference	-	-	-	-	-	-	-	Line 26 Less Line 27	28
29										29
30	Maximum On-peak									30
31	Period Demand Rates ($/kW):									31
32	Secondary	$ 0.27	$ 0.27	$ 1.25	$ 1.25	$ 1.25	$ 1.25		Statement BL, Page BL-1, Lines 11D & 12D	32
33	Primary	$ 0.26	$ 0.26	$ 1.21	$ 1.21	$ 1.21	$ 1.21		Statement BL, Page BL-1, Lines 11C & 12C	33
34	Transmission	$ 0.26	$ 0.26	$ 1.19	$ 1.19	$ 1.19	$ 1.19		Statement BL, Page BL-1, Lines 11B & 12B	34
35	Maximum On-peak Period Demand -									35
36	Revenues at Changed Rates:									36
37	Secondary	$ 376,413	$ 371,819	$ 1,958,787	$ 2,078,182	$ 2,222,715	$ 2,212,834	$ 13,456,751	Line 23 x Line 32	37
38	Primary	78,552	77,593	409,042	433,975	464,157	462,094	$ 2,809,728	Line 24 x Line 33	38
39	Transmission	10,705	10,575	48,076	51,007	54,554	54,312	$ 340,688	Line 25 x Line 34	39
40	Subtotal	$ 465,670	$ 459,987	$ 2,415,906	$ 2,563,164	$ 2,741,426	$ 2,729,239	$ 16,607,167	Sum Lines 37; 38; 39	40

NOTES:

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

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

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

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

Statement BG
SAN DIEGO GAS AND ELECTRIC COMPANY
Transmission Revenues Data to Reflect Changed Rates
Medium & Large Commercial / Industrial Customers
Rate Effective Period - Twelve Months Ending August 31, 2012

Line No.	Description	(A) Sep-11	(B) Oct-11	(C) Nov-11	(D) Dec-11	(E) Jan-12	(F) Feb-12	(G)	Reference	Line No.
1	Maximum Demand									1
2	at the Time of System Peak (kW) [4]:									2
3	Secondary	-	-	-	-	-	-		Statement BG, Page BGWP-3, Line 111	3
4	Primary	13,230	11,414	11,418	11,421	11,424	11,428		Statement BG, Page BGWP-3, Line 112	4
5	Transmission	80,346	73,422	73,444	73,465	73,487	73,508		Statement BG, Page BGWP-3, Line 113	5
6	Total	93,577	84,837	84,862	84,886	84,911	84,936		Sum Lines 3; 4; 5	6
7	Check Figure	93,577	84,837	84,862	84,886	84,911	84,936		Statement BG, Page BG-14, Line 9	7
8	Difference	-	-	-	-	-	-		Line 6 Less Line 7	8
9										9
10	Maximum Demand at the									10
11	Time of System Peak Rates ($/kW):									11
12	Secondary	$ -	$ -	$ -	$ -	$ -	$ -		Statement BL, Page BL-1, Lines 15 & 16, Col. D	12
13	Primary	$ 1.38	$ 0.27	$ 0.27	$ 0.27	$ 0.27	$ 0.27		Statement BL, Page BL-1, Lines 15 & 16, Col. C	13
14	Transmission	$ 1.37	$ 0.27	$ 0.27	$ 0.27	$ 0.27	$ 0.27		Statement BL, Page BL-1, Lines 15 & 16, Col. B	14
15	Maximum Demand at the Time of System									15
16	Peak - Revenues at Changed Rates:									16
17	Secondary	$ -	$ -	$ -	$ -	$ -	$ -		Line 3 x Line 12	17
18	Primary	18,258	3,082	3,083	3,084	3,085	3,085		Line 4 x Line 13	18
19	Transmission	110,075	19,824	19,830	19,836	19,841	19,847		Line 5 x Line 14	19
20	Subtotal	$ 128,332	$ 22,906	$ 22,913	$ 22,919	$ 22,926	$ 22,933		Sum Lines 17; 18; 19	20
21										21
22	Revenues at Changed Rates:									22
23	Secondary	$ 14,673,123	$ 11,449,177	$ 11,207,409	$ 10,985,318	$ 10,752,982	$ 10,511,901		Statement BG, Page BG-6 Line 21 + Page BG-7 Line 17 + Page BG-8 Line 17 + Page BG-9 Line 17	23
24	Primary	$ 2,888,075	$ 2,227,022	$ 2,184,786	$ 2,144,940	$ 2,107,095	$ 2,062,214		Statement BG, Page BG-6 Line 22 + Page BG-7 Line 18 + Page BG-8 Line 18 + Page BG-9 Line 18	24
25	Transmission	$ 842,547	$ 690,554	$ 688,392	$ 686,152	$ 684,776	$ 681,918		Statement BG, Page BG-6 Line 23 + Page BG-7 Line 19 + Page BG-8 Line 19 + Page BG-9 Line 19	25
26	Total	$ 18,403,745	$ 14,366,753	$ 14,080,587	$ 13,816,410	$ 13,544,853	$ 13,256,033		Sum Lines 23; 24; 25	26
27										27
28	Total Revenues at Changed Rates:	$ 18,403,745	$ 14,366,753	$ 14,080,587	$ 13,816,410	$ 13,544,853	$ 13,256,033		Sum Line 26; Statement BG, Page BG-6, Line 4	28

Line No.	Description	(A) Mar-12	(B) Apr-12	(C) May-12	(D) Jun-12	(E) Jul-12	(F) Aug-12	(G) Total	Reference	Line No.
29	Maximum Demand									29
30	at the Time of System Peak (kW) [4]:									30
31	Secondary	-	-	-	-	-	-	-	Statement BG, Page BGWP-3, Line 111	31
32	Primary	11,431	11,434	13,261	13,265	13,269	13,273	146,269	Statement BG, Page BGWP-3, Line 112	32
33	Transmission	73,529	73,551	80,534	80,557	80,581	80,604	917,030	Statement BG, Page BGWP-3, Line 113	33
34	Total	84,961	84,985	93,795	93,822	93,850	93,877	1,063,298	Sum Lines 31; 32; 33	34
35	Check Figure	84,961	84,985	93,795	93,822	93,850	93,877	1,063,298	Statement BG, Page BG-15, Line 9	35
36	Difference	-	-	-	-	-	-	-	Line 34 Less Line 35	36
37										37
38	Maximum Demand at the									38
39	Time of System Peak Rates ($/kW):									39
40	Secondary	$ -	$ -	$ -	$ -	$ -	$ -		Statement BL, Page BL-1, Lines 15 & 16, Col. D	40
41	Primary	$ 0.27	$ 0.27	$ 1.38	$ 1.38	$ 1.38	$ 1.38		Statement BL, Page BL-1, Lines 15 & 16, Col. C	41
42	Transmission	$ 0.27	$ 0.27	$ 1.37	$ 1.37	$ 1.37	$ 1.37		Statement BL, Page BL-1, Lines 15 & 16, Col. B	42
43	Maximum Demand at the Time of System									43
44	Peak - Revenues at Changed Rates:									44
45	Secondary	$ -	$ -	$ -	$ -	$ -	$ -	$ -	Line 31 x Line 40	45
46	Primary	3,086	3,087	18,300	18,306	18,311	18,316	$ 113,083	Line 32 x Line 41	46
47	Transmission	19,853	19,859	110,332	110,364	110,396	110,428	$ 690,483	Line 33 x Line 42	47
48	Subtotal	$ 22,939	$ 22,946	$ 128,632	$ 128,669	$ 128,707	$ 128,744	$ 803,567	Sum Lines 45; 46; 47	48
49										49
50	Revenues at Changed Rates:									50
51	Secondary	$ 10,659,938	$ 10,582,440	$ 12,341,193	$ 13,149,856	$ 14,142,437	$ 14,050,757	$ 144,506,530	Statement BG, Page BG-6 Line 45 + Page BG-7 Line 37 + Page BG-8 Line 37 + Page BG-9 Line 45	51
52	Primary	$ 2,089,656	$ 2,072,418	$ 2,449,450	$ 2,600,411	$ 2,785,020	$ 2,769,167	$ 28,380,253	Statement BG, Page BG-6 Line 46 + Page BG-7 Line 38 + Page BG-8 Line 38 + Page BG-9 Line 46	52
53	Transmission	$ 683,890	$ 682,361	$ 812,168	$ 823,068	$ 836,223	$ 835,522	$ 8,947,571	Statement BG, Page BG-6 Line 47 + Page BG-7 Line 39 + Page BG-8 Line 39 + Page BG-9 Line 47	53
54	Total	$ 13,433,484	$ 13,337,219	$ 15,602,811	$ 16,573,335	$ 17,763,680	$ 17,655,446	$ 181,834,354	Sum Lines 51; 52; 53	54
55										55
56	Total Revenues at Changed Rates:	$ 13,433,484	$ 13,337,219	$ 15,602,811	$ 16,573,335	$ 17,763,680	$ 17,655,446	$ 181,834,354	Sum Line 54; Statement BG, Page BG-6, Line 28	56

NOTES:

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

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

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

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

Statement BG
SAN DIEGO GAS AND ELECTRIC COMPANY
Transmission Revenues Data to Reflect Changed Rates
Standby Customers
Rate Effective Period - Twelve Months Ending August 31, 2012

Line No.	Description	(A) Sep-11	(B) Oct-11	(C) Nov-11	(D) Dec-11	(E) Jan-12	(F) Feb-12	(G)	Reference	Line No.
1	Demand - Billing									1
2	Determinants (kW):									2
3	Secondary	13,408	13,408	13,408	13,408	13,408	13,408		Statement BG, Page BGWP-4, Line 135	3
4	Primary	83,399	83,399	83,399	83,399	83,399	83,399		Statement BG, Page BGWP-4, Line 136	4
5	Transmission	50,275	50,275	50,275	50,275	50,275	50,275		Statement BG, Page BGWP-4, Line 137	5
6	Total	147,082	147,082	147,082	147,082	147,082	147,082		Sum Lines 3; 4; 5	6
7	Check Figure	147,082	147,082	147,082	147,082	147,082	147,082		Statement BG, Page BG-14, Line 15	7
8	Difference	-	-	-	-	-	-		Line 6 Less Line 7	8
9										9
10	Demand Rates ($/kW):									10
11	Secondary	$ 2.85	$ 2.85	$ 2.85	$ 2.85	$ 2.85	$ 2.85		Statement BL, Page BL-1, Line 20, Col. D	11
12	Primary	$ 2.76	$ 2.76	$ 2.76	$ 2.76	$ 2.76	$ 2.76		Statement BL, Page BL-1, Line 20, Col. C	12
13	Transmission	$ 2.73	$ 2.73	$ 2.73	$ 2.73	$ 2.73	$ 2.73		Statement BL, Page BL-1, Line 20, Col. B	13
14										14
15	Revenues at Changed Rates:									15
16	Secondary	$ 38,213	$ 38,213	$ 38,213	$ 38,213	$ 38,213	$ 38,213		Line 3 x Line 11	16
17	Primary	230,181	230,181	230,181	230,181	230,181	230,181		Line 4 x Line 12	17
18	Transmission	137,251	137,251	137,251	137,251	137,251	137,251		Line 5 x Line 13	18
19	Total	$ 405,645	$ 405,645	$ 405,645	$ 405,645	$ 405,645	$ 405,645		Sum Lines 16; 17; 18	19
20										20
21	Total Revenues									21
22	at Changed Rates:	$ 405,645	$ 405,645	$ 405,645	$ 405,645	$ 405,645	$ 405,645		Line 19	22

Line No.	Description	(A) Mar-12	(B) Apr-12	(C) May-12	(D) Jun-12	(E) Jul-12	(F) Aug-12	(G) Total	Reference	Line No.
23	Demand - Billing									23
24	Determinants (kW):									24
25	Secondary	13,408	13,408	13,408	13,408	13,408	13,408	160,896	Statement BG, Page BGWP-4, Line 135	25
26	Primary	83,399	83,399	83,399	83,399	83,399	83,399	1,000,788	Statement BG, Page BGWP-4, Line 136	26
27	Transmission	50,275	50,275	50,275	50,275	50,275	50,275	603,300	Statement BG, Page BGWP-4, Line 137	27
28	Total	147,082	147,082	147,082	147,082	147,082	147,082	1,764,984	Sum Lines 25; 26; 27	28
29	Check Figure	147,082	147,082	147,082	147,082	147,082	147,082	1,764,984	Statement BG, Page BG-15, Line 15	29
30	Difference	-	-	-	-	-	-	-	Line 28 Less Line 29	30
31										31
32	Demand Rates ($/kW):									32
33	Secondary	$ 2.85	$ 2.85	$ 2.85	$ 2.85	$ 2.85	$ 2.85		Statement BL, Page BL-1, Line 20, Col. D	33
34	Primary	$ 2.76	$ 2.76	$ 2.76	$ 2.76	$ 2.76	$ 2.76		Statement BL, Page BL-1, Line 20, Col. C	34
35	Transmission	$ 2.73	$ 2.73	$ 2.73	$ 2.73	$ 2.73	$ 2.73		Statement BL, Page BL-1, Line 20, Col. B	35
36										36
37	Revenues at Changed Rates:									37
38	Secondary	$ 38,213	$ 38,213	$ 38,213	$ 38,213	$ 38,213	$ 38,213	$ 458,556	Line 25 x Line 33	38
39	Primary	230,181	230,181	230,181	230,181	230,181	230,181	$ 2,762,172	Line 26 x Line 34	39
40	Transmission	137,251	137,251	137,251	137,251	137,251	137,251	$ 1,647,012	Line 27 x Line 35	40
41	Total	$ 405,645	$ 405,645	$ 405,645	$ 405,645	$ 405,645	$ 405,645	$ 4,867,740	Sum Lines 38; 39; 40	41
42										42
43	Total Revenues									43
44	at Changed Rates:	$ 405,645	$ 405,645	$ 405,645	$ 405,645	$ 405,645	$ 405,645	$ 4,867,740	Line 41	44

Statement - BG

SAN DIEGO GAS & ELECTRIC COMPANY

Rate Design Information - Wholesale Transmission Rates

CAISO TAC Rates Input Form - September 1, 2011 through August 31, 2012

High-Voltage Utility Specific Rates, Low -Voltage Wheeling Access Charge & Low Voltage Access Charge Rates

Line No.	Components	(1) High Voltage TRR	(2) Low Voltage TRR	(3) = (1) + (2) Combined TRR	Notes & Reference	Line No.
1	Wholesale Base Transmission Revenue Requirement [1]	$ 202,246,000	$ 188,929,000	$ 391,175,000	Statement BL Tab CAISO-Wholesale; Pg 2; Line 1	1
2					Statement BL	2
3	Wholesale TRBAA Forecast [2]	$ (2,847,102)	$ 277,808	$ (2,569,294)	Tab CAISO-Wholesale; Pg 2; Line 16	3
4					Statement BL	4
5	Transmission Standby Revenues [3]	$ (2,516,728)	$ (2,351,012)	$ (4,867,740)	Tab CAISO-Wholesale; Pg 2; Line 18	5
6						6
7	Wholesale Net Transmission Revenue Requirement	$ 196,882,170	$ 186,855,796	$ 383,737,966	Sum Lines 1; 3; 5	7
8						8
9	Gross Load - MWH	21,539,407	21,539,407		Statement BD; Page 1; Col. B; Line 14	9
10						10
11	Utility Specific Access Charges ($/MWH)	$ 9.1406	$ 8.6751		Line 7 / Line 9	11
12						12

NOTES:

1 Wholesale Base TRR comes from Statement BK2; Page 8 of 8; Line 15, in the instant informational filing.

2 TRBAA information comes from Docket No. ER11-2430-000, filed on December 21, 2010 and approved by FERC on February 16, 2011. The TRBAA balance shown on Line 16 will be effective until 12/31/2011. This TBAA amount will change effective January 1, 2012, after SDG&E makes it annual TRBAA filing in December 2011.

3 Standby Revenues come from Statement BG; Page 1, Line 9, Col. (A) of TO3-Cycle 5 filing. Standby Revenues are allocated based on TO3-Cycle 5 HV-LV splits of wholesale BTRR. See page 3 of CAISO - Wholesale Tab.

Statement BG
SAN DIEGO GAS AND ELECTRIC COMPANY
Revenue Data To Reflect Changed Rates
Rate Effectivce Period - Twelve Months Ending August 31, 2012
City of Escondido

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	
Line No.	Customer Class	Sep-11	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Total	Reference	Line No.
1	Billing Determinants (kWh)	1,542	1,542	1,542	1,542	1,542	1,542	1,542	1,542	1,542	1,542	1,542	1,542	18,500	Stmnt BG; Pages 14-16; Line 13	1
2																2
3																3
4	HV Access Charge Rate ($/kwh)[1]	$ 0.00648	$ 0.00648	$ 0.00648	$ 0.00648	$ 0.00648	$ 0.00648	$ 0.00648	$ 0.00648	$ 0.00648	$ 0.00648	$ 0.00648	$ 0.00648		See Note 1	4
5																5
6	LV Access Charge Rate ($/kwh)[2]	$ 0.00868	$ 0.00868	$ 0.00868	$ 0.00868	$ 0.00868	$ 0.00868	$ 0.00868	$ 0.00868	$ 0.00868	$ 0.00868	$ 0.00868	$ 0.00868		Stmnt BG; Pg 11; Ln 11; Col. 2	6
7																7
8																8
9	HV Access Charge Revenues	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 120	Line 1 x Line 4	9
10																10
11	LV Access Charge Revenues	13	13	13	13	13	13	13	13	13	13	13	13	160	Line 1 x Line 6	11
12																12
13	TOTAL Revenues	$ 23	$ 23	$ 23	$ 23	$ 23	$ 23	$ 23	$ 23	$ 23	$ 23	$ 23	$ 23	$ 280	Line 9 + Line 11	13

NOTES

[1] The High Voltage (HV) Access Charge Rate is the ISO TAC Rate of $6.4763 per MWH as billed by the ISO in its April 20, 2011 TAC rates summary.

[2] The Low Voltage (LV) Access Charge Rate is derived from Statement BG, Page 11 , Column 6, Line 11.

000013

Statement BG

SAN DIEGO GAS AND ELECTRIC COMPANY

Transmission Revenues Data to Reflect Changed Rates

Calculation of Total Rate Impact

Rate Effective Period - Twelve Months Ending August 31, 2012

Line No.	Description	(A) Current Rate (cents / kWh)	(B) Proposed Rate (cents / kWh)	(C) Change (cents / kWh)	(D) Change (%)	Line No.
1	Total System Electric Costs	14.672	14.672	-	0.00%	1
2						2
3	Base Transmission Costs	1.259	1.566	0.307	24.37%	3
4						4
5	Total	15.931	16.238	0.307	1.926%	5

Statement BG
SAN DIEGO GAS AND ELECTRIC COMPANY
Transmission Revenues Data to Reflect Changed Rates
Billing Determinants
Rate Effective Period - Twelve Months Ending August 31, 2012

Line No.	Customer Classes	(A) Sep-11 Billing Determinants Energy (kWh)	(A) Sep-11 Billing Determinants Demand (kW)	(B) Oct-11 Billing Determinants Energy (kWh)	(B) Oct-11 Billing Determinants Demand (kW)	(C) Nov-11 Billing Determinants Energy (kWh)	(C) Nov-11 Billing Determinants Demand (kW)	(D) Dec-11 Billing Determinants Energy (kWh)	(D) Dec-11 Billing Determinants Demand (kW)	(E) Jan-12 Billing Determinants Energy (kWh)	(E) Jan-12 Billing Determinants Demand (kW)	(F) Feb-12 Billing Determinants Energy (kWh)	(F) Feb-12 Billing Determinants Demand (kW)	Line No.
1	Residential	742,692,311		630,385,458		607,893,559		676,957,499		740,161,834		654,615,264		1
2														2
3	Small Commercial	192,136,877		171,835,412		164,461,703		162,259,771		164,303,954		159,406,233		3
4														4
5	Medium and Large Commercial/Industrial	1,002,350,490		901,252,873		885,222,793		869,872,441		856,104,451		838,470,127		5
6	Non-coincident (100%) [1]		119,225		112,660		100,301		92,465		71,404		68,344	6
7	Non-coincident (90%) [2]		2,554,765		2,289,120		2,254,433		2,218,586		2,195,664		2,150,577	7
8	Maximum On-peak Period Demand [3]		2,298,130		1,831,140		1,801,974		1,771,834		1,752,551		1,714,648	8
9	Maximum Demand at the Time of System Peak [4]		93,577		84,837		84,862		84,886		84,911		84,936	9
10														10
11	Street Lighting	9,513,816		9,521,902		9,530,002		9,538,116		9,532,714		9,538,101		11
12														12
13	Sale for Resale	1,542		1,542		1,542		1,542		1,542		1,542		13
14														14
15	Standby		147,082		147,082		147,082		147,082		147,082		147,082	15
16														16
17	TOTAL	1,946,695,037		1,712,997,186		1,667,109,598		1,718,629,370		1,770,104,495		1,662,031,267		17

NOTES:

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

Statement BG
SAN DIEGO GAS AND ELECTRIC COMPANY
Transmission Revenues Data to Reflect Changed Rates
Billing Determinants
Rate Effective Period - Twelve Months Ending August 31, 2012

Line No.	Customer Classes	(G) Mar-12 Billing Determinants		(H) Apr-12 Billing Determinants		(I) May-12 Billing Determinants		(J) Jun-12 Billing Determinants		(K) Jul-12 Billing Determinants		(L) Aug-12 Billing Determinants		Line No.
		Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	
1	Residential	624,214,046		576,135,213		566,234,778		594,769,177		678,998,511		723,478,668		1
2														2
3	Small Commercial	160,257,347		154,172,241		158,245,823		168,322,707		186,012,233		189,728,097		3
4														4
5	Medium and Large Commercial/Industrial	849,231,544		841,886,802		853,924,698		904,970,683		967,358,922		962,068,063		5
6	Non-coincident (100%) [1]		70,750		79,241		86,644		101,959		122,927		117,257	6
7	Non-coincident (90%) [2]		2,177,716		2,152,507		2,179,768		2,305,985		2,458,769		2,448,358	7
8	Maximum On-peak Period Demand [3]		1,737,420		1,716,216		1,945,482		2,064,066		2,207,617		2,197,803	8
9	Maximum Demand at the Time of System Peak [4]		84,961		84,985		93,795		93,822		93,850		93,877	9
10														10
11	Street Lighting	9,543,496		9,548,782		9,554,076		9,559,379		9,566,625		9,573,881		11
12														12
13	Sale for Resale	1,542		1,542		1,542		1,542		1,542		1,542		13
14														14
15	Standby		147,082		147,082		147,082		147,082		147,082		147,082	15
16														16
17	TOTAL	1,643,247,975		1,581,744,580		1,587,960,916		1,677,623,488		1,841,937,833		1,884,850,251		17

NOTES:

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

Statement BG
SAN DIEGO GAS AND ELECTRIC COMPANY
Transmission Revenues Data to Reflect Changed Rates
Billing Determinants
Rate Effective Period - Twelve Months Ending August 31, 2012

Line No.	Customer Classes	(M) 12 Months to Date Billing Determinants Energy (kWh)	Demand (kW)	Line No.
1	Residential	7,816,536,319	-	1
2				2
3	Small Commercial	2,031,142,400	-	3
4				4
5	Medium and Large Commercial/Industrial	10,732,713,885		5
6	Non-coincident (100%) [1]		1,143,176	6
7	Non-coincident (90%) [2]		27,386,246	7
8	Maximum On-peak Period Demand [3]		23,038,878	8
9	Maximum Demand at the Time of System Peak [4]		1,063,298	9
10				10
11	Street Lighting	114,520,891	-	11
12				12
13	Sale for Resale	18,500	-	13
14				14
15	Standby	-	1,764,984	15
16				16
17	TOTAL	20,694,913,495	54,396,583	17

NOTES:

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

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

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

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

San Diego Gas & Electric Company

Base Period
Statement – BK1
Retail Cost of Service
Which Determines Retail Base
Transmission Revenue Requirements
$BTRR_{EU}$

Docket No. ER11-4318-000

San Diego Gas & Electric Company
Statement BK-1
Derivation of Transmission Cost of Service
Base Period, Forecast Period & True-Up Period Revenues
In Effect During the Rate Effective Period September 1, 2011 - August 31, 2012
($1,000)

Line No.			Amounts	Reference	Line No.
1					1
2	Transmission O&M Expense - Excluding Intervener Funding Expense	$	43,628	Statement AH; Page 5, Line 10	2
3					3
4	Transmission Related A&G Expenses		29,466	Statement AH; Page 5, Line 53	4
5					5
6	CPUC Intervenor Funding Expense		-	Statement AH; Page 5, Line 9	6
7					7
8	Total O&M Expenses	$	73,094	Sum Lines 2; 4; 6	8
9					9
10	Transmission, Intangible, General and Common Depr. & Amort. Expense		48,805	Statement AJ; Page 7, Line 17	10
11					11
12	Valley Rainbow Project Cost Amortization Expense		1,893	Statement AJ; Page 7, Line 19	12
13					13
14	Transmission Related Property Taxes Expense		10,693	Statement AK; Page 8, Line 27	14
15					15
16	Transmission Related Payroll Taxes Expense		1,977	Statement AK; Page 8, Line 34	16
17					17
18	Sub-Total Expense	$	136,462	Sum Lines 8; 10; 12; 14; 16	18
19					19
20	Cost of Capital Rate $_{(COCR)}$		12.0558%	Statement AV; Page 14, Line 33	20
21					21
22	Transmission Rate Base	$	1,085,868	Statement BK-1; Page 2, Line 20	22
23					23
24	Return and Associated Income Taxes - Transmission Plant	$	130,910	Line 20 x Line 22	24
25	South Georgia Income Tax Adjustment		2,333	Statement AQ; Page 10, Line 1	25
26	Transmission Related Amortization of ITC		(265)	Statement AR; Page 11 Line 1	26
27	Transmission Related Amort of Excess Deferred Tax Liability		(4)	Statement AR; Page 11, Line 3	27
28	Transmission Related Revenue Credits		(2,250)	Statement AU; Page 12, Line 11	28
29	(Gains)/Losses from Sale of Plant Held for Future Use		-	Statement AU; Page 12, Line 13	29
30	End of Prior Year Revenues (PYRR $_{EU}$) Excluding FF&U	$	267,186	Line 18 + Sum Lines (24 thru 29)	30
31					31
32	Total (PYRR $_{EU}$) Excluding FF&U [1]	$	267,186	Line 30	32

[1] Total Prior Year Revenues (PYRR) or Base Period Cost of Service is for calendar year 2010.

San Diego Gas & Electric Company
Statement BK-1
Derivation of Transmission Cost of Service
Base Period, Forecast Period & True-Up Period Revenues
In Effect During the Rate Effective Period September 1, 2011 - August 31, 2012
($1,000)

Line No.			Amounts	Reference	Line No.
1	Net Transmission Plant:				1
2	Transmission Plant	$	1,127,932	Statement BK-1; Page 3; Line 16	2
3	Transmission Related Electric Miscellaneous Intangible Plant		214	Statement BK-1; Page 3; Line 17	3
4	Transmission Related General Plant		15,615	Statement BK-1; Page 3; Line 18	4
5	Transmission Related Common Plant		32,961	Statement BK-1; Page 3; Line 19	5
6	Net Transmission Plant	$	1,176,722	Sum Lines 2; 3; 4; 5	6
7					7
8	Rate Base Additions:				8
9	Transmission Plant Held for Future Use	$	28,695	Statement AG; Page 4; Line 3	9
10					10
11	Rate Base Reductions:				11
12	Transmission Related Accum. Def. Inc. Taxes	$	(144,388)	Statement AF; Page 3; Line 3	12
13					13
14	Working Capital:				14
15	Transmission Related Material and Supplies	$	10,609	Statement AL; Page 9; Line 5	15
16	Transmission Related Prepayments		5,093	Statement AL; Page 9; Line 9	16
17	Transmission Related Cash Working Capital		9,137	Statement AL; Page 9; Line 19	17
18	Total Working Capital	$	24,839	Sum Lines 15; 16; 17	18
19					19
20	Total Transmission Rate Base	$	1,085,868	Sum Lines 6; 9; 12; 18	20

San Diego Gas & Electric Company
Statement BK-1
Derivation of Transmission Cost of Service
Base Period, Forecast Period & True-Up Period Revenues
In Effect During the Rate Effective Period September 1, 2011 - August 31, 2012
($1,000)

Line No.			Amounts	Reference	Line No.
1	Gross Transmission Plant:				1
2	Transmission Plant	$	1,621,532	Statement AD; Page 1, Line 25	2
3	Transmission Related Electric Miscellaneous Intangible Plant		4,149	Statement AD; Page 1, Line 27	3
4	Transmission Related General Plant		27,214	Statement AD; Page 1, Line 29	4
5	Transmission Related Common Plant		72,483	Statement AD; Page 1, Line 31	5
6	Gross Transmission Plant	$	1,725,378	Sum Lines 2; 3; 4; 5	6
7					7
8	Accumulated Depreciation Reserve:				8
9	Transmission Related Depreciation Reserve for Transmission Plant	$	493,600	Statement AE; Page 2, Line 1	9
10	Transmission Related Electric Miscellaneous Intangible Amortization Reserve		3,935	Statement AE; Page 2, Line 11	10
11	Transmission Related General Plant Depr Reserve		11,599	Statement AE; Page 2, Line 13	11
12	Transmission Related Common Plant Depr Reserve		39,522	Statement AE; Page 2, Line 15	12
13	Total Transmission Related Depreciation Reserve	$	548,656	Sum Lines 9; 10; 11; 12	13
14					14
15	Net Transmission Plant:				15
16	Transmission Plant	$	1,127,932	Line 2 Minus Line 9	16
17	Transmission Related Electric Miscellaneous Intangible Plant		214	Line 3 Minus Line 10	17
18	Transmission Related General Plant		15,615	Line 4 Minus Line 11	18
19	Transmission Related Common Plant		32,961	Line 5 Minus Line 12	19
20	Total Net Transmission Plant	$	1,176,722	Sum Lines 16; 17; 18; 19	20

San Diego Gas & Electric Company
Statement BK-1
Derivation of Transmission Cost of Service
Base Period, Forecast Period & True-Up Period Revenues
In Effect During the Rate Effective Period September 1, 2011 - August 31, 2012
($1,000)

Line No.			Amounts	Reference	Line No.
	ANNUAL FIXED CHARGES APPLICABLE TO CAPITAL PROJECTS				
1	**A. Derivation of Annual Fix Charge Rate (AFCR $_{EU}$) Applicable to**				1
2	**Weighted Forecast Plant Additions:**				2
3	PYRR $_{EU}$ Excluding Franchise and Uncollectible	$	267,186	Statement BK-1; Page 1; Line 32	3
4	CPUC Intervenor Funding Expense		-	Statement BK-1; Page 1; Line 6	4
5	Valley Rainbow Project Cost Amortization Expense		(1,893)	Statement BK-1; Page 1; Line 12	5
6	South Georgia Income Tax Adjustment		(2,333)	Statement BK-1; Page 1; Line 25	6
7	Transmission Related Amortization of Investment Tax Credit		265	Statement BK-1; Page 1; Line 26	7
8	Transmission Related Amortization of Excess Deferred Tax Liabilities		4	Statement BK-1; Page 1; Line 27	8
9	(Gains)/Losses from Sale of Plant Held for Future Use		-	Statement BK-1; Page 1; Line 29	9
10	BTRR $_{EU}$ Adjusted	$	263,229	Sum Lines 3 through 9	10
11					11
12	Gross Transmission Plant	$	1,725,378	Statement BK-1; Page 3, Line 6	12
13					13
14	Annual Fix Charge Rate (AFCR $_{EU}$)		15.2563%	Line 10 / Line 12	14
15					15
16	Weighted Forecast Plant Additions	$	668,344	Summary of HV-LV Plant Additions; Page 1A	16
17					17
18	Forecast Period Capital Addition Revenue Requirements	$	101,965	Line 14 x Line 16	18

San Diego Gas & Electric Company
Statement BK-1
Derivation of Transmission Cost of Service
Base Period, Forecast Period & True-Up Period Revenues
In Effect During the Rate Effective Period September 1, 2011 - August 31, 2012
($1,000)

Line No.			Amounts		Reference	Line No.
1	**A. End Use Customer Base Transmission Revenue Requirement (BTRR $_{EU}$):**					1
2	Prior Year Revenues (PYRR $_{EU}$) Excluding FF&U	$	267,186		Statement BK-1; Page 1; Line 32	2
3						3
4	**12-Month TO3; Cycle 5; True-Up Period Adjustment**		$\boxed{\textbf{14,396}}$	√	Volume. 2; Sect. 2.1A; Pgs 1-3; Line 35	4
5						5
6	TO3-Cycle 4; Interest True-Up Adjustment		874		Vol. 2; Sect. 2.1B; Part 1.A;Pages 1-2; Line 20	6
7						7
8	TO3-Cycle 3; Interest True-Up Adjustment		30		Vol. 2; Sect. 2.1B; Part 2.A;Pages 1-2; Line 20	8
9						9
10	**B. Annual Fixed Charges Applicable to Forecast Capital Projects:**					10
11	Forecast Period Capital Addition Revenue Requirements		101,965		Statement BK-1; Page 4, Line 18	11
12						12
13	**C. Subtotal:**	$	384,451		Sum Lines 2; 4; 6; 8; 11	13
14						14
15	**Transmission Related Municipal Franchise Expenses**		**3,950**	√	Line 13 x 1.0275%	15
16	**Transmission Related Uncollectible Expense**		**542**	√	Line 13 x .141%	16
17						17
18	**D. Total Retail BTRR $_{EU}$:**	**$**	**388,943**	√	Sum Lines 13; 15; and 16	18
19						19
20	**E. Total Retail BTRR $_{EU}$:**	**$**	**388,943**	√	Sum of Line 18	20

√ Items that are in BOLD have changed between the instant compliance filing and the original TO3-Cycle 5 filing from last August 15, 2011.

San Diego Gas & Electric Company

Base Period
Statement – BK2
ISO Wholesale Cost of Service Which Determines Wholesale Base Transmission Revenue Requirements
$BTRR_{ISO}$

Docket No. ER11-4318-000

San Diego Gas & Electric Company
Statement BK-2
Derivation of ISO Transmission Cost of Service
Base Period, Forecast Period & True-Up Adjustment Revenues
In Effect During the Rate Effective Period September 1, 2011 - August 31, 2012
($1,000)

Line No.		Amounts	Reference	Line No.
1				1
2	Transmission Operation & Maintenance Expense	$ 43,628	Statement AH; Page 5; Line 10	2
3				3
4	Transmission Related A&G Expenses	29,466	Statement AH; Page 5; Line 53	4
5				5
6	CPUC Intervenor Funding Expense	-	Not Recoverable From Wholesale Customers	6
7				7
8	Total O&M Expenses	$ 73,094	Sum Lines 2; 4	8
9				9
10	Transmission, Intangible, Gen. and Common Depr. & Amort. Exp.	48,805	Statement AJ; Page 7; Line 17	10
11				11
12	Valley Rainbow Project Cost Amortization Expense	1,893	Statement AJ; Page 7; Line 19	12
13				13
14	Transmission Related Property Taxes Expense	10,693	Statement AK; Page 8; Line 27	14
15				15
16	Transmission Related Payroll Taxes Expense	1,977	Statement AK; Page 8; Line 34	16
17				17
18	Subtotal Expense	$ 136,462	Sum Lines 8; 10; 12; 14; 16	18
19				19
20	Cost of Capital Rate $_{(COCR)}$	12.0558%	Statement AV; Page 14; Line 33	20
21				21
22	Transmission Rate Base	$ 1,085,868	Statement BK-2; Page 2; Line 20	22
23				23
24	Return and Associated Income Taxes - Transmission Plant	$ 130,910	Line 20 x Line 22	24
25	South Georgia Income Tax Adjustment	-	Not Recoverable From Wholesale Customers	25
26	Transmission Related Amortization of ITC	(265)	Statement AR; Page 11; Line 1	26
27	Trans. Related Amort of Excess Deferred Tax Liability	(4)	Statement AR; Page 11; Line 3	27
28	Transmission Related Revenue Credits	(2,250)	Statement AU; Page 12; Line 11	28
29	(Gains)/Losses from Sale of Plant Held for Future Use	-	Statement AU; Page 12, Line 13	29
30	Prior Year Revenue (PYRR $_{ISO}$) Excluding FF&U	$ 264,853	Line 18 + Sum of Lines (24 thru 29)	30
31				31
32	Total (PYRR $_{ISO}$) Excluding FF&U [1]	$ 264,853	Line 30	32

[1] Total Prior Year Revenues (PYRR) or Base Period Cost of Service is for calendar year 2010.

San Diego Gas & Electric Company
Statement BK-2
Derivation of ISO Transmission Cost of Service
Base Period, Forecast Period & True-Up Adjustment Revenues
In Effect During the Rate Effective Period September 1, 2011 - August 31, 2012
($1,000)

Line No.			Amounts	Reference	Line No.
1	Net Transmission Plant:				1
2	Transmission Plant	$	1,127,932	Statement BK-2; Page 3; Line 16	2
3	Transmission Related Electric Misc. Intangible Plant		214	Statement BK-2; Page 3; Line 17	3
4	Transmission Related General Plant		15,615	Statement BK-2; Page 3; Line 18	4
5	Transmission Related Common Plant		32,961	Statement BK-2; Page 3; Line 19	5
6	Net Transmission Plant	$	1,176,722	Sum Lines 2; 3; 4; 5	6
7					7
8	Rate Base Additions:				8
9	Transmission Plant Held for Future Use	$	28,695	Statement AG; Page 4; Line 3	9
10					10
11	Rate Base Reductions:				11
12	Transmission Related Accum. Def. Inc. Taxes	$	(144,388)	Statement AF; Page 3; Line 3	12
13					13
14	Working Capital:				14
15	Transmission Related Material and Supplies	$	10,609	Statement AL; Page 9; Line 5	15
16	Transmission Related Prepayments		5,093	Statement AL; Page 9; Line 9	16
17	Transmission Related Cash Working Capital		9,137	Statement AL; Page 9; Line 21	17
18	Total Working Capital	$	24,839	Sum Lines 15; 16; 17	18
19					19
20	Total Transmission Rate Base	$	1,085,868	Sum Lines 6; 9; 12; 18	20

San Diego Gas & Electric Company
Statement BK-2
Derivation of ISO Transmission Cost of Service
Base Period, Forecast Period & True-Up Adjustment Revenues
In Effect During the Rate Effective Period September 1, 2011 - August 31, 2012
($1,000)

Line No.		Amounts	Reference	Line No.
1	Gross Transmission Plant:			1
2	Transmission Plant	$ 1,621,532	Statement AD; Page 1, Line 25	2
3	Transmission Related Electric Misc. Intangible Plant	4,149	Statement AD; Page 1, Line 27	3
4	Transmission Related General Plant	27,214	Statement AD; Page 1, Line 29	4
5	Transmission Related Common Plant	72,483	Statement AD; Page 1, Line 31	5
6	Gross Transmission Plant	$ 1,725,378	Sum Lines 2; 3; 4; 5	6
7				7
8	Accumulated Depreciation Reserve:			8
9	Transmission Related Depreciation Reserve for Transmission Plant	493,600	Statement AE; Page 2, Line 1	9
10	Transmission Related Electric Misc. Intangible Depreciation Reserve	3,935	Statement AE; Page 2, Line 11	10
11	Transmission Related General Plant Depr Reserve	11,599	Statement AE; Page 2, Line 13	11
12	Transmission Related Common Plant Depr Reserve	39,522	Statement AE; Page 2, Line 15	12
13	Total Transmission Related Depreciation Reserve	$ 548,656	Sum Lines 9; 10; 11; 12	13
14				14
15	Net Transmission Plant:			15
16	Transmission Plant	$ 1,127,932	Line 2 Minus Line 9	16
17	Transmission Related Electric Misc. Intangible Plant	214	Line 3 Minus Line 10	17
18	Transmission Related General Plant	15,615	Line 4 Minus Line 11	18
19	Transmission Related Common Plant	32,961	Line 5 Minus Line 12	19
20	Total Net Transmission Plant	$ 1,176,722	Sum Lines 16; 17; 18; 19	20

San Diego Gas & Electric Company
Statement BK-2
Derivation of ISO Transmission Cost of Service
Base Period, Forecast Period & True-Up Adjustment Revenues
In Effect During the Rate Effective Period September 1, 2011 - August 31, 2012
($1,000)

Line No.			Amounts	Reference	Line No.
	ANNUAL FIXED CHARGES APPLICABLE TO CAPITAL PROJECTS				
1	**A. Derivation of Annual Fix Charge Rate (AFCR $_{ISO}$) Applicable to**				1
2	**Weighted Forecast Plant Additions:**				2
3	PYRR $_{ISO}$ Excluding Franchise	$	264,853	Statement BK-2; Page 1; Line 32	3
4	Valley Rainbow Project Cost Amortization Expense		(1,893)	Statement BK-2; Page 1; Line 12	4
5	Transmission Related Amortization of Investment Tax Credit		265	Statement BK-2; Page 1; Line 26	5
6	Transmission Related Amortization of Excess Deferred Tax Liabilities		4	Statement BK-2; Page 1; Line 27	6
7	(Gains)/Losses from Sale of Plant Held for Future Use		-	Statement BK-2; Page 1; Line 29	7
8	BTRR $_{ISO}$ Adjusted	$	263,229	Sum Lines 3; 4; 5; 6; 7	8
9					9
10	Gross Transmission Plant	$	1,725,378	Statement BK-2; Page 3; Line 6	10
11					11
12	Annual Fix Charge Rate (AFCR $_{ISO}$)		15.2563%	Line 8 / Line 10	12
13					13
14	Weighted Forecast Plant Additions	$	668,344	See Volume 3 WPs.	14
15				Summary of WTD HV-LV Plant Adds; Page 1A; Ln. 6	15
16	Forecast Period Capital Additions Revenues	$	101,965	Line 12 x Line 14	16

San Diego Gas & Electric Company
Statement BK-2
Derivation of ISO Transmission Cost of Service
Base Period, Forecast Period & True-Up Adjustment Revenues
In Effect During the Rate Effective Period September 1, 2011 - August 31, 2012
($1,000)

Line No.		Amounts		Reference	Line No.
1	**A. Total ISO BTRR $_{ISO}$:**				1
2					2
3	Prior Year Revenue (PYRR $_{ISO}$) Excluding FF	$	264,853	Statement BK-2; Page 1; Line 32	3
4					4
5	**12-Month TO3; Cycle 5; True-Up Period Adjustment**		**19,624** √	Volume 2; Section 3.1A; Pgs. 1-3; Line 35	5
6					6
7	TO3-Cycle 4 Interest True-Up Adjustment		735	Vol. 2; Section 3.1B; Part 1.A; Pgs 1-2; Line 20	7
8					8
9	TO3-Cycle 3 Interest True-Up Adjustment		20	Vol. 2; Section 3.1B; Part 2.A; Pgs 1-2; Line 20	9
10					10
11	**B. Annual Fixed Charges Applicable to Capital Projects:**				11
12					12
13	Forecast Period Capital Addition Revenue Requirements		101,965	Statement BK-2; Page 4; Line 16	13
14					14
15	**C. Total BTRR $_{ISO}$ Excluding Franchise**	$	**387,196** √	Sum Lines 3; 5; 7; 9; and 13	15
16					16
17	**D. Total BTRR $_{ISO}$ Excluding Franchise**	$	**387,196** √	Sum Line 15	17

√ Items that are in BOLD have changed between the instant compliance filing and the original TO3-Cycle 5 filing from last August 15, 2011.

San Diego Gas & Electric Company
Statement BK-2
Derivation of ISO Transmission Cost of Service
Base Period, Forecast Period & True-Up Adjustment Revenues
In Effect During the Rate Effective Period September 1, 2011 - August 31, 2012
($1,000)

Line No.		Amounts	Reference	Line No.
1	**A. Derivation of Revenues for Recorded Facilities:**			1
2				2
3	**Total BTRR $_{ISO}$ Excluding Franchise**	$ **387,196** √	Statement BK-2; Page 5; Line 17	3
4				4
5	Less: Forecast Capital Additions Revenues Requirements			5
6	Forecast Period Capital Addition Revenue Requirements	101,965	Statement BK-2; Page 5; Line 13	6
7				7
8	Sub-Total Forecast Revenue Requirements	101,965	Sum Line 6	8
9				9
10	**Total True-Up Adjustment and Interest True-Up Adjustment**	**20,378** √	Statement BK-2; Page 5; Line 5; 7; & 9	10
11				11
12	Total End of Prior Year Revenue (PYRR $_{ISO}$) Excluding FF	264,853	Line 3 Minus Lines 8 & 10	12
13				13
14	**Total True-Up Adjustment and Interest True-Up Adjustment**	**20,378** √	Statement BK-2; Page 5; Line 5; 7; & 9	14
15				15
16	**End of Prior Year Revenue (PYRR $_{ISO}$) & True-Up Adjustment**	$ **285,231** √	Sum Lines 12 & 14	16

√ Items that are in BOLD have changed between the instant compliance filing and the original TO3-Cycle 5 filing from last August 15, 2011.

San Diego Gas & Electric Company
Statement BK-2
Derivation of ISO Transmission Cost of Service
Base Period, Forecast Period & True-Up Adjustment Revenues
In Effect During the Rate Effective Period September 1, 2011 - August 31, 2012
($1,000)

Line No.			Amounts	Reference	Line No.
1	A: Derivation of revenues related with Total				1
2	Transmission Facilities:				2
3	**End of Prior Year Revenue (PYRR $_{ISO}$)**	$	**285,231** √	Statement BK-2; Page 6; Line 16	3
4					4
5	Revenue Requirements Related With Transmission Forecast				5
6	Plant Additions From April 1, 2011 thru August 31, 2012.		101,965	Statement BK-2; Page 6; Line 8	6
7					7
8	**Revenues Related With Total Transmission Facilities**	$	**387,196** √	Sum Lines 3; 6	8
9					9

Line No.		(a) Total	(b) High Voltage	(c) Low Voltage	Reference	Line No.
10		(a)	(b)	(c)		10
11		Total	High Voltage	Low Voltage	Reference	11
12	B. Derivation of Split between HV and LV [1]:					12
13						13
14	**1. Percent Split Between HV & LV for Recorded**					14
15	**Gross Transmission Plant Facilities:**				(Vol. 3 WP Tab; HV-LV Study)	15
16	Gross Transmission Plant Facilities @ 12/31/2010	$ 1,682,943	$ 763,031	$ 919,912	Page 1; Cols. B and C.	16
17	HV-LV Plant Allocation Ratios @ 12/31/2010	100.00%	45.34%	54.66%	Ratios Based on Line 16	17
18	**Total Transmission Plant Facilities Revenues @ 12/31/2010**	√ $ **285,231** √	$ **129,321**	$ **155,910**	Line17 x Line18; Col A	18
19						19
20	**2. Percent Split Between HV and LV of Forecast**				Volume 3; WP Tab	20
21	**Plant Adds From 4/1/2011 - 8/31/2012:**	$ 668,344	$ 464,514	$ 203,830	Summary of Wtd HV-LV	21
22	Revenue related with forecast plant additions from	100.00%	69.50%	30.50%	Plant Adds; Page 1A; Line 8	22
23	April 1, 2011 thru August 31, 2012.	$ 101,965	$ 70,868	$ 31,097	Line 22 x Line 23; Col A	23
24						24
25	C. Summary of ISO Transmission Facilities by					25
26	High Voltage and Low Voltage Classification:					26
27						27
28	**Recorded Transmission Facilities BTRR $_{ISO}$**	√ $ **285,231** √	$ **129,321**	$ **155,910**	Line 18 From Above	28
29						29
30	Forecast Transmission Facilities BTRR $_{ISO}$	101,965	70,868	31,097	Line 23 From Above	30
31						31
32	**Total BTRR $_{ISO}$ Excluding Franchise**	√ $ **387,196** √	$ **200,189**	$ **187,007**	Line 28 + Line 30	32

[1] Pursuant to the ISO's July 5, 2005 filing in compliance with the Commission's December 21, 2004 order, 109 FERC ¶ 61,301 (December 21, Order) and June 2, 2005 Order, 111 FERC ¶ 61,337 (June 2 Order), SDG&E in the instant filing has followed the ISO's new guidelines to separate all elements of its transmission facilities into HV and LV components. TRBAA cost components shown in the instant filing are separated into the HV and LV components applicable to the ISO's HV and LV guidelines in effect 1/1/2005 pursuant to ISO Tariff Appendix F, Sch.3, Section 8.1.

√ Items that are in BOLD have changed between the instant compliance filing and the original TO3-Cycle 5 filing from last August 15, 2011.

San Diego Gas & Electric Company
Statement BK-2
Derivation of ISO Transmission Cost of Service
Base Period, Forecast Period & True-Up Adjustment Revenues
In Effect During the Rate Effective Period September 1, 2011 - August 31, 2012
($1,000)

Line No.			Total		High Voltage [2]		Low Voltage [2]	Reference	Line No.
1	**Summary of ISO HV and LV Transmission**								1
2	**Revenues:**								2
3									3
4	**Recorded Facilities Transmission Revenue Requirements**	√ $	**285,231**	√ $	**129,321**	$	**155,910**	Stmnt BK-2; Page 7, Ln28	4
5	**Base Franchise Fee (FF) @ 1.0275%** [1]	√	**2,931**	√	**1,329**		**1,602**	Line 4 x 1.0275%	5
6									6
7	**Total Forecast Transmission Facilities BTRR $_{ISO}$**	√ $	**288,162**	√ $	**130,650**	$	**157,512**	Sum Lines 4; 5	7
8									8
9									9
10	Forecast Transmission Facilities BTRR $_{ISO}$	$	101,965	$	70,868	$	31,097	Stmnt BK-2; Page 7, Ln30	10
11	Base Franchise Fee (FF) @ 1.0275%		1,048		728		320	Line 10 x 1.0275%	11
12									12
13	Total Recorded Facilities BTRR $_{ISO}$	$	103,013	$	71,596	$	31,417	Sum Lines 10; 11	13
14									14
15	**Total BTRR $_{ISO}$**	√ $	**391,175**	√ $	**202,246**	$	**188,929**	Line 7 + Line 13	15

[1] Base franchise fees are applicable to all SDG&E customers.

[2] The following HV-LV Wholesale Base Transmission Revenue Requirements will be used by the CAISO to develop the TAC rates for the rate effective period September 1, 2011 through August 31, 2012.

√ Items that are in BOLD have changed between the instant compliance filing and the original TO3-Cycle 5 filing from last August 15, 2011.

San Diego Gas & Electric Company

Base Period
Statement - BL
Retail Rate Design Information

Docket No. ER11-4318-000

Statement BL
SAN DIEGO GAS AND ELECTRIC COMPANY
Rate Design Information
Summary of Transmission Rates
Rate Effective Period - Twelve Months Ending August 31, 2012

Line No.	Customer Classes	(A) Transmission Energy Rates $/kWh	(B) Transmission Level Demand Rates $/kW-Mo	(C) Primary Level Demand Rates $/kW-Mo	(D) Secondary Level Demand Rates $/kW-Mo	Reference	Line No.
1	Residential	$ 0.01964				Statement BL, Page BL-4, Line 7	1
2							2
3	Small Commercial	$ 0.02327				Statement BL, Page BL-5, Line 7	3
4							4
5	Medium & Large Commercial/Industrial						5
6	Non-coincident Demand (100%) [1]		$ 6.15	$ 6.21	$ 6.42	Statement BL, Page BL-6, Lines 37; 36; 35	6
7							7
8	Non-coincident Demand (90%) [2]		$ 5.54	$ 5.59	$ 5.78	Statement BL, Page BL-7 Lines 9; 8; 7	8
9							9
10	Maximum On-peak Period Demand [3]						10
11	Summer		$ 1.19	$ 1.21	$ 1.25	Statement BL, Page BL-9, Lines 41; 40; 39	11
12	Winter		$ 0.26	$ 0.26	$ 0.27	Statement BL, Page BL-10, Lines 39; 38; 37	12
13							13
14	Maximum Demand at the Time of System Peak [4]						14
15	Summer		$ 1.37	$ 1.38	$ -	Statement BL, Page BL-11, Lines 42; 41; 40	15
16	Winter		$ 0.27	$ 0.27	$ -	Statement BL, Page BL-12, Lines 41; 40; 39	16
17							17
18	Street Lighting	$ 0.01257				Statement BL, Page BL-13, Line 7	18
19							19
20	Standby		$ 2.73	$ 2.76	$ 2.85	Statement BL, Page BL-14, Lines 37; 36; 35	20

NOTES:

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

Statement BL
SAN DIEGO GAS AND ELECTRIC COMPANY
Transmission Revenue Data to Reflect Changed Rates
Medium & Large Commercial/Industrial Customers - Summary of Revenues
Rate Effective Period - Twelve Months Ending August 31, 2012

Line No.	Description	(A) Sep-11	(B) Oct-11	(C) Nov-11	(D) Dec-11	(E) Jan-12	(F) Feb-12	(G)	Reference	Line No.
1	Energy:									1
2	Commodity Sales (kWh)	1,002,350,490	901,252,873	885,222,793	869,872,441	856,104,451	838,470,127		Page BG-6, Line 2	2
3	Commodity Revenues ($)	$ -	$ -	$ -	$ -	$ -	$ -		Page BG-6, Line 4	3
4										4
5	Non-coincident Demand (100%)[1]:									5
6	Demand (kW)	119,225	112,660	100,301	92,465	71,404	68,344		Page BG-6, Line 10	6
7	Revenues at Changed Rates ($)	$ 762,316	$ 720,340	$ 641,322	$ 591,219	$ 456,553	$ 436,990		Page BG-6, Line 24	7
8										8
9	Non-coincident Demand (90%) [2]:									9
10	Demand (kW)	2,554,765	2,289,120	2,254,433	2,218,586	2,195,664	2,150,577		Page BG-7, Line 6	10
11	Revenues at Changed Rates ($)	$ 14,659,271	$ 13,132,717	$ 12,933,379	$ 12,727,377	$ 12,595,648	$ 12,336,545		Page BG-7, Line 20	11
12										12
13	Maximum On-peak									13
14	Period Demand [3]:									14
15	Demand (kW)	2,298,130	1,831,140	1,801,974	1,771,834	1,752,551	1,714,648		Page BG-8, Line 6	15
16	Revenues at Changed Rates ($)	$ 2,853,826	$ 490,790	$ 482,972	$ 474,894	$ 469,726	$ 459,567		Page BG-8, Line 20	16
17										17
18	Maximum Demand									18
19	at the Time of System Peak [4]:									19
20	Demand (kW)	93,577	84,837	84,862	84,886	84,911	84,936		Page BG-9, Line 6	20
21	Revenues at Changed Rates ($)	$ 128,332	$ 22,906	$ 22,913	$ 22,919	$ 22,926	$ 22,933		Page BG-9, Line 20	21
22										22
23	Total Revenues at Changed Rates:	$ 18,403,745	$ 14,366,753	$ 14,080,587	$ 13,816,410	$ 13,544,853	$ 13,256,033		Page BG-9, Line 28	23

Line No.	Description	(A) Mar-12	(B) Apr-12	(C) May-12	(D) Jun-12	(E) Jul-12	(F) Aug-12	(G) Total	Reference	Line No.
24	Energy:									24
25	Commodity Sales (kWh)	849,231,544	841,886,802	853,924,698	904,970,683	967,358,922	962,068,063	10,732,713,885	Page BG-6, Line 26	25
26	Commodity Revenues ($)	-	-	-	-	-	-	-	Page BG-6, Line 28	26
27										27
28	Non-coincident Demand (100%) [1]:									28
29	Demand (kW)	70,750	79,241	86,644	101,959	122,927	117,257	1,143,176	Page BG-6, Line 34	29
30	Revenues at Changed Rates ($)	$ 452,374	$ 506,661	$ 553,997	$ 651,918	$ 785,987	$ 749,736	$ 7,309,413	Page BG-6, Line 48	30
31										31
32	Non-coincident Demand (90%) [2]:									32
33	Demand (kW)	2,177,716	2,152,507	2,179,768	2,305,985	2,458,769	2,448,358	27,386,246	Page BG-7, Line 26	33
34	Revenues at Changed Rates ($)	$ 12,492,499	$ 12,347,625	$ 12,504,277	$ 13,229,583	$ 14,107,560	$ 14,047,726	$ 157,114,207	Page BG-7, Line 40	34
35										35
36	Maximum On-peak									36
37	Period Demand [3]:									37
38	Demand (kW)	1,737,420	1,716,216	1,945,482	2,064,066	2,207,617	2,197,803	23,038,878	Page BG-8, Line 26	38
39	Revenues at Changed Rates ($)	$ 465,670	$ 459,987	$ 2,415,906	$ 2,563,164	$ 2,741,426	$ 2,729,239	$ 16,607,167	Page BG-8, Line 40	39
40										40
41	Maximum Demand									41
42	at the Time of System Peak [4]:									42
43	Demand (kW)	84,961	84,985	93,795	93,822	93,850	93,877	1,063,298	Page BG-9, Line 34	43
44	Revenues at Changed Rates ($)	$ 22,939	$ 22,946	$ 128,632	$ 128,669	$ 128,707	$ 128,744	$ 803,567	Pages BG-9, Line 48	44
45										45
46	Total Revenues at Changed Rates:	$ 13,433,484	$ 13,337,219	$ 15,602,811	$ 16,573,335	$ 17,763,680	$ 17,655,446	$ 181,834,354	Page BG-9, Line 56	46

NOTES:

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

Statement BL
SAN DIEGO GAS AND ELECTRIC COMPANY
Rate Design Information
Allocation of Base Transmission Revenue Requirements (BTRR) Based on 12 CPs
Rate Effective Period - Twelve Months Ending August 31, 2012
($1,000)

Line No.	Customer Classes	(A) Total 12 CPs @ Transmission Level [2]	(B) Percentages [3]	(C) Allocated Base Transmission Revenue Requirement	Reference	Line No.
1	Total Base Transmission Revenue Requirement [1]			388,943	Statement BK1, Page 5, Line 25	1
2						2
3	Allocation of BTRR Based on 12-CP:					3
4	Residential	15,742,820	39.46%	$ 153,477	Col.C4 = Col. C Line 1 x Col B. Line 4	4
5	Small Commercial	4,848,321	12.15%	$ 47,257	Col.C5 = Col. C Line 1 x Col. B Line 5	5
6	Medium & Large Commercial/Industrial	18,659,462	46.77%	$ 181,909	Col.C6 = Col. C Line 1 x Col. B Line 6	6
7	Street Lighting Revenues	146,179	0.37%	$ 1,439	Col.C7 = Col. C Line 1 x Col. B Line 7	7
8	Standby Revenues	499,375	1.25%	$ 4,862	Col.C8 = Col. C Line 1 x Col. B Line 8	8
9						9
10	Total	39,896,157	100.00%	$ 388,944	Sum Lines 4 Through 8	10
11						11
12	Total	39,896,157		$ 388,944	Line 10	12

NOTES:

1 Total Base Transmission Revenue Requirement comes from Cycle 4; Statement BK1; Page 6; Line 32
2 Statement BL, Page BL-16, Column D.
3 Statement BL, Page BL-16, Column E.

Statement BL
SAN DIEGO GAS AND ELECTRIC COMPANY
Rate Design Information
Residential Customers [1]
Rate Effective Period - Twelve Months Ending August 31, 2012
($1,000)

Line No.	Description	Derivation of Commodity Rate & Proof of Revenues Calculation		Reference	Line No.
1	Residential - Allocated Transmission Revenue Requirement	$	153,477	Statement BL, Page BL-3, Line 4	1
2					2
3	Residential - Billing Determinants (MWh)		7,816,536	Statement BG, Page BGWP-1, Line 6	3
4					4
5	Residential - Energy Rate per kWh	$	0.0196350	Line 1 / Line 3	5
6					6
7	Residential - Energy Rate per kWh - Rounded	$	0.01964	Line 5, Rounded to 5 Decimal Places	7
8					8
9	Proof of Revenues	$	153,517	Line 7 x Line 3	9
10					10
11	Difference	$	(40)	Line 1 Less Line 9	11

NOTES:

1 The following California Public Utilities Commission (CPUC) tariffs are offered to residential customers:
Schedules DR, DR-LI, DR-TOU, DR-TOU-DER, DR-SES, DM, DS, DT, DT-RV, EV-TOU, EV-TOU-2, and EV-TOU-3.

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Statement BL

SAN DIEGO GAS AND ELECTRIC COMPANY

Rate Design Information

Small Commercial Customers [1]

Rate Effective Period - Twelve Months Ending August 31, 2012

($1,000)

Line No.	Description	Derivation of Commodity Rate & Proof of Revenues Calculation	Reference	Line No.
1	Small Commercial - Allocated Transmission Revenue Requirement	$ 47,257	Statement BL, Page BL-3, Line 5	1
2				2
3	Small Commercial - Billing Determinants (MWh)	2,031,142	Statement BG, Page BGWP-1, Line 7	3
4				4
5	Small Commercial - Energy Rate per kWh	$ 0.0232660	Line 1 / Line 3	5
6				6
7	Small Commercial - Energy Rate per kWh - Rounded	$ 0.02327	Line 5, Rounded to 5 Decimal Places	7
8				8
9	Proof of Revenues	$ 47,265	Line 7 x Line 3	9
10				10
11	Difference	$ (8)	Line 1 Less Line 9	11

NOTES:

1 The following California Public Utilities Commission (CPUC) tariffs are offered to small commercial customers: Schedules A, A-TC, A-TOU, and PA.

Statement BL
SAN DIEGO GAS AND ELECTRIC COMPANY
Rate Design Information
Medium & Large Commercial/Industrial Customers [1]
Rate Effective Period - Twelve Months Ending August 31, 2012
($1,000)

Line No.	Description	Derivation of Commodity Rate & Proof of Revenues Calculation	Reference	Line No.
1	Med & Lrg. C/I - Demand Revenue Requirement	$ 181,909	Statement BL, Page BL-3, Line 6	1
2				2
3	Demand Determinants (with Transmission LF Adjustment)			3
4	Used to Allocate Total Class Revenues to Voltage Level (MW) [2]			4
5	Secondary	23,593	Statement BL, Page BL-17, Line 28, Col. D	5
6	Primary	4,587	Statement BL, Page BL-17, Line 29, Col. D	6
7	Transmission	1,429	Statement BL, Page Bl-17, Line 30, Col. D	7
8	Total	29,609	Sum Lines 5; 6; 7	8
9				9
10	Allocation Factors Per Above to Allocate			10
11	Demand Revenue Requirements to Voltage Level			11
12	Secondary	79.68%	Line 5 / Line 8	12
13	Primary	15.49%	Line 6 / Line 8	13
14	Transmission	4.83%	Line 7 / Line 8	14
15	Total	100.00%	Sum Lines 12; 13; 14	15
16				16
17	Allocation of Revenue Requirements to Voltage Level			17
18	Secondary	$ 144,945	Line 1 x Line 12	18
19	Primary	$ 28,178	Line 1 x Line 13	19
20	Transmission	$ 8,786	Line 1 x Line 14	20
21	Total	$ 181,909	Sum Lines 18; 19; 20	21
22				22
23	Demand Determinants by Voltage Level @ Meter Level (MW)			23
24	Secondary	22,562	Statement BL, Page BL-17, Line 28, Col. B	24
25	Primary	4,538	Statement BL, Page BL-17, Line 29, Col. B	25
26	Transmission	1,429	Statement BL, Page BL-17, Line 30, Col. B	26
27	Total	28,529	Sum Lines 24; 25; 26	27
28				28
29	Demand Rate by Voltage Level @ Meter			29
30	Secondary	$ 6.42427	Line 18 / Line 24	30
31	Primary	$ 6.20883	Line 19 / Line 25	31
32	Transmission	$ 6.14856	Line 20 / Line 26	32
33				33
34	Demand Rate by Voltage Level @ Meter (Rounded)			34
35	Secondary	$ 6.42	Line 30, Rounded to 2 Decimal Places	35
36	Primary	$ 6.21	Line 31, Rounded to 2 Decimal Places	36
37	Transmission	$ 6.15	Line 32, Rounded to 2 Decimal Places	37
38				38
39	Proof of Revenues			39
40	Secondary	$ 144,849	Line 24 x Line 35	40
41	Primary	$ 28,183	Line 25 x Line 36	41
42	Transmission	$ 8,788	Line 26 x Line 37	42
43	Total	$ 181,820	Sum Lines 40; 41; 42	43
44				44
45	Difference	$ 89	Line 1 Less Line 43	45

NOTES:

[1] The following California Public Utilities Commission (CPUC) tariffs are offered to Medium and Large Commercial/Industrial customers: Schedules AD, AY-TOU, AL-TOU, AL-TOU-DER, DG-R, A6-TOU, PA-T-1, and OL-TOU. No demand rates are applicable to schedule OL-TOU per CPUC Decision D.09-09-036

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

Statement BL
SAN DIEGO GAS AND ELECTRIC COMPANY
Rate Design Information
Medium & Large Commercial/Industrial Customers
Rate Effective Period - Twelve Months Ending August 31, 2012
($1,000)

Line No.	Description	Derivation of Commodity Rate & Proof of Revenues Calculation	Reference	Line No.
1	90% of Total Medium and Large Commercial/Industrial NCD Rates [1]	90.00%		1
2	Secondary	$ 5.77800	Line 1 x Statement BL, Page BL-6, Line 35	2
3	Primary	$ 5.58900	Line 1 x Statement BL, Page BL-6, Line 36	3
4	Transmission	$ 5.53500	Line 1 x Statement BL, Page BL-6, Line 37	4
5				5
6	90% of Total Medium and Large Commercial/Industrial NCD Rates (Rounded)			6
7	Secondary	$ 5.78	Line 2, Rounded to 2 Decimal Places	7
8	Primary	$ 5.59	Line 3, Rounded to 2 Decimal Places	8
9	Transmission	$ 5.54	Line 4, Rounded to 2 Decimal Places	9
10				10
11	Pertaining to Schedules @ 90% NCD with Maximum On-peak Period Demand [2]			11
12				12
13	NCD Determinants by Voltage Level @ Meter Level (MW)			13
14	Secondary	21,561	Statement BL, Page BL-17, Line 13, Col. B	14
15	Primary	4,221	Statement BL, Page BL-17, Line 14, Col. B	15
16	Transmission	290	Statement BL, Page BL-17, Line 15, Col. B	16
17	Total	26,072	Sum Lines 14; 15; 16	17
18				18
19	Annual Revenues from 100% of Total Med. & Lrg. Comm./Ind. NCD Rates			19
20	Secondary	$ 138,420	Line 14 x Statement BL, Page BL-6, Line 35	20
21	Primary	$ 26,213	Line 15 x Statement BL, Page BL-6, Line 36	21
22	Transmission	$ 1,785	Line 16 x Statement BL, Page BL-6, Line 37	22
23	Total	$ 166,418	Sum Lines 20; 21; 22	23
24				24
25	Annual Revenues from 90% of Total Med. & Lrg. Comm./Ind. NCD Rates			25
26	Secondary	$ 124,621	Line 7 x Line 14	26
27	Primary	$ 23,596	Line 8 x Line 15	27
28	Transmission	$ 1,608	Line 9 x Line 16	28
29	Total	$ 149,825	Sum Lines 26; 27; 28	29
30				30
31	Revenue Reallocation to Maximum On-peak Period Demand			31
32	Secondary	$ 13,799	Line 20 Less Line 26	32
33	Primary	$ 2,617	Line 21 Less Line 27	33
34	Transmission	$ 177	Line 22 Less Line 28	34
35	Total	$ 16,593	Sum Lines 32; 33; 34	35

NOTES:

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

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

Statement BL
SAN DIEGO GAS AND ELECTRIC COMPANY
Rate Design Information
Medium & Large Commercial/Industrial Customers
Rate Effective Period - Twelve Months Ending August 31, 2012
($1,000)

Line No.	Description	Derivation of Commodity Rate & Proof of Revenues Calculation	Reference	Line No.
1	Pertaining to Schedules @ 90% NCD with			1
2	Maximum Demand at Time of System Peak [1]			2
3				3
4	NCD Determinants by Voltage Level @ Meter Level (MW)			4
5	Secondary	-	Statement BL, Page BL-17, Line 21, Col. B	5
6	Primary	175	Statement BL, Page BL-17, Line 22, Col. B	6
7	Transmission	1,139	Statement BL, Page BL-17, Line 23, Col. B	7
8	Total	1,314	Sum Lines 5; 6; 7	8
9				9
10	Annual Revenues from 100% of Total Med. & Lrg. Comm./Ind. NCD Rates			10
11	Secondary	$ -	Line 5 x Statement BL, Page BL-6, Line 35	11
12	Primary	$ 1,089	Line 6 x Statement BL, Page BL-6, Line 36	12
13	Transmission	$ 7,003	Line 7 x Statement BL, Page BL-6, Line 37	13
14	Total	$ 8,092	Sum Lines 11; 12; 13	14
15				15
16	Annual Revenues from 90% of Total Med. & Lrg. Comm./Ind. NCD Rates			16
17	Secondary	$ -	Statement BL, Page BL-7, Line 7 x Line 5	17
18	Primary	$ 981	Statement BL, Page BL-7, Line 8 x Line 6	18
19	Transmission	$ 6,308	Statement BL, Page BL-7, Line 9 x Line 7	19
20	Total	$ 7,289	Sum Lines 17; 18; 19	20
21				21
22	Revenue Reallocation to Maximum Demand at the Time of System Peak			22
23	Secondary	$ -	Line 11 Less Line 17	23
24	Primary	$ 109	Line 12 Less Line 18	24
25	Transmission	$ 695	Line 13 Less Line 19	25
26	Total	$ 803	Sum Lines 23; 24; 25	26

NOTES:

[1] 90% NCD Rates and Maximum Demand at Time of System Peak charges are applicable to the following California Public Utilities Commission (CPUC) tariff: Schedule A6-TOU.

Statement BL
SAN DIEGO GAS AND ELECTRIC COMPANY
Rate Design Information
Medium & Large Commercial/Industrial Customers
Rate Effective Period - Twelve Months Ending August 31, 2012
($1,000)

Line No.	Description	Derivation of Commodity Rate & Proof of Revenues Calculation	Reference	Line No.
1	Revenue Reallocation to Maximum			1
2	On-Peak Period Demands [1]	$ 16,593	Statement BL, Page BL-7, Line 35	2
3				3
4	Summer Maximum On-peak Period Demands			4
5	by Voltage Level @ Meter Level (MW) [2]			5
6	Secondary	8,629	Statement BL, Page BL-17, Line 35, Col. B	6
7	Primary	1,862	Statement BL, Page BL-17, Line 36, Col. B	7
8	Transmission	222	Statement BL, Page BL-17, Line 37, Col. B	8
9	Total	10,713	Sum Lines 6; 7; 8	9
10				10
11	Summer Maximum On-peak Period Demands			11
12	by Voltage Level @ Transmission Level (MW)			12
13	Secondary	9,023	Statement BL, Page BL-17, Line 35, Col. D	13
14	Primary	1,882	Statement BL, Page BL-17, Line 36, Col. D	14
15	Transmission	222	Statement BL, Page BL-17, Line 37, Col. D	15
16	Total	11,127	Sum Lines 13; 14; 15	16
17				17
18	Summer Maximum On-peak Period Allocation to Voltage Levels			18
19	Secondary	81.09%	Line 13 / Line 16	19
20	Primary	16.91%	Line 14 / Line 16	20
21	Transmission	2.00%	Line 15 / Line 16	21
22	Total	100.00%	Sum Lines 19; 20; 21	22
23				23
24	Share of Total Revenue Allocation to Summer Peak Period	80.00%		24
25				25
26	Revenues for Summer Maximum			26
27	On-peak Period Demand Rates			27
28	Secondary	$ 10,764	Line 2 x Line 24 x Line 19	28
29	Primary	$ 2,245	Line 2 x Line 24 x Line 20	29
30	Transmission	$ 265	Line 2 x Line 24 x Line 21	30
31	Total	$ 13,274	Sum Lines 28; 29; 30	31
32				32
33	Summer Maximum On-peak Period Demand Rates [3]	$/kW		33
34	Secondary	$ 1.24745	Line 28 / Line 6	34
35	Primary	$ 1.20611	Line 29 / Line 7	35
36	Transmission	$ 1.19047	Line 30 / Line 8	36
37				37
38	Summer Maximum On-peak Period Demand Rates (Rounded)	$/kW		38
39	Secondary	$ 1.25	Line 34, Rounded to 2 Decimal Places	39
40	Primary	$ 1.21	Line 35, Rounded to 2 Decimal Places	40
41	Transmission	$ 1.19	Line 36, Rounded to 2 Decimal Places	41
42				42

NOTES:

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

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

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

Statement BL
SAN DIEGO GAS AND ELECTRIC COMPANY
Rate Design Information
Medium & Large Commercial/Industrial Customers
Rate Effective Period - Twelve Months Ending August 31, 2012
($1,000)

Line No.	Description	Derivation of Commodity Rate & Proof of Revenues Calculation	Reference	Line No.
1	Winter Maximum On-peak Period Demands			1
2	by Voltage Level @ Meter Level (MW) [1]			2
3	Secondary	9,890	Statement BL, Page BL-17, Line 40, Col. B	3
4	Primary	2,143	Statement BL, Page BL-17, Line 41, Col. B	4
5	Transmission	292	Statement BL, Page BL-17, Line 42, Col. B	5
6	Total	12,326	Sum Lines 3; 4; 5	6
7				7
8	Winter Maximum On-peak Period Demands			8
9	by Voltage Level @ Transmission Level (MW)			9
10	Secondary	10,342	Statement BL, Page BL-17, Line 40, Col. D	10
11	Primary	2,167	Statement BL, Page BL-17, Line 41, Col. D	11
12	Transmission	292	Statement BL, Page BL-17, Line 42, Col. D	12
13	Total	12,801	Sum Lines 10; 11; 12	13
14				14
15	Winter Maximum On-peak Period Allocation to Voltage Levels			15
16	Secondary	80.79%	Line 10 / Line 13	16
17	Primary	16.93%	Line 11 / Line 13	17
18	Transmission	2.28%	Line 12 / Line 13	18
19	Total	100.00%	Sum Lines 16; 17; 18	19
20				20
21	Share of Total Revenue Allocation to Winter Peak Period	20.00%		21
22				22
23	Revenues for Winter Maximum			23
24	On-peak Period Demand Rates			24
25	Secondary	$ 2,681	Statement BL, Page BL-9, Line 2 x Line 21 x Line 16	25
26	Primary	$ 562	Statement BL, Page BL-9, Line 2 x Line 21 x Line 17	26
27	Transmission	$ 76	Statement BL, Page BL-9, Line 2 x Line 21 x Line 18	27
28	Total	$ 3,319	Sum Lines 25; 26; 27	28
29				29
30	Winter Maximum On-peak Period Demand Rates [2]	$/kW		30
31	Secondary	$ 0.27109	Line 25 / Line 3	31
32	Primary	$ 0.26211	Line 26 / Line 4	32
33	Transmission	$ 0.25915	Line 27 / Line 5	33
34				34
35				35
36	Winter Maximum On-peak Period Demand Rates (Rounded)	$/kW		36
37	Secondary	$ 0.27	Line 31, Rounded to 2 Decimal Places	37
38	Primary	$ 0.26	Line 32, Rounded to 2 Decimal Places	38
39	Transmission	$ 0.26	Line 33, Rounded to 2 Decimal Places	39
40				40
41				41
42	Proof of Revenues			42
43	Secondary	$ 13,457	(Page BL-9, Line 6 x Page BL-9, Line 39) + (Line 3 x Line 37)	43
44	Primary	$ 2,810	(Page BL-9, Line 7 x Page BL-9, Line 40) + (Line 4 x Line 38)	44
45	Transmission	$ 341	(Page BL-9, Line 8 x Page BL-9, Line 41) + (Line 5 x Line 39)	45
46	Total	$ 16,607	Sum Lines 43; 44; 45	46
47				47
48	Difference	$ (14)	Statement BL, Page BL-9, Line 2 Less Line 46	48
49				49

NOTES:

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

2 Winter Maximum On-peak Period Demand Charges for the following California Public Utilities Commission (CPUC) tariffs:
Schedules AY-TOU, AL-TOU, AL-TOU-DER, and DG-R.

Statement BL
SAN DIEGO GAS AND ELECTRIC COMPANY
Rate Design Information
Medium & Large Commercial/Industrial Customers
Rate Effective Period - Twelve Months Ending August 31, 2012
($1,000)

Line No.	Description	Derivation of Commodity Rate & Proof of Revenues Calculation	Reference	Line No.
1	Revenue Reallocation to Maximum Demands at the Time of System Peak [1]	$ 803	Statement BL, Page BL-8, Line 26	1
2				2
3	Summer Maximum Demands at the Time of System Peak			3
4	by Voltage Level @ Meter Level (MW) [2]			4
5	Secondary	-	Statement BL, Page BL-17, Line 48, Col. B	5
6	Primary	66	Statement BL, Page BL-17, Line 49, Col. B	6
7	Transmission	403	Statement BL, Page BL-17, Line 50, Col. B	7
8	Total	469	Sum Lines 5; 6; 7	8
9				9
10	Summer Maximum Demands at the Time of System Peak			10
11	by Voltage Level @ Transmission Level (MW)			11
12	Secondary	-	Statement BL, Page BL-17, Line 48, Col. D	12
13	Primary	67	Statement BL, Page BL-17, Line 49, Col. D	13
14	Transmission	403	Statement BL, Page BL-17, Line 50, Col. D	14
15	Total	470	Sum Lines 12; 13; 14	15
16				16
17	Summer Maximum Demands at the Time of			17
18	System Peak Allocation to Voltage Levels (MW)			18
19	Secondary	0.00%	Line 12 / Line 15	19
20	Primary	14.26%	Line 13 / Line 15	20
21	Transmission	85.74%	Line 14 / Line 15	21
22	Total	100.00%	Sum Lines 19; 20; 21	22
23				23
24	Share of Total Revenue Allocation to Summer			24
25	Maximum Demand at the Time of System Peak	80.00%		25
26				26
27	Revenues for Summer Maximum			27
28	Demand at the Time of System Peak Rates			28
29	Secondary	$ -	Line 1 x Line 25 x Line 19	29
30	Primary	$ 92	Line 1 x Line 25 x Line 20	30
31	Transmission	$ 551	Line 1 x Line 25 x Line 21	31
32	Total	$ 643	Sum Lines 29; 30; 31	32
33				33
34	Summer Maximum Demand at the Time of System Peak Rates [3]	$/kW		34
35	Secondary	$ -	Line 29 / Line 5	35
36	Primary	$ 1.38190	Line 30 / Line 6	36
37	Transmission	$ 1.36870	Line 31 / Line 7	37
38				38
39	Summer Maximum Demand at the Time of System Peak Rates (Rounded)	$/kW		39
40	Secondary	$ -	Line 35, Rounded to 2 Decimal Places	40
41	Primary	$ 1.38	Line 36, Rounded to 2 Decimal Places	41
42	Transmission	$ 1.37	Line 37, Rounded to 2 Decimal Places	42
43				43

NOTES:

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

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

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

Statement BL
SAN DIEGO GAS AND ELECTRIC COMPANY
Rate Design Information
Medium & Large Commercial/Industrial Customers
Rate Effective Period - Twelve Months Ending August 31, 2012
($1,000)

Line No.	Description	Derivation of Commodity Rate & Proof of Revenues Calculation	Reference	Line No.
1	Winter Maximum Demands at the Time of System Peak			1
2	by Voltage Level @ Meter Level (MW) [1]			2
3	Secondary	-	Statement BL, Page BL-17, Line 53, Col. B	3
4	Primary	80	Statement BL, Page BL-17, Line 54, Col. B	4
5	Transmission	514	Statement BL, Page BL-17, Line 55, Col. B	5
6	Total	594	Sum Lines 3; 4; 5	6
7				7
8	Winter Maximum Demands at the Time of System Peak			8
9	by Voltage Level @ Transmission Level (MW)			9
10	Secondary	-	Statement BL, Page BL-17, Line 53, Col. D	10
11	Primary	81	Statement BL, Page BL-17, Line 54, Col. D	11
12	Transmission	514	Statement BL, Page BL-17, Line 55, Col. D	12
13	Total	595	Sum Lines 10; 11; 12	13
14				14
15	Winter Maximum Demands at the Time of			15
16	System Peak Allocation to Voltage Levels			16
17	Secondary	0.00%	Line 10 / Line 13	17
18	Primary	13.61%	Line 11 / Line 13	18
19	Transmission	86.39%	Line 12 / Line 13	19
20	Total	100.00%	Sum Lines 17; 18; 19	20
21				21
22	Share of Total Revenue Allocation to Winter			22
23	Maximum Demand at the Time of System Peak	20.00%		23
24				24
25	Revenues for Proposed Winter Maximum			25
26	Demand at the Time of System Peak Rates			26
27	Secondary	$ -	Statement BL, Page BL-11, Line 1 x Line 23 x Line 17	27
28	Primary	$ 22	Statement BL, Page BL-11, Line 1 x Line 23 x Line 18	28
29	Transmission	$ 139	Statement BL, Page BL-11, Line 1 x Line 23 x Line 19	29
30	Total	$ 161	Sum Lines 27; 28; 29	30
31				31
32	Winter Maximum Demand at the Time of System Peak Rates [2]	$/kW		32
33	Secondary	$ -	Line 27 / Line 3	33
34	Primary	$ 0.27351	Line 28 / Line 4	34
35	Transmission	$ 0.26982	Line 29 / Line 5	35
36				36
37				37
38	Winter Maximum Demand at the Time of System Peak Rates (Rounded)	$/kW		38
39	Secondary	$ -	Line 33, Rounded to 2 Decimal Places	39
40	Primary	$ 0.27	Line 34, Rounded to 2 Decimal Places	40
41	Transmission	$ 0.27	Line 35, Rounded to 2 Decimal Places	41
42				42
43				43
44	Proof of Revenues			44
45	Secondary	$ -	(Page BL-11, Line 5 x Page BL-11, Line 40) + (Line 3 x Line 39)	45
46	Primary	$ 113	(Page BL-11, Line 6 x Page BL-11, Line 41) + (Line 4 x Line 40)	46
47	Transmission	$ 690	(Page BL-11, Line 7 x Page BL-11, Line 42) + (Line 5 x Line 41)	47
48	Total	$ 804	Sum Lines 45; 46; 47	48
49				49
50	Difference	$ (0)	Statement BL, Page BL-11, Line 1 Less Line 48	50
51				51

NOTES:

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

2 Winter Maximum Demand at the time of System Peak Demand Charges for the following California Public Utilities Commission (CPUC) tariff:
Schedule A6-TOU.

Statement BL
SAN DIEGO GAS AND ELECTRIC COMPANY
Rate Design Information
Street Lighting Customers [1]
Rate Effective Period - Twelve Months Ending August 31, 2012
($1,000)

Line No.	Description		Derivation of Commodity Rate & Proof of Revenues Calculation	Reference	Line No.
1	Street Lighting - Allocated Transmission Revenue Requirement	$	1,439	Statement BL, Page BL-3, Line 7	1
2					2
3	Street Lighting - Billing Determinants (MWh)		114,521	Statement BG, Page BGWP-1, Line 11	3
4					4
5	Street Lighting - Energy Rate per kWh	$	0.0125650	Line 1 / Line 3	5
6					6
7	Street Lighting - Energy Rate per kWh - Rounded	$	0.01257	Line 5, Rounded to 5 Decimal Places	7
8					8
9	Proof of Revenues	$	1,440	Line 3 x Line 7	9
10					10
11	Difference	$	(1)	Line 1 Less Line 9	11

NOTES:

[1] The following California Public Utilities Commission (CPUC) tariffs are offered to street lighting customers:
Schedules DWL, OL-1, OL-2, LS-1, LS-2, and LS-3.

Statement BL
SAN DIEGO GAS AND ELECTRIC COMPANY
Rate Design Information
Standby Customers
Rate Effective Period - Twelve Months Ending August 31, 2012
($1,000)

Line No.	Description	Derivation of Standby Surcharge & Proof of Revenues Calculation	Reference	Line No.
1	Standby - Demand Revenue Requirement	$ 4,862	Statement BL, Page BL-3, Line 8	1
2				2
3	Demand Determinants (with Transmission LF Adjustment)			3
4	Used to Allocate Total Class Revenues to Voltage Level (MW) [1]			4
5	Secondary	168	Statement BL, Page BL-17, Line 60, Col. D	5
6	Primary	1,012	Statement BL, Page BL-17, Line 61, Col. D	6
7	Transmission	603	Statement BL, Page BL-17, Line 62, Col. D	7
8	Total	1,783	Sum Lines 5; 6; 7	8
9				9
10	Allocation Factors Per Above to Allocate			10
11	Demand Revenue Requirements to Voltage Level			11
12	Secondary	9.42%	Line 5 / Line 8	12
13	Primary	56.76%	Line 6 / Line 8	13
14	Transmission	33.82%	Line 7 / Line 8	14
15	Total	100.00%	Sum Lines 12; 13; 14	15
16				16
17	Allocation of Revenue Requirements to Voltage Level			17
18	Secondary	$ 458	Line 1 x Line 12	18
19	Primary	$ 2,760	Line 1 x Line 13	19
20	Transmission	$ 1,644	Line 1 x Line 14	20
21	Total	$ 4,862	Sum Lines 18; 19; 20	21
22				22
23	Demand Determinants By Voltage Level @ Meter (MW)			23
24	Secondary	161	Statement BL, Page BL-17, Line 60, Col. B	24
25	Primary	1,001	Statement BL, Page BL-17, Line 61, Col. B	25
26	Transmission	603	Statement BL, Page BL-17, Line 62, Col. B	26
27	Total	1,765	Sum Lines 24; 25; 26	27
28				28
29	Demand Rate By Voltage Level @ Meter			29
30	Secondary	$ 2.84656	Line 18 / Line 24	30
31	Primary	$ 2.75783	Line 19 / Line 25	31
32	Transmission	$ 2.72501	Line 20 / Line 26	32
33				33
34	Demand Rate By Voltage Level @ Meter (Rounded)			34
35	Secondary	$ 2.85	Line 30, Rounded to 2 Decimal Places	35
36	Primary	$ 2.76	Line 31, Rounded to 2 Decimal Places	36
37	Transmission	$ 2.73	Line 32, Rounded to 2 Decimal Places	37
38				38
39	Proof of Revenues			39
40	Secondary	$ 459	Line 24 x Line 35	40
41	Primary	$ 2,762	Line 25 x Line 36	41
42	Transmission	$ 1,647	Line 26 x Line 37	42
43	Total	$ 4,868	Sum Lines 40; 41; 42	43
44				44
45	Difference	$ (6)	Line 1 Less Line 43	45

NOTES:

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

Statement BL
SAN DIEGO GAS AND ELECTRIC COMPANY
Rate Design Information
Summary of Proof of Revenues
Rate Effective Period - Twelve Months Ending August 31, 2012
($1,000)

Line No.	Customer Classes	(A) Total Revenues Per Cost of Service Study	(B) Total Revenues Per Rate Design	(C) Difference	Reference	Line No.
1	Residential	$ 153,477	$ 153,517	$ (40)	(A): Statement BL, Page BL-3, Line 4	1
2					(B): Statement BL, Page BL-4, Line 9	2
3	Small Commercial	47,257	47,265	(8)	(A): Statement BL, Page BL-3, Line 5	3
4					(B): Statement BL, Page BL-5, Line 9	4
5	Medium and Large Commercial/Industrial	181,909	181,834	75	(A): Statement BL, Page BL-3, Line 6	5
6					(B): Statement BL, Page BL-6, Line 43, - (Statement BL, Page BL-10, Line 48 + Statement BL, Page BL-12, Line 50)	6
7	Street Lighting	1,439	1,440	(1)	(A): Statement BL, Pages BL-3, Line 7	7
8					(B): Statement BL, Page BL-13, Line 9	8
9	Standby	4,862	4,868	(6)	(A): Statement BL, Page BL-3, Line 8	9
10					(B): Statement BL, Page BL-14, Line 43	10
11	Grand Total	$ 388,944	$ 388,924	$ 20	Sum Lines 1 through 9	11

Statement BL
SAN DIEGO GAS AND ELECTRIC COMPANY
Rate Design Information
Development of 12-CP Allocation Factors
Rate Effective Period - Twelve Months Ending August 31, 2012

Line No.	(A) Customer Class	(B) 5-year Average Of 12 CPs Kilowatt @ Meter Level	(C) Transmission Loss Factors	(D) = (B) x (C) 5-year Average Of 12 CPs Kilowatt @ Transmission Level	(E) Ratio	Reference	Line No.
1	Five-year Average - 12-CP Allocation Factors:						1
2	Residential	15,054,815	1.0457	15,742,820	39.46%	Statement BB, Page BB-1, Line 1	2
3	Small Commercial	4,636,436	1.0457	4,848,321	12.15%	Statement BB, Page BB-1, Line 2	3
4	Medium & Large Commercial/Industrial						4
5	Secondary	13,510,244	1.0457	14,127,662	35.41%	Statement BB, Page BB-1, Line 4	5
6	Primary	3,295,181	1.0108	3,330,769	8.35%	Statement BB, Page BB-1, Line 5	6
7	Transmission	1,201,031	1.0000	1,201,031	3.01%	Statement BB, Page BB-1, Line 6	7
8	Total Med. & Large Comm./Ind.	18,006,456	1.0363	18,659,462	46.77%	Sum Lines 5; 6; 7	8
9							9
10	Street Lighting	139,791	1.0457	146,179	0.37%	Statement BB, Page BB-1, Line 9	10
11	Standby						11
12	Secondary	38,310	1.0457	40,061	0.10%	Statement BB, Page BB-1, Line 11	12
13	Primary	293,448	1.0108	296,617	0.74%	Statement BB, Page BB-1, Line 12	13
14	Transmission	162,697	1.0000	162,697	0.41%	Statement BB, Page BB-1, Line 13	14
15	Total Standby	494,455	1.0100	499,375	1.25%	Sum Lines 12; 13; 14	15
16							16
17	System Total	38,331,953		39,896,157	100.00%	Sum Lines 2; 3; 8; 10; 15	17

Statement BL
SAN DIEGO GAS AND ELECTRIC COMPANY
Rate Design Information
Development of 12-CP Allocation Factors
Rate Effective Period - Twelve Months Ending August 31, 2012

Line No.	(A) Customer Class	(B) Forecast Demand Determinants Megawatt @ Meter Level	(C) Transmission Loss Factors	(D) = (B) x (C) Forecast Demand Determinants Megawatt @ Transmission Level	(E) Ratios	Reference	Line No.
1	Forecast Demand Determinants for						1
2	Medium & Large Commercial/Industrial Customers:						2
3	Non-coincident Demand Determinants Pertaining to						3
4	Customers on Schedules @ 100% NCD Rate						4
5	Secondary	1,001	1.0457	1,047	87.98%	Page BGWP-1, Line 38 [1]	5
6	Primary	142	1.0108	143	12.02%	Page BGWP-1, Line 39	6
7	Transmission	-	1.0000	-	0.00%	Page BGWP-1, Line 40	7
8	Total	1,143		1,190	100.00%	Sum Lines 5; 6; 7	8
9							9
10	Non-coincident Demand Determinants Pertaining to						10
11	Customers on Schedules @ 90% NCD Rate						11
12	with Maximum On-peak Period Demand						12
13	Secondary	21,561	1.0457	22,546	83.19%	Page BGWP-2, Line 65	13
14	Primary	4,221	1.0108	4,267	15.74%	Page BGWP-2, Line 66	14
15	Transmission	290	1.0000	290	1.07%	Page BGWP-2, Line 67	15
16	Total	26,072		27,103	100.00%	Sum Lines 13; 14; 15	16
17							17
18	Non-coincident Demand Determinants Pertaining to						18
19	Customers on Schedules @ 90% NCD Rate						19
20	with Maximum Demand at the Time of System Peak						20
21	Secondary	-	1.0457	-	0.00%	Page BGWP-3, Line 101	21
22	Primary	175	1.0108	177	13.45%	Page BGWP-3, Line 102	22
23	Transmission	1,139	1.0000	1,139	86.55%	Page BGWP-3, Line 103	23
24	Total	1,314		1,316	100.00%	Sum Lines 21; 22; 23	24
25							25
26	Total Non-coincident Demand Determinants for						26
27	Medium & Large Commercial/Industrial Customers						27
28	Secondary	22,562	1.0457	23,593	79.68%	Sum Lines 5; 13; 21	28
29	Primary	4,538	1.0108	4,587	15.49%	Sum Lines 6; 14; 22	29
30	Transmission	1,429	1.0000	1,429	4.83%	Sum Lines 7; 15; 23	30
31	Total	28,529		29,609	100.00%	Sum Lines 28; 29; 30	31
32							32
33	Maximum On-peak Period Demand Determinants						33
34	Summer						34
35	Secondary	8,629	1.0457	9,023	81.09%	Page BGWP-2, Line 75	35
36	Primary	1,862	1.0108	1,882	16.91%	Page BGWP-2, Line 76	36
37	Transmission	222	1.0000	222	2.00%	Page BGWP-2, Line 77	37
38	Total	10,713		11,127	100.00%	Sum Lines 35; 36; 37	38
39	Winter						39
40	Secondary	9,890	1.0457	10,342	80.79%	Page BGWP-2, Line 75	40
41	Primary	2,143	1.0108	2,167	16.93%	Page BGWP-2, Line 76	41
42	Transmission	292	1.0000	292	2.28%	Page BGWP-2, Line 77	42
43	Total	12,326		12,801	100.00%	Sum Lines 40; 41; 42	43
44							44
45	Maximum Demand at the Time of						45
46	System Peak Determinants						46
47	Summer						47
48	Secondary	-	1.0457	-	0.00%	Page BGWP-3, Line 111	48
49	Primary	66	1.0108	67	14.26%	Page BGWP-3, Line 112	49
50	Transmission	403	1.0000	403	85.74%	Page BGWP-3, Line 113	50
51	Total	469		470	100.00%	Sum Lines 48; 49; 50	51
52	Winter						52
53	Secondary	-	1.0457	-	0.00%	Page BGWP-3, Line 111	53
54	Primary	80	1.0108	81	13.61%	Page BGWP-3, Line 112	54
55	Transmission	514	1.0000	514	86.39%	Page BGWP-3, Line 113	55
56	Total	594		595	100.00%	Sum Lines 53; 54; 55	56
57							57
58	Forecast Demand Determinants for Standby Customers:						58
59	Contracted Demand Determinants						59
60	Secondary	161	1.0457	168	9.42%	Page BGWP-4, Line 135	60
61	Primary	1,001	1.0108	1,012	56.76%	Page BGWP-4, Line 136	61
62	Transmission	603	1.0000	603	33.82%	Page BGWP-4, Line 137	62
63	Total	1,765		1,783	100.00%	Sum Lines 60; 61; 62	63

NOTES:

[1] Pages BGWP-1 and BGWP-2 are found in Statement BG.

San Diego Gas & Electric Company

Base Period
Statement - BL
Cal-ISO
Wholesale TRBAA & HV-LV Utility
Specific Rates Information

Docket No. ER11-4318-000

Statement - BL

SAN DIEGO GAS & ELECTRIC COMPANY

Rate Design Information - Wholesale Transmission Rates

CAISO TAC Rates Input Form - September 1, 2011 through August 31, 2012

High-Voltage Utility Specific Rates, Low -Voltage Wheeling Access Charge & Low Voltage Access Charge Rates

Line No.	Components	(1) High Voltage TRR	(2) Low Voltage TRR	(3) = (1) + (2) Combined TRR	Notes & Reference	Line No.
1	Wholesale Base Transmission Revenue Requirement [1]	$ 202,246,000	$ 188,929,000	$ 391,175,000	Statement BL Tab CAISO-Wholesale; Pg 2; Line 1	1
2						2
3	Wholesale TRBAA Forecast [2]	$ (2,847,102)	$ 277,808	$ (2,569,294)	Statement BL Tab CAISO-Wholesale; Pg 2; Line 16	3
4						4
5	Transmission Standby Revenues [3]	$ (2,516,728)	$ (2,351,012)	$ (4,867,740)	Statement BL Tab CAISO-Wholesale; Pg 2; Line 18	5
6						6
7	Wholesale Net Transmission Revenue Requirement	$ 196,882,170	$ 186,855,796	$ 383,737,966	Sum Lines 1; 3; 5	7
8						8
9	Gross Load - MWH	21,539,407	21,539,407		Statement BD; Page 1; Col. B; Line 14	9
10						10
11	Utility Specific Access Charges ($/MWH)	$ 9.1406	$ 8.6751		Line 7 / Line 9	11
12						12

NOTES:

1 Wholesale Base TRR comes from Statement BK2; Page 8 of 8; Line 15, in the instant informational filing.

2 TRBAA information comes from Docket No. ER11-2430-000, filed on December 21, 2010 and approved by FERC on February 16, 2011. The TRBAA balance shown on Line 16 will be effective until 12/31/2011. This TBAA amount will change effective January 1, 2012, after SDG&E makes it annual TRBAA filing in December 2011.

3 Standby Revenues come from Statement BG; Page 1, Line 9, Col. (A) of TO3-Cycle 5 filing. Standby Revenues are allocated based on TO3-Cycle 5 HV-LV splits of wholesale BTRR. See page 3 of CAISO - Wholesale Tab.

Statement - BL
SAN DIEGO GAS & ELECTRIC COMPANY
Wholesale Customers - Rate Design Information
High Voltage - Low Voltage Transmission Revenue Requirements Calculations
September 1, 2011 through August 31, 2012 CAISO - TAC Rates Input Information

Line No.	Components	(1) Total HIGH VOLTAGE Transmission Revenue Requirement	(2) Total LOW VOLTAGE Transmission Revenue Requirement	(3) = (1) + (2) Total Transmission Revenue Requirement	Reference	Line No.
1	Wholesale Base Trans. Revenue Requirement [1]	$ 202,246,000	$ 188,929,000	$ 391,175,000	Statement BK2 ; Page 8 of 8; Line 15	1
2						2
3	TRBAA Balance @ 9/30/10 [2]	780,609	(76,168)	704,441	See Footnote No. 2 Below	3
4						4
5	Transmission Revenue Credits Forecast:					5
6	Wheeling Revenues [2]	(3,894,439)	-	(3,894,439)	See Footnote No. 2 Below	6
7						7
8	Settlements, Metering and Client Relations [2]	5,571	6,429	12,000	See Footnote No. 2 Below	8
9						9
10	APS-IID ETC Cost Differentials [2]	298,053	343,947	642,000	See Footnote No. 2 Below	10
11						11
12	Total Transmission Revenue Credits Forecast	(3,590,815)	350,376	(3,240,439)	Sum {Line 6 through Line 10}	12
13						13
14	Franchise Fees Expense	(36,896)	3,600	(33,296)	Line 12 x 1.0275%	14
15						15
16	Total TRBAA [2]	$ (2,847,102)	$ 277,808	$ (2,569,294)	Sum Lines 3; 12; 14	16
17						17
18	Transmission Standby Revenue [3]	(2,516,728)	(2,351,012)	(4,867,740)	TAC Workpaper; Page 1; Line 23	18
19						19
20	Total Transmission Revenue Requirement	$ 196,882,170	$ 186,855,796	$ 383,737,966	Sum Lines 1; 16; 18	20

NOTES:
1 Wholesale Base TRR comes from Statement BK2; Page 8 of 8; Line 15, in the instant informational filing.
2 TRBAA information comes from Docket No. ER11-2430-000, filed on December 21, 2010 and approved by FERC on February 16, 2011. The TRBAA balance shown on Line 16 will be effective until 12/31/2011. This TBAA amount will change effective January 1, 2012, after SDG&E makes it annual TRBAA filing in December 2011.
3 Standby Revenues come from Statement BG; Page 1, Line 9, Col. (A) of TO3-Cycle 5 filing. Standby Revenues are allocated based on TO3-Cycle 5 HV-LV splits of wholesale BTRR. See page 3 of CAISO - Wholesale Tab.

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Statement - BL
SAN DIEGO GAS & ELECTRIC COMPANY
Wholesale Customers - Rate Design Information
Allocation of Standby Revenue Credits Between High Voltage & Low Voltage Facilities
CAISO TAC Rates Input Form - September 1, 2011 through August 31, 2012

Line No.	Components	(1) High Voltage	(2) Low Voltage	(3) = (1) + (2) Total	Notes & Reference	Line No.
					Statement BL	
1	Base Transmission Revenue Requirement [1]	$ 202,246,000	$ 188,929,000	$ 391,175,000	Tab CAISO-Wholesale; Pg. 1; Line 1	1
2						2
3	HV-LV Allocation Factors [2]	51.70218%	48.29782%	100.00000%	Ratios Based on Line 1 - Wholesale BTRR	3
4						4
5	Standby Revenue Credits [3]	$ (2,516,728)	$ (2,351,012)	$ (4,867,740)	Line 3 Ratios x (Col. 3; Line 9)	5
6						6
7	Total HV-LV Standby Revenue Credits	$ (2,516,728)	$ (2,351,012)	$ (4,867,740)	Sum of Line 5	7
8						8
9	Total Standby Revenue Credits			$ (4,867,740)	Statement BG; Page-1; Line 9; Col. A	9

NOTES:
1 Wholesale Base TRR comes from Statement BK2; Page 8 of 8; Line 15 of Cycle 5 filing.
2 HV-LV allocation ratios using the wholesale BTRR information from line 1.
3 Allocation of Standby Revenues derived from Statement BG, Page 1, Line 9, column (A) and applying the ratios developed on line 3.

TO3-Cycle 5 Annual Formulaic Rate Filing
SAN DIEGO GAS & ELECTRIC COMPANY
Comparison of CAISO Average HV-LV Rates
TO3-Cycle 5 Compliance Filing vs. TO3-Cycle 4

Line No.	Components	(1) Total High Voltage TRR	(2) Total Low Votage TRR	(3) = (1) + (2) Combined TRR	Notes & Reference	Line No.
1					Cycle 5 - Compliance Filing	1
2	Wholesale Base TRR - Cycle 5 Compliance Filing [1]	$ 202,246,000	$ 188,929,000	$ 391,175,000	Vol. 1; Stmnt BK2; Pg.8; Ln. 15	2
3	Gross Load Forecast - Cycle 5 (MWH)	21,539,407	21,539,407	21,539,407	Vol. 1; Stmnt BD; Pg.1; Ln. 14	3
4	Average Rate Per MWH	$ 9.38958	$ 8.77132	$ 18.16090	Line 2 / Line 3	4
5						5
6					Cycle 4 - Compliance Report Filing	6
7	Wholesale Base TRR - Cycle 4 [2]	$ 134,370,000	$ 178,400,000	$ 312,770,000	Vol. 1; Stmnt BK2; Pg.8; Ln. 15	7
8	Gross Load Forecast - Cycle 4 (MWH)	21,226,578	21,226,578	21,226,578	Vol. 1; Stmnt BD; Pg.1; Ln. 14	8
9	Average Rate Per MWH	$ 6.33027	$ 8.40456	$ 14.73483	Line 7 / Line 8	9
10						10
11						11
12	Difference ($)	$ 3.05931	$ 0.36676	$ 3.42607	Line 4 Minus Line 9	12
13	Difference (%)	48.33%	4.36%	23.25%	Line 12 / Line 9	13
14						14

1 Information comes from SDG&E's Cycle 5 Compliance filing that will be filed with the FERC on November 14, 2011.

2 Information comes from SDG&E's Cycle 4 refund report compliance filing, FERC docket number ER10-2235-001, filed with the FERC on November 8, 2010.

San Diego Gas & Electric Company

True-Up Period
Statement – AD
Cost of Plant

Docket No. ER11-4318-000

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

Line No		Amounts		Reference	Line No
1	Total Electric Miscellaneous Intangible Plant [2]	$ 28,039		Stmnt AD WP; Col C, Line 1	1
2					2
3	Total Steam Production Plant	343,909		Stmnt AD WP; Col C, Line 3	3
4					4
5	Total Nuclear Production Plant	1,369,640		Stmnt AD WP; Col C, Line 5	5
6					6
7	Total Hydraulic Production Plant	-		Stmnt AD WP; Col C, Line 7	7
8					8
9	Total Other Production Plant	289,817		Stmnt AD WP; Col C, Line 9	9
10					10
11	Total Production Plant and Intangible plant	$ 2,031,404		Sum Lines 1 thru 9	11
12					12
13	Total Distribution Plant	**4,477,368**	√	Stmnt AD WP; Col C, Line 13	13
14					14
15	Total Transmission Plant [1]	**1,645,668**	√	Stmnt AD WP; Col C, Line 15	15
16					16
17	Total General Plant [2]	182,263		Stmnt AD WP; Col C, Line 17	17
18					18
19	Total Common Plant [2]	483,398		Stmnt AD WP; Col C, Line 19	19
20					20
21	Total Plant in Service	$ **8,820,101**	√	Sum Lines 11 thru 19	21
22					22
23	Transmission Plant	**1,645,668**	√	Stmnt AD WP; Col C, Line 23	23
24					24
25	Transmission Wages and Salaries Allocation Factor	15.19%		Statement AI; Line 19	25
26					26
27	Transmission Related Electric Miscellaneous Intangible Plant	4,259		Line 1 x Line 25	27
28					28
29	Transmission Related General Plant	27,686		Line 17 x Line 25	29
30					30
31	Transmission Related Common Plant	73,428		Line 19 x Line 25	31
32					32
33	Transmission Related Plant in Service	$ **1,751,041**	√	Sum Lines 23; 27; 29; 31	33
34					34
35	Transmission Plant Allocation Factor [3]	**19.85%**	√	Line 33 / Line 21	35

NOTES:

√ **Items that are in bold have changed between the instant compliance filing and the original filing from last August 15, 2011.**

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

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

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

San Diego Gas & Electric Company

True-Up Period
Statement – AE
Accumulated Depreciation and Amortization

<u>Docket No. ER11-4318-000</u>

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

Line No			Amounts	Reference	Line No
1	Transmission Depreciation Reserve [1]	$	**499,335** √	Stmnt AE WP; Page-AE1; Col C, Line 1	1
2					2
3	Electric Miscellaneous Intangible Plant Amortization Reserve [2]		26,110	Stmnt AE WP; Page-AE1; Col C, Line 3	3
4					4
5	General Plant Depreciation Reserve [2]		78,271	Stmnt AE WP; Page-AE1; Col C, Line 5	5
6					6
7	Common Plant Depreciation Reserve [2]		268,994	Stmnt AE WP; Page-AE1; Col C, Line 7	7
8					8
9	Transmission Wages and Salaries Allocation Factor		15.19%	Statement AI; Line 19	9
10					10
11	Transmission Related Electric Miscellaneous Intangible Plant Amortization Reserve	$	3,966	Line 3 x Line 9	11
12					12
13	Transmission Related General Plant Depreciation Reserve		11,889	Line 5 x Line 9	13
14					14
15	Transmission Related Common Plant Depreciation Reserve		40,860	Line 7 x Line 9	15
16					16
17	Transmission Related Accumulated Depreciation Reserve	$	**556,050** √	Sum Lines 1; 11; 13 ;15	17

NOTES:

√ **Items that are in bold have changed between the instant compliance filing and the original filing from last August 15, 2011.**

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

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

San Diego Gas & Electric Company

True-Up Period
Statement – AH
Operation and Maintenance Expenses

Docket No. ER11-4318-000

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

Line No.			Amounts	Reference	Line No.
1	Derivation of Transmission Operation and Maintenance Expense:				1
2	Total Transmission Expenses	$	39,804	Stmnt AH WP; Page-AH1; Line 2	2
3	Less: Account (561) - Load Dispatching		(2,355)	Stmnt AH WP; Page-AH1; Line 3	3
4	Less: Account (565) - Transmission of Electricity by Others		(407)	Stmnt AH WP; Page-AH1; Line 4	4
5	Less: Account (566) - Miscellaneous Transmission Expenses		808	Stmnt AH WP; Page-AH1; Line 5	5
6	Less: Account (566) - Miscellaneous Transmission Expenses		6,707	Stmnt AH WP; Page-AH1; Line 6	6
7	Less: Account (575) - Market Administration Monitor		-	Stmnt AH WP; Page-AH1; Line 7	7
8	Total Transmission O&M Expenses Including Intervener Compensation Costs	$	44,557	Sum Lines 2 through 7	8
9	Less: CPUC Intervener Funding Expenses (See Statement BK1; Page 1; Line 6)		-	Stmnt AH WP; Page-AH1; Line 9	9
10	Total Transmission O&M Expense (See Statement BK1; Page 1; Line 2)	$	44,557	Sum Lines 8 through 9	10
11					11
12	Derivation of Administrative and General Expense:				12
13	Total Administrative & General Expenses	$	289,190	Stmnt AH WP; Page-AH1; Line 13	13
14	Adjustments to Per Book A&G expenses:		-		14
15	Nuclear Property Insurance Expenses		(1)	Stmnt AH WP; Page-AH1; Line 15	15
16	Nuclear Liability Insurance Expenses		(1,264)	Stmnt AH WP; Page-AH1; Line 16	16
17	**Wildfire Insurance Premium Allocation**		**(45,564)** √	Stmnt AH WP; Page-AH1; Line 17	17
18	CPUC Reimbursement Fees		(5,248)	Stmnt AH WP; Page-AH1; Line 18	18
19	Litigation Expense		(2,238)	Stmnt AH WP; Page-AH1; Line 19	19
20	CPSD Wildfire Investigation Settlement		(14,350)	Stmnt AH WP; Page-AH1; Line 20	20
21	CPUC Energy Effeciency Programs Expenses		(14,288)	Stmnt AH WP; Page-AH1; Line 21	21
22	AMI Lease Facilities		(816)	Stmnt AH WP; Page-AH1; Line 22	22
23	Hazardous Substances		(221)	Stmnt AH WP; Page-AH1; Line 23	23
24	Total Adjusted A&G Expenses Before Excluding Property Insurance	$	**205,200** √	Sum Lines 13 thru 23	24
25	Property Insurance (Reflected on Line 44 below due to different allocation factor)		(3,426)	Stmnt AH WP; Page-AH1; Line 25	25
26	Total Adjusted A&G Expenses Excluding Property Insurance	$	**201,774** √	Sum Lines 24 thru 25	26
27	Transmission Wages and Salaries Allocation Factor		15.19%	Statement AI; Line 19	27
28	Total Transmission Related Administrative and General Expense	$	**30,649** √	Line 26 x Line 27	28
29					29
30	Derivation of Transmission Plant Property Insurance Allocation Factor:				30
31	Transmission Plant	$	**1,645,668** √	Statement AD-WP; Line 23	31
32	Transmission Related General Plant		27,686	Statement AD-WP; Line 29	32
33	Transmission Related Common Plant		73,428	Statement AD-WP; Line 31	33
34	Total	$	**1,746,782** √	Sum Lines (31 thru 33)	34
35					35
36	Total Transmission Plant	$	**1,645,668** √	Statement AD-WP; Line 23	36
37	Total Steam Production Plant		343,909	Statement AD-WP; Line 3	37
38	Total Other Production Plant		289,817	Statement AD-WP; Line 9	38
39	Total Nuclear Production Plant		-	N/A in Ratio Development	39
40	Total Distribution plant		**4,477,368** √	Statement AD-WP; Col.C; Line 13	40
41	Total General Plant		182,263	Statement AD-WP; Col.C; Line 17	41
42	Total Common Plant		483,398	Statement AD-WP; Col.C; Line 19	42
43	Total Plant in Service Excluding SONGS	$	**7,422,422** √	Sum Lines (36 thru 42)	43
44					44
45	Transmission Plant Property Insurance Allocation Factor		**23.53%** √	Line 34 / Line 43	45
46					46
47	Total Property Insurance	$	3,426	See Line 25 Above	47
48					48
49	Property Insurance Allocated to Transmission, General, and Common Plant		**806** √	Line 45 x Line 47	49
50					50
51	Transmission Related A & G Expenses		**30,649** √	See Line 28 Above	51
52					52
53	Transmission Related A & G Expenses Including Property Insurance	$	**31,455** √	Line 49 + Line 51	53

√ Items that are in bold have changed between the instant compliance filing and the original filing from last August 15, 2011.

San Diego Gas & Electric
Administrative & General Expenses
12 - Months True-Up Ending March 31, 2011
($1,000)

Line No.		A	B	C = A + B	Line No.
	FERC Account	Total Per Books	Adj. & Excl. Amounts	Total Adjusted	
1	920 A&G Salaries	$ 14,969	$ -	$ 14,969	1
2	921 Office Supplies & Expenses	5,342	-	5,342	2
3	922 Less Construction Transfer	(5,965)	-	(5,965)	3
4	923 Outside Services	60,425	-	60,425	4
5	924 Property Insurance	3,427	(1)	3,426	5
6	925 Damages & Injuries	13,478	(1,408)	12,070	6
7	925 Wildfire Insurance Premium Alloc.	85,298	(61,183)	24,115	7
8	**925 Wildfire Damage Claims Adjustment**		**15,619**	**15,619**	8
9	926 Employee Pension & Benefits	51,696	(573)	51,123	9
10	927 Franchise Expenses	-	-	-	10
11	928 Regulatory Expenses	15,276	(7,486)	7,790	11
12	929 Company Energy Use	(1,741)	-	(1,741)	12
13	930 Misc. General Expenses	30,061	(27,920)	2,141	13
14	931 Rents	9,129	(816)	8,313	14
15	935 Maintenance of General Plant	7,795	(221)	7,574	15
16					16
17	**Total**	**$ 289,190**	**$ (83,989)**	**$ 205,201**	17
18					18
19			12 MTD Mar		19
20	Excluded Expenses		'11		20
21	924 Nuclear property insurance expenses		$ (1)		21
22	925 Nuclear liability insurance expenses		(1,264)		22
23	925.4 Wildfire Ins Premium Allocation		(61,183)		23
24	**925.4 Wildfire Damages**		**15,619**		24
25	928 CPUC reimbursement fees		(5,248)		25
26	928 Litigation Expense (LCMA)		(2,238)		26
27	930.2 CPSD Wildfire Investigation Settlement		(14,350)		27
28	925/926/930 CPUC energy efficiency programs		(14,287)		28
29	931 AMI Lease Facilities		(816)		29
30	935 Hazardous Substances		(221)		30
31	Total Excluded Expenses		$ (83,989)		31

* Account 925 is shown in three parts to reflect wildfire insurance expenses separately. The $15,619 allocated to SDG&E's electric division is a result of allocating SDG&E's total wildfire uninsured claims, equal to $44.5 million, to its non-regulated affiliates and to its regulated gas utilities based upon the use of labor ratios.

San Diego Gas & Electric Company

True-Up Period
Statement – AJ
Depreciation and Amortization Expenses

Docket No. ER11-4318-000

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

Line No.			Amounts	Reference	Line No.
1	Depreciation Expense for Transmission Plant [1]	$	**42,553** √	Stmnt AJ WP; Page-AJ1; Line 1	1
2					2
3	General Plant Depreciation Expense	$	8,162	Stmnt AJ WP; Page-AJ1; Line 3	3
4					4
5	Transmission Wages and Salaries Allocation Factor		15.19%	Statement AI; Line 19	5
6					6
7	Transmission Related General Plant Depreciation Expense	$	1,240	Line 3 x Line 5	7
8					8
9	Common Plant Depreciation Expense	$	38,690	Stmnt AJ WP; Page-AJ1; Line 9	9
10					10
11	Tranmission Related Common Plant Depreciation Expense	$	5,877	Line 9 x Line 5	11
12					12
13	Electric Miscellaneous Intangible Plant Depreciation Expense	$	925	Stmnt AJ WP; Page-AJ1; Line 13	13
14					14
15	Transmission Related Electric Miscellaneous Intangible Plant Depreciation Expense	$	140	Line 13 x Line 5	15
16					16
17	Total Transmission, Intangible, General and Common Depreciation & Amortization Exp	$	**49,810** √	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

√ **Items that are in bold have changed between the instant compliance filing and the original filing from last August 15, 2011.**

San Diego Gas & Electric Company

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

<u>Docket No. ER11-4318-000</u>

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

Line No.			Amounts		Reference	Line No.
1	Total Property Taxes	$	50,109		Stmnt AK WP; Page-AK1; Line 1	1
2						2
3	SONGS Property Taxes		2,920		Stmnt AK WP; Page-AK1; Line 3	3
4						4
5	Property Taxes Less SONGS	$	47,189		Line 1 Minus Line 3	5
6						6
7						7
8	Derivation of Transmission Related Property Tax Allocation Factor:					8
9	Transmission Plant	$	**1,645,668**	√	Statement AD-WP; Line 23	9
10	Total Miscellaneous Intangible Plant		4,259		Statement AD-WP; Line 27	10
11	Transmission Related General Plant		27,686		Statement AD-WP; Line 29	11
12	Transmission Related Common Plant		73,428		Statement AD-WP; Line 31	12
13	Total	$	**1,751,041**	√	Sum Lines 9 thru 12	13
14						14
15	Total Nuclear Plant	$	-		N/A in Ratio Development	15
16	Total Steam Plant		343,909		Statement AD-WP; Line 3	16
17	Total Other Production Plant		289,817		Statement AD-WP; Line 9	17
18	Total Transmission plant		**1,645,668**	√	Statement AD-WP; Line 23	18
19	Total Miscellaneous Intangible Plant		28,039		Statement AD-WP; Line 1	19
20	Total Distribution plant		**4,477,368**	√	Statement AD-WP; Col.C; Line 13	20
21	Total General Plant		182,263		Statement AD-WP; Col.C; Line 17	21
22	Total Common Plant		483,398		Statement AD-WP; Col.C; Line 19	22
23	Total Investment in Plant Excluding SONGS	$	**7,450,462**	√	Sum Lines 15 thru 22	23
24						24
25	Transmission Related Property Tax Allocation Factor		**23.50%**	√	Line 13 / Line 23	25
26						26
27	Transmission Related Property Taxes Expense	$	**11,089**	√	Line 5 x Line 25	27
28						28
29						29
30	Payroll Taxes:	$	12,872		Stmnt AK WP; Page-AK1; Line 7	30
31						31
32	Transmission Wages and Salaries Allocation Factor		15.19%		Statement AI; Line 19	32
33						33
34	Transmission Related Payroll Taxes Expense	$	1,955		Line 30 x Line 32	34

√ Items that are in bold have changed between the instant compliance filing and the original filing from last August 15, 2011.

San Diego Gas & Electric Company

True-Up Period
Statement – AL
Working Capital

Docket No. ER11-4318-000

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

Line No.			Amounts	Reference	Line No.
1	Plant Materials and Operating Supplies	$	53,783	Stmnt AL WP; Page-AL1; Line 1	1
2					2
3	Transmission Plant Allocation Factor		**19.85%** √	Statement AD WP; Line 35	3
4					4
5	Transmission Related Materials and Supplies	$	**10,676** √	(Line 1 x Line 3)	5
6					6
7	Prepayment		27,541	Stmnt AL WP; Page-AL1; Line 7	7
8					8
9	Transmission Related Prepayments	$	**5,467** √	(Line 3 x Line 7)	9
10					10
11	Derivation of Transmission Related Cash Working Capital:				11
12	Transmission Operation & Maintenance Expense	$	44,557	Statement AH; Page -AH1; Line 10	12
13	Transmission Related Administrative & General Expenses		**31,455** √	Statement AH; Page- AH1; Line 54	13
14	Intervenor Compensation Expenses		-	Statement AH; Page-AH1; Line 9	14
15	Total	$	**76,012** √	Sum Lines 12; 13; 14	15
16					16
17	One Eighth of O & M Percentage Rate		12.50%	FERC Method = 1/8 of O & M	17
18					18
19	Adjust O&M Percentage Rate to Account for 12-Month Period		12.50%	Line 17 / 1	19
20					20
21	Transmission Related Cash Working Capital - Retail Customers	$	**9,502** √	Line 15 x Line 19	21
22					22
23	Transmission Related Cash Working Capital - Wholesale Customers	$	**9,502** √	(Line 12 + Line 13) x Line 19	23

√ **Items that are in bold have changed between the instant compliance filing and the original filing from last August 15, 2011.**

San Diego Gas & Electric Company

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

Docket No. ER11-4318-000

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

Line No.					Amounts	Reference	Line No.
1	Long-Term Debt Component - Denominator:						1
2	(Plus): Account 221 - Bonds				$ 2,686,905	Stmnt AV WP; Page-AV1; Line 2	2
3	(Less): Account 222 - Reacquired Bonds				-	Stmnt AV WP; Page-AV1; Line 3	3
4	(Plus): Account 224 - Other Long-Term Debt (Acct. 224)				253,720	Stmnt AV WP; Page-AV1; Line 4	4
5	(Plus): Account 225 - Unamortized Premium on Long-Term Debt				-	Stmnt AV WP; Page-AV1; Line 5	5
6	(Less): Account 226 - Unamortized Discount on Long-Term Debt-Debit				9,271	Stmnt AV WP; Page-AV1; Line 6	6
7	Total Long Term Debt (LTD)				$ 2,931,354	Lines 2-3+4+5-6	7
8							8
9	Long-Term Debt Component - Numerator:						9
10	(Plus): Account 427 - Interest on Long-Term Debt				$ 138,022	Stmnt AV WP; Page-AV1; Line 10	10
11	(Plus): Account 428 - Amort. of Debt Disc. and Expense				2,027	Stmnt AV WP; Page-AV1; Line 11	11
12	(Plus): Account 428.1 - Amortization of Loss on Reacquired Debt				3,510	Stmnt AV WP; Page-AV1; Line 12	12
13	(Less): Account 429 - Amort. of Premium on Debt-Credit				-	Stmnt AV WP; Page-AV1; Line 13	13
14	(Less): Account 429.1 - Amortization of Gain on Reacquired Debt-Credit				-	Stmnt AV WP; Page-AV1; Line 14	14
15	Total LTD Interest = (i)				$ 143,559	Lines 10+11+12-13-14	15
16							16
17	Cost of Long-Term Debt:				4.90%	Line 15 / Line 7	17
18							18
19							19
20	Preferred Equity Component:						20
21	PF = Preferred Stock - Account 204				$ 78,475	Stmnt AV WP; Page-AV1; Line 21	21
22	d(pf) = Total Dividends Declared-Preferred Stocks - Account 437				4,820	Stmnt AV WP; Page-AV1; Line 22	22
23	Cost of Preferred Equity				6.14%	Line 22 / Line 21	23
24							24
25							25
26	Common Equity Component:						26
27	Proprietary Capital				$ 3,476,377	Stmnt AV WP; Page-AV1; Line 27	27
28	(Less): Account 204 Preferred Stock				78,475	Stmnt AV WP; Page-AV1; Line 28	28
29	(Less): Account 216.1 Unappropriated Undistributed Subsidiary Earnings				-	Stmnt AV WP; Page-AV1; Line 29	29
30	CS = Common Stock				$ 3,397,902	Line 27 - Line 28 - Line 29	30
31							31
32	Cost of Common Equity - Per Settlement:				11.35%	Appendix 8; Page 28; Item (a) iii	32
33		(a)	(b)	(c)	(d) = (b) x (c)		33
34			Cap. Struct.		Weighted		34
35	Weighted Cost of Capital:	Amount	Ratio	Cost of Capital	Cost of Capital		35
36							36
37	Long-Term Debt	$ 2,931,354	45.75%	4.90%	2.24%	Col. C = Line 17 Above	37
38	Preferred Equity	78,475	1.23%	6.14%	0.08%	Col. C = Line 23 Above	38
39	Common Equity	3,397,902	53.03%	11.35%	6.02%	Col. C = Line 32 Above	39
40	Total Capital	$ 6,407,732	100.00%		8.34%	Sum Lines 37; 38; 39	40
41							41
42							42
43	Cost of Equity Component (Preferred & Common):				6.10%	Sum Lines 38; 39	43

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

Line No.			Amounts	Reference	Line No.
1	Derivation of Cost of Capital Rate:				1
2					2
3	a) Federal Income Tax Component:				3
4					4
5	Where:				5
6	A = Sum of Preferred Stock and Return on Equity Component		6.10%	Statement AV; Page 13; Line 43	6
7	B = Trans. Related Amort. of ITC and Excess Deferred Tax Liab.	$	268	(Statement AR; Page 11; Line 5)	7
8	C = Equity AFUDC Component of Transmission Depreciation Expense	$	-		8
9	D = Transmission Rate Base	**$**	**1,111,691** √	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) =		3.2716%		13
14	1 - FT				14
15					15
16					16
17	b) State Income Tax Component:				17
18					18
19	Where:				19
20	A = Sum of Preferred Stock and Return on Equity Component		6.10%	Statement AV; Page 13; Line 43	20
21	B = Trans. Related Amort. of ITC and Excess Deferred Tax Liab.	$	268	(Statement AR; Page 11; Line 5)	21
22	C = Equity AFUDC Component of Transmission Depreciation Expense	$	-		22
23	D = Transmission Rate Base	**$**	**1,111,691** √	Statement BK1; Page 2; Line 20	23
24					24
25	FT = Federal Income Tax Expense Rate		3.2716%	Statement AV; Page14, Line 13	25
26	ST = State Income Tax Rate July 1, 2010		8.84%	State Income Tax Rate	26
27					27
28	State Income Tax = (A + [(C - B) / D] + Federal Income Tax) (ST) =		0.9065%		28
29	1 - ST				29
30					30
31	c) Total Federal & State Income Tax Expense Rate:		4.1781%	Sum Lines 13 and Line 28	31
32					32
33	d) Total Weighted Cost of Capital:		8.3400%	Statement AV; Page 13; Line 40	33
34					34
35	e) Cost of Capital Rate:		12.5181%	Line 31 + Line 33	35

√ **Items that are in bold have changed between the instant compliance filing and the original filing from last August 15, 2011.**

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

Section 2.1A
Summary of Retail True-Up Adjustment

Docket No. ER11-4318-000

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

Line No.	TO3-Formula Cycle in Effect / Description	Cycle - 3 Apr-10	Cycle - 3 May-10	Cycle - 3 Jun-10	Cycle - 3 Jul-10	Cycle - 3 Aug-10
1	**Beginning Balance (Overcollection)/Undercollection:**	$ -	$ 3,125,365	$ 6,394,806	$ 9,406,173	$ 12,652,254
2						
3	Total Recorded Revenues	$ 18,694,588	$ 18,170,421	$ 20,445,534	$ 22,658,338	$ 21,406,203
4						
5	**Amortization of True-Up Adjustment and Interest True-Up Adjustment:**					
6	**a) Amortization of Cycle 4 TU Adjustment and Interest True-Up Adjusment:**					
7	i. Amortization of Cycle 4 True-Up Adjustment					
8	ii. Amortization of Cycle 4 Interest True-Up Adjustment.					
9	**b) Amortization of Cycle 3 True-Up Adjustment and Interest True-Up Adjusment:**					
10	i. Amortization of Cycle 3 True-Up Adjustment	(641,105)	(606,971)	(656,518)	(717,162)	(1,272,418)
11	ii. Amortization of Cycle 3 Interest True-Up Adjustment					
12	**c) Amortization of Cycle 2 True-Up Adjustment and Interest True-Up Adjusment:**					
13	i. Amortization of Cycle 2 TU Adjustment	-	-	-	-	-
14	ii. Amortization of Cycle 2 Interest True-Up Adjustment	(30,529)	(28,903)	(31,263)	(34,151)	(39,198)
15	iii. Amortization of Cycle 2 Interest True-Up Adjustment Accrued After Fully Amortized					
16	**d) Amortization of TO2 Final True-Up Adjustment and Interest True-Up Adjusment:**					
17	i. Amortization of TO2 Final True-Up Adjustment	-	-	-	-	-
18	ii. Amortization of TO2 Final True-Up - Interest TU Adjustment	(137,380)	(130,065)	(140,683)	(153,678)	(319,786)
19	iii. Amortization of TO2 Final Interest TU Adjustment Accrued After Fully Amortized					
20	Total Amortization of True-Up Adjustments	$ (809,014)	$ (765,939)	$ (828,464)	$ (904,991)	$ (1,631,402)
21						
22	**Adjusted Total Recorded Revenues**	$ 17,885,574	$ 17,404,482	$ 19,617,070	$ 21,753,347	$ 19,774,801
23						
24	**Total True-Up Revenues (TU Cost of Service)**	$ 21,006,725	$ 20,660,626	$ 22,607,182	$ 24,968,589	$ 23,560,375
25						
26	**Net Monthly (Overcollection)/Undercollection:**	$ 3,121,151	$ 3,256,144	$ 2,990,112	$ 3,215,242	$ 3,785,573
27						
28	Interest Expense Calculations:					
29	Beginning Balance for Interest Calculation	$ -	$ -	$ -	$ 9,406,173	$ 9,406,173
30	Monthly Activity Included in Interest Calculation Basis	1,560,576	4,749,223	7,872,351	1,607,621	5,108,028
31	Basis for Interest Expense Calculation	1,560,576	4,749,223	7,872,351	11,013,794	14,514,202
32	Monthly Interest Rate	0.27000%	0.28000%	0.27000%	0.28000%	0.28000%
33	**Interest Expense**	$ 4,214	$ 13,298	$ 21,255	$ 30,839	$ 40,640
34						
35	**Ending Balance (Overcollection)/Undercollection:**	$ 3,125,365	$ 6,394,806	$ 9,406,173	$ 12,652,254	$ 16,478,467
36						
37		Apr-10	May-10	Jun-10	Jul-10	Aug-10
38	FERC INTEREST RATE	3.25%	3.25%	3.25%	3.25%	3.25%
39	Days in Year	365	365	365	365	365
40	Days in Month	30	31	30	31	31
41	Monthly Interest Rate - Calculated	0.27000%	0.28000%	0.27000%	0.28000%	0.28000%
42	FERC Interest Rates - Website	0.27000%	0.28000%	0.27000%	0.28000%	0.28000%
43	Difference	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%

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

Line No.	TO3-Formula Cycle in Effect / Description	Cycle - 4 Sep-10	Cycle - 4 Oct-10	Cycle - 4 Nov-10	Cycle - 4 Dec-10	Cycle - 4 Jan-11
1	**Beginning Balance (Overcollection)/Undercollection:**	**$ 16,478,467**	**$ 19,427,942**	**$ 17,687,698**	**$ 16,993,622**	**$ 16,392,122**
2						
3	Total Recorded Revenues	$ 27,022,152	$ 28,883,272	$ 25,743,058	$ 26,406,391	$ 27,709,822
4						
5	**Amortization of True-Up Adjustment and Interest True-Up Adjustment:**					
6	**a) Amortization of Cycle 4 TU Adjustment and Interest True-Up Adjusment:**					
7	i. Amortization of Cycle 4 True-Up Adjustment	(2,892,580)	(2,719,111)	(2,501,110)	(2,593,639)	(2,728,943)
8	ii. Amortization of Cycle 4 Interest True-Up Adjustment.					
9	**b) Amortization of Cycle 3 True-Up Adjustment and Interest True-Up Adjusment:**					
10	i. Amortization of Cycle 3 True-Up Adjustment					
11	ii. Amortization of Cycle 3 Interest True-Up Adjustment	(18,542)	(17,430)	(16,033)	(16,626)	(17,493)
12	**c) Amortization of Cycle 2 True-Up Adjustment and Interest True-Up Adjusment:**					
13	i. Amortization of Cycle 2 TU Adjustment	-	-	-	-	-
14	ii. Amortization of Cycle 2 Interest True-Up Adjustment	-	-	-	-	-
15	iii. Amortization of Cycle 2 Interest True-Up Adjustment Accrued After Fully Amortized	(1,854)	(1,743)	(1,603)	(1,663)	(1,749)
16	**d) Amortization of TO2 Final True-Up Adjustment and Interest True-Up Adjusment:**					
17	i. Amortization of TO2 Final True-Up Adjustment	-	-	-	-	-
18	ii. Amortization of TO2 Final True-Up - Interest TU Adjustment	-	-	-	-	-
19	iii. Amortization of TO2 Final Interest TU Adjustment Accrued After Fully Amortized	(18,542)	(17,430)	(16,033)	(16,626)	(17,493)
20	Total Amortization of True-Up Adjustments	$ (2,931,518)	$ (2,755,714)	$ (2,534,779)	$ (2,628,554)	$ (2,765,678)
21						
22	**Adjusted Total Recorded Revenues**	**$ 24,090,634**	**$ 26,127,558**	**$ 23,208,279**	**$ 23,777,837**	**$ 24,944,144**
23						
24	**Total True-Up Revenues (TU Cost of Service)**	**$ 26,991,894**	**$ 24,335,425**	**$ 22,467,586**	**$ 23,129,938**	**$ 24,232,019**
25						
26	**Net Monthly (Overcollection)/Undercollection:**	**$ 2,901,259**	**$ (1,792,133)**	**$ (740,693)**	**$ (647,899)**	**$ (712,125)**
27						
28	Interest Expense Calculations:					
29	Beginning Balance for Interest Calculation	$ 9,406,173	$ 19,427,942	$ 19,427,942	$ 19,427,942	$ 16,392,122
30	Monthly Activity Included in Interest Calculation Basis	8,451,445	(896,067)	(2,162,480)	(2,856,776)	(356,062)
31	Basis for Interest Expense Calculation	17,857,618	18,531,875	17,265,462	16,571,166	16,036,060
32	Monthly Interest Rate	0.27000%	0.28000%	0.27000%	0.28000%	0.28000%
33	**Interest Expense**	**$ 48,216**	**$ 51,889**	**$ 46,617**	**$ 46,399**	**$ 44,901**
34						
35	**Ending Balance (Overcollection)/Undercollection:**	**$ 19,427,942**	**$ 17,687,698**	**$ 16,993,622**	**$ 16,392,122**	**$ 15,724,898**
36						
37		Sep-10	Oct-10	Nov-10	Dec-10	Jan-11
38	FERC INTEREST RATE	3.25%	3.25%	3.25%	3.25%	3.25%
39	Days in Year	365	365	365	365	365
40	Days in Month	30	31	30	31	31
41	Monthly Interest Rate - Calculated	0.27000%	0.28000%	0.27000%	0.28000%	0.28000%
42	FERC Interest Rates - Website	0.27000%	0.28000%	0.27000%	0.28000%	0.28000%
43	Difference	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%

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

Line No.	TO3-Formula Cycle in Effect / Description	Cycle - 4 Feb-11	Cycle - 4 Mar-11	Total	Reference	Line No.
1	**Beginning Balance (Overcollection)/Undercollection:**	$ 15,724,898	$ 15,155,861	$ -	Previous Month's Balance	1
2						2
3	Total Recorded Revenues	$ 24,815,815	$ 25,230,125	$ 287,185,720	Section 2.2; Page 40; Line 11	3
4						4
5	**Amortization of True-Up Adjustment and Interest True-Up Adjustment:**					5
6	**a) Amortization of Cycle 4 TU Adjustment and Interest True-Up Adjusment:**					6
7	i. Amortization of Cycle 4 True-Up Adjustment	(2,459,266)	(2,491,275)	(18,385,924)	Section 2.1A; Page 6; Line 19; Cols (a)-(g)	7
8	ii. Amortization of Cycle 4 Interest True-Up Adjustment.					8
9	**b) Amortization of Cycle 3 True-Up Adjustment and Interest True-Up Adjusment:**					9
10	i. Amortization of Cycle 3 True-Up Adjustment			(3,894,174)	Section 2.1A; Pgs 9-10; Line 19; Cols (h)-(l)	10
11	ii. Amortization of Cycle 3 Interest True-Up Adjustment	(15,765)	(15,970)	(117,859)	Section 2.1A; Page 12; Line 19; Cols (a)-(g)	11
12	**c) Amortization of Cycle 2 True-Up Adjustment and Interest True-Up Adjusment:**					12
13	i. Amortization of Cycle 2 TU Adjustment	-	-	-		13
14	ii. Amortization of Cycle 2 Interest True-Up Adjustment	-	-	(164,044)	Section 2.1A; Pgs 15-16; Line 19; Cols (h)-(l)	14
15	iii. Amortization of Cycle 2 Interest True-Up Adjustment Accrued After Fully Amortized	(1,576)	(1,597)	(11,785)	Section 2.1A; Page 18; Line 19; Cols (a)-(g)	15
16	**d) Amortization of TO2 Final True-Up Adjustment and Interest True-Up Adjusment:**					16
17	i. Amortization of TO2 Final True-Up Adjustment	-	-	-		17
18	ii. Amortization of TO2 Final True-Up - Interest TU Adjustment	-	-	(881,592)	Section 2.1A; Pgs 21-22; Line 19; Cols (h)-(l)	18
19	iii. Amortization of TO2 Final Interest TU Adjustment Accrued After Fully Amortized	(15,765)	(15,970)	(117,859)	Section 2.1A; Page 24; Line 19; Cols (a)-(g)	19
20	Total Amortization of True-Up Adjustments	$ (2,492,372)	$ (2,524,812)	$ (23,573,237)	Sum Lines 7 through 19	20
21						21
22	**Adjusted Total Recorded Revenues**	**$ 22,323,443**	**$ 22,705,313**	**$ 263,612,483**	Sum Lines 3 & 20	22
23						23
24	**Total True-Up Revenues (TU Cost of Service)**	**$ 21,715,965**	**$ 21,904,596**	**$ 277,580,919**	Page 70; Line 11	24
25						25
26	**Net Monthly (Overcollection)/Undercollection:**	**$ (607,478)**	**$ (800,717)**	**$ 13,968,436**	Line 17 Minus Line 19	26
27						27
28	Interest Expense Calculations:					28
29	Beginning Balance for Interest Calculation	$ 16,392,122	$ 16,392,122		Beginning Quarterly Balances	29
30	Monthly Activity Included in Interest Calculation Basis	(1,015,864)	(1,719,962)		Interest Calculation Basis	30
31	Basis for Interest Expense Calculation	15,376,258	14,672,160		Sum Lines 24 & 25	31
32	Monthly Interest Rate	0.25000%	0.28000%		FERC Monthly Rates	32
33	**Interest Expense**	**$ 38,441**	**$ 41,082**	**$ 427,790**	Line 26 x Line 27	33
34						34
35	**Ending Balance (Overcollection)/Undercollection:**	**$ 15,155,861**	**$ 14,396,225**	**$ 14,396,225**	Sum Lines 1; 21; & 28	35
36						36
37		Feb-11	Mar-11			37
38	FERC INTEREST RATE	3.25%	3.25%		Annual Interest Rate - FERC Website	38
39	Days in Year	365	365	365	Number of Days Per Year	39
40	Days in Month	28	31	365	Number of Days Per Month	40
41	Monthly Interest Rate - Calculated	0.25000%	0.28000%	3.29000%	(Line 33)/(Line 34)x(Line 35)	41
42	FERC Interest Rates - Website	0.25000%	0.28000%	3.29000%	Monthly Interest Rate - FERC Website	42
43	Difference	0.00000%	0.00000%	0.00000%	Line 36 - Line 37	43

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

Section 2.3
Derivation of Retail True-Up Cost of Service

Docket No. ER11-4318-000

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

Line No.			Amounts	Reference	Line No.
1	Transmission Operation & Maintenance Expense	$	44,557	Statement AH; Page 5, Line 10	1
2					2
3	Transmission Related A&G Expenses		**31,455** √	Statement AH; Page 5, Line 54	3
4					4
5	CPUC Intervener Funding Expense		-	Statement AH; Page 5, Line 8	5
6					6
7	Total O&M Expenses	$	**76,012** √	Sum Lines 1; 3; and 5	7
8					8
9	Transmission, Intangible, General and Common Depr. & Amort. Expense		**49,810** √	Statement AJ; Page 7, Line 17	9
10					10
11	Valley Rainbow Project Cost Amortization Expense		1,893	Statement AJ; Page 7, Line 19	11
12					12
13	Transmission Related Property Taxes Expense		**11,089** √	Statement AK; Page 8, Line 27	13
14					14
15	Transmission Related Payroll Taxes Expense		1,955	Statement AK; Page 8, Line 34	15
16					16
17	Subtotal Expense	$	**140,759** √	Sum Lines 7 thru 15	17
18					18
19	Cost of Capital Rate ($AFCR_{CP}$)		12.5181%	Statement AV; Page 14, Line 35	19
20					20
21	Transmission Rate Base	$	**1,111,691** √	Statement BK-1; Pg 2, Line 20	21
22					22
23	Return and Associated Income Taxes	$	**139,162** √	(Line 19 x Line 21)	23
24	South Georgia Income Tax Adjustment		2,333	Statement AQ; Page 10, Line 1	24
25	Transmission Related Amortization of ITC		(265)	Statement AR; Page 11, Line 1	25
26	Transmission Related Amort of Excess Deferred Tax Liability		(3)	Statement AR; Page 11, Line 3	26
27	Transmission Related Revenue Credits		(7,611)	Statement AU; Page 12, Line 13	27
28					28
29	End of Prior Year Revenue ($PYRR_{EU}$)	$	**274,375** √	Line 17 + Sum of Lines (23 thru 27)	29
30					30
31	Transmission Related Municipal Franchise Expenses		-	Calculated Below	31
32	Transmission Related Uncollectible Expense		-	Calculated Below	32
33					33
34	End of Prior Year Revenue ($PYRR_{EU}$)	$	**274,375** √	Sum Lines (29 thru 32)	34

√ Items that are in bold have changed between the instant compliance filing and the original filing from last August 15, 2011.

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

Line No.			Amounts		Reference	Line No.
1	Net Transmission Plant:					1
2	Transmission Plant	$	1,146,333		Statement BK-1; Pg 3; Line 16	2
3	Electric Miscellaneous Intangible Plant		293		Statement BK-1; Pg 3; Line 17	3
4	Transmission Related General Plant		15,797		Statement BK-1; Pg 3; Line 18	4
5	Transmission Related Common Plant		32,568		Statement BK-1; Pg 3; Line 19	5
6	Net Transmission Plant	$	1,194,991		Sum Lines (2 thru 5)	6
7						7
8	Rate Base Reductions:					8
9	Transmission Related Accumulated Deferred Taxes	$	(148,838)		Statement AF; Page 3, Line 3	9
10						10
11	Rate Base Additions					11
12	Transmission Plant Held for Future Use	$	39,893		Statement AG; Page 4, Line 3	12
13						13
14	Working Capital:					14
15	Transmission Related Material and Supplies	$	**10,676**	√	Statement AL; Page 9, Line 5	15
16	Tranmission Related Prepayments		**5,467**	√	Statement AL; Page 9, Line 9	16
17	Transmission Related Cash Working Capital - Retail		**9,502**	√	Statement AL; Page 9, Line 21	17
18	Total Working Capital	$	**25,645**	√	Sum Lines (15 thru 17)	18
19						19
20	Total Transmission Rate Base	$	**1,111,691**	√	Sum Lines 6; 9; 12; 18	20

√ Items that are in bold have changed between the instant compliance filing and the original filing from last August 15, 2011.

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

Line No.			Amounts		Reference	Line No.
1	Gross Transmission Plant:					1
2	Transmission Plant	$	**1,645,668**	√	Statement AD; Page 1, Line 23	2
3	Electric Miscellaneous Intangible Plant		4,259		Statement AD; Page 1, Line 27	3
4	Transmission Related General Plant		27,686		Statement AD; Page 1, Line 29	4
5	Transmission Related Common Plant		73,428		Statement AD; Page 1, Line 31	5
6	Gross Transmission Plant	$	**1,751,041**	√	Sum Lines (2 thru 5)	6
7						7
8	Accumulated Depreciation Reserve:					8
9	Transmission Related Depreciation Reserve	$	**499,335**	√	Statement AE; Page 2, Line 1	9
10	Electric Miscellaneous Intangible Depreciation Reserve		3,966		Statement AE; Page 2, Line 11	10
11	Transmission Related General Plant Depr Reserve		11,889		Statement AE; Page 2, Line 13	11
12	Transmission Related Common Plant Depr Reserve		40,860		Statement AE; Page 2, Line 15	12
13	Total Transmission Related Depreciation Reserve	$	**556,050**	√	Sum Lines (9 thru 12)	13
14						14
15	Net Transmission Plant:					15
16	Transmission Plant	$	1,146,333		Line 2 Minus Line 9	16
17	Electric Miscellaneous Intangible Plant		293		Line 3 Minus Line 10	17
18	Transmission Related General Plant		15,797		Line 4 Minus Line 11	18
19	Transmission Related Common Plant		32,568		Line 5 Minus Line 12	19
20	Total Net Plant	$	1,194,991		Sum Lines (16 thru 19)	20

√ Items that are in bold have changed between the instant compliance filing and the original filing from last August 15, 2011.

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

Line No.		Amounts	Reference	Line No.
1	A. Derivation of Annual Fix Charge Rate Applicable to Forecast Period Capital Plant Addtions:			1
2	PYRR $_{EU}$ Excluding Franchise and Uncollectible	$ -	Statement BK-1; Page 1, Line 30	2
3	Valley Rainbow (VR) Project Cost Amortization	-	Statement BK-1; Page 1; Line 12	3
4	South Georgia Income Tax Adjustment	-	Statement BK-1; Page 1; Line 25	4
5	Transmission Related Amortization of Investment Tax Credit	-	Statement BK-1; Page 1; Line 26	5
6	Transmission Related Amortization of Excess Deferred Tax Liabilities	-	Statement BK-1; Page 1; Line 27	6
7	Adjusted Transmission Revenue	$ -	Sum Lines (2 thru 6)	7
8				8
9	Transmission Related Municipal Franchise Expenses	-	Calculated Below	9
10	Transmission Related Uncollectible Expense	-	Calculated Below	10
11	Subtotal	$ -	Sum Lines (7 thru 10)	11
12				12
13	Gross Electric Transmission Plant	$ **1,751,041** √	Statement BK-1; Page 3, Line 6	13
14				14
15	Annual Fix Charge Rate (AFCR $_{EU}$)	0.00%	N/A True-Up Adjustment Calculation	15
16				16
17				17
18				18
19	B. Derivation of Forecast Period Capital Additions Revenue Requirements:			19
20	Weighted Forecast Plant Addtions	$ -	N/A True-Up Adjustment Calculation	20
21				21
22	Annual Fix Charge Rate (AFCR $_{EU}$)	0.00%	Statement BK-1; Page 4, Line 15	22
23				23
24	Forecast Period Capital Additions Revenue Requirements	$ -	Line 20 x Line 22	24

√ Items that are in bold have changed between the instant compliance filing and the original filing from last August 15, 2011.

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

Line No.			Amounts		Reference	Line No.
1	End Use Customer Base Transmission Revenue Requirement (BTRR $_{EU}$):					1
2						2
3	True-Up Period Revenue Requirements (TUR $_{EU}$)	$	**274,375**	√	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	$	**274,375**	√	Line 3 + Line 5	7
8						8
9	Transmission Related Municipal Franchise Expenses		**2,819**	√	Line 9 x 1.0275%	9
10	Transmission Related Uncollectible Expense		**387**	√	Line 9 x .01410%	10
11						11
12	Total Retail TUR $_{EU}$	$	**277,581**	√	Sum Lines (7 thru 10)	12

√ Items that are in bold have changed between the instant compliance filing and the original filing from last August 15, 2011.

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

Section 2.3.1
Derivation of Retail True-Up Cost of Service Rates

Docket No. ER11-4318-000

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

Line No.	Customer Classes	(A) Transmission Energy Rates $/kWh	(B) Transmission Level Demand Rates $/kW-Mo	(C) Primary Level Demand Rates $/kW-Mo	(D) Secondary Level Demand Rates $/kW-Mo	Reference	Line No.
1	Residential	$ 0.0148790				Section 2.3.1; Page 3; Line 7	1
2							2
3	Small Commercial	$ 0.0170128				Section 2.3.1; Page 4; Line 7	3
4							4
5	Medium & Large Commercial/Industrial						5
6	Non-Coincident Demand (100%)[1]		$ 4.6226078	$ 4.6710569	$ 4.8325038	Section 2.3.1; Page 5; Lines 35;34;33	6
7							7
8	Non-Coincident Demand (90%)[2]		$ 4.1603470	$ 4.2039512	$ 4.3492534	Section 2.3.1; Page 6; Lines 8;7;6	8
9							9
10	Maximum On-Peak Period Demand [3]						10
11	Summer		$ 0.9415850	$ 0.9471568	$ 0.9798457	Section 2.3.1; Page 7; Lines 37; 36; 35	11
12	Winter		$ 0.1916601	$ 0.1943076	$ 0.2012271	Section 2.3.1; Page 8; Lines 30; 29; 28	12
13							13
14	Maximum Demand at the Time of System Peak[4]						14
15	Summer		$ 1.0557041	$ 1.0760029	$ -	Section 2.3.1; Page 9; Lines 37; 36; 35	15
16	Winter		$ 0.2053616	$ 0.2045328	$ -	Section 2.3.1; Page 10; Lines 33; 32; 31	16
17							17
18	Street Lighting	$ 0.0086821				Section 2.3.1; Page 11; Line 7	18
19							19
20	Standby Rate		$ 1.9737263	$ 1.9970548	$ 2.0688656	Section 2.3.1; Page 12; Lines 35;34;33	20

NOTES:

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

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

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

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

Section 2.3.1
SAN DIEGO GAS AND ELECTRIC COMPANY
TO3-Cycle 5 Annual Transmission Formulaic Rate Filing
Derivation of Retail True-Up Cos of Service Rates
For the True-Up Period - (April 1, 2010 - March 31, 2011)
Allocation of Base Transmission Revenue Requirements (BTRR) Based on 12 CPs
($1,000)

Line No.	Customer Classes	(A) Total 12 CPs @ Transmission Level [2]	(B) Percentages [3]	(C) Allocated Base Transmission Revenue Requirement	Reference	Line No.
1	Total Base Transmission Revenue Requirement [1]			$ 277,581	Section 2.3; Page 5 of 5; Line 12	1
2						2
3	Allocation of BTRR Based on 12-CP:					3
4	Residential	15,742,820	39.46%	$ 109,532	Col.C4 = Col C Ln1 x Col B. Ln 4	4
5	Small Commercial	4,848,321	12.15%	33,733	Col.C5 = Col C Ln1 x Col B. Ln 5	5
6	Medium & Large Commercial/Industrial	18,659,462	46.77%	129,825	Col.C6 = Col C Ln1 x Col B. Ln 6	6
7	Street Lighting Revenues	146,179	0.37%	1,017	Col.C7 = Col C Ln1 x Col B. Ln 7	7
8	Standby Revenues	499,375	1.25%	3,474	Col.C8 = Col C Ln1 x Col B. Ln 8	8
9						9
10	Total	39,896,157	100.00%	$ 277,581	Sum Lines 4 thru 8	10
11						11
12	Total	39,896,157		$ 277,581	Line 10	12

NOTES:

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

2 See Statement BL; Page 9; Column D.

3 See Statement BL; Page 9; Column E.

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

Line No.	Description	Derivation of Commodity Rate & Proof of Revenues Calculation	Reference	Line No.
1	Residential - Allocated Transmission Revenue Requirements	$ 109,532	Section 2.3.1; Page 2; Line 4	1
2				2
3	Billing Determinants - Residential Customer Class (MWh):	7,361,513	Section 2.3.1; Page 16.1; Line 4	3
4				4
5	Residential Energy Rate Per kWh	$ 0.0148790	Line 1 / Line 3	5
6				6
7	Residential Energy Rate Per kWh - Rounded	$ 0.0148790	Line 5, Rounded to 7 Decimal Places	7
8				8
9	Proof of Revenues	$ 109,532	Line 7 x Line 3	9
10				10
11	Difference	$ -	Line 1 - Line 9	11

NOTES:

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

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

Line No.	Description	Derivation of Commodity Rate & Proof of Revenues Calculation	Reference	Line No.
1	Small Commercial - Allocated Transmission Revenue Requirement	$ 33,733	Section 2.3.1; Page 2; Line 5	1
2				2
3	Billing Determinants - Small Commercial (MWh):	1,982,802	Section 2.3.1; Page 16.1; Line 5	3
4				4
5	Rate Per kWh Calculation	$ 0.0170128	Line 1 / Line 3	5
6				6
7	Rate Per kWh Calculation - Rounded	$ 0.0170128	Line 5, Rounded to 7 Decimal Places	7
8				8
9	Proof of Revenues	$ 33,733	Line 7 x Line 3	9
10				10
11	Difference	$ -	Line 1 - Line 9	11

NOTES:

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

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

Line No.	Description	Derivation of Commodity Rate & Proof of Revenues Calculation	Reference	Line No.
1	Med-Lrg C&I - Demand Revenue Requirement	$ 129,825	Section 2.3.1; Page 2; Line 6	1
2	***Demand Determinants @ Transmission Level Used to Allocate***			2
3	***Total Class Revenues to Voltage Level with Loss Factor Adjustment (MW) [2]:***			3
4	Secondary	22,208	Section 2.3.1; Page 15; Col. D; Line 23	4
5	Primary	4,326	Section 2.3.1; Page 15; Col. D; Line 24	5
6	Tranmission	1,559	Section 2.3.1; Page 15; Col. D; Line 25	6
7	Total	28,093	Sum Lines 4; 5; 6	7
8	***Allocation Factors Per Above to Allocate***			8
9	***Demand Revenue Requirements to Voltage Level:***			9
10	Secondary	79.05%	Line 4 / Line 7	10
11	Primary	15.40%	Line 5 / Line 7	11
12	Tranmission	5.55%	Line 6 / Line 7	12
13	Total	100.00%	Sum Lines 10; 11; 12	13
14				14
15	Allocation of Revenue Requirements to Voltage Level			15
16	Secondary	$ 102,629	Line 1 x Line 10	16
17	Primary	$ 19,992	Line 1 x Line 11	17
18	Tranmission	$ 7,205	Line 1 x Line 12	18
19	Total	$ 129,826	Sum Lines 16; 17; 18	19
20				20
21	Demand Determinants By Voltage Level @ Meter Level (MW)			21
22	Secondary	21,237	Section 2.3.1; Page 15; Col. B; Line 23	22
23	Primary	4,280	Section 2.3.1; Page 15; Col. B; Line 24	23
24	Tranmission	1,559	Section 2.3.1; Page 15; Col. B; Line 25	24
25	Total	27,076	Sum Lines 22; 23; 24	25
26				26
27	Demand Rate By Voltage @ Meter			27
28	Secondary	$ 4.8325038	Line 16 / Line 22	28
29	Primary	$ 4.6710569	Line 17 / Line 23	29
30	Tranmission	$ 4.6226078	Line 18 / Line 24	30
31				31
32	Demand Rate By Voltage @ Meter (Rounded)			32
33	Secondary	$ 4.8325038	Line 28, Rounded to 7 Decimal Places	33
34	Primary	$ 4.6710569	Line 29, Rounded to 7 Decimal Places	34
35	Tranmission	$ 4.6226078	Line 30, Rounded to 7 Decimal Places	35
36				36
37	Proof of Revenue Calculations:			37
38	Secondary	$ 102,629	Line 22 x Line 33	38
39	Primary	$ 19,992	Line 23 x Line 34	39
40	Tranmission	$ 7,205	Line 24 x Line 35	40
41	Total	$ 129,826	Sum Lines 38; 39; 40	41
42				42
43	Difference	$ (1)	Line 1 - Line 41	43

NOTES:

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

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

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

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

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Line No.	Description		Derivation of Commodity Rate & Proof of Revenues Calculation	Reference	Line No.
1	**Rate Proposal 90% of Total M&L C&I NCD Rates:** [1]		90.00%		1
2	Secondary	$	4.3492534	90% x Section 2.3.1; Page 5; Line 33	2
3	Primary	$	4.2039512	90% x Section 2.3.1; Page 5; Line 34	3
4	Tranmission	$	4.1603470	90% x Section 2.3.1; Page 5; Line 35	4
5	**Rate Proposal 90% of Total M&L C&I NCD Rates (Rounded):**				5
6	Secondary	$	4.3492534	Line 2, Rounded to 7 Decimal Places	6
7	Primary	$	4.2039512	Line 3, Rounded to 7 Decimal Places	7
8	Tranmission	$	4.1603470	Line 4, Rounded to 7 Decimal Places	8
9	**Pertaining to Schedules @ 90% NCD with Maximum On-Peak Period Demand:** [2]				9
10	NCD Determinants By Voltage Level @ Meter Level (MW)				10
11	Secondary [4]		20,261	Section 2.3.1; Page 15; Col. B; Line 10	11
12	Primary [4]		3,981	Section 2.3.1; Page 15; Col. B; Line 11	12
13	Transmission [4]		256	Section 2.3.1; Page 15; Col. B; Line 12	13
14	Total		24,498	Sum Lines 11; 12; 13	14
15	**Annual Revenues from Current NCD Rate 100% of Total M&L C&I NCD Rates:**				15
16	Secondary	$	97,912	Line 11 x Section 2.3.1; Page 5; Line 33	16
17	Primary	$	18,594	Line 12 x Section 2.3.1; Page 5; Line 34	17
18	Tranmission	$	1,182	Line 13 x Section 2.3.1; Page 5; Line 35	18
19	Total	$	117,688	Sum Lines 16; 17; 18	19
20	**Annual Revenues from Proposed NCD Rate 90% of Total M&L C&I NCD Rates:**				20
21	Secondary	$	88,121	Line 6 x Line 11	21
22	Primary	$	16,735	Line 7 x Line 12	22
23	Tranmission	$	1,063	Line 8 x Line 13	23
24	Total	$	105,919	Sum Lines 21; 22; 23	24
25	**Revenue Reallocation to Maximum On-Peak Period Demands:**				25
26	Secondary	$	9,791	Line 16 - Line 21	26
27	Primary	$	1,859	Line 17 - Line 22	27
28	Tranmission	$	119	Line 18 - Line 23	28
29	Total - **Reallocated to MAXIMUM ON-PEAK PERIOD DEMANDS**	$	11,769	Sum Lines 26; 27; 28	29
30	**Pertaining to Schedules @ 90% NCD with Maximum Demand at Time of System Peak:** [3]				30
31	NCD Determinants By Voltage Level @ Meter Level (MW)				31
32	Secondary [4]		-	Section 2.3.1; Page 15; Col. B; Line 17	32
33	Primary [4]		160	Section 2.3.1; Page 15; Col. B; Line 18	33
34	Transmission [4]		1,303	Section 2.3.1; Page 15; Col. B; Line 19	34
35	Total		1,463	Sum Lines 32; 33; 34	35
36	**Annual Revenues from Current NCD Rate 100% of Total M&L C&I NCD Rates:**				36
37	Secondary	$	-	Line 32 x Section 2.3.1; Page 5; Line 33	37
38	Primary	$	749	Line 33 x Section 2.3.1; Page 5; Line 34	38
39	Tranmission	$	6,023	Line 34 x Section 2.3.1; Page 5; Line 35	39
40	Total	$	6,772	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	$	674	Line 7 x Line 39	43
44	Tranmission	$	5,421	Line 8 x Line 40	44
45	Total	$	6,095	Sum Lines 42; 43; 44	45
46	**Revenue Reallocation to Maximum Demand at the Time of System Peak:**				46
47	Secondary	$	-	Line 37 - Line 42	47
48	Primary	$	75	Line 38 - Line 43	48
49	Tranmission	$	602	Line 39 - Line 44	49
50	Total	$	677	Sum Lines 47; 48; 49	50

NOTES:

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

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

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

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

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

Line No.	Description	Derivation of Commodity Rate & Proof of Revenues Calculation	Reference	Line No.
1	Med-Lrg C&I Maximum On-Peak Period Demand Proposal			1
2	Revenue Reallocation to Maximum On-Peak Period Demands: [1]	$ 11,769	Section 2.3.1; Page 6; Line 29	2
3				3
4	Summer - Maximum On-Peak Period Demands By Voltage Level @ Meter Level (MW) [2]			4
5	Secondary	7,819	Section 2.3.1; Page 15; Col. B; Line 30	5
6	Primary	1,723	Section 2.3.1; Page 15; Col. B; Line 31	6
7	Transmission	130	Section 2.3.1; Page 15; Col. B; Line 32	7
8	Total	9,671	Sum Lines 5; 6; 7	8
9				9
10	Summer - Maximum On-Peak Period Demands By Voltage Level @ Trans. Level (MW)			10
11	Secondary	8,176	Section 2.3.1; Page 15; Col. D; Line 30	11
12	Primary	1,742	Section 2.3.1; Page 15; Col. D; Line 31	12
13	Transmission	130	Section 2.3.1; Page 15; Col. D; Line 32	13
14	Total	10,048	Sum Lines 11; 12; 13	14
15				15
16	Summer Maximum On-Peak Period Allocation to Voltage Levels			16
17	Secondary	81.37%	Line 11 / Line 14	17
18	Primary	17.34%	Line 12 / Line 14	18
19	Tranmission	1.29%	Line 13 / Line 14	19
20	Total	100.00%	Sum Lines 17; 18; 19	20
21	Share of Total Revenue Allocation to Summer Peak Period	80.00%		21
22	Revenues for Proposed Summer Maximum On-Peak Period Demand Rates			22
23	Secondary	$ 7,661	(Line 2 x Line 21) x Line 17	23
24	Primary	$ 1,632	(Line 2 x Line 21) x Line 18	24
25	Transmission	$ 122	(Line 2 x Line 21) x Line 19	25
26	Total	$ 9,415	Sum Lines 23; 24; 25	26
27				27
28	Summer Maximum On-Peak Period Demand Rates [3]	$/kW		28
29	Secondary	$ 0.9798457	Line 23 / Line 5	29
30	Primary	$ 0.9471568	Line 24 / Line 6	30
31	Transmission	$ 0.9415850	Line 25 / Line 7	31
32				32
33				33
34	Summer Maximum On-Peak Period Demand Rates (Rounded)	$/kW		34
35	Secondary	$ 0.9798457	Line 29, Rounded to 7 Decimal Places	35
36	Primary	$ 0.9471568	Line 30, Rounded to 7 Decimal Places	36
37	Transmission	$ 0.9415850	Line 31, Rounded to 7 Decimal Places	37
38				38

NOTES:

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

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

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

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

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

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

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

Line No.	Description	Derivation of Commodity Rate & Proof of Revenues Calculation	Reference	Line No.
1	Winter Maximum On-Peak Period Demands By Voltage Level @ Meter Level (MW) [4]			1
2	Secondary	9,457	Section 2.3.1; Page 15; Col. B; Line 35	2
3	Primary	2,043	Section 2.3.1; Page 15; Col. B; Line 36	3
4	Transmission	277	Section 2.3.1; Page 15; Col. B; Line 37	4
5	Total	11,777	Sum Lines 3; 4; 5	5
6	Winter Maximum On-Peak Period Demands @ Transmission Level (MW)			6
7	Secondary	9,889	Section 2.3.1; Page 15; Col. D; Line 35	7
8	Primary	2,065	Section 2.3.1; Page 15; Col. D; Line 36	8
9	Transmission	277	Section 2.3.1; Page 15; Col. D; Line 37	9
10	Total	12,231	Sum Lines 3; 4; 5	10
11	Winter Maximum On-Peak Period Allocation to Voltage Levels			11
12	Secondary	80.85%	Line 7 / Line 10	12
13	Primary	16.88%	Line 8 / Line 10	13
14	Tranmission	2.26%	Line 9 / Line 10	14
15	Total	100.00%	Sum Lines 12; 13; 14	15
16	Share of Total Revenue Allocation to Winter Peak Period (October through April)	20.00%		16
17	Revenues for Proposed Winter Maximum On-Peak Period Demand Rates			17
18	Secondary	$ 1,903	(Page 7; Line 2 x Page 8; Line 16) x Line 12	18
19	Primary	$ 397	(Page 7; Line 2 x Page 8; Line 16) x Line 13	19
20	Transmission	$ 53	(Page 7; Line 2 x Page 8; Line 16) x Line 14	20
21	Total	$ 2,353	Sum Lines 18; 19; 20	21
22	Winter Maximum On-Peak Period Demand Rates [5]	$/kW		22
23	Secondary	$ 0.2012271	Line 18 / Line 2	23
24	Primary	$ 0.1943076	Line 19 / Line 3	24
25	Transmission	$ 0.1916601	Line 20 / Line 4	25
26				26
27	Winter Maximum On-Peak Period Demand Rates (Rounded)	$/kW		27
28	Secondary	$ 0.2012271	Line 23, Rounded to 7 Decimal Places	28
29	Primary	$ 0.1943076	Line 24, Rounded to 7 Decimal Places	29
30	Transmission	$ 0.1916601	Line 25, Rounded to 7 Decimal Places	30
31				31
32	Proof of Revenue Calculations:			32
33	Secondary	$ 9,564	(Page 7; Line 23) + (Page 8; Line 18)	33
34	Primary	$ 2,029	(Page 7; Line 24) + (Page 8; Line 19)	34
35	Transmission	$ 175	(Page 7; Line 25) + (Page 8; Line 20)	35
36	Total	$ 11,768	Sum Lines 33; 34; 35	36
37	Difference	$ 1	Page 7; Line 2 - Page 8; Line 36	37
38				38

NOTES:

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

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

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

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

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

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

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

Line No.	Description	Derivation of Commodity Rate & Proof of Revenues Calculation	Reference	Line No.
1	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]	$ 677	Section 2.3.1; Page 6; Line 50	2
3				3
4	Summer Maximum Demand at the Time of System Peak By Voltage Level @ Meter Level (MW) [2]			4
5	Secondary	-	Section 2.3.1; Page 15; Col. B; Line 42	5
6	Primary	47	Section 2.3.1; Page 15; Col. B; Line 43	6
7	Transmission	465	Section 2.3.1; Page 15; Col. B; Line 44	7
8	Total	512	Sum Lines 5; 6; 7	8
9				9
10	Summer Maximum Demand at the Time of System Peak @ Transmission Level (MW)			10
11	Secondary	-	Section 2.3.1; Page 15; Col. D; Line 42	11
12	Primary	48	Section 2.3.1; Page 15; Col. D; Line 43	12
13	Transmission	465	Section 2.3.1; Page 15; Col. D; Line 44	13
14	Total	513	Sum Lines 11; 12; 13	14
15				15
16	Summer Maximum Demand at the time of System Peak Allocation to Voltage Levels (MW)			16
17	Secondary	0.00%	Line 11 / Line 14	17
18	Primary	9.36%	Line 12 / Line 14	18
19	Transmission	90.64%	Line 13 / Line 14	19
20	Total	100.00%	Sum Lines 17; 18; 19	20
21	Share of Total Revenue Allocation to Summer Maximum Demand at the Time of System Peak	80.00%		21
22	Revenues for Proposed Summer Maximum Demand at the Time of System Peak Rates			22
23	Secondary	$ -	(Line 2 x Line 21) x Line 17	23
24	Primary	$ 51	(Line 2 x Line 21) x Line 18	24
25	Transmission	$ 491	(Line 2 x Line 21) x Line 19	25
26	Total	$ 542	Sum Lines 23; 24; 25	26
27				27
28	Summer Maximum Demand at the Time of System Peak Rates [3]	$/kW		28
29	Secondary	$ -	Line 23 / Line 5	29
30	Primary	$ 1.0760029	Line 24 / Line 6	30
31	Transmission	$ 1.0557041	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	$ 1.0760029	Line 30, Rounded to 7 Decimal Places	36
37	Transmission	$ 1.0557041	Line 31, Rounded to 7 Decimal Places	37
38				38

NOTES:

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

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

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

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

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

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

Line No.	Description		Derivation of Commodity Rate & Proof of Revenues Calculation	Reference	Line No.
1	Winter Maximum Demand at the Time of System Peak By Voltage Level @ Meter Level (MW) [4]				1
2	Secondary		-	Section 2.3.1; Page 15; Col. B; Line 47	2
3	Primary		88	Section 2.3.1; Page 15; Col. B; Line 48	3
4	Transmission		570	Section 2.3.1; Page 15; Col. B; Line 49	4
5	Total		658	Sum Lines 2; 3; 4	5
6					6
7	Winter Maximum Demand at the Time of System Peak @ Transmission Level (MW)				7
8	Secondary		-	Section 2.3.1; Page 15; Col. D; Line 47	8
9	Primary		89	Section 2.3.1; Page 15; Col. D; Line 48	9
10	Transmission		570	Section 2.3.1; Page 15; Col. D; Line 49	10
11	Total		659	Sum Lines 8; 9; 10	11
12					12
13	Winter Maximum Demand at the Time of System Peak Allocation to Voltage Levels				13
14	Secondary		0.00%	Line 8 / Line 11	14
15	Primary		13.51%	Line 9 / Line 11	15
16	Transmission		86.49%	Line 10 / Line 11	16
17	Total		100.00%	Sum Lines 14; 15; 16	17
18	Share of Total Revenue Allocation to Winter Maximum Demand at the Time of System Peak		20.00%		18
19	Revenues for Proposed Winter Maximum Demand at the Time of System Peak Rates				19
20	Secondary	$	-	(Page 9; Line 2 x Page 10; Line 18) x Line 14	20
21	Primary	$	18	(Page 9; Line 2 x Page 10; Line 18) x Line 15	21
22	Transmission	$	117	(Page 9; Line 2 x Page 10; Line 18) x Line 16	22
23	Total	$	135	Sum Lines 20; 21; 22	23
24					24
25	Winter Maximum Demand at the Time of System Peak Rates [5]		$/kW		25
26	Secondary	$	-	Line 20 / Line 2	26
27	Primary	$	0.2045328	Line 21 / Line 3	27
28	Transmission	$	0.2053616	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	$	0.2045328	Line 27, Rounded to 7 Decimal Places	32
33	Transmission	$	0.2053616	Line 28, Rounded to 7 Decimal Places	33
34					34
35	Proof of Revenue Calculations:				35
36	Secondary	$	-	(Page 9; Line 23) + (Page 10; Line 20)	36
37	Primary	$	69	(Page 9; Line 24) + (Page 10; Line 21)	37
38	Transmission	$	608	(Page 9; Line 25) + (Page 10; Line 22)	38
39	Total	$	677	Sum Lines 36; 37; 38	39
40	Difference	$	0	Page 9; Line 2 - Page 10; Line 39	40

NOTES:

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

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

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

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

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

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

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

Line No.	Description	Derivation of Commodity Rate & Proof of Revenues Calculation	Reference	Line No.
1	Street Lighting - Allocated Transmission Revenue Requirement	$ 1,017	Section 2.3.1; Page 2; Line 7	1
2				2
3	Billing Determinants - Street Lighting Customers (MWh) [1]:	117,138	Statement 2.3.1; Page 15; Line 9	3
4				4
5	Rate Per kWh Calculation	$ 0.0086821	Line 1 / Line 3	5
6				6
7	Rate Per kWh Calculation - Rounded	$ 0.0086821	Line 5, Rounded to 7 Decimal Places	7
8				8
9	Proof of Revenues:	$ 1,017	Line 3 x Line 7	9
10				10
11	Difference	$ -	Line 1 - Line 9	11

NOTES:

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

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

Line No.	Description	Derivation of Standby Surcharge & Proof of Revenues Calculation	Reference	Line No.
1	Standby - Demand Revenue Requirement	$ 3,474	Section 2.3.1; Page 2; Line 8	1
2	*Demand Determinants @ Transmission Level Used to Allocate*			2
3	*Total Class Revenues to Voltage Level with Loss Factor Adjustment (MW)* [1]*:*			3
4	Secondary	152	Section 2.3.1; Page 15; Col. D; Line 57	4
5	Primary	1,014	Section 2.3.1; Page 15; Col. D; Line 58	5
6	Tranmission	593	Section 2.3.1; Page 15; Col. D; Line 59	6
7	Total	1,759	Sum Lines 4; 5; 6	7
8	*Allocation Factors Per Above to Allocate*			8
9	*Demand Revenue Requirements to Voltage Level:*			9
10	Secondary	8.64%	Line 4 / Line 7	10
11	Primary	57.65%	Line 5 / Line 7	11
12	Tranmission	33.71%	Line 6 / Line 7	12
13	Total	100.00%	Sum Lines 10; 11; 12	13
14				14
15	Allocation of Revenue Requirements to Voltage Level			15
16	Secondary	$ 300	Line 1 x Line 10	16
17	Primary	$ 2,003	Line 1 x Line 11	17
18	Tranmission	$ 1,171	Line 1 x Line 12	18
19	Total	$ 3,474	Sum Lines 16; 17; 18	19
20				20
21	Demand Determinants By Voltage Level @ Meter (MW)			21
22	Secondary	145	Section 2.3.1; Page 15; Col. B; Line 57	22
23	Primary	1,003	Section 2.3.1; Page 15; Col. B; Line 58	23
24	Tranmission	593	Section 2.3.1; Page 15; Col. B; Line 59	24
25	Total	1,741	Sum Lines 22; 23; 24	25
26				26
27	Demand Rate By Voltage Level @ Meter			27
28	Secondary	$ 2.0688656	Line 16 / Line 22	28
29	Primary	$ 1.9970548	Line 17 / Line 23	29
30	Tranmission	$ 1.9737263	Line 18 / Line 24	30
31				31
32	Demand Rate By Voltage Level @ Meter (Rounded)			32
33	Secondary	$ 2.0688656	Line 28, Rounded to 7 Decimal Places	33
34	Primary	$ 1.9970548	Line 29, Rounded to 7 Decimal Places	34
35	Tranmission	$ 1.9737263	Line 30, Rounded to 7 Decimal Places	35
36				36
37	Proof of Revenue Calculations:			37
38	Secondary	$ 300	Line 22 x Line 33	38
39	Primary	$ 2,003	Line 23 x Line 34	39
40	Tranmission	$ 1,171	Line 24 x Line 35	40
41	Total	$ 3,474	Sum Lines 38; 39; 40	41
42				42
43	Difference	$ -	Line 1 - Line 41	43

NOTES:

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

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

Line No.	Customer Classes	(A) Total Revenues Per Cost of Service Study	(B) Total Revenues Per Rate Design	(C) Difference	Reference	Line No.
1	Residential Customers	$ 109,532	$ 109,532	$ -	Section 2.3.1; Pages 2 & 3	1
2						2
3	Small Commercial	33,733	33,733	-	Statement 2.3.1; Pages 2 & 4	3
4						4
5	Medium-Large Commercial	129,825	129,826	(1)	Statement 2.3.1; Pages 2 & 5	5
6						6
7	Street Lighting	1,017	1,017	-	Statement 2.3.1; Pages 2 & 11	7
8						8
9	Standby Revenues	3,474	3,474	-	Statement 2.3.1; Pages 2 & 12	9
10						10
11	Grand Total	$ 277,581	$ 277,582	$ (1)	Sum Lines 1 thru 9	11

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Section 2.3.1

SAN DIEGO GAS AND ELECTRIC COMPANY

TO3-Cycle 5 Annual Transmission Formulaic Rate Filing

Derivation of Retail True-Up Cos of Service Rates

For the True-Up Period - (April 1, 2010 - March 31, 2011)

Development of 12-CP Allocation Factors Using Recorded Data: 2004-2008

Line No.	(a) Customer Class	(b) 5-Year Average Of 12 CPs Kilowat @ Meter Level	(c) Transmission Loss Factors	(d) = (b) x (c) 5-Year Average Of 12 CPs Kilowat @ Transmission Level	(e) Ratio	(g) Reference	Line No.
1	5 Year Average - 12CP Allocation Factors:						1
2	Residential Customers	15,054,815	1.0457	15,742,820	39.46%	Statement BB; Page 1; Line 1	2
3	Small Commercial Customers	4,636,436	1.0457	4,848,321	12.15%	Statement BB; Page 1; Line 2	3
4	Medium-Large Commercial Customers						4
5	Secondary	13,510,244	1.0457	14,127,662	35.41%	Statement BB; Page 1; Line 4	5
6	Primary	3,295,181	1.0108	3,330,769	8.35%	Statement BB; Page 1; Line 5	6
7	Transmission	1,201,031	1.0000	1,201,031	3.01%	Statement BB; Page 1; Line 6	7
8	Total Medium-Large Commercial	18,006,456	1.0363	18,659,462	46.77%	Sum Lines 5; 6; 7	8
9							9
10	Street Lighting	139,791	1.0457	146,179	0.37%	Statement BB; Page 1; Line 9	10
11	Standby Customers						11
12	Secondary	38,310	1.0457	40,061	0.10%	Statement BB; Page 1; Line 11	12
13	Primary	293,448	1.0108	296,617	0.74%	Statement BB; Page 1; Line 12	13
14	Transmission	162,697	1.0000	162,697	0.41%	Statement BB; Page 1; Line 13	14
15	Total Standby Customers	494,455	1.0100	499,375	1.25%	Sum Lines 12; 13; 14	15
16							16
17	System Total	38,331,953	1.0408	39,896,157	100.00%	Sum Lines 2; 3; 8; 10; 15	17
18							18

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

Line No.	(A) Customer Class	(B) Recorded Demand Determinants Megawatt @ Meter Level	(C) Transmission Loss Factors	(D) = (B) x (C) Recorded Demand Determinants Megawatt @ Transmission Level	(E) Ratios	Reference	Line No.
1	Recorded Demand Determinants for Medium-Large Commercial Customers:						1
2	Non-Coincident Demand Determinants Pertaining to Customers on Schedules @ 100% NCD Rate						2
3	Secondary [1]	976	1.0457	1,021	87.94%	Col. B=Page 15.1; Col. E; Line 3	3
4	Primary [2]	139	1.0108	140	12.06%	Col. B=Page 15.1; Col. E; Line 4	4
5	Transmission [3]	-	1.0000	-	0.00%	Col. B=Page 15.1; Col. E; Line 5	5
6	Total	1,115		1,161	100.00%	Sum Lines 3; 4; 5	6
7							7
8	Non-Coincident Demand Determinants Pertaining to Customers on Schedules @ 90% NCD Rate						8
9	with Maximum On-Peak Period Demand						9
10	Secondary	20,261	1.0457	21,187	83.19%	Col. B=Page 15.1; Col. E; Line 10	10
11	Primary	3,981	1.0108	4,024	15.80%	Col. B=Page 15.1; Col. E; Line 11	11
12	Transmission	256	1.0000	256	1.01%	Col. B=Page 15.1; Col. E; Line 12	12
13	Total	24,498		25,467	100.00%	Sum Lines 10; 11; 12	13
14							14
15	Non-Coincident Demand Determinants Pertaining to Customers on Schedules @ 90% NCD Rate						15
16	with Maximum Demand at the Time of System Peak						16
17	Secondary	-	1.0457	-	0.00%	Col. B=Page 15.1; Col. E; Line 17	17
18	Primary	160	1.0108	162	11.06%	Col. B=Page 15.1; Col. E; Line 18	18
19	Transmission	1,303	1.0000	1,303	88.94%	Col. B=Page 15.1; Col. E; Line 19	19
20	Total	1,463		1,465	100.00%	Sum Lines 17; 18; 19	20
21							21
22	Total Non-Coincident Demand Determinants Pertaining to Medium-Large Commercial Customers						22
23	Secondary	21,237	1.0457	22,208	79.05%	Sum Lines 3; 10; 17	23
24	Primary	4,280	1.0108	4,326	15.40%	Sum Lines 4; 11; 18	24
25	Transmission	1,559	1.0000	1,559	5.55%	Sum Lines 5; 12; 19	25
26	Total	27,076		28,093	100.00%	Sum Lines 23; 24; 25	26
27							27
28	Maximum On-Peak Period Demand Determinants						28
29	Summer Months = (May, June, July, August, September)						29
30	Secondary	7,819	1.0457	8,176	81.37%	Col. B=Page 15.1; Col. E; Line 30	30
31	Primary	1,723	1.0108	1,742	17.34%	Col. B=Page 15.1; Col. E; Line 31	31
32	Transmission	130	1.0000	130	1.29%	Col. B=Page 15.1; Col. E; Line 32	32
33	Total	9,671		10,048	100.00%	Sum Lines 30; 31; 32	33
34	Winter Months = (October, November, December, January, February, March, April)						34
35	Secondary	9,457	1.0457	9,889	80.85%	Col. B=Page 15.1; Col. E; Line 35	35
36	Primary	2,043	1.0108	2,065	16.88%	Col. B=Page 15.1; Col. E; Line 36	36
37	Transmission	277	1.0000	277	2.26%	Col. B=Page 15.1; Col. E; Line 37	37
38	Total	11,777		12,231	99.99%	Sum Lines 35; 36; 37	38
39	Grand Total	21,448		22,279			39
40	Maximum Demand at the Time of System Peak Determinants						40
41	Summer						41
42	Secondary	-	1.0457	-	0.00%	Col. B=Page 15.1; Col. E; Line 42	42
43	Primary	47	1.0108	48	9.36%	Col. B=Page 15.1; Col. E; Line 43	43
44	Transmission	465	1.0000	465	90.64%	Col. B=Page 15.1; Col. E; Line 44	44
45	Total	512		513	100.00%	Sum Lines 42; 43; 44	45
46	Winter						46
47	Secondary	-	1.0457	-	0.00%	Col. B=Page 15.1; Col. E; Line 47	47
48	Primary	88	1.0108	89	13.51%	Col. B=Page 15.1; Col. E; Line 48	48
49	Transmission	570	1.0000	570	86.49%	Col. B=Page 15.1; Col. E; Line 49	49
50	Total	658		659	100.00%	Sum Lines 47; 48; 49	50
51	Grand Total	1,170		1,172			51
52							52
53		Recorded Demand		Recorded Demand			53
54		Determinants		Determinants			54
55		Megawatt @	Transmission	Megawatt @			55
56	Forecast Demand Determinants for Standby Customers:	Meter Level	Loss Factors	Transmission Level	Ratios		56
57	Contracted Demand Determinants						57
58	Secondary	145	1.0457	152	8.64%	Col. B=Page 16.3; Line 114	58
59	Primary	1,003	1.0108	1,014	57.65%	Col. B=Page 16.3; Line 115	59
60	Transmission	593	1.0000	593	33.71%	Col. B=Page 16.3; Line 116	60
61	Total	1,741		1,759	100.00%	Sum Lines 57; 58; 59	61

Section 2.3.1

San Diego Gas & Electric

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

Line No.															Line No.
1	**SDG&E: System Delivery Determinants**	Winter	Summer	Summer	Summer	Summer	Summer	Winter	Winter	Winter	Winter	Winter	Winter	Total	1
2															2
3	**Customer Class Deliveries (MWh)**	**Apr-10**	**May-10**	**Jun-10**	**Jul-10**	**Aug-10**	**Sep-10**	**Oct-10**	**Nov-10**	**Dec-10**	**Jan-11**	**Feb-11**	**Mar-11**	**Total**	3
4	Residential	560,384	517,201	550,609	593,511	590,340	686,248	639,924	589,348	671,935	724,209	628,060	609,744	7,361,513	4
5.	Small Commercial	157,999	137,325	162,432	177,346	163,651	189,247	177,357	162,507	164,000	171,088	159,604	160,245	1,982,802	5
6	Med. & Large Comm./Ind. (AD + PA-T-1)	21,162	19,894	24,223	27,331	27,123	30,064	26,805	20,895	19,901	17,916	19,926	20,362	275,603	6
7	Med. & Large Comm./Ind. (AL + AY + DGR)	708,903	692,577	744,964	827,532	755,332	871,898	817,218	756,976	723,654	772,108	698,123	742,483	9,111,768	7
8	Med. & Large Comm./Ind. (A6)	65,251	72,160	71,462	72,343	55,478	68,178	71,130	64,163	70,265	57,890	61,242	51,383	780,945	8
9	Lighting	12,741	6,011	9,449	9,467	9,718	8,583	10,585	9,387	12,835	6,110	9,498	12,754	117,138	9
10	Sale for Resale	1.5	0.0	3.5	0.0	1.5	0.0	6.4	0.0	2.1	1.7	3.6	0.0	20.4	10
11	**Total System**	**1,526,442**	**1,445,170**	**1,563,143**	**1,707,530**	**1,601,644**	**1,854,218**	**1,743,026**	**1,603,276**	**1,662,591**	**1,749,324**	**1,576,456**	**1,596,971**	**19,629,791**	11
12															12
13	**Med. & Large Comm./Ind.**														13
14	**Rate Schedule Billing Determinants**														14
15															15
16	**Schedules AD / PA-T-1:**	**Apr-10**	**May-10**	**Jun-10**	**Jul-10**	**Aug-10**	**Sep-10**	**Oct-10**	**Nov-10**	**Dec-10**	**Jan-11**	**Feb-11**	**Mar-11**	**Total**	16
17	**Total Deliveries (MWh)**	21,162	19,894	24,223	27,331	27,123	30,064	26,805	20,895	19,901	17,916	19,926	20,362	275,603	17
18															18
19	**Total Deliveries (%)**														19
20	% @ Secondary Service	91.58%	93.78%	93.65%	93.60%	91.70%	91.23%	90.41%	91.34%	91.56%	87.21%	85.53%	90.30%	91.15%	20
21	% @ Primary Service	8.42%	6.22%	6.35%	6.40%	8.30%	8.77%	9.59%	8.66%	8.44%	12.79%	14.47%	9.70%	8.85%	21
22	% @ Transmission Service	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	22
23		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	23
24	**Total Deliveries (MWh)**														24
25	MWh @ Secondary Service	19,380	18,657	22,685	25,582	24,872	27,427	24,234	19,085	18,221	15,625	17,043	18,387	251,199	25
26	MWh @ Primary Service	1,782	1,237	1,538	1,749	2,251	2,637	2,571	1,809	1,680	2,292	2,883	1,975	24,404	26
27	MWh @ Transmission Service	0	0	0	0	0	0	0	0	0	0	0	0	0	27
28		21,162	19,894	24,223	27,331	27,123	30,064	26,805	20,895	19,901	17,916	19,926	20,362	275,603	28
29	**Non-Coincident Demand (%)**														29
30	% @ Secondary Service	0.4645%	0.3810%	0.3496%	0.3242%	0.3390%	0.3116%	0.3507%	0.4303%	0.4382%	0.4666%	0.4670%	0.4543%	0.3886%	30
31	% @ Primary Service	0.4508%	0.7382%	0.8706%	0.6807%	0.5423%	0.4609%	0.4693%	0.6266%	0.6114%	0.5588%	0.5323%	0.5140%	0.5688%	31
32	% @ Transmission Service	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	32
33															33
34	**Non-Coincident Demand (MW)**														34
35	MW @ Secondary Service	90.020	71.082	79.308	82.936	84.316	85.463	84.989	82.124	79.846	72.906	79.589	83.533	976.113	35
36	MW @ Primary Service	8.032	9.135	13.392	11.907	12.208	12.152	12.064	11.338	10.269	12.805	15.348	10.152	138.802	36
37	MW @ Transmission Service	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	37
38		98.052	80.217	92.699	94.843	96.525	97.615	97.053	93.463	90.115	85.711	94.937	93.686	1,114.915	38
39															39
40															40
41															41

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San Diego Gas & Electric

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

Line No.	Schedules AL-TOU / AY-TOU / DG-R:	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Total	Line No.
43	Total Deliveries (MWh)	708,903	692,577	744,964	827,532	755,332	871,898	817,218	756,976	723,654	772,108	698,123	742,483	9,111,768	43
44															44
45	Total Deliveries (%)														45
46	% @ Secondary Service	79.27%	78.43%	82.11%	79.43%	78.58%	80.34%	77.71%	78.07%	81.77%	79.54%	79.60%	81.39%	79.68%	46
47	% @ Primary Service	19.02%	20.66%	17.19%	19.92%	20.47%	18.67%	19.01%	19.23%	17.28%	19.44%	19.90%	17.48%	19.02%	47
48	% @ Transmission Service	1.71%	0.91%	0.70%	0.65%	0.95%	0.99%	3.28%	2.70%	0.95%	1.02%	0.50%	1.13%	1.30%	48
49		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	49
50	Total Deliveries (MWh)														50
51	MWh @ Secondary Service	561,948	543,188	611,690	657,309	593,540	700,483	635,060	590,971	591,732	614,135	555,706	604,307	7,260,068	51
52	MWh @ Primary Service	134,833	143,086	128,059	164,844	154,616	162,783	155,353	145,567	125,047	150,098	138,926	129,786	1,733,001	52
53	MWh @ Transmission Service	12,122	6,302	5,215	5,379	7,176	8,632	26,805	20,438	6,875	7,876	3,491	8,390	118,700	53
54		708,903	692,577	744,964	827,532	755,332	871,898	817,218	756,976	723,654	772,108	698,123	742,483	9,111,768	54
55	Non-Coincident Demand (%)														55
56	% @ Secondary Service	0.2810%	0.2688%	0.2705%	0.2744%	0.2793%	0.2709%	0.2955%	0.2984%	0.2822%	0.2792%	0.2768%	0.2723%	0.2791%	56
57	% @ Primary Service	0.2376%	0.2190%	0.2213%	0.2386%	0.2236%	0.2289%	0.2400%	0.2369%	0.2403%	0.2205%	0.2216%	0.2273%	0.2297%	57
58	% @ Transmission Service	0.1981%	0.2219%	0.2323%	0.2659%	0.2727%	0.2418%	0.2261%	0.1460%	0.2803%	0.2419%	0.3092%	0.1336%	0.2154%	58
59															59
60	Non-Coincident Demand (MW)														60
61	MW @ Secondary Service	1,579.073	1,460.090	1,654.621	1,803.656	1,657.757	1,897.608	1,876.603	1,763.458	1,669.866	1,714.665	1,538.193	1,645.528	20,261.118	61
62	MW @ Primary Service	320.364	313.359	283.395	393.319	345.722	372.611	372.848	344.847	300.489	330.966	307.861	295.004	3,980.785	62
63	MW @ Transmission Service	24.014	13.985	12.114	14.303	19.568	20.872	60.606	29.840	19.270	19.051	10.793	11.209	255.624	63
64		1,923.452	1,787.434	1,950.130	2,211.277	2,023.047	2,291.090	2,310.056	2,138.145	1,989.625	2,064.681	1,856.847	1,951.741	24,497.526	64
65	On-Peak Demand (%)														65
66	% @ Secondary Service	0.2265%	0.2275%	0.2503%	0.2580%	0.2621%	0.2570%	0.2522%	0.2346%	0.2213%	0.2198%	0.2191%	0.2183%	0.2380%	66
67	% @ Primary Service	0.1996%	0.2075%	0.2313%	0.2366%	0.2323%	0.2339%	0.2293%	0.2085%	0.2107%	0.1977%	0.2061%	0.2063%	0.2173%	67
68	% @ Transmission Service	0.3645%	0.4230%	0.5473%	0.4202%	0.3757%	0.2874%	0.2268%	0.2739%	0.6176%	0.3522%	0.3647%	0.3891%	0.3421%	68
69	Maximum On-Peak Period Demand (MW)														69
70	On-Peak Demand (MW)	Winter	Summer	Summer	Summer	Summer	Summer	Winter	Winter	Winter	Winter	Winter	Winter	Total	70
71	MW @ Secondary Service	1,272.812	1,235.753	1,531.060	1,695.857	1,555.668	1,800.241	1,601.622	1,386.419	1,309.502	1,349.869	1,217.551	1,319.202	17,275.554	71
72	MW @ Primary Service	269.128	296.904	296.201	390.022	359.174	380.750	356.225	303.506	263.475	296.743	286.327	267.749	3,766.204	72
73	MW @ Transmission Service	44.186	26.659	28.540	22.602	26.959	24.808	60.793	55.981	42.458	27.738	12.730	32.646	406.100	73
74		1,586.125	1,559.317	1,855.801	2,108.481	1,941.801	2,205.799	2,018.640	1,745.906	1,615.435	1,674.350	1,516.609	1,619.596	21,447.858	74
75															75
76															76
77															77

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Section 2.3.1

San Diego Gas & Electric

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

Line No.															Line No.
78	Schedule A6-TOU:	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Total	78
79	Total Deliveries (MWh)	65,251	72,160	71,462	72,343	55,478	68,178	71,130	64,163	70,265	57,890	61,242	51,383	780,945	79
80															80
81	Total Deliveries (%)														81
82	% @ Secondary Service	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	82
83	% @ Primary Service	13.38%	6.55%	9.47%	11.89%	8.21%	14.54%	8.86%	7.59%	15.37%	8.27%	13.71%	20.59%	11.40%	83
84	% @ Transmission Service	86.62%	93.45%	90.53%	88.11%	91.79%	85.46%	91.14%	92.41%	84.63%	91.73%	86.29%	79.41%	88.60%	84
85		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	85
86	Total Deliveries (MWh)														86
87	MWh @ Secondary Service	0	0	0	0	0	0	0	0	0	0	0	0	0	87
88	MWh @ Primary Service	8,731	4,726	6,767	8,602	4,555	9,913	6,302	4,870	10,800	4,788	8,396	10,580	89,029	88
89	MWh @ Transmission Service	56,521	67,434	64,694	63,741	50,923	58,265	64,828	59,293	59,465	53,103	52,846	40,803	691,916	89
90		65,251	72,160	71,462	72,343	55,478	68,178	71,130	64,163	70,265	57,890	61,242	51,383	780,945	90
91	Non-Coincident Demand (%)														91
92	% @ Secondary Service	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	92
93	% @ Primary Service	0.1456%	0.1068%	0.1203%	0.1390%	0.1158%	0.1729%	0.0952%	0.1239%	0.1838%	0.4118%	0.2249%	0.2801%	0.1802%	93
94	% @ Transmission Service	0.1748%	0.1868%	0.1658%	0.1926%	0.1977%	0.1984%	0.1926%	0.1928%	0.1908%	0.1917%	0.1798%	0.2022%	0.1883%	94
95															95
96	Non-Coincident Demand (MW)														96
97	MW @ Secondary Service	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	97
98	MW @ Primary Service	12.712	5.048	8.141	11.956	5.274	17.140	6.000	6.034	19.850	19.715	18.883	29.634	160.387	98
99	MW @ Transmission Service	98.798	125.966	107.263	122.766	100.676	115.598	124.859	114.316	113.460	101.798	95.017	82.504	1,303.020	99
100		111.510	131.014	115.404	134.722	105.950	132.738	130.859	120.350	133.310	121.513	113.900	112.138	1,463.407	100
101	Coincident Peak Demand (%)														101
102	% @ Secondary Service	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	102
103	% @ Primary Service	0.1613%	0.1705%	0.1914%	0.1550%	0.0572%	0.1054%	0.1824%	0.1712%	0.1941%	0.1286%	0.1544%	0.1324%	0.1521%	103
104	% @ Transmission Service	0.1171%	0.1495%	0.1398%	0.1564%	0.1398%	0.1767%	0.1630%	0.1914%	0.1144%	0.1520%	0.1407%	0.1502%	0.1496%	104
105	Coincident Demand at Time of System of Peak														105
106	Coincident Peak Demand (MW)	Winter	Summer	Summer	Summer	Summer	Summer	Winter	Winter	Winter	Winter	Winter	Winter	Total	106
107	MW @ Secondary Service	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	107
108	MW @ Primary Service	14.082	8.059	12.953	13.332	2.605	10.448	11.495	8.337	20.962	6.157	12.964	14.008	135.403	108
109	MW @ Transmission Service	66.186	100.813	90.443	99.691	71.191	102.954	105.670	113.486	68.028	80.716	74.354	61.286	1,034.819	109
110		80.268	108.872	103.395	113.024	73.796	113.403	117.165	121.824	88.991	86.873	87.318	75.294	1,170.222	110
111															111
112	Schedule S: Standby Determinants:	Apr-10	May-10	Jun-09	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Total	112
113	Contracted Standby Demand (MW)														113
114	MW @ Secondary Service	11.224	11.224	11.226	11.124	11.124	11.123	12.075	12.075	13.498	13.498	13.408	13.408	145.007	114
115	MW @ Primary Service	84.822	85.002	85.316	85.022	84.287	84.287	80.481	80.481	83.769	83.386	82.725	83.399	1,002.977	115
116	MW @ Transmission Service	46.948	47.715	47.692	49.986	49.986	49.986	50.003	50.003	50.156	50.272	50.272	50.275	593.294	116
117		142.994	143.941	144.234	146.132	145.397	145.396	142.559	142.559	147.423	147.156	146.405	147.082	1,741.278	117
118															118
119															119
120															120

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Section – 2

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

Section 2.3.2

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

Docket No. ER11-4318-000

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

Line No.	Customer Classes	(a) Transmission Revenues @ Proposed Rates	(b) True-Up Period Total Cost of Service	(c) = (a) - (b) ($) Change	(d) = (c)/(a) (%) Change	Reference	Line No.
1	Residential Customers	$ 109,531,958	$ 109,532,000	$ (42)	0.00%	(a)=Section 2.3.2; Page 2; Line 1	1
2						(b)=Section 2.3.1; Page 2; Line 4	2
3	Small Commercial Customers	33,733,013	$ 33,733,000	$ 13	0.00%	(a)=Section 2.3.2; Page 2; Line 3	3
4						(b)=Section 2.3.1; Page 2; Line 5	4
5	Medium-Large Commercial Customers	129,824,942	$ 129,825,000	$ (58)	0.00%	(a)=Section 2.3.2; Page 2; Line 5	5
6						(b)=Section 2.3.1; Page 2; Line 6	6
7	Street Lighting Customers	1,017,005	$ 1,017,000	$ 5	0.00%	(a)=Section 2.3.2; Page 2; Line 7	7
8						(b)=Section 2.3.1; Page 2; Line 7	8
9	Standby Customers	3,474,001	$ 3,474,000	$ 1	0.00%	(a)=Section 2.3.2; Page 2; Line 9	9
10						(b)=Section 2.3.1; Page 2; Line 8	10
11	Grand Total	$ 277,580,919	$ 277,581,000	$ (81)	0.00%	Sum Lines 1 through 9	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, 2010 - March 31, 2011

Line No.	Season / Customer Class	(A) Apr-10 Winter	(B) May-10 Summer	(C) Jun-10 Summer	(D) Jul-10 Summer	(E) Aug-10 Summer	(F) Sep-10 Summer	(G) Oct-10 Winter	(H) Nov-10 Winter	(I) Dec-10 Winter	(J) Jan-11 Winter	(K) Feb-11 Winter	(L) Mar-11 Winter	(M) Total	Line No.
1	Residential Customers [1]	$ 8,337,954	$ 7,695,441	$ 8,192,505	$ 8,830,854	$ 8,783,671	$ 10,210,680	$ 9,521,436	$ 8,768,908	$ 9,997,719	$ 10,775,509	$ 9,344,903	$ 9,072,378	$ 109,531,958	1
2															2
3	Small Commercial [2]	2,688,013	2,336,291	2,763,431	3,017,148	2,784,158	3,219,621	3,017,345	2,764,695	2,790,091	2,910,688	2,715,312	2,726,220	33,733,013	3
4															4
5	Medium-Large Commercial [3]	9,584,864	10,289,551	11,281,471	12,746,931	11,618,171	13,197,074	11,420,347	10,568,082	9,936,485	10,199,101	9,281,118	9,701,747	129,824,942	5
6															6
7	Street Lighting [4]	110,617	52,192	82,037	82,189	84,376	74,521	91,897	81,502	111,431	53,047	82,464	110,731	1,017,005	7
8															8
9	Standby Revenues [5]	285,278	287,151	287,737	291,467	289,999	289,997	284,399	284,399	294,211	293,675	292,168	293,520	3,474,001	9
10															10
11	TOTAL	$ 21,006,725	$ 20,660,626	$ 22,607,182	$ 24,968,589	$ 23,560,375	$ 26,991,894	$ 24,335,425	$ 22,467,586	$ 23,129,938	$ 24,232,019	$ 21,715,965	$ 21,904,596	$ 277,580,919	11

NOTES:
1 See Pages 3 & 4; Line 25.
2 See Pages 3 & 4; Line 27.
3 See Pages 3 & 4; Lines 29 through 33.
4 See Pages 3 & 4; Line 35.
5 See Pages 3 & 4; Line 37.

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

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

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

Line No.	Customer Classes	(A) Apr-10 Changed Transmission Rates Energy (kWh)	(A) Apr-10 Demand (kW)	(B) May-10 Changed Transmission Rates Energy (kWh)	(B) May-10 Demand (kW)	(C) Jun-10 Changed Transmission Rates Energy (kWh)	(C) Jun-10 Demand (kW)	(D) Jul-10 Changed Transmission Rates Energy (kWh)	(D) Jul-10 Demand (kW)	(E) Aug-10 Changed Transmission Rates Energy (kWh)	(E) Aug-10 Demand (kW)	(F) Sep-10 Changed Transmission Rates Energy (kWh)	(F) Sep-10 Demand (kW)	Line No.
16	Residential Customers [1]	$ 0.0148790		$ 0.0148790		$ 0.0148790		$ 0.0148790		$ 0.0148790		$ 0.0148790		16
17														17
18	Small Commercial [1]	$ 0.0170128		$ 0.0170128		$ 0.0170128		$ 0.0170128		$ 0.0170128		$ 0.0170128		18
19														19
20	Medium-Large Commercial [1]													20
21														21
22	Street Lighting [1]	$ 0.0086821		$ 0.0086821		$ 0.0086821		$ 0.0086821		$ 0.0086821		$ 0.0086821		22
23														23
24	Standby Customers [1]													24

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

Line No.	Customer Classes	(A) Apr-10 Revenues @ Changed Rates Energy (kWh)	(A) Apr-10 Demand (kW)	(B) May-10 Revenues @ Changed Rates Energy (kWh)	(B) May-10 Demand (kW)	(C) Jun-10 Revenues @ Changed Rates Energy (kWh)	(C) Jun-10 Demand (kW)	(D) Jul-10 Revenues @ Changed Rates Energy (kWh)	(D) Jul-10 Demand (kW)	(E) Aug-10 Revenues @ Changed Rates Energy (kWh)	(E) Aug-10 Demand (kW)	(F) Sep-10 Revenues @ Changed Rates Energy (kWh)	(F) Sep-10 Demand (kW)	Line No.
25	Residential Customers	$ 8,337,954		$ 7,695,441		$ 8,192,505		$ 8,830,854		$ 8,783,671		$ 10,210,680		25
26														26
27	Small Commercial	$ 2,688,013		$ 2,336,291		$ 2,763,431		$ 3,017,148		$ 2,784,158		$ 3,219,621		27
28														28
29	Medium-Large Commercial	$ -		$ -		$ -		$ -		$ -		$ -		29
30	Non-Coincident (100%)		$ 472,540		$ 386,174		$ 445,808		$ 456,407		$ 464,484		$ 469,765	30
31	Non-Coincident (90%)		$ 8,778,966		$ 8,271,113		$ 8,918,621		$10,118,562		$ 9,185,833		$10,459,431	31
32	Maximum On-Peak Period Demand		$ 316,886		$ 1,517,164		$ 1,807,624		$ 2,052,372		$ 1,889,893		$ 2,147,947	32
33	Maximum Demand at the Time of System Peak		$ 16,472		$ 115,100		$ 109,418		$ 119,590		$ 77,960		$ 119,932	33
34														34
35	Street Lighting	$ 110,617		$ 52,192		$ 82,037		$ 82,189		$ 84,376		$ 74,521		35
36														36
37	Standby Customers		$ 285,278		$ 287,151		$ 287,737		$ 291,467		$ 289,999		$ 289,997	37
38														38
39	TOTAL	$ 11,136,584	$ 9,870,142	$ 10,083,924	$10,576,702	$ 11,037,973	$11,569,208	$ 11,930,191	$13,038,398	$ 11,652,205	$11,908,170	$ 13,504,822	$13,487,071	39
40														40
41	Grand Total		$21,006,725		$20,660,626		$22,607,182		$24,968,589		$23,560,375		$26,991,894	41

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

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

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

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

Line No.	Customer Classes	(G) Oct-10 Changed Transmission Rates Energy (kWh)	Demand (kW)	(H) Nov-10 Changed Transmission Rates Energy (kWh)	Demand (kW)	(I) Dec-10 Changed Transmission Rates Energy (kWh)	Demand (kW)	(J) Jan-11 Changed Transmission Rates Energy (kWh)	Demand (kW)	(K) Feb-11 Changed Transmission Rates Energy (kWh)	Demand (kW)	(L) Mar-11 Changed Transmission Rates Energy (kWh)	Demand (kW)	(M) Total Changed Transmission Rates Energy (kWh)	Demand (kW)	Line No.
16	Residential Customers [1]	$ 0.0148790		$ 0.0148790		$ 0.0148790		$ 0.0148790		$ 0.0148790		$ 0.0148790				16
17																17
18	Small Commercial [1]	$ 0.0170128		$ 0.0170128		$ 0.0170128		$ 0.0170128		$ 0.0170128		$ 0.0170128				18
19																19
20	Medium-Large Commercial [1]															20
21																21
22	Street Lighting [1]	$ 0.0086821		$ 0.0086821		$ 0.0086821		$ 0.0086821		$ 0.0086821		$ 0.0086821				22
23																23
24	Standby Customers [1]															24

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

Line No.	Customer Classes	(G) Oct-10 Revenues @ Changed Rates Energy (kWh)	Demand (kW)	(H) Nov-10 Revenues @ Changed Rates Energy (kWh)	Demand (kW)	(I) Dec-10 Revenues @ Changed Rates Energy (kWh)	Demand (kW)	(J) Jan-11 Revenues @ Changed Rates Energy (kWh)	Demand (kW)	(K) Feb-11 Revenues @ Changed Rates Energy (kWh)	Demand (kW)	(L) Mar-11 Revenues @ Changed Rates Energy (kWh)	Demand (kW)	(M) Total Revenues @ Changed Rates Energy (kWh)	Demand (kW)	Line No.
25	Residential Customers	$ 9,521,436		$ 8,768,908		$ 9,997,719		$ 10,775,509		$ 9,344,903		$ 9,072,378		$ 109,531,958	$ -	25
26																26
27	Small Commercial	$ 3,017,345		$ 2,764,695		$ 2,790,091		$ 2,910,688		$ 2,715,312		$ 2,726,220		$ 33,733,013	$ -	27
28																28
29	Medium-Large Commercial	$ -		$ -		$ -		$ -		$ -		$ -		$ -		29
30	Non-Coincident (100%)		$ 467,062		$ 449,829		$ 433,825		$ 412,131		$ 456,303		$ 451,097		$ 5,365,423	30
31	Non-Coincident (90%)		$10,526,074		$ 9,744,555		$ 9,161,563		$ 9,434,529		$ 8,503,814		$ 8,911,458		$ 112,014,519	31
32	Maximum On-Peak Period Demand		$ 403,159		$ 348,688		$ 322,840		$ 334,606		$ 303,080		$ 323,742		$ 11,768,000	32
33	Maximum Demand at the Time of System Peak		$ 24,052		$ 25,011		$ 18,258		$ 17,835		$ 17,921		$ 15,451		$ 677,000	33
34																34
35	Street Lighting	$ 91,897		$ 81,502		$ 111,431		$ 53,047		$ 82,464		$ 110,731		$ 1,017,005	$ -	35
36																36
37	Standby Customers		$ 284,399		$ 284,399		$ 294,211		$ 293,675		$ 292,168		$ 293,520	$ -	$ 3,474,001	37
38																38
39	TOTAL	$ 12,630,679	$11,704,746	$ 11,615,105	$10,852,481	$ 12,899,242	$10,230,696	$ 13,739,244	$10,492,776	$ 12,142,679	$ 9,573,286	$ 11,909,329	$ 9,995,267	$ 144,281,975	$ 133,298,943	39
40																40
41	Grand Total		$24,335,425		$22,467,586		$23,129,938		$24,232,019		$21,715,965		$21,904,596		$ 277,580,919	41

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

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

Line No.	Description	Winter Apr-10	Summer May-10	Summer Jun-10	Summer Jul-10	Summer Aug-10	Summer Sep-10	Winter Oct-10	Winter Nov-10	Winter Dec-10	Winter Jan-11	Winter Feb-11	Winter Mar-11	Total	Reference	Line No.
1	Energy Revenues															1
2	Commodity Sales - kWh	795,316,271	784,631,262	840,649,109	927,206,006	837,933,458	970,139,846	915,153,323	842,033,781	813,819,782	847,914,923	779,290,550	814,228,471	10,168,316,782	Section 2.3.2; Pages 9, 10 & 11; Line 5	2
3	Commodity Rate - $/kWh	-	-	-	-	-	-	-	-	-	-	-	-	-	Not Applicable	3
4	Total Commodity Revenues	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	Line 2 x Line 3	4
5																5
6	Non-Coincident Demand (100%) (kW)[1]:															6
7	Secondary	90,020	71,082	79,308	82,936	84,316	85,463	84,989	82,124	79,846	72,906	79,589	83,533	976,113	Section 2.3.2; Page 12; Line 37	7
8	Primary	8,032	9,135	13,392	11,907	12,208	12,152	12,064	11,338	10,269	12,805	15,348	10,152	138,802	Section 2.3.2; Page 12; Line 39	8
9	Transmission	-	-	-	-	-	-	-	-	-	-	-	-	-	Section 2.3.2; Page 12; Line 41	9
10	Total	98,052	80,217	92,699	94,843	96,525	97,615	97,053	93,463	90,115	85,711	94,937	93,686	1,114,915	Sum Lines 7; 8; 9	10
11	Check Figure	98,052	80,217	92,699	94,843	96,525	97,615	97,053	93,463	90,115	85,711	94,937	93,686	1,114,915	Section 2.3.2; Pages 1.1; Line 43	11
12	Difference	-	-	-	-	-	-	-	-	-	-	-	-	-	Line 10 - Line 11	12
13																13
14	Non-Coincident Demand (100%) Rates ($/kW):															14
15	Secondary	$ 4.8325038	$ 4.8325038	$ 4.8325038	$ 4.8325038	$ 4.8325038	$ 4.8325038	$ 4.8325038	$ 4.8325038	$ 4.8325038	$ 4.8325038	$ 4.8325038	$ 4.8325038		Section 2.3.1; Page 1; Line 6D	15
16	Primary	$ 4.6710569	$ 4.6710569	$ 4.6710569	$ 4.6710569	$ 4.6710569	$ 4.6710569	$ 4.6710569	$ 4.6710569	$ 4.6710569	$ 4.6710569	$ 4.6710569	$ 4.6710569		Section 2.3.1; Page 1; Line 6C	16
17	Transmission	$ 4.6226078	$ 4.6226078	$ 4.6226078	$ 4.6226078	$ 4.6226078	$ 4.6226078	$ 4.6226078	$ 4.6226078	$ 4.6226078	$ 4.6226078	$ 4.6226078	$ 4.6226078		Section 2.3.1; Page 1; Line 6B	17
18	Non-Coincident Demand (100%) - Revenues:															18
19	Secondary	$ 435,020	$ 343,505	$ 383,255	$ 400,790	$ 407,458	$ 413,002	$ 410,712	$ 396,867	$ 385,856	$ 352,318	$ 384,614	$ 403,675	$ 4,717,071	Line 7 x Line 15	19
20	Primary	37,520	42,668	62,552	55,617	57,026	56,763	56,350	52,962	47,969	59,813	71,690	47,422	$ 648,352	Line 8 x Line 16	20
21	Transmission	-	-	-	-	-	-	-	-	-	-	-	-	$ -	Line 9 x Line 17	21
22	Subtotal	$ 472,540	$ 386,174	$ 445,808	$ 456,407	$ 464,484	$ 469,765	$ 467,062	$ 449,829	$ 433,825	$ 412,131	$ 456,303	$ 451,097	$ 5,365,423	Sum Lines 19; 20; 21	22
23																23
24	Non-Coincident Demand (90%) (kW)[2]:															24
25	Secondary	1,579,073	1,460,090	1,654,621	1,803,656	1,657,757	1,897,608	1,876,603	1,763,458	1,669,866	1,714,665	1,538,193	1,645,528	20,261,118	Section 2.3.2; Page 12; Line 46	25
26	Primary	333,076	318,407	291,536	405,275	350,997	389,751	378,847	350,881	320,339	350,681	326,744	324,638	4,141,172	Section 2.3.2; Page 12; Line 47	26
27	Transmission	122,812	139,951	119,377	137,068	120,244	136,470	185,465	144,156	132,730	120,849	105,810	93,713	1,558,644	Section 2.3.2; Page 12; Line 48	27
28	Total	2,034,961	1,918,448	2,065,535	2,345,999	2,128,997	2,423,828	2,440,915	2,258,496	2,122,935	2,186,194	1,970,747	2,063,879	25,960,933	Sum Lines 25; 26; 27	28
29	Check Figure	2,034,961	1,918,448	2,065,535	2,345,999	2,128,997	2,423,828	2,440,915	2,258,496	2,122,935	2,186,194	1,970,747	2,063,879	25,960,933	Section 2.3.2; Pages 1.1; Line 49	29
30	Difference	-	-	-	-	-	-	-	-	-	-	-	-	-	Line 28 - Line 29	30
31																31
32	Non-Coincident Demand (90%) Rates ($/kW):															32
33	Secondary	$ 4.3492534	$ 4.3492534	$ 4.3492534	$ 4.3492534	$ 4.3492534	$ 4.3492534	$ 4.3492534	$ 4.3492534	$ 4.3492534	$ 4.3492534	$ 4.3492534	$ 4.3492534		Section 2.3.1; Page 1; Line 8D	33
34	Primary	$ 4.2039512	$ 4.2039512	$ 4.2039512	$ 4.2039512	$ 4.2039512	$ 4.2039512	$ 4.2039512	$ 4.2039512	$ 4.2039512	$ 4.2039512	$ 4.2039512	$ 4.2039512		Section 2.3.1; Page 1; Line 8C	34
35	Transmission	$ 4.1603470	$ 4.1603470	$ 4.1603470	$ 4.1603470	$ 4.1603470	$ 4.1603470	$ 4.1603470	$ 4.1603470	$ 4.1603470	$ 4.1603470	$ 4.1603470	$ 4.1603470		Section 2.3.1; Page 1; Line 8B	35
36	Non-Coincident Demand (90%) - Revenues:															36
37	Secondary	$ 6,867,789	$ 6,350,300	$ 7,196,367	$ 7,844,555	$ 7,210,004	$ 8,253,177	$ 8,161,821	$ 7,669,727	$ 7,262,672	$ 7,457,512	$ 6,689,993	$ 7,156,818	$ 88,120,736	Line 25 x Line 33	37
38	Primary	1,400,235	1,338,568	1,225,605	1,703,756	1,475,573	1,638,493	1,592,655	1,475,086	1,346,688	1,474,245	1,373,617	1,364,761	$ 17,409,283	Line 26 x Line 34	38
39	Transmission	510,941	582,246	496,649	570,251	500,256	567,761	771,598	599,741	552,202	502,772	440,204	389,880	$ 6,484,500	Line 27 x Line 35	39
40	Subtotal	$ 8,778,966	$ 8,271,113	$ 8,918,621	$ 10,118,562	$ 9,185,833	$ 10,459,431	$ 10,526,074	$ 9,744,555	$ 9,161,563	$ 9,434,529	$ 8,503,814	$ 8,911,458	$ 112,014,519	Sum Lines 37; 38; 39	40

NOTES:

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

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

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

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

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

Line No.	Description	Winter Apr-10	Summer May-10	Summer Jun-10	Summer Jul-10	Summer Aug-10	Summer Sep-10	Winter Oct-10	Winter Nov-10	Winter Dec-10	Winter Jan-11	Winter Feb-11	Winter Mar-11	Total	Reference	Line No.
1	Maximum On-Peak Period Demand (kW)[3]:															1
2	Secondary	1,272,812	1,235,753	1,531,060	1,695,857	1,555,668	1,800,241	1,601,622	1,386,419	1,309,502	1,349,869	1,217,551	1,319,202	17,275,554	Section 2.3.2; Pages 12; Line 17 x 1000	2
3	Primary	269,128	296,904	296,201	390,022	359,174	380,750	356,225	303,506	263,475	296,743	286,327	267,749	3,766,204	Section 2.3.2; Pages 12; Line 18 x 1000	3
4	Transmission	44,186	26,659	28,540	22,602	26,959	24,808	60,793	55,981	42,458	27,738	12,730	32,646	406,100	Section 2.3.2; Pages 12; Line 19 x 1000	4
5	Total	1,586,125	1,559,317	1,855,801	2,108,481	1,941,801	2,205,799	2,018,640	1,745,906	1,615,435	1,674,350	1,516,609	1,619,596	21,447,858	Sum Lines 2; 3; 4	5
6	Check Figure	1,586,125	1,559,317	1,855,801	2,108,481	1,941,801	2,205,799	2,018,640	1,745,906	1,615,435	1,674,350	1,516,609	1,619,596	21,447,858	Section 2.3.2; Pages 12; Line 20	6
7	Difference	-	-	-	-	-	-	-	-	-	-	-	-	-	Line 5 - Line 6	7
8																8
9	Maximum On-Peak Period Demand Rates ($/kW):	Winter	Summer	Summer	Summer	Summer	Summer	Winter	Winter	Winter	Winter	Winter	Winter			9
10	Secondary	$ 0.2012271	$ 0.9798457	$ 0.9798457	$ 0.9798457	$ 0.9798457	$ 0.9798457	$ 0.2012271	$ 0.2012271	$ 0.2012271	$ 0.2012271	$ 0.2012271	$ 0.2012271		Section 2.3.1; Page 1; Line 11D; 12D	10
11	Primary	$ 0.1943076	$ 0.9471568	$ 0.9471568	$ 0.9471568	$ 0.9471568	$ 0.9471568	$ 0.1943076	$ 0.1943076	$ 0.1943076	$ 0.1943076	$ 0.1943076	$ 0.1943076		Section 2.3.1; Page 1; Line 11C; 12C	11
12	Transmission	$ 0.1916601	$ 0.9415850	$ 0.9415850	$ 0.9415850	$ 0.9415850	$ 0.9415850	$ 0.1916601	$ 0.1916601	$ 0.1916601	$ 0.1916601	$ 0.1916601	$ 0.1916601		Section 2.3.1; Page 1; Line 11B; 12B	12
13	Maximum On-Peak Period Demand - Revenues:															13
14	Secondary	$ 256,124	$ 1,210,847	$ 1,500,202	$ 1,661,678	$ 1,524,315	$ 1,763,958	$ 322,290	$ 278,985	$ 263,507	$ 271,630	$ 245,004	$ 265,459	$ 9,564,000	Line 2 x Line 10	14
15	Primary	52,294	281,215	280,549	369,412	340,194	360,630	69,217	58,974	51,195	57,660	55,636	52,026	$ 2,029,000	Line 3 x Line 11	15
16	Transmission	8,469	25,102	26,873	21,282	25,384	23,359	11,652	10,729	8,138	5,316	2,440	6,257	$ 175,000	Line 4 x Line 12	16
17	Subtotal	$ 316,886	$ 1,517,164	$ 1,807,624	$ 2,052,372	$ 1,889,893	$ 2,147,947	$ 403,159	$ 348,688	$ 322,840	$ 334,606	$ 303,080	$ 323,742	$ 11,768,000	Sum Lines 14; 15; 16	17
18																18
19	Maximum Demand at the Time of System Peak (kW)[4]	Winter	Summer	Summer	Summer	Summer	Summer	Winter	Winter	Winter	Winter	Winter	Winter			19
20	Secondary	-	-	-	-	-	-	-	-	-	-	-	-	-	Section 2.3.2; Pages 12; Line 30 x 1000	20
21	Primary	14,082	8,059	12,953	13,332	2,605	10,448	11,495	8,337	20,962	6,157	12,964	14,008	135,403	Section 2.3.2; Pages 12; Line 31 x 1000	21
22	Transmission	66,186	100,813	90,443	99,691	71,191	102,954	105,670	113,486	68,028	80,716	74,354	61,286	1,034,819	Section 2.3.2; Pages 12; Line 32 x 1000	22
23	Total	80,268	108,872	103,395	113,024	73,796	113,403	117,165	121,824	88,991	86,873	87,318	75,294	1,170,222	Sum Lines 20; 21; 22	23
24	Check Figure	80,268	108,872	103,395	113,024	73,796	113,403	117,165	121,824	88,991	86,873	87,318	75,294	1,170,222	Section 2.3.2; Pages 12; Line 33	24
25	Difference	-	-	-	-	-	-	-	-	-	-	-	-	-	Line 23 - Line 24	25
26																26
27	Maximum Demand at the Time of System Peak Rates ($/kW):	Winter	Summer	Summer	Summer	Summer	Summer	Winter	Winter	Winter	Winter	Winter	Winter			27
28	Secondary	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		Section 2.3.1; Page 1; Line 15D; 16D	28
29	Primary	$ 0.2045328	$ 1.0760029	$ 1.0760029	$ 1.0760029	$ 1.0760029	$ 1.0760029	$ 0.2045328	$ 0.2045328	$ 0.2045328	$ 0.2045328	$ 0.2045328	$ 0.2045328		Section 2.3.1; Page 1; Line 15C; 16C	29
30	Transmission	$ 0.2053616	$ 1.0557041	$ 1.0557041	$ 1.0557041	$ 1.0557041	$ 1.0557041	$ 0.2053616	$ 0.2053616	$ 0.2053616	$ 0.2053616	$ 0.2053616	$ 0.2053616		Section 2.3.1; Page 1; Line 15B; 16B	30
31	Maximum Demand at the Time of System Peak - Revenues:															31
32	Secondary	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	Line 20 x Line 28	32
33	Primary	2,880	8,671	13,937	14,346	2,803	11,243	2,351	1,705	4,287	1,259	2,652	2,865	$ 69,000	Line 21 x Line 29	33
34	Transmission	13,592	106,429	95,481	105,244	75,157	108,689	21,701	23,306	13,970	16,576	15,269	12,586	$ 608,000	Line 22 x Line 30	34
35	Subtotal	$ 16,472	$ 115,100	$ 109,418	$ 119,590	$ 77,960	$ 119,932	$ 24,052	$ 25,011	$ 18,258	$ 17,835	$ 17,921	$ 15,451	$ 677,000	Sum Lines 32; 33; 34	35
36																36
37	Revenues at Changed Rates:	Winter	Summer	Summer	Summer	Summer	Summer	Winter	Winter	Winter	Winter	Winter	Winter			37
38	Secondary	$ 7,558,933	$ 7,904,652	$ 9,079,825	$ 9,907,023	$ 9,141,777	$ 10,430,137	$ 8,894,823	$ 8,345,579	$ 7,912,036	$ 8,081,460	$ 7,319,611	$ 7,825,952	$ 102,401,807	Pg.5 (Lines 19;37) + Pg.6(Lines 14;32)	38
39	Primary	$ 1,492,929	$ 1,671,122	$ 1,582,644	$ 2,143,131	$ 1,875,597	$ 2,067,129	$ 1,720,574	$ 1,588,727	$ 1,450,140	$ 1,592,976	$ 1,503,593	$ 1,467,073	$ 20,155,635	Pg.5 (Lines 20;38) + Pg.6(Lines 15;33)	39
40	Transmission	$ 533,002	$ 713,777	$ 619,003	$ 696,778	$ 600,797	$ 699,808	$ 804,950	$ 633,776	$ 574,310	$ 524,664	$ 457,914	$ 408,722	$ 7,267,500	Pg.5 (Lines 21;39) + Pg.6(Lines 16;34)	40
41	Total	$ 9,584,864	$ 10,289,551	$ 11,281,472	$ 12,746,932	$ 11,618,171	$ 13,197,074	$ 11,420,347	$ 10,568,082	$ 9,936,486	$ 10,199,100	$ 9,281,118	$ 9,701,747	$ 129,824,942	Sum Lines 38; 39; 40	41
42																42
43	Total Revenues at Changed Rates:	$ 9,584,864	$ 10,289,551	$ 11,281,472	$ 12,746,932	$ 11,618,171	$ 13,197,074	$ 11,420,347	$ 10,568,082	$ 9,936,486	$ 10,199,100	$ 9,281,118	$ 9,701,747	$ 129,824,942	See Line 41	43

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

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

Line No.	Description	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Total	Reference	Line No.
1	Demand - Billing Determinants (kW):															1
2	Secondary	11,224	11,224	11,226	11,124	11,124	11,123	12,075	12,075	13,498	13,498	13,408	13,408	145,007	Section 2.3.2; Page 11.3; Line 114 x 1000	2
3	Primary	84,822	85,002	85,316	85,022	84,287	84,287	80,481	80,481	83,769	83,386	82,725	83,399	1,002,977	Section 2.3.2; Page 11.3; Line 115 x 1000	3
4	Transmission	46,948	47,715	47,692	49,986	49,986	49,986	50,003	50,003	50,156	50,272	50,272	50,275	593,294	Section 2.3.2; Page 11.3; Line 116 x 1000	4
5	Total	142,994	143,941	144,234	146,132	145,397	145,396	142,559	142,559	147,423	147,156	146,405	147,082	1,741,278	Sum Lines 2; 3; 4	5
6	Check Figure	142,994	143,941	144,234	146,132	145,397	145,396	142,559	142,559	147,423	147,156	146,405	147,082	1,741,278	Section 2.3.2; Page 11.3; Line 117 x 1000	6
7	Difference	-	-	-	-	-	-	-	-	-	-	-	-	-	Line 5 Less Line 6	7
8																8
9	Demand Rates ($/kW):															9
10	Secondary	$ 2.0688656	$ 2.0688656	$ 2.0688656	$ 2.0688656	$ 2.0688656	$ 2.0688656	$ 2.0688656	$ 2.0688656	$ 2.0688656	$ 2.0688656	$ 2.0688656	$ 2.0688656		Section 2.3.1; Page 1; Line 20D	10
11	Primary	$ 1.9970548	$ 1.9970548	$ 1.9970548	$ 1.9970548	$ 1.9970548	$ 1.9970548	$ 1.9970548	$ 1.9970548	$ 1.9970548	$ 1.9970548	$ 1.9970548	$ 1.9970548		Section 2.3.1; Page 1; Line 20C	11
12	Transmission	$ 1.9737263	$ 1.9737263	$ 1.9737263	$ 1.9737263	$ 1.9737263	$ 1.9737263	$ 1.9737263	$ 1.9737263	$ 1.9737263	$ 1.9737263	$ 1.9737263	$ 1.9737263		Section 2.3.1; Page 1; Line 20B	12
13																13
14	Revenues at Changed Rates:															14
15	Secondary	$ 23,221	$ 23,221	$ 23,225	$ 23,014	$ 23,014	$ 23,012	$ 24,982	$ 24,982	$ 27,926	$ 27,926	$ 27,739	$ 27,739	$ 300,001	Line 2 x Line 10	15
16	Primary	169,394	169,754	170,381	169,794	168,326	168,326	160,725	160,725	167,291	166,526	165,206	166,552	2,003,000	Line 3 x Line 11	16
17	Transmission	92,663	94,176	94,131	98,659	98,659	98,659	98,692	98,692	98,994	99,223	99,223	99,229	1,171,000	Line 4 x Line 12	17
18	Total	$ 285,278	$ 287,151	$ 287,737	$ 291,467	$ 289,999	$ 289,997	$ 284,399	$ 284,399	$ 294,211	$ 293,675	$ 292,168	$ 293,520	$ 3,474,001	Sum Lines 15; 16; 17	18
19																19
20	Total Revenues at Changed Rates	$ 285,278	$ 287,151	$ 287,737	$ 291,467	$ 289,999	$ 289,997	$ 284,399	$ 284,399	$ 294,211	$ 293,675	$ 292,168	$ 293,520	$ 3,474,001	Line 18	20

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

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

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

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

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

NOTES:

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

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

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

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

Section 2.3.2

SAN DIEGO GAS AND ELECTRIC COMPANY

Transmission Revenue Data to Reflect Changed Rates

Recorded Billing Determinants

True-Up Period (April 1, 2010 - March 31, 2011)

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

NOTES:

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

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

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

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

Section 2.3.2

San Diego Gas & Electric

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

Line No.															Line No.
1	SDG&E: System Delivery Determinants	Winter	Summer	Summer	Summer	Summer	Summer	Winter	Winter	Winter	Winter	Winter	Winter	Total	1
2															2
3	Customer Class Deliveries (MWh)	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Total	3
4	Residential	560,384	517,201	550,609	593,511	590,340	686,248	639,924	589,348	671,935	724,209	628,060	609,744	7,361,513	4
5	Small Commercial	157,999	137,325	162,432	177,346	163,651	189,247	177,357	162,507	164,000	171,088	159,604	160,245	1,982,802	5
6	Med. & Large Comm./Ind. (AD + PA-T-1)	21,162	19,894	24,223	27,331	27,123	30,064	26,805	20,895	19,901	17,916	19,926	20,362	275,603	6
7	Med. & Large Comm./Ind. (AL + AY + DGR)	708,903	692,577	744,964	827,532	755,332	871,898	817,218	756,976	723,654	772,108	698,123	742,483	9,111,768	7
8	Med. & Large Comm./Ind. (A6)	65,251	72,160	71,462	72,343	55,478	68,178	71,130	64,163	70,265	57,890	61,242	51,383	780,945	8
9	Lighting	12,741	6,011	9,449	9,467	9,718	8,583	10,585	9,387	12,835	6,110	9,498	12,754	117,138	9
10	Sale for Resale	1.5	0.0	3.5	0.0	1.5	0.0	6.4	0.0	2.1	1.7	3.6	0.0	20.4	10
11	**Total System**	**1,526,442**	**1,445,170**	**1,563,143**	**1,707,530**	**1,601,644**	**1,854,218**	**1,743,026**	**1,603,276**	**1,662,591**	**1,749,324**	**1,576,456**	**1,596,971**	**19,629,791**	11
12															12
13	**Med. & Large Comm./Ind.**														13
14	**Rate Schedule Billing Determinants**														14
15															15
16	**Schedules AD / PA-T-1:**	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Total	16
17	Total Deliveries (MWh)	21,162	19,894	24,223	27,331	27,123	30,064	26,805	20,895	19,901	17,916	19,926	20,362	275,603	17
18															18
19	Total Deliveries (%)														19
20	% @ Secondary Service	91.58%	93.78%	93.65%	93.60%	91.70%	91.23%	90.41%	91.34%	91.56%	87.21%	85.53%	90.30%	91.15%	20
21	% @ Primary Service	8.42%	6.22%	6.35%	6.40%	8.30%	8.77%	9.59%	8.66%	8.44%	12.79%	14.47%	9.70%	8.85%	21
22	% @ Transmission Service	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	22
23		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	23
24	Total Deliveries (MWh)														24
25	MWh @ Secondary Service	19,380	18,657	22,685	25,582	24,872	27,427	24,234	19,085	18,221	15,625	17,043	18,387	251,199	25
26	MWh @ Primary Service	1,782	1,237	1,538	1,749	2,251	2,637	2,571	1,809	1,680	2,292	2,883	1,975	24,404	26
27	MWh @ Transmission Service	0	0	0	0	0	0	0	0	0	0	0	0	0	27
28		21,162	19,894	24,223	27,331	27,123	30,064	26,805	20,895	19,901	17,916	19,926	20,362	275,603	28
29	Non-Coincident Demand (%)														29
30	% @ Secondary Service	0.4645%	0.3810%	0.3496%	0.3242%	0.3390%	0.3116%	0.3507%	0.4303%	0.4382%	0.4666%	0.4670%	0.4543%	0.3886%	30
31	% @ Primary Service	0.4508%	0.7382%	0.8706%	0.6807%	0.5423%	0.4609%	0.4693%	0.6266%	0.6114%	0.5588%	0.5323%	0.5140%	0.5688%	31
32	% @ Transmission Service	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	32
33															33
34	Non-Coincident Demand (MW)														34
35	MW @ Secondary Service	90.020	71.082	79.308	82.936	84.316	85.463	84.989	82.124	79.846	72.906	79.589	83.533	976.113	35
36	MW @ Primary Service	8.032	9.135	13.392	11.907	12.208	12.152	12.064	11.338	10.269	12.805	15.348	10.152	138.802	36
37	MW @ Transmission Service	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	37
38		98.052	80.217	92.699	94.843	96.525	97.615	97.053	93.463	90.115	85.711	94.937	93.686	1,114.915	38
39															39
40															40
41															41
42	**Schedules AL-TOU / AY-TOU / DG-R:**	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Total	42
43	Total Deliveries (MWh)	708,903	692,577	744,964	827,532	755,332	871,898	817,218	756,976	723,654	772,108	698,123	742,483	9,111,768	43
44															44
45	Total Deliveries (%)														45
46	% @ Secondary Service	79.27%	78.43%	82.11%	79.43%	78.58%	80.34%	77.71%	78.07%	81.77%	79.54%	79.60%	81.39%	79.68%	46
47	% @ Primary Service	19.02%	20.66%	17.19%	19.92%	20.47%	18.67%	19.01%	19.23%	17.28%	19.44%	19.90%	17.48%	19.02%	47
48	% @ Transmission Service	1.71%	0.91%	0.70%	0.65%	0.95%	0.99%	3.28%	2.70%	0.95%	1.02%	0.50%	1.13%	1.30%	48
49		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	49

Section 2.3.2

San Diego Gas & Electric

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

Line No.															Line No.
50	**Total Deliveries (MWh)**														50
51	MWh @ Secondary Service	561,948	543,188	611,690	657,309	593,540	700,483	635,060	590,971	591,732	614,135	555,706	604,307	7,260,068	51
52	MWh @ Primary Service	134,833	143,086	128,059	164,844	154,616	162,783	155,353	145,567	125,047	150,098	138,926	129,786	1,733,001	52
53	MWh @ Transmission Service	12,122	6,302	5,215	5,379	7,176	8,632	26,805	20,438	6,875	7,876	3,491	8,390	118,700	53
54		708,903	692,577	744,964	827,532	755,332	871,898	817,218	756,976	723,654	772,108	698,123	742,483	9,111,768	54
55	**Non-Coincident Demand (%)**														55
56	% @ Secondary Service	0.2810%	0.2688%	0.2705%	0.2744%	0.2793%	0.2709%	0.2955%	0.2984%	0.2822%	0.2792%	0.2768%	0.2723%	0.2791%	56
57	% @ Primary Service	0.2376%	0.2190%	0.2213%	0.2386%	0.2236%	0.2289%	0.2400%	0.2369%	0.2403%	0.2205%	0.2216%	0.2273%	0.2297%	57
58	% @ Transmission Service	0.1981%	0.2219%	0.2323%	0.2659%	0.2727%	0.2418%	0.2261%	0.1460%	0.2803%	0.2419%	0.3092%	0.1336%	0.2154%	58
59															59
60	**Non-Coincident Demand (MW)**														60
61	MW @ Secondary Service	1,579.073	1,460.090	1,654.621	1,803.656	1,657.757	1,897.608	1,876.603	1,763.458	1,669.866	1,714.665	1,538.193	1,645.528	20,261.118	61
62	MW @ Primary Service	320.364	313.359	283.395	393.319	345.722	372.611	372.848	344.847	300.489	330.966	307.861	295.004	3,980.785	62
63	MW @ Transmission Service	24.014	13.985	12.114	14.303	19.568	20.872	60.606	29.840	19.270	19.051	10.793	11.209	255.624	63
64		1,923.452	1,787.434	1,950.130	2,211.277	2,023.047	2,291.090	2,310.056	2,138.145	1,989.625	2,064.681	1,856.847	1,951.741	24,497.526	64
65	**On-Peak Demand (%)**														65
66	% @ Secondary Service	0.2265%	0.2275%	0.2503%	0.2580%	0.2621%	0.2570%	0.2522%	0.2346%	0.2213%	0.2198%	0.2191%	0.2183%	0.2380%	66
67	% @ Primary Service	0.1996%	0.2075%	0.2313%	0.2366%	0.2323%	0.2339%	0.2293%	0.2085%	0.2107%	0.1977%	0.2061%	0.2063%	0.2173%	67
68	% @ Transmission Service	0.3645%	0.4230%	0.5473%	0.4202%	0.3757%	0.2874%	0.2268%	0.2739%	0.6176%	0.3522%	0.3647%	0.3891%	0.3421%	68
69	**Maximum On-Peak Period Demand (MW)**														69
70	**On-Peak Demand (MW)**	Winter	Summer	Summer	Summer	Summer	Summer	Winter	Winter	Winter	Winter	Winter	Winter	Total	70
71	MW @ Secondary Service	1,272.812	1,235.753	1,531.060	1,695.857	1,555.668	1,800.241	1,601.622	1,386.419	1,309.502	1,349.869	1,217.551	1,319.202	17,275.554	71
72	MW @ Primary Service	269.128	296.904	296.201	390.022	359.174	380.750	356.225	303.506	263.475	296.743	286.327	267.749	3,766.204	72
73	MW @ Transmission Service	44.186	26.659	28.540	22.602	26.959	24.808	60.793	55.981	42.458	27.738	12.730	32.646	406.100	73
74		1,586.125	1,559.317	1,855.801	2,108.481	1,941.801	2,205.799	2,018.640	1,745.906	1,615.435	1,674.350	1,516.609	1,619.596	21,447.858	74
75															75
76															76
77															77
78	**Schedule A6-TOU:**	**Apr-10**	**May-10**	**Jun-10**	**Jul-10**	**Aug-10**	**Sep-10**	**Oct-10**	**Nov-10**	**Dec-10**	**Jan-11**	**Feb-11**	**Mar-11**	**Total**	78
79	**Total Deliveries (MWh)**	65,251	72,160	71,462	72,343	55,478	68,178	71,130	64,163	70,265	57,890	61,242	51,383	780,945	79
80															80
81	**Total Deliveries (%)**														81
82	% @ Secondary Service	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	82
83	% @ Primary Service	13.38%	6.55%	9.47%	11.89%	8.21%	14.54%	8.86%	7.59%	15.37%	8.27%	13.71%	20.59%	11.40%	83
84	% @ Transmission Service	86.62%	93.45%	90.53%	88.11%	91.79%	85.46%	91.14%	92.41%	84.63%	91.73%	86.29%	79.41%	88.60%	84
85		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	85
86	**Total Deliveries (MWh)**														86
87	MWh @ Secondary Service	0	0	0	0	0	0	0	0	0	0	0	0	0	87
88	MWh @ Primary Service	8,731	4,726	6,767	8,602	4,555	9,913	6,302	4,870	10,800	4,788	8,396	10,580	89,029	88
89	MWh @ Transmission Service	56,521	67,434	64,694	63,741	50,923	58,265	64,828	59,293	59,465	53,103	52,846	40,803	691,916	89
90		65,251	72,160	71,462	72,343	55,478	68,178	71,130	64,163	70,265	57,890	61,242	51,383	780,945	90
91	**Non-Coincident Demand (%)**														91
92	% @ Secondary Service	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	92
93	% @ Primary Service	0.1456%	0.1068%	0.1203%	0.1390%	0.1158%	0.1729%	0.0952%	0.1239%	0.1838%	0.4118%	0.2249%	0.2801%	0.1802%	93
94	% @ Transmission Service	0.1748%	0.1868%	0.1658%	0.1926%	0.1977%	0.1984%	0.1926%	0.1928%	0.1908%	0.1917%	0.1798%	0.2022%	0.1883%	94
95															95
96	**Non-Coincident Demand (MW)**														96
97	MW @ Secondary Service	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	97
98	MW @ Primary Service	12.712	5.048	8.141	11.956	5.274	17.140	6.000	6.034	19.850	19.715	18.883	29.634	160.387	98
99	MW @ Transmission Service	98.798	125.966	107.263	122.766	100.676	115.598	124.859	114.316	113.460	101.798	95.017	82.504	1,303.020	99
100		111.510	131.014	115.404	134.722	105.950	132.738	130.859	120.350	133.310	121.513	113.900	112.138	1,463.407	100

Line No.	Section 2.3.2 San Diego Gas & Electric Recorded Sales for the True-Up Period: April 2010 - March 2011														Line No.
101	**Coincident Peak Demand (%)**														101
102	% @ Secondary Service	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	102
103	% @ Primary Service	0.1613%	0.1705%	0.1914%	0.1550%	0.0572%	0.1054%	0.1824%	0.1712%	0.1941%	0.1286%	0.1544%	0.1324%	0.1521%	103
104	% @ Transmission Service	0.1171%	0.1495%	0.1398%	0.1564%	0.1398%	0.1767%	0.1630%	0.1914%	0.1144%	0.1520%	0.1407%	0.1502%	0.1496%	104
105	**Coincident Demand at Time of System of Peak**														105
106	**Coincident Peak Demand (MW)**	Winter	Summer	Summer	Summer	Summer	Summer	Winter	Winter	Winter	Winter	Winter	Winter	Total	106
107	MW @ Secondary Service	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	107
108	MW @ Primary Service	14.082	8.059	12.953	13.332	2.605	10.448	11.495	8.337	20.962	6.157	12.964	14.008	135.403	108
109	MW @ Transmission Service	66.186	100.813	90.443	99.691	71.191	102.954	105.670	113.486	68.028	80.716	74.354	61.286	1,034.819	109
110		80.268	108.872	103.395	113.024	73.796	113.403	117.165	121.824	88.991	86.873	87.318	75.294	1,170.222	110
111															111
112	**Schedule S: Standby Determinants:**	**Apr-10**	**May-10**	**Jun-09**	**Jul-10**	**Aug-10**	**Sep-10**	**Oct-10**	**Nov-10**	**Dec-10**	**Jan-11**	**Feb-11**	**Mar-11**	**Total**	112
113	**Contracted Standby Demand (MW)**														113
114	MW @ Secondary Service	11.224	11.224	11.226	11.124	11.124	11.123	12.075	12.075	13.498	13.498	13.408	13.408	145.007	114
115	MW @ Primary Service	84.822	85.002	85.316	85.022	84.287	84.287	80.481	80.481	83.769	83.386	82.725	83.399	1,002.977	115
116	MW @ Transmission Service	46.948	47.715	47.692	49.986	49.986	49.986	50.003	50.003	50.156	50.272	50.272	50.275	593.294	116
117		142.994	143.941	144.234	146.132	145.397	145.396	142.559	142.559	147.423	147.156	146.405	147.082	1,741.278	117
118															118
119															119
120															120

Section 2.3.2

San Diego Gas & Electric Company

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

Line No.		Winter	Summer	Summer	Summer	Summer	Summer	Winter	Winter	Winter	Winter	Winter	Winter	Total	Reference	Line No.
2	**Schedules AD / PA-T-1:**	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Total		2
3	**Non-Coincident Demand (MW) - 100%**															3
4	MW @ Secondary Service	90.020	71.082	79.308	82.936	84.316	85.463	84.989	82.124	79.846	72.906	79.589	83.533	976.113	Section 2.3.2; Page 14.1; Line 35	4
5	MW @ Primary Service	8.032	9.135	13.392	11.907	12.208	12.152	12.064	11.338	10.269	12.805	15.348	10.152	138.802	Section 2.3.2; Page 14.1; Line 36	5
6	MW @ Transmission Service	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	Section 2.3.2; Page 14.1; Line 37	6
7	Sub-Total	98.052	80.217	92.699	94.843	96.525	97.615	97.053	93.463	90.115	85.711	94.937	93.686	1,114.915	Sum Lines 4; 5; 6	7
8																8
9	**Schedules AL-TOU / AY-TOU / DG-R:**															9
10	**Non-Coincident Demand (MW) - 90%**															10
11	MW @ Secondary Service	1,579.073	1,460.090	1,654.621	1,803.656	1,657.757	1,897.608	1,876.603	1,763.458	1,669.866	1,714.665	1,538.193	1,645.528	20,261.118	Section 2.3.2; Page 14.2; Line 61	11
12	MW @ Primary Service	320.364	313.359	283.395	393.319	345.722	372.611	372.848	344.847	300.489	330.966	307.861	295.004	3,980.785	Section 2.3.2; Page 14.2; Line 62	12
13	MW @ Transmission Service	24.014	13.985	12.114	14.303	19.568	20.872	60.606	29.840	19.270	19.051	10.793	11.209	255.624	Section 2.3.2; Page 14.2; Line 63	13
14	Sub-Total	1,923.452	1,787.434	1,950.130	2,211.277	2,023.047	2,291.090	2,310.056	2,138.145	1,989.625	2,064.681	1,856.847	1,951.741	24,497.526	Sum Lines 11; 12; 13	14
15																15
16	**On-Peak Demand (MW)**															16
17	MW @ Secondary Service	1,272.812	1,235.753	1,531.060	1,695.857	1,555.668	1,800.241	1,601.622	1,386.419	1,309.502	1,349.869	1,217.551	1,319.202	17,275.554	Section 2.3.2; Page 14.2; Line 71	17
18	MW @ Primary Service	269.128	296.904	296.201	390.022	359.174	380.750	356.225	303.506	263.475	296.743	286.327	267.749	3,766.204	Section 2.3.2; Page 14.2; Line 72	18
19	MW @ Transmission Service	44.186	26.659	28.540	22.602	26.959	24.808	60.793	55.981	42.458	27.738	12.730	32.646	406.100	Section 2.3.2; Page 14.2; Line 73	19
20	Sub-Total	1,586.125	1,559.317	1,855.801	2,108.481	1,941.801	2,205.799	2,018.640	1,745.906	1,615.435	1,674.350	1,516.609	1,619.596	21,447.858	Sum Lines 17; 18; 19	20
21																21
22	**Schedule A6-TOU:**															22
23	**Non-Coincident Demand (MW) - 90%**															23
24	MW @ Secondary Service	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	Section 2.3.2; Page 14.2; Line 97	24
25	MW @ Primary Service	12.712	5.048	8.141	11.956	5.274	17.140	6.000	6.034	19.850	19.715	18.883	29.634	160.387	Section 2.3.2; Page 14.2; Line 98	25
26	MW @ Transmission Service	98.798	125.966	107.263	122.766	100.676	115.598	124.859	114.316	113.460	101.798	95.017	82.504	1,303.020	Section 2.3.2; Page 14.2; Line 99	26
27	Sub-Total	111.510	131.014	115.404	134.722	105.950	132.738	130.859	120.350	133.310	121.513	113.900	112.138	1,463.407	Sum Lines 24; 25; 26	27
28																28
29	**Coincident Peak Demand (MW)**															29
30	MW @ Secondary Service	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	Section 2.3.2; Page 14.3; Line 107	30
31	MW @ Primary Service	14.082	8.059	12.953	13.332	2.605	10.448	11.495	8.337	20.962	6.157	12.964	14.008	135.403	Section 2.3.2; Page 14.3; Line 108	31
32	MW @ Transmission Service	66.186	100.813	90.443	99.691	71.191	102.954	105.670	113.486	68.028	80.716	74.354	61.286	1,034.819	Section 2.3.2; Page 14.3; Line 109	32
33	Sub-Total	80.268	108.872	103.395	113.024	73.796	113.403	117.165	121.824	88.991	86.873	87.318	75.294	1,170.222	Sum Lines 30; 31; 32	33
34																34
35	**TOTAL SUMMARY**															35
36	**Non-Coincident Demand (MWH) @ 100%**															36
37	MW @ Secondary Service	1,669,093	1,531,172	1,733,929	1,886,592	1,742,073	1,983,071	1,961,592	1,845,583	1,749,712	1,787,571	1,617,782	1,729,061	21,237,231	Apr-Aug; Lines (4, 11 and 24) x 1000	37
38															Sep-Mar; (Line 4 x 1000)	38
39	MW @ Primary Service	341,108	327,542	304,928	417,182	363,205	401,903	390,911	362,219	330,608	363,486	342,092	334,790	4,279,974	Apr-Aug; Lines (5, 12 and 25) x 1000	39
40															Sep-Mar; (Line 5 x 1000)	40
41	MW @ Transmission Service	122,812	139,951	119,377	137,068	120,244	136,470	185,465	144,156	132,730	120,849	105,810	93,713	1,558,644	Apr-Aug; Lines (6, 13 and 26) x 1000	41
42															Sep-Mar; (Line 6 x 1000)	42
43	Total - NONCoincident Demand @ 100%	2,133,013	1,998,665	2,158,234	2,440,842	2,225,522	2,521,443	2,537,968	2,351,959	2,213,050	2,271,905	2,065,684	2,157,564	27,075,849	Sum Lines 37 thru 42	43
44																44
45	**Non-Coincident Demand (MWH) @ 90%**															45
46	MW @ Secondary Service	1,579,073	1,460,090	1,654,621	1,803,656	1,657,757	1,897,608	1,876,603	1,763,458	1,669,866	1,714,665	1,538,193	1,645,528	20,261,118	Sep-Mar; ((Lines 11 & 24) x 1000)	46
47	MW @ Primary Service	333,076	318,407	291,536	405,275	350,997	389,751	378,847	350,881	320,339	350,681	326,744	324,638	4,141,172	Sep-Mar; ((Lines 12 & 25) x 1000)	47
48	MW @ Transmission Service	122,812	139,951	119,377	137,068	120,244	136,470	185,465	144,156	132,730	120,849	105,810	93,713	1,558,644	Sep-Mar; ((Lines 13 & 26) x 1000)	48
49	Total - NONCoincident Demand @ 90%	2,034,961	1,918,448	2,065,535	2,345,999	2,128,997	2,423,828	2,440,915	2,258,496	2,122,935	2,186,194	1,970,747	2,063,879	25,960,933	Sum Lines 46 thru 48	49
50																50

000115

Section – 3
Derivation of ISO Wholesale
True-Up Adjustment

Section 3.1A
Summary of ISO True-Up Adjustment

Docket No. ER11-4318-000

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

Line No.	TO3-Formula Cycle Transmission Rates in Effect / Description	Cycle - 3 Apr-10	Cycle - 3 May-10	Cycle - 3 Jun-10	Cycle - 3 Jul-10	Cycle - 3 Aug-10
1	**Beginning Balance (Overcollection)/Undercollection**	$ -	$ 3,026,851	$ 6,075,143	$ 9,415,013	$ 13,115,334
2						
3	**Total Recorded Revenues**	$ 18,772,316	$ 18,377,192	$ 20,104,237	$ 22,193,606	$ 20,944,318
4						
5	**Amortization of True-Up Adjustment and Interest True-Up Adjustment:**					
6	**a) Amortization of Cycle 4 True-Up Adjustment and Interest True-Up Adjustment:**					
7	i. Amortization of Cycle 4 True-Up Adjustment					
8	ii. Amortization of Cycle 4 Interest True-Up Adjustment					
9	**b) Amortization of Cycle 3 True-Up Adjustment and Interest True-Up Adjustment:**					
10	i. Amortization of Cycle 3 True-Up Adjustment	(429,002)	(406,083)	(439,251)	(479,804)	(795,656)
11	ii. Amortization of Cycle 3 Interest True-Up Adjustment					
12	**c) Amortization of Cycle 2 True-Up Adjustment and Interest True-Up Adjustment:**					
13	i. Amortization of Cycle 2 TU Adjustment					
14	ii. Amortization of Cycle 2 Interest True-Up Adjustment	(31,778)	(30,080)	(32,537)	(35,541)	(78,653)
15	iii. Amortization of Cycle 2 Interest TU Adjustment Accrued After Fully Amortized					
16	**d) Amortization of TO2 FINAL True-Up Adjustment and Interest True-Up Adjustment:**					
17	i. Amortization of TO2 Final True-Up Adjustment					
18	ii. Amortization of TO2 FINAL Interest True-Up Adjustment	(143,001)	(135,361)	(146,417)	(159,935)	(325,039)
19	iii. Amort. of TO2 FINAL Interest TU Adjustment Accrued After Fully Amortized					
20	Total Amortization of True-Up Adjustments	$ (603,781)	$ (571,524)	$ (618,205)	$ (675,280)	$ (1,199,348)
21						
22	**Adjusted Total Recorded Revenues**	$ 18,168,535	$ 17,805,668	$ 19,486,032	$ 21,518,326	$ 19,744,970
23						
24	**Total True-Up Revenues (TU Cost of Service)**	$ 21,191,305	$ 20,841,245	$ 22,805,064	$ 25,187,149	$ 23,766,750
25						
26	**Net Monthly (Overcollection)/Undercollection**	$ 3,022,771	$ 3,035,578	$ 3,319,032	$ 3,668,823	$ 4,021,780
27						
28	Interest Expense Calculations:					
29	Beginning Balance for Interest Calculation	$ -	$ -	$ -	$ 9,415,013	$ 9,415,013
30	Monthly Activity Included in Interest Calculation Basis	1,511,385	4,540,559	7,717,864	1,834,412	5,679,713
31	Basis for Interest Expense Calculation	1,511,385	4,540,559	7,717,864	11,249,424	15,094,726
32	Monthly Interest Rate	0.27000%	0.28000%	0.27000%	0.28000%	0.28000%
33	**Interest Expense**	$ 4,081	$ 12,714	$ 20,838	$ 31,498	$ 42,265
34						
35	**Ending Balance (Overcollection)/Undercollection**	$ 3,026,851	$ 6,075,143	$ 9,415,013	$ 13,115,334	$ 17,179,379
36						
37		Apr-10	May-10	Jun-10	Jul-10	Aug-10
38	FERC INTEREST RATE	3.25%	3.25%	3.25%	3.25%	3.25%
39	Days in Year	365	365	365	365	365
40	Days in Month	30	31	30	31	31
41	Monthly Interest Rate - Calculated	0.27000%	0.28000%	0.27000%	0.28000%	0.28000%
42	FERC Interest Rates - Website	0.27000%	0.28000%	0.27000%	0.28000%	0.28000%
43	Difference	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%

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

Line	TO3-Formula Cycle Transmission Rates in Effect	Cycle - 4	Cycle - 4	Cycle - 4	Cycle - 4	Cycle - 4
No.	Description	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11
1	**Beginning Balance (Overcollection)/Undercollection**	**$ 17,179,379**	**$ 17,521,334**	**$ 17,853,217**	**$ 18,152,895**	**$ 18,510,664**
2						
3	**Total Recorded Revenues**	**$ 29,387,471**	**$ 26,573,944**	**$ 24,535,851**	**$ 25,228,057**	**$ 26,414,916**
4						
5	**Amortization of True-Up Adjustment and Interest True-Up Adjustment:**					
6	**a) Amortization of Cycle 4 True-Up Adjustment and Interest True-Up Adjustment:**					
7	i. Amortization of Cycle 4 True-Up Adjustment	(2,412,253)	(2,267,552)	(2,085,751)	(2,163,613)	(2,276,583)
8	ii. Amortization of Cycle 4 Interest True-Up Adjustment					
9	**b) Amortization of Cycle 3 True-Up Adjustment and Interest True-Up Adjustment:**					
10	i. Amortization of Cycle 3 True-Up Adjustment					
11	ii. Amortization of Cycle 3 Interest True-Up Adjustment	(19,298)	(18,140)	(16,686)	(17,309)	(18,213)
12	**c) Amortization of Cycle 2 True-Up Adjustment and Interest True-Up Adjustment:**					
13	i. Amortization of Cycle 2 TU Adjustment					
14	ii. Amortization of Cycle 2 Interest True-Up Adjustment					
15	iii. Amortization of Cycle 2 Interest TU Adjustment Accrued After Fully Amortized	(3,860)	(3,628)	(3,337)	(3,462)	(3,643)
16	**d) Amortization of TO2 FINAL True-Up Adjustment and Interest True-Up Adjustment:**					
17	i. Amortization of TO2 Final True-Up Adjustment					
18	ii. Amortization of TO2 FINAL Interest True-Up Adjustment					
19	iii. Amort. of TO2 FINAL Interest TU Adjustment Accrued After Fully Amortized	(19,298)	(18,140)	(16,686)	(17,309)	(18,213)
20	Total Amortization of True-Up Adjustments	$ (2,454,709)	$ (2,307,460)	$ (2,122,460)	$ (2,201,693)	$ (2,316,652)
21						
22	**Adjusted Total Recorded Revenues**	**$ 26,932,762**	**$ 24,266,484**	**$ 22,413,391**	**$ 23,026,364**	**$ 24,098,264**
23						
24	**Total True-Up Revenues (TU Cost of Service)**	**$ 27,228,132**	**$ 24,548,912**	**$ 22,664,660**	**$ 23,333,150**	**$ 24,444,288**
25						
26	**Net Monthly (Overcollection)/Undercollection**	**$ 295,370**	**$ 282,428**	**$ 251,269**	**$ 306,786**	**$ 346,023**
27						
28	Interest Expense Calculations:					
29	Beginning Balance for Interest Calculation	$ 9,415,013	$ 17,521,334	$ 17,521,334	$ 17,521,334	$ 18,510,664
30	Monthly Activity Included in Interest Calculation Basis	7,838,288	141,214	408,063	687,090	173,012
31	Basis for Interest Expense Calculation	17,253,301	17,662,548	17,929,396	18,208,423	18,683,676
32	Monthly Interest Rate	0.27000%	0.28000%	0.27000%	0.28000%	0.28000%
33	**Interest Expense**	**$ 46,584**	**$ 49,455**	**$ 48,409**	**$ 50,984**	**$ 52,314**
34						
35	**Ending Balance (Overcollection)/Undercollection**	**$ 17,521,334**	**$ 17,853,217**	**$ 18,152,895**	**$ 18,510,664**	**$ 18,909,002**
36						
37		Sep-10	Oct-10	Nov-10	Dec-10	Jan-11
38	FERC INTEREST RATE	3.25%	3.25%	3.25%	3.25%	3.25%
39	Days in Year	365	365	365	365	365
40	Days in Month	30	31	30	31	31
41	Monthly Interest Rate - Calculated	0.27000%	0.28000%	0.27000%	0.28000%	0.28000%
42	FERC Interest Rates - Website	0.27000%	0.28000%	0.27000%	0.28000%	0.28000%
43	Difference	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%

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

Line No.	TO3-Formula Cycle Transmission Rates in Effect / Description	Cycle - 4 Feb-11	Cycle - 4 Mar-11	Total	Reference	Line No.
1	**Beginning Balance (Overcollection)/Undercollection**	$ 18,909,002	$ 19,263,697	$ -	Previous Month's Balance	1
2						2
3	**Total Recorded Revenues**	$ 23,686,858	$ 23,905,753	$ 280,124,518	Section 3.2.3; Page 82; Line 15	3
4						4
5	**Amortization of True-Up Adjustment and Interest True-Up Adjustment:**					5
6	**a) Amortization of Cycle 4 True-Up Adjustment and Interest True-Up Adjustment:**					6
7	i. Amortization of Cycle 4 True-Up Adjustment	(2,051,430)	(2,077,839)	(15,335,021)	Section 3.1A; Page 6; Line 22; (a) - (g)	7
8	ii. Amortization of Cycle 4 Interest True-Up Adjustment					8
9	**b) Amortization of Cycle 3 True-Up Adjustment and Interest True-Up Adjustment:**					9
10	i. Amortization of Cycle 3 True-Up Adjustment			(2,549,796)	Section 3.1A; Pgs 9-10; Ln. 22; Cols. (h)-(l)	10
11	ii. Amortization of Cycle 3 Interest True-Up Adjustment	(16,411)	(16,623)	(122,680)	Section 3.1A; Page 12; Line 22; (a) - (g)	11
12	**c) Amortization of Cycle 2 True-Up Adjustment and Interest True-Up Adjustment:**					12
13	i. Amortization of Cycle 2 TU Adjustment			-		13
14	ii. Amortization of Cycle 2 Interest True-Up Adjustment			(208,589)	Section 3.1A; Pgs 15-16; Ln. 22; Cols. (h)-(l)	14
15	iii. Amortization of Cycle 2 Interest TU Adjustment Accrued After Fully Amortized	(3,282)	(3,325)	(24,537)	Section 3.1A; Page 18; Line 22; (a) - (g)	15
16	**d) Amortization of TO2 FINAL True-Up Adjustment and Interest True-Up Adjustment:**					16
17	i. Amortization of TO2 Final True-Up Adjustment			-		17
18	ii. Amortization of TO2 FINAL Interest True-Up Adjustment			(909,753)	Section 3.1A; Pgs 21-22; Ln. 22; Cols. (h)-(l)	18
19	iii. Amort. of TO2 FINAL Interest TU Adjustment Accrued After Fully Amortized	(16,411)	(16,623)	(122,680)	Page 24; Line 22; Columns (a) - (g)	19
20	Total Amortization of True-Up Adjustments	$ (2,087,534)	$ (2,114,410)	$ (19,273,056)	Sum Lines (7 thru 19)	20
21						21
22	**Adjusted Total Recorded Revenues**	$ 21,599,324	$ 21,791,343	$ 260,851,463	Sum Lines 3 & 20	22
23						23
24	**Total True-Up Revenues (TU Cost of Service)**	$ 21,906,493	$ 22,097,081	$ 280,014,229	Section 3.3.3; Page 127; Line 15	24
25						25
26	**Net Monthly (Overcollection)/Undercollection**	$ 307,169	$ 305,737	$ 19,162,766	Line 24 Minus Line 22	26
27						27
28	Interest Expense Calculations:					28
29	Beginning Balance for Interest Calculation	$ 18,510,664	$ 18,510,664		Beginning Quarterly Balances	29
30	Monthly Activity Included in Interest Calculation Basis	499,608	806,061		Interest Calculation Basis	30
31	Basis for Interest Expense Calculation	19,010,272	19,316,726		Sum Lines 29 & 30	31
32	Monthly Interest Rate	0.25000%	0.28000%		FERC Monthly Rates	32
33	**Interest Expense**	$ 47,526	$ 54,087	$ 460,755	Line 31 x Line 32	33
34						34
35	**Ending Balance (Overcollection)/Undercollection**	$ 19,263,697	$ 19,623,521	$ 19,623,521	Sum Lines 1; 26; & 33	35
36						36
37		Feb-11	Mar-11			37
38	FERC INTEREST RATE	3.25%	3.25%		Annual Interest Rate - FERC Website	38
39	Days in Year	365	365	365	Number of Days Per Year	39
40	Days in Month	28	31	365	Number of Days Per Month	40
41	Monthly Interest Rate - Calculated	0.25000%	0.28000%	3.29000%	(Line 38)/(Line 39)x(Line 40)	41
42	FERC Interest Rates - Website	0.25000%	0.28000%	3.29000%	Monthly Interest Rate - FERC Website	42
43	Difference	0.00000%	0.00000%	0.00000%		43

Section – 3.3

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

Section 3.3.1

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

Docket No. ER11-4318-000

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

Line No.		Amounts	Reference	Line No.
1	Transmission Operation & Maintenance Expense	$ 44,557	Statement AH; Page 5, Line 6	1
2				2
3	Transmission Related A&G Expenses	**31,455** √	Statement AH; Page 5, Line 52	3
4				4
5	CPUC Intervener Funding Expense	-	Not Recoverable From Wholesale Customers	5
6				6
7	Total O&M Expenses	$ **76,012** √	Sum Lines 1; 3; and 5	7
8				8
9	Trans, Intang., Gen. and Comm. Depr. & Amort. Expense	**49,810** √	Statement AJ; Page 7, Line 17	9
10				10
11	Valley Rainbow Project Cost Amortization Expense	1,893	Statement AJ; Page 7, Line 19	11
12				12
13	Transmission Related Property Taxes Expense	**11,089** √	Statement AK; Page 8, Line 27	13
14				14
15	Transmission Related Payroll Taxes Expense	1,955	Statement AK; Page 8, Line 34	15
16				16
17	Subtotal Expense	$ **140,759** √	Sum Lines (7 thru 15)	17
18				18
19	Cost of Capital Rate ($AFCR_{CP}$)	12.5181%	Statement AV; Page 14, Line 33	19
20				20
21	Transmission Rate Base	$ **1,111,690** √	Statement BK-2; Pg 2, Line 20	21
22				22
23	Return and Associated Income Taxes	$ **139,162** √	(Line 19 x Line 21)	23
24	South Georgia Income Tax Adjustment	-	Not Recoverable From Wholesale Customers	24
25	Transmission Related Amortization of ITC	(265)	Statement AR; Page 11, Line 1	25
26	Trans. Related Amort of Excess Deferred Tax Liability	(3)	Statement AR; Page 11, Line 3	26
27	Transmission Related Revenue Credits	(2,484)	Statement AU; Page 12, Line 15	27
28				28
29	End of Prior Year Revenue ($PYRR_{ISO}$)	$ **277,169** √	Line 17 + Sum of Lines (23 thru 27)	29
30				30
31	Transmission Related Municipal Franchise Expenses	**2,848** √	Line 29 x 1.0275%	31
32	Transmission Related Uncollectible Expense	-	Not Applicable on Wholesale Customers	32
33				33
34	End of Prior Year Revenue ($PYRR_{ISO}$)	$ **280,017** √	Sum Lines (29 thru 32)	34

NOTE:

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

√ Items that are in bold have changed between the instant compliance filing and the original filing from last August 15, 2011.

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

Line No.			Amounts	Reference	Line No.
1	Net Transmission Plant:				1
2	Transmission Plant	$	1,146,333	Statement BK-2; Pg 3; Line 16	2
3	Electric Miscellaneous Intangible Plant		293	Statement BK-2; Pg 3; Line 17	3
4	Transmission Related General Plant		15,797	Statement BK-2; Pg 3; Line 18	4
5	Transmission Related Common Plant		32,568	Statement BK-2; Pg 3; Line 19	5
6	Net Transmission Plant	$	1,194,991	Sum Lines (2 thru 5)	6
7					7
8	Rate Base Reductions:				8
9	Transmission Related Accumulated Deferred Taxes	$	(148,838)	Statement AF; Page 3, Line 3	9
10					10
11	Rate Base Additions				11
12	Plant Held for Future Use	$	39,893	Statement AG; Page 4, Line 4	12
13					13
14	Working Capital:				14
15	Transmission Related Material and Supplies	$	**10,676** √	Statement AL; Page 9, Line 5	15
16	Tranmission Related Prepayments		**5,467** √	Statement AL; Page 9, Line 9	16
17	Transmission Related Cash Working Capital - Wholesale		**9,502** √	Statement AL; Page 9, Line 23	17
18	Total Working Capital	$	**25,645** √	Sum Lines (15 thru 17)	18
19					19
20	Total Transmission Rate Base	$	**1,111,690** √	Sum Lines 6; 9; 12; 18	20

√ Items that are in bold have changed between the instant compliance filing and the original filing from last August 15, 2011.

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

Line No.			Amounts		Reference	Line No.
1	Gross Transmission Plant:					1
2	Transmission Plant	$	**1,645,668**	√	Statement AD; Page 1, Line 23	2
3	Electric Miscellaneous Intangible Plant		4,259		Statement AD; Page 1, Line 27	3
4	Transmission Related General Plant		27,686		Statement AD; Page 1, Line 29	4
5	Transmission Related Common Plant		73,428		Statement AD; Page 1, Line 31	5
6	Gross Transmission Plant	$	**1,751,041**	√	Sum Lines (2 thru 5)	6
7						7
8	Accumulated Depreciation Reserve:					8
9	Transmission Related Depreciation Reserve	$	**499,335**	√	Statement AE; Page 2, Line 1	9
10	Electric Miscellaneous Intangible Depreciation Reserve		3,966		Statement AE; Page 2, Line 11	10
11	Transmission Related General Plant Depr Reserve		11,889		Statement AE; Page 2, Line 13	11
12	Transmission Related Common Plant Depr Reserve		40,860		Statement AE; Page 2, Line 15	12
13	Transmission Related Depreciation Reserve	$	**556,050**	√	Sum Lines (9 thru 12)	13
14						14
15	Net Transmission Plant:					15
16	Transmission Plant	$	1,146,333		Line 2 Minus Line 9	16
17	Electric Miscellaneous Intangible Plant		293		Line 3 Minus Line 10	17
18	Transmission Related General Plant		15,797		Line 4 Minus Line 11	18
19	Transmission Related Common Plant		32,568		Line 5 Minus Line 12	19
20	Total Net Plant	$	1,194,991		Sum Lines (16 thru 19)	20

√ Items that are in bold have changed between the instant compliance filing and the original filing from last August 15, 2011.

Section – 3.3

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

Section 3.3.2

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

Docket No. ER11-4318-000

Section 3.3.2

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

Line No.	Customer Classes	(a) Section 3.3.1 Statement BB Total 12 CPs @ Transmission Level [1]	(b) 12 CP Allocation Percentages @ Transmission Level [2]	(c) Allocated Base Transmission Revenue Requirement	(d) Reference	Line No.
1	Total Base Transmission Revenue Requirement			$ 280,017	TO3-Cycle 5; Section 3.3.1;	1
2					Page 1 of 3; Line 34	2
3	Allocation of BTRR Based on 12-CP:					3
4	Residential	15,742,820	39.46%	$ 110,495	Col.C4 = Col (c) Ln1 x Col B. Ln 4	4
5	Small Commercial	4,848,321	12.15%	34,022	Col.C5 = Col (c) Ln1 x Col B. Ln 5	5
6	Medium & Large Commercial/Industrial	18,659,462	46.77%	130,964	Col.C6 = Col (c) Ln1 x Col B. Ln 6	6
7	Street Lighting Revenues	146,179	0.37%	1,036	Col.C7 = Col (c) Ln1 x Col B. Ln 7	7
8	Standby Revenues	499,375	1.25%	3,500	Col.C8 = Col (c) Ln1 x Col B. Ln 8	8
9						9
10	Total	39,896,157	100.00%	$ 280,017	Sum Lines 4 thru 8	10
11						11
12	Total	39,896,157		$ 280,017	Line 10	12

NOTES:

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

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

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Section 3.3.2

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

Line No.	Customer Classes	Derivation of Commodity Rate & Proof of Revenues Calculation	Reference	Line No.
1	Residential - Allocated Transmission Revenue Requirements	$ 110,495	Section 3.3.2; Page 1; Line 4	1
2				2
3	Billing Determinants - Residential Customer Class @ MWh:	7,361,513	Section 3.3.2; Page 16.1; Line 3	3
4				4
5	Transmission Level Adjustment Factor	1.04570	Section 3.3.2; Page 14; Col. B; Line 2	5
6				6
7	Billing Determinants @ Transmission Level	7,697,935	Line 3 x Line 5	7
8				8
9	Residential Energy Rate Per kWh	$ 0.0143539	Line 1 / Line 7	9
10				10
11	Residential Energy Rate Per kWh - Rounded	$ 0.0143539	Line 9, Rounded to 7 Decimal Places	11
12				12
13	Proof of Revenues	$ 110,495	Line 7 x Line 11	13
14				14
15	Difference	$ (0)	Line 1 - Line 13	15

Notes:

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

Section 3.3.2

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

Line No.	Customer Classes	Derivation of Commodity Rate & Proof of Revenues Calculation	Reference	Line No.
1	Small Commercial - Allocated Transmission Revenue Requirement	$ 34,022	Section 3.3.2; Page 1; Line 5	1
2				2
3	Billing Determinants - Small Commercial @ MWh:	1,982,802	Section 3.3.2; Page 16.1; Line 7	3
4				4
5	Transmission Level Adjustment Factor	1.04570	Section 3.3.2; Page 14; Col. B; Line 3	5
6				6
7	Billing Determinants @ Transmission Level	2,073,416	Line 3 x Line 5	7
8				8
9	Energy Rate Per kWh @ Transmission Level	$ 0.0164087	Line 1 / Line 7	9
10				10
11	Energy Rate Per kWh - Rounded @ Transmission Level	$ 0.0164087	Line 9, Rounded to 7 Decimal Places	11
12				12
13	Proof of Revenues	$ 34,022	Line 7 x Line 11	13
14				14
15	Difference	$ (0)	Line 1 - Line 13	15

Notes:

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

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

Line No.	Customer Classes	Derivation of Demand Rates & Proof of Revenues Calculation	Reference	Line No.
1	**Med-Lrg C&I - Demand Revenue Requirement:**	$ 130,964	Section 3.3.2; Page 1; Line 6	1
2	*Non-Coincident Demand Determinants @ Transmission Level Used*			2
3	*to Allocate Total Customer Class Revenues to Voltage Level:*			3
4	Secondary [2]	22,208	Section 3.3.2; Page 14; Line 22; Col. C.	4
5	Primary [2]	4,326	Section 3.3.2; Page 14; Line 23; Col. C.	5
6	Transmission [2]	1,559	Section 3.3.2; Page 14; Line 24; Col. C.	6
7	Total	28,093	Sum Lines 4; 5; 6	7
8	*Allocation Factors % Per Above to Allocate*			8
9	*Demand Revenue Requirements to Voltage Level:*			9
10	Secondary	79.05%	Line 4 / Line 7	10
11	Primary	15.40%	Line 5 / Line 7	11
12	Transmission	5.55%	Line 6 / Line 7	12
13	Total	100.00%	Sum Lines 10; 11; 12	13
14				14
15	**Allocation of Revenue Requirements to Voltage Level:**			15
16	Secondary	$ 103,530	Line 1 x Line 10	16
17	Primary	20,167	Line 1 x Line 11	17
18	Transmission	7,267	Line 1 x Line 12	18
19	Total	$ 130,964	Sum Lines 16; 17; 18	19
20				20
21	**Non-Coincident Demand Determinants by Voltage Level @ Transmission:**			21
22	Secondary	22,208	Section 3.3.2; Page 14; Line 22; Col. C.	22
23	Primary	4,326	Section 3.3.2; Page 14; Line 23; Col. C.	23
24	Transmission	1,559	Section 3.3.2; Page 14; Line 24; Col. C.	24
25	Total	28,093	Sum Lines 22; 23; 24	25
26				26
27	**Non-Coincident Demand Rate By Voltage Level @ Transmission:**			27
28	Secondary	$ 4.6618336	Line 16 / Line 22	28
29	Primary	$ 4.6618123	Line 17 / Line 23	29
30	Transmission	$ 4.6613214	Line 18 / Line 24	30
31				31
32	**Non-Coincident Demand Rate By Voltage Level @ Transmission:**			32
33	Secondary	$ 4.6618336	Line 28 Rounded to 7 Decimal Places	33
34	Primary	$ 4.6618123	Line 29 Rounded to 7 Decimal Places	34
35	Transmission	$ 4.6613214	Line 30 Rounded to 7 Decimal Places	35
36				36
37	**Proof of Revenue Calculations:**			37
38	Secondary	$ 103,530	Line 22 x Line 33	38
39	Primary	20,167	Line 23 x Line 34	39
40	Transmission	7,267	Line 24 x Line 35	40
41	Total	$ 130,964	Sum Lines 38; 39; 40	41
42				42
43	Difference	$ -	Line 1 - Line 41	43

Notes:

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

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

Section 3.3.2

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

Line No.	Description	Derivation of Commodity Rate & Proof of Revenues Calculation	Reference	Line No.
1	Rate Proposal @ 90% of Total M&L C&I NCD Rates [1]	90.00%		1
2	Secondary	$ 4.1956502	90% x Section 3.3.2; Page 4; Line 33	2
3	Primary	$ 4.1956311	90% x Section 3.3.2; Page 4; Line 34	3
4	Tranmission	$ 4.1951893	90% x Section 3.3.2; Page 4; Line 35	4
5				5
6	Rate Proposal 90% of Total M&L C&I NCD Rates (Rounded)			6
7	Secondary	$ 4.1956502	Line 2, Rounded to 7 Decimal Places	7
8	Primary	$ 4.1956311	Line 3, Rounded to 7 Decimal Places	8
9	Tranmission	$ 4.1951893	Line 4, Rounded to 7 Decimal Places	9
10				10
11	**Pertaining to Schedules @ 90% NCD with Maximum On-Peak Period Demand[2]**			11
12	NCD Determinants By Voltage Level @ TRANSMISSION Level (MW)			12
13	Secondary	21,187	Section 3.3.2; Page 15; Line 10	13
14	Primary	4,024	Section 3.3.2; Page 15; Line 11	14
15	Tranmission	256	Section 3.3.2; Page 15; Line 12	15
16	Total	25,467	Sum Lines 12; 13; 14	16
17				17
18	Annual Revenues from Current NCD Rate 100% of Total M&L C&I NCD Rates			18
19	Secondary	$ 98,770	Line 13 x Section 3.3.2; Page 5; Line 33	19
20	Primary	$ 18,759	Line 14 x Section 3.3.2; Page 5; Line 34	20
21	Tranmission	$ 1,193	Line 15 x Section 3.3.2; Page 5; Line 35	21
22	Total	$ 118,722	Sum Lines 19; 20; 21	22
23				23
24	Annual Revenues from Proposed NCD Rate 90% of Total M&L C&I NCD Rates			24
25	Secondary	$ 88,893	Line 7 x Line 13	25
26	Primary	$ 16,883	Line 8 x Line 14	26
27	Tranmission	$ 1,074	Line 9 x Line 15	27
28	Total	$ 106,850	Sum Lines 25; 26; 27	28
29				29
30	Revenue Reallocation to Maximum On-Peak Period Demands			30
31	Secondary	$ 9,877	Line 19 - Line 25	31
32	Primary	$ 1,876	Line 20 - Line 26	32
33	Tranmission	$ 119	Line 21 - Line 27	33
34	Total	$ 11,872	Sum Lines 31; 32; 33	34
35				35
36	Pertaining to Schedules @ 90% NCD with Maximum Demand at Time of System Peak[3]			36
37	NCD Determinants By Voltage Level @ TRANSMISSION Level (MW)			37
38	Secondary	-	Section 3.3.2; Page 15; Col. D; Line 17	38
39	Primary	162	Section 3.3.2; Page 15; Col. D; Line 18	39
40	Tranmission	1,303	Section 3.3.2; Page 15; Col. D; Line 19	40
41	Total	1,465	Sum Lines 18; 19; 20	41
42				42
43	Annual Revenues from Current NCD Rate 100% of Total M&L C&I NCD Rates			43
44	Secondary	$ -	Line 38 x Section 3.3.2; Page 5; Line 33	44
45	Primary	$ 755	Line 39 x Section 3.3.2; Page 5; Line 34	45
46	Tranmission	$ 6,074	Line 40 x Section 3.3.2; Page 5; Line 35	46
47	Total	$ 6,829	Sum Lines 44; 45; 46	47
48				48
49	Annual Revenues from Proposed NCD Rate 90% of Total M&L C&I NCD Rates			49
50	Secondary	$ -	Line 7 x Line 38	50
51	Primary	$ 680	Line 8 x Line 39	51
52	Tranmission	$ 5,466	Line 9 x Line 40	52
53	Total	$ 6,146	Sum Lines 50; 51; 52	53
54				54
55	Revenue Reallocation to Maximum Demand at the Time of System Peak			55
56	Secondary	$ -	Line 44 - Line 50	56
57	Primary	$ 75	Line 45 - Line 51	57
58	Tranmission	$ 608	Line 46 - Line 52	58
59	Total	$ 683	Sum Lines 56; 57; 58	59

NOTES:

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

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

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

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

Line No.	Description	Derivation of Commodity Rate & Proof of Revenues Calculation	Reference	Line No.
1	Med-Lrg C&I Maximum On-Peak Period Demand Proposal			1
2	Revenue Reallocation to Maximum On-Peak Period Demands [1]	$ 11,872	Section 3.3.2; Page 5; Line 34	2
3				3
4	Summer Maximum On-Peak Period Demands By Voltage Level @ **Meter** Level (MW) [2]			4
5	Secondary	7,819	Section 3.3.2; Page 15; Col. B; Line 30	5
6	Primary	1,723	Section 3.3.2; Page 15; Col. B; Line 31	6
7	Tranmission	130	Section 3.3.2; Page 15; Col. B; Line 32	7
8	Total	9,671	Sum Lines 5; 6; 7	8
9				9
10	Summer Maximum On-Peak Period Demands @ Transmission Level (MW)			10
11	Secondary	8,176	Section 3.3.2; Page 15; Col. D; Line 30	11
12	Primary	1,742	Section 3.3.2; Page 15; Col. D; Line 31	12
13	Tranmission	130	Section 3.3.2; Page 15; Col. D; Line 32	13
14	Total	10,048	Sum Lines 11; 12; 13	14
15				15
16	Summer Maximum On-Peak Period Allocation to Voltage Levels			16
17	Secondary	81.37%	Line 11 / Line 14	17
18	Primary	17.34%	Line 12 / Line 14	18
19	Tranmission	1.29%	Line 13 / Line 14	19
20	Total	100.00%	Sum Lines 17; 18; 19	20
21	Share of Total Revenue Allocation to Summer Peak Period	80.00%		21
22	Revenues for Proposed Summer Maximum On-Peak Period Demand Rates	$ 9,498	Line 2 x Line 21	22
23	Secondary	$ 7,728	(Line 2 x Line 21) x Line 17	23
24	Primary	$ 1,647	(Line 2 x Line 21) x Line 18	24
25	Tranmission	$ 123	(Line 2 x Line 21) x Line 19	25
26	Total	**$ 9,498**	Sum Lines 23; 24; 25	26
27				27
28	Summer Maximum On-Peak Period Demand Rates [3]	$/kW		28
29	Secondary	$ 0.9452229	Line 23 / Line 11	29
30	Primary	$ 0.9452229	Line 24 / Line 12	30
31	Tranmission	$ 0.9452229	Line 25 / Line 13	31
32				32
33				33
34	Summer Maximum On-Peak Period Demand Rates (Rounded)	$/kW		34
35	Secondary	$ 0.9452229	Line 29, Rounded to 7 Decimal Places	35
36	Primary	$ 0.9452229	Line 30, Rounded to 7 Decimal Places	36
37	Tranmission	$ 0.9452229	Line 31, Rounded to 7 Decimal Places	37
38				38

NOTES:

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

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

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

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

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

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

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

Line No.	Description	Derivation of Commodity Rate & Proof of Revenues Calculation	Reference	Line No.
1	Winter Maximum On-Peak Period Demands By Voltage Level @ Meter Level (MW) [4]			1
2	Secondary	9,457	Section 3.3.2; Page 15; Col. B; Line 35	2
3	Primary	2,043	Section 3.3.2; Page 15; Col. B; Line 36	3
4	Tranmission	277	Section 3.3.2; Page 15; Col. B; Line 37	4
5	Total	11,777	Sum Lines 2; 3; 4	5
6				6
7	Winter Maximum On-Peak Period Demands @ TRANSMISSION Level (MW)			7
8	Secondary	9,889	Section 3.3.2; Page 15; Col. D; Line 35	8
9	Primary	2,065	Section 3.3.2; Page 15; Col. D; Line 36	9
10	Tranmission	277	Section 3.3.2; Page 15; Col. D; Line 37	10
11	Total	12,231	Sum Lines 8; 9; 10	11
12				12
13	Winter Maximum On-Peak Period Allocation to Voltage Levels			13
14	Secondary	80.85%	Line 8 / Line 11	14
15	Primary	16.88%	Line 9 / Line 11	15
16	Tranmission	2.26%	Line 10 / Line 11	16
17	Total	100.00%	Sum Lines 14; 15; 16	17
18	Share of Total Revenue Allocation to Winter Peak Period	20.00%		18
19	Revenues for Proposed Winter Maximum On-Peak Period Demand Rates	$ **2,374**	(Section 3.3.2; Page 5; Line 34) x Line 18	19
20	Secondary	$ 1,920	(Section 3.3.2; Page 5; Line 34 x Line 18) x Line 14	20
21	Primary	$ 401	(Section 3.3.2; Page 5; Line 34 x Line 18) x Line 15	21
22	Tranmission	$ 54	(Section 3.3.2; Page 5; Line 34 x Line 18) x Line 16	22
23	Total	$ **2,374**	Sum Lines 20; 21; 22	23
24				24
25	Winter Maximum On-Peak Period Demand Rates [5]	$/kW		25
26	Secondary	$ 0.1941297	Line 20 / Line 8	26
27	Primary	$ 0.1941297	Line 21 / Line 9	27
28	Tranmission	$ 0.1941297	Line 22 / Line 10	28
29				29
30				30
31	Winter Maximum On-Peak Period Demand Rates (Rounded)	$/kW		31
32	Secondary	$ 0.1941297	Line 26, Rounded to 7 Decimal Places	32
33	Primary	$ 0.1941297	Line 27, Rounded to 7 Decimal Places	33
34	Tranmission	$ 0.1941297	Line 28, Rounded to 7 Decimal Places	34
35				35
36				36
37	<u>Proof of Revenue Calculations:</u>			37
38	Secondary	$ 9,648	(Section 3.3.2; Page 6; Line 11 x Section Page 6; Line 35) + (Line 8 x Line 32)	38
39	Primary	$ 2,047	(Section 3.3.2; Page 6; Line 12 x Section Page 6; Line 36) + (Line 9 x Line 33)	39
40	Tranmission	$ 177	(Section 3.3.2; Page 6; Line 13 x Section Page 6; Line 37) + (Line 10 x Line 34)	40
41	Total	$ 11,872	Sum Lines 38; 39; 40	41
42				42
43	Difference	$ (0)	Section 3.3.2; Page 6; Line 2 Minus Page 7; Line 41	43
44				44

NOTES:

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

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

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

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

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

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

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

Line No.	Description		Derivation of Commodity Rate & Proof of Revenues Calculation	Reference	Line No.
1	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]	$	683	Section 3.3.2; Page 5; Line 59	2
3					3
4	Summer Maximum Demand at the Time of System Peak By Voltage Level @ **Meter** Level (MW) [2]				4
5	Secondary		-	Section 3.3.2; Page 15; Col. B; Line 42	5
6	Primary		47	Section 3.3.2; Page 15; Col. B; Line 43	6
7	Transmission		465	Section 3.3.2; Page 15; Col. B; Line 44	7
8	Total		512	Sum Lines 5; 6; and 7	8
9					9
10	Summer Maximum Demand at the Time of System Peak @ **TRANSMISSION** Level (MW)				10
11	Secondary		-	Section 3.3.2; Page 15; Col. D; Line 42	11
12	Primary		48	Section 3.3.2; Page 15; Col. D; Line 43	12
13	Tranmission		465	Section 3.3.2; Page 15; Col. D; Line 44	13
14	Total		513	Sum Lines 11; 12; and 13	14
15					15
16	Summer Maximum Demand at the time of System Peak Allocation to Voltage Levels (MW)				16
17	Secondary		0.00%	Line 11 / Line 14	17
18	Primary		9.36%	Line 12 / Line 14	18
19	Tranmission		90.64%	Line 13 / Line 14	19
20	Total		100.00%	Sum Lines 17; 18; and 19	20
21	Share of Total Revenue Allocation to Summer Maximum Demand at the Time of System Peak		80.00%		21
22	Revenues for Proposed Summer Maximum Demand at the Time of System Peak Rates	$	**546**	Line 2 x Line 21	22
23	Secondary	$	-	(Line 2 x Line 21) x Line 17	23
24	Primary	$	51	(Line 2 x Line 21) x Line 18	24
25	Tranmission	$	495	(Line 2 x Line 21) x Line 19	25
26	Total	$	**546**	Sum Lines 23; 24; and 25	26
27					27
28	Summer Maximum Demand at the Time of System Peak Rates [3]		$/kW		28
29	Secondary	$	-	Line 23 / Line 11	29
30	Primary	$	1.0651072	Line 24 / Line 12	30
31	Tranmission	$	1.0651072	Line 25 / Line 13	31
32					32
33					33
34	Summer Maximum Demand at the Time of System Peak Rates (Rounded)		$/kW		34
35	Secondary	$	-	Line 29, Rounded to 7 Decimal Places	35
36	Primary	$	1.0651072	Line 30, Rounded to 7 Decimal Places	36
37	Tranmission	$	1.0651072	Line 31, Rounded to 7 Decimal Places	37
38					38

NOTES:

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

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

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

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

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

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

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

Line No.	Description	Derivation of Commodity Rate & Proof of Revenues Calculation	Reference	Line No.
1	Winter Maximum Demand at the Time of System Peak By Voltage Level @ Meter Level (MW) [4]			1
2	Secondary	-	Section 3.3.2; Page 15; Col. B; Line 47	2
3	Primary	88	Section 3.3.2; Page 15; Col. B; Line 48	3
4	Tranmission	570	Section 3.3.2; Page 15; Col. B; Line 49	4
5	Total	658	Sum Lines 2; 3; 4	5
6				6
7	Winter Maximum Demand at the Time of System Peak @ Transmission Level (MW)			7
8	Secondary	-	Section 3.3.2; Page 15; Col. D; Line 47	8
9	Primary	89	Section 3.3.2; Page 15; Col. D; Line 48	9
10	Tranmission	570	Section 3.3.2; Page 15; Col. D; Line 49	10
11	Total	659	Sum Lines 8; 9; 10	11
12				12
13	Winter Maximum Demand at the Time of System Peak Allocation to Voltage Levels			13
14	Secondary	0.00%	Line 8 / Line 11	14
15	Primary	13.51%	Line 9 / Line 11	15
16	Tranmission	86.49%	Line 10 / Line 11	16
17	Total	100.00%	Sum Lines 14; 15; 16	17
18	Share of Total Revenue Allocation to Winter Maximum Demand at the Time of System Peak	20.00%		18
19	Revenues for Proposed Winter Maximum Demand at the Time of System Peak Rates	$ **137**	Section 3.3.2; Page 8; Line 2	19
20	Secondary	$ -	(Section 3.3.2; Page 8; Line 2 x Line 17) x Line 14	20
21	Primary	$ 18	(Section 3.3.2; Page 8; Line 2 x Line 18) x Line 15	21
22	Tranmission	$ 118	(Section 3.3.2; Page 8; Line 2 x Line 19) x Line 16	22
23	Total	$ **137**	Sum Lines 20; 21; 22	23
24				24
25	Winter Maximum Demand at the Time of System Peak Rates [5]	$/kW		25
26	Secondary	$ -	Line 20 / Line 8	26
27	Primary	$ 0.2072838	Line 21 / Line 9	27
28	Tranmission	$ 0.2072838	Line 21 / Line 10	28
29				29
30				30
31	Winter Maximum Demand at the Time of System Peak Rates (Rounded)	$/kW		31
32	Secondary	$ -	Line 26, Rounded to 7 Decimal Places	32
33	Primary	$ 0.2072838	Line 27, Rounded to 7 Decimal Places	33
34	Tranmission	$ 0.2072838	Line 28, Rounded to 7 Decimal Places	34
35				35
36				36
37	Proof of Revenue Calculations:			37
38	Secondary	$ -	Section 3.3.2; Page 8 (Line 5 x Line 35) + Page 9; (Line 8 x Line 32)	38
39	Primary	$ 70	Section 3.3.2; Page 8 (Line 6 x Line 36) + Page 9; (Line 9 x Line 33)	39
40	Tranmission	$ 613	Section 3.3.2; Page 8 (Line 7 x Line 37) + Page 9; (Line 10 x Line 34)	40
41	Total	$ 683	Sum Lines 38; 39; and 40	41
42				42
43	Difference	$ (0)	Section 3.3.2; Page 8; Line 2 Minus Page 9; Line 41	43
44				44

NOTES:

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

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

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

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

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

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

Section 3.3.2

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

Line No.	Customer Classes	Derivation of Commodity Rate & Proof of Revenues Calculation	Reference	Line No.
1	Street Lighting - Allocated Transmission Revenue Requirement	$ 1,036	Section 3.3.2; Page 1; Line 7	1
2				2
3	Billing Determinants - Street Lighting Customers @ MWh [1]:	117,138	Section 3.3.2; Page 16.1; Line 15	3
4				4
5	Transmission Level Adjustment Factor	1.04570	Section 3.3.2; Page 14; Col. B; Line 10	5
6				6
7	Billing Determinants @ Transmission Level	122,491	Line 3 x Line 5	7
8				8
9	Energy Rate Per kWh @ Transmission Level	$ 0.0084577	Line 1 / Line 7	9
10				10
11	Energy Rate Per kWh - Rounded @ Transmission Level	$ 0.0084577	Line 9, Rounded to 7 Decimal Places	11
12				12
13	Proof of Revenues	$ 1,036	Line 7 x Line 11	13
14				14
15	Difference	$ 0	Line 1 - Line 13	15

Notes:

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

Section 3.3.2
SAN DIEGO GAS AND ELECTRIC COMPANY
TO3-Cycle 5 Annual Transmission Formulaic Rate Filing
Derivation of True-Up Period ISO Retail Rates Base on True-Up Period Cost of Service
Standby Revenues Calculation
($000)

Line No.	Customer Classes	Derivation of Standby Surcharge & Proof of Revenues Calculation	Reference	Line No.
1	**Standby - Demand Revenue Requirement:**	$ 3,500	Section 3.3.2; Page 1; Line 8	1
2	*Demand Determinants @ Transmission Level Used to Allocate*			2
3	*Total Class Revenues to Voltage Level:*			3
4	Secondary [1]	152	Section 3.3.2; Page 15; Col. D; Line 54	4
5	Primary [1]	1,014	Section 3.3.2; Page 15; Col. D; Line 55	5
6	Tranmission [1]	593	Section 3.3.2; Page 15; Col. D; Line 56	6
7	Total	1,759	Sum Lines 4; 5; 6	7
8	*Allocation Factors Per Above to Allocate*			8
9	*Demand Revenue Requirements to Voltage Level:*			9
10	Secondary	8.64%	Line 4 / Line 7	10
11	Primary	57.65%	Line 5 / Line 7	11
12	Tranmission	33.71%	Line 6 / Line 7	12
13	Total	100.00%	Sum Lines 10; 11; 12	13
14				14
15	**Allocation of Revenue Requirements to Voltage Level:**			15
16	Secondary	$ 302	Line 1 x Line 10	16
17	Primary	2,018	Line 1 x Line 11	17
18	Tranmission	1,180	Line 1 x Line 12	18
19	Total	$ 3,500	Sum Lines 16; 17; 18	19
20				20
21	**Demand Determinants By Voltage Level @ Transmission:**			21
22	Secondary	152	Section 3.3.2; Page 15; Col. D; Line 54	22
23	Primary	1,014	Section 3.3.2; Page 15; Col. D; Line 55	23
24	Tranmission	593	Section 3.3.2; Page 15; Col. D; Line 56	24
25	Total	1,759	Sum Lines 22; 23; 24	25
26				26
27	**Demand Rate By Voltage Level @ Transmission:**			27
28	Secondary	$ 1.9868421	Line 16 / Line 22	28
29	Primary	$ 1.9901381	Line 17 / Line 23	29
30	Tranmission	$ 1.9898820	Line 18 / Line 24	30
31				31
32	**Demand Rate By Voltage Level @ Transmission (Rounded):**			32
33	Secondary	$ 1.9868421	Line 28 Rounded to 7 Decimal Places	33
34	Primary	$ 1.9901381	Line 29 Rounded to 7 Decimal Places	34
35	Tranmission	$ 1.9898820	Line 30 Rounded to 7 Decimal Places	35
36				36
37	**Proof of Revenue Calculations:**			37
38	Secondary	$ 302	Line 22 x Line 33	38
39	Primary	2,018	Line 23 x Line 34	39
40	Tranmission	1,180	Line 24 x Line 35	40
41	Total	$ 3,500	Sum Lines 38; 39; 40	41
42				42
43	Difference	$ -	Line 1 - Line 41	43

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

Section 3.3.2
SAN DIEGO GAS AND ELECTRIC COMPANY
TO3-Cycle 5 Annual Transmission Formulaic Rate Filing
WHOLESALE - Rate Design Information
Summary of TO3-CYCLE-5 Wholesale Transmission Rates Based on TO3-CYCLE-5 Wholesale True-Up Cost of Service
Using TO3-CYCLE-5 True-Up Period Billing Determinants (April 2010 - March 2011)

Line No.	Customer Classes	Transmission Energy Rates $/kWh	Transmission Level Demand Rates $/kW-Mo	Primary Level Demand Rates $/kW-Mo	Secondary Level Demand Rates $/kW-Mo	Reference	Line No.
1	Residential	$ 0.0143539				Section 3.3.2; Page 2; Line 11	1
2							2
3	Small Commercial	$ 0.0164087				Section 3.3.2; Page 3; Line 11	3
4							4
5	Med & Lrg Commercial/Industrial						5
6	Non-Coincident Demand (100%) [1]		$ 4.6613214	$ 4.6618123	$ 4.6618336	Section 3.3.2; Page 4; Lines 33;34;35	6
7							7
8	Non-Coincident Demand (90%) [2]		$ 4.1951893	$ 4.1956311	$ 4.1956502	Section 3.3.2; Page 5; Lines 7;8;9	8
9							9
10	Maximum On-Peak Demand [3]						10
11	Summer		$ 0.9452229	$ 0.9452229	$ 0.9452229	Section 3.3.2; Page 6; Lines 35;36;37	11
12	Winter		$ 0.1941297	$ 0.1941297	$ 0.1941297	Section 3.3.2; Page 7; Lines 32;33;34	12
13							13
14	Maximum Demand at the Time of System Peak [4]						14
15	Summer		$ 1.0651072	$ 1.0651072	$ -	Section 3.3.2; Page 8; Lines 29;30;31	15
16	Winter		$ 0.2072838	$ 0.2072838	$ -	Section 3.3.2; Page 9; Lines 35;36;37	16
17							17
18	Street Lighting	$ 0.0084577				Section 3.3.2; Page 10; Line 11	18
19							19
20	Standby Rate		$ 1.9898820	$ 1.9901381	$ 1.9868421	Section 3.3.2; Page 11; Lns 33;34;35	20

NOTES:

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

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

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

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

Section 3.3.2

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

Line No.	Customer Classes	Total Revenues Per Cost of Service Study	Total Revenues Per Rate Design	Difference	Reference	Line No.
1	Residential Customers	$ 110,495	$ 110,495	$ (0)	Sect. 3.3.2; Pg. 1; Ln. 4; Pg. 2; Ln. 13	1
2						2
3	Small Commercial	34,022	34,022	(0)	Sect. 3.3.2; Pg. 1; Ln. 5; Pg. 3; Ln. 13	3
4						4
5	Med & Lrg Commercial/Industrial	130,964	130,964	-	Sect. 3.3.2; Pg. 1; Ln. 6; Pg. 4; Ln. 41	5
6						6
7	Street Lighting	1,036	1,036	0	Sect. 3.3.2; Pg. 1; Ln. 7; Pg. 10; Ln. 13	7
8						8
9	Standby Revenues	3,500	3,500	-	Sect. 3.3.2; Pg. 1; Ln. 8; Pg. 11; Ln. 41	9
10						10
11	Grand Total	$ 280,017	$ 280,017	$ (0)	Sum Lines 1 thru 9	11

Section 3.3.2

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

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

NOTES:

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

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

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

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

Section 3.3.2

San Diego Gas & Electric

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

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

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

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

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

Line No.		Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Total	Line No.
39															39
40															40
41	Schedules AL-TOU / AY-TOU / DG-R:	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Total	41
42	Total Deliveries (MWh)	708,903	692,577	744,964	827,532	755,332	871,898	817,218	756,976	723,654	772,108	698,123	742,483	9,111,768	42
43															43
44	Total Deliveries (%)														44
45	% @ Secondary Service	79.27%	78.43%	82.11%	79.43%	78.58%	80.34%	77.71%	78.07%	81.77%	79.54%	79.60%	81.39%	79.68%	45
46	% @ Primary Service	19.02%	20.66%	17.19%	19.92%	20.47%	18.67%	19.01%	19.23%	17.28%	19.44%	19.90%	17.48%	19.02%	46
47	% @ Transmission Service	1.71%	0.91%	0.70%	0.65%	0.95%	0.99%	3.28%	2.70%	0.95%	1.02%	0.50%	1.13%	1.30%	47
48		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	48
49	Total Deliveries (MWh)														49
50	MWh @ Secondary Service	561,948	543,188	611,690	657,309	593,540	700,483	635,060	590,971	591,732	614,135	555,706	604,307	7,260,068	50
51	MWh @ Primary Service	134,833	143,086	128,059	164,844	154,616	162,783	155,353	145,567	125,047	150,098	138,926	129,786	1,733,001	51
52	MWh @ Transmission Service	12,122	6,302	5,215	5,379	7,176	8,632	26,805	20,438	6,875	7,876	3,491	8,390	118,700	52
53		708,903	692,577	744,964	827,532	755,332	871,898	817,218	756,976	723,654	772,108	698,123	742,483	9,111,768	53
54	Non-Coincident Demand (%)														54
55	% @ Secondary Service	0.2810%	0.2688%	0.2705%	0.2744%	0.2793%	0.2709%	0.2955%	0.2984%	0.2822%	0.2792%	0.2768%	0.2723%	0.2791%	55
56	% @ Primary Service	0.2376%	0.2190%	0.2213%	0.2386%	0.2236%	0.2289%	0.2400%	0.2369%	0.2403%	0.2205%	0.2216%	0.2273%	0.2297%	56
57	% @ Transmission Service	0.1981%	0.2219%	0.2323%	0.2659%	0.2727%	0.2418%	0.2261%	0.1460%	0.2803%	0.2419%	0.3092%	0.1336%	0.2154%	57
58															58
59	Non-Coincident Demand (MW)														59
60	MW @ Secondary Service	1,579.073	1,460.090	1,654.621	1,803.656	1,657.757	1,897.608	1,876.603	1,763.458	1,669.866	1,714.665	1,538.193	1,645.528	20,261.118	60
61	MW @ Primary Service	320.364	313.359	283.395	393.319	345.722	372.611	372.848	344.847	300.489	330.966	307.861	295.004	3,980.785	61
62	MW @ Transmission Service	24.014	13.985	12.114	14.303	19.568	20.872	60.606	29.840	19.270	19.051	10.793	11.209	255.624	62
63		1,923.452	1,787.434	1,950.130	2,211.277	2,023.047	2,291.090	2,310.056	2,138.145	1,989.625	2,064.681	1,856.847	1,951.741	24,497.526	63
64	On-Peak Demand (%)														64
65	% @ Secondary Service	0.2265%	0.2275%	0.2503%	0.2580%	0.2621%	0.2570%	0.2522%	0.2346%	0.2213%	0.2198%	0.2191%	0.2183%	0.2380%	65
66	% @ Primary Service	0.1996%	0.2075%	0.2313%	0.2366%	0.2323%	0.2339%	0.2293%	0.2085%	0.2107%	0.1977%	0.2061%	0.2063%	0.2173%	66
67	% @ Transmission Service	0.3645%	0.4230%	0.5473%	0.4202%	0.3757%	0.2874%	0.2268%	0.2739%	0.6176%	0.3522%	0.3647%	0.3891%	0.3421%	67
68															68
69	On-Peak Demand (MW)	W	S	S	S	S	S	W	W	W	W	W	W	Total	69
70	MW @ Secondary Service	1,272.812	1,235.753	1,531.060	1,695.857	1,555.668	1,800.241	1,601.622	1,386.419	1,309.502	1,349.869	1,217.551	1,319.202	17,275.554	70
71	MW @ Primary Service	269.128	296.904	296.201	390.022	359.174	380.750	356.225	303.506	263.475	296.743	286.327	267.749	3,766.204	71
72	MW @ Transmission Service	44.186	26.659	28.540	22.602	26.959	24.808	60.793	55.981	42.458	27.738	12.730	32.646	406.100	72
73		1,586.125	1,559.317	1,855.801	2,108.481	1,941.801	2,205.799	2,018.640	1,745.906	1,615.435	1,674.350	1,516.609	1,619.596	21,447.858	73
74															74

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

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

Section – 3.3

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

Section 3.3.3

Derivation of ISO Monthly Cost of Service (COS) Revenues Applicable to the 12-Month True-Up Period (Monthly True-Up Revenues)

Docket No. ER11-4318-000

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

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	
Line No.	Customer Class	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Total	Reference	Line No.
1	Residential Customers	$ 8,411,293	$ 7,763,129	$ 8,264,565	$ 8,908,528	$ 8,860,931	$ 10,300,492	$ 9,605,185	$ 8,846,038	$ 10,085,658	$ 10,870,288	$ 9,427,099	$ 9,152,177	$ 110,495,383	Section 3.3.3; Pages 19 & 20; Line 21	1
2																2
3	Small Commercial	2,711,045	2,356,310	2,787,110	3,043,001	2,808,015	3,247,209	3,043,200	2,788,384	2,813,999	2,935,629	2,738,579	2,749,580	34,022,060	Section 3.3.3; Pages 19 & 20; Line 23	3
4																4
5	Med-Lrg C&I @ 100% NCD	476,684	389,562	449,719	460,410	468,559	473,886	471,160	453,775	437,631	415,746	460,307	455,054	5,412,493	Section 3.3.3; Page 21; Line 21	5
6	Med-Lrg C&I @ 90% NCD	8,855,788	8,343,453	8,996,669	10,207,118	9,266,230	10,550,974	10,618,121	9,829,812	9,241,723	9,517,106	8,578,251	8,989,489	112,994,734	Section 3.3.3; Page 22; Line 33	6
7	Max On Peak Demand	319,771	1,530,313	1,823,307	2,070,221	1,906,301	2,166,623	406,835	351,869	325,774	337,639	305,821	326,677	11,871,151	Section 3.3.3; Page 23; Line 21	7
8	Max Dem-Time of System Peak	16,670	116,053	110,276	120,536	78,631	120,906	24,312	25,271	18,493	18,021	18,128	15,639	682,936	Section 3.3.3; Page 24; Line 21	8
9	Total Med-Lrg C&I	9,668,913	10,379,381	11,379,971	12,858,285	11,719,721	13,312,389	11,520,428	10,660,727	10,023,621	10,288,512	9,362,507	9,786,859	130,961,314	Sum Lines 5, 6, 7, 8	9
10																10
11	Street Lighting	112,683	53,167	83,569	83,724	85,951	75,912	93,613	83,024	113,512	54,037	84,004	112,799	1,035,995	Section 3.3.3; Pages 19 & 20; Line 27	11
12																12
13	Standby Revenues	287,371	289,259	289,849	293,611	292,132	292,130	286,486	286,486	296,361	295,821	294,304	295,666	3,499,476	Section 3.3.3; Page 25; Line 21	13
14																14
15	TOTAL Recorded [1]	$ 21,191,305	$ 20,841,245	$ 22,805,064	$ 25,187,149	$ 23,766,750	$ 27,228,132	$ 24,548,912	$ 22,664,660	$ 23,333,150	$ 24,444,288	$ 21,906,493	$ 22,097,081	$ 280,014,229	Sum Lines 1, 3, 9, 11, 13	15

NOTES:

1 For the recorded revenues by customer class from April 2010 - March 2011, the transmission rates were based on the wholesale transmission revenue requirements derived from Statement BK2 of the current cycle filing.
The total True-Up Period Cost of Service from Section 3.3.1; Page 1 of 3; Line 34 is $280,017,000. The total shown in Column M, Line 15 is $280,145,229. The difference of $2,771 is due to rounding.

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Section 3.3.3

SAN DIEGO GAS AND ELECTRIC COMPANY

TO3-Cycle 5 Annual Transmission Formulaic Rate Filing

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

For the True-Up Period April 2010 through March 2011

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

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

		(A)		(B)		(C)		(D)		(E)		(F)		(F)		
		Apr-10		May-10		Jun-10		Jul-10		Aug-10		Sep-10		Sub-Total		
		Derived Wholesale Transmission Rates		Derived Wholesale Transmission Rates		Derived Wholesale Transmission Rates		Derived Wholesale Transmission Rates		Derived Wholesale Transmission Rates		Derived Wholesale Transmission Rates		Derived Wholesale Transmission Rates		
Line No.	Customer Classes	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Line No.
12	Residential Customers	$ 0.0143539		$ 0.0143539		$ 0.0143539		$ 0.0143539		$ 0.0143539		$ 0.0143539				12
13																13
14	Small Commercial	$ 0.0164087		$ 0.0164087		$ 0.0164087		$ 0.0164087		$ 0.0164087		$ 0.0164087				14
15																15
16	Medium-Large Commercial															16
17																17
18	Street Lighting	$ 0.0084577		$ 0.0084577		$ 0.0084577		$ 0.0084577		$ 0.0084577		$ 0.0084577				18
19																19
20	Standby Customers															20

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

		(A)		(B)		(C)		(D)		(E)		(F)		(F)		
		Apr-10		May-10		Jun-10		Jul-10		Aug-10		Sep-10		Sub-Total		
		Revenues @ Present Rates		Revenues @ Present Rates		Revenues @ Present Rates		Revenues @ Present Rates		Revenues @ Present Rates		Revenues @ Present Rates		Revenues @ Changed Rates		
Line No.	Customer Classes	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Line No.
21	Residential Customers	$ 8,411,293		$ 7,763,129		$ 8,264,565		$ 8,908,528		$ 8,860,931		$ 10,300,492		$ 52,508,938	$ -	21
22																22
23	Small Commercial	$ 2,711,045		$ 2,356,310		$ 2,787,110		$ 3,043,001		$ 2,808,015		$ 3,247,209		$ 16,952,690	$ -	23
24																24
25	Medium-Large Commercial	$ -	$ 9,668,913	$ -	$10,379,381	$ -	$11,379,971	$ -	$12,858,285	$ -	$11,719,721	$ -	$13,312,389	$ -	$ 69,318,660	25
26																26
27	Street Lighting	$ 112,683		$ 53,167		$ 83,569		$ 83,724		$ 85,951		$ 75,912		$ 495,006	$ -	27
28																28
29	Standby Customers		$ 287,371		$ 289,259		$ 289,849		$ 293,611		$ 292,132		$ 292,130	$ -	$ 1,744,352	29
30																30
31	TOTAL	$ 11,235,021	$ 9,956,284	$ 10,172,605	$10,668,640	$ 11,135,244	$11,669,820	$ 12,035,253	$13,151,896	$ 11,754,897	$12,011,853	$ 13,623,613	$13,604,519	$ 69,956,634	$ 71,063,012	31
32																32
33	Grand Total		$21,191,305		$20,841,245		$22,805,064		$25,187,149		$23,766,750		$27,228,132		$141,019,646	33

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

Section 3.3.3

SAN DIEGO GAS AND ELECTRIC COMPANY

TO3-Cycle 5 Annual Transmission Formulaic Rate Filing

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

For the True-Up Period April 2010 through March 2011

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

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

		(H)		(I)		(J)		(K)		(L)		(M)		(N)		(O)		
		Oct-10		Nov-10		Dec-10		Jan-11		Feb-11		Mar-11		Sub-Total		Grand-Total		
		Transmission Rates @ Present		Transmission Rates @ Present		Transmission Rates @ Present		Transmission Rates @ Present		Transmission Rates @ Present		Transmission Rates @ Present		Transmission Rates @ Present		Changed Transmission Rates		
Line No.	Customer Classes	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Line No.
12	Residential Customers	$ 0.0143539		$ 0.0143539		$ 0.0143539		$ 0.0143539		$ 0.0143539		$ 0.0143539						12
13																		13
14	Small Commercial	$ 0.0164087		$ 0.0164087		$ 0.0164087		$ 0.0164087		$ 0.0164087		$ 0.0164087						14
15																		15
16	Medium-Large Commercial																	16
17																		17
18	Street Lighting	$ 0.0084577		$ 0.0084577		$ 0.0084577		$ 0.0084577		$ 0.0084577		$ 0.0084577						18
19																		19
20	Standby Customers																	20

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

		(H)		(I)		(J)		(K)		(L)		(M)		(N)		(O)		
		Oct-10		Nov-10		Dec-10		Jan-11		Feb-11		Mar-11		Sub-Total		Grand-Total		
		Revenues @ Present Rates		Revenues @ Present Rates		Revenues @ Present Rates		Revenues @ Present Rates		Revenues @ Present Rates		Revenues @ Present Rates		Revenues @ Changed Rates		Revenues @ Changed Rates		
Line No.	Customer Classes	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Line No.
21	Residential Customers	$ 9,605,185		$ 8,846,038		$ 10,085,658		$ 10,870,288		$ 9,427,099		$ 9,152,177		$ 57,986,445	$ -	$ 110,495,383	$ -	21
22																		22
23	Small Commercial	$ 3,043,200		$ 2,788,384		$ 2,813,999		$ 2,935,629		$ 2,738,579		$ 2,749,580		$ 17,069,371	$ -	$ 34,022,060	$ -	23
24																		24
25	Medium-Large Commercial	$ -	$11,520,428	$ -	$10,660,727	$ -	$10,023,621	$ -	$10,288,512	$ -	$ 9,362,507	$ -	$ 9,786,859	$ -	$61,642,654	$ -	$ 130,961,314	25
26																		26
27	Street Lighting	$ 93,613		$ 83,024		$ 113,512		$ 54,037		$ 84,004		$ 112,799		$ 540,989	$ -	$ 1,035,995	$ -	27
28																		28
29	Standby Customers		$ 286,486		$ 286,486		$ 296,361		$ 295,821		$ 294,304		$ 295,666	$ -	$ 1,755,124	$ -	$ 3,499,476	29
30																		30
31	TOTAL	$ 12,741,998	$11,806,914	$ 11,717,447	$10,947,213	$ 13,013,168	$10,319,982	$ 13,859,955	$10,584,333	$ 12,249,682	$ 9,656,811	$ 12,014,556	$10,082,525	$ 75,596,805	$63,397,778	$ 145,553,439	$ 134,460,790	31
32																		32
33	Grand Total		$24,548,912		$22,664,660		$23,333,150		$24,444,288		$21,906,493		$22,097,081		$138,994,583		$ 280,014,229	33

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

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Section 3.3.3
SAN DIEGO GAS AND ELECTRIC COMPANY
TO3-Cycle 5 Annual Transmission Formulaic Rate Filing
SUMMARY of Derived Revenues at Present Rates from the WHOLESALE Rates Developed in TO3-Cycle 5
Proof of Revenues - Medium & Large C&I Customers
Non-Coincident Demand @ 100%

Line No.	Description	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Total	Reference	Line No.
1	**Non-Coincident Demand (KW): Applied to 100%:**															1
2	Secondary	94,133	74,331	82,932	86,726	88,169	89,369	88,874	85,878	83,495	76,238	83,226	87,351	1,020,722	Section 3.3.3; Page 26.2; Ln. 54	2
3	Primary	8,119	9,233	13,536	12,035	12,340	12,283	12,194	11,461	10,380	12,943	15,513	10,262	140,301	Section 3.3.3; Page 26.2; Ln. 58	3
4	Transmission	-	-	-	-	-	-	-	-	-	-	-	-	-	Section 3.3.3; Page 26.2; Ln. 60	4
5	Total	102,253	83,564	96,468	98,762	100,510	101,652	101,068	97,338	93,875	89,181	98,739	97,613	1,161,023	Sum Lines 2; 3; 4	5
9																9
10	**Non-Coindent Demand Rates Per ($/KW) @ 100%:** [1]															10
11	Secondary	$ 4.6618336	$ 4.6618336	$ 4.6618336	$ 4.6618336	$ 4.6618336	$ 4.6618336	$ 4.6618336	$ 4.6618336	$ 4.6618336	$ 4.6618336	$ 4.6618336	$ 4.6618336		Section 3.3.2; Page 12; Line 6	11
12	Primary	$ 4.6618123	$ 4.6618123	$ 4.6618123	$ 4.6618123	$ 4.6618123	$ 4.6618123	$ 4.6618123	$ 4.6618123	$ 4.6618123	$ 4.6618123	$ 4.6618123	$ 4.6618123		Section 3.3.2; Page 12; Line 6	12
13	Transmission	$ 4.6613214	$ 4.6613214	$ 4.6613214	$ 4.6613214	$ 4.6613214	$ 4.6613214	$ 4.6613214	$ 4.6613214	$ 4.6613214	$ 4.6613214	$ 4.6613214	$ 4.6613214		Section 3.3.2; Page 12; Line 6	13
14																14
15	**Revenues @ Calculated Rates:**															15
16	Secondary	$ 438,834	$ 346,518	$ 386,616	$ 404,304	$ 411,031	$ 416,623	$ 414,314	$ 400,347	$ 389,240	$ 355,407	$ 387,986	$ 407,215	$ 4,758,435	Line 2 x Line 11	16
17	Primary	37,850	43,044	63,103	56,106	57,528	57,263	56,846	53,428	48,391	60,339	72,321	47,839	654,058	Line 3 x Line 12	17
18	Transmission	-	-	-	-	-	-	-	-	-	-	-	-	-	Line 4 x Line 13	18
19	Total	$ 476,684	$ 389,562	$ 449,719	$ 460,410	$ 468,559	$ 473,886	$ 471,160	$ 453,775	$ 437,631	$ 415,746	$ 460,307	$ 455,054	$ 5,412,493	Sum Lines 16; 17; 18	19
20																20
21	**Total Revenues @ Calculated Rates:**	$ 476,684	$ 389,562	$ 449,719	$ 460,410	$ 468,559	$ 473,886	$ 471,160	$ 453,775	$ 437,631	$ 415,746	$ 460,307	$ 455,054	$ 5,412,493	Line 19	21

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

Section 3.3.3

SAN DIEGO GAS AND ELECTRIC COMPANY

TO3-Cycle 5 Annual Transmission Formulaic Rate Filing

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

Proof of Revenues - Medium & Large C&I Customers

Non-Coincident Demand @ 90%

Line No.	Description	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Total	Reference	Line No.
1	Non-Coincident Demand (KW): Applied to 90%:															1
2																2
3	Schedules AL-TOU / AY-TOU / DG-R	1,651,237	1,526,816	1,730,237	1,886,083	1,733,516	1,984,328	1,962,364	1,844,048	1,746,179	1,793,025	1,608,489	1,720,729	21,187,051	Section 3.3.3; Page 26.2; Ln. 87	3
4	Schedule A6-TOU	-	-	-	-	-	-	-	-	-	-	-	-	-	Section 3.3.3; Page 26.3; Ln. 137	4
5	Total - Secondary	1,651,237	1,526,816	1,730,237	1,886,083	1,733,516	1,984,328	1,962,364	1,844,048	1,746,179	1,793,025	1,608,489	1,720,729	21,187,051	Sum Lines 3 and 4	5
6	Check Figure	1,651,237	1,526,816	1,730,237	1,886,083	1,733,516	1,984,328	1,962,364	1,844,048	1,746,179	1,793,025	1,608,489	1,720,729	21,187,051	Check Figure	6
7																7
8	Schedules AL-TOU / AY-TOU / DG-R:	323,824	316,743	286,456	397,567	349,456	376,635	376,874	348,571	303,734	334,540	311,186	298,190	4,023,777	Section 3.3.3; Page 26.3; Ln. 91	8
9	Schedule A6-TOU	12,849	5,102	8,229	12,085	5,331	17,325	6,064	6,099	20,064	19,928	19,087	29,954	162,119	Section 3.3.3; Page 26.4; Ln. 141	9
10	Total - Primary	336,673	321,846	294,685	409,652	354,787	393,960	382,939	354,670	323,798	354,468	330,273	328,144	4,185,895	Sum Lines 8 and 9	10
11	Check Figure	336,673	321,846	294,685	409,652	354,787	393,960	382,939	354,670	323,798	354,468	330,273	328,144	4,185,895	Check Figure	11
12																12
13	Schedules AL-TOU / AY-TOU / DG-R:	24,014	13,985	12,114	14,303	19,568	20,872	60,606	29,840	19,270	19,051	10,793	11,209	255,624	Section 3.3.3; Page 26.3; Ln. 93	13
14	Schedule A6-TOU	98,798	125,966	107,263	122,766	100,676	115,598	124,859	114,316	113,460	101,798	95,017	82,504	1,303,020	Section 3.3.3; Page 26.4; Ln. 143	14
15	Total - Transmission	122,812	139,951	119,377	137,068	120,244	136,470	185,465	144,156	132,730	120,849	105,810	93,713	1,558,644	Sum Lines 13 and 14	15
16	Check Figure	122,812	139,951	119,377	137,068	120,244	136,470	185,465	144,156	132,730	120,849	105,810	93,713	1,558,644	Check Figure	16
17	Total	2,110,722	1,988,613	2,144,299	2,432,803	2,208,548	2,514,758	2,530,767	2,342,875	2,202,708	2,268,342	2,044,571	2,142,585	26,931,591	Sum Lines 6; 11; 16	17
18																18
19	Non-Coindent Demand Rates Per ($/KW) @ 90%:															19
20	Secondary	$ 4.1956502	$ 4.1956502	$ 4.1956502	$ 4.1956502	$ 4.1956502	$ 4.1956502	$ 4.1956502	$ 4.1956502	$ 4.1956502	$ 4.1956502	$ 4.1956502	$ 4.1956502		Section 3.3.2; Page 12; Line 8	20
21	Primary	$ 4.1956311	$ 4.1956311	$ 4.1956311	$ 4.1956311	$ 4.1956311	$ 4.1956311	$ 4.1956311	$ 4.1956311	$ 4.1956311	$ 4.1956311	$ 4.1956311	$ 4.1956311		Section 3.3.2; Page 12; Line 8	21
22	Transmission	$ 4.1951893	$ 4.1951893	$ 4.1951893	$ 4.1951893	$ 4.1951893	$ 4.1951893	$ 4.1951893	$ 4.1951893	$ 4.1951893	$ 4.1951893	$ 4.1951893	$ 4.1951893		Section 3.3.2; Page 12; Line 8	22
23																23
24	Revenues @ Calculated Rates:															24
25	Secondary	$ 6,928,012	$ 6,405,985	$ 7,259,471	$ 7,913,343	$ 7,273,228	$ 8,325,548	$ 8,233,391	$ 7,736,982	$ 7,326,358	$ 7,522,906	$ 6,748,657	$ 7,219,575	$ 88,893,456	Line 5 x Line 20	25
26	Primary	1,412,556	1,350,346	1,236,389	1,718,748	1,488,557	1,652,911	1,606,670	1,488,066	1,358,538	1,487,217	1,385,703	1,376,769	17,562,470	Line 10 x Line 21	26
27	Transmission	515,220	587,122	500,809	575,027	504,445	572,515	778,060	604,764	556,827	506,983	443,891	393,145	6,538,808	Line 15 x Line 22	27
28	Total	$ 8,855,788	$ 8,343,453	$ 8,996,669	$ 10,207,118	$ 9,266,230	$ 10,550,974	$ 10,618,121	$ 9,829,812	$ 9,241,723	$ 9,517,106	$ 8,578,251	$ 8,989,489	$ 112,994,734	Sum Lines 25; 26; 27	28
29																29
30	Total Revenues @ Calculated Rates:	$ 8,855,788	$ 8,343,453	$ 8,996,669	$ 10,207,118	$ 9,266,230	$ 10,550,974	$ 10,618,121	$ 9,829,812	$ 9,241,723	$ 9,517,106	$ 8,578,251	$ 8,989,489	$ 112,994,734	Line 28	30

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

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Section 3.3.3

SAN DIEGO GAS AND ELECTRIC COMPANY

TO3-Cycle 5 Annual Transmission Formulaic Rate Filing

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

Proof of Revenues - Medium & Large C&I Customers

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

Line No.	Description	W Apr-10	S May-10	S Jun-10	S Jul-10	S Aug-10	S Sep-10	W Oct-10	W Nov-10	W Dec-10	W Jan-11	W Feb-11	W Mar-11	Total	Reference	Line No.
1	**On-Peak Demand (KW):**															1
2	Secondary	1,330,979	1,292,227	1,601,029	1,773,358	1,626,762	1,882,512	1,674,816	1,449,778	1,369,346	1,411,558	1,273,193	1,379,490	18,065,048	Section 3.3.3; Page 26.3; Ln. 105	2
3	Primary	272,034	300,111	299,400	394,234	363,053	384,862	360,072	306,784	266,320	299,948	289,420	270,640	3,806,879	Section 3.3.3; Page 26.3; Ln. 109	3
4	Transmission	44,186	26,659	28,540	22,602	26,959	24,808	60,793	55,981	42,458	27,738	12,730	32,646	406,100	Section 3.3.3; Page 26.3; Ln. 111	4
5	Total	1,647,199	1,618,997	1,928,970	2,190,194	2,016,774	2,292,182	2,095,681	1,812,543	1,678,125	1,739,243	1,575,343	1,682,776	22,278,026	Sum Lines 2; 3; 4	5
6																6
7	**Maximum On-Peak Demand Rates Per ($/KW):**	W	S	S	S	S	S	W	W	W	W	W	W			7
8	Secondary	$ 0.1941297	$ 0.9452229	$ 0.9452229	$ 0.9452229	$ 0.9452229	$ 0.9452229	$ 0.1941297	$ 0.1941297	$ 0.1941297	$ 0.1941297	$ 0.1941297	$ 0.1941297		Section 3.3.2; Pg 12; Lns 11&12	8
9	Primary	$ 0.1941297	$ 0.9452229	$ 0.9452229	$ 0.9452229	$ 0.9452229	$ 0.9452229	$ 0.1941297	$ 0.1941297	$ 0.1941297	$ 0.1941297	$ 0.1941297	$ 0.1941297		Section 3.3.2; Pg 12; Lns 11&12	9
10	Transmission	$ 0.1941297	$ 0.9452229	$ 0.9452229	$ 0.9452229	$ 0.9452229	$ 0.9452229	$ 0.1941297	$ 0.1941297	$ 0.1941297	$ 0.1941297	$ 0.1941297	$ 0.1941297		Section 3.3.2; Pg 12; Lns 11&12	10
11																11
12	**Revenues @ Calculated Rates:**															12
13	Secondary	$ 258,383	$ 1,221,442	$ 1,513,330	$ 1,676,218	$ 1,537,653	$ 1,779,393	$ 325,132	$ 281,445	$ 265,831	$ 274,025	$ 247,165	$ 267,800	$ 9,647,817	Line 2 x Line 8	13
14	Primary	52,810	283,672	283,000	372,639	343,166	363,781	69,901	59,556	51,701	58,229	56,185	52,539	2,047,179	Line 3 x Line 9	14
15	Transmission	8,578	25,199	26,977	21,364	25,482	23,449	11,802	10,868	8,242	5,385	2,471	6,338	176,155	Line 4 x Line 10	15
16	Total	$ 319,771	$ 1,530,313	$ 1,823,307	$ 2,070,221	$ 1,906,301	$ 2,166,623	$ 406,835	$ 351,869	$ 325,774	$ 337,639	$ 305,821	$ 326,677	$ 11,871,151	Sum Lines 13; 14; 15	16
17																17
18	**Total Revenues @ Calculated Rates:**	$ 319,771	$ 1,530,313	$ 1,823,307	$ 2,070,221	$ 1,906,301	$ 2,166,623	$ 406,835	$ 351,869	$ 325,774	$ 337,639	$ 305,821	$ 326,677	$ 11,871,151	Line 16	18

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

000151.

Section 3.3.3

SAN DIEGO GAS AND ELECTRIC COMPANY

TO3-Cycle 5 Annual Transmission Formulaic Rate Filing

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

Proof of Revenues - Medium & Large C&I Customers

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

Line No.	Description	W Apr-10	S May-10	S Jun-10	S Jul-10	S Aug-10	S Sep-10	W Oct-10	W Nov-10	W Dec-10	W Jan-11	W Feb-11	W Mar-11	Total	Reference	Line No.
1	Coincident Peak Demand (KW):															1
2	Secondary	-	-	-	-	-	-	-	-	-	-	-	-	-	Section 3.3.3; Page 26.4; Ln. 155	2
3	Primary	14,235	8,146	13,093	13,476	2,633	10,561	11,619	8,427	21,189	6,223	13,104	14,159	136,865	Section 3.3.3; Page 26.4; Ln. 159	3
4	Transmission	66,186	100,813	90,443	99,691	71,191	102,954	105,670	113,486	68,028	80,716	74,354	61,286	1,034,819	Section 3.3.3; Page 26.4; Ln. 161	4
5	Total	80,420	108,959	103,535	113,168	73,825	113,516	117,289	121,914	89,217	86,939	87,458	75,445	1,171,685	Sum Lines 2; 3; 4	5
9	-															9
10	Coincident Peak Demand Rates Per ($/KW):	W	S	S	S	S	S	W	W	W	W	W	W			10
11	Secondary	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		Section 3.3.2; Pg 12; Lns 15&16	11
12	Primary	$ 0.2072838	$ 1.0651072	$ 1.0651072	$ 1.0651072	$ 1.0651072	$ 1.0651072	$ 0.2072838	$ 0.2072838	$ 0.2072838	$ 0.2072838	$ 0.2072838	$ 0.2072838		Section 3.3.2; Pg 12; Lns 15&16	12
13	Transmission	$ 0.2072838	$ 1.0651072	$ 1.0651072	$ 1.0651072	$ 1.0651072	$ 1.0651072	$ 0.2072838	$ 0.2072838	$ 0.2072838	$ 0.2072838	$ 0.2072838	$ 0.2072838		Section 3.3.2; Pg 12; Lns 15&16	13
14																14
15	Revenues @ Calculated Rates:															15
16	Secondary	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	Line 2 x Line 11	16
17	Primary	2,951	8,676	13,945	14,354	2,805	11,249	2,408	1,747	4,392	1,290	2,716	2,935	69,468	Line 3 x Line 12	17
18	Transmission	13,719	107,377	96,331	106,182	75,826	109,657	21,904	23,524	14,101	16,731	15,412	12,704	613,468	Line 4 x Line 13	18
19	Total	$ 16,670	$ 116,053	$ 110,276	$ 120,536	$ 78,631	$ 120,906	$ 24,312	$ 25,271	$ 18,493	$ 18,021	$ 18,128	$ 15,639	$ 682,936	Sum Lines 16; 17; 18	19
20																20
21	Total Revenues @ Calculated Rates:	$ 16,670	$ 116,053	$ 110,276	$ 120,536	$ 78,631	$ 120,906	$ 24,312	$ 25,271	$ 18,493	$ 18,021	$ 18,128	$ 15,639	$ 682,936	Line 19	21

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

000152

Section 3.3.3

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

Line No.	Description	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Total	Reference	Line No.
1	Demand - Billing Determinants (KW):															1
2	Secondary	11,737	11,737	11,739	11,632	11,632	11,631	12,627	12,627	14,115	14,115	14,021	14,021	151,634	Section 3.3.3; Page 26.4; Ln. 168 x 1000	2
3	Primary	85,738	85,920	86,237	85,940	85,197	85,197	81,350	81,350	84,674	84,287	83,618	84,300	1,013,809	Section 3.3.3; Page 26.4; Ln. 172 x 1000	3
4	Transmission	46,948	47,715	47,692	49,986	49,986	49,986	50,003	50,003	50,156	50,272	50,272	50,275	593,294	Section 3.3.3; Page 26.4; Ln. 174 x 1000	4
5	Total	144,423	145,372	145,668	147,559	146,816	146,815	143,980	143,980	148,945	148,673	147,911	148,595	1,758,737	Sum Lines 2; 3; 4	5
9																9
10	Demand Rates Per ($/KW):															10
11	Secondary	$ 1.9868421	$ 1.9868421	$ 1.9868421	$ 1.9868421	$ 1.9868421	$ 1.9868421	$ 1.9868421	$ 1.9868421	$ 1.9868421	$ 1.9868421	$ 1.9868421	$ 1.9868421		Section 3.3.2; Pg 20; Ln. 20	11
12	Primary	$ 1.9901381	$ 1.9901381	$ 1.9901381	$ 1.9901381	$ 1.9901381	$ 1.9901381	$ 1.9901381	$ 1.9901381	$ 1.9901381	$ 1.9901381	$ 1.9901381	$ 1.9901381		Section 3.3.2; Pg 20; Ln. 20	12
13	Transmission	$ 1.9898820	$ 1.9898820	$ 1.9898820	$ 1.9898820	$ 1.9898820	$ 1.9898820	$ 1.9898820	$ 1.9898820	$ 1.9898820	$ 1.9898820	$ 1.9898820	$ 1.9898820		Section 3.3.2; Pg 20; Ln. 20	13
14																14
15	Revenues at Present Rates:															15
16	Secondary	$ 23,319	$ 23,319	$ 23,324	$ 23,112	$ 23,112	$ 23,110	$ 25,088	$ 25,088	$ 28,044	$ 28,044	$ 27,857	$ 27,857	$ 301,274	Line 2 x Line 10	16
17	Primary	170,631	170,993	171,624	171,033	169,554	169,554	161,898	161,898	168,512	167,742	166,412	167,768	2,017,619	Line 3 x Line 11	17
18	Transmission	93,421	94,947	94,901	99,466	99,466	99,466	99,500	99,500	99,805	100,035	100,035	100,041	1,180,583	Line 4 x Line 12	18
19	Total	$ 287,371	$ 289,259	$ 289,849	$ 293,611	$ 292,132	$ 292,130	$ 286,486	$ 286,486	$ 296,361	$ 295,821	$ 294,304	$ 295,666	$ 3,499,476	Sum Lines 15; 16; 17	19
20																20
21	Total Revenues at Present Rates	$ 287,371	$ 289,259	$ 289,849	$ 293,611	$ 292,132	$ 292,130	$ 286,486	$ 286,486	$ 296,361	$ 295,821	$ 294,304	$ 295,666	$ 3,499,476	Line 19	21

000153

Line No.	Section 3.3.3 San Diego Gas & Electric FERC Recorded Sales @ Transmission Level for the Period: April 2010 - March 2011														Line No.
1	**SDG&E: System Delivery Determinants**	Cycle 3	Cycle 3	Cycle 3	Cycle 3	Cycle 3	Cycle 4	Cycle 4	Cycle 4	Cycle 4	Cycle 4	Cycle 4	Cycle 4		1
2	**Customer Class Deliveries (MWh)**	**Apr-10**	**May-10**	**Jun-10**	**Jul-10**	**Aug-10**	**Sep-10**	**Oct-10**	**Nov-10**	**Dec-10**	**Jan-11**	**Feb-11**	**Mar-11**	**Total**	2
3	Residential	560,384	517,201	550,609	593,511	590,340	686,248	639,924	589,348	671,935	724,209	628,060	609,744	7,361,513	3
4	Transmission Level Adjustment Factor	**1.04570**	1.04570	1.04570	1.04570	1.04570	**1.04570**	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570		4
5	Residential @ Transmission Level	585,994	540,838	575,771	620,635	617,319	717,609	669,169	616,281	702,642	757,306	656,762	637,609	7,697,935	5
6															6
7	Small Commercial	157,999	137,325	162,432	177,346	163,651	189,247	177,357	162,507	164,000	171,088	159,604	160,245	1,982,802	7
8	Transmission Level Adjustment Factor	**1.04570**	1.04570	1.04570	1.04570	1.04570	**1.04570**	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570		8
9	Small Commercial @ Transmission Level	165,220	143,601	169,856	185,450	171,130	197,896	185,463	169,933	171,494	178,907	166,898	167,568	2,073,416	9
10															10
11	Med. & Large Comm./Ind. (AD + PA-T-1)	21,162	19,894	24,223	27,331	27,123	30,064	26,805	20,895	19,901	17,916	19,926	20,362	275,603	11
12	Transmission Level Adjustment Factor	**1.03652**	1.03652	1.03652	1.03652	1.03652	**1.03627**	1.03627	1.03627	1.03627	1.03627	1.03627	1.03627		12
13	Med&Lrg C/I (AD + PA-T-1)@Trans. Level	21,934	20,621	25,108	28,329	28,114	31,154	27,777	21,653	20,623	18,566	20,648	21,101	285,628	13
14															14
15	Med. & Large Comm./Ind. (AY + AL + DGR)	708,903	692,577	744,964	827,532	755,332	871,898	817,218	756,976	723,654	772,108	698,123	742,483	9,111,768	15
16	Transmission Level Adjustment Factor	**1.03652**	1.03652	1.03652	1.03652	1.03652	**1.03627**	1.03627	1.03627	1.03627	1.03627	1.03627	1.03627		16
17	Med&Lrg C/I (AY + AL + DGR)@Trans Level	734,791	717,869	772,169	857,752	782,915	903,517	846,855	784,428	749,897	800,109	723,440	769,409	9,443,152	17
18															18
19	Med. & Large Comm./Ind. (A6)	65,251	72,160	71,462	72,343	55,478	68,178	71,130	64,163	70,265	57,890	61,242	51,383	780,945	19
20	Transmission Level Adjustment Factor	**1.03652**	1.03652	1.03652	1.03652	1.03652	**1.03627**	1.03627	1.03627	1.03627	1.03627	1.03627	1.03627		20
21	Med. & Large Comm./Ind. (A6) @ Trans Level	67,634	74,795	74,071	74,985	57,504	70,651	73,710	66,490	72,813	59,990	63,463	53,246	809,352	21
22															22
23	Lighting	12,741	6,011	9,449	9,467	9,718	8,583	10,585	9,387	12,835	6,110	9,498	12,754	117,138	23
24	Transmission Level Adjustment Factor	**1.04570**	1.04570	1.04570	1.04570	1.04570	**1.04570**	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570		24
25	Street Lighting @ Transmission Level	13,323	6,286	9,881	9,899	10,163	8,976	11,068	9,816	13,421	6,389	9,932	13,337	122,491	25
26															26
27	Sale for Resale	1.5	0.0	3.5	0.0	1.5	0.0	6.4	0.0	2.1	1.7	3.6	0.0	20.4	27
28	Total System Delivery@Meter Exclude Resale	1,526,441	1,445,170	1,563,139	1,707,530	1,601,643	1,854,218	1,743,020	1,603,276	1,662,589	1,749,322	1,576,453	1,596,971	19,629,770	28
29	Total System Delivery@Trans. Exclude Resale	1,588,897	1,504,010	1,626,856	1,777,050	1,667,144	1,929,802	1,814,041	1,668,601	1,730,891	1,821,266	1,641,144	1,662,271	20,431,974	29
30	**Med. & Large Comm./Ind.**														30
31	**Rate Schedule Billing Determinants**														31
32		W	S	S	S	S	S	W	W	W	W	W	W		32
33	**Schedules AD / PA-T-1:Applicable to 100% NCD**	**Apr-10**	**May-10**	**Jun-10**	**Jul-10**	**Aug-10**	**Sep-10**	**Oct-10**	**Nov-10**	**Dec-10**	**Jan-11**	**Feb-11**	**Mar-11**	**Total**	33
34	**Total Deliveries (MWh)**	21,162	19,894	24,223	27,331	27,123	30,064	26,805	20,895	19,901	17,916	19,926	20,362	275,603	34
35															35
36	**Total Deliveries (%)**														36
37	% @ Secondary Service	91.58%	93.78%	93.65%	93.60%	91.70%	91.23%	90.41%	91.34%	91.56%	87.21%	85.53%	90.30%	91.15%	37
38	% @ Primary Service	8.42%	6.22%	6.35%	6.40%	8.30%	8.77%	9.59%	8.66%	8.44%	12.79%	14.47%	9.70%	8.85%	38
39	% @ Transmission Service	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	39
40		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	40
41	**Total Deliveries (MWh)**														41
42	MWh @ Secondary Service	19,380	18,657	22,685	25,582	24,872	27,427	24,234	19,085	18,221	15,625	17,043	18,387	251,199	42
43	MWh @ Primary Service	1,782	1,237	1,538	1,749	2,251	2,637	2,571	1,809	1,680	2,292	2,883	1,975	24,404	43
44	MWh @ Transmission Service	0	0	0	0	0	0	0	0	0	0	0	0	0	44
45		21,162	19,894	24,223	27,331	27,123	30,064	26,805	20,895	19,901	17,916	19,926	20,362	275,603	45

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

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

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Section 3.3.3

San Diego Gas & Electric

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

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

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Line No.	Section 3.3.3 San Diego Gas & Electric FERC Recorded Sales @ Transmission Level for the Period: April 2010 - March 2011														Line No.
133															133
134	**Non-Coincident Demand (MW)**														134
135	MW @ Secondary Service	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	135
136	Transmission Level Adjustment Factor	1.0457	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570		136
137	Non-Coincident Demand @ Transmission Level	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	137
138															138
139	MW @ Primary Service	12.712	5.048	8.141	11.956	5.274	17.140	6.000	6.034	19.850	19.715	18.883	29.634	160.387	139
140	Transmission Level Adjustment Factor	1.0108	1.01080	1.01080	1.01080	1.01080	1.01080	1.01080	1.01080	1.01080	1.01080	1.01080	1.01080		140
141	Non-Coincident Demand @ Transmission Level	12.849	5.102	8.229	12.085	5.331	17.325	6.064	6.099	20.064	19.928	19.087	29.954	162.119	141
142															142
143	MW @ Transmission Service	98.798	125.966	107.263	122.766	100.676	115.598	124.859	114.316	113.460	101.798	95.017	82.504	1,303.020	143
144	Non-Coincident Demand @ Meter Level	111.510	131.014	115.404	134.722	105.950	132.738	130.859	120.350	133.310	121.513	113.900	112.138	1,463.407	144
145	Non-Coincident Demand @ Transmission Level	111.647	131.068	115.492	134.851	106.007	132.923	130.924	120.416	133.524	121.726	114.104	112.458	1,465.139	145
146															146
147	**Coincident Peak Demand (%)**														147
148	% @ Secondary Service	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	148
149	% @ Primary Service	0.1613%	0.1705%	0.1914%	0.1550%	0.0572%	0.1054%	0.1824%	0.1712%	0.1941%	0.1286%	0.1544%	0.1324%	0.1521%	149
150	% @ Transmission Service	0.1171%	0.1495%	0.1398%	0.1564%	0.1398%	0.1767%	0.1630%	0.1914%	0.1144%	0.1520%	0.1407%	0.1502%	0.1496%	150
151															151
152	**Coincident Peak Demand (MW)**	W	S	S	S	S	S	W	W	W	W	W	W	Total	152
153	MW @ Secondary Service	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	153
154	Transmission Level Adjustment Factor	1.0457	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570		154
155	Coincident Peak Demand@Transmission Level	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	155
156															156
157	MW @ Primary Service	14.082	8.059	12.953	13.332	2.605	10.448	11.495	8.337	20.962	6.157	12.964	14.008	135.403	157
158	Transmission Level Adjustment Factor	1.0108	1.01080	1.01080	1.01080	1.01080	1.01080	1.01080	1.01080	1.01080	1.01080	1.01080	1.01080		158
159	Coincident Peak Demand@Transmission Level	14.235	8.146	13.093	13.476	2.633	10.561	11.619	8.427	21.189	6.223	13.104	14.159	136.865	159
160															160
161	MW @ Transmission Service	66.186	100.813	90.443	99.691	71.191	102.954	105.670	113.486	68.028	80.716	74.354	61.286	1,034.819	161
162	Coincident Peak Demand@Meter Level	80.268	108.872	103.395	113.024	73.796	113.403	117.165	121.824	88.991	86.873	87.318	75.294	1,170.222	162
163	Coincident Peak Demand@Transmission Level	80.420	108.959	103.535	113.168	73.825	113.516	117.289	121.914	89.217	86.939	87.458	75.445	1,171.685	163
164	**Schedule S: Standby Determinants:**	**Apr-10**	**May-10**	**Jun-10**	**Jul-10**	**Aug-10**	**Sep-10**	**Oct-10**	**Nov-10**	**Dec-10**	**Jan-11**	**Feb-11**	**Mar-11**	**Total**	164
165	**Contracted Standby Demand (MW)**														165
166	MW @ Secondary Service	11.224	11.224	11.226	11.124	11.124	11.123	12.075	12.075	13.498	13.498	13.408	13.408	145.007	166
167	Transmission Level Adjustment Factor	1.0457	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570	1.04570		167
168	Standby Demand @ Transmission Level	11.737	11.737	11.739	11.632	11.632	11.631	12.627	12.627	14.115	14.115	14.021	14.021	151.634	168
169															169
170	MW @ Primary Service	84.822	85.002	85.316	85.022	84.287	84.287	80.481	80.481	83.769	83.386	82.725	83.399	1,002.977	170
171	Transmission Level Adjustment Factor	1.0108	1.01080	1.01080	1.01080	1.01080	1.01080	1.01080	1.01080	1.01080	1.01080	1.01080	1.01080		171
172	Standby Demand @ Transmission Level	85.738	85.920	86.237	85.940	85.197	85.197	81.350	81.350	84.674	84.287	83.618	84.300	1,013.809	172
173															173
174	MW @ Transmission Service	46.948	47.715	47.692	49.986	49.986	49.986	50.003	50.003	50.156	50.272	50.272	50.275	593.294	174
175	Standby Demand@Meter Level	142.994	143.941	144.234	146.132	145.397	145.396	142.559	142.559	147.423	147.156	146.405	147.082	1,741.278	175
176	Standby Demand@Transmission Level	144.423	145.372	145.668	147.559	146.816	146.815	143.980	143.980	148.945	148.673	147.911	148.595	1,758.737	176
177															177

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

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

NOTES:

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

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Section 3.3.3

SAN DIEGO GAS AND ELECTRIC COMPANY

TO3-Cycle 5 Annual Transmission Formulaic Rate Filing

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

For the True-Up Period April 2010 through March 2011

Billing Determinants @ Transmission Level

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

NOTES:

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

Section 3.3.3

SAN DIEGO GAS AND ELECTRIC COMPANY

TO3-Cycle 5 Annual Transmission Formulaic Rate Filing

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

For the True-Up Period April 2010 through March 2011

Total Billing Determinants @ Transmission Level

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

Section 3.3.3

SAN DIEGO GAS AND ELECTRIC COMPANY

TO3-Cycle 5 Annual Transmission Formulaic Rate Filing

Summary of TO3-CYCLE-5 Wholesale Transmission Rates

Based on TO3-CYCLE-5 Wholesale True-Up Period Cost of Service

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

Line No.	Customer Classes	Transmission Energy Rates $/kWh	Transmission Level Demand Rates $/kW-Mo	Primary Level Demand Rates $/kW-Mo	Secondary Level Demand Rates $/kW-Mo	Reference	Line No.
1	Residential	$ 0.0143539				Section 3.3.2; Page 2; Line 11	1
2							2
3	Small Commercial	$ 0.0164087				Section 3.3.2; Page 3; Line 11	3
4							4
5	Med & Lrg Commercial/Industrial						5
6	Non-Coincident Demand (100%) [1]		$ 4.6613214	$ 4.6618123	$ 4.6618336	Section 3.3.2; Page 4; Lines 33;34;35	6
7							7
8	Non-Coincident Demand (90%) [2]		$ 4.1951893	$ 4.1956311	$ 4.1956502	Section 3.3.2; Page 5; Lines 7;8;9	8
9							9
10	Maximum On-Peak Demand [3]						10
11	Summer		$ 0.9452229	$ 0.9452229	$ 0.9452229	Section 3.3.2; Page 6; Lines 35;36;37	11
12	Winter		$ 0.1941297	$ 0.1941297	$ 0.1941297	Section 3.3.2; Page 7; Lines 32;33;34	12
13							13
14	Maximum Demand at the Time of System Peak [4]						14
15	Summer		$ 1.0651072	$ 1.0651072	$ -	Section 3.3.2; Page 8; Lines 29;30;31	15
16	Winter		$ 0.2072838	$ 0.2072838	$ -	Section 3.3.2; Page 9; Lines 32;33;34	16
17							17
18	Street Lighting	$ 0.0084577				Section 3.3.2; Page 10; Line 11	18
19							19
20	Standby Rate		$ 1.9898820	$ 1.9901381	$ 1.9868421	Section 3.3.2; Page 11; Lns 33;34;35	20

NOTES:

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

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

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

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

CERTIFICATE OF SERVICE

I hereby certify that I have this day served a copy of the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding. In addition, I certify that I have also caused the foregoing to be served by overnight delivery upon the following:

Frank Lindh
General Counsel
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102

Nancy Saracino
General Counsel
California Independent System Operator Corporation
151 Blue Ravine Road
Folsom, CA 95630

Dated at San Diego, California, this 14th day of November, 2011.

Joel Dellosa