Volume – 2

TO4 - Cycle 2 Retail 4-Month True-Up Adjustment Cost Statements, Including the True-Up Period Cost of Service; the True-Up Adjustment Calculation; and all Related Work Papers. (Exhibit SDG-2)

(December 1, 2014)

San Diego Gas & Electric Company Volume 2 Table of Contents

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True Up Period Statement – BK1 Retail Cost of Service Which Determines Base Transmission Revenue Requirements (BTRR_{EU})

Derivation of End Use Prior Year Revenue Requirements (PYRR _{EU}) (Manipulating Cost of Service Model Working Paper)

For the 4-Month True-Up Period Ending December 31,2013 (\$1,000)

Line				Line
No.		Amounts 5	Reference	No.
	1.0			
1 2	A. Revenues:	6 26 677	Ctatana at All, Dans 5 I in O	1
3	Transmission Operation & Maintenance Expense	\$ 26,677	Statement AH; Page 5, Line 9	2
4	Transmission Related A&G Expense	35,284	Statement AH; Page 5, Line 56	4
5	Transmission Related Acco Expense	33,264	Statement Ari, Fage 3, Line 30	5
6	CPUC Intervenor Funding Expense - Transmission	_	Statement AH; Page 5, Line 17	6
7	5 T		Summing 121, 1 age of 2010 17	7
8	Total O&M Expenses	\$ 61,961	Sum Lines 2 thru 6	8
9				9
10	Transmission, General, Common Plant Depn. Exp., and Electric Misc. Intangible Plant Amort. Exp.	34,866	Statement AJ; Page 7, Line 17	10
11				11
12	Valley Rainbow Project Cost Amortization Expense	158	Statement AJ; Page 7, Line 19	12
13	To a large to the state of the		G	13
14	Transmission Plant Abandoned Project Cost Amortization Expense		Statement AJ; Page 7, Line 23	14
15 16	Transmission Related Property Taxes Expense	8,877	Statement AV. Doga S. Line 27	15 16
17	Transmission Related Property Taxes Expense	0,0//	Statement AK; Page 8, Line 27	17
18	Transmission Related Payroll Taxes Expense	722	Statement AK; Page 8, Line 33	18
19	Transmission related Layron Taxes Expense	122	Statement AK, Fage 6, Line 55	19
20	Sub-Total Expense	\$ 106,584	Sum Lines 8 thru 18	20
21	Sub-Total Expense	<u> </u>	Sum Lines o unu 10	21
22	Cost of Capital Rate (COCR)	11.3334%	Statement AV; Page 15, Line 31	22
23	Transmission Rate Base	2,830,609	Statement BK-1; Page 2, Line 26	23
24	Annual Return and Associated Income Taxes	\$ 320,805	Line 22 x Line 23	24
25	Proration Factor for 4 Mo T/U	33%	1/3	25
26	Proated Four Month Return for 4 Month T/U	\$ 106,935	Line 24 x Line 25	26
27		,,		27
28	South Georgia Income Tax Adjustment	\$ 778	Statement AQ; Page 11, Line 1	28
29	Transmission Related Amortization of Investment Tax Credits	(88)	Statement AR; Page 12, Line 1	29
30	Transmission Related Amortization of Excess Deferred Tax Liabilities	(101)	Statement AR; Page 12, Line 3	30
31	Transmission Related Revenue Credits	(1,499)	Statement AU; Page 13, Line 11	31
32	Transmission Related Regulatory Debits		Misc. Statement; Page 17, Line 1	32
33	(Gains)/Losses from Sale of Plant Held for Future Use	-	Statement AU; Page 13, Line 13	33
34				34
35	End of Prior Year Revenues (PYRR EU) Excluding FF&U	\$ 212,608	Line 20 + Sum Lines (24 thru 31)	35
36				36
37	B. Incentive ROE Project Transmission Revenue:			37
38	Incentive Transmission Plant Depreciation Expense	\$ -	Statement AJ; Page 7; Line 21	38
39				39
40	Incentive Cost of Capital Rate (ICOCR)	0.0000%	Statement AV; Page 16, Line 31	40
41	Total Incentive ROE Project Transmission Rate Base	\$ -	Statement BK-1; Page 2; Line 31	41
42	Incentive ROE Project Return and Associated Income Taxes	\$ -	Line 38 x Line 39	42
43	m 17 1 2000 1 20			43
44	Total Incentive ROE Project Transmission Revenue	\$ -	Sum Lines 36; 40	44
45 46	C. Incontina Transmission Plant Abandoned Project Personne			45
47	C. Incentive Transmission Plant Abandoned Project Revenue: Incentive Transmission Plant Abandoned Project Cost Amortization Expense	\$ -	Statement AJ; Page 7; Line 25	46 47
48	incentive transmission train Adamdoned Project Cost Amortization Expense	Φ -	Statement AJ, Fage 7, Line 25	48
49	Total Incentive Transmission Plant Abandoned Project Cost Rate Base	\$ -	Statement BK-1; Page 2; Line 36	49
50	Cost of Capital Rate (COCR)	11,3334%	Statement AV; Page 15, Line 31	50
51	Incentive Transmission Plant Abandoned Project Return and Associated Income Taxes	\$ -	Line 47 x Line 48	51
52	moditive transmission than resultance troject retain and respectited meeting taxes		Diffe 17 X Biffe 10	52
53	Total Incentive Transmission Plant Abandoned Project Revenue	\$ -	Sum Lines 45; 49	53
54	and distance on a series in a contracting of the contraction of the co		,	54
55	D. Incentive Transmission Construction Work In Progress (CWIP) Revenue:			55
56	Incentive Transmission Construction Work In Progress ²	\$ -	Statement BK-1; Page 2; Line 38	56
57	Cost of Capital Rate (COCR)	11.3334%	Statement AV; Page 15, Line 31	57
58	Incentive CWIP Return and Associated Income Taxes	\$ -	Line 54 x Line 55	58
59	Commission and Advanced Commission of Advanced Commission (Advanced Advanced Advance			59
60	Total Incentive End of Prior Year Revenues (PYRR EU-IR) Excluding FF&U	\$ -	Sum Lines 42; 51; 56	60
61			and the second s	61
	E Tetal (DVDD) Evaluating EE 8-11 3	e 212 (00	0 1	
62	E. Total (PYRR FII) Excluding FF&U 3	\$ 212,608	Sum Lines 33; 58	62

¹ The incentive rate cost components for each ROE incentive project will be tracked and shown separately for each project and lines 36 through 40 will be repeated for each project. As a result, the data on this page may carryover to the next page.

² Incentive Transmission CWIP shall be the CWIP for which SDG&E is authorized to collect incentives under FERC Order No. 679 and will be tracked and shown for each project and lines 54 through 56 will be repeated for each project.

³ Total Prior Year Revenues (PYRR) or Base Period Revenue is for 4 months ending December 31, 2013

⁴ The Incentive Cost of Capital Rate will be tracked and shown separately for each project. However, this will be entered as 0% in BK-1 when there's no incentive project to show.

⁵ Blank lines that show up in the Formula Rate Spreadsheet will not be populated with any numbers absent a Section 205 filing to approve the blank lines.

Derivation of End Use Prior Year Revenue Requirements (PYRR EU)

For the 4-Month True-Up Period Ending December 31,2013 (\$1,000)

Line Line No. Reference No. Amounts A. Transmission Rate Base: 1 Net Transmission Plant: 1 Statement BK-1; Page 3; Line 16 2 Transmission Plant \$ 3,067,214 2 3 Transmission Related Electric Miscellaneous Intangible Plant 12,892 Statement BK-1; Page 3; Line 17 3 Transmission Related General Plant 27,329 Statement BK-1; Page 3; Line 18 Transmission Related Common Plant 46,508 Statement BK-1; Page 3; Line 19 5 Total Net Transmission Plant \$ 3,153,943 Sum Lines 2 thru 5 6 7 8 Rate Base Additions: 8 9 Transmission Plant Held for Future Use 6,546 Statement AG; Page 4; Line 1 10 Transmission Plant Abandoned Project Cost Misc. Statement; Page 17, Line 4 10 Total Rate Base Additions 6,546 Sum Lines 9 thru 10 11 11 12 12 13 Rate Base Reductions: 13 14 Transmission Related Accum. Def. Inc. Taxes (393,258) Statement AF; Page 3; Line 5 15 Transmission Plant Abandoned Accum. Def. Inc. Taxes Statement AF; Page 3; Line 9 15 Total Rate Base Reductions (393,258) Sum Lines 14 thru 15 16 16 17 17 18 Working Capital: 18 19 Transmission Related Materials and Supplies 22,401 Statement AL; Page 9; Line 5 19 20 Transmission Related Prepayments 17,742 Statement AL; Page 9; Line 9 20 21 Transmission Related Cash Working Capital 23,235 Statement AL; Page 9; Line 19 21 22 **Total Working Capital** Sum Lines 19 thru 21 22 63,378 23 23 24 Other Regulatory Assets/Liabilities Misc. Statement; Page 17, Line 7 24 25 25 26 Total Transmission Rate Base \$ 2,830,609 Sum Lines 6; 11; 16; 22; 24 26 2.7 27 28 B. Incentive ROE Project Transmission Rate Base: 28 Net Incentive Transmission Plant 1 29 Statement BK-1; Page 3; Line 25 29 30 Incentive Transmission Plant Accum. Def. Income Taxes Statement AF; Page 3; Line 7 30 31 Total Incentive ROE Project Transmission Rate Base Sum Lines 29 thru 30 31 32 32 33 C. Incentive Transmission Plant Abandoned Project Rate Base: 33 Misc. Statement; Page 17, Line 10 34 Incentive Transmission Plant Abandoned Project Cost 34 35 Incentive Transmission Plant Abandoned Project Cost Accum. Def. Inc. Taxes Statement AF; Page 3; Line 11 35 36 Total Incentive Transmission Plant Abandoned Project Cost Rate Base Sum Lines 34 thru 35 36 37 37 D. Incentive Transmission Construction Work In Progress ² 38 Statement AM; Page 10; Line 1 38

¹ The Incentive ROE Transmission Plant will be tracked and shown for each incentive project and lines 29 through 31 will be repeated for each project.

² Incentive CWIP projects will be tracked separately and line 38 will be shown for each project.

Derivation of End Use Prior Year Revenue Requirements (PYRR _{EU}) For the 4-Month True-Up Period Ending December 31,2013 (\$1,000)

Line				Line
No.		Amounts	Reference	No.
	A. Transmission Plant:			
1	Gross Transmission Plant:			1
2	Transmission Plant	\$ 3,723,358	Statement AD; Page 1, Line 15	2
3	Transmission Related Electric Misc. Intangible Plant	16,024	Statement AD; Page 1, Line 31	3
4	Transmission Related General Plant	45,182	Statement AD; Page 1, Line 33	4
5	Transmission Related Common Plant	92,352	Statement AD; Page 1, Line 35	5
6	Total Gross Transmission Plant	\$ 3,876,916	Sum Lines 2 thru 5	6
7				7
8	Transmission Related Depreciation Reserve:			8
9	Transmission Plant Depreciation Reserve	\$ 656,144	Statement AE; Page 2, Line 1	9
10	Transmission Related Electric Misc. Intangible Plant Amortization Reserve	3,132	Statement AE; Page 2, Line 11	10
11	Transmission Related General Plant Depr Reserve	17,853	Statement AE; Page 2, Line 13	11
12	Transmission Related Common Plant Depr Reserve	45,844	Statement AE; Page 2, Line 15	12
13	Total Transmission Related Depreciation Reserve	\$ 722,973	Sum Lines 9 thru 12	13
14				14
15	Net Transmission Plant:			15
16	Transmission Plant	\$ 3,067,214	Line 2 Minus Line 9	16
17	Transmission Related Electric Miscellaneous Intangible Plant	12,892	Line 3 Minus Line 10	17
18	Transmission Related General Plant	27,329	Line 4 Minus Line 11	18
19	Transmission Related Common Plant	46,508	Line 5 Minus Line 12	19
20	Total Net Transmission Plant	\$ 3,153,943	Sum Lines 16 thru 19	20
21				21
22	B. Incentive Project Transmission Plant:			22
23	Incentive Transmission Plant ¹	\$ -	Statement AD; Page 1, Line 17	23
24	Incentive Transmission Plant Depreciation Reserve 1	<u> </u>	Statement AE; Page 2, Line 19	24
25	Total Net Incentive Transmission Plant	\$ -	Line 23 Minus Line 24	25

¹ The Incentive ROE Transmission Plant and depreciation reserve will be tracked and shown for each incentive project and lines 23 and 24 will be repeated for each project.

Derivation of End Use Forecast Period Capital Additions Revenue Requirements (FC $_{\rm EU}$)

For the Forecast Period xxxxxx (\$1,000)

Line					Line
No.		Am	nounts	Reference	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 Fees and Uncollectible	\$	212,608	Statement BK-1; Page 1; Line 33	3
4	50% of Transmission O&M Expense		(13,339)	Statement BK-1; Page 1; Line 2 * 50%	4
5	50% of Transmission Related A&G Expense		(17,642)	Statement BK-1; Page 1; Line 4 * 50%	5
6	CPUC Intervenor Funding Expense - Transmission		-	Statement BK-1; Page 1; Line 6	6
7	Valley Rainbow Project Cost Amortization Expense		(158)	Statement BK-1; Page 1; Line 12	7
8	South Georgia Income Tax Adjustment		(778)	Statement BK-1; Page 1; Line 26	8
9	Transmission Related Amortization of Investment Tax Credit		88	Statement BK-1; Page 1; Line 27	9
10	Transmission Related Amortization of Excess Deferred Tax Liabilities		101	Statement BK-1; Page 1; Line 28	10
11	(Gains)/Losses from Sale of Plant Held for Future Use			Statement BK-1; Page 1; Line 31	11
12	Adjusted Total (PYRR EU) Excluding FF&U	\$	180,881	Sum Lines 3 thru 11	12
13					13
14	Gross Transmission Plant	\$ 3,	,876,916	Statement BK-1; Page 3, Line 6	14
15					15
16	Annual Fix Charge Rate (AFCR EU)		4.6656%	Line 12 / Line 14	16
17					17
				Summary of HV-LV Plant Additions; Pg 1; Ln 5,	
18	Weighted Forecast Plant Additions	\$	_	Col. (f)	18
19		-			19
20	Forecast Period Capital Addition Revenue Requirements	\$		Line 16 x Line 18	20

Derivation of End Use Forecast Period Capital Additions Revenue Requirements (FC EU)

For the Forecast Period xxxxxx (\$1,000)

Line Line Reference No. No. Amounts ANNUAL FIXED CHARGES APPLICABLE TO INCENTIVE CAPITAL PROJECTS A. Derivation of Annual Fix Charge Rate (AFCR EIL-IR-ROE) Applicable to 1 Incentive Weighted Forecast Plant Additions (ROE Incentive Only): 2 2 3 PYRR $_{\hbox{\scriptsize EU-IR-ROE}}$ Excluding Franchise Fees and Uncollectible \$ 212,608 Statement BK-1; Page 1; Line 33 + Line 42 3 50% of Transmission O&M Expense (13,339)Statement BK-1; Page 1; Line 2 * 50% Statement BK-1; Page 1; Line 4 * 50% 50% of Transmission Related A&G Expense (17,642)CPUC Intervenor Funding Expense - Transmission Statement BK-1; Page 1; Line 6 6 (158)Valley Rainbow Project Cost Amortization Expense Statement BK-1; Page 1; Line 12 7 South Georgia Income Tax Adjustment (778)Statement BK-1; Page 1; Line 26 8 Transmission Related Amortization of Investment Tax Credit Statement BK-1; Page 1; Line 27 Statement BK-1; Page 1; Line 28 Transmission Related Amortization of Excess Deferred Tax Liabilities 101 10 10 11 (Gains)/Losses from Sale of Plant Held for Future Use Statement BK-1; Page 1; Line 31 11 180,881 Sum Lines 3 thru 11 12 Adjusted Total (PYRR EU-IR-ROE) Excluding FF&U 13 13 14 Gross Transmission Plant & Incentive Transmission Plant \$ 3,876,916 Statement BK-1; Page 3, Line 6 + Line 23 14 15 Incentive Annual Fix Charge Rate (AFCR EU-IR-ROE) 16 4.6656% Line 12 / Line 14 16 17 17 Summary of HV-LV Plant Additions; Pg 1; Ln 8; 18 18 Incentive Weighted Forecast Plant Additions Col. (f) 19 19 Forecast Period Incentive Capital Addition Revenue Requirements (FC EU-IR-ROE) 20 Line 16 x Line 18 20 21 21 22 B. Derivation of Incentive Forecast Transmission CWIP Revenues: 22 1. For the Period After the Base Period and Before the Rate Effective Period: 23 23 Summary of HV-LV Plant Additions; Pg 1; Ln 10; 24 Incentive Weighted Forecast Transmission Construction Work In Progress Col. (f) 24 25 25 11.3334% Statement AV; Page 15, Line 31 26 Cost of Capital Rate (COCR) 26 27 27 28 Incentive Transmission Forecast CWIP Projects Revenue Requirements Line 24 x Line 26 28 29 29 30 2. For the Period During the Rate Effective Period: 30 Summary of HV-LV Plant Additions; Pg 1; Ln 12; 31 Incentive Weighted Forecast Transmission Construction Work In Progress Col. (f) 31 32 32 11.3334% Statement AV; Page 15, Line 31 33 33 Cost of Capital Rate (COCR) 34 34 Incentive Transmission Forecast CWIP Projects Revenue Requirements Line 31 x Line 33 35 35 36 36 37 Total Incentive Transmission Forecast CWIP Projects Revenue Requirements Sum Lines 28: 35 37

¹ The Incentive Annual Fixed Charge Rate will be tracked and shown for each incentive project as applicable.

Derivation of End Use Base Transmission Revenue Requirements (BTRR _{EU}) For the Rate Effective Period xxxxxx (\$1,000)

Line					Line
No.		A	mounts	Reference	No.
1	A. End Use Customer Base Transmission Revenue Requirement (BTRR FII):				1
2	A. End Ose Customer Base Transmission Revenue Requirement (BTRR FII).				2
3	End of Prior Year Revenues (PYRR FII) Excluding FF&U	S	212,608	Statement BK-1; Page 1; Line 33	3
4	End of Thos Total Revenues (1 Trace Eq.) Enduding Trace	Ψ	212,000	Statement Bit 1, 1 ago 1, Bitto 33	4
5	Incentive End of Prior Year Revenues (PYRR FULIR) Excluding FF&U			Statement BK-1; Page 1; Line 58	5
6	LU-IIV	-			6
7	Sub-Total Base Period Revenues	\$	212,608	Sum Lines 3 thru 5	7
8		-			8
9	Retail True-Up Period Adjustment	\$	-	(Retail TU Adj; Total Col; Line 29) / 1,000	9
10					10
11	Retail Interest True-Up Adjustment			(Retl Int TU-1 + Retl Int TU-2; Ttl Col; Ln 20)/1,000	11
12		_			12
13	Sub-Total True-Up Adjustments	_\$	-	Sum Lines 9 thru 11	13
14 15	P. Annual Final Chauses Applicable to Capital Projects.				14 15
16	B. Annual Fixed Charges Applicable to Capital Projects:				16
17	Forecast Period Capital Addition Revenue Requirements	\$	_	Statement BK-1; Page 4, Line 20	17
18	Torong Torong Capital Addition November Requirements	•		Statement Bit 1, 1 ago 1, Bite 20	18
19	C. Annual Fixed Charges Applicable to Incentive Capital Projects:				19
20					20
21	Forecast Period Incentive Capital Additions Revenue Requirements (FC EU-IR-ROE)	\$	-	Statement BK-1; Page 5, Line 20	21
22					22
23	D. Incentive Forecast Transmission CWIP Revenues:				23
24					24
25	Incentive Transmission Forecast CWIP Projects Revenue Requirements	\$	-	Statement BK-1; Page 5, Line 37	25
26					26
27	E. Subtotal BTRR FII Excluding FF&U:	\$	212,608	Sum Lines 7; 13; 17; 21; 25	27
28			0.100	1, 22 1 0210/	28
29	Transmission Related Municipal Franchise Fees Expenses		2,192	Line 27 x 1.031%	29
30	Transmission Related Uncollectible Expense		370	Line 27 x 0.174%	30
31	E T.4-I D.4-II DTDD W/4L EE@H	6	215 170	0 - 1: 27.4 20	31
32	F. Total Retail BTRR FII With FF&U		215,170	Sum Lines 27 thru 30	32

True Up Period Statement – BK2 ISO Wholesale Cost of Service Which Determines Base Transmission Revenue Requirements (BTRR_{ISO})

Derivation of CAISO Total Base Transmission Revenue Requirements
For the 4-Month True-Up Period Ending December 31,2013 (\$1,000)

Line				Line
No.		Amounts	Reference	No.
1 2	A. Total (PYRR FII) Excluding FF&U: 1	\$ 212,608	Statement BK-1; Page 1; Line 60	1 2
3	B. Wholesale BTRR Adjustments:			3
4	CPUC Intervenor Funding Expense - Transmission	=	Statement BK-1; Page 1; Line 6	4
5				5
6	CPUC Intervenor Funding Expense Revenue Adjustment	=	Statement AL; Page 9; Line 30	6
. 7				7
8	South Georgia Income Tax Adjustment	(778)	Statement BK-1; Page 1; Line 26	8
9				9
10	Transmission Related Amortization of Excess Deferred Tax Liabilities	101	Statement BK-1; Page 1; Line 28	10
11				11
12	Total Wholesale BTRR Adjustments	\$ (677)	Sum Lines 4 thru 10	12
13				13
14	Wholesale Prior Year Revenue Requirements (PYRR CAISO)	211,931	Sum Lines 1; 12	14
15				15
16	Wholesale True-Up Adjustment	-	(Wholesale TU Adj; Total Col; Line 29) / 1,000	16
17				17
18	Wholesale Interest True-Up Adjustment		(Wholesale Int TU-1 + Wholesale Int TU-2; Ttl Col; Ln 20) / 1000	18
19				19
20	Wholesale BTRR Before Forecast Prior Year Revenue Requirements (PYRR CAISO)	\$ 211,931	Sum Lines 14 thru 18	20
21				21
22	Forecast Period Capital Addition Revenue Requirements	+	Statement BK-1; Page 4; Line 20	22
23				23
24	Forecast Period Incentive Capital Addition Revenue Requirements (FC EU-IR-ROE)	-	Statement BK-1; Page 5; Line 20	24
25				25
26	Incentive Transmission Forecast CWIP Projects Revenue Requirements		Statement BK-1; Page 5; Line 37	26
27	•			27
28	C. Total Wholesale BTRR Excluding Franchise Fees	\$ 211,931	Sum Lines 20 thru 26	28

¹ Total Prior Year Revenues (PYRR) or Base Period Revenue is for 12 months ending the applicable cycle base period.

Derivation of CAISO HV Transmission Facility (BTRR CAISO-HV) & LV Transmission Facility (BTRR CAISO-LV) Revenue Requirements

For the Rate Effective Period xxxxxx (\$1,000)

Line		-				D C		Line
No.	A D. J. d. and D. L. IVIII W. I. I. D. IVII	Total	Reference			rence	No.	
	A. Derivation of Revenues Related With Total Transmission Facilities:	0 011 001	G	. DVI O				
1	Wholesale BTRR Before Forecast Prior Year Revenue Requirements (PYRR CAISO)	\$ 211,931	State	ment BK-2; I	Page I	; Line 20		1
2	Forecast David Carital Addition December Description		C4-4-		D 1	. T : 22		2
4	Forecast Period Capital Addition Revenue Requirements	-	State	ment BK-2; I	rage I	, Lille 22		3
5	Forecast Period Incentive Capital Additions Revenue Requirements (FC FILIR-ROF)	-	State	ment BK-2; I	Page 1	· I ine 24		5
6 -	Totocast Totoca moentive capital radiations revenue requirements (1 © E0-IR-ROE)		Diane	mem Dix-2, i	age 1	, Line 24		6
7	Incentive Transmission Forecast CWIP Projects Revenue Requirements	100	State	ment BK-2; I	Page 1	Line 26		7
8	The state of the s		Diane	211 2, 1		, 2010 20		8
9	Total Wholesale BTRR Excluding Franchise Fees	\$ 211,931		Sum Line	s 1 thi	ru 7		9
10								10
11	B. Derivation of Split Between HV and LV: 1	(a)		(b)		(c)		11
12	1. Percent Split Between HV & LV for Recorded Non-Incentive & Incentive	Total	Hi	gh Voltage	Lov	v Voltage	Reference	12
13	Gross Transmission Plant Facilities and Incentive CWIP:	3 -						13
14	Gross Transmission Plant Facilities ²	\$3,783,949	\$	2,562,714	\$	1,221,235	HV-LV Study, Line 3 below 6	14
15	HV-LV Plant Allocation Ratios 3	100.00%		67.73%		32.27%	Ratios Based on Line 14	15
16	Total HV-LV Transmission Plant Facilities Revenues	\$ 211,931	\$	143,533	\$	68,399	Line 15 x Line 16; Col A	16
17								17
18	2. Percent Split Between HV and LV of Forecast						Summary of HV-LV Splits for	18
19	Plant Adds Applicable to Forecast Period:	\$ -	\$	(4)	\$		Forecast Plant Adds; Page 1; Line 16	19
20	HV-LV Plant Allocation Ratios Based on Forecast Plant Additions	0.00%		0.00%		0.00%	Ratios Based on Line 19	20
21	Total HV-LV Transmission Forecast Plant Additions Revenues	\$ -	\$	#	\$	-	Line 20 x Line 21; Col A	21
22	C C. CANCO T. C. L. F. TVI.							22
23 24	C. Summary of CAISO Transmission Facilities by High Voltage and Low Voltage Classification:							23 24
25	Recorded Transmission Facilities (BTRR CAISO) Excluding Franchise Fees	\$ 211.931	\$	143,533	e	68,399	Line 16 From Above	25
	, orang,		o P	Maria de la Companio	φ	CARLES OF THE PARTY OF		
26	Franchise Fee (FF) @ 1.031% ⁴	2,185		1,480	Φ.	705	Line 25 x 1.031%	26
27	Total Recorded Transmission Facilities BTRR CAISO With Franchise Fees	\$ 214,116	\$	145,013	\$	69,104	Sum Lines 25 thru 26	27
28	F	6	ф		•		11 OLD 11	28
29	Forecast Transmission Facilities (BTRR CAISO) Excluding Franchise Fees	5 -	\$	-	\$	-	Line 21 From Above	29
30	Franchise Fee (FF) @ 1.031% 4					17 - VS	Line 29 x 1.031%	30
31	Total Recorded Transmission Facilities BTRR CAISO With Franchise Fees	_\$ -	\$	-	\$	-	Sum Lines 29 thru 30	31
32								32
33	D. Total (BTRR CAISO) With Franchise Fees 5	\$ 214,116	\$	145,013	\$	69,104	Line 27 + Line 31	33

Pursuant to the CAISO'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 CAISO'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 CAISO's HV and LV guidelines in effect 1/1/2005 pursuant to CAISO Tariff Appendix F, Sch.3, Section 8.1.

⁵ The following HV-LV Wholesale Base Transmission Revenue Requirements will be used by the CAISO to develop the TAC rates for the rate effective applicable period.

⁶ Transmission Plant HV/LV Study Classification Summary (\$1,000):	Ln	Total	HV	LV	See HV-LV Study WP
Existing	1	\$3,783,949	\$ 2,562,714	\$ 1,221,235	
New	2	12			
Total	3	\$3,783,949	\$ 2,562,714	\$ 1,221,235	i

² Use gross plant facilities as of December 31 for the applicable base period.

³ HV-LV plant ratios based upon footnote 2.

⁴ Base franchise fees are applicable to all SDG&E customers.

TO4 - Cycle 2

True Up
Statement AD
Cost of Plant

Statement AD Cost of Plant

For the 4-Month True-Up Period Ending December 31,2013 (\$1,000)

Line				Line
No	.	Amounts	Reference	No
1 2	Total Electric Miscellaneous Intangible Plant ¹	\$ 91,511	Stmnt AD WP; Page AD1; Line 1	1 2
3	Total Steam Production Plant	511,316	Stmnt AD WP; Page AD1; Line 3	3
5	Total Nuclear Production Plant		Stmnt AD WP; Page AD1; Line 5	5
7	Total Hydraulic Production Plant		Stmnt AD WP; Page AD1; Line 7	7 8
9 10	Total Other Production Plant	474,596	Stmnt AD WP; Page AD1; Line 9	9 10
11 12	Total Production Plant and Intangible Plant	\$ 1,077,423	Sum Lines 1 thru 9	11 12
13 14	Total Distribution Plant	\$ 5,171,968	Stmnt AD WP; Page AD1; Line 13	13 14
15 16	Transmission Plant ²	\$ 3,723,358	Stmnt AD WP; Page AD1; Line 15	15 16
17 18	Incentive Transmission Plant ³		Stmnt AD WP; Page AD1; Line 17	17 18
19 20	Total Transmission Plant & Incentive Transmission Plant	\$ 3,723,358	Sum Lines 15 thru 17	19 20
21 22	Total General Plant ¹	\$ 258,034	Stmnt AD WP; Page AD1; Line 21	21 22
23 24	Total Common Plant ¹	\$ 527,422	Stmnt AD WP; Page AD1; Line 23	23 24
25 26	Total Plant in Service	\$ 10,758,205	Sum Lines 11; 13; 19; 21; 23	25 26
27 28	Transmission Wages and Salaries Allocation Factor	17.51%	Statement AI; Line 19	27 28
29 30	Total Transmission Plant & Incentive Transmission Plant	\$ 3,723,358	See Line 19 Above	29 30
31 32	Transmission Related Electric Miscellaneous Intangible Plant	16,024	Line 1 x Line 27	31 32
33 34	Transmission Related General Plant	45,182	Line 21 x Line 27	33 34
35 36	Transmission Related Common Plant	92,352	Line 23 x Line 27	35 36
37 38	Transmission Related Total Plant in Service	\$ 3,876,916	Sum Lines 29; 31; 33; 35	37 38
39	Transmission Plant Allocation Factor ⁴	36.04%	Line 37 / Line 25	39

Electric Miscellaneous Intangible Plant, General Plant, and Common Plant are not affected by the "Seven-Element Adjustment Factor" because there's no transfer of transmission or distribution plant among these categories.

² The amounts stated above are ratemaking utility plant in service and as a result of implementing the "Seven-Element Adjustment Factor" which reflects transfers between generation and distribution functions.

³ The purpose of this footnote is to indicate for incentive projects the cost of the project.

⁴ Used to allocate all elements of working capital, other than working cash.

TO4 - Cycle 2

True Up Statement AE Accumulated Depreciation and Amortization

Statement AE

Accumulated Depreciation and Amortization For the 4-Month True-Up Period Ending December 31,2013

(\$1,000)

Line No	· · · · · · · · · · · · · · · · · · ·	Amounts	Reference	Line No
1 2	Transmission Plant Depreciation Reserve ¹	\$ 656,144	Stmnt AE WP; Page AE1; Line 1	1 2
3 4	Electric Miscellaneous Intangible Plant Amortization Reserve ²	\$ 17,885	Stmnt AE WP; Page AE1; Line 3	3 4
5 6	General Plant Depreciation Reserve ²	101,957	Stmnt AE WP; Page AE1; Line 5	5 6
7 8	Common Plant Depreciation Reserve ²	261,817	Stmnt AE WP; Page AE1; Line 7	7 8
9 10	Transmission Wages and Salaries Allocation Factor	17.51%		9 10
11	Transmission Related Electric Misc. Intangible Plant Amortization Reserve	\$ 3,132	Line 3 x Line 9	11 12
13 14	Transmission Related General Plant Depreciation Reserve	17,853	Line 5 x Line 9	13 14
15 16	Transmission Related Common Plant Depreciation Reserve	45,844	Line 7 x Line 9	15 16
17 18	Total Transmission Related Depreciation Reserve	\$ 722,973	Sum Lines 1; 11; 13; 15	17 18
19	Incentive Transmission Plant Depreciation Reserve	\$ -	Stmnt AE WP; Page AE1; Line 19	19

The amounts stated above are ratemaking utility plant in service as a result of implementing the "Seven-Element Adjustment Factor" which reflects transfers between generation and distribution functions.

Electric Miscellaneous Intangible Plant, General Plant, and Common Plant are not affected by the "Seven-Element Adjustment Factor" because there's no transfer of transmission or distribution plant among these categories.

TO4 - Cycle 2

True Up
Statement AF
Specified
Deferred Credits

Statement AF **Deferred Credits**

For the 4-Month True-Up Period Ending December 31,2013 (\$1,000)

Line	*			Line
No	_	Amounts	Reference	No
1	Transmission Related ADIT- Excluding Bonus Depreciation	\$ (265,395)	Stmnt AF WP; Page AF1; Line 1	1
3	Transmission Related ADIT from Bonus Depreciation	(127,863)	Stmnt AF WP; Page AF1; Line 3	3
5	Total Transmission Related ADIT	\$ (393,258)	Sum Lines 1 thru 3	5
7	Incentive Transmission Plant ADIT	\$ -	Stmnt AF WP; Page AF1; Line 8	7
9	Transmission Plant Abandoned ADIT	\$ -	Stmnt AF WP; Page AF1; Line 10	8
10 11	Incentive Transmission Plant Abandoned Project Cost ADIT	\$ -	Stmnt AF WP; Page AF1; Line 12	10 11

TO4 - Cycle 2

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

Statement AG

Specified Plant Account (Other than Plant in Service) and Deferred Debits
For the 4-Month True-Up Period Ending December 31,2013 (\$1,000)

Line	w	5.6	Line
<u>No</u>	Amounts	Reference	No
1 Transmission Plant Held for Future Use 1	\$ 6,546	Stmnt AG WP; Page AG1; Line 1	1

The balances for Transmission Plant Held for Future Use are derived based on a 13-month average balance.

TO4 - Cycle 2

True Up
Statement AH
Operation and
Maintenance
Expenses

Statement AH Operation and Maintenance Expenses

For the 4-Month True-Up Period Ending December 31,2013 (\$1,000)

Line				Line
No.		Amounts	Reference	No.
1	Derivation of Transmission Operation and Maintenance Expense:			1
2	Total Transmission O&M Expense	\$ 34,644	Stmnt AH WP; Page AH1; Line 2	2
3	Adjustments to Per Book Transmission O&M Expense:			3
4	FERC Acct 561.4 - Scheduling, System Control & Dispatch Services	(2,887)	Stmnt AH WP; Page AH1; Line 4	4
5	FERC Acct 561.8 - Reliability, Planning & Standards Development	(394)	Stmnt AH WP; Page AH1; Line 5	5
6	FERC Acct 565 - Transmission of Electricity by Others	(1,713)	Stmnt AH WP; Page AH1; Line 6	6
7	FERC Acct 566 - Miscellaneous Transmission Expense	(2,973)	Stmnt AH WP; Page AH1; Line 7	7
8	Other Transmission O&M Exclusion Adjustments		Stmnt AH WP; Page AH1; Line 8	8
9	Total Adjusted Transmission O&M Expenses	\$ 26,677	Sum Lines 2 thru 8	9
10				10
11	Derivation of Administrative and General Expense:			11
12	Total Administrative & General Expense	\$ 202,819	Stmnt AH WP; Page AH1; Line 12	12
13	Adjustments to Per Book A&G Expense:	C50000		13
14	Nuclear liability insurance expense	(291)	Stmnt AH WP; Page AH1; Line 14	14
15	Damages & Injuries - Wildfire Insurance Premium	*	Stmnt AH WP; Page AH1; Line 15	15
16	Damages & Injuries - Wildfire Damage Claims		Stmnt AH WP; Page AH1; Line 16	16
17	CPUC Intervenor Funding Expense - Transmission ¹		Stmnt AH WP; Page AH1; Line 17	17
18	CPUC Intervenor Funding Expense - Distribution	(296)	Stmnt AH WP; Page AH1; Line 18	18
19	CPUC reimbursement fees	(1,557)	Stmnt AH WP; Page AH1; Line 19	19
20	FERC Acct 930.1 - General Advertising Expenses		Stmnt AH WP; Page AH1; Line 20	20
21	Litigation expenses - Litigation Cost Memorandum Account (LCMA)	(9)	Stmnt AH WP; Page AH1; Line 21	21
22	CPUC energy efficiency programs	(1,665)	Stmnt AH WP; Page AH1; Line 22	22
23	Advanced Metering Infrastructure (AMI) lease facilities	(39)	Stmnt AH WP; Page AH1; Line 23	23
24	Hazardous substances - Hazardous Substance Cleanup Cost Account	(15)	Stmnt AH WP; Page AH1; Line 24	24
25	Other A&G Exclusion Adjustments	65	Stmnt AH WP; Page AH1; Line 25	25
26	Total Adjusted A&G Expenses Including Property Insurance	\$ 199,012	Sum Lines 12 thru 25	26
27	Less: Property Insurance (Reflected on Line 50 below due to different allocation factor)	(2,338)	Stmnt AH WP; Page AH1; Line 27	27
28	Total Adjusted A&G Expense Excluding Property Insurance	\$ 196,674	Sum Lines 26 and 27	28
29 30	Transmission Wages and Salaries Allocation Factor Total Transmission Related Administrative and General Expenses	\$ 34,438	Statement AI; Line 19	29
	Total Transmission Related Administrative and General Expenses	\$ 34,438	Line 28 x Line 29	30
31	Deletion CT and District Distr			31
32 33	Derivation of Transmission Plant Property Insurance Allocation Factor: Transmission Plant & Incentive Transmission Plant	\$ 3,723,358	Cturet All WD. Dana Alli, Line 22	32
34	Transmission Plant & Incentive Transmission Plant Transmission Related Electric Miscellaneous Intangible Plant	\$ 3,723,338	Stmnt AH WP; Page AHI; Line 33	33 34
35	Transmission Related General Plant	45,182	Stmnt AH WP; Page AH1; Line 34 Stmnt AH WP; Page AH1; Line 35	35
36	Transmission Related Common Plant	92,352	Stmnt AH WP; Page AH1; Line 36	36
37	Total Transmission Related Investment in Plant	\$ 3,860,892	Sum Lines 33 thru 36	37
38	Total Transmission Related III Visitient III Ttali	ψ 3,000,032	Juli Lines 33 till 30	38
39	Total Transmission Plant & Incentive Transmission Plant	\$ 3,723,358	Stmnt AH WP; Page AH1; Line 39	39
40	Total Steam Production Plant	511,316	Stmnt AH WP; Page AH1; Line 40	40
41	Total Nuclear Production Plant	511,510	Stmnt AH WP; Page AH1; Line 41	41
42	Total Other Production Plant	474,596	Stmnt AH WP; Page AH1; Line 42	42
43	Total Distribution Plant	5,171,968	Stmnt AH WP; Page AH1; Line 43	43
44	Total General Plant	258,034	Stmnt AH WP; Page AH1; Line 44	44
45	Total Common Plant	527,422	Stmnt AH WP; Page AH1; Line 45	45
46	Total Plant in Service Excluding SONGS	\$ 10,666,694	Sum Lines 39 thru 45	46
47				47
48	Transmission Plant Property Insurance Allocation Factor	36.20%	Line 37 / Line 46	48
49	The second of th		Eme 577 Eme 10	49
50	Total Property Insurance	\$ 2,338	See Line 27 Above	50
51	rotal respect, monante	Ψ 2,336	Bee Line 21 Above	51
52	Property Insurance Allocated to Transmission, General, and Common Plant	\$ 846	Line 48 x Line 50	52
53		4 010	Line to a Line 30	53
54	Transmission Related A & G Expense Excluding Property Insurance Expense	34,438	See Line 30 Above	54
55	Timeston Action of the Companies Employers Household Employers	31,130	See Line 30 Proofe	55
56	Transmission Related A & G Expense Including Property Insurance Expense	\$ 35,284	Sum Lines 52 & 54	56
	D. 197-19			

The CPUC Intervenor Expense for Transmission shall be treated as an exclusion in A&G but added back to the Retail BTRR on BK-1, page 1, line 6. This expense will be excluded in Wholesale BTRR on BK-2, page 1, line 4.

TO4 - Cycle 2

True Up Statement AI Wages and Salaries

Statement AI

Wages and Salaries For the 4-Month True-Up Period Ending December 31,2013 (\$1,000)

Line No.		Ar	mounts	Reference	Line No.
1	Production Wages & Salaries	\$	3,822	Stmnt AI WP; Page AI1; Line 1	1
3	Transmission Wages & Salaries		7,296	Stmnt AI WP; Page AI1; Line 3	3
5	Distribution Wages & Salaries		16,694	Stmnt AI WP; Page AI1; Line 5	5
7 8	Customer Accounts Wages & Salaries		7,420	Stmnt AI WP; Page AI1; Line 7	7
9 10	Customer Services and Informational Wages & Salaries		6,445	Stmnt AI WP; Page AI1; Line 9	9 10
11 12	Sales Wages & Salaries		-	Stmnt AI WP; Page AI1; Line 11	11 12
13 14	Sub-Total	\$	41,677	Sum Lines 1 thru 11	13 14
15 16	Administrative and General Wages & Salaries	\$	12,678	Stmnt AI WP; Page AI1; Line 15	15 16
17 18	Total Operating & Maintenance Wages & Salaries	\$	54,355	Sum Lines 13; 15	17 18
19	Transmission Wages and Salaries Allocation Factor		17.51%	Line 3 / Line 13	19

TO4 - Cycle 2

True Up Statement AJ Depreciation and Amortization Expenses

Statement AJ

Depreciation and Amortization Expense For the 4-Month True-Up Period Ending December 31,2013 (\$1,000)

Line No.		Amounts	Reference	Line No.
1 2	Transmission Plant Depreciation Expense (net of incentive depreciation expense on line 21)	\$ 30,341	Stmnt AJ WP; Page AJ1; Line 1	1 2
3	Electric Miscellaneous Intangible Plant Amortization Expense	\$ 4,218	Stmnt AJ WP; Page AJ1; Line 3	3
4 5 6	General Plant Depreciation Expense	3,232	Stmnt AJ WP; Page AJ1; Line 5	4 5 6
7	Common Plant Depreciation Expense	18,393	Stmnt AJ WP; Page AJ1; Line 7	7
8 9 10	Transmission Wages and Salaries Allocation Factor	17.51%	Stmnt AJ WP; Page AJ1; Line 9	8 9 10
11	Transmission Related Electric Misc. Intangible Plant Amortization Expense	\$ 738	Line 3 x Line 9	11 12
13	Transmission Related General Plant Depreciation Expense	566	Line 5 x Line 9	13
14 15 16	Transmission Related Common Plant Depreciation Expense	3,221	Line 7 x Line 9	14 15 16
17 18	Total Transmission, General, Common Plant Depn. Exp., and Electric Misc. Intangible Plant Amort. Exp.	\$ 34,866	Sum Lines 1; 11; 13; 15	17 18
19 20	Valley Rainbow Project Cost Amortization Expense 1	\$ 158	Stmnt AJ WP; Page AJ1; Line 19	19 20
21	Incentive Transmission Plant Depreciation Expense	\$ -	Stmnt AJ WP; Page AJ1; Line 21	21
22 23 24	Transmission Plant Abandoned Project Cost Amortization Expense	\$ -	Stmnt AJ WP; Page AJ1; Line 23	22 23 24
25	Incentive Transmission Plant Abandoned Project Cost Amortization Expense	\$ -	Stmnt AJ WP; Page AJ1; Line 25	25

¹ Amortization approval per ER03-601-000 issued May 2, 2003 for a 10-year period beginning October 2003 and ending September 2013.

TO4 - Cycle 2

True Up
Statement AK
Taxes Other
Than Income Taxes

Statement AK

Taxes Other Than Income Taxes For the 4-Month True-Up Period Ending December 31,2013 (\$1,000)

Line No.		Amounts	Reference	Line No.
	-	Amounts	Reference	140.
1 2	Total Property Taxes	\$ 26,313	Stmnt AK WP; Page AK1; Line 5	1 2
3	Less: SONGS Property Taxes	(1,792)	Stmnt AK WP; Page AK1; Line 7	3
4		(-1,)		4
5	Property Taxes Less SONGS	\$ 24,521	Line 1 Minus Line 3	5
6	,			6
7				7
8	Derivation of Transmission Related Property Tax Allocation Factor:			8
9	Total Transmission Plant & Incentive Transmission Plant	\$ 3,723,358	Stmnt AD WP; Page AD1; Line 29	9
10	Transmission Related Electric Miscellaneous Intangible Plant	0	Shall be Zero	10
11	Transmission Related General Plant	45,182	Stmnt AD WP; Page AD1; Line 33	11
12	Transmission Related Common Plant	92,352	Stmnt AD WP; Page AD1; Line 35	12
13	Total	\$ 3,860,892	Sum Lines 9 thru 12	13
14				14
15	Total Transmission Plant & Incentive Transmission Plant	3,723,358	Stmnt AD WP; Page AD1; Line 29	15
16	Total Electric Miscellaneous Intangible Plant	0	Shall be Zero	16
17	Total Steam Plant	511,316	Stmnt AD WP; Page AD1; Line 3	17
18	Total Nuclear Plant	0	Shall be Zero	18
19	Total Other Production Plant	474,596	Stmnt AD WP; Page AD1; Line 9	19
20	Total Distribution Plant	5,171,968	Stmnt AD WP; Page AD1; Line 13	20
21	Total General Plant	258,034	Stmnt AD WP; Page AD1; Line 21	21
22	Total Common Plant	527,422	Stmnt AD WP; Page AD1; Line 23	22
23	Total Investment in Plant Excluding SONGS	\$ 10,666,694	Sum Lines 15 thru 22	23
24				. 24
25	Transmission Related Property Tax Allocation Factor	36.20%	Line 13 / Line 23	25
26				26
27	Transmission Related Property Taxes Expense	\$ 8,877	Line 5 x Line 25	27
28				28
29	Payroll Taxes	\$ 4,122	Stmnt AK WP; Page AK1; Line 16	29
30				30
31	Transmission Wages and Salaries Allocation Factor	17.51%	Statement AI; Line 19	31
32				32
33	Transmission Related Payroll Taxes Expense	\$ 722	Line 29 x Line 31	33

TO4 - Cycle 2

True Up
Statement AL
Working
Capital

Statement AL Working Capital For the 4-Month True-Up Period Ending December 31,2013 (\$1,000)

Line					Line
No.	· ·	An	nounts	Reference	No.
1 2	A. Plant Materials and Operating Supplies ^a	\$	62,157	Stmnt AL WP; Page AL1; Line 1	1 2
3	Transmission Plant Allocation Factor		36.04%	Stmnt AD WP; Page AD1; Line 39	3
5	Transmission Related Materials and Supplies	\$	22,401	Line 1 x Line 3	5
7	B. Prepayments ^a	\$	49,230	Stmnt AL WP; Page AL1; Line 7	7
9 10	Transmission Related Prepayments	\$	17,742	Line 3 x Line 7	9 10
11 12	C. Derivation of Transmission Related Cash Working Capital: Transmission Operation & Maintenance Expense	¢	26,677	Stmnt AL WP; Page AL1; Line 12	11 12
13 14	Transmission Related Administrative & General Expense CPUC Intervenor Funding Expense - Transmission	Ψ.	35,284	Stmnt AL WP; Page AL1; Line 13 Stmnt AL WP; Page AL1; Line 14	13 14
15 16	Total	\$	61,961	Sum Lines 12 thru 14	15 16
17 18	One Eighth O&M Method		37.50%	4 Month T/U Proration Methond = 45 days /(360 x1/3)	17 18
19 20	Transmission Related Cash Working Capital - Retail Customers	\$	23,235	Line 15 x Line 17	19
21	D. Adj. to Back Out CPUC Intervenor Funding Exp. Embedded in Retail Working Cash:	e.		Charact AT W/D. Davis AT L. Line 22	20 21
22	CPUC Intervenor Funding Expense - Transmission	2	-	Stmnt AL WP; Page AL1; Line 22	22 23
24 25	One Eighth O&M Rule		37.50%	4 Month T/U Proration Methond = 45 days /(360 x1/3)	24 25
26 27	Adj. to Transmission Related Cash Working Capital - Wholesale Customers	\$		Line 22 x Line 24	26 27
28 29	Cost of Capital Rate (COCR)		11.3334%	Stmnt AL WP; Page AL1; Line 28	28 29
30	CPUC Intervenor Funding Exp. Revenue Adj. b	\$		Line 26 x Line 28	30

The balances for Materials & Supplies and Prepayments are derived based on a 13-month average balance.

This adjustment is being made to BK-2, page 1, line 6 to show that wholesale customers should not pay for this working cash item.

TO4 - Cycle 2

True Up
Statement AM
Construction
Work In Progress
(CWIP)

Statement AM

Construction Work In Progress

For the 4-Month True-Up Period Ending December 31,2013 (\$1,000)

Line		-	Line
<u>No.</u>	Amounts	Reference	No.
1 Incentive Transmission Construction Work In Progress ^a	\$ -	Stmnt AM WP; Page AM1; Line 1	1

a The balance for Incentive Transmission Construction Work In Progress is derived based on a 13-month average balance. A line will be shown for each applicable project.

TO4 - Cycle 2

True Up
Statement AQ
Federal Income
Tax Deductions —
Other than Interest

Statement AQ

Federal Income Tax Deductions, Other Than Interest For the 4-Month True-Up Period Ending December 31,2013 (\$1,000)

		Line
Amounts	Reference	No.

778

Stmnt AQ WP; Page AQ1; Line 1

Line No.

TO4 - Cycle 2

True Up
Statement AR
Federal Tax
Adjustments

Statement AR

Federal Tax Adjustments For the 4-Month True-Up Period Ending December 31,2013 (\$1,000)

Line No.	i -	Amounts	Reference	Line No.
1	Transmission Related Amortization of Investment Tax Credits	\$ (88)	Stmnt AR WP; Page AR1; Line 1	1
3	Transmission Related Amortization of Excess Deferred Tax Liabilities	(101)	Stmnt AR WP; Page AR1; Line 3	3
5	Total	\$ (189)	Sum Lines 1 thru 3	5

San Diego Gas & Electric Company

TO4 - Cycle 2

True Up
Statement AU
Revenue
Credits

Docket No. ER15-__-

Statement AU

Revenue Credits For the 4-Month True-Up Period Ending December 31,2013 (\$1,000)

Line No.		Amounts	Reference	Line No.
1	(451) Miscellaneous Service Revenues	\$ -	Stmnt AU WP; Page AU1; Line 1	1
3	(453) Sales of Water and Water Power		Stmnt AU WP; Page AU1; Line 3	3
5	(454) Rent from Electric Property	248	Stmnt AU WP; Page AU1; Line 5	5
6 7	(455) Interdepartmental Rents		Stmnt AU WP; Page AU1; Line 7	6 7
8 9	(456) Other Electric Revenues	1,252	Stmnt AU WP; Page AU1; Line 9	8 9
10 11	Transmission Related Revenue Credits	\$ 1,499	Sum Lines 1 thru 9	10 11
12		2,000		12
13	(411.6 & 411.7) Gain or Loss From Sale of Plant Held for Future Use	\$ -	Stmnt AU WP; Page AU1; Line 13	13

San Diego Gas & Electric Company

TO4 - Cycle 2

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

Docket No. ER15-__-

Statement AV

Cost of Capital and Fair Rate of Return

For the 4-Month True-Up Period Ending December 31,2013 (\$1,000)

Line							Line
No.	_				Amounts	Reference	No.
1	Long-Term Debt Component - Denominator:						1
2	(Plus): Account 221 - Bonds				\$ 3,926,855	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)	D.1.			123,900	Stmnt AV WP; Page AV1; Line 4	4
5	(Plus): Account 225 - Unamortized Premium on Long-Te				10.052	Stmnt AV WP; Page AV1; Line 5	5
6	(Less): Account 226 - Unamortized Discount on Long-Te	rm Debt-Debit			10,953	Stmnt AV WP; Page AV1; Line 6	6
7	Total Long Term Debt (LTD)				\$ 4,039,802	Line 2 Minus Line 3 Plus Lines 4 & 5 Minus Line 6	7
8							8
9	Long-Term Debt Component - Numerator:				1	And the second s	9
10	(Plus): Account 427 - Interest on Long-Term Debt				\$ 186,465	Stmnt AV WP; Page AV1; Line 10	10
11	(Plus): Account 428 - Amort. of Debt Disc. and Expense				3,084	Stmnt AV WP; Page AV1; Line 11	11
12	(Plus): Account 428.1 - Amortization of Loss on Reacqui				2,537	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 Reacqui	red Debt-Credit				Stmnt AV WP; Page AV1; Line 14	14
15	Total LTD Interest $=$ (i)				\$ 192,086	Sum Lines 10; 11; 12 Minus Lines 13 & 14	15
16							16
17	Cost of Long-Term Debt:				4.75%	Line 15 / Line 7	17
18							18
19	Preferred Equity Component:						19
20	PF = Preferred Stock - Account 204				\$ -	Stmnt AV WP; Page AV1; Line 20	20
21	d(pf) = Total Dividends Declared-Preferred Stocks - Acce	ount 437			\$ 1,205	Stmnt AV WP; Page AV1; Line 21	21
22	Cost of Preferred Equity				0.00%	Line 21 / Line 20	22
23							23
24	Common Equity Component:						24
25	Proprietary Capital				\$ 4,629,716	Stmnt AV WP; Page AV1; Line 25	25
26	(Less): Account 204 - Preferred Stock				-	Stmnt AV WP; Page AV1; Line 26	26
27	(Less): Account 216.1 - Unappropriated Undistributed Su	bsidiary Earnings				Stmnt AV WP; Page AV1; Line 27	27
28	(Less): Account 219 - Accumulated Other Comprehensive	e Income			9,010	Stmnt AV WP; Page AV1; Line 28	28
29	CS = Common Stock				\$ 4,620,706	Line 25 Minus Lines 26, 27 & 28	29
30							30
31	Return on Common Equity				10.05%	Stmnt AV WP; Page AV1; Line 31	31
32		(a)	(b)	(c)	(d) = (b) x (c)		32
33			Cap. Struct.	Cost of	Weighted		33
34	Weighted Cost of Capital:	Amount 1	Ratio	Capital	Cost of Capital		34
35							35
36	Long-Term Debt	\$ 4,039,802	46,65%	4.75%	2.22%	Col. C = Line 17 Above	36
37	Preferred Equity	-	0.00%	0.00%	0.00%	Col. C = Line 22 Above	37
38	Common Equity	4,620,706	53.35%	10.05%	5.36%	Col. C = Line 31 Above	38
39	Total Capital	\$ 8,660,508	100.00%		7.58%	Sum Lines 36 thru 38	39
40	•						40
41	Cost of Equity Component (Preferred & Common):				5.36%	Sum Lines 37; 38; Col. (d)	41
42							42
43							43
44	Incentive Return on Common Equity: 2				0.00%	Stmnt AV WP; Page AV1; Line 44	44
	incontivo feetam on common Equity.	(0)	(b)	(0)		Stillit AV WI, I age AVI, Ellie 44	
45		(a)	(b)	(c)	$(d) = (b) \times (c)$ Weighted		45
46	W. I. I. G	1	Cap. Struct.	Cost of	Weighted		46
47	Weighted Cost of Capital:	Amount 1	Ratio	Capital	Cost of Capital		47
48		Φ 4.020.055	1		2 222	010 11 17 17	48
	Long-Term Debt	\$ 4,039,802	46.65%	4.75%	2.22%	Col. C = Line 17 Above	49
	Preferred Equity	4 200 500	0.00%	0.00%	0.00%	Col. C = Line 22 Above	50
51	Common Equity	4,620,706	53.35%	0.00%	0.00%	Col. C = Line 44 Above	51
52	Total Capital	\$ 8,660,508	100.00%		2.22%	Sum Lines 49 thru 51	52
53					12 V212 V		53
54	Incentive Cost of Equity Component (Preferred & Comm	on):			0.00%	Sum Lines 50; 51; Col. (d)	54

¹ Amount is based upon December 31 balances.

² The Incentive Return on Common Equity will be tracked and shown separately for each project. As a result, lines 44 through 54 will be repeated for each project.

Statement AV

Cost of Capital and Fair Rate of Return For the 4-Month True-Up Period Ending December 31,2013 (\$1,000)

Line				Line
No.	_	Amounts	Reference	No.
1	Cost of Capital Rate (COCR) Calculation:			1
2	<u> </u>			2
3	a) Federal Income Tax Component:			3
4	a) I decid filodito Tan Componenti			4
5	Where:			5
6	A = Sum of Preferred Stock and Return on Equity Component	5,36%	Statement AV; Page 14; Line 41	6
7	B = Trans. Related Amort. of ITC and Excess Deferred Tax Liab.	\$ 567	Statement AR; Page 12; Line 5	7
8	C = Equity AFUDC Component of Transmission Depreciation Expense	\$ 4,175	Stmnt AV WP; Page AV2; Line 8	8
9	D = Transmission Rate Base	\$ 2,830,609	Statement BK1; Page 2; Line 26	9
10	FT = Federal Income Tax Rate @ 35%	35%	Stmnt AV WP; Page AV2; Line 10	10
11	1 100			11
12	Federal Income Tax = $(((A) + (C/D)) * FT) - (B/D)$	2.9348%	Federal Income Tax Expense	12
13	(1 - FT)			13
14				14
15	b) State Income Tax Component:			15
16				16
17	Where:			17
18	A = Sum of Preferred Stock and Return on Equity Component	5.36%	Statement AV; Page 14; Line 41	18
19	B = Equity AFUDC Component of Transmission Depreciation Expense	\$ 4,175	Line 8 Above	19
20	C = Transmission Rate Base	\$ 2,830,609	Statement BK1; Page 2; Line 26	20
21	FT = Federal Income Tax Expense	2.9348%	Line 12 Above	21
22	ST = State Income Tax Rate @ 8.84%	8.84%	Stmnt AV WP; Page AV2; Line 22	22
23	· · · · · · · · · · · · · · · · · · ·			23
24	State Income Tax = $((A) + (B/C) + Federal Income Tax)*(ST)$	0.8187%	State Income Tax Expense	24
25	(1 - ST)			25
26	8.			26
27	c) Total Federal & State Income Tax Expense:	3.7534%	Sum Lines 12; 24	27
28				28
29	d) Total Weighted Cost of Capital:	7.5800%	Statement AV; Page 14; Line 39	29
30				30
31	e) Cost of Capital Rate (COCR):	11.3334%	Sum Lines 27; 29	31

Statement AV Cost of Capital and Fair Rate of Return

For the 4-Month True-Up Period Ending December 31,2013 (\$1,000)

Line	,			Line
No.	_	Amounts	Reference	No.
1	Incentive Cost of Capital Rate (ICOCR) Calculation: 1			1
2				2
3	a) Federal Income Tax Component:			3
4				4
5	Where:	0.0004		5
6	A = Sum of Preferred Stock and Return on Equity Component	0.00%	Statement AV; Page 14; Line 54	6
7	B = Trans. Related Amort. of ITC and Excess Deferred Tax Liab.	\$ -	Stmnt AV WP; Page AV3; Line 7	7
8	C = Equity AFUDC Component of Transmission Depreciation Expense	\$ -	Stmnt AV WP; Page AV3; Line 8	8
9	D = Incentive ROE Project Transmission Rate Base	\$ -	Statement BK1; Page 2; Line 31	9
10	FT = Federal Income Tax Rate @ 35%	35%	Stmnt AV WP; Page AV3; Line 10	10
11	E 1 11	//DD1//01	P. J II T P.	11
12 13	Federal Income Tax = $(((A) + (C/D)) * FT) - (B/D)$ (1 - FT)	#DIV/0!	Federal Income Tax Expense	12
13	(1-F1)			13 14
15	b) State Income Tax Component:			15
16	b) state income Tax Component.			16
17	Where:			17
18	A = Sum of Preferred Stock and Return on Equity Component	0.00%	Statement AV; Page 14; Line 54	18
19	B = Equity AFUDC Component of Transmission Depreciation Expense	\$ -	Line 8 Above	19
20	C = Incentive ROE Project Transmission Rate Base	\$ -	Line 9 Above	20
21	FT = Federal Income Tax Expense	#DIV/0!	Line 12 Above	21
22	ST = State Income Tax Rate @ 8.84%	8.84%	Stmnt AV WP; Page AV3; Line 22	22
23	bi blate moone tax rate to 0.0470	0.0470	build AV W1, 1 age AV3, Ellie 22	23
24	State Income Tax = $((A) + (B/C) + Federal Income Tax)*(ST)$	#DIV/0!	State Income Tax Expense	24
25	(1 - ST)	"DITTO.	State meeme Tax Expense	25
26	(1 51)			26
27	c) Total Federal & State Income Tax Expense:	#DIV/0!	Sum Lines 12; 24	27
28	of Total Tederal de State Meetine Tax Expense.	mDITTO.	Built Effice 12, 21	28
29	d) Total Incentive Weighted Cost of Capital:	2.2200%	Statement AV; Page 14; Line 52	29
30	a, a contra door or daprim.	21220070		30
31	e) Incentive Cost of Capital Rate (ICOCR):	0.0000% 1	Sum Lines 27; 29	31

The Incentive Cost of Capital Rate Calculation will be tracked and shown separately for each project. As a result, lines 3 through 31 will be repeated for each project. However, this will be entered as 0% in BK-1 when there's no incentive project to show.

Miscellaneous Statement

For the 4-Month True-Up Period Ending December 31,2013 (\$1,000)

Line No.		Amounts	Reference	Line No.
1	Transmission Related Regulatory Debits		Note 1	1
2		The second section of the second seco		2
3				3
4	Transmission Plant Abandoned Project Cost		Note 1	4
5				5
6				6
7	Other Regulatory Assets/Liabilities		Note 1	7
8				8
9				9
10	Incentive Transmission Plant Abandoned Project Cost		Note 1	10

None of the above items apply to SDG&E's TO4 Cycle 1 filing. However, as one or more of these items apply, subject to FERC approval, the applicable data field will be filled.

San Diego Gas & Electric Company

True Up Period
Statement - AD
Cost of Plant
Workpapers

Docket No. ER15-___-

Statement AD - Workpapers Cost of Plant

For the 4-Month True-Up Period Ending December 31,2013 (\$1,000)

Line No	-	(a) 31-Aug-13	(b) 31-Dec-13		= [(a)+(b)]/2 rage Balance	Reference	Line No
1 2	Total Electric Miscellaneous Intangible Plant a, 1	\$ 89,869	\$ 93,154	\$	91,511	Stmt AD WP; Page AD-1	1 2
3	Total Steam Production Plant ^b				511,316	Stmt AD WP; Page AD-2	3 4
5 6	Total Nuclear Production Plant ^b				9-17-05	Stmt AD WP; Page AD-3	5 6
7 8	Total Hydraulic Production Plant ^b					Stmt AD WP; Page AD	7 8
9 10	Total Other Production Plant ^b				474,596	Stmt AD WP; Page AD-4	9 10
11 12	Total Production Plant and Intangible Plant			\$	1,077,423	Sum Lines 1 thru 9	11 12
13 14	Total Distribution Plant ^a	5,134,633	5,209,303		5,171,968	Stmt AD WP; Page AD-5	13 14
15 16	Transmission Plant b, 2				3,723,358	Stmt AD WP; Page AD-6	15 16
17 18	Incentive Transmission Plant ³					Stmt AD WP; Page AD	17 18
19 20	Total Transmission Plant & Incentive Transmission Plan	nt		-	3,723,358	Sum Lines 15 thru 17	19 20
21 22	Total General Plant a, 1	249,111	266,956		258,034	Stmt AD WP; Page AD-7	21 22
23 24	Total Common Plant a,1	520,846	533,999		527,422	Stmt AD WP; Page AD-8	23 24
25 26	Total Plant in Service			\$	10,758,205	Sum Lines 11; 13; 19; 21; 23	25 26
27 28	Transmission Wages and Salaries Allocation Factor				17.51%	Statement AI; Line 19	27 28
29 30	Total Transmission Plant & Incentive Transmission Plant			\$	3,723,358	See Line 19 Above	29 30
31 32 33	Transmission Related Electric Miscellaneous Intangible Pla Transmission Related General Plant	int			16,024 45,182	Line 1 x Line 27 Line 21 x Line 27	31 32 33
34 35	Transmission Related Common Plant				92,352	Line 23 x Line 27	34 35
36 37	Transmission Related Total Plant in Service			\$	3,876,916	Sum Lines 29; 31; 33; 35	36 37
38 39	Transmission Plant Allocation Factor ⁴				36.04%	Line 37 / Line 25	38 39

The balances for Electric Miscellaneous Intangible, Distribution, General and Common plant are derived based on a simple average balance using beginning and ending year balances.

b The balances for Steam, Nuclear, Hydraulic, Other Production, and Transmission plant are derived based on a 5-month average balance.

¹ Electric Miscellaneous Intangible Plant, General Plant, and Common Plant are not affected by the "Seven-Element Adjustment Factor" because there's no transfer of transmission or distribution plant among these categories.

² The amounts stated above are ratemaking utility plant in service and a result of implementing the "Seven-Element Adjustment Factor" which reflects transfers between generation and distribution functions.

The purpose of this footnote is to indicate for incentive projects the cost of the project.

Used to allocate all elements of working capital, other than working cash.

(\$1,000)

INTANGIBLE PLANT

Line No.	, p	Adjusted FERC Intangible Plant Balance	Reference From	Line No.
1	Aug-13	89,869	l-wp2	1
. 2	Dec-13	93,154	l-wp1	2
3	Beginning and End Period Average	91,511	·	3

STEAM PRODUCTION

		(1)		(2)		
		Total		Steam		
Line	Month	Steam	Reference	Production	Reference	Line
No.	3	Production	From	Ratemaking	From	No.
		Per Book				
1	Aug-13	493,709	п,	507,982	93	1
2	Sep	492,101	w v	506,375	11	2
3	Oct	496,705	и	510,978	317	3
4	Nov	497,582	и	511,856	II.	4
5	Dec-13	505,116	SP-wp1	519,390	SP-wp1	5
	*					
6	Total 5 Months	2,485,214		2,556,581	*	6
						1
7						7
-						1
8			ü			8
•						1
9	5-Month Average	497,043	121	511,316		9
. 5	0-Motitul Avet age	497,043		511,510		
51	<u> </u>			U		П

NUCLEAR PRODUCTION A

Line No. 1 2 3 4 5	Month Aug-13 Sep Oct Nov Dec-13	(1) Total Nuclear Production Per Book	Reference From " " " " NP-wp1	(2) Nuclear Production Adjusted Book	Reference From " " " " NP-wp1	Line No. 1 2 3 4 5
6 7 8 9	Total 5 Months 5-Month Average	-		-		6 7 ,8 9

SONGS was retired in June 2013

OTHER PRODUCTION

Line No.	Month	(1) Total Other Production Per Book	Reference From	(2) Other Production Ratemaking	Reference From	Line No.
1	Aug-13	512,782	11	473,564	19	1
2	Sep	513,046	11	473,647	11	2
3	Oct	513,136	п	473,737	11	3
4	Nov	514,151	xt.	473,916	. "	4
5	Dec-13	518,525	OP-wp1	478,117	OP-wp1	5
					,	
6	Total 5 Months	2,571,640		2,372,981		6
					,	
7						7
0						
8						8 .
9	5-Month Average	514,328	·c	474,596		9

DISTRIBUTION PLANT

Line No.	Month	(1) Total Distribution Plant Per Book	Reference From	(2) Distribution Plant Ratemaking	Reference From	Line No.
1	Aug-13	5,055,255	D-wp2	5,134,633	D-wp2	1
2	Dec-13	5,127,373	D-wp1	5,209,303	D-wp1	2
3	Beginning and End Period Average	5,091,314		5,171,968		3

TRANSMISSION PLANT

U				the same that the same to the same to	
		(1)		(2)	,
		Total		Transmission	
Line	Month	Transmission	Reference	Plant	Reference
No.		Plant	From	Ratemaking	From
		Per Book			i i
1	Aug-13	3,733,359	, sa	3,679,149	H
2	Sep	3,752,076		3,698,036	n
3	Oct	3,763,436	, н	3,708,854	w
4	Nov	3,802,096	п	3,746,801	nt .
5	Dec-13	3,839,521	T-wp1	6,786,949	T-wp1
					1
6	Total 5 Months	18,890,489		18,616,789	
7					
8					
			40		
9	5-Month Average	3,778,098		3,723,358	ļ

(\$1,000)

GENERAL PLANT

Line No.		Adjusted FERC General Plant Balance	Reference From	Line No.
1	Aug-13	249,111	G-wp2	1
2	Dec-13	266,956	G-wp1	2
3	Beginning and End Period Average	258,034		3

COMMON PLANT

Line No.	Month	Total Common Plant to Electric Per Book	Reference From	Line No.
1	Aug-13	520,846	C-wp2	1
2	Dec-13	533,999	C-wp1	2
3	Beginning and End Period Average	527,422		3

SDG&E TRANSMISSION FUNCTIONALIZATION STUDY

DERIVATION OF TRANSMISSION RELATED PLANT DOLLARS Balances as of 12/31/2013

In Thousands

					3						
1			(1)	(2)	(3)	(4)	(5)	(6)	(7)	. (8)	
ļ			8 "	Generation	Distribution	Transmission	Transmission	Transmission	Transmission	Total	1.
			Total	Account 101	Account 101	Account 101	Account 101	Account 101	Account 101	Transmission	1
3	1		Transmission	Plant Reclass	Plant Reclass	Plant Reclass	Plant Reclass	Plant Reclass	Plant Reclass	Plant	Line
	Account	Description	Account 101	as Transmission	to Transmission	Steam Prod.	Other Prod.	Nuclear	as Distribution	Adjusted Book	No.
- 1			1							SUM 1:7	1
		Production Related to Trans									1
Ì	303.0	Intangibles	-	-		-	-	-	-	-	1
Ì	310.1	Land	* = 1	-	- 1	-	-		-	•	2
	340.0	Land & Land Rights	- 1	4	-	-	-	-		4	3
1		Land & Land Rights		-	3,583	-	- '	-	-	3,583	4
1	361.0	Structures & Improvements	-	-	1,076	-	-	-	-	1,076	5
l	Į	-		•	-						4
	TOTAL	TRANSMISSION RELATED	-	4	4,659	-	-	-		4,664	6
											1
	350.0	Land & Land Rights	188,318	÷		-	- 1	-	(5,659)	182,660	7
.]	352.0	Structures & Improvements	268,634	-		(1,928)	- 1	-	(36,371)		
	353.0	Station Equipment	961,835	-		(10,619)	(1,420)		(2,513)	947,282	9
C	354.0	Towers and Fixtures	846,138	-			-	-	-	846,138	10
1	355.0	Poles and Fixtures	297,939	-		-	-		-	297,939	11
2	356.0	OH Conductors and Device	489,096	-			-	*	1-1	489,096	
3	357.0	Underground Conduit	245,528	-		-		-	-	245,528	
4	358.0	UG Conductors & Devices	280,882	, °		(1,726)	-	-	-	279,156	
5	359.0	Roads & Trails	261,150	-		-	-	-	-	261,150	15
					1 25						
6	TOTAL	TRANSMISSION PLANT	3,839,521			(14,273)	(1,420)		(44,543)	3,779,285	16
			•								
7	GRAND T	OTAL RECLASS TRANS PLANT	3,839,521	4	4,659	(14,273)	(1,420)		(44,543)	3,783,949	17

San Diego Gas & Electric Company

True Up Period Statement - AE Accumulated Depreciation and Amortization Workpapers

Docket No. ER15-__-

Statement AE - Workpapers

Accumulated Depreciation and Amortization

For the 4-Month True-Up Period Ending December 31,2013 (\$1,000)

Line No		(a) 31-Aug-13	(b) 31-Dec-13	(c) = [(a) Average	25 51000	Reference	Line No
1 2	Transmission Plant Depreciation Reserve a, 1			\$	656,144	Stmt AE WP; Page AE-1	1 2
3	Electric Misc. Intangible Plant Amortization Reserve ^{b, 2}	15,776	19,994		17,885	Stmt AE WP; Page AE-2	3 4
5 6	General Plant Depreciation Reserve b, 2	100,374	103,539	-	101,957	Stmt AE WP; Page AE-3	5 6
7 8	Common Plant Depreciation Reserve b, 2	253,011	270,623		261,817	Stmt AE WP; Page AE-4	7 8
9 10	Transmission Wages and Salaries Allocation Factor				17.51%	Statement AI; Line 19	9 10
11 12	Transmission Related Electric Misc. Intangible Plant Amortization Rese	erve		\$	3,132	Line 3 x Line 9	11 12
13 14	Transmission Related General Plant Depreciation Reserve			\$	17,853	Line 5 x Line 9	13 14
15 16	Transmission Related Common Plant Depreciation Reserve				45,844	Line 7 x Line 9	15 16
17 18	Total Transmission Related Depreciation Reserve			\$	722,973	Sum Lines 1; 11; 13; 15	17 18
19	Incentive Transmission Plant Depreciation Reserve			\$		Stmt AE WP; Page AE	19

^a The depreciation reserve for transmission plant is derived based on a 5-month average balance.

b The depreciation reserve for Electric Miscellaneous Intangible, General and Common plant is derived based on a simple average of beginning and end of year balances.

The amounts stated above are ratemaking utility plant in service and a result of implementing the "Seven-Element Adjustment Factor" which reflects transfers between generation and distribution functions.

² Electric Miscellaneous Intangible Plant, General Plant, and Common Plant are not affected by the "Seven-Element Adjustment Factor" because there's no transfer of transmission or distribution plant among these categories.

SAN DIEGO GAS & ELECTRIC COMPANY STATEMENT AE ACCUMULATED DEPRECIATION AND AMORTIZATION TRUE UP PERIOD - 9/1/2013 to 12/31/2013 PER BOOK (\$1,000)

TRANSMISSION PLANT

- 1		/43		(0)	
		(1)		(2)	
		Total		Transmission	
Line	Month	Transmission	Reference	Reserves	Reference
No.	×	Reserves	From	Ratemaking	From -
		Per Book		i.	
1	Aug-13	652,994	tri .	640,470	11
2	Sep	662,187	by .	649,712	**
3	Oct	670,293	n	657,717	
4	Nov	678,694	т -	666,013	
5	Dec-13	679,574	T-wp1	666,808	T-wp1
	æ			,	
6	Total 5 Months	3,343,741		3,280,720	
	,				
7	4				
*					
8					ļ
9	5-Month Average	668,748		656,144	
•	- month, revoluge	000,140		000,144	

SAN DIEGO GAS & ELECTRIC COMPANY STATEMENT AE ACCUMULATED DEPRECIATION AND AMORTIZATION TRUE UP PERIOD - 9/1/2013 to 12/31/2013 PER BOOK

(\$1,000)

INTANGIBLE PLANT

Line No.		Adjusted FERC Intangible Plant Balance	Reference From	Line No.
1	Aug-13	15,776	l-wp2	1
2	Dec-13	19,994	l-wp1	2
3	Beginning and End Period Average	17,885		3

SAN DIEGO GAS & ELECTRIC COMPANY STATEMENT AE ACCUMULATED DEPRECIATION AND AMORTIZATION TRUE UP PERIOD - 9/1/2013 to 12/31/2013 PER BOOK

(\$1,000)

GENERAL PLANT

Line No.	*	Adjusted FERC General Reserve Balance	Reference From	Line No.
1	Aug-13	100,374	G-wp2	1
2	Dec-13	103,539	G-wp1	2
3∙ ,	Beginning and Year End Average	101,957		3

SAN DIEGO GAS & ELECTRIC COMPANY STATEMENT AE ACCUMULATED DEPRECIATION AND AMORTIZATION TRUE UP PERIOD - 9/1/2013 to 12/31/2013 PER BOOK (\$1,000)

COMMON PLANT

Line No.	Month	Total Common Reserves to Electric Per Book	Reference From	Line No.
1	Aug-13	253,011	C-wp2	1
2	Dec-13	270,623	C-wp1	2
3	Beginning and Year End Average	261,817		3

San Diego Gas & Electric Company

True Up Period Statement - AF Specified Deferred Credits Workpapers

Docket No. ER15-__-

SAN DIEGO GAS AND ELECTRIC COMPANY Statement AF - Workpapers Deferred Credits For the 4-Month True-Up Period Ending December 31,2013 (\$1,000)

Line No	-	(a) 31-Aug-13	(b) 31-Dec-13	(c) = [(a)+(b Average Bala	\$57)	Reference	Line No
1 2	Transmission Related ADIT- Excluding Bonus Depreciation	\$ (254,666)	\$ (276,123)	\$ (265	(395) Stmt A	F WP; Page AF 1	1 2
3	Transmission Related ADIT from Bonus Depreciation	(114,793)	(140,932)	(127	(,863) Stmt A	F WP; Page AF 1	3 4
5 6 7	Total Transmission Related ADIT	\$ (369,459)	\$ (417,055)	\$ (393	<u>,257)</u> Sum o	of Lines 1 thru 3	5 6 7
8	Incentive Transmission Plant ADIT	\$ -	\$ -	\$	Stmt A	AF WP; Page AF	8 9
10 11	Transmission Plant Abandoned ADIT	\$ -	\$ -	\$	- Stmt A	AF WP; Page AF	10 11
12	Incentive Transmission Plant Abandoned Project Cost ADIT	\$ -	\$ -	\$	- Stmt A	AF WP; Page AF	12

San Diego Gas and Electric Company Transmission Deferred Credits

Line No	Description	8/31/2013	12/31/2013	Line No	
1 2	Transmission Related ADIT- Excluding Bonus Depreciation	\$ (254,666)	\$ (276,123)	1 2	
3	Transmission Related ADIT from Bonus Depreciation	(114,793)	(140,932)	3	
. 4 5	Total Transmission Related ADIT '	\$ (369,459)	\$ (417,055)	4 5	

^a These amounts come from the Tax Dept.

San Diego Gas and Electric Company Deferred Credits

Line No	Description	8/3	1/2013	12/3	1/2013	Line No
1	Incentive Transmission Plant ADIT	\$	_	\$		1
2				(a. 10)	8	2
3						3
4	Transmission Plant Abandoned ADIT	\$	-	\$	-	4
5	* ************************************					5
6	¥					6
7	Incentive Transmission Plant Abandoned Project Cost ADIT	\$		\$\$	-	7

San Diego Gas & Electric Company

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

Docket No. ER15-___-

Statement AG - Workpapers

Specified Plant Account (Other than Plant in Service) and Deferred Debits

For the 4-Month True-Up Period Ending December 31,2013 (\$1,000)

Line	(a)	(b)	(c) = [(a)+(b)]/2		Line
No	31-Aug-13	31-Dec-13	Average Balance	Reference	No
1 Transmission Plant Held for Future Use ¹			\$ 6,546	Stmt AG WP; Page AG-1	1

The balances for Transmission Plant Held for Future Use are derived based on a 5-month average balance.

SAN DIEGO GAS & ELECTRIC COMPANY STATEMENT AG SPECIFIED PLANT ACCOUNTS (OTHER THAN PLANT IN SERVICE) AND DEFERRED DEBITS TRUE UP PERIOD - 9/1/2013 TO 12/31/2013 PER BOOKS (\$1,000)

TRANSMISSION PLANT

Line No.	Month	Transmission Plant Held For Future Use	Line No.
1	Aug	6,546	1
2	Sep	6,546	2
3	Oct	6,546	3
4	Nov	6,546	4
5	Dec-13	6,546	5
6	Total 5 Months	32,732	6
7			7
8			8
9	5-Month Average	6,546	9
1			

San Diego Gas & Electric Company

True Up Period
Statement - AH
Operation and
Maintenance Expenses
Workpapers

Docket No. ER15-___-

Statement AH - Workpapers

Operation and Maintenance Expenses

For the 4-Month True-Up Period Ending December 31,2013 (\$1,000)

Line				Line
No.	-	Amounts	Reference	No.
1	Derivation of Transmission Operation and Maintenance Expense:			1
2	Total Transmission O&M Expense	\$ 34,644	Stmt AH WP; Page AH-2	2
3	Adjustments to Per Book Transmission O&M Expense:			3
4	FERC Acct 561.4 - Scheduling, System Control & Dispatch Services	(2,887)	Stmnt AH WP; Page AH-2	4
5	FERC Acct 561.8 - Reliability, Planning & Standards Development	(394)	Stmnt AH WP; Page AH-2	5
6	FERC Acct 565 - Transmission of Electricity by Others	(1,713)	Stmnt AH WP; Page AH-2	6
7	FERC Acct 566 - Miscellaneous Transmission Expense	(2,973)	Stmnt AH WP; Page AH-2	7
8	Other Transmission O&M Exclusion Adjustments		Stmnt AH WP; Page AH-2	8
9	Total Adjusted Transmission O&M Expenses	\$ 26,677	Sum Lines 2 thru 8	9
10				10
11	Derivation of Administrative and General Expense:			11
12	Total Administrative & General Expense	\$ 202,819	Stmnt AH WP; Page AH-3	12
13	Adjustments to Per Book A&G Expense:			13
14	Nuclear liability insurance expense	(291)	Stmnt AH WP; Page AH-3	14
15	Damages & Injuries - Wildfire Insurance Premium		Stmnt AH WP; Page AH-3	15
16	Damages & Injuries - Wildfire Damage Claims		Stmnt AH WP; Page AH-3	16
17	CPUC Intervenor Funding Expense - Transmission ¹		Stmnt AH WP; Page AH-3	17
18	CPUC Intervenor Funding Expense - Distribution	(296)	Stmnt AH WP; Page AH-3	18
19	CPUC reimbursement fees	(1,557)	Stmnt AH WP; Page AH-3	19
20	FERC Acct 930.1 - General Advertising Expenses	For Shape States	Stmnt AH WP; Page AH-3	20
21	Litigation expenses - Litigation Cost Memorandum Account (LCMA)	(9)	Stmnt AH WP; Page AH-3	21
22	CPUC energy efficiency programs	(1,665)	Stmnt AH WP; Page AH-3	22
23	Advanced Metering Infrastructure (AMI) lease facilities	(39)	Stmnt AH WP; Page AH-3	23
24	Hazardous substances - Hazardous Substance Cleanup Cost Account	(15)	Stmnt AH WP; Page AH-3	24
25	Other A&G Exclusion Adjustments	65	Stmnt AH WP; Page AH-3	25
26	Total Adjusted A&G Expenses Including Property Insurance	\$ 199,012	Sum Lines 12 thru 25	26
27	Less: Property Insurance (Reflected on Line 50 below due to different allocation factor)	(2,338)	Stmnt AH WP; Page AH-3	27
28	Total Adjusted A&G Expenses Excluding Property Insurance	\$ 196,674	Sum Lines 26 and 27	28
29	Transmission Wages and Salaries Allocation Factor	17.51%	Statement AI; Line 19	29
30	Transmission Related Administrative & General Expenses	\$ 34,438	Line 28 x Line 29	30
31				31
32	Derivation of Transmission Plant Property Insurance Allocation Factor:			32
33	Transmission Plant & Incentive Transmission Plant	\$ 3,723,358	Stmnt AD WP; Page AD1; Line 29	33
34	Transmission Related Electric Miscellaneous Intangible Plant	0	Shall be Zero	34
35	Transmission Related General Plant	45,182	Stmnt AD WP; Page AD1; Line 3	35
36	Transmission Related Common Plant	92,352	Stmnt AD WP; Page AD1; Line 35	36
37	Total Transmission Related Investment in Plant	\$ 3,860,892	Sum Lines 33 thru 36	37
38	The state of the s	Φ 2.500.050	0	38
39	Total Transmission Plant & Incentive Transmission Plant	\$ 3,723,358	Stmnt AD WP; Page AD1; Line 29	39
40	Total Steam Production Plant	511,316	Stmnt AD WP; Page AD1; Line 3	40
42	Total Nuclear Production Plant	474.506	Shall be Zero	42
41	Total Other Production Plant	474,596	Strant AD WP; Page AD1; Line 9	41
43	Total Distribution Plant	5,171,968	Stmnt AD WP; Page AD1; Line 13	43
44	Total General Plant Total Common Plant	258,034	Stmnt AD WP; Page AD1; Line 21	44
45		527,422 \$ 10,666,694	Stmnt AD WP; Page AD1; Line 23 Sum Lines 39 thru 45	45 46
46	Total Plant in Service Excluding SONGS	\$ 10,000,094	Sum Lines 39 unu 43	
47	Turney in its Direct Description Leaves and Allegation Factor	26.200/	Line 27 / Line 46	47
48	Transmission Plant Property Insurance Allocation Factor	36.20%	Line 37 / Line 46	48
49	m . 1 p	Φ 0.220	G . I	49
50	Total Property Insurance	\$ 2,338	See Line 27 Above	50
51	Description of Allertaids Transition Countries Countries	Φ 046	T: 10 T: 70	51
52	Property Insurance Allocated to Transmission, General, and Common Plant	\$ 846	Line 48 x Line 50	52
53	Transmission Deleted A & C Free Food dies December 1	24.420	C T: 20 41	53
54	Transmission Related A & G Expense Excluding Property Insurance Expense	34,438	See Line 30 Above	54 55
55	Transmission Related A & G Evnance Including Dyanosty Ingurance Evnance	¢ 25.201	Sum Lines 52 P. 54	55 56
56	Transmission Related A & G Expense Including Property Insurance Expense	\$ 35,284	Sum Lines 52 & 54	20

The CPUC Intervenor Expense for Transmission shall be treated as an exclusion in A&G but added back to the Retail BTRR on BK-1, page 1, line 6. This expense will be excluded in Wholesale BTRR on BK-2, page 1, line 4.

Electric Transmission O&M Expenses For 4-Month True-Up Adjustment September 1, 2013 to December 31, 2013 (\$1,000)

			(a)		(b)	(c) = (a) - (b)	* **	
Line	FERC		Total		Excluded	Total	-	Line
No.	Acct	Description	Per Book	S	Expenses	Adjusted	Reference	No.
1	.	Electric Transmission Operation		_				1
2	560	Operation Supervision and Engineering	\$ 2,53		\$ -	\$ 2,537	я	2
3		Load Dispatch - Reliability	150		-	150		3
4	561.2	Load Dispatch - Monitor and Operate Transmission System	3,282	2		3,282		4
5		Load Dispatch - Transmission Service and Scheduling		+	-	-		5
6		Scheduling, System Control and Dispatch Services	2,88	7	2,887	-		6
7		Reliability, Planning and Standards Development	-					7
8	561.6	Transmission Service Studies	-	.	-	-		8
9	561.7	Generation Interconnection Studies	-	\perp	-	-		9
10		Reliability, Planning and Standards Development Services	39	- 1	394	-		10
11	562	Station Expenses	53:	1	-	535		11
12	563	Overhead Line Expenses	77	5	-	775		12
13	564	Underground Line Expenses	-			-		13
14	565	Transmission of Electricity by Others	1,71	- 1	1,713	Η		14
15	566	Miscellaneous Transmission Expenses	7,47		2,973	4,502		15
16	567	Rents	71		-	717		16
17		Total Operation	\$ 20,46	5	\$ 7,967	\$ 12,498	Sum Lines 2 thru 16	17
18								18
19		Electric Transmission Maintenance						19
20	568	Maintenance Supervision and Engineering	26	8	-	268		20
21	569	Maintenance of Structures	-		-	-		21
22	569.1	Maintenance of Computer Hardware	60	4	-	604		22
23	569.2	Maintenance of Computer Software	87	8		878		23
24	569.3	Maintenance of Communication Equipment	-					24
25	569.4	Maintenance of Miscellaneous Regional Transmission Plant	1		-	11		25
26	570	Maintenance of Station Equipment	2,22		-	2,226		26
27	571	Maintenance of Overhead Lines	3,72	2		3,722		27
28	571	Maintenance of Overhead Lines - Sunrise/Other Projects Post				ŧ		28
		Construction Environmental Cost ¹	6,39	8	-	6,398		
29	572	Maintenance of Underground Lines	4	7	-	47	,	29
30	573	Maintenance of Miscellaneous Transmission Plant	2	5	-	25		30
31		Total Maintenance	\$ 14,17	9	\$ -	\$ 14,179	Sum Lines 20 thru 30	31
32								32
33		Total Transmission O&M Expenses	\$ 34,64	4	\$ 7,967	\$ 26,677	Line 17 + Line 31	33
34		*						34
35						1	1	35
36	Exclude	ed Expenses (recovery method in parentheses)				*		36
37		Scheduling, System Control and Dispatch Services (ERRA)			\$ 2,887			37
38		Reliability, Planning and Standards Development Services (ERRA)			394			38
39	565	Transmission of Electricity by Others (ERRA)			1,713			39
40	566	Miscellaneous Transmission Expenses:			***************************************			40
41		ISO Grid Management Costs (ERRA)	\$ 1,53	0				41
42		Reliability Services (RS rates)	2,42					42
43		Other (TRBAA, TACBA)	(97		2,973			43
44	Total E	xcluded Expenses			\$ 7,967	-9		44
45		-		=		=;		45
46	1	FERC acct 571 for Sunrise/Other Projects Post Construction Enviro	onmental C	ost :	includes Sur	rise Centinela	Solar and ISEC (Imperial Solar	
47		Energy Center).	omnoma C	J3t .	menuco ou	niso, continuid	ootaa ana toro (miportai oota	47
48		Energy Contery.						48
70			-					10

San Diego Gas & Electric Administrative & General Expenses 4-Months True-Up (September 1, 2013 to December 31, 2013) (In thousands of Dollars)

Line		A	В	C	Line
No.	Description			*	No.
1		4-Months Ending December 31, 2013			
2		Total	Excluded	Total	2
3	Administrative General	Per Books	Expenses	Adjusted	3
4					4
5	920 A&G Salaries	11,490		11,490	5
6	921 Office Supplies & Expenses	5,335		5,335	6
7	922 Less Construction Transfer	(2,882)	-	(2,882)	7
8	923 Outside Services	38,459	-	38,459	8
9	924 Property Insurance	2,629	(291)	2,338	9
10	925 Damages & Injuries	4,050	46	4,096	10
11.	925.4 Wildfire Damage Claims	75,779	_	75,779	11
12	925.4 Wildfire Ins Prem	28,290	-	28,290	12
13	926 Employee Pension & Benefits w/o POBP	20,435	(89)	20,346	13
14	926 PBOP	3,239	, ,	3,239	14
15	927 Franchise Expenses	0	-		15
16	928 Regulatory Expenses	6,964	(1,908)	5,056	16
17	929 Company Energy Use	(650)	-	(650)	17
18	930 Misc. General Expenses	4,388	(1,416)	2,972	18
19	931 Rents	2,691	(134)	2,557	19
20	935 Maintenance of General Plant	2,602	(15)	2,587	20
21			3.2.	6	21
22	Total	202,819	(3,807)	199,012	22
22					22
23				FERC	23
24	Excluded Expenses		Current Year	Account	24
25	Nuclear property insurance expenses	-	(291)	924	25
26	Nuclear liability insurance expenses		65	925	26
27	Wildfire Damage Claims		0	925.4	27
28	Wildfire Ins Premium		0	925.4	28
29	CPUC energy efficiency programs		(19)	925	29
30	CPUC energy efficiency programs		(89)	926	30
31	CPUC energy efficiency programs		(46)	928	31
32	Intervenor Compensation(SRA)	*	(296)	928	32
33	CPUC reimbursement fees	*	(1,557)	928	33
34	Litigation Expense (LCMA)		(9)	928	34
35	CPUC energy efficiency programs		(1,416)	930	35
36	AMI Lease Facilities		(39)	931	36
37	CPUC energy efficiency programs		(95)	931	37
38	Hazardous Substances		(15)	935	38
39	a		()	(a)	39
40	m . In . I . I . I		(A DOM)		

40

(3,807)

40 Total Excluded Expenses

COMMON ALLOCATION

True-up Period: Sep - Dec 2013

A)			COMMON AL	LOCATION TOTAL S	ep 13- Dec 2013
FERC Account	Account Description		Electric	Gas	Total Elec & Gas
920	A&G SALARIES		11,490,159.04	4,282,193.79	15,772,352.83
921	OFFICE SUPPLIES & EXPENSES		5,231,474.67	1,949,684.80	7,181,159.47
922	LESS CONSTRUCTION TRANSFER		(2,881,730.36)	(1,073,973.63)	(3,955,703.99)
923	OUTSIDE SERVICES		29,678,871.70	11,060,828.65	40,739,700.35
924	PROPERTY INSURANCE		2,490,352.12	391,332.81	2,881,684.93
925	INJURIES & DAMAGES		2,027,592.56	755,650.49	2,783,243.05
926	PENSIONS & BENEFITS		13,479,946.15	5,023,754.81	18,503,700.96
928	REGULATORY EXPENSES		2,716,088.29	. 1,012,241.55	3,728,329.84
930	MISC. GENERAL EXPENSES		173,525.21	64,670.00	238,195.21
931	RENTS		2,051,181.49	764,441.69	2,815,623.18
935	MAINTENANCE OF GENERAL PLANT		2,599,428.10	968,764.21	3,568,192.31
### TOTAL ##			69,056,888.97	25,199,589.17	94,256,478.14

B) A&G DIRECT CHARGES:

FERC Account	Account Description			Electric	Gas #	Total Elec & Gas
920	A&G SALARIES			0.36	6,697.78	6,698.14
921	OFFICE SUPPLIES & EXPENSES			103,970.93	- 32,056.63	136,027.56
922	LESS CONSTRUCTION TRANSFER			(117.61)	(1,134.02)	(1,251.63)
923	OUTSIDE SERVICES			8,780,006.33	33,57	8,780,039.90
924	PROPERTY INSURANCE			138,208.47	(1,315,686.74)	(1,177,478.27)
925	INJURIES & DAMAGES			106,091,624.68	364,950.30	106,456,574.98
926	PENSIONS & BENEFITS			10,193,903.62	3,180,049.79	13,373,953.41
927	FRANCHISE REQUIREMENTS	21		34,463,580.34	2,554,604.00	37,018,184.34
928	REGULATORY EXPENSES			4,248,199.53	169,620,69	4,417,820.22
929	DUPLICATE CHARGE			(650,439.43)	-	(650,439.43)
930	MISC. GENERAL EXPENSES			4,214,616.95	1,135,917.42	5,350,534.37
931	RENTS			639,545.13	0.04	639,545.17
935	MAINTENANCE OF GENERAL PLANT			2,931.87	9,826.12	12,757.99
IIIII TOTAL	PERCHASING PARTY OF THE PROPERTY OF THE PARTY OF THE PART		trackata	168,226,031.17	6,136,935.58	174,362,966.75

C=A+B			TOTAL				
FERC Account	Account Description	gallane out miles	Electric Hills	Gas 💢 📰	Total Elec & Gas		
920	A&G SALARIES		11,490,159.40	4,288,891.57	15,779,050.97		
921	OFFICE SUPPLIES & EXPENSES		5,335,445.60	1,981,741.43	7,317,187.03		
922	LESS CONSTRUCTION TRANSFER		(2,881,847.97)	(1,075,107.65)	(3,956,955.62)		
923	OUTSIDE SERVICES		38,458,878.03	11,060,862.22	49,519,740.25		
924	PROPERTY INSURANCE		2,628,560.59	(924,353.93)	1,704,206.66		
925	INJURIES & DAMAGES		108,119,217.24	1,120,600.79	109,239,818.03		
926	PENSIONS & BENEFITS		23,673,849.77	8,203,804.60	31,877,654.37		
927	FRANCHISE REQUIREMENTS		34,463,580.34	2,554,604.00	37,018,184.34		
928	REGULATORY EXPENSES		6,964,287.82	1,181,862.24	8,146,150.06		
929	DUPLICATE CHARGE		(650,439.43)	-	(650,439.43)		
930	MISC. GENERAL EXPENSES		4,388,142.16	1,200,587.42	5,588,729.58		
931	RENTS ~		2,690,726.62	764,441.73	3,455,168.35		
935	MAINTENANCE OF GENERAL PLANT		2,602,359,97	978,590.33	3,580,950,30		
TOTAL	TIED TO FERC FORM 1 & 2	#PREMISSIFF SUBSECTION	237,282,920.14	31,336,524.75	268,619,444.89		

Less 927 FERC A&G (TU)

(34,463,580.34) 202,819,339.80

True-Up Period: SEP - Dec 13

	·		APR 12 - MAR 20	113	SEP 13 - DEC 2013			TOTAL		
FERC Account	Account Description	Electric	Gas Gas	Total Elec & Gas	Electric	Gas	Total Elec & Gas	Total Electric	Total Gas	
920	A&G SALARIES			-	11,490,159.40	4,288,891.57	15,779,050.97	11,490,159.40	4,288,891.57	
921	OFFICE SUPPLIES & EXPENSES			-	5,335,445.60	1,981,741.43	7,317,187.03	5,335,445.60	1,981,741.43	
922	LESS CONSTRUCTION TRANSFER			-	(2,881,847.97)	(1,075,107.65)	(3,956,955.62)	(2,881,847.97)	(1,075,107.65)	
923	OUTSIDE SERVICES			-	38,458,878.03	11,060,862.22	49,519,740.25	38,458,878.03	11,060,862.22	
924	PROPERTY INSURANCE			-	2,628,560.59	(924,353.93)	1,704,206.66	2,628,560.59	(924,353.93)	
925	INJURIES & DAMAGES				108,119,217.24	1,120,600.79	109,239,818.03	108,119,217.24	1,120,600.79	
926	PENSIONS & BENEFITS			-	23,673,849.77	8,203,804.60	31,877,654.37	23,673,849.77	8,203,804.60	
927	FRANCHISE REQUIREMENTS				34,463,580.34	2,554,604.00	37,018,184.34	34,463,580.34	2,554,604.00	
928	REGULATORY EXPENSES			-	6,964,287.82	1,181,862.24	8,146,150.06	6,964,287.82	1,181,862.24	
929	DUPLICATE CHARGE			-	(650,439.43)	-	(650,439.43)	(650,439.43)	-	
930 .	MISC. GENERAL EXPENSES			•	4,388,142.16	1,200,587.42	5,588,729.58	4,388,142.16	1,200,587.42	
931	RENTS			-	2,690,726.62	764,441.73	3,455,168.35	2,690,726.62	764,441.73	
935	MAINTENANCE OF GENERAL PLANT			-	2,602,359.97	978,590.33	3,580,950.30	2,602,359.97	978,590.33	
TOTAL				Matalia (Militaria 🚉 👈	237,282,920.14	31,336,524.75	268,619,444.89	237,282,920.14	31,336,524.75	

True Up Period
Statement - AI
Wages and Salaries
Workpapers

Docket No. ER15-___-

Statement AI - Workpapers

Wages and Salaries

For the 4-Month True-Up Period Ending December 31,2013 (\$1,000)

Line					Line
No.		An	nounts	Reference	No.
1	Production Wages & Salaries (Includes Steam & Other Power Supply)	\$	3,822	Stmt AI WP; Page AI-2	1
2		pacacae			2
3	Transmission Wages & Salaries		7,296	Stmt AI WP; Page AI-2	3
4	•				4
5	Distribution Wages & Salaries	MARKE	16,694	Stmt AI WP; Page AI-2	5
6					6
7	Customer Accounts Wages & Salaries		7,420	Stmt AI WP; Page AI-2	7
8				, ,	8
9	Customer Services and Informational Wages & Salaries		6,445	Stmt AI WP; Page AI-2	9
10	č			, ,	10
11	Sales Wages & Salaries			Stmt AI WP; Page AI-2	11
12			11/14 - 2011 - 1-24	244474747474	12
13	Sub-Total	\$	41,677	Sum Lines 1 thru 11	13
14	540 1044	Ψ	11,077	Sam Emes 1 and 11	14
15	Administrative and General Wages & Salaries	N. T. W. C. D.	12,678	Stmt AI WP; Page AI-2	15
16	Administrative and General Wages & Salaries		12,078	Stillt AT WT, Tage AT-2	16
	Total Operating & Maintenance Wages & Calcuing	¢.	51255	Sum Lines 12: 15	
17	Total Operating & Maintenance Wages & Salaries	<u> </u>	54,355	Sum Lines 13; 15	17
18					18
19	Transmission Wages and Salaries Allocation Factor		17.51%	Line 3 / Line 13	19

		SAN DIEGO GAS AND ELECTRIC	COMF	PANY		
	0.3	STATEMENT AI				
		WAGES AND SALARIE				
		September 1, 2013 THROUGH Dece	ember 3	1, 2013		
		(\$1,000)			·	
Line		 	9/01/	2013-12/31/2013	Line	
No.	•	Title		(\$000's)	No.	
	500-514	Steam Production		4 700		
1			\$	1,728	1	
3	517-532	Nuclear Production (See Note Below)	\$	- 2.004	2 3	
	535-557	Other Power Supply	\$	2,094		
. 4	560-574	Transmission	\$	7,296	4	
5	580-598	Distribution	\$	16,694	5	
6	901E-905E	Customer Accounts	\$	7,420	6	
7	906E-910E	Customer Service and Informational	\$	6,445	7	
8	911E-917E	Sales	\$	_	8	,
9	920E-935E	Administrative and General	\$	12,678	9	
.10					10	
11					11	
12		TOTAL	\$	54,355	12	
Note:		Although San Diego Gas and Electric C				r
	 	power plant, it is not the operating comincurs minimal direct labor for these fac		ine plant. As a res	Suit, SDG&E	
		incurs minimal direct labor for these fac	inues.			
			\$	41,677	← Sum of lin	e 1 to 8
· · · · · ·	· · · · · · · · · · · · · · · · · · ·					
				17.51%		

True Up Period
Statement - AJ
Depreciation and
Amortization Expenses
Workpapers

Docket No. ER15-__-

Statement AJ - Workpapers

Depreciation and Amortization Expense For the 4-Month True-Up Period Ending December 31,2013 (\$1,000)

Line No.		Amounts	Reference	Line No.
	•			-
1	Transmission Plant Depreciation Expense (net of incentive depreciation expense on line 21)	\$ 30,341	Stmt AJ WP; Page AJ-2	1
2				2
3	Electric Miscellaneous Intangible Plant Amortization Expense	4,218	Stmt AJ WP; Page AJ-3	3
4				4
5	General Plant Depreciation Expense	3,232	Stmt AJ WP; Page AJ-4	5
6		CONTRACTOR OF THE PARTY OF THE		6
7	Common Plant Depreciation Expense	18,393	Stmt AJ WP; Page AJ-5	7
8				8
9	Transmission Wages and Salaries Allocation Factor	17.51%	Statement AI; Line 19	9
10			*:	10
11	Transmission Related Electric Misc. Intangible Plant Amortization Expense	\$ 738	Line 3 x Line 9	11
12	The state of the s	6 566	I : 5 I : 0	12
13	Transmission Related General Plant Depreciation Expense	\$ 566	Line 5 x Line 9	13
14	Townsieries Beletal Common Plant Demociation Function	¢ 2.221	Line 7 x Line 9	14 15
15 16	Transmission Related Common Plant Depreciation Expense	\$ 3,221	Line / X Line 9	16
17	Total Transmission, General, Common Plant Depn. Exp., and Electric Misc. Intangible Plant Amort. Exp.	\$ 34,866	Sum Lines 1; 11; 13; 15	17
18	Total Transmission, Octobra, Common Frant Dept. Exp., and Electric Misc. manigrote Frant Amore. Exp.	Ψ 31,000	Buil Blies 1, 11, 13, 13	18
	Valley Rainbow Project Cost Amortization Expense ¹	\$ 158	Ctust A.I.W.D. Dane A.I.2	19
19	valley Railloow Project Cost Amortization Expense	138	Stmt AJ WP; Page AJ-2	
20	I C T C C D C D C C D	Φ.	Ctoot A.I. W.D. D A.I.	20
21	Incentive Transmission Plant Depreciation Expense	7	Stmt AJ WP; Page AJ	21
22	m ' ' Pl (II I I I I I I I I	0	C. ALVID D. AL	22
23	Transmission Plant Abandoned Project Cost Amortization Expense	2	Stmt AJ WP; Page AJ	23
24	A STATE OF THE STA	0	C. ALIMB D. AL	24
25	Incentive Transmission Plant Abandoned Project Cost Amortization Expense	3	Stmt AJ WP; Page AJ	25

Amortization approval per ER03-601-000 issued May 2, 2003 for a 10-year period beginning October 2003 and ending September 2013.

Statement AJ - Workpapers

Depreciation and Amortization Expense For the 4-Month True-Up Period Ending December 31,2013 (\$1,000)

Line No.		Amounts	Reference	Line No.
	-			
1	Transmission Plant Depreciation Expense (net of incentive depreciation expense on line 21)	\$ 30,341	Stmt AJ WP; Page AJ-2	1
2			, ,	2
3	Electric Miscellaneous Intangible Plant Amortization Expense	4,218	Stmt AJ WP; Page AJ-3	3
4				4
5	General Plant Depreciation Expense	3,232	Stmt AJ WP; Page AJ-4	5
6				6
7	Common Plant Depreciation Expense	18,393	Stmt AJ WP; Page AJ-5	7
8				8
9	Transmission Wages and Salaries Allocation Factor	17.51%	Statement AI; Line 19	9
10		2790000	No. 20 and No. 100	10
11	Transmission Related Electric Misc. Intangible Plant Amortization Expense	\$ 738	Line 3 x Line 9	11
12	_ ,, _,, ,, _, ,, ,, ,, ,, ,, ,, ,, ,, ,			12
13	Transmission Related General Plant Depreciation Expense	\$ 566	Line 5 x Line 9	13
14	T ' ' DI LIG DI LD ' L' D	f. 2.001	Time Town in the	14
15	Transmission Related Common Plant Depreciation Expense	\$ 3,221	Line 7 x Line 9	15
16	Total Transmission Constal Common Blant Dann Eyra and Electric Miss. Intensible Blant Amont Eyra	¢ 24.066	C Lines 1, 11, 12, 15	16
17	Total Transmission, General, Common Plant Depn. Exp., and Electric Misc. Intangible Plant Amort. Exp.	\$ 34,866	Sum Lines 1; 11; 13; 15	17
18	WH DIL DILGIL CK D 1			18
19	Valley Rainbow Project Cost Amortization Expense	\$ 158	Stmt AJ WP; Page AJ-2	19
20				20
21	Incentive Transmission Plant Depreciation Expense	\$ -	Stmt AJ WP; Page AJ	21
22				22
23	Transmission Plant Abandoned Project Cost Amortization Expense	\$ -	Stmt AJ WP; Page AJ	23
24				24
25	Incentive Transmission Plant Abandoned Project Cost Amortization Expense	\$ -	Stmt AJ WP; Page AJ	25

Amortization approval per ER03-601-000 issued May 2, 2003 for a 10-year period beginning October 2003 and ending September 2013.

SDG&E STATEMENT AJ RANSMISSION EXPENSE AND EXPENSE RELATED TO TRANSMISSION In Thousands

Depreciation and Amortization Expense as of December 31, 2013

Decembles	FERC Transmission Expense Per Book	Transmission Expense Ratemaking
Description Intangibles		
Land and Land Rights	583	*
	1,601	
Structures and Improvements		
Station Equipment Towers and Fixtures	10,491	
	4,639 4,212	
Poles and Fixtures Overhead Conductors & Devices	1	
	4,141	
Underground Conduit	1,791	*
Underground Conductors & Devices	1,914	*
Roads and Trails	1,404	
Subtotal (a)	30,778	30,341
Valley Rainbow Amortization Expense (b)	158	158
Total Transmission Expense	30,935	30,499

Depreciation & Amortization Workpapers for Transmission Plant

SAN DIEGO GAS AND ELECTRIC COMPANY Statement AJ - Workpapers

TO4 - Annual Transmission Plant Depreciation Rates ¹

Cycle 2, For 12- Months Ending December 31, 2013

For use During the 4-Months Period from September 1 to December 31, 2013

			(a)	(b)	(c) = a + b	
Line	FERC		Life	Removal	Total	Line
No	Account	Description	Rate	Rate	Rate	No
1	E352.10	Other	1.36%	0.82%	2.18%	1
2	E352.20	SWPL	1.01%	0.61%	1.62%	2
3	E352.60	SRPL	1.39%	0.00%	1.39%	3
4	E352 - Total	Struct & Improv	1.36%	0.42%	1.78%	4
5	E353.10	Other	2.20%	1.32%	3.52%	5
6	E353.20	SWPL	2.51%	1.51%	4.02%	6
7	E353.40	CTC	2.03%	1.22%	3.25%	7
8	E353.60	SRPL	2.01%	0.00%	2.01%	8
9	E353	Station Equip	2.22%	1.12%	3.34%	9
10	E354.10	Other	1.57%	1.56%	3.13%	10
11	E354.20	SWPL	1.33%	1.32%	2.65%	11
12	E354.60	SRPL	1.47%	0.00%	1.47%	12
13	E354	Towers & Fixtrs	1.47%	0.22%	1.69%	13
14	E355.10	Other	2.33%	2.32%	4.65%	14
15	E355.20	SWPL	2.54%	2.54%	5.08%	15
16	E355.60	SRPL	2.26%	0.00%	2.26%	16
17	E355	Poles & Fixtrs	2.14%	2.12%	4.26%	17
18	E356.10	Other	2.13%	2.14%	4.27%	18
19	E356.20	SWPL	2.54%	2.54%	5.08%	19
20	E356.60	SRPL	2.26%	0.00%	2.26%	20
21	E356	OVH Cnd & Dev	1.58%	1.00%	2.58%	21
22	E357.00	Other & SWPL	1.68%	0.75%	2.43%	22
23	E357.60	Other & SRPL	1.69%	0.00%	1.69%	23
24	E357	Trans UG Cnduit	1.68%	0.48%	2.16%	24
25	E358.00	Other & SWPL	1.89%	0.19%	2.08%	25
26	E358.60	Other & SRPL	2.02%	0.00%	2.02%	26
27	E358	Trans UG Cndctr	1.95%	0.10%	2.05%	27
28	E359.10	Other	1.65%	0.00%	1.65%	28
29	E359.20	SWPL	1.44%	0.00%	1.44%	29
30	E359.60	SRPL	1.68%	0.00%	1.68%	30
31	E359	Roads & Trails	1.67%	0.00%	1.67%	31
32						32
33	Composite Dep	oreciation Rate	1.80%	0.72%	2.52%	33

The rates in these subaccounts will not change during the term of the TO4 Formula. Workpapers will be included in each Annual Information Filing that will calculate the annual composite rates shown on Line 33 pursuant to Term 53 in Appendix VIII.

	TO4 Depreciation	Rate - Co	omposite 2.52%									
	Α	В	С	1	2	3	4	5	6	7	8	
						(Col 1+Col 2) / 2			(Col 4 / Col 3) *12	(Col 5 / Col 3) *12	Col 8 = Col 6 + Col 7	7
Ln No	Asset Class	TO4 C1	Description	Aug-13	Sep-13	Sep-13	Sep-13	Sep-13	Depr	Depr	Total	Ln N
		Settleme	ent Rates	Mon EndDepr Base	Mon EndDepr Base	Wtd. Depr Base	Recorded Expense A	Recorded Expense A	Rate	Rate	Rate	
							Life	Removal	Life	Removal		
1	E0135210	0.0218	Struct & Imprv-Other	128,147,700.66	128,777,529.40	128,462,615.03	145,594.10	87,784.67	0.0136	0.0082	0.0218	1
2	E0135220	0.0162	Struct & Improv-SWPL	10,247,815.19	10,247,815.19	10,247,815.19	8,625.44	5,209.43	0.0101	0.0061	0.0162	2
	E0135260	0.0139	Struct & Improv-SRPL	170,471,725.25	120,746,965.83	145,609,345.54	168,664.19	=	0.0139		0.0139	3
4				308,867,241.10	259,772,310.42	284,319,775.76	322,883.73	92,994.10	0.0136	0.0039	0.0176	4
5												5
6	E0135310	0.0352	Station EquipOther	579,534,544,51	591,563,328,18	585,548,936.35	1,073,523.20	644,113.92	0.0220	0.0132	0.0352	6
	E0135320	0.0402	Station EquipSWPL	175,741,260.64	175,537,713.84	175,639,487.24	367,381.01	221,014.07	0.0251	0.0151	0.0402	
	E0135340	0.0325	Station Equip Generat	1,600,000.00	1,420,392.88	1,510,196.44	2,554.77	1,535.38	0.0203	0.0122	0.0325	
	E0135360	0.0201	Station EquipSRPL	268,259,141.08	149,044,474.22	208,651,807.65	349,491.84	-	0.0201	-	0.0201	
10				1,025,134,946.23	917,565,909.12	971,350,427.68	1,792,950.82	866,663.37	0.0221	0.0107	0.0329	10
11										The second secon		11
	E0135410	0.0313	Towers & Fxtrs-Other	65,567,730.53	65,590,963.06	65,579,346.80	85,801,47	85,254.96	0.0157	0.0156	0.0313	
	E0135420	0.0265	Towers & Fixtrs-SWPL	61,988,482,36	61,988,482,36	61,988,482.36	68,705.06	68,188,49	0.0133	0.0132	0.0265	
	E0135460	0.0147	Towers & Fixtrs-SRPL	540,049,456.88	716,637,702.29	628,343,579.59	769,721.00	-	0.0147	-	0.0147	
15	20100100	0.0117	TOWER OF THE OTT E	667,605,669,77	844,217,147.71	755,911,408.74	924,227.53	153,443.45	0.0147	0.0024	0.0171	15
16					· · · · · · · · · · · · · · · · · · ·		·					16
_	E0135510	0.0425	Poles & Fixtrs-Other	279,829,914.79	281,784,582.08	280,807,248.44	496,053.01	498,392,88	0.0212	0.0213	0.0425	
	E0135520	0.0508	Poles & Fixturs-SWPL	8,106,559.79	8,106,559.79	8,106,559.79	17,159.06	17.159.06	0.0254	0.0254	0.0508	
	E0135560	0.0226	Poles & Fixturs-SRPL	7,877,679.68	3,493,778.06	5,685,728.87	10,708.07	-	0.0226	0.0204	0.0226	
20	L0100000	0.0220	FOICS & FIXIGIS-ON E	295,814,154.26	293,384,919.93	294,599,537.10	523,920.13	515,551.94	0.0213	0.0210	0.0423	
21				200,011,101120			323,525.15					21
	E0135610	0.0320	Ovrhd Cnd & Dv-Other	274,876,032,68	275,308,865,67	275,092,449.18	366,223.28	366,223.28	0.0160	0.0160	0.0320	
	E0135620	0.0177	Ovrhd Cnd & Dev-SWPI	44,349,361.42	44,349,361.42	44,349,361.42	32,892.51	32,522,94	0.0089	0.0088	0.0177	
24	E0135660	0.0175	Ovrhd Cnd & Dev-SRPL	103,300,019.46	168,473,840.71	135,886,930.09	198,168.52	_	0.0175		0.0175	
25				422,525,413,56	488,132,067.80	455,328,740.68	597,284.31	398,746.21	0.0157	0.0105	0.0262	
26				,	, , , , , , , , , , , , , , , , , , , ,		,					26
27	E0135700	0.0243	Trans UG Conduit	155,599,554.98	155,970,098.44	155,784,826.71	218,099.19	97,365.71	0.0168	0.0075	0.0243	27
28	E0135760	0.0169	Trans UG Conduit-SRPL	148,727,259.59	80,289,921.35	114,508,590.47	161,266.31		0.0169		0.0169	28
29				304,326,814.57	236,260,019.79	270,293,417.18	379,365.50	97,365.71	0.0168	0.0043	0.0212	29
30								-				30
31	E0135800	0.0208	Trans UG Conductor	134,758,198.45	138,848,553.12	136,803,375.79	215,465.99	21,660.60	0.0189	0.0019	0.0208	31
32	E0135860	0.0202	Trans UG Conductor-SR	198,097,816.16	126,221,799.83	162,159,808.00	272,969.04	#	0.0202		0.0202	32
33				332,856,014.61	265,070,352.95	298,963,183.78	488,435.03	21,660.60	0.0196	0,0009	0.0205	33
34												34
	E0135910	0.0165	Roads & Trails-Other	38,429,446,59	38,522,699,69	38,476,073.14	52,904.82	2	0.0165	- 20	0.0165	
	E0135920	0.0144	Roads & Trails-SWPL	4,426,862,71	4,426,862,71	4,426,862.71	5,312.28		0.0144	-	0.0144	
	E0135960	0.0168	Roads & Trails-SRPL	146,255,296.94	218,000,758,50	182,128,027.72	254,979.21	-	0.0168	-	0.0168	
38				189,111,606.24	260,950,320.90	225,030,963.57	313,196.31	_	0.0167		0.0167	
39				100,111,000121			0.10,100.101				0.0.0.	39
40												40
	Total - September	2013		3,546,241,860.34	3,565,353,048.62	3.555,797,454,48	5,342,263.36	2,146,425.38	0.0180	0,0072	0.0253	41
42	Total - Ocpteriber	2310		0,040,241,000.04	0,000,000,040.02	0,000,101,404.40	0,042,200.00	2,140,420.00	0.0100	0.0012	0.0200	42
43												43
44	Polded amount =	oflocts to	tal monthly per book dep	rociation								43
												45
45	(A) Depreciation E	xpense is	s generated through final	ncial system								45

	TO4 Depreciation											
	Α	В	С	1	2		4	5	6	7	8	
						(Col 1+Col 2) / 2			(Col 4 / Col 3) *12	(Col 5 / Col 3) *12	Col 8 = Col 6 + Col 7	
	Asset Class	TO4 C1	Description	Sep-13	Oct-13	Oct-13	Oct-13	Oct-13	Depr	Depr	Total	
		Settleme	ent Rates	Mon EndDepr Base	Mon EndDepr Base	Wtd. Depr Base	Recorded Expense A	Recorded Expense A	Rate	Rate	Rate	
							Life	Removal	Life	Removal		
1 E	E0135210	0.0218	Struct & Imprv-Other	128,777,529.40	129,943,978.12	129,360,753.76	146,608.07	88,396.05	0.0136	0.0082	0.0218	1
	E0135220	0.0162	Struct & Improv-SWPL	10,247,815.19	10,247,815.19	10,247,815.19	8,625.19	5,209.27	0.0101	0.0061	0.0162	2
3 E	E0135260	0.0139	Struct & Improv-SRPL	120,746,965.83	120,739,846.46	120,743,406.15	139,861.14	-	0.0139	-	0.0139	3
4				259,772,310.42	260,931,639.77	260,351,975.10	295,094.40	93,605.32	0.0136	0.0043	0.0179	4
5												5
	E0135310	0.0352	Station EquipOther	591,563,328.18	594,697,487.85	593,130,408.02	1,085,195.25	650,614.32	0.0220	0.0132	0.0351	6
	E0135320	0.0402	Station EquipSWPL	175,537,713.84	175,709,237.00	175,623,475.42	367,345.12	220,992.48	0.0251	0.0151	0.0402	7
	E0135340	0.0325	Station Equip Generat	1,420,392.88	1,420,392.88	1,420,392.88	2,402.82	1,444.06	0.0203	0.0122	0.0325	8
	E0135360	0.0201	Station EquipSRPL	149,044,474.22	149,028,118.94	149,036,296.58	249,635.82	-	0.0201	-	0.0201	9
0				917,565,909.12	920,855,236.67	919,210,572.90	1,704,579.01	873,050.86	0.0223	0.0114	0.0337	10
1												11
	E0135410	0.0313	Towers & Fxtrs-Other	65,590,963.06	65,614,417.49	65,602,690.28	85,829.82	85,283.14	0.0157	0.0156	0.0313	12
	E0135420	0.0265	Towers & Fixtrs-SWPL	61,988,482.36	61,988,482.36	61,988,482.36	68,703.40	68,186.83	0.0133	0.0132	0.0265	13
	E0135460	0.0147	Towers & Fixtrs-SRPL	716,637,702.29	716,727,536.95	716,682,619.62	877,936.19	-	0.0147	-	0.0147	14
15				844,217,147.71	844,330,436.80	844,273,792.26	1,032,469.41	153,469.97	0.0147	0.0022	0.0169	15
6												16
	E0135510	0.0425	Poles & Fixtrs-Other	281,784,582.08	285,136,262.08	283,460,422.08	500,988.98	503,352.13	0.0212	0.0213	0.0425	17
	E0135520	0.0508	Poles & Fixturs-SWPL	8,106,559.79	8,106,559.79	8,106,559.79	17,158.82	17,158.82	0.0254	0.0254	0.0508	18
	E0135560	0.0226	Poles & Fixturs-SRPL	3,493,778.06	3,492,573.30	3,493,175.68	6,578.84	-	0.0226	-	0.0226	19
20				293,384,919.93	296,735,395.17	295,060,157.55	524,726.63	520,510.95	0.0213	0.0212	0.0425	20
21		0.000										21
	E0135610	0.0320	Ovrhd Cnd & Dv-Other	275,308,865.67	276,654,907.96	275,981,886.82	367,960.46	367,960.46	0.0160	0.0160	0.0320	22
	E0135620	0.0177	Ovrhd Cnd & Dev-SWPI	44,349,361.42	44,349,361.42	44,349,361.42	32,892.39	32,522.82	0.0089	0.0088	0.0177	23
	E0135660	0.0175	Ovrhd Cnd & Dev-SRPL	168,473,840.71	168,480,331.96	168,477,086.34	245,695.89	-	0.0175	-	0.0175	24
25				488,132,067.80	489,484,601.34	488,808,334.57	646,548.74	400,483.27	0.0159	0.0098	0.0257	25
26	-0105700	2 22 12		155.070.000.11	450 007 004 04	150 150 000 00						26
	E0135700	0.0243	Trans UG Conduit	155,970,098.44	156,337,834.34	156,153,966.39	217,985.08	97,141.30	0.0168	0.0075	0.0242	27
	E0135760	0.0169	Trans UG Conduit-SRPL	80,289,921.35	80,284,261.25	80,287,091.30	113,070.99	-	0.0169	-	0.0169	28
9				236,260,019.79	236,622,095.59	236,441,057.69	331,056.07	97,141.30	0.0168	0.0049	0.0217	29
30	-0405000	0.0000	T 110 0 1 1	100 010 550 10	110 150 050 01	100 500 700 00	201 215 27		2 2 / 2 2			30
	E0135800	0.0208	Trans UG Conductor	138,848,553.12	140,156,859.31	139,502,706.22	221,215.87	22,238.63	0.0190	0.0019	0.0209	31
	E0135860	0.0202	Trans UG Conductor-SF	126,221,799.83	126,215,711.44	126,218,755.64	212,468.27	-	0.0202	-	0.0202	32
33		-		265,070,352.95	266,372,570.75	265,721,461.85	433,684.14	22,238.63	0.0196	0.0010	0.0206	
84	-0125010	0.0405	Doods 9 Trails Other	20 500 000 00	20 500 400 44	20 500 040 07	F0 004 04		0.015=		0.04	34
	E0135910	0.0165	Roads & Trails-Other	38,522,699.69	38,599,136.44	38,560,918.07	53,021.24	-	0.0165	-	0.0165	35
	E0135920 E0135960	0.0144	Roads & Trails-SWPL	4,426,862.71	4,426,862.71	4,426,862.71	5,312.22	-	0.0144	-	0.0144	36
88	199800	0.0168	Roads & Trails-SRPL	218,000,758.50 260,950,320.90	218,053,677.65	218,027,218.08	305,238.15	-	0.0168	-	0.0168	37
9		-		200,950,320.90	261,079,676.80	261,014,998.85	363,571.61		0.0167	A. S.	0.0167	38
0		_										
	Total - October 20	112		3,565,353,048.62	3,576,411,652.89	3,570,882,350,76	5,331,730.01	2,160,500.30	0.0179	0.0073	0.0252	40
2	otal - October 20	113		3,303,333,048.62	3,370,411,032.89	3,370,002,330.76	5,331,730.01	2,160,500.30	0.0179	0.0073	0.0252	4
3												42
	Rolded amount	offects tot	al monthly per book depr	reciation								43
			generated through finar									44
0	A) Depreciation	Expense is	generated through finar	iciai systemi								45

	TO4 Depreciation	Rate - Co	omposite 2.52%									
	A	В	С	1	2	3	4	5	6	7	8	
		1				(Col 1+Col 2) / 2			(Col 4 / Col 3) *12	(Col 5 / Col 3) *12	Col 8 = Col 6 + Col 7	
						,				,		
	Asset Class	TO4 C1	Description	Oct-13	Nov-13	Nov-13	Nov-13	Nov-13	Depr	Depr	Total	
		Settleme	ent Rates	Mon EndDepr Base	Mon EndDepr Base	Wtd. Depr Base	Recorded Expense A	Recorded Expense A	Rate	Rate	Rate	
		Cottioni	THE HOLES	mon Enapopi Baco	mon Endbop: Edoc	Tital Dopi Dado	Life	Removal	Life	Removal	1,4410	
1	E0135210	0.0218	Struct & Imprv-Other	129,943,978.12	135,201,811.97	132,572,895.05	150,252.00	90,593.12	0.0136	0.0082	0.0218	1
	E0135220	0.0162	Struct & Improv-SWPL	10,247,815.19	10,247,815.19	10,247,815.19	8,625.18	5,209.26	0.0101	0.0061	0.0162	2
	E0135260	0.0139	Struct & Improv-SRPL	120,739,846.46	120,938,881.02	120,839,363.74	139,972.25	- 0,200.20	0.0139	- 0.0001	0.0139	3
4	L0100200	0.0100	Cirdot a improv civi E	260,931,639.77	266,388,508,18	263,660,073.98	298,849.43	95,802.38	0.0136	0.0044	0.0180	4
5				200,001,000.77	200,000,000.10	200,000,070.00	200,010.10	00,002.00	0.0,00	0.00	0.0,00	5
	E0135310	0.0352	Station EquipOther	594,697,487.85	600,524,471.31	597,610,979.58	1,095,666.96	656,892.57	0.0220	0.0132	0.0352	6
	E0135320	0.0402	Station EquipSWPL	175,709,237.00	175,722,410.89	175,715,823.95	367,538.37	221,108,74	0.0251	0.0151	0.0402	7
	E0135340	0.0325	Station Equip Generat	1,420,392.88	1,420,392.88	1,420,392.88	2,402.83	1,444.06	0.0203	0.0122	0.0325	8
	E0135340	0.0323	Station EquipSRPL	149,028,118.94	149,915,776.84	149,471,947.89	250,365.47	- 1,444.00	0.0201	0.0122	0.0201	9
10	L0133300	0.0201	Station EquipSixi E	920,855,236.67	927,583,051.92	924,219,144.30	1,715,973.62	879,445.38	0.0223	0,0114	0.0337	10
11		-		320,033,230.07	321,000,031.32	524,215,174.50	1,7 10,070.02	070,440.00	OLOZZO	0.0114	5,3001	11
	E0135410	0.0313	Towers & Fxtrs-Other	65,614,417.49	65,745,860.62	65,680,139.06	85,930.53	85,383.21	0.0157	0.0156	0.0313	12
	E0135410	0.0313	Towers & Fixtrs-SWPL	61,988,482.36	61,988,482.36	61,988,482.36	68,703,41	68,186.85	0.0133	0.0132	0.0265	13
	E0135460	0.0263	Towers & Fixtrs-SRPL	716,727,536.95	718,389,753.98	717,558,645.47	879,009.41	08,100.83	0.0147	0.0132	0.0203	14
15	E0133460	0.0147	Towers & Fixus-SRFL	844,330,436.80	846,124,096.96	845,227,266.88	1,033,643.36	153,570.05	0.0147	0,0022	0.0169	15
16				844,330,436.80	840,124,090.90	043,221,200.00	1,033,043.30	155,570.05	0.0147	0.0022	0,0103	16
	E040EE40	0.0425	Poles & Fixtrs-Other	285,136,262.08	286,818,222.28	285,977,242.18	513,976.09	516,400.50	0.0216	0.0217	0.0432	17
	E0135510		Poles & Fixturs-SWPL				17,158.84	17.158.84	0.0216	0.0217	0.0508	18
	E0135520	0.0508		8,106,559.79	8,106,559.79	8,106,559.79		17,158.84		0.0254	0.0508	19
	E0135560	0.0226	Poles & Fixturs-SRPL	3,492,573.30	3,491,093.23	3,491,833.27	6,576.26		0.0226	0.0215	0.0226	20
20		[F]		296,735,395.17	298,415,875.30	297,575,635.24	537,711.19	533,559.34	0.0217	0.0215	0.0432	21
21	E0405040	0.0000	0 -1 -1 0 - 1 0 D - 0 1	070 054 007 00	077 540 407 00	077 007 007 07	200 420 04	200 420 04	0.0400	0.0400	0.0000	22
	E0135610	0.0320	Ovrhd Cnd & Dv-Other	276,654,907.96	277,540,487.38	277,097,697.67	369,430.21	369,430.21	0.0160	0.0160	0.0320	
	E0135620	0.0177	Ovrhd Cnd & Dev-SWPI	44,349,361.42	44,345,870.23	44,347,615.83	32,891.19	32,521.62	0.0089	0.0088	0.0177	23
	E0135660	0.0175	Ovrhd Cnd & Dev-SRPL	168,480,331.96	167,135,284.45	167,807,808.21	244,719.62	-	0.0175	-	0.0175	24
25				489,484,601.34	489,021,642.06	489,253,121.70	647,041.02	401,951.83	0.0159	0.0099	0.0257	25
26		-										26
	E0135700	0.0243	Trans UG Conduit	156,337,834.34	165,215,723.27	160,776,778.81	225,087.40	100,485.45	0.0168	0.0075	0.0243	27
	E0135760	0.0169	Trans UG Conduit-SRPL	80,284,261.25	80,271,352.47	80,277,806.86	113,057.92		0.0169	-	0.0169	28
29				236,622,095.59	245,487,075.74	241,054,585.67	338,145.32	100,485.45	0.0168	0.0050	0.0218	29
30												30
	E0135800	0.0208	Trans UG Conductor	140,156,859.31	154,640,594.11	147,398,726.71	232,152.83	23,338.11	0.0189	0.0019	0.0208	31
	E0135860	0.0202	Trans UG Conductor-SR	126,215,711.44	126,202,198.23	126,208,954.84	212,451.75		0.0202	-	0.0202	32
33				266,372,570.75	280,842,792.34	273,607,681.55	444,604.58	23,338.11	0.0195	0.0010	0.0205	33
34											Q. g ti kee	34
	E0135910	0.0165	Roads & Trails-Other	38,599,136.44	38,601,702.40	38,600,419.42	53,075.44		0.0165	_	0.0165	35
	E0135920	0.0144	Roads & Trails-SWPL	4,426,862.71	4,426,862.71	4,426,862.71	5,312.25	-	0.0144	-	0.0144	36
	E0135960	0.0168	Roads & Trails-SRPL	218,053,677.65	218,065,857.20	218,059,767.43	305,283.64	<u> </u>	0.0168		0.0168	37
38				261,079,676.80	261,094,422.31	261,087,049.56	363,671.33	*	0.0167		0.0167	38
39												39
40												40
41	Total - November	2013		3,576,411,652.89	3,614,957,464.81	3,595,684,558.85	5,379,639.84	2,188,152.55	0.0180	0.0073	0.0253	41
42												42
43												43
44	Bolded amount	eflects to	tal monthly per book dep	reciation								44
45	(A) Depreciation I	Expense i	s generated through fina	ncial system								45
2000		T*		*								

			omposite 2.52%						•	-	
/	A	В	С	1	2	3	4	5	6	7	8
						(Col 1+Col 2) / 2			(Col 4 / Col 3) *12	(Col 5 / Col 3) *12	Col 8 = Col 6 + Col 7
Accot	Class	TO4 C1	Description	Nov-13	Dec-13	Dec-13	Dec-13	Dec-13	Depr	Depr	Total
ASSEL	Class		ent Rates				Recorded Expense A	Recorded Expense A	Rate	Rate	Rate
_		Settleme	ent Rates	Mon EndDepr Base	Mon EndDepr Base	Wtd. Depr Base	Life	Removal	Life	Removal	Rate
E0405044	•	0.0040	0	105 004 044 07	107 111 100 15	400 004 054 00					0.0040
E0135210		0.0218	Struct & Imprv-Other	135,201,811.97	137,441,490.15	136,321,651.06	154,531.33	93,173.30	0.0136	0.0082	0.0218
E0135220		0.0162	Struct & Improv-SWPL	10,247,815.19	10,247,815.19	10,247,815.19	8,625.18	5,209.27	0.0101	0.0061	0.0162
E0135260	0	0.0139	Struct & Improv-SRPL	120,938,881.02	120,944,822.82	120,941,851.92	140,090.99		0.0139	0.0044	0.0139
		-		266,388,508.18	268,634,128.16	267,511,318.17	303,247.50	98,382.57	0.0136	0.0044	0.0180
==10=01		0.0050		200 504 474 04	044 570 000 40	007.554.054.74	4 444 400 55	207.000.40	0.0000	0.0400	0.0050
E0135310		0.0352	Station EquipOther	600,524,471.31	614,578,038.16	607,551,254.74	1,114,160.55	667,980.16	0.0220	0.0132	0.0352
E0135320		0.0402	Station EquipSWPL	175,722,410.89	195,921,714.71	185,822,062.80	388,677.23	233,825.75	0.0251	0.0151	0.0402
E0135340		0.0325	Station Equip Generat	1,420,392.88	1,420,392.88	1,420,392.88	2,402.83	1,444.06	0.0203	0.0122	0.0325
E0135360	0	0.0201	Station EquipSRPL	149,915,776.84	149,914,505.56	149,915,141.20	251,107.88		0.0201	-	0.0201
				927,583,051.92	961,834,651.31	944,708,851.62	1,756,348.49	903,249.97	0.0223	0.0115	0.0338
E0135410		0.0313	Towers & Fxtrs-Other	65,745,860.62	65,768,806.85	65,757,333.74	86,032.03	85,484.05	0.0157	0.0156	0.0313
E0135420		0.0265	Towers & Fixtrs-SWPL	61,988,482.36	61,988,482.36	61,988,482.36	68,703.50	68,186.94	0.0133	0.0132	0.0265
E0135460	0	0.0147	Towers & Fixtrs-SRPL	718,389,753.98	718,380,550.88	718,385,152.43	880,021.88	-	0.0147	-	0.0147
				846,124,096.96	846,137,840.09	846,130,968.53	1,034,757.41	153,670.99	0.0147	0.0022	0.0169
E0135510		0.0425	Poles & Fixtrs-Other	286,818,222.28	286,341,737.18	286,579,979.73	506,579.60	508,969.13	0.0212	0.0213	0.0425
E0135520		0.0508	Poles & Fixturs-SWPL	8,106,559.79	8,106,559.79	8,106,559.79	17,158.84	17,158.84	0.0254	0.0254	0.0508
E0135560	0	0.0226	Poles & Fixturs-SRPL	3,491,093.23	3,491,093.23	3,491,093.23	6,574.90	-	0.0226	-	0.0226
				298,415,875.30	297,939,390.20	298,177,632.75	530,313.34	526,127.96	0.0213	0.0212	0.0425
E0135610	0	0.0320	Ovrhd Cnd & Dv-Other	277,540,487.38	277,616,444.97	277,578,466.18	369,989.76	369,989.76	0.0160	0.0160	0.0320
E0135620	0	0.0177	Ovrhd Cnd & Dev-SWPI	44,345,870.23	44,345,870.23	44,345,870.23	32,889.78	32,520.24	0.0089	0.0088	0.0177
E0135660		0.0175	Ovrhd Cnd & Dev-SRPL	167,135,284.45	167,133,409.22	167,134,346.84	243,737.55	-	0.0175		0.0175
				489,021,642.06	489,095,724.42	489,058,683.24	646,617.09	402,510.00	0.0159	0.0099	0.0257
				100,021,012.00	,,	13313331333	2.12,2.1.1.2	,			
E0135700)	0.0243	Trans UG Conduit	165,215,723.27	165,259,118.50	165,237,420.89	231,332.28	103,273.34	0.0168	0.0075	0.0243
E0135760		0.0169	Trans UG Conduit-SRPL	80,271,352.47	80,268,915.68	80,270,134.08	113,047.11	100,270.04	0.0169	-	0.0169
L0100700	J	0.0103	Trans 00 conduct-ord t	245,487,075.74	245,528,034.18	245,507,554,96	344,379.39	103,273.34	0.0168	0.0050	0.0219
				240,407,070.74	240,020,004.10	240,007,004.00	044,070.00	100,210.04	0.0100	0.0000	0.02.10
E0135800	1	0.0208	Trans UG Conductor	154,640,594.11	154,682,747.20	154,661,670.66	243,591.88	24,488.07	0.0189	0.0019	0.0208
E0135860		0.0202	Trans UG Conductor-SR	126,202,198.23	126,199,639.93	126,200,919.08	212,438.17	24,400.07	0.0202	0.0019	0.0202
E0133660	J	0.0202	Trans OG Conductor-SR	280,842,792.34	280,882,387.13	280,862,589.74	456,030.05	24,488.07	0.0202	0.0010	0.0202
_				200,042,792.54	200,002,307.13	200,002,009.14	430,030.03	24,400.07	0.0155	0.0010	0.0203
E0135910	2	0.0165	Roads & Trails-Other	38,601,702,40	38,602,081.30	38,601,891.85	53,077.51		0.0165		0.0165
E0135910		0.0165	Roads & Trails-Other Roads & Trails-SWPL		4.426.862.71	4,426,862,71	53,077.51	-	0.0165		0.0165
E0135920				4,426,862.71		218,093,678.10			0.0144		0.0144
E0135960	J	0.0168	Roads & Trails-SRPL	218,065,857.20 261,094,422,31	218,121,499.00 261,150,443.01	261,122,432,66	305,331.08 363,720.79	-	0.0167		0.0168
-				261,094,422.31	261,150,443.01	201,122,432.00	363,720.79		0.0167	-	0.0107
-											
T-4-1 -		0040		0.044.057.464.64	0.054.000.500.50	0.000.000.001.00	F 40F 44 4 00	0.044.700.00	0.0450	0.0070	0.0000
Total - De	ecember	2013		3,614,957,464.81	3,651,202,598.50	3,633,080,031.66	5,435,414.06	2,211,702.90	0.0180	0.0073	0.0253
Bolded a											
			tal monthly per book dep								
(A) Depre	eciation E	expense is	s generated through fina	ncial system							

Transmission Plant Monthly Depreciation Expense

September - December 2013

	Cumulative Wtd [Depr Base	9										\top
_	TO4 Depreciation	-		.52%									
	A	В		C	1	2	3	4	5	6	7	8	
							(Col 1+Col 2) / 2			(Col 4 / Col 3) *12	(Col 5 / Col 3) *12	Col 8 = Col 6 + Col 7	7
							9/1/2013-12/31/2013		9/1/2013- 12/31/2013				
	Asset Class	TO4 C1	Des	cription			Total	Total	Total	Depr	Depr	Total	
		Settleme	ent Rates		Mon EndDepr Base	Mon EndDepr Base	Wtd. Depr Base	Recorded Expense A	Recorded Expense A	Rate	Rate	Rate	
								Life	Removal	Life	Removal		
	E0135210	0.0218	Struct & In	mprv-Other			526,717,914.90	596,985.50	359,947.14	0.0136	0.0082	0.0218	
	E0135220	0.0162	Struct & In	mprov-SWPL			40,991,260.76	34,500.99	20,837.23	0.0101	0.0061	0.0162	
3	E0135260	0.0139	Struct & In	mprov-SRPL			508,133,967.35	588,588.57	-	0.0139	-	0.0139	
					_	-	1,075,843,143.00	1,220,075.06	380,784.37	0.0136	0.0042	0.0178	
5													
3	E0135310	0.0352	Station Eq	uipOther			2,383,841,578.68	4,368,545.95	2,619,600.98	0.0220	0.0132	0.0352	
	E0135320	0.0402	Station Eq	uipSWPL			712,800,849.41	1,490,941.73	896,941.04	0.0251	0.0151	0.0402	
	E0135340	0.0325		uip Generati	on		5,771,375.08	9,763.24	5,867.57	0.0203	0.0122	0.0325	
)	E0135360	0.0201	Station Eq	uipSRPL			657,075,193.32	1,100,601.01	-	0.0201	-	0.0201	
0					-	-	3,759,488,996.48	6,969,851.94	3,522,409.58	0.0222	0.0112	0.0334	
1													
2	E0135410	0.0313	Towers &	Fxtrs-Other			262,619,509.86	343,593.85	341,405.36	0.0157	0.0156	0.0313	
3	E0135420	0.0265	Towers &	Fixtrs-SWPL			247,953,929.44	274,815.38	272,749.10	0.0133	0.0132	0.0265	
4	E0135460	0.0147	Towers &	Fixtrs-SRPL			2,780,969,997.10	3,406,688.48	-	0.0147	-	0.0147	
5					-		3,291,543,436.40	4,025,097.71	614,154.46	0.0147	0.0022	0.0169	
3													
7	E0135510	0.0425	Poles & Fi	ixtrs-Other			1,136,824,892.43	2,017,597.67	2,027,114.65	0.0213	0.0214	0.0427	
3	E0135520	0.0508	Poles & Fi	ixturs-SWPL			32,426,239.16	68,635.55	68,635.55	0.0254	0.0254	0.0508	
9	E0135560	0.0226	Poles & Fi	ixturs-SRPL			16,161,831.05	30,438.07	-	0.0226	-	0.0226	
0					-	-	1,185,412,962.63	2,116,671.29	2,095,750.19	0.0214	0,0212	0.0426	
1													
2	E0135610	0.0320	Ovrhd Cnd	d & Dv-Other			1,105,750,499.84	1,473,603.70	1,473,603.70	0.0160	0.0160	0.0320	
3	E0135620	0.0177	Ovrhd Cnd	d & Dev-SWPL			177,392,208.90	131,565.88	130,087.61	0.0089	0.0088	0.0177	
4 1	E0135660	0.0175	Ovrhd Cnd	d & Dev-SRPL			639,306,171.46	932,321.58	-	0.0175	-	0.0175	
5					-	-	1,922,448,880.19	2,537,491.16	1,603,691.31	0.0158	0.0100	0.0258	
6													
	E0135700	0.0243	Trans UG				637,952,992.79	892,503.95	398,265.80	0.0168	0.0075	0.0243	
3 1	E0135760	0.0169	Trans UG	Conduit-SRPL			355,343,622.71	500,442.33	-	0.0169		0.0169	
9					-	-	993,296,615.50	1,392,946.28	398,265.80	0.0168	0.0048	0.0216	
)													
	E0135800	0.0208	Trans UG	Conductor			578,366,479.37	912,426.56	91,725.42	0.0189	0.0019	0.0208	
	E0135860	0.0202	Trans UG	Conductor-SRI	PL		540,788,437.55	910,327.23	-	0.0202	7 -	0.0202	
3						-	1,119,154,916.91	1,822,753.79	91,725.42	0.0195	0.0010	0.0205	
4													
5 1	E0135910	0.0165	Roads & T	rails-Other			154,239,302.48	212,079.01	-	0.0165		0.0165	
6 1	E0135920	0.0144	Roads & T	rails-SWPL			17,707,450.84	21,248.95	-	0.0144		0.0144	
' I	E0135960	0.0168	Roads & T	rails-SRPL			836,308,691.32	1,170,832.08	-	0.0168	-	0.0168	
3					-	-	1,008,255,444.64	1,404,160.04	-	0.0167		0.0167	
9													
0													
1	Total - Septembe	r to Dece	mber 2013		-	-	14,355,444,395.74	21,489,047.27	8,706,781.13	0.0180	0.0072	0.0252	
2													
3 .	TO4 Cycle 2 True-	Up Total	Depreciation	on Expense - S	Sept to Dec 2013		(1	Col. 4 + Col. 5, Line 255)	30,195,828.40				
4	-	ľ	T .	,			,						
5 (A) Depreciation E	xpense i	s generated	d through fina	ncial system								-

Depreciation & Amortization Workpapers for Electric Miscellaneous Intangible Plant

SAN DIEGO GAS & ELECTRIC COMPANY STATEMENT AJ DEPRECIATION AND AMORTIZATION EXPENSE TRUE UP PERIOD - 9/1/2013 TO 12/31/2013 PER BOOK

(\$1,000)

INTANGIBLE PLANT

Line No.		FERC Intangible Plant Expense	Reference From	Line No.
1	December 31, 2013 Expense	4,218	AJ8-lwp1	1

SAN DIEGO GAS AND ELECTRIC COMPANY Statement AJ - Workpapers TO4 - Annual Intangible Plant Authorized Amortization Period

Line	FERC	•	Amortization	Line
No	Acct No	DESCRIPTION	Period (Yrs) ¹	No
1				1
2		ELECTRIC DISTRIBUTION		2
3	E303	Electric Distribution Software	5,7, or 10 years	3
4	E360	Electric Distribution Easements (land rights)	45 years	4
5				5
6	*	ELECTRIC TRANSMISSION		6
7	E350	Electric Transmission Easements (land rights)	100 Years	7
8				8

These periods may not be changed absent a section 205 or 206 filing.
The annual Information Filing will reference the docket number of the FERC proceeding that establishes new General Plant and Common Plant depreciation rates and Intangible Plant amortization periods.

	Intangible I				tric Company ated Amortizatio	n at 12/31/2013		
				Source: SAP 12/31/	2013			
	or s							
Line	FERC		Year	Amortization	Plant	Accumulated	Amortization	Line
No.	Acct.		Placed	Period	Balance	Amortization	Expense	No.
1	A) ELECTRIC INTANGIBLE PLANT							1
2	Account E 303.00	5-year	2007	5	1,042,224.21	(1,042,224.21)	Fully Amortized	A 2
3	7000ditt E 000.00	o your	2010	5	866,553.93	(658,291.51)	172,355.10	3
4			2011	5	6,430,967.23	(2,926,751.03)	1,282,583.24	4
5			2012	5	14,954,446.25	(5,081,782.69)	3,032,433.94	5
6			2013	5	16,673,699.19	(1,706,944.46)	1,706,944.46	6
7					,.,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,	(1,1,1,1,1,1,1,1,1,1,1,1,1,1,1,1,1,1,1,	.,,,	7
8	E 303.00	Subtotal	5-year		39,967,890.81	(11,415,993.90)	6,194,316.74	8
9			-			· · · · · · · · · · · · · · · · · · ·		9
10	ELECTRIC INTANGIBLE PLANT							10
	Account E 303.00	10-year	2012	10	53,183,046.68	(8,576,508.99)	5,326,997.11	11
12			2013	10	3,028.73	(1,061.84)	1,061.84	12
13								13
14	E 303.00	Subtotal	10-year		53,186,075.41	(8,577,570.83)	5,328,058.95	14
15								15
16	E 303.00	Total			93,153,966.22	(19,993,564.73)	11,522,375.69	16
17								17
18	B) COMMON INTANGIBLE PLANT					.÷-		18
	Account C 303.00	5-Year	2008	5	11,185,909.02	(11,185,909.02)	1,885,308.70	19
20			2009	5	46,127,830.77	(43,358,903.52)	9,287,150.87	20
21			2010	5	37,979,104.02	(24,851,883.89)	7,649,488.68	21
22			2011	5	32,137,279.25	(15,897,136.16)	6,450,586.99	22
23			2012	5	30,741,759.67	(9,639,151.88)	6,153,877.48	23
24			2013	5	27,049,036.69	(3,633,512.04)	3,633,512.04	24
25								25
	C 303.00	Subtotal	5-Year		185,220,919.42	(108,566,496.51)	35,059,924.77	26
27								27
	COMMON INTANGIBLE PLANT							28
	Account C 303.00	15-Year	1998	15	31,037,051.77	(31,037,051.77)	Fully Amortized 1 '	29
30							•	30
	C 303.00	Subtotal	15-Year		31,037,051.77	(31,037,051.77)	-	31
32								32
33	C 303.00	Total			216,257,971.19	(139,603,548.28)	35,059,924.77	33
								-
A	Note this is fully amortized and there v	WOO DO OD	nortization	ovnense			54.	+

	Land Dights	_		ectric Compa	d Amortization	at 12/21/2012		
	Land Rights	Plant Dan		e: SAP 12/31/2013	u Amoruzation	at 12/3 1/2013		
Line	FERC		Year	Amortization	Plant	Accumulated	Amortization	Line
No.	Acct.		Placed	Period	Balance	Amortization	Expense	No.
NO.	Acct.		riaceu	Periou	Dalatice	Amortization	Expense	NO
1	A. ELECTRIC TRANSMISSION	-SW/DI						1
2	Account E 350.22	Land Rights	1982	100	4,983,146.20	(1,539,852.90)	49,831.46	2
3	Account E 330.22	Land Rights	1983	100	4,605,447.77	(1,374,823.20)	46,054.48	3
4			1984	100	2,872,876.25	(840,869.55)	28,728.77	4
5			1985	100	2,685,624.04	(765,400.75)	26,856.25	5
6					35,953.76		359.54	6
			1986	100		(9,816.10)		7
7			1987	100	196,089.13	(51,961.35)	1,960.89	
8			1988	100	15,201.27	(3,876.15)	152.01	8
9			1989	100	26,756.45	(6,559.40)	267.56	9
10			1990	100	7,944.79	(1,863.75)	79.45	10
11			1991	100	476.89	(108.55)	4.77	11
12						:		12
13	E 350.22	Total	Land Rights		15,429,516.55	(4,595,131.70)	154,295.18	13
14		2	4	***				14
15	B. ELECTRIC TRANSMISSION	-SUNRISE					-	15
16	Account E 350.26	Land Rights	2009	50/100	9,087,923.00	(291,404.04)	189,018.84	16
17			2010	50/100	46,081,702.23	(954,947.11)	619,425.15	17
18	1000		2011	50/100	8,510,253.91	(162,796.31)	105,597.62	18
19			2012	50/100	11,920,613.34	(160,074.86)	123,965.58	19
20			2013	50/100	577,134.38	(3,397.71)	3,397.71	20
21					211,101.00	(0,007.7.7)		21
22	E 350.26	Total	Land Rights		76,177,626.86	(1,572,620.03)	1,041,404.90	22
23	L 000.20	rotai	Lana ragnio		70,177,020.00	(1,012,020.00)	1,041,404.00	23
24	C. ELECTRIC TRANSMISSION	OTHER					*	24
25	Account E 350.21	Land Rights	Pre-1971	92	5,630,067.90	(2,611,916.58)	61,196.39	25
26	ACCOUNT E 330.21	Land Rights	N NO 15 11 17 17 17					26
27			1971	100	406,321.74	(155,767.46)	4,063.21	
			1972	100	331,723.97	(148,106.36)	3,317.24	27
28			1973	100	129,468.62	(44,658.82)	1,294.69	28
29			1974	100	215,282.18	(75,699.03)	2,152.82	29
30			1975	100	544,736.36	(197,201.25)	5,447.35	30
31			1976	100	109,341.05	(39,186.57)	1,093.41	31
32			1977	100	143,681.67	(52,714.30)	1,436.82	32
33			1978	100	47,799.63	(17,387.00)	478.00	33
34			1979	100	533,278.55	(192,780.56)	5,332.77	34
35			1980	100	78,620.31	(26,272.30)	786.22	35
36	*		1981	100	110,117.41	(34,669.04)	1,101.15	36
37	·		1982	100	104,074.88	(58,706.26)	1,040.75	37
38			1983	100	34,107.98	(32,452.20)	341.08	38
39			1984	100	218,156.80	(75,923.19)	2,181.56	39
40								
	-		1985	100	2,520,408.55	(713,120.35)	25,204.09	40
41			1986	100	452,616.08	(126,591.40)	4,526.16	41
42			1987	100	119,825.38	(25,826.75)	1,198.25	42
43	8		1988	100 .	351,570.90	(92,690.69)	3,515.70	43
44		×	1989	100	644,065.63	(115,727.90)	6,440.66	44
45			1990	100	543,433.97	(164,330.10)	5,434.34	45
46	e:		1991	100	14,318.85	(5,593.48)	143.19	46
47			1992	100	78,514.57	(9,609.24)	785.15	47
48			1993	100	244,348.10	(50,303.19)	2,443.48	48
49			1994	100	173,757.24	70,971.46	1,737.57	49
50			1994	100	61,160.15	(6,235.00)	611.60	50

	,			ectric Comp				
	Land Rights	Plant Bal			d Amortization	at 12/31/2013		
		T	Sourc	e: SAP 12/31/2013			<u> </u>	
Line No.	FERC Acct.		Year Placed	Amortization Period	Plant Balance	Accumulated Amortization	Amortization Expense	Line No.
		<u> </u>					TE CONTRACTOR OF THE CONTRACTO	
51			1996	100	2,420,911.21	(420,671.65)	24,209.11	51
52	,*		1997	100	7,643,026.25	(1,261,015.09)	76,430.27	52
53			1998	100	25,332.90	(3,857.95)	253.33	53
54	-		1999	100	17,875.83	(2,651.35)	178.77	54
55			2000	100	29,837.94	(4,163.24)	. 298.38	55
56			2001	100	46,414.03	(6,014.50)	464.14	56
57		,	2002	100	345,196.39	(40,929.49)	3,451.96	57
58	. ^		2003	100	190,551.10	(20,881.21)	1,905.51	58
59			2004	100	1,097,916.16	(109,334.18)	10,979.16	59
60			2005	100	14,218,183.86	(1,275,271.77)	142,181.83	60
61			2006	100	4,217,446.18	(328,521.98)	42,174.46	61
62			2007	100	1,210,207.50	(89,566.96)	12,102.07	62
63			2008	100	816,468.60	(46,512.38)	8,164.68	63
64			2009	100	9,667.40	(432.44)	96.68	64
65			2010	100	1,469,176.50	(48,072.93)	14,691.77	65
66			2011	100	306,617.58	(7,203.37)	3,066.18	66
67			2012	100	5,371,644.02	(80,017.34)	53,716.43	67
68			2013	100	2,711,039.22	(9,645.23)	9,645.23	68
69				145				69
70	E 350.21	Subtotal	Land Rights	.,	55,988,311.14	(8,757,260.62)	547,313.61	70
71	E 350.21	(a)			-	133,316.66	_	71
72								72
73	E 350.21	Subtotal	Land Rights		55,988,311.14	(8,623,943.96)	547,313.61	73
74								74
75	D. TOTAL ELECTRIC TRANSP	<u>MISSION</u>			147,595,454.55	(14,791,695.69)	1,743,013.69	75
76								76
77	E. ELECTRIC DISTRIBUTION	A						77
78	Account E 360.2	Land Rights	Pre-1971	35	3,603,031.86	(3,603,031.86)		78
79			1971	45	319,334.04	(296,366.55)	7,097.25	79
80			1972	45	468,022.37	(385,410.95)	10,400.50	80
81			1973	45	434,172.78	(379,751.30)	9,648.28	81
82			1974	45	502,745.61	(436,561.44)	11,172.12	82
83	¥		1975	45	525,827.21	(446,189.62)	11,686.60	83
84	4.		1976	45	546,737.84	(451,818.15)	12,149.73	84
85	3		1977	45	562,166.40	(452,786.52)	12,493.58	85
86			1978	45	687,000.00	(535,351.96)	15,270.09	86
87			1979	45	1,804,016.65	(1,349,977.03)	40,089.26	87
88			1980	45	2,122,873.23	(1,559,440.22)	47,174.96	88
89		::	1981	45	2,616,507.76	(1,842,844.09)	58,144.62	89
90		*	1982	45	2,389,217.77	(1,631,830.18)	53,093.73	90
91			1983	45	2,311,217.09	(1,526,173.08)	51,360.38	91
92			1984	45	2,634,066.50	(1,682,139.54)	58,534.81	92
93			1985	45	2,986,872.88	(1,851,075.76)	66,374.95	93
94			1986	45	3,170,065.72	(1,886,232.76)	70,445.90	94
95			1987	45	3,178,320.90	(1,801,481.63)	70,656.11	95
96			1988	45	2,929,529.12	(1,590,975.10)	65,100.65	96
97			1989	45	2,685,577.16	(1,406,502.19)	59,679.49	97
98			1990	45	2,098,993.18	(1,064,281.61)	46,647.97	98

	Land R	ights Plant Bal			d Amortization	at 12/31/2013		
	2		Sourc	e: SAP 12/31/2013				
								ļ
Line	FERC		Year	Amortization	Plant	Accumulated	Amortization	Line
No.	Acct.		Placed	Period	Balance	Amortization	Expense	No.
					¥		140	
99			1991	45	2,086,495.03	(982,722.57)	46,411.66	99
100			1992	45	1,933,189.87	(912,163.94)	42,976.94	100
101			1993	45	1,854,752.55	(817,411.40)	41,250.23	101
102	ŧ		1994	45	1,657,154.20	(683,717.92)	36,825.65	102
103			1995	45	1,164,829.75	(452,328.53)	25,885.11	103
104			1996	. 45	1,320,918.46	(492,139.14)	29,353.74	104
105			1997	45	1,156,627.68	(419,248.76)	25,717.54	105
106			1998	45	1,357,482.47	(466,921.08)	30,166.28	106
107			1999	45	1,025,781.79	(337,213.10)	22,795.15	107
108			2000	45	1,308,304.17	(405,796.95)	29,085.85	108
109			2001	45	1,307,624.31	(376,547.46)	29,058.32	109
110			2002	45	2,167,248.89	(575,926.34)	48,161.09	110
111			2003	45	1,821,591.71	(443,591.38)	40,479.82	111
112			2004	45	2,059,070.86	(455,664.78)	45,757.13	112
113			2005	45	2,115,468.08	(421,134.88)	47,010.40	113
114			2006	45	1,569,796.08	(267,604.29)	34,884.36	114
115			2007	45	1,973,255.63	(288,730.53)	43,857.79	115
116			2008	45	1,789,112.89	(221,707.03)	39,758.07	116
117			2009	45	1,613,029.57	(164,899.37)	35,907.70	117
118			2010	45	1,982,669.69	(154,738.58)	44,059.31	118
119	-		2011	45	1,973,727.82	(112,259.69)	43,860.62	119
120			2012	45	1,820,576.72	(64,486.23)	40,457.28	120
121			2013	45	1,448,974.02	(18,028.76)	18,045.42	121
122					.,	(,0200)		122
123	E 360.2	Subtotal	Land Rights		77,083,978.31	(35,715,204.25)	1,618,986.44	123
124	E 360.2	(B)			- 1,000,0,0,01	589,429.84	.,5,0,000.11	124
125		(5)				000,120.04		125
126	TOTAL ELECTRIC DISTR	RIBUTION			77,083,978.31	(35,125,774.41)	1,618,986.44	126
	(A) Only a very small amo	unt of Account 360).2 (Electric Di	stribution) is tra	nsferred to transm	nission		
-	to conform with FERC 7 F							

Depreciation & Amortization Workpapers for General Plant

SAN DIEGO GAS & ELECTRIC COMPANY STATEMENT AJ DEPRECIATION AND AMORTIZATION EXPENSE TRUE UP PERIOD - 9/1/2013 TO 12/31/2013 PER BOOK

(\$1,000)

GENERAL PLANT

Line No.		FERC General Plant Expense	Reference From	Line No.
. 1	December 31, 2013 Expense	3,232	AJ1-Gwp1	1

Statement AJ - Workpapers

TO4 - Annual General Plant Depreciation Rates

Cycle 2, For 12 - Months Ending December 31, 2013
For Use During the 12-Months Period from January 1 to December 31, 2013

2013 General Rates 1, 2

		Rates based on 12/31/	2012 Plant	Balances		
			(a)	(b)	(c) = a + b	
Line	FERC		Life	Removal	Total	Line
No	Account	Description	Rate	Rate	Rate	No
1						1
2	E0139000	Struct. and Improv.	4.69%	1.17%	5.86%	2
3	E0139220	Transprtn Eq-Trailer	4.46%	0.00%	4.46%	3
4	E0139310	Stores EquipOther	2.65%	0.00%	2.65%	4
5	E0139411	Portable Tools-Other	3.79%	0.00%	3.79%	5
6	E0139420	Shop Equipment	4.72%	0.00%	4.72%	6
7	E0139510	Laboratory EqOther	7.35%	0.00%	7.35%	7
8	E0139710	Commun. EquipOther	3.06%	0.46%	3.52%	8
9	E0139720	Commun. EquipSWPL	2.11%	0.32%	2.43%	9
10	E0139760	Commun. EquipSRPL	3.53%	0.53%	4.06%	10
11	E0139810	Misc. Equip Other	7.00%	0.00%	7.00%	11
12						12

- The above Electric General Plant depreciation rates are applicable to SDG&E's 2013 calendar year recorded depreciation.
- These rates may not be changed absent a section 205 or 206 filing.

 The annual Information Filing will reference the docket number of the FERC proceeding that establishes new General Plant and Common Plant depreciation rates and Intangible Plant amortization periods.

						San Die	go Gas & E	lectric C	Company					gn.		e	
				2000		2013 Gen	eral Plant D)eprecia	tion Rate	es		i i					
_ine	Asset Class	Description	Recorded Gross Plant as of (1/1/2013)	Future Net Salvg Percent	Future Net Salvg Amount	Recorded Depreciation Reserve as of (1/1/2013)	Net Balance	Avg Svc Life & Iowa Curve	Average Service Life (Yrs)	AGE of Assets	Average Remaining Life (Yrs)	Total Annual Accrual Amount (a)	Total Annual Accrual Percent	Life Rate	COR (Removal Rate)	Total	Line No
	E0139000	Struct. and Improv.	31,045,122	-25	(7,761,281)	(18,922,562)	19,883,841	30SQ	30	19.07	10.93	1,819,199	0.0586	4.69%	1.17%	5.86%	1
3 4	E0139220	Transprtn Eq-Trailer	58,146	0	_	(3,202)	54,944	27SQ	27	5.80	21.20	2,592	0.0446	4.46%	0.00%	4.46%	3 4
	E0139310	Stores EquipOther	17,466	0	-	(16,310)	1,156	25SQ	25	22.51	2.50	462	0.0265	2.65%	0.00%	2.65%	5
	E0139411	Portable Tools-Other	20,985,643	0	· ·	(6,279,051)	14,706,592	27SQ	27	8.50	18.50	794,951	0.0379	3.79%	0.00%	3.79%	7 8
9	E0139420	Shop Equipment	328,720	0	-	(196,745)	131,975	24SQ	24	15.50	8.50	15,526	0.0472	4.72%	0.00%	4.72%	9
11 12	E0139510	Laboratory EqOther	302,226	0	-	(49,149)	253,077	20SQ	. 20	8.60	11.40	22,200	0.0735	7.35%	0.00%	7.35%	11 12
13 14	E0139710	Commun. EquipOther	151,267,789	-15	(22,690,168)	(65,397,068)	108,560,889	28 R2	28	8.80	20.40	5,321,612	0.0352	3.06%	0.46%	3.52%	13 14
15 16	E0139720	Commun. EquipSWPL	5,945,573	-15	(891,836)	(4,828,623)	2,008,786	28 R2	28	17.50	13.90	144,517	0.0243	2.11%	0.32%	2.43%	15 16
17 18	E0139760	Commun. EquipSRPL	13,871,107	-15	(2,080,666)	(406,347)	15,545,426	28 R2	28	0.50	27.60	563,240	0.0406	3.53%	0.53%	4.06%	17
19 20	E0139810	Misc. Equip Other	1,367,470	0	No.	(228,290)	1,139,180	15SQ	15	3.10	11.90	95,729	0.0700	7.00%	0.00%	7.00%	19 20
21		Total	225,189,262		(33,423,951)	(96,327,347)	162,285,866				18.48	8,780,028	0.0390				21
-	This workpa	aper supports the life and	l i removal rates	shown in the	e preceding page	(AJ-3A).											
(a)		annual estimated deprec				-							***************************************				
	i ne total ex	xpense of \$8.8M is an an	nual estimate o	only to derive	the depreciation i	rate. The derived	rate is what a	ctually gen	erates the a	ctual dep	reciation expe	nse throughout	tne year.				

Depreciation & Amortization Workpapers for Common Plant

SAN DIEGO GAS & ELECTRIC COMPANY STATEMENT AJ DEPRECIATION AND AMORTIZATION EXPENSE TRUE UP PERIOD - 9/1/2013 TO 12/31/2013 PER BOOK (\$1,000)

COMMON PLANT

Line No.	Description	Total Common Expense to Electric Per Book	Reference From	Line No.
1	December 31, 2013 Expense	18,393	AJ1-Cwp1	1

Statement AJ - Workpapers

TO4 - Annual Common Plant Depreciation Rates

Cycle 2, For 12 - Months Ending December 31, 2013
For Use During the 12-Months Period from January 1 to December 31, 2013

2013 Common Rates 1, 2

		Rates based on 12/31/	2012 Plant	Balances		
			(a)	(b)	(c) = a + b	
Line	FERC		Life	Removal	Total	Line
No	Account	Description	Rate	Rate	Rate	No
1						1
2	C1839010	Struct & Imprv-Other	4.66%	0.46%	5.12%	2
3	C1839110	Offc Furn & Eq-Other	5.74%	0.00%	5.74%	3
4	C1839120	Offc Furn & Eq-Cmptr	19.40%	0.00%	19.40%	4
5	C1839220	Transprtn Eq-Trailer	32.11%	0.00%	32.11%	5
6	C1839310	Stores EquipOther	14.53%	0.00%	14.53%	6
7	C1839411	Portable Tools-Other	4.54%	0.00%	4.54%	7
8	C1839421	Shop Equip Other	4.86%	0.00%	4.86%	8
9	C1839431	Garage EquipOther	9.41%	0.00%	9.41%	9
10	C1839510	Laboratory EqOther	4.21%	0.00%	4.21%	10
11	C1839710	Commun. EquipOther	7.15%	0.00%	7.15%	11
12	C1839810	Misc. Equip Other	9.91%	0.00%	9.91%	12
13						13

The above Common Plant depreciation rates are applicable to SDG&E's 2013 calendar year recorded depreciation.

These rates may not be changed absent a section 205 or 206 filing.
The annual Information Filing will reference the docket number of the FERC proceeding that establishes new General Plant and Common Plant depreciation rates and Intangible Plant amortization periods.

							jo Gas & El		-								
		***************************************				2013 Comn	non Plant D)epreciat	ion Rate	s							
						*											
Line No	Asset Class	Description	Recorded Gross Plant as of (1/1/2013)	Future Net · Salvg Percent	Future Net Salvg Amount	Recorded Depreciation Reserve as of (1/1/2013)	Net Balance	Avg Svc Life & Iowa Curve	Average Service Life (Yrs)	AGE of Assets	Average Remaining Life	Fotal Annual Accrual Amount (a)	Total Annual Accrual Percent	Life Rate	COR (Removal Rate)	Total	Line No
1	C1839010	Struct & Imprv-Other	242,425,231	-10	(24,242,523)	(105,497,669)	161,170,085	26SQ	26	13.02	12.98	12,416,802	0.0512	4.66%	0.46%	5.12%	1
2	0.0000.0	Outdoo a mipri Outor		10	(24,242,020)	(100,407,000)	101,170,000	2000	20	13.02	12.50	12,410,002	0.0012	7.00/0	0.4070	0.12/0	2
3	C1839110	Offc Furn & Eq-Other	23,482,223	0	0	(9,999,944)	13,482,279	18SQ	18	8.00	10.00	1,348,228	0.0574	5.74%	0.00%	5.74%	3
4																	. 4
	C1839120	Offc Furn & Eq-Cmptr	71,095,233	0	0	(36,614,095)	34,481,138	5SQ	5	2.50	2.50	13,792,455	0.1940	19.40%	0.00%	19.40%	5
6	04000000			_													6
8	C1839220	Transprtn Eq-Trailer .	33,369	0	0	(6,584)	26,785	20SQ	20	17.50	2.50	10,714	0.3211	32.11%	0.00%	32.11%	7
_	C1839310	Stores EquipOther	144.926	0	0	(92,292)	52,634	20SQ	20	17.50	2.50	21,054	0.1453	14.53%	0.00%	14.53%	8
10	01000010	Otores EquipOtrei	144,320			(52,252)	32,034	2000	20	17.50	2.50	21,004	0.1433	14.00 /6	0.0076	14.55/6	10
	C1839411	Portable Tools-Other	1,193,702	0	0	(147,481)	1,046,221	23SQ	23	3.70	19.30	54,208	0.0454	4.54%	0.00%	4.54%	11
12						(,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,	.,,										12
13	C1839421	Shop Equip Other	248,289	.0	0	(142,125)	106,164	29SQ	29	20.20	8.80	12,064	0.0486	4.86%	0.00%	4.86%	13
14														2			14
	C1839431	Garage EquipOther	978,325	0	0	43,891	1,022,216	21SQ	21	9.90	11.10	92,092	0.0941	9.41%	0.00%	9.41%	15
16	C1839510	Laboratory EqOther	0.000.004	0	Ō	(000 000)	4 045 004	26SQ	26	11 70	14.30	04 440	0.0421	4.21%	0.00%	4.21%	16 17
18	01009010	Laboratory EqOther	2,236,234	U	U	(890,330)	1,345,904	203Q	20	11.70	14.50	94,119	0.0421	4.2170	0.00%	4.2170	18
	C1839710	Commun. EquipOther	112,129,060	0	0	(48,783,985)	63,345,075	13SQ	13	5.10	7.90	8,018,364	0.0715	7.15%	0.00%	7.15%	19
20		, , , , , , , , , , , , , , , , , , , ,	, ,, ,, ,,			(10)100(000)	00/010/010					5,0.0,00				111070	20
21	C1839810	Misc. Equip Other	2,472,920	10	247,292	(926,595)	1,299,033	14SQ	14	8.70	5.30	245,101	0.0991	9.91%	0.00%	9.91%	21
22																	22
23		Total	456,439,512		(23,995,231)	(203,057,209)	277,377,534				7.68	36,105,200	0.0791				23
\vdash	This workp	aper supports the life an	d removal rates	shown in th	e preceding page	(AJ-4B).						w.u.					
(a)	This is the	 annual estimated depred	ciation expense	based on th	l ne beginning of the	vear's net plan	t balances to d	erive the de	preciation r	ate to be a	oplied to the m	nonthly plant	balances				
		xpense of \$36.1M is an a												!			

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

Docket No. ER15-__-

Statement AK - Workpapers Taxes Other Than Income Taxes

For the 4-Month True-Up Period Ending December 31,2013 (\$1,000)

Line					Line
No.	_	Ar	nounts	Reference	No.
1 2	Total Property Taxes	\$	26,328	Stmt AK WP; Page AK-2A	1
3	Less: Other Taxes (Business license taxes)	M 25	(15)	Stmt AK WP; Page AK-1A	3
5 6	Net Property Taxes	\$	26,313	Line 1 Minus Lines 3	5 6
7 8	Less: SONGS Property Taxes		(1,792)	Stmt AK WP; Page AK-1A	7 8
9 10	Total Property Taxes Expense	\$	24,521	Line 5 Minus Line 7	9 10
11 12	Transmission Related Property Tax Allocation Factor		36.20%	Cost Statement AK; Pg 8 of 17; Line 25	11 12
13 14	Transmission Related Property Taxes Expense	\$	8,877	Line 9 x Line 11	13 14
15 16	Total Payroll Taxes Expense	\$	4,122	Stmt AK WP; Page AK-2A	15 16
17	,				17
18 19	Transmission Wages and Salaries Allocation Factor		17.51%	Statement AI; Line 19	18 19
20	Transmission Related Payroll Taxes Expense	\$	722	Line 16 x Line 18	20

Statement AK - Workpapers Taxes Other Than Income Taxes For 4-Months Ending - December 31, 2013 (\$1,000)

Line No.		A	mount	Reference	Line No.
1	Total Property Taxes	\$	26,328	See Footnote 1	1
2					2
3	Less: Other Taxes (Business license taxes)		(15)	See Footnote 1	3
4		-	-		4
5	Net Property Taxes	\$	26,313	Sum of Lines 1 thru 3	5
6	V 1000 V 1000 V 1000 V				6
7	Less: SONGS Property Taxes		(1,792)	See Footnote 2	7
8	•	************			8
9	Total Property Taxes Expense	\$	24,521	Line 5 Plus Line 7	9

The amount of property tax expense for the 4-months ending December 31, 2013 equals \$26.453 million and includes other taxes besides ad valorem tax. These other taxes consists of \$15K business license tax

The amount of property tax expense for the 4-months ending December 31, 2013 for the SONGS facilities is \$1.7 M.

Statement AK - Workpapers Taxes Other Than Income Taxes For 4-Months Ending - December 31, 2013 (\$1,000)

Line No.		A	amount	Reference	Line No.
1	Total Payroll Taxes	\$	4,122	See Note 1	1
3	Transmission Wages and Salaries Allocation Factor		17.51%	Statement AI; Line 19	3
4					4
5	Transmission Related Payroll Taxes Expense	\$	722	Line 1 x Line 3	5

The amount of payroll tax expense for the 4-months ending September, 2013 equals \$4.12 million

SDG8	kΕ				[
TO4 (Cycle 2 4-M	onth TU A	djustment	Workpap	er						
Netti	ng and Allo	cation of	Citizens Ad	ljustments							
Amou	ints in \$1,0	000									
Ln											
No.									,		
1	A. Netting	of Citizen	s Allocated	Property	Taxes fror	n Total Ele	ctric Divisi	on Pro	perty Taxe	es	
2						2.5					
3											
4	Total Elect	ric Division	Property	Taxes from	General L	.edger		\$	26,453		
5									,		
6	Less Citize	ns Allocate	Property	Tax page 1	1, col H, lir	ne 4		\$	(125)		
7											
8			Sum of Lin	e 4 and 6				\$	26,328		
9											
	B. Netting	of Citizen	s Payroll Ta	axes							
11											
12	Total Elect	ric Division	n Payroll Ta	ixes from G	General Lec	dger		\$	4,124		
13											
	Less Citize	ns Allocate	d Payroll T	axes page	11, col H,	line 5		\$	(2)		
15											
16			Sum of Lin	e 12 and 1	4			\$	4,122		
17											
18	C. Derivati						it,				
19	Working	Capital ar	d Franchis	e Fees Rev	enue Cred	it					
20	AU-	3 Page 10	11 line 1	7				\$	(46)		

San Diego Gas & Electric Company

True Up Period
Statement - AL
Working Capital
Workpapers

Docket No. ER15-__-

Statement AL - Workpapers Working Capital

For the 4-Month True-Up Period Ending December 31,2013 (\$1,000)

Line No.			orking Cash	-	Months age Balance	Reference	Line No.
1 2	A. Plant Materials and Operating Supplies ^a			\$	62,157	Stmt AL WP; Page AL-2	1 2
3	Transmission Plant Allocation Factor				36.04%	Stmnt AD WP; Page AD1; Line 39	3
5	Transmission Related Materials and Supplies			\$	22,401	Line 1 x Line 3	5
7	B. Prepayments ^a			\$	49,230	Stmt AL WP; Page AL-3	7
8 9 10	Transmission Related Prepayments			\$	17,742	Line 3 x Line 7	8 9 10
11 12 13 14 15	C. Derivation of Transmission Related Cash Working Capital - Retail: Transmission O&M Expense - Excl. Intervenor Funding Expense Transmission Related Administrative & General Expense CPUC Intervenor Funding Expense - Transmission Total	\$	26,677 35,284 - 61,961			Stmnt AH WP; Page AH1; Line 9 Stmnt AH WP; Page AH1; Line 56 Stmnt AH WP; Page AH1; Line 17 Sum Lines 12 thru 14	11 12 13 14 15
16 17	One Eighth O&M Rule Converted to 4 Months ^C		37.50%			4 Month T/U Proration Methond = 45 days /(360 x1/3)	16 17
18 19 20	Transmission Related Cash Working Capital - Retail Customers	\$	23,235			Line 15 x Line 17	18 19 20
21 22 23	D. Adj. to Back Out CPUC Intervenor Funding Exp. Embedded in Retail W. CPUC Intervenor Funding Expense - Transmission	orking C	Cash:			See Line 14 Above	21 22 23
24 25	One Eighth O&M Rule		37.50%			4 Month T/U Proration Methond = 45 days /(360 x1/3)	24 25
26 27	Adj. to Transmission Related Cash Working Capital - Wholesale Customers	\$	-			Line 22 x Line 24	26 27
28 29	Cost of Capital Rate (COCR)		11.3334%			Stmnt AV WP; Page AV2; Line 31	28 29
30	CPUC Intervenor Funding Exp. Revenue Adj. b	\$	-			Line 26 x Line 28	30

^a The balances for Materials & Supplies and Prepayments are derived based on a 5-month average balance.

This adjustment is being made to BK-2, page 1, line 6 to show that wholesale customers should not pay for this working cash item.

c To extent 12.50% amount is applicable to 12 month base period it has been adjusted to reflect 4 month TO4 Cycle 2 TU. This is reflected in Stmt AU Working Papers AU1C

SAN DIEGO GAS AND ELECTRIC COMPANY STATEMENT AL WORKING CAPITAL TRUE UP PERIOD - 9/1/2013 TO 12/31/2013 PER BOOKS (\$1,000)

ACCOUNT 154 PLANT MATERIALS AND OPERATING SUPPLIES ELECTRIC ALLOWABLE PER FERC FORMULA

			,
Line No.	Month	Total Electric Plant Materials & Supplies	Line No.
1	Aug-13	58,497	1
2	Sep	59,451	2
3	Oct	60,018	3
4	Nov	61,872	4
5	Dec-13	70,946	5
6	Total 5 Months	310,784	6
7			7
8			8
9	5-Month Average	62,157	9

SAN DIEGO GAS AND ELECTRIC COMPANY STATEMENT AL WORKING CAPITAL TRUE UP PERIOD - 9/1/2013 TO 12/31/2013 PER BOOKS (\$1,000)

ACCOUNT 165 PREPAYMENTS - ELECTRIC

Line No.	Month	Total Electric Plant Prepayments	Line No.
1	Aug-13	54,471	1
2	Sep	55,370	2
3	Oct	48,243	3
4	Nov	43,381	4
5	Dec-13	44,685	5
6	Total 5 Months	246,150	6
7			7
8	:	, , , , , , , , , , , , , , , , , , , ,	8
9	5-Month Average	49,230	9

San Diego Gas & Electric Company

True Up
Statement AM
Construction
Work In Progress
(CWIP)
Workpapers

Docket No. ER15-__-

Statement AM - Workpapers

Construction Work In Progress (CWIP)

For the 4-Month True-Up Period Ending December 31,2013 (\$1,000)

Line		13 Months		Line
No	_	Average Balance	Reference	No
1	Incentive Transmission Construction Work In Progress ^a	\$ -	Stmt AM WP; Page AM	1

^a The balance for Incentive Transmission Construction Work In Progress is derived based on a 13-month average balance. A line will be shown for each applicable project.

San Diego Gas & Electric Company

True Up
Statement - AQ
Federal Income
Tax Deductions Other than Interest
Workpapers

Docket No. ER15-___-

Statement AQ - Workpapers

Federal Income Tax Deductions, Other Than Interest

For the 4-Month True-Up Period Ending December 31,2013 (\$1,000)

Line			Line
No.	Amounts	Reference	No.
1 South Georgia Income Tax Adjustment	\$ 778	Stmt AQ WP; Page AQ-2	1

Statement AQ

Federal Income Tax Deductions, Other Than Interest For 4-Months Ending - December 31, 2013 (\$1,000)

Lin No		ä	Aı	mount	Reference	Line No.
1	South Georgia Income Tax Adjusment		\$	778.	Note 1	, 1

This amount come from the Tax Dept.

San Diego Gas & Electric Company

True Up
Statement - AR
Federal Income
Tax Adjustments
Workpapers

Docket No. ER15-___-

Statement AR - Workpapers

Federal Tax Adjustments

For the 4-Month True-Up Period Ending December 31,2013

(\$1,000)

Line No.		Amounts	Reference	Line No.
1 2	Transmission Related Amortization of Investment Tax Credits	\$ (88)	See Note 1	1 2
3	Transmission Related Amortization of Excess Deferred Tax Liabilities	(101)	See Note 1	3 4
5	Total	\$ (189)	Sum Lines 1; 3	5

1) These Numbers come from Tax Department

San Diego Gas & Electric Company

True Up
Statement - AU
Revenue Credits
Workpapers

Docket No. ER15-___-

Statement AU - Workpapers

Revenue Credits

For the 4-Month True-Up Period Ending December 31,2013 (\$1,000)

Line No.		Amounts	Reference	Line No.
1	(451) Miscellaneous Service Revenues		Stmt AU WP; Page AU-2	1
2				2
3	(453) Sales of Water and Water Power	ACCEPTANCE OF	Stmt AU WP; Page AU	3
4				4
5	(454) Rent from Electric Property	248	Stmt AU WP; Page AU-3	5
6				6
7	(455) Interdepartmental Rents		Stmt AU WP; Page AU	7
8				8
9	(456) Other Electric Revenues	1,252	Stmt AU WP; Page AU-3	9
10				10
11	Transmission Related Revenue Credits	\$ 1,499	Sum Lines 1 thru 9	11
12				12
13	(411.6 & 411.7) Gain or Loss From Sale of Plant Held for Future Use	\$ -	FERC Accounts 411.6 and 411.7	13

San Diego Gas and Electric Company Revenue Credits 12 Months Ending December 31, 2013

Line	SAP	FERC		(i)	(j)	(k)	(1)	(m)	Line
		1	CAD Assessed Description	155.000	10000	Nov-13		2	
No	Account#	Account#	SAP Account Description	Sep-13	Oct-13	Nov-13	Dec-13	Total	No
١, ١	1071010	454	D	m (100 (20)	0(10()	0 (04 005)	0 (0(10()	0 (10(070)	, ,
	4371049	454	Rents	\$ (120,432)	, , , , , , , , , , , , , , , , , , , ,				
2	4371050	454	Rent - Electric Property	(12,551)	(12,551)	(12,570)	(12,951)	(50,622)	_
3				(400.000)	(00.000	(0.000)	(20.0 0 = 4)	(2.47.700)	3
4			Total Rent from Electric Property	(132,983)	(38,676)	(36,864)	(39,076)	(247,599)	
5	,								5
6	4371016	456	Generation Interconnection	(118,663)	(33,425)			(161,479)	
7	4371040	456	Revenue Enhancement	(1,637)	(1,703)	(27)		(3,368)) 7
8	4371055	456	Shared Asset Revenue	(325,215)	(35,242)	(95,469)	(231,214)	(687,140)	8
9	4371058	456	Elec Trans Joint Pole Activity		(13,648)			(13,648)	9
10	4371061	456	Excess Microwave Capacity - Elec Trans	(1,439)	(1,439)	(1,439)	(1,439)	(5,754)) 10
11	4371065	456	Trans Revenue Trsfr to Gen				(61,000)	(61,000)) 11
12	4371067	456	Trans Revenue Trsfr to Dist				(405,000)	(405,000)) 12
13	4371070	456	Trans Revenue Trsfr from Dist				52,000	52,000	13
14	4371076	456	Environmental Lab - Elec Tran	(346)		(2,193)	(1,617)	(4,157)) 14
15	4371082	456	Other Elec Rev-SDGE Gen	104,000				104,000	15
16	4371806	456	Elec-Trans Fees/Rev	(20,000)				(20,000)) 16
17		456	Elec- Trans Rev- Citizens				(46,309)	(46,309)) 17
18									18
19			Total Other Electric Revenues	(363,300)	(85,456)	(105,503)	(697,596)	(1,251,855)) 19
20									20
21	Total Misce	llaneous Rev	renue	\$ (496,283)	\$ (124,132)	\$ (142,367)	\$ (736,672)	\$ (1,499,454)) 21
				,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,	, , , , , , ,		,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,		Ħ

SDG8	šЕ										
TO4 (Cycle 2 4-N	onth TU A	djustment	Workpap	er						
Netti	ng and All	ocation of	Citizens Ac	ljustments							
Amo	unts in \$1,	000									
Ln										•	
No.											
1	A. Netting	g of Citizen	s Allocated	d Property	Taxes from	n Total Ele	ctric Divisi	on Pr	operty Tax	es	
2											
3											
	Total Elec	tric Divisio	n Property	Taxes fron	General L	.edger		\$	26,453		
5									* v		
6	Less Citize	ns Allocate	Property	Tax page 1	1, col H, lir	ne 4		\$	(125)		
7											
8			Sum of Lir	e 4 and 6				\$	26,328		
9										ė.	
	B. Netting	of Citizen	s Payroll T	axes							
11											
12	Total Elec	tric Divisio	n Payroll Ta	xes from (General Le	dger		\$	4,124		
13											
14	Less Citize	ns Allocate	ed Payroll T	axes page	11, col H,	ine 5		\$	(2)		
15											
16			Sum of Lin	e 12 and 1	.4			\$	4,122		
17											
18			ens allocate				nt,				
19	Working	g Capital ar	nd Franchis	e Fees Rev	enue Cred	it					
20	AU-	3 Page 10	fl Line 1	2				\$	(46)		
	.,,,,,										

AU-3A

	A	В	С	D	E	F	G	Н	
	A	ь	<u> </u>	D	14	<u> </u>	3		
Ln			Prepaid ²						Ln
No.	Description		Lease Amt						No.
	Citizens Border-East Line Prepaid Lease Cost -Cycle 2		39,320,000						1
	These amounts are used as recorded revenues in the true-up adjustment	**************************************	2	D = C /			Col. G =		
	calculations.			11 Months	X		D + E + F		
		C2	Total		Allocation 4			H=	
		Carrying	C2 Annual	C2 Monthly	of C2 TUP	Allocation of		G * 4 Months	\Box
		Charge	Billing	Billing	(Over) / Under-	Monthly Interest	Monthly	Sept - Dec	
2	Allocation of Non-Direct O&M Expense & Other Specific Cost	Rates	Amount	Amount	collection	(204.67)	Costs	2013	2
			Col. C=						
3	Part A. Statement AK Adjustments		Col. B * \$39.2M						3
									igsquare
4	Property Taxes ³		255,608	23,237	7,926	(24.69)	31,139	124,555	4
5	Transmission Related Payroll Carry Charge Rate	0.06%	23,592	2,144.73	(1,564.73)	(0.04)	580	2,320	5
6	Part B. Statement AU Adjustments								6
020									
7	Transmission Related Gen & Common Plt Carry Charge Rate	0.56%	220,192	20,017.45	(12,490.01)	(0.47)	7,527	30,108	7
8	Transmission Related Working Capital Revenue Carry Charge Rate	0.15%	58,980	5,361.82	(1,714.56)	(0.12)	3,647	14,589	8
_					4440.00				-
9	Franchise Fees Rate Charge	0.03%	11,796	1,072.36	(669.08)	(0.02)	403	1,613	9
10			200.060	26.450	(7.1.07.1)	/45	11.555	46,000	10
10	Total Direct and Non-Direct O&M Costs Sum(L7:L9)		290,968	26,452	(14,874)	(1)	11,577	46,309	10
<u></u>								150 104	-
_	Grand Total							173,184	
_									+
-	C'' C 1 0 F'' D 1 1 1 T D 12 1 C C C C C 1 1 1 1 2 C C C C C C C								+
1	Citizens Cycle 2 Filing Docket No. ER13-1596-000, dated June 28, 2013	5. 							-
_	Q.I.O.I. 14 000 200; III. Q	1 O'': T	(m) (200 200 4 : 11	1 1 1 1	C''. 1 T	<u> </u>	F - 1	-
	Col. C, line 1 the \$39,320 million reflects a weighted average of \$85,194 and Other Costs - see Attachment 2, Section 2, Page 1 of 7, line 43. And								+
	and Other Costs - see Attachment 2, Section 2, Page 1 of 7, fine 43. And	used to allo	Take the above non	-анест сотгроне	nts using the applic	able charge rates sho	wh in Colum	n A.	+
-2	See Attachment 2, Statement BK2, Section 3 - Part B, Page 1 of 2. Propo	erty Tayes /	Montad to Citizan	 					+
3	oce Attachment 2, Statement BK2, Section 3 - Part B, Page 1 of 2. Propi	City Taxes F	Inocated to Citizen					 	+-
1	See Attachment 3, Derivation of True-Up Adjustment (July 2012- Dec 2	013) Colur	nn G line 16						+-
+		, , Coim	O, IIIO 10.						+-
5	See Cycle 2 TUP Adjustment calculation allocation of over-collection as	nd interest							-
٢	1 Company and the state of the								1
-	Col. H reflects Citizens Billing Invoice for Jul - Dec 2013	1				<u> </u>	1	 	+

AU-3 B

San Diego Gas & Electric Company

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

Docket No. ER15-___-

Statement AV - Workpapers

Cost of Capital and Fair Rate of Return

For the 4-Month True-Up Period Ending December 31,2013 (\$1,000)

Line No.		Amounts	Reference	Line No.
1 2 3 4 5 6 7	Long-Term Debt Component - Denominator: (Plus) Bonds (Acct. 221) (p112.Line18c) (Less) Reacquired Bonds (Acct. 222) (p112.Line19c) (Plus) Other Long-Term Debt (Acct. 224) (p112.Line21c) (Plus) Unamortized Premium on Long-Term Debt (Acct 225) (p112.Line22c) (Less) Unamortized Discount on Long-Term Debt-Debit (Acct 226) (p112.Line23c) LTD = Long Term Debt (p112, sum of Line17d thru Line22d, details on p256-257)	\$ 3,926,855 - 123,900 - 10,953 \$ 4,039,802	Form 1; Page 112; Line 18c Form 1; Page 112; Line 19c Form 1; Page 112; Line 21c Form 1; Page 112; Line 22c Form 1; Page 112; Line 23c Line 2 Minus Line 3 Plus Lines 4 & 5 Minus Line 6	1 2 3 4 5 6 7
8 9 10 11 12 13 14 15	Long-Term Debt Component - Numerator: (Plus) Interest on Long-Term Debt (427) (p117.Line62c) (Plus) Amort. of Debt Disc. and Expense (428) (p117.Line63c) (Plus) Amortization of Loss on Reacquired Debt (428.1) (p117.Line64c) (Less) Amort. of Premium on Debt-Credit (429) (p117.Line65c) (Less) Amortization of Gain on Reacquired Debt-Credit (429.1) (p117.Line66c) i = LTD interest (p117, sum of Line56c thru Line60c, details on p257))	\$ 186,465 3,084 2,537 - - \$ 192,086	Form 1; Page 117; Line 62c Form 1; Page 117; Line 63c Form 1; Page 117; Line 64c Form 1; Page 117; Line 65c Form 1; Page 117; Line 66c Sum Lines 10; 11; 12 Minus Lines 13 & 14	8 9 10 11 12 13 14 15
16 17 18 19 20 21 22	Cost of Long-Term Debt: Preferred Equity Component: PF = Preferred Stock - Acct 204 (p112.3c) d(pf) = Total Dividends Declared-Preferred Stocks (Acct. 437) (p118.29c) Cost of Preferred Equity	\$ - \$ 1,205 0.00%	Line 15 / Line 7 Form 1; Page 112; Line 3c Form 1; Page 118; Line 29c Line 21 / Line 20	16 17 18 19 20 21 22
23 24 25 26 27 28 29 30	Common Equity Component: Proprietary Capital (p112.16c) (Less) Preferred Stock - Acct 204 (p112.3c) (Less) Unappropriated Undistributed Subsidiary Earnings (Acct. 216.1) (p112.12c) (Less) Accumulated Other Comprehensive Income (Acct. 219) (p112.15c) CS = Common Stock	\$ 4,629,716 - - 9,010 \$ 4,620,706	Form 1; Page 112; Line 16c Form 1; Page 112; Line 3c Form 1; Page 112; Line 12c Form 1; Page 112; Line 15c Line 25 Minus Lines 26, 27 & 28	23 24 25 26 27 28 29 30
31 32 33	Return on Common Equity: (a) (b) (c) Cap. Struct. Cost of	$\frac{10.05\%}{\text{(d) = (b) x (c)}}$ Weighted	Offer of Settlement in FERC Docket No. ER13-941-001	31 32 33
34 35 36 37 38 39 40	Weighted Cost of Capital: Amount ¹ Ratio Capital Long-Term Debt \$ 4,039,802 46.65% 4.75% Preferred Equity - 0.00% 0.00% Common Equity 4,620,706 53.35% 10.05% Total Capital \$ 8,660,508 100.00%	<mark>6</mark> 0.00%	Col. C = Line 17 Above Col. C = Line 22 Above Col. C = Line 31 Above Sum Lines 36 thru 38	34 35 36 37 38 39 40
41 42 43	Cost of Equity Component (Preferred & Common):	5.36%	Sum Lines 37; 38; Col. (d)	41 42 43
44 45 46 47	Incentive Return on Common Equity: ² (a) (b) (c) Cap. Struct. Cost of Weighted Cost of Capital: Amount ¹ Ratio Capital	(d) = (b) x (c) Weighted Cost of Capital	Stmt AV WP; Page AV	44 45 46 47
48 49 50 51 52	Long-Term Debt \$ 4,039,802 46.65% 4.75% Preferred Equity - 0.00% 0.00% Common Equity 4,620,706 53.35% 0.00% Total Capital \$ 8,660,508 100.00%	<mark>6</mark> 0.00%	Col. C = Line 17 Above Col. C = Line 22 Above Col. C = Line 44 Above Sum Lines 49 thru 51	48 49 50 51 52
53 54	Incentive Cost of Equity Component (Preferred & Common):	0.00%	Sum Lines 50; 51; Col. (d)	53 54

Amount is based upon December 31 balances.

The Incentive Return on Common Equity will be tracked and shown separately for each project. As a result, lines 44 through 54 will be repeated for each project.

Statement AV

Cost of Capital and Fair Rate of Return For the 4-Month True-Up Period Ending December 31,2013 (\$1,000)

Line			D. 0	Line
No.	<u>-</u>	Amounts	Reference	No.
1	Cost of Capital Rate (COCR) Calculation:			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	5.36%	Stmnt AV WP; Page AV1; Line 41	6
7	B = Trans. Related Amort. of ITC and Excess Deferred Tax Liab.	\$ 567	Statement AR; Page 12; Line 5	7
8	C = Equity AFUDC Component of Transmission Depreciation Expense	\$ 4,175	Stmt AV WP; Page AV-1A	8
9	D = Transmission Rate Base	\$ 2,830,609	Statement BK1; Page 2; Line 26	9
10	FT = Federal Income Tax Rate @ 35%	35%	Federal Income Tax Rate	10
11				11
12	Federal Income Tax = $(((A) + (C/D)) * FT) - (B/D)$	2.9348%	Federal Income Tax Expense	12
13	(1 - FT)			13
14				14
15	B. State Income Tax Component:			15
16				16
17	Where:			17
18	A = Sum of Preferred Stock and Return on Equity Component	5.36%	Stmnt AV WP; Page AV1; Line 41	18
19	B = Equity AFUDC Component of Transmission Depreciation Expense	\$ 4,175	Line 8 Above	19
20	C = Transmission Rate Base	\$ 2,830,609	Statement BK1; Page 2; Line 26	20
21	FT = Federal Income Tax Expense	2.9348%	Line 12 Above	21
22	ST = State Income Tax Rate @ 8.84%	8.84%	State Income Tax Rate	22
23				23
24	State Income Tax = $((A) + (B / C) + Federal Income Tax)*(ST)$	0.8187%	State Income Tax Expense	24
25	(1 - ST)			25
26				26
27	C. Total Federal & State Income Tax Rate:	3.7534%	Sum Lines 12; 24	27
28				28
29	D. Total Weighted Cost of Capital:	7.5800%	Stmnt AV WP; Page AV1; Line 39	29
30				30
31	E. Cost of Capital Rate (COCR):	11.3334%	Sum Lines 27; 29	31

Statement AV

Cost of Capital and Fair Rate of Return For the 4-Month True-Up Period Ending December 31,2013 (\$1,000)

Line				Line
No.		Amounts	Reference	No.
	-			
1	Incentive Cost of Capital Rate (ICOCR) Calculation: 1			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	0.00%	Stmnt AV WP; Page AV1; Line 54	6
7	B = Trans. Related Amort. of ITC and Excess Deferred Tax Liab.	0	Shall be Zero for Incentive ROE Projects	7
8	C = Equity AFUDC Component of Transmission Depreciation Expense	\$	Stmt AV WP; Page AV	8
9	D = Incentive ROE Project Transmission Rate Base	\$ -	Statement BK1; Page 2; Line 31	9
10	FT = Federal Income Tax Rate @ 35%	35%	Stmnt AV WP; Page AV2; Line 10	10
11				11
12	Federal Income Tax = $(((A) + (C/D)) * FT) - (B/D)$	0.0000%	Federal Income Tax Expense	12
13	(1 - FT)			13
14				14
15	B. State Income Tax Component:			15
16				16
17	Where:			17
18	A = Sum of Preferred Stock and Return on Equity Component	0.00%	Stmnt AV WP; Page AV1; Line 54	18
19	B = Equity AFUDC Component of Transmission Depreciation Expense	\$ -	Line 8 Above	19
20	C = Incentive ROE Project Transmission Rate Base	\$ -	Line 9 Above	20
21	FT = Federal Income Tax Expense	0.0000%	Line 12 Above	21
22	ST = State Income Tax Rate @ 8.84%	8.84%	Stmnt AV WP; Page AV2; Line 22	22
23				23
24	State Income Tax = $((A) + (B/C) + Federal Income Tax)*(ST)$	0.0000%	State Income Tax Expense	24
25	(1 - ST)			25
26				26
27	C. Total Federal & State Income Tax Rate:	0.0000%	Sum Lines 12; 24	27
28				28
29	D. Total Incentive Weighted Cost of Capital:	2.2200%	Stmnt AV WP; Page AV1; Line 52	29
30				30
31	E. Incentive Cost of Capital Rate (ICOCR):	2.2200%	Sum Lines 27; 29	31

The Incentive Cost of Capital Rate Calculation will be tracked and shown separately for each project. As a result, lines 3 through 31 will be repeated for each project. However, this will be entered as 0% in BK-1 when there's no incentive project to show.

San Diego Gas & Electric Company **Equity AFUDC Component of Transmission Depreciation Expense** For Completed Transmission Capital Projects from 2001 Through 2013 Applicable to the 2013 TO4-Cycle 2 Base Period 1 For the 12-Month Period Ending December 31, 2013 (\$1,000) В \mathbf{C} D A **Equity AFUDC Component of AFUDC** Equity in Line Line Transmission Depreciation AFUDC in Plant Vintages of Plant **Plant Cost** Expense No. No. 2 2001 \$ 2,152 1,501 41 2 3 3 4 2002 4,222 2,968 78 4 5 5 2003 3,164 2,260 6 59 6 7 8 2004 4,321 3,166 85 8 9 9 10 2005 3,307 2,404 74 10 11 11 2006 5,324 12 3,752 123 12 13 13 2007 14 8,514 6,122 168 14 15 15 2008 16 11,899 8,607 240 16 17 17 18 2009 3,991 2,925 92 18 19 19 20 2010 104 4,778 3,471 20 21 21 22 2011 4,756 3,398 98 22 23 23 24 2012 183,838 131,336 24 3,066 25 25 26 2013 9.999 7,188 26 27 27 28 28 29 \$ 250,266 179,098 Total 4,325 29 30 30 Citizens' Adjustment (149)31 31 32 32 AFUDC Equity Depreciation Expense - Net of AFUDC Equity Depreciation Expense on Assets Leased to Citizens Sunrise. 33 4,175 33 34 34 The above schedule calculates the AFUDC equity in depreciation used in Statement AV to calculate the Federal and State Income Taxes as reflected in the TO4 Formula. This equity AFUDC component of transmission depreciation expense is derived as follows: Col. A - reflects the years that were taken into consideration to develop the table. The table begins in 2001 because all the data needed was not available until 2001 in SAP (SDG&E's general accounting system). Col. B - reflects the total AFUDC in plant additions that went into service in each year as indicated. Col. C - represents the AFUDC equity embedded in Col. B for each year. Col. D - line 29 represents the annual amortization of Col. C that is embedded in SDG&E's annual transmission depreciation expense. As a result, the total of Col. D, Line 29, reflects the total equity AFUDC component of transmission depreciation expense for the 2013 base period.

The \$4.175 million in Column D, Line 33, is also used to derive the 4-month True-Up Adjustment, as it is pro-rated down to reflect a 4-month amount when the annual rate of return as shown in BK1, Page 1 of 6, line 24, is multiplied by 33.33%, to reflect that this is only for a 4-month true-up cost of service.

Section -2

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

Section 2.2

Summary of Monthly Retail True-Up
Recorded Revenues

Docket No. ER14-__-

San Diego Gas Electric Co. TO4 - RETAIL True-Up Adjustment Calculation Sept 1, 2013- Dec 31, 2013

		1										
Line	TO4-Formula Cycle in Effect	Current Cycle	T	Current Cycle	(Current Cycle	Current Cycle	Cı	arrent Cycle	Current Cycle	Current Cyc	e
No.	Description	Jan	_	Feb		Mar	Apr		May	Jun	Jul	
1	Beginning Balance (Overcollection)/Undercollection:	s -		s -	\$		s -	\$		\$ -	S	_
2	Segmining Bulance (overconceason), endorconcensus				7			100				
3	Total Recorded Retail Revenues @ Meter Level 1	\$	5	3	\$	Mark Leading	\$	\$		\$ -	\$	-
4												
5	Amortization of True-Up Adjustment and Interest True-Up Adjustment:											
_ 6	a) Amortization of Prior Cycle True-Up Adjustment and Prior Interest True-Up Adjustment:					2 - 2 - 2 - 2 - 2 - 2 - 2 - 2 - 2 - 2 -	Automobile State of Cont.	7/2-1			NAME OF TAXABLE PARTY.	-
7	i. Amortization of Prior Cycle True-Up Adjustment. 2	\$ -	3		\$		\$	\$		\$	\$	-
8	ii. Amortization of Prior Interest True-Up Adjustment. 2	\$		3	\$	E 100 1 - 11	\$	\$	A Property of	\$	\$	=
9												
11			-									
12												
13	,											
14	Total Amortization of True-Up Adjustments & Interest True-Up Adjustment	\$ -	5	\$ -	\$		\$ -	\$	-	\$ -	\$	•
15			_									_
16	Adjusted Total Recorded Retail Revenues @ Meter Level 3	\$ -		-	\$	-	\$ -	\$		\$ -	\$	-
17		Openia - Connectant				The second second				0		- 100
18 19	Total True-Up Revenues (TU Cost of Service)	\$	26 8	Separate Services	\$		\$	\$	the second	\$	\$	=
20	Net Monthly (Overcollection)/Undercollection:	\$ -		§ -	\$		\$ -	\$	-	\$ -	S	-
21	recentification, onderconcerton.		+	,	Ψ		"					
22	Interest Expense Calculations:											
23	Beginning Balance for Interest Calculation	\$ -	5		\$	1 - 1 - 2	\$ -	\$	-	\$ -	\$	*
24	Monthly Activity Included in Interest Calculation Basis		0	0		0	0		0	0		0
25	Basis for Interest Expense Calculation		0	0		0	0		0	0		0
26 27	Monthly Interest Rate Interest Expense	\$ -		0.25%	\$	0.28%	\$ -	\$	0.28%	0.27% \$ -	S	.28%
28	Interest Expense	a -	+	· -	Φ		5 -	Φ		3 -	9	
	Ending Balance (Overcollection)/Undercollection:	\$ -	- 5	5 -	\$	*	\$ -	\$	*	s -	\$	-
30			T									
31		Jan		Feb		Mar	Apr		May	Jun	Jul	
32	FERC INTEREST RATE 4	3.25	1%	3.25%		3,25%	3,25%		3.25%	3,25%	3	.25%
	Days in Year	3	65	365		365	365		365	365		365
34	Days in Month ⁵		31	28		31	30		31	30		31
35	Monthly Interest Rate - Calculated	0.28	3%	0.25%		0.28%	0.27%		0.28%	0.27%	0	.28%
36	FERC Interest Rates - Website ⁴	0.28		0.25%	- Unit	0.28%	0.27%		0.28%	0.27%		,28%
37	Difference	0.00)%	0.00%		0.00%	0.00%		0.00%	0.00%	0	.00%
	NOTEC.				_							
A	NOTES:	-	-									
	The above format of the True-Up Adjustment Calculation will be used for each cycle,											
	with the exception of the cycle 2 4-month true-up adjustment. For the cycle 2 True-Up											
	Adjustment, the above format will be used for the months of Sep 2013 - Dec 2013.											
1	For the Retail True-Up Adjustment Calculation, the Recorded Retail Revenues are											
	measured at the Meter Level.											
2	The amortization of prior cycle True-Up Adjustment and prior Interest True-Up											
3	Adjustment will be repeated as needed in deriving the True-Up Adjustment.		-									
	For the Retail True-Up Adjustment Calculation, the Adjusted Total Recorded Retail Revenues are measured at the Meter Level.											
4	The FERC interest rate information comes from the FERC website.		+									
5	These are fixed days for each month except February for leap vs. non-leap years.											_
(80	riese are fixed days for each month except rebruary for leap vs. non-leap years.											

San Diego Gas Electric Co. TO4 - RETAIL True-Up Adjustment Calculation Sept 1, 2013- Dec 31, 2013

Line TO4-Formula Cycle in Effect	Cı	ırrent Cycle	C	urrent Cycle	(Current Cycle	С	urrent Cycle	C	urrent Cycle				Line
No. Description		Aug		Sep		Oct		Nov		Dec		Total	Reference	No.
	0		\$		S	5 555 221	\$	4,382,166	ф	5 250 011			7	1
1 Beginning Balance (Overcollection)/Undercollection:	2		2	3	Þ	5,555,321	2	4,382,100	2	5,250,011	_		Previous Month's Balance	2
3 Total Recorded Retail Revenues @ Meter Level 1	0		\$	61.573.513	0	52,003,761		47,551,335	0	48.073.217	Ф.	209,201,826	C D1. 1W 1D D 1:	3
4 Total Recorded Retail Revenues @ Meter Level	9		Ф	61,5/5,515	D.	52,005,761	9	47,331,333	D .	48,075,217	2	209,201,826	See Related Work Papers; Pages; Lines.	4
5 Amortization of True-Up Adjustment and Interest True-Up Adjustment:					-									5
6 a) Amortization of Prior Cycle True-Up Adjustment and Prior Interest True-Up Adjustment:														6
7 i. Amortization of Prior Cycle True-Up Adjustment. ²	\$		\$		\$		\$		\$		s	_	See Related Work Papers; Pages; Lines.	7
8 ii. Amortization of Prior Interest True-Up Adjustment. ²	\$		S		S		S		S		\$		See Related Work Papers; Pages; Lines.	8
9	9		φ		Ψ		ų.		Ψ		φ		See Related Work Papers, Pages, Lines.	9
10														10
11														11
12														12
13														13
14 Total Amortization of True-Up Adjustments & Interest True-Up Adjustment	\$		\$	-	\$	-	\$	-	\$	-	\$	-1	Sum Lines 7 through 12	14
15														15
16 Adjusted Total Recorded Retail Revenues @ Meter Level 3	\$		\$	61,573,513	\$	52,003,761	\$	47,551,335	\$	48,073,217	\$	209,201,826	Sum Lines 3 & 14	16
17			1 -0/-			TOTAL TRANSPORT OF TAXABLE		Total William Programme				CAUSE 1417 1517 1517 1517 1517 1517 1517 1517		17
18 Total True-Up Revenues (TU Cost of Service)	\$		\$	67,121,344	\$	50,816,713	\$	48,406,232	\$	48,826,218	\$	215,170,507	See Related Work Papers; Pages; Lines.	18
19			\$	5 5 4 5 0 2 1	_	(1.105.040)	Φ.	054.005		752.001		5.060.601		19
20 Net Monthly (Overcollection)/Undercollection:	\$	-	\$	5,547,831	\$	(1,187,048)	\$	854,897	\$	753,001	\$	5,968,681	Line 18 Minus Line 16	20
22 Interest Expense Calculations:	-				-						_			22
23 Beginning Balance for Interest Calculation	0	All the second	\$		0	5.555.321	•	5,555,321	\$	5.555.321	_		Beginning Quarterly Balances	23
24 Monthly Activity Included in Interest Calculation Basis	Ψ	0	Ψ	2,773,916	9	(593,524)	Ψ	(759,600)	Ψ	44,349			Interest Calculation Basis	24
25 Basis for Interest Expense Calculation		0		2,773,916		4,961,797		4,795,721		5,599,670			Sum Lines 23 & 24	25
26 Monthly Interest Rate		0.28%		0.27%		0.28%		0.27%		0.28%			FERC Monthly Rates	26
27 Interest Expense	\$		\$	7,490	\$	13,893	\$	12,948	\$	15,679	\$	50,010	Line 25 x Line 26	27
28														28
29 Ending Balance (Overcollection)/Undercollection:	\$	19	\$	5,555,321	\$	4,382,166	\$	5,250,011	\$	6,018,691	\$	6,018,691	Sum Lines 1; 20; & 27	29
30														30
31		Aug		Sep		Oct		Nov		Dec				31
32 FERC INTEREST RATE ⁴	i illisi	3.25%		3.25%	majori	3.25%		3,25%		3.25%			Annual Interest Rate - FERC Website	32
33 Days in Year		365		365		365		365		365		365	Line 34 Below Total Col.	33
34 Days in Month ⁵		31		30		31		30		31		365	Number of Days Per Month	34
35 Monthly Interest Rate - Calculated		0.28%		0.27%		0.28%		0.27%		0.28%		3.29%	(Line 32)/(Line 33)x(Line 34)	35
36 FERC Interest Rates - Website 4		0.28%	Mile-	0.27%	I NE	0.28%		0.27%		0.28%		3.29%	Monthly Interest Rate - FERC Website	36
37 Difference		0.00%		0.00%		0.00%		0.00%		0.00%		0.00%	Line 35 - Line 36	37
NOTES:														
A										2				1
The above format of the True-Up Adjustment Calculation will be used for each cycle,														
with the exception of the cycle 2 4-month true-up adjustment. For the cycle 2 True-Up														
Adjustment, the above format will be used for the months of Sep 2013 - Dec 2013. For the Retail True-Up Adjustment Calculation, the Recorded Retail Revenues are									_					+-
measured at the Meter Level.														
² The amortization of prior cycle True-Up Adjustment and prior Interest True-Up														-
Adjustment will be repeated as needed in deriving the True-Up Adjustment.														
³ For the Retail True-Up Adjustment Calculation, the Adjusted Total Recorded Retail														
Revenues are measured at the Meter Level.														
The FERC interest rate information comes from the FERC website.														
These are fixed days for each month except February for leap vs. non-leap years.														
The state of the s														

Section 2.2 SAN DIEGO GAS AND ELECTRIC COMPANY Monthly Retail True-Up Period Recorded Revenues 4-Month True-Up Period (September 1, 2013 - December 31, 2013)

		(A)	(B)	(C)	(D)	(g)	(h)	
Line No.	Customer Class	Sep-13	Oct-13	Nov-13	Dec-13	Sub - Total	Reference	Line No.
1 2	Residential Customers	\$ 24,753,295	\$ 19,673,789	\$ 17,929,159	\$ 20,982,803	\$ 83,339,046	Recorded Per Books	1 2
3 4	Small Commercial	7,291,997	6,274,228	5,947,696	5,393,462	24,907,382	Recorded Per Books	3 4
5	Medium-Large Commercial	28,561,753	25,231,277	22,822,504	20,467,409	97,082,942	Recorded Per Books	5 6
7 8	Street Lighting	216,871	134,018	179,665	239,601	770,155	Recorded Per Books	7 8
9	Standby Revenues	749,596	690,451	672,311	. 989,943	3,102,301	Recorded Per Books	9 10
11	TOTAL Recorded	\$ 61,573,513	\$ 52,003,761	\$ 47,551,335	\$ 48,073,217	\$ 209,201,826	Sum Lines 1; 3; 5; 7; 9	11

Section -2

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

Section 2.3

Derivation of Retail True-Up

Cost of Service

Docket No. ER14- -

SAN DIEGO GAS & ELECTRIC COMPANY

Transmission Revenues Data to Reflect Changed Rates

Comparison of Revenues

Recorded Billing Determinants

		(a)	(b)	(c) = (a) - (b)	(d) = (c)/(a)		
Line	1000	Transmission Revenues	True-Up Period				Line
No.	Customer Classes	@ Proposed Rates	Total Cost of Service	(\$) Change	(%) Change	Reference	No.
	Residential Customers	\$ 89,884,953	\$ 89,884,953	\$ (0)	0.00%	, , ,	1
3	Small Commercial Customers	25,064,995	\$ 25,064,995	\$ (0)	0.00%	(b)=Section 2.3.1; Page 2; Line 4 (a)=Section 2.3.2; Page 2; Line 3	3
5	Medium-Large Commercial Customers	96,199,281	\$ 96,199,281	\$ 0	0.00%	(b)=Section 2.3.1; Page 2; Line 5 (a)=Section 2.3.2; Page 2; Line 5	5
6 7	Street Lighting Customers	785,437	\$ 785,437	\$ (0)	0.00%	(b)=Section 2.3.1; Page 2; Line 6 (a)=Section 2.3.2; Page 2; Line 7	6 7
8 9	Standby Customers	3,235,841	\$ 3,235,841	\$ 0	0.00%	(b)=Section 2.3.1; Page 2; Line 7 (a)=Section 2.3.2; Page 2; Line 9	8 9
10						(b)=Section 2.3.1; Page 2; Line 8	10
11	Grand Total	\$ 215,170,507	\$ 215,170,507	\$ (0)	0.00%	Sum Lines 1 through 9	11

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 the True-Up Period - (September 1, 2013 - December 31, 2013)

			(A)		(B)	ĵ	(C)		(D)	(E	E)		(F)		(G)		(H)	(I)	(J)	(K)	(L)	(M)	
		J	an-13	F	eb-13	M	ar-13	A	pr-13	May	y-13	Ju	n-13	J	lul-13	I	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13		
Line	Season												2.5		name of consultations and a	4 10:5 Set U.Ar 2:222		Control of the contro					Line
No.	Customer Class			100000 %																		Total	No.
1 2	Residential Customers ¹	\$		\$	5	\$	à	\$	=	\$	×	\$	=0	\$	×	\$		\$ 27,406,919	\$ 20,986,547	\$ 19,118,029	\$ 22,373,458	\$ 89,884,953	1 2
3 4	Small Commercial ²		:		-		-	d.	-		-		•		-		·-	7,280,404	6,329,593	6,005,075	5,449,923	25,064,995	3
5 6	Medium-Large Commercial ³		-		-		Œ				Ħ		+		~		-	31,386,736	22,559,985	22,299,723	19,952,836	96,199,281	5
7 8	Street Lighting ⁴				-				-		-		=		-		.=	232,371	136,103	178,919	238,044	785,437	7 8
9	Standby Revenues 5		~		-		-		_		-		wii				-	814,913	804,485	804,485	811,957	3,235,841	9
10	TOTAL	\$	÷	\$	=	\$	-	\$	-	\$	¥	\$		\$	_	\$	-	\$ 67,121,344	\$ 50,816,713	\$ 48,406,232	\$ 48,826,218	\$ 215,170,507	10

NOTES:

- See Pages 3 & 4; Line 25.
- See Pages 3 & 4; Line 27.
- See Pages 3 & 4; Lines 29 through 33.
- See Pages 3 & 4; Line 35.
- ⁵ See Pages 3 & 4; Line 37.

SAN DIEGO GAS AND ELECTRIC COMPANY

Derivation of Monthly Retail Cost of Service

Revenues for True-Up Period Using Retail Rates Developed in Section 2.3.1

For the True-Up Period - (September 1, 2013 - December 31, 2013) (D) (E) (F) (A) (B) (C) Jan-13 Feb-13 Mar-13 Apr-13 May-13 Jun-13 Billing Determinants Billing Determinants Line Billing Determinants Billing Determinants Billing Determinants Billing Determinants Line Energy (kWh) Demand (kW) No. Customer Classes Energy (kWh) Demand (kW) No. 1 Residential Customers 2 2 Small Commercial 3 4 4 5 5 Medium-Large Commercial Non-Coincident (100%) 6 6 Non-Coincident (90%) 7 Maximum On-Peak Period Demand 8 8 9 Maximum Demand at the Time of System Peak 9 10 10 11 Street Lighting 11 12 12 13 Standby Customers 13 14 14 15 TOTAL 15

NOTES: The above billing determinants are the recorded determinants from January 2013 through December 2013

		(A))	(B))	(C)	74	(D)		(E)	(F))	
		Jan-	13	Feb-	13	Mar-	13	Apr-	13	May-	13	Jun-	13	
Line		Changed Transr		Changed Transi	nission Rates	Changed Transr	nission Rates	Changed Transr	nission Rates	Changed Transi	nission Rates	Changed Transi	mission 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)	No.
16 17	Residential Customers ¹	\$ 0.0357211750		\$ 0.0357211750		\$ 0.0357211750		\$ 0.0357211750		\$ 0.0357211750		\$ 0.0357211750		16
18 19	Small Commercial 1	\$ 0.0365806675		\$ 0.0365806675		\$ 0.0365806675		\$ 0.0365806675		\$ 0.0365806675		\$ 0.0365806675		18 19
20 21	Medium-Large Commercial ¹				:									20 21
22 23	Street Lighting 1	\$ 0.0237453029		\$ 0.0237453029		\$ 0.0237453029		\$ 0.0237453029		\$ 0.0237453029		\$ 0.0237453029		22 23
24	Standby Customers ¹													24

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

			(A))			(B)			(C)			(D))			(E))			(F)	
			Jan-				Feb-				Mar-				Apr-				May-				Jun-		
Line			ues @ Cl				nues @ C				renues @ C				enues @ Cl				nues @, Cl					nanged Rates	
No.	Customer Classes	Energy	(kWh)	Deman	d (kW)	Energ	gy (kWh)	Deman	d(kW)	Ener	gy (kWh)	Dema	nd (kW)	Ener	gy (kWh)	Dema	and (kW)	Energy	(kWh)	Demar	nd (kW)	Energy	(kWh)	Demand (k	W) No.
25	Residential Customers	9				•				¢				•				¢				g.	12		25
26	Residential Customers	3	-			ъ				9	18			9	- 53			Φ				Φ			26
27	Small Commercial	s	-			\$	-			S	(a)			s	_			\$	-			S	-		27
28																									28
29	Medium-Large Commercial	\$	-			\$	-:			\$	-			\$	-			\$	-			\$	-		29
30	Non-Coincident (100%)			\$	-			\$	-			\$	-			\$	-			\$	-			\$ -	30
31	Non-Coincident (90%)	1		\$	-			\$	=			\$	-			\$	-			\$	-			\$ -	31
32	Maximum On-Peak Period Demand			\$	E.			\$	÷			\$	-			\$	-			\$	-			\$ -	32
33	Maximum Demand at the Time of System Peak			\$	-			\$	-			\$	-			\$	-			\$	-			\$ -	33
34													1												34
	Street Lighting	\$	-		- 1	\$	-			\$	-			\$	-			\$	-			\$	-		35
36	5. 7. 6.																								36
C	Standby Customers			2	-			\$	-			18	-			\$				5	-			\$ -	37
38	TOTAL	0		\$		\$		\$		•		\$		\$		\$		S		S		\$	***************************************	\$ -	38
40	TOTAL	Ф	-	3		φ	-	D D		Ф		1 9		9		Φ		J.		٥	-	Þ	-	Ф -	40
41	Grand Total			\$	- 1			\$	_			S	_			8	_			S	-			\$ -	41
**												Ť													-

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. Statement BG Four Month 11 12.xlsx - A-Revenues@Changed Rates

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 the True-Up Period - (September 1, 2013 - December 31, 2013)

					ror ti	ie True-Up reriod	- (September 1	, 2013 - December	31, 2013)							
		(G)	(H)	(I)		(J)		(K)	(L)	(M)	
		Jul-	13	Aug-	-13	Sep-	13	Oct-1	13	Nov	-13	Dec-	-13	Tot	al	1
Line	1	Billing Det	erminants	Billing Dete	erminants	Billing Dete	rminants	Billing Dete	rminants	Billing Det	erminants	Billing Det	erminants	Billing Dete	rminants	Line
No.	Customer Classes	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	No.
1	Residential Customers	-	-	-	- 1	767,245,734	-	587,509,972	-	535,201,585	2:	626,335,993	-	2,516,293,284	~	1
2	l l				. 1											2
3	Small Commercial	-	-		-	199,023,264	-	173,031,100		164,159,798	-	148,983,686	-	685,197,848	-	3
4																4
5	Medium-Large Commercial	~		-]	976,843,057		878,302,107		828,427,934		804,101,009		3,487,674,107		5
6	Non-Coincident (100%)		14		~		99,043		90,102	1	97,634		76,900		363,679	6
7	Non-Coincident (90%)				14		2,417,923		2,208,229		2,174,249		1,960,556		8,760,957	7
8	Maximum On-Peak Period Demand		-		-		2,276,991		1,814,352		1,747,263		1,545,323		7,383,929	8
9	Maximum Demand at the Time of System Peak		-		-		88,430		163,851		62,709		121,874		436,863	9
10) ***									1						10
11	Street Lighting	-	-	-	-	9,785,998	:=	5,731,767	-	7,534,906	-	10,024,895	-	33,077,566	-	11
12	2 %															12
13	Standby Customers		-	-	-	-	171,867	-	169,648	-	169,648	-	171,258	-	682,421	13
14												person and amore CCI				14
15	TOTAL					1,952,898,053		1,644,574,946		1,535,324,223		1,589,445,583		6,722,242,805		15

NOTES: The above billing determinants are the recorded determinants from January 2013 through December 2013

	, , , , , , , , , , , , , , , , , , , ,	(G)	1	(H	1	(1)		(1)		(K)	(L)	(M	Λ	
		Jul-1		Aug-		Sep-	13	Oct-	13	Nov-	-13	Dec-	-13	Tot		1
Line		Changed Transr	nission Rates	Changed Transi	nission Rates	Changed Transi	nission Rates	Changed Transi	nission Rates	Changed Trans	mission Rates	Changed Trans	mission Rates	Changed Trans	mission Rates	Line
No.	Customer Classes	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	No.
16 17	Residential Customers ¹	\$ 0.0357211750		\$ 0.0357211750		\$ 0.0357211750		\$ 0.0357211750		\$ 0.0357211750		\$ 0.0357211750	•			16
18 19	Small Commercial ¹	\$ 0.0365806675		\$ 0.0365806675		\$ 0.0365806675		\$ 0.0365806675		\$ 0.0365806675		\$ 0.0365806675				18 19
20 21	Medium-Large Commercial ¹															20 21
22 23	Street Lighting 1	\$ 0.0237453029		\$ 0.0237453029		\$ 0.0237453029		\$ 0.0237453029		\$ 0.0237453029		\$ 0.0237453029				22 23
24	Standby Customers 1				and the second s											24

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

			(G))		(1	H)		(1)		(J)			(K)		(I	.)		(M)		
			Jul-1	13		Au	g-13		Sep	-13		Oct-	13		Nov-	-13		Dec	-13		Tot	al		1
Line		Revenues	@ Ch	hanged Rates	8	Revenues @	Chang	ged Rates	Revenues @ C	hanged Rates		Revenues @ Ch	anged Rates		Revenues @ C	hanged Rate	s	Revenues @ C	Changed Rates		Revenues @ C	nange	d Rates	Line
No.	Customer Classes	Energy (k)	Wh)	Demand (k)	W)	Energy (kWh)	De	emand (kW)	Energy (kWh)	Demand (kW) I	Energy (kWh)	Demand (kW)	Е	Energy (kWh)	Demand ((W)	Energy (kWh)	Demand (kW	F	nergy (kWh)	Der	mand (kW)	No.
								77777	- 1/2	A CONTRACT AND									30000 33000			- 100		
25	Residential Customers	\$	-	1		\$ -			\$ 27,406,919		\$	20,986,547		\$	19,118,029			\$ 22,373,458		\$	89,884,953	\$	-	25
26	The state of the s								1,000										1					26
27	Small Commercial	\$	-			\$ -			\$ 7,280,404	0	\$	6,329,593		\$	6,005,075			\$ 5,449,923		\$	25,064,995	\$	~	27
28	SISTEMATICAL CONTRACTOR CONTRACTO			1			1				1				13.01 No. 10.00									28
29	Medium-Large Commercial	\$	-			\$ -	1		s -		\$	-		\$	-			\$ -		\$				29
30	Non-Coincident (100%)			s -			\$	-		\$ 1,048,606			\$ 952,194			\$ 1,032	727		\$ 813,012			\$	3,846,539	30
31	Non-Coincident (90%)			\$ -			\$			\$22,949,911			\$20,938,976	1		\$ 20,651	598		\$ 18,576,984			\$	83,117,468	31
32	Maximum On-Peak Period Demand	1		s -			\$			\$ 6,968,568			\$ 619,512			\$ 596			\$ 526,141			\$	8,710,711	32
33	Maximum Demand at the Time of System Peak			s -			\$			\$ 419,651			\$ 49,304	1		\$ 18	909		\$ 36,700	c		\$	524,564	33
34																								34
35	Street Lighting	s	-			\$ -			\$ 232,371		\$	136,103		\$	178,919			\$ 238,044	2	\$	785,437	\$	4	35
36																								36
37	Standby Customers			\$ -			\$	-		\$ 814,913			\$ 804,485			\$ 804	485		\$ 811,957	\$	-	\$	3,235,841	37
38	,												-											38
39	TOTAL	\$	-	\$ -		\$ -	\$	-	\$ 34,919,694	\$32,201,649	\$	27,452,242	\$23,364,471	\$	25,302,023	\$ 23,104	209	\$ 28,061,424	\$ 20,764,794	\$	115,735,384	\$	99,435,123	39
40	!		-		T	The state of the s		*****************												1				40
41	Grand Total			s -			\$	-		\$ 67,121,344			\$50,816,713			\$ 48,406	232		\$ 48,826,218			\$ 2	15,170,507	41
				200200					1					1					tones	=				

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.

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 the True-Up Period - (September 1, 2013 - December 31, 2013) Medium and Large Commercial & Industrial Customers

Line					T		T	r	1		T	T			T		Line
No.		Jan-13		Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Αυφ-13	Sep-13	Oct-13	Nov-13	Dec-13	Total	Reference	No.
No.	Description	Jan-13	B	re0-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	1 otai	Reference	No.
١,																	
(1000)	Energy Revenues										0.000 0.00						1
2	Commodity Sales - kWh		-	-		-	-	-	-		976,843,057	878,302,107	828,427,934	804,101,009	3,487,674,107	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																	6
7	Secondary		-	-	-	-	-	-	-	-	88,278	75,368	84,311	65,264	313,221	Section 2.3.2; Page 12; Line 37	7
8	Primary		*			-	-	-	-	-	10,765	14,734	13,323	11,636	50,458	Section 2.3.2; Page 12; Line 39	8
9	Transmission		-	-	-	-	-	-	-	-		-	-	-	-	Section 2.3.2; Page 12; Line 41	9
10	Total		-	-	-	_	-	-	-		99,043		97,634	76,900	363,679	Sum Lines 7; 8; 9	10
11	Check Figure		-		-			-		-	99,043	90,102	97,634	76,900	363,679	Section 2.3.2; Pages 1.1; Line 43	11
12	Difference		-		-	-	-	-	-	-	-	-	-	-	-	Line 10 - Line 11	12
13							7.00		T	I							13
14		ł															14
15		\$10,625791	2891	\$10.6257912891	\$10.6257912891	\$10,6257912891	\$10.6257912891	\$10.6257912891	\$10,6257912891	\$10,6257912891	\$10.6257912891	\$10,6257912891	\$10,6257912891	\$10,6257912891		Section 2.3.1; Page 1; Line 6D	15
16		\$10.272187	2734	\$10,2721872734	\$10.2721872734	\$10,2721872734	\$10.2721872734	\$10,2721872734	\$10,2721872734	\$10,2721872734		\$10,2721872734	\$10,2721872734	\$10,2721872734		Section 2.3.1; Page 1; Line 6C	16
17	Transmission	\$10.169458	0573	\$10.1694580573	\$10.1694580573	\$10,1694580573	\$10,1694580573	\$10.1694580573	\$10,1694580573	\$10.1694580573				\$10,1694580573		Section 2.3.1; Page 1; Line 6B	17
18	Non-Coincident Demand (100%) - Revenues:		neste.	*******					4 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1					4.10.100.1000070		Southern and the first and the	18
19		s		\$ -	s -	s -	s -	s -	\$ -	\$.	\$ 938,024	\$ 800,843	\$ 895,869	\$ 693,486	\$ 3,328,222	Line 7 x Line 15	19
20		-									110,583	151,351	136,858	119,526	\$ 518,317	Line 8 x Line 16	20
21	Transmission		.	_			_		_	1	110,505	151,551	150,050	117,520	\$ 510,517	Line 9 x Line 17	21
22	Subtotal	S	-	s -	\$ -	s -	s -		s -	S -	S 1.048.606	S 952,194	S 1,032,727	S 813,012	\$ 3,846,539	Sum Lines 19; 20; 21	22
23		3	-	3	3		1	3	-	3	1,040,000	3 752,174	13 1,002,727	3 015,012	5 5,040,055	Sum Lines 19, 20, 21	23
	Non-Coincident Demand (90%) (kW)2:		[24
25							190			CO.	1,905,325	1.698.886	1,755,909	1,465,505	6,825,624	Section 2.3.2; Page 12; Line 46	25
26			- 1	-	_	_			-		403,712	328,803	331,002	336,233	1,399,750	_	26
27	Transmission		-	-	_					_	108.886	180.540	87,338	158,818	535,583	Section 2.3.2; Page 12; Line 47	27
28			-		-		-	-			2,417,923	2,208,229	2,174,249	1,960,556	8,760,957	Section 2.3.2; Page 12; Line 48 Sum Lines 25: 26: 27	28
29			_							ļ							28
			-	-	-	-	-	-		-	2,417,923	1		1,960,556	8,760,957	Section 2.3.2; Pages 1.1; Line 49	
30	Difference		-	-	-	•	-	-	-	-	-	-	-	-	-	Line 28 - Line 29	30
31																	31
32																	32
33	100000000000000000000000000000000000000	- North-Townson				\$ 9.5632121602			(4)	\$ 9.5632121602			First months are an arrangement	The state of the s		Section 2,3.1; Page 1; Line 8D	33
34	Primary	\$ 9.244968		5 S	\$ 9,2449685461	\$ 9.2449685461	Contraction of the contraction o	\$ 9.2449685461	\$ 9.2449685461	\$ 9.2449685461	\$ 9.2449685461	\$ 9.2449685461		\$ 9.2449685461		Section 2,3,1; Page 1; Line 8C	34
35	Transmission	\$ 9.152512	2516	\$ 9.1525122516	\$ 9.1525122516	\$ 9.1525122516	\$ 9.1525122516	\$ 9.1525122516	\$ 9.1525122516	\$ 9.1525122516	\$ 9.1525122516	\$ 9.1525122516	\$ 9,1525122516	\$ 9.1525122516		Section 2.3.1; Page 1; Line 8B	35
36			1														36
37	Secondary	\$	-	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 18,221,024	\$ 16,246,811	\$ 16,792,128	\$ 14,014,932	\$ 65,274,894	Line 25 x Line 33	37
38	Primary		- 1			-		-	•	-	3,732,307	3,039,771	3,060,104	3,108,466	\$ 12,940,648	Line 26 x Line 34	38
39	Transmission		-	-	-	-		-	-		996,579	1,652,395	799,366	1,453,586	\$ 4,901,926	Line 27 x Line 35	39
40	Subtotal	S	-	s -	s -	s -	\$ -	s -	s -	S -	S 22,949,911	\$ 20,938,976	\$ 20,651,598	\$ 18,576,984	\$ 83,117,468	Sum Lines 37; 38; 39	40
																a water contains	
																1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1	

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

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 the True-Up Period - (September 1, 2013 - December 31, 2013)

Medium and Large Commercial & Industrial Customers

Line	7 10 (2003)	Winter	Winter	Winter	Winter	Summer	Summer	Summer	Summer	Summer	Winter	Winter	Winter			Line
No.	Description	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	Total	Reference	No.
-	1 11 11 11 11 11 11 11 11 11 11 11 11 1								1							
1	Maximum On-Peak Period Demand (kW)3:		1				l									1
2	Secondary	-	-	-				-		1,807,544	1,485,775	1,431,109	1,159,115	5,883,543	Section 2,3,2; Pages 12; Line 17 x 1000	2
3	Primary		-		-	-		-	E.	434,562	320,285	282,622	319,624	1,357,092	Section 2.3.2; Pages 12; Line 18 x 1000	3
4	Transmission	-	_			-	-	-	-	34,885	8,292	33,532	66,584	143,293	Section 2.3.2; Pages 12; Line 19 x 1000	4
5	Total	-	-	-	-	-	-	-	-	2,276,991	1,814,352	1,747,263	1,545,323	7,383,929	Sum Lines 2; 3; 4	5
6	Check Figure	-	-	-	-	-	-	-	_	2,276,991	1,814,352	1,747,263	1,545,323	7,383,929	Section 2.3.2; Pages 12; Line 20	6
7	Difference	-	Ì -	_	-	-	-		-	-	-	-			Line 5 - Line 6	7
8													ĺ			8
9	Maximum On-Peak Period Demand Rates (\$/kW):	Winter	Winter	Winter	Winter	Summer	Summer	Summer	Summer	Summer	Winter	Winter	Winter			9
10	Secondary	\$0,3435763374	\$0,3435763374	\$0,3435763374	\$0,3435763374	\$3,0822581330	\$3,0822581330	\$3,0822581330	\$3,0822581330	\$3,0822581330	\$0,3435763374	\$0,3435763374	\$0,3435763374		Section 2.3.1; Page 1; Line 11D; 12D	10
11	Primary	\$0,3319549359	\$0.3319549359	\$0,3319549359	\$0.3319549359	\$2,9778914655	\$2,9778914655	\$2,9778914655	\$2,9778914655	\$2,9778914655	\$0.3319549359	\$0,3319549359	\$0.3319549359		Section 2.3.1; Page 1; Line 11C; 12C	11
12	Transmission	\$0,3273436869	\$0.3273436869	\$0,3273436869	\$0.3273436869	\$2,9575247160	\$2,9575247160	\$2,9575247160	\$2.9575247160	\$2,9575247160	\$0.3273436869	\$0,3273436869	\$0.3273436869		Section 2.3.1; Page 1; Line 11B; 12B	12
13	Maximum On-Peak Period Demand - Revenues:		l												*	13
14	Secondary	s -	s -	s -	s -	\$ -	\$ -	\$ -	\$ -	\$ 5,571,317	\$ 510,477	\$ 491,695	\$ 398,244	\$ 6,971,734	Line 2 x Line 10	14
15	Primary	-	-	-	-		-		-	1,294,078	106,320	93,818	106,101	\$ 1,600,317	Line 3 x Line 11	15
16	Transmission		_	-	_	10	-	-	-	103,173	2,714	10,977	21,796	\$ 138,659	Line 4 x Line 12	16
17	Subtotal	\$ -	\$ -	\$ -	\$ -	S -	s -	s -	s -	\$ 6,968,568	\$ 619,512	\$ 596,489	\$ 526,141	S 8,710,711	Sum Lines 14; 15; 16	17
18				1								T .				18
19	Maximum Demand at the Time of System Peak (kW)4	Winter	Winter	Winter	Winter	Summer	Summer	Summer	Summer	Summer	Winter	Winter	Winter			19
20	Secondary	-		-	-	-	-	-	-	-	-	-	-		Section 2.3.2; Pages 12; Line 30 x 1000	20
21	Primary	_	4	_		-		-	-	10,501	8,713	11,086	11,661	41,961	Section 2.3.2; Pages 12; Line 31 x 1000	21
22	Transmission	-	_	-	_		area areananana Erana			77,928	155,138	51,623	110,213	394,902	Section 2.3.2; Pages 12; Line 32 x 1000	22
23	Total	-		-			-		-	88,430	163,851	62,709	121,874	436,863	Sum Lines 20; 21; 22	23
24	Check Figure	-	-	_	-	-	_	-	_	88,430	163,851	62,709	121,874	436,863	Section 2.3.2; Pages 12; Line 33	24
25	Difference '			-		-			_	-	-	_	-	-	Line 23 - Line 24	25
26												}	·			26
27	Anximum Demand at the Time of System Peak Rates (S/kW);	Winter	Winter	Winter	Winter	Summer	Summer	Summer	Summer	Summer	Winter	Winter	Winter			27
28	Secondary	\$ -	\$ -	s -	s -	\$ -	\$ -	s -	\$ -	\$ -	\$ -	\$ -	\$.		Section 2.3.1; Page 1; Line 15D; 16D	28
29	Primary	\$0,3057725037	\$0,3057725037	\$0,3057725037	\$0,3057725037	\$4,9391716493	\$4.9391716493	\$4,9391716493	\$4,9391716493	\$4,9391716493	\$0,3057725037	\$0.3057725037	\$0,3057725037		Section 2.3.1; Page 1; Line 15C; 16C	29
30	Transmission	\$0.3006343347	\$0.3006343347	\$0.3006343347	\$0.3006343347	\$4.7195096896	\$4.7195096896	\$4.7195096896	\$4.7195096896	\$4.7195096896	\$0,3006343347	\$0.3006343347	\$0.3006343347		Section 2.3.1; Page 1; Line 15B; 16B	30
31	Maximum Demand at the Time of System Peak - Revenues:		00,000,000							- M. 1. 1. 1. 1. 1. 1. 1. 1. 1. 1. 1. 1. 1.	40.0000.000.	4 010 0 0 0 0 10 0 11	0.0000000000000000000000000000000000000		Section and it age it aline is at 100	31
32	Secondary	s -	s -	s -	s -	s -	s -	s -	s -	s -	s -	\$ -	s -	s -	Line 20 x Line 28	32
33	Primary	1 .								51.867	2,664	3.390	3,566	\$ 61,486	Line 21 x Line 29	33
34	Transmission	-		-	-		_	_	_	367,784	46,640	15,520	33,134	\$ 463,077	Line 22 x Line 30	34
35	Subtotal	s -	s -	s -	s -	s -	\$ -	\$ -	s -	\$ 419.651			\$ 36,700		Sum Lines 32; 33; 34	35
36																36
37	Revenues at Changed Rates:	Winter	Winter	Winter	Winter	Summer	Summer	Summer	Summer	Summer	Winter	Winter	Winter			37
38	Secondary	\$ -	\$ -	s -	8	s -	\$ -	\$ -	\$ -	\$ 24,730,365			\$ 15,106,663	\$ 75,574,850	Pg.5 (Lines 19;37) + Pg.6(Lines 14;32)	38
39	Primary	\$ -	s -	\$ -	s -	s -	s -	\$ -	s -	\$ 5,188,835	\$ 3,300,106	\$ 3,294,169	\$ 3,337,658		Pg.5 (Lines 20;38) + Pg.6(Lines 15;33)	39
40	Transmission	\$ -	s -	\$ -	s -	s -	\$ -	\$ -	s -	\$ 1,467,536		\$ 825.862	\$ 1.508.516		Pg.5 (Lines 21;39) + Pg.6(Lines 15;34)	40
41	Total		s -			s -	s -	4			\$ 22,559,985		\$ 19,952,837		Sum Lines 38: 39: 40	41
42	A U 6487		<u> </u>	+		1	<u> </u>			0 01,000,730	w mmq0074703	1 224277123	w 12425#4037	U 2041224202	50m Lines 30, 37, 40	42
	Total Revenues at Changed Rates:	s .	s -	s -	s .	s -	s -	s -	s -	S 31,386,736	\$ 22.550.005	S 22,299,723	\$ 19,952,837	\$ 96,199,282	See Line 41	42
43	total Revenues at Changen Rates:	3 -	D -	10 -		13 -	3 -		3 -	3 31,380,736	a 44,557,485	1 3 22,299,723	a 17,754,857	a 96,199,282	See Line 41	4.5
\Box	In State of the St	1		1		1										1

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 the True-Up Period (September 1, 2013 - December 31, 2013)

	 Standby Cust	omers	
	 The second second distance of the		

Line																Line
No.	Description	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	Total	Reference	No.
1	Demand - Billing Determinants (kW):															1
2	Secondary	-	*	*			-			11,019	11,019	11,019	10,559	43,616	Section 2,3,2; Page 11,3; Line 114 x 1000	2
3	Primary	-	-	-		-	-		=0	99,611	99,611	99,611	100,121	398,954	Section 2.3.2; Page 11.3; Line 115 x 1000	3
4	Transmission		-	-		-	-	-	-	61,237	59,018	59,018	60,578	239,851	Section 2.3.2; Page 11.3; Line 116 x 1000	4
5	Total		-			-	-	-	-	171,867	169,648	169,648	171,258	682,421	Sum Lines 2; 3; 4	5
6	Check Figure	-	•	-				-		171,867	169,648	169,648	171,258	682,421	Section 2.3.2; Page 11.3; Line 117 x 1000	- 6
7	Difference	-	-	-	-	•	•	-	-		-	-	-	-	Line 5 Less Line 6	7
8															3000	8
9	Demand Rates (\$/kW);	1									Ī					9
10	Secondary	\$ 4.9531330667	\$ 4.9531330667	\$ 4.9531330667	\$ 4.9531330667	\$ 4.9531330667	\$ 4.9531330667	\$ 4.9531330667	\$ 4.9531330667	\$ 4.9531330667	\$ 4.9531330667	\$ 4.9531330667	\$ 4.9531330667		Section 2.3.1; Page 1; Line 20D	10
11	Primary	\$ 4.7440605136	\$ 4.7440605136	\$ 4.7440605136	\$ 4.7440605136	\$ 4.7440605136	\$ 4.7440605136	\$ 4.7440605136	\$ 4.7440605136	\$ 4.7440605136	\$ 4.7440605136	\$ 4.7440605136	\$ 4.7440605136		Section 2.3.1; Page 1; Line 20C	11
12	Transmission	\$ 4.6993490714	\$ 4,6993490714	\$ 4.6993490714	\$ 4,6993490714	\$ 4,6993490714	\$ 4.6993490714	\$ 4.6993490714	\$ 4.6993490714	\$ 4.6993490714	\$ 4.6993490714	\$ 4.6993490714	\$ 4.6993490714		Section 2.3.1; Page 1; Line 20B	12
13			,,,,													13
14	Revenues at Changed Rates:															14
15	Secondary	\$ -	\$ -	S -	\$ -	S -	S -	S -	\$ -	\$ 54,579	\$ 54,579	\$ 54,579	\$ 52,300	\$ 216,036	Line 2 x Line 10	15
16	Primary .	-	-	-	-	-	-	-	-	472,561	472,561	472,561	474,980	1,892,662	Line 3 x Line 11	16
17	Transmission	-	-			-		-		287,774	277,346	277,346	284,677	1.127,144	Line 4 x Line 12	17
18	Total	\$ -	\$ -	S -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 814,913	\$ 804,485	\$ 804,485	\$ 811,957	\$ 3,235,841	Sum Lines 15; 16; 17	18
19																19
20	Total Revenues at Changed Rates	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 814,913	\$ 804,485	\$ 804,485	\$ 811,957	\$ 3,235,841	Line 18	20

SAN DIEGO GAS AND ELECTRIC COMPANY

Transmission Revenue Data to Reflect Changed Rates

Recorded Billing Determinants

True-Up Period (September 1, 2013 - December 31, 2013)

		(A	.)	(B	3)	(C	2)	(D)	(E)	(F)	
		Jan-	13	Feb-	-13	Mar	-13	Apr-	-13	May	-13	Jun-	13	1 1
Line		Billing Det	erminants	Billing Det	erminants	Billing Det	erminants	Line						
No.	Customer Classes	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	Energy (kWh)	Demand (kW)	No.						
1 2	Residential Customers			-		-		-	300000000000000000000000000000000000000	-		-		1 2
3	Small Commercial	-		-		-		-		-		-		3
5	Medium-Large Commercial	_		_		-		_		_		-		5
6	Non-Coincident (100%) ¹		-		-		-		-		-		-	6
7	Non-Coincident (90%) ²		-		-		_		-		-		15	7
8	Maximum On-Peak Period Demand ³		-		-		-		-		-		-	8
9	Maximum Demand at the Time of System Peak ⁴		-		-		-		_		-		-	9
10														10
11	Street Lighting	-		#1		8		-		-		-		11
12														12
13	Sale for Resale	-		-		-		-		-		-		13
14	Standby Customers													14
16	Standby Customers		-				~		-		-		-	16
	TOTAL	-		_		_		_		_		_		17
														1 1

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

SAN DIEGO GAS AND ELECTRIC COMPANY

Transmission Revenue Data to Reflect Changed Rates

Recorded Billing Determinants

True-Up Period (September 1, 2013 - December 31, 2013)

		(G	(G)		(H)		(I)		(J)		(K)			
		Jul-	Jul-13		-13	Sep-	13	Oct-	Oct-13		-13	Dec-	13	
Line	/	Billing Det	erminants	Billing Det	erminants	Billing Dete	erminants	Billing Det	erminants	Billing Det		Billing Dete		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)	No.
1 2	Residential Customers	-		-		767,245,734		587,509,972		535,201,585		626,335,993		1 2
3 4	Small Commercial	- ,		-		199,023,264		173,031,100		164,159,798		148,983,686		3 4
5	Medium-Large Commercial	-		-		976,843,057	00.040	878,302,107	00.100	828,427,934	00.024	804,101,009	74.000	5
6	Non-Coincident (100%)¹ Non-Coincident (90%)²		_		-		99,043 2,417,923	w.	90,102 2,208,229		97,634 2,174,249		76,900 1,960,556	7
8	Maximum On-Peak Period Demand ³		-		-		2,276,991		1,814,352		1,747,263		1,545,323	8
9	Maximum Demand at the Time of System Peak ⁴			3	-		88,430		163,851		62,709		121,874	9
10						0.705.000				7 524 006		10.024.005		10
11	Street Lighting	-		-		9,785,998		5,731,767		7,534,906		10,024,895		12
	Sale for Resale	-		-		15,252		-		6,763		9,726		13
14													i.c.	14
	Standby Customers		-		-		171,867		169,648		169,648		171,258	15
16	TOTAL			_		1,952,913,305		1,644,574,946		1,535,330,986		1,589,455,309		16 17
17	TOTAL					1,752,913,303		1,044,374,940		1,333,330,980		1,505,455,505		1 1

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

SAN DIEGO GAS AND ELECTRIC COMPANY

Transmission Revenue Data to Reflect Changed Rates **Recorded Billing Determinants**

True-Up Period (September 1, 2013 - December 31, 2013)

	Title Option (Soptember 1,			
		(N	A)	
		12 Month	is to Date	
Line		Billing De	terminants	Line
No.	Customer Classes	Energy (kWh)	Demand (kW)	No.
1	Residential Customers	2,516,293,284	-	1
2				2
3	Small Commercial	685,197,848	_	3
4				4
5	Medium-Large Commercial	3,487,674,107		5
6	Non-Coincident (100%) ¹		363,679	6
7	Non-Coincident (90%) ²		8,760,957	7
8	Maximum On-Peak Period Demand ³		7,383,929	8
9	Maximum Demand at the Time of System Peak ⁴		436,863	9
10	11.141.111.141.14		.50,005	10
11	Street Lighting	33,077,566	-	11
12	Su vot Eighting	22,011,000		12
13	Sale for Resale	31,741	_	13
14	bale tot Resale	31,711		14
15	Standby Customers	_	682,421	15
16	Sundoy Customors		002,421	16
17	TOTAL	6,722,242,805	17,627,849	17
17	1 O II MJ	0,122,212,000	17,027,047	1 '

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

The state of the s					Section 2.3.2								
		Records	ed Sales for		ego Gas & I	Electric eptember 20	13 - Decem	her 2013					
SDG&E: System Delivery Determinants	Winter	Winter	Winter	Winter	Summer	Summer 20	Summer	Summer	Summer	Winter	Winter	Winter	Total
								Later Control of the					
Customer Class Deliveries (MWh)	<u>Jan-13</u>	Feb-13	Mar-13	Apr-13	May-13	Jun-13	<u>Jul-13</u>	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	Total
Residential									767,246	587,510	535,202	626,336	2,516,293
Small Commercial									199,023	173,031	164,160	148,984	685,198
Med. & Large Comm./Ind. (AD + PA-T-1)									28,068	26,632	25,927	18,305	98,932
Med. & Large Comm./Ind. (AL + AY + DGR)									899,463	743,514	755,306	704,824	3,103,107
Med. & Large Comm./Ind. (A6)									49,312	108,156	47,194	80,972	285,635
Lighting									9,786	5,732	7,535	10,025	33,078
Sale for Resale									<u>15.3</u>	0.0	6.8	9.7	31.7
Total System	0	0	0	0	0	0	0	0	1,952,913	1,644,575	1,535,331	1,589,455	6,722,275
•													
Med. & Large Comm./Ind.												80-06-00	
Rate Schedule Billing Determinants													
	1												
Schedules AD / PA-T-1:	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	Total
Total Deliveries (MWh)	0	0	0	0	0	0	0		28,068	26,632	25,927	18,305	98,932
<u> </u>		7	-	-					,	,	,,_,	,	,
Total Deliveries (%)													
% @ Secondary Service									92.34%	86.97%	87.04%	89.63%	89.00%
% @ Primary Service									7.66%	13.03%	12.96%	10.37%	11.00%
% @ Transmission Service									0.00%	0.00%	0.00%	0.00%	0.00%
70 (6) Transmission Bervice	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Total Deliveries (MWh)	0.0070	0.0070	0.0070	0,0070	0,0070	0.0070	0.0070	0.0070	100.0070	100.0070	100.0070	100.0070	100.0070
MWh @ Secondary Service	0	0	0	0	0	0	0	0	25,918	23,162	22,567	16,406	88,053
MWh @ Primary Service	0	0	0	0	0	0	0	0	2,150	3,470	3,360	1,898	10,879
MWh @ Transmission Service	0								2,130	<u>0</u>	0,500	0	10,879
Will the Transmission Service	0	0	0	0	0	0	0	0	28,068	26,632	25,927	18,305	98,932
Non-Coincident Demand (%)		U	0	U	U	U	U	U	20,000	20,032	23,921	18,303	90,932
	Section Section (Section)			114 115 115 115 115 115 115 115 115 115					0.240604	0.22549/	0.272604	0.70798/	0.25570/
% @ Secondary Service									0.3406%	0.3254%	0.3736%	0.3978%	0.3557%
% @ Primary Service									0.5007%	0.4246%	0.3965%	0.6130%	0.4638%
% @ Transmission Service									0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
N G I II I B I I I I I I I I I I I I I I													
Non-Coincident Demand (MW)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	00.050	== 0.00	040::	(20(:	242.651
MW @ Secondary Service	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	88.278	75.368	84.311	65.264	313,221
MW @ Primary Service	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	10.765	14.734	13.323	11.636	50.458
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
	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	99.043	90.102	97.634	76.900	363.679
						WWW.50.5							
`													
Schedules AL-TOU / AY-TOU / DG-R:	<u>Jan-13</u>	Feb-13	<u>Mar-13</u>	Apr-13	May-13	<u>Jun-13</u>	<u>Jul-13</u>	<u>Aug-13</u>	<u>Sep-13</u>	Oct-13	<u>Nov-13</u>	<u>Dec-13</u>	Total
Total Deliveries (MWh)	0	0	0	0	0	0	0	0	899,463	743,514	755,306	704,824	3,103,107
Total Deliveries (%)												NAME OF THE OWNER OWNER OWNER OF THE OWNER O	
% @ Secondary Service									77.65%	80,74%	82.38%	74.82%	78.90%
% @ Primary Service									21.07%	18.77%	16.29%	22.55%	19.69%
% @ Transmission Service									1.28%	0.49%	1.33%	2.63%	1.41%
	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	100.00%	100.00%	100.00%	100.00%

						Section 2.3.2									
Line						ego Gas & F			2012						Line
No.		1	Recorde	d Sales for t	he True-Up	Period: Se	ptember 20	13 - Decemb	er 2013						No. 50
50 51	Total Deliveries (MWh)	0	0	0	0	0	0	0	0	698,433	600,313	622,221	527,350	2,448,317	51
	MWh @ Secondary Service		0	0	0	0	0	0	0	189,517	139,558	123,039	158,938	611,052	52
52 53	MWh @ Primary Service MWh @ Transmission Service	0	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	11,513	3,643	10,046	18,537	43,739	53
54	With the Transmission Service	0	0	0	0	0	0	0	0	899,463	743,514	755,306	704,824	3,103,107	54
55	Non-Coincident Demand (%)		U	U	V	.0	Ü	Ü	Ü	022,403	743,514	755,500	704,024	3,103,107	55
56	% @ Secondary Service									0,2728%	0,2830%	0.2822%	0,2779%	0.2788%	56
57	% @ Primary Service									0.2070%	0.2237%	0.2509%	0.2063%	0.2195%	57
58	% @ Transmission Service									0.2057%	0.1820%	0.2265%	0.1400%	0.1807%	58
59	70 (6) 11415111551011 5017100														59
60	Non-Coincident Demand (MW)														60
61	MW @ Secondary Service	0.000	0.000	0.000	0.000	0,000	0.000	0.000	0.000	1,905.325	1,698.886	1,755.909	1,465.505	6,825.624	61
62	MW @ Primary Service	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	392.300	312.190	308.706	327.889	1,341.085	62
63	MW @ Transmission Service	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	23.682	6.631	22.753	25.952	79.018	63
64		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		2,017.707		1,819.345	8,245.727	64
65	On-Peak Demand (%)	300,000 20 00								man ES	- EE	ACADA	Annie -	10.00	65
66	% @ Secondary Service									0.2588%	0.2475%	0.2300%	0.2198%	0.2403%	66
67	% @ Primary Service									0.2293%	0.2295%	0.2297%	0.2011%	0.2221%	67
68	% @ Transmission Service									0.3030%	0.2276%	0.3338%	0.3592%	0.3276%	68
69	Maximum On-Peak Period Demand (MW)				ANNEAR PARTIES CONTRACTORS	THE CONTRACTOR OF THE CONTRACT	Average and a second se			THE COLUMN TWO COLUMN TO THE COLUMN TWO COLU					69
70	On-Peak Demand (MW)	Winter	Winter	Winter	Winter	Summer	Summer	Summer	Summer	Summer	Winter	Winter	Winter	Total	70
71	MW @ Secondary Service	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1,807.544	1,485.775	1,431.109	1,159.115	5,883.543	71
72	MW @ Primary Service	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	434.562	320,285	282.622	319.624	1,357.092	72
73	MW @ Transmission Service	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	34.885	8.292	33.532	66.584	143.293	73
74	-	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	2,276.991	1,814.352	1,747.263	1,545.323	7,383.929	74
75															75
76		200													76
77															77
78	Schedule A6-TOU:	<u>Jan-13</u>	Feb-13	Mar-13	Apr-13	May-13	<u>Jun-13</u>	<u>Jul-13</u>	Aug-13	Sep-13	Oct-13	<u>Nov-13</u>	Dec-13	Total	78
79	Total Deliveries (MWh)	0	0	0	0	0	0	0	0	49,312	108,156	47,194	80,972	285,635	79
80															80
81	Total Deliveries (%)														81
82	% @ Secondary Service									0.00%	0.00%	0.00%	0.00%	0.00%	82
83	% @ Primary Service	10-17-18								16,65%	8.17%	20.39%	7.97%	11.60%	83
84	% @ Transmission Service	0.0001	0.000/	0.000/	0.0007	0.000/	0.008/	0.000/	0.0007	83.35%	91.83%	79.61%	92.03%	88.40%	84
85	The Act I De Harris of Charles	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	100.00%	100.00%	100.00%	100.00%	85
86	Total Deliveries (MWh)	_	^	0	0	0	0	0	0	0	0	0	0	0	86 87
87 88	MWh @ Secondary Service	0	0	0	0	0	0	0	0	8,210	8,836	9,623	6,453	33,123	
88	MWh @ Primary Service								0	41,101	99,320	9,623 37,571	74,519	252,511	89
90	MWh @ Transmission Service	0 0	<u>0</u> 0	<u>0</u> 0	0	<u>0</u>	<u>0</u>	<u>0</u> 0	0	49,312	108,156	47,194	80,972	285,635	90
91	Non-Coincident Demand (%)	"	U	U	J	U	U	U	U	77,312	100,100	77,174	00,712	200,000	91
92	% @ Secondary Service									0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	92
93	% @ Primary Service									0.1390%	0.1880%	0.2317%	0.1293%	0.1771%	93
94	% @ Transmission Service									0.2073%	0.1751%	0.1719%	0.1783%	0.1808%	94
95	7.0 (6) 1.1.1.1.1.1.1.1.1.1.1.1.1.1.1.1.1.1.1.										2147-270		J 70	0.100070	95
96	Non-Coincident Demand (MW)									e.					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	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	11.413	16.612	22.296	8.344	58.666	98
99	MW @ Transmission Service	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	85.203	173.909	64.585	132.867	456.565	99
100		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	96.616	190.522	86.881	141.211	515.230	

						Section 2.3.2	2				100				
Line			D1	J C-1 6		ego Gas & I		12 D	L 2012						Line
No.			Recorde	d Sales for	ine True-U	Period: Se	eptember 20	13 - Decem	Der 2013						No.
400000000000000000000000000000000000000	Coincident Peak Demand (%)	AND THE RESERVE OF THE PERSON									******************	F			101
102	% @ Secondary Service									0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	102
103	% @ Primary Service									0.1279%	0.0986%	0.1152%	0.1807%	0.1267%	103
104	% @ Transmission Service									0.1896%	0.1562%	0.1374%	0.1479%	0.1564%	104
105	Coincident Demand at Time of System of Peak														105
106	Coincident Peak Demand (MW)	Winter	Winter	Winter	Winter	Summer	Summer	Summer	Summer	Summer	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	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	10.501	8.713	11.086	11.661	41.961	108
109	MW @ Transmission Service	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	77.928	155.138	51.623	110.213	394.902	109
110		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	88.430	163.851	62,709	121.874	436,863	
111															111
112	Schedule S: Standby Determinants:	Jan-13	Feb-13	Jun-09	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	Total	112
113	Contracted Standby Demand (MW)														113
114	MW @ Secondary Service									11.019	11.019	11.019	10.559	43.616	114
115	MW @ Primary Service									99.611	99.611	99,611	100.121	398.954	115
116	MW @ Transmission Service									61.237	59.018	59,018	60,578	239.851	
117		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	171.867	169,648	169,648	171,258	682.421	
118															118
119															119
120															120

						Section 2.3.	2								
Line						Gas & Elect									Line
No.	M-I & I C A-I			ecorded Sales			CONTROL OF THE PROPERTY OF THE								No.
1	Med. & Large Comm./Ind.	Winter	Winter	Winter	Winter	Summer	Summer	Summer	Summer	Summer	Winter	Winter	Winter	Total	1
2 3	Rate Schedule Billing Determinants														2 3
4	Schedules AD / PA-T-1:	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Iun 12	Jul-13	Aug 12	Con 12	Oct-13	Nov-13	Dec-13	Total	4
5	Total Deliveries (MWh)	0	0	<u>Mai-13</u>	Apr-13 0	<u>May-13</u>	Jun-13 0	<u>Jui-13</u>	Aug-13 0	Sep-13 28,068	26,632	25.927	18,305	98,932	
6	Total Deliveries (IVI VIII)	•	O	0	O	0	U	O	0	28,008	20,032	23,921	16,505	70,732	6
7	Total Deliveries (%)														7
8	% @ Secondary Service	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	92.34%	86.97%	87.04%	89.63%	89.00%	1 1
9	% @ Primary Service	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	7.66%	13.03%	12.96%	10.37%	11.00%	1 3
10	% @ 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%	10
11		0,00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	100.00%	100.00%	100.00%	100.00%	1 1
12	Total Deliveries (MWh)						-						-		12
13	MWh @ Secondary Service	0	0	0	0	0	0	0	0	25,918	23,162	22,567	16,406	88,053	
14	MWh @ Primary Service	0	0	0	0	0	0	0	0	2,150	3,470	3,360	1,898	10,879	1 1
15	MWh @ Transmission Service	<u>0</u>	<u>0</u>	<u>0</u>	0	<u>0</u>	<u>0</u>	0	0	0	<u>0</u>	<u>0</u>	0	0	15
16		0	0	0	0	0	0	0	0	28,068	26,632	25,927	18,305	98,932	16
17	Non-Coincident Demand (%)														17
18	% @ Secondary Service	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.34%	0.33%	0.37%	0.40%	0.3557%	18
19	% @ Primary Service	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.50%	0.42%	0.40%	0.61%	0.4638%	19
20	% @ 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%	0.0000%	20
21															21
22	Non-Coincident Demand (MW)														22
23	MW @ Secondary Service	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	88.278	75.368	84.311	65.264	313.221	23
24	MW @ Primary Service	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	10.765	14.734	13.323	11.636	50.458	24
25	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	25
26		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	99.043	90.102	97.634	76.900	363.679	
27															27
28	Schedules AL-TOU / AY-TOU / DG-R:	<u>Jan-13</u>	Feb-13	<u>Mar-13</u>	Apr-13	May-13	Jun-13	<u>Jul-13</u>	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	Total	28
29	Total Deliveries (MWh)	0	0	0	0	0	0	0	0	899,463	743,514	755,306	704,824	3,103,107	29
30	T-4-1 D-1' (0/)														30
31	Total Deliveries (%)	0.000/	0.00%	0.00%	0.0007	0.000/	0.000/	0.000/	0.000/	77 (50/	00 740/	00.200/	71.000/	70.000/	31
33	% @ Secondary Service % @ Primary 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% 0.00%	77.65% 21.07%	80.74% 18.77%	82.38% 16.29%	74.82% 22.55%	78.90% 19.69%	32 33
34	% @ Transmission Service	0.00%	0.00%	0.00%	0.00%			0.00%	0.00%					100/10/10/10 10 10	
35	% (w Transmission Service	0.00%	0.00%	0.00%	0.00%	<u>0.00%</u> 0.00%	<u>0.00%</u> 0.00%	0.00%	0.00%	1.28% 100.00%	<u>0.49%</u> 100.00%	1.33% 100.00%	2.63% 100.00%	1.41% 100.00%	34 35
36	Total Deliveries (MWh)	0.0078	0.00%	0.0076	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	100.00%	100.00%	100.00%	100.00%	36
37	MWh @ Secondary Service	0	0	0	0	0	0	0	0	698,433	600,313	622,221	527,350	2,448,317	
38	MWh @ Primary Service	0	0	0	0	0	0	0	0	189,517	139,558	123,039	158,938	611,052	38
39	MWh @ Transmission Service	0	0	<u>0</u>	0	0	<u>0</u>	<u>0</u>	<u>0</u>	11,513	3,643	10,046	18,537	43,739	39
40	Transmission Solvino	0	0	0	0	0	0	0	0	899,463	743,514	755,306	704,824	3,103,107	40
41	Non-Coincident Demand (%)		•	•	J	3	Ŭ		3	0,,,,,,,,,	, , , , , , , , ,	,55,500	, 04,024	5,105,107	41
42	% @ Secondary Service	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.2728%	0.2830%	0.2822%	0.2779%	0.2788%	42
43	% @ Primary Service	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.2070%	0.2237%	0.2509%	0.2063%	0.2195%	43
44	% @ Transmission Service	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.2057%	0.1820%	0.2265%	0.1400%	0.1807%	44
45						emananti eferitaria									45

						Section 2.3.	2								
Line						Gas & Elect									Line
No.			Re	ecorded Sales	for the True-	Up Period: S	eptember 201	3 - December	2013						No.
46	Non-Coincident Demand (MW)														46
47	MW @ Secondary Service	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1,905.325	1,698.886	1,755.909	1,465.505	6,825.624	47
48	MW @ Primary Service	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	392,300	312.190	308.706	327.889	1,341.085	48
49	MW @ Transmission Service	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	23.682	6.631	22.753	25.952	79,018	49
50		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	2,321.307	2,017.707	2,087.368	1,819.345	8,245.727	50
51	On-Peak Demand (%)														51
52	% @ Secondary Service	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.2588%	0.2475%	0.2300%	0.2198%	0.2403%	52
53	% @ Primary Service	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.2293%	0.2295%	0.2297%	0.2011%	0.2221%	53
54	% @ Transmission Service	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.3030%	0.2276%	0.3338%	0.3592%	0.3276%	54
55															55
56	On-Peak Demand (MW)														56
57	MW @ Secondary Service	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1,807.544	1,485.775	1,431.109	1,159.115	5,883.543	57
58	MW @ Primary Service	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	434.562	320.285	282.622	319.624	1,357.092	58
59 60	MW @ Transmission Service	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	34.885	8.292	33.532	66.584	143.293	59
61		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	2,276.991	1,814.352	1,747.263	1,545.323	7,383.929	60 61
62	Schedule A6-TOU:	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug 12	Sep-13	Oct-13	Nov-13	Dec-13	Total	62
63	Total Deliveries (MWh)	<u>3811-13</u>	<u>reb-13</u>	<u>Mar-13</u>	Apr-13 0	<u>May-15</u>	<u>Jun-13</u>	Jui-13	Aug-13 0	49,312		47,194	80,972		63
64	Total Deliveries (MWII)	U	U	U	U	U	U	U	U	49,312	108,156	47,194	80,972	285,635	64
65	Total Deliveries (%)														65
66	% @ 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%	66
67	% @ Primary Service	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	16.65%	8.17%	20.39%	7.97%	11.60%	67
68	% @ Transmission Service	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	83.35%	91.83%	79.61%	92.03%	88.40%	68
69	76 (a) Transmission betwee	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	100,00%	100.00%	100.00%	100.00%	69
70	Total Deliveries (MWh)	0,0070	0.0070	0.0070	0.0070	0.0070	0.0070	0.0070	0.0070	100.0070	100.0070	100.0076	100.0070	100.0070	70
71	MWh @ Secondary Service	0	0	0	0	0	0	0	0	0	0	0	0	0	71
72	MWh @ Primary Service	0	0	0	0	0	0	0	0	8,210	8,836	9,623	6,453	33,123	72
73	MWh @ Transmission Service	0	<u>0</u>	<u>0</u>	0	0	<u>0</u>	0	0	41,101	99,320	37,571	74,519	252,511	73
74		0	0	0	0	0	0	0	0	49,312	108,156	47,194	80,972	285,635	74
75	Non-Coincident Demand (%)											S. 100 March 14	, ,	•	75
76	% @ 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%	76
77	% @ Primary Service	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.1390%	0.1880%	0.2317%	0.1293%	0.1771%	77
78	% @ Transmission Service	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.2073%	0.1751%	0.1719%	0.1783%	0.1808%	78
79															79
80	Non-Coincident Demand (MW)														80
81	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	81
82	MW @ Primary Service	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	11.413	16.612	22.296	8.344	58,666	82
83	MW @ Transmission Service	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	85.203	173.909	64.585	132.867	456,565	83
84		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	96.616	190.522	86.881	141.211	515.230	84
85	Coincident Peak Demand (%)														85
86	% @ 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%	86
87	% @ Primary Service	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.1279%	0.0986%	0.1152%	0.1807%	0.1267%	87
88	% @ Transmission Service	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.1896%	0.1562%	0.1374%	0.1479%	0.1564%	88
89															89
90	Coincident Peak Demand (MW)	0.000	0.000	0.000	0.000	0.000									90
91	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	91
92	MW @ Primary Service	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	10.501	8.713	11,086	11.661	41.961	92
93	MW @ Transmission Service	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	77.928	<u>155.138</u>	51.623	110.213	394.902	93
94		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	88.430	163.851	62,709	121,874	436.863	94
95															95

		1.5				Section 2.3	.2								
Line						o Gas & Elect									Line
No.			R	Recorded Sales	for the True	-Up Period: S	eptember 201	3 - December	r 2013						No.
96	Med. & Large Comm./Ind.	Jan-13	<u>Feb-13</u>	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	Total	96
97	Class Total														97
98	Total Deliveries (MWh)	0	0	0	0	0	0	0	0	976,843	878,302	828,428	804,101	3,487,67	4 98
99															99
100	Total Deliveries (MWh)														100
101	MWh @ Secondary Service	0	0	0	0	0	0	0	0	724,351	623,475	644,789	543,756	2,536,37	0 101
102	MWh @ Primary Service	0	0	0	0	0	0	0	0	199,877	151,864	136,022	167,290	655,05	3 102
103	MWh @ Transmission Service	0	0	0	0	0	0	0	0	52,615	102,963	47,617	93,055	296,25	0 103
104		0	0	0	0	0	0	0	0	976,843	878,302	828,428	804,101	3,487,67	4 104
105	Non-Coincident Demand (MW)														105
106	MW @ Secondary Service	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1,993.603	1,774.254	1,840.220	1,530.769	7,138.84	5 106
107	MW @ Primary Service	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	414.478	343.537	344.325	347.869	1,450.20	9 107
108	MW @ Transmission Service	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	108.886	180.540	87.338	158.818	535.58	3 108
109		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	2,516.966	2,298.331	2,271.883	2,037.456	9,124.63	7 109
110															110
111															111

						Section	Salamana, Anni ili epatimenti									
Line No.			FERCI	Recorded Sa			lectric Compriod: Septer		December :	2013					Reference	Line No.
1		Winter	Winter	Winter	Winter	Summer	Summer	Summer	Summer	Summer	Winter	Winter	Winter	Total	Acres direc	1
2	Schedules AD / PA-T-1:	Jan-13	Feb-13	Mar-13	Apr-13	<u>May-13</u>	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	Total		2
3	Non-Coincident Demand (MW) - 100%															3
4	MW @ Secondary Service	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	88.278	75.368	84.311	65.264	313.221	Section 2.3.2; Page 14.1; Line 35	4
5	MW @ Primary Service	0,000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	10,765	14.734	13.323	11,636	50.458	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	0,000	0.000	0.000	0.000	0.000	0,000	0,000	0,000	99.043	90.102	97.634	76.900	363,679	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	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1,905.325	1,698.886	1,755,909	1,465.505	6,825.624	Section 2.3.2; Page 14.2; Line 61	11
12	MW @ Primary Service	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	392.300	312.190	308.706	327.889	1,341.085	Section 2.3.2; Page 14.2; Line 62	12
13	MW @ Transmission Service	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	23.682	6.631	22,753	25.952	79.018	Section 2.3.2; Page 14.2; Line 63	13
14	Sub-Total	0,000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	2,321.307	2,017.707	2,087.368	1,819.345	8,245.727	Sum Lines 11; 12; 13	14
15																15
16	On-Peak Demand (MW)															16
17	MW @ Secondary Service	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1,807.544	1,485.775	1,431,109	1,159.115	5,883.543	Section 2.3.2; Page 14.2; Line 71	17
18	MW @ Primary Service	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	434.562	320,285	282,622	319.624	1,357.092	Section 2.3.2; Page 14.2; Line 72	18
19	MW @ Transmission Service	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	34.885	8.292	33.532	66,584	143,293	Section 2.3.2; Page 14.2; Line 73	19
20	Sub-Total	0.000	0.000	0.000	0,000	0,000	0.000	0,000	0,000	2,276.991	1,814.352	1,747.263	1,545.323	7,383.929	Sum Lines 17; 18; 19	20
21										,		,			, , , , , ,	21
22	Schedule A6-TOU:	-		(315.11.04.010)												22
23	Non-Coincident Demand (MW) - 90%													1		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	0.000	0.000	0.000	0.000	0,000	0.000	0.000	0.000	11.413	16.612	22.296	8.344	58.666	Section 2.3.2; Page 14.2; Line 98	25
26	MW @ Transmission Service	0,000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	85.203	173.909	64.585	132,867	456.565	Section 2.3.2; Page 14.2; Line 99	26
27	Sub-Total	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	96.616	190.522	86.881	141.211	515,230	Sum Lines 24; 25; 26	27
28	240 70411	0.000	0,000	0.000	0,000	0,000	0.000	0.000	0.000	50.010	170.022	00,001	171.211	313,230	Sun Billes 24, 23, 20	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	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	10.501	8.713	11.086	11.661	41.961	Section 2.3.2; Page 14.3; Line 108	31
32	MW @ Transmission Service	0.000	0.000	0,000	0.000	0,000	0.000	0.000	0.000	77.928	155.138	51,623	110.213	394,902	Section 2.3.2; Page 14.3; Line 109	32
33	Sub-Total	0,000	0.000	0.000	0.000	0.000	0,000	0.000	0.000	88.430	163.851	62.709	121.874	436.863	Sum Lines 30; 31; 32	33
34	540 7544	0.000	0.000	0.000	0,000	0,000	0.000	0.000	0,000	55,450	105,051	02.703	121.074	450,005	5un Emes 30, 31, 32	34
35	TOTAL SUMMARY															35
36	Non-Coincident Demand (MWH) @ 100%													1		36
37	MW @ Secondary Service	0	0	0	0	n	0	0	0	1,993,603	1,774,254	1,840,220	1,530,769	7,138,845	Apr-Aug; Lines (4, 11 and 24) x 1000	37
38	in vi tag secondary service	G		Ü	V	·	· ·	· ·	V	1,555,005	1,774,254	1,040,220	1,550,705	7,130,043	Sep-Mar; (Line 4 x 1000)	38
	MW @ Primary Service	0	0	0	0	0	0	0	0	414,478	343,537	344,325	347,869	1,450,209	Apr-Aug; Lines (5, 12 and 25) x 1000	39
40	S Timary borriot	U	J	J	U	Ü	U	U	U	717,770	1 66,676	J-14,34J	J=1,007	1,700,209	Sep-Mar; (Line 5 x 1000)	40
41	MW @ Transmission Service	0	0	0	0	0	0	0	0	108,886	180,540	87,338	158,818	535,583	Apr-Aug; Lines (6, 13 and 26) x 1000	41
42	171 W (W Transmission Service	U	V	O.	Ü	· ·	U	U	U	100,000	180,540	01,330	136,616	232,263	Sep-Mar; (Line 6 x 1000)	42
43	Total - NONCoincident Demand @ 100%	0	0	0	0	0	0	0	0	2,516,966	2,298,331	2,271,883	2,037,456	9,124,637	Sum Lines 37 thru 42	43
44	Total - NONCOllicident Demand @ 100%		0		0	Ů	0	V	V	2,310,900	2,290,331	2,271,003	2,037,430	9,124,037	Sum Lines 37 tinu 42	
45	Non-Coincident Demand (MWH) @ 90%															44
		_	0		•					1 005 35 5	1 (00 001	1 755 000			0.10.000	45
46	MW @ Secondary Service	0	•	0	0	0	0	0	0	1,905,325	1,698,886	1,755,909	1,465,505	6,825,624	Sep-Mar; ((Lines 11 & 24) x 1000)	46
	MW @ Primary Service	0	0	0		0	0	0	0	403,712	328,803	331,002	336,233	1,399,750	Sep-Mar; ((Lines 12 & 25) x 1000)	47
48	MW @ Transmission Service	0	0	0	0	0	0	0	0	108,886	180,540	87,338	158,818	535,583	Sep-Mar; ((Lines 13 & 26) x 1000)	48
49	Total - NONCoincident Demand @ 90%	-	-	4	-	-	0	0	0	2,417,923	2,208,229	2,174,249	1,960,556	8,760,957	Sum Lines 46 thru 48	49
50																50

Section 2.3.1 SAN DIEGO GAS AND ELECTRIC COMPANY TO4-Cycle 2 Annual Transmission Formulaic Rate Filing Derivation of Retail True-Up Cos of Service Rates For the True-Up Period - (September 1, 2013 - December 31, 2013) Development of 12-CP Allocation Factors

		ment of 12-CP Anoca		(D) = (D) - (C)	(E)		F
	(A)	(B)	(C)	$(D) = (B) \times (C)$	(E)		
. 1		Recorded Demand		Recorded Demand			
		Determinants		Determinants			
Line		Megawatt @	Transmission	Megawatt @			Line
No.	Customer Class	Meter Level	Loss Factors	Transmission Level	Ratios	Reference	No.
1	Recorded Demand Determinants for Medium-Large Commercial Customers:						1
	Non-Coincident Demand Determinants Pertaining to Customers on Schedules @ 100% NCD Rate					1	2
3	Secondary 1	313	1.0457	328	86,54%	Cal Dana 15 1, Cal Dalina 2	3
1		1		1	N 909		1
4	Primary ²	50	1.0108	51	13.46%	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	364		379	100.00%	Sum Lines 3; 4; 5	6
7						Salah Parana Panganan Panganan Panganan Pangan	7
	Non-Coincident Demand Determinants Pertaining to Customers on Schedules @ 90% NCD Rate						8
9							9
	with Maximum On-Peak Period Demand						
10	Secondary	6,826	1.0457	7,138	83,26%	Comment of the control of the contro	10
11	Primary	1,341	1.0108	1,356	15.82%		11
12	Transmission	79	1.0000	79	0.92%	Col. B=Page 15.1; Col. E; Line 12	12
13	Total	8,246		8,573	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	59	1.0108	59	11.43%		18
19	Transmission	457	1,0000	457	88.57%		19
20	Total	515		516	100.00%	Sum Lines 17; 18; 19	20
21						1	21
22	Total Non-Coincident Demand Determinants Pertaining to Medium-Large Commercial Customers					İ	22
23	Secondary	7,139	1.0457	7,465	78.85%	Sum Lines 3; 10; 17	23
24		1,450	1.0108		15.49%		24
	Primary			1,466	The second secon	Sum Lines 4; 11; 18	
25	Transmission	536	1.0000	536	5.66%	Sum Lines 5; 12; 19	25
26	Total	9,125		9,467	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	1,808	1.0457	1,890	79.95%	Col. B=Page 15.1; Col. E; Line 30	30
31	Primary	435	1.0108	439	18.57%		31
	·	1					
32	Transmission	35	1.0000	35	1.48%	Col. B=Page 15.1; Col. E; Line 32	32
33	Total	2,277		2,364	100.00%	Sum Lines 30; 31; 32	33
34	Winter Months = (October, November, December, January, February, March, April)						34
35	Secondary	4,076	1.0457	4,262	80.38%	Col. B=Page 15.1; Col. E; Line 35	35
36	Primary	923	1.0108	932	17.58%	Col. B=Page 15.1; Col. E; Line 36	36
37	Transmission	108	1.0000	108	2.04%		37
38	Total	5,107	1,0000	5,302	100.00%	Sum Lines 35; 36; 37	38
39	Grand Total		***		100,0076	Jun Lines 33, 30, 37	
		7,384		7,666			39
40	Maximum Demand at the Time of System Peak Determinants						40
41	Summer Months = (May, June, July, August, September)						41
42	Secondary	-	1.0457	-	0.00%	Col. B=Page 15.1; Col. E; Line 42	42
43	Primary	11	1.0108	11	12.36%	Col. B=Page 15.1; Col. E; Line 43	43
44	Transmission	78	1,0000	78	87.64%		44
45	Total	88		89	100.00%		45
46	Winter Months = (October, November, December, January, February, March, April)			321	100,0070	12, 13, 11	46
			10155	_	0.000	G.I D.D. 151 G I D 1	1
47	Secondary		1.0457	-	0.00%		47
48	Primary	31	1.0108	32	9.17%		48
49	Transmission	317	1,0000	317	90.83%		49
50	Total	348		349	100,00%	Sum Lines 47; 48; 49	50
51	Grand Total	437		438			51
52							52
53		Recorded Demand		Recorded Demand			53
54		Determinants		Determinants			
							54
55	VC	Megawatt @	Transmission	Megawatt @	7570 (440)		55
1	Forecast Demand Determinants for Standby Customers:	Meter Level	Loss Factors	Transmission Level	Ratios		56
57	Contracted Demand Determinants					1	57
58	Secondary	44	1.0457	46	6.68%	Col. B=Page 16.3; Line 114	58
	Primary	399	1,0108	403	58.49%	Col. B=Page 16.3; Line 115	59
1 29 1	ROMAN AND AND AND AND AND AND AND AND AND A	2007.00	1.0000	240	34.83%	Col. B=Page 16.3; Line 116	60
59	Transmission						
60 61	Transmission Total	240 682	1,0000	689	100.00%	Sum Lines 57; 58; 59	61

$\underline{Section-2}$

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

Section 2.3.1

Derivation of Retail True-Up

Cost of Service Rates

Docket No. ER14-__-

Section 2.3.1 SAN DIEGO GAS AND ELECTRIC COMPANY **TO4-Cycle 2 Annual Transmission Formulaic Rate Filing** True-Up Period Rate Design Information For the True-Up Period - (September 1, 2013 - December 31, 2013) **Summary of Transmission Rates** (A) (B) (C) (D) Transmission Primary Secondary Transmission Level Level Level **Demand Rates Demand Rates Demand Rates** Line Line **Energy Rates** \$/kW-Mo \$/kW-Mo \$/kW-Mo Reference Customer Classes \$/kWh No. No. 1 Residential \$ 0.0357211750 Section 2.3.1; Page 3; Line 7 1 2 2 3 3 Small Commercial \$ 0.0365806675 Section 2.3.1; Page 4; Line 7 4 4 5 Medium & Large Commercial/Industrial 5 Non-Coincident Demand (100%) 6 \$ 10.1694580573 \$ 10.2721872734 \$ 10.6257912891 Section 2.3.1; Page 5; Lines 35;34;33 6 7 7 8 Non-Coincident Demand (90%)² \$ 9.1525122516 \$ 9.2449685461 \$ 9.5632121602 Section 2.3.1; Page 6; Lines 8;7;6 8 9 9 Maximum On-Peak Period Demand 3 10 10 Section 2.3.1; Page 7; Lines 37; 36; 35 \$ 2.9575247160 \$ 2.9778914655 \$ 3.0822581330 11 11 Summer Section 2.3.1; Page 8; Lines 30; 29; 28 \$ 0.3273436869 \$ 0.3319549359 \$ 0.3435763374 12 12 Winter 13 13 Maximum Demand at the Time of System Peak⁴ 14 14 15 \$ 4.7195096896 \$ 4.9391716493 Section 2.3.1; Page 9; Lines 37; 36; 35 15 Summer \$ 0.3057725037 16 16 Winter \$ 0.3006343347 Section 2.3.1; Page 10; Lines 33; 32; 31 17 17 18 Street Lighting \$ 0.0237453029 Section 2.3.1; Page 11; Line 7 18 19 19 20 Standby Rate \$ 4.6993490714 \$ 4.7440605136 \$ 4.9531330667 Section 2.3.1; Page 12; Lines 35;34;33 20 NOTES: Non-Coincident Demand (NCD) (100%) rates are applicable to the following California Public Utilities Commission (CPUC) tariffs: Schedules AD and PA-T-1 ²NCD (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

SAN DIEGO GAS AND ELECTRIC COMPANY

$TO 4-Cycle\ 2\ Annual\ Transmission\ Formulaic\ Rate\ Filing$

Derivation of Retail True-Up Cos of Service Rates

For the True-Up Period - (September 1, 2013 - December 31, 2013)

Allocation of Base Transmission Revenue Requirements (BTRR) Based on 12 CPs (\$1,000)

		(A)	(B)	(C)		
				Allocated Base		
				Transmission		
Line		Total 12 CPs @		Revenue		Line
No.	Customer Classes	Transmission Level ²	Percentages ³	Requirement	Reference	No.
1	Total Base Transmission Revenue Requirement ¹			\$ 215,170	Section 2.3; Page 5 of 5; Line 12	1
2						2
3	Allocation of BTRR Based on 12-CP:					3
4	Residential	5,799,957	41.774%	\$ 89,884.953	Col.C Ln 4 = Col C Ln 1 x Col B. Ln 4	4
5	Small Commercial	1,617,355	11.649%	25,064.995	Col.C Ln 5 = Col C Ln1 x Col B. Ln 5	5
6	Medium & Large Commercial/Industrial	6,207,398	44.708%	96,199.281	Col.C Ln 6 = Col C Ln1 x Col B. Ln 6	6
7	Street Lighting Revenues	50,681	0.365%	785.437	Col.C Ln 7 = Col C Ln1 x Col B. Ln 7	7
8	Standby Revenues	208,797	1.504%	3,235.841	Col.C Ln 8 = Col C Ln 1 x Col B. Ln 8	8
9						9
10	Total	13,884,188	100.00%	\$ 215,171	Sum Lines 4 thru 8	10
11						11
12	Total	13,884,188		\$ 215,171	Line 10	12

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

² See Statement BL; Page 9; Column D.

See Statement BL; Page 9; Column E.

SAN DIEGO GAS AND ELECTRIC COMPANY

TO4-Cycle 2 Annual Transmission Formulaic Rate Filing Derivation of Retail True-Up Cos of Service Rates

For the True-Up Period - (September 1, 2013 - December 31, 2013)

Residential Customers ¹ (\$000)

Line		Co	Derivation of mmodity Rate & oof of Revenues		Line
No.	Description		Calculation	Reference	No.
		Φ.	00.005		
	Residential - Allocated Transmission Revenue Requirements	\$	89,885	Section 2.3.1; Page 2; Line 4	1
2 3 4	Billing Determinants - Residential Customer Class (MWh):		2,516,293	Section 2.3.1; Page 16.1; Line 4	2 3 4
5 6	Residential Energy Rate Per kWh	\$	0.0357211750	Line 1 / Line 3	5 6
7 8	Residential Energy Rate Per kWh - Rounded	\$	0.0357211750	Line 5, Rounded to 7 Decimal Places	7 8
9	Proof of Revenues	\$	89,885	Line 7 x Line 3	9
10	Difference	e	0.00	Line 1 - Line 9	10 11
11	Difference	Ф	0.00	Line 1 - Line 9	11

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

Section 2.3.1 SAN DIEGO GAS AND ELECTRIC COMPANY

TO4-Cycle 2 Annual Transmission Formulaic Rate Filing

Derivation of Retail True-Up Cos of Service Rates

For the True-Up Period - (September 1, 2013 - December 31, 2013)

Small Commercial Customers ¹ (\$000)

		0.000			
Line No.	Description	l .	Derivation of ommodity Rate & coof of Revenues Calculation	Reference	Line No.
1	Small Commercial - Allocated Transmission Revenue Requirement	\$	25,065	Section 2.3.1; Page 2; Line 5	1
2 3 4 5 6	Billing Determinants - Small Commercial (MWh): Rate Per kWh Calculation	\$	685,198 0.0365806675	Section 2.3.1; Page 16.1; Line 5 Line 1 / Line 3	2 3 4 5 6
7 8	Rate Per kWh Calculation - Rounded	\$	0.0365806675	Line 5, Rounded to 7 Decimal Places	7 8
9	Proof of Revenues	\$	25,065	Line 7 x Line 3	9
10 11	Difference	\$	0.00	Line 1 - Line 9	10 11

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

SAN DIEGO GAS AND ELECTRIC COMPANY

TO4-Cycle 2 Annual Transmission Formulaic Rate Filing

Derivation of Retail True-Up Cos of Service Rates

For the True-Up Period - (September 1, 2013 - December 31, 2013)

Medium-Large Commercial Customers 1

(\$000)

	(\$000)	•	C. C	
		Derivation of		
		Commodity Rate &		
Line		Proof of Revenues		Line
No.	Description	Calculation	Reference	No.
1	Med-Lrg C&I - Demand Revenue Requirement	\$ 96,199	Section 2.3.1; Page 2; Line 6	1
		Ψ 70,177	Section 2.3.1, 1 age 2, Diffe o	
2	Demand Determinants @ Transmission Level Used to Allocate			2
3	Total Class Revenues to Voltage Level with Loss Factor Adjustment (MW) 2:		0	3
4	Secondary	7,465	Section 2.3.1; Page 15; Col. D; Line 23	4
5	Primary	1,466	Section 2.3.1; Page 15; Col. D; Line 24	5
6	Tranmission	536	Section 2.3.1; Page 15; Col. D; Line 25	6
7	Total	9,467	Sum Lines 4; 5; 6	7
8	Allocation Factors Per Above to Allocate			8
9	Demand Revenue Requirements to Voltage Level:			9
10	Secondary	78.85286%	Line 4 / Line 7	10
11	Primary	15.48537%	Line 5 / Line 7	11
12	Tranmission	5.66177%	Line 6 / Line 7	12
13	Total	100.00000%	Sum Lines 10; 11; 12	13
14	1000	100,000070	5 mil	14
	All CD D ' All I I		*	_
15	Allocation of Revenue Requirements to Voltage Level	77.076		15
16	Secondary	\$ 75,856	Line 1 x Line 10	16
17	Primary	\$ 14,897	Line 1 x Line 11	17
18	Tranmission	\$ 5,447	Line 1 x Line 12	18
19	Total	\$ 96,199	Sum Lines 16; 17; 18	19
20		*		20
21	Demand Determinants By Voltage Level @ Meter Level (MW)			21
22	Secondary	7,139	Section 2.3.1; Page 15; Col. B; Line 23	22
23	Primary	1,450	Section 2.3.1; Page 15; Col. B; Line 24	23
24	Tranmission	536	Section 2.3.1; Page 15; Col. B; Line 25	24
25	Total	9,125	Sum Lines 22; 23; 24	25
26	1 Otti	7,123	54iii Eiiies 22, 23, 24	26
$\overline{}$	D. ID. D. W.I. C.W.			_
27	Demand Rate By Voltage @ Meter			27
28	Secondary	\$ 10.6257912891	Line 16 / Line 22	28
29	Primary	\$ 10.2721872734	Line 17 / Line 23	29
30	Tranmission	\$ 10.1694580573	Line 18 / Line 24	30
31				31
32	Demand Rate By Voltage @ Meter (Rounded)			32
33	Secondary	\$ 10.6257912891	Line 28, Rounded to 7 Decimal Places	33
34	Primary	\$ 10.2721872734	Line 29, Rounded to 7 Decimal Places	34
35	Tranmission	\$ 10.1694580573	Line 30, Rounded to 7 Decimal Places	35
36				36
37	Proof of Revenue Calculations:			37
38	Secondary	\$ 75,856	Line 22 x Line 33	38
39	Primary	\$ 14,897	Line 23 x Line 34	39
40	Tranmission	\$ 5,447	Line 24 x Line 35	40
22.			Sum Lines 38; 39; 40	41
41	Total	\$ 96,199	Sum Lines 38; 39; 40	
42	99 700			42
43	Differenc	\$ 0.00	Line 1 - Line 41	43

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

SAN DIEGO GAS AND ELECTRIC COMPANY

TO4-Cycle 2 Annual Transmission Formulaic Rate Filing

Derivation of Retail True-Up Cos of Service Rates

For the True-Up Period - (September 1, 2013 - December 31, 2013)

Medium-Large Commercial Customers

(\$000)

Derivation of Cerumodity Rela & Proof Revenues Celumodity		(2000)				
Line Proof Revenues Calculability Reference No.		100000000000000000000000000000000000000		Derivation of		
Description Cabaulation Reference No.			Co	mmodity Rate &		
1 Rate Proposal 90% of Total M&L C&I NCD Rates: 50,000% 50	Line		Pr	oof of Revenues		Line
Secondary	No.	Description		Calculation	Reference	No.
3	1	Rate Proposal 90% of Total M&L C&I NCD Rates: 1		90.00%		1
A Transission S 9.1525122516 90% x Section 2.3.1; Page 5, Line 3 5 4	2	Secondary	\$	9.5632121602	90% x Section 2.3.1; Page 5; Line 33	2
Secondary	3	Primary	\$	9.2449685461	90% x Section 2.3.1; Page 5; Line 34	3
Secondary Seco	4	Tranmission	\$	9.1525122516	90% x Section 2.3.1; Page 5; Line 35	4
Primary \$ 0.2449685461 Line 2, Rounded to 7 Decimal Places R	5	Rate Proposal 90% of Total M&L C&I NCD Rates (Rounded):				5
8 Transmission	6	Secondary	\$	9.5632121602		6
9 Pertraining to Schedules @ 90% NCD with Maximum On-Peak Period Demand: 2 9 10 11 12 13 14 15 14 15 15 15 15 15	7	Primary	\$	9.2449685461		
NCD Determinants By Voltage Level @ Meter Level (MW)	8		\$	9.1525122516	Line 4, Rounded to 7 Decimal Places	
11 Secondary	9	Pertaining to Schedules @ 90% NCD with Maximum On-Peak Period Demand: 2				9
1.34 Section 2.3.1; Page 15; Col. B; Line 11 12 12 13 Transmission d 79 Section 2.3.1; Page 15; Col. B; Line 12 13 14 Total 8,246 Sum Lines 11; 12; 12 14 15 Annual Revenues from Current NCD Rate 100% of Total M&L C&I NCD Rates:	10	NCD Determinants By Voltage Level @ Meter Level (MW)				10
Transmission	11	Secondary ⁴		6,826	Section 2.3.1; Page 15; Col. B; Line 10	11
Total Sum Lines 11; 12; 13 14	12	Primary ⁴		1,341	Section 2.3.1; Page 15; Col. B; Line 11	12
15	13	Transmission ⁴		79	Section 2.3.1; Page 15; Col. B; Line 12	13
Secondary	14	Total		8,246	Sum Lines 11; 12; 13	14
Primary S 13,776 Line 12 x Section 2.3.1; Page 5; Line 34 17 Transmission S 804 Line 13 x Section 2.3.1; Page 5; Line 34 17 Line 13 x Section 2.3.1; Page 5; Line 35 18 Line 7 x Line 13 x Section 2.3.1; Page 5; Line 35 18 Line 7 x Line 13 x Section 2.3.1; Page 5; Line 35 18 Line 7 x Line 13 x Section 2.3.1; Page 5; Line 35 18 Line 7 x Line 19 Line 8 x Line 11 Line 12 Line 8 x Line 11 Line 12 Line 8 x Line 11 Line 8 x Line 11 Line 8 x Line 11 Line 8 x Line 13 Line 17 x Line 12 Line 8 x Line 13 Line 17 x Line 12 Line 8 x Line 13 Line 17 x Line 12 Line 8 x Line 13 Line 17 x Line 12 Line 8 x Line 13 Line 17 x Line 12 Line 18 x Line 19 L	15	Annual Revenues from Current NCD Rate 100% of Total M&L C&I NCD Rates:				15
Tranmission	16	Secondary	\$	72,528	Line 11 x Section 2.3.1; Page 5; Line 33	16
Total S	17	Primary	\$	13,776	Line 12 x Section 2.3.1; Page 5; Line 34	17
Annual Revenues from Proposed NCD Rate 90% of Total M&L C&I NCD Rates: Secondary	18	Tranmission	\$	804	Line 13 x Section 2.3.1; Page 5; Line 35	18
Secondary \$ \$ \$ \$ \$ \$ \$ \$ \$	19	Total	\$	87,107	Sum Lines 16; 17; 18	19
Primary	20	Annual Revenues from Proposed NCD Rate 90% of Total M&L C&I NCD Rates:				20
Trammission	21	Secondary	\$	65,275	Line 6 x Line 11	
Total S 78,396 Sum Lines 21; 22; 23 24	22	Primary	\$	12,398	Line 7 x Line 12	
25 Revenue Reallocation to Maximum On-Peak Period Demands: 25 Secondary \$ 1,378	23	Tranmission				
Secondary S	24		\$	78,396	Sum Lines 21; 22; 23	
Primary	2000			X	** 0	
Tranmission			1			
Total - Reallocated to MAXIMUM ON-PEAK PERIOD DEMANDS \$ 8,711 Sum Lines 26; 27; 28 29	4.00.000			200004		
Pertaining to Schedules @ 90% NCD with Maximum Demand at Time of System Peak: 3 NCD Determinants By Voltage Level @ Meter Level (MW) 31 Secondary 4						
NCD Determinants By Voltage Level @ Meter Level (MW) Secondary		\$	8,711	Sum Lines 26; 27; 28		
Secondary Seco	000000					
Secondary Seco					0 221 P 15 G l P I 15	1 1
Transmission 4 Section 2.3.1; Page 15; Col. B; Line 19 34 35 36 36 Annual Revenues from Current NCD Rate 100% of Total M&L C&I NCD Rates: Secondary Section 2.3.1; Page 5; Line 33 37 38 Primary Secondary Section 2.3.1; Page 5; Line 34 38 39 Transmission Secondary Section 2.3.1; Page 5; Line 34 38 38 39 Transmission Secondary Section 2.3.1; Page 5; Line 34 38 38 39 Transmission Secondary Section 2.3.1; Page 5; Line 34 38 39 Transmission Secondary S	1					1 1
Total Sim Lines 32; 33; 34 35	W 100	· · · · · · · · · · · · · · · · · · ·				
Annual Revenues from Current NCD Rate 100% of Total M&L C&I NCD Rates: Secondary	200 00	200				
37 Secondary \$ - Line 32 x Section 2.3.1; Page 5; Line 33 37 38 Primary \$ 603 Line 33 x Section 2.3.1; Page 5; Line 34 38 39 Tranmission \$ 4,643 Line 34 x Section 2.3.1; Page 5; Line 35 39 40 Total \$ 5,246 Sum Lines 37; 38; 39 40 40 41 Annual Revenues from Proposed NCD Rate 90% of Total M&L C&I NCD Rates: \$ - Line 6 x Line 38 42 42 42 Secondary \$ 542 Line 7 x Line 39 43 43 44 Tranmission \$ 4,719 Line 8 x Line 40 44 44 45 46 Total \$ 4,721 Sum Lines 42; 43; 44 45 46 Revenue Reallocation to Maximum Demand at the Time of System Peak: \$ - Line 37 - Line 42 47 47 48 Primary \$ 60 Line 38 - Line 43 48 48 49 Tranmission \$ 464 Line 39 - Line 44 49				515	Sum Lines 32; 33; 34	4 1
38 Primary \$ 603 Line 33 x Section 2.3.1; Page 5; Line 34 38 39 Tranmission \$ 4,643 Line 34 x Section 2.3.1; Page 5; Line 35 39 40 Total \$ 5,246 Sum Lines 37; 38; 39 40 41 Annual Revenues from Proposed NCD Rate 90% of Total M&L C&I NCD Rates: \$ - Line 6 x Line 38 42 42 Secondary \$ 542 Line 7 x Line 39 43 44 Tranmission \$ 4,179 Line 8 x Line 40 44 45 Total \$ 4,721 Sum Lines 42; 43; 44 45 46 Revenue Reallocation to Maximum Demand at the Time of System Peak: \$ - Line 37 - Line 42 47 48 Primary \$ 60 Line 38 - Line 43 48 49 Tranmission \$ 464 Line 39 - Line 44 49					T' 20 G (' 0.2 t B - 5 T' 22	
Tranmission \$ 4,643 Line 34 x Section 2.3.1; Page 5; Line 35 39 40		and a		-		
Total \$ 5,246 Sum Lines 37; 38; 39 40				7-07-07-07-07		
Annual Revenues from Proposed NCD Rate 90% of Total M&L C&I NCD Rates: Secondary		30-45-450-30-450-450-450-450-450-450-450-450-450-45				
42 Secondary \$ - Line 6 x Line 38 42 43 Primary \$ 542 Line 7 x Line 39 43 44 Tranmission \$ 4,179 Line 8 x Line 40 44 45 Total \$ 4,721 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 \$ 60 Line 38 - Line 43 48 49 Tranmission \$ 464 Line 39 - Line 44 49		Commence and the commen	Þ	3,240	Sum Lines 37, 38, 37	4 1
43 Primary \$ 542 Line 7 x Line 39 43 44 Tranmission \$ 4,179 Line 8 x Line 40 44 45 Total \$ 4,721 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 \$ 60 Line 38 - Line 43 48 49 Tranmission \$ 464 Line 39 - Line 44 49		-	•		Ling 6 v. Ling 39	
44 Tranmission \$ 4,179 Line 8 x Line 40 44 45 Total \$ 4,721 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 \$ 60 Line 38 - Line 43 48 49 Tranmission \$ 464 Line 39 - Line 44 49	100000			542		
45 Total		*				
46 Revenue Reallocation to Maximum Demand at the Time of System Peak: 46 47 Secondary \$ - Line 37 - Line 42 47 48 Primary \$ 60 Line 38 - Line 43 48 49 Tranmission \$ 464 Line 39 - Line 44 49		C5444204100000000000000000000000000000000			NO PRODUCE IN INCOMESSION VI IN	V000 10
47 Secondary \$ - Line 37 - Line 42 47 48 Primary \$ 60 Line 38 - Line 43 48 49 Tranmission \$ 464 Line 39 - Line 44 49			Ψ	1,721	2011 Annual 149 (25 11	1 I
48 Primary \$ 60 Line 38 - Line 43 48 49 Tranmission \$ 464 Line 39 - Line 44 49	1		\$	-	Line 37 - Line 42	
49 Tranmission \$ 464 Line 39 - Line 44 49				60		- 2
A COLL COLL COLL COLL COLL COLL COLL COL						
1 DV 1 TOTAL 1 DV	50	Total	\$	525	Sum Lines 47; 48; 49	50

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:

⁴ Represents NCD billing determinants based on Maximum On-Peak Period Demand during the period in which the new rate structure was in effect. Stat BL Four Month 11.12.xlsx - Medium&Large C-I Part 2

SAN DIEGO GAS AND ELECTRIC COMPANY

TO4-Cycle 2 Annual Transmission Formulaic Rate Filing

Derivation of Retail True-Up Cos of Service Rates

For the True-Up Period - (September 1, 2013 - December 31, 2013)

Medium-Large Commercial Customers (\$000)

	(\$000)		8		
]	Derivation of		
		Cor	nmodity Rate &		
Line		1	of of Revenues	*	Line
No.	Description		Calculation	Reference	No.
1	Med-Lrg C&I Maximum On-Peak Period Demand Proposal				1
2	Revenue Reallocation to Maximum On-Peak Period Demands: 1	\$	8,711	Section 2.3.1; Page 6; Line 29	2
3		Ψ	0,711	beetion 2.3.1, 1 age 0, Bille 2)	3
4	Summer - Maximum On-Peak Period Demands By Voltage Level @ Meter Level (MW) ²	+		11.14.00.00.00.00.00.00.00.00.00.00.00.00.00	4
5	(30) PANS 1329A 191 A		1 000	Section 2.2.1. Page 15: Cal D. Line 20	5
6	Secondary		1,808	Section 2.3.1; Page 15; Col. B; Line 30	1
7	Primary		435	Section 2.3.1; Page 15; Col. B; Line 31	6
	Transmission		35	Section 2.3.1; Page 15; Col. B; Line 32	7
8	Total	-	2,277	Sum Lines 5; 6; 7	8
9					9
10	Summer - Maximum On-Peak Period Demands By Voltage Level @ Trans. Level (MW)	İ			10
11	Secondary		1,890	Section 2.3.1; Page 15; Col. D; Line 30	11
12	Primary	1	439	Section 2.3.1; Page 15; Col. D; Line 31	12
13	Transmission		35	Section 2.3.1; Page 15; Col. D; Line 32	13
14	Total		2,364	Sum Lines 11; 12; 13	14
15					15
16	Summer Maximum On-Peak Period Allocation to Voltage Levels				16
17	Secondary		79.95%	Line 11 / Line 14	17
18	Primary		18.57%	Line 12 / Line 14	18
19	Tranmission		1.48%	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	\$	5,571	(Line 2 x Line 21) x Line 17	23
24	Primary	\$	1,294	(Line 2 x Line 21) x Line 18	24
25	Transmission	\$	103	(Line 2 x Line 21) x Line 19	25
26	Total	\$	6,969	Sum Lines 23; 24; 25	26
27					27
28	Summer Maximum On-Peak Period Demand Rates ³		\$/kW		28
29	Secondary	\$	3.0822581330	Line 23 / Line 5	29
30	Primary	\$	2.9778914655	Line 24 / Line 6	30
31	Transmission	\$	2.9575247160	Line 25 / Line 7	31
32	The second state of the second	1			32
33					33
34	Summer Maximum On-Peak Period Demand Rates (Rounded)		\$/kW		34
35	Secondary	\$	3.0822581330	Line 29, Rounded to 7 Decimal Places	35
36	Primary	\$	2.9778914655	Line 30, Rounded to 7 Decimal Places	36
37	Transmission	\$	2.9575247160	Line 31, Rounded to 7 Decimal Places	37
38	**************************************	Ψ	2.73,3247100	51, rounded to / Decimal Flaces	38
20	L				20

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

SAN DIEGO GAS AND ELECTRIC COMPANY

TO4-Cycle 2 Annual Transmission Formulaic Rate Filing

Derivation of Retail True-Up Cos of Service Rates

For the True-Up Period - (September 1, 2013 - December 31, 2013)

Medium-Large Commercial Customers (\$000)

	(\$000)				
]	Derivation of		
		Cor	nmodity Rate &		
Line		Pro	of of Revenues		Line
No.	Description		Calculation	Reference	No.
1	Winter Maximum On-Peak Period Demands By Voltage Level @ Meter Level (MW) 4				1
2	Secondary		4,076	Section 2.3.1; Page 15; Col. B; Line 35	2
3	Primary		923	Section 2.3.1; Page 15; Col. B; Line 36	3
4	Transmission		108	Section 2.3.1; Page 15; Col. B; Line 37	4
5	Total		5,107	Sum Lines 3; 4; 5	5
6	Winter Maximum On-Peak Period Demands @ Transmission Level (MW)				6
7	Secondary		4,262	Section 2.3.1; Page 15; Col. D; Line 35	7
8	Primary		932	Section 2.3.1; Page 15; Col. D; Line 36	8
9	Transmission		108	Section 2.3.1; Page 15; Col. D; Line 37	9
10	Total		5,302	Sum Lines 3; 4; 5	10
11	Winter Maximum On-Peak Period Allocation to Voltage Levels				11
12	Secondary		80.38476%	Line 7 / Line 10	12
13	Primary		17.57827%	Line 8 / Line 10	13
14	Tranmission		2.03697%	Line 9 / Line 10	14
15	Total		100.00000%	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		N - 100° - 310 - 11 100° - 10		17
18	Secondary	\$	1,400	(Page 7; Line 2 x Page 8; Line 16) x Line 12	18
19	Primary	\$	306	(Page 7; Line 2 x Page 8; Line 16) x Line 13	19
20	Transmission	\$	35	(Page 7; Line 2 x Page 8; Line 16) x Line 14	20
21	Total	\$	1,742	Sum Lines 18; 19; 20	21
22	Winter Maximum On-Peak Period Demand Rates 5		\$/kW		22
23	Secondary	\$	0.3435763374	Line 18 / Line 2	23
24	Primary	\$	0.3319549359	Line 19 / Line 3	24
25	Transmission	\$	0.3273436869	Line 20 / Line 4	25
26		1			26
27	Winter Maximum On-Peak Period Demand Rates (Rounded)		\$/kW		27
28	Secondary	\$	0.3435763374	Line 23, Rounded to 7 Decimal Places	28
29	Primary	\$	0.3319549359	Line 24, Rounded to 7 Decimal Places	29
30	Transmission	\$	0.3273436869	Line 25, Rounded to 7 Decimal Places	30
31		10200			31
32	Proof of Revenue Calculations:				32
33	Secondary	\$	6,972	(Page 7; Line 23) + (Page 8; Line 18)	33
34	Primary	\$	1,600	(Page 7; Line 24) + (Page 8; Line 19)	34
35	Transmission	\$	139	(Page 7; Line 25) + (Page 8; Line 20)	35
36	Total	\$	8,711	Sum Lines 33; 34; 35	36
37	Difference	\$	(0.00)	Page 7; Line 2 - Page 8; Line 36	37
38					38

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

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

SAN DIEGO GAS AND ELECTRIC COMPANY

TO4-Cycle 2 Annual Transmission Formulaic Rate Filing

Derivation of Retail True-Up Cos of Service Rates

For the True-Up Period - (September 1, 2013 - December 31, 2013)

Medium-Large Commercial Customers (\$000)

	(3000)				
]]	Derivation of		1 1
		Cor	nmodity Rate &		1
Line		Pro	of of Revenues		Line
No.	Description		Calculation	Reference	No.
1	Med-Lrg C&I Maximum Demand at the Time of System Peak Proposal				1
2	Revenue Reallocation to Maximum Demand at the Time of System Peak ¹	0	525	Section 2.3.1; Page 6; Line 50	2
750	Revenue Reallocation to Maximum Demand at the Time of System Leak	\$	525	Section 2.3.1, Page 6, Line 30	
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		11	Section 2.3.1; Page 15; Col. B; Line 43	6
7	Transmission		78	Section 2.3.1; Page 15; Col. B; Line 44	7
8	Total		. 88	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		11	Section 2.3.1; Page 15; Col. D; Line 43	12
13	Transmission		78	Section 2.3.1; Page 15; Col. D; Line 44	13
14	Total		89	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		0.000000%	Line 11 / Line 14	17
18	Primary	1	12.359551%	Line 12 / Line 14	18
19			87.640449%	Line 13 / Line 14	19
	Transmission	-			20
20	Total	_	100.000000%	Sum Lines 17; 18; 19	
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	\$	52	(Line 2 x Line 21) x Line 18	24
25	Transmission	\$	368	(Line 2 x Line 21) x Line 19	25
26	Total	\$	420	Sum Lines 23; 24; 25	26
27					27
28	Summer Maximum Demand at the Time of System Peak Rates ³	8	\$/kW		28
29	Secondary	\$	-	Line 23 / Line 5	29
30	Primary	\$	4.9391716493	Line 24 / Line 6	30
31	Transmission	\$	4.7195096896	Line 25 / Line 7	31
32			Secretary special section of the second		32
33		\top			33
34	Summer Maximum Demand at the Time of System Peak Rates (Rounded)		\$/kW		34
35	Secondary	\$	Ψ/ IX YY	Line 29, Rounded to 7 Decimal Places	35
36	Primary	\$	4.9391716493	Line 30, Rounded to 7 Decimal Places	36
37		\$	4.7195096896	Line 31, Rounded to 7 Decimal Places	37
	Transmission	1 2	4./193090890	Line 31, Rounded to / Decimal Places	38
38					38

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

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

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

SAN DIEGO GAS AND ELECTRIC COMPANY

TO4-Cycle 2 Annual Transmission Formulaic Rate Filing

Derivation of Retail True-Up Cos of Service Rates

For the True-Up Period - (September 1, 2013 - December 31, 2013)

Medium-Large Commercial Customers (\$000)

			
		Derivation of	
		Commodity Rate	&
Line		Proof of Revenu	es Li
No.	Description	Calculation	Reference N
	Winter Maximum Demand at the Time of System Peak By Voltage Level @ Meter Level (MW) 4	Curculation	Total circle
1			1
2	Secondary	-	Section 2.3.1; Page 15; Col. B; Line 47
3	Primary	T.	Section 2.3.1; Page 15; Col. B; Line 48
4	Transmission	3	17 Section 2.3.1; Page 15; Col. B; Line 49
5	Total	3	Sum Lines 2; 3; 4
6			
7	Winter Maximum Demand at the Time of System Peak @ Transmission Level (MW)		
8	Secondary	_	Section 2.3.1; Page 15; Col. D; Line 47
9	Primary		32 Section 2.3.1; Page 15; Col. D; Line 48
10	Transmission	E .	Section 2.3.1; Page 15; Col. D; Line 49
11	Total		49 Sum Lines 8; 9; 10
-	Total	3	
12			1
13	Winter Maximum Demand at the Time of System Peak Allocation to Voltage Levels	Service and Property Co.	1
14	Secondary	0.000000	
15	Primary	9.169054	1% Line 9 / Line 11 1
16	Transmission	90.830945	5% Line 10 / Line 11 1
17	Total	100.000000	0% Sum Lines 14; 15; 16 1
18	Share of Total Revenue Allocation to Winter Maximum Demand at the Time of System Peak	20.0	0%
19	Revenues for Proposed Winter Maximum Demand at the Time of System Peak Rates		
20	Secondary	\$ -	(Page 9; Line 2 x Page 10; Line 18) x Line 14
21	Primary	100	(Page 9; Line 2 x Page 10; Line 18) x Line 15
22	SON PRODUCTION OF THE PRODUCTI		
	Transmission		
23	Total	3 1	05 Sum Lines 20; 21; 22 2
24			2
25	Winter Maximum Demand at the Time of System Peak Rates ⁵	\$/kW	2
26	Secondary	\$ -	Line 20 / Line 2
27	Primary	\$ 0.30577250	37 Line 21 / Line 3 2
28	Transmission	\$ 0,30063433	47 Line 22 / Line 4 2
29			2
30	Winter Maximum Demand at the Time of System Peak Rates (Rounded)	\$/kW	
31			
	Secondary	\$ -	
32	Primary	\$ 0.305772503	1
33	Transmission	\$ 0.300634334	
34			3
35	Proof of Revenue Calculations:		3
36	Secondary	\$ -	(Page 9; Line 23) + (Page 10; Line 20) 3
37	Primary	\$	61 (Page 9; Line 24) + (Page 10; Line 21) 3
38	Transmission	Di contra di con	63 (Page 9; Line 25) + (Page 10; Line 22) 3
39	Total		Sum Lines 36; 37; 38 3
40	Difference		DO Page 9; Line 2 - Page 10; Line 39 4
40	Difference	- μ	1 age 7, Line 2 - Fage 10, Line 39 4

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

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

SAN DIEGO GAS AND ELECTRIC COMPANY

TO4-Cycle 2 Annual Transmission Formulaic Rate Filing

Derivation of Retail True-Up Cos of Service Rates

For the True-Up Period - (September 1, 2013 - December 31, 2013)

Street Lighting Customers

(\$000)

			Derivation of		
		Con	mmodity Rate &		
Line		Pro	oof of Revenues		Line
No.	Description		Calculation	Reference	No.
1	Street Lighting - Allocated Transmission Revenue Requirement	\$	785	Section 2.3.1; Page 2; Line 7	1
2					2
3	Billing Determinants - Street Lighting Customers (MWh) 1:		33,078	Statement 2.3.1; Page 16.1; Line 9	3
4					4
5	Rate Per kWh Calculation	\$	0.0237453029	Line 1 / Line 3	5
6					6
7	Rate Per kWh Calculation - Rounded	\$	0.0237453029	Line 5, Rounded to 7 Decimal Places	7
8					8
9	Proof of Revenues:	\$	785	Line 3 x Line 7	9
10					10
11	Difference	\$	(0.00)	Line 1 - Line 9	11

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

SAN DIEGO GAS AND ELECTRIC COMPANY

TO4-Cycle 2 Annual Transmission Formulaic Rate Filing

Derivation of Retail True-Up Cos of Service Rates

For the True-Up Period - (September 1, 2013 - December 31, 2013)

Standby Revenues Calculation (\$000)

	(\$000)	2002200		
		Derivation of		
		Standby Surcharge &		
Line		Proof of Revenues		Line
No.	Description	Calculation	Reference	No.
	1			
1	Standby - Demand Revenue Requirement	\$ 3,236	Section 2.3.1; Page 2; Line 8	1
2	Demand Determinants @, Transmission Level Used to Allocate	ψ 5,220	20000 20000, 1 486 2, 2000 0	2
3	Total Class Revenues to Voltage Level with Loss Factor Adjustment (MW) 1:			3
4	Secondary	46	Section 2.3.1; Page 15; Col. D; Line 57	4
5	Primary	403		5
6	Tranmission		Section 2.3.1; Page 15; Col. D; Line 58	
7	Total	240 689	Section 2.3.1; Page 15; Col. D; Line 59	6
		089	Sum Lines 4; 5; 6	7
8	Allocation Factors Per Above to Allocate			8
9	Demand Revenue Requirements to Voltage Level:	AS .		9
10	Secondary	6.67634%	Line 4 / Line 7	10
11	Primary	58.49057%	Line 5 / Line 7	11
12	Tranmission	34.83309%	Line 6 / Line 7	12
13	Total	100.00000%	Sum Lines 10; 11; 12	13
14				14
15	Allocation of Revenue Requirements to Voltage Level			15
16	Secondary	\$ 216	Line 1 x Line 10	16
17	Primary	\$ 1,893	Line 1 x Line 11	17
18	Tranmission	\$ 1,127	Line 1 x Line 12	18
19	Total	\$ 3,236	Sum Lines 16; 17; 18	19
20			,,	20
21	Demand Determinants By Voltage Level @ Meter (MW)			21
22	Secondary	44	Section 2.3.1; Page 15; Col. B; Line 57	22
23	Primary	399	Section 2.3.1; Page 15; Col. B; Line 58	23
24	Tranmission	240	Section 2.3.1; Page 15; Col. B; Line 59	24
25	Total	682	Sum Lines 22; 23; 24	25
	Total	082	Sum Lines 22, 23, 24	1 1
26				26
27	Demand Rate By Voltage Level @ Meter			27
28	Secondary	\$ 4.9531330667	Line 16 / Line 22	28
29	Primary	\$ 4.7440605136	Line 17 / Line 23	29
30	Tranmission	\$ 4.6993490714	Line 18 / Line 24	30
31				31
32	Demand Rate By Voltage Level @ Meter (Rounded)			32
33	Secondary	\$ 4.9531330667	Line 28, Rounded to 7 Decimal Places	33
34	Primary	\$ 4.7440605136	Line 29, Rounded to 7 Decimal Places	34
35	Tranmission	\$ 4.6993490714	Line 30, Rounded to 7 Decimal Places	35
36				36
37	Proof of Revenue Calculations:			37
38	Secondary	\$ 216	Line 22 x Line 33	38
39	Primary	\$ 1,893	Line 23 x Line 34	39
40	Tranmission	\$ 1,127	Line 24 x Line 35	40
41	Total	\$ 3,236	Sum Lines 38; 39; 40	41
42			des-topic-reners - sections (PS) (PS)(S) (PS) (S) (S) (F) (S) (S)	42
43	Difference	\$ (0.00)	Line 1 - Line 41	43
		(0.00)		
	<u> </u>			I

 $^{^{1}}$ 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

TO4-Cycle 2 Annual Transmission Formulaic Rate Filing

Derivation of Retail True-Up Cos of Service Rates

For the True-Up Period - (September 1, 2013 - December 31, 2013)

Summary of Proof of Revenues (\$1,000)

		(A)			(B)		(C)		
Line		Total Revenues Per Cost of		Total Revenues Per Rate					Line
No.	Customer Classes	Service Stud	У		Design	Diff	ference	Reference	No.
1 2	Residential Customers	\$ 89,8	35	\$	89,885	\$	0	Section 2.3.1; Pages 2 & 3	1 2
3	Small Commercial	25,0	55		25,065		0	Statement 2.3.1; Pages 2 & 4	3
4									4
1	Medium-Large Commercial	96,1	99		96,199		0	Statement 2.3.1; Pages 2 & 5	5
6		_							6
1	Street Lighting	7	35		785		(0)	Statement 2.3.1; Pages 2 & 11	7
8	G. 11 B	2.2			2.226		(0)	G	8
9	Standby Revenues	3,2	36		3,236		(0)	Statement 2.3.1; Pages 2 & 12	9
10	0 15 1	0 0151	7.1	Φ.	015 171	Φ.			10
11	Grand Total	\$ 215,1	/1	\$	215,171	\$	0	Sum Lines 1 thru 9	11

SAN DIEGO GAS AND ELECTRIC COMPANY

$TO 4-Cycle\ 2\ Annual\ Transmission\ Formulaic\ Rate\ Filing$

Derivation of Retail True-Up Cos of Service Rates

For the True-Up Period - (September 1, 2013 - December 31, 2013)

Development of 12-CP Allocation Factors Using Recorded Data: 2007-2011

	(a)	(b)	(c)	$(d) = (b) \times (c)$	(e)	(g)	
		5-Year Average Of 12 CPs		5-Year Average Of 12 CPs			
Line		Kilowat @	Transmission	Kilowat @			Line
No.	Customer Class	Meter Level	Loss Factors	Transmission Level	Ratio	Reference	No.
1	5 Year Average - 12CP Allocation Factors:	7.716.100	1.045		44.550		1
2	Residential Customers	5,546,483	1.0457	5,799,957	41.77%	Statement BB; Page 1; Line 1	2
3	Small Commercial Customers	1,546,672	1.0457	1,617,355	11.65%	Statement BB; Page 1; Line 2	3
4	Medium-Large Commercial Customers						4
5	Secondary	4,441,062	1.0457	4,644,018	33.45%	Statement BB; Page 1; Line 4	5
6	Primary	1,103,224	1.0108	1,115,139	8.03%	Statement BB; Page 1; Line 5	6
7	Transmission	448,241	1.0000	448,241	3.23%	Statement BB; Page 1; Line 6	7
8	Total Medium-Large Commercial	5,992,527	1.0359	6,207,398	44.71%	Sum Lines 5; 6; 7	8
9							9
10	Street Lighting	48,466	1.0457	50,681	0.37%	Statement BB; Page 1; Line 9	10
11	Standby Customers	•		200			11
12	Secondary	13,012	1.0457	13,607	0.10%	Statement BB; Page 1; Line 11	12
13	Primary	121,014	1.0108	122,321	0.88%	Statement BB; Page 1; Line 12	13
14	Transmission	72,869	1.0000	72,869	0.52%	Statement BB; Page 1; Line 13	14
15	Total Standby Customers	206,895	1.0092	208,797	1.50%	Sum Lines 12; 13; 14	15
16							16
17	System Total	13,341,043	1.04071	13,884,188	100.01%	Sum Lines 2; 3; 8; 10; 15	17
18							18

Section 2.3.1
SAN DIEGO GAS AND ELECTRIC COMPANY
TO4-Cycle 2 Annual Transmission Formulaic Rate Filing
Derivation of Retail True-Up Cos of Service Rates
For the True-Up Period - (September 1, 2013 - December 31, 2013)
Development of 12-CP Allocation Factors

2 Non 3 4 5 6 7 8 Non 9 with 11 12 13 14	Customer Class Customer Class corded Demand Determinants for Medium-Large Commercial Customers; on-Coincident Demand Determinants Pertaining to Customers on Schedules @ 100% NCD Rate Secondary Primary Transmission Transmission Transmission Transmission	(B) Recorded Demand Determinants Megawatt @ Meter Level	(C) Transmission Loss Factors	(D) = (B) x (C) Recorded Demand Determinants Megawatt @ Transmission Level	(E)		Line
No. Rec 2 Noi 3 4 5 6 7 8 Noi 9 with 10 11 12 13 14	corded Demand Determinants for Medium-Large Commercial Customers; on-Coincident Demand Determinants Pertaining to Customers on Schedules @ 100% NCD Rate Secondary ¹ Primary ²	Determinants Megawatt @ Meter Level		Determinants Megawatt @	Dation		Line
No. Rec 2 Noi 3 4 5 6 7 8 Noi 9 with 10 11 12 13 14	corded Demand Determinants for Medium-Large Commercial Customers; on-Coincident Demand Determinants Pertaining to Customers on Schedules @ 100% NCD Rate Secondary ¹ Primary ²	Megawatt @ Meter Level		Megawatt @	Delier		Line
No. Rec 2 Noi 3 4 5 6 7 8 Noi 9 with 10 11 12 13 14	corded Demand Determinants for Medium-Large Commercial Customers; on-Coincident Demand Determinants Pertaining to Customers on Schedules @ 100% NCD Rate Secondary ¹ Primary ²	Meter Level		· · ·	Delier		Line
No. Rec 2 Noi 3 4 5 6 7 8 Noi 9 with 10 11 12 13 14	corded Demand Determinants for Medium-Large Commercial Customers; on-Coincident Demand Determinants Pertaining to Customers on Schedules @ 100% NCD Rate Secondary ¹ Primary ²	Meter Level	Loss Factors	· · ·	Dation		
1 Rec Nor 1	corded Demand Determinants for Medium-Large Commercial Customers; on-Coincident Demand Determinants Pertaining to Customers on Schedules @ 100% NCD Rate Secondary ¹ Primary ²					Reference	No.
2 Nor 3 4 5 6 7 8 Nor 9 with 10 11 12 13	on-Coincident Demand Determinants Pertaining to Customers on Schedules @ 100% NCD Rate Secondary ¹ Primary ²	313			Tuttoo	Accioned	1
3 4 5 6 7 8 Noo with 11 12 13 14	Secondary ¹ Primary ²	313	I	20			2
4 5 6 7 8 Noo 9 with 10 11 12 13 14	Primary ²	313					
5 6 7 8 Nor 9 with 10 11 12 13 14		0.0	1,0457	328	86.54%	Col. B=Page 16.1; Col. E; Line 3	3
6 7 8 Nor 9 with 10 11 12 13 14	Transmission ³	50	1.0108	51	13.46%	Col. B=Page 16.1; Col. E; Line 4	4
6 7 8 Nor 9 with 10 11 12 13 14			1.0000	ru.	0.00%	Col. B=Page 16.1; Col. E; Line 5	5
7 8 Nor 9 with 10 11 12 13	Tabl	364	1.0000	379	100.00%		6
8 Nor 9 with 10 11 12 13 14	Total	304		319	100.00%	Sum Lines 3; 4; 5	1
9 with 10 11 12 13 14							7
10 11 12 13 14	on-Coincident Demand Determinants Pertaining to Customers on Schedules @ 90% NCD Rate				ĺ		8
11 12 13 14	th Maximum On-Peak Period Demand						9
11 12 13 14	Secondary	6,826	1.0457	7,138	83.26%	Col. B=Page 16.2; Col. E; Line 10	10
12 13 14	Primary	1,341	1.0108	1,356	15.82%	Col. B=Page 16.2; Col. E; Line 11	11
13 14	Transmission	79	1.0000	79	0.92%	Col. B=Page 16.2; Col. E; Line 12	12
14			1,0000				
	Total	8,246		8,573	100.00%	Sum Lines 10; 11; 12	13
10 121							14
15 Nor	on-Coincident Demand Determinants Pertaining to Customers on Schedules @ 90% NCD Rate						15
	th Maximum Demand at the Time of System Peak						16
	Secondary	_	1.0457	: <u>u</u>	0.00%	Col. B=Page 16.3; Col. E; Line 17	17
	Primary	59	1.0108	59	11.43%	Col. B=Page 16.3; Col. E; Line 18	18
		457	1,0000	457	88.57%	Col. B=Page 16.3; Col. E; Line 19	19
	Transmission		1,0000				
20	Total	515		516	100.00%	Sum Lines 17; 18; 19	20
21							21
22 Tot	tal Non-Coincident Demand Determinants Pertaining to Medium-Large Commercial Customers						22
	Secondary	7,139	1.0457	7,465	78.85%	Sum Lines 3; 10; 17	23
	Primary	1,450	1.0108	1,466	15.49%	Sum Lines 4; 11; 18	24
			1,0000	S. Carrier and S. Car	1	the same and the s	25
	Transmission	536	1,0000	536	5.66%	Sum Lines 5; 12; 19	
26	Total	9,125		9,467	100.00%	Sum Lines 23; 24; 25	26
27							27
28 Ma	aximum On-Peak Period Demand Determinants	1			1		28
	Summer Months = (May, June, July, August, September)						29
1	Secondary	1,808	1.0457	1,890	79,95%	Col. B=Page 16.2; Col. E; Line 30	30
		435	1,0108	1200012000	0.0000000000000000000000000000000000000	Col. B=Page 16.2; Col. E; Line 31	31
	Primary	200000	599900 59990000	439	18,57%	The state of the s	
	Transmission	35	1.0000	35	1.48%	Col. B=Page 16.2; Col. E; Line 32	32
33	Total	2,277		2,364	100,00%	Sum Lines 30; 31; 32	33
34 H	Winter Months = (October, November, December, January, February, March, April)						34
35	Secondary	4,076	1.0457	4,262	80,38%	Col. B=Page 16.2; Col. E; Line 35	35
	Primary	923	1.0108	932	17.58%	Col. B=Page 16.2; Col. E; Line 36	36
	Transmission	108	1.0000	108	2.04%	Col. B=Page 16.2; Col. E; Line 37	37
		5,107	1.0000	5,302	100.00%		38
38	Total				100.00%	Sum Lines 35; 36; 37	
39	Grand Total	7,384		7,666			39
40 Ma	aximum Demand at the Time of System Peak Determinants						40
41 S	Summer Months = (May, June, July, August, September)						41
	Secondary		1.0457	-	0.00%	Col. B=Page 16.3; Col. E; Line 42	42
	Primary	11	1.0108	11	12.36%	Col. B=Page 16.3; Col. E; Line 43	43
	Transmission	78	1.0000	78	87.64%	Col. B=Page 16.3; Col. E; Line 44	44
1 100		88	1,0000	89	100.00%		45
45	Total	88		89	100.00%	Sum Lines 42; 43; 44	
	Winter Months = (October, November, December, January, February, March, April)						46
47	Secondary		1,0457		0.00%	Col. B=Page 16.3; Col. E; Line 47	47
48	Primary	31	1.0108	32	9.17%	Col. B=Page 16.31; Col. E; Line 48	48
	Transmission	317	1.0000	317	90,83%	Col. B=Page 16.31; Col. E; Line 49	49
50	Total	348		349	100.00%	Sum Lines 47; 48; 49	50
51	Grand Total	437		438	100.0070		51
	Grand Total	437		430			
52				12 12 24 14 1			52
53		Recorded Demand		Recorded Demand			53
54		Determinants		Determinants			54
55		Megawatt @	Transmission	Megawatt @			55
	recast Demand Determinants for Standby Customers:	Meter Level	Loss Factors	Transmission Level	Ratios		56
-	ontracted Demand Determinants						57
			Loses	12	C C001	Col D-Dogo 16 2: Time 11 4	
100	Secondary	44	1,0457	46	6.68%	Col. B=Page 16.3; Line 114	58
- 63	Primary	399	1.0108	403	58.49%	Col. B=Page 16.3; Line 115	59
	Transmission	240	1.0000	240	34.83%	Col. B=Page 16,3; Line 116	60
61	Total	682		689	100.00%	Sum Lines 57; 58; 59	61
							1

SDG&E Load Research Data: 2006-2011

Sum of 4 Coincident Peaks By Customer Class

Customer Class	Sep02-Dec02	Sep03-Dec03	Sep04-Dec04	Sep05-Dec05	Sep06-Dec06	Sep07-Dec07	Sep08-Dec08	Sep09-Dec09	Sep10-Dec10	Sep11-Dec11	5-Year Average
<u>KW</u>		3310,000									
Residential						5,086,154	5,812,172	5,686,258	5,587,487	5,560,342	5,546,483
Small Commercial						1,607,248	1,625,684	1,462,428	1,522,061	1,515,938	1,546,672
Med & Large Comm/Ind						6,598,702	6,478,418	6,044,539	6,656,504	6,152,426	6,386,118
Lighting						54,628	53,886	55,678	27,284	50,852	48,466
Total System						13,346,732	13,970,160	13,248,903	13,793,336	13,279,558	13,527,739
% of Total System											
Residential						38.1%	41.6%	42.9%	40.5%	41.9%	41.00%
Small Commercial						12.0%	11.6%	11.0%	11.0%		11.43%
Med & Large Comm/Ind						49.4%	46.4%	45.6%	48.3%		47.21%
Lighting						0.4%	0.4%	0.4%	0.2%	0.4%	0.36%
Total System		0.600				100.0%	100.0%	100.0%	100.0%		100.0%

Medium & Large C/I Breakdown: Service Voltage Level & Standby Demand

Customer Class	5-Year Average
KW	
Med & Large Comm/Ind	
Secondary	4,441,062
Primary	1,103,224
Transmission	448,241
Subtotal	5,992,527
Standby	
Secondary	13,012
Primary	121,014
Transmission	72,869
Subtotal	206,895
Total	6,199,422

Data Source Contacts: Josh Mondragon and Downie Beckett / Forecasting & Load Analysis

						Section 2.3.									
Line						ego Gas & I									Line
No.			Record	ed Sales for	the True-U	Period: Se	eptember 20	13 - Decem	ber 2013						No.
1	SDG&E: System Delivery Determinants	Winter	Winter	Winter	Winter	Summer	Summer	Summer	Summer	Summer	Winter	Winter	Winter	Total	1
2															2
3	Customer Class Deliveries (MWh)	<u>Jan-13</u>	Feb-13	<u>Mar-13</u>	<u>Apr-13</u>	May-13	Jun-13	<u>Jul-13</u>	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	<u>Total</u>	3
4	Residential	100								767,246	587,510	535,202	626,336	2,516,293	4
5	Small Commercial									199,023	173,031	164,160	148,984	685,198	5
6	Med. & Large Comm./Ind. (AD + PA-T-1)									28,068	26,632	25,927	18,305	98,932	6
7	Med. & Large Comm./Ind. (AL + AY + DGR)									899,463	743,514	755,306	704,824	3,103,107	7
8	Med. & Large Comm./Ind. (A6)	1000								49,312	108,156	47,194	80,972	285,635	8
9	Lighting									9,786	5,732	7,535	10,025	33,078	9
10	Sale for Resale									<u>15.3</u>	0.0	<u>6.8</u>	<u>9.7</u>	31.7	10
11	Total System	0	0	0	0	0	0	0	0	1,952,913	1,644,575	1,535,331	1,589,455	6,722,275	11
12															12
13	Med. & Large Comm./Ind.														13
14	Rate Schedule Billing Determinants														14
15							-								15
16	Schedules AD / PA-T-1:	<u>Jan-13</u>	Feb-13	<u>Mar-13</u>	Apr-13	May-13	<u>Jun-13</u>	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	Total	16
17	Total Deliveries (MWh)	0	0	0	0	0	0	0	0	28,068	26,632	25,927	18,305	98,932	17
18															18
19	Total Deliveries (%)														19
20	% @ Secondary Service									92.34%	86.97%	87.04%	89.63%	89.00%	20
21	% @ Primary Service									7.66%	13.03%	12.96%	10.37%	11.00%	21
22	% @ Transmission Service									0.00%	0.00%	0.00%	0.00%	0.00%	22
23		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	100.00%	100.00%	100.00%	100.00%	23
24	Total Deliveries (MWh)														24
25	MWh @ Secondary Service	0	0	0	0	0	0	0	0	25,918	23,162	22,567	16,406	88,053	25
26	MWh @ Primary Service	0	0	0	0	0	0	0	0	2,150	3,470	3,360	1,898	10,879	26
27	MWh @ Transmission Service	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	0	<u>0</u>	0	0	0	27
28		0	0	0	0	0	0	0	0	28,068	26,632	25,927	18,305	98,932	28
29	Non-Coincident Demand (%)														29
	% @ Secondary Service									0.3406%	0.3254%	0.3736%	0.3978%	0.3557%	30
	% @ Primary Service									0.5007%	0.4246%	0.3965%	0.6130%	0.4638%	31
32	% @ Transmission Service				and the second of the second o					0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	32
33						V. 104 (2007) V. Seculo V.	0-4-553-051 / 0-8-5 31.031-04-19-31 9701001121.07-1								33
34	Non-Coincident Demand (MW)											2000-20 P. 2051			34
35	MW @ Secondary Service	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	88.278	75.368	84.311	65.264	313.221	35
36	MW @ Primary Service	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	10.765	14.734	13.323	11.636	50.458	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		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	99.043	90.102	97.634	76.900	363.679	38
39															39
40															40
41															41
	The state of the s	WAS WRITTEN THE WORKS THE PARTY OF THE PARTY	resource Parallel and Market	n erema dri Noblev (reme 1908/2015)	Curto-Dalitoy Centalizative (19)	n grosspiller zamueren di 1918	Name and State State (N. 1986)		reservate visitatis programa variatis (Sa	margages (CMO) (COOKS (CARSON) (CMO) (CMO)	oversome KHI POMPHOLEDSKIP PRESS.	varevastinious imparagitation	names e Mariena e e e e e e e e e e e e e e e e e e	SAVE SIGNATURA SIGNATURA SILE PROPERTY SILE	

			100			Section 2.3.	1						a Silveria		
Line					San Di	ego Gas & l	Electric								Line
No.			Record	ed Sales for	the True-U	p Period: S	eptember 20	13 - Decem	ber 2013						No.
42	Schedules AL-TOU / AY-TOU / DG-R:	<u>Jan-13</u>	Feb-13	<u>Mar-13</u>	<u>Apr-13</u>	<u>May-13</u>	<u>Jun-13</u>	<u>Jul-13</u>	Aug-13	<u>Sep-13</u>	Oct-13	Nov-13	<u>Dec-13</u>	<u>Total</u>	42
43	Total Deliveries (MWh)	0	0	0	0	0	0	0	0	899,463	743,514	755,306	704,824	3,103,107	43
44															44
45	Total Deliveries (%)							WILLIAM AND AND AND AND AND AND AND AND AND AND	Cooperative control is conscious a state and manager			11010001111111111111111111111111111111			45
46	% @ Secondary Service									77.65%	80.74%	82.38%	74.82%	78.90%	46
47	% @ Primary Service									21.07%	18.77%	16.29%	22.55%	19.69%	47
48	% @ Transmission Service									1.28%	0.49%	<u>1.33%</u>	2.63%	<u>1.41%</u>	48
49	NH 201 0 2000/0224400	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	100.00%	100.00%	100.00%	100.00%	49
50	Total Deliveries (MWh)														50
51	MWh @ Secondary Service	0	0	0	0	0		0		698,433	600,313	622,221	527,350	2,448,317	51
52	MWh @ Primary Service	0	0	0	0	0	0	0	0	189,517	139,558	123,039	158,938	611,052	
53	MWh @ Transmission Service	0	0	0	<u>0</u>	0	0	0		11,513	3,643	<u>10,046</u>	18,537	43,739	
54		0	0	0	0	0	0	0	0	899,463	743,514	755,306	704,824	3,103,107	54
55	Non-Coincident Demand (%)		1000,000,000,000,000,000,000,000,000,00								1241411277127701111111111111111111111111		Nacional de Computer de la Computer		55
56	% @ Secondary Service									0.2728%	0.2830%	0.2822%	0.2779%	0.2788%	56
57	% @ Primary Service									0.2070%	0,2237%	0.2509%	0.2063%	0.2195%	57
58	% @ Transmission Service									0.2057%	0.1820%	0.2265%	0.1400%	0.1807%	58
59															59
60	Non-Coincident Demand (MW)														60
61	MW @ Secondary Service	0.000	0.000	0.000	0.000	0.000	0.000	0.000		1,905.325	1,698.886		1,465.505	6,825.624	61
62	MW @ Primary Service	0.000	0.000	0.000	0.000	0.000	0.000	0.000		392.300	312.190	308.706	327.889	1,341.085	62
63	MW @ Transmission Service	0.000	0.000	0.000	0.000	0.000	0.000	0.000	+	23.682	6.631	22.753	25.952	<u>79.018</u>	63
64		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	2,321.307	2,017.707	2,087.368	1,819.345	8,245.727	64
65	On-Peak Demand (%)	-			A TOTAL SHOWING STATE ST								L		65
66	% @ Secondary Service									0.2588%	0.2475%	0.2300%	0.2198%	0.2403%	66
67	% @ Primary Service									0.2293%	0.2295%	0.2297%	0.2011%	0.2221%	67
68	% @ Transmission Service									0.3030%	0.2276%	0.3338%	0.3592%	0.3276%	68
69	Maximum On-Peak Period Demand (MW)														69
70	On-Peak Demand (MW)	Winter	Winter	Winter	Winter	Summer	Summer	Summer	Summer	Summer	Winter	Winter	Winter	Total	70
71	MW @ Secondary Service	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1,807.544	1,485.775	1,431.109	1,159.115	5,883.543	71
72	MW @ Primary Service	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	434.562	320.285	282.622	319.624	1,357.092	72
73	MW @ Transmission Service	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	34.885	8.292	33.532	66.584	143.293	73
74		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	2,276.991	1,814.352	1,747.263	1,545.323	7,383.929	74
75															75
76															76
77															77
0.0		perupus pus a se militar de l'acce	uagrogassopsiniper#####	over experience and the second second		enovano (1865) (SCCC) por SCCC)	THE RESERVE OF THE PROPERTY OF THE PARTY OF	organización de la companyo de la co				porter and of the Second Electric Confidence	AND THE PROPERTY OF THE PARTY O		

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Line						ego Gas & 1									Line
No.			Record	ed Sales for	the True-Up	Period: Se	eptember 20	13 - Decem	ber 2013						No.
78	Schedule A6-TOU:	<u>Jan-13</u>	Feb-13	<u>Mar-13</u>	Apr-13	May-13	<u>Jun-13</u>	<u>Jul-13</u>	<u>Aug-13</u>	<u>Sep-13</u>	Oct-13	Nov-13	<u>Dec-13</u>	<u>Total</u>	78
79	Total Deliveries (MWh)	0	0	0	0	0	0	0	0	49,312	108,156	47,194	80,972	285,635	79
80															80
81	Total Deliveries (%)	NATIONAL INCOMES IN VARIABLE AND AND AND AND AND AND AND AND AND AND	WEST CONTROL OF THE SAME AND AND ASSESSMENT OF THE SAME ASSESSMENT OF THE SAME ASSES												81
82	% @ Secondary Service									0.00%	0.00%	0.00%	0.00%	0.00%	82
83	% @ Primary Service									16.65%	8.17%	20.39%	7.97%	11.60%	83
84	% @ Transmission Service								· London management	83.35%	91.83%	<u>79.61%</u>	92.03%	<u>88.40%</u>	84
85		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	100.00%	100.00%	100.00%	100.00%	85
86	Total Deliveries (MWh)										***				86
	MWh @ Secondary Service	0	0	0	0	0	0	0		0	0	0	0	0	87
88	MWh @ Primary Service	0	0	0	0	0	0	0	0	8,210	8,836	9,623	6,453	33,123	88
89	MWh @ Transmission Service	<u>0</u>	<u>0</u>	<u>0</u>	0	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	41,101	99,320	37,571	74,519	252,511	89
90		0	0	0	0	0	0	0	0	49,312	108,156	47,194	80,972	285,635	90
91	Non-Coincident Demand (%)														91
92	% @ Secondary Service									0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	92
	% @ Primary Service									0.1390%	0.1880%	0.2317%	0.1293%	0.1771%	93
94	% @ Transmission Service									0.2073%	0.1751%	0.1719%	0.1783%	0.1808%	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	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	11.413	16.612	22.296	8.344	58.666	98
99	MW @ Transmission Service	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	85.203	173.909	64.585	132.867	456.565	99
100		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	96.616	190.522	86.881	141.211	515.230	100
101	Coincident Peak Demand (%)	2 2000													101
	% @ Secondary Service									0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	102
	% @ Primary Service									0.1279%	0.0986%	0.1152%	0.1807%	0.1267%	103
	% @ Transmission Service									0.1896%	0.1562%	0.1374%	0.1479%	0.1564%	104
	Coincident Demand at Time of System of Peak							nuli miliju akonomici Pylingina La			0.150270	0.151.70		0.150170	105
106	Coincident Peak Demand (MW)	Winter	Winter	Winter	Winter	Summer	Summer	Summer	Summer	Summer	Winter	Winter	Winter	Total	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	107
	MW @ Primary Service	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	10.501	8.713	11.086	11.661		107
	MW @ Transmission Service	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	77.928	155.138			394.902	108
1109	W (a) Transmission Service	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	88.430	163.851	51.623 62.709	110.213 121.874		110
111		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	88.430	103.831	62.709	121.874	430.803	
		Y 10	T 1 10	Y 00	1 10	75 10	Y 40	7 1 40	1 40	~ 10	0	XI 40			111
112	Schedule S: Standby Determinants:	<u>Jan-13</u>	Feb-13	<u>Jun-09</u>	<u>Apr-13</u>	<u>May-13</u>	<u>Jun-13</u>	<u>Jul-13</u>	Aug-13	<u>Sep-13</u>	Oct-13	<u>Nov-13</u>	<u>Dec-13</u>	<u>Total</u>	112
113	Contracted Standby Demand (MW)														113
114	MW @ Secondary Service									11.019	11.019	11.019	10.559	43.616	
	MW @ Primary Service									99.611	99.611	99.611	100.121		115
116	MW @ Transmission Service									61.237	<u>59.018</u>	<u>59.018</u>	60.578	239.851	116
117		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	171.867	169.648	169.648	171.258	682.421	117
118												,			118
119															119
120															120