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Overview of SCE Retail Base TRR

SCE's retail Base Transmission Revenue Requirement is the sum of the following components:

TRR Component	Amount
Prior Year TRR	$624,309,375
Incremental Forecast Period TRR	$267,368,661
True-Up Adjustment	$2,414,937
Forecast Adjustment	$0
Base TRR (retail)	$894,092,973

These components represent the following costs that SCE incurs:

1) The Prior Year TRR component is the TRR associated with the Prior Year (most recent calendar year). The Prior Year TRR is calculated using End-of-Year Rate Base values, as set forth in the "BaseTRR" Worksheet.

2) The Incremental Forecast Period TRR is the component of Base TRR associated with forecast additions to in-service plant or CWIP, as set forth in the "IFPTRR" Worksheet.

3) The True Up Adjustment is a component of the Base TRR that reflects the difference between projected and actual costs, as set forth in the "TrueUpAdjust" Worksheet.

4) The Forecast Adjustment component may be included as provided in the Tariff protocols.

Southern California Edison Company

Cells shaded yellow are input cells

Formula Transmission Rate

Line		Notes	FERC Form 1 Reference or Instruction	2011 Value
RATE BASE				
1	ISO Transmission Plant		PlantInService WS, Line 19	$3,309,597,309
2	General Plant + Electric Miscellaneous Intangible Plant		PlantInService WS, Line 27	$150,851,379
3	Transmission Plant Held for Future Use		PHFU WS, Line 8	$9,942,155
4	Abandoned Plant		AbandonedPlant WS, Line 3	$11,028,000
	Working Capital amounts			
5	Materials and Supplies		WorkCap WS, Line 5	$13,372,597
6	Prepayments		WorkCap WS, Line 14	$5,217,698
7	Cash Working Capital		(Line 65 + Line 66) / 8	$15,383,175
8	Working Capital		Line 5 + Line 6 + Line 7	$33,973,470
	Accumulated Depreciation Reserve Balances			
9	Transmission Depreciation Reserve - ISO	Negative amount	AccDep WS, Line 13, Col. 12	-$1,018,886,633
10	Distribution Depreciation Reserve - ISO	Negative amount	AccDep WS, Line 16, Col. 5	-$1,088,416
11	General + Intangible Plant Depreciation Reserve	Negative amount	AccDep WS, Line 26	-$54,841,671
12	Accumulated Depreciation Reserve		Line 9 + Line 10 + Line 11	-$1,074,816,720
13	Accumulated Deferred Income Taxes	Negative amount	ADIT WS, Line 5, Col. 2	-$443,725,797
14	CWIP Plant		IncentivePlant WS, Line 12, Col 1	$1,277,500,411
15	Other Regulatory Assets/Liabilities		RegAssets WS, Line 14	$0
16	Network Upgrade Credits	Negative amount	NUCs WS, Line 5	-$18,816,506
17	Rate Base		L1 + L2 + L3 + L4 + L8 + L12 + L13 + L14+ L15+ L16	$3,255,533,701
OTHER TAXES				
18	Total Property Taxes	Row 37, Column i	FF1 263.2 (see note to left)	$189,815,354
19	Transmission Plant Allocation Factor		Allocators WS, Line 22	9.6866%
20	Property Taxes		Line 18 * Line 19	$18,386,586
21	Payroll Taxes Expense			
22	FICA		Line 23 + Line 24+ Line 25	$130,062,378
23	Fed Ins Cont Amt -- Current	Row 5, Column i	FF1 263 (see note to left)	$129,728,541
24	FICA/OASDI Emp Incntv.	Row 7, Column i	FF1 263 (see note to left)	$341,297
25	FICA/HIT Emp Incntv.	Row 8, Column i	FF1 263 (see note to left)	-$7,460
26	SUI	Row 23, Column i	FF1 263 (see note to left)	$5,992,476
27	FUTA	Row 9, Column i	FF1 263 (see note to left)	$1,081,427
28	CADI Vol Plan Assess	Row 39, Column i	FF1 263.1 (see note to left)	$17,497
29	SF Payroll Expense Tax - SCE	Row 37, Column i	FF1 263.1 (see note to left)	$27,424
30	Total Electric Payroll Tax Expense		Line 22 + (Line 26 to Line 29)	$137,181,202
31	Capitalized Overhead portion of Electric Payroll Tax Expense		TaxRates WS, Line 50	$45,967,326
32	Remaining Electric Payroll Tax Expense to Allocate		Line 30 - Line 31	$91,213,876
33	Transmission Wages and Salaries Allocation Factor		Allocators WS, Line 9	4.0986%
34	Payroll Taxes Expense		Line 32 * Line 33	$3,738,488
35	Other Taxes		Line 20 + Line 34	$22,125,074

Southern California Edison Company

Cells shaded yellow are input cells

Formula Transmission Rate

Line		**Notes**	**FERC Form 1 Reference or Instruction**	**2011 Value**
RETURN AND CAPITALIZATION CALCULATIONS				
	Debt			
36	Long Term Debt Amount		ROR-1 WS, Line 12	$7,465,081,240
37	Cost of Long Term Debt		ROR-1 WS, Line 20	$433,630,897
38	Long Term Debt Cost Percentage		ROR-1 WS, Line 21	5.8088%
	Preferred Stock			
39	Preferred Stock Amount		ROR-1 WS, Line 25	$1,006,462,141
40	Cost of Preferred Stock		ROR-1 WS, Line 29	$59,309,449
41	Preferred Stock Cost Percentage		ROR-1 WS, Line 30	5.8929%
	Equity			
42	Common Stock Equity Amount		ROR-1 WS, Line 36	$8,633,498,106
43	Total Capital		Line 36 + Line 39 + Line 42	$17,105,041,487
	Capital Percentages			
44	Long Term Debt Capital Percentage		Line 36 / Line 43	43.6426%
45	Preferred Stock Capital Percentage		Line 39 / Line 43	5.8840%
46	Common Stock Capital Percentage		Line 42 / Line 43	50.4734%
			Line 44 + Line 45+ Line 46	100.0000%
	Annual Cost of Capital Components			
47	Long Term Debt Cost Percentage		Line 38	5.8088%
48	Preferred Stock Cost Percentage		Line 41	5.8929%
49	Return on Equity	Note 1	SCE Return on Equity	10.43%
	Calculation of Cost of Capital Rate			
50	Weighted Cost of Long Term Debt		Line 38 * Line 44	2.5351%
51	Weighted Cost of Preferred Stock		Line 41 * Line 45	0.3467%
52	Weighted Cost of Common Stock		Line 46 * Line 49	5.2644%
53	Cost of Capital Rate		Line 50 + Line 51 + Line 52	8.1462%
54	Equity Rate of Return Including Preferred Stock	Used for Tax calculation	Line 51 + Line 52	5.6111%
55	Return on Capital: Rate Base times Cost of Capital Rate		Line 17 * Line 53	$265,202,916
INCOME TAXES				
56	Federal Income Tax Rate		Tax Rates WS, Line 1	35.0000%
57	State Income Tax Rate		Tax Rates WS, Line 8	9.0559%
58	Composite Tax Rate	= F + [S * (1 - F)]	(L56 + L57) - (L56 * L57)	40.8863%
	Calculation of Credits and Other:			
59	Amortization of Excess Deferred Tax Liability	Note 2		$200
60	Investment Tax Credit Flowed Through	Note 2		-$520,000
61	South Georgia Income Tax Adjustment	Note 2		$2,606,000
62	Credits and Other		Line 59 + Line 60+ Line 61	$2,086,200
63	Income Taxes:		Formula on Line 64	$129,875,018

64 Income Taxes = [(RB * ER) * (CTR/(1 – CTR))] + CO/(1 – CTR)

Where:
RB = Rate Base
ER = Equity Rate of Return Including Preferred Stock
CTR = Composite Tax Rate
CO = Credits and Other

Southern California Edison Company

Formula Transmission Rate

Cells shaded yellow are input cells

Line		**Notes**	**FERC Form 1 Reference or Instruction**	**2011 Value**
PRIOR YEAR TRANSMISSION REVENUE REQUIREMENT				
	Component of Prior Year TRR:			
65	O&M Expense		OandM WS, Line 135, Col. 6	$82,076,701
66	A&G Expense		AandG WS, Line 23	$40,988,695
67	Network Upgrade Interest Expense		NUCs WS, Line 10	$1,275,701
68	Depreciation Expense		Depreciation WS, Line 70	$100,376,004
69	Abandoned Plant Amortization Expense		AbandonedPlant WS, Line 1	$0
70	Other Taxes		Line 35	$22,125,074
71	Revenue Credits	Negative amount	Revenue Credits WS, Line 45	-$42,619,773
72	Return on Capital		Line 55	$265,202,916
73	Income Taxes		Line 63	$129,875,018
74	Gains and Losses on Trans. Plant Held for Future Use -- Land	Gain negative, loss positive	PHFU WS, Line 10	-$9,724
75	Regulatory Debits		RegAssets WS, Line 16	$0
76	Prior Year Incentive Adder		IncentiveAdder WS, Line 14	$17,893,618
77	Total without FF&U		Sum of Lines 65 to 76	$617,184,230
78	Franchise Fees Expense		Line 77 * FF (from FFU WS)	$5,640,323
79	Uncollectibles Expense		Line 77 * U (from FFU WS)	$1,484,822
80	Prior Year TRR		Line 77 + Line 78+ Line 79	$624,309,375
TOTAL BASE TRANSMISSION REVENUE REQUIREMENT				
	Calculation of Base Transmission Revenue Requirement			
81	Prior Year TRR		Line 80	$624,309,375
82	Incremental Forecast Period TRR		IFPTRR WS, Line 81	$267,368,661
83	True Up Adjustment	Note 3	TrueUpAdjust WS, Line 60	$2,414,937
84	Initial Prior Year?: No	If Initial Prior Year, enter "Yes", else "No"		
85	Forecast Adjustment	Note 4		$0
86	Base Transmission Revenue Requirement (Retail)	For Retail Purposes	L 81 + L 82 + L 83 + L 85	$894,092,973
	Wholesale Base Transmission Revenue Requirement			
87	Base TRR (Retail)		Line 86	$894,092,973
88	Wholesale Difference to the Base TRR		WholesaleDifference WS, Line 34	-$6,078,472
89	Wholesale Base Transmission Revenue Requirement		Line 87 + Line 88	$888,014,501

Notes:

1) No change in Return on Equity will be made absent a filing at the Commission. Includes 50 basis point ISO Participation Adder. Does not include any project-specific ROE adders.
2) No change in "Credits and Other" terms will be made absent a filing at the Commission
3) The True Up Adjustment for the initial Base TRR is $0.
4) Forecast Adjustment may be included as provided in the Tariff protocols.

Calculation of Incremental Forecast Period TRR ("IFPTRR")

The IFP TRR is equal to the sum of:
1) Forecast Plant Additions * AFCR
2) Forecast Period Incremental CWIP * AFCR for CWIP

1) Calculation of Annual Fixed Charge Rates:

Line			
	a) Annual Fixed Charge Rate for CWIP ("AFCRCWIP")		
1			
2	AFCRCWIP represents the return and income tax costs associated with $1 of CWIP,		
3	expressed as a percent.		
4			
5	AFCRWIP = CLTD + (COS * (1/(1 - CTR)))		
6			
7	where:		
8	CLTD = Weighted Cost of Long Term Debt		
9	COS = Weighted Cost of Common and Preferred Stock		
10	CTR = Composite Tax Rate		
11			**Reference**
12	Wtd. Cost of Long Term Debt:	2.535%	BaseTRR WS, Line 50
13	Wtd. Cost of Common + Pref. Stock:	5.611%	BaseTRR WS, Line 54
14	Composite Tax Rate:	40.886%	BaseTRR WS, Line 58
15			
16	AFCRCWIP =	12.027%	Line 12 + (Line 13 * (1/(1 - Line 14))
17			
18	**b) Annual Fixed Charge Rate ("AFCR")**		
19			
20	The AFCR is calculated by dividing the Prior Year TRR (without CWIP related costs)		
21	by Net Plant:		
22			
23	AFCR = (Prior Year TRR - CWIP-related costs) / Net Plant		
24			
25	**Determination of Net Plant:**		
26			**Reference**
27	Transmission Plant - ISO:	$3,302,962,475	PlantInService WS, Line 13
28	Distribution Plant - ISO:	$6,634,834	PlantInService WS, Line 16
29	Transmission Dep. Reserve - ISO:	$1,018,886,633	AccDep WS, Line 13
30	Distribution Dep. Reserve - ISO:	$1,088,416	AccDep WS, Line 16
31	Net Plant:	$2,289,622,260	(L27 + L28) - (L29 + L30)
32			
33	**Determination of Prior Year TRR without CWIP related costs:**		
34			
35	**a) Determination of CWIP-Related Costs**		
36	**1) Direct (without ROE adder) CWIP costs**		
37	CWIP Plant - Prior Year:	$1,277,500,411	CWIP WS, L 13 C1
38	AFCRCWIP:	12.027%	Line 16
39	Direct CWIP Related Costs:	$153,647,237	Line 49 * Line 50
40			
41	**2) CWIP ROE Adder costs:**		
42	IREF:	$8,538	IncentiveAdder WS, Line 3
43			
44	Tehachapi CWIP Amount:	$1,059,868,753	CWIP WS, Line 13
45	Tehachapi ROE Adder %:	1.25%	IncentiveAdder WS, Line 5
46	Tehachapi ROE Adder $:	$11,311,930	Below formula
47			
48	DCR CWIP Amount:	$151,361,046	CWIP WS, Line 13
49	DCR ROE Adder %:	1.00%	IncentiveAdder WS, Line 6
50	DCR ROE Adder $:	$1,292,376	Formula on Line 52
51			
52	ROE Adder $ = (CWIP/$1,000,000) * IREF * (ROE Adder/1%)		
53			
54	CWIP Related Costs wo FF&U:	$166,251,542	Line 39 + Line 46 + Line 50
55	FF&U Expenses:	$1,919,308	FF + U Factors from FFU WS
56	CWIP Related Costs with FF&U:	$168,170,849	Line 54 + Line 55
57			

58	**b) Determination of AFCR:**		
59			
60	CWIP Related Costs:	$168,170,849	Line 56
61	Prior Year TRR:	$624,309,375	BaseTRR WS, Line 81
62	Prior Year TRR wo CWIP Related Costs:	$456,138,526	Line 61 - Line 60
63	AFCR:	19.922%	Line 62 / Line 31
64			
65	**2) Calculation of IFP TRR**		
66			
67			**Reference**
68	Forecast Plant Additions:	$1,105,891,385	PlantAdditions WS, L 22, C1
69	AFCR:	19.922%	Line 63
70	AFCR * Forecast Plant Additions:	$220,315,672	Line 68 * Line 69
71			
72	Forecast Period Incremental CWIP:	$365,851,045	CWIP WS, L 92, C1
73	AFCRCWIP:	12.027%	Line 16
74	AFCRCWIP * FP Incremental CWIP:	$44,001,553	Line 72 * Line 73
75			
76	IFPTRR without FF&U:	$264,317,225	Line 70 + Line 74
77			
78	Franchise Fees Expense:	$2,415,542	Line 76 * FF (from FFU WS)
79	Uncollectibles Expense:	$635,894	Line 76 * U (from FFU WS)
80			
81	Incremental Forecast Period TRR:	$267,368,661	Line 76 + Line 78 + Line 79

Calculation of True Up Adjustment Component of TRR

1) Summary of True Up Adjustment calculation:

a) Attribute True Up TRR to months in the Prior Year (see Note #1) to determine "Monthly True Up TRR" for each month (see Note #2). If formula was not in effect in Prior Year, do not populate Column 2 or 3, Lines 11 to 22.
b) Determine monthly retail transmission revenues attributable to this formula transmission rate received during Prior Year.
c) Compare costs in (a) to revenues in (b) on a monthly basis and determine "Cumulative Excess (-) or Shortfall (+) in Revenue with Interest".
d) Continue interest calculation through the end of the previous Rate Effective Period (Line 31).
e) Amortize this ending balance from (d) over the current Rate Effective Period so that the ending balance on Line 51 is equal to $0.

2) Comparison of True Up TRR and Actual Retail Transmission Revenues received during the Prior Year, Including previous year True Up Adjustment.

Line										
1		True Up TRR:	$564,280,849	Source:	From TUTRR WS, Line 42					
2										
3		**Col 1**	**Col 2**	**Col 3**	**Col 4**	**Col 5**	**Col 6**	**Col 7**	**Col 8**	**Col 9**
4	Calculations:		See Note 2	See Note 3	See Note 4	= C2 - C3 + C 4	See Note 5	See Note 6	See Note 7	=C7 + C8
5								**Cumulative**		
6					**One-Time and**			**Excess (-) or**		**Cumulative**
7				**Actual**	**Previous**	**Monthly**		**Shortfall (+)**		**Excess (-) or**
8			**Monthly**	**Retail Base**	**Period**	**Excess (-) or**	**Monthly**	**in Revenue**	**Interest**	**Shortfall (+)**
9			**True Up**	**Transmission**	**True Up**	**Shortfall (+)**	**Interest**	**wo Interest for**	**for Current**	**in Revenue**
10	**Month**	**Year**	**TRR**	**Revenues**	**Adjustment**	**in Revenue**	**Rate**	**Current Month**	**Month**	**with Interest**
11	January	2011	$0	$0		$0	0.27%	$0	$0	$0
12	February	2011	$0	$0	NA	$0	0.27%	$0	$0	$0
13	March	2011	$0	$0	NA	$0	0.27%	$0	$0	$0
14	April	2011	$0	$0	NA	$0	0.27%	$0	$0	$0
15	May	2011	$0	$0	NA	$0	0.27%	$0	$0	$0
16	June	2011	$0	$0	NA	$0	0.27%	$0	$0	$0
17	July	2011	$0	$0	NA	$0	0.27%	$0	$0	$0
18	August	2011	$0	$0	NA	$0	0.27%	$0	$0	$0
19	September	2011	$0	$0	NA	$0	0.27%	$0	$0	$0
20	October	2011	$0	$0		$0	0.27%	$0	$0	$0
21	November	2011	$0	$0		$0	0.27%	$0	$0	$0
22	December	2011	$0	$0		$0	0.27%	$0	$0	$0
23	January	2012	---	---	-$7,839,769	-$7,839,769	0.27%	-$7,839,769	-$10,584	-$7,850,353
24	February	2012	---	---		$0	0.27%	-$7,850,353	-$21,196	-$7,871,549
25	March	2012	---	---		$0	0.27%	-$7,871,549	-$21,253	-$7,892,802
26	April	2012	---	---		$0	0.27%	-$7,892,802	-$21,311	-$7,914,112
27	May	2012	---	---	$10,272,408	$10,272,408	0.27%	$2,358,296	-$7,500	$2,350,795
28	June	2012	---	---		$0	0.27%	$2,350,795	$6,347	$2,357,142
29	July	2012	---	---		$0	0.27%	$2,357,142	$6,364	$2,363,507
30	August	2012	---	---		$0	0.27%	$2,363,507	$6,381	$2,369,888
31	September	2012	---	---		$0	0.27%	$2,369,888	$6,399	$2,376,287
32										

33 **3) Amortization of September balance over Rate Effective Period:**

Line		Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8
35			See Note 8	See Note 9	See Note 10	=C3 + C4	See Note 11	=C5 + C6	= - C4
36						**Month**			**True Up**
37			**Monthly**	**Month**		**Ending**	**Interest**	**Month**	**Adjustment**
38			**Interest**	**Beginning**		**Balance**	**for Current**	**Ending**	**Received (+)/**
39		**Year**	**Rate**	**Balance**	**Amortization**	**wo Interest**	**Month**	**Balance**	**Returned (-)**
40	October	2012	0.27%	$2,376,287	-$201,245	$2,175,042	$6,144	$2,181,186	$201,245
41	November	2012	0.27%	$2,181,186	-$201,245	$1,979,942	$5,618	$1,985,559	$201,245
42	December	2012	0.27%	$1,985,559	-$201,245	$1,784,315	$5,089	$1,789,404	$201,245
43	January	2013	0.27%	$1,789,404	-$201,245	$1,588,159	$4,560	$1,592,719	$201,245
44	February	2013	0.27%	$1,592,719	-$201,245	$1,391,474	$4,029	$1,395,503	$201,245
45	March	2013	0.27%	$1,395,503	-$201,245	$1,194,258	$3,496	$1,197,754	$201,245
46	April	2013	0.27%	$1,197,754	-$201,245	$996,509	$2,962	$999,472	$201,245
47	May	2013	0.27%	$999,472	-$201,245	$798,227	$2,427	$800,654	$201,245
48	June	2013	0.27%	$800,654	-$201,245	$599,409	$1,890	$601,299	$201,245
49	July	2013	0.27%	$601,299	-$201,245	$400,055	$1,352	$401,406	$201,245
50	August	2013	0.27%	$401,406	-$201,245	$200,162	$812	$200,974	$201,245
51	September	2013	0.27%	$200,974	-$201,245	-$271	$271	$0	$201,245
52					-$2,414,937			Shortfall or Excess Revenue in Prior Year:	$2,414,937

53

54 Total Amortization in Rate Effective Period (See Instruction #4): -$2,414,937

55

56 **4) True Up Adjustment**

Line			
57			**Notes:**
58	One Time Adjustments:	$0	Line 11, Col. 4. Also, see instruction 5.
59	Shortfall or Excess Revenue in Prior Year:	$2,414,937	Column 8, Line 52
60	True Up Adjustment:	$2,414,937	Line 58 + Line 59. Positive amount is to be collected by SCE (included in Base TRR as a positive amount).
61			Negative amount is to be returned to customers by SCE (included in Base TRR as a negative amount).

62 **5) Final True Up Adjustment**

63 The Final True Up Adjustment begins on the month after the last True Up Adjustment and extends through the termination date of
64 this formula transmission rate.
65 The Final True Up Adjustment shall be calculated as above, with interest to the termination date of the Formula Transmission Rate.
66

67	**Partial Year TRR Attribution Allocation Factors:**							
68			**Partial Year**					
69		**Month**	**TRR AAF**	**Note:**				
70		January	6.376%	See Note 2.				
71		February	5.655%					
72		March	7.183%					
73		April	8.224%					
74		May	8.018%					
75		June	8.945%					
76		July	9.891%					
77		August	10.141%					
78		September	10.218%					
79		October	9.179%					
80		November	7.530%					
81		December	8.640%					
82		Total:	100.000%					
83								
84	**Transmission Revenues: (Note 12)**							
85								
86		**Col 1**	**Col 2**	**Col 3**	**Col 4**	**Col 5**	**Col 6**	**Col 7**
87		See Note 13	See Note 14					Sum of left
88								
89		**Actual**						**Monthly**
90	**Prior**	**Retail Base**						**Total**
91	**Year**	**Transmission**	**Other**			**Public**		**Retail**
92	**Month**	**Revenues**	**Transmission**	**Distribution**	**Generation**	**Purpose**	**Other**	**Revenue**
93	Jan							$0
94	Feb							$0
95	Mar							$0
96	Apr							$0
97	May							$0
98	Jun							$0
99	Jul							$0
100	Aug							$0
101	Sep							$0
102	Oct							$0
103	Nov							$0
104	Dec							$0
105	Totals:	$0	$0	$0	$0	$0	$0	$0
106								
107			"Total Sales to Ultimate Consumers" from FERC Form 1 Page 300, Line 10, Column b:					$10,031,333,560

Instructions:

1) Enter applicable years on Column 1, Lines 11-31 and 40-51.
2) Enter Previous Period True Up Adjustment (if any) on Column 4, Lines 20-31. See Note 4 for definition of Previous Period True Up Adjustment.
Enter with the same sign as in previous Informational Update. If there is no Previous Period True Up Adjustment, then enter $0 in these cells.
3) Enter monthly interest rates in accordance with interest rate specified in the regulations of FERC at
18 C.F.R. §35.19a on lines 11 to 31, Column 6. If interest rate for any months not known, use most recent known month.
4) Enter "Total Amortization" amount on Line 54, column 6 to set September Month Ending Balance Column 7, Line 51 equal to $0. Iterate if necessary to solve.
(i.e., so that the Month Beginning Balance in Column 3, Line 40 is completely amortized away by the Amortization amounts in Column 4).
5) Enter any One time Adjustments on Column 4, Line 11 and Line 58. If SCE is owed enter as positive, if SCE is to return to customers enter as negative.
One time adjustments include:
  a) Enter CWIP mechanism final balance in first True Up Adjustment calculation in accordance with tariff protocols.
  b) In the event that a Commission Order revises SCE's True Up TRR for a previous Prior Year,
    SCE shall also include that difference in the True Up Adjustment, including interest, at the first opportunity, in accordance with tariff protocols.
    Entering on Line 11 ensures these One time Adjustments are recovered from or returned to customers.
    Entering on Line 58 ensures that transmission rates for the Rate Effective Period will reflect these One Time Adjustments.
  c) Any refunds attributable to SCE's previous CWIP TRR cases (Docket Nos. ER08-375, ER09-187, ER10-160, and ER11-1952), not previously returned to customers.
6) Fill in matrix of all retail revenues from Prior Year in table on lines 93 to 104.
7) Enter Total Sales to Ultimate Consumers on line 107 and verify that it equals the total on line 105.
8) If true up period is less than entire calendar year, then adjust calculation accordingly by including $0 Monthly True Up TRR and for
Actual Retail Base Transmission Revenues for any months not included in True Up Period.

Notes:

1) The true up period is the portion (all or part) of the Prior Year for which the Formula Transmission Rate was in effect.
2) The Monthly True Up TRR is derived by multiplying the annual True Up TRR on Line 1 by 1/12, if formula was in effect. In the event of
a Partial Year True Up, use the Partial Year TRR Attribution Allocation Factors on Lines 70 to 81 for each month of Partial Year True Up .
Only enter in the Prior Year, Lines 11 to 22, or portion of year formula was in effect in case of Partial Year True Up.
3) "Actual Retail Base Transmission Revenues" are SCE retail transmission revenues attributable to this formula transmission rate.
as shown on Lines 93 to104, Column 1.
4) The "Previous Period True Up Adjustment" are the values of the "True Up Adjustment Received/Returned" in the previous Informational Filing (Same sign).
These are the 12 monthly values of the "True Up Adjustment Received/Returned" in Column 8, Lines 40 -51 from the previous Informational Filing,
They are input into Column 4, lines 20-31 of this current Informational Filing, corresponding to the Rate Effective Period of the previous Informational Filing.
One time True Up Adjustment amounts (see Instruction #5) attributable to a previous Prior Year are entered on Column 4, Line 11.
5) Monthly Interest Rates in accordance with interest rate specified in the regulations of FERC (See Instruction #3).
6) "Cumulative Excess (-) or Shortfall (+) in Revenue wo Interest for Current Month" is: 1) in month 1, the amount in Column 5;
and 2) in subsequent months is the amount in Column 9 for previous month plus the current month amount in Column 5.
7) Interest for Current Month is calculated on average of beginning and ending balances (Column 9 previous month and Column 7 current month).
(First month average is 1/2 of ending balance).
8) The Interest Rate in Rate Effective Period is equal to average of interest rates in previous 12 months (lines 20-31).
9) The "Month Beginning Balance" is Month Ending Balance from previous month in Column 7 (October is from Column 9, Line 31).
10) Amortization equals amount in Line 54 divided by 12 each month. See Instruction #4 also for further detail.
11) Interest for Current Month is calculated on average of beginning and end balances (wo interest) in Columns 3 and 5.
12) Only provide if formula was in effect during Prior Year.
13) Only include Base Transmission Revenue attributable to this formula transmission rate.
Any other Base Transmission Revenue or refunds is included in "Other".
14) Other Transmission Revenue includes the following:
  a) Transmission Revenue Balancing Account Adjustment revenue
  b) Transmission Access Charge Balancing Account Adjustment
  c) Reliability Services Revenue
  d) Any Base Transmission Revenue not attributable to this formula.

Calculation of True Up TRR

A) Rate Base for True Up TRR

Line	Rate Base Item	Calculation Method	Notes	FERC Form 1 Reference or Instruction	Amount
1	ISO Transmission Plant	13-Month Avg.		PlantInService WS, Line 18	$3,268,064,270
2	General + Elec. Misc. Intangible Plant	BOY/EOY Avg.		PlantInService WS, Line 24	$139,361,284
3	Transmission Plant Held for Future Use	BOY/EOY Avg.		PHFU WS, Line 9	$4,971,078
4	Abandoned Plant	BOY/EOY Avg.		AbandonedPlant WS Line 4	$5,514,000
	Working Capital Amounts				
5	Materials and Supplies	BOY/EOY Avg.		WorkCap WS, Line 6	$13,059,227
6	Prepayments	BOY/EOY Avg.		WorkCap WS, Line 11	$5,029,350
7	Cash Working Capital	1/8 (O&M + A&G)		Base TRR WS Line 7	$15,383,175
8	Working Capital			Line 5 + Line 6 + Line 7	$33,471,752
	Accumulated Depreciation Reserve Amounts				
9	Transmission Depreciation Reserve - ISO	13-Month Avg.	Negative amount	AccDep WS, Line 14, Col. 12	-$1,039,891,123
10	Distribution Depreciation Reserve - ISO	BOY/EOY Avg.	Negative amount	AccDep WS, Line 17, Col. 5	-$2,679,923
11	G + I Depreciation Reserve	BOY/EOY Avg.	Negative amount	AccDep WS, Line 23	-$51,286,053
12	Accumulated Depreciation Reserve			Line 9 + Line 10 + Line 11	-$1,093,857,098
13	Accumulated Deferred Income Taxes	13-Month Avg.		ADIT WS, Line 15	-$430,038,717
14	CWIP Plant	13-Month Avg.		IncentivePlant WS, L 12, C2	$899,913,283
15	Network Upgrade Credits	BOY/EOY Avg.	Negative amount	NUCs WS, Line 9	-$24,908,249
16	Other Regulatory Assets/Liabilities	BOY/EOY Avg.		RegAssets WS, Line 15	$0
17	Rate Base			L1+L2+L3+L4+L8+L12+ L13+L14+L15+L16	$2,802,491,602

b) Return on Capital

Line			
18	Cost of Capital Rate	Base TRR WS L 53	8.1462%
19	Return on Capital: Rate Base times Cost of Capital Rate	Line 17 * Line 18	$228,297,113

c) Income Taxes

20	Income Taxes = [(RB * ER) * (CTR/(1 – CTR))] + CO/(1 – CTR)		$112,292,646
	Where:		
21	RB = Rate Base	Line 17	$2,802,491,602
22	ER = Equity Rate of Return including Preferred Stock	Base TRR WS L 54	5.6111%
23	CTR = Composite Tax Rate	Base TRR WS L 58	40.8863%
24	CO = Credits and Other	Base TRR WS L 62	$2,086,200

d) True Up TRR Calculation

25	O&M Expense	Base TRR WS L 65	$82,076,701
26	A&G Expense	Base TRR WS L 66	$40,988,695
27	Network Upgrade Interest Expense	Base TRR WS L 67	$1,275,701
28	Depreciation Expense	Base TRR WS L 68	$100,376,004
29	Abandoned Plant Amortization Expense	Base TRR WS L 69	$0
30	Other Taxes	Base TRR WS L 70	$22,125,074
31	Revenue Credits	Base TRR WS L 71	-$42,619,773
32	Return on Capital	Line 19	$228,297,113
33	Income Taxes	Line 20	$112,292,646
34	Gains and Losses on Transmission Plant Held for Future Use -- Land	Base TRR WS L 74	-$9,724
35	Regulatory Debits	Base TRR WS L 75	$0
36	Total without True Up Incentive Adder	Sum Line 25 to Line 35	$544,802,437
37	True Up Incentive Adder	IncentiveAdder WS L 20	$14,368,263
38	True Up TRR without Franchise Fees Expense included:	Line 36 + Line 37	$559,170,700

3) Calculation of final True Up TRR with Franchise Fees

Line			Reference:
39	True Up TRR wo FF:	$559,170,700	Line 38
40	Franchise Fee Factor:	0.914%	FFU WS, L 5
41	Franchise Fee Expense:	$5,110,149	Line 39 * Line 40
42	True Up TRR:	$564,280,849	Line 39 + Line 41

Calculation of Components of Cost of Capital Rate

Cells shaded yellow are input cells

RETURN AND CAPITALIZATION CALCULATIONS

Line		**Notes**	**FERC Form 1 Reference or Instruction**	**2011 Value**
	Calculation of Long Term Debt Amount			
1	Bonds -- Account 221	13-month avg.	ROR-2 WS, Line 1	$7,978,229,231
2	Less Reacquired Bonds -- Account 222	13-month avg.; enter negative	ROR-2 WS, Line 2	-$347,872,308
3	Other Long Term Debt -- Account 224	13-month avg.	ROR-2 WS, Line 3	$359,069,668
4	Unamortized Premium on Long Term Debt -- Account 225	13-month avg.	ROR-2 WS, Line 4	$0
5	Less Unamortized Discount on Long Term Debt -- Account 226	13-month avg.; enter negative	ROR-2 WS, Line 5	-$28,671,389
6	Unamortized Debt Expenses -- Account 181	13-month avg.; enter negative	ROR-2 WS, Line 6	-$59,933,440
7	Unamortized Loss on Reacquired Debt -- Account 189	13-month avg.; enter negative	ROR-2 WS, Line 7	-$257,876,721
8	Composite Tax Rate		BaseTRR WS, Line 58	40.886%
9	After tax amount of Unamortized Loss on Reacquired Debt		Line 7 * (1 - Line 8)	-$152,440,445
10	Removal of Long Term Debt Related to Fuel Inventories	13-month avg.; enter negative	ROR-2 WS, Line 10	-$284,615,385
11	Adjustments related to "LT Debt Related to Fuel Inventories"		ROR-2 WS, Line 11	$1,315,306
12	Long Term Debt Amount		L1 + L2 + L3 + L4 + L5 + L6 + L9 + L10 + L11	$7,465,081,240
	Calculation of Cost of Long-Term Debt			
13	Interest on Long-Term Debt -- Account 427		FF1 117.62c	$414,553,608
14	Amortization of Debt Discount and Expense -- Account 428		FF1 117.63c	$30,149,018
15	Amortization of Loss on Reacquired Debt -- Account 428.1		FF1 117.64c	$0
16	Less Amortization of Premium on Debt -- Account 429	Enter negative	FF1 117.65c	$0
17	Less Amort. of Gain on Reacquired Debt -- Account 429.1	Enter negative	FF1 117.66c	$0
18	Interest on Long Term Debt Related to Fuel Inventories	Enter negative	See Note 1	-$10,655,370
19	Amortizations related to "Long-Term Debt Related to Fuel Inventories"		See Note 2	-$416,359
20	Cost of Long Term Debt		Sum of Lines 13 to 19	$433,630,897
21	Long-Term Debt Cost Percentage		Line 20 / Line 12	5.8088%
	Calculation of Preferred Stock Amount			
22	Preferred Stock Amount -- Account 204	13-month avg.	ROR-2 WS, Line 22	$1,016,158,796
23	Unamortized Issuance Costs	13-month avg.	ROR-2 WS, Line 23	-$7,930,951
24	Net Gain (Loss) From Purchase and Tender Offers	13-month avg.	ROR-2 WS, Line 24	-$1,765,705
25	Preferred Stock Amount		Sum of Lines 22 to 24	$1,006,462,141
	Calculation of Cost of Preferred Stock			
26	Cost of Preferred Stock -- Account 437	Enter positive	FF1 118.29c	$58,788,054
27	Amortization of Net Gain (Loss) From Purchases and Tender Offers		See Note 3	$205,468
28	Amortization Issuance Costs		See Note 4	$315,927
29	Cost of Preferred Stock -- Account 437		Sum of Lines 26 to 28	$59,309,449
30	Preferred Stock Cost Percentage		Line 29 / Line 25	5.8929%
	Calculation of Common Stock Equity Amount			
31	Total Proprietary Capital	13-month average	ROR-2 WS, Line 31	$9,628,637,288
32	Less Preferred Stock Amount -- Account 204	Same as L 22, but negative	ROR-2 WS, Line 22	-$1,016,158,796
33	Minus Net Gain (Loss) From Purchase and Tender Offers	Same as L 24, but reverse sign	See Note 5	$1,765,705
34	Less Unappropriated Undist. Sub. Earnings -- Acct. 216.1	13-month avg.; enter negative	ROR-2 WS, Line 34	-$3,725,676
35	Less Accumulated Other Comprehensive Loss -- Account 219	13-month avg., enter - of FF1	ROR-2 WS, Line 35	$22,979,585
36	Common Stock Equity Amount		Sum of Lines 31 to 35	$8,633,498,106

Notes:

1) Enter amount associated with bonds for which SCE has California Public Utilities Commission authority to utilize 100% for fuel inventories, amounts from SCE internal records.
2) Enter amount associated with bonds for which SCE has California Public Utilities Commission authority to utilize 100% for fuel inventories, amounts from SCE internal records.
3) Annual amortization associated with events listed in note 12 on ROR-2.
4) Annual amortization associated with preferred equity issues listed in note 11 on ROR-2.
5) Negative of Line 24, charge to common equity reversed for ratemaking.

Calculation of 13-Month Average Capitalization Balances

Line	Item	Col 1 13-Month Avg. = Sum (C2 to C14)/13	Col 2 December	Col 3 January	Col 4 February	Col 5 March	Col 6 April	Col 7 May	Col 8 June	Col 9 July	Col 10 August	Col 11 September	Col 12 October	Col 13 November	Col 14 December
	Bonds -- Account 221 (Note 1):														
1		$7,978,229,231	$7,577,445,000	$7,577,445,000	$7,577,445,000	$7,577,445,000	$7,577,445,000	$8,077,445,000	$8,132,985,000	$8,132,985,000	$8,132,985,000	$8,162,985,000	$8,312,985,000	$8,562,985,000	$8,314,400,000
	Reacquired Bonds -- Account 222 (Note 2):														
2		-$347,872,308	-$323,585,000	-$323,585,000	-$323,585,000	-$323,585,000	-$323,585,000	-$379,125,000	-$379,125,000	-$379,125,000	-$379,125,000	-$409,125,000	-$409,125,000	-$409,125,000	-$160,540,000
	Other Long Term Debt -- Account 224 (Note 3):														
3		$359,069,668	$400,783,845	$400,780,004	$400,776,146	$400,772,273	$400,768,383	$400,764,476	$345,220,554	$345,216,614	$345,212,658	$306,908,685	$306,904,696	$306,900,690	$306,896,667
	Unamortized Premium on Long Term Debt -- Account 225 (Note 4):														
4		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Unamortized Discount on Long Term Debt -- Account 226 (Note 5):														
5		-$28,671,389	-$27,742,650	-$27,594,869	-$27,461,866	-$27,299,307	-$27,156,452	-$29,878,667	-$29,485,303	-$29,308,947	-$29,138,279	-$28,973,301	-$28,796,945	-$30,035,926	-$29,855,541
	Unamortized Debt Expenses -- Account 181 (Note 6):														
6		-$59,933,440	-$59,702,555	-$59,205,361	-$58,842,995	-$58,361,994	-$57,866,679	-$61,262,118	-$61,000,604	-$60,536,471	-$60,076,746	-$59,958,835	-$59,969,154	-$62,172,499	-$60,178,705
	Unamortized Loss on Reacquired Debt -- Account 189 (Note 7):														
7		-$257,876,721	-$267,941,069	-$266,143,925	-$264,346,782	-$262,549,638	-$260,752,494	-$259,591,093	-$258,017,219	-$256,216,042	-$254,414,865	-$252,604,288	-$251,244,890	-$249,434,314	-$249,140,759
	Long Term Debt Related to Fuel Inventories (Note 8):														
10		-$284,615,385	-$250,000,000	-$250,000,000	-$250,000,000	-$250,000,000	-$250,000,000	-$250,000,000	-$250,000,000	-$250,000,000	-$250,000,000	-$250,000,000	-$400,000,000	-$400,000,000	-$400,000,000
	Adjustments related to "LT Debt Related to Fuel Inventories" (Note 9):														
11		$1,315,306	$1,283,857	$1,254,970	$1,226,136	$1,197,195	$1,168,325	$1,139,420	$1,110,550	$1,081,645	$1,052,757	$1,023,888	$1,919,982	$1,847,757	$1,792,499
	Preferred Stock Amount -- Account 204 (Note 10):														
22		$1,016,158,796	$920,004,950	$920,004,950	$920,004,950	$1,045,004,950	$1,045,004,950	$1,045,004,950	$1,045,004,950	$1,045,004,950	$1,045,004,950	$1,045,004,950	$1,045,004,950	$1,045,004,950	$1,045,004,950
	Unamortized Issuance Costs (Note 11):														
23		-$7,930,951	-$5,994,294	-$5,974,253	-$5,954,211	-$8,642,090	-$8,614,505	-$8,586,921	-$8,559,337	-$8,531,752	-$8,504,168	-$8,476,584	-$8,448,999	-$8,421,415	-$8,393,830
	Net Gain (Loss) From Purchase and Tender Offers Note 12):														
24		-$1,765,705	-$1,868,438	-$1,851,316	-$1,834,194	-$1,817,072	-$1,799,949	-$1,782,827	-$1,765,705	-$1,748,582	-$1,731,460	-$1,714,338	-$1,697,215	-$1,680,093	-$1,662,971
	Total Proprietary Capital (Note 13):														
31		$9,628,637,288	$9,207,566,591	$9,294,081,854	$9,349,324,865	$9,437,924,950	$9,504,068,512	$9,561,267,490	$9,535,912,748	$9,652,163,149	$9,822,899,208	$9,831,798,570	$9,969,354,610	$10,048,621,042	$9,957,301,162
	Unappropriated Undist. Sub. Earnings -- Acct. 216.1 (Note 14):														
34		-$3,725,676	-$3,413,591	-$3,482,555	-$3,559,167	-$3,569,360	-$3,607,276	-$3,621,654	-$3,714,713	-$3,837,828	-$3,896,367	-$3,896,832	-$3,906,894	-$3,906,371	-$4,021,177
	Accumulated Other Comprehensive Loss -- Account 219 (Note 15):														
35		$22,979,585	$24,687,325	$24,177,463	$23,667,601	$23,779,822	$23,269,960	$22,760,098	$22,900,638	$22,398,732	$21,896,826	$22,007,296	$21,505,390	$21,207,609	$24,475,843

Instructions:

1) Enter 13 months of balances for capital structure for Prior Year and December previous to Prior Year in Columns 2-14.
Beginning and End of year amounts in Columns 2 and 14 are from FERC Form 1, as referenced in below notes.
2) Enter information in Note 8 for any Fuel Inventory Bonds. SCE must have California Public Utilities Commission approval to utilize 100% of the proceeds of such Fuel Inventory Bonds only to finance fuel inventory.
3) Update notes 11 and 12 as necessary.

Notes:

1) Amount in Column 2 from FF1 112.18c, amount in Column 14 from FF1 112.18d, amounts in columns 3-13 from SCE internal records.
2) Amount in Column 2 from FF1 112.19c, amount in Column 14 from FF1 112.19d, amounts in columns 3-13 from SCE internal records.
3) Amount in Column 2 from FF1 112.21c, amount in Column 14 from FF1 112.21d, amounts in columns 3-13 from SCE internal records.
4) Amount in Column 2 from FF1 112.22c, amount in Column 14 from FF1 112.22d, amounts in columns 3-13 from SCE internal records.
5) Amount in Column 2 from FF1 112.23c, amount in Column 14 from FF1 112.23d, amounts in columns 3-13 from SCE internal records.
6) Amount in Column 2 from FF1 111.69c, amount in Column 14 from FF1 111.69d, amounts in columns 3-13 from SCE internal records.
7) Amount in Column 2 from FF1 111.81c, amount in Column 14 from FF1 111.81d, amounts in columns 3-13 from SCE internal records.
8) Enter amount of bonds for which SCE has California Public Utilities Commission authority to utilize 100% for fuel inventories.
List qualifying bond issuances, Face Amount, Coupon Interest Rate, Issuance Date, Expiration Date, and CPUC authority:

Issue	Face Amount	Coupon Interest Rate	Issuance Date	Maturity Date	CPUC Authority
2009B	$250,000,000	4.15%	3/20/09	9/15/14	CPUC D.03-11-018
2011D	$150,000,000	3M Libor+45bps	10/12/11	9/15/14	CPUC D.03-11-018
…					

9) Unamortized discount and expense for fuel inventory bonds on Line 10, amounts in columns 2-14 from SCE internal records.
10) Amount in Column 2 from FF1 112.3c, amount in Column 14 from FF1 112.3d, amounts in columns 3-13 from SCE internal records.
11) Amounts in columns 2-14 are from SCE internal records.
List associated securities, Face Amount, Issuance Date, Issuance Costs, Amortization Period:

Issue	Face Amount	Issuance Date	Issuance Costs	Amortization Period	Notes
Series A Pref., 5.349% initial rate	$400,000,000	4/27/05	$5,426,936	5 years	Dividend rate is variable after 4/30/2010
Series B Pref., 6.125%	$200,000,000	9/15/05	$3,435,743	30 years	
Series C Pref., 6.000%	$200,000,000	1/24/06	$3,779,170	30 years	
Series D Pref., 6.500%	$125,000,000	3/10/11	$2,715,463	30 years	
…					

12) Amounts in columns 2-14 are from SCE internal records.
List associated securities and event, Event Date, Amortization Amount, Amortization Period:

Issue/Event	**Event Date**	**Amortization Amount**	**Amortization Period**	**Notes**
8.540% Preferred, premium	November 1985	$286,600	34 years	Net gain from open-market purchase of 67,400 shares in November 1985
12.000% Preferred, redemption	February 1986	$6,247,500	34 years	Redemption premium paid to holders (so loss to company)
12.000% Preferred, redemption	February 1986	$1,025,000	34 years	Initial issue discount
…				

13) Amount in Column 2 from FF1 112.16c, amount in Column 14 from FF1 112.16d, amounts in columns 3-13 from SCE internal records.
14) Amount in Column 2 from FF1 112.12c, amount in Column 14 from FF1 112.12d, amounts in columns 3-13 from SCE internal records.
15) Amount in Column 2 from FF1 112.15c, amount in Column 14 from FF1 112.15d, amounts in columns 3-13 from SCE internal records.

Plant In Service

Inputs are shaded yellow

1) Transmission Plant - ISO

Balances for Transmission Plant - ISO during the Prior Year, including December of previous year (See Note 1):

Line	Col 1 Prior Year Month	Col 2 350.1	Col 3 350.2	Col 4 352	Col 5 353	Col 6 354	Col 7 355	Col 8 356	Col 9 357	Col 10 358	Col 11 359	Col 12 Sum C2 - C11 Total
1	December	$73,238,678	$80,739,600	$175,457,663	$1,680,213,303	$625,307,190	$113,770,199	$422,173,397	$284,096	$2,302,928	$28,619,068	$3,202,106,122
2	January	$73,457,067	$80,546,971	$175,531,481	$1,682,797,635	$567,348,227	$113,938,319	$481,950,573	$295,578	$2,404,664	$28,589,735	$3,206,860,251
3	February	$74,787,427	$80,611,201	$169,945,549	$1,690,133,298	$567,137,049	$113,779,197	$481,820,290	$279,721	$2,294,340	$28,585,656	$3,209,373,728
4	March	$74,795,217	$80,612,219	$169,790,454	$1,690,160,751	$567,661,454	$113,755,178	$481,718,133	$279,788	$2,027,536	$28,585,633	$3,209,386,364
5	April	$74,795,235	$80,612,604	$169,924,865	$1,696,326,180	$566,761,574	$113,916,544	$481,642,642	$279,915	$2,032,634	$28,579,817	$3,214,872,010
6	May	$74,795,239	$80,620,101	$170,558,044	$1,714,436,873	$566,864,532	$113,893,084	$482,371,551	$288,922	$2,136,936	$28,573,849	$3,234,539,129
7	June	$74,844,263	$81,691,266	$170,958,762	$1,735,666,103	$577,247,106	$114,731,218	$494,362,200	$482,728	$2,163,632	$28,542,192	$3,280,689,471
8	July	$74,920,480	$81,729,920	$171,060,161	$1,743,964,018	$574,223,968	$114,567,873	$492,517,255	$559,090	$3,553,785	$28,542,591	$3,285,639,141
9	August	$74,920,538	$81,744,340	$171,926,958	$1,746,839,739	$574,264,333	$114,577,668	$493,513,718	$576,137	$3,735,051	$28,542,594	$3,290,641,076
10	September	$74,920,593	$81,754,780	$171,968,348	$1,749,282,822	$549,677,062	$131,446,925	$422,626,020	$574,863	$3,570,476	$110,386,399	$3,296,208,289
11	October	$74,920,599	$81,804,913	$171,978,342	$1,747,977,369	$549,752,298	$131,513,375	$422,414,349	$573,331	$3,537,284	$110,386,759	$3,294,858,619
12	November	$74,633,157	$82,090,720	$171,931,707	$1,754,489,045	$549,890,097	$131,633,765	$422,512,012	$566,812	$3,500,178	$110,386,746	$3,301,634,238
13	December	$74,607,469	$82,090,981	$170,948,030	$1,756,511,619	$550,516,805	$132,075,054	$421,892,563	$558,943	$3,408,604	$110,352,407	$3,302,962,475
14	13-Mo. Avg:	$74,587,382	$81,280,740	$171,690,797	$1,722,215,289	$568,203,976	$119,507,569	$461,654,977	$430,763	$2,820,619	$53,744,111	$3,256,136,224

2) Distribution Plant - ISO

Balances for Distribution Plant - ISO (See Note 2)

Line	Col 1 Prior Year Month	Col 2 360	Col 3 361	Col 4 362	Col 5 Sum C2 - C4 Total
15	December	$25,780	$1,107,531	$16,087,946	$17,221,257
16	December	$75,876	$683,247	$5,875,711	$6,634,834
17	Average:	$50,828	$895,389	$10,981,829	$11,928,046

3) ISO Transmission Plant

ISO Transmission Plant is the sum of "Transmission Plant - ISO" and "Distribution Plant - ISO"

		Amount	Source
18	Average value:	$3,268,064,270	Sum of Line 14, Col 12 and Line 17, Col 5
19	EOY Value:	$3,309,597,309	Sum of Line 13, Col 12 and Line 16, Col 5

4) General Plant + Electric Miscellaneous Intangible Plant ("G&I Plant)

General and Intangible Plant is an allocated portion of Total G&I Plant based on the Trans. W&S Allocation Factor

	Note 1 Prior Year Month	Data Source	Col 1 General Plant Balances	Col 2 Intangible Plant Balances	Col 3 Total G&I Plant Balances	Notes
20	December	FF1 206.99.b and 204.5b	$1,804,660,920	$1,315,217,471	$3,119,878,391	Beginning of year amount
21	December	FF1 207.99.g and 204.5g	$2,123,098,622	$1,557,464,316	$3,680,562,938	End of year amount

a) BOY/EOY Average G&I Plant

		Amount	Source
22	Average BOY/EOY Value:	$3,400,220,665	Average of Line 20 and 21.
23	Transmission W&S Allocation Factor:	4.0986%	Allocators WS, Line 9
24	General + Intangible Plant:	$139,361,284	Line 22 * Line 23.

b) EOY G&I Plant

		Amount	Source
25	EOY Value:	$3,680,562,938	Line 21.
26	Transmission W&S Allocation Factor:	4.0986%	Allocators WS, Line 9
27	General + Intangible Plant:	$150,851,379	Line 25 * Line 26.

Transmission Activity Used to Determine Monthly Transmission Plant - ISO Balances

1) Total Transmission Activity by Account (See Note 3)

	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11	Col 12
												Sum C2 - C11
	Prior Year Month	350.1	350.2	352	353	354	355	356	357	358	359	Total
28	January	$218,388	-$181,276	$401,078	$7,769,717	-$57,127,766	$2,374,043	$60,385,293	$141,439	$688,306	$13,388	$14,682,610
29	February	$1,330,361	$96,010	-$1,732,527	$9,174,729	-$426,118	-$1,482,854	-$267,227	-$195,331	-$746,409	-$4,220	$5,746,413
30	March	$8,779	$1,209	$161,418	$1,116,987	$913,059	$189,607	-$55,330	$825	-$1,805,085	-$7	$531,462
31	April	$18	$385	$1,455,152	$18,935,734	-$855,884	$1,647,604	$119,367	$1,568	$34,490	-$5,789	$21,332,645
32	May	$4	$11,185	$20,541,095	$52,525,225	$252,034	-$138,575	$1,709,539	$110,951	$705,663	-$3,523	$75,713,598
33	June	$49,024	$1,071,907	$4,840,823	$65,276,287	$10,339,993	$2,409,647	$11,170,603	$2,387,403	$180,614	-$31,634	$97,694,668
34	July	$85,931	$57,978	$1,197,392	$25,709,365	-$3,342,666	-$1,681,311	-$2,115,815	$940,657	$9,405,201	$457	$30,257,190
35	August	$57	$20,974	$10,279,784	$8,939,394	$480,234	$99,899	$1,037,614	$210,000	$1,226,369	$135	$22,294,461
36	September	$56	$15,029	$201,294	$6,854,995	-$24,918,653	$17,934,766	-$66,639,979	-$15,693	-$1,113,442	$81,843,858	$14,162,231
37	October	$6	$75,012	$228,632	-$4,021,319	$87,742	$680,857	-$555,270	-$18,870	-$224,565	$378	-$3,747,399
38	November	-$287,442	$284,952	-$559,042	$10,853,985	$138,515	$1,233,536	$15,107	-$80,311	-$251,045	$64	$11,348,318
39	December	-$28,961	$390	-$418,702	$3,879,096	$947,495	$4,521,523	-$1,677,600	-$96,931	-$619,552	$167,071	$6,673,828
40	Total:	$1,376,220	$1,453,755	$36,596,398	$207,014,195	-$73,512,016	$27,788,740	$3,126,303	$3,385,706	$7,480,545	$81,980,178	$296,690,025

2) Incentive Plant Activity (See Note 4)

	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11	Col 12 Sum C2 - C11
	Prior Year Month	350.1	350.2	352	353	354	355	356	357	358	359	Total
41	January	$218,388	-$215,448	$43,577	$71,391	-$59,039,125	-$70,457	$59,282,364	$0	$0	-$22,050	$268,642
42	February	$1,330,361	$348	-$5,942,014	$6,444,416	$68,141	-$15,957	-$18,854	$0	$0	-$4,103	$1,862,338
43	March	$29	$635	-$184,343	-$500,557	$19,339	-$47,123	-$140,260	$0	$0	-$21	-$852,299
44	April	$18	$385	$12,365	-$23,315	-$957,054	$625	-$234,044	$0	$0	-$5,811	-$1,206,830
45	May	$4	$82	-$1,206,447	$1,432,727	-$90,771	-$11,011	-$69,010	$0	$0	-$5,551	$50,024
46	June	$49,024	$1,069,671	-$9,577	-$116,847	$10,437,910	$668,171	$12,657,905	$0	$0	-$31,654	$24,724,604
47	July	-$9	-$186	$122	-$140,020	-$2,607,904	$827	-$1,624,545	$0	$0	$409	-$4,371,306
48	August	$57	$1,244	-$3,026	-$62,855	-$531,255	$50	$962,979	$0	$0	$25	$367,220
49	September	$56	$1,215	$26,613	$304,982	-$24,156,632	$16,754,019	-$74,343,980	$0	$0	$81,843,814	$430,088
50	October	$6	$124	-$10,210	$10,710	$58,985	$0	$67,908	$0	$0	$363	$127,886
51	November	-$287,442	$287,527	$715	$4,407,307	$136,867	$0	$164,838	$0	$0	$0	$4,709,812
52	December	$0	$0	-$1,035,885	$1,122,867	$209,839	$0	$241,546	$0	$0	$0	$538,367
53	Total:	$1,310,492	$1,145,599	-$8,308,108	$12,950,806	-$76,451,660	$17,279,146	-$3,053,152	$0	$0	$81,775,423	$26,648,546

3) Transmission Activity Not Including Incentive Plant Activity (See Note 5):

	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11	Col 12 Sum C2 - C11
	Prior Year Month	350.1	350.2	352	353	354	355	356	357	358	359	Total
54	January	$0	$34,172	$357,501	$7,698,326	$1,911,359	$2,444,500	$1,102,928	$141,439	$688,306	$35,437	$14,413,967
55	February	$0	$95,663	$4,209,487	$2,730,313	-$494,260	-$1,466,897	-$248,373	-$195,331	-$746,409	-$117	$3,884,075
56	March	$8,750	$573	$345,761	$1,617,544	$893,720	$236,730	$84,930	$825	-$1,805,085	$13	$1,383,760
57	April	$0	$0	$1,442,787	$18,959,049	$101,170	$1,646,979	$353,410	$1,568	$34,490	$23	$22,539,475
58	May	$0	$11,103	$21,747,542	$51,092,498	$342,804	-$127,565	$1,778,550	$110,951	$705,663	$2,028	$75,663,574
59	June	$0	$2,236	$4,850,400	$65,393,134	-$97,916	$1,741,476	-$1,487,302	$2,387,403	$180,614	$20	$72,970,064
60	July	$85,940	$58,164	$1,197,270	$25,849,385	-$734,762	-$1,682,138	-$491,270	$940,657	$9,405,201	$48	$34,628,496
61	August	$0	$19,730	$10,282,810	$9,002,249	$1,011,489	$99,849	$74,635	$210,000	$1,226,369	$110	$21,927,241
62	September	$0	$13,813	$174,681	$6,550,013	-$762,020	$1,180,747	$7,704,001	-$15,693	-$1,113,442	$44	$13,732,144
63	October	$0	$74,887	$238,841	-$4,032,029	$28,757	$680,857	-$623,178	-$18,870	-$224,565	$15	-$3,875,285
64	November	$0	-$2,576	-$559,757	$6,446,678	$1,648	$1,233,536	-$149,731	-$80,311	-$251,045	$64	$6,638,507
65	December	-$28,961	$390	$617,183	$2,756,229	$737,656	$4,521,523	-$1,919,146	-$96,931	-$619,552	$167,071	$6,135,461
66	Total:	$65,729	$308,156	$44,904,506	$194,063,390	$2,939,644	$10,509,595	$6,179,455	$3,385,706	$7,480,545	$204,755	$270,041,479

4) Calculation of change in Non-Incentive ISO Plant:

A) Change in ISO Plant Balance December to December (See Note 6)

	350.1	350.2	352	353	354	355	356	357	358	359	Total
67	$1,368,791	$1,351,381	-$4,509,633	$76,298,316	-$74,790,385	$18,304,855	-$280,834	$274,847	$1,105,676	$81,733,339	$100,856,353

B) Change in Incentive ISO Plant (See Note 7)

	350.1	350.2	352	353	354	355	356	357	358	359	Total
68	$1,310,492	$1,145,599	-$8,308,108	$12,950,806	-$76,451,660	$17,279,146	-$3,053,152	$0	$0	$81,775,423	$26,648,546

C) Change in Non-Incentive ISO Plant (See Note 8)

	350.1	350.2	352	353	354	355	356	357	358	359	Total
69	$58,299	$205,782	$3,798,475	$63,347,510	$1,661,275	$1,025,709	$2,772,318	$274,847	$1,105,676	-$42,084	$74,207,807

5) Other Transmission Activity without Incentive Plant Activity (See Note 9):

	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11	Col 12
												Sum C2 - C11
	Prior Year Month	**350.1**	**350.2**	**352**	**353**	**354**	**355**	**356**	**357**	**358**	**359**	**Total**
70	January	$0	$22,819	$30,241	$2,512,941	$1,080,162	$238,577	$494,812	$11,482	$101,736	-$7,284	$4,485,486
71	February	$0	$63,882	$356,081	$891,248	-$279,320	-$143,165	-$111,429	-$15,857	-$110,324	$24	$651,139
72	March	$7,761	$383	$29,248	$528,010	$505,066	$23,104	$38,102	$67	-$266,804	-$3	$864,934
73	April	$0	$0	$122,045	$6,188,744	$57,174	$160,741	$158,552	$127	$5,098	-$5	$6,692,477
74	May	$0	$7,414	$1,839,626	$16,677,966	$193,728	-$12,450	$797,919	$9,007	$104,302	-$417	$19,617,095
75	June	$0	$1,493	$410,296	$21,346,078	-$55,335	$169,964	-$667,255	$193,806	$26,696	-$4	$21,425,738
76	July	$76,226	$38,841	$101,277	$8,437,935	-$415,235	-$164,172	-$220,401	$76,361	$1,390,153	-$10	$9,320,976
77	August	$0	$13,176	$869,824	$2,938,576	$571,620	$9,745	$33,484	$17,047	$181,266	-$23	$4,634,715
78	September	$0	$9,224	$14,776	$2,138,100	-$430,639	$115,238	$3,456,282	-$1,274	-$164,574	-$9	$5,137,125
79	October	$0	$50,009	$20,204	-$1,316,163	$16,251	$66,450	-$279,579	-$1,532	-$33,192	-$3	-$1,477,556
80	November	$0	-$1,720	-$47,350	$2,104,369	$932	$120,390	-$67,174	-$6,520	-$37,106	-$13	$2,065,807
81	December	-$25,688	$261	$52,208	$899,707	$416,870	$441,289	-$860,995	-$7,869	-$91,574	-$34,339	$789,870
82	Total:	$58,299	$205,782	$3,798,475	$63,347,510	$1,661,275	$1,025,709	$2,772,318	$274,847	$1,105,676	-$42,084	$74,207,807

Notes:

1) Amounts on Line 1 must match Plant Study amounts for Transmission Plant - ISO for previous year.
Amounts on Line 13 must match amounts on PlantStudy WS for Transmission Plant - ISO.
Calculation of remaining amounts is sum of:
a) Other Transmission Activity without Incentive Plant Activity (on Lines 70 to 81)
b) Incentive Plant Activity (on Lines 41 to 52)
c) Previous month balance
2) Amounts on Line 15 must match Plant Study amounts for Distribution Plant - ISO for previous year.
Amounts on Line 16 must match amounts on PlantStudy WS for Distribution Plant - ISO.
3) Includes recorded Transmission Plant-In-Service additions, retirements, transfers and adjustments.
4) Column 12 matches 'Activity for Incentive Projects' on incentivePlant WS, Lines 39 to 52.
5) Amount in matrix on lines 28 to 39 minus amount in matrix on lines 41 to 52
6) Amount on Line 13 less amount on Line 1 for each account.
7) Line 53
8) Amount on Line 67 less amount on Line 68 for each account.
9) Amount in matrix on Lines 54 to 65 times ratio of amount on Line 69 to amount on Line 66 for each account.

Transmission Plant Study

Input cells are shaded yellow

A) Plant Classified as Transmission in FERC Form 1:

Line	Account	Col 1 Total Plant	Data Source	Col 2 Transmission Plant - ISO	Col 3 ISO % of Total	Notes
1						
2	**Substation**					
3	352	$334,506,130	FF1 207.49g	$170,948,030	51.10%	
4	353	$3,421,750,786	FF1 207.50g	$1,756,511,619	51.33%	
5	**Total Substation**	$3,756,256,916	L 3 + L 4	$1,927,459,649	51.31%	
6						
7	**Land**					
8	350	$238,723,489	FF1 207.48g	$156,698,450	65.64%	
9						
10	**Total Substation and Land**	$3,994,980,405	L 5 + L 8	$2,084,158,099	52.17%	
11						
12	**Lines**					
13	354	$601,728,049	FF1 207.51g	$550,516,805	91.49%	
14	355	$545,742,642	FF1 207.52g	$132,075,054	24.20%	
15	356	$617,979,720	FF1 207.53g	$421,892,563	68.27%	
16	357	$46,153,375	FF1 207.54g	$558,943	1.21%	
17	358	$183,442,134	FF1 207.55g	$3,408,604	1.86%	
18	359	$113,892,832	FF1 207.56g	$110,352,407	96.89%	
19	**Total Lines**	$2,108,938,752	Sum L13 to L18	$1,218,804,376	57.79%	
20						
21	**Total Transmission**	**$6,103,919,157**	L 10 + L 19	**$3,302,962,475**	**54.11%**	Note 1

B) Plant Classified as Distribution in FERC Form 1:

Line	Account	Total Plant	Data Source	Distribution Plant - ISO	ISO % of Total	
22						
23	**Land:**					
24	360	$105,855,063	FF1 207.60g	$75,876	0.07%	
25	**Structures:**					
26	361	$431,350,909	FF1 207.61g	$683,247	0.16%	
27	362	$1,609,973,202	FF1 207.62g	$5,875,711	0.36%	
28	**Total Structures**	$2,041,324,111	L 26 + L 27	$6,558,958	0.32%	
29						
30	**Total Distribution**	**$2,147,179,174**	L 24 + L 28	**$6,634,834**	**0.31%**	Note 2

Notes:

1) Total transmission does not include account 359.1 "Asset Retirement Costs for Transmission Plant"
Total on this line is also equal to FF1 207.58g (Total Transmission Plant)
less FF1 207.57g (Asset Retirement Costs for Transmission Plant).
2) Only accounts 360-362 included as there is no ISO plant in any other Distribution accounts.

Instructions:

1) Perform annual Transmission Study pursuant to instructions in tariff.
2) Enter total amounts of plant from FERC Form 1 in Column 1, "Total Plant".
3) Enter ISO portion of plant in Column 2, "Transmission Plant - ISO, or Distribution Plant - ISO".

Accumulated Depreciation Reserve

Input cells are shaded yellow

1) Transmission Depreciation Reserve - ISO

Balances for Transmission Depreciation Reserve - ISO during the Prior Year, including December of previous year (See Note 1):

	Col 1	**Col 2**	**Col 3**	**Col 4**	**Col 5**	**Col 6**	**Col 7**	**Col 8**	**Col 9**	**Col 10**	**Col 11**	**Col 12**
		FERC Account:										=Sum C2 to C11
Line	**Prior Year Month**	**350.1**	**350.2**	**352**	**353**	**354**	**355**	**356**	**357**	**358**	**359**	**Total**
1	December	$0	$5,241,220	$39,543,082	$240,191,715	$344,249,627	$34,281,907	$320,132,658	$156,437	$1,008,747	$10,949,954	$995,755,348
2	January	$0	$5,352,989	$39,416,502	$242,721,821	$347,363,534	$34,941,832	$322,569,563	$159,035	$1,050,423	$10,974,446	$1,004,550,146
3	February	$0	$5,464,492	$40,043,584	$247,415,436	$350,573,081	$35,556,796	$325,364,541	$161,313	$1,090,598	$10,997,232	$1,016,667,071
4	March	$0	$5,576,083	$46,376,002	$248,600,935	$355,081,243	$34,912,411	$330,189,444	$161,570	$967,671	$11,010,310	$1,032,875,668
5	April	$0	$5,687,676	$47,527,353	$252,898,170	$359,204,574	$35,267,815	$334,162,303	$162,391	$998,303	$11,026,248	$1,046,934,834
6	May	$0	$5,799,269	$44,116,771	$256,876,385	$361,111,466	$36,142,918	$334,284,810	$169,622	$1,049,707	$11,073,747	$1,050,624,695
7	June	$0	$5,910,873	$43,915,137	$259,741,499	$366,599,479	$36,192,711	$340,559,528	$171,591	$1,008,866	$11,095,268	$1,065,194,951
8	July	$0	$6,023,958	$44,098,444	$264,315,240	$370,454,869	$36,272,535	$344,555,290	$173,528	$1,041,459	$11,113,642	$1,078,048,963
9	August	$0	$6,137,097	$42,667,182	$266,356,151	$372,024,244	$36,339,009	$346,548,372	$179,294	$1,100,920	$11,150,220	$1,082,502,491
10	September	$0	$6,250,256	$30,058,479	$275,704,329	$373,632,402	$37,285,802	$345,518,277	$188,679	$1,182,916	$11,264,042	$1,081,085,183
11	October	$0	$6,363,430	$38,957,229	$247,157,945	$355,177,616	$33,944,051	$329,362,791	$229,958	$1,412,779	$11,633,539	$1,024,239,339
12	November	$0	$6,476,673	$39,022,245	$241,491,390	$356,284,668	$33,401,152	$331,063,892	$229,324	$1,466,994	$11,782,937	$1,021,219,276
13	December	$0	$6,590,309	$37,414,556	$237,973,212	$357,349,553	$33,638,583	$332,289,563	$240,593	$1,461,025	$11,929,238	$1,018,886,633
14	13-Mo. Avg:	$0	$5,913,410	$41,012,044	$252,418,787	$359,162,027	$35,244,425	$333,584,695	$183,333	$1,141,570	$11,230,833	$1,039,891,123

2) Distribution Depreciation Reserve - ISO (See Note 2)

	Col 1	**Col 2**	**Col 3**	**Col 4**	**Col 5**	
		FERC Account:			=Sum C2 to C4	
		360	**361**	**362**	**Total**	
15	BOY:	903	477,157	3,793,370	$4,271,430	
16	EOY:	3,791	236,706	847,920	$1,088,416	
17	BOY/EOY Average:	$2,347	$356,931	$2,320,645	$2,679,923	Average of Line 15 and Line 16

3) General and Intangible Depreciation Reserve

		Total General and Intangible Depreciation Reserve	Source
18	BOY:	$1,164,555,911	FF1 219.28c for previous year
19	EOY:	$1,338,060,181	FF1 219.28c
20	BOY/EOY Average:	$1,251,308,046	Average of Line 18 and Line 19

a) Average BOY/EOY General and Intangible Depreciation Reserve

		Amount	Source
21	Total G+I Dep. Reserve on Average BOY/EOY basis:	$1,251,308,046	Line 20
22	Transmission W&S Allocation Factor:	4.0986%	Allocators WS, Line 9
23	G + I Plant Dep. Reserve (BOY/EOY Average):	$51,286,053	Line 21 * Line 22

a) EOY General and Intangible Depreciation Reserve

		Amount	Source
24	Total G+I Dep. Reserve on Average EOY basis:	$1,338,060,181	Line 19
25	Transmission W&S Allocation Factor:	4.0986%	Allocators WS, Line 9
26	G + I Plant Dep. Reserve (EOY):	$54,841,671	Line 24 * Line 25

Transmission Activity Used to Determine Monthly Transmission Depreciation Reserve - ISO Balances

1) Total Transmission Activity by Account (See Note 3)

	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11	Col 12 Sum C2 - C11
	Prior Year Month	350.1	350.2	352	353	354	355	356	357	358	359	Total
27	January	$0	$165,841	$422,805	$2,502,752	$467,029	$912,566	$520,786	$25,293	$379,270	$10,822	$5,407,164
28	February	$0	$165,590	$352,416	$4,718,112	$241,550	$829,001	$586,851	$21,515	$359,736	$7,325	$7,282,096
29	March	$0	$165,899	-$194,829	$1,125,315	-$374,821	-$1,498,449	-$610,178	-$1,055	-$1,407,541	-$12,815	-$2,808,474
30	April	$0	$165,738	$289,885	$4,311,822	-$190,730	$349,706	-$108,462	$5,309	$268,124	-$6,881	$5,084,511
31	May	$0	$165,739	$717,310	$3,984,812	$857,355	$1,309,922	$2,160,561	$77,628	$493,470	$58,621	$9,825,419
32	June	$0	$165,754	$418,356	$2,844,015	-$840,245	-$215,582	-$1,462,135	$18,126	-$511,342	$4,722	$421,667
33	July	$0	$167,240	$383,254	$4,592,584	-$33,899	-$162,337	-$63,347	$15,032	$285,082	-$1,766	$5,181,844
34	August	$0	$167,321	$534,656	$1,998,459	$1,040,576	-$186,570	$1,108,467	$57,156	$532,593	$36,011	$5,288,668
35	September	$0	$167,350	$1,583,173	$9,481,160	$1,022,313	$1,440,653	$2,894,929	$97,737	$771,485	$196,308	$17,655,109
36	October	$0	$167,371	-$430,364	-$29,324,097	$10,458,360	-$6,532,196	$11,481,125	$457,599	$2,382,094	$612,485	-$10,727,624
37	November	$0	$167,475	$396,717	-$5,894,421	$1,183,720	-$1,358,755	$955,581	-$15,257	$476,161	$155,735	-$3,933,045
38	December	$0	$166,763	$553,215	-$3,694,762	$1,204,141	$83,346	$1,236,250	$119,121	-$176,071	$149,310	-$358,689
39	Total:	$0	$1,998,082	$5,026,592	-$3,354,249	$15,035,350	-$5,028,696	$18,700,428	$878,204	$3,853,060	$1,209,875	$38,318,646

2) Depreciation Expense (See Note 4)

	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11	Col 12
												Sum C2 - C11
	Prior Year Month	350.1	350.2	352	353	354	355	356	357	358	359	Total
40	January	$0	$111,690	$375,772	$3,668,466	$1,318,356	$362,168	$1,231,339	$391	$7,427	$37,205	$7,112,813
41	February	$0	$111,423	$375,930	$3,674,108	$1,196,159	$362,704	$1,405,689	$406	$7,755	$37,167	$7,171,342
42	March	$0	$111,512	$363,967	$3,690,124	$1,195,714	$362,197	$1,405,309	$385	$7,399	$37,161	$7,173,769
43	April	$0	$111,514	$363,635	$3,690,184	$1,196,820	$362,121	$1,405,011	$385	$6,539	$37,161	$7,173,369
44	May	$0	$111,514	$363,922	$3,703,645	$1,194,922	$362,634	$1,404,791	$385	$6,555	$37,154	$7,185,524
45	June	$0	$111,524	$365,278	$3,743,187	$1,195,139	$362,560	$1,406,917	$397	$6,892	$37,146	$7,229,041
46	July	$0	$113,006	$366,137	$3,789,538	$1,217,029	$365,228	$1,441,890	$664	$6,978	$37,105	$7,337,574
47	August	$0	$113,060	$366,354	$3,807,655	$1,210,656	$364,708	$1,436,509	$769	$11,461	$37,105	$7,348,275
48	September	$0	$113,080	$368,210	$3,813,933	$1,210,741	$364,739	$1,439,415	$792	$12,046	$37,105	$7,360,061
49	October	$0	$113,094	$368,299	$3,819,267	$1,158,902	$418,439	$1,232,659	$790	$11,515	$143,502	$7,266,469
50	November	$0	$113,163	$368,320	$3,816,417	$1,159,061	$418,651	$1,232,042	$788	$11,408	$143,503	$7,263,354
51	December	$0	$113,559	$368,220	$3,830,634	$1,159,352	$419,034	$1,232,327	$779	$11,288	$143,503	$7,278,696
52	Total:	$0	$1,348,139	$4,414,044	$45,047,160	$14,412,851	$4,525,183	$16,273,898	$6,931	$107,262	$764,817	$86,900,286

3) Total Transmission Activity less Depreciation Expense (See Note 5)

	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11	Col 12
												Sum C2 - C11
	Prior Year Month	350.1	350.2	352	353	354	355	356	357	358	359	Total
53	January	$0	$54,152	$47,033	-$1,165,714	-$851,327	$550,397	-$710,553	$24,902	$371,843	-$26,383	-$1,705,650
54	February	$0	$54,167	-$23,514	$1,044,004	-$954,609	$466,297	-$818,838	$21,108	$351,981	-$29,842	$110,754
55	March	$0	$54,387	-$558,796	-$2,564,809	-$1,570,535	-$1,860,647	-$2,015,487	-$1,439	-$1,414,940	-$49,976	-$9,982,242
56	April	$0	$54,225	-$73,750	$621,638	-$1,387,549	-$12,415	-$1,513,474	$4,924	$261,585	-$44,043	-$2,088,858
57	May	$0	$54,225	$353,388	$281,167	-$337,567	$947,288	$755,770	$77,243	$486,915	$21,467	$2,639,896
58	June	$0	$54,230	$53,077	-$899,173	-$2,035,385	-$578,142	-$2,869,052	$17,728	-$518,234	-$32,424	-$6,807,374
59	July	$0	$54,234	$17,117	$803,047	-$1,250,929	-$527,564	-$1,505,236	$14,368	$278,104	-$38,871	-$2,155,729
60	August	$0	$54,261	$168,302	-$1,809,196	-$170,080	-$551,278	-$328,041	$56,387	$521,132	-$1,095	-$2,059,608
61	September	$0	$54,270	$1,214,963	$5,667,227	-$188,428	$1,075,914	$1,455,514	$96,945	$759,439	$159,203	$10,295,048
62	October	$0	$54,277	-$798,663	-$33,143,365	$9,299,458	-$6,950,635	$10,248,465	$456,809	$2,370,579	$468,982	-$17,994,093
63	November	$0	$54,311	$28,397	-$9,710,838	$24,659	-$1,777,406	-$276,461	-$16,045	$464,753	$12,232	-$11,196,399
64	December	$0	$53,204	$184,994	-$7,525,397	$44,790	-$335,688	$3,923	$118,341	-$187,360	$5,807	-$7,637,385
65	Total:	$0	$649,942	$612,548	-$48,401,409	$622,499	-$9,553,879	$2,426,530	$871,273	$3,745,798	$445,058	-$48,581,640

4) Calculation of Other Transmission Activity

A) Change in Depreciation Reserve - ISO (See Note 6)

	350.1	350.2	352	353	354	355	356	357	358	359	Total
66	$0	$1,349,089	-$2,128,526	-$2,218,503	$13,099,926	-$643,323	$12,156,906	$84,155	$452,279	$979,283	$23,131,285

B) Total Depreciation Expense (See Note 7)

	350.1	350.2	352	353	354	355	356	357	358	359	Total
67	$0	$1,348,139	$4,414,044	$45,047,160	$14,412,851	$4,525,183	$16,273,898	$6,931	$107,262	$764,817	$86,900,286

C) Other Activity (See Note 8)

	350.1	350.2	352	353	354	355	356	357	358	359	Total
68	$0	$949	-$6,542,570	-$47,265,664	-$1,312,925	-$5,168,506	-$4,116,992	$77,224	$345,017	$214,466	-$63,769,001

5) Other Transmission Activity (See Note 9)

	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11	Col 12 Sum C2 - C11
	Prior Year Month	350.1	350.2	352	353	354	355	356	357	358	359	Total
69	January	$0	$79	-$502,352	-$1,138,360	$1,795,551	$297,757	$1,205,566	$2,207	$34,250	-$12,713	$1,681,985
70	February	$0	$79	$251,152	$1,019,506	$2,013,387	$252,260	$1,389,289	$1,871	$32,420	-$14,380	$4,945,584
71	March	$0	$79	$5,968,451	-$2,504,625	$3,312,449	-$1,006,582	$3,419,594	-$128	-$130,327	-$24,083	$9,034,829
72	April	$0	$79	$787,717	$607,051	$2,926,511	-$6,716	$2,567,848	$436	$24,094	-$21,223	$6,885,796
73	May	$0	$79	-$3,774,505	$274,569	$711,970	$512,468	-$1,282,284	$6,846	$44,849	$10,345	-$3,495,662
74	June	$0	$79	-$566,913	-$878,073	$4,292,874	-$312,766	$4,867,801	$1,571	-$47,733	-$15,625	$7,341,215
75	July	$0	$79	-$182,829	$784,203	$2,638,361	-$285,404	$2,553,872	$1,274	$25,616	-$18,731	$5,516,439
76	August	$0	$79	-$1,797,615	-$1,766,743	$358,719	-$298,233	$556,574	$4,998	$48,000	-$527	-$2,894,748
77	September	$0	$79	-$12,976,913	$5,534,245	$397,417	$582,053	-$2,469,510	$8,593	$69,950	$76,717	-$8,777,369
78	October	$0	$79	$8,530,451	-$32,365,652	-$19,613,688	-$3,760,190	-$17,388,146	$40,489	$218,349	$225,995	-$64,112,313
79	November	$0	$79	-$303,304	-$9,482,972	-$52,009	-$961,550	$469,060	-$1,422	$42,807	$5,894	-$10,283,417
80	December	$0	$78	-$1,975,909	-$7,348,812	-$94,467	-$181,602	-$6,656	$10,489	-$17,257	$2,798	-$9,611,340
81	Total:	$0	$949	-$6,542,570	-$47,265,664	-$1,312,925	-$5,168,506	-$4,116,992	$77,224	$345,017	$214,466	-$63,769,001

Notes:

1) Amounts on Line 1 derived from Plant Study for previous year Prior Year.
   Amounts on Line 13 derived from Plant Study for Prior Year.
Calculation of remaining amounts is sum of:
   a) Depreciation Expense (on Lines 40 to 51)
   b) Other Transmission Activity (on Lines 69 to 80)
   c) Previous month balance
2) Amounts on Line 15 derived from Plant Study for previous year Prior Year.
   Amounts on Line 16 derived from Plant Study for Prior Year.
3) Total Transmission Activity by Account represents accumulated depreciation changes for all Transmission plant.
4) From Depreciation Worksheet, Lines 24 to 35.
5) Amount in matrix on lines 27 to 38 minus amount in matrix on lines 40 to 51.
6) Line 13 - Line 1.
7) Line 52.
8) Line 66 - Line 67.
9) Amount in matrix on Lines 53 to 64 times ratio of amount on Line 68 to amount on Line 65 for each account.

Accumulated Deferred Income Taxes

Cells shaded yellow are input cells

1) Summary of Accumulated Deferred Income Taxes

a) End of Year Accumulated Deferred Income Taxes

	Col 1	Col 2	
Line	**Account**	**Total ADIT**	**Source**
1	Account 190	$32,110,601	Line 353, Col. 2
2	Account 282	-$483,534,147	Line 452, Col. 2
3	Account 283	-$15,638,023	Line 803, Col. 2
4	IRC Section 168(i)(9) Normalization Adjustment	$23,335,771	Line 809, Col. 5
5	Total Accumulated Deferred Income Taxes	-$443,725,797	Sum of Lines 1 to 4
6			
7	**b) Beginning of Year Accumulated Deferred Income Taxes**		
8		**BOY**	
9		**ADIT**	**Source**
10	Total Accumulated Deferred Income Taxes	-$416,351,637	Previous Year Informational Filing, Line 5, Col. 2
11			
12	**c) Average of Beginning and End of Year Accumulated Deferred Income Taxes**		
13		**Average**	
14		**ADIT**	**Source**
15	Average BOY/EOY ADIT:	-$430,038,717	Average of Line 5 and Line 10

2) Account 190 Detail

		Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7
	ACCT 190	DESCRIPTION	END BAL per G/L	Gas, Generation or Other Related	ISO Only	Plant Related	Labor Related	Description
	Electric:							
100	190.000	Amort of Debt Issuance Cost	$656,267			$656,267		Relates to all Regulated Electric Property
101	190.000	ECAC	$21,364	$21,364				Relates Entirely to CPUC Balancing Account Recovery
102	190.000	Franchise Requirements	$3,680			$3,680		Relates to all Regulated Electric Property
103	190.000	Relicensing Fees	-$12,132,675	-$12,132,675				Relates to Generation Relicensing Fees
104	190.000	AC Def Inc Tax - Exchg Energy	-$2,239,842	-$2,239,842				Relates Entirely to CPUC Balancing Account Recovery
105	190.000	AC Def Inc Tax - ECAC Incent	-$30,591	-$30,591				Relates Entirely to CPUC Balancing Account Recovery
106	190.000	Yuma Axis Generating Stn	$0	$0				Relates Entirely to CPUC Balancing Account Recovery
107	190.000	Executive Incentive Comp	$5,223,846				$5,223,846	Relates to employees in all functions
108	190.000	Public Purpose Program Aid & Statutory Costs	-$43,734,348	-$43,734,348				Relates Entirely to CPUC Balancing Account Recovery
109	190.000	Acc charges	$2,155,510	$2,155,510				Relates to PVNGS CPUC Cost Recovery
110	190.000	DIT - APS Right of Way	-$64,266		-$64,266			Relates to 100% ISO facilities
111	190.000	Corp Name Change	$13,777			$13,777		Relates to all Regulated Electric Property
112	190.000	QF termination payments	$1	$1				Power Procurement Costs B/A - State PUC
113	190.000	Mescalero Fuel Storage	-$89,223	-$89,223				Relates to Generation Costs
114	190.000	Photovoltaic Facilities	-$131,254	-$131,254				Relates to Generation Costs
115	190.000	Uncollectible Accts. Exp.	-$617,580	-$617,580				Component of Working Capital Rate Base Adj.
116	190.000	CCFT - TSB -FAS 109	$565,837	$565,837				Relates to Telecom Business Costs
117	190.000	RAR Rollforward	$0				$0	Relates to employees in all functions
118	190.000	Prepaid Expenses	-$7,190,886	-$7,190,886				Relates to Nuclear Generation Insurance Costs
119	190.000	Bond Discount Amort	$2,413,867			$2,413,867		Relates to all Regulated Electric Property
120	190.000	CCFT - Electric	$24,373,367	$24,373,367				Non-Rate Base FAS 109 Tax Flow-Through
121	190.000	Decom Net Earn - Non Qua	$94,977,296	$94,977,296				Relates to Generation Costs
122	190.000	Def Tax Flow Thru ITC	$34,320,011	$34,320,011				Not Component of Rate Base Per IRC §46(f)(2)
123	190.000	Def Tax ITC 2-Yr Average	$935,731	$935,731				Not Component of Rate Base Per IRC §46(f)(2)
124	190.000	Executive Incentive Plan	$5,355,399				$5,355,399	Relates to employees in all functions
125	190.000	Executive Incentive Plan	$0				$0	Relates to employees in all functions
126	190.000	Pension Reserve	$119,047,042	$119,047,042				Component of Working Capital Rate Base Adj.
127	190.000	Uncollectible Accounts E	$29,436,241	$29,436,241				Component of Working Capital Rate Base Adj.
128	190.000	Exec Retrmnt Provision - FAS109	$0	$0				Relates to Power Procurement Costs
129	190.000	ARAM	$7,535,477	$7,535,477				Non-Rate Base FAS 109 Tax Flow-Through
130	190.000	Ins - Inj/Damages Prov	$67,302,150				$67,302,150	Relates to employees in all functions
131	190.000	Misc Def Tax	-$9,417,474	-$9,417,474				Non-Rate Base FAS 109 Tax Flow-Through
132	190.000	Unrealized Gain - Decomm	$373,530,113	$373,530,113				Relates to Nuclear Decommissioning Costs
133	190.000	Hazardous Waste	$30,204	$30,204				Relates to Generation Costs
134	190.000	Accrued Vacation	$25,711,320				$25,711,320	Relates to employees in all functions
135	190.000	Health Care - IBNR	$1,642,329				$1,642,329	Relates to employees in all functions
136	190.000	Uncollec Accts-Claims	$5,213,759	$5,213,759				Component of Working Capital Rate Base Adj.
137	190.000	Def Tax - CCFT Base Rates - R.L.	$29,586,312			$29,586,312		Relates to all Regulated Electric Property
138	190.000	Ins Res/Casualty Loss	$49,878			$49,878		Relates to all Regulated Electric Property
139	190.000	Stock Options Accrue to APIC	$36,046,544				$36,046,544	Relates to Executive Compensation
140	190.000	Decomm NQ Expenses	$82,624,768	$82,624,768				Relates to Nuclear Decommissioning Costs
141	190.000	DIT - SFAS 158 - Short Term	$8,980,343	$8,980,343				Exclude interest-related debt costs

Continuation of Account 190 Detail

	ACCT 190	Col 1 DESCRIPTION	Col 2 END BAL per G/L	Col 3 Gas, Generation or Other Related	Col 4 ISO Only	Col 5 Plant Related	Col 6 Labor Related	Col 7 Description
	Electric:							
142	190.000	GRC Marine Mitigation	$2,210,064	$2,210,064				Relates Entirely to CPUC Balancing Account Recovery
143	190.000	Nuc Decomm Adj Mech (NDAM)	$0	$0				Relates Entirely to CPUC Balancing Account Recovery
144	190.000	Pub Purp Prg Adj Mech (PPPAM)	-$22,007,953	-$22,007,953				Relates Entirely to CPUC Balancing Account Recovery
145	190.000	DIT - SRPIM	$0	$0				Relates Entirely to CPUC Balancing Account Recovery
146	190.000	DIT WECC Statutory Costs	$0	$0				Relates Entirely to CPUC Balancing Account Recovery
147	190.000	Base Revenue Requirement	-$50,315,947	-$50,315,947				Relates Entirely to CPUC Balancing Account Recovery
148	190.000	Demand Responsiveness Memo	$0	$0				Relates Entirely to CPUC Balancing Account Recovery
149	190.000	DIT - FIN Reporting Reserves	$9,560,242	$9,560,242				Relates Entirely to CPUC Balancing Account Recovery
150	190.000	Nuclear Fuel	-$40,082,616	-$40,082,616				Relates to Generation Costs
151	190.000	NQ Decom. Withdraws	-$120,688,813	-$120,688,813				Relates to Nuclear Decommissioning Costs
152	190.000	R&D Overcollection	$0	$0				Relates Entirely to CPUC Balancing Account Recovery
153	190.000	DSMAC Expenses	$0	$0				Relates Entirely to CPUC Balancing Account Recovery
154	190.000	Cont in Aid of Const	-$46,121,981	-$46,121,981				Relates to CIAC Non-ISO Property Costs
155	190.000	Int Capitalized - AFUDC	$200,689,898			$200,689,898		Relates to all Regulated Electric Property
156	190.000	ITCC - CIAC - State	$295,902,393	$295,902,393				Relates to CIAC Non-ISO Property Costs
157	190.000	PBOP 401H Amortization	$54,306,653				$54,306,653	Relates to employees in all functions
158	190.000	Fixed Costs	$12,907,877	$12,907,877				Relates to Generation Costs
159	190.000	LSFO Differential	-$13,398,916	-$13,398,916				Relates to Generation Fuel Costs
160	190.000	LSFO Differential	$13,398,916	$13,398,916				Relates to Generation Fuel Costs
161	190.000	DFO Differential	$71,090	$71,090				Relates to Generation Fuel Costs
162	190.000	ADIT - Environ Remed	-$998,888	-$998,888				Relates to Generation Costs
163	190.000	ADIT - Environ Remed	$998,888	$998,888				Relates to Generation Costs
164	190.000	DIT DSM-ENERGY EFFICIENCY	$0	$0				Relates Entirely to CPUC Balancing Account Recovery
165	190.000	DIT DSM-LOW INCOME	$0	$0				Relates Entirely to CPUC Balancing Account Recovery
166	190.000	DIT FIRM TRANSMISSION RIGHTS BA	$458,781	$458,781				Relates to Power Procurement Costs
167	190.000	SOLAR INVESTMENT TAX CREDIT	$24,039,390	$24,039,390				Non-Rate Base FAS 109 Gross Up - Generation
168	190.000	MountainView Generating Station	-$138,962	-$138,962				Relates to Generation Costs
169	190.000	Marine Mitigation	-$472,825	-$472,825				Relates to Generation Costs
170	190.000	DIT MISC Reg Liab/Asset	$13,251,947	$13,251,947				Relates Entirely to CPUC Balancing Account Recovery
171	190.000	MRTUMA	-$14,527,134	-$14,527,134				Relates Entirely to CPUC Balancing Account Recovery
172	190.000	FHPMA LT	-$9,792,332	-$9,792,332				Relates Entirely to CPUC Balancing Account Recovery
173	190.000	FC Cpital LT	-$29,119	-$29,119				Relates Entirely to CPUC Balancing Account Recovery
174	190.000	DIT Renewable Portfolio STD Costs MA	-$281,766	-$281,766				Relates Entirely to CPUC Balancing Account Recovery
175	190.000	STATE RATE ADJUSTMENT	$15,810,624			$15,810,624		Relates to all Regulated Electric Property
176	190.000	NUCLEAR FUEL (STATE)	-$7,497,298	-$7,497,298				Relates to Generation Fuel Costs
177	190.000	CREDIT CARRYFORWARDS	$9,781,218	$9,781,218				Not Component of Rate Base
178	190.000	CHARITABLE CONTRIBUTION CARRYFORWARDS	$5,516,385	$5,516,385				Not Component of Rate Base
179	190.000	EMS	$177,823			$177,823		Relates to all Regulated Electric Property
180	…							
								Source
250		Total Electric 190	$1,214,831,932	$769,905,831	-$64,266	$249,402,126	$195,588,241	Sum of Above Lines beginning on Line 100

Account 190 Gas and Other Income:

		Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7
300	190.000	DIT - RAR Rollforward - State	$120,325,151	$120,325,151				Gas and Other Non-ISO Related Costs
301	190.000	DIT - RAR Rollforward - Federal	-$484,122,755	-$484,122,755				Gas and Other Non-ISO Related Costs
302	190.000	Ad Val Lien Date-Other	-$453,789	-$453,789				Gas and Other Non-ISO Related Costs
303	190.000	CCFT - Gas	-$12,036	-$12,036				Gas and Other Non-ISO Related Costs
304	190.000	CCFT - Other	-$5,100,151	-$5,100,151				Gas and Other Non-ISO Related Costs
305	190.000	CCFT - Water	-$9,042	-$9,042				Gas and Other Non-ISO Related Costs
306	190.000	Def Tax - Etiwanda Wst Wtr	$4,717	$4,717				Gas and Other Non-ISO Related Costs
307	190.000	Rollforward Orig Issue State 09 May Filing	$23,554,610	$23,554,610				Gas and Other Non-ISO Related Costs
308	190.000	Rollforward of settled audit ATL NONRB-Fed	-$1,687,553	-$1,687,553				Gas and Other Non-ISO Related Costs
309	190.000	Rollforward of settled audit ATL NONRB-State	-$67,327,155	-$67,327,155				Gas and Other Non-ISO Related Costs
310	190.000	Residential Energy Disconnections MA (REDMA) - LT	$0	$0				Gas and Other Non-ISO Related Costs
311	190.000	Palo Verde O&M	$0	$0				Gas and Other Non-ISO Related Costs
312	190.000	CCA BA	-$20,849,987	-$20,849,987				Gas and Other Non-ISO Related Costs
313	190.000	Capital Balancing Accounts	-$5,547,384	-$5,547,384				Gas and Other Non-ISO Related Costs
314	190.000	Reclass Acct 190 Credit and Acct 283 Debit Balances	$1,271,570,341	$1,271,570,341				Other - Offset Reclass Between Accounts
315	…							

	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Source
350	Total Account 190 Gas and Other Income	$830,344,968	$830,344,968	$0	$0	$0	Sum of Above Lines beginning on Line 300
351	Total Account 190	$2,045,176,900	$1,600,250,799	-$64,266	$249,402,126	$195,588,241	Line 250 + Line 350
352	Allocation Factors (Plant and Wages)				9.687%	4.099%	Allocators WS Lines 22 and 9 respectively.
353	Total Account 190 ADIT	$32,110,601		-$64,266	$24,158,497	$8,016,370	Line 351 * Line 352 for Cols 5 and 6. Col. 4 100% ISO.
	(Sum of amounts in Columns 4 to 6)						
354	FERC Form 1 Account 190	$2,045,176,900	Must match amount on Line 351, Col. 2				FF1 234.18c

3) Account 282 Detail

	ACCT 282	Col 1 DESCRIPTION	Col 2 END BAL per G/L	Col 3 Gas, Generation or Other Related	Col 4 ISO Only	Col 5 Plant Related	Col 6 Labor Related	Col 7 Description
400	282.000	Def Inc Tax-Other Prop Opr Inc	-$7,800,250	-$7,800,250				Gas and Other Non-ISO Related Costs
401	282.000	Acc Def Inc Tax-So Reas Rev	-$771,375	-$771,375				Gas and Other Non-ISO Related Costs
402	282.000	Acc Def Inc Tax-Acrs Opr Inc	-$2,630,079,822	-$2,630,079,822				Property-Related CPUC Costs
403	282.000	Fully Normalized Deferred Tax	-$441,435,402		-$441,435,402			Property-Related FERC Costs
404	282.000	Acc Def Inc Tax-Direct Access	$1,235,260	$1,235,260				Property-Related CPUC Costs
405	282.000	DIT - 605 Freeway	-$16,876,578	-$16,876,578				Pre-'98 T&D State PUC-Related Costs
406	282.000	Def Inc Tax Songs 2&3 ICIP	$24,711,625	$24,711,625				Relates to Nuclear Generation Costs
407	282.000	Acc Def Inc Tax-Acrs ICIP PV	$16,433,381	$16,433,381				Relates to Nuclear Generation Costs
408	282.000	ACRS - Gas & Water	-$186,396	-$186,396				Gas and Other Non-ISO Related Costs
409	282.000	Acc Def Inc Tax-AFUDC	-$127,768,670			-$127,768,670		Relates to all Regulated Electric Property
410	282.000	Repairs 3115 - Retirement Adj	$4,632,600	$4,632,600				Property-Related CPUC Costs
411	282.000	Repairs 3115 - FERC Deduction	-$11,842,170		-$11,842,170			Property-Related FERC Costs
412	282.000	MISC_Year 2009	-$81,088,325	-$81,088,325				Relates to Steam Generation Costs
413	282.000	R&D Overcollection	$0	$0				Property-Related CPUC Costs
414	282.000	Def Tax LT - Prop	$1,026,207	$1,026,207				Property-Related CPUC Costs
415	282.000	Def Tax LT - Prop	$9,001	$9,001				Property-Related CPUC Costs
416	282.000	Fully Normalized Deferred Tax - Book	$1,545,303		$1,545,303			Property-Related FERC Costs
417	282.000	Bonus Depreciation CPUC Adj	$0	$0				Property-Related CPUC Costs
418	282.000	Street Lights	-$33,458,028	-$33,458,028				Property-Related CPUC Costs
419	282.000	Property-Related Def Tax Adjust	-$154,238,672			-$154,238,672		Relates to all Regulated Electric Property
420	282.000	DPV2 ADIT - Abandonment	-$4,485,057		-$4,485,057			Property-Related FERC Costs
421	…							

	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Source
450	Total Account 282	-$3,460,437,367	-$2,722,212,701	-$456,217,325	-$282,007,342	$0	Sum of Above Lines beginning on Line 400
451	Allocation Factors (Plant and Wages)				9.687%	4.099%	Allocators WS Lines 22 and 9 respectively.
452	Total Account 282 ADIT (Sum of amounts in Columns 4 to 6)	-$483,534,147		-$456,217,325	-$27,316,822	$0	Line 450 * Line 451 for Cols 5 and 6. Col. 4 100% ISO.
453	FERC Form 1 Account 282	-$3,460,437,367	Must match amount on Line 450, Col. 2				FF1 275.5k

4) Account 283 Detail

	ACCT 283	Col 1 DESCRIPTION	Col 2 END BAL per G/L	Col 3 Gas, Generation or Other Related	Col 4 ISO Only	Col 5 Plant Related	Col 6 Labor Related	Col 7 Description
	Electric:							
500	283.000	Def Tax State - Other (GSI)	-$1,089,589	$0	-$1,089,589			FERC-Related state deductions
501	283.000	Lease Acctng - PPBU - Short-term	$1,617,885	$1,617,885				Relates Entirely to CPUC Balancing Account Recovery
502	283.000	Reg Asset - Deferred Tax - Temp	$5,171,997	$5,171,997				Retail Costs - State PUC
503	283.000	Solar Photovoltaic Program MA (SPVPMA)	$0	$0				Relates Entirely to CPUC Balancing Account Recovery
504	283.000	Balancing Account Overcollection	-$88,188,888	-$88,188,888				Relates Entirely to CPUC Balancing Account Recovery
505	283.000	EDRA	$0	$0				Relates Entirely to CPUC Balancing Account Recovery
506	283.000	Payroll Tax	-$1,930,349				-$1,930,349	Relates to employees in all functions
507	283.000	Mohave Transition Costs	-$178,094	-$178,094				Relates Entirely to CPUC Balancing Account Recovery
508	283.000	Ad Valorem Lien Date Adj-Electric	-$63,008,846			-$63,008,846		Relates to all Regulated Electric Property
509	283.000	Firm Transmission Rights (Other)	$0	$0				Relates Entirely to CPUC Balancing Account Recovery
510	283.000	Procurement Energy EFF BA	$0	$0				Relates Entirely to CPUC Balancing Account Recovery
511	283.000	DIT MISC Reg Liab/Asset	-$759,648	-$759,648				Relates Entirely to CPUC Balancing Account Recovery
512	283.000	Haz Waste Bal Acct. - 182.376 & 254.376	-$2,242,412	-$2,242,412				Relates Entirely to CPUC Balancing Account Recovery
513	283.000	Ad Valorem Lien Date - Plant Sale	-$2,215,619	-$2,215,619				Relates to Generation Costs
514	283.000	Real Time Energy Metering Account	$0	$0				Relates Entirely to CPUC Balancing Account Recovery
515	283.000	CARE Adjustment (Formerly LISAC)	-$22,081,116	-$22,081,116				Relates Entirely to CPUC Balancing Account Recovery
516	283.000	RSBA	-$1,628,028	-$1,628,028				Relates Entirely to FERC Balancing Account Recovery
517	283.000	ESMA - Dynergy	$0	$0				Relates Entirely to CPUC Balancing Account Recovery
518	283.000	ESMA - PS Colorado	$0	$0				Relates Entirely to CPUC Balancing Account Recovery
519	283.000	ESMA - Duke	$0	$0				Relates Entirely to CPUC Balancing Account Recovery
520	283.000	ESMA - Reliant	$0	$0				Relates Entirely to CPUC Balancing Account Recovery
521	283.000	ESMA - Enron Settlement	$0	$0				Relates Entirely to CPUC Balancing Account Recovery
522	283.000	ESMA - PS Colorado Settlement	$0	$0				Relates Entirely to CPUC Balancing Account Recovery
523	283.000	Pension Cost Balancing Account	-$9,416,435	-$9,416,435				Relates Entirely to CPUC Balancing Account Recovery
524	283.000	Mohave B/A	$0	$0				Relates Entirely to CPUC Balancing Account Recovery
525	283.000	Project Devel Div. M/A	-$3,186,540	-$3,186,540				Relates Entirely to CPUC Balancing Account Recovery
526	283.000	Compl. Filings Audit M/A - Qtrly	$236,720	$236,720				Relates Entirely to CPUC Balancing Account Recovery
527	283.000	DIT DOE Litigation MEMO Account - New 2008	$107,761	$107,761				Relates Entirely to CPUC Balancing Account Recovery
528	283.000	CWIP Balancing Account - ST	$0	$0				FERC-Related Balancing Account
529	283.000	New System Generation M/A - ST	-$8,480,926	-$8,480,926				Relates Entirely to CPUC Balancing Account Recovery
530	283.000	DIT AIMMA	$24,640,579	$24,640,579				Relates Entirely to CPUC Balancing Account Recovery
531	283.000	LT Proc. Plan Tech Assistance M/A (LTAMA)	-$11,555	-$11,555				Relates Entirely to CPUC Balancing Account Recovery
532	283.000	NDSCMA - (New 10/08)	-$50,280	-$50,280				Relates Entirely to CPUC Balancing Account Recovery
533	283.000	Amortization of Debt Expense	$383,109			$383,109		Relates to all Regulated Electric Property
534	283.000	Refundable Receivable Line Extension	$304,244	$304,244				Relates to Refundable Distribution Costs
535	283.000	DOE Decontamination & Decommissioning	$2,282,911	$2,282,911				Relates to Nuclear Decommissioning Costs
536	283.000	Cum. Effect - FAS 109-SONGS NUC DBD Csts	-$1,482,208	-$1,482,208				Relates to Nuclear Decommissioning Costs
537	283.000	263A Adjustment	$28,888,962	$28,888,962				Not Component of Rate Base
538	283.000	AFUDC - Equity	-$381,354,707	-$381,354,707				Not Component of Rate Base
539	283.000	CIAC-Deferred Rev-FAS 109 Gross-up	$62,945,950	$62,945,950				Non-Rate Base FAS 109 Tax Flow-Thru - CIAC

Continuation of Account 283 Detail

		Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7
	ACCT 283	DESCRIPTION	END BAL per G/L	Gas, Generation or Other Related	ISO Only	Plant Related	Labor Related	Description
	Electric (continued):							
540	283.000	Depreciation - Cal Electric	-$916,463,952	-$916,463,952				Non-Rate Base FAS 109 Tax Flow-Thru - State Deprec
541	283.000	Removal Costs - Electric	-$325,533,677	-$325,533,677				Non-Rate Base FAS 109 Tax Flow-Thru - Removal
542	283.000	Repair Allowance	-$208,179,120	-$208,179,120				Non-Rate Base FAS 109 Tax Flow-Thru - Repair
543	283.000	Right of Way Amort.	-$3,973,893	-$3,973,893				Non-Rate Base FAS 109 Tax Flow-Thru - ROW
544	283.000	Unreal Gain - Decom - Q - Invest	-$373,530,113	-$373,530,113				Non-Rate Base FAS 109 Tax Flow-Thru - Nuclear
545	283.000	Capitalized Software - Others - NEW IN 11/07	-$178,532,798	-$178,532,798				Non-Rate Base FAS 109 Tax Flow-Thru - Software
546	283.000	Capitalized Software Costs -Tax	-$3,971,309	-$3,971,309				Non-Rate Base FAS 109 Tax Flow-Thru - Software
547	283.000	Capitalized Software Costs	-$100,152,677	-$100,152,677				Non-Rate Base FAS 109 Tax Flow-Thru - Software
548	283.000	Repair - CPUC Repair Deduction	-$422,034,428	-$422,034,428				Property-Related CPUC Costs - Repair
549	283.000	Repair - Contra Deferreds/Repair Deduction Reserve	$161,385,759	$161,385,759				Property-Related CPUC Costs - Repair
550	283.000	Capitalized Software - ERP (Flowthru) - NEW IN 11/07	-$35,718,904	-$35,718,904				Non-Rate Base FAS 109 Tax Flow-Thru - Software
551	283.000	Capitalized Software - ERP	-$125,259	-$125,259				Non-Rate Base FAS 109 Tax Flow-Thru - Software
552	283.000	Lease Acctng - PPBU - Short-term	-$1,617,885	-$1,617,885				Relates Entirely to CPUC Balancing Account Recovery
553	283.000	Nuclear Unit Deferred Chges	-$1,021,261	-$1,021,261				Non-Rate Base FAS 109 Tax Flow-Thru - Nuclear
554	283.000	ITC - Deferred Tax - Plant Sale	$10,930,907	$10,930,907				Not Component of Rate Base Per IRC §46(f)(2)
555	283.000	Radio Frequency	-$6,135,889	-$5,520,342				Non-Rate Base FAS 109 Tax Flow-Thru - Frequency
556	283.000	Decomm Trust Earnings - Book	-$38,691,657	-$38,691,657				Non-Rate Base FAS 109 Tax Flow-Thru - Nuclear
557	283.000	Contribution to Qualified Decommissioning Trust	-$2,198,396	-$2,198,396				Relates to Nuclear Decommissioning Costs
558	283.000	Depreciation - Book - Plant Sale	-$115,892,045	-$115,892,045				Relates to Sale of Generation Facilities
559	283.000	Environmental Remediation	-$18,701,734	-$18,701,734				Relates to Generation Costs
560	283.000	SFAS 158 - Long Term	$7,797,553	$7,797,553				Non-Rate Base FAS 109 Tax Flow-Thru
561	283.000	Environmental Remediation	-$3,355,098	-$3,355,098				Relates to Generation Costs
562	283.000	FERC South Georgia	-$22,369,177	-$22,369,177				Non-Rate Base FAS 109 Tax Flow-Thru - SGA
563	283.000	DIT DOE Litigation MEMO Account - New 2008	-$284,177	-$284,177				Relates to Nuclear Decommissioning Costs
564	283.000	Palo Verde Common	-$649,967	-$649,967				Relates to Nuclear Generation Costs
565	283.000	Catastrophic Memo Account	-$11,363,166	-$11,363,166				Relates Entirely to CPUC Balancing Account Recovery
566	283.000	Refunding & Retirement of Debt	-$86,726,629			-$86,726,629		Relates to all Regulated Electric Property
567	283.000	CONTRA DIT - CCFT (STATE - S/T)	-$526,686	-$526,686				FIN 48 exclusion for FERC
568	283.000	CONTRA DIT - CCFT (STATE - S/T)	-$762,828	-$762,828				FIN 48 exclusion for FERC
569	283.000	Four Corners Capital	-$1,063,138	-$1,063,138				Relates to Generation Costs
570	283.000	Medical B/A (new 12/08)	-$2,334,462	-$2,334,462				Relates Entirely to CPUC Balancing Account Recovery
571	283.000	HYDROGEN ENERGY CALIFORNIA ACCOUNT	-$5,294,783	-$5,294,783				Not Component of Rate Base
572	283.000	SGARRAMA	-$1,075,882	-$1,075,882				Relates Entirely to CPUC Balancing Account Recovery
573	283.000	EMS	-$22,756			-$22,756		Relates to all Regulated Electric Property
574	…							
650		Total Electric 283	-$3,168,914,648	-$3,015,904,042	-$1,089,589	-$149,375,122	-$1,930,349	Sum of Above Lines beginning on Line 500

Acount 283 Gas and Other:

		Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7
700	283.000	Ad Valorem Lien Date Adj-Gas	-$12,112	-$12,112				Gas and Other Non-ISO Related Costs
701	283.000	Depreciation - Cal - Gas	-$527,599	-$527,599				Gas and Other Non-ISO Related Costs
702	283.000	GCAC	-$45,243	-$45,243				Gas and Other Non-ISO Related Costs
703	283.000	Ad Valorem Lien Date Adj-Water	-$69,939	-$69,939				Gas and Other Non-ISO Related Costs
704	283.000	ENVEST - Bad Debt	$0	$0				Gas and Other Non-ISO Related Costs
705	283.000	CFC Capital Loss	-$2	-$2				Gas and Other Non-ISO Related Costs
706	283.000	Depreciation - Book - Other	-$166,335,089	-$166,335,089				Gas and Other Non-ISO Related Costs
707	283.000	Depreciation - Cal Water	$1,298,220	$1,298,220				Gas and Other Non-ISO Related Costs
708	283.000	Executive Retirement Provision	-$1,139,356	-$1,139,356				Gas and Other Non-ISO Related Costs
709	283.000	Capitalized Software Costs - Normalized	$4,057,792	$4,057,792				Gas and Other Non-ISO Related Costs
710	283.000	Depreciation - Book - Telecom	-$3,461,344	-$3,461,344				Gas and Other Non-ISO Related Costs
711	283.000	Depreciation - Book - Telecom	$177,407	$177,407				Gas and Other Non-ISO Related Costs
712	283.000	Telecom - Deferred Tax on Reg Asset	$7,067	$7,067				Gas and Other Non-ISO Related Costs
713	283.000	Reclass Acct 190 Credit and Acct 283 Debit Balances	-$1,271,570,332	-$1,271,570,332				Other - Offset Reclass Between Accounts
714	…							

	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Source
800	Total Account 283 Gas and Other	-$1,437,620,530	-$1,437,620,530	$0	$0	$0	Sum of Above Lines beginning on Line 700
801	Total Account 283	-$4,606,535,179	-$4,453,524,572	-$1,089,589	-$149,375,122	-$1,930,349	Line 650 + Line 800
802	Allocation Factors (Plant and Wages)				9.687%	4.099%	Allocators WS Lines 22 and 9 respectively.
803	Total Account 283 ADIT (Sum of amounts in Columns 4 to 6)	-$15,638,023		-$1,089,589	-$14,469,317	-$79,117	Line 801 * Line 802 for Cols 5 and 6. Col. 4 100% ISO.
804	FERC Form 1 Account 283	-$4,606,535,179	Must match amount on Line 801, Col. 2				FF1 277.19k

5) Normalization Adjustment for Unused Bonus Depreciation

	ACCT	Col 1 IRC Section 168(i)(9) Normalization Adjustment	Col 2 END BAL per G/L	Col 3 Gas, Generation or Other Related	Col 4 ISO Only	Col 5 Plant Related	Col 6 Labor Related	Col 7 Description
805	236	Federal Income Taxes Payable	-$239,018,349					FF1 263.3i - See Note 1
806		Interest Income Reclassification	-$1,890,303					See Note 2
807		Remaining Amount of FIT Payable	-$240,908,652					Line 805 + Line 806
808		Plant Allocation Factor				9.687%		See Note 3
809		IRC Section 168(i)(9) Normalization Adjustment (In Column 5)	$240,908,652	$217,572,881		$23,335,771		- Line 807 * Line 808 for Column 5

Note 1: Only include if Federal Income Tax Account 236 payable in FF1 page 263 charged to Acct 409.1 or 408.1 in Column (i) is a negative amount (i.e., debit balance).
Note 2: Adjustment to exclude interest component related portion of Federal Income Taxes Payable on Line 805.
Note 3: Allocate "Remaining Amount of FIT Payable" based on Transmission Plant Allocation Factor
Remaining Amount is Gas, Generation, or Other Related.

Prior Year CWIP and Forecast Period Incremental CWIP by Project

Prior Year CWIP is the amount of Construction Work In Progress for projects that have received Commission approval to include CWIP in Rate Base.

1) Prior Year CWIP, Total and by Project

Line	**Prior Year Month**	**Year**	**Col 1** = Sum of all columns **Monthly Total CWIP**	**Col 2** **Tehachapi**	**Col 3** **Devers to Colorado River**	**Col 4** **Eldorado Ivanpah**	**Col 5** **Lugo-Pisgah/**	**Col 6** **Red Bluff**
1	December	2010	$614,995,912	$558,943,045	$46,143,765	$9,532,330	-$143,874	$520,646
2	January	2011	$643,199,950	$585,367,564	$47,472,972	$9,766,684	-$50,413	$643,143
3	February	2011	$690,949,206	$630,397,468	$49,340,185	$10,409,831	-$4,755	$806,476
4	March	2011	$750,119,213	$682,761,916	$52,380,329	$11,169,440	$77,648	$1,197,745
5	April	2011	$799,393,755	$727,006,420	$54,124,627	$12,913,844	-$186,847	$1,635,916
6	May	2011	$853,883,047	$776,547,285	$56,948,570	$13,628,198	-$166,923	$2,543,101
7	June	2011	$877,307,159	$791,891,828	$62,493,330	$14,641,606	$118,849	$3,144,670
8	July	2011	$920,268,070	$827,413,766	$66,974,515	$15,658,432	$18,445	$4,713,459
9	August	2011	$964,107,865	$861,355,315	$73,613,131	$17,199,068	$60,164	$5,636,264
10	September	2011	$1,031,449,263	$912,787,886	$86,555,254	$18,686,380	-$199,812	$6,292,318
11	October	2011	$1,098,153,935	$951,944,103	$102,306,727	$24,053,354	-$187,001	$7,820,459
12	November	2011	$1,177,544,894	$1,004,195,645	$125,869,186	$21,195,396	-$107,603	$9,090,813
13	December	2011	$1,277,500,411	$1,059,868,753	$151,361,046	$30,843,632	-$73,288	$14,678,203
14	13 Month Averages:		$899,913,283	$797,729,307	$75,044,895	$16,130,630	-$65,031	$4,517,170

Line	**Prior Year Month**	**Year**	**Col 7** **Whirlwind Substation Expansion**	**Col 8** **Colorado River Substation Expansion**	**Col 9** **South of Kramer**	**Col 10** **West of Devers**	**Col 11** **Project X**	**Col 12** **Project Y**
15	December	2010	$0	$0	$0	$0	---	---
16	January	2011	$0	$0	$0	$0	---	---
17	February	2011	$0	$0	$0	$0	---	---
18	March	2011	$26,164	$307,048	$266,771	$1,932,152	---	---
19	April	2011	$40,848	$1,478,650	$348,485	$2,031,814	---	---
20	May	2011	$119,804	$1,680,637	$443,062	$2,139,313	---	---
21	June	2011	$217,914	$1,924,101	$580,562	$2,294,299	---	---
22	July	2011	$236,258	$2,012,634	$717,960	$2,522,602	---	---
23	August	2011	$371,264	$2,084,280	$953,823	$2,834,556	---	---
24	September	2011	$629,592	$2,243,373	$1,247,348	$3,206,925	---	---
25	October	2011	$1,602,950	$5,527,353	$1,533,961	$3,552,030	---	---
26	November	2011	$2,617,403	$8,950,716	$1,798,198	$3,935,140	---	---
27	December	2011	$2,893,212	$10,959,974	$2,144,420	$4,824,458	---	---
28	13 Month Averages:		$673,493	$2,859,136	$771,892	$2,251,791	---	---

2) Forecast Period CWIP, Total and by Project

Forecast Period CWIP is the amount of CWIP in Rate Base expected for these projects.

	See Note 1		Col 1	Col 2	Col 3	Col 4	Col 5	Col 6
Line	**Forecast Period Month**	**Year**	= Sum of all columns **Forecast Monthly Total CWIP**	**Tehachapi**	**Devers to Colorado River**	**Eldorado Ivanpah**	**Lugo-Pisgah**	**Red Bluff**
29	January	2012	$1,317,355,667	$1,078,610,889	$164,639,970	$35,978,191	-$70,361	$16,138,686
30	February	2012	$1,234,485,847	$966,699,731	$181,443,593	$39,548,256	-$70,358	$21,720,183
31	March	2012	$1,314,765,001	$994,158,544	$216,423,530	$44,039,134	-$70,358	$29,565,786
32	April	2012	$1,264,090,402	$899,640,245	$241,137,098	$51,123,072	-$70,358	$34,947,432
33	May	2012	$1,178,428,141	$738,808,099	$283,528,710	$54,440,797	-$70,358	$58,237,686
34	June	2012	$1,258,613,156	$764,825,997	$311,223,055	$63,628,346	-$70,358	$67,747,161
35	July	2012	$1,230,172,859	$686,821,314	$332,957,715	$76,111,196	-$70,358	$78,058,241
36	August	2012	$1,327,266,312	$703,155,131	$384,263,384	$88,912,257	-$70,358	$89,754,426
37	September	2012	$1,424,666,747	$733,908,068	$435,110,798	$104,171,447	-$70,358	$93,314,227
38	October	2012	$1,531,609,773	$759,633,196	$483,837,462	$120,848,705	-$70,358	$106,087,215
39	November	2012	$1,519,586,695	$669,977,223	$525,112,802	$143,229,206	-$70,358	$115,245,783
40	December	2012	$1,502,242,093	$576,543,463	$570,679,746	$158,533,244	-$70,358	$120,989,613
41	January	2013	$1,601,630,715	$601,684,918	$618,573,877	$170,429,859	-$70,358	$129,015,349
42	February	2013	$1,689,030,548	$625,589,737	$654,304,717	$183,620,676	-$70,358	$137,070,087
43	March	2013	$1,776,244,502	$647,415,019	$687,405,901	$197,948,724	-$70,358	$147,989,356
44	April	2013	$1,835,544,470	$644,725,256	$716,565,525	$210,724,157	-$70,358	$161,526,115
45	May	2013	$1,891,106,464	$641,914,249	$745,117,807	$222,430,700	-$70,358	$173,136,436
46	June	2013	$1,959,994,106	$654,693,412	$769,303,396	$240,007,065	-$70,358	$178,472,070
47	July	2013	$1,767,069,923	$665,973,546	$791,817,257	$0	-$70,358	$183,276,386
48	August	2013	$1,827,685,943	$680,297,780	$807,589,803	$0	-$70,358	$189,233,824
49	September	2013	$1,037,156,953	$689,448,710	$0	$0	-$70,358	$193,828,378

	See Note 1		Col 7	Col 8	Col 9	Col 10	Col 11	Col 12
Line	**Forecast Period Month**	**Year**	**Whirlwind Substation Expansion**	**Colorado River Substation Expansion**	**South of Kramer**	**West of Devers**	**Project X**	**Project Y**
50	January	2012	$3,194,615	$11,369,053	$2,351,145	$5,143,478	---	---
51	February	2012	$3,224,880	$13,613,820	$2,731,153	$5,574,588	---	---
52	March	2012	$4,589,787	$16,626,697	$3,181,821	$6,250,060	---	---
53	April	2012	$4,668,379	$21,873,979	$3,653,948	$7,116,607	---	---
54	May	2012	$4,815,525	$26,573,468	$4,329,544	$7,764,671	---	---
55	June	2012	$5,344,097	$32,435,816	$4,989,977	$8,489,065	---	---
56	July	2012	$6,065,946	$35,233,512	$5,669,856	$9,325,438	---	---
57	August	2012	$6,755,759	$37,972,477	$6,363,862	$10,159,374	---	---
58	September	2012	$868,975	$39,399,089	$7,024,455	$10,940,046	---	---
59	October	2012	$1,162,199	$40,626,017	$7,718,621	$11,766,715	---	---
60	November	2012	$2,484,378	$42,617,507	$8,408,762	$12,581,393	---	---
61	December	2012	$3,204,698	$49,680,088	$9,101,186	$13,580,413	---	---
62	January	2013	$3,536,364	$54,033,602	$9,852,037	$14,575,067	---	---
63	February	2013	$3,913,096	$58,387,116	$10,601,654	$15,613,823	---	---
64	March	2013	$4,609,317	$62,740,630	$11,370,096	$16,835,818	---	---
65	April	2013	$5,245,739	$67,094,144	$12,063,314	$17,670,578	---	---
66	May	2013	$5,879,172	$71,447,658	$12,752,260	$18,498,541	---	---
67	June	2013	$9,020,707	$75,801,172	$13,441,206	$19,325,435	---	---
68	July	2013	$11,989,255	$79,753,185	$14,191,119	$20,139,533	---	---
69	August	2013	$31,800,573	$82,668,342	$15,218,666	$20,947,313	---	---
70	September	2013	$33,545,396	$82,668,342	$15,970,715	$21,765,771	---	---

3) Forecast Period Incremental CWIP, Total and by Project

Forecast Period Incremental CWIP is the amount of CWIP in Rate Base expected for these projects, minus the Prior Year year-end amount. Equals amounts from Lines 29-49 and 50-70 minus amount on Lines 13 and 27.

Line	See Note 1 Forecast Period Month	Year	Col 1 Sum of all Cols Total Forecast Monthly Incremental CWIP	Col 2 Tehachapi	Col 3 Devers to Colorado River	Col 4 Eldorado Ivanpah	Col 5 Lugo-Pisgah/	Col 6 Red Bluff
71	January	2012	$39,855,255	$18,742,136	$13,278,924	$5,134,559	$2,927	$1,460,482
72	February	2012	-$43,014,565	-$93,169,022	$30,082,547	$8,704,624	$2,930	$7,041,980
73	March	2012	$37,264,590	-$65,710,209	$65,062,484	$13,195,502	$2,930	$14,887,583
74	April	2012	-$13,410,009	-$160,228,508	$89,776,052	$20,279,440	$2,930	$20,269,229
75	May	2012	-$99,072,270	-$321,060,655	$132,167,664	$23,597,165	$2,930	$43,559,482
76	June	2012	-$18,887,255	-$295,042,756	$159,862,009	$32,784,714	$2,930	$53,068,958
77	July	2012	-$47,327,552	-$373,047,439	$181,596,669	$45,267,564	$2,930	$63,380,038
78	August	2012	$49,765,901	-$356,713,622	$232,902,338	$58,068,625	$2,930	$75,076,223
79	September	2012	$147,166,336	-$325,960,685	$283,749,752	$73,327,815	$2,930	$78,636,024
80	October	2012	$254,109,362	-$300,235,558	$332,476,416	$90,005,073	$2,930	$91,409,012
81	November	2012	$242,086,284	-$389,891,530	$373,751,756	$112,385,574	$2,930	$100,567,580
82	December	2012	$224,741,682	-$483,325,290	$419,318,700	$127,689,612	$2,930	$106,311,410
83	January	2013	$324,130,304	-$458,183,835	$467,212,831	$139,586,227	$2,930	$114,337,146
84	February	2013	$411,530,137	-$434,279,016	$502,943,671	$152,777,044	$2,930	$122,391,883
85	March	2013	$498,744,091	-$412,453,734	$536,044,855	$167,105,092	$2,930	$133,311,152
86	April	2013	$558,044,059	-$415,143,498	$565,204,479	$179,880,525	$2,930	$146,847,912
87	May	2013	$613,606,053	-$417,954,505	$593,756,761	$191,587,068	$2,930	$158,458,233
88	June	2013	$682,493,694	-$405,175,341	$617,942,350	$209,163,433	$2,930	$163,793,866
89	July	2013	$489,569,512	-$393,895,207	$640,456,211	-$30,843,632	$2,930	$168,598,183
90	August	2013	$550,185,532	-$379,570,973	$656,228,757	-$30,843,632	$2,930	$174,555,621
91	September	2013	-$240,343,459	-$370,420,044	-$151,361,046	-$30,843,632	$2,930	$179,150,174
92	13 Month Averages:		$365,851,045	-$398,960,709	$449,055,807	$103,921,274	$2,930	$133,720,630

Line	See Note 1 Forecast Period Month	Year	Col 7 Whirlwind Substation Expansion	Col 8 Colorado River Substation Expansion	Col 9 South of Kramer	Col 10 West of Devers	Col 11 Project X	Col 12 Project Y
93	January	2012	$301,403	$409,080	$206,725	$319,020	---	---
94	February	2012	$331,668	$2,653,846	$586,733	$750,130	---	---
95	March	2012	$1,696,575	$5,666,723	$1,037,401	$1,425,602	---	---
96	April	2012	$1,775,167	$10,914,005	$1,509,528	$2,292,149	---	---
97	May	2012	$1,922,313	$15,613,494	$2,185,123	$2,940,213	---	---
98	June	2012	$2,450,885	$21,475,842	$2,845,557	$3,664,607	---	---
99	July	2012	$3,172,733	$24,273,538	$3,525,435	$4,500,980	---	---
100	August	2012	$3,862,547	$27,012,504	$4,219,441	$5,334,916	---	---
101	September	2012	-$2,024,237	$28,439,115	$4,880,035	$6,115,588	---	---
102	October	2012	-$1,731,013	$29,666,044	$5,574,201	$6,942,257	---	---
103	November	2012	-$408,835	$31,657,533	$6,264,341	$7,756,935	---	---
104	December	2012	$311,486	$38,720,114	$6,956,765	$8,755,955	---	---
105	January	2013	$643,152	$43,073,628	$7,707,617	$9,750,609	---	---
106	February	2013	$1,019,884	$47,427,142	$8,457,234	$10,789,365	---	---
107	March	2013	$1,716,105	$51,780,656	$9,225,676	$12,011,359	---	---
108	April	2013	$2,352,527	$56,134,170	$9,918,893	$12,846,120	---	---
109	May	2013	$2,985,960	$60,487,684	$10,607,840	$13,674,083	---	---
110	June	2013	$6,127,495	$64,841,199	$11,296,786	$14,500,977	---	---
111	July	2013	$9,096,042	$68,793,211	$12,046,699	$15,315,075	---	---
112	August	2013	$28,907,361	$71,708,368	$13,074,246	$16,122,855	---	---
113	September	2013	$30,652,184	$71,708,368	$13,826,294	$16,941,313	---	---
114	13 Month Averages:		$6,126,778	$51,110,556	$9,218,202	$11,655,576	---	---

Notes:

1) Forecast Period is October of year following the Prior Year through September of the next year.

Instructions:

1) Enter recorded amounts of CWIP during Prior Year on Lines 1-13, 15-27 (including December of year previous to Prior Year).
2) Enter forecast CWIP total balances for these projects on Lines 29-49, 50-70.
3) If Commission approval is granted to include CWIP in Rate Base for additional projects, utilize Project X, Y, and Z columns.
If additional projects receive approval, add additional columns in same format.

TRANSMISSION PLANT HELD FOR FUTURE USE

Inputs are shaded yellow

Transmission Plant Held for Future Use shall be amounts of Electric Plant Held for Future Use (account 105) intended to be placed under the Operational Control of the ISO, plus an allocated amount of any General Electric Plant Held for Future Use, with the allocation factor being the Transmission Wages and Salaries AF.

Line		**Beginning of Year Balance**	**End of Year Balance**	**Source**
1	Total Electric PHFU	$480,549	$16,261,747	FF1 page 214.47d

Plant intended to be placed under the Operational Control of the ISO:

	Col 1 **Description**	**Col 2** **Type of Plant**	**Col 3** **Beginning of Year Balance**	**Col 4** **End of Year Balance**	**Col 5** **Source**
2a	Alberhill	Sub	$0	$9,942,155	SCE Records
2b					
2c					
2d					
2e					
2f					
2g					
2h					
	…				
3		Total:	$0	$9,942,155	Sum of above lines

		Beginning of Year Balance	**End of Year Balance**	**Source**
4	General Plant Held for Future Use	$0	$0	FF1 page 214
5	Wages and Salaries AF:	4.099%	4.099%	Allocators WS, L 9
6	Portion for Transmission PHFU:	$0	$0	L 4 * L 5

All other Electric Plant Held for Future Use not intended to be placed under the Operational Control of the ISO:

		Beginning of Year Balance	**End of Year Balance**	**Source**
7		$480,549	$6,319,592	Note 1

		Beginning of Year Balance	**End of Year Balance**	**Source**
8	Transmission PHFU:	$0	$9,942,155	L 3 + L 6

9	Average of BOY and EOY Transmission PHFU:	$4,971,078		Sum of Line 8 / 2

Calculation of Gain or Loss on Transmission Plant Held for Future Use -- Land

			Source
10	Gain or Loss on Transmission Plant Held for Future Use --- Land	$9,724	SCE Records

Instructions:

1) For any Electric Plant Held for Future Use intended to be placed under the Operational Control of the ISO, list on lines 2a, 2b, etc. Provide description in Column 1. Note type of plant (land or other) in Column 2. Under "Source" (Column 5), state the line number on FERC Form 1 page 214 from which the amount is derived. BOY amount will be EOY value from previous year FERC Form 1, EOY amount will be in current year FF1.
2) For any Electric Plant Held for Future Use classified as General note amount on Line 4.
3) Add additional lines 2 i, j, k, etc. as necessary to include additional projects intended to be placed under the Operational Control of the ISO.
4) Gains and Losses on Transmission Plant Held for Future Use - Land is treated in accordance with Commission policy. Any gain or loss on non-land portions of Transmission Plant Held for Future Use is not included.

Notes:

1) Amount of Line 1 not intended to be placed under the Operational Control of the ISO.

Determination of amount of Abandoned Plant and Abandoned Plant Amortization Expense

Input data is shaded yellow

Initially Abandoned Plant Amortization Expense and Abandoned Plant are both zero.

Upon Commission approval of recovery of abandoned plant costs for a specific project or projects, SCE will complete this worksheet in accordance with that Order.

Abandoned Plant for each project represents the amount of costs that the Order approves for inclusion in Rate Base.

Abandoned Plant Amortization Expense for each project represents the annual amortization of abandoned costs that the Order approves as an annual expense.

Line		**Amount for Prior Year**	**Note:**
1	Abandoned Plant Amortization Expense:	$0	Sum of projects below for PY.
2	Abandoned Plant (BOY):	$0	Sum of projects below for PY.
3	Abandoned Plant (EOY):	$11,028,000	Sum of projects below for PY.
4	Abandoned Plant (BOY/EOY Average):	$5,514,000	Average of Lines 2 and 3.

		First Project:	DPV2 Arizona	**2nd Project:**	Fill in Name	**3rd Project:**	Fill in Name
5	**Year**	**EOY Abandoned Plant**	**Abandoned Plant Amort. Expense**	**EOY Abandoned Plant**	**Abandoned Plant Amort. Expense**	**EOY Abandoned Plant**	**Abandoned Plant Amort. Expense**
6	2011	$11,028,000					
7	2012		$11,028,000				
8	2013						
9	2014						
10	2015						
11	2016						
12	2017						
13	2018						
14	2019						
15	2020						
16	2021						
17	2022						
18	2023						
19	2024						
20	2025						
21	2026						
22	2027						
23	2028						
24	2029						
25	2030						
26	2031						
27	2032						
28	2033						
29	2034						
30	2035						
31	…						

Instructions:

1) Upon Commission approval of recovery of abandoned plant costs for a project:
   a) Fill in the name the project in order (First Project, Second Project, Third Project, etc.).
   b) Fill in the table with annual End of Year ("EOY") Abandoned Plant and Abandoned Plant Amortization Expense amounts in Accordance with the Order.
   If table can not be filled out completely, fill out at least through the Prior Year at issue.
   c) Sum project-specific amounts for each project and enter in lines 1, 2, and 3 for the Prior Year at issue.
   (BOY value is EOY value from previous year)
2) Add additional projects if necessary in same format.
3) Add additional years past 2035 if necessary.

Calculation of Components of Working Capital

Inputs are shaded yellow

1) Calculation of Materials and Supplies

Materials and Supplies is the amount of total Account 154 Materials and Supplies times the Transmission Wages and Salaries AF

Line	Month	Year	Data Source	Total Materials and Supplies Balances	Notes
1	December	2010	FF1 227.12b	$310,981,122	Beginning of year ("BOY") amount
2	December	2011	FF1 227.12c	$326,272,689	End of Year ("EOY") amount
3	Average BOY/EOY Value Account 154:			$318,626,906	(Line 1 + Line 2) / 2
4	Transmission Wages and Salaries AF:			4.099%	Allocators WS, Line 9
5	**Materials and Supplies**		EOY Value:	$13,372,597	Line 2 * Line 4
6	Average BOY/EOY Value:			$13,059,227	Line 3 * Line 4

2) Calculation of Prepayments

Prepayments is an allocated portion of Total Prepayments based on the Transmission Plant Allocation Factor.

	Month	Year	Data Source	Total Prepayments Balances	Notes
7	December	2010	FF1 111.57d	$49,976,455	See Note 1, c
8	December	2011	FF1 111.57c	$53,865,316	See Note 1, f
	a) BOY/EOY Average calculation				
9	Average BOY/EOY Value:			$51,920,886	(Line 7 + Line 8) / 2
10	Transmission Plant Allocation Factor:			9.6866%	Allocators WS, Line 22
11	Prepayments:			$5,029,350	Line 9 * Line 10
	b) EOY calculation				
12	EOY Value:			$53,865,316	Line 8
13	Transmission Plant Allocation Factor:			9.6866%	Allocators WS, Line 22
14	Prepayments:			$5,217,698	Line 12 * Line 13

Notes:

1) Remove any amounts related to years prior to the effective date of the formula on b and e below.

a) Beginning of Year Amount

		Prepayments Balances	Source
a	FERC Form 1 Acct. 165 Recorded Amount:	$132,347,508	FF1 111.57d
b	Prior Period Adjustment:	$82,371,053	Note 1
c	BOY Prepayments Amount:	$49,976,455	a - b

a) End of Year Amount

		Prepayments Balances	Source
d	FERC Form 1 Acct. 165 Recorded Amount:	$111,759,392	FF1 111.57c
e	Prior Period Adjustment:	$57,894,076	Note 1
f	BOY Prepayments Amount:	$53,865,316	d - e

Plant Balances For Incentive Projects Receiving either ROE Incentives ("Transmission Incentive Plant") or CWIP ("CWIP Plant")

Input data is shaded yellow

A) Summary of Incentive Project plant balances receiving ROE incentives ("Transmission Incentive Plant") and/or CWIP ("CWIP Plant") and calculation of balances needed to determine the following:

1) Rate Base in Prior Year
2) Prior Year Incentive Rate Base - End of Year
3) Prior Year Incentive Rate Base - 13-Month Average

Transmission Incentive Project plant balances and CWIP Plant may affect the following:

a) CWIP Plant during the Prior Year is included in Rate Base (used in Prior Year TRR and True Up TRR).
b) Forecast Period Incremental CWIP contributes to Forecast Plant Additions
c) CWIP Plant receiving an ROE adder contributes to Prior Year Incentive Rate Base - EOY, or Prior Year Incentive Rate Base - 13 Month Average as appropriate.
d) "TIP Net Plant In Service" at EOY Prior Year is used to calculate the PY Incentive Rate Base (on EOY basis).
e) "TIP Net Plant In Service" in PY is used to calculate the Prior Year Incentive Rate Base (on 13-month average basis).

1) Summary of CWIP Plant in Prior Year and Forecast Period

Line	**Incentive Project**	**Col 1** Prior Year End-of-Year CWIP Plant Amount	**Col 2** Prior Year 13-Month Average CWIP Plant Amount	**Col 3** Forecast Period Incremental CWIP 13-Month Avg. Amount	**Notes:**
1	1) Tehachapi	$1,059,868,753	$797,729,307	-$398,960,709	CWIP WS Lines 13, 14, and 92
2	2) Devers-Colorado River	$151,361,046	$75,044,895	$449,055,807	CWIP WS Lines 13, 14, and 92
3	3) Eldorado-Ivanpah	$30,843,632	$16,130,630	$103,921,274	CWIP WS Lines 13, 14, and 92
4	4) Lugo-Pisgah	-$73,288	-$65,031	$2,930	CWIP WS Lines 13, 14, and 92
5	5) Red Bluff	$14,678,203	$4,517,170	$133,720,630	CWIP WS Lines 13, 14, and 92
6	6) Whirlwind Substation Exp.	$2,893,212	$673,493	$6,126,778	CWIP WS Lines 27, 28, and 114
7	7) Colorado River Sub. Exp.	$10,959,974	$2,859,136	$51,110,556	CWIP WS Lines 27, 28, and 114
8	8) South of Kramer	$2,144,420	$771,892	$9,218,202	CWIP WS Lines 27, 28, and 114
9	9) West of Devers	$4,824,458	$2,251,791	$11,655,576	CWIP WS Lines 27, 28, and 114
10	10) Project X	---	---	---	Add additional lines as appropriate
11	…				
12	Totals:	$1,277,500,411	$899,913,283	$365,851,045	

2) Summary of Prior Year Incentive Rate Base amounts (EOY Values)

		Col 1 = C2 + C3 Prior Year Incentive Rate Base	**Col 2** EOY CWIP Portion	**Col 3** EOY TIP Net Plant In Service	**Notes:**
13	1) Rancho Vista	$179,233,968	$0	$179,233,968	Line 37, C4
14	2) Tehachapi	$1,447,909,315	$1,059,868,753	$388,040,562	Line 1, C1, and Line 37, C2
15	3) Devers-Colorado River	$151,361,046	$151,361,046	$0	Line 2, C1, and Line 37, C3
16	4) Project X	---	---	---	Add additional lines as appropriate
17	…				
18	Total PY Incentive Net Plant:	$1,778,504,329			End of Year

3) Summary of Prior Year Incentive Rate Base amounts (13-Month Average values)

	Incentive Project	**Col 1** = C2 + C3 Prior Year Incentive Rate Base	**Col 2** 13-Month Avg. CWIP Portion	**Col 3** 13-Month Avg. TIP Net Plant In Service Portion	**Notes:**
19	1) Rancho Vista	$181,872,286	$0	$181,872,286	Line 38, C4
20	2) Tehachapi	$1,177,058,496	$797,729,307	$379,329,189	Line 1, C2, and Line 38, C2
21	3) Devers-Colorado R	$75,061,661	$75,044,895	$16,766	Line 2, C2, and Line 38, C3
22	4) Project X	---	---	---	Add additional lines as appropriate
23	…				
24	Total PY Incentive Net Plant:	$1,433,992,443			13 Month Average

4) Prior Year TIP Net Plant In Service

	Prior Year Month	Year	Col 1 Total TIP Net Plant In Service	Col 2 Tehachapi	Col 3 Devers to Colorado River	Col 4 Rancho Vista	Col 5 Project X	Notes
25	December	2010	$556,387,010	$372,376,781	$48,738	$183,961,490	---	←December of year previous to Prior Year
26	January	2011	$555,385,437	$371,780,401	$53,642	$183,551,395	---	
27	February	2011	$555,929,431	$371,274,009	$58,350	$184,597,072	---	
28	March	2011	$553,757,409	$369,557,165	$58,354	$184,141,890	---	
29	April	2011	$551,232,861	$368,712,279	-$1,122	$182,521,705	---	
30	May	2011	$549,969,019	$367,813,277	$0	$182,155,742	---	
31	June	2011	$573,378,526	$391,639,342	$0	$181,739,184	---	
32	July	2011	$567,630,718	$386,308,000	$0	$181,322,718	---	
33	August	2011	$566,631,164	$385,725,723	$0	$180,905,441	---	
34	September	2011	$565,692,932	$385,205,359	$0	$180,487,573	---	
35	October	2011	$564,559,809	$384,490,104	$0	$180,069,705	---	
36	November	2011	$568,008,288	$388,356,451	$0	$179,651,836	---	
37	December	2011	$567,274,530	$388,040,562	$0	$179,233,968	---	
38	13 Month Averages:		$561,218,241	$379,329,189	$16,766	$181,872,286		

5) Total Transmission Activity for Incentive Projects

	Prior Year Month	Year	Col 1 Total Transmission Activity for Incentive Projects	Col 2 Account 360-362 Activity	Col 3 = C1 - C2 Account 350-359 Activity for Incentive Projects	Source
39	December	2010	$0	$0	$0	C1: Sum of below projects for each month
40	January	2011	$268,642	$0	$268,642	
41	February	2011	$1,862,338	$0	$1,862,338	
42	March	2011	-$852,299	$0	-$852,299	
43	April	2011	-$1,206,830	$0	-$1,206,830	
44	May	2011	$50,024	$0	$50,024	
45	June	2011	$24,724,604	$0	$24,724,604	
46	July	2011	-$4,371,306	$0	-$4,371,306	
47	August	2011	$367,220	$0	$367,220	
48	September	2011	$430,088	$0	$430,088	
49	October	2011	$127,886	$0	$127,886	
50	November	2011	$4,709,812	$0	$4,709,812	
51	December	2011	$538,367	$0	$538,367	
52	Total		$26,648,546	$0	$26,648,546	

6) Calculation of Prior Year Net Plant in Service amounts for each Incentive Project

a) Tehachapi

	Prior Year Month	Year	Col 1 Plant In-Service	Col 2 Accumulated Depreciation	Col 3 = C1 - C2 Net Plant In Service	Col 4 = C1 - Previous Month C1 Transmission Activity
53	December	2010	$383,067,609	$10,690,828	$372,376,781	$0
54	January	2011	$383,322,277	$11,541,876	$371,780,401	$254,668
55	February	2011	$383,715,034	$12,441,025	$371,274,009	$392,757
56	March	2011	$382,898,407	$13,341,242	$369,557,165	-$816,628
57	April	2011	$382,951,809	$14,239,530	$368,712,279	$53,402
58	May	2011	$382,951,213	$15,137,935	$367,813,277	-$596
59	June	2011	$407,675,631	$16,036,289	$391,639,342	$24,724,418
60	July	2011	$403,304,325	$16,996,325	$386,308,000	-$4,371,306
61	August	2011	$403,671,545	$17,945,822	$385,725,723	$367,220
62	September	2011	$404,101,633	$18,896,274	$385,205,359	$430,088
63	October	2011	$404,229,519	$19,739,415	$384,490,104	$127,886
64	November	2011	$408,939,331	$20,582,880	$388,356,451	$4,709,812
65	December	2011	$409,477,698	$21,437,136	$388,040,562	$538,367

b) Rancho Vista

	Prior Year Month	Year	Col 1 Plant In-Service	Col 2 Accumulated Depreciation	Col 3 = C1 - C2 Net Plant In Service	Col 4 = C1 - Previous Month C1 Transmission Activity
66	December	2010	$191,744,013	$7,782,523	$183,961,490	$0
67	January	2011	$191,752,976	$8,201,581	$183,551,395	$8,963
68	February	2011	$193,217,731	$8,620,659	$184,597,072	$1,464,755
69	March	2011	$193,181,926	$9,040,036	$184,141,890	-$35,805
70	April	2011	$191,981,041	$9,459,336	$182,521,705	-$1,200,885
71	May	2011	$192,031,660	$9,875,918	$182,155,742	$50,620
72	June	2011	$192,031,846	$10,292,662	$181,739,184	$185
73	July	2011	$192,031,846	$10,709,128	$181,322,718	$0
74	August	2011	$192,031,846	$11,126,405	$180,905,441	$0
75	September	2011	$192,031,846	$11,544,273	$180,487,573	$0
76	October	2011	$192,031,846	$11,962,141	$180,069,705	$0
77	November	2011	$192,031,846	$12,380,009	$179,651,836	$0
78	December	2011	$192,031,846	$12,797,878	$179,233,968	$0

c) Devers to Colorado River

	Prior Year Month	Year	Col 1 Plant In-Service	Col 2 Accumulated Depreciation	Col 3 = C1 - C2 Net Plant In Service	Col 4 = C1 - Previous Month C1 Transmission Activity
79	December	2010	$49,375	$637	$48,738	$0
80	January	2011	$54,387	$745	$53,642	$5,012
81	February	2011	$59,213	$863	$58,350	$4,826
82	March	2011	$59,347	$993	$58,354	$134
83	April	2011	$0	$1,122	-$1,122	-$59,347
84	May	2011	$0	$0	$0	$0
85	June	2011	$0	$0	$0	$0
86	July	2011	$0	$0	$0	$0
87	August	2011	$0	$0	$0	$0
88	September	2011	$0	$0	$0	$0
89	October	2011	$0	$0	$0	$0
90	November	2011	$0	$0	$0	$0
91	December	2011	$0	$0	$0	$0

d) Eldorado Ivanpah

	Prior Year Month	Year	Col 1 Plant In-Service	Col 2 Accumulated Depreciation	Col 3 = C1 - C2 Net Plant In Service	Col 4 = C1 - Previous Month C1 Transmission Activity
92	December	2010	$0	$0	$0	$0
93	January	2011	$0	$0	$0	$0
94	February	2011	$0	$0	$0	$0
95	March	2011	$0	$0	$0	$0
96	April	2011	$0	$0	$0	$0
97	May	2011	$0	$0	$0	$0
98	June	2011	$0	$0	$0	$0
99	July	2011	$0	$0	$0	$0
100	August	2011	$0	$0	$0	$0
101	September	2011	$0	$0	$0	$0
102	October	2011	$0	$0	$0	$0
103	November	2011	$0	$0	$0	$0
104	December	2011	$0	$0	$0	$0

e) Lugo Pisgah

	Prior Year Month	Year	Col 1 Plant In-Service	Col 2 Accumulated Depreciation	Col 3 = C1 - C2 Net Plant In Service	Col 4 = C1 - Previous Month C1 Transmission Activity
105	December	2010	$0	$0	$0	$0
106	January	2011	$0	$0	$0	$0
107	February	2011	$0	$0	$0	$0
108	March	2011	$0	$0	$0	$0
109	April	2011	$0	$0	$0	$0
110	May	2011	$0	$0	$0	$0
111	June	2011	$0	$0	$0	$0
112	July	2011	$0	$0	$0	$0
113	August	2011	$0	$0	$0	$0
114	September	2011	$0	$0	$0	$0
115	October	2011	$0	$0	$0	$0
116	November	2011	$0	$0	$0	$0
117	December	2011	$0	$0	$0	$0

f) Red Bluff

	Prior Year Month	Year	Col 1 Plant In-Service	Col 2 Accumulated Depreciation	Col 3 = C1 - C2 Net Plant In Service	Col 4 = C1 - Previous Month C1 Transmission Activity
118	December	2010	$0	$0	$0	$0
119	January	2011	$0	$0	$0	$0
120	February	2011	$0	$0	$0	$0
121	March	2011	$0	$0	$0	$0
122	April	2011	$0	$0	$0	$0
123	May	2011	$0	$0	$0	$0
124	June	2011	$0	$0	$0	$0
125	July	2011	$0	$0	$0	$0
126	August	2011	$0	$0	$0	$0
127	September	2011	$0	$0	$0	$0
128	October	2011	$0	$0	$0	$0
129	November	2011	$0	$0	$0	$0
130	December	2011	$0	$0	$0	$0

g) Whirlwind Substation Expansion

	Prior Year Month	Year	Col 1 Plant In-Service	Col 2 Accumulated Depreciation	Col 3 = C1 - C2 Net Plant In Service	Col 4 = C1 - Previous Month C1 Transmission Activity
131	December	2010	$0	$0	$0	$0
132	January	2011	$0	$0	$0	$0
133	February	2011	$0	$0	$0	$0
134	March	2011	$0	$0	$0	$0
135	April	2011	$0	$0	$0	$0
136	May	2011	$0	$0	$0	$0
137	June	2011	$0	$0	$0	$0
138	July	2011	$0	$0	$0	$0
139	August	2011	$0	$0	$0	$0
140	September	2011	$0	$0	$0	$0
141	October	2011	$0	$0	$0	$0
142	November	2011	$0	$0	$0	$0
143	December	2011	$0	$0	$0	$0

h) Colorado River Substation Expansion

	Prior Year Month	Year	Col 1 Plant In-Service	Col 2 Accumulated Depreciation	Col 3 = C1 - C2 Net Plant In Service	Col 4 = C1 - Previous Month C1 Transmission Activity
144	December	2010	$0	$0	$0	$0
145	January	2011	$0	$0	$0	$0
146	February	2011	$0	$0	$0	$0
147	March	2011	$0	$0	$0	$0
148	April	2011	$0	$0	$0	$0
149	May	2011	$0	$0	$0	$0
150	June	2011	$0	$0	$0	$0
151	July	2011	$0	$0	$0	$0
152	August	2011	$0	$0	$0	$0
153	September	2011	$0	$0	$0	$0
154	October	2011	$0	$0	$0	$0
155	November	2011	$0	$0	$0	$0
156	December	2011	$0	$0	$0	$0

i) South of Kramer

	Prior Year Month	Year	Col 1 Plant In-Service	Col 2 Accumulated Depreciation	Col 3 = C1 - C2 Net Plant In Service	Col 4 = C1 - Previous Month C1 Transmission Activity
157	December	2010	$0	$0	$0	$0
158	January	2011	$0	$0	$0	$0
159	February	2011	$0	$0	$0	$0
160	March	2011	$0	$0	$0	$0
161	April	2011	$0	$0	$0	$0
162	May	2011	$0	$0	$0	$0
163	June	2011	$0	$0	$0	$0
164	July	2011	$0	$0	$0	$0
165	August	2011	$0	$0	$0	$0
166	September	2011	$0	$0	$0	$0
167	October	2011	$0	$0	$0	$0
168	November	2011	$0	$0	$0	$0
169	December	2011	$0	$0	$0	$0

j) West of Devers

	Prior Year Month	Year	Col 1 Plant In-Service	Col 2 Accumulated Depreciation	Col 3 = C1 - C2 Net Plant In Service	Col 4 = C1 - Previous Month C1 Transmission Activity
170	December	2010	$0	$0	$0	$0
171	January	2011	$0	$0	$0	$0
172	February	2011	$0	$0	$0	$0
173	March	2011	$0	$0	$0	$0
174	April	2011	$0	$0	$0	$0
175	May	2011	$0	$0	$0	$0
176	June	2011	$0	$0	$0	$0
177	July	2011	$0	$0	$0	$0
178	August	2011	$0	$0	$0	$0
179	September	2011	$0	$0	$0	$0
180	October	2011	$0	$0	$0	$0
181	November	2011	$0	$0	$0	$0
182	December	2011	$0	$0	$0	$0

k) Project Z

Add additional Incentive Projects as approved.

6) Summary of Incentive Projects and incentives granted

	A) Rancho Vista Incentives Received:		**Cite:**
183	CWIP:	Yes	121 FERC ¶ 61,168 at P 57
184	ROE adder:	0.75%	121 FERC ¶ 61,168 at P 129
185	100% Abandoned Plant:	No	-------
	B) Tehachapi Incentives Received:		**Cite:**
186	CWIP:	Yes	121 FERC ¶ 61,168 at P 57
187	ROE adder:	1.25%	121 FERC ¶ 61,168 at P 129
188	100% Abandoned Plant:	Yes	121 FERC ¶ 61,168 at P 71
	C) Devers to Colorado River Incentives Received:		**Cite:**
189	CWIP:	Yes	121 FERC ¶ 61,168 at P 57
190	ROE adder:	1.00%	121 FERC ¶ 61,168 at 129; modified by ER10-160 Settlement, see
191			P 7 and P 11
192	100% Abandoned Plant:	Yes	121 FERC ¶ 61,168 at P 71
	D) Devers to Palo Verde 2 Incentives Received:		**Cite:**
193	CWIP:	No	121 FERC ¶ 61,168 at P 57; modified by ER10-160 Settlement, see
194			P2 and P3
195	ROE adder:	0.00%	121 FERC ¶ 61,168 at P 129; modified by ER10-160 Settlement, see
196			P 3 and P 7
197	100% Abandoned Plant:	Yes	121 FERC ¶ 61,168 at P 71
	E) Eldorado Ivanpah Incentives Received:		**Cite:**
198	CWIP:	Yes	129 FERC ¶ 61,246 at P 55, and 133 FERC ¶ 61,108 at P 92
199	ROE adder:	0.00%	133 FERC ¶ 61,108 at P 98
200	100% Abandoned Plant:	Yes	129 FERC ¶ 61,246 at PP 68-69, and 133 FERC ¶ 61,108 at PP 85-86
	F) Lugo Pisgah Incentives Received:		**Cite:**
201	CWIP:	Yes	133 FERC ¶ 61,107 at P 76
202	ROE adder:	0.00%	133 FERC ¶ 61,107 at P 102
203	100% Abandoned Plant:	Yes	133 FERC ¶ 61,107 at P 88
	G) Red Bluff Incentives Received:		**Cite:**
204	CWIP:	Yes	133 FERC ¶ 61,107 at P 76
205	ROE adder:	0.00%	133 FERC ¶ 61,107 at P 102
206	100% Abandoned Plant:	Yes	133 FERC ¶ 61,107 at P 88
	H) Whirlwind Substation Expansion Incentives Received:		**Cite:**
207	CWIP:	Yes	134 FERC ¶ 61,181 at P 79
208	ROE adder:	0.00%	---
209	100% Abandoned Plant:	Yes	134 FERC ¶ 61,181 at P 79
	I) Colorado River Substation Expansion Incentives Received:		**Cite:**
210	CWIP:	Yes	134 FERC ¶ 61,181 at P 79
211	ROE adder:	0.00%	---
212	100% Abandoned Plant:	Yes	134 FERC ¶ 61,181 at P 79
	J) South of Kramer Incentives Received:		**Cite:**
213	CWIP:	Yes	134 FERC ¶ 61,181 at P 79
214	ROE adder:	0.00%	---
215	100% Abandoned Plant:	Yes	134 FERC ¶ 61,181 at P 79
	K) West of Devers Incentives Received:		**Cite:**
216	CWIP:	Yes	134 FERC ¶ 61,181 at P 79
217	ROE adder:	0.00%	---
218	100% Abandoned Plant:	Yes	134 FERC ¶ 61,181 at P 79
	L) Future Incentive Projects		**Cite:**
219	CWIP:		
220	ROE adder:		
221	100% Abandoned Plant:		
	…		

Instructions:

1) Upon Commission approval of any incentives for additional projects, add additional projects and provide cite to the Commission decision.

Determination of Incentive Adders Components of the TRR

Input data is shaded yellow

Two Incentive Adders are calculated:
a) The Prior Year Incentive Adder is a component of the Prior Year TRR.
b) The True Up Incentive Adder is a component of the True Up TRR.

1) Calculation of Incremental Return on Equity Factor

The Incremental Return on Equity Factor is the incremental Prior Year TRR expressed per 100 basis points of ROE incentive, for each million dollars of Incentive Net Plant. It is calculated according to the following formula:

IREF = CSCP * 0.01 * (1/(1 - CTR)) * $1,000,000

Line	where:		Value	**Source**
1	CSCP = Common Stock Capital Percentage		50.4734%	BaseTRR WS, L 46
2	CTR = Composite Tax Rate		40.8863%	BaseTRR WS, L 58
3		IREF =	$8,538	Above formula

2) Determination of multiplicative factors for use in calculating Incentive Adders:

Multiplicative factors are used to calculate the Incentive Adders on an Transmission Incentive Project specific basis.
Multiplicative factor for each project is the ratio of its ROE adder to 1%.

Line		**ROE Adder**	**Multiplicative Factor**	**Source**
4	1) Rancho Vista	0.75%	0.75	IncentivePlant WS, L 184
5	2) Tehachapi	1.25%	1.25	IncentivePlant WS, L 187
6	3) Devers to Colorado Riv	1.00%	1.00	IncentivePlant WS, L 190
7	4) Project X			
8	…			

3) Calculation of Prior Year Incentive Adder (EOY)

1) Determine Prior Year Incentive Adder for each Incentive Project by multiplying the IREF, the Multiplicative Factor, and the million $ of Prior Year Incentive Rate Base.
2) Sum project-specific Incentive Adders to yield the total Prior Year Incentive Adder.

Line		**Prior Year Incentive Rate Base**	**Multiplicative Factor**	**Prior Year Incentive Adder**	**Source**
9	1) Rancho Vista	$179,233,968	0.75	$1,147,773	IncentivePlant WS, L 13, Col. 1
10	2) Tehachapi	$1,447,909,315	1.25	$15,453,469	IncentivePlant WS, L 14, Col. 1
11	3) Devers to Colorado Riv	$151,361,046	1.00	$1,292,376	IncentivePlant WS, L 15, Col. 1
12	4) Project X				
13	…				
14			Prior Year Incentive Adder =	$17,893,618	Sum of above PY Incentive Adders for each individual project

4) Calculation of True-Up Incentive Adder

1) Determine True Up Incentive Adder for each Incentive Project by multiplying the IREF, the Multiplicative Factor, and the million $ of True Up Incentive Net Plant.
2) Sum project-specific Incentive Adders to yield the total True Up Incentive Adder.

Line		**True-Up Incentive Net Plant**	**Multiplicative Factor**	**True-Up Incentive Adder**	**Source**
15	1) Rancho Vista	$181,872,286	0.75	$1,164,669	IncentivePlant WS, L 19, Col. 1
16	2) Tehachapi	$1,177,058,496	1.25	$12,562,690	IncentivePlant WS, L 20, Col. 1
17	3) Devers to Colorado Riv	$75,061,661	1.00	$640,904	IncentivePlant WS, L 21, Col. 1
18	4) Project X				
19	…				
20			True-Up Incentive Adder =	$14,368,263	Sum of above PY Incentive Adders for each individual project

5) Calculation of Total ROE for Plant-In Service in the True Up TRR

a) Transmission Incentive Plant Net Plant In Service

Line	Incentive Project	13-Month Avg. TIP Net Plant In Service	Source
21	1) Rancho Vista	$181,872,286	IncentivePlant WS, L 19, Col. 3
22	2) Tehachapi	$379,329,189	IncentivePlant WS, L 20, Col. 3
23	3) Devers-Colorado R	$16,766	IncentivePlant WS, L 21, Col. 3
24	4) Project X		Add additional lines as appropriate
	…		

b) Calculation of ROE Adders on TIP Net Plant In Service

Line	Incentive Project	Col 1 True Up Incentive Adder	Col 2 After-Tax True Up Incentive Adder	Source
25	1) Rancho Vista	$1,164,669	$688,479	See Note 1
26	2) Tehachapi	$4,048,563	$2,393,255	See Note 1
27	3) Devers-Colorado R	$143	$85	See Note 1
28	4) Project X			See Note 1
29	…			
30		Total:	$3,081,818	

c) Equity Portion of Plant In Service Rate Base

Line		Amount	Source
31	Total Rate Base:	$2,802,491,602	TUTRR WS, Line 17
32	CWIP Portion of Rate Base:	$899,913,283	TUTRR WS, Line 14
33	Plant In Service Rate Base:	$1,902,578,318	Line 31 - Line 32
34	Equity percentage:	50.4734%	BaseTRR WS, Line 46
35	Equity Portion of Plant In Service Rate Base:	$960,296,198	Line 33 * Line 34

d) Total ROE for Plant In Service in the True Up TRR

Line			
36	Plant In Service ROE Adder Percentage:	0.32%	Line 30 * Line 35
37	Base ROE (Including 50 basis point		
38	CAISO Participation Adder):	10.43%	BaseTRR WS, Line 49
39	Total ROE for Plant In Service in True Up TRR:	10.75%	Line 36 + Line 38

Instructions:
1) If additional projects receive ROE adders, add to end of lists, and include in calculation of each Incentive Adder.

Notes:
1) Column 1: The True Up Incentive Adder for each Incentive Project equals the IREF on Line 3, times the applicable Multiplicative Factor on Lines 15 to 18, times the million $ of TIP Net Plant In Service on Lines 21 to 24.
Column 2: The After Tax True Up Incentive Adder is derived by multiplying the amounts in Column 1 by (1 - CTR) (Where the CTR is on Line 2).

Forecast Plant Additions for In-Service ISO Transmission Plant

Yellow shaded cells are Input Data

Forecast Plant Additions represents the total increase in ISO Transmission Net Plant, not including CWIP, during the Rate Effective Period, incremental to the year-end Prior Year amount.
It is calculated on a 13-Month Average Basis during the Rate Effective Period.

			Col 1	Col 2	Col 3	Col 4
Line	Forecast Period Month	Year	= C2 - C4 Forecast Net Plant Additions	Forecast Total Gross Plant Additions	Forecast Low Voltage Gross Plant Additions	Forecast Accumulated Depreciation on Gross Plant Additions
1	January	2012	$1,123,342	$1,123,342	$0	$0
2	February	2012	$168,295,757	$168,298,228	$336,327	$2,471
3	March	2012	$170,566,500	$170,939,228	$336,327	$372,727
4	April	2012	$311,085,097	$311,833,890	$336,327	$748,794
5	May	2012	$521,538,594	$522,973,422	$336,327	$1,434,828
6	June	2012	$553,827,135	$556,412,505	$336,327	$2,585,370
7	July	2012	$656,785,909	$660,595,386	$336,327	$3,809,477
8	August	2012	$661,753,945	$667,016,732	$336,327	$5,262,787
9	September	2012	$681,594,117	$688,324,341	$336,327	$6,730,224
10	October	2012	$685,025,548	$693,270,085	$336,327	$8,244,538
11	November	2012	$810,970,333	$820,740,064	$336,327	$9,769,732
12	December	2012	$1,000,373,966	$1,011,949,325	$1,385,554	$11,575,360
13	January	2013	$1,006,109,803	$1,019,911,451	$1,385,554	$13,801,648
14	February	2013	$1,009,421,634	$1,025,467,087	$1,385,554	$16,045,454
15	March	2013	$1,020,387,515	$1,038,688,996	$1,385,554	$18,301,481
16	April	2013	$1,050,980,485	$1,071,567,082	$1,385,554	$20,586,597
17	May	2013	$1,079,432,003	$1,102,376,048	$1,385,554	$22,944,045
18	June	2013	$1,107,217,301	$1,132,586,573	$16,735,244	$25,369,272
19	July	2013	$1,359,601,065	$1,387,462,028	$16,735,244	$27,860,962
20	August	2013	$1,366,115,515	$1,397,028,894	$16,735,244	$30,913,379
21	September	2013	$2,199,358,722	$2,233,345,564	$16,735,244	$33,986,842
22	13-Month Averages:		$1,105,891,385	$1,124,824,426	$5,866,406	$18,933,041

Forecast Plant Additions is amount on Line 22, Column 1.

Depreciation Expense

Input cells are shaded yellow

1) Calculation of Depreciation Expense for Transmission Plant - ISO

Balances for Transmission Plant - ISO during the Prior Year, including December of previous year: **Source:** PlantInService worksheet, Lines 1-13.

	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11	Col 12
	Prior	FERC										
	Year	Account:										
Line	**Month**	**350.1**	**350.2**	**352**	**353**	**354**	**355**	**356**	**357**	**358**	**359**	**Total**
1	December	$73,238,678	$80,739,600	$175,457,663	$1,680,213,303	$625,307,190	$113,770,199	$422,173,397	$284,096	$2,302,928	$28,619,068	$3,202,106,122
2	January	$73,457,067	$80,546,971	$175,531,481	$1,682,797,635	$567,348,227	$113,938,319	$481,950,573	$295,578	$2,404,664	$28,589,735	$3,206,860,251
3	February	$74,787,427	$80,611,201	$169,945,549	$1,690,133,298	$567,137,049	$113,779,197	$481,820,290	$279,721	$2,294,340	$28,585,656	$3,209,373,728
4	March	$74,795,217	$80,612,219	$169,790,454	$1,690,160,751	$567,661,454	$113,755,178	$481,718,133	$279,788	$2,027,536	$28,585,633	$3,209,386,364
5	April	$74,795,235	$80,612,604	$169,924,865	$1,696,326,180	$566,761,574	$113,916,544	$481,642,642	$279,915	$2,032,634	$28,579,817	$3,214,872,010
6	May	$74,795,239	$80,620,101	$170,558,044	$1,714,436,873	$566,864,532	$113,893,084	$482,371,551	$288,922	$2,136,936	$28,573,849	$3,234,539,129
7	June	$74,844,263	$81,691,266	$170,958,762	$1,735,666,103	$577,247,106	$114,731,218	$494,362,200	$482,728	$2,163,632	$28,542,192	$3,280,689,471
8	July	$74,920,480	$81,729,920	$171,060,161	$1,743,964,018	$574,223,968	$114,567,873	$492,517,255	$559,090	$3,553,785	$28,542,591	$3,285,639,141
9	August	$74,920,538	$81,744,340	$171,926,958	$1,746,839,739	$574,264,333	$114,577,668	$493,513,718	$576,137	$3,735,051	$28,542,594	$3,290,641,076
10	September	$74,920,593	$81,754,780	$171,968,348	$1,749,282,822	$549,677,062	$131,446,925	$422,626,020	$574,863	$3,570,476	$110,386,399	$3,296,208,289
11	October	$74,920,599	$81,804,913	$171,978,342	$1,747,977,369	$549,752,298	$131,513,375	$422,414,349	$573,331	$3,537,284	$110,386,759	$3,294,858,619
12	November	$74,633,157	$82,090,720	$171,931,707	$1,754,489,045	$549,890,097	$131,633,765	$422,512,012	$566,812	$3,500,178	$110,386,746	$3,301,634,238
13	December	$74,607,469	$82,090,981	$170,948,030	$1,756,511,619	$550,516,805	$132,075,054	$421,892,563	$558,943	$3,408,604	$110,352,407	$3,302,962,475
14												
15	Depreciation Rates (Percent per year) See "DepRates" worksheet.											
16		**350.1**	**350.2**	**352**	**353**	**354**	**355**	**356**	**357**	**358**	**359**	
17		0.00%	1.66%	2.57%	2.62%	2.53%	3.82%	3.50%	1.65%	3.87%	1.56%	
18												
19	Monthly Depreciation Expense for Transmission Plant - ISO by FERC Account:					See Note 1						
20												
21	**Prior**	FERC										
22	**Year**	Account:										**Month**
23	**Month**	**350.1**	**350.2**	**352**	**353**	**354**	**355**	**356**	**357**	**358**	**359**	**Total**
24	January	$0	$111,690	$375,772	$3,668,466	$1,318,356	$362,168	$1,231,339	$391	$7,427	$37,205	$7,112,813
25	February	$0	$111,423	$375,930	$3,674,108	$1,196,159	$362,704	$1,405,689	$406	$7,755	$37,167	$7,171,342
26	March	$0	$111,512	$363,967	$3,690,124	$1,195,714	$362,197	$1,405,309	$385	$7,399	$37,161	$7,173,769
27	April	$0	$111,514	$363,635	$3,690,184	$1,196,820	$362,121	$1,405,011	$385	$6,539	$37,161	$7,173,369
28	May	$0	$111,514	$363,922	$3,703,645	$1,194,922	$362,634	$1,404,791	$385	$6,555	$37,154	$7,185,524
29	June	$0	$111,524	$365,278	$3,743,187	$1,195,139	$362,560	$1,406,917	$397	$6,892	$37,146	$7,229,041
30	July	$0	$113,006	$366,137	$3,789,538	$1,217,029	$365,228	$1,441,890	$664	$6,978	$37,105	$7,337,574
31	August	$0	$113,060	$366,354	$3,807,655	$1,210,656	$364,708	$1,436,509	$769	$11,461	$37,105	$7,348,275
32	September	$0	$113,080	$368,210	$3,813,933	$1,210,741	$364,739	$1,439,415	$792	$12,046	$37,105	$7,360,061
33	October	$0	$113,094	$368,299	$3,819,267	$1,158,902	$418,439	$1,232,659	$790	$11,515	$143,502	$7,266,469
34	November	$0	$113,163	$368,320	$3,816,417	$1,159,061	$418,651	$1,232,042	$788	$11,408	$143,503	$7,263,354
35	December	$0	$113,559	$368,220	$3,830,634	$1,159,352	$419,034	$1,232,327	$779	$11,288	$143,503	$7,278,696
36	Totals:	$0	$1,348,139	$4,414,044	$45,047,160	$14,412,851	$4,525,183	$16,273,898	$6,931	$107,262	$764,817	
37											Total Annual Depreciation Expense for Transmission Plant - ISO:	$86,900,286
38											(equals sum of monthly amounts)	

39	**2) Calculation of Depreciation Expense for Distribution Plant - ISO**					
40						
41		**360**	**361**	**362**		**Source**
42	Distribution Plant - ISO BOY	$25,780	$1,107,531	$16,087,946		PlantInService WS Line 15.
43	Distribution Plant - ISO EOY	$75,876	$683,247	$5,875,711		PlantInService WS Line 16.
44	Average BOY/EOY :	$50,828	$895,389	$10,981,829		
45						
46	Depreciation Rates (Percent per year) See "DepRates" worksheet.					
47		**360**	**361**	**362**		
48		1.67%	3.15%	2.90%		
49						
50	Depreciation Expense for Distribution Plant - ISO			See Note 2		
51						
52		**360**	**361**	**362**	**Total**	
53		$848.83	$28,204.75	$318,473.03	$347,527	Total is sum of Depreciation Expense for accounts
54						360, 361, and 362
55						

56	**3) Calculation of Depreciation Expense for General Plant and Intangible Plant**		
57			
58	Total General Plant Depreciation Expense	$159,045,538	FF1 336.10f
59	Total Intangible Plant Depreciation Expense	$161,263,993	FF1 336.1f
60	Sum of Total General and Total Intangible Depreciation Expense	320,309,531	Line 58 + Line 59
61	Transmission Wages and Salaries Allocation Factor	4.099%	Allocators WS, Line 9
62	General and Intangible Depreciation Expense	$13,128,191	Line 60 * Line 61
63			

64	**4) Depreciation Expense**		
65			
66	Depreciation Expense is the sum of:	**Amount**	**Source**
67	1) Depreciation Expense for Transmission Plant - ISO	$86,900,285.97	Line 37, Col 12
68	2) Depreciation Expense for Distribution Plant - ISO	$347,527	Line 53
69	3) General and Intangible Depreciation Expense	$13,128,191	Line 62
70	Depreciation Expense:	$100,376,003.89	Line 67 + Line 68 + Line 69

Notes:

1) Depreciation Expense for each account for each month is equal to the previous month balance of Transmission Plant - ISO for that same account, times the Monthly Depreciation Rate for that account. Monthly rate = annual rate on Line 17 / 12.

2) Depreciation Expense for each account is equal to the Average BOY/EOY value on Line 44 times the Depreciation Rate on Line 48.

Depreciation Rates

1) Transmission Plant - ISO

Line	FERC Account	Description	Plant Less Salvage	Removal Cost	Total
1	350.1	Fee Land	0.00%	0.00%	0.00%
2	350.2	Easements	1.66%	0.00%	1.66%
3	352	Structures and Improvements	1.84%	0.73%	2.57%
4	353	Station Equipment	2.49%	0.13%	2.62%
5	354	Towers and Fixtures	1.23%	1.30%	2.53%
6	355	Poles and Fixtures	1.64%	2.18%	3.82%
7	356	Overhead Conductors and Devices	1.07%	2.43%	3.50%
8	357	Underground Conduit	1.65%	0.00%	1.65%
9	358	Underground Conductors and Devices	2.68%	1.19%	3.87%
10	359	Roads and Trails	1.56%	0.00%	1.56%
11					

2) Distribution Plant - ISO

	FERC Account	Description	Plant Less Salvage	Removal Cost	Total
12	360	Land and Land Rights	1.67%	0.00%	1.67%
13	361	Structures and Improvements	2.52%	0.63%	3.15%
14	362	Station Equipment	2.52%	0.38%	2.90%

3) General Plant

	FERC Account	Description	Plant Less Salvage	Removal Cost	Total
15	389	Land and Land Rights	1.67%	0.00%	1.67%
16	390	Structures and Improvements	1.53%	0.09%	1.62%
17	391.1	Office Furniture	5.00%	0.00%	5.00%
18	391.5	Office Equipment	20.00%	0.00%	20.00%
19	391.6	Duplicating Equipment	20.00%	0.00%	20.00%
20	391.2	Personal Computers	20.00%	0.00%	20.00%
21	391.3	Mainframe Computers	20.00%	0.00%	20.00%
22	391.7	PC Software	20.00%	0.00%	20.00%
23	391.4	DDSMS - CPU & Processing	14.29%	0.00%	14.29%
24	391.4	DDSMS - Controllers, Receivers, Comm.	10.00%	0.00%	10.00%
25	391.4	DDSMS - Telemetering & System	6.67%	0.00%	6.67%
26	391.4	DDSMS - Miscellaneous	5.00%	0.00%	5.00%
27	391.4	DDSMS - Map Board	4.00%	0.00%	4.00%
28	393	Stores Equipment	5.00%	0.00%	5.00%
29	395	Laboratory Equipment	6.67%	0.00%	6.67%
30	398	Misc Power Plant Equipment	5.00%	0.00%	5.00%
31	397	Telecom System Equipment	14.29%	0.00%	14.29%
32	397	Netcomm Radio Assembly	10.00%	0.00%	10.00%
33	397	Microwave Equip. & Antenna Assembly	6.67%	0.00%	6.67%
34	397	Fiber Optic Communication Cables	4.19%	0.01%	4.20%
35	397	Telecom Infrastructure	2.57%	0.04%	2.61%
36	392	Transportation Equip.	14.29%	0.00%	14.29%
37	394.4	Garage & Shop -- Equip.	10.00%	0.00%	10.00%
38	394.5	Tools & Work Equip. -- Shop	10.00%	0.00%	10.00%
39	396	Power Oper Equip	6.67%	0.00%	6.67%

4) Intangible Plant

	FERC Account	Description	Plant Less Salvage	Removal Cost	Total
40	302	Hydro Relicensing	17.37%	0.00%	17.37%
41	303	Radio Frequency	2.50%	0.00%	2.50%
42	301	Other Intangibles	5.00%	0.00%	5.00%
43	303	Cap Soft 5yr	20.00%	0.00%	20.00%
44	303	Cap Soft 7yr	14.29%	0.00%	14.29%
45	303	Cap Soft 10yr	10.00%	0.00%	10.00%
46	303	Cap Soft 15yr	6.67%	0.00%	6.67%

Operations and Maintenance Expenses

Cells shaded yellow are input cells

1) Determination of Adjusted Operations and Maintenance Expenses for each account (Note 1)

	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11
		= C3 + C4			Note 2	= C7 + C8			= C10 + C11	= C3 + C7	= C4 + C8
		Total Recorded O&M Expenses			Adjustments				Adjusted Recorded O&M Expenses		
	Account/Work Activity Rev	Total	Labor	Non-Labor	Reason	Total	Labor	Non-Labor	Total	Labor	Non-Labor
Line	**Transmission Accounts**										
1	560 - Operations Engineering	$12,746,579	$6,405,720	$6,340,858		$0			12,746,579	6,405,720	6,340,858
2	560 - Sylmar/Palo Verde	$282,901	$0	$282,901		$0			282,901	-	282,901
3	561.000 Load Dispatching	$379,490	-$10	$379,500		$0			379,490	(10)	379,500
4	561.100 Load Dispatch-Reliability	$675,463	$494,162	$181,302		$0			675,463	494,162	181,302
5	561.200 Load Dispatch Monitor and Operate Trans. System	$5,385,359	$4,264,421	$1,120,938		$0			5,385,359	4,264,421	1,120,938
6	561.400 Scheduling, System Control and Dispatch Services	$40,489,134	$0	$40,489,134	A	-$40,489,134	$0	-$40,489,134	-	-	-
7	561.500 Reliability, Planning and Standards Development	$4,587,545	$4,101,812	$485,733		$0			4,587,545	4,101,812	485,733
8	562 - MOGS Station Expense	$64,683	$64,683	$0	B	-$64,683	-$64,683	$0	-	-	-
9	562 - Operating Transmission Stations	$15,837,321	$11,184,332	$4,652,989		$0			15,837,321	11,184,332	4,652,989
10	562 - Routine Testing and Inspection	$4,030,768	$2,416,867	$1,613,901		$0			4,030,768	2,416,867	1,613,901
11	562 - Sylmar/Palo Verde	$682,254	$0	$682,254		$0			682,254	-	682,254
12	563 - Inspect and Patrol Line	$4,781,156	$2,733,193	$2,047,963		$0			4,781,156	2,733,193	2,047,963
13	564 - Underground Line Expense	$1,102,726	$793,687	$309,040		$0			1,102,726	793,687	309,040
14	565 - Wheeling Costs	$279,936	$0	$279,936	C	-$279,936	$0	-$279,936	-	-	-
15	565 - WAPA Transmission for Remote Service	$222,920	$0	$222,920		$0			222,920	-	222,920
16	565 - Transmission for Four Corners	$5,404,697	$9	$5,404,688		$0			5,404,697	9	5,404,688
17	566 - ISO/RSBA/TSP Balancing Accounts	$28,154,011	$183,979	$27,970,032	D	-$28,154,011	-$183,979	-$27,970,032	-	-	-
18	566 - Training/Other	$28,843,903	$13,183,643	$15,660,260		$0			28,843,903	13,183,643	15,660,260
19	566 - NERC/CIP Compliance	$1,194,518	$1,013,661	$180,857		$0			1,194,518	1,013,661	180,857
20	566 - Transmission Regulatory Policy	$1,007,825	$944,121	$63,704		$0			1,007,825	944,121	63,704
21	566 - FERC Regulation & Contracts	$4,091,462	$3,120,279	$971,184		$0			4,091,462	3,120,279	971,184
22	566 - Grid Contract Management	$1,837,084	$1,708,878	$128,206		$0			1,837,084	1,708,878	128,206
23	566 - Sylmar/Palo Verde/Other General Functions	$616,273	$0	$616,273		$0			616,273	-	616,273
24	567 - Line Rents	$8,580,893	$163,584	$8,417,309		$0			8,580,893	163,584	8,417,309
25	567 - Morongo Lease	$1,899,867	-$133	$1,900,000		$0			1,899,867	(133)	1,900,000
26	567 - Eldorado	$80,795	$2,200	$78,595		$0			80,795	2,200	78,595
27	567 - Sylmar/Palo Verde	$297,668	$52	$297,616		$0			297,668	52	297,616
28	568 - Maintenance Supervision and Engineering	$2,231,460	$1,778,138	$453,322		$0			2,231,460	1,778,138	453,322
29	568 - Sylmar/Palo Verde	-$70,710	$0	-$70,710		$0			(70,710)	-	(70,710)
30	569 - Maintenance of Structures	$84,408	$14,892	$69,516		$0			84,408	14,892	69,516
31	569.100 Hardware	$4,236,985	$0	$4,236,985	F	-$3,769,709		-$3,769,709	467,276	-	467,276
32	569.200 Software	$7,793,521	$0	$7,793,521	F	-$6,937,213		-$6,937,213	856,308	-	856,308
33	569.300 Communication	$2,195,284	$0	$2,195,284	F	-$1,952,870		-$1,952,870	242,414	-	242,414
34	569 - Sylmar/Palo Verde	$178,167	$0	$178,167		$0			178,167	-	178,167
35	570 - Maintenance of Power Transformers	$1,161,166	$737,585	$423,581		$0			1,161,166	737,585	423,581
36	570 - Maintenance of Transmission Circuit Breakers	$1,628,825	$1,152,608	$476,217		$0			1,628,825	1,152,608	476,217
37	570 - Maintenance of Transmission Voltage Equipment	$238,935	$365,609	-$126,675		$0			238,935	365,609	(126,675)
38	570 - Maintenance of Miscellaneous Transmission Equipment	$2,679,487	$1,360,643	$1,318,844		$0			2,679,487	1,360,643	1,318,844
39	570 - Substation Work Order Related Expense	$3,687,240	$1,502,280	$2,184,960		$0			3,687,240	1,502,280	2,184,960
40	570 - Sylmar/Palo Verde	$1,327,263	$105	$1,327,158		$0			1,327,263	105	1,327,158
41	571 - Poles and Structures	$3,038,762	$1,561,641	$1,477,121		$0			3,038,762	1,561,641	1,477,121
42	571 - Insulators and Conductors	$8,089,022	$4,281,351	$3,807,671		$0			8,089,022	4,281,351	3,807,671
43	571 - Transmission Line Rights of Way	$12,122,042	$1,587,022	$10,535,020		$0			12,122,042	1,587,022	10,535,020
44	571 - Transmission Work Order Related Expense	$7,093,361	$1,066,200	$6,027,161		$0			7,093,361	1,066,200	6,027,161
45	571 - Sylmar/Palo Verde	$751,562	$0	$751,562		$0			751,562	-	751,562
46	572 - Maintenance of Underground Transmission Lines	$624,356	$145,540	$478,816		$0			624,356	145,540	478,816
47	572 - Sylmar/Palo Verde	$108,307	$0	$108,307		$0			108,307	-	108,307
48	573 - Provision for Property Damage Expense to Trans. Fac.	$2,298,000	$497,329	$1,800,670		$0			2,298,000	497,329	1,800,670
49	…	---	---	---	---	$0	---	---			
50	Transmission Results Sharing (Note 3)	-	-	-	E	$9,198,519	$9,198,519	$0	$9,198,519	$9,198,519	$0
51	**Total Transmission O&M**	$235,054,669	$68,830,083	$166,224,586		-$72,449,037	$8,949,857	-$81,398,894	$162,605,632	$77,779,940	$84,825,693
52											

	Col 1	Col 2 = C3 + C4	Col 3	Col 4	Col 5 Note 2	Col 6 = C7 + C8	Col 7	Col 8	Col 9 = C10 + C11	Col 10 = C3 + C7	Col 11 = C4 + C8
		Total Recorded O&M Expenses			**Adjustments**				**Adjusted Recorded O&M Expenses**		
	Account/Work Activity Rev	**Total**	**Labor**	**Non-Labor**	**Reason**	**Total**	**Labor**	**Non-Labor**	**Total**	**Labor**	**Non-Labor**
	Distribution Accounts										
53	582 - Operation and Relay Protection of Distribution Substatio	18,675,047	$13,058,906	$5,616,140		-			18,675,047	13,058,906	5,616,140
54	582 - Testing and Inspecting Distribution Substation Equipmen	11,083,363	$8,178,767	$2,904,597		-			11,083,363	8,178,767	2,904,597
55	590 - Maintenance Supervision and Engineering	2,204,134	$1,778,095	$426,040		-			2,204,134	1,778,095	426,040
56	591 - Maintenance of Structures	250,797	$10,952	$239,845		-			250,797	10,952	239,845
57	592 - Maintenance of Distribution Transformers	796,802	$480,520	$316,281		-			796,802	480,520	316,281
58	592 - Maintenance of Distribution Circuit Breakers	2,281,930	$1,727,060	$554,871		-			2,281,930	1,727,060	554,871
59	592 - Maintenance of Distribution Voltage Control Equipment	757,179	$517,070	$240,109		-			757,179	517,070	240,109
60	592 - Maintenance of Miscellaneous Distribution Equipment	746,617	$574,149	$172,468					746,617	574,149	172,468
61	Accounts with no ISO Distribution Costs	449,080,157	$187,238,672	$261,841,485			(136,428)	(412,009)	449,080,157	187,102,244	261,429,476
62	Distribution Results Sharing (Note 3)	-	-	-	E	28,540,924	28,540,924	-	28,540,924	28,540,924	-
63	**Total Distribution O&M**	485,876,026	213,564,191	272,311,835		28,540,924	28,404,496	(412,009)	514,416,950	241,968,687	271,899,826
64											
65	**Total Transmission and Distribution O&M**	720,930,696	282,394,274	438,536,422		(43,908,113)	37,354,353	(81,810,903)	677,022,583	319,748,627	356,725,519
66											
67	Total Transmission O&M Expenses in FERC Form 1:	$235,054,669	FF1 321.112b	Must equal Line 51, Column 2.							
68	Total Distribution O&M Expenses in FERC Form 1:	$485,876,026	FF1322.156b	Must equal Line 63, Column 2.							
69	Total TDBU Results Sharing	$37,739,442	AandG WS, Note 2, g								

2) Determination of ISO Operations and Maintenance Expenses for each account (Note 5).

	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8
		From C9 above	From C10 above	From C11 above	Note 6	= C7 + C8	= C3 * C5	= C4 * C5
		Adjusted Recorded O&M Expenses			Percent	ISO O&M Expenses		
	Account/Work Activity Rev	Total	Labor	Non-Labor	ISO	Total	Labor	Non-Labor
Line	Transmission Accounts							
70	560 - Operations Engineering	12,746,579	6,405,720	6,340,858	45.5%	5,794,191	2,911,838	2,882,354
71	560 - Sylmar/Palo Verde	282,901	-	282,901	100.0%	282,901	-	282,901
72	561.000 Load Dispatching	379,490	(10)	379,500	48.9%	185,571	(5)	185,575
73	561.100 Load Dispatch-Reliability	675,463	494,162	181,302	48.9%	330,302	241,645	88,657
74	561.200 Load Dispatch Monitor and Operate Trans. System	5,385,359	4,264,421	1,120,938	48.9%	2,633,441	2,085,302	548,139
75	561.400 Scheduling, System Control and Dispatch Services	-	-	-	0.0%	-	-	-
76	561.500 Reliability, Planning and Standards Development	4,587,545	4,101,812	485,733	100.0%	4,587,545	4,101,812	485,733
77	562 - MOGS Station Expense	-	-	-	0.0%	-	-	-
78	562 - Operating Transmission Stations	15,837,321	11,184,332	4,652,989	19.4%	3,072,440	2,169,760	902,680
79	562 - Routine Testing and Inspection	4,030,768	2,416,867	1,613,901	12.2%	491,754	294,858	196,896
80	562 - Sylmar/Palo Verde	682,254	-	682,254	100.0%	682,254	-	682,254
81	563 - Inspect and Patrol Line	4,781,156	2,733,193	2,047,963	49.1%	2,347,548	1,341,998	1,005,550
82	564 - Underground Line Expense	1,102,726	793,687	309,040	1.7%	18,746	13,493	5,254
83	565 - Wheeling Costs	-	-	-	0.0%	-	-	-
84	565 - WAPA Transmission for Remote Service	222,920	-	222,920	0.0%	-	-	-
85	565 - Transmission for Four Corners	5,404,697	9	5,404,688	100.0%	5,404,697	9	5,404,688
86	566 - ISO/RSBA/TSP Balancing Accounts	-	-	-	0.0%	-	-	-
87	566 - Training/Other	28,843,903	13,183,643	15,660,260	45.5%	13,111,526	5,992,867	7,118,659
88	566 - NERC/CIP Compliance	1,194,518	1,013,661	180,857	100.0%	1,194,518	1,013,661	180,857
89	566 - Transmission Regulatory Policy	1,007,825	944,121	63,704	100.0%	1,007,825	944,121	63,704
90	566 - FERC Regulation & Contracts	4,091,462	3,120,279	971,184	51.2%	2,094,829	1,597,583	497,246
91	566 - Grid Contract Management	1,837,084	1,708,878	128,206	59.0%	1,083,879	1,008,238	75,641
92	566 - Sylmar/Palo Verde/Other General Functions	616,273	-	616,273	100.0%	616,273	-	616,273
93	567 - Line Rents	8,580,893	163,584	8,417,309	72.1%	6,189,052	117,987	6,071,066
94	567 - Morongo Lease	1,899,867	(133)	1,900,000	90.8%	1,725,079	(121)	1,725,200
95	567 - Eldorado	80,795	2,200	78,595	100.0%	80,795	2,200	78,595
96	567 - Sylmar/Palo Verde	297,668	52	297,616	100.0%	297,668	52	297,616
97	568 - Maintenance Supervision and Engineering	2,231,460	1,778,138	453,322	43.5%	970,318	773,198	197,121
98	568 - Sylmar/Palo Verde	(70,710)	-	(70,710)	100.0%	(70,710)	-	(70,710)
99	569 - Maintenance of Structures	84,408	14,892	69,516	25.1%	21,149	3,731	17,418
100	569.100 Hardware	467,276	-	467,276	45.5%	212,409	-	212,409
101	569.200 Software	856,308	-	856,308	45.5%	389,251	-	389,251
102	569.300 Communication	242,414	-	242,414	45.5%	110,194	-	110,194
103	569 - Sylmar/Palo Verde	178,167	-	178,167	100.0%	178,167	-	178,167
104	570 - Maintenance of Power Transformers	1,161,166	737,585	423,581	18.6%	215,977	137,191	78,786
105	570 - Maintenance of Transmission Circuit Breakers	1,628,825	1,152,608	476,217	28.3%	460,957	326,188	134,769
106	570 - Maintenance of Transmission Voltage Equipment	238,935	365,609	(126,675)	79.2%	189,236	289,563	(100,326)
107	570 - Maintenance of Miscellaneous Transmission Equipment	2,679,487	1,360,643	1,318,844	43.5%	1,165,105	591,640	573,465
108	570 - Substation Work Order Related Expense	3,687,240	1,502,280	2,184,960	58.7%	2,162,751	881,163	1,281,588
109	570 - Sylmar/Palo Verde	1,327,263	105	1,327,158	100.0%	1,327,263	105	1,327,158
110	571 - Poles and Structures	3,038,762	1,561,641	1,477,121	49.1%	1,492,032	766,766	725,266
111	571 - Insulators and Conductors	8,089,022	4,281,351	3,807,671	49.1%	3,971,710	2,102,144	1,869,566
112	571 - Transmission Line Rights of Way	12,122,042	1,587,022	10,535,020	49.1%	5,951,923	779,228	5,172,695
113	571 - Transmission Work Order Related Expense	7,093,361	1,066,200	6,027,161	43.6%	3,092,689	464,861	2,627,829
114	571 - Sylmar/Palo Verde	751,562	-	751,562	100.0%	751,562	-	751,562
115	572 - Maintenance of Underground Transmission Lines	624,356	145,540	478,816	1.7%	10,614	2,474	8,140
116	572 - Sylmar/Palo Verde	108,307	-	108,307	100.0%	108,307	-	108,307
117	573 - Provision for Property Damage Expense to Trans. Fac.	2,298,000	497,329	1,800,670	45.0%	1,034,521	223,889	810,632
118	…	---	---	---	---	---	---	---
119	Transmission Results Sharing (Note 4)	9,198,519	9,198,519	-		4,181,958	4,181,958	-
120	**Total Transmission - ISO O&M**	162,605,632	77,779,940	84,825,693		81,160,215	35,361,395	45,798,820
121								

	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8
		From C9 above	From C10 above	From C11 above	Note 6	= C7 + C8	= C3 * C5	= C4 * C5
		Adjusted Recorded O&M Expenses			**Percent**	**ISO O&M Expenses**		
	Account/Work Activity Rev	**Total**	**Labor**	**Non-Labor**	**ISO**	**Total**	**Labor**	**Non-Labor**
	Distribution Accounts							
122	582 - Operation and Relay Protection of Distribution Substatio	18,675,047	13,058,906	5,616,140	2.49%	465,148	325,264	139,884
123	582 - Testing and Inspecting Distribution Substation Equipmen	11,083,363	8,178,767	2,904,597	2.49%	276,059	203,712	72,346
124	590 - Maintenance Supervision and Engineering	2,204,134	1,778,095	426,040	2.49%	54,899	44,288	10,612
125	591 - Maintenance of Structures	250,797	10,952	239,845	2.49%	6,247	273	5,974
126	592 - Maintenance of Distribution Transformers	796,802	480,520	316,281	0.28%	2,231	1,345	886
127	592 - Maintenance of Distribution Circuit Breakers	2,281,930	1,727,060	554,871	1.66%	37,880	28,669	9,211
128	592 - Maintenance of Distribution Voltage Control Equipment	757,179	517,070	240,109	7.32%	55,425	37,849	17,576
129	592 - Maintenance of Miscellaneous Distribution Equipment	746,617	574,149	172,468	2.49%	18,596	14,301	4,296
130	Accounts with no ISO Distribution Costs	449,080,157	187,102,244	261,429,476	0.00%	-	-	-
131	Distribution Results Sharing (Note 4)	28,540,924	28,540,924	-	0.00%	-	-	-
132	**Total Distribution - ISO O&M**	514,416,950	241,968,687	271,899,826		916,486	655,702	260,784
133								
134								
135	**Total ISO O&M Expenses (in Column 6)**	677,022,583	319,748,627	356,725,519		82,076,701	36,017,097	46,059,604
136	Line 120 + Line 132							

Notes:

1) "Adjusted Operations and Maintenance Expenses for each account" are the total amounts of O&M costs booked to each Transmission or Distribution account, less adjustments as noted.

2) Reasons for excluded amounts:

A: Exclude entire amount, all attributable to CAISO costs recovered in Energy Resource Recovery Account.
B: Exclude amount related to MOGS Station Expense.
C: Exclude amount attributable to CAISO costs recovered in Energy Resource Recovery Account.
D: Exclude amount recovered through to Reliability Services Balancing Account, the Transmission Access Charge Balancing Account Adjustment, and the American Reinvestment Recovery Act for the Tehachapi Wind Energy Storage Project.
E: Add Results Sharing annual payout
F: Exclude amount of costs transferred to account from A&G account 920 pursuant to Order 668
…

3) Total TDBU Results Sharing is allocated to Transmission and Distribution in proportion to labor in the respective functions. Transmission Results Sharing equals Total TDBU Results Sharing times the Transmission Results Sharing Percentage calculated below. Distribution Results Sharing equals Total TDBU Results Sharing times the Distribution Results Sharing Percentage below.

Total TDBU Results Sharing is on Line: 69

	Percentage	Calculation
Transmission Results Sharing Percentage:	24.3738%	Line 51, Col 3 / Line 65, Col 3
Distribution Results Sharing Percentage:	75.6262%	Line 63, Col 3 / Line 65, Col 3

4) Results Sharing attributable to ISO Transmission is calculated as total Transmission Results Sharing in Column 4 times the ratio of the total ISO O&M Labor Expenses in Column 8 to the total Labor expenses in Column 4. No Distribution Results Sharing is allocated to ISO Transmission.

5) "ISO Operations and Maintenance Expenses" is the amount of costs in each Transmission or Distribution account related to ISO Transmission Facilities.

6) "Percent ISO" percentages are calculated in accordance with the method set forth in SCE's TO Tariff protocols.

Schedule 20
Administrative and General Expenses

Calculation of Administrative and General Expense

Inputs are shaded yellow

Line	Acct.	Description	Col 1 FERC Form 1 Amount	Col 2 Data Source	Col 3 See Note 1 Total Amount Excluded	Col 4 A&G Expense	Notes
1	920	A&G Salaries	$524,914,232	FF1 323.181b	$81,270,325	$443,643,907	
2	921	Office Supplies and Expenses	$151,198,075	FF1 323.182b	$736,420	$150,461,655	
3	922	A&G Expenses Transferred	-$121,390,767	FF1 323.183b	-$22,934,725	-$98,456,042	
4	923	Outside Services Employed	$72,174,387	FF1 323.184b	$0	$72,174,387	
5	924	Property Insurance	$13,490,781	FF1 323.185b	$0	$13,490,781	
6	925	Injuries and Damages	$62,577,421	FF1 323.186b	$0	$62,577,421	
7	926	Employee Pensions and Benefits	$260,102,912	FF1 323.187b	-$16,753,855	$276,856,767	
8	927	Franchise Requirements	$100,494,668	FF1 323.188b	$100,494,668	$0	
9	928	Regulatory Commission Expenses	$19,609,268	FF1 323.189b	$0	$19,609,268	
10	929	Duplicate Charges	$0	FF1 323.190b	$0	$0	
11	930.1	General Advertising Expense	$0	FF1 323.191b	$0	$0	
12	930.2	Miscellaneous General Expense	$11,068,617	FF1 323.192b	$6,724,220	$4,344,397	
13	931	Rents	$20,261,927	FF1 323.193b	$0	$20,261,927	
14	935	Maintenance of General Plant	$16,709,287	FF1 323.196b	$0	$16,709,287	
15			$1,131,210,808		Total A&G Expenses:	$981,673,755	

Line		Amount	Source
16	Remaining A&G after exclusions & Results Sharing Adjustment:	$981,673,755	Line 15
17	Less Account 924:	$13,490,781	Line 5
18	Amount to apply the Transmission W&S AF:	$968,182,974	Line 16 - Line 17
19	Transmission Wages and Salaries Allocation Factor:	4.0986%	Allocators WS, Line 9
20	Transmission W&S AF Portion of A&G:	$39,681,902	Line 18 * Line 19
21	Transmission Plant Allocation Factor:	9.6866%	Allocators WS, Line 22
22	Property Insurance portion of A&G:	$1,306,793	Line 5 Col 4 * Line 21
23	Administrative and General Expenses:	$40,988,695	Line 20 + Line 22

Note 1: Itemization of exclusions

	Acct.	Total Amount Excluded (Sum of Col 1 to Col 4)	Col 1 Shareholder or Other Exclusions	Col 2 Franchise Requirements	Col 3 Results Sharing	Col 4 PBOPs	Notes
24	920	$81,270,325	-$11,012,309		$92,282,634		See Note 2
25	921	$736,420	$736,420				
26	922	-$22,934,725			-$22,934,725		
27	923	$0					
28	924	$0					
29	925	$0					
30	926	-$16,753,855	$2,002,145			-$18,756,000	See Note 3
31	927	$100,494,668	$0	$100,494,668	$0	$0	See Note 4
32	928	$0					
33	929	$0					
34	930.1	$0					
35	930.2	$6,724,220	$6,724,220				
36	931	$0					
37	935	$0					

Note 2: Results Sharing Adjustment

Adjust Results Sharing by excluding accrued Results Sharing Amount and replacing with the actual A&G Results Sharing payout.

		Amount	Source
a	Accrued Results Sharing Amount:	$127,415,138	Note 2
b	Actual A&G Results Sharing payout:	$35,132,504	Note 2, d
c	Adjustment:	$92,282,634	

Actual Results Sharing Payouts:

	Department	Amount	Source
d	A&G	$35,132,504	Note 2
e	Customer Service Business Unit	$15,137,191	Note 2
f	Power Production Business Unit	$19,127,980	Note 2
g	Trans. And Dist. Business Unit	$37,739,442	Note 2
	Total:	$107,137,117	Sum of d to g

Note 3: PBOPs Exclusion Calculation

		Amount	Note:
a	Authorized PBOPs expense amount:	$52,707,000	See instruction #4
b	Prior Year FF1 PBOPs expense:	$33,951,000	See instruction #4
c	PBOPs Expense Exclusion:	-$18,756,000	b - a

Note 4:

Amount in Line 31, column 2 equals amount in Line 8, column 1 because all Franchise Requirements Expenses are excluded
Franchise Fees Expenses component of the Prior Year TRR are based on Franchise Fee Factors.

Instructions:

1) Enter amounts of A&G expenses from FERC Form 1 in Lines 1 to 14.
2) Fill out "Itemization of Exclusions" table for all input cells. Results Sharing amount in Column 3, line 24 is calculated in Note 2. The PBOPs exclusion in Column 4, line 30 is calculated in Note 3.
   a) Exclude amount of any Shareholder Adjustments, costs incurred on behalf of SCE shareholders, from relevant account in Column 1.
   b) Exclude entire amount of account 927 "Franchise Requirements" in Column 2, as those costs are recovered through the Franchise Fees Expense item.
   c) Exclude any amount of Account 930.1 "General Advertising Expense" not related to advertising for safety, siting, or informational purposes in column 1.
   d) Exclude all of Account 930.2 "Miscellaneous General Expense" in Column 1.
3) Results Sharing adjustment in Column 3 is made by determining the difference between the total accrued Results Sharing amount included in the FERC Form 1 recorded cost amounts and the actual A&G Results Sharing payout (see note 2).
4) Determine the PBOPs exclusion. The authorized amount of PBOPs expense (line) may only be revised pursuant to Commission acceptance of an SCE FPA Section 205 filing to revise the authorized PBOPs expense, in accordance with the tariff protocols. Accordingly, any amount different than the authorized PBOPs expense is excluded from account 926 (see note 3).

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
							Traditional OOR				GRSM		Other Ratemaking	
Line	FERC ACCT	ACCT	ACCT DESCRIPTION	DOLLARS	Category	Total	ISO	Non-ISO	Total	A/P	Threshold [10]	Incremental	Total	Notes
1a	450	4191110	Late Payment Charge- Comm. & Ind.	6,172,738	Traditional OOR	6,172,738	0	6,172,738	0			0	0	1
1b	450	4191115	Residential Late Payment	10,078,838	Traditional OOR	10,078,838	0	10,078,838	0			0	0	1
1c	450	4191120	Non-Residential Late Payment	0	Traditional OOR	0	0	0	0			0	0	1
2	**450 Total**			**16,251,576**		**16,251,576**	**0**	**16,251,576**	**0**		**0**	**0**	**0**	
3	**FF-1 Total for Acct 450 - Forfeited Discounts, p300.16b (Must Equal Line 2)**			$16,251,576										
4a	451	4182110	Recover Unauthorized Use/Non-Energy	246,255	Traditional OOR	246,255	0	246,255	0			0	0	1
4b	451	4182115	Miscellaneous Service Revenue - Ownership Cost	1,371,962	Traditional OOR	1,371,962	0	1,371,962	0			0	0	1
4c	451	4192110	Miscellaneous Service Revenues	111,992,762	Traditional OOR	111,992,762	0	111,992,762	0			0	0	1
4d	451	4192115	Returned Check Charges	1,441,759	Traditional OOR	1,441,759	0	1,441,759	0			0	0	1
4e	451	4192125	Service Reconnection Charges	6,132,937	Traditional OOR	6,132,937	0	6,132,937	0			0	0	1
4f	451	4192130	Service Establishment Charge	15,837,565	Traditional OOR	15,837,565	0	15,837,565	0			0	0	1
4g	451	4192140	Field Collection Charges	6,882,259	Traditional OOR	6,882,259	0	6,882,259	0			0	0	1
4h	451	4192510	Quickcheck Revenue	6,066,240	GRSM	0	0	0	6,066,240	P	1,041,798	5,024,442	0	2
4i	451	4192910	PUC Reimbursement Fee-Elect	230,139	Other Ratemaking	0	0	0	0			0	230,139	6
5	**451 Total**			**150,201,878**		**143,905,499**	**0**	**143,905,499**	**6,066,240**		**1,041,798**	**5,024,442**	**230,139**	
6	**FF-1 Total for Acct 451 - Misc. Service Revenues, p300.17b (Must Equal Line 5)**			$150,201,878										
7a	453	4183110	Sales of Water & Water Power - San Joaquin	147,100	Traditional OOR	147,100	0	147,100	0			0	0	3
7b	453	4183115	Sales of Water & Water Power - Headwater	126,707	Traditional OOR	126,707	0	126,707	0			0	0	3
7c	453	-	Miscellaneous Adjustments	(20,642)	Traditional OOR	(20,642)	0	(20,642)	0			0	0	3
8	**453 Total**			**253,165**		**253,165**	**0**	**253,165**	**0**		**0**	**0**	**0**	
9	**FF-1 Total for Acct 453 - Sales of Water and Power, p300.18b (Must Equal Line 8)**			$253,165										
10a	454	4184110	Joint Pole - Tariffed Conduit Rental	507,136	Traditional OOR	507,136	0	507,136	0			0	0	4
10b	454	4184112	Joint Pole - Tariffed Pole Rental - Cable Cos.	2,491,093	Traditional OOR	2,491,093	0	2,491,093	0			0	0	4
10c	454	4184114	Joint Pole - Tariffed Process & Eng Fees - Cable	682,960	Traditional OOR	682,960	0	682,960	0			0	0	4
10d	454	4184116	Joint Pole - Tariffed Process & Eng Fees - Conduit	0	Traditional OOR	0	0	0	0			0	0	4
10e	454	4184118	Joint Pole - Pl Attchmnt Audit - Undoc P&E Fee	6,657	Traditional OOR	6,657	0	6,657	0			0	0	4
10f	454	4184120	Joint Pole - Aud - Unauth Penalty	0	Traditional OOR	0	0	0	0			0	0	4
10g	454	4184510	Joint Pole - Non-Tariffed Pole Rental	110,333	GRSM	0	0	0	110,333	P	20,761	89,572	0	2
10h	454	4184512	Joint Pole - Non-Tariff Process & Engineering Fees	320	GRSM	0	0	0	320	P	0	320	0	2
10i	454	4184514	Joint Pole - Non-Tariff Requests for Information	2,199	GRSM	0	0	0	2,199	P	268	1,931	0	2
10j	454	4184516	Oil And Gas Royalties	48,102	GRSM	0	0	0	48,102	P	11,749	36,353	0	2
10k	454	4184518	Def Operating Land & Facilities Rent Rev	(756,869)	Traditional OOR	(756,869)	0	(756,869)	0			0	0	4
10l	454	4184810	Facility Cost -EIX/Nonutility	1,797,454	Other Ratemaking	82,845	82,845	0	0			0	1,714,609	6, 12
10m	454	4184815	Facility Cost- Utility	3,196	Traditional OOR	3,196	147	3,048	0			0	0	7
10n	454	4184820	Rent Billed to Non-Utility Affiliates	1,173,959	Other Ratemaking	54,108	54,108	0	0			0	1,119,851	6, 12
10o	454	4184825	Rent Billed to Utility Affiliates	1,464	Traditional OOR	1,464	67	1,396	0			0	0	7
10p	454	4194110	Meter Leasing Revenue	476	Traditional OOR	476	0	476	0			0	0	1
10q	454	4194115	Company Financed Added Facilities	10,188,975	Traditional OOR	10,188,975	0	10,188,975	0			0	0	4
10r	454	4194120	Company Financed Interconnect Facilities	758,245	Traditional OOR	758,245	0	758,245	0			0	0	4
10s	454	4194130	SCE Financed Added Faclty	25,111,552	Traditional OOR	25,111,552	0	25,111,552	0			0	0	4
10t	454	4194135	Interconnect Facility Finance Charge	14,287,762	Traditional OOR	14,287,762	2,118,386	12,169,376	0			0	0	8
10u	454	4204515	Operating Land & Facilities Rent Revenue	17,748,784	GRSM	0	0	0	17,748,784	P	3,336,675	14,412,109	0	2
10v	454	4867020	Nonoperating Misc Land & Facilities Rent	800,564	Traditional OOR	800,564	0	800,564	0			0	0	4
10w	454	-	Miscellaneous Adjustments	(9,146)	Traditional OOR	(9,146)	0	(9,146)	0			0	0	1
10x	454	4206515	Op Misc Land/Fac Rev	723,026	GRSM	0	0	0	723,026	P	0	723,026	0	2
11	**454 Total**			**75,678,241**		**54,211,017**	**2,255,553**	**51,955,464**	**18,632,764**		**3,369,453**	**15,263,311**	**2,834,461**	
12	**FF-1 Total for Acct 454 - Rent from Elec. Property, p300.19b (Must Equal Line 11)**			$75,678,241										

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
							Traditional OOR				GRSM		Other Ratemaking	
Line	**FERC ACCT**	**ACCT**	**ACCT DESCRIPTION**	**DOLLARS**	**Category**	**Total**	**ISO**	**Non-ISO**	**Total**	**A/P**	**Threshold [10]**	**Incremental**	**Total**	**Notes**
12a	456	4186114	Energy Related Services	4,073,087	Traditional OOR	4,073,087	0	4,073,087	0			0	0	1
12b	456	4186118	Distribution Miscellaneous Electric Revenues	2,993,479	Traditional OOR	2,993,479	0	2,993,479	0			0	0	4
12c	456	4186120	Added Facilities - One Time Charge	481,418	Traditional OOR	481,418	0	481,418	0			0	0	4
12d	456	4186122	Building Rental - Nev Power/Mohave Cr	12,147	Traditional OOR	12,147	0	12,147	0			0	0	3
12c	456	4186126	Service Fee - Optimal Bill Prd	960	Traditional OOR	960	0	960	0			0	0	1
12d	456	4186128	Miscellaneous Revenues	1,782,680	Traditional OOR	1,782,680	0	1,782,680	0			0	0	1
12e	456	4186130	Tule Power Plant - Revenue	300	Traditional OOR	300	0	300	0			0	0	3
12f	456	4186142	Microwave Agreement	3,437	Traditional OOR	3,437	0	3,437	0			0	0	4
12g	456	4186150	Utility Subs Labor Markup	604	Traditional OOR	604	28	576	0			0	0	7
12h	456	4186155	Non Utility Subs Labor Markup	329,184	Other Ratemaking	15,172	15,172	0	0			0	314,012	6, 12
12i	456	4186162	Reliant Eng FSA Ann Pymnt-Mandalay	1,447	Traditional OOR	1,447	0	1,447	0			0	0	4
12j	456	4186164	Reliant Eng FSA Ann Pymnt-Ormond Beach	14,522	Traditional OOR	14,522	0	14,522	0			0	0	4
12k	456	4186166	Reliant Eng FSA Ann Pymnt-Etiwanda	4,388	Traditional OOR	4,388	0	4,388	0			0	0	4
12l	456	4186168	Reliant Eng FSA Ann Pymnt-Ellwood	993	Traditional OOR	993	0	993	0			0	0	4
12m	456	4186170	Reliant Eng FSA Ann Pymnt-Coolwater	845	Traditional OOR	845	0	845	0			0	0	4
12n	456	4186194	Property License Fee revenue	208,656	Traditional OOR	208,656	0	208,656	0			0	0	4
12o	456	4186512	Revenue From Recreation, Fish & Wildlife	1,400,773	GRSM	0	0	0	1,400,773	P	160,577	1,240,197	0	2
12p	456	4186514	Mapping Services	123,501	GRSM	0	0	0	123,501	P	18,024	105,477	0	2
12q	456	4186518	Enhanced Pump Test Revenue	58,430	GRSM	0	0	0	58,430	P	6,380	52,050	0	2
12r	456	4186520	RTTC Revenue	0	GRSM	0	0	0	0	P	0	0	0	2
12s	456	4186524	Revenue From Scrap Paper - General Office	15,093	GRSM	0	0	0	15,093	P	4,729	10,364	0	2
12t	456	4186528	CTAC Revenues	(1,150)	GRSM	0	0	0	(1,150)	P	0	(1,150)	0	2
12u	456	4186530	AGTAC Revenues	4,235	GRSM	0	0	0	4,235	P	2,472	1,762	0	2
12v	456	4186536	Other Inc/erd Party DC-ESM	0	GRSM	0	0	0	0	P	0	0	0	2
12w	456	4186538	3rd Party-Div Tmg-Cr PPD training	0	GRSM	0	0	0	0	P	0	0	0	2
12x	456	4186716	ADT Vendor Service Revenue	0	GRSM	0	0	0	0	A	0	0	0	2
12y	456	4186718	Read Water Meters - Irvine Ranch	0	GRSM	0	0	0	0	A	0	0	0	2
12z	456	4186720	Read Water Meters - Rancho California	0	GRSM	0	0	0	0	A	0	0	0	2
12aa	456	4186722	Read Water Meters - Long Beach	0	GRSM	0	0	0	0	A	0	0	0	2
12bb	456	4186730	SSID Transformer Repair Services Revenue	12,802	GRSM	0	0	0	12,802	A	2,146	10,656	0	2
12cc	456	4186815	Employee Transfer/Affiliate Fee	380,833	Other Ratemaking	0	0	0	0			0	380,833	6
12dd	456	4186910	ITCC/CIAC Revenues	21,335,218	Traditional OOR	21,335,218	0	21,335,218	0			0	0	4
12ee	456	4186912	Revenue From Decomission Trust Fund	86,134,485	Other Ratemaking	0	0	0	0			0	86,134,485	6
12ff	456	4186914	Revenue From Decomissioning Trust FAS115	(25,927,940)	Other Ratemaking	0	0	0	0			0	(25,927,940)	6
12gg	456	4186916	Offset to Revenue from NDT Earnings/Realized	(84,711,817)	Other Ratemaking	0	0	0	0			0	(84,711,817)	6
12hh	456	4186918	Offset to Revenue from FAS 115 FMV	25,927,940	Other Ratemaking	0	0	0	0			0	25,927,940	6
12ii	456	4186920	Revenue From Decomissioning Trust FAS115-1	39,334,703	Other Ratemaking	0	0	0	0			0	39,334,703	6
12jj	456	4186922	Offset to Revenue from FAS 115-1 Gains & Loss	(39,334,703)	Other Ratemaking	0	0	0	0			0	(39,334,703)	6
12kk	456	4188712	Power Supply Installations - IMS	0	GRSM	0	0	0	0	A	0	0	0	2
12ll	456	4188714	Consulting Fees - IMS	0	GRSM	0	0	0	0	A	1,000	(1,000)	0	2
12mm	456	4188818	FTR Auction Revenue	0	Other Ratemaking	0	0	0	0			0	0	6
12nn	456	4196105	DA Revenue	491,817	Traditional OOR	491,817	0	491,817	0			0	0	1
12oo	456	4196154	Direct Access Monthly Customer Charges	0	Traditional OOR	0	0	0	0			0	0	1
12pp	456	4196158	EDBL Customer Finance Added Facilities	1,986,553	Traditional OOR	1,986,553	0	1,986,553	0			0	0	4
12qq	456	4196162	SCE Energy Manager Fee Based Services	521,525	Traditional OOR	521,525	0	521,525	0			0	0	4
12rr	456	4196166	SCE Energy Manager Fee Based Services Adj	(1,040)	Traditional OOR	(1,040)	0	(1,040)	0			0	0	4
12ss	456	4196172	Off Grid Photo Voltaic Revenues	16,889	Traditional OOR	16,889	0	16,889	0			0	0	1
12tt	456	4196174	Scheduling/Dispatch Revenues	2,392	Traditional OOR	2,392	0	2,392	0			0	0	4
12uu	456	4196176	Interconnect Facilities Charges-Customer Financed	2,108,744	Traditional OOR	2,108,744	0	2,108,744	0			0	0	4
12vv	456	4196178	Interconnect Facilities Charges - SCE Financed	2,805,161	Traditional OOR	2,805,161	0	2,805,161	0			0	0	4
12ww	456	4196184	DMS Service Fees	1,253	Traditional OOR	1,253	0	1,253	0			0	0	4
12xx	456	4196188	CCA - Information Fees	4,453	Traditional OOR	4,453	0	4,453	0			0	0	6
12yy	456	4206515	Operating Miscellaneous Land & Facilitie	0	GRSM	0	0	0	0	P	0	0	0	2
12zz	456	-	Miscellaneous Adjustments	8	Traditional OOR	8	0	8	0			0	0	1
12aaa	456	4186911	Grant Amortization	2,134,436	Other Ratemaking	0	0	0	0			0	2,134,436	6
13	**456 Total**			**44,732,739**		**38,867,107**	**15,200**	**38,851,907**	**1,613,684**		**195,327**	**1,418,357**	**4,251,948**	
14	**FF-1 Total for Acct 456 - Other electric Revenues, p300.21b (Must Equal Line 13)**			$44,732,739										

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
							Traditional OOR				GRSM		Other Ratemaking	
Line	**FERC ACCT**	**ACCT**	**ACCT DESCRIPTION**	**DOLLARS**	**Category**	**Total**	**ISO**	**Non-ISO**	**Total**	**A/P**	**Threshold [10]**	**Incremental**	**Total**	**Notes**
				(0)										
15a	456.1	4188112	Trans of Elec of Others - Pasadena	0	Traditional OOR	0	0	0	0			0	0	5
15b	456.1	4188114	FTS PPU/Non-ISO	299,738	Traditional OOR	299,738	0	299,738	0			0	0	4
15c	456.1	4188116	FTS Non-PPU/Non-ISO	981,163	Traditional OOR	981,163	0	981,163	0			0	0	4
15d	456.1	4188812	ISO-Wheeling Revenue - Low Voltage	96,907	Other Ratemaking	0	0	0	0			0	96,907	6
15e	456.1	4188814	ISO-Wheeling Revenue - High Voltage	45,625,238	Other Ratemaking	0	0	0	0			0	45,625,238	6
15f	456.1	4188816	ISO-Congestion Revenue	0	Other Ratemaking	0	0	0	0			0	0	6
15g	456.1	4198110	Transmission of Elec of Others	30,536,537	Traditional OOR	30,536,537	30,536,537	0	0			0	0	5
15h	456.1	4198112	WDAT	4,846,732	Traditional OOR	4,846,732	0	4,846,732	0			0	0	4
15i	456.1	4198114	Radial Line Rev-Base Cost - Reliant Coolwater	394,622	Traditional OOR	394,622	0	394,622	0			0	0	4
15j	456.1	4198115	High Voltage Trans Access Rev (Existing Contracts)	0	Other Ratemaking	0	0	0	0			0	0	6
15k	456.1	4198116	Radial Line Rev-Base Cost - Reliant Ormond Beach	1,081,986	Traditional OOR	1,081,986	0	1,081,986	0			0	0	4
15l	456.1	4198118	Radial Line Rev-O&M - AES Huntington Beach	400,687	Traditional OOR	400,687	0	400,687	0			0	0	4
15m	456.1	4198120	Radial Line Rev-O&M - Reliant Mandalay	199,708	Traditional OOR	199,708	0	199,708	0			0	0	4
15n	456.1	4198122	Radial Line Rev-O&M - Reliant Coolwater	551,002	Traditional OOR	551,002	0	551,002	0			0	0	4
15o	456.1	4198124	Radial Line Rev-O&M - Ormond Beach	650,488	Traditional OOR	650,488	0	650,488	0			0	0	4
15p	456.1	4198126	High Desert Tie-Line Rental Rev	264,133	Traditional OOR	264,133	0	264,133	0			0	0	4
15q	456.1	4198128	Scheduling/Dispatch Revenues (CSS)	88,108	Traditional OOR	88,108	0	88,108	0			0	0	4
15r	456.1	4198130	Inland Empire CRT Tie-Line EX	42,492	Traditional OOR	42,492	0	42,492	0			0	0	4
15s	456.1	4198910	Reliability Service Revenue - Non-PTO's	24,799	Other Ratemaking	0	0	0	0			0	24,799	6
16	**456.1 Total**			**86,084,341**		**40,337,397**	**30,536,537**	**9,800,860**	**0**		**0**	**0**	**45,746,944**	
17	**FF-1 Total for Account 456.1 - Revenues from Trans. Of Electricity of Others, p300.22b (Must Equal Line 16)**			$86,084,341										
18a														
19	**457.1 Total**			**0**		**0**	**0**	**0**	**0**		**0**	**0**	**0**	
20	**FF-1 Total for Account 457.1 - Regional Control Service Revenues, p300.23b (Must Equal Line 19)**			$0										
21a														
22	**457.2 Total**			**0**		**0**	**0**	**0**	**0**		**0**	**0**	**0**	
23	**FF-1 Total for Account 457.2- Miscellaneous Revenues, p300.24b (Must Equal Line 22)**			$0										
	Edison Carrier Solutions (ECS)													
24a	417	4863135	ECS - Pass Pole Attachments	0	GRSM	0	0	0	0	P	0	0	0	2
24b	417	4863130	ECS - Distribution Facilities	723,785	GRSM	0	0	0	723,785	P	121,022	602,763	0	2
24c	417	4862110	ECS - Dark Fiber	6,038,137	GRSM	0	0	0	6,038,137	A	1,237,254	4,800,883	0	2
24d	417	4862115	ECS - SCE Net Fiber	3,279,976	GRSM	0	0	0	3,279,976	A	556,569	2,723,407	0	2
24e	417	4862120	ECS - Transmission Right of Way	1,344,293	GRSM	0	0	0	1,344,293	A	74,144	1,270,150	0	2
24f	417	4862135	ECS - Wholesale FCC	26,864,362	GRSM	0	0	0	26,864,362	A	4,392,878	22,471,484	0	2
24g	417	4864110	ECS - Infrstructure Leasing	0	GRSM	0	0	0	0	A	0	0	0	2
24h	417	4864115	ECS - EU FCC Rev	347,409	GRSM	0	0	0	347,409	A	56,282	291,127	0	2
24i	417	4862125	ECS - Cell Site Rent and Use (Active)	12,847,155	GRSM	0	0	0	12,847,155	A	2,155,019	10,692,135	0	2
24j	417	4862130	ECS - Cell Site Reimbursable (Active)	4,657,383	GRSM	0	0	0	4,657,383	A	750,644	3,906,739	0	2
24k	417	4863120	ECS - Communication Sites	368,636	GRSM	0	0	0	368,636	P	67,398	301,238	0	2
24l	417	4863110	ECS - Cell Site Rent and Use (Passive)	2,928,901	GRSM	0	0	0	2,928,901	P	473,237	2,455,665	0	2
24m	417	4863115	ECS - Cell Site Reimbursable (Passive)	398,898	GRSM	0	0	0	398,898	P	17,649	381,249	0	2
24n	417	4863125	ECS - Micro Cell	1,045,148	GRSM	0	0	0	1,045,148	P	149,957	895,191	0	2
24o	417	4864120	ECS - End User Universal Service Fund Fee	18,457	GRSM	0	0	0	18,457	A	2,874	15,583	0	2
25	**417 ECS Total**			**60,862,540**		**0**	**0**	**0**	**60,862,540**		**10,054,928**	**50,807,612**	**0**	
26	**417 Other**			**13,867,814**										
27	**FF-1 Total for Account 417 - Revenues From Nonutility Operations p117.33c (Must Equal Line 25 + 26)**			$74,730,354										

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
						Traditional OOR			GRSM				Other Ratemaking	
Line	FERC ACCT	ACCT	ACCT DESCRIPTION	DOLLARS	Category	Total	ISO	Non-ISO	Total	A/P	Threshold [10]	Incremental	Total	Notes
	Subsidiaries													
28a	418.1		ESI (Gross Revenues - Active)	11,246,108	GRSM	0	0	0	11,246,108	A	1,993,685	9,252,423	0	2,9
28b	418.1		ESI (Gross Revenues - Passive)	150,173	GRSM	0	0	0	150,173	P	16,198	133,975	0	2,9
28c	418.1		Southern States Realty	0	GRSM	0	0	0	0	P		0	0	2, 15
28d	418.1		Mono Power Company	(2,065)	Traditional OOR	(2,065)	(95)	(1,970)	0			0	0	12, 13
28e	418.1		SCE Capital Company	(4,943)	Traditional OOR	(4,943)	(228)	(4,715)	0			0	0	12, 14
29	**418.1 Subsidiaries Total**			**11,389,273**		**(7,008)**	**(323)**	**(6,685)**	**11,396,281**		**2,009,884**	**9,386,397**	**0**	
30	**418.1 Other**													
31	**FF-1 Total for Account 418.1 -Equity in Earnings of Subsidiary Companies, p117.36c (Must Equal Line 29 + 30)**			$607,586										
32			**Totals**	**445,453,753**		**293,818,752**	**32,806,967**	**261,011,785**	**98,571,509**		**16,671,389**	**81,900,120**	**53,063,492**	

				Calculation
33		Ratepayers' Share of Threshold Revenue	16,671,389	= Line 32K
34		ISO Ratepayers' Share of Threshold Revenue (%)	32.54%	see Note 11
35		ISO Ratepayers' Share of Threshold Revenue	5,425,127	= Line 33D * Line 34D
36				
37		Total Active Incremental Revenue	55,433,586	= Sum Active categories in column L
38		Ratepayers' Share of Active Incremental Revenue	5,543,359	= Line 37D * 10%
39		Total Passive Incremental Revenue	26,466,533	= Sum Passive categories in column L
40		Ratepayers' Share of Passive Incremental Revenue	7,939,960	= Line 39D * 30%
41		Total Ratepayers' Share of Incremental Revenue	13,483,319	= Line 38D + Line 40D
42		ISO Ratepayers' Share of Incremental Revenue (%)	32.54%	see Note 11
43		ISO Ratepayers' Share of Incremental Revenue	4,387,679	= Line 41D * Line 42D
44		**Total ISO Ratepayers' Share of NTP&S Gross Revenue**	**9,812,806**	= Line 35D * Line 43D

		Amount	Calculation
45	**Total Revenue Credits:**	$42,619,773	Sum of Column D, Line 44 and Column G, Line 32

Notes:

1- CPUC Jurisdictional service related.

2- Subject to sharing per the Gross Revenue Sharing Mechanism (GRSM). On an annual basis, once SCE obtains $16,671,389.55 (Threshold Gross Revenue) in NTP&S Revenues, any additional revenues (Incremental Gross Revenues) that SCE receives are shared between shareholders and ratepayers. For GRSM categories deemed Active, the Imcremental Gross Revenues are shared 90/10 between shareholders and ratepayers. For those categories deemed Passive, the Incremental Gross Revenues are shared 70/30 between shareholders and ratepayers.

3- Generation related.

4- Non-ISO facilities related.

5- ISO transmission system related.

6- Subject to balancing account treatment

7- Allocated based on the currently approved CPUC GRC allocator.
ISO Allocator = 0.04609

8- ISO portion of Traditional OOR relates to monthly revenues received from customers for facilities that are part of the ISO network.

9- Edison ESI is a subsidiary company. Gross revenues are not reported in FF-1, only net earnings. Net Earnings for ESI are reported on Acct 418.1, pg 225.5e.

10- The first $16,671,389 million in gross revenues generated by GRSM activities are automatically classified as Threshold Revenue.

11- Allocator is equal to the jurisdictional split of the Threshold Revenue, which is jurisdictionalized as $5.425M to FERC ratepayers and $11.246M to CPUC ratepayers per the 2009 CPUC General Rate Case. The ISO ratepayers' share of ratepayer revenue is $5.425M/$16.671M = 32.54%.

12- Allocated based on the currently approved CPUC Base Revenue Requirement Balancing Account (BRRBA) allocator. ISO portion of revenue is treated as Traditional OOR.
ISO Allocator = 0.04609

13- Mono Power Company is a subsidiary company. Net Earnings are reported on Acct 418.1, pg 225.11e

14- SCE Capital Company is a subsidiary company. Net Earnings are reported on Acct 418.1, pg 225.23e

15- Southern States Realty is a subsidiary company. Gross revenues are not reported in FF-1, only net earnings. Net Earnings for ESI are reported on Acct 418.1, pg 225.17e.

NETWORK UPGRADE CREDIT AND INTEREST EXPENSE

1) Beginning of Year Balances: (Note 1)

Line		Balance	Notes
1	Outstanding Network Upgrade Credits Recorded in FERC Acct 252	$30,999,991	See Note 1
2	Acct 252 Other	$80,926,998	SCE Records
3	Total Acct 252	$111,926,989	Line 1 + Line 2
4	(Must equal Line 3)	$111,926,989	FF1 113.56d
	2) End of Year Balances: (Note 2)		
5	Outstanding Network Upgrade Credits Recorded in FERC Acct 252	$18,816,506	See Note 3
6	Acct 252 Other	$119,334,857	SCE Records
7	Total Acct 252	$138,151,363	Line 5 + Line 6
8	(Must equal Line 7)	$138,151,363	FF1 113.56c
9	Average Outstanding Network Upgrade Credits Beginning and End of Year	$24,908,249	(Line 1 + Line 5) / 2
10	Interest On Network Upgrade Credits Recorded in FERC Acct 242	$1,275,701	See Note 4
11	Acct 242 Other	$691,975,795	SCE Records
12	Total Acct 242	$693,251,496	Line 10 + Line 11
13	(Must equal Line 12)	$693,248,507	FF1 113.48c

Notes:

1 Beginning of Year Balances are from December of the year previous to the Prior Year.
2 End of Year Balances are from December of the Prior Year.
3 Only projects that are in Rate Base in the year reported are included.
4 Interest relates to refund of facility and one-time payments by generator. For facility costs, pre-in-service date interest is excluded. For one-time costs, pre-in-service and post-in-service interest is included.

Schedule 23
Regulatory Assets and Liabilities

Determination of Regulatory Assets/Liabilities and Regulatory Debits

Line
1 Other Regulatory Assets/Liabilities are a component of Rate Base representing costs that are created
2 resulting from the ratemaking actions of regulatory agencies, not includable in other accounts.
3 Pursuant to the Commission's Uniform System of Accounts, they are booked to account 182.3.
4
5 SCE shall include a non-zero amount of Other Regulatory Assets/Liabilities only with Commission
6 approval received subsequent to an SCE Section 205 filing requesting such treatment.
7
8 Regulatory Debits are amounts approved for recovery in this formula transmission rate representing the
9 approved annual recovery of Other Regulatory Assets/Liabilities as an expense item in the Base TRR,
10 consistent with a Commission Order.
11

Line		Prior Year Amount	Calculation
14	Other Regulatory Assets/Liabilities (EOY):	$0	Sum of Column 2 below
15	Other Regulatory Assets/Liabilities (BOY/EOY average):	$0	Avg. of L 20, C1 and C2
16	Regulatory Debits:	$0	Line 20, C3

Line	Description of Issue Resulting in Other Regulatory Asset/Liability	(1) Prior Year BOY Other Reg Asset/Liability	(2) Prior Year EOY Other Reg Asset/Liability	(3) Prior Year Regulatory Debit	
17	Issue #1	$0	$0	$0	
18	Issue #2	$0	$0	$0	
19	Issue #3	$0	$0	$0	
20	Totals:	$0	$0	$0	Sum of above

Instructions:
1) Upon Commission approval of recovery of Other Regulatory Assets/Liabilities or Regulatory Debits costs through this formula transmission rate:
   a) Fill in Description for issue in above table.
   b) Enter costs in columns 1-3 in above table for the applicable Prior Year.
2) Add additional lines as necessary for additional issues.

Calculation of the Contribution of CWIP to the Base TRR

1) CWIP Contribution to the Prior Year TRR and True Up TRR

a) CWIP Balances:

Line	Project	Col 1 Prior Year EOY Amount	Col 2 Prior Year Average Amount	Col 3 Forecast Period Amount	Source
1	Tehachapi:	$1,059,868,753	$797,729,307	-$398,960,709	CWIP WS, Lines 13, 14, 92
2	Devers to Colorado River:	$151,361,046	$75,044,895	$449,055,807	CWIP WS, Lines 13, 14, 92
3	Eldorado Ivanpah:	$30,843,632	$16,130,630	$103,921,274	CWIP WS, Lines 13, 14, 92
4	Lugo-Pisgah:	-$73,288	-$65,031	$2,930	CWIP WS, Lines 13, 14, 92
5	Red Bluff:	$14,678,203	$4,517,170	$133,720,630	CWIP WS, Lines 13, 14, 92
6	Whirlwind Sub Expansion:	$2,893,212	$673,493	$6,126,778	CWIP WS, Lines 27, 28, 114
7	Colorado River Sub Expansion:	$10,959,974	$2,859,136	$51,110,556	CWIP WS, Lines 27, 28, 114
8	South of Kramer:	$2,144,420	$771,892	$9,218,202	CWIP WS, Lines 27, 28, 114
9	West of Devers:	$4,824,458	$2,251,791	$11,655,576	CWIP WS, Lines 27, 28, 114
10	Project X:	---	---	---	CWIP WS, Lines 27, 28, 114
11	Project Y:	---	---	---	CWIP WS, Lines 27, 28, 114
12	Totals:	$1,277,500,411	$899,913,283	$365,851,045	Sum of Lines 1 to 11

b) Return:

Line		EOY Amount	Average Amount	Source
13	CWIP Amount:	$1,277,500,411	$899,913,283	Line 12
14	Cost of Capital Rate:	8.1462%	8.1462%	BaseTRR WS, Line 53
15	Cost of Capital:	$104,067,986	$73,308,910	Line 13 * Line 14

c) Income Taxes

Line		EOY Amount	Average Amount	Source
16	CWIP Amount:	$1,277,500,411	$899,913,283	Line 12
17	Equity ROR w Preferred Stock ("ER"):	5.6111%	5.6111%	BaseTRR WS, Line 54
18	Composite Tax Rate:	40.8863%	40.8863%	BaseTRR WS, Line 58
19	Income Taxes:	$49,579,251	$34,925,254	Formula below

20

21 Income Taxes = [(RB * ER) * (CTR/(1 – CTR)]

22 (No "Credits and Other Term", as Credits and Other is not related to CWIP)

23

d) ROE Incentives:

Line		Value	Source
24	IREF =	$8,538	IncentiveAdder WS, Line 3

1) Tehachapi

Line		EOY Amount	Average Amount	
25	Tehachapi CWIP Amount:	$1,059,868,753	$797,729,307	Line 1
26	ROE Adder %:	1.25%	1.25%	IncentiveAdder WS, Line 5
27	ROE Adder $:	$11,311,930	$8,514,128	Below formula

2) Devers to Colorado River

Line		EOY Amount	Average Amount	
28	DCR EOY CWIP:	$151,361,046	$75,044,895	Line 2
29	ROE Adder %:	1.00%	1.00%	IncentiveAdder WS, Line 6
30	ROE Adder $:	$1,292,376	$640,761	Below formula

31

32 ROE Adder $ = (CWIP/$1,000,000) * IREF * (ROE Adder/1%)

e) Total of Return, Income Taxes, and ROE Incentives contribution to PYTRR and True Up TRR

Line		PYTRR Amount	True Up TRR Amount	Source
33	Return:	$104,067,986	$73,308,910	Line 15
34	Income Taxes:	$49,579,251	$34,925,254	Line 19
35	ROE Adder Tehachapi:	$11,311,930	$8,514,128	Line 27
36	ROE Adder DCR:	$1,292,376	$640,761	Line 30
37	FF&U:	$1,919,308	$1,072,795	Note 1
38	Total:	$168,170,849	$118,461,847	Sum Lines 33 to 37

f) Contribution from each Project to the Prior Year TRR and True Up TRR

1) Contribution to the Prior Year TRR

		Col 1	Col 2	Col 3	Col 4	Col 5	
		Cost of	Income			= Sum C1 to C4	
	Project	Capital	Taxes	ROE Adder	FF&U	Total	Source
39	Tehachapi:	$86,339,233	$41,133,058	$11,311,930	$1,602,208	$140,386,430	Note 2
40	Devers to Colorado River:	$12,330,203	$5,874,258	$1,292,376	$225,083	$19,721,920	Note 2
41	Eldorado Ivanpah:	$2,512,590	$1,197,028	$0	$42,826	$3,752,444	Note 2
42	Lugo-Pisgah:	-$5,970	-$2,844	$0	-$102	-$8,916	Note 2
43	Red Bluff:	$1,195,719	$569,655	$0	$20,381	$1,785,754	Note 2
44	Whirlwind Sub Expansion:	$235,687	$112,284	$0	$4,017	$351,989	Note 2
45	Colorado River Sub Expansion:	$892,824	$425,352	$0	$15,218	$1,333,393	Note 2
46	South of Kramer:	$174,689	$83,224	$0	$2,978	$260,891	Note 2
47	West of Devers:	$393,011	$187,235	$0	$6,699	$586,945	Note 2
48	Project X:	---	---	---	---	---	Note 2
49	Project Y:	---	---	---	---	---	Note 2
50	Totals:	$104,067,986	$49,579,251	$12,604,305	$1,919,308	$168,170,849	Sum L 39 to L 49

2) Contribution to the True Up TRR

		Col 1	Col 2	Col 3	Col 4	Col 5	
		Cost of	Income			= Sum C1 to C4	
	Project	Capital	Taxes	ROE Adder	FF	Total	Source
51	Tehachapi:	$64,984,779	$30,959,537	$8,514,128	$954,625	$105,413,069	Note 3
52	Devers to Colorado River:	$6,113,322	$2,912,461	$640,761	$88,341	$9,754,884	Note 3
53	Eldorado Ivanpah:	$1,314,037	$626,023	$0	$17,730	$1,957,789	Note 3
54	Lugo-Pisgah:	-$5,298	-$2,524	$0	-$71	-$7,893	Note 3
55	Red Bluff:	$367,979	$175,309	$0	$4,965	$548,253	Note 3
56	Whirlwind Sub Expansion:	$54,864	$26,138	$0	$740	$81,742	Note 3
57	Colorado River Sub Expansion:	$232,911	$110,962	$0	$3,143	$347,016	Note 3
58	South of Kramer:	$62,880	$29,957	$0	$848	$93,685	Note 3
59	West of Devers:	$183,436	$87,391	$0	$2,475	$273,302	Note 3
60	Project X:	---	---	---	---	---	Note 3
61	Project Y:	---	---	---	---	---	Note 3
62	Totals:	$73,308,910	$34,925,254	$9,154,888	$1,072,795	$118,461,847	Sum of L 51 to 61

2) Contribution from the Incremental Forecast Period TRR

a) Total of all CWIP projects

		Value	Source
63	Forecast Period Incremental CWIP:	$365,851,045	Line 12, Col 3
64	AFCRCWIP:	12.027%	IFPTRR WS, Line 16
65	CWIP component of IFPTRR without FF&U:	$44,001,553	Line 63 * Line 64
66	FF&U:	$507,980	Line 65 * (FF + U Factors from FFU WS)
67	CWIP component of IFPTRR including FF&U:	$44,509,533	Line 65 + Line 66

b) Individual Project Contribution

	Project	Amount wo FF&U	Amount with FF&U	Source
68	Tehachapi:	-$47,983,711	-$48,537,664	Note 4
69	Devers to Colorado River:	$54,008,737	$54,632,246	Note 4
70	Eldorado Ivanpah:	$12,498,796	$12,643,089	Note 4
71	Lugo-Pisgah:	$352	$356	Note 4
72	Red Bluff:	$16,082,817	$16,268,487	Note 4
73	Whirlwind Sub Expansion:	$736,878	$745,385	Note 4
74	Colorado River Sub Expansion:	$6,147,157	$6,218,124	Note 4
75	South of Kramer:	$1,108,689	$1,121,489	Note 4
76	West of Devers:	$1,401,837	$1,418,020	Note 4
77	Project X:	---	---	Note 4
78	Project Y:	---	---	Note 4
79	Totals:	$44,001,553	$44,509,533	Sum of Lines 68 to 78

3) Total Contribution of CWIP to the Retail and Wholesale Base TRRs:

a) Total of all CWIP projects

		Value	Source
80	PY Total Return, Taxes, Incentive:	$166,251,542	Sum Line 33 to 36
81	CWIP component of IFPTRR wo FF&U:	$44,001,553	Line 65
82	Total without FF&U:	$210,253,095	Line 80 + Line 81
83	FF Factor:	0.9139%	FFU WS, Line 5
84	U Factor:	0.2406%	FFU WS, Line 5
85	Franchise Fees Amount:	$1,921,461	Line 82 * Line 83
86	Uncollectibles Amount:	$505,827	Line 82 * Line 84
87	Total Contribution of CWIP to Retail Base TRR:	$212,680,383	Line 82 + Line 85 + Line 86
88	Total Contribution of CWIP to Wholesale Base TRR:	$212,174,556	Line 82 + Line 85

b) Individual CWIP Project Contribution to the Retail Base TRR

		Col 1 PYTRR wo FF&U	Col 2 IFPTRR wo FF&U	Col 3 FF&U	Col 4 Total	Source
89	Tehachapi:	$138,784,221	-$47,983,711	$1,048,256	$91,848,766	Note 5
90	Devers to Colorado River:	$19,496,837	$54,008,737	$848,592	$74,354,166	Note 5
91	Eldorado Ivanpah:	$3,709,618	$12,498,796	$187,120	$16,395,534	Note 5
92	Lugo-Pisgah:	-$8,814	$352	-$98	-$8,560	Note 5
93	Red Bluff:	$1,765,374	$16,082,817	$206,050	$18,054,241	Note 5
94	Whirlwind Sub Expansion:	$347,972	$736,878	$12,524	$1,097,374	Note 5
95	Colorado River Sub Expansion:	$1,318,175	$6,147,157	$86,184	$7,551,517	Note 5
96	South of Kramer:	$257,913	$1,108,689	$15,777	$1,382,380	Note 5
97	West of Devers:	$580,246	$1,401,837	$22,882	$2,004,965	Note 5
98	Project X:	---	---	---	---	Note 5
99	Project Y:	---	---	---	---	Note 5
100	Totals:	$166,251,542	$44,001,553	$2,427,288	$212,680,383	

c) Individual CWIP Project Contribution to the Wholesale Base TRR

		Col 1 PYTRR wo FF&U	Col 2 IFPTRR wo FF&U	Col 3 FF	Col 4 Total	Source
101	Tehachapi:	$138,784,221	-$47,983,711	$829,808	$91,630,318	Note 6
102	Devers to Colorado River:	$19,496,837	$54,008,737	$671,753	$74,177,326	Note 6
103	Eldorado Ivanpah:	$3,709,618	$12,498,796	$148,125	$16,356,539	Note 6
104	Lugo-Pisgah:	-$8,814	$352	-$77	-$8,539	Note 6
105	Red Bluff:	$1,765,374	$16,082,817	$163,111	$18,011,302	Note 6
106	Whirlwind Sub Expansion:	$347,972	$736,878	$9,914	$1,094,764	Note 6
107	Colorado River Sub Expansion:	$1,318,175	$6,147,157	$68,224	$7,533,557	Note 6
108	South of Kramer:	$257,913	$1,108,689	$12,489	$1,379,092	Note 6
109	West of Devers:	$580,246	$1,401,837	$18,114	$2,000,197	Note 6
110	Project X:	---	---	---	---	Note 6
111	Project Y:	---	---	---	---	Note 6
112	Totals:	$166,251,542	$44,001,553	$1,921,461	$212,174,556	

Notes:

1) (Sum Lines 33 to 36) * (FF + U Factors from FFU WS) for Prior Year TRR
(Sum Lines 34 to 37) * (FF Factor from FFU WS) for True Up TRR
2) Project Cost of capital is a fraction of total Cost of Capital on Line 15 based on fraction of project CWIP Balances on Lines 1 to 12, Col 1.
Project Income Taxes is a fraction of total Income on Line 19 based on fraction of project CWIP Balances on Lines 1 to 12, Col 1.
ROE Adder is from Lines 35 and 36. FF&U Expenses are based on FF&U Factors on FFU worksheet.
3) Project Cost of capital is a fraction of total Cost of Capital on Line 15 based on fraction of project CWIP Balances on Lines 1 to 12, Col 2.
Project Income Taxes is a fraction of total Income on Line 19 based on fraction of project CWIP Balances on Lines 1 to 12, Col 2.
ROE Adder is from Lines 35 and 36. FF Expenses is based on FF Factor on FFU worksheet.
4) Project contribution to total IFPTRR is based on fraction of Forecast Period CWIP Balances on Lines 1 to 12, Col 3.
5) Column 1 is from Lines 39 to 49, Sum of Column 1-3 (no FF&U).
Column 2 is from Lines 68 to 78 (no FF&U).
Column 3 is sum of FF and U factors times sum of Columns 1 and 2
6) Same as Note 5 except no Uncollectibles Expense in Column 3.

Calculation of Wholesale Difference to the Base TRR

Inputs are shaded yellow

The Wholesale Difference to the Base TRR represents the amount by which the Wholesale Base TRR differs as compared to the Retail Base TRR. This difference is attributable to differences in the following five items. These five items may affect the Base TRR by affecting Rate Base, or affecting an annual expense (amortization). If the annual amortization affects Income Taxes, there is an additional annual Income Tax Effect. The table summarizes these impacts for each item:

Line		Rate Base Difference	Expense (Amortization) Difference	Expense Tax Impact
1	a) Depreciation	Yes	Yes	No
2	b) Taxes Deferred -Make Up Adjustment (South Georgia)	Yes	Yes	Yes
3	c) Excess Deferred Taxes	Yes	Yes	Yes
4	d) Taxes Deferred - Acct. 282 ACRS/MACRS	Yes	Yes	No
5	e) Uncollectibles Expense	No	Yes	No

1) Calculation of Wholesale Rate Base Difference and Wholesale Rate Base Adjustment

a) Quantification of the Initial 2010 Wholesale Rate Base Difference and annual change

The difference between Retail and Wholesale Rate Base is attributable to the following four items, with with the Initial Prior Year 2010 Rate Base differences and annual changes as follows:

		Data Source		Col 1 2010 Rate Base Difference (Wholesale less Retail)	Col 2 Annual Change (Amortization)
6	1) Accumulated Depreciation	Fixed values		$31,556,000	-$2,176,300
7	2) Taxes Deferred - Make Up Adjustment	Fixed values		-$35,044,000	$2,503,000
8	3) Excess Deferred Taxes	Fixed values		-$624,650	$43,100
9	4) Taxes Deferred - Acct. 282 ACRS/MACRS	Fixed values		-$7,410,000	$511,200
10			Totals:	-$11,522,650	$881,000

b) Quantification of the Wholesale Rate Base Adjustment

The Wholesale Rate Base Adjustment represents the impact on the Wholesale Base TRR relative to the Retail Base TRR of the Wholesale Rate Base Difference for the Prior Year.

		Data Source	Value	Notes/Instructions
11	Fixed Charge Rate	IFPTRR WS L 16	12.03%	1
12	Prior Year		2011	2
13	Wholesale Rate Base Difference for Prior Year		-$10,641,650	3
14	Wholesale Rate Base Adjustment	Line 13 * Line 11	-$1,279,890	

2) Calculation of Wholesale Expense Difference

The annual Wholesale Expense Difference impact is the negative of amounts stated in Lines 6 to 9 above, Column 2. It represents the effect on expenses (Wholesale less Retail) of amortizing the associated balances each year. If an annual amortization amount affects Income Taxes, the expense difference must be grossed up for income taxes.

a) Calculation of the Wholesale South Georgia Income Tax Adjustment to the TRR

		Source	Value
15	South Georgia Amortization	Line 7	$2,503,000
16	Composite Tax Rate ("CTR")	BaseTRR WS L 58	40.886%
17	Tax Gross Up Factor	(1/(1-CTR))	1.6917
18	Wholesale South Georgia		
19	Income Tax Adjustment to the TRR:	- Line 15 * Line 17	-$4,234,213.79

b) Calculation of "Excess Deferred Taxes" Grossed Up for Income Taxes

		Source	Value
20	Annual Amort. of "Excess Deferred Taxes":	Line 8	$43,100
21	Tax Gross Up Factor	Line 17	1.6917
22	Excess Deferred Taxes Grossed Up for Income Taxes:	- Line 20 * Line 21	-$72,910

	c) Total Expense Difference			**Notes/Instructions**
23	1) Wholesale Depreciation Difference	- Line 6, Col. 2	$2,176,300	
24	2) Taxes Deferred - Make Up Adjustment	Line 19	-$4,234,214	
25	3) Excess Deferred Taxes	Line 22	-$72,910	
26	4) Taxes Deferred - Acct. 282 ACRS/MACRS	- Line 9, Col. 2	-$511,200	
27		Total Expense Difference:	-$2,642,024	

3) Calculation of the Wholesale Difference to the Base TRR

		Source	**Value**	
28	Wholesale Rate Base Adjustment	Line 14	-$1,279,890.1	
29	Expense Difference	Line 27	-$2,642,024	
30	Uncollectibles Expense -- Prior Year TRR	- Base TRR WS, L 79	-$1,484,822	
31	Uncollectibles Expense -- IFPTRR	- IFPTRR WS, L 79	-$635,894	
32	Subtotal:	Sum Line 28 to Line 31	-$6,042,630	
33	Franchise Fee Exclusion		-$35,842	Note 4
34	Wholesale Difference to the Base TRR:	Line 32 + Line 33	-$6,078,472	

Notes/Instructions:

1) Fixed Charge Rate of capital and income tax costs associated with $1 of Rate Base is defined elsewhere in this formula as "AFCRCWIP".
2) Input Prior Year for this Informational Filing in Line 12.
3) Calculation: (Line 10, Col 1) + ((Line 10, Col 2) * (Line 12 - 2010)).
4) Franchise Fee Exclusion is equal to the Franchise Fee Factor on the FFU WS Line 5 times Line 28 + 29.

Calculation of Income Tax Rates

	1) Federal Income Tax rate			Inputs are shaded yellow	
Line		**Prior Year**	**Federal Income Tax Rate ("FITR")**	**Source**	
1		2011	35.00%	1) Input marginal Federal Income Tax rate for	
2				the Prior Year. See Note 1.	
3	**2) Composite State Income Tax Rate**				
4					
5					
6					
7		**Prior Year**	**Composite State Income Tax Rate ("CSITR")**	**Source**	
8		2011	9.0559%	1) See calculation below on Line 45 based on inputs	
9				for apportionment factors and state tax rates.	
10				for the applicable Prior Year	
11					
12	**Calculation of Composite State Income Tax Rate for the Prior Year:**				
13					
14					
15		**State**	**Apportionment Factors ("AFs")**	**Source**	
16	California		96.7445%	1) Input most recent available Apportionment Factors.	
17	New Mexico		0.8536%		
18	Arizona		2.3752%		
19	D.C.		0.0051%		
20					
21					
22		**State**	**Statutory Tax Rate ("STR")**		
23	California		8.8400%	2) Input STR for the Prior Year	
24	New Mexico		7.6000%	for each state. See Note 1.	
25	Arizona		6.9680%		
26	D.C.		9.9750%		
27					
28					
29					
30					
31					
32		**State**	**Ratio of SCE State Taxable Income to SCE California Taxable Income**		
33	California		100.0000%	3) Input most recent available ratios based on	
34	New Mexico		-15.2251%	taxable income from state return filings.	
35	Arizona		309.8227%		
36	D.C.		148.7298%		
37					
38					
39		**State**	**Effective State Tax Rate**		
40	California		8.5522%	Line 16 * Line 23 * Line 33	
41	New Mexico		-0.0099%	Line 17 * Line 24 * Line 34	
42	Arizona		0.5128%	Line 18 * Line 25 * Line 35	
43	D.C.		0.0008%	Line 19 * Line 26 * Line 36	
44					
45	**Composite State Income Tax Rate =**		9.0559%	Sum of Lines 40 to 43	
46					
47	**3) Capitalized Overhead portion of Electric Payroll Tax Expense**				
48					**Amount**
49	Total Electric Payroll Tax Expense (From BaseTRR WS, Line 30				$137,181,202
50	Capitalized Overhead portion of Electric Payroll Tax Expense Note 2)				$45,967,326
51	Non-Capitalized Overhead portion of Electric Payroll Tax Expense (Line 49 - Line 50)				$91,213,876
52					

Notes:

1) In the event that statutory marginal tax rates change during the Prior Year, the effective tax rate used in the formula shall be weighted by the number of days each such rate was in effect. For example, a 35% rate in effect for 120 days superseded by a 40% rate in effect for the remainder of the year will be calculated as: ((.3500 x 120) + (.4000 x 245))/365 = .3836.

2) Enter the capitalized overhead portion of Electric Payroll Tax Expense.

Calculation of Allocation Factors

Inputs are shaded yellow

1) Calculation of Transmission Wages and Salaries Allocation Factor

Line		**Notes**	**FERC Form 1 Reference or Instruction**	**Prior Year Value**
1	ISO Transmission Wages and Salaries		OandM WS Line 135, Col. 7	$36,017,097
2	Total Wages and Salaries		FF1 354.28b	$1,135,485,499
3	Less Total A&G Wages and Salaries		FF1 354.27b	$328,723,251
4	Total Wages and Salaries wo A&G		Line 2 - Line 3	$806,762,248
5	Total Results Sharing		AandG WS, Note 2	$107,137,117
6	Less A&G Results Sharing		AandG WS, Note 2	$35,132,504
7	Results Sharing wo A&G Results Sharing		Line 5 - Line 6	$72,004,614
8	Total non-A&G W&S with Results Sharing		Line 4 + Line 7	$878,766,862
9	Transmission Wages and Salary Allocation Factor		Line 1 / Line 8	4.0986%
10				
11	**2) Calculation of Transmission Plant Allocation Factor**			
12			**FERC Form 1 Reference**	**Prior Year**
13		**Notes**	**or Instruction**	**Value**
14	Transmission Plant - ISO		PlantStudy WS, Line 21	$3,302,962,475
15	Distribution Plant - ISO		PlantStudy WS, Line 30	$6,634,834
16	Total Electric Miscellaneous Intangible Plant		PlantInService WS, Line 21, C2	$1,557,464,316
17	Electric Miscellaneous Intangible Plant		Line 16 * Line 9	$63,834,159
18	Total General Plant		PlantInService WS, Line 21, C1	$2,123,098,622
19	General Plant		Line 18 * Line 9	$87,017,220
20	Total Plant In Service		FF1 207.104g	$35,724,211,772
21				
22	Transmission Plant Allocation Factor		(L14 + L15 + L17 + L19) / L20	9.6866%

Franchise Fees and Uncollectibles Expense Factors

1) Approved Franchise Fee Factor(s)

Inputs are shaded yellow

Line	From	To	FF Factor	Reference
1	2009	present	0.91388%	CPUC D. 09-03-025 Appendix C, page 2
2				

2) Approved Uncollectibles Expense Factor(s)

	From	To	U Factor	Reference
3	2009	present	0.24058%	CPUC D. 09-03-025 Appendix C, page 2
4				

3) FF and U Factors

	Prior Year	FF Factor	U Factor	Notes
5	2011	0.91388%	0.24058%	

Notes:
1) Franchise Fees represent payments that SCE makes to municipal entities for the right to locate facilities within the municipality.

Instructions:
1) Enter Franchise Fee and Uncollectibles Factors as approved by the California Public Utilities Commission in modules 1 and 2 above. If approved factors changed during Prior Year, enter both, and note period of time for which each applies in "From" and "To" columns.
2) Calculate in module 3 the weighted average FF and U factors from the factors in modules 1 and 2 based on the length of time each FF and U factor was in effect during the Prior Year at issue.

CALCULATION OF SCE WHOLESALE HIGH AND LOW VOLTAGE TRRS

Inputs are shaded yellow

Line	TRR Values		Notes	Source	
1	$888,014,501	= Wholesale Base TRR		BaseTRR WS, Line 89	
2	-$60,654,041	= Total Wholesale TRBAA	Note 1	2012 TRBAA	ER12-236
3	-$60,454,429	= HV Wholesale TRBAA		2012 TRBAA	ER12-236
4	-$199,612	= LV Wholesale TRBAA		2012 TRBAA	ER12-236
5	-$9,326,770	= Total Standby Transmission Revenues	Note 2	SCE Retail Standby Rate Revenue	
6	94.0422%	= HV Allocation Factor		HVLV WS, Line 36	
7	5.9578%	= LV Allocation Factor		HVLV WS, Line 36	

Calculation of Total High Voltage and Low Voltage components of Wholesale TRR

		Col 1 TOTAL	Col 2 High Voltage	Col 3 Low Voltage	Source
8	**Wholesale Base TRR:**	$888,014,501	$835,108,762	$52,905,739	See Note 3
9	**CWIP Component of Wholesale Base TRR:**	$212,174,556	$212,174,556	$0	See Note 4
10	**Non-CWIP Component of Wholesale Base TRR:**	$675,839,945	$622,934,206	$52,905,739	See Note 5
11	**Wholesale TRBAA:**	-$60,654,041	-$60,454,429	-$199,612	Lines 2 to 4
12	**Less Standby Transmission Revenues:**	-$9,326,770	-$8,771,104	-$555,666	See Note 6
13	**Components of Wholesale Transmission Revenue Requirement:**	$818,033,690	$765,883,229	$52,150,461	Sum of Lines 8, 11, and 12

Notes:

1) TRBAA is "Transmission Revenue Balancing Account Adjustment". The TRBAA is determined pursuant to SCE's Transmission Owner Tariff and may be revised each January 1, upon commission acceptance of a revised TRBAA amount, or upon the date the Commission orders.
2) From Retail Rates worksheet. See Line: 32o
3) Column 1 is from Line 1.
   Column 2 equals Column 1 * Line 6.
   Column 3 equals Column 1 * Line 7.
4) From CWIP TRR WS, Line 88. All High Voltage.
5) Line 8 - Line 9
6) Column 1 is from Line 5.
   Column 2 equals Column 1 * Line 6.
   Column 3 equals Column 1 * Line 7.

Calculation of SCE Wholesale Rates (See Note 1)

SCE's wholesale rates are as follows:

1) Low Voltage Access Charge
2) Low Voltage Wheeling Access Charge
3) High Voltage Utility-Specific Rate
4) HV Existing Contracts Access Charge
5) LV Existing Contracts Access Charge

Calculation of Low Voltage Access Charge:

Line				**Source**
1	LV TRR =	$52,150,461		WholesaleTRRs WS, Line 13, C3
2	Gross Load =	90,531,472	MWh	Gross Load WS
3	Low Voltage Access Charge =	$0.00058	per kWh	Line 1 / (Line 2 * 1000)

Calculation of Low Voltage Wheeling Access Charge:

				Source
4	LV TRR =	$52,150,461		WholesaleTRRs WS, Line 13, C3
5	Gross Load =	90,531,472	MWh	Gross Load WS
6	Low Voltage Wheeling Access Charge =	$0.00058	per kWh	Line 4 / (Line 5 * 1000)

Calculation of High Voltage Utility Specific Rate:
(used by ISO in billing of ISO TAC)

				Source
7	SCE HV TRR =	$765,883,229		WholesaleTRRs WS, Line 13, C2
8	Gross Load =	90,531,472	MWh	Gross Load WS
9	High Voltage Utility-Specific Rate =	$0.0084599	per kWh	Line 7 / (Line 8 * 1000)

Calculation of High Voltage Existing Contracts Access Charge:

				Source
10	HV Wholesale TRR =	$765,883,229		WholesaleTRRs WS, Line 13, C2
11	Sum of Monthly Peak Demands:	180,565	MW	Gross Load WS
12	HV Existing Contracts Access Charge:	$4.24	per kW	Line 10 / (Line 11 * 1000)

Calculation of Low Voltage Existing Contracts Access Charge:

				Source
13	LV Wholesale TRR =	$52,150,461		WholesaleTRRs WS, Line 13, C3
14	Sum of Monthly Peak Demands:	180,565	MW	Gross Load WS
15	LV Existing Contracts Access Charge:	$0.29	per kW	Line 13 / (Line 14 * 1000)

Notes:
1) SCE's wholesale rates are subject to revision upon acceptance by the Commission of a revised TRBAA amount. See Note 1 on WholesaleTRRs worksheet.

Derivation of High Voltage and Low Voltage Gross Plant Percentages

Determination of HV and LV Gross Plant Percentages for ISO Transmission Plant in accordance with ISO Tariff Appendix F, Schedule 3, Section 12.

A) Total ISO Plant from Prior Year

Input cells are shaded yellow

Line	Classification of Facility:	Total ISO Gross Plant	Land	Structures	HV Land	LV Land	HV Structures	LV Structures	HV/LV Transformers
1	**Lines:**								
2	HV Transmission Lines	$1,219,154,555	$114,287,921	$1,104,866,634	$114,287,921	$0	$1,104,866,634	$0	$0
3	LV Transmission Lines	$122,066,888	$8,129,145	$113,937,742	$0	$8,129,145	$0	$113,937,742	$0
4	**Total Transmission Lines:**	$1,341,221,443	$122,417,066	$1,218,804,376	$114,287,921	$8,129,145	$1,104,866,634	$113,937,742	$0
5									
6	**Substations:**								
7	HV Substations (>= 200 kV)	$1,651,895,519	$33,507,352	$1,618,388,167	$33,507,352	$0	$1,618,388,167	$0	$0
8	Straddle Substations (Cross 200 kV bounda	227,306,250	$192,635	$227,113,615	$143,033	$49,602	$143,971,633	$67,508,336	$15,633,646
9	LV Substations (Less Than 220kV)	89,174,098	$657,273	$88,516,826	$0	$657,273	$0	$88,516,826	$0
10	**Total all Substations**	$1,968,375,868	$34,357,260	$1,934,018,608	$33,650,386	$706,874	$1,762,359,799	$156,025,162	$15,633,646
11									
12	**Total Lines and Substations**	$3,309,597,310	$156,774,326	$3,152,822,984	$147,938,307	$8,836,020	$2,867,226,433	$269,962,904	$15,633,646
13									
14									

Line		High Voltage	Low Voltage	Total	Notes:
15	Gross Plant That can directly be determined to be HV or LV:				
16					
17					
18	Land	$147,938,307	$8,836,020	$156,774,326	From above Line 12
19	Structures	$2,867,226,433	$269,962,904	$3,137,189,338	From above Line 12
20	Total Determined HV/LV:	$3,015,164,740	$278,798,924	$3,293,963,664	Sum of lines 18 and 19
21	Gross Plant Percentages (Prior Year):	91.536%	8.464%		Percent of Total
22					
23	Straddling Transformers	$14,310,424	$1,323,222	$15,633,646	Straddling Transformers split by Gross Plant Percentages
24	Total HV and LV Gross Plant for Prior Year	$3,029,475,165	$280,122,146	$3,309,597,310	Sum of lines 20 and 23
25					
26					

B) Gross Plant Percentage for the Rate Effective Period:

Line		High Voltage	Low Voltage	Total	Notes:
27	**B) Gross Plant Percentage for the Rate Effective Period:**				
28					
29					
30					
31	Total HV and LV Gross Plant for Prior Year	$3,029,475,165	$280,122,146	$3,309,597,310	Line 24
32	In Service Additions in Rate Effective Period:	$1,118,958,020	$5,866,406	$1,124,824,426	13-Month Average: PlantAdditionsWS, Line 27, Cols 2 and 3.
33	CWIP in Rate Effective Period	$365,851,045	$0	$365,851,045	13 Month Average: CWIP WS, Line 91, Col. 1
34	Total HV and LV Gross Plant for REP	$4,514,284,230	$285,988,552	$4,800,272,781	Line 31 + Line 32 + Line 33
35					
36	HV and LV Gross Plant Percentages:	94.042%	5.958%		Percent of Total on Line 34
37	(HV Allocation Factor and				
38	LV Allocation Factor)				

Calculation of Forecast Gross Load

Line		MWh	Calculation	Source
1	SCE Retail Sales at ISO Grid level:	90,246,856		Note 1
2	Pump Load forecast:	284,616		Note 2
3	Forecast Gross Load:	90,531,472	Line 1 + Line 2	Sum of above
4	Forecast 12-CP Load:	180,565		Note 1

Notes:

1) Latest SCE approved sales forecast as of April 15 of each year.
2) SCE pump load forecast as of April 15 of each year.

Calculation of SCE Retail Transmission Rates

		Source
Retail Base TRR:	$894,092,973	BaseTRR WS, Line 86

Input cells are shaded yellow

1) Derivation of "Total Demand Rate" and "Total Energy Rate":

		Col 1	**Col 2**	**Col 3**	**Col 4**	**Col 5**	**Col 6**	**Col 7**	**Col 8**	**Col 9**	**Col 10**
		Note 1		Note 2	Note 3	Note 4	Note 5	Note 6	Note 18	Note 18	
			= Retail Base TRR * Line 1:Col 1	Applies to kWh charges	Applies to monthly maximum kW demand charges	Applies to monthly contracted standby kW demand charges			Applies to monthly maximum kW demand charges	Applies to monthly contracted standby kW demand charges	
				Forecast Billing Determinants:					Forecast Billing Determinants		
Line	**CPUC Rate Group**	**12-CP factors**	**Total Allocated costs**	**Sales (GWh)**	**Maximum demand (excess CRC) - MW**	**Standby demand (CRC) - MW**	**Total energy rates - $/kWh**	**Total demand rates - $/kW-month**	**220 kV Maximum demand (excess CRC) - MW**	**220 kV Standby demand (CRC) - MW**	**Notes**
1a	Domestic	39.37%	$351,983,066	29,173	0	0	$0.01207	---			
1b	GS-1	6.81%	$60,928,453	5,031	0	1	$0.01211	---			
1c	TC-1	0.05%	$474,637	66	0	0	$0.00722	---			
1d	GS-2	18.99%	$169,763,994	15,280	52,936	36	---	$3.20			
1e	TOU-GS-3	9.78%	$87,440,950	8,537	24,506	90	---	$3.56			
1f	TOU-8-SEC	9.69%	$86,608,793	9,209	23,005	464	---	$3.69			
1g	TOU-8-PRI	6.13%	$54,834,373	6,433	14,506	1,532	---	$3.42			
1h	TOU-8-SUB $^{\text{includes 220 kV}}$	6.43%	$57,468,046	8,175	14,228	8,739	---	$2.50	135	2,440	
1i	PA-1	0.29%	$2,559,968	277	4,158	0	---	$0.62			
1j	PA-2	0.24%	$2,175,455	242	1,091	1	---	$1.99			
1k	TOU-AG	1.69%	$15,103,368	2,250	9,211	5	---	$1.64			
1l	TOU-PA-5	0.14%	$1,259,232	176	417	4	---	$2.99			
1m	Street Lighting	0.39%	$3,492,638	728	0	0	$0.00479	---			
1n	TOU-8-SEC (Standby)	---	---	---	---	---	---	---			Note 7
1o	TOU-8-PRI (Standby)	---	---	---	---	---	---	---			Note 7
1p	TOU-8-SUB (Standby) $^{\text{includes 220 kV}}$	---	---	---	---	---	---	---	---	---	Note 7
1q	Ag TOU <= 200 kW	---	---	---	---	---	---	---			Note 7
1r	Ag TOU > 200 kW	---	---	---	---	---	---	---			Note 7
1s	…	---	---	---	---	---	---	---			
2	Totals:	100.00%	$894,092,973	85,577	144,060	10,872					
3											
4											

5 **2) Determination of Standby Demand Rates for Rate Groups with Directly-Allocated Costs**

		Col 1	**Col 2**	**Col 3**	**Col 4**	**Col 5**	**Col 6**	**Col 7**	**Col 8**
7		from Line1:Col 2	from Line 30:Col 4	from Line 30:Col 5	Note 9	Note 10	from Line 1:	Note 11	
8		Note 8					(Col 5, Col 9)		
9									
10 11 12	**CPUC Rate Group**	**Total Allocated Costs**	**Total 12-CP**	**Backup 12-CP**	**Allocation to Maximum kW demand (Excess**	**Allocation to contract Standby kW demand**	**Standby demand (CRC) - MW**	**Standby demand (CRC) rates - $/kW**	**Notes**
13a	TOU-8-SEC	$86,608,793	18,203	199	$85,660,179	$948,613	464	$2.05	
13b	TOU-8-PRI	$54,834,373	11,603	501	$52,466,073	$2,368,300	1,532	$1.55	
13c	TOU-8-SUB $^{\text{includes 220 kV}}$	$57,468,046	11,720	1,169	$51,735,290	$5,732,757	8,739	---	
13c$_1$	TOU-8-SUB $^{\text{below 220 kV}}$	$55,518,122	11,322	803	$51,580,332	$3,937,790	6,299	$0.63	
13c$_2$	TOU-8-SUB $^{\text{220 kV}}$	$1,949,924	398	366	$154,958	$1,794,966	2,440	$0.74	Note 18
13d	TOU-8-SUB (Standby) $^{\text{includes 220 kV}}$	---	---	---	---	---	---	---	Note 7
13d$_1$	TOU-8-SUB (Standby) $^{\text{below 220 kV}}$	---	---	---	---	---	---	---	Note 7
13d$_2$	TOU-8-SUB $^{\text{(Standby) 220 kV}}$	---	---	---	---	---	---	---	Note 7
14									

15 **3) End-User Transmission Rates**

16

17		**Col 1**	**Col 2**	**Col 3**	**Col 4**	**Col 5**	**Col 6**	**Col 7**	**Col 8**	**Col 9**	**Col 10**
18		from Line 1:Col 2	Note 12	Note 13		Note 14	Note 15	Note 16	Note 17	Note 17	
19						**Retail Transmission Rates**					
20 21 22 23	**CPUC Rate Group**	**Total Allocated Costs**	**Maximum demand revenue (excess CRC)**	**Standby demand (CRC)**		**Energy Charge - $/kWh**	**Maximum demand Charge - $/kW-month (excess Standby)**	**Standby demand Charge - $/kW-month**	**Maximum demand Charge - $/HP-month (excess Standby)**	**Standby demand Charge - $/HP-month**	**Notes**
24a	Domestic	$351,983,066	$351,983,066	$0		$0.01207	---	---	---	---	
24b	GS-1	$60,928,453	$60,928,453	$0		$0.01211	---	---	---	---	
24c	TC-1	$474,637	$474,637	$0		$0.00722	---	---	---	---	
24d	GS-2	$169,763,994	$169,689,692	$74,302		---	$3.21	$2.05	---	---	
24e	TOU-GS-3	$87,440,950	$87,257,479	$183,471		---	$3.56	$2.05	---	---	
24f	TOU-8-SEC	$86,608,793	$85,660,179	$948,613		---	$3.72	$2.05	---	---	
24g	TOU-8-PRI	$54,834,373	$52,466,073	$2,368,300		---	$3.62	$1.55	---	---	
24h	TOU-8-SUB	$57,468,046	$51,735,290	$5,732,757		---	---	---	---	---	
$24h_1$	TOU-8-SUB $^{\text{below 220 kV}}$	---	$51,580,332	$3,937,790		---	$3.66	$0.63	---	---	
$24h_2$	TOU-8-SUB $^{\text{220 kV}}$	---	$154,958	$1,794,966		---	$1.15	$0.74	---	---	Note 18
24i	PA-1	$2,559,968	$2,559,894	$74		---	$0.62	$0.62	$0.46	$0.46	
24j	PA-2	$2,175,455	$2,173,591	$1,865		---	$1.99	$1.99	---	---	
24k	TOU-AG	$15,103,368	$15,094,696	$8,672		---	$1.64	$1.64	$1.23	$1.23	
24l	TOU-PA-5	$1,259,232	$1,250,515	$8,717		---	$3.00	$2.05	---	---	
24m	Street Lighting	$3,492,638	$3,492,638	$0		$0.00479	---	---	---	---	
24n	TOU-8-SEC (Standby)	---	---	---		---	---	---	---	---	Note 7
24o	TOU-8-PRI (Standby)	---	---	---		---	---	---	---	---	Note 7
24p	TOU-8-SUB (Standby)	---	---	---		---	---	---	---	---	Note 7
$24p_1$	TOU-8-SUB (Standby) $^{\text{below 220 kV}}$	---	---	---		---	---	---	---	---	Note 7
$24p_2$	TOU-8-SUB (Standby) $^{\text{220 kV}}$	---	---	---		---	---	---	---	---	Note 7
24q	Ag TOU <= 200 kW	---	---	---		---	---	---	---	---	Note 7
24r	Ag TOU > 200 kW	---	---	---		---	---	---	---	---	Note 7
24s	…	---	---	---		---	---	---	---	---	
25	Totals:	$894,092,973	$884,766,203	$9,326,770							

26 **Notes:**

1) See Lines 28a, 28b, etc.
2) Sales Forecast in total Giga-watt hours usage - applies to non-demand schedules, and it's the customers' total annual kWh consumption.
3) Sales Forecast pertaining to the sum of monthly maximum Mega-watt demand - applies to demand schedules (the customer's monthly metered maximum kW demand).
4) Sales Forecast pertaining to the sum of monthly contracted standby Mega-watt demand - - applies to standby schedules (the customer's monthly contracted standby kW demand).
5) For non-demand Schedules, "Total Energy Rate - $/kWh" = Line 1:Col 2 / (Line 1:Col 3) * 1,000,000.
6) For demand Schedules, "Total Demand Rate - $/kW" = Line 1:Col 2 / (Line 1:(Col 4 + Col 5)) * 1,000.
However, the demand Rate for "TOU-8-Sub" which includes "220 kV" are calculated together
(i.e., using sum of "Maximum Demand" and "Standby Demand" of each).
7) These Rate Groups are being proposed in SCE's 2012 General Rate Case at the California Public Utilities
Commission, but may not be in effect until 2013.
8) TOU-8-SUB (below 220 kV) is derived by multiplying the total allocated costs of TOU-8-Sub (includes 220 kV) of Col 1, by the ratio of the Total 12-CP (Line 13:Col 2) pertains to
TOU-8-SUB (below 220 kV) to TOU-8-SUB (includes 220 kV). TOU-8-SUB (220 kV) is derived by subtracting the TOU-8-SUB (below 220 kV) from The total allocated costs TOU-8-SUB (includes 220 kV).
9)Line 13:(Col 1 - Col 5).
10) Line 13:Col 1 * Line 13:(Col 3 / Col 2).
11) Line 13:(Col 5 / Col 6) * 1,000.
12) Line 24:(Col 1 - Col 3). However, for TOU-8-SEC, TOU-8-Pri, TOU-8-SUB (includes 220 kV), TOU-8-SUB (below 220 kV), TOU-8-SUB (220 kV)
See corresponding Line 13:Col 4.
13) Line 1:Col 5 * Line 24:Col 7 * 1,000. However, for TOU-8-SEC, TOU-8-Pri, TOU-8-SUB (includes 220 kV), TOU-8-SUB (below 220 kV), TOU-8-SUB (220 kV)
See corresponding Line 13:Col 5.
14) From Line 1:Col 6 (applicable to all kWh usage).
15) Line 24:Col 2 / Line 1:Col 4 * 1,000 (applicable to monthly maximum kW demand). However, for TOU-8-SUB (below 220 kV), it is derived by the corresponding Line 24:Col 2 / Line 1:(Col 4 - Col 8) * 1,000.
And TOU-8-SUB (220 kV) is equal to the corresponding Line 24:Col 2 / Line 1:Col 8 * 1,000.
16) Minimum of (TOU-8-SEC from Line 13:Col 7, or corresponding Line 1:Col 7). However, for TOU-8-SEC, TOU-8-Pri, TOU-8-SUB (below 220 kV), TOU-8-SUB (220 kV)
equals to the Standby Demand Rate from corresponding Line 13:Col 7.
17) Applicable to Connected Load options in $/HP (Horsepower). Connected load rate is equal to the $/kW in corresponding Line 24:(Col 6,Col 7) time 75%.
18) 220 kV service is part of the TOU-8-SUB rate group, however, intervening parties in the CPUC proceedings agreed to identify these customers for rate design treatment purposes

Rate Schedules in each CPUC Rate Group:

	CPUC Rate Group	Rate Schedules included in Each Rate Group in the Rate Effective Period
27a	Domestic	All rate options, including D, D-APS, D-APS-E, D-CARE, DE, DM, DMS-1, DMS-2, DMS-3, DS,
27b	Domestic Con't.	TOU-D-1, TOU-D-2, and TOU-EV1, TOU-D-T and TOU-D-TEV
27c	GS-1	All rate options, including GS-1, GS-APS, GS-APS-E, TOU-EV-3, and TOU-GS-1.
27d	TC-1	All rate options, including TC-1, WTR, and Wi-Fi-1.
27e	GS-2	All rate options, including GS-2, GS-APS, GS-APS-E, and TOU-EV-4.
27f	TOU-GS-3	All rate options, including TOU-GS-3 and TOU-GS-3-SOP
27g	TOU-8-SEC	All rate options, including TOU-8, TOU-8-BU and RTP-2 based on voltage of service
27h	TOU-8-PRI	All rate options, including TOU-8, TOU-8-BU and RTP-2 based on voltage of service
27i	TOU-8-SUB	All rate options, including TOU-8, TOU-8-BU and RTP-2 based on voltage of service
$27i_1$	TOU-8-SUB $^{\text{below 220 kV}}$	All rate options, including TOU-8, TOU-8-BU and RTP-2 based on voltage of service
$27i_2$	TOU-8-SUB $^{\text{220 kV}}$	All rate options, including TOU-8, TOU-8-BU and RTP-2 based on voltage of service
27j	PA-1	All rate options, including PA-1.
27k	PA-2	All rate options, including PA-2.
27l	TOU-AG	All rate options, including TOU-PA, PA-RTP, and TOU-PA-SOP
27m	TOU-PA-5	All rate options, including TOU-PA-5.
27n	Street Lighting	All rate options, including AL-2, DWL, LS-1, LS-2, LS-3, and OL-1.
27o	TOU-8-SEC (Standby)	
27p	TOU-8-PRI (Standby)	
27q	TOU-8-SUB (Standby)	
$27q_1$	TOU-8-SUB (Standby) $^{\text{below 220 kV}}$	
$27q_2$	TOU-8-SUB (Standby) $^{\text{220 kV}}$	
27r	Ag TOU <= 200 kW	
27s	Ag TOU > 200 kW	
27t	…	
27u	…	
27v	…	

Recorded 12-CP Load Data by Rate Group (MW)

		Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10
					=(Col 1 + Col 2 + Col 3) / 3		=(Col 4 * Col 5)	from Line 1: Col 3	= Col 4*Col 5/Col 6 * Col 7	= Col 8 / Sum of Col 8	
		12-CP MW									
Line	**CPUC Rate Group**	**2008**	**2009**	**2010**	**Three-Year Average**	**Line losses**	**Recorded Average Sales (2008 - 2010) - GWh**	**Sales Forecast - GWh**	**Loss Adjusted Average 12-CP**	**12-CP factors**	**Notes**
28a	Domestic	70,407	68,373	63,488	67,423	1.0975	29,449	29,173	73,303	39.37%	
28b	GS-1	11,486	10,675	10,675	10,946	1.0977	4,763	5,031	12,689	6.81%	
28c	TC-1	94	93	91	93	1.0987	68	66	99	0.05%	
28d	GS-2	34,335	32,332	33,001	33,223	1.0974	15,757	15,280	35,355	18.99%	
28e	TOU-GS-3	17,095	15,964	16,556	16,538	1.0969	8,505	8,537	18,210	9.78%	
28f	TOU-8-SEC	17,453	16,217	16,070	16,580	1.0979	9,294	9,209	18,037	9.69%	
28g	TOU-8-PRI	11,198	10,769	10,602	10,856	1.0688	6,537	6,433	11,420	6.13%	
28h	TOU-8-SUB $^{\text{includes 220 kV}}$	11,710	11,051	11,258	11,340	1.0335	8,005	8,175	11,968	6.43%	
28i	PA-1	779	663	536	659	1.0980	376	277	533	0.29%	
28j	PA-2	569	534	412	505	1.0980	296	242	453	0.24%	
28k	TOU-AG	2,035	2,173	2,670	2,293	1.0967	1,799	2,250	3,145	1.69%	
28l	TOU-PA-5	1,231	1,080	490	934	1.0975	687	176	262	0.14%	
28m	Street Lighting	682	790	472	648	1.1014	715	728	727	0.39%	
28n	TOU-8-SEC (Standby)	---	---	---	---	---	---	---	---	---	Note 7
28o	TOU-8-PRI (Standby)	---	---	---	---	---	---	---	---	---	Note 7
28p	TOU-8-SUB (Standby) $^{\text{includes 220 kV}}$	---	---	---	---	---	---	---	---	---	Note 7
28q	Ag TOU <= 200 kW	---	---	---	---	---	---	---	---	---	Note 7
28r	Ag TOU > 200 kW	---	---	---	---	---	---	---	---	---	Note 7
28s	…	---	---	---	---	---	---	---	---	---	
28t	…	---	---	---	---	---	---	---	---	---	
28u	…	---	---	---	---	---	---	---	---	---	
29	Totals:	179,075	170,714	166,321	172,037		86,250	85,577	186,201	100.00%	

Allocation Factors for Backup Rates:

		Col 1	Col 2	Col 3	Col 4	Col 5	Col 6
		12-CP MW			= (Col 1 * Col 3)	= (Col 2 * Col 3)	
					Loss Adjusted		
Line	**CPUC Rate Group**	Total 12-CP (08-10 average)	Backup demand (08-10 average)	Line losses	Total 12-CP	Backup 12-CP	**Notes**
30a	TOU-8-SEC	16,580	182	1.0979	18,203	199	
30b	TOU-8-PRI	10,856	469	1.0688	11,603	501	
30c	TOU-8-SUB $^{\text{includes 220 kV}}$	11,340	1,131	1.0335	11,720	1,169	
$30c_1$	TOU-8-SUB $^{\text{below 220 kV}}$	10,955	777	1.0335	11,322	803	
$30c_2$	TOU-8-SUB $^{\text{220 kV}}$	385	354	1.0335	398	366	Note 18
30d	TOU-8-SEC (Standby)	---	---	---	---	---	Note 7
30e	TOU-8-PRI (Standby)	---	---	---	---	---	Note 7
30f	TOU-8-SUB (Standby) $^{\text{includes 220 kV}}$	---	---	---	---	---	Note 7
$30f_1$	TOU-8-SUB (Standby) $^{\text{below 220 kV}}$	---	---	---	---	---	Note 7
$30f_2$	TOU-8-SUB (Standby) $^{\text{220 kV}}$	---	---	---	---	---	Note 7

End-User Transmission Rates

Line	Retail Rate Group	12-CP Allocation Percentage	Allocated Retail Base TRR ($)	Forecast Sales (GWh)	Forecast Maximum Demand (MW)	Forecast Standby Demand (MW)	Base TRR Energy Charge ($/kWh)	Base TRR Demand Charge ($/kW)	Standby Demand Charge ($/kW)
		Col 1	**Col 2**	**Col 3**	**Col 4**	**Col 5**	**Col 6**	**Col 7**	**Col 8**
		from Line 1:Col 1	from Line 1:Col 2	from Line 1:Col 3	from Line 1:(Col 4,Col 8)	from Line 1:(Col 5,Col 9)	from Line 24:Col 5	from Line 24:Col 6	from Line 24:Col 7
31a	Domestic	39.37%	$351,983,066	29,173	0	0	**$0.01207**		
31b	GS-1	6.81%	$60,928,453	5,031	0	1	**$0.01211**		
31c	TC-1	0.05%	$474,637	66	0	0	**$0.00722**		
31d	GS-2	18.99%	$169,763,994	15,280	52,936	36		**$3.21**	**$2.05**
31e	TOU-GS-3	9.78%	$87,440,950	8,537	24,506	90		**$3.56**	**$2.05**
31f	TOU-8-SEC	9.69%	$86,608,793	9,209	23,005	464		**$3.72**	**$2.05**
31g	TOU-8-PRI	6.13%	$54,834,373	6,433	14,506	1,532		**$3.62**	**$1.55**
31h	TOU-8-SUB $^{\text{below 220 kV}}$	6.43%	$57,468,046	8,175	14,093	6,299		**$3.66**	**$0.63**
31i	TOU-8-SUB $^{\text{220 kV}}$				135	2,440		**$1.15**	**$0.74**
31j	PA-1	0.29%	$2,559,968	277	4,158	0		**$0.62**	**$0.62**
31k	PA-2	0.24%	$2,175,455	242	1,091	1		**$1.99**	**$1.99**
31l	TOU-AG	1.69%	$15,103,368	2,250	9,211	5		**$1.64**	**$1.64**
31m	TOU-PA-5	0.14%	$1,259,232	176	417	4		**$3.00**	**$2.05**
31n	Street Lighting	0.39%	$3,492,638	728	0	0	**$0.00479**		
31o	System Total	100.00%	$894,092,973	85,577	144,060	10,872			

End-User Transmission Rates Revenues

Line	Retail Rate Group	Forecasted kWh Charge Revenue ($)	Forecasted Monthly Maximum Demand Revenue ($)	Forecasted Monthly Standby demand Revenue ($M)	Forecasted Total Retail Base Transmission Revenue ($)
		Col 1	**Col 2**	**Col 3**	**Col 4**
		Line 31:(Col 3 * Col 6) * 10^6	Line 31:(Col 4 * Col 7) * 1,000	Line 31:(Col 5 * Col 8) * 1,000	Line 32:(Col 1 + Col 2 + Col 3)
32a	Domestic	351,983,066			351,983,066
32b	GS-1	60,928,453			60,928,453
32c	TC-1	474,637			474,637
32d	GS-2		169,689,692	74,302	169,763,994
32e	TOU-GS-3		87,257,479	183,471	87,440,950
32f	TOU-8-SEC		85,660,179	948,613	86,608,793
32g	TOU-8-PRI		52,466,073	2,368,300	54,834,373
32h	TOU-8-SUB below 220 kV		51,580,332	3,937,790	55,518,122
32i	TOU-8-SUB 220 kV		154,958	1,794,966	1,949,924
32j	PA-1		2,559,894	74	2,559,968
32k	PA-2		2,173,591	1,865	2,175,455
32l	TOU-AG		15,094,696	8,672	15,103,368
32m	TOU-PA-5		1,250,515	8,717	1,259,232
32n	Street Lighting	3,492,638			3,492,638
32o	System Total	$416,878,795	$467,887,409	$9,326,770	$894,092,973